2015

Electric Integrated Resource Plan Appendices

August 31, 2015

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2015 Electric Integrated Resource Plan

Appendix A – 2015 Technical Advisory Committee Presentations

2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 1 Agenda

Thursday, May 29, 2014
Conference Room 428

Topic	Time	Staff
Introductions	8:30	Kalich
TAC Meeting Expectations	8:35	Lyons
2013 IRP Commission Acknowledgements	9:00	Kalich
Break	10:00	
2013 Action Plan Update	10:15	Gall
Energy Independence Act Compliance	11:30	Gall/Lyons
Lunch	12:00	
Pullman Energy Storage Project	1:00	Gibson
Demand Response Study Discussion	1:30	Kalich
Break	2:00	
Draft 2015 Electric IRP Work Plan	2:15	Lyons
Adjourn	3:00	

2015 Electric IRP
TAC Meeting Expectations

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
May 29, 2014

Integrated Resource Planning

- The Integrated Resource Plan (IRP):
- Required by Idaho and Washington every other year
- Guides resource strategy over the next two years
- Resource procurements over the next 20 years – Preferred Resource Strategy (PRS)
- Snapshot of the current and projected load & resource position

Integrated Resource Planning (Cont)

- Based on significant modeling and many assumptions
  - Fuel prices
  - Economic activity
  - Policy considerations
  - Resource costs
  - Energy efficiency
- Action Items – areas for more research in the next IRP
- This is not an advocacy forum
- Not a forum on a particular resource or resource type
- Supports rate recovery, but not a preapproval process

Technical Advisory Committee

- The public process piece of the IRP – input on what to study, how to study, and review of assumptions and results
- Wide range of participants in all or some of the process
- Open forum, but we need to stay on topic to get through the agenda
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies we can do
  - The earlier study requests are made, the more accommodating we can be
- Planning team is also available by email or phone for questions or comments between the TAC meetings

Expectations

- Avista:
  - Input about assumptions and areas to study
  - Six TAC meetings with set agendas that can change based on input. Topics will be covered later today in the Draft Work Plan.

- TAC Members: What are your expectations?

2013 IRP Commission Acknowledgements

Clint Kalich
First Technical Advisory Committee Meeting
May 29, 2014

Idaho Acceptance Order (32980)

- No Public Comments
- Comments by ICL, SRA, and SC/MEIC
  - Concerns with Colstrip costs and risk analysis
    - Regional haze, GHG regulation, prevention of significant deterioration, ambient air quality standards, mercury and air toxics, coal combustion waste, coal costs
  - Request more analysis of Colstrip replacement options
  - Too much natural gas in the plan
  - Changes to net metering rules are not necessary

Idaho Acceptance Order (32980)

- Comments by IPUC Staff
  - Accept IRP as filed
  - Additional analysis of net metering and impacts on system
  - Closely monitor load growth for 2015 IRP given significant decrease between 2011 and 2013 IRPs
  - More detailed analysis around selected planning margin
  - More description of rationale for arriving at Conservation Achievable Potential Savings

Idaho Acceptance Order (32980)

- Idaho Commission Order
  - Accept 2013 IRP as filed
  - Encourage commenters to actively participate in 2015 IRP
  - Consider and discuss concerns and suggestions offered by commenters
  - Continue exploring demand response
  - Continue to monitor federal environmental regulations, and their impacts on planning
  - Monitor actual load growth for 2015 IRP

Washington Acceptance Letter

- No Public Comments
- Commission
  - Evaluate value of risk mitigation when choosing among competing resource strategies. Provide justification of the choice of the PRS, including desired level of portfolio risk
  - Re-evaluate planning margin
  - Investigate modeling energy efficiency as a selectable and scalable resource within the IRP (PRiSM)
  - Incorporate a non-zero carbon value in the Expected Case
  - Continue evaluating Colstrip, including rate impacts of a hypothetical portfolio absent them
  - Evaluate the benefits of storage to Avista's generation portfolio

Idaho Acknowledgement Order Specifics

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over Avista, an electric utility, and the issues in this case under Title 61 of the Idaho Code and the Commission Rules of Procedure, IDAPA 31.01.01.000 *et seq*. The Commission has reviewed the filings in this case, including the 2013 Electric IRP, the comments, and the Company's reply. Based on that review, the Commission finds that the Company's 2013 Electric IRP contains the required information and is in the appropriate format as established in Commission Order Nos. 22299 and 25260. Accordingly, we find it reasonable to accept the Company's 2013 Electric IRP.

We appreciate the written comments submitted in this case. We encourage the commenters and other interested persons to participate in the IRP process and to provide further input to the Company as it develops its 2015 IRP. We expect the Company to consider and discuss at the TAC meetings the various concerns and suggestions that are and have been offered. In particular, we expect the Company to monitor federal developments, such as the promulgation of federal environmental regulations, and to account for their impact in its resource planning. We also encourage the Company to continue exploring the use of DR as a resource, and to be actively involved in and apprise us of matters relating to Colstrip. Lastly, given the decrease in load growth forecasts—a phenomenon that other utilities have reported—we encourage the Company to closely monitor actual load growth as it prepares its 2015 IRP.

As always, our acceptance of the Company's IRP should not be interpreted as an endorsement of any particular element of the plan or of any proposed resource acquisition contained in the plan. An IRP is a utility planning document that incorporates many assumptions and projections at a specific point in time. By accepting the Company's filing, we acknowledge only the Company's ongoing planning process, not the conclusions or results reached through that process.

Washington Acceptance Letter Specifics

While specific comments regarding its filed IRP are attached, the Commission provides Avista with the following guidance for its next IRP filing:

- With input from the Technical Advisory Committee, evaluate the value of risk mitigation when choosing among competing resource strategies. Avista should provide justification of its choice of a preferred resource strategy, including justification of its desired level of portfolio risk.
- With input from the Technical Advisory Committee, re-evaluate Avista's choice of basic planning margin.
- With input from the Technical Advisory Committee, investigate modeling energy efficiency as a selectable and scalable resource within the IRP.
- Incorporate a non-zero expected value cost of carbon into the Expected Case. Avista should also work with the Technical Advisory Committee to investigate incorporating a range of prospective carbon policies into the Expected Case stochastic analysis.
- Continue to evaluate scenarios related to the continued operation of units 3 and 4 of the coal-fired generating facility in Colstrip, Montana. As a component of this evaluation, Avista should provide an assessment of the impact on rates of a hypothetical portfolio that does not include these units.
- Use the Company's new modeling capabilities to evaluate the benefits of storage resources to Avista's generation portfolio.

2013 IRP Action Plan Update

James Gall
First Technical Advisory Committee Meeting
May 29, 2014

Action Items- A Progress Report

Demand Forecasting

- Review and update the energy forecast methodology to better integrate economic, regional, and weather drivers of energy use.
  - Move from 30-year average temperatures to 20-year moving average
  - Integration of U.S. industrial production as an economic driver
  - Discuss the relationship between energy demand and population, energy pricing, income, and family size

Existing Resources

- Continue to evaluate scenarios related to Colstrip and how each scenario may impact power supply costs.
  - Avista will update its 2013 IRP scenarios and consider other scenarios later in the process
- Evaluate options to integrate intermittent resources.
  - As part of the storage RFP, we will get information regarding demand side options (to be discussed later)
  - Avista is part of the Energy Imbalance Market (EIM) process
  - Avista is developing a 1 MW storage project to test this benefit (to be discussed later)

Identifying Need

- Evaluate the benefits of a short-term (up to 24-months) capacity position report.
  - Avista will implement this report this summer for single hour and sustained peak events
  - Report will integrate short-term planning and long-term capacity planning
- Revisit with the TAC the benefits and costs of the Company's 2013 IRP planning margin target to determine if a different level is warranted in the 2015 IRP.
  - Current method is 14% of peak load plus operating reserves & regulation
  - To be discussed at future TAC meeting

Policy Implications

- Continue monitoring state and federal climate change policies and report work from Avista's Climate Change Council.
  - Gov. Inslee's executive order and the EPA's Emission Performance Standards are current climate change initiatives
- Evaluate and explicitly document various options for quantifying carbon costs in the IRP
  - For discussion at future TAC meeting
- Work with TAC to determine which carbon quantification method should be employed in the Expected Case of the 2015 IRP
  - Washington Order requires a non-zero carbon cost
  - For discussion at future TAC meeting

Supply Side Options

- Consider Spokane and Clark Fork River hydro upgrade options in the next IRP as potential resource options to meet energy, capacity and environmental requirements.
  - To be included as resource options in 2015 plan
- Continue to evaluate potential locations for the natural gas-fired resource identified to be online by the end of 2019, including environmental reviews, transmission studies, and potential land acquisition.
  - Avista is working to identify potential locations
- Use Avista's new modeling capabilities to further evaluate the benefits of storage resources to its generation portfolio, including the impacts on ancillary services needs.
  - Avista is in process of modeling storage in its new portfolio optimization tool

Demand Side

- Work with NPCC, commissions, and others to resolve adjusted market baseline issues for setting energy efficiency target setting and acquisition claims in Washington
  - Completed in December 2013 and is discussed in the 2014-15 WA Biennial Conservation Plan
- Update processes and protocols for conservation measurement, evaluation and verification
  - The third party evaluator "Cadmus" completed the study and will be filed May 30th as part of the 2012-13 compliance/ cost recovery/ prudence case in Washington

Demand Side (Continued)

- Commission a demand response potential and cost assessment of commercial and industrial customers per its inclusion in the middle of the PRS action plan
  - RFP to be released in June, to be discussed this afternoon
- Assess energy efficiency potential on Avista's generation facilities
  - This study is in process of this study and will be a presentation on the findings at a future TAC meeting

Transmission

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load
- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area
- Continue to participate in regional and sub-regional efforts to establish new regional transmission structures to facilitate long-term expansion of the regional transmission system
- Study and quantify transmission and distribution efficiency projects as they apply to EIA goals
  - Navigant completed the study and will be filed May 30th as part of the 2012-13 compliance/ cost recovery/ prudence case in Washington

Evaluation

- Continue participation in regional IRP and regional planning processes and monitor regional surplus capacity and continue to participate in regional capacity planning processes.
  - We participate in the NPCC's 7th Plan, PNUCC, Regional IRPs
- Evaluate the impacts of targeting individual or groups of energy efficiency options within PRiSM instead of targeting quantities using avoided cost
  - A test will be completed this summer using the 2013 IRP data to compare the methodologies.
  - The results will be discussed at a future TAC meeting along with a decision whether or not to use PRiSM or the current avoided cost methodology for the 2015 plan

Evaluation (Continued)

- Evaluate with the TAC the impacts of different points along the efficient frontier.
  - For discussion at future TAC meeting

Energy Independence Act Compliance (Renewable Energy)

James Gall and John Lyons, Ph.D.
First Technical Advisory Committee Meeting
May 29, 2014

The Energy Independence Act

- RCW 19.285 or Initiative Measure No. 937
  - Voted into Washington law November 2006
  - Utilities with more than 25,000 customers qualify
  - Requires acquisition of all cost-effective conservation
- Renewable energy goals
  - Based on a percentage of the two year average of Washington state retail sales
  - 3% by January 1, 2012 (166,047 MWh or 19 aMW)
  - 9% by January 1, 2016 (506,000 MWh or 57.8 aMW)
  - 15% by January 1, 2020 (867,000 MWh or 99 aMW)

Energy Independence Act

- RCW 19.285 – The Energy Independence Act (EIA) or Initiative Measure No. 937 (I-937)
  - Requires utilities with over 25,000 customers to obtain 15% of their electricity from qualified renewable resources by 2020.
  - Qualified resources include solar, wind, hydro upgrades, biomass, and wave/ocean/tidal power.
  - Requires the acquisition of all cost-effective energy conservation.
- I-937 approved by Washington voters on November 6, 2006.

Reporting Requirements

Annual compliance report (WAC 480-109-040) is due annually by June 1st:

- Report includes: background, alternative compliance (cost or low load growth), annual loads, renewable energy target for last year, current year progress, WREGIS certificates, incremental cost, and appendices
- Appendix A – UTC Compliance Report Spreadsheet: details about eligible resources and renewable resource credits (RECs)
- Appendix B – Incremental Cost Calculations
- Appendices C, D and E – Clark Fork River, Spokane River and Wanapum Hydro Upgrade Calculations
- Appendix F – Department of Commerce EIA Renewables Report

Ongoing Issues

Active rulemaking by the Washington Commission and the Department of Commerce

- Reporting issues – WREGIS and attestations
- Incremental hydro quantities
- Incremental cost calculation

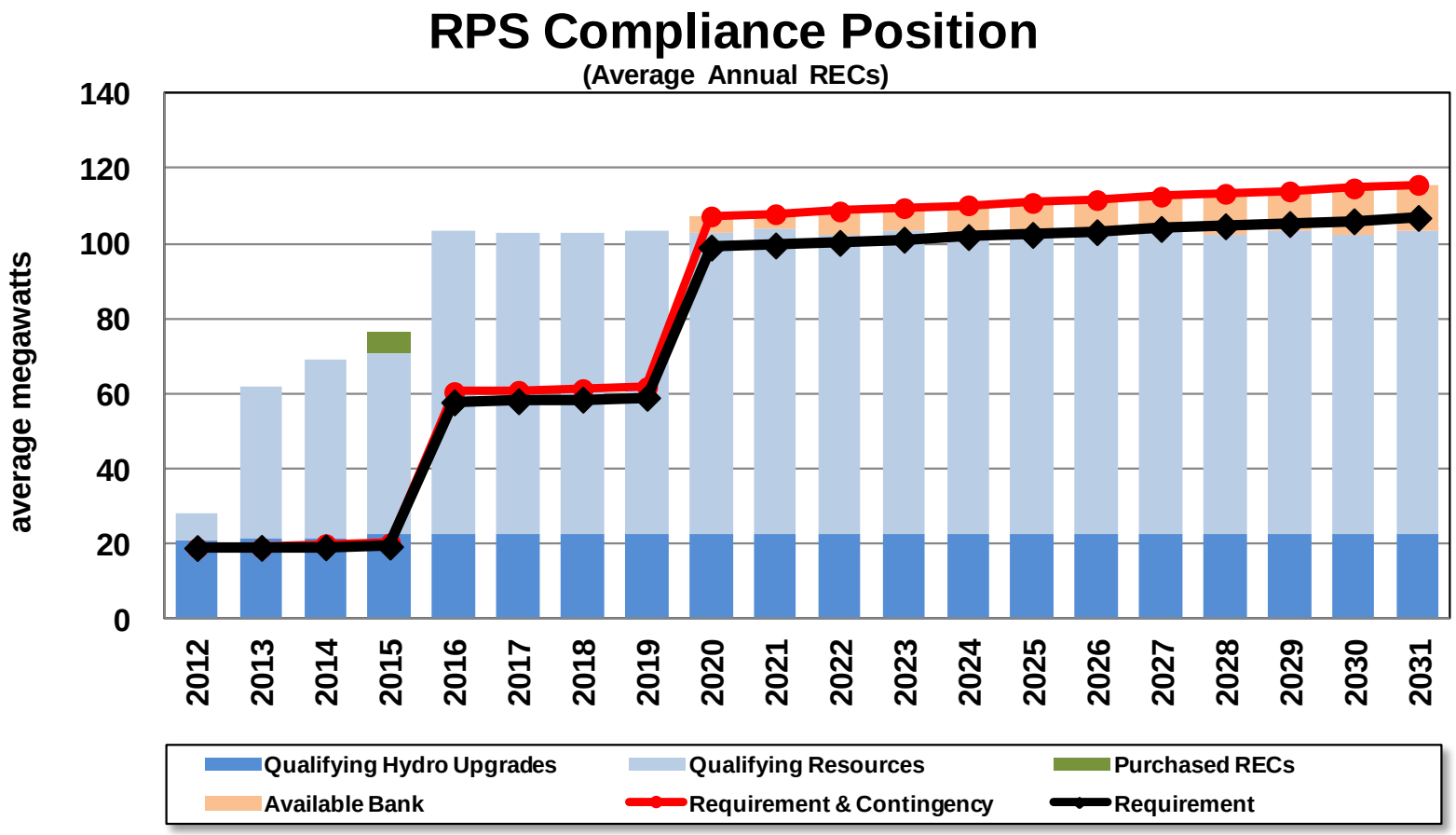
Incremental Cost Calculation

- Incremental hydro filed as a zero incremental cost
- Palouse wind: Incremental system cost- $8.2m
  - Washington Share: $5.4m
- Idaho REC transfer: $350k
- Total Washington Incremental Cost: $5.7m
- 1.22% of Washington Revenue Requirement

2013 EIA Compliance

	MWh	aMW
Required Renewable Energy	**166,740**	**19.0**
Spokane River		
Long Lake #3	14,197	1.6
Little Falls #4	4,862	0.6
Clark Fork River		
Cabinet Gorge 2-4	95,333	10.8
Noxon Rapids 1-4	55,697	6.4
Wanapum Fish Bypass	21,927	2.5
Total Hydro Upgrades	**192,016**	**21.9**
Palouse Wind (Includes apprentice credit)	356,432	40.7

Avista's Projected EIA Compliance



Energy Storage Proposal for Washington State Clean Energy Fund

John Gibson
First Technical Advisory Committee Meeting
May 29, 2014

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Agenda

Washington Clean Energy Fund

- Target Categories
- Schedule
- Avista Consortium

Vanadium Flow Battery

Energy Storage System Architecture

Use Case Value Streams

Washington Clean Energy Fund

Target Categories

$15 Million in Total Funding:

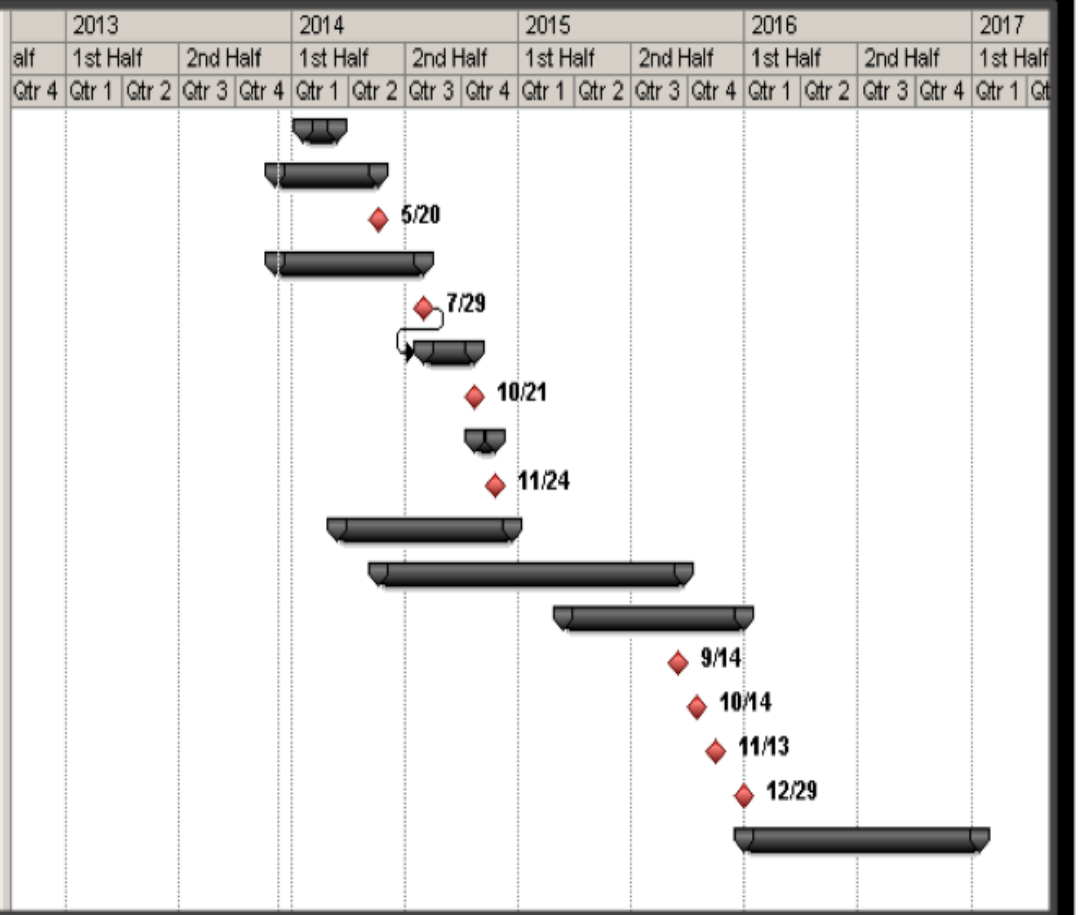
Preliminary discussions on funding: Avista; PSE; Snohomish PUD

- ✓ Integrate intermittent renewable energy projects through energy storage and information technology (IT)
- ✓ Demonstrate dispatch of energy storage resources from utility energy control centers
- \- Use thermal properties and electric load of buildings or district energy systems to store energy
- ✓ Improve reliability and reduce cost of intermittent or distributed energy resources

Washington Clean Energy Fund

Schedule

	Task Name
1	**Contracts**
5	**Permitting**
8	Permits Received
9	**Design**
39	Design Complete
40	**Construction**
47	Construction Complete
48	**Initial Systems Integration Testing**
52	Battery On-line for Manual Remote Operation
53	**Refinement of Value and Business Case**
56	**Development of Control System**
65	**Integration of Control System**
74	Use Case Group 1 On-Line for Manual Remote Operation
75	Use Case Group 2 On-Line for Manual Remote Operation
76	Use Case Group 3 On-Line for Manual Remote Operation
77	Use Case Group 4 On-Line for Manual Remote Operation
78	**Monitoring and Validation of Storage Performance**



Washington State Clean Energy Fund

Avista Team

Avista Consortium

- UniEnergy Technologies – Vanadium Flow Battery
- Pacific Northwest National Laboratory – Value Stream Methodology
- Washington State University – Optimization Value Stream Algorithm

UniEnergy Technologies

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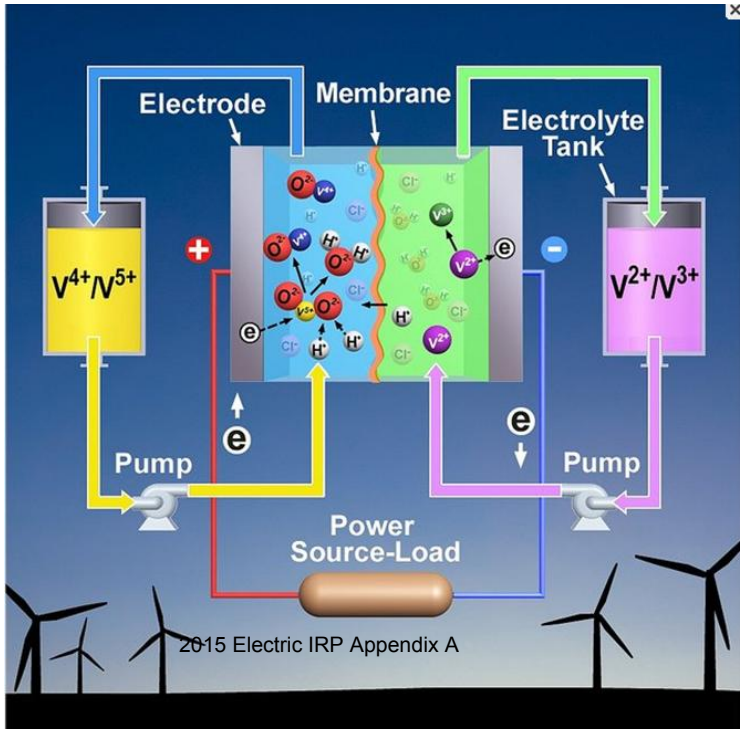
Vanadium Flow Battery

Chemistry

- **Charging the Battery:**
  - The electrical energy is converted into chemical energy stored in the vanadium ion tanks
- **Discharging the Battery:**
  - The vanadium electrolytes are pumped into battery central stack
  - The chemical energy is converted into electrical energy by transferring electrons



Vanadium Flow Battery [41]

Performance

- Can be quickly brought up to full power when needed
  - response time charge to discharge (50ms)
- Offers a long cycle life > (UET: 10,000 cycles)
- Energy efficiencies charge to discharge AC to AC 70%
- Does not present a fire hazard and uses no highly reactive or toxic substances
- Can sit idle for long periods of time without losing storage capacity

Vanadium Flow Battery [42]

Container

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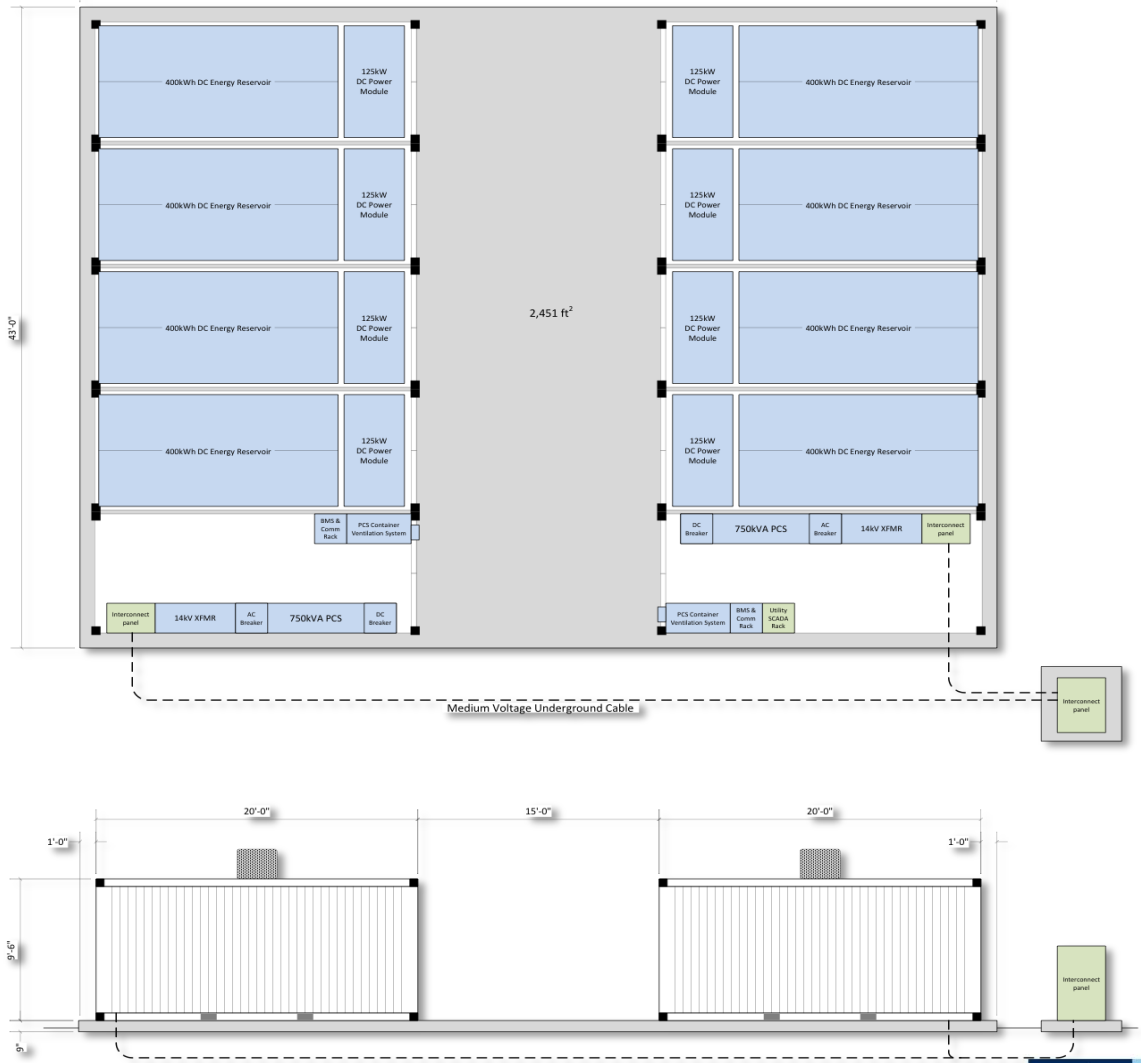
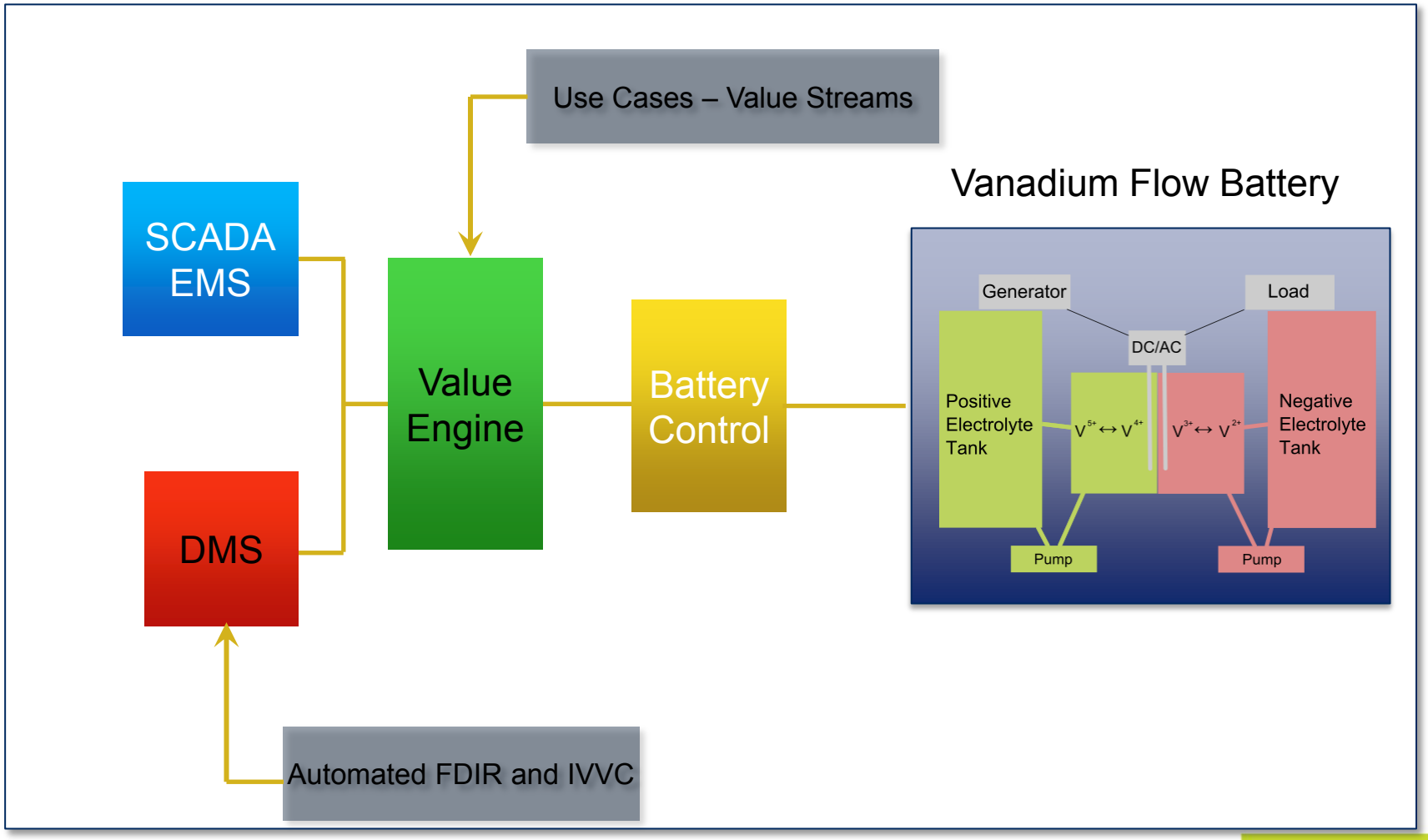
Vanadium Flow Battery

System Footprint



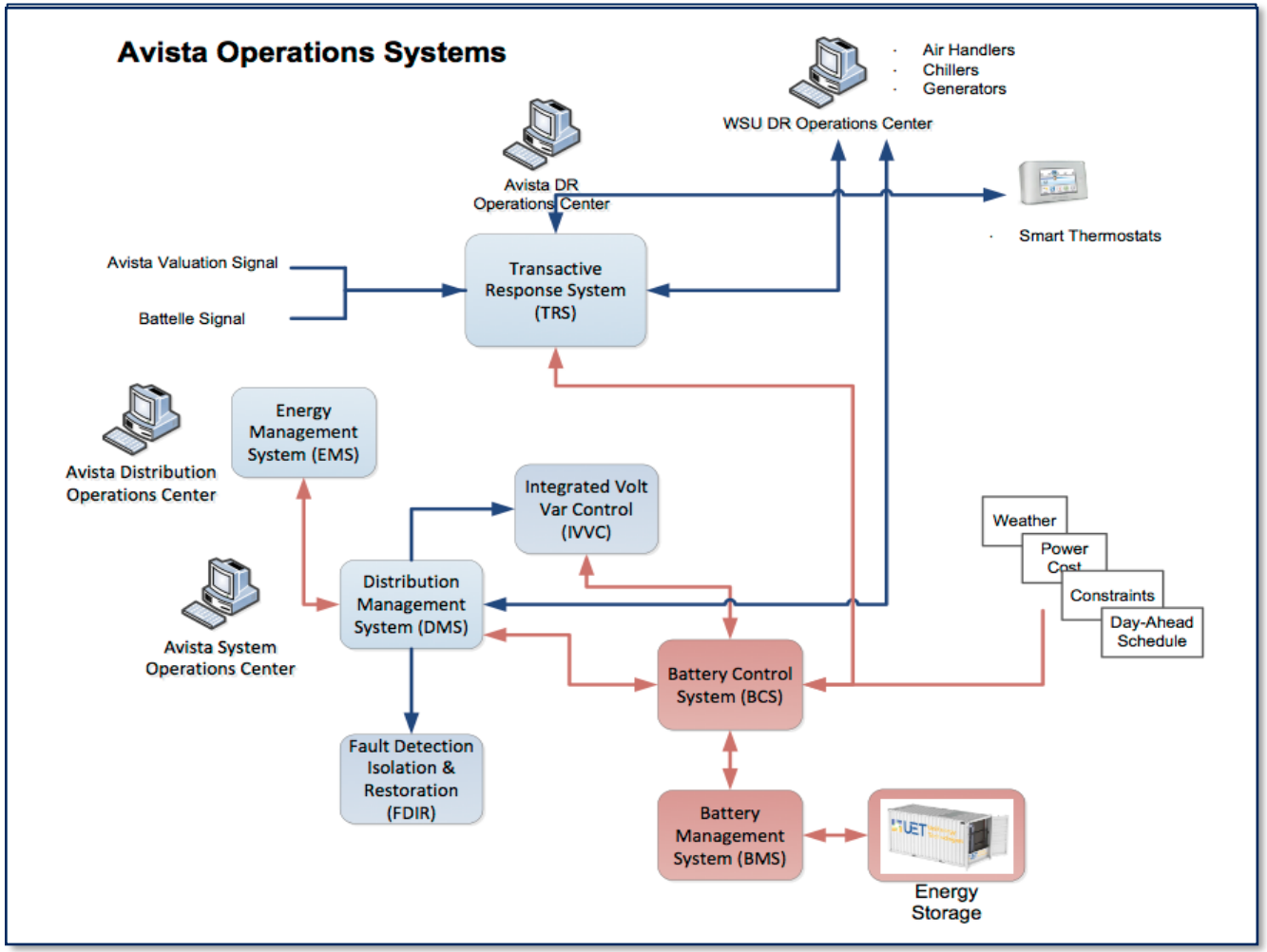
Energy Storage System

Architecture



Avista Smart Grid System

Integration



Washington State Clean Energy Fund

Use Cases - Value Streams

- Transmission System
- Distribution System
- Micro-grid Operations
- Maximizing the Total Value of Storage
- Demand Response and Energy Storage

Use Case

Bulk Power /Transmission System

- **Energy Shifting**
  - **The use case will demonstrate the following grid services:**
    - **Near-zero energy pricing market – abundant wind and water resource**
    - **General arbitrage instrument – charging during low-price discharging during high price**
- **Provide Grid Flexibility**
  - **The use case will demonstrate the following grid services:**
    - **Regulation services and load following grid services – battery operational boundaries**
    - **Services for ramping and flex rate markets**

Use Case
Distribution System

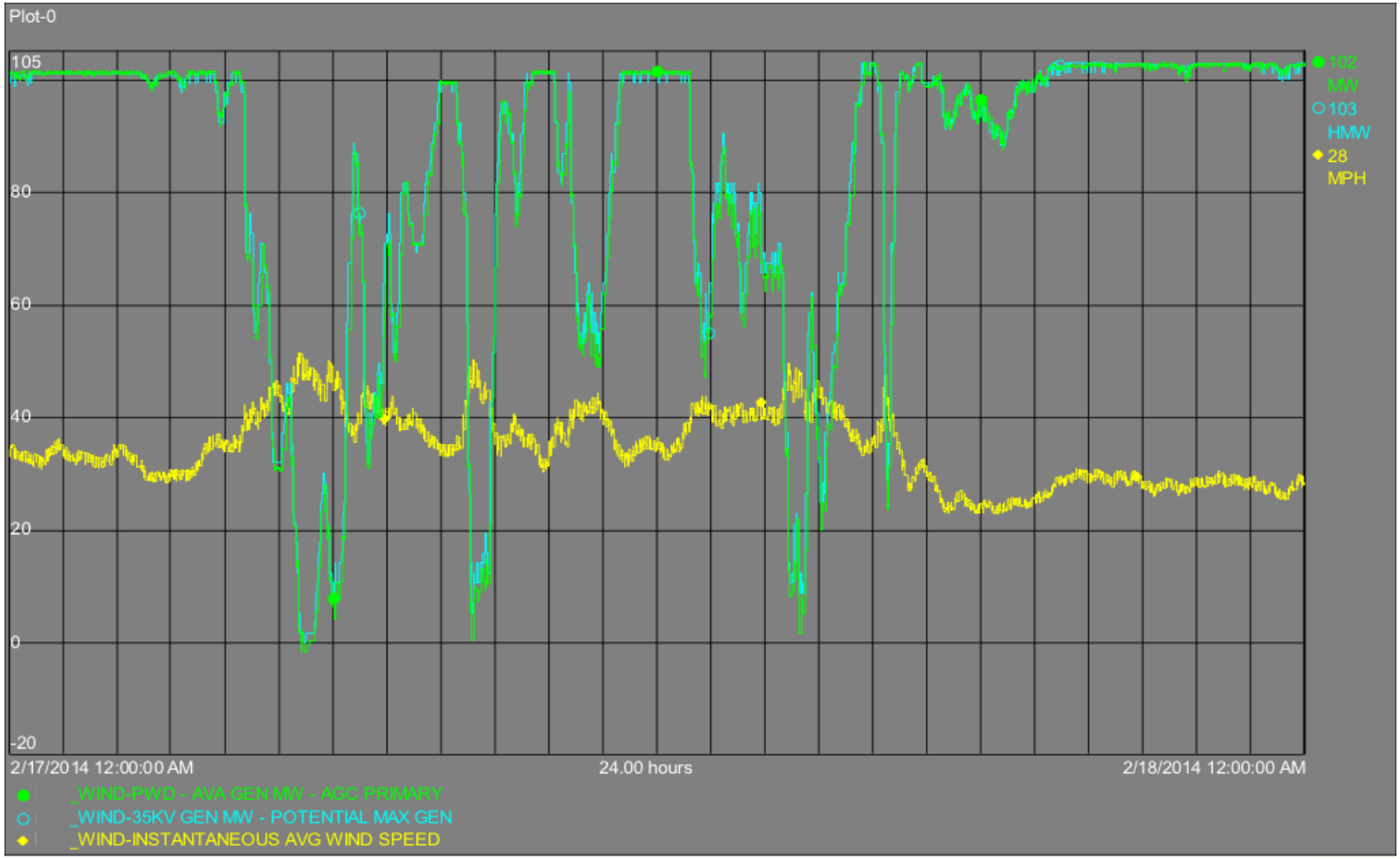
- **Improved Distribution Systems Efficiency**
  - **The use case will demonstrate the following grid services:**
    - **Volt/Var control with local and/or remote information**
      - **4-quadrant inverter controller to perform Volt/Var control**
    - **Load shaping service**
      - **Demand limiting strategy – demand threshold**
      - **Deferment of distribution system upgrades**
- **Outage Management of Critical Loads**
  - **The use case will demonstrate the following grid services:**
    - **Critical load support for one customer or several customer load components**
- **Enhanced Voltage Control**
  - **The use case will demonstrate the following grid services:**
    - **Expand the voltage control strategy to support enhanced CVR**

Use Case

Micro-grid, Optimal Utilization of Energy Storage, Demand Response

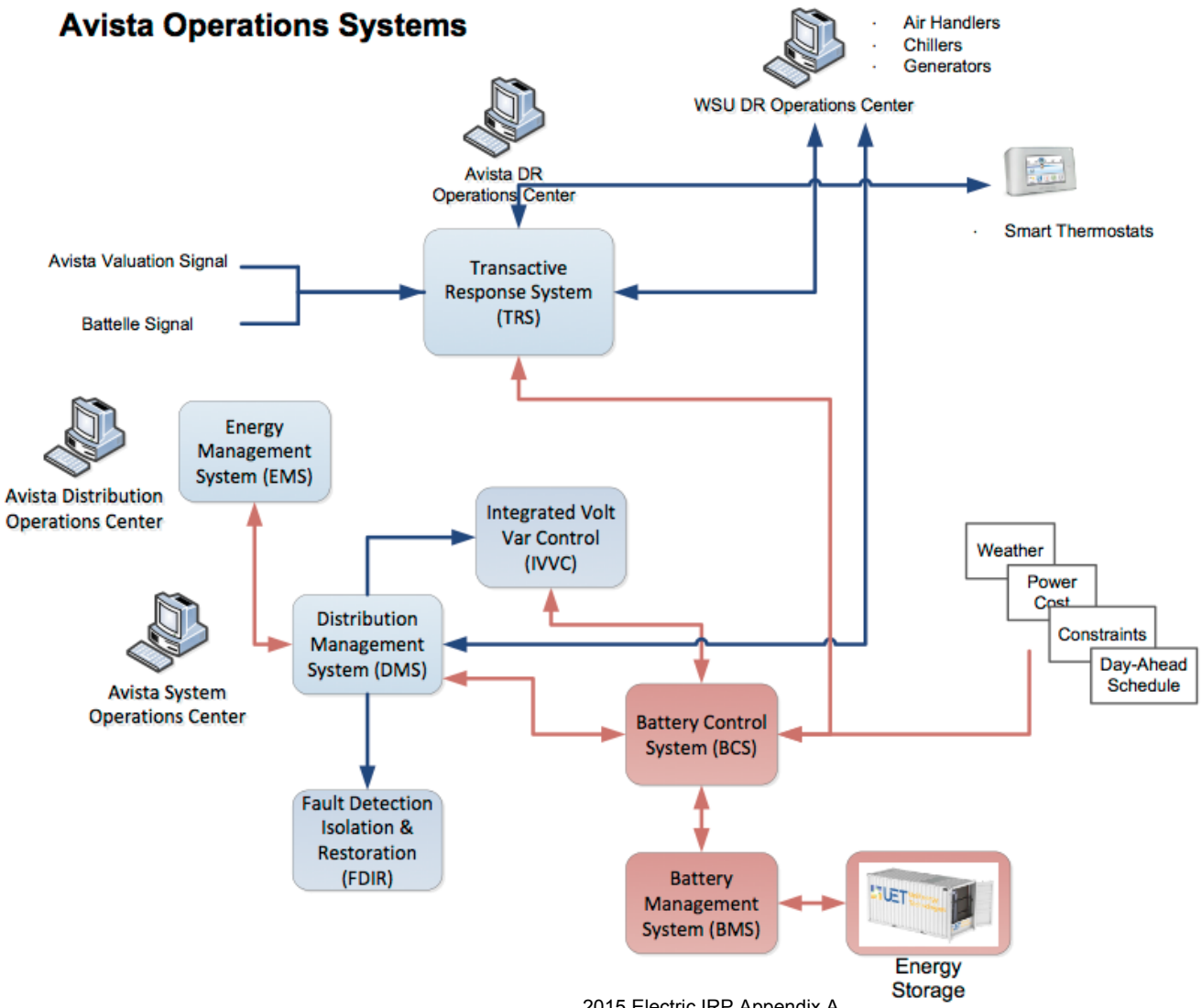
- **Grid-connected and islanded micro-grid operations**
  - **The use case will demonstrate the following grid services:**
    - **Micro-grid operation while grid-connected**
    - **Micro-grid operation in islanded mode**
- **Optimal Utilization of Energy Storage**
  - **The use case will demonstrate the following grid services:**
    - **The use-case must demonstrate the optimization of multiple use cases**
- **Demand Response and Energy Storage**
  - **The use case will demonstrate the following grid services:**
    - **The demand response can be coupled to storage to optimize the use of battery**

Example: Wind Generation

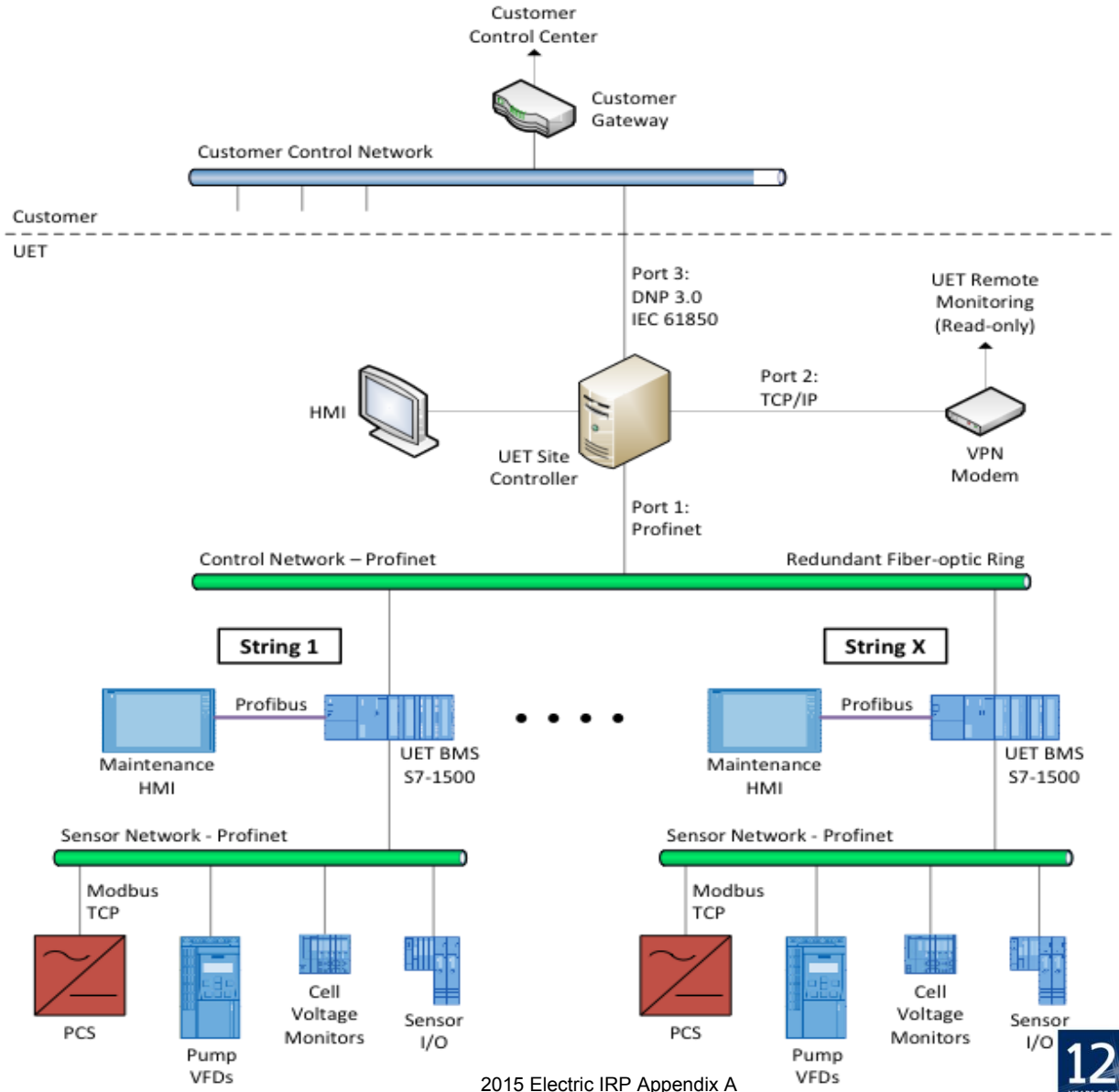


Questions

CEF - Systems Overview



Battery Network Diagram



Confidential Information – Proprietary to UET

WA State Clean Energy Fund - Grant

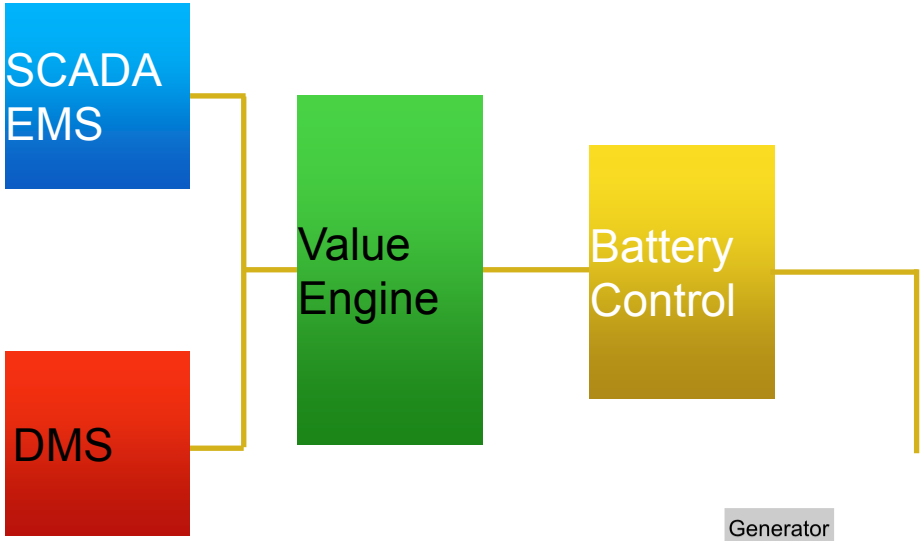
Schedule:

Project Award: June 20, 2014

Installation: 2nd Qtr 2015

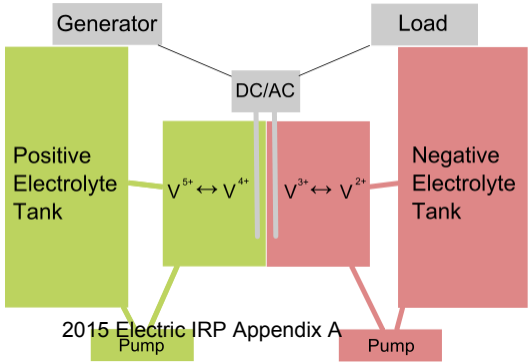
Use Case Testing: All of 2015

All Use Cases In Service: 3rd Qtr 2016



1.2 MW, 3.6MWh Capacity

Vanadium Flow Battery



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WA State Clean Energy Fund - Grant

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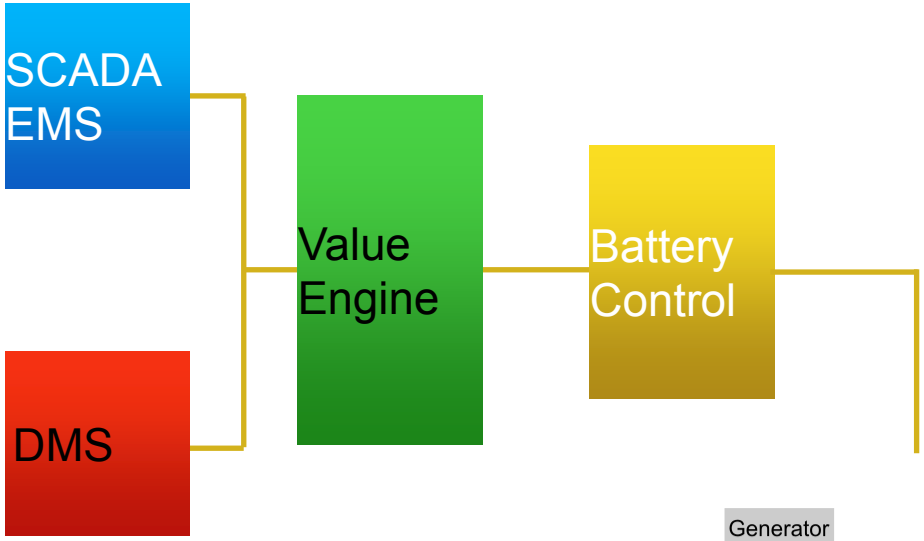
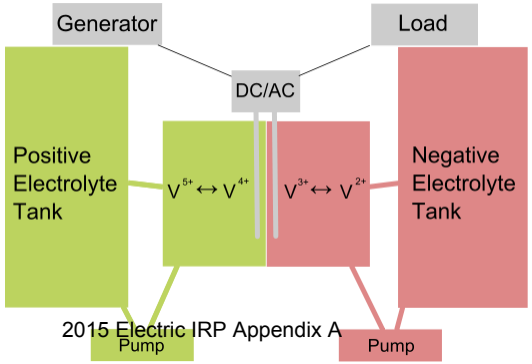


1.2 MW, 3.6MWh Capacity

Vanadium Flow Battery



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AVISTA

Avista Corp.
East 1411 Mission Ave.
Spokane, WA 99220

Exhibit A
Avista Statement of Work
Demand Response Potential Assessment

1. Project Overview

Avista requires a study ("Study") that provides an assessment of potential demand response within its commercial and industrial sectors in Washington and Idaho as described in Avista's attached 2013 Electric Integrated Resource Plan. For informational purposes, Avista is also seeking a survey of residential demand response programs and their statuses across the nation.

2. Background and Purpose

DRAFT

Avista's has offered a variety of temporary emergency demand response programs for residential, commercial and industrial customers since 2001 and more recently offered (2) two residential demand response pilot programs, and has gained a good understanding of residential demand response programs and their costs and benefits in the Avista service territory. The purpose of this Statement of Work ("SOW") is to set forth the various analyses required to develop a Study (the "Services"), which should enable Avista to gain a better understanding of demand response in the commercial and industrial sectors, and the corresponding cost and benefits.

3. Scope of Services

Consultant shall provide the labor and materials required to develop the Study including, without limitation:

3.1 National Overview of Demand Response Programs

Consultant shall provide a high level assessment of existing Demand Response programs for commercial, industrial and residential sectors across the United States, excluding pilot demand response programs. The Study shall:

- Summarize rate structures and contracts in place for each general program category;
- Provide methods used for calculating capacity and energy reduction and possible snapback values for each program (i.e., how to avoid gaming or falsely paying for phantom kW and kWh);
- Describe penalties (if any) and rules for each program;
- Identify all costs of each program
  - Demand Response vendor/contractor costs
  - Internal Program costs, administration, marketing, training etc.
  - Other program costs such as damage claims, maintenance, etc.
- Analyze peak clipping verses load shifting implied with each program;
- Analyze the pros/cons of RFP vs tariff vs contracts;
- Describe valuation used for effectiveness
  - Breakeven point
  - Avoided cost
- Identify commercial and industrial loads and processes that are used for demand response.
  - Describe how these loads/processes impact peak shifting or load reduction when used for demand response
  - Describe how these loads/processes stack in a supply curve when used for demand response
  - Describe ancillary service benefits, if any, gained from the demand response programs
  - Describe the reliability of the resource
- Identify any barriers to higher levels of program participation and the design and actions of the program that made it a success.

Avista Corp.
East 1411 Mission Ave.
Spokane, WA 99220

Exhibit A
Avista Statement of Work
Demand Response Potential Assessment

3.2 Analysis of the Timing of Implementing New Demand Response Programs

Consultant shall analyze and include in the Study the benefits and risks of offering Demand Response ahead of need versus waiting for the need. Special focus should be given to the uniqueness of the Pacific Northwest region's customers and their attitudes, and power market.

3.3 Determination of Adequate Customer Incentive Levels for various Commercial and Industrial Demand Response

Consultant shall identify and include in the Study, commercial and industrial loads and processes used for demand response and the levels of incentives needed to encourage each of those loads to participate in demand response, and determine if Avista's energy and capacity rates are adequate to meet those incentive requirements.

3.4 Analysis of Avista's Customer Mix and Associated Expected Demand Response Capability from Commercial and Industrial Loads

DRAFT

- Consultant shall include in the Study:
  - A break down and description of Avista's customer sectors by size, revenue class, demand and usage using Avista's Conservation Potential Assessment.
  - A break-down of expected demand and energy savings from possible demand response loads and processes (off-peak, on-peak, time of day, and ancillary services).
- Consultant shall meet with Avista's staff from the areas set forth below to get their perspectives for the analyses:
  - Account Executive team
  - Power Supply team
  - Conservation team
  - Other key utility staff

3.5 Analysis of the Costs and Benefits to Implement a Commercial and/or Industrial Demand Response Program for Avista

Consultant shall apply the knowledge gained in providing the Services applicable under this SOW to analyze the expected cost to operate a commercial or commercial/industrial demand response program at Avista to determine:

- Program mix and costs for 5 MW, 10 MW, 15 MW, 20 MW, 25 MW and 50 MW acquisition scenarios;
- Potential acquisition scenarios across the supply curve for spring, summer and winter seasons;
- Pros/cons of using a 3rd party aggregator;
- Pros/cons of using a mix of 3rd party aggregator and utility staff;
- Pros/cons of implementing a utility sponsored demand response program without an outside vendor. Examine aspects across the spectrum from Utility direct load control to interruptible rates.

4. Attachment:

Attachment A – 2013 Electric Integrated Resource Plan

Draft 2015 Electric IRP Work Plan

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
May 29, 2014

Technical Advisory Committee Meetings

- **TAC 1 (May 29, 2014):** TAC Meeting Expectations, 2013 IRP Acknowledgement Letters, 2015 Action Plan Update, Pullman Energy Storage Project, Energy Independence Act Compliance & Forecast, Demand Response Study Discussion, and draft 2015 Electric IRP Work Plan.
- **September 2014:** Review conservation selection methodology, energy and economic forecasts, generation options, and 2014 Shared Value Report.
- **November 2014:** Peak load forecast, reliability planning, Colstrip discussion, energy storage technologies, 2015 IRP modeling, and energy efficiency.
- **February 2015:** Electric and natural gas price forecasts, transmission planning, resource needs assessment, and market portfolio scenario development.
- **March 2015:** Draft Preferred Resource Strategy (PRS), review of scenarios and futures, and portfolio analysis.
- **June 2015:** Review of the final PRS and Action Items.

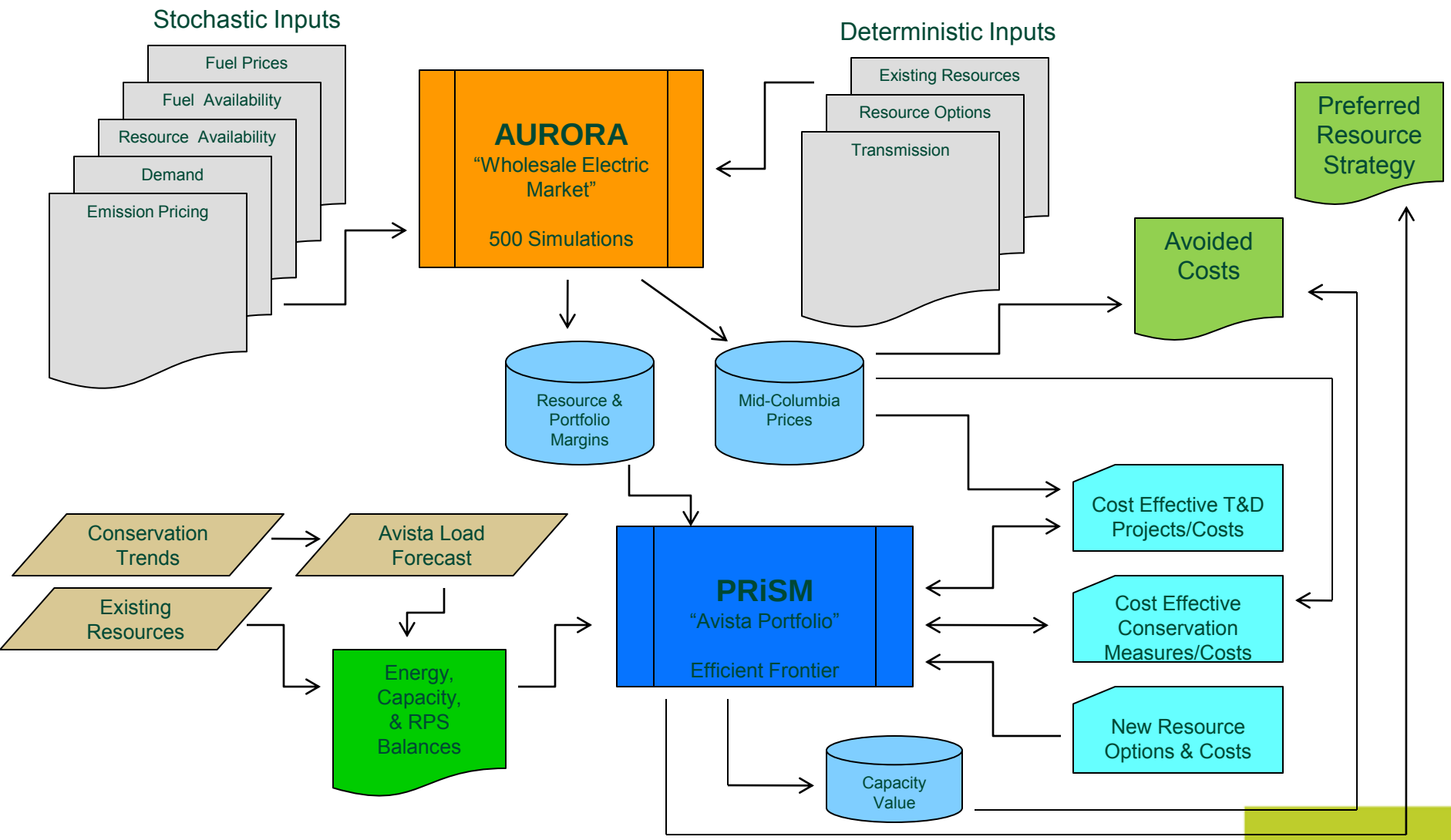
2015 Draft Electric IRP Timeline

Preferred Resource Strategy (PRS) Tasks	Target Date
Finalize energy demand forecast	July 2014
Identify regional resource options for electric market price forecast	September 2014
Identify Avista's supply & conservation resource options	September 2014
Finalize Peak Load Forecast	September 2014
Update AURORA^{xmp} database for electric market price forecast	October 2014
Finalize data sets/statistics variables for risk studies	October 2014
Energy efficiency load shapes input into AURORA^{xmp}	October 2014
Draft transmission study due	October 2014
Energy efficiency load shapes input into AURORA^{xmp}	October 2014
Final transmission study due	December 2014
Finalize Distribution Feeder Forecast	December 2014
Select natural gas price forecast	December 2014
Finalize deterministic base case	December 2014
Due date for study requests	January 15,2015
Base case stochastic study complete	January 2015
Finalize PRiSM model	January 2015
Develop efficient frontier and PRS	January 2015
Simulation of risk studies "futures' complete	February 2015
Simulate market scenarios in AURORA^{xmp}	February 2015
Evaluate resource strategies against market futures and scenarios	March 2015
Present preliminary study and PRS to TAC	March 2015

2015 Draft Electric IRP Timeline

Writing Tasks	Target Date
File 2015 IRP Work Plan	August 29, 2014
Prepare report and appendix outline	October 2014
Prepare text drafts	April 2015
Prepare charts and tables	April 2015
Internal drafts released at Avista	May 2015
External draft released to the TAC	June 2015
Final editing and printing	August 2015
Final IRP submission to Commissions and distribution to TAC	August 31, 2015

2015 IRP Modeling Process



2015 Electric IRP Draft Outline

- Executive Summary
- Introduction and Stakeholder Involvement
- Economic and Load Forecast
  - Economic Conditions
  - Avista Energy and Peak Load Forecast
  - Load Forecast Scenarios
- Existing Resources
  - Avista Resources
  - Contractual Resources and Obligations

2015 Electric IRP Draft Outline

- Energy Efficiency and Demand Response
  - Conservation Potential Assessment
  - Demand Response Opportunities
- Long-Term Position
  - Reliability Planning and Reserve Margins
  - Resource Requirements
  - Reserves and Flexibility Assessment
- Policy Considerations
  - Environmental Concerns
  - Greenhouse Gas Issues
  - State and Federal Policies

2015 Electric IRP Draft Outline

- Transmission Planning
  - Avista's Transmission System
  - Future Upgrades and Interconnections
  - Transmission Construction Costs and Integration
  - Transmission and Distribution Efficiencies
- Generation Resource Options
  - New Resource Options
  - Avista Plant Upgrades

2015 Electric IRP Draft Outline

- Market Analysis
  - Marketplace
  - Fuel Price Forecasts
  - Market Price Forecast
  - Scenario Analysis
- Preferred Resource Strategy
  - Resource Selection Process
  - 2015 Preferred Resource Strategy
  - Efficient Frontier Analysis
  - Avoided Cost

2015 Electric IRP Draft Outline

- Portfolio Scenarios
  - Portfolio Scenarios
  - Tipping Point Analysis
- Action Plan
  - 2013 Action Plan Summary
  - 2015 Action Plan

2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Tuesday, September 23, 2014
Conference Room 130

Topic	Time	Staff
1. Introduction & TAC 1 Recap	8:30	Lyons
2. Conservation Selection Methodology	8:35	Gall
3. Load and Economic Forecasts	9:15	Forsyth
4. Shared Value Report	10:45	Fielder
5. Lunch	11:30	
6. Generation Options	12:30	Gall/Dempsey
7. Clean Power Plan Proposal Discussion	1:45	Lyons/Kalich
8. Adjourn	3:00	

2015 Electric IRP
TAC Meeting Expectations and Schedule

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
September 23, 2014

Technical Advisory Committee

- The public process piece of the IRP – input on what to study, how to study, and review of assumptions and results
- Wide range of participants in all or some of the process
- Open forum, but we need to stay on topic to get through the agenda
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - January 15, 2015 is the final date to receive study requests
- Action Items – areas for more research in the next IRP
- This is not an advocacy forum
- Not a forum on a particular resource or resource type
- Supports rate recovery, but not a preapproval process
- Planning team is available by email or phone for questions or comments between the TAC meetings

Remaining TAC Meetings

- **TAC 3 – Friday, November 21, 2014:** Planning margin, Colstrip discussion, cost of carbon, modeling overview and conservation potential assessment methodology.
- **TAC 4 – February 2015:** Electric and natural gas price forecasts, transmission planning, resource needs assessment, market and portfolio scenario development, energy storage and ancillary service evaluation
- **TAC 5 – March 2015:** Completed conservation potential assessment, draft PRS, review of scenarios and futures and portfolio analysis
- **TAC 6 – June 2015:** Review of final PRS and action items.

2015 IRP Tasks for the PRS

Exhibit 1: 2015 Electric IRP Timeline	
Task	**Target Date**
Preferred Resource Strategy (PRS)	
Finalize energy demand forecast	July 2014
Identify Avista's supply & conservation resource options	September 2014
Finalize peak load forecast	September 2014
Update AURORA^{xmp} database for market price forecast	October 2014
Energy efficiency load shapes input into AURORA^{xmp}	October 2014
Finalize datasets/statistics variables for risk studies	November 2014
Transmission study due	December 2014
Finalize distribution feeder forecast	December 2014
Select natural gas price forecast	December 2014
Finalize deterministic base case	January 2015
Due date for study requests	Jan. 15, 2015
Base case stochastic study complete	January 2015
Develop efficient frontier and PRS	January 2015
Finalize PRiSM model	February 2015
Simulation of risk studies "futures" complete	February 2015
Simulate market scenarios in AURORA^{xmp}	February 2015
Evaluate resource strategies against market futures and scenarios	March 2015
Present preliminary study and PRS to TAC	March 2015

2015 IRP Writing Tasks – Work Plan

Writing Tasks	
File 2015 IRP work plan	August 2014
Prepare report and appendix outline	October 2014
Prepare text drafts	April 2015
Prepare charts and tables	April 2015
Internal draft released at Avista	May 2015
External draft released to the TAC	June 2015
Final editing and printing	August 2015
Final IRP submission and TAC	August 31, 2015

Conservation Modeling Options

James Gall
Second Technical Advisory Committee Meeting
September 23, 2014

2013 IRP WUTC Acknowledgement Request

….the Commission requests that Avista, together with input from the TAC, investigate incorporating energy efficiency into its 2015 IRP as a selectable resource within PRiSM.

1. The model cannot readily adapt to new scenarios, changes in model assumptions, or the different avoided costs generated under various resource strategies.
2. The model cannot choose to accelerate acquisition of conservation, even in cases where the acceleration of acquisition is the least-cost resource or provides substantial risk mitigation value. Instead, the acquisition rate is defined by the ramp rates within the CPA.

Avista's 2005-2013 IRP Conservation Selection Methodology

1. Develop a Conservation Potential Assessment (CPA) study
2. Identify resource requirements prior to conservation
3. PRiSM selects generating resources to meet resource deficits
4. Avoided energy, capacity, and risk costs are derived from resource selection
5. Potential conservation measures are compared to Avoided Costs and the economic conservation is selected (uses 10% premium on all avoided costs, including losses and T&D savings)
6. New resource requirements are developed based on selected conservation
7. PRiSM develops an efficient frontier and the PRS is selected

Pros & Cons with Avista's Conservation Selection Methodology

- Pros
  - Generation resources selection is faster, allowing more scenarios
  - Conservation resources with capacity contribution can get a 10% avoided cost premium
    - Power Council's proposed RPM model only includes conservation adder on the avoided market prices for energy savings.
  - Third party conservation resource selection
- Cons
  - When selecting different portfolios along the efficient frontier, conservation remains unchanged, unless scenario analysis is used
  - Third party conservation resource selection

Lessons from Modeling Conservation in PRiSM- Analysis Perspective

- Model produces conservation acquisition consistent with 2013 IRP.
- Short lived conservation measures get free energy savings after life (due to code or other reasons), modeling this in PRiSM bias more short term conservation because of long term free benefits. To avoid this, levelized costs have to be included after the resource life.
- Ramp rates for each program year are required, but the model can select a program to begin earlier than CPA, with more detail on program population, costs, and constraints.
- Levelized program costs have to be used rather than upfront cost to avoid detailed modeling beyond 20 years. This bias higher cost programs as it doesn't see any benefits beyond 20 years. End effects may be required to be modeled.

Lessons from Modeling Conservation in PRiSM- Technical Perspective

- PRiSM currently resides in Excel with Lindo System's What's Best as the optimization engine.
  - The optimization is a MIP- Mixed Integer Program
  - MIP's solution time increases exponentially with additional variables
- Solution time without adjustable conservation is ~2 minutes.
- Adding conservation causes solution time issues, some simulations are ~7 minutes, some go forever- typically on lower risk scenarios along efficient frontier.
- Alternatives for resolving solution times.
  1. Use existing method
  2. Try alternative optimization engines
  3. Re-write program into a programing language and use Gurobi as a solver
  4. Use LP for efficient frontier analysis, and MIP for scenario and PRS selection

Load and Economic Forecasts

Grant D. Forsyth, Ph.D.
Chief Economist
September 23, 2014
Second Technical Advisory Committee Meeting

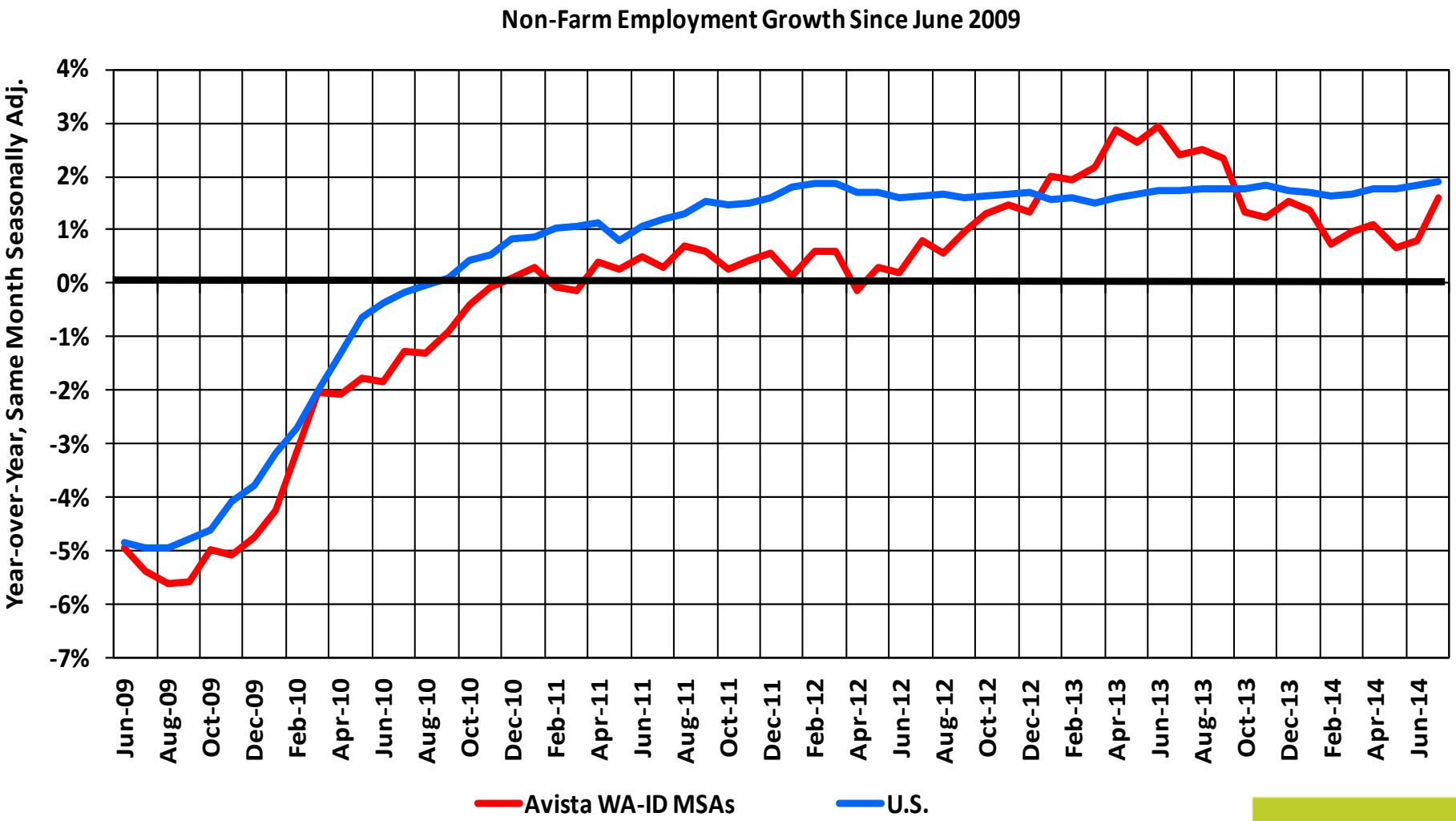
Main Topic Areas

- **Service Area Economy**
- **Peak Load Forecast**
- **Long-run Forecast and Load Impacts of Residential Solar Penetration**

Service Area Economy

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

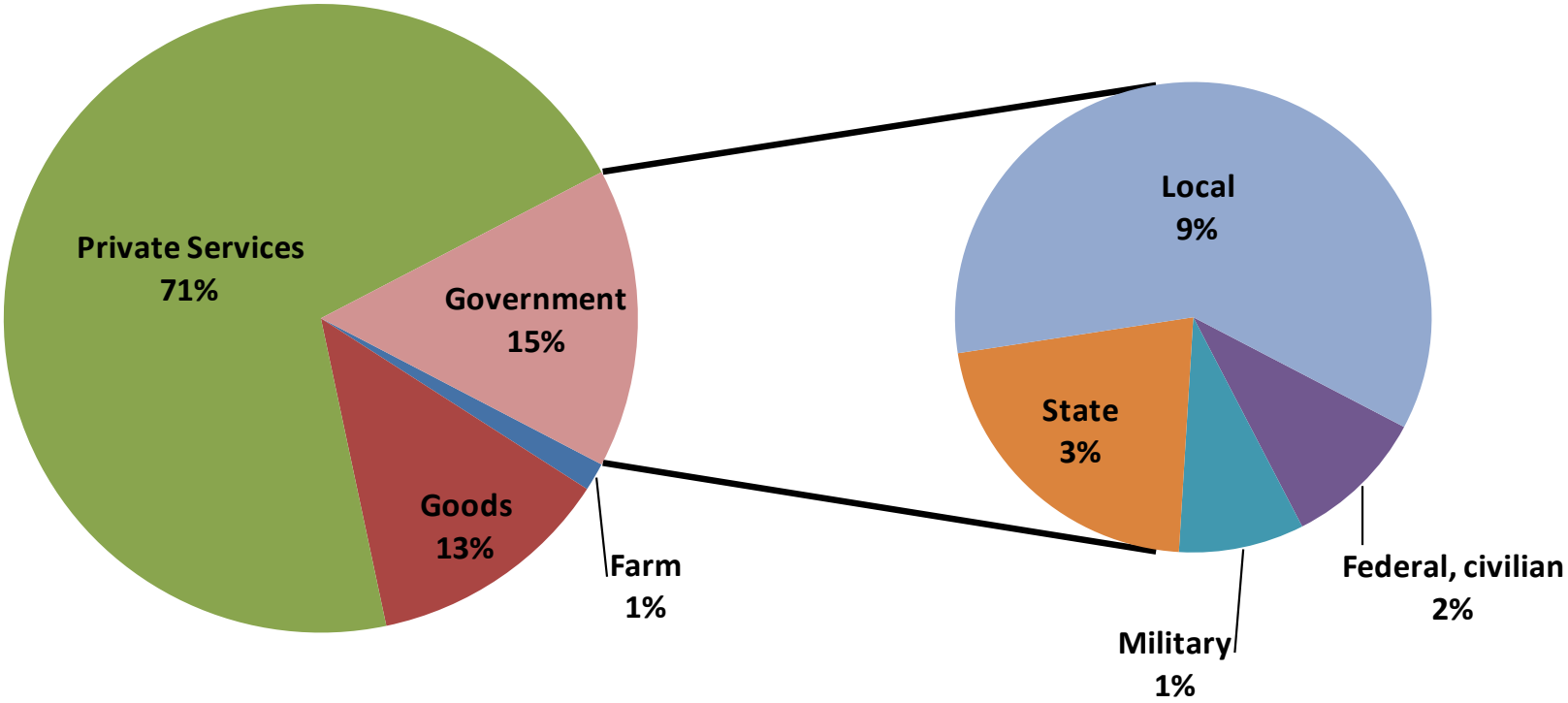
Non-Farm Employment: A Long, Slow Recovery



Source: BLS and author's calculations.

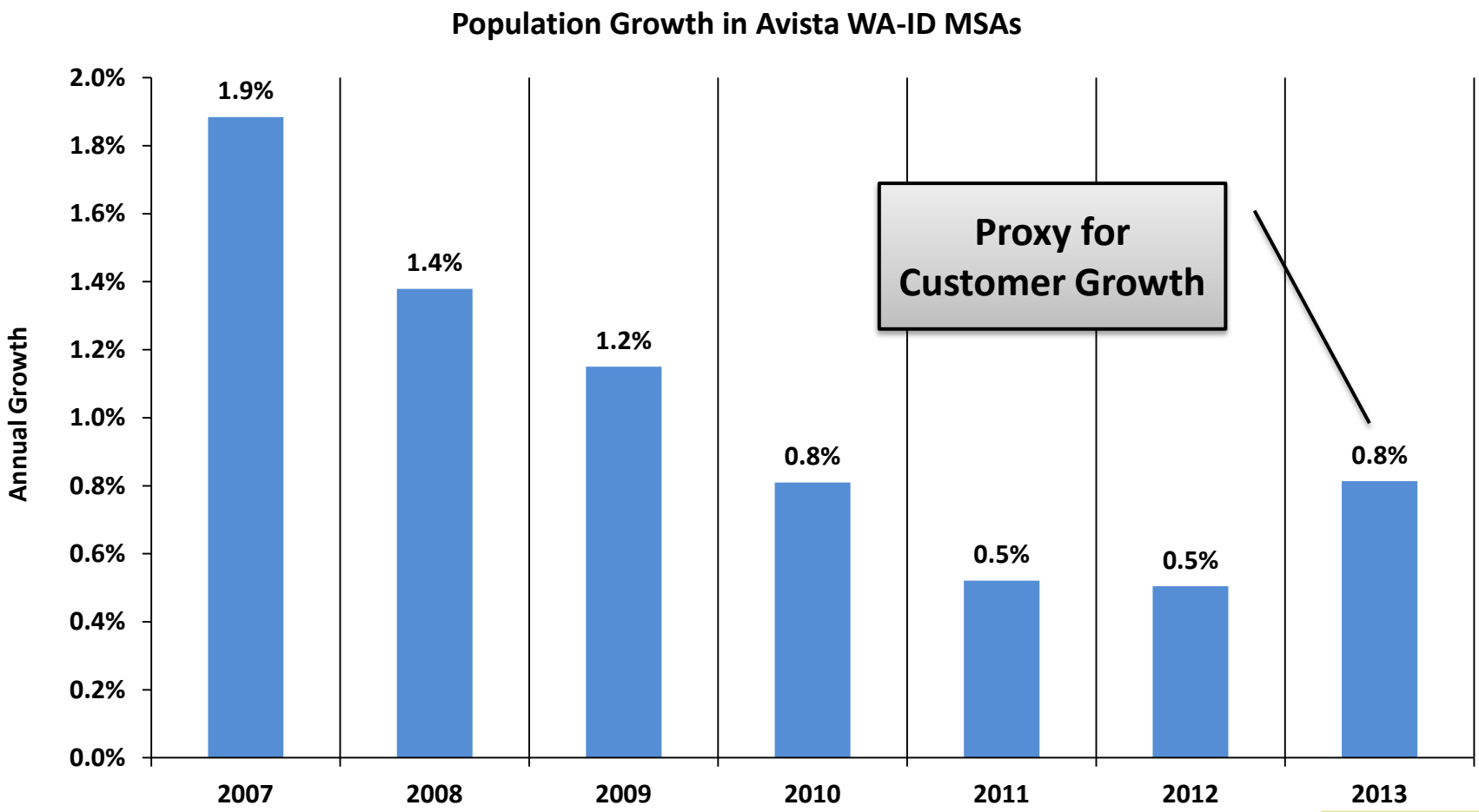
Distribution of Employment: Services and Government are Dominant

WA-ID MSA Employment, 2012



Source: BEA and author's calculations.

Population Growth: Slowly Recovering with Employment Growth



Source: BEA, U.S. Census, and author's calculations.

Peak Load Forecast

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

The Basic Model

- **Monthly time-series regression model that initially excludes certain industrial loads.**

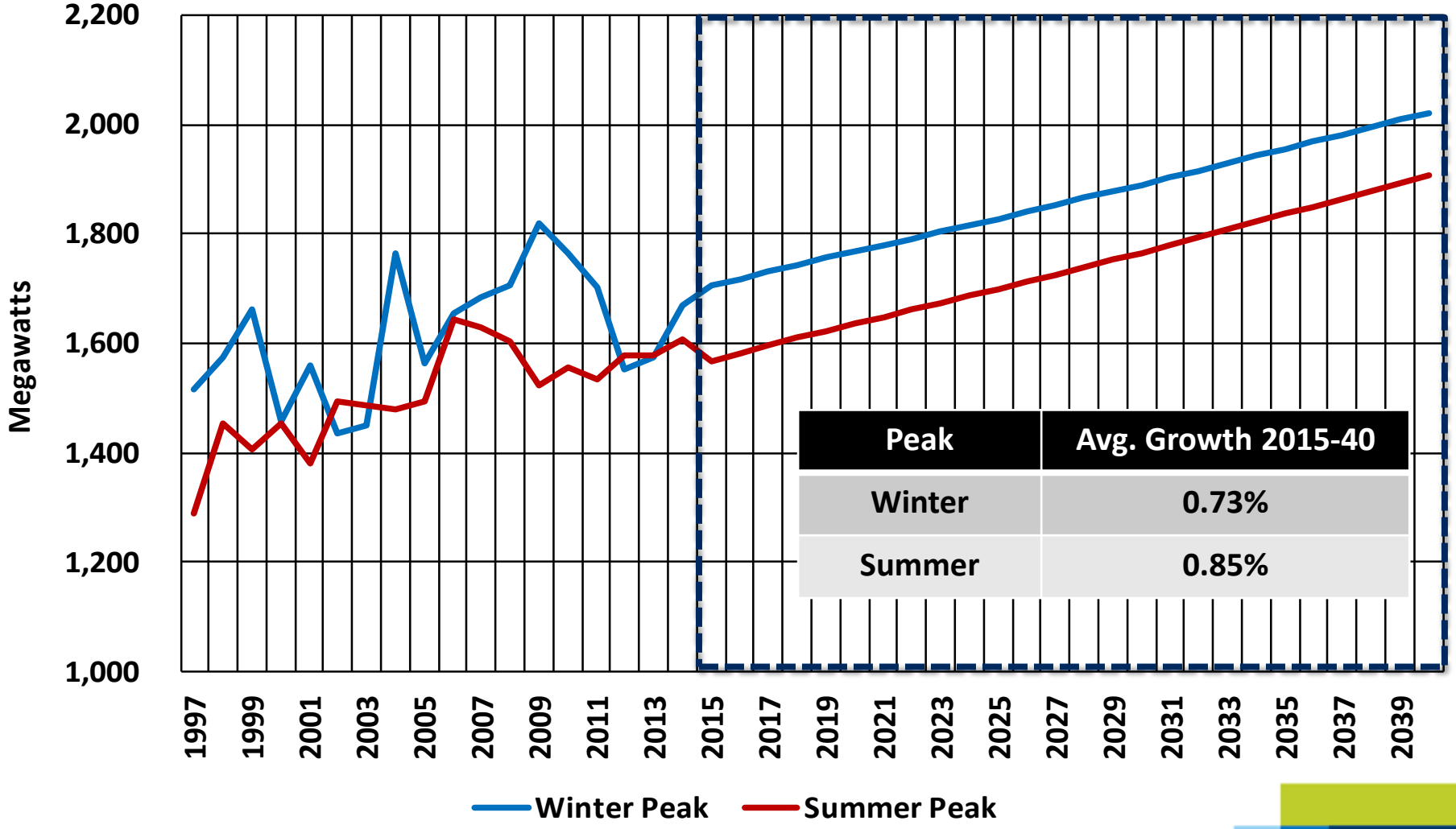
- **Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.**

- **Explanatory variables include HDD-CDD and monthly and day-of-week dummy variables. The level of real U.S. GDP is the primary economic driver in the model—the higher GDP, the higher peak loads. The historical impacts of DSM programs are "trended" into the forecast.**

- **The coefficients of the model are used to generate a distribution of peak loads by month based on historical max/min temperatures, holding GDP constant. An expected peak load can then be calculated for the current year (e.g., 2014). Model confirms Avista is a winter peaking utility for the forecast period; however, the summer peak is growing faster than the winter peak.**

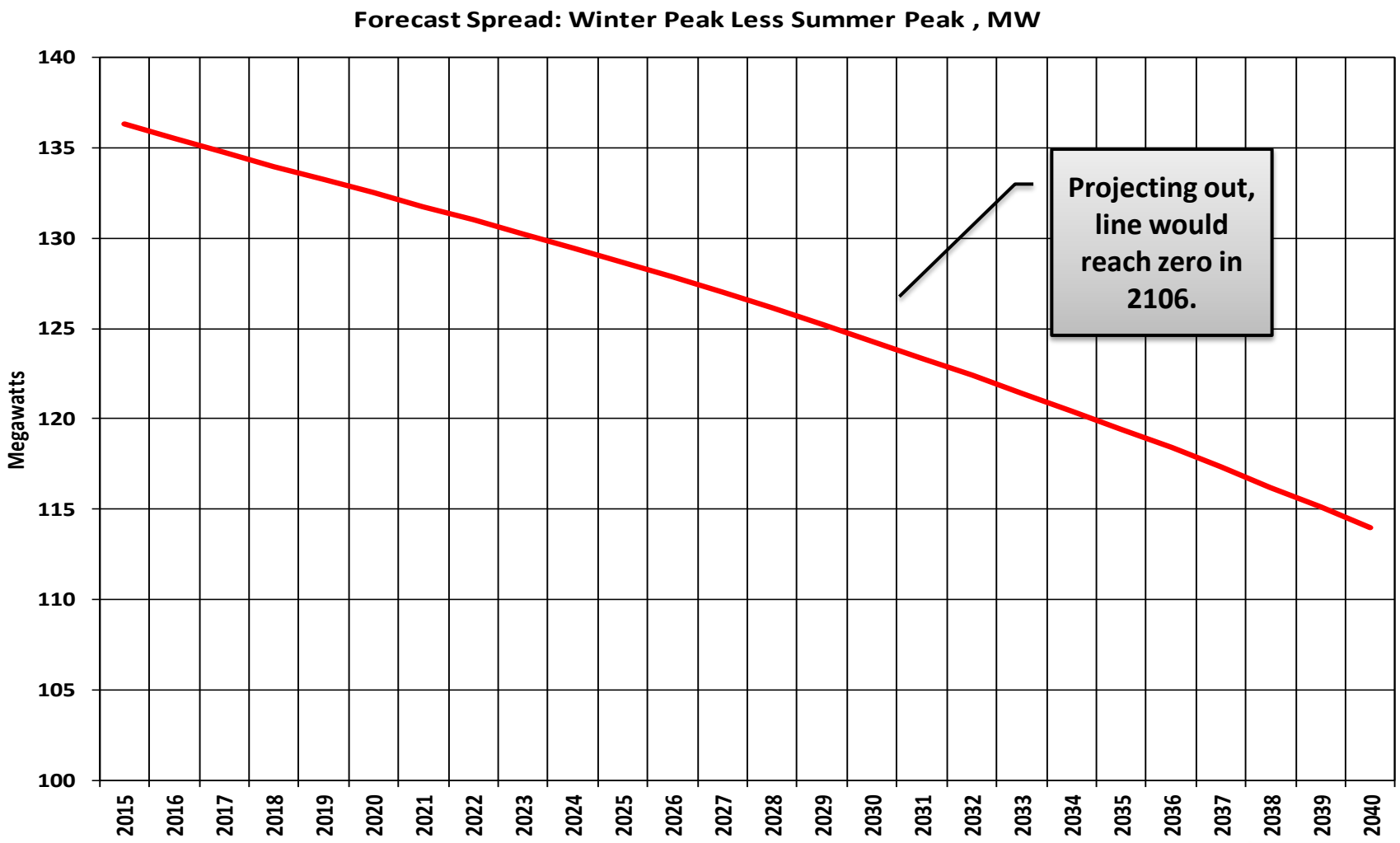
- **The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "ceteris paribus" assumption for weather and other factors.**

Current Peak Load Forecasts for Winter and Summer, 2015-2040

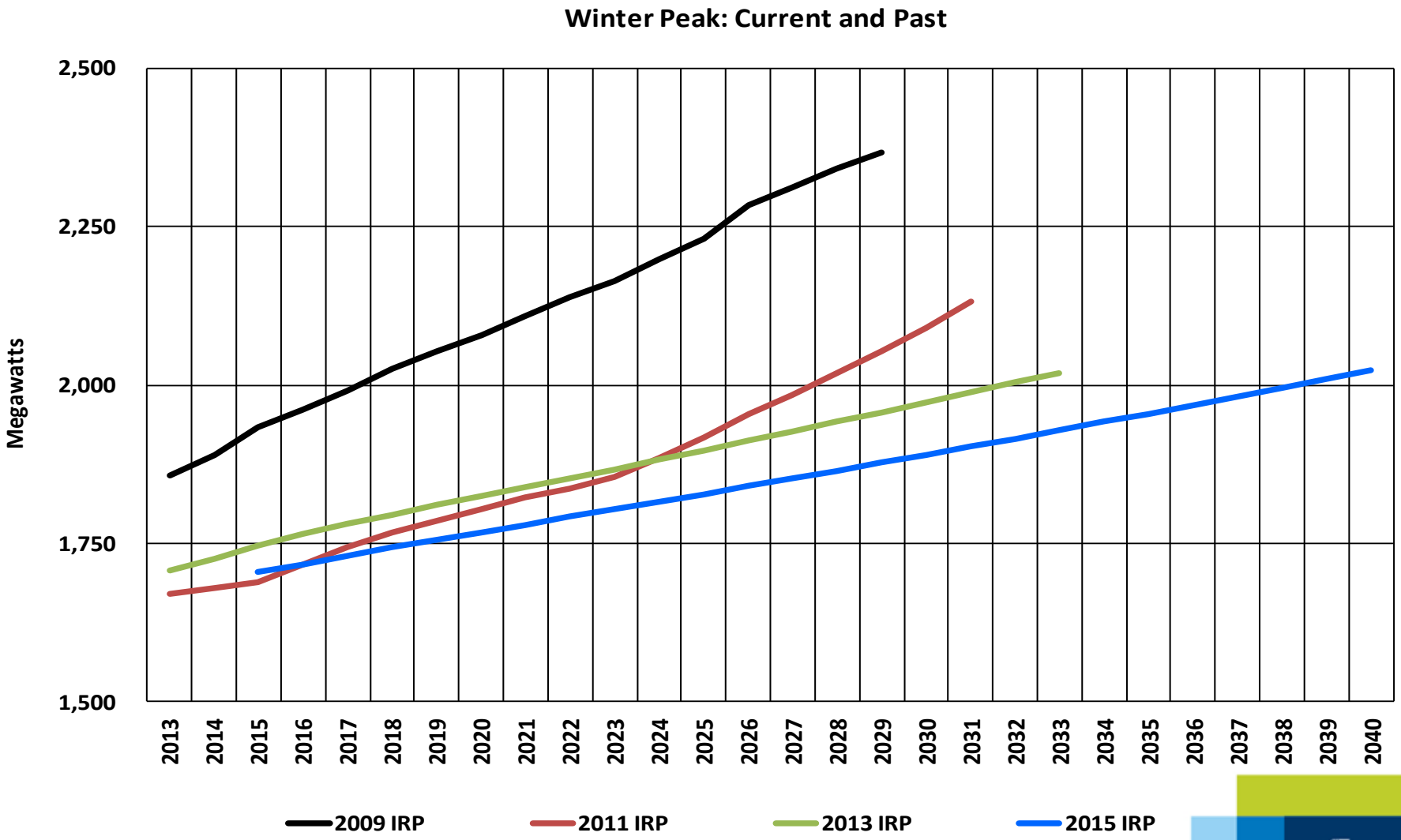


Peak	Avg. Growth 2015-40
Winter	0.73%
Summer	0.85%

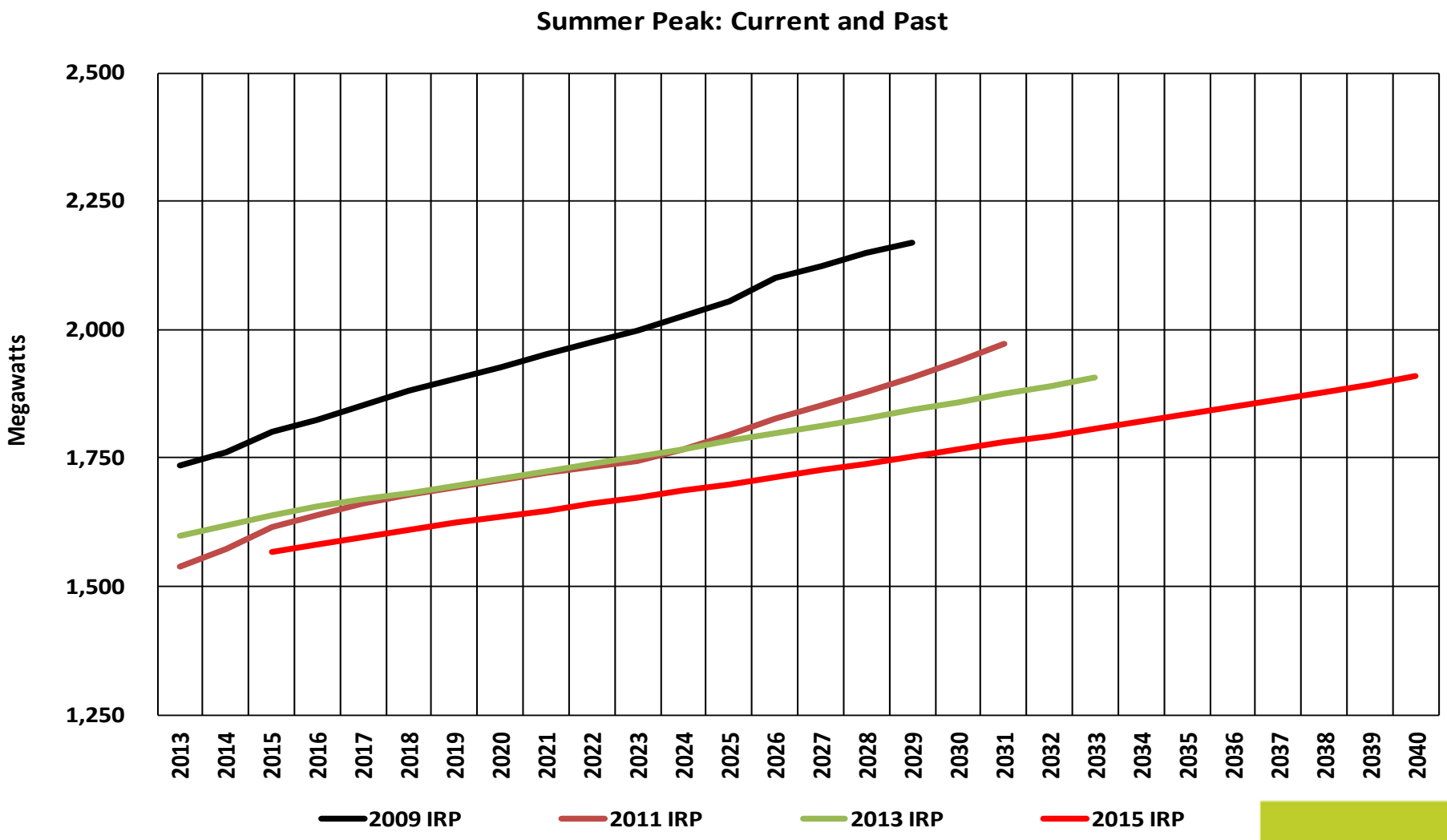
MW Spread Between Peak Forecasts for Winter and Summer, 2015-2040



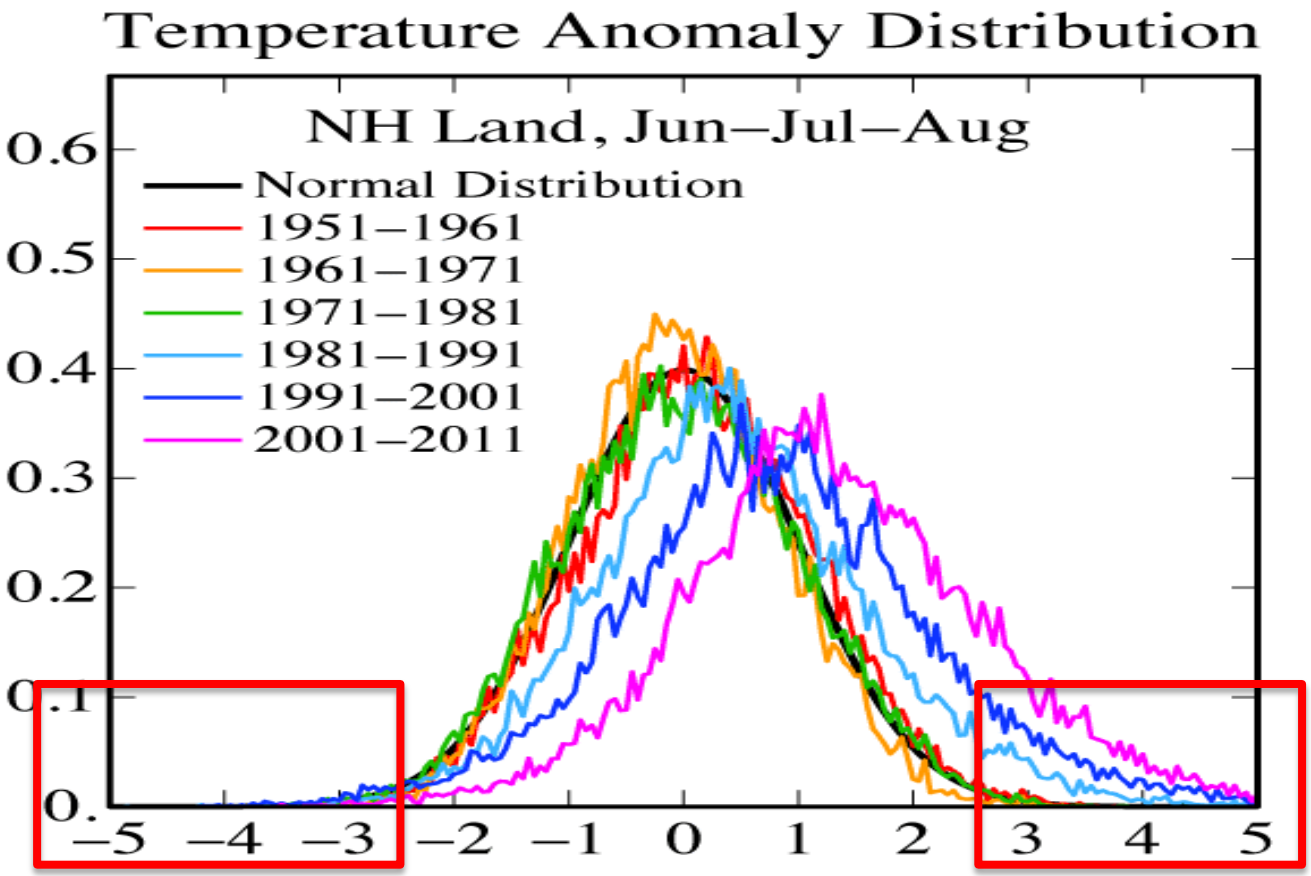
Current and Past Peak Load Forecasts for Winter Peak, 2013-2040



Current and Past Peak Load Forecasts for Summer Peak, 2015-2014

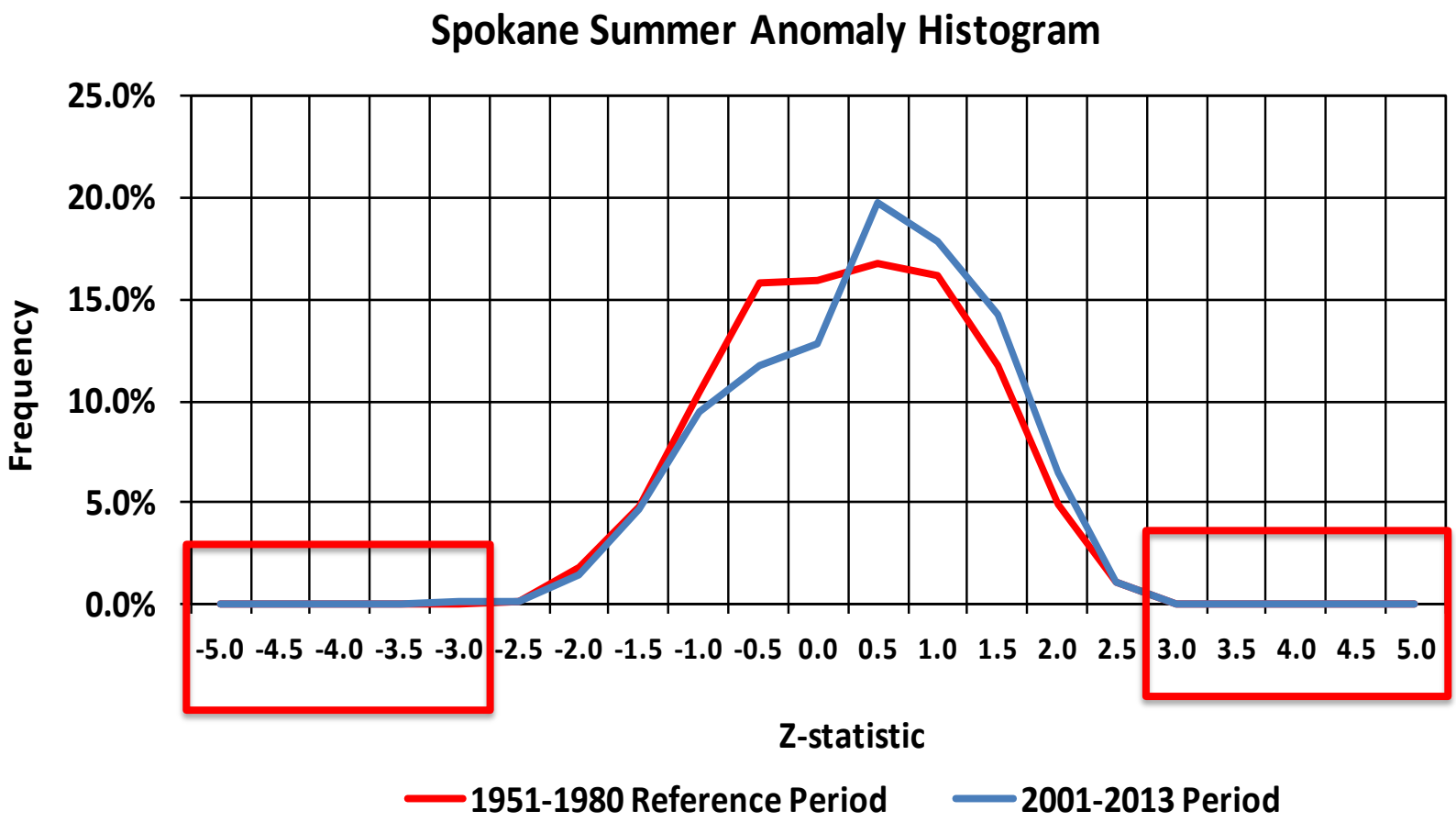


Distribution of Summer Temperature Anomalies in the Northern Hemisphere



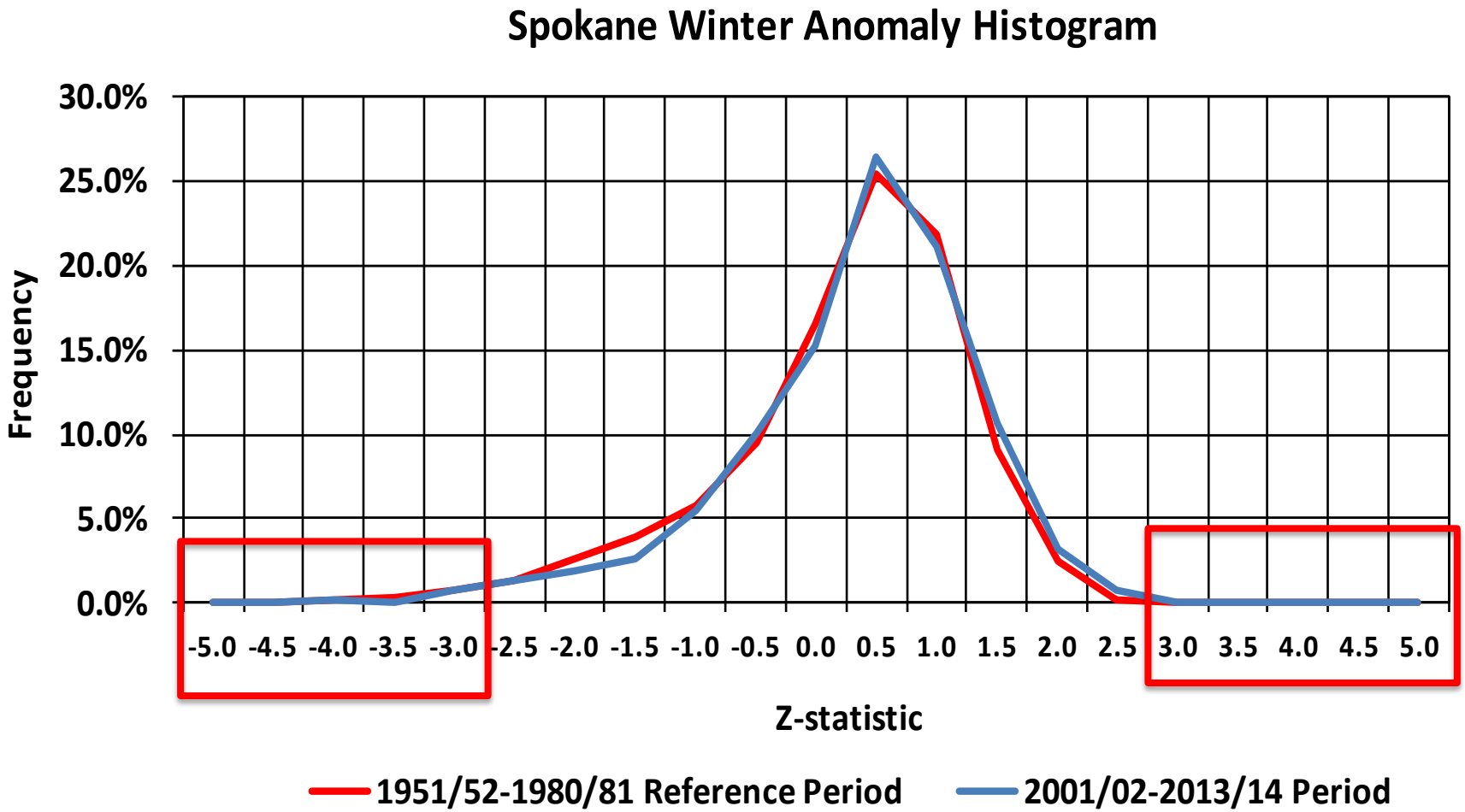
Temperature anomaly distribution: The frequency of occurrence (vertical axis) of local temperature anomalies (relative to 1951-1980 mean) in units of local standard deviation (horizontal axis). Area under each curve is unity. Image credit: NASA/GISS. See also NASA/GISS *Science Brief* , by James Hansen, Makiko Sato, Reto Ruedy (August 2012) at http://www.giss.nasa.gov/research/briefs/hansen_17/#fn1

Distribution of Summer Temperature Anomalies in the Spokane Region



Note: Due to the movement of the Spokane temperature gage to the Spokane International Airport in 1947, this anomaly analysis was restricted to the 1947-2013/14 period.

Distribution of Winter Temperature Anomalies in the Spokane Region



Note: Due to the movement of the Spokane temperature gage to the Spokane International Airport in 1947, this anomaly analysis was restricted to the 1947-2013/14 period.

Long-Term Load Forecast and the Time Dynamics of Residential Solar Penetration

Grant D. Forsyth, Ph.D.
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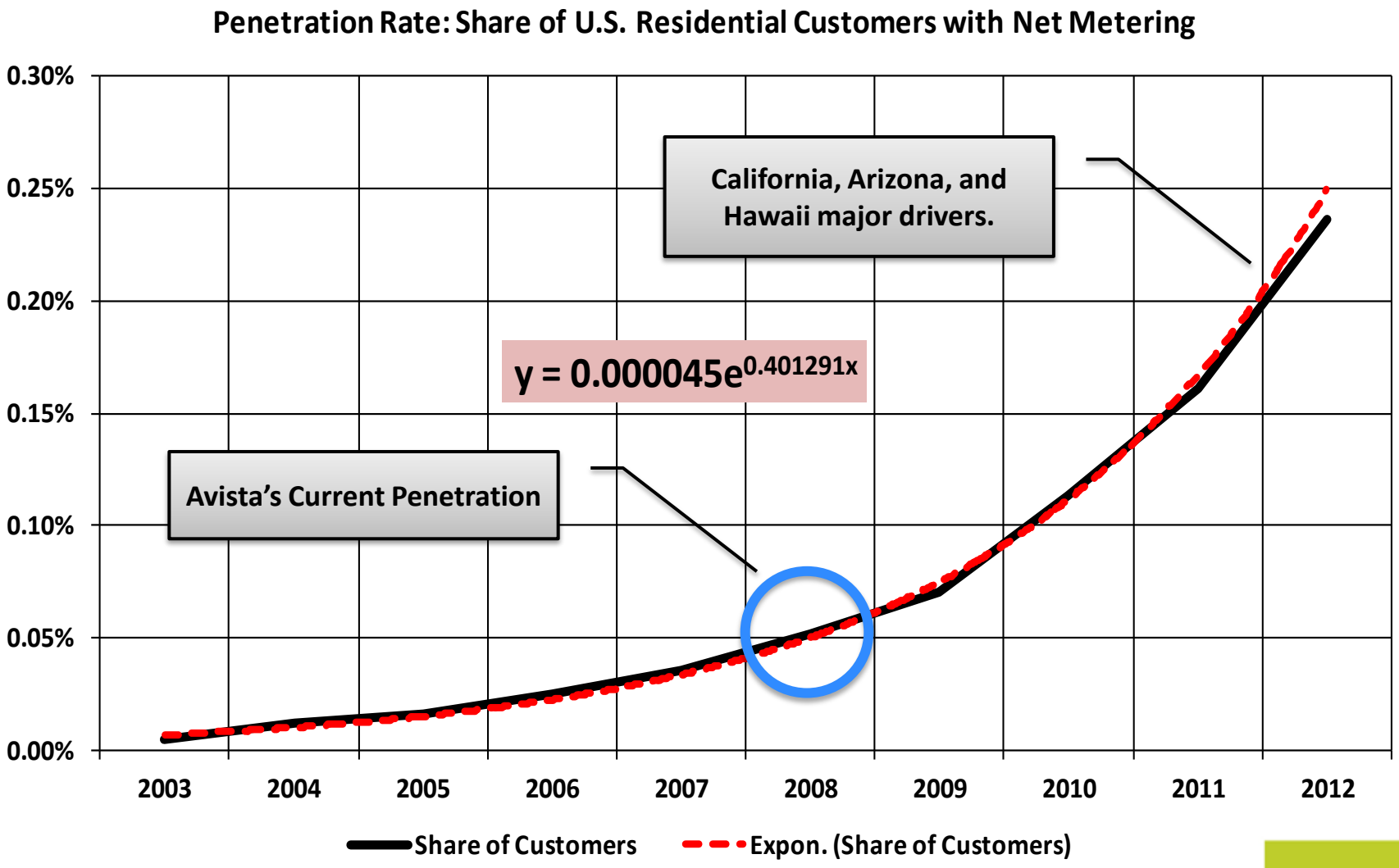
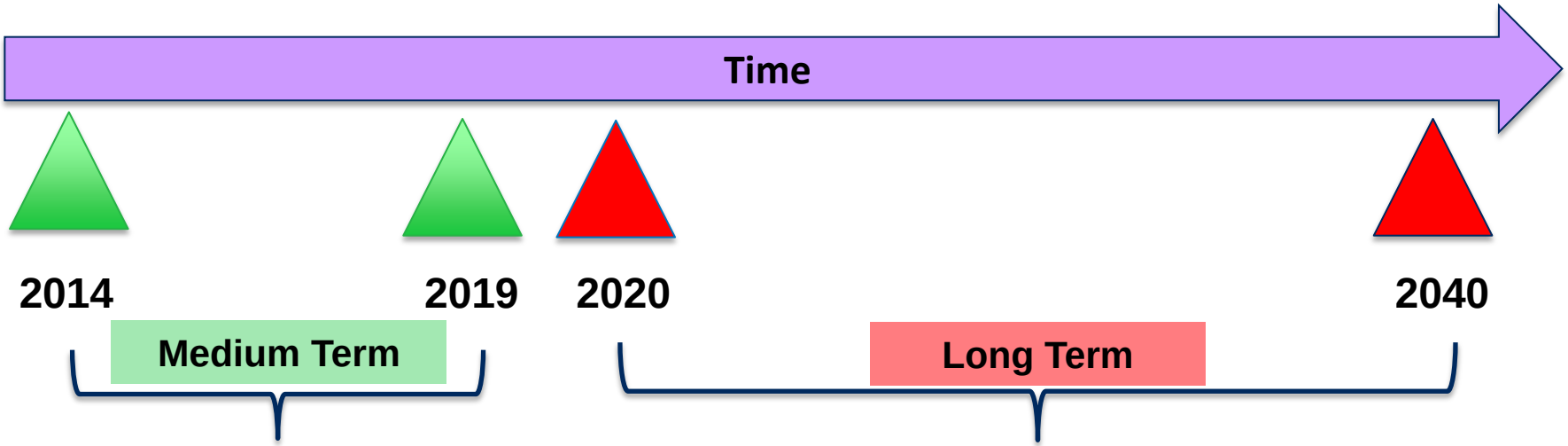
U.S. Penetration Rate for Residential Net Metering



Source: EIA and author's calculations.

Basic Forecast Approach



1) Monthly econometric model by schedule for each class.
2) Customer and UPC forecasts.
3) 20-yr MA for "normal weather."
4) Economic drivers: GDP, industrial production, employment growth, population, price, household size.
5) ARIMA error correction.
6) Native load (energy) forecast derived from retail load forecast.

1) Boot strap off medium term forecast.
2) Apply long-run load growth relationships to develop simulation model for high/low scenarios.
3) Include different scenarios for renewable penetration with controls for price elasticity, average household size, and EV/PHEVs.

The Long-Term Residential Relationship, 2020-2040

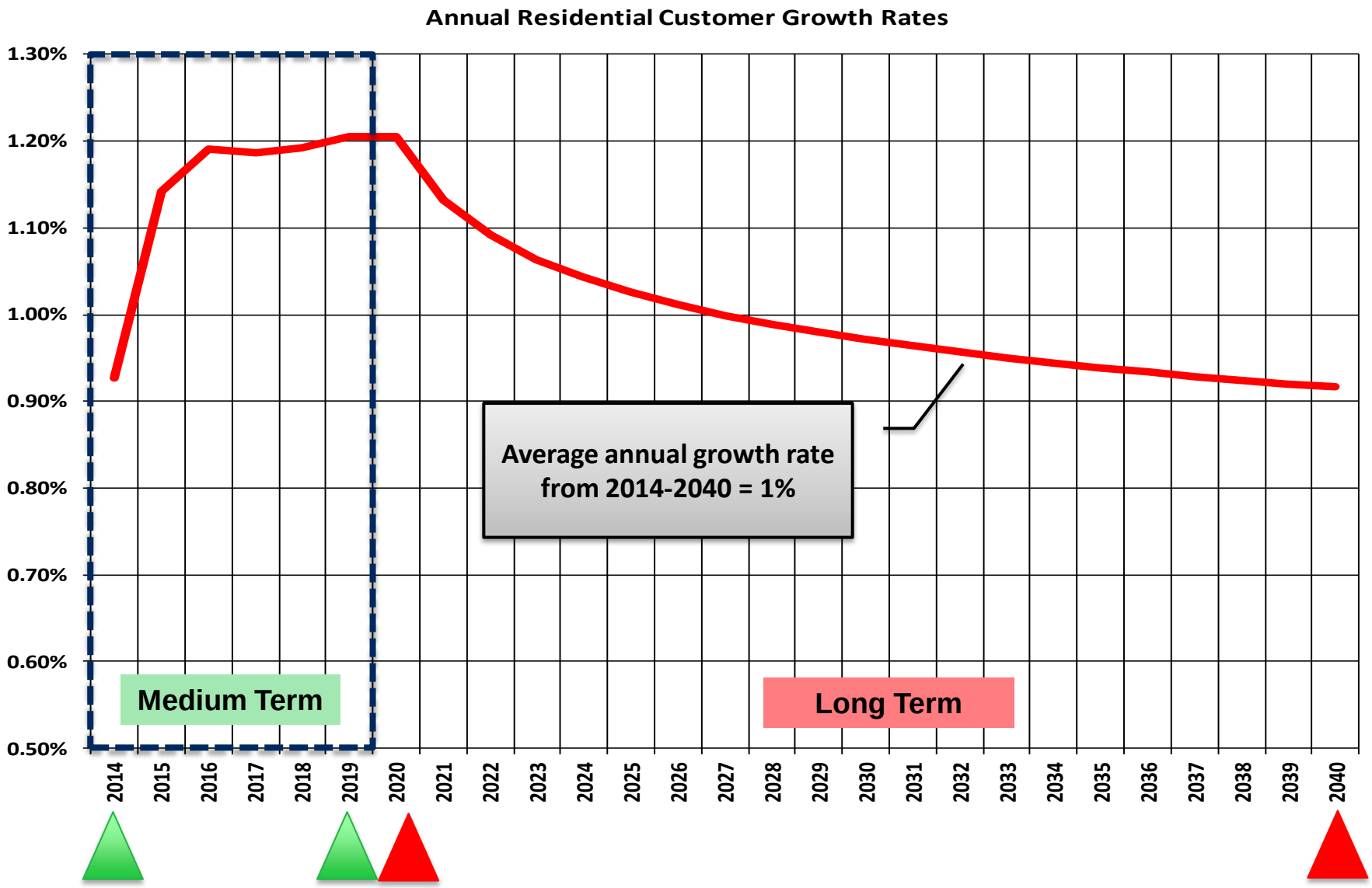
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

Assumed to be same as population growth, commercial growth will follow residential, and no real change in industrial.

Assumed to be a function of multiple factors including renewable penetration.

The Basic Idea: Base-Line Residential Customer Growth Starting in 2020



Assumptions for Residential UPC Growth

- **The Time-Path of Renewable Penetration Rate (Share of Customers with PV)**
- **Starting PV size, generation per Customer, capacity factor, and the time-path of PV size**

- **Own Price Elasticity**
- **Average Household Size Elasticity**
- **Long-Run Trend for EV/PHEV adoption.**

Scenario analysis assuming 1% p.a. residential customer growth and a solar capacity factor of 0.13:

- **Base-Line Scenario: Residential penetration continues to grow in a linear fashion from 0.06% to 0.30% by 2040. PV system size does not change from the current average of 3,000 watts.**
- **Low-Shock Scenario: Residential penetration at an exponential rate from 0.06% to 1% by 2025, and thereafter. PV additions grow to 6,000 watts by 2040.**
- **Medium-Shock Scenario: Residential penetration at an exponential rate from 0.06% to 5% by 2025, and thereafter. PV additions grow to 6,000 watts by 2040.**
- **High-Shock Scenario: Residential penetration at an exponential rate from 0.06% to 10% by 2025, and thereafter. PV additions grow to 6,000 watts by 2040.**

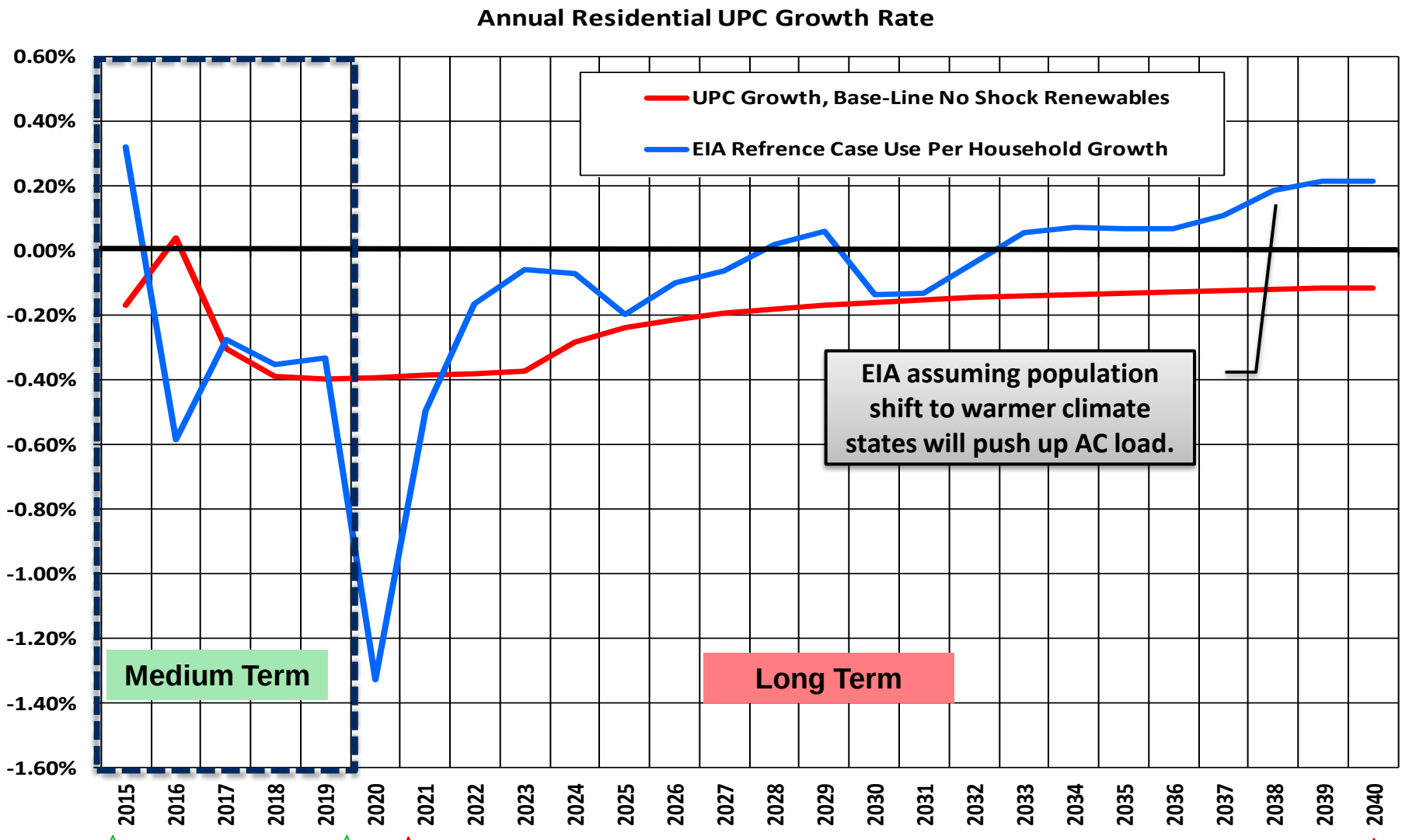
Based on historical norms, the following assumptions are also made:

1. Residential and commercial customer growth will be the same in the long-run.

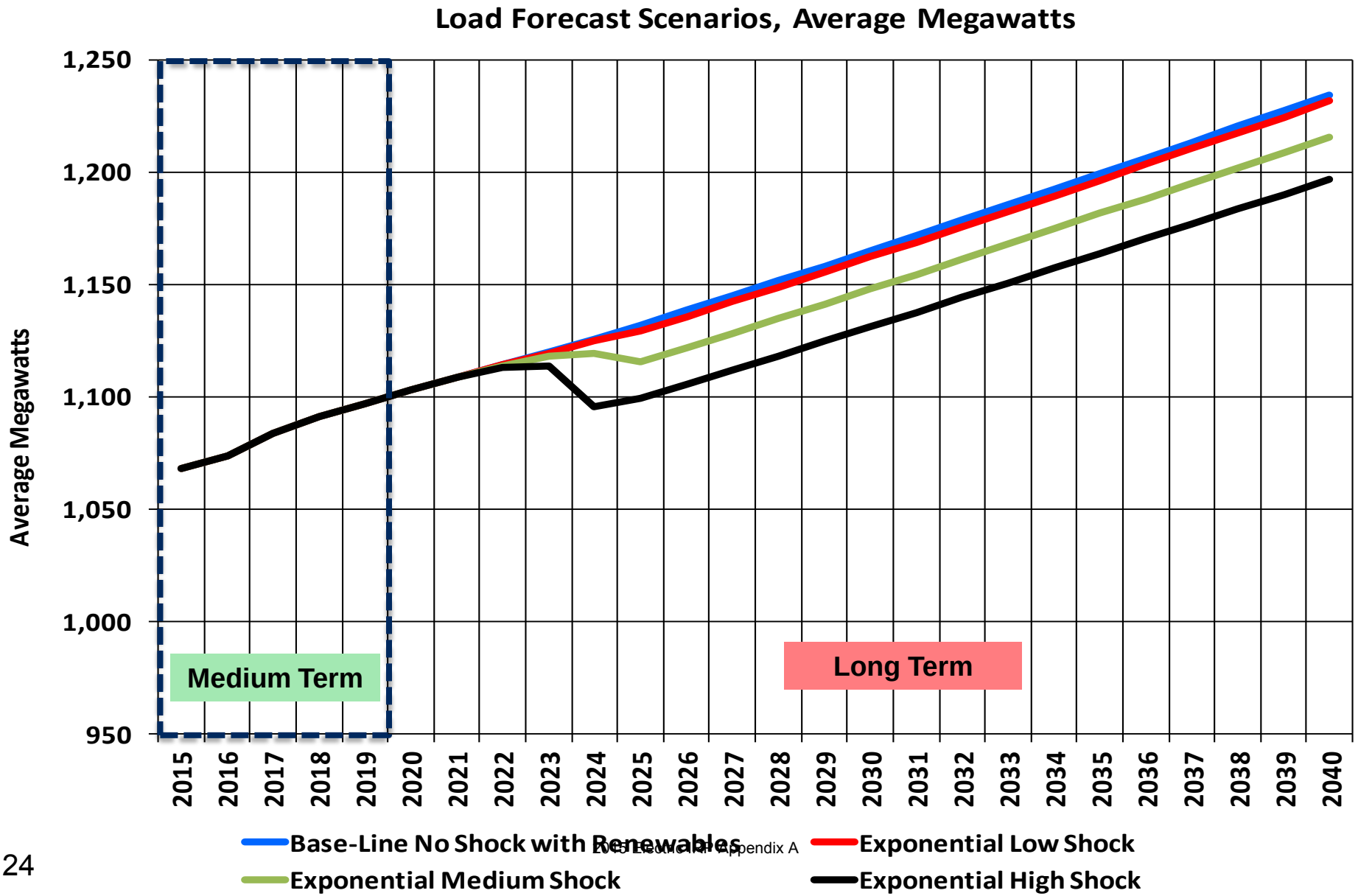
2. Commercial load growth and residential load growth will follow each other based on a historical spread. This assumption is a proxy for commercial price impacts and renewable penetration.

3. Industrial load and customer growth are low and industrial load and customer growth are not strongly correlated with residential or commercial loads.

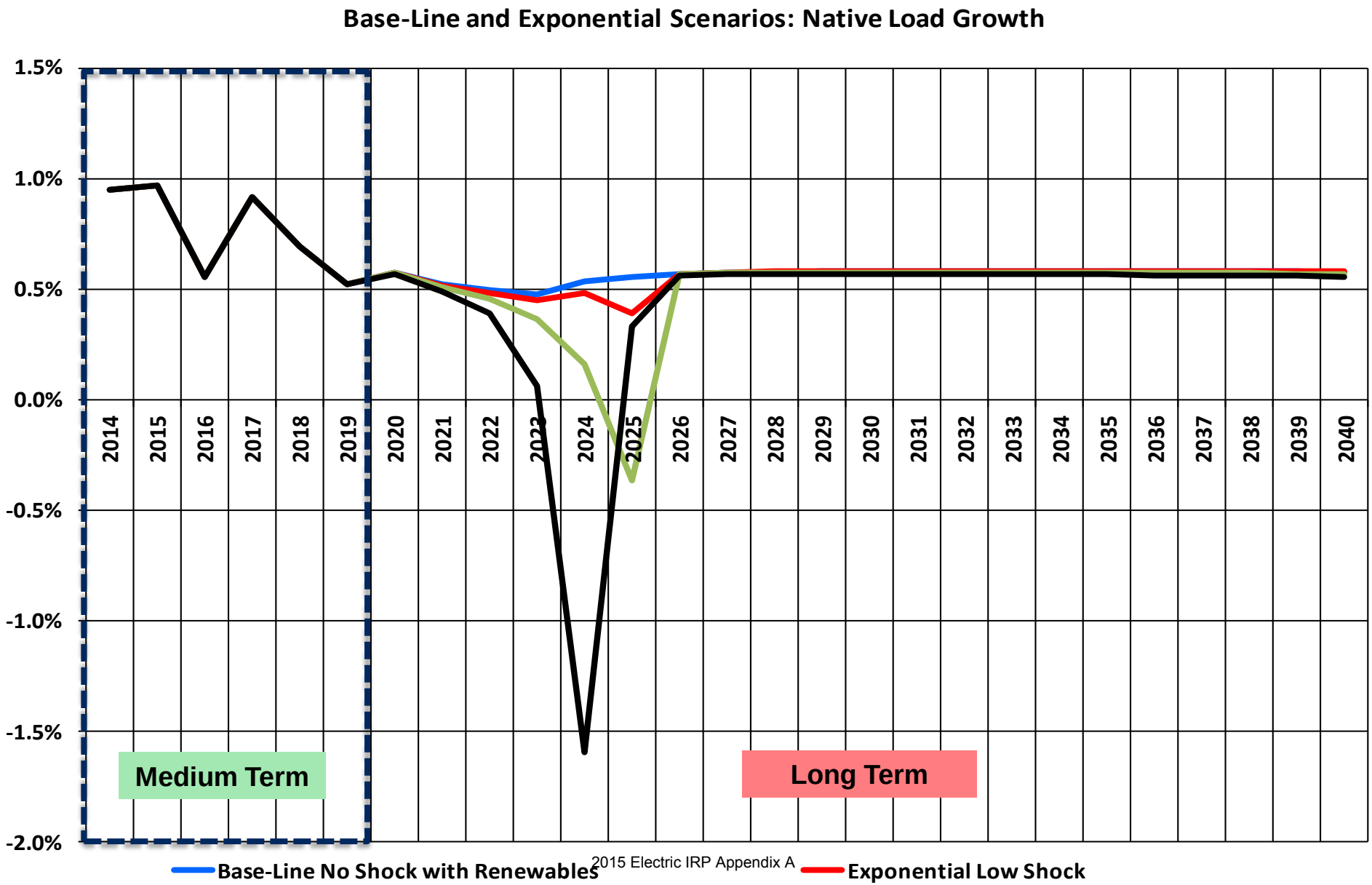
Base-Line Residential UPC Growth Compared with EIA's Residential Reference Case



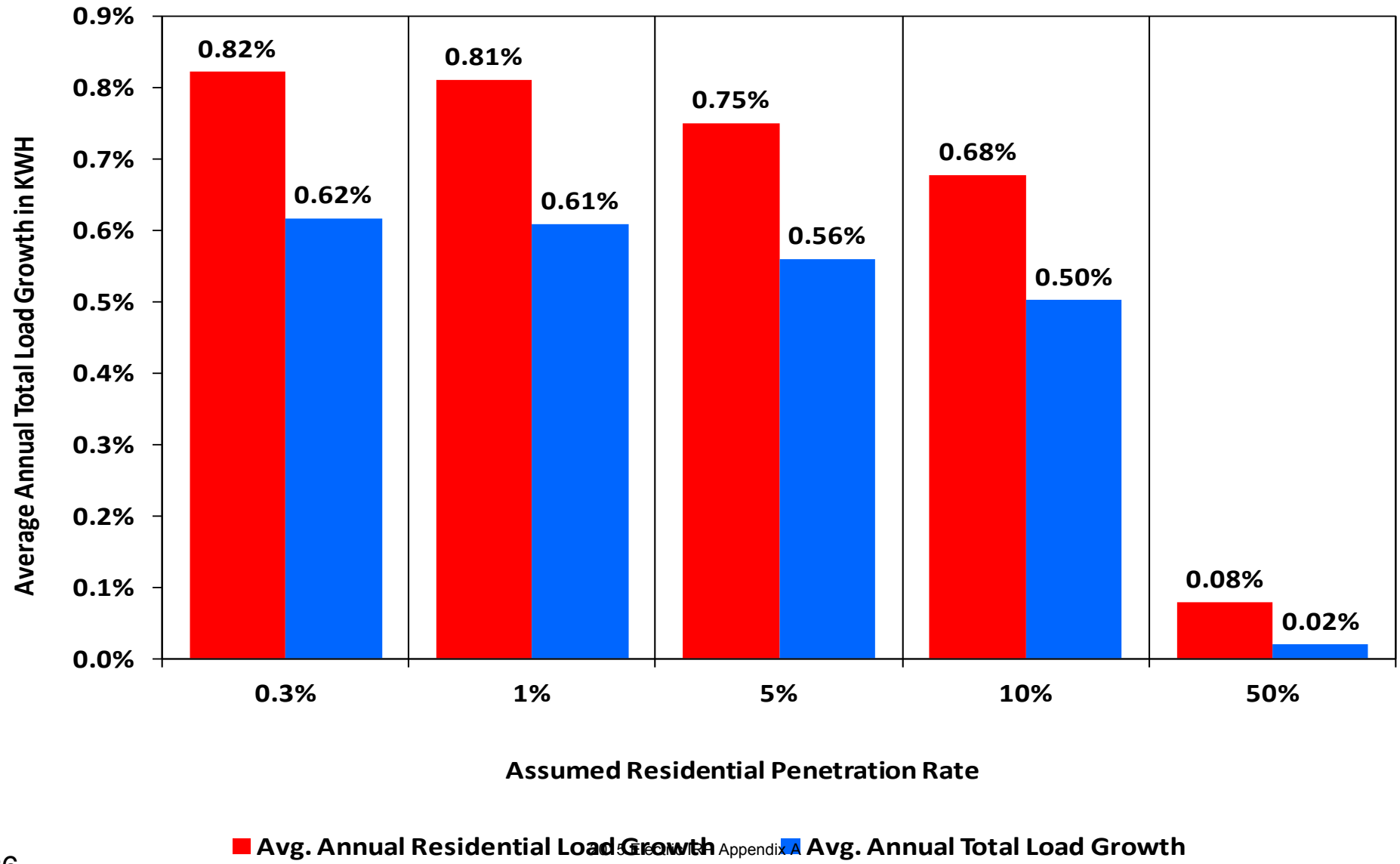
Native Load Scenarios, 2020-2040



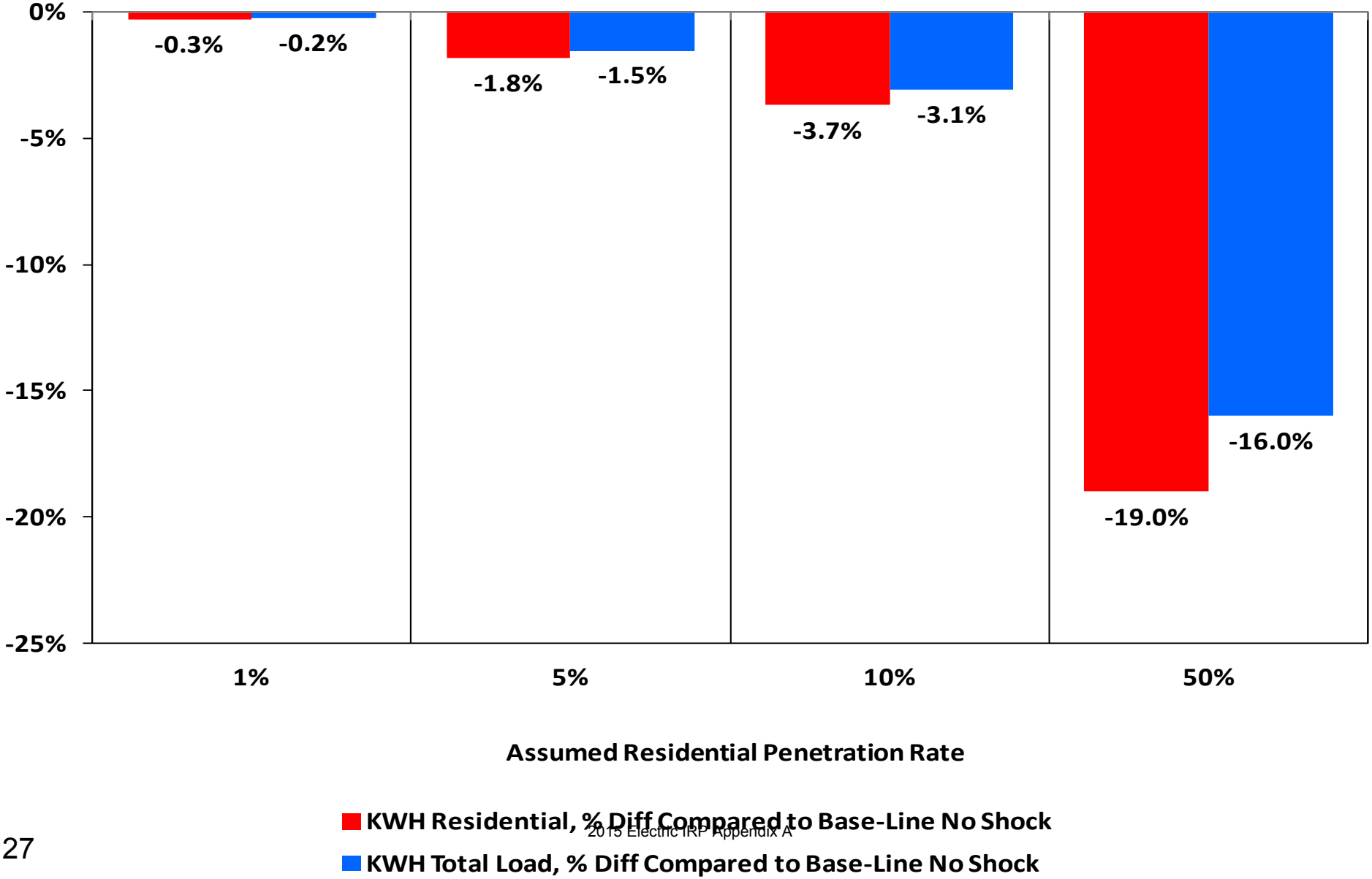
Native Load Growth Scenarios, 2020-2040



KWH Average Annual Load Growth by Scenario, 2014-2040



KWH Load Changes Compared to the Base-Line Scenario, 2020-2040



Final Comment on EV/PHEV Penetration: Large Forecast Variation

Forecast Source	Forecasted Penetration Rate as Share of Vehicles by 2030-2050 Period
U.C. Berkley	65% by 2030 for EVs
EPRI	60% to 65% by 2035 for PHEVs
ORNL	40% by 2035 for PHEVs, 10% by 2050 for EVs
PNNL	30% by 2035-2045 for PHEVs
UMTRI	5% to 25% by 2040 for PHEVs
U.S. DOE	5% to 20% by 2035 for PEVs

Source: From 2013 presentation by Patrick J. Balducci, Pacific Northwest National Laboratory, at the 2013 Pacific Northwest Regional Economic Conference.

Creating Shared Value
Avista's 2014 Report on Our Operations

Casey Fielder

Second Technical Advisory Committee Meeting

September 23, 2014

Our Approach

- Engage with stakeholders throughout the company
- Cross-company Shared Value Action Team

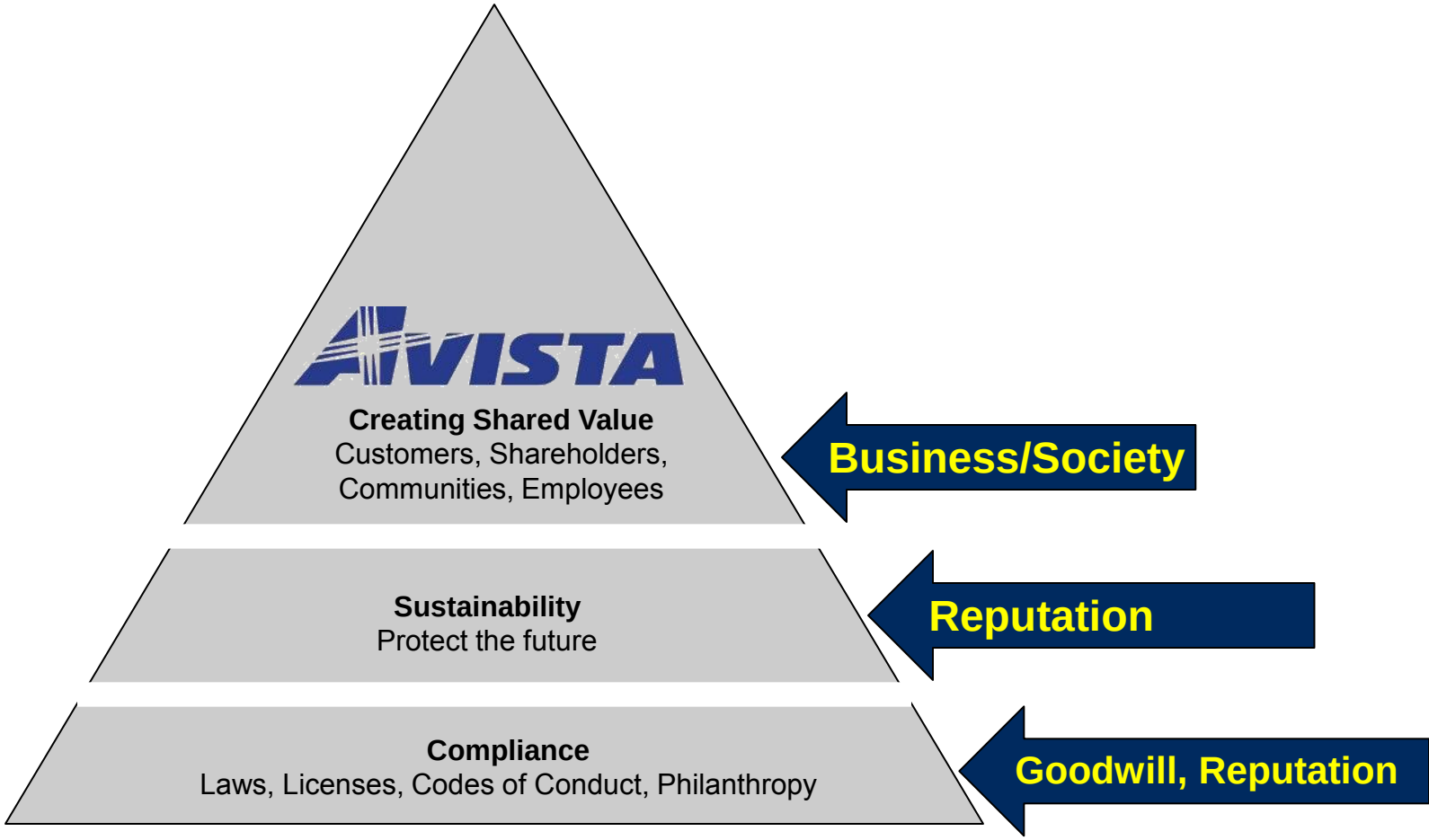
Consumer Affairs
Customer Service
Electric Operations
Energy Solutions/DSM
Environmental
Facilities
Gas Operations
Generation & Production
Health & Safety
Human Resources
Rates
Resource Planning
Supply Chain

125 Years of Shared Value
Avista's Report On Our Performance 2014

Why Report?

- Tell our story
- Educate about our operations
- Communicate the information our stakeholders want to know
- Enhance transparency

The "Shared Value" Pyramid



Defining Shared Value

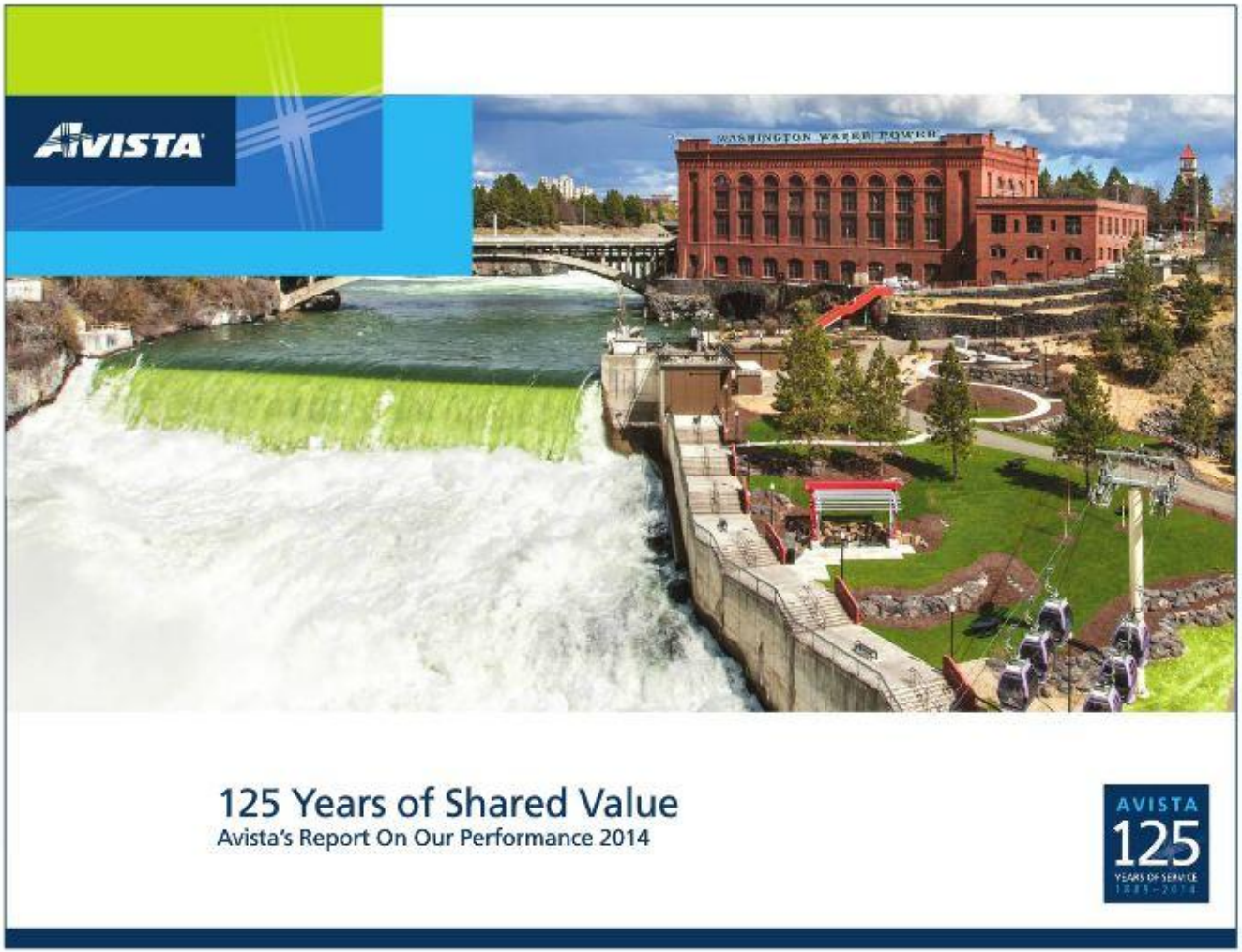
Harvard Business Review – Jan. 2011

The principle of shared value…involves creating economic value in a way that *also* creates value for society by addressing its needs and challenges. Businesses must reconnect company success with social progress. Shared value is not social responsibility, philanthropy, or even sustainability, but a new way to achieve economic success.

Shared Value – The Opportunity

A snapshot in time of what Avista does well that grows our business and at the same time provides “social” value

Highlights from 2014 Report



Highlights from 2014 Report

Shared Value In Action

Palouse Wind Event

Highlights from 2014 Report

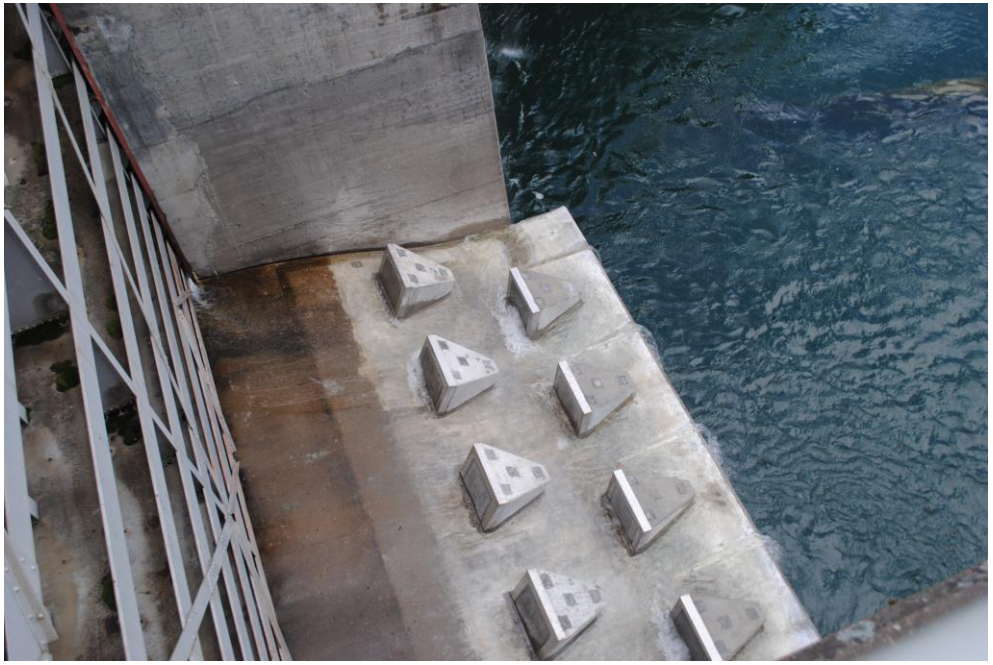
Shared Value In Action

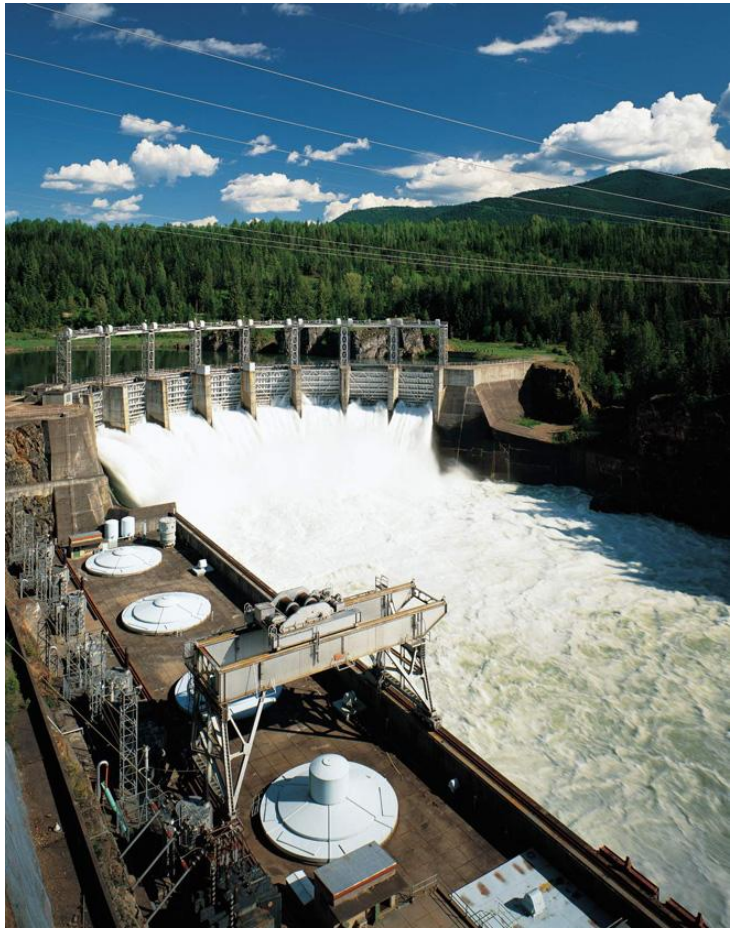
Smart Technology At Work In Real Situation

Highlights from 2014 Report

Shared Value In Action

Cabinet Gorge Dam Reaches New Milestone In 2013 With Total Dissolved Gas Abatement Project





Highlights from 2014 Report

Shared Value In Action

Energy Resource Team Van

Materiality

CORPORATE CITIZENSHIP
Community relations, volunteerism, philanthropy, sponsorships

ENVIRONMENTAL PERFORMANCE
Stewardship of environmental elements impacted by operations

SYSTEM RELIABILITY
Consistency of energy delivery

RESOURCE PLANNING
Short and long-term outlook to meet customers' energy needs

CUSTOMER SATISFACTION
Company performance in ways that meet customer needs

Materiality

The Role of Our Stakeholders

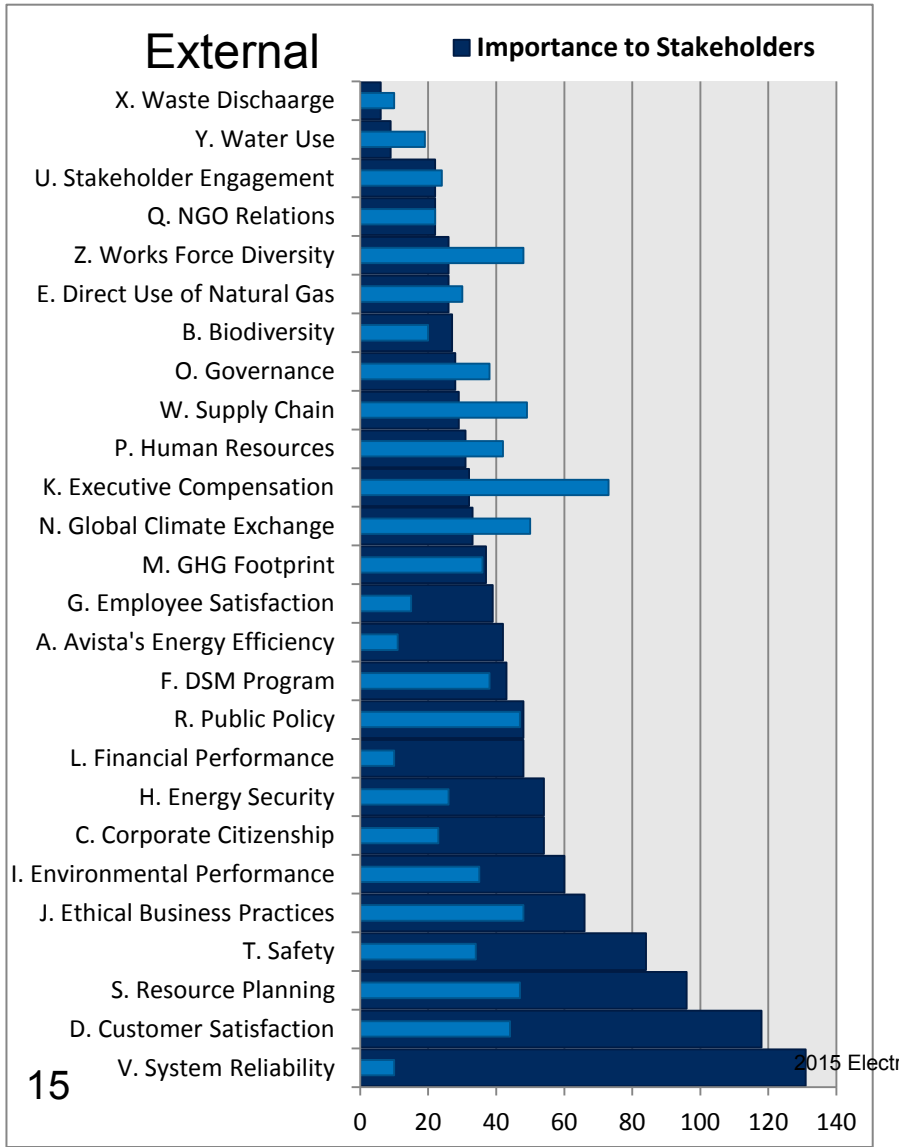
Engaging Our Stakeholders

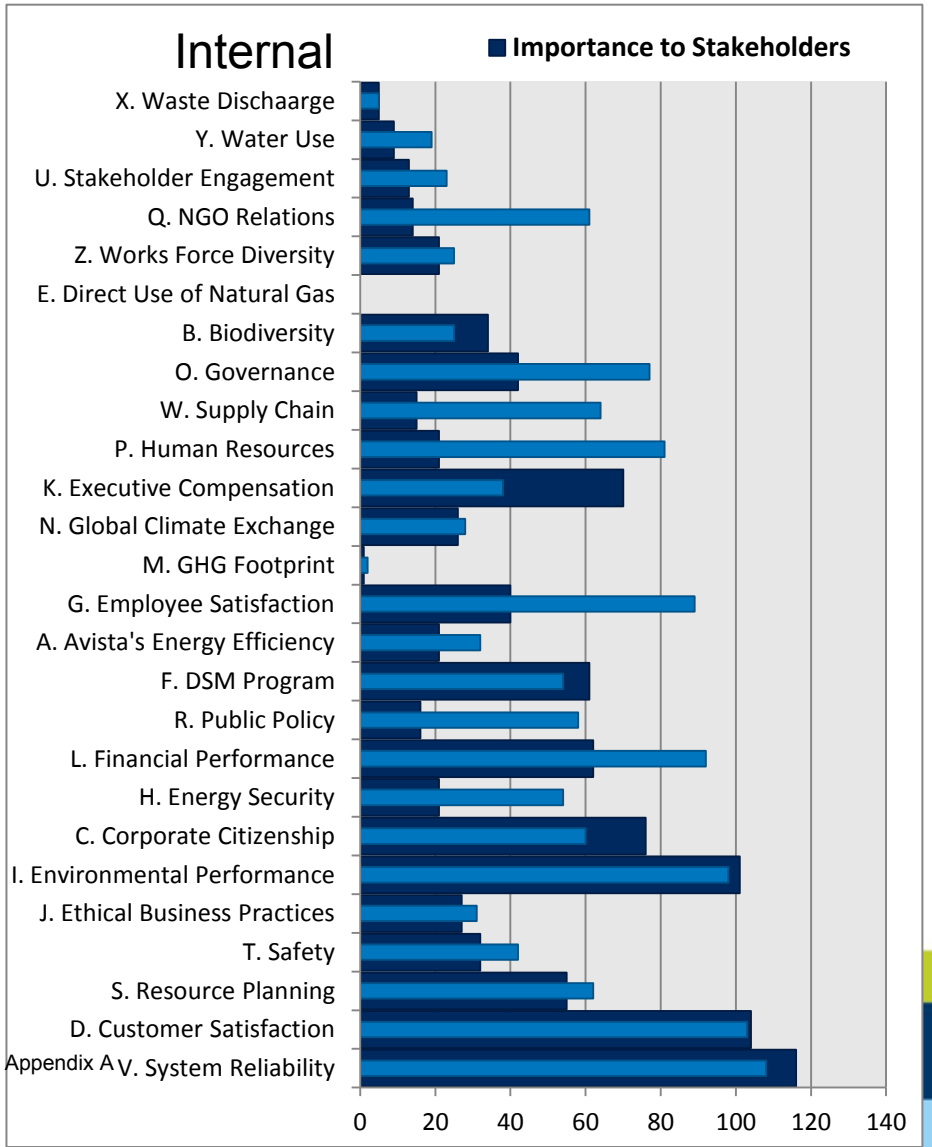
Approaches To Stakeholder Engagement

Identification Of Stakeholders

Key Topics Raised By Stakeholders

Determining Content Materiality





Materiality Exercise

Consider each of the topics on the list for:

-- The importance you think each has for the stakeholders of Avista
-- The relevance or impact each could have for Avista

Plot the letter of each topic on the grid depending on the intersection of the values of importance to stakeholders and relevance for Avista

125 Years of Shared Value
Available at avistautilities.com

Feedback: SharedValue@avistacorp.com

Generation Options

Thomas Dempsey, P.E. and James Gall
Second Technical Advisory Committee Meeting
September 23, 2014

Natural Gas Generation Options

- Existing site vs. new site (“Brownfield” vs. “Greenfield”)
- Simple cycle combustion turbines (peaking)
- Simple cycle piston engines (peaking/hybrid, operation/load following)
- Combined cycle (base load/load following)
- Simple cycle combustion turbine with subsequent conversion to combined cycle

Natural Gas Generation Options Considerations

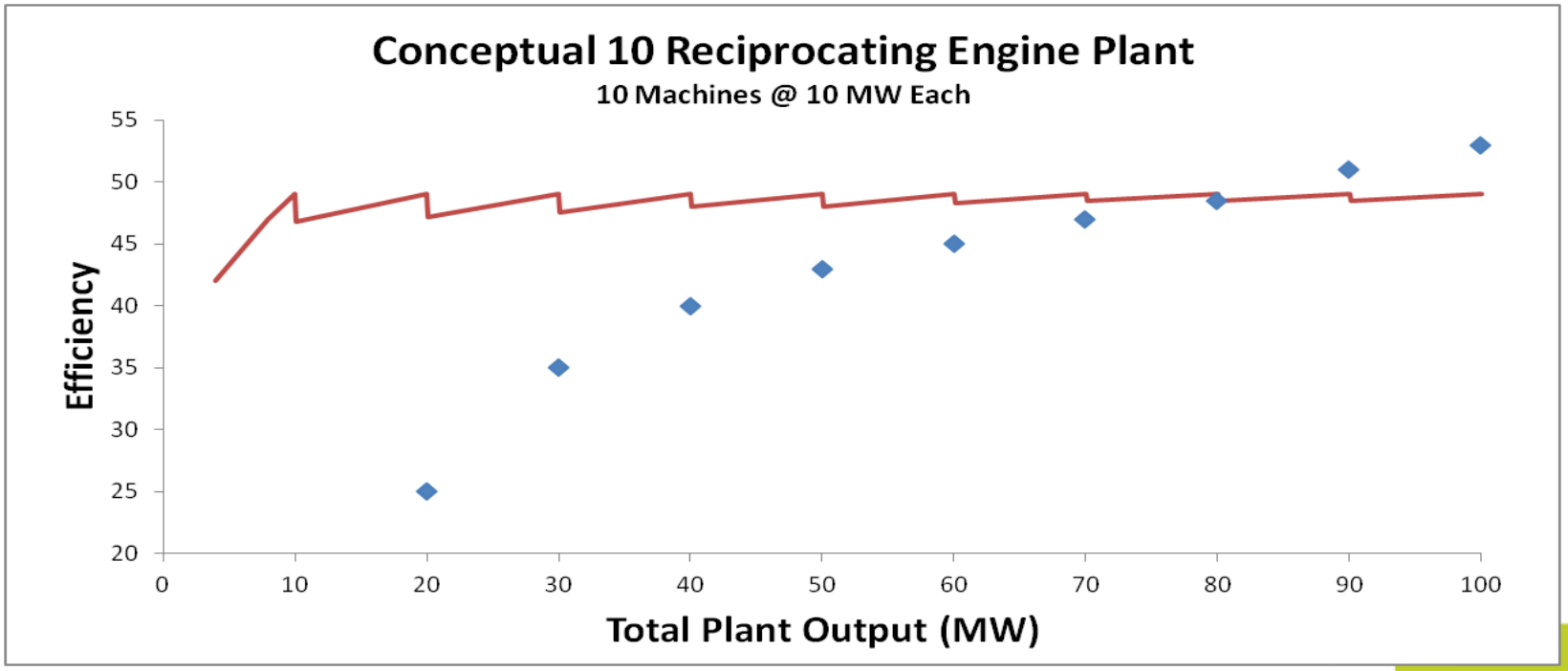
- Efficiency
  - Fuel efficiency
  - Responsible use of resources
  - Environmental impacts
- Flexibility- meets operational requirements
  - Start time
  - Part load efficiency
  - Ability to, and speed of, cycling
- Costs
  - Upfront installation
  - Fuel
  - Ongoing operations & maintenance

Efficiency

- Greater efficiency means lower fuel costs
- Greater efficiency means lower emissions
  - NOx, SO_2, VOC's, CO, CO_2
- Efficiency is very important for options expected to have many run hours, but less important for options selected for peaking service or reserves
- Other considerations, such as water or other consumable use is also considered

Flexibility

- A flexible plant is quick to start, quick to full load, can withstand large frequent load swings (i.e., backing up variable resources), has low emissions across its operational range, and can be operated with minimal staff.



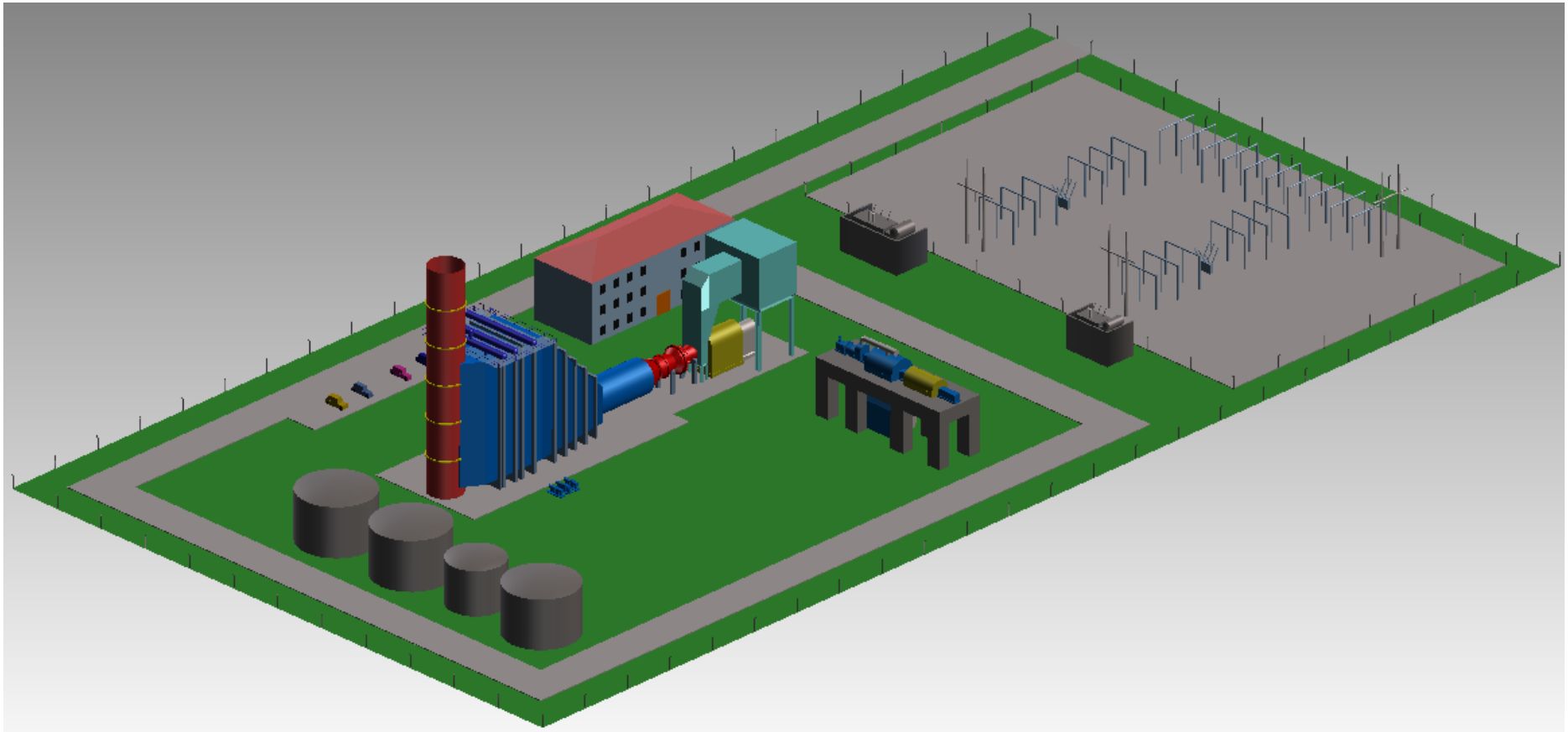
Costs

- Avista has access to an extensive turbine database including machine price data that allows us to choose more effective cost options.
- Initial capital cost
  - Brownfield vs. Greenfield
  - Economies of scale
- Ongoing operations & maintenance costs
- Fuel costs

Thermoflow

- Sophisticated program allowing Avista to create preliminary plant designs
- Allows for detailed initial cost estimates
- Initial plant layouts
- Site specific performance modeling
- Plant Engineering And Cost Estimation (PEACE)

Thermoflow PEACE Output



Thermoflow PEACE Output

Project Cost Summary	Reference Cost	Estimated Cost	
Power Plant:			
I Specialized Equipment	122,940,000	130,316,000	USD
II Other Equipment	10,993,000	11,652,000	USD
III Civil	19,827,000	25,879,000	USD
IV Mechanical	20,516,000	28,135,000	USD
V Electrical Assembly & Wiring	5,711,000	7,946,000	USD
VI Buildings & Structures	11,842,000	15,631,000	USD
VII Engineering & Plant Startup	15,063,000	15,104,000	USD
Gasification Plant	NA	NA	
Desalination Plant	NA	NA	
CO2 Capture Plant	NA	NA	
Subtotal - Contractor's Internal Cost	206,891,000	234,664,000	USD
VIII Contractor's Soft & Miscellaneous Costs	43,676,000	53,971,000	USD
Contractor's Price	250,567,000	288,635,000	USD
IX Owner's Soft & Miscellaneous Costs	10,109,000	11,522,000	USD
Total - Owner's Cost (1 USD per US Dollar)	260,676,000	300,157,000	USD
Nameplate Net Plant Output	343	343	MW
Price per kW - Contractor's	730.2	841.1	USD per kW
Cost per kW - Owner's	759.7	874.7	USD per kW
* Cost estimates as of April 2014.			

Available Gas Turbine Upgrades For Avista Plants

- Supplemental Compression- enhances capability of simple cycle 7EA machines at the Rathdrum CT
- Inlet Evaporation System- increases summer capability
- High efficiency turbine blades
- Water injected NOx control to allow for firing temperature increase

Kettle Falls Efficiency Improvements

- Fuel stabilization- fuel drying or conditioning to keep the boiler operating at a continuously efficient point
- Turbine and generator efficiency improvements to achieve greater output using the same amount of fuel

Hydro Upgrades

- Same assumptions and options as 2013 IRP, adjusted for cost inflation
- Post Falls- A detailed study is being performed to study long-term options for the 104 year old project- results will not be available for this IRP cycle

Project	MW	Capacity Factor	Winter Peak Credit	Summer Peak Credit	Capital Cost (Mil $)	$/MWh-Levelized
Long Lake 2nd Powerhouse	68	34%	100%	100%	$140	$108
Monroe Street/Upper Falls 2nd Powerhouse	80	34%	31%	0%	$152	$93
Cabinet Gorge 2nd Powerhouse*	110	17%	0%	0%	$231	$197

* Project is limited to water rights

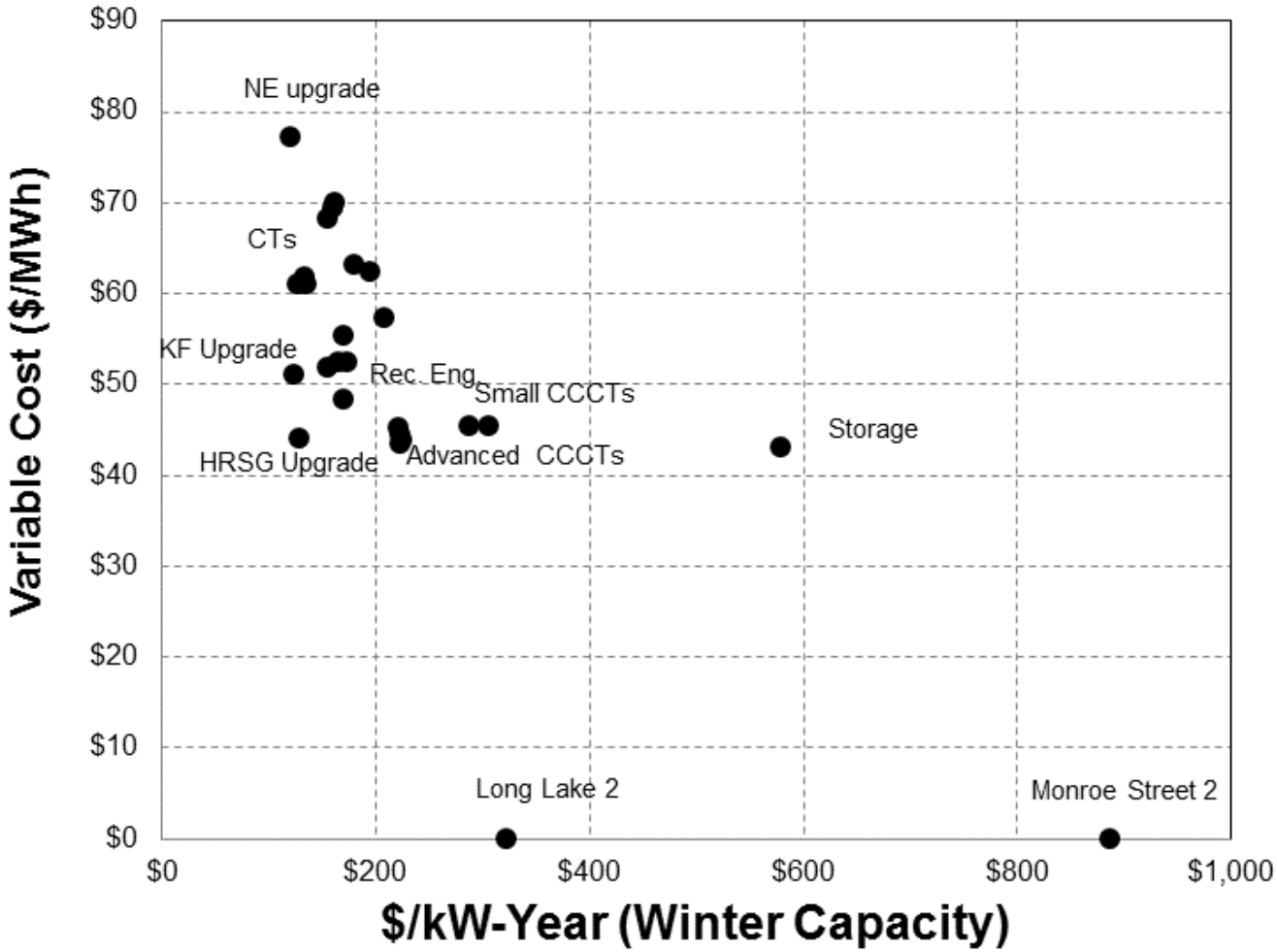
Natural Gas Turbine Resource Options

Resource Option	Technology	Plant Size (MW) (59F)	Capital Cost Excludes AFUDC (2014$/kW)	Fixed O&M (2014$/kW/Yr)	Variable Costs (2014$/MWh)	Net HHV Heat Rate(s) (Btu/kWh)
Advanced Large Frame CT	Frame SC	203	608	2	3.50	9,931
Modern Large Frame CT	Frame SC	171	636	2	2.50	10,007
Modern Large Frame CT with HRSG Option	Frame SC	170	710	3	2.50	10,009
Advanced Small Frame CT	Frame SC	96	814	3	2.50	11,265
Frame/Aero Hybrid CT	Advanced Aero SC	101	965	3	3.00	8,916
Large Reciprocating Engine Facility	NG Recip	184	1,048	7	3.00	8,427
Small Reciprocating Engine Facility (Option 1)	NG Recip	110	1,072	8	3.00	8,427
Small Reciprocating Engine Facility (Option 2)	NG Recip	93	1,075	8	3.00	7,700
Modern Small Frame CT	Frame SC	45	1,206	4	2.50	10,252
Aero CT option 1	2 on 1 SS	45	1,221	6	2.50	10,392
Aero CT option 2	Aero SS	42	1,255	6	2.50	9,359
1 on 1 Advanced CCCT option 1	1 on 1 CC	341	1,045	18	3.75	6,631
1 on 1 Advanced CCCT option 2	1 on 1 CC	343	1,045	18	3.75	6,895
1 on 1 Advanced CCCT option 3	1 on 1 CC	294	1,091	19	3.50	6,790
1 on 1 modern CCCT option 3	1 on 1 CC	286	1,099	15	3.00	6,720
3 x 2 small CCCT	3 on 2 CC	225	1,601	27	3.50	6,980
2 x 1 small CCCT	2 on 1 CC	150	1,645	34	3.50	6,968
Add HRSG to Large Frame CT	1 on 1 CC	286	635	20	3.50	6,720

Levelized costs for Natural Gas-Fired Resources

- In past IRP's, Avista communicated levelized costs for all resources.
- Levelized costs work well for energy only resources, but do not communicate the cost of capacity
- Rather than showing levelized costs for capacity resources, the following slide shows capacity cost vs. energy costs for capacity resources
- Least cost resources represent the right mix of cost between low cost capacity and energy

Fixed vs. Variable Costs

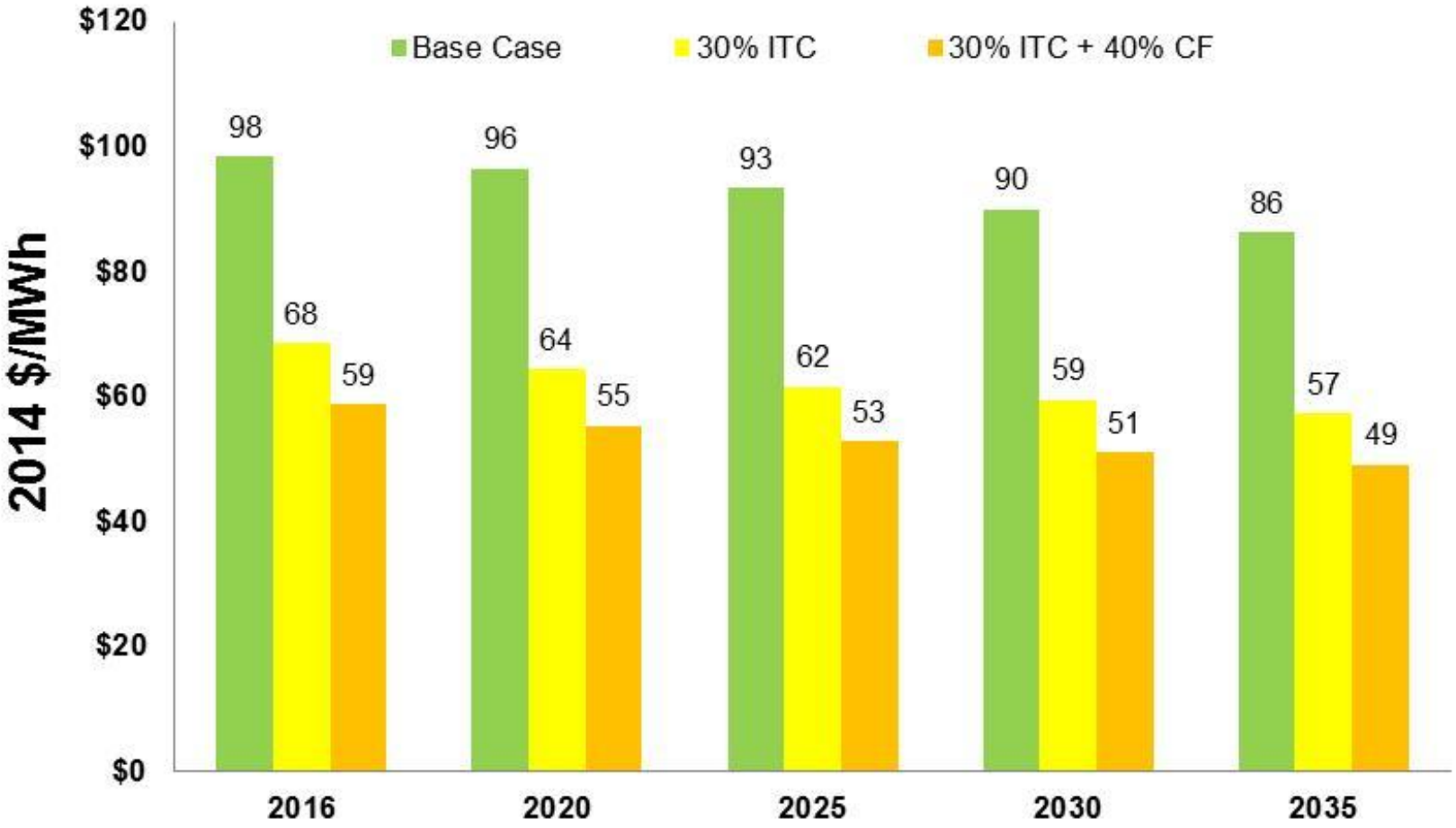


Renewables & Storage

Resource	MW	Capacity Factor	Winter Peak Credit	Summer Peak Credit	Capital Cost * (2014$/kW)	$2015/MWh-Levelized
Wind On-System	99	35%	0%	0%	$2,050	$102
Solar Photovoltaic Fixed Array	5.0	14%	0%	60%	$2,100	$197
Solar Photovoltaic Fixed Array	25.0	14%	0%	60%	$2,000	$180
Solar Photovoltaic with Single Axis Tracking	25.0	18%	0%	70%	$2,500	$185
Battery Storage	25.0	N/A	100%	100%	$4,000	N/A

** Capital Costs excludes AFUDC*

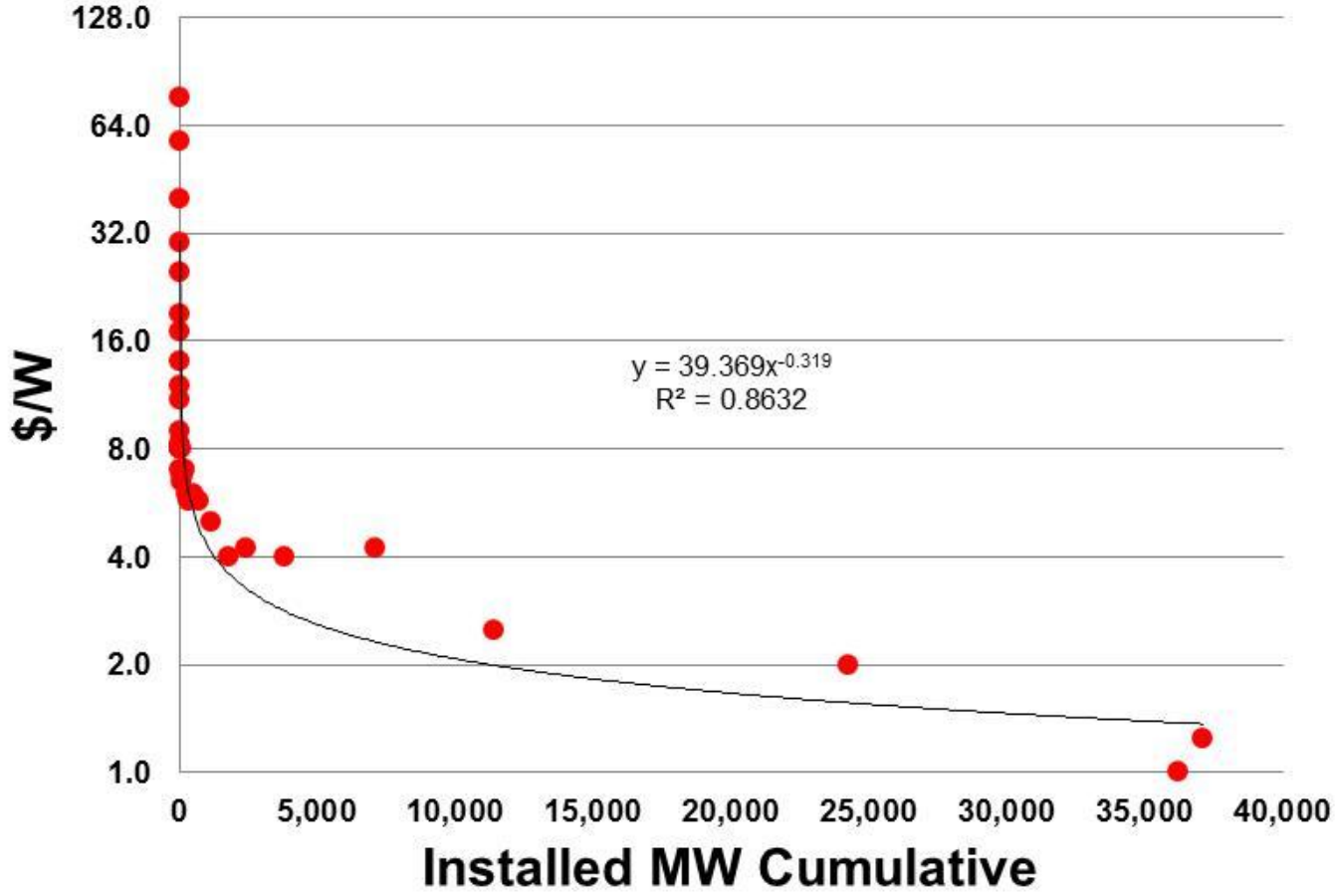
Wind Levelized Costs Forecast



Assumptions:
1) Cost shown are 2014 dollars levelized for first 20 years of asset life
2) ITC benefit taken up front, rather than utility amortization method

Solar Experience Curve (Past)

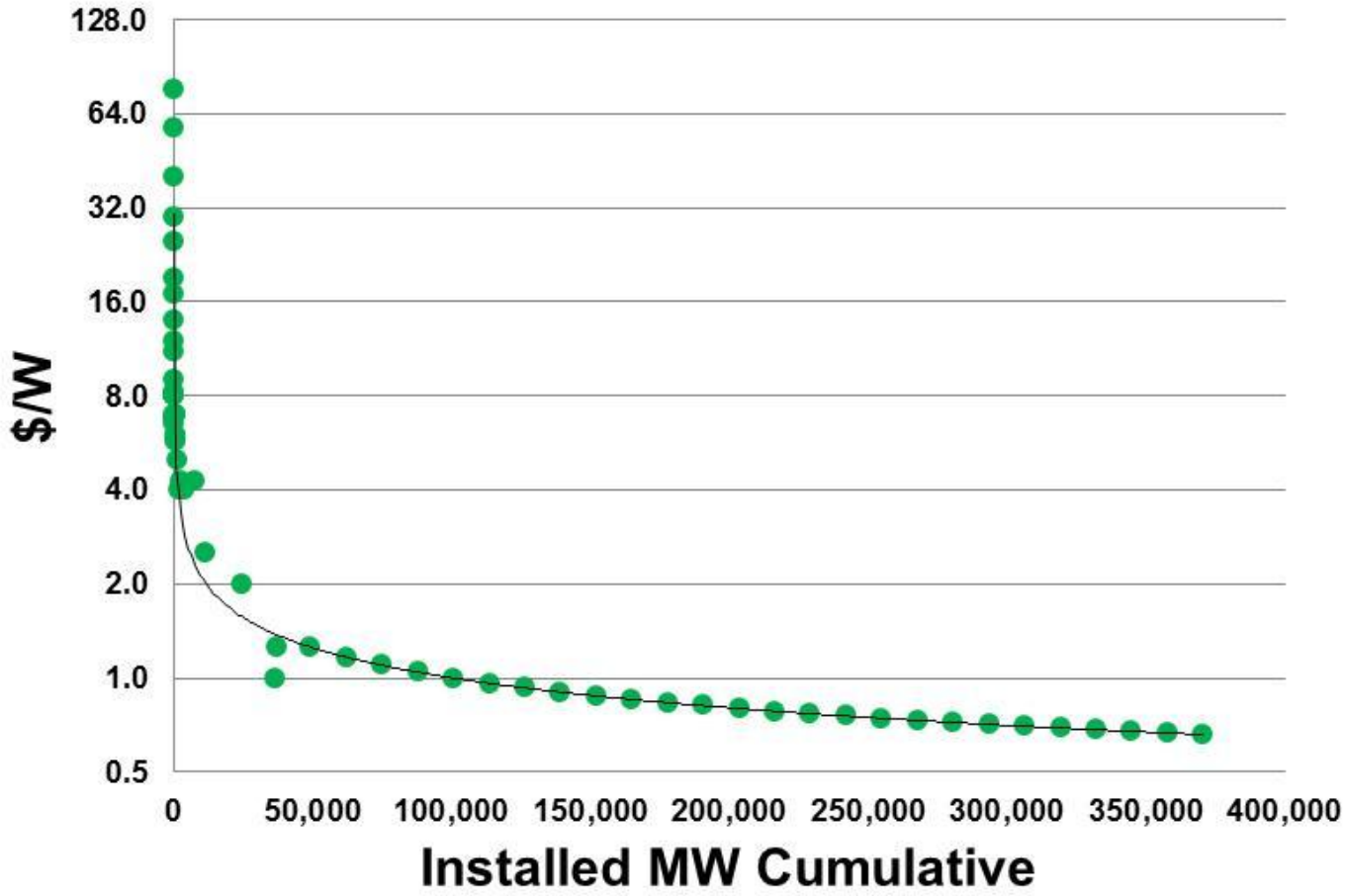
As production increase, costs fall



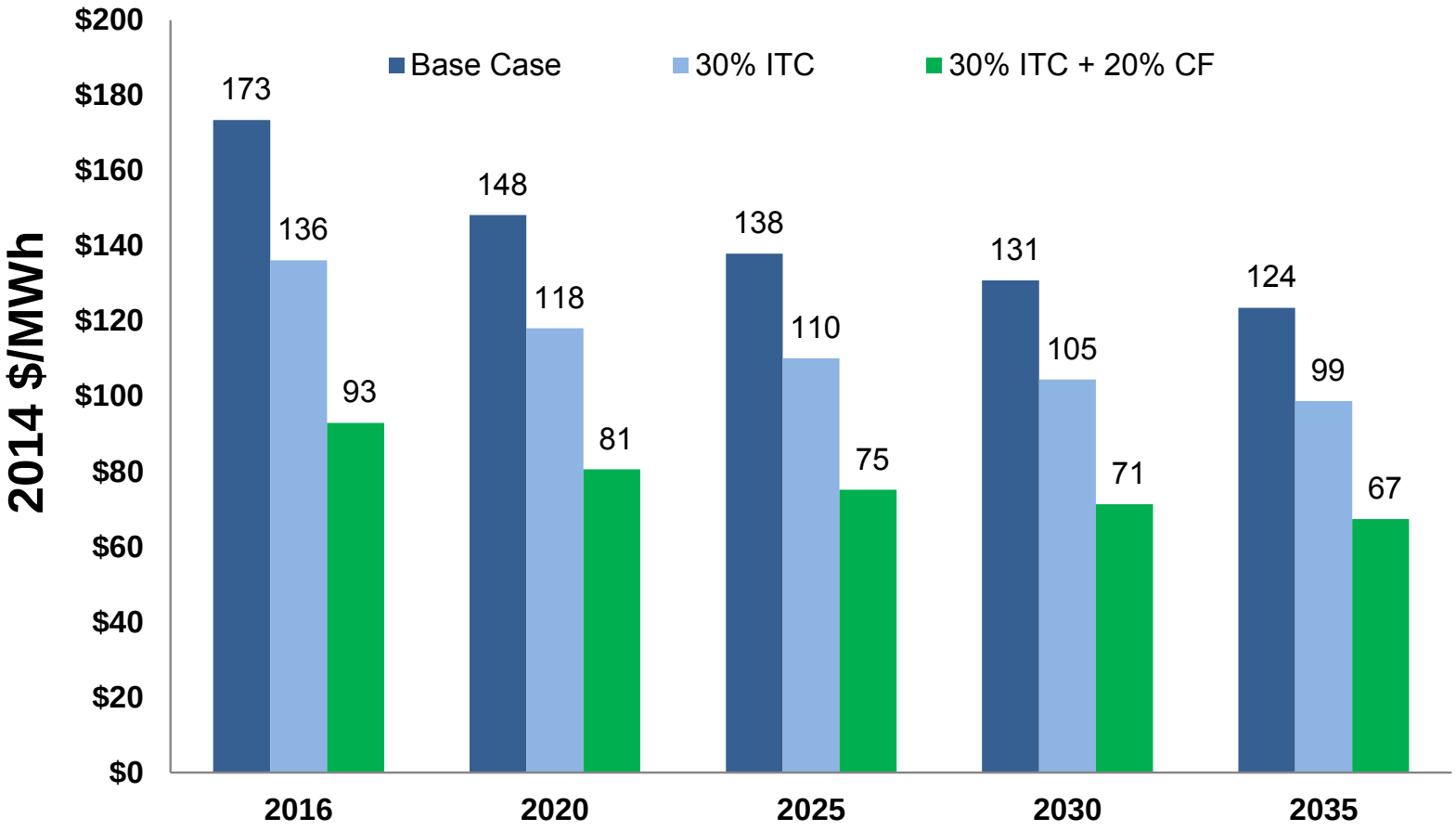
World Solar Photovoltaic Production,1975-2012
Data from Earth Policy Institute and Bloomberg

Solar Experience Curve (Future)

How could costs change with 10 times the cumulative installation

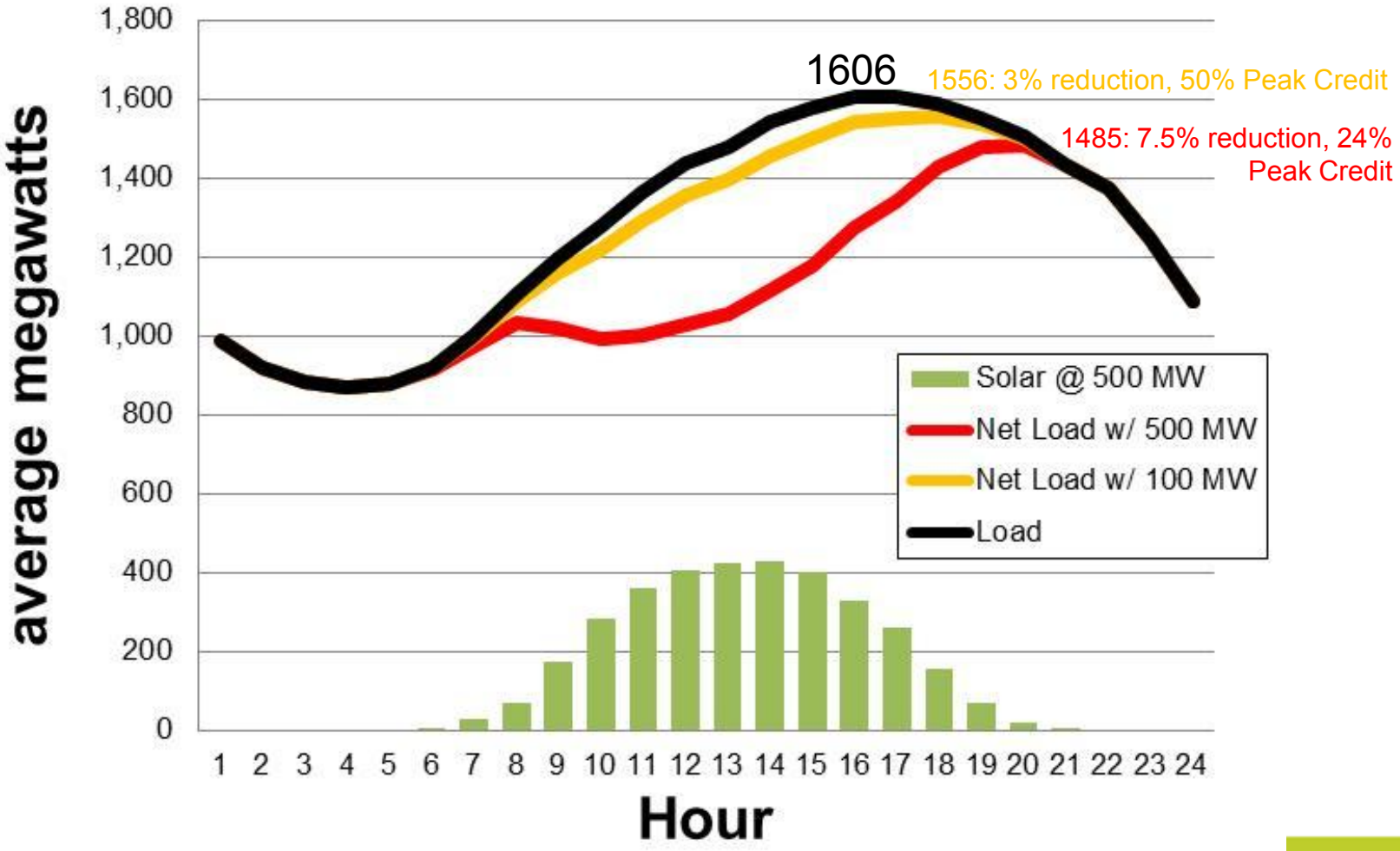


Solar Levelized Costs Forecast



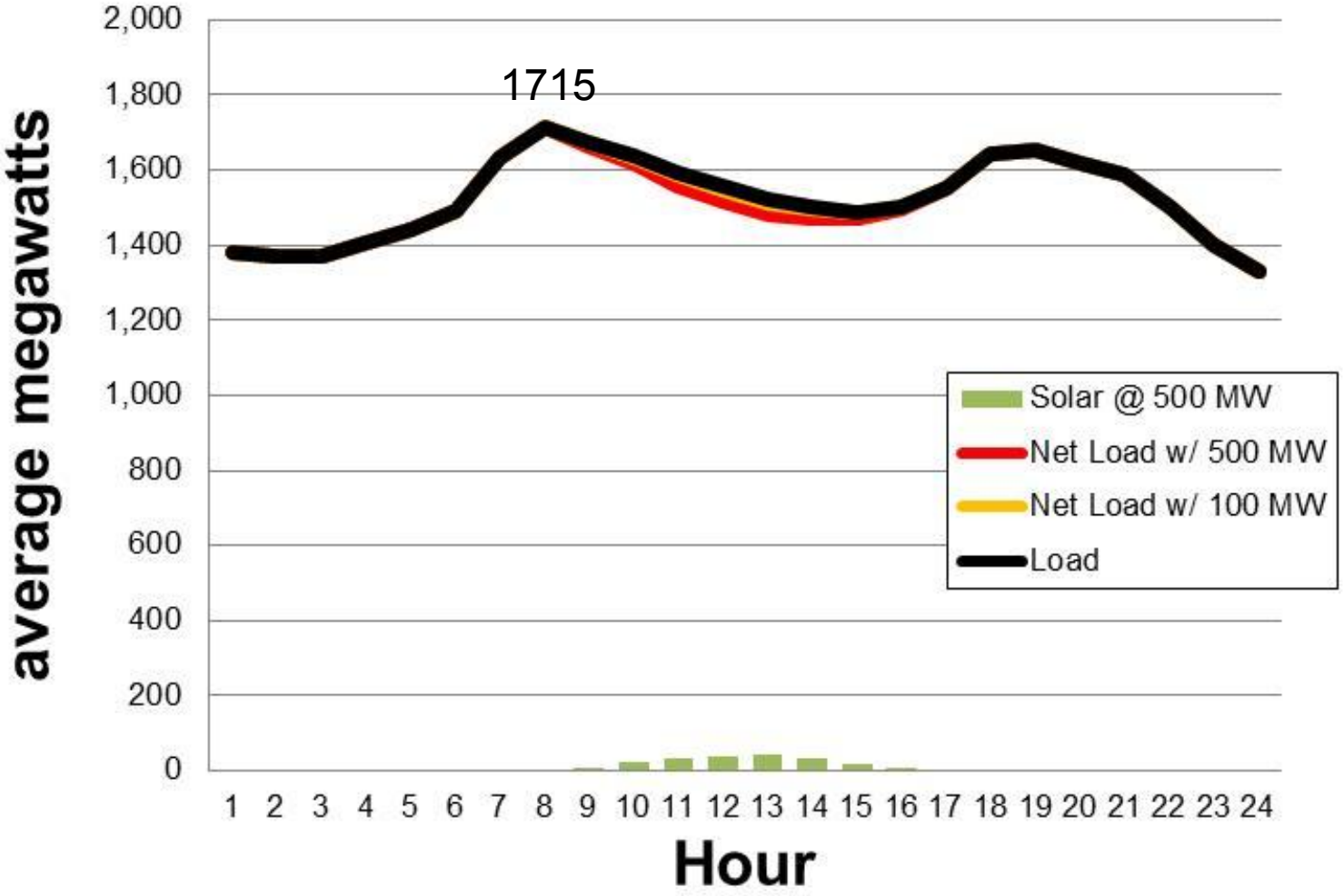
Assumptions:
1) Cost shown are 2014 dollars levelized for first 20 years of asset life
2) ITC benefit taken up front, rather than utility amortization method

Fixed Solar on Summer Peak (7/16/14)



25 MW would get 60% peak credit

Fixed Solar on Winter Peak (1/21/14)



25 MW would get 0% peak credit

Standby Generation

- Avista is exploring the use of customer's standby generation for meeting peak and non-spinning reserve requirements
- Portland General Electric currently has a similar program with over 100 MW enrolled in the program
- 30 MW of capability is required to have a viable program (e.g. 60 customers with 500 kW generators)
- Feasibility study is expected to be finished by the end of the year – update will be made at a future TAC meeting

Clean Power Plan Discussion

John Lyons, Ph.D. and Clint Kalich
Second Technical Advisory Committee Meeting
September 23, 2014

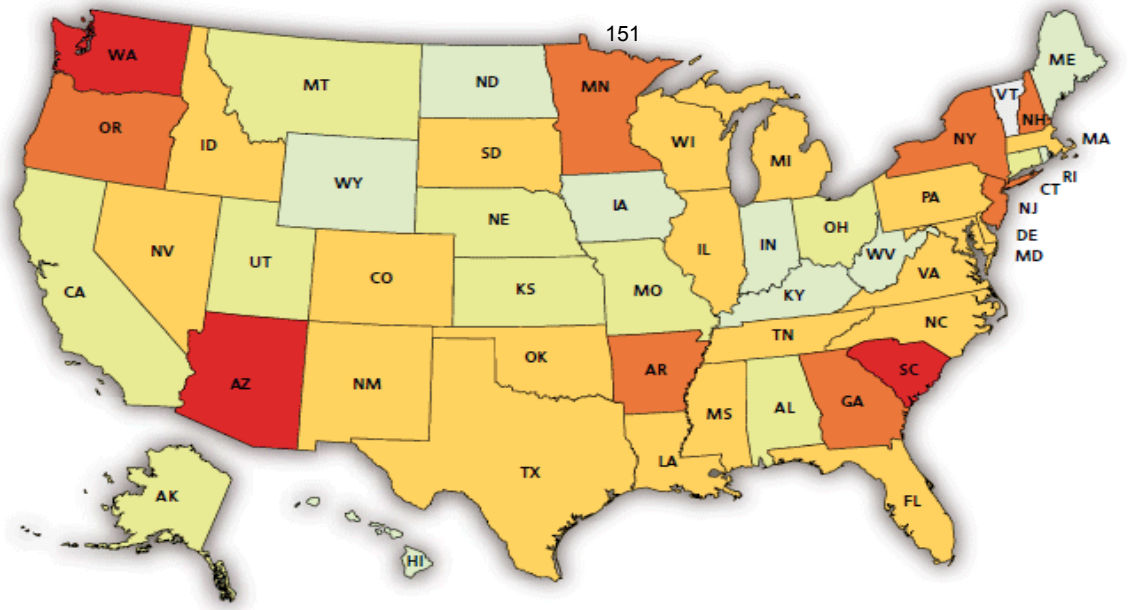
Introduction

- Clean Power Plan Overview
- Avista 111(d) Model
- Clean Power Plan Modeling Inputs Discussion

Clean Power Plan

- June 2, 2014 proposal covers certain existing fossil-fueled resources under 111(d) of the Clean Air Act
- Goal is about a 30% reduction in CO_2 emissions intensity from 2005 by 2030
- Goals set using 2012 base year data
- Comments are now due by December 1, 2014
- http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule
- EPA anticipates final rule in June 2015
- Proposal includes state-by-state CO_2 emissions intensity reduction goals
- States submit a compliance plan one year after the final rule, or two years if a multi-state plan is proposed

EPA's proposed carbon emissions rates for existing power plants (lbs/MWh)



Percent change (2012-2030)

11% - 20% | 21% - 30% | 31% - 40% | 41% - 50% | 51% - 72%

SNL

State	Historical emissions rate (2012)	Avg. interim emissions rate goal (2020 - 2029)	Final emissions rate goal (2030+)	Required change (2012-2030)
Alabama	1,444	1,147	1,059	27%
Alaska	1,351	1,097	1,003	26%
Arizona	1,453	735	702	52%
Arkansas	1,640	968	910	45%
California	698	556	537	23%
Colorado	1,714	1,159	1,108	35%
Connecticut	765	597	540	29%
Delaware	1,234	913	841	32%
Florida	1,200	794	740	38%
Georgia	1,500	891	834	44%
Hawaii	1,540	1,378	1,306	15%
Idaho	339	244	228	33%
Illinois	1,895	1,366	1,271	33%
Indiana	1,923	1,607	1,531	20%
Iowa	1,552	1,341	1,301	16%
Kansas	1,940	1,578	1,499	23%
Kentucky	2,158	1,844	1,763	18%
Louisiana	1,466	948	883	40%
Maine	437	393	378	14%
Maryland	1,870	1,347	1,187	37%
Massachusetts	925	655	576	38%
Michigan	1,696	1,227	1,161	32%
Minnesota	1,470	911	873	41%
Mississippi	1,130	732	692	39%
Missouri	1,963	1,621	1,544	21%

State	Historical emissions rate (2012)	Avg. interim emissions rate goal (2020 - 2029)	Final emissions rate goal (2030+)	Required change (2012-2030)
Montana	2,245	1,882	1,771	21%
Nebraska	2,009	1,596	1,479	26%
Nevada	988	697	647	34%
New Hampshire	905	546	486	46%
New Jersey	932	647	531	43%
New Mexico	1,586	1,107	1,048	34%
New York	983	635	549	44%
North Carolina	1,646	1,077	992	40%
North Dakota	1,994	1,817	1,783	11%
Ohio	1,850	1,452	1,338	28%
Oklahoma	1,397	931	895	36%
Oregon	717	407	372	48%
Pennsylvania	1,540	1,179	1,052	32%
Rhode Island	907	822	782	14%
South Carolina	1,597	840	772	52%
South Dakota	1,135	800	741	35%
Tennessee	1,903	1,254	1,163	39%
Texas	1,298	853	791	39%
Utah	1,813	1,378	1,322	27%
Virginia	1,297	884	810	38%
Washington	763	264	215	72%
West Virginia	2,019	1,748	1,620	20%
Wisconsin	1,827	1,281	1,203	34%
Wyoming	2,115	1,808	1,714	19%

Sources: U.S. EPA Clean Power Plan, CleanPowerPlanmaps.epa.gov
Map credit: Whit Varner

Resources Covered

Washington (Coal/Gas)

- Centralia Coal
- Big Hanaford
- Chehalis
- Encogen
- Ferndale
- Frederickson
- Goldendale
- Grays Harbor
- March Point
- Mint Farm
- River Road
- Sumas

Oregon (Coal/Gas)

- Boardman Coal
- Beaver
- Coyote Springs 1
- ***Coyote Springs 2***
- Hermiston
- Klamath Cogen
- Port Westward

Montana (All Coal)

- Colstrip 1 & 2
- ***Colstrip 3 & 4***
- Hardin
- J E Corette
- Lewis & Clark
- Yellowstone

Idaho (All Gas)

- ***Rathdrum, LLC (aka Lancaster)***
- Langley Gulch

*Plants in ***bold italics*** serve Avista customer load

Building Blocks

- Block 1: Heat Rate Improvement – 6% improvement on coal plants
- Block 2: Re-dispatch to Existing Natural Gas Combined Cycle Plants (NGCC) – dispatch NGCC in place of coal up to 70%
- Block 3: Renewable and Nuclear – maintain nuclear at risk and increase renewables up to 21% in the western region by 2030
- Block 4: End-use Energy Efficiency – 10.7% cumulative savings by 2030

Avista 111(d) Modeling Discussion Agenda

- Disclaimers and Contact Information
- Purpose of Model
- External Release of Model
- Data and Assumptions
- Future of Model, Including Upgrades
- Model Introduction
- Observations

Disclaimers and Contact Information

- The Avista 111(d) model (and this presentation) is based on preliminary analysis and subject to change
- Parties using the Avista 111(d) model should independently verify its results
- No warranty of the Avista 111(d) model is made or implied
- Users must holds Avista harmless for any and all uses of the Avista 111(d) model
- Use of the Avista 111(d) model is free; simply notify Avista of your use, or who you pass the model along to
  - ensures you and others receive any offered updates
  - email clint.kalich@avistacorp.com

The Purpose of Avista's 111(d) Model

- To emulate the draft EPA rule 111(d)
- Decipher the EPA math
- Focus on the building blocks discussed by EPA, as well as potential other blocks that Avista believes may provide similar impacts
- Help Avista make decisions with regard to EPA's draft rules

Purpose of Avista's 111(d) Model, Cont.

- Inform its potential comments on the draft rule
- Support policy-level recommendations
- Integrated resource (and other) planning
- Quantify potential compliance costs
- Assist with external party communication

External Release of Avista 111(d) Model

- There is a lot of confusion about the EPA rule
- Model may assist in understanding/quantifying 111(d) proposal
- Avista provides its model for free use
- Avista cannot provide passwords to allow reverse engineering
- No warranty is granted or implied

Data and Assumptions

- Most data from EPA worksheets *
- Minor other “behind-the-scenes” assumptions
- Some assumptions can be changed by the user
- All regulated states are included in the model
- User can combine states to perform a regional view
- Default choices are already built into the model

* See http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-state-goal-data-computation_1.xlsx and http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-plant-level-data-unit-level-inventory_0.xlsx

Future of Model and Upgrades

- Updates will be provided as deemed necessary by Avista
- Updates will include enhancements and new features
- User feedback will help dictate much of the future release features and frequency
- Changes to the proposed rule will be incorporated in future releases as more information becomes known
- Model may be revised by Avista without notification

Model Introduction

Preliminary Analysis Prepared by Avista and Subject to Change. Parties Should Independently Verify Results Before Use.

All Of United States

$0.0 billion in new investment
0.0 millions of metric tons CO2 reduced per year (from 2012)
$0 per capita (2010 census)
$0 levelized cost ($2015/ton)

Instructions and Release Notes

Model v2.1
8/20/14

	GWh	Growth (GWh)	% of 2012
2012 Load	3,954,089		0.0%
2020 Load	4,197,656	243,567	6.2%
2030 Load	4,523,321	569,232	14.4%
Pre-Conservation Load Growth Rate			0.75%

Reset States and Plants

Modify States & Plants

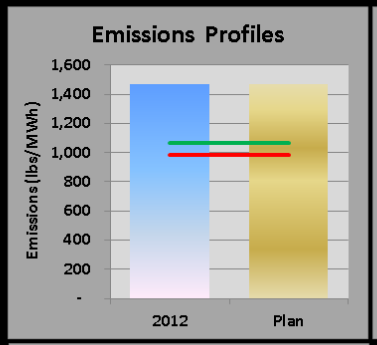
Rate Based
Mass Based

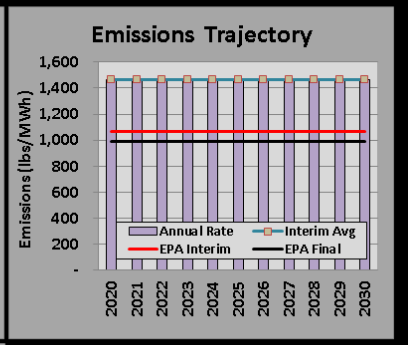
Emissions Rates (lbs/MWh)

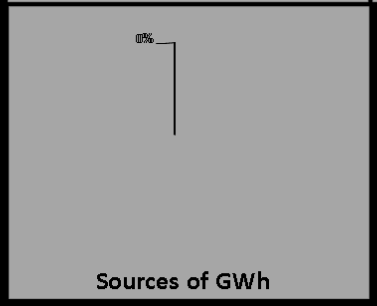
2012 Base	2012 EPA	
1,464.7	1,156.4	Modeled Plan
Interim EPA	2030 EPA	
1,064.5	986.6	1,464.7

Federal Compliance Path Option	Action	2020 Generic Retired/ Modified	User-Specific Retired by 2030	2030 GWh	2030 aMW	Estimated 2030 New Build MW	Assumed NCF of New Resource	Assumed 2015 Cost ($/kW)
1	Coal Heat Rate Improvement	0.00%					85.0%	500
2	New Renewables (30% NCF) as % of Load Growth	0.00%		-	-	-	30.0%	3,000
2	New Nuclear as % of 2012-30 Load Growth	0.00%		-	-	-	85.0%	7,500
3	Coal % to Existing Gas (no new capacity)	0.00%	0.0%	-	-	-	60.0%	250
3	Coal % to New Nuclear	0.00%	0.0%	-	-	-	85.0%	7,750
3	Coal % to New Gas	0.00%	0.0%	-	-	-	60.0%	2,750
3	Coal % to New Renewables (30% NCF)	0.00%	0.0%	-	-	-	30.0%	1,500
4	Conservation % of Load (AARG through 2017-30)	0.00%		-	-	-	100.0%	2,205

Other Possible Compliance Options	Action	2020 Generic Retired/ Modified	User-Specific Retired by 2030	2030 GWh	2030 aMW	Estimated 2030 New Build MW	Assumed NCF of New Resource	Assumed 2015 Cost ($/kW)
5	Existing Gas Heat Rate Improvement	0.00%					50.0%	500
6	Retire Existing CCCT Plants w/o Replacing	0.00%	0.0%	-	-	-	60.0%	250
6	Existing Gas % to New Nuclear	0.00%	0.0%	-	-	-	85.0%	6,500
6	Existing Gas % to New Renewables (30% NCF)	0.00%	0.0%	-	-	-	30.0%	1,500
6	Existing Gas % to New Gas	0.00%	0.0%	-	-	-	60.0%	1,500
7	End-Use Fuel Switching to Gas % of Load (AARG 2017-30)	0.00%		-	-	-	15.0%	3,000







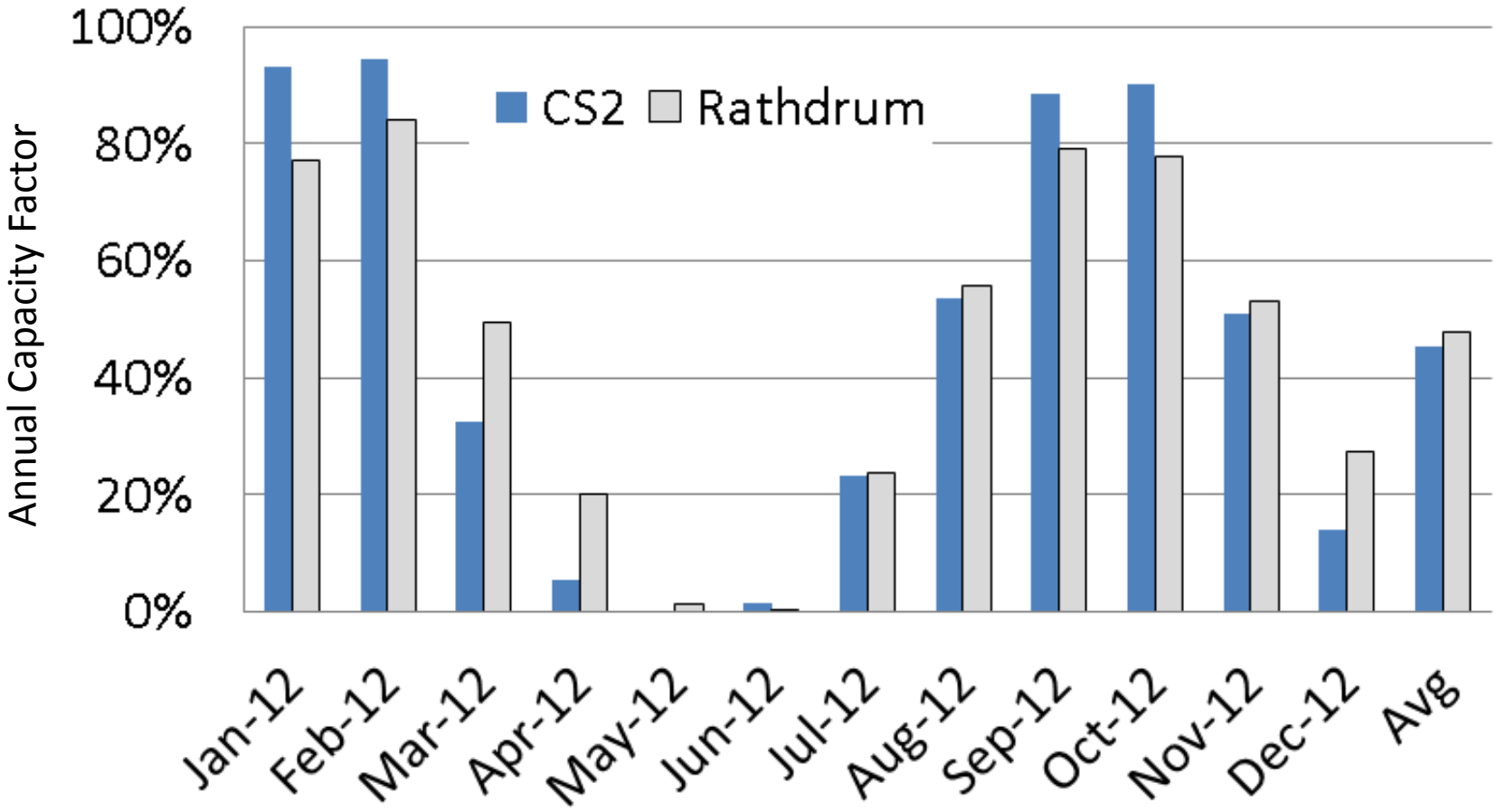
Some Observations

- Compliance costs appear much higher than EPA estimates
- Retirement without replacing with qualifying non-carbon resources is much less impactful on the emissions rate than building replacement resources
- Higher conservation or renewables means fewer mass-based emissions reduction
- EPA rule does not appear focused on electricity system reliability
- 2012 base year has very high hydro generation
  - and a correlated low carbon emissions level

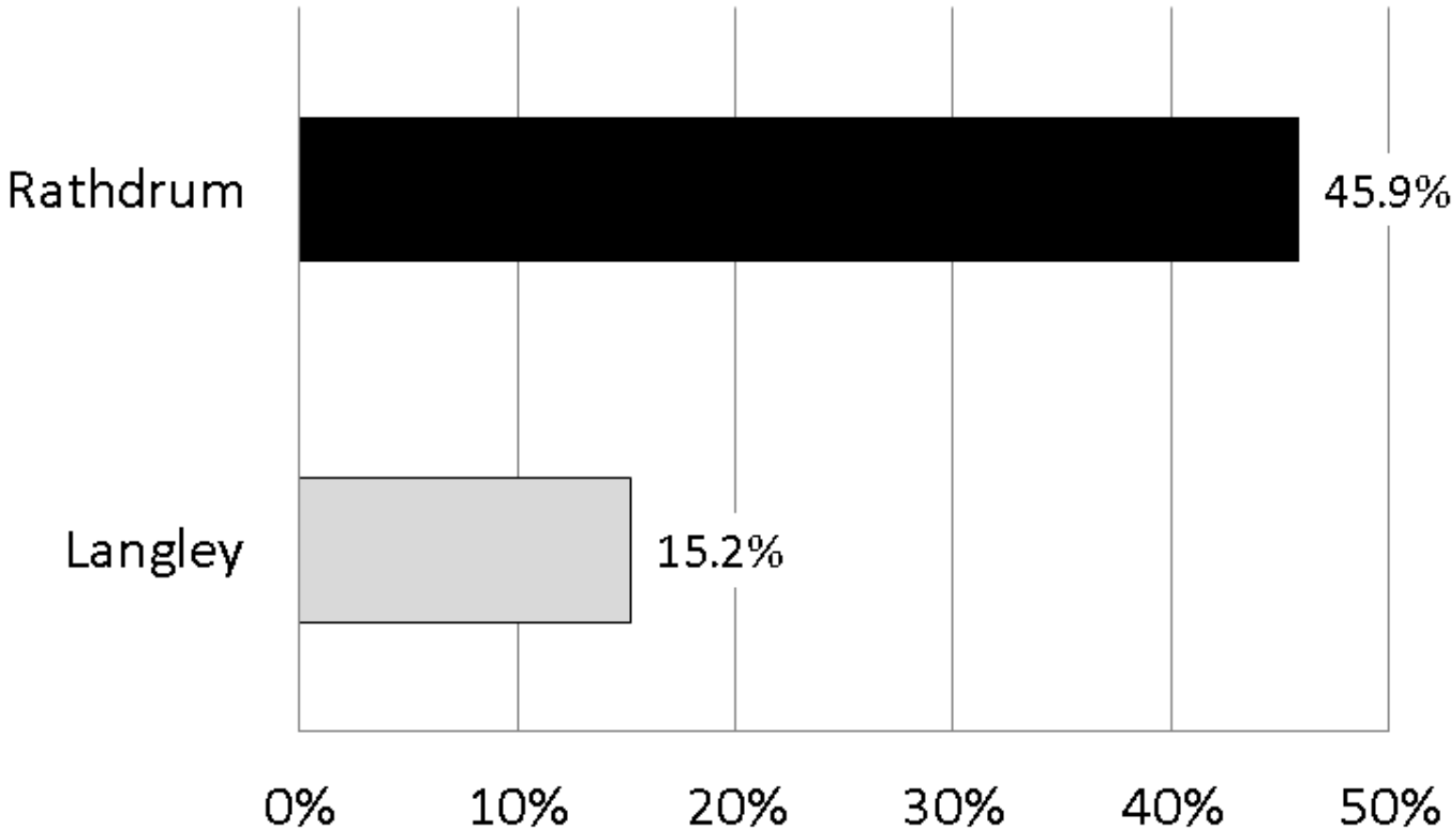
Some Observations, Cont.

- Hydro/renewables variability is ignored in the math
- States receive no credit for early action (e.g., Centralia, aggressive conservation)
- Idaho has only two gas-fired plants regulated by 111(d), one of which operated only half of the 2012 base year
- For Oregon and Washington the only EPA options are conservation and renewables, as coal plants already are in the baseline
- In Montana, retiring coal for gas does not reduce emissions rate

2012 Operations at Coyote Springs 2 (OR) and Rathdrum LLC (ID)

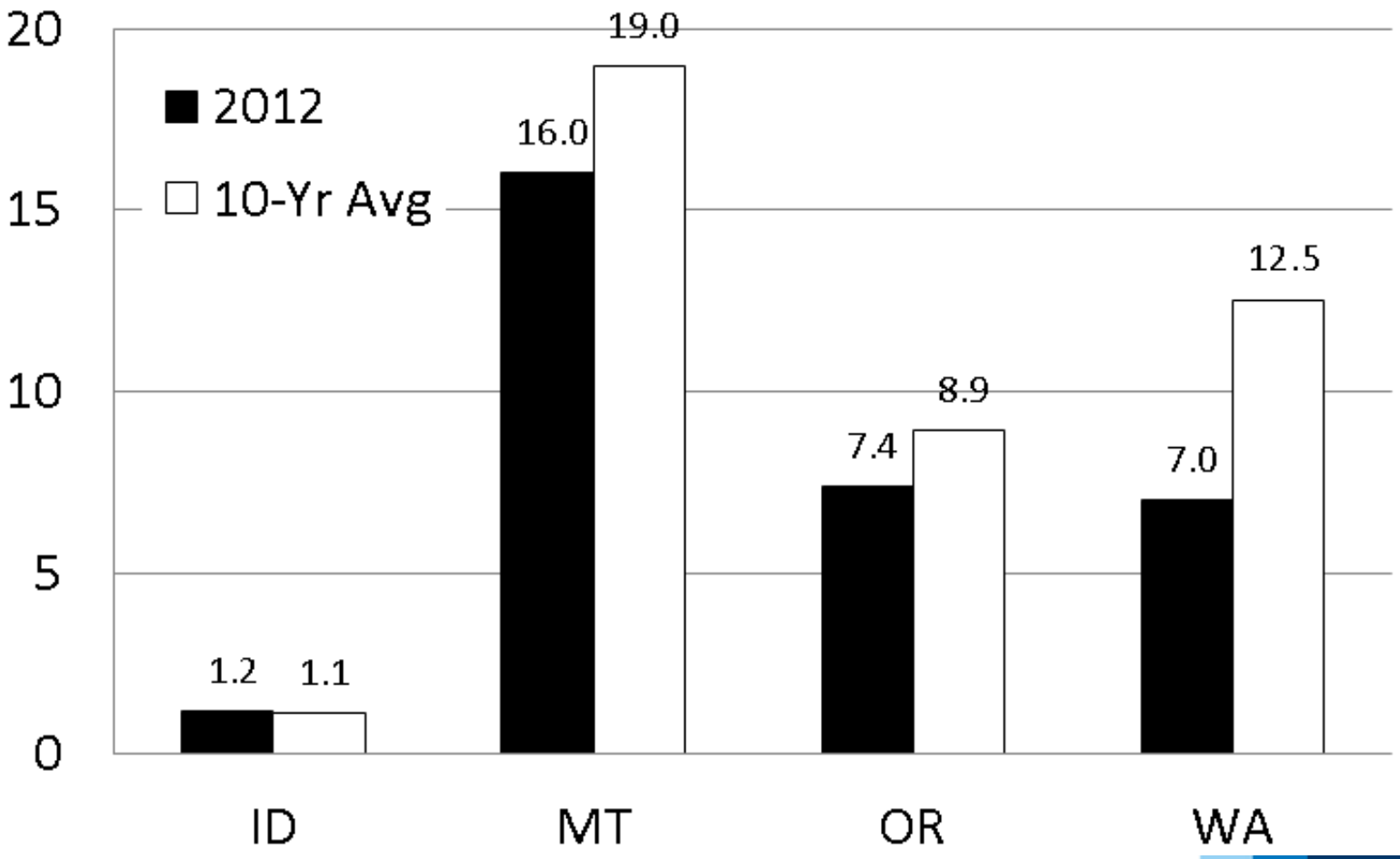


Idaho Comparison: 2012 Langley Gulch and Rathdrum Power LLC Plant Operations

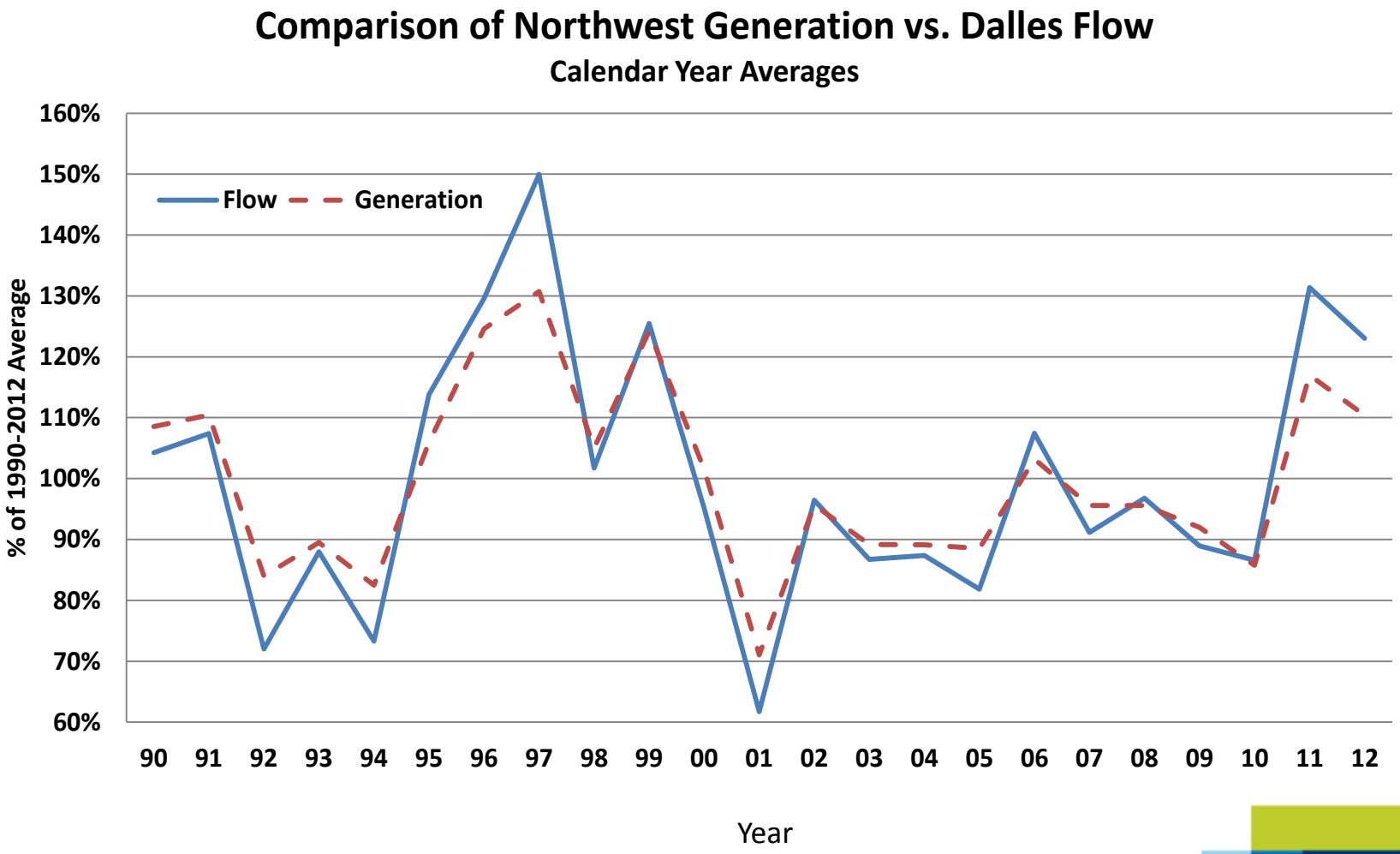


Annual Capacity Factor

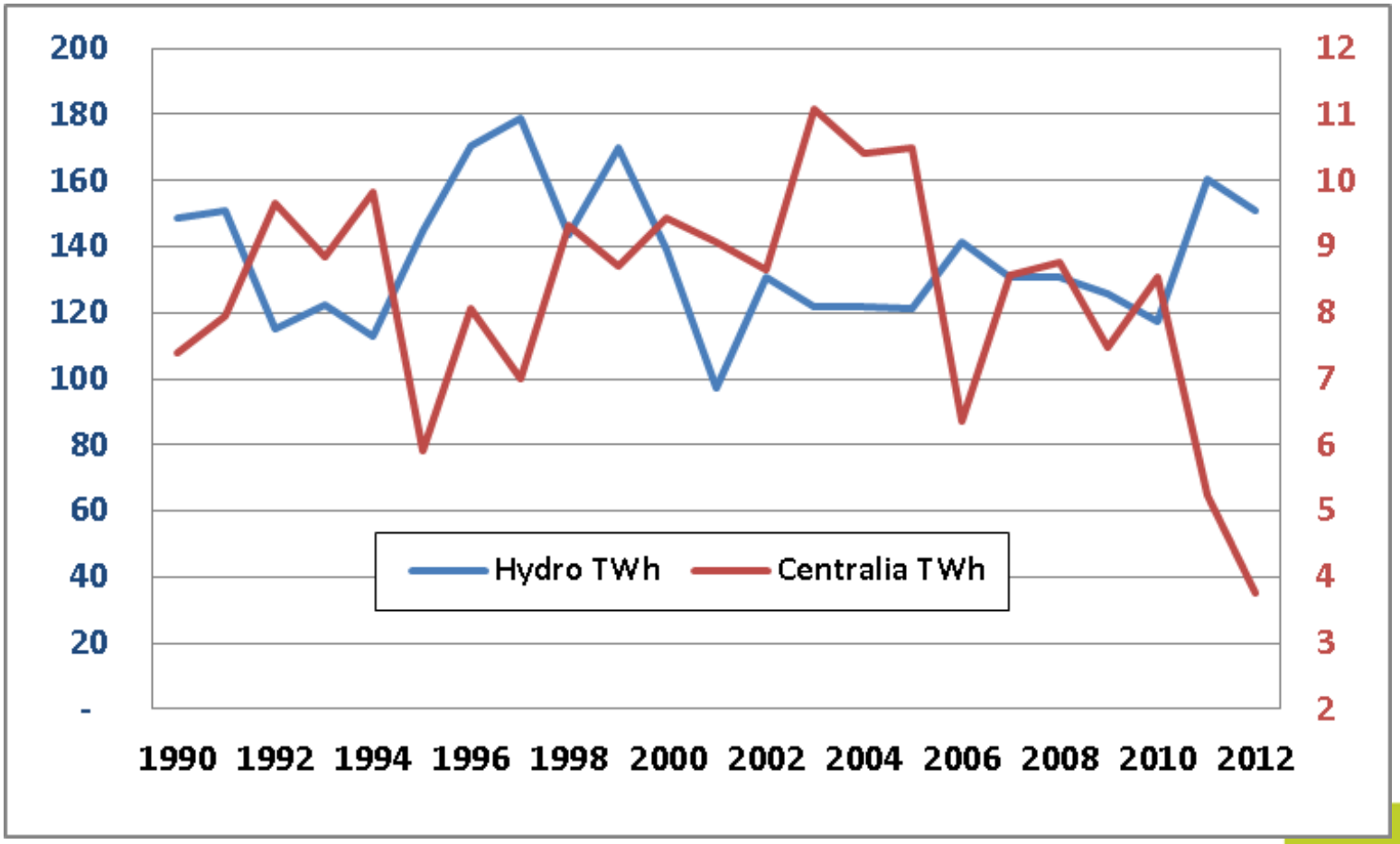
Historical Carbon Emissions (millions of CO_2 tons)



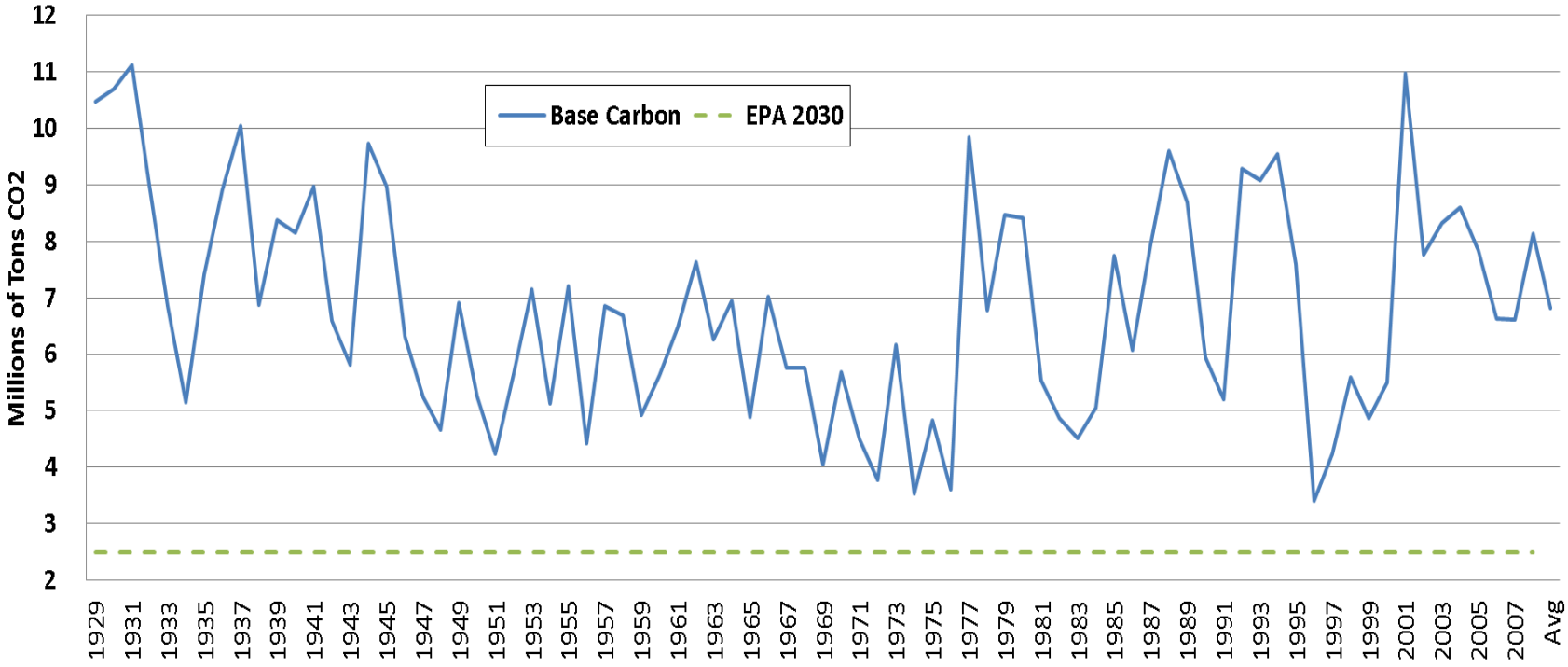
Pacific Northwest Hydroelectricity vs. Dalles Inflow Variability



Pacific Northwest Hydroelectricity vs. Coal Emissions (Centralia)



Hydro Variability in WA



Clean Power Plan Modeling Inputs Discussion

- Base Case assumptions
- Scenarios

2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 3 Agenda

Friday, November 21, 2014
Conference Room 130

Topic	Time	Staff
1. Introduction & TAC 2 Recap	8:30	Lyons
2. Planning Margin	8:35	Gall
3. Colstrip Discussion	9:15	Lyons
4. Cost of Carbon	10:45	Lyons
5. Lunch	11:30	
6. IRP Modeling Overview	12:30	Gall
7. Conservation Potential Assessment	1:45	Kester
8. Adjourn	3:00	

2015 Electric IRP
TAC Meeting Expectations and Schedule

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
November 21, 2014

Technical Advisory Committee

- The public process of the IRP – input on what to study, how to study, and review of assumptions and results
- Technical forum with a range of participants with different areas of input and expertise
- Open forum, but we need to stay on topic to get through the agenda and allow all participants to ask questions and make comments
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies
  - The earlier study requests are made, the more accommodating we can be
  - January 15, 2015 is the final date to receive study requests
- Action Items – areas for more research in the next IRP

Technical Advisory Committee

- Technical forum on inputs and assumptions, not an advocacy forum
- Focus is on developing a resource strategy based on sound assumptions and inputs, instead of a forum on a particular resource or resource type
- We request that everyone maintain a high level of respect and professional demeanor to encourage an ongoing conversation about the IRP process
- Supports rate recovery, but not a preapproval process
- Planning team is available by email or phone for questions or comments between the TAC meetings

Remaining TAC Meetings

- **TAC 4 – February 2015:** Electric and natural gas price forecasts, transmission planning, resource needs assessment, market and portfolio scenario development, energy storage and ancillary service evaluation
- **TAC 5 – March 2015:** Completed conservation potential assessment, draft preferred resource strategy (PRS), review of scenarios, market futures, and portfolio analysis
- **TAC 6 – June 2015:** Review of final PRS and action items.

2015 IRP Tasks for the PRS

Exhibit 1: 2015 Electric IRP Timeline	
Task	**Target Date**
Preferred Resource Strategy (PRS)	
Finalize energy demand forecast	July 2014
Identify Avista's supply & conservation resource options	September 2014
Finalize peak load forecast	September 2014
Update AURORA^{xmp} database for market price forecast	October 2014
Energy efficiency load shapes input into AURORA^{xmp}	October 2014
Finalize datasets/statistics variables for risk studies	November 2014
Transmission study due	December 2014
Finalize distribution feeder forecast	December 2014
Select natural gas price forecast	December 2014
Finalize deterministic base case	January 2015
Due date for study requests	Jan. 15, 2015
Base case stochastic study complete	January 2015
Develop efficient frontier and PRS	January 2015
Finalize PRiSM model	February 2015
Simulation of risk studies "futures" complete	February 2015
Simulate market scenarios in AURORA^{xmp}	February 2015
Evaluate resource strategies against market futures and scenarios	March 2015
Present preliminary study and PRS to TAC	March 2015

2015 IRP Writing Tasks – Work Plan

Writing Tasks	
File 2015 IRP work plan	August 2014
Prepare report and appendix outline	October 2014
Prepare text drafts	April 2015
Prepare charts and tables	April 2015
Internal draft released at Avista	May 2015
External draft released to the TAC	June 2015
Final editing and printing	August 2015
Final IRP submission and TAC	August 31, 2015

TAC #2 Recap

- Introduction & TAC 1 Recap – Lyons
- Conservation Selection Methodology – Gall
- Load and Economic Forecasts – Forsyth
- Shared Value Report – Fielder
- Generation Options – Gall/Dempsey
- Clean Power Plan Proposal Discussion – Lyons/Kalich

Today's Agenda

- Introduction & TAC 2 Recap (8:30) – Lyons
- Planning Margin (8:35) – Gall
- Colstrip Discussion (9:15) – Lyons
- Cost of Carbon (10:45) – Lyons
- Lunch (11:30)
- IRP Modeling Overview (12:30) – Gall
- Conservation Potential Assessment (1:45) – Kester
- Adjourn 3:00
- Reminders: restrooms are across the hall and all visitors need Avista escorts to the lobby to leave the building

Planning Margin (Reserve Planning)

James Gall
Third Technical Advisory Committee Meeting
November 21, 2014

What is the role of reserves for peak planning

- **Planning Margin[1]:** Generally, the projected demand is based on a 50/50 forecast. Based on experience, for Bulk Power Systems that are not energy-constrained, reserve margin is the difference between available capacity and peak demand, normalized by peak demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity
- **Operating Reserves:** is required capacity to meet an instantaneous loss of generation.
  - New rule in WECC, 3% of load and 3% of operating generation is carried. Half of the capacity must be "synced" to the grid (spinning) and the other half must be available to sync within 10 minutes (non-spinning/supplemental).
- **Regulation** is required intra hour capacity to meet instantaneous load changes instantly

1. http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx. 50/50 is also referred to as a 1-in-2 forecast

NERC's Reference Reserve Margin

- is equivalent to the Target Reserve Margin Level provided by the Regional/subregion's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems. As the planning reserve margin is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources.

http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

2013 IRP WUTC Acknowledgement Request

- *In its updated action plan, Avista committed to re-assess with the TAC the benefits and costs of the Company's 2013 IRP planning margin to determine if a different level is warranted in the 2015 IRP. The Commission supports this approach.*
- The 2013 IRP used the following planning margin
  - Greater of 1 hour or 18 hour sustained peak deficit
    - Includes the top six load hours of three consecutive days
  - Winter: 14% adder to the 1 in 2 peak forecast + Ancillary Services Requirement (~6% operating reserves + 1.3% regulation reserve) = 21% – 22 %
  - Summer: 0% adder to the 1 in 2 peak forecast + Ancillary Services Requirement (~6% operating reserves + 1.3% regulation reserve) = 7% - 8%

North American Planning Margin Survey

- Planning margin added to peak load is most common
- Some plan for 5% LOLP, others 1 in 10 years
- Operating reserves is often included in estimates
- Organized market have firm requirements
- Northwest utilities/organizations recommend higher planning margins

Regional Planning Margins

- Organized systems

PJM	15.7%
MISO	14.8%
TVA	15.0%
SPP	13.6%
NYISO	17.1%
ISO New England	15.0%
ERCOT	13.8%
California PUC	15.0%

- Non Northwest Utilities

New Brunswick Power	22.0%
Hydro Quebec	8.0%
Nova Scotia Power	20.0%
Hydro One	20.0%
FPL	20.0%
Progress Energy	20.0%
Entergy- New Orleans	12.0%
Sunflower Coop	12.0%
Kansas City B of PU	12.0%
Basin Electric	15.0%
LADWP	25.0%
San Diego Gas & Electric	15.0%
Roseville Electric	15.0%

Dominion	15.6%
Minnesota Power	11.3%
Indianoplis Light & Power	12.7%
Duke- Indiana	13.9%
Duke- Carolina's	14.5%
Oklahoma Gas & Electric	12.0%
Platte River Power Authority	15.0%
XCEL- Colorado	16.3%
XCEL- New Mexico	13.6%
Colorado Springs Utilities	18.0%
Salt River Project	12.0%
APS	15.0%
UNS Electric	15.0%

El Paso Electric	15.0%
Sierra Pacific	15.0%
Nevada Power	12.0%
Public Service Co of NM	13.0%
Tri-State G&T	15.0%

Northwest Planning Margins

- Northwest Utilities

PSE (2018-19)	14.0%
PSE (2020+)	16.0%
PacifiCorp	13.0%
PGE	12.0%
Clark PUD	18.0%
Cowlitz PUD	23.0%
EWEB	17.0%
Northwestern	0.0%
Idaho Power	10.3%
Fortis	10.0%
BC Hydro	20.0%

- Northwest Organizations

WECC- PNW Summer	17.9%
WECC- PNW Winter	19.9%
WECC- PNW Summer	18.8%
WECC- PNW Winter	21.6%
NPCC- Summer	24.0%
NPCC- Winter	23.0%
NWPP (NPCC)	<28.0%
WECC (NPCC)	18.0%
PNUCC	12.0%-20%

Single Largest Resource Contingency

Largest shaft as a percent of 2014 forecast peak load
Western Interconnect utilities with a control area

Utility	%	Resource (MW)
Public Service of CO	9%	Comanche- 525
Public Service of NM	13%	San Juan- 248
LADWP	8%	Scattergood- 450
Salt River Project	6%	Springerville- 415
Arizona Public Service	7%	Redhawk- 500
El Paso Electric	12%	Palo Verde- 207
Sierra Pacific	33%	Tracy CCCT- 553
Nevada Power	10%	Lenzie- 551

Utility	%	Resource (MW)
Puget Sound Energy	6%	Mint Farm- 297
PacifiCorp- West	15%	Chehalis- 477
PacifiCorp- East	9%	Lake Side 2- 628
Portland General Electric	16%	Boardman- 517
Bonneville Power Admin	7%	Coulee- 805
Idaho Power	10%	Langley Gultch-318
BC Hydro	5%	Various- 500
Avista- Summer	16%	Coyote Springs 2- 277
Avista- Winter	20%	Coyote Springs 2- 312

Planning Margins Contrasts Between Interconnected and Electrical Islands

- Since Avista is part of a larger power system it can leverage assets of the system to help meet peaks rather than rely entirely on its only system keeping planning margins low
- This is the opposite from Avista's newly acquired Alaska Electric Light & Power subsidiary; AELP must provide all its own reserves for reliability and plans on a 100% planning margin + largest single contingency within its core system.
- The Northwest Planning Conservation Council (NPCC) attempts provide direction on system reliability on a regional basis for northwest interconnect utilities.

Northwest Power Conservation Council's LOLP Results for 2019

LOLP Results for 2019 (%)

(Effects of Load and Import Uncertainties)

Load / Import	-2.5%	-1.5%	Medium	+1.5%	+2.5%
0 (MW)	7.5	8.6	10.5	12.9	14.9
1700	4.5	5.3	6.5	8.0	9.3
2000	4.3	4.9	6.2	7.7	9.0
2500	4.0	4.7	5.9	7.2	8.5
3000	3.8	4.5	5.4	6.7	7.9
3400	3.7	4.4	5.3	6.4	7.7

Northwest Power and Conservation Council 4 nwcouncil.org

http://www.nwcouncil.org/media/7148382/100914-raac-tech-2019-review.pdf

AVISTA

Northwest Market Depth

Assumptions:

- 1% load growth rate to match NPCC's peak load forecast
- Uses NPCC's assumptions for shares of borderline resources contributing to NW
- Centralia, Boardman, Big Hanaford, Corette offline as forecasted
- Only new resources under construction are assumed
- Excludes wind resources
- Operating reserves and regulation requirements are satisfied ~8% of load
- Winter import is 2,500 MW, summer exports IPP resources

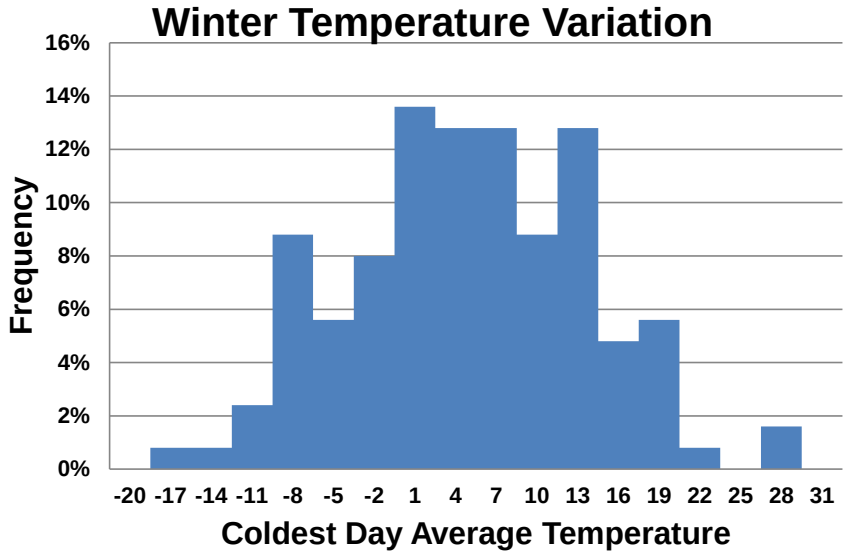
Year	January 1 Hour	January 4 Hour	January 10 Hour	July 1 Hour	July 4 Hour	July 10 Hour	Jan Margin	July Margin
2017	12,222	8,014	5,315	11,323	10,740	9,829	28%	50%
2018	11,864	7,663	4,979	11,034	10,457	9,557	27%	49%
2019	11,503	7,309	4,639	10,742	10,170	9,283	26%	47%
2020	11,138	6,951	4,296	10,447	9,881	9,006	24%	46%
2021	9,514	5,334	2,694	9,182	8,623	7,759	20%	41%
2022	9,014	4,842	2,217	8,754	8,201	7,349	19%	39%
2023	8,638	4,474	1,863	8,450	7,903	7,063	18%	38%
2024	8,258	4,101	1,506	8,143	7,602	6,775	16%	36%
2025	7,875	3,725	1,145	7,833	7,298	6,483	15%	35%
2026	6,683	2,541	(23)	7,386	6,857	6,055	14%	33%
2027	6,291	2,158	(391)	7,070	6,548	5,758	13%	32%
2028	5,896	1,770	(763)	6,750	6,234	5,457	11%	31%
2029	5,497	1,379	(1,138)	6,428	5,918	5,154	10%	29%
2030	5,093	984	(1,517)	6,102	5,599	4,848	9%	28%

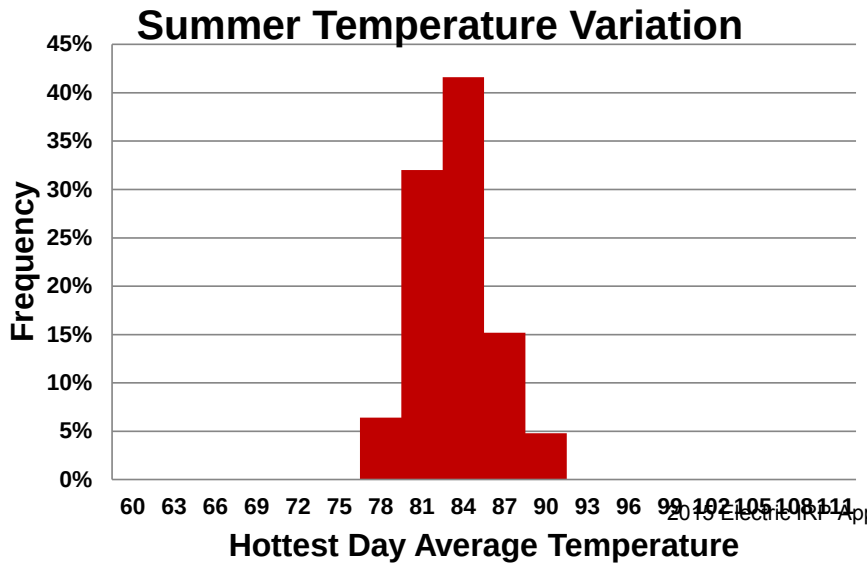
Violation of 5% LOLP

Avista's Peak Situation

- Peak can occur in summer or winter, but winter peak predominate concern
- Large single largest contingency
- Peak load is 5 percent of the Northwest's peak load
- Well connected to other utilities
- Equal mix of hydro and thermal resources
- Have mix of flexible hydro and flexible natural gas fired units to meet flexibility requirements

Spokane Temperature Volatility

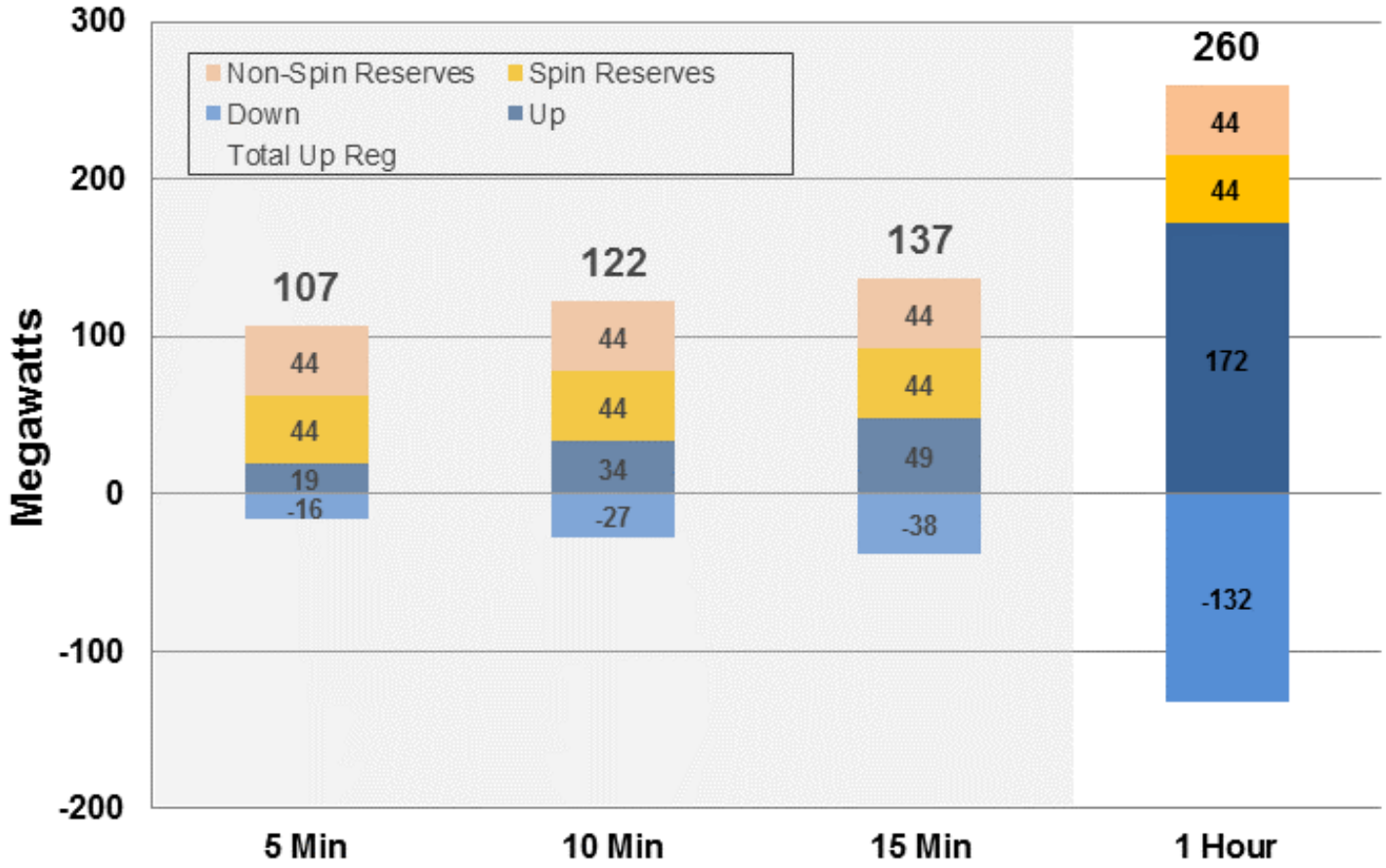




Temperature Statistics

	Winter	Summer
Mean	4	82
Tail (10%)	-9	86
Extreme	-17	90
Stdev	9	3
Recent Events	2014: 5 2008: -7 2004: -9	2014: 84 2008: 86 2006: 87

Flexibility Requirements (99th Percentile) 2013 CY Data



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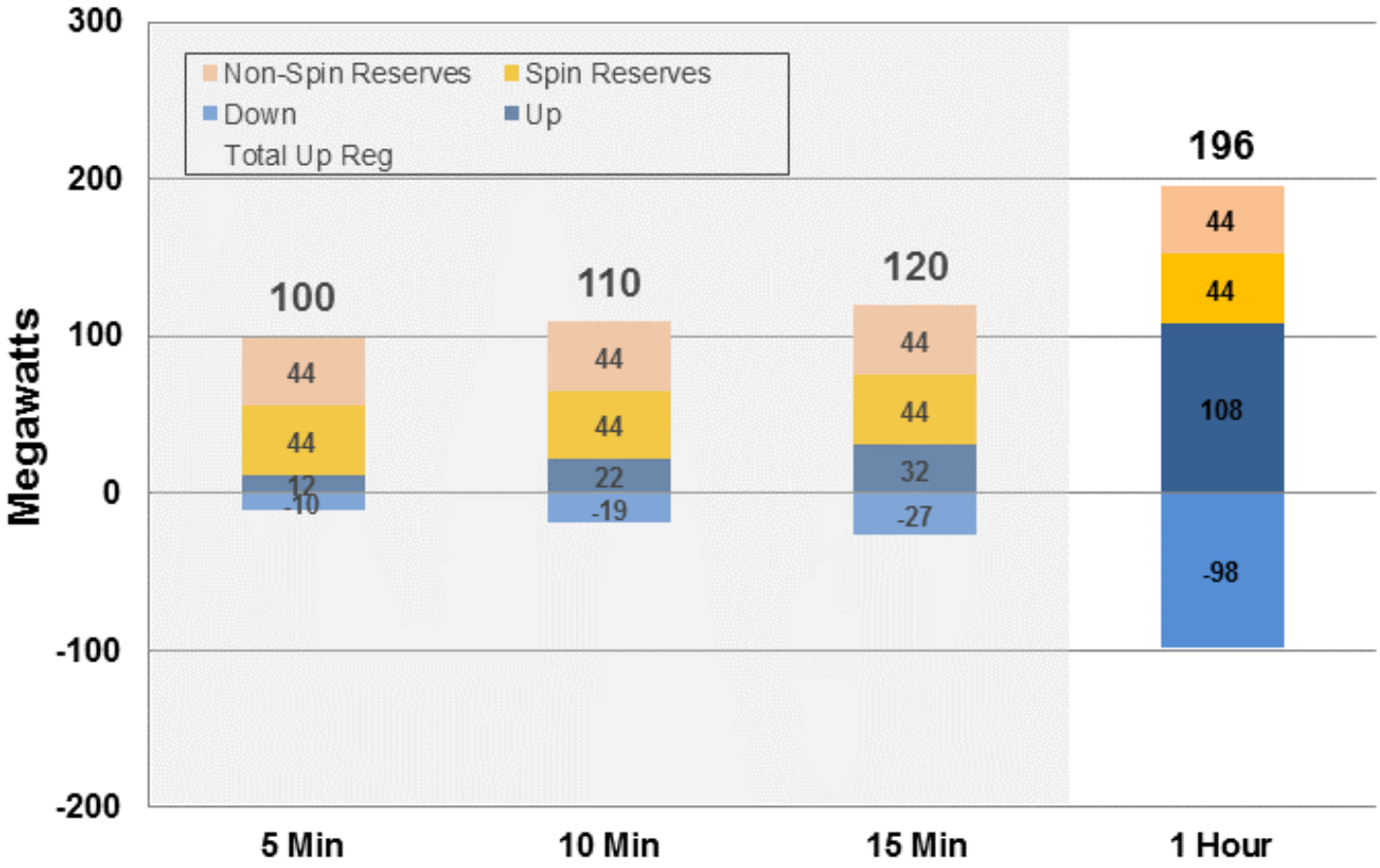
Flexibility Requirements (95th Percentile) 2013 CY Data



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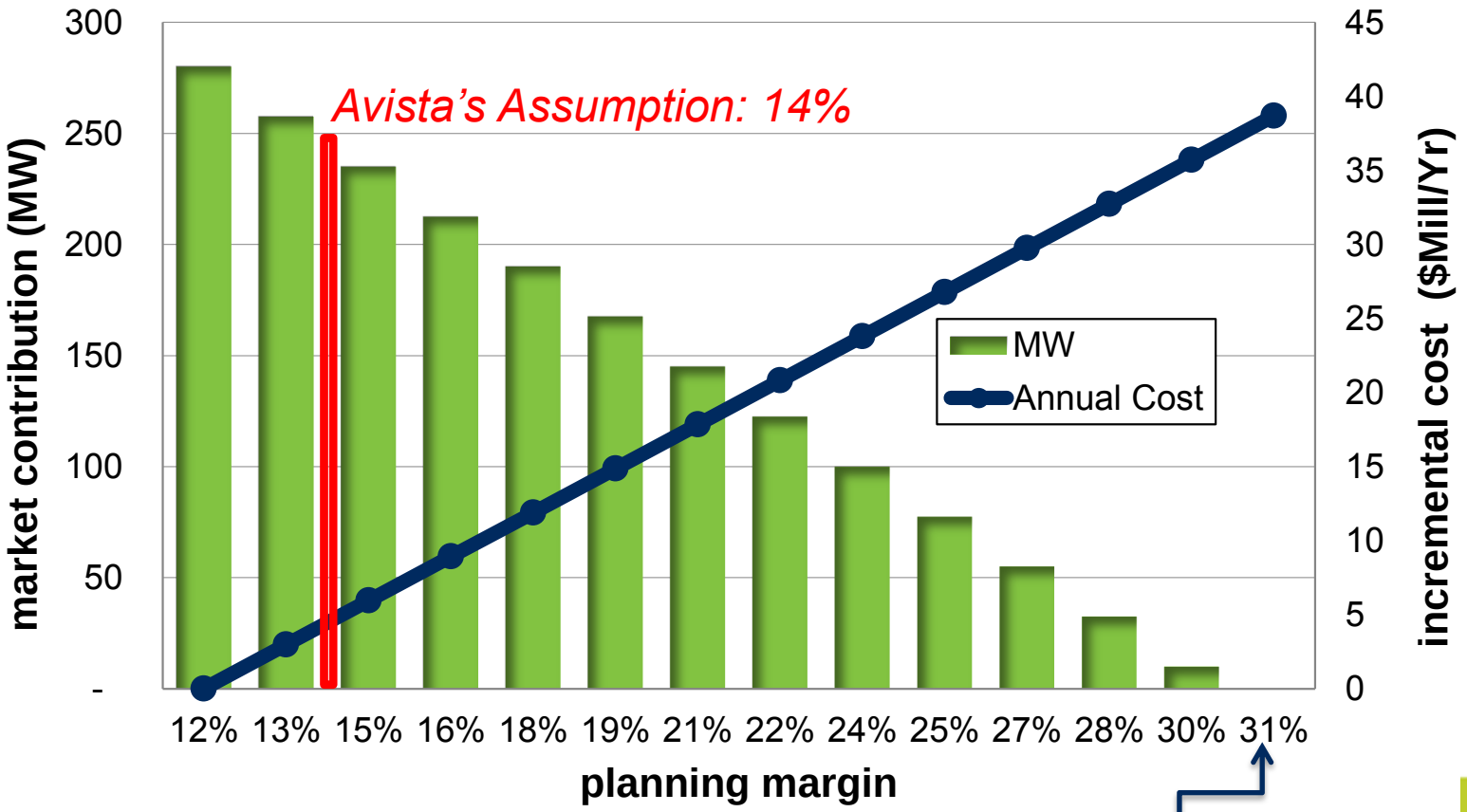
2013 IRP Planning Margin vs Market Reliance Cost Trade-Off

Winter Planning Margin in addition to Ancillary Services Requirements



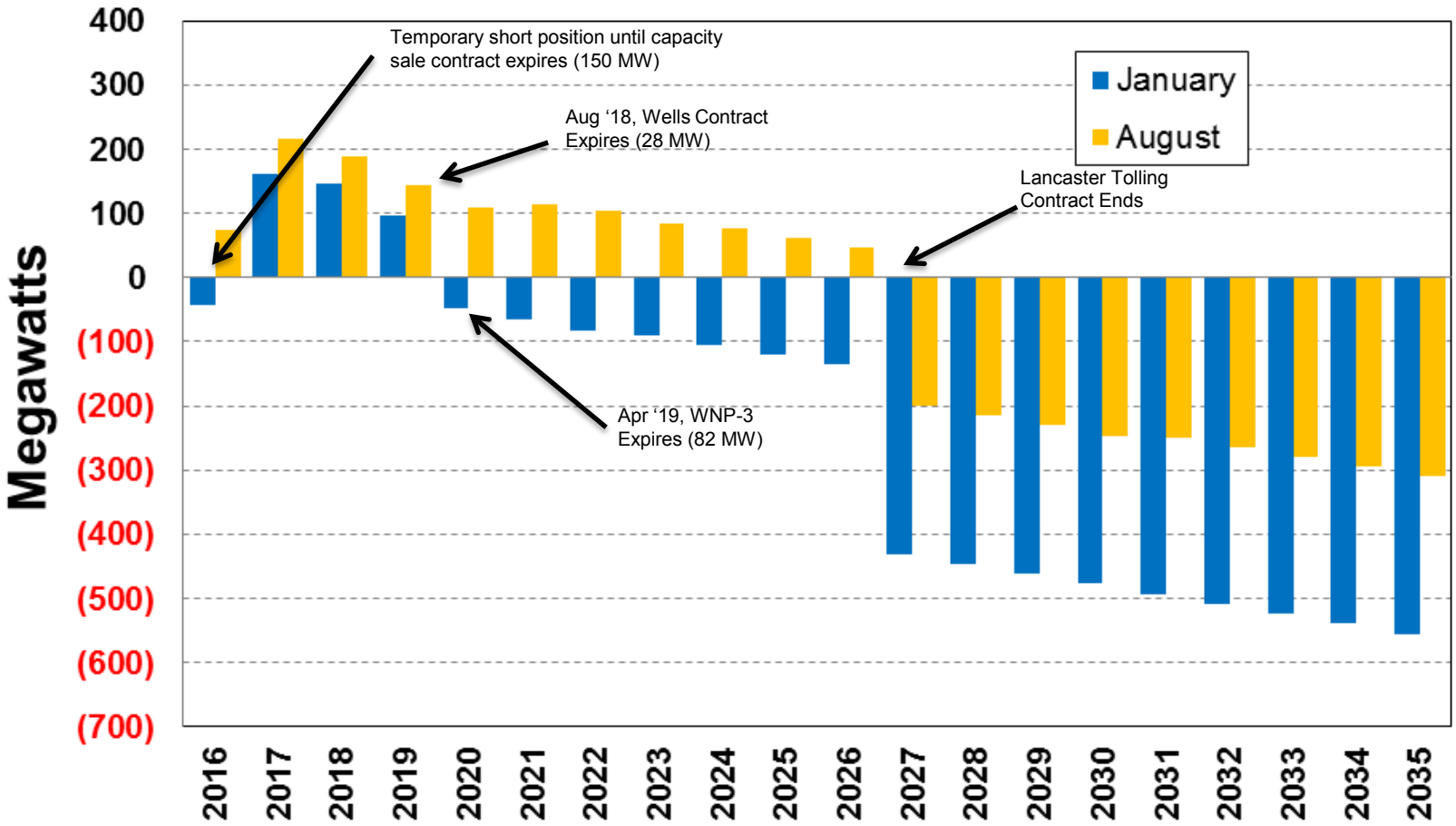
Use if Avista is an electrical island

2015 IRP Planning Margin Proposal

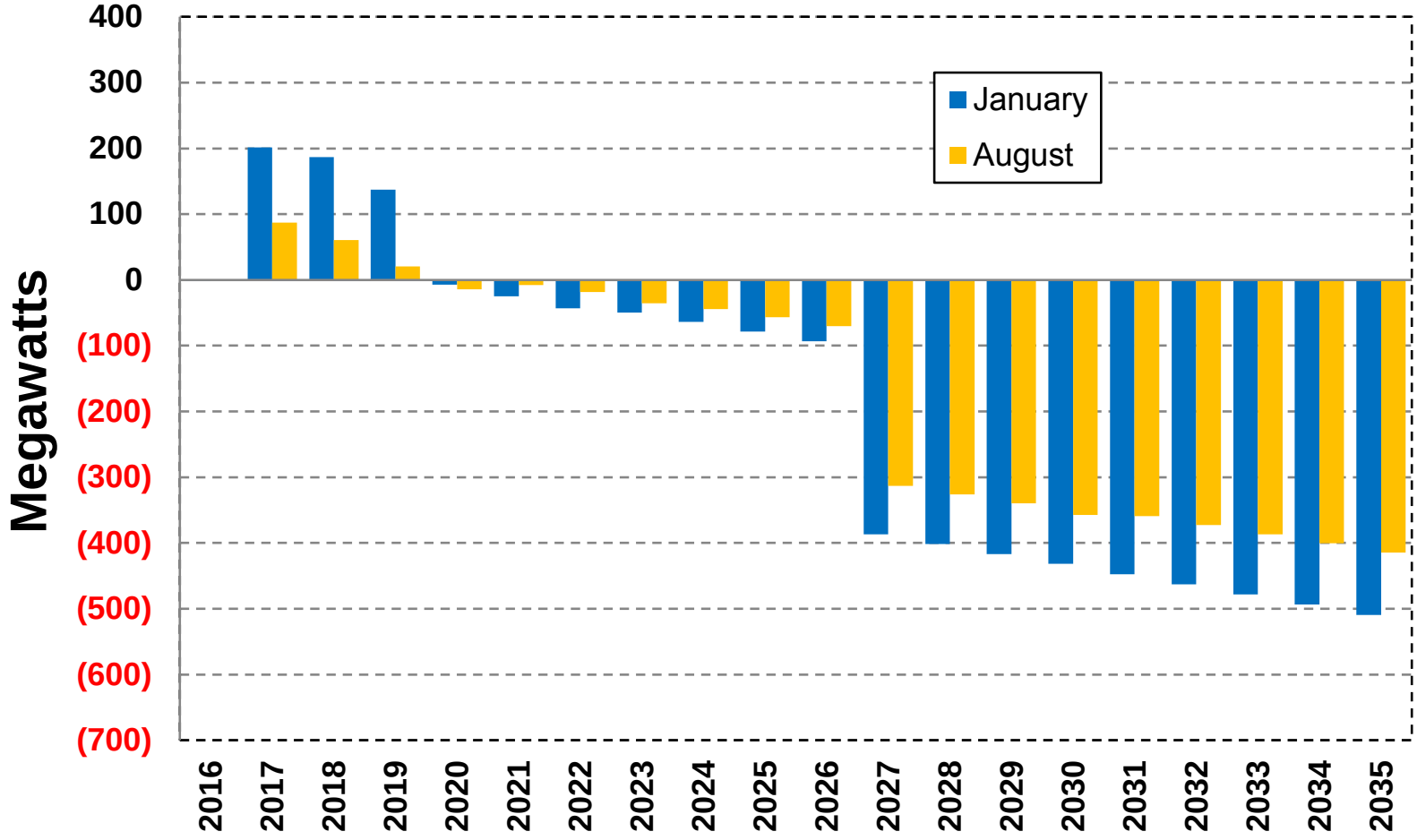
- Greater of 1 Hour or 18 Hour sustained peak deficit
- Winter
  - 14% Planning Margin +
  - Control Area Operating Reserves +
  - Regulation (16 MW)
- Summer
  - 0% Planning Margin +
  - Control Area Operating Reserves +
  - Regulation (16 MW)
- Market Power Available
  - Winter: Through 2018
  - Summer: Available throughout the study

22.6% Planning Margin for January 2015

1 Hour Net Load/Resource Position (No Short-Term Market)



18 Hour Net Load/Resource Position (No Short-Term Market)



Colstrip Discussion

John Lyons, Ph.D.
Third Technical Advisory Committee Meeting
November 21, 2014

Future of Colstrip – Planning

- Direction from the Washington Commission Acknowledgement of the 2013 IRP:
  - "Continue to evaluate scenarios related to the continued operation of units 3 and 4 of the coal-fired generating facility in Colstrip, Montana. As a component of this evaluation, Avista should provide an assessment of the impact on rates of a hypothetical portfolio that does not include these units." (Docket No. UE-121421)

- Idaho Commission Acknowledgement
  - "We expect the Company to consider and discuss at the TAC meetings the various concerns and suggestions that are and have been offered. In particular, we expect the Company to monitor federal developments, such as the promulgation of federal environmental regulations, and to account for their impact in its resource planning. We also encourage the Company to continue exploring the use of DR as a resource, and to be actively involved in and apprise us of matters relating to Colstrip." (Order No. 32997)

2013 IRP Comments Regarding Colstrip

- No public comments received in Washington

- Summary comments to the Idaho PUC
  - Colstrip risks regarding continued operation:
    - Regional Haze
    - Greenhouse gas regulations
    - Permitting for prevention of significant deterioration
    - National Ambient Air Quality Standards
    - Mercury and Air Toxics Rule
    - Coal combustion wastes
    - Coal costs and the Rosebud mine
  - Colstrip retirement

Colstrip Ownership Information

Colstrip Basic Data			Colstrip Ownership Percentages					
Colstrip Unit #	Size (MW)	Year Online	Avista	NorthWestern Energy, LLC	PacifiCorp	Portland General Electric	PPL Montana, LLC	Puget Sound Energy
Unit #1	307	1975	0%	0%	0%	0%	50%	50%
Unit #2	307	1976	0%	0%	0%	0%	50%	50%
Unit #3	740	1984	15%	0%	10%	20%	30%	25%
Unit #4	740	1986	15%	30%	10%	20%	0%	25%
Total	2,094		11%	11%	7%	14%	25%	32%

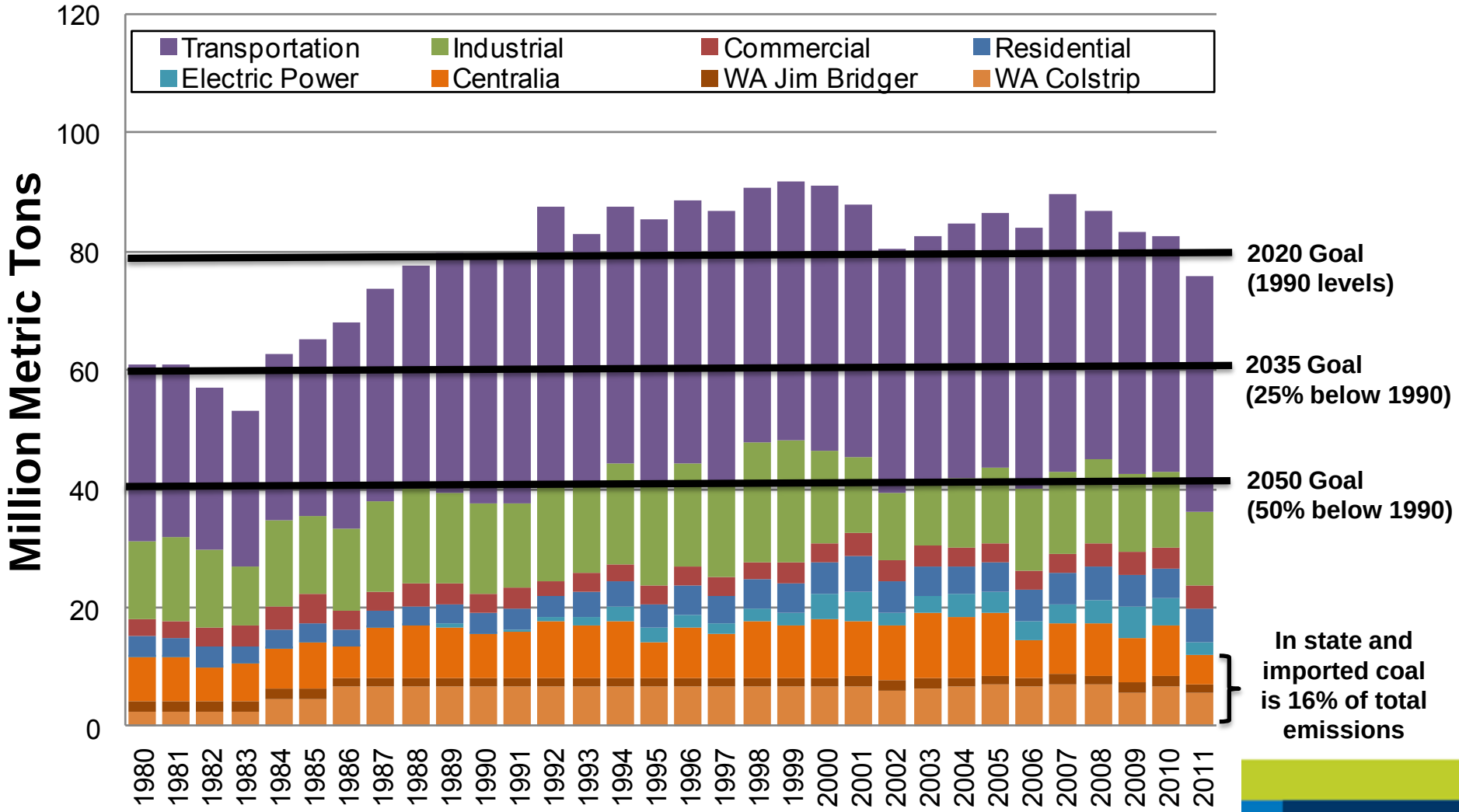
- 9% of Avista's owned and contracted capacity
- 14.86% of 2013 energy profile (Draft 2014 Washington Department of Commerce Fuel Mix Report)

Colstrip Economic Benefits

- The plant employs 360 people and the mine has 373 employees
- $104 million in annual Montana state and local taxes (4.5% of all state revenue collections)
- 3,740 additional jobs and 7,700 more residents in Montana
- $360 million in additional personal income
- $638 million more in additional Montana economic output
- Second lowest cost resource after hydroelectric for Avista
- Baseload resource with stable fuel price

Data from *The Economic Contribution of Colstrip Steam Electric Station Units 1-4,* November 2010.

Washington State Carbon Emissions & Goals



Source: EIA- does not include agriculture and waste management and estimates differ than WA Ecology

Issues Related to Colstrip in this IRP

Modeling Assumptions:

- Greenhouse gas regulations:
  - emissions performance standards (CA, OR and WA)
  - 30% WECC-wide reduction identified pursuant to 111(d)
- National Ambient Air Quality Standards
- Mercury and Air Toxics Rule (HAPs)
- Regional Haze

Emerging Issues:

- Finalization of the 111(d) rule at the federal and state levels
- Coal combustion residuals
- Washington Executive Order 14-04
- Cost of closing the plant and continued use of the site

Colstrip Modeling in the 2015 IRP

Expected Case Assumptions:

- Assumes compliance with known environmental regulations (discussed in the previous slide)
- Expected Case assumptions do not speculate – alternatives considered under futures/scenarios studies
- Colstrip Units #3 – 4 in service through IRP modeling period
- Cost of carbon (to be discussed in the next presentation)

Draft Alternative Colstrip Scenarios:

- SCR on units 3 and 4 in 2025 and 2026
- No SCR, shut down units 3 and 4 by end of 2026

Carbon Prices in the 2015 Electric IRP

John Lyons, Ph.D.
Third Technical Advisory Committee Meeting
November 21, 2014

Background

- Washington:
  - "Incorporate a non-zero expected value cost of carbon into the Expected Case. Avista should also work with the Technical Advisory Committee to investigate incorporating a range of prospective carbon policies into the Expected Case stochastic analysis." (UE-121421 – 2013 IRP Acknowledgement Letter)
- Forms of carbon regulation:
  - Cap and trade: an example is AB 32 in California
  - Direct regulation: EPA proposal under 111(d), RCW 80.80
  - Carbon tax: British Columbia
  - Indirectly through an RPS
- Four cases plus two others selected by the TAC (Expected Case, Benchmark Case, 111(d) Case and No Colstrip Case)

State of Carbon Regulation

- No carbon prices for resources in our jurisdictions
- Washington goal of 50 percent below 1990 emissions by 2050, but no implementation strategy.
  - 970 pounds/MWh for new baseload resources (RCW 80.80)
- Emissions offset requirements for new baseload thermal resources in Oregon and Washington
- No carbon prices in Idaho
- Federal: 111(b) and 111(d) proposals
- Other jurisdictions modeled in WECC includes their applicable prices: British Columbia's carbon tax and California's AB32.

2013 IRP Expected Case Carbon Assumptions

- In the 2013 IRP, the implied cost of carbon in the expected case was $95.33 per metric ton.
  - Implied cost to the whole region from coal plant retirements and the cost to replace the lost capacity.
  - Avista's implied cost was much lower than the region because of no expected lost capacity from coal. Avista's implied cost included higher electric market prices ($1.79/MWh or 3.5%) due to the lost capacity between 2020-2033.
- Assuming the price adder is from a 7,000 heat rate natural gas-fired plant the implied 2013 IRP carbon price is $4.70/metric ton levelized between 2020-2033.

Draft 2015 Expected Case Assumptions

- Target 30% minimum reduction in carbon emissions rate from 2005 for plants covered under 111(d)
- Adjust load forecast assumption to include additional conservation
- 21% RPS for the region (not necessarily state-by-state)
- 10% probability of carbon cost adder to generation ($12 nominal in 2020 with 5% escalation)
- Options:
  - Will determine actionable measures needed to reduce existing plant emissions (rate or mass based)
  - Retire enough plants to hit 30% and calculate carbon price necessary to force retirement
  - Increased energy efficiency above utility forecasts
  - 2020 start date, but not the same EPA glide path
- Scenario Purpose: provides market prices and conditions used to determine the Preferred Resource Strategy

Benchmarking Case

- Assumes that 111(d) does not occur so we have a benchmark to show the costs of the 111(d) proposal and other carbon scenarios
- Maintains existing RPS, emissions performance standards, plant retirements and existing energy efficiency programs
- Scenario Purpose: only used to show costs and effects of the 111(d) proposal and regional haze programs

EPA 111(d) Draft Rule Case

- Assumes suggested adoption of EPA building blocks for each state in the WECC
- 21% RPS – state-level requirement
- 10.7% DSM – state-level requirement
- 6% heat rate improvements at coal plants
- Shut down of planned/announced coal retirements
- Caps EGU output to EPA level, with the exception of an adjustment for Langley Gulch to show a full year of output
- Scenario Purpose: shows the impacts of the 111(d) draft rule

No Colstrip Case

- Uses Expected Case assumptions, but removes Colstrip from the resource stack in 2026
- Does not make assumptions about why the plant is no longer available, but shows the costs and how it would be replaced
- Scenario Purpose: answers question posed by the Washington Commission in the 2013 IRP acknowledgement letter

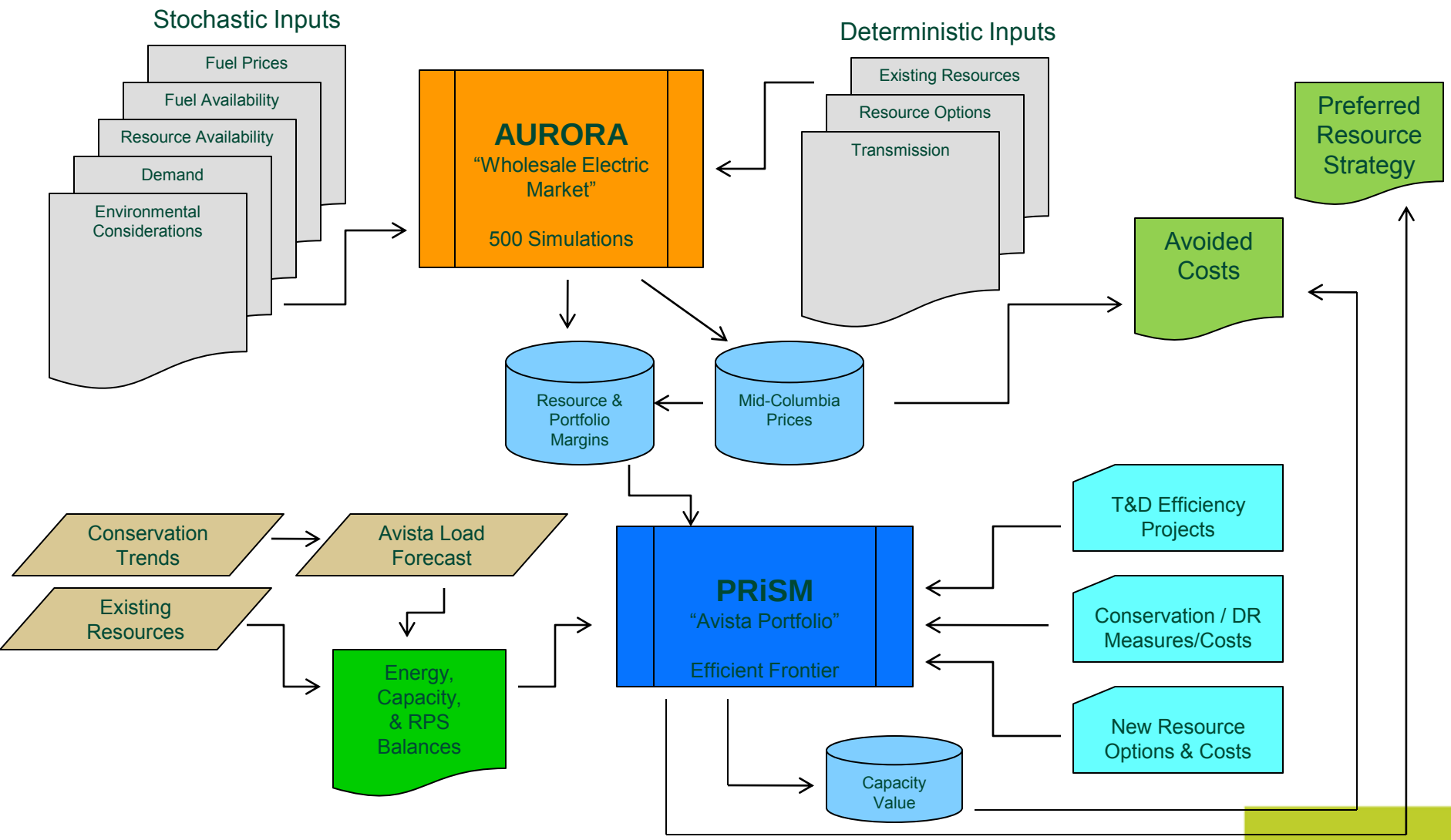
Other Potential Cases for Discussion

- Regional cap and trade for carbon emissions
- Coal limitations without retirement
- All U.S. WECC coal retires by a certain date
- Social cost of carbon as a price adder

2013 IRP Modeling Approach

James Gall
Third Technical Advisory Committee Meeting
November 21, 2014

2015 IRP Modeling Process



Electric Market Modeling

AURORAxmp® by EPIS, Inc.
COMPREHENSIVE POWER FORECASTING

- 3rd party software- EPIS, Inc.
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet load
- Outputs:
  - Market prices
  - Regional energy mix
  - Transmission usage
  - Greenhouse gas emissions
  - Power plant margins, generation levels, fuel costs
  - Avista's variable power supply costs

AVISTA

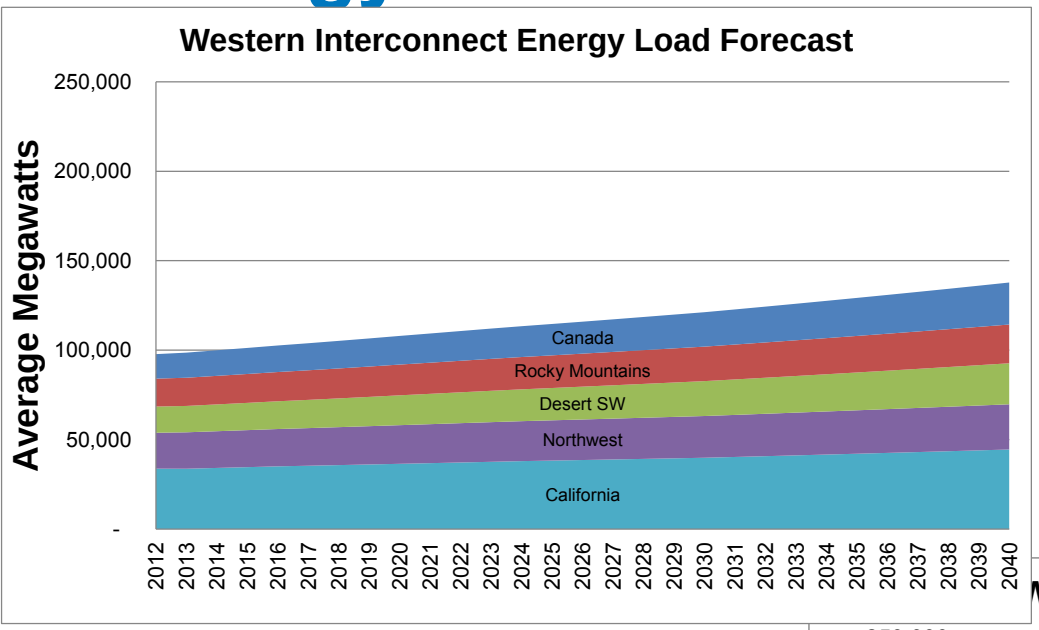
AURORA Inputs

- Regional loads
- Fuel prices
- Hydro levels
- Wind variation
- Environmental resolutions
- Resource availability
- Transmission

Regional Loads

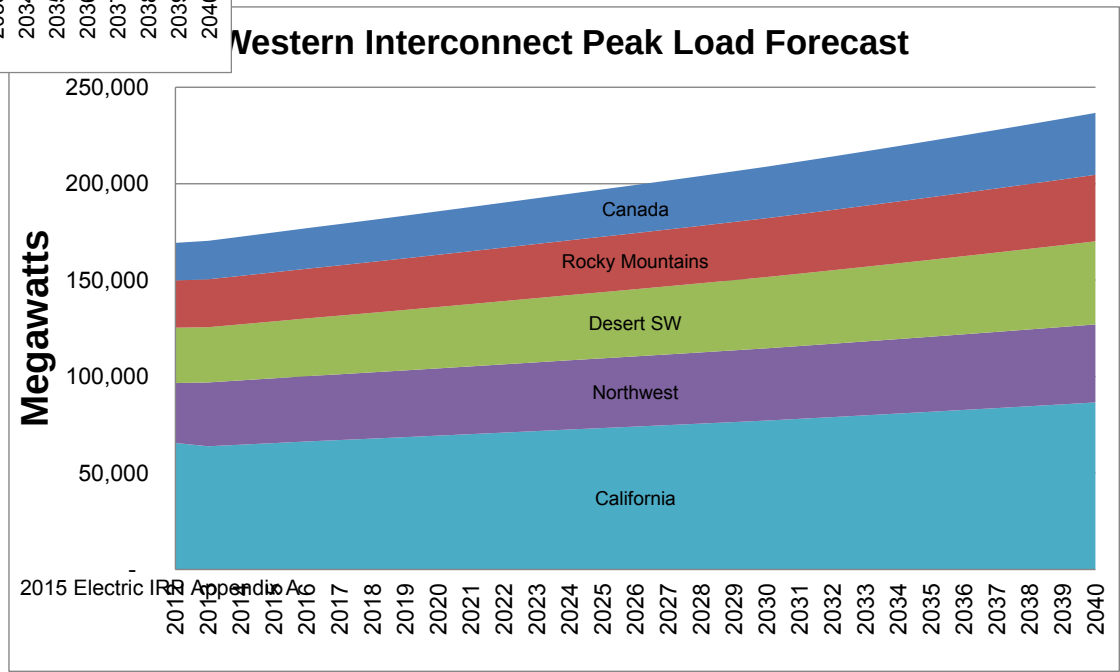
- Forecast load growth for all regions in the Western Interconnect
- Consider both peak and energy
- Use regional published studies and public IRP's
- Stochastic modeling simulates load changes due to weather and considers regional correlation of weather patterns
- Load changes due to economic reasons are difficult to quantify and are usually picked up as IRP's are published every two years
- Peak load is becoming more difficult to quantify as "Demand Response" programs my cause data integrity issues
- Energy demand forecasts need to be net of conservation

Energy & Peak Forecast (draft)



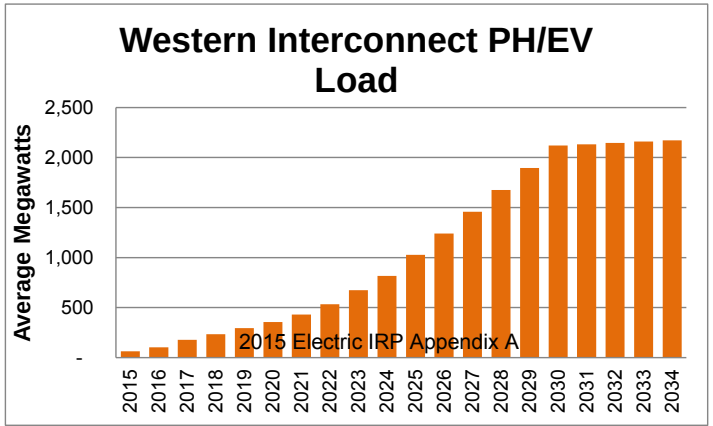
Energy	AAGR
Canada	1.95%
Rocky Mtns.	1.18%
Desert SW	1.61%
California	0.99%
Northwest	0.82%

Peak	AAGR
Canada	1.80%
Rocky Mtns.	1.23%
Desert SW	1.46%
California	1.00%
Northwest	0.95%



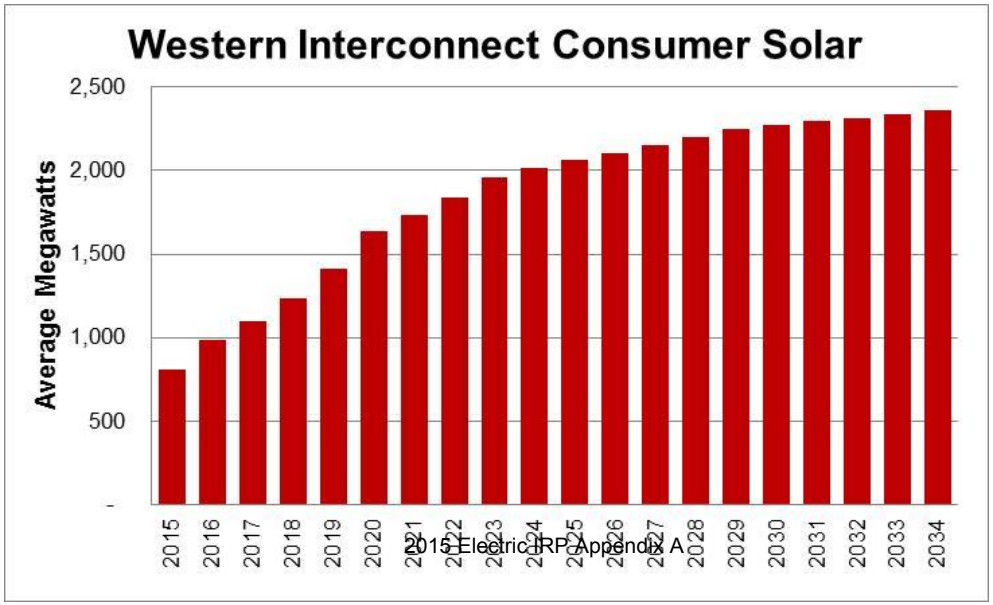
Electric Vehicles (PH/EV)

- Customer load shapes will be a result of PHEV
- To address this- a load adder will be applied to reflect new demand with a majority of load added in off peak hours
- By 2030 the following are the percent of vehicle sales,
  - 25%: CA
  - 15%: AZ, CO, OR, WA
  - 10%: NM, NV,UT
  - 5%: WY, MT, ID
- Beyond 2030 growth is equal to traditional vehicle growth (1/2 of population growth)



Rooftop Solar

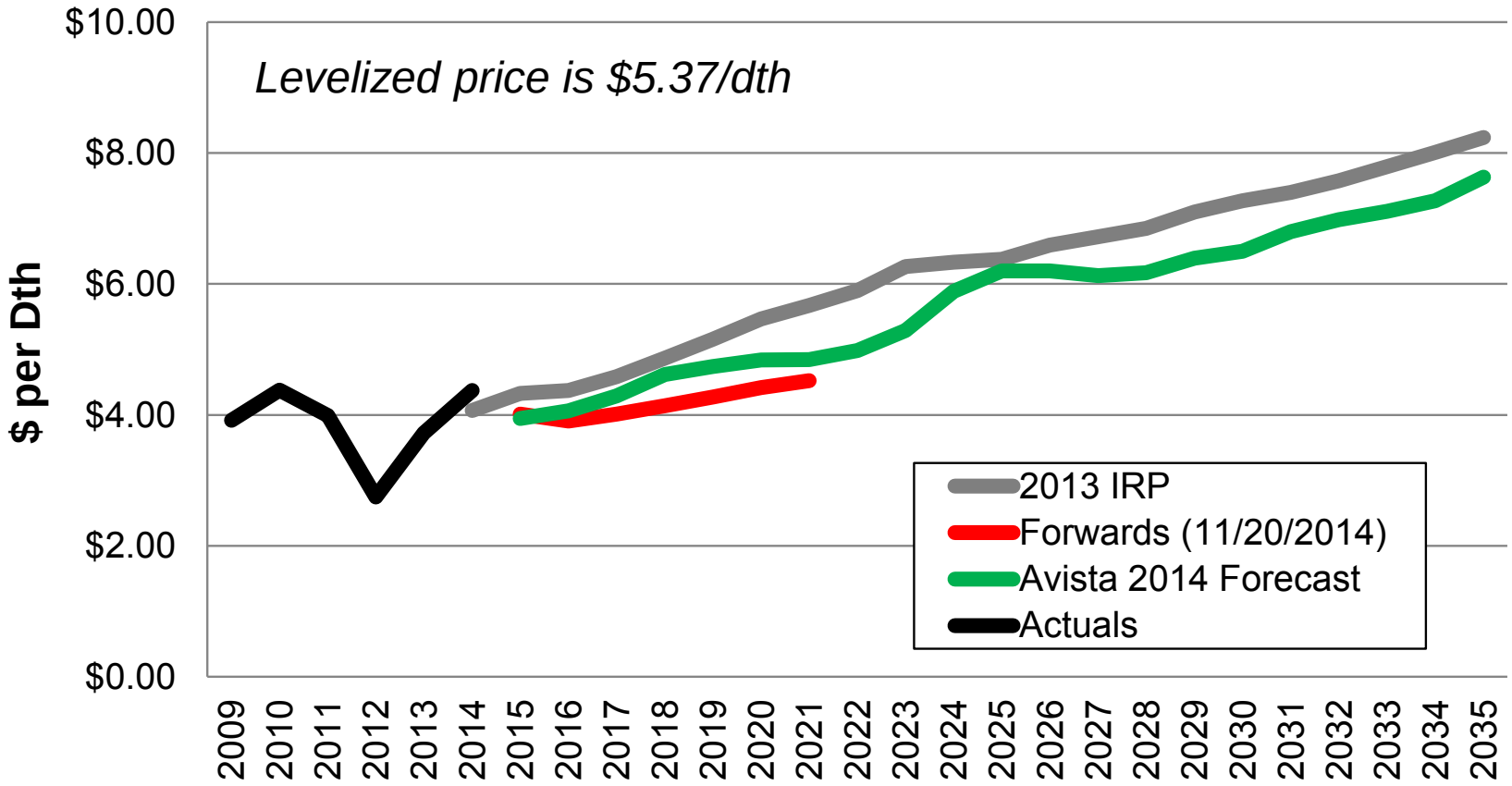
- As with PH/EV, rooftop solar will impact future load growth and its hourly profile
- Future growth will be dependent upon policy choices
- Assumes 20-40% growth, before leveling off to long run growth 1-3% in 2020's



Natural Gas Prices

- Natural gas prices are one of the most difficult inputs to quantify
- A combination of forward prices and consultant studies will be used as the “Expected Case” for this IRP. This work should be complete by December 2014
- 500 different prices using an auto regressive technique will be modeled, the mean value of the 500 simulations will be equal to the “Expected Case” forecast
- A controversial input for these prices is the amount of variance within the 500 simulation.
  - Historically prices were highly volatile, recent history is more stable
  - Final variance estimates will look at current market volatility and implied variance from options contracts

Henry Hub Natural Gas Prices *



* Based on methodology described above, to be updated

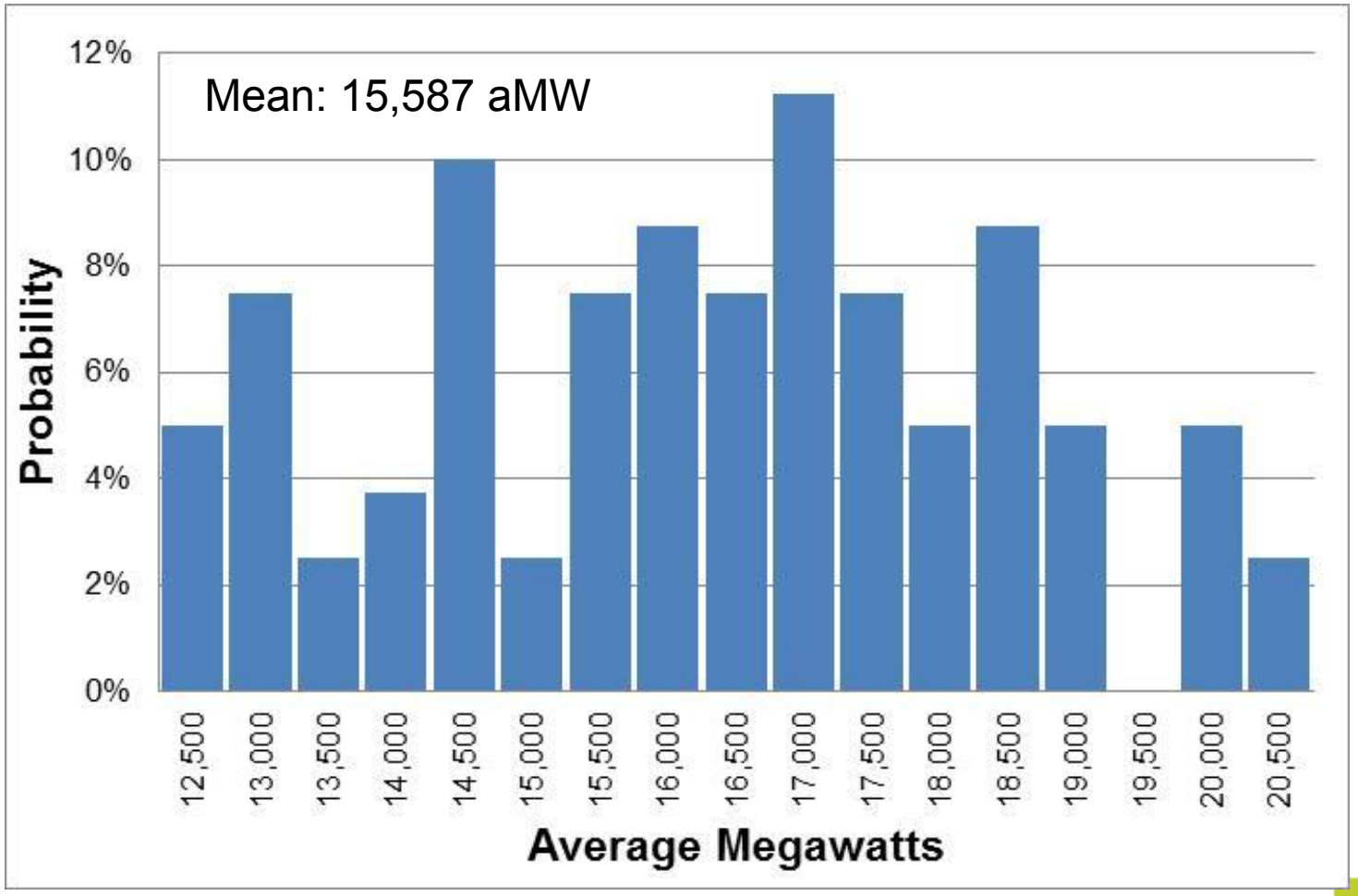
Coal Prices

- With lower natural gas prices and EPA regulations the demand for US based coal is lower, but potential exports may stabilize the industry
- Western US coal plants typically have long-term contracts and many are mine mouth
- Rail coal projects are subject to diesel price risk
- Prices will be based on review of coal plant publically available prices and EIA mine mouth and rail forecasts

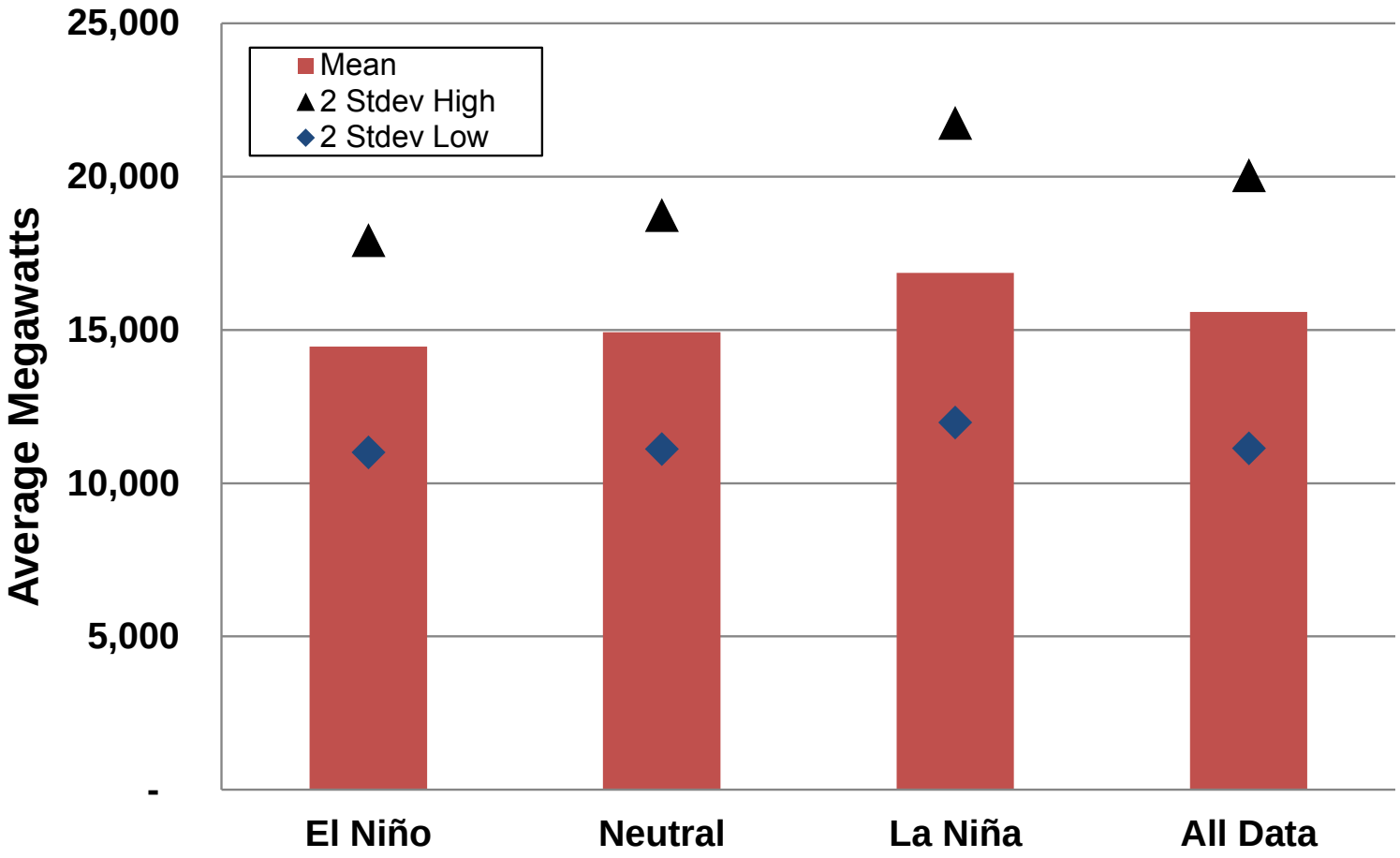
Hydro

- 80 years of hydro conditions are used for the Northwest states, British Columbia and California provided by BPA
  - Hydro levels change monthly
  - AURORA dispatches the monthly hydro based on whether its run-of-river or storage.
- For stochastic studies the hydro levels will be randomly drawn from the 80-year record
- A new Columbia River Treaty could change regional hydro patterns, but until there is resolution, no changes will be included

Northwest State Hydro Volatility



Northwest Hydro Variability (1929-2008)

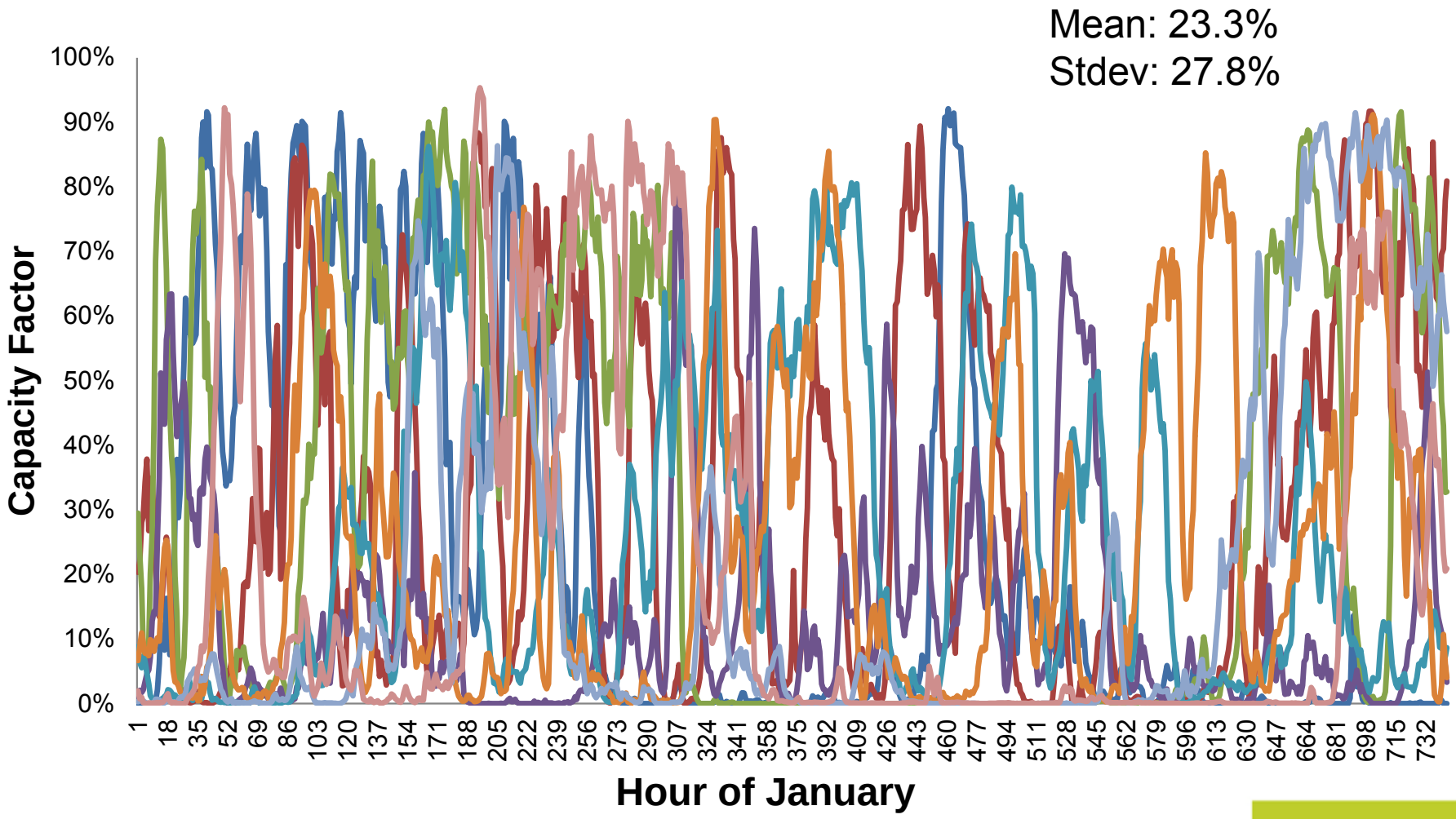


Annual Probability	28%	52%	20%

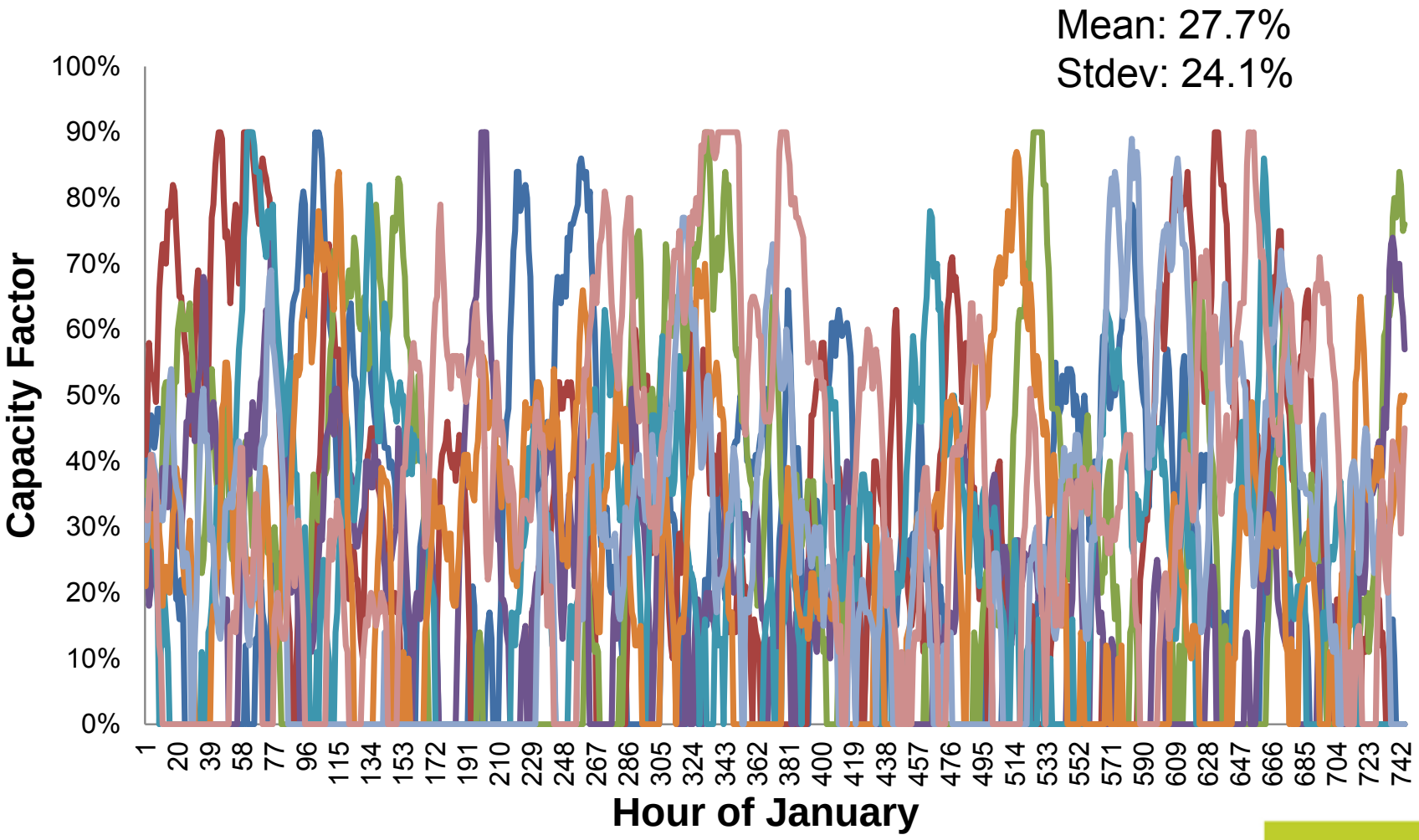
Wind

- Wind generation in the Northwest's is the fastest growing resource type
- RECs and PTC's have caused wind facilities to economically generate in oversupply periods in the Northwest- particularly in the spring months
- Wind is modeled using an autoregressive technique to simulate output in similar to reported data available from BPA, CAISO, and other publically available data sources- also considers correlation between regions
- For stochastic studies several wind curves, will be drawn from to simulate variation in wind output each year

Wind Generation Profile (January 2007-14 from BPA)

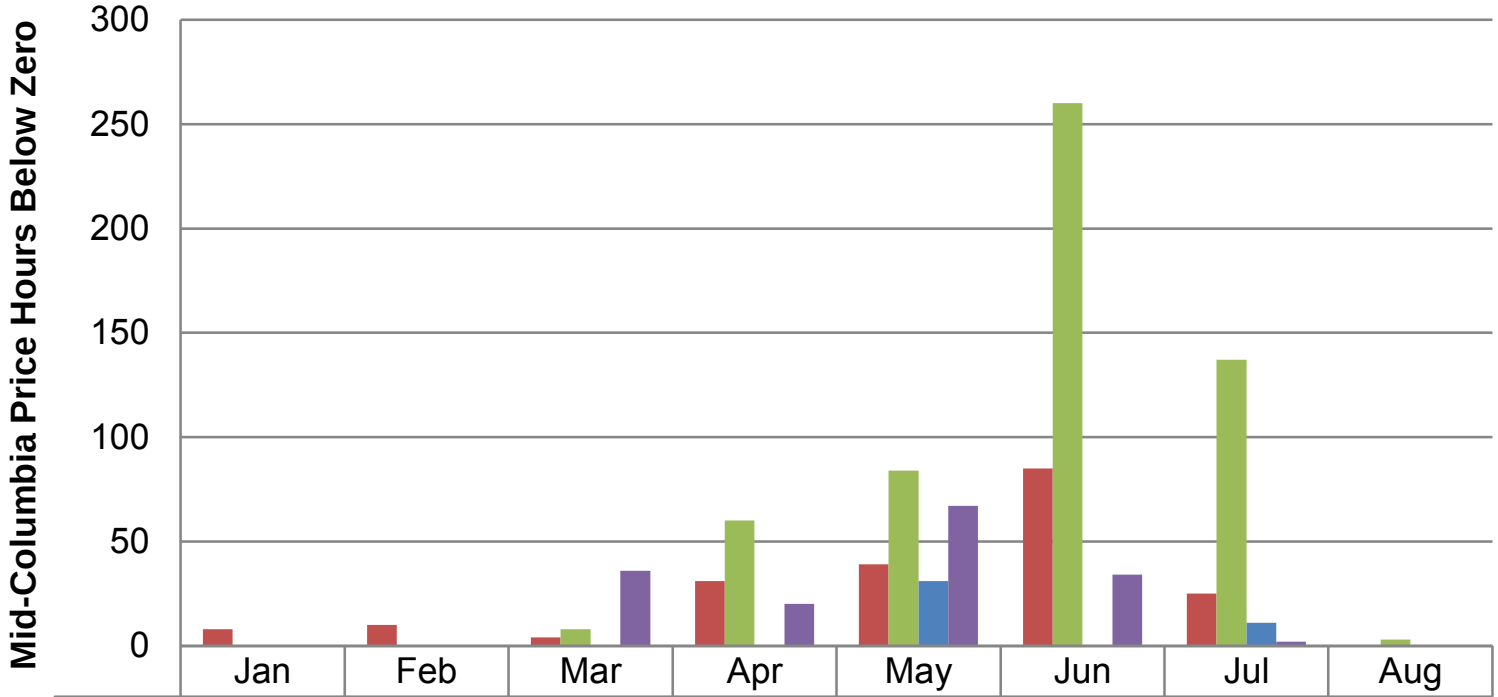


Modeled Wind Generation Profile



Oversupply

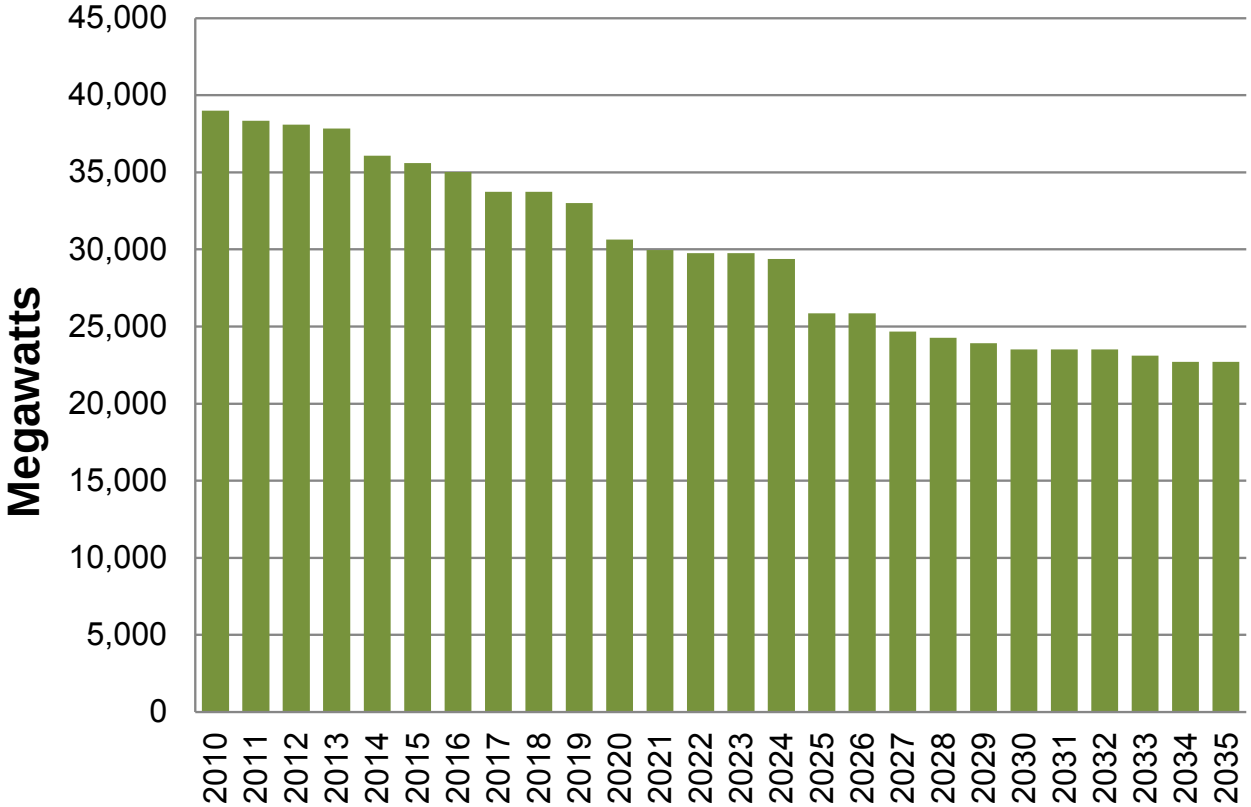
Hours Mid-Columbia Prices Were Less Than $0/MWh



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
2011	8	10	4	31	39	85	25	0	202
2012	0	0	8	60	84	260	137	3	552
2013	0	0	0	0	31	0	11	0	42
2014	0	0	36	20	67	34	2	0	159

Source: Powerdex daily average prices- substantially more hours had trades with negative pricing

Western Interconnect Coal Capacity Forecast

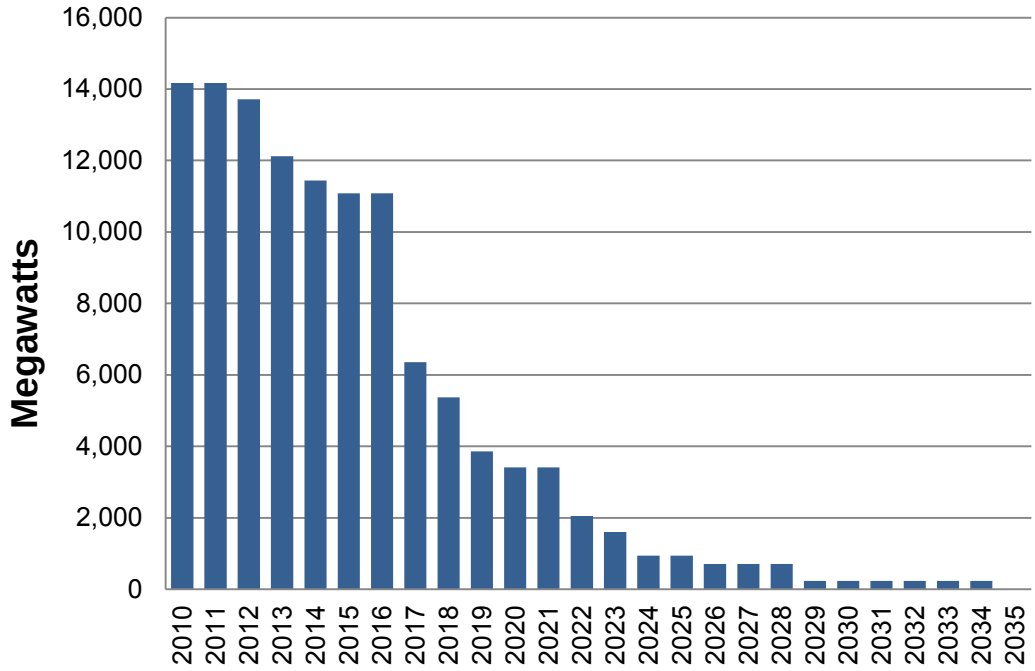


- Announced retirements are 42% of coal plant capacity in the west between 2010 and 2035

Cooling Water Issues

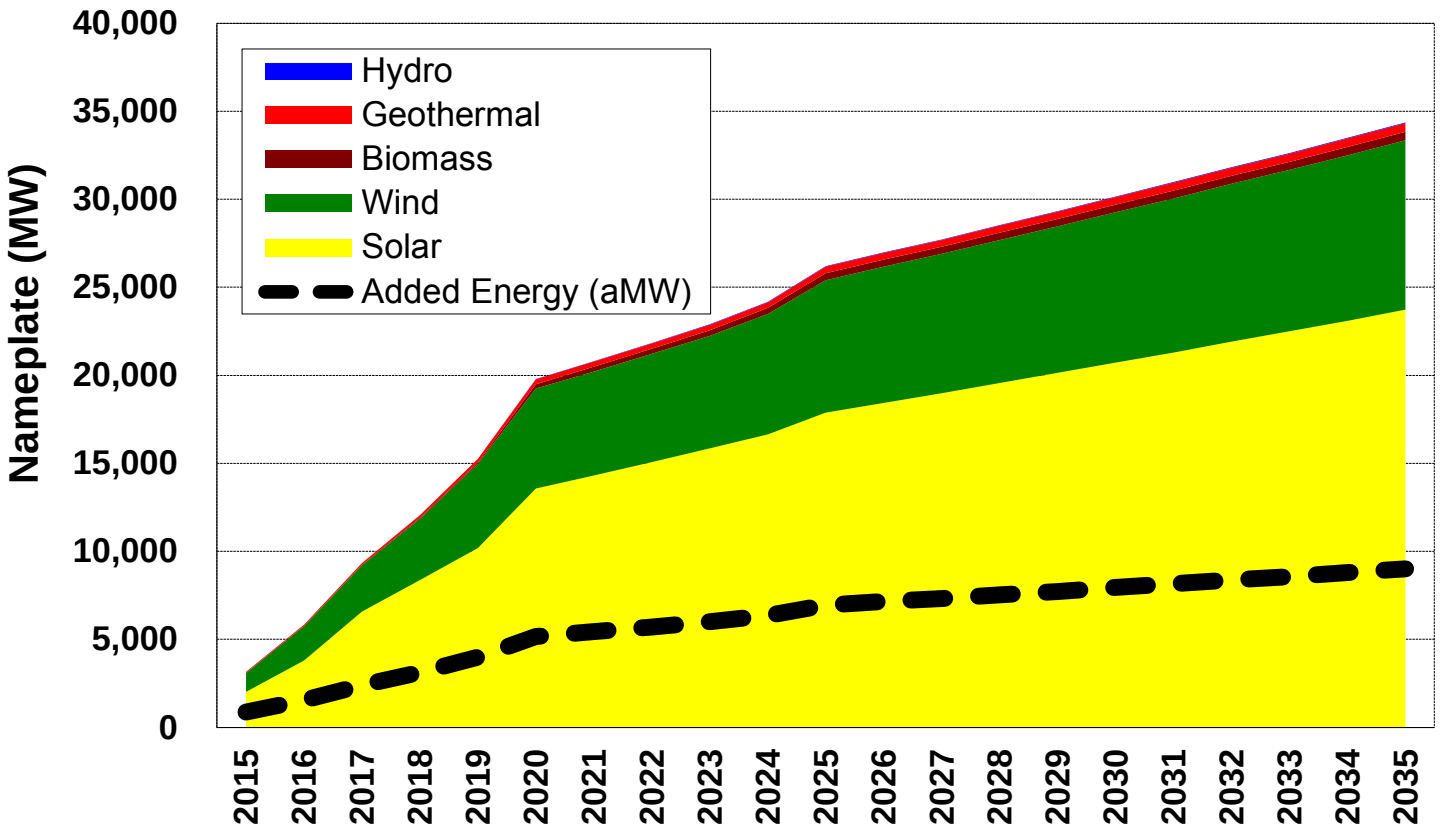
- Once-through cooling
  - California plants with this cooling technology must be converted to alternative cooling methods or retired
  - For modeling purposes: older natural gas units will be retired and Diablo Canyon will be retrofitted
- Traditional water cooling
  - New NG resources are finding it more difficult to use water cooling- for new resources air cooling will be assumed

Once-Through Cooling Affect



- 14,167 MW of natural gas plants in California are affected by once-through-cooling rules
- Represents 29% of California's natural gas fleet

Western State's Renewable Portfolio Standards Capacity/Energy Forecast



PRiSM- Preferred Resource Strategy Model

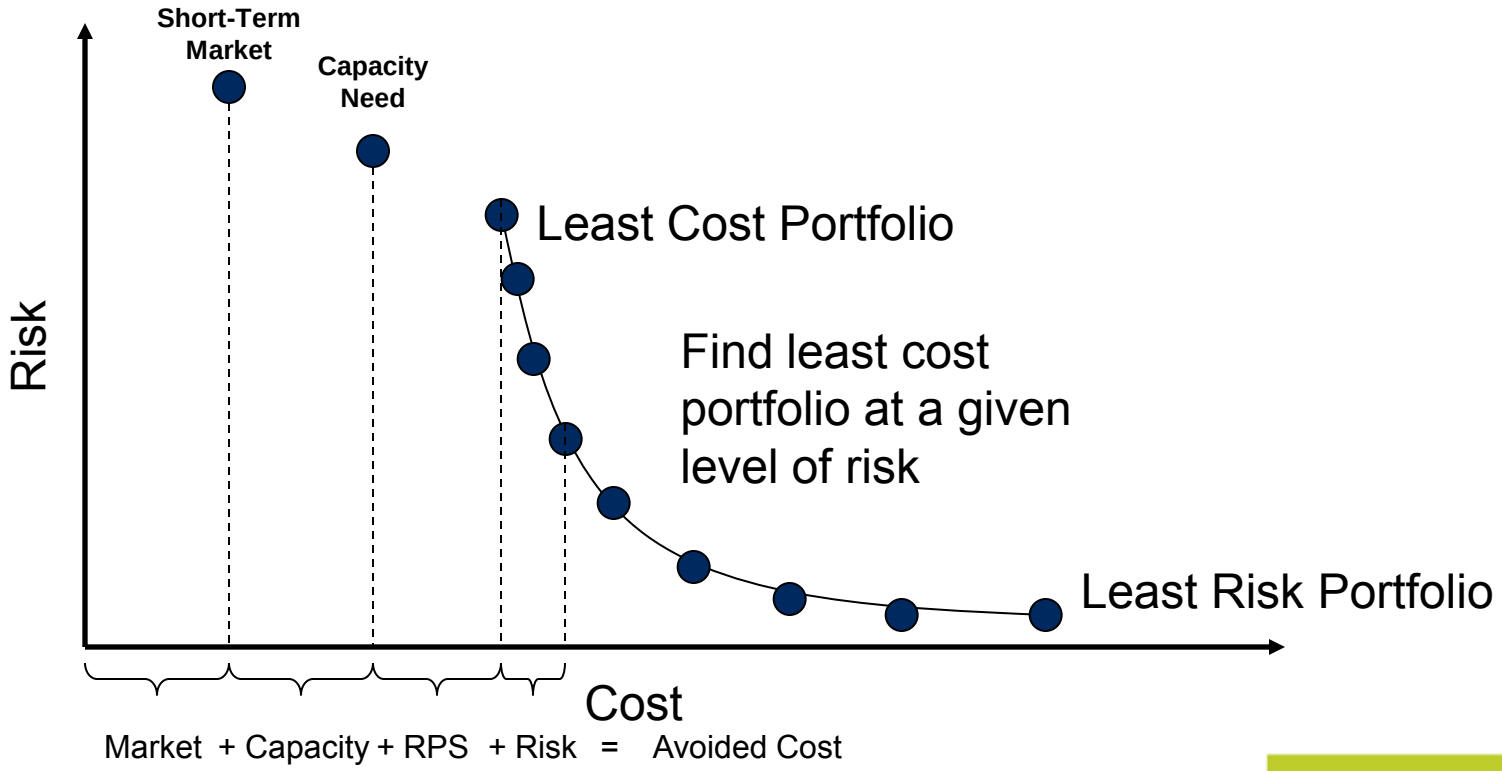
- Internally developed using Excel based linear/mixed integer program model (What's Best)
- Selects new resources to meet Avista's capacity, energy, and renewable energy requirements
- Outputs:
  - Power supply costs (variable and fixed)
  - Power supply costs variation
  - New resource selection (generation/conservation)
  - Emissions
  - Capital requirements

PRiSM

- Find optimal resource strategy to meet resource deficits over planning horizon
- Model selects its resources to reduce cost, risk, or both.
- Objective Function:
  - Minimize: Total Power Supply Cost on NPV basis (2016-2054)- Focus on first 20 years of the plan
  - Subject to:
    - Risk level
    - Capacity need +/- deviation
    - Energy need +/- deviation
    - Renewable portfolio standards
    - Resource limitations, sizes, and timing

Efficient Frontier

- Demonstrates the trade off of cost and risk
- Avoided Cost Calculation



AEG
Applied Energy Group

Conservation Potential Assessment

Technical Advisory Committee Meeting

November 21, 2014

Outline

Study Approach

LoadMAP Overview

Market Characterization

Baseline Projection

Measure Development

Ramp Rate Development

Economic Screening

Potential Results

Consistency with Council Methodology

Study approach

LoadMAP

Study results

Synthesize Sensitivity analysis

Achievable potential

Establish Customer Acceptance
Avista programs Other studies
Market acceptance/ramp rates

Technical and economic potential

Screen Measures and Options
Measure descriptions
Avista avoided costs
Avista program data
NWPCC/RTF workbooks

End-use forecast by segment

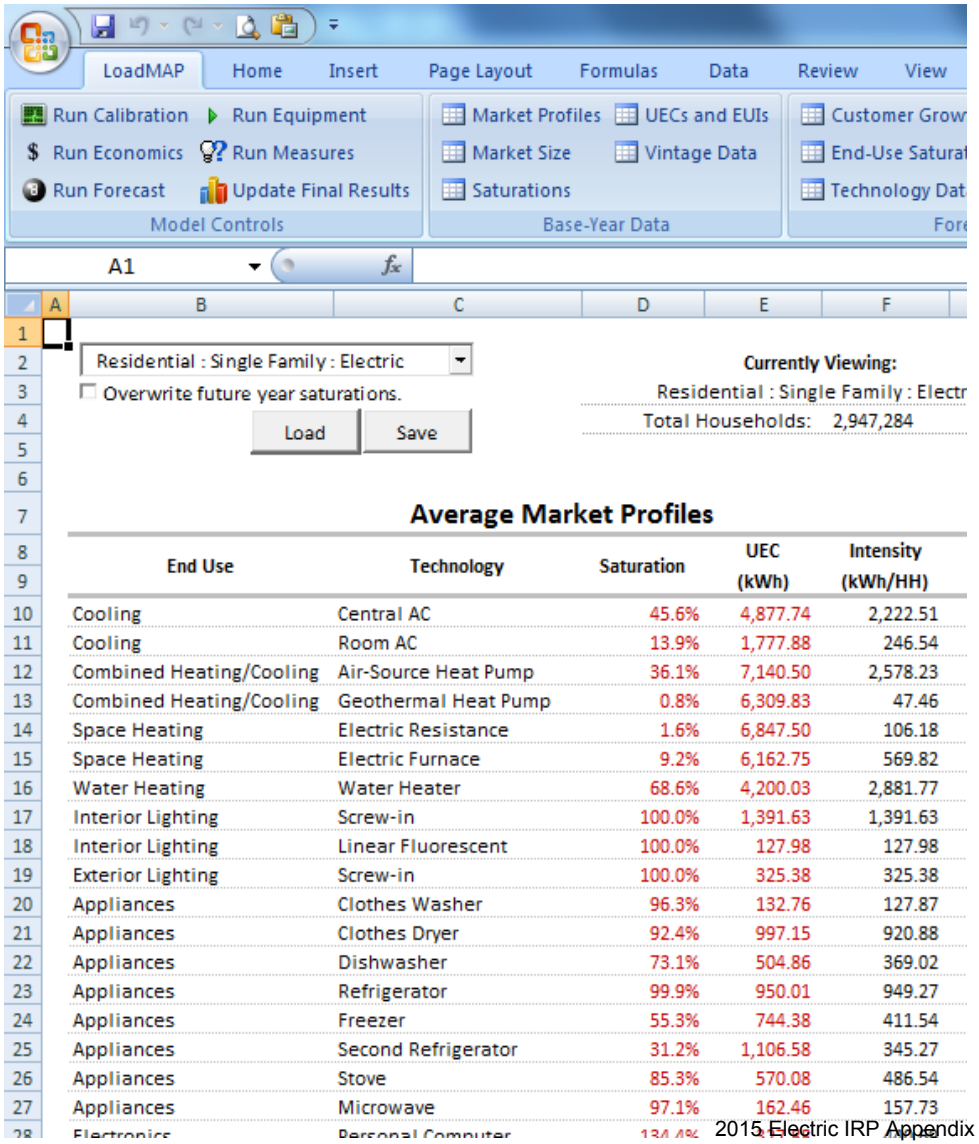
Project the Baseline
Prototypes and energy analysis (***BEST***)
Codes and standards
RTF data
Avista forecast data
Secondary data

Base-year energy use by segment

Characterize the Market
Avista billing data
Avista GenPOP, RBSA, CBSA
Avista program data and other surveys
Energy Market Profiles
Secondary data
Previous study results

Study objectives

LoadMAP™ analysis tool



End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)
Cooling	Central AC	45.6%	4,877.74	2,222.51
Cooling	Room AC	13.9%	1,777.88	246.54
Combined Heating/Cooling	Air-Source Heat Pump	36.1%	7,140.50	2,578.23
Combined Heating/Cooling	Geothermal Heat Pump	0.8%	6,309.83	47.46
Space Heating	Electric Resistance	1.6%	6,847.50	106.18
Space Heating	Electric Furnace	9.2%	6,162.75	569.82
Water Heating	Water Heater	68.6%	4,200.03	2,881.77
Interior Lighting	Screw-in	100.0%	1,391.63	1,391.63
Interior Lighting	Linear Fluorescent	100.0%	127.98	127.98
Exterior Lighting	Screw-in	100.0%	325.38	325.38
Appliances	Clothes Washer	96.3%	132.76	127.87
Appliances	Clothes Dryer	92.4%	997.15	920.88
Appliances	Dishwasher	73.1%	504.86	369.02
Appliances	Refrigerator	99.9%	950.01	949.27
Appliances	Freezer	55.3%	744.38	411.54
Appliances	Second Refrigerator	31.2%	1,106.58	345.27
Appliances	Stove	85.3%	570.08	486.54
Appliances	Microwave	97.1%	162.46	157.73
Electronics	Personal Computer	134.4%	[illegible]	[illegible]

- **LoadMAP stands for Load Management, Analysis and Planning**
  - Analyzes EE, DR, distributed generation/renewables and electricification trends
  - Used for more than 40 potential assessments in last six years
- **LoadMAP modeling features**
  - Embodies principles of rigorous end-use models (like EPRI's REEPS and COMMEND)
  - Uses stock-accounting
  - Uses a simple decision logic
  - Models are customized by end use
- **User friendly and transparent algorithms:**
  - Excel-based model
  - Can easily update all assumptions and results flow through to pre-formatted charts and tables
  - Conduct sensitivity analysis
  - Answer what-if questions from senior management

Segmentation for the CPA

Dimension	Segmentation Variable	Dimension Examples
1	State	Washington and Idaho
2	Sector	Residential, Commercial, Industrial
3	Segment	Residential: by housing type and income
		Commercial: by building type
		Industrial: as a whole
4	Vintage	Existing and new construction
5	End uses	Cooling, heating, ventilation, lighting, water heat, refrigeration, motors, etc. (customized for each sector)
6	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by size, etc.
7	Equipment efficiency levels for new purchases	Baseline efficiency and an array of higher-efficiency options as appropriate for each technology

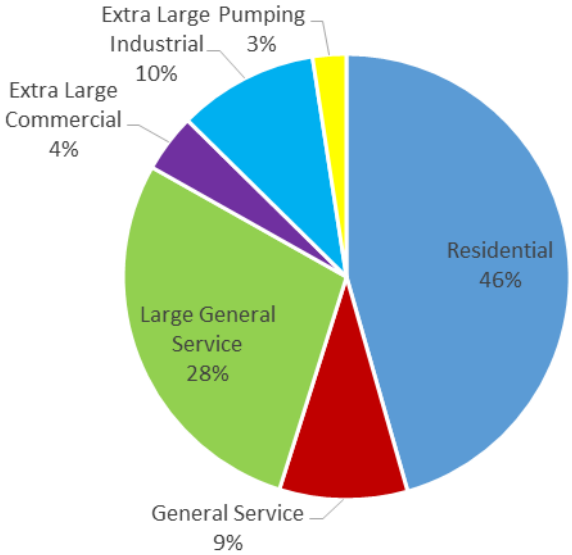
We begin with a high-level market characterization

Source: Avista 2012 CPA

Washington	Customers	2013 Electricity Sales (GWh)
Residential	200,134	2,452
General Service	27,142	416
Large General Service	3,352	1,557
Extra Large Commercial	9	266
Extra Large Industrial	13	614
Pumping	2,361	136
Total	**233,011**	**5,440**

Idaho	Customers	2013 Electricity Sales (GWh)
Residential	99,580	1,182
General Service	19,245	323
Large General Service	1,456	700
Extra Large Commercial	3	70
Extra Large Industrial	6	196
Pumping	1,312	59
Total	**121,602**	**2,530**

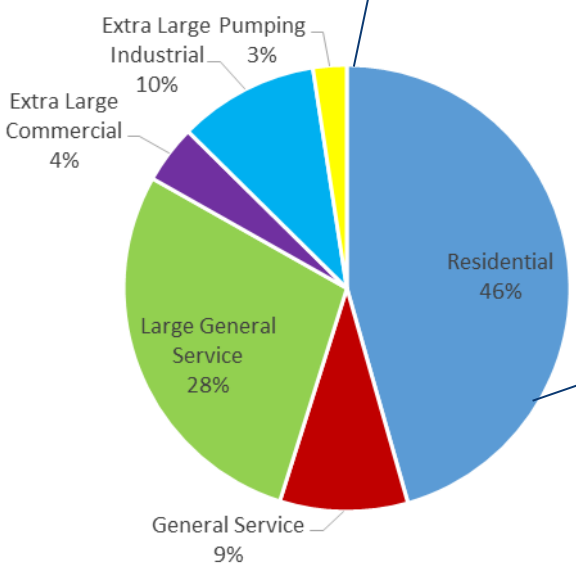
Avista (WA and ID)	Customers	2013 Electricity Sales (GWh)
Residential	299,714	3,634
General Service	46,387	739
Large General Service	4,808	2,257
Extra Large Commercial	12	336
Extra Large Industrial	19	810
Pumping	3,673	195
Total	**354,613**	**7,970**



We disaggregate sectors into most important segments

Source: Avista 2012 CPA

Residential Avista Total	Number of Customers	Annual Use (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	168,339	2,399	66%	14,251
Multi Family	23,456	202	6%	8,612
Mobile Home	10,022	128	4%	12,772
Low Income	97,896	905	25%	9,245
Total	299,714	3,634	100%	12,125



We develop energy market profiles for each sector

Source: Avista 2012 CPA

Market profiles characterize how customers use energy in the base year.

- All buildings/dwellings
- New construction

Basic Equation:

$$Energy = \sum_{e} (N \times Sat_e \times UEC_e)$$

where

Energy = annual energy use
e = equipment technology
N = number of homes
Sat_e = saturation of homes with the equip
UEC_e = unit energy consump in homes with the equipment present

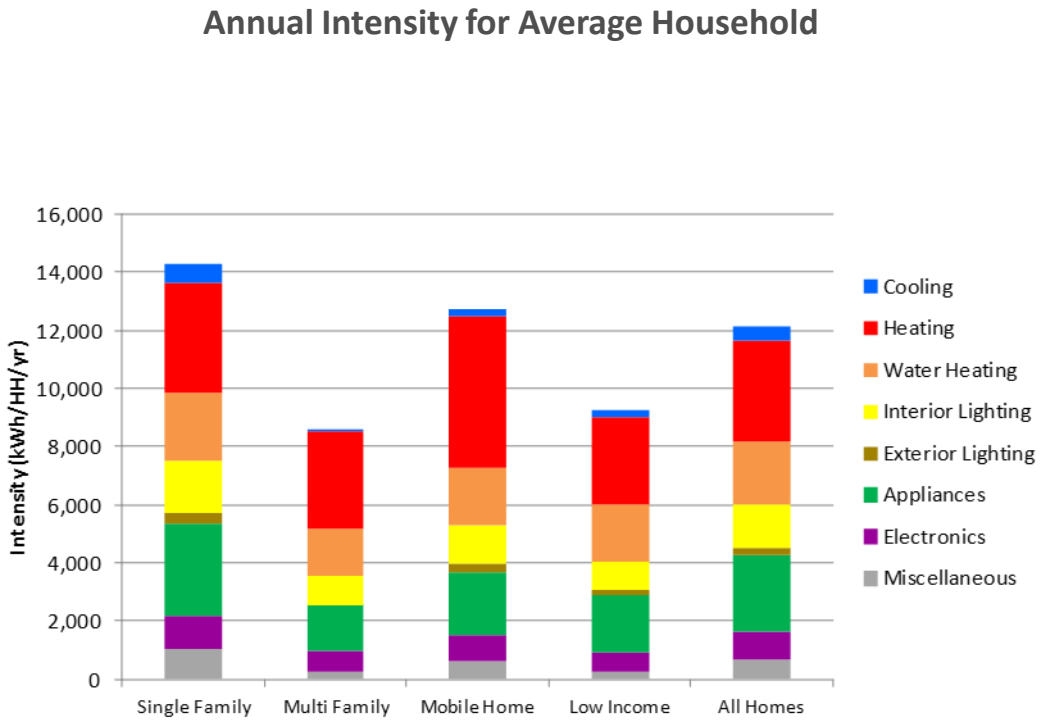
This sample market profile is captured from LoadMAP. Saturations and UECs are inputs to the model. LoadMAP calculates the intensity and usage. Values shown in the Total line match the market characterization control totals.

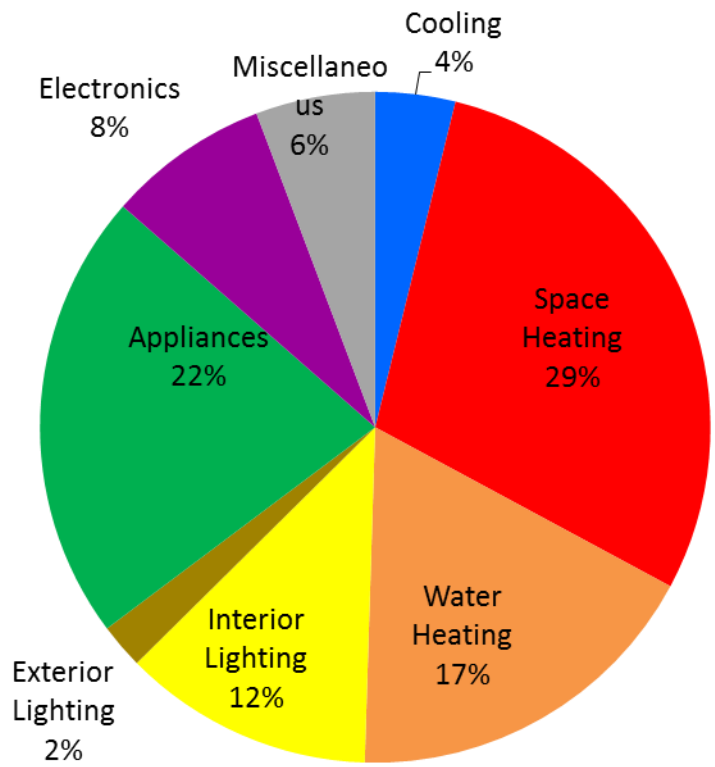
Average Market Profiles - Washington

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	28.6%	1,150	330	66
Cooling	Room AC	20.7%	360	75	15
Cooling	Air Source Heat Pump	16.3%	735	120	24
Cooling	Geothermal Heat Pump	0.2%	730	2	0
Space Heating	Electric Resistance	20.4%	6,624	1,350	270
Space Heating	Electric Furnace	10.7%	9,173	980	196
Space Heating	Air Source Heat Pump	16.3%	7,498	1,222	245
Space Heating	Geothermal Heat Pump	0.2%	4,833	11	2
Space Heating	Supplemental	7.8%	260	20	4
Water Heating	Water Heater <= 55 Gal	66.3%	3,074	2,038	408
Water Heating	Water Heater > 55 Gal	3.1%	4,552	140	28
Interior Lighting	Screw-in	100.0%	1,060	1,060	212
Interior Lighting	Linear Fluorescent	100.0%	107	107	21
Interior Lighting	Specialty	100.0%	275	275	55
Exterior Lighting	Screw-in	100.0%	254	254	51
Appliances	Clothes Washer	82.7%	114	94	19
Appliances	Clothes Dryer	78.8%	493	389	78
Appliances	Dishwasher	85.6%	386	330	66
Appliances	Refrigerator	100.0%	694	694	139
Appliances	Freezer	56.1%	774	434	87
Appliances	Second Refrigerator	25.9%	977	253	51
Appliances	Stove	87.7%	386	338	68
Appliances	Microwave	95.6%	114	109	22
Electronics	Personal Computers	119.0%	205	244	49
Electronics	TVs	204.4%	221	452	90
Electronics	Set-top Boxes/DVR	155.2%	128	198	40
Electronics	Devices and Gadgets	100.0%	55	55	11
Miscellaneous	Pool Pump	3.6%	1,415	52	10
Miscellaneous	Furnace Fan	43.7%	577	252	50
Miscellaneous	Miscellaneous	100.0%	373	373	75
	Total			**12,250**	**2,452**

Energy market profiles summarized

Source: Avista 2012 CPA





Data sources for energy market profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	Avista billing data, GenPOP survey, American Community Survey, NEEA surveys and reports, NPCC Sixth Plan
Annual intensity	Residential: Annual energy use (kWh/household) Commercial: Annual energy use (kWh/ sq ft) Industrial: Annual energy use (kWh/employee)	Avista billing data, AEG Energy Market Profiles database , NEEA surveys and reports, AEO, previous studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology; Percentage of commercial floor space or industrial employment with equipment/technology	GenPOP survey, NEAA surveys and reports, RECS, AEG Energy Market Profiles, and other secondary data
UEC/EUI for each end-use technology	UEC: Annual electricity use for a technology in dwellings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	NEAA surveys and reports, RTF/SEEM data, RTF UES workbooks, engineering analysis, BEST prototype simulations, engineering analysis
Appliance/equipment vintage distribution	Age distribution for each technology	NEEA surveys and reports, secondary data (DEEM, EIA, EPRI, DEER, etc.)
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	RTF, Council workbooks, prototype simulations, engineering analysis, appliance/equipment standards, secondary data, previous studies

We develop a baseline projection

Projects energy market profiles into the future

- Baseline projection is an end-use forecast of energy usage absent the effects of future conservation programs. Includes the effects of appliance standards and building codes, but holds efficiency purchasing trends at current levels (assumes no naturally-occurring conservation).

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I sectors	Data provided by Avista's Forecasting Department
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Avista program results Shipments data from AEO AEO regional forecast assumptions RTF data on current market baseline NEEA surveys and reports Appliance/efficiency standards analysis
Exogenous forecast drivers	Retail price forecasts Personal income forecasts Other	Avista forecasts AEO
Utilization model parameters	Elasticities for each forecast driver	EPRI's REEPS and COMMEND models AEO Avista's historical weather data and normal weather data (cooling & heating degree days)

Timeline of current residential appliance standards

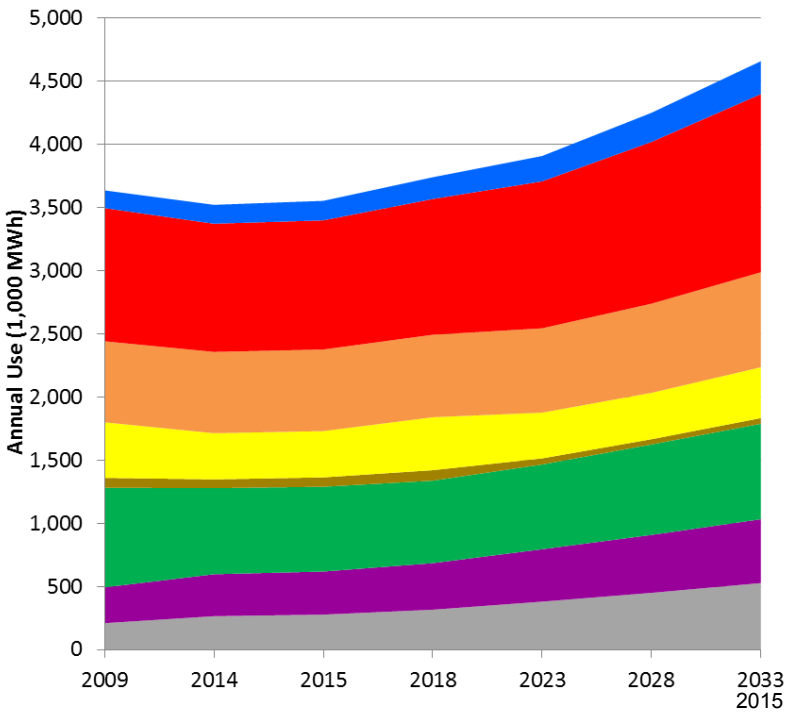
Today's Efficiency or Standard Assumption
1st Standard (relative to today's standard)
2nd Standard (relative to today's standard)

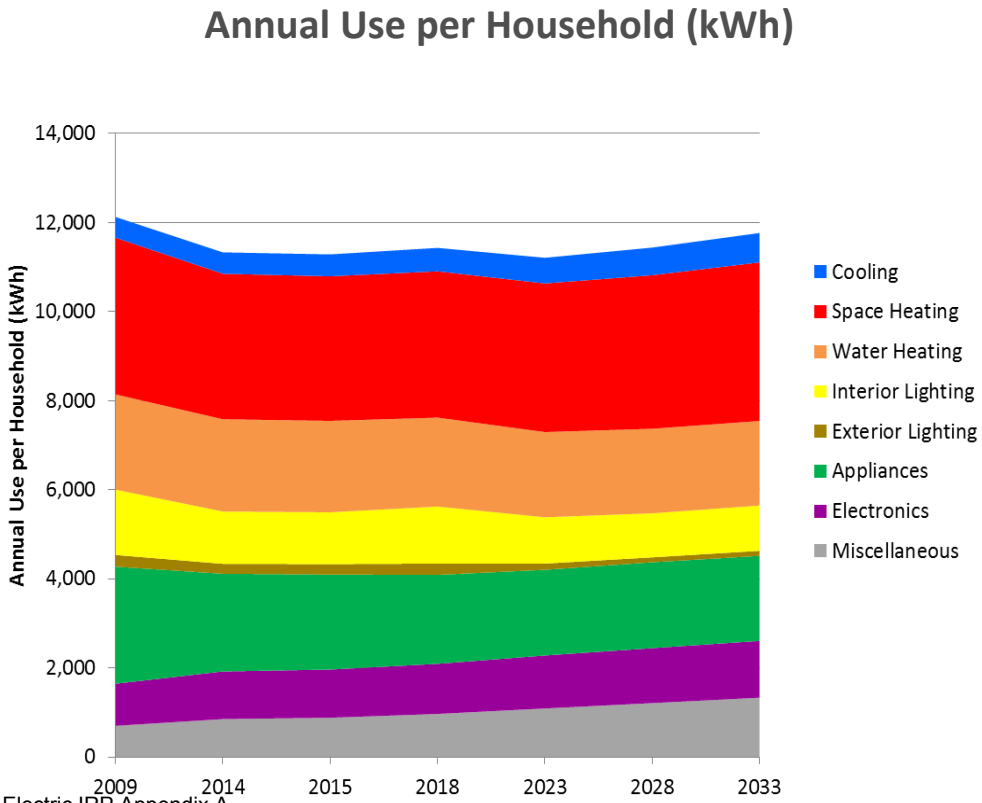
End Use	Technology	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13													
	Room AC	EER 9.8		EER 11.0											
	Evaporative Central AC	Conventional													
	Evaporative Room AC	Conventional													
Cooling/Heating	Heat Pump	SEER 13.0/HSPF 7.7			SEER 14.0/HSPF 8.0										
Space Heating	Electric Resistance	Electric Resistance													
Water Heating	Water Heater (<=55 gallons)	EF 0.90			EF 0.95										
	Water Heater (>55 gallons)	EF 0.90			Heat Pump Water Heater										
Lighting	Screw-in/Pin Lamps	Incandescent		Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T12	T8												
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard		25% more efficient											
	Freezer	NAECA Standard		25% more efficient											
	Dishwasher	Conventional (355kWh/yr)	14% more efficient (307 kWh/yr)												
	Clothes Washer	Conventional (MEF 1.26 for top loader)			MEF 1.72 for top loader			MEF 2.0 for top loader							
	Clothes Dryer	Conventional (EF 3.01)			5% more efficient (EF 3.17)										

Example of a residential baseline projection

Source: Avista 2012 CPA

- Growth of 32% from ‘09 to '33, or 1.5% per year on average.
- Per household basis, use is increasing slightly at 4% for the forecast period, or 0.2% per year.





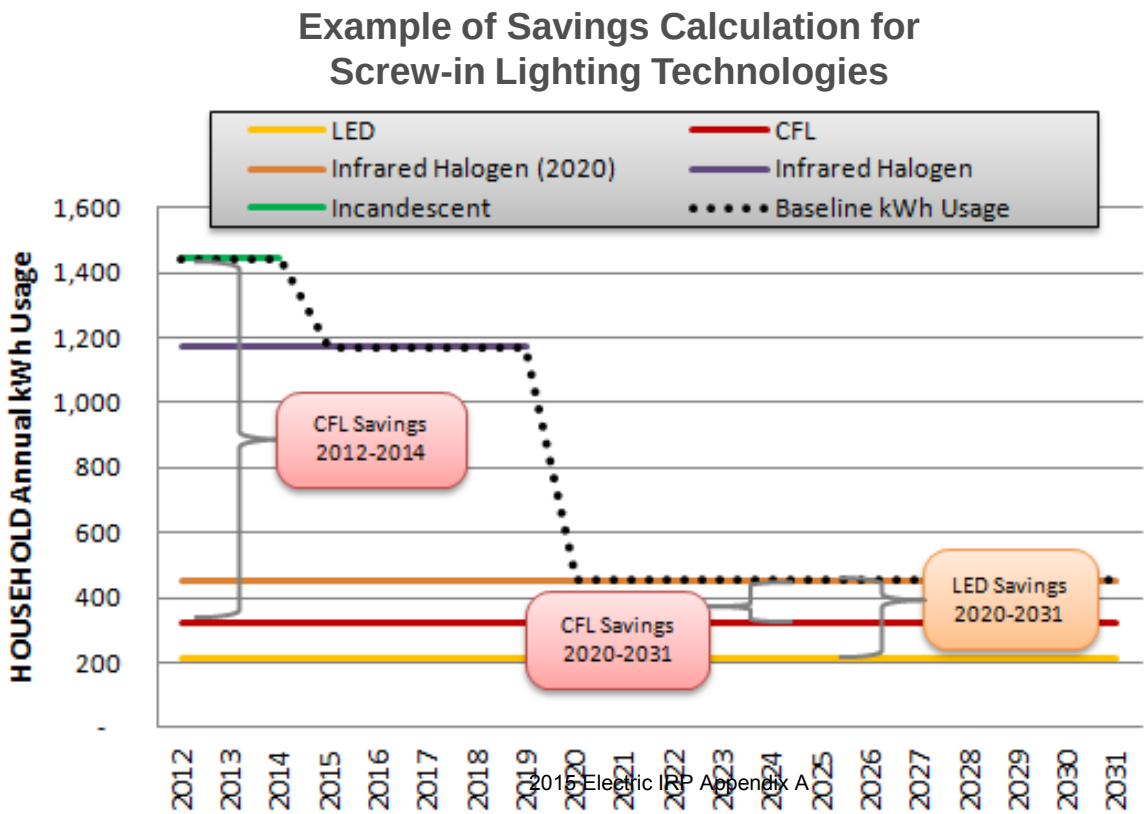
ECM identification & characterization

- Develop measure list using
  - Council workbooks
  - Existing programs
  - AEG databases
- Characterization
  - Description
  - Costs
  - Savings
  - Applicability
  - Lifetime
- Data sources
  - RTF
  - Avista data
  - AEG's database
  - BEST simulations
- Measure Crosswalk

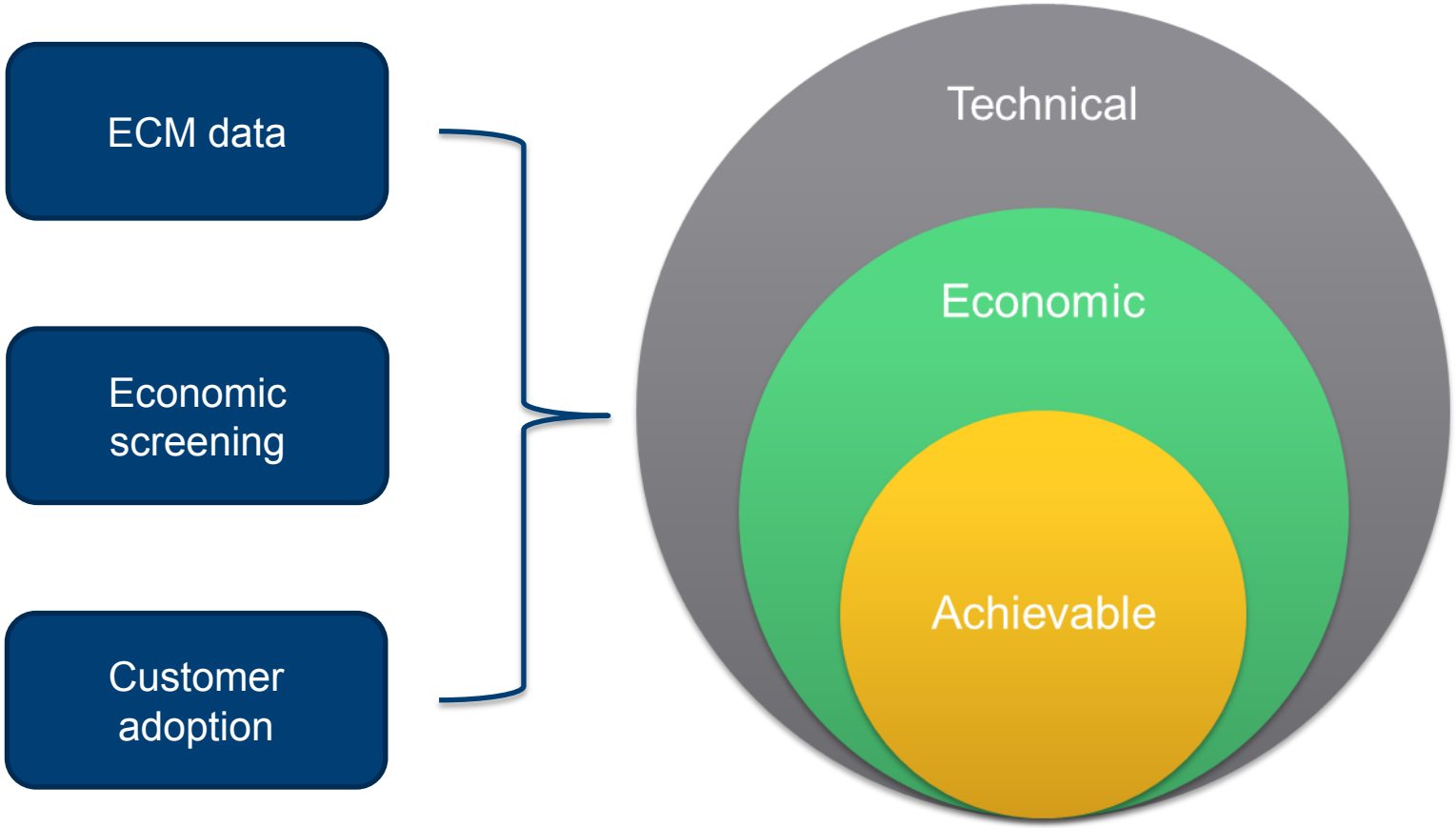
Example: Water heating measures
Conventional (EF 0.95)
Heat pump water heater (EF 2.3)
Solar water heater
Low-flow showerheads
Timer / Thermostat setback
Tank blanket

ECM savings and costs

- Measure savings change relative to baseline throughout study (as shown)
- We use a market baseline, consistent with RTF/Council
- Measure costs change with market projections and expectations



Calculating the three levels of potential



Estimating potential and ramp rates

Technical potential assumes most efficient option is chosen by all customers

Economic potential assumes all customers choose the highest-efficiency option that passes economic screen

- Use TRC and Avista's avoided cost to perform economic screen

Achievable potential is a subset of economic potential

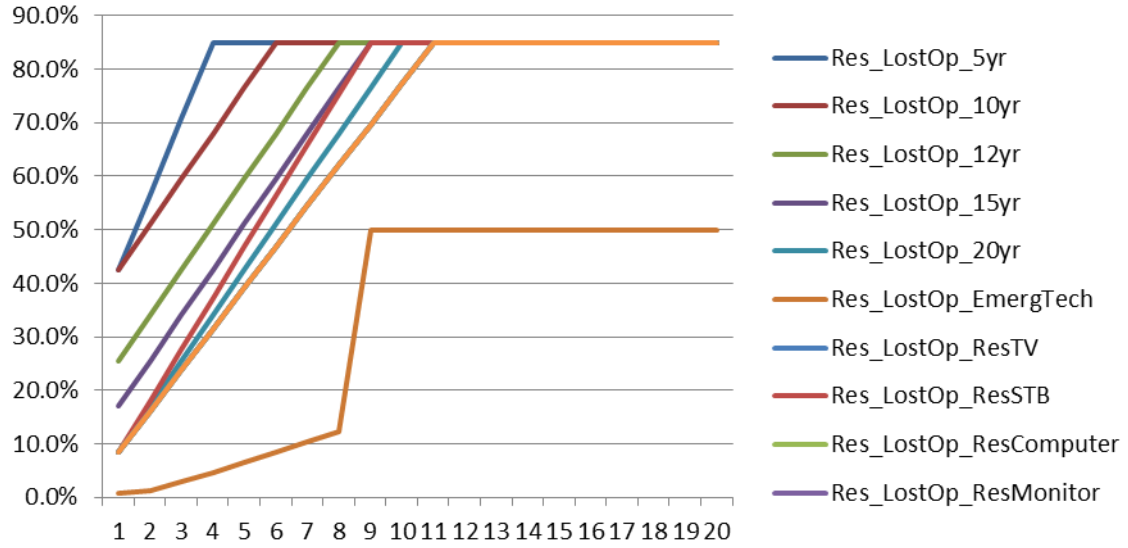
- Calculated by applying ramp rates to economic potential
- Our approach for Avista:
  - Start with ramp rates from the 6th Power Plan
  - Map the Council ramp rates to ECMs in our analysis
  - Adjust the starting point for each measure's ramp rate to align with Avista's recent program accomplishments

Customer adoption (ramp) rates

Residential ramp rates from NWPCC

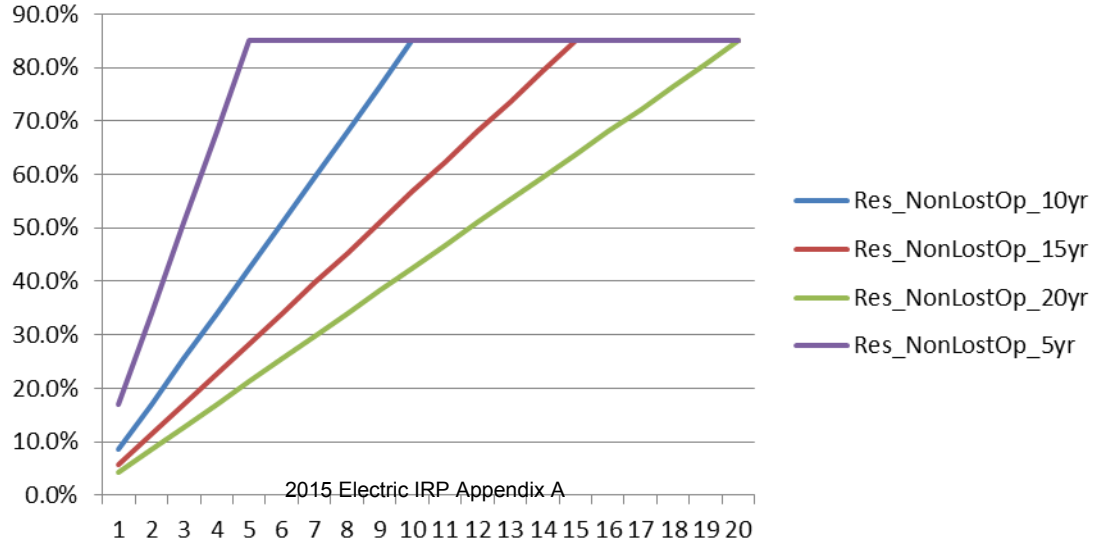
Lost Opportunity Ramp Rates:

Applied to equipment units each year that are turning over into a new purchase decision.



Non-Lost Opportunity Ramp Rates:

Applied cumulatively to all applicable opportunities in the market over time.

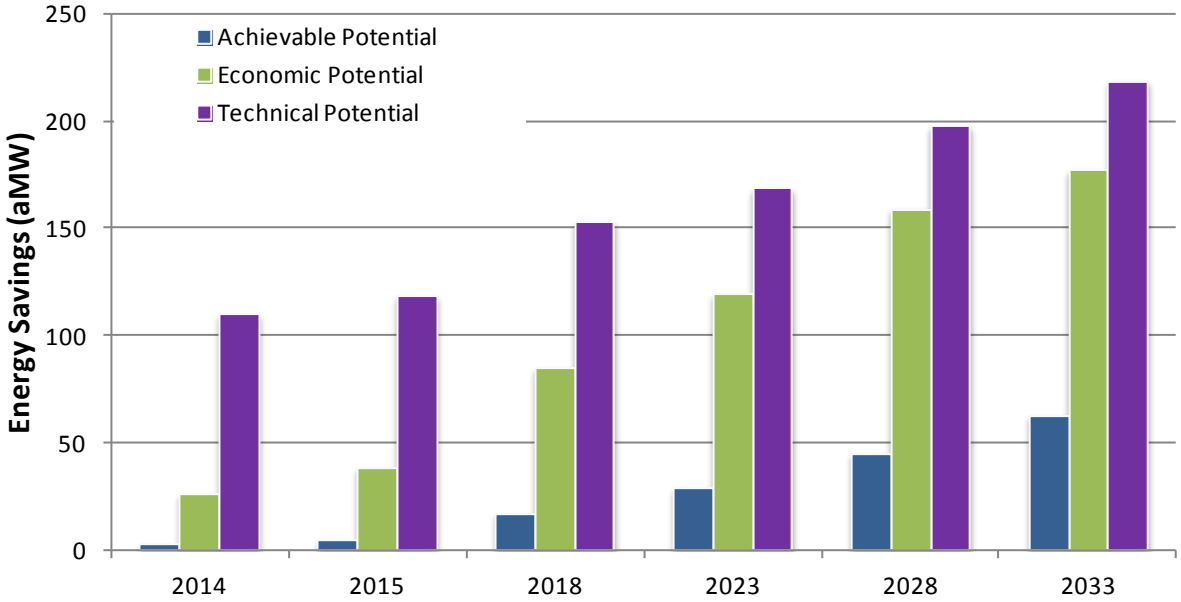


Residential conservation potential

Example from Avista 2012 CPA

For 2014 to 2023, ten-year achievable potential savings are about 252 GWh.

This is 28.8 aMW.



	2014	2015	2018	2023	2028	2033
Cumulative WA and ID Savings (MWh)						
Achievable Potential	21,848	42,786	147,588	251,961	392,098	547,119
Economic Potential	231,078	335,111	744,684	1,041,719	1,390,377	1,549,252
Technical Potential	963,411	1,037,905	1,338,457	1,473,324	1,727,383	1,911,746
Cumulative Savings (aMW)						
Achievable Potential	2.5	4.9	16.8	28.8	44.8	62.5
Economic Potential	26.4	38.3	85.0	118.9	158.7	176.9
Technical Potential	110.0	118.5	152.8	168.2	197.2	218.2

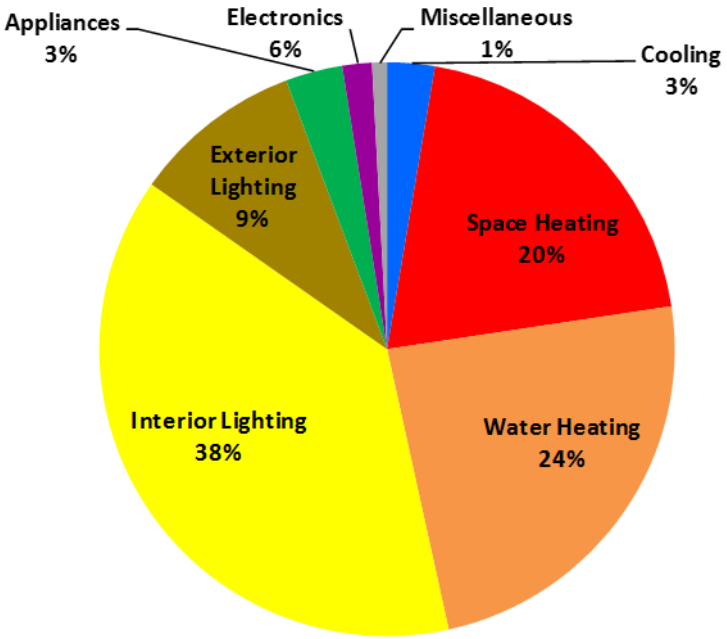
2015 Electric IRP Appendix A

Top measures in the residential sector

Example from Avista 2012 CPA

Measure/Technology	2018 Cumulative Savings (MWh)	% of Total
Interior Lighting Screw-in	39,805	27%
Electric Furnace	17,175	12%
Interior Specialty Lighting	16,484	11%
Exterior Screw-in Lighting	14,121	10%
Water Heater <= 55 Gal	11,129	8%
Water Heater - Tank Blanket/Insulation	7,317	5%
Thermostat - Clock/Programmable	6,783	5%
Water Heater - Low Flow Showerheads	5,885	4%
Water Heater - Pipe Insulation	4,790	3%
Electric Resistance	3,738	3%
Water Heater - Faucet Aerators	3,244	2%
Central AC	2,687	2%
Water Heater - Thermostat Setback	2,626	2%
Refrigerator	2,187	1%
Insulation - Infiltration Control	1,692	1%
Furnace Fan	1,170	1%
Personal Computers	1,111	1%
Insulation - Foundation	791	1%
Freezer	789	1%
TVs	745	1%

Achievable Potential in 2018



AEG Consistency with Council Methodology

End-use model — bottom-up

- Building characteristics, fuel and equipment saturations
- Stock accounting based on measure life
- Codes and standards that have been enacted are included in baseline
- Lost- and non-lost opportunities treated differently

Measures – comprehensive list

- RTF measure workbooks
- BPA data
- AEG databases, which draw upon same sources used by RTF

Economic potential, total resource cost (TRC) test

- Considers HVAC interactions, non-energy benefits
- Avoided costs include 10% credit based on Conservation Act

Achievable potential – ramp rates

- Based on Sixth Plan ramps rates, but modified to reflect Avista's program history

AEG
Applied Energy Group

Thank You!

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Fuong Nguyen
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Sharon Yoshida
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2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 4 Agenda

Tuesday, February 24, 2015

Red Lion River Inn – Shoreline Ballroom A, Spokane, WA

Topic	Time	Staff
1. Introduction & TAC 3 Recap	8:30	Lyons
2. Demand Response Study	8:45	Doege
3. Natural Gas Price Forecast	9:15	Dorr
Break		
4. Electric Price Forecast	10:30	Gall
5. Lunch	11:30	
6. Resource Requirements	12:30	Kalich
Break		
7. Interconnection Studies	1:15	Maguire
8. Market Scenarios and Portfolio Analysis	2:15	Lyons
9. Adjourn	3:00	

TAC meeting location: Red Lion River Inn Spokane
Shoreline Ballroom A
700 N. Division
Spokane, WA 99202

Directions: http://www.redlion.com/river-inn-spokane/map-directions

2015 Electric IRP
TAC Meeting Expectations and Schedule

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
February 24, 2015

Technical Advisory Committee

- The public process of the IRP – input on what to study, how to study, and review assumptions and results
- Technical forum with a range of participants with different areas of input and expertise
- Open forum, but we need to stay on topic to get through the agenda and allow all participants to ask questions and make comments
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies
  - The earlier study requests are made, the more accommodating we can be
  - January 15, 2015 was the final date to receive study requests
- Action Items – areas for more research in the next IRP

Technical Advisory Committee

- Technical forum on inputs and assumptions, not an advocacy forum
- Focus is on developing a resource strategy based on sound assumptions and inputs, instead of a forum on a particular resource or resource type
- We request that everyone maintain a high level of respect and professional demeanor to encourage an ongoing conversation about the IRP process
- Supports rate recovery, but not a preapproval process
- Planning team is available by email or phone for questions or comments between the TAC meetings

Remaining TAC Meetings

- **TAC 5 – March 24, 2015:** Completed conservation potential assessment, draft preferred resource strategy (PRS), review of scenarios, market futures, and portfolio analysis
- **TAC 6 – June 24, 2015:** Review of final PRS and action items.

TAC #3 Recap

- Introduction & TAC 2 Recap – Lyons
- Planning Margin – Gall
- Colstrip Discussion – Lyons
- Cost of Carbon – Lyons
- IRP Modeling Overview – Gall
- Conservation Potential Assessment – Kester

Today's Agenda

- Introduction & TAC 3 Recap (8:30) – Lyons
- Demand Response Study (8:45) – Doege
- Natural Gas Price Forecast (9:15) – Scott
  - Break
- Electric Price Forecast (10:30) – Gall
- Lunch (11:30)
- Resource Requirements (12:30) – Kalich
  - Break
- Interconnection Studies (1:15) – Maguire
- Market Scenarios and Portfolio Analysis (2:15) – Lyons
- Adjourn 3:00

Demand Response Potential Assessment Study

Study & Report by: Applied Energy Group & Avista

Prepared by Leona Doege
Fourth Technical Advisory Committee Meeting
February 24, 2015

Purpose of Study

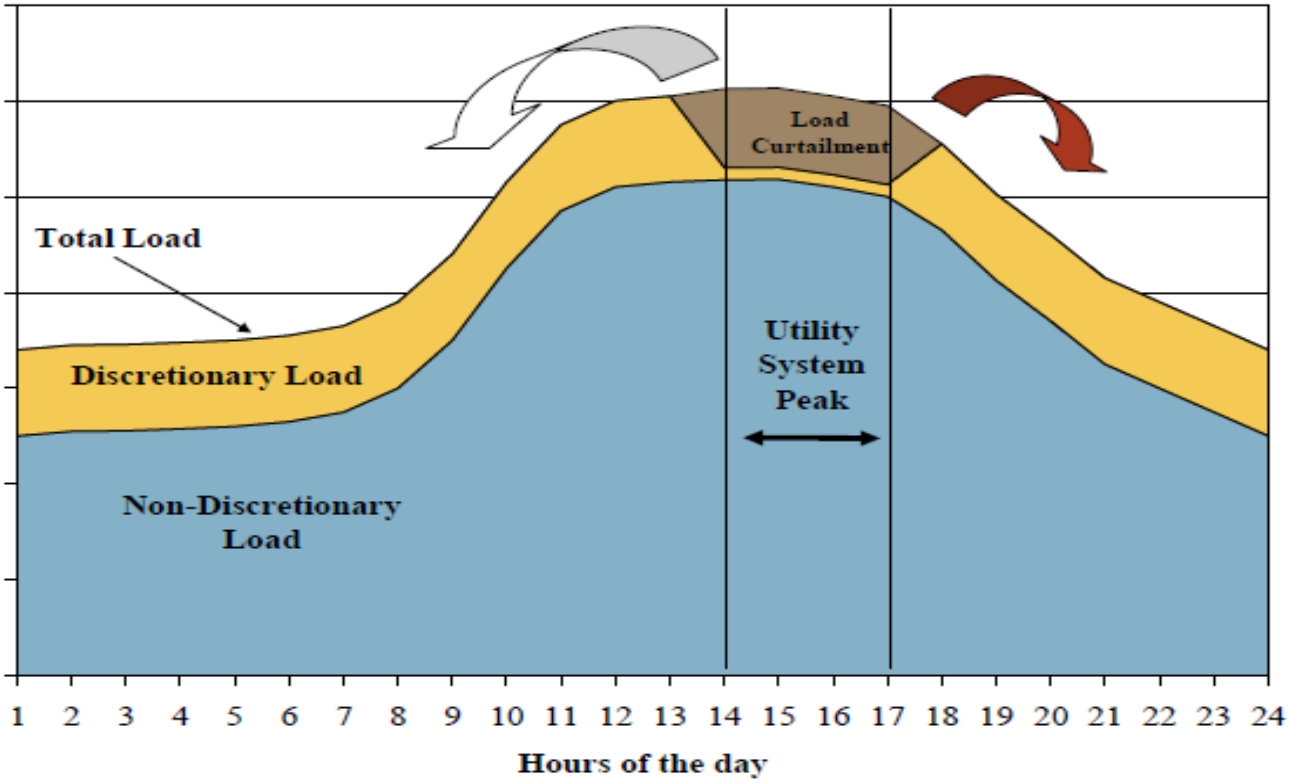
2013 Electric IRP Action Item

Answer the following questions:

- How much capacity for DR?
- How long will it take to reach it (ramp rate)?
- How much will it cost?

Demand Response

Customers making a change to their consumption in response to a price or incentive signal.

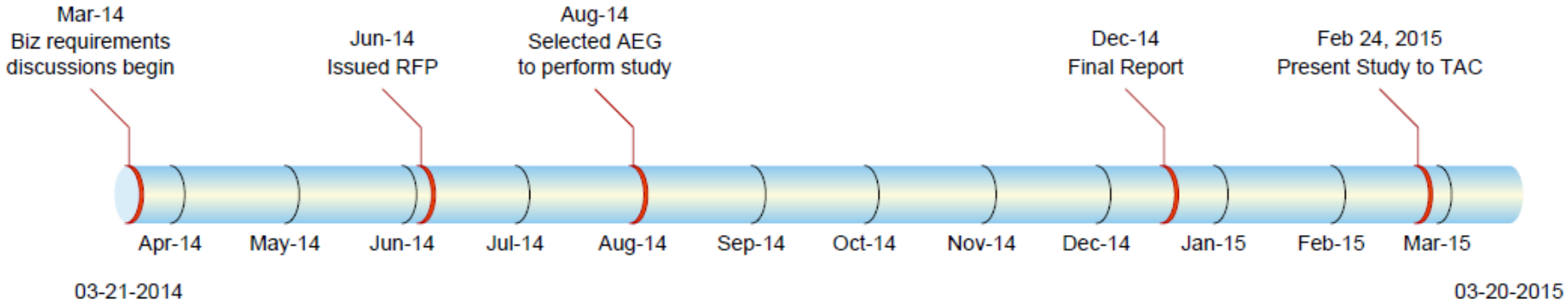


Graph Source: FERC Demand Response Report 2006

Demand Response History at Avista

- **2001:** Nickel buyback program
- **2006:** Public plea, & bilateral agreements (emergency load shedding)
- **2007-2009:** Idaho 2-year residential direct load control pilot
- **2012-2014**: Washington: 2.5-year residential & WSU direct load control demonstration (SGDP- Pullman)

Study Approach

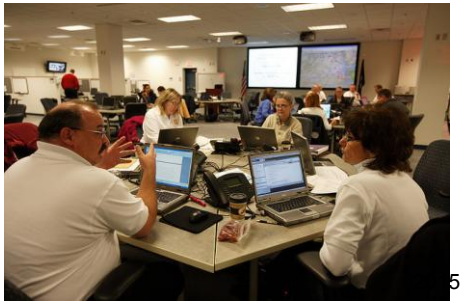


- Review U.S. Demand Response Programs
  - Categorized DR Programs
- Segmented Avista C&I customers
- Identify DR Programs relevant to Avista & C&I customers
- Develop & discuss assumptions
- Develop framework

Demand Response Programs Relevant to Avista

Category	Program	Applicable Customer Class
Non-pricing	Direct Load Control	General Service (GS)
		Large General Service (LGS)
	Firm Curtailment	Large General Service (LGS)
		Extra Large General Service (XLGS)
Pricing	Critical Peak Pricing	General Service (GS)
		Large General Service (LGS)
		Extra Large General Service (XLGS)

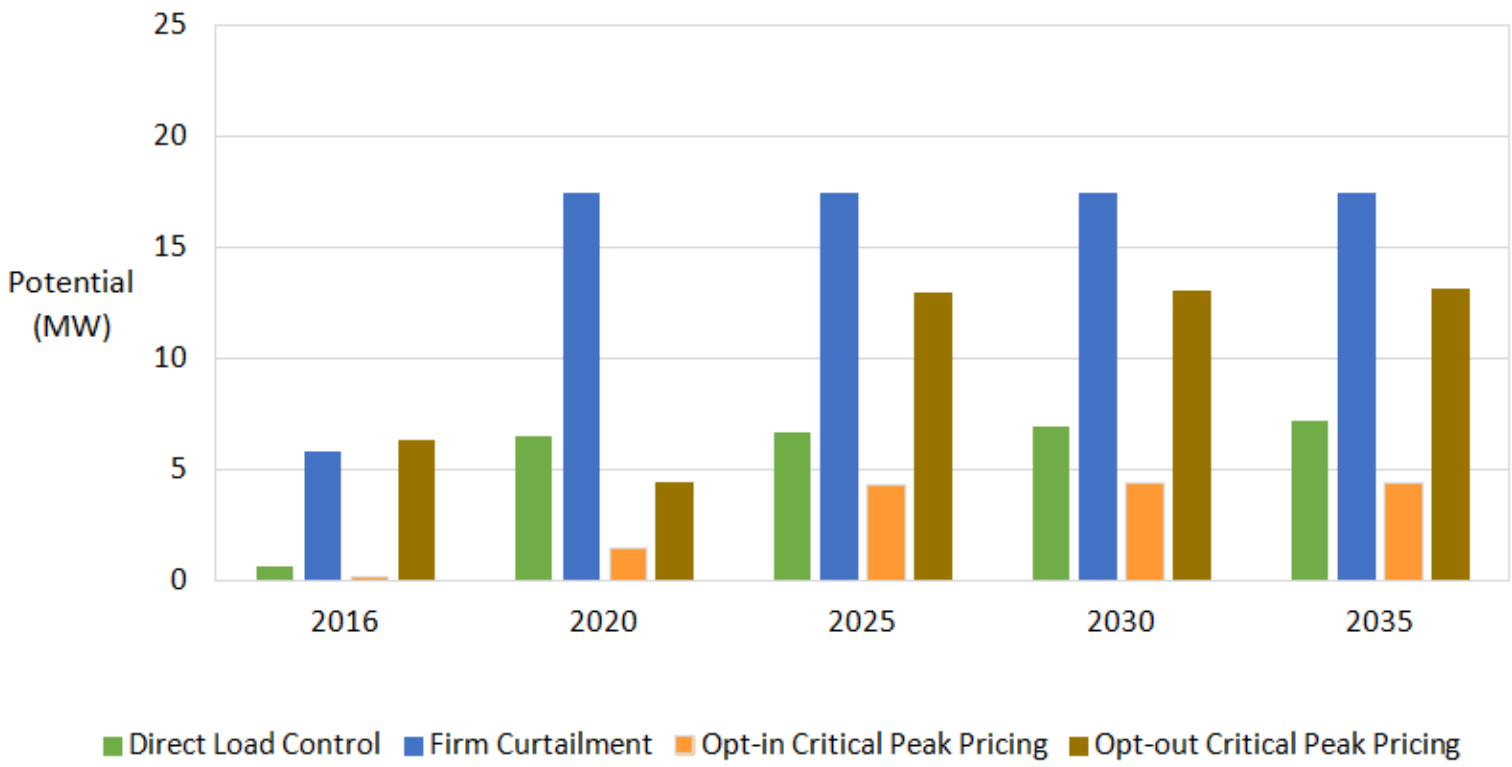
Load Aggregator



Demand Response Options Overview

	DLC	Firm	RTP
Targeted Segment	Sch 11 & 21	Sch 21 & 25	Sch 11, 21 & 25
Resource Availability	Varies	Year Around	Year Around
Event Notification	Day Ahead	Day ahead – preferred or 30 min	Day Ahead
Max Event Hrs/YR	60 hours	60 hours	60 Hours
Event Duration	4 to 6 hours each	1 to 8 hours each	4 hours each
Type of Response	Space & water heat	Non-essential loads or **back-up gen.**	Load curtailment or back-up gen.
Participant Incentive	$60 annually SH $50 annually WH	Determined & paid by 3rd party	On-Off peak price differential
Other	Directly admin by Avista	Admin by 3rd party Need AMI	10-15 max events per year. Need AMI

Summary of Results



Graph from page 30 of report

DR Potential by Option

	2016	2020	2025	2030	2035
Total System Peak (MW)	**1,718**	**1,768**	**1,828**	**1,891**	**1,995**
Weather Sensitive Peak (MW)	**1,590**	**1,640**	**1,700**	**1,763**	**1,827**
Estimated C&I Peak (MW)	**610**	**622**	**630**	**638**	**649**
Achievable Potential (MW)					
Direct Load Control	0.64	6.48	6.68	6.91	7.16
Firm Curtailment	5.80	17.46	17.42	17.42	17.46
Opt-in Critical Peak Pricing	0.13	1.40	4.30	4.33	4.38
Opt-out Critical Peak Pricing	6.27	4.38	12.93	13.01	13.12
Achievable Potential (% of C&I Peak)					
Direct Load Control	*0.10%*	*1.04%*	*1.06%*	*1.08%*	*1.10%*
Firm Curtailment	*0.95%*	*2.81%*	*2.77%*	*2.73%*	*2.69%*
Opt-in Critical Peak Pricing	*0.02%*	*0.23%*	*0.68%*	*0.68%*	*0.68%*
Opt-out Critical Peak Pricing	*1.03%*	*0.70%*	*2.05%*	*2.04%*	*2.02%*

from page 30 of report

Program Costs & Potential

Stand Alone

Table 5-4 DR Program Costs and Potential

DR Option	2035 MW Potential	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-year)
Direct Load Control	7.16	$16.07	$0.80	$143.82
Firm Curtailment	17.46	$40.68	$2.03	$118.59
Opt-in Critical Peak Pricing	4.38	$25.61	$1.28	$432.65
Opt-out Critical Peak Pricing	13.12	$26.69	$1.33	$109.86

Interactive

Table 5-5 DR Program Costs and Potential - Interactive

DR Option	2035 MW Potential	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-year)
Direct Load Control	7.16	$16.07	$0.80	$143.82
Firm Curtailment	16.57	$38.65	$1.93	$118.52
Opt-in Critical Peak Pricing	3.35	$25.27	$1.26	$555.77
Opt-out Critical Peak Pricing	9.90	$26.32	$1.32	$141.03

Charts from pages 32 & 33 of report
Firm Curtailment and standby generation have overlapping capacity

Standby Generation Partnership

Prepared by Marc Schaffner
Fourth Technical Advisory Committee Meeting
February 24, 2015

What is Standby Generation Partnership?

A prospective partnership between customers and Avista to meet future peak load needs utilizing existing and future standby distributed generation.

Standby Generation Opportunities

- Interconnect customers diesel or natural gas-powered generators to Avista's distribution system
- Utilize standby generator output as a peak resource and to improve voltage regulation on Avista's electric distribution system
- Introduce natural gas blending to diesel-powered generators for cleaner, more economical operation
- Utilize standby generators as a cost-effective non-spinning reserve
- Conduct an in-house pilot by interconnecting Avista's standby generators at its headquarters in Spokane

2015 Electric IRP
Natural Gas Price Forecast

Eric Scott, Manager of Natural Gas Resources
Fourth Technical Advisory Committee Meeting
February 24, 2015

North American Pipeline Infrastructure

Pacific Northwest Supply and Infrastructure

SUPPLY

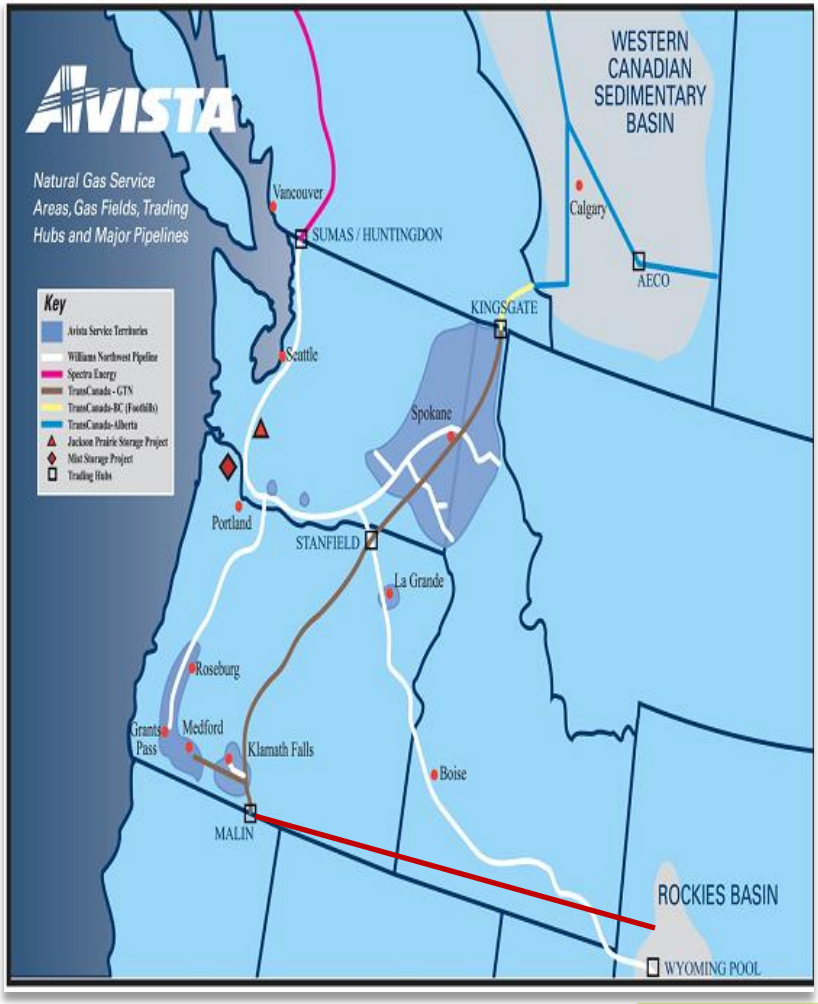
- **AECO**
  Canadian gas coming out of Alberta, Canada
- **Rockies**
  U.S. domestic gas coming from Wyoming and Colorado
- **Sumas**
  Canadian gas coming out of British Columbia, Canada
- **Malin**
  South central at the Oregon and California border
- **Stanfield**
  Intersection of two major pipelines in North Central Oregon

PIPELINES

- **Williams Northwest Pipeline**
- **TransCanada Gas Transmission Northwest**
- **TransCanada Foothills**
- **TransCanada Alberta**
- **Spectra Energy**
- **Ruby Pipeline**

STORAGE

- **Jackson Prairie Storage**
- **Mist Storage**



Types of Pipeline Contracts

Firm Transport

- Contractual rights to:
  - Receive
  - Transport
  - Deliver
- From point A to point B

Interruptible Transport

- Contractual rights to:
- Receive
- Transport
- Deliver
- From point A to Point B *AFTER FIRM TRANSPORT HAS BEEN SCHEDULED*

Seasonal Transport

- Firm service available for limited periods (Nov-Mar) or for a limited amount (TF2 on NWP)

Alternate Firm Transport

- The use of firm transport outside of the primary path
- Priority rights below firm
- Priority rights above interruptible

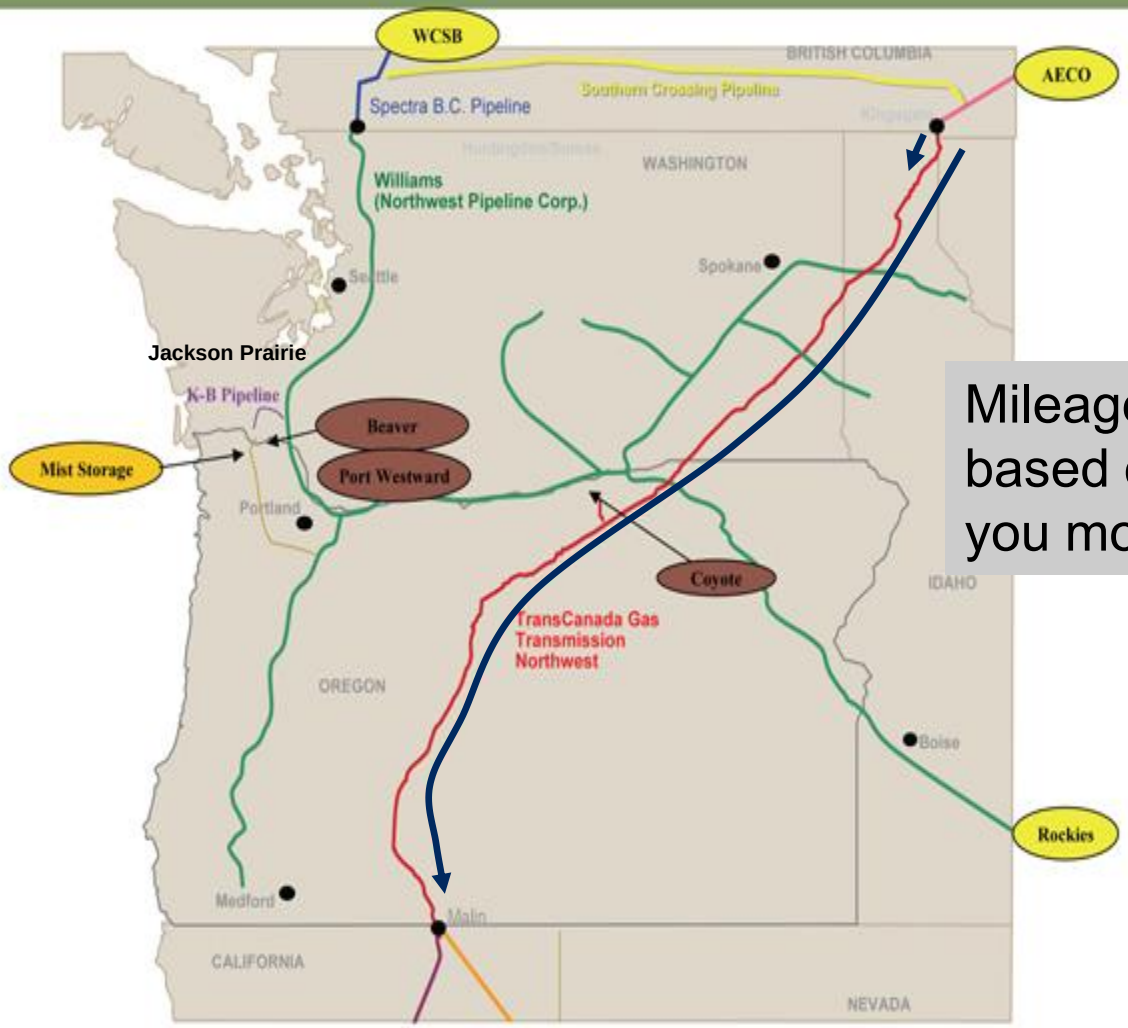
Pipeline Rate Structure

Straight Fixed Variable (SFV)	• Pipeline charges a higher demand charge and a lower variable or commodity charge
Enhanced fixed variable	• Pipeline charges a lower demand charge and a higher variable or commodity charge
Postage Stamp Rate	• Pay the same demand and variable costs regardless of how far the gas is transported
Mileage Based	• Pay a variable and demand charge based on how far the gas is transported

TransCanada Gas Transmission Northwest (GTN)

- Mileage Based
- Point to Point
- Alternate firm allowed in path
- Mostly – demand based with a couple Nomination based points
    - Demand based refers to gas that will be taken off the pipeline based on the demand behind the delivery point.
    - Nomination based refers to the pipeline only delivering what was nominated (requested).
- Usually requires upstream transportation

Natural Gas Transportation

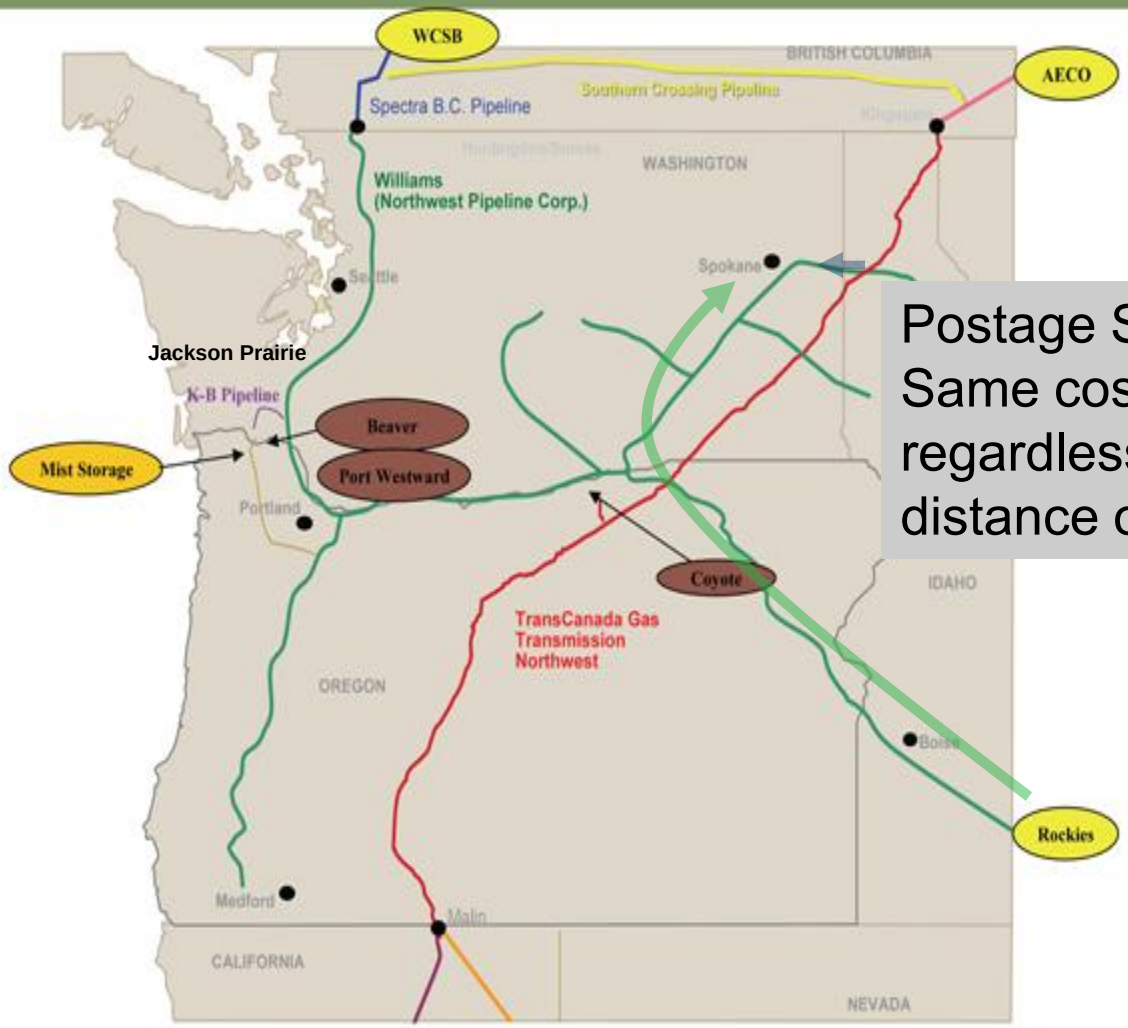


Mileage Base: Pay based on how far you move the gas

Williams Northwest Pipeline (NWP)

- Postage Stamp Based
- Point to Point
    - Delivery to ‘zones’ allowed
- Alternate firm allowed in and out of path
- Demand based delivery
    - Demand based refers to gas that will be taken off the pipeline based on the demand behind the delivery point.
    - Nomination based refers to the pipeline only delivering what was nominated (requested).
- May or may not require upstream transportation
- Enhanced fixed variable structure

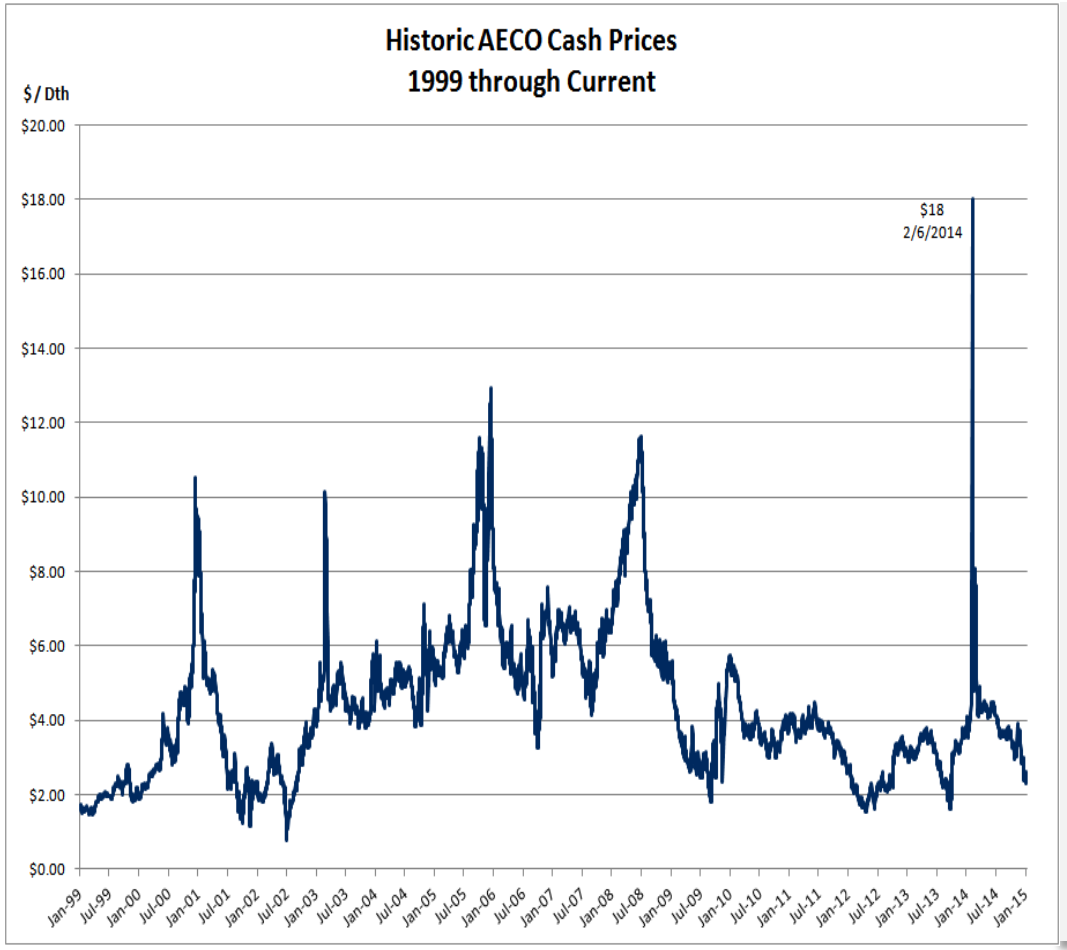
Natural Gas Transportation



Postage Stamp: Same costs regardless of distance or locations

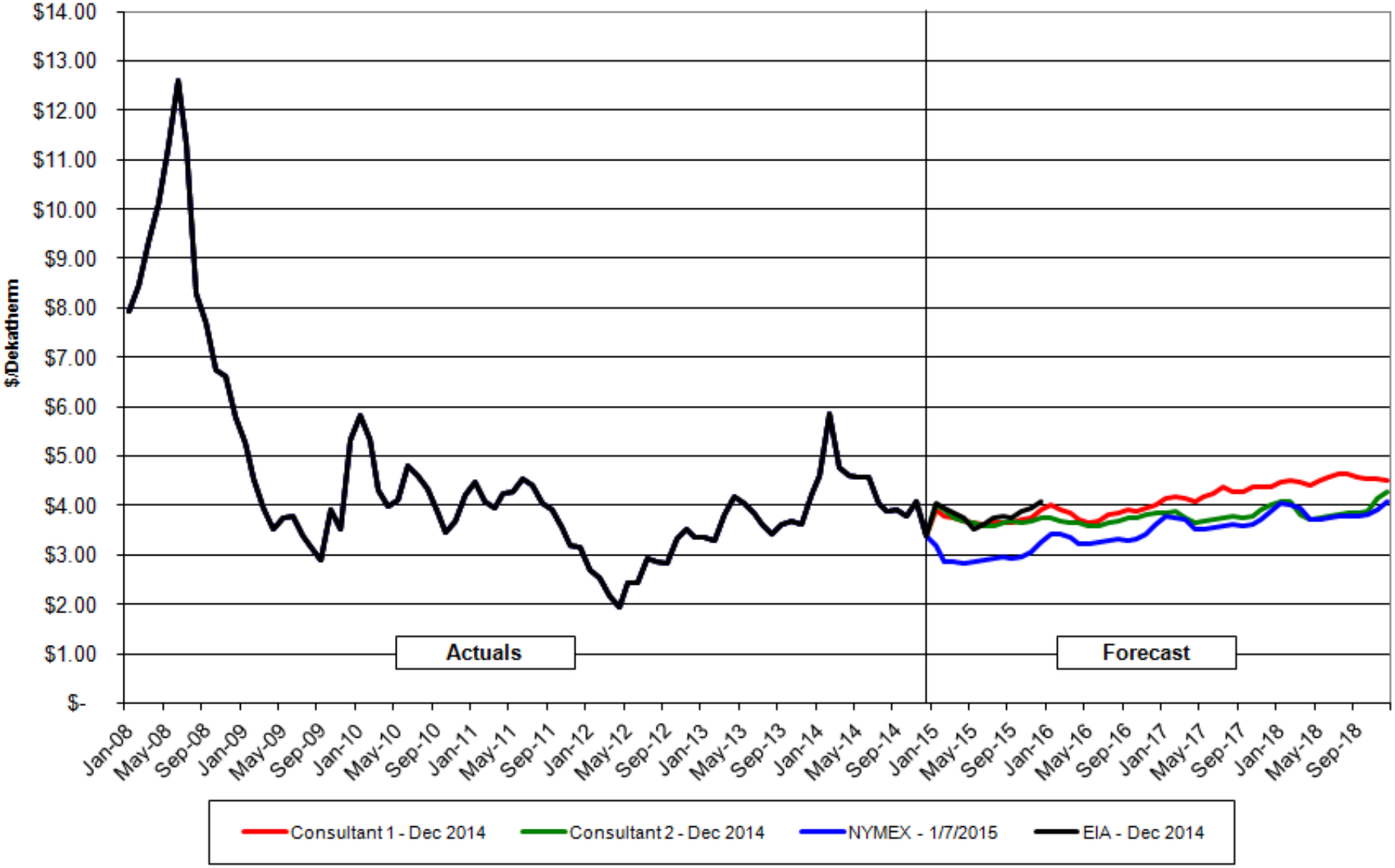
Natural Gas Pricing Fundamentals

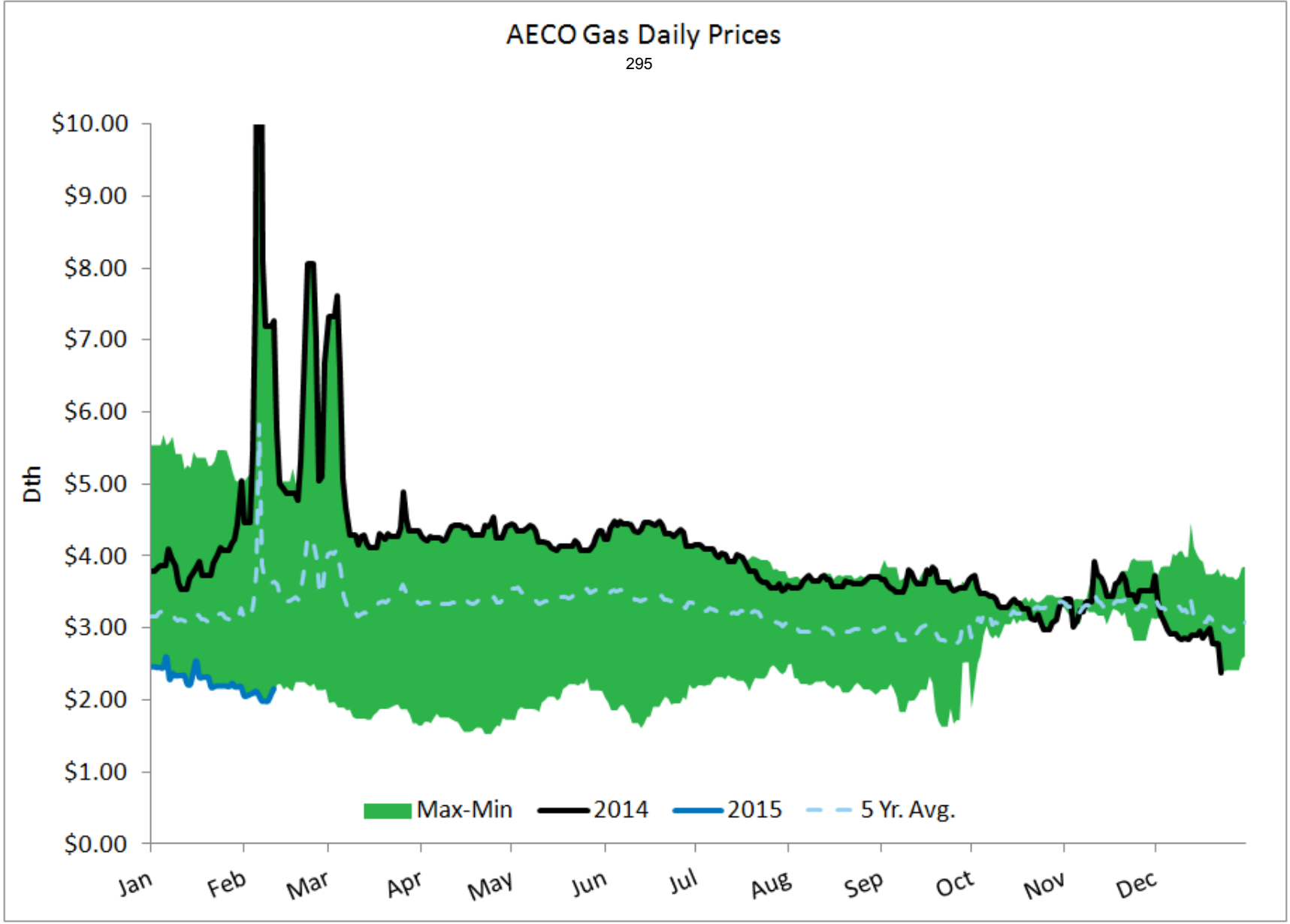
What Drives the Natural Gas Market? Natural Gas Spot Prices



- **Supply**
  - Type: Conventional vs. Non-conventional
  - Location
  - Cost
- **Demand**
  - Residential/Commercial/Industrial
  - Power Generation
  - Natural Gas Vehicles
- **Legislation**
  - Environmental
- **Energy Correlations**
  - Oil vs. Gas
  - Coal vs. Gas
  - Natural Gas Liquids
- **Weather**
- **Storage**

Fundamental Forecasts vs. Actual Prices
Henry Hub




AECO Gas Daily Prices
295
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
Dth
Max-Min
2014
2015
5 Yr. Avg.
Jan
Feb
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Apr
May
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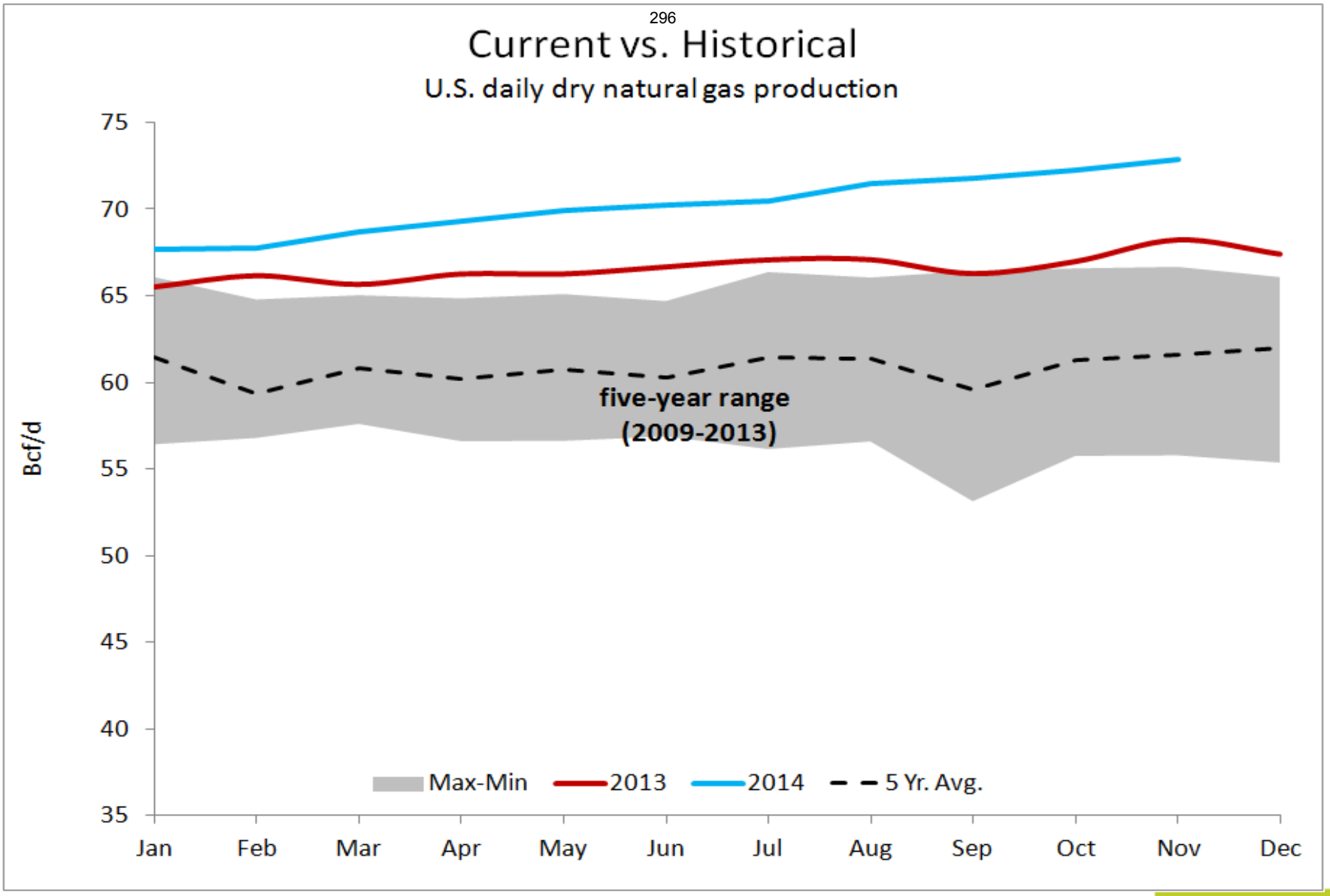
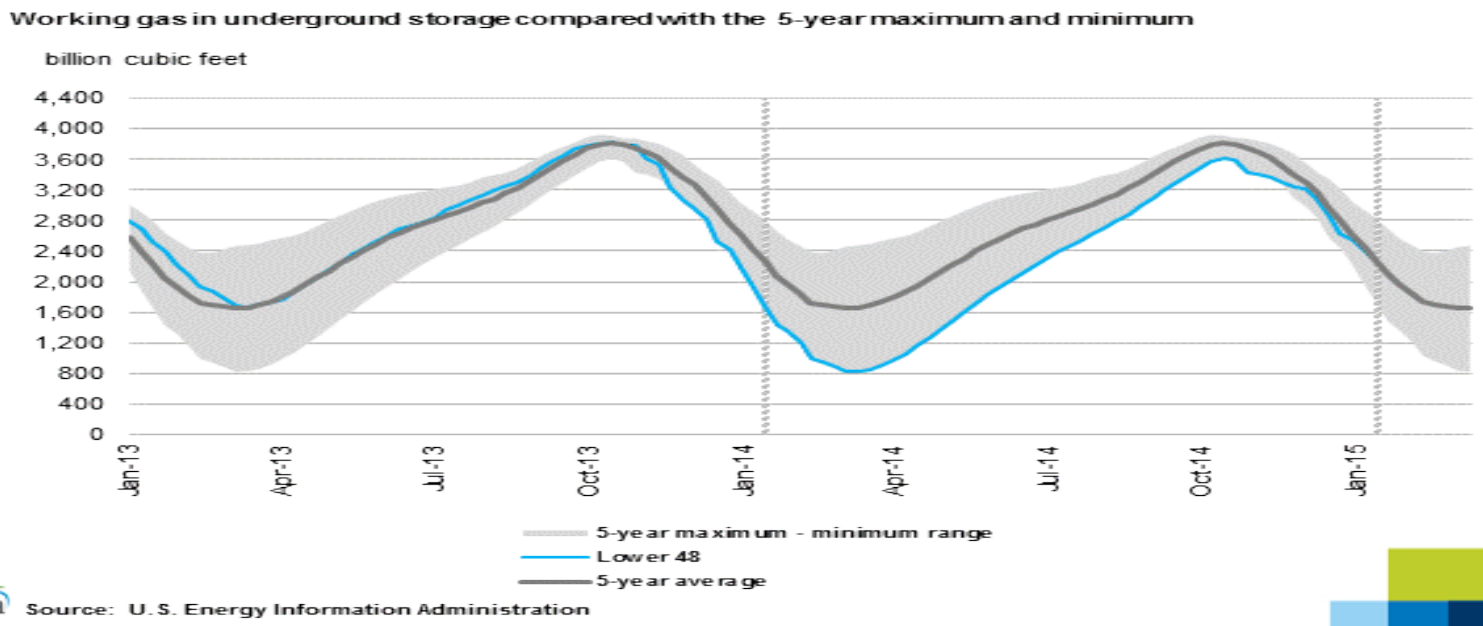
Jul
Aug
Sep
Oct
Nov
Dec


Current vs. Historical
U.S. daily dry natural gas production
Bcf/d
75
70
65
60
55
50
45
40
35
five-year range
(2009-2013)
Max-Min
2013
2014
5 Yr. Avg.
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Natural Gas Storage

Region	2/6/2015	1/30/2015	change (Bcf)	Year Ago (02/06/14) "Stocks (Bcf)	% change	5-Year average (2010-2014) Stocks (Bcf)	% change
East	1081	1,194	-113	829	30.4	1,113	-2.9
West	371	371	0	265	40	333	11.4
Producing	816	863	-47	632	29.1	833	-2
Salt	231	247	-16	113	104.4	160	44.4
Nonsalt	585	616	-31	518	12.9	672	-12.9
Total	**2,268**	**2,428**	**-160**	**1,726**	**31.4**	**2,279**	**-0.5**



The Short Term Fundamentals

Bulls

Dwindling rig counts

Economic recovery

LNG & Ethanol Plants

Weather – Normal is now bullish

Bears

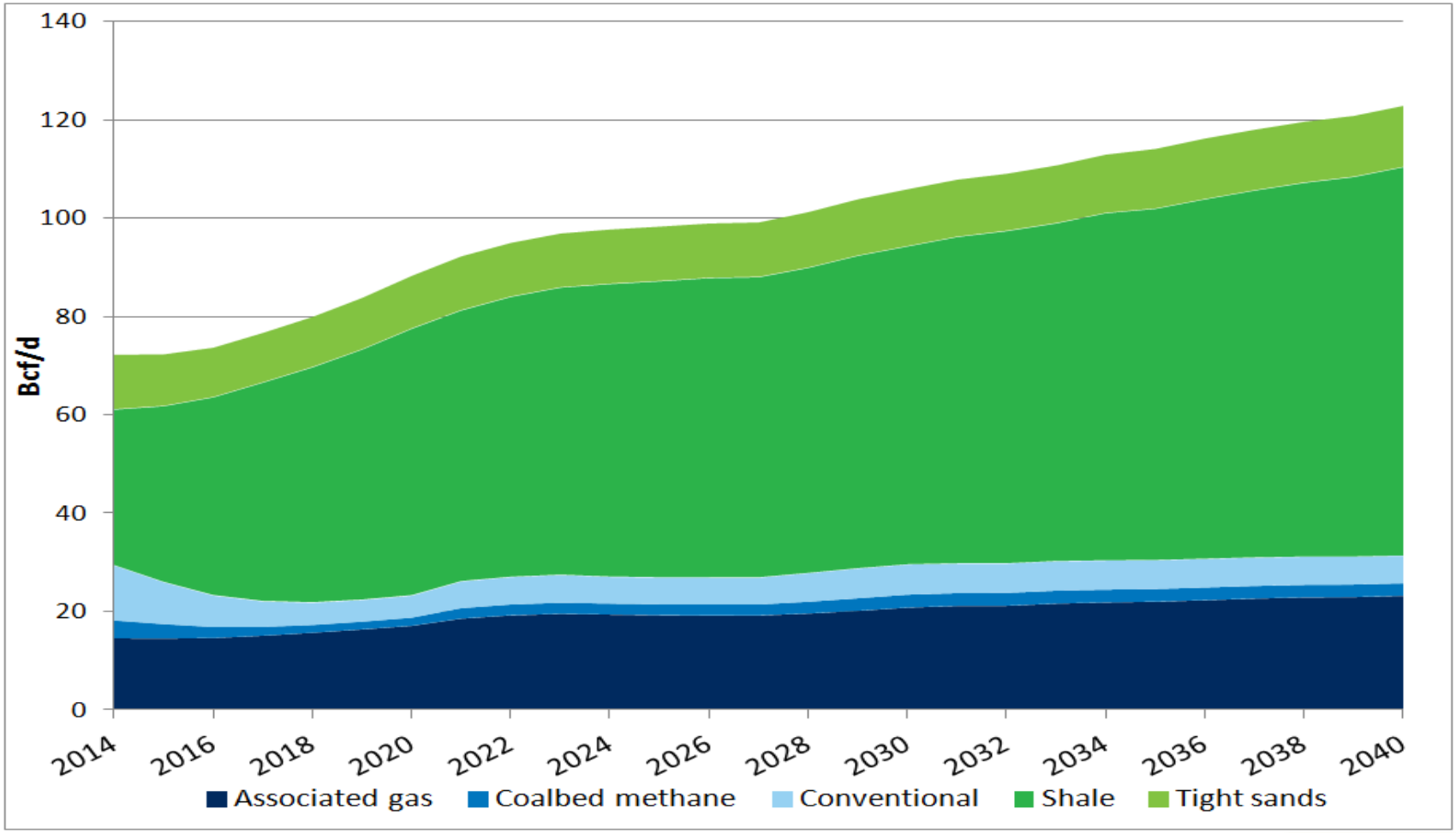
Demand is weak

Storage is full

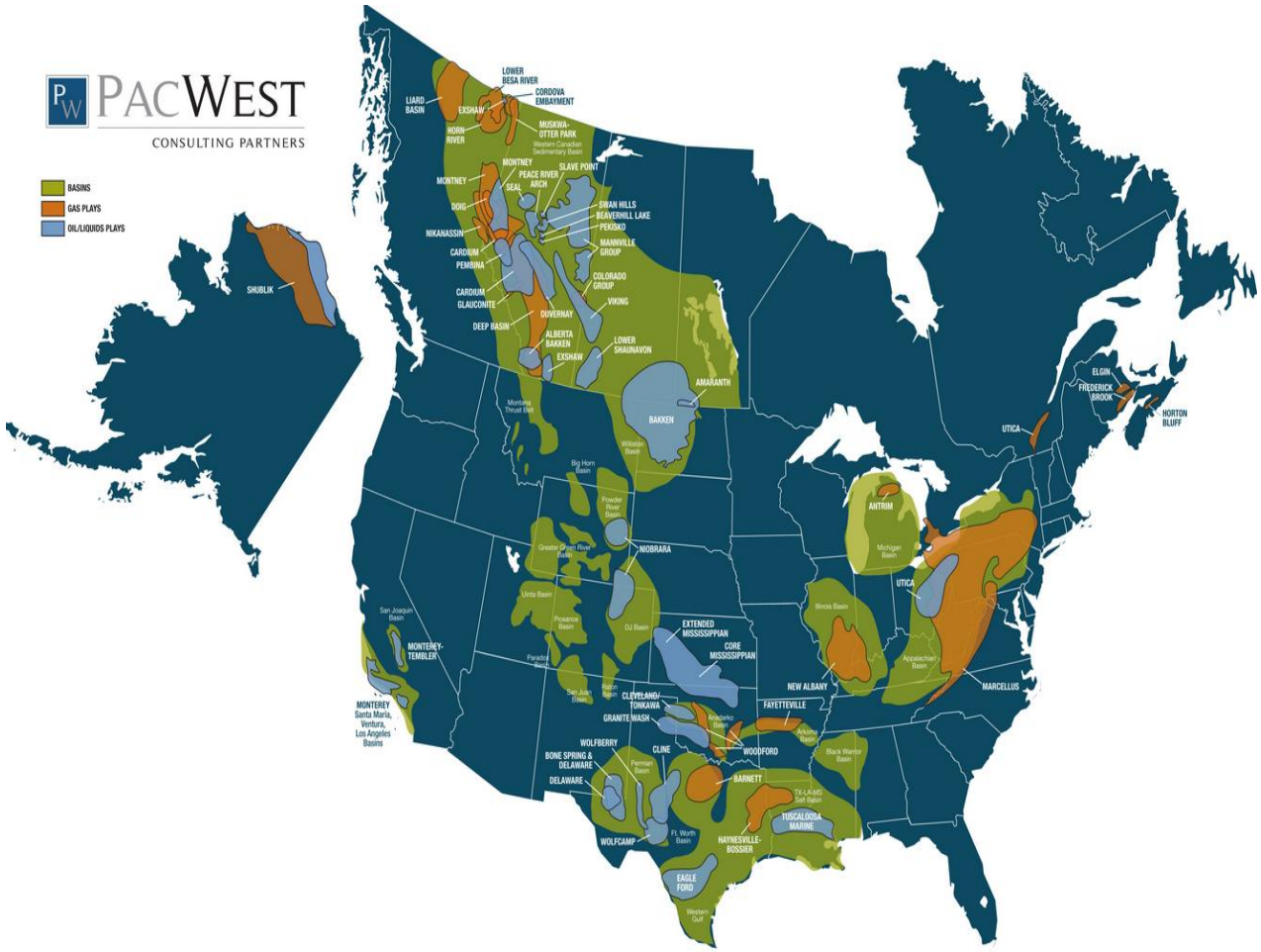
Oil Prices are near 5 year lows

Record Production

US Production – Where will it come from?



What is Shale Gas?

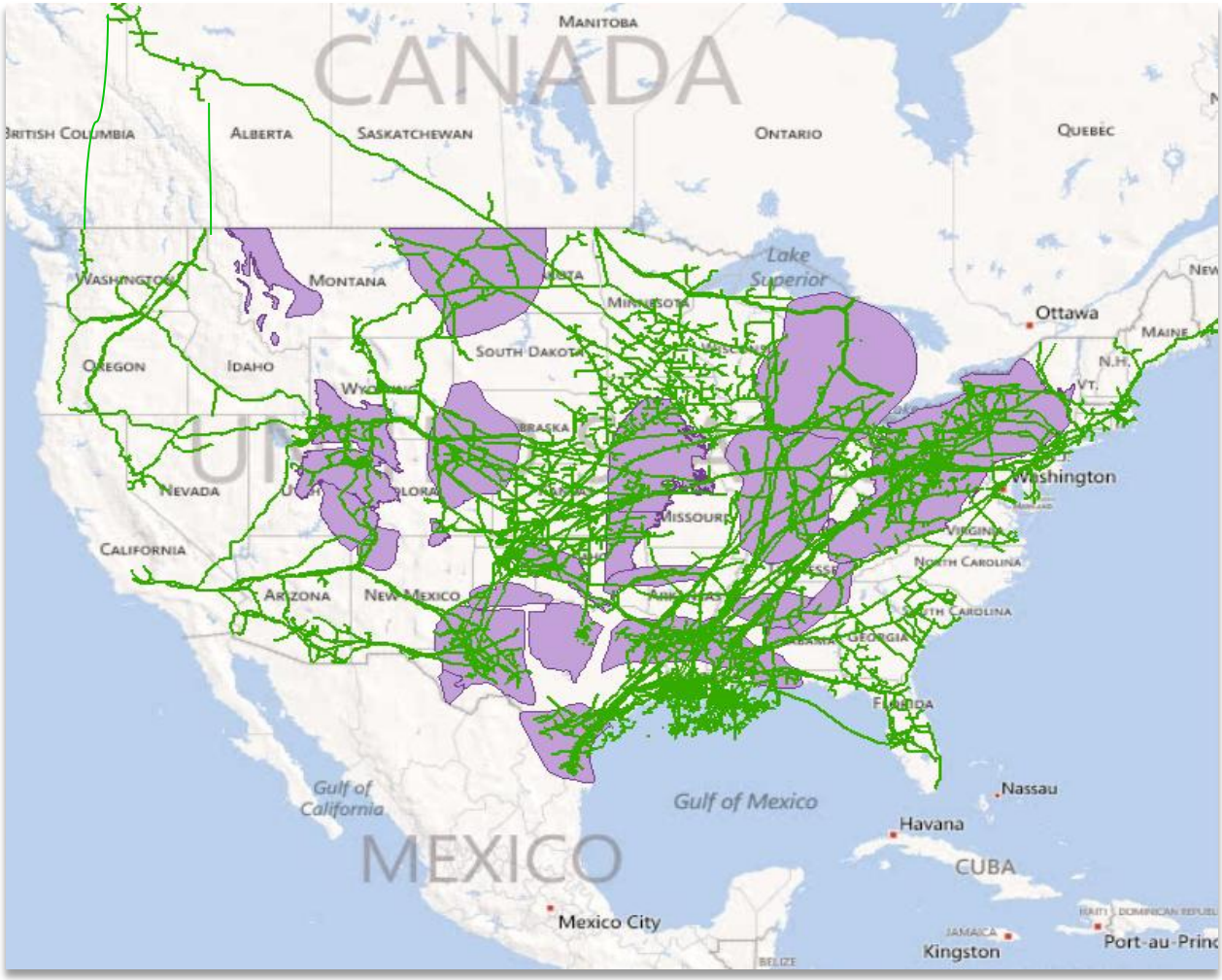


Shale gas refers to natural gas that is trapped within shale formations.

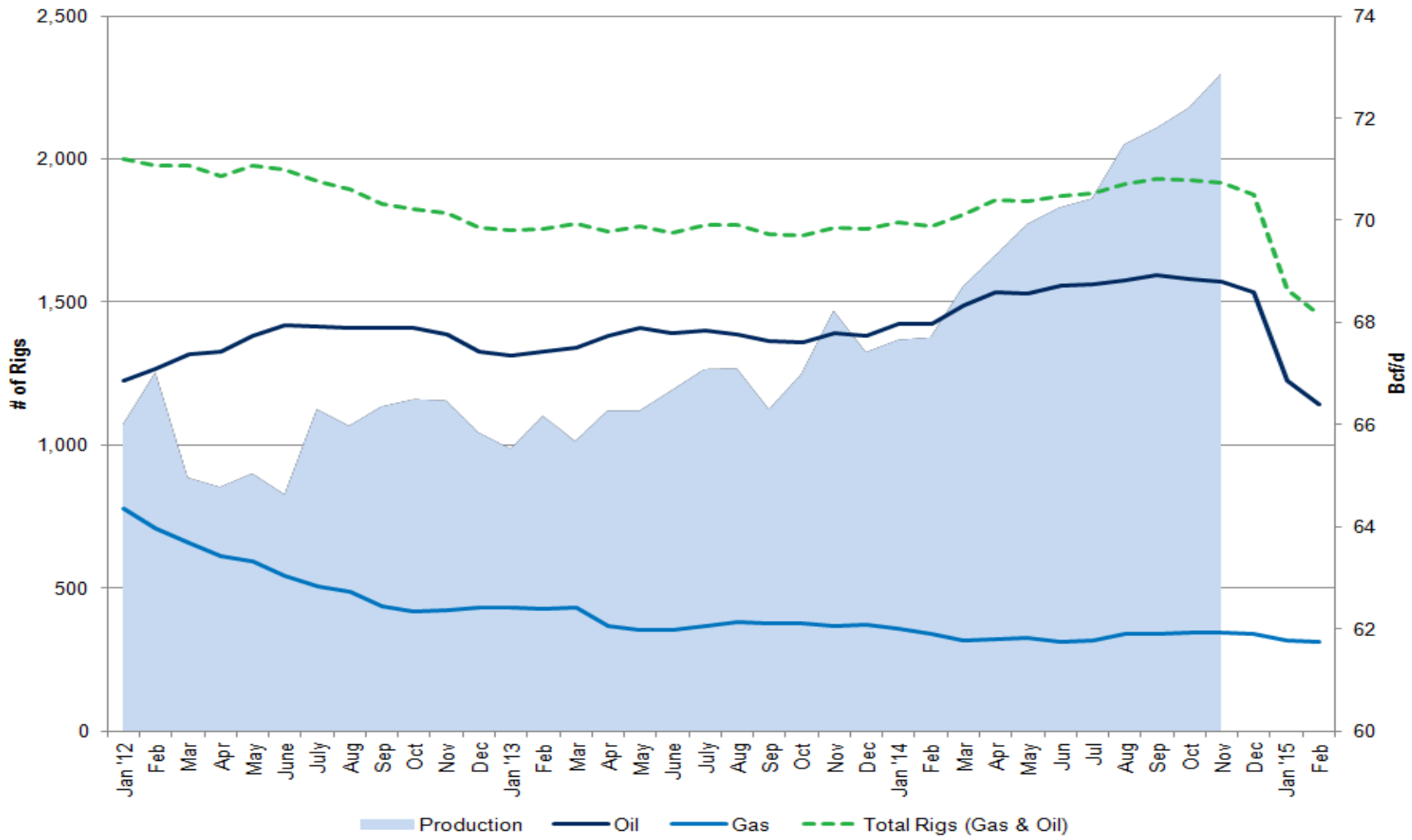
Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.

Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce.

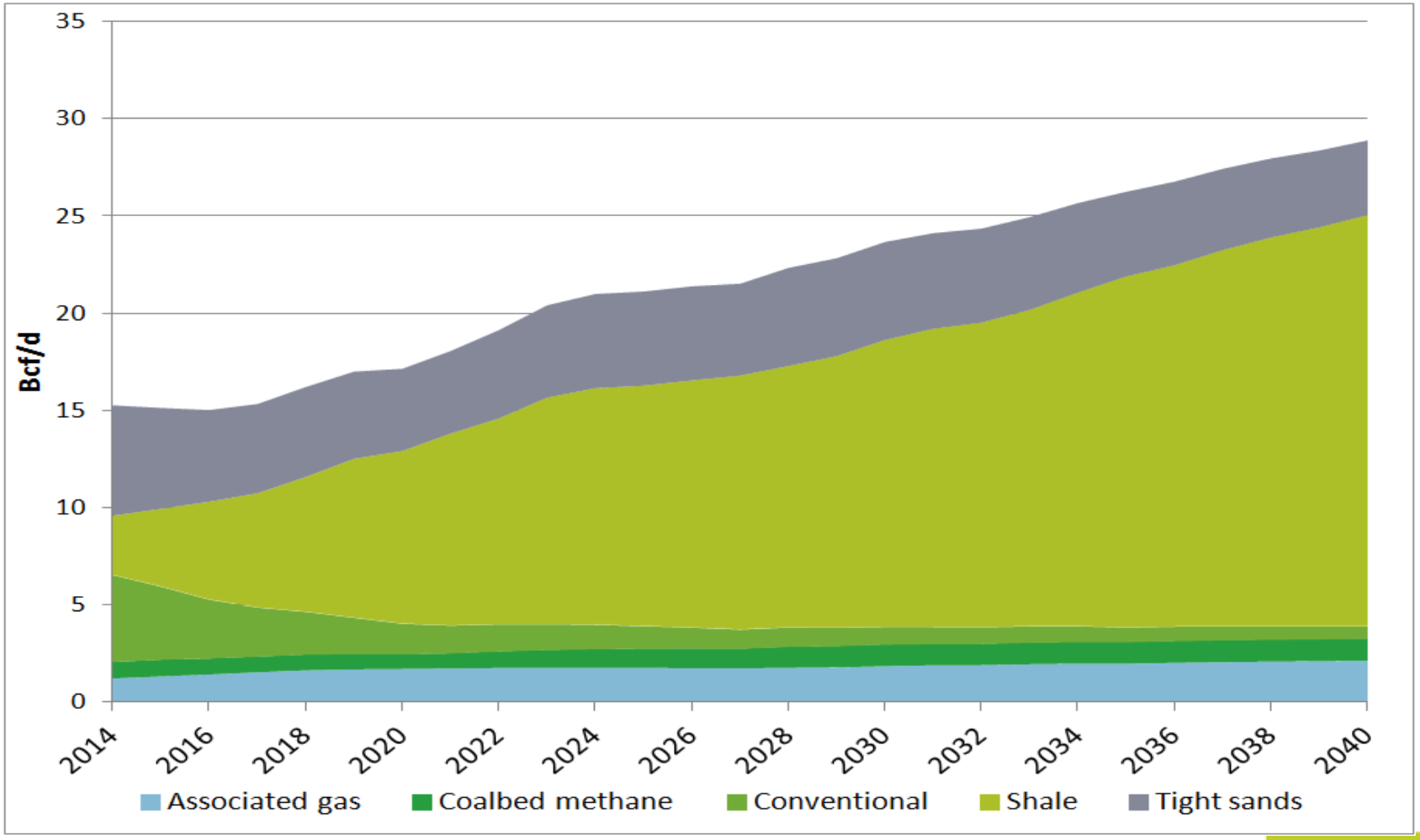
Evolving Flow Dynamics



The Link Between Rig Counts and Production

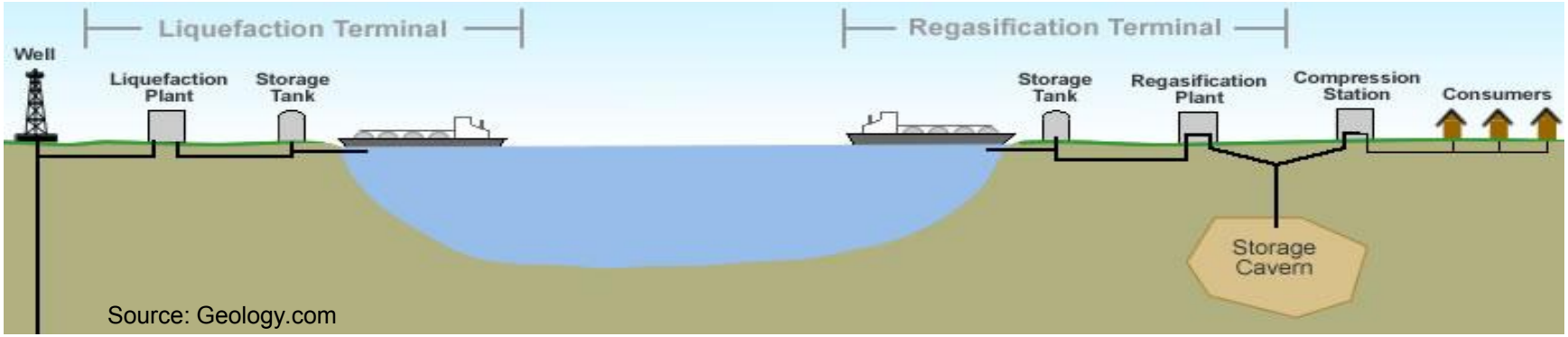


Our friends to the North - Production



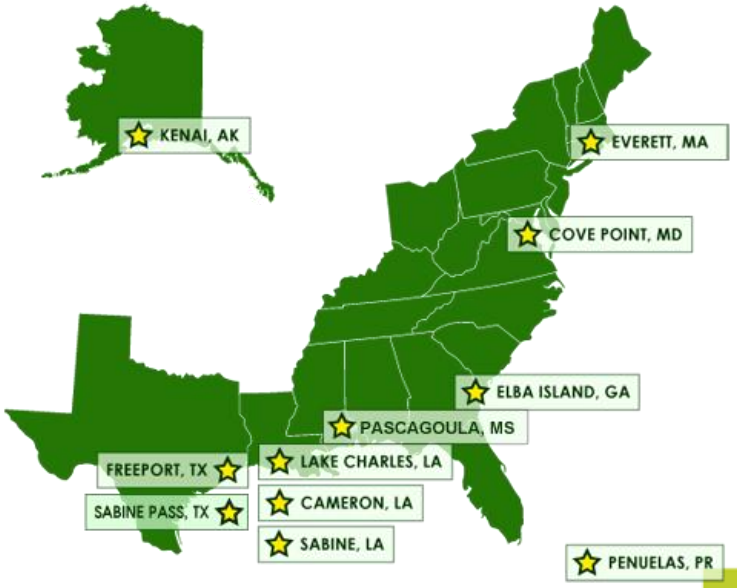
LNG Export is the New Import

LNG traditionally flows to North America after other higher-priced markets receive their share



Source: Geology.com

Source: Apache LNG



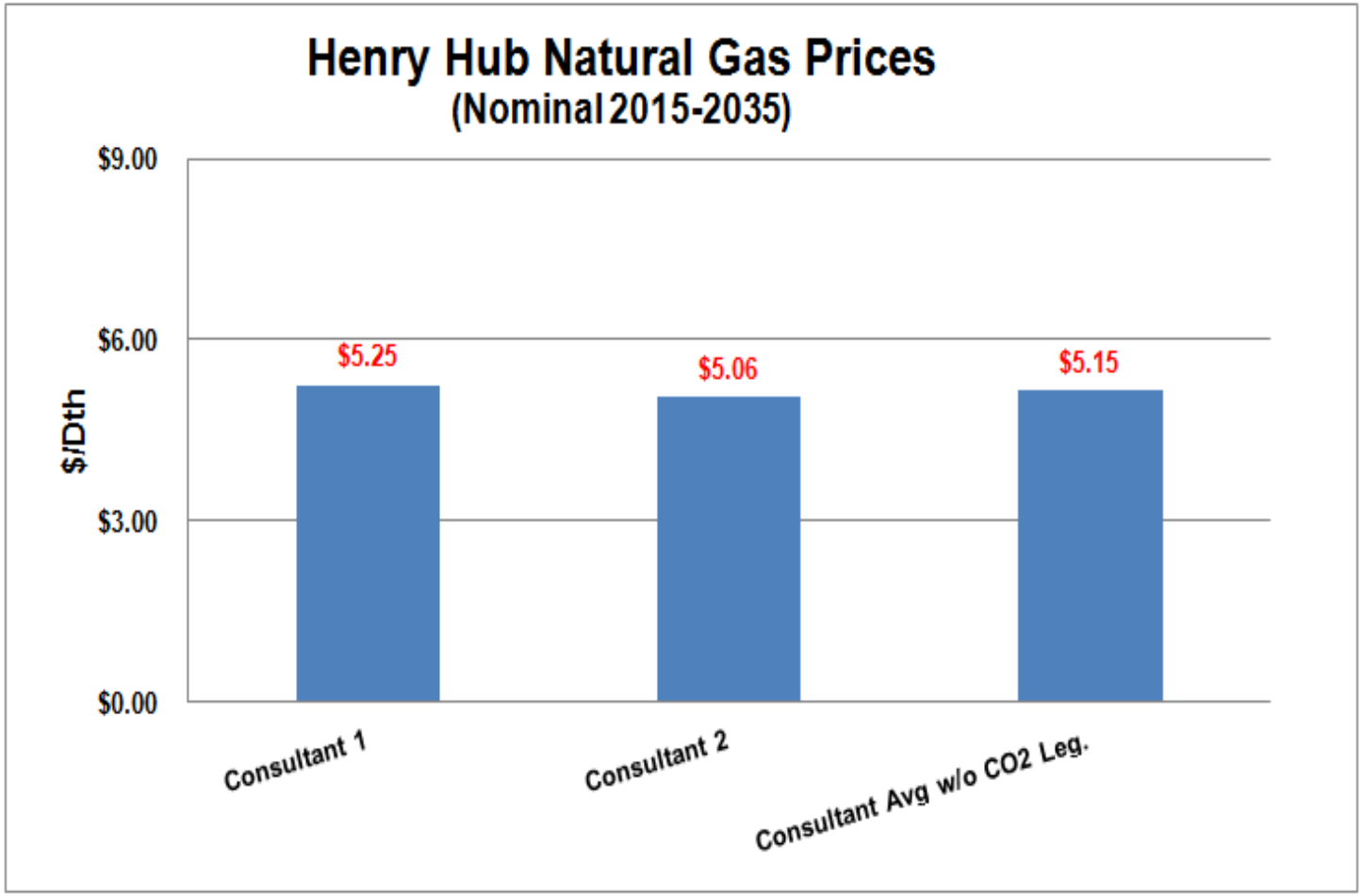
Source: Federal Energy Regulatory Commission

*As of January 8th, 2015

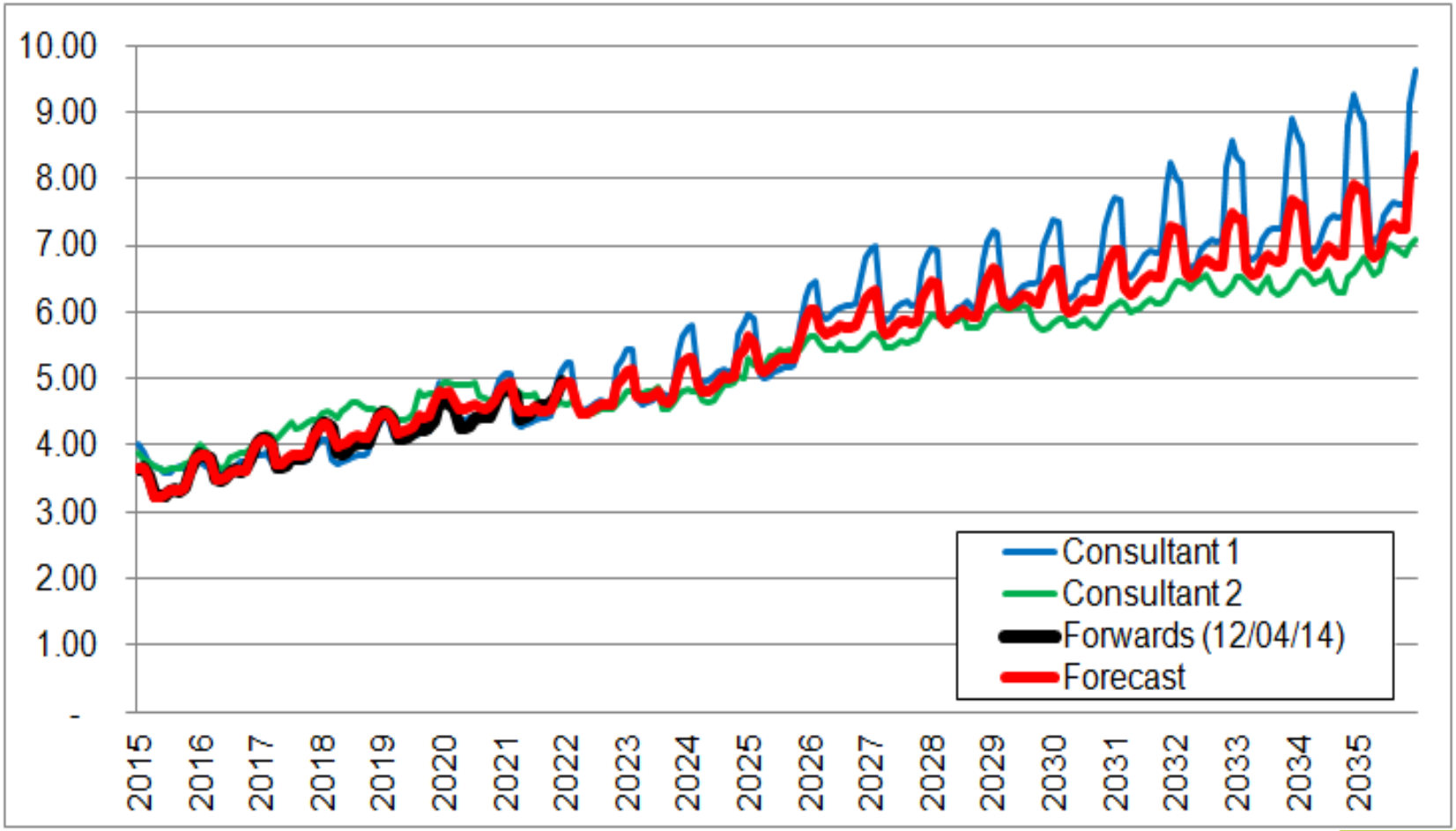
IRP Natural Gas Price Forecast Methodology

1. Two fundamental forecasts (Consultant #1 & Consultant #2)
2. Forward prices
3. Year 1: forward price only
4. Year 2: 75% forward price / 25% average consultant forecasts
5. Year 3: 50% forward price / 50% average consultant forecasts
6. Year 4 – 6: 25% forward price / 75% average consultant forecasts
7. Year 7+: 50% average consultant without CO_2 / 50% average consultant with CO_2

Forecasted Levelized Price



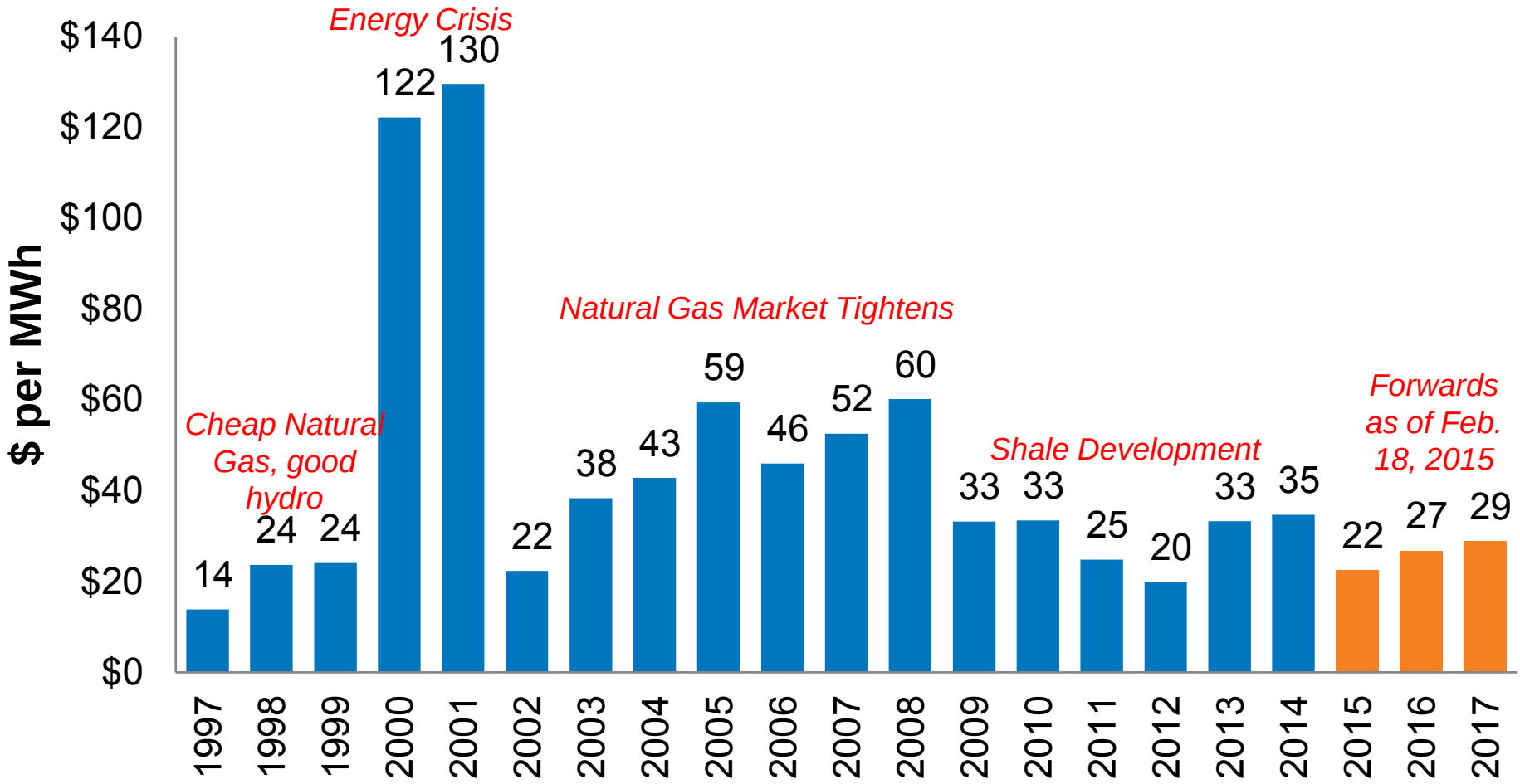
Henry Hub Forecasted Prices



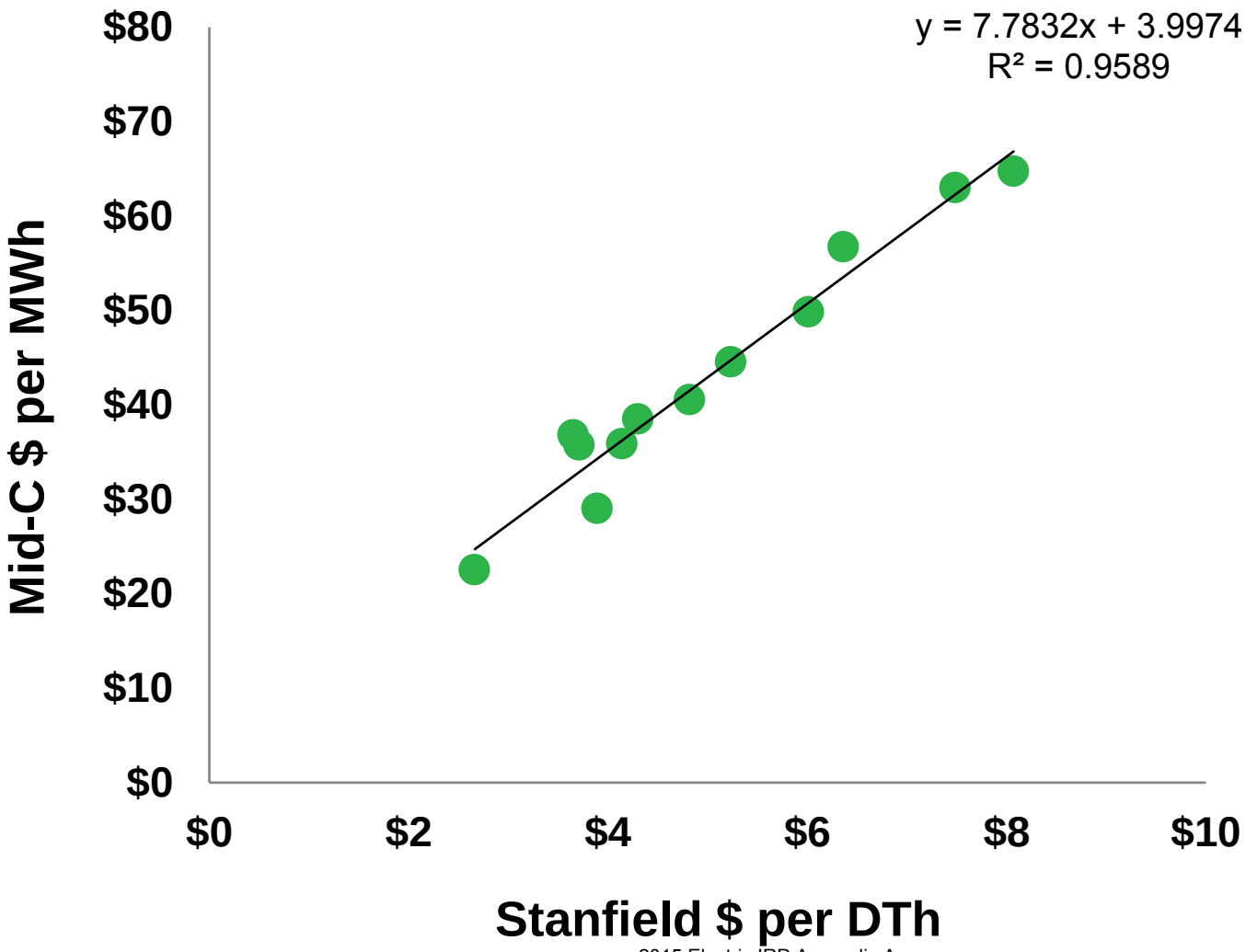
2015 Electric IRP
Electric Market Forecast

James Gall, Senior Power Supply Analyst
Fourth Technical Advisory Committee Meeting
February 24, 2015

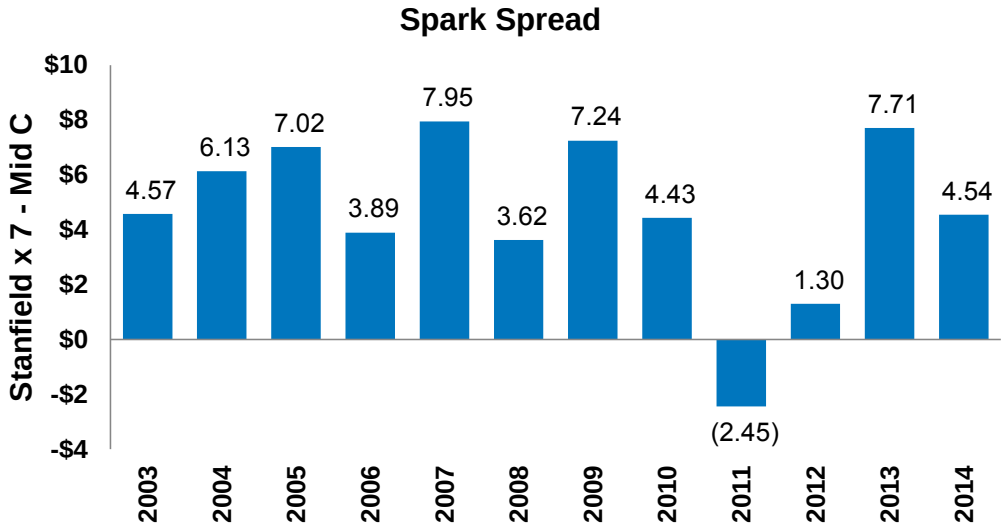
Mid-Columbia Flat Firm Price Index History

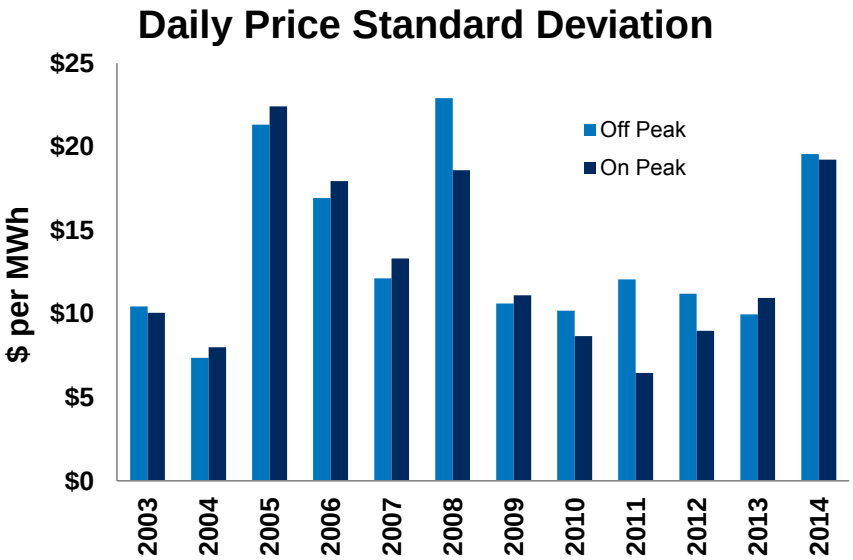


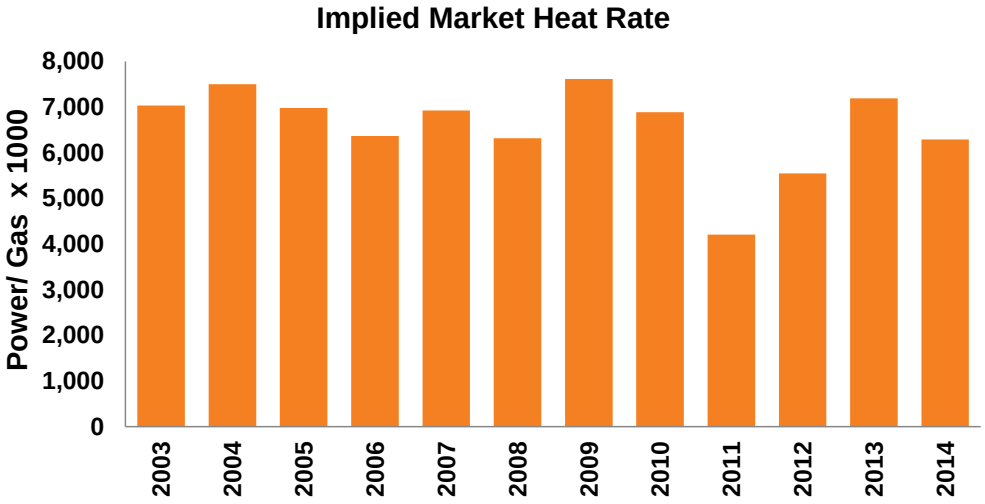
Natural Gas vs. Electric Prices (2003-14)



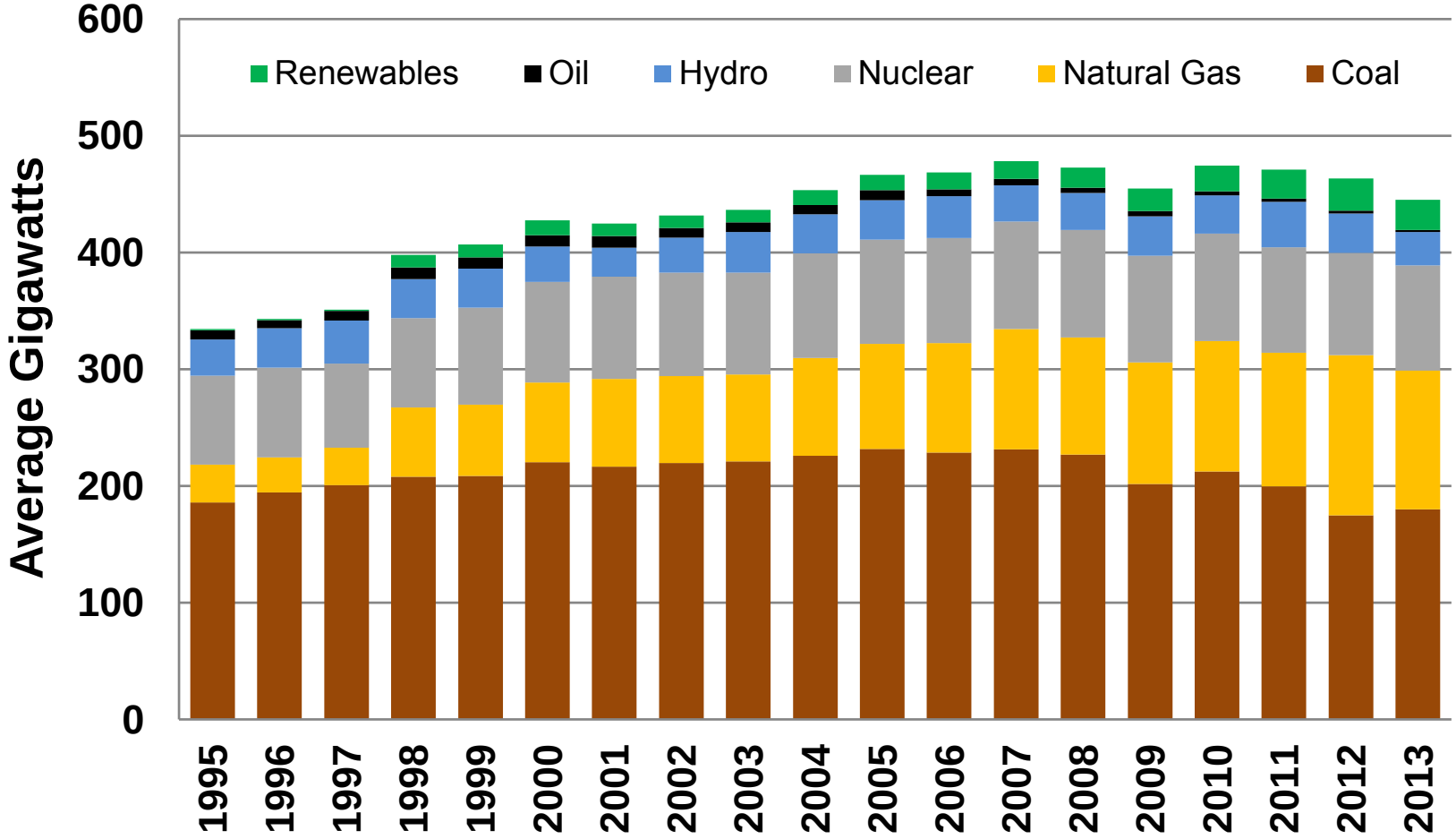
Market Indicators





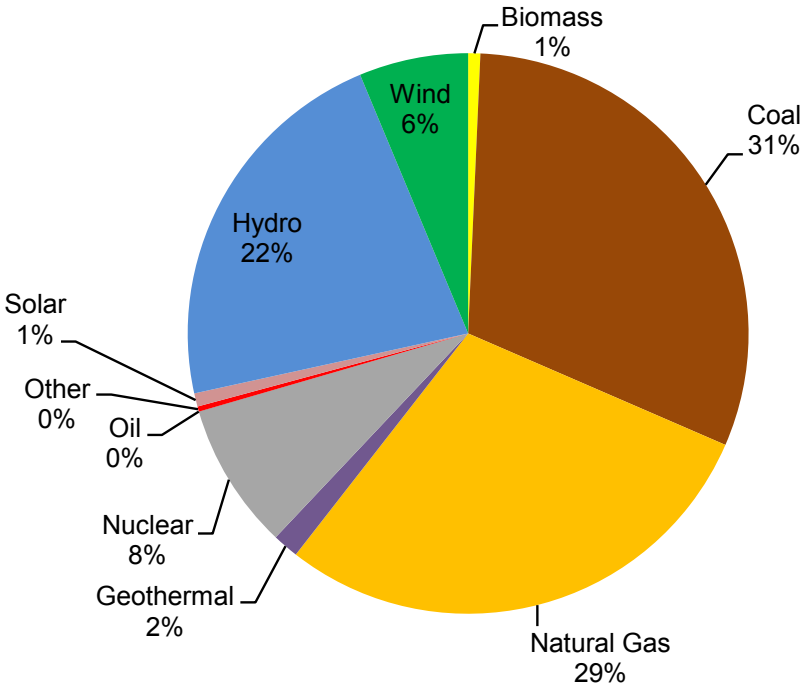


US Power Generation

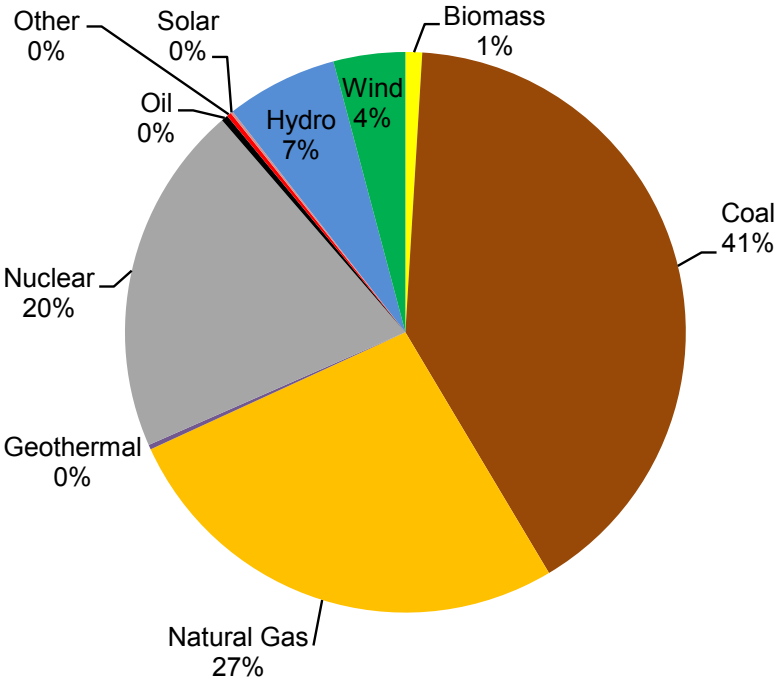


Fuel Mix Comparison

US Western Interconnect

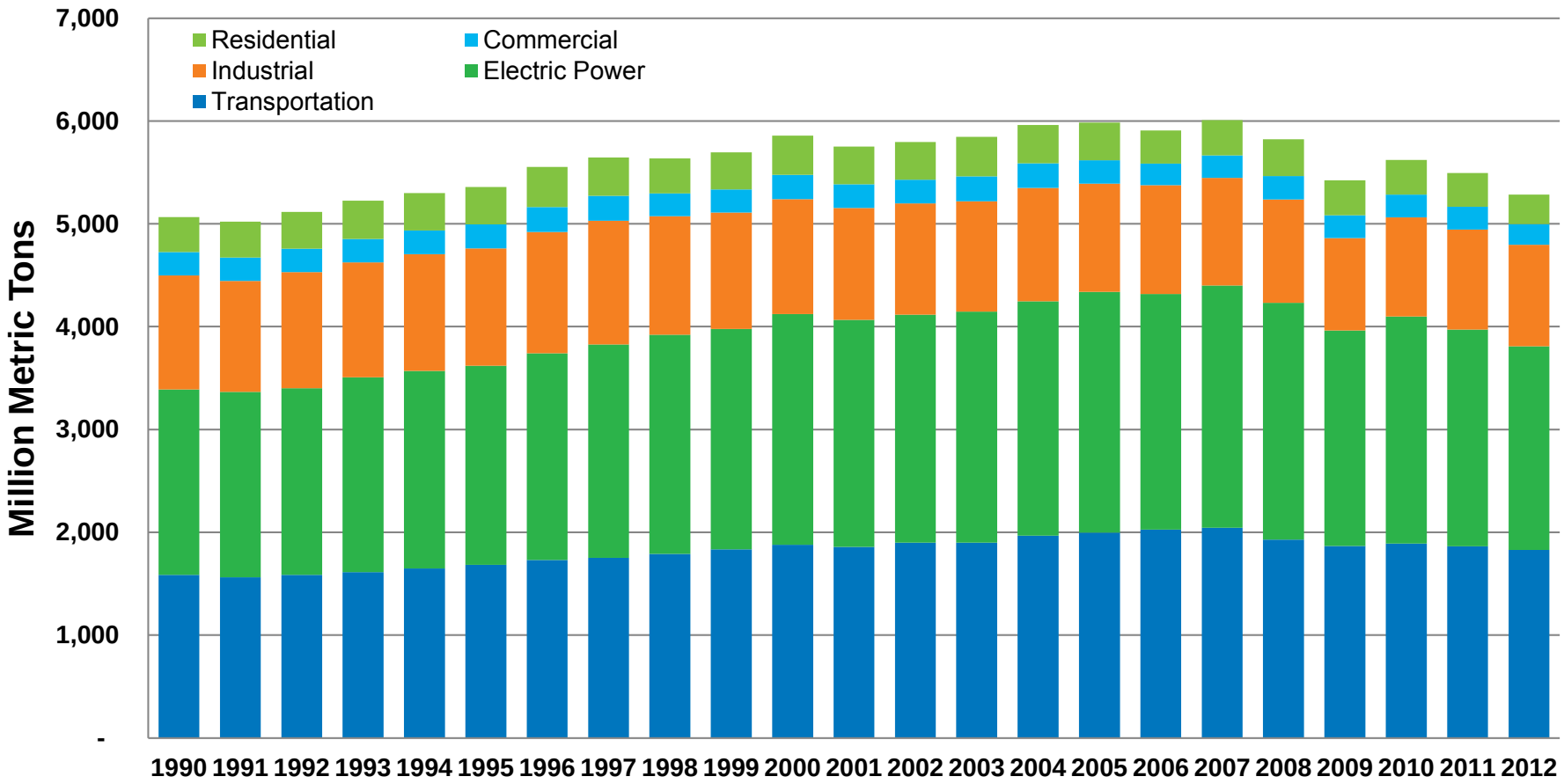


US Total



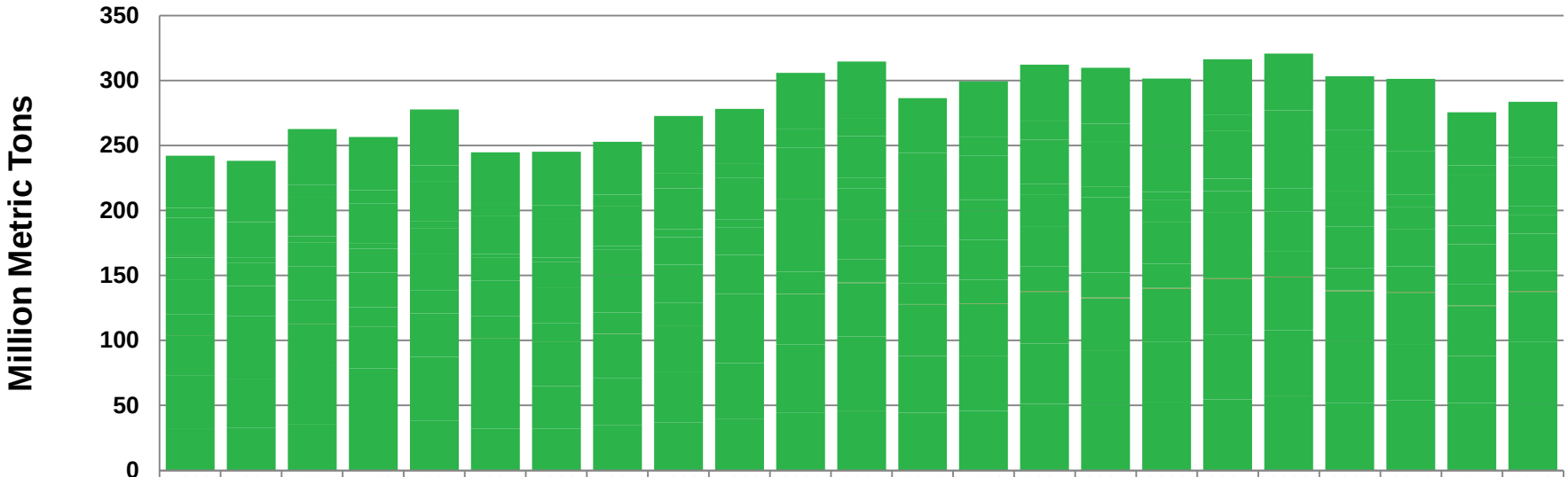
US Greenhouse Gas Emissions

All Sources



Source: http://epa.gov/statelocalclimate/resources/state_energyco2inv.html

Western Greenhouse Gas Emissions



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WY	40	39	43	41	43	40	41	41	44	42	44	44	42	43	44	43	43	43	44	41	42	41	43
WA	8	8	10	10	12	8	11	9	12	11	14	14	11	14	14	14	9	12	13	13	13	7	6
UT	29	28	30	30	31	29	30	31	31	32	33	32	33	34	34	35	35	37	38	35	34	33	31
OR	2	4	5	4	5	3	3	3	6	6	7	9	6	8	8	8	6	10	10	9	10	6	7
NV	17	18	19	18	20	18	20	19	21	21	25	24	21	23	25	26	17	17	18	18	17	14	15
NM	27	23	26	27	28	27	28	29	29	30	31	30	28	30	30	32	32	31	30	32	29	31	29
MT	16	17	18	15	18	17	14	16	18	18	17	18	16	18	19	19	19	20	20	17	20	16	15
ID	0	0	0	0	0	0	0	0	0	0	0	1	0	1	1	1	1	1	1	1	1	0	1
CO	31	31	32	32	33	33	34	34	35	35	39	41	40	40	40	40	41	42	41	38	39	38	39
CA	40	38	46	42	49	37	33	36	39	43	53	58	44	43	46	42	46	50	51	48	43	36	48
AZ	33	33	35	37	38	32	32	35	37	39	44	45	45	46	51	50	52	55	57	52	54	52	51
TOTAL	242	238	263	256	278	245	245	253	273	278	306	315	286	299	312	310	302	316	321	303	301	275	284

Source: http://epa.gov/statelocalclimate/resources/state_energyco2inv.html

Electric Market Modeling

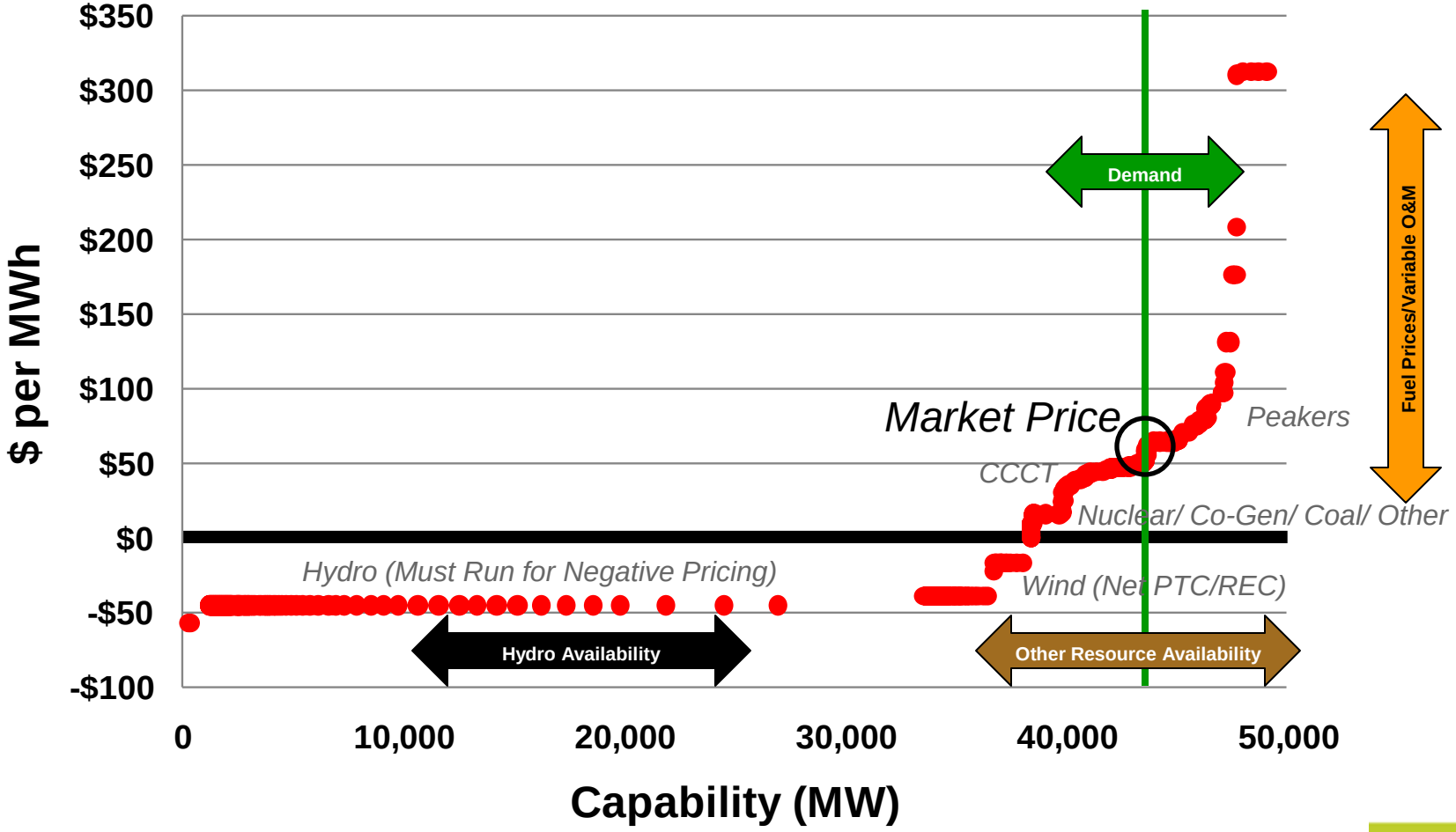
AURORAxmp® by EPIS, Inc.
COMPREHENSIVE POWER FORECASTING

- 3rd party software- EPIS, Inc.
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet load
- Outputs:
  - Market prices
  - Regional energy mix
  - Transmission usage
  - Greenhouse gas emissions
  - Power plant margins, generation levels, fuel costs
  - Avista's variable power supply costs

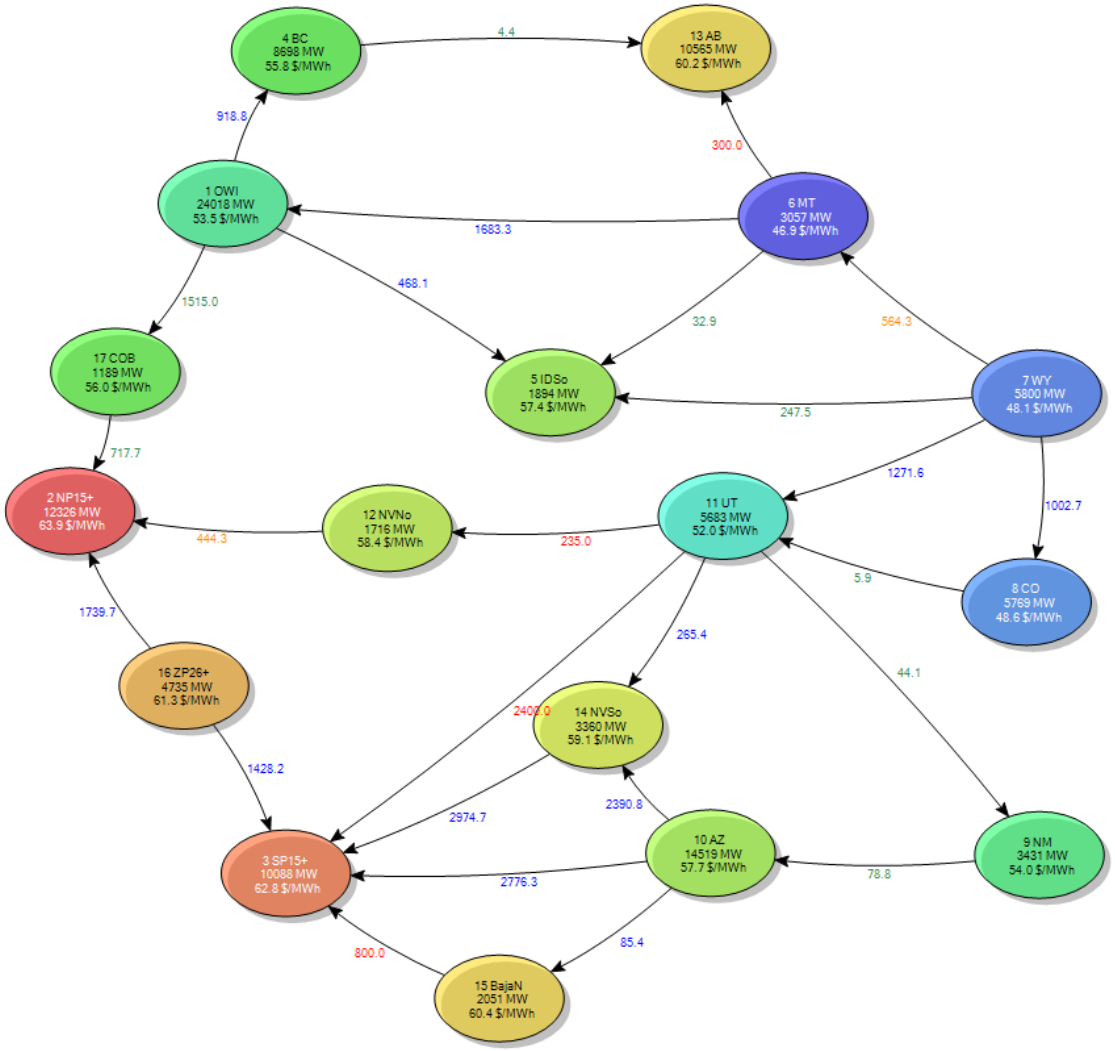
Stochastic Approach

- Simulate Western Electric market hourly for next 20 years (2016-35)
  - That is 175,248 hours for each study
- Model 500 potential outcomes
  - Variables include fuel prices, loads, wind, hydro, outages, inflation
  - Simulating 87.6 million hours
- Run time is about 5 days on 30 processors
- Why do we do this?
  - Allows for complete financial evaluation of resource alternatives
  - Without stochastic prices we cannot account for tail risk

Aurora Pricing Example- Supply/Demand Curve



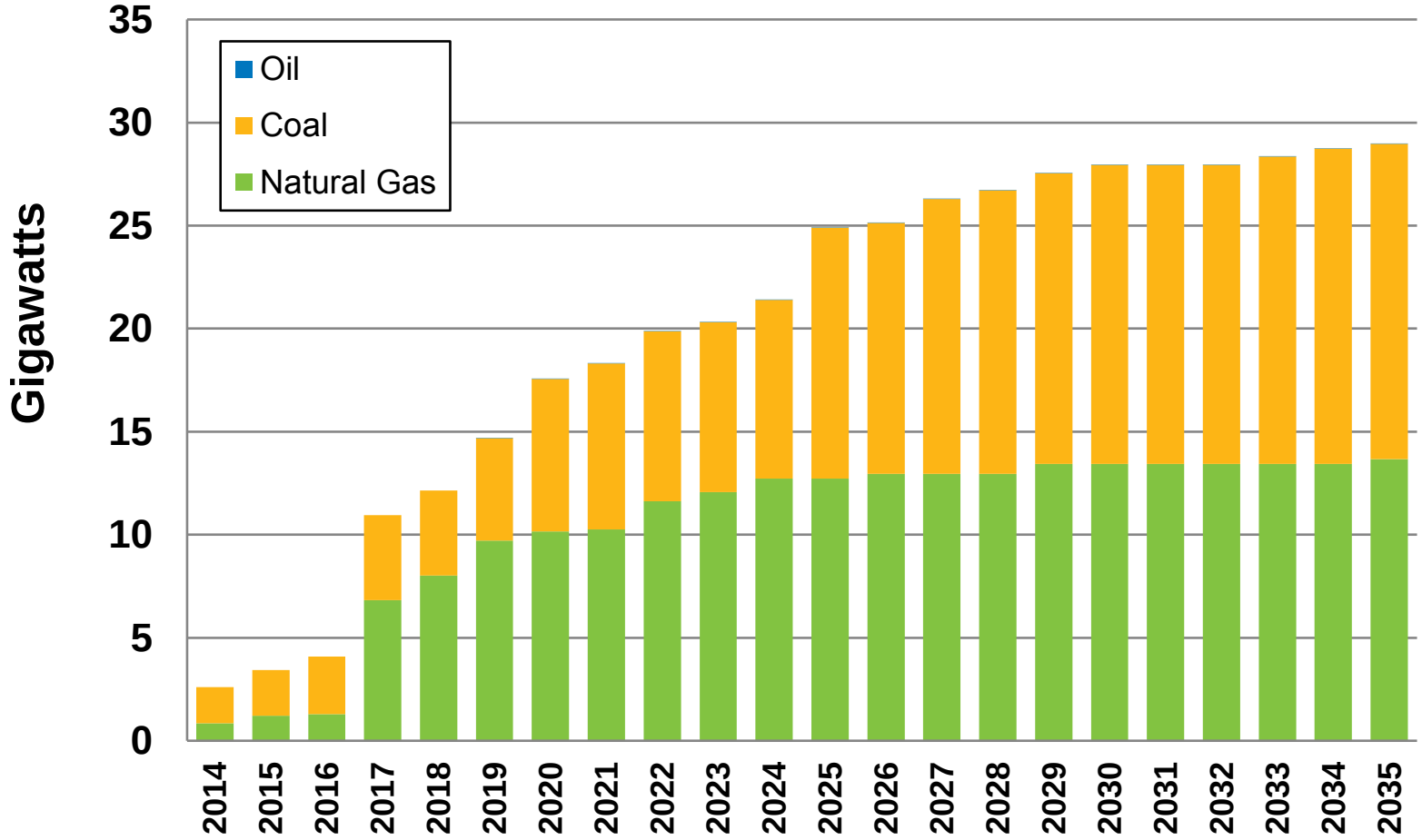
Modeled Western Interconnect Topology



Greenhouse Gas Reduction Modeling

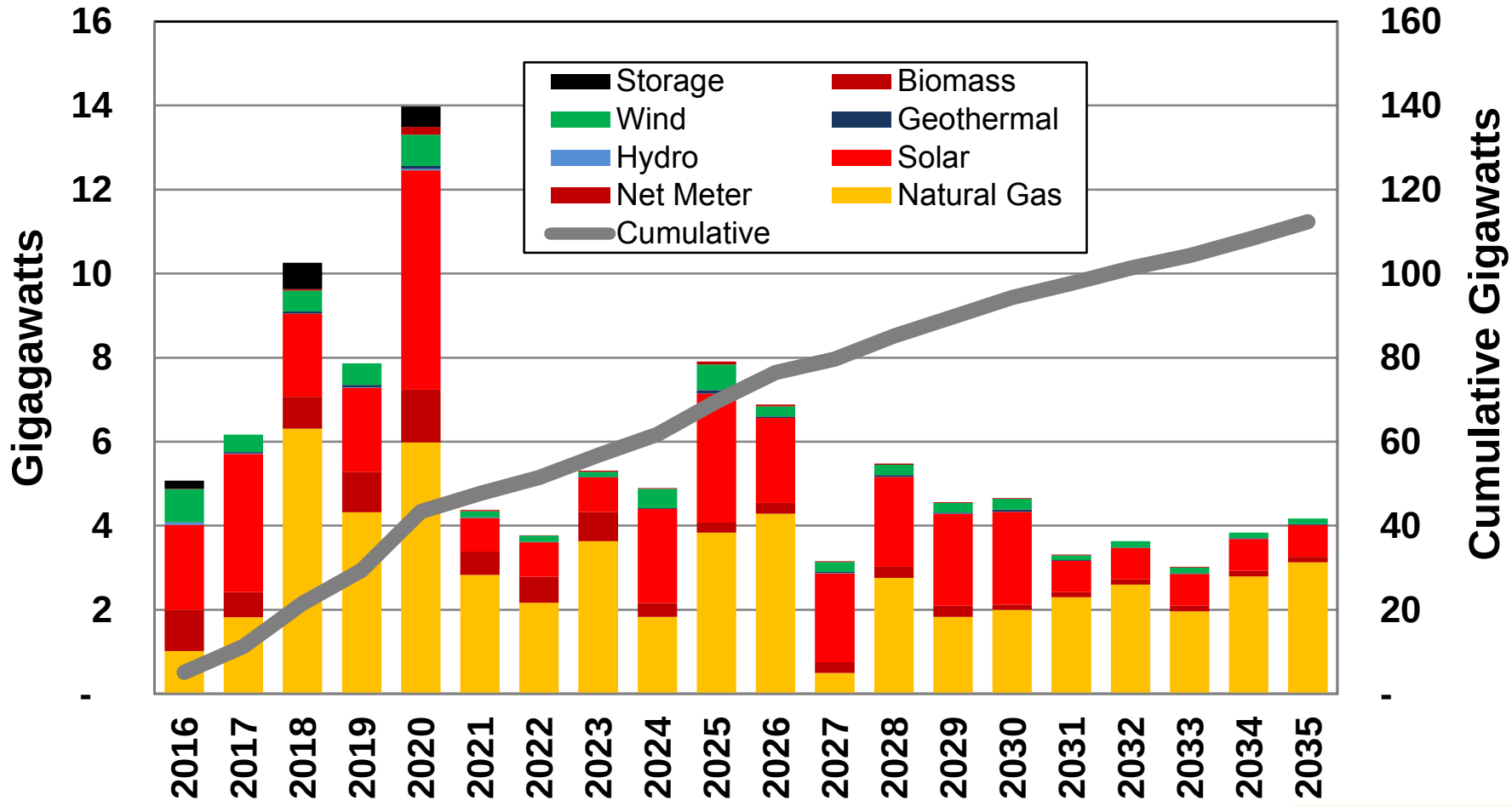
- California, BC, and Alberta include CO_2 price adder
- 10% probability for other states to have future carbon price adder ("Tax")
  - Price is $12 per metric ton beginning in 2020, with a 5% escalator
- Meets EPA 111(d) glide path reduction for total region by 2030
- Load growth is lowered to less than 1% across the Western Interconnect to account for increased conservation
- No new coal-fired generation
- Uses existing state Renewable Portfolio Standards

Western Resource Planned Retirements



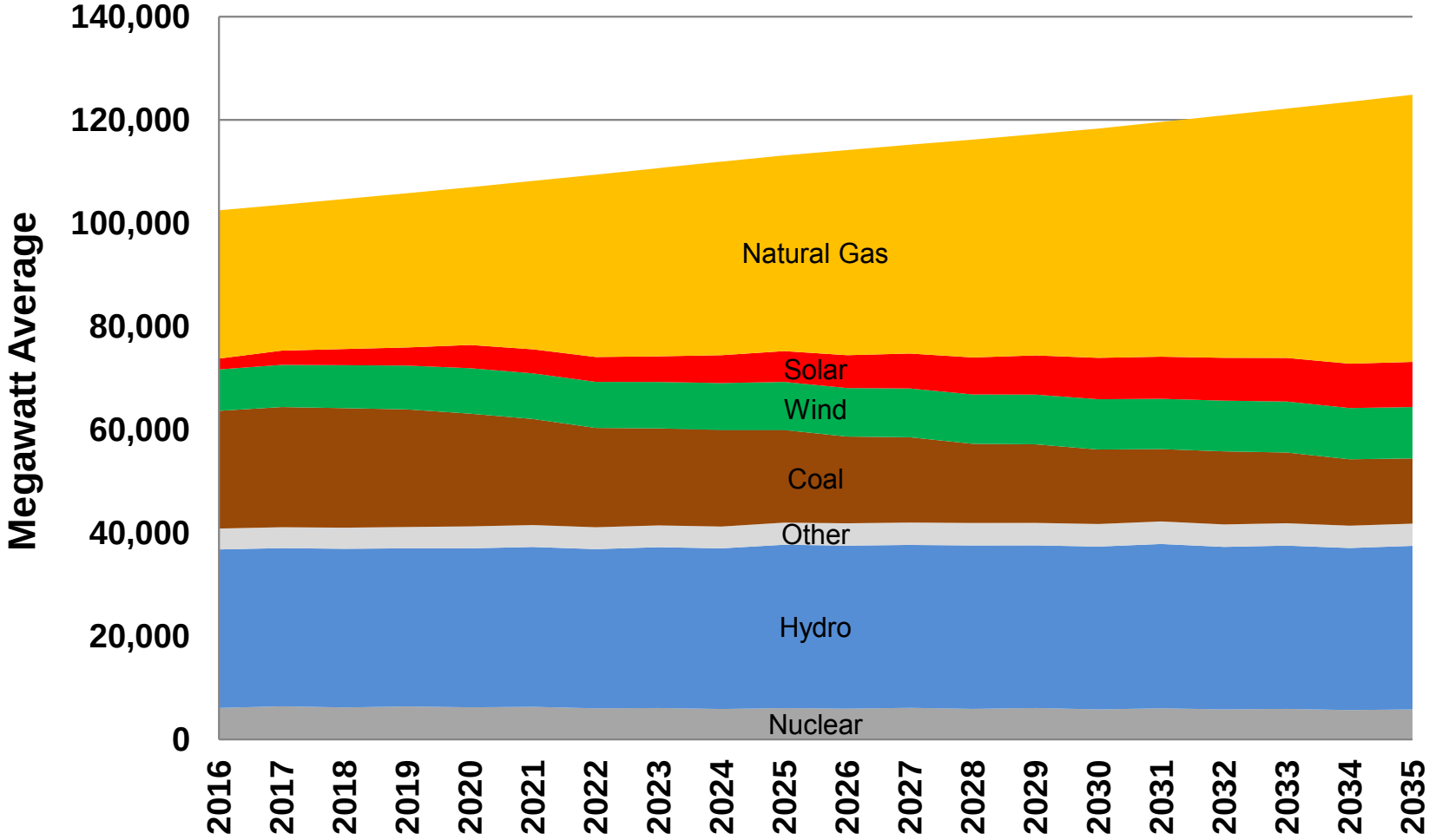
Note: Includes only announced plants, and small coal plants in carbon constrained states
Majority of natural gas retirements are once through cooling

New Resources to Western Interconnect

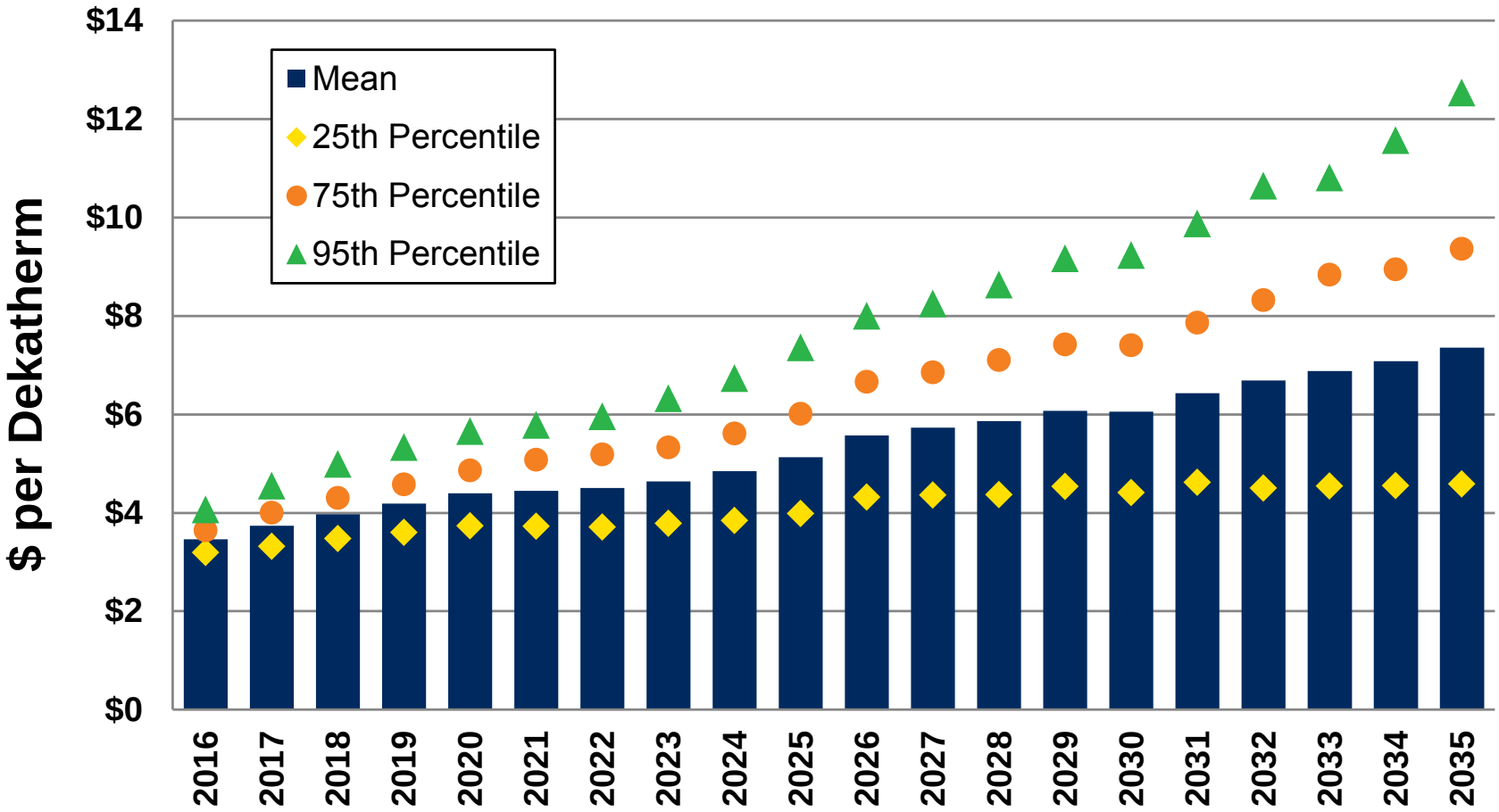


Resource Type Mix Forecast

(Western Interconnect)



Stanfield Natural Gas Price Forecast

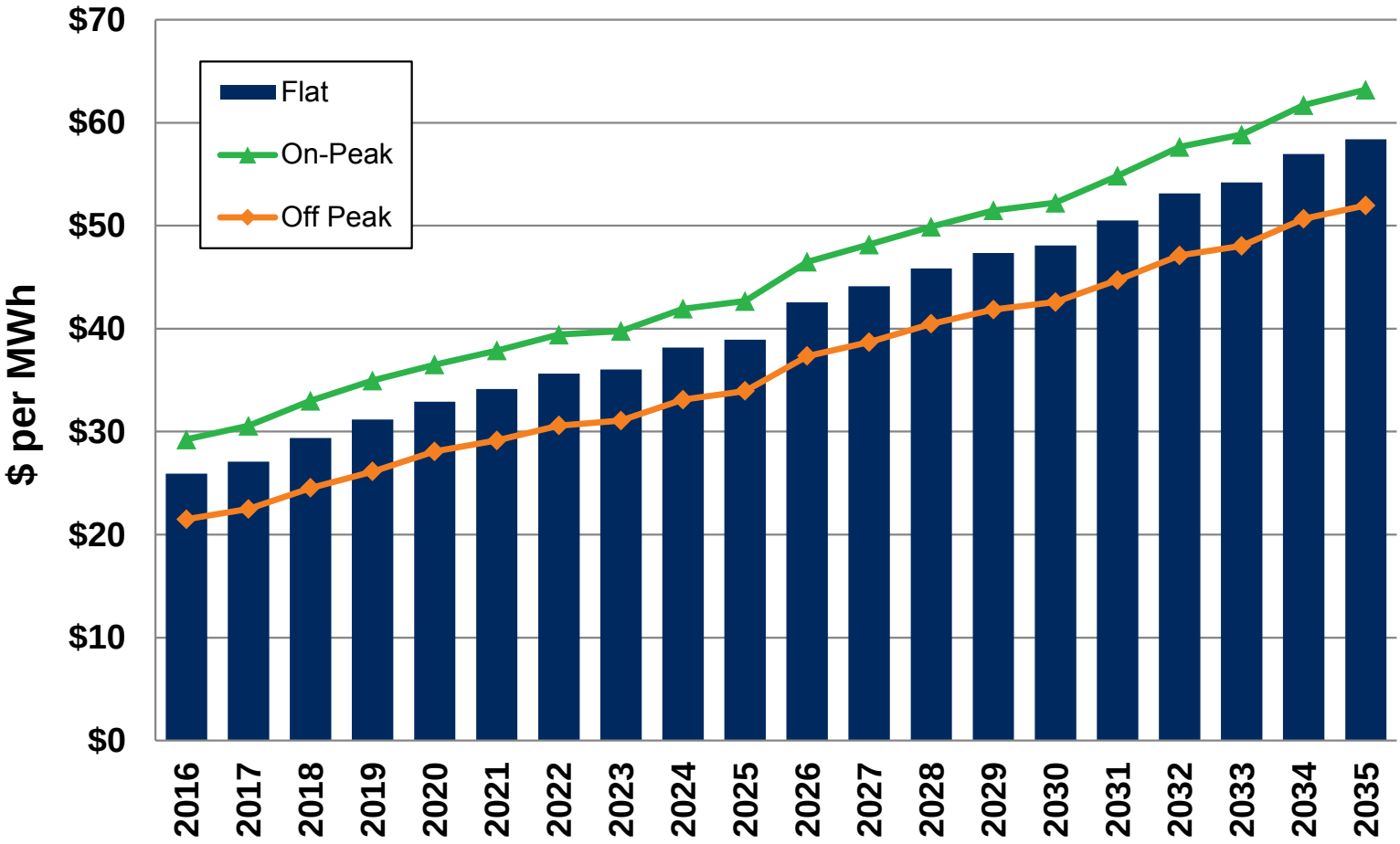


Levelized mean price $4.85/dth

Note: Coefficient of variation (stdev/mean) in 2016 is 15%, in 2035, the volatility increases to 56%

Mid-Columbia Electric Price Forecast

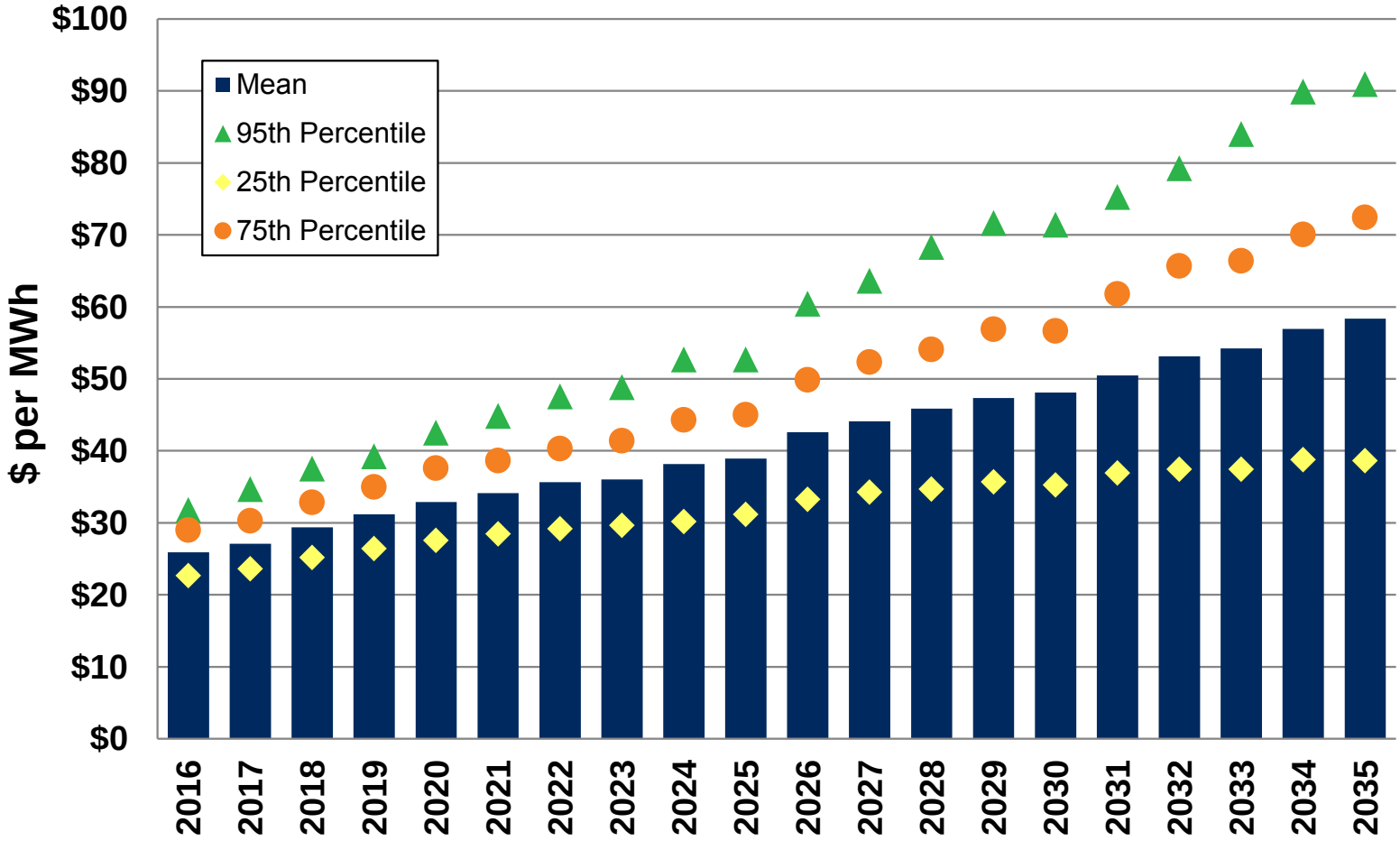
(Mean of 500 iterations)



Levelized Prices
Flat: $37.29/MWh
On Peak: $41.08/MWh
Off Peak: $32.24/MWh

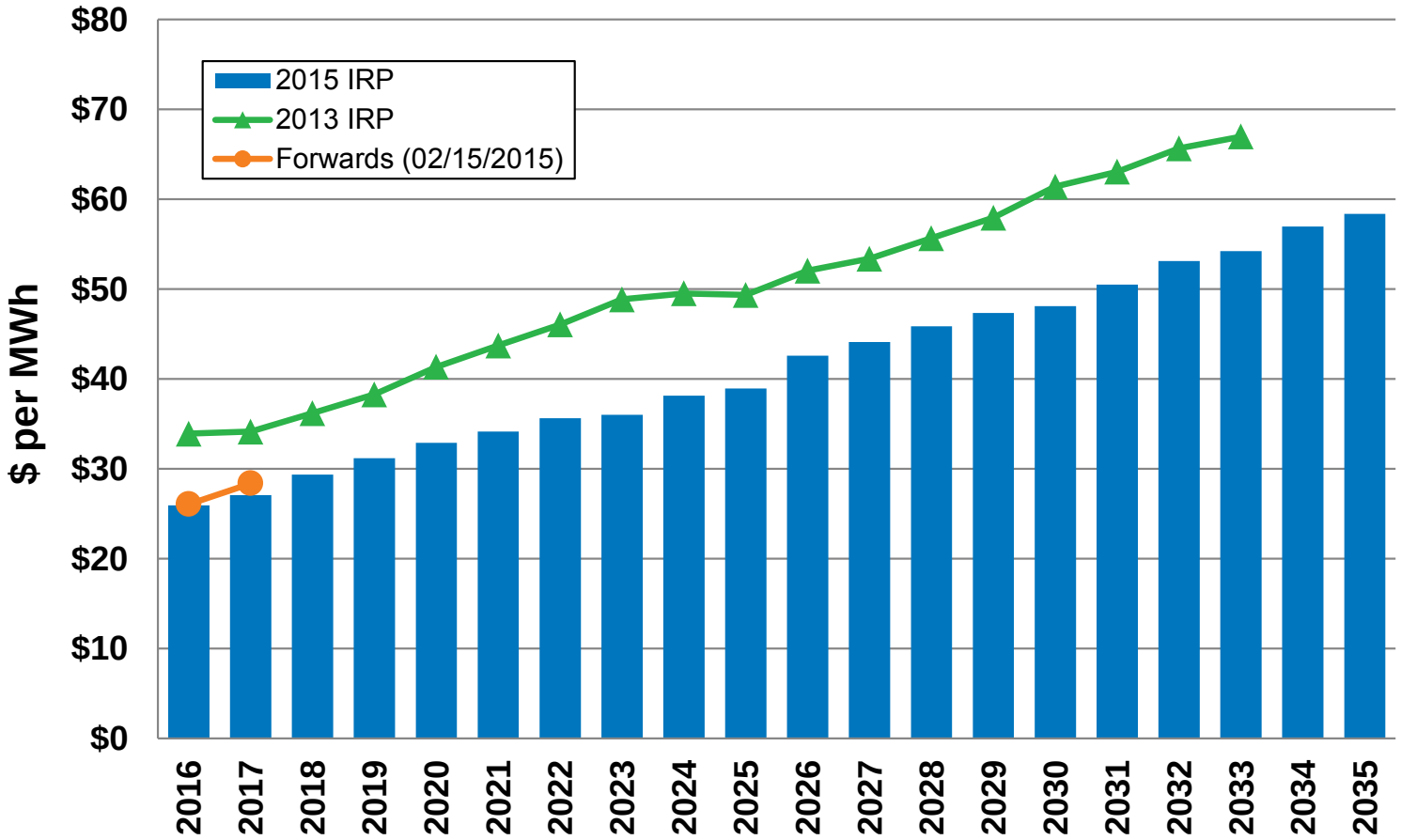
Mid-Columbia Electric Price Forecast

(Flat Price Statistics)

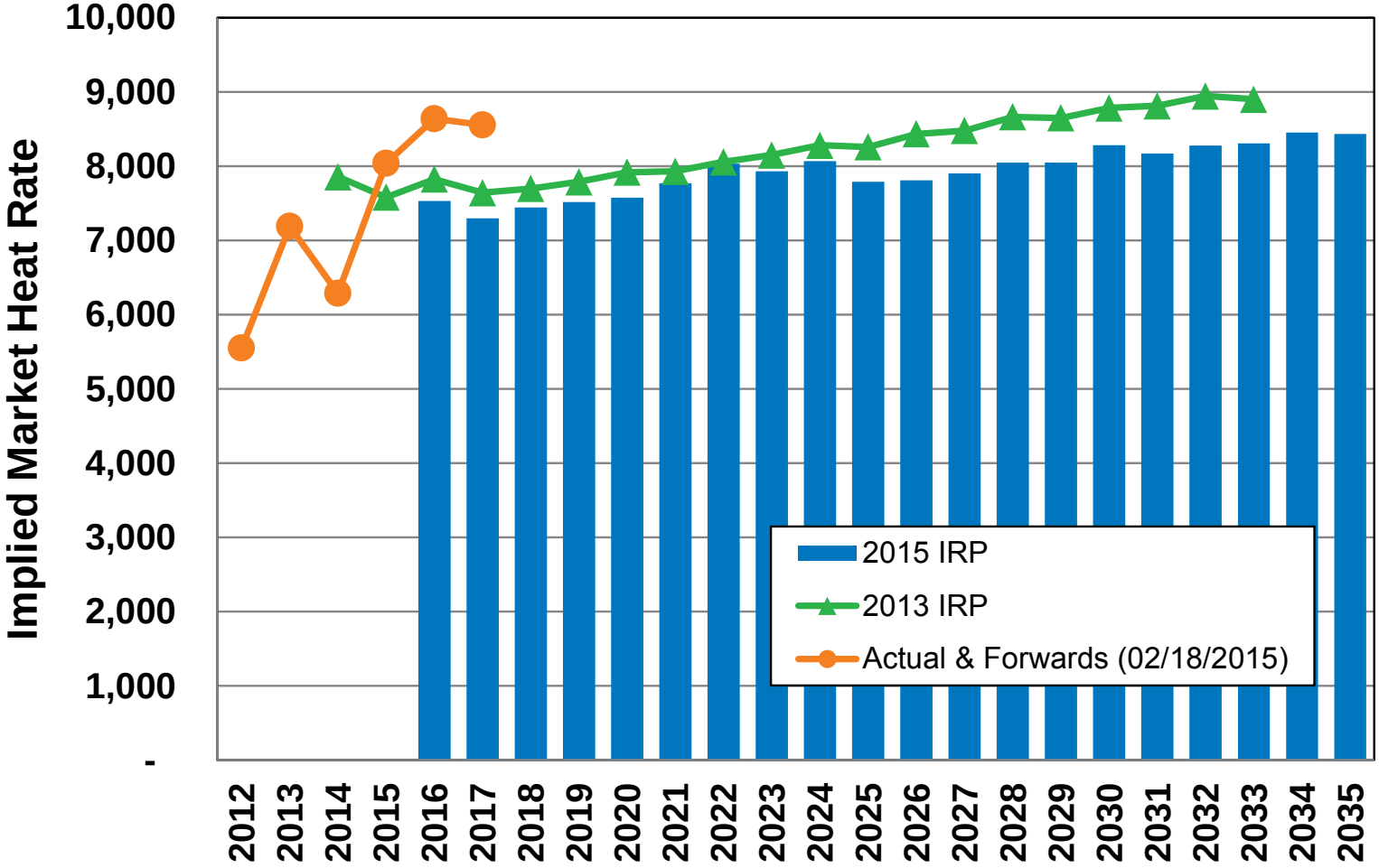


Note: Coefficient of variation (stdev/mean) in 2016 is 22%, in 2035, the volatility increases to 52%

IRP Price Forecast Comparison (Flat Prices)

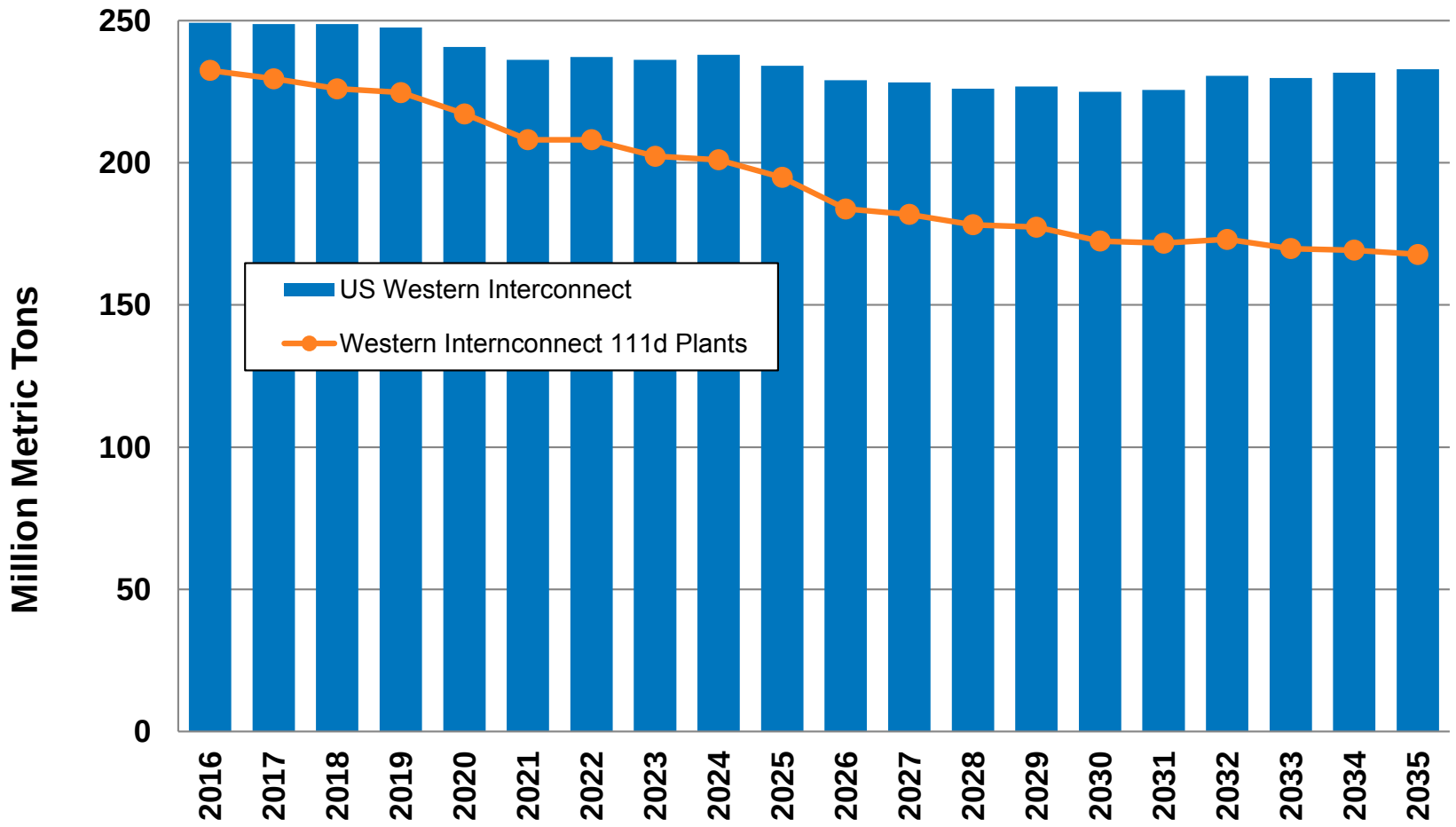


Implied Market Heat Rate



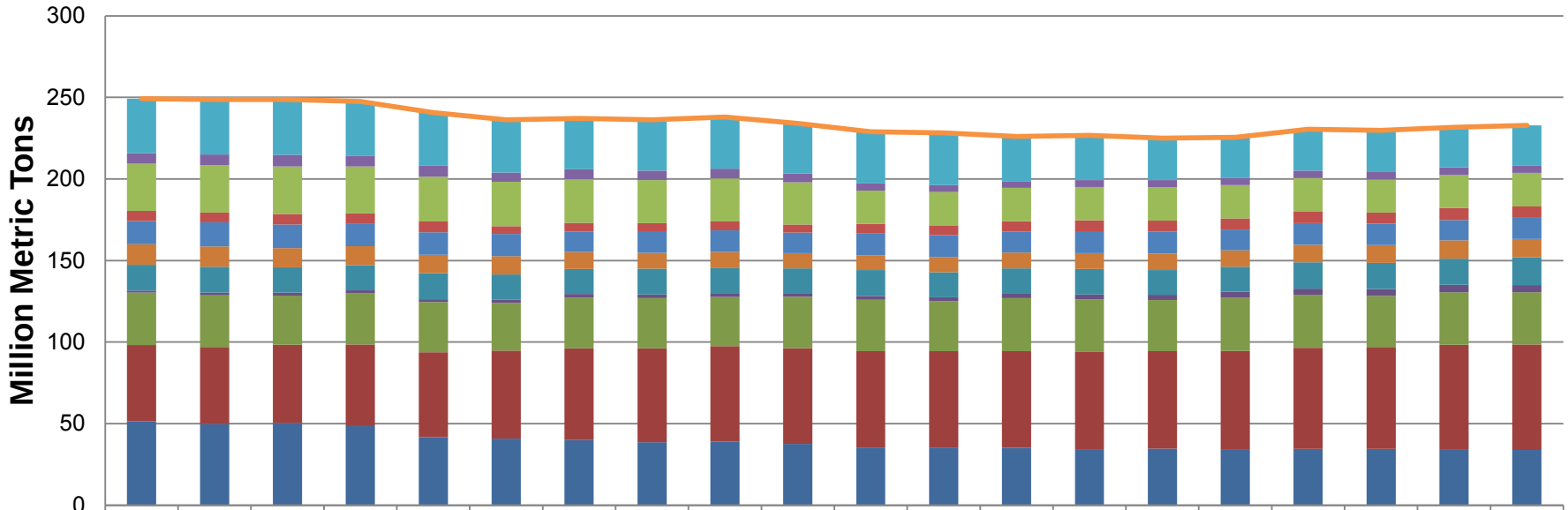
Greenhouse Gas Emissions Forecast

(US Western Interconnect Total)



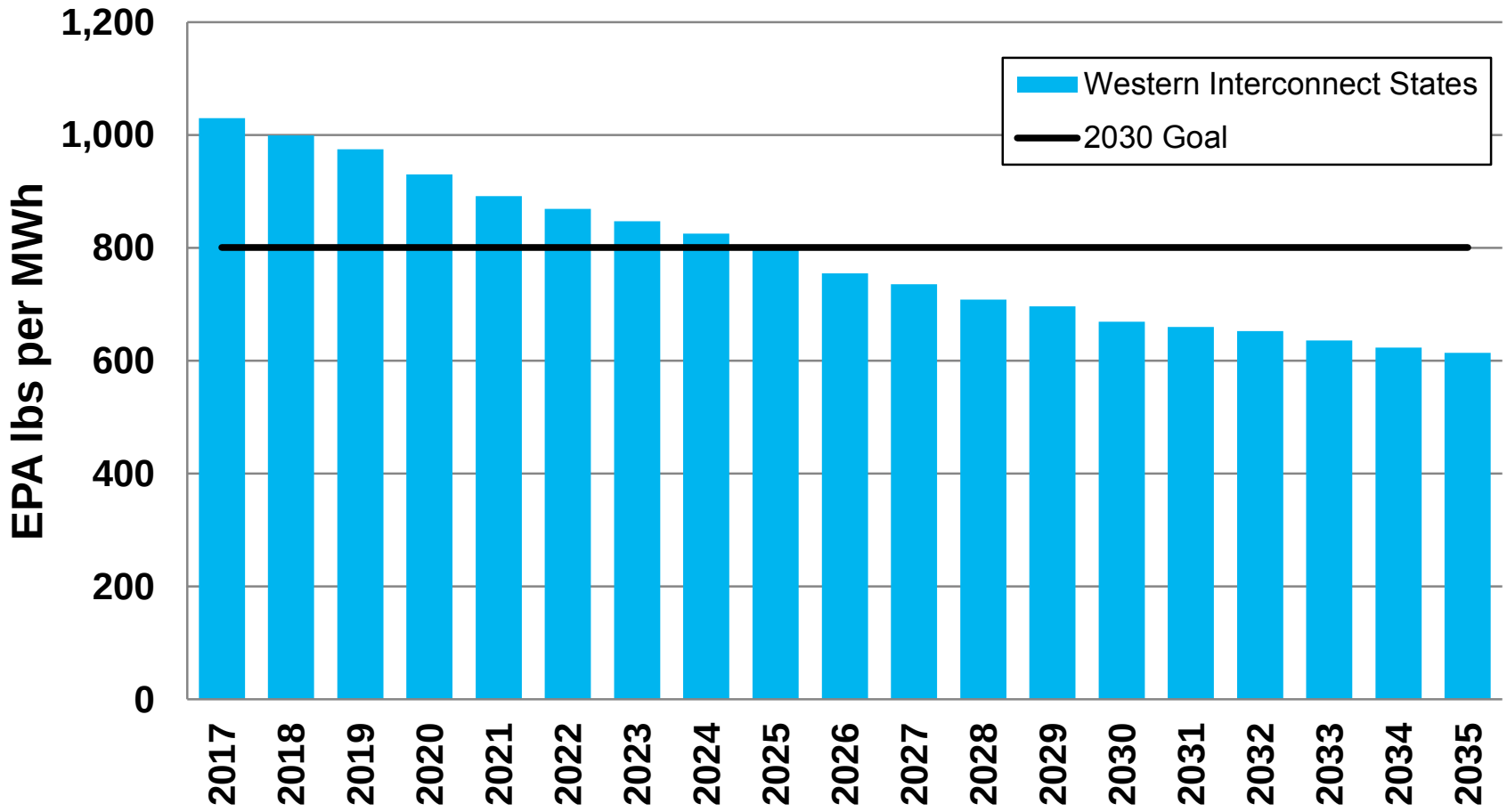
Greenhouse Gas Emission Forecast

(State Level)



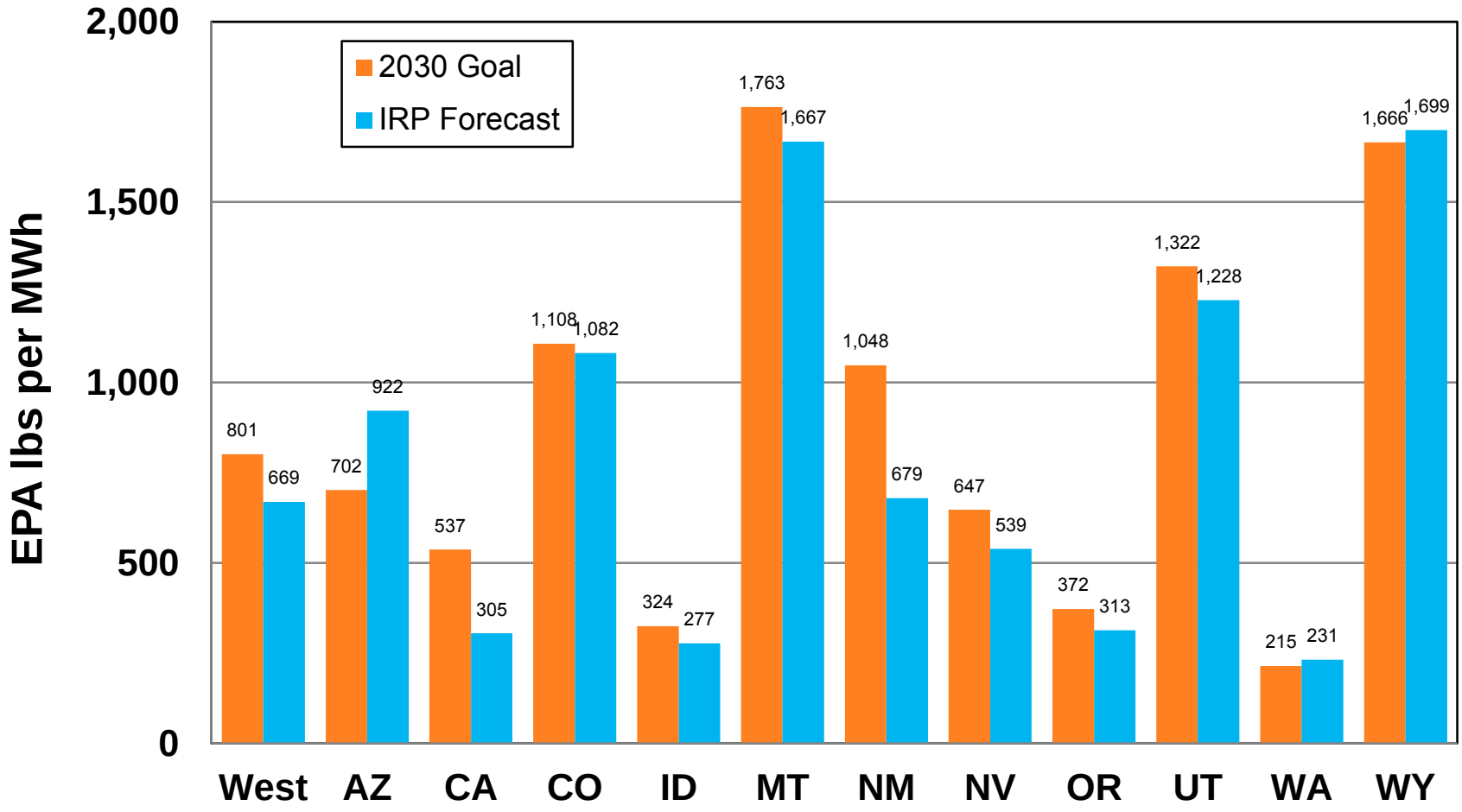
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Wyoming	33.3	33.7	34.0	33.2	32.4	32.2	31.2	31.0	31.6	30.7	31.7	31.9	27.3	27.5	25.6	25.0	25.4	25.5	24.4	24.5
Washington	6.5	6.7	7.1	6.7	6.9	5.7	6.0	5.8	6.0	5.4	4.3	4.3	4.2	4.2	4.4	4.3	4.6	4.5	4.8	4.6
Utah	28.9	28.8	29.0	28.7	27.5	27.2	26.8	26.3	26.4	25.8	20.5	20.3	20.4	20.5	20.5	20.4	20.5	20.3	20.2	20.5
Oregon	6.2	6.0	6.6	6.5	6.6	4.8	5.2	5.1	5.4	5.0	5.6	5.9	6.3	6.6	6.8	6.7	7.0	6.9	7.3	7.0
New Mexico	14.3	14.9	14.5	13.6	13.8	13.5	12.7	13.1	13.2	12.5	13.6	13.5	12.9	13.4	13.3	12.7	13.3	13.1	12.5	13.0
Nevada	12.7	12.5	11.7	11.7	11.2	11.4	10.2	9.7	9.9	9.5	9.2	9.4	9.7	9.8	10.1	10.1	10.8	10.9	11.2	11.3
Montana	15.8	15.8	15.5	15.4	16.0	15.4	15.4	15.9	15.4	15.0	15.8	15.2	15.2	15.7	15.3	15.3	16.3	15.9	16.1	16.9
Idaho	1.1	1.7	1.8	1.9	1.7	1.9	2.2	2.2	2.3	2.3	2.2	2.4	3.0	3.1	3.2	3.7	3.7	4.3	4.5	4.4
Colorado	32.2	31.7	30.1	31.4	30.9	29.4	31.1	30.9	30.1	31.5	31.6	30.6	32.6	32.2	31.3	32.6	32.4	31.3	32.3	32.0
California	46.9	47.1	48.0	49.9	52.1	53.9	56.2	57.5	58.6	58.8	59.1	59.2	59.3	59.4	59.7	60.2	62.0	62.6	63.9	64.7
Arizona	51.3	49.9	50.4	48.5	41.6	40.8	40.1	38.6	39.0	37.6	35.3	35.3	35.1	34.4	34.7	34.4	34.5	34.5	34.3	33.8
USA	249.	248.	248.	247.	240.	236.	237.	236.	238.	234.	229.	228.	226.	226.	225.	225.	230.	229.	231.	232.

EPA 111d Goal Comparison

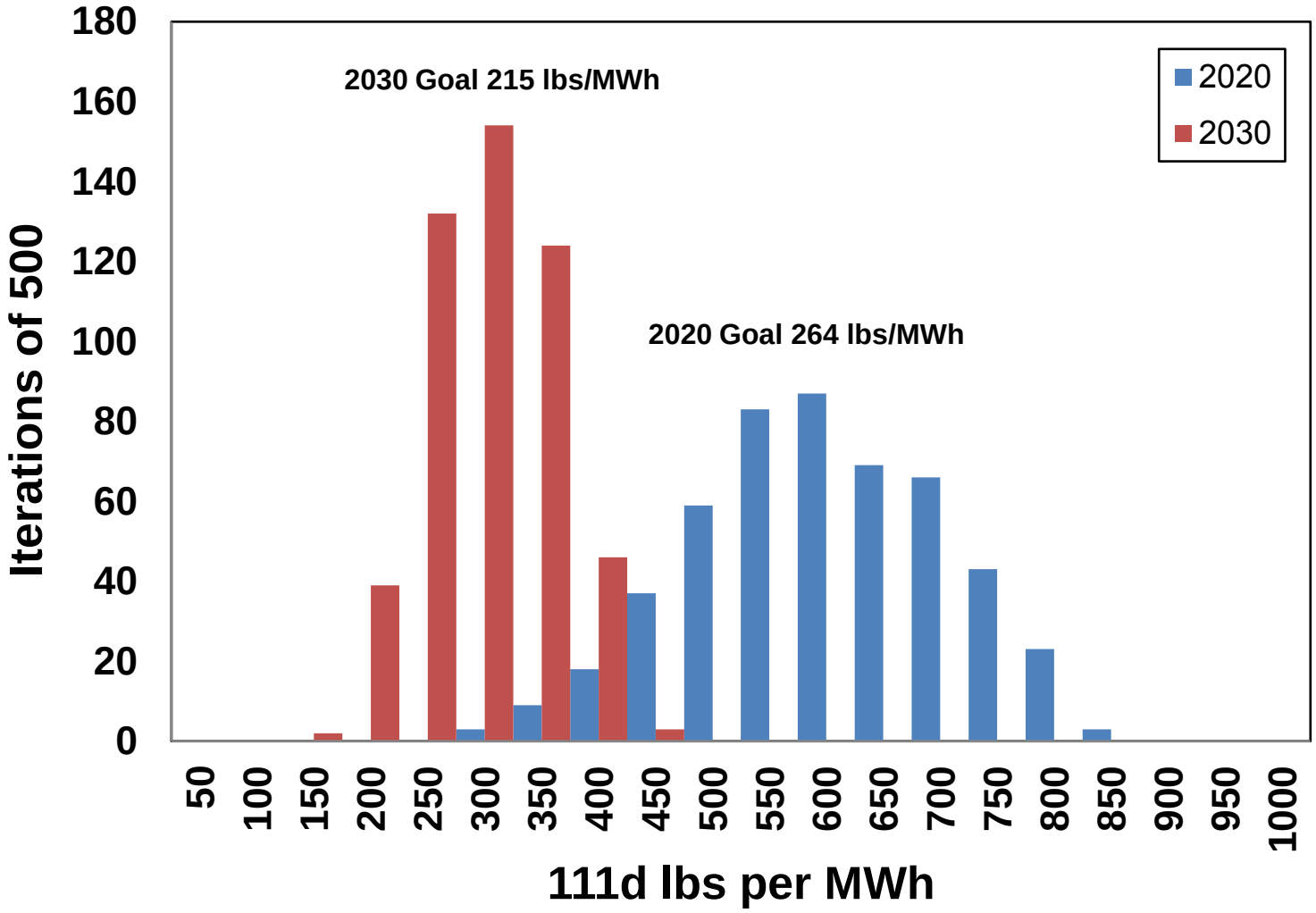


Note: EPA 2030 goal is adjusted for Langley Gulch and plants residing outside of the Western Interconnect

111(d) EPA State Goal Comparison



Washington Emission Volatility



2015 Electric IRP Resource Requirements

Clint Kalich, Manager of Resource Planning and Analysis
Fourth Technical Advisory Committee Meeting
February 24, 2015

L&R Methodology Review

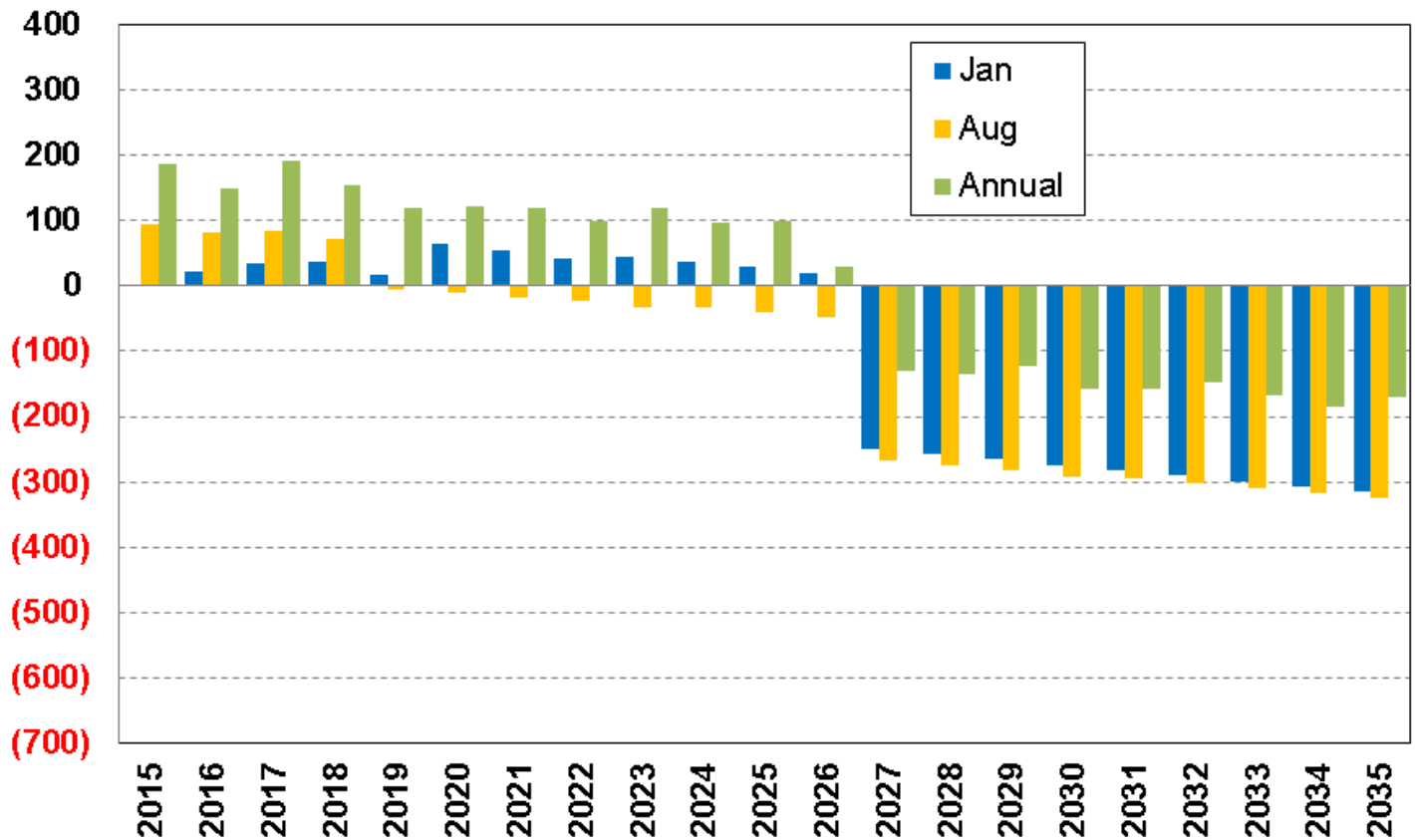
- Sum up resource capabilities against loads
  - Reduced by planned outages
- Capacity
  - Planning Margin
  - Operating Reserves and Regulation (~8%)
  - Largest deficit months between 1- and 18-hour analyses

L&R Methodology Review

- Energy
  - Reduced by planned and forced (5-year average)
  - Maximum *potential* thermal generation over the year
  - 80-year hydro average, adjusted down to 10th percentile
- Renewable Portfolio Standards
  - 3% / 9% / 15% requirement of Washington retail load in 2012 / 2016 / 2020
  - Qualifying resources less any forward sales obligations
  - Banking provisions help smooth out year-to-year variation
- Final resource need determined by shortest position each year

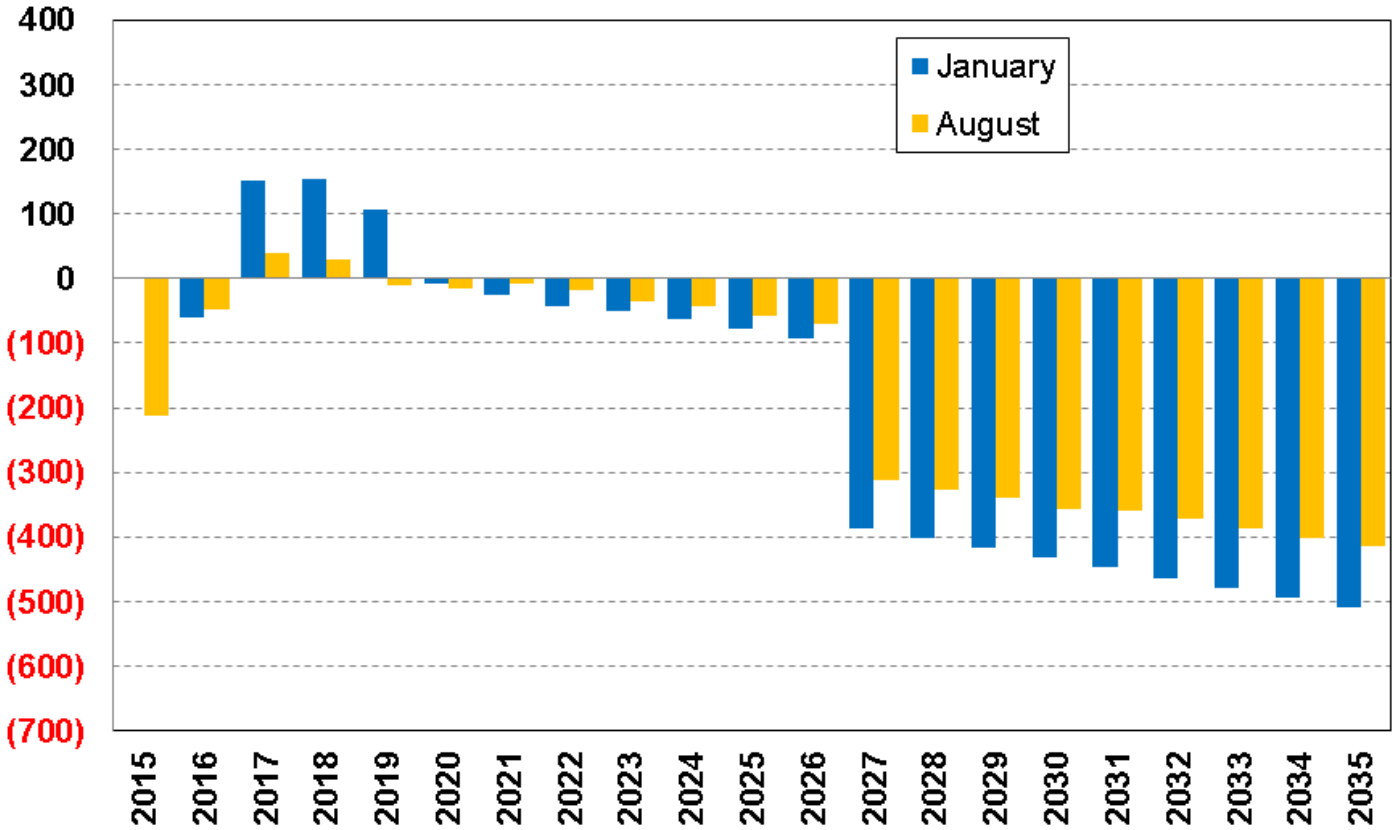
Energy Position (aMW)

Year	Jan	Aug
2014	0	0
2015	0	94
2016	23	81
2017	34	84
2018	36	73
2019	17	(4)
2020	64	(11)
2021	53	(18)
2022	42	(22)
2023	43	(32)
2024	36	(34)
2025	29	(40)
2026	21	(47)
2027	(249)	(268)
2028	(257)	(274)
2029	(265)	(281)
2030	(274)	(292)
2031	(282)	(295)
2032	(290)	(302)
2033	(298)	(309)
2034	(307)	(316)
2035	(315)	(323)



18-Hour Capacity Position (MW)

Year	Jan	Aug
2014	0	0
2015	(7)	(212)
2016	(60)	(48)
2017	151	38
2018	155	30
2019	106	(10)
2020	(7)	(14)
2021	(25)	(8)
2022	(43)	(18)
2023	(45)	(39)
2024	(64)	(44)
2025	(78)	(57)
2026	(93)	(70)
2027	(387)	(373)
2028	(401)	(326)
2029	(416)	(339)
2030	(432)	(357)
2031	(447)	(359)
2032	(463)	(373)
2033	(478)	(387)
2034	(494)	(400)
2035	(509)	(414)



1-Hour Capacity Position (MW)

Year	Jan	Aug
2014	0	0
2015	0	(266)
2016	(99)	36
2017	115	177
2018	115	167
2019	65	124
2020	(44)	120
2021	(62)	126
2022	(80)	144
2023	(87)	96
2024	(101)	87
2025	(116)	73
2026	(131)	59
2027	(425)	(185)
2028	(440)	(199)
2029	(455)	(214)
2030	(470)	(232)
2031	(486)	(235)
2032	(501)	(250)
2033	(517)	(265)
2034	(532)	(280)
2035	(548)	(295)

Year	Jan	Aug
2014	0	0
2015	0	(266)
2016	(99)	36
2017	115	177
2018	115	167
2019	65	124
2020	(44)	120
2021	(62)	126
2022	(80)	144
2023	(87)	96
2024	(101)	87
2025	(116)	73
2026	(131)	59
2027	(425)	(185)
2028	(440)	(199)
2029	(455)	(214)
2030	(470)	(232)
2031	(486)	(235)
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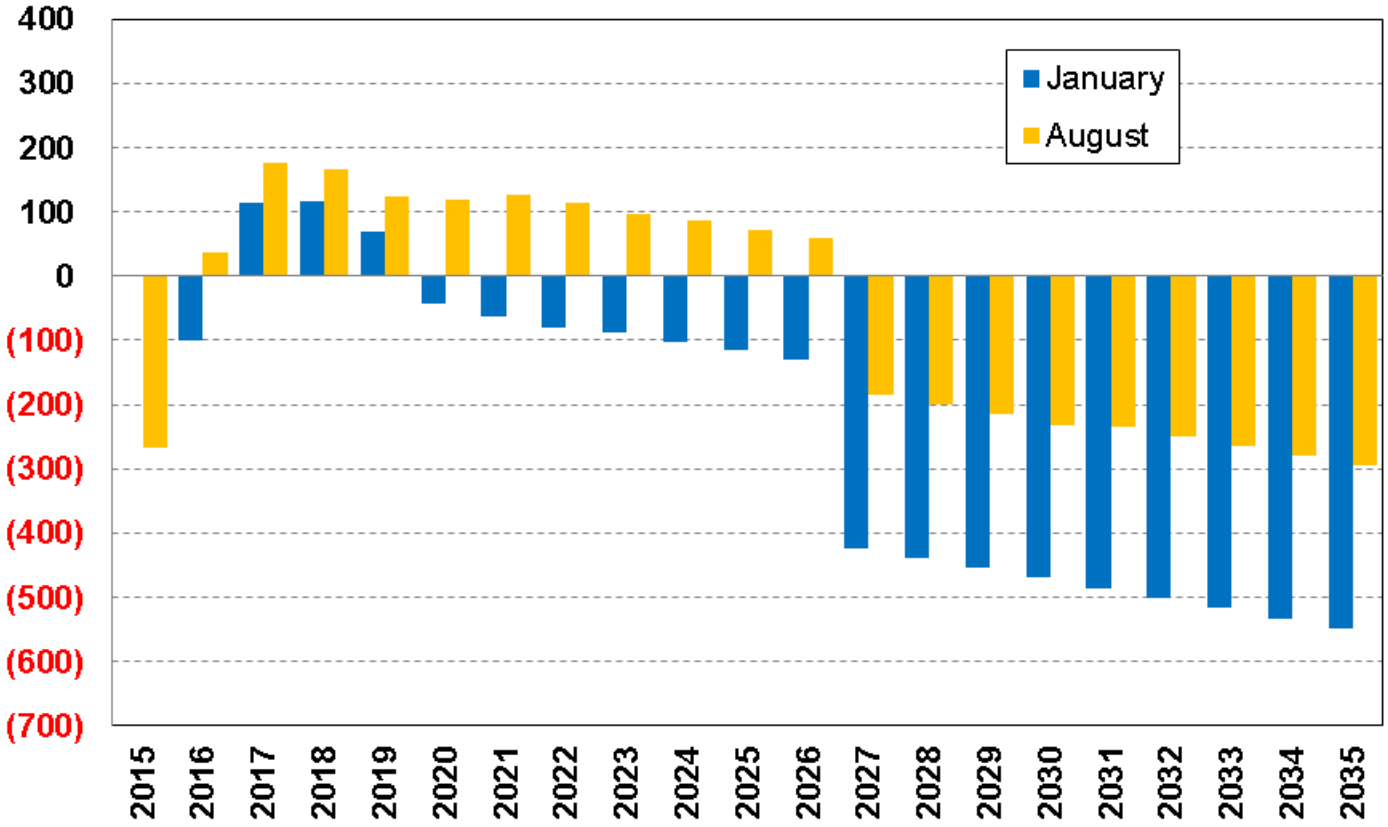
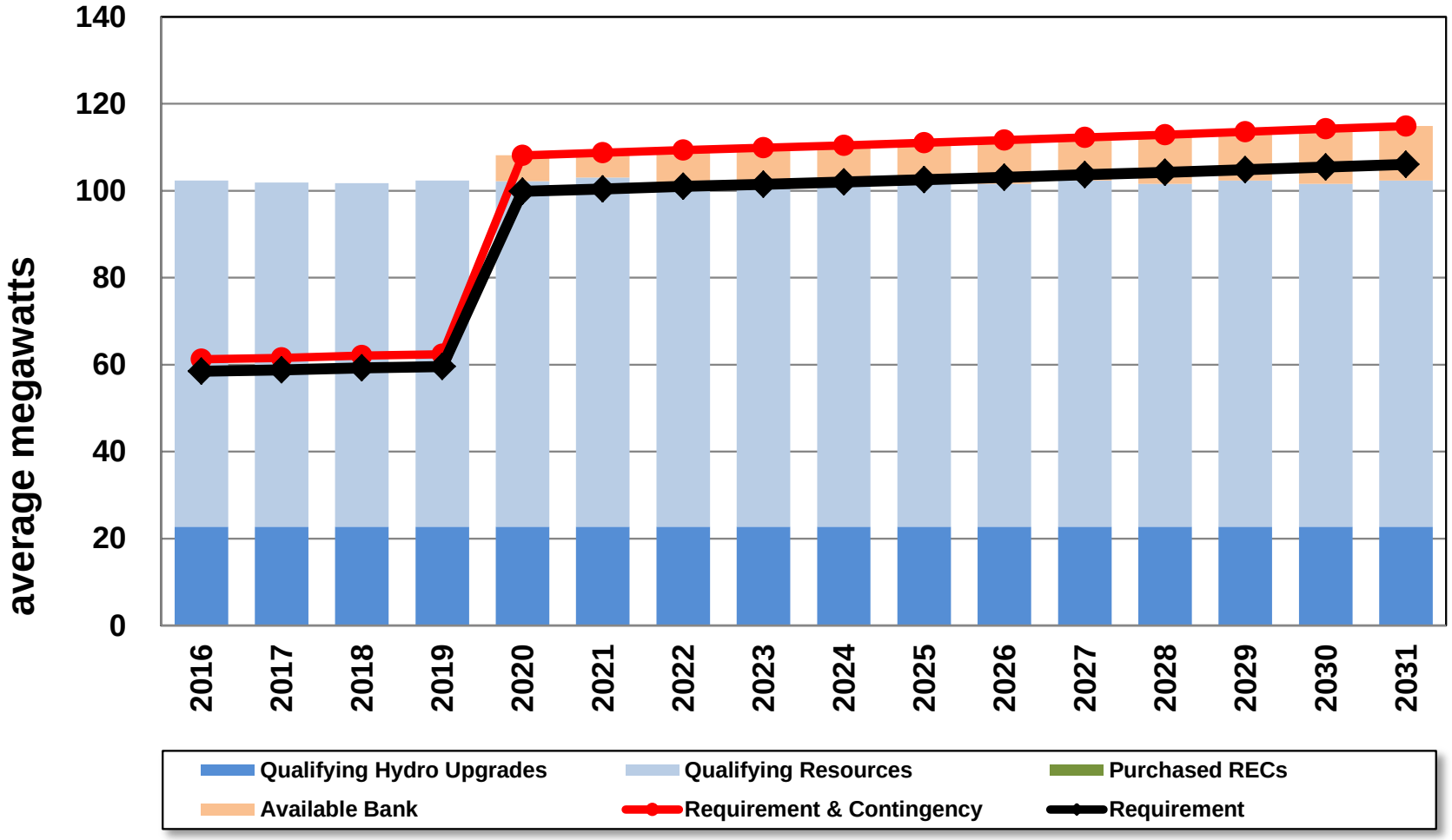
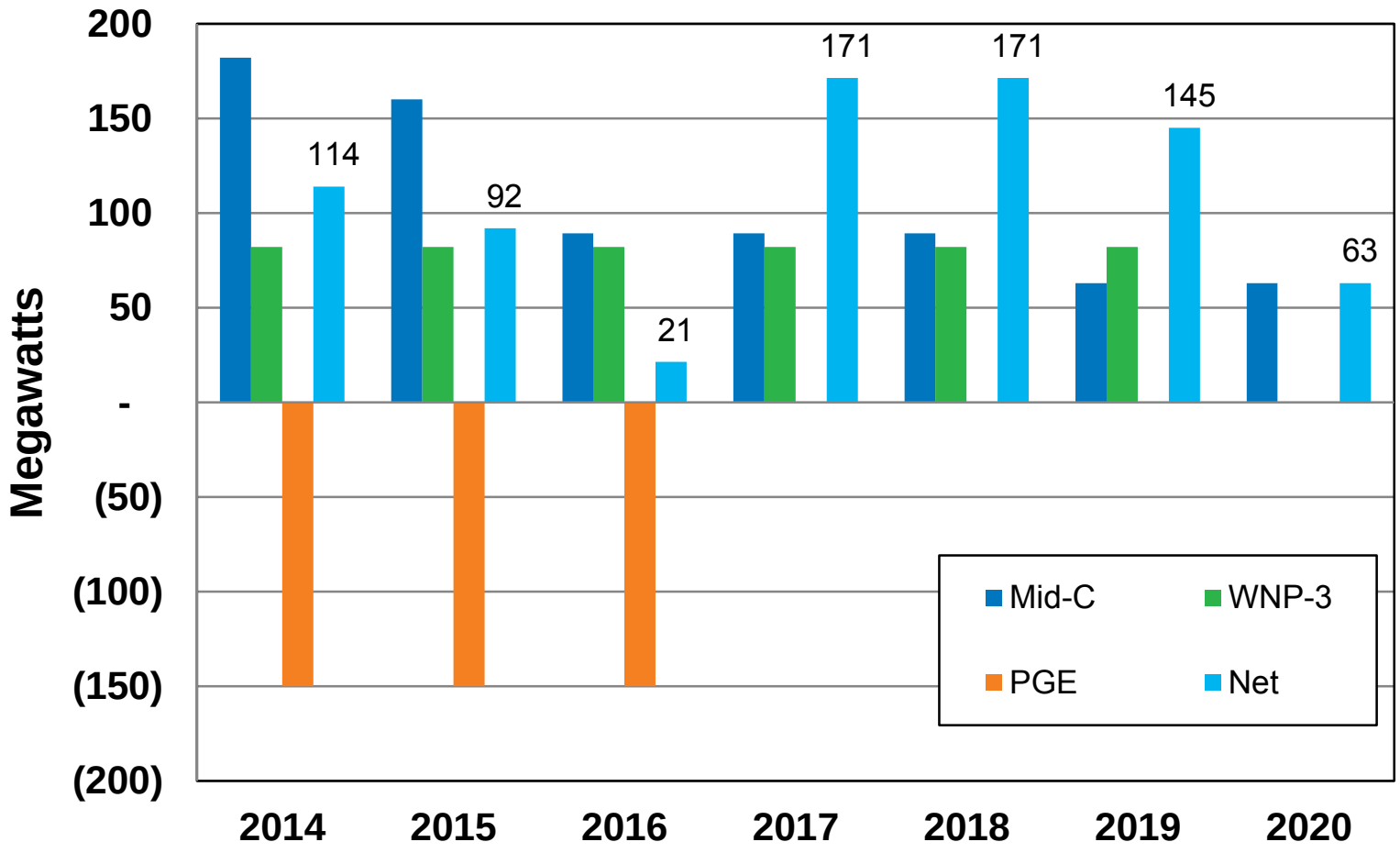


Washington RPS Position (aMW RECs)



Impact of Major Contracts (Winter Capacity)



Position Summaries

Energy

Year	Jan	Aug
2014	0	0
2015	0	94
2016	23	81
2017	34	84
2018	36	73
2019	17	(4)
2020	64	(11)
2021	53	(18)
2022	42	(22)
2023	43	(32)
2024	36	(34)
2025	29	(40)
2026	21	(47)
2027	(249)	(268)
2028	(257)	(274)
2029	(265)	(281)
2030	(274)	(292)
2031	(282)	(295)
2032	(290)	(302)
2033	(298)	(309)
2034	(307)	(316)
2035	(315)	(323)

18-Hr Cap

Year	Jan	Aug
2014	0	0
2015	0	(212)
2016	(60)	(48)
2017	151	(238)
2018	155	(30)
2019	106	(10)
2020	(7)	(14)
2021	(25)	(18)
2022	(43)	(18)
2023	(49)	(35)
2024	(64)	(44)
2025	(78)	(57)
2026	(93)	(70)
2027	(387)	(313)
2028	(401)	(326)
2029	(416)	(339)
2030	(432)	(357)
2031	(447)	(359)
2032	(463)	(373)
2033	(478)	(387)
2034	(494)	(400)
2035	(509)	(414)

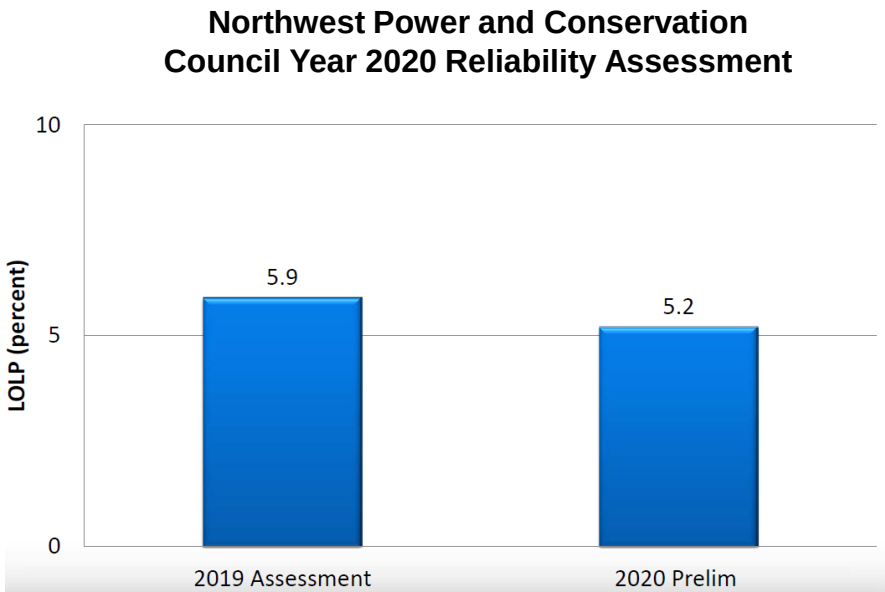
1-Hr Cap

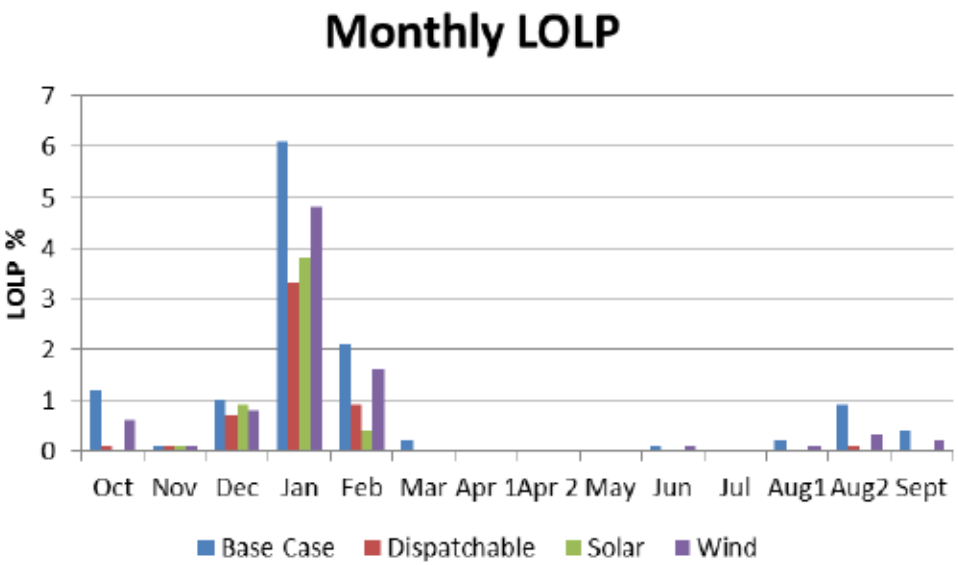
Year	Jan	Aug
2014	0	0
2015	0	(266)
2016	(99)	36
2017	119	177
2018	118	167
2019	145	124
2020	144	120
2021	(62)	126
2022	(80)	144
2023	(87)	96
2024	(101)	87
2025	(116)	73
2026	(131)	59
2027	(425)	(185)
2028	(440)	(199)
2029	(455)	(214)
2030	(470)	(232)
2031	(486)	(235)
2032	(501)	(250)
2033	(517)	(265)
2034	(532)	(280)
2035	(548)	(295)

Rely on the Wholesale Market?

- Market is made up of real generating assets
- Largest market reliance questions for Avista
  - Is there enough surplus in region to meet our and other utilities' future needs?
  - Are we willing to expose ourselves to market volatility?

Rely on the Wholesale Market?





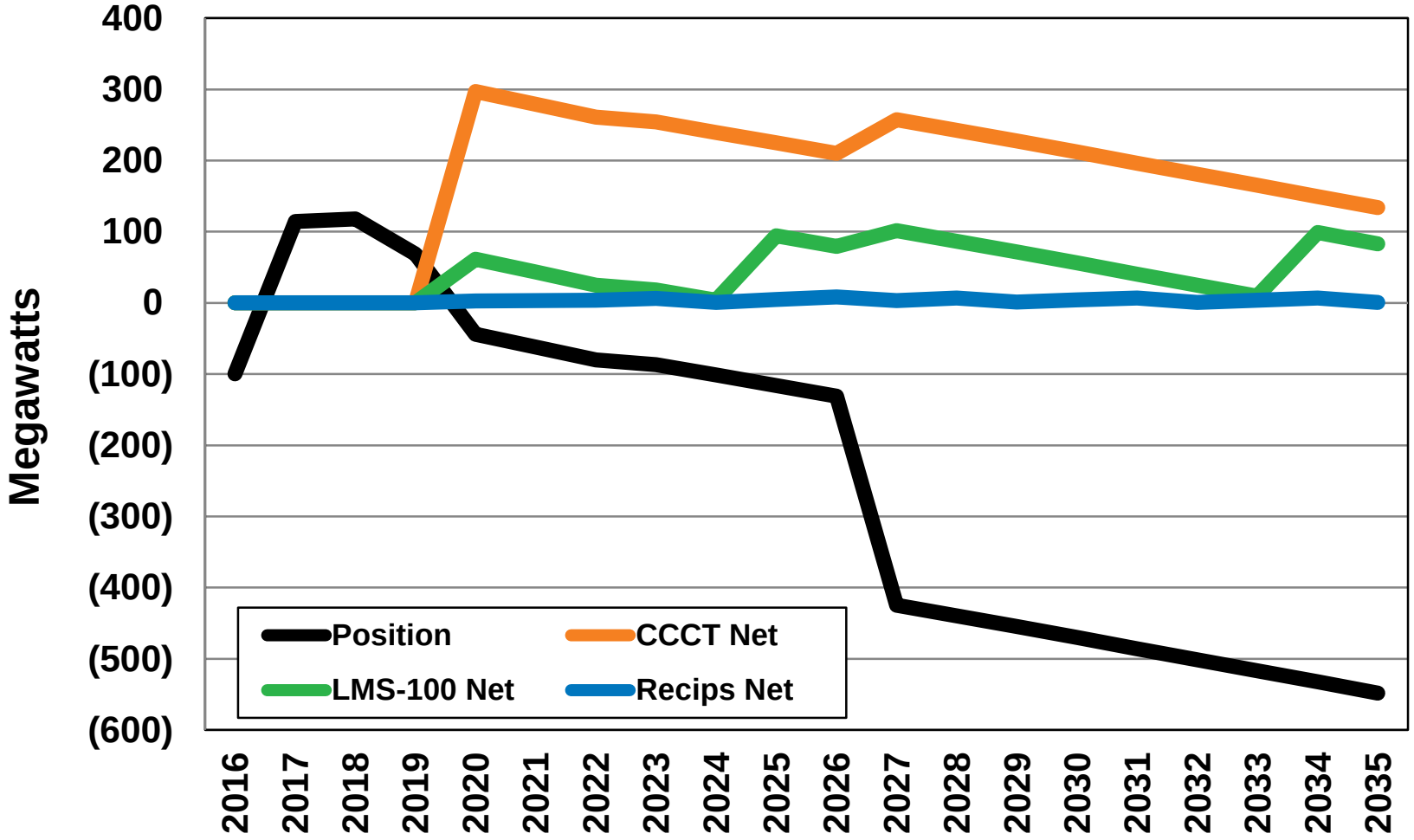
- 5% is considered by industry to be a minimum level for reliability
- 2021 likely will be worse given closure of Boardman and Centralia Unit 1 in 2020 (over 1,200 MW)
- 2026 loss of Centralia Unit 2 (670 MW)

Resource Option Capacity Contributions

Technology	Type	Name-plate (MW)	Winter Capacity	Summer Capacity
GE - 7F.05	Gas Peaker	203.0	109%	97%
GE - 7F.04	Gas Peaker	170.5	109%	96%
GE - 7F.04- Add HRSG	Gas CCCT	115.3	107%	96%
GE - 7EA	Gas Peaker	96.1	106%	96%
GE - LMS100PA	Gas Hybrid	101.2	105%	94%
Jenbacher 920 flex	Gas Recip	9.3	100%	100%
Siemens- SGT-800-50	Gas Peaker	45.1	110%	96%
GE - LM6000- PF Sprint	Gas Peaker	42.5	107%	95%
GE - 7F.05 1x1	Gas CCCT	341.3	106%	97%
GE - 7F.04 1x1	Gas CCCT	285.8	107%	96%
Wind On System	Wind	33.0	0%	0%
Solar Photovoltaic Fixed	Solar	10.0	0%	62%
Solar Photovoltaic 1 Axis	Solar	10.0	0%	70%
Battery Storage	Battery	25.0	100%	100%
Northeast CT Water Injection	Upgrade	7.5	100%	100%

Technology	Type	Name-plate (MW)	Winter Capacity	Summer Capacity
Rathdrum Supplemental Compression	Upgrade	24.0	100%	100%
Rathdrum CT 2055 Uprates	Upgrade	5.0	100%	100%
Kettle Falls Upgrade	Upgrade	12.0	100%	100%
Rathdrum CT: Inlet Evaporation	Upgrade	4.3	0%	403%
Kettle Falls Fuel Stabilization	Upgrade	3.0	100%	100%
Long Lake 2nd Powerhouse	Upgrade	68.0	100%	100%
Post Falls Upgrade	Upgrade	22.0	24%	0%
Monroe St 2nd Powerhouse	Upgrade	80.0	31%	0%
Cabinet Gorge 2nd Powerhouse	Upgrade	110.0	0%	0%
Direct Load Control	Customer	7.2+	100%	100%
Firm Curtailment	Customer	7.5+	100%	100%
Time-Of-Use	Customer	1+	100%	100%
Critical Peak Pricing	Customer	4+	100%	100%
StandbyGeneration	Customer	20+	100%	100%

Resources Acquisitions Are Lumpy



Options to Address Lumpiness

- Wait until size of need is larger
  - Pro: no surplus, Con: exposed to market
- Build smaller-sized units
  - Pro: closely meets need, Con: higher cost machines
- Partner with other utilities
  - Pro: better match of need, Con: not much interest

2015 Electric IRP Interconnection Studies

Richard Maguire, System Planning Engineer

Fourth Technical Advisory Committee Meeting

February 24, 2015

Federal Standards of Conduct

1. No non-public transmission information can be shared with Avista Merchant Function employees
2. There are Avista Merchant Function employees attending today
3. We will not be sharing any non-public transmission information

Agenda

- Introduction to Avista System Planning
- Two Big Changes This Year
- Recent Avista Projects
- Generation Interconnection Study Process
- Large Generation Interconnection Queue
- Integrated Resource Plan (IRP) Requests
- Future Transmission Planning Initiatives

Introduction to Avista System Planning

- Transmission system planning
- Distribution system planning
- Asset Management
- We all care about:
  - Federal, regional, and state compliance
  - Regional system coordination
  - Internal standards and processes

Big Change #1 – Regional Coordination

$$\frac{WECC}{SanDiegoOutage} = \frac{WECC}{2} + Peak$$

- WECC

  "has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection"

- Peak Reliability

  "is listed on the NERC Compliance Registry to perform the Reliability Coordinator (RC) and Interchange Authority (IA) functions as statutory activities"

PEAKRELIABILITY
assuring the wide area view

AVISTA

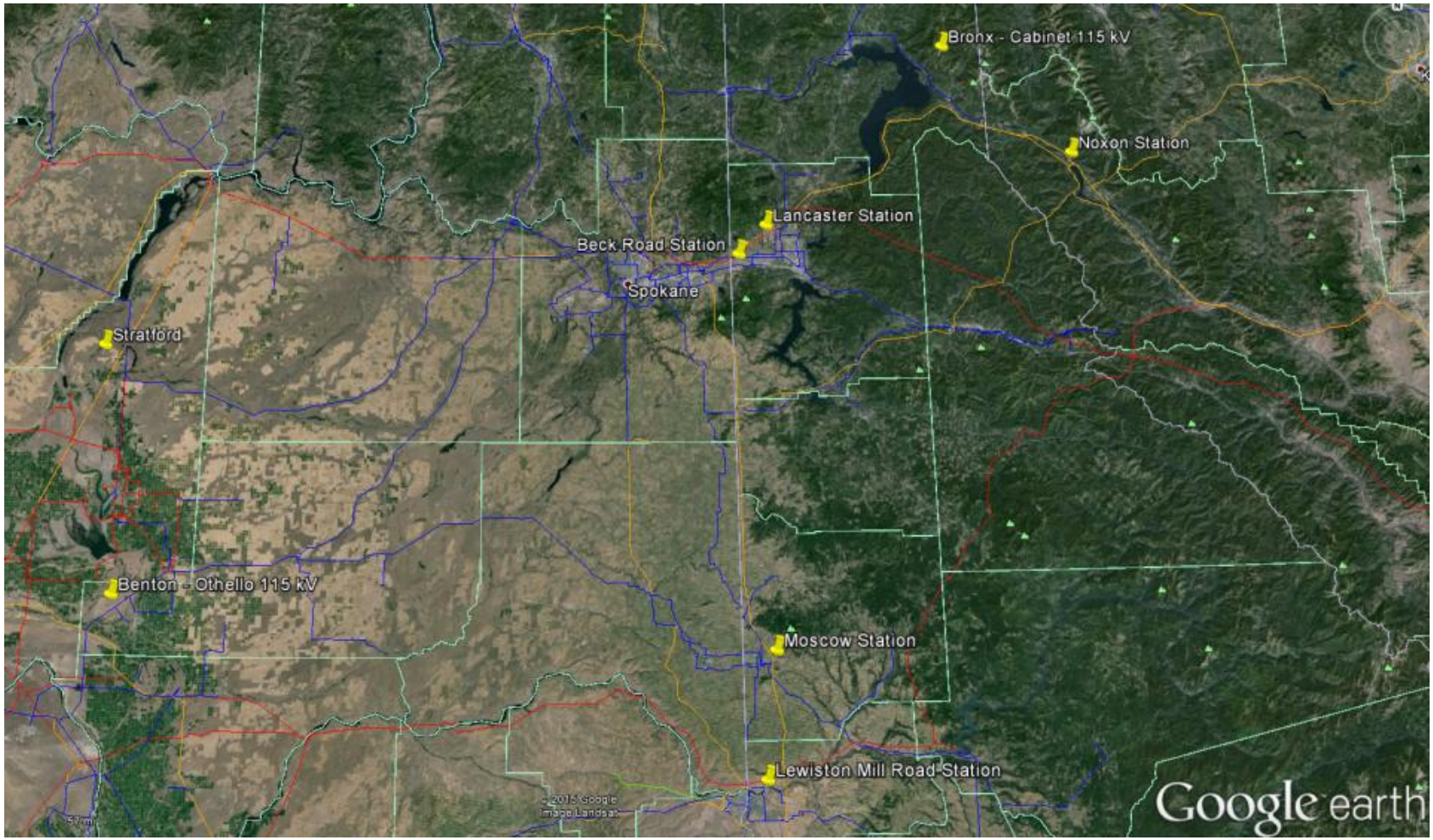
Big Change #2 – NREC TPL Standards

- Background
  - Loss of two or more elements (N-1-1)
    - If you have 300 elements (line, xfmr, bus, etc)
      - 300 X 299 = 89,700 outage events
      - If order does not matter (AB = BA)
        - » COMBIN(300,2) = 44,850 outage events
  - 44,850 analysis takes about **12 hours** on my laptop
- "Out with the old": TPL-xxx-3
  - N-1-1 termed, 'Category C'
  - Engineering judgment allowed pairing down the list
- "In with the new": TPL-xxx-4
  - N-1-1 termed, 'P6'
  - More 'teeth' in standard means more testing necessary
    - We need to look at all P6 events
  - Takes about a month on a study machine for all cases

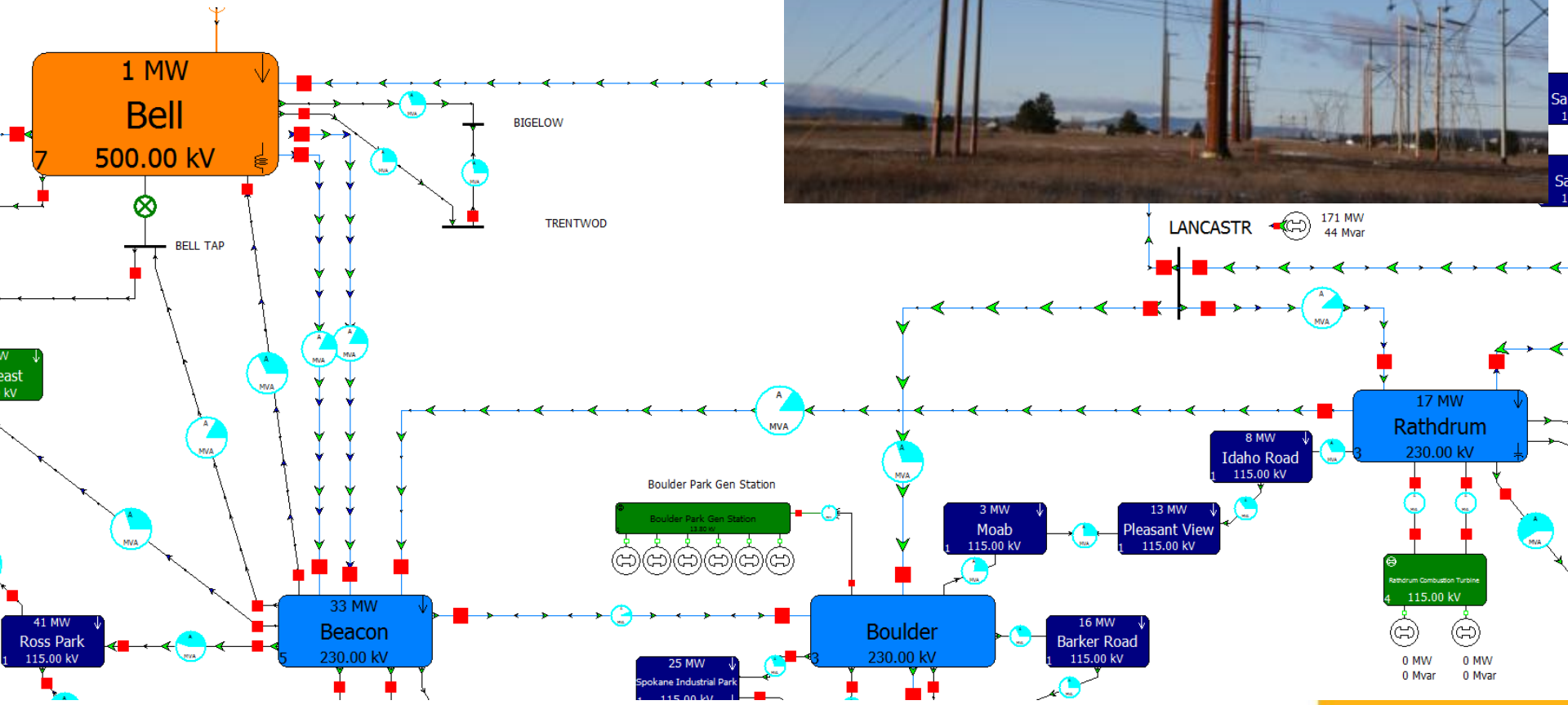
Big Change #2 – What are we doing?

- People possibilities
  - We could work longer, or we could take work home
  - We could take on risk and use engineering judgment
  - We could hire another engineer
- Process possibilities
  - We are working with PowerWorld Corporation to enhance their 'Distributed Computing' environment
  - We are investigating new study machine purchases
  - A collection of machines working concurrently REALLY reduces analysis times

Recent Transmission Projects



Lancaster 'Loop-in'



Moscow Station

Noxon Station

Generation Interconnection Study Process

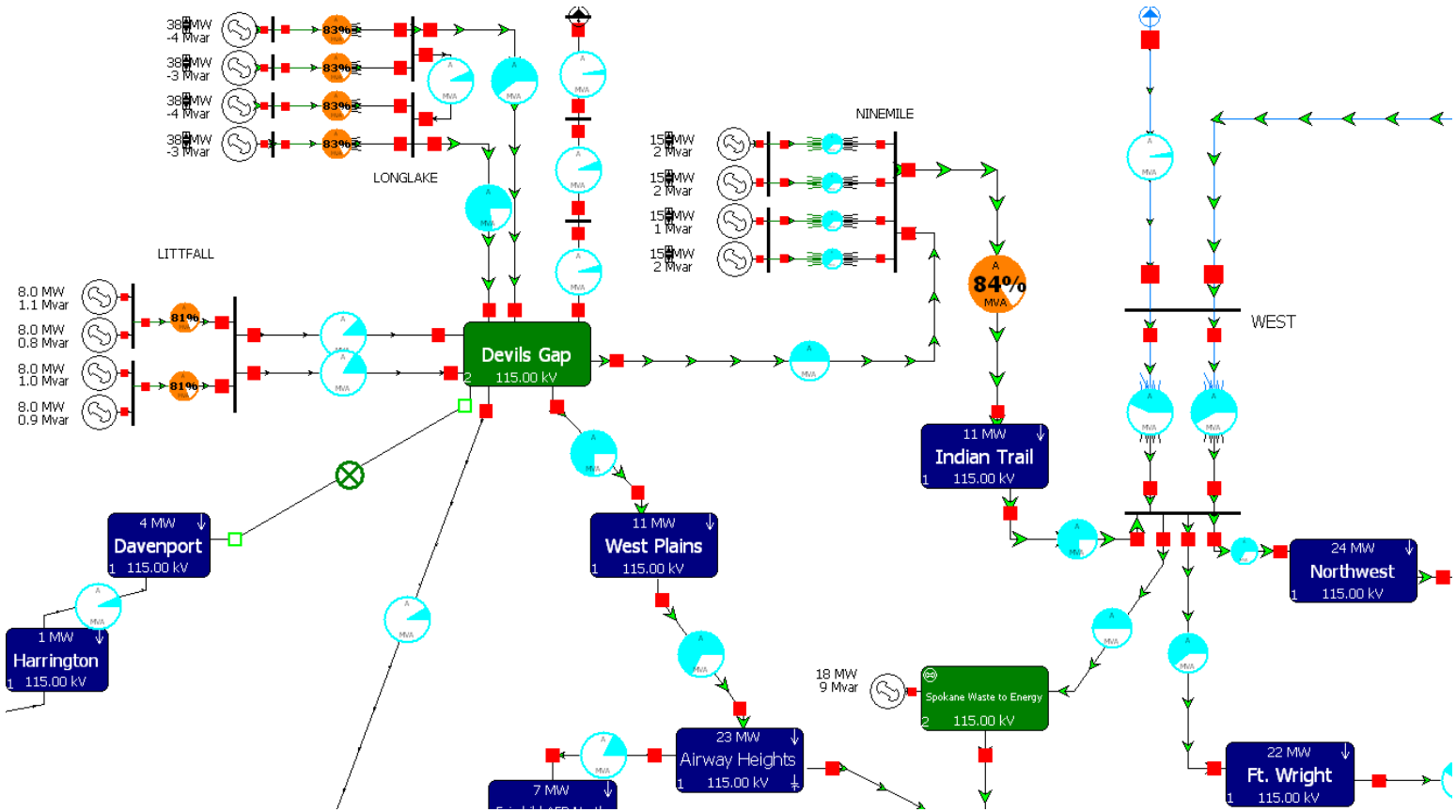
- Typical Process for Generation Requests
  - We generally get requests via two sources:
    - External developers
    - Internal IRP requests
  - Typical process:
    - We hold a scoping meeting to discuss particulars
    - We outline a study plan
    - We augment WECC approved cases for our studies
    - We analyze the system against the standards
    - We publish our findings and recommendations

Generate Study Cases

	From Number	From Name	To Nur	To Name	Circu	Status	Xfrmr	R	X	B	Lim A MVA
1	40017	ADDY	48007	ADDY AVA	1	Closed	YES	0.03883	0.70558	0.00000	20.0
2	40017	ADDY	48071	CHEWELAH	1	Closed	NO	0.01395	0.05425	0.00778	111.0
3	40017	ADDY	48135	GIFFORD	1	Closed	NO	0.14267	0.13096	0.01488	29.5
4	40017	ADDY	48223	METCHIP	1	Closed	NO	0.00606	0.02316	0.00345	111.0
5	40023	AHSAHKA	48303	OROFINO	1	Closed	NO	0.00500	0.02072	0.00268	111.0
6	40087	BELL BPA	48033	BELL TAP	1	Open	NO	0.00118	0.00369	0.00043	85.9
7	40087	BELL BPA	48449	WAIKIKIT	1	Closed	NO	0.00093	0.00373	0.00051	111.0
8	40149	BR									
9	40149	BR									

Western Montana Hydro	625.6 MW	West of Hatwai (Path 6)	117.4 MW
Noxon Rapids (562MW)	137.9 MW	Lolo-Oxbow 230kV	276.8 MW
Cabinet Gorge (265MW)	81.7 MW	Dry Creek-Walla Walla 230kV	159.6 MW
Libby (605MW)	216.0 MW		
Hungry Horse (430MW)	190.0 MW	West of Cabinet	1109.1 MW
		Montana-Northwest (Path 8)	970.0 MW
Colstrip Total			
Colstrip 1 (330MW)	330.0 MW	Idaho-Northwest (Path 14)	-584.6 MW
Colstrip 2 (330MW)	330.0 MW	Midpoint-Summer Lake (Path 75)	-75.2 MW
Colstrip 3 (823MW)	763.8 MW	Idaho-Montana (Path 18)	-274.5 MW
Colstrip 4 (823MW)	775.5 MW		

Analyze Study Cases



Publish Results

- Customer News
- FERC Filings
- FERC Order 890
- Integrated Resource Plan
  - 2007 Native Load IRP Table
  - 2007 Native Load IRP Table w/Rev
  - 2009 IRP Meeting - March 25, 2009
  - 2009 IRP Meeting Announcement
  - 2009 IRP Posting Notice
  - 2009 IRP Transmission Request
  - 2009 Native Load IRP Table
  - 2010 IRP TAC Meeting Notice
  - 2010 IRP TAC Meeting Presentation
  - 2011 IRP Follow Up Meeting
  - 2011 IRP Posting Notice
  - 2011 Native Load IRP Table
  - 2013 IRP Generation Study (Cabinet Gorge)
  - 2013 IRP Generation Study (Nine Mile HED)
- Interconnection Requirements

www.oasis.oati.com/avat/index.html

LGIA #43 – 150 MW Wind Project

2015 IRP Request Snapshot

Station	Request (MW)	POI Voltage	Cost Estimate ($ million)
Kootenai County	100	230 kV	12 - 16.1
Kootenai County	350	230 kV	47.2
Rathdrum	26	115 kV	2.84 - 10.9
Rathdrum	50	115 kV	10.7 – 18.7
Rathdrum	200	115 kV	10.3 - 48.5
Rathdrum	50	230 kV	7 – 16.8
Rathdrum	200	230 kV	15.5 – 21.5
Thornton	30	230 kV	.4
Thornton	100	230 kV	.4
Othello	25	115 kV	2
Northeast	10	115 kV	0
Kettle Falls	10	115 kV	0
Long Lake	68	115 kV	19.7
Monroe Street	80	115 kV	7
Post Falls	10	115 kV	2.1
Post Falls	20	115 kV	5.2

2015 Electric IRP Appendix A

[1] Preliminary estimates are given as -25% to +75%

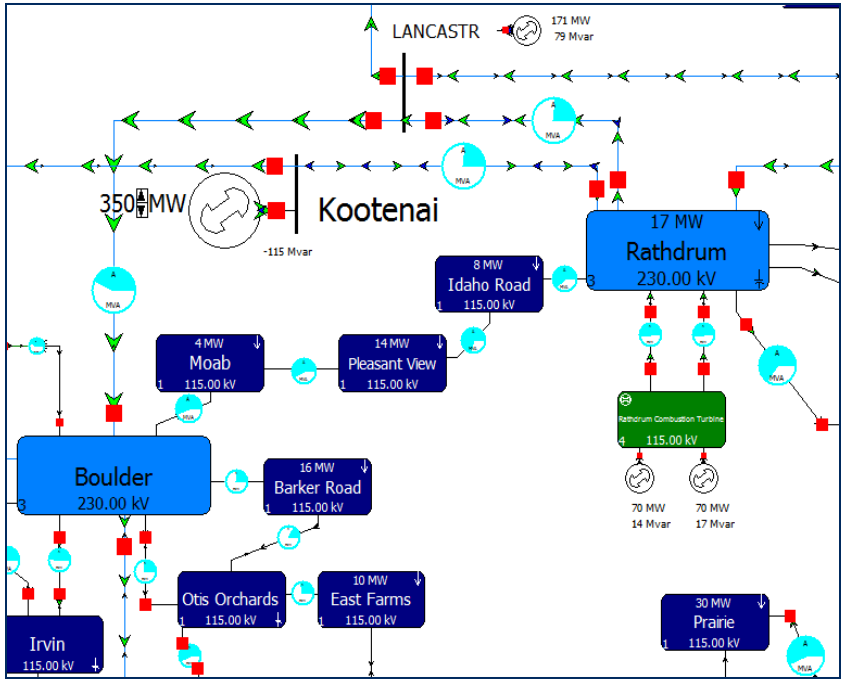
Cost Assignment for Generation Integration

- Simulate Generation Integration
  - Develop new list of “gen” violated elements
  - Compare new list to previous violated elements (without gen)
    - New violated elements are assigned to gen project
  - If previous violated elements need a corrective action advanced in time
    - Consider assignment of advancement cost to gen project
  - Any projects that improve transmission service to existing AVA customers need consideration as a network upgrade

2015 IRP Study Notes

- These are pre-feasibility studies
  - Limited cases and scenarios
  - No stability studies
- All generation fully on
- Results include incremental issues, not base case issues
- $$ estimates for planned projects are flexible

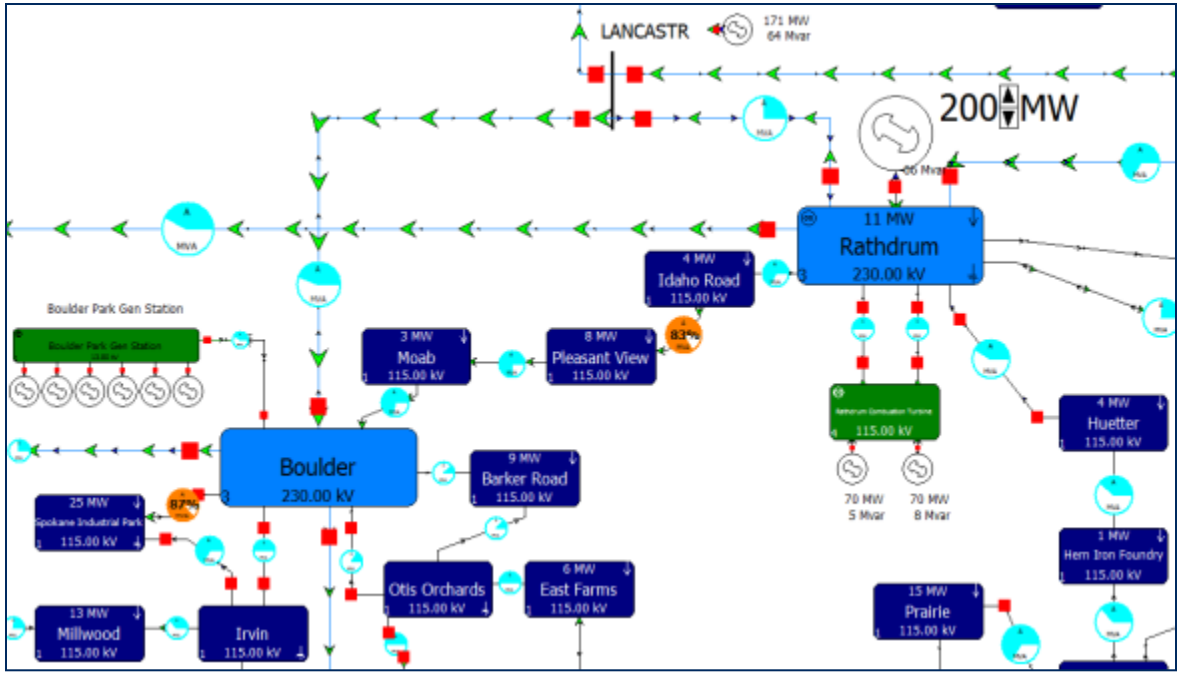
Kootenai: 100 MW to 350 MW



- $16 to $48 Million
- Overlaps existing projects
- 426 MW existing already

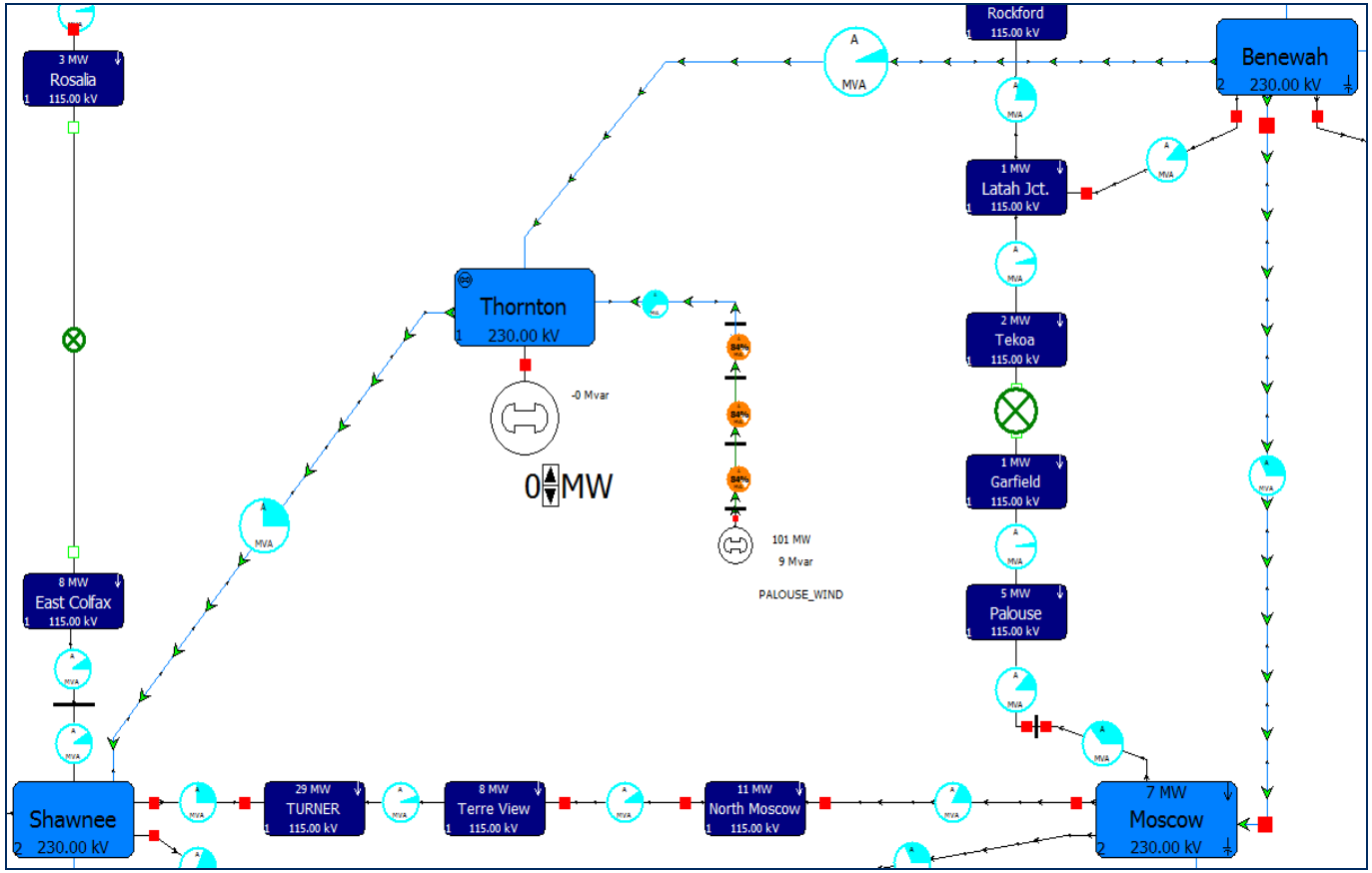
Rathdrum: 26 MW to 200 MW

- $2.84 to $48.5 Million
- Overlaps existing projects
- 426 MW existing already



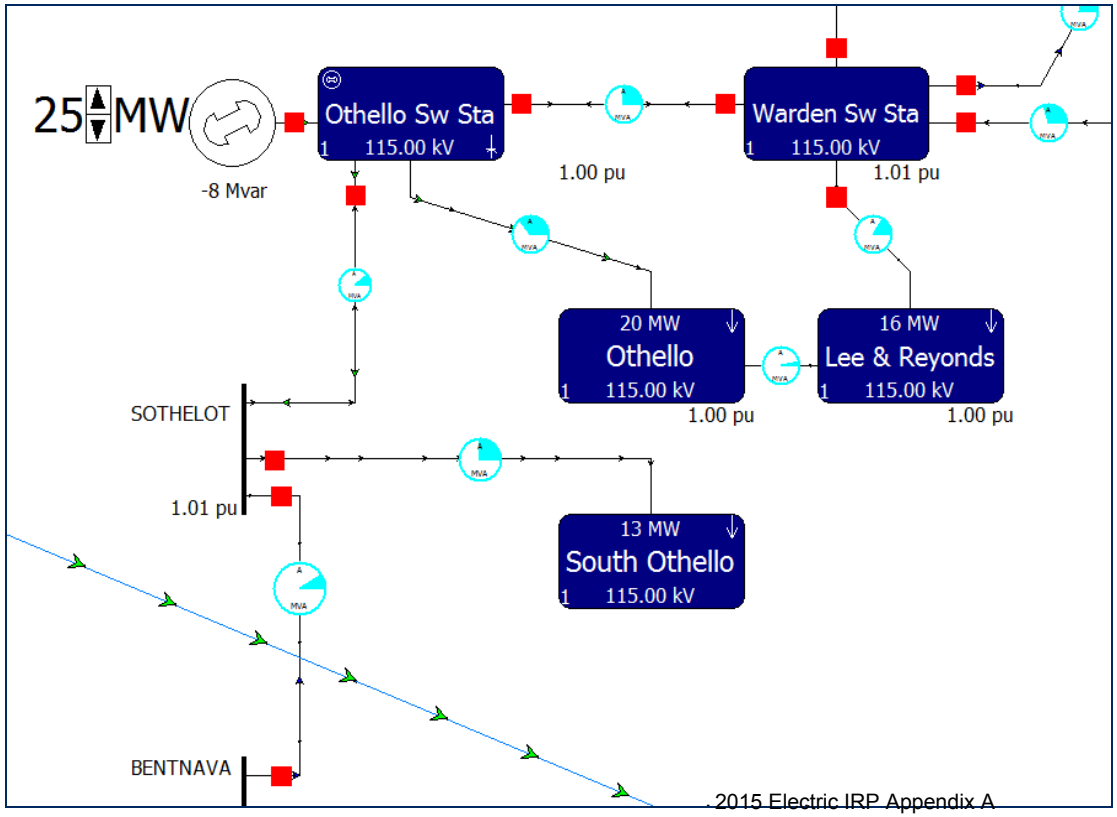
Thornton: 30 MW to 100 MW

- $400 K for new breaker



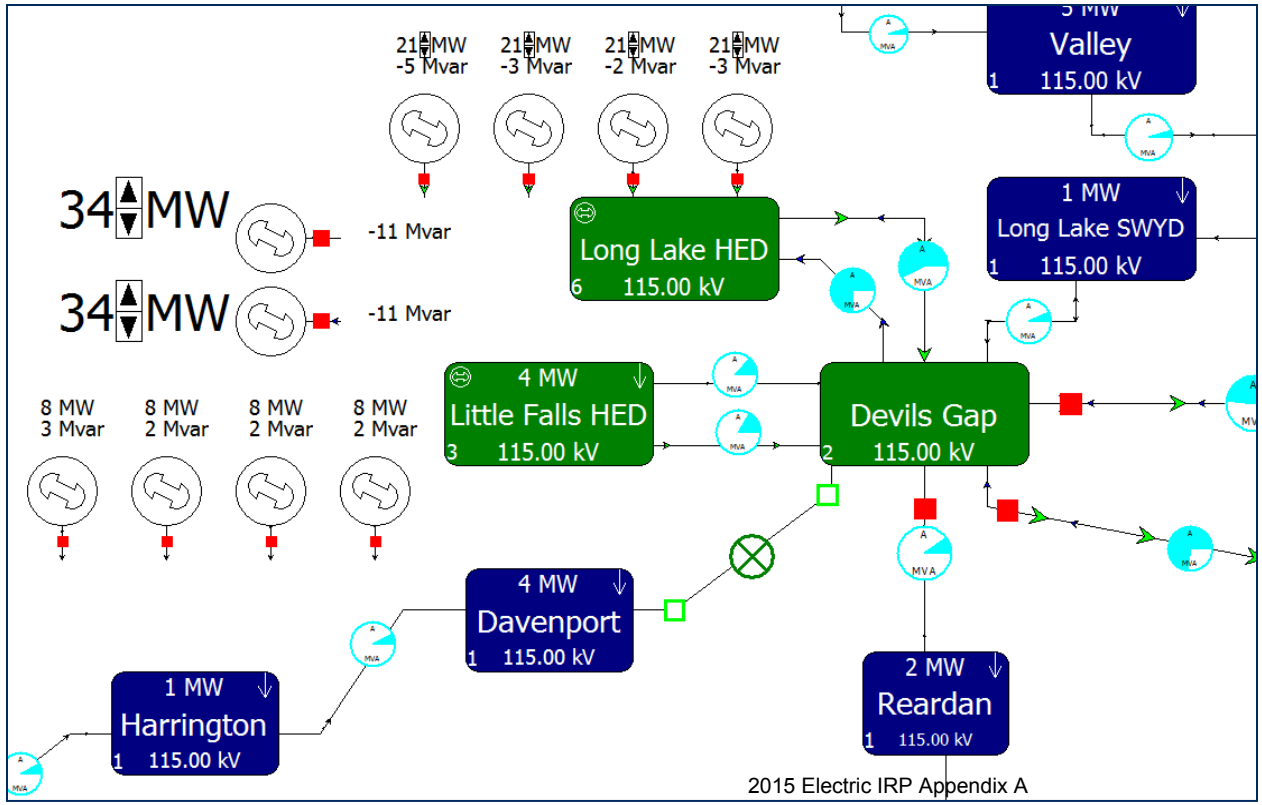
Othello: 25 MW

- $2 Million
- Station work only



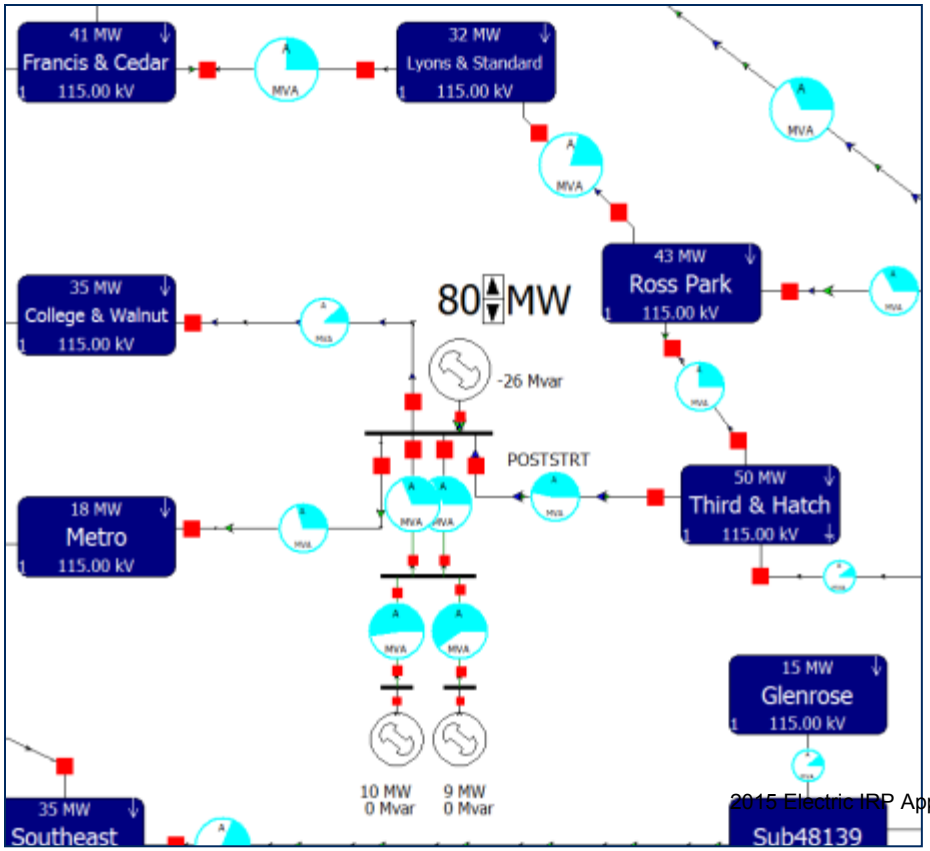
Long Lake: 68 MW

- $19.7 Million
- 108 MW existing + 9 mile



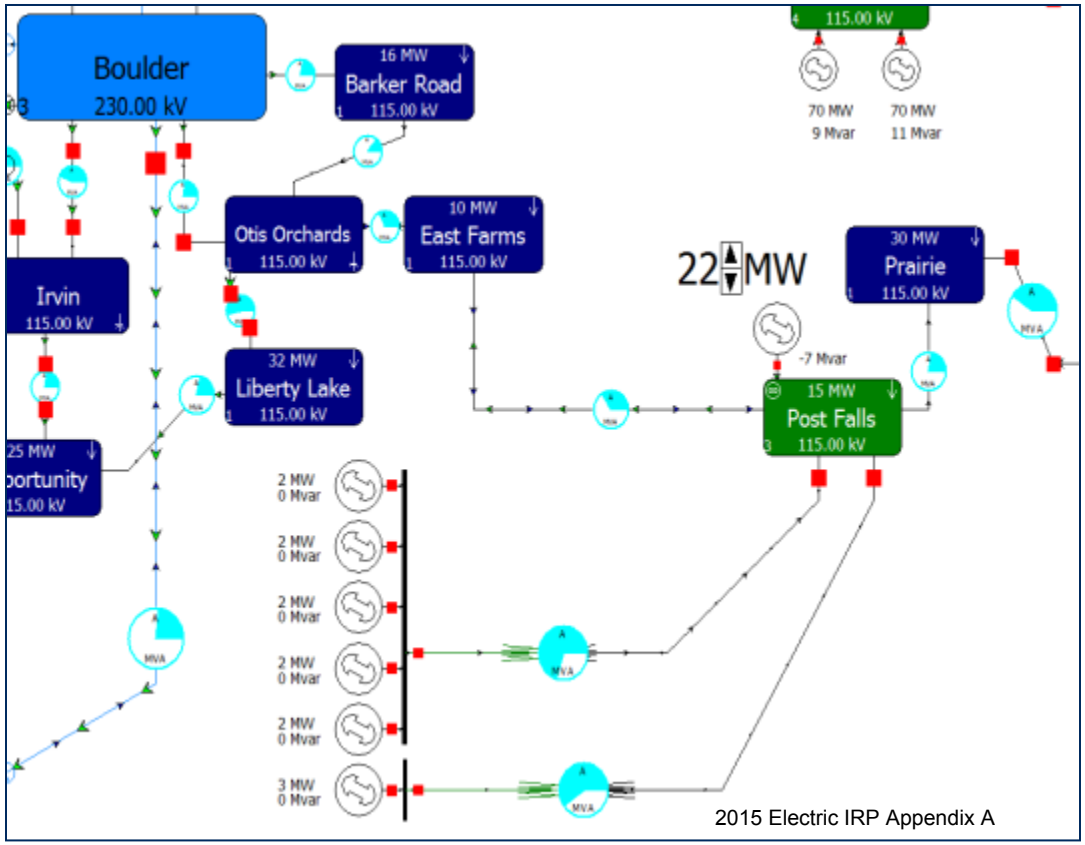
Monroe Street: 80 MW

- $7 Million
- College & Walnut Station



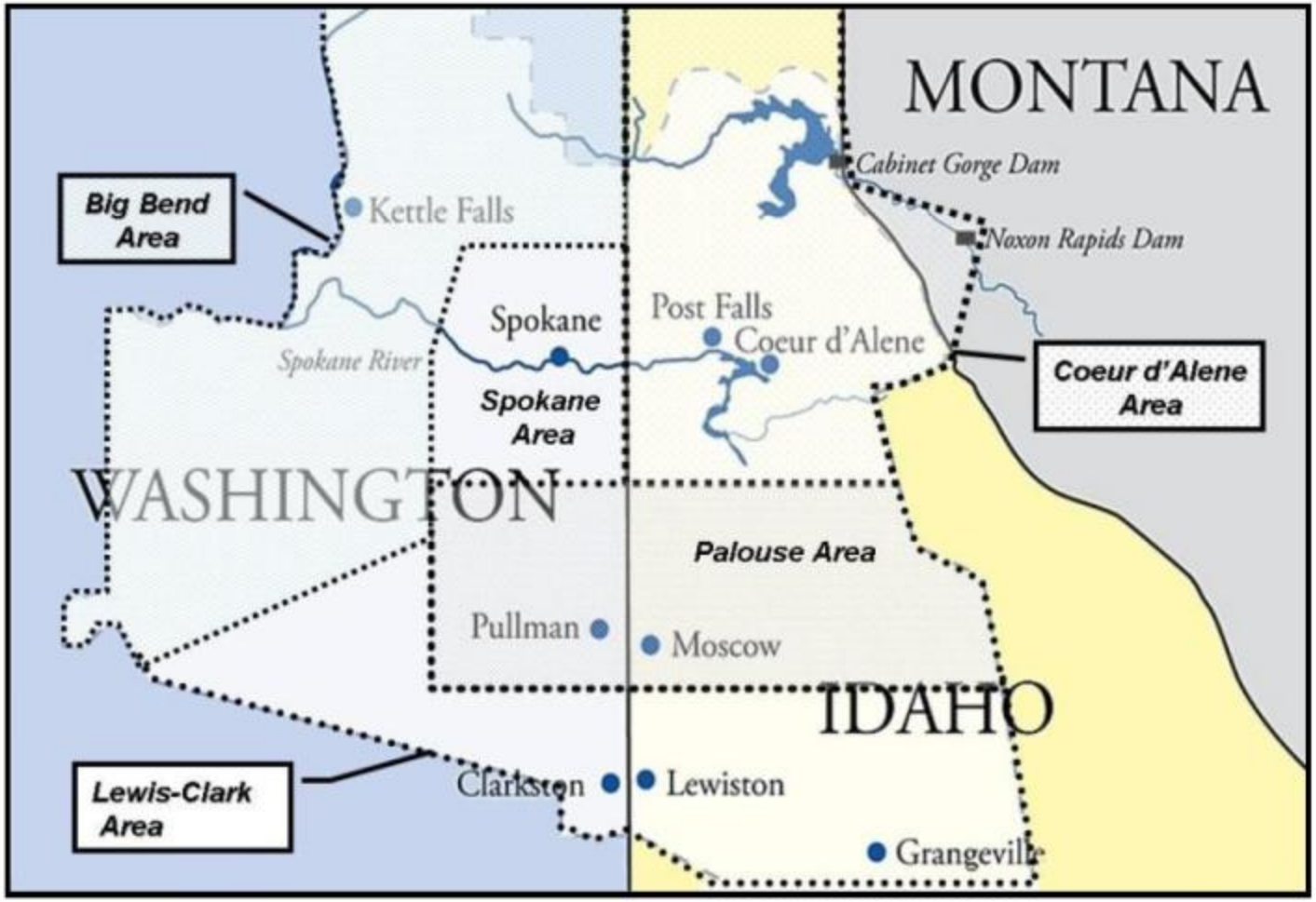
Post Falls: 10 MW to 20 MW

- $2.1 to $5.2 Million
- Congested area already



2015 Electric IRP Appendix A

Future Planning Initiatives



Future Initiatives

- Big Bend
  - New 230 kV transformation needed
- Coeur d' Alene
  - Noxon Station work
  - 115 kV rebuilds
- Lewiston / Clarkston
  - Voltage issues
- Palouse
  - Two transformer outage scenario
- Spokane
  - Long-term 230 kV transformation additions

2015 Electric IRP
Market Scenarios and Portfolio Analysis

John Lyons, Ph.D. – Senior Resource Policy Analyst
Fourth Technical Advisory Committee Meeting
February 24, 2015

Scenarios in the 2015 IRP

- Scenarios are modeled to provide details about the impacts of different critical planning assumptions that could impact future resource choices, such as:
  - Technological innovations
  - Regulatory changes
  - Environmental regulations or legislation
  - Load and resource changes

2015 IRP Scenario Types

1. Deterministic Market Scenarios: use expected input levels (natural gas prices, hydro, loads, wind, and thermal outages)

2. Stochastic Market Scenarios: use Monte Carlo analysis

3. Portfolio Scenarios: show alternative portfolios to highlight the cost differences from the PRS

Market Scenarios

Stochastic scenarios test the preferred resource strategy (PRS) across several fundamentally different futures:

- Expected Case
- Expected Case without Colstrip (2027-2035)
- Benchmarking Case
- 111(d) draft rule by state meets 2020 goals
- Social Cost of Carbon

Portfolio Scenarios

380

- Shut down Colstrip in 2026
- 2013 PRS
- High and low load forecasts
- All load growth with renewables and peakers for capacity:
  - All hydro, wind, solar
- All deficits met by market purchases
- Efficient frontier
- Efficient frontier with tail risk
- TAC requested high cost Colstrip case
- Retire CCCT/coal and replace with renewables
- Increased distributed solar penetration

2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Tuesday, May 19, 2015
Conference Room 130

Topic	Time	Staff
1. Introduction & TAC 4 Recap	8:30	Lyons
2. Review of Market Futures	8:40	Gall
3. Ancillary Services Valuation	9:30	Shane
4. Conservation Potential Assessment	10:00	Kester (AEG)
5. Lunch	11:30	
6. Draft 2015 PRS & Portfolio Analysis	12:30	Planning Group
7. Adjourn	3:00	

2015 Electric IRP
TAC Meeting Expectations and Schedule

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
May 19, 2015

Technical Advisory Committee

- The public process of the IRP – input on what to study, how to study, and review assumptions and results
- Technical forum with a range of participants with different areas of input and expertise
- Open forum, but we need to stay on topic to get through the agenda and allow all participants to ask questions and make comments
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies
  - The earlier study requests are made, the more accommodating we can be
  - January 15, 2015 was the final date to receive study requests
- Action Items – areas for more research in the next IRP

Technical Advisory Committee

- Technical forum on inputs and assumptions, not an advocacy forum
- Focus is on developing a resource strategy based on sound assumptions and inputs, instead of a forum on a particular resource or resource type
- We request that everyone maintain a high level of respect and professional demeanor to encourage an ongoing conversation about the IRP process
- Supports rate recovery, but not a preapproval process
- Planning team is available by email or phone for questions or comments between the TAC meetings
- **TAC 6 – June 24, 2015:** Review of final PRS, draft 2015 IRP document and Action Items.

TAC #4 Recap

- Introduction & TAC 3 Recap – Lyons
- Demand Response Study – Doege
- Natural Gas Price Forecast – Scott
- Electric Price Forecast – Gall
- Resource Requirements – Kalich
- Interconnection Studies – Maguire
- Market Scenarios and Portfolio Analysis – Lyons

Today's Agenda

- Introduction & TAC 4 Recap (8:30) – Lyons
- Review of Market Futures (8:40) – Gall
- Ancillary Services Valuation (9:30) – Shane
- Conservation Potential Assessment (10:00) – Kester (AEG)
- Lunch (11:30)
- Draft 2015 PRS and Portfolio Analysis (12:30) – Planning Group
- Adjourn 3:00

DRAFT

Market Futures

James Gall
Fifth Technical Advisory Committee Meeting
May 19, 2015

DRAFT

Introduction

- Follow up presentation to the “Expected Case” market price forecast from the previous TAC meeting- this presentation shows alternatives prices given each future scenario
- Used to value the cost of energy and resource options for potential resource strategies
- Illustrate macro level impacts of environmental policies

DRAFT

Market Futures Overview

- Expected Case
  - Stochastic, meets regional 111(d) goals, 10% probability of $13.23 CO_2 "tax" (1st yr), Stanfield $4.65/dth levelized, 80 year hydro
- Benchmark Case
  - Similar to expected case, stochastic, no CO_2 "tax", no 111d goal
- Social Cost of Carbon
  - Stochastic case, similar to expected case, except includes ~$21/short ton CO_2 "tax" levelized
- Colstrip Retires
  - Stochastic case, similar to expected case, except Colstrip 1-4 retires by the end of 2026 and replaced with natural gas combined cycle plants
- State-by-State 111(d)
  - Deterministic case, each state meets 111(d) goals
  - MWh credit remains in state generated in
  - Includes a low water year scenario

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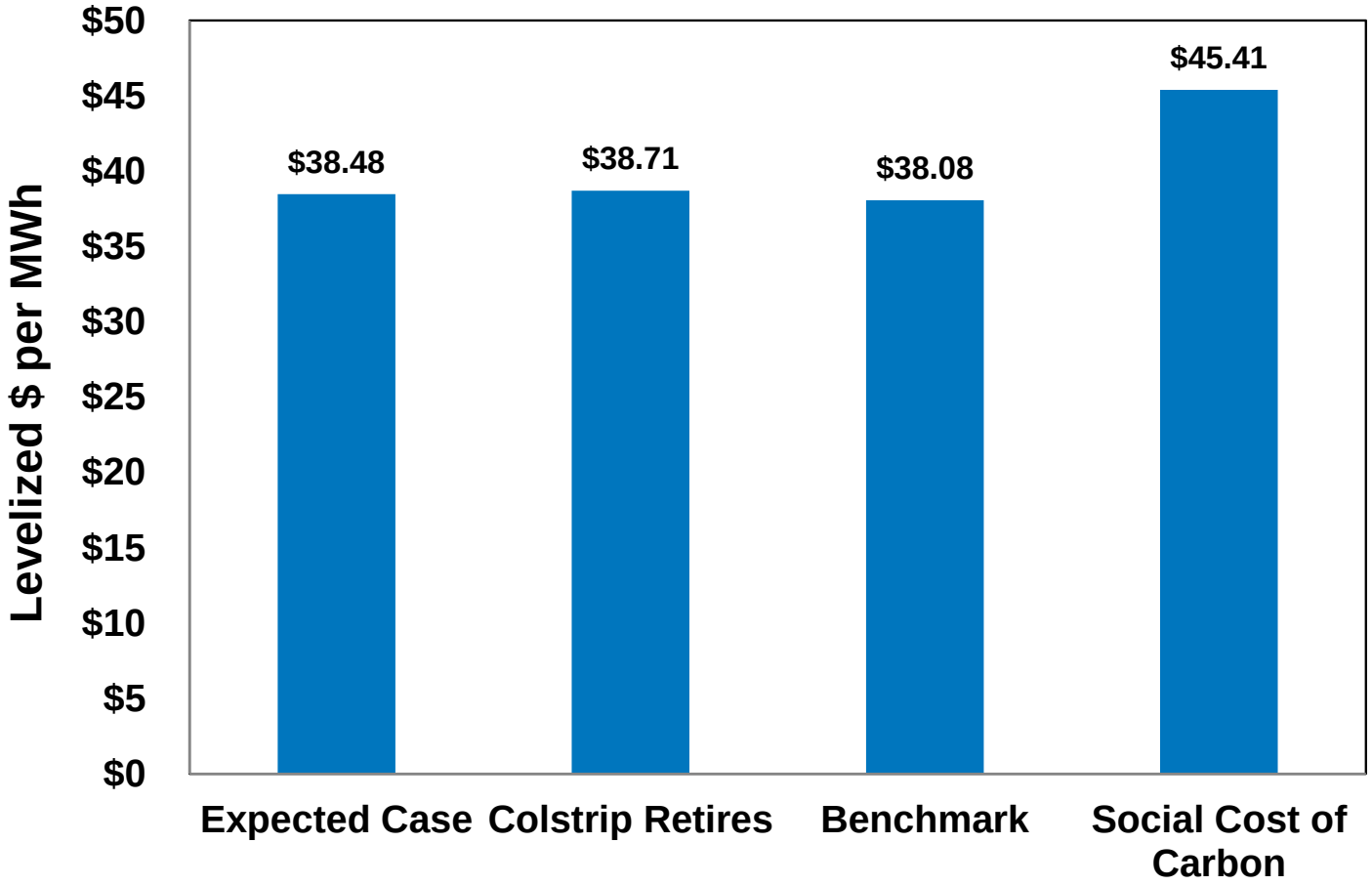
20-year Levelized Flat Mid-C Electric Price Comparison (Stochastic)



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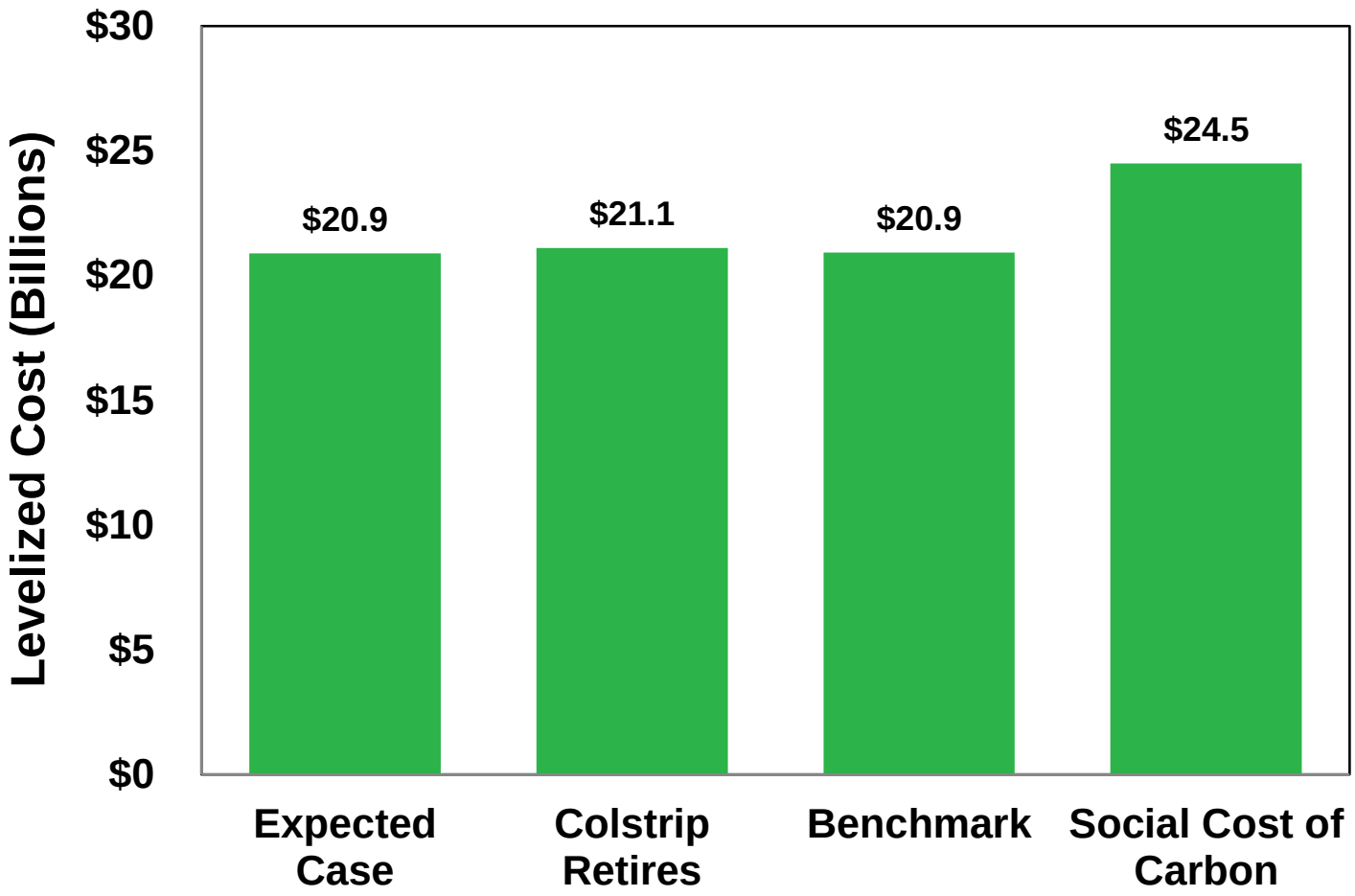
Cost to Serve
US West: Production + Fixed Costs



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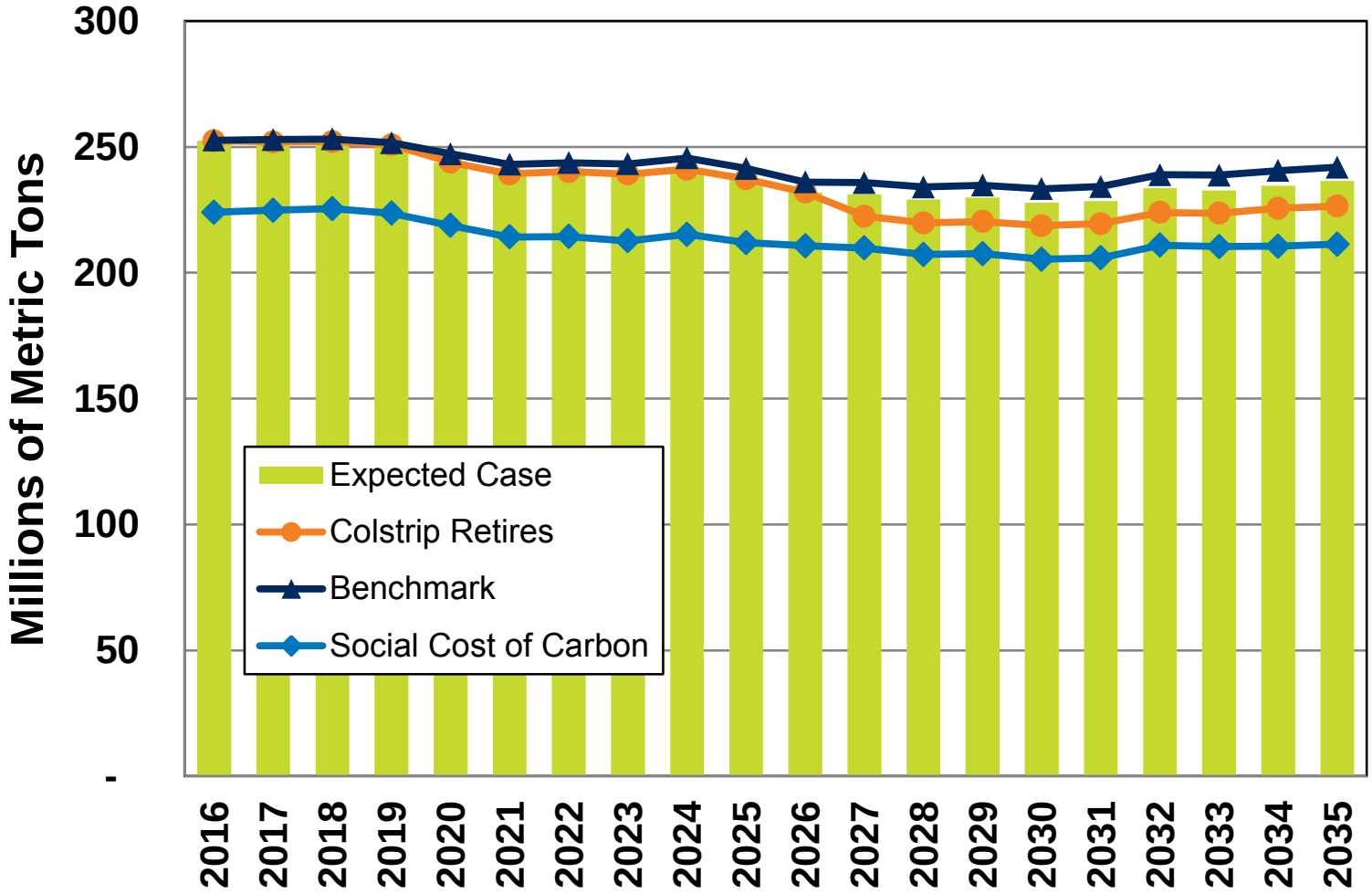
US West: Greenhouse Gas Emissions Comparison



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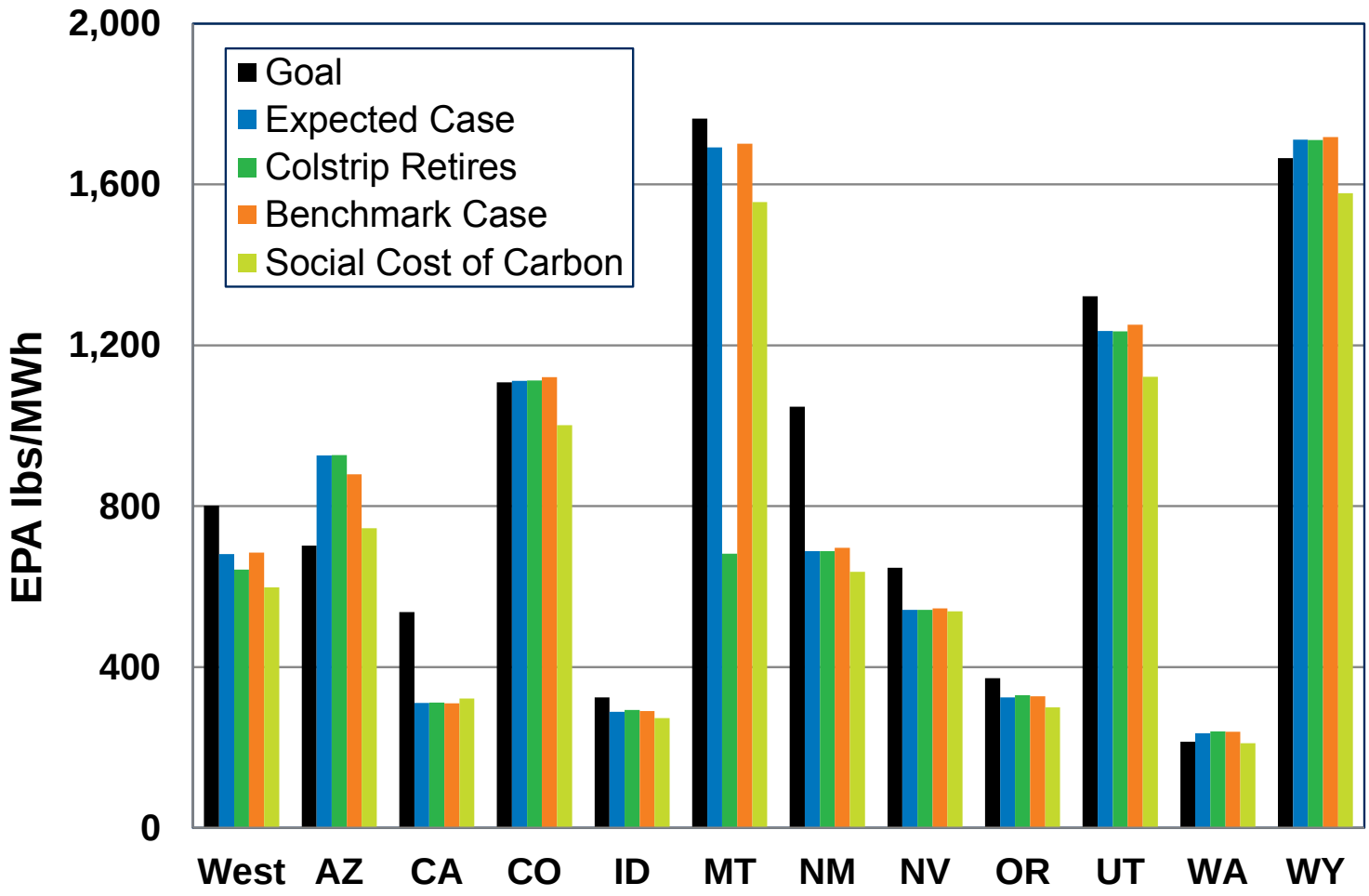
Meeting 111(d) Targets in 2030



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How to Meet the Proposed 111(d) in 2020 & 2030 State by State

- Resource Retirements:
  - Northwest: Centralia and Boardman must close by end of 2019
  - Other States: Most of SW coal must retire earlier
- Conservation:
  - Continue acquisition levels from Expected Case
- Renewables:
  - Arizona & Utah must increase penetration
  - Other states stay on current steady track
- NW Carbon Pricing
  - WA & OR required $1.25/ton charge nominal 2020-2035
  - ID required $3.00/ton 2020-2029 and $1.50/ton 2030-2035

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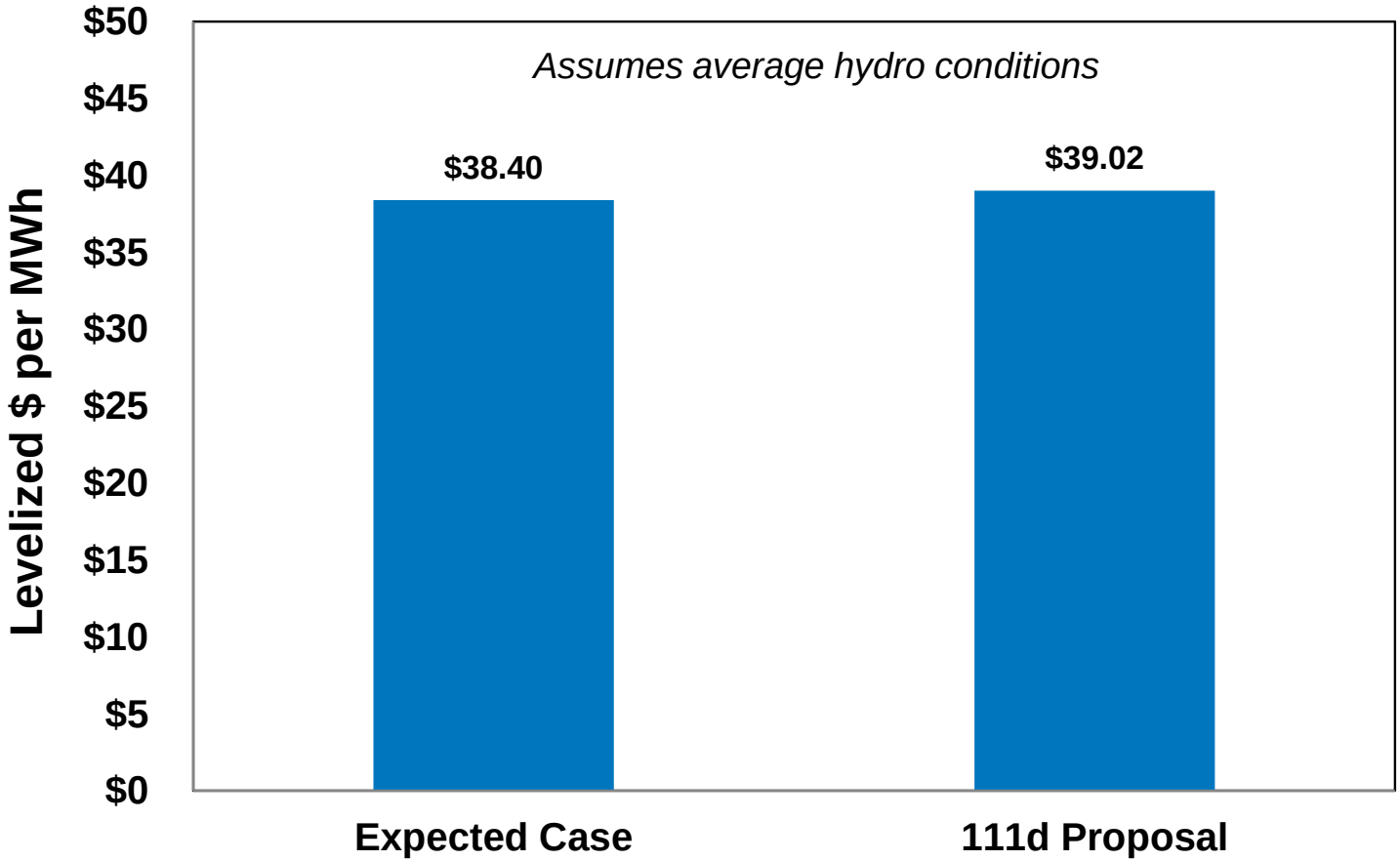
Mid-C Market Price Impact of the 111(d) Proposal Scenario (Deterministic)



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111(d) Impact in a Low Water Year

- Can the Northwest meet 111(d) goals in a low water year?
- Modeled 1941 water year (10th percentile year)
- Solve for Carbon Price to meet goal in each year
  - WA: $18/ton (2020), $18/ton (2030)
  - OR: $19/ton (2020), $15/ton (2030)
  - ID: $23/ton (2020), $14/ton (2030)
  - Neighboring states have small price increases

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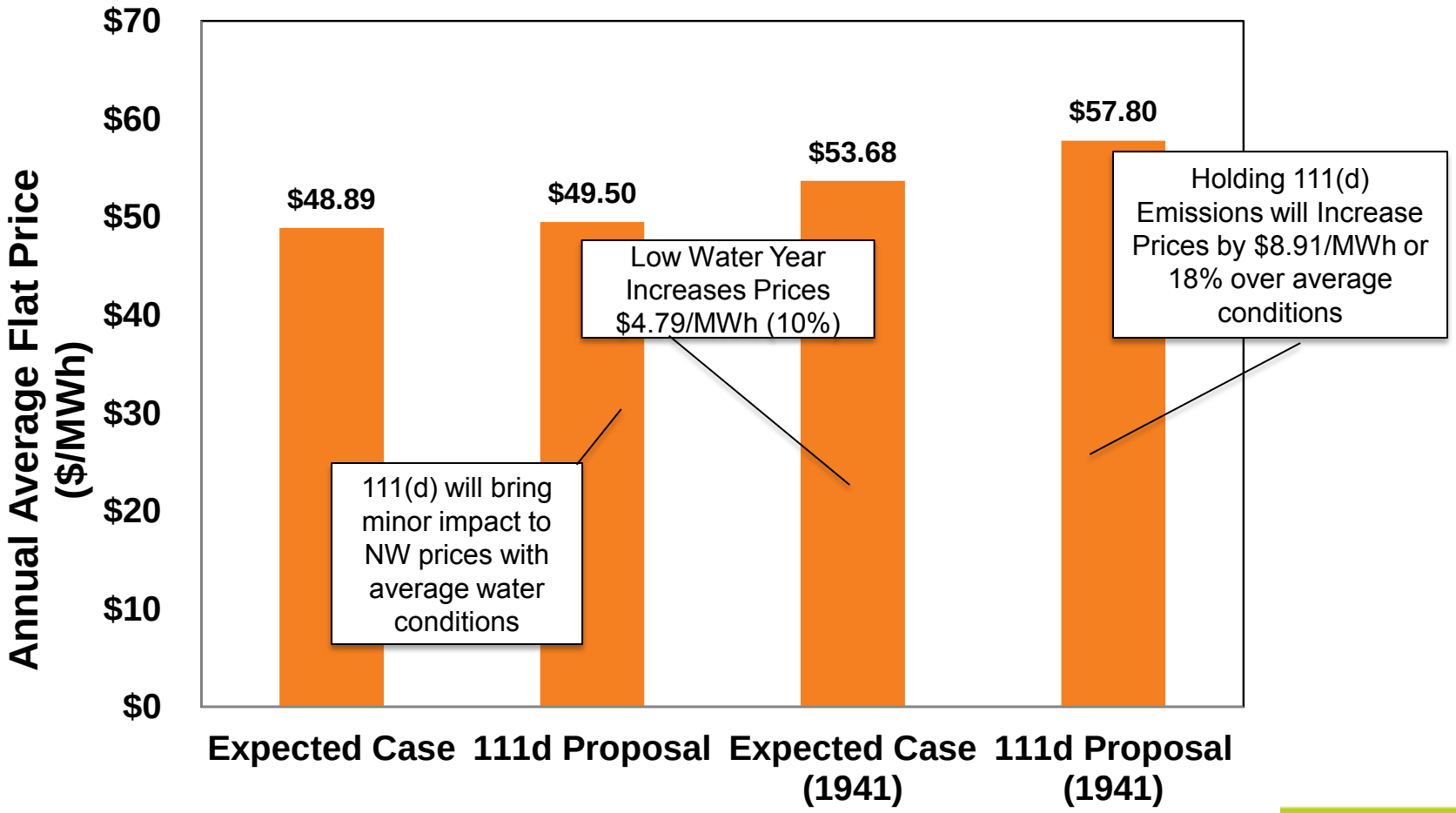
Mid-C Market Prices: 111(d) Low Water Year 2030 With Water Year = 1941



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Financial Impact to Western States

- Proposed 111(d) goal's annual levelized cost to the US West is **$340 million** over the Expected Case in an Average Water Year.
- In Low Water Year the US West will pay up to **$1.6 billion (2020)** beyond the Expected Case's Low Water Year cost, declining to **$175 million** in 2030. *(levelized $755 million)*

Ancillary Services Valuation

Xin Shane
Fifth Technical Advisory Committee Meeting
May 19, 2015

Ancillary Services Valuation Basics

What?

- The U.S. Federal Energy Regulatory Commission (FERC) defines ancillary services as: "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."
- FERC identifies six different ancillary services:
  - scheduling and dispatch
  - reactive power and voltage control
  - loss compensation
  - load following
  - system protection
  - energy imbalance

Why?

- Ancillary services are a significant value component of a generating unit
- The Washington UTC asked Avista to "use the Company's new modeling capabilities to evaluate the benefits of storage resources to Avista's generation portfolio."

Overview of ADSS Model

Mixed-Integer Linear Programming Definition

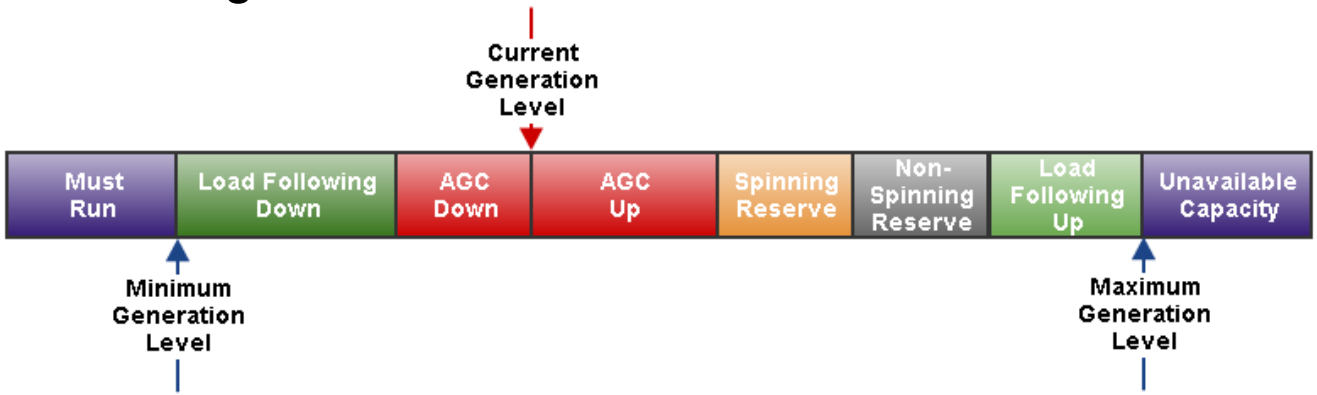
A mixed-integer linear program is a problem with

- Linear objective function, $f'x$, where f is a column vector of constants, and x is the column vector of unknowns
- Bounds and linear constraints, but no nonlinear constraints (for definitions, see Writing Constraints)
- Restrictions on some components of x to have integer values

In mathematical terms, given vectors f, lb, and ub, matrices A and Aeq, corresponding vectors b and beq, and a set of indices `intcon`, find a vector x to solve

$$\min_x f^T x \text{ subject to } \begin{cases} x(\text{intcon}) \text{ are integers} \\ A \cdot x \le b \\ Aeq \cdot x = beq \\ lb \le x \le ub. \end{cases}$$

- Mixed-Integer linear program
- Full emulation of utility power supply problem
  - hourly analysis out to 20+ years
  - trading floor behavior
  - energy and ancillary services
  - unit- and engineering-level system definitions
  - modeling of transmission and market hubs



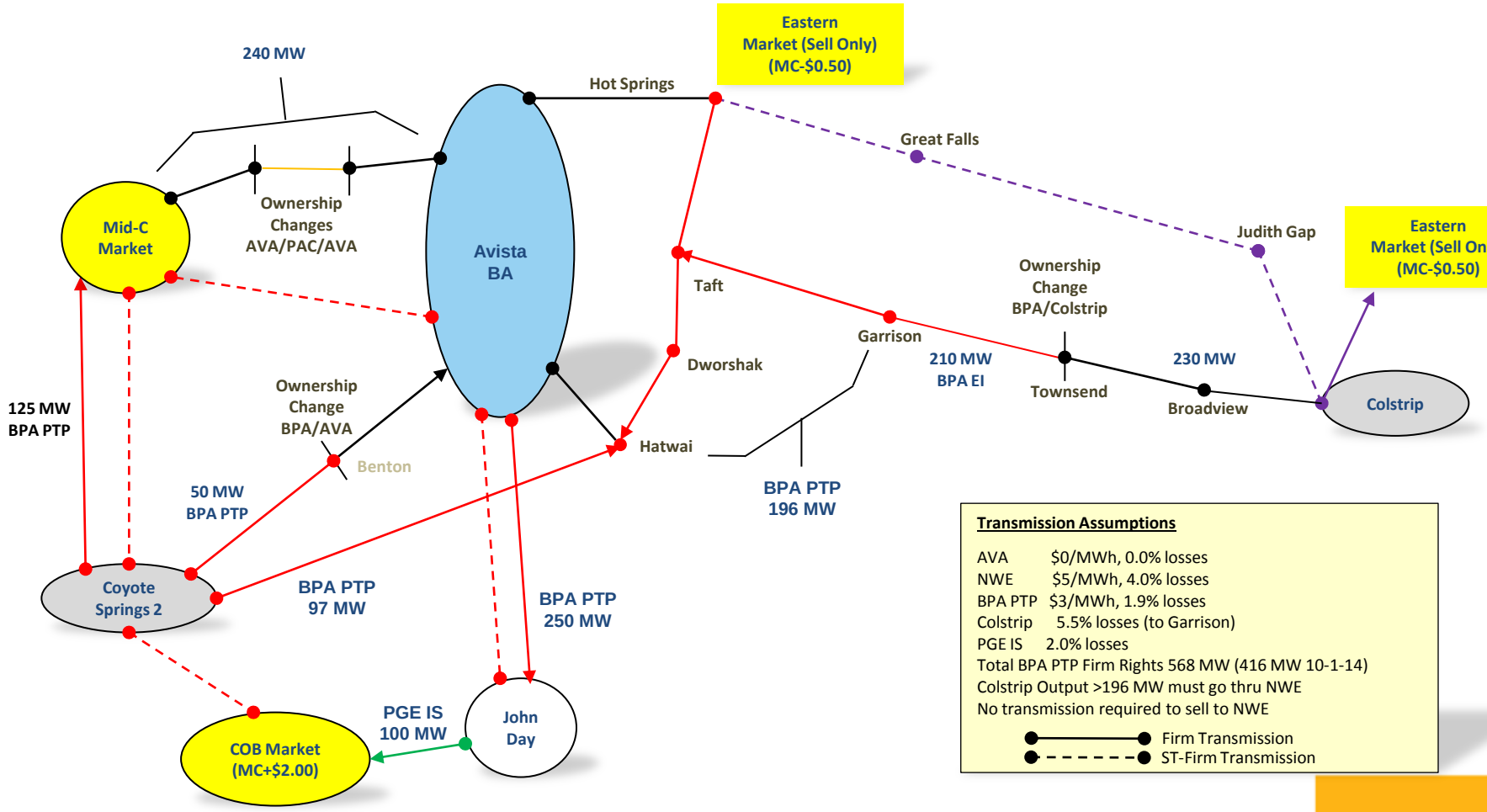
Hydro Modeling in ADSS

- Cascading hydro
- "Engineering level" representation
- Full power curve modeling
- Flow limitations
  - ramping rates
  - minimums/maximums
  - in-stream flow limits
  - dissolved gas
- Plant head
  - impacts of flow on head ("live" tailrace)
  - in-plant head losses
  - impacts of head on efficiency curves
- Operating considerations
  - min/max up/down times
  - must run
  - dispatch and merit order
  - motoring/condensing
  - AGC control
  - start-up/shut-down costs
  - min/max turbine/generator limits
  - rough zones, thermal limits
  - flash boards, Obermeyer gates
  - unit steady states
  - elevation targets
  - water right limits

Thermal Modeling in ADSS

- "Engineering level" representation
- Weather impacts
  - barometric pressures
  - dew point
  - temperature
  - humidity
- Detailed heat rate curves
- Start-up & shut down costs
  - fuel, O&M, ramp rates
- Multiple fuels
- Detailed emissions modeling
  - NO_X, SO_X, VO_X, Hg, CO_2
  - generation-level production
  - permit limit optimization (allocation)
- Multiple operating stages
  - duct firing
- Operating considerations
  - ramp rates
  - min/max up/down times
  - must run
  - dispatch and merit order (on and off)
  - AGC control
  - min/max turbine/generator limits
  - thermal limits
  - equal wear cycling
  - unit steady-states
  - water right limits

Transmission/Market Modeling in ADSS



Transmission Assumptions

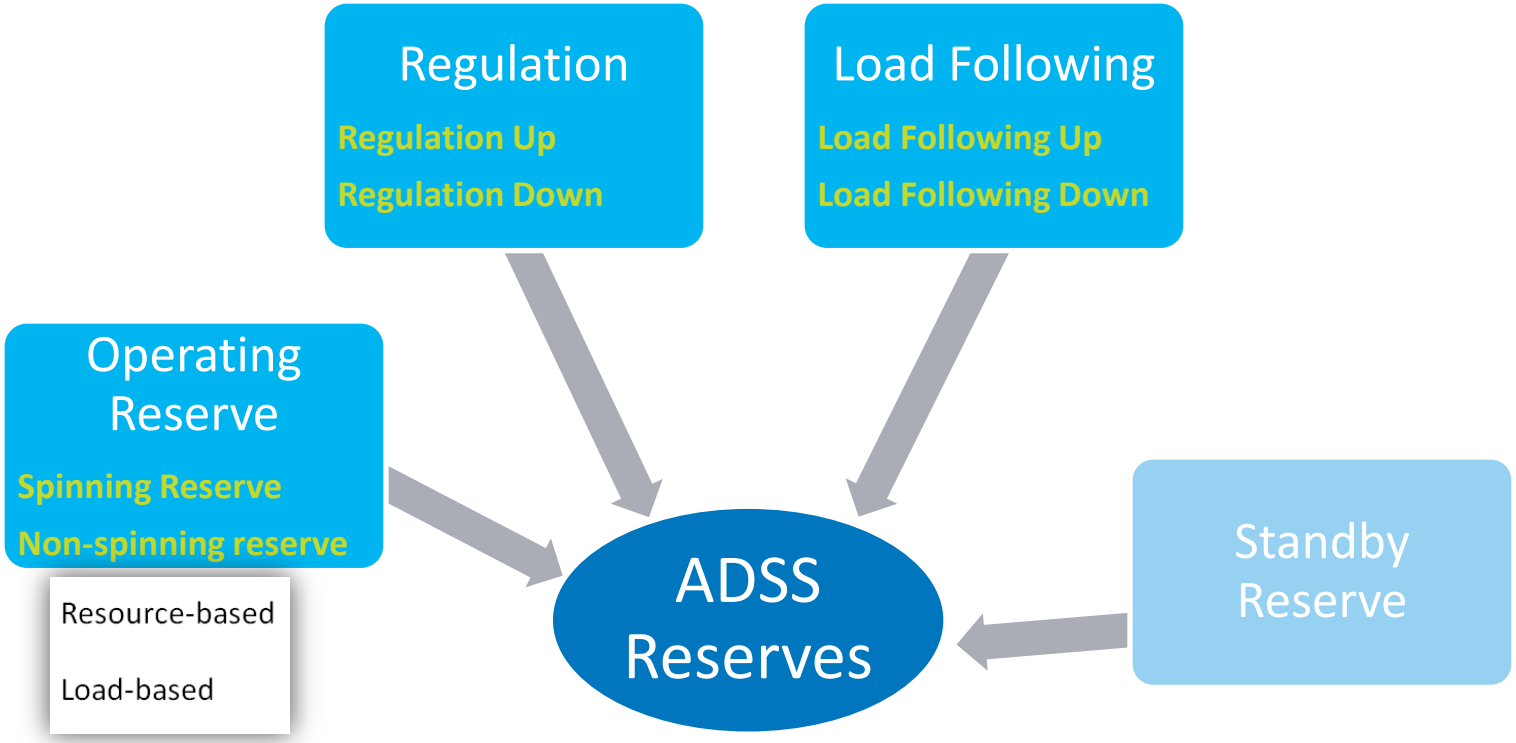
AVA $0/MWh, 0.0% losses
NWE $5/MWh, 4.0% losses
BPA PTP $3/MWh, 1.9% losses
Colstrip 5.5% losses (to Garrison)
PGE IS 2.0% losses
Total BPA PTP Firm Rights 568 MW (416 MW 10-1-14)
Colstrip Output >196 MW must go thru NWE
No transmission required to sell to NWE

Firm Transmission
ST-Firm Transmission

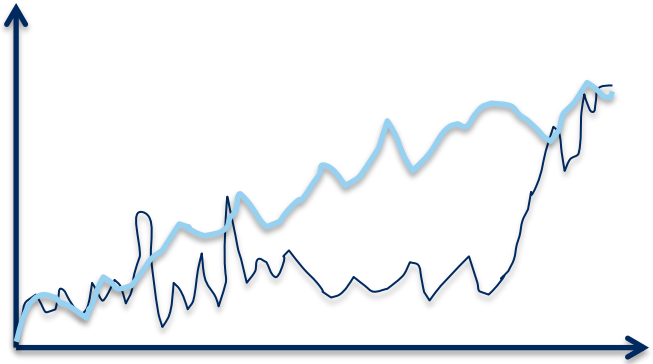
Reserve Modeling in ADSS

Load Following Up = Max Load – Average Load

Load Following Down = Average Load – Min Load



Storage Valuation



Key Input Assumptions

- Storage Specification
  - Max Storage = 3 × Capacity
    - e.g., 1 MW = 3 MWh
  - 85% Efficiency
  - Hourly Charge/Discharge Rate = 100% of Capacity
  - Capable of All Ancillary Services
    - Regulation +/- 100%
    - Load following +/- 100%
    - Spin/non-spin +/- 100%
- Model Input
  - Year 2012 Historical Data
  - Year 2015 Gas and Power Prices
  - Average Hydro

Study Scenario

- By Size
  - 35 MW, 30 MW, 25 MW, 10 MW, 5 MW and 1 MW
- By Ancillary Service Product Type
  - Charge/Discharge only
  - With Load Following/Contingency Reserve/Regulation
- By Energy Consumption Rate
  - 10%, 25% and 50% of Load Following and Regulation

Storage Valuation Results

Battery Value Summary by Size

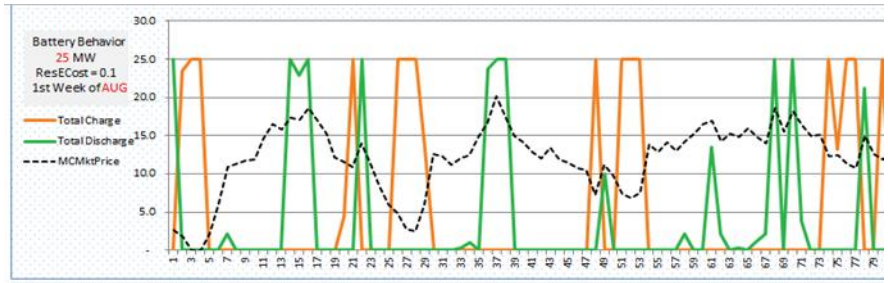
Battery Cap (MW)	Annual Value	Annual Value/KW
35	$ 1,201,590	$ 34.33
30	$ 1,024,569	$ 34.15
25	$ 923,291	$ 36.93
10	$ 381,407	$ 38.14
5	$ 189,000	$ 37.80
1	$ 36,862	$ 36.86

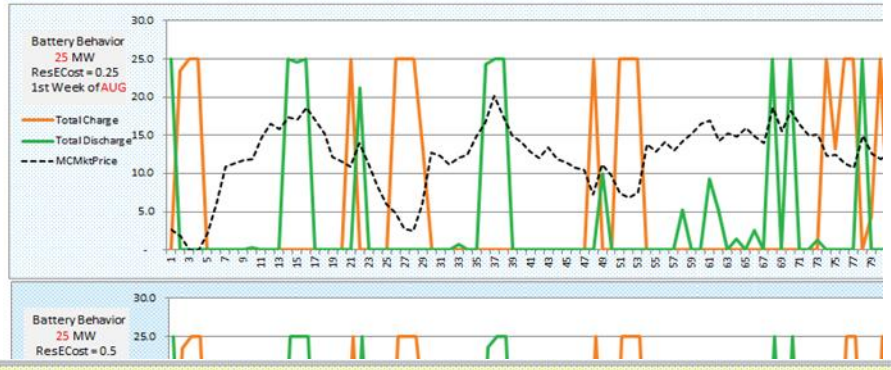
Battery Value Summary by Capability for 25MW

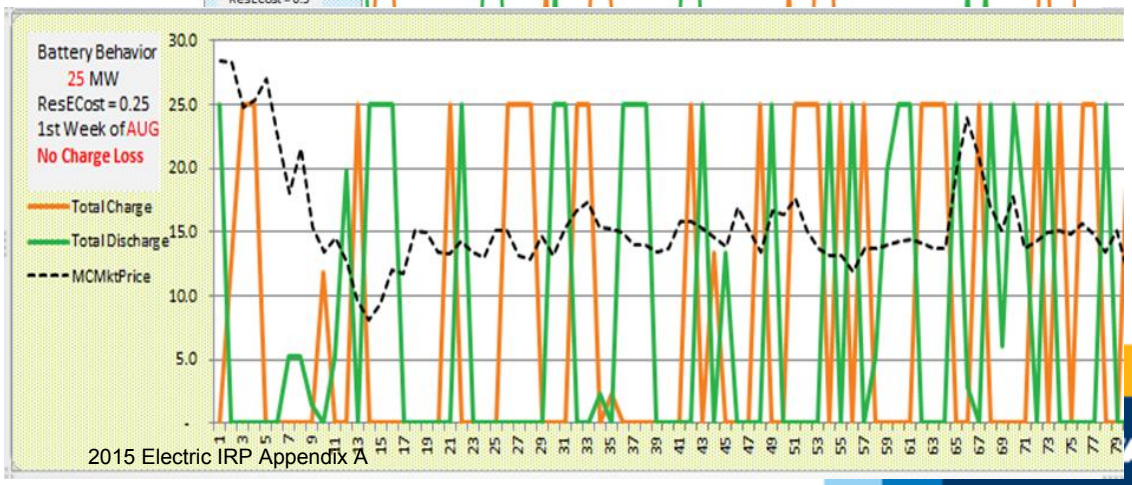
Capability	Annual Value - 25 MW	Incremental	
Charge/Discharge Only	$ 629,082		64.2%
Load Following	$ 905,114	$ 276,032	28.2%
SpinR/NSpinR	$ 678,906	$ 49,824	5.1%
Regulation(AGC)	$ 653,402	$ 24,320	2.5%

Battery Value Summary by Energy Cost Ratio of AS for 25MW

Energy Cost Ratio	Annual Value
0.10	$ 884,093
0.25	$ 923,291
0.50	$ 876,962







New Generating Resource Ancillary Services Valuation

- New Resources Included in Study
  - 100 MW CCCT
  - 100 MW LMS
  - 100 MW Recip
  - 25 MW Diesel Back-up Generator

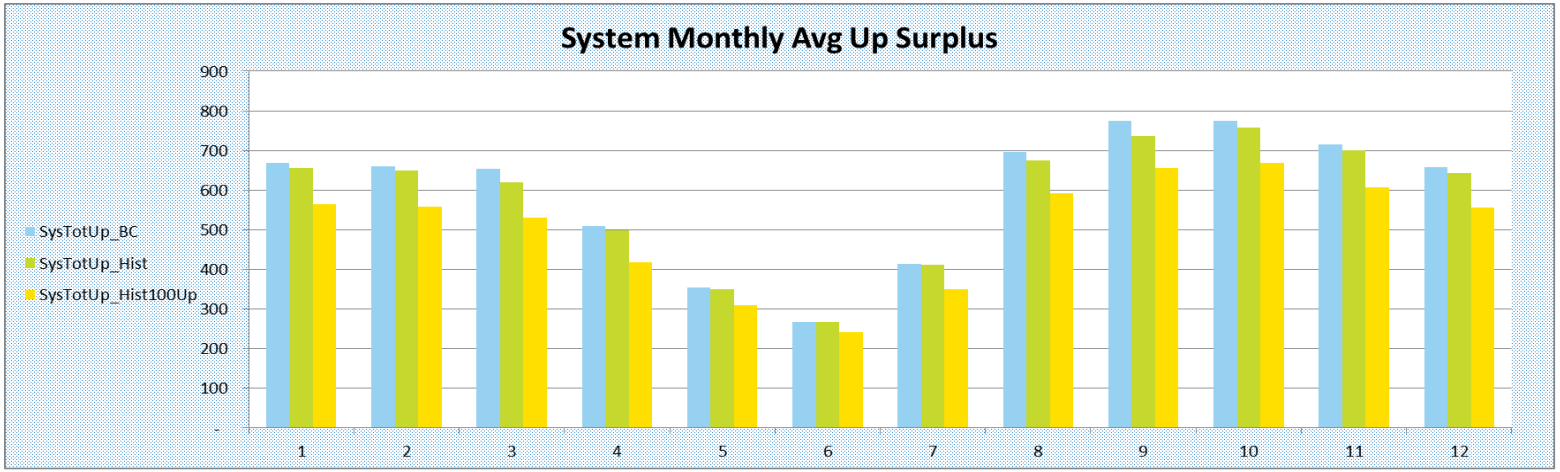
New Generating Resources	Ancillary Services Capability	Ancillary Service Value ($/kw year)
100 MW CCCT	Load Following/SpinR/Reg	$ 0.00
100 MW LMS	Load Following/SpinR/NSpinR/Reg	$ 1.12
100 MW Recip	Load Following/SpinR	$ 0.61
25 MW Diesel Back-up Generator	NSpinR	$ -

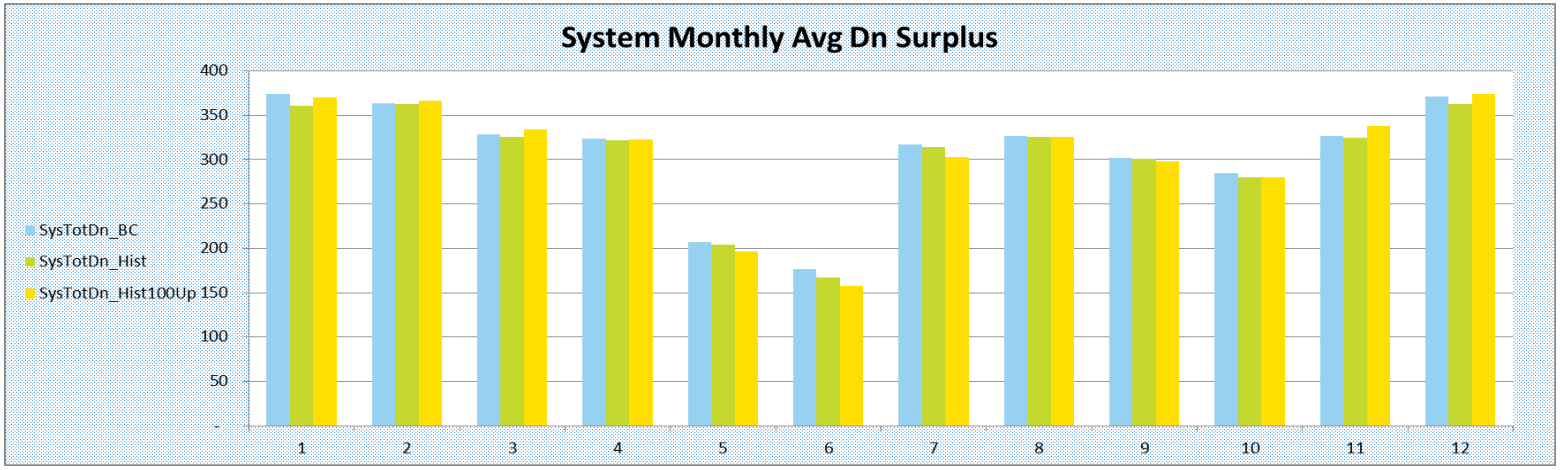
- Model Input
  - Based on Historical Data of Years 2010-14
  - Portfolio Contracts adjusted to Year 2020 Conditions
  - Load adjusted to Year 2020 Conditions

- Run Scenario: for each new resource
  - Base Case Run with Existing Portfolio of Year 2020 Conditions
  - Energy-Only Run (i.e., no ability to generate ancillary services)
  - Energy/Capacity Run (i.e., ability to generate energy *and* ancillary services)

Ancillary service value will be unique to each system

Why Are Ancillary Service Values Low





Avista Conservation Potential Assessment

Presentation to the Technical Advisory Committee

May 19, 2015

Outline

- Study Approach
  - Market Characterization
  - Baseline Projection
  - Measure Development
  - Economic Screening
  - Ramp Rate Development
- Potential Results
  - Overall – Washington and Idaho
  - Washington by sector
  - Idaho by sector
- Consistency with Council Methodology
- Supplemental slides
  - Market characterization for all three sectors for WA and ID

AEG Uses a Bottom-up Analysis Approach

LoadMAP™

Achievable potential

Establish Customer Acceptance

Program results
Council ramp rates
Other studies

Technical and economic potential

Screen EE Measures

Measure descriptions
Emerging technologies
RTF data
Avoided costs
AEG's DEEM

End-use projection by segment

Project the Baseline

Prototypes and energy analysis (***AEG's BEST***)
Avista Forecast data
Customer surveys
Secondary data

Base-year energy use by segment

Characterize the Market

Avista data
Customer surveys
Secondary data
AEG's Energy Market Profiles

Establish objectives

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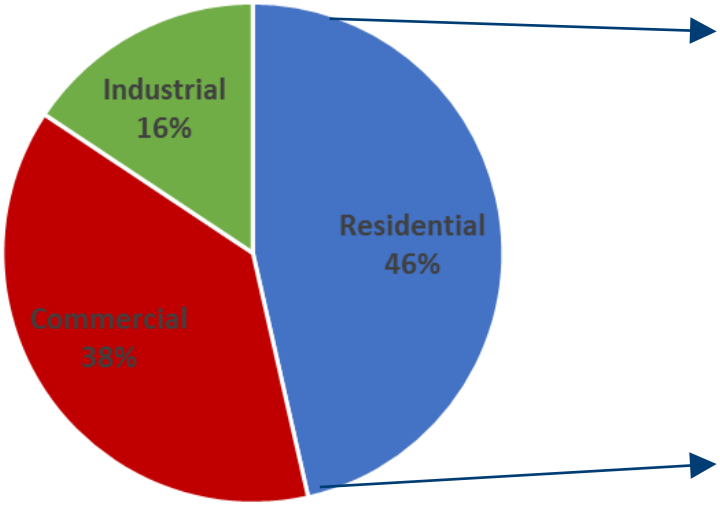
Applied Energy Group

Overview of Analysis Approach Using the Residential Sector

Step 1a: Characterize the Market

High-level characterization by sector – Washington and Idaho combined

Avista Sales in 2013
8,081 GWh



Segment	Number of Customers	Annual Sales (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	195,222	2,626	70%	13,450
Multi Family	17,229	139	4%	8,082
Mobile Home	12,526	151	4%	12,063
Low Income	96,112	837	22%	8,711
Total	**321,089**	**3,753**	**100%**	**11,690**

Step 1a: Characterize the Market

Residential characterization by state

- Full market characterization for Washington and Idaho is provided in the supplemental slides
- The following slides focus on Washington

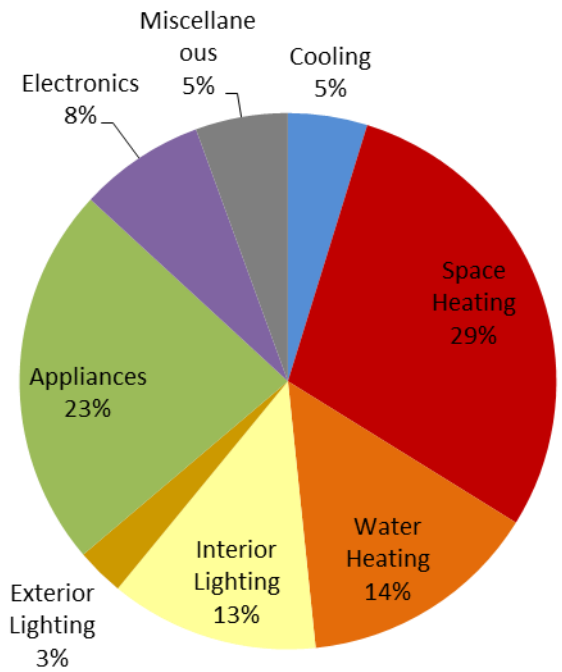
Washington				
Segment	Number of Customers	Annual Sales (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	129,893	1,783	70%	13,726
Multi Family	11,964	99	4%	8,236
Mobile Home	7,691	95	4%	12,354
Low Income	64,092	570	22%	8,892
Total	**213,640**	**2,546**	**100%**	**11,919**

Idaho				
Segment	Number of Customers	Annual Sales (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	65,329	843	70%	12,902
Multi Family	5,265	41	3%	7,733
Mobile Home	4,835	56	5%	11,599
Low Income	32,020	267	22%	8,349
Total	**107,449**	**1,207**	**100%**	**11,233**

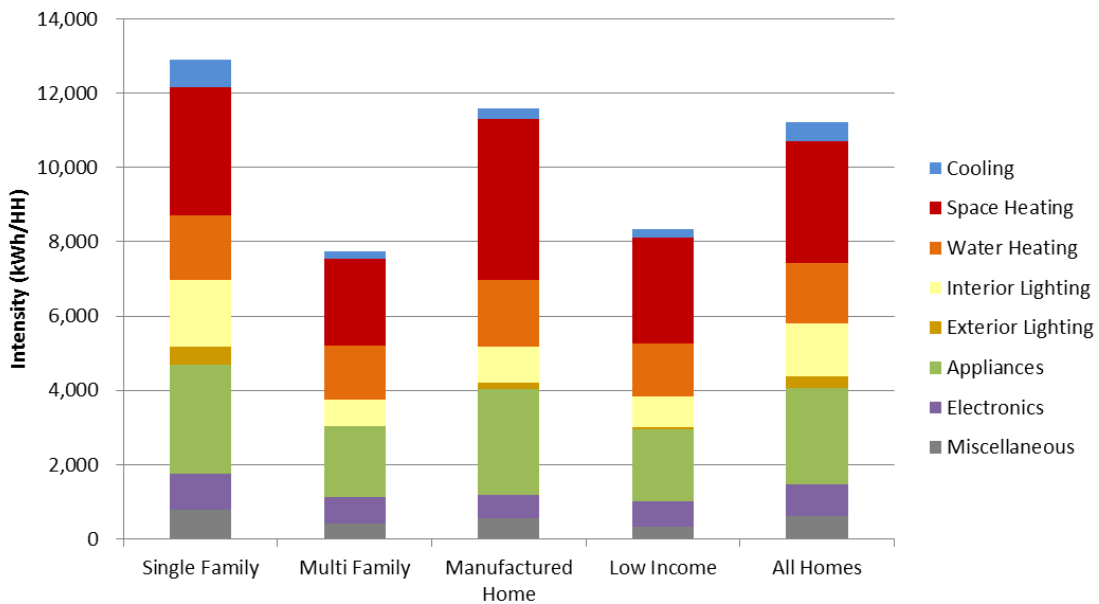
Step 1b: Develop Market Profiles by Sector and Segment

Base-year annual energy use by segment and end use

Total 2013 Residential Sales by End Use - Washington



Annual Intensity for Average Household - Washington

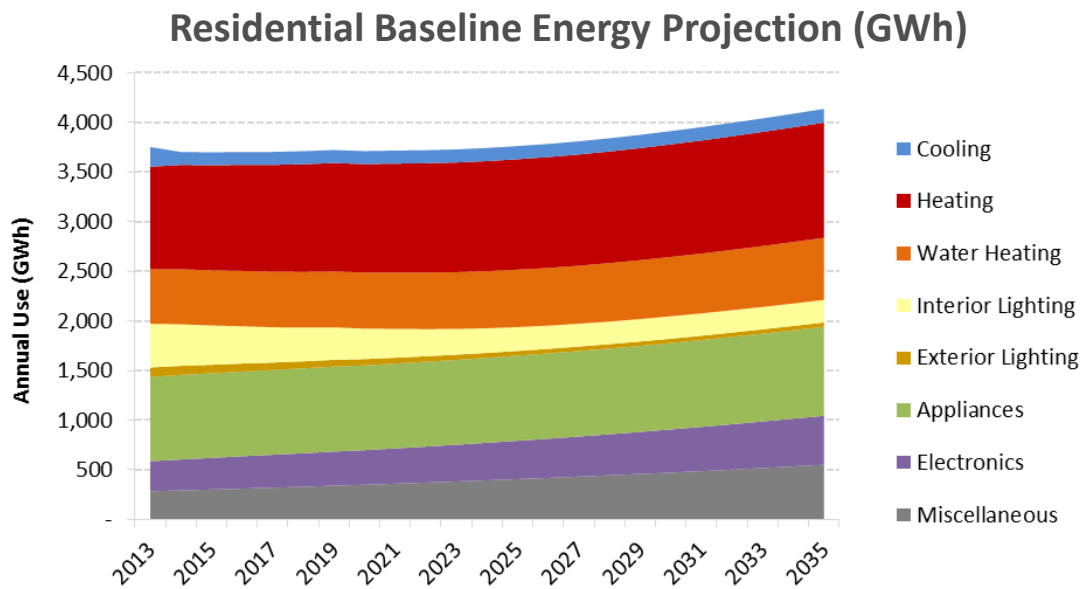


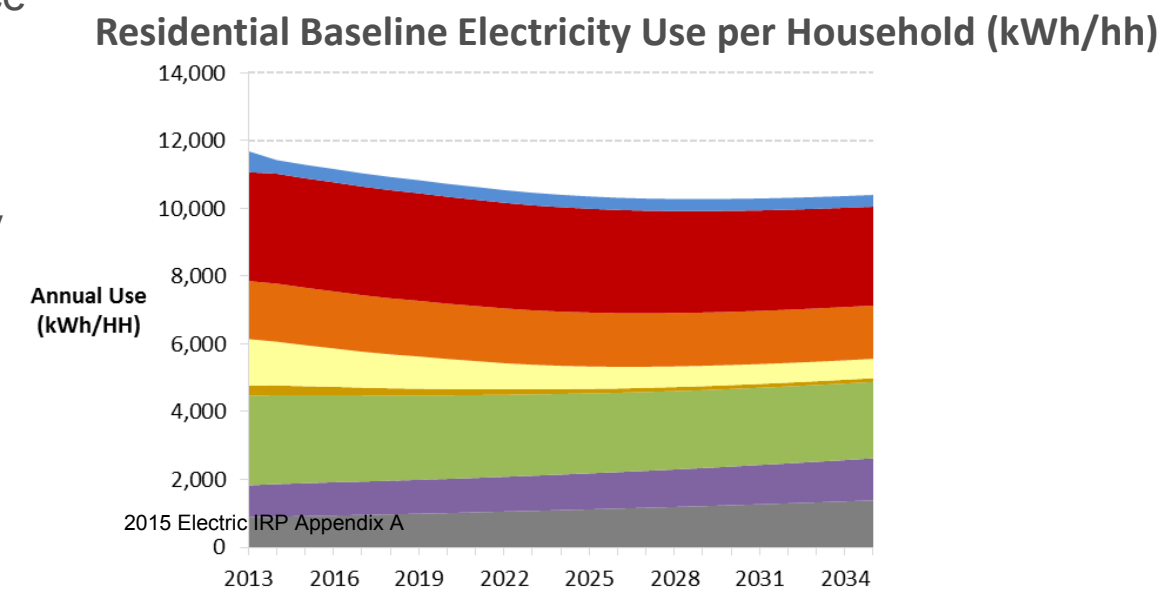
Data Sources:

- Avista billing data and residential GenPOP appliance saturation survey
- Residential Building Stock Assessment (NEEA)
- Commercial Building Stock Assessment (NEEA)
- Secondary data as needed to fill gaps

Step 2: Project the Baseline

- Baseline projection provides foundation for estimating potential future savings from conservation initiatives and reflects
  - Household growth and electricity price forecasts (from Avista)
  - Appliance standards in place at end of 2014 (AEG database)
  - No naturally occurring conservation or future utility programs
  - Alignment with Avista load forecast





Step 3: Screen EE Measures

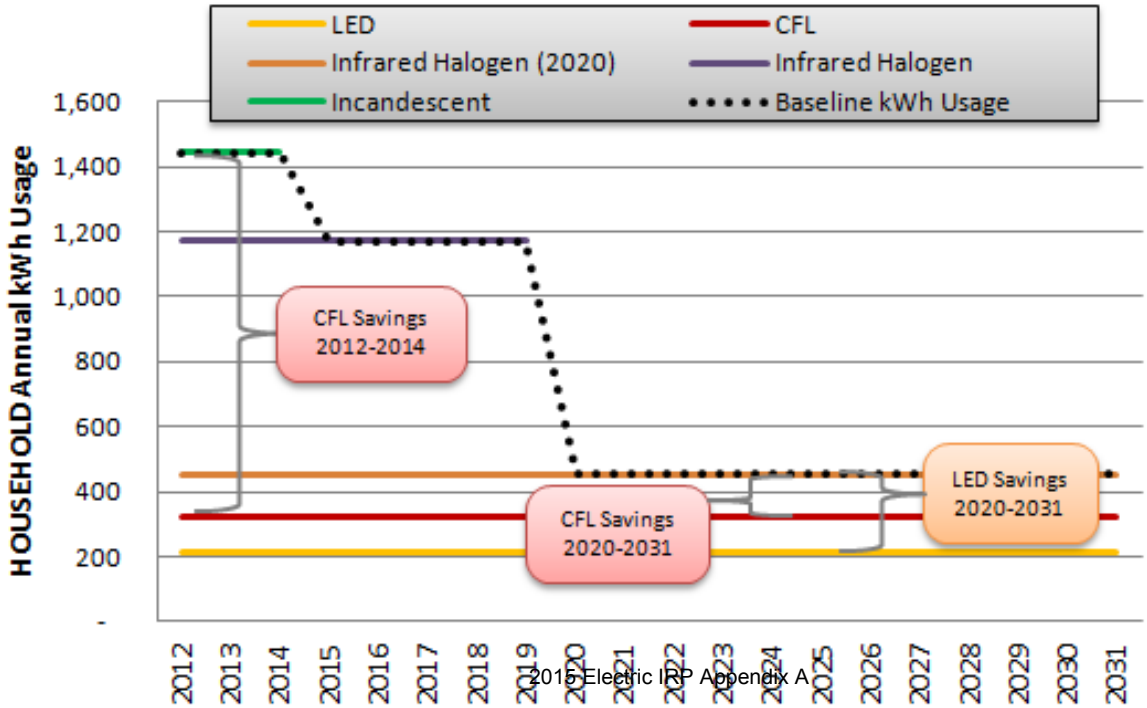
- Develop measure list using
  - Council workbooks
  - Existing programs
  - AEG databases
- Characterization
  - Description
  - Costs
  - Savings
  - Applicability
  - Lifetime
- Data sources
  - RTF
  - Avista data
  - AEG's database
  - BEST simulations
- Measure Crosswalk

Example: Water heating measures
Conventional (EF 0.95)
Heat pump water heater (EF 2.3)
Solar water heater
Low-flow showerheads
Timer / Thermostat setback
Tank blanket

Step 3: Screen EE Measures

- Measure savings change relative to baseline throughout study (as shown)
- We use a market baseline, consistent with RTF/Council
- Measure costs change with market projections and expectations

Example of Savings Calculation for Screw-in Lighting Technologies



Step 4: Estimate Potential Future Savings

Use LoadMAP model to estimate potential

Technical Potential

Theoretical upper limit of EE, where all efficiency measures are phased in regardless of cost

Economic Potential

Also a theoretical upper limit of EE, but includes only cost-effective measures

Achievable Potential

EE potential that can be realistically achieved by utilities, accounting for customer adoption rates and how quickly programs can be implemented

Estimating Potential and Developing Ramp Rates

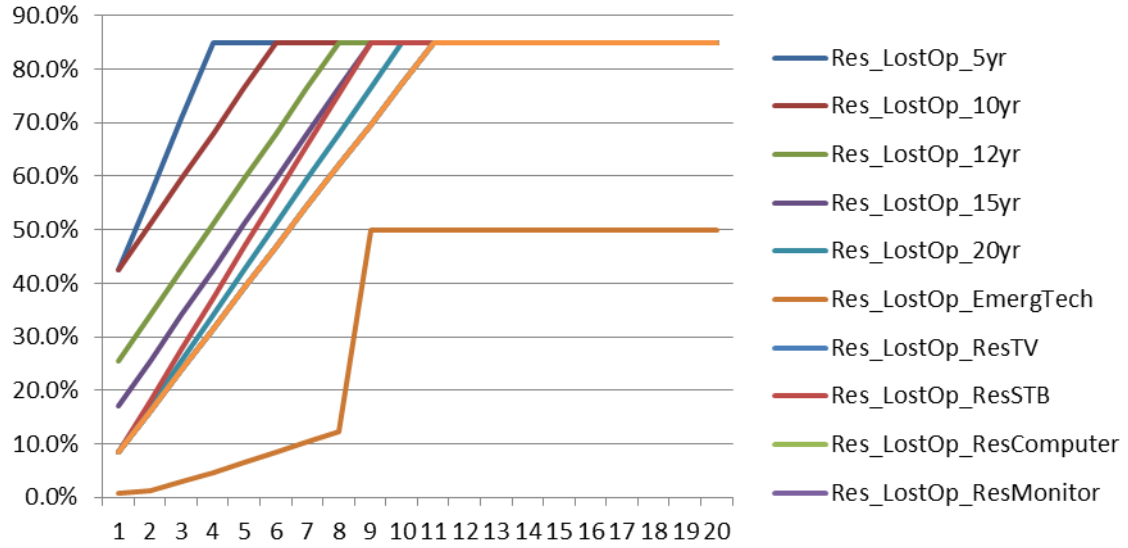
- **Technical potential** assumes most efficient option is chosen by all customers
- **Economic potential** assumes all customers choose the highest-efficiency option that passes economic screen
  - Use TRC and Avista's avoided cost to perform economic screen
- **Achievable potential** is a subset of economic potential
  - Calculated by applying ramp rates to economic potential
  - Our approach for Avista:
    - Start with ramp rates from the 6th Power Plan
    - Map the Council ramp rates to ECMs in our analysis
    - Adjust the starting point for each measure's ramp rate to align with Avista's recent program accomplishments

Customer Adoption (Ramp) Rates

Residential ramp rates from NWPCC

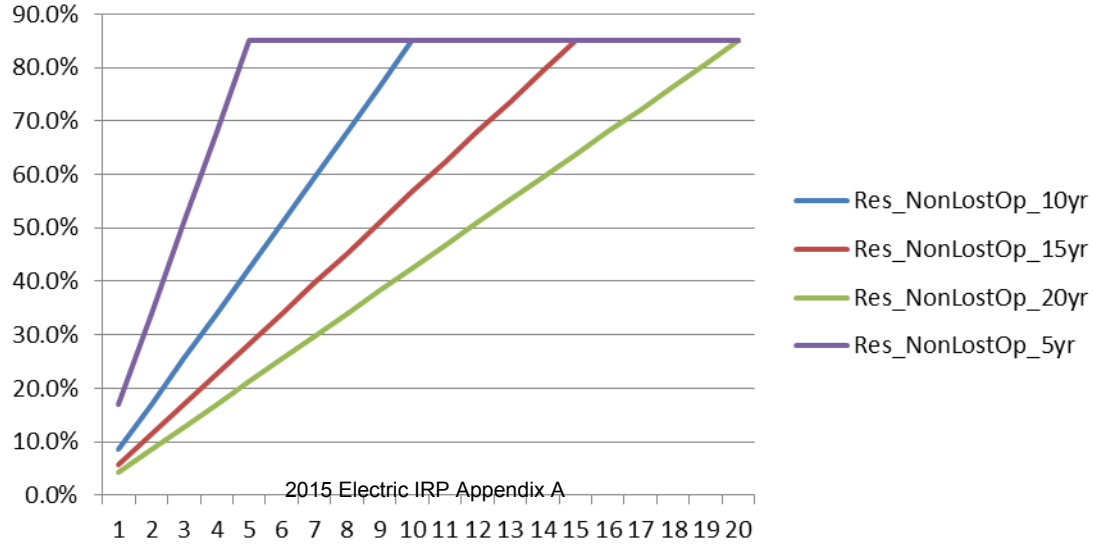
Lost Opportunity Ramp Rates:

Applied to equipment units each year that are turning over into a new purchase decision.



Non-Lost Opportunity Ramp Rates:

Applied cumulatively to all applicable opportunities in the market over time.



Summary of Changes since Previous study

- Updated base year from 2011 to 2013
- Refined the market segmentation
- Incorporated Avista's GenPOP residential saturation survey
- Supplemented with NEEA's Residential Building Stock Assessment (RBSA) and Commercial Building Stock Assessment (CBSA) data
- Characterized summer peak demand, in addition to annual energy use by segment and end use
  - Also estimated potential summer-peak savings
- Used updated forecasting assumptions for baseline projection
- Developed revised ramp rates using Council ramp rates as starting point and adjusting to reflect Avista program results in recent years
  - Developed estimates based solely on Council ramp rates for comparison purposes
- Incorporated new avoided costs
- And otherwise updated all measure, technology and modeling assumptions
  - There was substantial change in lighting: LED prices came down and lamps are readily available and acceptable to customers

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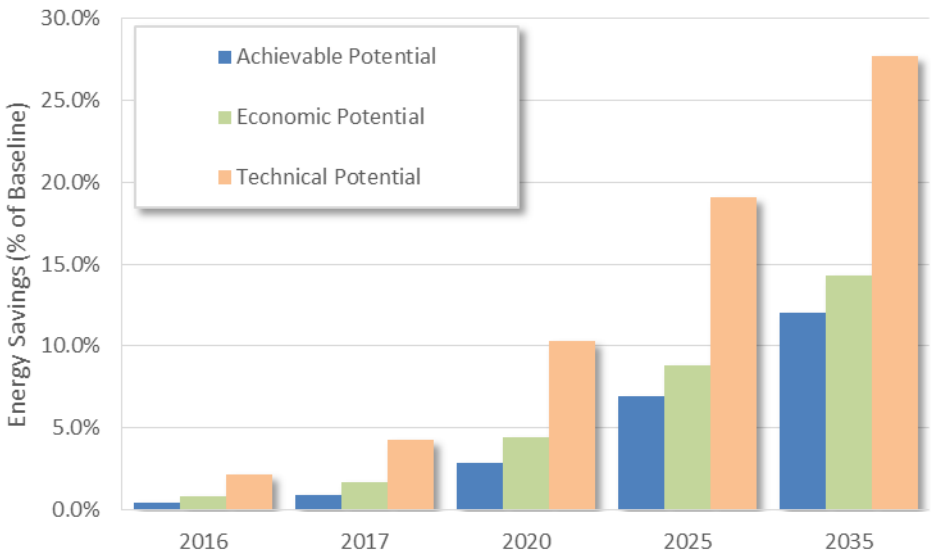
Summary of Conservation Potential Across All Sectors

Avista Conservation Potential – All Sectors

Washington and Idaho combined

From 2015 to 2025, cumulative achievable potential savings are 574 GWh, or 65.6 aMW.

Achievable potential in 2025 is about 78% of economic potential.



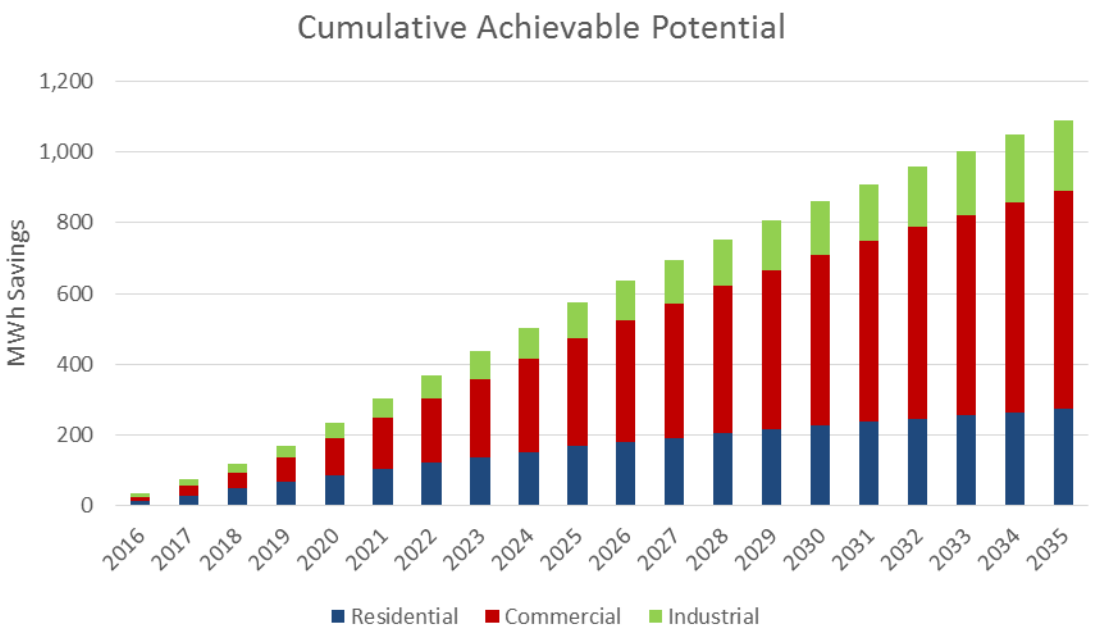
	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	34	74	236	574	1,090
Economic Potential	68	139	360	733	1,292
Technical Potential	173	344	837	1,581	2,506
Cumulative Savings (aMW)					
Achievable Potential	3.9	8.5	27.0	65.6	124.5
Economic Potential	7.7	15.8	41.1	83.7	147.5
Technical Potential	19.7	39.3	95.5	180.5	286.1

2015 Electric IRP Appendix A

Avista Conservation Potential – All Sectors

Washington and Idaho combined

In the early years, savings from residential and commercial are about the same. Starting in 2020, savings are more likely to come from the commercial sector as a result of appliance standards. Industrial consistently contributes about 20% of the savings each year.



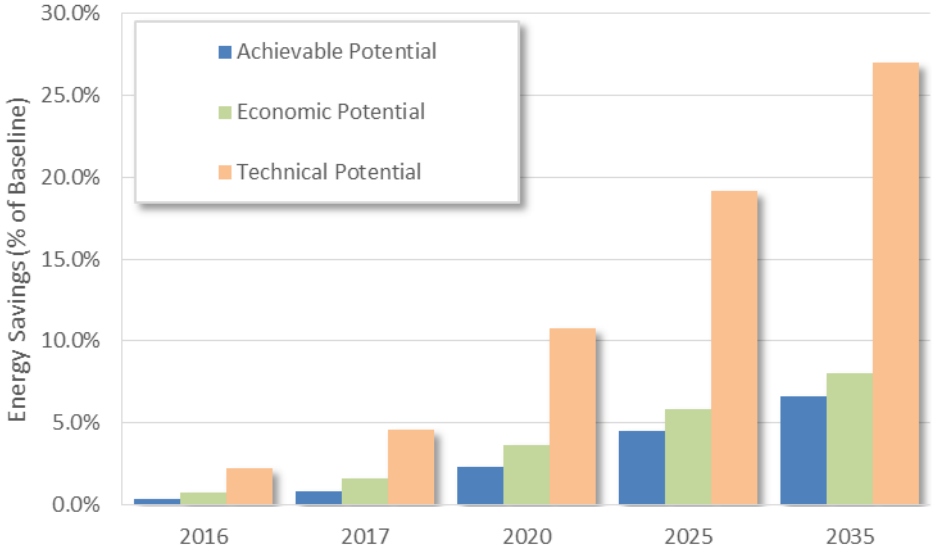
2015 Electric IRP Appendix A

Avista Conservation Potential – Residential

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 169 GWh, or 19.3 aMW.

Achievable potential in 2025 is about 77% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	13.1	29.9	87.1	168.6	274.1
Economic Potential	29.3	60.1	136.7	219.4	333.8
Technical Potential	84.5	168.7	400.1	718.9	1,116.7
Cumulative Savings (aMW)					
Achievable Potential	1.5	3.4	9.9	19.3	31.3
Economic Potential	3.3	6.9	15.6	25.0	38.1
Technical Potential	9.6	19.3	45.7	82.1	127.5

2015 Electric IRP Appendix A

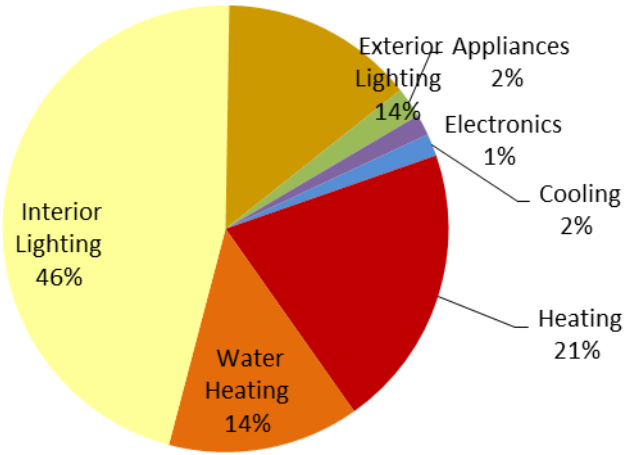
Avista Residential Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Screw-in/Hard-wire (LED)	13,616	45.6%
Ducting - Repair and Sealing	5,057	16.9%
Exterior Lighting - Screw-in/Hard-wire (LED)	4,152	13.9%
Water Heater - Pipe Insulation	2,264	7.6%
Water Heater - Faucet Aerators	1,037	3.5%
Behavioral Programs	688	2.3%
Thermostat - Clock/Programmable	674	2.3%
Insulation - Ducting	621	2.1%
Water Heater - Low-Flow Showerheads	419	1.4%
Electronics - Personal Computers	285	1.0%
Total	**28,800**	**96.4%**

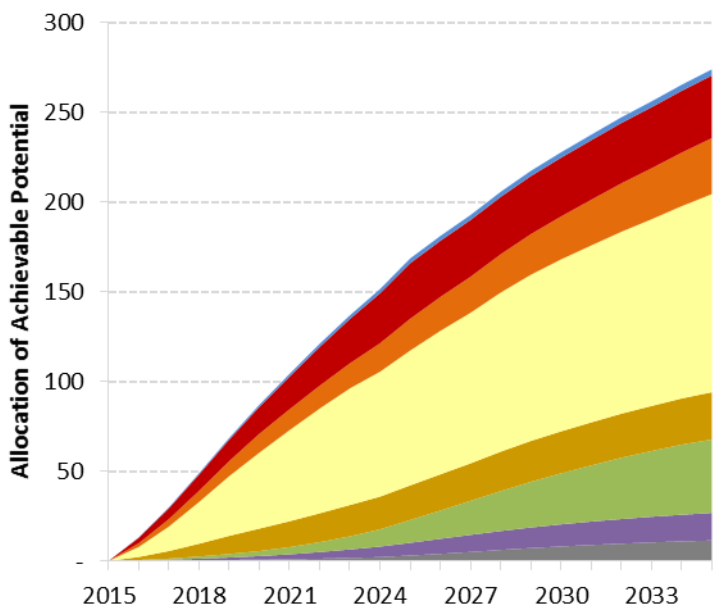
Energy savings by end use



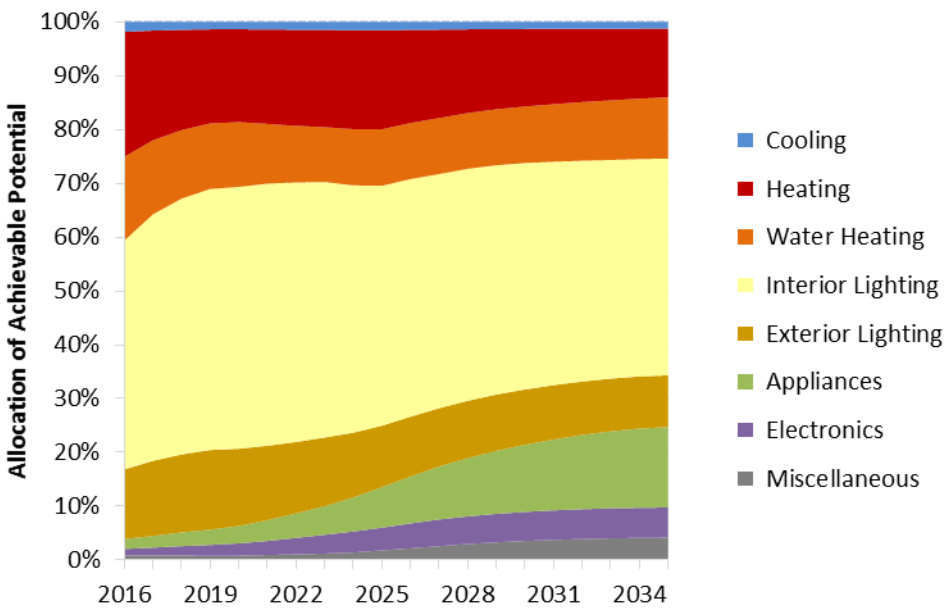
Avista Residential Savings Potential – WA & ID

Cumulative achievable energy savings potential over time

Cumulative Achievable Potential (GWh)



% of Cumulative Achievable Potential

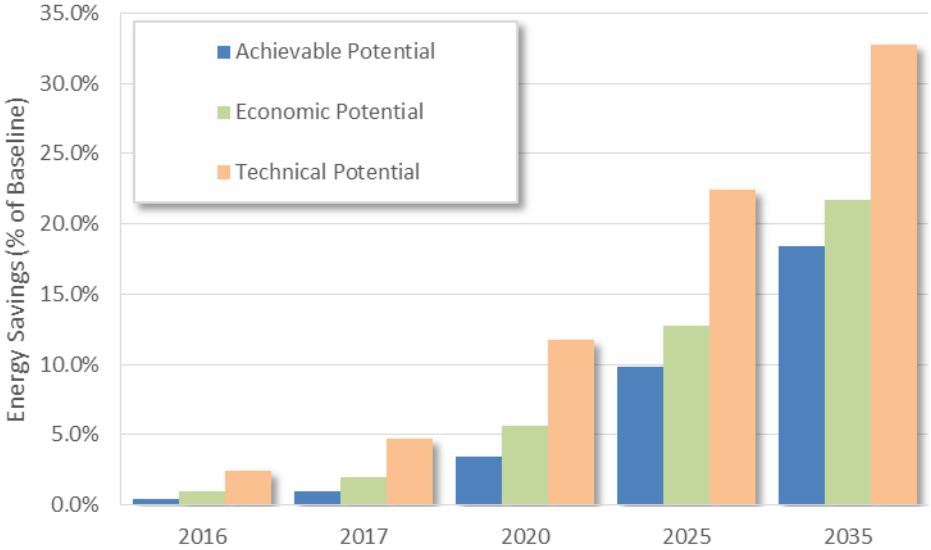


Avista Conservation Potential – Commercial

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 304 GWh, or 34.7 aMW.

Achievable potential in 2025 is about 77% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	13.2	28.4	104.7	304.4	617.3
Economic Potential	29.2	59.7	171.1	395.3	727.7
Technical Potential	71.2	141.7	352.8	694.2	1,095.9
Cumulative Savings (aMW)					
Achievable Potential	1.5	3.2	12.0	34.7	70.5
Economic Potential	3.3	6.8	19.5	45.1	83.1
Technical Potential	8.1	16.2	40.3	79.2	125.1

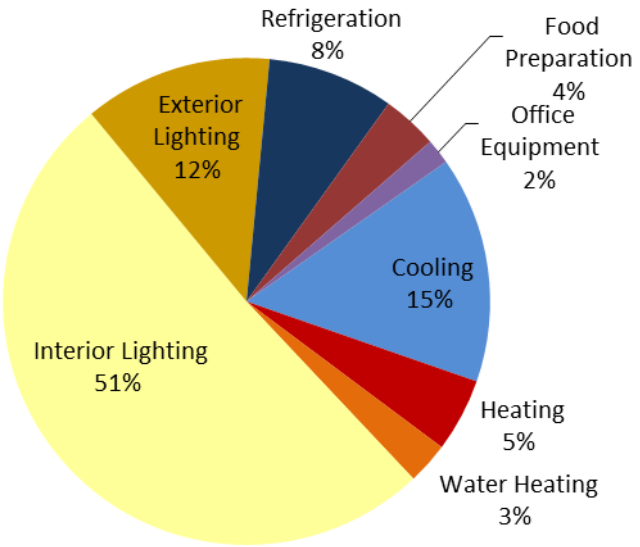
Avista Commercial Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Linear LED	6,604	23.3%
Interior Lighting - Screw-in/Hard-wire LED and CFL	3,889	13.7%
Chiller - Chilled Water Reset	1,362	4.8%
Exterior Lighting - Linear LED	1,135	4.0%
Interior Lighting - High-Bay Fixtures T5 and LED	1,130	4.0%
HVAC - Duct Repair and Sealing	1,068	3.8%
Interior Lighting - Occupancy Sensors	975	3.4%
Interior Lighting - Skylights	831	2.9%
Exterior Lighting - Screw-in/Hard-wire CFL and LED	702	2.5%
Exterior Lighting – HID T5 and LED	671	2.4%
Total Top 10 Measures	**18,367**	**64.7%**

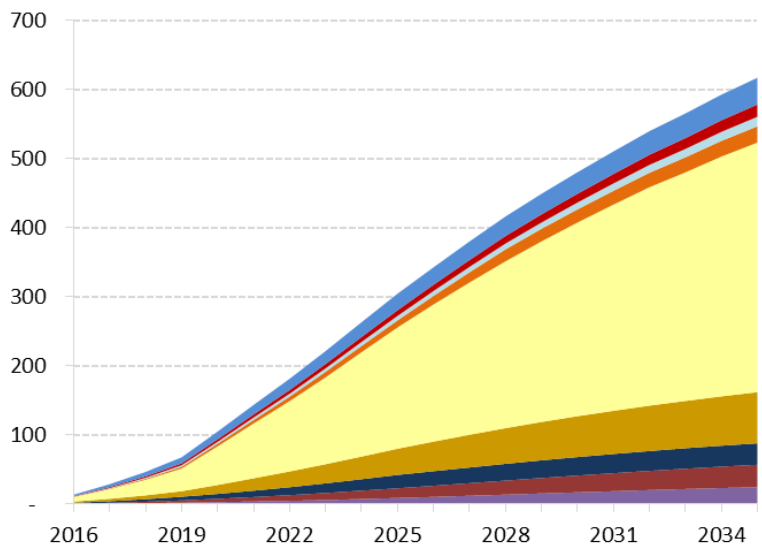
Energy savings by end use



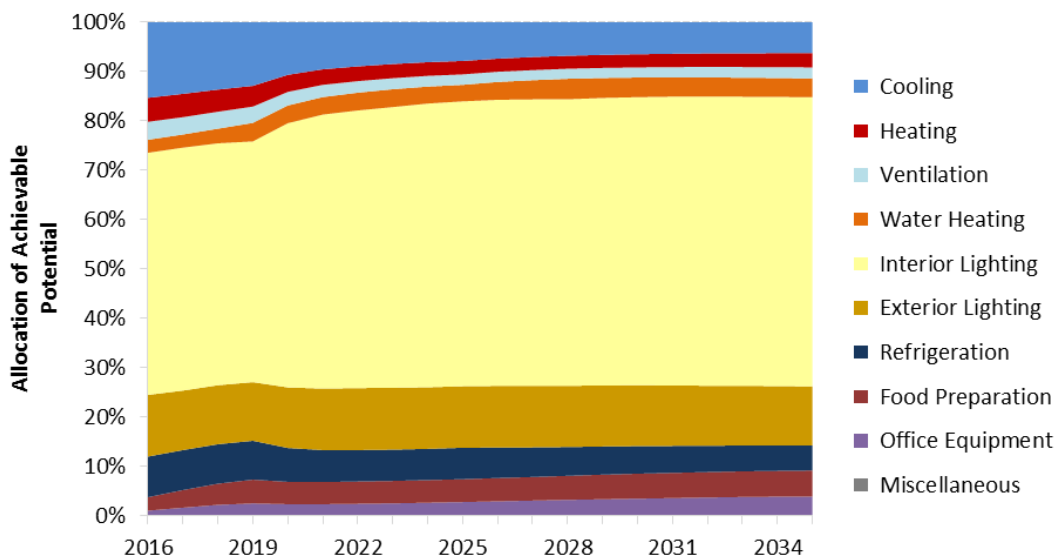
Avista Commercial Savings Potential – WA & ID

Cumulative achievable energy savings potential over time

Cumulative Achievable Potential (GWh)



% of Cumulative Achievable Potential

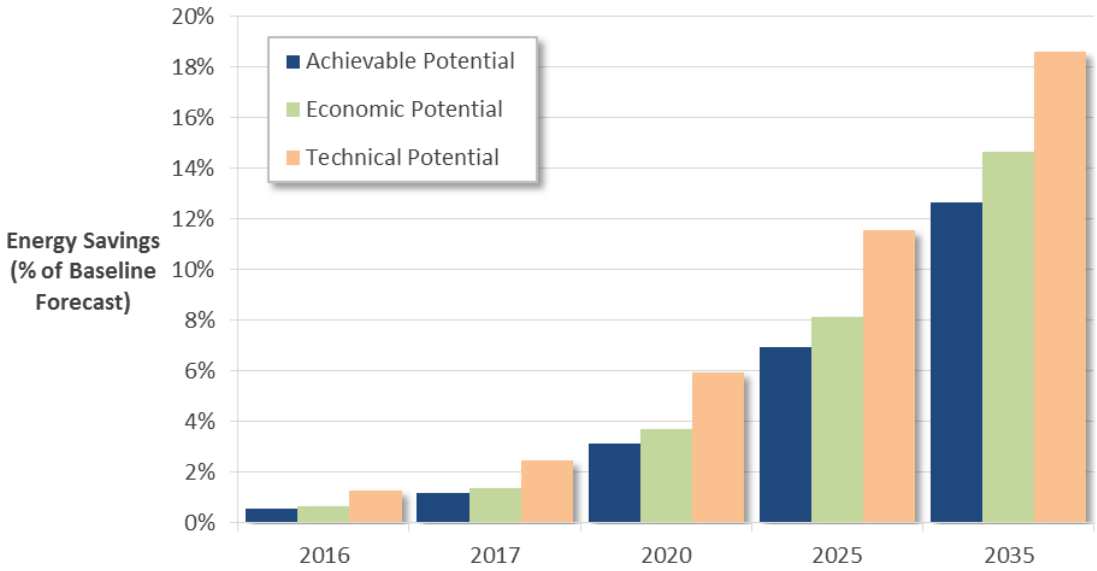


Avista Conservation Potential – Industrial

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 102 GWh, or 11.6 aMW.

Achievable potential in 2025 is about 86% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	7.8	16.0	44.4	101.5	199.0
Economic Potential	9.1	18.8	52.1	118.4	230.8
Technical Potential	17.1	33.9	83.7	168.4	293.2
Cumulative Savings (aMW)					
Achievable Potential	0.9	1.8	5.1	11.6	22.7
Economic Potential	1.0	2.1	5.9	13.5	26.3
Technical Potential	1.9	3.9	9.6	19.2	33.5

2015 Electric IRP Appendix A

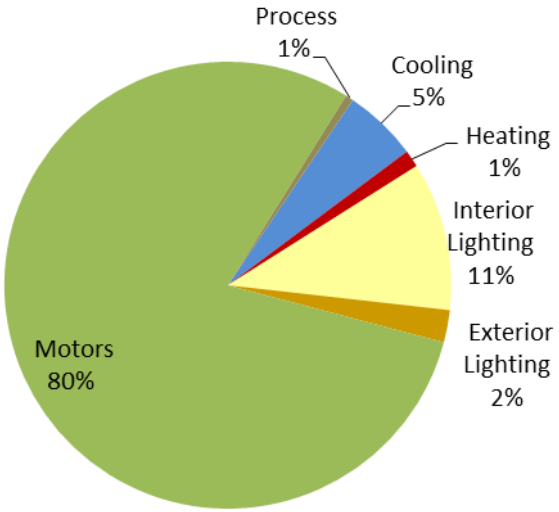
Avista Industrial Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Fan System - Optimization and Improvements	4,524	28.3%
Motors - Variable Frequency Drive (Pumps)	3,020	18.9%
Motors - Variable Frequency Drive (Fans & Blowers)	1,505	9.4%
Compressed Air - Air Usage Reduction	1,247	7.8%
Pumping System - Optimization and Improvements	893	5.6%
Interior Lighting - Occupancy Sensors	703	4.4%
Interior Lighting - High-Bay Fixtures	420	2.6%
Fan System - Maintenance	414	2.6%
Interior Lighting - Screw-in/Hard-wire LED	403	2.5%
Motors - Variable Frequency Drive (Compressed Air)	399	2.5%
Total Top 10 Measures	**13,528**	**84.5%**

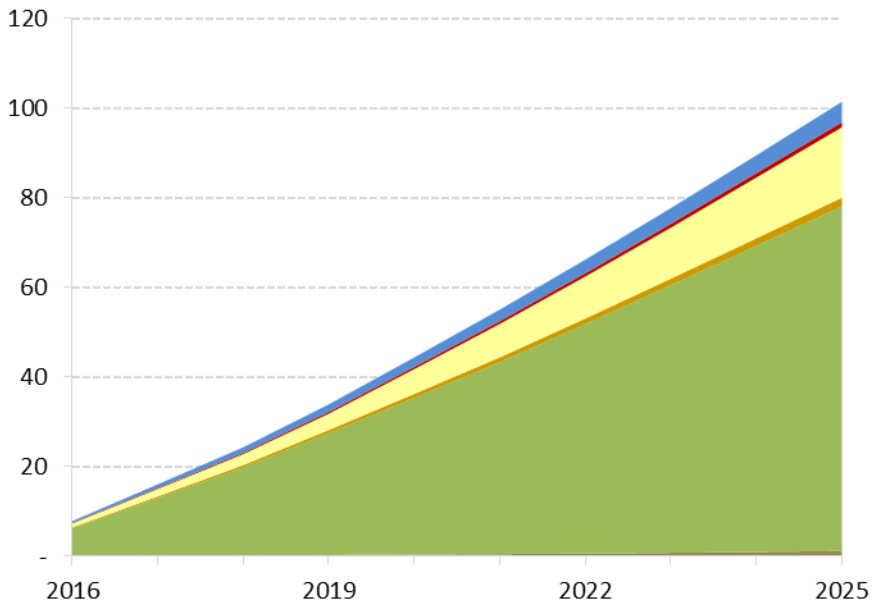
Energy savings by end use



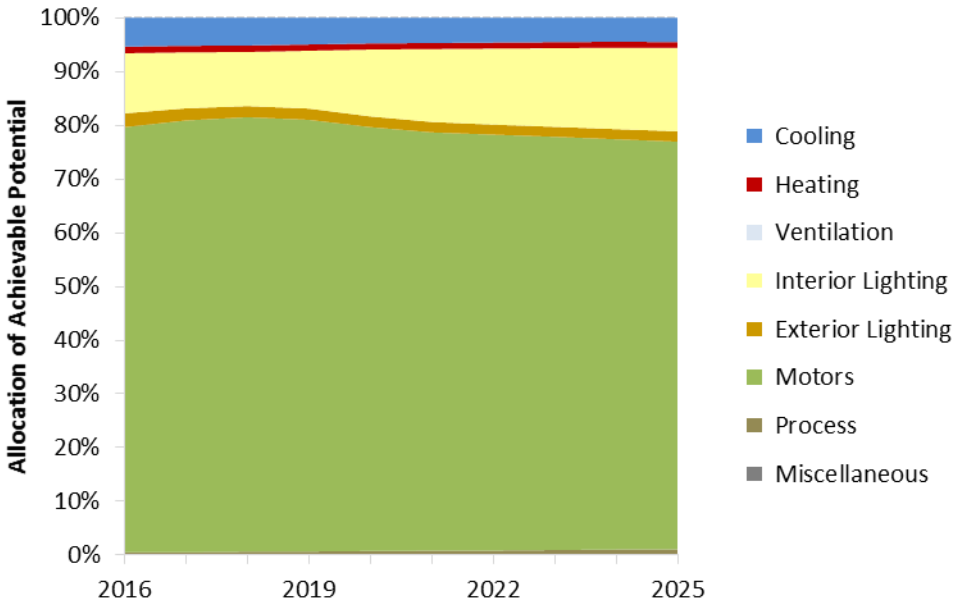
Avista Industrial Savings Potential – WA & ID

Cumulative achievable energy savings potential over time

Cumulative Achievable Potential (GWh)



% of Cumulative Achievable Potential



AEG Consistency with Council Methodology

- End-use model — bottom-up
  - Building characteristics, fuel and equipment saturations
  - Stock accounting based on measure life
  - Codes and standards that have been enacted are included in baseline
  - Lost- and non-lost opportunities treated differently
- Measures – comprehensive list
  - RTF measure workbooks
  - AEG databases, which draw upon same sources used by RTF
- Economic potential, total resource cost (TRC) test
  - Considers HVAC interactions, non-energy benefits
  - Avoided costs include 10% credit based on Conservation Act
- Achievable potential – ramp rates
  - Based on Sixth Plan ramps rates, but modified to reflect Avista's program history

AEG
Applied Energy Group

Summary of Conservation Potential Across All Sectors – Sensitivity Case

Sensitivity Case

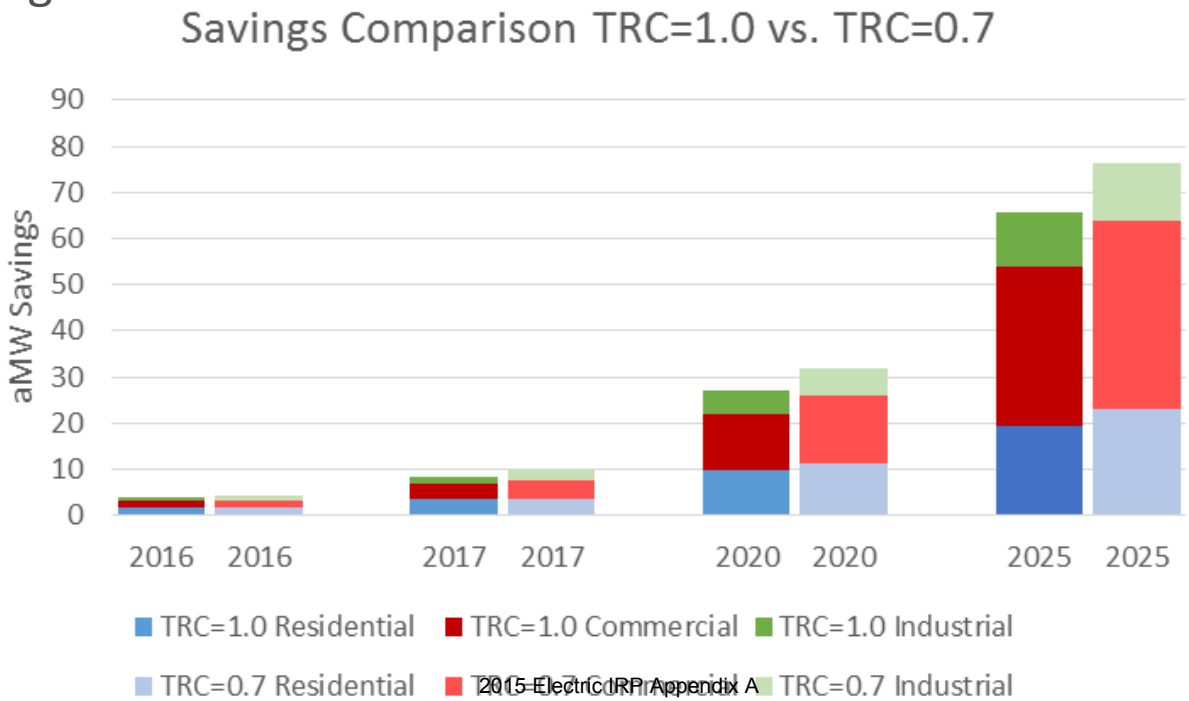
- Ran another version of the model to see which measures were on the edge of passing the TRC
  - Set the TRC threshold to 0.7
- The biggest impact was in the commercial sector
- The measures that pass at the 0.7 level, but not the 1.0 level include:
  - ENERGY STAR Homes
  - Weatherization in more segments
  - Commercial faucet aerators and low flow nozzles
  - LED light bulbs pass in more segments
  - Industrial compressed air replacements

Avista Conservation Potential – All Sectors

Washington and Idaho combined

The case with TRC=0.7 provides more savings since more measures pass the economic screen. With the lower TRC, there is an additional 0.5 aMW in 2016 and an additional 10.7 aMW in 2025.

- The biggest increase in savings is in the commercial sector with the addition of linear LED light bulbs, faucet aerators and additional screw-in LED light bulbs.



AEG
Applied Energy Group

Thank You!

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Applied Energy Group

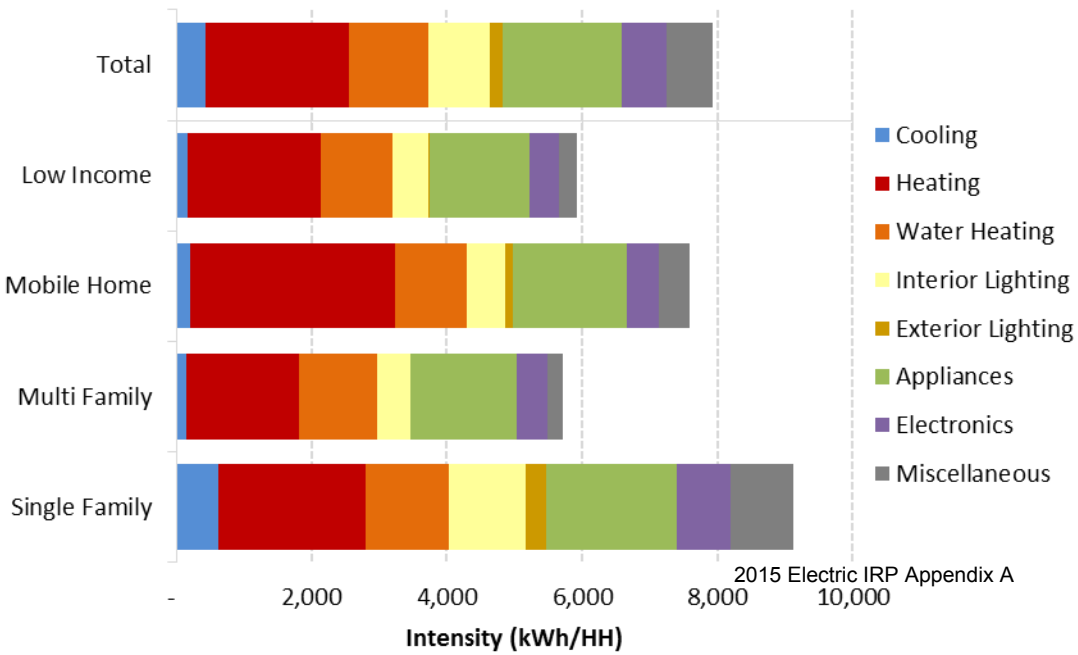
Supplemental Slides:

Base-year market profiles, baseline projection and sector-level peak-demand savings

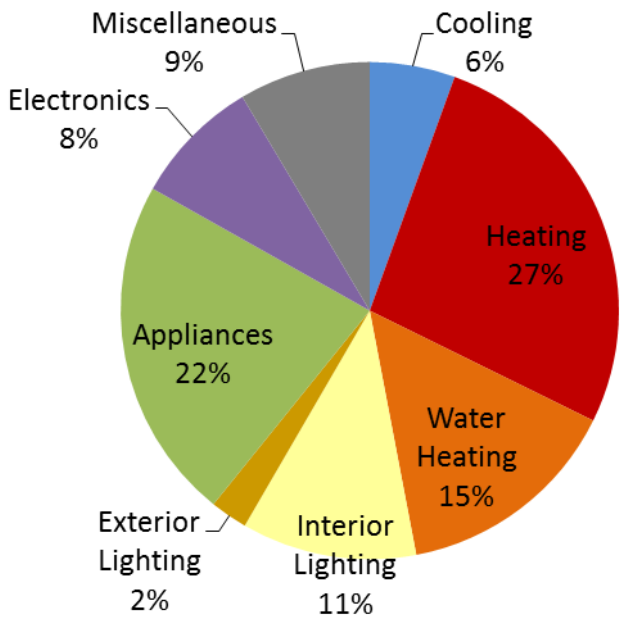
WA Residential Market Profile, 2013

Segment	Number of Customers	Annual Use (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	129,893	1,783	70%	13,726
Multi Family	11,964	99	4%	8,236
Mobile Home	7,691	95	4%	12,354
Low Income	64,092	570	22%	8,892
Total	**213,640**	**2,546**	**100%**	**11,919**

Annual Intensity for Average Household

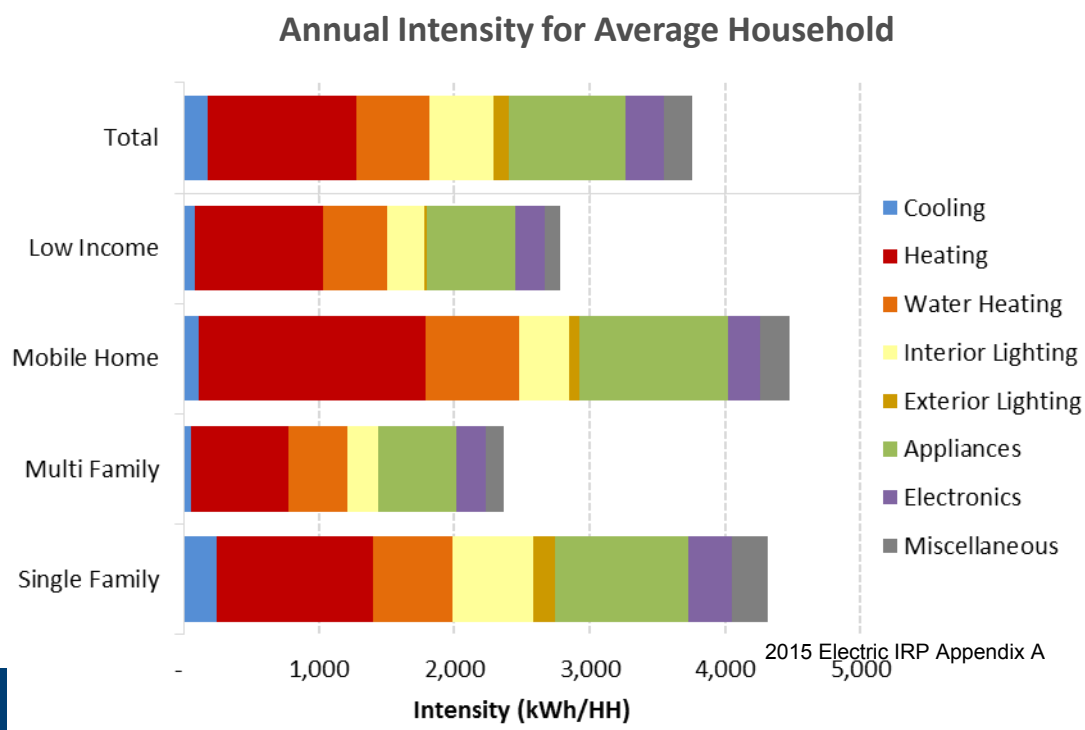


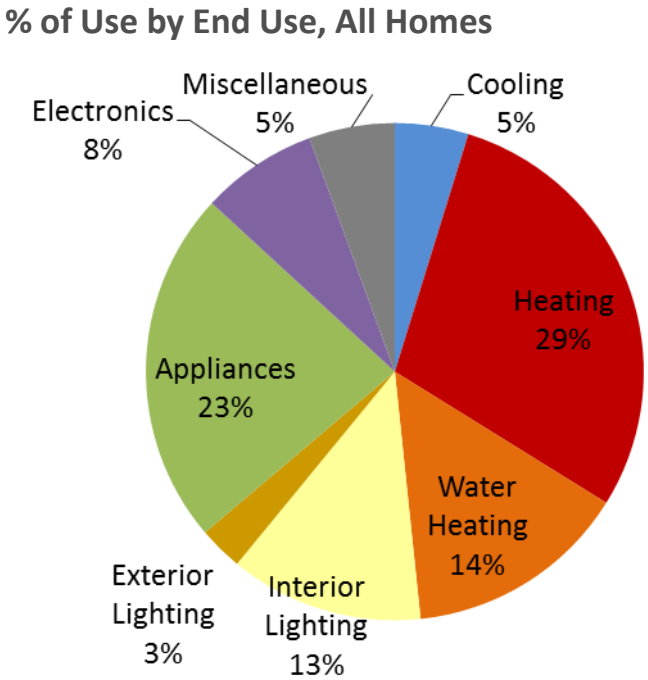
% of Use by End Use, All Homes



ID Residential Market Profile, 2013

Segment	Number of Customers	Annual Use (GWh)	% of Sales	Intensity (kWh/HH)
Single Family	65,329	843	70%	12,902
Multi Family	5,265	41	3%	7,733
Mobile Home	4,835	56	5%	11,599
Low Income	32,020	267	22%	8,349
Total	**107,449**	**1,207**	**100%**	**11,233**





WA Residential Market Profile, 2013

The technology detail behind the end-use profiles

Market profiles characterize how customers use electricity in the base year (2013)

Basic Equation:

$$Energy = \sum_{e} (N \times Sat_e \times UEC_e)$$

where

Energy	=	annual energy use
e	=	equipment technology
N	=	number of homes
Sat_e	=	saturation of homes with the equipment
UEC_e	=	unit energy consumption in homes with the equipment

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	36.9%	1,249	461	98
Cooling	Room AC	26.4%	402	106	23
Cooling	Air-Source Heat Pump	6.5%	1,268	82	17
Cooling	Geothermal Heat Pump	0.2%	1,326	2	0
Cooling	Evaporative AC	1.2%	809	10	2
Space Heating	Electric Room Heat	24.3%	5,302	1,288	275
Space Heating	Electric Furnace	13.4%	9,021	1,213	259
Space Heating	Air-Source Heat Pump	6.5%	10,487	677	145
Space Heating	Geothermal Heat Pump	0.2%	5,564	10	2
Water Heating	Water Heater (<= 55 Gal)	50.9%	3,025	1,539	329
Water Heating	Water Heater (55 to 75 Gal)	6.5%	3,145	203	43
Water Heating	Water Heater (> 75 Gal)	0.3%	4,209	12	3
Interior Lighting	Screw-in/Hard-wire	100.0%	955	955	204
Interior Lighting	Linear Fluorescent	100.0%	114	114	24
Interior Lighting	Specialty Lighting	100.0%	286	286	61
Exterior Lighting	Screw-in/Hard-wire	100.0%	289	289	62
Appliances	Clothes Washer	91.8%	104	95	20
Appliances	Clothes Dryer	49.9%	738	368	79
Appliances	Dishwasher	77.1%	447	345	74
Appliances	Refrigerator	100.0%	829	829	177
Appliances	Freezer	55.3%	669	370	79
Appliances	Second Refrigerator	20.7%	1,010	209	45
Appliances	Stove	70.3%	453	318	68
Appliances	Microwave	94.8%	139	132	28
Electronics	Personal Computers	64.3%	214	138	29
Electronics	Monitor	78.6%	91	71	15
Electronics	Laptops	76.3%	57	43	9
Electronics	TVs	177.4%	255	452	97
Electronics	Printer/Fax/Copier	72.6%	65	47	10
Electronics	Set top Boxes/DVRs	143.9%	128	184	39
Electronics	Devices and Gadgets	100.0%	54	54	11
Miscellaneous	Pool Pump	1.9%	2,514	49	10
Miscellaneous	Pool Heater	0.5%	4,025	19	4
Miscellaneous	Furnace Fan	58.7%	249	146	31
Miscellaneous	Well pump	9.3%	642	60	13
Miscellaneous	Miscellaneous	100.0%	744	744	159
	Total			**11,919**	**2,546**

ID Residential Market Profile, 2013

The technology detail behind the end-use profiles

Market profiles characterize how customers use electricity in the base year (2013)

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where

Energy	=	annual energy use
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N	=	number of homes
Sat_e	=	saturation of homes with the equipment
UEC_e	=	unit energy consumption in homes with the equipment

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	33.4%	1,134	379	41
Cooling	Room AC	18.6%	416	77	8
Cooling	Air-Source Heat Pump	5.3%	1,282	68	7
Cooling	Geothermal Heat Pump	0.0%	0	0	0
Cooling	Evaporative AC	1.5%	777	12	1
Space Heating	Electric Room Heat	24.2%	6,354	1,540	165
Space Heating	Electric Furnace	13.1%	8,904	1,168	126
Space Heating	Air-Source Heat Pump	5.3%	10,465	557	60
Space Heating	Geothermal Heat Pump	0.0%	0	0	0
Water Heating	Water Heater (<= 55 Gal)	49.2%	2,904	1,429	154
Water Heating	Water Heater (55 to 75 Gal)	6.2%	3,025	189	20
Water Heating	Water Heater (> 75 Gal)	0.3%	3,847	11	1
Interior Lighting	Screw-in/Hard-wire	100.0%	1,041	1,041	112
Interior Lighting	Linear Fluorescent	100.0%	129	129	14
Interior Lighting	Specialty Lighting	100.0%	243	243	26
Exterior Lighting	Screw-in/Hard-wire	100.0%	323	323	35
Appliances	Clothes Washer	85.1%	99	84	9
Appliances	Clothes Dryer	60.3%	754	454	49
Appliances	Dishwasher	77.6%	424	329	35
Appliances	Refrigerator	100.0%	789	789	85
Appliances	Freezer	52.3%	643	337	36
Appliances	Second Refrigerator	21.1%	945	199	21
Appliances	Stove	63.6%	433	275	30
Appliances	Microwave	91.2%	132	120	13
Electronics	Personal Computers	56.9%	200	114	12
Electronics	Monitor	69.6%	85	59	6
Electronics	Laptops	79.3%	53	42	5
Electronics	TVs	174.6%	248	434	47
Electronics	Printer/Fax/Copier	66.7%	61	41	4
Electronics	Set top Boxes/DVRs	92.5%	120	111	12
Electronics	Devices and Gadgets	100.0%	51	51	5
Miscellaneous	Pool Pump	1.6%	2,342	38	4
Miscellaneous	Pool Heater	0.4%	3,750	15	2
Miscellaneous	Furnace Fan	59.7%	239	142	15
Miscellaneous	Well pump	12.5%	598	75	8
Miscellaneous	Miscellaneous	100.0%	356	356	38
	Total			**11,233**	**1,207**

WA Commercial Market Characterization, 2013

Segment	Electricity Sales (GWh)	% of Total Usage	Floor Space (Million Sq. Ft.)	Intensity (Annual kWh/SqFt)	Peak Demand (MW)
Small Office	280	13%	18.1	15.4	71
Large Office	106	5%	6.0	17.5	16
Restaurant	70	3%	1.7	42.4	11
Retail	285	14%	20.7	13.8	59
Grocery	209	10%	4.4	47.3	33
College	78	4%	5.6	13.9	13
School	117	6%	11.9	9.9	5
Hospital	271	13%	9.3	29.1	41
Lodging	112	5%	7.0	16.1	14
Warehouse	103	5%	13.7	7.5	12
Miscellaneous	455	22%	33.1	13.8	93
Total	**2,086**	**100%**	**132**	**15.9**	**368**

ID Commercial Market Characterization, 2013

Segment	Electricity Sales (GWh)	% of Total Usage	Floor Space (Million Sq. Ft.)	Intensity (Annual kWh/SqFt)	Peak Demand (MW)
Small Office	134	14%	8.7	15.4	35
Large Office	17	2%	1.0	17.5	3
Restaurant	12	1%	0.3	42.4	2
Retail	168	17%	12.1	13.8	35
Grocery	92	9%	1.9	47.3	14
College	73	7%	5.2	13.9	12
School	109	11%	11.1	9.9	4
Hospital	106	11%	3.6	29.1	16
Lodging	49	5%	3.0	16.1	6
Warehouse	47	5%	6.3	7.5	5
Miscellaneous	168	17%	12.2	13.8	34
Total	**976**	**100%**	**66**	**14.9**	**167**

WA Commercial Market Profile, 2013

The technology detail behind the end-use profiles

Market profiles characterize how customers use electricity in the base year (2013)

Basic Equation:

$$Energy = \sum_{e} (N \times Sat_e \times UEC_e)$$

where

Energy = annual energy use

e = equipment technology

N = total floor space in sq. ft.

Sat_e = saturation of sq. ft. with the equipment

UEC_e = unit energy consumption for square footage with the equipment

Electric Market Profiles

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	10.3%	3.38	0.35	46.0
Cooling	Water-Cooled Chiller	12.3%	5.11	0.63	83.0
Cooling	RTU	37.5%	3.27	1.22	161.1
Cooling	Room AC	4.6%	2.93	0.13	17.5
Cooling	Air-Source Heat Pump	5.6%	3.01	0.17	22.1
Cooling	Geothermal Heat Pump	1.8%	1.85	0.03	4.4
Heating	Electric Furnace	12.7%	6.72	0.86	112.5
Heating	Electric Room Heat	7.6%	7.69	0.58	76.9
Heating	Air-Source Heat Pump	5.6%	5.87	0.33	43.1
Heating	Geothermal Heat Pump	1.8%	4.30	0.08	10.1
Ventilation	Ventilation	100.0%	1.59	1.59	209.2
Water Heating	Water Heater	53.1%	1.69	0.90	118.2
Interior Lighting	Screw-in/Hard-wire	100.0%	0.92	0.92	121.3
Interior Lighting	High-Bay Fixtures	100.0%	0.51	0.51	67.3
Interior Lighting	Linear Fluorescent	100.0%	2.17	2.17	285.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	30.0
Exterior Lighting	HID	100.0%	0.64	0.64	83.8
Exterior Lighting	Linear Fluorescent	100.0%	0.35	0.35	46.4
Refrigeration	Walk-in Refrigerator/Freezer	8.8%	1.81	0.16	21.1
Refrigeration	Reach-in Refrigerator/Freezer	12.1%	0.29	0.04	4.6
Refrigeration	Glass Door Display	15.6%	0.98	0.15	20.1
Refrigeration	Open Display Case	7.7%	9.75	0.76	99.3
Refrigeration	Icemaker	29.6%	0.54	0.16	21.2
Refrigeration	Vending Machine	20.2%	0.33	0.07	8.9
Food Preparation	Oven	15.5%	0.92	0.14	18.8
Food Preparation	Fryer	3.3%	2.63	0.09	11.4
Food Preparation	Dishwasher	16.8%	1.68	0.28	37.2
Food Preparation	Steamer	3.3%	2.23	0.07	9.6
Food Preparation	Hot Food Container	6.4%	0.32	0.02	2.7
Office Equipment	Desktop Computer	100.0%	0.62	0.62	82.2
Office Equipment	Laptop	98.8%	0.08	0.08	10.9
Office Equipment	Server	86.8%	0.20	0.17	22.9
Office Equipment	Monitor	100.0%	0.11	0.11	14.5
Office Equipment	Printer/Copier/Fax	100.0%	0.08	0.08	9.9
Office Equipment	POS Terminal	57.7%	0.05	0.03	4.0
Miscellaneous	Non-HVAC Motors	53.0%	0.19	0.10	13.2
Miscellaneous	Pool Pump	5.8%	0.02	0.00	0.2
Miscellaneous	Pool Heater	1.8%	0.03	0.00	0.1
Miscellaneous	Other Miscellaneous	100.0%	1.03	1.03	135.1
Total				**15.86**	**2,086.3**

ID Commercial Market Profile, 2013

The technology detail behind the end-use profiles

Market profiles characterize how customers use electricity in the base year (2013)

Basic Equation:

$$Energy = \sum_{e} (N \times Sat_e \times UEC_e)$$

where

Energy = annual energy use

e = equipment technology

N = total floor space in sq. ft.

Sat_e = saturation of sq. ft. with the equipment

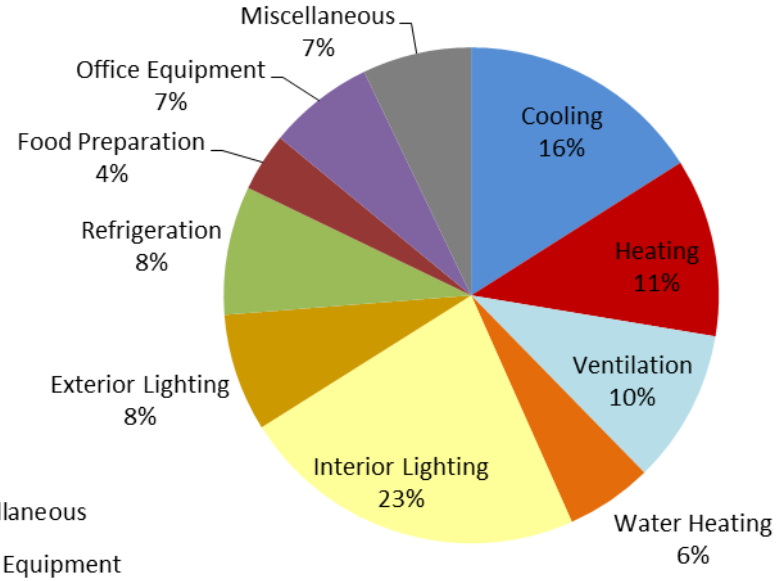
UEC_e = unit energy consumption for square footage with the equipment

Electric Market Profiles

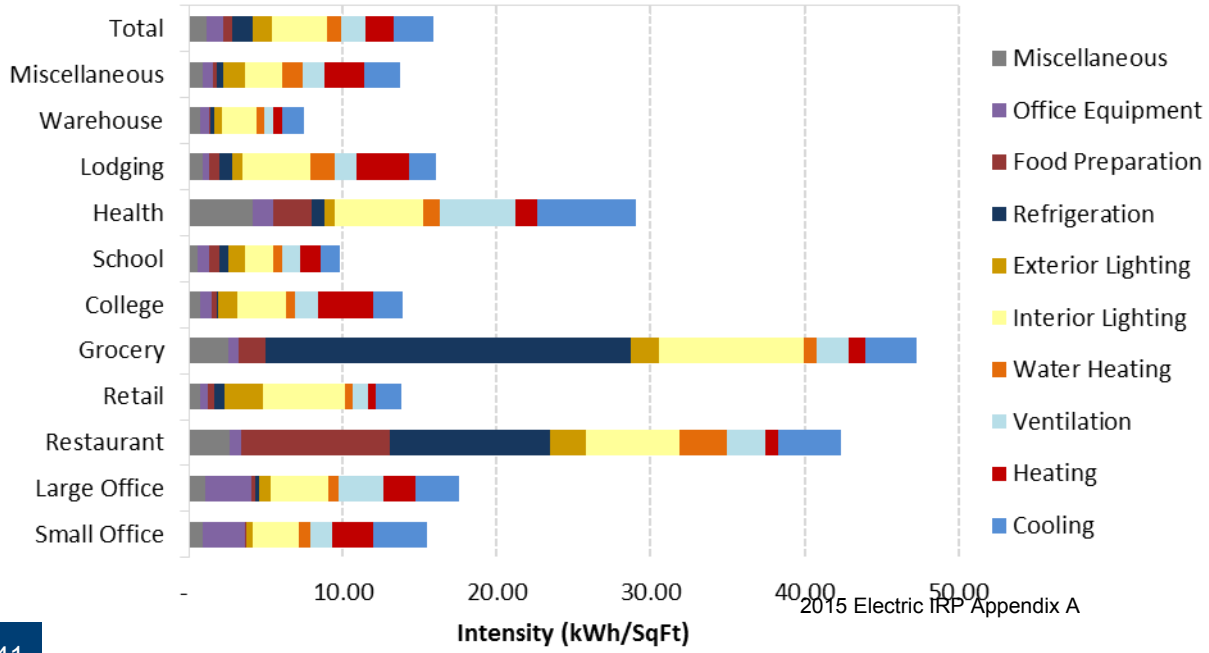
End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	12.4%	3.24	0.40	26.4
Cooling	Water-Cooled Chiller	10.2%	5.15	0.53	34.6
Cooling	RTU	35.6%	3.17	1.13	74.0
Cooling	Room AC	4.6%	2.77	0.13	8.4
Cooling	Air-Source Heat Pump	5.6%	2.81	0.16	10.2
Cooling	Geothermal Heat Pump	1.8%	1.68	0.03	2.0
Heating	Electric Furnace	11.5%	6.74	0.77	50.7
Heating	Electric Room Heat	7.6%	7.76	0.59	38.9
Heating	Air-Source Heat Pump	5.6%	5.91	0.33	21.5
Heating	Geothermal Heat Pump	1.8%	4.41	0.08	5.2
Ventilation	Ventilation	100.0%	1.46	1.46	95.5
Water Heating	Water Heater	51.4%	1.58	0.81	53.2
Interior Lighting	Screw-in/Hard-wire	100.0%	0.88	0.88	57.5
Interior Lighting	High-Bay Fixtures	100.0%	0.51	0.51	33.3
Interior Lighting	Linear Fluorescent	100.0%	2.11	2.11	138.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.20	0.20	13.1
Exterior Lighting	HID	100.0%	0.60	0.60	39.1
Exterior Lighting	Linear Fluorescent	100.0%	0.47	0.47	30.7
Refrigeration	Walk-in Refrigerator/Freezer	8.8%	1.30	0.11	7.5
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.26	0.04	2.3
Refrigeration	Glass Door Display	15.4%	0.85	0.13	8.6
Refrigeration	Open Display Case	8.4%	7.98	0.67	44.1
Refrigeration	Icemaker	31.6%	0.48	0.15	10.0
Refrigeration	Vending Machine	20.0%	0.32	0.06	4.1
Food Preparation	Oven	16.2%	0.86	0.14	9.1
Food Preparation	Fryer	3.1%	2.15	0.07	4.3
Food Preparation	Dishwasher	16.1%	1.49	0.24	15.7
Food Preparation	Steamer	3.1%	1.99	0.06	4.0
Food Preparation	Hot Food Container	7.4%	0.25	0.02	1.2
Office Equipment	Desktop Computer	100.0%	0.58	0.58	37.7
Office Equipment	Laptop	98.9%	0.07	0.07	4.7
Office Equipment	Server	89.1%	0.18	0.16	10.7
Office Equipment	Monitor	100.0%	0.10	0.10	6.7
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	4.7
Office Equipment	POS Terminal	57.6%	0.05	0.03	1.8
Miscellaneous	Non-HVAC Motors	51.6%	0.17	0.09	5.8
Miscellaneous	Pool Pump	5.7%	0.02	0.00	0.1
Miscellaneous	Pool Heater	1.7%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.91	0.91	59.5
Total				**14.87**	**975.5**

WA Commercial Market Profile, 2013

Base Year Sales by End Use

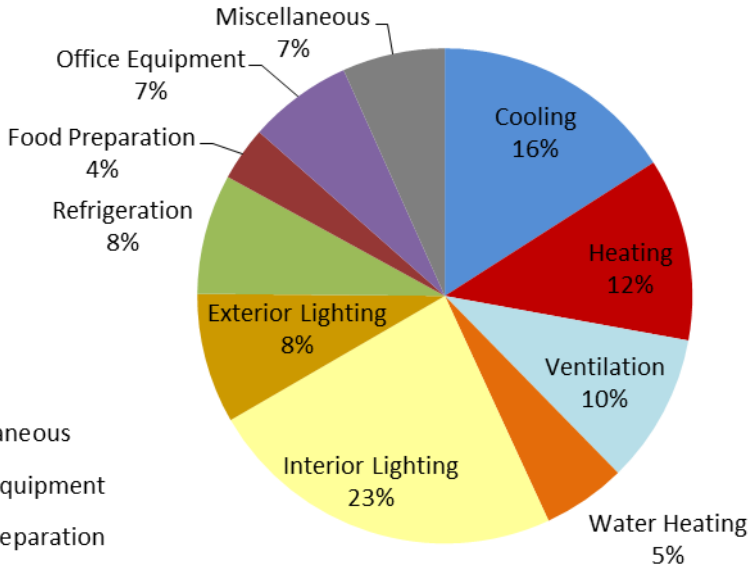


Annual Intensity by Building Type and End Use

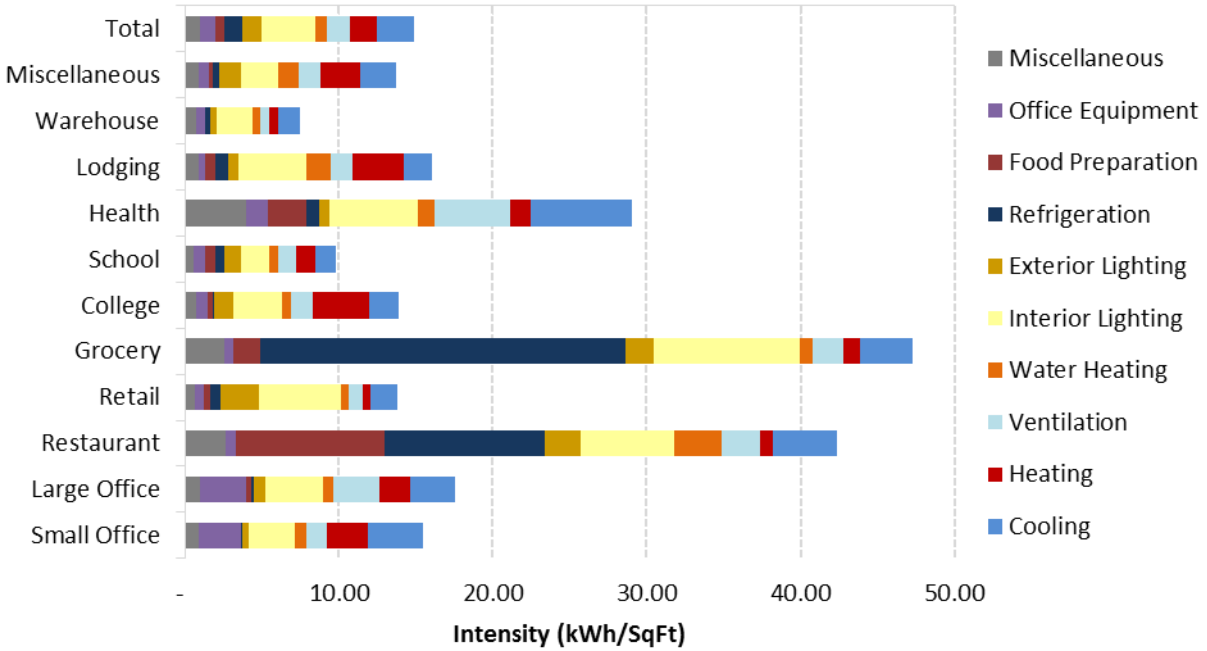


ID Commercial Market Profile, 2013

Base Year Sales by End Use

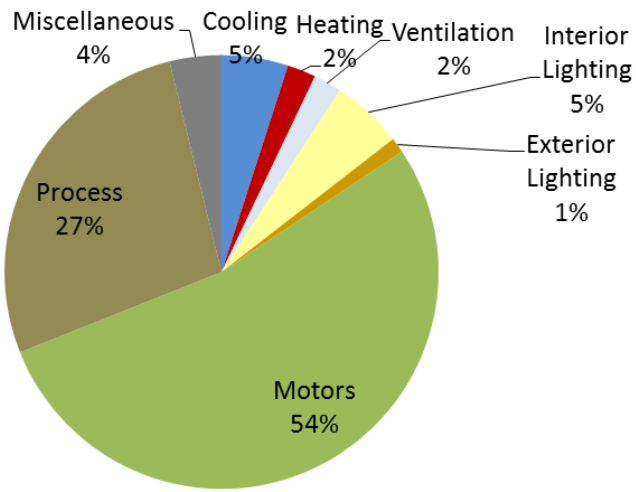


Annual Intensity by Building Type and End Use



WA Industrial Market Profile, 2013

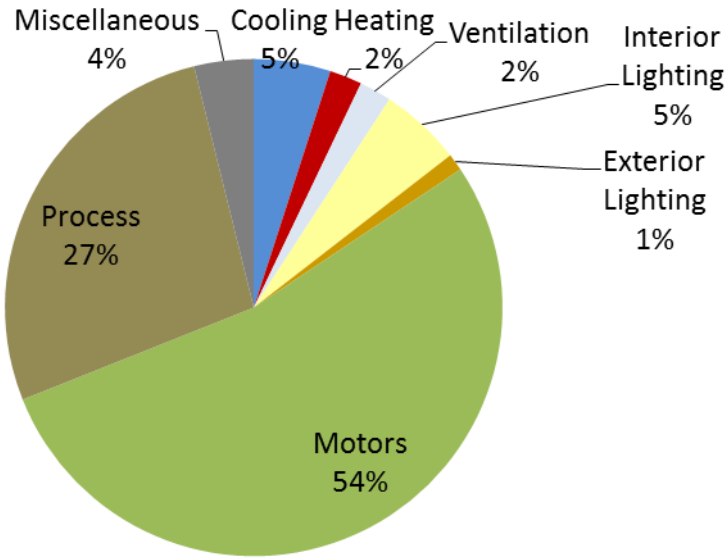
The technology detail behind the end-use profiles



Average Market Profiles			
End Use	**Technology**	**Usage (GWh)**	**Intensity (kWh/Employee)**
Cooling	Air-Cooled Chiller	17.4	1,072
Cooling	Water-Cooled Chiller	2.2	137
Cooling	RTU	22.4	1,383
Cooling	Room AC	1.5	94
Cooling	Air-Source Heat Pump	2.1	130
Cooling	Geothermal Heat Pump	0.0	0
Heating	Electric Furnace	12.5	769
Heating	Electric Room Heat	4.2	258
Heating	Air-Source Heat Pump	3.1	189
Heating	Geothermal Heat Pump	0.0	0
Ventilation	Ventilation	19.3	1,190
Interior Lighting	Screw-in/Hard-wire	4.9	302
Interior Lighting	High-Bay Fixtures	20.4	1,256
Interior Lighting	Linear Fluorescent	23.8	1,466
Exterior Lighting	Screw-in/Hard-wire	3.9	238
Exterior Lighting	HID	3.2	196
Exterior Lighting	Linear Fluorescent	3.2	198
Motors	Pumps	86.8	5,352
Motors	Fans & Blowers	68.0	4,189
Motors	Compressed Air	54.3	3,345
Motors	Conveyors	245.0	15,101
Motors	Other Motors	38.0	2,341
Process	Process Heating	99.2	6,115
Process	Process Cooling	32.5	2,005
Process	Process Refrigeration	32.5	2,005
Process	Process Electro-Chemical	64.5	3,972
Process	Process Other	21.8	1,345
Miscellaneous	Miscellaneous	35.6	2,197
	Total	**922.3**	**56,846**

ID Industrial Market Profile, 2013

The technology detail behind the end-use profiles



Average Market Profiles

End Use	Technology	Usage (GWh)	Intensity (kWh/Employee)
Cooling	Air-Cooled Chiller	6.5	734
Cooling	Water-Cooled Chiller	0.8	94
Cooling	RTU	8.4	947
Cooling	Room AC	0.6	64
Cooling	Air-Source Heat Pump	0.8	89
Cooling	Geothermal Heat Pump	0.0	0
Heating	Electric Furnace	4.6	516
Heating	Electric Room Heat	1.5	173
Heating	Air-Source Heat Pump	1.1	127
Heating	Geothermal Heat Pump	0.0	0
Ventilation	Ventilation	7.2	807
Interior Lighting	Screw-in/Hard-wire	1.8	205
Interior Lighting	High-Bay Fixtures	7.6	854
Interior Lighting	Linear Fluorescent	8.8	997
Exterior Lighting	Screw-in/Hard-wire	1.4	162
Exterior Lighting	HID	1.2	134
Exterior Lighting	Linear Fluorescent	1.2	134
Motors	Pumps	32.3	3,640
Motors	Fans & Blowers	25.3	2,850
Motors	Compressed Air	20.2	2,275
Motors	Conveyors	91.1	10,272
Motors	Other Motors	14.1	1,593
Process	Process Heating	36.9	4,159
Process	Process Cooling	12.1	1,364
Process	Process Refrigeration	12.1	1,364
Process	Process Electro-Chemical	24.0	2,702
Process	Process Other	8.1	915
Miscellaneous	Miscellaneous	13.3	1,494
	Total	**343.0**	**38,668**

AEG
Applied Energy Group

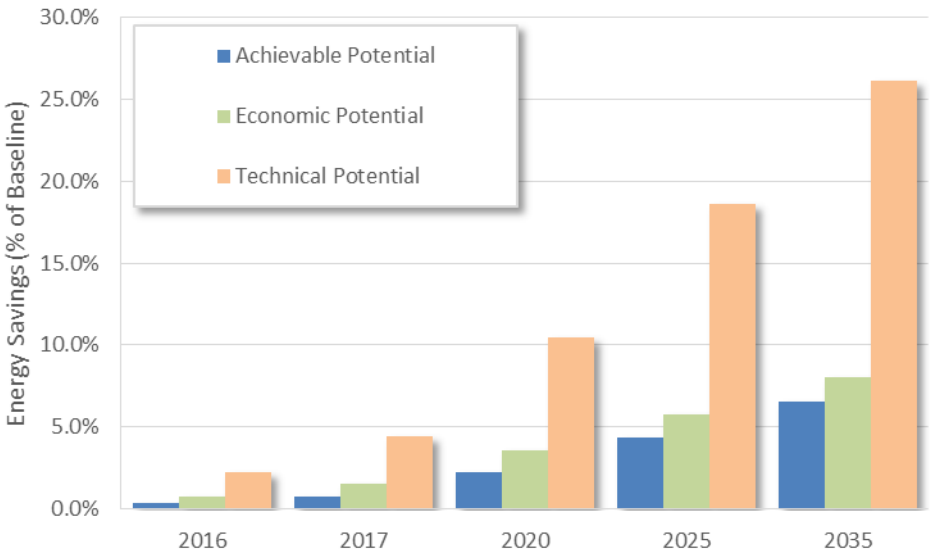
Sector-level Potential Savings - Washington

Avista Conservation Potential – Residential

Washington

From 2015 to 2025, cumulative achievable potential savings are 111 GWh, or 12.6 aMW.

Achievable potential in 2025 is about 76% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA Savings (GWh)					
Achievable Potential	8.5	19.3	56.2	110.7	181.1
Economic Potential	18.9	38.7	88.4	144.7	221.1
Technical Potential	55.2	110.0	261.0	469.4	721.3
Cumulative Savings (aMW)					
Achievable Potential	1.0	2.2	6.4	12.6	20.7
Economic Potential	2.2	4.4	10.1	16.5	25.2
Technical Potential	6.3	12.6	29.8	53.6	82.3

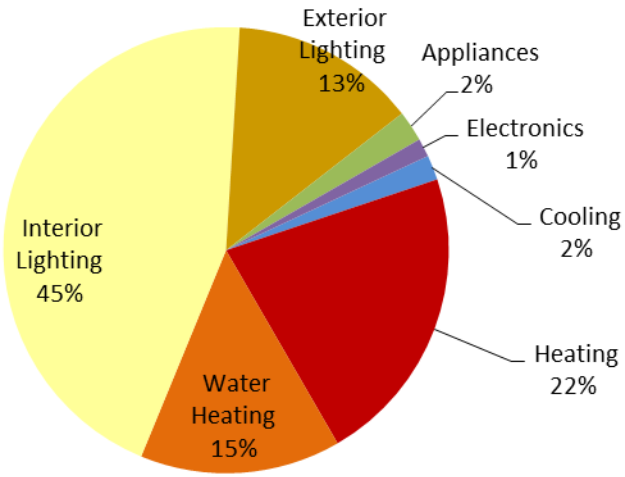
Avista Residential Savings Potential - Washington

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Screw-in/Hard-wire LED and CFL	8,479	44.1%
Ducting - Repair and Sealing	3,483	18.1%
Exterior Lighting - Screw-in/Hard-wire CFL and LED	2,564	13.3%
Water Heater - Pipe Insulation	1,535	8.0%
Water Heater - Faucet Aerators	699	3.6%
Behavioral Programs	464	2.4%
Thermostat - Clock/Programmable	443	2.3%
Insulation - Ducting	429	2.2%
Water Heater - Low-Flow Showerheads	284	1.5%
Appliances – Freezer ENERGY STAR	177	0.9%
Total Top 10 Measures	**18,578**	**96.4%**

Energy savings by end use

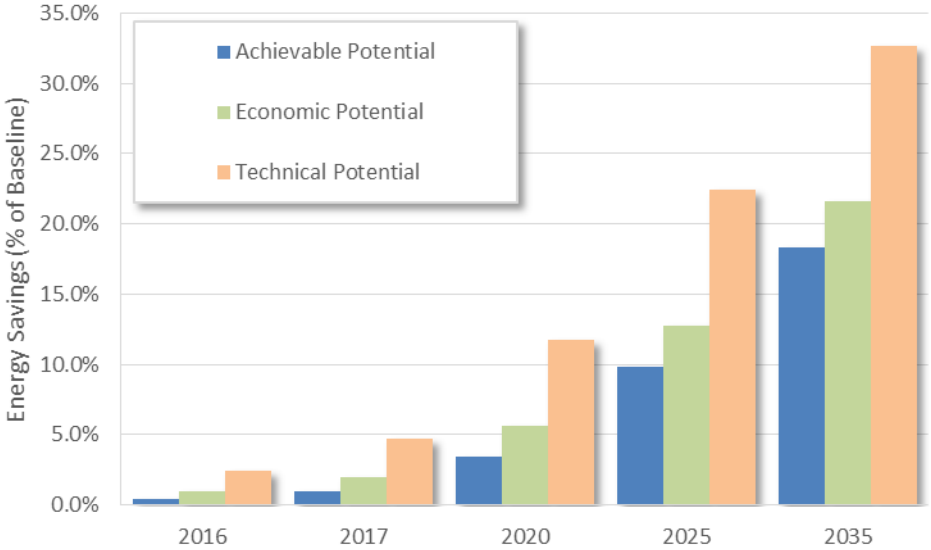


Avista Conservation Potential – Commercial

Washington

From 2015 to 2025, cumulative achievable potential savings are 207 GWh, or 23.6 aMW.

Achievable potential in 2025 is about 77% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA Savings (GWh)					
Achievable Potential	9.0	19.3	71.3	206.7	418.9
Economic Potential	19.9	40.6	116.4	268.4	493.8
Technical Potential	48.5	96.6	240.5	473.0	746.4
Cumulative Savings (aMW)					
Achievable Potential	1.0	2.2	8.1	23.6	47.8
Economic Potential	2.3	4.6	13.3	30.6	56.4
Technical Potential	5.5	11.0	27.5	54.0	85.2

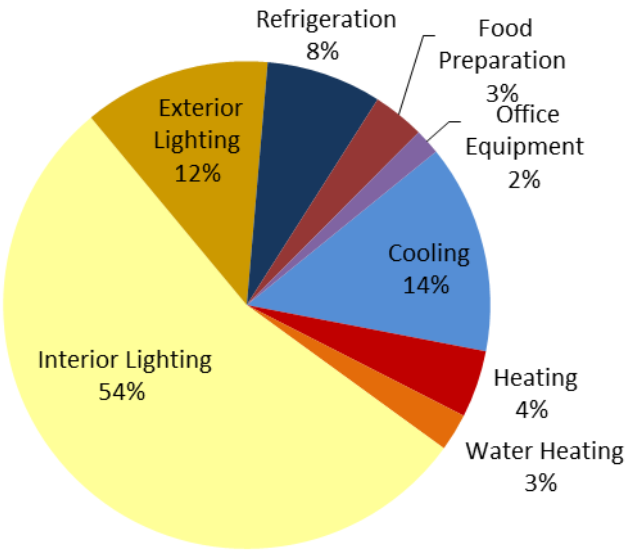
Avista Commercial Savings Potential - Washington

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Savings (MWh)	% of Total
Interior Lighting - Linear LED	4,470	23.1%
Interior Lighting - Screw-in/Hard-wire CFL and LED	2,652	13.7%
Chiller - Chilled Water Reset	924	4.8%
HVAC - Duct Repair and Sealing	793	4.1%
Interior Lighting - High-Bay Fixtures T5 and LED	764	4.0%
Exterior Lighting - Linear LED	688	3.6%
Interior Lighting - Occupancy Sensors	678	3.5%
Interior Lighting - Skylights	561	2.9%
Exterior Lighting - Screw-in/Hard-wire CFL and LED	478	2.5%
Grocery - Open Display Case - Night Covers	459	2.4%
Total Top 10 Measures	**12,467**	**64.5%**

Energy savings by end use

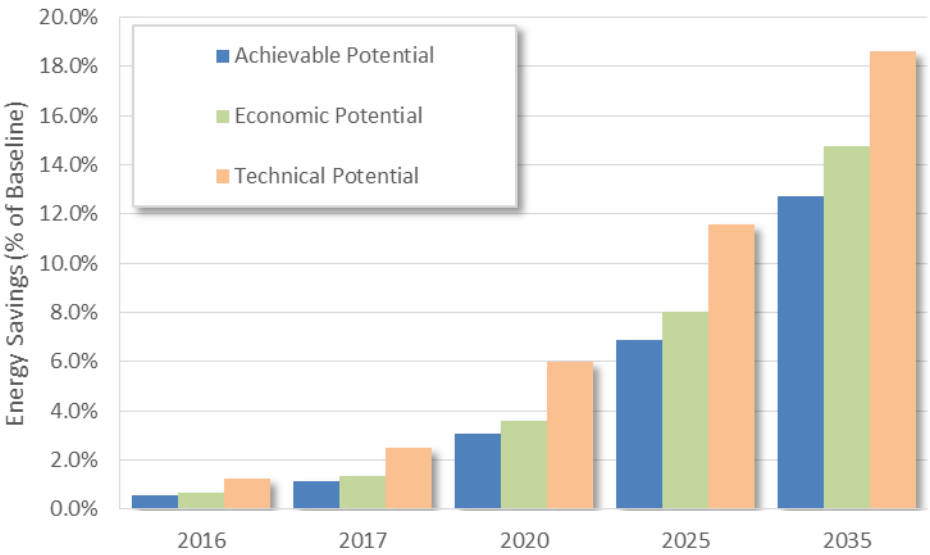


Avista Conservation Potential – Industrial

Washington

From 2016 to 2025, cumulative achievable potential savings are 73 GWh, or 8.4 aMW.

Achievable potential in 2025 is about 86% of economic potential.



	2016	2017	2020	2025	2035
Cumulative WA Savings (GWh)					
Achievable Potential	5.4	11.2	31.3	73.3	146.0
Economic Potential	6.3	13.1	36.8	85.5	169.3
Technical Potential	12.4	24.7	61.1	122.8	213.8
Cumulative Savings (aMW)					
Achievable Potential	0.6	1.3	3.6	8.4	16.7
Economic Potential	0.7	1.5	4.2	9.8	19.3
Technical Potential	1.4	2.8	7.0	14.0	24.4

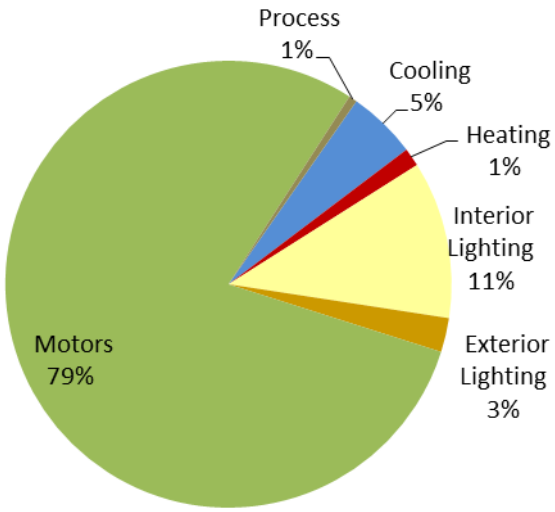
Avista Industrial Savings Potential - Washington

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Savings (MWh)	% of Total
Fan System - Optimization and Improvements	3,298	29.5%
Motors - Variable Frequency Drive (Pumps)	2,206	19.8%
Motors - Variable Frequency Drive (Fans & Blowers)	1,098	9.8%
Compressed Air - Air Usage Reduction	911	8.2%
Pumping System - Optimization and Improvements	663	5.9%
Interior Lighting - Occupancy Sensors	520	4.7%
Motors - Variable Frequency Drive (Compressed Air)	377	3.4%
Interior Lighting - High-Bay Fixtures LED	306	2.7%
Interior Lighting - Screw-in/Hard-wire CFL and LED	294	2.6%
HVAC - Duct Repair and Sealing	264	2.4%
Total Top 10 Measures	**9,938**	**89.0%**

Energy savings by end use



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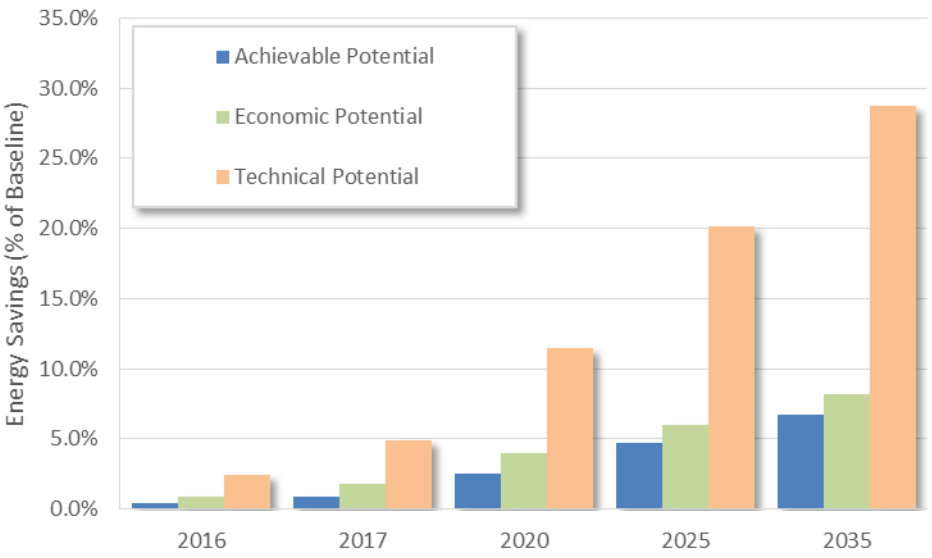
Sector-level Potential Savings - Idaho

Avista Conservation Potential – Residential

Idaho

From 2016 to 2025, cumulative achievable potential savings are 58 GWh, or 6.6 aMW.

Achievable potential in 2025 is about 76% of economic potential.



	2016	2017	2020	2025	2035
Cumulative ID Savings (GWh)					
Achievable Potential	4.6	10.6	30.9	58.0	93.0
Economic Potential	10.4	21.4	48.3	74.7	112.8
Technical Potential	29.2	58.7	139.0	249.5	395.3
Cumulative Savings (aMW)					
Achievable Potential	0.5	1.2	3.5	6.6	10.6
Economic Potential	1.2	2.4	5.5	8.5	12.9
Technical Potential	3.3	6.7	15.9	28.5	45.1

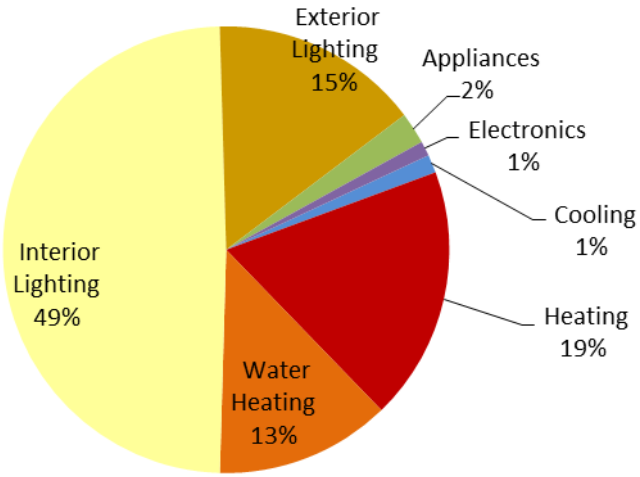
Avista Residential Savings Potential - Idaho

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Screw-in/Hard-wire LED and CFL	5,137	48.5%
Exterior Lighting - Screw-in/Hard-wire LED and CFL	1,588	15.0%
Ducting - Repair and Sealing	1,574	14.9%
Water Heater - Pipe Insulation	729	6.9%
Water Heater - Faucet Aerators	337	3.2%
Thermostat - Clock/Programmable	231	2.2%
Behavioral Programs	225	2.1%
Insulation - Ducting	193	1.8%
Water Heater - Low-Flow Showerheads	135	1.3%
Appliances – Freezer ENERGY STAR	95	0.9%
Total Top 10 Measures	**10,243**	**96.8%**

Energy savings by end use

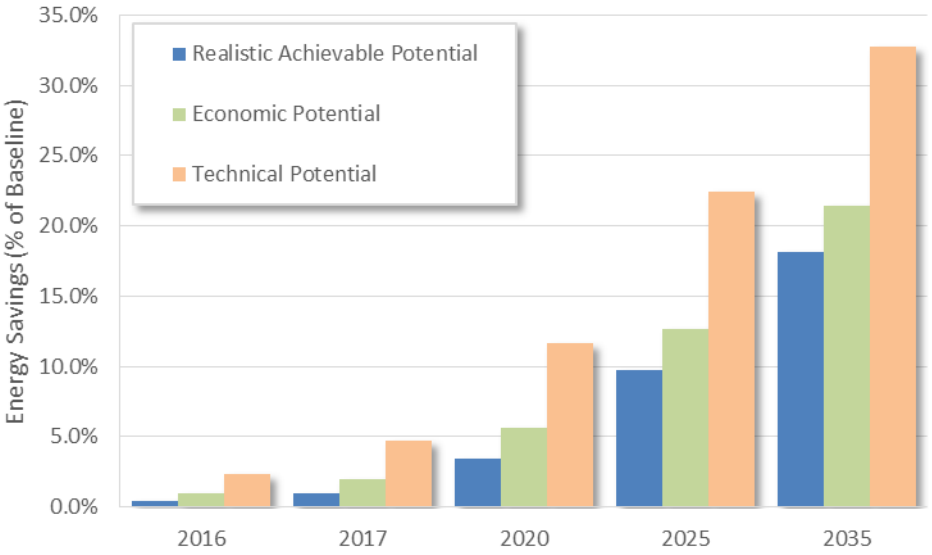


Avista Conservation Potential – Commercial

Idaho

From 2015 to 2025, cumulative achievable potential savings are 98 GWh, or 11.2 aMW.

Achievable potential in 2025 is about 77% of economic potential.



	2016	2017	2020	2025	2035
Cumulative ID Savings (GWh)					
Achievable Potential	4.2	9.0	33.4	97.7	198.4
Economic Potential	9.3	19.1	54.6	126.9	233.9
Technical Potential	22.7	45.1	112.3	221.2	349.5
Cumulative Savings (aMW)					
Achievable Potential	0.5	1.0	3.8	11.2	22.6
Economic Potential	1.1	2.2	6.2	14.5	26.7
Technical Potential	2.6	5.2	12.8	25.3	39.9

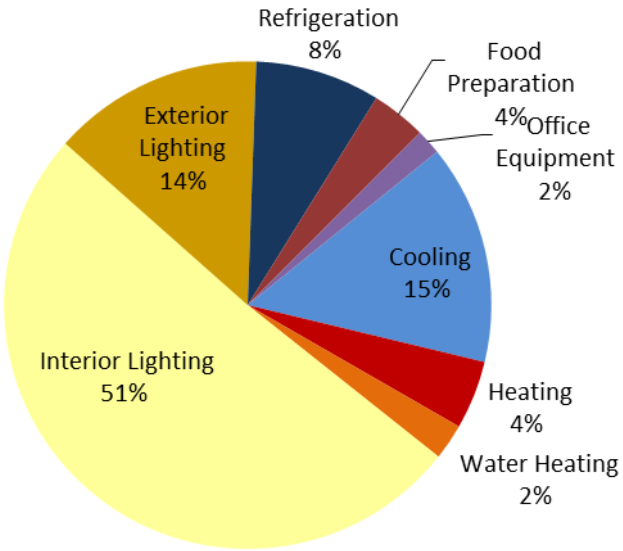
Avista Commercial Savings Potential - Idaho

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Savings (MWh)	% of Total
Interior Lighting - Linear LED	2,134	23.9%
Interior Lighting - Screw-in/Hard-wire LED and T5	1,237	13.8%
Exterior Lighting - Linear LED	448	5.0%
Chiller - Chilled Water Reset	437	4.9%
Interior Lighting - High-Bay Fixtures LED	366	4.1%
Interior Lighting - Occupancy Sensors	297	3.3%
HVAC - Duct Repair and Sealing	275	3.1%
Interior Lighting - Skylights	270	3.0%
Exterior Lighting - Screw-in/Hard-wire CFL and LED	224	2.5%
Exterior Lighting – HID T5 and LED	217	2.4%
Total Top 10 Measures	**5,905**	**65.4%**

Energy savings by end use

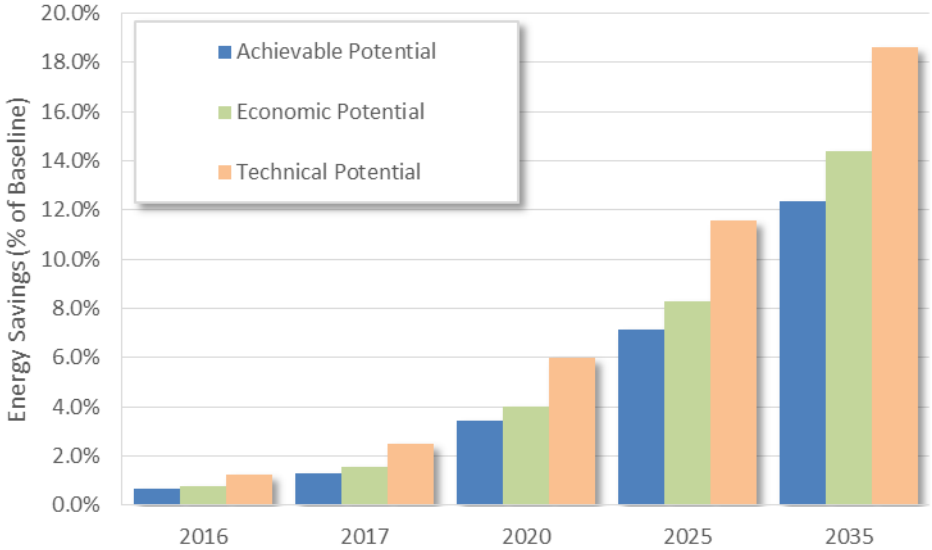


Avista Conservation Potential – Industrial

Idaho

From 2015 to 2025, cumulative achievable potential savings are 28 GWh, or 3.2 aMW.

Achievable potential in 2025 is about 85% of economic potential.



	2016	2017	2020	2025	2035
Cumulative ID Savings (GWh)					
Achievable Potential	2.4	4.8	13.0	28.2	53.0
Economic Potential	2.8	5.7	15.3	32.9	61.5
Technical Potential	4.6	9.2	22.7	45.6	79.4
Cumulative Savings (aMW)					
Achievable Potential	0.3	0.6	1.5	3.2	6.0
Economic Potential	0.3	0.6	1.7	3.8	7.0
Technical Potential	0.5	1.0	2.6	5.2	9.1

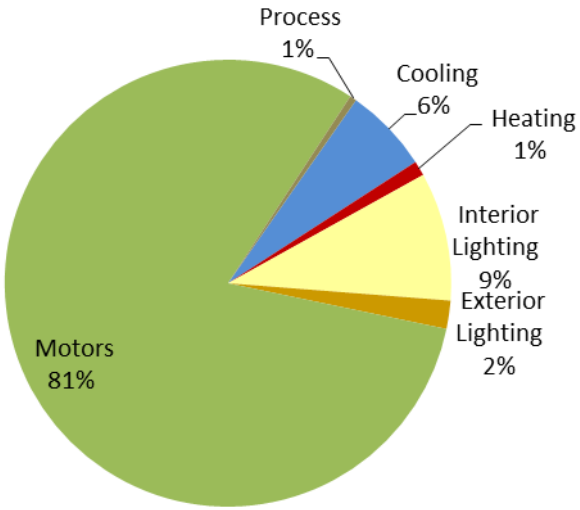
Avista Industrial Savings Potential - Idaho

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Savings (MWh)	% of Total
Fan System - Optimization and Improvements	1,226	25.4%
Motors - Variable Frequency Drive (Pumps)	814	16.8%
Fan System - Maintenance	414	8.6%
Motors - Variable Frequency Drive (Fans & Blowers)	407	8.4%
Compressed Air - Air Usage Reduction	336	7.0%
Compressed Air - System Optimization and Improvements	271	5.6%
Pumping System - Optimization and Improvements	230	4.8%
Interior Lighting - Occupancy Sensors	183	3.8%
Interior Lighting - High-Bay Fixtures LED	114	2.4%
Motors - Variable Frequency Drive (Other)	110	2.3%
Total Top 10 Measures	**4,104**	**84.9%**

Energy savings by end use



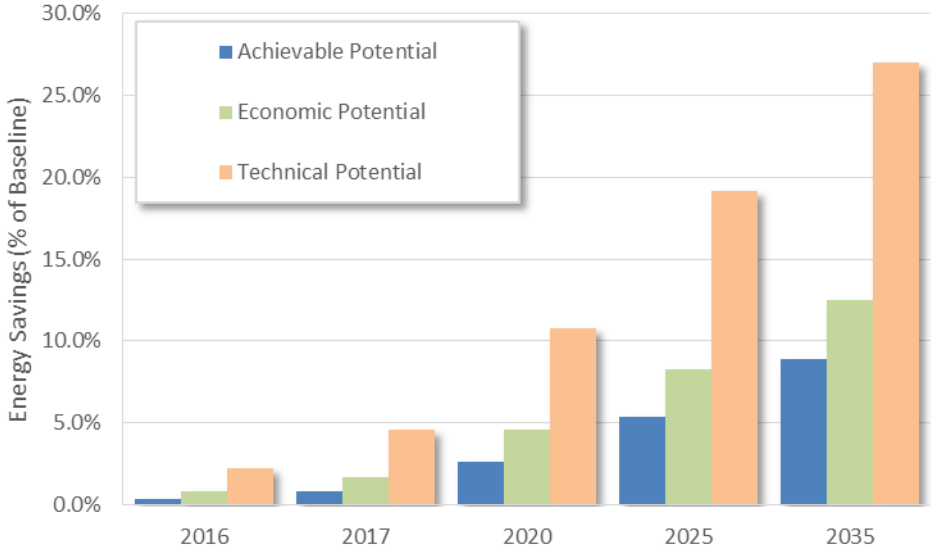
Summary of Conservation Potential – Sensitivity Case

Avista Conservation Potential – Residential

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 201 GWh, or 23.0 aMW.

An additional 3.7 aMW is possible by 2025, compared to the TRC=1.0 case.



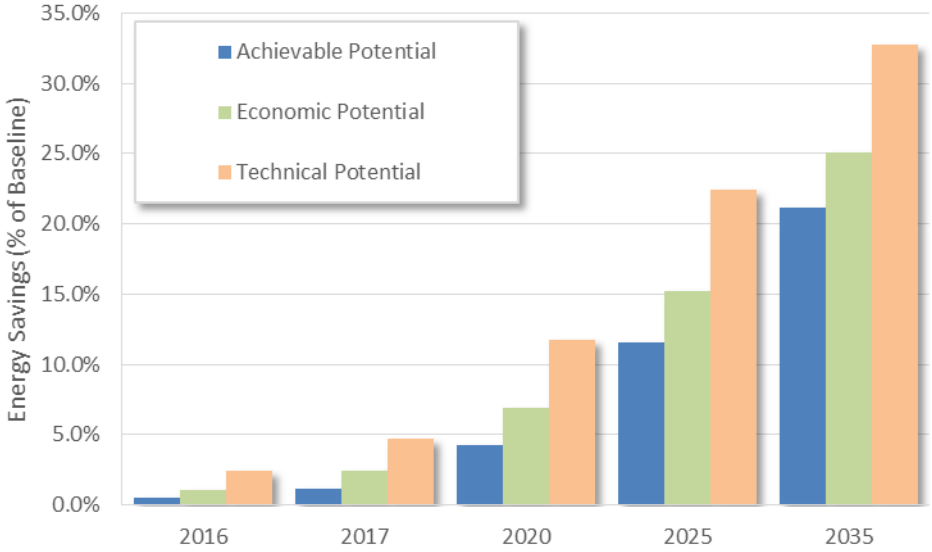
	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	13.6	31.0	97.5	201.5	368.8
Economic Potential	30.7	63.5	171.4	311.2	517.2
Technical Potential	84.5	168.7	400.1	718.9	1,116.7
Cumulative Savings (aMW)					
Achievable Potential	1.5	3.5	11.1	23.0	42.1
Economic Potential	3.5	7.2	19.6	35.5	59.0
Technical Potential	9.6	19.3	45.7	82.1	127.5

Avista Conservation Potential – Commercial

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 356 GWh, or 40.7 aMW.

An additional 6.0 aMW is possible by 2025, compared to the TRC=1.0 case.



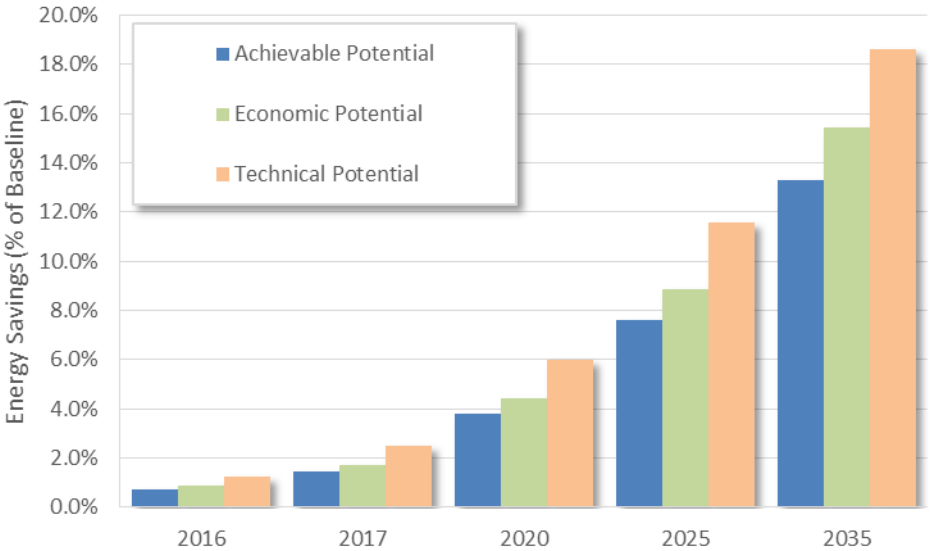
	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	15.3	35.5	128.8	356.1	708.8
Economic Potential	32.7	72.0	208.5	470.5	839.8
Technical Potential	71.2	141.7	352.8	694.2	1,095.9
Cumulative Savings (aMW)					
Achievable Potential	1.7	4.1	14.7	40.7	80.9
Economic Potential	3.7	8.2	23.8	53.7	95.9
Technical Potential	8.1	16.2	40.3	79.2	125.1

Avista Conservation Potential – Industrial

Washington and Idaho combined

From 2016 to 2025, cumulative achievable potential savings are 111 GWh, or 12.7 aMW.

An additional 1.1 aMW is possible by 2025, compared to the TRC=1.0 case.



	2016	2017	2020	2025	2035
Cumulative WA and ID Savings (GWh)					
Achievable Potential	9.9	19.9	53.0	110.9	209.5
Economic Potential	11.6	23.4	62.3	129.4	242.9
Technical Potential	17.1	33.9	83.7	168.4	293.2
Cumulative Savings (aMW)					
Achievable Potential	1.1	2.3	6.0	12.7	23.9
Economic Potential	1.3	2.7	7.1	14.8	27.7
Technical Potential	1.9	3.9	9.6	19.2	33.5

Avista Residential Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Screw-in/Hard-wire (LED)	13,616	43.9%
Ducting - Repair and Sealing	5,057	16.3%
Exterior Lighting - Screw-in/Hard-wire	4,152	13.4%
Water Heater - Pipe Insulation	2,264	7.3%
Water Heater - Faucet Aerators	1,037	3.3%
Thermostat - Clock/Programmable	726	2.3%
Behavioral Programs	689	2.2%
Insulation - Ducting	630	2.0%
ENERGY STAR Homes	606	2.0%
Total	**28,777**	**92.7%**

- Programmable thermostats passed in the multi-family segments, moving it up in the rankings
- Insulation – ducting passed in the multi-family segment, increasing the savings
- ENERGY STAR Homes did not pass the TRC at the 1.0 level in any segment

Avista Commercial Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Interior Lighting - Linear LED	6,604	18.6%
Interior Lighting - Screw-in/Hard-wire LED and CFL	3,923	11.0%
Interior Lighting - Occupancy Sensors	3,211	9.0%
Chiller - Chilled Water Reset	1,360	3.8%
Interior Lighting - High-Bay Fixtures T5 and LED	1,205	3.4%
Exterior Lighting - Linear LED	1,135	3.2%
HVAC - Duct Repair and Sealing	1,068	3.0%
Water Heater - Faucet Aerators/Low Flow Nozzles	917	2.6%
Interior Lighting - Skylights	831	2.3%
Exterior Lighting – HID T5 and LED	820	2.3%
Total Top 10 Measures	**21,075**	**59.3%**

- Interior lighting – screw-in includes more LED in more segments
- Occupancy sensors pass in more segments
- High Bay fixtures pass in more segments
- Faucet aerators and Low flow nozzles did not pass when the TRC threshold was 1.0
- Exterior lighting includes more LED

Avista Industrial Savings Potential – WA & ID

Cumulative achievable potential in 2017

Top measures by energy savings

Measure / Technology	2017 Cumulative Energy Savings (MWh)	% of Total
Fan System - Optimization and Improvements	4,524	22.8%
Motors - Variable Frequency Drive (Pumps)	3,020	15.2%
Fan System - Maintenance	1,635	8.2%
Motors - Variable Frequency Drive (Fans & Blowers)	1,505	7.6%
Compressed Air - Air Usage Reduction	1,247	6.3%
Compressed Air - Air Compressor Replacement	1,217	6.1%
Motors - Variable Frequency Drive (Compressed Air)	936	4.7%
Pumping System - Optimization and Improvements	891	4.5%
Interior Lighting - Occupancy Sensors	713	3.6%
Interior Lighting - High-Bay Fixtures	420	2.1%
Total Top 10 Measures	16,108	81%

- Fan system maintenance savings increased
- Compressed air – compressor replacement did not pass when the TRC threshold was 1.0
- Motors – Variable Frequency Drives savings increased

AEG
Applied Energy Group

Thank You!

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2015 Preferred Resource Strategy & Portfolio Analysis

James Gall
Fifth Technical Advisory Committee Meeting
May 19, 2015

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Introduction

- Discuss how Avista plans to meet resource deficits (PRS)
- Review methodology and decision making logic
- Discuss alternative resource strategies
- Discuss the impact to resource strategies with a different future than the Expected Case's future

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2013 IRP Preferred Resource Strategy

Resource		By the End of Year	Nameplate (MW)
Simple Cycle CT	Wells/WNP-3	2019	83
Simple Cycle CT		2023	83
Combined Cycle CT	Lancaster PPA	2026	270
Simple Cycle CT		2027	83
Rathdrum CT Upgrade		2028	6
Simple Cycle CT		2032	50
Total			**575**
Energy Efficiency		2014-2033	164 aMW
Demand Response		2022-2027	19 MW
Distribution Efficiencies		2014-2017	<1 MW

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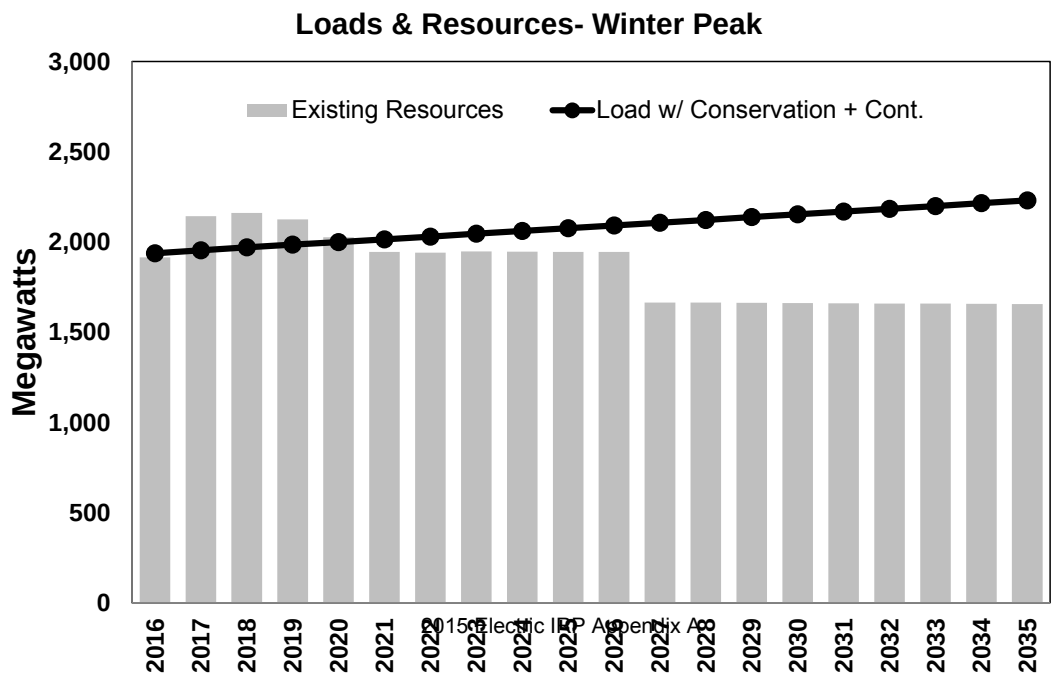
Resource Requirements

- Since the last TAC meeting, the peak capacity need has been pushed from 2020 to 2021.
- Avista signed a five year contract for five percent share of the Chelan County PUD's Rocky Reach and Rock Island projects



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Developing Resource Portfolios

- "1990 Methodology" Least Cost
  - "Experts" package plausible resource portfolios
    - Mixes of resource start dates, resource types
  - Lowest cost is the goal
  - No quantitative risk measurement
  - Likely misses best portfolio and its timing

	Portfolio	Gas Peaking	Gas CCCT	Wind	Solar	Coal	Market
1	Market Reliance	0	0	0	0	0	100
2	All Gas Peaking	100	0	0	0	0	0
3	All Gas	50	50	0	0	0	0
4	Gas & Wind	50	0	50	0	0	0
5	Balanced	20	2	20	0	20	20
6	High Renewables	25	0	50	25	0	0
7	All Renewables	0	0	75	25	0	0

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Developing Resource Portfolios, Cont.

- Hybrid Approach
  - Continue arbitrary portfolio development
  - Add stochastic analysis to measure risk
- Benefits
  - Allows risk measurement
  - Disqualifies portfolio outliers
  - May show benefits of additional spending for risk reduction
- Costs
  - May not select lowest cost portfolio for the level of risk
  - Many best portfolios are missed

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Avista's Portfolio Approach

- Best Practice- Efficient Frontier developed using a Mixed Integer Program (MIP)
- Each portfolio is the least cost "best" portfolio for each level of risk
- No need to build arbitrary portfolios
- Ensures the best portfolios are developed
- Allows for explicit and comprehensive measure of risk vs. cost
- Still does not pick the "ideal" portfolio

Efficient Frontier Video
http://www.investopedia.com/terms/e/efficientfrontier.asp

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Avista's Portfolio Approach, Cont.

- Mixed Integer Program (MIP)
  - Lindo System's What's Best software using Gurobi solver
    - *Superior speed improvement allowing more complex modeling*
  - Solves for least cost mix to meet Avista's resource shortfall
    - *NPV of power supply for next 25 years along with a small weighting of costs beyond 25 years*
  - New generating resources, resource upgrades, conservation, demand response all compete to meet the resource shortfall
    - *Options are treated as integers, therefore no partial units (including conservation)*
  - Model can solve to reduce power supply risk by selecting different resource strategies, while adhering to resource sizes
  - Can still test "arbitrary" portfolios to illustrate concepts

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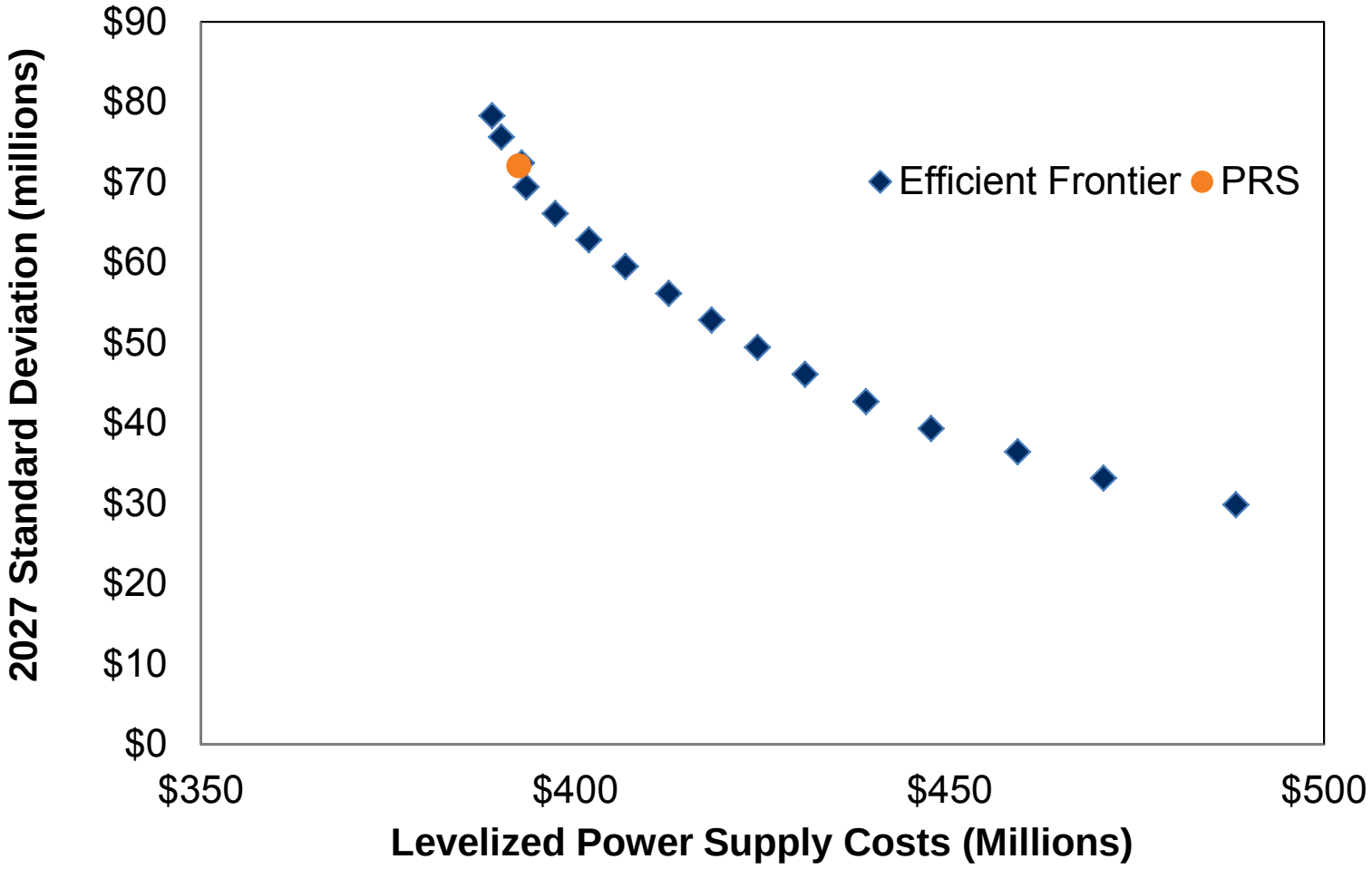
2015 IRP Efficient Frontier



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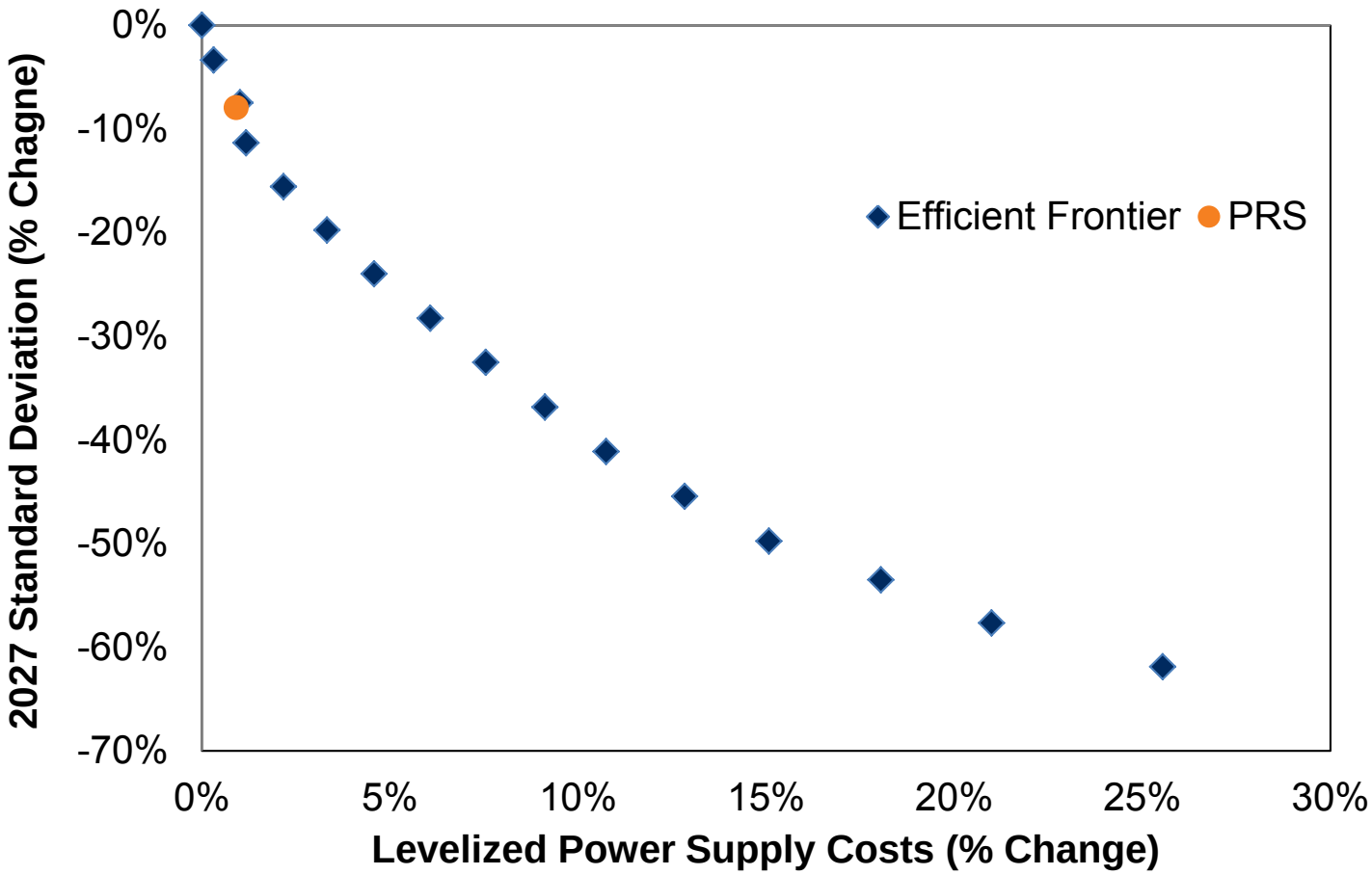
Efficient Frontier as Percent Change from Least Cost



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Selecting the "Best" Portfolio

- Using Avista's methodology, all portfolios are best for the assigned level of risk
- Academic research uses indifference curves "risk tolerance" to help select the "best" portfolio
- Other metrics to help select the portfolio
  - Risk adjusted PVRRs
  - Point to point derivatives

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Risk Adjusted PVRR

- This metric adds to each year's revenue requirement, five percent of the added cost of the 95th percentile
  - If expected cost was $100, the 95th percentile is $200, the cost would be $105.
  - Method simulates the added cost of a 1 in 20 bad outcome
- Methodology is useful in "hybrid" portfolio development as it can distinguish between un-optimized portfolios
  - A less useful measure in MIP-derived portfolios as model minimizes this cost for each level of risk

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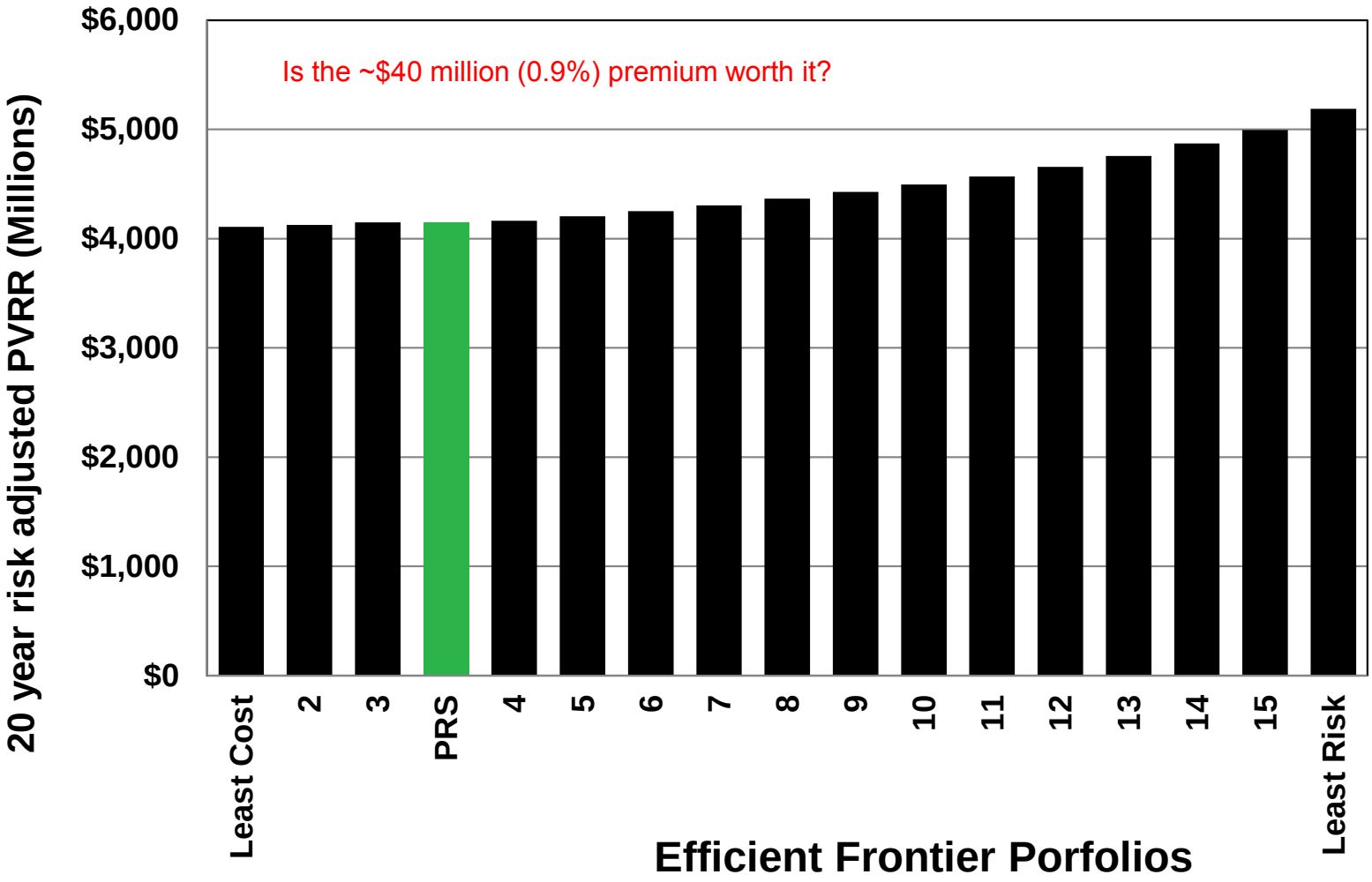
Risk Adjusted PVRR Results



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Point to Point Derivatives

- Distinguishes the relationship between added cost and risk reduction
- Typically want good trade off, but each portfolio manager's judgment of the trade off is different
- Avista selects a portfolio where there is a good trade off between cost and risk
- The measure used by Avista since 2005, when adopting present method, to select a preferred resource portfolio

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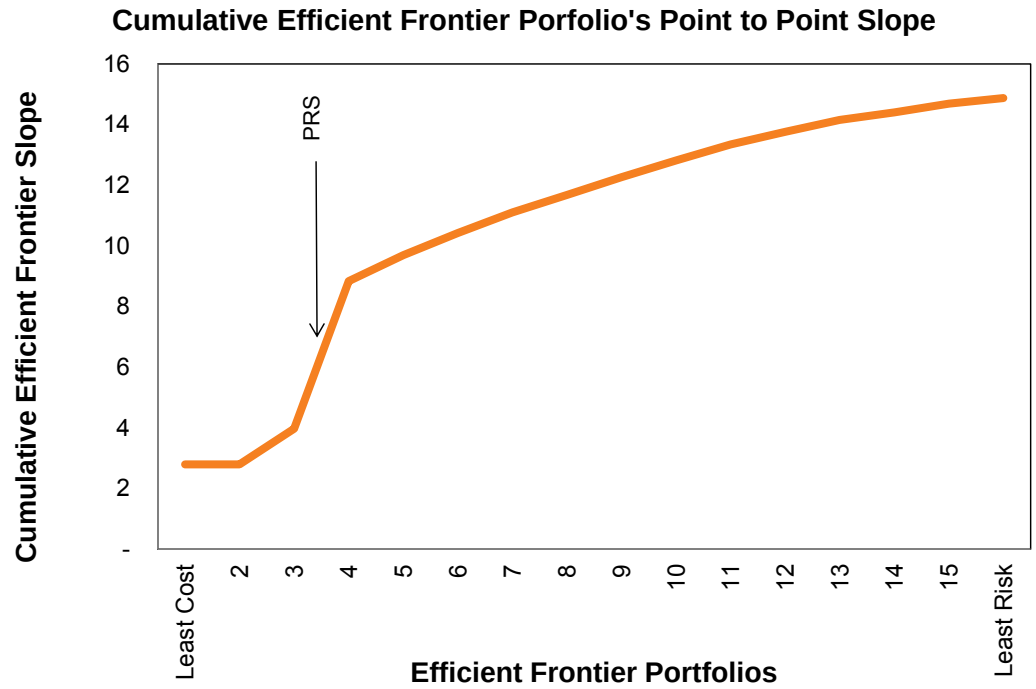
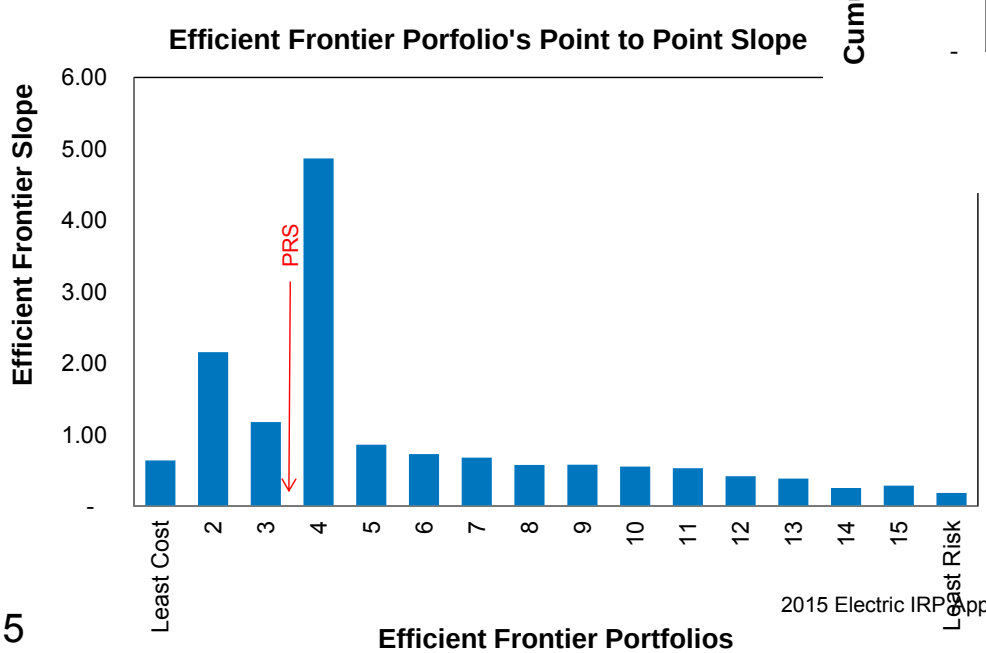
Point to Point Derivatives

- Portfolio's between #3 and #4 vary the size of the 2027 CCCT





An inflection point does not necessarily mean it is the best place to land, as the benefit could be greatly outweighed by the cost—this could be the case in the 2015 IRP

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2015 IRP: Preferred Resource Strategy

Resource	By End of Year	ISO Conditions (MW)	Winter Capacity (MW)	Energy (aMW)
Natural Gas Peaker	2020	96	102	89
Thermal Upgrades	2021-2025	38	38	35
Combined Cycle CT	2026	286	306	265
Natural Gas Peaker	2027	96	102	89
Thermal Upgrades	2033	3	3	3
Natural Gas Peaker	2034	47	47	43
Total		**565**	**597**	**524**
Conservation (w/ T&D losses)	2016-2035		192	132

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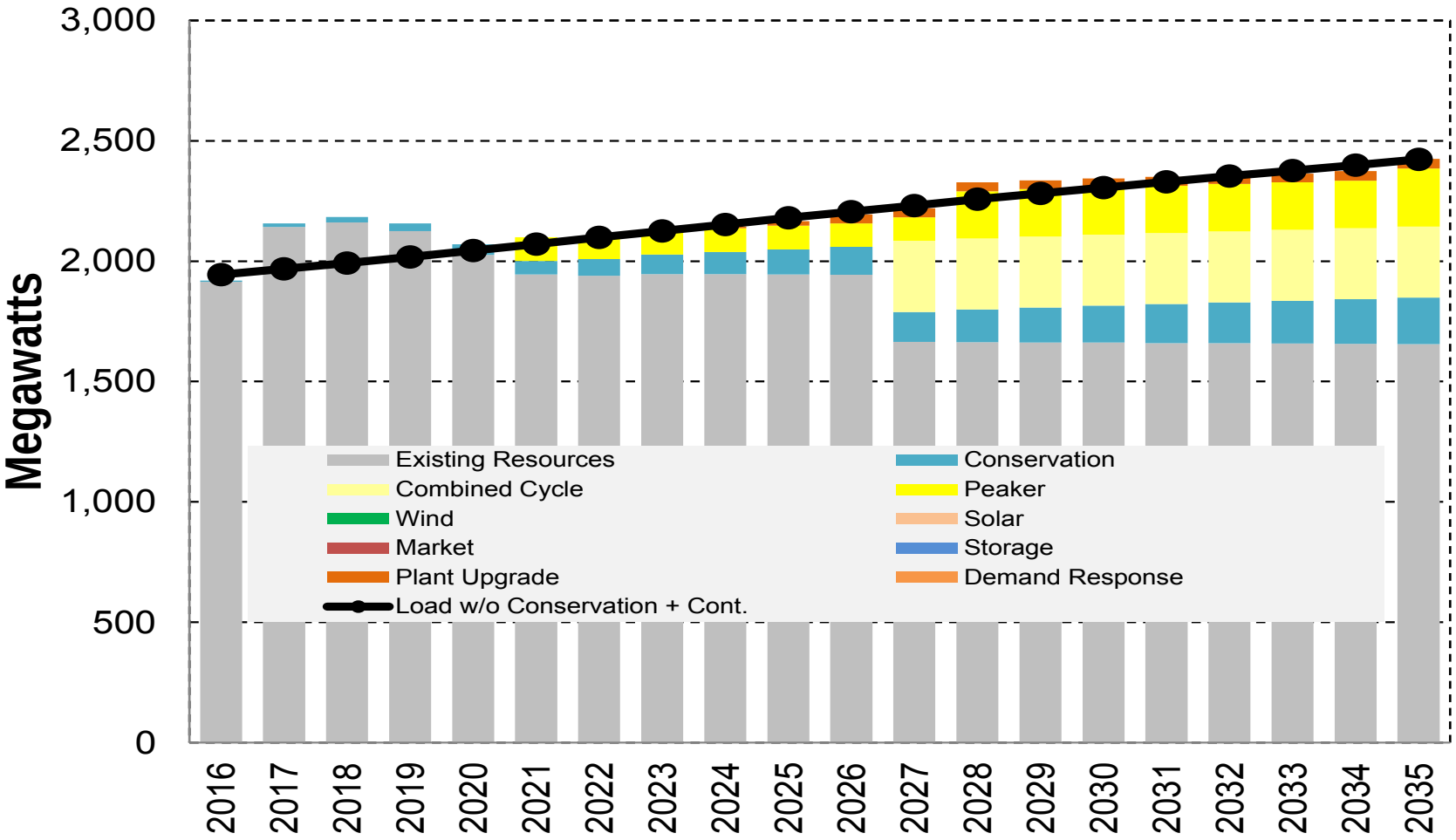
Loads & Resources- Winter Peak



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Conservation Modeling

- Load forecast adjusted higher to evaluate portfolio without conservation, grossed up using AEG's CPA conservation level
- Conservation measures are considered as resource options
  - ~2,500 programs below 130% of the avoided cost are included in PRiSM
  - Additional programs above 130% threshold are excluded
- PRiSM may chose conservation program or generation resource to fill resource deficits
  - PRiSM looks at the added energy, winter, and summer capacity for each program compared to its cost and energy savings
  - When valuing the energy savings, the Power Act 10% premium is included
- Programs are either on/off. A program cannot start and end unless its life cycle is complete

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Conservation Avoided Cost

- Energy: *$38.38/ MWh (flat delivery)* ***PLUS***
- Capacity & Risk: *$94.84/ kW-year (winter peak)* ***PLUS***
- T&D Capacity: *$12.30/ kW-year (winter peak)* ***PLUS***
- T&D Losses: *6.1%* ***PLUS***
- Power Act Adder: *10% added to energy & loss values*

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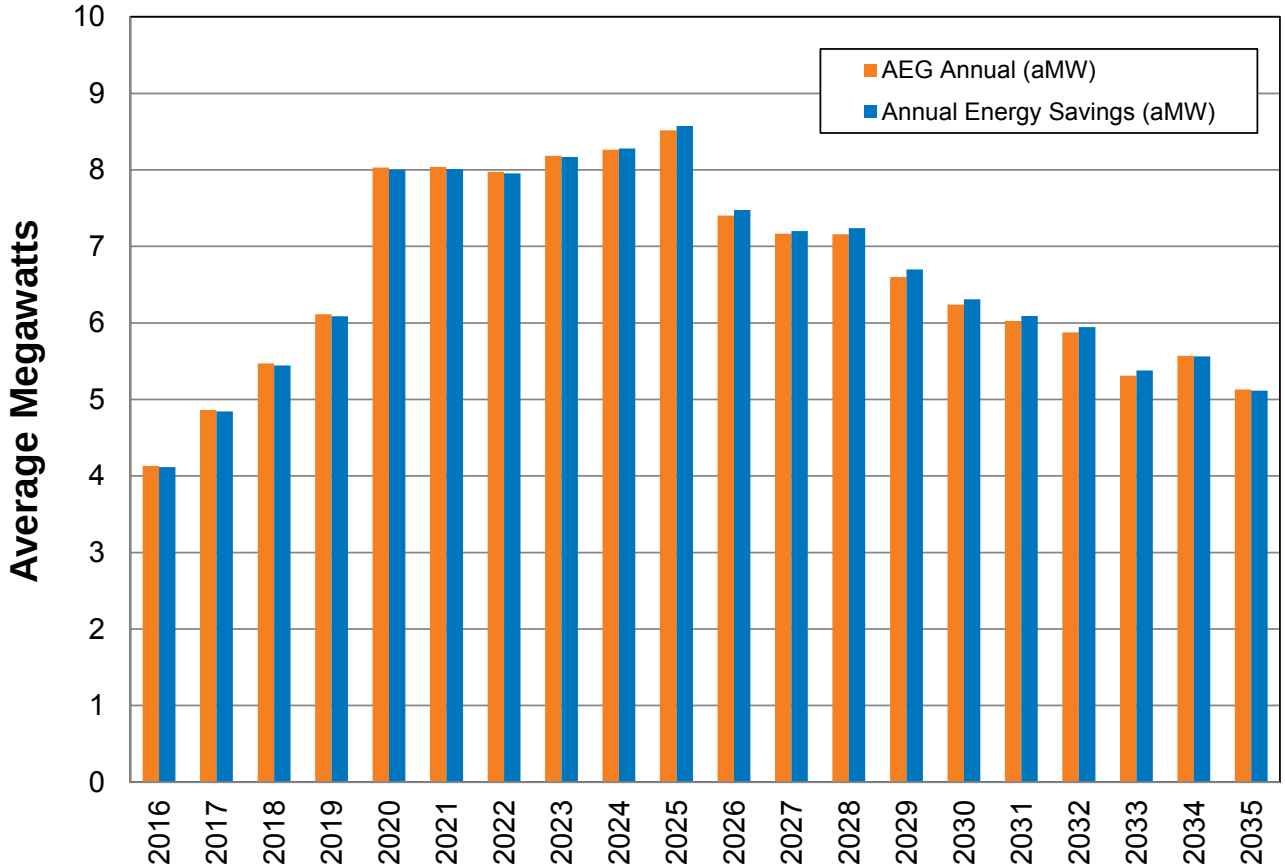
Conservation Selection vs. CPA with Losses



aMW	2016-2017	2016-2035
CPA	8.99	132.06
PRiSM	8.96	132.48

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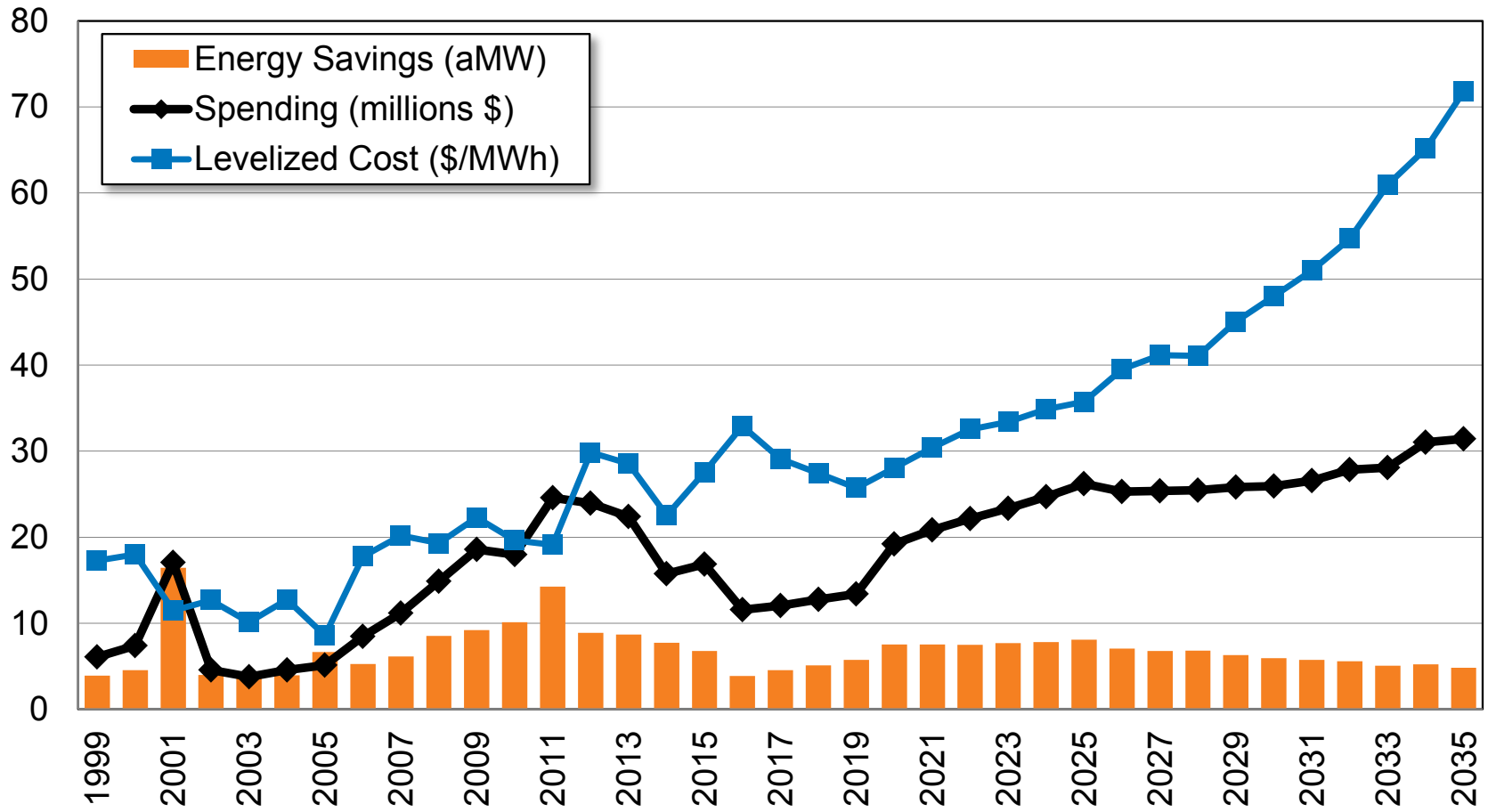
Utility Cost of Conservation



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Integer vs. Linear Programing

- Linear programming allows all resource options to be chosen in any increment subject to min and max constraints
  - For example, a Combined Cycle CT can be selected with a capacity of 158.45 MW rather then the full 286 MW plant
- Integer programing holds resource options to specific sizes. Integer programming models resources lumpy rather then precise additions.
  - Lumpy resource additions adds costs compared to perfect resource acquisition

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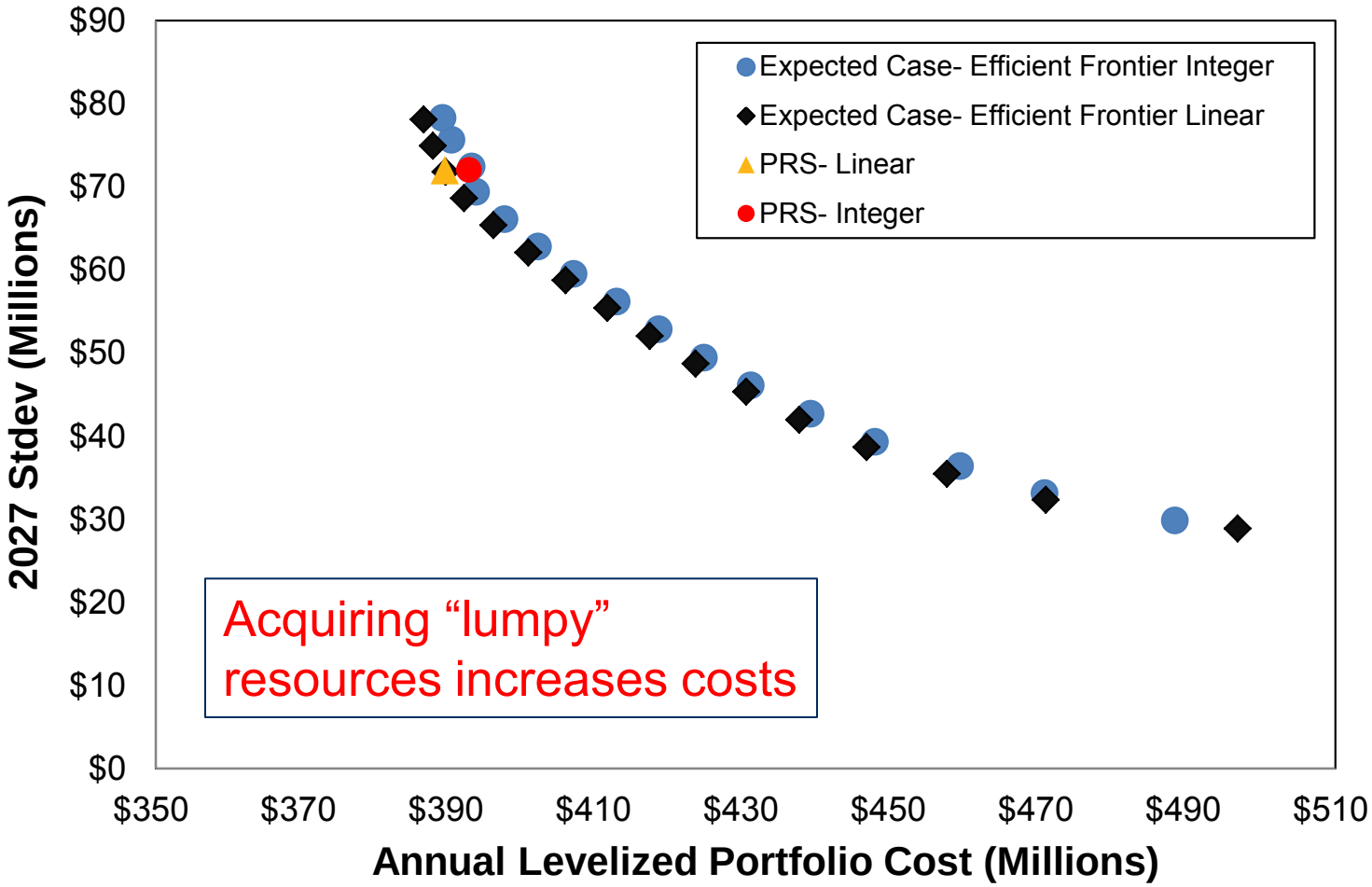
Mix Integer vs. Linear Programing



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Other Resource Portfolios Along the Frontier (Nameplate MW)

Portfolio	NG Peaker	NG CCCT	Wind	Solar	Demand Response	Thermal Upgrade	Hydro Upgrade	Conservation
Least Cost	527	-	-	-	-	38	-	128
2	524	-	-	-	-	41	-	135
3	239	286	-	-	-	38	-	128
PRS	239	286	-	-	-	41	-	132
4	143	341	-	-	-	38	-	138
5	189	341	50	10	-	41	-	139
6	140	341	100	20	-	41	-	143
7	189	341	200	-	-	38	-	141
8	140	341	250	20	-	41	-	142
9	186	341	300	70	-	38	-	141
10	186	341	400	30	-	38	-	141
11	140	341	450	80	-	38	-	144
12	140	341	500	150	-	41	-	142
13	186	341	500	290	-	38	-	143
14	93	627	500	270	-	38	-	140
15	93	627	500	480	-	38	-	141
Least Risk	186	683	500	600	-	23	-	144

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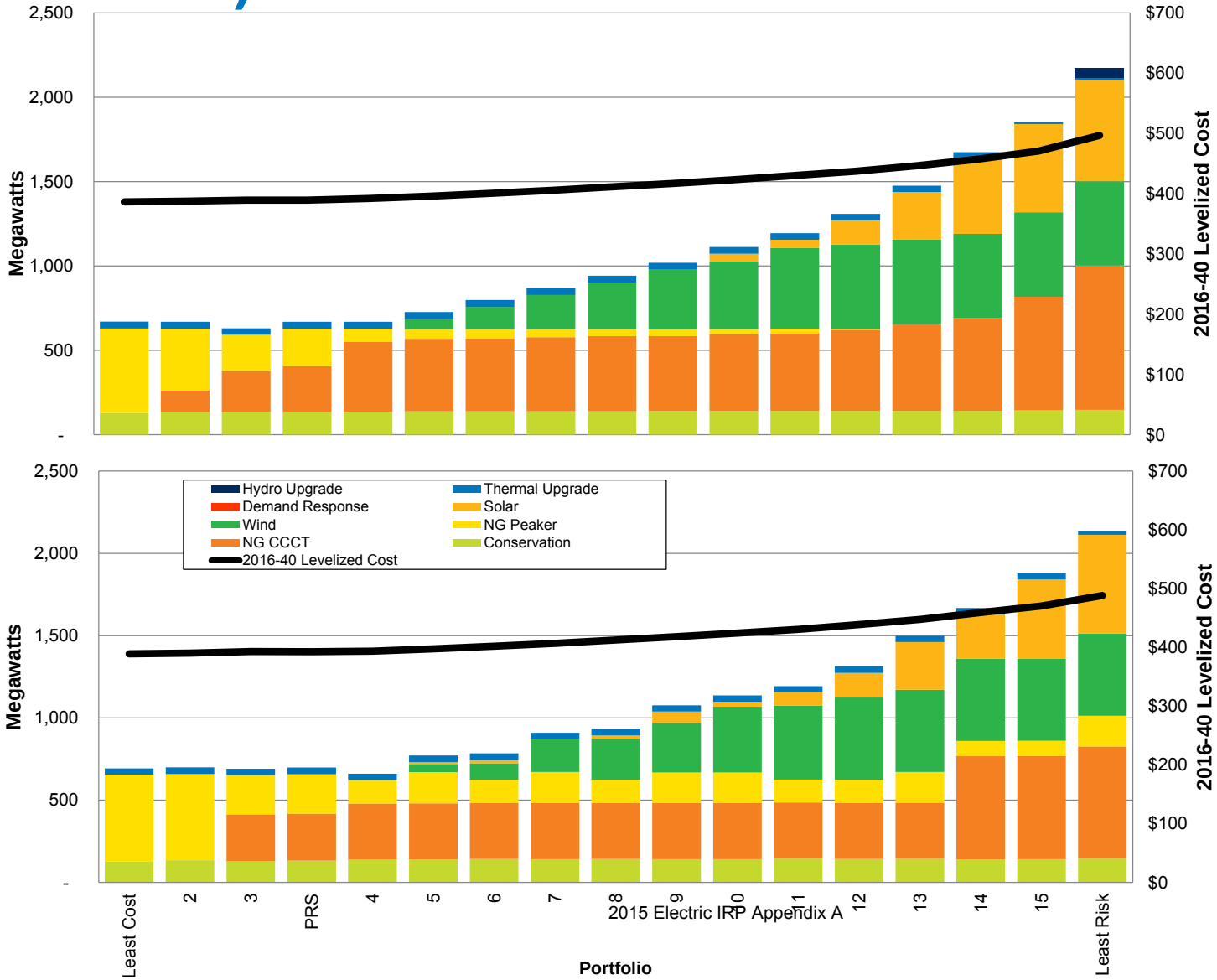
Efficient Frontier Portfolios (Integer vs. Linear)



Linear shows CCCT earlier and smoothed resource changes

Integer has delayed CCCT and lumpy resource changes

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Portfolio Scenarios

- Load forecast
  - Low, high, increases DG solar penetration
- Colstrip retires end of 2026
- High cost Colstrip Retention
  - Colstrip retires end of 2022
- Market & Conservation
- 2013 PRS
- Renewables Meet All Load Growth
- Hydro Upgrades & Peakers
- Peakers & Hydro Total Portfolio

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Load Sensitivities

- *Purpose: Describe changes in PRS with alternative future load conditions*
- Low Load
  - Assumes lower GDP* growth (2.0%)
- High Load
  - Assumes higher GDP* growth (3.2%)
- DG Solar Penetration
  - Expected case forecast with DG solar penetration growing exponentially to 10% of residential customers with an 6 kW average system size by 2040

** Expected Case GDP forecast is ~2.6%*

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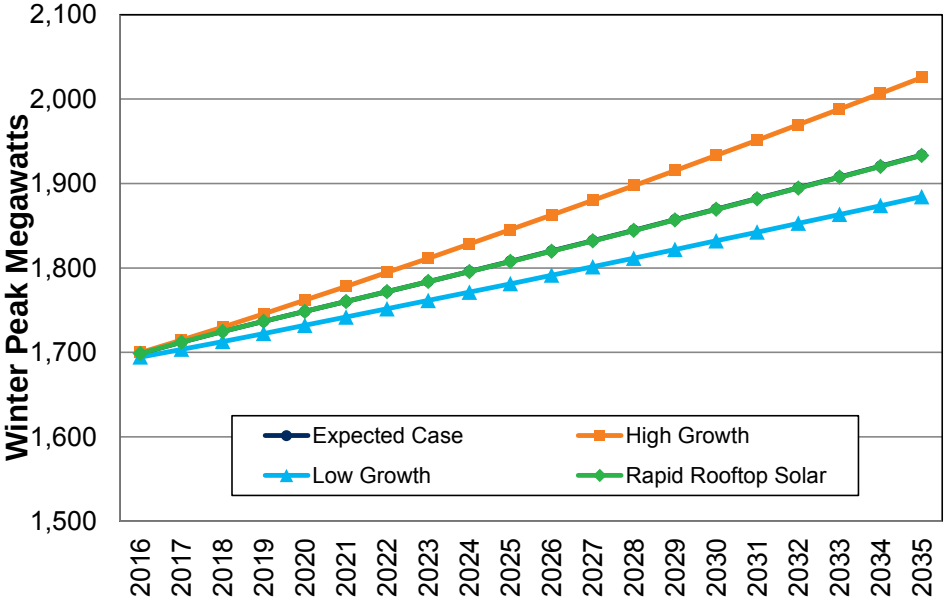
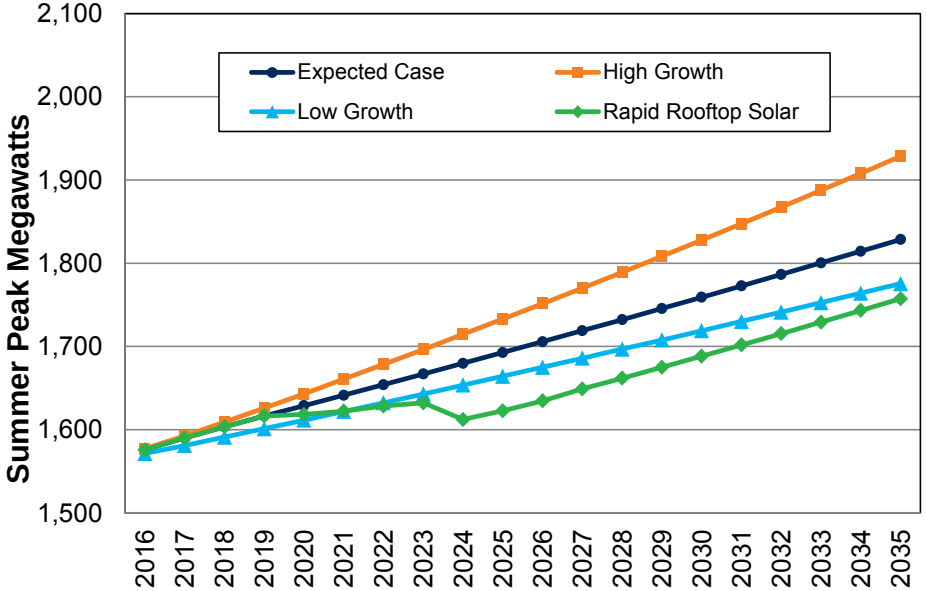
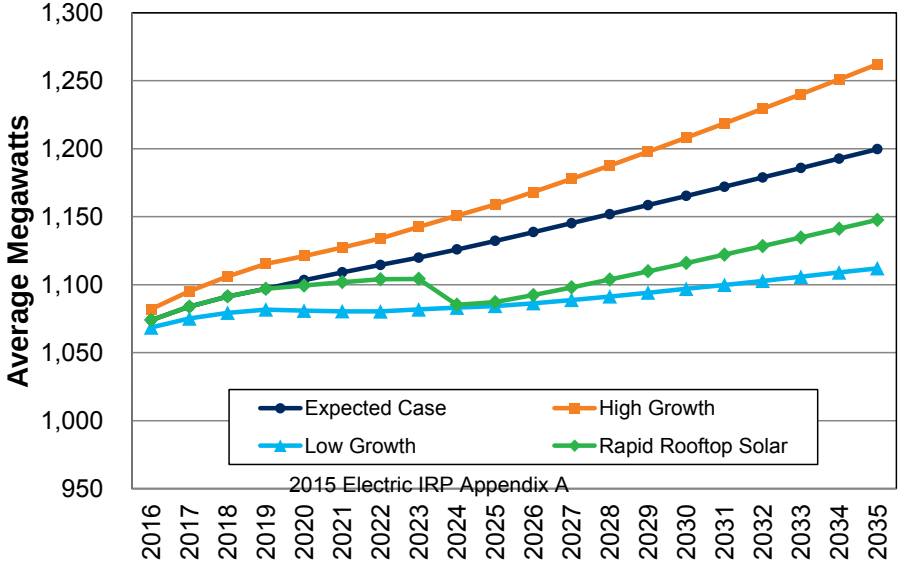
Load Sensitivities (continued)







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Load Sensitivity Resource Strategies

Resource	Expected Case PRS	Low Loads	High Loads	High DG Solar Penetration
NG Peaker	239	192	335	239
NG Combined Cycle CT	286	286	286	286
Wind	0	0	0	0
Solar	0	0	0	0
Demand Response	0	0	0	0
Thermal Upgrades	41	41	41	41
Hydro Upgrades	0	0	0	0
Total	**565**	**519**	**662**	**565**

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SCENARIO: Colstrip Analysis

- Assumes Colstrip retires at the end of 2026
- No Selective Catalytic Reduction (SCR) investment
- Plant is fully depreciated by end of 2031
- Pond closure costs begin in 2027
- Replacement resources similar to Expected Case PRS

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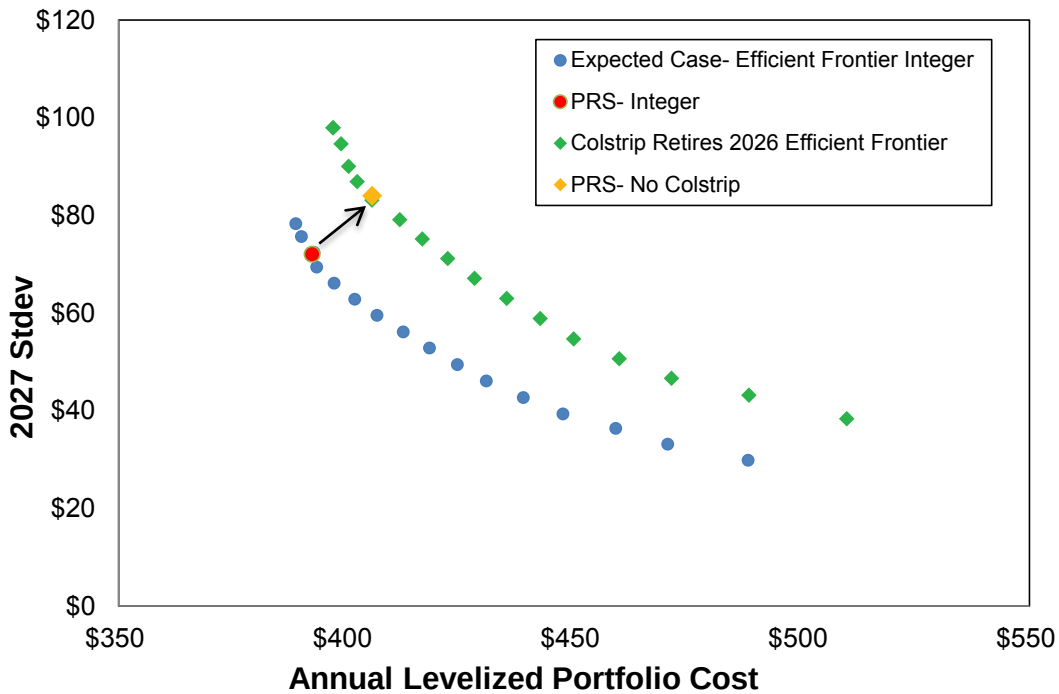
SCENARIO: Colstrip Retires in 2026



Resource	By End of Year	ISO Conditions (MW)
Natural Gas Peaker	2020	96
Thermal Upgrades	2021-2025	38
Combined Cycle CTs	2026	627
Total		**761**
Conservation (w/ T&D losses)	2016-2035	130.7

25-year levelized cost increase of $13.4 million (+ 4%) per year, risk increase $12 million (+ 17%), the 2027 increase is $58 million

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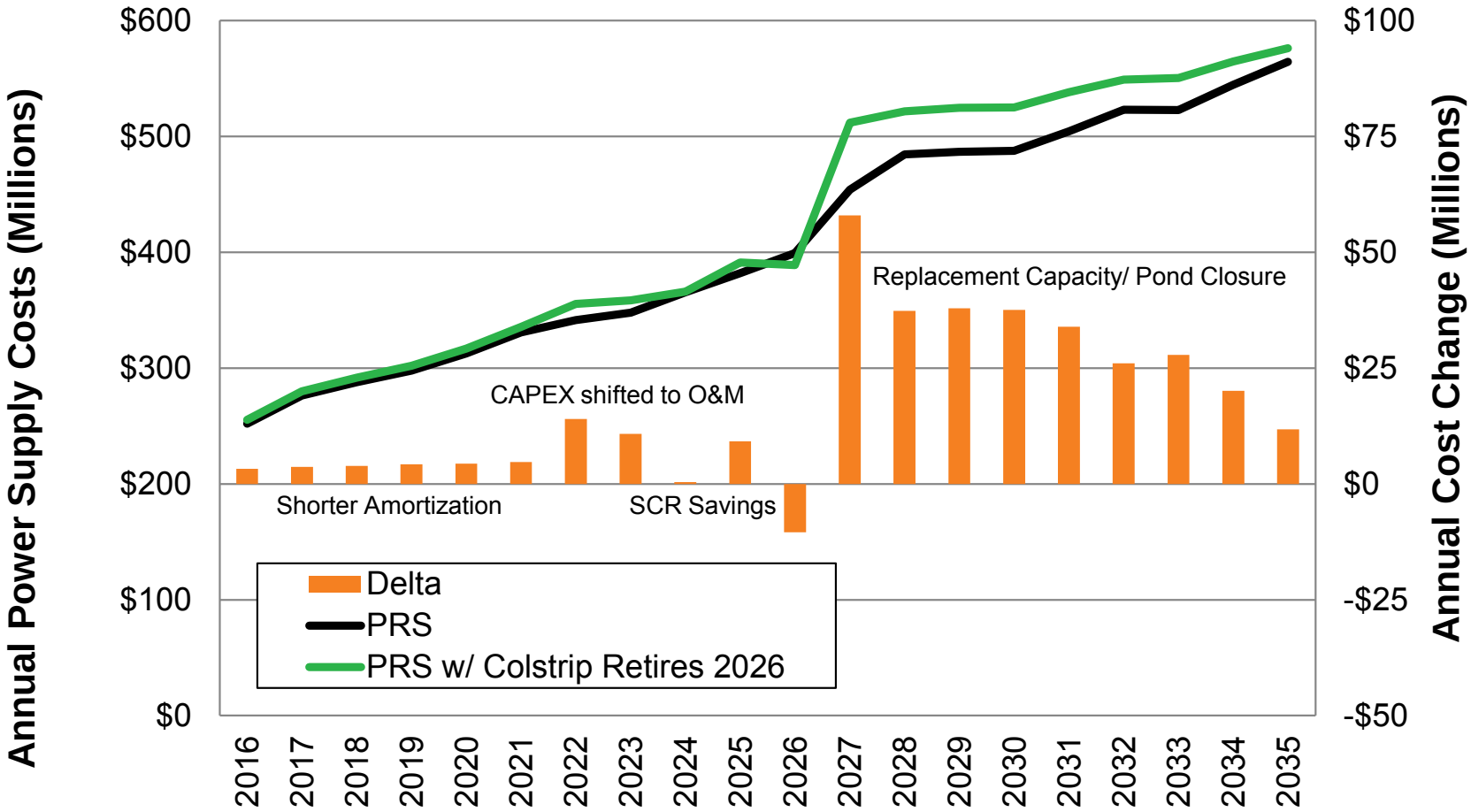
Annual Power Supply Cost Impact After Colstrip Closure in 2026



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SCENARIO: High-Cost Colstrip Retention

- Higher-cost Colstrip compliance assumptions provided by TAC members
  - Assumptions include:
    - SO_2 Scrubbers: $700 million (2022) w/ $45 million annual O&M
    - Dry Ash Handling Conversion: $60 million (2022) w/ $3 million annual O&M
    - Replacement Landfill: $9 million (2022) w/ $0.33 million annual O&M
    - New SCR: $268 million (2022) w/ $35 million annual O&M
    - Colstrip 1 & 2 retire in 2017, w/ common costs shifted to 3 & 4 owners
- Assumptions have not been vetted by Avista
- Two scenarios studied
  - PRS with higher compliance costs
  - Colstrip retirement at the end of 2022

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SCENARIO: Colstrip Retires 2022

Resource	By End of Year	ISO Conditions (MW)
Natural Gas Peaker	2020	56
Thermal Upgrades	2021-2035	41
Combined Cycle CTs	2023-2026	627
Natural Gas Peaker	2035	47
Total		**770**
Conservation (w/ T&D losses)	2016-2035	131.0

- Early Colstrip retirement scenario adds CCCT earlier in the plan
- Peaker still required in 2020
  - More detailed economics could support bigger CCCT in 2020 rather than splitting between CCCT and a peaker

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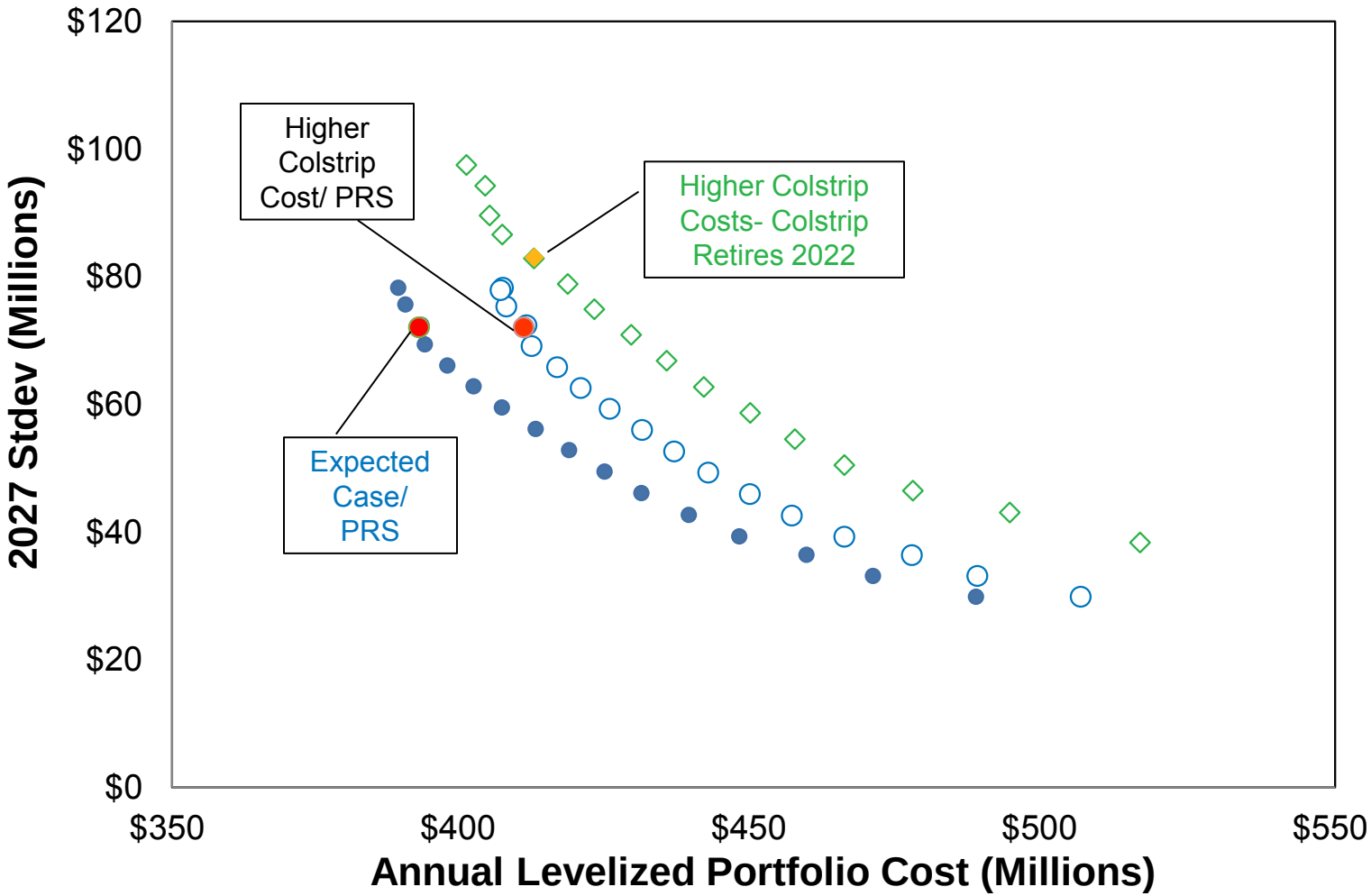
Colstrip Scenario Efficient Frontier Analysis



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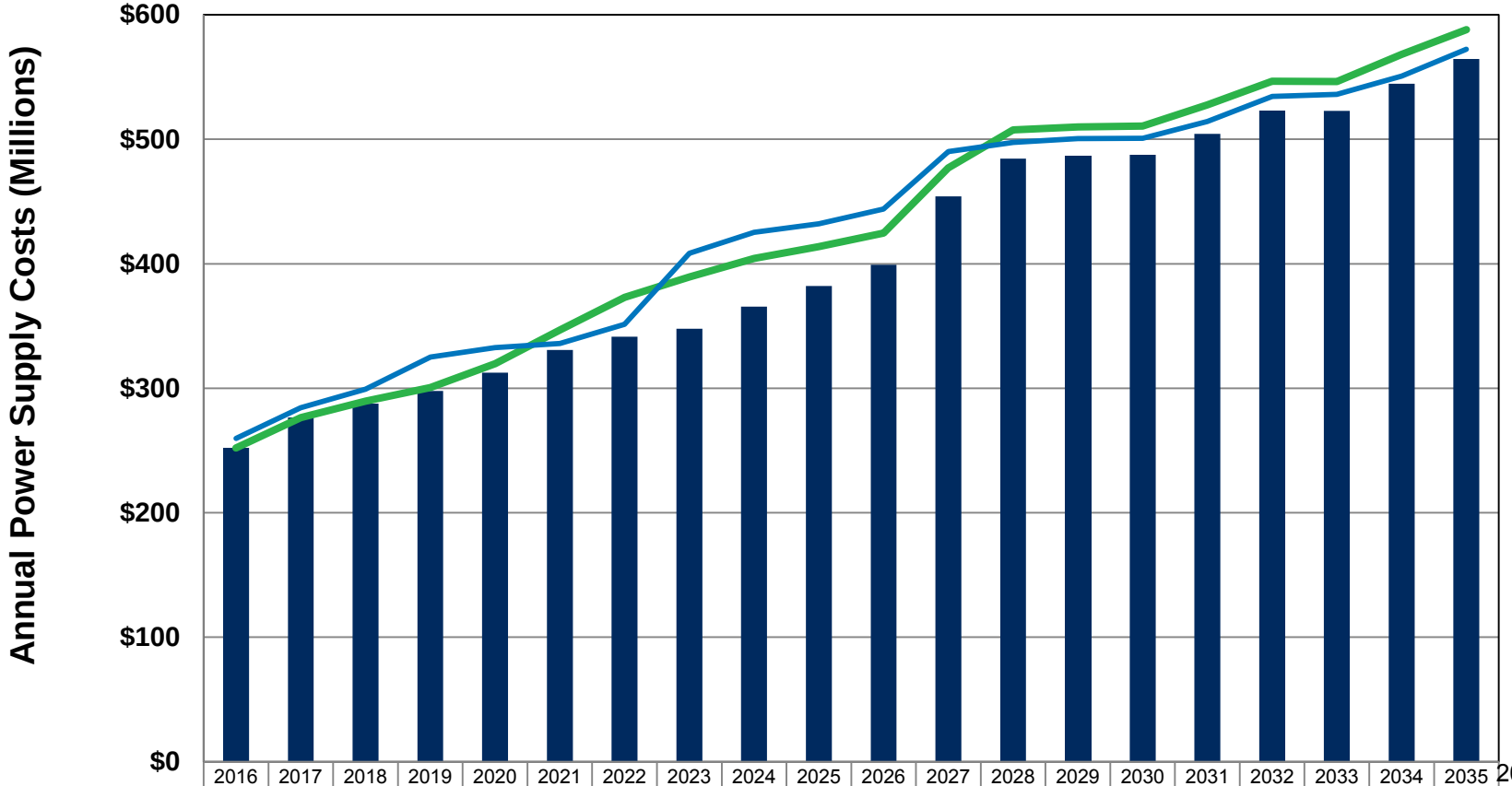
Colstrip Scenarios (Continued)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	20-yr Levelize
PRS	252	276	288	298	313	331	341	348	366	382	399	454	484	487	488	504	523	523	545	564	$374
PRS High Colstrip Costs	252	276	290	301	320	347	373	389	404	414	425	477	507	510	511	528	547	546	568	588	$391
PRS Colstrip Retires 2022	260	284	299	325	333	336	351	408	425	432	444	490	498	500	501	514	534	536	551	572	$395

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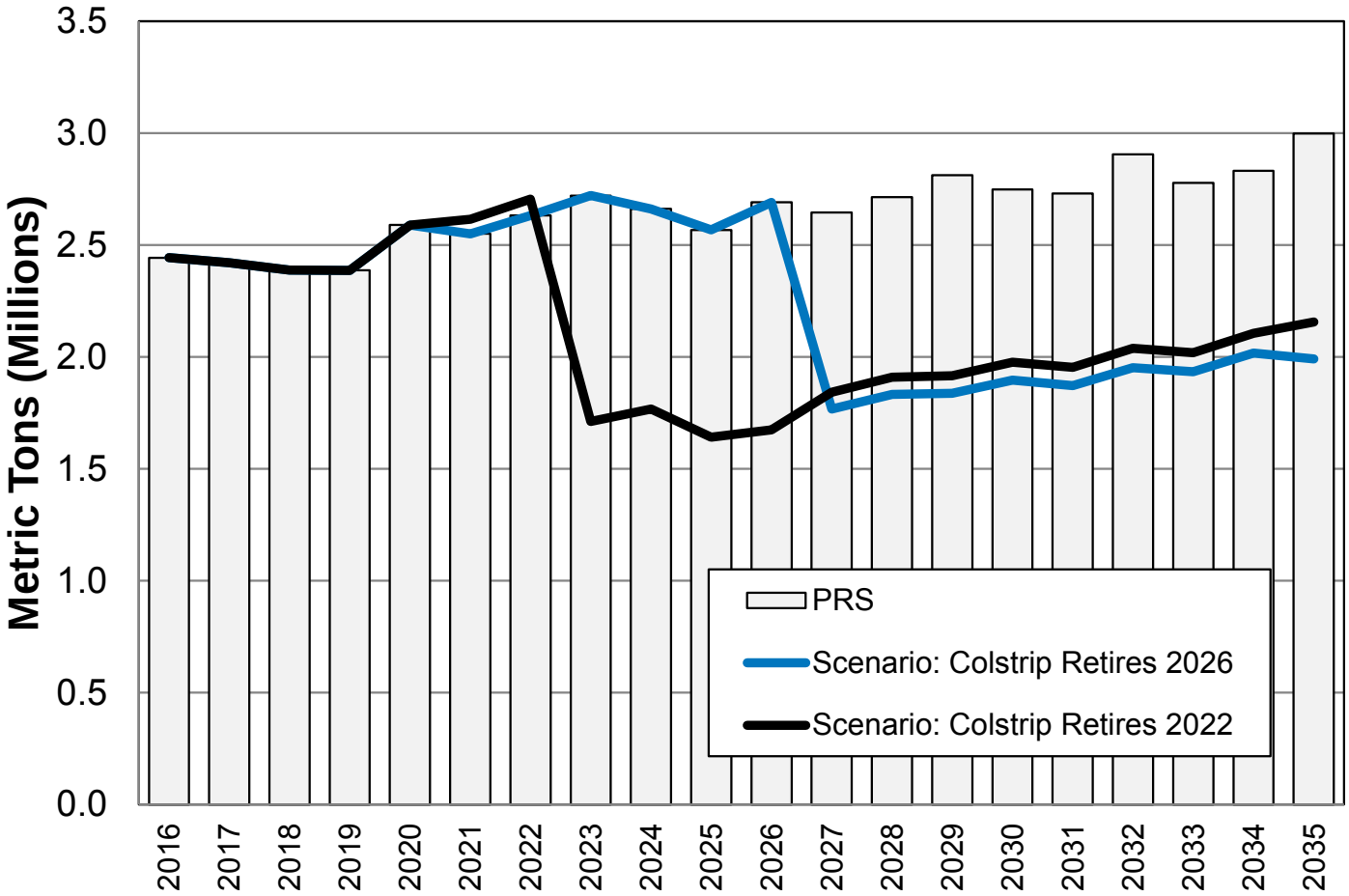
Colstrip Scenarios' Greenhouse Gas Emissions



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Other Resource Scenarios

- **Market & Conservation**
  - All future needs are met by conservation and market purchases
- **2013 PRS**
  - Build similar resources as the 2013 preferred resource strategy
- **Renewables Meet All Load Growth**
  - All load growth is met by renewable energy (wind)
- **Hydro Upgrades & Peakers**
  - Assumes Monroe Street & Long Lake upgrades in 2027
  - Peaking resources meet remaining capacity needs
- **Peakers & Hydro Total Portfolio**
  - By 2027 Avista retains only gas-fired peakers and hydro in its portfolio

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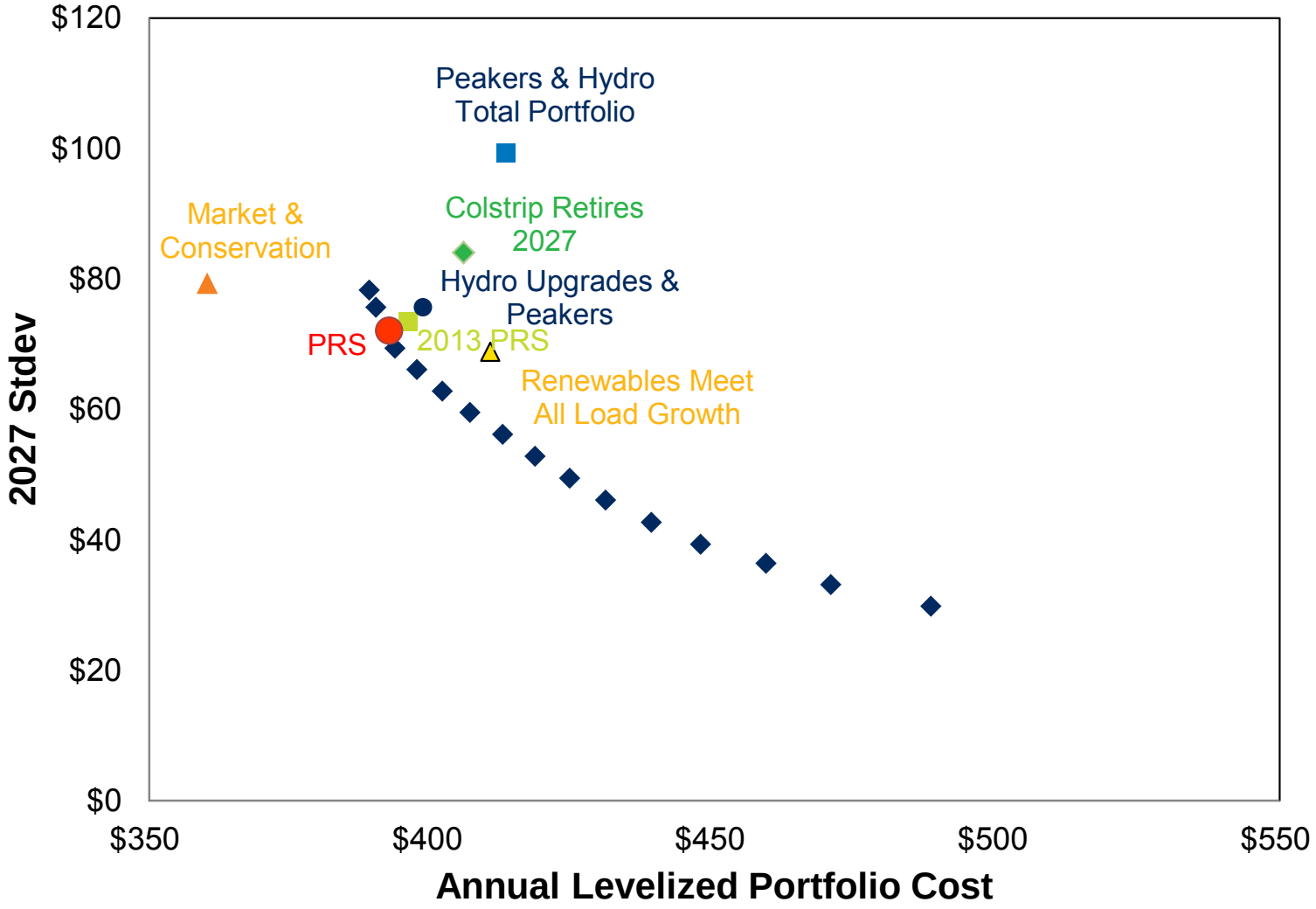
Other Portfolio Scenarios Efficient Frontier



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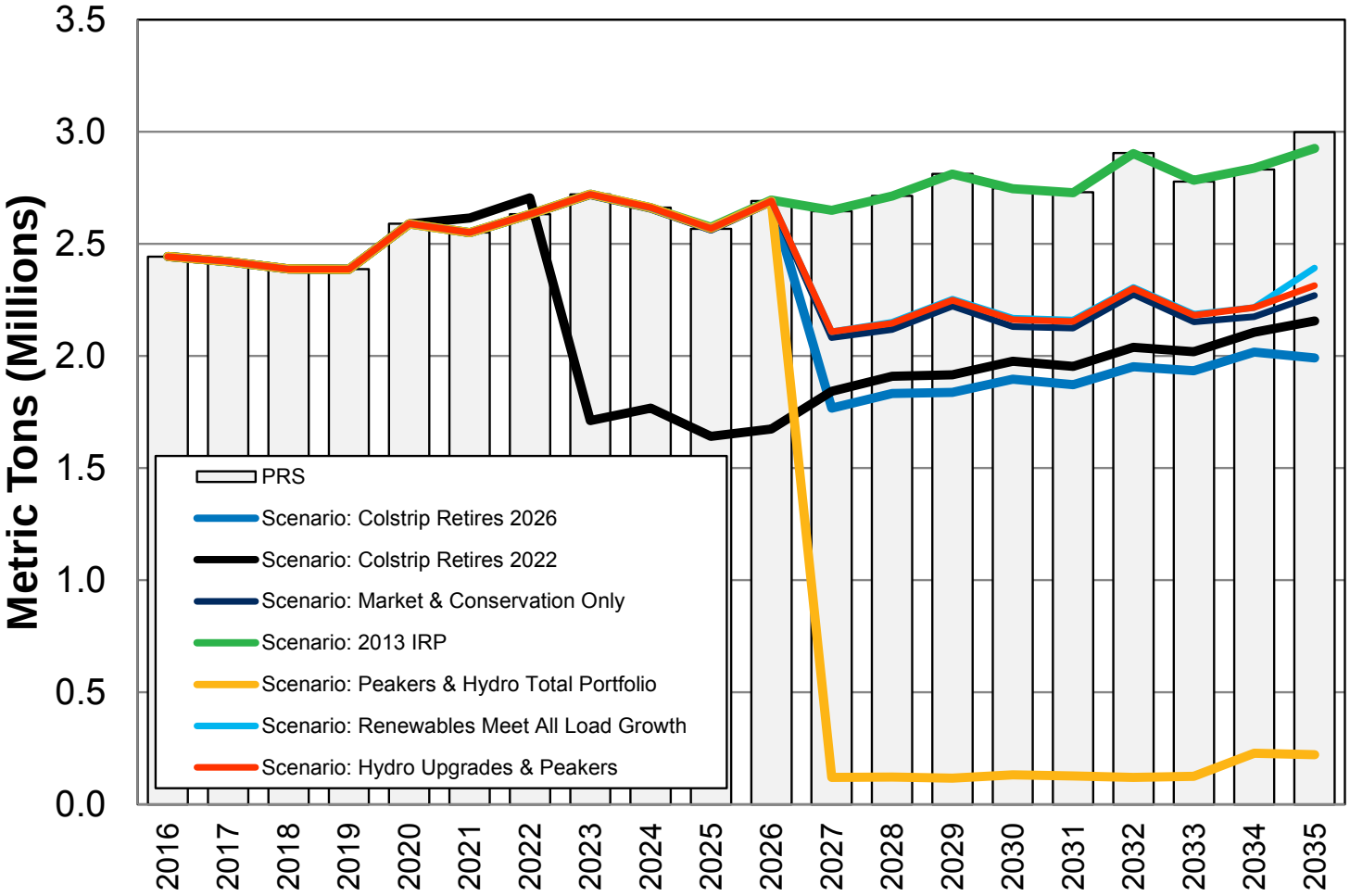
Other Portfolio Scenario Greenhouse Emissions



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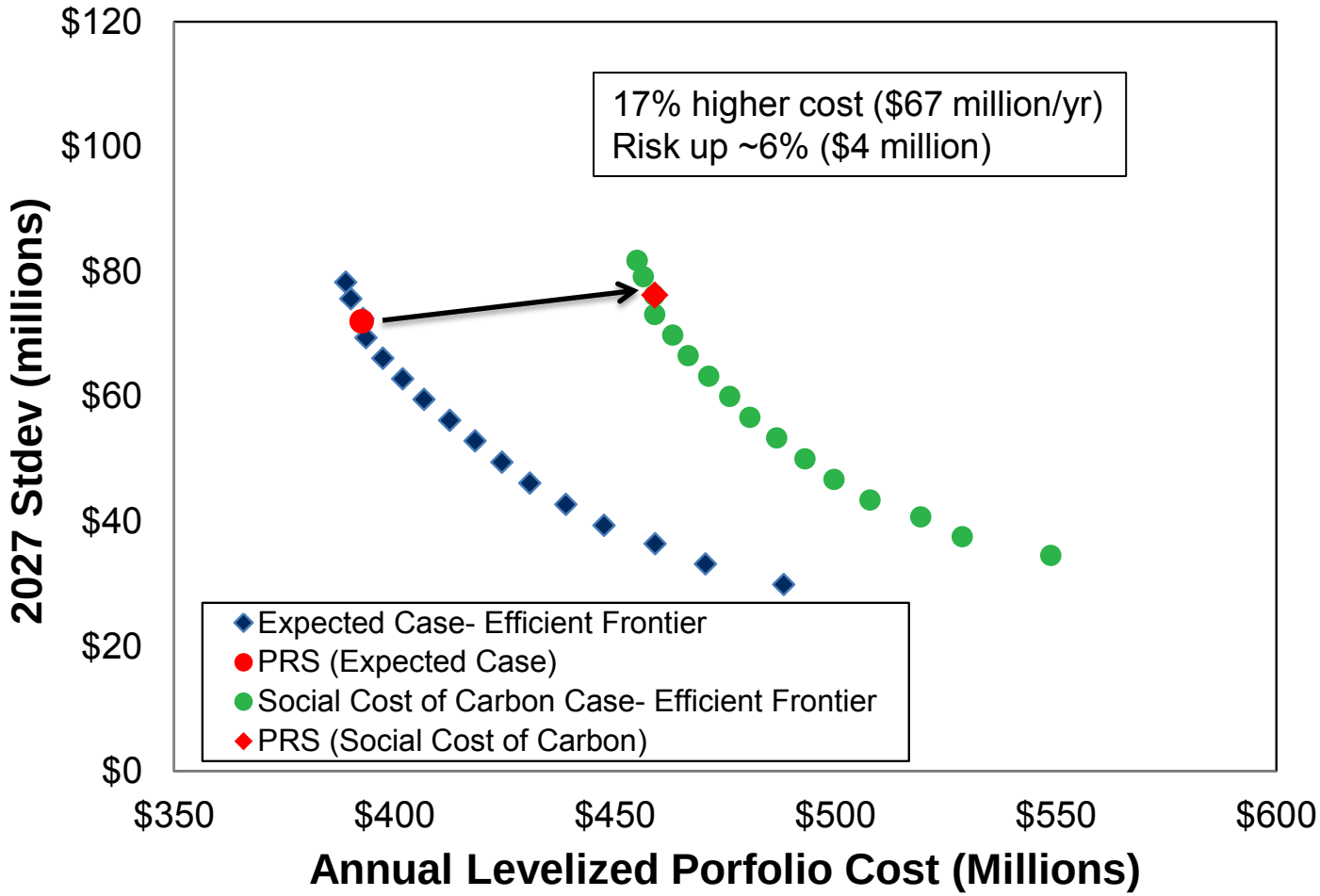
Efficient Frontier w/ Social Carbon Cost



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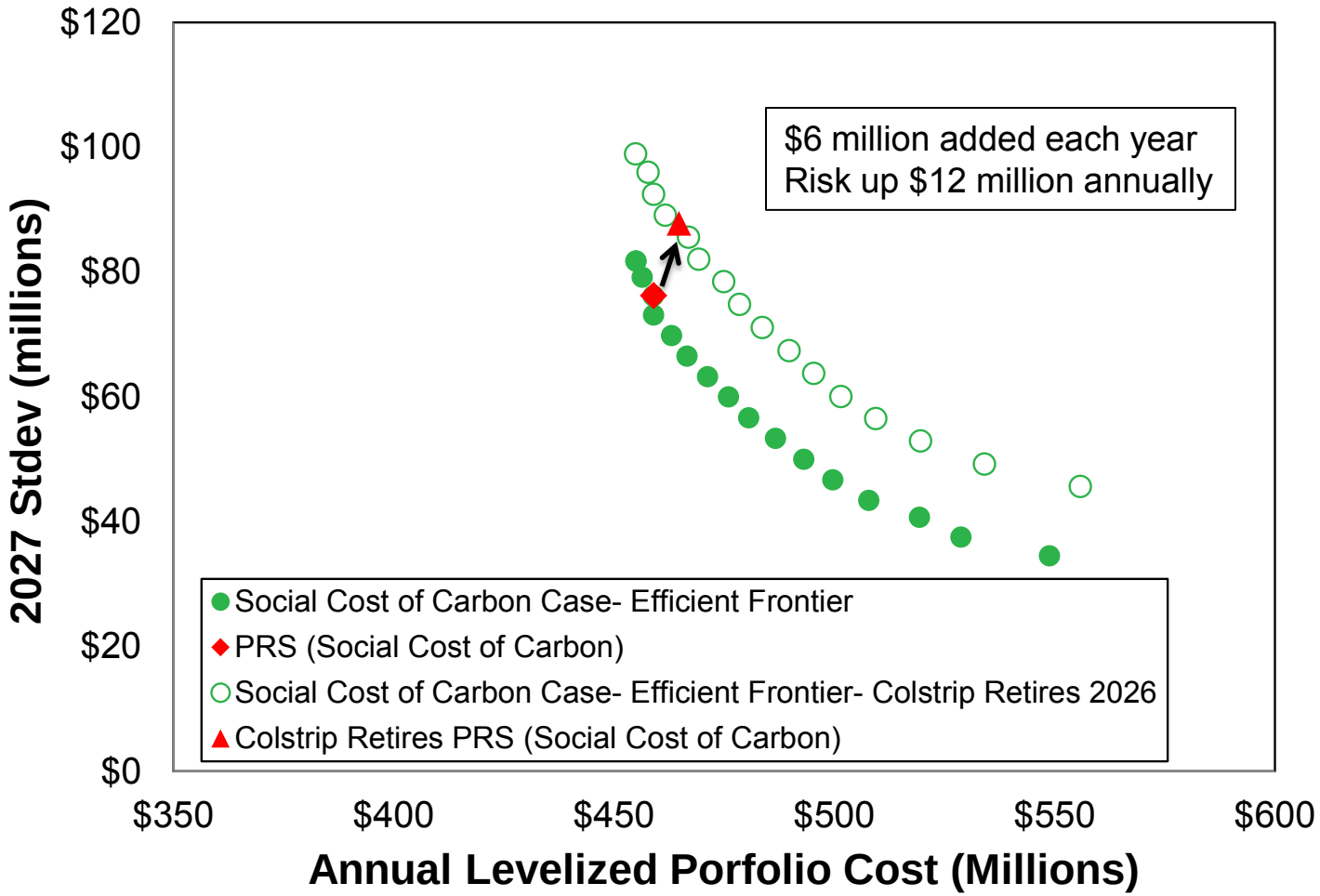
Efficient Frontier w/ Social Carbon Cost (Colstrip Retires 2026)



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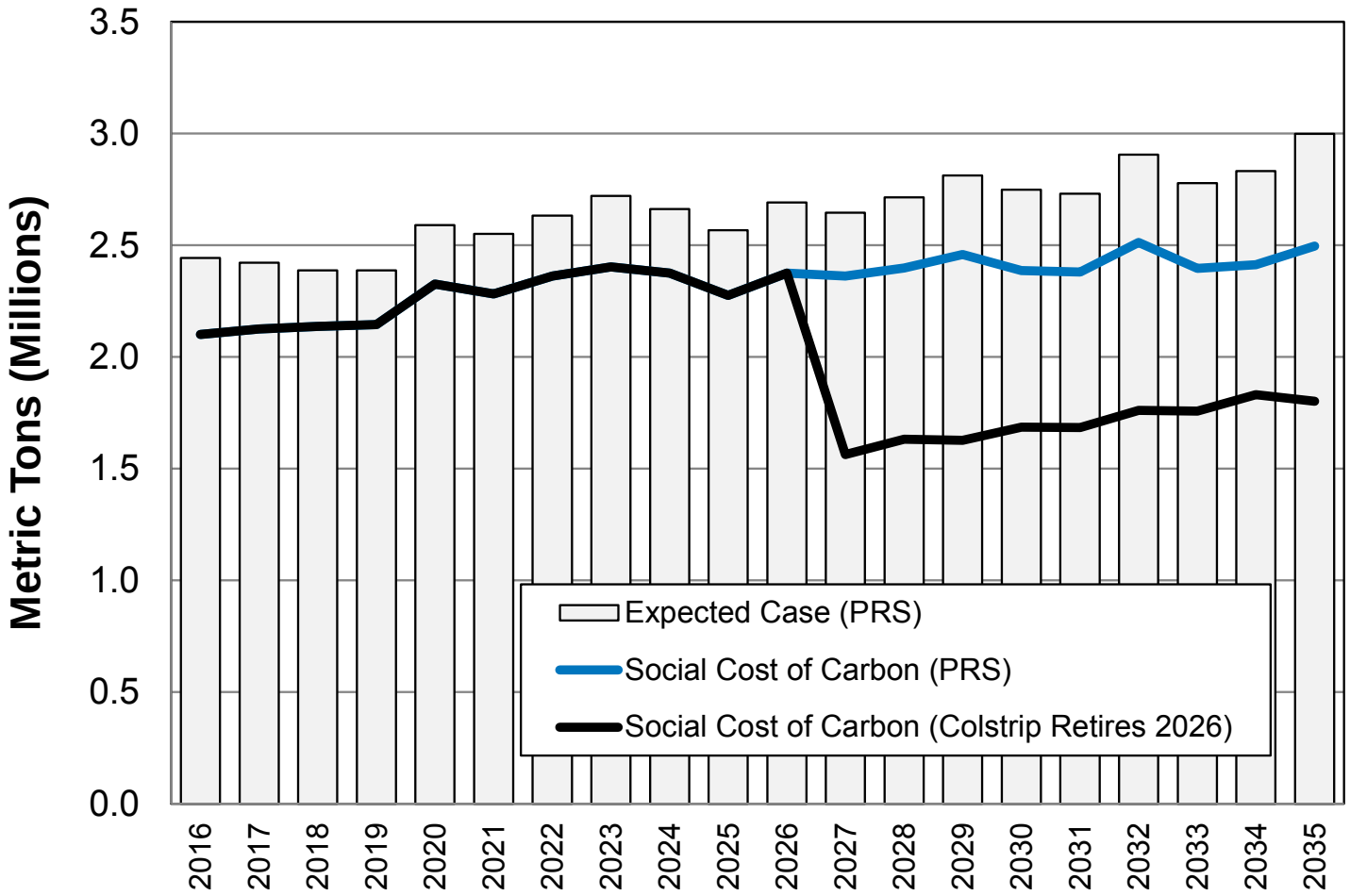
Avista Emissions with Social Cost of Carbon Market Future



DRAFT

Social Cost of Carbon Summary

- Annual Power Supply Costs will increase approximately $67 million per year (17%)
- Avista's greenhouse gas emissions fall 17%
- Colstrip still remains lower cost option
- Retiring Colstrip in 2026 increases levelized costs by $6 million compared to $13 million per year in the Expected Case
- Retiring Colstrip and a Social Cost of Carbon Market Future reduces Avista's greenhouse gas emissions 48%

2015 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 6 Agenda

Wednesday, June 24, 2015
Conference Room 130

Topic	Time	Staff
1. Introduction & TAC 5 Recap	8:30	Lyons
2. Avista Community Solar	8:35	Magalsky
3. 2015 Action Plan	9:15	Lyons
4. Final 2015 PRS	10:00	Gall
5. 2015 IRP Document Introduction	10:30	Staff
6. Lunch and Adjourn	11:30	

2015 Electric IRP
TAC Meeting Expectations and Schedule

John Lyons, Ph.D.
Sixth Technical Advisory Committee Meeting
June 24, 2015

Technical Advisory Committee

- The public process of the IRP – input on what to study, how to study, and review assumptions and results
- Technical forum with a range of participants with different areas of input and expertise
- Open forum, but we need to stay on topic to get through the agenda and allow all participants to ask questions and make comments
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the amount of studies
  - The earlier study requests are made, the more accommodating we can be
  - January 15, 2015 was the final date to receive study requests
- Action Items – areas for more research in the next IRP

Technical Advisory Committee

- Technical forum on inputs and assumptions, not an advocacy forum
- Focus is on developing a resource strategy based on sound assumptions and inputs, instead of a forum on a particular resource or resource type
- We request that everyone maintain a high level of respect and professional demeanor to encourage an ongoing conversation about the IRP process
- Supports rate recovery, but not a preapproval process
- Planning team is available by email or phone for questions or comments between the TAC meetings
- Today is the final TAC meeting for the 2015 IRP.
- The TAC meetings for the 2017 IRP will start in the second quarter of 2016.

TAC #5 Recap

- Introduction & TAC 4 Recap – Lyons
- Review of Market Futures – Gall
- Ancillary Services Valuation – Shane
- Conservation Potential Assessment – Kester (AEG)
- Draft 2015 PRS & Portfolio Analysis – Planning Staff

Today's Agenda

- Introduction & TAC 5 Recap (8:30) – Lyons
- Avista Community Solar (8:35) – Magalsky
- 2015 Action Plan (9:15) – Lyons
- Final 2015 PRS (10:00) – Gall
- 2015 IRP Document Introduction – Planning Group
- Lunch and Adjourn (11:30)

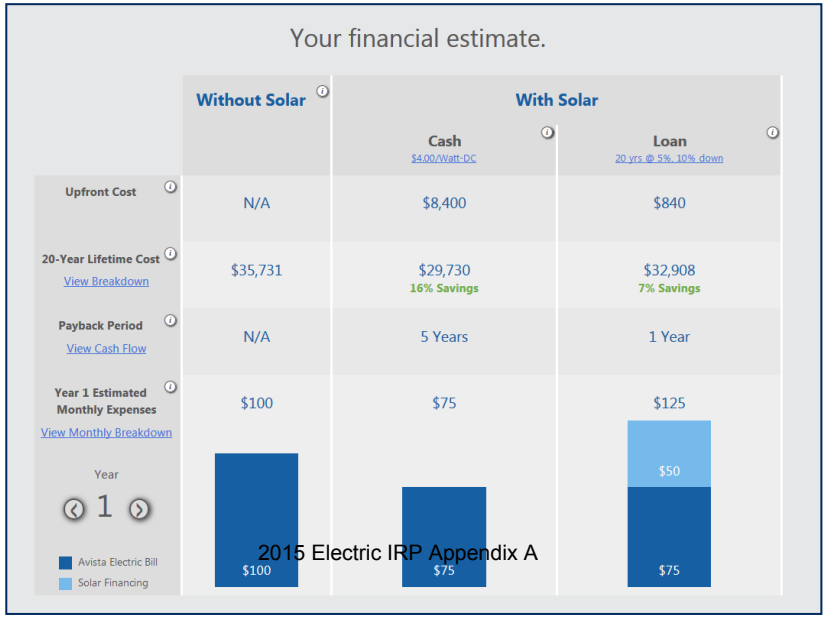
Solar Overview

Kelly Magalsky
Sixth Technical Advisory Committee Meeting
June 24, 2015

Concierge Model

www.avistautilities.com/solarestimator

Solar Estimator



Avista Community Solar Project

Avista Community Solar Program

- Utility Owned 423 kW array (1,512 panels)
- Lottery to select customer/participants
- Expect 500 - 800 participants

- Site: Spokane Valley, WA
- Customer Enrollment: Now – July 17th

www.avistacommunitysolar.com or 1-800-923-9551

2015 Electric IRP Action Items

John Lyons, Ph.D.
Sixth Technical Advisory Committee Meeting
June 24, 2015

Generation Resource Related Analysis

- Analysis of the continued feasibility of the Northeast Combustion Turbine due to its age.
- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
- Increase the number of manufacturers and sizes of natural gas-fired turbines modeled for the PRS analysis.
- Evaluate the need for, and perform if needed, updated wind and solar integration studies.
- Participate and evaluate the potential to join a Northwest Energy Imbalance Market.
- Monitor regional winter and summer resource adequacy.
- Participate in state-level development of the Clean Power Plan.

Energy Efficiency

- Continue to study and quantify transmission and distribution efficiency projects as they apply to EIA goals.
- Complete the assessment of energy efficiency potential on Avista's generation facilities.

Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies.
- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area.
- Continue to participate in regional and sub-regional efforts to facilitate long-term economic expansion of the regional transmission system.

Other 2015 Action Items

- Any areas of concern or suggestions?
- Please call or email the planning team with any suggestions or added Action Items.
- Can also make edits to the draft IRP when it is released.

2015 Electric IRP
Preferred Resource Strategy

James Gall
Sixth Technical Advisory Committee Meeting
June 24, 2015

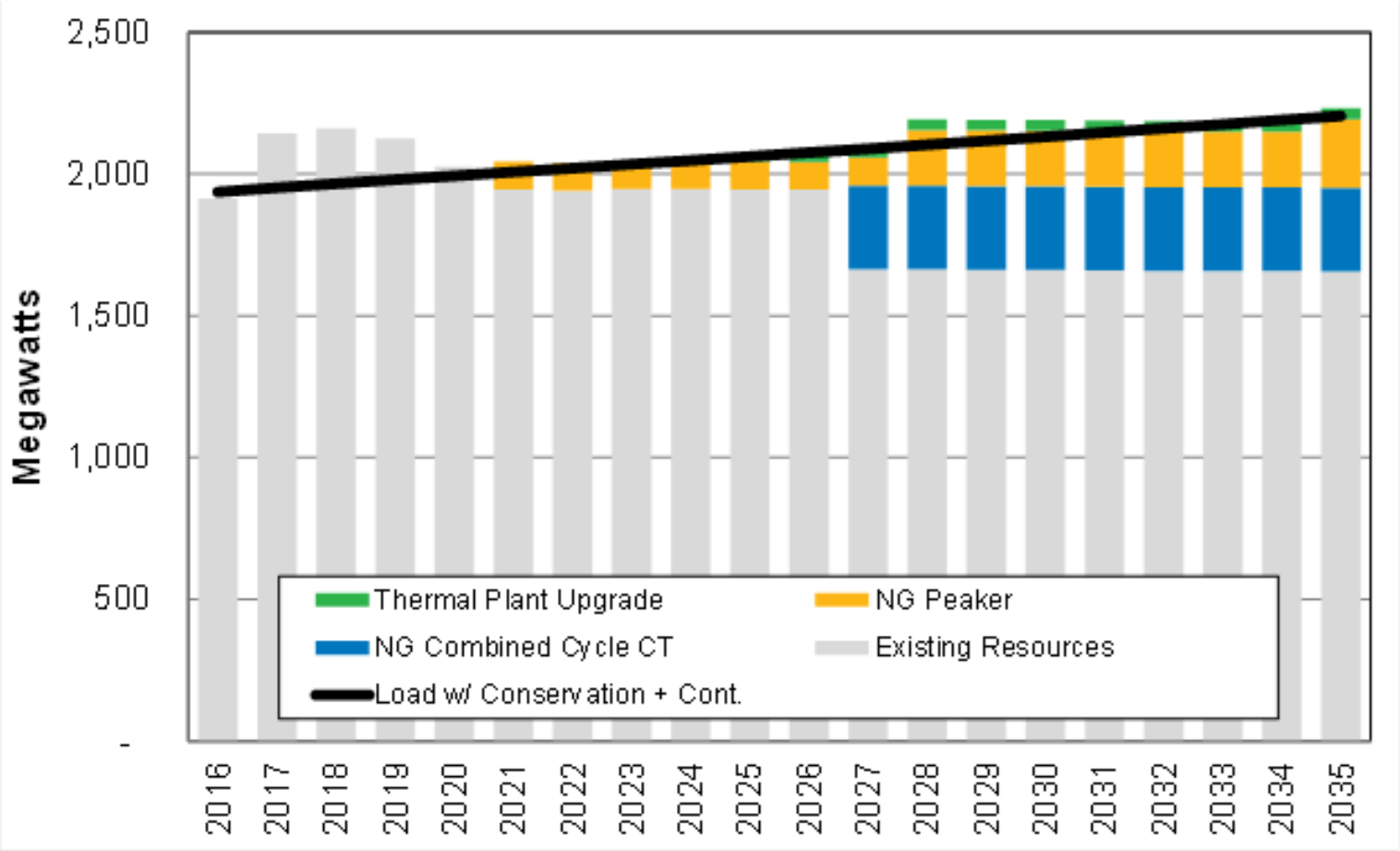
Introduction

- Discuss how Avista plans to meet resource deficits (PRS)
- No Changes to Preferred Resource Strategy since last TAC meeting
- Review tipping point analysis for resource options not selected in IRP

Tipping Point Analysis

- Lower resource costs to point PRiSM picks a different the resource in question, all capital costs are in 2014 dollars
- Utility Scale Solar:
  - *$1,300/kW would have to decline to $671/kW to be selected in 2022 (-48%)*
- Utility Scale Energy Storage:
  - *$2,736/kW, would have to decline to $770/kW in 2021 (-72%)*
- Demand Response:
  - *$217/kW-yr (levelized nominal) would have to decline to $117/kW-yr (-46%)*

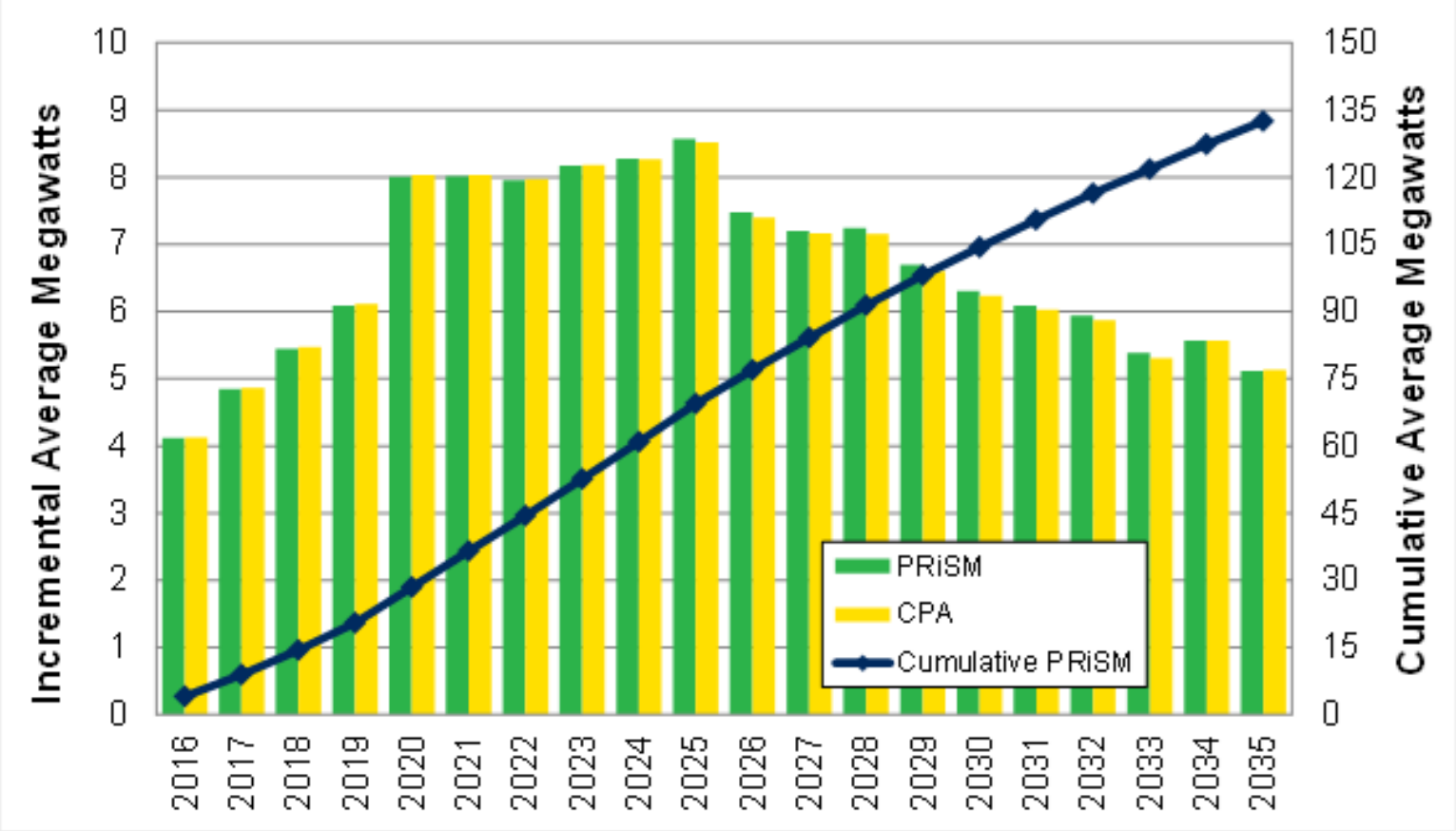
2015 IRP Load and Resource Additions



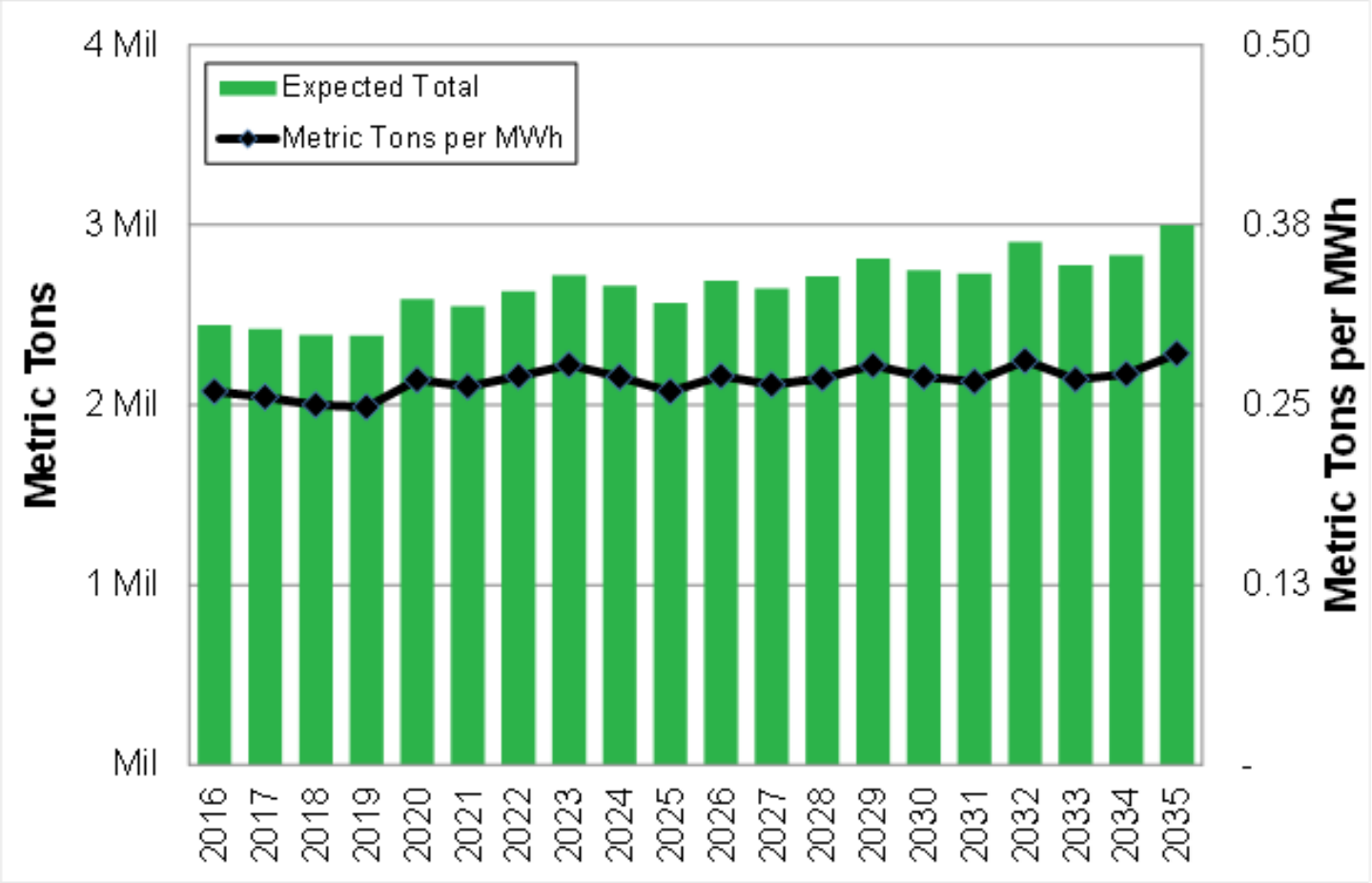
2015 IRP: Preferred Resource Strategy

Resource	By the End of Year	ISO Conditions (MW)	Winter Peak (MW)	Energy (aMW)
Natural Gas Peaker	2020	96	102	89
Thermal Upgrades	2021-2025	38	38	35
Combined Cycle CT	2026	286	306	265
Natural Gas Peaker	2027	96	102	89
Thermal Upgrades	2033	3	3	3
Natural Gas Peaker	2034	47	47	43
Total		**565**	**597**	**524**
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction (MW)**	**Energy (aMW)**
Energy Efficiency	2016-2035		193	132
Distribution Efficiencies			<1	<1
Total			**193**	**132**

Conservation Forecast



Greenhouse Gas Emissions Forecast



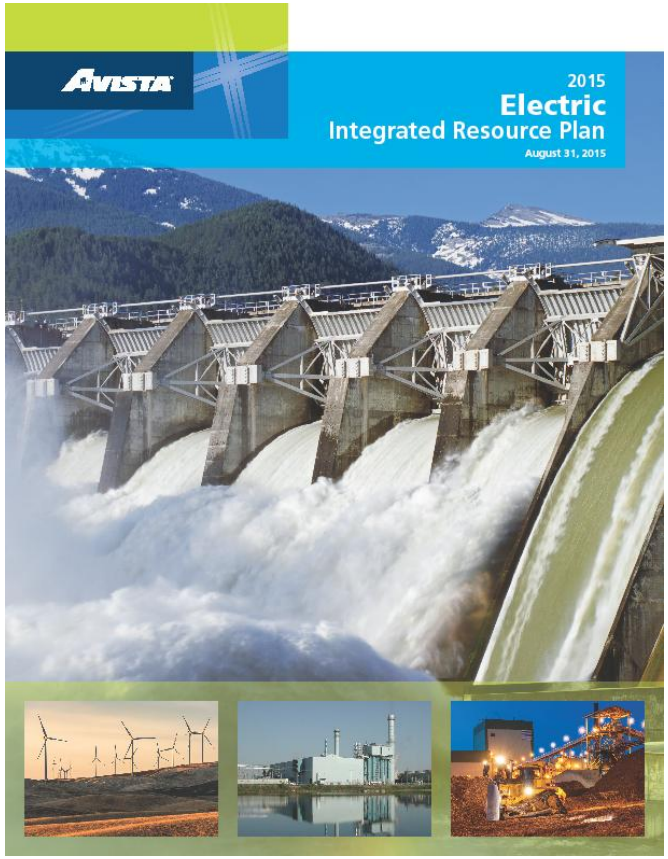
2015 Electric IRP Document Introduction

Planning Staff
Sixth Technical Advisory Committee Meeting
June 24, 2015

2015 Electric IRP Chapters

1. Executive Summary
2. Introduction and Stakeholder Involvement
3. Economic and Load Forecast
4. Existing Resources
5. Energy Efficiency and Demand Response
6. Long-Term Position
7. Policy Considerations
8. Transmission and Distribution Planning
9. Generation Resource Options
10. Market Analysis
11. Preferred Resource Strategy
12. Portfolio Scenarios
13. Action Plan

1. Executive Summary
2. Introduction and Stakeholder Involvement



3. Economic and Load Forecast

- Population and employment growth is starting to recover from the end of the Great Recession in 2009.
- The 2015 Expected Case's energy forecast grows 0.6 percent per year, replacing the 1.0 percent annual growth rate in the 2013 IRP.
- The retail sales forecast, residential use per customer continues to decline.
- Peak load growth is higher than energy growth, at 0.72 percent in the winter and 0.85 percent in the summer.
- Testing performed for this IRP shows that historical extreme weather events contain temperature extremes that are still valid for peak load modeling.

4. Existing Resources

- Hydroelectric represents about half of Avista's winter generating capability.
- Natural gas-fired plants represent the largest portion of generation potential.
- Seven percent of Avista's generating capability is biomass and wind.
- Nine Mile Falls rehabilitation and upgrade will be completed in 2016.
- 280 of Avista's customers net meter 1.8 megawatts of their own generation.

5. Energy Efficiency and Demand Response

- Current Avista-sponsored conservation reduces retail loads by nearly 11 percent, or 127 aMW.
- 2015 IRP evaluates over 3,000 equipment options, and over 2,300 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption.
- This IRP co-optimizes conservation and demand response selection with generation resource options using our PRiSM model.

6. Long-Term Position

- Avista's first long-term capacity deficit net of energy efficiency is in 2021; the first energy deficit is in 2026.
- Avista uses a 14 percent winter planning margin in addition to meeting operating reserves for a 22.6 percent planning margin.
- The 2015 IRP meets all EIA mandates over the next 20 years with a combination of RECs, qualifying hydroelectric upgrades, Palouse Wind, and Kettle Falls.

7. Policy Considerations

- The 2015 IRP uses
  - existing carbon costs;
  - the goals of the Clean Power Plan proposal;
  - and a 10 percent probability of a carbon price to reduce greenhouse gas emissions.
- Scenario analyses address the impacts of the Clean Power Plan proposal by state and regionally, as well as various issues for Avista's Colstrip ownership interest.
- Avista's Climate Policy Council monitors greenhouse gas legislation and environmental regulation issues.

8. Transmission and Distribution Planning

- Avista actively participates in regional transmission planning forums.
- Avista System Planning transitioned from a biannual to an annual study process.
- Projects completed since the last IRP include new sections of transmission lines, and rebuilds and upgrades through the grid modernization project.
- Planned projects include reconductoring, and station rebuilds and reinforcements.
- Significant generation interconnection study work around Lind substation continues.

9. Generation Resource Options

- Only resources with well-defined costs and operating histories are options to meet future resource needs.
- Wind, solar and hydroelectric upgrades represent renewable options available to Avista.
- Upgrades to Avista's Spokane and Clark Fork River facilities are included as resource options.
- Future requests for proposals might identify different technologies.
- Renewable resource costs assume no extensions of current state and federal incentives.

10. Market Analysis

- Natural gas, solar, and wind resources dominate new generation additions in the Western Interconnect.
- Clean Power Plan regulation could cause large price and costs swings, but without a final rule, the impacts are unknown.
- The Expected Case forecasts a continuing reduction of Western Interconnect greenhouse gas emissions due to coal plant shut downs brought on by federal and state regulations and low natural gas prices.

11. Preferred Resource Strategy

- Avista's first anticipated resource acquisition is a natural gas-fired peaker by the end of 2020 to replace expiring contracts and serve growing loads.
- A combined cycle combustion turbine replaces the Lancaster Facility when its contract ends in 2026.
- Upgrades to existing facilities help meet resource deficits.
- Energy efficiency offsets 52 percent of projected load growth through the 20-year IRP timeframe.

12. Portfolio Scenarios

- Lower or higher future loads do not materially change the resources strategy.
- Colstrip remains a cost-effective and reliable source of power to meet future customer loads.
- In the Without Colstrip in 2027 scenario, customer bills increase $68 million.
- A $19 per metric ton social cost of carbon market scenario increases customer's costs by $67 million per year levelized.
- Tipping point analysis suggests utility scale solar costs would need to decline another 48 percent to be in the Preferred Resource Strategy.

13. Action Plan

- Covered in earlier presentation

- Generation resource related analysis
- Energy efficiency
- Transmission and distribution planning

Remaining 2015 IRP Schedule

- July 10, 2015 – external draft released to TAC
- July 31, 2015 – external draft comments due
- August 28, 2015 – file final 2015 IRP with Commissions
- August 31, 2015 – 2015 IRP available to the public on Avista's web site
- Public comments period will be determined by the Commissions

2015 Electric Integrated Resource Plan

Appendix B – 2015 Electric IRP Work Plan

Avista Corporation's

2015 Electric Integrated Resource Plan (IRP) Work Plan

For the
Washington Utilities and Transportation Commission

August 29, 2014

2015 Electric Integrated Resource Planning Work Plan

This Work Plan is submitted in compliance with the Washington Utilities and Transportation Commission's Integrated Resource Planning (IRP) rules (WAC 480-100-238). It outlines the process Avista will follow to develop its 2015 IRP for filing with Washington and Idaho Commissions by August 31, 2015. Avista uses a public process to solicit technical expertise and feedback throughout the development of the IRP through a series of public Technical Advisory Committee (TAC) meetings. Avista held the first TAC meeting for the 2015 IRP on May 29, 2014.

The 2015 IRP process will be similar to those used to produce the previous IRP. Avista will use AURORA^{xmp} for electric market price forecasting, resource valuation and for conducting Monte-Carlo style risk analyses. AURORA^{xmp} modeling results will be used to select the Preferred Resource Strategy (PRS) using Avista's proprietary PRiSM model. This tool fills future capacity and energy (physical/renewable) deficits using an efficient frontier approach to evaluate quantitative portfolio risk versus portfolio cost while accounting for environmental laws and regulations. Qualitative risk evaluations are in separate analyses. Exhibit 1 shows the process timeline and the process to identify the PRS is in Exhibit 2.

Avista intends to use both detailed site-specific and generic resource assumptions in development of the 2015 IRP. The assumptions combine Avista's research of similar generating technologies, engineering studies, and the development of the Northwest Power and Conservation Council's Seventh Power Plan. This IRP will study renewable portfolio standards, environmental costs, sustained peaking requirements and resource adequacy, energy efficiency programs and demand response. The IRP will develop a strategy that meets or exceeds both the renewable portfolio standards and greenhouse gas emissions regulations.

Avista intends to test the PRS against a range of scenarios and potential futures. The TAC meetings will help to determine the underlying assumptions used in the scenarios and futures. The IRP process is very technical and data intensive; public comments are welcome but timely

input and participation will be necessary for inclusion into the process so the plan can be submitted according to the tentative schedule in this Work Plan.

The following topics and meeting times may change depending on the availability of presenters and requests for additional topics from the TAC members. The tentative timeline and agenda items for TAC meetings follows:

- **TAC 1 – May 29, 2014:** Setting Expectations, review of 2013 IRP acknowledgement letters and Action Plan, Energy Independence Act compliance, Pullman Energy Storage Project update, demand response study discussion and review the 2015 IRP draft Work Plan.

- **TAC 2 – September 23, 2014:** Review conservation selection methodology, update on the Company's demand response study, load and economic forecasts, generation options and Clean Power Plan proposal discussion.

- **TAC 3 – November 2014:** Planning margin, Colstrip discussion, cost of carbon, modeling overview and conservation potential assessment methodology.

- **TAC 4 – February 2015:** Electric and natural gas price forecasts, transmission planning, resource needs assessment, market and portfolio scenario development, energy storage and ancillary service evaluation

- **TAC 5 – March 2015:** Completed conservation potential assessment, draft PRS, review of scenarios and futures and portfolio analysis

- **TAC 6 – June 2015:** Review of final PRS and action items.

2015 Electric IRP Draft Outline

The following is a draft outline of the major sections envisioned for the 2015 Electric IRP. This outline may change with the input from the Company's TAC, and as IRP studies are completed and have been received:

1. **Executive Summary**
2. **Introduction and Stakeholder Involvement**
3. **Economic and Load Forecast**
   a. Economic Conditions
   b. Avista Energy & Peak Load Forecast
   c. Load Forecast Scenarios
4. **Existing Resources**
   a. Avista Resources
   b. Contractual Resources and Obligations
5. **Energy Efficiency and Demand Response**
   a. Conservation Potential Assessment
   b. Demand Response Opportunities
6. **Long-Term Position**
   a. Reliability Planning and Reserve Margins
   b. Resource Requirements
   c. Reserves and Flexibility Assessment
7. **Policy Considerations**
   a. Environmental Concerns
   b. State and Federal Policies
8. **Transmission & Distribution Planning**
   a. Avista's Transmission System
   b. Future Upgrades and Interconnections
   c. Transmission Construction Costs and Integration
   d. Efficiencies
9. **Generation Resource Options**
   a. New Resource Options
   b. Avista Plant Upgrades
10. **Market Analysis**
    a. Marketplace
    b. Fuel Price Forecasts
    c. Market Price Forecast
    d. Scenario Analysis
11. **Preferred Resource Strategy**
    a. Resource Selection Process
    b. Preferred Resource Strategy
    c. Efficient Frontier Analysis
    d. Avoided Cost

12. Portfolio Scenarios
   a. Portfolio Scenarios
   b. Tipping Point Analysis

13. Action Plan
   a. 2013 Action Plan Summary
   b. 2015 Action Plan

Avista Corporation's

2015 Electric Integrated Resource Plan (IRP)
Work Plan

Exhibit 1
2015 Electric IRP Timeline

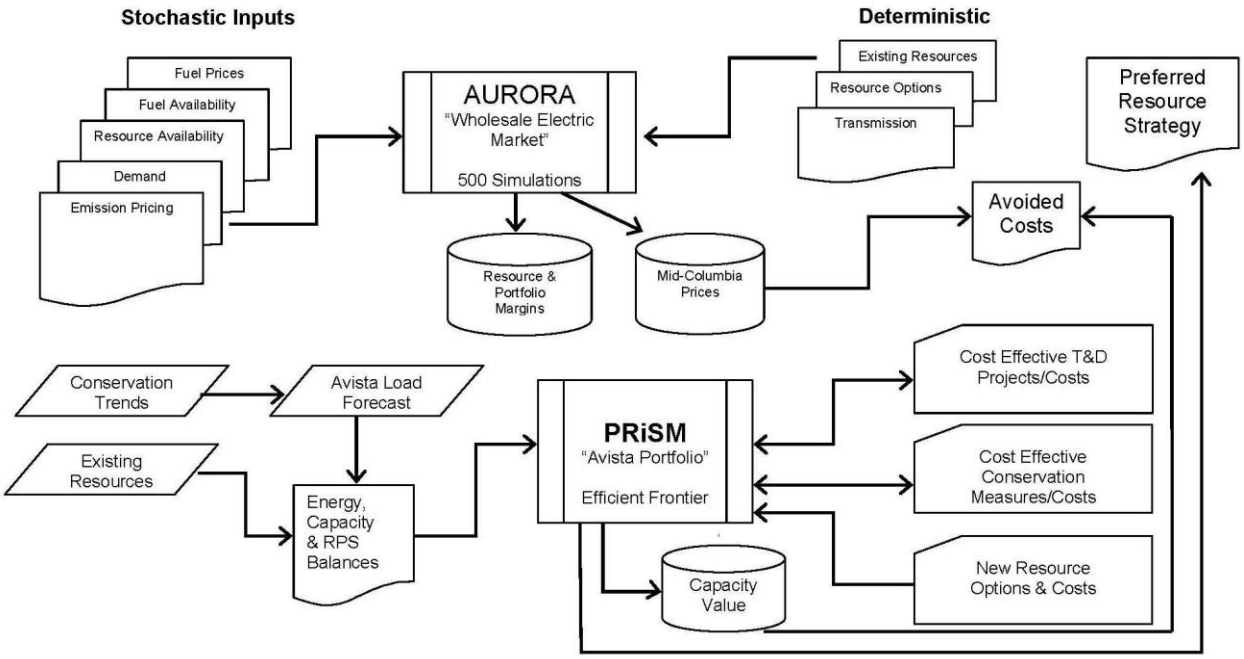
Exhibit 1: 2015 Electric IRP Timeline	
Task	**Target Date**
Preferred Resource Strategy (PRS)	
Finalize energy demand forecast	July 2014
Identify Avista's supply & conservation resource options	September 2014
Finalize peak load forecast	September 2014
Update AURORA^{xmp} database for market price forecast	October 2014
Energy efficiency load shapes input into AURORA^{xmp}	October 2014
Finalize datasets/statistics variables for risk studies	November 2014
Transmission study due	December 2014
Finalize distribution feeder forecast	December 2014
Select natural gas price forecast	December 2014
Finalize deterministic base case	January 2015
Due date for study requests	Jan. 15, 2015
Base case stochastic study complete	January 2015
Develop efficient frontier and PRS	January 2015
Finalize PRiSM model	February 2015
Simulation of risk studies "futures" complete	February 2015
Simulate market scenarios in AURORA^{xmp}	February 2015
Evaluate resource strategies against market futures and scenarios	March 2015
Present preliminary study and PRS to TAC	March 2015
Writing Tasks	
File 2015 IRP work plan	August 2014
Prepare report and appendix outline	October 2014
Prepare text drafts	April 2015
Prepare charts and tables	April 2015
Internal draft released at Avista	May 2015
External draft released to the TAC & filed with Commissions	June 2015
Final editing and printing	August 2015
Final IRP submission and TAC	August 31, 2015

Avista Corporation's

2015 Electric Integrated Resource Plan (IRP) Work Plan

Exhibit 2
2015 Electric IRP Modeling Process

Exhibit 2: 2015 Electric IRP Modeling Process



2015 Electric Integrated Resource Plan

Appendix C – AEG Studies

- Demand Response Study
- Conservation Potential Assessment

Avista Corporation
Commercial & Industrial Demand Response Potential Study

Final Report

Applied Energy Group, Inc.
500 Ygnacio Valley Road
Suite 450
Walnut Creek, CA 94596
510.982.3525
www.appliedenergygroup.com

Prepared for:
Avista Corporation

December 19, 2014

This report was prepared by

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C. Carrera

Subcontractor:

The Brattle Group
A. Faruqui

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SECTION | 1

Introduction

Avista Corporation commissioned Applied Energy Group (AEG), with subcontractor the Brattle Group, to provide an assessment of demand response potential within its commercial and industrial (C&I) sectors in Washington and Idaho. The purpose of this study was to help Avista gain a better understanding of implementing demand response programs in the commercial and industrial sectors, and the corresponding cost and benefits.

This study provides demand response potential and cost estimates, including supply curves, for the 20-year planning horizon of 2016–2035 to inform the development of Avista's 2015 Integrated Resource Plan (IRP). It primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DR resources likely available to Avista over the 20-year planning horizon. The study focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics that may hinder resource acquisition. Study results will be incorporated into Avista's 2015 IRP and subsequent DR planning and program development efforts.

This study focused on developing DR potential and cost estimates for C&I customers only. Avista had recently offered two residential demand response pilot programs that have helped gain a good understanding of residential demand response programs and their costs and benefits in Avista's service territory. Additional assessment of demand response potential for residential customers was outside the scope of the current study. However, as part of this study, Avista was interested in obtaining information from a national review of DR programs offered to residential customers.

This document is organized as follows:

- Section 2 describes the analysis approach and the data sources used to develop potential and cost estimates.
- Section 3 presents market characterization data used for our analysis.
- Section 4 identifies and describes relevant DR programs and presents assumptions on key program parameters.
- Section 5 presents potential and cost results from our analysis.

SECTION | 2

Analysis Approach

This section describes our analysis approach and the data sources used to develop potential and cost estimates.

The following three steps broadly outline our analysis approach:

1. Segment C&I customers for DR analysis and develop market characteristics (customer count and coincident peak demand values) by segment for the base year and planning period.
2. Identify and describe relevant DR programs and develop assumptions on key program parameters for potential and cost analysis.
3. Assess achievable potential by DR program for the 2016-2035 planning period and estimate program budgets and levelized costs.

We describe these analysis steps throughout the remainder of this chapter.

Market Characterization

The first step in the DR analysis was to segment C&I customers and develop characteristics for each segment.[1] The two relevant characteristics for DR potential analysis are the number of eligible customers in each market segment and their coincident peak demand values.

Segmentation Basis

We used Avista's rate schedules as the basis for C&I customer segmentation. We segmented C&I customers into General Service, Large General Service, and Extra Large General Service classes.[2] Customers in rate schedule no. 11 belong to the "General Service" class, customers in rate schedule no. 21 belong to the "Large General Service" class and customers in rate schedule no. 25 belong to the "Extra Large General Service" class.

We selected 2013 to be the base year for the study since it the latest year for which complete customer count and electricity sales data are available.

Key Market Data

Once the customer segments were defined and the base year was selected, we developed customer count and coincident peak demand values for the three C&I segments. We developed these estimates separately for Washington and Idaho.

We obtained the 2013 customer count and electricity sales data by rate schedule from Avista. We used the electricity sales data to derive coincident peak demand estimates by segment. We did this by calculating load factors for each segment. In order to calculate these load factors, we relied on electricity sales and coincident peak demand values provided in the 2010 load research study conducted by Avista. The study provided electricity sales and coincident peak demand values for General Service, Large General Service, and Extra Large General Service customers for Washington and Idaho, for the year 2010. We used this data to calculate load factors by segment and by state and applied this to the 2013 electricity sales to derive coincident peak demand estimates.

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[1] This study estimates DR potential for C&I customers only. Residential DR potential estimates are outside the scope of this study.
[2] We excluded two largest industrial customers from our analysis. Avista may wish to engage with these two customers directly to gauge their interest in participating in a DR program.

Baseline Projection

Once the base year market characteristics were defined, we developed customer count and coincident peak demand projections by state and segment for the period 2014-2035.

Avista provided customer count and electricity sales projections by rate schedules for Washington and Idaho over the 2014-2019 timeframe. We used this data to calculate the average annual growth in customer count and sales. We then applied these same average annual growth rates to develop customer count and sales projections over the 2020-2035 timeframe. For General Service customers, however, this method produced an inaccurate growth rate due to near-term changes in the customer mix. We therefore developed a more reasonable growth rate in collaboration with Avista to project the trends for 2020-2035.

Once the electricity sales projections were developed, we applied the calculated load factors from the earlier step to develop coincident peak demand projections by segment and by state. We assumed that load factor for a particular customer segment in a state remains unchanged from the 2010 value for the 2016-2035 planning period.

End Use Saturation

Another key component of market characterization for DR analysis is electric space heating and water heating saturation data. This is required to further segment the market and identify eligible customers for direct control of electric space heating and water heating equipment. We obtained saturation data from the Conservation Potential Assessment study conducted by Avista in 2013. We assumed water heating and electric space heating saturation values remain constant over the analysis timeframe.

Section 3 of the report presents customer count, coincident peak demand and saturation data by customer segment.

DR Program Descriptions

Once we completed the market characterization, we focused on identification of relevant DR programs for Avista's commercial and industrial customers.

In order to conduct this task, we initially prepared a universal list of DR programs that could be considered relevant for Avista. This initial list was based on a national review of different DR program types currently offered in the industry. We used the 2012 national DR program survey database, published by FERC, to conduct this task.

We selected representative program examples within each type of program and further researched these programs. We presented the universal list of relevant DR programs in a memo to Avista and followed it up with a research report that summarized key findings from our research.

Subsequently, our team (AEG and Brattle) participated in a workshop with Avista to discuss these options and obtain Avista's feedback. Based on guidance received from Avista, we modified our programs list and proceeded to develop detailed descriptions of programs included in that list.

Key Program Parameters

We developed assumptions on key program parameters used to estimate DR programs savings and costs. These parameters include program participation rates, per participant load reductions, and program costs.

We relied on secondary data sources and the AEG-Brattle team's collective experience to develop these assumptions. The primary data source for DR programs was the 2012 FERC national DR program survey database. We combined the FERC survey data with other relevant data source from EIA Form 861 and FERC Form 1 to develop data on key program parameters.

We also used individual program evaluation reports, wherever available. For pricing programs, we relied on Brattle's extensive database that includes information compiled from a very large number of national and international pricing programs and pilots.

We developed detailed itemized assumptions on various fixed and variable cost components including program development costs, annual program administration costs, marketing and recruitment costs, costs for purchase and installation of enabling technology, annual O&M costs, and participant incentives. These cost assumptions are informed by our team's consultation with industry experts involved in actual program implementation. We also relied heavily on inputs provided by Avista to develop these assumptions.

Appendix A summarizes the key findings from our review of DR programs. Section 4 provides detailed descriptions of key program features and presents assumptions on key program parameters that are used to develop potential and cost estimates.

Participation Rates

The steady-state participation assumptions are based on an extensive database of existing program information and insights from market research results, and represent "best-practices" estimates for participation in these programs. This approach is commonly followed in the industry for arriving at achievable potential estimates. However, practical implementation experience suggests that uncertainties in factors such as market conditions, regulatory climate, and economic environment are likely to influence customer participation in DR.

Once initiated, DR options require a time period to ramp up and reach a steady state because customers need time for education, marketing, and recruitment, in addition to the physical implementation and installation of any hardware, software, telemetry, or other equipment. You cannot merely flip a switch on human behavior, so the customer engagement aspect of these options must be carefully considered.

In this analysis, we model programs as ramping up generally in a three-year to five-year timeframe to their steady state, which is typical of industry experience. For direct load control and pricing options, participation is assumed to ramp up following an "S-shaped" diffusion curve over a five-year timeframe. The rate of participation growth accelerates over the first half of the five-year period, and then slows over the second half. For the Firm Curtailment option, which is typically third-party delivered over shorter contract periods of three to five years, participation is assumed to ramp up linearly within a three-year timeframe. An annual attrition rate of 1% is uniformly applied to participants across all options to account for customers dropping out of the programs.

Potential and Cost Estimates

The last step in our analysis was to calculate savings from DR programs and estimate costs for achieving these savings. We conducted our analysis in two stages. We developed savings and cost estimates for individual DR programs considered on a standalone basis. This does not take into consideration any participation overlap that may occur if Avista were to implement multiple programs simultaneously. Therefore, the potential and cost estimates for individual DR options are not additive as there would be some amount of overlap among the target market of participating customers. We expect this effect to be relatively small among customers.

We then used itemized cost assumptions to estimate total and annual program budgets, calculate levelized costs for DR programs, and develop resource supply curves.

Section 5 presents potential and cost analysis results.

SECTION | 3

Market Characterization

The first step in the DR analysis was to segment C&I customers and develop customer count and peak demand values for the base year and the 2016-2035 planning period. This section presents the C&I segments selected for our analysis and shows the customer count and coincident peak demand values for these segments. We have also included electric space heating and water heating saturation values that are relevant for the DR analysis.

Market Segmentation

We segmented C&I customers into two dimensions: by state and customer class. Table 3-1 summarizes the market segmentation we developed for this study.

Table 3-1 Market Segmentation

Market Dimension	Segmentation Variable	Description
1	State	Idaho, Washington
2	Customer Class	By rate schedule: General Service: Rate Schedule 11 Large General Service: Rate Schedule 21 Extra Large General Service: Rate Schedule 25 [3]

We excluded Avista's two largest industrial customers from our analysis. To accurately estimate demand reduction potential for these customers, we would need to develop a detailed understanding of their industrial processes and associated possibilities for load reduction and develop specific DR potential estimates for each customer. The common approach followed to estimate potential for other customers does not apply to these extremely large customers, and therefore we did not include them in the analysis. However, Avista may wish to engage with these two customers directly to gauge their interest in participating in a DR program.

Customer Count by Segment

Once we segmented the market, we developed customer counts for the base year and forecast years included in the analysis. We considered 2013 as the base year for the study, since this is the most recent year with 12 months of available customer data, and 2016 to 2035 as the forecast years.

Avista provided us with actual customer counts by rate schedule for 2013 and forecasts for 2014 to 2019. We calculated the average annual growth rate for each customer class over that period and used the average to project the number of customers in 2020-2035.

Table 3-2 below shows customer count data by state for the base year and selected future years.

[3] Excluding the two largest Schedule 25 and Schedule 25P customers.

Table 3-2 Baseline C&I Customer Forecast by State and Customer Class

Customer Class	2013	2016	2020	2025	2030	2035
Washington						
General Service	20,983	22,309	23,517	25,515	27,683	30,035
Large General Service	1,983	1,954	1,949	1,925	1,901	1,877
Extra Large General Service	20	20	20	20	20	19
Total C&I	**22,987**	**24,283**	**25,486**	**27,459**	**29,603**	**31,931**
Idaho						
General Service	15,532	15,991	16,946	18,158	19,457	20,849
Large General Service	1,127	1,127	1,126	1,117	1,109	1,101
Extra Large General Service	9	9	9	9	9	9
Total C&I	**16,531**	**16,893**	**18,081**	**19,285**	**20,575**	**21,959**

System and Coincident Peak Demand by Segment

The next step in market characterization was to define peak forecasts for each customer segment. Avista provided us with 2013 system peak demand value and peak forecasts for 2015 through 2035. Table 3-3 shows the system peak demand for the base year and selected future years. The overall system peak demand values in the table represent the total demand on Avista's system. The "weather sensitive" peak represents the overall system peak demand minus the demand for Avista's two largest industrial customers.

Table 3-3 Baseline System Peak Forecast (MW @Generator) [4]

Peak Demand	2013	2016	2020	2025	2030	2035
Overall System Peak	1,669	1,718	1,768	1,828	1,891	1,995
Weather-sensitive Peak	1,569	1,590	1,640	1,700	1,763	1,827

To develop the coincident peak forecast for each segment, we started with electricity sales by customer class. Avista provided electricity sales by rate schedule for the 2013 through 2019. For General Service customers, Avista provided projected average annual sales growth for Washington and Idaho.[5] For Large General Service and Extra Large General Service customers, we projected electricity sales for 2019 through 2035 using the average annual growth rate over the 2014-2019 timeframe.

Next, we applied load factors by customer class and state to the electricity sales forecast to calculate coincident peak demand. To estimate the load factors, we used data from Avista's 2010 load research study which provided coincident peak demand and electricity sales by state and customer class. Table 3-4 below shows the load factors and coincident peak values for the base year and selected future years.

[4] The system peak forecast shown here is the net native load forecast from data provided by Avista, excluding the two largest industrial loads.

[5] Based on information from Avista, we directly used an average of 0.8% sales growth for GS customers in Washington and an average 1.4% sales growth for GS customers in Idaho for the 2019-2035 period

Table 3-4 Load Factors and Baseline Coincident Peak Forecast by Segment (MW @Meter)

Segment Level Coincident Peaks	*Load Factor*	2013	2016	2020	2025	2030	2035
Washington							
General Service	*0.64*	75	76	78	81	85	88
Large General Service	*0.75*	193	193	193	188	184	179
Extra Large General Service	*0.79*	86	89	93	92	90	89
Total C&I	***n/a***	**354**	**359**	**364**	**361**	**358**	**356**
Idaho							
General Service	*0.80*	60	60	64	69	74	79
Large General Service	*0.82*	105	103	103	102	101	100
Extra Large General Service	*0.79*	43	48	51	57	64	72
Total C&I	***n/a***	**207**	**211**	**218**	**227**	**238**	**251**

Saturation Assumptions for Relevant End-Uses

Another important factor in Avista market characterization is the saturation level of relevant end uses included in the DR analysis: electric space heating and water heating. The two relevant space heating equipment for DR analysis are central furnaces and heat pumps. The saturations are relevant for estimating savings from direct-load control programs which are applicable to General Service and Large General Service customers (see Section 4). Table 3-5 below shows saturation estimates by state and customer class. We obtained all saturation values from the Conservation Potential Assessment study conducted by Avista in 2013.

Table 3-5 Electric Space Heating and Water Heating Saturation by State and Customer Class

End-use Saturation by Equipment Type	General Service	Large General Service
Space Heating Saturation for Washington		
Heat Pump	3.6%	9.1%
Central Furnace	17.7%	12.7%
Total (Applicable for DR Analysis)	*21.3%*	*21.8%*
Space Heating Saturation for Idaho		
Heat Pump	3.6%	9.1%
Central Furnace	17.7%	12.7%
Total (Applicable for DR Analysis)	*21.3%*	*21.8%*
Water Heating Saturation for Washington		
All equipment	63.0%	54.2%
Water Heating Saturation for Idaho		
All equipment	54.2%	54.2%

SECTION | 4

DR Program Descriptions

This section identifies and describes the relevant Demand Response programs for Avista. It highlights the key features for each program and presents assumptions on program parameters that are required for potential and cost calculations. Program features describe characteristics such as targeted customer segment, typical end-uses controlled, available hours, event notification and duration, type of response, incentive levels to participants, metering requirements and mechanisms for program delivery. These characteristics will help support future DR program design by Avista. In addition to these characteristics, this section presents participation, impact, and cost assumptions for individual DR programs and provides detailed documentation for these assumptions. These assumptions serve as a foundation for potential and cost analysis results presented in Section 5.

Relevant DR Programs

Table 4-1 presents the DR programs included in our analysis, which we developed in consultation with Avista staff. There were other options we considered but the final set is shown below. The different types of DR programs can be broadly classified into two types: non-pricing programs and pricing programs

- Non-pricing programs represent firm, dispatchable resources that Avista could count on to fulfill system resource requirements when needed. The two types of non-pricing programs included in our analysis are Direct Load Control (DLC) and Firm Curtailment (FC) program. DLC programs target space heating and water heating, as described below.
- Dynamic pricing options, on the other hand, represent non-firm resources that may not be available for dispatch when needed. The pricing option considered to be relevant for Avista is Critical Peak Pricing (CPP).

Table 4-1 Relevant DR Programs for Avista

Category	Program	Applicable Customer Class
Non-pricing	Direct Load Control	General Service (GS)
		Large General Service (LGS)
	Firm Curtailment	Large General Service (LGS)
		Extra Large General Service (XLGS)
Pricing	Critical Peak Pricing	General Service (GS)
		Large General Service (LGS)
		Extra Large General Service (XLGS)

In addition to the above options included in the study, we considered three additional options that were qualitatively screened out of the potentials analysis. A listing of these options and the rationale for ultimately not including each is below.

- **Thermal Energy Storage (TES)**. Thermal energy storage technologies are a relatively mature technology that is worthwhile in some niche applications and climates. Otter Tail Power has a successful TES program. However, this option is not well-suite to Avista's relatively mild climate.

- **Conservation Voltage Reduction (CVR)**. We screened CVR out of the analysis here because Avista is already doing this.
- **DR providing ancillary services (Fast DR).** DR resources for providing ancillary services such as frequency regulation or spinning reserves need to be Auto-DR enabled and possess very fast response times. They need to be available 24x7 with a high degree of reliability. Fast DR is well suited to a number of industries, such as mechanical digesters at paper-pulp mills and rock crushers. The potential for this program option would likely be captured by customers who would enroll in the Firm Curtailment program.

Additional information about TES and Fast DR is provided in Appendix A.

Direct Load Control Program

A DLC program would target Avista's General Service and Large General Service customers in Washington and Idaho. This program would directly control electric space heating load in winter and water heating load throughout the year for these customers through a load control switch or a programmable thermostat for space heating. The two types of space heating equipment that could be controlled are central electric furnaces and heat pumps, which would be cycled on and off during the events. Water heaters would be completely turned off during the DR event period. Water heaters of all sizes are eligible for control. Avista could offer this program beginning in 2016. Typically a DLC program takes five years to ramp up to maximum participation levels. Therefore, it is likely that by 2020 the full potential of this program would be realized. Table 4-2 below describes key DLC program attributes.

Table 4-2 Direct Load Control Program Features

Program Attributes	Description	Comments
Targeted Segment	General Service and Large General Service customers in WA and ID with eligible electric space heating and water heating equipment.	Only heat pumps and central furnaces are eligible for DLC. The combined saturation is the same for Washington and Idaho at 21.3%. Electric water heating saturation is 63% in Washington and 54% in Idaho.
Resource Availability	Space heating is controlled during the winter months (October-April). Most events are likely to be called during the months of December-February when demand is high. Water heating is controlled throughout the year.	October through April are the winter months for Avista. System peak usually occurs in December and demand is significantly high during January and February. Therefore most events are likely to be called during December to February.
Event Notification	Day ahead event notification via email, phone, or SMS.	Avista peaks happen during the early morning hours so participants need to be provided with day-ahead notification.
Maximum Annual Event Hours	60 hours	Based on Duke Energy Carolinas DLC program.
Event Duration	Event duration can range from 4 to 6 hours.	Based on Duke Energy Carolinas and Florida Power and Light's DLC program information.
Type of Response	Space heaters can be cycled or completed turned off during the event period or the temperature can be set using a Programmable Communicating Thermostat. Water heaters are completely shut off during the event period.	

Delivery Mechanism	Avista is responsible for delivering the program.	Most DLC programs in the industry are delivered directly by the utility.
Participant Incentive	$60 annual payment for space heating control during the winter; $50 annual payment for water heating control throughout the year.	Incentive payments to DLC customers are typically in the $20-$100 range. Our assumption is at the midpoint of this range for space heating control. For water heating control, we assumed $4/month incentive for control all year round.
Metering Requirements	Customers can participate with existing meters.	Interval meters are not required to participate.

Direct Load Control Program Assumptions

The key parameters required to estimate potential for a DLC program are participation rate, per participant load reduction and program costs. We have described below our assumptions of these parameters.

Participation Rate

Avista could offer this program from 2016 to General Service and Large General Service customers with eligible space heating and water heating equipment. We used information from the most successful programs identified in the FERC survey to develop these assumptions. Based on industry experience, we estimated that the program would follow an S-shaped ramp and reach steady-state participation level by 2020. Table 4-3 below shows participation rates assumptions.

Table 4-3 DLC Participation Rates (% of eligible customers)

Assumption	Unit	2016	2017	2018	2019	2020-35
Participation Rates	% of eligible customers	1.5%	4.5%	9.0%	13.5%	15.0%

Table 4-4 below describes the basis for the steady-state participation rate and program ramp up period assumptions.

Table 4-4 Basis for Direct Load Control Program Participation Assumptions

Assumption	Unit	Value	Basis for Assumptions
Steady-state Participation Rate	% of eligible customers	15%	Assumed to be slightly larger than the weighted average participation rate of 23 C&I DLC programs reported in the FERC survey database.[6]
Ramp Rate	No. of years required to attain steady-state participation level	5	Interviews with utility program managers; FERC National Assessment of DR Potential database.

DLC Load Reduction

Table 4-5 presents per-participant load reduction for space heating and water heating control and explains the basis for these assumptions.

Table 4-5 Per Participant Impact Assumptions for Direct Load Control Program

[6] http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

End use and Customer Class	Value (kW)	Basis for Assumptions
Space Heating Control		
General Service	1.50	Values are assumed to be 25% higher than residential impacts from Puget Sound Energy (PSE) residential DLC pilot.
Large General Service	15.0	Assumed to be 15% of the class average coincident demand of 100 kW.
Water Heating Control		
General Service	0.47	Values are assumed to be 25% higher than residential impacts from Puget Sound Energy (PSE) residential DLC pilot.
Large General Service	10.0	Assumed to be 10% of the class average coincident demand of 100 kW.

Program Costs

Table 4-6 presents itemized cost assumptions for the DLC program and the basis for the assumptions.

Table 4-6 DLC Program Cost Assumptions

Assumption	Unit	Value	Basis for Assumption
Program Development Cost	$/program	$150,000	We assumed that 1 FTE (@$150,000 annual cost) is required to develop the DLC program for both WA and ID and the cost is equally split between the two customer classes for each state.
Program Administration Cost	$/year	$150,000	We assumed 1 FTE annual cost for DLC program administration for WA and ID, split equally between the two customer classes.
Annual Marketing and Recruitment Costs (GS)	$/new participant	$100	Standard assumption for residential customers is $50. For small commercial customers, we assumed costs to be 25% higher than the costs for residential.
Annual Marketing and Recruitment Costs (Large GS)	$/new participant	$133	We assumed 33% higher costs for Large General Service customers than comparable costs for General Service customers.
Cost of Equip + Install for Space Heating Control (GS)	$/new participant	$375	Load control switch capital cost = $100. Average of 1.25 control units per customer. Implies capital cost per participant = $125. Switch installation cost = $125. License and permit-related costs = $125 per participant (25% higher than equivalent cost for residential customers at $100).
Cost of Equip + Install for Space Heating Control (Large GS)	$/new participant	$550	Control switch capital and installation cost = $200. License and permit related costs = $150 per participant.
Cost of Equip + Install for Water Heating Control (GS)	$/new participant	$350	Load control switch capital cost= $100. Switch installation cost = $125. One water heating control unit per participant. Implies cost per participant is $225. License and permit related costs = $125 per participant (25% higher than equivalent cost for residential customers at $100).
Cost of Equip + Install for Water Heating Control (Large GS)	$/new participant	$450	Load control switch capital and installation cost = $150 each. License and permit related costs = $150 per participant (50% higher than equivalent cost for residential customers at $100).
Annual O&M cost (GS)	$/participant per year	$15	Annual O&M cost = 10% of the control equipment cost.
Annual O&M cost (Large GS)	$/participant per year	$20	Annual O&M cost = 10% of the control equipment cost.
Per participant annual incentive for Space Heating (GS)	$/participant per year	$60	Incentive payments to DLC customers are typically in the $20-$100 range. Assumed values are at the midpoint of this range.
Per participant annual incentive for Space Heating control (Large GS)	$/participant per year	$160	$1.5/kW monthly incentive payment. For an average 15 kW of reduction per participant, this translates into $160 total incentive payment over seven winter months.
Per participant annual incentive for Water Heating control	$/participant per year	$50	$4/month incentive payment to participants. Water heaters are controlled throughout the year.

Other Assumptions

The other key parameters needed for potential and cost analysis are program life and capacity derating factor. Table 4-7 below describes these assumptions for DLC.

Table 4-7 Direct Load Control Program Lifetime and Capacity Derating Factor

Assumption	Unit	Value	Basis for Assumption
Program Life	Years	8	The DLC program life is tied to the life of the switch. We assumed the control switch life to be 8 years.
Capacity derating factor	Factor	0.8	Capacity derating values generally range from 0.6 to 1.0. We assumed the de-rating factor to be at the midpoint of this range, with a value of 0.8.

Firm Curtailment Program

A Firm Curtailment program would target Large General Service and Extra Large General Service customers in Avista's service territory. Under this program, participating customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year). Customers are paid to be on-call even though actual load curtailments may not occur. The amount of capacity payment typically varies with the firm reliability-commitment level. In addition to the fixed capacity payment, participants receive a payment for energy reduction. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity (ICAP) requirements. Penalties may be are assessed for under-performance or non-performance.

Industry experiences shows that typically customers with greater than 200 kW demand participate in this type of program. However, there are a few programs where customers with 100 kW maximum demand participate. In Avista's case, we have lowered the demand threshold level to include Large General Service customers with an average demand of 100 kW.

Avista could offer this program from 2016 to eligible customers in Washington and Idaho. Customers with flexibility in their operations are attractive candidates for participation. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants, and industries with process storage (e.g. pulp and paper, cement manufacturing). Customers with 24x7 operations/continuous processes or with obligations to continue providing service (such as schools and hospitals) are not often good candidates for this option.

Typically Firm Curtailment programs in the industry are delivered through third parties who are responsible for all aspects of program implementation including program marketing and outreach, customer recruitment, technology installation, and incentive payments to participants. Avista would enter into a contract with a third party to deliver a fixed amount of capacity reduction over a certain specified timeframe. The payment to the third party would be based on the contracted capacity reduction and the actual energy reduction during DR events.

Table 4-8 below describes the key attributes for a Firm Curtailment program that could help guide future program design by Avista.

Table 4-8 Firm Curtailment Program Features

Program Attributes	Description	Comments
Targeted Segment	Large General Service and Extra Large General Service customers.	C&I customers with a minimum load of 100 kW are suitable for participation.
Resource Availability	Program is available year round.	Firm curtailment programs are available all year round.
	During the winter months of October to April, events can be called anytime between 6 AM to 10 AM and 4 PM to 8 PM on weekdays.	Events can be called to address dual peak during the winter season.
	During the summer months of May to September, events can be called anytime between 12 noon to 7 PM on weekdays.	Events can be called to address the late afternoon and early evening peak during summer.
Event Notification	Day ahead notification via email, phone or SMS.	Typically, events are called either a day in advance or 30 minutes prior to the event. Participants prefer day-ahead notification.
Maximum Annual Event Hours	60 hours	Typical specification in the industry.
Event Duration	Events can range from 1-8 hours.	Typical specification in the industry.
Type of Response	Non-essential load is curtailed; participants can also shift their usage to backup generators. Participants can either respond manually or have automated response strategies.	Program implementation experience.
Delivery Mechanism	The program is delivered through a third party.	Most utilities deliver Firm Curtailment programs through third parties.
Delivery Cost	Delivery cost consists of two components: 1) $/kW-year capacity payment to the third-party at $70/kW-year 2)Energy payment to the third-party at $110/MWh; Internal program administration cost for Avista is assumed to be approximately 10% of the capacity delivery cost. This increases the overall per-kW delivery cost to $77/kW-year.	Based on third-party program implementation experience, capacity delivery cost is in the $60-80/kW range and energy delivery cost is in the $75-150/MWh range. We are using the midpoint of the ranges. We also assume additional utility administrative costs to account program management, regulatory filings, internal book keeping, etc. These costs are estimated to be 10% of the capacity delivery cost.
Participant Incentive	The third party is responsible for payment of incentives to participants, so incentive cost is part of the delivery cost.	
Metering and Communication Requirements	Preferable to have 5-minute interval data but 15-minute or hourly data are sufficient. Participants should be able to receive and confirm curtailment requests in real time.	Typical specification for this type of program.

Firm Curtailment Program Assumptions

The key parameters required to estimate potential for a Firm Curtailment program are participation rate, per participant load reduction and program costs.

Program Participation Rate

Table 4-9 below shows Form Curtailment program participation assumptions. Based on industry experience, we estimate the program will ramp up to a steady-state participation level over three years, which is the typical contract duration for third-party delivered programs.

As noted in the table above, customers may use back-up generation to achieve load reduction under this program. We estimate that roughly one fourth of the load reduction achieved through this option would be provided by customers with backup generation.

To gain a better understanding of customer generation capabilities, Avista is conducting a separate analysis to estimate the amount of back-up generation in the service area. The results of this analysis may be useful to better understanding the overlap between programs targeted at customers with backup-generation and response to a Firm Curtailment program, should Avista offer these in the future.

Table 4-9 Firm Curtailment Program Participation Rates (% of eligible customers)

Customer Segment	2016	2017	2018	2019	2020-35
Large General Service and Extra Large General Service	7.4%	14.9%	22.3%	22.3%	22.3%

Table 4-10 below describes the basis for the steady-state participation rate and program ramp up assumptions.

Table 4-10 Basis for Firm Curtailment Program Participation Assumptions

Assumption	Unit	Value	Basis for Assumptions
Steady-state participation	% of eligible customers	22.3%	Steady-state participation is the average of 50th and 75th percentile values from a dataset of 7 programs listed in the FERC 2012 DR Program Survey database.[7] We applied a 5% de-rating factor to the average participation level to account for the fact that some facilities with backup generators may not be eligible for participation due to RICE/NESHAP regulations.
Program Ramp Rate	No. of years required to attain steady-state participation level	3	Program implementation experience. This is based on the typical contract duration for a third-party delivered program.

Per Participant Load Reduction

Table 4-11 below presents the assumed per-participant load reduction for a Firm Curtailment program and explains the basis for this assumption. Customer respond by curtailing a variety of end uses customized for their circumstances. Some customers also use back-up generators to achieve the load shed. Therefore, the estimates we present here may overlap with peak-load reduction estimates Avista is developing in a separate study.

Table 4-11 Per Participant Load Reduction Assumption for the Firm Curtailment Program

Assumption	Unit	Value	Basis for Assumption

[7] http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp.
Note that Firm Curtailment programs, primarily delivered by load aggregators, are relatively new and fewer in number than legacy DLC programs. Therefore, the dataset size for these programs is relatively small. Also, participation data is not available for all programs listed in the survey database, which further restricted our choice set for developing participation estimates.

Per-participant load reduction for Large General Service & Extra Large General Service	% of enrolled load	21%	Weighted average impact estimates from aggregator DR programs administered by CA utilities (Ref: 2012 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs Volume 1: Ex post and Ex ante Load Impacts; Christensen Associates Energy Consulting; April 1, 2013). We combined these estimates with data from the 2012 FERC National Survey database of DR programs.

Program Costs

Table 4-12 presents cost assumptions for the Firm Curtailment program. We developed these cost assumptions in consultation with industry experts. The delivery cost shown in the table represents Avista's all-in payment to the contracted third party for delivering a fixed amount of load reduction. It consists of two components: a capacity component and an energy component. The third party is responsible for all program costs including incentive payments to participants. Typically, 50 percent of the delivery cost is passed through as incentive payment to participants. Other than the third-party delivery costs, we assumed that Avista would incur additional internal administration costs for deploying this program.

Table 4-12 Firm Curtailment Program Cost Assumptions

Assumption	Unit	Value	Basis for Assumption
Program Delivery Cost (administered by third party)	$/kW-year	$77	Based on third-party program implementation experience, delivery cost is expected to be in the range of $60-80/kW and we assumed the midpoint This is inclusive of all costs to run the program, including equipment purchase and installation costs, maintenance costs, network communications costs, sales and marketing costs, and payments to the customer. Avista would also incur administrative costs for program management, regulatory filings, internal book keeping, etc. These costs were estimated to be 10% of the capacity delivery costs.
Payment for energy delivery	$/kWh	$0.11	Based on third-party program implementation experience, energy dispatch prices typically fall in the $75-150/MWh range. Our assumed price level is at the midpoint of this range.

Other Assumptions

The other key parameters needed for potential and cost analysis are program life and capacity derating factor. Table 4-13 below describes these assumptions for the Firm Curtailment program.

Table 4-13 Firm Curtailment Program Lifetime and Capacity Derating Factor

Assumption	Unit	Value	Basis for Assumption
Program Life	Years	3	Typical contract duration for third-party delivered Firm Curtailment programs.
Capacity derating factor	Factor	0.8	Capacity derating values generally range from 0.6 to 1.0. We assumed the de-rating factor to be at the midpoint of this range, with a value of 0.8.

Critical Peak Pricing

We considered Critical Peal Pricing (CPP) in our analysis. The CPP option involves significantly higher prices during relatively short critical peak periods on event days only to encourage customers to reduce their usage. CPP is usually offered in conjunction with a time-of-use rate, which implies at least three time periods: critical peak, on peak and off peak. The customer incentive is a more heavily discounted rate during off-peak hours throughout the year (relative to a standard TOU rate). Event days are dispatched on relatively short notice (day ahead or day-of) typically for a limited number of days during the year. Over time, event-trigger criteria become well-established so that customers can expect events based on hot weather or other factors. Events can also be called during times of system contingencies or emergencies. The CPP rate included here is based on a 6:1 peak to off-peak price ratio assumption. We assumed that this rate is offered to all three C&I classes.

We considered two types of offers for CPP. With an **opt-in** rate**,** participants voluntarily enroll in the rate. With an **opt-out** rate, all customers are placed on the time-varying rate but they may oft-out and select another rate if they so desire.

Participation in CPP rates requires AMI. At this time, Avista's Extra Large General Service customers have sophisticated telemetry and communications infrastructure in place and may be offered CPP rates beginning in 2016. For the other two customer classes, CPP is not available until the AMI rollout is completed in 2020. Therefore, we assumed that CPP rates can be offered to General Service and Large General Service customers starting in 2021.

Studies have shown that impacts from dynamic pricing program vary according to whether customers have enabling technology to automate their response. For General Service and Large General Service customers, the enabling technology is a programmable communicating thermostat (PCT). For Extra Large General Service customers, the enabling technology is Automated Demand Response (Auto-DR), implemented through energy management and control systems.

Table 4-14 describes the features of a CPP rate. If Avista were to offer these rates, it would need to undertake a formal rate design analysis using customer billing data to specify peak and off-peak price levels and define the periods during which these rate would be available. Design of these rates is outside the scope of the current study.

Table 4-14 Critical Peak Pricing Program Features

Program Attributes	Description	Comments
Targeted Segment	General Service, Large General Service and Extra Large General Service customers.	Customers of all sizes are eligible to participate in a CPP program.
Type of Offer	Two types of offers are possible: 1. CPP is offered as a voluntary rate to all customer classes with opt-in provision. 2. CPP is offered as a default rate to all customer classes with opt-out provision.	
Resource Availability	CPP events can be called any time during the year, based on system requirements.	
Event Notification	Day ahead event notification via email, phone, or SMS.	Participants can be notified on either a day-ahead or day-of basis, but day-ahead is preferred.
Maximum Number of CPP Events in a Year	10 to 15	Avista can choose to call more events during winter and fewer or none during summer, as needed.
Maximum Annual Event Hours	60 hours	Industry experience.
Event Duration	Typical event duration is 4 hours.	
Type of Response	Load curtailment and shifting to backup generators. Enabling technology can enhance response. For GS and LGS, enabling technology is assumed to PCT. For Extra Large General Service, enabling technology is assumed to be Auto-DR.	
Delivery Mechanism	Avista is responsible for delivering the program.	
Participant Incentive	The critical peak to off-peak price differential induces participant to reduce usage during critical peak periods. The off-peak rate is lower than the participant's standard rate.	
Metering Requirements	AMI is required for metering and settlement.	

Critical Peak Pricing Assumptions

The key parameters required to estimate potential for CPP are participation rate, per participant load reduction and costs for deploying these rates. We have described below our assumptions for these parameters.

Program Participation Rate

We have defined participation rates for two pricing options, assuming independent offers of CPP rates: voluntary, opt-in CPP rates to all customers and default CPP rates with opt-out.

All participation assumptions are based on Brattle's extensive database on pricing program and pilot experiences.

Table 4-15 presents assumed participation rates for C&I customers in independent CPP rate offers. Table 4-15 presents assumed participation rates in independent default rate offers for these two options. We assumed that participation ramps up over a five-year timeframe to reach a steady-state level. For the opt-in offer, ramp up to steady-state participation follows an "S-shaped" diffusion curve, in which the participation growth rate accelerates over the first half of the five year period and then slows over the second half. A similar but inverse S-shaped diffusion curve is used to account for the rate at which customers opt-out of the default rate. CPP rates could be offered to Extra Large General service customers in 2016. For the other two classes, these rate are offered after AMI has been fully deployed by 2021.

Table 4-15 Opt-in CPP Participation Rates (% of eligible customers)

Option	Start Yr.	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yrs. 5-19	Comments
Opt-in							Standalone participation estimates represent average enrollment rates in independent rate offerings across full scale deployments and market research studies. (Source: Brattle's Pricing Program Database)
General Service & Large General Service	2021	1.8%	5.4%	10.8%	16.2%	18.0%	
Extra Large General Service	2016	1.8%	5.4%	10.8%	16.2%	18.0%	
Opt-out							
General Service & Large General Service	2021	100%	96.0%	85.7%	65.8%	63.0%	
Extra Large General Service	2016	100%	96.0%	85.7%	65.8%	63.0%	

Percentage of Customers with Enabling Technology in CPP Rates[8]

Earlier we mentioned that the load reductions from CPP participants could be enhanced through the use of enabling technology. Table 4-16 shows the percentage of total CPP participants equipped with enabling technology for the opt-in and opt-out cases. Enabling technology is defined as Programmable Communicating Thermostat (PCT) for General Service and Large General Service customers, and Auto-DR for Extra Large General Service customers.

Table 4-16 Percentage of CPP Participants with Enabling Technology (% of total participants)

Option	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yrs. 5-19
Opt-in CPP	25%	25%	25%	25%	25%
Opt-out CPP	2%	4%	6%	8%	10%

Per Participant Load Reduction

Table 4-17 below presents assumed per participant load reduction in CPP rates by customer class. The assumed impact values are based on a 6:1 critical peak to off-peak price ratio. Estimated load reductions with enabling technology are significantly higher than those achieved without enabling technology use.

[8] Enabling technology is not included with TOU because the peak period price signal is non-dispatchable.

Table 4-17 Per-Participant Load Reduction in CPP Rates by Customer Class

Customer Class	Value	Comments
GS without enabling technology	0.6%	These impacts assume 6:1 critical peak to off-peak price ratio. Source: Brattle's Database on Pricing Programs.
GS with enabling technology	12.5%	
Large GS without enabling technology	7.3%	
Large GS with enabling technology	11.7%	
Extra Large GS without enabling technology	8.4%	
Extra Large GS with enabling technology	15.6%	

Program Costs

The major cost components for implementation of time varying rates are the fixed annual costs for administering the rates and providing billing analysis. For an opt-out offer, additional call center staff may be required during the initial program years to handle the relatively large volume of calls from customers defaulted to these rates.

Table 4-18 below shows cost assumptions for deployment of opt-in and opt-out CPP rates. The cost items for CPP are similar to those for TOU rates. A major portion of CPP program costs is enabling technology purchase and installation for a fraction of the total participants.

Table 4-18 CPP Program Cost Assumptions for Opt-in and Opt-out Offers

Item	Unit	Value	Comments
Costs Applicable to Opt-in and Opt-out:			
Program Development Cost	$/program	$170,000	One FTE at $170,000 annual cost for program development.
Annual Program Administration Cost	$/year	$170,000	One FTE at $170,000 annual cost to administer the CPP rates
Billing Analyst Cost	$/year	$105,000	One billing analyst at $105,000 in the call center to provide customer service.
Enabling Technology Cost	$/GS participant	$375	We assumed per participant PCT capital and installation cost is the same as DLC.
	$/LGS participant	$550	We assumed per participant PCT capital and installation cost is the same as DLC.
	$/kW load reduction for XLGS	$200	Based on Auto-DR enablement costs from a CA utility.
Billing system upgrade	$	$7.5 million	Avista provided this estimate
Additional costs applicable to Opt-in:			
Per Customer Annual Marketing/Recruitment Cost	$/new GS participant	$100	Same as DLC Program marketing cost.
	$/new LGS participant	$133	For LGS customers, costs are assumed to be a third higher than costs for GS customers.
	$/new XLGS participant	$250	For XLGS customers, costs are assumed to be approximately double the costs for LGS customers.
Additional costs applicable to Opt-out:			
Additional call center staff	$/yr. for first two program years	$255,000	We assumed that 3 additional call center staff at $85,000 each annual cost to handle customer calls for an opt-out rate.
Per Customer Annual Marketing/Recruitment Cost	$/new GS participant	$10	For opt-out CPP rates, these costs are assumed to be one-tenth of the costs for opt-in CPP rates.
	$/new LGS participant	$15	
	$/new XLGS participant	$25	

Other Assumptions

The other key parameters needed for potential and cost analysis are program life and capacity derating factor. Table 4-19 below describes these assumptions for the pricing options.

Table 4-19 Program Lifetime and Capacity Derating Factor for Pricing Options

Item	Unit	Value	Basis for Assumption
Program Life	Years	20	Program life is tied to the life of the interval meter.
Capacity derating factor	Factor	0.5	Load reductions from pricing options are less firm than load reductions from non-pricing options. Therefore we assumed capacity derating factor to be lower at 0.5.

Other Cross-cutting Assumptions

In addition to the above program-specific assumptions, there are three that affect all programs:

- **Discount rate**. We used a nominal discount rate of 7% to calculate the net present value (NPV) of costs over the useful life of each DR program. All cost results are shown in nominal dollars. We assumed 1.86% inflation rate for escalating costs.
- **Line losses**. Avista provided a line loss factor of 6.5% to convert estimated demand savings at the customer meter level to demand savings at the generator level. In the next section, we report our analysis results at the generator level.
- **Snapback**. In this context, snapback refers to the amount of energy savings that result from DR programs. We have assumed in this analysis that the amount of kWh savings from DR programs is negligible since most of the reduction during events is typically shifted to other times of day, either before or after the event.

SECTION | 5

DR Potential and Cost Estimates

This section presents analysis results on demand savings and cost estimates for DR programs. We conducted an independent assessment of DR options which considered each option as a standalone offering. As such, this approach does not account for participation overlaps among DR options targeted at the same customer segment and therefore savings and cost results for individual DR options are not additive. The standalone analysis results help provide a comparative assessment of individual DR options and costs and are useful for selection of DR options in a program portfolio.

At the very end of this section, we present high-level results in 2035 after considering integrated effects that occur if more than on DR option is offered to Avista customers.

All potential results presented in this section represent capacity savings in terms of equivalent generation capacity after derating factors have been applied.

Potential Results

Figure 5-1 and Table 5-1 show demand savings from individual DR options for selected years of the analysis. These savings represent combined savings from DR options in Avista's Washington and Idaho service territories.

Key findings include:

- The firm curtailment option has highest savings potential at approximately 2.7-2.8% of estimated C&I peak demand from 2020 onward. We assumed that Avista offers this option to Large General Service and Extra Large General Service customers in 2016 and participation ramps up to a steady state by 2019. Therefore potential remains almost steady from that time onward.
- An opt-out CPP offer has second highest savings potential at approximately 2% of C&I peak demand from 2025 onward. We assumed that Avista could offer this as a default rate to all customer classes after AMI deployment is completed in 2020. Participation ramps up over a five-year time frame and reaches a steady state by 2025. Only Extra Large General Service customers are assumed to have the necessary metering infrastructure in place and could be offered a CPP rate from 2016.
- DLC for General Service and Large General Service customers provides third highest savings potential at approximately 1% of C&I peak demand from 2020 onward. This is offered in 2016 and ramps up to steady-state participation levels by 2020.
- Savings potential from opt-in CPP are approximately 0.7% of the system peak from 2025.

Figure 5-1 Summary Potential Analysis Results for Avista (MW @Generator)

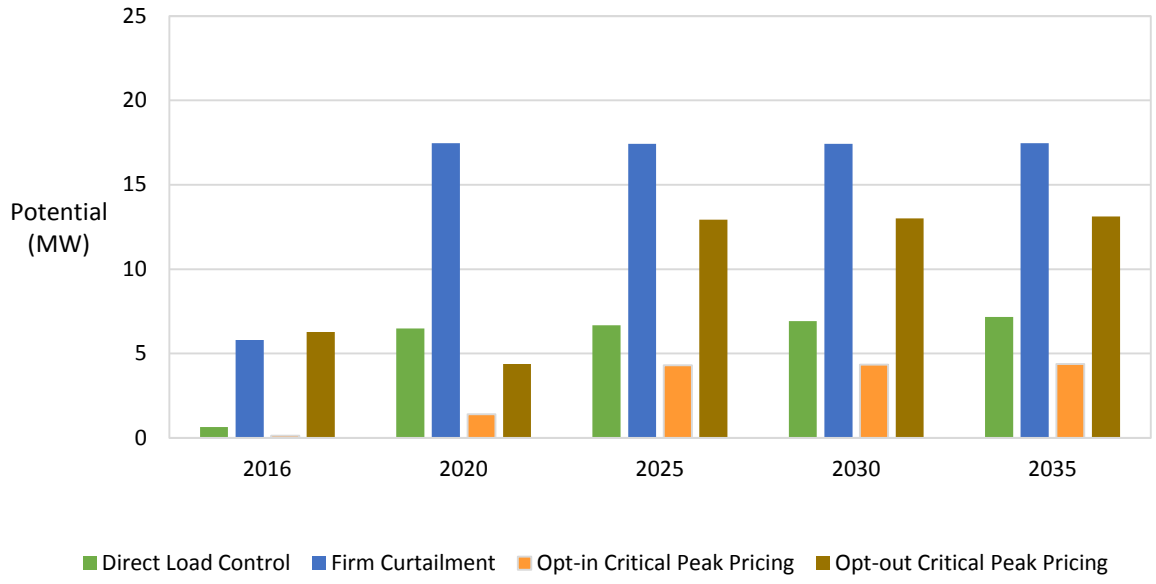

Table 5-1 Achievable DR Potential by Option for Avista (MW @Generator)

	2016	2020	2025	2030	2035
Total System Peak (MW)	**1,718**	**1,768**	**1,828**	**1,891**	**1,995**
Weather Sensitive Peak (MW)	**1,590**	**1,640**	**1,700**	**1,763**	**1,827**
Estimated C&I Peak (MW)	**610**	**622**	**630**	**638**	**649**
Achievable Potential (MW)					
Direct Load Control	0.64	6.48	6.68	6.91	7.16
Firm Curtailment	5.80	17.46	17.42	17.42	17.46
Opt-in Critical Peak Pricing	0.13	1.40	4.30	4.33	4.38
Opt-out Critical Peak Pricing	6.27	4.38	12.93	13.01	13.12
Achievable Potential (% of C&I Peak)					
Direct Load Control	*0.10%*	*1.04%*	*1.06%*	*1.08%*	*1.10%*
Firm Curtailment	*0.95%*	*2.81%*	*2.77%*	*2.73%*	*2.69%*
Opt-in Critical Peak Pricing	*0.02%*	*0.23%*	*0.68%*	*0.68%*	*0.68%*
Opt-out Critical Peak Pricing	*1.03%*	*0.70%*	*2.05%*	*2.04%*	*2.02%*

Table 5-2 and Table 5-3 show demand savings by individual DR option for Washington and Idaho.

Table 5-2 Achievable DR Potential by Option for Washington (MW @Generator)

	2016	2020	2025	2030	2035
Total System Peak (MW)	**1,718**	**1,768**	**1,828**	**1,891**	**1,995**
Weather Sensitive Peak (MW)	**1,590**	**1,640**	**1,700**	**1,763**	**1,827**
Estimated C&I Peak (MW)	**610**	**622**	**630**	**638**	**649**
Achievable Potential (MW)					
Direct Load Control	0.39	4.00	4.12	4.26	4.42
Firm Curtailment	3.78	11.36	11.11	10.87	10.63
Opt-in Critical Peak Pricing	0.09	0.91	2.69	2.65	2.61
Opt-out Critical Peak Pricing	4.08	2.83	8.15	8.01	7.87
Achievable Potential (% of C&I Peak)					
Direct Load Control	*0.06%*	*0.64%*	*0.65%*	*0.67%*	*0.68%*
Firm Curtailment	*0.62%*	*1.83%*	*1.76%*	*1.70%*	*1.64%*
Opt-in Critical Peak Pricing	*0.01%*	*0.15%*	*0.43%*	*0.41%*	*0.40%*
Opt-out Critical Peak Pricing	*0.67%*	*0.46%*	*1.29%*	*1.26%*	*1.21%*

Table 5-3 Achievable DR Potential by Option for Idaho (MW @Generator)

	2016	2020	2025	2030	2035
Total System Peak (MW)	**1,718**	**1,768**	**1,828**	**1,891**	**1,995**
Weather Sensitive Peak (MW)	**1,590**	**1,640**	**1,700**	**1,763**	**1,827**
Estimated C&I Peak (MW)	**610**	**622**	**630**	**638**	**649**
Achievable Potential (MW)					
Direct Load Control	0.24	2.48	2.56	2.64	2.74
Firm Curtailment	2.02	6.10	6.31	6.55	6.82
Opt-in Critical Peak Pricing	0.05	0.49	1.61	1.69	1.78
Opt-out Critical Peak Pricing	2.19	1.54	4.78	5.00	5.25
Achievable Potential (% of C&I Peak)					
Direct Load Control	*0.04%*	*0.40%*	*0.41%*	*0.41%*	*0.42%*
Firm Curtailment	*0.33%*	*0.98%*	*1.00%*	*1.03%*	*1.05%*
Opt-in Critical Peak Pricing	*0.01%*	*0.08%*	*0.26%*	*0.26%*	*0.27%*
Opt-out Critical Peak Pricing	*0.36%*	*0.25%*	*0.76%*	*0.78%*	*0.81%*

Cost Results

Table 5-4 presents total utility costs for deployment of individual DR options over the 2016-2035 timeframe. It also shows the average annual cost and the levelized costs per kW of equivalent generation capacity over 2016-2035. We show 2035 savings potential from DR options for reference purposes.

Table 5-4 DR Program Costs and Potential

DR Option	2035 MW Potential	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-year)
Direct Load Control	7.16	$16.07	$0.80	$143.82
Firm Curtailment	17.46	$40.68	$2.03	$118.59
Opt-in Critical Peak Pricing	4.38	$25.61	$1.28	$432.65
Opt-out Critical Peak Pricing	13.12	$26.69	$1.33	$109.86

Key findings include:

- The Firm Curtailment option could deliver highest savings at approximately $118/kW-year cost. The cumulative costs to Avista over a 20 year planning periods for realizing 17 MW of savings in 2035 is around $40 million. Capacity-based and energy-based payments to the third party constitutes the major cost component for this option. In addition, Avista would incur a relatively small amount of internal administrative costs for managing the third party.
- Opt-out CPP has lowest levelized cost among all DR options. It could deliver 13 MW in 2035 at $109/kW-yr. We estimate that Avista would need to spend approximately $26 million over 2016-2035 to deploy a default CPP rate to all customer classes. Enabling technology purchase and installation costs for enhancing customer response is a large part of CPP deployment costs.
- Opt-in CPP has a cost of $432/kW-year and is significantly higher than opt-out CPP. The major cost component for an opt-in CPP offer cost is the annual fixed program administration cost for administering the rate. This cost is spread over the smaller number of customers who choose to participate in this rate.
- Direct load control provides the third highest savings, 7 MW in 2035, at a relatively high cost of $144/kW-year. The significant cost components for DLC program implementation are associated with purchase and installation of enabling technology and with program marketing and outreach activities. There are also additional permitting and licensing fees that Avista customers must incur.

Integrated Results

The above analysis assumes that the programs are offered on a stand-alone basis. That is, only one program, and not the others, is offered to Avista customers. If Avista offered more than one program, then the potential for double counting exists. To address this possibility, we created a participation hierarchy to define the order in which the programs are taken by customers. Then we computed the savings and costs under this scenario. We assumed the following hierarchy:

1. Direct load control
2. Firm curtailment
3. Opt-in CPP or Opt-out CPP

Table 5-5 shows the potential estimates in 2035, as well as the costs, if more than one program is offered. The savings and costs for DLC remain unchanged, since it is first in the hierarchy.

However, the savings for Firm Curtailment and CPP are slightly lower as are the cumulative and average program costs. Levelized costs for Firm Curtailment are slightly lower as well, but the levelized cost for CPP are higher because the program costs are spread across a smaller amount of savings.

Table 5-5 DR Program Costs and Potential - Interactive

DR Option	2035 MW Potential	2016 – 2035 Cumulative Utility Spend (Million $)	2016 – 2035 Average Spend per Year (Million $)	2016 – 2035 Levelized Cost ($/kW-year)
Direct Load Control	7.16	$16.07	$0.80	$143.82
Firm Curtailment	16.57	$38.65	$1.93	$118.52
Opt-in Critical Peak Pricing	3.35	$25.27	$1.26	$555.77
Opt-out Critical Peak Pricing	9.90	$26.32	$1.32	$141.03

APPENDIX | A

Literature Review

Before we performed the analysis of demand response (DR) for the Avista service territory, we conducted a literature review to provide Avista with an overview of what is already being done in the industry on DR. This review was originally provided to Avista under separate cover.

Introduction

Over the past decade, DR has evolved in many ways and a review and research of DR programs will provide Avista with a good overview and basis for the remainder of the study.

We have reviewed information available from national surveys of DR programs, most notably the FERC DR program survey database[9]. This national survey database is the most comprehensive data source on DR programs available in the industry, with a list of more than 1,500 DR programs and rate options offered to residential, commercial and industrial (C&I) and irrigation customers. The database has information on type of DR program and rate option, the type of entities offering the program, end-use equipment being controlled, participation requirements, number of customers enrolled, and realized load reduction amounts. In our research, we have covered all types of DR programs offered to residential and C&I customers.

We have combined the information from this data source with other relevant national data sources to arrive at key program characteristics, including performance metrics such as program participation rates and load reduction impacts. These data sources include: EIA Form 861 database[10], FERC Form 1 filing data[11], and the FERC National Assessment of Demand Response Potential Study[12]. We have also reviewed program reports, evaluation studies, and other types of industry publications to collect information about the different DR program types.

We have subdivided the relevant program information into two broad categories of program types: non-pricing and pricing programs. Non-pricing programs include Direct Load Control (DLC), Firm Curtailment programs, and Non-Firm Curtailment programs. Pricing options include Critical Peak Pricing (CPP) and Real Time Pricing (RTP).

We have identified a list of DR programs that we consider relevant for Avista and from that list we have selected a number of programs for in-depth research. For these programs, we describe the key characteristics including targeted customer segments and loads, event trigger, notification process, response requirements, timing and frequency of events, event duration, type of enabling technology for response, incentive structure, metering and other infrastructure requirements.

In addition to specific program information, we discuss items constituting benefits and costs for DR programs and the overall approach used for assessing cost-effectiveness of programs. At the end, we also include descriptions on commonly used methods for estimating program impacts.

This appendix consists of the following parts:

- A description of the approach we followed to identify relevant DR programs and to select a list of programs for in-depth research.

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[9] 2012 Survey on Demand Response and Advanced Metering, available at http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp
[10] http://www.eia.gov/electricity/data/eia861/
[11] http://www.ferc.gov/docs-filing/forms/form-1/data.asp
[12] http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

- Program descriptions for each selected program type
- Cost-effectiveness approaches for DR
- Impact estimation for DR

Research Approach

We first developed a list of proposed DR options by customer class. Then we identified and described representative programs for each type of program.

Proposed List of DR Options by Customer Class

We developed a comprehensive list of DR options for Avista's consideration in Table A-1 below. The customer class definitions are based on Avista's rate schedule information taken from Avista's System Load Research project, dated March, 2010. We have included two broad categories of DR options: non-pricing options and pricing options. In addition, we have included DR options for providing ancillary/load following services.

Table A-6 Proposed List of DR Options

Category	Option	Applicable Customer Class
Non-pricing	Direct Load Control	Residential
		General Service (GS)
		Large General Service (LGS)
	Curtailment- Firm	Large General Service (LGS)
		Extra Large General Service (XLGS)
	Curtailment- Non-firm	Large General Service (LGS)
		Extra Large General Service (XLGS)
Pricing	Time-of-Use Rates	Residential
		General Service (GS)
		Large General Service (LGS)
		Extra Large General Service (XLGS)
	Critical Peak Pricing	Residential
		General Service (GS)
		Large General Service (LGS)
		Extra Large General Service (XLGS)
	Real Time Pricing	Extra Large General Service (XLGS)
Ancillary Services / Load Following	Ancillary Services / Load Following	Residential
		General Service (GS)
		Large General Service (LGS)
		Extra Large General Service (XLGS)

Approach for Selecting Representative Programs for Further Research

To develop the list of programs, we followed the steps listed below:

1. Identify the universe of relevant DR programs,
2. Develop criteria for selecting representative programs to research in depth, and
3. Apply selection criteria to develop the list of recommended programs for further research.

We describe each of these steps in detail below.

Identify a List of Relevant DR Programs

To identify relevant programs for Avista, we reviewed the DR program information available in the 2012 FERC National DR program survey database.[13] This is the most comprehensive national database of DR programs in the industry.

We prioritized our review to select winter-peaking utilities to align with Avista's demand reduction objectives during the winter season. Because these are relatively few, we also included summer-peaking utilities with significant winter demand. To help identify these utilities, we calculated the winter peak as a percentage of the summer peak, and selected those utilities for whom their winter peak was at least 65 percent of the summer peak.[14] We present the universe of relevant DR offerings in Table A-2 through Table A-7.

[13] 2012 Survey on Demand Response and Advanced Metering, available at http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp
[14] We obtained summer and winter peak demand data, by utility, from EIA Form 861 for 2012.

Table A-2 Relevant Direct Load Control Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
Adams Electric Cooperative Inc.	PA	Residential	97.6%
BPA- City of Port Angeles	WA	Residential	120%
BPA- Emerald People's Utility District (EPUD)	OR	Residential	120%
BPA- Orcas Power and Light Coop	WA	Residential	120.3%
BPA-Central Electric Cooperative	OR	Residential	120.3%
Central Alabama Electric Coop	AL	Residential	105.5%
Connexus Energy	MN	Residential	65.3%
Crow Wing Cooperative Power & Light Comp	MN	Residential	68.1%
Duke Energy Carolinas, LLC	NC	Residential	90.4%
Florida Power & Light Co	FL	Residential	83.6%
Jackson Energy Coop Corp - (KY)	KY	Residential	120.6%
Kentucky Utilities Co	KY	Residential	97.0%
Lake Country Power	MN	Residential	185.8%
Minnesota Power Inc.	MN	Residential	99.8%
Northern Virginia Electric Coop	VA	Residential	70.6%
Otter Tail Power Co	ND	Residential	121.8%
Puget Sound Energy Inc.	WA	Residential	135.1%
Santee Electric Coop, Inc.	SC	Residential	101.9%
South Central Power Company	OH	Residential	89.3%
Southeastern Electric Coop Inc. - (SD)	SD	Residential	79.3%
United Electric Coop, Inc. - (PA)	PA	Residential	100.5%
Otter Tail Power Co	ND	C&I	121.8%
Duke Energy Carolinas, LLC	NC	C&I	90.4%
Clay-Union Electric Corp	SD	C&I	77.3%
Duke Energy Progress- SC	SC	C&I	-

Table A-3 Relevant Firm Curtailment Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
City of Burlington Electric - (VT)	VT	C&I	91.3%
Duke Energy-Carolinas	NC	C&I	-
Duke Energy-Kentucky	KY	C&I	-
Louisville Gas & Electric and Kentucky Utilities Company	KY	C&I	97.0%
PJM Demand Response	PA	C&I	-
PJM Demand Response	OH	C&I	-
Tampa Electric Co	FL	C&I	90.2%
Tennessee Valley Authority	AL	C&I	-
Tennessee Valley Authority	TN	C&I	90.1%

Table A-4 Relevant Non-Firm Curtailment Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
Duke Energy-Carolinas	NC	C&I	
Duke Energy-Kentucky	KY	C&I	-
New York State Electric and Gas	NY	C&I	87%
PJM Demand Response	PA	C&I	-
PJM Demand Response	OH	C&I	-

Table A-5 Relevant Critical Peak Pricing Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
Gulf Power Co[15]	FL	Residential	91%
Sioux Valley SW Electric Coop.	ND	Residential	94.5%
Southern California Edison Co.	CA	C&I	65.9%
Tampa Electric Co.	FL	R	90.2%

Table A-6 Relevant Real Time Pricing Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
Duke Energy Carolinas, LLC	NC	C&I	90.4%
Duke Energy Ohio, Inc.	OH	C&I	78.7%
Georgia Power Co	GA	C&I	85.8%
Gulf Power Co	FL	C&I	91.0%
Otter Tail Power Co	ND	C&I	121.8%
West Penn Power Company	PA	C&I	91.7%

Table A-7 Relevant Ancillary Services/Load Following Programs

Offering Entity	State	Sector	Winter Peak as % of Summer Peak
BPA- Mason County PUD No. 3	WA	Res	120%
BPA- City of Port Angeles	WA	C&I	120%
BPA-Eugene Water and Electric Board	OR	C&I	120%

Table A-8 below shows the number of programs included by DR option type.

[15] Gulf Power Company's CPP program was not listed in the FERC survey database. Therefore we obtained program information from outside sources.

Table A-8 Number of Relevant DR Programs by Option

Category	Option	Number of Programs
Non-pricing	Direct Load Control	34
	Curtailment- Firm	6
	Curtailment- Non-firm	2
Pricing	Time-of-Use Rates	TOU rate offerings by various utilities[16]
	Critical Peak Pricing	4
	Real Time Pricing	6
Ancillary Services / Load Following	Ancillary Services / Load Following	3

Develop Criteria for Selecting Representative Programs

Once we identified the list of relevant programs, we developed criteria to select representative programs for detailed investigation. We considered the following criteria:

- Program size and maturity: We identified the size of the program in terms of number of customers enrolled, based on FERC 2012 DR survey data. We present available enrollment data in the "All Programs" worksheet. We considered only mature programs with a sizeable number of customers enrolled.
- Average retail rate of the utility relative to Avista's rate: We compared each utility's average retail rate with Avista's rate to screen out utilities with rates much higher than Avista's.
- Pacific Northwest region experience: We included all DR initiatives from the Pacific Northwest region, even though these were mostly pilots.

Apply Selection Criteria to Develop a List of Programs for Further Research

As a last step in the process, we applied the selection criteria outlined above to the list of relevant programs presented above. Table A-9 shows the selected programs by DR option type.

[16] We found that a very large number of utilities across the states included in our list offered TOU tariffs. We did not explicitly record the number of TOU rate offerings by these utilities.

Table A-9 Selected Programs

Offering Entity	State	Sector	Scale	Winter Peak as % of Summer Peak	Retail Rate Difference with Avista (%)	No. of Customers Enrolled
Direct Load Control Programs						
BPA- City of Port Angeles	WA	Res	Pilot	120%	-	35
BPA- Emerald People's Utility District (EPUD)	OR	Res	Pilot	120%	-	200
Puget Sound Energy Inc	WA	Res	Pilot	135%	19.3%	528
Otter Tail Power Co	ND	Res	Program	122%	0.4%	6,479
Duke Energy Carolinas, LLC	NC	Res	Program	90.4%	17.7%	3,963
South Central Power Company	OH	Res	Program	89.3%	32.6%	20,000
Florida Power & Light Co	FL	Res	Program	83.6%	19.8%	799,812
Minnesota Power Inc.	MN	Res	Program	99.8%	5.7%	7,217
Crow Wing Cooperative Power & Light Company	MN	Res	Program	68.1%	23%	8,625
Clay Union Electric	SD	C&I	Program	77.3%	-	591
Otter Tail Power Co	ND	C&I	Program	121.8%	-23.3%	1,579
Firm Curtailment Programs						
Tampa Electric Co	FL	C&I	Program	90.2%	15.6%	94
Tennessee Valley Authority	TN	C&I	Program	90.1%	-	139[17]
Louisville Gas & Electric/ Kentucky Utilities Company	KY	C&I	Program	97%	-22.7%	-
Non-Firm Curtailment Programs						
New York State Electric and Gas	NY	C&I	Program	87%	0.4%	106
Critical Peak Pricing Programs						
Gulf Power Co[18]	FL	Res	Program	91%	39%	10,000
Southern California Edison Co.	CA	C&I	Program	65.9%	47.4%	3,255
Real Time Pricing Programs						
Georgia Power Company	GA	C&I	Program	85.8%	-9.1%	2,033
Ancillary Services/Load Following Pilots						
BPA-City of Port Angeles	WA	C&I	Pilot	120%	-	-
BPA-Mason County PUD No. 3	WA	Res	Pilot	120%	-	-

Table A-10 shows the number of selected programs by DR option.

[17] TVA offers this program to its member utilities. Enrollment data presented here is for Memphis Light, Gas, and Water Division (MLGW), which has the highest enrollment level among all TVA members.
[18] Gulf Power Company's CPP program was not listed in the FERC survey database. Therefore we obtained program information from outside sources.

Table A-10 Number of Selected DR Programs by Option

Category	Option	Number of Programs
Non-pricing	Direct Load Control	11
	Firm Curtailment	3
	Non-firm Curtailment	1
Pricing	Critical Peak Pricing	2
	Real Time Pricing	1
Ancillary Services / Load Following	Ancillary Services/Load Following	3

Direct Load Control Programs

With Direct Load Control (DLC) programs, the utility directly controls specific end-uses such as electric space heating, cooling, water heating, and pool pumps. In exchange, the customer receives an incentive payment or bill credit. Operation of DLC typically occurs during times of high peak demand or supply-side constraints. During an event, participants' equipment is controlled either by a one-way remote load control switch or by a Programmable Communicating Thermostat (PCT).

General Program Characteristics

Most of the legacy DLC programs offered by utilities nationwide target summer cooling load. These programs target central air conditioning which has a fairly low saturation in the Avista service area. Programs that target space heating load during winter and water heating load throughout the year are much fewer in number than summer DLC programs. In our research, we have specifically included programs that target space heating and/or water heating loads, since Avista is primarily interested in DLC programs for addressing winter peak reduction.

We found a variety of DLC programs that control electric space heating and water heating, such as:

- Programs that cycle and shut off equipment during event hours.
- Programs that target space heating and water heating equipment with thermal storage capabilities that enable load shifting to off-peak hours.
- Programs that target specifically space heating and water heating systems with dual fuel backup that enable these systems to use alternate fuels for providing service during control periods.

Table A-11 below summarizes some of the characteristics of Direct Load Control programs that are common across program offerings.

Table A-11 Summary of Key Direct Load Control Program Characteristics

Program Attributes	Description
Targeted segments	• Residential • Small and medium sized C&I customers (typically customers with less than 100 kW maximum demand)
DR Strategies	• Cycling space heating equipment. • Turning off equipment (water heating and space heating) during control periods. • Shifting usage to off-peak hours using end-use devices with thermal storage features. • Shifting usage from electricity to natural gas using dual fuel backup for space heating and water heating
Enabling Technology	Load control switch or programmable thermostat
Event Notification	Event notification does not apply, since end-use equipment is directly controlled by the utility.
Event Duration	• Varies widely by program: from 4 to 14 hours. • Longer event duration found for programs that control equipment with thermal storage or dual fuel backup.
Incentive structure	• Participants are often offered a fixed annual bill credit for each type of equipment being controlled. • In cases where the equipment has dual fuel backup, participants are placed on a separate rider with discounted tariffs, as compared to their normal rates. • Participants sometimes receive a rebate for purchasing equipment with thermal storage features.

Specific Pilot and Program Examples

Below are summaries of the specific characteristics of the DLC pilots and programs we researched. We have included information from the Pacific Northwest pilot initiatives, since these are likely to be relevant for Avista. For all other areas, we have included only program experiences.

Puget Sound Energy's Direct Load Control Pilot

Puget Sound Energy conducted a residential DLC pilot during 2010-2011. The pilot was conducted on Bainbridge Island, located in the western portion of the utility's service area. Table A-12 below lists specific characteristics of the pilot program.

Table A-12 Puget Sound Energy's Residential DLC Pilot

Attributes	Description
Targeted Segment	Residential customers with electric space heating and cooling, and water heating.
Controlled End-uses	• Electric water heating and space heating equipment were controlled during winter. Space heating equipment included heat pumps, central electric furnaces, and baseboard wall heaters. • Electric water heating and heat pumps (in cooling mode) were controlled during summer.
Enabling Technology for Control	• Load control switches used for controlling water heaters. • Load control switches with adaptive algorithm used for controlling electric space heating. • Programmable communicating thermostat used for controlling space cooling.
Communication Infrastructure	Two way communication using broadband.
Incentive Payment	Participants received an annual $50 incentive, as long as they participated in more than 50% of curtailment events.
Impact Findings	<u>Space heating</u> • Among the three electric space heating technologies, controlling heat pumps provided the highest level of load reductions, especially during winter mornings. • Impacts per device for heat pumps ranged from 2.88 kW in the morning to 1.21 kW in the afternoon. • Impacts per device for electric furnaces ranged from 1.88 kW in the morning to 1.71 kW in the afternoon. • Impacts per device for baseboards ranged from 0.18 kW in the morning to 0 kW in the afternoon. <u>Water heating</u> • Water heater control was found to be the most effective means for achieving winter demand reduction, especially during winter mornings. During afternoon control, snapback impact was observed to be greater than DR impact. • Water heater winter impacts per device ranged from 0.77 kW in the morning to 0.49 kW in the afternoon.

Key Findings from the Pilot

- **Overall Customer Satisfaction.** Although overall customer satisfaction was reported to be high for the pilot, an evaluation study points to a number of factors that affected customer satisfaction. These factors include:
  - Highest level of customer dissatisfaction was related to equipment technical issues, such as:
    - Network connectivity problems
    - Difficulties in PCT operation and lack of "easy to use" features for the thermostat
    - Safety concerns related to the specific PCT brand used in the pilot, which faced a product recall
    - Equipment installation problems, especially with the digital gateway.
    - Technical difficulties related to operation of the load control device for space heaters.

- Very few participants experienced discomfort when their devices were being controlled, except heat pump participants. More than half of the heat pump participants experienced discomfort and had to take alternative actions to stay warm during events. Snapback in demand, after the event, was observed for these participants.
- Participants had low awareness of the opt-out feature and some expressed dissatisfaction with loss of control over heating.
- Participants expressed dissatisfaction with aesthetic impacts resulting from the installation of control and communication hardware inside their homes.
- Participants did not have sufficient instructions/guidance to operate the installed equipment.
- Use of multiple control technologies complicated installation procedures and led to technical problems.

- **Program Marketing and Customer Communication.** Pilot promotional letter and newspaper articles were effective communication channels for informing participants about the pilot. Strong support of the pilot by local community groups, extensive local media promotion, and individual social networking contributed to a higher enrollment rate than typically experienced with utility pilots.
- **Motivation for Participation.** The strongest motivation for participation was environmental/altruistic reasons, rather than achieving monetary savings.
- **Level of Incentive Payment.** Participants perceived the annual incentive payment to be sufficient.

BPA- City of Port Angeles Voluntary Peak Power Project

The City of Port Angeles Voluntary Peak Power project in northern Washington constitutes one of several pilots that BPA is currently implementing to test Direct Load Control with multiple end-uses. The pilot incorporates a number of unique and innovative features and therefore, learning from the pilot experience is likely to be of significance for Avista.

The pilot involves control of multiple end-uses along with water heating and space heating equipment. The pilot is testing space heating equipment with thermal storage features. All pilot participants have AMI installed and therefore, control and communications techniques leverage the AMI backbone.

Table A-13 below lists specific characteristics of the pilot. Additional information on pilot performance was not available.

Table A-13 BPA-City of Port Angeles Voluntary Peak Power Project

Attributes	Description
Targeted Segment	Residential customers with electric space heating and water heating.
Controlled End-uses	• Electric water heating • Electric space heating along with multiple end-uses. Space heating equipment includes room heaters and central electric furnaces with thermal storage capability (ceramic bricks).
Enabling Technology for Control	• A load control device wired into the water heater's electrical control system is used for WH control. • A smart thermostat is used for controlling electric space heating. It is equipped with Home Area Network (HAN) connectivity and can be used to control multiple end-uses, such as appliances. • Control of electric space heating (room heaters or central electric furnaces) with thermal storage involves drawing electricity during low demand periods and storing it in ceramic bricks, which can heat over 1,500 degrees F and are sealed inside the unit. A variable speed fan automatically circulates heat throughout the room. Participants control the temperature using a programmable thermostat.
Metering and Communication Infrastructure	All pilot participants have AMI installed.
Incentive payment	Participants receive $120 for participation, along with free control devices.
Impact findings	NA

BPA- Emerald People's Utility District Direct Load Control Pilot

BPA is undertaking a DLC pilot with Emerald People's Utility District to test control of space heating and water heating technologies with thermal storage capabilities. The overall objective of the pilot is to develop load control strategies that can be used for integration with renewable resources. This is one of the few pilots that are being conducted to address renewable integration challenges. Learning from these pilot experiences is likely to be useful for Avista, since wind generation is a significant portion of its supply fleet.

Table A-14 below lists specific characteristics of the pilot program. Additional information on pilot performance was not available.

Table A-14 BPA-Emerald People's Utility District Direct Load Control Pilot

Attributes	Description
Targeted Segment	Residential customers with electric space heating and water heating.
Controlled End-uses	• Electric water heating with thermal storage capabilities • Electric space heating with thermal storage capabilities.
Enabling Technology	• Thermal storage systems store electrical energy in well insulated ceramic brick cores. • Built-in microprocessor-based control systems regulate the charging level and rate. • Storage occurs as utilities signal the unit to charge with available renewable, off-peak energy, or in response to other needs of the grid. Storage equipment has the ability to take on "extra" storage during periods when excess energy is available (e.g., when the wind fleet ramps up rapidly) or to turn off when the power supply is limited (e.g., when the wind fleet ramps down).
Metering and Communication Infrastructure	NA
Incentive Payment	NA
Impact Findings	NA

Otter Tail Power Company Direct Load Control Program

Otter Tail Power Company offers a direct control program for space heating and water heating loads with dual fuel during the winter season. The program also offers an option to control cooling loads on air-source heat pumps during summer. In addition, the utility controls water heaters without dual fuel backup by turning off the water heater during event hours.

Table A-15 below lists specific characteristics of the program.

Table A-15 Otter Tail Power Company's DLC Program

Attributes	Description
Targeted Segment	Residential and commercial customers with electric space heating and water heating.
Controlled End-uses	• Space heating and water heating with alternate fuel backup controlled during winter • Space cooling controlled during summer: air-source heat pumps in cooling mode. The units are cycled during summer with 50% control strategy (15 minutes on and 15 minutes off)
Enabling Technology	Load control switch
Event Duration	• Heating loads on dual fuel may be controlled up to 24 hours a day • Water-heating loads may be controlled up to 14 hours a day
Metering and Communication Infrastructure	NA

Incentive Payment	There is no separate incentive payment for participating in the program. Customers with dual fuel option are placed on a separate rider with the following components:
	• A fixed monthly charge of $7
	• Summer electricity rate: 3.659 cents/kWh
	• Winter electricity rate: 3.451 cents/kWh
	• Penalties apply for not being able to shift load during control periods to alternate fuels. These are:
	  ○ 38.61 c/kWh during summer months
	  ○ 12.92 c/kWh during winter months
	Customers with water heater control only are placed on a separate rider with the following components:
	• A fixed monthly charge of $2
	• Summer electricity rate: 5.773 cents/kWh
	• Winter electricity rate: 5.638 cents/kWh

Impact Findings	NA

Minnesota Power Direct Load Control Program

This program is similar to Otter Tail Power Company's Direct Load Control program with the dual fuel component. In addition, the company also offers an option for controlling electric space heating units with thermal storage. Table A-16lists specific characteristics of the program.

Table A-16 Minnesota Power's DLC Program

Attributes	Description
Targeted Segment	Residential and commercial customers with electric space heating and water heating.
Controlled End-uses	• Space heating and water heating with alternate fuel backup controlled during winter. • Space heating with thermal storage capability controlled during winter. Space heating equipment includes heat pumps, central furnaces, and a variety of room heating devices.
Enabling Technology	Load control switch
Event Duration	Not defined
Metering and Communication Infrastructure	NA
Incentive Payment	There is no separate incentive payment for participating in the program. Participants are placed on separate riders with differential rates.
Evaluation Findings	NA

Duke Energy Carolinas Direct Load Control Program

This is a winter load control program targeting electric space heating and water heating end-uses. Table A-17 lists specific characteristics of the program.

Table A-17 Duke Energy Carolinas' DLC Program

Attributes	**Description**
Targeted Segment	Residential customers with electric space heating and water heating.
Controlled End-uses	• Space heating - central electric heat pump units with strip heat • Water heating – water heaters with at least 30 gallons capacity
Enabling Technology	Load control switch
Event Duration	• Both space heating and water heating can be controlled up to 4 hours during an event. • Space heating can be controlled up to a maximum of 60 hours annually
Metering and Communication Infrastructure	NA
Incentive Payment	Customers receive an annual bill credit of $25 each for space heating and WH control, in addition to $25 for signing up (applied to each equipment).
Evaluation Findings	NA

Florida Power and Light's Direct Load Control Program

Florida Power and Light's "On Call" program is one of the largest DLC programs in the nation. The program controls multiple end-uses and targets both summer and winter loads. [19]

Table A-18 lists specific characteristics of the program.

Table A-18 Florida Power and Light's DLC Program

Attributes	Description
Targeted Segment	Residential customers with electric space hating and water heating.
Controlled End-uses	• Central heating • Electric water heating • Central air conditioning • Pool pumps
Enabling Technology	Load control switch
Event Duration	There are two options under the program. One is the "Cycle Option", and the other is the "Extended Option." The event duration differs for these two options. • Under the Cycle Option, the central heater is turned off for 15 minutes, every half hour. • Under the Extended Option, all controlled equipment can be turned off for up to 4 hours.
Metering and Communication Infrastructure	Power line communication with two-way communications feature.
Incentive Payment	• Under the Cycle Option, participants receive a $10 annual bill credit for controlling central heat. • Under the Extended Option, participants receive a $20 annual bill credit for controlling central heat, and an $18 annual credit for water heater control.
Evaluation Findings	NA

[19] The Business On Call program targeting commercial customers controls cooling load only during the summer.

Crow Wing Cooperative's Direct Load Control Program

Crow Wing Electric Cooperative's direct load control program utilizes dual fuel backup for controlling electric heat during winter. The utility also controls water heaters and space heating equipment with thermal storage capability. Table A-19 lists specific characteristics of the program.

Table A-19 Crow Wing Power's Direct Load Control Program

Attributes	Description
Targeted Segment	Residential customers with electric space heating and water heating
Controlled End-uses	• Electric space heating with dual fuel backup (alternate fuels include natural gas, propane, or fuel oil) • Water heating for water heaters with at least 100 gallons of storage. • Electric heating system with thermal storage
Enabling technology for control	Load control switch
Event Duration	For electric space heating control with dual fuel, there is no limit on duration of individual events. However, electric space heaters with dual fuel can be controlled up to a maximum of 600 hours, per heating season.
Metering and Communication Infrastructure	NA
Incentive payment	Participants with dual fuel heating systems are offered the following incentives: • A discounted electricity rate of 5.3 cents/kWh. • In addition, participants receive a rebate for the purchase of qualifying control equipment. These are as follows: $200 for plenum heaters and electric boilers. $100/ton for a Ground Source Heat Pump (GSHP). $330 - $630 for an Air Source Heat Pump (ASHP). $100 for a whole house baseboard heating system. Participants with space and water heating systems with thermal storage are offered the following incentives: • A discounted electricity rate of 4.3 cents/kWh. • In addition, participants receive a rebate for purchase of qualifying control equipment. These are as follows: $25/kW of installed capacity for heating systems with storage. $200-300 rebate for water heater with storage.
Evaluation findings	NA

South Central Power Company Water Heater Switch Program

The Water Heater Switch program offered by South Central Power Company is a legacy water heater control program with a sizeable number of customers enrolled. Table A-20 below lists specific characteristics of the program.

Table A-20 South Central Power Company Water Heater Switch Program

Attributes	Description
Targeted Segment	Residential customers with electric water heating.
Controlled End-uses	Water Heaters with a capacity of 50 gallons or more.
Enabling technology for control	Radio controlled switch
Event Duration	NA
Metering and Communication Infrastructure	NA
Incentive payment	$15 annual payment, plus $1.25 off on monthly electricity bill.
Evaluation findings	NA

Clay Union Electric's Direct Load Control Program

The utility offers a direct load control program targeting water heaters for business customers. Other than the program participation and impact data in the FERC survey, we did not find any additional information for the program.

Firm Curtailment Programs

Firm Curtailment programs that were selected for further investigation are listed in Table A-21 below. The table includes two additional program characteristics that relate to program performance: participation rates and impact estimates. We will use these two characteristics along with customer enrollment values when conducting the potential study in a subsequent task. The data on these characteristics are taken from the FERC survey database, wherever available. We indicate "NA" for cases where the data are not available.

Table A-21 Selected Firm Curtailment Programs

Offering entity	State	Scale	Winter Peak as % of summer peak	Retail Rate Difference with Avista (%)	No. of customers enrolled	Participation Rate (% of eligible customers)	Unit Impact (% of enrolled load)
Tampa Electric Co	FL	Program	90.2%	15.60%	94	44%	100%[20]
Tennessee Valley Authority	TN	Program	90.1%	-	139[21]	NA	NA
Louisville Gas & Electric/Kentucky Utilities Company	KY	Program	97.0%	-22.74%	-	NA	NA

Below, we discuss some of the general program characteristics that are common across all programs of this type followed by specific program examples and their characteristics.

General Program Characteristics

Under the Firm Curtailment type of program, participating customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of capacity payment typically varies with the firm reliability-commitment level. In addition to the fixed capacity payment, participants receive a payment for energy reduction. Because the program includes a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity (ICAP) requirements. Penalties are assessed for under-performance or non-performance. Demand-reduction events may be called on a day-of or day-ahead basis as conditions warrant.

This program is typically third-party administered by load aggregators. It is most common in areas with deregulated wholesale electricity markets such as in PJM, New York ISO, and ISO-New England jurisdictions. However, increasingly utilities are directly offering this type of program to their large commercial and industrial customers.

The targeted segment typically includes customers with electricity demand greater than 200 kW, though individual program requirements may vary. Customers with flexibility in their operations are attractive candidates for participation. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants, and industries with process

[20] 100% load reduction implies that the load is shifted entirely to back up generators.
[21] TVA offers this program to its member utilities. Enrollment data presented here is for Memphis Light, Gas, and Water Division (MLGW), which has the highest enrollment level among all TVA members.

storage (e.g. pulp and paper, cement manufacturing). Customers with 24x7 operations/continuous processes or with obligations to continue providing service (such as schools and hospitals) are not often good candidates for this option.

Table A-22 below summarizes some of the characteristics of Firm Curtailment programs that are common across program offerings.

Table A-22 Key Firm Curtailment Program Characteristics

Program Attributes	Description
Type of Contract	Participants have a firm capacity reduction commitment. Therefore participation is mandatory.
Resource Reliability	Capacity reductions can be counted toward Installed Capacity (ICAP), since participants have a firm commitment for capacity reduction.
Targeted segment	Commercial and industrial customers, with maximum demand values typically greater than 200 kW. In some cases a lower maximum demand threshold of 100 kW may be used.
DR Strategies	Load reduction and shifting to backup generators.
Examples of Curtailable Processes	Examples of commercial and light industrial curtailable processes include: air handlers, anti-sweat heaters, chiller control, chilled water systems, defrost elements, elevators, escalators, external lighting, external water features, HAVC systems, internal lighting, irrigation pumps, motors, outside signage, parking lot lighting, production equipment, processing lines, pool pumps/heaters, refrigeration systems, and water heating.
Event Trigger	Event trigger is typically emergency system conditions, such as actual or forecasted operating reserves shortage.
Event Notification	30 minutes to day-ahead
Event Duration	Varying duration: typically ranges from 1 to 8 hours
Program Hours	Events are usually called during business hours on working days, therefore loads need to be available during that time.
Incentive structure	Participants are offered both capacity ($/kW-month) and energy ($/kWh) payments.
Penalties for non-performance	Participants are subjected to non-performance penalties for performance below pre-determined threshold levels.
Metering and Communication Systems	• These programs preferably require 5-minute interval data (although 15 minute or hourly interval data may be sufficient.) • Communication systems need to receive and confirm system operator requests, preferably in real-time.

Specific Program Examples

Below are summaries of the specific characteristics of the programs we researched.

Tennessee Valley Authority's Demand Response Program

This is a third-party administered program offered by TVA to its member utilities. The program was launched in 2008 and is currently in operation. It is administered by EnerNOC. Table A-23 below lists specific characteristics of the program.

Table A-23 TVA's Demand Response Program Characteristics

Program Attributes	Description
Targeted Segment	C&I customers with a minimum load reduction amount of 100 kW.
Resource Availability	• Program is available year round. • During the summer months of April to October, program hours are from 12 noon to 8 PM on weekdays. • During the winter months of November to March, program hours are from 5 AM to 1 PM on weekdays.
Event Notification	30 minutes. Notification is via email, phone, or SMS.
Maximum Annual Event Hours	40 hours.
Event Duration	Events can range from 2-8 hours; average event duration is 3.5 hours.
Maximum Number of Events	No more than 6 events can be called in a month; events cannot be called on more than 2 consecutive days.
Incentive Payment	Capacity payment is $22/kW-year; energy payments are $40-50/MWh; Participants are offered $225/MWh or more for emergency energy payments.
Type of Response	Both manual and Auto-DR strategies
Metering Requirements	All participating customers receive free, near real-time 5 minute interval metering.

Tampa Electric Company's Networked Demand Response Program

This is a third-party administered program offered by Tampa Electric Company in Florida. The program was launched in 2008, and the contract is active until 2016. It is administered by EnerNOC. Table A-24 below lists specific characteristics of the program.

Table A-24 Tampa Electric Company's Networked Demand Response Program Characteristics

Program Attributes	Description
Targeted Segment	Targeted customer segments include city and county agencies, telecommunication companies, big-box retailers, grocery stores, and others. No information available on minimum load reduction amount.
Resource Availability	• Program is available year round. • Program hours are from 7 AM to 7 PM on weekdays.
Event Notification	30 minutes.
Maximum Annual Event Hours	NA
Event Duration	Events can range from 1-8 hours.
Maximum number of events	NA
Incentive payment	NA
Type of Response	Both manual and Auto-DR strategies
Metering requirements	All participating customers receive free, near real-time 5 minute interval metering.

Louisville Gas and Electric and Kentucky Utilities Demand Response Program

This is a third-party administered program offered by Louisville Gas and Electric and Kentucky Utilities Company (LG&E and KU). The program was launched in 2012 and is currently operational. It is administered by EnerNOC. The program has a bilateral contract for delivering 10 MW of load reduction. Information on specific program characteristics was not available.

Non-Firm Curtailment Programs

The Non-Firm Curtailment program selected for further investigation is listed in Table A-25 below. The table includes two additional program characteristics that relate to program performance: participation rates and impact estimates. The data on these characteristics are taken from the FERC survey database, wherever available.

Table A-25 Selected Non-Firm Curtailment Programs

Offering entity	State	Scale	Winter Peak as % of summer peak	Retail Rate Difference with Avista (%)	No. of customers enrolled	Participation Rate (% of eligible customers)	Unit Impact (% of enrolled load)
New York State Electric and Gas	NY	Program	87%	0.43%	106	9%	30%

General Program Characteristics

Under the Non-firm Curtailment type of program, participants voluntarily reduce load when an emergency event is called. In contrast to the "Firm Curtailment" option, customers are not under contract to deliver a specific quantity of load reduction. There is usually no penalty for not being able to reduce load when events are called. Events may be called on a day-of or day-ahead basis, as conditions warrant. Participants are paid a credit for each kWh they reduce during the event. The $/kWh payment is typically based on Locational Marginal Prices (LMPs). There is no capacity payment associated with this option since it does not represent a firm resource. This option complements the firm capacity commitment contracts and offers a flexible option for customers that may not be able to provide firm capacity reduction commitments.

Table A-26 below summarizes characteristics of the Non-firm Curtailment program.

Table A-26 Key Non-Firm Curtailment Program Characteristics

Program Attributes	Description
Type of Contract	Participants do not have a firm capacity reduction commitment. Therefore, participation is voluntary.
Resource Reliability	Load reductions cannot be counted toward Installed Capacity (ICAP) requirements, since participants do not have a firm capacity reduction commitment.
Targeted segment	Commercial and industrial customers, with maximum demand values typically greater than 200 kW.
DR Strategies	Load reduction and shifting to backup generators.
Examples of Curtailable Processes	Examples of commercial and light industrial curtailable processes are: air handlers, anti-sweat heaters, chiller control, chilled water systems, defrost elements, elevators, escalators, external lighting, external water features, HAVC systems, internal lighting, irrigation pumps, motors, outside signage, parking lot lighting, production equipment, processing lines, pool pumps/heaters, refrigeration systems, and water heating.
Event Trigger	Event trigger is high Locational Marginal Prices (LMPs), especially during times of high system demand.
Event Notification	Varies from 30 minutes to day-ahead
Event Duration	Varies
Program Hours	Events are usually called during business hours on working days, therefore loads need to be available during that time.
Incentive structure	Participants are offered energy ($/kWh) payments.
Penalties for non-performance	No penalties exist, since participation is voluntary.
Metering and Communication Systems	• These programs preferably require 5-minute interval data (although 15 minute or hourly interval data may be sufficient). • Communication systems need to receive and confirm system operator requests, preferably in real-time.

Specific Program Examples

Below are summaries of the specific characteristics of the programs we researched.

New York ISO's Emergency Demand Response Program

New York ISO operates the Emergency Demand Response Program (EDRP), which is one of the largest and most successful non-firm curtailment type DR program. The program has been operational since 2001. New York State Electric and Gas is one among other New York state utilities that offer the ISO administered program to its retail customers. DR events are triggered whenever there is a need to address system reliability in the NYISO service area.

Table A-27 below lists specific characteristics of the program.

Table A-27 NYISO Emergency Demand Response Program Characteristics

Program Attributes	Description
Targeted Segment	C&I customers with a minimum load reduction amount of 100 kW.
Resource Availability	Program can be called at any time. Therefore, resources need to be available all year round.
Event Notification	2 hours
Event Duration	4 hours
Incentive Payment	Payment is based on real-time Locational Based Marginal Price (LBMP) and measured energy reduction during an event, with a minimum rate of $500/MWh.
DR Strategy	Load reduction and shifting to backup generators. Most of the load reduction achieved in the program has been through shifting to backup generators.
Metering Requirements	Hourly meter required for participation

Critical Peak Pricing Programs

Critical Peak Pricing programs that were selected for further are listed in Table A-28 below. The table includes two additional program characteristics that relate to program performance: participation rates and impact estimates. The data on these characteristics are taken from the FERC survey database, wherever available. We indicate "NA" for cases where the data are not available.

Table A-28 Selected Critical Peak Pricing Programs

Offering entity	State	Scale	Winter Peak as % of summer peak	Retail Rate Difference with Avista (%)	No. of customers enrolled	Participation Rate (% of eligible customers)	Unit Impact (% of enrolled load)
Gulf Power Company[22]	FL	Program	91%	39%	10,000	2.6%	NA
Southern California Edison Co.	CA	Program	65.9%	47.4%	3,255	~50%	6.3%[23]

General Program Characteristics

A CPP rate includes an extremely high peak price during specific critical demand periods of the year. The rate specifies the number of times CPP events can be called and the maximum duration of a single event. Participants enrolled on CPP have a lower off-peak rate than the class average retail tariff. CPP events can be called on a day-ahead or day-of basis. They can be offered either as a voluntary rate with opt-in or as a default rate with opt-out provision. The type of offering varies by customer class and utility.

Table A-29 below summarizes some of the characteristics of the CPP program that are common across program offerings.

Table A-29 Key Critical Peak Pricing Program Characteristics

Program Attributes	Description
Resource Reliability	Non-firm
Targeted segment	All residential and C&I customers.
DR Strategies	Load reduction and shifting to backup generators.
Event Trigger	Events can be triggered under system emergency situations or under high price conditions.
Event Notification	30 minutes to day-ahead
Event Duration	Varies by program
Incentive structure	No separate incentive payment. CPP participants are offered a discounted rate during off-peak periods.
Penalties for non-performance	Not applicable.
Metering and Communication Systems	AMI is preferred for metering and settlement purposes.

[22] Gulf Power Company's CPP program was not listed in the FERC survey database. Therefore we obtained program information from outside sources.
[23] This is based on impact evaluation results from the "2012 California's Statewide Non-residential Critical Peak Pricing Evaluation Report".

Specific Program Examples

Below are summaries of the specific characteristics of the programs we researched.

Gulf Power Company's Residential CPP Program

Energy Select, Gulf Power's residential CPP program, is one of the oldest and most successful CPP programs offered to residential customers. The program was launched in 2000. Before launching the program, a two-year pilot was conducted to evaluate customer acceptance and equipment performance. The program attained an industry landmark in 2012 with 10,000 participants voluntarily enrolled in the program. There are plans to extend program participation to 16,000 participants by 2016. The program is administered by Comverge. Table A-30 below lists specific characteristics of the program.

Table A-30 Gulf Power Company's Residential CPP Program Characteristics

Program Attributes	Description
Targeted Segment	Residential customers.
Enabling Technology for Load Control	Programmable Communicating Thermostat (PCT)
CPP Rate Structure	The electricity price is four tiered: • Low- 7 cents/kWh • Medium- 8 cents/kWh • High- 15 cents/kWh • Critical- 58 cents/kWh Standard electricity price is around 10 cents/kWh.
Number of times events can be called annually	-
Event Notification	Day-ahead or day-of.
Event Duration	1-2 hours.
Metering Requirements	The program uses Broadband for communicating between the utility and the home, and Zigbee RF communication for communicating to devices within the home.

Since this is one of the leading examples of residential CPP programs in the country, learnings from program design and implementation experience are likely to be useful for Avista. Below, we summarize some of the key findings related to program deployment experience.

- **Program Planning**
  - Before designing a program, a pilot is essential to evaluate customer acceptance of rates and test equipment performance.
  - Regulatory approval process takes a very long time and therefore, a utility needs to plan ahead.
- **Technology Deployment**
  - A utility needs to focus on how the technology affects the customer. Technology changes rapidly and the utility needs to stay ahead of the game. This is one of the most important lessons learned from this program.
    - For example, switch to broadband communication from land line based communication can open up participation to many more customers.

    - In Gulf Power's example, initially communication was based on land-lines telephones. But participation was affected as customers started dropping their land line phones. Switching to broadband communication helped increase participation levels dramatically.

- **Program Design and Development**
  - Education and training are key components of program development.
  - Offering the program to all residential customers, instead of restricting it to single family home customers, help increase enrollment levels.
  - Two key program design features that can help increase participation levels are shortening the event duration and avoiding monthly participation charges.
    - In Gulf Power's case, shortening the high price period from nine to five hours in the summer and avoiding a monthly participation charge of $5 per month helped increase participation levels.
- **Marketing and Outreach**
  - During early stages of the program, cost effective channels for program marketing are direct mail, internet, TV, and outdoor advertising. Channels such as newspaper and radio are less effective.
  - After the program matures, internet can serve as the primary channel for program promotion.
    - In Gulf Power's case, program enrollment is completely done online.
- **Program Participation**
  - Primary drivers for customer satisfaction are the following:
    - Simple rate design that participants can easily understand.
    - Perceived energy savings and control over energy use and savings opportunities.
    - Ability to program and control devices online.

Southern California Edison Company's C&I CPP Program

Southern California Edison, along with other utilities in California, has implemented critical peak pricing rates for non-residential customers. Table A-31 below lists specific characteristics of the program.

Table A-31 Southern California Edison's C&I CPP Program Characteristics

Program Attributes	Description
Targeted Segment	• Large C&I customers with maximum demand greater than 200 kW are defaulted to CPP rate. • Small C&I (with less than 20 kW demand), and medium C&I customers (with 20-200 kW demand) are offered CPP rates on a voluntary basis.
Enabling Technology for Load Control	Manual and Auto-DR strategies.
CPP Rate Structure[24]	1. TOU component during summer: Energy charges per kWh: On-peak: $0.124 Semi-peak: $0.091 Off-peak: $0.065 Demand charges per kW: On-peak: $12.96 Semi-peak: $3.08 Maximum: $13.3 2. CPP component during summer: CPP event adder (energy charges and credits per kWh): $1.362 Demand credit per kW: $11.62
Number of Times Events can be Called Annually	9 to 15 times. Maximum total CPP events per year is 60.
Event Notification	Day-ahead
Event Duration	4 hours
Metering Requirements	AMI is required

Key findings from impact evaluation studies of the 2012 SCE CPP program include:

- **Overall Demand Reductions.** In aggregate, participants reduced demand by 6.9% across the 2 to 6 PM event window for the average event day, delivering 32.9 MW of demand reduction.
- **Demand reductions are highly concentrated in specific industry segments.** Manufacturing and Wholesale, Transport and Other Utilities, and Agriculture accounted for the bulk of demand reductions. These customers made up 45% of program enrollment and 44% of program load at SCE, but accounted for 87% of overall demand reductions. Manufacturing and Wholesale, and Transport customers reduced a larger share of their demand than the average CPP customer, at 13.8% and 9.4% of enrolled load, respectively.

[24] Based on 2012 Impact Evaluation Study

Real Time Pricing Programs

The Real Time Pricing programs that were selected for further investigation is listed in Table A-32 below. The table includes two additional program characteristics that relate to program performance: participation rates and impact estimates. The data on these characteristics are taken from the FERC survey database, wherever available. We indicate "NA" for cases where the data are not available.

Table A-32 Selected Real Time Pricing Programs

Offering entity	State	Scale	Winter Peak as % of summer peak	Retail Rate Difference with Avista (%)	No. of customers enrolled	Participation Rate (% of eligible customers)	Unit Impact (% of enrolled load)
Georgia Power Company	GA	Program	85.8%	-9.1%	2,033	~40%	NA

General Program Characteristics

A Real Time Pricing (RTP) rate, with prices varying by hour, is offered to large C&I customers. Hourly prices are often indexed to wholesale market prices. AMI is required for metering and settlement purposes.

Table A-33 below summarizes some of the characteristics of a RTP rate.

Table A-33 Summary of Program Characteristics

Program Attributes	Description
Resource Reliability	Non-firm.
Targeted segment	C&I customers.
DR Strategies	Load reduction and shifting to backup generators.
Event Trigger	No specific trigger, prices vary by the hour.
Event Notification	Day-ahead or hour-ahead.
Event Duration	Not applicable.
Incentive structure	Not applicable.
Penalties for non-performance	Not applicable.
Metering and Communication Systems	AMI for metering and settlement purposes.

Specific Program Examples

Below are summaries of the specific characteristics of the programs we researched.

Georgia Power Company's C&I RTP Program

Georgia Power has one of the largest Real Time Pricing (RTP) programs in the nation. The program offers two provisions for RTP rates: a day-ahead provision and an hour-ahead provision. The utility engages in a high level of customer education and outreach regarding the rate. This has been one of the most successful RTP program.

Table A-34 below lists specific characteristics of the program.

Table A-34 Georgia Power Company's C&I RTP Program Characteristics

Program Attributes	Description
Targeted Segment	Day-ahead provision: Large sized C&I customers with maximum demand greater than 250 kW. Hour-ahead provision: Large sized C&I customers with maximum demand greater than 5,000 kW.
Enabling Technology for Load Control	Manual and Auto-DR strategies.
Tariff structure	It has two parts: • Customer is billed for normal "baseline" usage at standard prices. • Any usage at the margin, above or below the baseline, is billed at the real time price.
Basis for Hourly Rates	Hourly prices are determined each day based on projections of the hourly running cost of incremental generation (including approved environmental costs), provisions for losses, projections of hourly transmission costs, reliability capacity costs for each day (when applicable), and a 3 mill/kWh recovery factor.
Number of times events can be called annually	Not applicable.
Event Notification	Day-ahead or hour ahead.
Event Duration	Not applicable.
Metering Requirements	AMI is required.

Ancillary Services / Load Following Pilots

Ancillary Services/Load Following pilots that were selected for further investigation are listed in Table A-35 below.

Table A-35 Selected Ancillary Services/Load Following Pilots

Offering entity	State	Scale	Winter Peak as % of summer peak	Retail Rate Difference with Avista (%)	No. of customers enrolled	Participation Rate (% of eligible customers)	Unit Impact
BPA-City of Port Angeles	WA	Pilot	120%	-	-	-	-
BPA-Mason County PUD No. 3	WA	Pilot	120%	-	-	-	-

Below, we discuss some of the general characteristics that are common for ancillary/load following services and then we provide descriptions of the selected pilots. We conclude by summarizing some of the important design and deployment aspects that any utility needs to keep in mind when considering DR resources to provide ancillary/load following services.

General Program Characteristics

For DR providing ancillary (spinning, non-spinning, regulation) and load following services, loads need to respond within a very short notification period, typically less than 10 minutes. This is often referred to as "Fast DR". DR providing load following services is relevant in the context of integrating intermittent renewable resources such a solar and wind. With increasing penetration of renewables, there is growing interest among utilities and system operators in this type of service.

Well-established programs exist in ERCOT, PJM, NYISO and HECO jurisdictions. BPA has launched pilots to specifically test DR integration with renewables.

Table A-36 below summarizes characteristics for DR providing ancillary/load following services.

Table A-36 Key Characteristics of Ancillary Services/Load Following Services Programs

Program Attributes	Description
Targeted Segments	Residential and C&I customers.
Event Notification	Less than or equal to 10 minutes.
Resource Availability	Resources need to be available all year round.
Annual Event Hours	• Typically range from 50-100 hours for providing ancillary services. • Events may be called with high frequency.
Typical Event Duration	• 10-60 minutes for providing ancillary services • Longer event hours, may be extending over a couple of hours or more, apply for providing load following services
DR Strategies	Load reduction and shifting to backup generators.
Event Trigger	• System contingency conditions requiring ancillary services. • Need for balancing intermittencies in renewable energy supply.
Incentive structure	Participants are offered both availability ($/kW-hr) and energy ($/kWh) payments.
Penalties for non-performance	Penalties apply for non-performance.
Customer segments and loads that could serve as good candidates	• Sites having flexibility in their operations, from having some sort of storage within the process (e.g. thermal energy) and production processes that are not adversely impacted by frequent starts and stops, are likely to be good candidates. • DR resources, without any energy storage component, have limited ability to provide regulation-down services, which is increasing load in response to sudden increase in supply. • Facilities with pumping loads often have storage capacity, which allows for load shifting without impacting production levels. Customer segments with pumping loads, such as water and wastewater treatment plants, municipal waterworks, and agricultural pumps, are likely to be good candidates. • Facilities with large thermal mass and refrigeration/compressor load are likely to be good candidates. These sites may be able to increase or decrease temperature set points, based on the facility load requirements. Examples of such facilities are food distribution warehouses and food processing plants, arenas/stadiums/convention centers, data centers, universities, hospitals. • Certain industrial processes with storage capacity can provide ancillary and flexible capacity products without disruptions in operations. Examples are pulp and paper, and cement. • Facilities with ventilating fan capacity can often reduce loads by cycling or turning off fans. Examples are manufacturing with volatile organic compounds or particulate processes, automobile painting.
Metering and Communication Systems	• Real time metering and communications required. • Meter data interval needs to be at 1 minute or less intervals.

Specific Examples

Below are brief descriptions of the pilots we researched.

BPA-City of Port Angeles C&I DR Pilot

This pilot was conducted during the period April to August 2012. The objective of this pilot was to test whether process storage could be used to support wind integration, with capabilities for both load curtailment and load increase. The technical infrastructure set up for monitoring load performance allowed visibility at one minute intervals.

Nine C&I sites were recruited for participation in the pilot, which included diverse customer types such as City Hall, waste water utility, housing authority, courthouse, library, medical center, and pulp and paper mill.

The pulp and paper mill exhibited greatest success in pilot performance. For the pulp and paper mill, DR signals were dispatched directly to the mill and all load response was directly controlled by mill personnel. The pulp and paper mill response was supported by inherent "process storage" capabilities in the production line.

Overall, the pilot was successful in demonstrating the technical feasibility of load response for integration with wind. Both load increase and load decrease could be attained with 10 minute response time. The next phase of this pilot is currently testing commercial feasibility of load response during the 2013-2014 time period.

BPA-Mason County PUD Pilot

This pilot tested water heater controls activated by a renewable energy signal, using Auto-DR technologies, for residential customers of Mason County Public Utility District No. 3. The pilot used a special device and an algorithm to allow water heaters to "sync" with wind turbines. The algorithm helped predict ahead of time when the wind power would be generated. The device, which was attached to the heaters, gave the utility the capability to turn them on and off during wind production cycles. Customers also had override switches. Overall, the pilot reported a high level of customer satisfaction with no impact on participant homes.

Cost Effectiveness Assessment for Demand Response

Below we describe what constitutes DR program costs and benefits and the overall approach used for assessing cost-effectiveness of DR programs.

DR Program Costs

Based on our experience with DR potential studies, we have constructed Table A-37 below that lists the cost components typically considered for a DR program. We briefly discuss these cost items and how they apply to the different program types included in our analysis.

An important aspect to consider in developing DR program costs is the underlying assumptions related to program delivery. A DR program can either be delivered by a utility or by a third-party. The allocation of costs across different types of programs in Table A-37 assumes in-house delivery across all program types, except for the Firm Curtailment program. For this particular program, based on commonly observed trends in the industry, we assume that it is delivered by a third party. Other types of programs, such as Non-Firm Curtailment programs and DLC programs can also be delivered by third parties. However, that is less commonly observed in the industry. Our delivery-mechanism assumptions for developing cost components are based on commonly observed industry trends.

Table A-37 Cost Components by DR Program Type

Cost Items	Unit	Type of Program				
		Direct Load Control	Firm Curtailment	Non-Firm Curtailment	Pricing Programs	Ancillary/ Load Following Services
Program Development Cost	$/program	x		x	x	x
Administration Cost	$/MW-year	x	x	x	x	x
Annual Marketing and Recruitment Costs	$/new participant	x		x	x	x
Equipment capital and installation costs	$/device installed	x			x	x
Annual O&M costs	$/year	x			x	x
Participant incentives	$/participant/ year	x				
	$/kW-year					x
	$/kWh			x		x
Third-party program delivery cost	$/kW-year		x			

A brief description of these cost items and how they are treated across programs follows.

- **Program Development Cost.** This is a one-time cost that is incurred for setting up a brand new program. This cost is usually specified in the number of FTEs required for setting a program up. It usually applies uniformly across all program types. The only exception could

be a third-party delivered firm curtailment program, in which the utility itself does not incur any cost for setting up the program.

- **Annual Program Administration Cost.** This constitutes an annual recurring expense that is incurred for administering a DR program. It usually applies uniformly across all program types. It is common to specify this cost in terms of the unit load reduction amount ($/MW-year). There may be cases where the cost is specified as a fixed annual cost in terms of $/year.
- **Annual Marketing and Recruitment Costs.** This typically applies to all program types, except third-party delivered curtailment programs, in which case customer marketing and outreach activities are primarily undertaken by the third party. For pricing programs in particular, marketing and recruitment costs depend on whether a particular rate is offered on a voluntary basis with opt-in provision or as a default rate from which customers can opt-out. For a voluntary rate offer, per participant marketing and recruitment costs may be much higher than those incurred by defaulting all customers to a rate. Therefore, one needs to take into account the type of offer in developing costs for pricing options.
- **Equipment Capital and Installation Costs.** This usually refers to capital and installation costs for a load control switch or a thermostat in a DLC program. In pricing programs, this cost applies to the enabling technology used for achieving load reductions for residential and small commercial customers. For medium and large sized customers on DR programs, enabling technology costs commonly refer to costs for enabling Auto-DR on customer premises. Usually for third party delivered programs, the technology cost is rolled into a composite program delivery cost, especially where the third party is responsible for bearing technology costs.
- **Annual O&M Costs.** This is usually estimated as a fraction of the equipment capital cost and applies wherever specific enabling technology is deployed for load control.
- **Participant Incentives.** This applies to all DR programs that are non-price based. The structure of the incentive may differ, depending on the program type. For example, for DLC, incentives are usually structured as a fixed annual payment to the participant, irrespective of the load reduction amount. For other programs, incentive payments are based on actual performance. Although customer incentives do not apply to pricing options such as TOU, CPP and RTP rates, they apply to a Peak Time Rebate (PTR) type of offer.
- **Third-party Program Delivery Costs.** This constitutes the main cost item for a Firm Curtailment type program, delivered by a third party. The cost is specified in terms of unit annual capacity reduction ($/kW-year). Items such as customer incentive costs, program marketing and outreach, and equipment capital and installation costs, are all rolled into the program delivery cost.

There may be additional items that can be classified as DR program costs, but which may be difficult to estimate and quantify. Examples are increased costs of environmental compliance in cases where backup generators are operated for load shifting, costs arising out of "value of lost service", and other transaction costs associated with program participation. Therefore, these items cannot be included in assessing overall program costs.

DR Program Benefits

We discuss below items considered in estimation of DR program benefits.

- **Avoided Capacity Cost.** The primary component that is included in estimating benefits from DR programs is the avoided capacity cost. This is universally applied across all types of DR programs.
- **Avoided T&D Cost.** This item specifically applies to DR programs that address network congestion and are deployed to address transmission and distribution capacity constraints. It does not apply to programs that address only peak load reductions, since T&D capacity constraints are not a consideration for these programs.

- **Avoided Energy Benefits.** Unlike energy efficiency programs, energy savings benefits are typically not included in estimating DR program benefits. This is due to the small number of hours that are impacted by DR programs. When programs are called over extended periods of time, energy savings benefits may need to be included. However, one needs to take into consideration possible "snapback" effects that could arise after completion of a DR event, which effectively increases energy usage after DR events. Similarly, if any pre-cooling strategies are used prior to an event, increase in energy use for such behavior needs to be considered.
- **Avoided Ancillary Services Cost.** For DR programs providing ancillary/load following services, avoided ancillary services costs need to be estimated for calculating benefits. Ancillary services are valued differently than avoided capacity.

Additional benefits arising from DR programs that are usually difficult to estimate and quantify include items such as enhanced wholesale market competitiveness, reduced price volatility, and insurance against extreme events. However, since these are difficult to quantify, they are usually not included in overall benefit calculations.

Derating of Avoided Costs

One important consideration in estimating DR program benefits is the derating of avoided capacity benefits. The full value of the avoided costs is based on the performance of a peaking generator, which is not exactly equivalent to a DR program. For estimating DR benefits, a derating factor is often applied to the avoided capacity costs to reflect that DR programs typically supply a lower resource value than equivalent supply-side options. The lower resource value can be attributed primarily to the following factors:

- A DR program is not as dispatchable as a supply-side option, like a natural gas peaking generator. A peaking plant will run approximately 200 to 400 hours per year, while a DR program is typically constrained to run from 40 to 100 hours per year.
- Many DR programs are vested with a seasonal limitation, for example, one cannot exercise direct load control for Central AC in the middle of the winter.
- DR programs are also limited by constraints on human behavior and/or presence of automation systems.

Derating factors are often applied by utilities and grid operators to account for the reduced value of the different availability and dispatchability profiles. There are many ways to calculate the de-rating factor, based on program characteristics, value of load at certain hours, but there does not appear to be an industry-standard. Adjustment factors are developed at various levels of granularity, depending on what the state protocol specifies. For example, California protocols account for program limitations by applying multiple adjustment factors to the avoided cost of a new combustion turbine. These factors are determined and applied separately by each load serving entity in California and vary by program type, depending on the dispatchability and reliability of the resource. In certain other jurisdictions, a simpler approach may be followed by applying a common derating factor across all program types. A review of available literature on the topic indicated capacity derating values generally range from 0.60 to 1.00

Cost-effectiveness Assessment Framework

The Total Resource Cost (TRC) test is commonly followed for assessing cost-effectiveness of DR programs. Usually in DR programs, customers do not incur additional participation costs. Also, loss of revenue to the utility may be negligible. Under these conditions, the TRC formulation essentially becomes equivalent to the utility cost test (UCT) and the ratepayer impact measure (RIM) test. All of these tests use the same stream of benefits by default, and for DR, they reduce to the same stream of costs as well. However, there may be exceptions where program participation costs are significant and/or loss of revenue is substantial. Under such situations, one may need to consider additional tests other than TRC.

Additional Items for Assessing Cost-Effectiveness

Two additional items that are required for assessing cost-effectiveness of DR programs are program lifetime assumptions and discount rates. Lifetime assumptions vary by DR program. For example, DLC programs typically have a 10 to 15 year lifetime, depending on the life of the control technology (load control switch or thermostat). For pricing assumptions, program life is tied to the life of the meter, which is typically assumed to be 20 years. Curtailment Agreements, which are third-party-delivered capacity reductions, usually have a contract term of three to five years.

Impact Estimation Methods for Demand Response

This chapter discusses the commonly used approaches for estimating impacts from DR programs. It does not go into specifics of how impacts are estimated for a particular type of program. The discussion focuses on event-based DR programs. Therefore, the methods discussed in this chapter are likely to apply to all programs types included in this report, other than Real Time Pricing programs which are non-event based.

Types of Impact Estimation

Impact estimation can broadly be of two types: ex post or ex ante.

- **Ex post impact estimation** is required for assessing program performance and is also sometimes used for settlement purposes. However, most programs base settlement on calculated reductions from a program, which are calculated simply as the sum of demand reductions determined for each participant, using the program's settlement methods. Impact estimation for settlement purposes needs to be simple and produce rapid results. A more rigorous and accurate program level impact assessment is conducted in later stages to assess program performance, which may not be practical for settlement purposes.
- **Ex ante impact estimation** is required for projecting demand savings from future programs and cost-effectiveness of programs. It can also be used retrospectively for settlement purposes.

Baseline Calculation Methods[25]

The commonly followed approaches for calculating baseline load are briefly described below.

Baseline Window

The first step in calculating baseline load is to define the baseline window. This is the period of time preceding and optionally following a DR event over which electricity usage data is collected for establishing a baseline. Examples of baseline windows are:

- Last 10 non-holiday weekdays.
- 10 most recent program-eligible non-event days.
- 10 most recent program-eligible days beginning 2 days before the event.
- Last 45 calendar days.
- Previous year.

The common rules for excluding specific days from the baseline window are the following: exclude days with DR events, exclude days with outages, exclude days with extreme weather, and exclude days with highest or lowest loads.

[25] "Measurement and Verification for Demand Response" prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group". February, 2013.

Baseline Load Calculation

There are a number of methods for developing the baseline load value using load data from the baseline window. These are briefly discussed below.

- **Average Value Method.** This is the most commonly used method for baseline load calculation, where one simply calculates the average value of the load by hour, for the hours included in the baseline window.
- **Maximum Value Method.** This method takes the maximum load over the window period to calculate baseline load.
- **Regression Method.** This method calculates load by regressing the load from included days on weather and other variables, using separate regression coefficients for each hour of the day.
- **Rolling Average Method.** This method calculates the unadjusted baseline for an operating day as equal to 90 percent of the prior unadjusted baseline load, plus 10% of the load on the most recent included day.

Baseline Adjustments

Once the baseline load is calculated by one of the above methods, an adjustment factor is applied to align the baseline load with observed conditions during the event day. The baseline load calculated in the earlier step is referred to as the "unadjusted baseline". Adjustment factors may be based on variables such as temperature, humidity, and event day operating conditions.

The North American Energy Standards Board (NAESB) has set some guidelines that define the adjustment window, which is the timeframe that needs to be considered for baseline load adjustment. It specifies that the adjustment window should begin no more than four hours prior to the DR event. Commonly followed examples of adjustment windows are an hour before the event, two hours before the event, and the two hours that end two hours before the event.

Impact Estimation Methods[26]

Alternative methods used for estimating impacts from DR programs are briefly described below.

- **Individual regression analysis.** This method fits a regression model to an individual customer's load data over a year or a particular season. A common approach is to develop a model that describes a customer's load as a function of weather variables such as temperature and humidity. The model is developed to fit loads on non-event days and is used to estimate a customer's load that would have occurred absent a DR event. The impact is then calculated as the difference between the observed and modeled load over each event hour. The model can also be used to calculate post event rebound effects.
- **Pooled regression analysis.** This method uses a similar approach as the individual regression analysis, but fits a single model across a large group of participants and hours. A single set of coefficients is used to describe an average load pattern for all customers in the pool. This is a better method for estimating coefficients that may not be determined for an individual customer using individual regression analysis.
- **Match days**. This method first identifies one or more non-event days that are similar to each event day based on criteria such as similar temperature, temperature-humidity index, similar system load, or similar customer load during non-event hours. A particular customer's load on the match day, or the average of the loads across multiple match days, serves as the baseline or reference load. Demand reductions are calculated as the difference between the match day and event day hourly loads. However, estimating the accuracy of this method is

[26] "Measurement and Verification for Demand Response" prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group". February, 2013.

more difficult than accessing the precision of a regression model, and therefore, this method is not commonly used.

- **Experimental design.** This involves a random assignment of customers into two groups, one of which is the "treatment" group and the other is a "control" group. The treatment group is subjected to event dispatches while the control group is not. The average demand reduction per participant is calculated as the difference between the averages for the two groups. An alternative method for calculating impacts is to use the difference of differences method. In this method, baseline load is estimated separately for both treatment and control groups. The impact is then calculated as the difference between the treatment group's modeled and observed load, minus the corresponding difference for the control group.

  This method has been used for estimating impacts for large scale residential and/or commercial direct load control programs deployed by utilities, especially in California. It applies to customers who have interval metering data.

In addition to these approaches, end-use metering data can directly be used for estimating impacts, wherever interval meter data is available.

APPENDIX | B

Time-of-Use Rates

Although TOU rates are out of scope for an analysis of demand response, AEG offered to perform an analysis of TOU rates so that Avista would have the information for future reference.

Program Description

A TOU rate is a time-varying rate. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with an incentive to shift consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a demand-response option, per se, but rather a permanent load shifting opportunity. Large price differentials are generally more effective than smaller differentials. The TOU rate included here is based on a 2:1 on-peak to off-peak price ratio. We assumed that this rate is offered to all three C&I classes.

We considered two types of TOU pricing options. With an **opt-in** rate**,** participants voluntarily enroll in the rate. With an **opt-out** rate, all customers are placed on the time-varying rate but they may oft-out and select another rate if they so desire.

Participation in TOU rates requires interval meters. At this time, Avista's Extra Large General Service customers have sophisticated telemetry and communications infrastructure in place and may be offered TOU beginning in 2016. For the other two customer classes, pricing options are not available until the AMI rollout is completed in 2020. Therefore, we assumed that TOU rates can be offered to General Service and Large General Service customers starting in 2021.

Table B-1 describes the features of a TOU rate.

Table B-1 Time of Use Rate Features

Program Attributes	Description	Comments
Targeted Segment	All C&I classes.	All customers are eligible to participate in a TOU rate.
Type of Offer	Two types of offers are possible: 1) TOU is offered as a voluntary rate to all customer classes with opt-in provision. 2) TOU is offered as a default rate to all customer classes with opt-out provision.	Based on program and pilot implementation experiences.
Resource Availability	TOU rates are available throughout the year. The peak period and off-peak period definitions can vary by season.	The peak and off-peak periods need to be defined based on Avista's specific requirements.
Delivery Mechanism	Delivered by Avista	Time varying rates are directly administered by the utility.
Type of Response	Load curtailment during peak period for a variety of end-uses and shifting of usage to off-peak periods.	
Participant Incentive	Peak to off-peak price differential induces participant to shift usage from peak period to off-peak periods. The off-peak rate is lower than the participant's standard rate	
Metering Requirements	Interval meter required for participation	Based on industry experience.

TOU Assumptions

The key parameters required to estimate potential for the two pricing options are participation rate, per participant load reduction and costs for deploying these rates. We have described below our assumptions on these parameters.

Program Participation Rate

We have defined participation rates for pricing options assuming independent offers of TOU, which results in voluntary, opt-in TOU rates to all customers and default TOU rates to all customers with opt-out.

All participation assumptions in pricing options are based on Brattle's extensive database on pricing program and pilot experiences.

Table B-2 presents assumed participation rates for C&I customers in independent TOU rate offers. We assumed that participation ramps up over a five-year timeframe to reach a steady-state level. For the opt-in offer, ramp up to steady-state participation follows an "S-shaped" diffusion curve, in which the participation growth rate accelerates over the first half of the five year period and then slows over the second half. A similar but inverse S-shaped diffusion curve is used to account for the rate at which customers opt-out of the default rate. TOU rates could be offered to Extra Large General service customers in 2016. For the other two classes, these rate are offered after AMI has been fully deployed by 2021.

Table B-2 TOU Participation Rates (% of eligible customers)

Option	Start Yr.	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yrs. 5-19	Comments
Opt-in							Standalone participation estimates represent average enrollment rates in independent rate offerings across full scale deployments and market research studies. (Source: Brattle's Pricing Program Database)
General Service & Large General Service	2021	1.3%	3.9%	7.8%	11.7%	13.0%	
Extra Large General Service	2016	1.3%	3.9%	7.8%	11.7%	13.0%	
Opt-out							
General Service & Large General Service	2021	100%	85.4%	78.9%	75.6%	74.0%	
Extra Large General Service	2016	100%	85.4%	78.9%	75.6%	74.0%	

Per Participant Load Reduction

Table B-3 below presents assumed per participant load reduction in TOU rates by customer class. The assumed impact values are based on a 2:1 peak to off-peak price ratio.

Table B-3 Per-Participant Load Reduction in TOU Rates by Customer Class

Customer Class	Value	Comments
General Service	0.2%	These impacts assume 2:1 peak to off-peak price ratio. Source: Brattle's Database on Pricing Programs.
Large General Service	2.6%	
Extra Large General Service	3.1%	

Program Costs

The major cost components for implementation of time varying rates are the fixed annual costs for administering the rates and providing billing analysis. For an opt-out offer, additional call center staff may be required during the initial program years to handle the relatively large volume of calls from customers defaulted to these rates. Table B-4 below shows itemized cost assumptions for opt-in and opt-out TOU offers. We developed these assumptions in consultation with the Avista team.

Table B-4 TOU Program Cost Assumptions for Opt-in and Opt-out Offers

Item	Unit	Value	Comments
Costs Applicable to Opt-in and Opt-out:			
Program Development Cost	$/program	$170,000	One FTE at $170,000 annual cost to design the TOU rates.
Annual Program Administration Cost	$/year	$170,000	One FTE at $170,000 annual cost to administer the TOU rates
Billing Analyst Cost	$/year	$105,000	One billing analyst at $105,000 in the call center to provide customer service.
Billing system upgrade	$	$7.5 million	Avista provided this estimate; Avista has no time-varying prices at the present time
Additional costs applicable to Opt-in:			
Per Customer Annual Marketing/Recruitment Cost	$/new participant/year	$10	Costs for TOU rates are assumed to be one fifth the costs for dynamic rates such as CPP. (Source: TVA Potential Study, 2011)
Additional costs applicable to Opt-out:			
Additional call center staff	$/year for first two program years	$255,000	We assumed that 3 additional call center staff @$85,000 each annual cost to handle customer calls for an opt-out rate.
Per Customer Annual Marketing/Recruitment Cost	$/new participant/year	$1	For opt-out TOU rates, these costs are assumed to be a tenth of the costs for opt-in TOU rates.

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Avista Electric Conservation Potential Assessment Study

Final Report

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SECTION | 1

Introduction

Avista Corporation (Avista) engaged Applied Energy Group (AEG, formerly EnerNOC Utility Solutions) to conduct a Conservation Potential Assessment (CPA). The CPA is a 20-year study, performed in accordance with Washington Initiative 937 (I-937), that provides data on conservation resources to support development of Avista's 2013 Integrated Resource Plan (IRP). The study updates Avista's last CPA, which AEG performed in 2013.

This study provided enhanced analysis compared to the previous studies.

- The base-year for the analysis was brought forward from 2011 to 2013.
- For the residential sector, the study incorporated Avista's GenPOP residential saturation survey from 2012. This provided the foundation for the base-year market characterization and energy market profiles. The recently completed 2014 Residential Building Stock Assessment (RBSA) supplemented the GenPOP survey.
- For the commercial sector, the analysis was performed for the major building types in the service territory. Preliminary results from the 2015 Commercial Building Stock Assessment (CBSA) provided useful information for this characterization.
- This study also incorporated changes to the list of energy conservation measures, as a result of research by the Regional Technical Forum (RTF). In particular, LED lamps have dropped in price and now provide a significant opportunity for savings.
- The study incorporates updated forecasting assumptions that line up with the most recent Avista load forecast.
- Measure-adoption rates were developed using the Northwest Power and Conservation Council's (Council) ramp rates as a starting point and adjusted to reflect Avista program results in recent years.
- Finally, in addition to analyzing annual energy savings, the study also estimated the opportunity for reduction of summer peak demand. This involved a full characterization by sector, segment and end use of summer peak demand in the base year.

Compared to the previous study, potential savings decreased. The 10-year potential for Washington and Idaho in this CPA is 65.6 aMW, compared to 72.4 aMW from the previous study. This is a result of lower avoided costs, the expected impact of the most recent wave of appliance standards, the lighting standards in Energy Independence and Security Act (EISA) legislation, and Avista's recent capture of low-hanging fruit.

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
aMW	Average annual megawatt
ACS	American Community Survey
AEO	Annual Energy Outlook forecast developed by EIA
AHAM	Association of Home Appliance Manufacturers
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
Auto-DR	Automated Demand Response
B/C Ratio	Benefit to Cost Ratio
BEST	AEG's Building Energy Simulation Tool
C&I	Commercial and Industrial
CAC	Central Air Conditioning
CBSA	Commercial Building Stock Assessment
CFL	Compact fluorescent lamp
CBECS	Commercial Buildings Energy Consumption Survey
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPA	Conservation Potential Assessment
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
DEEM	Database of Energy Efficiency Measures
DEER	Database for Energy Efficient Resources
DHW	Domestic Hot Water
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EUL	Estimated Useful Life
EUI	Energy Use Intensity
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-hour
HH	Household
HID	High intensity discharge lamps
HVAC	Heating Ventilation and Air Conditioning
KWh	Kilowatt-hour
I-937	Washington Initiative 937
ICAP	Installed Capacity

Acronym	Explanation
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
LED	Light emitting diode lamp
LoadMAP	AEG's Load Management Analysis and Planning™ tool
MECS	Manufacturing Energy Consumption Survey
MW	Megawatt
NAPEE	National Action Plan for Energy-Efficiency
NEEA	Northwest Energy Efficiency Alliance
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NPCC	Northwest Power and Conservation Council
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
RBSA	Residential Building Stock Assessment
RECS	Residential Energy Consumption Survey
RTF	Regional Technical Forum
RTU	Roof top unit
SEER	Seasonal Energy Efficiency Ratio
SIC	Standard Industrial Classification
Sixth Plan	Sixth Northwest Conservation and Electric Power Plan
TRC	Total Resource Cost test
UEC	Unit Energy Consumption
WH	Water heater

SECTION | 2

Analysis Approach and Data Development

This section describes the analysis approach taken for the study and the data sources used to develop the potential estimates.

Overview of Analysis Approach

To perform the potential analysis, AEG used a bottom-up approach following the major steps listed below. We describe these analysis steps in more detail throughout the remainder of this chapter.

1. Perform a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, 2013.
2. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2013 through 2035.
3. Define and characterize several hundred conservation measures to be applied to all sectors, segments, and end uses.
4. Estimate technical, economic, and achievable potential at the measure level in terms of energy and peak demand impacts from conservation measures for 2015-2035.

LoadMAP Model

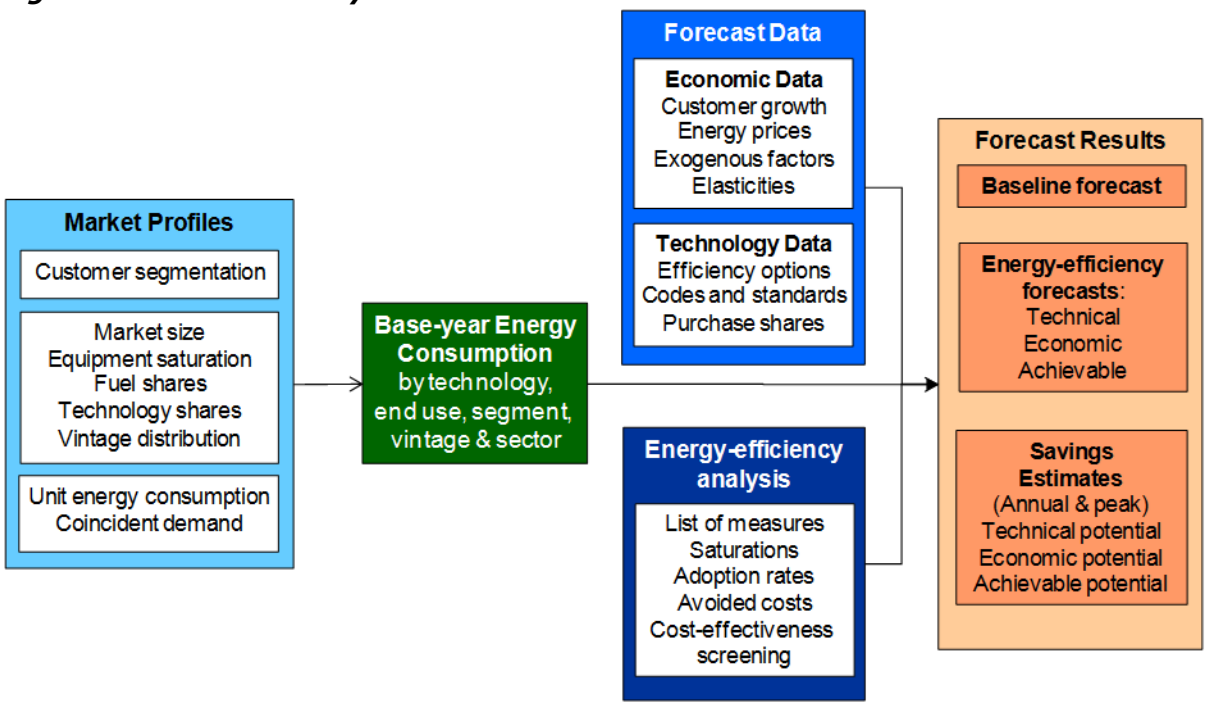
AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 4.0 to develop both the baseline projection and the estimates of potential. AEG developed LoadMAP in 2007 and has enhanced it over time, using it for the Electric Power Research Institute (EPRI) National Potential Study and numerous utility-specific forecasting and potential studies since that time. Built in Excel, the LoadMAP framework (see Figure 2-1) is both accessible and transparent and has the following key features.

- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life and appliance vintage distributions defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.

- Includes appliance and equipment models customized by end use. For example, the logic for lighting is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).
- Incorporates conservation measures, demand-response options, combined heat and power (CHP) and distributed generation options and fuel switching.

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential.[1]

Figure 2-1 LoadMAP Analysis Framework



[1] The model computes energy and peak-demand forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy and peak-demand savings are calculated as the difference between the value in the baseline projection and the value in the potential forecast (e.g., the technical potential forecast).

Definitions of Potential

In this study, the conservation potential estimates represent gross savings developed for three levels of potential: technical potential, economic potential, and achievable potential. These levels are described below.

- **Technical Potential** is defined as the theoretical upper limit of conservation potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.

  Technical potential also assumes the adoption of every other available measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and air conditioner maintenance in all existing buildings with central and room air conditioning. These retrofit measures are phased in over a number of years to align with the stock turnover of related equipment units, rather than modeled as immediately available all at once.
- **Economic Potential** represents the adoption of all ***cost-effective*** conservation measures. In this analysis, the cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the costs of the delivering the measure through a utility program, with incentives not included since they are a transfer payment. If the benefits outweigh the costs (that is, if the TRC ratio is equal to or greater than 1.0), a given measure is included in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture.
- **Achievable Potential** takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the conservation savings that a utility can hope to achieve through its programs. It is determined by applying a series of annual market adoption factors to the economic potential for each conservation measure. These factors represent the ramp rates at which technologies will penetrate the market. To develop these factors, the project team reviewed Avista's past conservation achievements and program history over the last five years, as well as the Northwest Power and Conservation Council's (Council) ramp rates used in the Council's Sixth Plan. Details regarding the market adoption factors appear in Appendix B.

Market Characterization

Now that we have described the modeling tool and provided the definitions of the potential cases, the first step in the analysis approach is market characterization. In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used. This characterization begins with a segmentation of Avista's electricity footprint to quantify energy use by sector, segment, end-use application, and the current set of technologies used. We rely primarily on information from Avista, Northwest Energy Efficiency Alliance (NEEA) and secondary sources as necessary.

Segmentation for Modeling Purposes

The market assessment first defined the market segments (building types, end uses, and other dimensions) that are relevant in the Avista service territory. The segmentation scheme for this project is presented in Table 2-1. Note that the low income segment is defined as 200% of the poverty level. Assuming 2.5 people per household, this is approximately annual household income of $35,000. The distribution to residential segment is based on the results of the Avista GenPOP survey.

Table 2-1 Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Sector	Residential, commercial, industrial
2	Segment	**Residential**: single family, multi family, manufactured home, low income **Commercial**: small office, large office, restaurant, retail, grocery, college, school, health, lodging, warehouse, and miscellaneous **Industrial**: total
3	Vintage	Existing and new construction
4	End uses	Cooling, lighting, water heat, motors, etc. (as appropriate by sector)
5	Appliances/end uses and technologies	Technologies such as lamp type, air conditioning equipment, motors by application, etc.
6	Equipment efficiency levels for new purchases	Baseline and higher-efficiency options as appropriate for each technology

With the segmentation scheme defined, we then performed a high-level market characterization of electricity sales in the base year to allocate sales to each customer segment. We used Avista data and secondary sources to allocate energy use and customers to the various sectors and segments such that the total customer count, energy consumption, and peak demand matched the Avista system totals from 2013 billing data. This information provided control totals at a sector level for calibrating the LoadMAP model to known data for the base-year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is overall electricity use.
- **Saturations** define the fraction of homes or square feet with the various technologies. (e.g., homes with electric space heating).
- **UEC (unit energy consumption) or EUI (energy-use intensity)** describes the amount of energy consumed in 2013 by a specific technology in buildings that have the technology. For electricity, UECs are expressed in kWh/household for the residential sector, and EUIs are expressed in kWh/square foot for the commercial sector.
- **Annual Energy Intensity** for the residential sector represents the average energy use for the technology across all homes in 2013. It is computed as the product of the saturation and the UEC and is defined as kWh/household for electricity. For the commercial sector, intensity, computed as the product of the saturation and the EUI, represents the average use for the technology across all floor space in 2013.
- **Annual Usage** is the annual energy use by an end-use technology in the segment. It is the product of the market size and intensity and is quantified in gigawatt-hour (GWh).
- **Peak Demand** for each technology, summer peak and winter peak are calculated using peak fractions of annual energy use from AEG's EnergyShape library and Avista system peak data.

The market characterization results and the market profiles are presented in Chapter 3.

Baseline Projection

The next step was to develop the baseline projection of annual electricity use and summer peak demand for 2013 through 2034 by customer segment and end use without new utility programs. The end-use projection includes the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates that were defined as of December 2013 are included in the baseline. The baseline projection is the foundation for the analysis of savings from future conservation efforts as well as the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Avista's internally developed sector-level projections for electricity sales

We also developed a baseline projection for summer and winter peak by applying the peak fractions from the energy market profiles to the annual energy forecast in each year.

We present the baseline-projection results for the system as a whole and for each sector in Chapter 4.

Conservation Measure Analysis

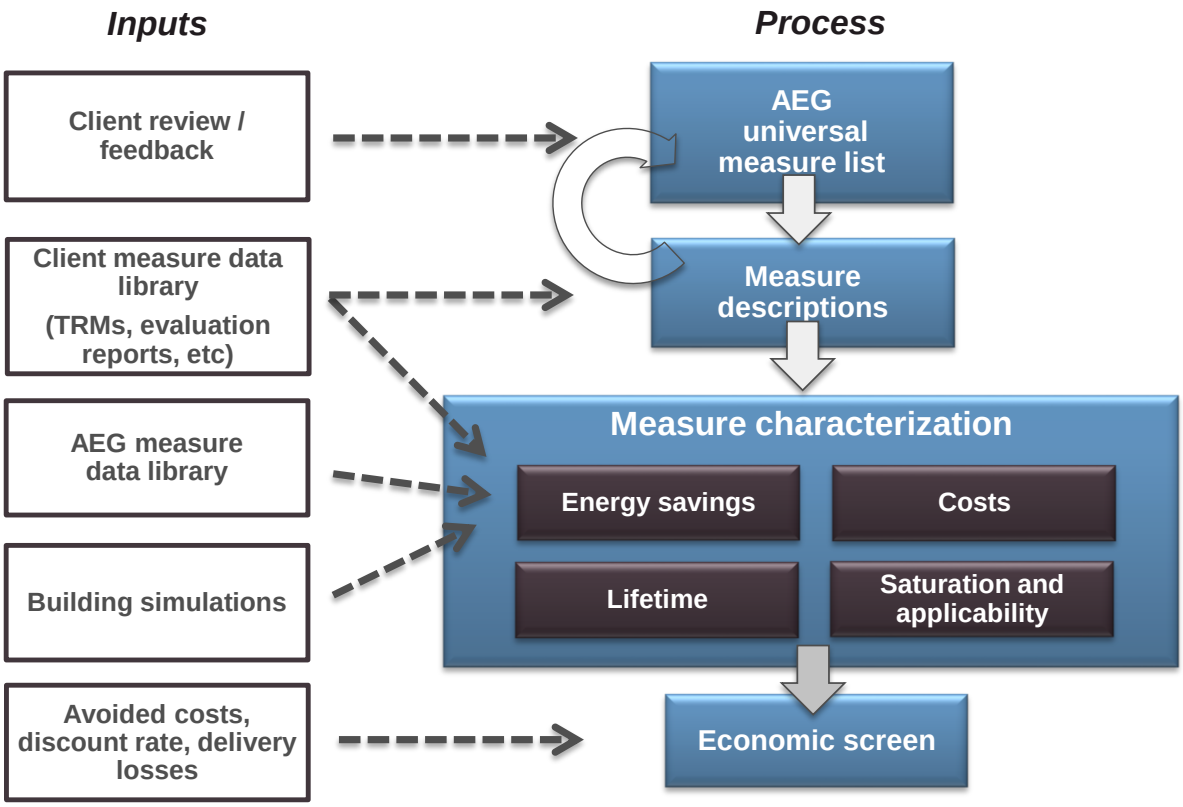
This section describes the framework used to assess the savings, costs, and other attributes of conservation measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. For all measures, AEG assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information, along with Avista's avoided costs data, in the economic screen to determine economically feasible measures.

Conservation Measures

Figure 2-2 outlines the framework for conservation measure analysis. The framework for assessing savings, costs, and other attributes of conservation measures involves identifying the list of measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening. Potential measures include the replacement of a unit that has failed or is at the end of its useful life with an efficient unit, retrofit or early replacement of equipment, improvements to the building envelope, the application of controls to optimize energy use, and other actions resulting in improved energy efficiency.

We compiled a robust list of conservation measures for each customer sector, drawing upon Avista's measure database, and the Regional Technical Forum (RTF) deemed measures databases, as well as a variety of secondary sources. This universal list of conservation measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. If considered today, some of these measures would not pass the economic screens initially, but may pass in future years as a result of lower projected equipment costs or higher avoided costs.

Figure 2-2 Approach for Conservation Measure Assessment



The selected measures are categorized into two types according to the LoadMAP taxonomy: equipment measures and non-equipment measures.

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels may be available for a given technology, ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of central air conditioners, this list begins with the current federal standard SEER 13 unit and spans a broad spectrum up to a maximum efficiency of a SEER 24 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not involve replacement or purchase of major end-use equipment (such as a refrigerator or air conditioner). An example would be a programmable thermostat that is pre-set to run heating and cooling systems only when people are home. Non-equipment measures can apply to more than one end use. For instance, addition of wall insulation will affect the energy use of both space heating and cooling. Non-equipment measures typically fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, energy management system)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (building orientation, passive solar lighting)
    - Lighting retrofits (included as a non-equipment measure because retrofits are performed prior to the equipment's normal end of life)

- Displacement measures (ceiling fan to reduce use of central air conditioners)
- Commissioning and retro commissioning (initial or ongoing monitoring of building energy systems to optimize energy use)

We developed a preliminary list of conservation measures, which was distributed to the Avista project team for review. The list was finalized after incorporating comments and is presented in the appendix to this volume.

Once we assembled the list of conservation measures, the project team characterized measure savings, incremental cost, service life, and other performance factors, drawing upon data from the Avista measure database, the RTF deemed measure workbooks, and simulation modeling. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic and achievable potential.

Representative Conservation Measure Data Inputs

To provide an example of the conservation measure data, Table 2-2 and Table 2-3 present examples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential central air conditioning (CAC) in single-family homes. Table 2-2 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 2-2 Example Equipment Measures for Central AC – Single-Family Home

Efficiency Level	Useful Life (yrs)	Equipment Cost	Energy Usage (kWh/yr)	On Market	Off Market
SEER 13	14 to 20	$2,549	1,466	2013	n/a
SEER 14 (Energy Star)	14 to 20	$3,072	1,344	2013	n/a
SEER 15 (CEE Tier 2)	14 to 20	$3,158	1,300	2013	n/a
SEER 16 (CEE Tier 3)	14 to 20	$3,148	1,262	2013	n/a
SEER 18	14 to 20	$3,708	1,203	2013	n/a
SEER 21	14 to20	$4,090	1,139	2013	n/a
SEER 24 (Ductless, Var. Ref. Flow)	14 to 20	$4,946	1,094	2013	n/a

Table 2-3 lists some of the non-equipment measures applicable to CAC in an existing single-family home. All measures are evaluated for cost-effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings and costs are calculated for each year of the study and depend on the base year saturation of the measure, the applicability[2] of the measure, and the savings as a percentage of the relevant energy end uses.

[2] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes where there is insufficient space in the attic or there is no attic at all.

Table 2-3 Example Non-Equipment Measures – Single Family Home, Existing

End Use	Measure	Saturation in 2013[3]	Applica-bility	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Cooling	Insulation - Ceiling	35%	50.0%	45	$1,134	5%
Cooling	Insulation - Radiant Barrier	15%	75.0%	15	$1,245	13%
Cooling	Ducting - Repair and Sealing	15%	50.0%	20	$538	5%
Cooling	Windows - High Efficiency	20%	75.0%	45	$2,908	9%
Cooling	Thermostat - Clock/Programmable	30%	40.0%	15	$230	4%

Screening Measures for Cost-Effectiveness

Only measures that are cost-effective are included in economic and achievable potential. Therefore, for each individual measure, LoadMAP performs an economic screen. This study uses the TRC test that compares the lifetime energy and peak demand benefits of each applicable measure with its cost. The lifetime benefits are calculated by multiplying the annual energy and demand savings for each measure by all appropriate avoided costs for each year, and discounting the dollar savings to the present value equivalent. Lifetime costs represent incremental measure cost and annual operations and maintenance (O&M) costs. The analysis uses each measure's values for savings, costs, and lifetimes that were developed as part of the measure characterization process described above.

The LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the projection.

It is important to note the following about the economic screen:

- The economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition.
- The economic screening was conducted only for measures that are applicable to each building type and vintage; thus if a measure is deemed to be irrelevant to a particular building type and vintage, it is excluded from the respective economic screen.
- If multiple equipment measures have benefit to cost ratios (B/C ratios) greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Table 2-4 summarizes the number of measures evaluated for each segment within each sector.

Table 2-4 Number of Measures Evaluated

Sector	Total Measures	Measure Permutations w/ 2 Vintages	Measure Permutations w/ Segments
Residential	60	120	480
Commercial	82	164	1,804
Industrial	57	114	114
Total Measures Evaluated	**199**	**398**	**2,398**

[3] Note that saturation levels reflected for the base year change over time as more measures are adopted.

The appendix to this volume presents results for the economic screening process by segment, vintage, end use and measure for all sectors.

Conservation Potential

The approach we used for this study to calculate the conservation potential adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies (November 2007).[4] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying conservation potential. As described in Chapter 2, three types of potential were developed as part of this effort: technical potential, economic potential and achievable potential.

- **Technical potential** is a theoretical construct that assumes the highest efficiency measures that are technically feasible to install are adopted by customers, regardless of cost or customer preferences. Thus, determining the technical potential is relatively straightforward. LoadMAP "chooses" the most efficient equipment options for each technology at the time of equipment replacement. In addition, it installs all relevant non-equipment measures for each technology to calculate savings. For example, for central air conditioning, as shown in Table 2-2, the most efficient option is a SEER 24. The multiple non-equipment measures shown in Table 2-3 are then applied to the energy used by the SEER 24 system to further reduce air conditioning energy use. LoadMAP applies the savings due to the non-equipment measures one-by-one to avoid double counting of savings. The measures are evaluated in order of their B/C ratio, with the measure with the highest B/C ratio applied first. Each time a measure is applied, the baseline energy use for the end use is reduced and the percentage savings for the next measure is applied to the revised (lower) usage.
- **Economic potential** results from the purchase of the most efficient cost-effective option available for a given equipment or non-equipment measure as determined in the cost-effectiveness screening process described above. As with technical potential, economic potential is a phased-in approach. Economic potential is still a hypothetical upper-boundary of savings potential as it represents only measures that are economic, but does not yet consider customer acceptance and other factors.
- **Achievable potential** defines the range of savings that is very likely to occur. It accounts for customers' awareness of efficiency options, any barriers to customer adoption, limits to program design, and other factors that influence the rate at which conservation measures penetrate the market.

The calculation of technical and economic potential is a straightforward algorithm. To develop estimates for achievable potential, we develop market adoption rates for each measure that specify the percentage of customers that will select the highest–efficiency economic option. For Avista, the project team began with the ramp rates specified in the Sixth Plan conservation workbooks, but modified these to match Avista program history and service territory specifics. For specific measures, we examined historic program results for the most recent program results. We then adjusted the 2014 achievable potential for these measures to approximately match the historical results. This provided a starting for 2014 potential that was aligned to historic results. For future years, we increased the potential factors to model increasing market acceptance and program improvements. For measures not currently included in Avista programs, we relied upon the Sixth Plan ramp rates and recent AEG potential studies to create market adoption rates for Avista. The market adoption rates for each measure appear in Appendix B.

Results of all the potentials analysis are presented in Chapter 5.

[4] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied. In general, data sources were applied in the following order: Avista data, Northwest data and, finally, other secondary sources.

Data Sources

The data sources are organized into the following categories:

- Avista data
- Northwest Energy Efficiency Alliance data
- Measure data
- AEG's databases and analysis tools
- Other secondary data and reports

Avista Data

Our highest priority data sources for this study were those that were specific to Avista.

- **Avista customer data:** Avista provided billing data for development of customer counts and energy use for each sector. We also used the results of the Avista GenPOP survey, a residential saturation survey.
- **Load forecasts:** Avista provided an economic growth forecast by sector; electric load forecast; peak-demand forecasts at the sector level; and retail electricity price history and forecasts.
- **Economic information:** Avista Power provided avoided cost forecasts, a discount rate, and line loss factor.
- **Avista program data**: Avista provided information about past and current programs, including program descriptions, goals, and achievements to date.

Northwest Energy Efficiency Alliance Data

The Northwest Energy Efficiency Alliance conducts research on an ongoing basis for the Northwest region. The following studies were particularly useful for this study:

- **Northwest Energy Efficiency Alliance, 2011 Residential Building Stock Assessment Single-Family**, Market Research Report, http://neea.org/docs/reports/residential-building-stock-assessment-single-family-characteristics-and-energy-use.pdf?sfvrsn=8
- **Northwest Energy Efficiency Alliance, 2011 Residential Building Stock Assessment: Manufactured Home**, Market Research Report, #E13-249, January, 2013. http://neea.org/docs/default-source/reports/residential-building-stock-assessment--manufactured-homes-characteristics-and-energy-use.pdf?sfvrsn=8
- **Northwest Energy Efficiency Alliance, Long-Term Northwest Residential Lighting Tracking and Monitoring Study**, Market Research Report, 11-228, August, 2011. http://neea.org/research/reports/E11-231_Combinedv2.pdf
- **Northwest Energy Efficiency Alliance, 2011 Residential Building Stock Assessment: Multifamily**, Market Research Report, #13-263, September, 2013. http://neea.org/docs/default-source/reports/residential-building-stock-assessment--multi-family-characteristics-and-energy-use.pdf?sfvrsn=4
- **Northwest Energy Efficiency Alliance, 2014 Commercial Building Stock Assessment**, December 16, 2014**,** http://neea.org/docs/default-source/reports/2014-cbsa-final-report_05-dec-2014.pdf?sfvrsn=12.

Conservation Measure Data

Several sources of data were used to characterize the conservation measures. We used the following regional data sources and supplemented with AEG's data sources to fill in any gaps.

- **Northwest Power and Conservation Council Sixth Plan Conservation Supply Curve Workbooks.** To develop its Sixth Power Plan, the Council used workbooks with detailed information about measures, available at http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm .
- **Regional Technical Forum Deemed Measures.** The NPCC Regional Technical Forum maintains databases of deemed measure savings data, available at http://www.nwcouncil.org/energy/rtf/measures/Default.asp .

AEG Data

AEG maintains several databases and modeling tools that we use for forecasting and potential studies. Relevant data from these tools has been incorporated into the analysis and deliverables for this study.

- **AEG Energy Market Profiles**: For more than 10 years, AEG staff has maintained profiles of end-use consumption for the residential, commercial, and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use by fuel (electricity and natural gas), customer segment and end use for 10 regions in the U.S. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST)**. AEG's BEST is a derivative of the Department of Energy (DOE) 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for heating, ventilation and air conditioning (HVAC)-related measures.
- **AEG's EnergyShape™:** This database of load shapes includes the following:
  - Residential – electric load shapes for ten regions, three housing types, 13 end uses
  - Commercial – electric load shapes for nine regions, 54 building types, ten end uses
  - Industrial – electric load shapes, whole facility only, 19 2-digit SIC codes, as well as various 3-digit and 4-digit SIC codes
- **AEG's Database of Energy Efficiency Measures (DEEM):** AEG maintains an extensive database of measure data for our studies. Our database draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the Energy Information Administration (EIA) Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.
- **Recent studies**. AEG has conducted numerous studies of conservation potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include Tacoma Power, Idaho Power, PacifiCorp, Ameren Missouri, Vectren Energy, Indianapolis Power & Light, Tennessee Valley Authority, Ameren Missouri, Ameren Illinois, and Seattle City Light. In addition, we used the information about impacts of building codes and appliance standards from recent reports for the Edison Electric Institute[5].

[5] AEG staff has prepared three white papers on the topic of factors that affect U.S. electricity consumption, including appliance standards and building codes. Links to all three white papers are provided:
http://www.edisonfoundation.net/IEE/Documents/IEE_RohmundApplianceStandardsEfficiencyCodes1209.pdf
http://www.edisonfoundation.net/iee/Documents/IEE_CodesandStandardsAssessment_2010-2025_UPDATE.pdf.
http://www.edisonfoundation.net/iee/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Annual Energy Outlook**. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2013 AEO.
- **Local Weather Data:** Weather from NOAA's National Climatic Data Center for Spokane, WA was used as the basis for building simulations.
- **EPRI End-Use Models (REEPS and COMMEND)**. These models provide the elasticities we apply to electricity prices, household income, home size and heating and cooling.
- **Database for Energy Efficient Resources (DEER).** The California Energy Commission and California Public Utilities Commission (CPUC) sponsor this database, which is designed to provide well-documented estimates of energy and peak demand savings values, measure costs, and effective useful life (EUL) for the state of California. We used the DEER database to cross check the measure savings we developed using BEST and DEEM.
- **Other relevant regional sources:** These include reports from the Consortium for Energy Efficiency, the Environmental Protection Agency (EPA), and the American Council for an Energy-Efficient Economy.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity use and households/floor space for the residential, commercial and industrial sectors, we used Avista billing data and customer surveys to estimate energy use.

- For the residential sector, Avista estimated the numbers of customers and the average energy use per customer for each of the three segments, based on its GenPOP survey, matched to billing data for surveyed customers. AEG compared the resulting segmentation with data from the American Community Survey (ACS) regarding housing types and income and found that the Avista segmentation corresponded well with the ACS data. (See Chapter 3 for additional details.)
- To segment the commercial and industrial segments, we relied upon the allocation from the previous energy efficiency potential study. For the previous study, customers and sales were allocated to building type based on standard industrial classification (SIC) codes, with some adjustments between the commercial and industrial sectors to better group energy use by facility type and predominate end uses. (See Chapter 3 for additional details.)

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-5. To develop the market profiles for each segment, we did the following:

1. Developed control totals for each segment. These include market size, segment-level annual electricity use, and annual intensity.
2. Used the Avista GenPOP Survey, NEEA's RBSA, NEEA's CBSA and AEG's Energy Market Profiles database to develop existing appliance saturations, appliance and equipment characteristics, and building characteristics.

3. Ensured calibration to control totals for annual electricity sales in each sector and segment.
4. Compared and cross-checked with other recent AEG studies.
5. Worked with Avista staff to vet the data against their knowledge and experience.

Data Application for Baseline Projection

Table 2-5 summarizes the LoadMAP model inputs required for the baseline projection. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-5 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	Avista billing data Avista GenPOP Survey NEEA RBSA and CBSA AEO 2013
Annual intensity	**Residential**: Annual use per household **Commercial**: Annual use per square foot **Industrial**: Annual use per employee	Avista billing data AEG's Energy Market Profiles NEEA RBSA and CBSA AEO 2013 Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Avista GenPOP Survey NEEA RBSA and CBSA AEG's Energy Market Profiles Avista Load Forecasting
UEC/EUI for each end-use technology	UEC: Annual electricity use in homes and buildings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	NPCC Sixth Plan and RTF data HVAC uses: BEST simulations using prototypes developed for Idaho Engineering analysis DEEM Recent AEG studies
Appliance/equipment age distribution	Age distribution for each technology	NPCC Sixth Plan and RTF data NEEA regional survey data Utility saturation surveys Recent AEG studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	AEG DEEM AEO 2013 DEER NPCC workbooks, RTF Previous studies
Peak factors	Share of technology energy use that occurs during the peak hour	EnergyShape database

Table 2-5 Data Needs for the Baseline Projection and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I sectors	Avista load forecast AEO 2013 economic growth forecast
Equipment purchase shares for baseline projection	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2013 regional forecast assumptions[6] Appliance/efficiency standards analysis Avista program results and evaluation reports
Electricity prices	Forecast of average energy and capacity avoided costs and retail prices	Avista forecast
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models AEO 2013

In addition, we implemented assumptions for known future equipment standards as of December 2013, as shown in Table 2-6, Table 2-7 and Table 2-8. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

[6] We developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2013), which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future EE programs that may be embedded in the AEO forecasts.

Table 2-6 Residential Electric Equipment Standards[7]

2013's Efficiency or Standard Assumption
1st Standard (relative to 2013's standard)
2nd Standard (relative to 2013's standard)

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13												
	Room AC	EER 9.8	EER 11.0											
	Evaporative Central AC	Conventional												
	Evaporative Room AC	Conventional												
Cooling/Heating	Heat Pump	SEER 13.0/HSPF 7.7		SEER 14.0/HSPF 8.2										
Space Heating	Electric Resistance	Electric Resistance												
Water Heating	Water Heater (<=55 gallons)	EF 0.90		EF 0.95										
	Water Heater (>55 gallons)	EF 0.90		Heat Pump Water Heater										
Lighting	Screw-in/Pin Lamps	Incandescent	Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T8 (89 lumens/watt)					T8 (92.5 lumens/watt)							
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard	25% more efficient											
	Freezer	NAECA Standard	25% more efficient											
	Dishwasher	14% more efficient than 2010 standard (307 kWh/yr)												
	Clothes Washer	Conventional (MEF 1.26 for top loader)		MEF 1.72 for top loader			MEF 2.0 for top loader							
	Clothes Dryer	Conventional (EF 3.01)		EF 3.73										
	Microwave Ovens	Conventional			1.0 Watts (maximum standby power)									
Miscellaneous	Furnace Fans	Conventional						40% more efficient						

[7] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-7 Commercial Electric Equipment Standards[8]

2013's Efficiency or Standard Assumption | 1st Standard (relative to 2013's standard) | 2nd Standard (relative to 2013's standard)

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Chillers	2007 ASHRAE 90.1												
	Roof Top Units	EER 11.0/11.2												
	Packaged Terminal AC/HP	EER 11.0/11.2												
Cooling/Heating	Heat Pump	EER 11.0/COP 3.3												
Ventilation	Ventilation	Constant Air Volume/Variable Air Volume												
Lighting	Screw-in/Pin Lamps	Incandescent	Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T8 (89 lumens/watt)					T8 (92.5 lumens/watt)							
	High Intensity Discharge	EPACT 2005 (Mercury Vapor Fixture Phase-out)				Metal Halide Ballast Improvement								
Water Heating	Water Heater	EF 0.97												
Refrigeration	Walk-in Refrigerator/Freezer	EISA 2007 Standard				10-38% more efficient								
	Reach-in Refrigerator	EPACT 2005 Standard				40% more efficient								
	Glass Door Display	EPACT 2005 Standard				12-28% more efficient								
	Open Display Case	EPACT 2005 Standard				10-20% more efficient								
	Vending Machines	33% more efficient than EPAC 2005 Standard												
	Ice maker	2010 Standard					15% more efficient							
Miscellaneous	Non-HVAC Motors	EISA 2007 Standards			Expanded EISA 2007 Standards									

[8] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-8 Industrial Electric Equipment Standards[9]

2013's Efficiency or Standard Assumption | 1st Standard (relative to 2013's standard) | 2nd Standard (relative to 2013's standard)

End Use	Technology	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Chillers	2007 ASHRAE 90.1												
	Roof Top Units	EER 11.0/11.2												
	Packaged Terminal AC/HP	EER 11.0												
Cooling/Heating	Heat Pump	EER 11.0/COP 3.3												
Ventilation	Ventilation	Constant Air Volume/Variable Air Volume												
Lighting	Screw-in/Pin Lamps	Incandescent	Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T8 (89 lumens/watt)					T8 (92.5 lumens/watt)							
	High Intensity Discharge	EPACT 2005 (Mercury Vapor Fixture Phase-out)				Metal Halide Ballast Improvement								
Motors	Pumps, Fans & Blowers, Compressed Air, Material Handling and Processing	EISA 2007 Standards			Expanded EISA 2007 Standards									

[9] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Conservation Measure Data Application

Table 2-9 details the energy-efficiency data inputs to the LoadMAP model. It describes each input and identifies the key sources used in the Avista analysis.

Table 2-9 Data Needs for the Measure Characteristics in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Avista measure data NPCC Sixth Plan conservation workbooks BEST AEG DEEM AEO 2013 DEER NPCC workbooks, RTF Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each electric measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	Avista measure data NPCC Sixth Plan conservation workbooks BEST AEG DEEM EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-household, per-square-foot, per employee or per service point basis for the residential, commercial, and industrial sectors, respectively. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Avista measure data NPCC Sixth Plan conservation workbooks RTF deemed measure database AEG DEEM AEO 2013 DEER RS Means Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Avista measure data NPCC Sixth Plan conservation workbooks RTF deemed measure database AEG DEEM AEO 2013 DEER Other secondary sources
Applicability	Estimate of the percentage of dwellings in the residential sector, square feet in the commercial sector, or employees in the industrial sector where the measure is applicable and where it is technically feasible to implement.	Avista measure data NPCC Sixth Plan conservation workbooks RTF deemed measure database AEG DEEM DEER Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Data Application for Cost-effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were analyzed as real 2013 dollars. We applied a discount rate of 4% in in real dollars. All impacts in this report are presented at the customer meter, but electric energy delivery losses of 6.5% were provided by Avista in order to gross up impacts to the generator for economic analysis. The avoided costs provided by Avista were increased by 10% to account for the Power Act's conservation preference.

Achievable Potential Estimation

To estimate achievable potential, two sets of parameters are needed to represent customer decision making behavior with respect to energy-efficiency choices.

- **Technical diffusion curves for non-equipment measures**. Equipment measures are installed when existing units fail. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the projection (instantaneous potential), they are phased in according to adoption schedules that generally align with the diffusion of similar equipment measures. The adoption rates for the Avista study were based on ramp rate curves specified in the NPCC Sixth Power Plan, but modified to reflect Avista program history. These adoption rates are used within LoadMAP to generate the Technical and Economic potentials for non-equipment measures.
- **Adoption rates**. Customer adoption rates or take rates are applied to Economic potential to estimate Achievable Potential. These rates were developed by mapping each measure to a ramp rate developed by the Northwest Power and Conservation Council for the Sixth Plan. These rates are then compared with the recent Avista program results and adjustments were made, if necessary. For example, if the program had been running for several years and had achieved higher results in the previous year, the ramp rate started further along in the curve. These rates represent customer adoption of economic measures when delivered through a best-practice portfolio of well-operated efficiency programs under a reasonable policy or regulatory framework. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. The primary barrier to adoption reflected in this case is customer preferences. Adoption rates are presented in Appendix B.

SECTION | 3

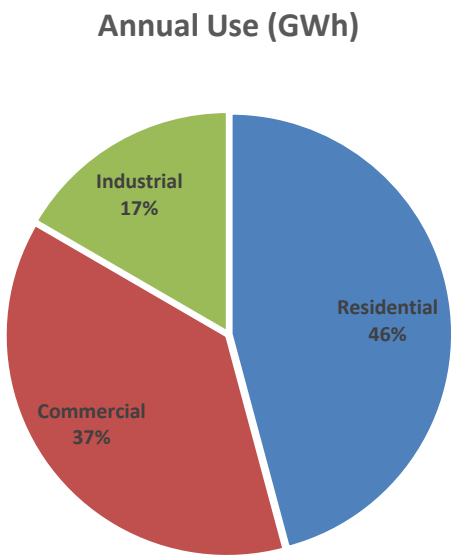
Market Characterization and Market Profiles

In this section, we describe how customers in the Avista service territory use electricity in the base year of the study, 2013. It begins with a high-level summary of energy use across all sectors and then delves into each sector in more detail.

Energy Use Summary

Total electricity use for the residential, commercial, and industrial sectors for Avista in 2013 was 8,081 GWh; 5,555 GWh (WA) and 2,526 GWh (ID). As shown in the tables below, in both states the residential sector accounts for over 45% of the annual energy use, followed by commercial with over 35% of the annual energy use. In terms of summer peak demand, the total system peak in 2013 was 1,459 MW; 1,017 MW (WA) and 442 MW (ID). The total system peak in the winter was 1,417 MW; 973 MW (WA) and 444 MW (ID). In both states, the residential sector contributes over 40% to peak.

Figure 3-1 Sector-Level Electricity Use in Base Year 2013, Washington



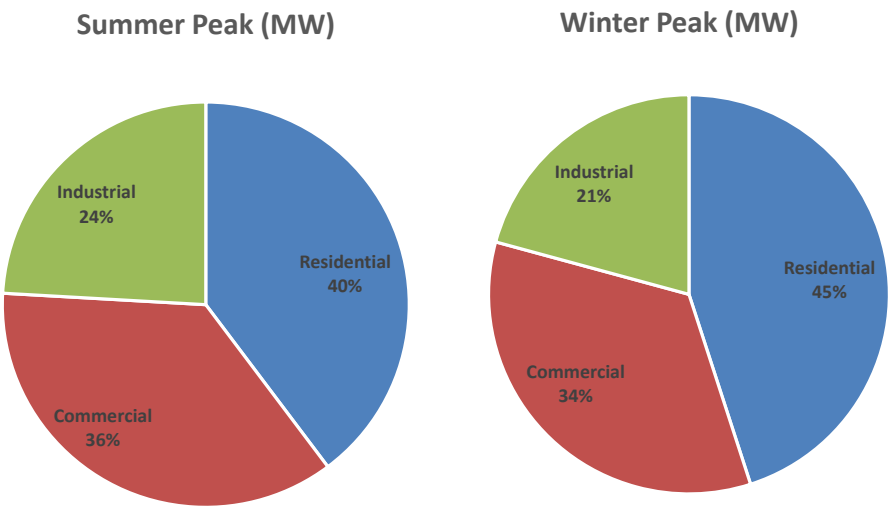


Table 3-1 Avista Sector Control Totals (2013), Washington

Sector	Annual Electricity Use (GWh)	% of Annual Use	Summer Peak Demand (MW)	% of Summer Peak	Winter Peak Demand (MW)	% of Winter Peak
Residential	2,546	46%	404	40%	438	45%
Commercial	2,086	38%	368	36%	333	34%
Industrial	922	17%	245	24%	202	21%
Total	**5,555**	**100%**	**1,017**	**100%**	**973**	**100%**

Figure 3-2 Sector-Level Electricity Use in Base Year 2013, Idaho

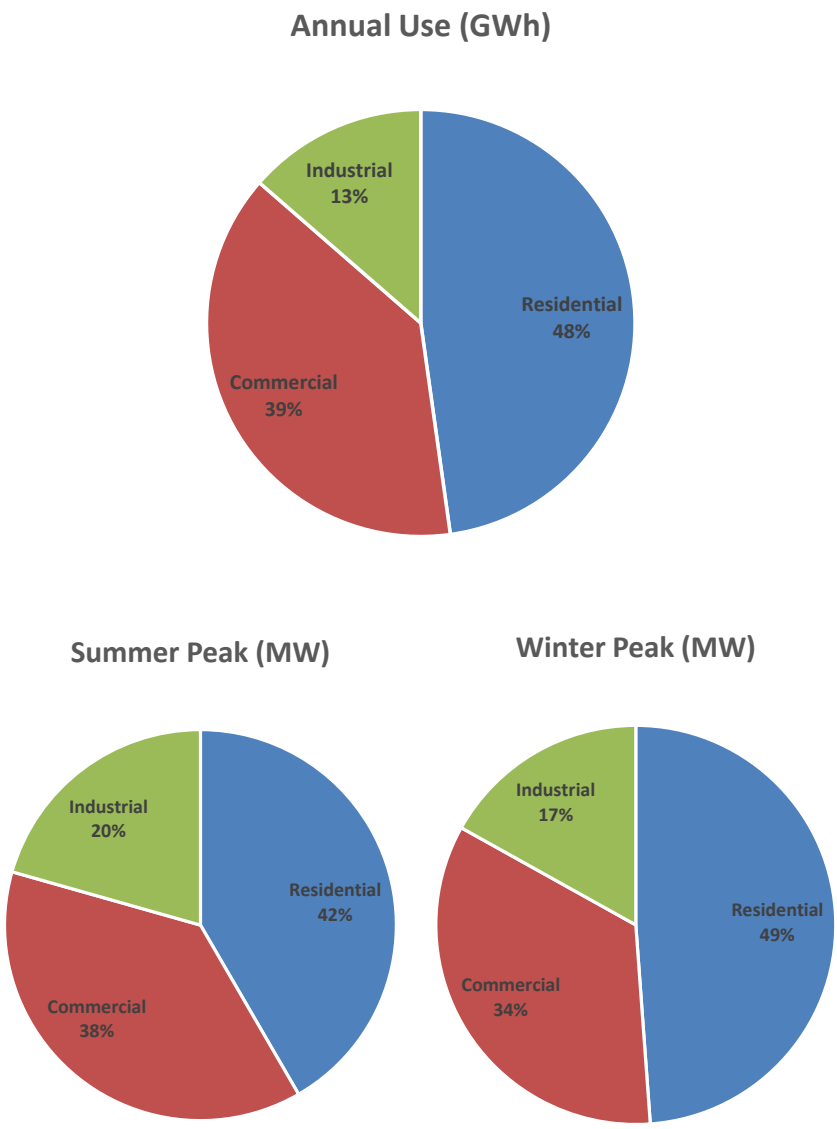


Table 3-2 Avista Sector Control Totals (2013), Idaho

Sector	Annual Electricity Use (GWh)	% of Annual Use	Summer Peak Demand (MW)	% of Summer Peak	Winter Peak Demand (MW)	% of Winter Peak
Residential	1,207	48%	184	42%	217	49%
Commercial	976	39%	167	38%	152	34%
Industrial	343	14%	91	21%	75	17%
Total	**2,526**	**100%**	**442**	**100%**	**444**	**100%**

Residential Sector

The total number of households and electricity sales for the service territory were obtained from Avista's customer database. In 2013, there were 213,640 households in the state of Washington

that used a total of 2,546 GWh with a summer peak demand of 404 MW and a winter peak demand of 438 MW. Average use per customer (or household) at 11,919 kWh is about average compared to other regions of the country. We allocated these totals into four residential segments and the values are shown in Table 3-3.

Table 3-4 shows the total number of households and electricity sales in the state of Idaho. . In 2013, there were 107,449 households that used a total of 1,207 GWh with summer peak demand of 184 MW and winter peak demand of 217 MW. Average use per customer (or household) was 11,233.

Table 3-3 Residential Sector Control Totals (2013), Washington

Segment	Number of Customers	Electricity Use (GWh)	% of Annual Use	Annual Use/Customer (kWh/HH)	Summer Peak (MW)	Winter Peak (MW)
Single Family	129,893	1,783	70%	13,726	296	304
Multifamily	11,964	99	4%	8,236	13	22
Mobile Home	7,691	95	4%	12,354	13	16
Low Income	64,092	570	22%	8,892	82	96
Total	**213,640**	**2,546**	**100%**	**11,919**	**404**	**438**

Table 3-4 Residential Sector Control Totals (2013), Idaho

Segment	Number of Customers	Electricity Use (GWh)	% of Annual Use	Annual Use/Customer (kWh/HH)	Summer Peak (MW)	Winter Peak (MW
Single Family	65,329	843	70%	12,902	133	153
Multifamily	5,265	41	3%	7,733	6	9
Mobile Home	4,835	56	5%	11,599	8	10
Low Income	32,020	267	22%	8,349	38	46
Total	**107,449**	**1,207**	**100%**	**11,233**	**184**	**217**

As we describe in the previous chapter, the market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector is presented in Table 3-5 (WA) and Table 3-6 (ID). Segment-specific market profiles are presented in Appendix A.

Figure 3-3 (WA) and Figure 3-4 (ID) show the distribution of annual electricity use by end use for all customers. Two main electricity end uses —appliances and space heating— account for approximately 50% of total use. Appliances include refrigerators, freezers, stoves, clothes washers, clothes dryers, dishwashers, and microwaves. The remainder of the energy falls into the water heating, lighting, cooling, electronics, and the miscellaneous category – which is comprised of furnace fans, pool pumps, and other "plug" loads (all other usage not covered by those listed in Table 3-5 and Table 3-6 such as hair dryers, power tools, coffee makers, etc.).

The charts also show estimates of peak demand by end use. Appliances are the largest contributor to summer peak demand, followed by water heating. During the winter, heating is the largest contributor to peak demand, followed by appliances.

Figure 3-5 (WA) and Figure 3-6 (ID) present the electricity intensities by end use and housing type. Single family homes have the highest use per customer at 13,726 kWh/year (WA) and 12,902 kWh/year (ID).

Figure 3-3 Residential Electricity Use and Summer Peak Demand by End Use (2013), Washington

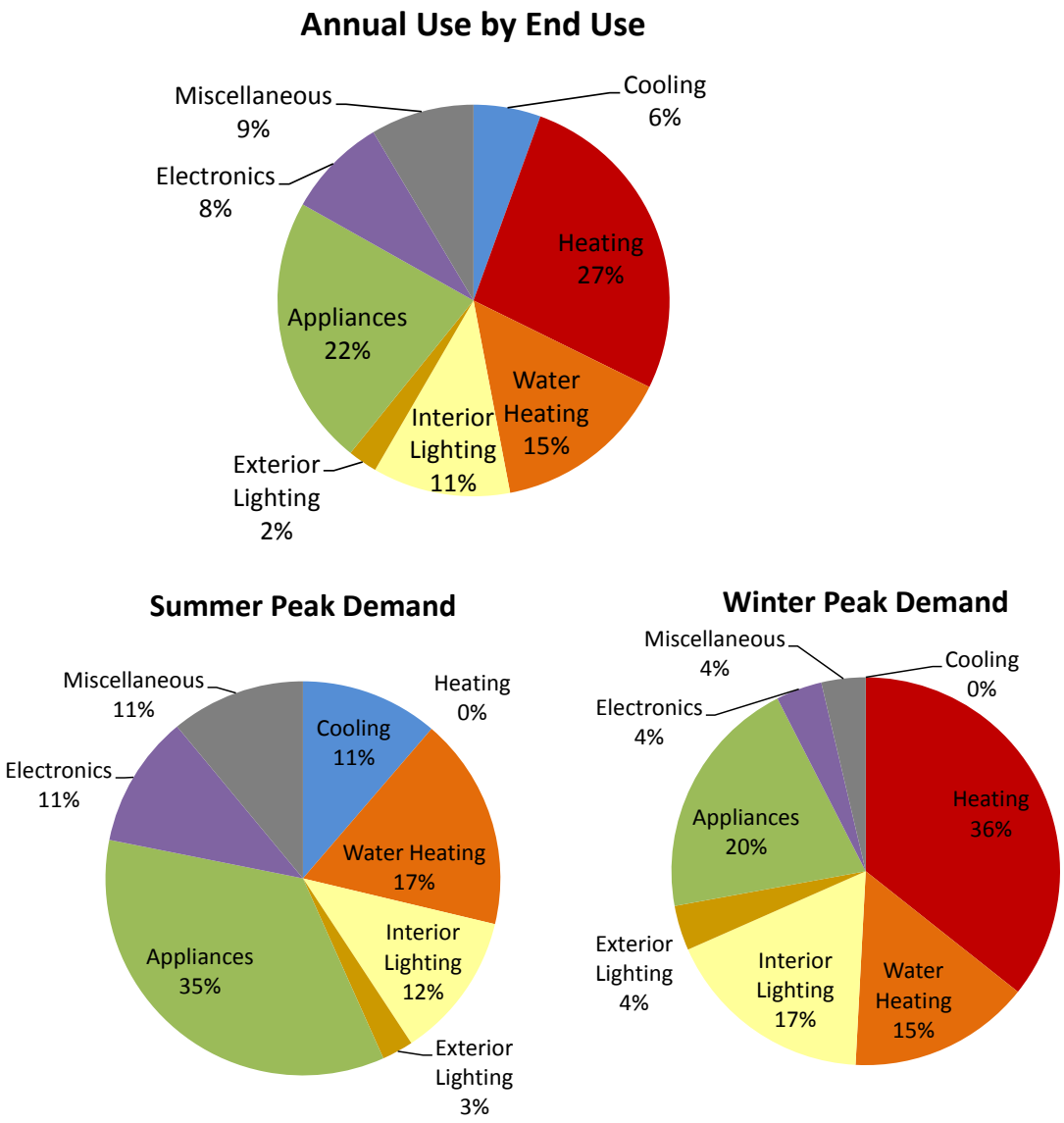


Figure 3-4 Residential Electricity Use and Summer Peak Demand by End Use (2013), Idaho

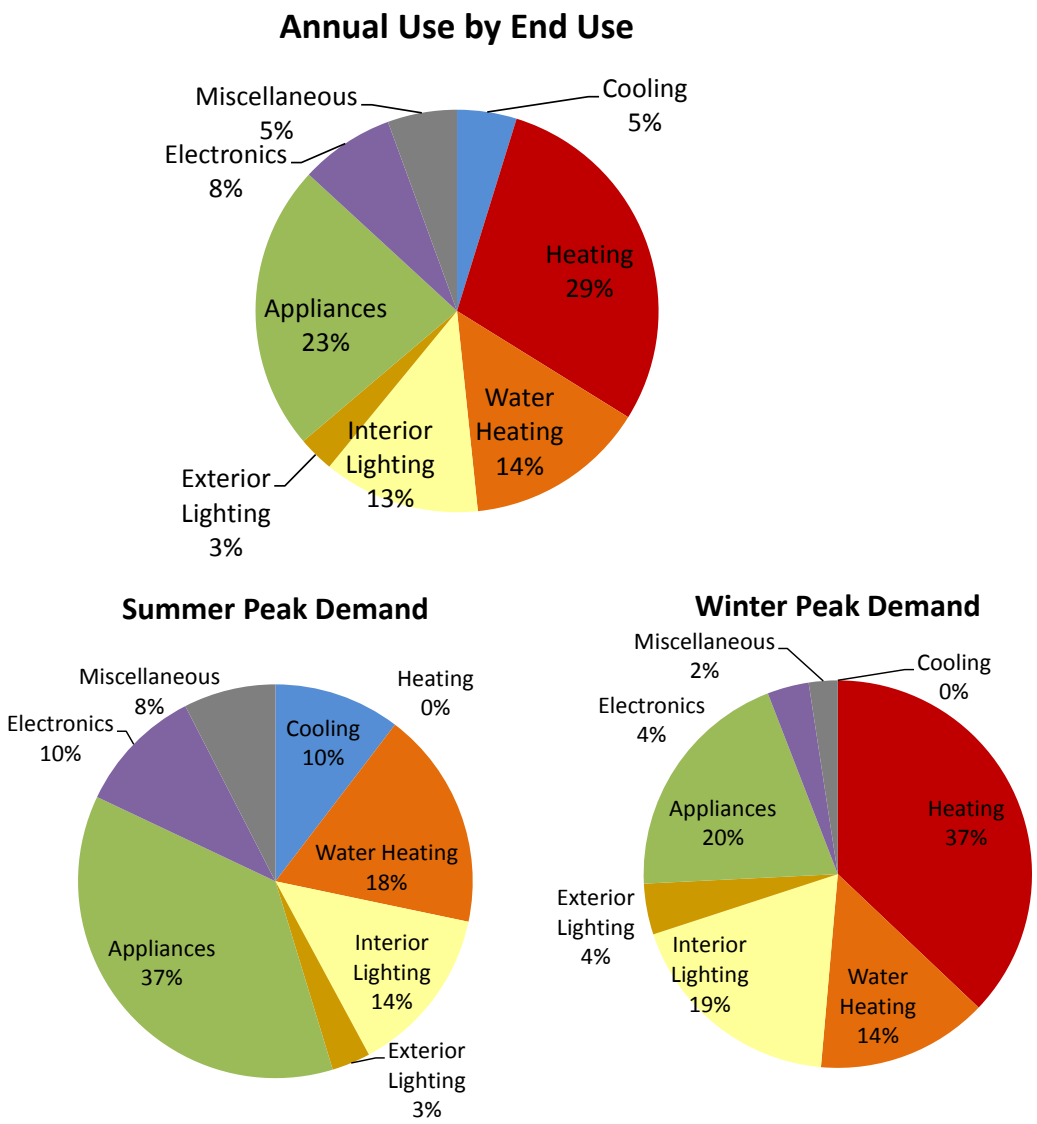


Figure 3-5 Residential Intensity by End Use and Segment (Annual kWh/HH, 2013), Washington

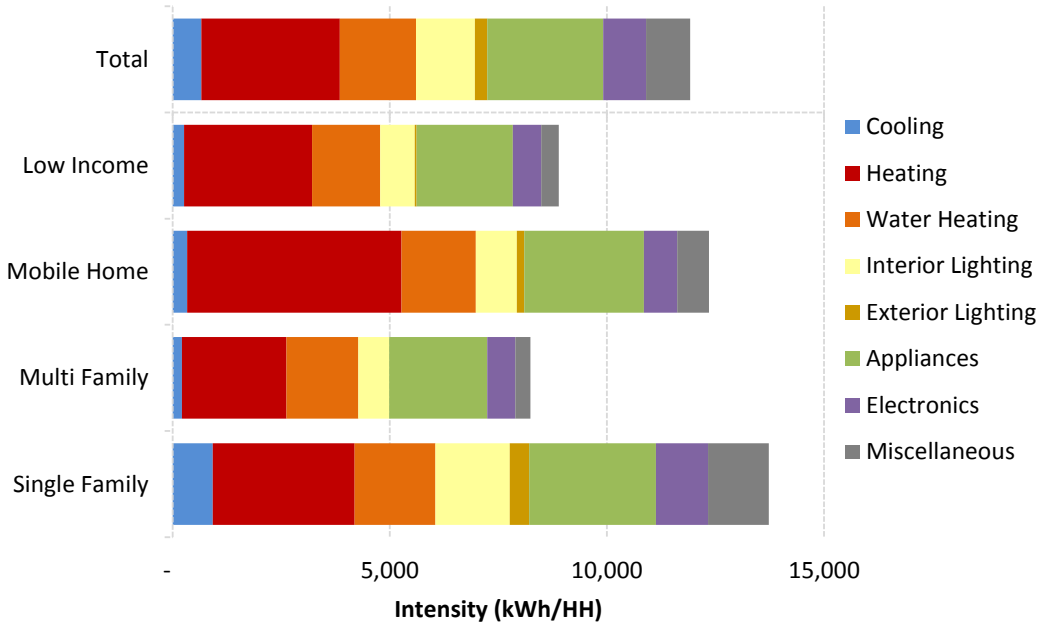


Figure 3-6 Residential Intensity by End Use and Segment (Annual kWh/HH, 2013), Idaho

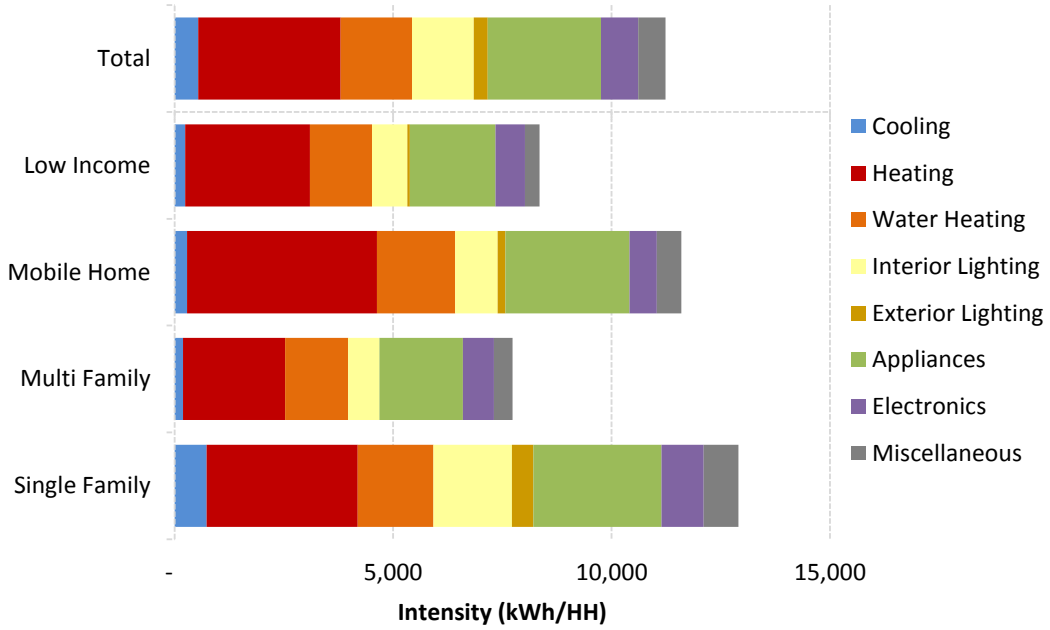


Table 3-5 Average Market Profile for the Residential Sector, 2013, Washington

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	36.9%	1,249	461	98
Cooling	Room AC	26.4%	402	106	23
Cooling	Air-Source Heat Pump	6.5%	1,268	82	17
Cooling	Geothermal Heat Pump	0.2%	1,326	2	0
Cooling	Evaporative AC	1.2%	809	10	2
Space Heating	Electric Room Heat	24.3%	5,302	1,288	275
Space Heating	Electric Furnace	13.4%	9,021	1,213	259
Space Heating	Air-Source Heat Pump	6.5%	10,487	677	145
Space Heating	Geothermal Heat Pump	0.2%	5,564	10	2
Water Heating	Water Heater (<= 55 Gal)	50.9%	3,025	1,539	329
Water Heating	Water Heater (55 to 75 Gal)	6.5%	3,145	203	43
Water Heating	Water Heater (> 75 Gal)	0.3%	4,209	12	3
Interior Lighting	Screw-in/Hard-wire	100.0%	955	955	204
Interior Lighting	Linear Fluorescent	100.0%	114	114	24
Interior Lighting	Specialty Lighting	100.0%	286	286	61
Exterior Lighting	Screw-in/Hard-wire	100.0%	289	289	62
Appliances	Clothes Washer	91.8%	104	95	20
Appliances	Clothes Dryer	49.9%	738	368	79
Appliances	Dishwasher	77.1%	447	345	74
Appliances	Refrigerator	100.0%	829	829	177
Appliances	Freezer	55.3%	669	370	79
Appliances	Second Refrigerator	20.7%	1,010	209	45
Appliances	Stove	70.3%	453	318	68
Appliances	Microwave	94.8%	139	132	28
Electronics	Personal Computers	64.3%	214	138	29
Electronics	Monitor	78.6%	91	71	15
Electronics	Laptops	76.3%	57	43	9
Electronics	TVs	177.4%	255	452	97
Electronics	Printer/Fax/Copier	72.6%	65	47	10
Electronics	Set top Boxes/DVRs	143.9%	128	184	39
Electronics	Devices and Gadgets	100.0%	54	54	11
Miscellaneous	Pool Pump	1.9%	2,514	49	10
Miscellaneous	Pool Heater	0.5%	4,025	19	4
Miscellaneous	Furnace Fan	58.7%	249	146	31
Miscellaneous	Well pump	9.3%	642	60	13
Miscellaneous	Miscellaneous	100.0%	744	744	159
Total				**11,919**	**2,546**

Table 3-6 Average Market Profile for the Residential Sector, 2013, Idaho

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	33.4%	1,134	379	41
Cooling	Room AC	18.6%	416	77	8
Cooling	Air-Source Heat Pump	5.3%	1,282	68	7
Cooling	Geothermal Heat Pump	0.0%	0	0	0
Cooling	Evaporative AC	1.5%	777	12	1
Space Heating	Electric Room Heat	24.2%	6,354	1,540	165
Space Heating	Electric Furnace	13.1%	8,904	1,168	126
Space Heating	Air-Source Heat Pump	5.3%	10,465	557	60
Space Heating	Geothermal Heat Pump	0.0%	0	0	0
Water Heating	Water Heater (<= 55 Gal)	49.2%	2,904	1,429	154
Water Heating	Water Heater (55 to 75 Gal)	6.2%	3,025	189	20
Water Heating	Water Heater (> 75 Gal)	0.3%	3,847	11	1
Interior Lighting	Screw-in/Hard-wire	100.0%	1,041	1,041	112
Interior Lighting	Linear Fluorescent	100.0%	129	129	14
Interior Lighting	Specialty Lighting	100.0%	243	243	26
Exterior Lighting	Screw-in/Hard-wire	100.0%	323	323	35
Appliances	Clothes Washer	85.1%	99	84	9
Appliances	Clothes Dryer	60.3%	754	454	49
Appliances	Dishwasher	77.6%	424	329	35
Appliances	Refrigerator	100.0%	789	789	85
Appliances	Freezer	52.3%	643	337	36
Appliances	Second Refrigerator	21.1%	945	199	21
Appliances	Stove	63.6%	433	275	30
Appliances	Microwave	91.2%	132	120	13
Electronics	Personal Computers	56.9%	200	114	12
Electronics	Monitor	69.6%	85	59	6
Electronics	Laptops	79.3%	53	42	5
Electronics	TVs	174.6%	248	434	47
Electronics	Printer/Fax/Copier	66.7%	61	41	4
Electronics	Set top Boxes/DVRs	92.5%	120	111	12
Electronics	Devices and Gadgets	100.0%	51	51	5
Miscellaneous	Pool Pump	1.6%	2,342	38	4
Miscellaneous	Pool Heater	0.4%	3,750	15	2
Miscellaneous	Furnace Fan	59.7%	239	142	15
Miscellaneous	Well pump	12.5%	598	75	8
Miscellaneous	Miscellaneous	100.0%	356	356	38
Total				**11,233**	**1,207**

Commercial Sector

The total electric energy consumed by commercial customers in Avista's service area in 2013 was 2,086 GWh (WA) and 976 GWh (ID). Summer peak demand was 368 MW (WA) and 167 MW (ID). Winter peak demand was 333 MW (WA) and 152 MW (ID). Avista billing data, CBSA and secondary data were used to allocate this energy usage to building type segments and to develop estimates of energy intensity (annual kWh/square foot). Using the electricity use and intensity estimates, we infer floor space which is the unit of analysis in LoadMAP for the commercial sector. The values are shown in Table 3-7 (WA) and Table 3-8 (ID).

Table 3-7 Commercial Sector Control Totals (2013), Washington

Segment	Electricity Sales (GWh)	% of Total Usage	Intensity (Annual kWh/SqFt)	Summer Peak (MW)	Winter Peak (MW)
Small Office	280	13%	15.4	71	48
Large Office	106	5%	17.5	16	19
Restaurant	70	3%	42.4	11	11
Retail	285	14%	13.8	59	43
Grocery	209	10%	47.3	33	28
College	78	4%	13.9	13	14
School	117	6%	9.9	5	13
Health	271	13%	29.1	41	39
Lodging	112	5%	16.1	14	23
Warehouse	103	5%	7.5	12	17
Miscellaneous	455	22%	13.8	93	78
Total	**2,086**	**100%**	**15.9**	**368**	**333**

Table 3-8 Commercial Sector Control Totals (2013), Idaho

Segment	Electricity Sales (GWh)	% of Total Usage	Intensity (Annual kWh/SqFt)	Summer Peak (MW)	Winter Peak (MW)
Small Office	134	14%	15.4	35	23
Large Office	17	2%	17.5	3	3
Restaurant	12	1%	42.4	2	2
Retail	168	17%	13.8	35	25
Grocery	92	9%	47.3	14	12
College	73	7%	13.9	12	13
School	109	11%	9.9	4	12
Health	106	11%	29.1	16	15
Lodging	49	5%	16.1	6	10
Warehouse	47	5%	7.5	5	8
Miscellaneous	168	17%	13.8	34	29
Total	**976**	**100%**	**14.9**	**167**	**152**

Figure 3-7 (WA) and Figure 3-8 (ID) show the distribution of annual electricity consumption and peak demand by end use across all commercial buildings. Electric usage is dominated by cooling and lighting, which comprise almost 50% of annual electricity usage. Summer peak demand is dominated by cooling and winter peak demand is dominated by heating.

Figure 3-9 (WA) and Figure 3-10 (ID) presents the electricity usage in GWh by end use and segment. Small offices, retail, and miscellaneous buildings use the most electricity in the service territory. As far as end uses, cooling and lighting are the major uses across all segments. Office equipment is concentrated more in the larger customers.

Figure 3-7 Commercial Sector Electricity Consumption by End Use (2013), Washington

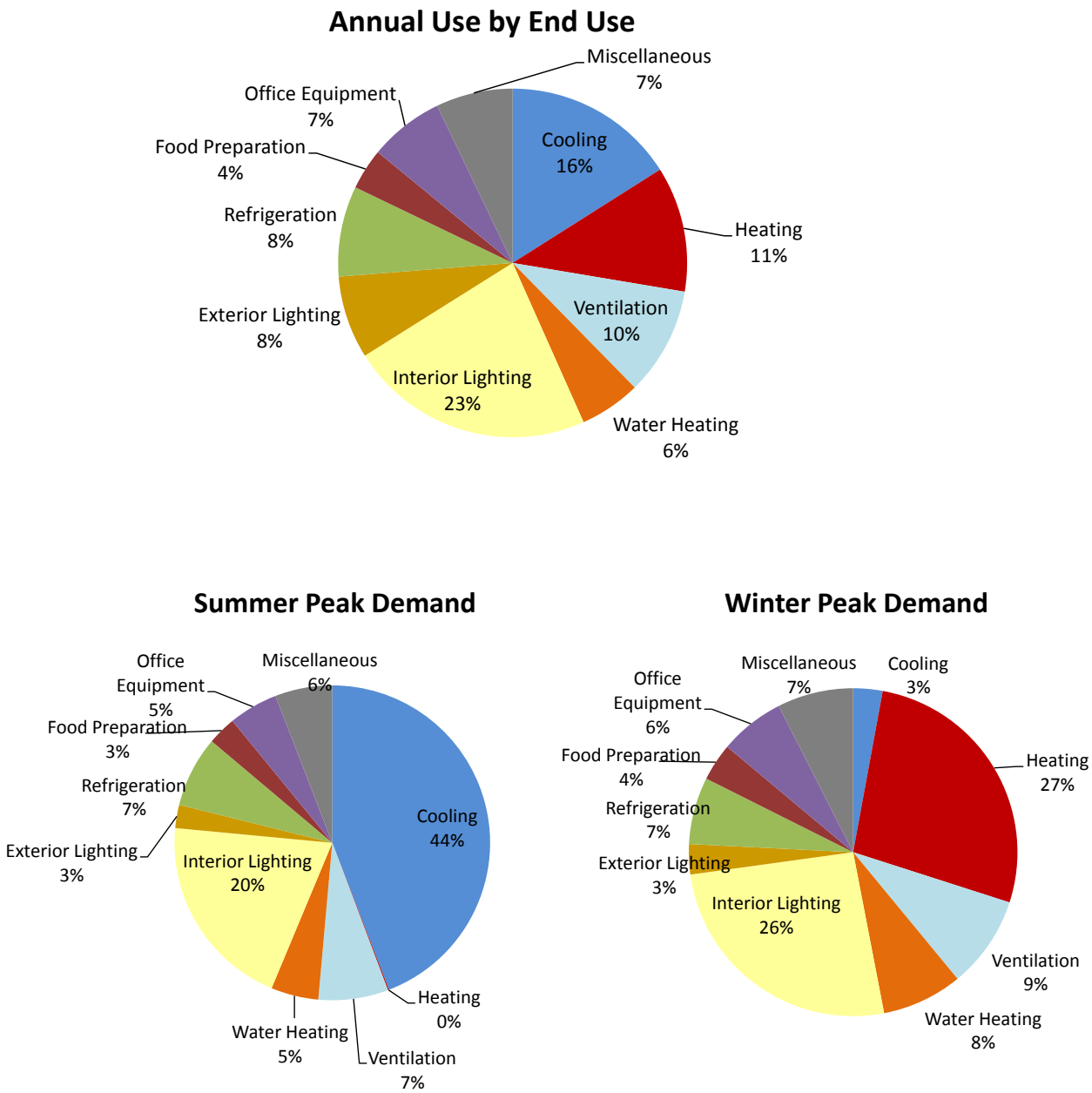
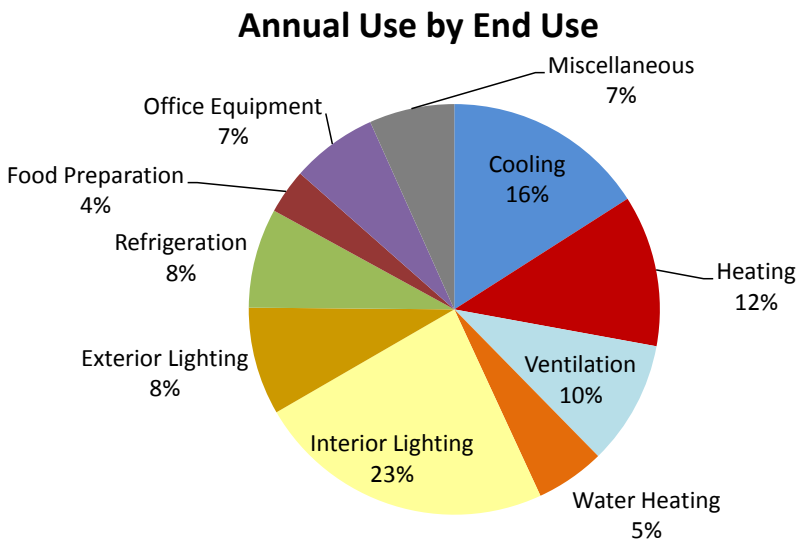
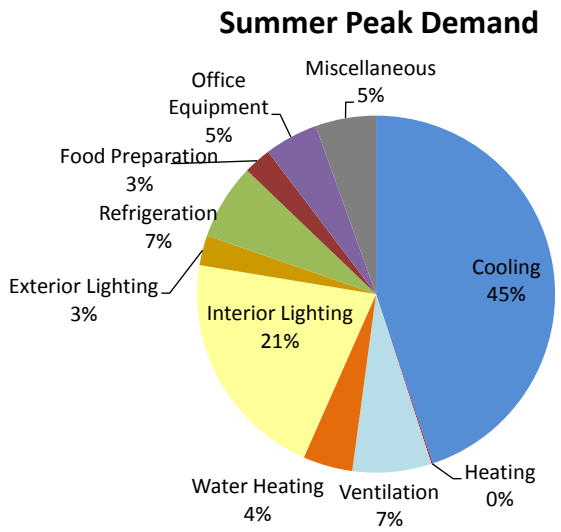


Figure 3-8 Commercial Sector Electricity Consumption by End Use (2013), Idaho





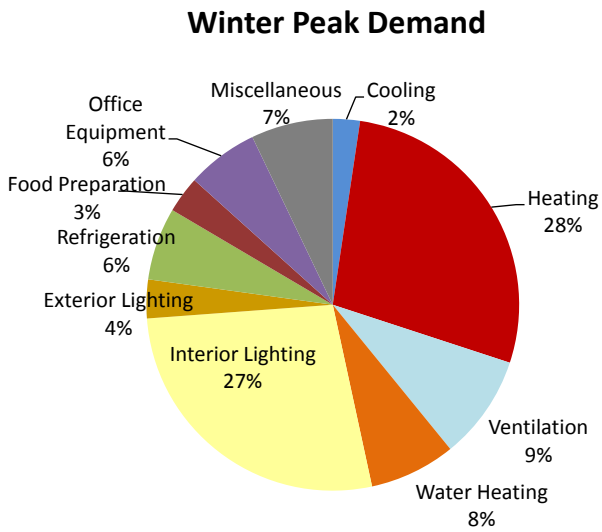


Figure 3-9 Commercial Electricity Usage by End Use Segment (GWh, 2013), Washington

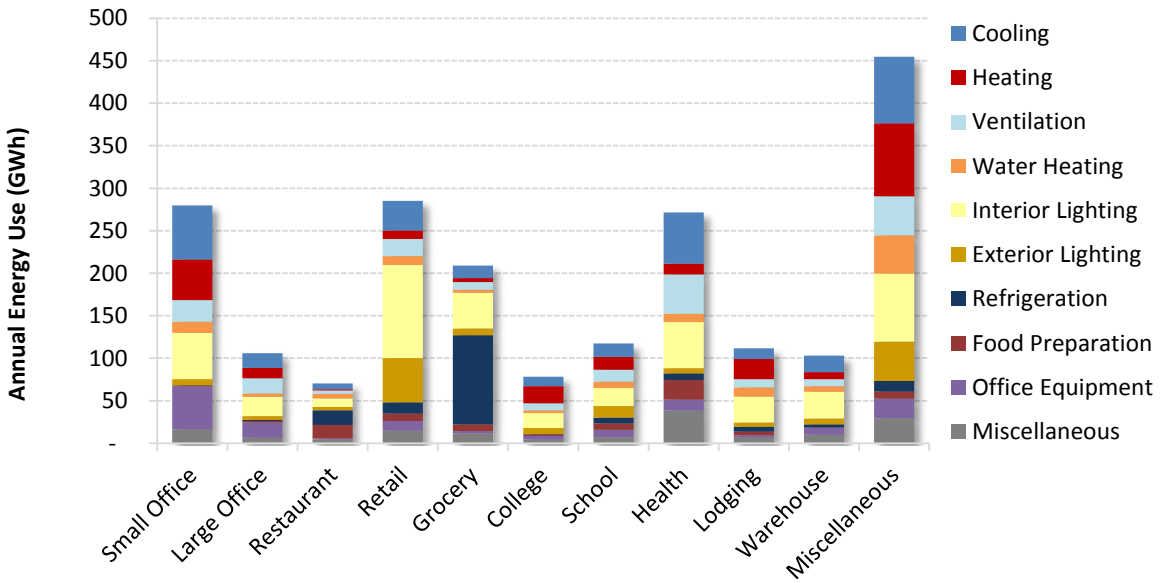


Figure 3-10 Commercial Electricity Usage by End Use Segment (GWh, 2013), Idaho

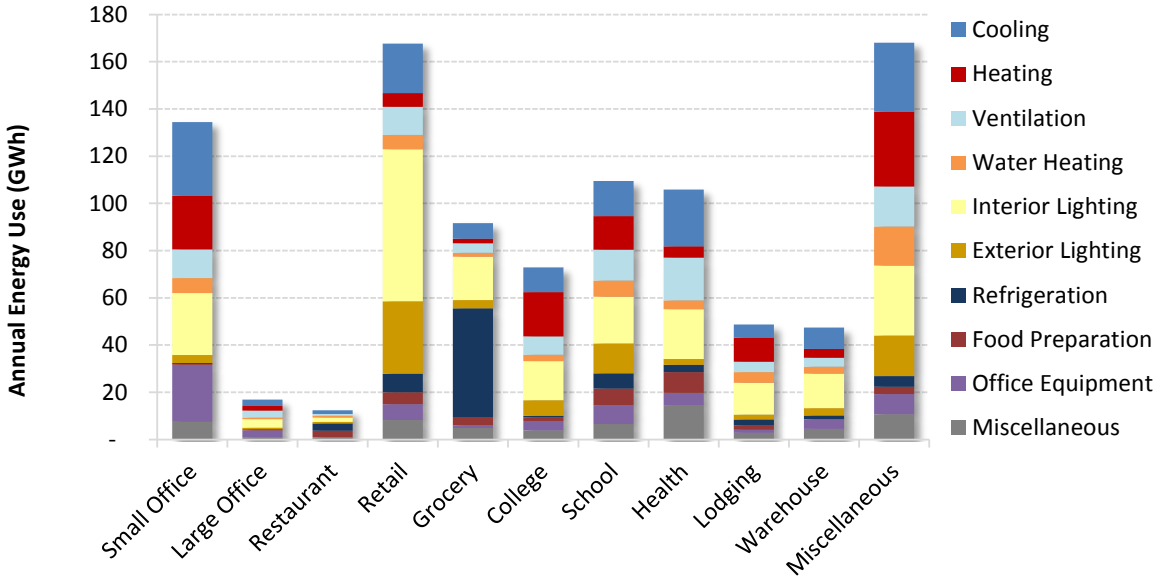


Table 3-9 (WA) and Table 3-10 (ID) show the average market profile for electricity of the commercial sector as a whole, representing a composite of all segments and buildings. Market profiles for each segment are presented in the appendix to this volume.

Table 3-9 Average Electric Market Profile for the Commercial Sector, 2013, Washington

Electric Market Profiles

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	10.3%	3.38	0.35	46.0
Cooling	Water-Cooled Chiller	12.3%	5.11	0.63	83.0
Cooling	RTU	37.5%	3.27	1.22	161.1
Cooling	Room AC	4.6%	2.93	0.13	17.5
Cooling	Air-Source Heat Pump	5.6%	3.01	0.17	22.1
Cooling	Geothermal Heat Pump	1.8%	1.85	0.03	4.4
Heating	Electric Furnace	12.7%	6.72	0.86	112.5
Heating	Electric Room Heat	7.6%	7.69	0.58	76.9
Heating	Air-Source Heat Pump	5.6%	5.87	0.33	43.1
Heating	Geothermal Heat Pump	1.8%	4.30	0.08	10.1
Ventilation	Ventilation	100.0%	1.59	1.59	209.2
Water Heating	Water Heater	53.1%	1.69	0.90	118.2
Interior Lighting	Screw-in/Hard-wire	100.0%	0.92	0.92	121.3
Interior Lighting	High-Bay Fixtures	100.0%	0.51	0.51	67.3
Interior Lighting	Linear Fluorescent	100.0%	2.17	2.17	285.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	30.0
Exterior Lighting	HID	100.0%	0.64	0.64	83.8
Exterior Lighting	Linear Fluorescent	100.0%	0.35	0.35	46.4
Refrigeration	Walk-in Refrigerator/Freezer	8.8%	1.81	0.16	21.1
Refrigeration	Reach-in Refrigerator/Freezer	12.1%	0.29	0.04	4.6
Refrigeration	Glass Door Display	15.6%	0.98	0.15	20.1
Refrigeration	Open Display Case	7.7%	9.75	0.76	99.3
Refrigeration	Icemaker	29.6%	0.54	0.16	21.2
Refrigeration	Vending Machine	20.2%	0.33	0.07	8.9
Food Preparation	Oven	15.5%	0.92	0.14	18.8
Food Preparation	Fryer	3.3%	2.63	0.09	11.4
Food Preparation	Dishwasher	16.8%	1.68	0.28	37.2
Food Preparation	Steamer	3.3%	2.23	0.07	9.6
Food Preparation	Hot Food Container	6.4%	0.32	0.02	2.7
Office Equipment	Desktop Computer	100.0%	0.62	0.62	82.2
Office Equipment	Laptop	98.8%	0.08	0.08	10.9
Office Equipment	Server	86.8%	0.20	0.17	22.9
Office Equipment	Monitor	100.0%	0.11	0.11	14.5
Office Equipment	Printer/Copier/Fax	100.0%	0.08	0.08	9.9
Office Equipment	POS Terminal	57.7%	0.05	0.03	4.0
Miscellaneous	Non-HVAC Motors	53.0%	0.19	0.10	13.2
Miscellaneous	Pool Pump	5.8%	0.02	0.00	0.2
Miscellaneous	Pool Heater	1.8%	0.03	0.00	0.1
Miscellaneous	Other Miscellaneous	100.0%	1.03	1.03	135.1
Total				**15.86**	**2,086.3**

Table 3-10 Average Electric Market Profile for the Commercial Sector, 2013, Idaho

Electric Market Profiles

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	12.4%	3.24	0.40	26.4
Cooling	Water-Cooled Chiller	10.2%	5.15	0.53	34.6
Cooling	RTU	35.6%	3.17	1.13	74.0
Cooling	Room AC	4.6%	2.77	0.13	8.4
Cooling	Air-Source Heat Pump	5.6%	2.81	0.16	10.2
Cooling	Geothermal Heat Pump	1.8%	1.68	0.03	2.0
Heating	Electric Furnace	11.5%	6.74	0.77	50.7
Heating	Electric Room Heat	7.6%	7.76	0.59	38.9
Heating	Air-Source Heat Pump	5.6%	5.91	0.33	21.5
Heating	Geothermal Heat Pump	1.8%	4.41	0.08	5.2
Ventilation	Ventilation	100.0%	1.46	1.46	95.5
Water Heating	Water Heater	51.4%	1.58	0.81	53.2
Interior Lighting	Screw-in/Hard-wire	100.0%	0.88	0.88	57.5
Interior Lighting	High-Bay Fixtures	100.0%	0.51	0.51	33.3
Interior Lighting	Linear Fluorescent	100.0%	2.11	2.11	138.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.20	0.20	13.1
Exterior Lighting	HID	100.0%	0.60	0.60	39.1
Exterior Lighting	Linear Fluorescent	100.0%	0.47	0.47	30.7
Refrigeration	Walk-in Refrigerator/Freezer	8.8%	1.30	0.11	7.5
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.26	0.04	2.3
Refrigeration	Glass Door Display	15.4%	0.85	0.13	8.6
Refrigeration	Open Display Case	8.4%	7.98	0.67	44.1
Refrigeration	Icemaker	31.6%	0.48	0.15	10.0
Refrigeration	Vending Machine	20.0%	0.32	0.06	4.1
Food Preparation	Oven	16.2%	0.86	0.14	9.1
Food Preparation	Fryer	3.1%	2.15	0.07	4.3
Food Preparation	Dishwasher	16.1%	1.49	0.24	15.7
Food Preparation	Steamer	3.1%	1.99	0.06	4.0
Food Preparation	Hot Food Container	7.4%	0.25	0.02	1.2
Office Equipment	Desktop Computer	100.0%	0.58	0.58	37.7
Office Equipment	Laptop	98.9%	0.07	0.07	4.7
Office Equipment	Server	89.1%	0.18	0.16	10.7
Office Equipment	Monitor	100.0%	0.10	0.10	6.7
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	4.7
Office Equipment	POS Terminal	57.6%	0.05	0.03	1.8
Miscellaneous	Non-HVAC Motors	51.6%	0.17	0.09	5.8
Miscellaneous	Pool Pump	5.7%	0.02	0.00	0.1
Miscellaneous	Pool Heater	1.7%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.91	0.91	59.5
Total				**14.87**	**975.5**

Industrial Sector

The total electricity used in 2013 by Avista's industrial customers was 1,265 GWh; 922 GWh (WA) and 343 GWh (ID). Summer peak demand was 336 MW; 245 MW (WA) and 91 MW (ID). Winter peak demand was 277 MW; 202 MW (WA) and 75 MW (ID). Avista billing data, load forecast and secondary sources were used to develop estimates of energy intensity (annual kWh/employee). Using the electricity use and intensity estimates, we infer the number of employees which is the unit of analysis in LoadMAP for the industrial sector. These are shown in Table 3-11.

Table 3-11 Industrial Sector Control Totals (2013)

State	Electricity Sales (GWh)	Intensity (Annual kWh/employee)	Summer Peak (MW)	Winter Peak (MW)
Washington	922	56,846	245	202
Idaho	343	38,668	91	75

Figure 3-11 shows the distribution of annual electricity consumption and summer and winter peak demand by end use for all industrial customers. Motors are the largest overall end use for the industrial sector, accounting for 54% of energy use. Note that this end use includes a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, conveyor motors, and fans. The process end use accounts for 27% of annual energy use, which includes heating, cooling, refrigeration, and electro-chemical processes. Lighting is the next highest, followed by cooling, miscellaneous, heating and ventilation.

Figure 3-11 Industrial Electricity Use by End Use (2013), All Industries, WA and ID

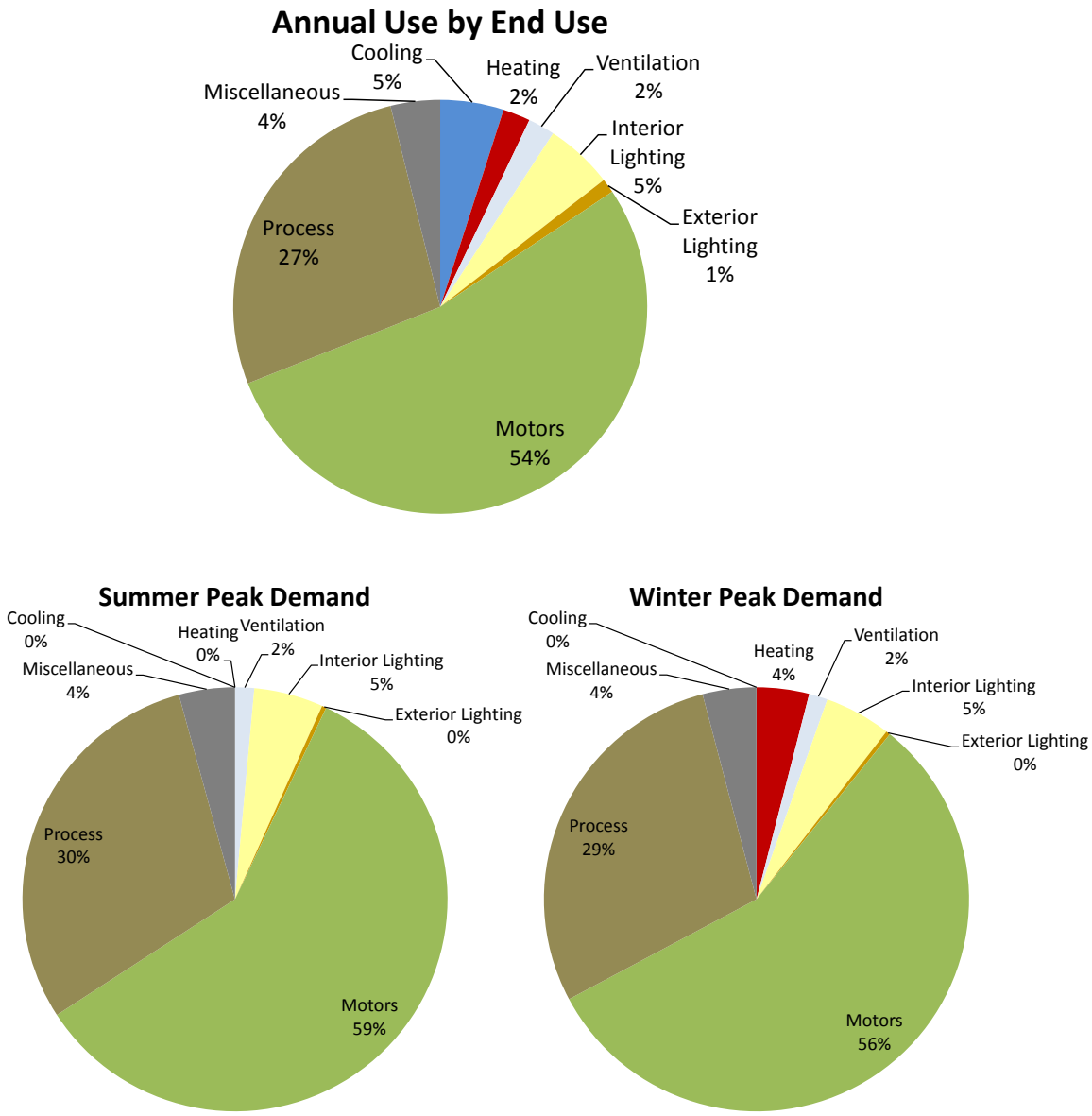


Table 3-12 (WA) and Table 3-13 (ID) show the composite market profile for the industrial sector.

Table 3-12 Average Electric Market Profile for the Industrial Sector, 2013, Washington

Average Market Profiles			
End Use	**Technology**	**Saturation**	**Usage (GWh)**
Cooling	Air-Cooled Chiller	13.0%	17.4
Cooling	Water-Cooled Chiller	1.4%	2.2
Cooling	RTU	17.0%	22.4
Cooling	Room AC	1.1%	1.5
Cooling	Air-Source Heat Pump	1.6%	2.1
Cooling	Geothermal Heat Pump	0.0%	0.0
Heating	Electric Furnace	4.9%	12.5
Heating	Electric Room Heat	1.7%	4.2
Heating	Air-Source Heat Pump	1.6%	3.1
Heating	Geothermal Heat Pump	0.0%	0.0
Ventilation	Ventilation	100.0%	19.3
Interior Lighting	Screw-in/Hard-wire	100.0%	4.9
Interior Lighting	High-Bay Fixtures	100.0%	20.4
Interior Lighting	Linear Fluorescent	100.0%	23.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	3.9
Exterior Lighting	HID	100.0%	3.2
Exterior Lighting	Linear Fluorescent	100.0%	3.2
Motors	Pumps	100.0%	86.8
Motors	Fans & Blowers	100.0%	68.0
Motors	Compressed Air	100.0%	54.3
Motors	Conveyors	100.0%	245.0
Motors	Other Motors	100.0%	38.0
Process	Process Heating	100.0%	99.2
Process	Process Cooling	100.0%	32.5
Process	Process Refrigeration	100.0%	32.5
Process	Process Electro-Chemical	100.0%	64.5
Process	Process Other	100.0%	21.8
Miscellaneous	Miscellaneous	100.0%	35.6
	Total		**922.3**

Table 3-13 Average Electric Market Profile for the Industrial Sector, 2013, Idaho

Average Market Profiles			
End Use	**Technology**	**Saturation**	**Usage (GWh)**
Cooling	Air-Cooled Chiller	13.0%	6.5
Cooling	Water-Cooled Chiller	1.4%	0.8
Cooling	RTU	17.0%	8.4
Cooling	Room AC	1.1%	0.6
Cooling	Air-Source Heat Pump	1.6%	0.8
Cooling	Geothermal Heat Pump	0.0%	0.0
Heating	Electric Furnace	4.9%	4.6
Heating	Electric Room Heat	1.7%	1.5
Heating	Air-Source Heat Pump	1.6%	1.1
Heating	Geothermal Heat Pump	0.0%	0.0
Ventilation	Ventilation	100.0%	7.2
Interior Lighting	Screw-in/Hard-wire	100.0%	1.8
Interior Lighting	High-Bay Fixtures	100.0%	7.6
Interior Lighting	Linear Fluorescent	100.0%	8.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	1.4
Exterior Lighting	HID	100.0%	1.2
Exterior Lighting	Linear Fluorescent	100.0%	1.2
Motors	Pumps	100.0%	32.3
Motors	Fans & Blowers	100.0%	25.3
Motors	Compressed Air	100.0%	20.2
Motors	Conveyors	100.0%	91.1
Motors	Other Motors	100.0%	14.1
Process	Process Heating	100.0%	36.9
Process	Process Cooling	100.0%	12.1
Process	Process Refrigeration	100.0%	12.1
Process	Process Electro-Chemical	100.0%	24.0
Process	Process Other	100.0%	8.1
Miscellaneous	Miscellaneous	100.0%	13.3
	Total		**343.0**

SECTION | 4

Baseline Projection

Prior to developing estimates of energy-efficiency potential, we developed a baseline end-use projection to quantify what the consumption is likely to be in the future and in absence of any future conservation programs. The savings from past programs are embedded in the forecast, but the baseline projection assumes that those past programs cease to exist in the future. Possible savings from future programs are captured by the potential estimates.

The baseline projection incorporates assumptions about:

- Customer population and economic growth
- Appliance/equipment standards and building codes already mandated (see Section 2)
- Forecasts of future electricity prices and other drivers of consumption
- Trends in fuel shares and appliance saturations and assumptions about miscellaneous electricity growth

Although it aligns closely with it, the baseline projection is not Avista's official load forecast. Rather it was developed to serve as the metric against which conservation potentials are measured. This chapter presents the baseline projections we developed for this study. Below, we present the baseline projections for each sector and state, which include projections of annual use in GWh and summer and winter peak demand in MW. We also present a summary across all sectors.

Please note that the base-year for the study is 2013. Annual energy use and peak demand values reflect actual weather in that year. In future years, energy use and peak demand reflect normal weather, as defined by Avista. In the figures below, the shift from actual to normal weather is apparent in the decrease in energy use and peak demand in 2014 for the residential and commercial sectors. This results from the fact that 2013 was hotter during the summer months or cooler during the winter months than normal.

Residential Sector

Annual Use

Table 4-1 (WA) and Table 4-2 (ID) present the baseline projection for electricity at the end-use level for the residential sector as a whole. Overall in Washington, residential use increases from 2,546 GWh in 2013 to 2,761 GWh in 2035, an increase of 8%. Residential use in Idaho increases from 1,207 GWh in 2013 to 1,375 GWh, an increase of 14%. This reflects a modest customer growth forecast in both states. Figure 4-1 (WA) and Figure 4-3 (ID) display the graphical representation of the baseline projection.

Figure 4-2 (WA) and Figure 4-4 (ID) present the baseline projection of annual electricity use per household. Most noticeable is that lighting use decreases throughout the time period as the lighting standards from EISA come into effect. Usage in the cooling decreases over the forecast due to going from actual weather in 2014 to normal weather for the rest of the forecast.

Table 4-1 Residential Baseline Sales Projection by End Use (GWh), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	141	92	93	93	93	96	-32%
Heating	681	702	706	713	722	743	9%
Water Heating	375	379	380	381	388	416	11%
Interior Lighting	289	244	230	196	151	140	-52%
Exterior Lighting	62	51	48	40	30	27	-56%
Appliances	569	572	571	568	567	585	3%
Electronics	211	226	229	239	262	331	57%
Miscellaneous	218	238	245	267	311	423	94%
Total	**2,546**	**2,503**	**2,500**	**2,498**	**2,523**	**2,761**	**8.4%**

Table 4-2 Residential Baseline Sales Projection by End Use (GWh), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	58	38	38	39	40	42	-26%
Heating	351	366	370	379	392	417	19%
Water Heating	175	179	180	184	190	211	20%
Interior Lighting	152	132	126	111	89	87	-43%
Exterior Lighting	35	29	28	24	18	17	-50%
Appliances	278	282	283	286	291	312	12%
Electronics	91	99	102	108	122	160	75%
Miscellaneous	67	73	76	82	96	129	92%
Total	**1,207**	**1,199**	**1,203**	**1,213**	**1,238**	**1,375**	**13.9%**

Figure 4-1 Residential Baseline Sales Projection by End Use (GWh), Washington

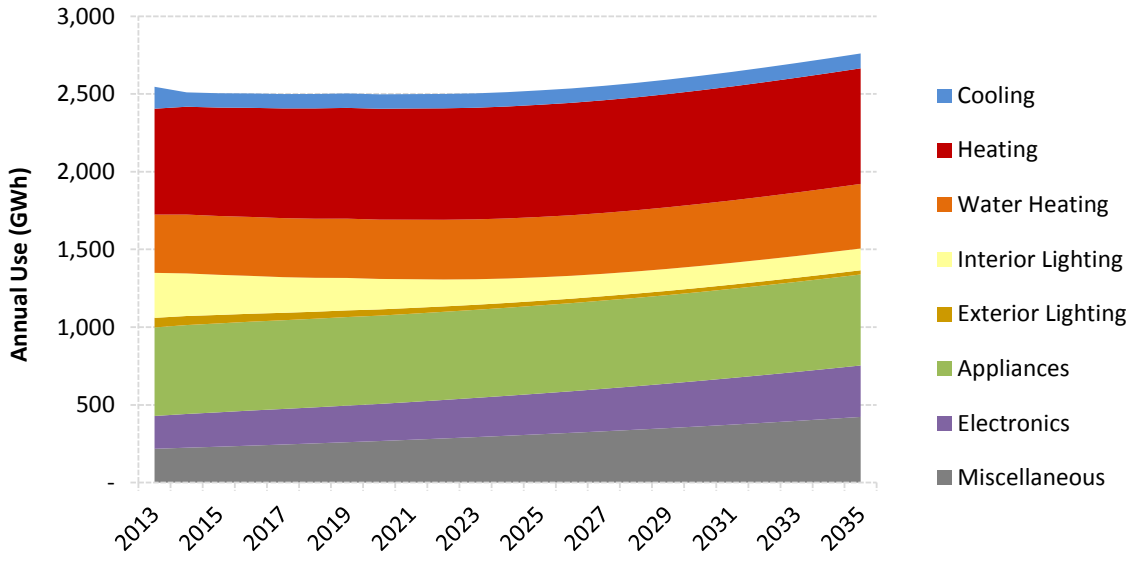


Figure 4-2 Residential Baseline Sales Projection by End Use – Annual Use per Household, Washington

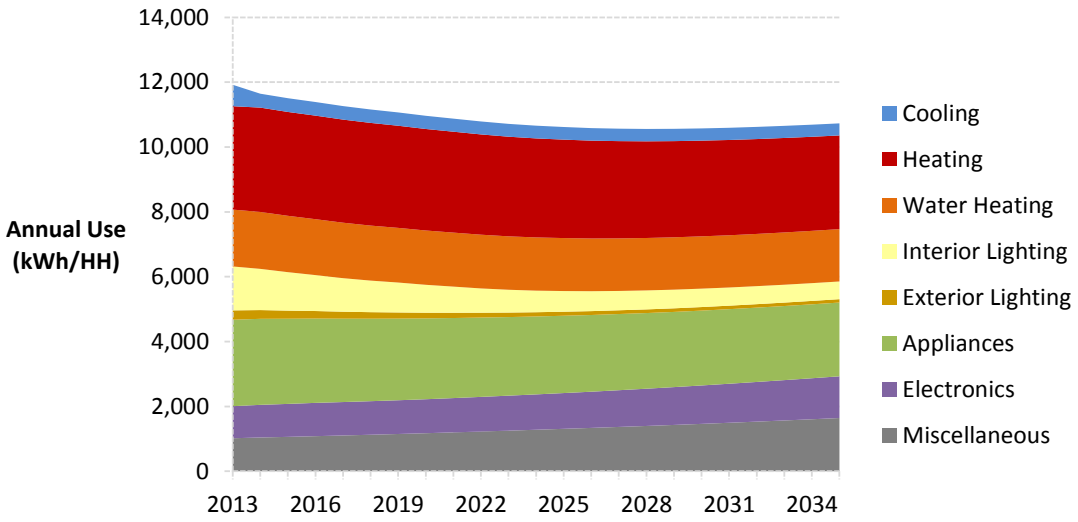


Figure 4-3 Residential Baseline Projection by End Use (GWh), Idaho

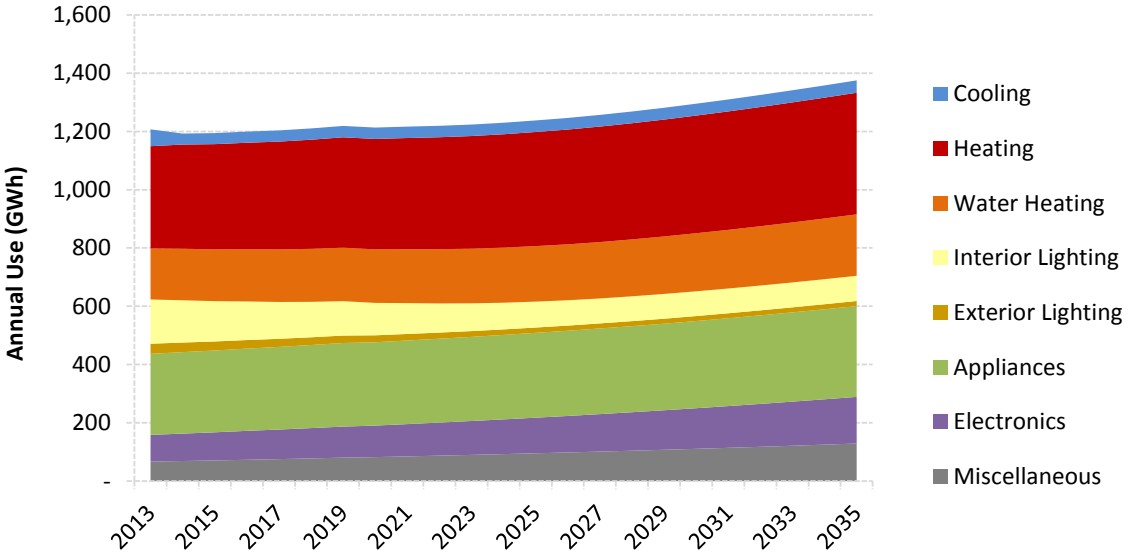
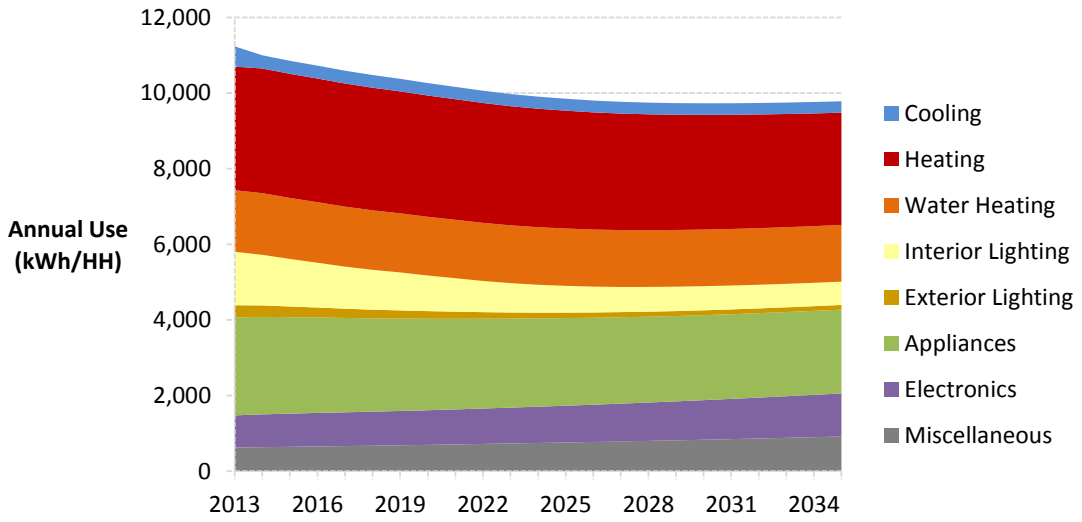


Figure 4-4 Residential Baseline Sales Projection by End Use – Annual Use per Household, Idaho



Residential Summer Peak Projection

Table 4-3 (WA) and Table 4-4 (ID) present the residential baseline projection for summer peak demand at the end-use level. Overall in Washington, residential summer peak increases from 404 MW in 2013 to 438 MW in 2035, an increase of 8%. In Idaho, the residential summer peak increases from 184 MW to 207 MW, an increase of 13%. All end uses except cooling and lighting show increases in the baseline peak projections. The summer peak associated with electronics and miscellaneous uses increases substantially, in correspondence with growth in annual energy use. Figure 4-5 (WA) and Figure 4-6 (ID) display the graphical representation of the baseline projection for summer peak. Usage in residential cooling decreases over the forecast due to going from actual weather in 2014 to weather-normal weather for the forecast.

Table 4-3 Residential Summer Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	46	30	30	30	31	32	-30%
Heating	-	-	-	-	-	-	0%
Water Heating	71	71	71	72	73	78	11%
Interior Lighting	49	41	39	33	25	24	-52%
Exterior Lighting	10	9	8	7	5	5	-56%
Appliances	141	141	141	140	140	144	2%
Electronics	44	47	48	50	54	69	57%
Miscellaneous	44	49	50	55	64	87	95%
Total	**404**	**388**	**387**	**386**	**392**	**438**	**8.3%**

Table 4-4 Residential Summer Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	19	13	13	13	13	14	-24%
Heating	-	-	-	-	-	-	0%
Water Heating	33	34	34	35	36	40	20%
Interior Lighting	25	22	21	19	15	15	-43%
Exterior Lighting	6	5	5	4	3	3	-50%
Appliances	68	69	69	69	71	75	11%
Electronics	19	21	21	23	26	34	75%
Miscellaneous	14	15	16	17	20	27	93%
Total	**184**	**178**	**179**	**180**	**183**	**207**	**12.6%**

Figure 4-5 Residential Summer Peak Baseline Projection by End Use (MW), Washington

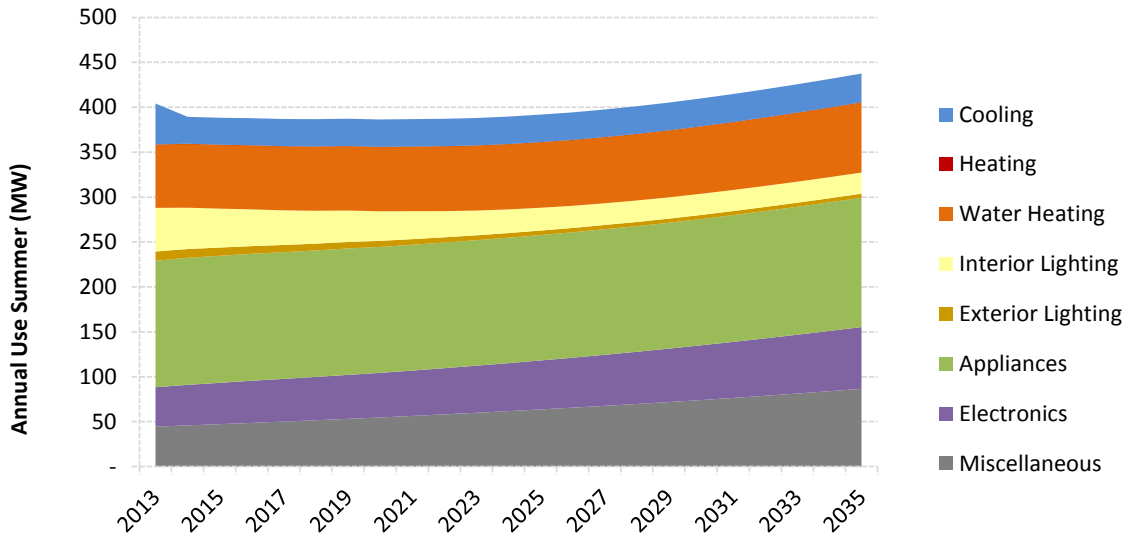
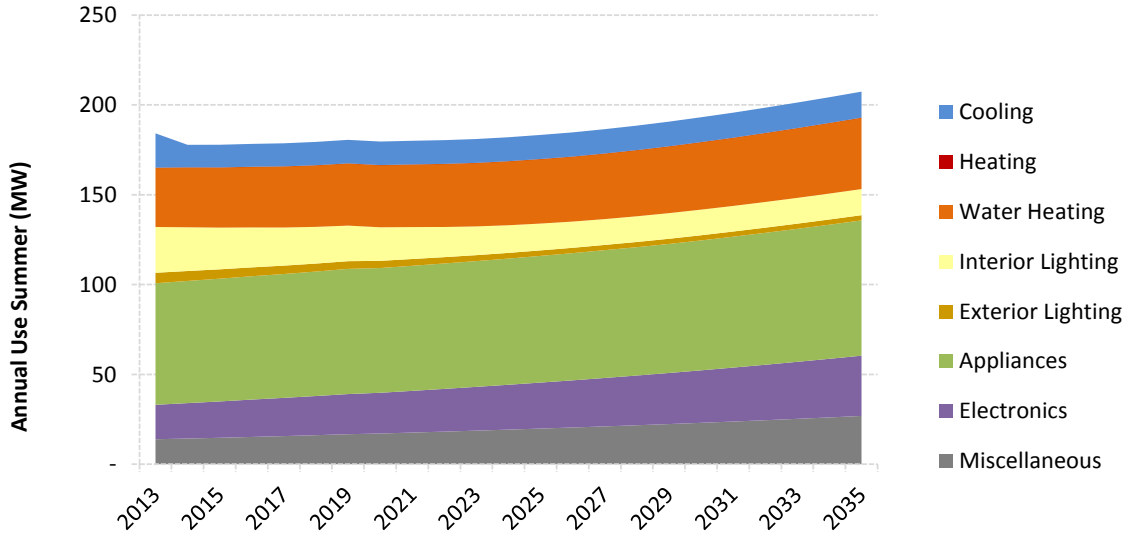


Figure 4-6 Residential Summer Peak Baseline Projection by End Use (MW), Idaho



Residential Winter Peak Projection

Table 4-5 (WA) and Table 4-6 (ID) present the residential baseline projection for winter peak demand at the end-use level. Overall in Washington, residential winter peak increases from 438 MW in 2013 to 440 MW in 2035, an increase of 0.4%. In Idaho, the residential winter peak increases from 217 MW to 233 MW, an increase of 8%. All end uses except lighting show increases in the baseline peak projections. The winter peak associated with electronics and miscellaneous uses increases substantially, in correspondence with growth in annual energy use. Figure 4-7Figure 4-5 (WA) and Figure 4-8Figure 4-6 (ID) display the graphical representation of the baseline projection for winter peak.

Table 4-5 Residential Winter Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	156	161	162	164	165	170	9%
Water Heating	66	67	67	68	69	74	11%
Interior Lighting	77	65	61	52	40	37	-52%
Exterior Lighting	16	14	13	11	8	7	-56%
Appliances	89	90	90	89	90	94	5%
Electronics	17	18	18	19	21	26	56%
Miscellaneous	16	18	18	20	23	32	96%
Total	**438**	**432**	**429**	**422**	**416**	**440**	**0.4%**

Table 4-6 Residential Winter Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	80	84	85	87	90	96	19%
Water Heating	31	32	32	33	34	37	20%
Interior Lighting	40	35	34	30	24	23	-43%
Exterior Lighting	9	8	7	6	5	5	-50%
Appliances	43	44	44	45	46	49	14%
Electronics	8	8	8	9	10	13	75%
Miscellaneous	5	6	6	6	8	10	97%
Total	**217**	**216**	**216**	**215**	**215**	**233**	**7.6%**

Figure 4-7 Residential Winter Peak Baseline Projection by End Use (MW), Washington

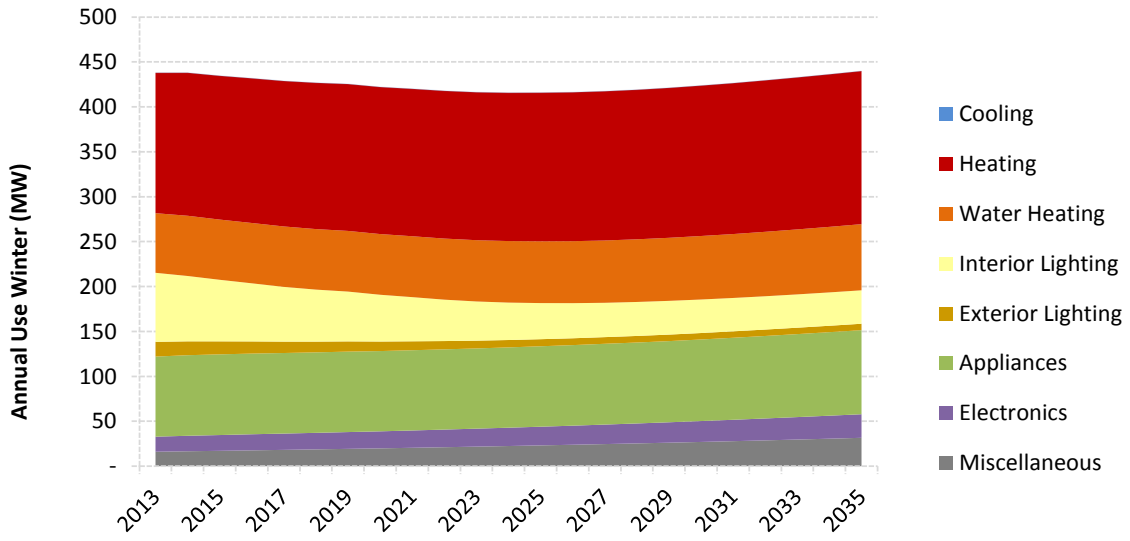
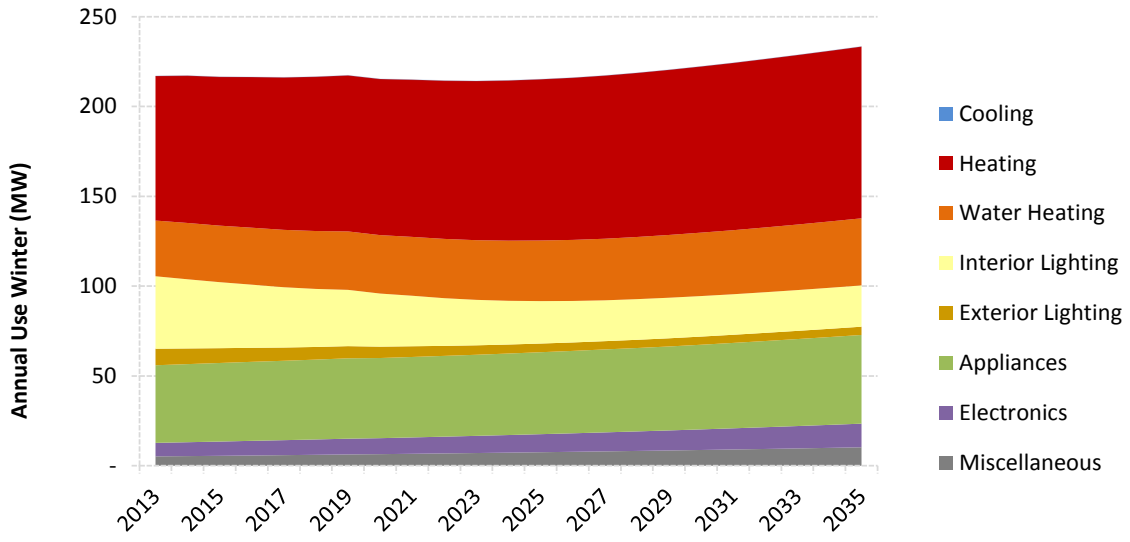


Figure 4-8 Residential Winter Peak Baseline Projection by End Use (MW), Idaho



Commercial Sector Baseline Projections

Annual Use

In Washington, annual electricity use in the commercial sector grows during the overall forecast horizon, starting at 2,086 GWh in 2013, and increasing to 2,282 in 2035, an increase of 9%. In Idaho, annual electricity use grows from 976 GWh in 2013 to 1,063 GWh in 2035, an increase of 9%. The tables and graphs below present the baseline projection at the end-use level for the commercial sector as a whole. Usage in lighting is declining throughout the forecast, due largely to the phasing in of codes and standards such as the EISA 2007 lighting standards. Usage in commercial cooling decreases over the forecast due to going from actual weather in 2014 to weather-normal weather for the forecast.

Table 4-7 Commercial Baseline Sales Projection by End Use (GWh), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change

							('13-'35)
Cooling	334	282	282	285	287	293	-12.3%
Heating	243	248	250	255	263	277	14.3%
Ventilation	209	211	212	215	217	224	6.9%
Water Heating	118	119	119	121	125	132	11.9%
Interior Lighting	474	462	460	455	452	475	0.1%
Exterior Lighting	160	146	143	133	122	121	-24.6%
Refrigeration	175	186	191	204	227	276	57.6%
Food Preparation	80	83	84	88	94	115	44.9%
Office Equipment	144	136	134	132	134	145	0.4%
Miscellaneous	149	153	155	166	184	224	51.0%
Total	**2,086**	**2,027**	**2,031**	**2,053**	**2,106**	**2,282**	**9.4%**

Table 4-8 Commercial Baseline Sales Projection by End Use (GWh), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	156	131	131	132	133	135	-13.3%
Heating	116	119	119	122	125	130	12.1%
Ventilation	96	96	97	98	98	101	5.5%
Water Heating	53	53	54	54	56	59	10.1%
Interior Lighting	229	223	222	219	217	226	-1.4%
Exterior Lighting	83	77	75	71	66	66	-20.7%
Refrigeration	77	82	84	90	100	123	61.1%
Food Preparation	34	36	37	39	42	52	50.8%
Office Equipment	66	63	62	61	62	68	2.1%
Miscellaneous	65	68	70	75	84	104	59.1%
Total	**976**	**949**	**950**	**960**	**983**	**1,063**	**9.0%**

Figure 4-9 Commercial Baseline Projection by End Use, Washington

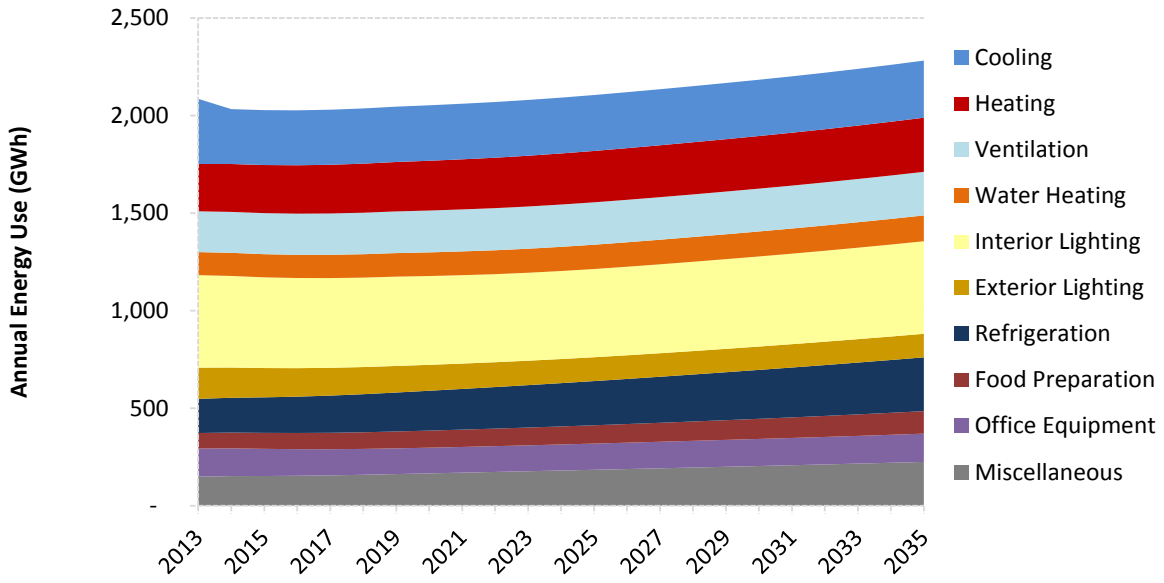
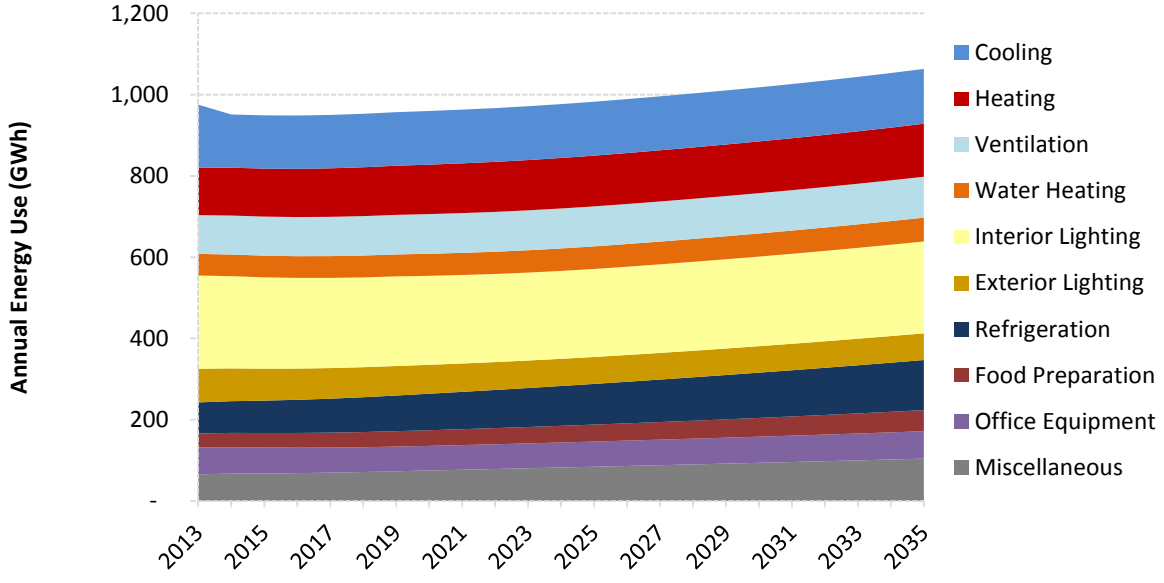


Figure 4-10 Commercial Baseline Projection by End Use, Idaho



Commercial Summer Peak Demand Projection

The tables and charts below present the summer peak baseline projection at the end-use level for the commercial sector as a whole. In Washington, summer peak demand increases during the overall forecast horizon, starting at 368 MW in 2013 and increasing by 4% to 383 MW in 2035. In Idaho, the summer peak demand is 167 MW in 2013 and 173 MW in 2035, an increase of 4%.

Table 4-9 Commercial Summer Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	162	137	137	138	139	143	-12.2%
Heating	0	0	0	0	0	0	17.5%
Ventilation	26	27	27	27	27	28	7.0%
Water Heating	18	18	18	18	19	20	13.4%
Interior Lighting	74	73	72	72	71	75	0.7%
Ext. Lighting	9	8	8	7	7	7	-24.6%
Refrigeration	27	28	29	31	35	42	57.7%
Food Prep	11	11	11	12	13	16	49.6%
Office Equip	19	18	17	17	17	19	1.4%
Miscellaneous	22	22	23	24	27	33	51.6%
Total	**368**	**342**	**343**	**347**	**356**	**383**	**4.1%**

Table 4-10 Commercial Summer Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	75	63	63	64	64	65	-12.9%
Heating	0	0	0	0	0	0	17.5%
Ventilation	12	12	12	12	12	13	5.5%
Water Heating	7	8	8	8	8	8	12.1%
Interior Lighting	35	34	34	34	33	35	-0.3%
Ext. Lighting	5	4	4	4	4	4	-20.7%
Refrigeration	11	12	13	14	15	19	62.1%
Food Prep	4	4	5	5	5	7	62.9%
Office Equip	8	8	8	7	8	8	2.6%
Miscellaneous	9	10	10	10	12	15	60.7%
Total	**167**	**155**	**156**	**157**	**161**	**173**	**3.8%**

Figure 4-11 Commercial Summer Peak Baseline Projection by End Use (MW), Washington

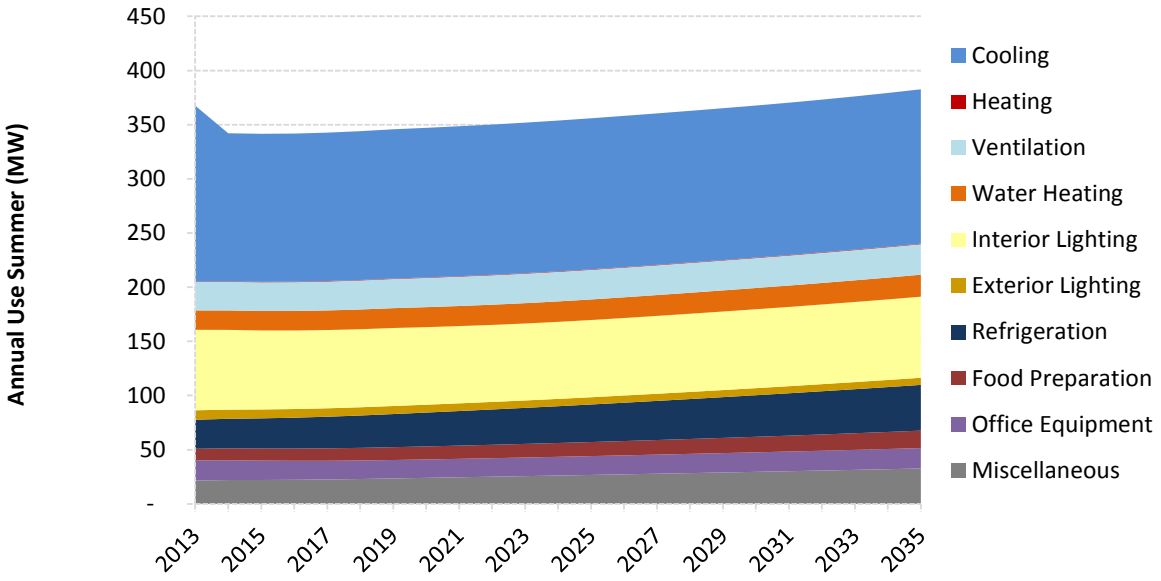
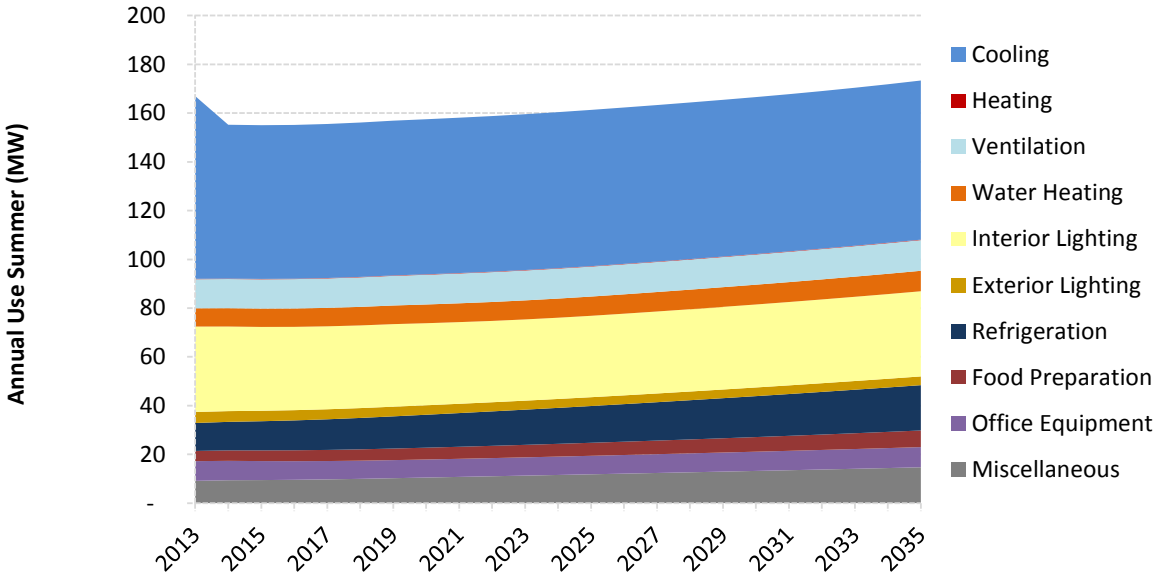


Figure 4-12 Commercial Summer Peak Baseline Projection by End Use (MW), Idaho



Commercial Winter Peak Demand Projection

The tables and charts below present the winter peak baseline projection at the end-use level for the commercial sector as a whole. In Washington, winter peak demand increases during the overall forecast horizon, starting at 333 MW in 2013 and increasing by 14% to 380 MW in 2035. In Idaho, the winter peak demand is 152 MW in 2013 and 173 MW in 2035, an increase of 14%.

Table 4-11 Commercial Winter Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	10	8	8	8	8	9	-11.4%
Heating	90	92	93	95	98	103	14.8%
Ventilation	30	31	31	31	31	32	6.9%
Water Heating	26	27	27	27	28	30	13.0%
Interior Lighting	86	84	84	83	82	86	0.4%
Ext. Lighting	10	9	9	8	8	7	-24.6%
Refrigeration	22	23	24	26	28	35	57.2%
Food Prep	12	13	13	14	15	18	49.2%
Office Equip	21	20	20	20	20	22	1.3%
Miscellaneous	25	26	26	28	31	38	51.5%
Total	**333**	**332**	**334**	**339**	**350**	**380**	**14.2%**

Table 4-12 Commercial Winter Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	4	3	3	3	3	3	-11.7%
Heating	42	43	43	44	45	48	13.0%
Ventilation	14	14	14	14	14	15	5.5%
Water Heating	11	11	11	12	12	13	11.4%
Interior Lighting	41	40	40	40	39	41	-0.9%
Ext. Lighting	5	5	5	4	4	4	-20.7%
Refrigeration	10	10	10	11	13	15	60.8%
Food Prep	5	5	5	6	6	8	61.7%
Office Equip	9	9	9	9	9	10	2.3%
Miscellaneous	11	11	12	12	14	17	60.0%
Total	**152**	**152**	**153**	**155**	**160**	**173**	**13.9%**

Figure 4-13 Commercial Winter Peak Baseline Projection by End Use (MW), Washington

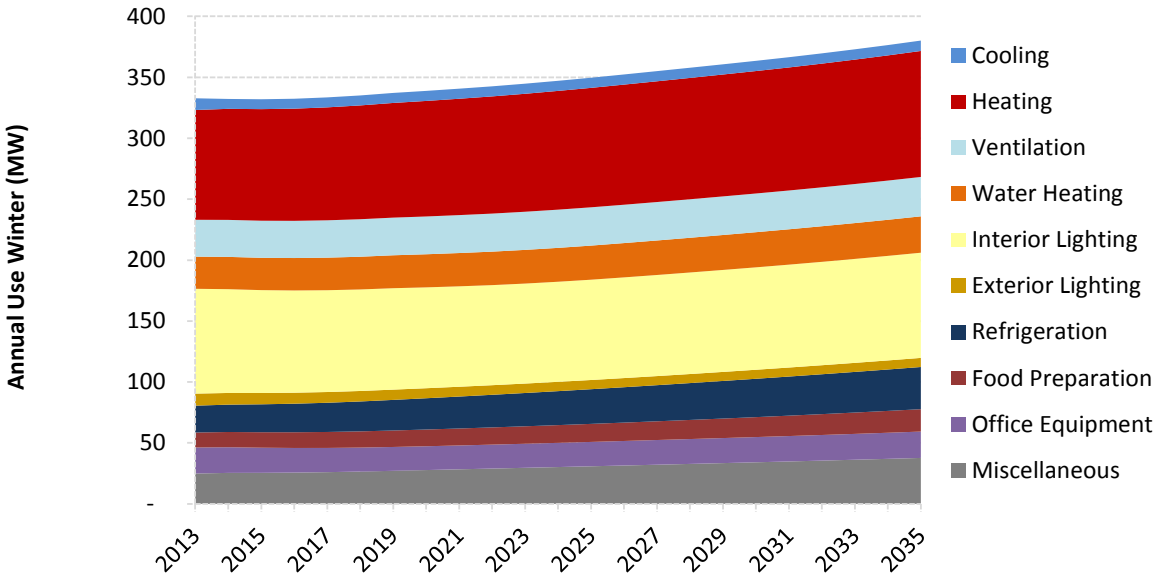
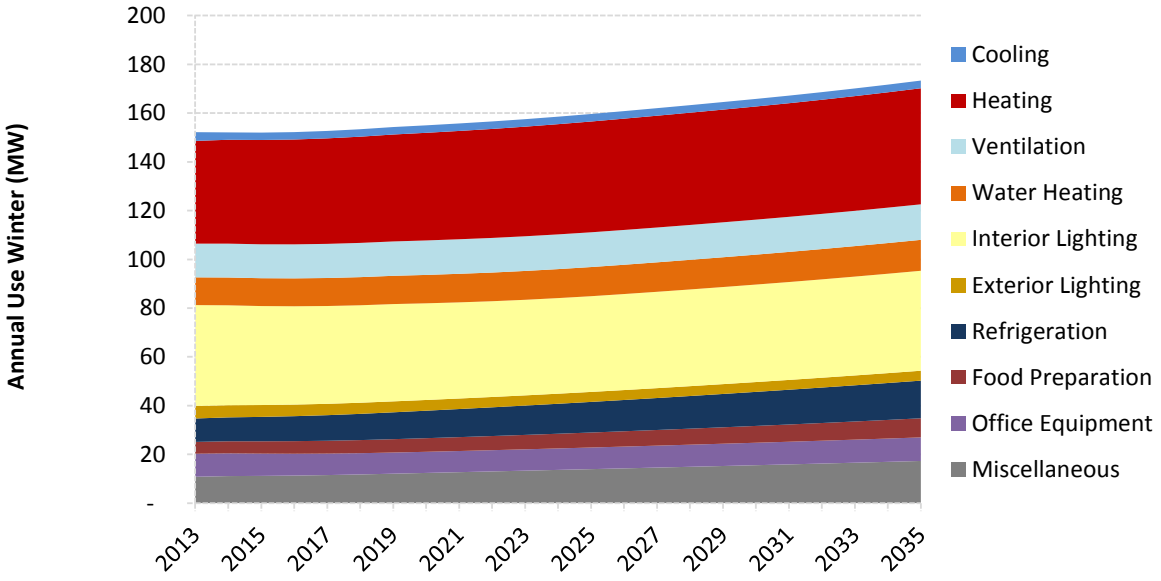


Figure 4-14 Commercial Winter Peak Baseline Projection by End Use (MW), Idaho



Industrial Sector Baseline Projections

Annual Use

Annual industrial use increases almost 25% through the forecast horizon, driven primarily by expected customer growth. The tables and graphs below present the projection at the end-use level. Overall in Washington, industrial annual electricity use increases from 922 GWh in 2013 to 1,149 GWh in 2035. In Idaho, annual electricity use increases from 343 GWh in 2013 to 426 GWh in 2035. This comprises an overall increase of 25% over the 23-year period in both states.

Table 4-13 Industrial Baseline Projection by End Use (GWh), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	46	41	41	41	42	44	-4%
Heating	20	21	22	22	23	24	23%
Ventilation	19	20	20	19	18	16	-18%
Interior Lighting	49	52	52	52	53	57	16%
Exterior Lighting	10	10	10	10	10	10	-1%
Process	492	534	540	555	578	626	27%
Motors	251	272	275	282	294	319	27%
Miscellaneous	36	40	40	42	46	53	48%
Total	**922**	**989**	**999**	**1,024**	**1,064**	**1,149**	**24.5%**

Table 4-14 Industrial Baseline Projection by End Use (GWh), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	17	15	15	15	16	16	-5%
Heating	7	8	8	8	8	9	23%
Ventilation	7	7	7	7	7	6	-18%
Interior Lighting	18	19	19	19	20	21	15%
Exterior Lighting	4	4	4	4	4	4	-1%
Process	183	198	200	206	215	232	27%
Motors	93	101	102	105	109	118	27%
Miscellaneous	13	15	15	16	17	20	48%
Total	**343**	**367**	**371**	**380**	**395**	**426**	**24.3%**

Figure 4-15 Industrial Baseline Projection by End Use (GWh), Washington

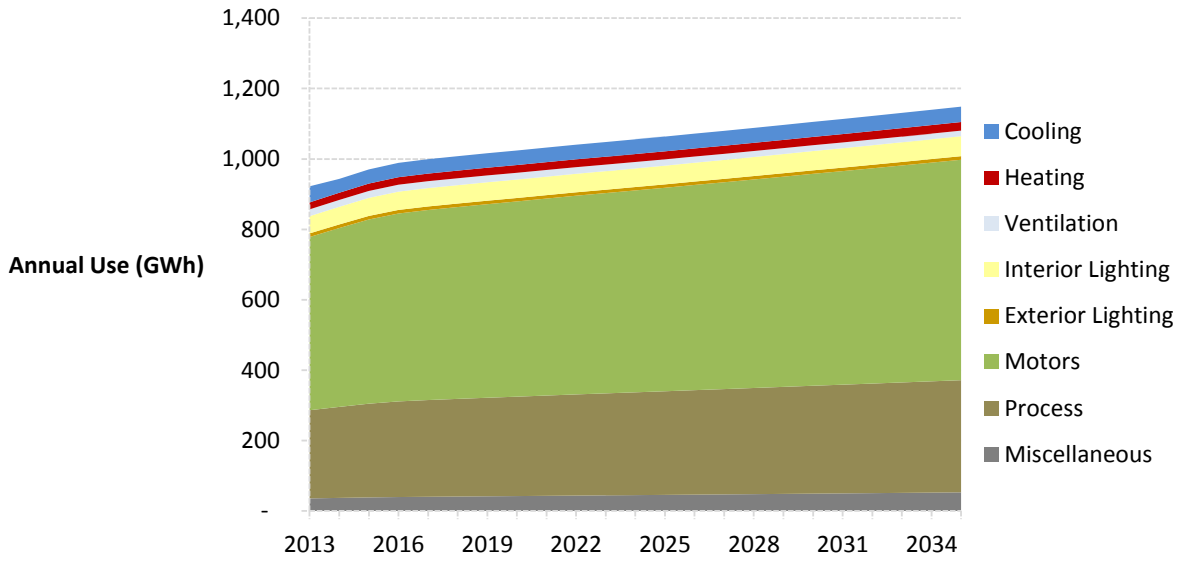
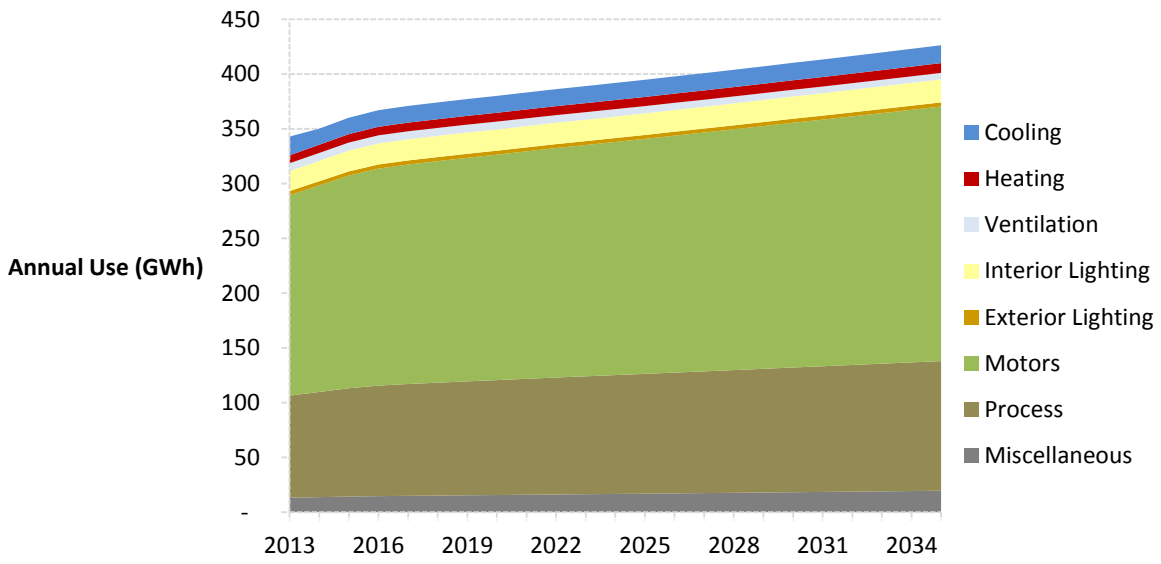


Figure 4-16 Industrial Baseline Projection by End Use (GWh), Idaho



Industrial Summer Peak Demand Projection

The tables and graphs below present the projection of summer peak demand for the industrial sector. This projection looks similar to the energy forecast largely because the industrial sector has a high load factor.

Table 4-15 Industrial Summer Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	-	-	-	-	-	-	0%
Ventilation	4	4	4	4	3	3	-18%
Interior Lighting	13	14	14	14	14	15	16%
Exterior Lighting	1	1	1	1	1	1	-1%
Process	144	156	158	162	169	183	27%
Motors	73	79	80	83	86	93	27%
Miscellaneous	10	12	12	12	13	15	48%
Total	**245**	**265**	**268**	**275**	**287**	**311**	**26.8%**

Table 4-16 Industrial Summer Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	-	-	-	-	-	-	0%
Ventilation	1	1	1	1	1	1	-18%
Interior Lighting	5	5	5	5	5	6	15%
Exterior Lighting	0	0	0	0	0	0	-1%
Process	54	58	59	60	63	68	27%
Motors	27	30	30	31	32	35	27%
Miscellaneous	4	4	4	5	5	6	48%
Total	**91**	**99**	**100**	**102**	**106**	**115**	**26.6%**

Figure 4-17 Industrial Summer Peak Baseline Projection by End Use (MW), Washington

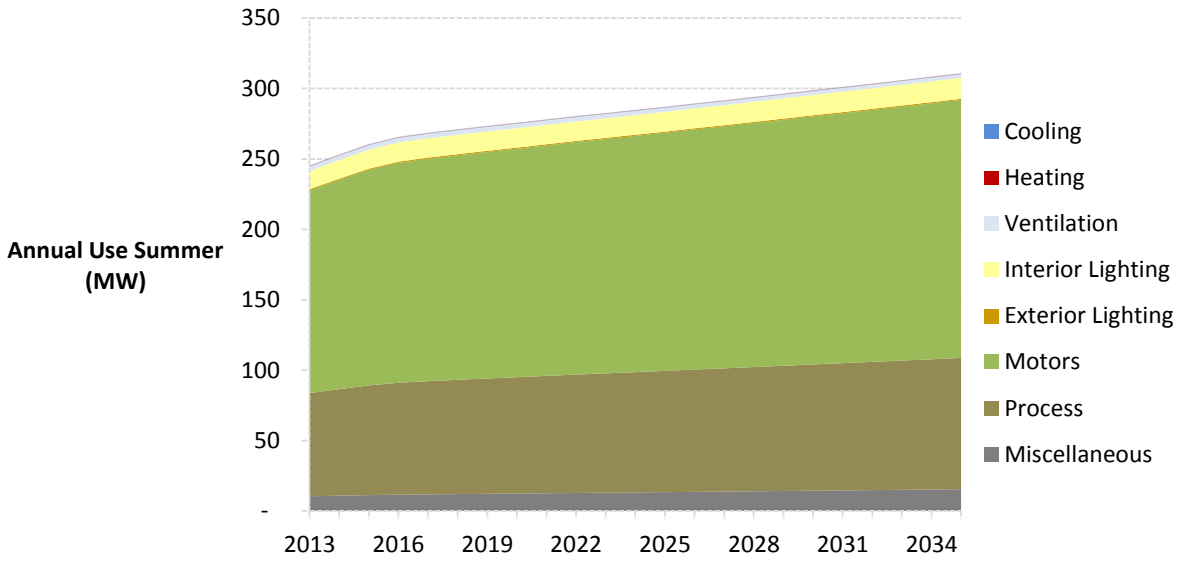
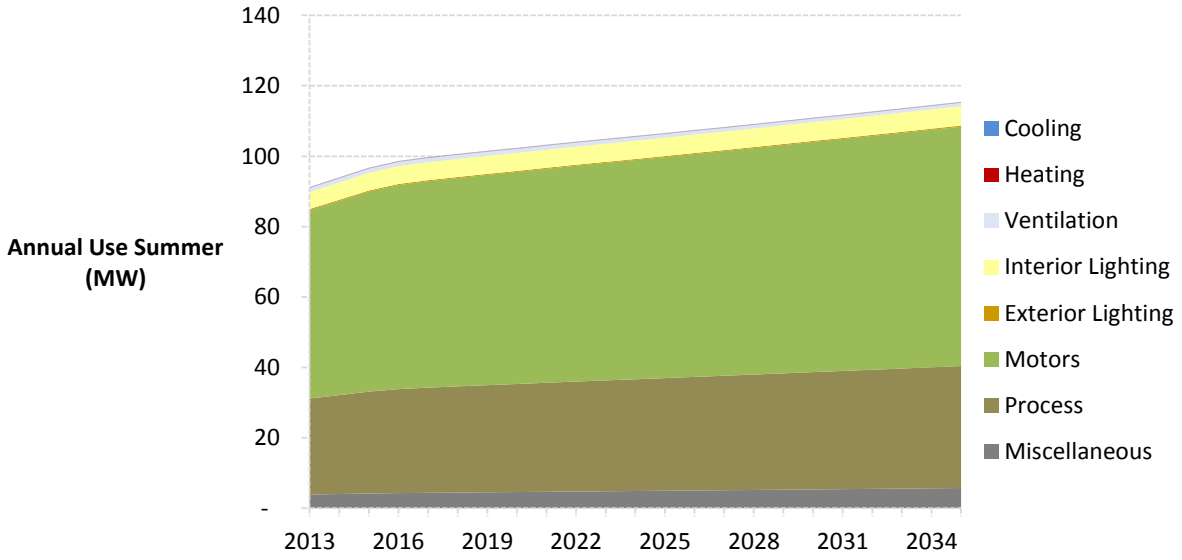


Figure 4-18 Industrial Summer Peak Baseline Projection by End Use (MW), Idaho



Industrial Winter Peak Demand Projection

The tables and graphs below present the projection of winter peak demand for the industrial sector. This projection looks similar to the energy forecast largely because the industrial sector has a high load factor.

Table 4-17 Industrial Winter Peak Baseline Projection by End Use (MW), Washington

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	8	9	9	9	9	10	23%
Ventilation	3	3	3	3	3	2	-18%
Interior Lighting	10	11	11	11	11	12	16%
Exterior Lighting	1	1	1	1	1	1	-1%
Process	114	124	125	128	134	145	27%
Motors	58	63	64	65	68	74	27%
Miscellaneous	8	9	9	10	11	12	48%
Total	**202**	**219**	**221**	**227**	**236**	**256**	**26.63%**

Table 4-18 Industrial Winter Peak Baseline Projection by End Use (MW), Idaho

End Use	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Cooling	-	-	-	-	-	-	0%
Heating	3	3	3	3	3	4	23%
Ventilation	1	1	1	1	1	1	-18%
Interior Lighting	4	4	4	4	4	4	15%
Exterior Lighting	0	0	0	0	0	0	-1%
Process	42	46	46	48	50	54	27%
Motors	22	23	24	24	25	27	27%
Miscellaneous	3	3	3	4	4	5	48%
Total	**75**	**81**	**82**	**84**	**88**	**95**	**26.42%**

Figure 4-19 Industrial Winter Peak Baseline Projection by End Use (MW), Washington

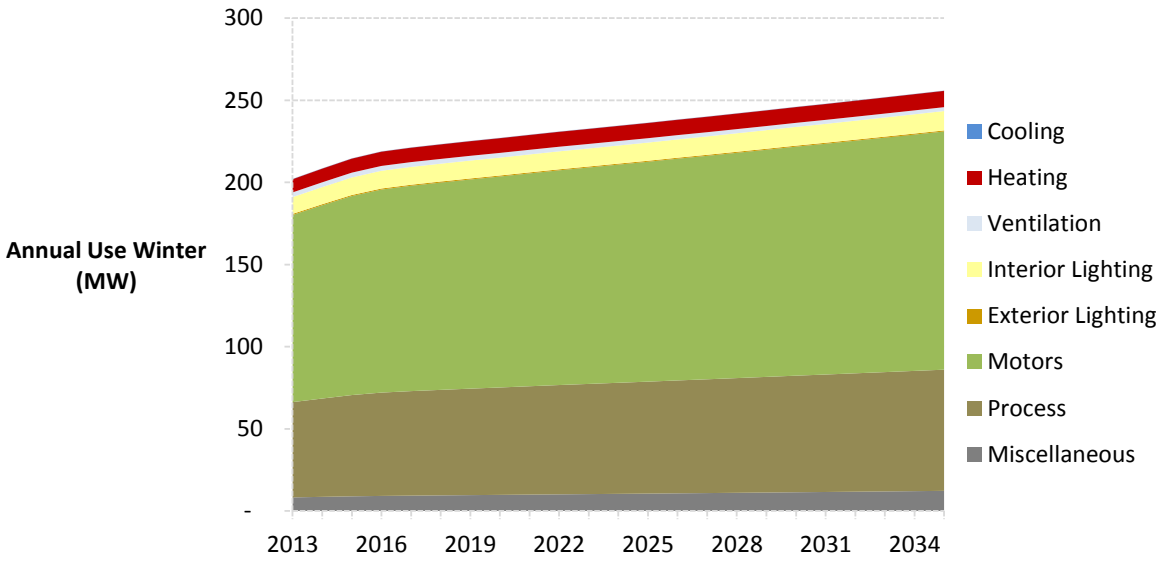
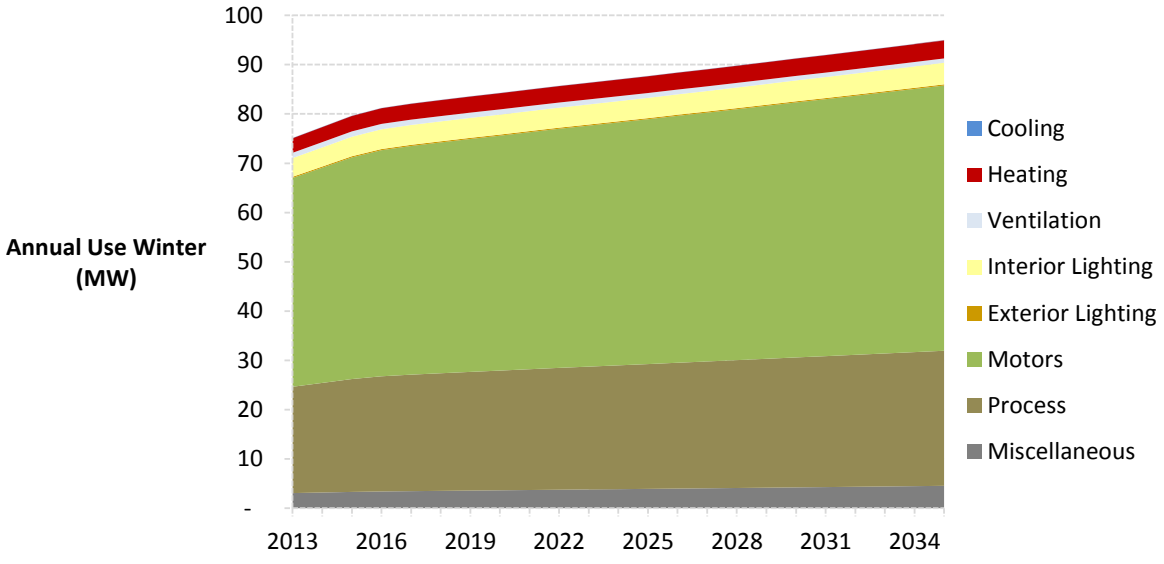


Figure 4-20 Industrial Winter Peak Baseline Projection by End Use (MW), Idaho



Summary of Baseline Projections across Sectors and States

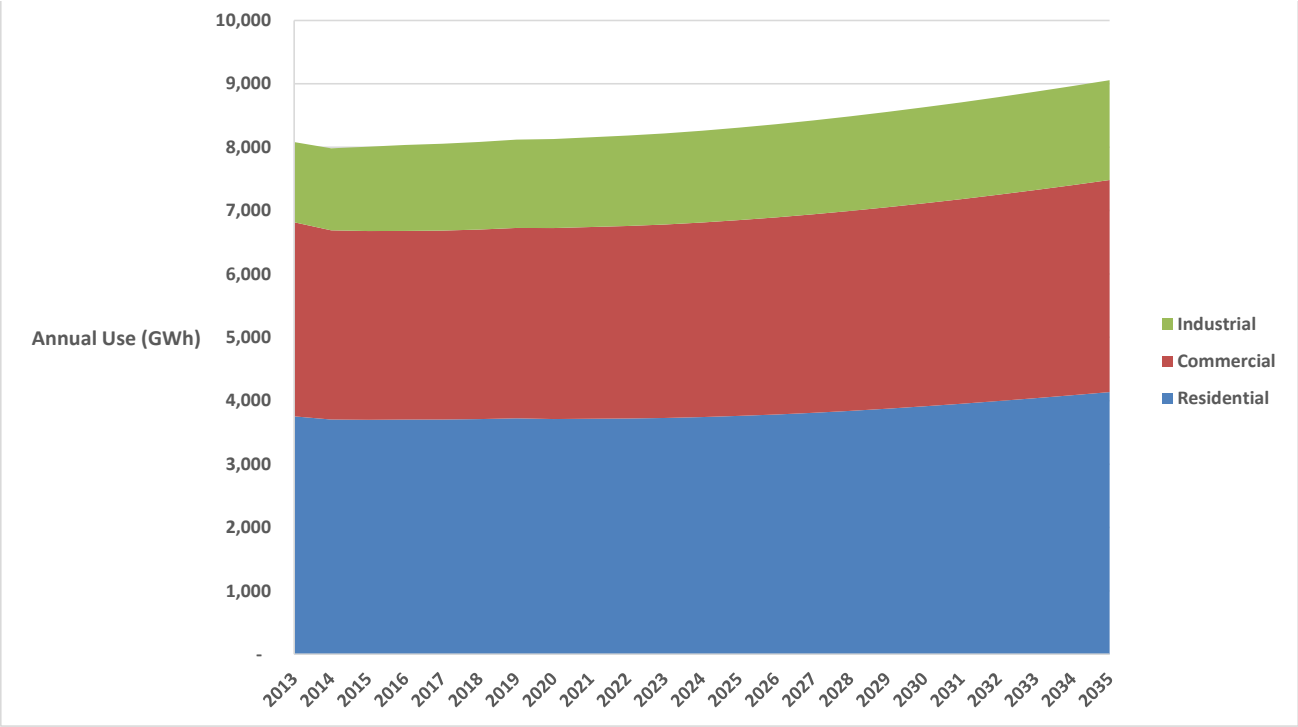
Annual Use

Table 4-19 and Figure 4-21 provide a summary of the baseline projection for annual use by sector for the entire Avista service territory. Overall, the projection shows strong growth in electricity use, driven primarily by customer growth forecasts.

Table 4-19 Baseline Projection Summary (GWh), WA and ID Combined

Sector	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Residential	3,753	3,703	3,703	3,711	3,761	4,136	10.2%
Commercial	3,062	2,976	2,981	3,013	3,089	3,346	9.3%
Industrial	1,265	1,356	1,370	1,404	1,458	1,575	24.5%
Total	**8,081**	**8,035**	**8,054**	**8,128**	**8,308**	**9,057**	**12.1%**

Figure 4-21 Baseline Projection Summary (GWh), WA and ID Combined



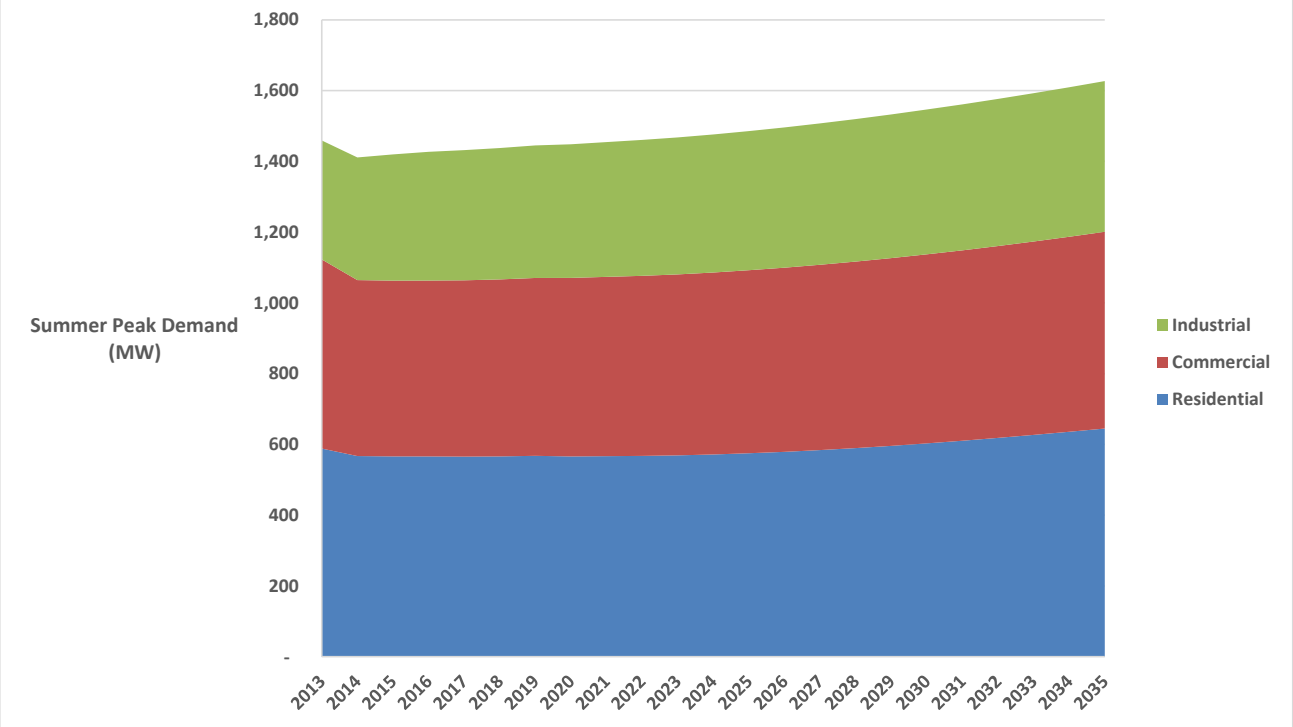
Summer Peak Demand Projection

Table 4-20 and Figure 4-22 provide a summary of the baseline projection for summer peak demand. Overall, the projection shows steady growth.

Table 4-20 Baseline Summer Peak Projection Summary (MW), WA and ID Combined

Sector	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Residential	588	566	566	566	575	645	9.6%
Commercial	535	497	498	505	517	556	4.0%
Industrial	336	364	368	378	393	426	26.7%
Total	**1,459**	**1,427**	**1,432**	**1,448**	**1,486**	**1,627**	**11.5%**

Figure 4-22 Baseline Summer Peak Projection Summary (MW), WA and ID Combined



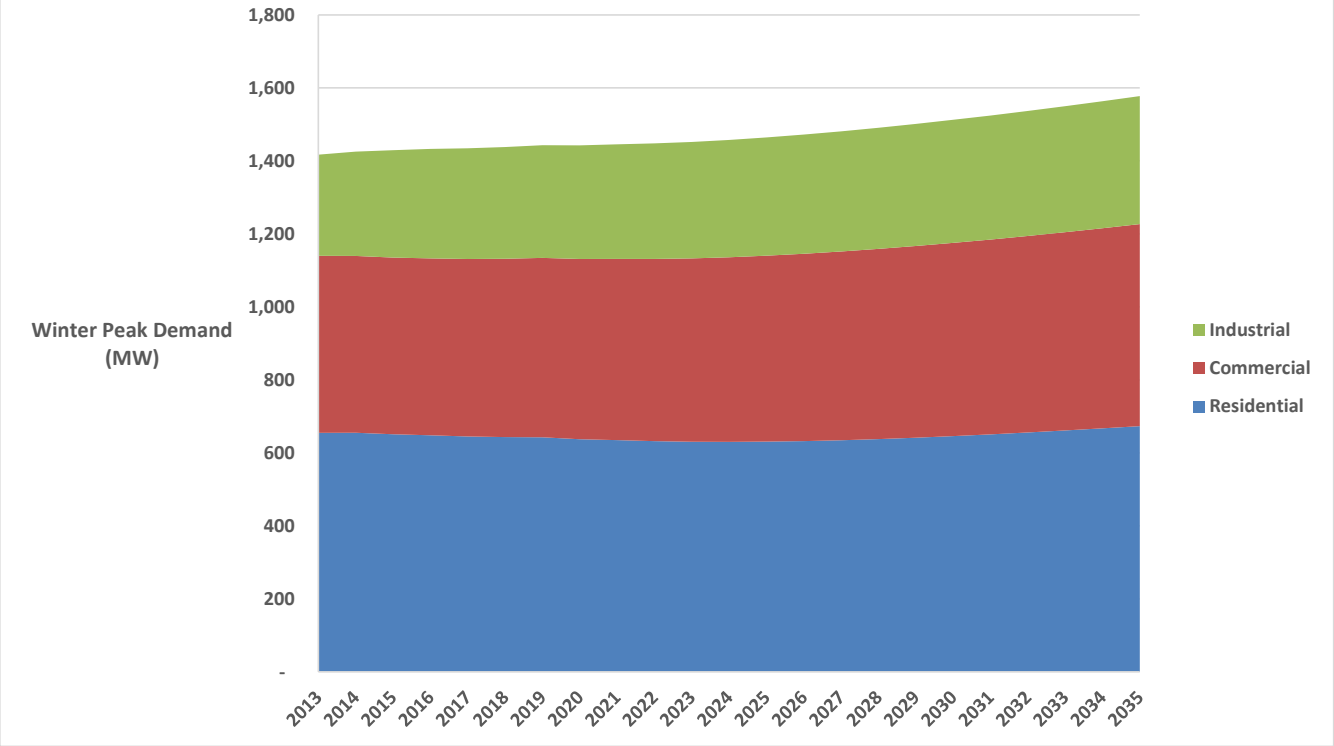
Winter Peak Demand Projection

Table 4-21Table 4-20 and Figure 4-23 provide a summary of the baseline projection for winter peak demand. Overall, the projection shows steady growth.

Table 4-21 Baseline Winter Peak Projection Summary (MW), WA and ID Combined

Sector	2013	2016	2017	2020	2025	2035	% Change ('13-'35)
Residential	655	648	645	637	631	673	2.8%
Commercial	485	485	486	494	509	554	14.1%
Industrial	277	300	303	311	324	351	26.6%
Total	**1,417**	**1,433**	**1,434**	**1,442**	**1,464**	**1,577**	**11.3%**

Figure 4-23 Baseline Winter Peak Projection Summary (MW), WA and ID Combined



SECTION | 5

Conservation Potential

This section presents the measure-level conservation potential for Avista. This includes every possible measure that is considered in the measure list, regardless of program implementation concerns.

We present the annual energy savings in GWh and aMW for selected years from conservation measures. Year-by-year savings for annual energy and peak demand are available in the LoadMAP model, which was provided to Avista at the conclusion of the study.

This section begins a summary of annual energy savings across all three sectors. Then we provide details for each sector. Please note that all savings are provided at the customer meter.

Overall Summary of Energy Efficiency Potential

Summary of Annual Energy Savings

Table 5-1 (WA) and Table 5-2 (ID) summarize the EE savings in terms of annual energy use for all measures for three levels of potential relative to the baseline projection. Figure 5-1(WA) and Figure 5-2 (ID) displays the three levels of potential by year. Figure 5-3 (WA) and Figure 5-4 (ID) display the EE projections.

- **Technical potential** reflects the adoption of all conservation measures regardless of cost-effectiveness. For Washington, first-year savings are 116 GWh, or 2.1% of the baseline projection. Cumulative savings in 2035 are 1,682 GWh, or 27.2% of the baseline. For Idaho, first-year savings are 57 GWh, or 2.2% of the baseline projection. Cumulative savings in 2035 are 824 GWh, or 28.8% of the baseline.
- **Economic potential** reflects the savings when the most efficient cost-effective measures are taken by all customers. For Washington, the first-year savings in 2016 are 45 GWh, or 0.8% of the baseline projection. By 2035, cumulative savings reach 884 GWh, or 14.3% of the baseline projection. For Idaho, the first-year savings in 2016 are 23 GWh, or 0.9% of the baseline projection. By 2035, cumulative savings reach 408 GWh, or 14.2% of the baseline projection.
- **Achievable potential** represents savings that are possible through utility programs. It shows for Washington, 23 GWh savings in the first year, or 0.4% of the baseline and by 2035 cumulative achievable savings reach 746 GWh, or 12% of the baseline projection. This results in average annual savings of 0.5% of the baseline each year. Achievable potential reflects 84% of economic potential throughout the forecast horizon. For Idaho, first year savings are 11 GWh or 0.4% of the baseline and by 2035 cumulative achievable savings reach 344 GWh, or 12% of the baseline.

Table 5-1 Summary of EE Potential (Annual Energy, GWh), Washington

	2016	2017	2020	2025	2035
Baseline projection (GWh)	5,520	5,530	5,575	5,693	6,192
Cumulative Savings (GWh)					
Achievable Potential	23	50	159	391	746
Economic Potential	45	92	242	499	884
Technical Potential	116	231	563	1,065	1,682
Cumulative Savings (aMW)					
Achievable Potential	2.6	5.7	18.1	44.6	85.2
Economic Potential	5.1	10.6	27.6	56.9	100.9
Technical Potential	13.3	26.4	64.2	121.6	192.0
Cumulative Savings as a % of Baseline					
Achievable Potential	0.4%	0.9%	2.8%	6.9%	12.0%
Economic Potential	0.8%	1.7%	4.3%	8.8%	14.3%
Technical Potential	2.1%	4.2%	10.1%	18.7%	27.2%

Table 5-2 Summary of EE Potential (Annual Energy, GWh), Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	2,515	2,525	2,553	2,615	2,865
Cumulative Savings (GWh)					
Achievable Potential	11	24	77	184	344
Economic Potential	23	46	118	234	408
Technical Potential	57	113	274	516	824
Cumulative Savings (aMW)					
Achievable Potential	1.3	2.8	8.8	21.0	39.3
Economic Potential	2.6	5.3	13.5	26.8	46.6
Technical Potential	6.5	12.9	31.3	58.9	94.1
Cumulative Savings as a % of Baseline					
Achievable Potential	0.4%	1.0%	3.0%	7.0%	12.0%
Economic Potential	0.9%	1.8%	4.6%	9.0%	14.2%
Technical Potential	2.2%	4.5%	10.7%	19.7%	28.8%

Figure 5-1 Summary of EE Potential as % of Baseline Projection (Annual Energy), Washington

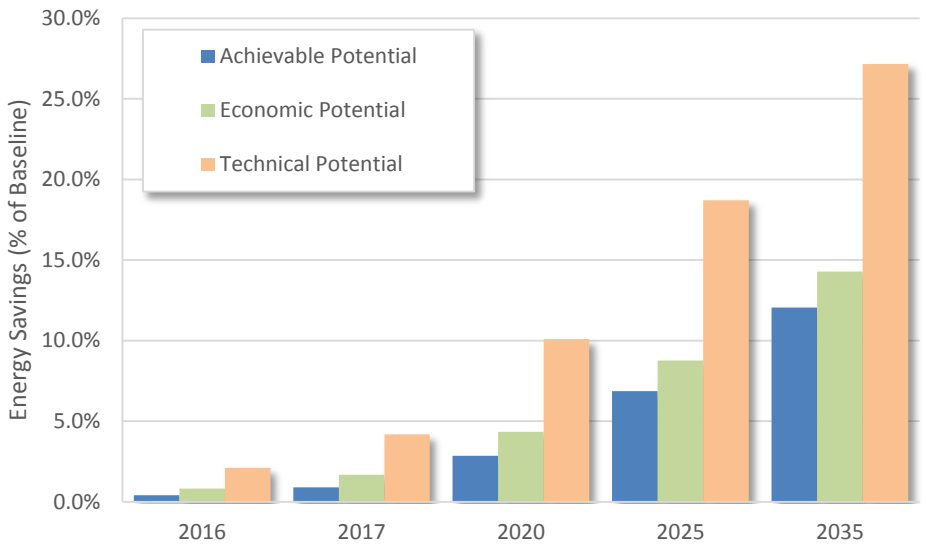


Figure 5-2 Summary of EE Potential as % of Baseline Projection (Annual Energy), Idaho

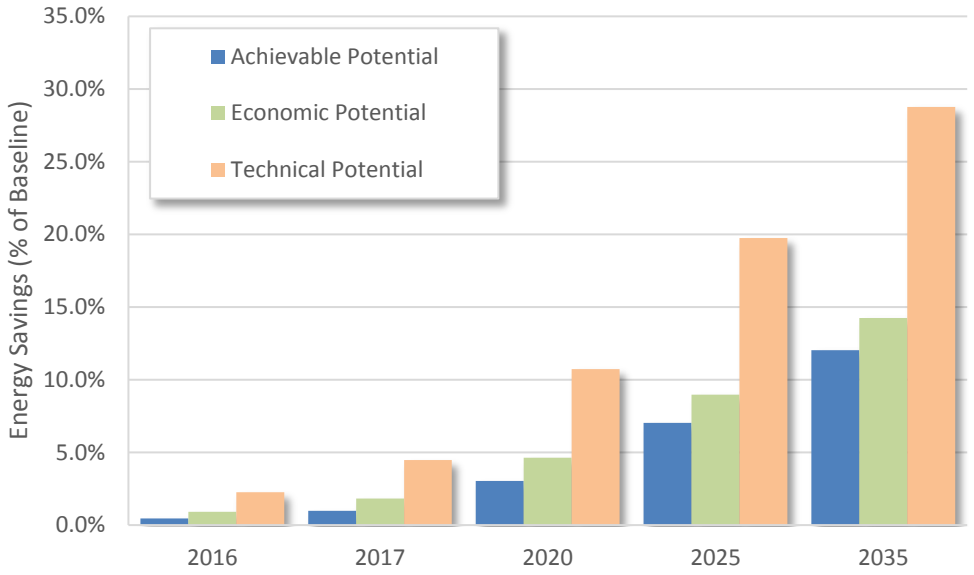


Figure 5-3 Baseline Projection and EE Forecast Summary (Annual Energy, GWh), Washington

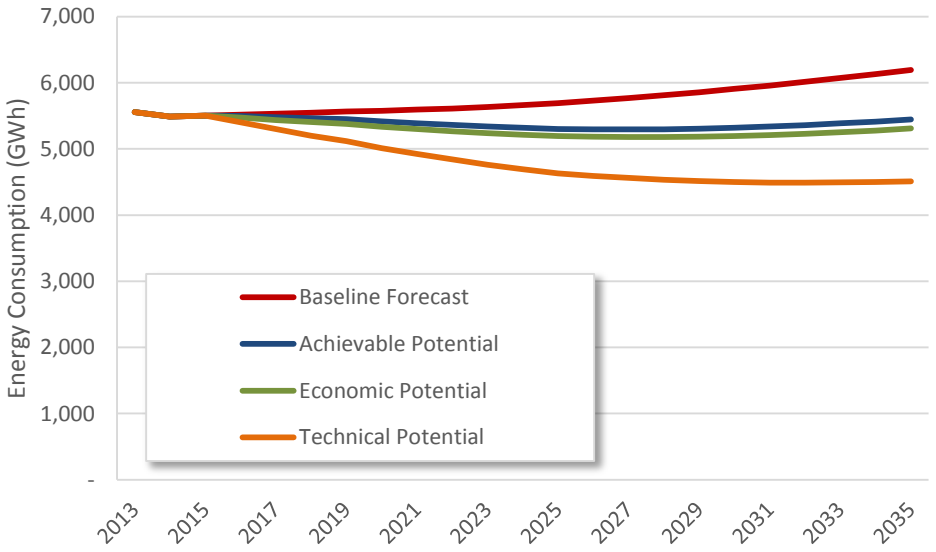
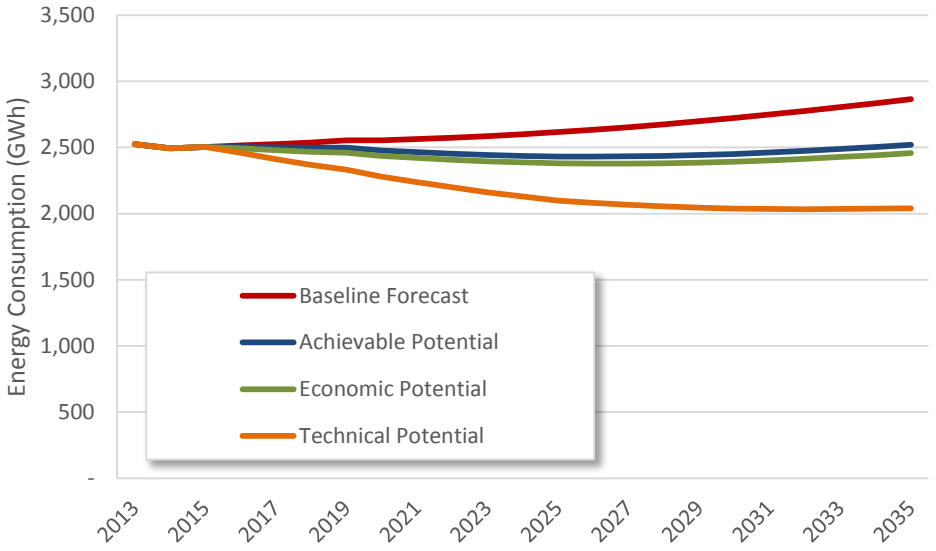


Figure 5-4 Baseline Projection and EE Forecast Summary (Annual Energy, GWh), Idaho



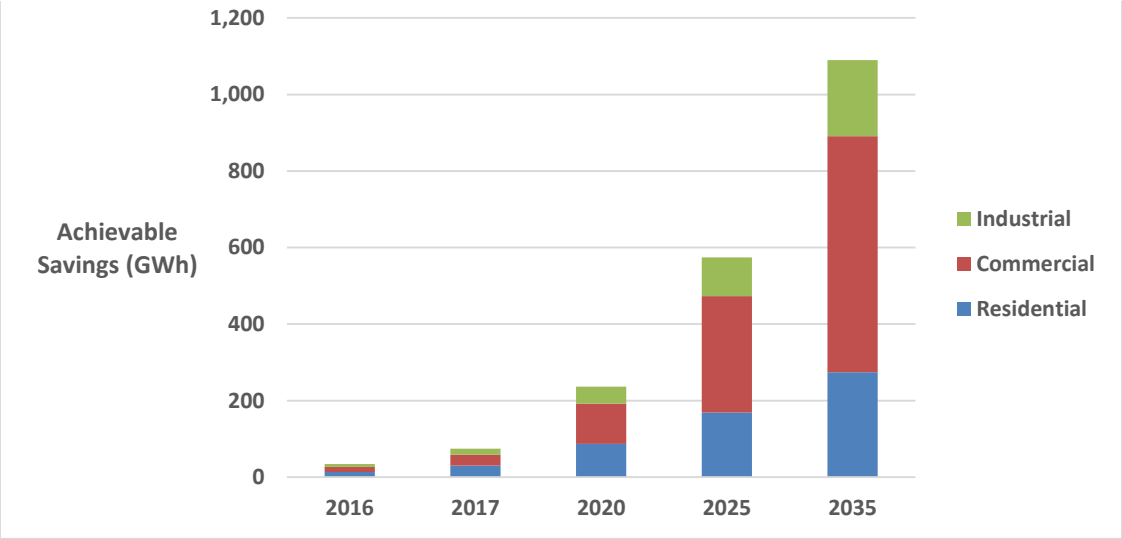
Summary of Conservation Potential by Sector

Table 5-3 and Figure 5-5 summarize the range of electric achievable potential by sector, both states combined. The residential and commercial sectors contribute the most savings in the early years, but by 2020 the commercial sector provides the most savings.

Table 5-3 Achievable Conservation Potential by Sector (Annual Use), WA and ID

	2016	2017	2020	2025	2035
Cumulative Savings (GWh)					
Residential	13	30	87	169	274
Commercial	13	28	105	304	617
Industrial	8	16	44	101	199
Total	**34**	**74**	**236**	**574**	**1,090**
Cumulative Savings (aMW)					
Residential	1.5	3.4	9.9	19.3	31.3
Commercial	1.5	3.2	12.0	34.7	70.5
Industrial	0.9	1.8	5.1	11.6	22.7
Total	3.9	8.5	27.0	65.6	124.5

Figure 5-5 Achievable Conservation Potential by Sector (Annual Energy, GWh)



Residential Conservation Potential

Table 5-4 (Total), Table 5-5 (WA) and Table 5-6 (ID) present estimates for measure-level conservation potential for the residential sector in terms of annual energy savings. Figure 5-6 (WA) and Figure 5-7 (ID) display the three levels of potential by year. For Washington, achievable potential in the first year, 2016 is 9 GWh, or 0.3% of the baseline projection. By 2035, cumulative achievable savings are 181 GWh, or 6.6% of the baseline projection. At this level, it represents over 80% of economic potential. For Idaho, first year achievable savings are 5 GWh or 0.4% of the baseline and by 2035 cumulative achievable savings reach 93 GWh, or 6.8% of the baseline.

Table 5-4 Residential Conservation Potential (Annual Energy), Washington and Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	3,703	3,703	3,711	3,761	4,136
Cumulative Net Savings (GWh)					
Achievable Potential	13	30	87	169	274
Economic Potential	29	60	137	219	334
Technical Potential	84	169	400	719	1,117
Cumulative Net Savings (aMW)					
Achievable Potential	1.5	3.4	9.9	19.3	31.3
Economic Potential	3.3	6.9	15.6	25.0	38.1
Technical Potential	9.6	19.3	45.7	82.1	127.5
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.4%	0.8%	2.3%	4.5%	6.6%
Economic Potential	0.8%	1.6%	3.7%	5.8%	8.1%
Technical Potential	2.3%	4.6%	10.8%	19.1%	27.0%

Table 5-5 Residential Conservation Potential (Annual Energy), Washington

	2016	2017	2020	2025	2035
Baseline projection (GWh)	2,503	2,500	2,498	2,523	2,761
Cumulative Net Savings (GWh)					
Achievable Potential	9	19	56	111	181
Economic Potential	19	39	88	145	221
Technical Potential	55	110	261	469	721
Cumulative Net Savings (aMW)					
Achievable Potential	1.0	2.2	6.4	12.6	20.7
Economic Potential	2.2	4.4	10.1	16.5	25.2
Technical Potential	6.3	12.6	29.8	53.6	82.3
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.3%	0.8%	2.2%	4.4%	6.6%
Economic Potential	0.8%	1.5%	3.5%	5.7%	8.0%
Technical Potential	2.2%	4.4%	10.5%	18.6%	26.1%

Table 5-6 Residential Conservation Potential (Annual Energy), Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	1,199	1,203	1,213	1,238	1,375
Cumulative Net Savings (GWh)					
Achievable Potential	5	11	31	58	93
Economic Potential	10	21	48	75	113
Technical Potential	29	59	139	250	395
Cumulative Net Savings (aMW)					
Achievable Potential	0.5	1.2	3.5	6.6	10.6
Economic Potential	1.2	2.4	5.5	8.5	12.9
Technical Potential	3.3	6.7	15.9	28.5	45.1
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.4%	0.9%	2.5%	4.7%	6.8%
Economic Potential	0.9%	1.8%	4.0%	6.0%	8.2%
Technical Potential	2.4%	4.9%	11.5%	20.2%	28.8%

Figure 5-6 Residential Conservation Savings as a % of the Baseline Projection (Annual Energy), Washington

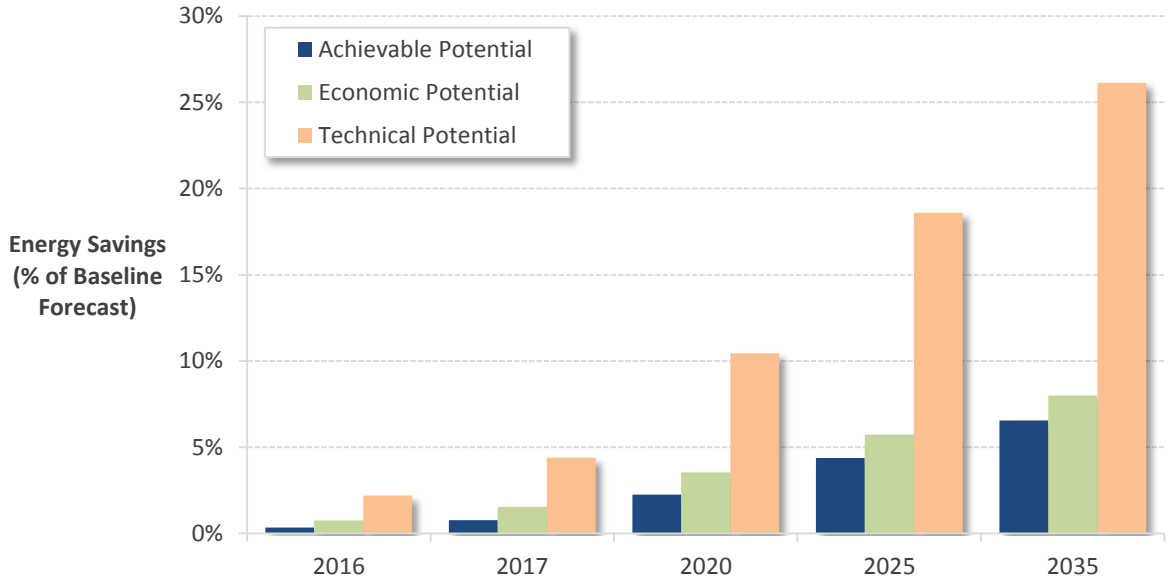
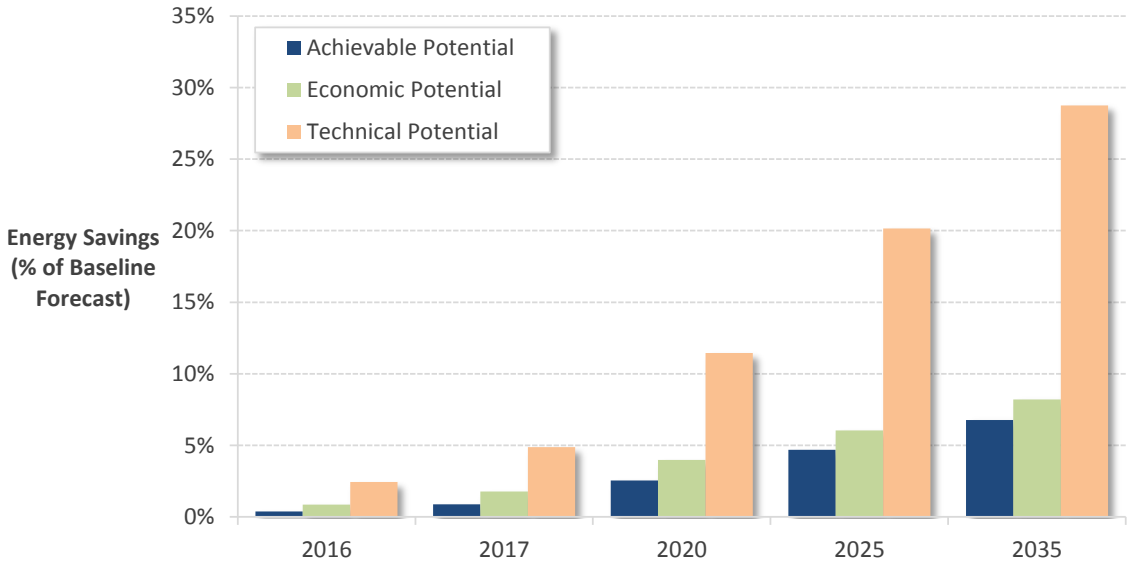


Figure 5-7 Residential Conservation Savings as a % of the Baseline Projection (Annual Energy), Idaho



Below, we present the top residential measures from the perspective of annual energy use. We first present information for both states, followed by Washington-only results and Idaho-only results.

Table 5-7 identifies the top 20 residential measures from the perspective of annual energy savings in 2017 for Washington and Idaho combined. The top three measures include interior and exterior lighting measures and repair and sealing of ducting. The lighting measures are a result of purchases of LED lamps which are cost effective throughout the forecast horizon.

Table 5-7 Residential Top Measures in 2017 (Annual Energy, MWh), Washington and Idaho

Rank	Residential Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Screw-in/Hard-wire	13,616	46%
2	Ducting - Repair and Sealing	5,057	17%
3	Exterior Lighting - Screw-in/Hard-wire	4,152	14%
4	Water Heater - Pipe Insulation	2,264	8%
5	Water Heater - Faucet Aerators	1,037	3%
6	Behavioral Programs	688	2%
7	Thermostat - Clock/Programmable	674	2%
8	Insulation - Ducting	621	2%
9	Water Heater - Low-Flow Showerheads	419	1%
10	Electronics - Personal Computers	285	1%
11	Appliances - Freezer	272	1%
12	Water Heater - Drainwater Heat Recovery	241	1%
13	Miscellaneous - Pool Pump	172	1%
14	Appliances - Second Refrigerator	169	1%
15	Electronics - Laptops	77	0%
16	Appliances - Refrigerator	56	0%
17	Water Heating - Water Heater (55 to 75 Gal)	36	0%
18	Water Heater - Desuperheater	17	0%
19	Electronics - Monitor	13	0%
20	Electronics - TVs	7	0%
Total	**Total**	**29,875**	**100.0%**

Table 5-8 identifies the top 20 residential measures from the perspective of annual energy savings in 2017 for Washington. The top three measures include interior and exterior lighting measures and repair and sealing of ducting. The lighting measures are a result of purchases of LED lamps which are cost effective throughout the forecast horizon.

Table 5-8 Residential Top Measures in 2017 (Annual Energy, MWh), Washington

Rank	Residential Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Screw-in/Hard-wire	8,479	44.0%
2	Ducting - Repair and Sealing	3,483	18.1%
3	Exterior Lighting - Screw-in/Hard-wire	2,564	13.3%
4	Water Heater - Pipe Insulation	1,535	8.0%
5	Water Heater - Faucet Aerators	699	3.6%
6	Behavioral Programs	464	2.4%
7	Thermostat - Clock/Programmable	443	2.3%
8	Insulation - Ducting	429	2.2%
9	Water Heater - Low-Flow Showerheads	284	1.5%
10	Electronics - Personal Computers	199	1.0%
11	Appliances - Freezer	177	0.9%
12	Water Heater - Drainwater Heat Recovery	157	0.8%
13	Miscellaneous - Pool Pump	121	0.6%
14	Appliances - Second Refrigerator	110	0.6%
15	Electronics - Laptops	51	0.3%
16	Appliances - Refrigerator	36	0.2%
17	Water Heating - Water Heater (55 to 75 Gal)	24	0.1%
18	Water Heater - Desuperheater	12	0.1%
19	Electronics - Monitor	9	0.0%
20	Electronics - TVs	5	0.0%
Total	**Total**	**19,280**	**100.0%**

Figure 5-8 presents forecasts of cumulative energy savings for Washington. Lighting savings account for a substantial portion of the savings throughout the forecast horizon. The same is true for exterior lighting. Savings from heating measures and appliances are steadily increasing throughout the forecast horizon.

Figure 5-8 Residential Achievable Savings Forecast (Cumulative GWh), Washington

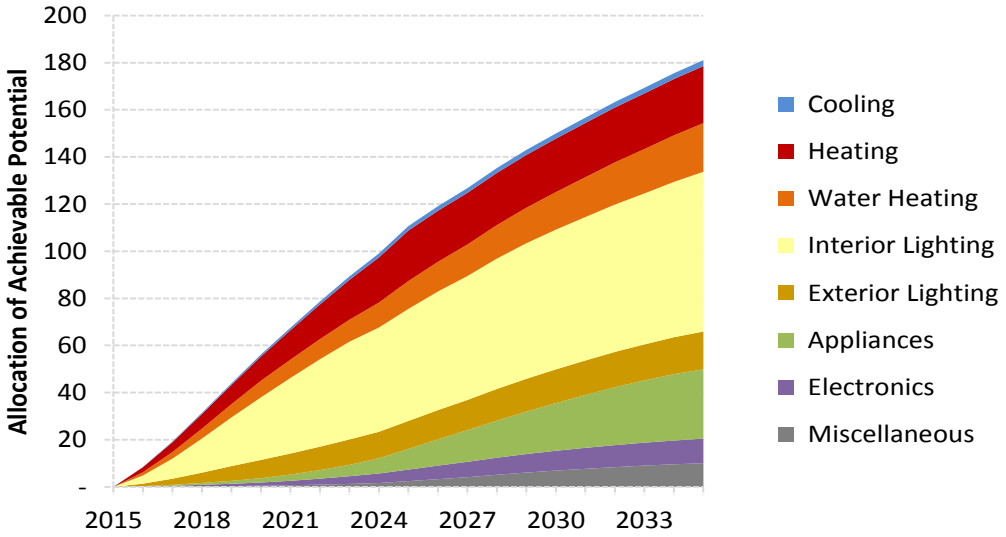


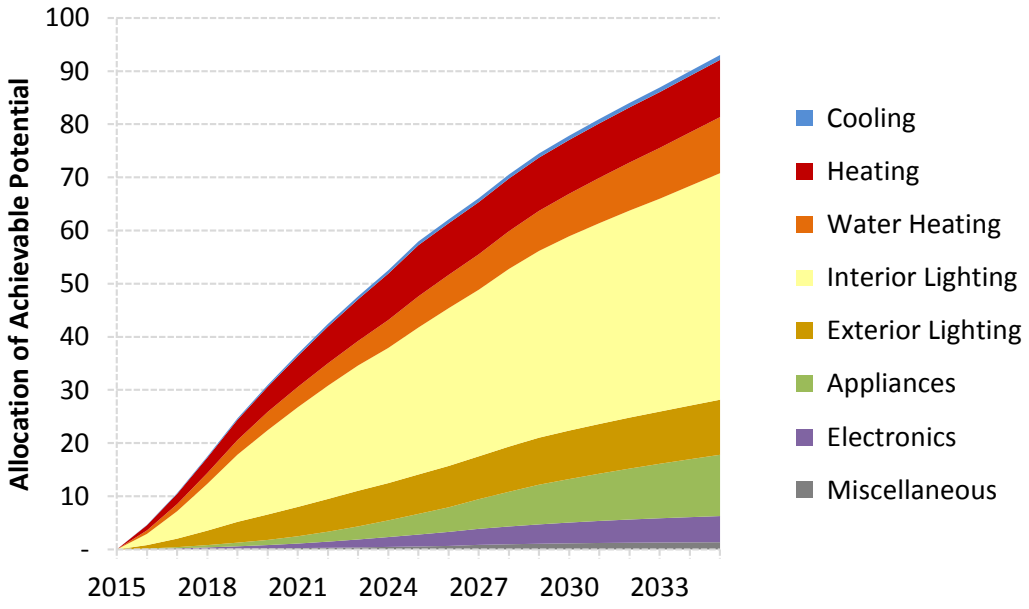
Table 5-9 identifies the top 20 residential measures from the perspective of annual energy savings in 2017 for Idaho. The top three measures include interior and exterior lighting measures and repair and sealing of ducting. The lighting measures are a result of purchases of LED lamps which are cost effective throughout the forecast horizon.

Table 5-9 Residential Top Measures in 2017 (Annual Energy, MWh), Idaho

Rank	Residential Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Screw-in/Hard-wire	5,137	48.5%
2	Exterior Lighting - Screw-in/Hard-wire	1,588	15.0%
3	Ducting - Repair and Sealing	1,574	14.9%
4	Water Heater - Pipe Insulation	729	6.9%
5	Water Heater - Faucet Aerators	337	3.2%
6	Thermostat - Clock/Programmable	231	2.2%
7	Behavioral Programs	225	2.1%
8	Insulation - Ducting	193	1.8%
9	Water Heater - Low-Flow Showerheads	135	1.3%
10	Appliances - Freezer	95	0.9%
11	Electronics - Personal Computers	86	0.8%
12	Water Heater - Drainwater Heat Recovery	85	0.8%
13	Appliances - Second Refrigerator	59	0.6%
14	Miscellaneous - Pool Pump	51	0.5%
15	Electronics - Laptops	26	0.2%
16	Appliances - Refrigerator	21	0.2%
17	Water Heating - Water Heater (55 to 75 Gal)	12	0.1%
18	Water Heater - Desuperheater	6	0.1%
19	Electronics - Monitor	4	0.0%
20	Electronics - TVs	2	0.0%
Total	**Total**	**10,595**	**100.0%**

Figure 5-9 presents forecasts of cumulative energy savings for Idaho. Results are similar to Washington.

Figure 5-9 Residential Achievable Savings Forecast (Cumulative GWh), Idaho



Commercial Conservation Potential

Table 5-10 (Total), Table 5-11 (WA) and Table 5-12 (ID) present estimates for the three levels of conservation potential for the commercial sector from the perspective of annual energy savings. Figure 5-10 (WA) and Figure 5-11(ID) display the three levels of potential by year. For Washington, the first year of the projection, achievable potential is 9 GWh, or 0.4% of the baseline projection. By 2035, savings are 419 GWh, or 18.4% of the baseline projection. Throughout the forecast horizon, achievable potential represents about 85% of economic potential. . For Idaho, first year achievable savings are 4 GWh or 0.4% of the baseline and by 2035 cumulative achievable savings reach 198 GWh, or 18.7% of the baseline.

Table 5-10 Commercial Conservation Potential (Energy Savings), Washington and Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	2,976	2,981	3,013	3,089	3,346
Cumulative Net Savings (GWh)					
Achievable Potential	13	28	105	304	617
Economic Potential	29	60	171	395	728
Technical Potential	71	142	353	694	1,096
Cumulative Net Savings (aMW)					
Achievable Potential	1.5	3.2	12.0	34.7	70.5
Economic Potential	3.3	6.8	19.5	45.1	83.1
Technical Potential	8.1	16.2	40.3	79.2	125.1
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.4%	1.0%	3.5%	9.9%	18.4%
Economic Potential	1.0%	2.0%	5.7%	12.8%	21.7%
Technical Potential	2.4%	4.8%	11.7%	22.5%	32.8%

Table 5-11 Commercial Conservation Potential (Energy Savings), Washington

	2016	2017	2020	2025	2035
Baseline projection (GWh)	2,027	2,031	2,053	2,106	2,282
Cumulative Net Savings (GWh)					
Achievable Potential	9	19	71	207	419
Economic Potential	20	41	116	268	494
Technical Potential	49	97	241	473	746
Cumulative Net Savings (aMW)					
Achievable Potential	1.0	2.2	8.1	23.6	47.8
Economic Potential	2.3	4.6	13.3	30.6	56.4
Technical Potential	5.5	11.0	27.5	54.0	85.2
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.4%	1.0%	3.5%	9.8%	18.4%
Economic Potential	1.0%	2.0%	5.7%	12.7%	21.6%
Technical Potential	2.4%	4.8%	11.7%	22.5%	32.7%

Table 5-12 Commercial Conservation Potential (Energy Savings), Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	949	950	960	983	1,063
Cumulative Net Savings (GWh)					
Achievable Potential	4	9	33	98	198
Economic Potential	9	19	55	127	234
Technical Potential	23	45	112	221	349
Cumulative Net Savings (aMW)					
Achievable Potential	0.5	1.0	3.8	11.2	22.6
Economic Potential	1.1	2.2	6.2	14.5	26.7
Technical Potential	2.6	5.2	12.8	25.3	39.9
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.4%	1.0%	3.5%	9.9%	18.7%
Economic Potential	1.0%	2.0%	5.7%	12.9%	22.0%
Technical Potential	2.4%	4.7%	11.7%	22.5%	32.9%

Figure 5-10 Commercial Conservation Savings (Energy), Washington

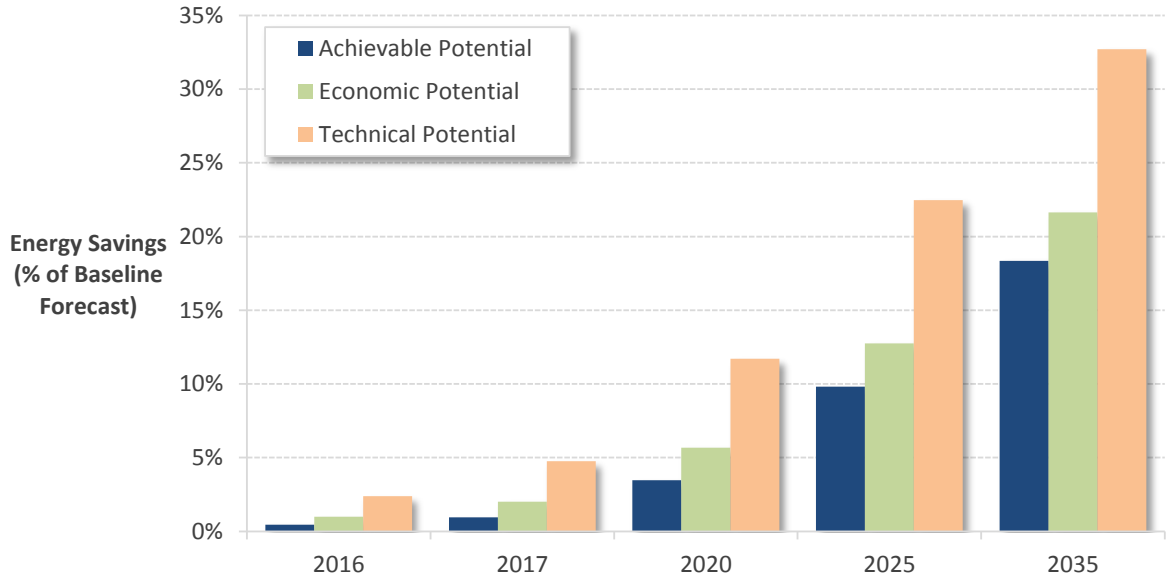
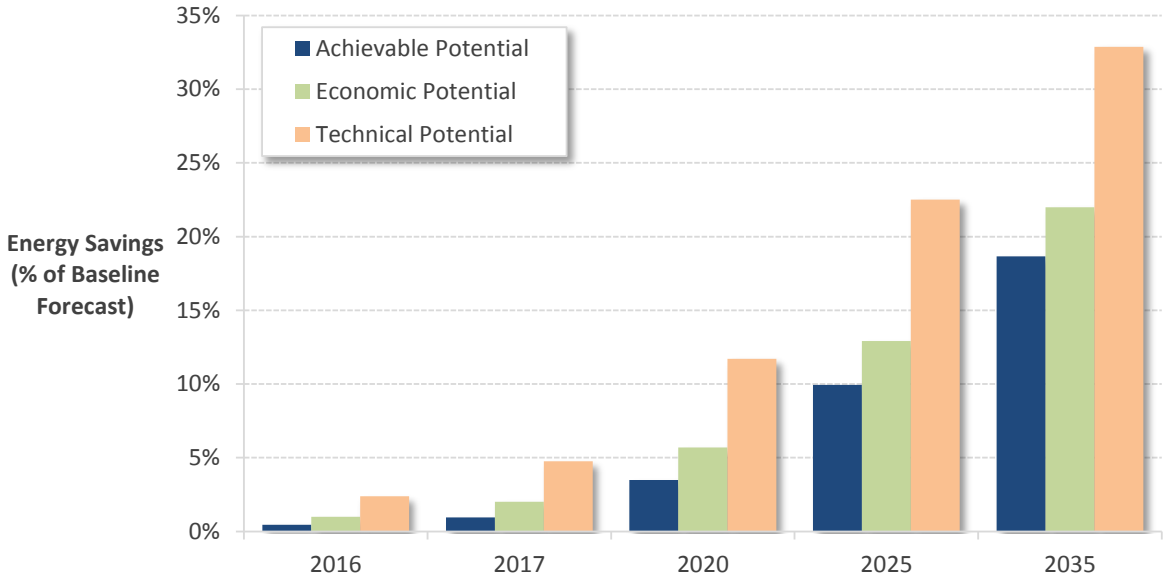


Figure 5-11 Commercial Conservation Savings (Energy), Idaho



Below, we present the top commercial measures from the perspective of annual energy use for Washington and Idaho combined, followed by each state on its own.

Table 5-13 identifies the top 20 commercial-sector measures from the perspective of annual energy savings in 2017 for Washington and Idaho combined. The top measure is interior LED replacements for linear-fluorescent style lighting applications. Lighting dominates the top 10 measures. Other measures among the top 10 include chilled water reset, duct repair and sealing, and night covers for open display cases in grocery stores.

Table 5-13 Commercial Top Measures in 2017 (Annual Energy, MWh), Washington and Idaho

Rank	Commercial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Linear LED	6,604	23.3%
2	Interior Lighting - Screw-in/Hard-wire	3,889	13.7%
3	Chiller - Chilled Water Reset	1,362	4.8%
4	Exterior Lighting - Linear LED	1,135	4.0%
5	Interior Lighting - High-Bay Fixtures	1,130	4.0%
6	HVAC - Duct Repair and Sealing	1,068	3.8%
7	Interior Lighting - Occupancy Sensors	975	3.4%
8	Interior Lighting - Skylights	831	2.9%
9	Exterior Lighting - Screw-in/Hard-wire	702	2.5%
10	Exterior Lighting - HID	671	2.4%
11	Grocery - Open Display Case - Night Covers	661	2.3%
12	Insulation - Ducting	599	2.1%
13	Refrigerator - High Efficiency Compressor	575	2.0%
14	Cooling - Water-Cooled Chiller	540	1.9%
15	HVAC - Economizer	519	1.8%
16	Food Preparation - Dishwasher	506	1.8%
17	Insulation - Ceiling	475	1.7%
18	Space Heating - Heat Recovery Ventilator	468	1.7%
19	Exterior Lighting - Bi-Level Fixture	458	1.6%
20	Exterior Lighting - Photovoltaic Installation	453	1.6%
Total	**Total Top 20**	**23,620**	**83.0%**

Table 5-14 identifies the top 20 commercial-sector measures from the perspective of annual energy savings in 2017 in Washington and Table 5-15 shows the top measures for Idaho. For both states, the top measure is interior LED replacements for linear-fluorescent style lighting applications. Lighting dominates the top 10 measures. Other measures among the top 10 include chilled water reset, duct repair and sealing, and night covers for open display cases in grocery stores.

Figure 5-12 (WA) and Figure 5-13 (ID) present forecasts of cumulative energy savings by end use. Lighting savings from interior and exterior applications account for a substantial portion of the savings throughout the forecast horizon. Cooling savings are also substantial throughout the forecast.

Table 5-14 Commercial Top Measures in 2017 (Annual Energy, MWh), Washington

Rank	Commercial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Linear LED	4,470	23.1%
2	Interior Lighting - Screw-in/Hard-wire	2,652	13.7%
3	Chiller - Chilled Water Reset	924	4.8%
4	HVAC - Duct Repair and Sealing	793	4.1%
5	Interior Lighting - High-Bay Fixtures	764	4.0%
6	Exterior Lighting - Linear LED	688	3.6%
7	Interior Lighting - Occupancy Sensors	678	3.5%
8	Interior Lighting - Skylights	561	2.9%
9	Exterior Lighting - Screw-in/Hard-wire	478	2.5%
10	Grocery - Open Display Case - Night Covers	459	2.4%
11	Exterior Lighting - HID	454	2.3%
12	Insulation - Ducting	408	2.1%
13	Refrigerator - High Efficiency Compressor	401	2.1%
14	Cooling - Water-Cooled Chiller	391	2.0%
15	Food Preparation - Dishwasher	347	1.8%
16	HVAC - Economizer	345	1.8%
17	Insulation - Ceiling	337	1.7%
18	Space Heating - Heat Recovery Ventilator	315	1.6%
19	Exterior Lighting - Bi-Level Fixture	299	1.5%
20	Exterior Lighting - Photovoltaic Installation	289	1.5%
Total	**Total Top 20**	**16,053**	**83.0%**

Figure 5-12 Commercial Achievable Savings Forecast (Cumulative GWh), Washington

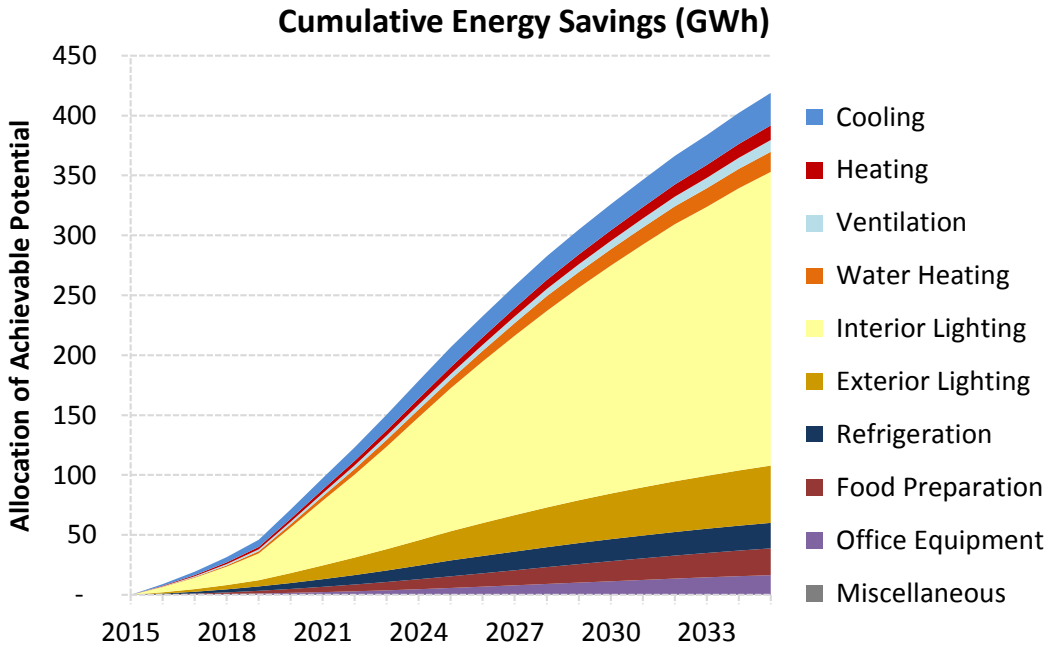
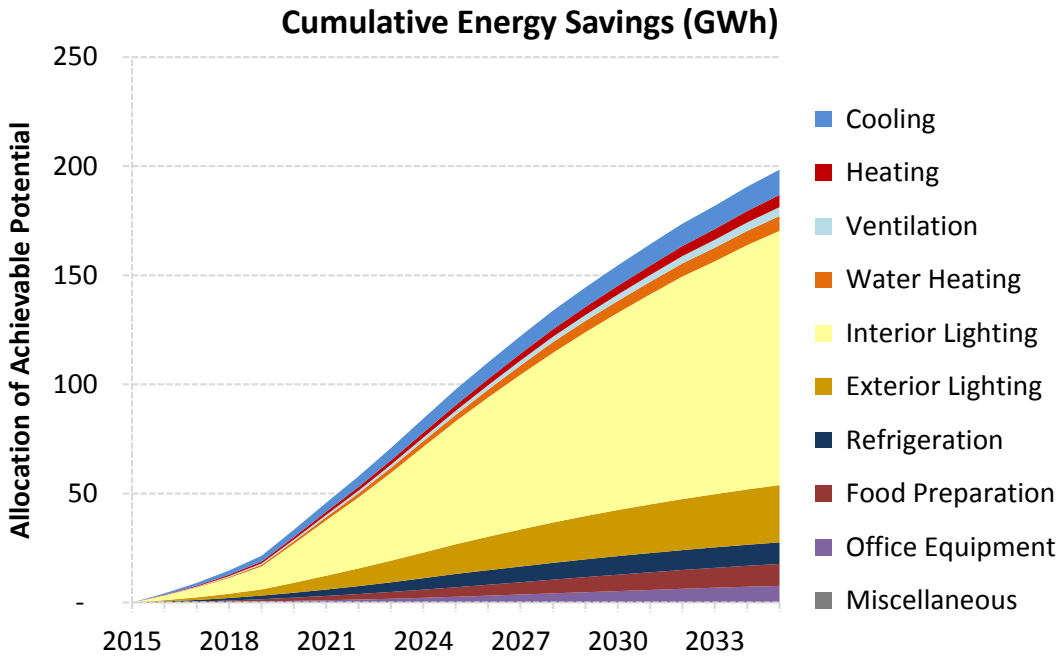


Table 5-15 Commercial Top Measures in 2017 (Annual Energy, MWh), Idaho

Rank	Commercial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - Linear LED	2,134	23.6%
2	Interior Lighting - Screw-in/Hard-wire	1,237	13.7%
3	Exterior Lighting - Linear LED	448	5.0%
4	Chiller - Chilled Water Reset	437	4.8%
5	Interior Lighting - High-Bay Fixtures	366	4.1%
6	Interior Lighting - Occupancy Sensors	297	3.3%
7	HVAC - Duct Repair and Sealing	275	3.0%
8	Interior Lighting - Skylights	270	3.0%
9	Exterior Lighting - Screw-in/Hard-wire	224	2.5%
10	Exterior Lighting - HID	217	2.4%
11	Grocery - Open Display Case - Night Covers	202	2.2%
12	Insulation - Ducting	191	2.1%
13	Refrigerator - High Efficiency Compressor	174	1.9%
14	HVAC - Economizer	174	1.9%
15	Exterior Lighting - Photovoltaic Installation	164	1.8%
16	Food Preparation - Dishwasher	159	1.8%
17	Exterior Lighting - Bi-Level Fixture	158	1.8%
18	Space Heating - Heat Recovery Ventilator	153	1.7%
19	Cooling - Water-Cooled Chiller	149	1.6%
20	Refrigerator - Variable Speed Compressor	140	1.6%
Total	**Total Top 20**	**7,569**	**83.8%**

Figure 5-13 Commercial Achievable Savings Forecast (Cumulative GWh), Idaho



Industrial Conservation Potential

Table 5-16 (Total), Table 5-17 (WA) and Table 5-18 (ID) present potential estimates at the measure level for the industrial sector, from the perspective of annual energy savings.

Figure 5-14 (WA) and Figure 5-15 (ID) display the three levels of potential by year.

For Washington, achievable savings in the first year, 2016, are 5 GWh, or 0.5% of the baseline projection. In 2035, savings reach 146 GWh, or 12.7% of the baseline projection. For Idaho, achievable savings in the first year, 2016, are 2 GWh, or 0.7% of the baseline projection. In 2035, savings reach 53 GWh, or 12.4% of the baseline projection.

Table 5-16 Industrial Conservation Potential (Annual Energy, GWh), Washington and Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	1,356	1,370	1,404	1,458	1,575
Cumulative Net Savings (GWh)					
Achievable Potential	8	16	44	101	199
Economic Potential	9	19	52	118	231
Technical Potential	17	34	84	168	293
Cumulative Net Savings (aMW)					
Achievable Potential	0.9	1.8	5.1	11.6	22.7
Economic Potential	1.0	2.1	5.9	13.5	26.3
Technical Potential	1.9	3.9	9.6	19.2	33.5
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.6%	1.2%	3.2%	7.0%	12.6%
Economic Potential	0.7%	1.4%	3.7%	8.1%	14.7%
Technical Potential	1.3%	2.5%	6.0%	11.5%	18.6%

Table 5-17 Industrial Conservation Potential (Annual Energy, GWh), Washington

	2016	2017	2020	2025	2035
Baseline projection (GWh)	989	999	1,024	1,064	1,149
Cumulative Net Savings (GWh)					
Achievable Potential	5	11	31	73	146
Economic Potential	6	13	37	86	169
Technical Potential	12	25	61	123	214
Cumulative Net Savings (aMW)					
Achievable Potential	0.6	1.3	3.6	8.4	16.7
Economic Potential	0.7	1.5	4.2	9.8	19.3
Technical Potential	1.4	2.8	7.0	14.0	24.4
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.5%	1.1%	3.1%	6.9%	12.7%
Economic Potential	0.6%	1.3%	3.6%	8.0%	14.7%
Technical Potential	1.3%	2.5%	6.0%	11.5%	18.6%

Table 5-18 Industrial Conservation Potential (Annual Energy, GWh), Idaho

	2016	2017	2020	2025	2035
Baseline projection (GWh)	367	371	380	395	426
Cumulative Net Savings (GWh)					
Achievable Potential	2	5	13	28	53
Economic Potential	3	6	15	33	61
Technical Potential	5	9	23	46	79
Cumulative Net Savings (aMW)					
Achievable Potential	0.3	0.6	1.5	3.2	6.0
Economic Potential	0.3	0.6	1.7	3.8	7.0
Technical Potential	0.5	1.0	2.6	5.2	9.1
Cumulative Net Savings as a % of Baseline					
Achievable Potential	0.7%	1.3%	3.4%	7.1%	12.4%
Economic Potential	0.8%	1.5%	4.0%	8.3%	14.4%
Technical Potential	1.3%	2.5%	6.0%	11.5%	18.6%

Figure 5-14 Industrial Conservation Potential as a % of the Baseline Projection (Annual Energy), Washington

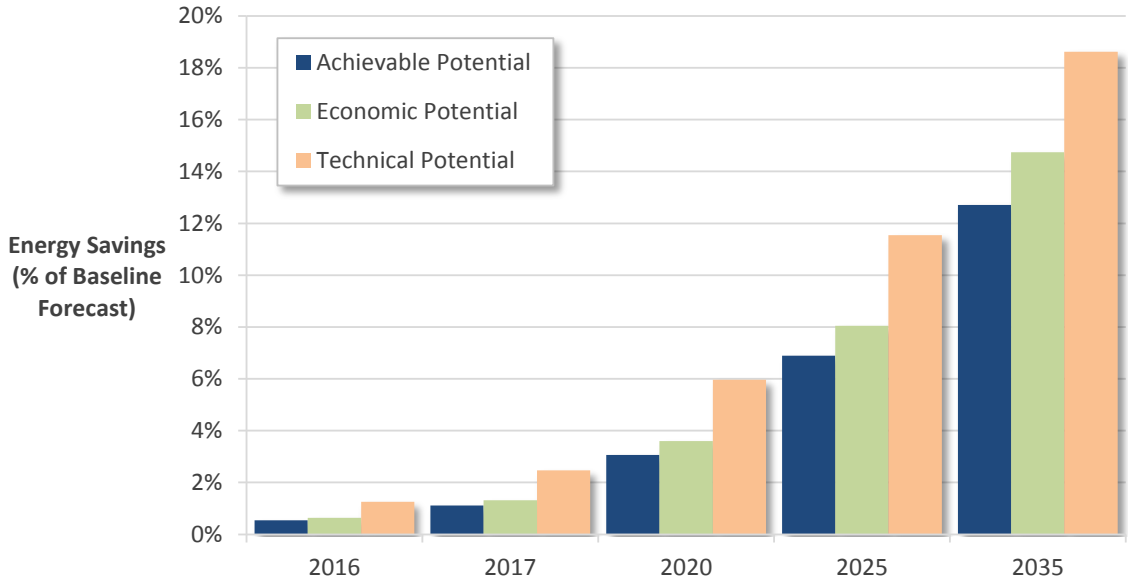
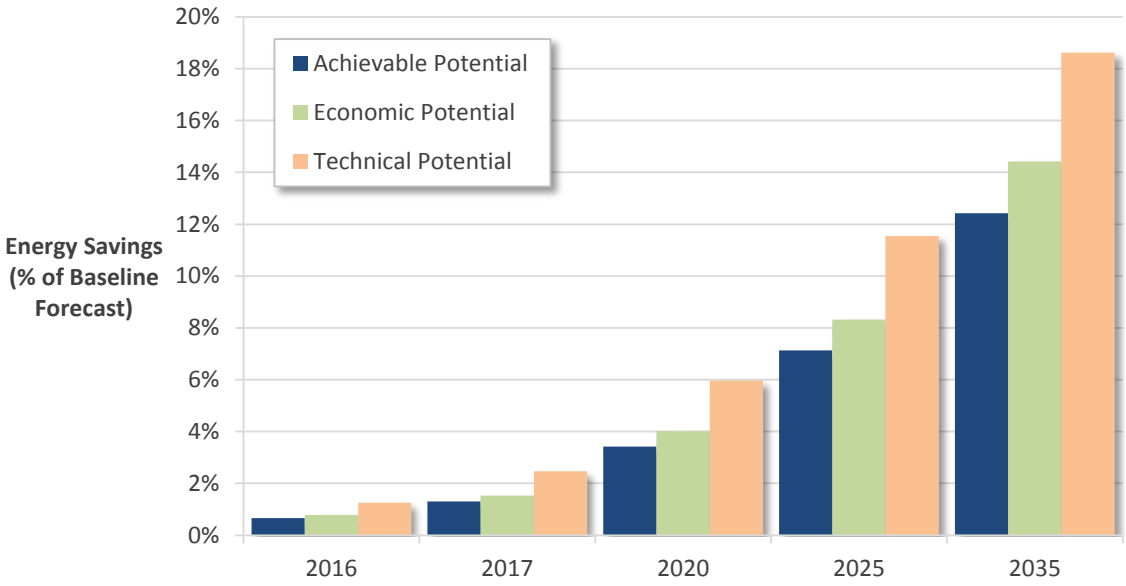


Figure 5-15 Industrial Conservation Potential as a % of the Baseline Projection (Annual Energy), Idaho



Below, we present the top industrial measures from the perspective of annual energy use for Washington and Idaho combined, followed by each state.

Table 5-19 identifies the top 20 industrial measures from the perspective of annual energy savings in 2017 for Washington and Idaho. Table 5-20 and Table 5-21 show the top measures for each state individually. For both states, the top measure is optimization and improvements on fan systems. The measure with the second highest savings is variable frequency drive for pumps.

Figure 5-16 (WA) and Figure 5-17 (ID) present forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Motor-related measures account for a substantial portion of the savings throughout the forecast horizon. The share of savings by end use remains fairly similar throughout the forecast period.

Table 5-19 Industrial Top Measures in 2017 (Annual Energy, GWh), Washington and Idaho

Rank	Industrial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Fan System - Optimization and Improvements	4,524	28.3%
2	Motors - Variable Frequency Drive (Pumps)	3,020	18.9%
3	Motors - Variable Frequency Drive (Fans & Blowers)	1,505	9.4%
4	Compressed Air - Air Usage Reduction	1,247	7.8%
5	Pumping System - Optimization and Improvements	893	5.6%
6	Interior Lighting - Occupancy Sensors	703	4.4%
7	Interior Lighting - High-Bay Fixtures	420	2.6%
8	Fan System - Maintenance	414	2.6%
9	Interior Lighting - Screw-in/Hard-wire	403	2.5%
10	Motors - Variable Frequency Drive (Compressed Air)	399	2.5%
11	HVAC - Duct Repair and Sealing	362	2.3%
12	Transformer - High Efficiency	298	1.9%
13	Motors - Variable Frequency Drive (Other)	272	1.7%
14	Compressed Air - System Optimization and Improvements	271	1.7%
15	Exterior Lighting - Screw-in/Hard-wire	240	1.5%
16	Chiller - Chilled Water Reset	216	1.3%
17	Insulation - Wall Cavity	143	0.9%
18	Compressed Air - Compressor Replacement	142	0.9%
19	Interior Lighting - Skylights	118	0.7%
20	Destratification Fans (HVLS)	101	0.6%
Total	**Total**	**15,692**	**98.1%**

Table 5-20 Industrial Top Measures in 2017 (Annual Energy, GWh), Washington

Rank	Industrial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Fan System - Optimization and Improvements	3,298	29.5%
2	Motors - Variable Frequency Drive (Pumps)	2,206	19.8%
3	Motors - Variable Frequency Drive (Fans & Blowers)	1,098	9.8%
4	Compressed Air - Air Usage Reduction	911	8.2%
5	Pumping System - Optimization and Improvements	663	5.9%
6	Interior Lighting - Occupancy Sensors	520	4.7%
7	Motors - Variable Frequency Drive (Compressed Air)	377	3.4%
8	Interior Lighting - High-Bay Fixtures	306	2.7%
9	Interior Lighting - Screw-in/Hard-wire	294	2.6%
10	HVAC - Duct Repair and Sealing	264	2.4%
11	Transformer - High Efficiency	217	1.9%
12	Exterior Lighting - Screw-in/Hard-wire	175	1.6%
13	Motors - Variable Frequency Drive (Other)	162	1.4%
14	Chiller - Chilled Water Reset	157	1.4%
15	Insulation - Wall Cavity	106	1.0%
16	Compressed Air - Compressor Replacement	104	0.9%
17	Interior Lighting - Skylights	86	0.8%
18	Chiller - Chilled Water Variable-Flow System	47	0.4%
19	Exterior Lighting - HID	44	0.4%
20	Chiller - VSD on Fans	43	0.4%
Total	**Total**	**11,080**	**99.2%**

Figure 5-16 Industrial Achievable Savings Forecast (Cumulative GWh), Washington

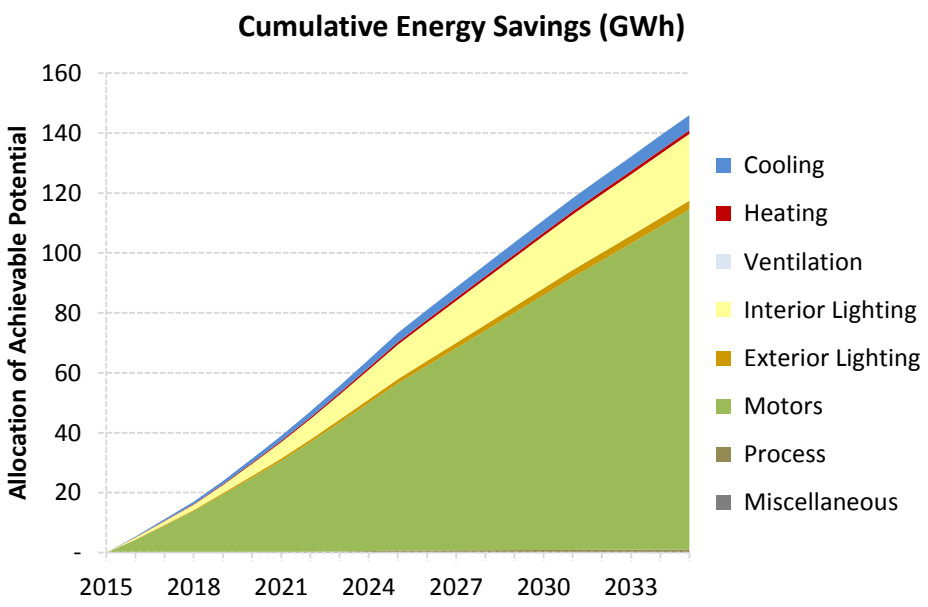
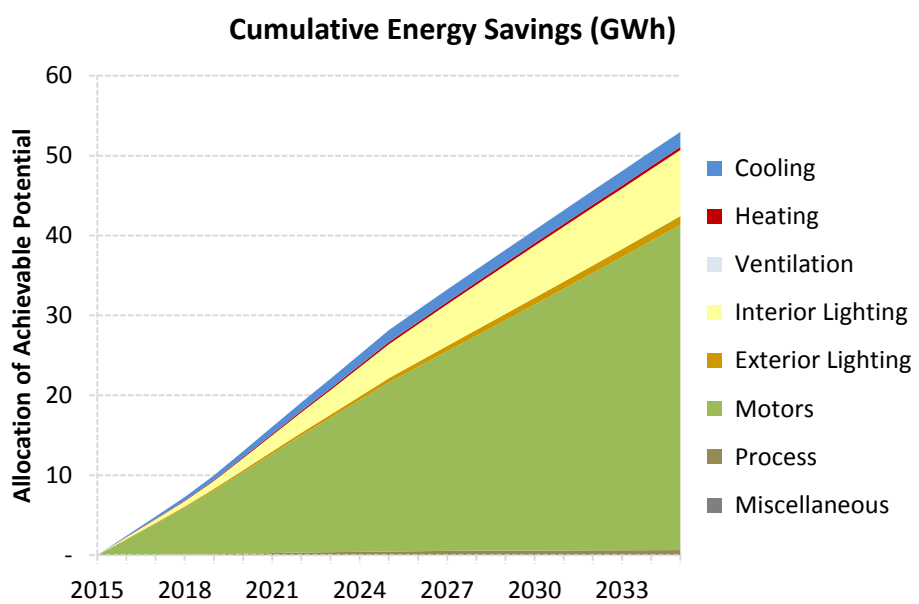


Table 5-21 Industrial Top Measures in 2017 (Annual Energy, GWh), Idaho

Rank	Industrial Measure	2017 Cumulative Energy Savings (MWh)	% of Total
1	Fan System - Optimization and Improvements	1,226	25.4%
2	Motors - Variable Frequency Drive (Pumps)	814	16.8%
3	Fan System - Maintenance	414	8.6%
4	Motors - Variable Frequency Drive (Fans & Blowers)	407	8.4%
5	Compressed Air - Air Usage Reduction	336	7.0%
6	Compressed Air - System Optimization and Improvements	271	5.6%
7	Pumping System - Optimization and Improvements	230	4.8%
8	Interior Lighting - Occupancy Sensors	183	3.8%
9	Interior Lighting - High-Bay Fixtures	114	2.4%
10	Motors - Variable Frequency Drive (Other)	110	2.3%
11	Interior Lighting - Screw-in/Hard-wire	109	2.3%
12	Destratification Fans (HVLS)	101	2.1%
13	HVAC - Duct Repair and Sealing	98	2.0%
14	Transformer - High Efficiency	81	1.7%
15	Exterior Lighting - Screw-in/Hard-wire	65	1.3%
16	Chiller - Chilled Water Reset	59	1.2%
17	Compressed Air - Compressor Replacement	39	0.8%
18	Insulation - Wall Cavity	37	0.8%
19	Interior Lighting - Skylights	32	0.7%
20	Motors - Variable Frequency Drive (Compressed Air)	22	0.5%
Total	**Total**	**4,747**	**98.2%**

Figure 5-17 Industrial Achievable Savings Forecast (Annual Energy, GWh), Idaho



APPENDIX | A

Market Profiles

This appendix presents the market profiles for each sector and segment for Washington, followed by Idaho.

Table A-1 Residential Single Family Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	47.8%	1,462	699	91
Cooling	Room AC	15.3%	532	81	11
Cooling	Air-Source Heat Pump	8.0%	1,531	123	16
Cooling	Geothermal Heat Pump	0.3%	1,352	4	0
Cooling	Evaporative AC	1.3%	1,054	14	2
Space Heating	Electric Room Heat	6.3%	15,052	951	124
Space Heating	Electric Furnace	7.4%	17,137	1,271	165
Space Heating	Air-Source Heat Pump	8.0%	12,902	1,034	134
Space Heating	Geothermal Heat Pump	0.3%	5,686	16	2
Water Heating	Water Heater (<= 55 Gal)	42.1%	3,866	1,629	212
Water Heating	Water Heater (55 to 75 Gal)	5.1%	4,065	209	27
Water Heating	Water Heater (> 75 Gal)	0.4%	4,261	19	2
Interior Lighting	Screw-in/Hard-wire	100.0%	1,135	1,135	147
Interior Lighting	Linear Fluorescent	100.0%	154	154	20
Interior Lighting	Specialty Lighting	100.0%	425	425	55
Exterior Lighting	Screw-in/Hard-wire	100.0%	445	445	58
Appliances	Clothes Washer	96.4%	111	107	14
Appliances	Clothes Dryer	38.6%	862	333	43
Appliances	Dishwasher	80.9%	476	385	50
Appliances	Refrigerator	100.0%	888	888	115
Appliances	Freezer	59.1%	710	419	54
Appliances	Second Refrigerator	29.4%	1,034	304	40
Appliances	Stove	66.9%	509	341	44
Appliances	Microwave	95.6%	148	142	18
Electronics	Personal Computers	80.5%	223	180	23
Electronics	Monitor	98.4%	95	93	12
Electronics	Laptops	94.4%	59	56	7
Electronics	TVs	205.8%	253	521	68
Electronics	Printer/Fax/Copier	85.5%	68	58	8
Electronics	Set top Boxes/DVRs	175.4%	134	234	30
Electronics	Devices and Gadgets	100.0%	58	58	7
Miscellaneous	Pool Pump	3.1%	2,526	78	10
Miscellaneous	Pool Heater	0.8%	4,045	31	4
Miscellaneous	Furnace Fan	75.8%	279	212	28
Miscellaneous	Well pump	14.9%	645	96	12
Miscellaneous	Miscellaneous	100.0%	982	982	128
	Total			**13,726**	**1,783**

Table A-2 Residential Multifamily Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	16.2%	355	57	1
Cooling	Room AC	48.5%	282	137	2
Cooling	Air-Source Heat Pump	3.6%	355	13	0
Cooling	Geothermal Heat Pump	0.0%	314	0	0
Cooling	Evaporative AC	0.9%	293	3	0
Space Heating	Electric Room Heat	74.4%	2,814	2,095	25
Space Heating	Electric Furnace	7.8%	3,204	249	3
Space Heating	Air-Source Heat Pump	3.6%	1,754	63	1
Space Heating	Geothermal Heat Pump	0.0%	773	0	0
Water Heating	Water Heater (<= 55 Gal)	65.9%	2,205	1,453	17
Water Heating	Water Heater (55 to 75 Gal)	8.7%	2,319	202	2
Water Heating	Water Heater (> 75 Gal)	0.0%	2,430	0	0
Interior Lighting	Screw-in/Hard-wire	100.0%	639	639	8
Interior Lighting	Linear Fluorescent	100.0%	40	40	0
Interior Lighting	Specialty Lighting	100.0%	37	37	0
Exterior Lighting	Screw-in/Hard-wire	100.0%	0	0	0
Appliances	Clothes Washer	82.7%	96	79	1
Appliances	Clothes Dryer	69.1%	593	410	5
Appliances	Dishwasher	70.9%	413	293	4
Appliances	Refrigerator	100.0%	771	771	9
Appliances	Freezer	46.4%	620	288	3
Appliances	Second Refrigerator	3.0%	898	27	0
Appliances	Stove	74.5%	357	266	3
Appliances	Microwave	93.6%	129	121	1
Electronics	Personal Computers	35.5%	194	69	1
Electronics	Monitor	43.4%	82	36	0
Electronics	Laptops	41.9%	52	22	0
Electronics	TVs	124.7%	269	335	4
Electronics	Printer/Fax/Copier	49.5%	59	29	0
Electronics	Set top Boxes/DVRs	91.4%	116	106	1
Electronics	Devices and Gadgets	100.0%	50	50	1
Miscellaneous	Pool Pump	0.0%	2,197	0	0
Miscellaneous	Pool Heater	0.0%	3,517	0	0
Miscellaneous	Furnace Fan	18.9%	98	19	0
Miscellaneous	Well pump	0.0%	556	0	0
Miscellaneous	Miscellaneous	100.0%	328	328	4
	Total			**8,236**	**99**

Table A-3 Residential Manufactured Home Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	30.8%	556	171	1
Cooling	Room AC	29.1%	439	128	1
Cooling	Air-Source Heat Pump	5.1%	556	29	0
Cooling	Geothermal Heat Pump	0.0%	490	0	0
Cooling	Evaporative AC	1.7%	354	6	0
Space Heating	Electric Room Heat	4.1%	7,208	294	2
Space Heating	Electric Furnace	52.3%	8,207	4,295	33
Space Heating	Air-Source Heat Pump	5.1%	6,752	346	3
Space Heating	Geothermal Heat Pump	0.0%	3,094	0	0
Water Heating	Water Heater (<= 55 Gal)	63.3%	2,370	1,501	12
Water Heating	Water Heater (55 to 75 Gal)	8.4%	2,492	209	2
Water Heating	Water Heater (> 75 Gal)	0.0%	2,612	0	0
Interior Lighting	Screw-in/Hard-wire	100.0%	724	724	6
Interior Lighting	Linear Fluorescent	100.0%	87	87	1
Interior Lighting	Specialty Lighting	100.0%	134	134	1
Exterior Lighting	Screw-in/Hard-wire	100.0%	170	170	1
Appliances	Clothes Washer	91.2%	91	83	1
Appliances	Clothes Dryer	66.7%	888	592	5
Appliances	Dishwasher	70.2%	394	277	2
Appliances	Refrigerator	100.0%	732	732	6
Appliances	Freezer	61.4%	586	360	3
Appliances	Second Refrigerator	21.0%	852	179	1
Appliances	Stove	82.5%	510	421	3
Appliances	Microwave	93.0%	123	114	1
Electronics	Personal Computers	45.8%	184	85	1
Electronics	Monitor	56.0%	78	44	0
Electronics	Laptops	66.7%	49	33	0
Electronics	TVs	156.3%	273	426	3
Electronics	Printer/Fax/Copier	58.3%	56	33	0
Electronics	Set top Boxes/DVRs	91.7%	110	101	1
Electronics	Devices and Gadgets	100.0%	48	48	0
Miscellaneous	Pool Pump	0.0%	2,087	0	0
Miscellaneous	Pool Heater	0.0%	3,341	0	0
Miscellaneous	Furnace Fan	84.6%	205	173	1
Miscellaneous	Well pump	0.0%	428	0	0
Miscellaneous	Miscellaneous	100.0%	560	560	4
	Total			**12,354**	**95**

Table A-4 Residential Low Income Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	19.4%	456	88	6
Cooling	Room AC	44.7%	333	149	10
Cooling	Air-Source Heat Pump	4.0%	460	18	1
Cooling	Geothermal Heat Pump	0.0%	406	0	0
Cooling	Evaporative AC	1.0%	350	3	0
Space Heating	Electric Room Heat	53.8%	3,606	1,939	124
Space Heating	Electric Furnace	22.1%	4,106	906	58
Space Heating	Air-Source Heat Pump	4.0%	2,697	108	7
Space Heating	Geothermal Heat Pump	0.0%	1,202	0	0
Water Heating	Water Heater (<= 55 Gal)	64.3%	2,142	1,378	88
Water Heating	Water Heater (55 to 75 Gal)	8.5%	2,253	191	12
Water Heating	Water Heater (> 75 Gal)	0.0%	2,361	1	0
Interior Lighting	Screw-in/Hard-wire	100.0%	676	676	43
Interior Lighting	Linear Fluorescent	100.0%	51	51	3
Interior Lighting	Specialty Lighting	100.0%	68	68	4
Exterior Lighting	Screw-in/Hard-wire	100.0%	42	42	3
Appliances	Clothes Washer	84.3%	91	77	5
Appliances	Clothes Dryer	67.1%	603	405	26
Appliances	Dishwasher	71.4%	393	280	18
Appliances	Refrigerator	100.0%	732	732	47
Appliances	Freezer	48.5%	589	286	18
Appliances	Second Refrigerator	6.2%	853	53	3
Appliances	Stove	74.9%	360	270	17
Appliances	Microwave	93.7%	123	115	7
Electronics	Personal Computers	39.0%	184	72	5
Electronics	Monitor	47.7%	78	37	2
Electronics	Laptops	47.3%	49	23	1
Electronics	TVs	132.4%	255	337	22
Electronics	Printer/Fax/Copier	52.4%	56	29	2
Electronics	Set top Boxes/DVRs	96.2%	110	106	7
Electronics	Devices and Gadgets	100.0%	48	48	3
Miscellaneous	Pool Pump	0.2%	2,087	4	0
Miscellaneous	Pool Heater	0.0%	3,341	1	0
Miscellaneous	Furnace Fan	28.5%	119	34	2
Miscellaneous	Well pump	0.8%	519	4	0
Miscellaneous	Miscellaneous	100.0%	361	361	23
	Total			**8,892**	**570**

Table A-5 Small Office Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.5%	4.59	0.02	0.4
Cooling	Water-Cooled Chiller	0.0%	5.20	0.00	0.0
Cooling	RTU	77.9%	3.79	2.96	53.5
Cooling	Room AC	3.6%	3.90	0.14	2.6
Cooling	Air-Source Heat Pump	8.2%	3.79	0.31	5.6
Cooling	Geothermal Heat Pump	3.2%	2.31	0.07	1.3
Heating	Electric Furnace	16.0%	6.82	1.09	19.7
Heating	Electric Room Heat	14.5%	6.50	0.94	17.1
Heating	Air-Source Heat Pump	8.2%	5.76	0.47	8.5
Heating	Geothermal Heat Pump	3.2%	4.38	0.14	2.5
Ventilation	Ventilation	100.0%	1.40	1.40	25.3
Water Heating	Water Heater	69.8%	1.05	0.73	13.2
Interior Lighting	Screw-in/Hard-wire	100.0%	0.62	0.62	11.3
Interior Lighting	High-Bay Fixtures	100.0%	0.34	0.34	6.2
Interior Lighting	Linear Fluorescent	100.0%	2.05	2.05	37.1
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.14	0.14	2.5
Exterior Lighting	HID	100.0%	0.19	0.19	3.4
Exterior Lighting	Linear Fluorescent	100.0%	0.07	0.07	1.2
Refrigeration	Walk-in Refrigerator/Freezer	0.2%	2.34	0.01	0.1
Refrigeration	Reach-in Refrigerator/Freezer	1.6%	0.52	0.01	0.2
Refrigeration	Glass Door Display	0.5%	0.54	0.00	0.0
Refrigeration	Open Display Case	0.5%	3.19	0.01	0.3
Refrigeration	Icemaker	0.5%	0.88	0.00	0.1
Refrigeration	Vending Machine	0.2%	0.41	0.00	0.0
Food Preparation	Oven	0.8%	1.50	0.01	0.2
Food Preparation	Fryer	0.1%	2.17	0.00	0.0
Food Preparation	Dishwasher	1.0%	2.99	0.03	0.5
Food Preparation	Steamer	0.1%	2.19	0.00	0.0
Food Preparation	Hot Food Container	0.1%	0.41	0.00	0.0
Office Equipment	Desktop Computer	100.0%	1.55	1.55	28.1
Office Equipment	Laptop	100.0%	0.24	0.24	4.3
Office Equipment	Server	100.0%	0.46	0.46	8.3
Office Equipment	Monitor	100.0%	0.27	0.27	5.0
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	3.8
Office Equipment	POS Terminal	40.0%	0.12	0.05	0.9
Miscellaneous	Non-HVAC Motors	22.0%	0.20	0.04	0.8
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.86	0.86	15.5
Total				**15.44**	**279.6**

Table A-6 Large Office Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	23.5%	2.69	0.63	3.8
Cooling	Water-Cooled Chiller	23.5%	2.97	0.70	4.2
Cooling	RTU	33.4%	3.28	1.10	6.6
Cooling	Room AC	0.6%	3.37	0.02	0.1
Cooling	Air-Source Heat Pump	7.5%	3.28	0.25	1.5
Cooling	Geothermal Heat Pump	6.5%	2.00	0.13	0.8
Heating	Electric Furnace	15.7%	5.04	0.79	4.8
Heating	Electric Room Heat	14.3%	4.80	0.68	4.1
Heating	Air-Source Heat Pump	7.5%	4.62	0.35	2.1
Heating	Geothermal Heat Pump	6.5%	3.66	0.24	1.4
Ventilation	Ventilation	100.0%	2.96	2.96	17.9
Water Heating	Water Heater	68.0%	0.99	0.67	4.1
Interior Lighting	Screw-in/Hard-wire	100.0%	0.62	0.62	3.8
Interior Lighting	High-Bay Fixtures	100.0%	0.37	0.37	2.3
Interior Lighting	Linear Fluorescent	100.0%	2.74	2.74	16.6
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.14	0.14	0.8
Exterior Lighting	HID	100.0%	0.37	0.37	2.2
Exterior Lighting	Linear Fluorescent	100.0%	0.23	0.23	1.4
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	1.62	0.03	0.2
Refrigeration	Reach-in Refrigerator/Freezer	14.0%	0.36	0.05	0.3
Refrigeration	Glass Door Display	4.0%	0.37	0.01	0.1
Refrigeration	Open Display Case	4.0%	2.22	0.09	0.5
Refrigeration	Icemaker	4.0%	0.61	0.02	0.1
Refrigeration	Vending Machine	2.1%	0.29	0.01	0.0
Food Preparation	Oven	10.0%	0.76	0.08	0.5
Food Preparation	Fryer	1.0%	1.10	0.01	0.1
Food Preparation	Dishwasher	12.0%	1.52	0.18	1.1
Food Preparation	Steamer	1.0%	1.11	0.01	0.1
Food Preparation	Hot Food Container	1.0%	0.21	0.00	0.0
Office Equipment	Desktop Computer	100.0%	1.96	1.96	11.8
Office Equipment	Laptop	100.0%	0.30	0.30	1.8
Office Equipment	Server	100.0%	0.19	0.19	1.2
Office Equipment	Monitor	100.0%	0.35	0.35	2.1
Office Equipment	Printer/Copier/Fax	100.0%	0.18	0.18	1.1
Office Equipment	POS Terminal	40.0%	0.03	0.01	0.1
Miscellaneous	Non-HVAC Motors	89.6%	0.22	0.20	1.2
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.86	0.86	5.2
Total				**17.54**	**105.9**

Table A-7 Restaurant Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.3%	3.59	0.01	0.0
Cooling	Water-Cooled Chiller	0.0%	3.97	0.00	0.0
Cooling	RTU	76.3%	4.51	3.44	5.7
Cooling	Room AC	6.6%	4.63	0.31	0.5
Cooling	Air-Source Heat Pump	6.6%	4.51	0.30	0.5
Cooling	Geothermal Heat Pump	3.3%	2.75	0.09	0.1
Heating	Electric Furnace	5.1%	7.05	0.36	0.6
Heating	Electric Room Heat	0.1%	6.72	0.01	0.0
Heating	Air-Source Heat Pump	6.6%	4.98	0.33	0.5
Heating	Geothermal Heat Pump	3.3%	3.51	0.12	0.2
Ventilation	Ventilation	100.0%	2.48	2.48	4.1
Water Heating	Water Heater	35.2%	8.81	3.10	5.1
Interior Lighting	Screw-in/Hard-wire	100.0%	2.09	2.09	3.5
Interior Lighting	High-Bay Fixtures	100.0%	0.40	0.40	0.7
Interior Lighting	Linear Fluorescent	100.0%	3.62	3.62	6.0
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	0.4
Exterior Lighting	HID	100.0%	1.61	1.61	2.7
Exterior Lighting	Linear Fluorescent	100.0%	0.47	0.47	0.8
Refrigeration	Walk-in Refrigerator/Freezer	74.0%	6.56	4.85	8.0
Refrigeration	Reach-in Refrigerator/Freezer	7.0%	2.94	0.21	0.3
Refrigeration	Glass Door Display	77.6%	1.51	1.17	1.9
Refrigeration	Open Display Case	26.0%	8.95	2.33	3.9
Refrigeration	Icemaker	75.9%	2.47	1.88	3.1
Refrigeration	Vending Machine	0.0%	1.16	0.00	0.0
Food Preparation	Oven	16.0%	9.79	1.57	2.6
Food Preparation	Fryer	14.0%	14.16	1.98	3.3
Food Preparation	Dishwasher	48.0%	9.75	4.68	7.8
Food Preparation	Steamer	14.0%	7.15	1.00	1.7
Food Preparation	Hot Food Container	31.0%	1.33	0.41	0.7
Office Equipment	Desktop Computer	100.0%	0.29	0.29	0.5
Office Equipment	Laptop	100.0%	0.04	0.04	0.1
Office Equipment	Server	50.0%	0.34	0.17	0.3
Office Equipment	Monitor	100.0%	0.05	0.05	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.1
Office Equipment	POS Terminal	100.0%	0.09	0.09	0.1
Miscellaneous	Non-HVAC Motors	20.0%	0.58	0.12	0.2
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.57	2.57	4.3
Total				**42.40**	**70.3**

Table A-8 Retail Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	9.5%	2.74	0.26	5.4
Cooling	Water-Cooled Chiller	2.4%	3.10	0.07	1.5
Cooling	RTU	54.2%	2.26	1.23	25.4
Cooling	Room AC	2.8%	2.48	0.07	1.4
Cooling	Air-Source Heat Pump	1.7%	2.26	0.04	0.8
Cooling	Geothermal Heat Pump	1.4%	1.38	0.02	0.4
Heating	Electric Furnace	5.8%	4.86	0.28	5.8
Heating	Electric Room Heat	2.1%	4.63	0.10	2.0
Heating	Air-Source Heat Pump	1.7%	3.89	0.07	1.4
Heating	Geothermal Heat Pump	1.4%	2.65	0.04	0.7
Ventilation	Ventilation	100.0%	0.98	0.98	20.2
Water Heating	Water Heater	63.0%	0.79	0.50	10.3
Interior Lighting	Screw-in/Hard-wire	100.0%	0.85	0.85	17.5
Interior Lighting	High-Bay Fixtures	100.0%	1.02	1.02	21.1
Interior Lighting	Linear Fluorescent	100.0%	3.43	3.43	70.9
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.36	0.36	7.4
Exterior Lighting	HID	100.0%	1.30	1.30	26.9
Exterior Lighting	Linear Fluorescent	100.0%	0.87	0.87	18.0
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	2.04	0.04	0.8
Refrigeration	Reach-in Refrigerator/Freezer	0.0%	0.46	0.00	0.0
Refrigeration	Glass Door Display	16.3%	0.47	0.08	1.6
Refrigeration	Open Display Case	14.0%	2.79	0.39	8.1
Refrigeration	Icemaker	7.1%	0.77	0.05	1.1
Refrigeration	Vending Machine	22.8%	0.36	0.08	1.7
Food Preparation	Oven	8.0%	2.43	0.19	4.0
Food Preparation	Fryer	1.6%	3.51	0.06	1.2
Food Preparation	Dishwasher	2.0%	4.84	0.10	2.0
Food Preparation	Steamer	1.6%	3.55	0.06	1.2
Food Preparation	Hot Food Container	1.0%	0.66	0.01	0.1
Office Equipment	Desktop Computer	100.0%	0.34	0.34	7.0
Office Equipment	Laptop	100.0%	0.05	0.05	1.1
Office Equipment	Server	82.0%	0.06	0.05	1.0
Office Equipment	Monitor	100.0%	0.06	0.06	1.2
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	1.0
Office Equipment	POS Terminal	100.0%	0.01	0.01	0.3
Miscellaneous	Non-HVAC Motors	40.2%	0.17	0.07	1.4
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.64	0.64	13.2
Total				**13.80**	**285.2**

Table A-9 Grocery Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	5.3%	5.10	0.27	1.2
Cooling	Water-Cooled Chiller	0.0%	5.77	0.00	0.0
Cooling	RTU	69.6%	4.21	2.93	13.0
Cooling	Room AC	0.0%	4.33	0.00	0.0
Cooling	Air-Source Heat Pump	3.1%	3.72	0.12	0.5
Cooling	Geothermal Heat Pump	0.0%	1.57	0.00	0.0
Heating	Electric Furnace	15.4%	5.68	0.87	3.9
Heating	Electric Room Heat	1.5%	5.41	0.08	0.4
Heating	Air-Source Heat Pump	3.1%	3.05	0.10	0.4
Heating	Geothermal Heat Pump	0.0%	1.95	0.00	0.0
Ventilation	Ventilation	100.0%	2.07	2.07	9.2
Water Heating	Water Heater	38.2%	2.18	0.83	3.7
Interior Lighting	Screw-in/Hard-wire	100.0%	1.93	1.93	8.5
Interior Lighting	High-Bay Fixtures	100.0%	1.70	1.70	7.5
Interior Lighting	Linear Fluorescent	100.0%	5.83	5.83	25.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.19	0.19	0.8
Exterior Lighting	HID	100.0%	1.16	1.16	5.1
Exterior Lighting	Linear Fluorescent	100.0%	0.48	0.48	2.1
Refrigeration	Walk-in Refrigerator/Freezer	16.0%	5.13	0.82	3.6
Refrigeration	Reach-in Refrigerator/Freezer	83.1%	0.33	0.27	1.2
Refrigeration	Glass Door Display	95.6%	3.37	3.23	14.3
Refrigeration	Open Display Case	95.6%	19.99	19.12	84.6
Refrigeration	Icemaker	66.6%	0.28	0.18	0.8
Refrigeration	Vending Machine	36.5%	0.26	0.09	0.4
Food Preparation	Oven	17.0%	2.44	0.42	1.8
Food Preparation	Fryer	13.0%	3.53	0.46	2.0
Food Preparation	Dishwasher	7.0%	4.86	0.34	1.5
Food Preparation	Steamer	13.0%	3.57	0.46	2.1
Food Preparation	Hot Food Container	16.0%	0.67	0.11	0.5
Office Equipment	Desktop Computer	100.0%	0.25	0.25	1.1
Office Equipment	Laptop	64.0%	0.04	0.03	0.1
Office Equipment	Server	100.0%	0.15	0.15	0.7
Office Equipment	Monitor	100.0%	0.04	0.04	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.1
Office Equipment	POS Terminal	100.0%	0.10	0.10	0.4
Miscellaneous	Non-HVAC Motors	34.6%	0.57	0.20	0.9
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.40	2.40	10.6
Total				**47.25**	**209.1**

Table A-10 College Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	34.8%	3.08	1.07	6.0
Cooling	Water-Cooled Chiller	8.7%	4.56	0.40	2.2
Cooling	RTU	15.6%	2.00	0.31	1.7
Cooling	Room AC	5.0%	2.05	0.10	0.6
Cooling	Air-Source Heat Pump	3.6%	1.99	0.07	0.4
Cooling	Geothermal Heat Pump	0.0%	1.21	0.00	0.0
Heating	Electric Furnace	10.5%	8.76	0.92	5.1
Heating	Electric Room Heat	29.7%	8.34	2.48	13.9
Heating	Air-Source Heat Pump	3.6%	6.22	0.23	1.3
Heating	Geothermal Heat Pump	0.0%	4.81	0.00	0.0
Ventilation	Ventilation	100.0%	1.48	1.48	8.3
Water Heating	Water Heater	26.3%	2.02	0.53	3.0
Interior Lighting	Screw-in/Hard-wire	100.0%	0.83	0.83	4.6
Interior Lighting	High-Bay Fixtures	100.0%	0.30	0.30	1.7
Interior Lighting	Linear Fluorescent	100.0%	2.04	2.04	11.5
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.01	0.01	0.0
Exterior Lighting	HID	100.0%	0.27	0.27	1.5
Exterior Lighting	Linear Fluorescent	100.0%	0.97	0.97	5.4
Refrigeration	Walk-in Refrigerator/Freezer	7.7%	0.29	0.02	0.1
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.13	0.02	0.1
Refrigeration	Glass Door Display	8.0%	0.07	0.01	0.0
Refrigeration	Open Display Case	4.8%	0.40	0.02	0.1
Refrigeration	Icemaker	28.2%	0.22	0.06	0.3
Refrigeration	Vending Machine	8.8%	0.10	0.01	0.1
Food Preparation	Oven	13.7%	0.68	0.09	0.5
Food Preparation	Fryer	1.6%	0.98	0.02	0.1
Food Preparation	Dishwasher	11.7%	1.35	0.16	0.9
Food Preparation	Steamer	1.6%	0.99	0.02	0.1
Food Preparation	Hot Food Container	8.4%	0.19	0.02	0.1
Office Equipment	Desktop Computer	100.0%	0.51	0.51	2.9
Office Equipment	Laptop	100.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.06	0.06	0.3
Office Equipment	Monitor	100.0%	0.09	0.09	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	0.4
Office Equipment	POS Terminal	36.0%	0.02	0.01	0.0
Miscellaneous	Non-HVAC Motors	88.8%	0.14	0.12	0.7
Miscellaneous	Pool Pump	6.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.61	0.61	3.4
Total				**13.93**	**78.1**

Table A-11 School Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	24.5%	2.56	0.63	7.5
Cooling	Water-Cooled Chiller	6.1%	3.79	0.23	2.8
Cooling	RTU	11.9%	1.66	0.20	2.4
Cooling	Room AC	5.0%	1.70	0.09	1.0
Cooling	Air-Source Heat Pump	8.6%	1.65	0.14	1.7
Cooling	Geothermal Heat Pump	3.9%	1.01	0.04	0.5
Heating	Electric Furnace	3.7%	9.39	0.35	4.2
Heating	Electric Room Heat	1.8%	8.94	0.16	1.9
Heating	Air-Source Heat Pump	8.6%	6.66	0.57	6.8
Heating	Geothermal Heat Pump	3.9%	5.16	0.20	2.4
Ventilation	Ventilation	100.0%	1.17	1.17	14.0
Water Heating	Water Heater	38.1%	1.63	0.62	7.4
Interior Lighting	Screw-in/Hard-wire	100.0%	0.55	0.55	6.6
Interior Lighting	High-Bay Fixtures	100.0%	0.13	0.13	1.5
Interior Lighting	Linear Fluorescent	100.0%	1.10	1.10	13.1
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.00	0.00	0.1
Exterior Lighting	HID	100.0%	0.17	0.17	2.0
Exterior Lighting	Linear Fluorescent	100.0%	0.96	0.96	11.5
Refrigeration	Walk-in Refrigerator/Freezer	19.0%	0.51	0.10	1.2
Refrigeration	Reach-in Refrigerator/Freezer	33.0%	0.23	0.08	0.9
Refrigeration	Glass Door Display	19.7%	0.12	0.02	0.3
Refrigeration	Open Display Case	11.9%	0.69	0.08	1.0
Refrigeration	Icemaker	69.7%	0.38	0.27	3.2
Refrigeration	Vending Machine	21.8%	0.18	0.04	0.5
Food Preparation	Oven	34.0%	0.58	0.20	2.3
Food Preparation	Fryer	4.0%	0.84	0.03	0.4
Food Preparation	Dishwasher	29.0%	1.15	0.33	4.0
Food Preparation	Steamer	4.0%	0.84	0.03	0.4
Food Preparation	Hot Food Container	21.0%	0.16	0.03	0.4
Office Equipment	Desktop Computer	100.0%	0.45	0.45	5.4
Office Equipment	Laptop	100.0%	0.03	0.03	0.3
Office Equipment	Server	100.0%	0.11	0.11	1.3
Office Equipment	Monitor	100.0%	0.08	0.08	1.0
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	0.6
Office Equipment	POS Terminal	36.0%	0.01	0.01	0.1
Miscellaneous	Non-HVAC Motors	43.7%	0.11	0.05	0.6
Miscellaneous	Pool Pump	6.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.55	0.55	6.6
Total				**9.85**	**117.5**

Table A-12 Health Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	16.5%	5.62	0.93	8.7
Cooling	Water-Cooled Chiller	65.9%	7.38	4.86	45.4
Cooling	RTU	10.8%	5.40	0.58	5.5
Cooling	Room AC	0.4%	5.55	0.02	0.2
Cooling	Air-Source Heat Pump	1.1%	5.39	0.06	0.5
Cooling	Geothermal Heat Pump	0.4%	3.28	0.01	0.1
Heating	Electric Furnace	0.3%	13.34	0.04	0.3
Heating	Electric Room Heat	9.3%	12.71	1.18	11.1
Heating	Air-Source Heat Pump	1.1%	9.12	0.10	0.9
Heating	Geothermal Heat Pump	0.4%	6.69	0.02	0.2
Ventilation	Ventilation	100.0%	4.96	4.96	46.3
Water Heating	Water Heater	22.3%	4.64	1.03	9.7
Interior Lighting	Screw-in/Hard-wire	100.0%	1.54	1.54	14.3
Interior Lighting	High-Bay Fixtures	100.0%	0.35	0.35	3.3
Interior Lighting	Linear Fluorescent	100.0%	3.92	3.92	36.6
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.04	0.04	0.4
Exterior Lighting	HID	100.0%	0.46	0.46	4.3
Exterior Lighting	Linear Fluorescent	100.0%	0.16	0.16	1.5
Refrigeration	Walk-in Refrigerator/Freezer	33.0%	1.05	0.35	3.2
Refrigeration	Reach-in Refrigerator/Freezer	50.0%	0.23	0.12	1.1
Refrigeration	Glass Door Display	8.6%	0.24	0.02	0.2
Refrigeration	Open Display Case	6.7%	1.43	0.10	0.9
Refrigeration	Icemaker	21.1%	0.79	0.17	1.6
Refrigeration	Vending Machine	27.9%	0.37	0.10	1.0
Food Preparation	Oven	13.0%	2.58	0.34	3.1
Food Preparation	Fryer	10.0%	3.73	0.37	3.5
Food Preparation	Dishwasher	25.0%	5.14	1.28	12.0
Food Preparation	Steamer	10.0%	3.77	0.38	3.5
Food Preparation	Hot Food Container	10.0%	0.70	0.07	0.7
Office Equipment	Desktop Computer	100.0%	0.91	0.91	8.5
Office Equipment	Laptop	100.0%	0.06	0.06	0.5
Office Equipment	Server	100.0%	0.11	0.11	1.0
Office Equipment	Monitor	100.0%	0.16	0.16	1.5
Office Equipment	Printer/Copier/Fax	100.0%	0.10	0.10	0.9
Office Equipment	POS Terminal	100.0%	0.07	0.07	0.7
Miscellaneous	Non-HVAC Motors	74.1%	0.37	0.27	2.6
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	3.84	3.84	35.8
Total				**29.06**	**271.4**

Table A-13 Lodging Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	4.4%	1.18	0.05	0.4
Cooling	Water-Cooled Chiller	17.8%	1.54	0.27	1.9
Cooling	RTU	8.1%	2.62	0.21	1.5
Cooling	Room AC	27.5%	2.69	0.74	5.1
Cooling	Air-Source Heat Pump	17.6%	2.62	0.46	3.2
Cooling	Geothermal Heat Pump	2.5%	2.26	0.06	0.4
Heating	Electric Furnace	60.2%	4.21	2.54	17.6
Heating	Electric Room Heat	3.6%	4.01	0.15	1.0
Heating	Air-Source Heat Pump	17.6%	3.85	0.68	4.7
Heating	Geothermal Heat Pump	2.5%	2.50	0.06	0.4
Ventilation	Ventilation	100.0%	1.42	1.42	9.9
Water Heating	Water Heater	31.5%	4.81	1.51	10.5
Interior Lighting	Screw-in/Hard-wire	100.0%	3.31	3.31	23.0
Interior Lighting	High-Bay Fixtures	100.0%	0.27	0.27	1.8
Interior Lighting	Linear Fluorescent	100.0%	0.87	0.87	6.0
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.13	0.13	0.9
Exterior Lighting	HID	100.0%	0.51	0.51	3.6
Exterior Lighting	Linear Fluorescent	100.0%	0.03	0.03	0.2
Refrigeration	Walk-in Refrigerator/Freezer	3.0%	0.82	0.02	0.2
Refrigeration	Reach-in Refrigerator/Freezer	19.0%	0.18	0.03	0.2
Refrigeration	Glass Door Display	40.0%	0.19	0.08	0.5
Refrigeration	Open Display Case	0.0%	1.12	0.00	0.0
Refrigeration	Icemaker	88.9%	0.62	0.55	3.8
Refrigeration	Vending Machine	57.8%	0.29	0.17	1.2
Food Preparation	Oven	24.0%	0.83	0.20	1.4
Food Preparation	Fryer	4.0%	1.20	0.05	0.3
Food Preparation	Dishwasher	39.0%	0.82	0.32	2.2
Food Preparation	Steamer	4.0%	0.60	0.02	0.2
Food Preparation	Hot Food Container	10.0%	0.11	0.01	0.1
Office Equipment	Desktop Computer	100.0%	0.20	0.20	1.4
Office Equipment	Laptop	100.0%	0.03	0.03	0.2
Office Equipment	Server	100.0%	0.12	0.12	0.8
Office Equipment	Monitor	100.0%	0.04	0.04	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.2
Office Equipment	POS Terminal	58.0%	0.03	0.02	0.1
Miscellaneous	Non-HVAC Motors	91.3%	0.15	0.14	1.0
Miscellaneous	Pool Pump	76.0%	0.02	0.02	0.1
Miscellaneous	Pool Heater	27.0%	0.03	0.01	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.76	0.76	5.3
Total				**16.08**	**111.7**

Table A-14 Warehouse Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.0%	4.14	0.54	7.4
Cooling	Water-Cooled Chiller	1.4%	4.74	0.07	0.9
Cooling	RTU	17.0%	4.07	0.69	9.5
Cooling	Room AC	1.1%	4.18	0.05	0.6
Cooling	Air-Source Heat Pump	1.6%	4.07	0.07	0.9
Cooling	Geothermal Heat Pump	0.0%	2.48	0.00	0.0
Heating	Electric Furnace	4.9%	7.90	0.39	5.3
Heating	Electric Room Heat	1.7%	7.53	0.13	1.8
Heating	Air-Source Heat Pump	1.6%	5.91	0.09	1.3
Heating	Geothermal Heat Pump	0.0%	4.50	0.00	0.0
Ventilation	Ventilation	100.0%	0.60	0.60	8.2
Water Heating	Water Heater	76.9%	0.61	0.47	6.4
Interior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	3.2
Interior Lighting	High-Bay Fixtures	100.0%	0.96	0.96	13.2
Interior Lighting	Linear Fluorescent	100.0%	1.12	1.12	15.4
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.18	0.18	2.5
Exterior Lighting	HID	100.0%	0.15	0.15	2.1
Exterior Lighting	Linear Fluorescent	100.0%	0.15	0.15	2.1
Refrigeration	Walk-in Refrigerator/Freezer	1.1%	4.49	0.05	0.7
Refrigeration	Reach-in Refrigerator/Freezer	2.0%	1.01	0.02	0.3
Refrigeration	Glass Door Display	0.0%	1.03	0.00	0.0
Refrigeration	Open Display Case	0.0%	6.13	0.00	0.0
Refrigeration	Icemaker	8.3%	1.69	0.14	1.9
Refrigeration	Vending Machine	6.9%	0.80	0.05	0.7
Food Preparation	Oven	0.0%	0.28	0.00	0.0
Food Preparation	Fryer	0.0%	0.41	0.00	0.0
Food Preparation	Dishwasher	2.0%	0.56	0.01	0.2
Food Preparation	Steamer	0.0%	0.41	0.00	0.0
Food Preparation	Hot Food Container	0.0%	0.08	0.00	0.0
Office Equipment	Desktop Computer	100.0%	0.23	0.23	3.2
Office Equipment	Laptop	100.0%	0.03	0.03	0.4
Office Equipment	Server	89.0%	0.27	0.24	3.4
Office Equipment	Monitor	100.0%	0.04	0.04	0.6
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.4
Office Equipment	POS Terminal	77.0%	0.07	0.06	0.8
Miscellaneous	Non-HVAC Motors	49.9%	0.14	0.07	1.0
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.65	0.65	8.9
Total				**7.50**	**102.9**

Table A-15 Miscellaneous Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	4.2%	3.85	0.16	5.3
Cooling	Water-Cooled Chiller	16.7%	4.36	0.73	24.0
Cooling	RTU	34.5%	3.18	1.10	36.3
Cooling	Room AC	4.9%	3.27	0.16	5.3
Cooling	Air-Source Heat Pump	6.2%	3.18	0.20	6.5
Cooling	Geothermal Heat Pump	1.1%	1.94	0.02	0.7
Heating	Electric Furnace	15.2%	8.97	1.36	45.0
Heating	Electric Room Heat	8.4%	8.54	0.72	23.7
Heating	Air-Source Heat Pump	6.2%	7.44	0.46	15.1
Heating	Geothermal Heat Pump	1.1%	5.77	0.07	2.2
Ventilation	Ventilation	100.0%	1.39	1.39	45.9
Water Heating	Water Heater	51.3%	2.64	1.35	44.8
Interior Lighting	Screw-in/Hard-wire	100.0%	0.75	0.75	24.9
Interior Lighting	High-Bay Fixtures	100.0%	0.25	0.25	8.1
Interior Lighting	Linear Fluorescent	100.0%	1.42	1.42	46.9
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.43	0.43	14.2
Exterior Lighting	HID	100.0%	0.91	0.91	30.0
Exterior Lighting	Linear Fluorescent	100.0%	0.07	0.07	2.3
Refrigeration	Walk-in Refrigerator/Freezer	9.0%	0.98	0.09	2.9
Refrigeration	Reach-in Refrigerator/Freezer	0.0%	0.22	0.00	0.0
Refrigeration	Glass Door Display	15.0%	0.23	0.03	1.1
Refrigeration	Open Display Case	0.0%	1.34	0.00	0.0
Refrigeration	Icemaker	41.6%	0.37	0.15	5.1
Refrigeration	Vending Machine	28.6%	0.35	0.10	3.3
Food Preparation	Oven	28.0%	0.24	0.07	2.3
Food Preparation	Fryer	4.0%	0.35	0.01	0.5
Food Preparation	Dishwasher	31.0%	0.49	0.15	5.0
Food Preparation	Steamer	4.0%	0.36	0.01	0.5
Food Preparation	Hot Food Container	7.0%	0.07	0.00	0.2
Office Equipment	Desktop Computer	100.0%	0.37	0.37	12.4
Office Equipment	Laptop	100.0%	0.06	0.06	1.9
Office Equipment	Server	66.0%	0.22	0.15	4.8
Office Equipment	Monitor	100.0%	0.07	0.07	2.2
Office Equipment	Printer/Copier/Fax	100.0%	0.04	0.04	1.4
Office Equipment	POS Terminal	28.0%	0.06	0.02	0.5
Miscellaneous	Non-HVAC Motors	59.9%	0.15	0.09	3.0
Miscellaneous	Pool Pump	4.0%	0.02	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.79	0.79	26.2
Total				**13.75**	**454.6**

Table A-16 Industrial Electric Market Profile, Washington

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.0%	8,256	1,072	17.40
Cooling	Water-Cooled Chiller	1.4%	9,464	137	2.22
Cooling	RTU	17.0%	8,121	1,383	22.44
Cooling	Room AC	1.1%	8,347	94	1.53
Cooling	Air-Source Heat Pump	1.6%	8,118	130	2.12
Cooling	Geothermal Heat Pump	0.0%	5,414	0	0.00
Heating	Electric Furnace	4.9%	15,767	769	12.47
Heating	Electric Room Heat	1.7%	15,016	258	4.18
Heating	Air-Source Heat Pump	1.6%	11,786	189	3.07
Heating	Geothermal Heat Pump	0.0%	7,861	0	0.00
Ventilation	Ventilation	100.0%	1,190	1,190	19.30
Interior Lighting	Screw-in/Hard-wire	100.0%	302	302	4.90
Interior Lighting	High-Bay Fixtures	100.0%	1,256	1,256	20.38
Interior Lighting	Linear Fluorescent	100.0%	1,466	1,466	23.78
Exterior Lighting	Screw-in/Hard-wire	100.0%	238	238	3.86
Exterior Lighting	HID	100.0%	196	196	3.19
Exterior Lighting	Linear Fluorescent	100.0%	198	198	3.21
Motors	Pumps	100.0%	5,352	5,352	86.83
Motors	Fans & Blowers	100.0%	4,189	4,189	67.97
Motors	Compressed Air	100.0%	3,345	3,345	54.27
Motors	Conveyors	100.0%	15,101	15,101	245.01
Motors	Other Motors	100.0%	2,341	2,341	37.99
Process	Process Heating	100.0%	6,115	6,115	99.21
Process	Process Cooling	100.0%	2,005	2,005	32.53
Process	Process Refrigeration	100.0%	2,005	2,005	32.53
Process	Process Electro-Chemical	100.0%	3,972	3,972	64.45
Process	Process Other	100.0%	1,345	1,345	21.83
Miscellaneous	Miscellaneous	100.0%	2,197	2,197	35.64
	Total			**56,846**	**922.32**

Table A-17 Residential Single Family Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	38.2%	1,424	544	36
Cooling	Room AC	12.3%	518	64	4
Cooling	Air-Source Heat Pump	7.0%	1,491	104	7
Cooling	Geothermal Heat Pump	0.0%	1,317	0	0
Cooling	Evaporative AC	1.6%	1,027	16	1
Space Heating	Electric Room Heat	9.8%	14,299	1,397	91
Space Heating	Electric Furnace	7.4%	16,280	1,212	79
Space Heating	Air-Source Heat Pump	7.0%	12,257	852	56
Space Heating	Geothermal Heat Pump	0.0%	5,402	0	0
Water Heating	Water Heater (<= 55 Gal)	43.1%	3,530	1,523	100
Water Heating	Water Heater (55 to 75 Gal)	5.3%	3,712	195	13
Water Heating	Water Heater (> 75 Gal)	0.5%	3,890	18	1
Interior Lighting	Screw-in/Hard-wire	100.0%	1,267	1,267	83
Interior Lighting	Linear Fluorescent	100.0%	179	179	12
Interior Lighting	Specialty Lighting	100.0%	350	350	23
Exterior Lighting	Screw-in/Hard-wire	100.0%	491	491	32
Appliances	Clothes Washer	95.5%	103	98	6
Appliances	Clothes Dryer	65.6%	802	527	34
Appliances	Dishwasher	80.1%	443	355	23
Appliances	Refrigerator	100.0%	826	826	54
Appliances	Freezer	66.3%	660	438	29
Appliances	Second Refrigerator	29.4%	962	283	18
Appliances	Stove	58.4%	474	277	18
Appliances	Microwave	93.1%	138	129	8
Electronics	Personal Computers	63.3%	208	131	9
Electronics	Monitor	77.3%	88	68	4
Electronics	Laptops	85.7%	55	47	3
Electronics	TVs	199.0%	245	487	32
Electronics	Printer/Fax/Copier	76.9%	63	49	3
Electronics	Set top Boxes/DVRs	105.8%	124	131	9
Electronics	Devices and Gadgets	100.0%	54	54	3
Miscellaneous	Pool Pump	2.6%	2,350	61	4
Miscellaneous	Pool Heater	0.6%	3,763	24	2
Miscellaneous	Furnace Fan	70.2%	279	196	13
Miscellaneous	Well pump	20.0%	600	120	8
Miscellaneous	Miscellaneous	100.0%	389	389	25
	Total			**12,902**	**843**

Table A-18 Residential Multifamily Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	22.3%	373	83	0
Cooling	Room AC	31.6%	296	94	0
Cooling	Air-Source Heat Pump	1.9%	373	7	0
Cooling	Geothermal Heat Pump	0.0%	329	0	0
Cooling	Evaporative AC	1.9%	307	6	0
Space Heating	Electric Room Heat	59.5%	2,937	1,748	9
Space Heating	Electric Furnace	16.7%	3,343	557	3
Space Heating	Air-Source Heat Pump	1.9%	1,831	34	0
Space Heating	Geothermal Heat Pump	0.0%	807	0	0
Water Heating	Water Heater (<= 55 Gal)	57.4%	2,205	1,266	7
Water Heating	Water Heater (55 to 75 Gal)	7.6%	2,319	176	1
Water Heating	Water Heater (> 75 Gal)	0.0%	2,430	0	0
Interior Lighting	Screw-in/Hard-wire	100.0%	639	639	3
Interior Lighting	Linear Fluorescent	100.0%	40	40	0
Interior Lighting	Specialty Lighting	100.0%	37	37	0
Exterior Lighting	Screw-in/Hard-wire	100.0%	0	0	0
Appliances	Clothes Washer	59.6%	96	57	0
Appliances	Clothes Dryer	42.3%	593	251	1
Appliances	Dishwasher	73.1%	413	302	2
Appliances	Refrigerator	100.0%	771	771	4
Appliances	Freezer	23.1%	620	143	1
Appliances	Second Refrigerator	3.0%	898	27	0
Appliances	Stove	69.2%	357	247	1
Appliances	Microwave	86.5%	129	112	1
Electronics	Personal Computers	46.3%	194	90	0
Electronics	Monitor	56.6%	82	47	0
Electronics	Laptops	74.1%	52	38	0
Electronics	TVs	140.7%	269	379	2
Electronics	Printer/Fax/Copier	51.9%	59	31	0
Electronics	Set top Boxes/DVRs	64.8%	116	75	0
Electronics	Devices and Gadgets	100.0%	50	50	0
Miscellaneous	Pool Pump	0.0%	2,197	0	0
Miscellaneous	Pool Heater	0.0%	3,517	0	0
Miscellaneous	Furnace Fan	33.3%	98	33	0
Miscellaneous	Well pump	0.0%	556	0	0
Miscellaneous	Miscellaneous	100.0%	395	395	2
	Total			**7,733**	**41**

Table A-19 Residential Manufactured Home Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	35.9%	500	180	1
Cooling	Room AC	20.5%	395	81	0
Cooling	Air-Source Heat Pump	5.1%	500	26	0
Cooling	Geothermal Heat Pump	0.0%	441	0	0
Cooling	Evaporative AC	0.0%	319	0	0
Space Heating	Electric Room Heat	10.7%	6,758	724	4
Space Heating	Electric Furnace	42.9%	7,694	3,297	16
Space Heating	Air-Source Heat Pump	5.1%	6,330	325	2
Space Heating	Geothermal Heat Pump	0.0%	2,900	0	0
Water Heating	Water Heater (<= 55 Gal)	66.2%	2,370	1,570	8
Water Heating	Water Heater (55 to 75 Gal)	8.8%	2,492	219	1
Water Heating	Water Heater (> 75 Gal)	0.0%	2,612	0	0
Interior Lighting	Screw-in/Hard-wire	100.0%	750	750	4
Interior Lighting	Linear Fluorescent	100.0%	61	61	0
Interior Lighting	Specialty Lighting	100.0%	158	158	1
Exterior Lighting	Screw-in/Hard-wire	100.0%	184	184	1
Appliances	Clothes Washer	94.9%	91	87	0
Appliances	Clothes Dryer	82.1%	888	729	4
Appliances	Dishwasher	74.4%	394	293	1
Appliances	Refrigerator	100.0%	732	732	4
Appliances	Freezer	48.7%	586	286	1
Appliances	Second Refrigerator	21.0%	852	179	1
Appliances	Stove	82.1%	510	419	2
Appliances	Microwave	92.3%	123	113	1
Electronics	Personal Computers	46.4%	184	86	0
Electronics	Monitor	56.8%	78	44	0
Electronics	Laptops	50.0%	49	25	0
Electronics	TVs	110.7%	273	302	1
Electronics	Printer/Fax/Copier	42.9%	56	24	0
Electronics	Set top Boxes/DVRs	89.3%	110	99	0
Electronics	Devices and Gadgets	100.0%	48	48	0
Miscellaneous	Pool Pump	0.0%	2,087	0	0
Miscellaneous	Pool Heater	0.0%	3,341	0	0
Miscellaneous	Furnace Fan	71.4%	205	146	1
Miscellaneous	Well pump	0.0%	428	0	0
Miscellaneous	Miscellaneous	100.0%	415	415	2
	Total			**11,599**	**56**

Table A-20 Residential Low Income Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	25.1%	481	121	4
Cooling	Room AC	29.0%	351	102	3
Cooling	Air-Source Heat Pump	2.6%	485	13	0
Cooling	Geothermal Heat Pump	0.0%	428	0	0
Cooling	Evaporative AC	1.6%	363	6	0
Space Heating	Electric Room Heat	50.0%	3,842	1,920	61
Space Heating	Electric Furnace	19.6%	4,374	859	28
Space Heating	Air-Source Heat Pump	2.6%	2,951	77	2
Space Heating	Geothermal Heat Pump	0.0%	1,319	0	0
Water Heating	Water Heater (<= 55 Gal)	57.7%	2,155	1,244	40
Water Heating	Water Heater (55 to 75 Gal)	7.6%	2,266	173	6
Water Heating	Water Heater (> 75 Gal)	0.0%	2,374	1	0
Interior Lighting	Screw-in/Hard-wire	100.0%	692	692	22
Interior Lighting	Linear Fluorescent	100.0%	51	51	2
Interior Lighting	Specialty Lighting	100.0%	72	72	2
Exterior Lighting	Screw-in/Hard-wire	100.0%	54	54	2
Appliances	Clothes Washer	66.5%	90	60	2
Appliances	Clothes Dryer	49.1%	610	299	10
Appliances	Dishwasher	73.7%	389	286	9
Appliances	Refrigerator	100.0%	725	725	23
Appliances	Freezer	29.1%	583	170	5
Appliances	Second Refrigerator	7.0%	844	59	2
Appliances	Stove	70.3%	363	255	8
Appliances	Microwave	87.7%	121	106	3
Electronics	Personal Computers	47.3%	182	86	3
Electronics	Monitor	57.9%	77	45	1
Electronics	Laptops	71.5%	49	35	1
Electronics	TVs	140.2%	253	354	11
Electronics	Printer/Fax/Copier	52.1%	55	29	1
Electronics	Set top Boxes/DVRs	70.6%	109	77	2
Electronics	Devices and Gadgets	100.0%	47	47	2
Miscellaneous	Pool Pump	0.2%	2,065	3	0
Miscellaneous	Pool Heater	0.0%	3,306	1	0
Miscellaneous	Furnace Fan	40.7%	123	50	2
Miscellaneous	Well pump	1.2%	510	6	0
Miscellaneous	Miscellaneous	100.0%	272	272	9
	Total			**8,349**	**267**

Table A-21 Small Office Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.5%	4.68	0.02	0.2
Cooling	Water-Cooled Chiller	0.0%	5.30	0.00	0.0
Cooling	RTU	77.9%	3.86	3.01	26.2
Cooling	Room AC	3.6%	3.97	0.14	1.3
Cooling	Air-Source Heat Pump	8.2%	3.86	0.32	2.7
Cooling	Geothermal Heat Pump	3.2%	2.36	0.08	0.7
Heating	Electric Furnace	16.0%	6.76	1.08	9.4
Heating	Electric Room Heat	14.5%	6.44	0.93	8.1
Heating	Air-Source Heat Pump	8.2%	5.71	0.47	4.1
Heating	Geothermal Heat Pump	3.2%	4.34	0.14	1.2
Ventilation	Ventilation	100.0%	1.40	1.40	12.1
Water Heating	Water Heater	69.8%	1.05	0.73	6.4
Interior Lighting	Screw-in/Hard-wire	100.0%	0.62	0.62	5.4
Interior Lighting	High-Bay Fixtures	100.0%	0.34	0.34	3.0
Interior Lighting	Linear Fluorescent	100.0%	2.05	2.05	17.8
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.14	0.14	1.2
Exterior Lighting	HID	100.0%	0.19	0.19	1.7
Exterior Lighting	Linear Fluorescent	100.0%	0.07	0.07	0.6
Refrigeration	Walk-in Refrigerator/Freezer	0.2%	2.34	0.01	0.0
Refrigeration	Reach-in Refrigerator/Freezer	1.6%	0.52	0.01	0.1
Refrigeration	Glass Door Display	0.5%	0.54	0.00	0.0
Refrigeration	Open Display Case	0.5%	3.19	0.01	0.1
Refrigeration	Icemaker	0.5%	0.88	0.00	0.0
Refrigeration	Vending Machine	0.2%	0.41	0.00	0.0
Food Preparation	Oven	0.8%	1.50	0.01	0.1
Food Preparation	Fryer	0.1%	2.17	0.00	0.0
Food Preparation	Dishwasher	1.0%	2.99	0.03	0.3
Food Preparation	Steamer	0.1%	2.19	0.00	0.0
Food Preparation	Hot Food Container	0.1%	0.41	0.00	0.0
Office Equipment	Desktop Computer	100.0%	1.55	1.55	13.5
Office Equipment	Laptop	100.0%	0.24	0.24	2.1
Office Equipment	Server	100.0%	0.46	0.46	4.0
Office Equipment	Monitor	100.0%	0.27	0.27	2.4
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	1.8
Office Equipment	POS Terminal	40.0%	0.12	0.05	0.4
Miscellaneous	Non-HVAC Motors	22.0%	0.19	0.04	0.4
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.82	0.82	7.1
Total				**15.44**	**134.4**

Table A-22 Large Office Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	23.5%	2.74	0.64	0.6
Cooling	Water-Cooled Chiller	23.5%	3.03	0.71	0.7
Cooling	RTU	33.4%	3.35	1.12	1.1
Cooling	Room AC	0.6%	3.44	0.02	0.0
Cooling	Air-Source Heat Pump	7.5%	3.35	0.25	0.2
Cooling	Geothermal Heat Pump	6.5%	2.04	0.13	0.1
Heating	Electric Furnace	15.7%	4.99	0.78	0.8
Heating	Electric Room Heat	14.3%	4.75	0.68	0.7
Heating	Air-Source Heat Pump	7.5%	4.57	0.34	0.3
Heating	Geothermal Heat Pump	6.5%	3.62	0.24	0.2
Ventilation	Ventilation	100.0%	2.96	2.96	2.9
Water Heating	Water Heater	68.0%	0.99	0.67	0.6
Interior Lighting	Screw-in/Hard-wire	100.0%	0.62	0.62	0.6
Interior Lighting	High-Bay Fixtures	100.0%	0.37	0.37	0.4
Interior Lighting	Linear Fluorescent	100.0%	2.74	2.74	2.7
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.14	0.14	0.1
Exterior Lighting	HID	100.0%	0.37	0.37	0.4
Exterior Lighting	Linear Fluorescent	100.0%	0.23	0.23	0.2
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	1.62	0.03	0.0
Refrigeration	Reach-in Refrigerator/Freezer	14.0%	0.36	0.05	0.0
Refrigeration	Glass Door Display	4.0%	0.37	0.01	0.0
Refrigeration	Open Display Case	4.0%	2.22	0.09	0.1
Refrigeration	Icemaker	4.0%	0.61	0.02	0.0
Refrigeration	Vending Machine	2.1%	0.29	0.01	0.0
Food Preparation	Oven	10.0%	0.76	0.08	0.1
Food Preparation	Fryer	1.0%	1.10	0.01	0.0
Food Preparation	Dishwasher	12.0%	1.52	0.18	0.2
Food Preparation	Steamer	1.0%	1.11	0.01	0.0
Food Preparation	Hot Food Container	1.0%	0.21	0.00	0.0
Office Equipment	Desktop Computer	100.0%	1.96	1.96	1.9
Office Equipment	Laptop	100.0%	0.30	0.30	0.3
Office Equipment	Server	100.0%	0.19	0.19	0.2
Office Equipment	Monitor	100.0%	0.35	0.35	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.18	0.18	0.2
Office Equipment	POS Terminal	40.0%	0.03	0.01	0.0
Miscellaneous	Non-HVAC Motors	89.6%	0.21	0.19	0.2
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.83	0.83	0.8
Total				**17.54**	**17.0**

Table A-23 Restaurant Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.3%	3.65	0.01	0.0
Cooling	Water-Cooled Chiller	0.0%	4.03	0.00	0.0
Cooling	RTU	76.3%	4.58	3.49	1.0
Cooling	Room AC	6.6%	4.71	0.31	0.1
Cooling	Air-Source Heat Pump	6.6%	4.58	0.30	0.1
Cooling	Geothermal Heat Pump	3.3%	2.79	0.09	0.0
Heating	Electric Furnace	5.1%	6.99	0.36	0.1
Heating	Electric Room Heat	0.1%	6.66	0.01	0.0
Heating	Air-Source Heat Pump	6.6%	4.94	0.32	0.1
Heating	Geothermal Heat Pump	3.3%	3.48	0.11	0.0
Ventilation	Ventilation	100.0%	2.48	2.48	0.7
Water Heating	Water Heater	35.2%	8.81	3.10	0.9
Interior Lighting	Screw-in/Hard-wire	100.0%	2.09	2.09	0.6
Interior Lighting	High-Bay Fixtures	100.0%	0.40	0.40	0.1
Interior Lighting	Linear Fluorescent	100.0%	3.62	3.62	1.1
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	0.1
Exterior Lighting	HID	100.0%	1.61	1.61	0.5
Exterior Lighting	Linear Fluorescent	100.0%	0.47	0.47	0.1
Refrigeration	Walk-in Refrigerator/Freezer	74.0%	6.56	4.85	1.4
Refrigeration	Reach-in Refrigerator/Freezer	7.0%	2.94	0.21	0.1
Refrigeration	Glass Door Display	77.6%	1.51	1.17	0.3
Refrigeration	Open Display Case	26.0%	8.95	2.33	0.7
Refrigeration	Icemaker	75.9%	2.47	1.88	0.5
Refrigeration	Vending Machine	0.0%	1.16	0.00	0.0
Food Preparation	Oven	16.0%	9.79	1.57	0.5
Food Preparation	Fryer	14.0%	14.16	1.98	0.6
Food Preparation	Dishwasher	48.0%	9.75	4.68	1.4
Food Preparation	Steamer	14.0%	7.15	1.00	0.3
Food Preparation	Hot Food Container	31.0%	1.33	0.41	0.1
Office Equipment	Desktop Computer	100.0%	0.29	0.29	0.1
Office Equipment	Laptop	100.0%	0.04	0.04	0.0
Office Equipment	Server	50.0%	0.34	0.17	0.0
Office Equipment	Monitor	100.0%	0.05	0.05	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.0
Office Equipment	POS Terminal	100.0%	0.09	0.09	0.0
Miscellaneous	Non-HVAC Motors	20.0%	0.56	0.11	0.0
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.52	2.52	0.7
Total				**42.40**	**12.4**

Table A-24 Retail Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	9.5%	2.80	0.27	3.2
Cooling	Water-Cooled Chiller	2.4%	3.17	0.08	0.9
Cooling	RTU	54.2%	2.31	1.25	15.2
Cooling	Room AC	2.8%	2.53	0.07	0.9
Cooling	Air-Source Heat Pump	1.7%	2.31	0.04	0.5
Cooling	Geothermal Heat Pump	1.4%	1.41	0.02	0.2
Heating	Electric Furnace	5.8%	4.81	0.28	3.4
Heating	Electric Room Heat	2.1%	4.58	0.10	1.2
Heating	Air-Source Heat Pump	1.7%	3.85	0.07	0.8
Heating	Geothermal Heat Pump	1.4%	2.62	0.04	0.4
Ventilation	Ventilation	100.0%	0.98	0.98	11.9
Water Heating	Water Heater	63.0%	0.79	0.50	6.1
Interior Lighting	Screw-in/Hard-wire	100.0%	0.85	0.85	10.3
Interior Lighting	High-Bay Fixtures	100.0%	1.02	1.02	12.4
Interior Lighting	Linear Fluorescent	100.0%	3.43	3.43	41.7
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.36	0.36	4.3
Exterior Lighting	HID	100.0%	1.30	1.30	15.8
Exterior Lighting	Linear Fluorescent	100.0%	0.87	0.87	10.6
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	2.04	0.04	0.5
Refrigeration	Reach-in Refrigerator/Freezer	0.0%	0.46	0.00	0.0
Refrigeration	Glass Door Display	16.3%	0.47	0.08	0.9
Refrigeration	Open Display Case	14.0%	2.79	0.39	4.7
Refrigeration	Icemaker	7.1%	0.77	0.05	0.7
Refrigeration	Vending Machine	22.8%	0.36	0.08	1.0
Food Preparation	Oven	8.0%	2.43	0.19	2.4
Food Preparation	Fryer	1.6%	3.51	0.06	0.7
Food Preparation	Dishwasher	2.0%	4.84	0.10	1.2
Food Preparation	Steamer	1.6%	3.55	0.06	0.7
Food Preparation	Hot Food Container	1.0%	0.66	0.01	0.1
Office Equipment	Desktop Computer	100.0%	0.34	0.34	4.1
Office Equipment	Laptop	100.0%	0.05	0.05	0.6
Office Equipment	Server	82.0%	0.06	0.05	0.6
Office Equipment	Monitor	100.0%	0.06	0.06	0.7
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	0.6
Office Equipment	POS Terminal	100.0%	0.01	0.01	0.2
Miscellaneous	Non-HVAC Motors	40.2%	0.16	0.07	0.8
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.61	0.61	7.5
Total				**13.80**	**167.6**

Table A-25 Grocery Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	5.3%	5.20	0.28	0.5
Cooling	Water-Cooled Chiller	0.0%	5.89	0.00	0.0
Cooling	RTU	69.6%	4.30	2.99	5.8
Cooling	Room AC	0.0%	4.42	0.00	0.0
Cooling	Air-Source Heat Pump	3.1%	3.80	0.12	0.2
Cooling	Geothermal Heat Pump	0.0%	1.60	0.00	0.0
Heating	Electric Furnace	15.4%	5.62	0.86	1.7
Heating	Electric Room Heat	1.5%	5.35	0.08	0.2
Heating	Air-Source Heat Pump	3.1%	3.01	0.09	0.2
Heating	Geothermal Heat Pump	0.0%	1.93	0.00	0.0
Ventilation	Ventilation	100.0%	2.07	2.07	4.0
Water Heating	Water Heater	38.2%	2.18	0.83	1.6
Interior Lighting	Screw-in/Hard-wire	100.0%	1.93	1.93	3.7
Interior Lighting	High-Bay Fixtures	100.0%	1.70	1.70	3.3
Interior Lighting	Linear Fluorescent	100.0%	5.83	5.83	11.3
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.19	0.19	0.4
Exterior Lighting	HID	100.0%	1.16	1.16	2.2
Exterior Lighting	Linear Fluorescent	100.0%	0.48	0.48	0.9
Refrigeration	Walk-in Refrigerator/Freezer	16.0%	5.13	0.82	1.6
Refrigeration	Reach-in Refrigerator/Freezer	83.1%	0.33	0.27	0.5
Refrigeration	Glass Door Display	95.6%	3.37	3.23	6.3
Refrigeration	Open Display Case	95.6%	19.99	19.12	37.1
Refrigeration	Icemaker	66.6%	0.28	0.18	0.4
Refrigeration	Vending Machine	36.5%	0.26	0.09	0.2
Food Preparation	Oven	17.0%	2.44	0.42	0.8
Food Preparation	Fryer	13.0%	3.53	0.46	0.9
Food Preparation	Dishwasher	7.0%	4.86	0.34	0.7
Food Preparation	Steamer	13.0%	3.57	0.46	0.9
Food Preparation	Hot Food Container	16.0%	0.67	0.11	0.2
Office Equipment	Desktop Computer	100.0%	0.25	0.25	0.5
Office Equipment	Laptop	64.0%	0.04	0.03	0.0
Office Equipment	Server	100.0%	0.15	0.15	0.3
Office Equipment	Monitor	100.0%	0.04	0.04	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.1
Office Equipment	POS Terminal	100.0%	0.10	0.10	0.2
Miscellaneous	Non-HVAC Motors	34.6%	0.56	0.19	0.4
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.35	2.35	4.6
Total				**47.25**	**91.7**

Table A-26 College Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	34.8%	3.14	1.09	5.7
Cooling	Water-Cooled Chiller	8.7%	4.66	0.41	2.1
Cooling	RTU	15.6%	2.04	0.32	1.7
Cooling	Room AC	5.0%	2.09	0.10	0.5
Cooling	Air-Source Heat Pump	3.6%	2.03	0.07	0.4
Cooling	Geothermal Heat Pump	0.0%	1.24	0.00	0.0
Heating	Electric Furnace	10.5%	8.67	0.91	4.8
Heating	Electric Room Heat	29.7%	8.26	2.45	12.8
Heating	Air-Source Heat Pump	3.6%	6.15	0.22	1.2
Heating	Geothermal Heat Pump	0.0%	4.76	0.00	0.0
Ventilation	Ventilation	100.0%	1.48	1.48	7.7
Water Heating	Water Heater	26.3%	2.02	0.53	2.8
Interior Lighting	Screw-in/Hard-wire	100.0%	0.83	0.83	4.3
Interior Lighting	High-Bay Fixtures	100.0%	0.30	0.30	1.6
Interior Lighting	Linear Fluorescent	100.0%	2.04	2.04	10.7
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.01	0.01	0.0
Exterior Lighting	HID	100.0%	0.27	0.27	1.4
Exterior Lighting	Linear Fluorescent	100.0%	0.97	0.97	5.1
Refrigeration	Walk-in Refrigerator/Freezer	7.7%	0.29	0.02	0.1
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.13	0.02	0.1
Refrigeration	Glass Door Display	8.0%	0.07	0.01	0.0
Refrigeration	Open Display Case	4.8%	0.40	0.02	0.1
Refrigeration	Icemaker	28.2%	0.22	0.06	0.3
Refrigeration	Vending Machine	8.8%	0.10	0.01	0.0
Food Preparation	Oven	13.7%	0.68	0.09	0.5
Food Preparation	Fryer	1.6%	0.98	0.02	0.1
Food Preparation	Dishwasher	11.7%	1.35	0.16	0.8
Food Preparation	Steamer	1.6%	0.99	0.02	0.1
Food Preparation	Hot Food Container	8.4%	0.19	0.02	0.1
Office Equipment	Desktop Computer	100.0%	0.51	0.51	2.7
Office Equipment	Laptop	100.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.06	0.06	0.3
Office Equipment	Monitor	100.0%	0.09	0.09	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	0.4
Office Equipment	POS Terminal	36.0%	0.02	0.01	0.0
Miscellaneous	Non-HVAC Motors	88.8%	0.14	0.12	0.6
Miscellaneous	Pool Pump	6.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.61	0.61	3.2
Total				**13.93**	**72.9**

Table A-27 School Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	24.5%	2.59	0.63	7.0
Cooling	Water-Cooled Chiller	6.1%	3.83	0.23	2.6
Cooling	RTU	11.9%	1.68	0.20	2.2
Cooling	Room AC	5.0%	1.72	0.09	1.0
Cooling	Air-Source Heat Pump	8.6%	1.67	0.14	1.6
Cooling	Geothermal Heat Pump	3.9%	1.02	0.04	0.4
Heating	Electric Furnace	3.7%	9.33	0.35	3.9
Heating	Electric Room Heat	1.8%	8.88	0.16	1.8
Heating	Air-Source Heat Pump	8.6%	6.62	0.57	6.3
Heating	Geothermal Heat Pump	3.9%	5.13	0.20	2.2
Ventilation	Ventilation	100.0%	1.17	1.17	13.0
Water Heating	Water Heater	38.1%	1.63	0.62	6.9
Interior Lighting	Screw-in/Hard-wire	100.0%	0.55	0.55	6.1
Interior Lighting	High-Bay Fixtures	100.0%	0.13	0.13	1.4
Interior Lighting	Linear Fluorescent	100.0%	1.10	1.10	12.2
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.00	0.00	0.0
Exterior Lighting	HID	100.0%	0.17	0.17	1.9
Exterior Lighting	Linear Fluorescent	100.0%	0.96	0.96	10.7
Refrigeration	Walk-in Refrigerator/Freezer	19.0%	0.51	0.10	1.1
Refrigeration	Reach-in Refrigerator/Freezer	33.0%	0.23	0.08	0.8
Refrigeration	Glass Door Display	19.7%	0.12	0.02	0.3
Refrigeration	Open Display Case	11.9%	0.69	0.08	0.9
Refrigeration	Icemaker	69.7%	0.38	0.27	3.0
Refrigeration	Vending Machine	21.8%	0.18	0.04	0.4
Food Preparation	Oven	34.0%	0.58	0.20	2.2
Food Preparation	Fryer	4.0%	0.84	0.03	0.4
Food Preparation	Dishwasher	29.0%	1.15	0.33	3.7
Food Preparation	Steamer	4.0%	0.84	0.03	0.4
Food Preparation	Hot Food Container	21.0%	0.16	0.03	0.4
Office Equipment	Desktop Computer	100.0%	0.45	0.45	5.0
Office Equipment	Laptop	100.0%	0.03	0.03	0.3
Office Equipment	Server	100.0%	0.11	0.11	1.2
Office Equipment	Monitor	100.0%	0.08	0.08	0.9
Office Equipment	Printer/Copier/Fax	100.0%	0.05	0.05	0.6
Office Equipment	POS Terminal	36.0%	0.01	0.01	0.1
Miscellaneous	Non-HVAC Motors	43.7%	0.11	0.05	0.5
Miscellaneous	Pool Pump	6.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.54	0.54	6.0
Total				**9.85**	**109.4**

Table A-28 Health Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	16.5%	5.72	0.94	3.4
Cooling	Water-Cooled Chiller	65.9%	7.50	4.94	18.0
Cooling	RTU	10.8%	5.49	0.59	2.2
Cooling	Room AC	0.4%	5.64	0.02	0.1
Cooling	Air-Source Heat Pump	1.1%	5.48	0.06	0.2
Cooling	Geothermal Heat Pump	0.4%	3.34	0.01	0.0
Heating	Electric Furnace	0.3%	13.21	0.04	0.1
Heating	Electric Room Heat	9.3%	12.58	1.17	4.3
Heating	Air-Source Heat Pump	1.1%	9.03	0.10	0.4
Heating	Geothermal Heat Pump	0.4%	6.62	0.02	0.1
Ventilation	Ventilation	100.0%	4.96	4.96	18.1
Water Heating	Water Heater	22.3%	4.64	1.03	3.8
Interior Lighting	Screw-in/Hard-wire	100.0%	1.54	1.54	5.6
Interior Lighting	High-Bay Fixtures	100.0%	0.35	0.35	1.3
Interior Lighting	Linear Fluorescent	100.0%	3.92	3.92	14.3
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.04	0.04	0.1
Exterior Lighting	HID	100.0%	0.46	0.46	1.7
Exterior Lighting	Linear Fluorescent	100.0%	0.16	0.16	0.6
Refrigeration	Walk-in Refrigerator/Freezer	33.0%	1.05	0.35	1.3
Refrigeration	Reach-in Refrigerator/Freezer	50.0%	0.23	0.12	0.4
Refrigeration	Glass Door Display	8.6%	0.24	0.02	0.1
Refrigeration	Open Display Case	6.7%	1.43	0.10	0.3
Refrigeration	Icemaker	21.1%	0.79	0.17	0.6
Refrigeration	Vending Machine	27.9%	0.37	0.10	0.4
Food Preparation	Oven	13.0%	2.58	0.34	1.2
Food Preparation	Fryer	10.0%	3.73	0.37	1.4
Food Preparation	Dishwasher	25.0%	5.14	1.28	4.7
Food Preparation	Steamer	10.0%	3.77	0.38	1.4
Food Preparation	Hot Food Container	10.0%	0.70	0.07	0.3
Office Equipment	Desktop Computer	100.0%	0.91	0.91	3.3
Office Equipment	Laptop	100.0%	0.06	0.06	0.2
Office Equipment	Server	100.0%	0.11	0.11	0.4
Office Equipment	Monitor	100.0%	0.16	0.16	0.6
Office Equipment	Printer/Copier/Fax	100.0%	0.10	0.10	0.4
Office Equipment	POS Terminal	100.0%	0.07	0.07	0.3
Miscellaneous	Non-HVAC Motors	74.1%	0.36	0.27	1.0
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	3.75	3.75	13.6
Total				**29.06**	**105.8**

Table A-29 Lodging Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	4.4%	1.20	0.05	0.2
Cooling	Water-Cooled Chiller	17.8%	1.56	0.28	0.8
Cooling	RTU	8.1%	2.65	0.21	0.7
Cooling	Room AC	27.5%	2.72	0.75	2.3
Cooling	Air-Source Heat Pump	17.6%	2.65	0.47	1.4
Cooling	Geothermal Heat Pump	2.5%	2.29	0.06	0.2
Heating	Electric Furnace	60.2%	4.18	2.52	7.6
Heating	Electric Room Heat	3.6%	3.98	0.14	0.4
Heating	Air-Source Heat Pump	17.6%	3.83	0.67	2.0
Heating	Geothermal Heat Pump	2.5%	2.48	0.06	0.2
Ventilation	Ventilation	100.0%	1.42	1.42	4.3
Water Heating	Water Heater	31.5%	4.81	1.51	4.6
Interior Lighting	Screw-in/Hard-wire	100.0%	3.31	3.31	10.0
Interior Lighting	High-Bay Fixtures	100.0%	0.27	0.27	0.8
Interior Lighting	Linear Fluorescent	100.0%	0.87	0.87	2.6
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.13	0.13	0.4
Exterior Lighting	HID	100.0%	0.51	0.51	1.6
Exterior Lighting	Linear Fluorescent	100.0%	0.03	0.03	0.1
Refrigeration	Walk-in Refrigerator/Freezer	3.0%	0.82	0.02	0.1
Refrigeration	Reach-in Refrigerator/Freezer	19.0%	0.18	0.03	0.1
Refrigeration	Glass Door Display	40.0%	0.19	0.08	0.2
Refrigeration	Open Display Case	0.0%	1.12	0.00	0.0
Refrigeration	Icemaker	88.9%	0.62	0.55	1.7
Refrigeration	Vending Machine	57.8%	0.29	0.17	0.5
Food Preparation	Oven	24.0%	0.83	0.20	0.6
Food Preparation	Fryer	4.0%	1.20	0.05	0.1
Food Preparation	Dishwasher	39.0%	0.82	0.32	1.0
Food Preparation	Steamer	4.0%	0.60	0.02	0.1
Food Preparation	Hot Food Container	10.0%	0.11	0.01	0.0
Office Equipment	Desktop Computer	100.0%	0.20	0.20	0.6
Office Equipment	Laptop	100.0%	0.03	0.03	0.1
Office Equipment	Server	100.0%	0.12	0.12	0.4
Office Equipment	Monitor	100.0%	0.04	0.04	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.1
Office Equipment	POS Terminal	58.0%	0.03	0.02	0.1
Miscellaneous	Non-HVAC Motors	91.3%	0.15	0.14	0.4
Miscellaneous	Pool Pump	76.0%	0.02	0.02	0.1
Miscellaneous	Pool Heater	27.0%	0.03	0.01	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.76	0.76	2.3
Total				**16.08**	**48.7**

Table A-30 Warehouse Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.0%	4.17	0.54	3.4
Cooling	Water-Cooled Chiller	1.4%	4.78	0.07	0.4
Cooling	RTU	17.0%	4.11	0.70	4.4
Cooling	Room AC	1.1%	4.22	0.05	0.3
Cooling	Air-Source Heat Pump	1.6%	4.10	0.07	0.4
Cooling	Geothermal Heat Pump	0.0%	2.50	0.00	0.0
Heating	Electric Furnace	4.9%	7.82	0.38	2.4
Heating	Electric Room Heat	1.7%	7.45	0.13	0.8
Heating	Air-Source Heat Pump	1.6%	5.85	0.09	0.6
Heating	Geothermal Heat Pump	0.0%	4.46	0.00	0.0
Ventilation	Ventilation	100.0%	0.60	0.60	3.8
Water Heating	Water Heater	76.9%	0.61	0.47	2.9
Interior Lighting	Screw-in/Hard-wire	100.0%	0.23	0.23	1.5
Interior Lighting	High-Bay Fixtures	100.0%	0.96	0.96	6.1
Interior Lighting	Linear Fluorescent	100.0%	1.12	1.12	7.1
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.18	0.18	1.1
Exterior Lighting	HID	100.0%	0.15	0.15	0.9
Exterior Lighting	Linear Fluorescent	100.0%	0.15	0.15	1.0
Refrigeration	Walk-in Refrigerator/Freezer	1.1%	4.49	0.05	0.3
Refrigeration	Reach-in Refrigerator/Freezer	2.0%	1.01	0.02	0.1
Refrigeration	Glass Door Display	0.0%	1.03	0.00	0.0
Refrigeration	Open Display Case	0.0%	6.13	0.00	0.0
Refrigeration	Icemaker	8.3%	1.69	0.14	0.9
Refrigeration	Vending Machine	6.9%	0.80	0.05	0.3
Food Preparation	Oven	0.0%	0.28	0.00	0.0
Food Preparation	Fryer	0.0%	0.41	0.00	0.0
Food Preparation	Dishwasher	2.0%	0.56	0.01	0.1
Food Preparation	Steamer	0.0%	0.41	0.00	0.0
Food Preparation	Hot Food Container	0.0%	0.08	0.00	0.0
Office Equipment	Desktop Computer	100.0%	0.23	0.23	1.5
Office Equipment	Laptop	100.0%	0.03	0.03	0.2
Office Equipment	Server	89.0%	0.27	0.24	1.5
Office Equipment	Monitor	100.0%	0.04	0.04	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.2
Office Equipment	POS Terminal	77.0%	0.07	0.06	0.4
Miscellaneous	Non-HVAC Motors	49.9%	0.14	0.07	0.4
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.65	0.65	4.1
Total				**7.50**	**47.4**

Table A-31 Miscellaneous Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	4.2%	3.89	0.16	2.0
Cooling	Water-Cooled Chiller	16.7%	4.41	0.73	9.0
Cooling	RTU	34.5%	3.22	1.11	13.6
Cooling	Room AC	4.9%	3.30	0.16	2.0
Cooling	Air-Source Heat Pump	6.2%	3.22	0.20	2.4
Cooling	Geothermal Heat Pump	1.1%	1.96	0.02	0.3
Heating	Electric Furnace	15.2%	8.92	1.36	16.6
Heating	Electric Room Heat	8.4%	8.49	0.71	8.7
Heating	Air-Source Heat Pump	6.2%	7.40	0.46	5.6
Heating	Geothermal Heat Pump	1.1%	5.74	0.07	0.8
Ventilation	Ventilation	100.0%	1.39	1.39	17.0
Water Heating	Water Heater	51.3%	2.64	1.35	16.6
Interior Lighting	Screw-in/Hard-wire	100.0%	0.75	0.75	9.2
Interior Lighting	High-Bay Fixtures	100.0%	0.25	0.25	3.0
Interior Lighting	Linear Fluorescent	100.0%	1.42	1.42	17.3
Exterior Lighting	Screw-in/Hard-wire	100.0%	0.43	0.43	5.3
Exterior Lighting	HID	100.0%	0.91	0.91	11.1
Exterior Lighting	Linear Fluorescent	100.0%	0.07	0.07	0.8
Refrigeration	Walk-in Refrigerator/Freezer	9.0%	0.98	0.09	1.1
Refrigeration	Reach-in Refrigerator/Freezer	0.0%	0.22	0.00	0.0
Refrigeration	Glass Door Display	15.0%	0.23	0.03	0.4
Refrigeration	Open Display Case	0.0%	1.34	0.00	0.0
Refrigeration	Icemaker	41.6%	0.37	0.15	1.9
Refrigeration	Vending Machine	28.6%	0.35	0.10	1.2
Food Preparation	Oven	28.0%	0.24	0.07	0.8
Food Preparation	Fryer	4.0%	0.35	0.01	0.2
Food Preparation	Dishwasher	31.0%	0.49	0.15	1.8
Food Preparation	Steamer	4.0%	0.36	0.01	0.2
Food Preparation	Hot Food Container	7.0%	0.07	0.00	0.1
Office Equipment	Desktop Computer	100.0%	0.37	0.37	4.6
Office Equipment	Laptop	100.0%	0.06	0.06	0.7
Office Equipment	Server	66.0%	0.22	0.15	1.8
Office Equipment	Monitor	100.0%	0.07	0.07	0.8
Office Equipment	Printer/Copier/Fax	100.0%	0.04	0.04	0.5
Office Equipment	POS Terminal	28.0%	0.06	0.02	0.2
Miscellaneous	Non-HVAC Motors	59.9%	0.15	0.09	1.1
Miscellaneous	Pool Pump	4.0%	0.02	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.78	0.78	9.6
Total				**13.75**	**168.1**

Table A-32 Industrial Electric Market Profile, Idaho

Average Market Profiles - Electricity

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.0%	5,652	734	6.51
Cooling	Water-Cooled Chiller	1.4%	6,479	94	0.83
Cooling	RTU	17.0%	5,559	947	8.40
Cooling	Room AC	1.1%	5,714	64	0.57
Cooling	Air-Source Heat Pump	1.6%	5,557	89	0.79
Cooling	Geothermal Heat Pump	0.0%	3,706	0	0.00
Heating	Electric Furnace	4.9%	10,593	516	4.58
Heating	Electric Room Heat	1.7%	10,088	173	1.54
Heating	Air-Source Heat Pump	1.6%	7,918	127	1.13
Heating	Geothermal Heat Pump	0.0%	5,281	0	0.00
Ventilation	Ventilation	100.0%	807	807	7.16
Interior Lighting	Screw-in/Hard-wire	100.0%	205	205	1.82
Interior Lighting	High-Bay Fixtures	100.0%	854	854	7.58
Interior Lighting	Linear Fluorescent	100.0%	997	997	8.84
Exterior Lighting	Screw-in/Hard-wire	100.0%	162	162	1.44
Exterior Lighting	HID	100.0%	134	134	1.18
Exterior Lighting	Linear Fluorescent	100.0%	134	134	1.19
Motors	Pumps	100.0%	3,640	3,640	32.29
Motors	Fans & Blowers	100.0%	2,850	2,850	25.28
Motors	Compressed Air	100.0%	2,275	2,275	20.18
Motors	Conveyors	100.0%	10,272	10,272	91.13
Motors	Other Motors	100.0%	1,593	1,593	14.13
Process	Process Heating	100.0%	4,159	4,159	36.90
Process	Process Cooling	100.0%	1,364	1,364	12.10
Process	Process Refrigeration	100.0%	1,364	1,364	12.10
Process	Process Electro-Chemical	100.0%	2,702	2,702	23.97
Process	Process Other	100.0%	915	915	8.12
Miscellaneous	Miscellaneous	100.0%	1,494	1,494	13.26
	Total			**38,668**	**343.03**

APPENDIX | **B**

Market Adoption (Ramp) Rates

This appendix presents the market adoption rates we applied to economic potential to estimate achievable potential.

Avista Appendix - Market Adoption Ra

Equipment Measure Data

Please see measure-level assumptions and details in the file "*Avista Appendix- Equipment Measure Data.xlsx*"

Avista Appendix - Equipment Measure

APPENDIX | **D**

Non-Equipment Measure Data

Please see measure-level assumptions and details in the file "*Avista Appendix- Non-Equipment Measure Data.xlsx*"

Avista Appendix - Non-Equipment Me

Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 250
Walnut Creek, CA 94596

P: 510.982.3525
F: 925.284.3147

2015 Electric Integrated Resource Plan

Appendix D – Avista Generation Energy Efficiency Studies

Energy Efficiency Improvements Audit Report

Prepared for

Boulder Park Generating Facility

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

January 16, 2015

Overview

Facility: Boulder Park Thermal Generation Facility
Audited by:, Andy Paul PE, Bryce Eschenbacher PE and Levi Westra PE
Onsite Staff: James Mittlestadt and Mike Mecham
Facility Audited on: January 8th, 2015

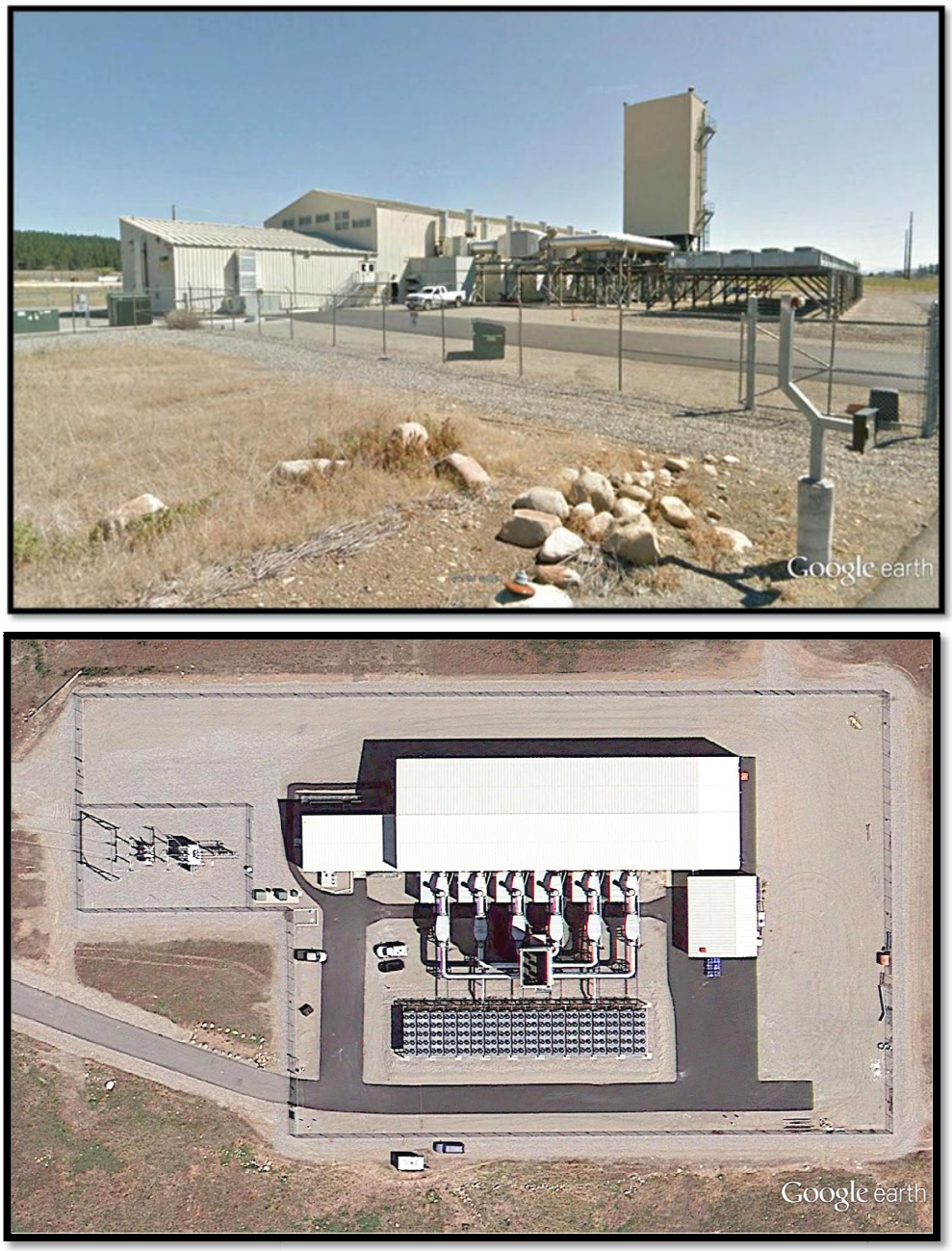


Figure 1 Google Earth Images of the Boulder Park Generation Facility

Avista's DSM Engineering staff visited the Boulder Park generating facility to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically,

this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility, potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of an office, network room, and large high bay warehouse which houses (6) sound isolated natural gas burning compression-ignition 4-stroke engine generator sets; with a 7th unit available for parts.

Shell

There are several areas around the facility where additional weatherization work can be conducted.

1. The roll up doors could use new weather stripping along the outside edges of the doors and along the bottom. A noticeable draft can be felt when you stand next to the doors.

2. The man doors would also benefit from additional weather stripping.

3. There are several areas along where the foundation and exterior walls meet that daylight can be seen from the inside. These gaps in the wall construction should be sealed; a closed cell foam product would work well here.

While these measures will conserve energy, those savings will be negligible in comparison to the measures listed further in this report.

Lighting

The site employs T12, T8 and T5 linear fluorescent lighting as well as 400 Watt Metal Halide (MH) high-bay and 250 Watt MH exterior lighting on dusk to dawn sensors. No parking lot lighting was observed.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Control Room Lighting	**$13,850**	**20 yrs**	**3,931**
2	Generating Floor High Bays	**$16,848**	**20 yrs**	**16,099**
3	Replacing Engine Bay Lights	**$17,976**	**20 yrs**	**6,739**
4	Replace Exterior Wall Packs	**$10,702**	**20 yrs**	**16,054**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The facility currently has (x40) two lamp F32T8 fluorescent fixtures lighting the control room, break room, and restroom. The fixtures average 2,600 hrs of operation a year. The proposed project looks at replacing these fixtures with (x40) 40W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 7%.
    - The provided project is $13,850, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.
2. Proposed Project #2: The facility currently has (x24) single lamp 400W Metal Halide fixtures lighting the main generation facility. The fixtures average 2,080 hrs of operation a year. The proposed project looks at replacing these fixtures with (x24) 200W linear LED high bay fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 23%.
    - The provided project is $16,484, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.
3. Proposed Project #3: The facility has six engine bays; each bay is lit by (x8) two lamp F96T12 fixtures. The fixtures average 2,080 hrs of operation a year. The proposed project looks at replacing all (x48) fixtures with 50W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 59%.
    - The provided project is $17,976, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.
4. Proposed Project #4: The facility currently has (x16) single lamp 250W Metal Halide wall packs on the exterior of the plant. The fixtures average 4,288 hrs (dusk to dawn) of operation a year. The proposed project looks at replacing these fixtures with (x16) 52W LED wall packs. A simple lumen calculation shows that the overall lumens for the job were decreased by 66%.

- The provided project is $10,702, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

5. It should be noted that while the total system lumens decrease for each of these projects, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

Low Cost No Cost Opportunities

In addition to the lighting replacement projects listed above we discussed a few re-circuiting projects that would help further reduce the electric load.

1. The three rows of lights on the generating floor are currently controlled by one switch. We recommend separating them out to one switch per row. This would allow the operators to leave the center row of lights off except during maintenance above the engine rooms.

2. The lights in the engine rooms are turned on when the engines are running and remain on for the duration. We recommend that these lights be put on bi-level switching. When the engines are running half the lights would come on, an occupancy sensor would turn the other half on when an operator entered a room.

HVAC

1. The control room, restroom, break room, and the MCC room are conditioned by two heat pump roof top units mounted on grade outside the building. Each of these units appears to be original to the building, based on the age they are in the 13 SEER (seasonal energy efficiency rating) range. While there are newer units available that have efficiencies closer to SEER 19, the cost to purchase and install these units outweighs the potential energy savings. Our recommendation is to replace these units when they have reached their end of life. When you do replace these units purchase the most efficient units that can be afforded.

   You may also consider replacing these units with gas fired units. When these units were purchased and installed the price of gas was high enough that it made heat pumps the more economical choice for heating. Now the price of gas is low enough that gas furnaces and roof top units, down to 80% efficient, is the more economical option. Currently the most efficient roof top unit on the market is around 82%. A few companies are working on 90+% efficient models, but none have come to market.

2. The generation floor has two 80% efficient natural gas fired unit heaters to provide supplemental heat in the winter. Currently Reznor makes a 90% efficient unit heater. While replacing the existing heaters with a new higher efficiency unit would generate gas savings, the price of these units is high enough that the project would more than likely not make financial sense. In addition the staff stated that these units do not operate all that often. In the future when these units are at end of life we recommend purchasing and installing the most efficient units that can be afforded.

3. The low speed/high volume destratification fan on the east end of the generating floor was making a rattling noise during our site visit. We recommend having the fan and motor be serviced before more serious damage is incurred.

Process

- **Compressed Air System**

	Brief EEM Description	EEM Cost	Electric kWh Savings	Residential energy retail value	Simple Payback
	Instrument Air Cycling Air-Dryers	**$6,600**	**10,074**	**$891/yr**	**14.8 yr**

Scope of Work:

- Proposed Project - Boulder Park Generating facility employs a single Kaeser SM 15 (15 hp, 53 scfm @ 100psi) rotary screw air-compressor supplying air to instruments and controls. The air is dried using two non-cycling Zeks NC 75 (75 cfm) refrigeration dryers. The EEM replaces those units with one appropriately sized Hankison HES90 (90 cfm) cycling refrigeration dryer. The analysis is based upon observed air-compressor operation (run time during audit) manufacturer's specifications and assumed annual hours of operation (24/7/365). A copy of the analysis is appended to this document in a SMath Studio Worksheet.
- Mitch Johnson, of Rogers Machinery, provided a cost estimate of $3,300 for a non-cycling unit. This does not include install costs; the facility's excellent maintenance staff will have no problem installing this unit.
- **Oil reservoir heaters**
- Currently the facility uses 5 kW thermal elements for the engine oil heating system. There are two elements per tank and six engines for a total of 60 kW. This is a purely resistive load that operates continuously to maintain a tank oil temperature of 120 ºF. The estimated annual energy consumed by this system is approximately 525,600 kWh (this type of system is nearly 100% efficient). The cost associated with this type of heating is about $36,800 (using Avista WA rate schedule 21 and $0.07/kWh). The opportunity here is to investigate the possibility of replacing the electric resistive elements with an NG hydronic system that would circulate heated water

through the tank via some type of finned tube arrangement. On a strictly "per BTU" basis, the cost savings would approximately be as follows:

- 525,600 kWh*(3412 BTU/kWh) = 1,800 MMBTU*(therms/1E5BTU) = 17,933 therms

- Assuming a heating (tube) efficiency effectiveness of about 75%, the final NG consumption is expected to be 23,911 therms per year. Using a per therm cost of $0.69 (WA natural gas schedule 111) this translates to an operating cost of approximately $16,500 per year, giving a reduction of 55% in operating costs. Depending on the final system, piping, materials, and circulation pump sizing, the final energy cost reduction could be expected to be 50%. The 5% "conservative" factor also includes the initial energy required to raise the water temp from 52oF to 120oF and standby losses. There may (and probably will) also be some additional maintenance costs associated with regular tube inspections and cleaning. Obviously, whether or not this is a prudent investment depends largely on the equipment, installation, and commissioning costs associated with the project. Once estimates are provided, project simple paybacks and return on investments can be calculated.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra - January 19, 2015

Name: Boulder Park Generating Facility - Control Room Lighting		
Acct#		
Existing Annual Consumption: (kilowatt hours)	7,706.40	
Lighting Energy Savings:(kilowatt hours)	3,650.40	
Lighting Demand Savings: (kilowatt demand)	1.15	
Cooling System Savings: (kilowatt hours)	281.08	
Cooling System Demand Savings: (kW demand)	0.09	
Lumen Comparison New/Existing	93.03%	
Total Energy Savings: (kilowatt hours)	3,931.48	
Total Demand Savings: (kilowatt demand)	**1.24**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**(31.76)**	
Maintenance Savings:	($30.69)	

Name: Boulder Park Generating Facility - Generating Floor		
Acct#		
Existing Annual Consumption: (kilowatt hours)	28,392.00	
Lighting Energy Savings:(kilowatt hours)	16,099.20	
Lighting Demand Savings: (kilowatt demand)	4.95	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	76.92%	
Total Energy Savings: (kilowatt hours)	16,099.20	
Total Demand Savings: (kilowatt demand)	**4.95**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$238.60	

Name: Boulder Park Generating Facility -Engine Room		
Acct#		
Existing Annual Consumption: (kilowatt hours)	9,859.20	
Lighting Energy Savings:(kilowatt hours)	6,739.20	
Lighting Demand Savings: (kilowatt demand)	4.15	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	41.29%	
Total Energy Savings: (kilowatt hours)	6,739.20	
Total Demand Savings: (kilowatt demand)	**4.15**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$117.10	

Name: Boulder Park Generating Facility - Wall Packs		
Acct#		
Existing Annual Consumption: (kilowatt hours)	19,621.89	
Lighting Energy Savings:(kilowatt hours)	16,054.27	
Lighting Demand Savings: (kilowatt demand)	3.00	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	33.69%	
Total Energy Savings: (kilowatt hours)	16,054.27	
Total Demand Savings: (kilowatt demand)	**3.00**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$306.46	

Customer: Avista Generation; Boulder Park Internal Combustion Topping Plant
Project State: EEM Evaluation
Date: 01/08/15
Analysis Description: The facility employs a single Kaeser SM 15 rotary screw compressor operating with on/off controls with (2) Zeks NC 75 non-cycling refrigeration air-dryers for the facility's controls.

$pct := \frac{1}{100}$ input: assign "percent" to SMath Studio

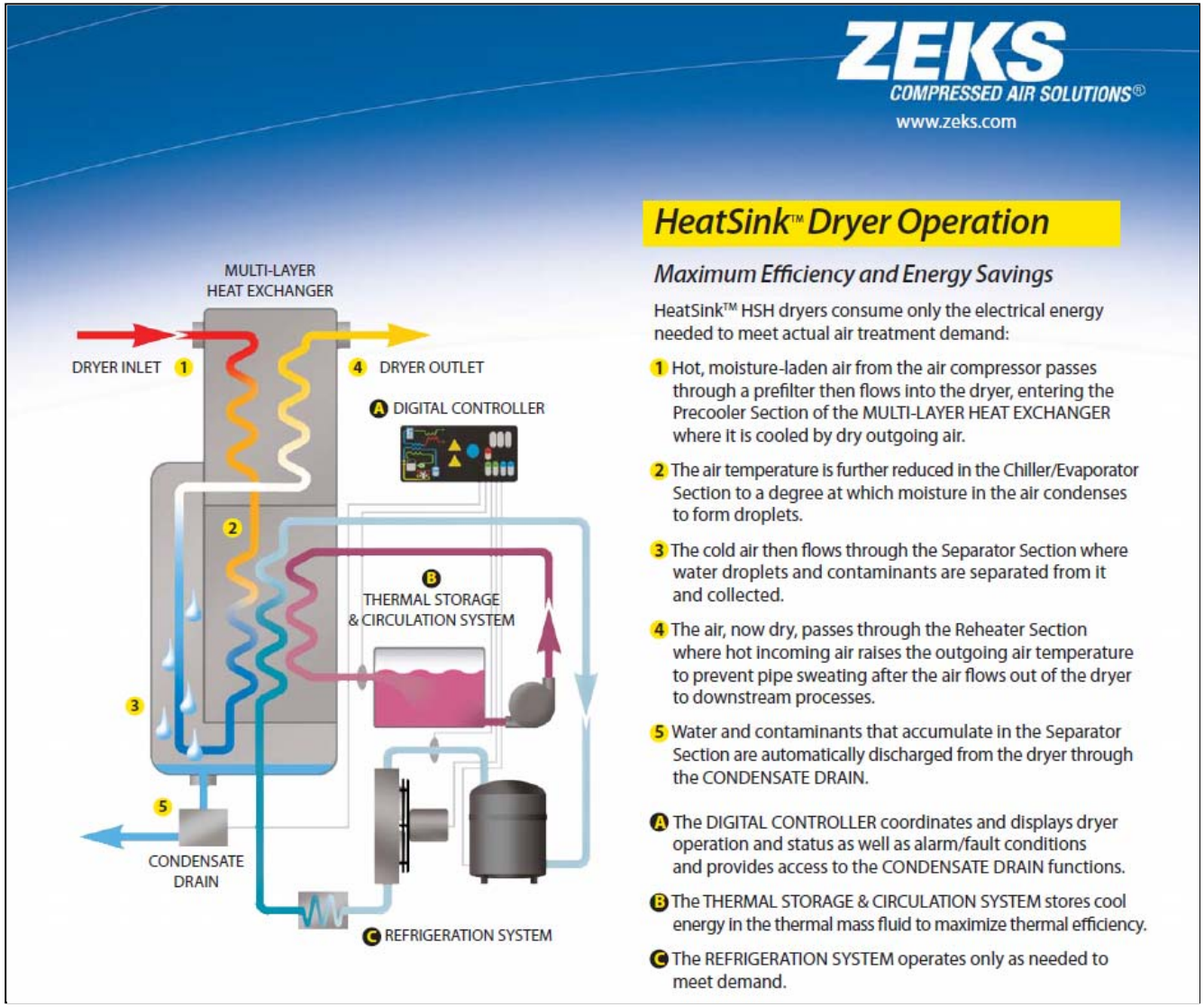


Figure 1. Explanation of cycling air-dryer technology

Table 1. Technical specifications for existing non-cycling refrigeration air-dryers

NC Series™ Technical Specifications

Left Front 75-150 | Right Front 200-400 | Left Front 500-800 | Left Front 1000-1600 | Front Right 2000-2400

MODEL	CAPACITY* SCFM 38°F PDP	CAPACITY* SCFM 50°F PDP	PRESSURE DROP** PSI	DIMENSIONS W IN.	DIMENSIONS D IN.	DIMENSIONS H IN.	SHIP WEIGHT AIR-COOL LBS.	SHIP WEIGHT WATER-COOL LBS.	AIR CONNECT IN/OUT	DRAIN CONNECT FPT	REFRIG COMP AIR-COOL HP	REFRIG COMP WATER-COOL HP	OPERATING KW*** AIR-COOL	OPERATING KW*** WATER-COOL	REFRIG TYPE	MAX WORKING PRESSURE	VOLTAGES§
75NCG	75	103	1.3	14	21	31	145	NA	1"MPT	1/4"	.3	NA	.67	NA	R404	300 psig	115-1-60 208/230-1-60 220-1-50
100NCG	100	138	2.5	14	21	31	150	NA	1"MPT	1/4"	.5	NA	1.0	NA	R404	300 psig	
125NCG	125	172	2.0	14	21	31	180	NA	1 1/2"MPT	1/4"	.6	NA	1.3	NA	R404	300 psig	
150NCG	150	207	2.6	14	21	31	200	NA	1 1/2"MPT	1/4"	.6	NA	1.3	NA	R404	300 psig	

Table 2. Technical specifications for proposed cycling refrigeration air-dryers

Model	Rated Flow [1]		Voltages	Power	Inlet/Outlet Connection [2]	Dimensions H	W	D	Weight	Std Δp[3] Grade 9		Opt Δp[4] Grade 5	
	scfm	nm³/h	V/ph/Hz	kW	NPT		in	in	lbs	psig	barg	psig	barg
HES90	90	153	100/1/50 115/1/60 208-230/1/60 220-240/1/50	0.95	1.0"	38	27	20	241	2.9	0.2	4.1	0.3
HES120	120	204		1.28	1.0"	38	27	20	258	3.7	0.3	5.0	0.3
HES140	140	238		1.29	1.0"	38	27	20	263	4.1	0.3	5.5	0.4

Inputs:

$P_{base_nom} := 0.67\ kW$ input: basline power consumption; manufacturer specified, see Table 1.

$Qty := 2$ input: number of baseline 75 scfm air dryers; assume two needed for n+1 redundancy

$P_{EEM_nom} := 0.95\ kW$ input: EEM power consumption; manufacturer specified, see Table 2.

$U_{ave} := 10 \cdot pct$ input: assumed utilization rate; based on air-compressor operation observed during site audit; air compressor cycled on once for a few minutes during the hour long visit.

$t_{op} := 8760 \frac{hr}{yr}$ input: assumed annual hours of operation

Calculations:

$E_{base} := Qty \cdot P_{base_nom} \cdot t_{op}$ calc: energy consumed annually by the baseline non-cycling units

$E_{base} = 11738.4 \frac{kW\,hr}{yr}$

$E_{EEM} := Qty \cdot P_{EEM_nom} \cdot t_{op} \cdot U_{ave}$ calc: energy consumed annually by the EEM cycling units

$E_{EEM} = 1664.4 \frac{kW\,hr}{yr}$

$E_{savings_annual} := E_{base} - E_{EEM}$ calc: energy saved annually converting to the EEM units

$E_{savings_annual} = 10074 \frac{kW\,hr}{yr}$

Contacted Mitch at Rogers' Machinery and he gave me a rough estimate for a Hankinson HES90 cycling compressor of ~$3,300/unit.

$dollar := 1$ input: assign "dollar" to SMath Studio

$Cost := 2 \cdot 3300 \cdot dollar$ input: cost estimate for one EEM

$Rate := 0.08848 \cdot \frac{dollar}{kW\,hr}$ input: assumed average energy sales rate based upon blended 3 tiers of residential

$C_{savings} := E_{savings_annual} \cdot Rate$ calc: annual revenue from EEM

$C_{savings} = 891.3 \frac{dollar}{yr}$

$SPB := \frac{Cost \cdot Qty}{C_{savings}}$ calc: average energy simple payback

$SPB = 14.8\,yr$

Non-Energy Benefits (NEBs):
- Life (years of operation before failure) of the dryer(s) will be increased due to reduced hours of compressor operation. This is even more evident when the (2) units are operated in an N+1 redundancy configuration.

Energy Efficiency Improvements Audit Report

Prepared for

Cabinet Gorge Hydro Electric Dam

Prepared by

Andy Paul, PE

Bryce Eschenbacher, PE

Levi Westra, PE

Energy Solutions Engineers

April 13, 2015

Overview

Facility: Cabinet Gorge Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE
Onsite Staff: Alan Lackner
Facility Audited on: March 30th, 2015

Figure 1 Google Images of the Cabinet Gorge Hydro Electric Dam

Avista's DSM Engineering staff visited the Cabinet Gorge Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation, and its estimated cost, is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of a control room, office space, break area and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

Due to the design of the facility there are no real shell measures that can be undertaken that would benefit the facility or save energy.

Lighting

The lighting system is the largest inefficiency in the facility.

Cabinet Gorge is slated to have its lighting system completely replaced similarly to Noxon Rapids HED. The majority of the new system will be linear LED's with some screw in LED lamps where necessary. Based on the number of fixtures present in the facility it will reduce that plant electric load by a similar amount to Noxon Rapids load decrease, ~300,000 kWh.

HVAC

The facility is currently conditioned by several 480v electric unit heaters. These unit heaters have to run 24/7 in the winter to keep the temperature in the facility above 50ºF. In addition to the heaters there is a fresh air intake system, this system brings in outside air (OSA) and ducts it all around the facility. The OSA system will do a nightly flush of the facility during the warmer months in an attempt to keep the internal temperature low during the day. Currently there are no active heating and cooling elements in the system.

It is recommended that a water source heat pump system, similar to Noxon Rapids, be considered to condition the facility. The major costs of adding an HVAC system is the duct work and cooling/heating coils, the facility is already completely ducted and several cooling/heating coils are in place.

We recommend that the most efficient equipment that can be afforded be installed. This will be an expensive project to take on, but it will reduce the extreme temperature swings that happen inside the facility throughout the year and would provide protection for some of the sensitive equipment.

The relay tech room and the break room currently have window style AC units and small electric heaters to keep the space conditioned. It is recommended that stand alone ductless heat pump systems be installed to serve these spaces. Certain Mitsubishi and Daikin units can have multiple inside units, cassettes, paired with one condensing unit.

Compressed air

The facility's pneumatic systems consisted of several small (~25HP) reciprocating compressors along with two large oil-free rotary screw units. No recommendations will be made at this time with regards to the reciprocating units as they are near-perfect part-load machines. However, the two 250HP Kobelco compressors may represent an energy saving opportunity. The specifications for the machines are as follows:

TWO-STAGE, HEAVY-DUTY, OIL-FREE, WATER-COOLED, ROTARY SCREW AIR COMPRESSOR MOUNTED ON A FABRICATED STEEL BASE AND DRIVEN BY A 250 HP, 3/60/460 VOLT, PREMIUM EFFICIENCY, OPEN DRIPPROOF MOTOR.
.
SOLID-STATE (SOFT-START) MOTOR STARTER, 250 HP, 3/60/460 VOLT, IN NEMA 1 ENCLOSURE, MOUNTED, WIRED AND TESTED ON THE ASSEMBLY.
.
CUSTOM ENGINEERING AND FABRICATION.
SPECIAL ENGINEERING AND FACTORY FABRICATION TO DESIGN COMPRESSORS SO THEY CAN BE BROKEN DOWN AT THE JOBSITE, TRANSPORTED, AND REASSEMBLED IN THE COMPRESSOR ROOM.

The system is a serves a common header and the two units are controlled on a lead/lag fashion. Depending on the hours of operation and the actual cfm demand, a bolt-on variable frequency drive (VFD) on one of the units (the one providing the trim load) might be a good option. VFDs will modulate the compressor down so that the input power nearly matches the cfm demand with very little waste in the form of heat and blown off (unloaded) air. The system should be configured in such a way that the VFD-equipped machine responds to the base cfm demand below (100%) until it reaches near 100%. At that time the fixed-speed unit should cycle on to meet that full base load and the VFD unit trims. Again the cost-effectiveness depends on cfm demand and run-hours. We estimate the VFD cost for one compressor to be approximately $50,000 including installation and programming.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – April 13th, 2015

Energy Efficiency Improvements Audit Report

Prepared for

Coyote Springs Thermal Generating Facility

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

June 22, 2015

Overview

Facility: Coyote Springs Thermal Generation Facility
Audited by: Andy Paul PE, Bryce Eschenbacher PE and Levi Westra PE
Onsite Staff: Dan Turley, PGE
Facility Audited on: June 18th, 2015

Figure 1 Google Earth Images of the Coyote Springs Generation Facility

Avista's DSM Engineering staff visited the Coyote Springs generating facility to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility, potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of an office, network room, and large high bay warehouse which houses two combine cycle steam turbines. Unit #2 belongs to Avista Utilities.

Shell

The majority of the facility houses the generating equipment, and associated process loads. The waste heat coming off of the equipment is the main source of heat during the winter months and the plant is not conditioned during the summer months. This reduces the amount of shell measure projects; insulation, weather sealing, windows, etc, that can be undertaken in this part of the facility. There are several areas; control room, MCC enclosures, switch gear, office areas, that may benefit from upgraded insulation and at the very least routine inspection and maintenance. Below are some suggestions for areas that should be checked.

1. Any man door leading to an area that is mechanically conditioned should have its weather stripping checked a couple of times a year and replaced as necessary.
2. If the roof insulation area above the office area is less than R19 additional insulation should be added. The office space has a drop ceiling throughout; un-faced batt insulation could easily be added above the ceiling panels.
3. The remainder of the facility is well insulated and does not have any weatherization or shell improvements required at this time. It is recommended that the roll up and man doors be checked periodically and maintenance be done as necessary.

While these measures will conserve energy, those savings will be negligible in comparison to the measures listed further in this report.

Lighting

The site employs T12 and T8 linear fluorescent lighting as well as 400 Watt high pressure sodium (HPS) high-bay and 250 Watt MH exterior lighting on dusk to dawn sensors. No parking lot lighting was observed.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Control Room Lighting	**$5,194**	**20 yrs**	**6,368**
2	Generating Floor High Bays	**$44,646**	**20 yrs**	**85,778**
3	Roadway Lighting	**$225**	**20 yrs**	**1,085**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The facility currently has (x15) three lamp F32T8 fluorescent fixtures lighting the control room. The fixtures average 8,760 hrs of operation a year. The proposed project looks at replacing these fixtures with (x15) 40W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 34%.

    - The provided project is $5,194, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

2. Proposed Project #2: The facility currently has (x32) single lamp 400W High Pressure Sodium fixtures lighting the main generation facility. The fixtures average 8,760 hrs of operation a year. The proposed project looks at replacing these fixtures with (x32) 144W LED high bay fixtures (HEGRC4KN-SNG Dialight). A simple lumen calculation shows that the overall lumens for the job were increased by 50%.

    - The provided project is $44,646, this cost was calculated using fixture and install costs for a project at a local paper mill.

    During our conversation with facility staff it was mentioned that any fixture that would be installed on the generating floor would need to be able to operate in extreme temperatures. The ceiling on is upwards of 120 feet and the temperature can easily get over 120ºF. The proposed Dialight fixture has an operating temperature range of -40ºF to 149ºF. These fixtures should be able to handle the conditions at Coyote Springs. It is recommended that a couple of test fixtures be purchased and installed, this will allow the facility staff to see how the lights perform in the extreme temperatures present and evaluate how the like the quality of the light produced.

3. Proposed Project #3: The roadway is lit by single Lamp 250W metal halide cobra heads. This project would replace these with Cree 42W LED cobra heads. It is assumed that these fixtures have an average of 4,288 hrs/yr (dusk to dawn) annual operating hours. A simple lumen calculation shows that the overall lumens for the job were decreased by 71%. This analysis looks at the cost and energy savings for replacing one of these fixtures.

    - The provided project is $225, this cost was calculated using fixture and install costs for one of these fixtures at Noxon Rapids HED.

4. It should be noted that while the total system lumens decrease for projects 1 and 3, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

HVAC

1. The control room, office, restroom, break room, and the switch gear rooms are conditioned by two gas fired roof top units mounted on grade outside the building. One unit belongs to Avista and only serves Avista's switch gear; the other unit handles the control room, office, and PGE's switch gear. These units appear to have been recently replaced. The units have a cooling efficiency of 11.6 EER; energy code minimum efficiency is 11 EER. It is recommended that when these units come up for replacement in the future they are replaced with the most efficient piece of equipment that can be afforded.

    The supply and return ductwork for these units is un-insulated, it is recommended that insulation be added. There is a significant length of ductwork, 10 to 20 feet, exposed to the elements before turning into the building.

2. The generation floor has several 80% efficient natural gas fired unit heaters to provide supplemental heat in the winter. Currently Reznor makes a 90% efficient unit heater. While

replacing the existing heaters with a new higher efficiency unit would generate gas savings, the price of these units is high enough that the project would more than likely not make financial sense. In addition the staff stated that these units do not operate all that often. In the future when these units are at end of life we recommend purchasing and installing the most efficient units that can be afforded.

Process

Compressed Air System

The facility instrumentation and control air is provided by two Ingersol-Rand SSR-HP75 75kW rotary-screw load/unload compressors in an N+1 failsafe configuration. The compressors feed an Ingersoll-Rand TZ300 desiccant air-dryer and a large dry receiver. The air-dryer is a heatless unit and uses a timer to control regeneration cycles. There are several opportunities for reducing energy consumption of these devices, including adding VFDs to the compressors and upgrading the dryer to a heated/demand controlled unit.

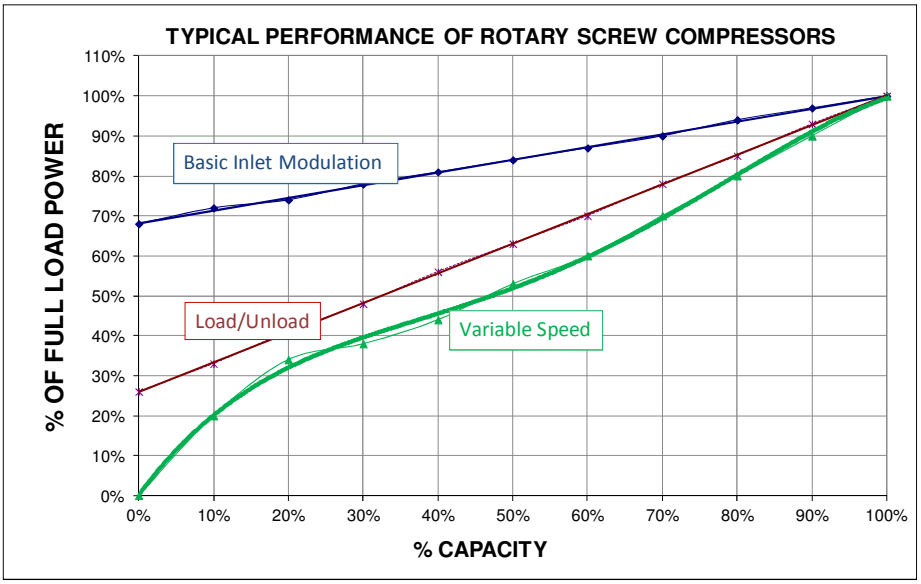


Figure 2 Comparison of rotary-screw air compressor controls (% load vs % flowrate)

A comparison of the existing load/unload controls to a VFD controlled air-compressor operating at 60% load 8760 hr/yr results in a 20% energy savings or around 130,000 kWh/yr. The 60% load is an assumption; this value may be higher or lower and will affect the annual energy savings. The $15,000 EEM cost assumes only one of the compressors is converted or replaced.

Table 2 Possible savings and roughly estimated costs for compressed air system EEMs.

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Air-Compressor VFD	**$15,000**	**12 yrs**	**130,000**
2	Retrofit Air-Dryer with Dew-Point Controls	**$5,000**	**12 yrs**	**25,000**

The existing timer controlled compressed air-dryer operates on a 10 minute regeneration cycle regardless of the dew point of the treated air. The EEM would retrofit this unit with dew-point controls which would initiate a regeneration cycle only as required. The number of cycles will be reduced; they will become dependent on the amount of moisture in the ambient air and the amount of air being consumed by the facility. On average dew-point controls will reduce energy consumption about 40%, however, in central Oregon, where the average humidity levels are quite low, the savings will likely be greater. If the decision is made to replace the entire dryer, please consider replacing the unit with a heated unit for even more energy savings.

Boiler feed water pumps

The facility is presently equipped with two 2500HP boiler feedwater pumps, one with variable speed control (estimated installation, 2008). It is assumed that the pump operation is alternated with only one running at any given time. It is unclear as to why both pumps were not originally equipped with VFDs (budgetary concerns, no available changeover downtime, etc.?) unless the fixed-speed pump serves only as an installed backup. If they do in fact alternate duty, installing a bolt-on VFD to the remaining fixed speed pump should be a good option in terms of economics. Tremendous energy savings can be achieved by controlling flow rates by pump speed control as opposed to modulating the flow rates with control valves. Another option would be to control both feedwater pumps with only one VFD. The technology exists such that multiple motors can be controlled with one drive provided that the motor sizes are the same and that the speed reductions are the same, i.e. if one motor runs are 45Hz the other running motors must also run at 45Hz. This option might be worth looking into if both pumps are running at 30Hz (I assume that this is the minimum motor speed even though the Toshiba performance reports go down to 25% or 15Hz) and can deliver enough pressure to inject water into the high-pressure drum.

The above suggestion applies also to other process pumps such as the 700HP cooling tower pumps as well as other smaller process pumps. Pumps that; operate for a high percentage of time, have their flow rates varied via controls valves, and do not necessarily need to provide full flow/pressure to a process, are good candidates for variable frequency drives. Control valves (or any other fittings) represent an obstruction in the flow path. This obstruction creates a head loss and pressure drop that the pump/motor must overcome in order to meet pressure/flow requirements. As mentioned in the boiler feedwater paragraph above, removing (or adjusting control valve(s) to 100% open) these pipe components and controlling flow via motor speed, significant energy savings and process flexibility/longevity can be achieved.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – June 22nd 2015

Name: Coyote Springs Generating Facility - Control Room Lighting		
Acct#		
Existing Annual Consumption: (kilowatt hours)	11,169.00	
Lighting Energy Savings:(kilowatt hours)	5,913.00	
Lighting Demand Savings: (kilowatt demand)	0.54	
Cooling System Savings: (kilowatt hours)	455.30	
Cooling System Demand Savings: (kW demand)	0.04	
Lumen Comparison New/Existing	66.15%	
Total Energy Savings: (kilowatt hours)	6,368.30	
Total Demand Savings: (kilowatt demand)	**0.58**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**(51.44)**	
Maintenance Savings:	($373.22)	

Name: Coyote Springs Generating Facility - Generating Floor		
Acct#		
Existing Annual Consumption: (kilowatt hours)	126,144.00	
Lighting Energy Savings:(kilowatt hours)	85,777.92	
Lighting Demand Savings: (kilowatt demand)	7.83	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	150.00%	
Total Energy Savings: (kilowatt hours)	85,777.92	
Total Demand Savings: (kilowatt demand)	**7.83**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$518.36	

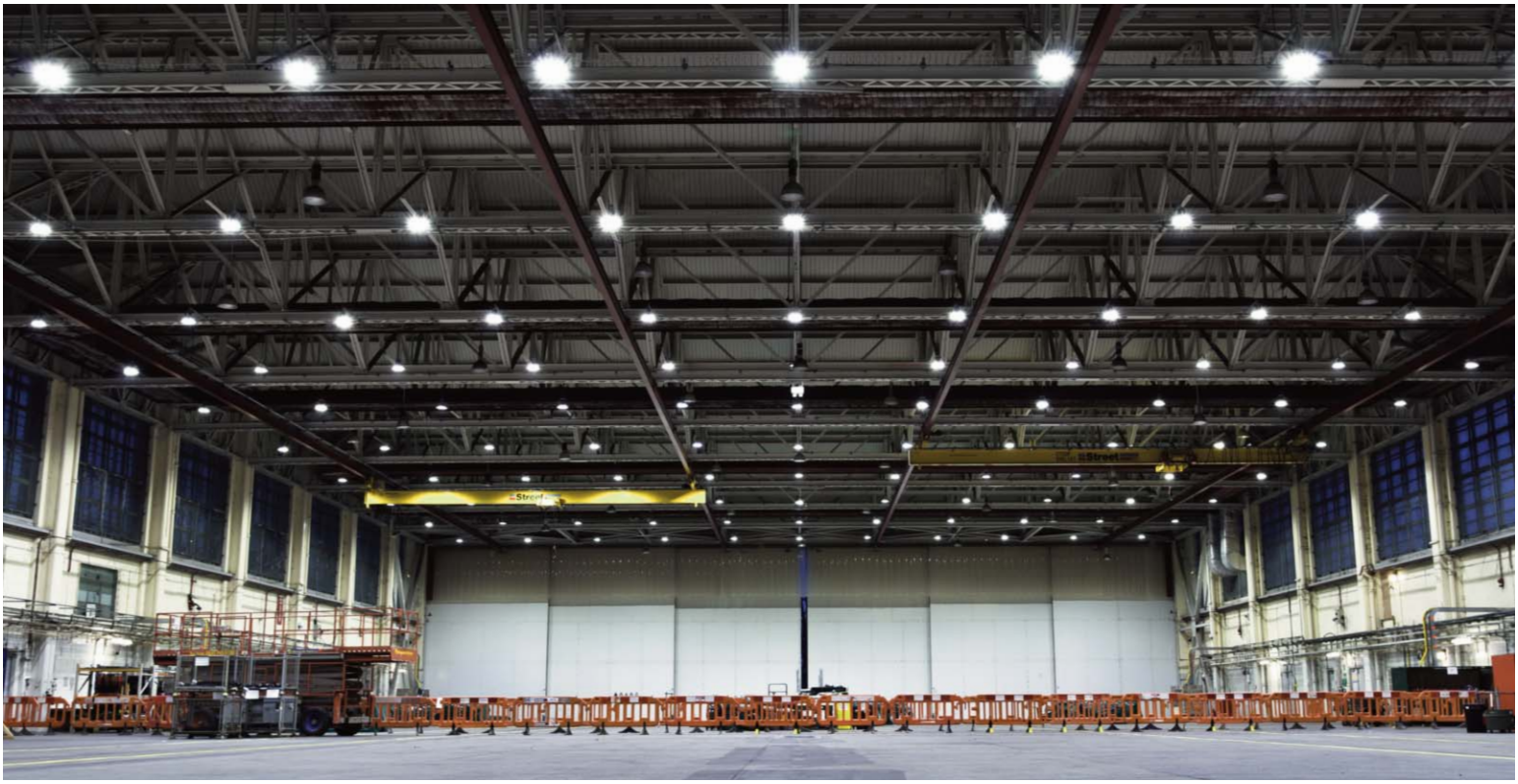
Name: Coyote Springs - Pole Lights		
Acct#		
Existing Annual Consumption: (kilowatt hours)	1,264.96	
Lighting Energy Savings:(kilowatt hours)	1,084.86	
Lighting Demand Savings: (kilowatt demand)	0.20	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	18.59%	
Total Energy Savings: (kilowatt hours)	1,084.86	
Total Demand Savings: (kilowatt demand)	**0.20**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$8.30	

Vigilant® LED High Bay

for Indoor and Outdoor Industrial Applications

Vigilant® LED High Bay

for Indoor and Outdoor Industrial Applications



About Dialight

Dialight (LSE: DIA.L) is leading the energy efficient LED lighting revolution around the world for industrial and hazardous areas as well as transportation and infrastructure applications. For 40 years it has been committed to the development of LED lighting solutions that enable organizations to vastly reduce energy use and maintenance needs, improve safety, ease disposal and reduce CO_2 emissions.

History at a Glance

1938 → Dialight founded in Brooklyn, NY
1971 → LED Circuit Board Indicator
1994 → LED Transit Vehicle Signals
1995 → LED Traffic Signals
2000 → FAA certified LED Obstruction Lights
2007 → LED Lighting for Hazardous Locations
2009 → LED High Bay Fixtures
2012 → Full performance 10-year warranty
2013 → Controls for LED Lighting
2014 → 125lm/W High Bay

Typical Applications

- Oil, Gas & Petrochemical
- Power Generation
- Mining
- Chemical
- Pharmaceutical
- Water & Sewage
- Food & Beverage
- Manufacturing
- Warehousing
- Cold Storage

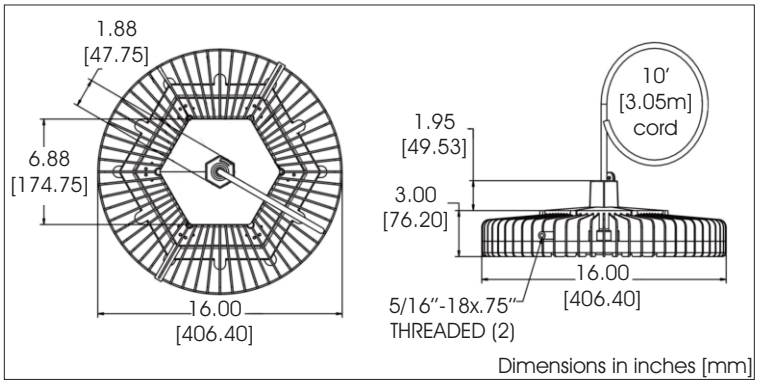
View the full case studies at:

G.S. Dunn Limited - www.dialight.com/news/details/gsdunn_case_study
Rockline Industries - www.dialight.com/news/details/rockline_case_study
MedSafe - www.dialight.com/news/details/medsafe_case_study
Kuehne + Nagel - www.dialight.com/news/details/kuehne_nagel_case_study

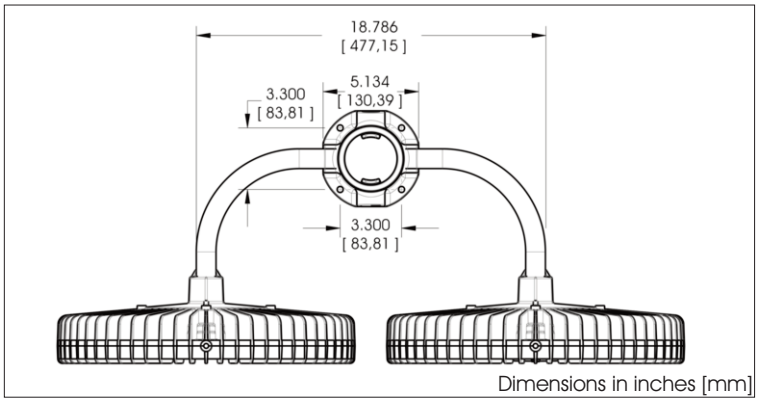
Dialight also offers their products for Hazardous Locations

Complete your own Return on Investment calculation at: www.dialight.com/tcoCalculator/Vigilant_HighBay

Vigilant® LED High Bay
125 LPW



Dual Bracket



Certifications & Ratings
- UL 1598/A
- CSA 22 #250
- CE
- NEMA 4X
- IP 66
- Dark Sky Compliant

Features & Benefits
- L70 rated for >100,000 hours @ 25°C
- 10 year full performance warranty
- Up to 125 LPW
- Dual Mounting option available
- For 347-480V AC applications, consult factory
- Significantly reduced glare
- Instant on/off
- Maintenance free
- Mercury free
- No UV or IR
- Resistant to shock and vibration

Application:
At 125 lumens per Watt, Dialight's new ultra-efficient industrial LED High Bay revolutionizes the world of LED lighting and is by far the most innovative LED fixture available today. With a market-leading 10 year full performance warranty, the new 26,500 lumen high bay utilizes cutting-edge optical and electrical design to provide for significantly reduced glare and superior light distribution.

In its compact and lightweight structure, Dialight's new 125 lumen per Watt LED High Bay is designed to meet the most demanding specifications and is perfect for any industrial application where improved light levels are needed at minimum energy consumption for more than a decade.

Mechanical Information	
Fixture weight:	18 lbs
Shipping weight:	24 lbs
Mounting:	(1) 3/4" NPT - top (2) 5/16"-18 x .75" UNC - side
Cabling:	10' (3.5m) STOOW Power Cord
Electrical Specifications	
Operating Voltage: 24,250-26,500lm: 16,500-18,000lm:	 110 - 277V AC 100 – 277V AC (For 347 - 480V AC application, consult factory)
Total system power consumption:	See Table
Operating Temp:	-40°F to +149°F (-40°C to +65°C)
Harmonics:	IEC 61000-3-2
Noise requirement / EMC:	FCC Title 47, Subpart B, Section 15, class A device. RF Immunity; 10V/m, 80MHz-1GHz
Transient protection:	Protection devices capable of handling up to 6kV. Tested at independent laboratory for 6kV/2 ohm combination wave, as per IEEE C62.41, line-line and line-ground
Power Factor:	> 0.9
Construction:	
Housing:	Copper free aluminum
Finish:	Polyester powder coated gray RAL 7040
Lens:	Tempered glass
Photometric Information	
CRI:	75
CCT:	5,000K (cool white) 4,000K (neutral white)

All values typical unless otherwise stated
Lumen values are typical (tolerance +/- 10%)

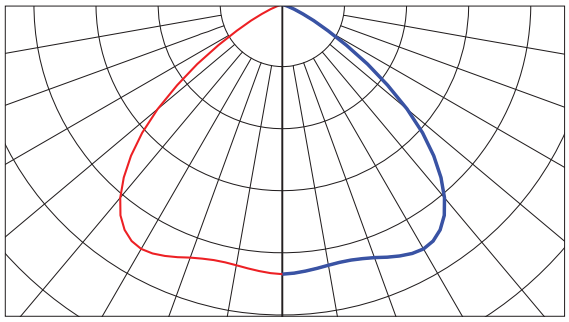
Vigilant® LED High Bay - Ordering Information

Part Number	Initial Fixture Lumens	Watt	Lumens Per Watt	CCT	UL-1598, IP-66, NEMA 4X CSA 22.2 #250, Marine Wet Locations	Safety Bracket	External Fuse	Lens	Optical Pattern	
									Circular	Wide
110 - 277V AC Models										
HEGMC4PN-SNG	26,500	212W	125	5,000K	•			Tempered Glass	•	
HEGRC4PN-SNG	26,500	212W	125	5,000K	•			Tempered Glass		•
HEGMN4PN-SNG	24,250	212W	114	4,000K	•			Tempered Glass	•	
HEGRN4PN-SNG	24,250	212W	114	4,000K	•			Tempered Glass		•
HEGMC4PN-SSG	26,500	212W	125	5,000K	•	•		Tempered Glass	•	
HEGRC4PN-SSG	26,500	212W	125	5,000K	•	•		Tempered Glass		•
HEGMN4PN-SSG	24,250	212W	114	4,000K	•	•		Tempered Glass	•	
HEGRN4PN-SSG	24,250	212W	114	4,000K	•	•		Tempered Glass		•
HEGMC4PN-SFG	26,500	212W	125	5,000K			•	Tempered Glass	•	
HEGRC4PN-SFG	26,500	212W	125	5,000K			•	Tempered Glass		•
HEGMN4PN-SFG	24,250	212W	114	4,000K			•	Tempered Glass	•	
HEGRN4PN-SFG	24,250	212W	114	4,000K			•	Tempered Glass		•
HEGMC4PN-SGG	26,500	212W	125	5,000K		•	•	Tempered Glass	•	
HEGRC4PN-SGG	26,500	212W	125	5,000K		•	•	Tempered Glass		•
HEGMN4PN-SGG	24,250	212W	114	4,000K		•	•	Tempered Glass	•	
HEGRN4PN-SGG	24,250	212W	114	4,000K		•	•	Tempered Glass		•
100 - 277V AC Models										
HEGMC4KN-SNG	18,000	144W	125	5,000K	•			Tempered Glass	•	
HEGRC4KN-SNG	18,000	144W	125	5,000K	•			Tempered Glass		•
HEGMN4KN-SNG	16,500	144W	114	4,000K	•			Tempered Glass	•	
HEGRN4KN-SNG	16,500	144W	114	4,000K	•			Tempered Glass		•
HEGMC4KN-SSG	18,000	144W	125	5,000K	•	•		Tempered Glass	•	
HEGRC4KN-SSG	18,000	144W	125	5,000K	•	•		Tempered Glass		•
HEGMN4KN-SSG	16,500	144W	114	4,000K	•	•		Tempered Glass	•	
HEGRN4KN-SSG	16,500	144W	114	4,000K	•	•		Tempered Glass		•
HEGMC4KN-SFG	18,000	144W	125	5,000K			•	Tempered Glass	•	
HEGRC4KN-SFG	18,000	144W	125	5,000K			•	Tempered Glass		•
HEGMN4KN-SFG	16,500	144W	114	4,000K			•	Tempered Glass	•	
HEGRN4KN-SFG	16,500	144W	114	4,000K			•	Tempered Glass		•
HEGMC4KN-SGG	18,000	144W	125	5,000K		•	•	Tempered Glass	•	
HEGRC4KN-SGG	18,000	144W	125	5,000K		•	•	Tempered Glass		•
HEGMN4KN-SGG	16,500	144W	114	4,000K		•	•	Tempered Glass	•	
HEGRN4KN-SGG	16,500	144W	114	4,000K		•	•	Tempered Glass		•

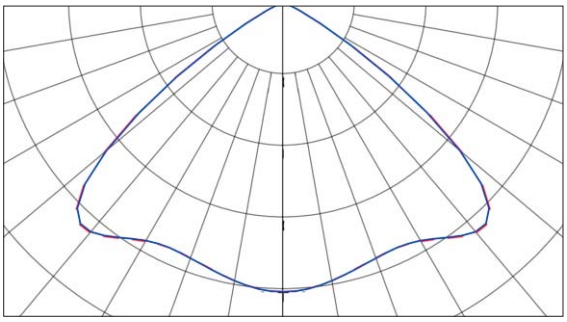
For 347 - 480V AC applications, consult factory

Optical Patterns

Circular Pattern



Wide Pattern



Vigilant® LED High Bay

Options and Accessories

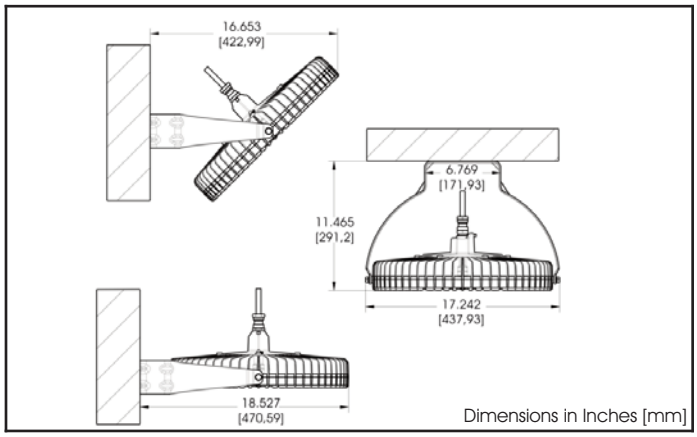
	Part Number	Description	Kit Includes
	HBXDUALBRCKT	Dual Bracket	Junction Box
	No Part Number	Pendant Mount (conduit supplied by installer)	Conduit supplied by installer
	HBXW2	Swivel Bracket and Cable Gland	Swivel Bracket Bracket to fixture hardware Cable Gland (1/2"), Reducer (3/4" to 1/2")
	HBXW3	Swivel Bracket	Swivel Bracket Bracket to Fixture Hardware
	HBXCU	Ceiling Mount	Swivel Hanger Cover 3" Conduit Nipple
	HBXCG	Cable Gland	Cable Gland (1/2") Reducer (3/4" to 1/2")
	HBXL	Loop (consult factory when using with occupancy sensor models)	Hanger Loop (GE LOOPM353)
	HBXH	Hook (consult factory when using with occupancy sensor models)	Hanger Hook (GE HOOKM353)
	HBXCAB48	48" Long Stainless Steel Safety Rope	5/32" Diameter Stainless rope with locking spring clip
	HBXTH347480[1]	Top hat with 347-480V isolated step down transformer (consult factory when using with hook or loop)	Top and bottom clam shell Conduit nipple 6' STOOW cable 347-480V step down transformer Fuse holder, 2 Fuses
	HBXLENGC	Tempered Glass	Lens, replacement clips, screws, gasket
	HBXREF22	22" Acrylic Reflector (must be ordered with High Bay, not a retrofit option)	Reflector, brackets, screws
	HBXDC	Dust Cover	Dust cover, clamp, spacer

[1]Top hat cannot be used with a mounting bracket

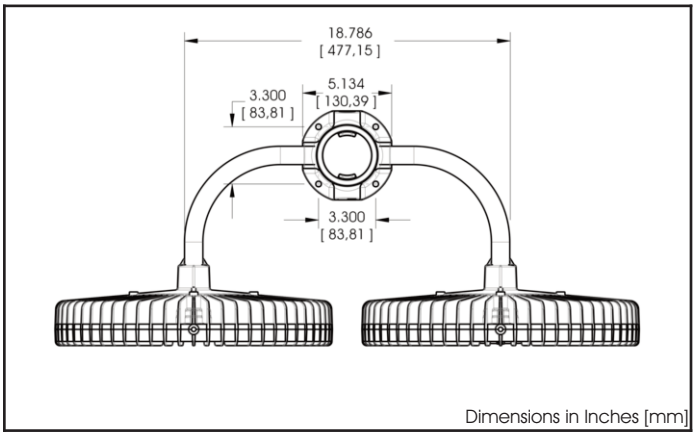
Vigilant® LED High Bay

Options and Accessories

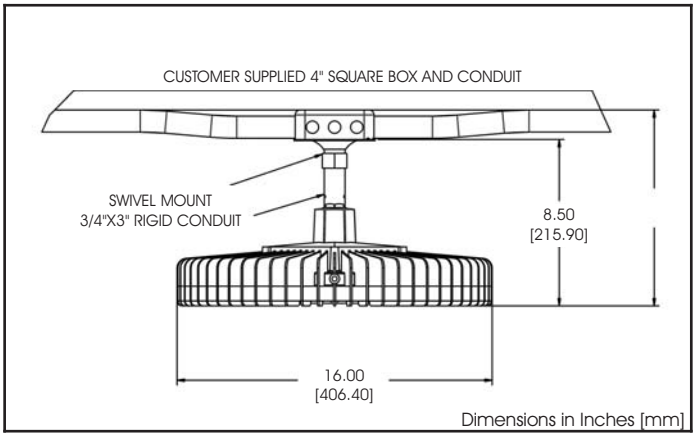
HBXW2 - Swivel Bracket and Cable Gland



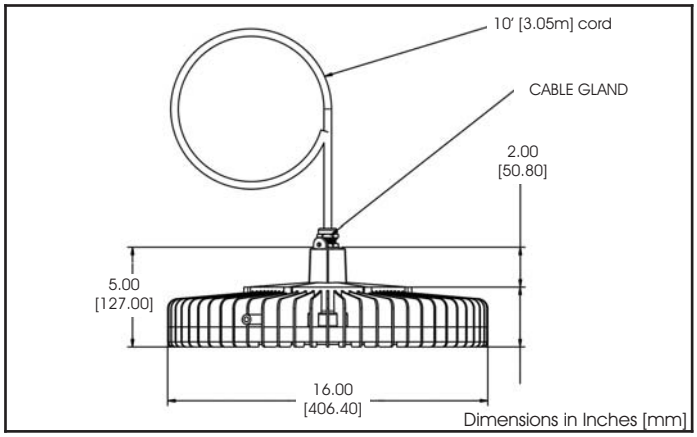
HBXDUALBRCKT - Dual Bracket



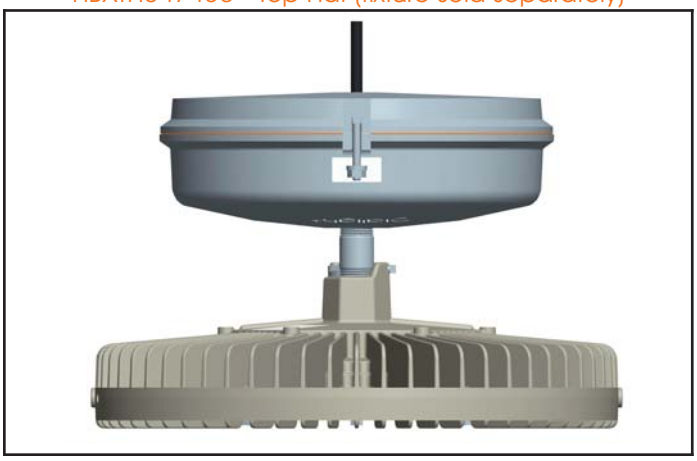
HBXCU - Ceiling Mount



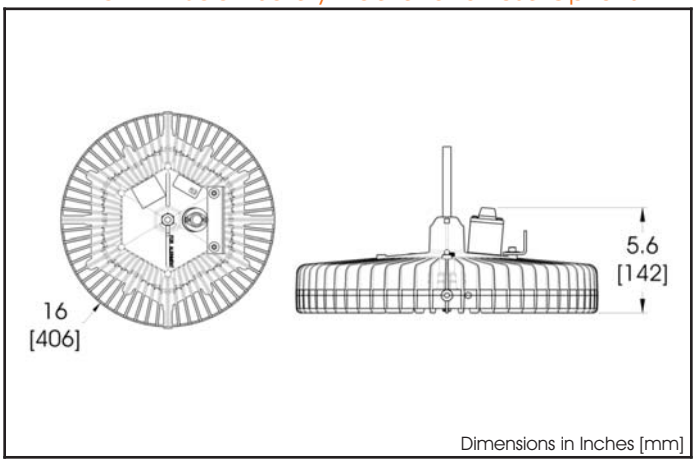
HBXCG - Cable Gland



HBXTH347480 - Top Hat (fixture sold separately)



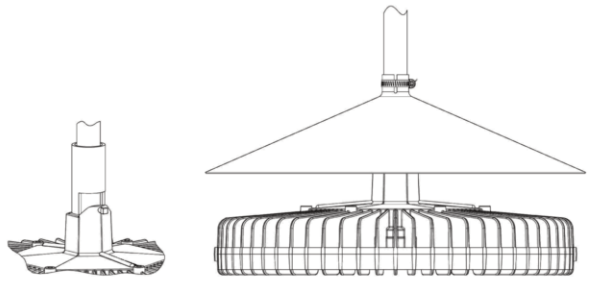
HEGMxxxx-SGG - Safety Bracket and Fuse Options



Vigilant® LED High Bay

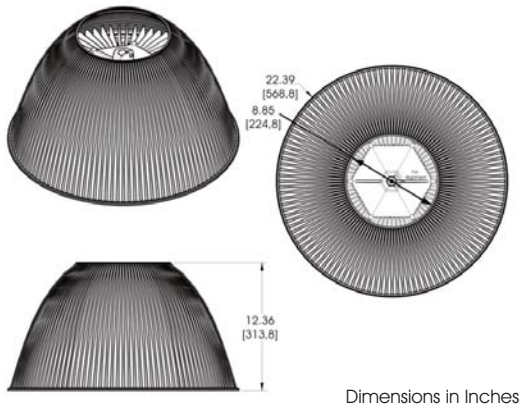
Options and Accessories

HBXDC - Dust Cover



Dimensions in Inches [mm]

HBXREF22 - 22" Acrylic Reflector



Dimensions in Inches [mm]

Dialight reserves the right to make changes at any time in order to supply the best product possible. The most current version of this document will always be available at: www.dialight.com/Assets/Brochures_And_Catalogs/Illumination/MDEXHB125X001.pdf

Warranty Statement: EXCEPT FOR THE WARRANTY EXPRESSLY PROVIDED FOR [HEREIN/ABOVE/BELOW], DIALIGHT DISCLAIMS ANY AND ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY WARRANTIES OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE, AND NONINFRINGEMENT.

Energy Efficiency Improvements Audit Report

Prepared for

Kettle Falls Generating Facility

Prepared by
Andy Paul, PE
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Levi Westra, PE
Energy Solutions Engineers

March 24, 2015

Overview

Facility: Kettle Falls Thermal Generation Facility
Audited by: Andy Paul PE, Bryce Eschenbacher PE and Levi Westra PE
Onsite Staff: Mike Floener and Greg Wiggins
Facility Audited on: March 5th, 2015

Figure 1 Google Earth Images of the Kettle Falls Generation Facility

Avista's DSM Engineering staff visited the Kettle Falls generating facility to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon

historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of office space, network room, shop areas, and 7 story high bay warehouse which contains the hog fuel boiler and steam turbine. In addition there are several outbuildings that house the water treatment facility, and other generating equipment.

Shell

There are several areas around the facility where additional weatherization work can be conducted.

1. The roll up doors could use new weather stripping along the outside edges of the doors and along the bottom. A noticeable draft can be felt when you stand next to the doors.

2. The man doors would also benefit from additional weather stripping.

These measures are applicable to the main plant area; this area is conditioned by waste heat off the boiler. The measures would apply to the support buildings, machine shop, and office space. While these measures will conserve energy, those savings will be negligible in comparison to the measure listed further in this report.

Lighting

The site employs T12 and T8 linear fluorescent lighting as well as 250 Watt High Pressure Sodium (HPS) high-bay, 70 Watt mercury vapor (MV) yard light and 1000W MV yard lights. The lights in the plant operate 24/7, yard lights operate dusk to dawn (4,288 hrs/yr), and it is assumed that the office lights operate 2,080 hrs/yr.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Plant Lighting	**$56,515**	**20 yrs**	**150,190**
2	Plant Lighting Controls	**$66,515**	**20 yrs**	**183,058**
3	Yard Lighting	**$19,099**	**20 yrs**	**48,180**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The facility currently has (x127) single lamp 250W high pressure sodium fixtures in the main plant area. The main plant is seven floors; the lighting count includes each floor and the stairwell lighting. The fixtures operate 24/7, 8,760 hrs/yr. The proposed project looks at replacing these fixtures with (x127) single lamp 160W LED low bay fixtures, CREE CXB. A simple lumen calculation shows that the overall lumens for the job were decreased by 18.5%.

    - The provided project is $56,515, this cost was calculated using fixture costs, $370 per fixture, off the internet and estimated labor costs, $75 per fixture.

- It should be noted that the fixture count used for this analysis is as close as could be done while on site. If more fixtures are found the kWh savings and project cost will go up.

2. Proposed Project #2: This project looks at the additional savings that could be seen by installing occupancy sensors to the main generating facility. The controls proposed would leave 67 of the fixtures on 24/7 and the remaining 60 would only come on when someone is present in the space. This would reduce the operating hours for the 60 fixture by an estimated 35%.

    - The provided project is an additional $10,000 over the straight replacement project. This cost is purely an estimate and should be verified by a lighting professional. A high cost was estimated due to the complexity of the controls required for the space. Since the flooring in the plant is all metal grate there is a potential the lights on floor 6, for example, may come on when someone walks by on floor 5. To operate properly the sensors would need to be calibrated to only pick up on motion on the floor that they are located on.

3. Proposed Project #3: The facility currently has (x27) single lamp 70W mercury vapor fixtures and (x13) 1000W mercury vapor fixtures lighting up the yard. The fixtures operate dusk to dawn, 4,288 hrs/yr. The proposed project looks at replacing these fixtures with (x27) single lamp 52W RAB LED pole fixtures and (x13) single lamp 300W LED street lights, MaxLite Merek Series. A simple lumen calculation shows that the overall lumens for the job were decreased by 30%.

    - The provided project is $19,099, this cost was calculated using fixture costs, $499 per 300W fixture and $356 per 52W fixture, off the internet and estimated labor costs, $75 per fixture.

    - It should be noted that the fixture count used for this analysis is as close as could be done while on site. If more fixtures are found the kWh savings and project cost will go up.

4. It should be noted that while the total system lumens decrease for each of these projects, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

HVAC

1. The control room, restrooms, break room, and office space are conditioned by several gas fired roof top units. Some of these units have been replaced recently and the remaining units have been in service for a while. We were unable to determine the efficiency of the existing units. While there are newer units available that have efficiencies closer to SEER 19, the cost to purchase and install these units outweighs the potential energy savings. Our recommendation is to replace these units when they have reached their end of life. When you do replace these units purchase the most efficient units that can be afforded. It should also be noted the units use R-22 refrigerant, this refrigerant is no longer being manufactured. Should a unit need to be recharged you should consider replacing it with a high efficient unit at that point.

2. The generation floor has several natural gas unit heaters on each floor to provide supplemental heat. These units are only used during shutdowns. Due to the low annual usage it would not be a cost effective project to replace them. In the future when these units are at end of life we recommend purchasing and installing the most efficient units that can be afforded.

3. The machine shop has several natural gas radiant tubes to provide space heat. This type of heating in a shop area is an efficient option since it focuses on heating the occupants and not the surrounding area. It is important to have the thermostats set appropriately for this type of heat though. You want to set the temperature around 55º and have the thermostat closer to the ground than a typical installation. This will insure that the units are not heating the airspace to 55º and are instead only providing occupant comfort.

Boiler Forced Draft Blower System

The site employs a wood fired boiler to generate steam to drive a turbine. The boiler relies on a Forced Draft (FD) and Induced Draft (ID) fans driven by single-speed motors to provide combustion air. Currently combustion air flow-rates through the FD are regulated using inlet dampers which are open/closed depending on desired plant output and combustion performance. There is an opportunity to reduce average blower power draw and energy consumption using a Variable Frequency Drive (VFD).

	Brief EEM* Description	Roughly Estimated EEM Cost	Measure Life	Electric kWh Savings
1	FD Fan VSD	**$510,000**	**15 yrs**	**700,000**

1. Adjusting blower speed is the most efficient way to vary airflow rates. Based on SCADA, from a 2012 analysis, which documents plant gross output, FD fan current draw, and FD damper position, an estimated 700,000 kW*hr of energy could be "saved" using a VFD. A summary of the analysis, assumptions and results is appended to this document.

   Please note that during the 2015 site audit, the operations staff indicated that some processes and equipment had been changed since 2012 that reduced the average damper position from ~65% to ~50%. This has a noticeable impact on estimated energy savings. The value presented above is the average of the two configurations.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – March 24th, 2015

Name: Kettle Falls Generating Facility - Main Plant Lighting
Acct#

Existing Annual Consumption: (kilowatt hours)	328,193.40	
Lighting Energy Savings:(kilowatt hours)	150,190.20	
Lighting Demand Savings: (kilowatt demand)	13.72	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	81.45%	
Total Energy Savings: (kilowatt hours)	150,190.20	
Total Demand Savings: (kilowatt demand)	**13.72**	
Estimated Project Cost: (Rough Estimate)	$73,152.00	
Customer Supplied Cost	$0.00	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$549.75	

Costs updated on 1/0/1900

AE Jayson Hunnel

Name: Kettle Falls Generating Facility - Main Plant Lightign w/ controls
Acct#

Existing Annual Consumption: (kilowatt hours)	328,193.40	
Lighting Energy Savings:(kilowatt hours)	183,057.72	
Lighting Demand Savings: (kilowatt demand)	13.72	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	81.45%	
Total Energy Savings: (kilowatt hours)	183,057.72	
Total Demand Savings: (kilowatt demand)	**13.72**	
Estimated Project Cost: (Rough Estimate)	$83,152.00	
Customer Supplied Cost	$83,152.00	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	#DIV/0!	

Costs updated on 01-00-1900

AE Jayson Hunnel

Name: Kettle Falls Generating Facility - Yard Lights
Acct#

Existing Annual Consumption: (kilowatt hours)	70,923.52	
Lighting Energy Savings:(kilowatt hours)	48,179.97	
Lighting Demand Savings: (kilowatt demand)	8.99	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	69.68%	
Total Energy Savings: (kilowatt hours)	48,179.97	
Total Demand Savings: (kilowatt demand)	**8.99**	
Estimated Project Cost: (Rough Estimate)	$19,099.00	
Customer Supplied Cost	$0.00	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$453.66	

Costs updated on 1/0/1900

AE Jayson Hunnel

Customer: Avista Generation; Kettle Falls Generation station ID/FD Fan VSD evaluation
Project State: EEM Evaluation
Date: 05/14/15
Analysis Description:
-Estimate the possible energy savings of converting the facility's ID/FD combustion blower to variable speed control.
-Assume that air-flow rates are proportional to generation rate.
-Assume the EEM will open the damper to 100%, combustion air flow-rate controlled via blower speed.
-Assume 4180 VAC nominal voltage and 0.7 power factor.

Inputs:

Table 1. Binned operational data from 2012 SCADA data. See excel worksheet "KF GS FD ID Fan VSD eval 101712.xlsm"

GS Output [MW]	Operation [hours]	Operation [%]
0	867	10%
5	493	6%
10	7	0%
15	284	3%
20	215	2%
25	35	0%
30	89	1%
35	39	0%
40	95	1%
45	736	8%
50	3635	42%
55	2261	26%
60	0	0%
65	0	0%
70	0	0%
Total	8756	

Figure A. Image of the FD damper actuator during 2015 audit. Note the position ~50%.

Figure 1. Graph of FD damper position versus averaged fan current draw. Sourced from SCADA data. Note the R2 value which indicates fan current is directly effected by damper position. Note the blower motor is 4180 volt.

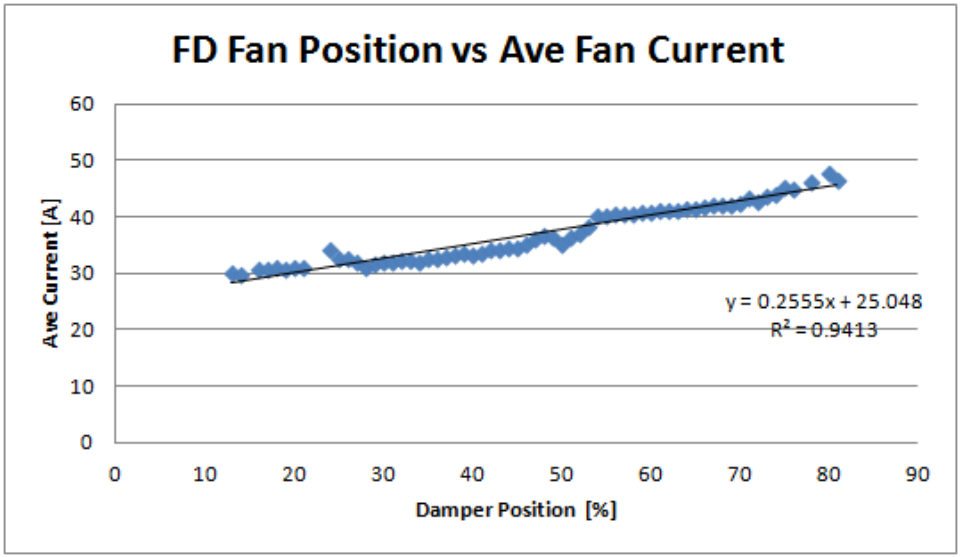


Figure 2. Graph of Station's power output vs damper positon. Note that the R2 value is somewhat low, this indicates that there are other variable effecting the output; likely fuel type, humidity, moisture content, air temperature.

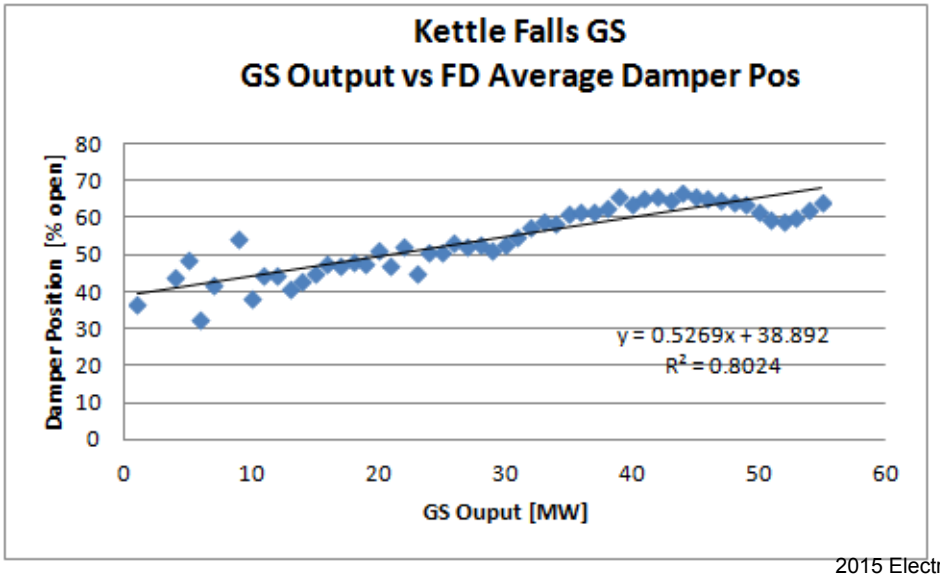
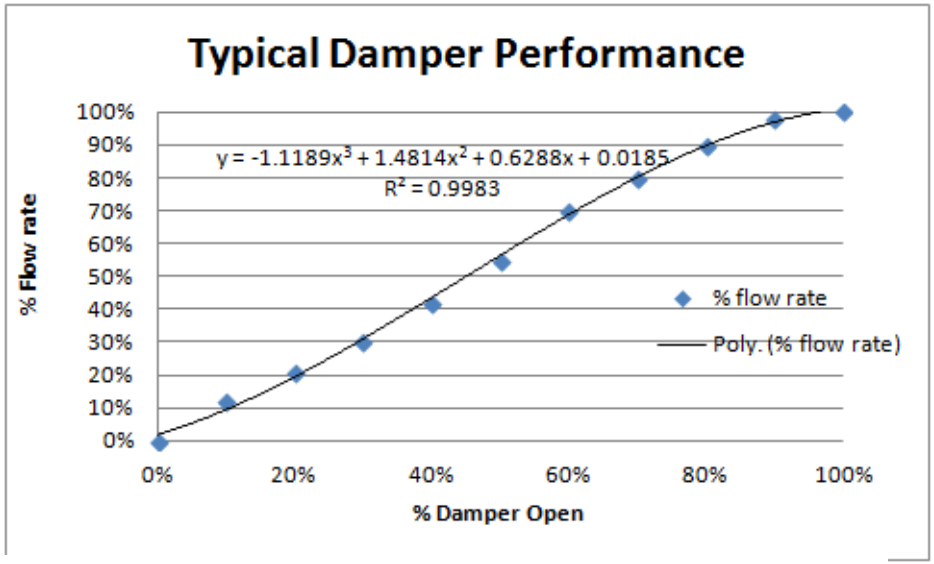


Figure 3. Typical damper performance from HVAC handbook. Assumes closed damper is ~25% of duct system total pressure drop



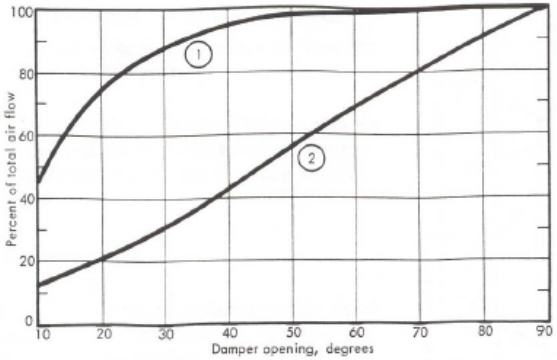


Figure 2. How well damper controls air flow depends on the ratio of damper's resistance (in wide open position) to that of the duct system. Parallel-leaf damper has characteristics of curve 1 when damper's resistance is 1 to 2 percent of total system loss. Preferred traits of curve 2 are obtained when damper represents 25 to 30 percent of total resistance. For opposed-leaf damper, best performance occurs when resistance is from 2 to 5 percent of total.

Table 2. Example of baseline and EEM FD fan analysis, based upon 2012 SCADA data and typical performance of dampered and VSD controlled blowers. See Excel worksheet "KF GS FD ID Fan VSD eval 101712.xlsm" for actual calculations.

	SCADA Logged Data				Baseline Inlet Damper		EEM VSD	
	GS Gross Output [MW]	[%]	% Damper Pos	Estimated % Flow Rate	Calc. Ave Baseline Fan Power [kW]	Energy Consumed [kW*hr]	Calc. Ave VSD Fan Power	Energy Consumed [kW*hr]
1/1/10 0:00	48	64	64%	74%	210	210	139	139
1/1/10 1:00	47	64	64%	74%	210	210	139	139
1/1/10 2:00	50	64	64%	74%	210	210	139	139
1/1/10 3:00	48	64	64%	74%	210	210	139	139
1/1/10 4:00	48	65	65%	74%	211	211	141	141
1/1/10 5:00	45	65	65%	74%	211	211	141	141

Table 3. Summary of FD EEM performance based upon 2012 SCADA data.

Summary of EEM Analysis Using 2012 SCADA Data		
Baseline Ave Damper % Open	65%	-
Estimated Baseline Ave Flow Rate	73%	-
Baseline Ave Power	212	kW
Baseline Annual Energy Consumption	1,853,772	kW*hr/yr
EEM Ave Power	143	kW
EEM Estimated Annual Energy Consumption	1,252,798	kW*hr/yr
Estimated Annual Savings	**600,974**	**kW*hr/yr**

Table 4. Summary of FD EEM performance based on operator input that due to recent facility equipment changes that the FD blower has been operating with damper ~50% open.

Summary of Data Based on Observations during 2015 Walk Through		
Assumed Baseline Damper % Open	50%	-
Corresponding Baseline Flow Rate	56%	-
Corresponding Ave Baseline Fan Power	180	kW
Annual Baseline Energy Consumption	1,573,171	kW*hr/yr
Estimated Ave EEM Fan Power	81	kW
Annual EEM Energy Consumption	712,913	kW*hr/yr
Estimated Annual Energy Savings	**860,258**	**kW*hr/yr**

Simple Payback Analysis

$dollar := 1$

$rate_{ele} := 0.07 \cdot \frac{dollar}{kW\,hr}$ input: assumed average value of the energy commodity.

$E_{savings} := \frac{\left(\frac{600000\,kW\,hr}{yr} + \frac{850000\,kW\,hr}{yr}\right)}{2}$ calc: estimated annual energy savings of the VFD.

$E_{savings} = 725000 \frac{kW\,hr}{yr}$

$Sales := E_{savings} \cdot rate_{ele}$ calc: estimated increase in energy sales.

$Sales = 50750 \frac{1}{yr}$

$rate_{VFD_MV} := 1000 \cdot \frac{dollar}{hp}$ input: estimate of typical medium voltage VFD installation cost.

$P_{VFD} := 300\,hp$ input: estimated VFD size.

$Cost_{project} := rate_{VFD_MV} \cdot P_{VFD}$ calc: rough estimate project cost.

$Cost_{project} = 300000\,dollar$

$SPB := \frac{Cost_{project}}{Sales}$ calc: energy simple payback of the EEM.

$SPB = 5.9\,yr$

Energy Efficiency Improvements Audit Report

Prepared for

Little Falls Generating Facility

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

February 13, 2015

Overview

Facility: Little Falls Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff:
Facility Audited on: February 10th, 2015

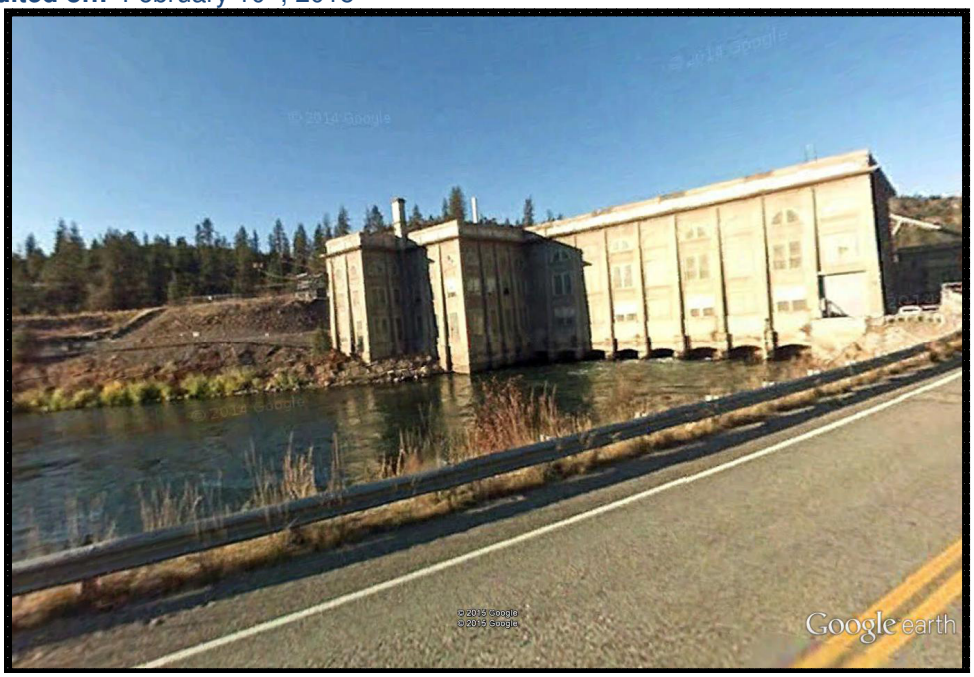


Figure 1 Google Images of Little Falls Hydro Electric Dam

Avista's DSM Engineering staff visited the Little Falls Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation.

Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

It should be noted that this facility is currently undergoing a complete overhaul. Due to this there are very few projects that can be suggested that are not already going to be implemented.

The facility consists of a control room and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

There are several areas around the facility where additional weatherization work can be conducted:

All exterior entry doors should have their weather stripping checked and replaced if necessary.

All windows that are not required to remain historically accurate should be replaced with energy efficient double pane windows.

Any portion of the plant that is going to have cooling installed; control room, battery room etc, should have the walls and ceiling insulated. The insulation will help thermally isolate it from the rest of the plant and reduce the amount of cooling required in the summer time.

There is currently little to no insulation above or below the roof deck in the plant. It is recommended that insulation, R-19 at the very least, be added below the deck. This insulation will aid in reducing the amount of time a unit has to be motored during the winter months to maintain space temperature.

Lighting

The facility currently employs T12 fluorescent lighting in the control room and surrounding areas and 400 Watt Metal Halide (MH) high-bay fixtures on the generating floor. The facility will have a brand new all LED lighting system installed during the overhaul. The DSM group at Avista made suggestions on what LED fixtures would be appropriate. Nathan Fletcher in the Generation Dept was in charge of the lighting design.

While there will be energy savings for this project, specifically with the generating floor lighting as well as the control room lighting, there will also be an additional lighting load installed. There are portions of the plant that were under lit and needed additional lighting fixtures installed. Regardless of the additional lighting fixtures, the new system will be as efficient as possible due to the installation of the LED fixtures in lieu of more traditional linear fluorescent and HID fixtures.

HVAC

The control room and few other areas in the plant will be getting new HVAC units installed to heat and cool the spaces. When selecting equipment considered installing the most efficient units that can be afforded. It is also recommended that heat pump units be installed instead of standard condensing units with electric resistive heat. New heat pumps are capable of working efficiently down to temperatures below zero. Since no natural gas is available at the Dam a heat pump is by far the most efficient way to provide space heat.

The main generating floor has no dedicated HVAC units. The heat from the generators keeps the space conditioned during the winter months. A generator will be motored to maintain heat if no generation is going on. It is recommended that dedicated HVAC units be installed to maintain the space temperature

when the units are not running. This would reduce unnecessary wear and tear on the generating equipment as well as provide a known dedicated source of heat.

Installing two (possibly three) low speed/high volume destratification fans to help de-stratify the air within in the facility is recommended. With 40' ceilings the majority of buildings heated air will stack at the top, the fans would push that heated air back towards the floor and create a homogenous air temperature. This would reduce the amount of time that the space heat would need to run.

In addition these fans could be run in reverse during the summer months to help pull warm air off the floor and exhaust it out of the exhaust louvers located in the roof.

Process

	Brief EEM* Description	Rough EEM Cost Est.	Measure Life	Electric kWh Savings
1	Speed Controls Cooling/Exhaust Fans	**$10,000**	**16 yr**	**247,909**

The facility employs (4) exhaust fans, for ventilating the generator room, and (4) cooling fans for cooling the generation equipment. Currently the fans are controlled manually, turning fans on and off as needed; fans are operated independently, with units powered on as ventilation/cooling is required. There are some energy savings if the fans were each controlled automatically using Variable Frequency Drives (VFDs). The estimated savings is based upon switching from a manual control system to one that relies on indoor air temperature and equipment temperatures to power on and vary fan speeds to maintain temperatures. Reducing fan speeds reduces power requirements exponentially, resulting in the energy savings. A copy of the SMath Studio model and analysis is appended to the end of this document.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, Levi Westra, February 13th, 2015

Customer: Avista Generation; Little Falls Hydro Generation Station
Project State: Scoping Audit
Date: 03/04/15
Analysis Description: Evaluate the possible energy savings of retrofitting generation floor cooling and exhaust fans with variable speed drives.

Assumptions:
1. System is 3 ph 480VAC (nominal)
2. Units sized for 60% of their service
3. Baseline fan units operate 24/7/365
4. EEM operation is dependent on outside air temperature
5. Power factor nominal 0.80

Inputs:

$pct := \frac{1}{100}$ input- assign percentage

$V_{nom} := 480\ V$ input- assign nominal supplied voltage

$PF := 0.80$ input - assign assumed operational power factor

$Qty_{exhaust} := 4$ input - number of exhaust fans

$Qty_{cooling} := 4$ input - number of cooling fans

$A_{breaker_exh} := 15\ A$ input - exhaust fan breaker/circuit size

$A_{breaker_cooling} := 50\ A$ input - cooling fan breaker/circuit size

$F_{service} := 60 \cdot pct$ input - assumed sizing factor; percent power draw based on circuit size

$Duty_{cycle} := 69 \cdot pct$ input - assumed generator annual duty cycle; based on long lake VFD project notes.

$n := 2.5$ input - exponent for affinity law power calculations

Calculations:

$$P_{exhaust} := A_{breaker_exh} \cdot V_{nom} \cdot F_{service} \cdot PF \cdot \sqrt{3}$$

$$P_{exhaust} = 6\ kW$$

$$P_{cooling} := A_{breaker_cooling} \cdot V_{nom} \cdot F_{service} \cdot PF \cdot \sqrt{3}$$

$$P_{cooling} = 20\ kW$$

Savings based on Spokane bin data

Table 1. Results from Excel Worksheet Bin analysis.

Spokane TMY Bin Data (°F)

							Baseline Power [KW]		EEM Power [kW]		Baseline Energy [kWh/yr]		EEM Energy [kWh/yr]	
	Bin Low	Bin High	Hours	% of year	Duty cyle Hours	% fan speed	exhaust	cooling	exhaust	cooling	exhaust	cooling	exhaust	cooling
1	-20	-15	0	0.0%	0	0%	0	0	0.0	0	0	0	0	0
2	-15	-10	8	0.1%	6	20%	6	20	0.4	1.4	33	110	2	8
3	-10	-5	7	0.1%	5	23%	6	20	0.6	2.1	29	97	3	10
4	-5	0	12	0.1%	8	27%	6	20	0.9	3.0	50	166	7	25
5	0	5	19	0.2%	13	30%	12	40	1.2	4.1	157	524	16	54
6	5	10	6	0.1%	4	34%	12	40	1.6	5.4	50	166	7	22
7	10	15	34	0.4%	23	37%	12	40	2.1	6.8	282	938	48	160
8	15	20	133	1.5%	92	41%	12	40	2.6	8.5	1,101	3,671	235	784
9	20	25	472	5.4%	326	44%	12	40	3.1	10.5	3,908	13,027	1,024	3,412
10	25	30	544	6.2%	375	48%	12	40	3.8	12.7	4,504	15,014	1,425	4,750
11	30	35	981	11.2%	677	51%	12	40	4.5	15.1	8,123	27,076	3,063	10,209
12	35	40	1280	14.6%	883	55%	18	60	5.3	17.8	15,898	52,992	4,708	15,695
13	40	45	922	10.5%	636	58%	18	60	6.2	20.7	11,451	38,171	3,956	13,186
14	45	50	854	9.7%	589	62%	18	60	7.2	24.0	10,607	35,356	4,236	14,119
15	50	55	653	7.5%	451	65%	18	60	8.2	27.5	8,110	27,034	3,714	12,381
16	55	60	707	8.1%	488	69%	18	60	9.4	31.3	8,781	29,270	4,579	15,264
17	60	65	679	7.8%	469	72%	18	60	10.6	35.4	8,433	28,111	4,976	16,587
18	65	70	461	5.3%	318	76%	18	60	11.9	39.8	5,726	19,085	3,800	12,668
19	70	75	330	3.8%	228	79%	24	80	13.4	44.6	5,465	18,216	3,044	10,146
20	75	80	262	3.0%	181	83%	24	80	14.9	49.6	4,339	14,462	2,691	8,970
21	80	85	221	2.5%	152	86%	24	80	16.5	55.0	3,660	12,199	2,516	8,388
22	85	90	93	1.1%	64	90%	24	80	18.2	60.7	1,540	5,134	1,169	3,897
23	90	95	55	0.6%	38	93%	24	80	20.0	66.8	911	3,036	761	2,535
24	95	100	25	0.3%	17	97%	24	80	22.0	73.2	414	1,380	379	1,263
25	100	105	2	0.0%	1	100%	24	80	24.0	80.0	33	110	33	110
26	105	110	0	0.0%	0	0%	0	0	0.0	0	0	0	0	0
27	110	115	0	0.0%	0	0%	0	0	0.0	0	0	0	0	0
28	115	120	0	0.0%	0	0%	0	0	0.0	0	0	0	0	0
	Total		8760	100.0%	6044						103,604	345,345	46,394	154,646

Inputs to Calculation		
69%	generator average duty cycle	
20%	minimum VFD speed	
100%	maximum VFD speed	
80%	range	
23	temp bins	
3.5%	increase in VFD speed per increase in temp bin	
6	kW	Exhaust fan nominal power
20	kW	Cooling Fan nominal power

$E_{baseline} := 103604\,kW\,hr + 345345\,kW\,hr$

calc - total annual baseline nergy consumption of the exhaust and cooling fans; assumes 69% duty cycle, 60% sizing factor and linear reduction in # of fans operated based on binned outside temperature data for Spokane area. Reference Excel worsheet "Little Falls DAm_EEM Eval_Exhaust Cooling Fan_030415.xls" for details. A copy of the worksheets results is above in table 1.

$E_{EEM} := 46394\,kW\,hr + 154646\,kW\,hr$

calc - total annual EEM energy consumption of the exhaust and cooling fans; assumes 69% duty cycle, 60% sizing factor and linear reduction in fan speeds based on binned outside temperature data for Spokane area.
see excel worksheet "Little Falls DAm_EEM Eval_Exhaust Cooling Fan_030415.xls" for details.

$E_{savings} := E_{baseline} - E_{EEM}$

$\boxed{E_{savings} = 247909\,kW\,hr}$

Double check of above model

Energy Efficiency Improvements Audit Report

Prepared for

Long Lake Hydro Electric Dam

Prepared by

Andy Paul, PE

Bryce Eschenbacher, PE

Levi Westra, PE

Energy Solutions Engineers

February 13, 2015

Overview

Facility: Long Lake Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff:
Facility Audited on: February 10th, 2015

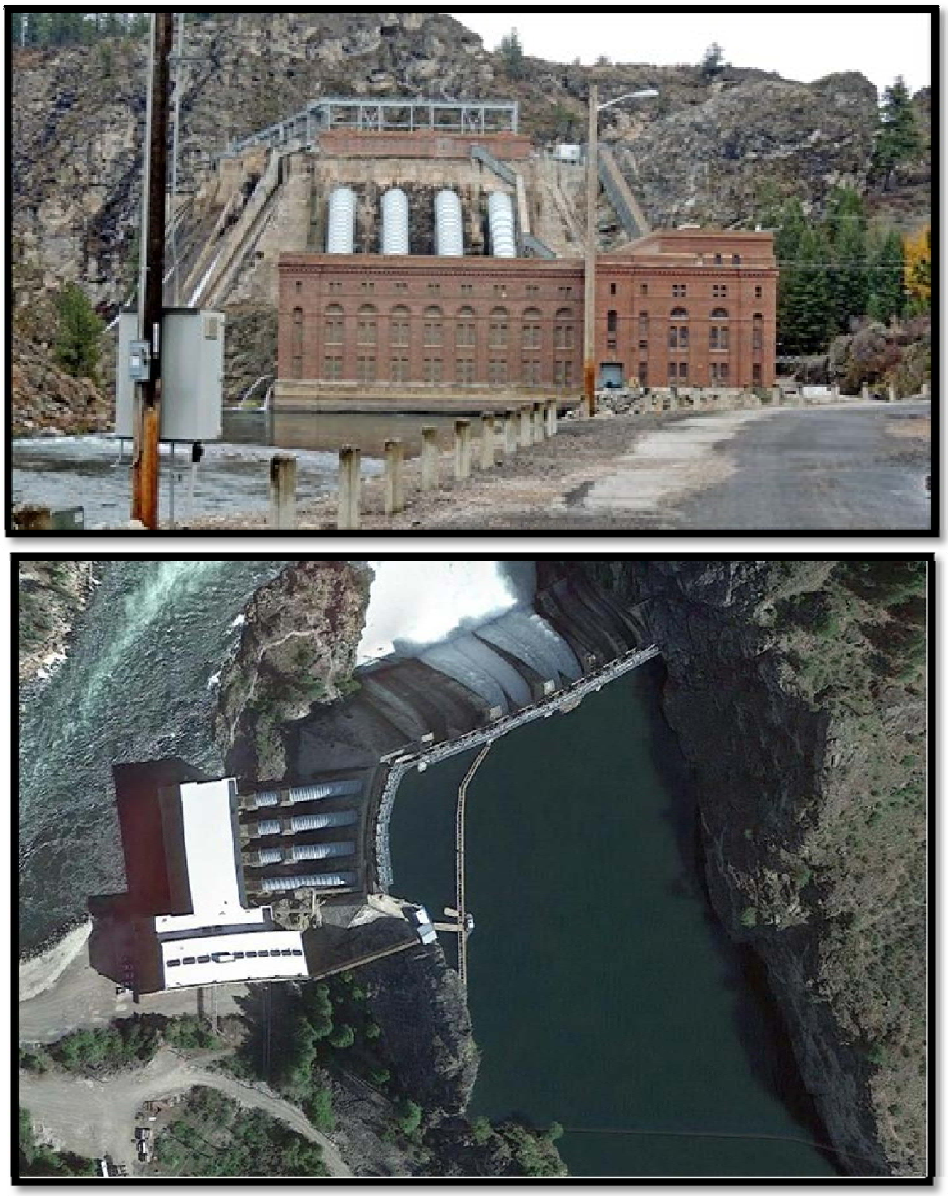


Figure 1 Google Images of the Long Lake Hydro Electric Dam

Avista's DSM Engineering staff visited the Long Lake Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of a control room, office space, break area and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

There are several areas around the facility where additional weatherization work can be conducted.

1. All exterior entry doors should have their weather stripping checked and replaced if necessary.

2. All windows that are not required to remain historically accurate should be replaced with energy efficient double pane windows.

3. Any portion of the plant that currently has heating or cooling installed should have the walls and ceiling insulated. The insulation will help thermally isolate it from the rest of the plant and reduce the amount of cooling required in the summer time.

4. There is currently little to no insulation above or below the roof deck in the plant. It is recommended that insulation, R-19 at the very least, be added below the deck. This insulation will aid in reducing the amount of time a unit has to be motored during the winter months to maintain space temperature.

Lighting

The site employs T12, T8 and T5 linear fluorescent lighting as well as 400 Watt Metal Halide (MH) high-bay and 250 Watt MH exterior lighting on dusk to dawn sensors. No parking lot lighting was observed.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Generating Floor High Bays	**$18,252**	**20 yr**	**17,441**
2	Exterior Wall Packs	**$1,339**	**20 yr**	**2,084**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The facility currently has (x11) single lamp 400W Metal Halide fixtures and (x8) single lamp 1000W incandescent fixtures lighting the main generation facility. It is assumed that the lights are on for an average 3,600 hrs a year. The proposed project looks at replacing these fixtures with (x30) 200W linear LED high bay fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 43%.

    - The provided project is $18,252, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

2. Proposed Project #2: The facility currently has (x2) single lamp 250W high pressure sodium cobra head fixtures outside the main entry door. The fixtures average 4,288 hrs (dusk to dawn) of

operation a year. The proposed project looks at replacing these fixtures with (x2) 52W LED wall packs. A simple lumen calculation shows that the overall lumens for the job were decreased by 73%.

- The provided project cost is $1,336, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

3. It should be noted that while the total system lumens decrease for each of these projects, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

4. In addition to the projects listed above there are several other areas that would benefit from installing new lighting fixtures.

    - The control room and machine shop both have 2L T12 fluorescent fixtures that should be replaced with the new LED fixtures or at the very least 2L T8 fluorescent fixtures.

    - The breaker floor is severely under lit and would greatly benefit from additional lighting fixtures being installed. There is no chance of energy savings in this case since there are only 5 light fixtures in the entire area. The greater benefit would be the increased worker safety and having more light to perform work.

    - The generator floor entry hallway is lit by 100W incandescent fixtures. It is recommended that these be replace with a comparable 20W LED screw in lamp or at the very least a 23W compact fluorescent lamp.

HVAC

1. During the walk through it was mentioned that the control room has a dedicated cooling system but no heating, the generators provide heat for the facility. It is recommended that some type of supplemental electric heat be installed to heat the control room.
2. The main generating floor has no dedicated HVAC units. The heat from the generators keeps the space conditioned during the winter months. A generator will be motored to maintain heat if no generating is going on. It is recommended that dedicated HVAC units be installed to maintain the space temperature when the units are not running. This would reduce unnecessary wear and tear on the generating equipment as well as provide a known dedicated source of heat.
3. Installing two (possibly three) low speed/high volume destratification fans to help de-stratify the air within in the facility is recommended. With 40’ ceilings the majority of buildings heated air will stack at the top, the fans would push that heated air back towards the floor and create a homogenous air temperature. This would reduce the amount of time that the space heat would need to run.

   In addition these fans could be run in reverse during the summer months to help pull warm air off the floor and exhaust it out of the exhaust louvers located in the roof.

Process

Brief EEM Description	Annual Electric kWh Savings
Variable Speed Stator Cooling Blowers	135,000

- Generator cooling fan controls- The (4) hydro-turbine power generators require cooling to operate reliably. Currently the operators operate (4) 100 hp blowers to circulate air from a plenum located below the generators. The blowers operate at a fixed speed forcing outside air to maintain stator temperatures. In the winter the outside air temperature is too low, louvers/baffles are manually opened to re-circulate pre-heated air from within the generator room to keep stator temps from dropping. The EEM would automatically adjust blower speed to reduce flow of the colder outside air across the stators instead of re-circulating pre-heated air eliminating the baffle/louver operation. Because blowers are variable torque devices power consumption is exponentially related to blower speed. The above estimated savings is the annual estimated energy savings based on average yearly temperatures, one time measured power draw, stator temperature goals, and affinity laws for four stators. A copy of the analysis is appended to this document.

Figure 2 Long Lake generator.

Figure 3 Long Lake dam generator passage for cooling air.

Figure 4 Long Lake stator cooling blower (left) and motor (right).

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – February 13th, 2015

Customer: Long Lake Dam;
Project: Cooling Fan VFD Drive Evaluation
Date: 01/07/10

Define the Situation:

Randy Gnaedinger contacted Tom about having the team evaluate the possible benefits of installing VFD drives on the (4) ~100hp generator cooling fans at the Long Lake Dam. Tom, Andy and I visited the site on 12/30/09. We met with Bill Maltby, the facility's chief operator. He gave us a tour. We took air temperature, air speed, air flow rate, plenum, and power measurements of the (4) operating fan units.

Goals:

1. Determine fan speeds required maintain stator temperature at 60°C (ideal operational temp)
2. Evaluate power draw of fans at required fan speeds
3. Compare power draw with EEM to power draw without EEM

Assumptions:

-system is steady state, no accounting for stator/generator mass
-air temperature measured supplying fan #5 was 74°F, while air temp supplying fan #1 was 53°F. It is assumed that this is attributed to the team leaving the access door open to the plenum during the tour. For this analysis I will use 53°F as the baseline for all of the fans.
-this analysis does not account for the effect VFDs will have on the air temperature within the generator room.
-assume that the louvers in the room will no longer be used to control fan supply air temp. fans will draw only outside air, temperature will be purely ambient.
-assume the dry bulb temperaure equals the wet bulb temperature of air coming out of air washers which will assume is equal to the dew point temp pluse 2°F (conservative); unless the water temperature exceeds the dew point, at which point employ the water temperature.
-assume the dry bulb temp is equal to the ambient temperature when the air washer is not being used (winter months).
-apply infinity fan laws to estimate fan speed and power based on air flow needs
-assumed that the air washers would be employed shortly after the last freezing potential in the spring, and discontinued once freezing temperatures were encountered in the fall. Reviewed 1987 data, and it appears assuming air washers come on line begining in May and taken offline begining in October is appropriate. Currently there is no schedule for air washers. The

electrician enables the system sometime in the spring when it seems like it won't freeze, and disables the system in the fall when it starts to get cold. The operators start washing the air once they are unable to maintain stator temps at or below the 60°C optimal temperature.
-applied a website generated excel equation to calculate wet bulb temp based on dry bulb and releative humidity: http://www.the-snowman.com/wetbulb2.html

I verified the relative accuracy of the calculation using the pychrometric chart located in the MERM appendix 38.C
-assumed that a VFD turndown ratio at a minimum of 20% did not hinder or cause problems for fan operation
-assumed all four fans are delivering the same air flow to each generator

Inputs: **Supporting Results/Comments:**

$temp_{air_exit_stator} := 76\,°F = 297.6\,K$ measured 74°F air coming through the access door to the plenum, for a conservative estimate I added a fudge factor.

$temp_{stator} := 60\,°C = 333.1\,K$ this is the target stator temperature. facilities team adjusts internal louvers and air washer operation in order to maintain this temperature at 60°C

$temp_{fan1_air} := 60\,°F = 288.7\,K$ measured temperature of air supplied to fan #1 during visit on 12/30/09

$air_speed_{fan1} := 1900\,\frac{ft}{min}$ measured average air speed using the kestrel

$air_speed_{fan5} := 2500\,\frac{ft}{min}$ measured average air speed using the kestrel

$Xarea_{plenum_fan5} := 39in \cdot 81in = 21.9 \cdot ft^2$ measured plenum cross-secitonal area, note plenum 5 does not share the same dimensions with 1-4.

$Xarea_{plenum_fan1to4} := 48in \cdot 96in = 32 \cdot ft^2$ measured plenum cross-sectional area, note fans 1-4 all share the same plenum size

$air_flow_{fan5} := 44000\,\frac{ft^3}{min}$ measured air flow rate using kestrel hand held meter using plenum dimensions inputted into unit.

$power_{fan1} := 75kW$ measured power draw by fan #1 during tour

$power_{fan2} := 7kW$

$power_{fan4} := 19kW$

$power_{fan5} := 36kW$

$average_duty := 69\%$ typical duty cycle of each of the (4) generators per year.

$\eta_{sat_air_washer} := 90\%$ $air_flow_calc_{fan5} := air_speed_{fan5} \cdot Xarea_{plenum_fan5} = 54843.7 \cdot \frac{ft^3}{min}$ sanity check on kestrel air flow measurement

$\eta_{VFD} := 98\%$

$Cp_{air_290K} := 1.0048 \cdot 10^3 \frac{J}{kg \cdot K}$ specific heat of air at a mixing cup temperature of 290K ref. MERM ap.35.D

$\rho_{air_290K} := 1.246 \frac{kg}{m^3} = 0.1 \cdot \frac{lbm}{ft^3}$ density of air at a mixing cup temp of 290K ref MERM ap.35.D

Calculations:

Goal #1

Estimating Power rejected by Gen 1 as heat

$$temp_{air_mixing_cup} := \frac{temp_{air_exit_stator} + temp_{fan1_air}}{2} = 293.1\,K$$

$$\frac{1000kW}{20 \cdot 10^6 W} = 5\,\%$$

$$air_flow_calc_{fan1} := air_speed_{fan1} \cdot Xarea_{plenum_fan1to4} = 60800 \cdot \frac{ft^3}{min}$$

$$m_{dot_fan1} := air_flow_calc_{fan1} \cdot \rho_{air_290K} = 4729.3 \cdot \frac{lbm}{min}$$

$$heat_transfer_{stator} := m_{dot_fan1} \cdot Cp_{air_290K} \cdot \left(temp_{air_exit_stator} - temp_{fan1_air}\right) = 319.3 \cdot kW$$

estimated amount of heat being rejected to air by generator #1

$$heat_transfer_{stator} := 1MW$$

after a discussion with Randy, to be better represent actual generator efficiency (~95%) I assigned 1 MW to be rejected via forced convection. Overroad my heat calculation and forced 1MW rejection into model

Estimating Power rejected by Gen 1 as heat

Generator 1 - Final Analysis with weather and gen schedule data

Data Imports from GEG Bin data 1987

$Temp_{drybulb_hourly} :=$ _____

$Temp_{est_wetbulb_hourly} :=$ _____

$schedule_{generator_1} :=$ _____

factor of safety to approximate some building air recirculation back into the plenum to maintain building air temp above 50F

$$temp_{drybulb_out_airwasher} := \left[\left(Temp_{drybulb_hourly} + temp_{FS}\right) - \eta_{sat_air_washer} \cdot \left(Temp_{drybulb_hourly} - Temp_{est_wetbulb_hourly}\right)\right] °F$$

calculation of predicted dry bulb air temp leaving the air washers,
calculation referenced from MERM eq 38.34 assumed air washer saturation efficiency of 90% (conservative value)

$Temp_{est_wetbulb_hourly} =$

	0
98	30
99	28.9
100	28.9
101	28.9
102	28
103	28.9
104	...

$schedule_{generator_1} =$

	0
0	0
1	0
2	0
3	0
4	...

$temp_{drybulb_out_airwasher} =$

	0
0	30
1	30
2	30
3	30
4	...

$\cdot °F$

results of calculating dry bulb temperature; includes air washer scheduled operation

$temp_{air__EEM_exit_stator} := 92\,°F$

assigned a value to the exit air temperature from the stator; based on best estimate of ideal exit temperature to maintain stator temperature

$heat_transfer_{stator} = 1000\,kW$

$$m_{dot_generator_1} := \frac{heat_transfer_{stator}}{Cp_{air_290K} \cdot \left(temp_{air__EEM_exit_stator} - temp_{drybulb_out_airwasher}\right)}$$

$n := 8759$

$i := 0 .. n$

$m_{dot_generator_1} =$

	0
0	28.9
1	28.9
2	28.9
3	...

$\frac{kg}{s}$

$m_{dot_schedule_generator1_i} := m_{dot_generator_1_i} \cdot schedule_{generator_1_i}$

adjusting air requirements for when generator is operating. Based on data obtained from Rodney Picket for hourly generator operation for 2009

$m_{dot_schedule_generator1} =$

	0
0	0
1	0
2	...

$\frac{kg}{s}$

$air_flow_{generator_1} := \frac{m_{dot_schedule_generator1}}{\rho_{air_290K}}$

$air_flow_{generator_1} =$

	0
5	49150.7
6	49150.7
7	49874.9
8	50772.7
9	...

$\cdot \frac{ft^3}{min}$

$air_flow_calc_{fan1} = 60800 \cdot \frac{ft^3}{min}$

$\max(air_flow_{generator_1}) = 189450.2 \cdot \frac{ft^3}{min}$

$fan_speed_percentage_{EEM_generator_1} := \frac{air_flow_{generator_1}}{air_flow_calc_{fan1}}$

$fan_speed_percentage_{EEM_generator_1} =$

	0
2029	122.4
2030	122.4
2031	119.3
2032	119.3
2033	...

$\cdot \%$

need an adjusted fan speed. when fan speed requirements exceed 100% the fan can only deliver that 100%

$$\text{adjusted_fan_speed}(\text{fan_speed}) := \text{if}(\text{fan_speed} > 1, 1, \text{fan_speed})$$

$$\text{adjusted_fan_speed}_{\text{gen1}_i} := \text{adjusted_fan_speed}\left(\text{fan_speed_percentage}_{\text{EEM_generator_1}_i}\right)$$

$\text{adjusted_fan_speed}_{\text{gen1}} =$

	0
0	0
1	0
2	0
3	0
4	0.8
5	0.8
6	0.8
7	0.8
8	0.8
9	0.9
10	0.9
11	0.9
12	0.9
13	0.9
14	0.9
15	...

$$\max\left(\text{adjusted_fan_speed}_{\text{gen1}}\right) = 100 \cdot \%$$

note from Randy: every year, for approximately 1 week, the sytem's needs exceed flow rate needs

$$power_{EEM_generator_1} := \frac{power_{fan1}}{\eta_{VFD}} \cdot \left(adjusted_fan_speed_{gen1}\right)^3$$

$power_{EEM_generator_1} =$

	0
0	0
1	0
2	0
3	...

$\cdot kW$

$$power_{generator_1} := schedule_{generator_1} \cdot power_{fan1}$$

$power_{generator_1} =$

	0
0	0
1	0
2	...

$\cdot kW$

$$annual_fan_energy_{EEM_generator_1} := \sum power_{EEM_generator_1} \cdot hr = 380508.9 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan if a VFD were installed during 2009 operating year

$$annual_fan_energy_{generator_1} := \sum power_{generator_1} \cdot hr = 452925 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan during 2009 operating year

Generator 1 - Final Analysis with weather and gen schedule data

Generator 2 - Final Analysis with weather and gen schedule data

$schedule_{generator_2} :=$ _____

$$m_{dot_generator_2} := \frac{heat_transfer_{stator}}{Cp_{air_290K} \cdot \left(temp_{air__EEM_exit_stator} - temp_{drybulb_out_airwasher}\right)}$$

$m_{dot_generator_2} =$

	0
0	28.9
1	28.9
2	28.9
3	...

$\frac{kg}{s}$

$$m_{dot_schedule_generator2_i} := m_{dot_generator_2_i} \cdot schedule_{generator_2_i}$$

$m_{dot_schedule_generator2} =$

	0
0	0
1	0
2	0
3	...

$\frac{kg}{s}$

adjusting air requirements for when generator is operating. Based on data obtained from Rodney Picket for hourly generator operation for 2009

$air_flow_calc_{fan2} := air_flow_calc_{fan1}$

$$air_flow_{generator_2} := \frac{m_{dot_schedule_generator2}}{}$$

$air_flow_{generator_2} =$

	0
0	0
1	0
2	0
3	...

$\cdot \frac{ft^3}{min}$

$air_flow_{generator_2} =$

	0
0	0
1	0
2	...

$\cdot \frac{ft^3}{min}$

$$\max\left(air_flow_{generator_2}\right) = 189450.2 \cdot \frac{ft^3}{min}$$

$$fan_speed_percentage_{EEM_generator_2} := \frac{air_flow_{generator_2}}{air_flow_calc_{fan2}}$$

$fan_speed_percentage_{EEM_generator_2} =$

	0
0	0
1	0
2	0
3	...

$\cdot\%$

$$adjusted_fan_speed_{gen2_i} := adjusted_fan_speed\left(fan_speed_percentage_{EEM_generator_2_i}\right)$$

$adjusted_fan_speed_{gen2} =$

	0
0	0
1	0
2	0
3	0
4	80.8
5	80.8
6	80.8
7	...

$\%$

$$\max\left(adjusted_fan_speed_{gen2}\right) = 100\cdot\%$$

$$power_{EEM_generator_2} := \frac{power_{fan2}}{\eta_{VFD}}\cdot\left(adjusted_fan_speed_{gen2}\right)^3$$

$power_{EEM_generator_2} =$

	0
4	3.8
5	3.8
6	...

$\cdot kW$

$$power_{generator_2} := schedule_{generator_2}\cdot power_{fan2}$$

$power_{generator_2} =$

	0
0	0
1	0

$\cdot kW$

2	...

$$annual_fan_energy_{EEM_generator_2} := \sum power_{EEM_generator_2} \cdot hr = 35196 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan if a VFD were installed during 2009 operating year

$$annual_fan_energy_{generator_2} := \sum power_{generator_2} \cdot hr = 42490 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan during 2009 operating year

Generator 2 - Final Analysis with weather and gen schedule data

Generator 3 - Final Analysis with weather and gen schedule data

$schedule_{generator_3} :=$ _____

$schedule_{generator_3} =$

	0
0	1
1	1
2	1
3	...

$$m_{dot_generator_3} := \frac{heat_transfer_{stator}}{Cp_{air_290K} \cdot \left(temp_{air__EEM_exit_stator} - temp_{drybulb_out_airwasher}\right)}$$

$m_{dot_generator_3} =$

	0
0	28.9
1	28.9
2	...

$\frac{kg}{s}$

$$m_{dot_schedule_generator3_i} := m_{dot_generator_3_i} \cdot schedule_{generator_3_i}$$

$m_{dot_schedule_generator3} =$

	0
0	28.9
1	28.9
2	28.9
3	...

$\frac{kg}{s}$

adjusting air requirements for when generator is operating. Based on data obtained from Rodney Picket for hourly generator operation for 2009

$$air_flow_{calc_{fan3}} := air_flow_calc_{fan1}$$

$$air_flow_{generator_3} := \frac{m_{dot_schedule_generator3}}{\rho_{air_290K}}$$

$air_flow_{generator_3} =$

	0
0	49150.7
1	49150.7
2	...

$\cdot \frac{ft^3}{min}$

$air_flow_{generator_3} =$

	0
0	49150.7
1	49150.7
2	...

$\cdot \frac{ft^3}{min}$

$$\max(air_flow_{generator_2}) = 189450.2 \cdot \frac{ft^3}{min}$$

$$fan_speed_percentage_{EEM_generator_3} := \frac{air_flow_{generator_3}}{air_flow_calc_{fan3}}$$

$fan_speed_percentage_{EEM_generator_3} =$

	0
0	80.8
1	80.8
2	80.8
3	...

$\cdot \%$

$$adjusted_fan_speed_{gen3_i} := adjusted_fan_speed(fan_speed_percentage_{EEM_generator_3_i})$$

$adjusted_fan_speed_{gen3} =$

	0
0	80.8
1	80.8
2	80.8
3	80.8
4	...

%

$\max(adjusted_fan_speed_{gen3}) = 100 \cdot \%$

*Note: Fan #3 is used as a backup; I assumed fan #4 is supplying ~100% of the flow to gen 3

$$power_{EEM_generator_3} := \frac{power_{fan4}}{\eta_{VFD}} \cdot (adjusted_fan_speed_{gen3})^3$$

$power_{EEM_generator_3} =$

	0
0	10.2
1	10.2
2	...

$\cdot kW$

$$power_{generator_3} := schedule_{generator_3} \cdot power_{fan4}$$

$power_{generator_3} =$

	0
0	19
1	19
2	...

$\cdot kW$

$$annual_fan_energy_{EEM_generator_3} := \sum power_{EEM_generator_3} \cdot hr = 95546.3 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan if a VFD were installed during 2009 operating year

$$annual_fan_energy_{generator_3} := \sum power_{generator_3} \cdot hr = 114019 \cdot kW \cdot hr$$

estimated power used by generator 1's cooling fan during 2009 operating year

Generator 3 - Final Analysis with weather and gen schedule data

Generator 4 - Final Analysis with weather and gen schedule data

$$schedule_{generator_4} := _____$$

$$m_{dot_generator_4} := \frac{heat_transfer_{stator}}{Cp_{air_290K} \cdot \left(temp_{air__EEM_exit_stator} - temp_{drybulb_out_airwasher}\right)}$$

$schedule_{generator_4} =$

	0
0	1
1	...

$m_{dot_generator_4} =$

	0
0	28.9
1	28.9
2	...

$\frac{kg}{s}$

$$m_{dot_schedule_generator4_i} := m_{dot_generator_4_i} \cdot schedule_{generator_4_i}$$

$m_{dot_schedule_generator4} =$

	0
0	28.9
1	28.9
2	...

$\frac{kg}{s}$

adjusting air requirements for when generator is operating. Based on data obtained from Rodney Picket for hourly generator operation for 2009

$$air_flow_{calc_{fan4}} := air_flow_calc_{fan1}$$

$$air_flow_{generator_4} := \frac{m_{dot_schedule_generator4}}{\rho_{air_290K}}$$

$air_flow_{generator_4} =$

	0
0	49150.7
1	49150.7
2	...

$\cdot \frac{ft^3}{min}$

$air_flow_{generator_4} =$

	0
0	49150.7
1	49150.7
2	...

$\cdot \frac{ft^3}{min}$

$$\max(air_flow_{generator_2}) = 189450.2 \cdot \frac{ft^3}{min}$$

$$fan_speed_percentage_{EEM_generator_4} := \frac{air_flow_{generator_4}}{air_flow_calc_{fan4}}$$

$fan_speed_percentage_{EEM_generator_4} =$

	0
0	80.8
1	...

$\cdot \%$

$$adjusted_fan_speed_{gen4_i} := adjusted_fan_speed(fan_speed_percentage_{EEM_generator_4_i})$$

$$\text{adjusted_fan_speed}_{gen4} =$$

	0
0	80.8
1	80.8
2	80.8
3	...

%

$$\max\left(\text{adjusted_fan_speed}_{gen4}\right) = 100 \cdot \%$$

*Note: Fan #3 is used as a backup; I assumed fan #5 is supplying ~100% of the flow to gen 4

$$\text{power}_{EEM_generator_4} := \frac{\text{power}_{fan5}}{\eta_{VFD}} \cdot \left(\text{adjusted_fan_speed}_{gen4}\right)^3$$

$$\text{power}_{EEM_generator_4} =$$

	0
0	19.4
1	19.4
2	19.4
3	19.4
4	...

$\cdot kW$

$$\text{power}_{generator_4} := \text{schedule}_{generator_4} \cdot \text{power}_{fan5}$$

$$\text{power}_{generator_4} =$$

	0
0	36
1	36
2	...

$\cdot kW$

$$\boxed{\text{annual_fan_energy}_{EEM_generator_4} := \sum \text{power}_{EEM_generator_4} \cdot hr = 176804.6 \cdot kW \cdot hr}$$

estimated power used by generator 1's cooling fan if a VFD were installed during 2009 operating year

$$\boxed{annual_fan_energy_{generator_4} := \sum power_{generator_4} \cdot hr = 214380 \cdot kW \cdot hr}$$

estimated power used by generator 1's cooling fan during 2009 operating year

Generator 4 - Final Analysis with weather and gen schedule data

Summary of Results:

$$total_energy_annual_{no_VFD} := annual_fan_energy_{generator_1} + annual_fan_energy_{generator_2} + annual_fan_energy_{generator_3} \cdots + annual_fan_energy_{generator_4}$$

$$\boxed{total_energy_annual_{no_VFD} = 823814 \cdot kW \cdot hr}$$

$$\frac{total_energy_annual_{no_VFD}}{365 day} = 2257\, kW \cdot \frac{hr}{day}$$

typically the dam personel see ~4-6 aMW*hr/day

$$total_energy_annual_{VFD} := annual_fan_energy_{EEM_generator_1} + annual_fan_energy_{EEM_generator_2} \cdots + annual_fan_energy_{EEM_generator_3} + annual_fan_energy_{EEM_generator_4}$$

$$\boxed{total_energy_annual_{VFD} = 688055.8 \cdot kW \cdot hr}$$

$$\boxed{energy_savings := total_energy_annual_{no_VFD} - total_energy_annual_{VFD} = 135758.2 \cdot kW \cdot hr}$$

$$energy_rate := \frac{100\$}{1 MW \cdot hr}$$

$$\boxed{savings := energy_savings \cdot energy_rate = 13575.8\, \$}$$

$$\boxed{\frac{savings}{12\%} = 113131.9\, \$}$$

Energy Efficiency Improvements Audit Report

Prepared for

Nine Mile Hydro Electric Dam

Prepared by

Andy Paul, PE

Bryce Eschenbacher, PE

Levi Westra, PE

Energy Solutions Engineers

February 13, 2015

Overview

Facility: Nine Mile Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff:
Facility Audited on: February 10th, 2015

Figure 1 Google Images of Nine Mile Hydro Electric Dam

Avista's DSM Engineering staff visited the Nine Mile Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation.

Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

It should be noted that this facility is currently undergoing a complete overhaul. Due to this there are very few projects that can be suggested that are not already going to be implemented.

The facility consists of a control room and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

There are several areas around the facility where additional weatherization work can be conducted.

1. All exterior entry doors should have their weather stripping checked and replaced if necessary.

2. All windows that are not required to remain historically accurate should be replaced with energy efficient double pane windows.

3. Any portion of the plant that is going to have cooling installed; control room, battery room etc, should have the walls and ceiling insulated. The insulation will help thermally isolate it from the rest of the plant and reduce the amount of cooling required in the summer time.

4. There is currently little to no insulation above or below the roof deck in the plant. It is recommended that insulation, R-19 at the very least, be added below the deck. This insulation will aid in reducing the amount of time a unit has to be motored during the winter months to maintain space temperature.

Lighting

The facility currently employs T12 fluorescent lighting in the control room and surrounding areas and 400 Watt Metal Halide (MH) high-bay fixtures on the generating floor. The facility will have a brand new all LED lighting system installed during the overhaul. The DSM group at Avista made suggestions on what LED fixtures would be appropriate. Quinton Snead in the Generation Dept was in charge of the lighting design.

While there will be energy savings for this project, specifically with the generating floor lighting as well as the control room lighting, there will also be an additional lighting load installed. There are portions of the plant that were under lit and needed additional lighting fixtures installed. Regardless of the additional lighting fixtures, the new system will be as efficient as possible due to the installation of the LED fixtures in lieu of more traditional linear fluorescent and HID fixtures.

HVAC

1. The control room and few other areas in the plant will be getting new HVAC units installed to heat and cool the spaces. When selecting equipment considered installing the most efficient units that can be afforded. It is also recommended that heat pump units be installed instead of standard condensing units with electric resistive heat. New heat pumps are capable of working efficient down to temperatures below zero. Since no natural gas is available at the Dam a heat pump is by far the most efficient way to provide space heat.

2. The main generating floor has no dedicated HVAC units. The heat from the generators keeps the space conditioned during the winter months. A generator will be motored to maintain heat if no generating is going on. It is recommended that dedicated HVAC units be installed to maintain the space temperature when the units are not running. This would reduce unnecessary wear and tear on the generating equipment as well as provide a known dedicated source of heat.
3. Installing two (possibly three) low speed/high volume destratification fans to help de-stratify the air within in the facility is recommended. With 40' ceilings the majority of buildings heated air will stack at the top, the fans would push that heated air back towards the floor and create a homogenous air temperature. This would reduce the amount of time that the space heat would need to run.

   In addition these fans could be run in reverse during the summer months to help pull warm air off the floor and exhaust it out of the exhaust louvers located in the roof.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – February 13th, 2015

Energy Efficiency Improvements Audit Report

Prepared for

North East Combustion Turbine Thermal Facility

Prepared by

Bryce Eschenbacher, PE
Energy Solutions Engineer

June 19, 2015

Overview

Facility: North East Combustion Turbine
Audited by: Bryce Eschenbacher PE
Onsite Staff: Dwayne Wright
Facility Audited on: June 16th, 2015

Figure 1 Google Image of the North East Combustion Turbine Thermal Facility

Avista's DSM Engineering staff visited the North East CT to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

Shell

The main warehouse at the facility was completed recently and is well insulated with good exterior doors. No improvements need to be made at this point in time. Below are some recommendations of the few other buildings that may benefit from insulation or weatherization:

1. The MCC building has a through wall AC unit and small electric heater. The weather stripping for the exterior door should be checked and replaced if it's found to be faulty. This will aid in reducing the AC load in the summer and the heating load in the winter.
2. The pump house and tool crib are similar to the MCC and should have their exterior door weather stripping checked.

Lighting

The new warehouse employs T8 linear fluorescent fixtures; the remainder of the facility is a mix of T12 linear fluorescents and screw in incandescent fixtures. The yard lights are quartz halogen fixtures. The majority of these fixtures only operate a couple of hours a day and would not generate enough energy savings to justify their replacement on those grounds. The increase in efficiency and longevity of the fixtures on the other hand should be consider and replacement based on this planned. Below is a list of potential lighting projects to consider.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Halogen Pole Lights	**$1,350**	**20 yr**	**5,145.6**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: There are currently (x6) quartz halogen yard lights. For this analysis it is assumed that they are 250W lamps. These lights only operate when work is being down at the facility. It was stated that the lights should be on dusk to dawn to provide some security lighting as well. This analysis looks at the potential savings that would be seen if the existing lights were on dusk to dawn. The proposed project looks at replacing these fixtures with 50W LED spot lights. A simple lumen calculation shows that the overall lumens for the job were increased by 43%.
    - The provided project cost is $3,600; this cost was calculated using fixture cost found online and an estimated $75 per fixture for install.
2. The two lamp F48T12 linear fluorescent fixtures in the MCC room, tool crib, pump house, and generator room, should be replaced with new linear LED fixtures. The 50W linear fixtures that were used at Noxon Rapids are recommended for these areas. The cost to purchase and install these fixtures is $347.50 (based on invoiced costs from Noxon).

HVAC

1. The main warehouse is conditioned by a gas fired unit hearer in the work area and a Mitsubishi ductless heat pump serves the office area. The unit heater should be replaced with a 90%+ unit when the current unit has reached its end of life. The ductless heat pump is a compact and efficient means of condition the office space.
2. There are several small through the wall air conditioning units at some of the smaller outbuildings. It is recommended that these be replaced with the most efficient units available when the existing units fail.
3. The engine compartments are conditioned by two 1.5 ton York roof top unit mounted on grade outside of the units. These units keep the engine compartment above freezing in the winter and cool it down when maintenance needs to be done in the summer. The existing units are aged and use R-22 refrigerant, which is no longer manufactured. At some point it will be necessary to replace these units as parts and refrigerant become scarce. It is recommended that they be replaced with the most efficient units that can be afforded.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Bryce Eschenbacher – June 19, 2015

Name: North East CT - Halogen to LED		
Acct#		
Existing Annual Consumption: (kilowatt hours)	6,432.00	
Lighting Energy Savings:(kilowatt hours)	5,145.60	
Lighting Demand Savings: (kilowatt demand)	0.96	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	142.86%	
Total Energy Savings: (kilowatt hours)	5,145.60	
Total Demand Savings: (kilowatt demand)	**0.96**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$50.76	

Energy Efficiency Improvements Audit Report

Prepared for

Noxon Rapids Hydro Electric Dam

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

February 10, 2015

Overview

Facility: Noxon Rapids Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE
Onsite Staff:
Facility Audited on: January 15th, 2015

Figure 1 Google Images of the Noxon Rapids Hydro Electric Dam

Avista's DSM Engineering staff visited the Noxon Rapids Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of a control room, office space, break area and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

Due to the design of the facility there are no real shell measures that can be undertaken that would benefit the facility or save energy.

Lighting

The site recently completed a full lighting system replacement. The old system was made up of old two lamp 48W T12 fluorescent fixtures, incandescent screw in lamps of varying wattages, and metal halide fixtures. The system is entirely made up of LED fixtures. The Majority being linear LED fixtures with some screw in lamps throughout. This lighting project reduced the annual lighting load by 382,115 kWh. The lighting system was the largest inefficiency in this facility.

In addition to the new lighting fixtures the entire lighting system was re-wired. New lighting panels were installed as well.

HVAC

1. The facility employs a water source heat pump, along with a couple of air handlers and several unit heaters, to condition the generating floor and all rooms on that same level. The access and observation galleries are unconditioned.

   During the audit we were not able to determine the size or efficiency of the unit because the name plate was in-accessible. Based on the equipments vintage, and a statement from facility staff that the equipment needs regular maintenance, we recommend that this equipment be replace with a modern efficient water source heat pump. It is recommended that the most efficient equipment that can be afforded be installed.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher – February 10th, 2015

Energy Efficiency Improvements Audit Report

Prepared for

Post Falls Hydro Electric Dam

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

May 28, 2015

Overview

Facility: Post Falls Hydro Electric Dam
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff: Laroy Dowd
Facility Audited on: May 20th, 2015

Figure 1 Google Images of the Post Falls Hydro Electric Dam

Avista's DSM Engineering staff visited the Post Falls Hydro Electric Dam to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically,

this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of a control room, office space, break area and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

There are several areas around the facility where additional weatherization work can be conducted. It should be noted that this facility has no dedicated heating source due to an almost constant operation of at least one unit, which provides enough heat for generating floor and control room. The control room area has a couple of window style air conditioning units for the summer months. The recommendations made below should only be acted on if there are future plans to provide this facility with a dedicated heating and cooling source. As the facility operates now, these measures are not necessary and will not reduce the electric load.

1. All exterior entry doors should have their weather stripping checked and replaced if necessary.

2. All windows that are not required to remain historically accurate should be replaced with energy efficient double pane windows.

3. Any portion of the plant that currently has heating or cooling installed should have the walls and ceiling insulated. The insulation will help thermally isolate it from the rest of the plant and reduce the amount of cooling required in the summer time.

4. There is currently little to no insulation above or below the roof deck in the plant. It is recommended that insulation, R-19 at the very least, be added below the deck.

Lighting

The site employs T12 and T8 linear fluorescent lighting, linear LED fixtures, as well as 150 Watt High Pressure sodium high-bay fixtures. No parking lot lighting was observed.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Control Room T12s	**$3,462.50**	**20 yr**	**1,776**
2	Generating Floor HPS	**$2,423.75**	**20 yr**	**3,312**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The control room currently has (x4) Two lamp F48T12 and (x3) Two lamp F96T12 fluorescent fixtures serving the break room and storage areas. The proposed project

looks at replacing these fixtures with (x10) 40W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 11%.

- The provided project is $3,462.50, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

2. Proposed Project #2: The facility currently has (x7) single lamp 150W high pressure sodium fixtures located above the units on the generating floor. It is assumed that the fixtures average 3,600 hrs of operation a year. The proposed project looks at replacing these fixtures with 40W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were increased by 28%.

    - The provided project cost is $2,423.75; this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

3. It should be noted that while the total system lumens decrease for project #1, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

HVAC

1. The main generating floor has no dedicated HVAC units. The heat from the generators keeps the space conditioned during the winter months. A generator will be motored to maintain heat if no generating is going on, which is rare at this plant. During the summer months the heat from the generators is exhausted from the space via several exhausts fans mounted in the upper windows of the power house. These exhaust fans are controlled manually are on 24/7 during the warmer months. It is recommended that thermostats be installed to control these exhaust fans. The thermostats will reduce the run time of the fans during spring and fall when the fans are more than likely left on when they may not be necessary.
2. It is recommended that the control room have a dedicated HVAC unit installed. The space is currently heated by residual heat from the generators and controls cabinets, and is cooled by a couple of window style air conditioners. A dedicated system would provide a more comfortable environment for the operators as well as the controls equipment present in the space. If this is a project that is going to be implemented, moving forward with shell recommendation number 3 is advised.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – May 28, 2015

Name: Post Falls Hydro Electric Dam - T12 to LED		
Acct#		
Existing Annual Consumption: (kilowatt hours)	3,088.80	
Lighting Energy Savings:(kilowatt hours)	1,648.80	
Lighting Demand Savings: (kilowatt demand)	0.37	
Cooling System Savings: (kilowatt hours)	126.96	
Cooling System Demand Savings: (kW demand)	0.03	
Lumen Comparison New/Existing	88.53%	
Total Energy Savings: (kilowatt hours)	1,775.76	
Total Demand Savings: (kilowatt demand)	**0.39**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	($30.72)	

Name: Post Falls Hydro Electric Dam - Generating Floor		
Acct#		
Existing Annual Consumption: (kilowatt hours)	5,472.00	
Lighting Energy Savings:(kilowatt hours)	3,312.00	
Lighting Demand Savings: (kilowatt demand)	0.74	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	128.04%	
Total Energy Savings: (kilowatt hours)	3,312.00	
Total Demand Savings: (kilowatt demand)	**0.74**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	($311.14)	

Energy Efficiency Improvements Audit Report

Prepared for

Post Street Hydro Electric Facility
Upper Falls Hydro Electric Facility

Prepared by
Andy Paul, PE
Bryce Eschenbacher, PE
Levi Westra, PE
Energy Solutions Engineers

June 19th, 2015

Overview

Facility: Post Street Hydro Electric Facility/Upper Falls Hydro Electric Facility
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff: Josh Stringfellow
Facility Audited on: June 10th, 2015

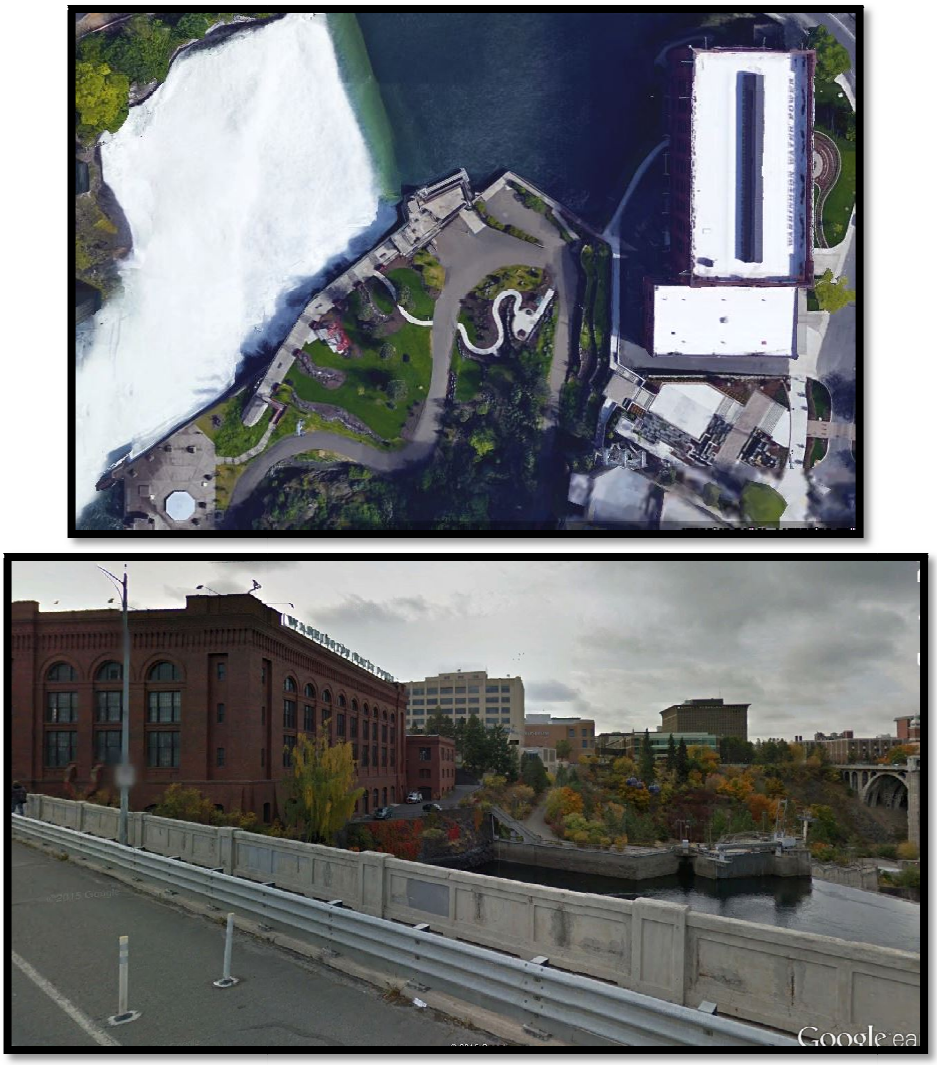


Figure 1 Google Images of the Post St/Monroe Hydro Electric Dam

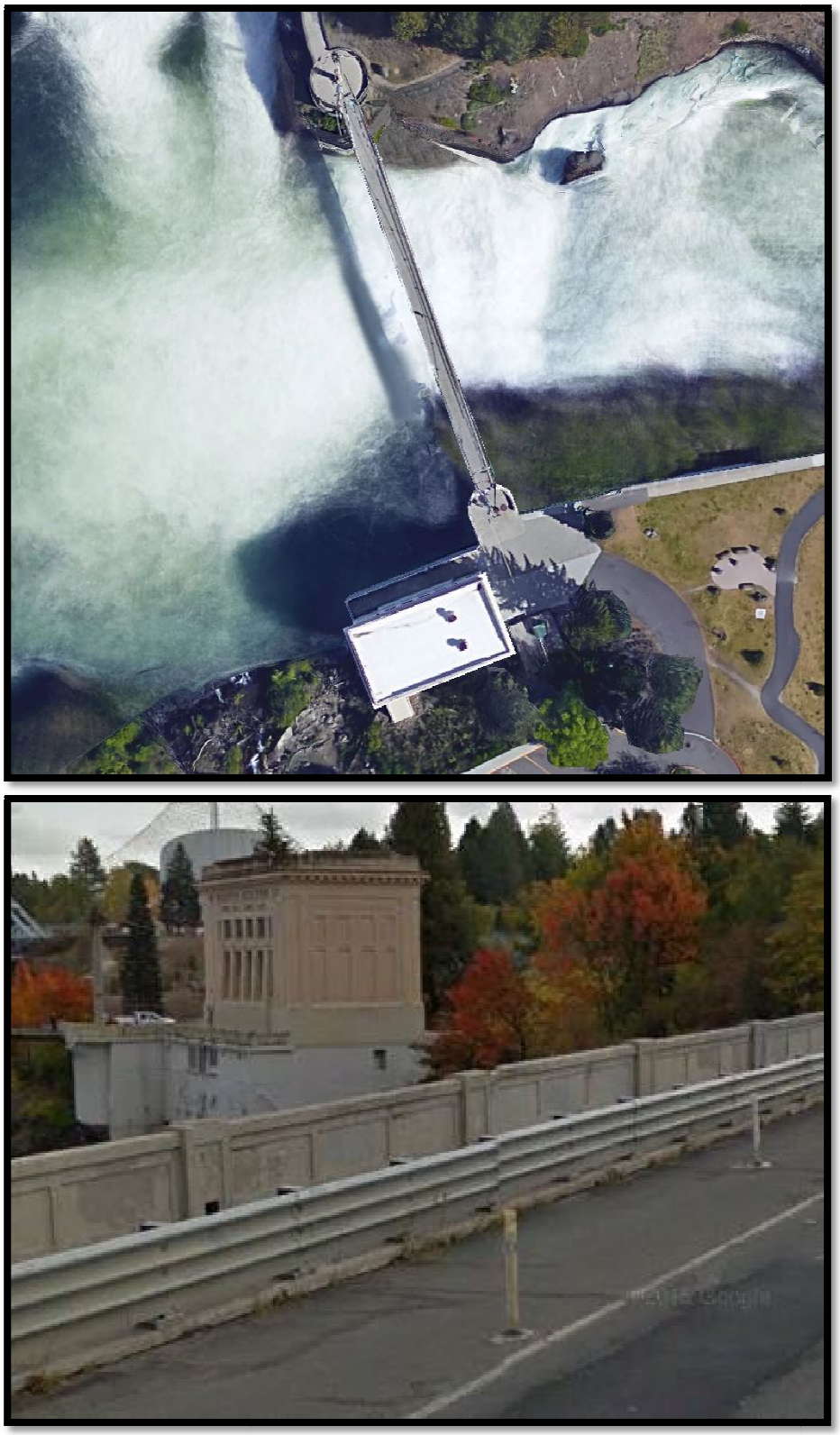


Figure 2 Google Images of the Upper Falls Hydro Electric Project

Avista's DSM Engineering staff visited the Post St. / Monroe St. Hydro Electric facility to review their current building systems and discuss several concerns that the user's encountered during typical operation. We were unable to visit the Upper falls facility due a time constraint and limited access due to their being no operator on site currently. We did discuss the systems at Upper Falls and have recommendations for improvements listed below. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

The facility consists of a control room, office space, break area and generation specific process areas including but not limited to generation floor and breaker floor.

Shell

There are several areas around the facility where additional weatherization work can be conducted.

1. All exterior entry doors should have their weather stripping checked and replaced if necessary.

2. The control room should have insulation installed above the ceiling and in the walls if possible. The insulation will help thermally isolate it from the rest of the plant, which is only maintained at above freezing in the winter and is unconditioned otherwise.

3. There is currently little to no insulation above or below the roof deck above the substation. During the winter four Reznor natural gas unit heaters keep the space above freezing. It is recommended that insulation, R-19 at the very least, be added below the deck. This insulation will aid in reducing the amount of time the unit heaters have to run to maintain the space temperature.

Lighting

The site employs T12, induction fluorescent high bays as well as various wattages of incandescent and compact fluorescent screw in lamps.

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Utility men break room	**$1,498**	**20 yr**	**2,151**
2	Control room	**$3,745**	**20 yr**	**4,340**
3	Network Feeder tunnel	**$5,718**	**20 yr**	**8,344**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The Utility Men break room currently has (x4) four lamp F48T12 fluorescent fixtures that operate 2,080 hrs a year (40hrs/wk). The proposed project looks at replacing these

fixtures with (x4) 50W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 60%.

- The provided project is $1,498, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

2. Proposed Project #2: The facility currently has (x10) two lamp fluorescent fixtures that operate 8,760 hrs a year (40hrs/wk). The proposed project looks at replacing these fixtures with (x10) 50W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 20%.

    - The provided project cost is $3,745, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.

3. Proposed Project #3: The facility currently has (x15) two lamp fluorescent fixtures that operate 8,760 hrs a year (40hrs/wk). The proposed project looks at replacing these fixtures with (x15) 50W linear LED fixtures. A simple lumen calculation shows that the overall lumens for the job were decreased by 20%. In addition to switching out the lights it is proposed that an occupancy sensor be installed to control these lights. This is an area of the facility that is only checked once or twice a day, unless maintenance is being performed. A properly located occupancy sensor will be able to turn the lights on before an operator reaches the space and will keep the lights on during the time that they are present. Otherwise they will go off.

    - The provided project cost is $5,717.50; this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED. An additional $100 was added for the occupancy sensor.

4. It should be noted that while the total system lumens decrease for each of these projects, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

5. In addition to the projects listed above there are several other areas that would benefit from installing new lighting fixtures.

    - Most of the lower levels are lit with incandescent screw in lamps which remain on 24/7. It is recommended that these lamps be switch out for comparable LED screw in lamps and that the fixtures are placed on occupancy sensors. The sensors for these lights would need to be placed in the stairwells coming down to the space. This would ensure that the lights are on when the operator enters the space. In addition a redundant sensor (or two) should be placed in the space to provide the control necessary to keep the lights on when they are working in the space. It is highly recommend that a lighting design professional be brought in to properly design this system.

    - There are (x22) screw in compact fluorescent lamps located along the crane rail. It is recommended that these are replaced with comparable LED screw in lamps.

6. The lighting in the Monroe St. Turbine pit is all T8 linear fluorescent fixtures. A simple upgrade would be to change out the existing 32W T8 lamps with 25W T8 lamps. This would also require the ballasts to be changed. These fixtures could also be converted to linear LED tubes. We recommend that the lighting in the Post St. Building be upgraded before replacing the lighting at Monroe St.

7. The lighting at the Upper Falls facility was stated to be high pressure sodium fixtures. It is assumed that these are 400W lamps. It is recommended that these fixtures be upgraded to high

bay LED fixtures. Little Falls Dam is upgrading all of the high pressure sodium fixtures these to LED, Nathan Fletcher was in charge of that design.

HVAC

1. The control room is conditioned by an electric forced air furnace paired with a condensing unit for cooling. The condensing unit was recently replaced and is fairly efficient. It is recommended that that the furnace be replaced with a 90%+ efficient gas unit. On average a gas furnace will use ½ of the energy that an electric furnace will to provide the amount of heat. Gas is located nearby for the Reznor unit heaters.
2. The substation floor is conditioned by (x4) Reznor unit heaters. These heaters are used to keep the space above freezing during the winter. The units are 80% efficient and appear to be in good working order. When the time comes to replace them it is recommended that 90%+ unit heaters be purchased.
3. Installing two (possibly three) low speed/high volume destratification fans to help de-stratify the air within in the facility is recommended. With 40' ceilings the majority of buildings heated air will stack at the top, the fans would push that heated air back towards the floor and create a homogenous air temperature. This would reduce the amount of time that the space heat would need to run.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – June 19th 2015

Name:Post St. Hydro Electric Dam - Utility Men Break Room		
Acct#		
Existing Annual Consumption: (kilowatt hours)	2,412.80	
Lighting Energy Savings:(kilowatt hours)	1,996.80	
Lighting Demand Savings: (kilowatt demand)	0.77	
Cooling System Savings: (kilowatt hours)	153.75	
Cooling System Demand Savings: (kW demand)	0.06	
Lumen Comparison New/Existing	39.79%	
Total Energy Savings: (kilowatt hours)	2,150.55	
Total Demand Savings: (kilowatt demand)	**0.83**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**(17.37)**	
Maintenance Savings:	$25.63	

Name: Post St. Hydro Electric Dam - Control Room		
Acct#		
Existing Annual Consumption: (kilowatt hours)	8,409.60	
Lighting Energy Savings:(kilowatt hours)	4,029.60	
Lighting Demand Savings: (kilowatt demand)	0.37	
Cooling System Savings: (kilowatt hours)	310.28	
Cooling System Demand Savings: (kW demand)	0.03	
Lumen Comparison New/Existing	79.58%	
Total Energy Savings: (kilowatt hours)	4,339.88	
Total Demand Savings: (kilowatt demand)	**0.40**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**(35.06)**	
Maintenance Savings:	($0.23)	

Name: Post St. Hydro Electric Dam - Network Feeder Lighting		
Acct#		
Existing Annual Consumption: (kilowatt hours)	12,614.40	
Lighting Energy Savings:(kilowatt hours)	8,343.90	
Lighting Demand Savings: (kilowatt demand)	0.55	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	79.58%	
Total Energy Savings: (kilowatt hours)	8,343.90	
Total Demand Savings: (kilowatt demand)	**0.55**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$106.38	

Energy Efficiency Improvements Audit Report

Prepared for

Rathdrum Combustion Turbine Thermal Facility

Prepared by

Andy Paul, PE

Bryce Eschenbacher, PE

Levi Westra, PE

Energy Solutions Engineers

May 28, 2015

Overview

Facility: Rathdrum Combustion Turbine
Audited by: Andy Paul PE, Bryce Eschenbacher PE, and Levi Westra PE
Onsite Staff: N/A
Facility Audited on: May 20th, 2015

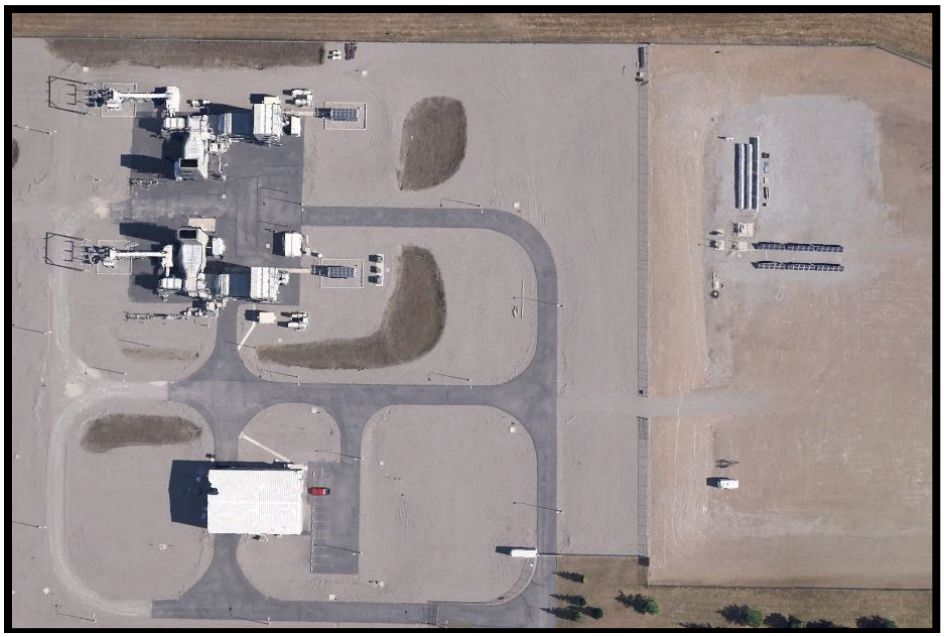


Figure 1 Google Image of the Rathdrum Combustion Turbine Thermal Facility

Avista's DSM Engineering staff visited the Rathdrum CT to review their current building systems and discuss several concerns that the user's encountered during typical operation. Specifically, this audit was conducted to identify all possible energy efficiency improvements not related to the power generation process.

After completing a tour of the facility potential improvement measures were identified for consideration including capital projects as well as low-cost no-cost measures. This report is intended to provide a cursory review of possible energy savings. Each listed recommendation and costing is based upon historical experience and costing projections. Equipment life and performance will vary and a Statement of Work (SOW) for the capital project will determine the actual project costs and performance.

Shell

There are a couple of areas around the facility where additional weatherization work can be conducted. It should be noted that this facility is rarely staffed and is generally operated remotely when it is needed. That being said, it is assumed that shop building is maintained at 55º in the winter (freeze protection) and below 78º in the summer. We were unable to verify the actual HVAC set point. Even with minimal HVAC the weatherization recommendations below will save energy.

1. All exterior entry doors should have their weather stripping checked and replaced if necessary. This includes the 5 man door and 2 roll up doors.
2. There are a couple of exhaust louvers on the backside of the shop building. If these louvers are not equipped with motorized dampers with proper blade seals, it is recommended that they are installed. When the louvers are not needed a large amount of outside air may be making its way back into the building, which would increase the HVAC load.

Lighting

The site employs metal halide road way light and halogen pole lights around the equipment. We were not able to get inside of the shop building to inspect the lights present. Based on the age of the facility

Table 1 Capital Project Lighting Opportunity Summary

	Brief EEM* Description	EEM Cost	Measure Life	Electric kWh Savings
1	Roadway lighting	**$10,020**	**20 yr**	**16,273**
2	Halogen Pole Lights	**$3,600**	**20 yr**	**3,200**

*EEM – Energy Efficiency Measure

1. Proposed Project #1: The roadway is lit by (x15) Single Lamp 250W Metal halide cobra heads. This project would replace these with (x15) Cree 42W LED cobra heads. It is assumed that these fixtures have an average of 4,288 hrs/yr (dusk to dawn) annual operating hours. A simple lumen calculation shows that the overall lumens for the job were decreased by 81%.
    - The provided project is $10,020, this cost was calculated using fixture and install costs for these fixtures at Noxon Rapids HED.
2. Proposed Project #2: The facility currently has (x16) single lamp halogen pole mounted lights. Wattage could not be confirmed for these lamps. For this analysis it is assumed that they are 250W lamps. It is also assumed that the fixtures average 1,000 hrs of operation a year and are only used for spot lighting when work is being done. The proposed project looks at replacing these fixtures with 50W LED spot lights. A simple lumen calculation shows that the overall lumens for the job were increased by 43%.
    - The provided project cost is $3,600; this cost was calculated using fixture cost found online and an estimated $75 per fixture for install.
3. It should be noted that while the total system lumens decrease for project #1, the actual lumens that reach the working space will more the likely increase. LED fixtures are very directional in the way they deliver lighting lumens. In addition the existing high pressure sodium fixtures produce a yellow light which is not conducive to good visibility while working. We recommend replacing a few light fixtures to make sure that they will meet your lighting needs. If you would like to see the fixtures in operation we recommend a trip to Noxon Rapids HED.

HVAC

1. The main facility shop building's office area is conditioned by a 5 ton air conditioner paired with a natural gas furnace. Based on the age of the building is assumed that the furnace is around 80% efficient. Since this facility is rarely manned the payback for installing a new HVAC system is too long to consider on a financial basis. But when the existing equipment fails it is recommended that the most efficient equipment be purchased to replace it.
2. There are several small through the wall air conditioning units at some of the smaller outbuildings. It is recommended that these be replaced with the most efficient units available when the existing units fail.

We hope that this report helps to identify some areas that the generating facility can gain some operational efficiency and reduce the parasitic load that these systems represent. If you decide to pursue any of these potential energy savings projects please let the Energy Solutions team know ahead of the start of the project.

Respectfully,

Andy Paul, Bryce Eschenbacher, and Levi Westra – May 28, 2015

Name: Rathdrum CT - Pole Lights		
Acct#		
Existing Annual Consumption: (kilowatt hours)	18,974.40	
Lighting Energy Savings:(kilowatt hours)	16,272.96	
Lighting Demand Savings: (kilowatt demand)	3.04	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	18.59%	
Total Energy Savings: (kilowatt hours)	16,272.96	
Total Demand Savings: (kilowatt demand)	**3.04**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$124.47	

Name: Rathdrum CT - Halogen to LED		
Acct#		
Existing Annual Consumption: (kilowatt hours)	4,000.00	
Lighting Energy Savings:(kilowatt hours)	3,200.00	
Lighting Demand Savings: (kilowatt demand)	2.56	
Cooling System Savings: (kilowatt hours)	0.00	
Cooling System Demand Savings: (kW demand)	0.00	
Lumen Comparison New/Existing	142.86%	
Total Energy Savings: (kilowatt hours)	3,200.00	
Total Demand Savings: (kilowatt demand)	**2.56**	
Estimated Project Cost: (Rough Estimate)	See Report	
Heating System Penalty: (therms)	**0.00**	
Maintenance Savings:	$63.43	

2015 Electric Integrated Resource Plan

Appendix E – 2015 Electric IRP New Resource Table for Transmission

Appendix E

2015 Avista Electric IRP

New Resource Table For Transmission
Updated August 25, 2015

Resource	Note	Resource Location	POR or Local Area	POD	Start	Stop	Capacity MW	Year Total
Nine Mile		Nine Mile Falls, WA	Nine Mile	AVA System	4/1/2016	Indefinite	7.6	7.6
SCCT	1	TBD	Mid-C/AVA System	AVA System	10/1/2020	Indefinite	102.0	102.0
Northeast		Spokane, WA	Northeast	AVA System	10/1/2023	Indefinite	7.5	7.5
Kettle Falls		Kettle Falls, WA	Kettle Falls	AVA System	10/1/2024	Indefinite	12.0	12.0
Rathdrum		Rathdrum, WA	Rathdrum	AVA System	10/1/2025	Indefinite	18.5	18.5
CCCT	1	TBD	Mid-C/AVA System	AVA System	10/1/2026	Indefinite	306.0	306.0
SCCT	1	TBD	Mid-C/AVA System	AVA System	10/1/2027	Indefinite	102.0	102.0
Kettle Falls		Kettle Falls, WA	Kettle Falls	AVA System	10/1/2033	Indefinite	3.0	3.0
SCCT	1	TBD	Mid-C/AVA System	AVA System	10/1/2034	Indefinite	46.5	46.5
						Total	605.1	605.1

Mid-Columbia Anticipated Contract Extensions
Mid-C contract extensions may replace or modify resources named above

Resource	Note	Resource Location	POR or Local Area	POD	Start	Stop	Capacity MW	Year Total
Rocky Reach		Mid-C	Mid-C	AVA System	1/1/2021	TBD	59.0	
Rock Island		Mid-C	Mid-C	AVA System	1/1/2021	TBD	21.0	80.0
Wells		Mid-C	Mid-C	AVA System	8/1/2018	TBD	28.0	28.0
						Total	108.0	108.0

1 Modified POR to "Mid-C/AVA System" to reflect possibility of off-system SCCT integrated at Mid-C

Avista System Planning

2014 IRP Interconnection Study

Richard Maguire
Avista System Planning
November 25, 2014

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Introduction

Avista Utilities' Integrated Resource Planning group requested preliminary estimates for the generation interconnections listed below. Avista's System Planning Group conducted studies, and the results of those studies are summarized below and described in more detail throughout this report.

TABLE 1: SUMMARY ESTIMATES FOR GENERATION INTERCONNECTION REQUESTS

Station	Request (MW)	POI Voltage	Cost Estimate ($ million)[1]
Kootenai County (New)	100	230 kV	12 - 16.1
Kootenai County (New)	350	230 kV	47.2
Rathdrum	26	115 kV	2.84 - 10.9
Rathdrum	50	115 kV	10.7 – 18.7
Rathdrum	200	115 kV	10.3 - 48.5
Rathdrum	50	230 kV	7 – 16.8
Rathdrum	200	230 kV	15.5 – 21.5
Thornton	30	230 kV	.4
Thornton	100	230 kV	.4
Othello	25	115 kV	2
Northeast	10	115 kV	0
Kettle Falls	10	115 kV	0
Long Lake	68	115 kV	19.7
Monroe Street	80	115 kV	7
Post Falls	10	115 kV	2.1
Post Falls	20	115 kV	5.2

[1] Preliminary estimates are given as -25% to +75%

Study Methodology and Assumptions

Steady-state power flow analysis was performed for each request under the following conditions:

- Two Avista Planning Cases[2] were used for each request:
  - 2024 Heavy Summer – based on WECC 2024 HS1-S Base Case
  - 2019 High Transfer – rated West of Hatwai flow based on WECC 2014 LS1 Operating Case
- 737 contingency events were analyzed using select P1 – P7 [3] events
  - **Important Note**: cost estimates could be significantly increased by a more complete study that includes all P6 contingencies. A System Impact Study is necessary for more accurate cost estimates.
- Study case topology includes the Avista projects documented in Appendix A
- All existing generation local to each request was enabled at full output
- New generation was modeled using +/- 0.95 power factor
- PowerWorld's *Contingency Analysis* tool was used to determine only those facility violations that are new and caused by the requested generation. **This is different** from standard assessment presentations of contingency results, and the reader should keep this in mind when looking at study results.
- PowerWorld's *Available Transfer Capability (ATC) tool, not to be confused with the 'ATC' posted on Avista's OASIS,* was used to provide an indication of next-most-limiting facilities as the studied generator output was increased and the list of contingencies analyzed. This analysis was conducted for each request with the following settings:
  - Buyer modeled as all WECC generators except those within Avista's Balancing Authority Area
  - Ramping of modeled generation occurred in the pre-contingency state
  - Assumed reactive power did not change
  - ATC results cross-checked with standard contingency analysis
- Facility performance was measured against NERC Standards[4] TPL-001-4 and FAC-010
  - Voltage performance not assessed during this study

[2] Avista Planning Cases are described in Avista Standards TP-SPP-04 Data Preparation and TP-SPP-06 Contingency Analysis

[3] 'P' type Performance Planning Events described in NERC TPL-001-4

[4] See http://www.nerc.net/standardsreports/standardssummary.aspx

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Analysis

Kootenai County

100 to 350 MW of generation was requested to be studied at a new station in Kootenai County near Post Falls, Idaho. This request was modeled as a new station approximately 2.5 electrical miles southwest of Rathdrum station on the Beacon – Rathdrum 230 kV Transmission Line (See Figure 1).

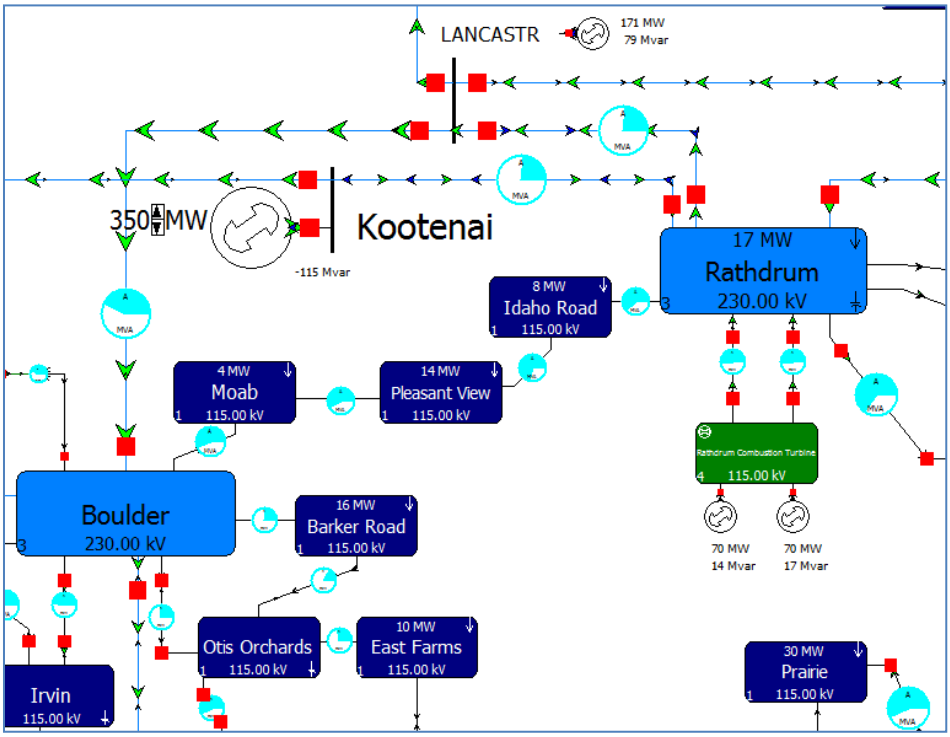

FIGURE 1: KOOTENAI STATION; 2024 HEAVY SUMMER SCENARIO

System performance in this area is dominated by several factors:

1. Inflow from the east on the Lancaster – Noxon and Cabinet – Rathdrum 230 kV transmission lines
2. Outflow to the west on the Bell – Lancaster, Boulder – Lancaster, and Beacon – Rathdrum 230 kV transmission lines
3. Load in the Coeur d' Alene area served from Rathdrum Station
4. Generation (426 MW) locally from Lancaster, Rathdrum, Post Falls, and Boulder stations

In general, given the prevailing east-to-west flow of energy in the area under study, mitigating projects tend toward adding transmission capacity to the west, or to the south, or to both.

Kootenai 100 MW Request; $16 to $20.1 million

Analysis

For P0 conditions, both study cases received generation up to 100 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for new facility violations created by requested generation at 100 MW.

TABLE 2: ATC RESULTS; 100 MW OUTPUT

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
hs	19.79	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	5.06
ht	25.46	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-4.9
ht	30.09	Line BOULDERE (48522) TO IRVIN (48165) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	4.35
ht	35.85	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	3.55
ht	36.2	Line EASTFARM (48117) TO POST FLS (48329) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-7.6
hs	45.15	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-9.51
ht	54.6	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Beacon - Boulder 230 kV	4.1
ht	63.74	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-4.9
ht	64.84	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BF: A290 Hot Springs 230 kV, Hot Springs-Rattlesnake	-3.95
ht	65.04	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BUS: Beacon North 230 kV	4.69
ht	69.54	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-5.08
hs	76.6	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-9.51
ht	78.81	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-10.49
ht	80.77	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	-7.22
ht	88.71	Line EASTFARM (48117) TO OTIS (48311) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	7.6
ht	89.08	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-4.9
hs	105.53	Line IRVIN (48165) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BF: R427 Beacon North & South 230 kV	-7.56

TABLE 3: CONTINGENCY RESULTS; 100 MW OUTPUT

Element	Label	Percent	Case
PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	110.24	hs
BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	107.47	ht
MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	106.63	hs
PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	N-1: Boulder - Lancaster 230 kV	105.68	ht
PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	105.42	ht
POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	105.08	ht
PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	104.69	ht
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at SPKINDPK	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	103.12	hs
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at SPKINDPK	N-2 (ADJ): Beacon - Boulder #2 115 kV and Beacon - Ninth & Central #2 115 kV	102.77	hs
MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	N-1: Boulder - Lancaster 230 kV	102.64	ht
BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	102.57	ht
MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	102.41	ht
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	102.17	ht
RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	101.82	hs
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	N-1: Beacon - Boulder 230 kV	101.75	ht
MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	101.65	ht
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	BUS: Beacon North 230 kV	101.53	ht
SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	BF: R427 Beacon North & South 230 kV	101.47	hs
IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	101.18	ht
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	100.87	ht
EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	100.58	ht
OPPORTUN (48299) -> CHESTER (48069) CKT 1 at CHESTER	BF: A600 Beacon North & South 115 kV	100.2	hs

Figure 2 shows system performance during the highest overload contingency noted in Table 3. Figure 2 provides a fairly accurate depiction of issues in the area as power flows on the underlying 115 kV system for some single or double-circuit outage on the east-west 230 kV system.

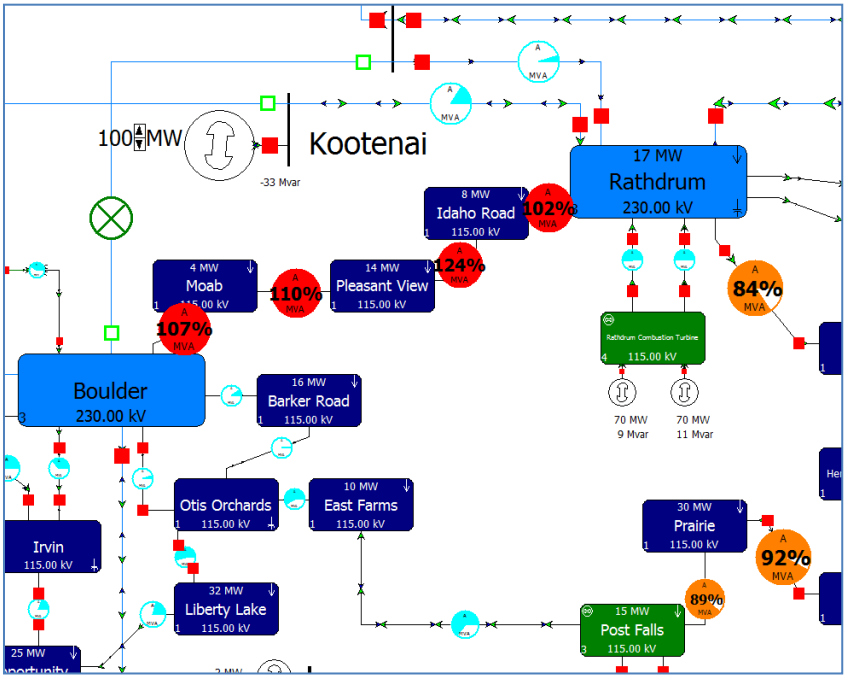

FIGURE 2: WORST INCREMENTAL PERFORMANCE DURING CONTINGENCIES; HEAVY SUMMER CASE; 100 MW REQUEST

Project Alternatives

1. Point of Interconnection (POI)
    a. New 3 position Double Bus Double Breaker station (Kootenai); $4 million
2. Project options necessary to mitigate new facility violations
    a. Back-tripping with transmission line upgrades:
        i. Implement the back-tripping scheme currently described in Avista's 2013 Local Planning Report[5] for an estimated $400,000
        ii. Upgrade 27.6 miles of 115 kV transmission lines to a minimum summer rating of 132 MVA for an estimated $11.6 million.
    b. Transmission line upgrades without back-tripping:
        i. Upgrading 38 miles of 115 kV transmission line to a minimum summer rating of 132 MVA for an estimated $16 million
        ii. Upgrade 0.1 miles of the BPA Bell – Lancaster 230 kV Transmission Line to a summer rating of 800 MVA for an estimated $100,000

[5] http://www.oasis.oati.com/AVAT/AVATdocs/2013_Avista_System_Planning_Assessment_-_Rev_0.pdf; Page 108

Kootenai 350 MW request; $47.2 million

Analysis

For P0 conditions, both study cases received generation up to 350 MW without issue. Table 4 shows results from the ATC analysis, and Appendix B shows Contingency Analysis results for new facility violations created by the requested generation.

TABLE 4: ATC RESULTS; 350 MW OUTPUT

ID	Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
197	hs	19.79	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	5.06
57	ht	25.46	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-4.9
56	ht	30.09	Line BOULDERE (48522) TO IRVIN (48165) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	4.35
55	ht	35.85	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	3.55
54	ht	36.2	Line EASTFARM (48117) TO POST FLS (48329) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-7.6
196	hs	45.15	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-9.51
53	ht	54.6	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Beacon - Boulder 230 kV	4.1
52	ht	63.74	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-4.9
51	ht	64.84	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BF: A290 Hot Springs 230 kV, Hot Springs-Rattlesnake	-3.95
50	ht	65.04	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BUS: Beacon North 230 kV	4.69
49	ht	69.54	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-5.08
195	hs	76.6	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-9.51
48	ht	78.81	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-10.49
47	ht	80.77	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	-7.22
46	ht	88.71	Line EASTFARM (48117) TO OTIS (48311) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	7.6
45	ht	89.08	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-4.9
44	ht	90	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BF: A286 Hot Springs 230 kV, Flathead-Hot Springs	-3.82
194	hs	105.53	Line IRVIN (48165) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BF: R427 Beacon North & South 230 kV	-7.56
43	ht	113.23	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-8.68
42	ht	118.15	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A388 Bell S2 & S3 230 kV	3.9
193	hs	120.3	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2: Beacon - Boulder 230 kV & Boulder - Irvin #2 115 kV	5.95
41	ht	132.66	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	5.08
40	ht	134.68	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-1: Lancaster - Rathdrum 230 kV	10.28
192	hs	135.44	Line CHESTER (48069) TO OPPORTUN (48299) CKT 1[115.00 - 115.00 kV]	BF: A600 Beacon North & South 115 kV	-4.01
39	ht	135.9	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	-3.94
38	ht	137.3	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1186 Lancaster-Noxon, Boulder-Lancaster	5.29
37	ht	145.41	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	PSF: Ramsey 115 kV	3.98
36	ht	146.75	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1186 Lancaster-Noxon, Boulder-Lancaster	-5.29
35	ht	148.64	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-10.5
191	hs	170.76	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	8.62
34	ht	173.9	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	-6.1
33	ht	180.38	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BF: A288 Hot Springs 230 kV, Hot Springs-Noxon Rapids #1	-3.82
32	ht	182.63	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-4.14
31	ht	185.51	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BUS: Hot Springs 230 kV	-3.82
30	ht	194.18	Line EASTFARM (48117) TO POST FLS (48329) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	-5.42
29	ht	199.14	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-10.49
28	ht	204.71	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-3.99
27	ht	207.05	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-3.99
190	hs	220.28	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: A506 Rathdrum 115 kV, Pine Street-Rathdrum	-4.11
189	hs	221.52	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	5.19
188	hs	221.85	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	5.19
187	hs	224.66	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BUS: Rathdrum East 115 kV	-4.11
186	hs	229.41	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-8
185	hs	250.4	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-8
184	hs	251.35	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	5.37
26	ht	254.81	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-8.68
25	ht	285.24	Line BELL S3 (40090) TO BELCOU31 (90012) CKT 3 [230.00 - 230.00 kV]	N-2 (ADJ): Bell - Coulee #6 500kV and Coulee - Westside 230kV	8.91
24	ht	285.53	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: A1186 Lancaster-Noxon, Boulder-Lancaster	-4.26
23	ht	295.13	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-5.08
22	ht	299.48	Line EASTFARM (48117) TO OTIS (48311) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	5.42
21	ht	320.34	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-4.9
20	ht	321.03	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-4.9
19	ht	343.98	Line HATWAI (40519) TO MOSCOW (48249) CKT 1[230.00 - 230.00 kV]	BF: 4652 Dworshak-Taft, Dworshak-Hatwai, Dworshak 500 kV Switched Shunt	-7.55
18	ht	345.85	Line BELLAN11 (90011) TO LANCASTR (40624) CKT 1[230.00 - 230.00 kV]	BF: R427 Beacon North & South 230 kV	-32.19
17	ht	346.31	Line BELLAN11 (90011) TO LANCASTR (40624) CKT 1[230.00 - 230.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	-31.02
183	hs	350.23	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: A638 Rathdrum 115 kV, Appleway-Rathdrum	-4.11

Contingency analysis for the 350 MW request reveals 141 new facility violations between the two cases studied, with the highest instance of thermal overloading shown in Figure 3 for the loss of both the Beacon – Kootenai and Boulder – Lancaster 230 kV transmission lines.

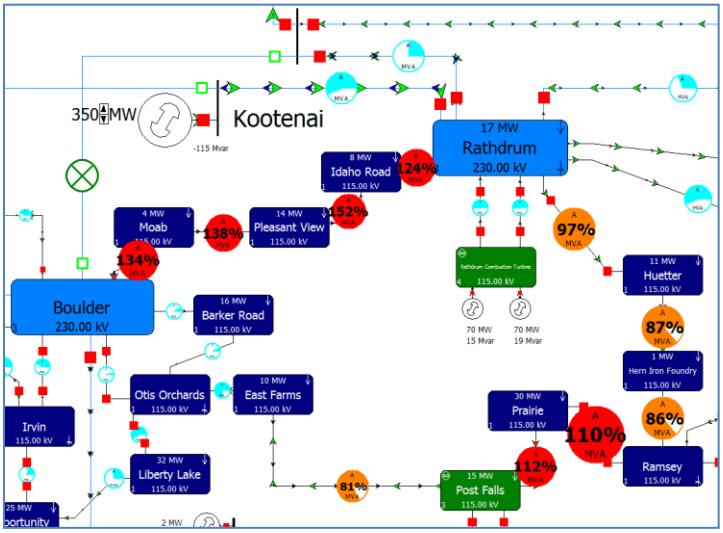

FIGURE 3: WORST PERFORMING CONTINGENCY EVENT; HEAVY SUMMER CASE; 350 MW REQUEST

Project Alternatives

Historic generation interconnection studies[6] done for the same area of this request show that reconductoring alone is not sufficient for this level of incremental generation. In addition to the alternatives presented in the referenced study, a promising option includes:

1. Point of Interconnection (POI)
    a. New 3 position Double Bus Double Breaker station (Kootenai); $4 million
2. Upgrade 23.5 miles of 115 kV transmission line to a minimum summer rating of 166 MVA for $7.0 million
3. Construct a new, 5-position 230 kV station approximately 1 mile west of Indian Trails station for $11 million
    a. Terminate the Bell – Westside and Coulee – Westside 230 kV transmission lines at this station
4. Construct a new 35 mile 230 kV, 800 MVA summer rated transmission line from Rathdrum station to the newly construction station for $25.2 million

[6] http://www.oasis.oati.com/AVAT/AVATdocs/Rathdrum500_Final.pdf

Rathdrum Station

Three incremental outputs were requested for this station: 26, 50, and 200 MW. These requests were studied as follows:

- 26 MW supplied by upgrading the existing turbines
- 50 and 200 MW coming from symmetrical generators at each of the Rathdrum 115 kV buses
- 50 and 200 MW supplied by a single generator placed at the Rathdrum 230 kV bus (see Figure 4)

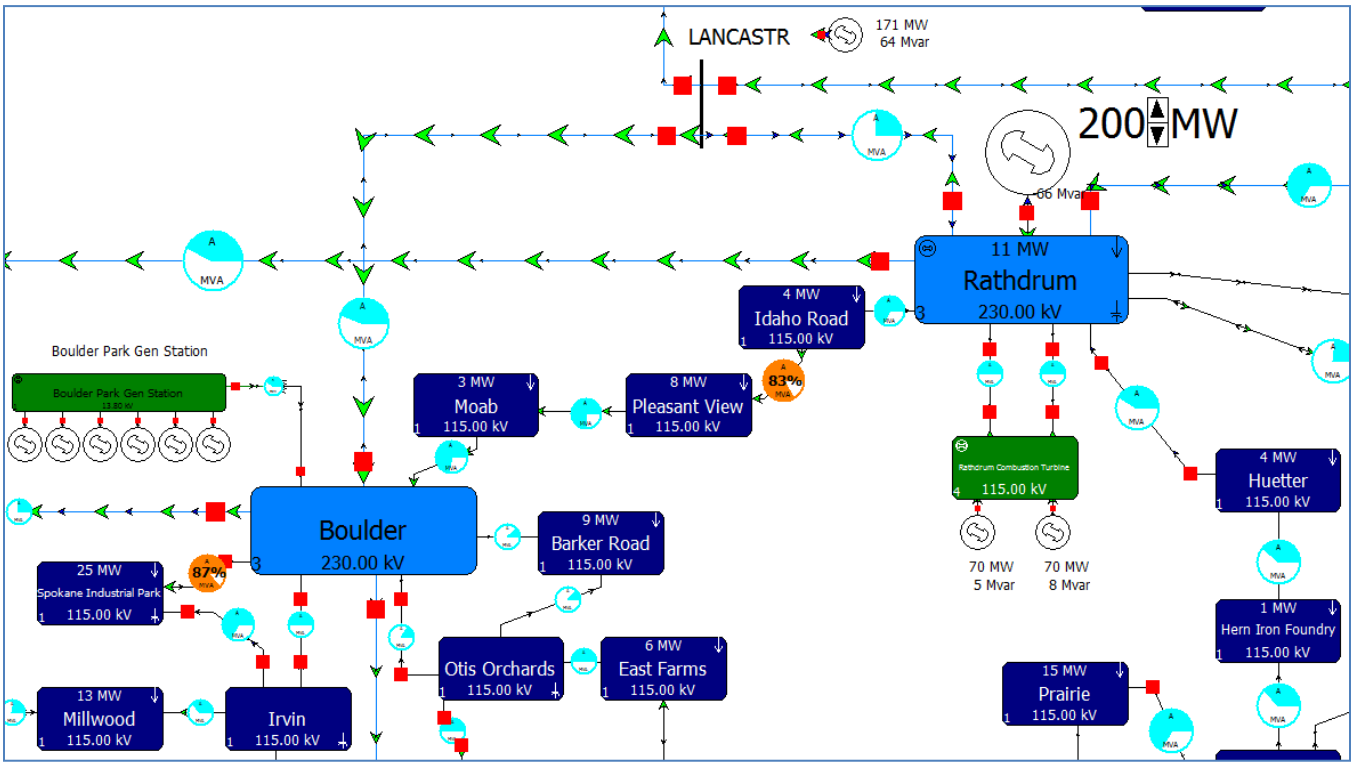

FIGURE 4: 200 MW INCREMENTAL GENERATION AT RATHDRUM; 2019 HIGH TRANSFER CASE

Rathdrum 26 MW request; 115 kV interconnection; $2.84 million to $10.9 million

Analysis

For P0 conditions, both study cases received generation up to 26 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for new facility thermal violations created by requested generation at 26 MW.

TABLE 5: ATC RESULTS FOR 26 MW REQUEST

Case	Generation	Limiting Element	Limiting CTG	% OTDF
ht	8.16	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-12.38
hs	12.85	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	8.52
ht	13.16	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-12.79
ht	13.75	Line EASTFARM (48117) TO OTIS (48311) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	22.45
hs	18	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-15.45
ht	18.81	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-12.37
ht	23.08	Line BOULDERE (48522) TO IRVIN (48165) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	7.63
ht	27.97	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	6.88

TABLE 6: CONTINGENCY ANALYSIS RESULTS FOR 26 MW REQUEST; THERMAL VIOLATIONS ONLY

Label	Element	Percent	Case
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.58	hs
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11	101.84	ht
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.83	ht
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	101.82	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.74	ht
BUS: Beacon South 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.63	ht
N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.27	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.04	ht
N-2 (ADJ): Beacon - Boulder #2 115 kV and Beacon - Ninth & Central #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at SPKINDPK	100.86	hs

Project Alternatives

1. If back-tripping ($400,000) is used to mitigate some of the existing issues, all issues created by the additional 26 MW can be mitigated by upgrading 5.8 miles of 115 kV transmission line to a minimum summer rating of 124 MVA for a cost of approximately $2.44 million.
2. If back-tripping is not employed, all issues created by the additional 26 MW can be mitigated by upgrading:
    a. 13.8 miles of 115 kV transmission line to a minimum summer rating of 124 MVA for $5.8 million
    b. 7.1 miles of the BPA's Bell – Lancaster 230 kV Transmission Line to a minimum summer rating of 675 MVA for $5.11 million

Rathdrum 50 MW request; 115 kV interconnection; $10.7 to $18.7 million

Analysis

For P0 conditions, both study cases received generation up to 50 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for new facility thermal violations created by requested generation at 50 MW.

TABLE 7: ATC RESULTS FOR 50 MW REQUEST

Case	Generation	Limiting Element	Limiting CTG	% OTDF
ht	8.16	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-12.38
hs	12.85	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	8.52
ht	13.16	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-12.79
ht	13.75	Line EASTFARM (48117) TO OTIS (48311) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	22.45
hs	18	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-15.45
ht	18.81	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-12.37
ht	23.08	Line BOULDERE (48522) TO IRVIN (48165) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	7.63
ht	27.97	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	6.88
ht	32.72	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	BF: A290 Hot Springs 230 kV, Hot Springs-Rattlesnake	5.72
ht	33.1	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-12.38
ht	33.9	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	BUS: Bell S3 230 kV	6.52
ht	36.77	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-17.63
ht	36.98	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-12.79
hs	37.18	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	26.84
ht	38.49	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-1: Beacon - Boulder 230 kV	7.19
ht	43.98	Line EASTFARM (48117) TO POST FLS (48329) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-12.47
ht	44.01	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-12.37
ht	44.6	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: A388 Bell S2 & S3 230 kV	12.22
ht	46.05	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	PSF: Ramsey 115 kV	14.06
hs	47.62	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	-15.45
ht	47.7	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	-14.27
ht	51.76	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	-12.25

TABLE 8: CONTINGENCY RESULTS FOR THERMAL ISSUES; 50 MW REQUEST

Label	Element	Percent	Case
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	107.8	hs
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	106.31	ht
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.59	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.46	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	104.66	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	104.2	hs
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11	103.53	ht
BUS: Beacon South 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	103.3	ht
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.26	hs
N-1: Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	102.57	ht
N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.54	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	102.47	ht
N-2 (ADJ): Beacon - Boulder #2 115 kV and Beacon - Ninth & Central #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at SPKINDPK	102.09	hs
N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at SPKINDPK	101.83	hs
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	101.63	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	101.27	ht
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	101.26	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.21	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	101.17	ht
PSF: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.87	ht
N-1: Beacon - Boulder 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.51	ht

Project Alternatives

1. POI at Rathdrum Station would cost an estimated $1 million
2. Project options necessary to mitigate new facility violations:
    a. If back-tripping ($400,000) is used to mitigate some of the existing issues, all issues created by the additional 50 MW can be mitigated by upgrading 22.2 miles of 115 kV transmission line to a minimum summer rating of 131 MVA for a cost of approximately $9.3 million.
    b. If back-tripping is not employed, all issues created by the additional 50 MW can be mitigated by upgrading:
        i. 29.8 miles of 115 kV transmission line to a minimum summer rating of 131 MVA for $12.5 million
        ii. 7.2 miles of the BPA's Bell – Lancaster 230 kV Transmission Line to a summer rating of 675 MVA for $5.18 million

Rathdrum 200 MW request; 115 kV interconnection; $10.3 to $48.5 million

Analysis

For P0 conditions, both study cases show significant loading on the local 115 kV system as shown in Figure 5.

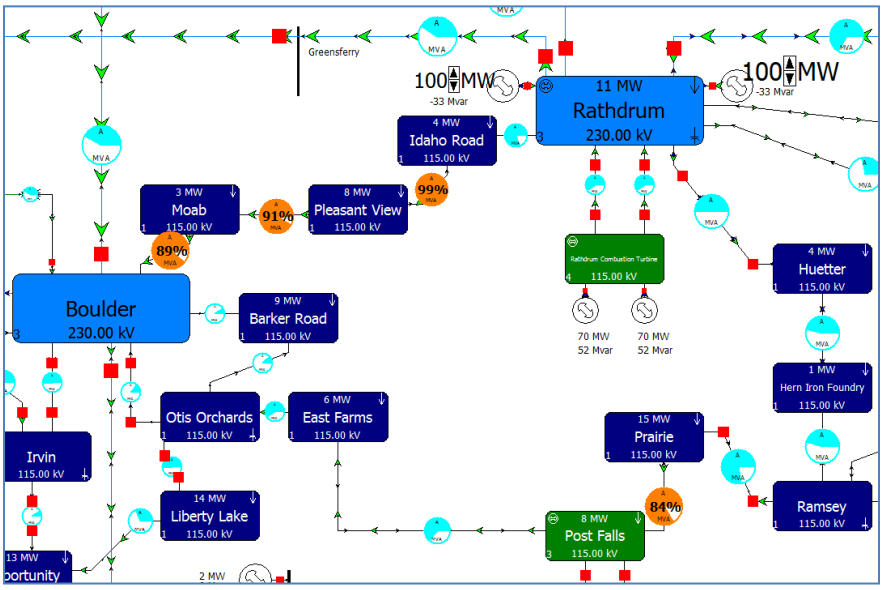

FIGURE 5: P0 LOADING FOR 200 MW REQUEST DURING HIGH TRANSFER SCENARIO

For performance during contingencies, an additional 200 MW at Rathdrum station 115 kV buses creates facility thermal violations for 137 unique contingency events (See Appendix C). Table 9 presents a list of all facilities overloaded for this generation level, and it shows the sum of percent thermal overload for each facility in each case.

TABLE 9: SUM OF FACILITY THERMAL OVERLOADS; 200 MW REQUEST

Facilities	hs	ht
IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	1211.48	11050.11
BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	1062.15	2939.24
PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	574.11	4778.41
RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	421.5	201.68
RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	325.84	
PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	324.22	2633.82
MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	260.06	4351.73
RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	239.45	422.67
HUETTER (48159) -> HERN (48155) CKT 1 at HERN	200.73	
SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	110.04	
OPPORTUN (48299) -> CHESTER (48069) CKT 1 at CHESTER	107.21	
ROSSPARK (48371) -> THIRHACH (48431) CKT 1 at ROSSPARK	100.55	
POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS		231.07
LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11		114.64
BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE		112.19
WEST (48463) -> WESTBPA2 (41276) CKT 1 at WESTBPA2		102.26
BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11		112.03
EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM		356.45

Figure 6 shows system thermal performance after the loss of both the Kootenai – Rathdrum and Lancaster – Rathdrum 230 kV transmission lines; this is the worst performing event.

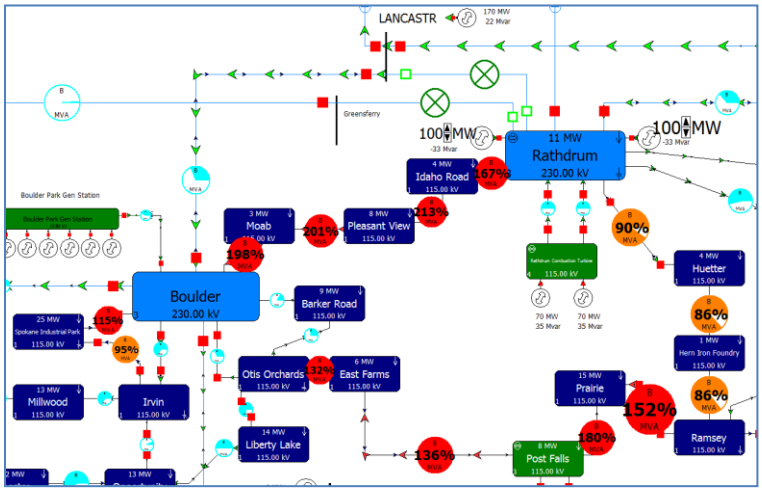

FIGURE 6: WORST PERFORMING CONTINGENCY EVENT; HIGH TRANSFER SCENARIO

Project Alternatives

1. POI at Rathdrum Station would cost an estimated $1 million
2. Three alternatives for mitigating new facility violations:
    a. If back-tripping is used to mitigate some of the existing issues, all issues created by the additional 50 MW can be mitigated by upgrading 22.2 miles of 115 kV transmission line to a minimum summer rating of 131 MVA for a cost of approximately $9.3 million.
    b. If back-tripping is not employed, all issues created by the additional 200 MW can be mitigated by upgrading:
        i. 52.8 miles of 115 kV transmission line to a minimum summer rating of 174 MVA for $22.2 million
        ii. 7.2 miles of the BPA's Bell – Lancaster 230 kV Transmission Line to a summer rating of 675 MVA for $5.18 million
    c. Construct a new 230 kV transmission line from Rathdrum Station to a new station north of Westside Station
        i. Construct a new, 5-position 230 kV station approximately 1 mile west of Indian Trails station alongside the 500 kV right-of-way for $11 million
            1. Terminate the Bell – Westside and Coulee – Westside 230 kV transmission lines at this station
        ii. Construct a new, 35 mile 230 kV, 800 MVA summer rated transmission line from Rathdrum station to the newly construction station for $25.2 million
        iii. Upgrade 31.7 miles of 115 kV transmission lines to a summer rating greater than 156 MVA for $13.3 million

Rathdrum 50 MW Request; 230 kV interconnection; $7 to $16.8 million

Analysis

For P0 conditions, both study cases received generation up to 50 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for new facility violations created by requested generation at 50 MW.

TABLE 10: ATC RESULTS FOR 50 MW REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	% OTDF
ht	3.85	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	-5.65
ht	3.86	Line EASTFARM (48117) TO OTIS (48311) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	20.28
ht	25.55	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	-5.65
ht	26.31	Line BOULDERE (48522) TO IRVIN (48165) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	5.3
ht	33.11	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	4.15
hs	34.3	Line BOULDERE (48522) TO MOAB (47511) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-9.48
hs	38.3	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	24.1
ht	39.42	Line EASTFARM (48117) TO POST FLS (48329) CKT 1 [115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-7.6
ht	47.21	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1 [115.00 - 115.00 kV]	N-1: Beacon - Boulder 230 kV	5
ht	56.03	Line MOAB (47511) TO PLEASANT (48319) CKT 1 [115.00 - 115.00 kV]	N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	-4.55

TABLE 11: CONTINGENCY RESULTS FOR 50 MW REQUEST

Label	Element	Percent	Case
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	107.55	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.51	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.02	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	102.75	ht
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.67	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.5	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	102.06	hs
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.79	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	101.18	ht
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	100.51	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.49	ht

Project Alternatives

1. POI at Rathdrum Station would cost an estimated $1.5 million
2. Project options necessary to mitigate new facility violations:
    a. If back-tripping is used to mitigate some of the existing issues, all issues created by the additional 50 MW can be mitigated by upgrading 13 miles of 115 kV transmission line to a minimum summer rating of 131 MVA for a cost of approximately $5.5 million.
    b. If back-tripping is not employed, all issues created by the additional 50 MW can be mitigated by upgrading:
        i. 36.3 miles of 115 kV transmission line to a summer rating of 131 MVA for $15.2 million
        ii. 0.1 miles of the BPA's Bell – Bell AN11 230 kV Transmission Line to a summer rating of 800 MVA for $100,000

Rathdrum 200 MW Request; 230 kV interconnection; $15.5 to $21.5 million

Analysis

For P0 conditions, both study cases received generation up to 200 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for new facility violations created by requested generation at 200 MW.

TABLE 12: ATC RESULTS FOR 200 MW REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
ht	2.69	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BUS: Ramsey 115 kV	4.57
ht	3.14	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BUS: Otis Orchards 115 kV	3.69
ht	4.04	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Post Falls - Ramsey 115 kV & Ramsey - Rathdrum # 1 115 kV	4.51
ht	7.09	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BF: A288 Hot Springs 230 kV, Hot Springs-Noxon Rapids # 1	-4.16
ht	10.83	Line BENEWAH (48037) TO PINE CRK (48317) CKT 1[230.00 - 230.00 kV]	BUS: Hot Springs 230 kV	-4.16
ht	23.7	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1561 Boulder-Lancaster, Lancaster Generator # 1 & # 2	-6.86
ht	26.27	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-1: Lancaster - Rathdrum 230 kV	-11.43
hs	34.3	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-9.48
ht	36.76	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R508 Lancaster-Rathdrum, Rathdrum # 1 230/115 Transformer	-10.04
hs	38.3	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	24.1
ht	41.36	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	-5.85
ht	45.32	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	PSF: Otis Orchards 115 kV	3.69
ht	47.76	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	-11.48
ht	49.09	Line EASTFARM (48117) TO OTIS (48311) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	6.29
ht	50.42	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	-9.7
ht	57.6	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A388 Bell S2 & S3 230 kV	-4.5
ht	59.23	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R408 Lancaster-Rathdrum, Rathdrum # 2 230/115 Transformer	-9.33
ht	63.75	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder # 2 230/115 Transformer	-5.65
ht	64.36	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder # 1 230/115 Transformer	-5.65
ht	66.1	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R508 Lancaster-Rathdrum, Rathdrum # 1 230/115 Transformer	-10.04
ht	73.78	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Rathdrum 230kV and Lancaster - Noxon 230kV	4.87
ht	73.88	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	-11.48
ht	73.99	Line IRVIN (48165) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-8.05
hs	77.96	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-9.48
ht	79.55	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: A1561 Boulder-Lancaster, Lancaster Generator # 1 & # 2	-5.85
hs	88.83	Line MOAB (47511) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-24.1
ht	91.38	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	BF: R408 Lancaster-Rathdrum, Rathdrum # 2 230/115 Transformer	-9.33
ht	96.43	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	N-1: Lancaster - Rathdrum 230 kV	-9.46
hs	102.87	Line BOULDERE (48522) TO MOAB (47511) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-24.1
ht	114.54	Line BELLAN11 (90011) TO LANCASTR (40624) CKT 1[230.00 - 230.00 kV]	BF: R427 Beacon North & South 230 kV	-32.19
ht	115.07	Line BELLAN11 (90011) TO LANCASTR (40624) CKT 1[230.00 - 230.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Rathdrum 230 kV	-31.02
hs	119.79	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-24.1
ht	119.94	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-13.17
ht	137.25	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	-9.49
ht	137.57	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	N-1: Lancaster - Rathdrum 230 kV	-11.43
hs	140.52	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder # 2 115 kV	6.08
ht	145.93	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: R508 Lancaster-Rathdrum, Rathdrum # 1 230/115 Transformer	-8.32
hs	146.04	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder # 2 115 kV and Beacon - Ninth & Central # 2 115 kV	3.84
ht	154.16	Line HERN (48155) TO HUETTER (48159) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-13.17
ht	154.96	Line BELL S3 (40090) TO BELLAN11 (90011) CKT 1[230.00 - 230.00 kV]	BF: R427 Beacon North & South 230 kV	-32.19
ht	157.02	Line BELL S3 (40090) TO BELLAN11 (90011) CKT 1[230.00 - 230.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Rathdrum 230 kV	-31.02
ht	160.88	Line HERN (48155) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	13.17
ht	166	Line IDAHO_RD (48161) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: A1186 Lancaster-Noxon, Boulder-Lancaster	-6.08
hs	180.74	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	-20.29
ht	185.55	Line IRVIN (48165) TO MILLWOOD (48237) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Rathdrum 230 kV	7.57
hs	198.16	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R554 Boulder-Lancaster, Boulder # 1 230/115 Transformer	5.92
hs	198.55	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: R454 Boulder-Lancaster, Boulder # 2 230/115 Transformer	5.91
ht	201.01	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	BF: A1186 Lancaster-Noxon, Boulder-Lancaster	-4.95
hs	215.17	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2: Beacon - Boulder 230 kV & Boulder - Irvin # 2 115 kV	7.15
hs	216.58	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Lancaster 230 kV	6.12
hs	231.38	Line IRVIN (48165) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BF: R427 Beacon North & South 230 kV	-7.57
hs	238.18	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-7.97
hs	243.76	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	-7.97
hs	293.13	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BUS: Rathdrum East 115 kV	-4.51
hs	299.93	Line HUETTER (48159) TO RATHDRMW (48355) CKT 1[115.00 - 115.00 kV]	BF: A506 Rathdrum 115 kV, Pine Street-Rathdrum	-4.51
hs	301.74	Line PRAIRIEB (40855) TO RAMSEY (48349) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	-6.59
hs	311.86	Line POST FLS (48329) TO PRAIRIEB (40855) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	-6.59
ht	326.58	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BUS: Bell S3 230 kV	5.36
ht	326.58	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: A572 Bell S3 230 kV, Bell-Boundary # 3	5.36
ht	337.01	Line IDAHO_RD (48161) TO PLEASANT (48319) CKT 1[115.00 - 115.00 kV]	BF: 4148 Garrison-Taft # 2, Hot Springs-Taft	3.92
hs	368.83	Line CHESTER (48069) TO OPPORTUN (48299) CKT 1[115.00 - 115.00 kV]	BF: A600 Beacon North & South 115 kV	-4.37

TABLE 13: NEW FACILITY THERMAL VIOLATIONS FOR 200 MW REQUEST

Label	Element	Percent	Case
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	142.76	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	131.27	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	130.97	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	127.64	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	122.3	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	118.82	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	116.18	hs
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	BELLAN11(90011) -> BELL S3 (40090) CKT 1 at BELLAN11	115	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	113.44	ht
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	112.61	ht
BF: R554 Boulder-Lancaster, Boulder # 1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	112.19	ht
BF: R454 Boulder-Lancaster, Boulder # 2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.32	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	110.94	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	110.38	hs
N-1: Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	109.6	ht
BF: R554 Boulder-Lancaster, Boulder # 1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	109.21	ht
BF: R454 Boulder-Lancaster, Boulder # 2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.3	ht
N-1: Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	107.27	ht
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder # 1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	107.21	ht
N-2 (ADJ): Beacon - Rathdrum 230kV and Bell - Lancaster 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.79	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Boulder - Lancaster 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	106.51	ht
N-1: Beacon - Boulder 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.09	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.96	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator # 1 & # 2	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.65	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	105.63	hs
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.41	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.28	ht
N-2 (ADJ): Beacon - Rathdrum 230kV and Bell - Lancaster 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.18	ht
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.83	ht
N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder # 2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	103.8	hs
PSF: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.54	ht
BF: R508 Lancaster-Rathdrum, Rathdrum # 1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.27	ht
N-2 (STR): Beacon - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	103.24	hs
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	103.02	ht
N-1: Opportunity - Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.9	ht
N-2 (ADJ): Beacon - Boulder # 2 115 kV and Beacon - Ninth & Central # 2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.01	hs
N-2: Beacon - Boulder 230 kV & Beacon - Irvin # 1 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.87	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.36	ht
BUS: Beacon North 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.31	ht
BF: R427 Beacon North & South 230 kV	SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	101.28	hs
BF: R408 Lancaster-Rathdrum, Rathdrum # 2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.16	ht
BF: R554 Boulder-Lancaster, Boulder # 1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.15	hs
N-1: Beacon - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.15	ht
BF: R454 Boulder-Lancaster, Boulder # 2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.12	hs
BF: A717 Boulder East & West 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.94	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.8	ht
N-2: Beacon - Boulder 230 kV & Boulder - Irvin # 2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.68	hs
N-1: Opportunity - Otis Orchards 115 kV Open @ OPT	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.67	ht
N-1: Boulder - Lancaster 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.59	ht
BF: A667 Ramsey 115 kV, Appleway-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.53	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum # 1	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.48	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	100.35	ht
N-2 (ADJ): Beacon - Bell # 4 230kV and Beacon - Rathdrum 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.3	ht
N-1: Beacon - Rathdrum 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.28	ht
N-2 (ADJ): Beacon - Bell # 4 230kV and Beacon - Rathdrum 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.27	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.04	ht

Project Alternatives

1. POI at Rathdrum Station would cost an estimated $1.5 million
2. Project options necessary to mitigate new facility violations:
    a. If back-tripping is used to mitigate some of the existing issues, all issues created by the additional 200 MW can be mitigated by upgrading 33.4 miles of 115 kV transmission line to a minimum summer rating of 175 MVA for a cost of approximately $14.0 million.
    b. If back-tripping is not employed, all issues created by the additional 200 MW can be mitigated by upgrading:
        i. 47.3 miles of 115 kV transmission line to a minimum summer rating of 175 MVA for $19.9 million
        ii. 0.1 miles of the BPA's Bell – Bell AN11 230 kV Transmission Line to a summer rating of 800 MVA for $100,000

Thornton Station

Thornton 30 MW and 100 MW Request; $400,000

Two incremental wind energy outputs were requested for this station: 30 MW and 100 MW. These requests were studied as coming from a single wind plant as depicted in Figure 7:

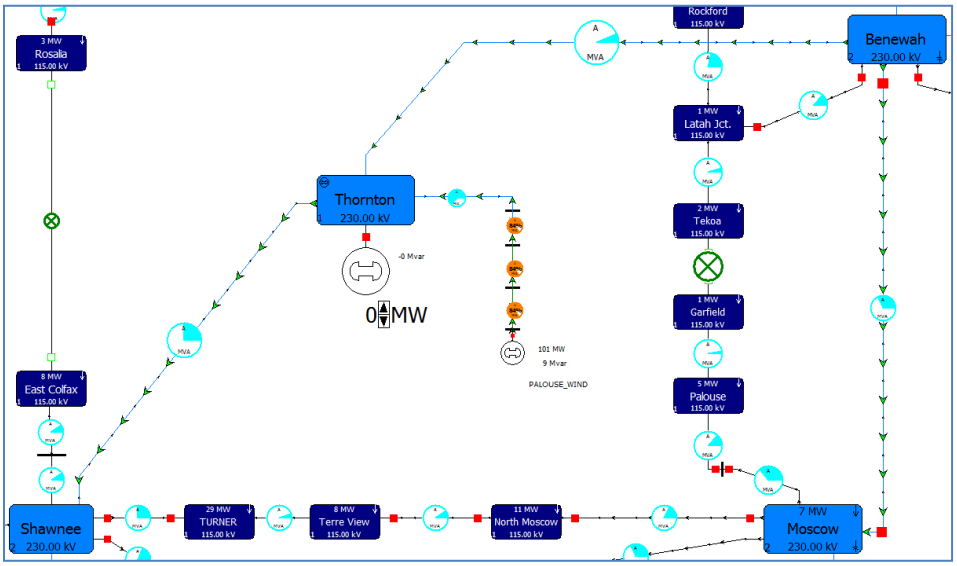

FIGURE 7: THORNTON WIND REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 100 MW without issue.

For performance during contingencies, Table 2 shows results from the ATC analysis, and Table 3 shows Contingency Analysis results for existing facility violations exacerbated by requested generation at 100 MW.

TABLE 14: ATC RESULTS FOR THORNTON WIND REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
19ht	25.07	Line BOULDERE (48522) TO IRVIN (48165) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder # 1 115kV	5.32
24hs	36.5	Line IRVIN (48165) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	BF: R427 Beacon North & South 230 kV	-5.23
19ht	45.81	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Beacon - Boulder 230 kV	5.03
24hs	110.87	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-1: Boulder - Irvin # 2 115 kV	3.81
24hs	138.73	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2 (STR): Beacon - Boulder 230 kV & Beacon - Rathdrum 230 kV	5.95
19ht	141.46	Line BOULDERW (48520) TO SPKINDPK (48405) CKT 1[115.00 - 115.00 kV]	N-2: Beacon - Boulder 230 kV & Beacon - Irvin # 1 115 kV	4.62

TABLE 15: THERMAL FACILITY VIOLATIONS EXACERBATED BY NEW GENERATION

Label	Element	Percent	Case
N-2: Beacon - Boulder 230 kV & Boulder - Irvin # 2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.63	24hs
BF: R427 Beacon North & South 230 kV	SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	104.47	24hs
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder # 1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	103.7	19ht
N-1: Beacon - Boulder 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.83	19ht
BF: A600 Beacon North & South 115 kV	OPPORTUN (48299) -> CHESTER (48069) CKT 1 at CHESTER	102.27	24hs
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.1	19ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.83	24hs
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.07	19ht

Project Alternatives

POI at Thornton Station would cost an estimated $400,000

Othello Station

Othello 25 MW Solar request; $2 million

This request involves interconnecting up to 25 MW of solar generation, which is modeled in this study as a simple generic source at the Othello Switching Station as show in Figure 8.

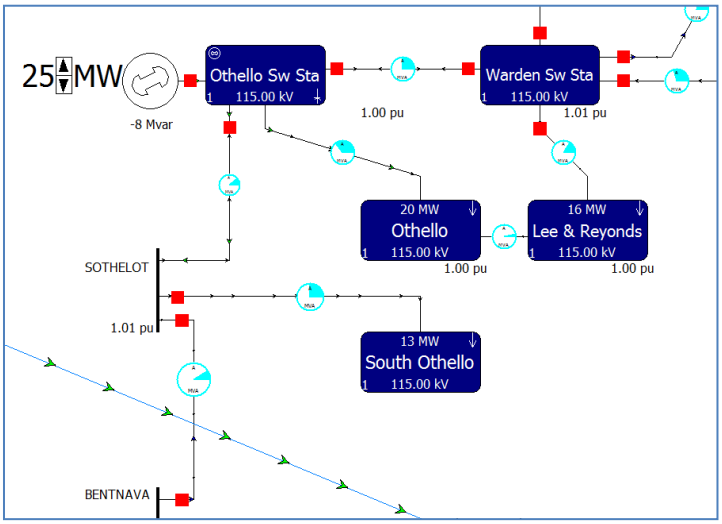

FIGURE 8: OTHELLO GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 25 MW without issue.

For performance during contingencies, Table 16 shows results from the ATC analysis, and there are no new facility violations created by requested generation at 25 MW.

TABLE 16: ATC RESULTS FOR OTHELLO GENERATION REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	% OTDF
ht	95.58	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Othello SS - Warden # 2 115 kV Open @ OSS	60.49
ht	105.61	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Othello SS - Warden # 2 115 kV (OSS-L&R)	60.49
ht	107.02	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-1: Othello SS - Warden # 1 115 kV	-54.95
ht	110.59	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Benton - Midway # 2 230 kV and Benton - Othello SS 115 kV	62.79
ht	110.64	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV (OSS-SOT)	62.79
ht	110.68	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV Open @ OSS	62.79
hs	115.23	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV Open @ OSS	-37.21
hs	115.29	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Benton - Midway # 2 230 kV and Benton - Othello SS 115 kV	-37.21
hs	115.35	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV (OSS-SOT)	-37.21
hs	115.43	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-2 (ROW): Benton - Midway # 2 230 kV and Benton - Midway # 1 115 kV and Benton - Othello SS 115 kV	-37.21
hs	115.52	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Benton - Midway # 1 115 kV and Benton - Othello SS 115 kV	-37.21
hs	115.88	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Othello SS - Warden # 2 115 kV Open @ OSS	60.65
hs	119.53	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV Open @ OSS	62.79
hs	119.59	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Benton - Midway # 2 230 kV and Benton - Othello SS 115 kV	62.79
hs	119.65	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV (OSS-SOT)	62.79
hs	119.74	Line OTHELOSS (48309) TO WARDEN A (48455) CKT 1[115.00 - 115.00 kV]	N-2 (ROW): Benton - Midway # 2 230 kV and Benton - Midway # 1 115 kV and Benton - Othello SS 115 kV	62.79
ht	125.82	Line OTHELLO (48307) TO OTHELOSS (48309) CKT 1[115.00 - 115.00 kV]	N-1: Benton - Othello SS 115 kV Open @ OSS	-37.21

Project Alternatives

POI at Othello Station would cost an estimated $2 million

Northeast Station

Northeast 10 MW; $0

This request involves interconnecting up to 10 MW of additional generation, which is modeled in this study as a simple generic source at the Northeast Station as show in **Error! Reference source not found.**.

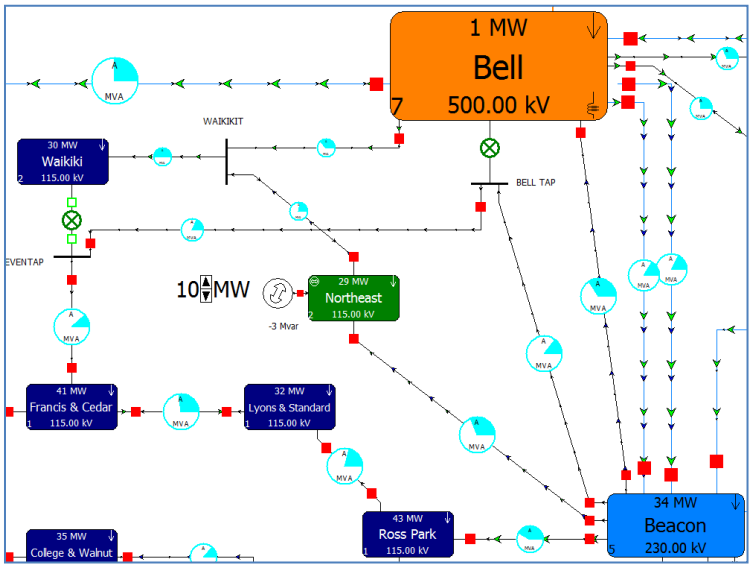

FIGURE 9: NORTHEST GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 10 MW without issue.

For performance during contingencies, Table 17 shows results from the ATC analysis, and there are no new facility violations created by requested generation at 10 MW.

TABLE 17: ATC RESULTS FOR NORTHEAST GENERATION REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
ht	76.49	Line BEACON N (48023) TO NORTHEAS (48277) CKT 1[115.00 - 115.00 kV]	N-2 (ROW and ADJ): Beacon - Francis & Cedar 115 kV and Bell - Northeast 115 kV	-100
ht	76.52	Line BEACON N (48023) TO NORTHEAS (48277) CKT 1[115.00 - 115.00 kV]	N-1: Bell - Northeast 115 kV	-100
ht	76.55	Line BEACON N (48023) TO NORTHEAS (48277) CKT 1[115.00 - 115.00 kV]	N-1: Bell - Northeast 115 kV Open @ NE	-100
ht	77.16	Line BEACON N (48023) TO NORTHEAS (48277) CKT 1[115.00 - 115.00 kV]	BF: B356 Bell 115 kV, Bell-Northeast	-100
ht	89.73	Line BEACON N (48023) TO NORTHEAS (48277) CKT 1[115.00 - 115.00 kV]	BF: B346 Bell 115 kV, Addy-Bell	-100
ht	93.44	Line BELL BPA (40087) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	N-2 (ROW): Beacon - Bell #5 230 kV and Beacon - Francis & Cedar 115 kV and Beacon - Northeast 115 kV	-100
ht	94.58	Line BELL BPA (40087) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	BF: A600 Beacon North & South 115 kV	-100
ht	94.64	Line BELL BPA (40087) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	N-2 (ROW): Beacon - Bell #4 230 kV and Beacon - Bell #1 115 kV and Beacon - Northeast 115 kV and Beacon - Francis & Cedar 115 kV	-100
ht	95.3	Line NORTHEAS (48277) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	BF: A572 Bell S3 230 kV, Bell-Boundary #3	62.72
ht	95.42	Line NORTHEAS (48277) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	BUS: Bell S3 230 kV	62.72
ht	97.6	Line NORTHEAS (48277) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	N-2 (ROW): Bell - Taft 500 kV and Bell - Lancaster 230 kV and Beacon - Rathdrum 230 kV and Boulder - Lancaster 230 kV	62.09
ht	98.22	Line NORTHEAS (48277) TO WAIKIKIT (48449) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	62.11
ht	101.71	Line BOULDER (48524) TO BENEWAH (48037) CKT 1[230.00 - 230.00 kV]	N-2 (ROW): Bell - Coulee #6 500 kV and Bell - Coulee #3 230 kV and Bell - Coulee #5 230 kV and Coulee - Westside 230 kV and Bell - Creston 115 kV	12.81

Project Alternatives

None required

Kettle Falls Station

Kettle Falls 10 MW; $0

This request involves interconnecting up to 10 MW of additional generation, which is modeled in this study as a simple generic source at the Kettle Falls Station as shown in Figure 10.

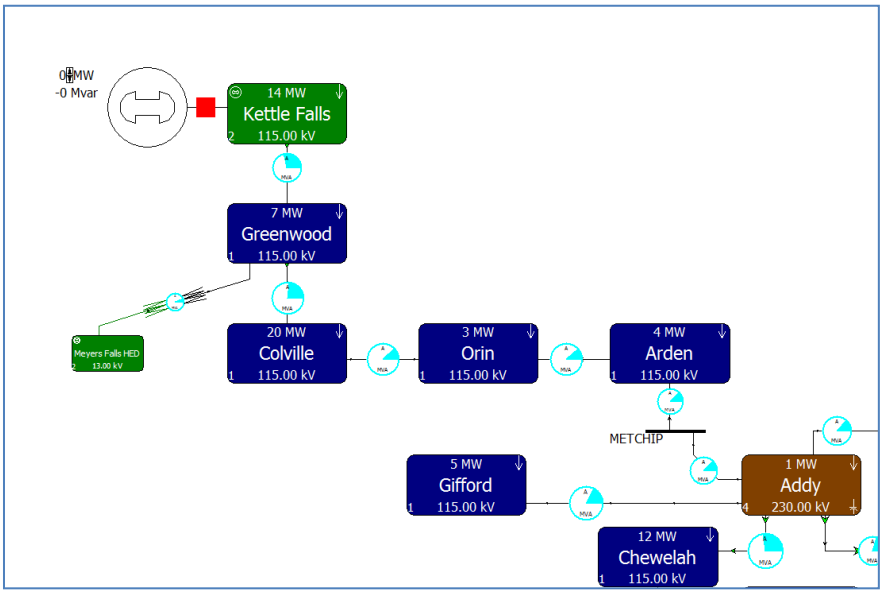

FIGURE 10: KETTLE FALLS GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 10 MW without issue.

For performance during contingencies, Table 18 shows results from the ATC analysis, and there are no new facility violations created by requested generation at 10 MW.

TABLE 18: ATC RESULTS FOR KETTLE FALLS GENERATION REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
ht	76.04	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Addy - Colville BPA 115 kV	-63.23
ht	76.3	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV	-100
ht	76.32	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV Open @ KET	-100
ht	76.74	Line KETTLE T (40607) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	BF: B1145 Addy 115 kV, Addy-Kettle Falls	-100
ht	76.75	Line KETTLE T (40607) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Addy - Kettle Falls 115 kV Open @ KET	-100
ht	77.26	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	BF: B1768 Colville BPA 115 kV, Colville BPA-Kettle Falls	-100
ht	77.98	Line KETTLE T (40607) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Addy - Kettle Falls 115 kV	-100
ht	79.91	Line COLV AVA (48083) TO GREENWDA (48143) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV Open @ KET	-100
ht	79.92	Line COLV AVA (48083) TO GREENWDA (48143) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV	-100
ht	80.93	Line COLV AVA (48083) TO GREENWDA (48143) CKT 1[115.00 - 115.00 kV]	BF: B1768 Colville BPA 115 kV, Colville BPA-Kettle Falls	-100
ht	81.78	Line COLV AVA (48083) TO GREENWDA (48143) CKT 1[115.00 - 115.00 kV]	N-1: Addy - Colville BPA 115 kV	-63.23
ht	83.12	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	BF: B1766 Colville BPA 115 kV, Boundary-Box Canyon-Colville BPA	-100
ht	86.75	Line COLV AVA (48083) TO GREENWDA (48143) CKT 1[115.00 - 115.00 kV]	BUS: Colville 115 kV	-100
hs	89.01	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV	-100
hs	89.01	Line GREENWDA (48143) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Kettle Falls Tap 115 kV Open @ KET	-100
hs	89.15	Line KETTLE T (40607) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	BF: B1145 Addy 115 kV, Addy-Kettle Falls	-100
hs	89.15	Line KETTLE T (40607) TO KETTLEAV (48175) CKT 1[115.00 - 115.00 kV]	N-1: Addy - Kettle Falls 115 kV Open @ KET	-100

Project Alternatives

No mitigating steps are necessary for this request

Long Lake Dam

Long Lake 68 MW; $19.7 million

This request involves adding 68 MW at Long Lake station, which is modeled in this study as two generators, one at each 115 kV bus as shown in Figure 11.

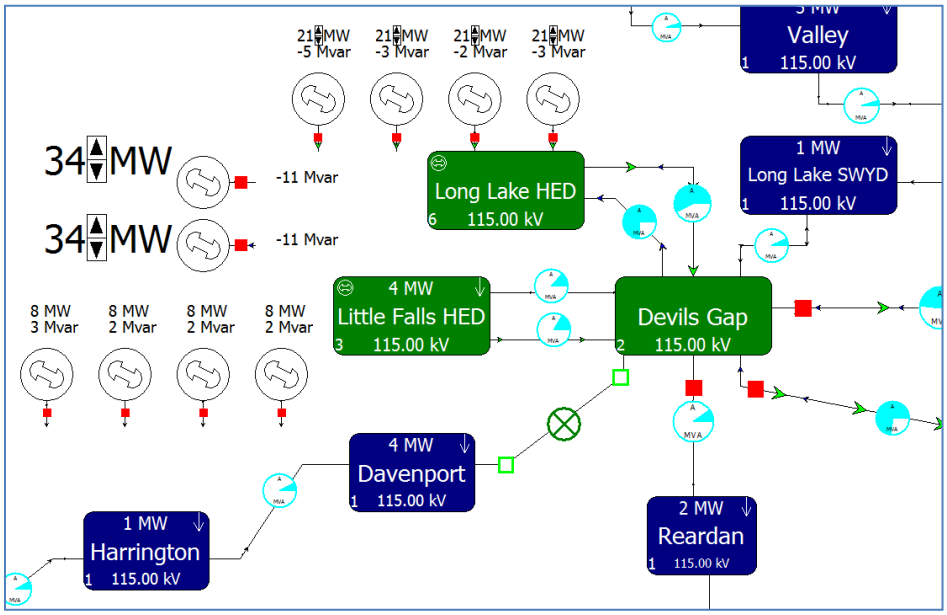

FIGURE 11: LONG LAKE GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 68 MW without issue.

For performance during contingencies, Table 19 shows results from the ATC analysis, and Table 20 shows Contingency Analysis results for new facility violations created by requested generation.

TABLE 19: ATC RESULTS FOR LONG LAKE GENERATION REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
ht	9.73	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	65.77
ht	11.39	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV	65.77
ht	12.27	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	65.77
ht	12.29	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	PSF: Airway Heights 115 kV	65.77
ht	16.64	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	65.77
ht	18.37	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV	65.77
ht	19.17	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	65.77
ht	19.19	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	PSF: Airway Heights 115 kV	65.77
ht	20.62	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	65.77
ht	26.21	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ NMS	62.44
ht	26.4	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV	62.44
ht	27.63	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	65.77
ht	29.37	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	PSF: Westside 115 kV	60.74
ht	31.29	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ WES	62.44
ht	31.45	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	62.35
ht	33.76	Line AIRWAYHT (48009) TO GARDENSP (48131) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ NMS	62.44
ht	33.94	Line AIRWAYHT (48009) TO GARDENSP (48131) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV	62.44
hs	34.7	Line DEVILGPE (48103) TO LONGLAKE (48201) CKT 1[115.00 - 115.00 kV]	N-1: Devils Gap - Long Lake # 2 115 kV	-100
hs	34.88	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	PSF: Westside 115 kV	60.14
hs	35.15	Line DEVILGPE (48103) TO LONGLAKW (48199) CKT 1[115.00 - 115.00 kV]	N-1: Devils Gap - Long Lake # 1 115 kV	-100
ht	35.38	Line DEVILGPE (48103) TO LONGLAKE (48201) CKT 1[115.00 - 115.00 kV]	N-1: Devils Gap - Long Lake # 2 115 kV	-100
ht	35.54	Line DEVILGPE (48103) TO LONGLAKW (48199) CKT 1[115.00 - 115.00 kV]	N-1: Devils Gap - Long Lake # 1 115 kV	-100
hs	37.06	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	BF: A413 Westside 115 kV, Ninemile-Westside	60.75
ht	37.11	Line AIRWAYHT (48009) TO GARDENSP (48131) CKT 1[115.00 - 115.00 kV]	PSF: Westside 115 kV	60.74
ht	38.74	Line AIRWAYHT (48009) TO GARDENSP (48131) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ WES	62.44
ht	38.98	Line AIRWAYHT (48009) TO GARDENSP (48131) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	62.35
ht	41.13	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ NMS	-62.44
ht	41.3	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV	-62.44
hs	42.44	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	65.77
hs	44.63	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV	65.77
ht	44.68	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	PSF: Westside 115 kV	-60.74
ht	46.1	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ WES	-62.44
hs	46.32	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	65.77
ht	46.35	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	-62.35
hs	46.38	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	PSF: Airway Heights 115 kV	65.77
hs	46.64	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	62.35
hs	46.67	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ NMS	62.45
hs	46.98	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV	62.45
hs	48.6	Line DEVILGPE (48103) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	BUS: Westside 115 kV	60.75
hs	56.53	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	PSF: Westside 115 kV	-60.14
ht	56.57	Line DEVILGPE (48103) TO NINEMILE (48269) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	65.77
hs	57.61	Line NINEMILE (48269) TO INDTRAIL (48164) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	65.77
ht	58.07	Line DEVILGPE (48103) TO NINEMILE (48269) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV	65.77
hs	58.28	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	BF: A413 Westside 115 kV, Ninemile-Westside	-60.75
ht	58.92	Line DEVILGPE (48103) TO NINEMILE (48269) CKT 1[115.00 - 115.00 kV]	BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	65.77
ht	58.92	Line DEVILGPE (48103) TO NINEMILE (48269) CKT 1[115.00 - 115.00 kV]	PSF: Airway Heights 115 kV	65.77
hs	59.85	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	65.77
hs	62.25	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV	65.77
hs	63.91	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	65.77
hs	63.91	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	PSF: Airway Heights 115 kV	65.77
hs	67.15	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV Open @ NMS	-62.45
ht	67.21	Line DEVILGPE (48103) TO NINEMILE (48269) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	65.77
hs	67.62	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	-62.35
hs	67.96	Line AIRWAYHT (48009) TO W.PLAINS (47513) CKT 1[115.00 - 115.00 kV]	N-1: Nine Mile - Westside 115 kV	-62.45
hs	74.67	Line INDTRAIL (48164) TO WEST (48461) CKT 1[115.00 - 115.00 kV]	N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	65.77

TABLE 20: NEW FACILIYT THERMAL VIOLATIONS FOR 68 MW REQUEST

Label	Element	Percent	Case
N-1: Devils Gap - Long Lake # 2 115 kV	LONGLAKE (48201) -> DEVILGPE (48103) CKT 1 at LONGLAKE	130.97	hs
N-1: Devils Gap - Long Lake # 1 115 kV	LONGLAKW (48199) -> DEVILGPE (48103) CKT 1 at LONGLAKW	130.95	hs
N-1: Devils Gap - Long Lake # 2 115 kV	LONGLAKE (48201) -> DEVILGPE (48103) CKT 1 at LONGLAKE	125.79	ht
N-1: Devils Gap - Long Lake # 1 115 kV	LONGLAKW (48199) -> DEVILGPE (48103) CKT 1 at LONGLAKW	125.78	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	124.01	ht
N-1: Airway Heights - Devils Gap 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	123.88	ht
BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	123.51	ht
PSF: Airway Heights 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	123.51	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	121.13	ht
N-1: Airway Heights - Devils Gap 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	121	ht
PSF: Airway Heights 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	120.6	ht
BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	120.6	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	119.94	ht
BUS: Airway Heights 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	119.54	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	117.06	ht
N-1: Nine Mile - Westside 115 kV Open @ NMS	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	116.91	ht
N-1: Nine Mile - Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	116.85	ht
BUS: Airway Heights 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	116.64	ht
PSF: Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	115.4	ht
N-1: Nine Mile - Westside 115 kV Open @ WES	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	114.99	ht
N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	114.79	ht
BF: A413 Westside 115 kV, Ninemile-Westside	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	114.76	ht
N-1: Nine Mile - Westside 115 kV Open @ NMS	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	114.64	ht
N-1: Nine Mile - Westside 115 kV	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	114.57	ht
PSF: Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	113.35	hs
BUS: Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	112.95	ht
BF: A413 Westside 115 kV, Ninemile-Westside	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	112.87	hs
PSF: Westside 115 kV	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	112.67	ht
BF: A470 Westside 115 kV, College & Walnut-Westside	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	112.67	ht
N-1: Nine Mile - Westside 115 kV Open @ WES	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	112.28	ht
N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	112.07	ht
BF: A413 Westside 115 kV, Ninemile-Westside	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	111.91	ht
N-1: Nine Mile - Westside 115 kV Open @ NMS	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	111.27	ht
N-1: Nine Mile - Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	111.21	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	110.56	hs
N-1: Airway Heights - Devils Gap 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	110.37	hs
PSF: Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	109.78	ht
BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	109.7	hs
PSF: Airway Heights 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	109.7	hs
BUS: Westside 115 kV	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	109.69	ht
N-1: Airway Heights - Garden Springs 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	109.64	ht
N-2: Airway Heights - Garden Springs 115 kV and Garden Springs - Westside 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	109.48	ht
N-1: Nine Mile - Westside 115 kV Open @ WES	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	109.35	ht
N-1: Nine Mile - Westside 115 kV Open @ NMS	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	109.33	hs
BF: A470 Westside 115 kV, College & Walnut-Westside	AIRWAYHT (48009) -> GARDENSP (48131) CKT 1 at AIRWAYHT	109.32	ht
N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	109.26	hs
N-1: Nine Mile - Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	109.19	hs
N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	109.14	ht
BF: A413 Westside 115 kV, Ninemile-Westside	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	109.14	ht
BUS: Westside 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	108.26	hs
BF: A470 Westside 115 kV, College & Walnut-Westside	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	107.77	hs
BUS: Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	107.33	ht
BF: A470 Westside 115 kV, College & Walnut-Westside	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	107.06	ht
N-1: Airway Heights - Garden Springs 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	106.74	ht
N-2: Airway Heights - Garden Springs 115 kV and Garden Springs - Westside 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	106.57	ht
PSF: Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	105.42	hs
BF: A413 Westside 115 kV, Ninemile-Westside	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	105.03	hs
N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	104.82	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	104.77	hs
N-1: Airway Heights - Devils Gap 115 kV	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	104.69	ht
BUS: Nine Mile 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	104.5	ht
N-1: Nine Mile - Westside 115 kV Open @ WES	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	104.46	hs
PSF: Nine Mile 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	104.44	ht
BF: A655 Ninemile 115 kV, Ninemile-Westside	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	104.44	ht
PSF: Airway Heights 115 kV	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	104.29	ht
BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	104.29	ht
BUS: Airway Heights 115 kV	NINEMILE (48269) -> INDTRAIL (48164) CKT 1 at NINEMILE	104.1	hs
N-1: Devils Gap - Nine Mile 115 kV	DEVILGPE (48103) -> W.PLAINS (47513) CKT 1 at DEVILGPE	104.04	ht
N-1: Airway Heights - Devils Gap 115 kV Open @ DGP	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	103.57	hs
N-1: Airway Heights - Devils Gap 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	103.4	hs
PSF: Airway Heights 115 kV	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	102.69	hs
BF: A180 Airway Heights 115 kV, Airway Heights-Devils Gap	INDTRAIL (48164) -> WEST (48461) CKT 1 at INDTRAIL	102.69	hs
N-1: Nine Mile - Westside 115 kV Open @ NMS	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	101.58	hs
N-2 (ADJ): Coulee - Westside 230kV and Nine Mile - Westside 115kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	101.48	hs
N-1: Nine Mile - Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	101.45	hs
N-1: Airway Heights - Devils Gap 115 kV Open @ AIR	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	100.72	ht
BUS: Westside 115 kV	W.PLAINS (47513) -> AIRWAYHT (48009) CKT 1 at W.PLAINS	100.42	hs
BUS: Airway Heights 115 kV	DEVILGPE (48103) -> NINEMILE (48269) CKT 1 at DEVILGPE	100.32	ht

Project Alternatives; $19.7 million

The level of generation requested at Long Lake can be integrated with the following projects:

1. Construct a new 115 kV transmission line between Reardan and Silver Lake
    a. Build a new 3 position 115 kV station at Reardan; $4 million
    b. Build a new 4 position 115 kV station at Silver Lake; $5 million
    c. Construct 18 miles of 115 kV transmission line with a minimum summer rating of 138 MVA between the new stations; $7.56 million
2. Rebuild 15.7 miles of existing 115 kV transmission line to minimum summer rating of 205 MVA; $3.14 million

Monroe Street

Monroe Street 80 MW; $7 million

This request involves adding 80 MW at Monroe Street, which is modeled in this study as a single generator at Post Street station as shown in Figure 12.

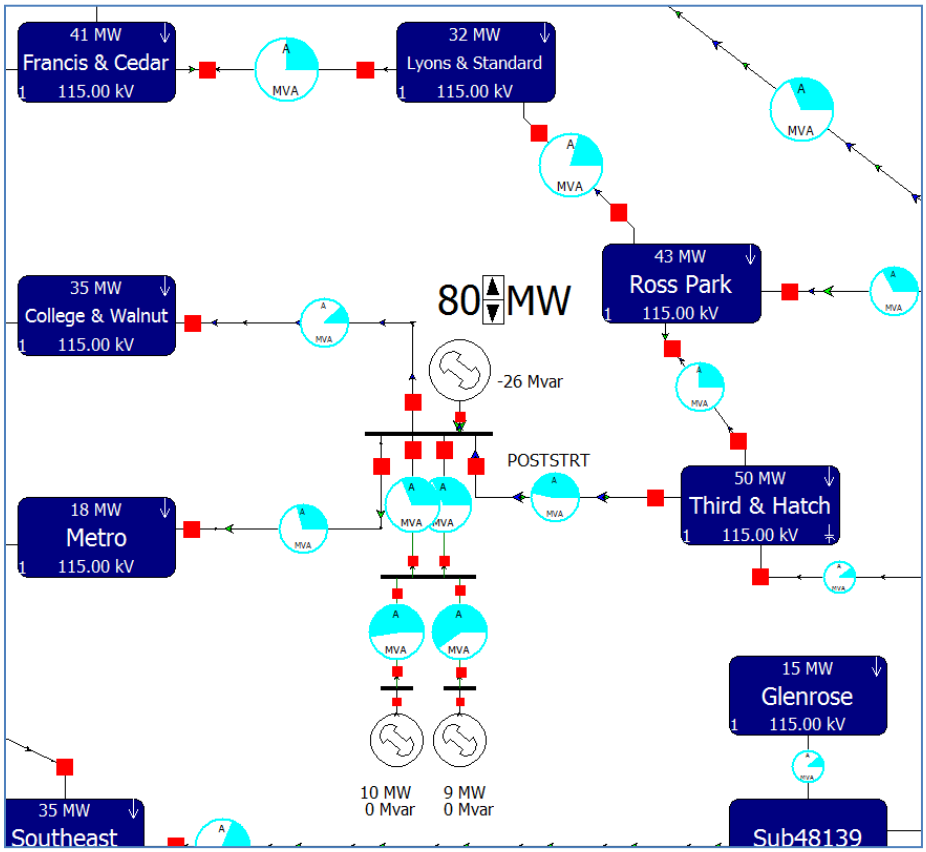

FIGURE 12: MONROE STREET GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 80 MW without issue.

For performance during contingencies, Table 21 shows results from the ATC analysis. No new facility violations were discovered for the requested generation.

TABLE 21: ATC RESULTS FOR MONROE STREET GENERATION REQUEST

Case	Trans Lim	Limiting Element	Limiting CTG	%OTDF
hs	146.85	Line POSTSTRT (48339) TO THIRHACH (48431) CKT 1 [115.00 - 115.00 kV]	PSF: Sunset 115 kV	72.49
hs	148.05	Line POSTSTRT (48339) TO THIRHACH (48431) CKT 1 [115.00 - 115.00 kV]	BUS: Metro 115 kV	72.82
hs	148.65	Line POSTSTRT (48339) TO THIRHACH (48431) CKT 1 [115.00 - 115.00 kV]	N-1: Metro - Post Street 115 kV	72.82
hs	151.06	Line POSTSTRT (48339) TO THIRHACH (48431) CKT 1 [115.00 - 115.00 kV]	N-1: Metro - Sunset 115 kV	72.82
hs	157.62	Line POSTSTRT (48339) TO THIRHACH (48431) CKT 1 [115.00 - 115.00 kV]	BUS: Sunset 115 kV	72.49
hs	194.06	Line METRO (48225) TO SUNSET (48421) CKT 1 [115.00 - 115.00 kV]	N-1: Post Street - Third & Hatch 115 kV	60.99
hs	208.98	Line METRO (48225) TO SUNSET (48421) CKT 1 [115.00 - 115.00 kV]	BUS: Third & Hatch 115 kV	60.85
hs	243.87	Line METRO (48225) TO POSTSTRT (48339) CKT 1 [115.00 - 115.00 kV]	N-1: Post Street - Third & Hatch 115 kV	-60.99
hs	246.2	Line METRO (48225) TO POSTSTRT (48339) CKT 1 [115.00 - 115.00 kV]	BUS: Third & Hatch 115 kV	-60.85
ht	281.68	Line SPKWASTE (48409) TO WEST (48461) CKT 1 [115.00 - 115.00 kV]	BUS: Post Street 115 kV	-41.32

Project Alternatives

While the study connected the new generation at Post Street station, this is not a feasible POI. The POI for this request would be chosen as College and Walnut Station, and this would cost an estimated $7 million

Post Falls

Post Falls 10 to 22 MW; $2.1 to $5.2 million

This request involves adding from 10 to 22 MW at Post Falls, which is modeled in this study as a single generator at Post Falls 115 kV bus as shown in.

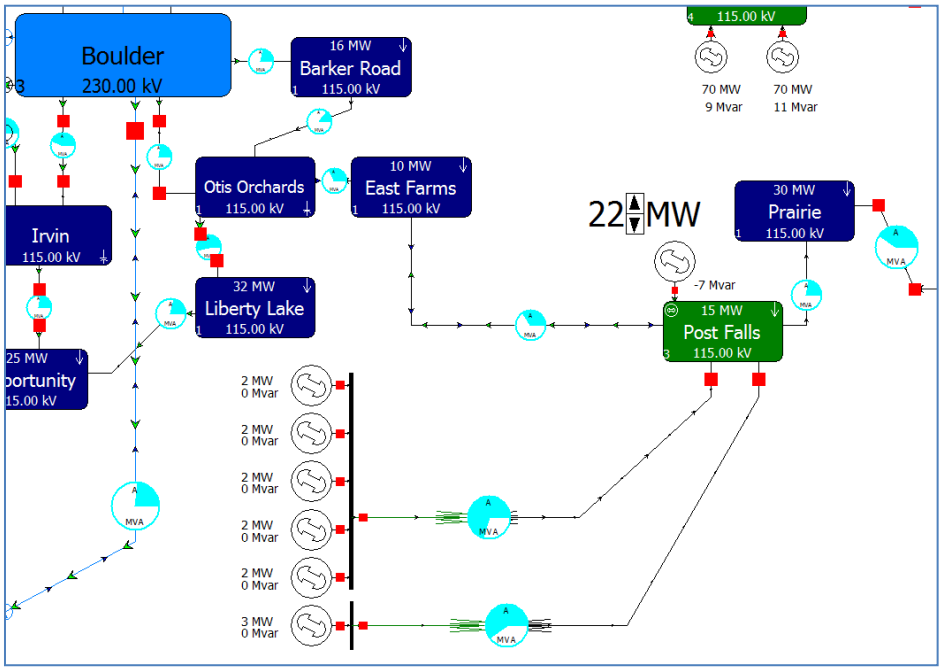

FIGURE 13: POST FALLS GENERATION REQUEST; 2024 HEAVY SUMMER CASE

Analysis

For P0 conditions, both study cases received generation up to 22 MW without issue.

For performance during contingencies, two 115 kV transmission line segments present issues:

- 10 MW request; East Farms – Post Falls 115 kV segment overloads
- 22 MW request; Otis Orchards – Post Falls 115 kV Transmission Line overloads

Project Alternatives

- 10 MW Request - rebuild East Farms – Post Falls line to minimum summer rating of 160 MVA for $2.01 million
- 22 MW Request – above project in addition to rebuilding the Otis Orchard – Post Falls 115 kV Transmission Line to minimum summer rating of 170 MVA for $3.2 million

Appendix A

Future projects included in this analysis

Project Name	Project Scope	Targeted Date of Operation
Chelan - Stratford River Crossing Rebuild Project	Rebuild the Columbia River crossing to 795ACSS to correct Chelan – Stratford line overload	2015
Odessa Capacitor Installation	Install two steps of 13.4 MVAR shunt capacitors for reactive support at Odessa Substation for added restoration capability	2015
Stratford Strain Bus Rebuild Project	Stratford strain bus replacement to relieve existing bottle neck on Stratford - Larson line within the Stratford Substation	2015
Ninth and Central – Sunset 115 kV Line Reconductoring	Reconductor 1.97 miles of limiting 250 CU conductor with 795AAC conductor with minimum thermal capacity rating of 150 MVA at 40C.	2016
Benton – Othello SS 115 kV Transmission Line Rebuild	Reconductor Avista's 26 mile section of the Benton – Othello Switching Station 115 kV Transmission Line with 795 ACSS with a minimum thermal capacity of 205MVA at 40C.	2016
Spokane Valley Transmission Reinforcement	A comprehensive project that includes: 1) Replace 4.37 miles of 556 AAC conductor with 150 MVA capacity or better conductor. 2) Rebuild Millwood, 20 MVA Transformers & 4 Feeders. Normally Open (SCADA controlled switch) provides Back-Up service for IEP Load. 3) New Irvin Switching Station, breaker & a half, 6 line termination with 2 future line terminations, distribution facilities per Distribution Engineering Group, one 33.5 MVAr capacitor bank with space for one future capacitor bank, 4) Replace 1.74 miles of 4/0 ACSR conductor with 150 MVA capacity or better conductor. 5) Convert Opportunity to a Switching Station (single bus, single breaker). 6) New 2.19 miles Single Circuit 150 MVA (IEP Tap). Possible double circuit with Irvin-Opportunity 115 kV Line.	2016
Addy – Devil's Gap 115 kV Transmission Line	Reconductor 5.19 miles (rebuild between Ford and Long Lake Tap) of limiting conductor which consist of 266.8 ACSR and 397.5 ACSR conductor resulting in a capacity limitation of 71.5 MVA at 40C, to be rebuilt to a capacity of 150 MVA at 40C	2017

Project Name	Project Scope	Targeted Date of Operation
Noxon Reactors Installation	Install two steps of 50 MVAR shunt reactors for reactive support at Odessa Substation for high voltages	2017
Sandcreek-Bronx-Cabinet Rebuild	Bronx - Cabinet Rebuild from Cabinet to Clark Fork with 795 ACSS	2017
Coeur d'Alene - Pine Creek 115 Rebuild	Coeur d'Alene - Pine Creek 115 Rebuild replace with 795 conductor and operate closed	2018
Hallett & White – Silver Lake 115 kV Transmission Line Rebuild	The transmission line will be rebuilt with 795 ACSR conductor with minimum thermal capacity of 150 MVA at 40C	2018
Westside Transformer phase 1	Westside Transformer Replacement Project includes a new 250 MVA Westside No.1 230/115 kV Transformer installation which was identified in the 2013 Planning Assessment to be implemented by 2018 for an N-1 contingency (Westside No.2 230/115 kV outage)	2018
Garden Springs 115 Station	Garden Springs 115 kV station -Loops the existing Airway Height - Sunset line into Garden Springs -Includes rebuild of Sunset - Westside from GDN to SUN with 795	2019
Roxboro-Warden Rebuild	The Lind – Warden 115 kV Transmission Line is 21 miles long, and is constructed primarily with 7#8 CU conductor resulting in a capacity limit of 57 MVA at 40C. Rebuild to 795 ACSS with aminimum of 150 MVA thermal capacity at 40C.	2020
Westside Transformer phase 2	Remove Westside Transformers 1 and 2 and replace with a new 250 MVA Transformer.	2020

Appendix B

New facility violations for Kootenai 350 MW request

Label	Element	Percent	Case
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	138.25	hs
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	134.6	hs
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	130.67	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	127.9	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	124.08	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	123.57	hs
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	121.95	ht
N-1: Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	121.42	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	121.16	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	120.41	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	120.19	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	119.82	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	119.73	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	119.58	ht
N-1: Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	118.9	ht
BF: R427 Beacon North & South 230 kV	SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	118.86	hs
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	118.14	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	117.36	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	117.2	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.91	ht
N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	115.77	hs
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	115.38	hs
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	114.84	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.8	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.62	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.55	ht
N-2: Beacon - Boulder 230 kV & Boulder - Irvin #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	114.15	hs
N-1: Lancaster - Rathdrum 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	113.6	ht
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	113.53	ht
N-1: Beacon - Boulder 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	113.26	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	113.03	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	112.69	hs
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.93	ht
N-1: Beacon - Kootenai 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	111.76	ht
BUS: Beacon North 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	111.71	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	111.67	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	110.91	hs
N-2 (ADJ): Beacon - Boulder #2 115 kV and Beacon - Ninth & Central #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	110.78	hs
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	110.66	ht
PSF: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	110.59	ht
N-1: Lancaster - Rathdrum 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	110.58	ht
BF: A600 Beacon North & South 115 kV	OPPORTUN (48299) -> CHESTER (48069) CKT 1 at CHESTER	109.39	hs
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	109.18	hs
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	109.16	hs
N-1: Opportunity - Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	109.13	ht
N-1: Boulder - Lancaster 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	109.13	ht
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	108.94	ht
N-1: Beacon - Kootenai 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	108.92	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.9	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	108.68	ht
N-2: Beacon - Boulder 230 kV & Beacon - Irvin #1 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	108.48	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	108.16	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.06	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.89	ht
N-2 (ADJ): Bell - Coulee #6 500 kV and Bell - Creston 115 kV	WEST (48463) -> WESTBPA2 (41276) CKT 1 at WESTBPA2	107.8	ht
N-1: Boulder - Lancaster 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	107.74	hs
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.69	ht
BF: A667 Ramsey 115 kV, Appleway-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	107.57	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum #1	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	107.51	ht
BF: A717 Boulder East & West 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.31	ht
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	107.07	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	107.05	ht

BF: R427 Beacon North & South 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.95	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OPT	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.89	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.89	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.88	hs
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	106.85	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	106.78	ht
N-1: Post Falls - Ramsey 115 kV Open @ RAM	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.72	ht
BUS: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.67	ht
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.61	hs
N-2 (STR): Post Falls - Ramsey 115 kV & Ramsey - Rathdrum #1 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.31	ht
BF: 4122 Bell-Taft, Hot Springs-Taft	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.28	ht
BF: R452 Beacon-Boulder, Boulder #2 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.77	ht
N-1: Boulder - Irvin #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.72	hs
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.57	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.54	hs
BF: A211 Post Falls 115 kV, Post Falls-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.37	ht
N-1: Post Falls - Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.37	ht
BF: A669 Ramsey 115 kV, Post Falls-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.34	ht
BUS: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.29	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.16	ht
BF: R552 Beacon-Boulder, Boulder #1 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.04	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.02	ht
BF: A506 Rathdrum 115 kV, Pine Street-Rathdrum	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	104.87	hs
PSF: Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	104.86	ht
PSF: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.75	ht
BUS: Rathdrum East 115 kV	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	104.72	hs
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.5	hs
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	104.3	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	104.04	ht
BUS: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.02	hs
N-1: Beacon - Kootenai 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.89	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	103.84	ht
BUS: Beacon North 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.84	ht
BF: R427 Beacon North & South 230 kV	LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11	103.83	ht
N-1: Bell - Coulee #6 500 kV	WEST (48463) -> WESTBPA2 (41276) CKT 1 at WESTBPA2	103.79	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	103.76	ht
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11	103.71	ht
N-2 (ADJ): Beacon - Francis & Cedar 115kV and Bell - Coulee #6 500kV	WEST (48463) -> WESTBPA2 (41276) CKT 1 at WESTBPA2	103.68	ht
N-1: Boulder - Lancaster 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	103.58	ht
BUS: Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.25	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ PF	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.24	ht
N-1: Post Falls - Ramsey 115 kV Open @ PF	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.24	ht
PSF: Ramsey 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.97	ht
BF: A641 Otis Orchards 115 kV, Opportunity-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.88	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	102.85	ht
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.8	ht
BF: A688 Ninth & Central North & South 115 kV	ROSSPARK (48371) -> THIRHACH (48431) CKT 1 at ROSSPARK	102.78	hs
N-1: Otis Orchards - Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.75	ht
BF: A324 Post Falls 115 kV, Otis Orchards-Post Falls	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.73	ht
BF: 4119 Bell-Taft, Garrison-Taft #1	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.67	ht
BF: AXXX Bell S0 & S1 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.6	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	102.43	ht
N-1: Bell - Taft 500 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.35	ht
N-2 (STR): Bell - Coulee #3 230 kV & Bell - Westside 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.21	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	102.12	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	102.05	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ OTI	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.94	ht
BF: AXXX Irvin - IEP 115 kV, Boulder - Irvin #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.84	ht
N-1: Lancaster - Rathdrum 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	101.55	ht
N-1: Bell - Westside 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.48	ht
BF: R427 Beacon North & South 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	101.46	ht
PSF: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.46	hs
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	101.35	ht
BF: R476 Benewah-Moscow 230, Benewah 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.1	ht
N-2: Ninth & Central - Opportunity 115 kV & Opportunity - Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.09	ht
BF: A388 Bell S2 & S3 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.95	ht
BUS: Boulder West 115 kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	100.85	hs
N-1: Beacon - Kootenai 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.84	ht

N-2 (ADJ): Bell - Coulee #6 500kV and Bell - Westside 230kV	FRANCEDR (48127) -> NORTHWES (48279) CKT 1 at FRANCEDR	100.81	ht
BUS: Beacon North 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.8	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.74	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	100.74	hs
BF: A638 Rathdrum 115 kV, Appleway-Rathdrum	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	100.6	hs
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.41	hs
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	IRVIN (48165) -> MILLWOOD (48237) CKT 1 at IRVIN	100.4	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.37	ht
N-2 (ADJ): Bell - Taft 500 kV and Lancaster - Noxon 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.31	ht
BF: A370 Bell S1 & S2 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	100.16	ht
BF: R427 Beacon North & South 230 kV	IRVIN (48165) -> MILLWOOD (48237) CKT 1 at IRVIN	100.1	ht

Appendix C

New facility thermal violations for Rathdrum 200 MW request; 115 kV option

Label	Element	Percent	Case
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	146.18	hs
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	134.09	hs
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	133.17	hs
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	131.81	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	130.46	hs
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	129.6	hs
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	126.81	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	126	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	125.09	ht
N-1: Boulder - Lancaster 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	123.81	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	123.54	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	123.32	ht
PSF: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	123.28	ht
BF: R400 Kootenai-Rathdrum, Rathdrum #2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	123.14	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	123.03	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	122.08	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	121.53	ht
BF: R500 Kootenai-Rathdrum, Rathdrum #1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	120.97	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	120.23	hs
BF: A667 Ramsey 115 kV, Appleway-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	120.22	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum #1	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	120.16	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	119.38	ht
BUS: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	119.31	ht
N-1: Post Falls - Ramsey 115 kV Open @ RAM	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	119.29	ht
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	119.22	hs
N-2 (STR): Post Falls - Ramsey 115 kV & Ramsey - Rathdrum #1 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	119	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	118.79	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	118.16	ht
BF: A669 Ramsey 115 kV, Post Falls-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	118	ht
N-1: Lancaster - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	117.96	ht
N-1: Post Falls - Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	117.96	ht
BF: A211 Post Falls 115 kV, Post Falls-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	117.78	ht
PSF: Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	117.28	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	117	ht
BUS: Beacon North 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	116.72	ht
N-1: Beacon - Kootenai 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	116.6	ht
N-1: Kootenai - Rathdrum 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	116.58	ht
N-1: Post Falls - Ramsey 115 kV Open @ PF	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.87	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	115.86	ht
PSF: Ramsey 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	115.76	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.76	hs
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.73	hs
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.72	ht
BUS: Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.69	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	115.45	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ PF	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.43	ht
BF: R400 Kootenai-Rathdrum, Rathdrum #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	115.29	ht
BF: A324 Post Falls 115 kV, Otis Orchards-Post Falls	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	115.2	ht
N-1: Otis Orchards - Post Falls 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.95	ht
N-1: Boulder - Lancaster 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.52	hs
BF: A717 Boulder East & West 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	114.42	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ OTI	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	114.15	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	113.66	ht
N-2 (STR and ADJ): Beacon - Boulder 230 kV & Beacon - Boulder #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	113.38	hs
BF: R500 Kootenai-Rathdrum, Rathdrum #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	113.13	ht
N-1: Boulder - Lancaster 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	113.12	ht
BF: R427 Beacon North & South 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	112.91	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	112.87	ht
PSF: Ramsey 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	112.81	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	LANCASTR (40624) -> BELLAN11 (90011) CKT 1 at BELLAN11	112.74	ht
BF: A667 Ramsey 115 kV, Appleway-Ramsey	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	112.71	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum #1	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	112.64	ht

N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	112.58	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	112.57	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	112.41	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	112.4	ht
BF: R400 Kootenai-Rathdrum, Rathdrum #2 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	112.26	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	112.15	ht
BUS: Ramsey 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.8	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.8	ht
N-1: Post Falls - Ramsey 115 kV Open @ RAM	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.72	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	111.72	ht
BUS: Otis Orchards 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	111.59	ht
N-2: Beacon - Boulder 230 kV & Boulder - Irvin #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	111.53	hs
N-2 (STR): Post Falls - Ramsey 115 kV & Ramsey - Rathdrum #1 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.45	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	111.34	ht
BUS: Beacon South 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	111.31	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	111.2	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	POST FLS (48329) -> EASTFARM (48117) CKT 1 at POST FLS	110.91	ht
BF: A641 Otis Orchards 115 kV, Opportunity-Otis Orchards	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	110.82	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	110.72	ht
PSF: Otis Orchards 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	110.71	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	110.63	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	110.55	ht
BF: A669 Ramsey 115 kV, Post Falls-Ramsey	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	110.51	ht
N-1: Post Falls - Ramsey 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	110.4	ht
N-2 (ADJ): Beacon - Boulder 230kV and Beacon - Boulder #1 115kV	BOULDERE (48522) -> IRVIN (48165) CKT 1 at BOULDERE	110.25	ht
BF: A211 Post Falls 115 kV, Post Falls-Ramsey	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	110.24	ht
N-1: Lancaster - Rathdrum 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	110.18	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	BELLAN11 (90011) -> BELL S3 (40090) CKT 1 at BELLAN11	110.16	ht
BF: R500 Kootenai-Rathdrum, Rathdrum #1 230/115 Transformer	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	110.1	ht
BF: A506 Rathdrum 115 kV, Pine Street-Rathdrum	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	110.08	hs
BF: R427 Beacon North & South 230 kV	SPKINDPK (48405) -> IRVIN (48165) CKT 1 at IRVIN	110.04	hs
BUS: Rathdrum East 115 kV	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	109.93	hs
N-2 (ADJ): Beacon - Boulder #2 115 kV and Beacon - Ninth & Central #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	109.81	hs
PSF: Post Falls 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	109.75	ht
BF: A667 Ramsey 115 kV, Appleway-Ramsey	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	109.75	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum #1	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	109.69	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	109.12	ht
BUS: Beacon North 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	109.03	ht
N-1: Beacon - Boulder 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	108.94	ht
N-1: Beacon - Kootenai 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.9	ht
N-1: Kootenai - Rathdrum 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.89	ht
N-1: Rathdrum #2 230/115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	108.88	ht
BUS: Ramsey 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.85	ht
N-1: Benewah - Pine Creek 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	108.83	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	108.83	hs
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.83	ht
N-1: Post Falls - Ramsey 115 kV Open @ RAM	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.75	ht
N-2 (STR): Post Falls - Ramsey 115 kV & Ramsey - Rathdrum #1 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.49	ht
BF: R474 Benewah-Pine Creek, Benewah 230/115 Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	108.43	ht
N-1: Post Falls - Ramsey 115 kV Open @ PF	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.33	ht
BF: A1561 Boulder-Lancaster, Lancaster Generator #1 & #2	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	108.23	ht
PSF: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	108.2	hs
BUS: Post Falls 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.17	ht
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	108.03	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ PF	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	107.93	ht
N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	107.77	ht
N-2 (STR): Beacon - Kootenai 230 kV & Boulder - Lancaster 230 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	107.77	hs
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.76	hs
BF: A324 Post Falls 115 kV, Otis Orchards-Post Falls	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	107.68	ht
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.63	hs
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	107.58	ht
BF: A669 Ramsey 115 kV, Post Falls-Ramsey	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	107.57	ht
BF: A720 Boulder East 115 kV, Boulder-Rathdrum	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.54	ht
PSF: Boulder East 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	107.54	ht
N-1: Otis Orchards - Post Falls 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	107.45	ht
N-1: Post Falls - Ramsey 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	107.44	ht
BF: A211 Post Falls 115 kV, Post Falls-Ramsey	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	107.28	ht
BF: A600 Beacon North & South 115 kV	OPPORTUN (48299) -> CHESTER (48069) CKT 1 at CHESTER	107.21	hs

N-1: Lancaster - Rathdrum 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	107.17	ht
N-1: Boulder - Lancaster 230 kV	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	107.16	ht
PSF: Post Falls 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	106.79	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ OTI	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	106.67	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	EASTFARM (48117) -> OTIS (48311) CKT 1 at EASTFARM	106.64	ht
N-1: Opportunity - Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.61	ht
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.6	ht
N-2 (ADJ): Beacon - Kootenai 230kV and Bell - Lancaster 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	106.54	ht
N-1: 3TM Bell - Boundary #1 230 kV Open @ BELL	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.48	ht
N-2 (STR): Kootenai - Rathdrum 230 kV & Lancaster - Rathdrum 230 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	106.46	hs
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	106.43	ht
N-2 (STR): Hot Springs - Noxon #1 230 kV & Hot Springs - Noxon #2 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	106.29	ht
N-2 (STR): Boulder - Lancaster 230 kV & Boulder - Rathdrum 115 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	106.26	hs
BUS: Beacon North 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	106.03	ht
N-1: Beacon - Kootenai 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.9	ht
N-1: Kootenai - Rathdrum 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.89	ht
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	RATHDRMW (48355) -> IDAHO_RD (48161) CKT 1 at RATHDRMW	105.88	ht
BF: A638 Rathdrum 115 kV, Appleway-Rathdrum	RATHDRMW (48355) -> HUETTER (48159) CKT 1 at HUETTER	105.83	hs
N-2 (ADJ): Kootenai - Rathdrum 230kV and Lancaster - Noxon 230kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.66	ht
BUS: Boulder East 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	105.59	ht
BF: AXXX Bell S0 & S1 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.46	ht
N-1: Post Falls - Ramsey 115 kV Open @ PF	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.37	ht
BUS: Pine Creek 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.34	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.27	hs
N-1: Rathdrum #1 230/115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	105.26	ht
BF: R427 Beacon North & South 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	105.26	ht
BUS: Post Falls 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.22	ht
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.12	hs
N-1: Opportunity - Otis Orchards 115 kV Open @ OTI	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	105.08	hs
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	105.03	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ PF	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	104.99	ht
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	104.94	ht
N-1: Boulder - Irvin #2 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.82	hs
BF: A324 Post Falls 115 kV, Otis Orchards-Post Falls	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	104.74	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	104.71	ht
BF: A370 Bell S1 & S2 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	104.58	ht
N-1: Otis Orchards - Post Falls 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	104.51	ht
N-2: Beacon - Boulder 230 kV & Beacon - Irvin #1 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.44	ht
BF: R400 Kootenai-Rathdrum, Rathdrum #2 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	104.43	ht
N-1: Opportunity - Otis Orchards 115 kV Open @ OPT	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	104.38	ht
BF: A1184 Lancaster-Noxon, Lancaster-Rathdrum	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	104.27	ht
N-2 (ADJ): Bell - Taft 500 kV and Bell - Lancaster 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	104.17	ht
BUS: Otis Orchards 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.91	ht
BF: R408 Lancaster-Rathdrum, Rathdrum #2 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	103.84	ht
N-1: Otis Orchards - Post Falls 115 kV Open @ OTI	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	103.73	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.71	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	103.67	ht
BUS: Bell S2 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.53	ht
N-2 (STR): Boulder - Boulder Park 115 kV & Boulder - Rathdrum 115 kV (8)	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	103.48	ht
BF: R400 Kootenai-Rathdrum, Rathdrum #2 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	103.45	ht
BF: A668 Ramsey 115 kV, Ramsey-Rathdrum #1	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	103.14	hs
BF: A641 Otis Orchards 115 kV, Opportunity-Otis Orchards	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.14	ht
BF: R500 Kootenai-Rathdrum, Rathdrum #1 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	103.09	ht
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.04	ht
PSF: Otis Orchards 115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	103.04	ht
BF: 4122 Bell-Taft, Hot Springs-Taft	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.97	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.88	hs
BF: R452 Beacon-Boulder, Boulder #2 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.76	ht
N-1: Boulder - Rathdrum 115 kV Open @ RAT	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	102.7	ht
N-1: Bell - Usk 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.69	ht
BF: R554 Boulder-Lancaster, Boulder #1 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.68	hs
BF: R454 Boulder-Lancaster, Boulder #2 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	102.65	hs
BF: R500 Kootenai-Rathdrum, Rathdrum #1 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	102.49	ht
BF: A374 Bell S1 230 kV, Bell-Boundary #1	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.44	ht
BF: R427 Beacon North & South 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.41	hs
BUS: Bell S1 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.41	ht
N-1: 3TM Bell - Boundary #1 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.41	ht
BUS: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.4	hs

BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.35	ht
BF: R427 Beacon North & South 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	102.28	ht
BF: R508 Lancaster-Rathdrum, Rathdrum #1 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	102.24	ht
N-2 (ADJ): Beacon - Bell #4 230kV and Beacon - Kootenai 230kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.23	ht
N-1: Beacon - Kootenai 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.22	ht
BF: 4148 Garrison-Taft #2, Hot Springs-Taft	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.19	ht
N-1: Kootenai - Rathdrum 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.19	ht
BF: 4122 Bell-Taft, Hot Springs-Taft	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.19	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.14	hs
BF: A667 Ramsey 115 kV, Appleway-Ramsey	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	102.07	hs
BUS: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	102.07	ht
N-2 (STR): Bell - Coulee #3 230 kV & Bell - Westside 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.97	ht
N-2 (STR): Beacon - Boulder 230 kV & Beacon - Kootenai 230 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	101.95	ht
BF: R552 Beacon-Boulder, Boulder #1 230/115 Transformer	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.9	ht
N-1: Ramsey - Rathdrum #1 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.9	ht
BF: A958 Bell-Usk, Usk 230/115 kV Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.89	ht
BUS: Beacon North 230 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.86	hs
BF: A953 Boundery-Usk, Usk 230/115 kV Transformer	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.84	ht
N-1: Boulder #1 230/115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.83	ht
BF: A642 Otis Orchards 115 kV, Otis Orchards-Post Falls	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	101.7	ht
N-1: Bell - Westside 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.62	ht
N-1: Ramsey - Rathdrum #1 115 kV Open @ RAT	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.55	ht
PSF: Otis Orchards 115 kV	BOULDERW (48520) -> SPKINDPK (48405) CKT 1 at BOULDERW	101.54	ht
N-1: Boulder - Lancaster 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.52	hs
N-1: Boulder - Rathdrum 115 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	101.41	ht
N-2 (ADJ): Bell - Boundary #1 230 kV and Bell - Boundary #3 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.34	ht
N-1: Benewah - Pine Creek 230 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.32	ht
BUS: Ramsey 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.28	hs
N-1: Coeur d'Alene 15th St - Rathdrum 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.22	ht
N-1: Ramsey - Rathdrum #1 115 kV Open @ RAM	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	101.17	ht
N-1: Rathdrum #2 230/115 kV	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	101.1	ht
BF: A717 Boulder East & West 115 kV	RAMSEY (48349) -> PRAIRIEB (40855) CKT 1 at RAMSEY	101.01	hs
N-1: Boulder #2 230/115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.94	ht
BF: R474 Benewah-Pine Creek, Benewah 230/115 Transformer	PLEASANT (48319) -> MOAB (47511) CKT 1 at PLEASANT	100.92	ht
BUS: Otis Orchards 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.9	ht
N-1: Hot Springs - Noxon #1 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.87	ht
BF: B1145 Addy 115 kV, Addy-Kettle Falls	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.86	ht
N-1: Hot Springs - Noxon #2 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.84	ht
N-1: Hot Springs - Noxon #1 230 kV Open @ HOTS	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.82	ht
N-1: Appleway - Rathdrum 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.79	ht
N-2 (STR): Appleway - Ramsey 115kV and Coeur d'Alene - Ramsey 115kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.79	ht
N-1: Hot Springs - Noxon #1 230 kV Open @ NOX	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.78	ht
N-2 (STR): Bell - Boundary #3 230 kV & Addy - Bell 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.77	ht
BF: A1558 Bell-Lancaster, Lancaster-Rathdrum	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.74	ht
N-1: 3TM Bell - Boundary #3 230 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.59	ht
BUS: Addy 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.58	ht
N-1: Benewah - Pine Creek 230 kV	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.55	ht
BF: A688 Ninth & Central North & South 115 kV	ROSSPARK (48371) -> THIRHACH (48431) CKT 1 at ROSSPARK	100.55	hs
N-1: Albeni Falls - Sacheen 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.5	ht
N-1: 3TM Bell - Boundary #3 230 kV Open @ BOUN	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.5	ht
BF: B323 Sacheen 115 kV, Albeni Falls-Sacheen	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.49	ht
N-1: Albeni Falls - Sacheen 115 kV Open @ ALB	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.49	ht
BF: A521 Devils Gap East 115 kV, Addy-Devils Gap	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.46	ht
BF: A540 Devil's Gap East & West 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.46	ht
BUS: Devils Gap East 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.46	ht
BF: A506 Rathdrum 115 kV, Pine Street-Rathdrum	HUETTER (48159) -> HERN (48155) CKT 1 at HERN	100.44	hs
N-1: Appleway - Rathdrum 115 kV Open @ RAT	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.42	ht
BF: B1137 Addy 115 kV, Addy-Devils Gap	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.34	ht
BUS: Rathdrum East 115 kV	HUETTER (48159) -> HERN (48155) CKT 1 at HERN	100.29	hs
BF: A526 Devils Gap East 115 kV, Airway Heights-Devils Gap	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.26	ht
PSF: Devils Gap East 115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.26	ht
BF: A1186 Lancaster-Noxon, Boulder-Lancaster	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.25	ht
N-1: Sacheen 230/115 kV	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.22	ht
BF: R474 Benewah-Pine Creek, Benewah 230/115 Transformer	PRAIRIEB (40855) -> POST FLS (48329) CKT 1 at PRAIRIEB	100.17	ht
N-1: Albeni Falls - Sacheen 115 kV Open @ SACH	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.17	ht
N-1: Appleway - Rathdrum 115 kV Open @ APW	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.14	ht
BF: A641 Otis Orchards 115 kV, Opportunity-Otis Orchards	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.14	ht
BF: B1135 Addy 115 kV, Addy-Bell	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.07	ht

N-1: Post Falls - Ramsey 115 kV Open @ RAM	IDAHO_RD (48161) -> PLEASANT (48319) CKT 1 at IDAHO_RD	100.05	hs
BF: A645 Otis Orchards 115 kV, Boulder-Otis Orchards	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.04	ht
PSF: Otis Orchards 115 kV	MOAB (47511) -> BOULDERE (48522) CKT 1 at MOAB	100.04	ht