2020 Electric Integrated Resource Plan Appendices

Table of Contents

2020 Electric Integrated Resource Plan

Appendix A – 2020 Technical Advisory Committee Presentations and Meeting Minutes

2019 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 1 Agenda
Wednesday, July 25, 2018
Conference Room 130

Topic	**Time**	**Staff**
Introductions	9:00	Lyons
TAC Expectations and Process Overview	9:05	Lyons
2017 IRP Acknowledgements & Policies	9:30	Gall
Break	10:15	
Demand and Economic Forecast	10:30	Forsyth
Lunch	12:00	
2017 Action Plan Updates	1:00	Gall
2019 IRP Draft Work Plan	1:30	Lyons
Break	2:15	
Hydro One Merger Agreements	2:30	Gall
Adjourn	3:00	

2019 Electric IRP
TAC Meeting Expectations

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
July 25, 2018

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next two years
- Current and projected load & resource position
- Preferred Resource Strategy (PRS)
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Expected case
- Market and portfolio scenarios for uncertain future events and issues

Integrated Resource Planning (Cont)

- Requires significant modeling and 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, resource type or any particular issue
- 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 topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - January 2019 at the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

Today's Agenda

- 9:00 – Introduction and TAC Expectations and Process Overview, Lyons
- 9:30 – 2017 IRP Acknowledgments and Policies, Gall
- 10:15 – Break
- 10:30 – Demand and Economic Forecast, Forsyth
- 12:00 – Lunch
- 1:00 – 2017 IRP Action Plan Updates, Gall
- 1:30 – 2019 IRP Draft Work Plan
- 2:15 – Break
- 2:30 – Hydro One Merger Agreements, Gall
- 3:00 – Adjourn

TAC Expectations

- Avista:
  - Input about assumptions and areas to study
  - Five TAC meetings with agendas that may change based on input
  - Topics covered later today in the Draft Work Plan

- TAC Members:
  - What are your expectations?
  - Comments or questions about the process

2017 Electric IRP Commission Acknowledgement Update

James Gall, IRP Manager

July 25, 2018

Idaho

- Idaho Commission acknowledged the 2017 IRP on February 1, 2018 in order No. 33971 of AVU-E-17-08.
- Comments were provided by the Commission Staff, Idaho Conservation League (ICL), and 23 members of the public.
- The Commission in this order confirms … *"The appropriate place to determine the prudence of the IRP or the Company's decision to follow or not follow it, and the validation of predicted performance under the IRP, will be a general rate case or another proceeding in which the issue is noticed."*

Specific Idaho Staff Comments (highlights)

- Scenarios should include renewing the Lancaster contract.
- Clearly state how the Company's portfolio complies with the EPA's Clean Power Plan.
- Concern with natural gas prices being "extremely low throughout the entire planning period".
- Failed to provide evidence supporting its claim "that coal price risk is not a significant factor for Colstrip operations."
- Continue analyzing alternatives and cost mitigation strategies for Colstrip.
- Regarding Colstrip, specify significant capital investments required for plant operation and provide a more transparent assessment of the costs and availability of fuel for the plant.

Specific ICL Comments (highlights)

- Asks the Commission to direct Avista to include a "thorough and detailed discussion" in its 2019 IRP, of the policies and financial plans of the utility co-owners of Colstrip Units 3 and 4, and their impact on the cost of producing and distributing electricity from Avista's share of Units 3 and 4.
  - Such discussion should include analysis of provisions in Puget Sound Energy's (PSE) 2017 settlement with the Washington Utilities and Transportation Commission that (1) changed the depreciation schedule for Units 3 and 4 from 2045 to 2027; and (2) allocated $10 million for transition funds to the community of Colstrip.
- Recommends Avista include analysis of Oregon State Bill 1547, directing PGE and PacifiCorp to end distribution of coal-generated electricity in Oregon by 2030.
- Provide a more transparent accounting and explanation" of how Avista's AURORA and PRiSM models work.
- Avista provide a more thorough analysis "of the fuel price of coal at Colstrip and a forecasted range of price volatility over the 20-year timeframe of the 2019 IRP."

Customer Comments in Idaho

- The Commission conducted a public telephone hearing at which 18 people testified, most of whom were Avista customers.
- The hearing participants testified about retiring Colstrip early, switching from coal to renewables, and other environmental concerns.
- The Commission also received 23 written comments.
- Most comments opposed investing in Colstrip, although a few supported it.

Specific Idaho Recommendations

- We note that customers and Staff commented on alternatives regarding the closure of Colstrip and the inclusion in the PRS of a new gas peaker plant after the expiration of the Lancaster agreement.
- We encourage the Company to continue evaluating all options regarding these resources, and to consider the best interests of its customers when developing the 2019 IRP.
- The Commission appreciates the Company's collaboration with stakeholders in developing the 2017 Electric IRP.

Washington 2017 IRP Acknowledgement

- Washington Commission acknowledged the 2017 IRP on May 7, 2018 in Docket No. UE-161036
- It is important that the Commission take this opportunity to thank the members of the public that participated in the Company's Advisory Committee process, commented in the docket, and made oral statements at the public meeting.

- Specific Comments:
  – Colstrip Units 3 & 4
  – Conservation potential assessment
  – Demand response & AMI
  – Forecasted natural gas prices
  – Distribution system upgrade planning
  – Optimal planning reserve margin
  – Update legacy studies
  – Portfolio scenario cost comparison
  – Emissions price modeling and cost abatement supply curve
  – Public Process

Colstrip Comments and Recommendations

1. Regarding fuel source cost and risk:
    a. How dependent is Colstrip on a single-source mine for its fuel?
    b. How well understood is the supply of coal from the Colstrip mine?
        i. What are the financial risks of the type of mining used to extract the existing coal?
        ii. As the need for fuel for Colstrip declines, how does the cost per unit of coal from the Colstrip mine increase?
        iii. What are the counter-party risks of mine operation?
        iv. What risks to coal supply and coal cost does the Joint Colstrip ownership agreement impose? How will Avista manage them?
    c. How does the fuel supply risk from Colstrip compare to that of natural gas?
2. Does Avista have an assessment of the cost related to the counter-party risk of Riverstone ceasing operation of its share of Colstrip Unit 3? If not, why not?
3. Does Avista have an assessment of the cost of the counter-party risk of Riverstone being financially unable or otherwise failing to pay its share of decommissioning and remediation costs for Unit 3?
4. What are the economics of the high-cost scenario under a “low gas” scenario forecast?
5. How are the economics of Colstrip Units 3 & 4 affected if natural gas prices continue to remain relatively flat?
6. What are Avista’s best estimates of remediation and decommissioning costs associated with Colstrip Units 3 & 4?
7. Has the Company quantified capacity replacement costs for Colstrip Units 3 & 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip?
8. What is the risk of the failure of a large cost component of Colstrip Units 3 & 4 (such as: the heat exchangers, steam turbine or drive shafts) over Avista’s expected 20-year life of the plant?

Other Colstrip Recommendations

- Develop a list of events regarding the economic viability of Colstrip
  - For each event identify the cost, probability of occurrence, and cost range
- The 2019 plan should clearly and transparently
  - Identify cost data and discuss in detail the relationship between the range of these input assumptions, portfolio modeling logic, and the output of the modeling, as well as how the Company used such analysis to choose its PRS.

Conservation Potential Assessment

The 2019 IRP must include the following:

1. All conservation measures excluded from the CPA, including those excluded prior to technical potential determination.
2. The rationale for excluding any measure.
3. A description, and source, of Unit Energy Savings data for each measure included in the CPA.
4. An explanation for any differences in economic and achievable potential savings.

- The Company should also share its proposed energy efficiency measure lists with the Conservation Advisory Group prior to completing the CPA.

Demand Response and Advanced Metering Infrastructure (AMI) Project

- The 2017 IRP does not consider the adoption of AMI technology in its energy efficiency or demand response modeling, nor does it demonstrate any potential benefits of deploying AMI.
- The Commission notes that the IRP is also one of the Company's opportunities to develop a record for the future demonstration of prudent resource acquisition.

Forecasted Price of Natural Gas

- The Commission does not expect utilities to predict future natural gas prices with perfect accuracy, acknowledging this exercise is a forecast.
- We expect the utility to question and investigate the facts and reasoning used by the consultants to derive their forecasts, given that past IRPs have included a high-side bias to natural gas prices.
- Avista must ensure its natural gas price forecast represents the most reasonable expectation of the future.

Distribution System Upgrade Planning

- Any analysis of a distribution system upgrade should include consideration of storage options that capture locational benefits associated with the site in question.
- The Commission encourages Avista's use of sub-hourly models in the core IRP development process to identify distribution system enhancements in its next IRP.
- Avista should perform a study to determine ancillary services valuation in the market and use that value to evaluate the cost effectiveness of storage and peaking technologies using intra-hour modeling capabilities.
- Advises Avista to model generic commercially available storage technologies within the IRP, including consideration of efficiency rates, capital cost, operation and maintenance, life cycle costs, and ability to provide non-power supply benefits.

Other Comments and Recommendations

- Optimal Planning Reserve Margin
  - The Commission urges Avista to monitor winter and summer resource adequacy and continue to analyze planning margins, using its loss of load model, and continue to work with the Council to validate and update its requirements while examining additional tools such as Expected Loss of load and Expected Unserved Energy.
- Update Legacy Studies
  - For future IRPs, citations to legacy analysis should be accompanied by a rationale for why the study does not need to be updated.
- Portfolio Scenario Cost Comparison
  - In displaying the costs and risks of a portfolio scenario in its IRP, Avista should prominently display a comparison chart of the present value of revenue requirement of each portfolio scenario along with its associated risk.

Emissions Price Modeling and Cost Abatement Supply Curve

- In future IRPs, Avista should incorporate in its preferred resource strategy the cost of risk of future greenhouse gas regulation in addition to known regulations.
- This cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization.
- We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate.
- Avista should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.
- The Company must also develop a supply curve of emissions abatement measures in its next IRP.

Public Process

- Expect the Company to provide written responses to all Advisory Committee questions submitted to the Company in writing,
- Provide minutes for each Advisory Committee meeting.

Washington IRP Rulemaking

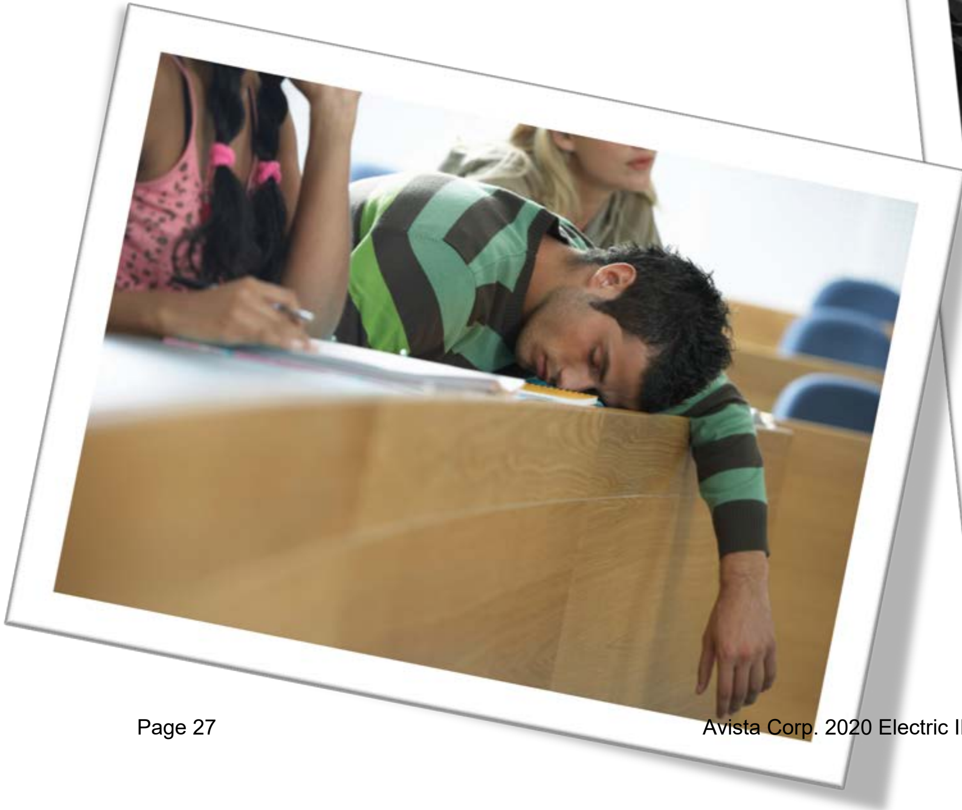
- The Washington Commission opened Docket No. U-161024 on September 2016 to consider the following topics:
  - Energy storage;
  - Requests for proposals;
  - Avoided costs;
  - Transmission and distribution planning;
  - Flexible resource modeling; and
  - General procedural improvements.
- Work has been ongoing for this docket and the process is expected to wrap up before the end of this year.

Load and Economic Forecasts

Grant D. Forsyth, Ph.D.
Chief Economist
First Technical Advisory Committee Meeting
July 25, 2018

Main Topic Areas

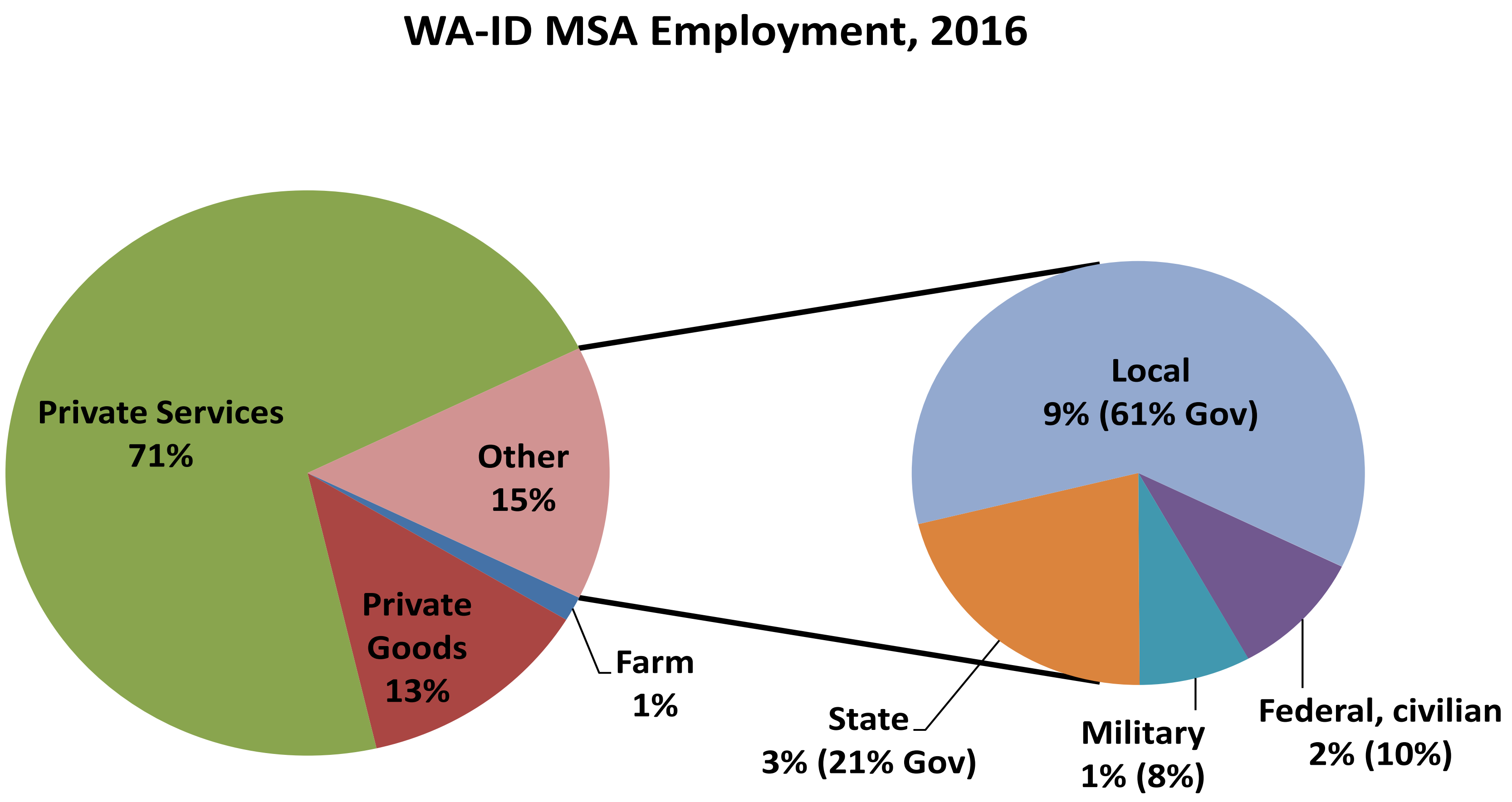
- Service Area Economy
- Peak Load Forecast
- Long-run Forecast



Service Area Economy

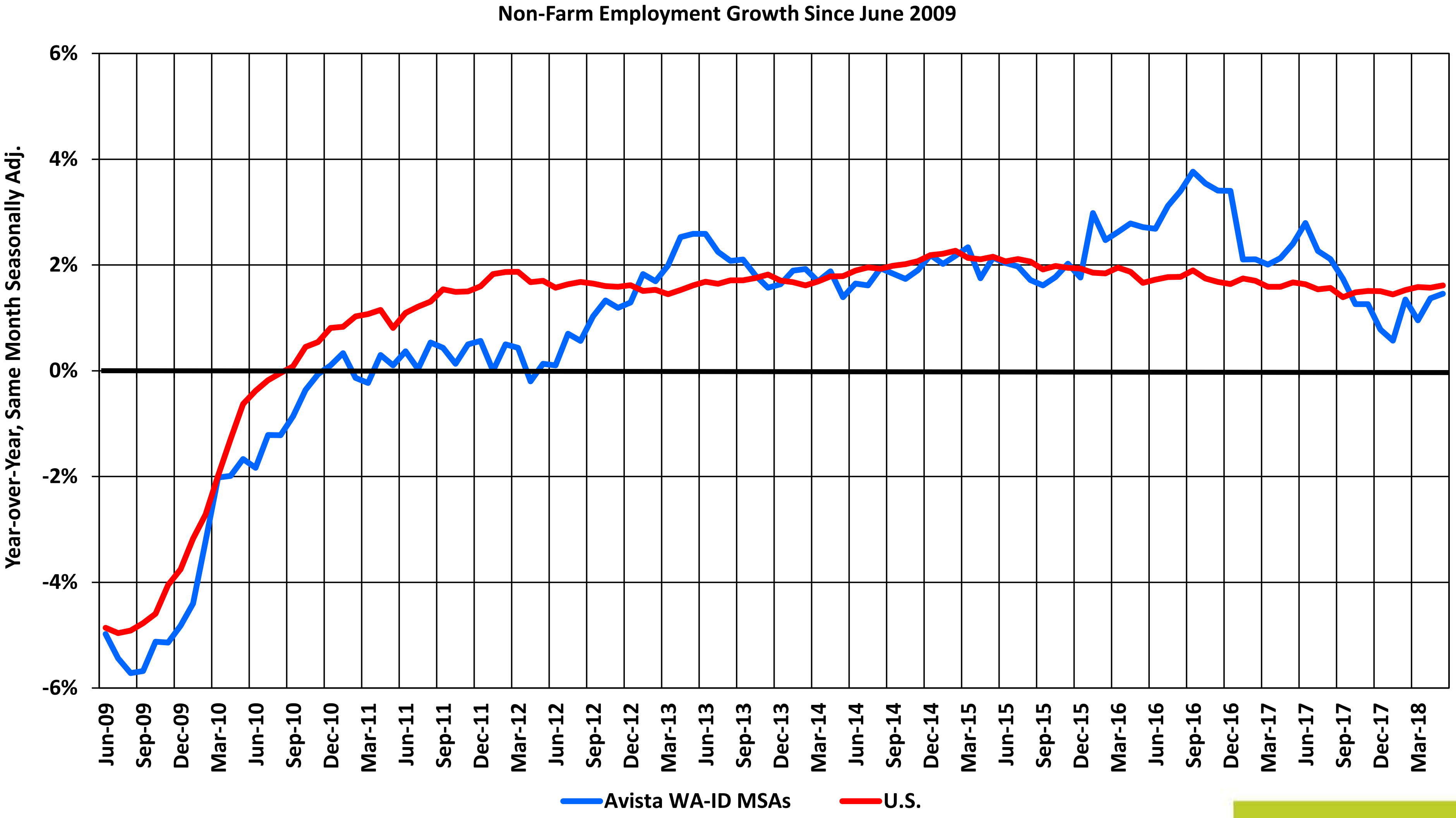
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Distribution of Employment: Services and Government are Dominant



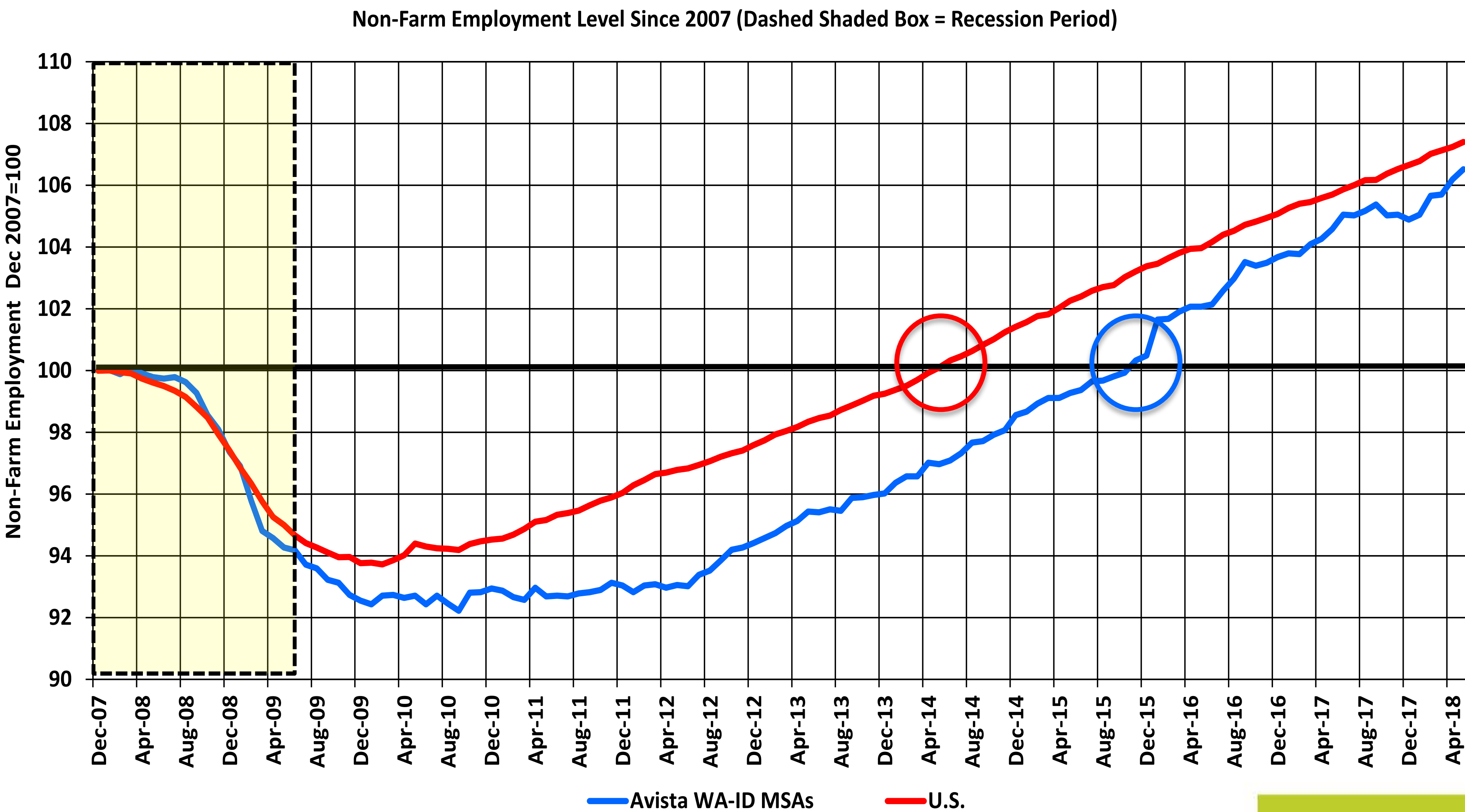
Source: BEA and author's calculations.

Non-Farm Employment Growth, 2009-2018



Source: BLS and author's calculations.

Non-Farm Employment: Finally Catching Up



Source: BLS and author's calculations.

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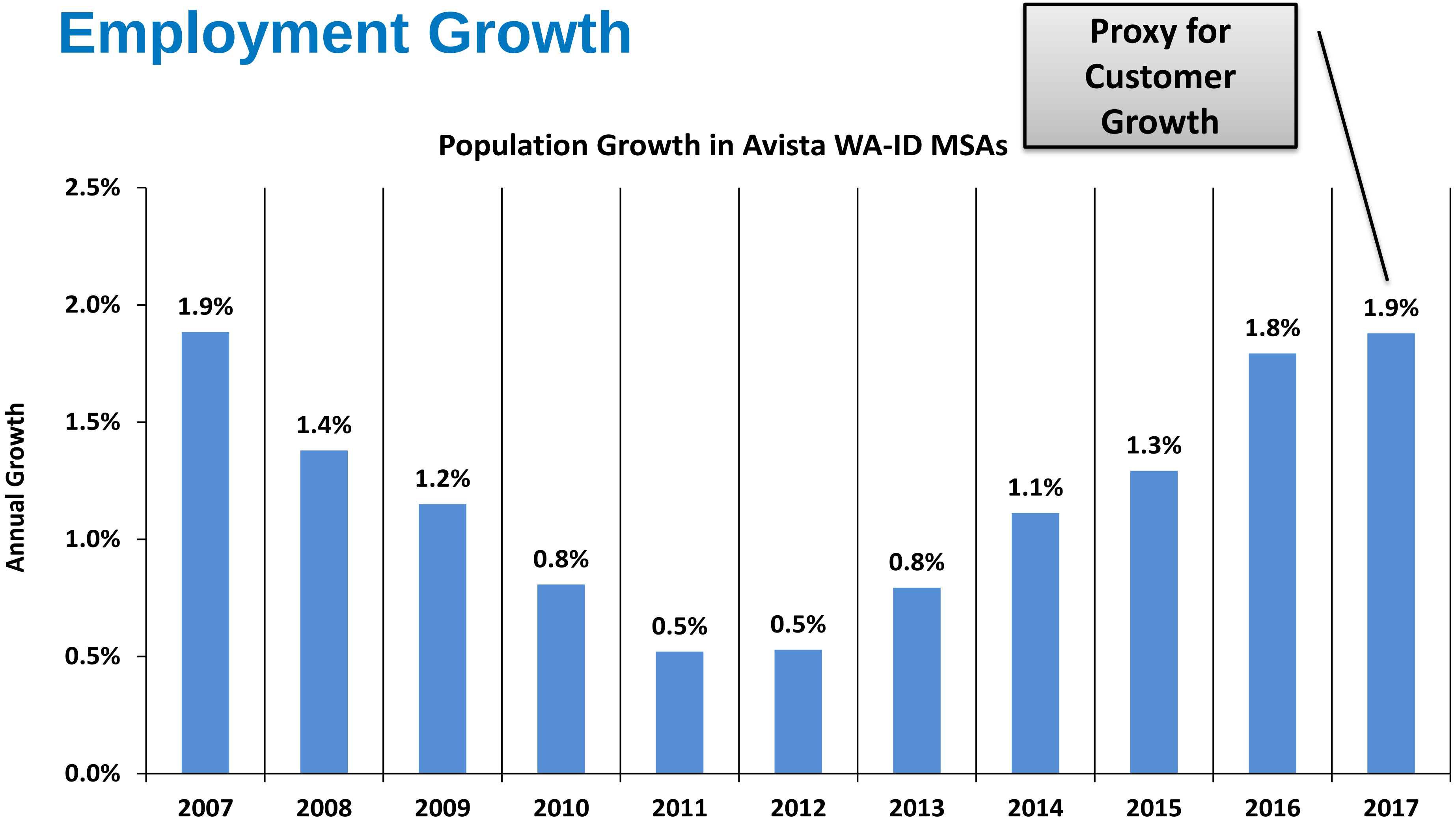
Population Growth: Recovering with Employment Growth



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

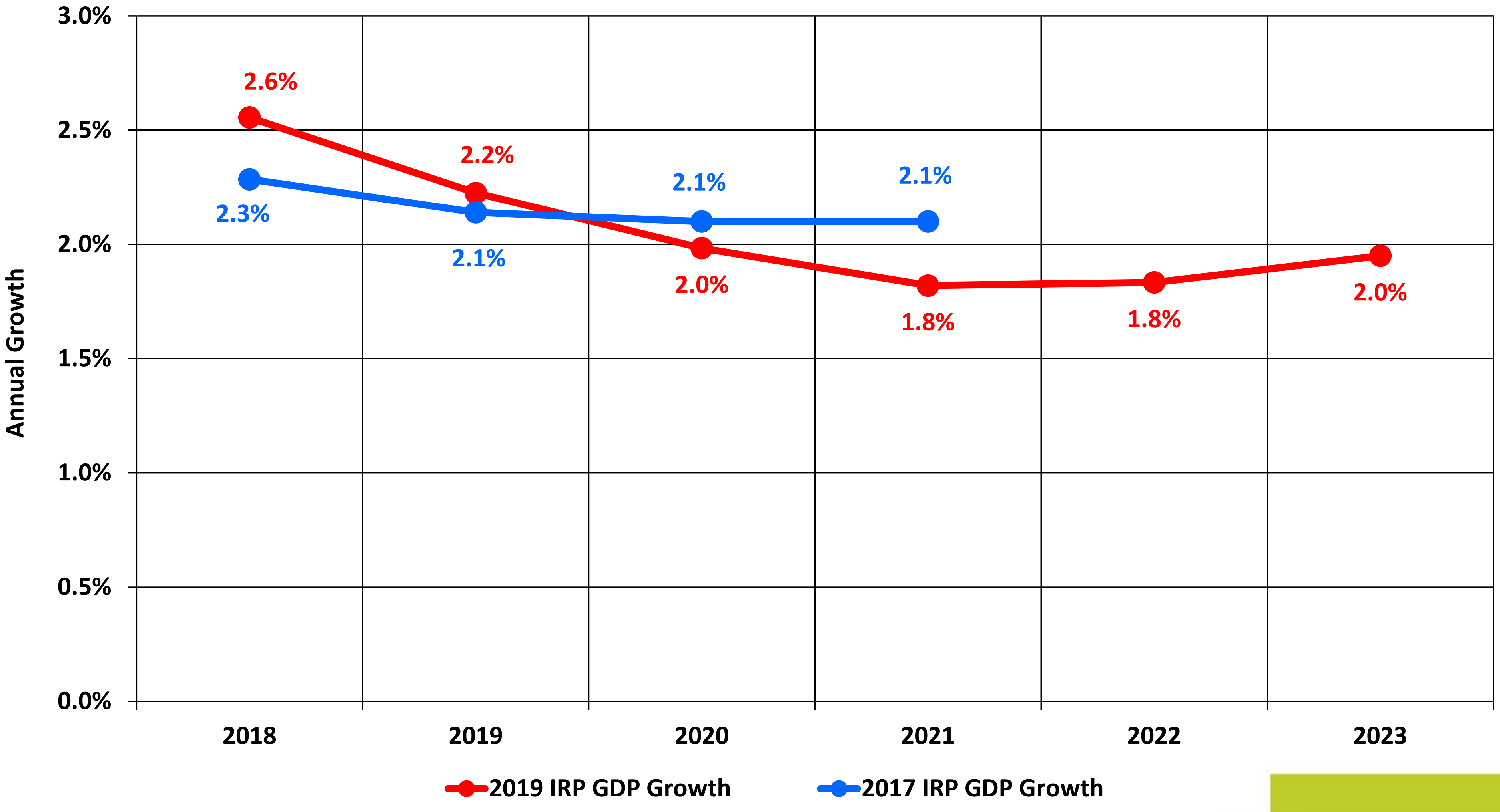
Peak Load Forecast

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

The Basic Model

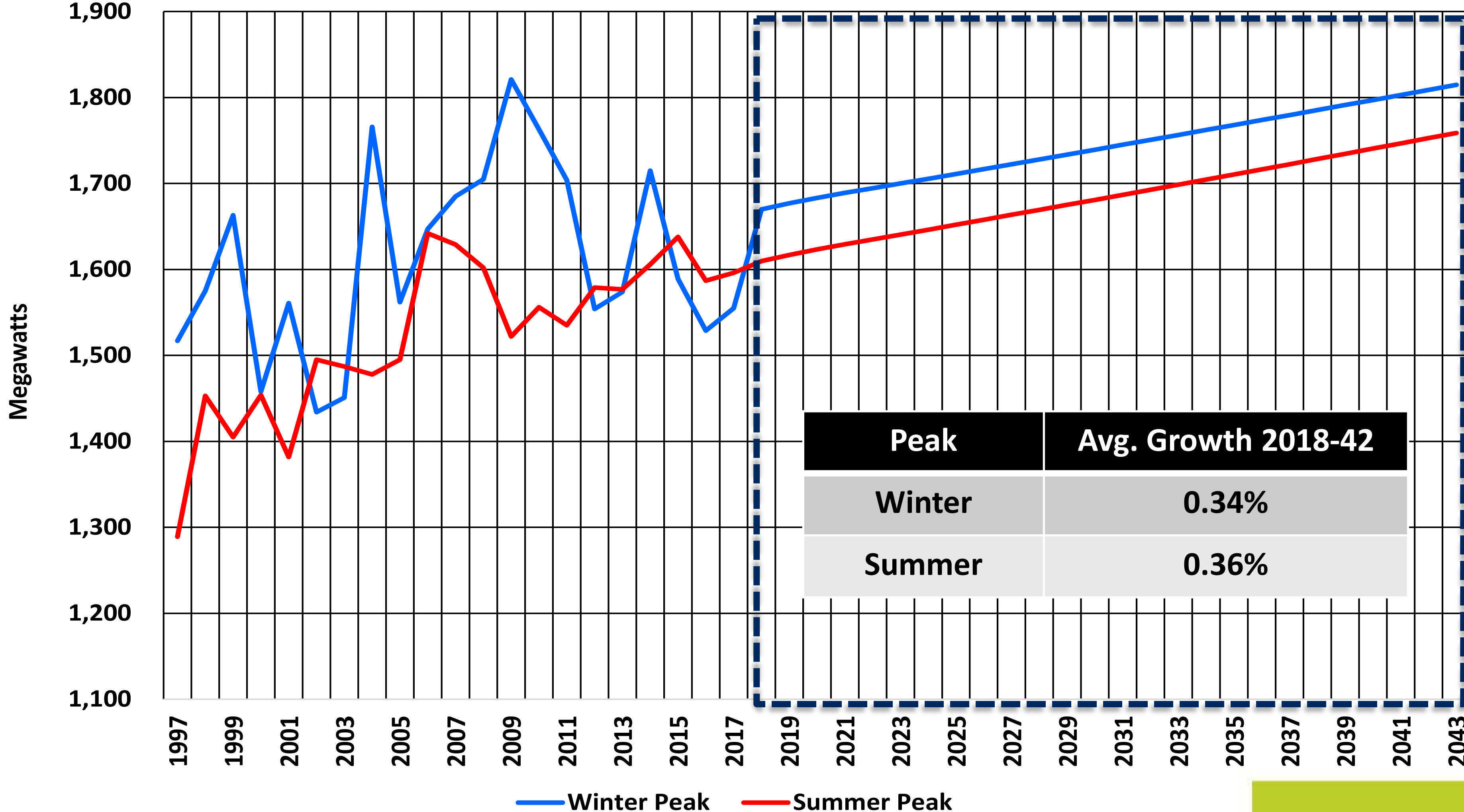
- Monthly time-series regression model that initially excludes certain industrial loads.
- Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.
- Explanatory variables include HDD-CDD and monthly and day-of-week dummy variables. The level of 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., 2016). Model confirms Avista is a winter peaking utility for the forecast period; however, the summer peak is growing at a 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.

GDP Growth Assumptions: 2015 IRP vs. 2017 IRP



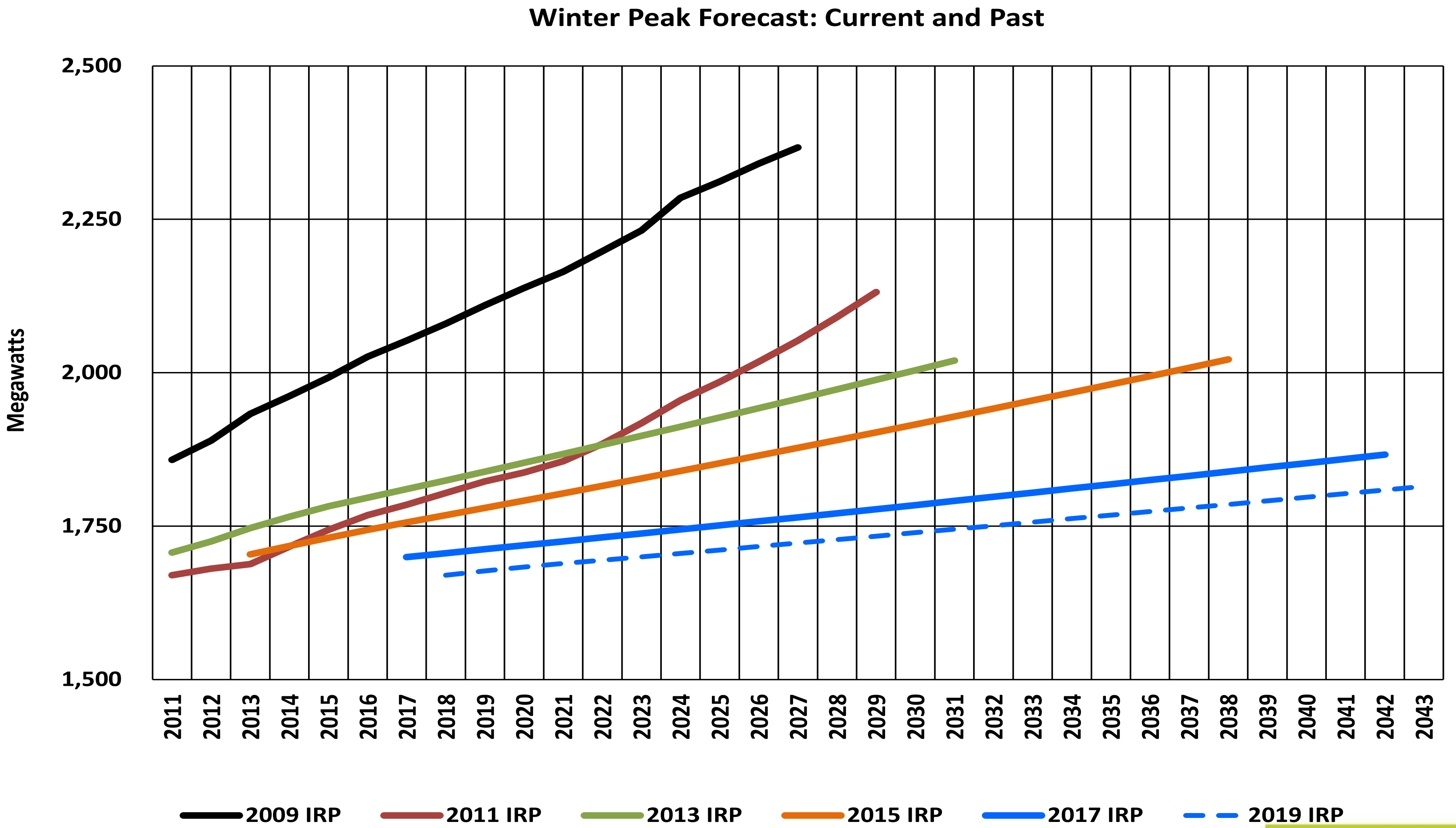
Source: Various and author's calculations.

Current Peak Load Forecasts for Winter and Summer, 2018-2043

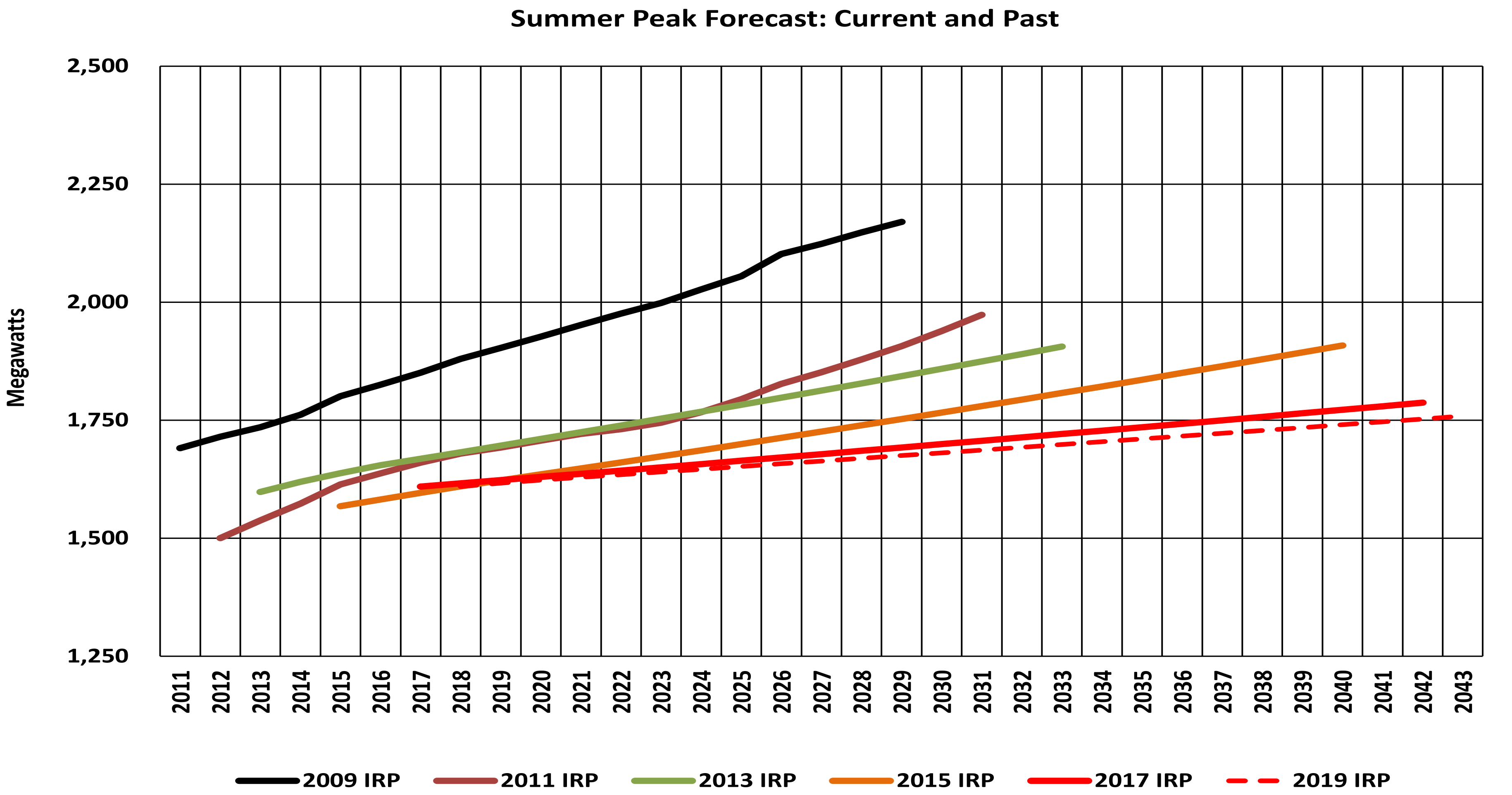


Peak	Avg. Growth 2018-42
Winter	0.34%
Summer	0.36%

Current and Past Peak Load Forecasts for Winter Peak, 2011-2043



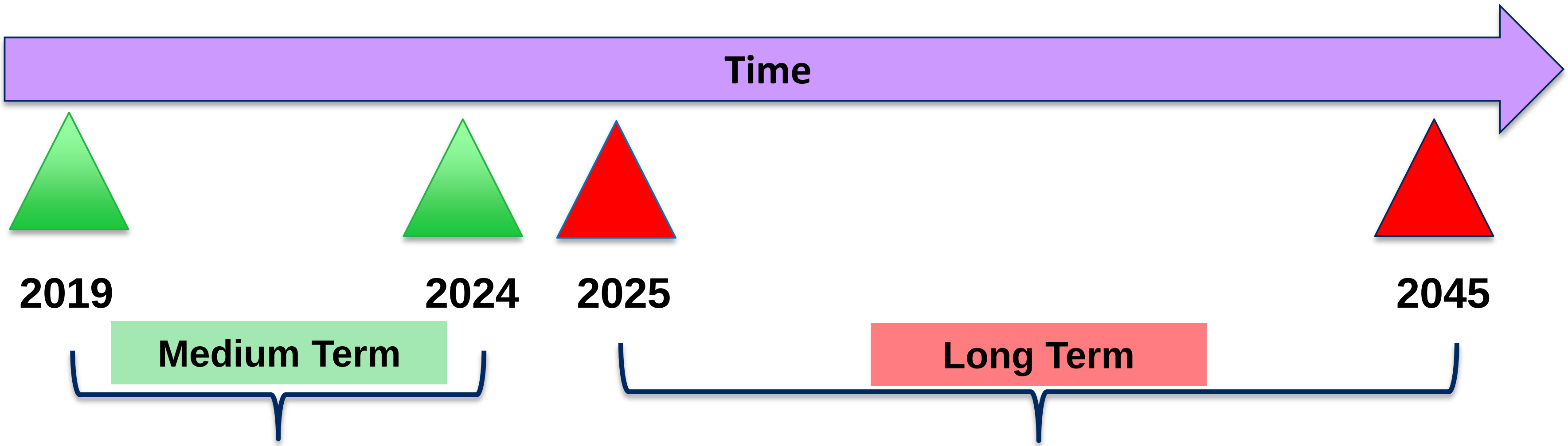
Current and Past Peak Load Forecasts for Summer Peak, 2011-2043



Long-Term Load Forecast

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

Basic Forecast Approach



1) Monthly econometric model by schedule for each class.
2) Customer and UPC forecasts.
3) 20-year moving average for "normal weather."
4) Economic drivers: GDP, industrial production, employment growth, population, price, and ARIMA error correction.
5) 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 and EV/PHEVs.

The Long-Term Residential Relationship, 2020-2040

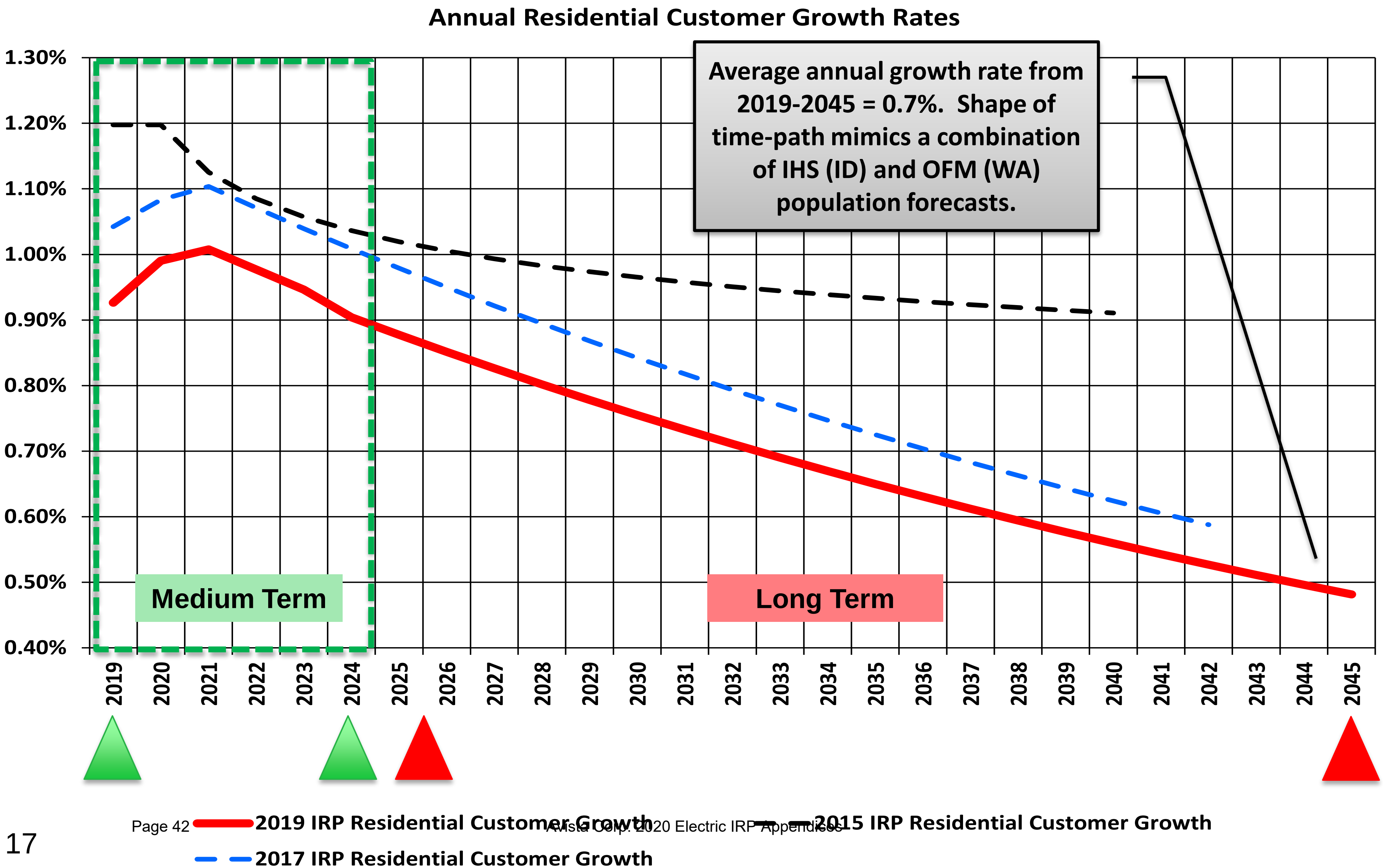
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

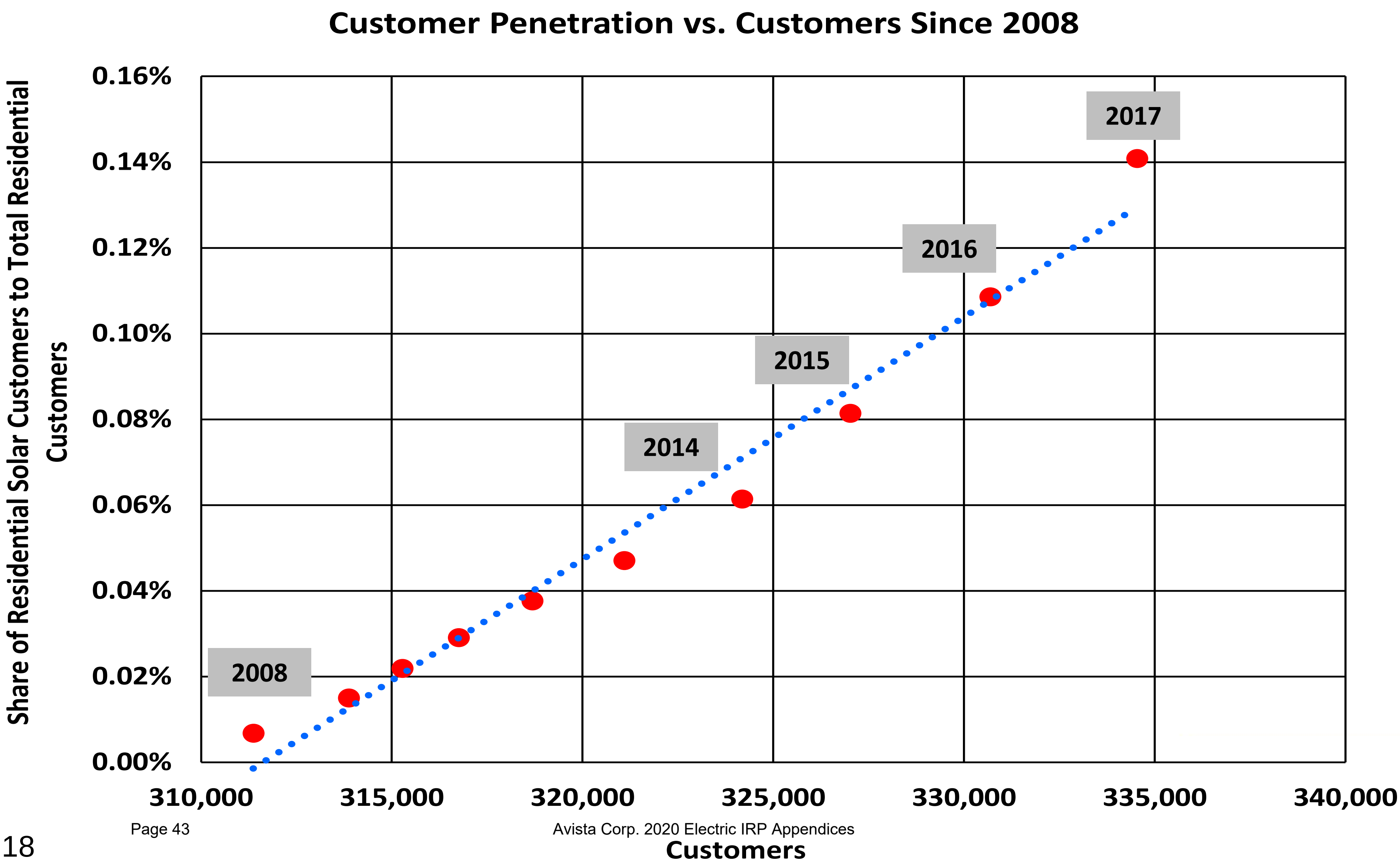
Assumed to be same as population growth, commercial growth will follow residential, and slow decline in industrial.

Assumed to be a function of multiple factors including renewable penetration, gas penetration, and EVs/PHEVs.

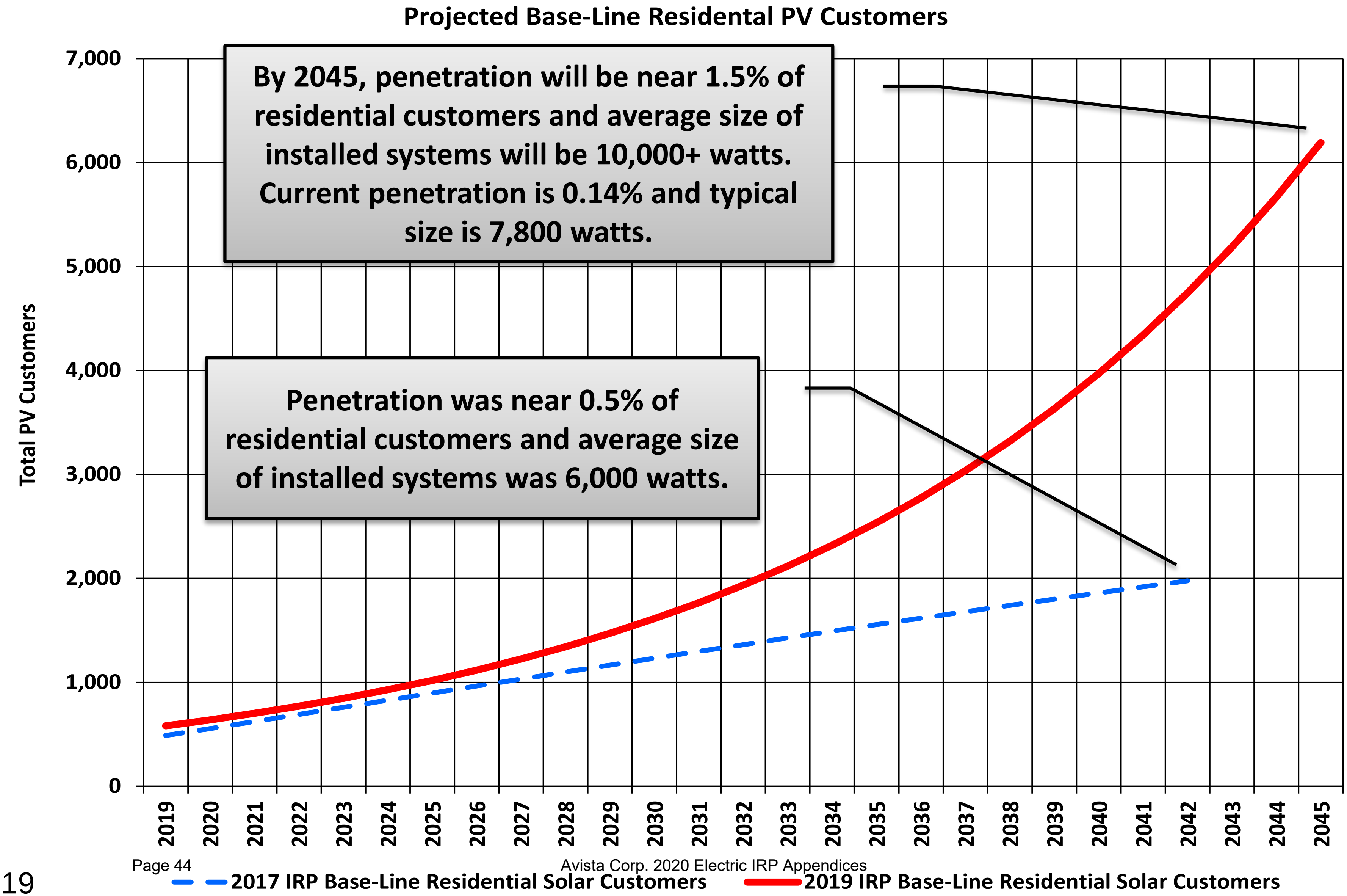
Residential Customer Growth, 2019-2045



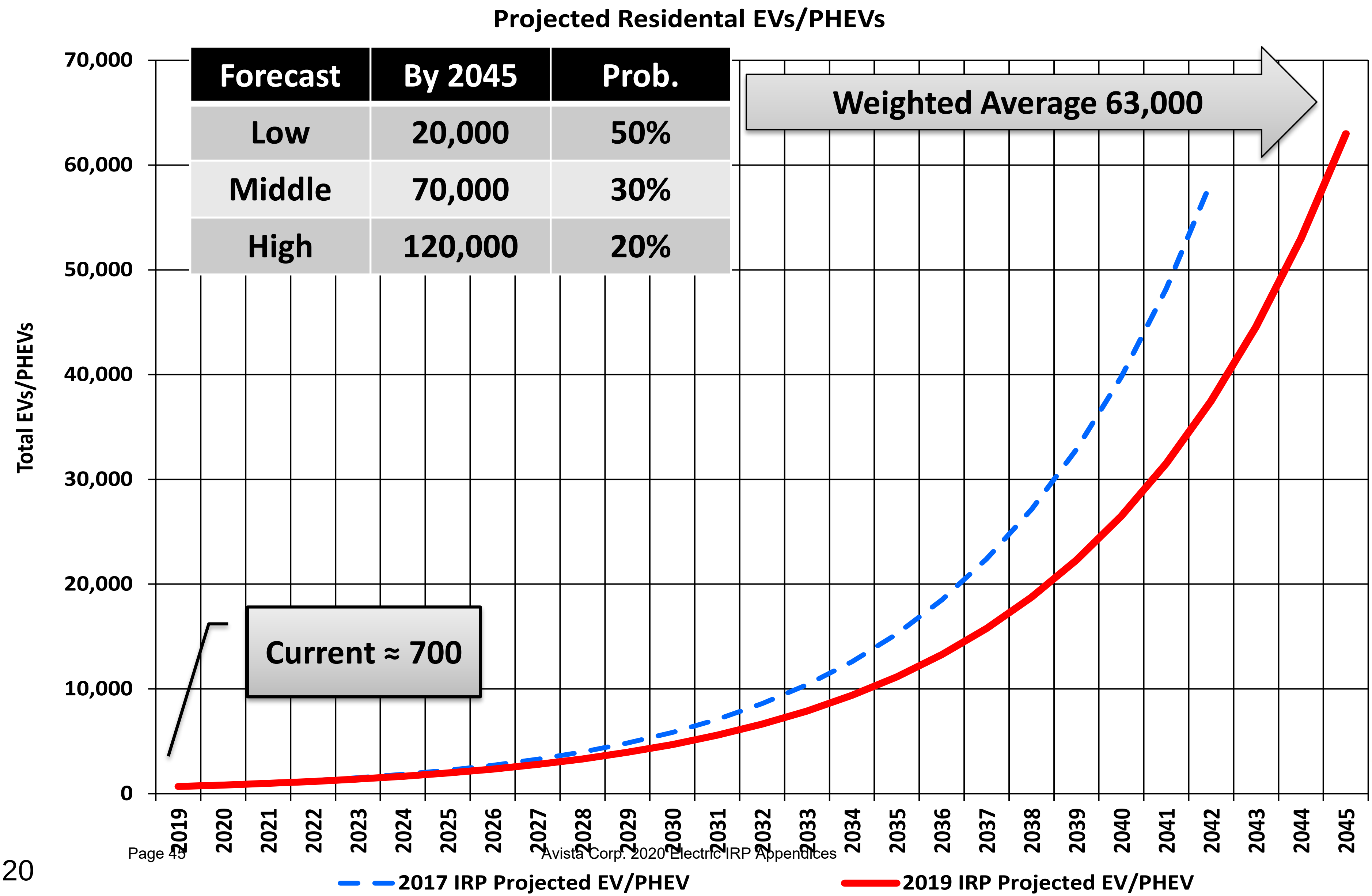
Residential Solar Penetration, 2008-2017



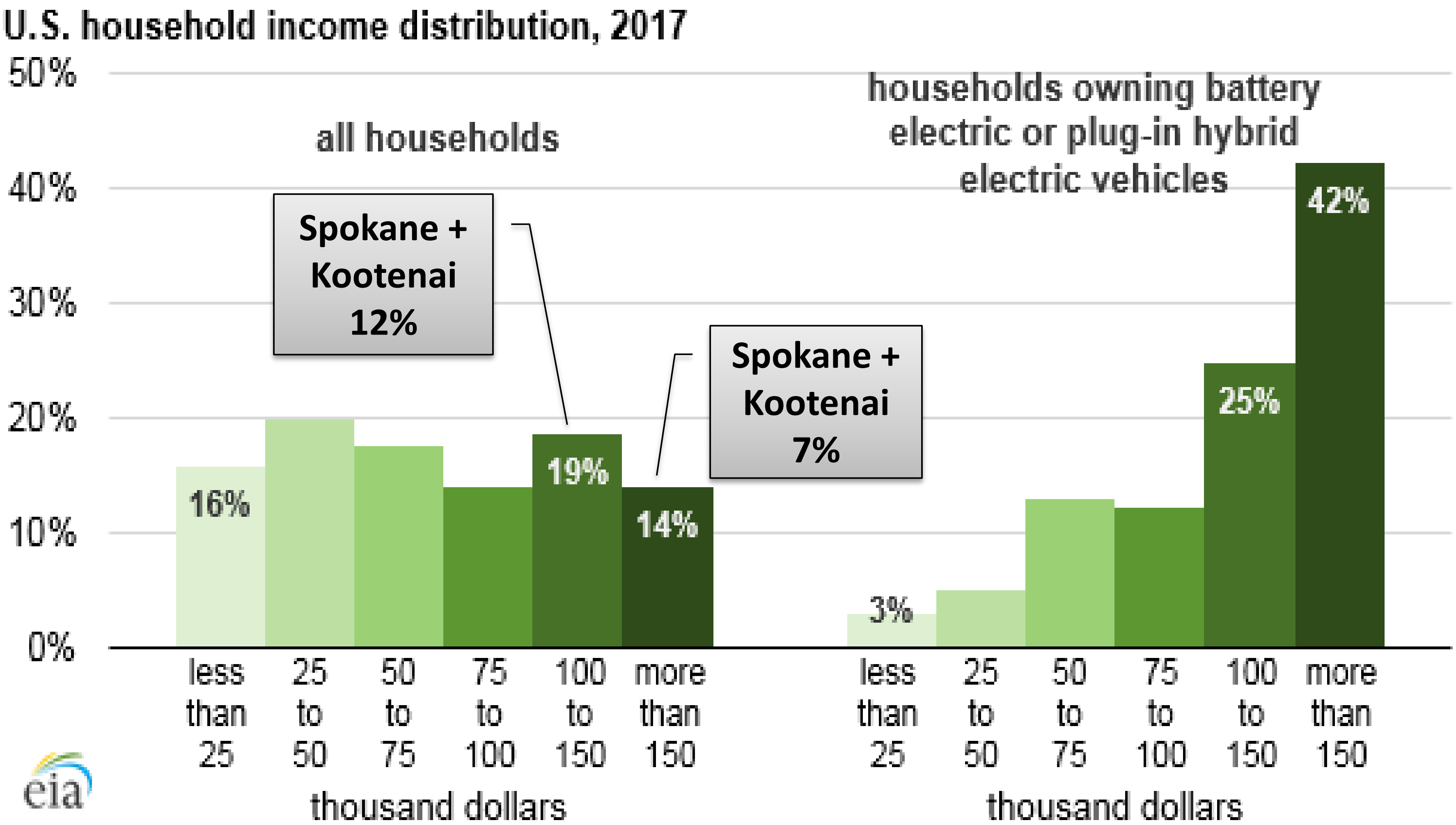
Residential Solar Penetration, 2019-2045



Residential EVs/PHEVs, 2019-2045

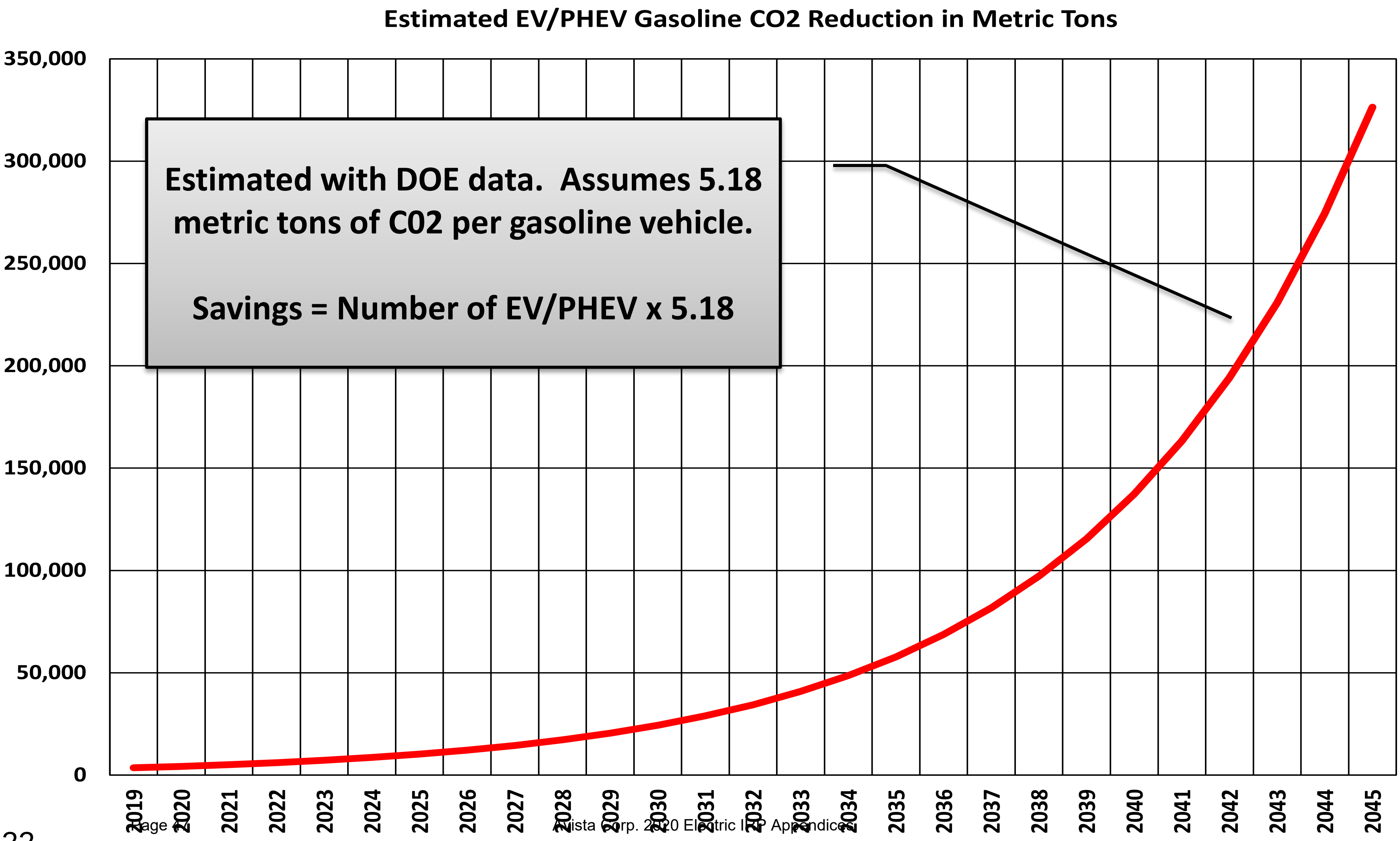


Residential EVs/PHEVs by Household Income

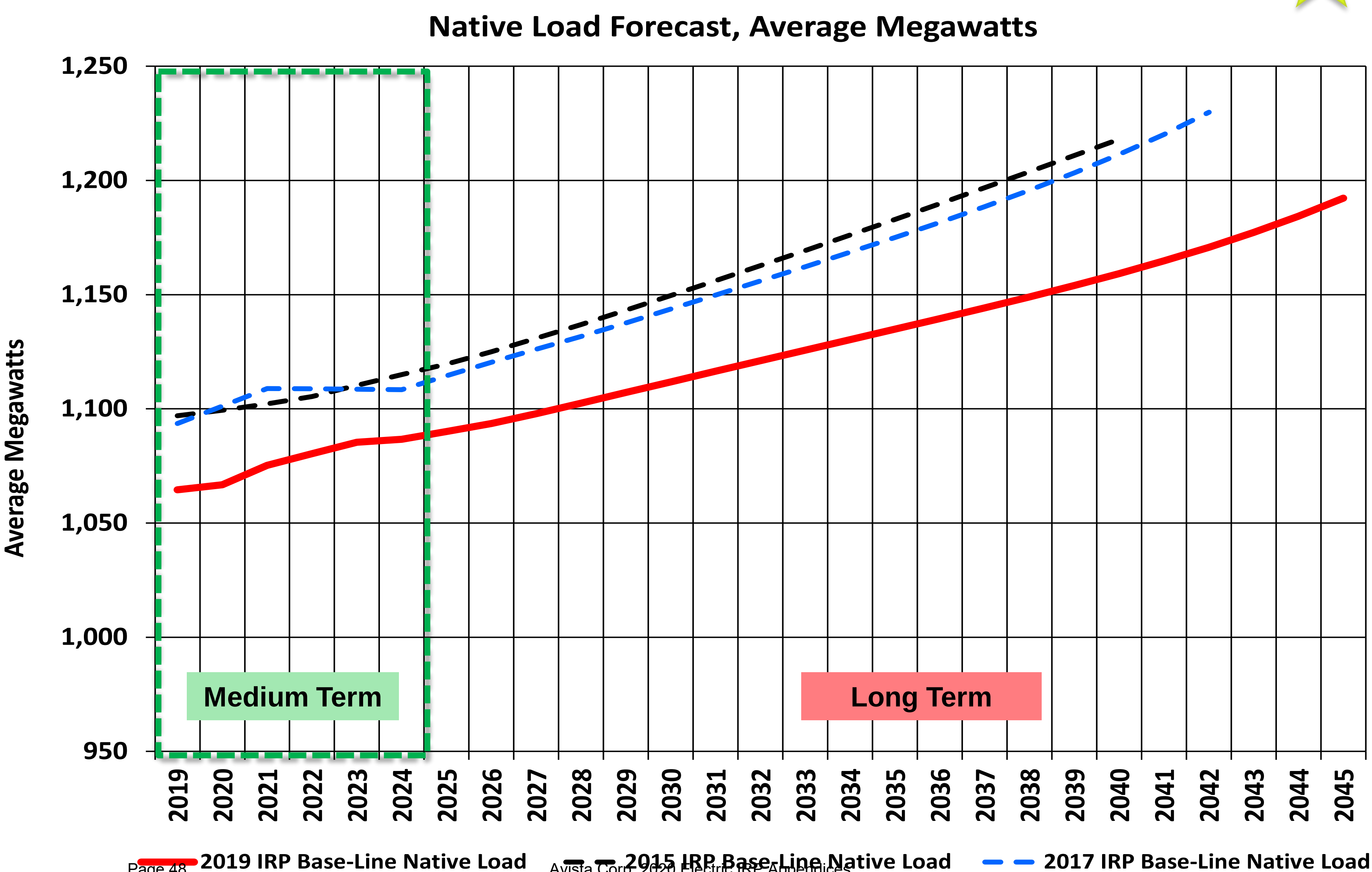


Source: EIA, *Today in Energy*, May 2018. Regional data from U.S. Census

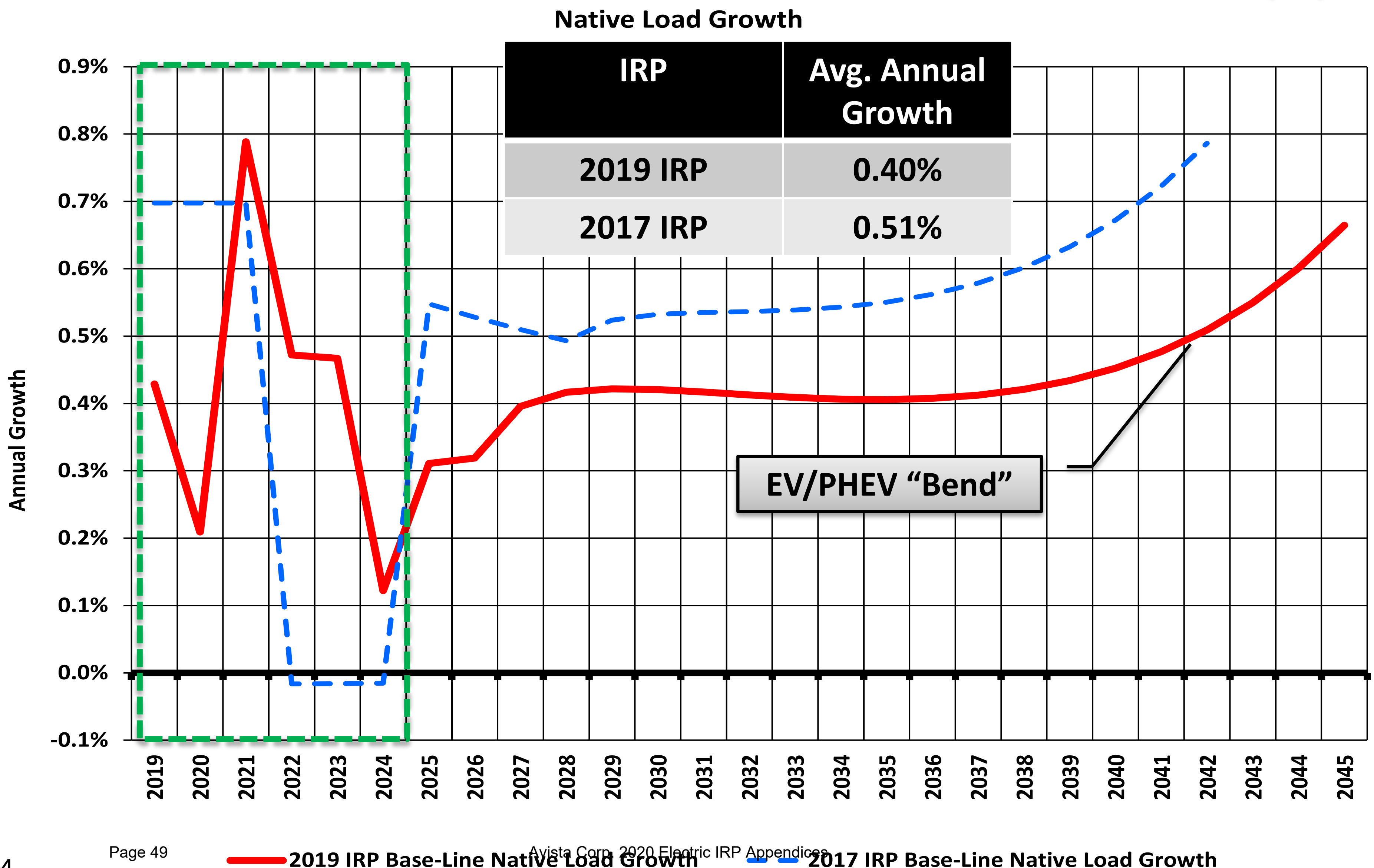
EV/PHEV Gasoline CO2 Savings Avista Service Territory



Native Load Forecast, 2019-2045

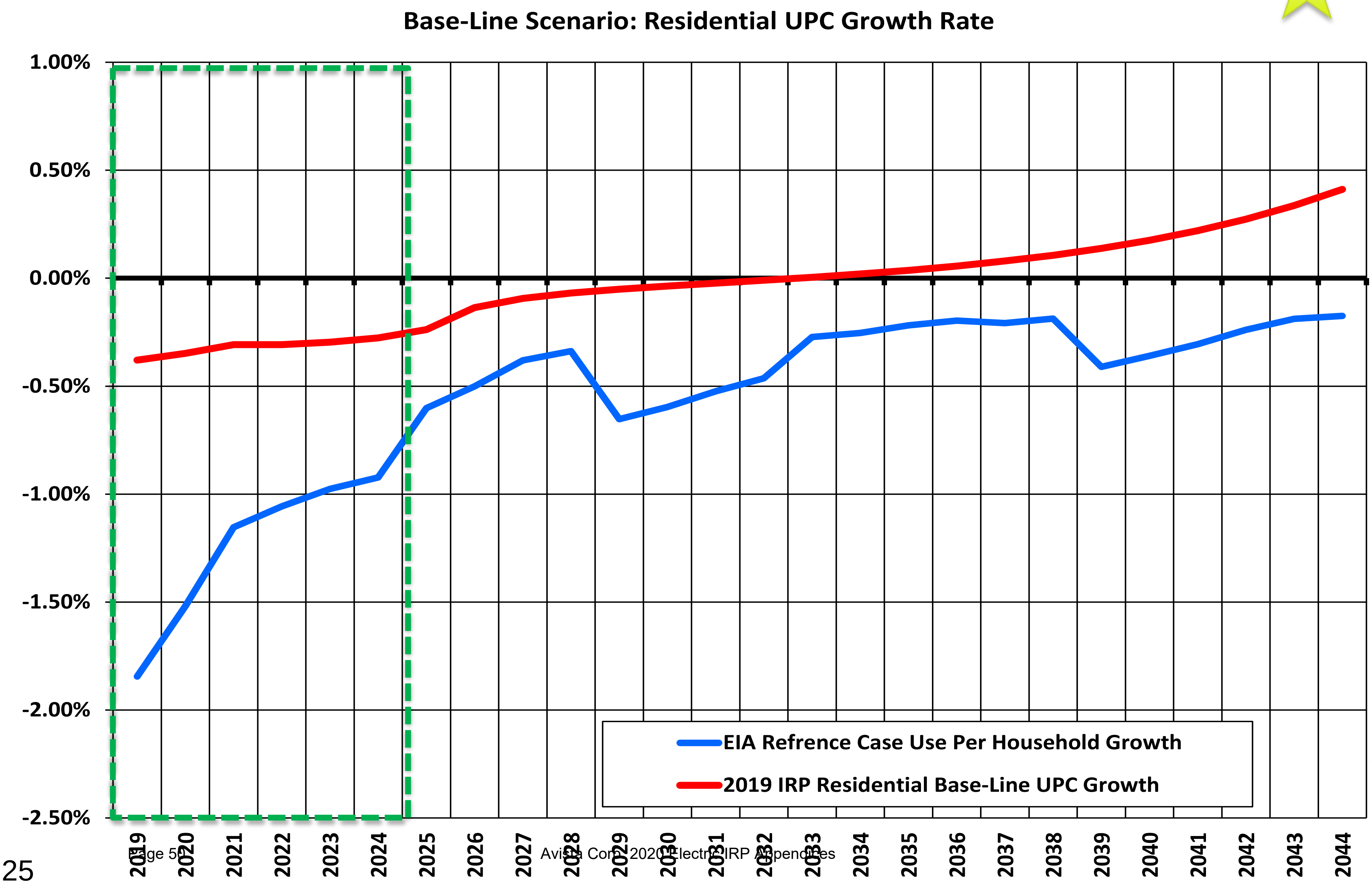


Native Load Growth Forecast, 2019-2045



IRP	Avg. Annual Growth
2019 IRP	0.40%
2017 IRP	0.51%

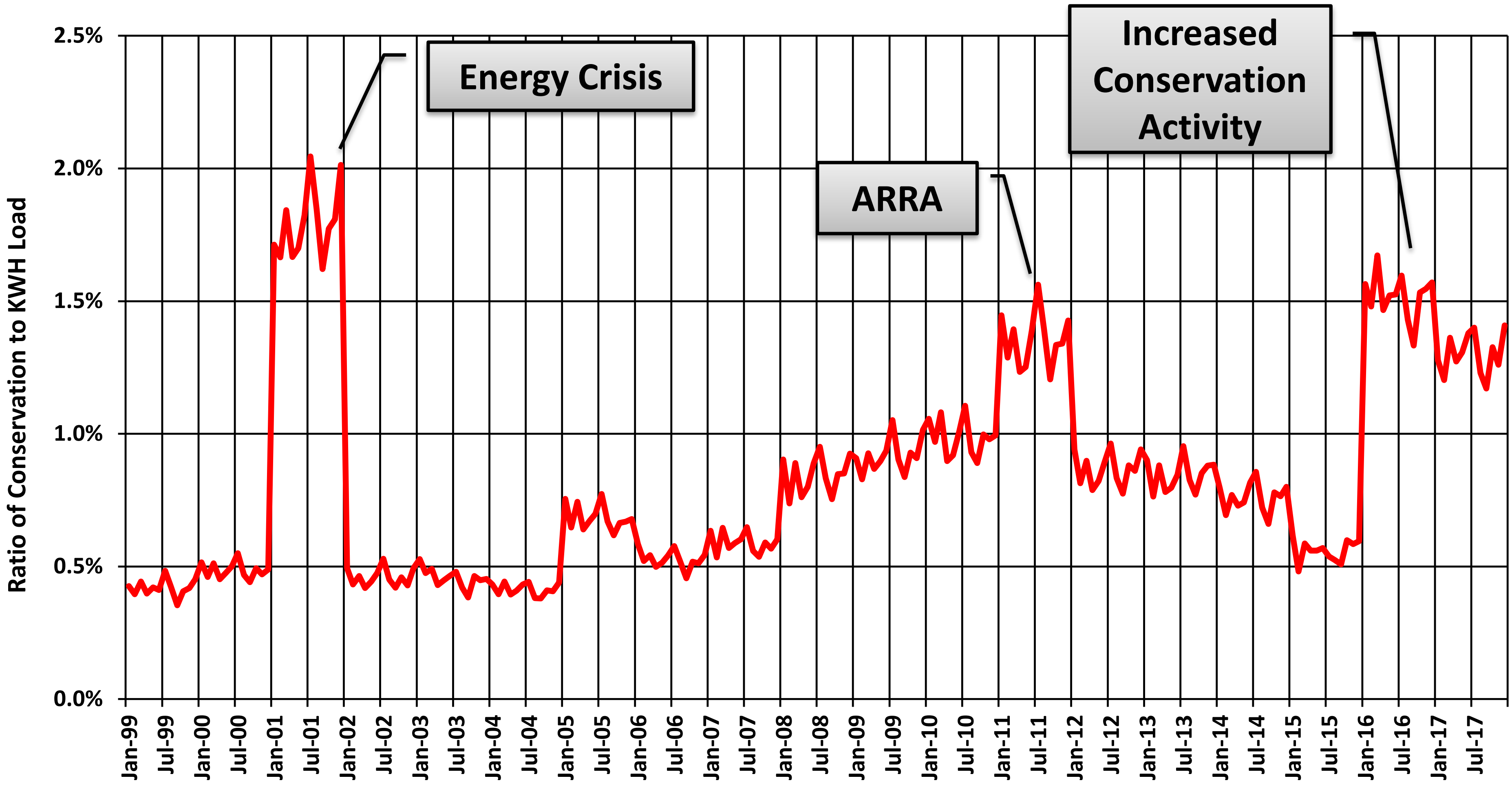
Residential UPC Growth: 2019-2045



Long-Term Load Forecast: Conservation Adjustment

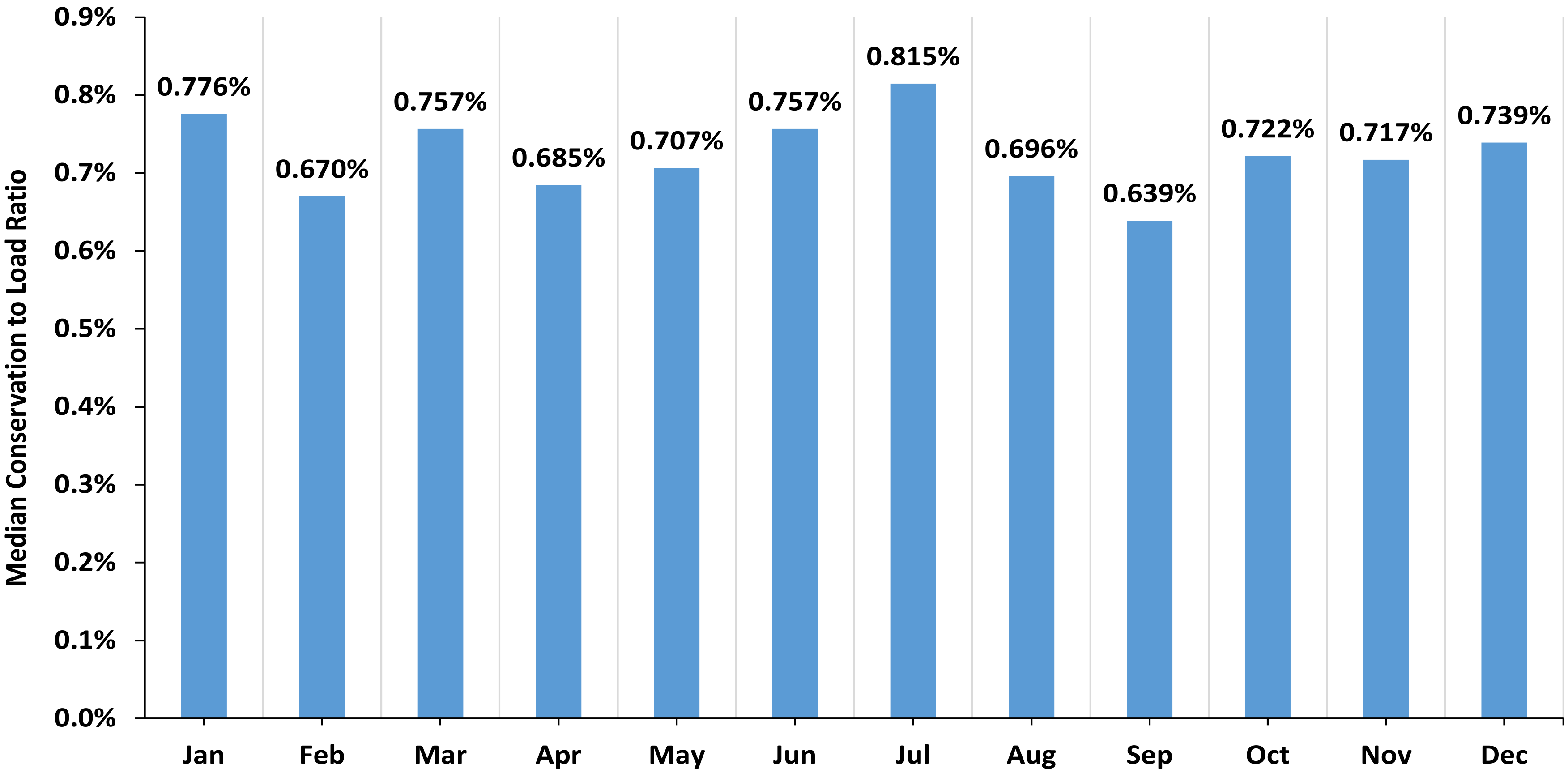
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



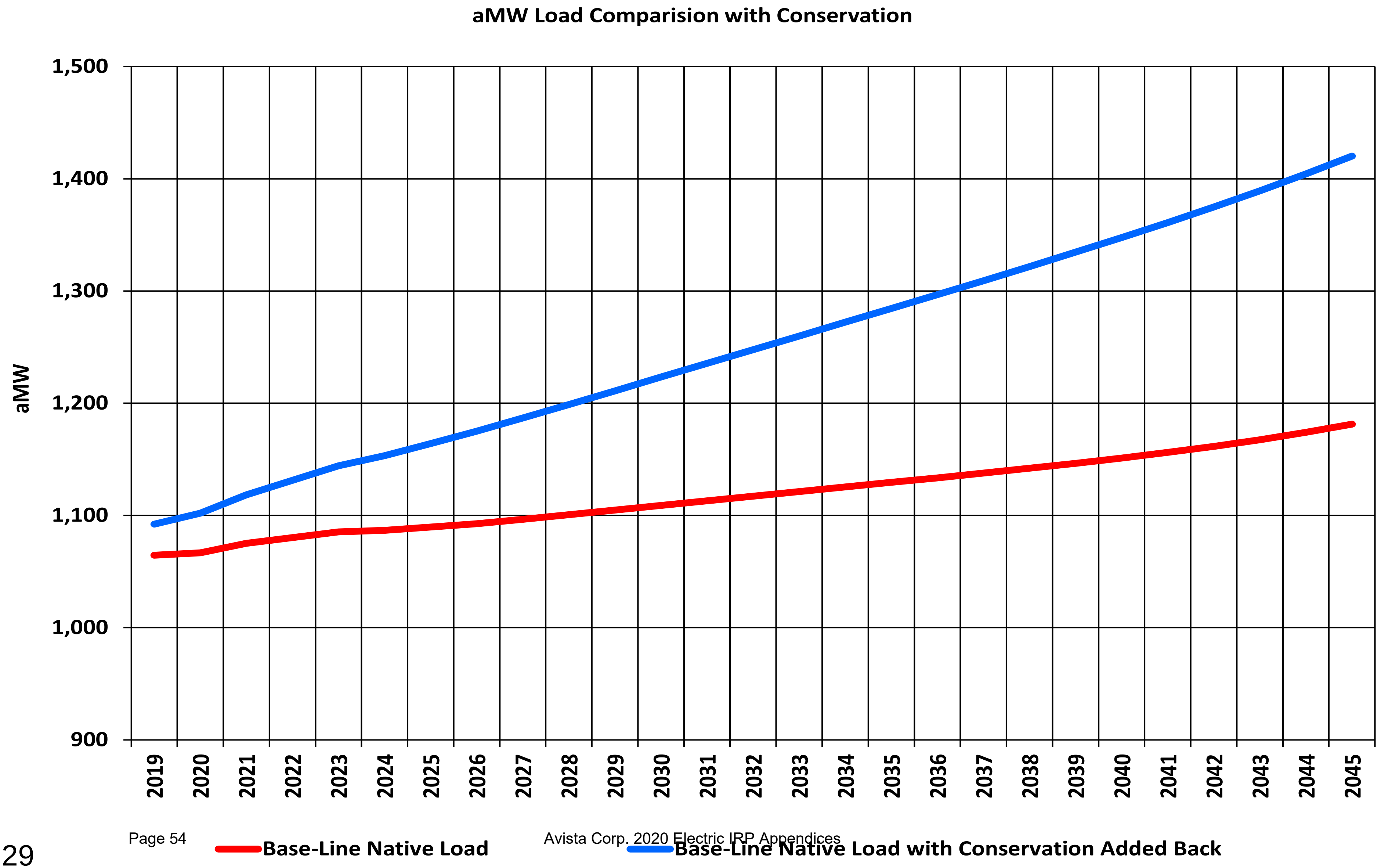
$$\text{Ratio} = \frac{\mathit{Estimated\ Conservation\ Month\ t, Year\ y}}{\mathit{Actual\ KWH\ Load\ Month\ t, Year\ Y}}$$

Median Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



$$Median\ Ratio\ Month\ t = Median\left(\frac{Estimated\ Conservation\ Month\ t}{Actual\ KWH\ Load\ Month\ t}\right),\ excluding\ 2001$$

Comparison of Native Load Forecasts, 2019-2045



2017 IRP Action Plan Update

James Gall, IRP Manager
First Technical Advisory Committee Meeting
July 25, 2018

Generation Resource Related Analysis

- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
  - Avista is currently evaluating opportunities at Kettle Falls and Post Falls.
- Model specific commercially available storage technologies within the IRP; including efficiency rates, capital cost, O&M, life cycle, and ability to provide non-power supply benefits.
  - Avista will model a suite of storage options using third party data for cost and operating data. For benefits, Avista will model both distribution and transmission level storage to quantify locational benefits.
- Update the TAC regarding the EIM study and Avista plan of action.
  - Update to be provided later this year.
- Monitor regional winter and summer resource adequacy, provide TAC with additional Avista LOLP study analysis.
  - LOLP/ELCC analysis is currently in process and will be presented at November meeting.
- Update the TAC regarding progress regarding Post Falls Hydroelectric Project redevelopment.
  - Avista is evaluating multiple options at Post Falls, an update on the plan will be at the February 2019 meeting.

Generation Resource Related Analysis

- Perform a study to determine ancillary services valuation for storage and peaking technologies using intra hour modeling capabilities. Further, use this technology to estimate costs to integrate variable resources.
  - Avista plans on performing this study with the Avista's ADSS model. At this time intra hour logic is not available. If it is not available at the time of the IRP analysis, sensitivities analysis will be performed to simulate this changes in reserve requirements.
- Monitor state and federal environmental policies effecting Avista's generation fleet.
  - Avista is continually monitoring policies that may impact the generation fleet.

Energy Efficiency and Demand Response

- Determine whether or not to move the T&D benefits estimate to a forward looking value versus a historical value.
  - Avista is participating in the PNUCC and the NPCC investigation into a reasonable methodology to determine T&D deferral values. Avista plans to use the preferred methodology from this effort. As of now, the method is based on the utilization factor of expected capital spending on T&D projects.
- Determine if a study is necessary to estimate the potential and costs for a winter and a summer residential demand response program and along with an update to the existing commercial and industrial analysis.
  - Avista has engaged AEG to conduct this study. The results will be shared at the March Meeting.
- Use the utility cost test methodology to select conservation potential for Idaho program options.
  - Avista is still committed to this methodology
- Share proposed energy efficiency measure list with Advisory Groups prior to CPA completion.
  - A list will be made available prior to the March meeting.

Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load.
  - Avista is committed to this Action Item and actively engages in this area.
- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area.
  - Avista is committed to this Action Item and actively engages in this area.
- Continue to participate in regional and sub-regional efforts to facilitate long-term economic expansion of the regional transmission system.
  - Avista is committed to this Action Item and participates in these efforts.
- IRP and T&D planning will coordinate on evaluating opportunities for alternative technologies to solve T&D constraints.
  - Avista will model at least five locations for both transmission and distribution assets where the system could alternatively be upgraded with a distributed energy resources (DER) rather than traditional assets to test whether or not a coordinated DER is a lower cost to customers.

Draft 2019 Electric IRP Work Plan

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
July 25, 2018

Tentative TAC Meetings

- **TAC 1 (July 25, 2018):** TAC Meeting Expectations and IRP process overview, review of 2017 IRP Commission acknowledgement letters and policy statements, demand and economic forecast, draft 2019 Electric IRP Work Plan, and Hydro One's merger agreement's impact on the 2019 IRP.
- **November 2018:** Modeling process overview, generation options (costs and assumptions), resource adequacy and ELCC analysis, overview of home heating technologies and efficiency, expected case key assumptions (regional loads, CO2 regulation, etc…), and market and portfolio scenarios.
- **February 2019:** Natural gas price forecast, electric market forecast, IRP transmission planning studies, distribution planning within the IRP, existing resource overview – Colstrip, Lancaster and other resources, and final resource needs assessment.
- **March 2019:** Ancillary services and intermittent generation analysis, conservation and demand response potential assessment (AEG), Pullman Smart Grid Demonstration Project review, draft Preferred Resource Strategy, and draft market and portfolio results.
- **April 2019:** Review of final PRS, market scenario results, portfolio scenario results, carbon cost abatement supply curves and 2019 Action Items.

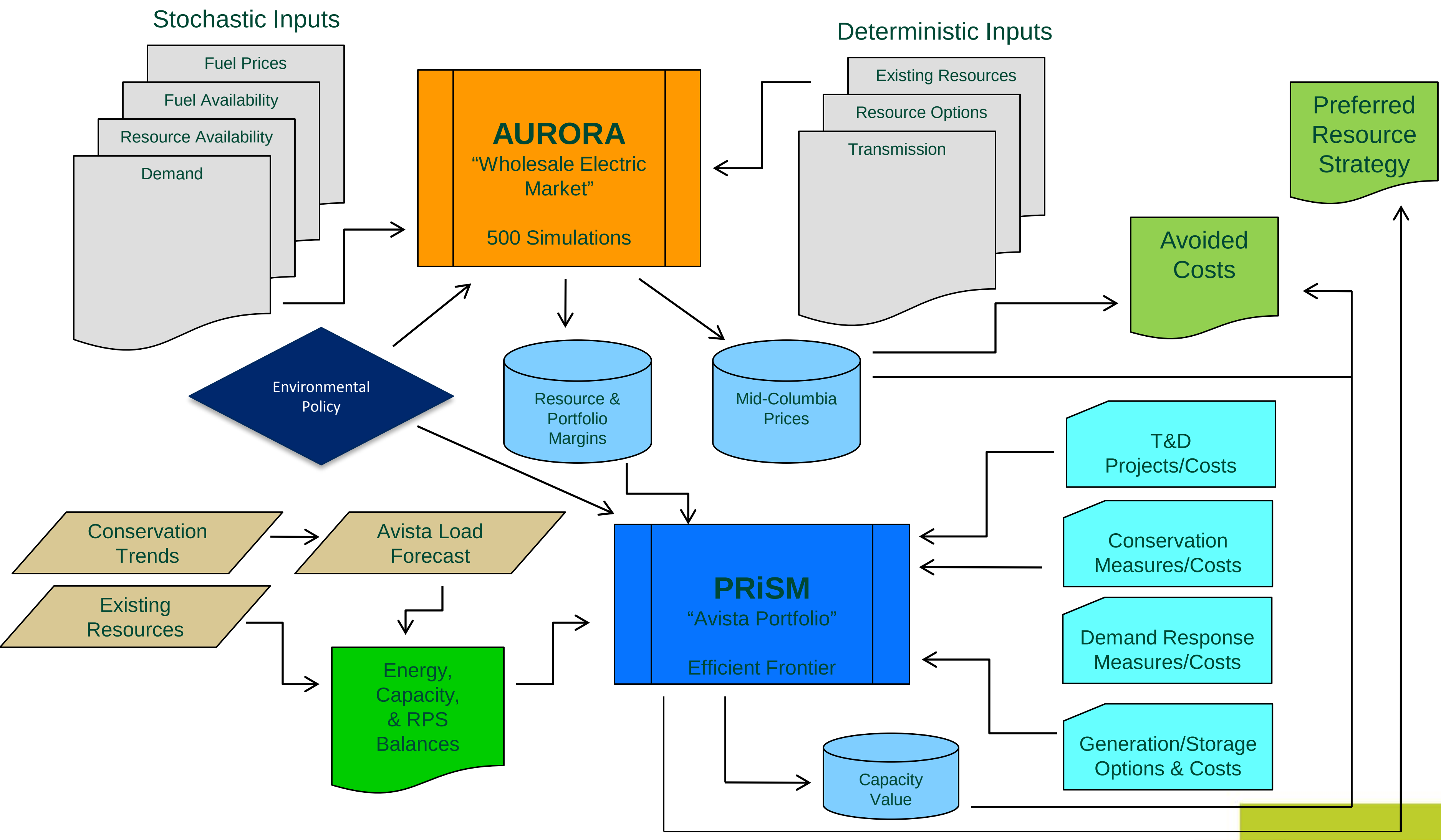
2019 Draft Electric IRP Timeline

Preferred Resource Strategy (PRS) Tasks	Target Date
Finalize energy forecast	July 2018
Identify Avista's supply resource options	September 2018
Begin Aurora market model development	October 2018
Energy efficiency load shapes input into Aurora	November 2018
Finalize data sets/statistics variables for risk studies	November 2018
Transmission and Distribution studies due	December 2018
Finalize natural gas price forecast	December 2018
Communicate energy efficiency options to TAC	December 2018
Finalize deterministic & stochastic expected case market studies	January 2019
Due date for additional study requests	**January 15, 2019**
Develop PRiSM model	January 2019
Finalize peak load forecast	February 2019
Finalize PRiSM model assumptions	February 2019
Simulation of risk studies "futures" complete	February 2019
Simulate market scenarios in Aurora	February 2019
Evaluate resource strategies against market futures and scenarios	March 2019
Present preliminary study and PRS to TAC	March 2019

2019 Draft Electric IRP Timeline

Writing Tasks	Target Date
File 2019 IRP Work Plan	August 31, 2018
Prepare report and appendix outline	October 2018
Prepare text drafts	April 2019
Prepare charts and tables	April 2019
Internal drafts released at Avista	May 2019
External draft released to the TAC	May 31, 2019
TAC comments and edits due	**June 28, 2019**
Final editing and printing	August 2019
Final IRP submission to Commissions and distribution to TAC	August 31, 2019

2019 IRP Modeling Process



2019 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 Supply Resources
  - Avista Resources
  - Contractual Resources and Obligations

2019 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

2019 Electric IRP Draft Outline

- Transmission & Distribution 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

2019 Electric IRP Draft Outline

- Market Analysis
  - Marketplace
  - Fuel Price Forecasts
  - Market Price Forecast
  - Scenario Analysis
- Preferred Resource Strategy
  - Resource Selection Process
  - 2017 Preferred Resource Strategy
  - Efficient Frontier Analysis
  - Avoided Cost

2019 Electric IRP Draft Outline

- Portfolio Scenarios
  - Portfolio Scenarios
  - Tipping Point Analyses
- Action Plan
  - 2017 Action Plan Summary
  - 2019 Action Plan

Hydro One Merger Agreements Related to Resource Planning

James Gall, IRP Manager
First Technical Advisory Committee Meeting
July 25, 2018

Avista's Proposed Merger with Hydro One

- Regulatory process update:
- Announced proposed merger July 2017
- Applications for approval filed in September 2017
- Federal approvals received
- Approvals from Alaska and Montana received
- Settlement agreements reached and filed in Washington, Idaho and Oregon. Approvals are still pending in these states.
- We continue to work through the regulatory process toward approval

More information at www.myavista.com/hydroone

Presentation Objective

- This presentation will review agreements between Avista, Hydro One and intervening parties related to the Electric IRP per the merger agreements in Washington & Idaho.
- These agreements will include methodology and specific goals the next IRP shall include if the merger is approved.

WA #52 Renewable Portfolio Standard Requirements

Hydro One acknowledges Avista’s obligations under applicable renewable portfolio standards, and Avista will continue to comply with such obligations.

Avista will acquire all renewable energy resources required by law and such other renewable energy resources as may from time to time be deemed advisable in accordance with Avista’s integrated resource planning (“IRP”) process and applicable regulations.

WA #53 Renewable Energy Resources

Avista's non-fossil fueled generation resources constitute more than 50% of its generation portfolio, and Avista exceeds the renewable energy standards currently applicable to the company under RCW 19.285.040(2).

Avista makes the following renewable energy commitments. Both commitments are made only to the extent resources are reasonably commercially available and are (1) necessary to meet load and (2) consistent with the lowest reasonable cost resource portfolio pursuant to Avista's established IRP and pursuant to the Commission's resource evaluation and acquisition rules and policies.

WA #53 (a) Renewable Energy Resources

Avista will commit to initiating a Request for Proposal with the intent of acquiring additional eligible renewable energy resources as part of this process above and beyond the current renewable energy standards in law. Avista will commit to obtain approximately 50 aMW of expected energy from new eligible renewable resources by 2022.

The aMW obtained under this commitment may be used to satisfy any increase that may be caused by changes to the renewable energy standards in law after the date an Order approving this merger has been entered.

ID #52: Renewable Energy Resources

Avista will continue to offer renewable power programs in consultation with stakeholders.

Communications with customers shall accurately reflect the environmental attributes associated with power delivered to such customers. Hydro One and Avista acknowledge that Avista retains the burden of proof to demonstrate the prudence of any resource acquisition.

Nothing in this Commitment prohibits Avista from selling renewable energy credits that arise from resources included in base rates applicable in Idaho. Hydro One acknowledges Avista's obligations under applicable renewable portfolio standards, and Avista will continue to comply with such obligations.

RFP Schedule

- June 6, 2018 – RFP Issuance
- June 20, 2018 – **Preliminary Information due (CLOSED)**
- June 29, 2018 – Short list identified
- July 20, 2018 – **Detailed Proposals due from short-listed bidders (Exhibit C)**
- July 23, 2018 through August 15, 2018 – Negotiations with short-listed bidders
- August 29, 2018 – **Final bidder(s) selected**
- November 2, 2018 - Final contracting complete with successful bidder(s)

RFP Bid Summary

- Nearly 900 aMW from 48 bids
- Proposals included wind, solar, geothermal, fuel cells, and storage
- From Washington, Idaho, Montana, Oregon, and Nevada
- Both PPA's and build to own transfers were received

WA #53 (b) Renewable Energy Resources

Avista will commit to obtain at least 90 aMW of expected energy from new eligible renewables resources to become operational approximately within a year of the timeframe that Colstrip 3 and 4 go offline.

“Resources” is understood to include Power Purchase Agreements (“PPAs”). Nothing in either commitment prohibits Avista from retaining or selling renewable energy credits associated with such resources that are surplus to Avista’s needs to meet Washington Renewable Portfolio Standards targets.

Communications with customers shall accurately reflect the environmental attributes associated with power delivered to such customers. Hydro One and Avista acknowledge that Avista retains the burden of proof to demonstrate the prudence of any resource acquisition.

The utility should work with an independent third-party consultant, with expertise in renewable energy resources, to ensure that the utility has up-to-date resource cost and performance assumptions, as well as the appropriate learning curves.

WA #54 & ID #56 Greenhouse Gas and Carbon Initiatives

Hydro One acknowledges Avista's Greenhouse Gas and Carbon Initiatives contained in its current Integrated Resource Plan, and Avista will continue to work with interested parties on such initiatives.

WA #57 Energy Efficiency Goals and Objectives

Hydro One acknowledges Avista's energy efficiency goals and objectives set forth in Avista's 2017 Integrated Resource Plan and other plans, and Avista will continue its ongoing collaborative efforts to expand and enhance them.

ID #53 Regulatory IRP Sideboards

Avista and its affiliates agree to consider in all resource planning and acquisition efforts both demand-side and renewable energy resources that are consistent with the Idaho Commission's resource evaluation and acquisition rules and policies.

- Avista and its affiliates agree that "Resources" to be considered in all IRPs include Power Purchase Agreements ("PPAs").
- Avista commits to calculating a variable generation resource's contribution to capacity in terms of that resource's contribution to resource adequacy and that resource's ability to reduce the loss of load probability in some or all hours or days utilizing the Effective Load Carrying Capability ("ELCC") methodology or an appropriate approximation. *[WA #60]*
- Avista will work with an independent third-party consultant, with expertise in renewable energy resources, to ensure that the utility has up-to-date resource cost and performance assumptions, as well as the appropriate learning curves, for use in the 2019 IRP process.
- Unless it conflicts with any instructions contained in the Commission's acknowledgement letter in response to Avista's current integrated resource plan (IRP), beginning with the next IRP, Avista commits to modeling a range of potential costs for greenhouse gas emissions, and will work with its IRP Advisory Group to determine the appropriate values to model. *[WA #55]*

WA #76 & ID #69 Colstrip Depreciation

Hydro One and Avista agree to a depreciation schedule for Colstrip Units 3 and 4 that assumes a remaining useful life of those units through December 31, 2027.

WA: See Attachment A to Appendix A (Master List of Commitments in Washington) to the Settlement Stipulation, “Colstrip Commitment Summary and Description”

ID: See #69 for full description of commitment

Other “IRP” Related Items

WA #58: Optional renewable power program

WA #59 & ID #54: Energy Imbalance Market (“EIM”)

WA #61: Industrial customers’ self direct conservation

WA #62 & ID #55: Transport electrification

WA #63: Professional home energy audit

WA #65 & ID #58: Low-income energy efficiency funding

WA #67: Funding for low-income participation in new renewables

WA #69: Replacement of manufactured homes

WA #70: Low-income weatherization

ID #59 & #60: Industrial load DSM assistance

ID #71: Colstrip transmission planning

Attendees: TAC 1, July 25, 2018 at Avista Headquarters in Spokane, Washington:

John Lyons, Avista; Kirsten Wilson, Washington State DES; Amy Wheeless, NW Energy Coalition; David Nightingale, Washington UTC; Doug Howell, Sierra Club; Kathlyn Kinney, Biomethane; Grant Forsyth, Avista; Jorgen Rasmussen, Solar Acres Farm; John Barber, Rockwood Retirement Communities; Gerry Snow, PERA; Dean Kinzer, Whitman County Commission; Garret Brown, Avista; Scott Kinney, Avista; Yao Yin, IPUC; Ben Serrurier, Cyprus Creek Renewables; Terrence Browne, Avista; Jason Thackston, Avista; Darrell Soyars, Avista; Kim Vollan, Avista; Kevin Davis, IEP; Matt Nykiel, ICL; Ryan Finesilver, Avista; Paul Kimmel, Avista; and John Osborne, MD.

Phone:

Kelly Hall, Climate Solutions; Mike Starrett, NPCC; Steve Johnson, Washington UTC; Ian Bledsoe; Energy Consultant, NW Energy Coalition

These notes follow the progression of the meeting. They include summaries of the questions and comments from those not presenting, the responses (in italics), as well as significant points raised by the presenters that are not shown on the slides

TAC Expectations and Process Overview, John Lyons

Presentation covering the background behind the electric IRP, TAC member involvement, review agenda for the day and expectations from Avista and from the TAC.

- Jorgen Rasmussen: Can we have someone come in and talk about energy security? *Yes, Avista will look into adding this as a topic.*
- Amy Wheeless: Request to track all questions, requests and responses.
- Matt Nykiel: Asked about getting assumptions earlier in the process to be able to understand them better and make comments. Y*es, Avista will work on this and many of the assumptions will be made available at the next meeting in November 2019.*
- Amy Wheeless: How do we discuss the assumptions? The TAC gets the slides with the assumptions ahead of the meetings.
- Doug Howell: Would like to see the slides three days ahead of the meetings. *Slides will go out on Friday before the Tuesday or Wednesday meetings.*
- Matt Nykiel: Concerns about slide #3 and limitations to the discussions and questions asked. *The points are in the slides to make sure we can get through the agenda for each TAC meeting.*
- Amy Wheeless: We want an open exchange of ideas. Request that participants can provide data and Avista will consider using it. *It is best if the data is publically available.*
- David Nightingale: Discussion on minutes of the TAC and how they will be made available. *Avista is still working on the logistics of this, possibly by email or even posted on the web site.*

- Gerry Snow: Is there a continuing forum between meetings? Can Google Docs be used? *There isn't an ongoing forum or discussion group, but the IRP is available by email and phone for any questions, comments and concerns. Information can then be passed on to the whole TAC. No, IT policy doesn't allow us to use Google Docs, but could explore the use of One Drive if email doesn't work for TAC members.*
- Clint Kalich: Discuss how the Avista web site is used in conjunction with the IRP. Showed the TAC where to find the IRP section of the web site and the documents available there.

2017 IRP Acknowledgements & Policies, James Gall

Presentation covering the expectations and comments in the acknowledgment letters received from the Idaho and Washington Commissions for the 2017 Electric IRP.

- Doug Howell: Passed around letter dated June 26, 2018 to the Idaho, Montana, Oregon and Washington utility commissions concerning Westmoreland Coal Company; handout titled "Fracked Gas The Next Big Climate Fight;" and a July 24, 2018 article from The Billings Gazette concerning the Colstrip outage.
- Doug Howell: Wants more details on the assumptions for air quality controls at Colstrip.
- Steve Johnson: Comment about sheltering or excluding anyone involved in negotiations for a new contract or purchase of the Lancaster facility from non-public analysis to ensure they are arm's length from any new transaction.
- Doug Howell: Colstrip remediation and decommissioning and how it is going to be paid for in a way that provides intergenerational equity.
- Doug Howell: How are existing capital projects used for supporting investment in the IRP, Colstrip capital? *This is a resource decision that uses the IRP developed avoided cost to analyze new projects.*
- Steve Johnson replied that unsure if the IRP is the place to describe how much and when money is to be recovered for Colstrip. The Company would demonstrate prudence in a future rate proceeding, not jumping ahead in an IRP to design a cost recovery mechanism. The IRP recognizes such costs to be included in depreciation recovery. IRP should identify all risks for Colstrip Units 3 and 4 and potential costs in response to the acknowledgment letter from the Washington UTC.
- Matt Nykiel: Wants the group to be kept informed on whether a decision has been made on depreciation at Colstrip.
- Steve Johnson offered to have a more detailed meeting with the public about rate making.
- Dave Nightingale: Anticipation of a resource becoming unavailable if uneconomic. Identify resources that are at risk of going away.

- Matt Nykiel: Will the November meeting discuss regional coal policies from Portland General Electric and PacifiCorp in Oregon? *Yes, regional coal policies will be covered in a later meeting.*
- Doug Howell: Wants to include the risk associated with the growing liabilities of upstream natural gas leakages. *Avista has not historically considered externalities beyond those required by laws or regulations, but will take this request into consideration.*
- Doug Howell: The Sierra Club wants the inputs for Aurora so they can have a consultant review them and run the models. *This will require a discussion at Avista to determine what data could be shared and how it could be shared.*
- Matt Nykiel: Concerns with how we can discuss the inputs without having all of the data.
- Ben Serrurier: Do the consultants provide the data that supports how they derived their natural gas price forecasts and can that be shared with the TAC? *Yes, Avista can provide what we are allowed to. Probably cannot give specific details, but should be able to share the main driving forces behind the gas price forecasts.*
- Yao Yin: What if there are big differences between the two consultants for the gas price forecasts if there are conflicting or different assumptions? *Avista has blended these forecasts in the past and has not seen fundamentally different forecasts. Any major differences would probably be due to conflicting assumptions.*
- Dave Nightingale: Will there be high, low and medium cases? *Avista does an expected case with stochastics with an average of the 500 futures as the expected case. Ask the consultant to do a high and low forecast. Avista will check into this with the consultants, but it may be too costly.*
- James Gall: Should we include some more information here about distributed generation and energy storage? *Yes and storage will be included as a new resource option.*
- Amy Wheeless: More distributed resources and non-traditional. *Yes, Avista will include more options and will need to see how far we can take this.*
- Ben Serrurier: How are you choosing the five projects for distribution upgrades? *The amounts were small enough that we asked that group for five. UTC threshold, but we are looking at needs and what could be met by a distributed energy resource to solve constraints in the IRP timeframe.*
- Kirsten Wilson: Regarding Washington Executive Order 1801, is vehicle-to-grid storage going to be included? Washington State University may have to follow the rules identified in the Executive Order. *Avista will try to incorporate this, but really has no control over this type of resource. Vehicle-to-grid storage may end up being a scenario.*

- Steve Johnson: Offline, examine paragraph 43 of the UTC policy on storage framework or method. Is this practical or is there a better way of doing it? Criticism has been leveled at this method. *Avista will probably do this in PRiSM.*
- Doug Howell: For carbon prices, include the implications of the upstream emissions.
- Dave Nightingale: Regarding how to share meeting minutes, they usually get approved at the next meeting. *Avista still needs to decide on the best way to share the meeting minutes with the TAC.*
- Dave Nightingale: The second and third bullets (WUTC IRP Rulemaking about requests for proposals and avoided costs) are being handled separately as two rulemakings under separate dockets. On a parallel track with conservation (under the Advisory Group) with a subgroup for distribution planning. This is still in discussions and a new draft will be ready in the next month or so. It will be done by the end of the year, but will be surprised if the new regulations get applied to this IRP.
- Yao Yin: Third point, avoided cost, trying to unwind: PURPA, resource differences, and improved rule on how to use it. Idaho has a SAR (surrogate avoided resource) and IRP method. Larger and smaller resource methods, maybe we should talk offline about these.
- Doug Howell: Suggest using the Washington Governor's Deep De-carbonization Study to get assumptions on EV, building codes, solar and others. *Avista will run a scenario with higher assumptions.*

Break (back at 10:55)

Demand and Economic Forecast, Grant Forsyth

- Grant Forsyth: Employment is one of the big drivers for customer growth, 71% of the local economy is service based.
- Clint Kalich: Does local government include schools? *Yes, it is the biggest share and includes faculty, teachers and administrators.*
- Grant Forsyth: Fairchild Air Force Base is going to be accepting all of the older KC135 tankers as the new tankers are deployed elsewhere, so there will be a buildup at Fairchild.
- Grant Forsyth: Idaho is growing faster than Washington service territory in employment and population. The MSA (Metropolitan Statistical Area) is a well-defined urban area with over 50,000 people.
- Dave Nightingale: Why is non-farming used? *Farming is so low for employment it does not make a huge difference. It is much bigger for income.*
- Grant Forsyth: In-migration is the key driver for customer growth
- Grant Forsyth: Population growth is a strong proxy for customer growth.
- Garrett Brown: What is the impact of the recent announcement by Amazon? [Warehouse in Airway Heights with 1,500 expected employees] *Not a large direct impact because they will be an Inland Power Customer, but Avista will serve their*

natural gas needs and will benefit from in-migration with some amount of household and ancillary business growth.

- Doug Howell: Which are excluded to run the regression [in the peak load forecast]? *Excludes Clearwater and IEP (Inland Empire Paper) and then adds them back in.*
- Kathlyn Kinney: Why is the summer peak growing faster? *It is a combination of weather changes (why we moved from 30 to 20-year weather data); increased air conditioning load because of higher incomes and lower costs for air conditioners; winter conservation; and fuel switching from electric to natural gas.*
- Grant Forsyth: There is a less strong impact from GDP on loads than in the past.
- Dave Nightingale: Graphically look at this, do these make sense based on the past.
- Dave Nightingale: Are these GDP numbers regional? *No, they are national GDP estimates because our region follows the national numbers closely and regional forecasts are scarce.*
- Yao Yin: Questions about GDP differences in slide 11 (Current Peak Load Forecasts for winter and summer, 2018-2043). *Yes, they are different for each year for 5 to 6 years, then extended out for the rest of the forecast.*
- James Gall: Peak demand – we are planning to serve this load over the next 20 years plus a 14% peak planning margin and operating reserves. This made us short in 2027 in the last plan. We may make adjustments as we get more data.
- Amy Wheeless: How does 14% compare to others? 11 – 17%. *Depends on what is included. We add operating reserves putting us at 21-22%, NPPC is about 23%. Water based utilities usually have higher planning margins for running out of water. There is a chart on this in the last two IRPs.*
- Yao Yin: Is PM necessary? *Yes, we were able to cover the 2009 extreme cold event.*
- Matt Nykiel: Actual vs. forecast, do you have a chart? *No, but James Gall looks at the forecast vs. the actual after every event. We are not sure if we could add this.*

Long-term load forecast section

- Doug Howell: Is the 20-year data capturing the warming shift? *It varies within our service territory based on the work done by NASA. There is more of a warming shift in Medford than Washington. The data shows the shift has somewhat stabilized in the 20-year period.*
- Amy Wheeless: UW climate impact and SnoPUD have data on this.
- Matt Nykiel: How do you pick the forward climate model? Can we use an average like GDP? *Potentially, we can verify GDP with historic data, but climate data may be tough to correlate because it is lumpy, not uniform.*
- Steve Johnson: Currently, is Avista’s view that the risk of climate change is open ended? *Yes, to the extent we can’t quantify it.*

- Clint Kalich: Magnitude of temperature and could also run scenarios on other changes with similar results. Put a statement about risk and what we are thinking.
- Yao Yin: Why not an econometric model for the long term? *We could, but would also need a population growth forecast.*
- Garrett Brown: Is it positive or negative growth? *Still positive, but about half percent long term. 5% or more solar penetration starts making a difference. More aggressive solar growth with larger projects over 10,000 watts.*
- Yao Yin: Relationship between load and solar. How much is solar taking off of load, the net impact?
- Doug Howell: What about the Commerce predictions for electric vehicles (Executive Order 18-01)? *Have not been able to determine where they got their goals from, maybe the Governor's deep de-carbonization pathway. We are going to run some scenarios on different levels of electric vehicles, solar and electrification.*
- Amy Wheeless: Are electric vehicle fleets growing faster? *In the model, there is a connection to residential and commercial loads.*
- David Nightingale: Distribution of model by Washington EVs (electric vehicles) may be shifting with new models. *Income and household density are the drivers for EVs. Density is 4 times less in Spokane, so people live far enough away to have some range anxiety.*
- Jorgen Rasmussen: Also need to consider the used EV market and the number and location of chargers. There are fewer chargers in our service territory.
- Jorgen Rasmussen: Could also consider the consumption of refineries. How far do we take this?
- Yao Yin: Why not include solar in the resource side? *This is for customer-owned solar.*
- Gerry Snow: When will we see the "duck curve"? *Partly by feeder. 5% and higher penetration will affect us for solar. This is more on an issue with Power Supply. The location of the solar is important.*
- Doug Howell: It would be useful if we could see growth rates and efficiency in a deep de-carbonization scenario and how this overlays with the economic forecast. *Would need to see what kind of specific data we could get for this.*
- David Nightingale: Electric vehicles are not utility scale, but impact Avista's system. Reliable, planning level at what point for electric vehicles and solar? *Summer peaks maybe.*
- Doug Howell: When are the peaks? *6 pm in the summer and 7 – 8 am / 5 – 6 pm in the winter.*
- Kathlyn Kinney: Energy storage with hydrogen could change this.
- Yao Yin: (Slide 29 Median Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates): Have the ratios for the Navigant coefficients stayed the same? T*hey have increased a bit, but not very much since using the*

median rather than the average. The conservation estimate is from the DSM area.

- Jorgen Rasmussen: Have there been more energy savings in the LEDs vs. the conversions to natural gas? *Yes, the LED lighting conversions are about double the energy savings for lighting. Conversions to LED provide more savings than fuel conversions on a per kWh basis.*
- Amy Wheeless: The WUTC is wanting less fuel conversions.
- On the last slide, the blue line is the starting point for conservation selection

Lunch 12:00

2017 Action Plan Updates, James Gall

- Amy Wheeless: Are we presenting data on bullet 1, page 4. *Yes, we will present. Yes, publically.*
- Doug Howell: List of BPA commitments with Governor Bullock's (Montana) process. *Scott Kinney replied that we have done most of them and the rest are up to BPA.*

2019 IRP Draft Work Plan, John Lyons

- Dave Nightingale: Consider placing a draft IRP review place holder meeting at the end.
- Gerry Snow: Are you considering additional storage instead of new resources? *Yes.*
- Doug Howell: There is an expectation of signing a non-disclosure agreement to be able to get the inputs used for the March and April meetings. We want to set up a process to the data? *Avista will need to meet internally and discuss this.*
- Matt Nykiel: Timing of the November meeting, add time to the agenda to follow up on assumptions.
- Amy Wheeless: Can Avista be more nimble for inputs to be shared regarding CO2? *We are going to try, but there are several moving parts with the election and potential upcoming state legislative efforts in Washington.*
- Doug Howell: How are you going to decide how to implement the social cost of carbon and the citizen's initiative (I-1631 carbon fee)? *Avista is still determining how to do this and waiting for the results of the November election.*
- Jorgen Rasmussen: Remember the initiative (I-1631) is considered a fee instead of a tax. *Yes, it is modeled the same as a tax even though it's a fee and the recent state court ruling upheld I-1631 as a fee instead of a tax.*
- Scott Kinney: Would like to add that there may be limits to the amount of studies that can be run based on how many requests we receive.

Break

Hydro One Merger Agreements, James Gall

- Jason Thackston: Avista is accelerating the depreciation for Colstrip as part of the Hydro One agreement in Washington and only if the transaction is approved in all five states and is consummated. Idaho has a separate depreciation study case.
- Mike Starrett (phone): For the RFP short-list (for new, renewable generation), are they below cost? *Avista cannot share the specific cost information, but we are getting current pricing data on renewable generation.*
- Doug Howell: Would like to acknowledge the $4.5 million commitment to the City of Colstrip by Hydro One.

Adjourn

2019 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Tuesday, November 27, 2018

Conference Room 130

Topic	**Time**	**Staff**
Introductions and TAC 1 Recap	9:30	Lyons
Modeling Process Overview	9:40	Gall
Generation Resource Options	10:10	Gall
Break	11:00	
Home Heating Technologies Overview	11:15	Lienhard
Lunch	12:00	
Resource Adequacy and Effective Load Carrying Capability	1:00	Gall
Electric IRP Key Assumptions	1:45	Gall/Lyons
Break	2:30	
2019 IRP Futures and Scenarios	2:45	Gall/Lyons
Adjourn	3:30	

2019 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
November 27, 2018

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next two years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

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 while balancing need to get through all of the topics

- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - January 2019 at the latest to be able to complete studies in time for publication

- Planning team is available by email or phone for questions or comments between the TAC meetings

TAC #1 Recap – July 25, 2018

- Introduction
- TAC Expectations and Process Overview
- 2017 IRP Acknowledgments and Policies
- Avista's Demand and Economic Forecast
- 2017 Action Plan Updates
- 2019 IRP Draft Work Plan
- Hydro One Merger Agreements
- Meeting minutes are available on the IRP web site at https://www.myavista.com/about-us/our-company/integrated-resource-planning

Today's Agenda

- 9:30 – Introductions and TAC 1 Recap, Lyons
- 9:40 – Modeling Process Overview, Gall
- 10:15 – Generation Resource Options, Gall
- 11:00 – Break
- 11:15 – Home Heating Technologies Overview, Lienhard
- 12:00 – Lunch
- 1:00 – Resource Adequacy and Effective Load Carrying Capability, Gall
- 1:45 – Key Assumptions, Gall and Lyons
- 2:30 – Break
- 2:45 – Futures and Scenarios, Gall and Lyons
- 3:30 – Adjourn

TAC 3 Topics

- TAC 3 on Wednesday, February 6, 2019
- Natural Gas Price Forecast
- Electric Market Forecast
- IRP Transmission Planning Studies
- Distribution Planning within the IRP
- Existing Resource Overview (Colstrip, Lancaster, and other resources)
- Final Resource Needs Assessment

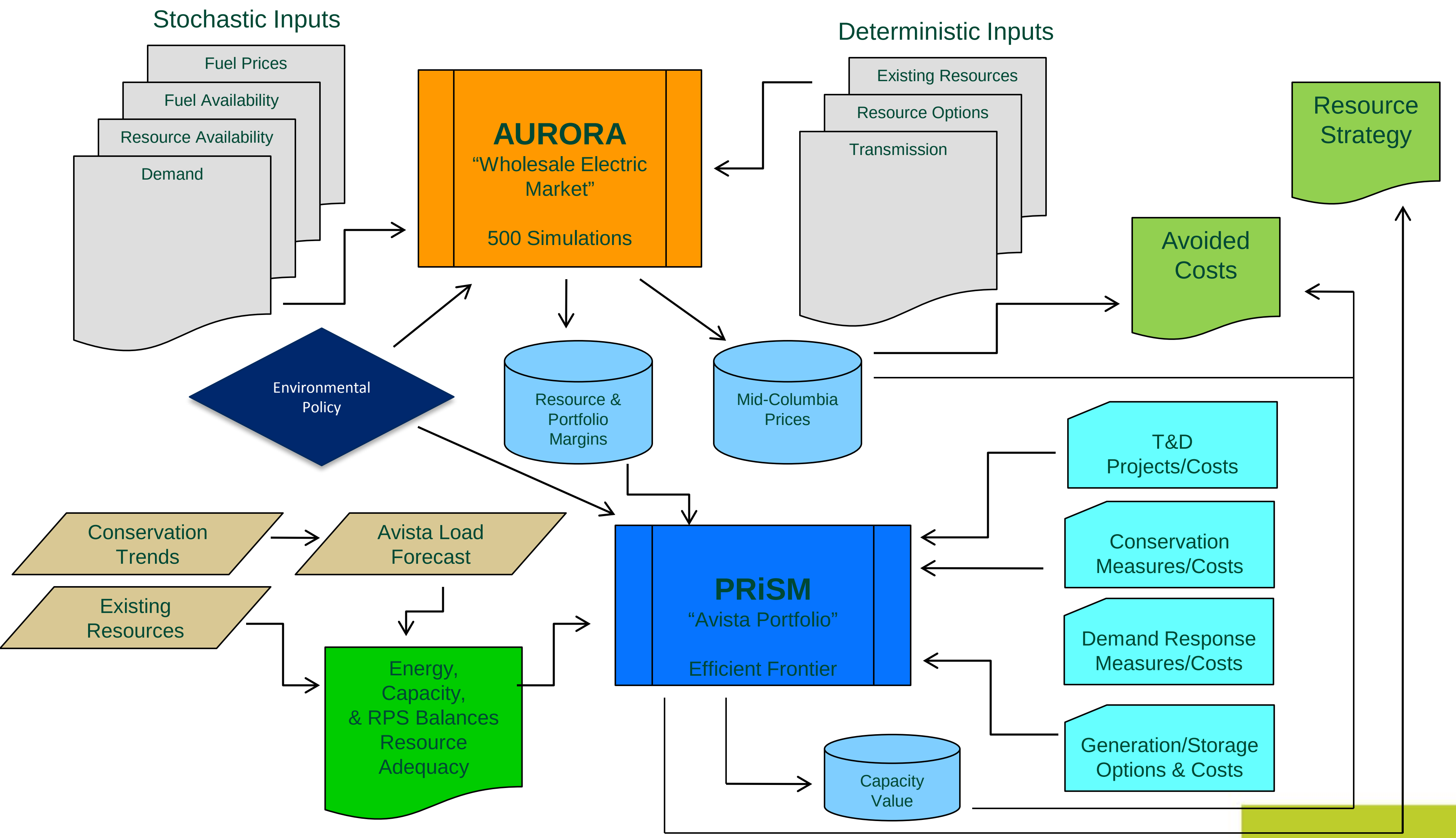
2019 IRP Modeling Process Overview

James Gall, IRP Manager
Second Technical Advisory Committee Meeting
November 27, 2018

IRP Modeling Process

- The purpose of this discussion is to help you understand the steps and process associated with the analysis of the IRP.
- This presentation outlines the steps to develop the plan along with a high level discussion of how the tools and methods are used.

2019 IRP Modeling Process



Electric Market Modeling

- 3rd party software- EPIS, Inc./Energy Exemplar
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet load and allows for system constraints

Inputs:
- Regional loads*
- Fuel prices*
- Fuel availability*
- Resources (availability*)
- New resources costs
- Transmission

*Stochastic input

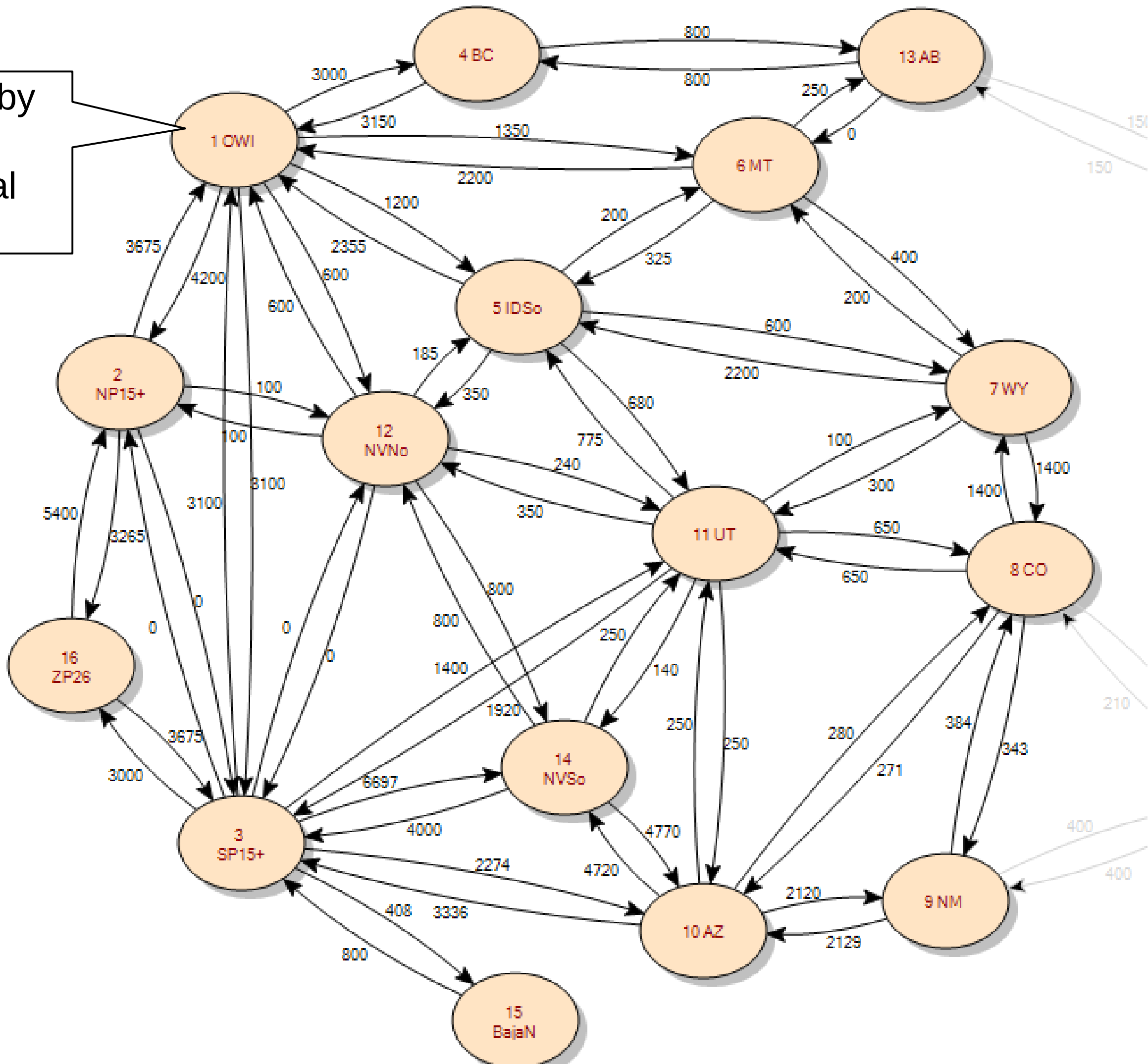
Outputs:
- Market prices
- Energy mix
- Transmission usage
- Emissions
- Power plant margins, generation levels, fuel costs
- Avista's variable power supply costs

Aurora Modeling Changes from 2017 IRP

- Use Epis/Energy Exemplar latest database vs. Avista's proprietary database
- Updates to the Epis database will include:
  - Avista specific characteristics (load/generation/fuel)
  - Fuel prices
  - Regional hydro conditions (80-year record)
  - Adjustments to allow market prices to go negative
  - Load shape changes (electric vehicles/rooftop solar)
  - Known regional resource retirements
  - Split Northwest area between WA, OR, and ID (TBD)

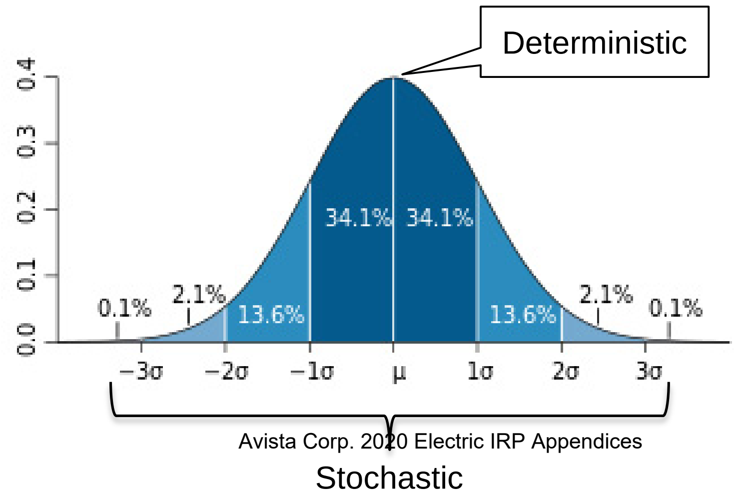
Aurora Load Area Topology

Potential split by state due to environmental policies



Stochastic vs. Deterministic Analysis

- Deterministic analysis forecasts for a specific set of inputs.
  - Easy to understand
  - Works great for sensitivity analysis of specific changes
- Stochastic analysis forecasts for a range of inputs.
  - Range (or distribution) of results
  - Works great to understand risks of the inputs with variation



PRiSM- Preferred Resource Strategy Model

- Internally developed using Excel based linear/mixed integer program model (What's Best & Gurobi)
- 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

GUROBI OPTIMIZATION

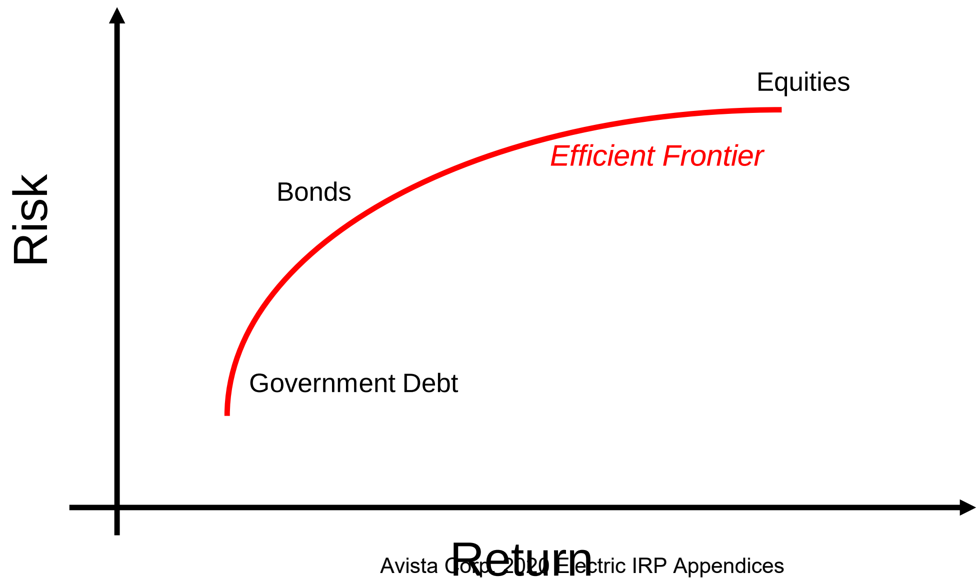
PRiSM

- Find optimal resource strategy to meet resource deficits over planning horizon
- New for the plan: Split Avista's resources and loads
  - City of Spokane
  - Idaho
  - Washington
- Model selects its resources to reduce cost, risk, or both.
- Objective Function:
  - Minimize: Total Power Supply Cost on NPV basis (2020-2058)
  - Focus on first 20 years of the forecast
  - Subject to:
    - Risk level
    - Capacity need +/- deviation
    - Energy need +/- deviation
    - Renewable portfolio standards
    - Resource limitations, sizes, and timing

Efficient Frontier Concept

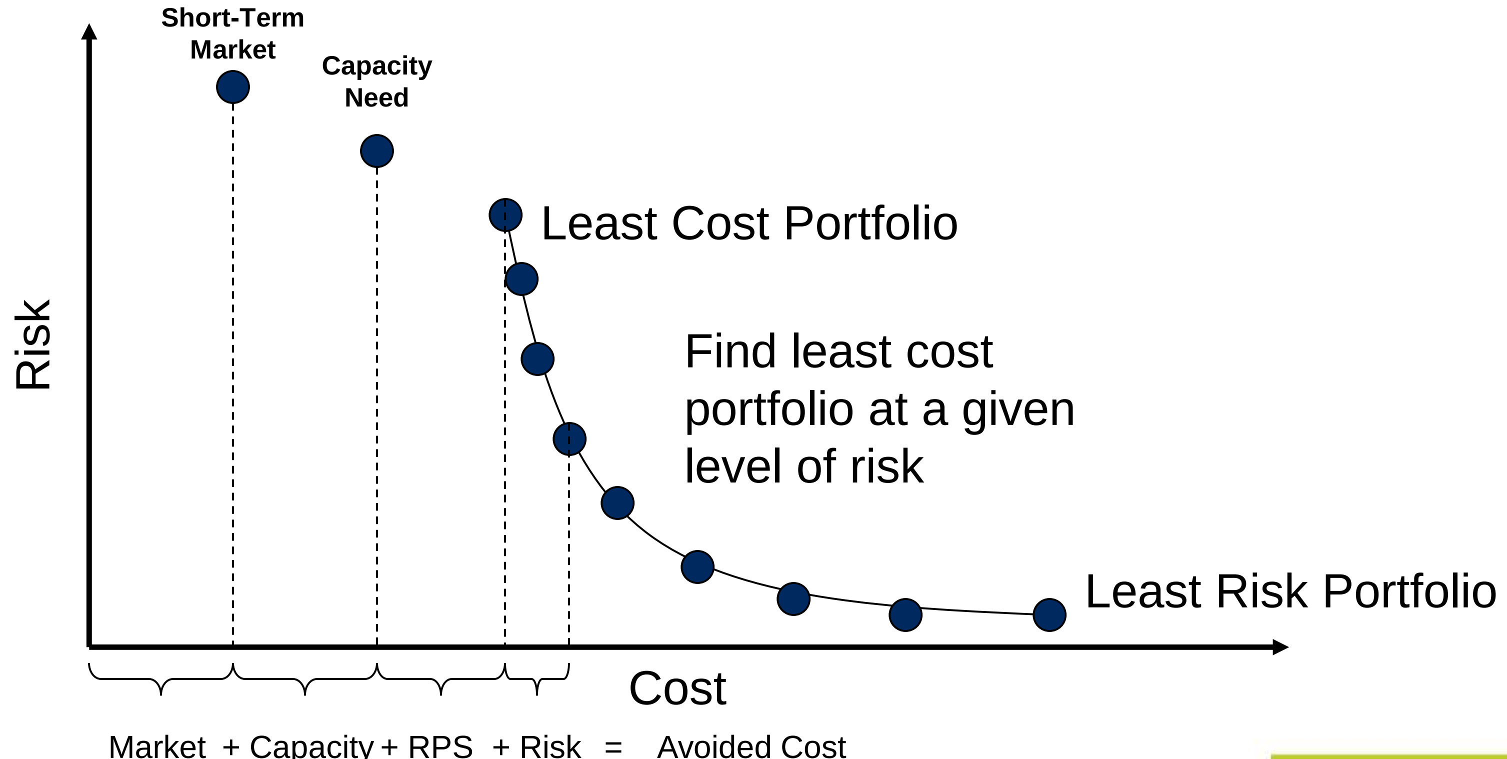
- <u>Does not</u> find the optimal portfolio, only the optimal portfolio for a given level of risk.
- Used in investment finance for portfolio management.

Stock vs. Bond Example



Efficient Frontier

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



2019 Electric IRP
Generation Resource Options

James Gall,
Second Technical Advisory Committee Meeting
November 27, 2018

Overview & Considerations

- The assumptions discussed are "today's" estimates and will likely have periodic revisions.
- Resource costs vary depending on location, equipment, fuel prices, and ownership; while IRPs use point estimates, actual costs will be different.
- Avista retained Black & Veatch to review the renewable and storage resource assumptions as part of the Hydro One merger agreement.
- Certain resources will be modeled as purchase power agreements (PPA) while others will be modeled as Avista "owned". These assumptions do not mean they are the only means of resource acquisition.
- No transmission or interconnection costs are included at this time.
- Natural gas prices used "today" will be revised with the "final" assumption in January 2019.
- An Excel file will be distributed with all resources, assumptions and cost calculations for TAC members to review and provide feedback.

Proposed Natural Gas Resource Options

Peakers

- Simple Cycle Combustion Turbine (CT)
  - Aero and frame units
  - Smaller units 44 MW to 80 MW
  - Larger units up to 245 MW
- Hybrid CT
  - 92 MW
- Reciprocating Engines
  - 9 MW to 18 MW units with up to 10 engines

Baseload

- Both modern and advanced Combined Cycle CT (CCCT) will be evaluated
  - Smaller options 158 MW to 308 MW (3x2, 1x1)
  - Larger options 324 MW to 480 MW (1x1)
- Large 2x1 technology not modeled

Natural gas turbines are modeled using a 30-year life with Avista ownership

Renewable Resource Options

All Purchase Power Agreement (PPA) Options

Wind

- On-system wind (101 MW)
- Off-system wind (101 MW)
- Montana wind (101 MW)
- Off shore wind (100 MW)
  - Share of a larger project

Solar

- Fixed PV array (5 MW AC)
- On-System Single Axis Tracking Array (100 MW AC)
- Off-system Single Axis Tracking Array (100 MW AC) located in southern PNW
- On-System Single Axis Tracking Array (100 MW AC) with 25 MW 4 hour lithium-ion storage resource

Other “Clean” Resource Options

- Geothermal (20 MW)
  - Off-system PPA
- Biomass (100 MW)
  - i.e. Kettle Falls 3
- Nuclear (100 MW)
  - Off-system PPA share of a larger facility

Storage Technologies

Lithium-Ion

- Assumes: 88% round trip efficiency (RTE), 10-year operating life
- Assumes Avista ownership
- 5 MW Distribution Level
  - 4 hours (20 MWh)
  - 8 hours (40 MWh)
- 25 MW Transmission Level
  - 4 hours (100 MWh)
  - 8 hours (200 MWh)
  - 16 hours (400 MWh)
  - 40 hours (1,000 MWh)

Updates to storage costs are likely as additional information becomes available

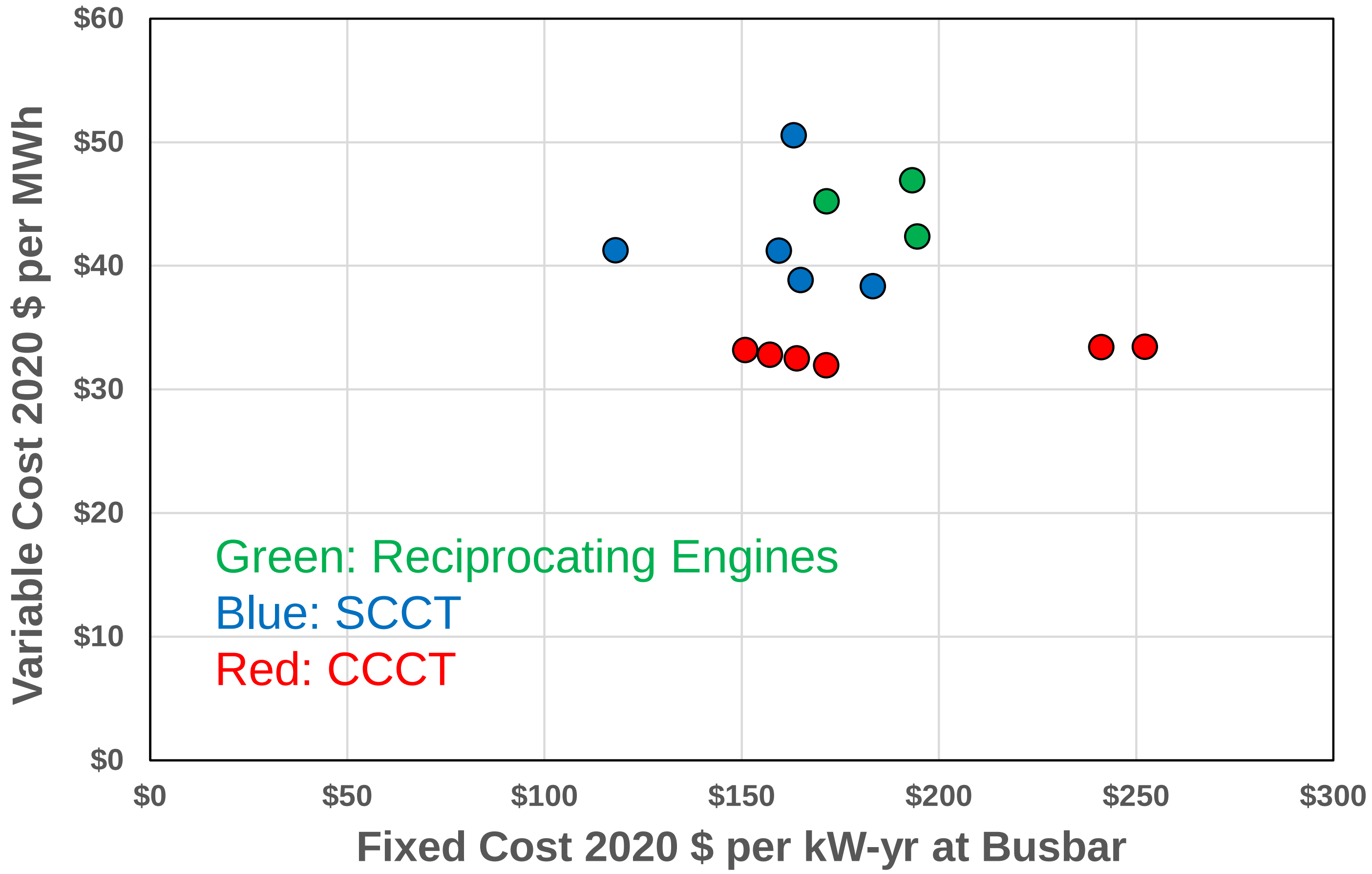
Other Storage Options

- Assumes 20 to 30-year life and Avista ownership
- 25 MW Vanadium Flow (70% RTE)
  - 4 hours (100 MWh)
- 25 MW Zinc Bromide Flow (67% RTE)
  - 4 hours (100 MWh)
- 25 MW Hydrogen Fuel Cell (varies)
  - 4 hours (100 MWh)
  - 16 hours (200 MWh)
  - 40 hours (1,000 MWh)
- 25 MW Liquid Air (65% RTE)
- Liquid Air (retrofit natural gas CT)
  - 12.7 MW (59 MWh)
  - 78 MW (700 MWh)
- 100 MW Pumped Hydro
  - Share of larger project
  - 16 hours of storage
  - PPA assumption

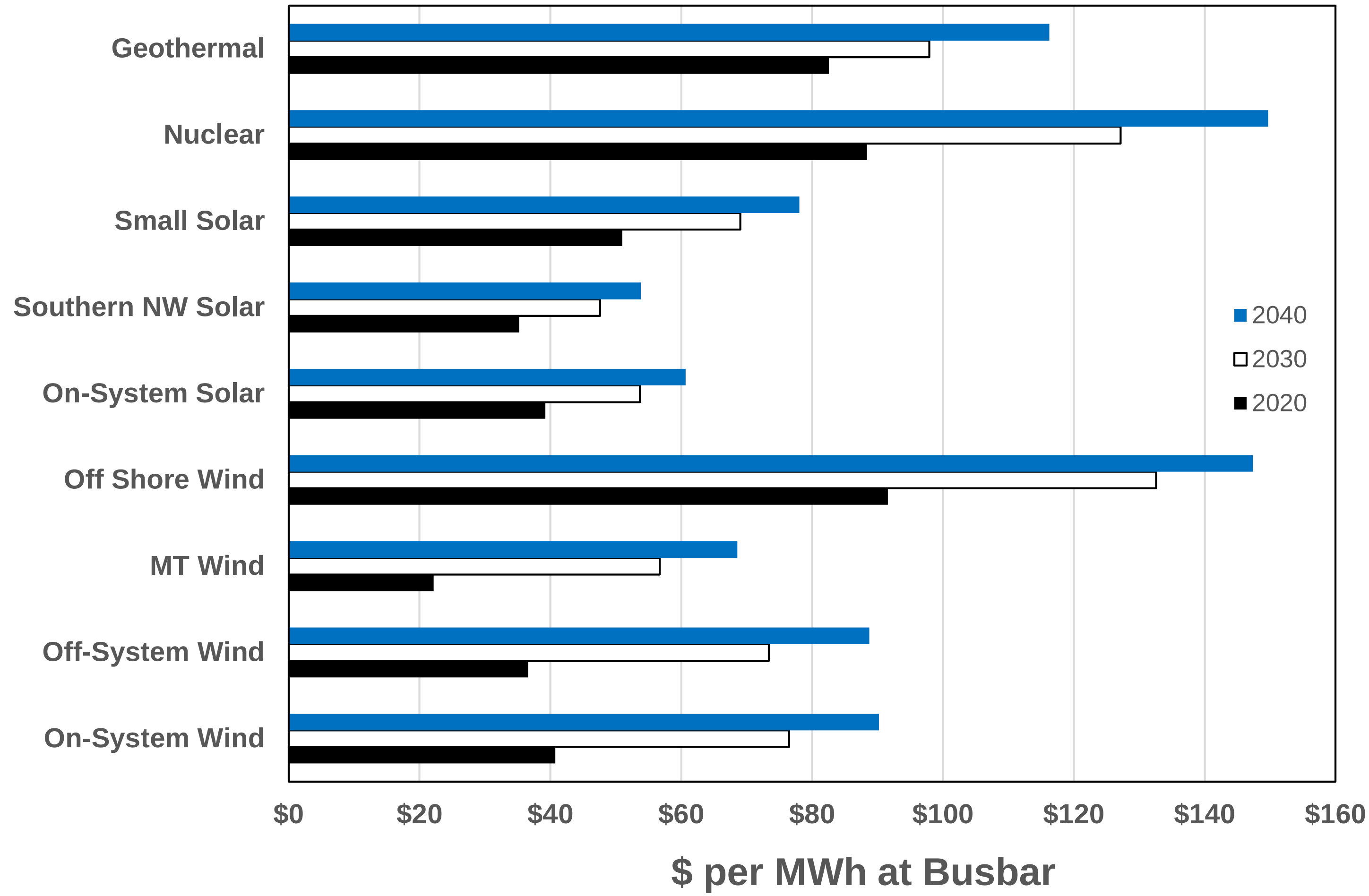
Resource Upgrades

- **Northeast** *[natural gas peaker]*
  - 7.5 MW using water injection
- **Rathdrum CT** *[natural gas peaker]*
  - 5 MW by 2055 uprates
  - 24 MW add supplemental compression
  - 17 MW (summer), 0 MW (winter) Inlet Evaporation
- **Kettle Falls** *[biomass]*
  - 12 MW by repowering with larger turbine during replacement
- **Post Falls Redevelopment** *[hydroelectric]*
  - 8 MW, 4.5 aMW with larger modern units
- **Long Lake 2nd Powerhouse** *[hydroelectric]*
  - 68 MW, 12 aMW with additional powerhouse located at the current “cutoff” dam
- **Monroe Street/Upper Falls** *[hydroelectric]*
  - 80 MW, 27 aMW with additional powerhouse located in Huntington Park
- **Cabinet Gorge** *[hydroelectric]*
  - 110 MW, 18 aMW using the “bypass” tunnels to capture runoff spill

Natural Gas Fixed & Variable Costs



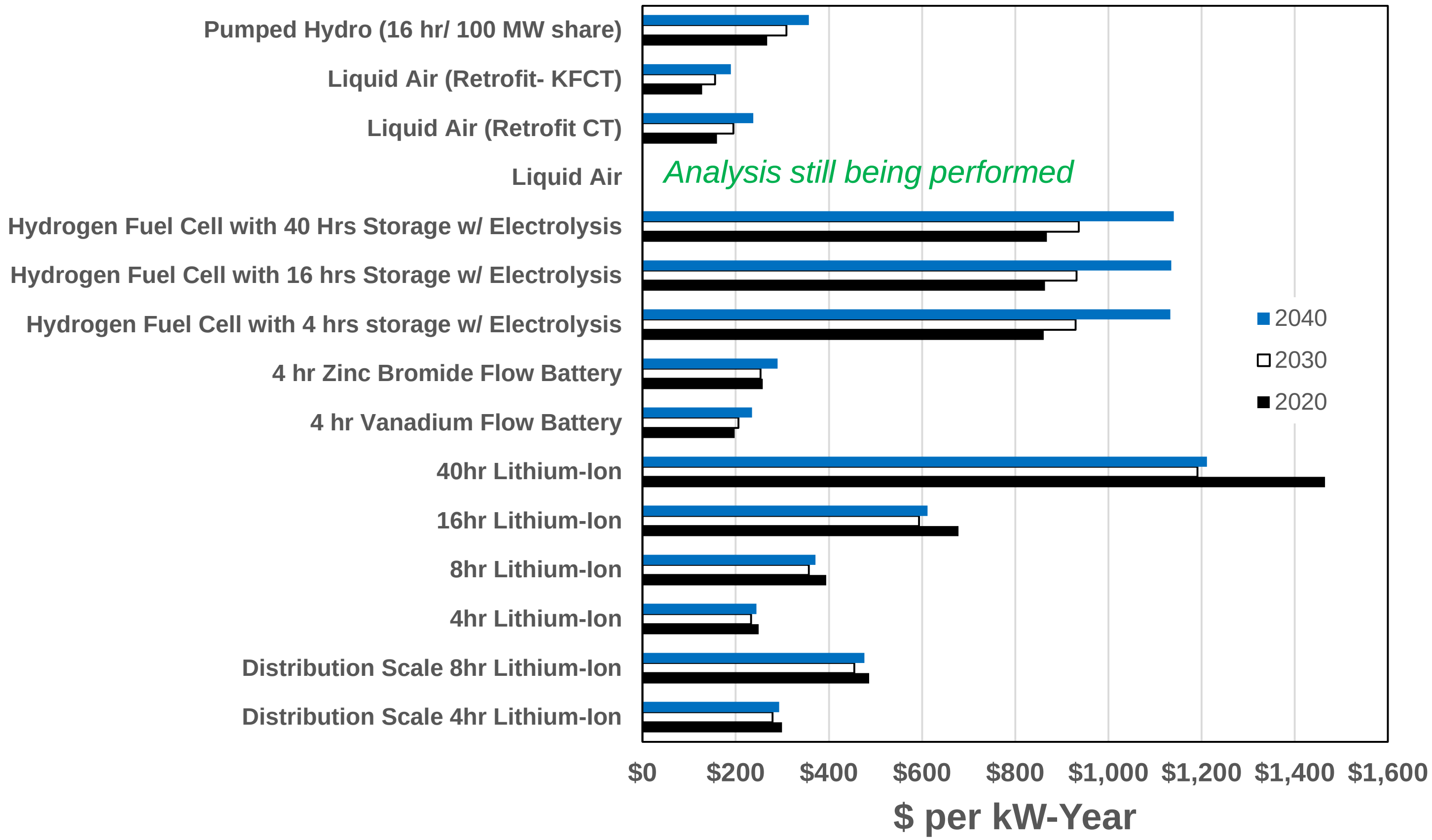
PPA Resource Cost Analysis



Prices include utility loading such as variability integration and revenue taxes

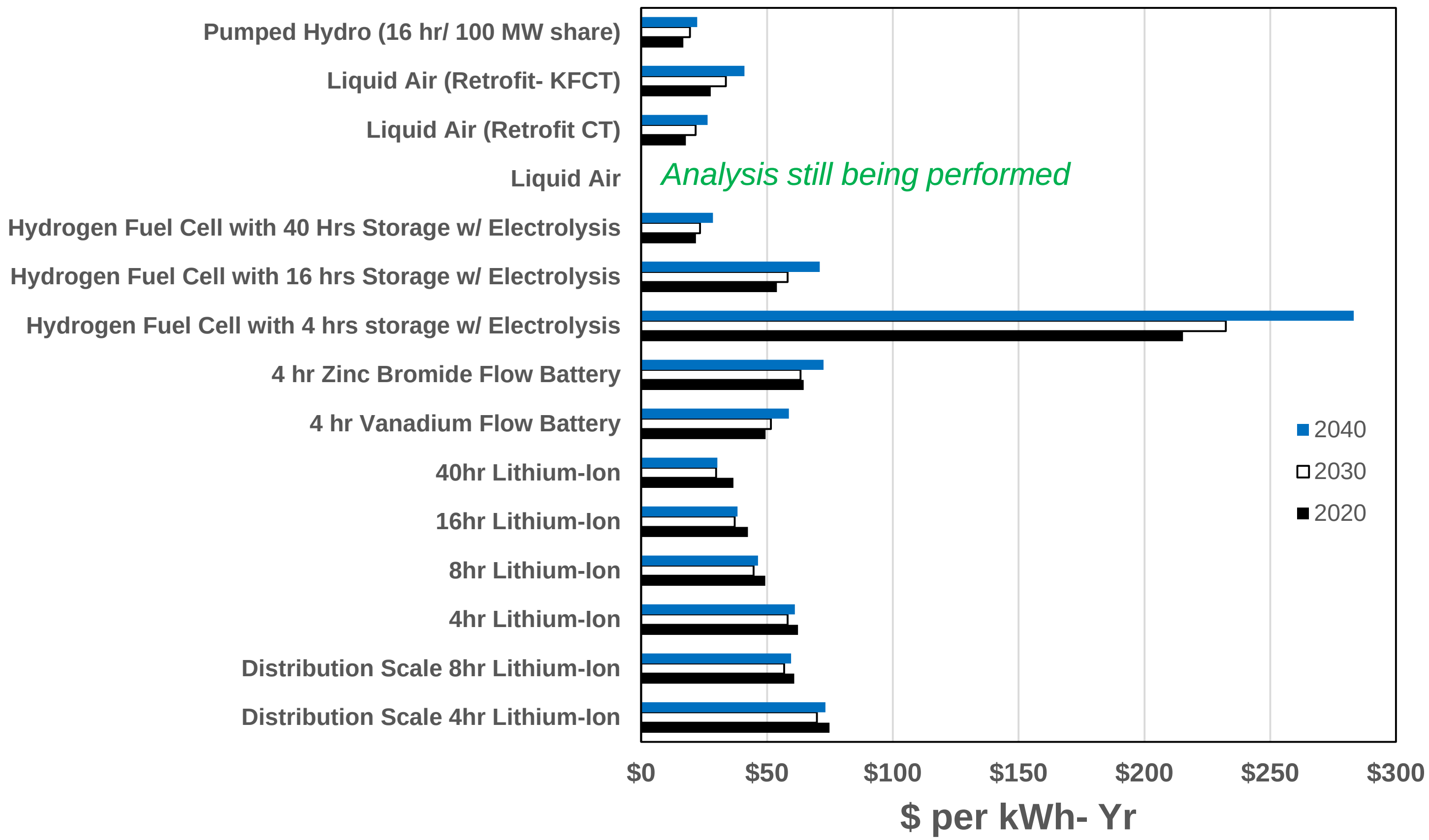
Storage Costs

Capacity based cost analysis

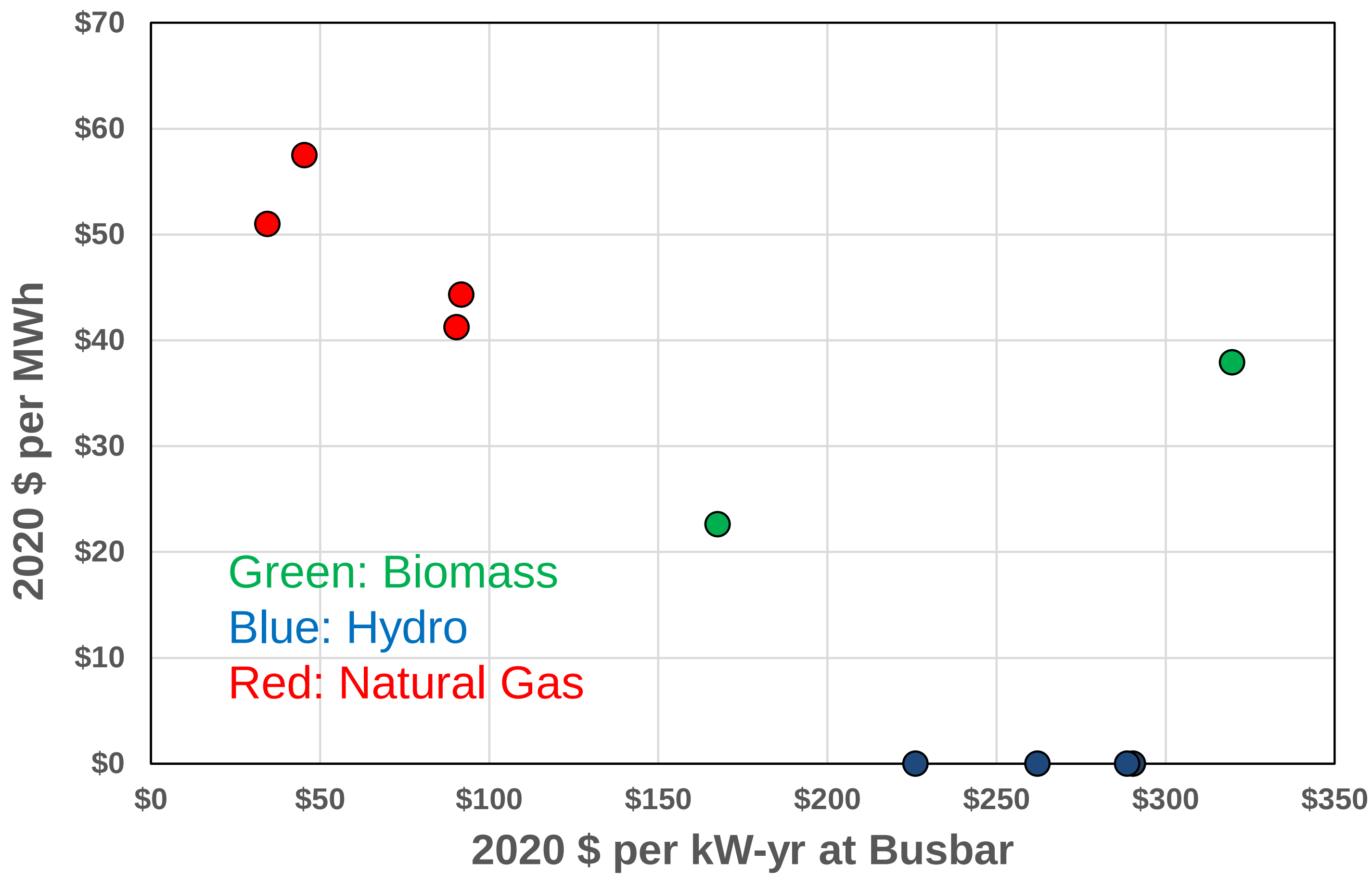


Storage Costs

Energy based cost analysis



Facility Upgrade Cost Analysis



Other Power Purchase Options

- Market Power Purchases
  - Firm purchases
  - Real-time
- Mid-Columbia Hydro
  - Renegotiate slice contracts from Mid-C PUDs
- Acquire existing resources from IPPs
- Renegotiate Lancaster PPA
- BPA
  - Block surplus contract: up to 7-year term at BPA "cost"
  - NR Energy Sales: $78.94 MWh
  - After 2028, other potential options when current Regional Dialog contracts expire

Review Excel Sheet

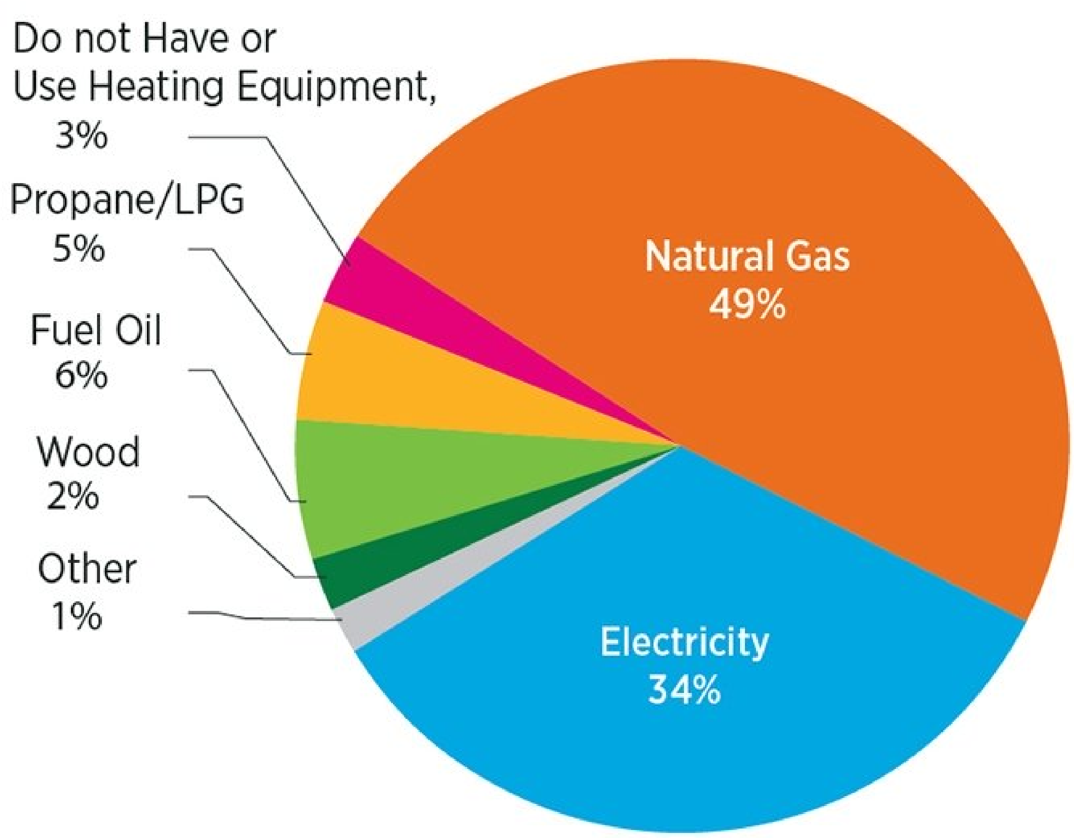
Home Heating Technologies Overview

Tom Lienhard, Chief Energy Efficiency Engineer
Second Technical Advisory Committee Meeting
November 27, 2018

Home Heating Systems

- Delivery method
  - Radiation
  - Convection
  - Forced Convection
- Number of controlled heating segments
- Fuel used for heating the fluid
  - Electricity
  - Natural Gas
  - Other
- Efficiency of fuel delivery
- Heating load of the residence

Home Heating Systems in US



Household Heating Systems: Although several different types of fuels are available to heat our homes, nearly half of use natural gas. | Source: Buildings Energy Data Book 2011

Delivery Method

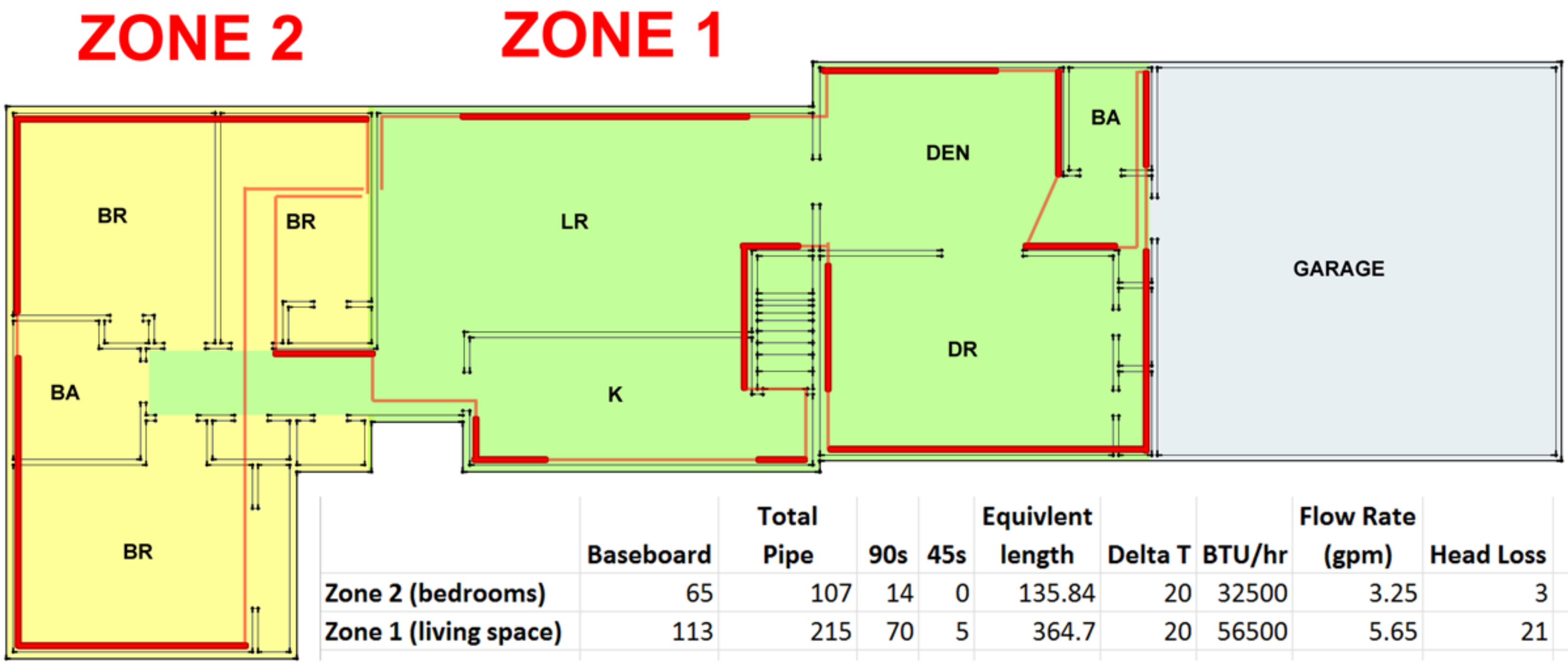
- Radiation – heated by radiant energy. Radiant floor heating can use 40% of the energy of convective heating systems.
- Baseboard or fluid registers on the outer portions of the home cause natural convection.
- Furnaces and fans in heaters create forced convection.

Zoning

- Increasing number of controlled zones decreases amount of heat needed. When two or more areas can be kept at different temperatures based on need or occupancy, savings may occur.

- Home furnaces controlled by single thermostat cannot benefit from zoning. Attempts to zone a forced air system often reduce heating efficiency and have a greater impact on air source heat pumps.

Zoning



	Baseboard	Total Pipe	90s	45s	Equivlent length	Delta T	BTU/hr	Flow Rate (gpm)	Head Loss
Zone 2 (bedrooms)	65	107	14	0	135.84	20	32500	3.25	3
Zone 1 (living space)	113	215	70	5	364.7	20	56500	5.65	21

Fuel Used to Heat the Transfer Fluid

- Radiant surfaces can be fueled by any source.
  - Electric use electric resistance coils.
  - Transfer liquids can be heated by electricity, natural gas or any other fuel.
- Forced and natural convection systems can be fueled by natural gas, electric elements, heat pump, wood, or any other fuel.
- Low carbon future could use dual fuel sources.

Fuel Delivery Efficiency

- Natural gas limited to 98% efficiency when exhausting combustion product outside. Natural gas heat pumps with a coefficient of performance (COP) around 1.5 under development.

- Electricity has a low threshold of 100% efficient with resistive electric, although an air source heat pump backed by resistance can operate below 100% during defrost and low temperatures. Electric heat pumps can approach an annual COP of 4, depending on outside temperature, soil type and heat pump type.

Fuel Delivery Efficiency– cont.

- Ground source heat pump
  - Highest performing units
  - Utilize stored energy of the sun in the earth to transfer heat

- Highest performing air source heat pumps are ductless units
  - Perfectly coupled between interior and exterior units.
  - CO_2 heat pumps being tested in the US do not have the exterior temperature issues that other air source heat pumps have with efficiency degradation due to cold weather (NW CO_2 Pilots)

Fuel Delivery Efficiency – cont.

- Lowest efficiency fuel is wood
  - An average of 50% of the heat makes it into the space.
  - If the damper is left open on a chimney flue, the house will evacuate the heat inside after the fire goes out through the stack affect.
  - One of the best home audit measures is to plug the flue of unused fireplaces to reduce lost heat.

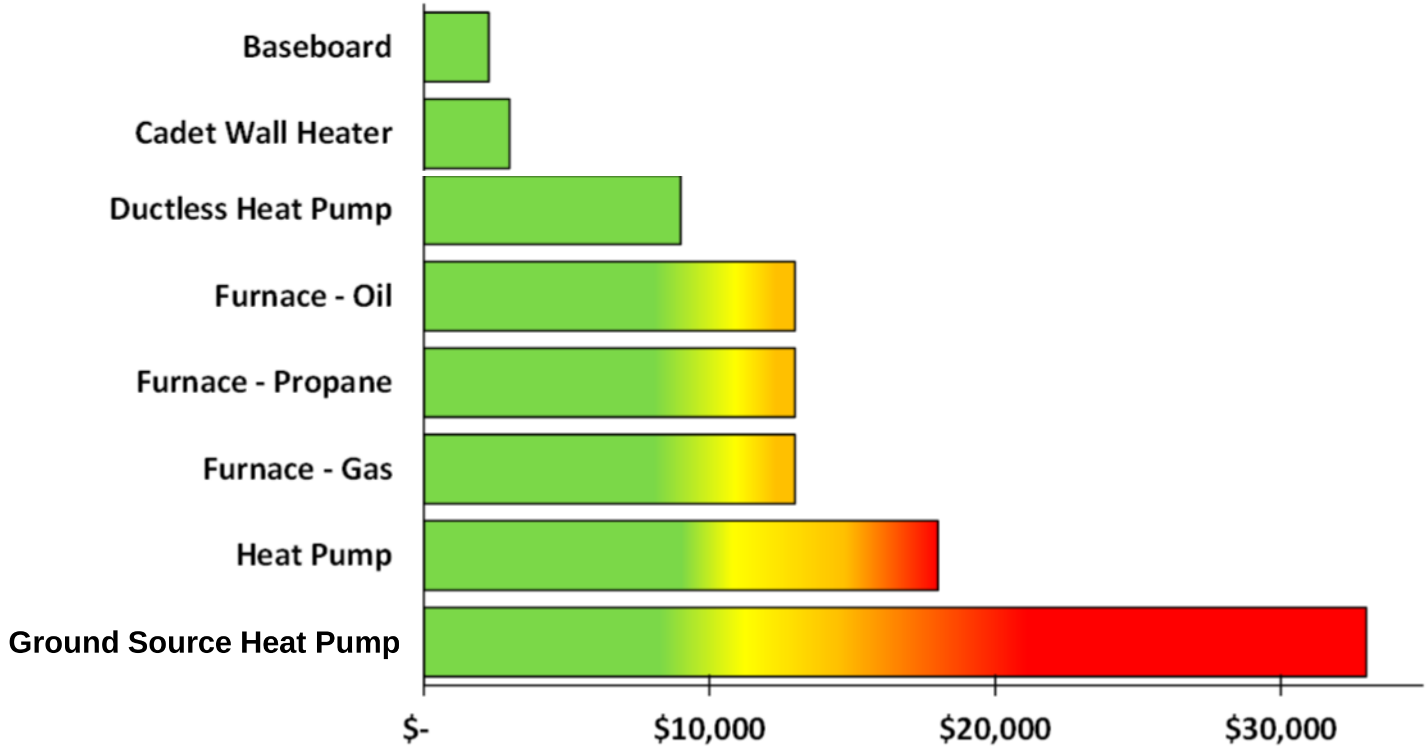
First Cost of Technologies

- Ground source heat pumps add $10,000 to $20,000 to a home budget if feasible.

- In-floor radiant systems add $10,000 to $15,000 to normal forced air system in new construction.

- Full home multi-head zoned ductless units can be $10,000 to $30,000 above baseline natural gas systems.

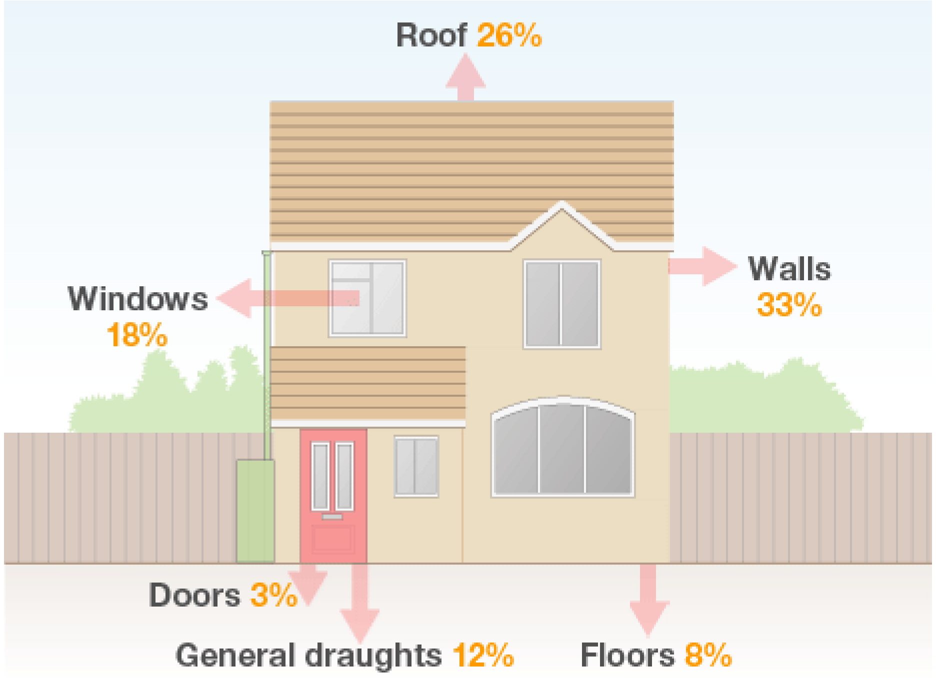
First Costs


Baseboard
Cadet Wall Heater
Ductless Heat Pump
Furnace - Oil
Furnace - Propane
Furnace - Gas
Heat Pump
Ground Source Heat Pump
$-
$10,000
$20,000
$30,000

Home Heating Needed

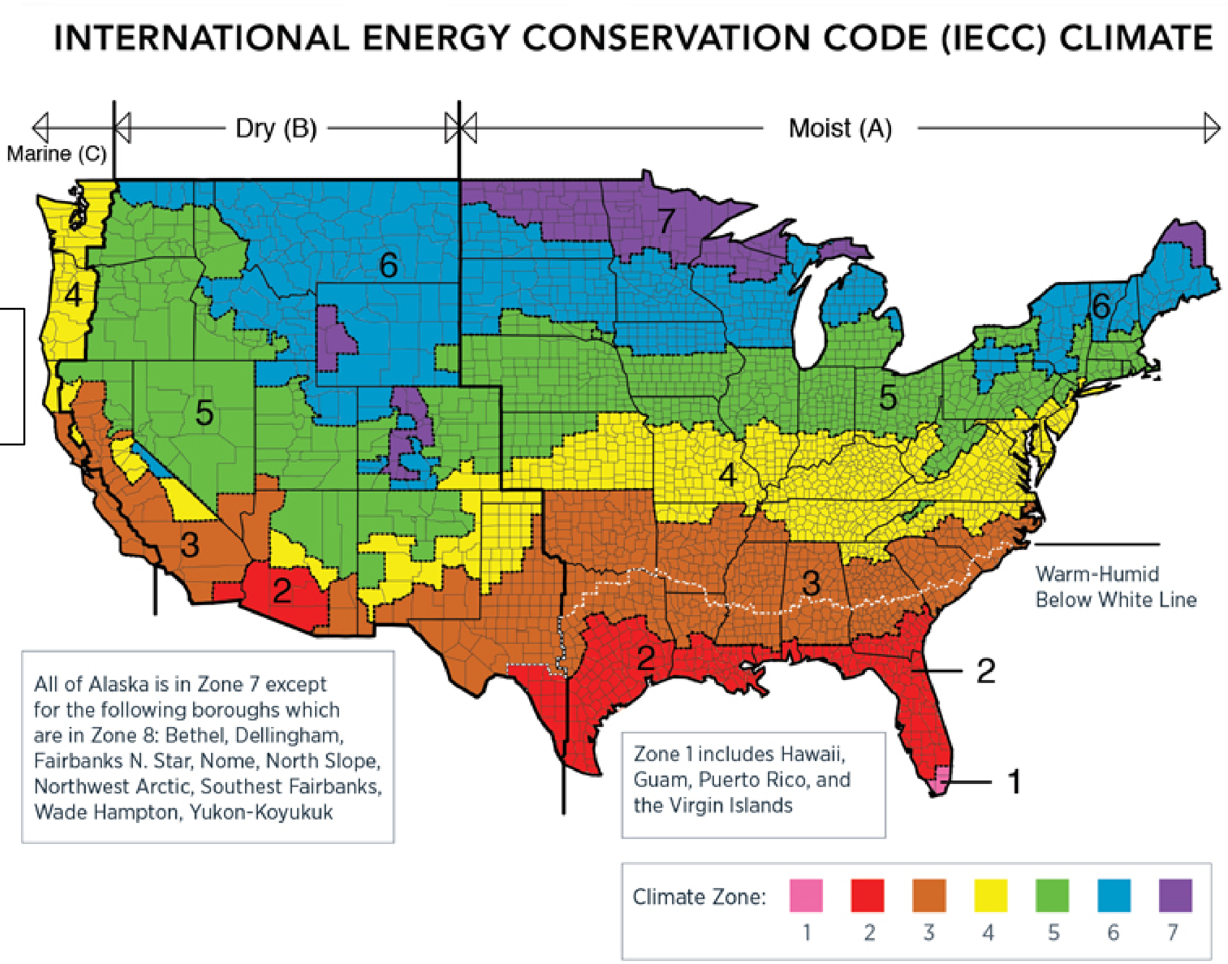
- **Size:** smaller is better
- **Insulation:** more is better
- **Location and installation of ductwork:** inside is better
- **Infiltration:** none is better, need Energy Recovery Ventilator
- **Number of people:** more is better
- **Humidity:** some is better than none

Home Heat Loss



Source: Energy Saving Trust

Climate Zones



RTF identifies zones 4, 5 & 6 zones 1, 2 & 3

https://basc.pnnl.gov/images/iecc-climate-zone-map

Home Heat Loss Calculation

- Most loss from conduction through envelope and infiltration/exfiltration through cracks.

- $E_L = UA(T_{in}-T_{out})$
  - U is thermal conductivity,
  - A is the surface area of the home, and
  - T_{in} is temperature inside and T_{out} temperature outside

- 1,000 ft^2 home with 8 foot ceilings has an area of 3,760 ft^2. If the average R value is 25, it has a U factor of .04 $BTU/hr*ft^2*F$.

Cost of Heat Loss – Example

- If average outdoor temperature during the heating season is 42° and the set point is 72°, then the hourly heat loss is 4,512 BTU/hour
  - .04*3,760*30 = 4,512 BTUs or 3,248,640 BTU's per month. That is 951 kWh with electric resistance heat, about 560 kWh with an air source heat pump, and about 33 therms.
- At Avista's current rates, losses would be $95 for resistance heat, $56 for a heat pump, and $30 for natural gas.
- This is for a very small home with very good insulation in Northwest climate zone 4 ignoring heat gain from humans or solar.

Heating Degree Days (HDD)

- Difference between 65° and outside temperature measured in days.

- 6,800 HDD: Spokane average of a 38° difference between 65° and outside over 6 month heating season.

- 4,700 HDD: Seattle average of a 29° difference between 65° and outside over 6 month heating season.

- Heat pumps operate in their wheelhouse in Seattle and below optimum in Spokane.

Fuel Cost

- Natural Gas heat is 1/3 the cost per BTU compared to electricity.
  - The average electric home costs more to operate than a natural gas home in climate zones 2 and 3 at Avista's current gas and electric prices.
- Avista's electric peak often occurs at the coldest point in December, so electric homes highest consumption coincides with our highest load.
  - This includes net zero homes which don't produce during our winter peak.

Questions

Resource Adequacy and Effective Load Carrying Capability

James Gall, IRP Manager

Second Technical Advisory Committee Meeting

November 27, 2018

Why Does Resource Adequacy Matter?

- Helps determine how much new capacity our customers need.
- Informs “us” how much capacity we rely on from our neighbors.
- Provides insight on how certain resource help provide reliable capacity.

We discovered this type of analysis requires a lot of process time, specific locational assumptions for renewable resources, and is an “art” rather than a specific science.

Loss of Load Probability (LOLP)

- LOLP is the current regional measurement for resource adequacy.
- Measures probability of a resource adequacy deficiency over a one year time period.
- No regulatory body enforces a particular resource adequacy standard or metric.
- This is a great measure of probability of reliability, but…according to the NPCC…
  - *"No measure of magnitude*
  - *No measure of duration*
  - *No measure of frequency within the year*
  - *Two scenarios with same LOLP can have vastly different curtailment magnitude and duration"*

Reliability Metrics Options

What we are modeling for?

- Events not serving all load and reserve requirements due to insufficient resources/market availability

Metrics

- LOLP: Loss of Load Probability
  - Number of draws with an event (probability of a draw with an event)
- LOLH: Loss of Load Hours
  - Hours with events / iterations (time in hours)
- LOLE: Loss of Load Events
  - Days with events / iterations (time in days)
- EUE: Expected Unserved Energy
  - Average MWh not served during an event (Magnitude)
- ELCC: Effective Load Carrying Capability
  - Percentage of resource capacity equal to CTs

Model Assumptions & Challenges

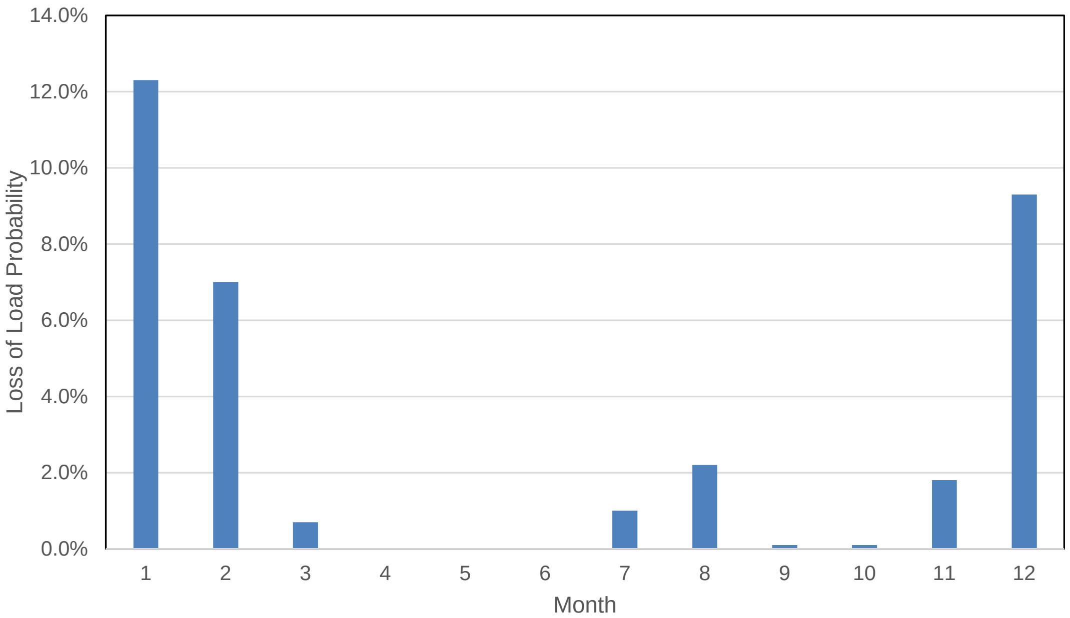
The Model

- Built in Excel with What's Best optimizer
- 1,000 simulations
- Randomizes:
  - Forced outages
  - 80 years of hydro data
  - 128 years of weather data (load & generation)
- Challenges:
  - Time: three days to run per study, to date over 70 studies since April have been completed.
  - Randomization: may not get same results with same assumptions.
  - This is becoming more of an "art" then a "science"

The Key Assumptions

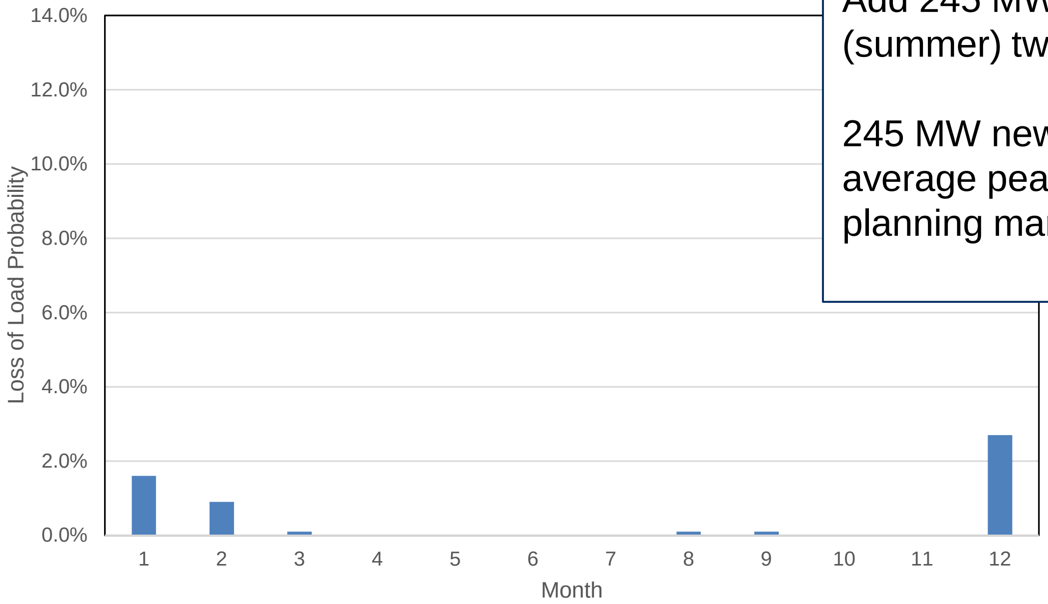
- 2030 load and resources
- Average peak load: 1,778 MW (Winter), 1,636 MW (Summer)
- Average hourly load: 1,081 MW
- Major resource changes from today: No Lancaster, less Mid-C, no WNP-3 contract
- Off-peak market purchases limited to 1,000 MW
- On-peak market purchase limited to 400 MW
- When daily temps > 84 and < 4 degrees Fahrenheit, market purchases are limited 250 MW

Without resource additions, what is our reliability metrics in 2030?



- LOLP: 27.9%
- LOLH: 18.29
- LOLE: 1.41
- EUE: 3,430 MWh

How much capacity is required to be at 5% LOLP?

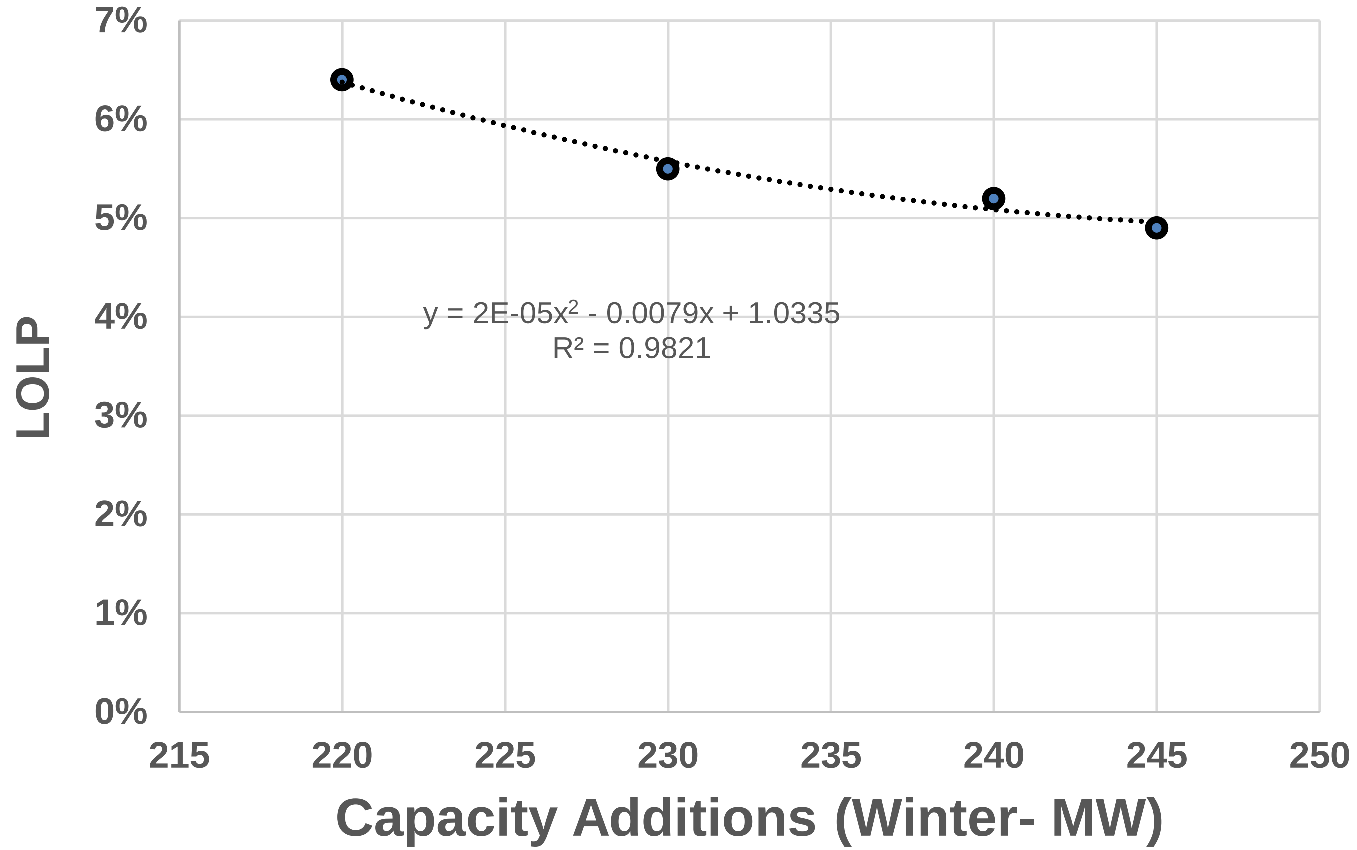


Add 245 MW (winter) / 182 MW (summer) two unit CT

245 MW new gen / 1,778 MW average peak load = 13.8% planning margin

- LOLP: 4.9%
- LOLH: 1.85
- LOLE: 0.16
- EUE: 318.7 MWh

LOLP at Different Levels of Capacity Additions



Does Wind Improve Reliability?

- Wind can improve reliability, but not equal to a CT
- Location diversification improves capacity credit!
- Studies to date include two studies:
  - Case 1: NW Wind
  - Case 2: Montana Wind

Case 1: NW Wind

- 1st study: exclude Palouse Wind

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Palouse Wind excluded	5.5%	1.86	0.17	307

- 2nd study: decrease CTs by 25 MW and add more wind until 5% LOLP is achieved

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
+ 300 MW wind	5.5%	1.80	0.15	296
+ 400 MW wind	5.5%	1.72	0.14	256
+ 500 MW wind	5.4%	1.70	0.14	280
Reference case -15 MW CT	5.5%	1.93	0.17	319

1) 5% LOLP never achieved
2) other metrics improve with more wind
3) Suggest ELCC for NW wind: 15/300= 5%

- Concerns:
  - How will other NW projects with less correlation to Palouse change this result?

Case 2: Montana Wind

- Reduce CTs by 25 MW, add wind until 5% LOLP is maintained

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
+ 60 MW MT wind	4.9%	1.49	0.13	249
+ 70 MW MT wind	4.9%	1.39	0.12	203
+ 100 MW MT wind	4.1%	1.18	0.10	205

ELCC for MT Wind: 25/60= 42%

- Concerns:
  - Low temperature cut outs, wind turbines must curtail when temperatures are below -30 Celsius (-22 F)
  - All Montana wind regimes may not be the same
  - Earlier analysis showed 30% capacity contribution with alternate data
  - Avista needs to perform more studies including larger reduction in capacity deficit positions

Does Solar Improve Reliability?

- Solar studies are performed similar to wind, but use an earlier version of the model
- CT reductions:
  - 76 MW Winter
  - 56 MW Summer
- Never get to 5% LOLP!
- Summer LOLP reduces to zero in high cases
- Conducted a new reference case with 20 MW less CT winter capacity to arrive at a 5.8% LOLP
- ELCC is 2.2% (20 / 900)

Case	LOLP	LOLH	LOLE	EUE
Reference	5.0%	1.75	0.15	254
Reference – 76 MW CTs	9.4%	3.73	0.30	689
300 MW	7.8%	2.71	0.22	440
600 MW	7.6%	2.29	0.21	353
900 MW	5.8%	2.14	0.18	350
Reference – 20 MW CT	5.8%	1.75	0.17	327

Does Demand Response (DR) Improve Reliability?

- Demand response temporarily reduces load for a period of time
- Studied three scenarios compared to "CT" reference case
  - 25 MW, 4 hour reduction up to 10 times per year
  - 25 MW, 8 hour reduction up to 10 times per year
  - 25 MW, 16 hour reduction up to 10 times per year

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
4 hour duration	6.1%	1.99	0.18	338
8 hour duration	5.7%	1.87	0.16	316
16 hour duration	5.6%	1.67	0.15	282
Reference case -15 MW CT	5.5%	1.93	0.17	319

- Proposed ELCC:
  - 4 hour: 8% (2 MW / 25 MW)
  - 8 hour: 60% (15 MW / 25 MW)
  - 16 hour: 64% (16 MW / 25 MW)

Does Storage Improve Reliability?

- Storage moves energy, but doesn't create energy!
  - Storage can lose 10% to 50% of the energy it stores
  - Study assumes 90% round trip efficiency (i.e. Lithium-ion technology)
  - Storage requires the ability to add additional energy to the system from another source to add significant capacity value
  - Higher storage penetration may lead to less capacity contribution

Storage Results

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
25 MW, 4 hour storage	5.8%	2.13	0.19	352
25 MW, 16 hour storage	5.7%	2.04	0.17	315
25 MW, 40 hour storage	5.6%	1.92	0.17	387
25 MW, 4 hour storage, w/ 50 MW solar	5.6%	1.96	0.18	330
50 MW, 4 hour storage, w/ 50 MW Solar	5.3%	1.95	0.17	302
50 MW, 4 hour storage, w/ 100 MW Solar	5.2%	2.23	0.19	379

Avista proposes to use the following capacity credits for low capacity additions
4 hour: 56% (14 MW / 25 MW)
16 hour: 52% (13 MW / 25 MW)
40 hour: 48% (12 MW / 25 MW)

A third party analysis estimates 10% capacity credit results without new energy resources. With new energy resources its between 12% and 60%

Resource Combination Analysis

What if we remove new “CTs” and planned our system with non-traditional resources

Case	LOLP	LOLH	LOLE	EUE
No new resources	27.9%	18.3	1.41	3,430
Reference case (add 245 MW CT)	4.9%	1.85	0.16	319
Add: 200 MW MT wind, 155 MW NW wind, 50 MW DR, 125 MW 6 hour storage, and 250 MW solar	6.3%	2.43	0.20	429
Add: 200 MW MT wind, 245 MW NW wind, 50 MW DR, 150 MW 6 hour storage, and 350 MW solar	4.8%	2.40	0.17	487
Exclude Colstrip from portfolio & no new resources	75.8%	106.8	8.43	21,265
Add: 400 MW MT wind, 400 MW NW wind, 100 MW DR, 200 MW 6 hour storage, and 500 MW solar	13.2%	5.46	0.45	1,174

Third Party ELCC Analysis

Slides not included at this time for distribution or webcast

2019 Electric IRP Key Assumptions

James Gall, IRP Manager
John Lyons, Senior Resource Policy Analyst
Second Technical Advisory Committee Meeting
November 27, 2018

Existing Forms of Carbon Regulation

- Indirect: Renewable resource additions, higher RPS
- Carbon tax: British Columbia
- Direct regulation: Affordable Clean Energy Rule
- Cap and trade: AB 32 in California
- State mandates: Oregon SB 1547 and emissions performance standards

Renewables

- Renewables drive emissions lower, but may be indirect to the location of the renewable generation’s location
- RPS standards in each state (large utility goals shown below)
  - WA: 15% by 2020 (100% clean proposals)
  - OR: 50% goal by 2040
  - CA: 45% by 2023, 50% by 2026, 60% goal by end of 2030, and 100% by 2045 (SB 100)
  - NV: 25% by 2025 (50% by 2030, needs another yes vote in 2020)
  - AZ: 15% by 2025 (50% by 2035 failed in Nov. election)
  - NM: 20% by 2020
  - CO: 30% by 2020 (Higher proposals expected)
  - MT: 15%
- Consumer Driven Renewables
  - Rooftop solar
  - Large commercial direct investment
  - Green tariffs (jurisdictional and organizational)

Direct Regulation

Washington SB 6001- Emissions performance standard limits "baseload" generation to 930 lbs of CO_2 per MWh for new resources or contracts five years or longer

Affordable Clean Energy Rule (ACE) – August 2018 replacement proposal for the Clean Power Plan

1. Defines the "best system of emission reduction" (BSER) for existing plants as on-site, heat-rate efficiency improvements;
2. Provides "candidate technologies" for states to establish standards of performance for their plans;
3. Updates the New Source Review (NSR) permitting program to encourage efficiency improvements at existing plants; and
4. Aligns regulations under CAA section 111(d) to give states time and flexibility to develop their own plans.

Carbon Regulation and Taxes

- AB 32 in California
  - 1990 levels by 2020 and 80% below 1990 levels by 2050
  - Typically modeled as a “price” adder due to economy-wide trading system, using minimum price
- Oregon
  - Coal to Clean: coal can no longer serve Oregon loads after 2030/2035
  - Cap and trade program expectations in next legislative session
- Washington 100% Clean Proposals
- Affordable Clean Energy Rule
- Canadian Carbon Taxes
  - British Columbia: $30/metric ton (Can$)
  - Alberta: $30/metric ton (Can$)

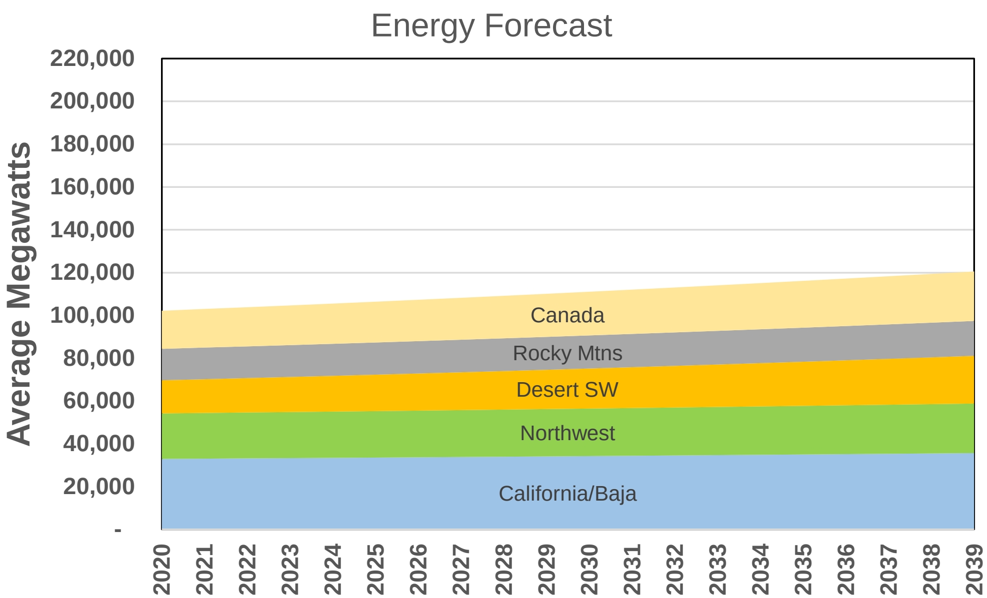
Aurora Inputs

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

Regional Loads

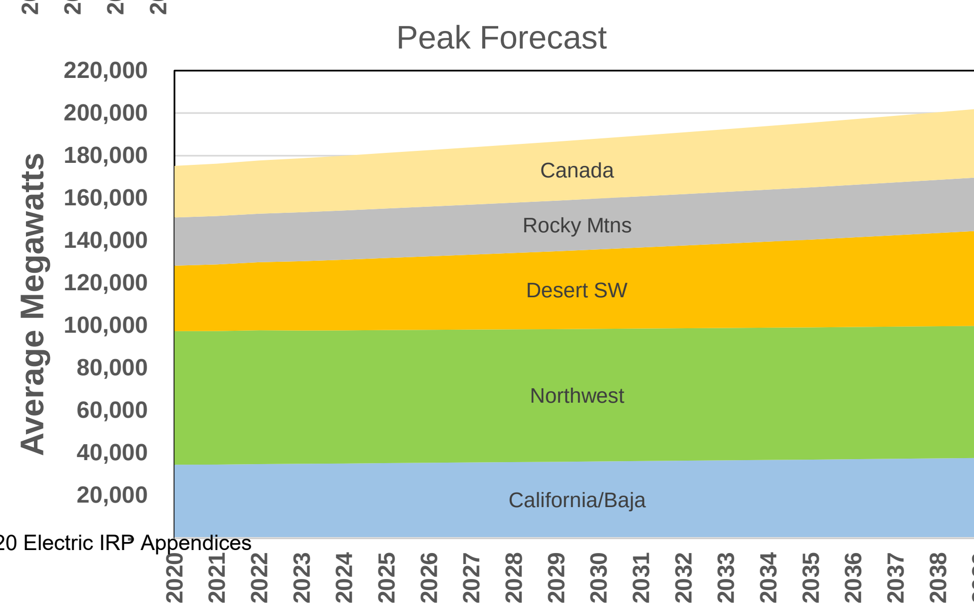
- Forecast load growth for all Western Interconnect regions
- Consider both peak and energy growth
- Use latest load forecast from Epis
- Stochastic modeling simulates load changes due to weather and considers regional correlation of weather patterns
- Economically driven load changes are difficult to quantify and are usually picked up as IRPs are published
- Peak load is increasingly more difficult to quantify as “Demand Response” programs may cause data integrity issues
- Energy demand forecasts need to be net of conservation, electric vehicle forecasts, and behind the meter generation

Energy & Peak Forecast



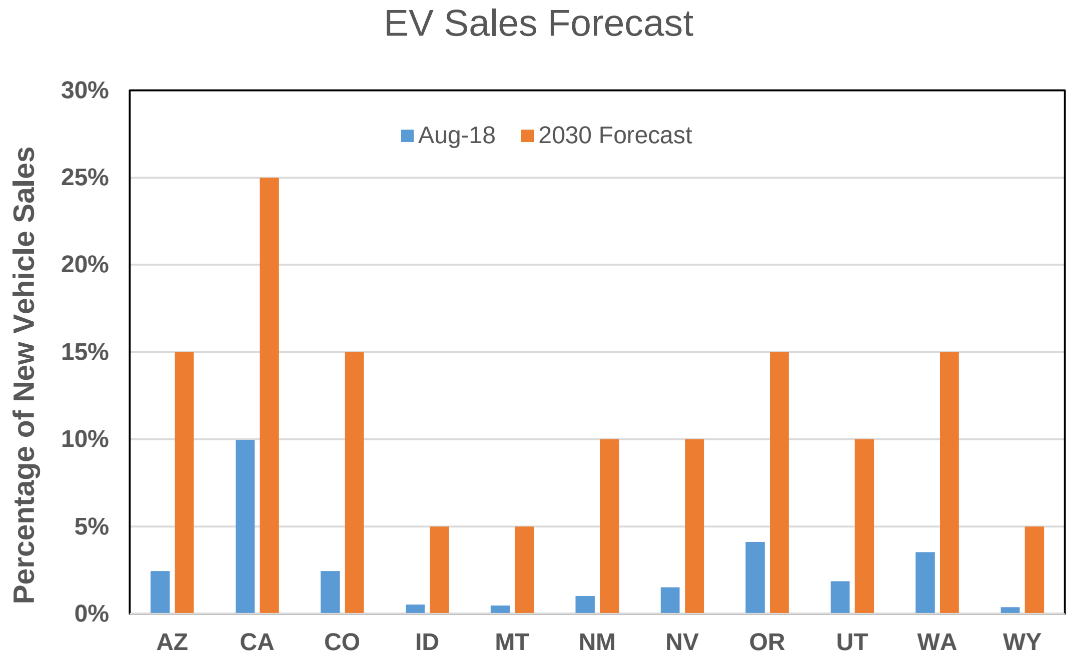
Energy	AAGR	Change
Canada	1.32%	↓
Rocky Mtns.	0.53%	↑
Desert SW	1.84%	↑
California	0.40%	↑
Northwest	0.42%	↓
Total	0.83%	↓

Peak	AAGR	Change
Canada	1.44%	↓
Rocky Mtns.	0.52%	↑
Desert SW	1.89%	↑
California	-0.06%	↓
Northwest	0.44%	↓
Total	0.72%	↓



Electric Vehicles (EV)

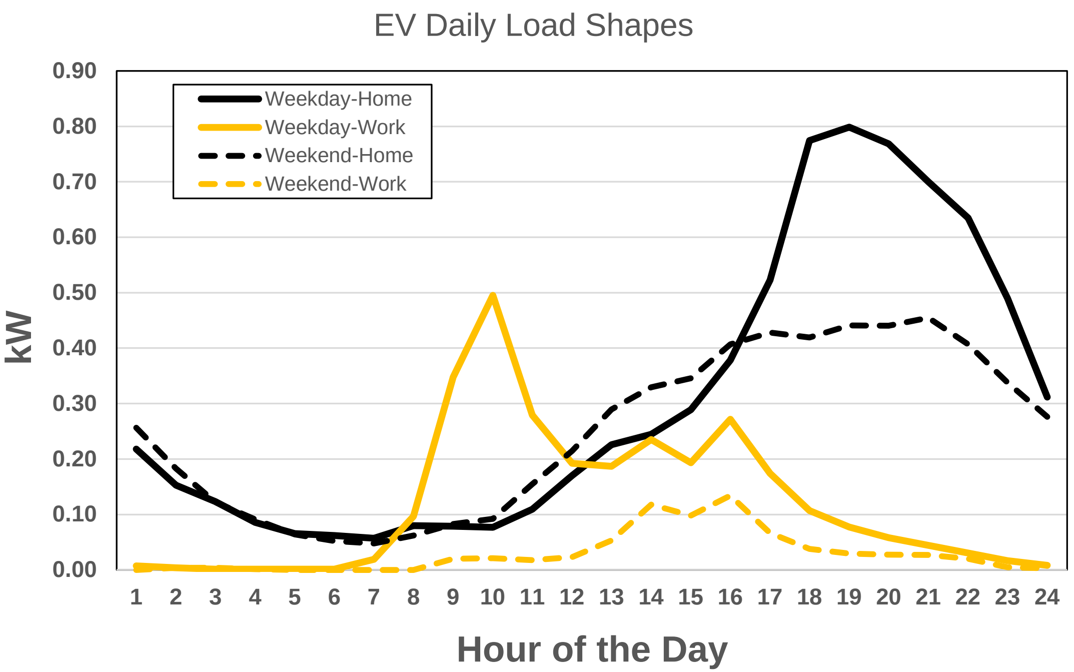
- Current load shapes have low EV penetration, but by 2030, load shapes will differ due to EV and behind the meter solar
- EV percentage of new vehicle sales forecast by 2030
- After 2030, EV growth equals traditional vehicle growth (half of population growth)



http://evadoption.com/ev-market-share/ev-market-share-state/

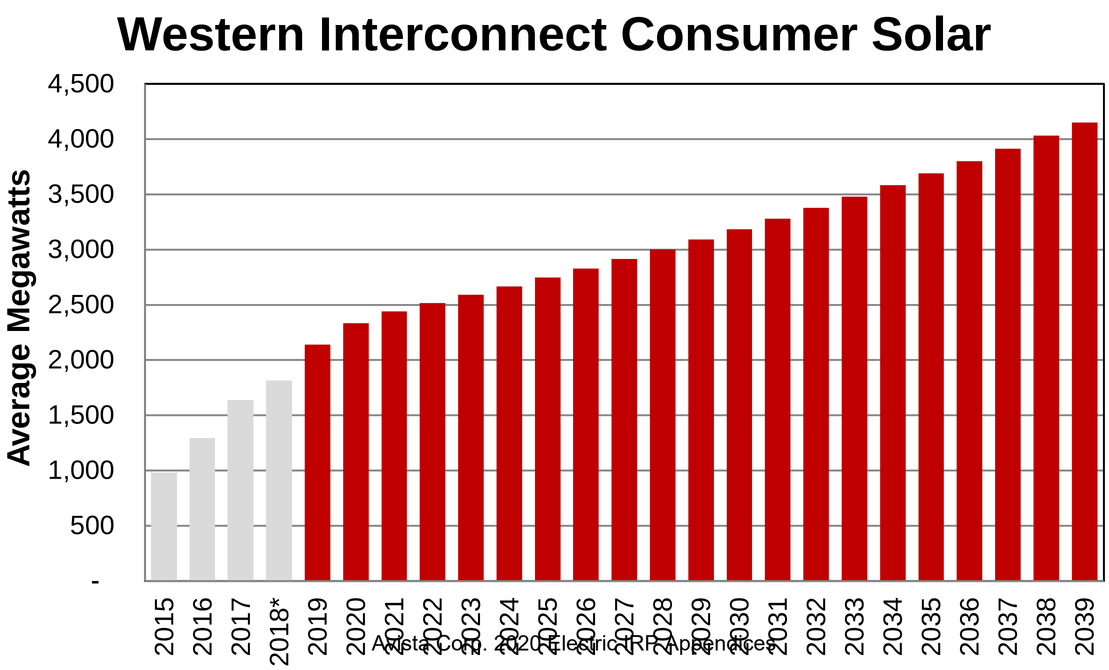
EV Load Shaping

A combined hourly load shape for EV's will be combined using Avista EV load data from its Pilot Project



Rooftop Solar

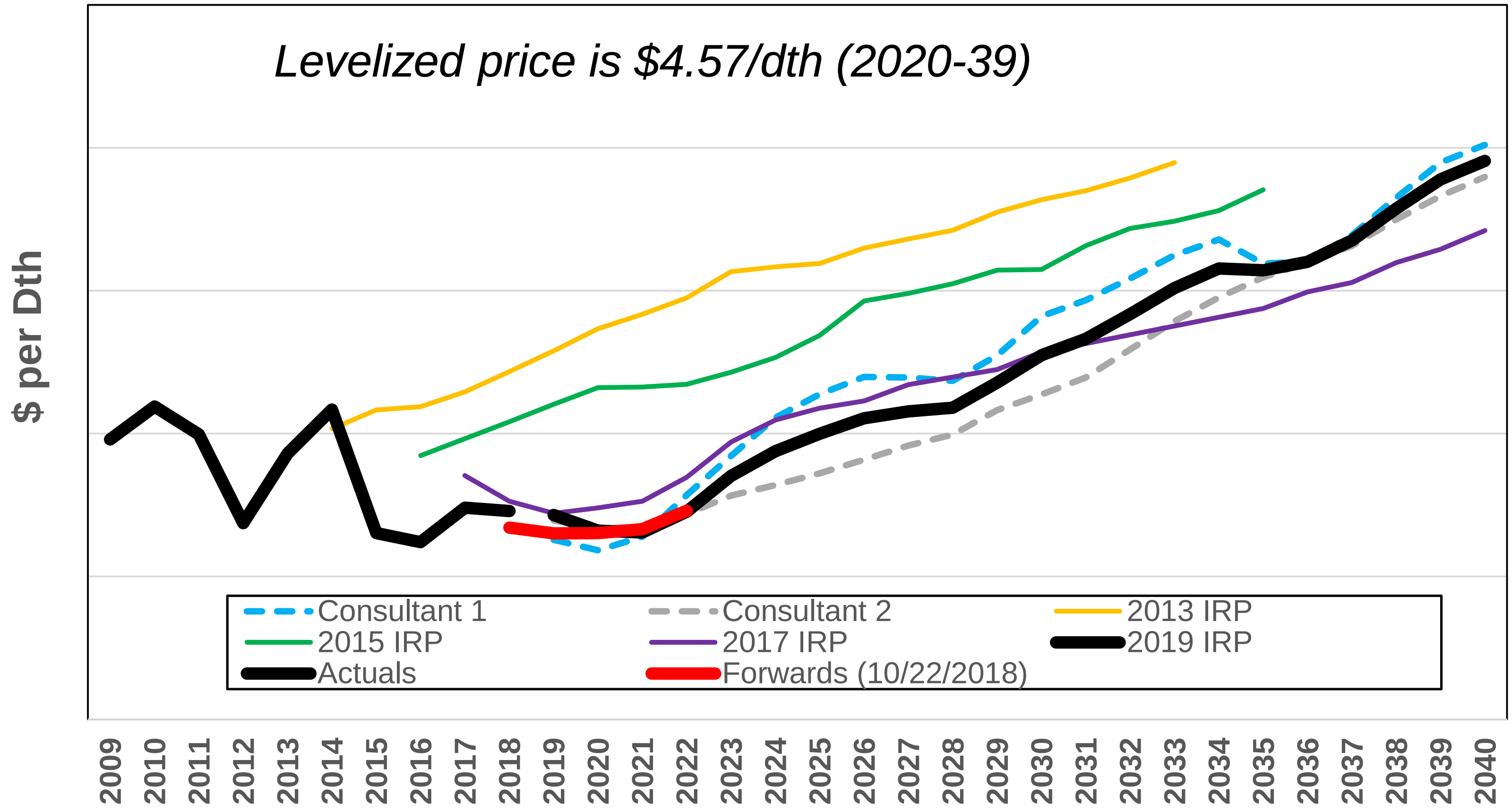
- Rooftop solar impacts future load growth and changes its hourly profile
- Future rooftop solar growth depends on policy choices
- Assumes 20-30% growth, before leveling off to 3% long run growth in 2020s



Natural Gas Prices

- Natural gas prices among the most difficult inputs to quantify
- A combination of forward prices and consultant studies will be used for this IRP. This work should be complete by December 2018 (i.e. deterministic forecast)
- 500 different prices using an auto regressive technique will be modeled, the mean value of the 500 simulations will be equal to the deterministic forecast
- A controversial input for these prices is the amount of variance within the 500 simulations
  - Historically prices were highly volatile, recent history is more stable
  - Final variance estimates consider current market volatility and implied variance from options contracts

Henry Hub Natural Gas Prices *



* Based on methodology described above, **to be updated**

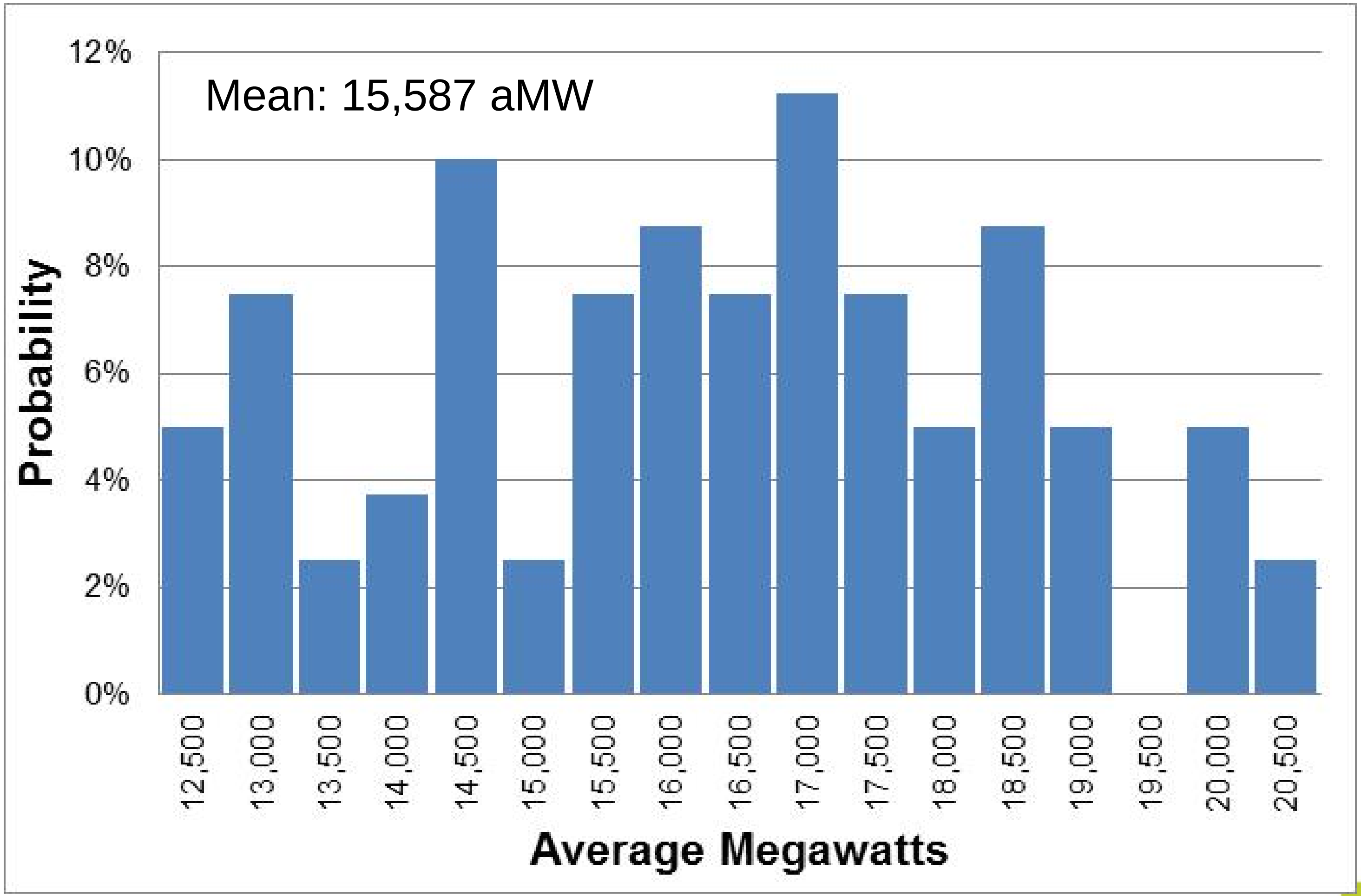
Coal Prices

- Decreased demand for US based coal with lower natural gas prices and state and federal regulations, but potential exports may stabilize the industry
- Western US coal plants typically have long-term contracts and many are mine mouth
- Rail coal projects incur diesel price risk
- Prices will be based on review of coal plant publically available prices and EIA mine mouth and rail forecasts, currently the price escalator is ~2.5%
- Colstrip Fuel Prices will be discussed at the February TAC meeting with final fuel 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
- Columbia River Treaty could change regional hydro patterns, but until there is a new treaty, no changes will be included

Northwest State Hydro Volatility



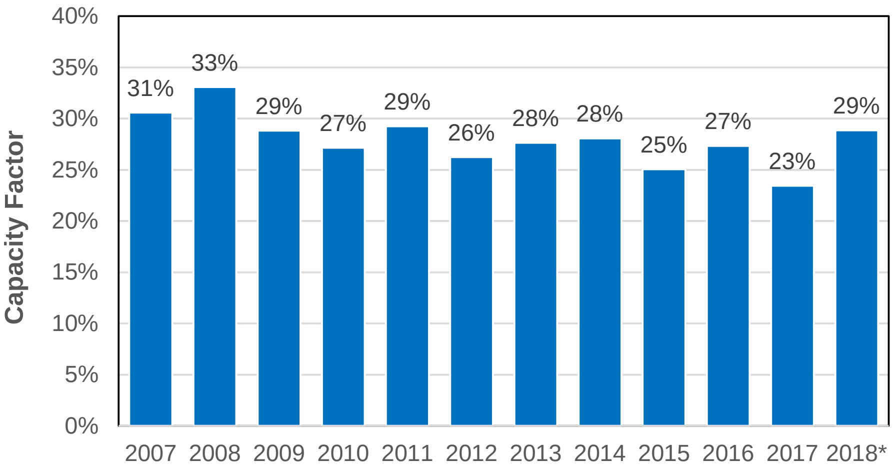
Wind

- Modeling technique
  - 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 for each of the 500 draws

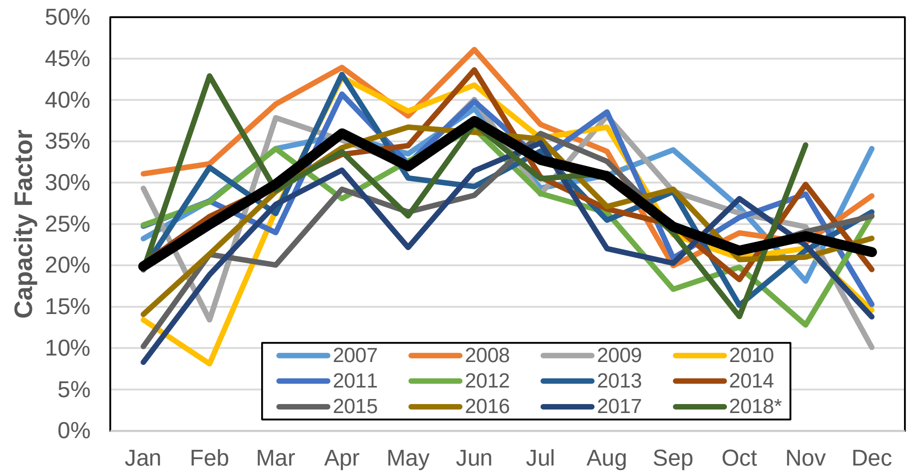
- Oversupply modeling technique
  - RECs and PTC's have caused wind facilities to economically generate in oversupply periods in the Northwest- particularly in the spring months
  - Wind is modeled in Aurora as a negative marginal cost, allowing for the model to simulate negative prices

NW Wind Capacity Factor History

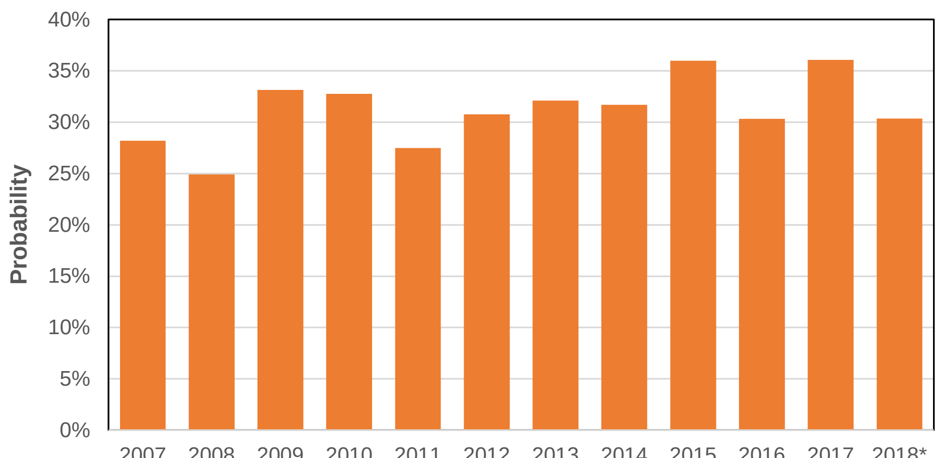
Annual Capacity Factor



Monthly Capacity Factor



Portion of Hours Less Than 5% Capacity Factor



Source: https://transmission.bpa.gov/business/operations/wind/

Western Interconnect Coal Retirements

Plant	Units	State	Summer Capacity (MW)	Retirement Year	Committed or Proposed	Fuel Conversion
Apache Station	2	Arizona	175	2017	Committed	Natural gas
Hardin	1	Montana	107	2018	Proposed	
Naughton	3	Wyoming	330	2018	Proposed	
Navajo	1 to 3	Arizona	2,250	2019	Committed	
Centralia Complex	1	Washington	670	2020	Committed	
Centralia Complex	2	Washington	670	2025	Committed	
Cholla	4	Arizona	380	2020	Proposed	Natural gas
Boardman (OR)	1	Oregon	585	2021	Committed	
North Valmy	1	Nevada	254	2021	Proposed	
Colstrip	1 & 2	Montana	614	2022	Committed	
Comanche	1	Colorado	325	2022	Proposed	
Nucla	1-3, ST4	Colorado	100	2022	Proposed	
San Juan Generating Station	1 & 4	New Mexico	847	2022	Proposed	
TS Power Plant	ST	Nevada	218	2022	Proposed	
Cholla	1 & 3	Arizona	387	2025	Proposed	
Comanche	2	Colorado	335	2025	Proposed	
Craig (CO)	1	Colorado	428	2025	Committed	
Intermountain	ST1 & ST2	Utah	1,800	2025	Proposed	Natural gas
North Valmy	2	Nevada	268	2025	Proposed	
Dave Johnston	1 to 4	Wyoming	762	2027	Proposed	
Jim Bridger	1	Wyoming	531	2028	Proposed	
Naughton	1 & 2	Wyoming	357	2029	Proposed	
Hayden	1 & 2	Colorado	446	2030	Proposed	

The price forecast simulation may find additional coal retirements in the later half of the study period

Initiative 1631

- 2018 Carbon Emissions Fee Measure
  - $15 per metric ton of carbon emissions fee on January 1, 2020
  - Increase fee $2 per year until state emissions goals met
  - Direct proceeds to various programs and projects to improve carbon emissions
- Failed with 56.55% voting against the measure
  - Avista counties 67% voting against
- Will update TAC and modeling for new legislation in the upcoming Washington session

City of Spokane 100% Renewable Goal

- Spokane City Council adopts aspirational goal to have the city served with all renewable power by 2030 (August 2018)
- Committee will be formed to scope and define this ordinance
  – Net renewable or something else?
  – How it will be ramped in?
  – Implications and help for low income and other at risk groups?
  – Rate issues

2019 IRP Futures and Scenarios

James Gall, IRP Manager
John Lyons, Senior Resource Policy Analyst
Second Technical Advisory Committee Meeting
November 27, 2018

IRP Modeling Plan for Environmental Policies

- No expected case due to potential policy uncertainty
- Three futures used rather than an expected case + scenarios
- Alternative futures and scenarios can also be studied, but will need to be minimal due to resource constraints
- Proposed Futures (500 simulations each)
  1. Existing policies & trends
  2. Social Cost of Carbon
  3. Clean Resources

Existing Policies & Trends

Major future assumption change is a greenhouse gas price distribution with:

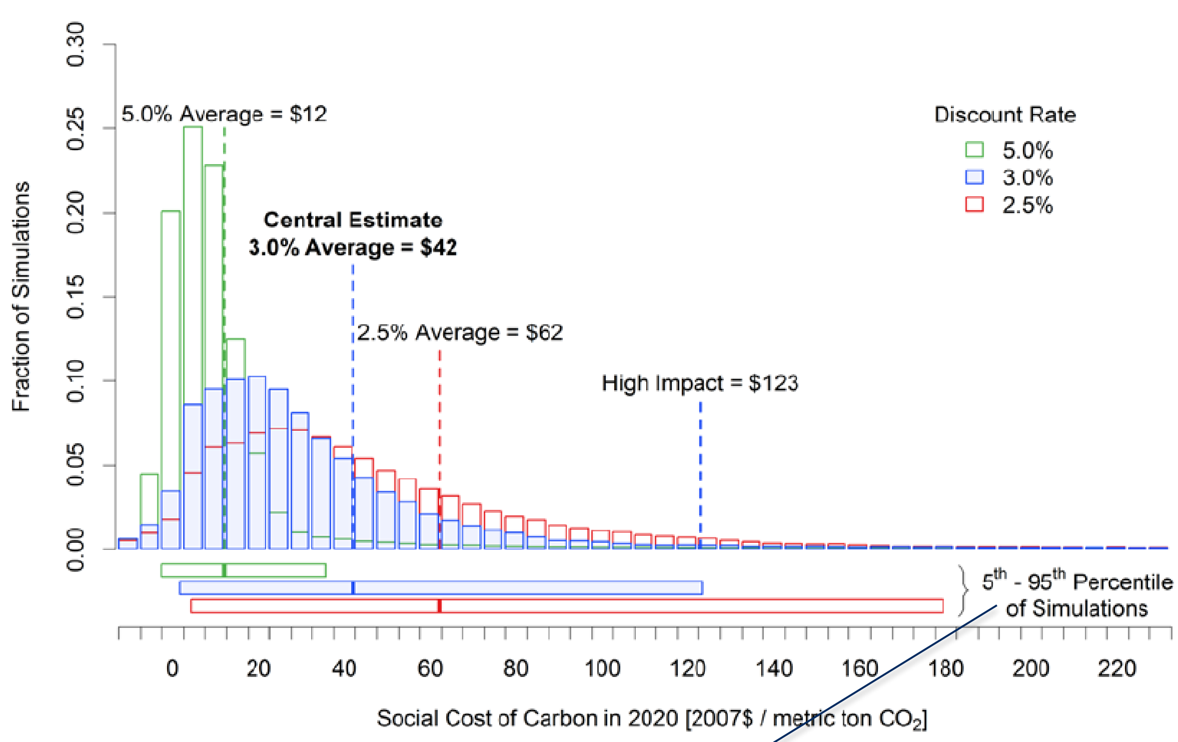
- 1/3 probability of no pricing
- 1/3 probability of $10/metric ton (2018$) escalating at 2.5% year
  - Begins in 2025
  - Applies to all of Western Interconnect resources
- 1/3 probability of cap and trade of 20% below 1990 levels
  - 20% goal by 2030
  - 40% goal by 2040
  - Applies to all of Western Interconnect
  - An implied CO_2 price will be a result of each study

Social Cost of Carbon (SCC)

- No CO_2 cost penalties for dispatch, the SCC will be included as a cost in resource and energy efficiency acquisitions
- Pricing will be a distribution of costs from the Interagency Working Group on Social Cost of Carbon (Aug 2016)
  - 1/3 probability of 5.0% discount rate pricing distribution (90th Confidence Level)
  - 1/3 probability of 3.0% discount rate pricing distribution (90th Confidence Level)
  - 1/3 probability of 2.5% discount rate pricing distribution (90th Confidence Level)
- SCC will be applied to the Washington portion of load service for Avista resource portfolios

Social Cost of Carbon Pricing Distribution From

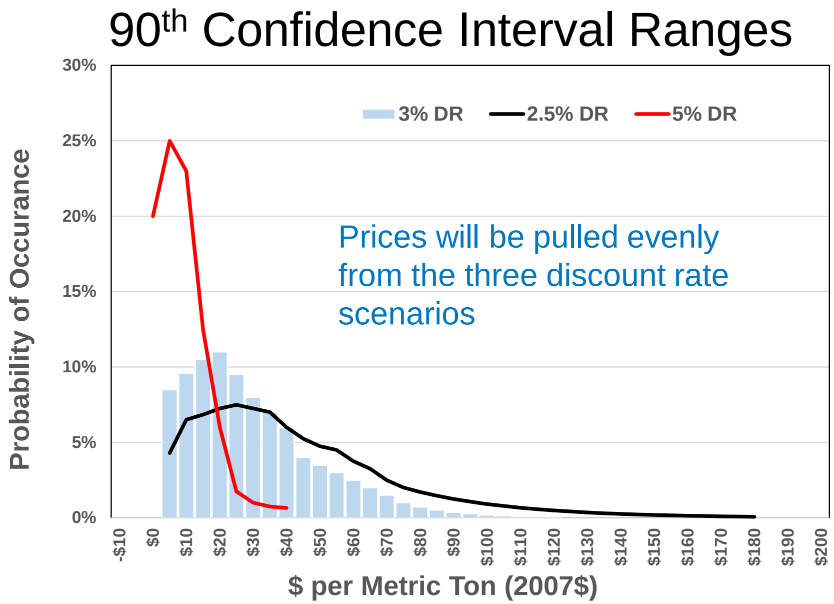
Figure ES-1: Frequency Distribution of SC-CO_2 Estimates for 2020[3]

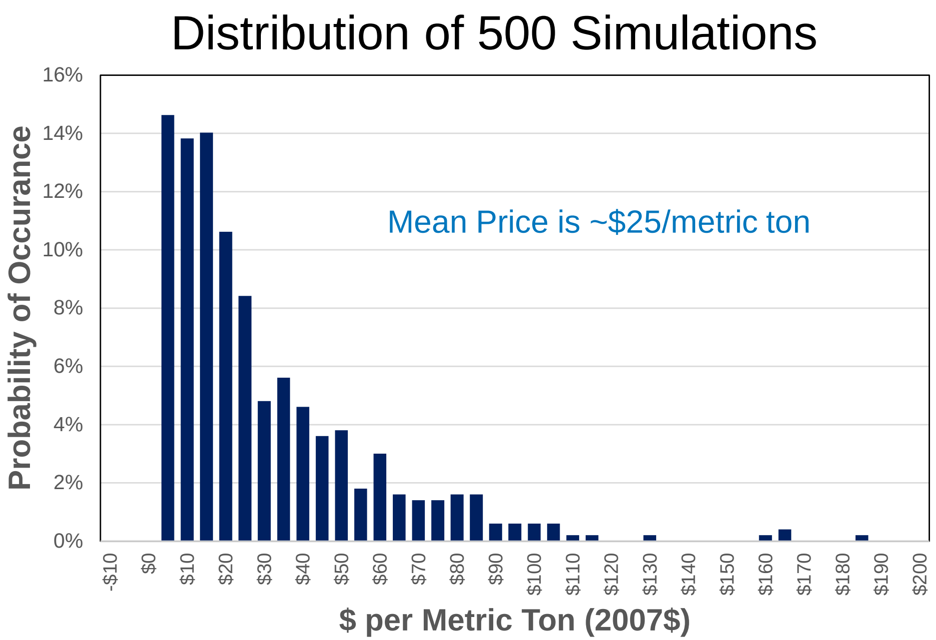


Use 90th confidence interval for each of the three distributions for the 500 simulations

Social Cost of Carbon

Confidence Interval





Clean Resource Future

- Washington: 100% of load met by “clean” resources on a “net” basis
  - 80% by 2030, 90% by 2040, and 100% by 2050
  - Qualifying resources can be sourced from anywhere in the Western Interconnect
  - Up to 20% of resources can be “RECs” from outside of the region or alternative compliance
  - Price cap of $5 per metric ton ($2018) beginning in 2030 and 1% revenue requirement for portfolio modeling
- Oregon cap and trade
  - 20% below 1990 levels by 2030
  - 50% below 1990 levels by 2040
  - 80% below 1990 levels by 2050

Additional Scenarios

Aurora Studies

- High natural gas prices (deterministic)
- Low natural gas prices (deterministic)
- Social Cost of Carbon (stochastic)
- High Colstrip fuel cost (deterministic)
- Colstrip shutdown (stochastic)

PRiSM Studies

- Study from each of the Aurora cases
- Colstrip closes in 2027
- Colstrip closes in 2035
- High cost to retain Colstrip (with low gas)
- Low and high load growth, alternative load cases (i.e. electrification, EV, behind the meter generation, power-to-gas, etc.)
- Lancaster continues
- High cost to retain Colstrip
- Colstrip fuel prices
- Conservation TRC vs. UCT
- Tipping point scenarios

High and Low Natural Gas Prices

- Deterministic studies to show the impacts of consistently lower or higher natural gas prices than the expected price forecast
- Low case will have existing price levels and not increase
- High case level TBD – more details forthcoming at February 2019 TAC meeting

Social Cost of Carbon

- Differs from the future discussed earlier by including the price for dispatch for all plants in the Western Interconnect
- Will include the same prices as discussed in the SCC future

Colstrip Basic Assumptions

- Avista's share of fuel, O&M, and capital investment costs
- Increased common costs due to shut down of units 1 & 2 in 2022
- Selective catalytic reduction (SCR) – 2027 and 2028, includes capital costs, ammonia and fixed and variable O&M to reduce NO_x
- Enhanced mercury controls
- Coal Combustion Residuals (CCR's)
  - Coal dry ash handling (2022) and long term storage
- Smart Burn combustion controls installed in 2017
- Water management
- Depreciation schedule shortened to 2027 per merger agreement
- Additional details on the specifics will be provided in TAC 4

Colstrip Scenarios

- Retire Colstrip Units #3 and #4 in 2027 as an alternative to SCR investment
- Retire Colstrip Units #3 and #4 in 2035 as an alternative to SCR investment
- Colstrip fuel prices increase 30%
- High cost to retain Colstrip case (next slide)

High Cost to Retain Colstrip Case

- This case answers questions about several higher cost issues impacting Colstrip's compliance cost
- This scenario uses assumptions in the three futures, except:
  - EPA expands regional air quality programs and rules to the western U.S. such as CASPR and NAAQS requiring SCR installation on Units #3 and #4 at an earlier date (End of 2023)
  - Units #1 and #2 shut down earlier than announced, increasing the amount of shared costs cover by Units #3 and #4 (End of 2019)
  - MACT PM/MATS RTR compliance problems. Dry system required to remove particulates and reduce water use (End of 2023)
  - No enhancement to existing SO_2 scrubbers as no current regulation drives reduction levels beyond current plant emissions
  - Higher Colstrip fuel costs
  - Low natural gas cost environment
  - Specific cost details will be provided in TAC 4

Load Growth Scenarios

- High and low load growth scenarios due to economic changes in the service territory
- Potential load study scenarios
  - High EV penetration case (120,000 EVs by 2045)
  - Behind-the-meter generation (10% penetration by 2030)
  - Fuel switching electric to natural gas
  - Fuel switching natural gas to electric

Lancaster Continues

- Lancaster PPA currently ends October 2026
- PPA has an option to extend the contract 5 years at a negotiated price
- Implications of extending the PPA or purchasing the plant beyond the current end of the PPA

Alternative Energy Efficiency Evaluations

- All cases will model cost effectiveness of energy efficiency using the total resource cost (TRC) in Washington and the utility cost test (UCT) in Idaho
- This scenario tests both methods of evaluation

Tipping Point Analyses

- Estimates the cost reduction or operating characteristics needed to change the resource strategy
  - Are there any assumptions that need to be tested to find the cost tipping point?
  - Past studies have included capital costs for solar and storage

Attendees: TAC 2, Tuesday, November 27, 2018 at Avista Headquarters in Spokane, Washington:

John Lyons, Avista; Jennifer Snyder, Washington UTC; Amy Wheeless, NW Energy Coalition; Steve Johnson, Washington UTC; Michael Eldred, Idaho Public Utilities Commission; Matt Nykiel, Idaho Conservation League; Shelby Herber, Idaho Conservation League; Dave Van Hersett, Avista residential customer; John Barber, Rockwood Retirement Community; Brian Parker, 350.org; Jørgen Rasmussen, Solar Acres Farm; Kirsten Wilson, DES Energy Program; Garrett Brown Avista; Clint Kalich, Avista; Barry Kathrens, 350.org; Pauline Druffel, 350 Spokane; Thomas Dempsey, Avista; Terrence Browne, Avista; Darrell Soyars, Avista; Scott Kinney, Avista; Mary Tyrie, Avista; Tom Lienhard, Avista; Tom Pardee, Avista; Kaylene Schultz, Avista; Amber Gifford, Avista; Rachelle Farnsworth, Idaho Public Utilities Commission; James Gall, Avista; and Gerry Snow, PERA.

Phone Participants:

Doug Howell, Sierra Club; Sarah Laycock, Washington State Attorney General's Office; Mike Starrett, Power Council; Nancy Estep, NW Energy Coalition.

These notes follow the progression of the meeting. The notes include summaries of the questions and comments from participants, Avista responses are in italics, and significant points raised by presenters that are not shown on the slides are also included.

TAC Expectations and Process Overview, John Lyons

Matt Nykiel: On the topics, what is available and when, and what will not be available?

Avista is developing a matrix of the data to indicate timing and availability of data.

Doug Howell: Why are there less meetings (5 instead of 6) for this IRP? *We are having fuller agendas in five meetings rather than spreading out to six.*

2019 IRP Modeling Process Overview, James Gall

Matt Nykiel: Which of these are going to be available publically? *For the February TAC meeting – market price results high level inputs, annual fuel, demand and resources today. Existing publically available data, transmission, and the load forecast provided in the last TAC meeting. Resource position will be next TAC meeting, Demand Side Management and Demand Response information will be at a later meeting. High level or detail level would be available in FERC level data.*

(See separate data matrix file sent with these meeting notes)

Steve Johnson: Simple list of items, where they are found and when they will be released.

Doug Howell: PSE has distinct scenarios for load, gas and fuel prices. How is Avista different in the process? *We will hit this later today.*

Brian Parker: Will proprietary data be included in the list? Why is it proprietary? *Often contractual and market intelligence data is proprietary, such as the natural gas price forecast we purchase.*

Doug Howell: Across the country we now have non-disclosure agreements in eight different states. Hoping to have them soon in Louisiana with the same owners as PSE (Puget Sound Energy). So we can have a consultant run the model, we want the data under a nondisclosure agreement. We hope to have one with PSE too.

Doug Howell: Are known and expected resource retirements included? *Includes publically announced retirements. If plants are uneconomic when modeled, but not announced, Aurora would shut those plants down too.*

James Gall: For the OWI (Oregon, Washington and Idaho) region, which Avista has modeled as one bubble in Aurora, we will try to split this region up by state to accommodate state-level resource policy decisions.

Amy Wheeless: What about resource shuffling? *This will be covered later.*

Matt Nykiel: Do we have a guideline for what will be modeled stochastically versus deterministically? *Avista tries to run as many studies as we can stochastically, but each study takes about a week to complete. We generally default to deterministic studies as we run out of modeling time which is limited.*

PRiSM Section

Doug Howell: What is the rationale for splitting up the region? [OWI being modeled as separate areas instead of one area] *Splitting up the region allows us to account for a situation where a state or city wants a unique policy that differs from the rest of the region, such as a 100% renewable energy requirement for a city.*

Mike Starrett: How are we going to do this for prudence? What if the city and state are not aligned like PGE and the City of Spokane. *Would probably develop a green tariff.*

Clint Kalich: This is an exercise for information. What costs might be if this type of policy occurred. The IRP doesn't promote tariffs, but informs the development of them.

Steve Johnson: Boutique resource portfolios for new resources from PSE. Shows cost differentials for core and unique customers.

Matt Nykiel: How practically can we identify them?

James Gall: More of an accounting mechanism. We know generation, but need to account for overages and surplus.

Brian Parker: What will we be able to share from the study?

James Gall: We would be able to share what is selected by PRiSM and the least cost results. We will talk about Spokane later.

Doug Howell: I have heartburn about long-term impacts, like coal ash having horribly wrong cost estimates, and how to reconcile them. Also low balling cost estimates of wind and solar. And climate cost estimates resulting in obsolete resources in the future.

Slide 10 – 11

James Gall: We are taking market risk. Others in scenario risk.

Amy Wheeless: Risks? *Market load, hydro and wind variability, not other risks.*

Clint Kalich: Qualitative choices.

John Lyons: Scenarios are used for fundamentally different futures with second order change, like a future with a new low-cost efficient car battery that changes the market for electric cars.

Amy Wheeless: BPA used an efficient frontier with how they picked DSM.

James Gall: We look at all 5,000 plus DSM measures, so conservation lowers risk, cost, and reduces summer/winter peak.

Generation Resource Options, James Gall

Steve Johnson: So actual runs will have the transmission cost where applicable later on.

Matt Nykiel: When will gas prices be locked in? *Probably after the February meeting.*

Steve Johnson: Price excursions with the British Columbia pipeline. *Will discuss later since Tom Pardee (Natural Gas IRP Manager) is not in the room.*

John Barber: What is the hybrid technology? *LMS 100 is a mix of frame and aero derivative. The compressor section compresses, cools and reinjects the air. It is more efficient than a peaker, but not as efficient as a combined-cycle plant.*

Steve Johnson: Does Avista model oil backup? *No, we have been able to rely on the pipelines not being fully subscribed. Now that they are fully subscribed, we will need to decide if we need to model oil, LNG or purchase gas as a backup.*

Jennifer Snyder: Ask PSE (Puget Sound Energy) if they got any traction in offshore wind.

Steve Johnson: Where does Avista get its updated data for expected capacity factors? How does Avista compare unknowns? Wind vs. solar. *Avista has gotten data from renewable RFPs with wind at a 38% capacity factor, but our actual experience has been much lower. We only pay by the megawatt-hour for actual generation under a contract.*

Wind on Avista's system is in the high 30s and high 40s for wind projects in Montana. Solar capacity factors are also for RFPs, as well as generation from the solar projects at Lind and Boulder Park. There is also solar data from NOAA, which is being used by bidders.

John Barber: Just lithium ion? *Yes, in conjunction with solar and all types of battery storage for other projects.*

Steve Johnson: Ramping costs, shut off, curtailment. *Yes, we can shut it off wind, but still have to pay for it.*

James Gall: Modeling on an hourly basis. Some may have PPAs with certain hours or ramping.

Amy Wheeless: Biomass seems pretty big. *Yes, we have the opportunity to do one biomass project that big.* Is nuclear included? *Yes, small nuclear is being modeled.*

John Barber: Doesn't biomass operate as a baseload plant and not as a peaker. *Usually true, this project would operate more as a peaking biomass facility in the winter.*

Pauline Druffel: Doesn't biomass produce greenhouse gases? *Yes, but biomass is carbon neutral under Washington law.*

Page 5 – Other Clean Resource Options

Amy Wheeless: Are hydro PPA's going to be included? *Yes, on a later slide (Slide #13)*

Slide #6 - Storage Technologies

Thomas Dempsey: Liquid air is a long-term energy storage using solar and wind generation to compress and liquefy the air. When using this system, the plant does not have to compress air, so we would get full use of the generating resource.

Steve Johnson: What are the efficiencies? *60 – 70% round trip efficiency. Hydrolysis is only 25% efficient.*

James Gall: We are using the Lazard Study, and a new version should be available next month, so we will use the most up-to-date costs available.

Steve Johnson: For hydro and Post Falls. PSE costs for rebuilding Snoqualmie Falls were much higher than expected. Make sure you are modeling these hydro rebuilding costs really carefully. The project economics didn't work out.

Steve Johnson: Power purchase options. Design a model to capture the value of an asset's value of these contracts. Green value. Very important to know it would serve load with the value of different kinds of resources. And articulate why, how, and ways resources are driving costs meeting loads with market options.

Resource Option Spreadsheet

Amy Wheeless: What is the deadline for comments on the resource spreadsheet? *By the middle to end of January.*

Steve Johnson: With the 20-year timeframe, are we adding more noise than necessary? Would retrofitting be cheaper? *Avista models retrofitting options if we know about the potentials.*

Home Heating Technologies Overview, Tom Lienhard

Garrett Brown: What is the payback on slide 11 [First cost of technologies]? *In floor radiant heat uses less than half the energy. Good if staying in the house for 20 years. Need to work to overcome the first costs. When they do a good job.*

Barry Kathrens: Comfort is another benefit. My woodshop has radiant floor heat and adds like an extra dollar a day.

Tom Lienhard: Maybe we need an Air B&B for people to be able to try out a good efficient house in the winter.

Kirsten Wilson: We were able to remove and replace the old heating system for an additional $15,000 in an existing structure. But we are both engineers.

Jørgen Rasmussen: How does a CO2 heat pump compare. *COP of 3, equal or better* than *96%, and is about $5,000 for the unit.*

Brian Parker: I came here from California where they were more sophisticated about these matters. I've had trouble finding HVAC contractors who could do certain efficiency calculations. Either they wouldn't show up or they didn't come back. *Yes, it is a design issue and requires meeting with the right HVAC installers to make these things happen.*

Tom Lienhard: 10% humidity when cold in continental climate works the same way. 72 degrees feels like 64 degrees since heat can't transfer. At 45% relative humidity, 72 degrees feels like 72 degrees. This also affects heat pumps here where there is general not as much humidity.

Tom Lienhard: The RTF uses zones 1, 2 and 3. Avista is in zones 2 and 3. The map in slide #15 calls these zones 4, 5 and 6.

Slide 19 is referring to RTF zones 2 and 3.

Steve Johnson: So a BTU of natural gas is about one third the cost of a BTU of electricity? *Yes.*

Jørgen Rasmussen: But are they CO2 equivalent? Doesn't Kendall Yards [Spokane housing development near downtown] have all heat pumps? *Not all. There are one or two heat pumps per condo and the rest are resistance heat.*

Pauline Drury: Sounds like CO2 heat pumps are something for reducing heat. Is this for the source of electricity because I have a personal feeling that we should be reducing carbon? *These are CO2 heat pumps that use CO2 in the system.*

Jørgen Rasmussen: Greenhouse gas free because CO2 is less potent than other refrigerants.

Gerry Snow: More penetration of renewables makes the power budget (E&G) move to electrification, like British Columbia, and even more extreme as hydrogen in natural gas pipes. Where is the trade off? If it's a capacity issue, more storage is better.

Resource Adequacy and Effective Load Carrying Capability, James Gall

Steve Johnson: Balancing area has performance standards. Different kind of things. Obligations to meet load within the house. NPCC quote.

Steve Johnson: You don't model natural gas fuel disruptions? *No, we don't assume pipeline or storage disruptions. This study is not cost, just availability.*

Steve Johnson: Power Council, couldn't you just get something from another. *We have a winter problem.*

Amy Wheeless: Becoming more summer peaking regionally. *Yes and no. Summer is more consistent than winter.*

Steve Johnson: Don't have a good way of moving up summer or winter temperatures to set "benefits" of global warming for resource adequacy. *The means are changing, but the extremes not so much.*

James Gall: Wind improves reliability, but not by as much as thought. There is lots of variation site-to-site so more work is needed to pick the right number to use for reliable wind capacity – 5 to 10% range is probably right.

Clint Kalich: Does the Power Council still use 5% for wind?

Mike Starrett: Northwest capacity contribution for Columbia Gorge wind is 3% on its own, 9.5% when integrated with hydro. Solar is 3% and higher when integrated.

Steve Johnson: Their model accounts for energy at night allowing more daytime hydro. *Avista's model does too.*

James Gall: Need to consider correlation with very low temperatures in Montana compared to us. So we need more studies. Solar helps a little bit at 2.2% by moving hydro and if we peak in February. We had one of our last peaks with zero wind and solar for a week. This study considers demand response at 10 times per year now, ELCC (Effective Load Carrying Capability) would go up if there were more times per year.

Steve Johnson: Is the curve used to develop the LOLP (loss of load probability) accurate? *Yes, if want to use renewables to back up LOLP, need to add multiples of the renewable resources to get a better chance they are available when needed. Learned from the past model.*

Amy Wheeless: Why not reduce gas more?

James Gall: Storage moves and loses energy. The losses vary by the type of storage like lithium ion or hydrogen. Storage needs to be paired with something to charge it.

Matt Nykiel: Does this include carbon (cost)? *No, but about 5 times more expensive.*

Clint Kalich: About 6 times. This is for peaking capacity, so only runs about 5 percent of the time for reliability or low hydro conditions.

Mike Starrett: I have some questions about the numbers in the slides that can't be shown online.

Steve Johnson: Diversity – Avista could build a whole bunch and pay full cost while helping everyone else. It's great to think of one big utility, but we don't share the fixed costs.

Clint Kalich: Today, we are already long as a region. This is an additional surplus needed to charge these batteries. At a certain point, it doesn't help more. Is this incremental energy? This is how much wind and storage is needed to help.

Mike Starrett: More midday curtailment. Policy changes a little bit later. In Aurora, are those resources being curtailed so that adding more renewables lowers the value of them?

2019 Electric IRP Key Case Assumptions

Steve Johnson: Fully electric percentage? (Slide #9, Electric Vehicles) *We don't have the all-electric percentages broken out. Rendall Farley might. There is less separation between all-electric EVs and plug-in hybrids.*

Steve Johnson: Looking at the causal effect, if all these things are different, volatility may be different for loads, uses, etc.

Steve Johnson: Not a normal distribution? *No, it isn't.*

Jennifer Snyder: BPA has a forward looking study for hydro conditions (due to climate change). *Briefly, Avista expects the same amount of water for hydro, but the timing of it moves from the spring to the winter based on the studies we have reviewed.*

Garret Brown: Was the last hydro year good? *Hydro was really good the first six months and worse the rest of the year. About 5% lower regionally, but Avista did better than the regional average.*

Matt Nykiel: What is the time frame for coal prices deadline to comment? *Proposals in February, comment deadline a week or so after the next TAC meeting [February 6] and scenarios could be a few weeks later.*

Steve Johnson: Not sure of not doing a risk analysis for climate changes to hydro.

Mike Starrett: BPA came in and did a presentation last meeting (Power Council) and in person to the council. Is it a sensitivity or not? More winter rain, so a shortage from winter to summer.

Steve Johnson: You have examples of what it looks like when it warms. You could do a scenario or something like a single year look at it.

Rachelle Farnsworth: How do you include the risk associated with Colstrip? *We have a slide for that.*

Steve Johnson: There will be a different value for renewables before and after greenhouse gas prices. *The shadow price is not going down much.*

Clint Kalich: But people who waited and bought after I-937 paid less.

Matt Nykiel: No one wants to pay $20 per dekatherm, but there is a cost.

Futures and Scenarios, James Gall and John Lyons

Jennifer Snyder: I would be more comfortable using 2020 instead of 2025 (for the start date of carbon pricing).

Steve Johnson: Another approach setting an objective function with an objective function.

Steve Johnson: We should probably set up a meeting with Brad (Cebulko) and others to go through this.

Matt Nykiel: Why only Washington? *It was for a WUTC request. A later slide shows a scenario for all of Avista's service territory.*

Steve Johnson: Look at the Northwest Natural IRP for their natural gas price for any divergent numbers.

Steve Johnson: Will you include the updated forced outage rates for Colstrip? *Yes, we will use the most recent forced outage rates.*

Matt Nykiel: Changes in ownership structure in Colstrip Units 3 and 4.

Steve Johnson: If not operating, an exit provision.

Steve Johnson: You should make sure to have a letter shielding any employees with knowledge of what would be paid in the future for the ownership interest in Lancaster. *Avista Corporation sold its ownership interest in Lancaster in 2006.*

Public Counsel (phone): Is the social cost of carbon included in its own case? *It is one of three futures, treated at the same time.*

Amy Wheeless: Spreadsheet available by the end of the week or early next week? *Yes.*

Matt Nykiel: Will there be a breakdown of basic assumptions for Colstrip? *Costs and when they are expected to occur.*

Matt Nykiel: What happens if someone walks away (from Colstrip), can you show how costs get reapportioned? *Would need to check on what could happen.*

2020 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 3 Agenda

Tuesday, April 16, 2019
Avista Headquarters, Conference Room 130

Topic	Time	Staff
Introductions and TAC 2 Recap	9:00	Lyons
Regional Legislative Update	9:10	Lyons
IRP Transmission Planning Studies	9:30	Rolstad
Break	10:30	
Distribution Planning Within the IRP	10:45	Fisher
Lunch	12:00	
Conservation Potential Assessment	1:00	AEG
Demand Response Potential Assessment	2:00	AEG
Break	3:00	
Pullman Smart Grid Demonstration Project Review	3:15	Doege
E3 Study – Resource Adequacy in the Pacific Northwest	3:45	Gall
Adjourn	4:30	

2019 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
November 27, 2018

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next two years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

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 while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - June 15, 2019 at the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

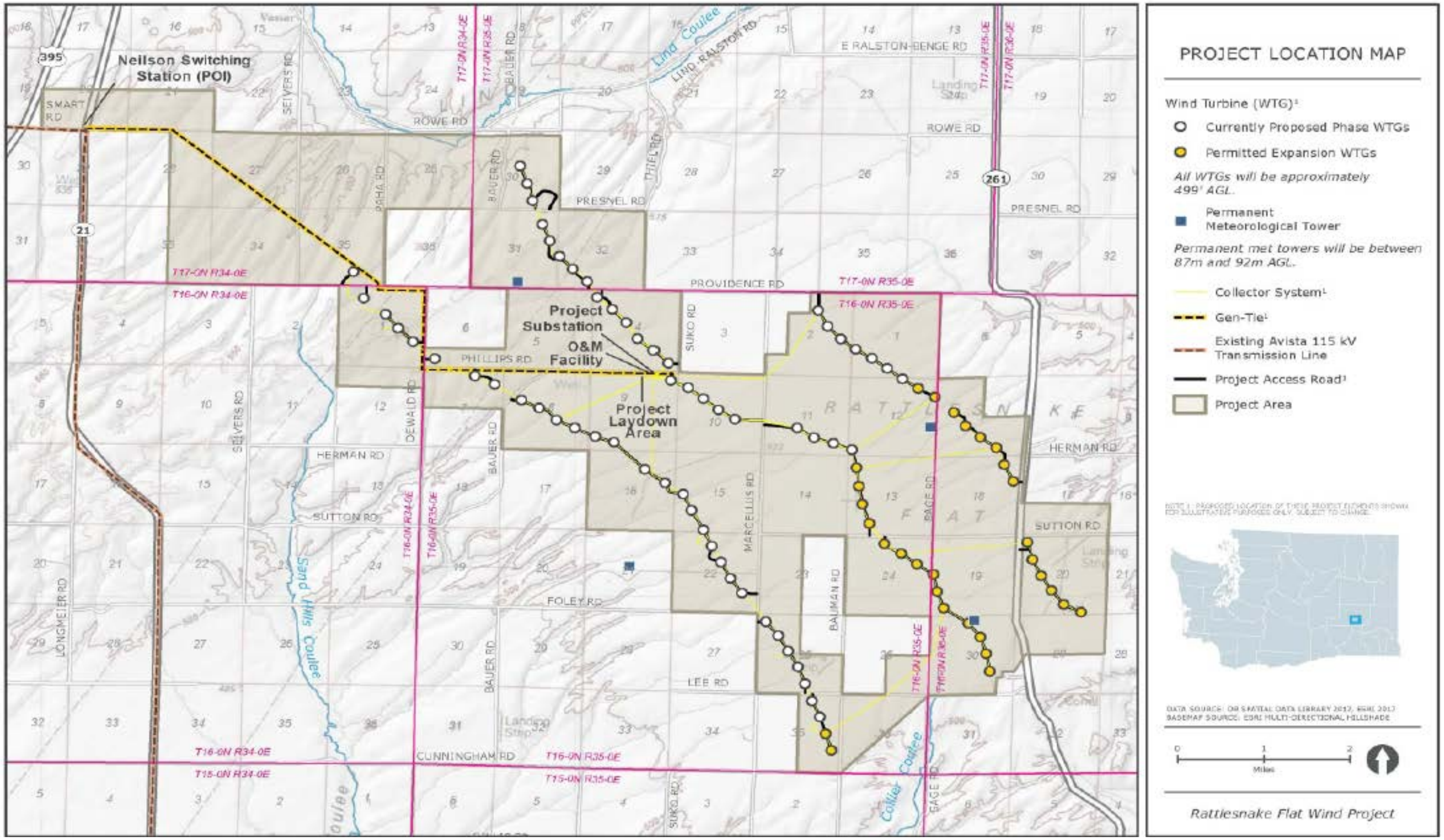
TAC #2 Recap – November 27, 2018

- Introductions and TAC 1 Recap, Lyons
- Modeling Process Overview, Gall
- Generation Resource Options, Gall
- Home Heating Technologies Overview, Lienhard
- Resource Adequacy and Effective Load Carrying Capability, Gall
- Key Assumptions, Gall and Lyons
- Futures and Scenarios, Gall and Lyons
- Meeting minutes available on IRP web site at: https://www.myavista.com/about-us/our-company/integrated-resource-planning

Updates – Rattlesnake Flat Wind PPA

- Issued RFP June 6, 2018 to capture low renewables pricing resulting from expiring PTC and ITC
- Bids for over 2,000 MW from 40 wind and solar offers
- 9/19/18: 150 MW Rattlesnake Flat Wind (Clearway Energy)
- Contract signed March 7, 2019
- Construction begins May 2019 and scheduled to be online 12/31/20
- About 12 miles southeast of Lind, Washington on 20,000 acres

Rattlesnake Flat Wind Project



Today's Agenda

- 9:00 – Introductions and TAC 2 Recap, Lyons
- 9:10 – Regional Legislative Update, Lyons
- 9:30 – IRP Transmission Planning Studies, Rolstad
- 10:30 – Break
- 10:45 – Distribution Planning within the IRP, Fisher
- Noon – Lunch
- 1:00 – Conservation Potential Assessment, AEG
- 2:00 – Demand Response Potential Assessment, AEG
- 3:00 – Break
- 3:15 – Pullman Smart Grid Demonstration Project, Doege
- 3:45 – Review E3 Study – Resource Adequacy in the Pacific Northwest, Gall
- 4:30 – Adjourn

TAC 4 Topics

- TAC 4 on Tuesday, August 6, 2019
  - Natural Gas Price Forecast
  - Electric Market Forecast
  - Energy and Peak Load Forecast
  - Existing Resource Overview (Colstrip, Lancaster, and other resources)
  - Final Resource Needs Assessment

- TAC 5: Tuesday, October 15, 2019
- TAC 6: Tuesday, November 19, 2019

2019 Electric IRP Regional Legislative Update

John Lyons, Ph.D.

Third Technical Advisory Committee Meeting

April 16, 2019

Washington Legislation

- SB 5981: Greenhouse gas emissions cap and trade program
  - Public hearing held on March 21 in the Senate Environment, Energy and Technology Committee. No further action scheduled.
- HB 1257: Energy efficient buildings and natural gas conservation
  - Governor requested for new conservation requirements for natural gas utilities by setting energy performance standards for commercial buildings and utility administered incentive program for early energy performance retrofits. Authorizes utilities to propose renewable natural gas (RNG) procurement program and voluntary RNG tariffs. Passed House 3/29/19 and put on Senate Floor calendar.
- HB 1444: Appliance efficiency standards
  - Department of Commerce requested minimum efficiency and testing standards for certain appliances. Passed House 3/5/19 and on Senate Floor calendar.
- HB 1512: Electrification of transportation
  - Allows electrification of transportation plan and incentives. Passed both chambers.
- HB 1126 Distributed resource planning
  - Declare state policy that utility DER planning process accomplish certain goals and require Legislature to conduct an initial review of the state's policy by January 1, 2023.

Washington SB 5116 Clean Electricity Bill

- Governor's clean electricity bill – 100 percent carbon neutral by 2030
- Eliminates coal-fired electricity serving Washington customers by 12/31/25,
- 100 percent carbon neutral resources by 2030
- Eliminating use of fossil-fuel generation to serve Washington load beginning in 2045
- Passed Senate and House, back to Senate to approve House changes
- 2% annual cost cap
- Must consider the social cost of carbon for conservation evaluation and selection, developing IRP and clean energy plans, and evaluating and selecting intermediate and long-term resources

Idaho and Montana Updates

Idaho: No major legislative proposals impacting the IRP

Montana:

- SB 331: Allow preapproval of 150 MW additional from Colstrip unit 4 for NorthWestern. Passed Senate.
- SB 201: revise requirements to hold mine permits to make sure Rosebud Mine pensions are paid. Passed House and Senate.
- SB 252: Revise Montana Facility Siting Act to allow a coal mining permit owner to get coal from outside of the Rosebud Mine. Passed and back to Senate with amendments.
- HB 476: low interest loans from Montana Board of Investment for NorthWestern to acquire additional interest in Colstrip and Talen to replace coal supply agreement. Passed House and Senate.
- SB 189: Carbon Tax bill tabled.

Oregon Update

HB 2020: Greenhouse gas cap and trade

- Establishes a cap and trade program for entities with 25,000 tons or more of greenhouse gas emissions. Creates the Carbon Policy Office within Oregon Department of Administrative Services and directs the Director of Carbon Policy Office to adopt Oregon Climate Action Program by rule.

IRP Transmission Planning Studies

Tracy Rolstad, Transmission Planning

Third Technical Advisory Committee Meeting

April 16, 2019

Education

- Tracy Rolstad
  - Diploma, Naval War College, College of Naval Command and Staff
  - BSEE, University of Idaho
  - Nuclear Navy
    - Nuclear Operational Prototype (S1C)
    - Nuclear Power School (Reactor Operator)
    - Electronics Technician School
      - Radar, Communications, etc.
  - Professional Technical Education
    - Too numerous to list…

Resume…

– Avista Corporation

- Senior Pwr Sys Consultant, System Planning
- WECC DS Chair, WECC TSS Chair

– Utility System Efficiencies

- Senior Power Systems Analyst

– The Bonneville Power Administration

- Senior Engineer, System Operations

– The Joint Warfare Analysis Center

- EP Senior Analyst, PACOM Chief of Targets
- Special Technical Operations Action Officer

– Nuclear Navy (Attack Submarines)

- Chief Petty Officer (ETC/SS)
- Engineering Watch Supervisor

Something Novel About Me

FERC Standards of Conduct

Non-public transmission information can not be shared with Avista Merchant Function employees

There are Avista Merchant Function employees attending today

We will not be sharing any non-public transmission information (OASIS is the place where this information is made public)

Agenda

- Introduction to Avista System Planning
  - Useful information about Transmission Planning
  - Recent Avista projects

- Generation Interconnection Study Process
  - Integrated Resource Plan (IRP) Requests
  - Large Generation Interconnection Queue

Introduction to Avista System Planning

Avista's System Planning Group includes:

- Transmission Planning
- Distribution Planning
- And we all care about:
  - Federal, regional, and state compliance
  - Regional system coordination
  - Reliable electric service
- We provide transmission service
  - To anyone
  - To any type of generation or load
    - We are ambivalent about type (must perform though)

Information About Transmission Planning

- We care about the Bulk Electric System (BES)
  - Our 115 kV and 230 kV facilities (>100 kV)
- If the Avista BES looks like it won't reliably deliver electrons to our customers in the near or distant future, we put together plans to fix it
  - "Corrective Action Plans"
  - Mandated and Described in NERC TPL-001-4
- We live in the world of NERC Mandatory Standards
  - Energy Policy Act of 2005

TPL-001-4

- Describes outages we must study
  - P0: everything online and working
  - P1: single facility outages, like a transformer
  - P2 to P5: increasing levels of outages
  - P6: any combination of two facilities

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

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

8

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
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

9

TPL-001-4

- A couple of NERC directives for the faults above
  - "The System shall remain stable"
  - "Applicable Facility Ratings shall not be exceeded"
  - "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events"

Two Approaches to Reliability Issues

- Transmission Operators (TO) are guided by *significantly* different standards than Transmission Planners (TP).
- TO standards provide *flexibility* that TP standards do not allow
  - Operators can do anything to ***SAVE*** the interconnected system
    - Planners hopefully give them the tools to do this
      - We HAVE changed our ways since 2007 (NERC stds)
        - » Inverse dog years are utility years

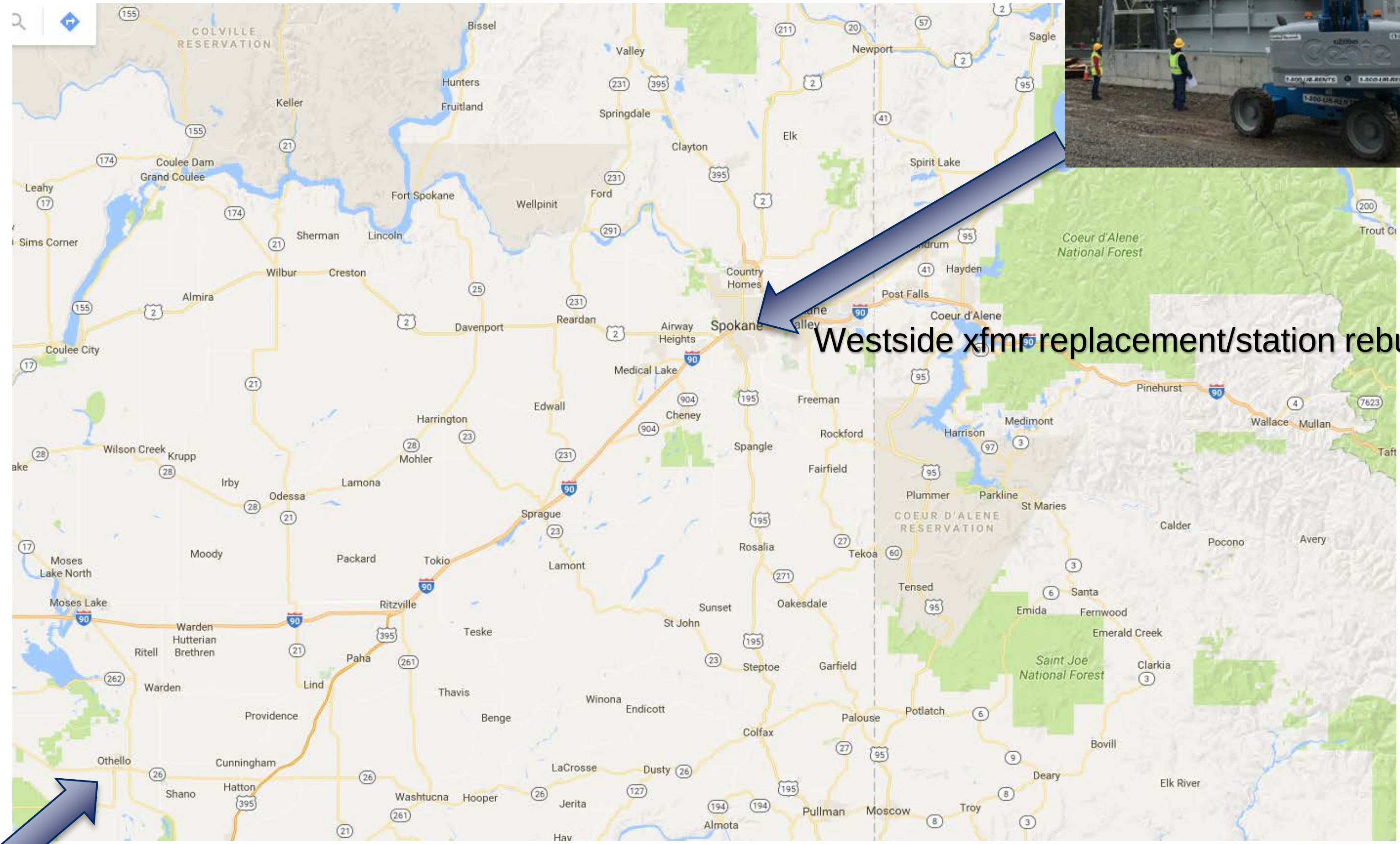
We Are Recovering From This…

A quote from the late 90's: "***That's our stuff, we will take the hit and shed load if needed***."

WSCC DISTURBANCE-PERFORMANCE TABLE
OF ALLOWABLE EFFECT ON OTHER SYSTEMS(1)

Performance Level	Disturbance(2) Initiated By: No Fault 3 Ø Fault With Normal Clearing SLG Fault With Delayed Clearing DC Disturbance (3)	Transient Voltage Dip Criteria (4)(5)(6)	Minimum Transient Frequency (4)(5)	Post Transient Voltage Deviation (4)(5)(6)(7)	Loading Within Emergency Ratings	Damping
A	Generator One Circuit One Transformer DC Monopole (8)	Max V Dip - 25% Max Duration of V Dip Exceeding 20% - 20 cycles	59.6 hz Duration of f Below 59.6 hz - 6 cycles	5%	Yes	>0
B	Bus Section	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 20 cycles	59.4 hz Duration of f Below 59.4 hz - 6 cycles	5%	Yes	>0
C	Two Generators Two Circuits DC Bipole (8)	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 40 cycles	59.0 hz Duration of f Below 59.0 hz - 6 cycles	10%	Yes	>0
D	Three or More circuits on ROW Entire Substation Entire Plant Including Switchyard	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 60 cycles	58.1 hz Duration of f Below 58.1 hz - 6 cycles	10%	No	≥0

Recent Transmission Projects



Westside xfmr replacement/station rebuild

Benton – Othello 115 kV Rebuild (still ongoing)

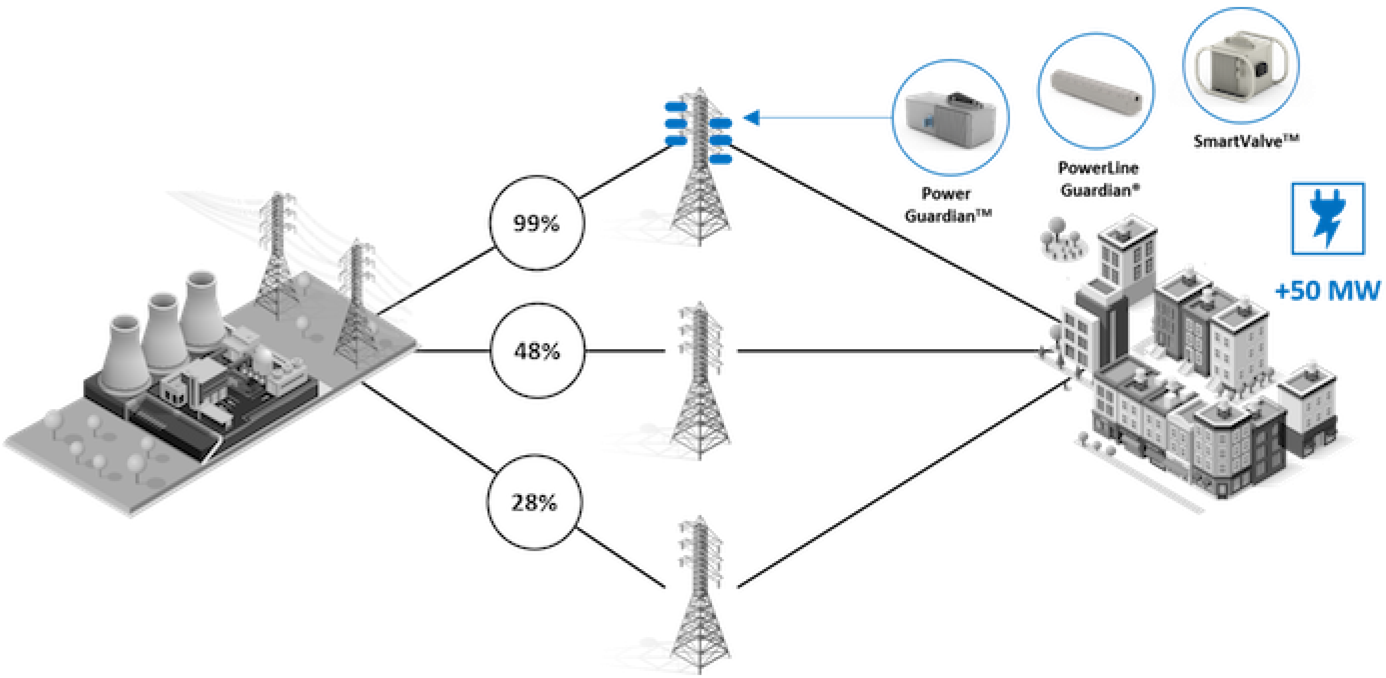
Non Wires (or perhaps no new wires)

- Avista made "non-wires" Columbia Grid workshop happen (held at PSE HQ)

1_Drivers for Non-Wires & Non-Wires Technology_Tracy Rolstad....	Adobe Acrobat Document
2_Idaho Power Experience with Non-Wires_Patrick Perry.pdf	Adobe Acrobat Document
3_PSE Glacier Battery Storage Project_Kelly Kozdras.pdf	Adobe Acrobat Document
4_Avista Energy Storage Project_Kenny Dillon.pdf	Adobe Acrobat Document
5_SPUD Energy Storage Project_Bob Anderson.pdf	Adobe Acrobat Document
6_Energize Eastside Case Study_Jens Nedrud.pdf	Adobe Acrobat Document
7_BPA Non-Wire Alternative for South of Allston_Dave Cathcart.pdf	Adobe Acrobat Document
8_DER Modeling_Erik Olson.pdf	Adobe Acrobat Document
9_Non-Wires Alternatives Discussion_Final Presentation_Jens Nedr...	Adobe Acrobat Document
2018-08-15 Non-Wires Workshop Agenda_v2.docx	Microsoft Word Document
2018-08-15 Non-Wires Workshop Notes.docx	Microsoft Word Document

Non Wire Solutions are always evaluated

- We are documenting this with more clarity
- Non wires REQUIRE robust wires to perform
  - Smartwire evaluation (our wires are too small!)
    - Avista is working on the transmission fundamentals



New wires…same footprint

- Small wire replacement
  - Mostly copper replacement
    - Facilitates use of SmartWires technology
      - But practically eliminates the need in the near term
        - » It DOES literally physical support the devices…

Avista Planning has been studying these since 2015. Partnered with U of I as well sponsoring R&D on DFACTS

ACSS @ 200C tremendous ratings -or- Trap Wire…

Evaluated Batteries for T-1-1

- TPL-001-4 T-1-1 Evaluation
  - Double transformer outages
    - Shawnee 230/115 kV
      - Concurrent with outage of Moscow 230/115 kV
    - Could we mitigate performance issues with storage?
      - Yes…but…
        - » We would need a 100 MW battery
          - Charge is 8 hours, discharge for 12 to 16 hours
            - A third transformer is a better solution
              - Robust performance and much less $$$$

Requisitions: Requisitions >

Requisition 162964

Description: M08 - Westide 250/280MVA, 230-115-13.8kV, three phase auto transformer.
Created By: Wilson, Barnes Scott (Scott)
Creation Date: 12/06/2017 12:49:35
Deliver-To: One Time Ship To
Justification: This is the second transformer associated with the Westside Substation rebuild.

Status: Approved
Change History: No
Urgent Requisition: No
Attachment: View
Note to Buyer: Quote attached. Bid evaluation sheet pre Shelly Campbell.

Details

Line	Description	Need-By	Deliver-To	Unit	Quantity	Qty Delivered	Qty Cancelled	Open Quantity	Price	Amount (USD)
1	250/280MVA, 230-115-13.8kV, three phase auto transformer.	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	2397826 USD	2,397,826.00
2	SFRA Testing at factory and field	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	5400 USD	5,400.00
									Total	2,403,226.00

Generation Interconnection Study Process

Process for Generation Requests

- Two sources:
  - External developers
    - Enter via the OATT
  - Internal IRP requests
    - Feasibility Lite Study…then OATT
      - AVA Merchant MUST follow the OATT just like external parties
- Typical process:
  - Hold a scoping meeting to discuss particulars
  - Outline a study plan
  - Augment WECC approved cases for our studies
  - Analyze the system against the standards
  - Publish our findings and recommendations

2019 IRP *Transmission* Cost Estimates

RAS changes everything!

Station	Request (MW)	POI Voltage	Cost Estimate ($ million)
Kootenai County (GF)	100	230 kV	2
Kootenai County (GF)	200/300	230 kV	80-100
Rathdrum	25/50/100	115 kV	<1
Rathdrum	200	115 kV	55
Rathdrum	50/100	230 kV	<1
Rathdrum	200	230 kV	60
Benewah	100/200	230 kV	<1
Tokio	50/100	115	<1, 20
Othello/Lind	50/100/200	115 kV	Queue Issues
Lewiston/Clarkston	100/200	230 kV	<1
Northeast	10	115 kV	<1
Kettle Falls	12	115 kV	<1
Kettle Falls	24/100/124	115 kV	<20
Long Lake	68	115 kV	33
Monroe Street	80	115 kV	2
Post Falls	10	115 kV	<1
Cabinet Gorge	110	230 kV	<14

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

Current Queue

Generator Interconnection Applications

Proj #	Date of Request	Status of Request	Service Type NR or ER	Location	Max Summer output	Max Winter output	Total (MW)	Station or Trans Line where interconn will be made	Projected In-Service Date	Known deviations to in-service date.	Availability of related studies	Type of facility (combined cycle, base load, CT, fuel type)	If not completed-explanation	Deviations from study timelines	Study reports posted subsequent to meeting & discussion of results.	Basecase containing powerflow/stability/short circuit data and contingency list
69	9/20/2018	FS	ER	Approximately 85 miles NE of Colstrip, MT in Rosebud and Custer Counties.	750	750	750.00	Colstrip 500 kV transmission line approximately 6 miles south of the project location		0	0	Wind	0	0	NA	
70	8/31/2018	SIS	NR	Near Liberty Lake 115 kV Station	2.5	2.5	2.50	Liberty Lake 12F4	1/1/2019	0	0	Energy Storage - Battery	0	0	NA	
71	10/4/2018	FS	NR	Near Harrington 115 kV Station	7	7	7.00	Harrington Substation 13.8kV	8/15/2020	0	0	Solar	0	0	NA	
72	10/9/2018	FS	NR/ER	Near Ritzville 115 kV Station	80	80	80.00	Ritzville 115 kV station	6/30/2021	0	0	Solar	0	0	NA	
73	10/12/2018	FS	NR/ER	Near Ritzville 115 kV Station	100	100	100.00	Ritzville 115 kV station	6/30/2020	0	0	Solar	0	0	NA	
74	11/16/2018	SIS	NR/ER	SIP 12F2	0.1	0.1	0.10	SIP 115/13.8 kV station	1/15/2019	0	0	Energy Storage - Battery	0	0	NA	
75	11/20/2018	Withdrawn	NR/ER	10 miles west of the Hot Springs station	80	80	80.00	Hot Springs - Noxon 230 kV line	12/31/2020	0	0	Solar	0	0	NA	
76	11/27/2018	FS	NR/ER	20 miles east of the Wanapum station	200	200	200.00	Wanapum - Saddle Mt 230 kV line	12/31/2020	0	0	Solar	0	0	NA	
77	12/4/2018	FS	NR/ER	Near Reardan 115 kV station	5	5	5.00	Reardan 115 kV station	12/31/2020	0	0	Solar	0	0	NA	
78	12/4/2018	Withdrawn	NR/ER	Near Rosalia 115 kV station	5	5	5.00	Rosalia 115 kV station	12/31/2020	0	0	Solar	0	0	NA	
79	12/4/2018	FS	NR/ER	Near Airway Hts 115 kV station	5	5	5.00	Airway Hts 115 kV station	6/30/2020	0	0	Solar	0	0	NA	
80	12/17/2018	FS	NR/ER	Near Silver Lake 115 kV station	19	19	19.00	Silver Lake 115 kV station	6/30/2020	0	0	Solar	0	0	NA	
81	12/18/2018	FS	NR/ER	Adams County approximately 17 miles east of Lind, WA	94	94	94.00	Lind - Shawnee 115 kV line	6/30/2020	0	0	Solar	0	0	NA	
82	2/20/2019	New	NR/ER	Approximately 3 miles west of Martinsdale, MT in Meagher County MT	600	600	600.00	Colstrip 500 kV transmission line approximately 6 miles south of the project location	12/31/2021	0	0	Wind	0	0	NA	

Study reports (listed under column P) are available upon request. Contact Randy Gnaedinger @ 509-495-2047 or Randy.Gnaedinger@Avistacorp.com to request a copy of a report. Reports may contain Critical Energy Infrastructure Information ("CEII") and may require the requestor to sign a CEII Non-Disclosure Agreement prior to obtaining a copy of the report.

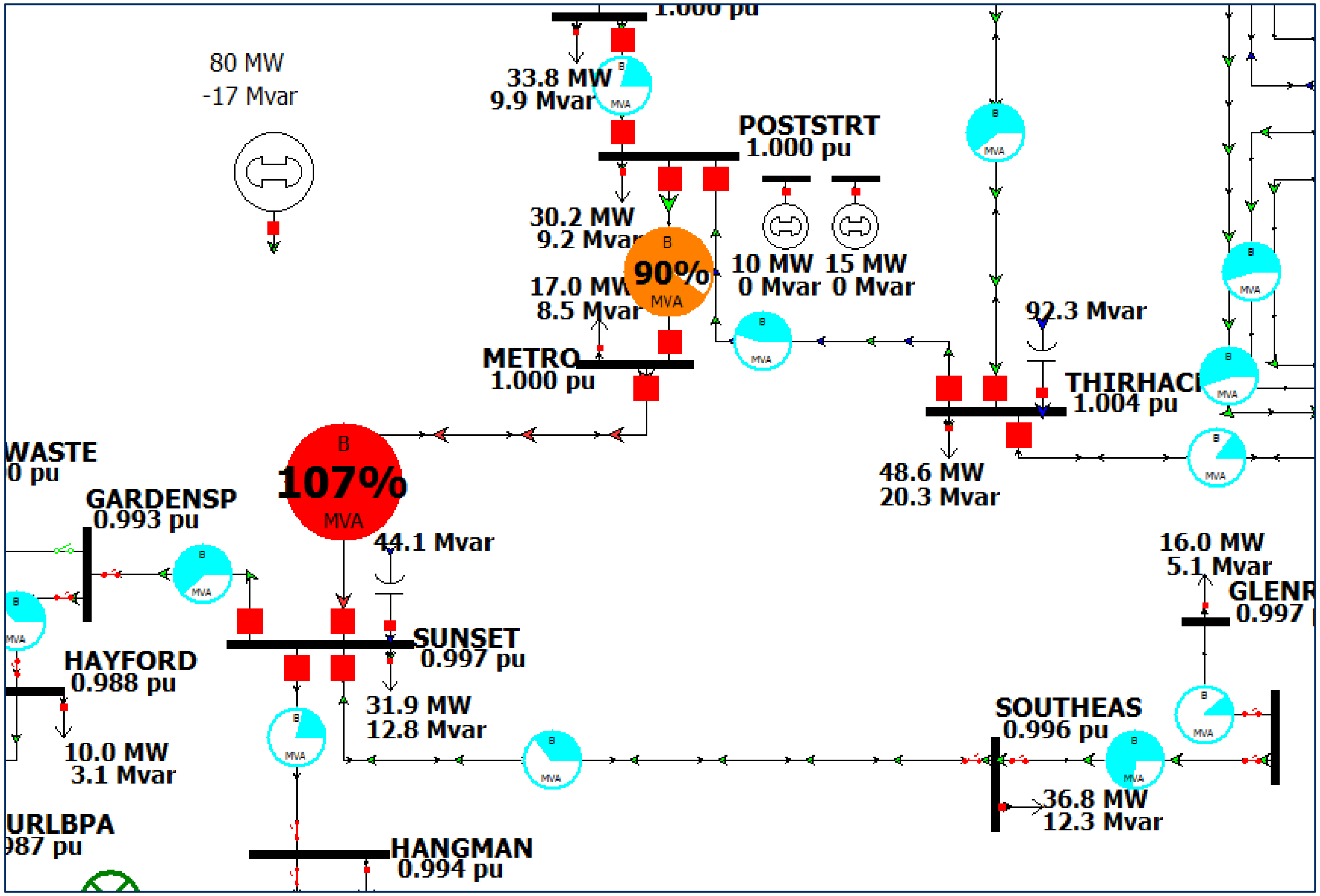
Glossary of terms

Construction ... ion phase

9 of 12

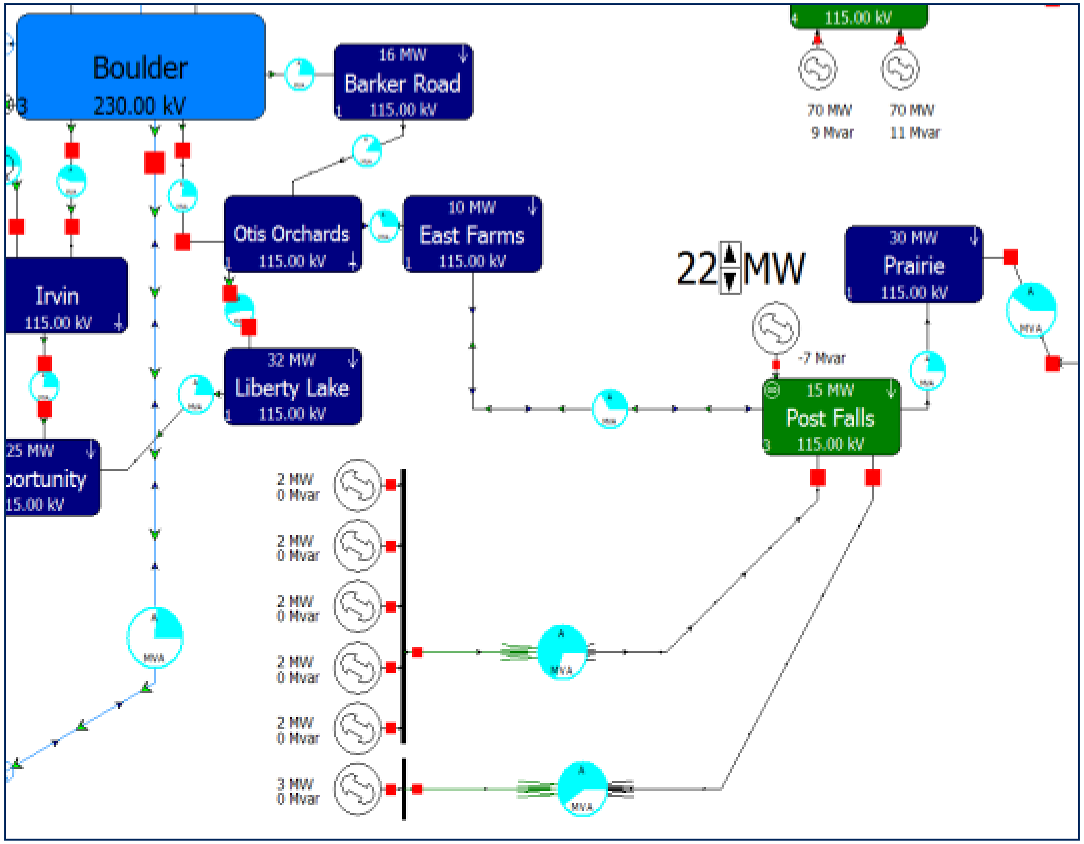
Monroe Street: 80 MW

- 3 miles of 115 kV



Post Falls: 10 MW to 20 MW

- Interconnection Only



Questions?

Avista OASIS link:

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

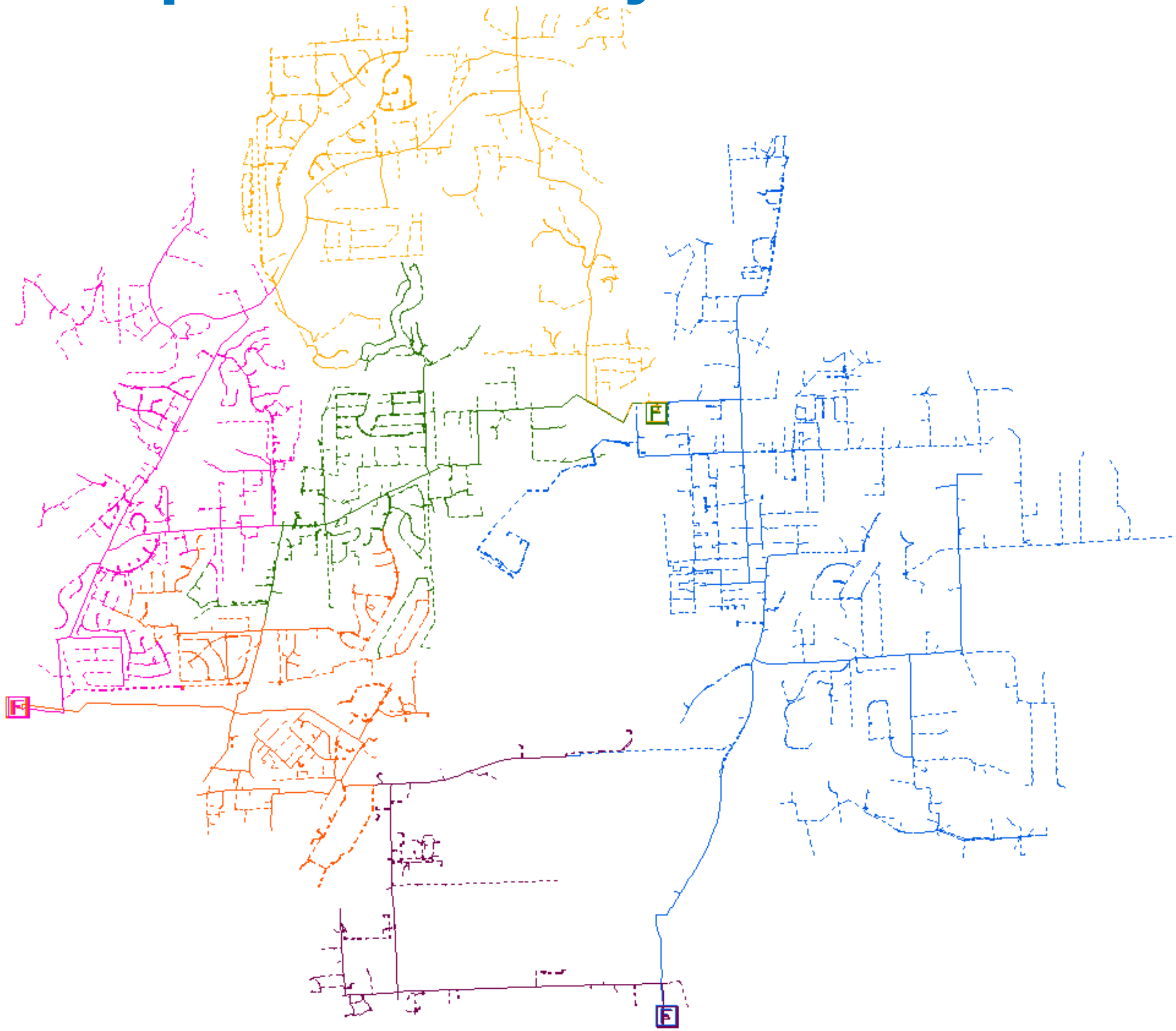
Electric Distribution Within the IRP

Damon Fisher, System Planning
Third Technical Advisory Committee Meeting
April 16, 2019

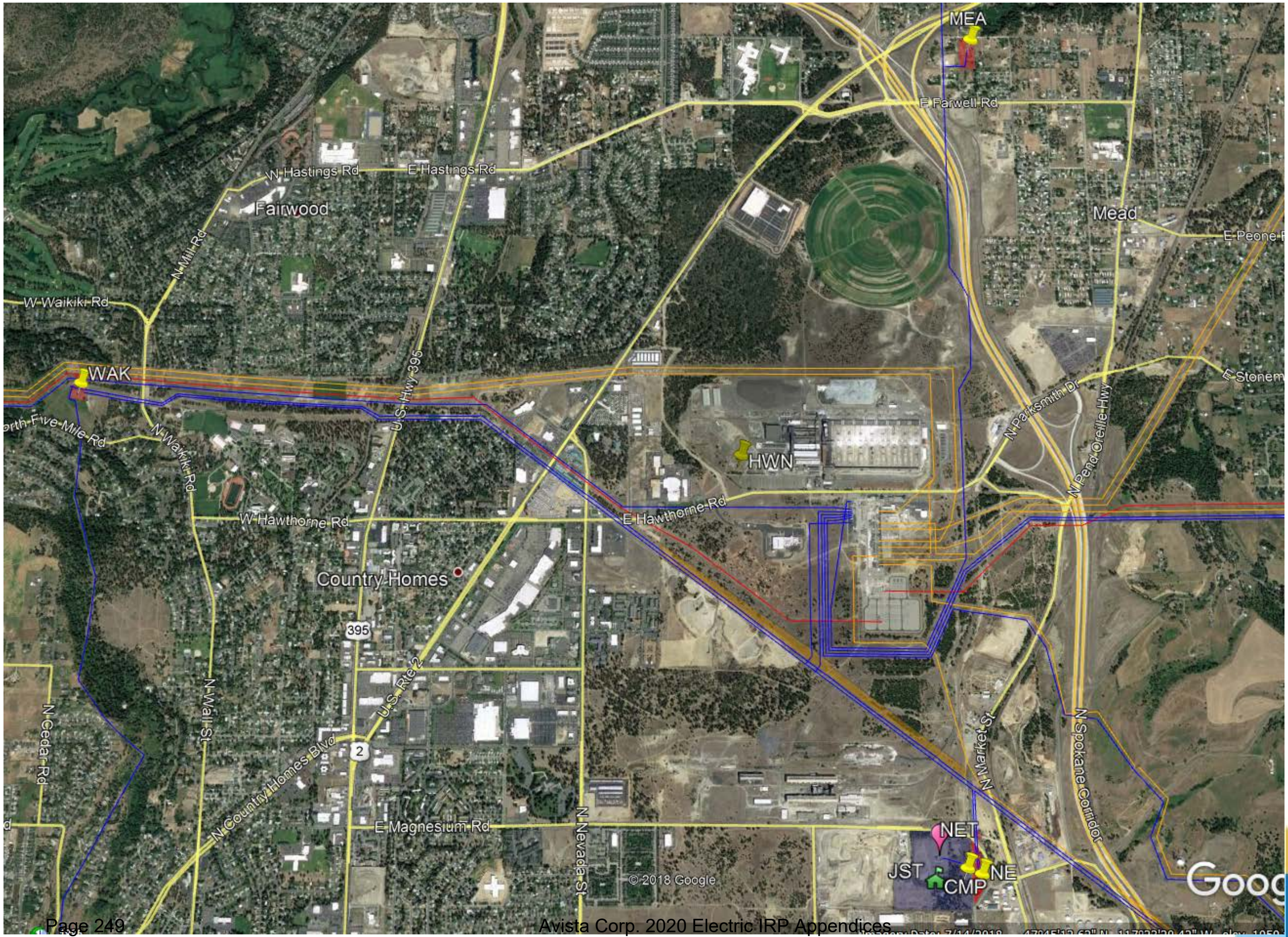
Goals of Electric Distribution Planning

- Ensure electric distribution infrastructure to serve customers now and in the future with a focus on:
  - Safety
  - Reliability
  - Capacity
  - Efficiency
  - Level of service
    - Voltage, Power Quality, etc.
  - Operational flexibility
  - Meet Corporate/Regulatory goals

North Spokane Study

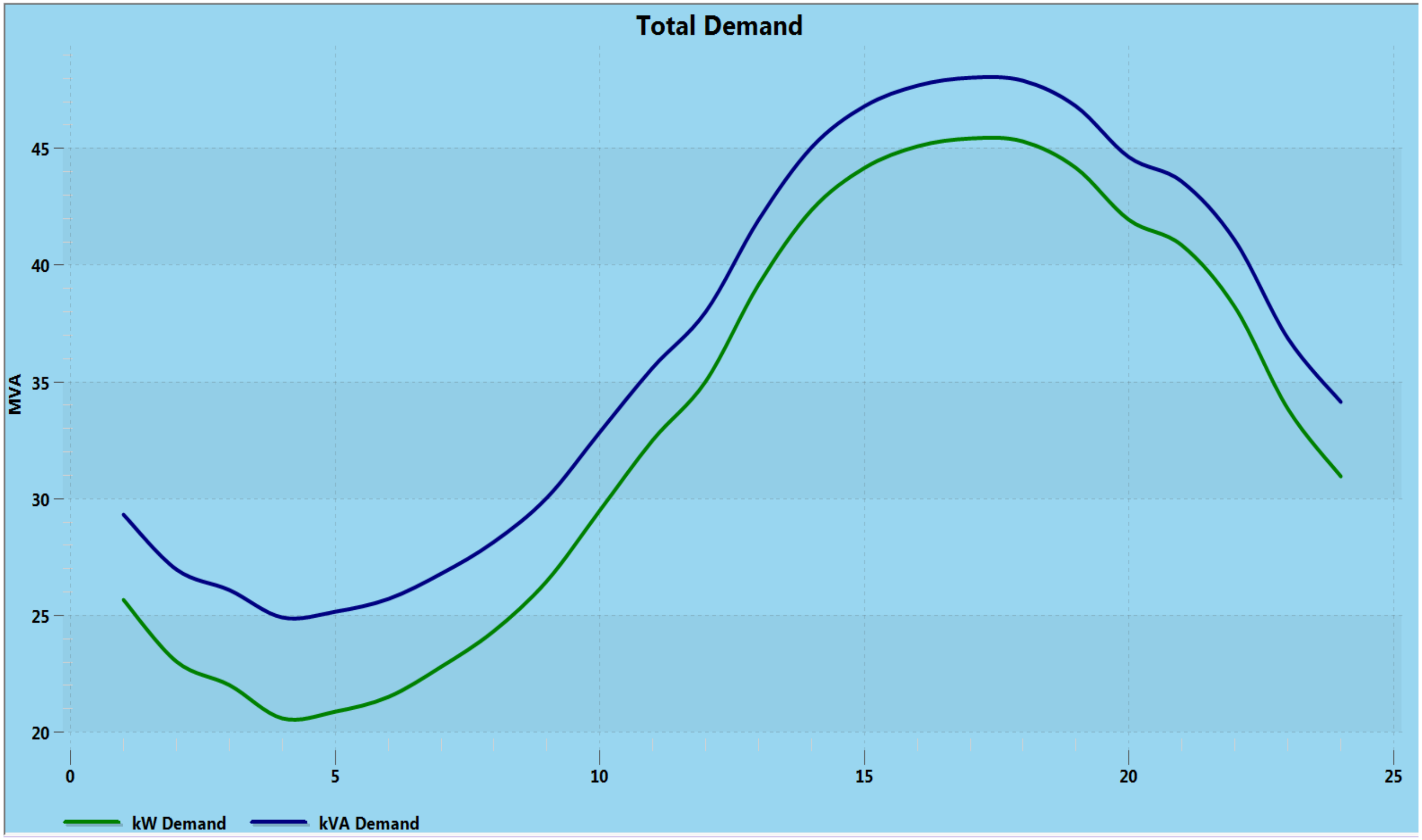


Study Area Map

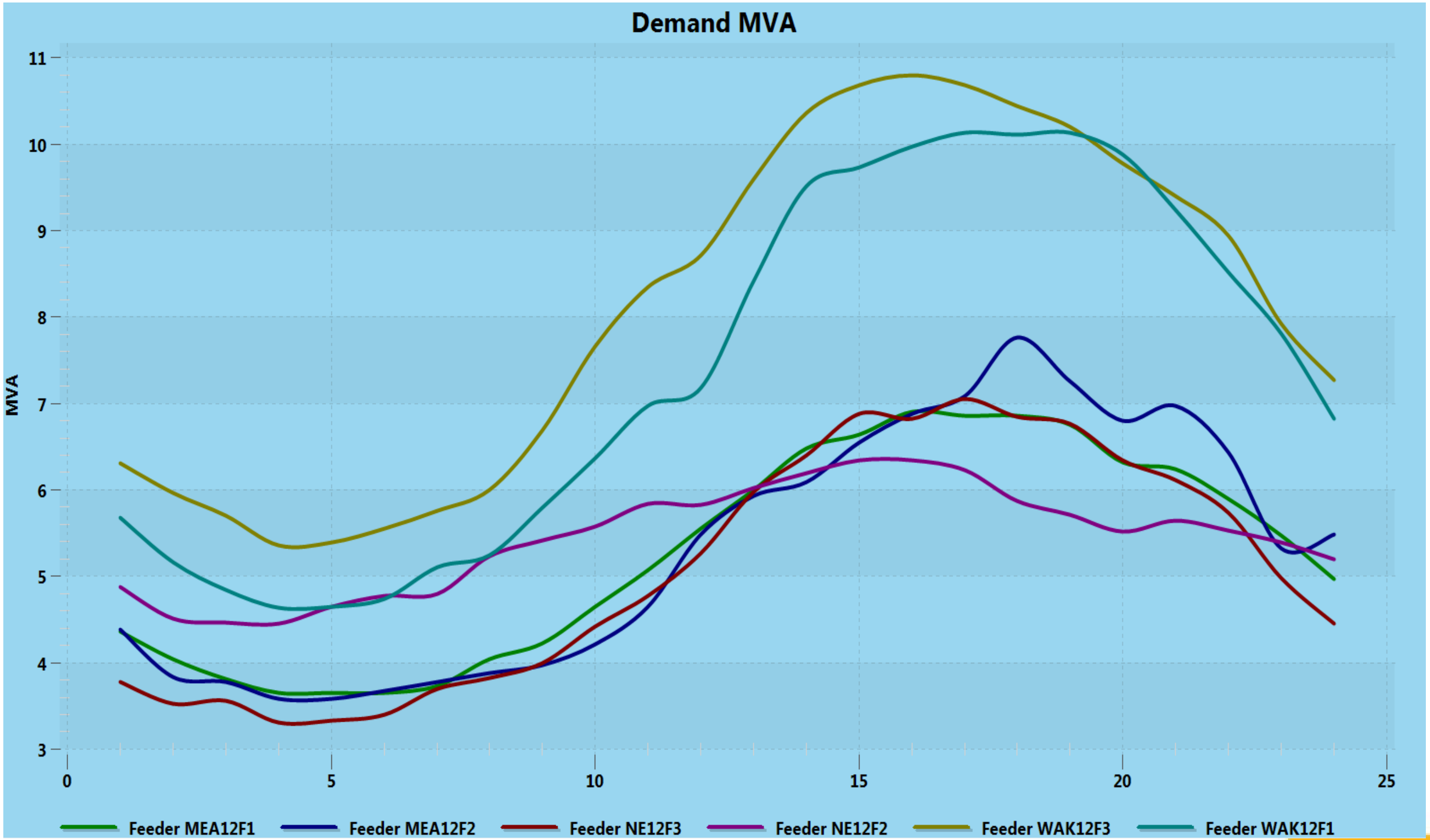


AVISTA

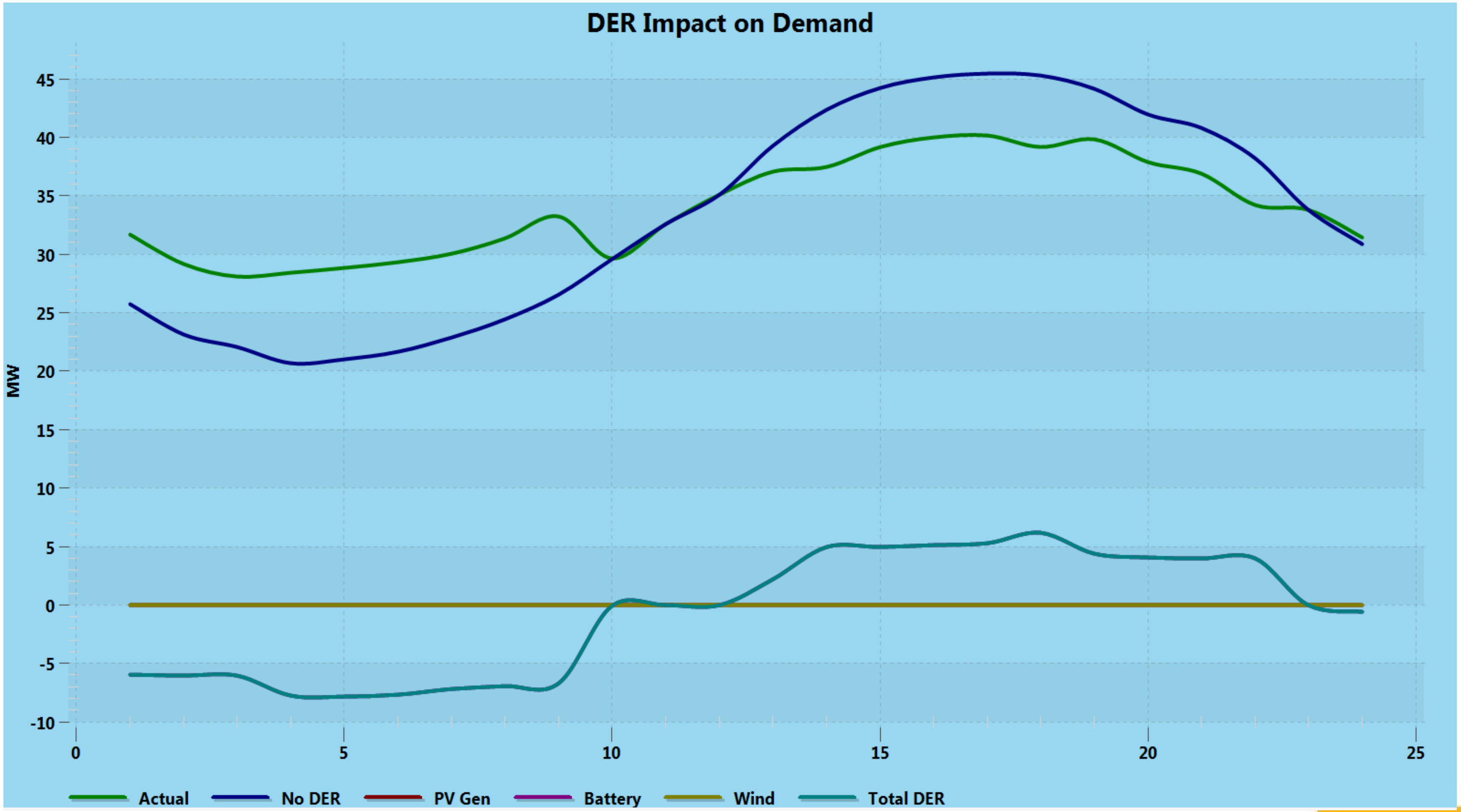
Total Area Demand 8/10/18



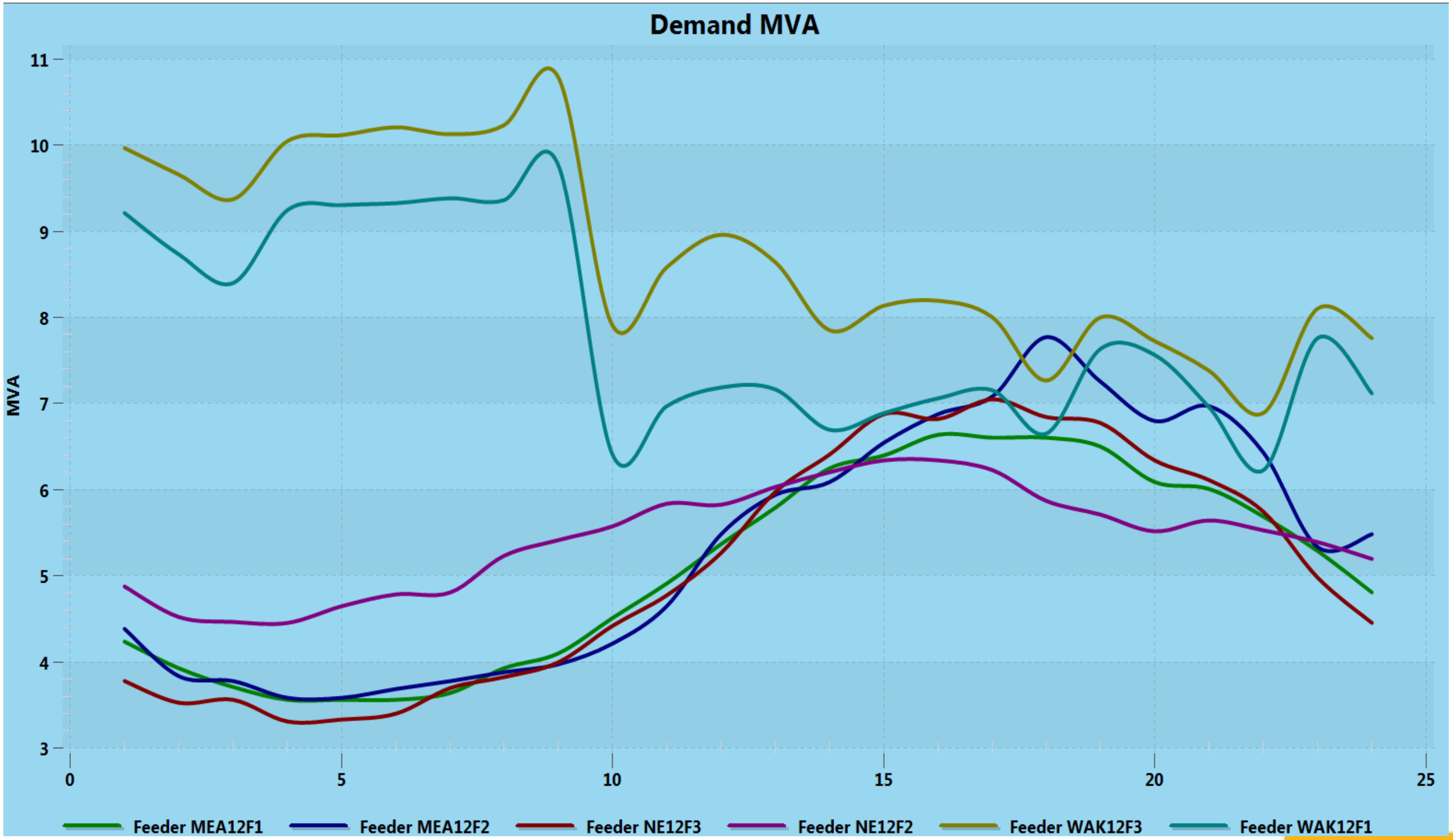
Feeder Demand 8/10/18



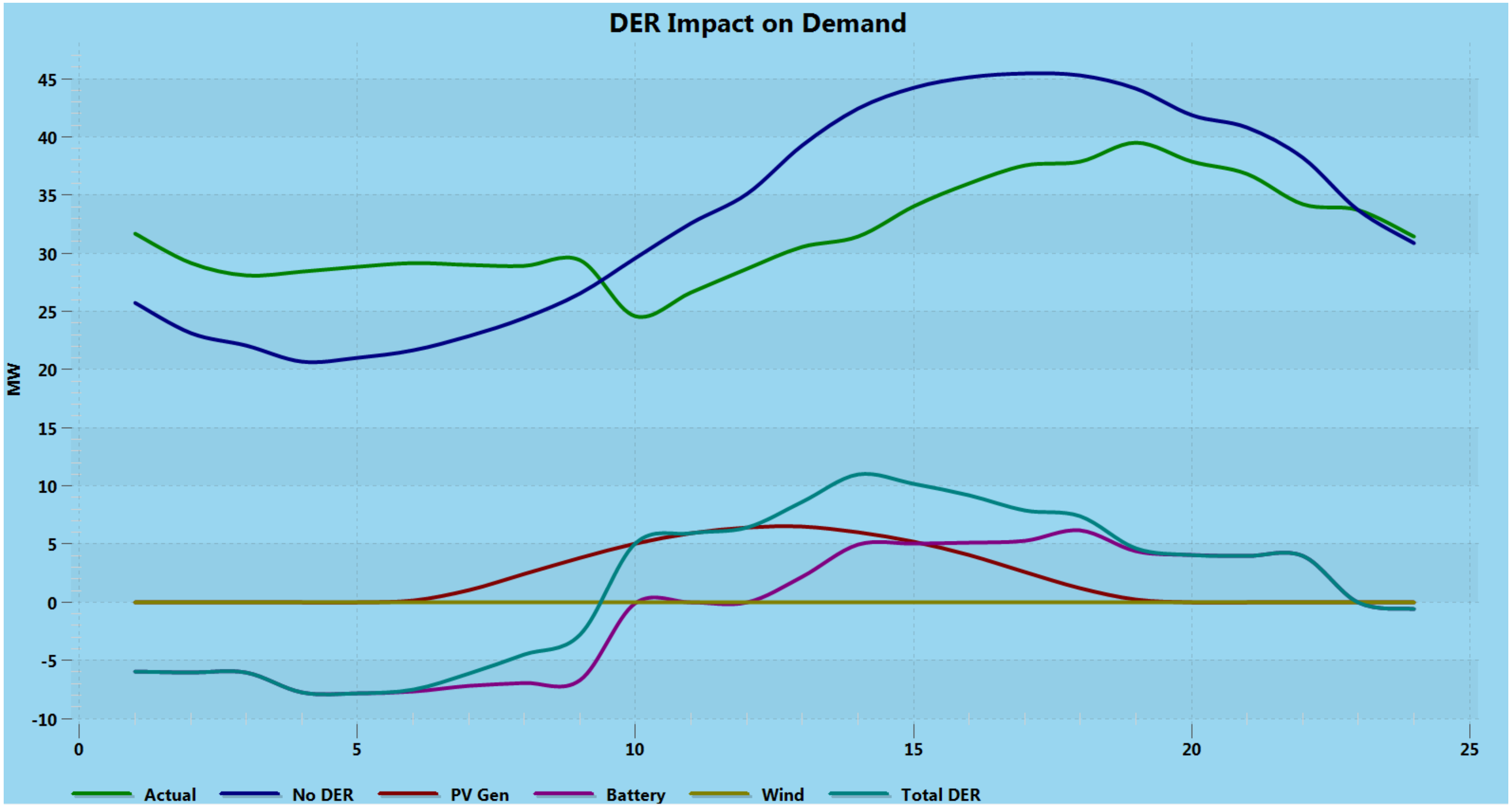
Add two 5MW 6 Hour Batteries



Feeder Demand with Batteries

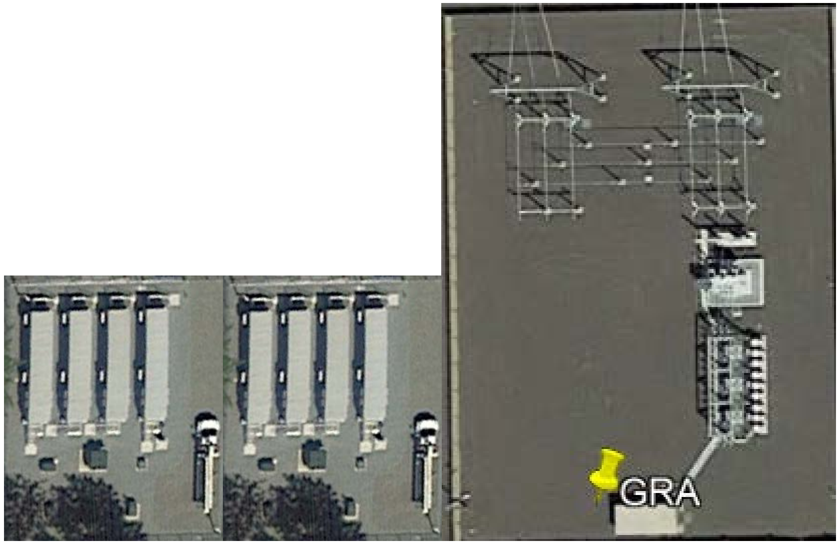


Modest Solar Installation



Assumes addition of 1.5 MW of solar per feeder
or 9 MW total solar capacity

Perspective ~ 4MW 4 Hour Battery vs. 60MW 8,760 Hour Substation



200ft

Substation/Transmission- $5 Million
Batteries (10MW with 6 hours)- ~$25 Million

Distribution Battery Benefits

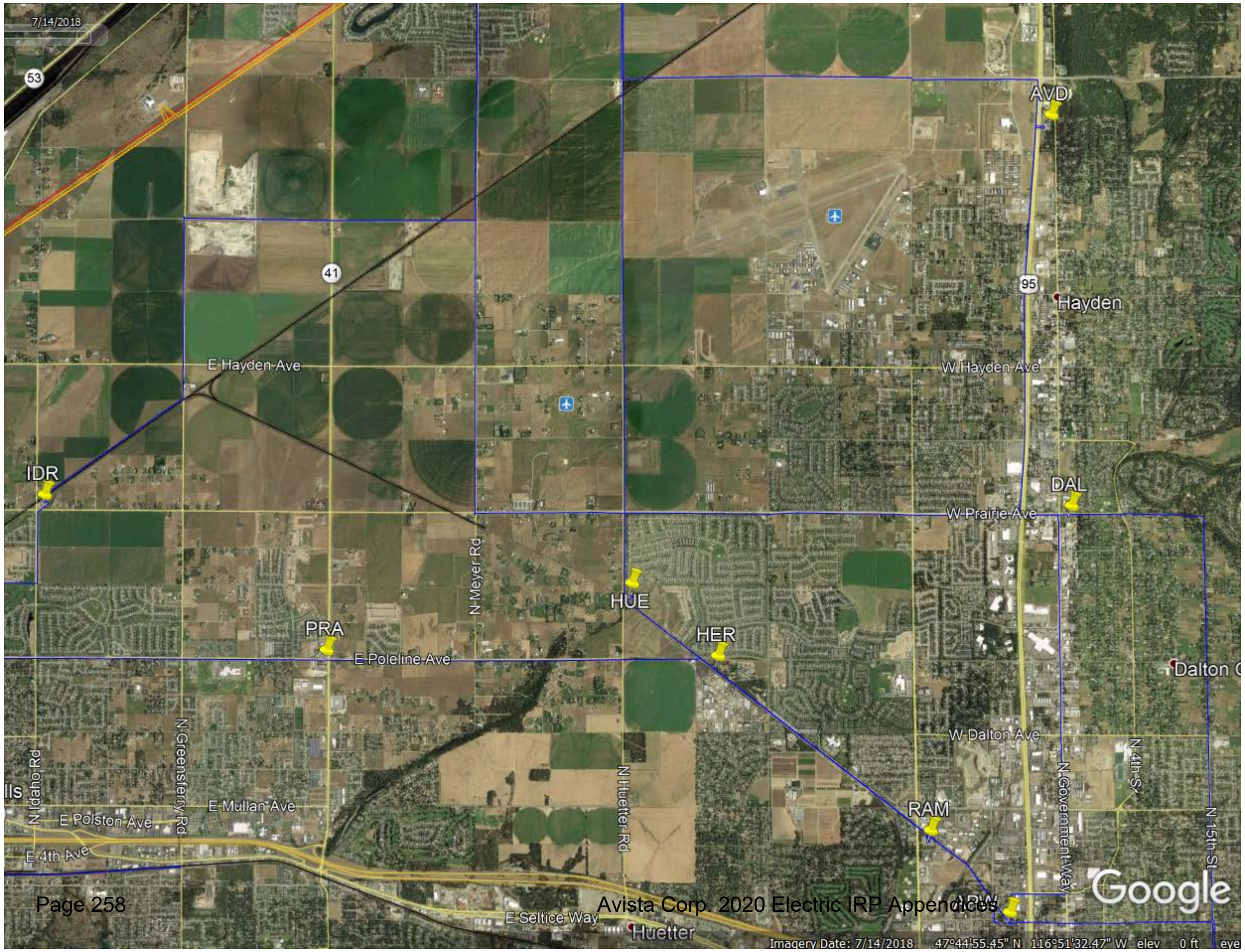
- Peak shaving
- Outage remediation (Islanded)
- Operational flexibility (back up a feeder)
- Generation shifting

Other Projects

- New Flint Road Substation
  - Offload overloaded feeders in Airway Heights

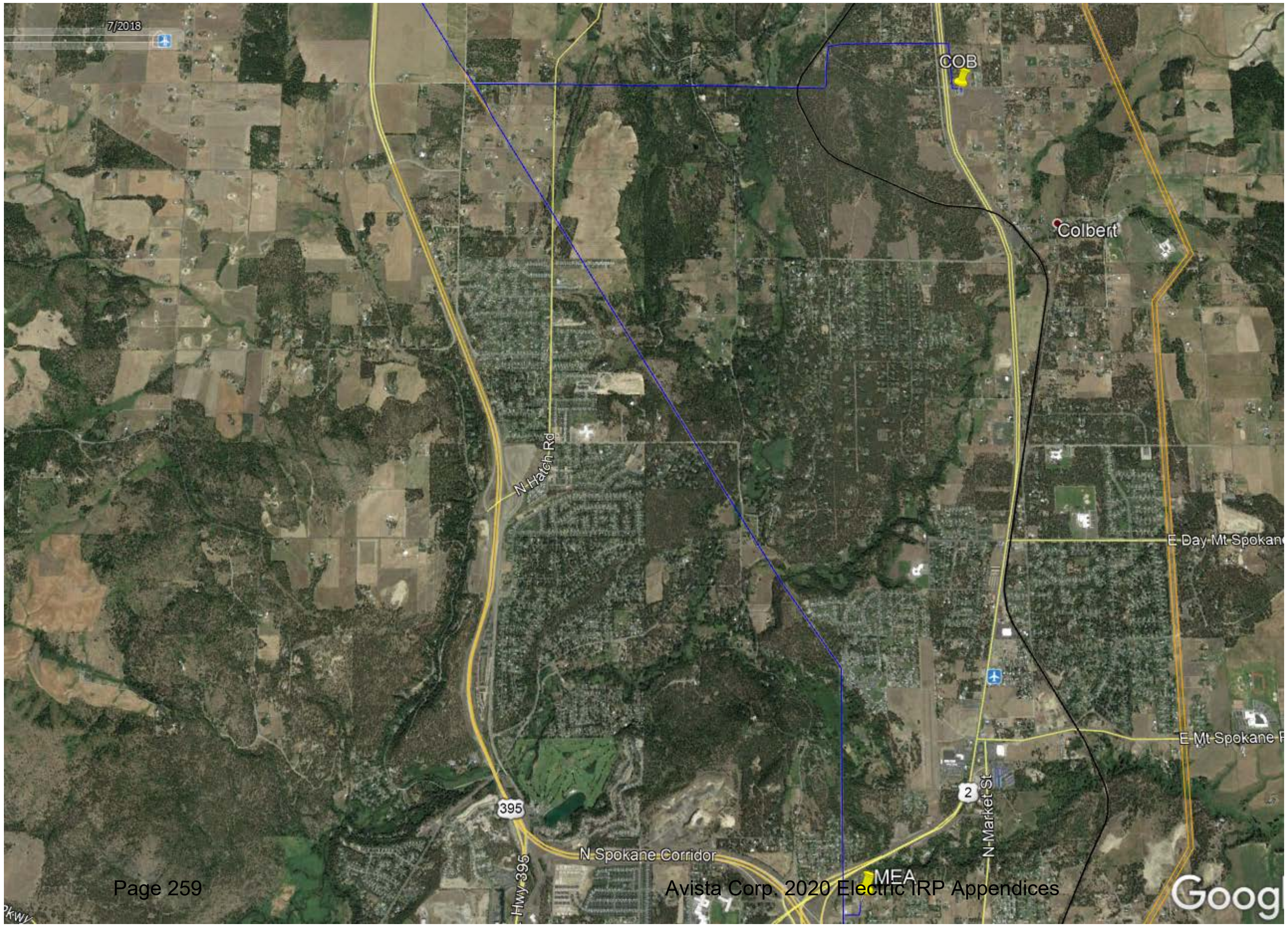
Other Projects

- Huetter Road Substation
  - Offload overloaded feeders in Coeur d'Alene

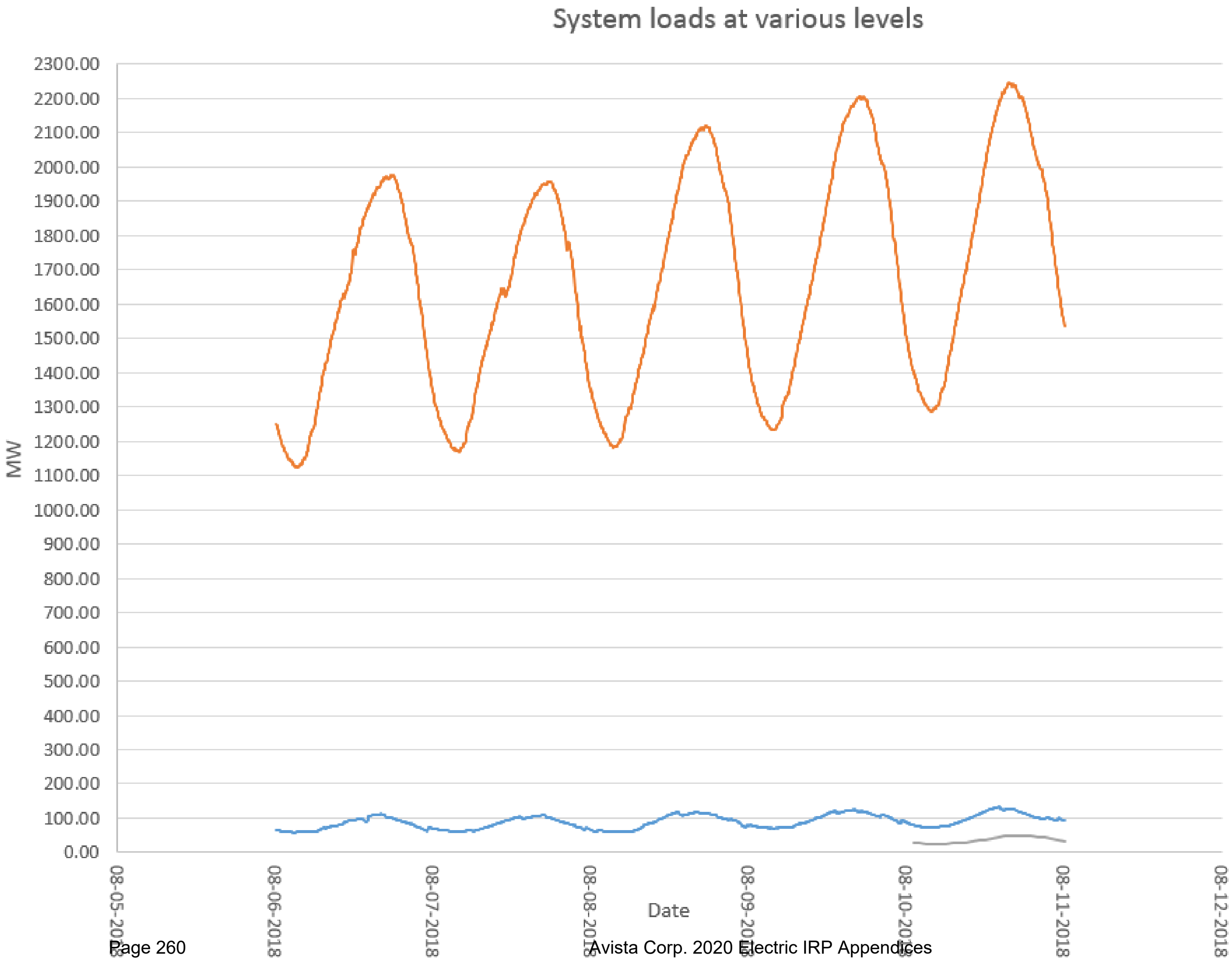


Other Projects

- New Colbert Substation
  - Offload overloaded Colbert Feeders



Conclusion



System loads at various levels
2300.00
2200.00
2100.00
2000.00
1900.00
1800.00
1700.00
1600.00
1500.00
1400.00
1300.00
1200.00
1100.00
1000.00
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
MW
08-05-2018
08-06-2018
08-07-2018
08-08-2018
08-09-2018
08-10-2018
08-11-2018
08-12-2018
Date

Questions?

AEG
Applied Energy Group

2018 ELECTRIC CPA RESULTS SUMMARY

Prepared for Avista Energy

AGENDA

Topics

AEG Introduction

Approach

Summary of Findings

Comparison with 2016 Potential Study

DR Analysis

Supplemental Slides

Sector-Level Results

Summer DR Impacts

Standalone DR Analysis

ABOUT AEG

AEG Applied Energy Group

Planning

- Baseline studies
- Market assessment studies
- Program design & action plans
- End-use forecasting

EM&V

- EE portfolio & targeted programs
- Demand response programs & dynamic pricing
- Pilot design & experimental design
- Behavioral programs

Implementation & Technical Services

- Engineering review, due-diligence, QA/QC
- M&V, modeling & simulation, onsite assessments
- Technology R&D and data tools (DEEM)
- Program admin, marketing, implementation, application processing

Market Research

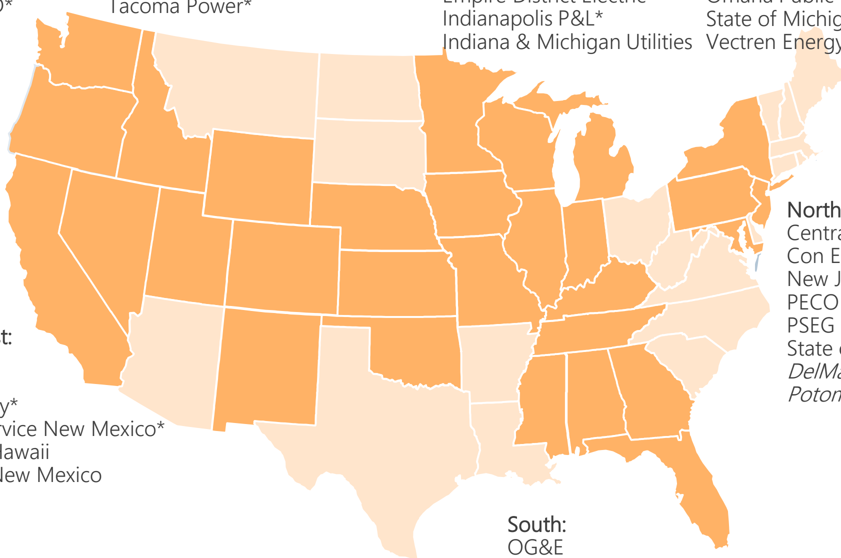
- Program / service pricing optimization
- Process evaluations
- Market assessment / saturation surveys
- Market segmentation
- Customer satisfaction / customer engagement

VISION DSM™ Platform

Full DSM lifecycle tracking & reporting

AEG EXPERIENCE IN PLANNING

Including Potential Studies and End-Use Forecasting



Northwest & Mountain:
Avista Energy*
BPA*
Cascade Natural Gas
Chelan PUD
Cheyenne LFP
Colorado Electric*
Cowlitz PUD*
Avista*
Inland P&L*
Oregon Trail EC
PacifiCorp*
PNGC
PGE*
Seattle City Light*
Tacoma Power*

Midwest:
Ameren Illinois*
Ameren Missouri*
Citizens Energy
Empire District Electric
Indianapolis P&L*
Indiana & Michigan Utilities
Kansas City Power & Light
MERC
NIPSCO*
Omaha Public Power District
State of Michigan
Vectren Energy*

Northeast & Mid Atlantic:
Central Hudson G&E*
Con Edison of NY*
New Jersey BPU
PECO Energy
PSEG Long Island
State of Maryland (*BG&E, DelMarva, PEPCO, Potomac Edison, SMECO*)

Southwest:
HECO
LADWP
NV Energy*
Public Service New Mexico*
State of Hawaii
State of New Mexico
Xcel/SPS

South:
OG&E
Kentucky Power
Southern Company (*APC, GPC, Gulf Power, MPC)*
TVA

Regional & National:
Midcontinent ISO*
EEI/IEE*
EPRI
FERC

* Two or more studies

AEG has conducted more than 60 planning studies for more than 40 utilities / organizations in the past five years.

AEG has a team of 11 experienced Planning staff plus support from AEG's Technical Services and Program Evaluation groups

Approach

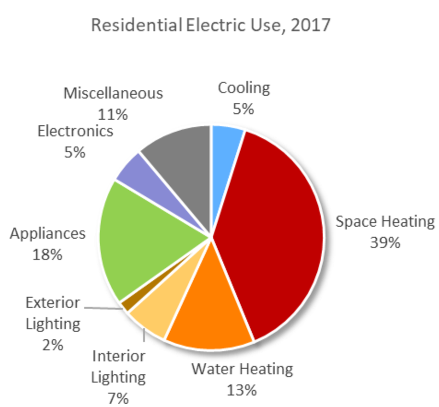
OVERVIEW OF AEG'S APPROACH
Overview

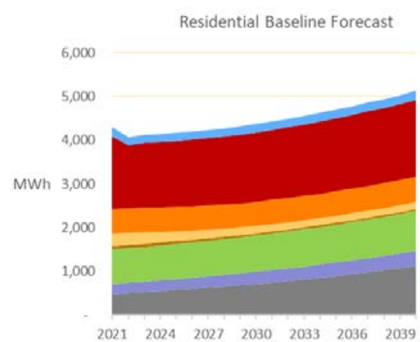
Market Characterization
- Avista control totals
- Customer account data
- Secondary data
- Avista market research

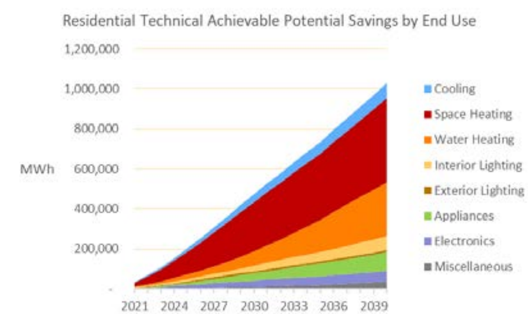
Identify Demand-Side Resources
- EE technologies
- EE measures
- Emerging

Baseline Projection
- Avista Load Forecast
- Customer growth
- Standards and building codes
- Efficiency options
- Purchase Shares

Potential Estimation
- Technical
- Technical Achievable
- Economic Screen *(TRC and UCT) are handled by Avista's IRP in this study*







KEY SOURCES OF DATA
Prioritization of Avista Data

Data from Avista was prioritized when available, followed by regional data, and finally well-vetted national data.

Avista sources include:

- 2013 Residential GenPop Survey
- Customer Account Database
- Forecast data and load research
- Recent-year accomplishments and plans

Regional sources include:

- NEEA studies (RBSA 2016, CBSA 2014, IFSA)
- RTF and Power Council methodologies, ramp rates, and measure assumptions

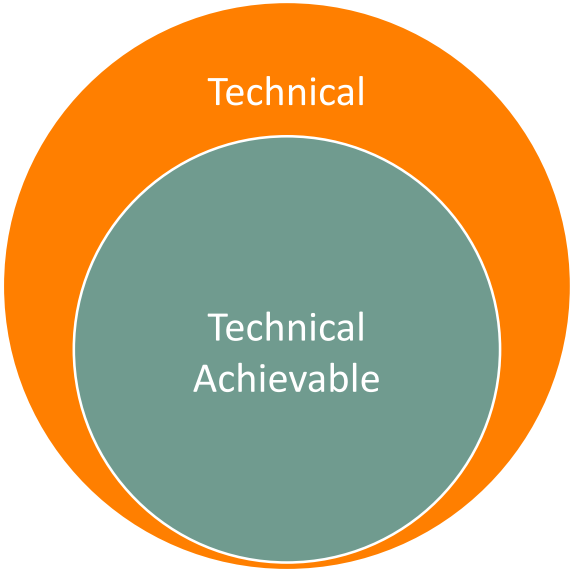
Additional sources include:

- U.S. DOE's Annual Energy Outlook
- U.S. DOE's projections on solid state lighting technology improvements
- Technical Reference Manuals and California DEER
- AEG Research

TWO LEVELS OF SAVINGS ESTIMATES

Power Council Methodology

- Focus of the study is to explore a wide range of options for reducing annual energy use
- This study develops two sets of estimates:
  - Technical potential (TP): everyone chooses efficient option when equipment fails
  - Technical Achievable Potential (TAP) is a subset of TP that accounts for customer preference and likelihood to adopt through **both** utility-and non-utility driven mechanisms



- In addition to these estimates, the study produces cost data for the TRC and UCT tests that can be used by Avista's IRP process to select energy efficiency measures in competition with other resources

2017-2018 ACTION PLAN
New Activities for 2019 IRP

From the Avista 2017 Electric IRP Acknowledgement Attachment (UE-161036):

In its comments in this docket, Commission Staff wrote that it has concerns with how the Company performs its conservation potential assessment (CPA), such as the Company's exclusion of conservation measures from the CPA prior to determining its technical potential.16 We share Staff's concern. It is critical that the Company achieve all cost-effective conservation, not only because this is required under the Energy Independence Act, but also because conservation and efficiency resources are the foundation of a least-cost resource stack.

In its 2019 IRP, the Company must ensure the entity performing the CPA evaluates and includes the following information:

1. All conservation measures excluded from the CPA, including those excluded prior to technical potential determination.
2. The rationale for excluding any measure.
3. A description, and source, of Unit Energy Savings data for each measure included in the CPA.
4. An explanation for any differences in economic and achievable potential savings.

The Company should also share its proposed energy efficiency measure lists with the Conservation Advisory Group prior to completing the CPA.

Action Items from Chapter 13 of the 2017 IRP: Energy Efficiency and Demand Response

- Determine whether or not to move the T&D benefits estimate to a forward looking value versus a historical value.
- Determine if a study is necessary to estimate the potential and costs for a winter and summer residential demand response program and along with an update to the existing commercial and industrial analysis.
- Use the utility cost test methodology to select conservation potential for Idaho program options.

MEASURE SCREENING
Exclusions from CPA

Recommended Activity:

In the 2019 IRP, ensure that the entity performing the Conservation Potential Assessment (CPA) evaluates and includes the following information:

- All conservation measures excluded from the CPA, including those excluded prior to technical potential determination;
- Rationale for excluding any measure;

Handling in CPA:

- Very few measures were excluded from the current CPA prior to estimation of technical potential. Those explicitly excluded were:
  - Some emerging tech measures where available cost or savings data was insufficient for characterization
  - Highly custom commercial and industrial controls/process measures that were instead captured under a retrocommissioning or strategic energy management program
- Measures that did not pass the economic screen were still counted in within achievable technical potential, allowing Avista to review for inclusion in programs if portfolio-level cost-effectiveness allows.

MEASURE DOCUMENTATION

Documentation of Savings and Other Assumptions

Recommended Activity:

- Description of Unit Energy Savings (UES) for each measure included in the CPA; specify how it was derived and the source of the data;

Handling in CPA:

- The measure list developed during the CPA includes descriptions of each measure included. AEG will provide this as an appendix to the final report.
- Source documentation for assumptions, including UES, lifetime, and costs (including NEIs) may be found in the "Measure Summary" spreadsheet delivered as an appendix to the final report.
  - This will include the name of the source and version (if applicable)

ECONOMIC POTENTIAL

Explanation of Difference between Achievable and Economic

Recommended Activity:

- Provide an explanation for any differences in economic and achievable potential savings.
- Use the utility cost test methodology to select conservation potential for Idaho program options

Handling in CPA:

- This round of the CPA delivers the full Achievable Technical potential for all measures along with the associated TRC and UCT levelized costs ($/MWh) for each measure.
  - Avista's IRP process will then perform its own economic considerations
- As both TRC and UCT levelized costs are provided, Idaho potential can be evaluated using UCT costs as recommended.

DEMAND RESPONSE

Assess Potential Value of Summer Peak and Residential

Recommended Activity:

- Determine if a study is necessary to estimate the potential and costs for a winter and summer residential demand response program and along with an update to the existing commercial and industrial analysis.

Handling in CPA:

- The DR analysis included Summer as well as winter impacts, and Residential program options, so that Avista will have the needed data to evaluate possible program combinations for DR

Applied Energy Group

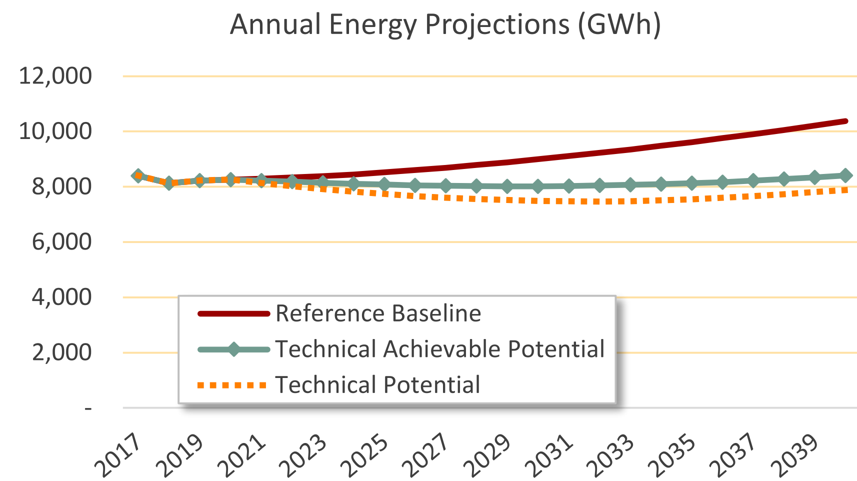
Summary of Findings

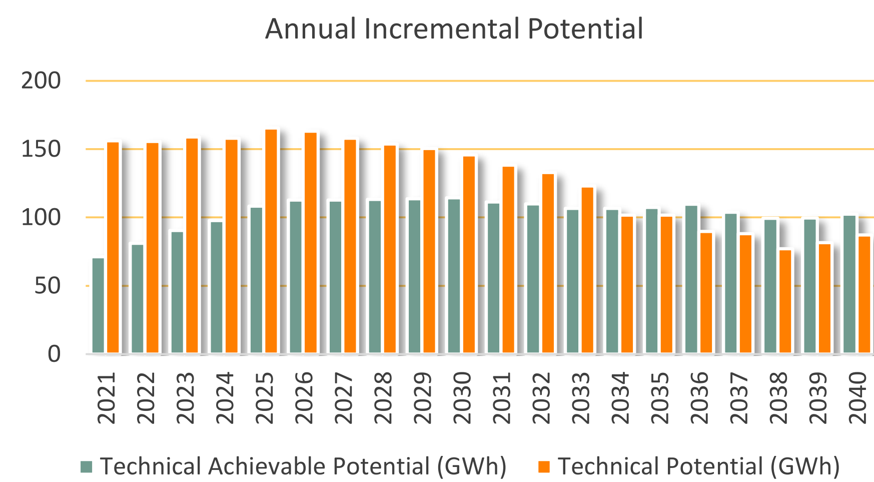
ENERGY EFFICIENCY POTENTIAL

Potential Summary –WA & ID All Sectors

Projections indicate that energy savings of ~1.1% of baseline consumption per year are Technically Achievable.

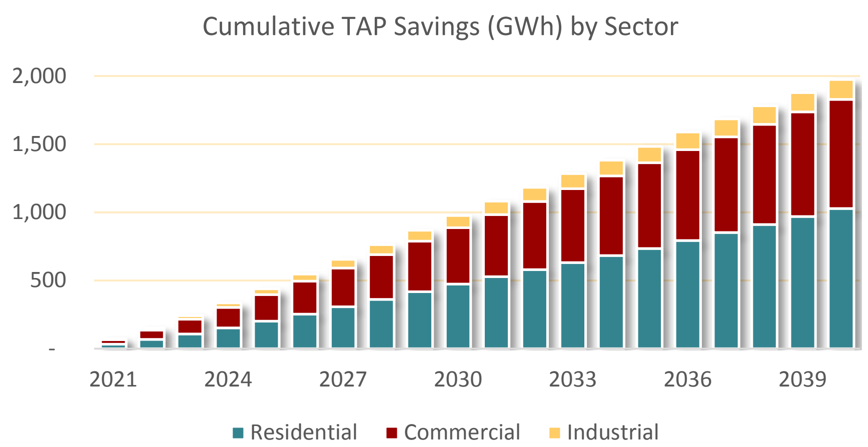
- 152 GWh (17 aMW) in biennium period (2021-2022)
- 976 GWh (111 aMW) by 2030
- This level of savings offsets future load growth

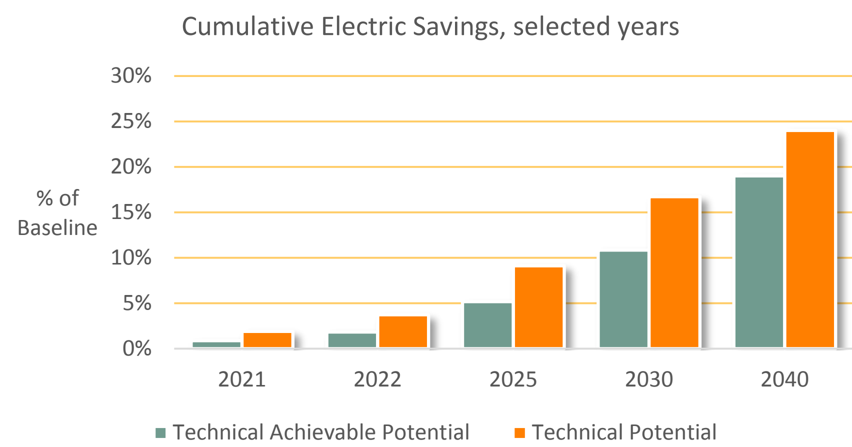




EE POTENTIAL, CONTINUED

Potential Summary – WA & ID, All Sectors





Summary of Energy Savings (GWh), Selected Years	2021	2022	2025	2030	2040
Reference Baseline (GWh)	**8,291.9**	**8,334.1**	**8,518.5**	**8,994.6**	**10,375.9**
Cumulative Savings (GWh)					
Technical Achievable Potential	71.4	151.6	439.3	976.3	1,973.7
Technical Potential	156.1	310.2	777.4	1,505.6	2,490.1
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.9%	1.8%	5.2%	10.9%	19.0%
Technical Potential	1.9%	3.7%	9.1%	16.7%	24.0%
Incremental Savings (GWh)					
Technical Achievable Potential	71.4	81.1	108.4	114.4	102.4
Technical Potential	156.1	155.6	165.5	145.7	87.2

EE POTENTIAL - TOP MEASURES

Cumulative Potential Summary – WA & ID All Sectors

Technical Achievable Potential, Ranked by Savings in 2030 (MWh)

Rank	Measure / Technology	2022 Achievable Technical Potential Savings (MWh)	% of Total	2030 Achievable Technical Potential Savings (MWh)	% of Total
1	Commercial - Linear Lighting	5,660.6	3.7%	63,530.2	6.5%
2	Residential - Ductless Mini Split Heat Pump (Ducted Forced Air)	5,708.8	3.8%	48,099.2	4.9%
3	Commercial - High-Bay Lighting	3,930.5	2.6%	44,231.0	4.5%
4	Residential - Ductless Mini Split Heat Pump (Zonal)	4,294.6	2.8%	34,379.2	3.5%
5	Residential - Water Heater (<= 55 Gal)	346.4	0.2%	33,635.3	3.4%
6	Commercial - Area Lighting	2,803.7	1.8%	30,902.6	3.2%
7	Residential - ENERGY STAR Home Design	896.7	0.6%	28,424.9	2.9%
8	Residential - Thermostat - Connected	3,390.5	2.2%	27,597.7	2.8%
9	Residential - Windows - Cellular Shades	2,584.2	1.7%	23,018.4	2.4%
10	Residential - Advanced New Construction Design - Zero Net Energy	184.9	0.1%	16,806.7	1.7%
11	Residential - Dishwasher	904.0	0.6%	15,986.0	1.6%
12	Residential - Water Heater - Low-Flow Showerheads	4,362.8	2.9%	15,789.3	1.6%
13	Residential - General Service Screw-in	2,233.8	1.5%	13,532.3	1.4%
14	Commercial - Ventilation	770.8	0.5%	13,191.0	1.4%
15	Commercial - Space Heating - Heat Recovery Ventilator	3,416.7	2.3%	12,791.7	1.3%
16	Industrial - High-Bay Lighting	1,086.5	0.7%	12,412.0	1.3%
17	Commercial - Refrigeration - Evaporative Condenser	3,198.8	2.1%	11,817.8	1.2%
18	Residential - Monitor	2,234.5	1.5%	11,685.1	1.2%
19	Residential - Windows - Low-e Storm Addition	2,991.7	2.0%	11,275.0	1.2%
20	Commercial - RTU	0.0	0.0%	11,263.4	1.2%
	Total of Top 20 Measures	**51,000.4**	**33.65%**	**480,369.0**	**49.21%**
	Total Cumulative Savings	**151,553.0**	**100.00%**	**976,256.8**	**100.00%**

Low Cost | High Cost

EE POTENTIAL

Top Measure Notes

- Some expensive or emerging measures have significant **technical achievable** potential, but may not be selected by the IRP due to costs
  - Highlighted in orange on previous slide
- Heat Pump measures, including DHPs and HPWHs, have significant energy benefits, however since heat pumps revert to electric resistance heating during extreme cold, they have no effect on winter peak
- In addition to being expensive, some emerging tech measures are included in Technical Achievable which may not prove feasible for programs at this time, but can be kept in mind for future programs, e.g.:
  - Advanced New Construction – Zero Net Energy
  - Connected Home Control Systems

EE POTENTIAL - CONTINUED

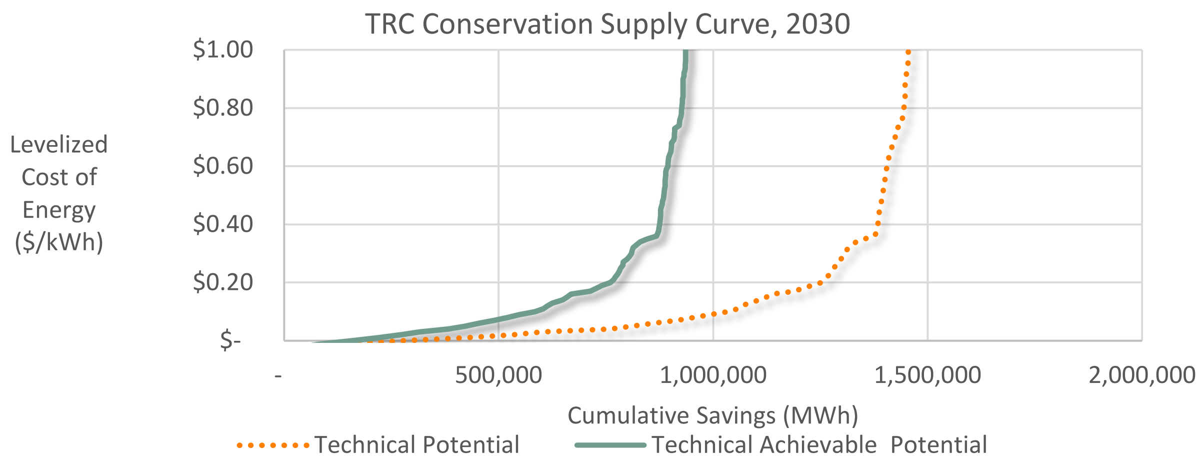
Peak Impacts – **Technical Achievable Potential**

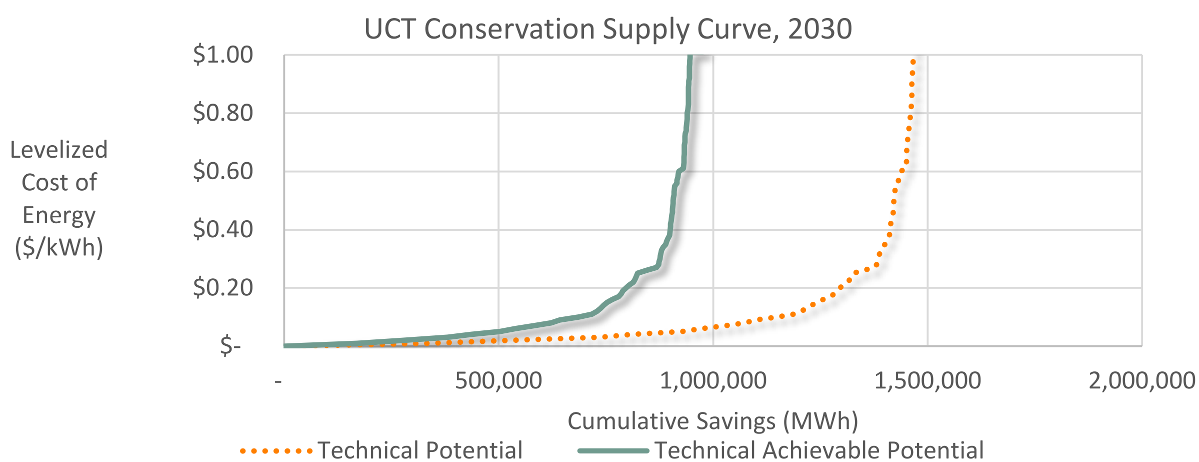
	Top Measures - Winter Peak (MW) Reduction by 2030	2030 MW	% of Total
1	Commercial - Linear Lighting	6.5	6.2%
2	Residential - ENERGY STAR Home Design	5.8	5.5%
3	Commercial - High-Bay Lighting	4.9	4.7%
4	Residential - Thermostat - Connected	4.7	4.4%
5	Residential - Windows - Cellular Shades	3.9	3.7%
6	Commercial - Space Heating - Heat Recovery Ventilator	3.3	3.1%
7	Residential - Advanced New Construction Design - Zero Net Energy	2.8	2.6%
8	Residential - General Service Screw-in	2.5	2.4%
9	Residential - Insulation - Floor Installation	2.5	2.3%
10	Residential - Water Heater - Low-Flow Showerheads	2.4	2.3%
11	Residential - Windows - Low-e Storm Addition	2.2	2.1%
12	Industrial - Destratification Fans (HVLS)	2.0	1.9%
13	Residential - Building Shell - Infiltration Control	2.0	1.9%
14	Industrial - High-Bay Lighting	1.9	1.8%
15	Residential - Dishwasher	1.8	1.7%
16	Residential - Insulation - Wall Cavity Installation	1.7	1.6%
17	Residential - Ducting - Repair and Sealing	1.6	1.5%
18	Commercial - Commissioning	1.5	1.4%
19	Commercial - Interior Lighting - Networked Fixture Controls	1.4	1.3%
20	Commercial - Destratification Fans (HVLS)	1.3	1.2%
	Total of Top Measures	**56.5**	**53.5%**
	Total Technical Achievable Reduction (MW)	**105.6**	**100.0%**

	Top Measures - Summer Peak (MW) Reduction by 2030	2030 MW	% of Total
1	Residential - Ductless Mini Split Heat Pump (Ducted Forced Air)	5.2	5.4%
2	Residential - Water Heater (<= 55 Gal)	5.2	5.4%
3	Commercial - Linear Lighting	5.0	5.2%
4	Commercial - High-Bay Lighting	3.8	4.0%
5	Residential - Water Heater - Low-Flow Showerheads	3.1	3.3%
6	Commercial - RTU	2.9	3.0%
7	Residential - ENERGY STAR Home Design	2.6	2.7%
8	Residential - Dishwasher	2.5	2.6%
9	Commercial - RTU - Advanced Controls	2.4	2.5%
10	Residential - Advanced New Construction Design - Zero Net Energy	2.3	2.4%
11	Industrial - High-Bay Lighting	2.2	2.3%
12	Residential - General Service Screw-in	1.9	2.0%
13	Residential - Monitor	1.6	1.6%
14	Residential - Freezer - Decommissioning and Recycling	1.5	1.5%
15	Commercial - Chiller - Variable Flow Chilled Water Pump	1.5	1.5%
16	Commercial - RTU - Evaporative Precooler	1.5	1.5%
17	Residential - Advanced Power Strips - IR Sensing	1.4	1.4%
18	Commercial - Commissioning	1.2	1.3%
19	Residential - Stove/Oven	1.1	1.2%
20	Residential - Refrigerator - Decommissioning and Recycling	1.1	1.2%
	Total of Top Measures	**50.1**	**52.1%**
	Total Technical Achievable Reduction (MW)	**96.0**	**100.0%**

SUPPLY CURVES

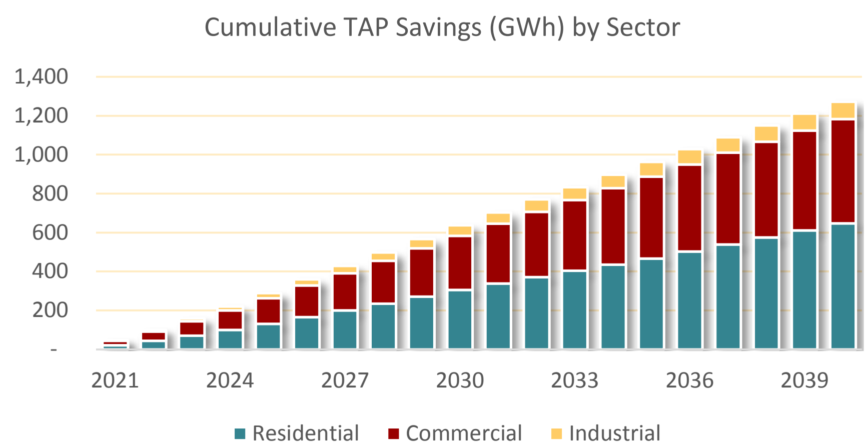
WA & ID Technical Achievable Potential by 2030

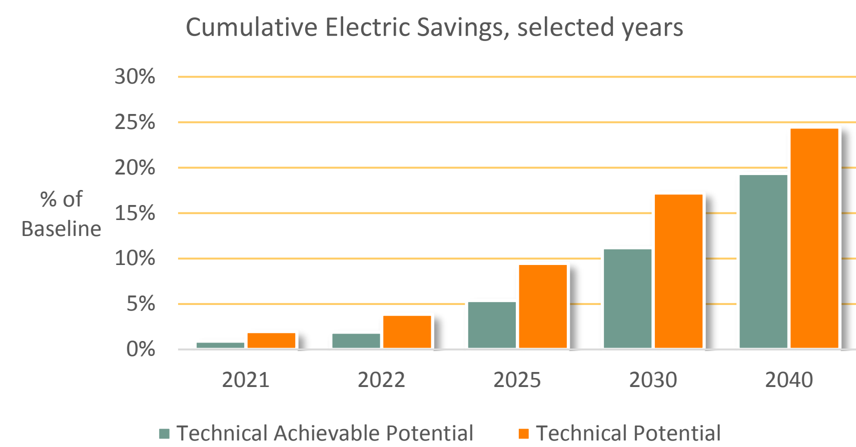




EE POTENTIAL, CONTINUED

Potential Summary – Washington, All Sectors

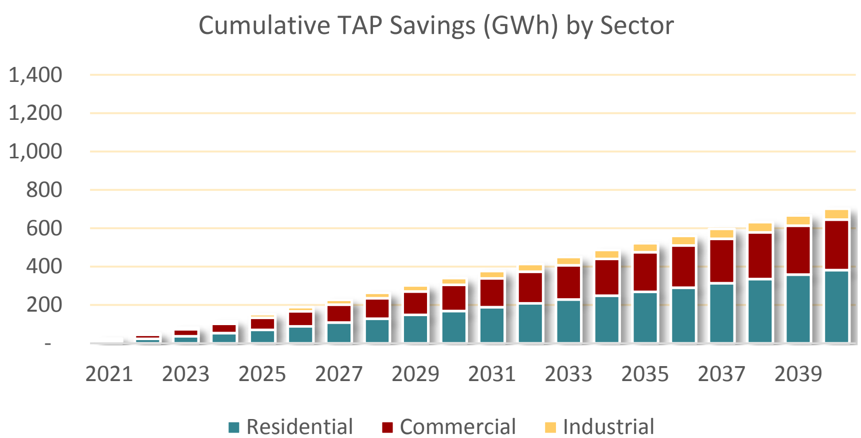


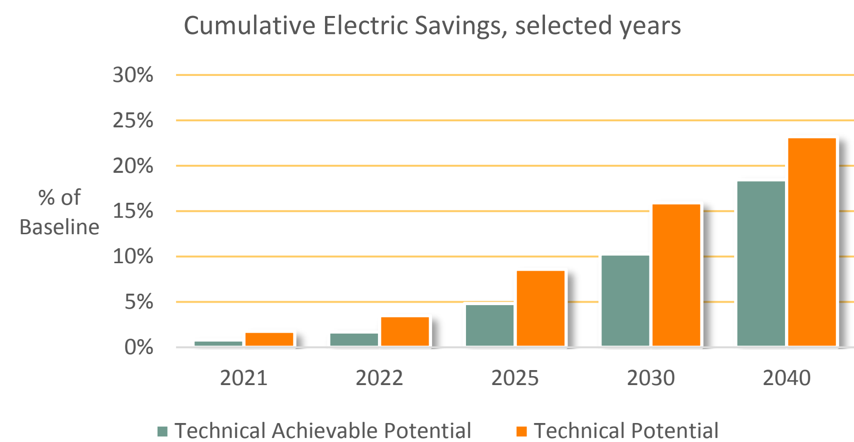


Summary of Energy Savings (GWh), Selected Years	2021	2022	2025	2030	2040
Reference Baseline (GWh)	5,243.2	5,268.4	5,381.1	5,686.8	6,571.8
Cumulative Savings (GWh)					
Technical Achievable Potential	47.2	100.0	288.5	636.5	1,272.0
Technical Potential	102.5	203.4	508.2	979.2	1,607.3
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.9%	1.9%	5.4%	11.2%	19.4%
Technical Potential	2.0%	3.9%	9.4%	17.2%	24.5%
Incremental Savings (GWh)					
Technical Achievable Potential	47.2	53.4	71.1	74.0	64.7
Technical Potential	102.5	101.9	108.1	94.2	54.9

EE POTENTIAL, CONTINUED

Potential Summary – Idaho, All Sectors





Summary of Energy Savings (GWh), Selected Years	2021	2022	2025	2030	2040
Reference Baseline (GWh)	3,048.7	3,065.7	3,137.4	3,307.8	3,804.1
Cumulative Savings (GWh)					
Technical Achievable Potential	24.2	51.6	150.7	339.8	701.7
Technical Potential	53.6	106.8	269.2	526.3	882.8
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.8%	1.7%	4.8%	10.3%	18.4%
Technical Potential	1.8%	3.5%	8.6%	15.9%	23.2%
Incremental Savings (GWh)					
Technical Achievable Potential	24.2	27.6	37.4	40.4	37.7
Technical Potential	53.6	53.7	57.4	51.5	32.4

Comparison with 2016 Potential Study

NOTES ON COMPARISON

Comparison with Prior Potential Study

We are often asked to compare results between current and prior potential study estimates – it is important to define comparison parameters.

Aligning calendar years, rather than study years results in a more thorough comparison

- E.g. lighting potential in 2019 and 2021 is very different

Since we are no longer estimating potential in 2017-2020, potential for those years must be removed from the comparison

- **First-Year Incremental Potential** - 2021
  - Prior Study: 4th year of potential
  - Current Study: first year
  - This reduces potential since it accounts for two extra high-UES lighting years before EISA

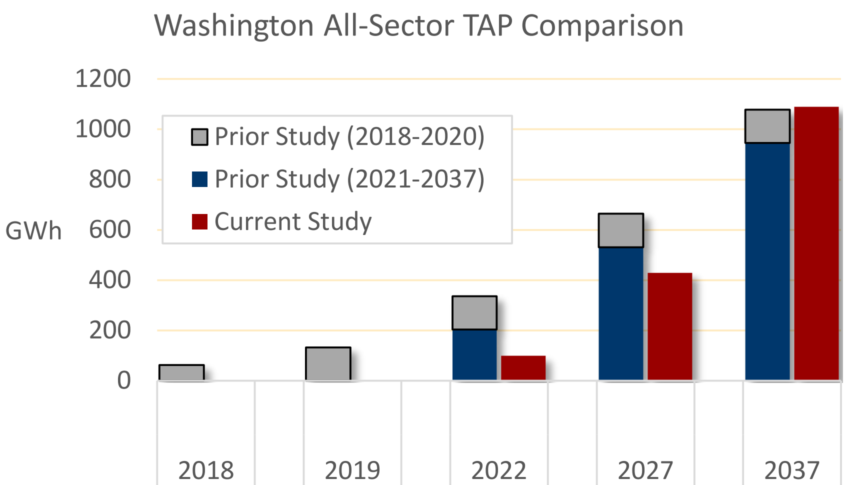
The previous study's 20-year look ended in 2037, therefore we must remove 2038-2040 from the comparison

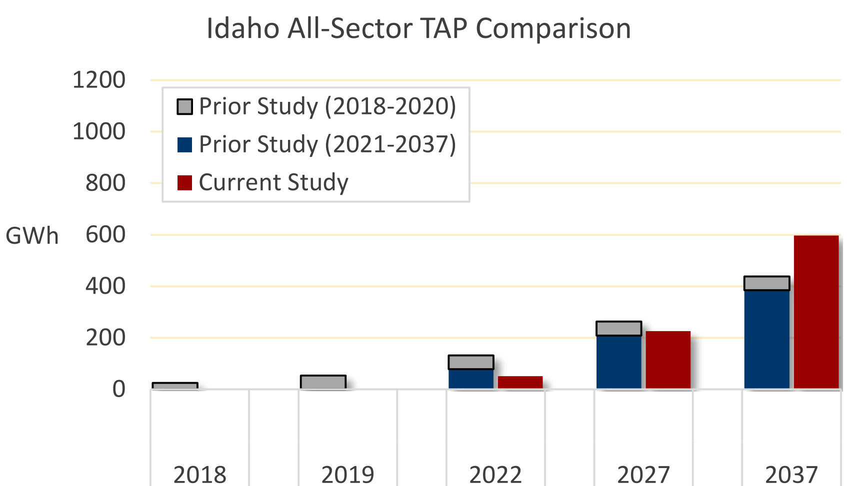
- **Cumulative Potential Comparisons** – 2021 through year 2036
  - This should have a minimal impact on potential since retrofits are mainly captured prior to this point

As a result, we can draw up to a 17 year comparison (2021-2037)

ACHIEVABLE POTENTIAL COMPARISON

Comparison with Prior Potential Study (2021-2037 **TAP**)

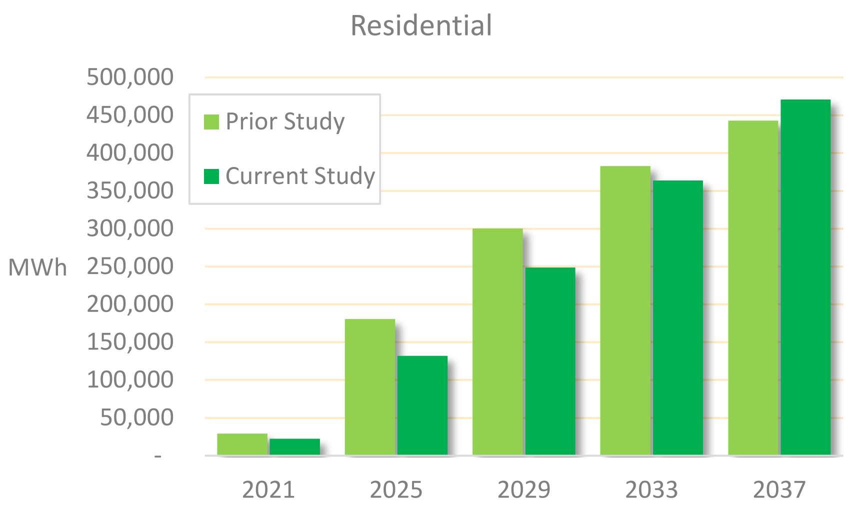


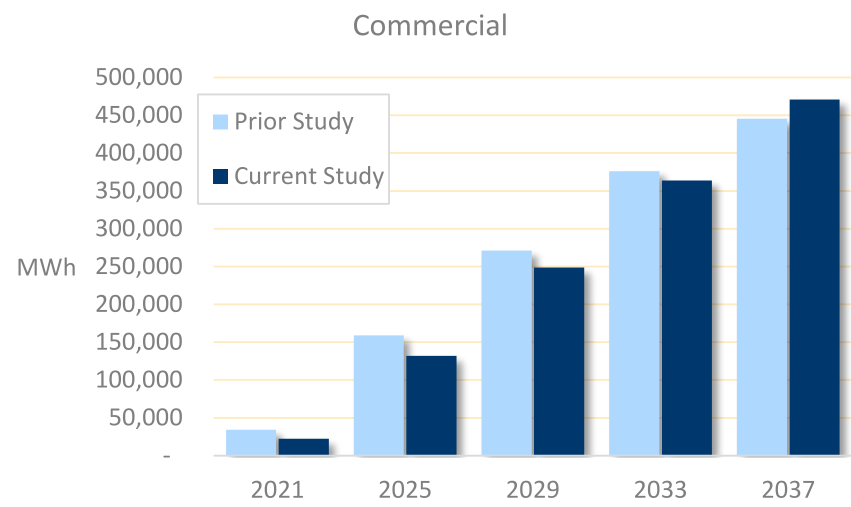


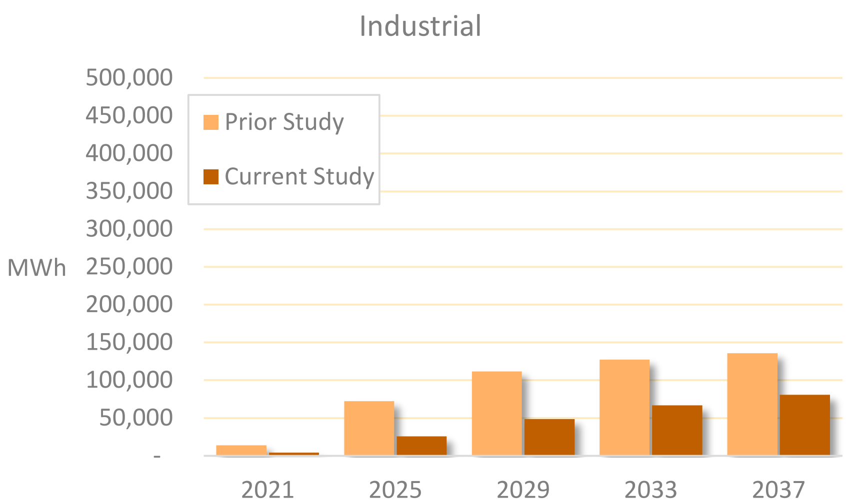
Sector (All States)	End Use	Prior CPA 2037 MWh	Current Study 2037 MWh	Diff.
Residential	Cooling	44,269	63,188	18,919
	Heating	242,917	366,549	123,632
	Water Heating	191,988	206,932	14,944
	Interior Lighting	43,555	55,064	11,509
	Exterior Lighting	8,102	10,986	2,884
	Appliances	72,894	76,363	3,469
	Electronics	39,573	47,688	8,115
	Miscellaneous	8,910	24,586	15,676
Commercial	Cooling	108,883	100,887	-7,996
	Heating	53,198	46,496	-6,702
	Ventilation	73,836	60,660	-13,176
	Water Heating	11,199	23,150	11,951
	Interior Lighting	225,353	270,791	45,438
	Exterior Lighting	81,887	100,530	18,643
	Refrigeration	21,665	63,885	42,220
	Food Preparation	23,287	23,200	-87
	Office Equipment	25,305	11,713	-13,592
	Miscellaneous	322	2,091	1,770
Industrial	Cooling	6,303	5,455	-849
	Heating	4,370	11,528	7,158
	Ventilation	6,472	5,775	-697
	Interior Lighting	22,925	40,131	17,206
	Exterior Lighting	9,500	10,952	1,452
	Motors	122,296	47,316	-74,980
	Process	14,848	9,987	-4,860
	Miscellaneous	1,665	566	-1,099
Grand Total		**1,465,522**	**1,686,470**	**220,948**

SECTOR-LEVEL ACHIEVABLE POTENTIAL

Washington - Comparison with Prior Study **– Technical Achievable**



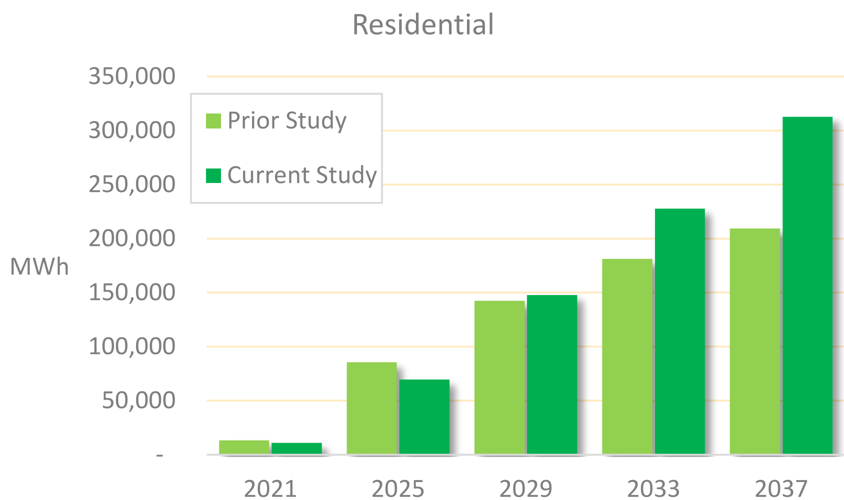


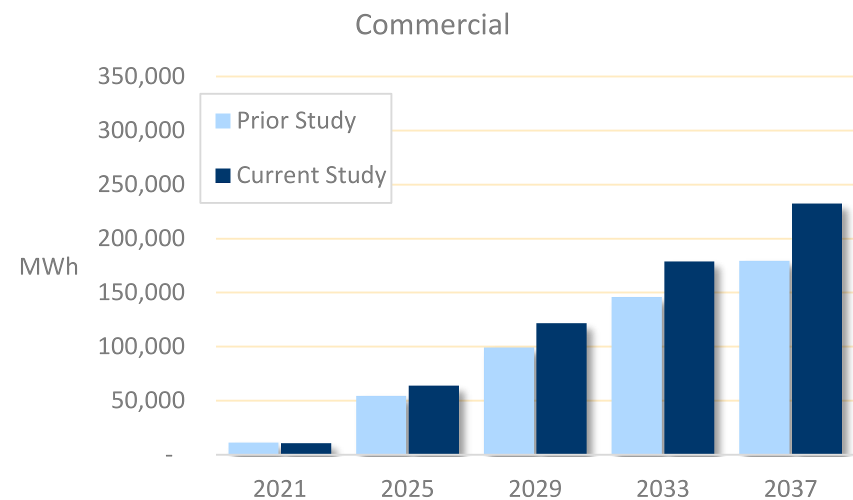


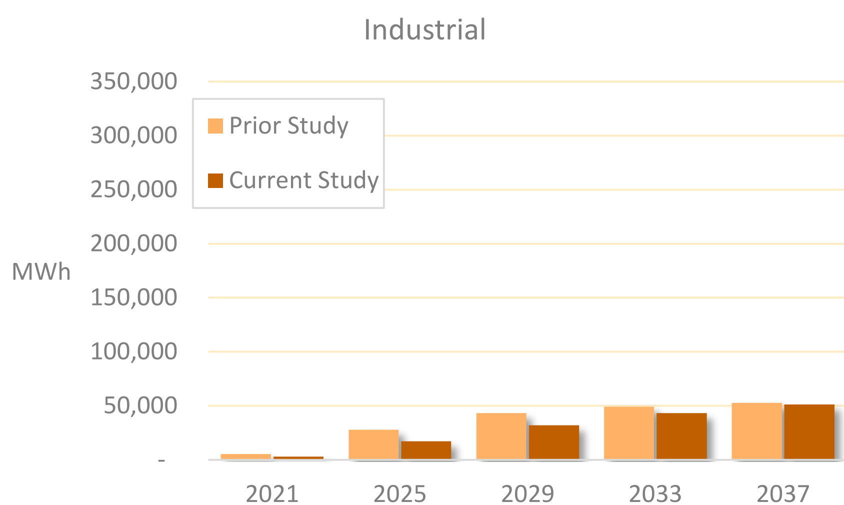
- 2018-2020 already removed from prior study values

SECTOR-LEVEL ACHIEVABLE POTENTIAL

Idaho - Comparison with Prior Study **– Technical Achievable**







- 2018-2020 already removed from prior study values

SECTOR-LEVEL NOTES

Comparison with Prior Potential Study – **Technical Achievable**

Residential:

- Potential reduced due to RTF “Market Baseline” assumption substantially lowering screw-in lighting savings
- DOE expanded definition of “General Service” now includes reflectors, reducing exempted lighting potential
- Idaho residential has extra potential in emerging New Construction measures (less impactful in WA due to the strict energy code)
  - However these measures are very expensive and unlikely to be selected by IRP

Commercial:

- Increases in lighting potential primarily due to new linear and high-bay lighting technology combination with integrated fixture controls
- Decreases in weatherization, particularly in WA, reflecting continuing influence of building codes and construction trends

Industrial:

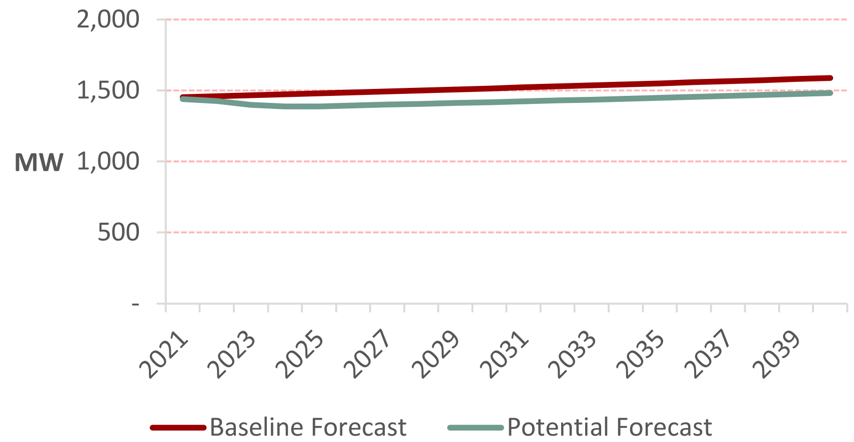
- Removed key large accounts from WA Industrial control totals so as not to treat these singular entities as an “average population” that would have regular ramp-up and measure installations

DR Potential Results

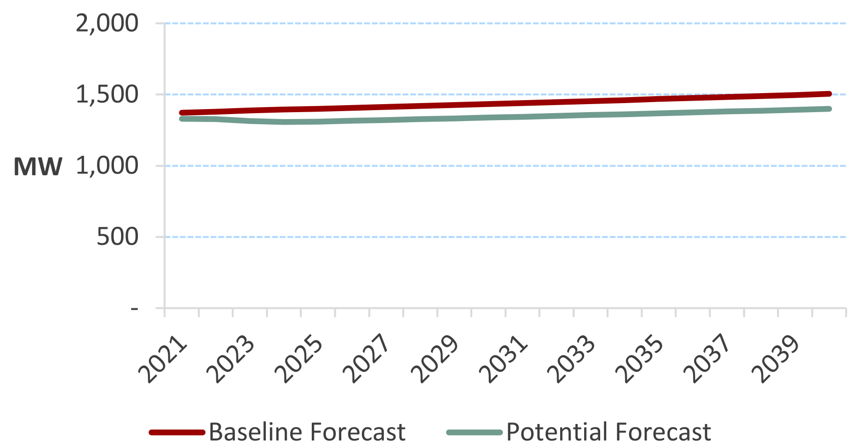
OVERALL PROJECTION

Annual Winter Peak MW, Two Scenarios

Winter Peak MW	2021	2022	2025	2030	2040
Baseline Projection	1,453	1,460	1,481	1,515	1,589
Market Potential	13.0	33.2	91.9	97.0	106.9
Potential (% of baseline)	0.9%	2.3%	6.2%	6.4%	6.7%
Potential Projection	1,440	1,427	1,389	1,418	1,482



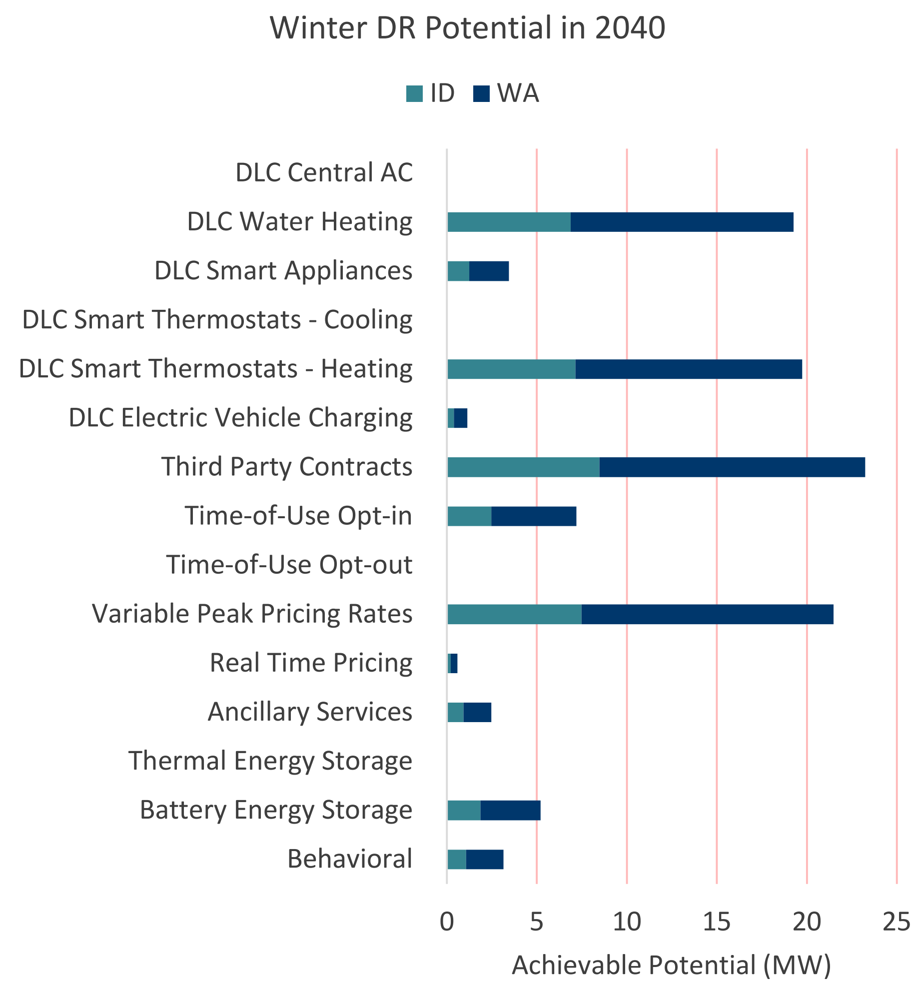
Summer Peak MW	2021	2022	2025	2030	2040
Baseline Projection	1,374	1,380	1,400	1,434	1,505
Market Potential	11.9	30.8	85.6	90.6	100.0
Potential (% of baseline)	0.9%	2.2%	6.1%	6.3%	6.6%
Potential Projection	1,362	1,350	1,315	1,343	1,405



WINTER PEAK MW REDUCTIONS

By 2040, by State and Option, TOU Opt-in Scenario

Winter Potential in 2040	ID	WA	Grand Total
DLC			
DLC Central AC	0.00	0.00	0.00
DLC Water Heating	6.88	12.38	19.27
DLC Smart Thermostats - Cooling	0.00	0.00	0.00
DLC Smart Thermostats - Heating	7.14	12.60	19.74
DLC Smart Appliances	1.24	2.21	3.45
DLC Electric Vehicle Charging	0.39	0.74	1.14
Third Party Contracts	8.47	14.78	23.25
Rates			
Time-of-Use Opt-in	2.47	4.72	7.20
Time-of-Use Opt-out			
Variable Peak Pricing Rates	7.48	14.00	21.48
Real Time Pricing	0.21	0.38	0.58
Ancillary Services	0.93	1.55	2.48
Thermal Energy Storage	0.00	0.00	0.00
Battery Energy Storage	1.87	3.34	5.21
Behavioral	1.07	2.08	3.15
Grand Total	**38.16**	**68.78**	**106.95**



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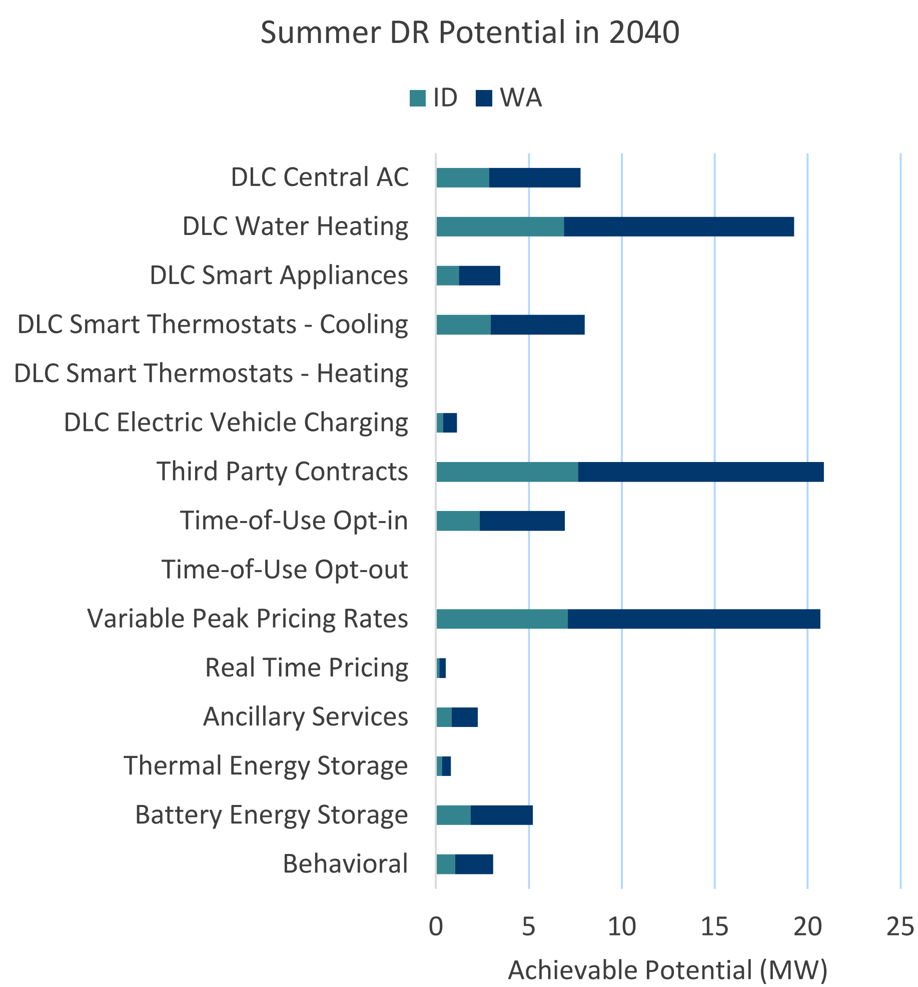
SUMMER PEAK MW REDUCTIONS

By 2040, by State and Option, TOU Opt-in Scenario

Summer Potential in 2040	ID	WA	Grand Total
DLC			
DLC Central AC	2.85	4.92	**7.78**
DLC Water Heating	6.88	12.38	**19.27**
DLC Smart Thermostats - Cooling	1.24	2.21	**3.45**
DLC Smart Thermostats - Heating	2.94	5.06	**8.00**
DLC Smart Appliances	0.00	0.00	**0.00**
DLC Electric Vehicle Charging	0.39	0.74	**1.14**
Third Party Contracts	7.64	13.23	**20.87**
Rates			
Time-of-Use Opt-in	2.35	4.58	**6.93**
Time-of-Use Opt-out	0.00	0.00	**0.00**
Variable Peak Pricing Rates	7.10	13.59	**20.69**
Real Time Pricing	0.19	0.33	**0.52**
Ancillary Services	0.85	1.40	**2.25**
Thermal Energy Storage	0.32	0.48	**0.80**
Battery Energy Storage	1.87	3.34	**5.21**
Behavioral	1.03	2.05	**3.08**
Grand Total	**35.64**	**64.34**	**99.98**



Comparison with 2016 Potential Study

NOTES ON COMPARISON

Comparison with Prior Potential Study

There were several changes made to the previous DR Potential Study:

- Included Summer Peak in analysis
  - This presentation will focus on Winter Potential only to directly compare to the previous study
- Included Residential Sector in analysis
- Changes to Measure Options this year:
  - Critical Peak Pricing → Variable Peak Pricing
  - Firm Curtailment → Third Party Contracts
  - Prioritized Smart Thermostats over Space Heating Switches

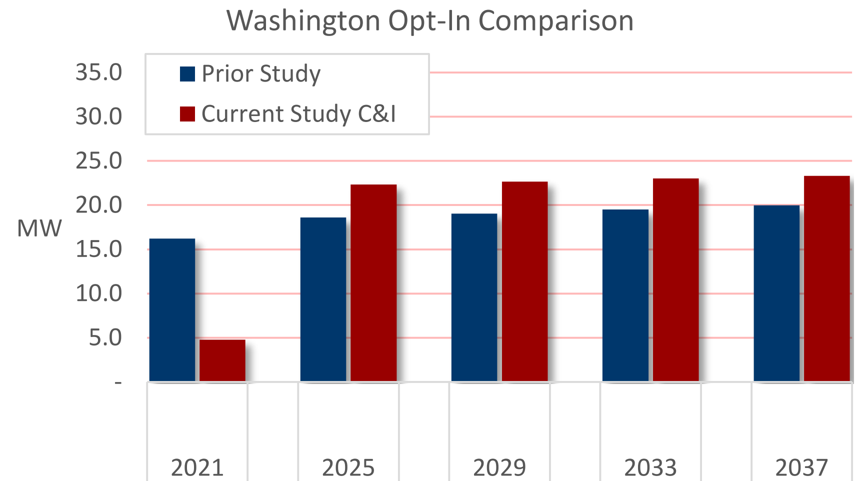
- Note: Comparison between calendar years for DR does not remove previous year impacts like the EE comparison

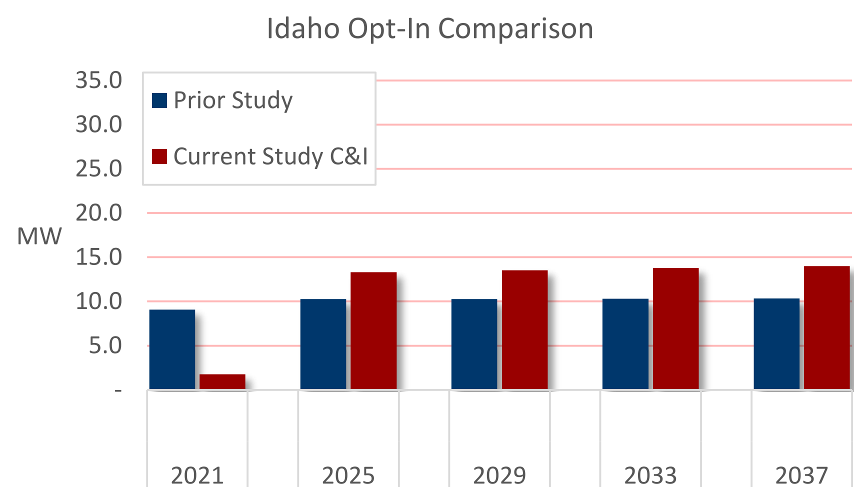
DR POTENTIAL COMPARISON OPT-IN

Comparison with Prior Potential Study by State (

Notes on comparison:

- 2021 values for Prior study include ramp-up to participation from prior years, while current study is in its first year
- In the prior study, the AMI program was still in its early planning phase and rollout had to be assumed. In the current study, the AMI rollout is defined by Avista's active program plan





DLC COMPARISON TO PRIOR STUDY

Potential in year 2037 by sector

DLC Options	Option	Current Study	Previous Study
Residential	DLC Central AC	-	
	DLC Water Heating	16.9	
	DLC Smart Appliances	3.0	
	DLC Smart Thermostats - Cooling	-	
	DLC Smart Thermostats - Heating	16.0	
	DLC Electric Vehicle Charging	1.0	
	Residential Total	**37.0**	
C&I	DLC Central AC	-	
	DLC Water Heating	1.7	
	DLC Smart Appliances	0.4	
	DLC Smart Thermostats - Cooling	-	
	DLC Smart Thermostats - Heating	2.9	
	Third Party Contracts	23.2	17.8
	DLC Controls		4.1
	C&I Total	**28.1**	**21.9**

RATES COMPARISON TO PRIOR STUDY

Potential in year 2037 by sector

Rates Opt-in	Option	Current Study	Previous Study
Residential	Time-of-Use Opt-in	5.8	
	Time-of-Use Opt-out	-	
	Variable Peak Pricing Rates	16.9	
	Ancillary Services	0.2	
	Battery Energy Storage	4.3	
	Behavioral	3.1	
	Residential Total	**30.3**	
C&I	Time-of-Use Opt-in	1.3	0.7
	Time-of-Use Opt-out	-	
	Variable Peak Pricing Rates/ CPP	4.3	3.6
	Real Time Pricing	0.6	
	Ancillary Services	2.3	
	Thermal Energy Storage	-	
	Battery Energy Storage	0.7	
	C&I Total	**9.2**	**4.3**

Rates Opt-Out	Option	Current Study	Previous Study
Residential	Time-of-Use Opt-in	-	
	Time-of-Use Opt-out	19.7	
	Variable Peak Pricing Rates	5.2	
	Ancillary Services	0.2	
	Battery Energy Storage	4.3	
	Behavioral	3.1	
	Residential Total	**32.5**	
C&I	Time-of-Use Opt-in	-	
	Time-of-Use Opt-out	7.4	3.9
	Variable Peak Pricing Rates/ CPP	1.3	10.6
	Real Time Pricing	0.2	
	Ancillary Services	2.3	
	Thermal Energy Storage	-	
	Battery Energy Storage	0.7	
	C&I Total	**11.9**	**14.5**

Thank You!

Kurtis Kolnowski, Senior Project Manager
kkolnowski@appliedenergygroup.com

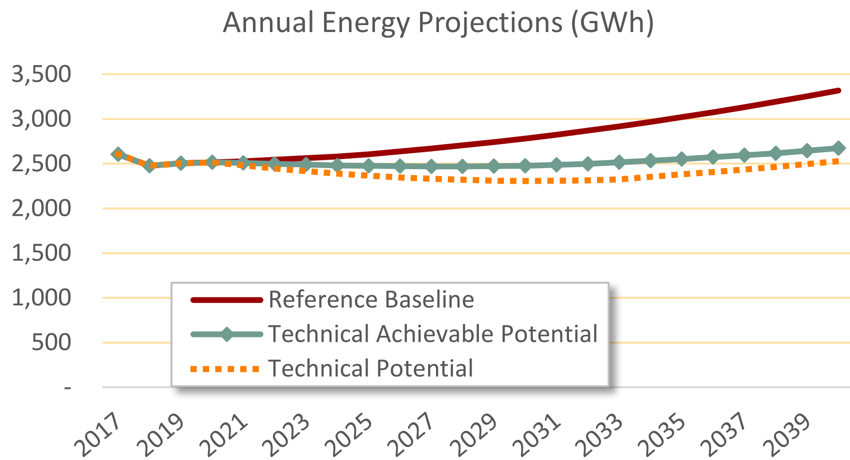
Ken Walter, Senior Energy Analyst
kwalter@appliedenergygroup.com

Sector EE Results

ENERGY EFFICIENCY POTENTIAL

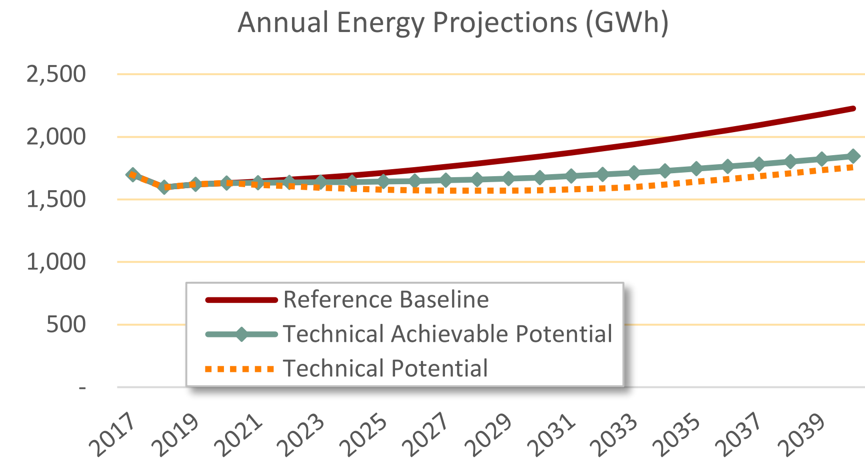
Potential Summary – Residential

Washington



	2021	2022	2025	2030	2040
Reference Baseline (GWh)	2,528	2,543	2,607	2,783	3,319
Potential Forecasts (GWh)					
Technical Achievable Potential	2,507	2,499	2,476	2,478	2,672
Technical Potential	2,480	2,448	2,367	2,307	2,528
Cumulative Savings (GWh)					
Technical Achievable Potential	21	44	131	305	647
Technical Potential	48	96	240	475	791
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.8%	1.7%	5.0%	11.0%	19.5%
Technical Potential	1.9%	3.8%	9.2%	17.1%	23.8%
Incremental Savings (GWh)					
Technical Achievable Potential	21	24	33	37	39
Technical Potential	48	48	51	47	34

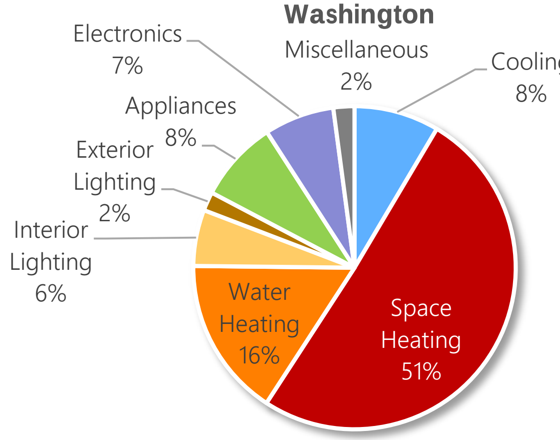
Idaho

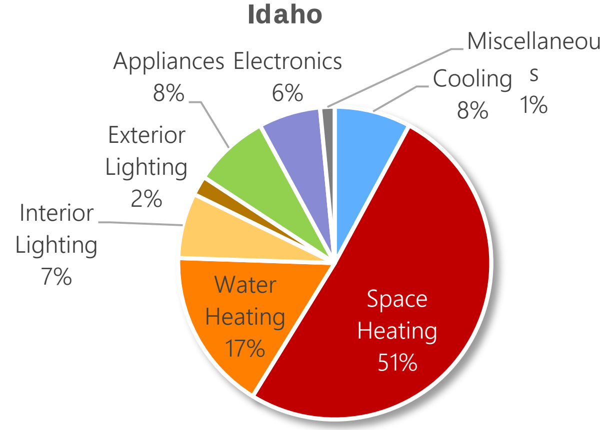


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	1,644	1,658	1,713	1,844	2,226
Potential Forecasts (GWh)					
Technical Achievable Potential	1,633	1,635	1,643	1,675	1,845
Technical Potential	1,618	1,605	1,579	1,574	1,758
Cumulative Savings (GWh)					
Technical Achievable Potential	11	23	70	168	382
Technical Potential	26	53	134	270	468
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.7%	1.4%	4.1%	9.1%	17.1%
Technical Potential	1.6%	3.2%	7.8%	14.6%	21.0%
Incremental Savings (GWh)					
Technical Achievable Potential	11	12	18	22	25
Technical Potential	26	27	29	27	22

EE POTENTIAL - CONTINUED

Top Measures – Residential, Technical Achievable Potential





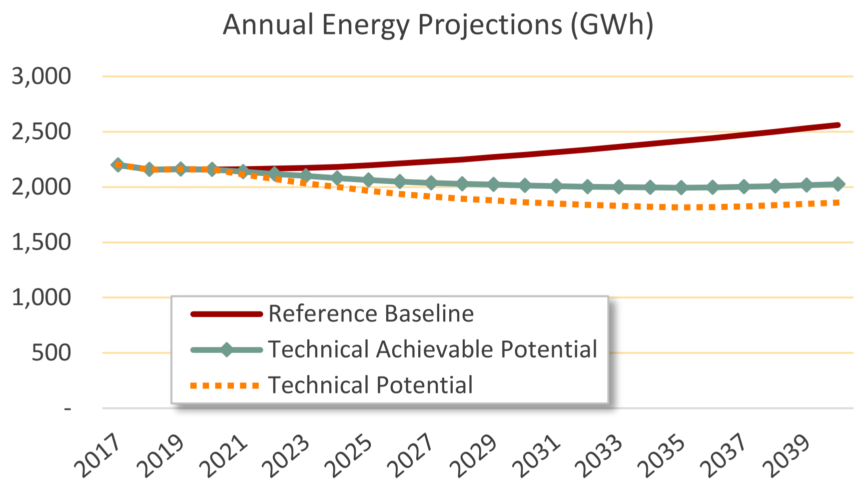
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Ductless Mini Split Heat Pump (Ducted Forced Air)	3,651	11,941	30,156	9.9%
2	Ductless Mini Split Heat Pump (Zonal)	2,727	8,760	21,357	7.0%
3	Water Heater (<= 55 Gal)	215	2,270	20,804	6.8%
4	Thermostat - Connected	2,303	7,472	18,445	6.1%
5	ENERGY STAR Home Design	549	3,509	17,286	5.7%
6	Windows - Cellular Shades	1,754	5,866	15,450	5.1%
7	Dishwasher	589	2,939	10,356	3.4%
8	Advanced New Construction Design - Zero Net Energy	112	1,342	10,162	3.3%
9	Water Heater - Low-Flow Showerheads	2,834	6,866	10,144	3.3%
10	General Service Screw-in	1,374	3,839	8,098	2.7%
	Total of Top 10 Measures	16,109	54,804	162,257	53.2%
	Total Cumulative Savings	**44,428**	**131,104**	**304,829**	**100.0%**

Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Ductless Mini Split Heat Pump (Ducted Forced Air)	2,057	6,873	17,944	10.7%
2	Ductless Mini Split Heat Pump (Zonal)	1,568	5,145	13,022	7.7%
3	Water Heater (<= 55 Gal)	131	1,392	12,832	7.6%
4	ENERGY STAR Home Design	347	2,259	11,139	6.6%
5	Thermostat - Connected	1,087	3,594	9,152	5.4%
6	Windows - Cellular Shades	830	2,815	7,568	4.5%
7	Advanced New Construction Design - Zero Net Energy	72	876	6,645	3.9%
8	Water Heater - Low-Flow Showerheads	1,529	3,760	5,646	3.4%
9	Dishwasher	315	1,590	5,630	3.3%
10	General Service Screw-in	860	2,458	5,434	3.2%
	Total of Top 10 Measures	**8,798**	**30,761**	**95,012**	**56.5%**
	Total Cumulative Savings	**23,101**	**69,599**	**168,308**	**100.0%**

ENERGY EFFICIENCY POTENTIAL

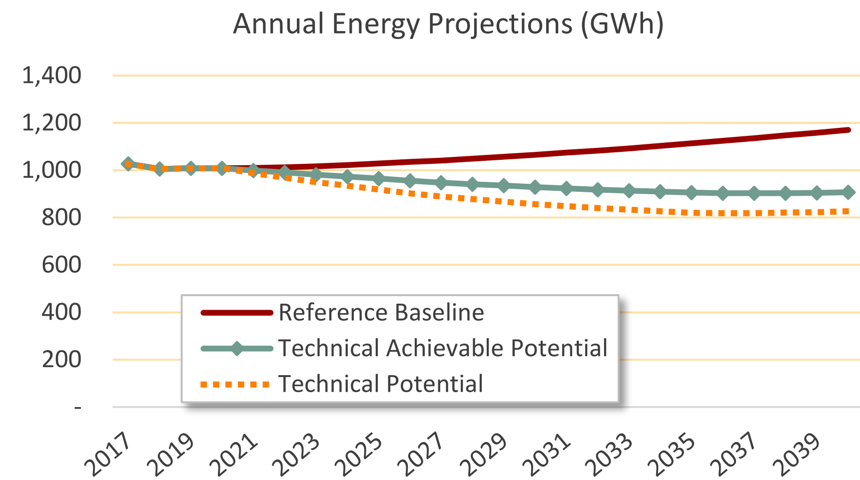
Potential Summary – Commercial

Washington



	2021	2022	2025	2030	2040
Reference Baseline (GWh)	2,162	2,166	2,196	2,292	2,562
Potential Forecasts (GWh)					
Technical Achievable Potential	2,140	2,119	2,064	2,014	2,026
Technical Potential	2,114	2,073	1,966	1,862	1,859
Cumulative Savings (GWh)					
Technical Achievable Potential	22	47	132	278	536
Technical Potential	47	93	230	430	703
Energy Savings (% of Baseline)					
Technical Achievable Potential	1.0%	2.2%	6.0%	12.1%	20.9%
Technical Potential	2.2%	4.3%	10.5%	18.7%	27.4%
Incremental Savings (GWh)					
Technical Achievable Potential	22	25	32	31	22
Technical Potential	47	46	49	40	18

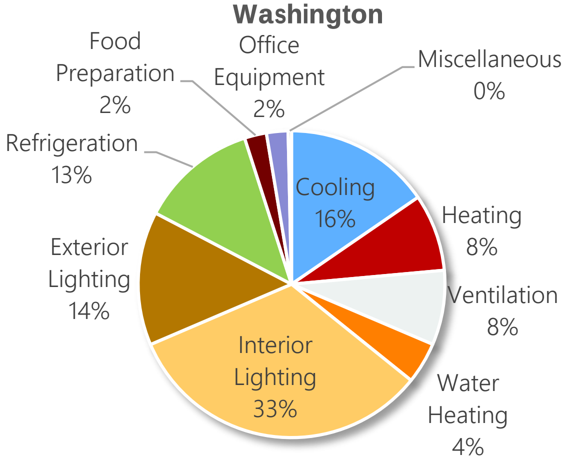
Idaho

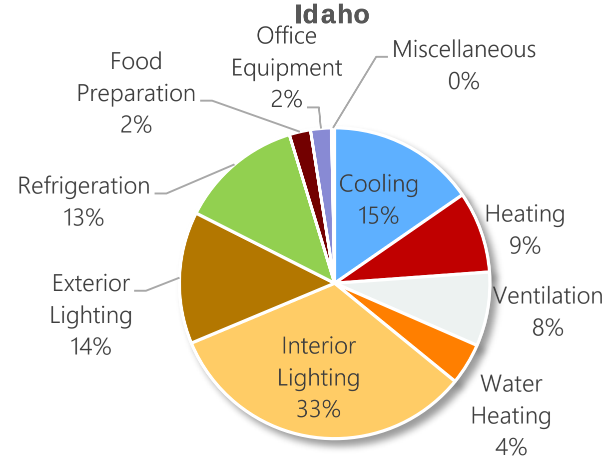


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	1,010	1,012	1,029	1,065	1,171
Potential Forecasts (GWh)					
Technical Achievable Potential	999	990	965	929	906
Technical Potential	987	968	918	857	826
Cumulative Savings (GWh)					
Technical Achievable Potential	11	22	64	136	264
Technical Potential	22	44	110	208	344
Energy Savings (% of Baseline)					
Technical Achievable Potential	1.0%	2.2%	6.2%	12.8%	22.6%
Technical Potential	2.2%	4.4%	10.7%	19.6%	29.4%
Incremental Savings (GWh)					
Technical Achievable Potential	11	12	16	15	11
Technical Potential	22	22	23	20	9

EE POTENTIAL - CONTINUED

Top Measures – Commercial, Technical Achievable Potential





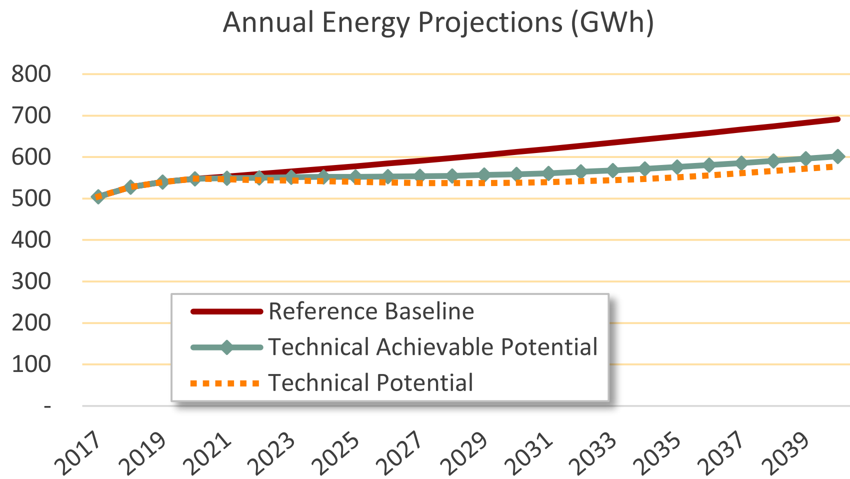
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Linear Lighting	3,852	15,024	43,235	15.6%
2	High-Bay Lighting	2,674	10,375	30,106	10.8%
3	Area Lighting	1,908	7,347	21,034	7.6%
4	Ventilation	525	2,546	8,984	3.2%
5	Space Heating - Heat Recovery Ventilator	2,252	5,394	8,208	3.0%
6	Refrigeration - Evaporative Condenser	2,181	5,245	8,053	2.9%
7	RTU	0	2,334	7,669	2.8%
8	Interior Lighting - Networked Fixture Controls	922	3,242	7,633	2.7%
9	Refrigeration - Replace Single-Compressor with Subcooled Multiplex	1,607	3,948	6,239	2.2%
10	RTU - Advanced Controls	164	1,213	5,961	2.1%
	Total of Top 20 Measures	**16,084**	**56,669**	**147,122**	**53.0%**
	Total Cumulative Savings	**46,666**	**131,925**	**277,801**	**100.0%**

Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Linear Lighting	1,809	7,068	20,295	14.9%
2	High-Bay Lighting	1,256	4,882	14,125	10.4%
3	Area Lighting	896	3,457	9,869	7.2%
4	Space Heating - Heat Recovery Ventilator	1,165	2,889	4,584	3.4%
5	Commissioning	310	1,440	4,473	3.3%
6	Ventilation	246	1,196	4,207	3.1%
7	Refrigeration - Evaporative Condenser	1,018	2,450	3,764	2.8%
8	Interior Lighting - Networked Fixture Controls	432	1,525	3,601	2.6%
9	RTU	0	1,098	3,595	2.6%
10	Refrigeration - Replace Single-Compressor with Subcooled Multiplex	750	1,844	2,916	2.1%
	Total of Top 20 Measures	**7,882**	**27,849**	**71,428**	**52.5%**
	Total Cumulative Savings	**22,325**	**63,909**	**136,133**	**100.0%**

ENERGY EFFICIENCY POTENTIAL

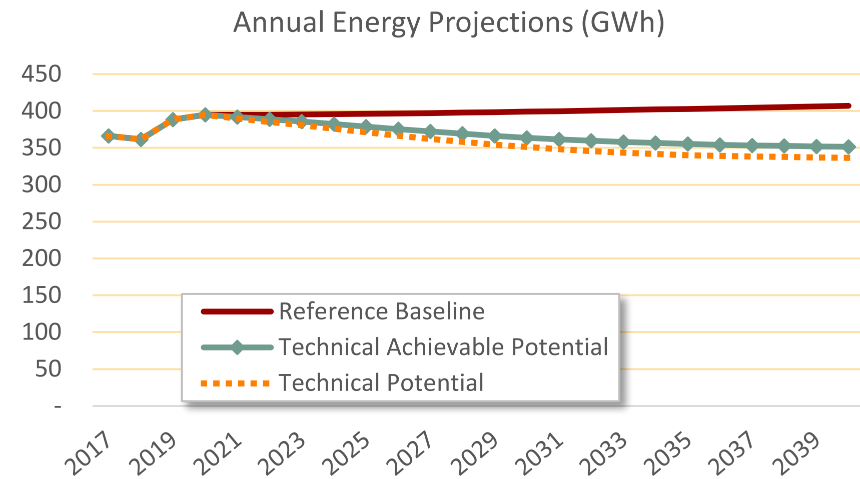
Potential Summary – Industrial

Washington



	2021	2022	2025	2030	2040
Reference Baseline (GWh)	553	559	578	612	691
Potential Forecasts (GWh)					
Technical Achievable Potential	549	550	552	558	602
Technical Potential	546	544	540	538	578
Cumulative Savings (GWh)					
Technical Achievable Potential	4	9	25	54	89
Technical Potential	7	15	38	74	114
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.8%	1.6%	4.4%	8.8%	12.9%
Technical Potential	1.3%	2.6%	6.6%	12.2%	16.4%
Incremental Savings (GWh)					
Technical Achievable Potential	4	5	6	6	3
Technical Potential	7	7	8	7	3

Idaho

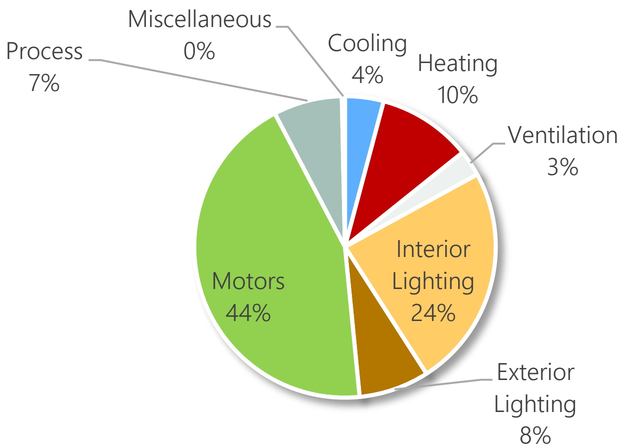


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	395	395	396	399	407
Potential Forecasts (GWh)					
Technical Achievable Potential	392	389	379	364	351
Technical Potential	390	385	371	351	336
Cumulative Savings (GWh)					
Technical Achievable Potential	3	6	17	35	56
Technical Potential	5	10	25	48	71
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.7%	1.6%	4.4%	8.9%	13.7%
Technical Potential	1.2%	2.4%	6.3%	12.0%	17.4%
Incremental Savings (GWh)					
Technical Achievable Potential	3	3	4	3	2
Technical Potential	5	5	5	4	2

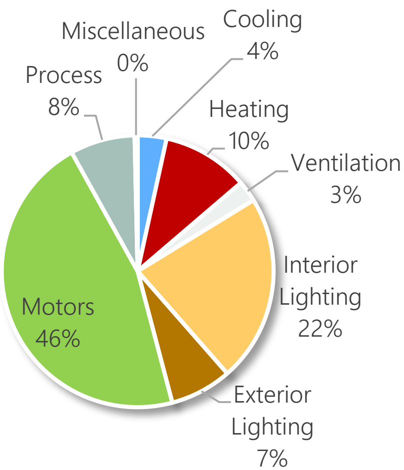
AEG Applied Energy Group

EE POTENTIAL - CONTINUED

Top Measures – Industrial, Technical Achievable Potential



Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	High-Bay Lighting	673	2,636	7,770	14.4%
2	Destratification Fans (HVLS)	1,263	3,192	5,178	9.6%
3	Compressed Air - Equipment Upgrade	746	1,890	3,073	5.7%
4	Compressed Air - Leak Management Program	728	1,833	2,962	5.5%
5	Area Lighting	184	714	2,074	3.9%
6	Linear Lighting	169	666	1,915	3.6%
7	Material Handling - Variable Speed Drive	216	713	1,831	3.4%
8	Fan System - Variable Speed Drive	192	631	1,606	3.0%
9	Pumping System - Equipment Upgrade	372	926	1,472	2.7%
10	Interior Lighting - Networked Fixture Controls	173	610	1,431	2.7%
	Total of Top 20 Measures	4,717	13,811	29,312	54.4%
	Total Cumulative Savings	**8,883**	**25,481**	**53,860**	**100.0%**



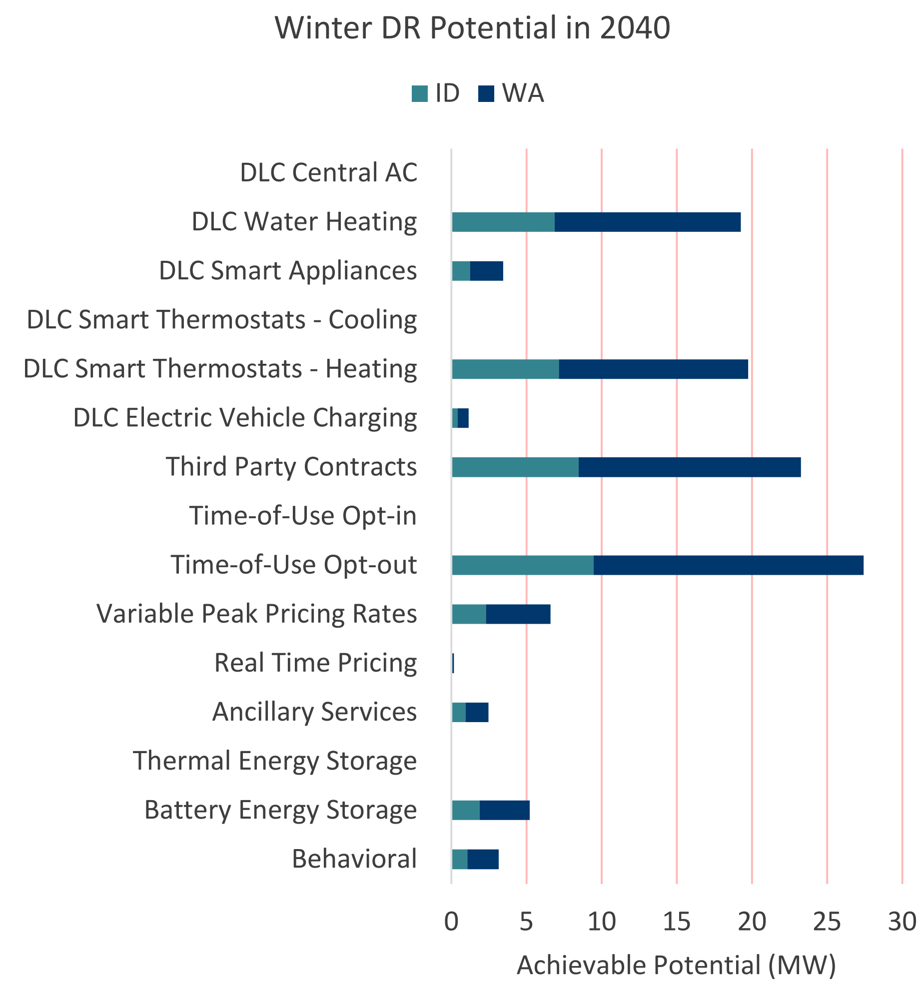
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	High-Bay Lighting	413	1,600	4,642	13.1%
2	Destratification Fans (HVLS)	863	2,149	3,426	9.7%
3	Compressed Air - Equipment Upgrade	537	1,338	2,136	6.0%
4	Compressed Air - Leak Management Program	524	1,297	2,058	5.8%
5	Material Handling - Variable Speed Drive	155	503	1,250	3.5%
6	Area Lighting	113	433	1,239	3.5%
7	Linear Lighting	104	407	1,153	3.3%
8	Fan System - Variable Speed Drive	138	445	1,096	3.1%
9	Pumping System - Equipment Upgrade	268	655	1,022	2.9%
10	Interior Lighting - Networked Fixture Controls	112	394	915	2.6%
	Total of Top 20 Measures	3,226	9,219	18,937	53.6%
	Total Cumulative Savings	**6,149**	**17,236**	**35,326**	**100.0%**

Additional Slides from Current Study

WINTER PEAK MW REDUCTIONS

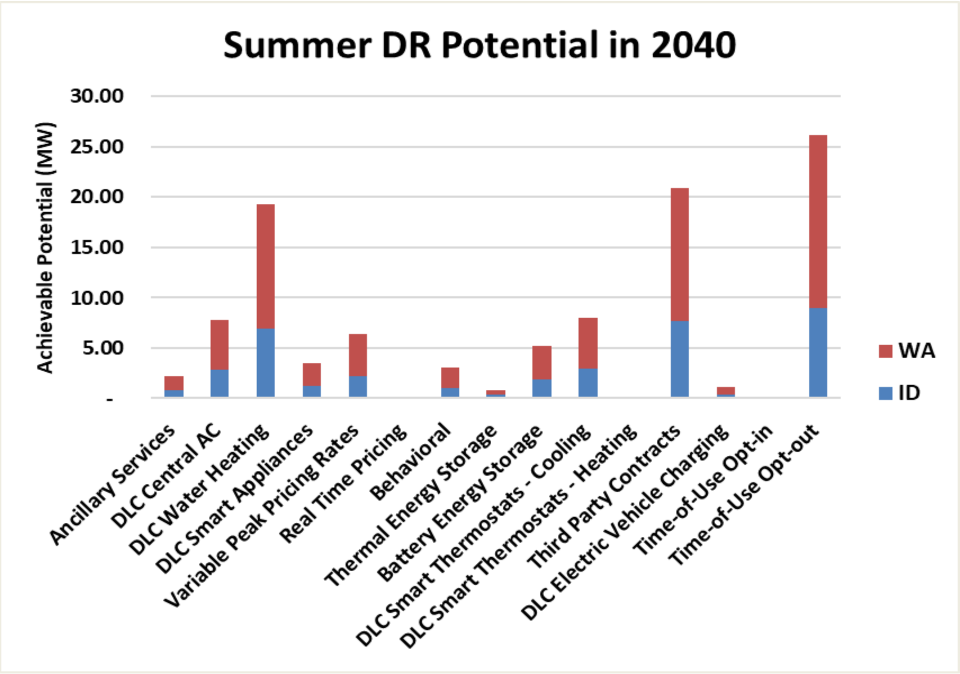
By 2040, by State and Option, TOU Opt-out Scenario

Winter Potential in 2040	ID	WA	Grand Total
DLC			
DLC Central AC	0.00	0.00	0.00
DLC Water Heating	6.88	12.38	19.27
DLC Smart Thermostats - Cooling	1.24	2.21	3.45
DLC Smart Thermostats - Heating	0.00	0.00	0.00
DLC Smart Appliances	7.14	12.60	19.74
DLC Electric Vehicle Charging	0.39	0.74	1.14
Third Party Contracts	8.47	14.78	23.25
Rates			
Time-of-Use Opt-in			
Time-of-Use Opt-out	9.47	17.95	27.42
Variable Peak Pricing Rates	2.30	4.30	6.59
Real Time Pricing	0.06	0.12	0.18
Ancillary Services	0.93	1.55	2.48
Thermal Energy Storage	0.00	0.00	0.00
Battery Energy Storage	1.87	3.34	5.21
Behavioral	1.07	2.08	3.15
Grand Total	**39.83**	**72.05**	**111.88**



SUMMER POTENTIAL IN 2040 BY STATE (TOU OPT-OUT)

Summer Potential in 2040	ID	WA	Grand Total
Ancillary Services	0.8	1.4	2.2
DLC Central AC	2.9	4.9	7.8
DLC Water Heating	6.9	12.4	19.3
DLC Smart Appliances	1.2	2.2	3.4
Variable Peak Pricing Rates	2.2	4.2	6.3
Real Time Pricing	0.1	0.1	0.2
Behavioral	1.0	2.1	3.1
Thermal Energy Storage	0.3	0.5	0.8
Battery Energy Storage	1.9	3.3	5.2
DLC Smart Thermostats - Cooling	2.9	5.1	8.0
DLC Smart Thermostats - Heating			
Third Party Contracts	7.6	13.2	20.9
DLC Electric Vehicle Charging	0.4	0.7	1.1
Time-of-Use Opt-in			
Time-of-Use Opt-out	8.9	17.3	26.2
Grand Total	**37.2**	**67.4**	**104.5**

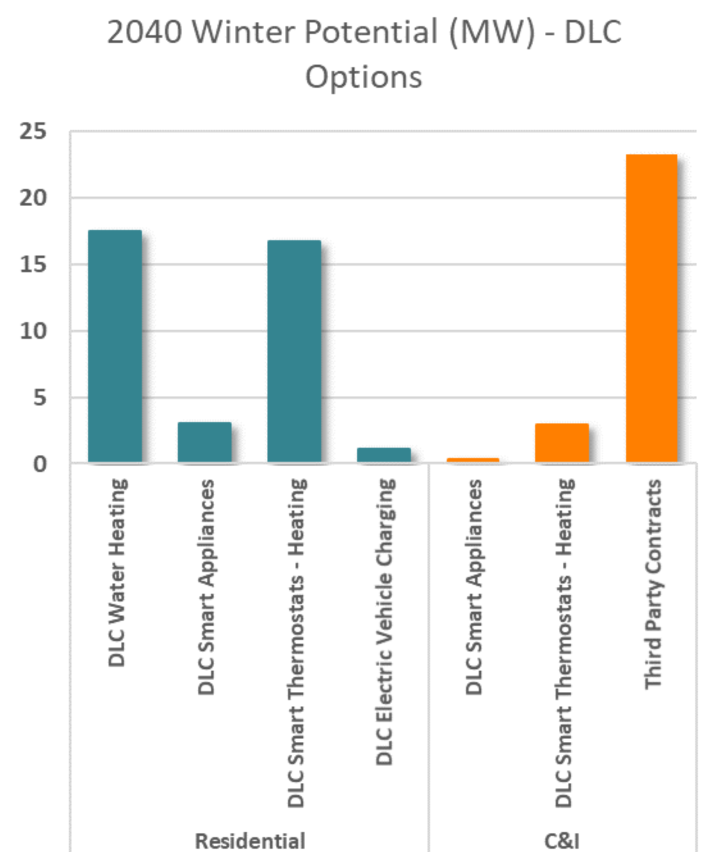


Stand-Alone Results by Program

MW BY OPTION – WINTER DLC

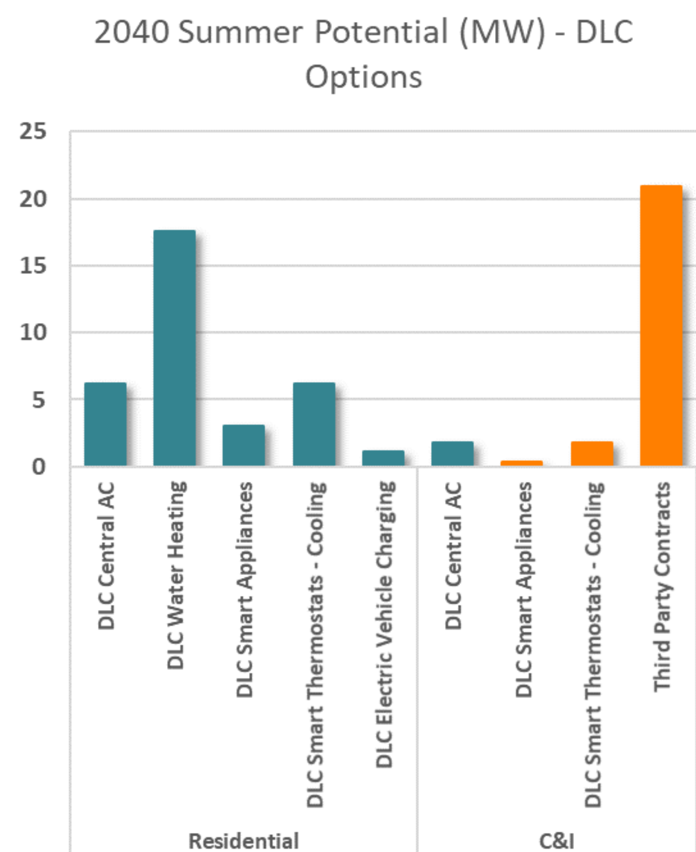
AEG Applied Energy Group

Sector	Option	2021	2022	2030	2040
Residential	DLC Central AC	-	-	-	-
	DLC Water Heating	1.4	4.3	15.6	17.5
	DLC Smart Appliances	0.3	0.8	2.8	3.1
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	1.3	3.9	14.5	16.8
	DLC Electric Vehicle Charging	0.0	0.0	0.6	1.1
C&I	DLC Central AC	-	-	-	-
	DLC Water Heating	0.1	0.4	1.6	1.7
	DLC Smart Appliances	0.0	0.1	0.3	0.4
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	0.2	0.7	2.7	3.0
	Third Party Contracts	3.4	9.5	23.0	23.2



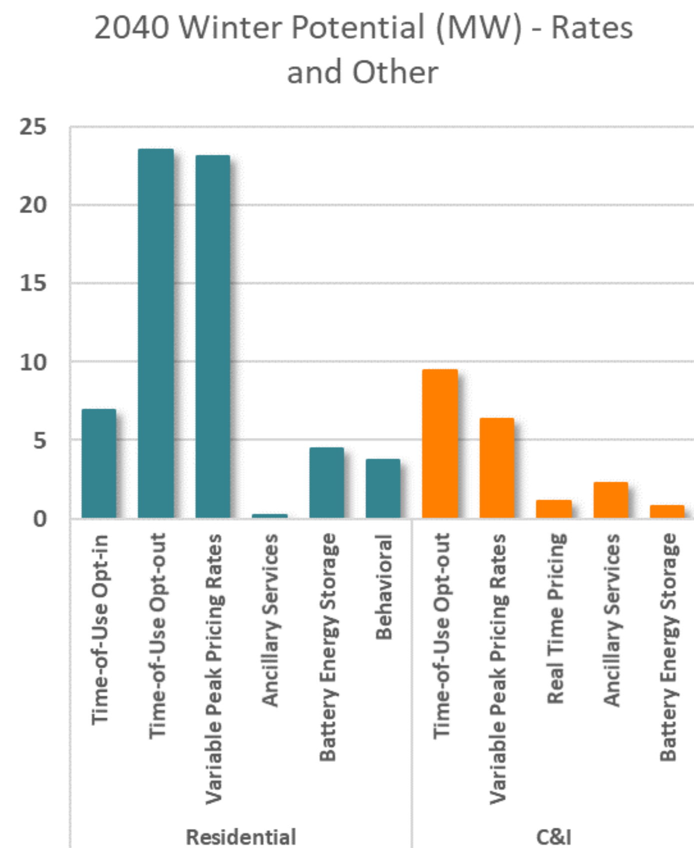
MW BY OPTION – SUMMER DLC

Sector	Option	2021	2022	2030	2040
Residential	DLC Central AC	0.5	1.4	5.4	6.2
	DLC Water Heating	1.4	4.3	15.6	17.5
	DLC Smart Appliances	0.3	0.8	2.8	3.1
	DLC Smart Thermostats - Cooling	0.5	1.4	5.4	6.2
	DLC Smart Thermostats - Heating	-	-	-	-
	DLC Electric Vehicle Charging	0.0	0.0	0.6	1.1
C&I	DLC Central AC	0.1	0.4	1.5	1.8
	DLC Water Heating	0.1	0.4	1.6	1.7
	DLC Smart Appliances	0.0	0.1	0.3	0.4
	DLC Smart Thermostats - Cooling	0.1	0.4	1.5	1.8
	DLC Smart Thermostats - Heating	-	-	-	-
	Third Party Contracts	3.0	8.5	20.7	20.9



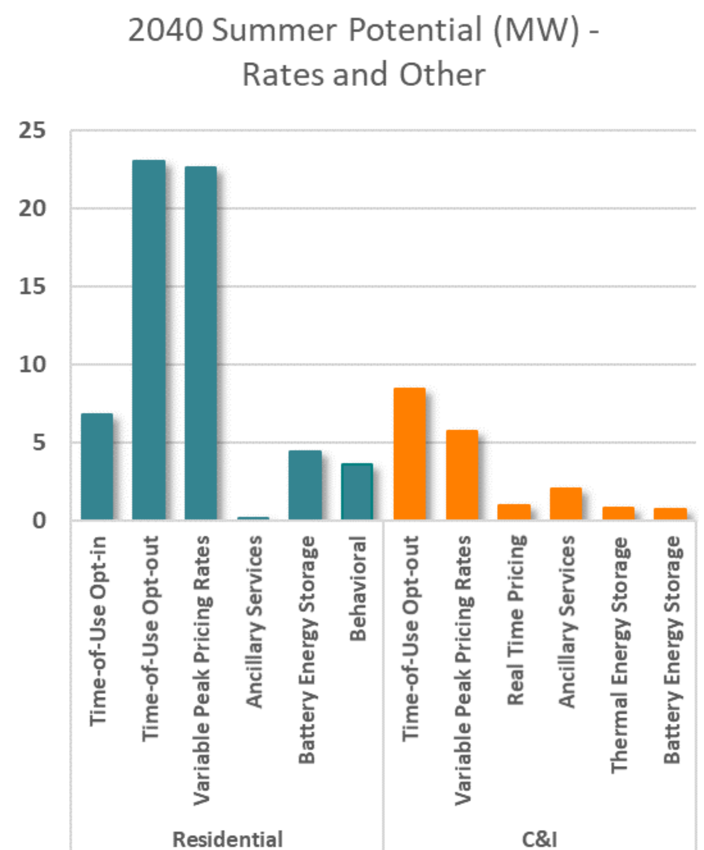
MW BY OPTION – WINTER RATES AND OTHER OPTIONS

Sector	Option	2021	2022	2030	2040
Residential	Time-of-Use Opt-in	0.6	1.9	6.5	6.9
	Time-of-Use Opt-out	28.3	24.3	22.1	23.5
	Variable Peak Pricing Rates	2.1	6.2	21.8	23.1
	Ancillary Services	0.0	0.0	0.1	0.2
	Battery Energy Storage	0.1	0.2	2.4	4.4
	Behavioral	0.8	1.7	3.5	3.7
C&I	Time-of-Use Opt-in	0.1	0.4	1.7	1.7
	Time-of-Use Opt-out	8.2	9.3	9.4	9.4
	Variable Peak Pricing Rates	0.3	1.5	6.2	6.4
	Real Time Pricing	0.1	0.3	1.1	1.1
	Ancillary Services	2.2	2.2	2.2	2.3
	Thermal Energy Storage	-	-	-	-
	Battery Energy Storage	0.0	0.0	0.4	0.8



MW BY OPTION – SUMMER RATES AND OTHER OPTIONS

Sector	Option	2021	2022	2030	2040
Residential	Time-of-Use Opt-in	0.6	1.8	6.4	6.8
	Time-of-Use Opt-out	27.7	23.8	21.7	23.0
	Variable Peak Pricing Rates	2.0	6.1	21.3	22.6
	Ancillary Services	0.0	0.0	0.1	0.2
	Battery Energy Storage	0.1	0.2	2.4	4.4
	Behavioral	0.8	1.6	3.4	3.6
C&I	Time-of-Use Opt-in	0.1	0.4	1.5	1.5
	Time-of-Use Opt-out	7.2	8.3	8.4	8.4
	Variable Peak Pricing Rates	0.3	1.3	5.6	5.7
	Real Time Pricing	0.1	0.3	1.0	1.0
	Ancillary Services	1.9	2.0	2.0	2.1
	Thermal Energy Storage	0.0	0.2	0.8	0.8
	Battery Energy Storage	0.0	0.0	0.4	0.8



Smart Grid Demonstration Project

2009 – 2015 Pullman WA

www.smartgrid.gov/files/OE0000190_Battelle_FinalRep_2015_06.pdf

NW Smart Grid Demonstration Project

NETL

Bonneville Power Administration

Battelle NW

3 Tier
Areva
IBM
Netezza
Quality
Logic

Utility Partners

Avista
Benton PUD
City of Ellensburg
Flathead Electric
Idaho Falls Power
Lower Valley Energy
Milton-Freewater
Northwestern Energy
Peninsula Light
PGE
Seattle City Light

hp

Itron

Spirae

Washington State University
World Class. Face to Face.

AVISTA

Transactive System

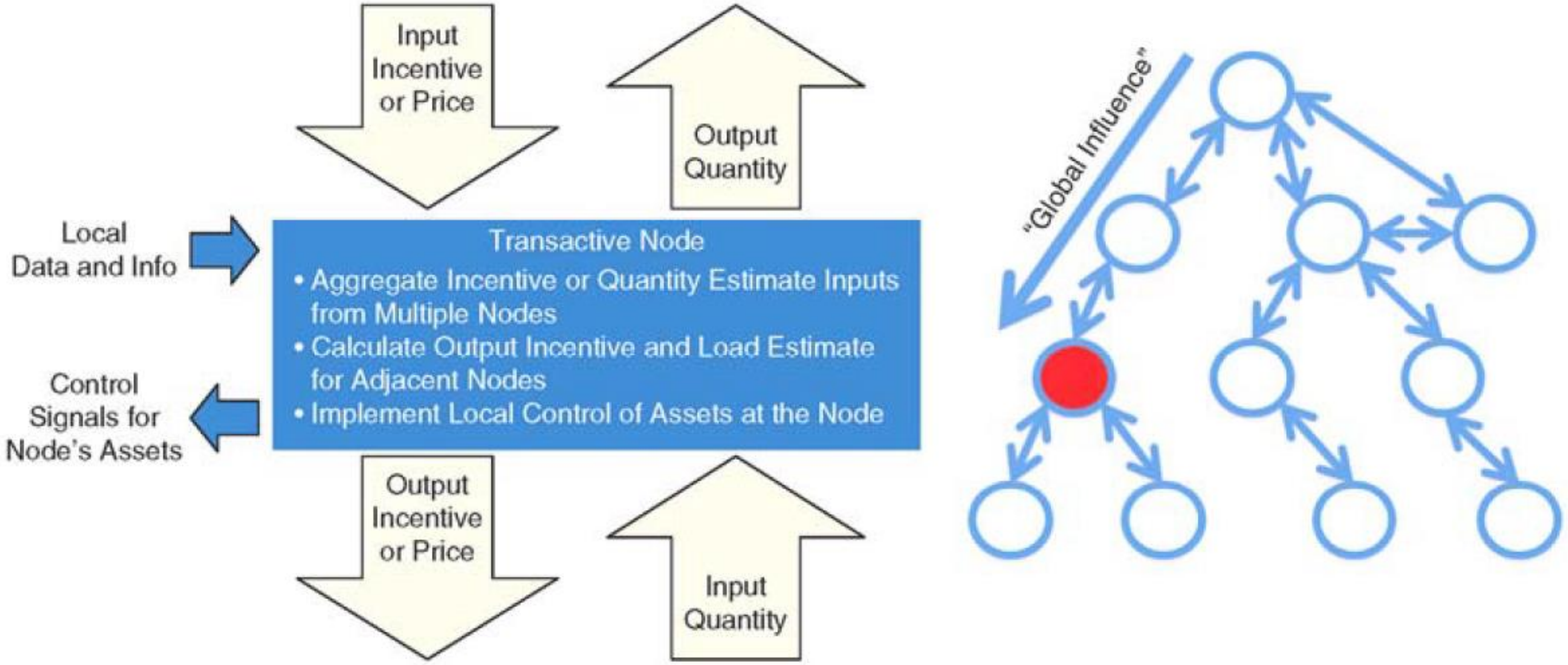


Figure courtesy of PNNL study Transactive System, December 2017

Avista Demand Response

Smart thermostats

- Residential & Small Commercial
  - Air-Conditioning
  - & some electric heat loads
- Avg. 57 participants (up to 75)
- 637 DR Events (Transactive & AGS)
  - Duration 5 minutes - 6 hours

Washington State University

Tier 1 HVAC (39 points)	12 DR events
Tier 2 Chillers (9 points)	5 DR events
Tier 3-5 Generators	5 DR events

Customer Engagement and Energy Efficiency

Smart Meter Usage Web Portal

Bill-to-Date & Usage Charts

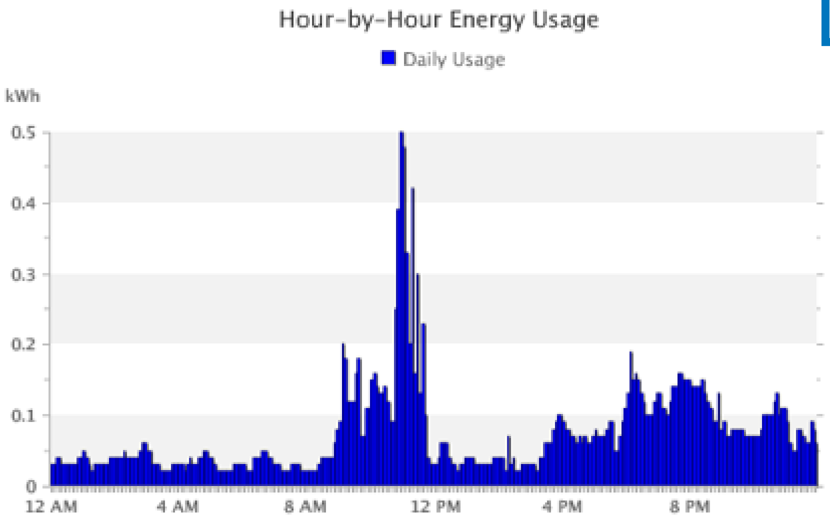
Advanced Meter
Bill-to-Date Estimate

You are 16 days into your billing cycle.	
Estimated Cost as of 10/7/2011	$43.74

Detailed Service Listing

Electric	$24.45
Gas	$19.29

This Bill-to-Date feature provides an estimate of electric and/or gas charges since your last statement, including the full amount of the monthly basic service charge(s). City tax, if applicable, is not included.



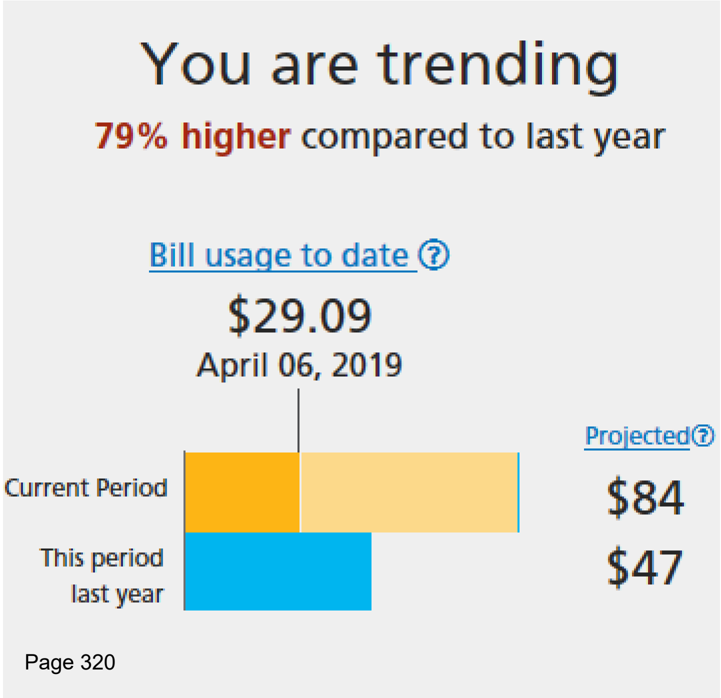
Usage notifications & alerts between bills

Daily:	Comparison
Weekly:	Bill-to-date
Monthly:	Budget threshold

New Customer Programs

Smart Thermostat Rebates

Washington Smart Meter Roll-Out



New AMI Web-Portal Features

<demo AMI web-portal>

Notifications & Alerts

Add to Mobile App

QUESTIONS…

COMMENTS…

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

Serving Load Reliably under a Changing Resource Mix

February 2019

Arne Olson, Sr. Partner
Zach Ming, Managing Consultant

Outline

- Study Background & Methodology
- Results
  - 2018
  - 2030
  - 2050
  - Capacity contribution of wind, solar, storage and demand response
- Key Findings

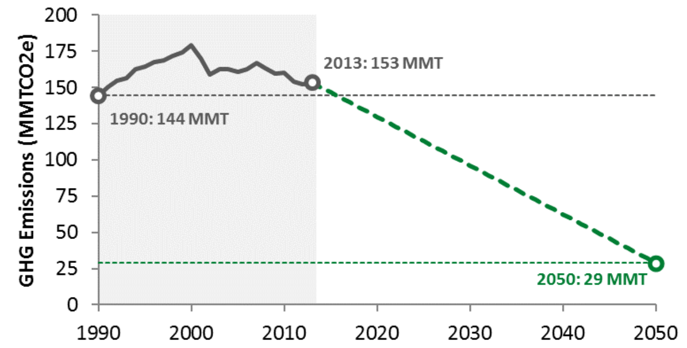
Energy+Environmental Economics

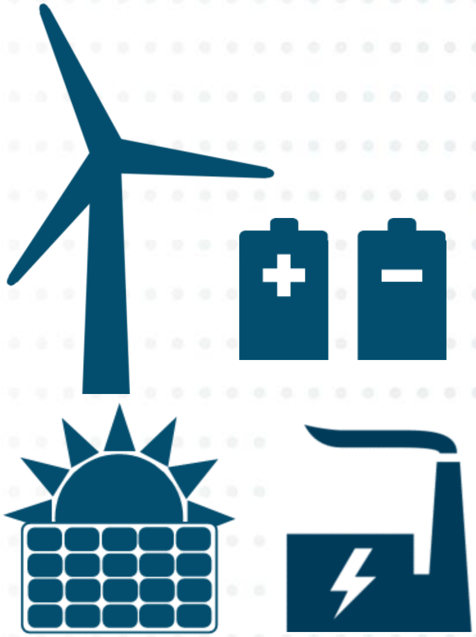
STUDY BACKGROUND & METHODOLOGY

About This Study

- **The Pacific Northwest is expected to undergo significant changes to its generation resource mix over the next 30 years due to changing economics and more stringent policy goals**
  - Increased penetration of wind and solar generation
  - Retirements of coal generation
  - Questions about the role of new natural gas generation
- **This raises questions about the region's ability to serve load reliably as firm generation is replaced with variable resources**
- **This study was sponsored by 13 Pacific Northwest utilities to examine Resource Adequacy under a changing resource mix**
  - How to maintain Resource Adequacy in the 2020-2030 time frame under growing loads and increasing coal retirements
  - How to maintain Resource Adequacy in the 2040-2050 time frame under stringent carbon abatement goals

Historical and Projected GHG Emissions for OR and WA





Study Sponsors

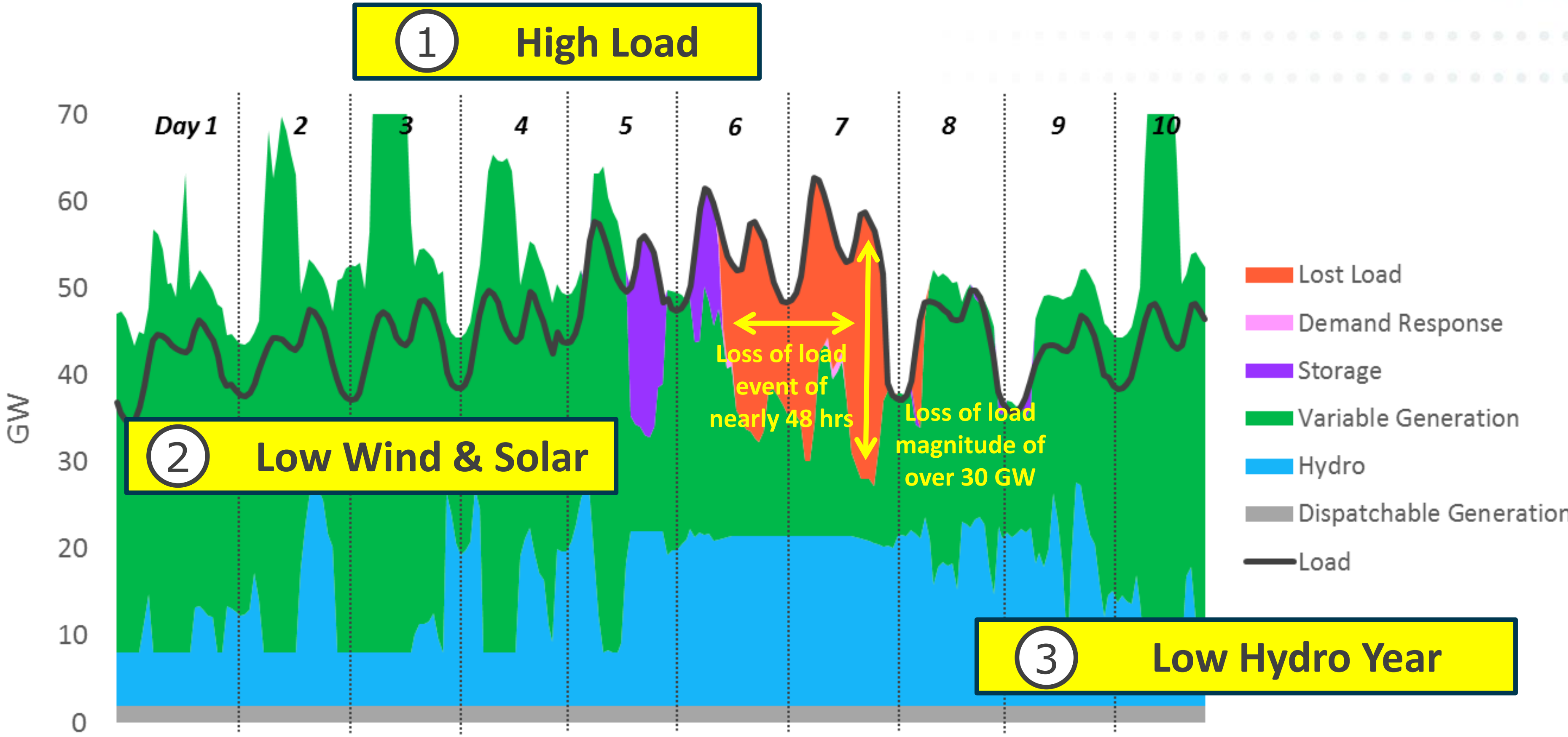
- This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy and the Public Generating Pool (PGP)

  - PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington.

E3 thanks the staff of the Northwest Power and Conservation Council for providing data and technical review

Three Reliability Challenges on a Deeply-Decarbonized Grid

+ The most challenging conditions in a deeply-decarbonized Pacific Northwest grid occur when a multi-day cold snap coincides with low wind, solar and hydro production

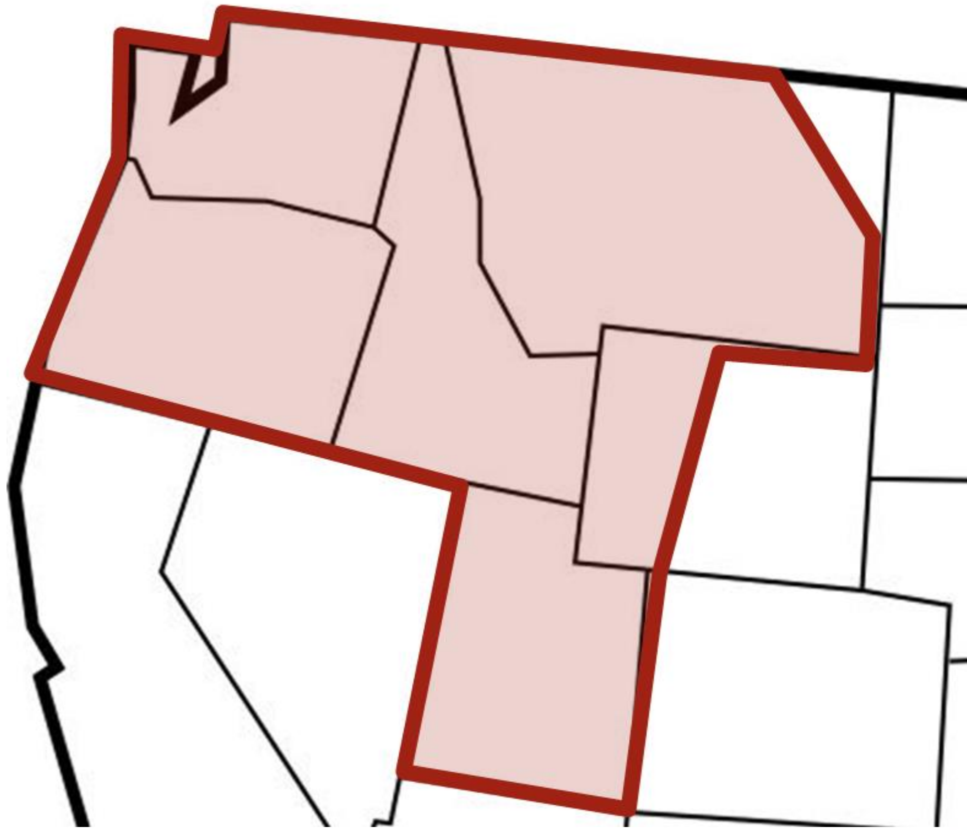


Long-run Reliability and Resource Adequacy

+ **This study focuses on long-run (planning) reliability, a.k.a. Resource Adequacy (RA)**
  - A system is "Resource Adequate" if it has sufficient capacity to serve load across a broad range of weather conditions, subject to a long-run standard for frequency of reliability events, for example 1-day-in-10 yrs.
+ **There is no mandatory or voluntary national standard for RA**
  - Each Balancing Authority establishes its own standard subject to oversight by state commissions or locally-elected boards
  - North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC) publish information about Resource Adequacy but have no formal governing role
+ **Study uses a 1-in-10 standard of no more than 24 hours of lost load in 10 years, or no more than 2.4 hours/year**
  - This is the most common standard used across the industry

Study Region – The Greater NW

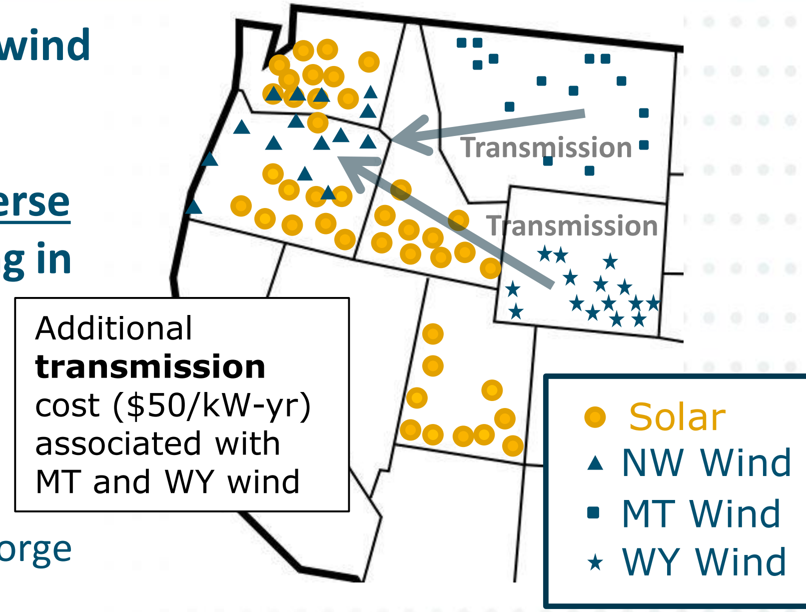
- **The study region consists of the U.S. portion of the Northwest Power Pool (excluding Nevada)**
- **It is assumed that any resource in any area can serve any need throughout the Greater NW region**
  - Study assumes no transmission constraints or transactional friction
  - Study assumes full benefits from regional load and resource diversity
  - The system as modeled is more efficient and seamless than the actual Greater NW system



Balancing Authority Areas include: Avista, Bonneville Power Administration, Chelan County PUD, Douglas County PUD, Grant County PUD, Idaho Power, NorthWestern Energy, PacifiCorp (East & West), Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, Western Area Power Administration

New wind and solar resources are added across a geographically diverse footprint

- The study considers additions nearly 100 GW of wind and 50 GW of solar across the six-state region
- The portfolios studied are <u>significantly more diverse</u> than the renewable resources currently operating in the region
  - Each dot in the map represents a location where wind and solar is added in the study
  - NW wind is more diverse than existing Columbia Gorge wind
- New renewable portfolios are within the bounds of current technical potential estimates, but are nearly an order of magnitude higher than other studies have examined
- The cost of new transmission is assumed for delivery of remote wind and solar generation but siting and construction is not studied in detail



NREL Technical Potential (GW)

State	Wind
WA	18
OR	27
CA	34
ID	18
MT	944
WY	552
UT	13
Total	**1588**

https://www.nrel.gov/docs/fy12osti/51946.pdf

Energy+Environmental Economics

Additional metric definitions used for scenario development

- **GHG Reduction %** is the reduction below 1990 emission levels for the study region
  - The study region emitted 60 million metric electricity sector emissions in 1990
- **CPS %** is the total quantity of GHG-free generation divided by retail electricity sales
  - "Clean Portfolio Standard" includes renewable energy plus hydro and nuclear
  - Common policy target metric, including California's SB 100
- **GHG-Free Generation %** is the total quantity of GHG-free generation, *minus* exported GHG-free generation, divided by total wholesale load
  - Assumed export capability up to 6,000 MW
- **Renewable Curtailment %** is the total quantity of wind/solar generation that is not delivered or exported divided by total wind/solar generation

The study considers Resource Adequacy needs under multiple scenarios representing alternative resource mixes

2018-2030 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
2018 Case[4]	-6%	71%	75%	63
2030 Reference Case[4]	-12%	61%	65%	67
2030 Coal Retirement	30%	61%	65%	42

2050 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
Reference Case	16%	60%	63%	50
60% GHG Reduction	60%	80%	86%	25
80% GHG Reduction	80%	90%	100%	12
90% GHG Reduction	90%	95%	108%	6
98% GHG Reduction	98%	99%	117%	1
100% GHG Reduction	100%	100%	123%	0

[1]Greater NW Region 1990 electricity sector emissions = 60 MMT/yr.
[2]GHG-Free Generation % = renewable + hydro + nuclear generation, minus exports, divided by total wholesale load
[3]CPS % = renewable + hydro + nuclear generation divided by retail electricity sales
[4]2018 and 2030 cases assumes coal capacity factor of 60%

Individual utility impacts will differ from the regional impacts

- **Cost impacts in this study are presented from a societal perspective and represent an aggregation of all costs and benefits within the Greater NW region**
  - Societal costs include all investment (i.e. "steel-in-the-ground") and operational costs (i.e. fuel and O&M) that are incurred in the region
- **Cost of decarbonization may be higher or lower for individual utilities as compared to the region as a whole**
  - Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources
- **Resource Adequacy needs will be different for each utility**
  - Individual systems will need a higher reserve margin than the Greater NW region due to smaller size and less diversity
  - Capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production

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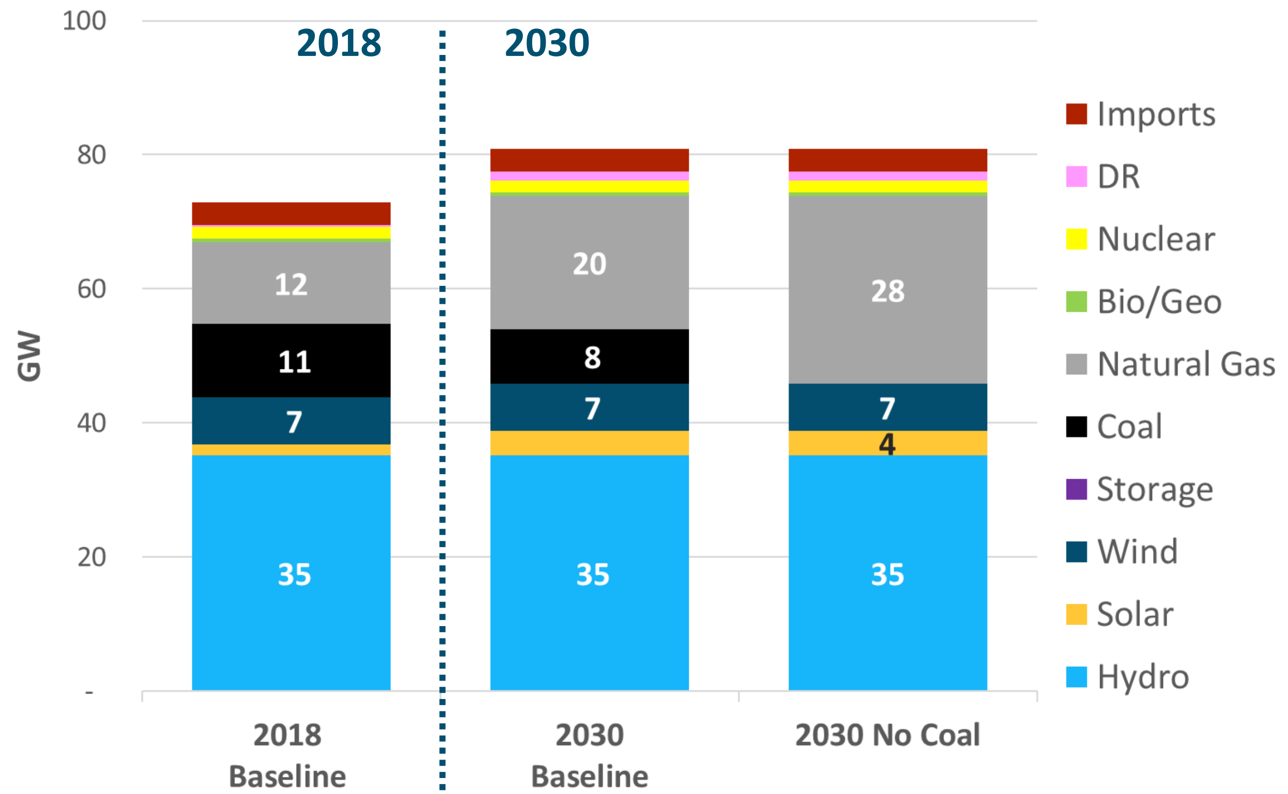
2030 RESULTS

2030 Portfolios



GHG Free Generation (%)	61%	61%
Carbon (MMT CO2)	67	42
% GHG Reduction from 1990 Level	-12%*	31%

***Assumes 60% coal capacity factor**

5 GW net new capacity by 2030 is needed for reliability (450 MW/yr)

With planned coal retirements of 3 GW, 8 GW of new capacity by 2030 is needed (730 MW/yr)

If all coal is retired, then 16 GW new capacity is needed (1450 MW/yr)

The Northwest system will need 8 GW of new effective capacity by 2030

- The 2030 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2030 system does not meet standard for Annual LOLP (5%)
- Load growth and planned coal retirements lead to the need for 8 GW of new effective capacity by 2030

	2030 with No New Capacity	2030 with 8 GW of New Capacity
Annual LOLP (%)	**48%**	2.8%
LOLE (hrs/yr)	**106**	2.4
EUE (MWh/yr)	178,889	1,191
EUE norm (EUE/load)	0.07%	0.0004%

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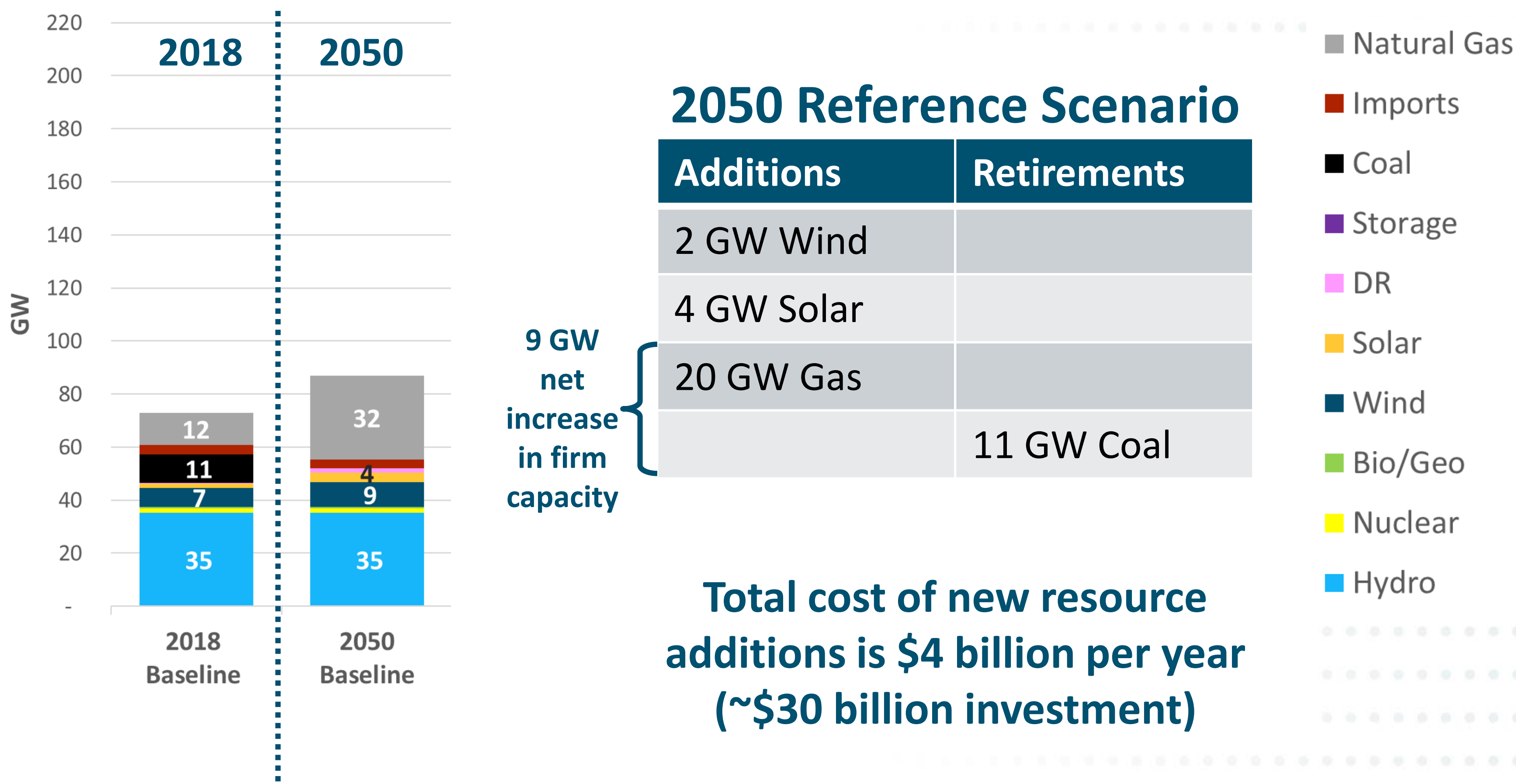
2050 RESULTS

Scenario Summary

Greater NW System in 2050



2050 Reference Scenario

Additions	Retirements
2 GW Wind	
4 GW Solar	
20 GW Gas	
	11 GW Coal

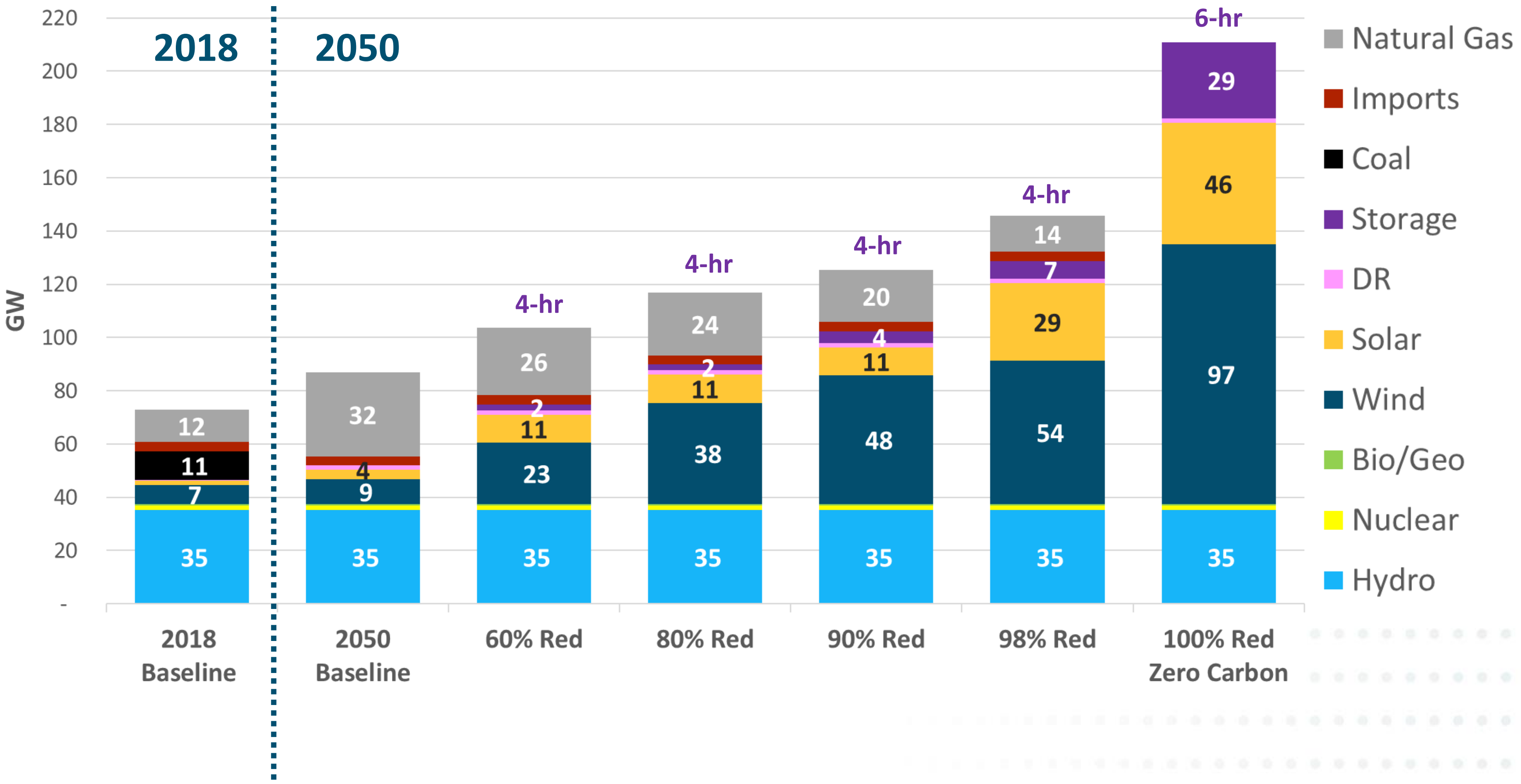
9 GW net increase in firm capacity

Total cost of new resource additions is $4 billion per year (~$30 billion investment)

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

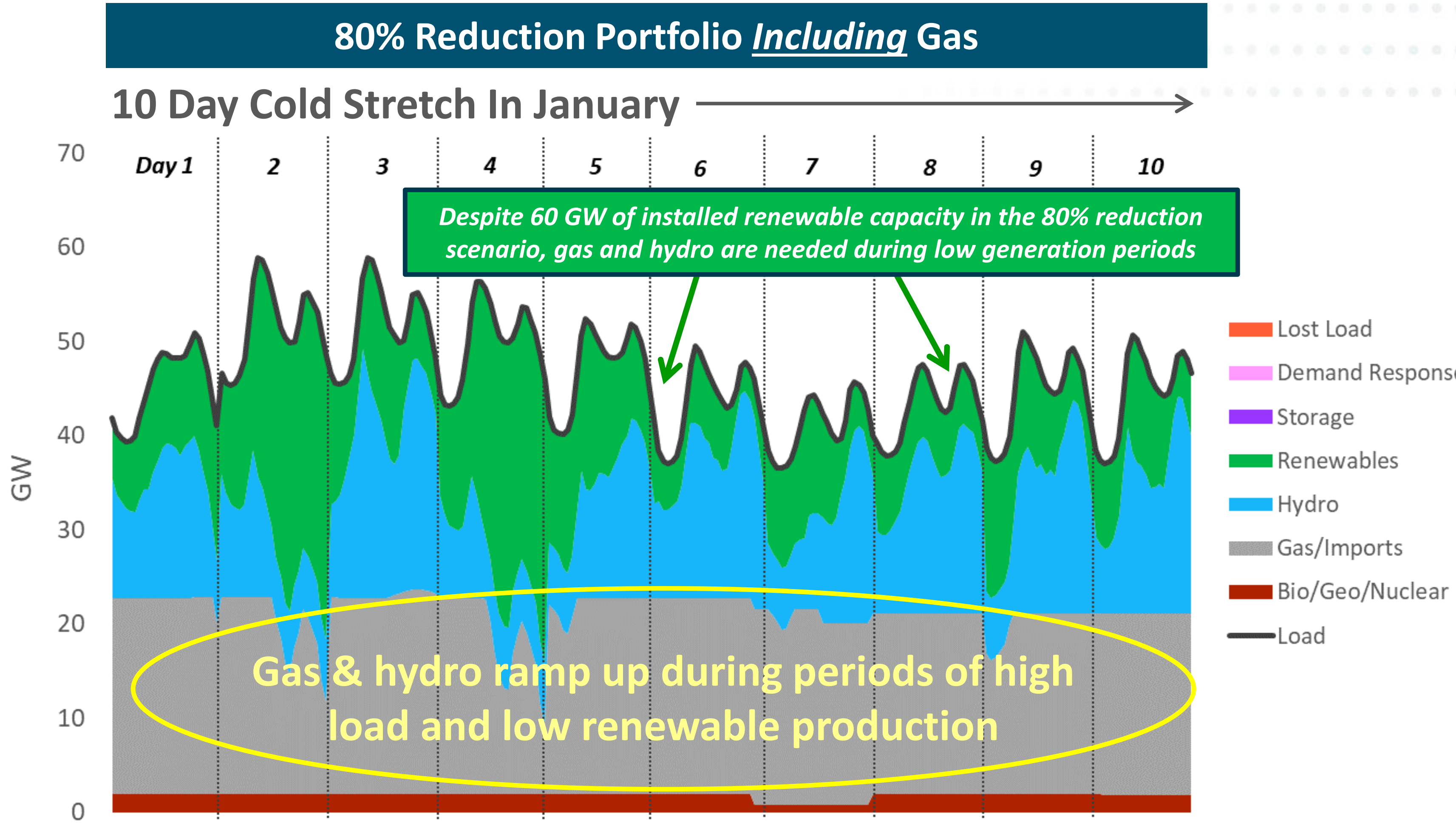
Scenario Summary
Greater NW System in 2050



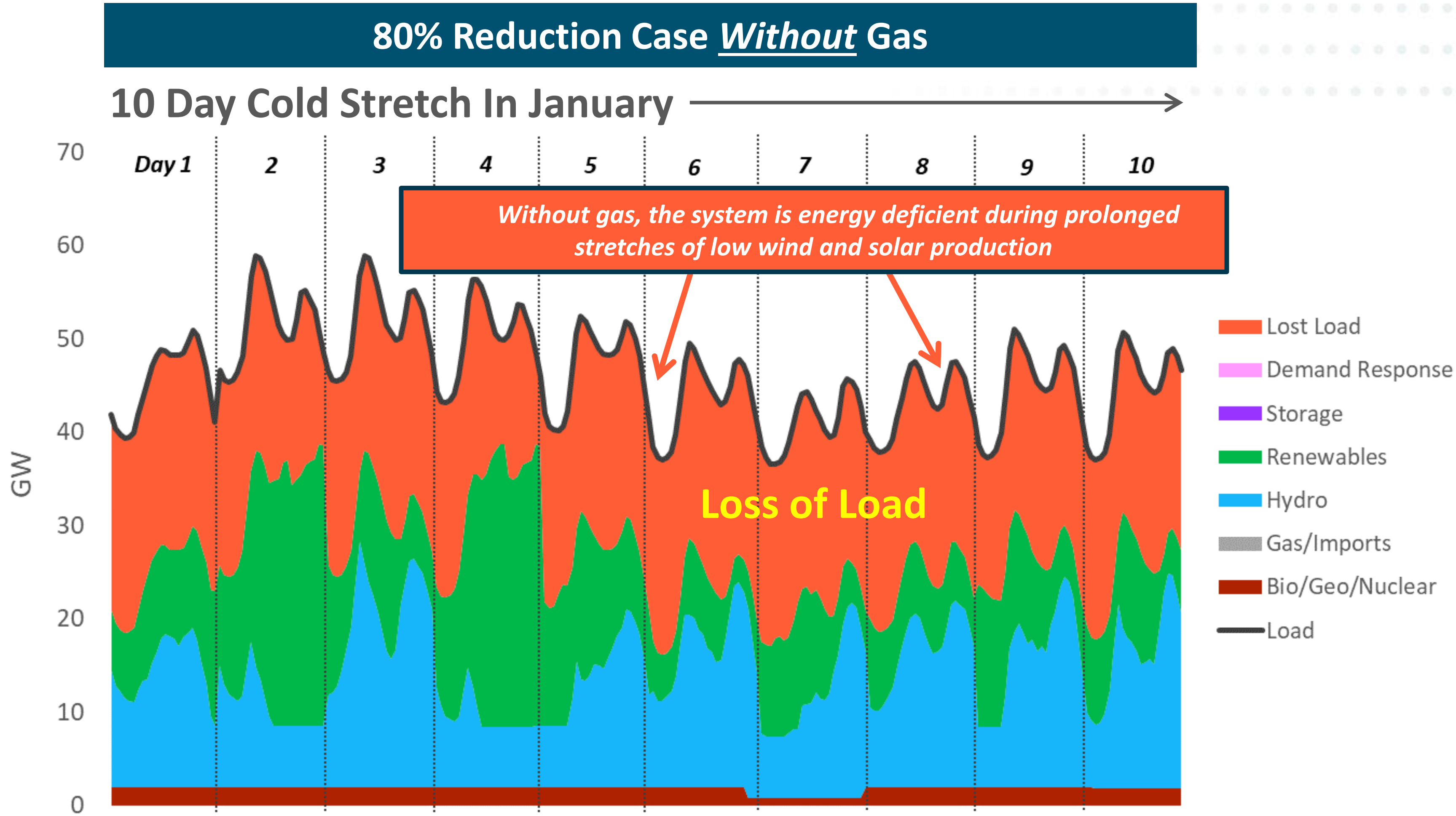
[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Illustrating the Need for Firm Capacity – January

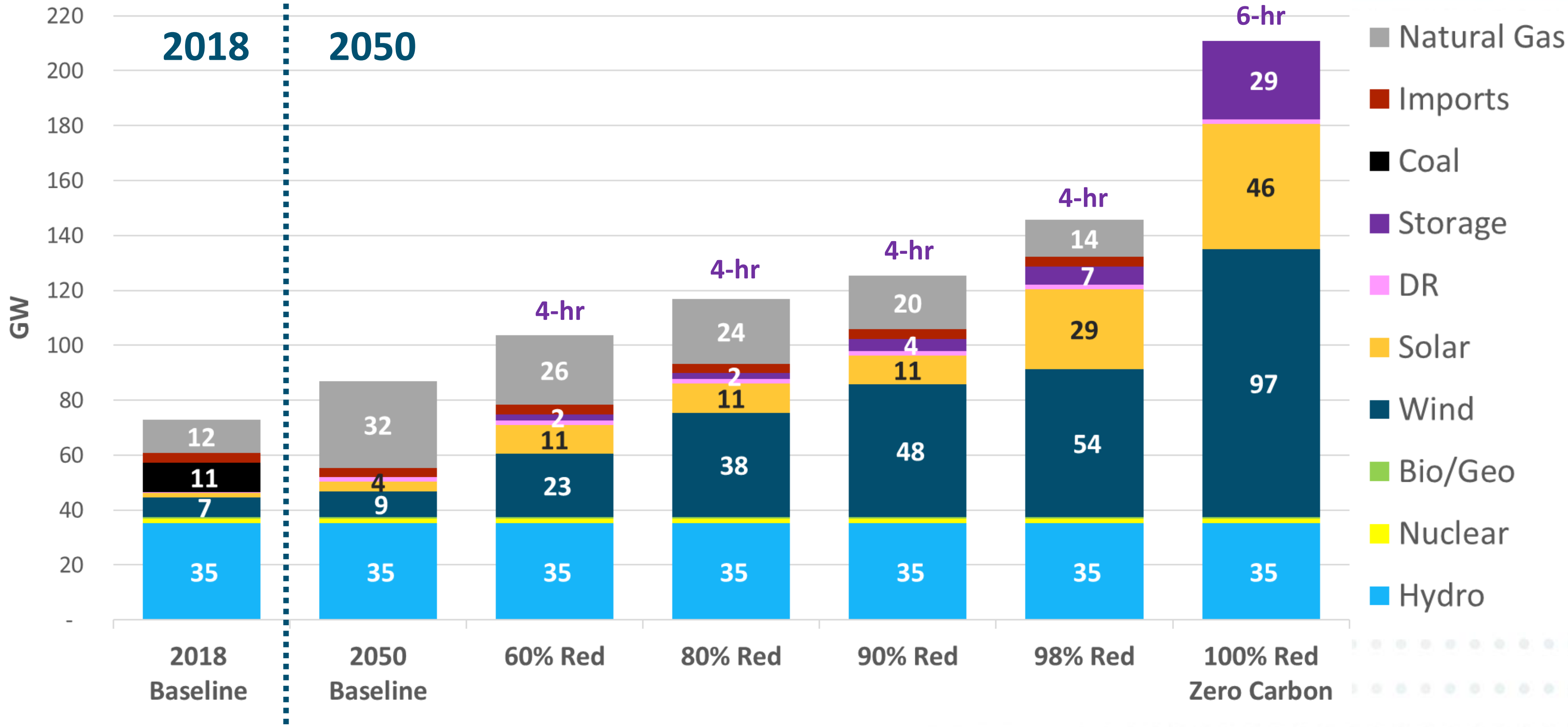


Illustrating the Need for Firm Capacity – January



Scenario Summary

2050 Emissions Reductions

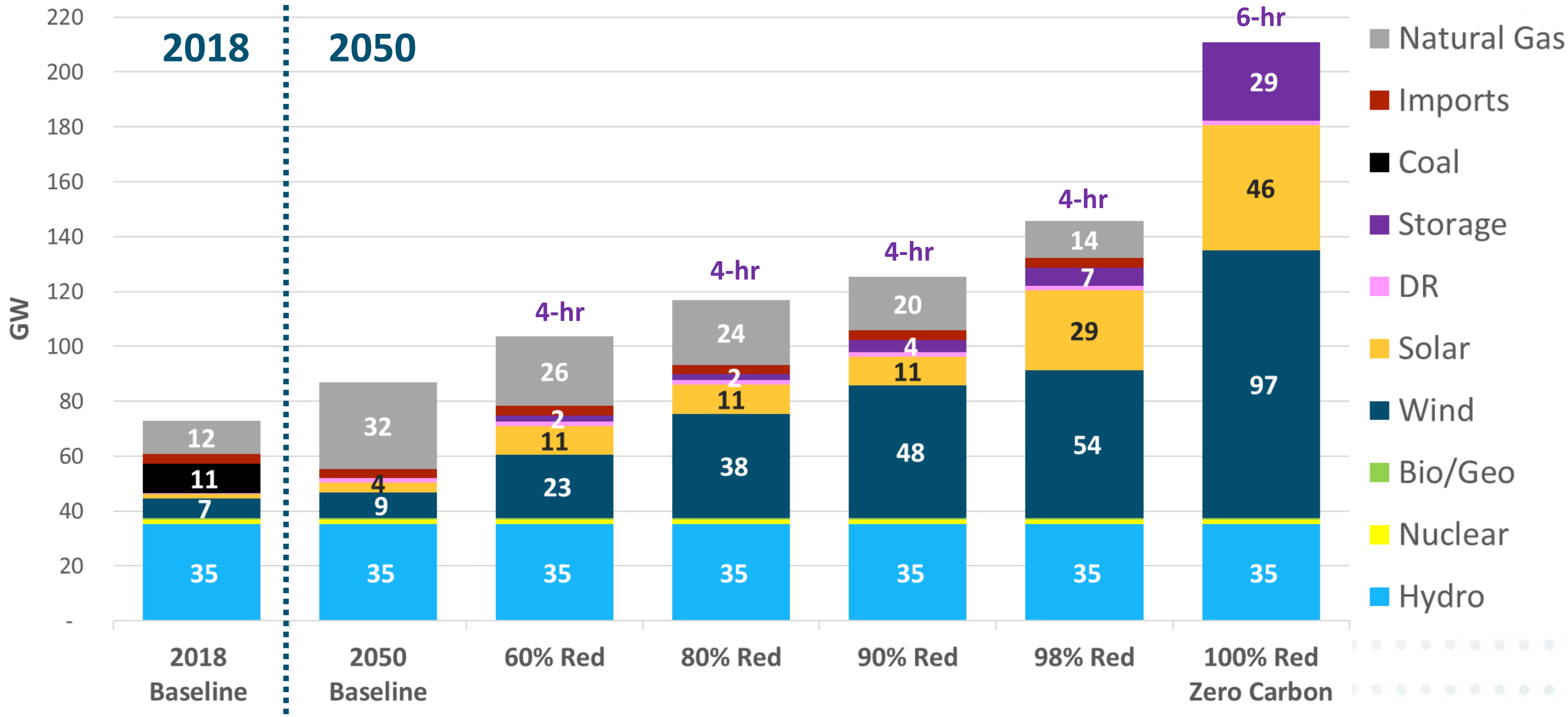


Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary
2050 Resource Use



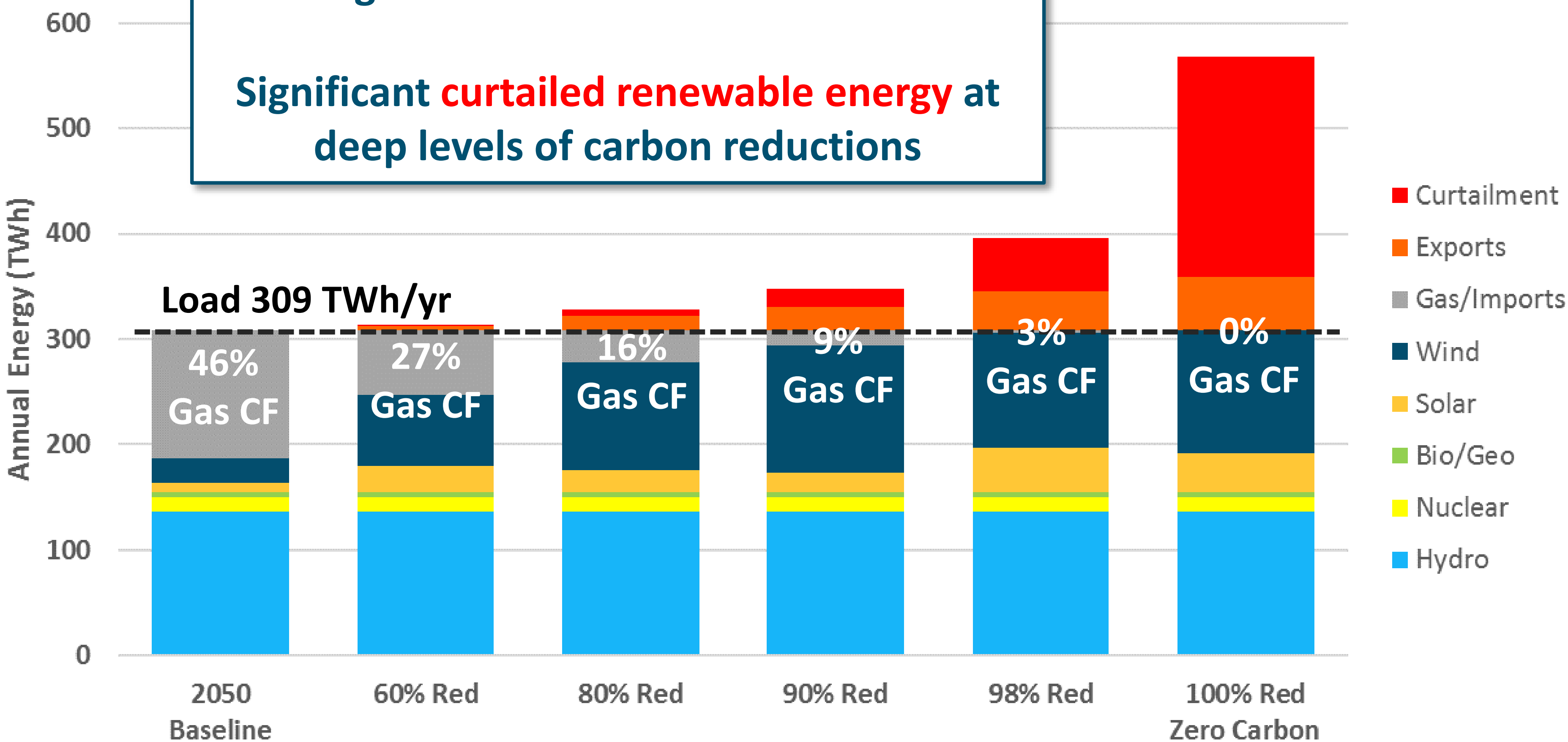
Renewable Capacity (GW)	13	34	49	59	83	143
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Gas Capacity (GW)	32	26	24	20	14	0
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

2050 Annual Energy Balance

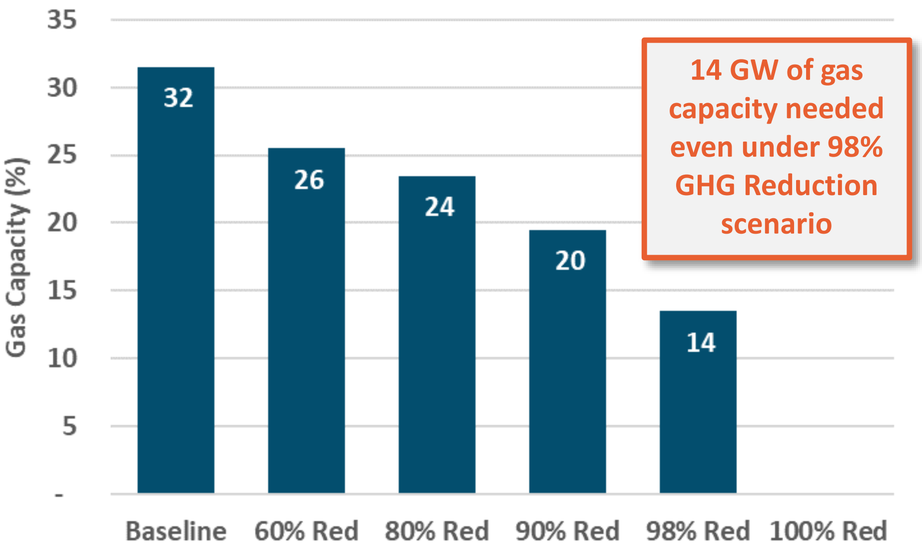
Gas capacity factor declines significantly at higher levels of decarbonization

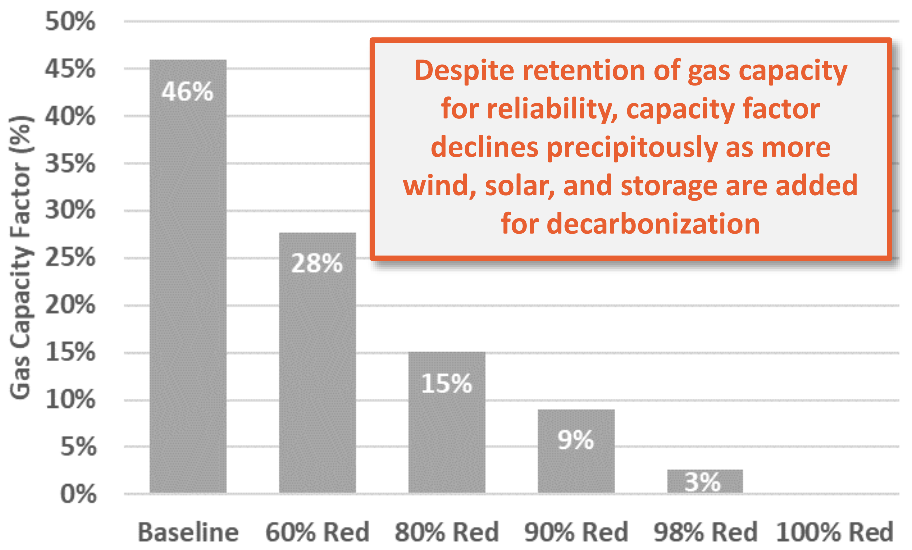
Significant curtailed renewable energy at deep levels of carbon reductions



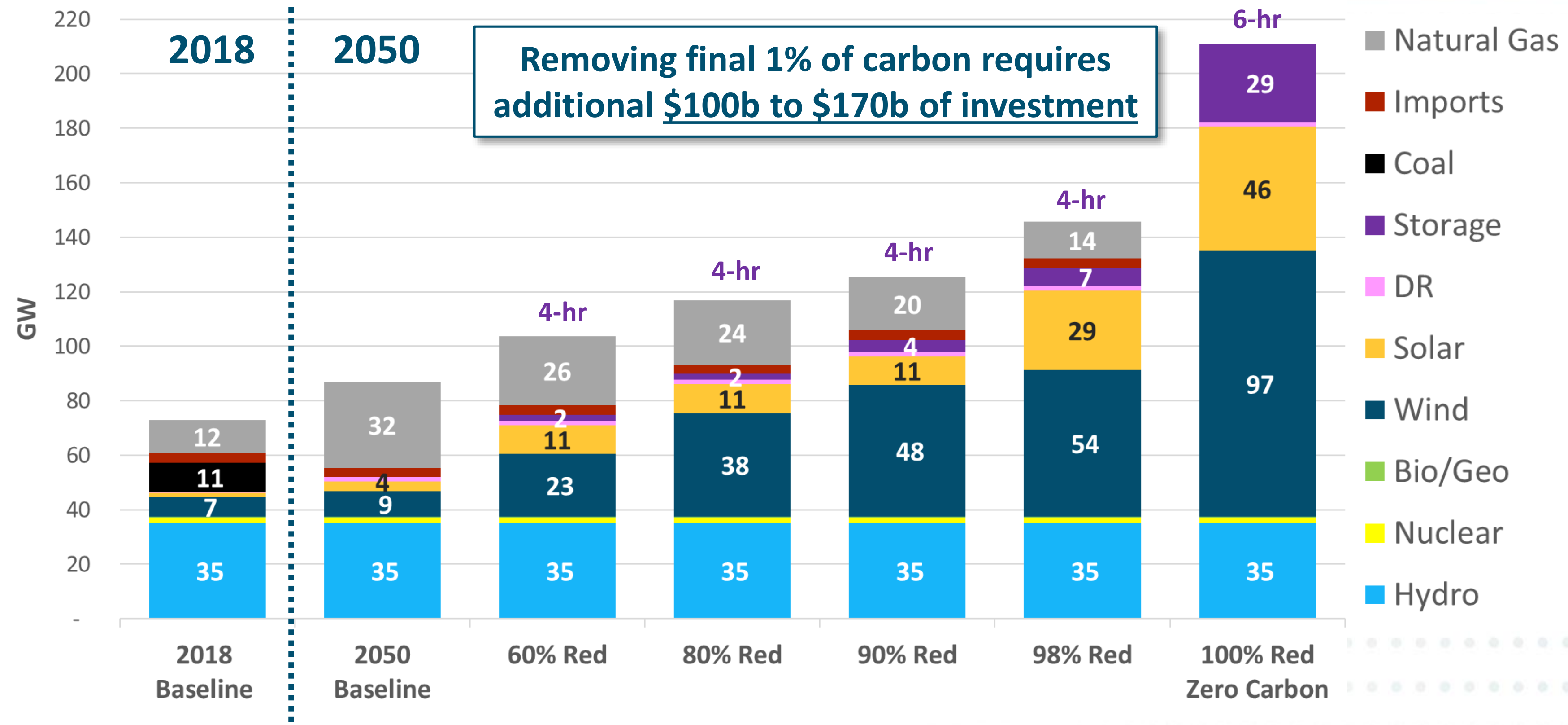
Firm capacity is still needed for reliability under deep decarbonization despite much lower utilization

- Natural gas *energy production* declines substantially as the GHG increases
- Natural gas *capacity* is part of the least-cost mix of resources to reduce carbon emissions to 1 million tons by 2050
- All scenarios except 100% GHG reductions select more gas capacity than exists on the system today (12 GW)





Scenario Summary
2050 Costs

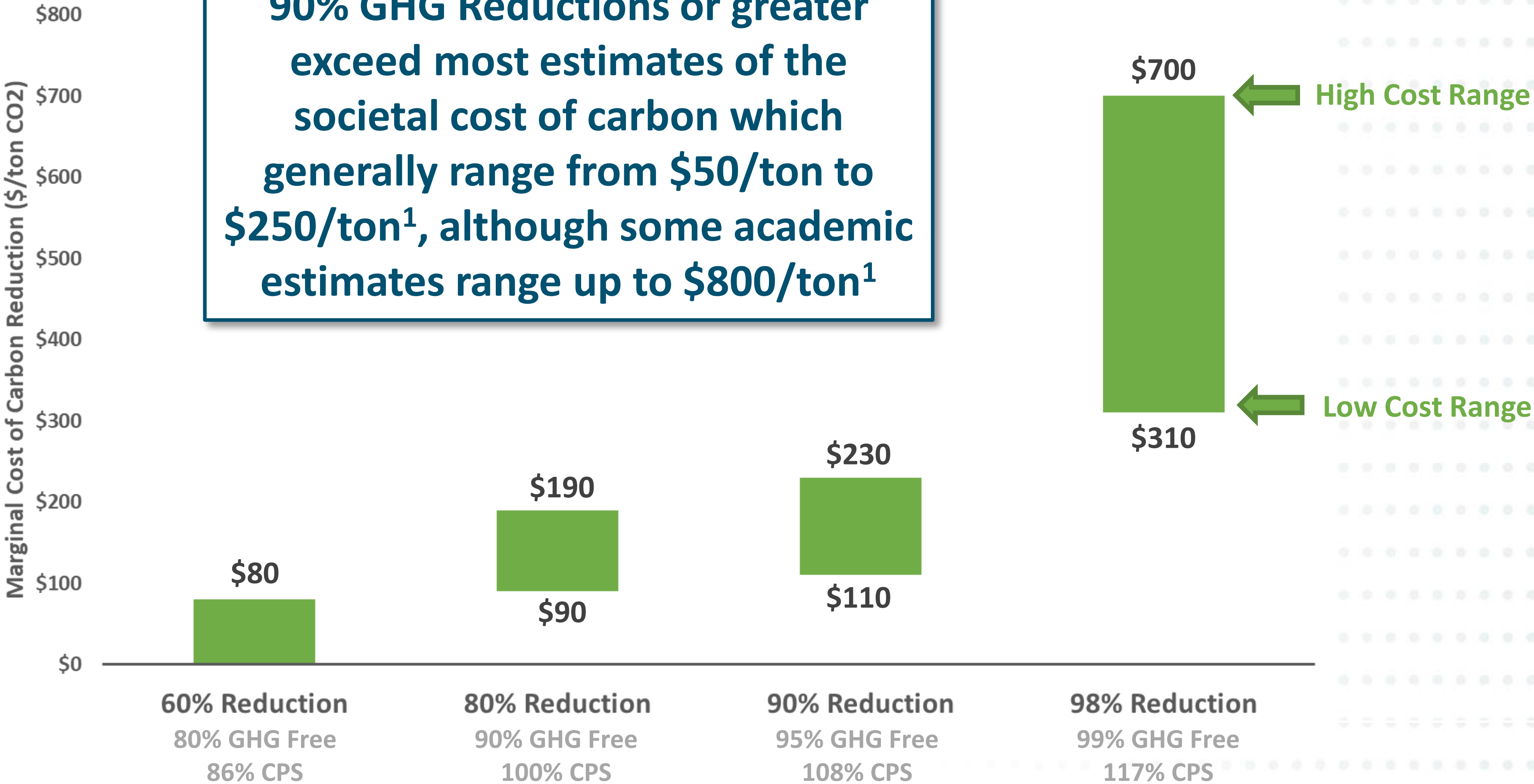


Marginal Carbon Reduction Cost ($/Metric Ton)	Base	$0 - $80	$90 - $190	$110 - $230	$310 - $700	$11,000 – $16,000
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

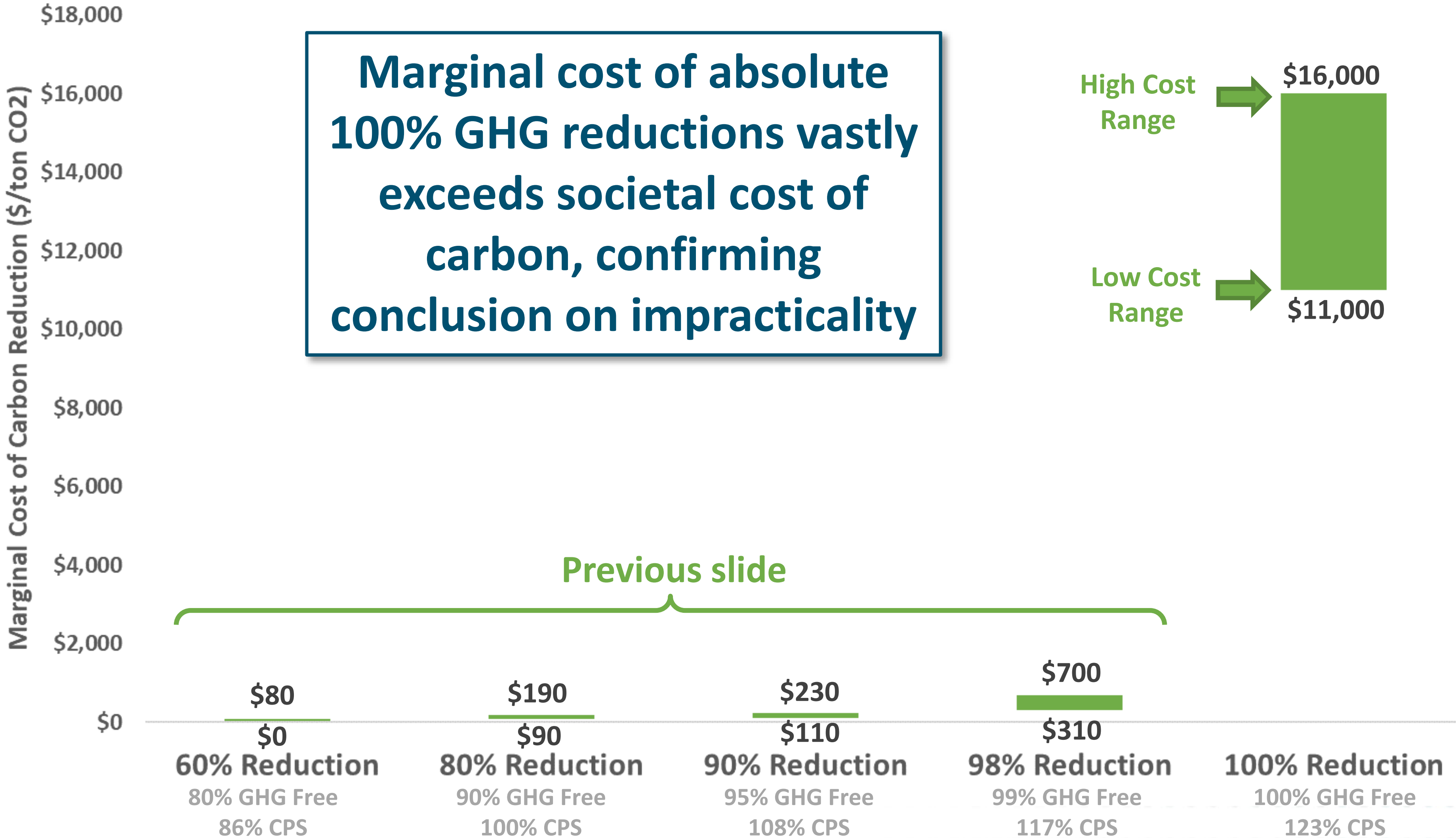
Marginal Cost of GHG Reduction

Marginal cost of CO2 reductions at 90% GHG Reductions or greater exceed most estimates of the societal cost of carbon which generally range from \$50/ton to \$250/ton[1], although some academic estimates range up to \$800/ton[1]



[1] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html; https://www.nature.com/articles/s41558-018-0282-y

Marginal Cost of GHG Reduction



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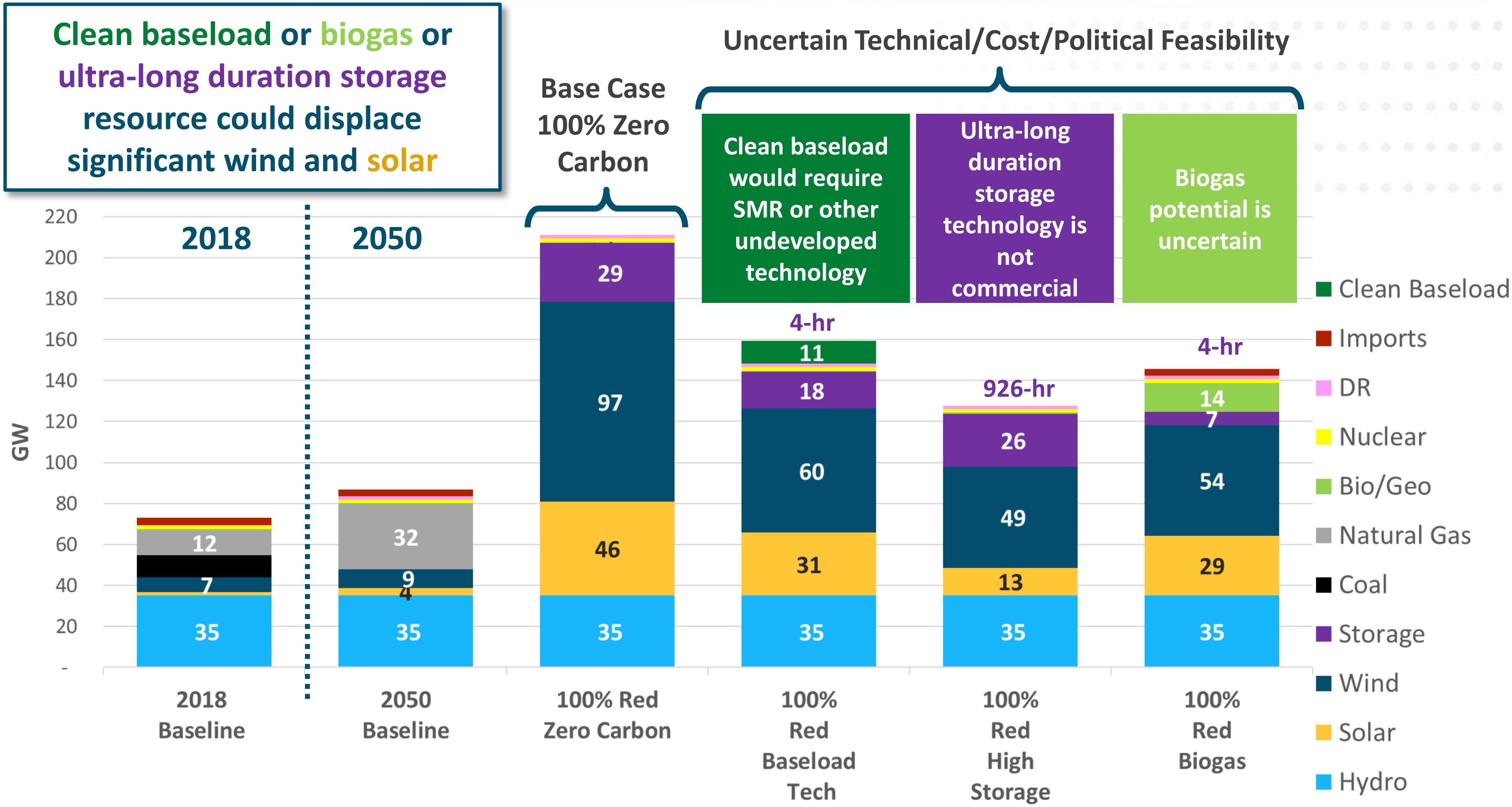
100% Reduction Portfolio Alternatives in 2050



Carbon (MMT CO2)	50	0	0	0	0
Annual Cost Delta ($B)	Base	$16- $28	$14-$21	$550-$990	$4 - $9
Additional Cost ($/MWh)	Base	$52-$89	$46-$69	$1,800-$3,200	$14 - $30

Renewable Land Use
2018 Installed Renewables

Technology	Nameplate GW
● Solar	1.6
▲ NW Wind	5.3
▪ MT Wind	0.6
★ WY Wind	1.2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind – Total Land Use (thousand acres)
Today	12	19	223 – 1,052

Land use today ranges from

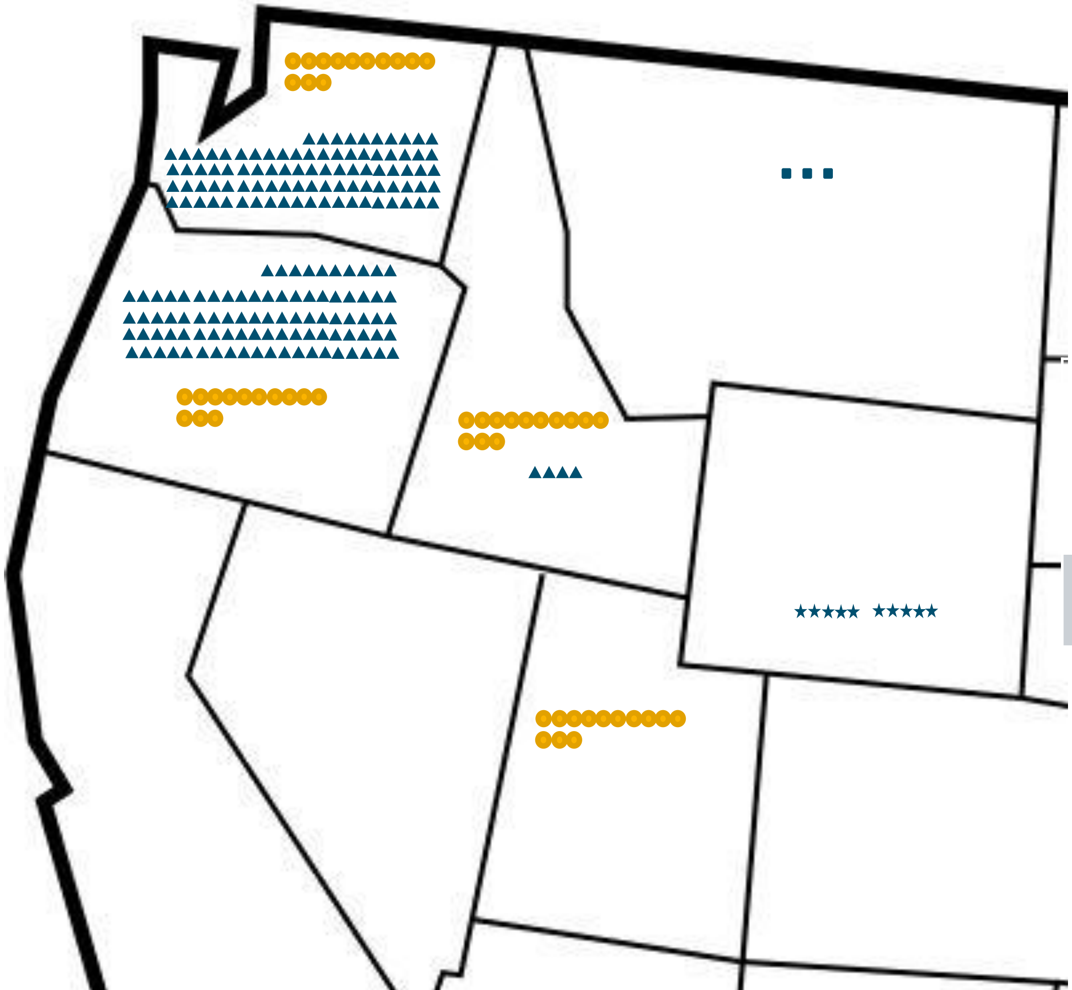
1.6 to 7.5x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

Renewable Land Use
80% Reduction in 2050



Technology	Nameplate GW
● Solar	11
▲ NW Wind	36
▪ MT Wind	0
★ WY Wind	2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Red	84	94	1,135 – 5,337

Land use in 80% Reduction case ranges from

8 to 37x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

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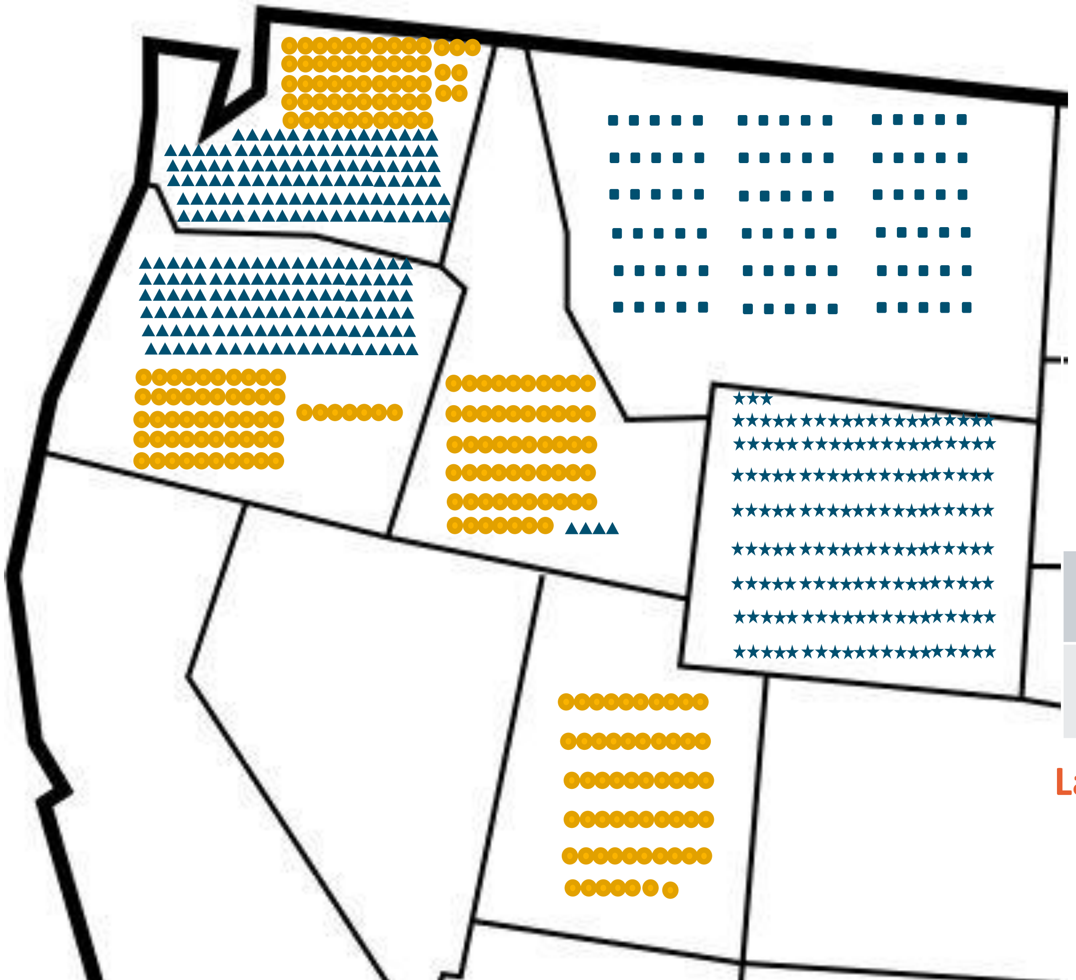
Renewable Land Use

100% Reduction in 2050



Technology	Nameplate GW
Solar	46
NW Wind	47
MT Wind	18
WY Wind	33

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Clean	84	94	1,135 – 5,337
100% Red	361	241	2,913 – 13,701

Land use in 100% Reduction case ranges from

20 to 100x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

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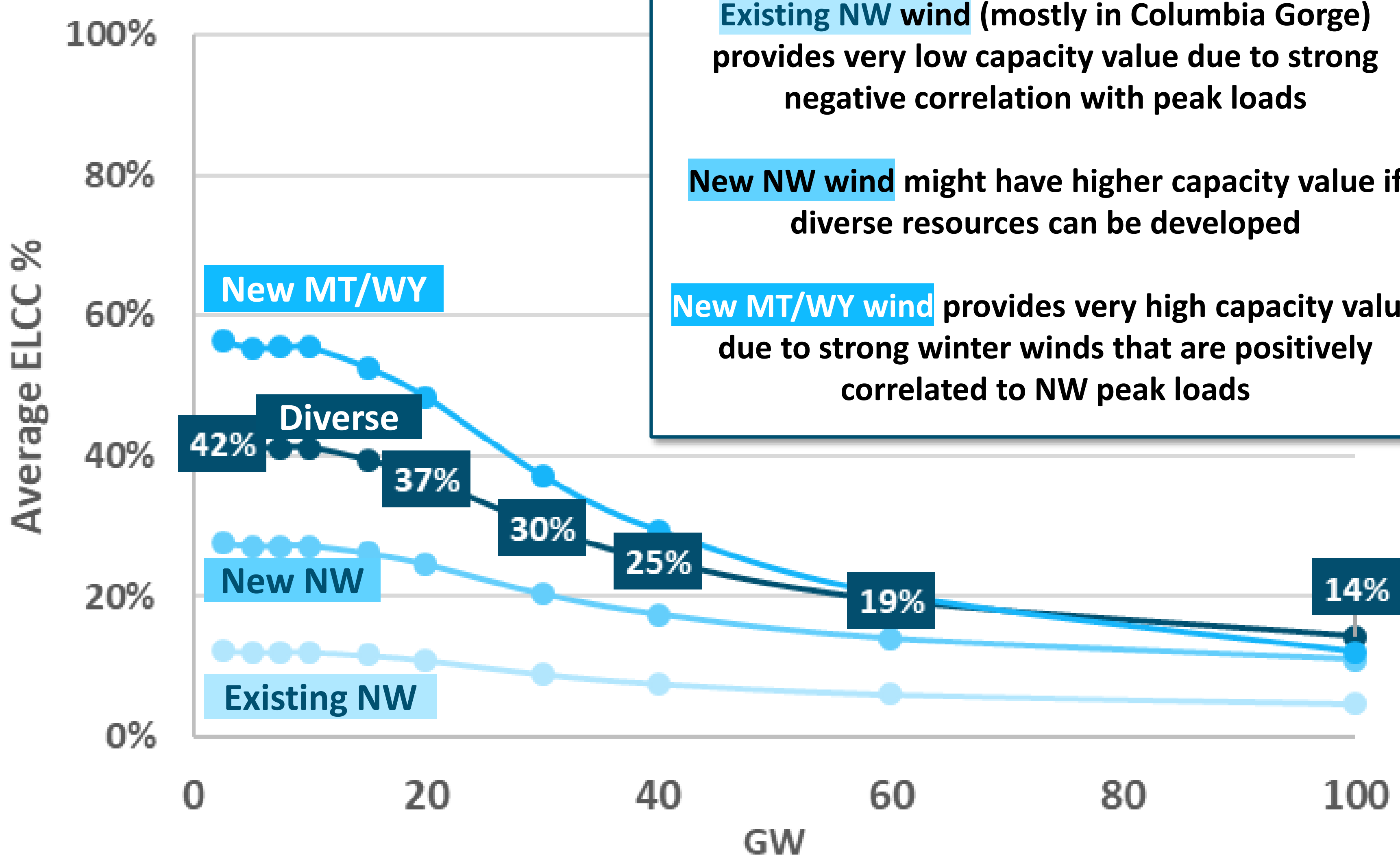
Wind ELCC varies widely by location

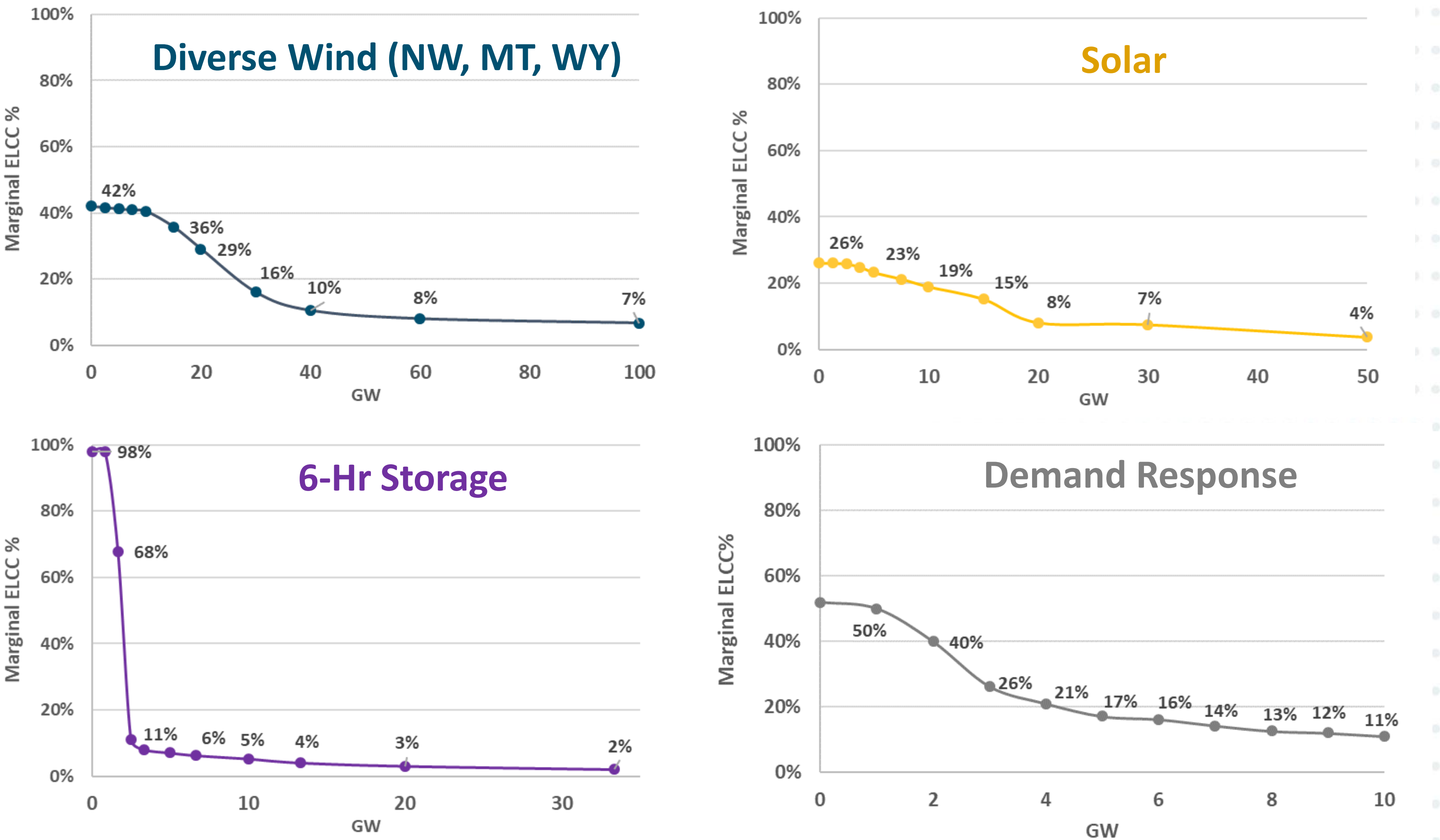


Existing NW wind (mostly in Columbia Gorge) provides very low capacity value due to strong negative correlation with peak loads

New NW wind might have higher capacity value if diverse resources can be developed

New MT/WY wind provides very high capacity value due to strong winter winds that are positively correlated to NW peak loads

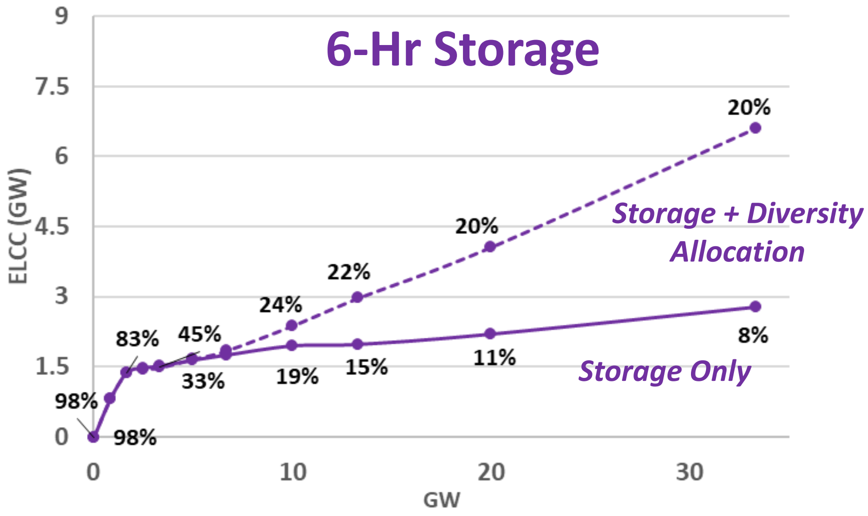
Effective capacity from wind, solar, storage, and demand response is limited due to saturation effects

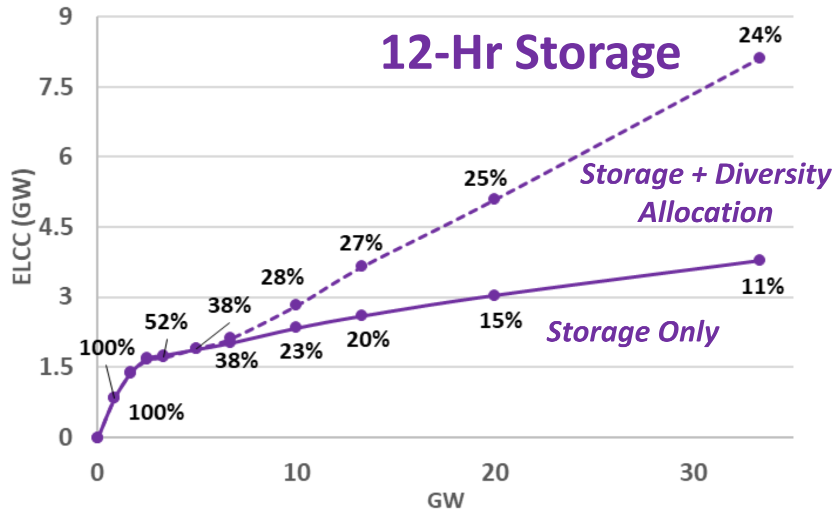


ELCC = Effective Load Carrying Capability = firm contribution to system peak load

Value of Storage Duration

+ **Increasing the duration of storage provides additional ELCC capacity value, but there are still strong diminishing returns even for storage up to a duration of 12-hours**





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KEY FINDINGS

Key Findings (1 of 2)

1. **It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient firm capacity is available during periods of low wind, solar and hydro production**
   - Natural gas generation is the most economic source of firm capacity, and adding new gas *capacity* is not inconsistent with deep reductions in carbon emissions
   - Wind, solar, demand response and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs
   - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) gas or coal generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas
2. **It would be extremely costly and impractical to replace all carbon-emitting firm generation capacity with solar, wind and storage, due to the very large quantities of these resources that would be required**
3. **The Northwest is anticipated to need new capacity in the near-term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements**

Key Findings (2 of 2)

4. **Current planning practices risk underinvestment in new capacity required to ensure Resource Adequacy at acceptable levels**
   - Reliance on "market purchases" or "front office transactions" reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region
   - However, because the region lacks a formal mechanism for counting physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity
   - Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory
   - The region might benefit from and should investigate a formal mechanism for sharing of planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

The results/findings in this analysis represent the Greater NW region in aggregate, but results may differ for individual utilities

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Thank You!

Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
Web http://www.ethree.com

Arne Olson, Senior Partner (arne@ethree.com)
Zach Ming, Managing Consultant (zachary.ming@ethree.com)

This study utilizes E3's Renewable Energy Capacity Planning (RECAP) Model

+ Resource adequacy is a critical concern under high renewable and decarbonized systems

- Renewable energy availability depends on the weather
- Storage and Demand Response availability depends on many factors

+ RECAP evaluates adequacy through time-sequential simulations over thousands of years of plausible load, renewable, hydro, and stochastic forced outage conditions

- Captures thermal resource and transmission forced outages
- Captures variable availability of renewables & correlations to load
- Tracks hydro and storage state of charge

RECAP calculates reliability metrics for high renewable systems:

- **LOLP: Loss of Load Probability**
- **LOLE: Loss of Load Expectation**
- **EUE: Expected Unserved Energy**
- **ELCC: Effective Load-Carrying Capability for hydro, wind, solar, storage and DR**
- **PRM: Planning Reserve Margin needed to meet specified LOLE**

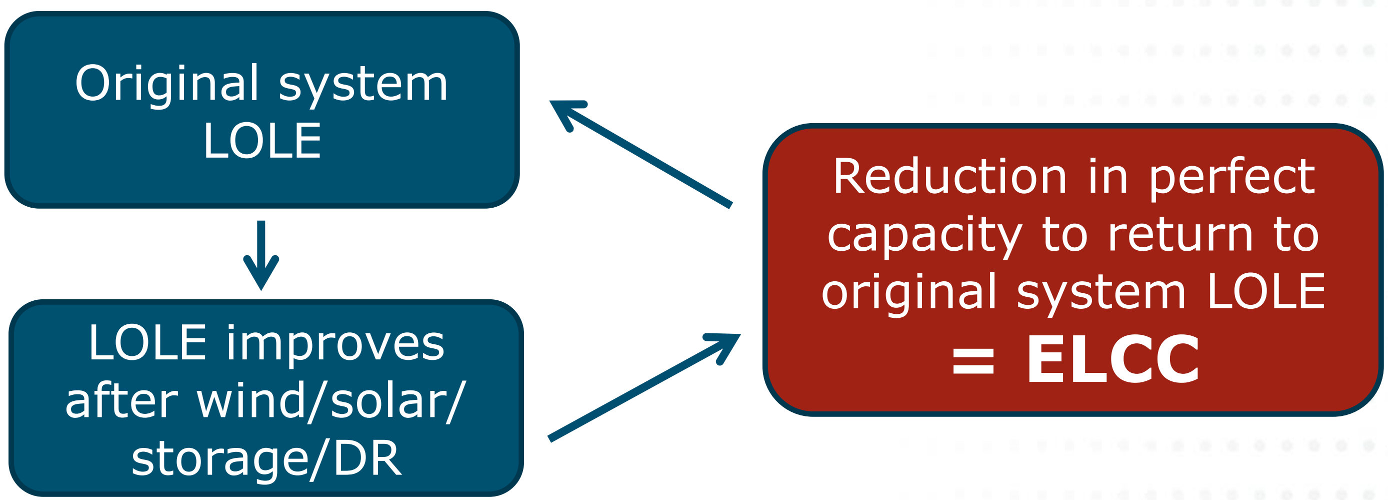
Information about E3's RECAP model can be found here:
https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

RECAP calculates a number of metrics that are useful for resource planning

- **Annual Loss of Load Probability (aLOLP) (%):** is the probability of a shortfall (load plus reserves exceed generation) in a given year
- **Annual Loss of Load Expectation (LOLE) (hrs/yr):** is total number of hours in a year wherein load plus reserves exceeds generation
- **Annual Expected Unserved Energy (EUE) (MWh/yr):** is the expected unserved load plus reserves in MWh per year
- **Effective Load Carrying Capability (ELCC) (%):** is the additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage and demand response)
- **Planning Reserve Margin (PRM) (%):** is the resource margin above 1-in-2-year peak load, in %, that is required in order to maintain acceptable resource adequacy

"ELCC" is used to determine effective capacity contribution from wind, solar, storage and demand response

- Effective load carrying capability (ELCC) is the quantity of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, hydro, storage or demand response while providing equivalent system reliability
- The following slides present ELCC values calculated using the 2050 80% GHG Reduction Scenario as the baseline conditions



2030 Load and Resource Balance

	2030
Load (GW)	
Peak Load (Pre-EE)	50.0
Peak Load (Post-EE)	47.0
PRM	*12%*
PRM	5.0
Total Load Requirement	52.0

Resources / Effective Capacity (GW)	
Coal	8.0
Gas	20.0
Bio/Geo	0.6
Imports	2.0
Nuclear	1.0
DR	1.0
Hydro	19.0
Wind	0.6
Solar	0.2
Storage	0.0
Total Supply	52.0

8 GW new gas capacity needed by 2030

Wind and solar contribute little effective capacity with ELCC* of 9% and 14%

Nameplate Capacity (GW)	ELCC (%)	Capacity Factor (%)
35.0	*56%*	*44%*
7.1	*9%*	*26%*
1.6	*14%*	*27%*

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**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

2050 Load and Resource Balance

	2050		
	80% Reduction	90% Reduction	100% Reduction
Load (GW)			
Peak (Pre-EE)	65	65	65
Peak (Post-EE)	54	54	54
PRM (%)	*9%*	*9%*	*7%*
PRM	5	5	4
Total Load Requirement	59	59	57

Resources / Effective Capacity (GW)				Nameplate Capacity (GW)			ELCC (%)			Capacity Factor (%)		
				80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.
Coal	0	0	0									
Gas	24	20	0									
Bio/Geo	0.6	0.6	0.6									
Imports	2	2	0									
Nuclear	1	1	1									
DR	1	1	1									
Hydro	20	20	20	*35*	*35*	*35*	*58%*	*58%*	*57%*	*44%*	*44%*	*44%*
Wind	7	11	21	*38*	*48*	*96*	*19%*	*22%*	*22%*	*35%*	*36%*	*37%*
Solar	2.0	2.2	7.5	*11*	*11*	*46*	*19%*	*21%*	*16%*	*27%*	*27%*	*27%*
Storage	1.6	1.8	5.8	*2.2*	*4.4*	*29*	*71%*	*41%*	*20%*	*N/A*	*N/A*	*N/A*
Total Supply	59	59	57									

Wind ELCC* values are higher than today due to significant contribution from MT/WY wind

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

Attendees: TAC 3, Tuesday, April 16, 2019 at Avista Headquarters in Spokane, Washington:

John Lyons, Avista; James Gall, Avista; Leona Doege, Avista; Amber Gifford, Avista; Kurtis Kolnowski, AEG; Ken Walter, AEG; Brian Parker, 350.org; John Barber, Rockwood Retirement Community; Doug Howell, Sierra Club; Barry Kathrens, 350.org; Ryan Finesilver, Avista; Clint Kalich, Avista; Dave Van Hersett, Avista Customer; Matt Nykiel, Idaho Conservation League; Amy Wheeless, NW Energy Coalition; Michael Eldred, Idaho Public Utilities Commission; Rachelle Farnsworth, Idaho Public Utilities Commission; Aimee Higby, Washington Utilities and Transportation Commission; Jennifer Snyder, Washington Utilities and Transportation Commission; Xin Shane, Avista; Terrence Browne, Avista; Scott Wilson, Avista; Damon Fisher, Avista; Tracy Rolstad, Avista; John Gross, Avista; Chris Zentz, National Grid; Eric Lee, 4Sight Energy; and Garrett Brown, Avista.

Phone Participants:

Sarah Laycock, Washington State Attorney General's Office plus two others; Mike Starrett, Power Council; Nancy Esteb, NW Energy Coalition; and David Howarth, National Grid Ventures.

These notes follow the progression of the meeting. The notes include summaries of the questions and comments from participants, Avista/Presenter responses are in *italics*, and significant points raised by presenters that are not shown on the slides are also included.

Introductions and TAC 2 Recap, John Lyons

Doug Howell: Request for studies, what has changed? *Some studies, such as those shutting down Colstrip at later dates, may no longer be necessary with the legislative changes.*

Matt Nykiel: Update on the RFP for wind and solar? *Already included using information from the recent RFP.*

Dave Van Hersett: What is the length of the PPA for wind? *20 years with a confidential price that we cannot make public. Lind Solar is also a 20-year PPA. The cost assumption for new wind is in the low $30/MWh range and would roughly be the energy portion of a customer bill.*

Kathlyn Kinney: Is it cheaper than coal? *Hard to compare old/new coal and the attributes. Old coal is an existing sunk costs, lower costs to run, so can be cheaper for an existing coal plant. Also, new coal plants cannot be built under Washington law.*

Regional Legislative Update, John Lyons

Dave Van Hersett: Cow power? *Cow manure in a digester that counts as biomass power.*

1444 requires new electric water storage under the water heater provision.

Doug Howell: Coal-fired provision. 11 million tons of emissions makes me concerned over resources being put into Colstrip. Provisions in the ownership contract not have to pay for, and prolonging the life of the resource.

Dave Van Hersett: I prefer reliable resources that don't raise my rates. Last 40 years effect of forest fires. AVA vs. PSE.

Doug Howell: Cleanup costs Units 3 and 4 expected to be $780 million. Montana AG superfund site which are often 2, 5 or 8 times more expensive to remediate than expected.

Linda Faulkner Gervais: No matter where or how we will continue to discuss the capital costs at Colstrip with the regulators.

Jennifer Snyder: Have you considered modeling the IRP out to 2045? *Yes, we actually look out 25 to 30 years, but have only shown 20 years in the IRP.*

John Barber: The general thrust of Montana is opposite that of Washington. *Yes.*

SB 5116 also has a 2% cost cap for meeting the renewable portion of the law over 4-year blocks to help with hydro variability.

Matt Nykiel: Is there an update on the coal contracts? *Yes, the new mine owners that took over after Westmoreland are honoring the contract through the end of 2019 and we are working on a new contract.*

Dave Van Hersett: What are in the [SB] 5116 rulemakings? *Things such as the 2.5 discount rate for social cost of carbon.*

Matt Nykiel: How prices might increase with coal contract? Are you using scenarios on price for coal. *We expect a new coal contract by the end of the year.*

IRP Transmission Planning Studies, Tracy Rolstad

Doug Howell: [SB] 5116 transmission reliability? *Experience of Federal rules are relatively tight and give us the mechanisms to study it. State laws are a mix of resiliency and reliability. They are probably not going to be more demanding than that table on slide 9.*

Dave Van Hersett: What is a non-wires solution? *Perhaps a battery to discharge. Install and operate series capacitors or reactors to increase power flow on lines or force power* *flow onto other lines to maximize utilization of existing transmission capacity. We want to maximize existing infrastructure with these non-wires solutions.*

Dave Van Hersett: What is the biggest battery? *100 MW in Australia, but it is still in development.*

James Gall: Battery duration is the challenge. Currently 4 hours, maybe up to 6 hours, and we need 8 to 18 hours from a battery.

Location specific is the issue. Placement and duration.

Clint Kalich: Coordination – transformer sits there and performs as needed. Batteries – is this a solution to many of our problems? $200 million versus a $2.5 million solution. *Novel idea, will it find a place where it performs well. The policy is up against the technology. Give us enough money and we will make anything work.*

Clint Kalich: Othello/Lind? *About 800 MW in the queue in this area. There was about 2,000 MW in our RFP and a bunch if it was there.*

Kathlyn Kinney: Looks to me like it makes smaller projects easier to build. *In the past, we have posted on Oasis here are the places where you can plug in certain amounts of generation relatively cheap. Speculative developers can look at this and decide where to go. Small numbers or really powerful parts of our system.*

Jim Le Tellier: How does this work? *We have to respect the queue and layer it on to engage in queue management. On ramps/off ramps for a cluster study or look at it all together instead of first come first served. Take or pay. Can sign a contract for transmission.*

Dave Van Hersett: What is RAS? *Remedial action scheme. Only owner or developer of generation agrees to be tripped for a line loss. Done all over the northwest. It saves the need for a new transmission line. Not really at this time in the IRP process, but rotating machines have bigger impacts of those in play in northwest for 40 years (non-wires solution).*

Doug Howell: Do you have to use it [RAS] often? *It happens, but not often. BPA has saved billions of dollars doing this.*

Dave Van Hersett: Not your distribution, its transmission. How much of an addition to transmission over the next 20 years? *Good question. It depends on where it goes, shaping intermittency. California's load literally goes away during the day, but gets busy at night. BC Hydro sells energy to California to cover the ramp up which could be a challenge in the future. No empirical data yet, but very good modeling. Predictability is quite a bit less now, it's not your grandfather's utility.*

Jim Le Tellier: Fairly represent marginal cost for developers who pay those costs for us. If another utility gets it, then they pay all or some of the network upgrades. *The lumpiness of these upgrades affords opportunities for others.*

James Gall: Small portion of costs relative to the grand scheme of things. Upfront costs amortized over 50 years.

Dave Van Hersett: How does wind/solar affect the timing and different directions of our transmission capability. *It is behaving differently, but still operating. California is going to become a net exporter and we will need to manage hydro differently.*

Distribution Planning within the IRP, Damon Fisher

John Barber (Slide 5, August 10th, 106 degrees): Did load end higher than it began? *The day was hotter than the last and lines cut off by software.*

Damon Fisher (Slide 8): Does the electric car load take away the ability to shift other load at night?

John Barber: You said two Waikiki feeders serve Whitworth area. Rockwood is up there too, when do batteries come in? *That is in the middle of the most vulnerable area.*

Jennifer Snyder: Do we look at one or more coordinated interventions targeted for efficiency, whole package or by measure? *Intend to look at a package. Feeder-by-feeder, considering the costs of all solutions.*

Dave Van Hersett: But the transmission guy said that batteries won't work. *Scale and cost of problems being solved with batteries are different between distribution and transmission.*

Kathlyn Kinney: Curious if storage folks bear cost like Costco. *We have an obligation to serve where we credit them some of the cost of installation. Can't really charge benefits to the whole system.*

Garrett Brown: Schedule 51 line extension tariffs for cost sharing that identifies all of the components.

Slide #9: modest photovoltaic (rooftop solar) assumes 300 installs of 5 kW on feeder, 1.5 MW of solar per feeder.

Doug Howell (Slide 10): There doesn't look to be any advantage to battery cost, is that the full story? *No, do we install a substation for $5 million or a $25 million battery with all of the other benefits it provides? To who and when is the stated value happening? This slide is what it looks like to the distribution system only.*

Conservation Potential Assessment, AEG

James Gall: We have a need based on Grant's load forecast. We want all resources to compete at the same time so they are treated equally. Old way was back and forth where errors could be made and could miss things mathematically.

Jennifer Snyder: Every measure is individual against demand response and generation, peak and energy level.

Clint Kalich: Customized avoided cost. May incentivize them based on cost, but that doesn't account for characteristics rather than lumping them together. Lowering risk instead of iterating.

Barry Kathrens: Do we consider building codes with a solar requirement? *No, we stick to what is on the books.* Why not? *Would need to talk to the legislature, AEG could supply some estimates. Energy efficiency is not as simple since there are real impacts to the distribution system. Could try a scenario.*

Doug Howell: What are TRC and UCT? *Total Resource Cost is used in Washington and Utility Cost Test is used in Idaho. UCT only looks at the portion of cost the utility bears, so we don't include customer benefits like saving water. More potential passes [for programs] because of lower upfront costs.*

Jennifer Snyder (Slide 8): everyone technical 100% (ramp rates with RTF).

Doug Howell: Look at doing a deep retrofit. *That is the finance mechanism, so if cost effective, we could do it. We are present valuing all of the benefits and costs. Bundling all of the benefits.*

Clint Kalich: Maybe we need to meet on this. Public vs. IOU, average low bundle, but a lot of those programs wouldn't fit.

PSE had a solicitation demonstration project [of a deep retrofit].

Jennifer Snyder: Achievement needs to stay cost effective at the portfolio level.

Doug Howell: Washington State study says we need deep efficiency and we are not achieving that by missing the dynamic of how a building operates. This could be encouraged with Avista financing – Housing Finance Corp.

Amy Wheeless: The whole building is not as well captured. *The information is in there.*

James Gall: We ignore how it [efficiency] is being funded. Incentives now, but loan programs in the past.

Ryan Finesilver: We have a team of account executives that look at whole building systems. This is based on more of a simple payback.

James Gall: We are doing something similar with the Catalyst Building

Doug Howell: Hope this is not outside of the IRP. This area is ripe for innovation.

James Gall: I think AEG is already doing this.

Curtis AEG: Possible to be done, but could do it with other studies.

Dave Van Hersett: Is this a government requirement?

Amy Wheeless: There is a bill that would set large building, non-agriculture or industrial – $75 million available if it passes.

Jennifer Snyder: TRC for ductless heat pumps. Did we include 2.5? *Yes.*

Amy Wheeless: Cold weather heat pumps? *Yes, available, but they are five to 10 times more expensive.*

Slide 20. TRC goes negative. It doesn't start at zero from a non-energy saving. Like not paying to replace LEDs as often UCT never goes negative.

EISA – Energy Security Act of 2005. Next backstop in 2020 forces CFLs and LED is the difference between 2019 and 2020. Standard practices will make LEDs the default.

Dave Van Hersett: Do we have data yet for pay for performance vs. estimated savings? *AEG Seattle City Light had this in the September GRAC meeting. We have some site specific information, but didn't have any numbers in mind. Third party EM&V.*

Demand Response Potential Assessment, AEG

Doug Howell: On water heater, doesn't 1444 require to be DR ready? *Port required [on the water heater] to be DR ready. The study does not capture this yet, since not in law now.*

Jennifer Snyder: What about energy efficiency and demand response overlapping potential? *Following the methodology of the Power Council, energy efficiency goes first.*

John Barber: Does this shut off? *Yes, but override and signup on insulated tank is voluntary. Defer reheat until later.*

Kurtis Kolnowski: 85% doesn't apply to DR side, about 25%.

Amy Wheeless: Midwest utilities have been doing more DR when they don't own generation. Will even give a free water heater to customers when you agree to let them control it.

Grant Forsyth (Slide 31): Behavioral – entirely up to the customer. *Yes, suggestion.*

Amy Wheeless: For the October BC event [natural gas transmission line rupture], did you send out a gas event? *Yes for Oregon. No for the electric side. It was a yes for PSE for both.*

Clint Kalich: What gap is third party contract filling in? *Business program targeting medium to large businesses, getting more energy efficiency since often dealing with a facility measure with an intermediary.*

Phone Participant: Similar impacts both ways, but more popular to have a third party. We just pay for megawatts. Third party gets it [energy efficicency]. They can do more hand holding, more cost effective than a utility and have economies of scale doing the programs with more than one utility.

James Gall: Large industrial customers are not on here, but we are doing back up generation as non-spinning reserves similar to the PGE program.

Dave Van Hersett: Where does own electric generation fall? *Based on our own study. Would be used as a non-spinning reserve product that we would turn on if all hell breaks loose.*

Pullman Smart Grid Demonstration Project Review, Leona Doege

Dave Van Hersett: What was the population [of this pilot]? *75 installed out of 3,600 single family homes, but 57 to be called out in DR events.*

Rachelle Farnsworth: So it was a yearlong program? *It Ran from 2012 to August 2014.*

Matt Nykiel: Were these only smart thermostat customers in Washington? *No, both Washington and Idaho. Idaho was added back after adding back gas programs.*

Rachelle Farnsworth: Were there surveys of customers? *Yes, we did a survey.* Did you notice offsets and would you do again? *Very unlikely we would do this again, $400 payment for early participants. We used a local contractor who took two hours per installation.*

Grant Forsyth: Any analysis of age bias of who took meters? *Early tech adopters, not necessarily correlated with age.*

E3 Study – Resource Adequacy in the Pacific Northwest, James Gall

This assumes the system operates as a single utility.

John Barber: Why not Nevada? *It was a choice because at the time of the study, they were voting on retail choice so they would have operated like California. They have since voted this down.*

Rachelle Farnsworth: Hydro? *Same.*

Barry Kathrens: Climate, should we assume to be more pessimistic? *Assuming same historical data using 80-year record. May change water shape and make it more volatile with warming temperatures.*

Dave Van Hersett (Slide 22): 2050 baseline is the load we have to meet. *Yes.*

Jennifer Snyder (Slide 25): So 60% in red can be achieved for little or no cost. *Yes, using the current trajectory for technology.*

Barry Kathrens: Using constant costs? *No, using declining costs.*

Dave Van Hersett: Generation and transmission only? *Yes.*

Jim Le Tellier: What does this compare to California?

AEG: High cost is about what we find in comparison to California.

James Gall: $2,200 to $4,000 to convert to an all-electric home.

Dave Van Hersett: What would drive me out? Cost. *Converting all heating to natural gas and everything else to electric may be a cheaper way to reduce emissions.*

Clint Kalich (Slide 22): Interesting how economic. Societally, where should the dollars be spent? It may be better spent in other areas.

2020 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 4 Agenda

Tuesday, August 6, 2019
Conference Room 130

Topic	**Time**	**Staff**
Introductions and TAC 3 Recap	9:00	Lyons
Washington SB 5116 and IRP Updates	9:10	Lyons
Energy and Peak Load Forecast Update	9:30	Forsyth
Natural Gas Price Forecast	11:00	Pardee
Lunch	12:00	
Electric Price Forecast	1:00	Gall
Existing Resource Overview	2:00	Lyons
Final Resource Needs Assessment	3:00	Lyons
Adjourn	4:00	

2020 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
August 6, 2019

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next twenty years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

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 while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - June 15, 2019 at the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

TAC #3 Recap – April 16, 2019

- Introductions and TAC 2 Recap, Lyons
- Regional Legislative Update, Lyons
- IRP Transmission Planning Studies, Rolstad
- Distribution Planning Within the IRP, Fisher
- Conservation Potential Assessment, AEG
- Demand Response Potential Assessment, AEG
- Pullman Smart Grid Demonstration Project, Doege
- E3 Study – Resource Adequacy in the Pacific Northwest, Gall

- Meeting minutes available on IRP web site at: https://www.myavista.com/about-us/our-company/integrated-resource-planning

Today's Agenda

9:00 – Introductions and TAC 3 Recap, Lyons

9:10 – Washington SB 5116 and IRP Updates, Lyons

9:30 – Energy and Peak Load Forecast Update, Forsyth

11:00 – Natural Gas Price Forecast, Pardee

Noon – Lunch

1:00 – Electric Price Forecast, Gall

2:00 – Existing Resource Overview, Lyons

3:00 – Final Resource Needs Assessment, Lyons

4:00 – Adjourn

Future TAC Topics

- TAC 5: Tuesday, October 15, 2019
  - Ancillary services and intermittent generation analysis
  - Energy Imbalance Market analysis
  - Review Preliminary PRS
  - Market scenario results
  - Preliminary Portfolio scenario results

- TAC 6: Tuesday, November 19, 2019
  - Review of final PRS
  - Market scenario results (continued)
  - Final Portfolio scenario results
  - Carbon cost abatement supply curves
  - 2020 IRP Action Items

Washington SB 5116 and IRP Updates

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
August 6, 2019

Clean Energy Transformation Act (CETA)

- E2SSB 5116 Clean Energy Transformation Act (CETA)
- No coal serving Washington customers after 2025 or earlier
- Carbon neutrality beginning in 2030
  - 80% or greater clean energy requirement
  - Alternate compliance options for up to 20%
  - Penalties for non-compliance unless out of utility’s control or for reliability
  - Four-year compliance periods beginning with 2030-33
- 100% clean energy 2045
- 2% incremental cost cap
- Many areas of additional rule making are required and discussed later

Other CETA Provisions

- A utility extending service to new customers through condemnation must comply with the clean energy standard and Energy Independence Act (EIA)
- Utilities must assess and plan for obtaining enough funds to meet 60% of low-income energy assistance need by 2030 and 90% by 2050
- By January 1, 2022, the company must begin filing four-year clean energy implementation plans with the UTC
- Affirms the UTC authority to use alternative ratemaking mechanisms
- Clarifies the identification of used and useful property during a rate period for up to four years
- Allows deferred accounting for up to three years for major projects in a utilities clean energy action plan as part of its IRP
- Allows an imputed return on power purchase agreements of no less than the cost of debt and no more than the authorized rate of return
- Includes federal incremental hydroelectricity in the definition of an eligible renewable resource under the EIA
- Extends sales and use tax breaks for renewable resource until 2030 provided specific labor standards are met

CETA Rule Making

- WUTC opened Docket U-190485 for implementation of legislation passed in the 2019 legislative session
- Phase 0: July 1, 2019 to August 30, 2019
  - Initiate rulemaking processes
  - Docket U-190531: Inquiry into Valuation of Public Service Company Property Used and Useful after Rate Effective Date
  - Timeline finalized after public comment
  - Close IRP Rulemaking Docket No. U-161024, incorporate IRP procedural rules, RFP rules and Distributions System Planning in this docket
- Phase 1: August 2019 to January 1, 2021
  - Results due by January 1, 2021
- Phase 2: Beginning January 1, 2021
  - Results due on or before June 30, 2022

Phase 1

- Publication of social cost of carbon with inflation rate
- Issue policy statement for Valuation of Public Service Company Property Used and Useful after Rate Effective Date (U-190531)
- Start four rulemakings and one policy statement
- IRP Updates
  - IRP inputs, structure, public involvement process, outputs of Clean Energy Action Plans, social cost of carbon, equitable distribution of benefits, and assessment informed by cumulative impact analysis
- Used and useful standard policy statement
- EIA rulemaking
  - Equitable distribution, definitions of low-income and energy assistance need, low-income efficiency target, and updated hydro eligibility and tracking
- Clean Energy Implementation Plan (CEIP) rulemaking
  - Guidelines, equitable distribution of benefits, and incremental cost methodology
- Acquisition rulemaking
  - Existing RFP work, ensure new standard met for construction and acquisition of property and the provision of electric service, and resource adequacy

Phase 2 and Additional Projects

Start four rulemakings

1. Cumulative impact analysis
2. Carbon and electricity markets
3. Natural gas conservation
4. Natural gas IRP

Additional projects without statutory deadlines

- Interconnection standard
- Capital budgeting
- Distribution system planning
- Reliability and resiliency
- Demand response policy statement
- Pricing signals policy statement
- Pilot projects policy statement
- Rate making adequacy inquiry

Load and Economic Forecasts: Redux

Grant D. Forsyth, Ph.D.
Chief Economist
Fourth Technical Advisory Committee Meeting
August 6, 2019

Main Topic Areas

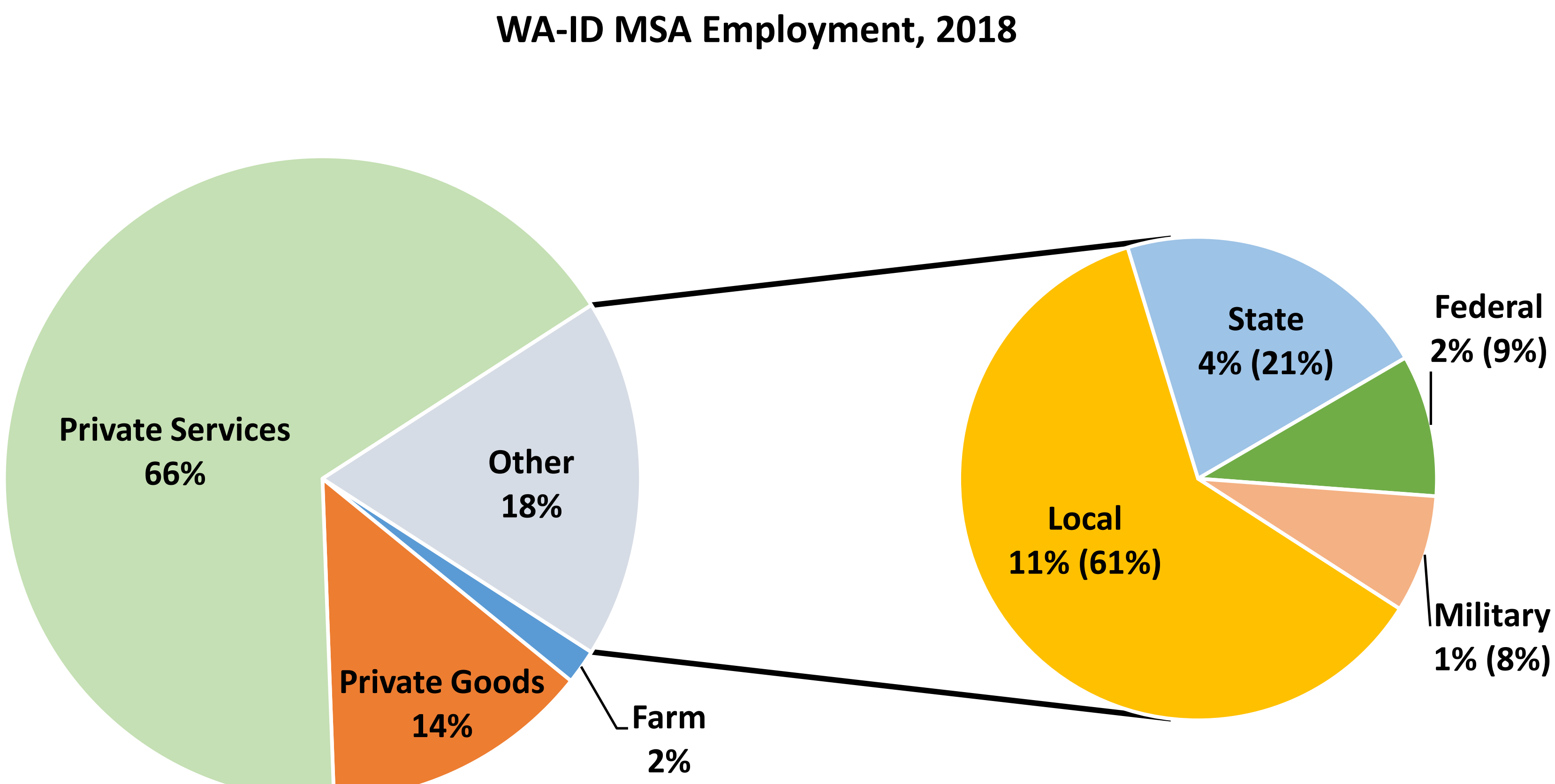
- **Service Area Economy**
- **Peak Load Forecast**
- **Long-run Forecast**

Painting: Jan Steen, 1640, Netherlands. *As the Old Sing, Pipe the Young.*

Service Area Economy

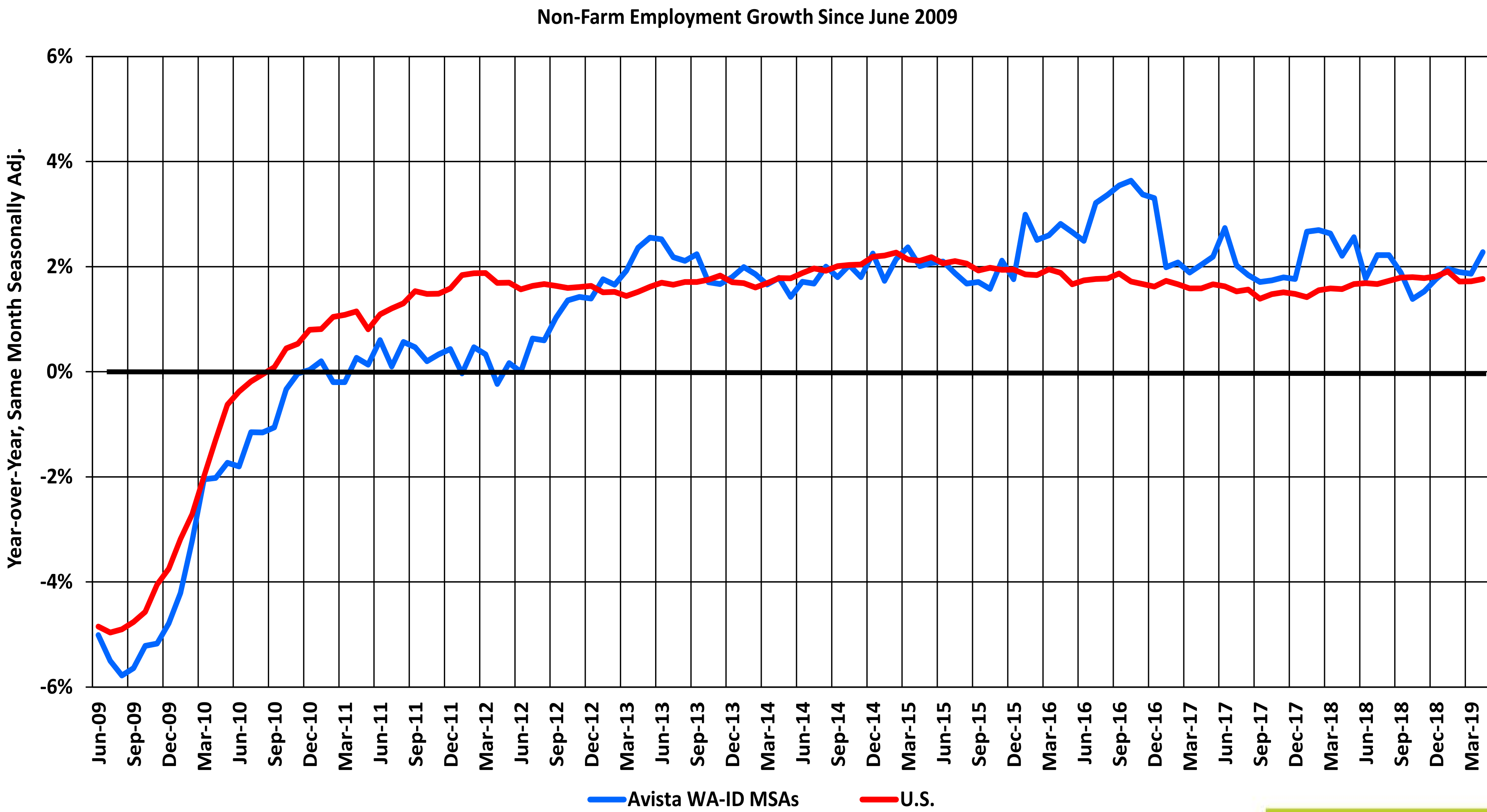
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Distribution of Employment: Services and Government are Dominant



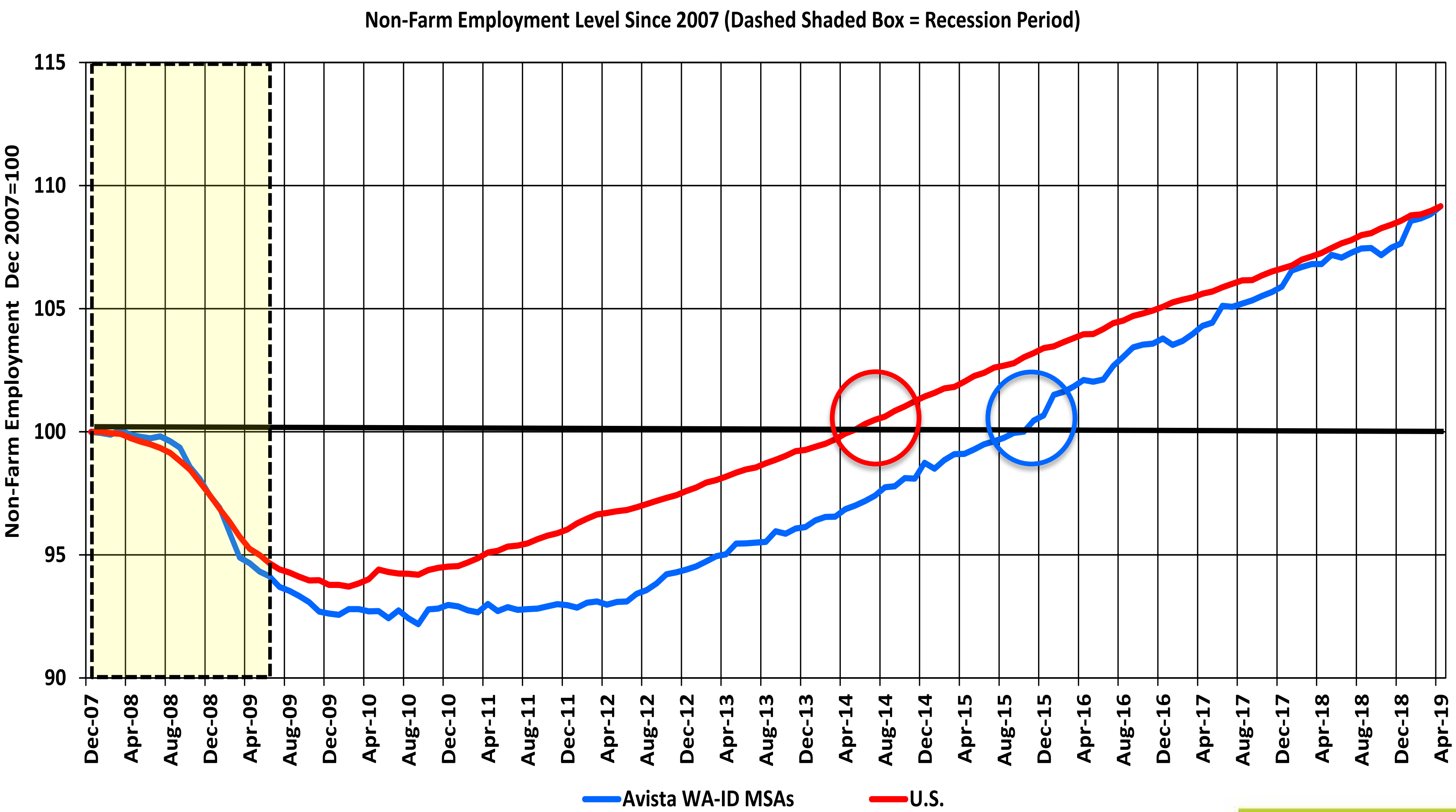
Source: BLS, BEA and author's calculations.

Non-Farm Employment Growth, 2009-2019



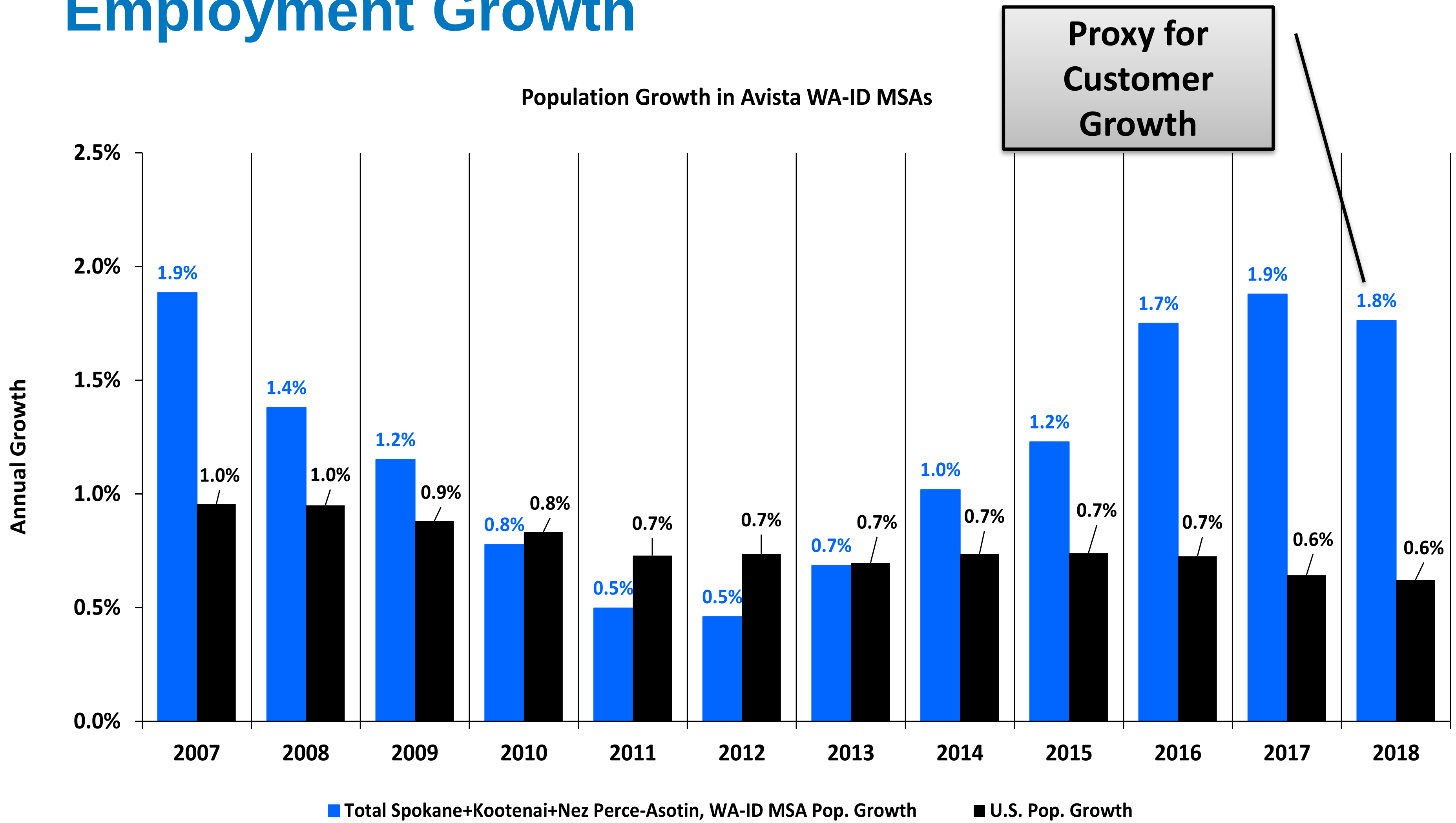
Source: BLS and author's calculations.

Non-Farm Employment: Finally Catching Up



Source: BLS and author's calculations.

Population Growth: 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.

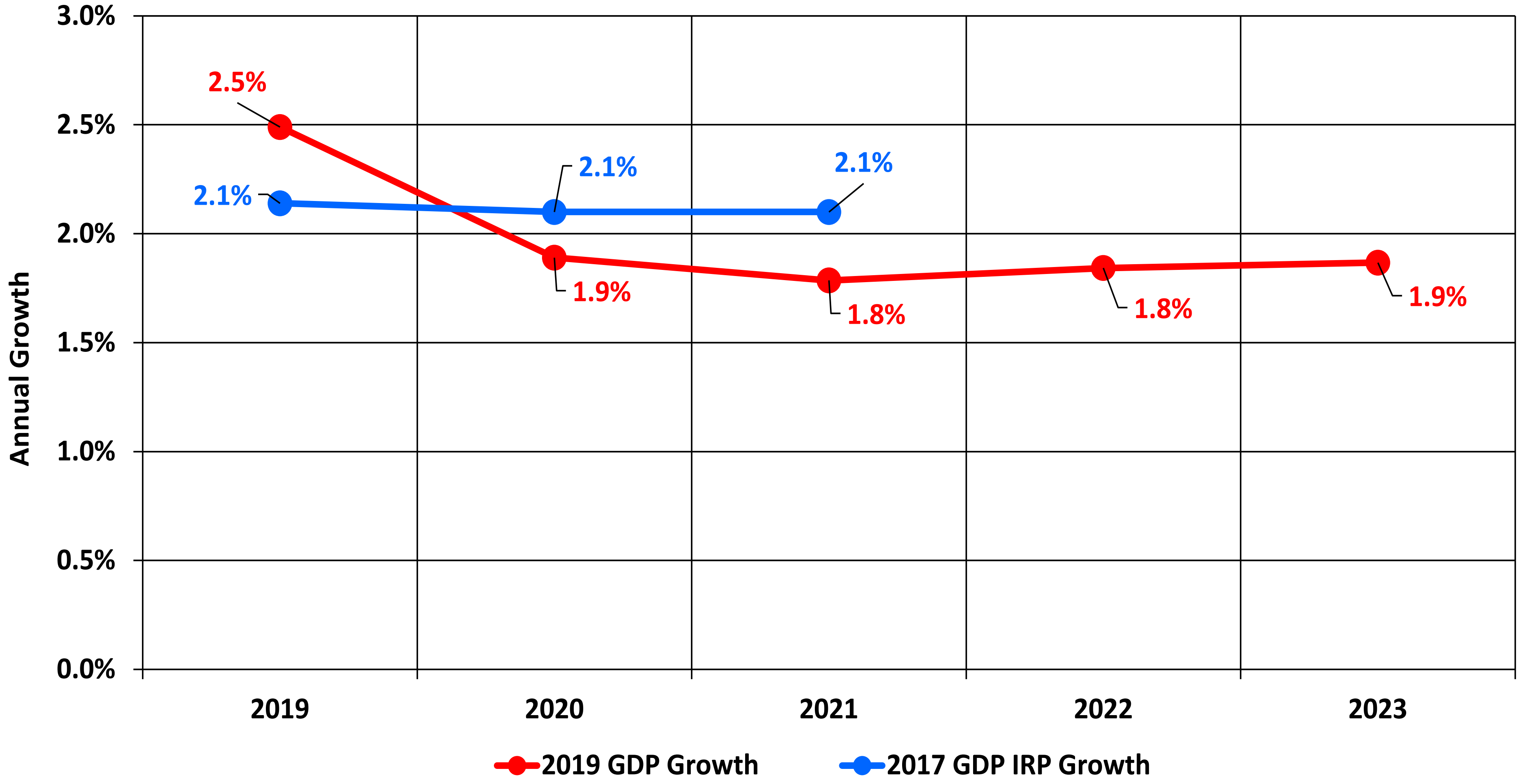
- Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.

- 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. ***Model was recently recalibrated to allow GDP impact to differ between winter and summer.*** 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., 2019). Model confirms Avista is a winter peaking utility for the forecast period; however, the summer peak is growing at a faster than the winter peak.

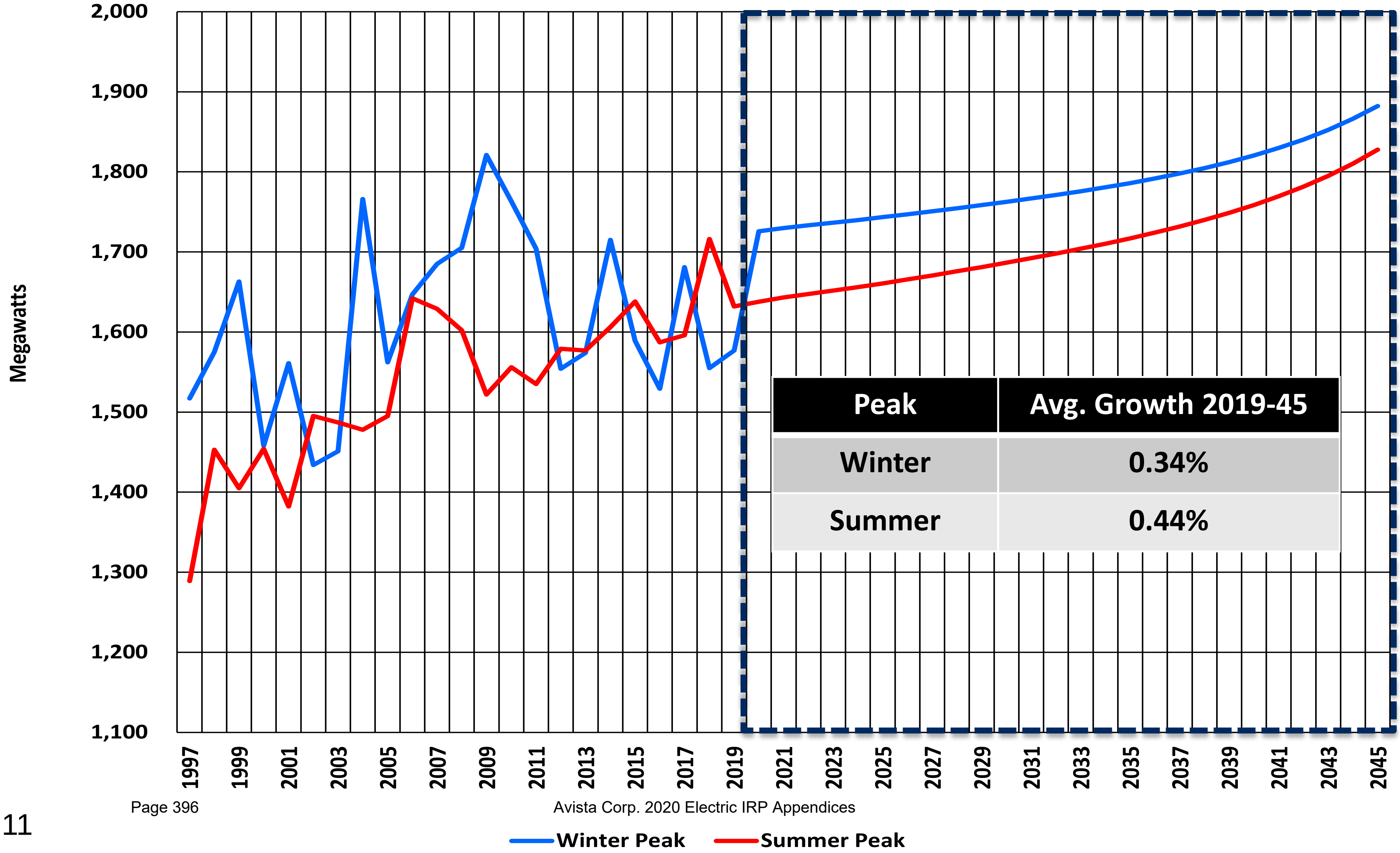
- The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "*ceteris paribus*" assumption for weather and other factors.

GDP Growth Assumptions: 2019 IRP vs. 2017 IRP



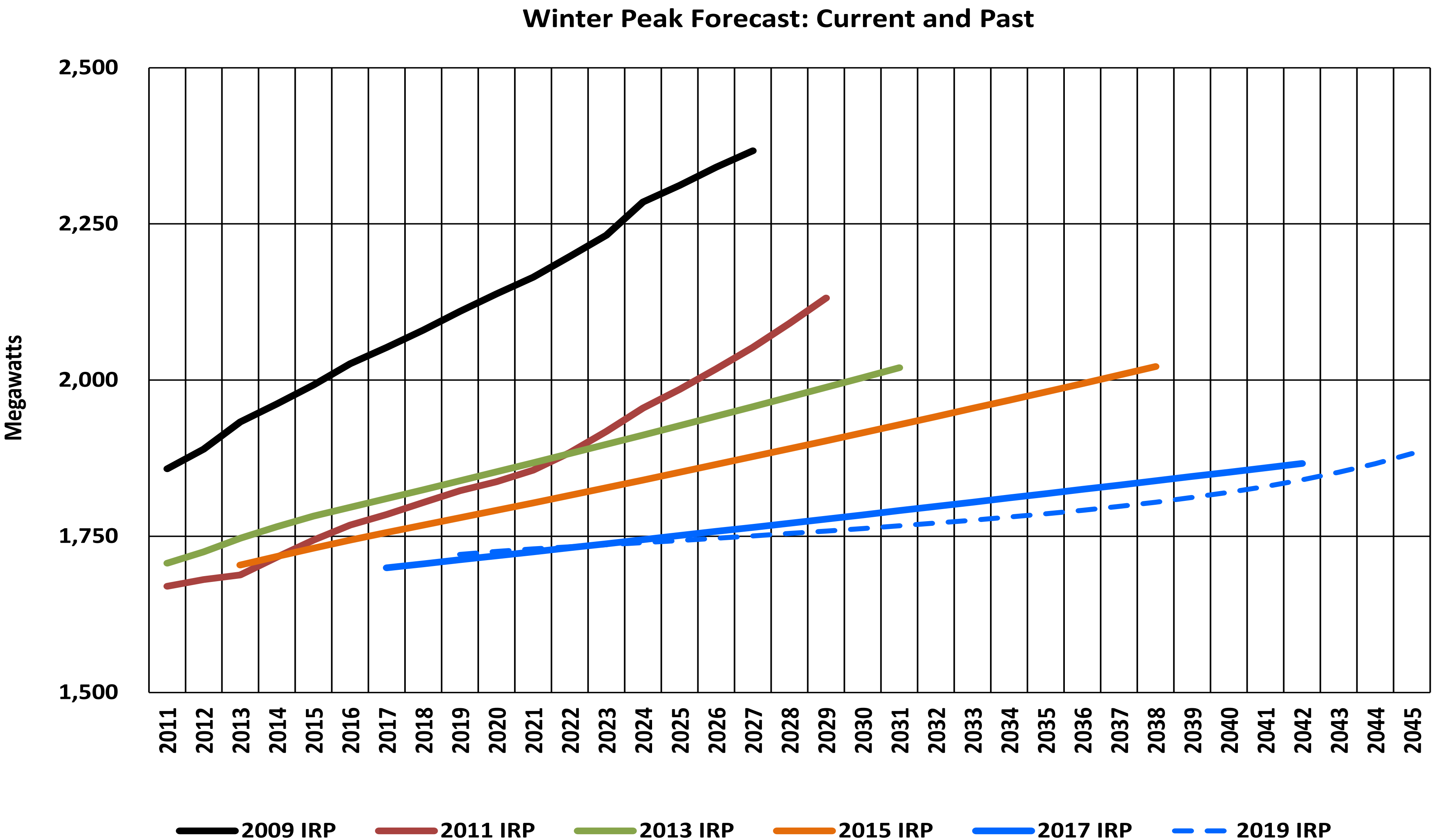
Source: Various and author's calculations.

Current Peak Load Forecasts for Winter and Summer, 2019-2045

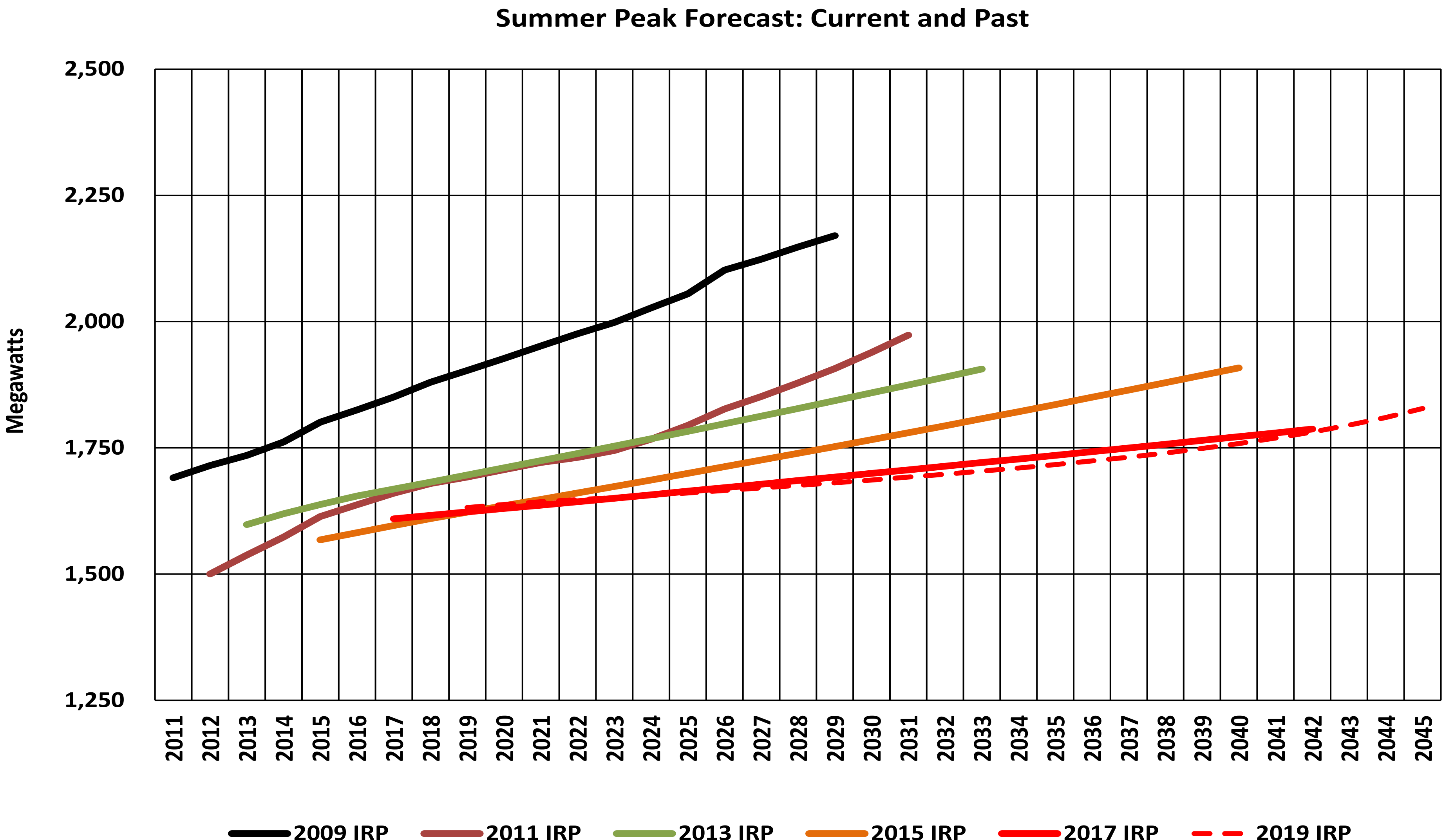


Peak	Avg. Growth 2019-45
Winter	0.34%
Summer	0.44%

Current and Past Peak Load Forecasts for Winter Peak, 2011-2043



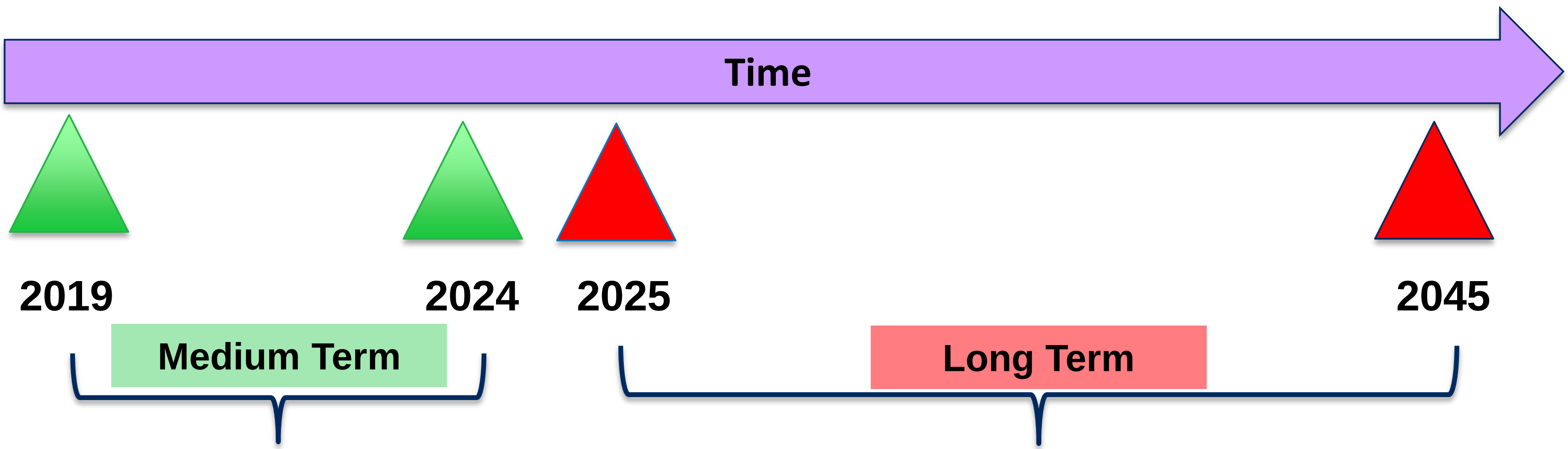
Current and Past Peak Load Forecasts for Summer Peak, 2011-2045



Long-Term Load Forecast

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

Basic Forecast Approach



1) Monthly econometric model by schedule for each class.
2) Customer and UPC forecasts.
3) 20-year moving average for “normal weather.”
4) Economic drivers: GDP, industrial production, employment growth, population, price, natural gas penetration, and ARIMA error correction.
5) 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, EV/PHEVs, and natural gas penetration.

The Long-Term Residential Relationship, 2020-2040

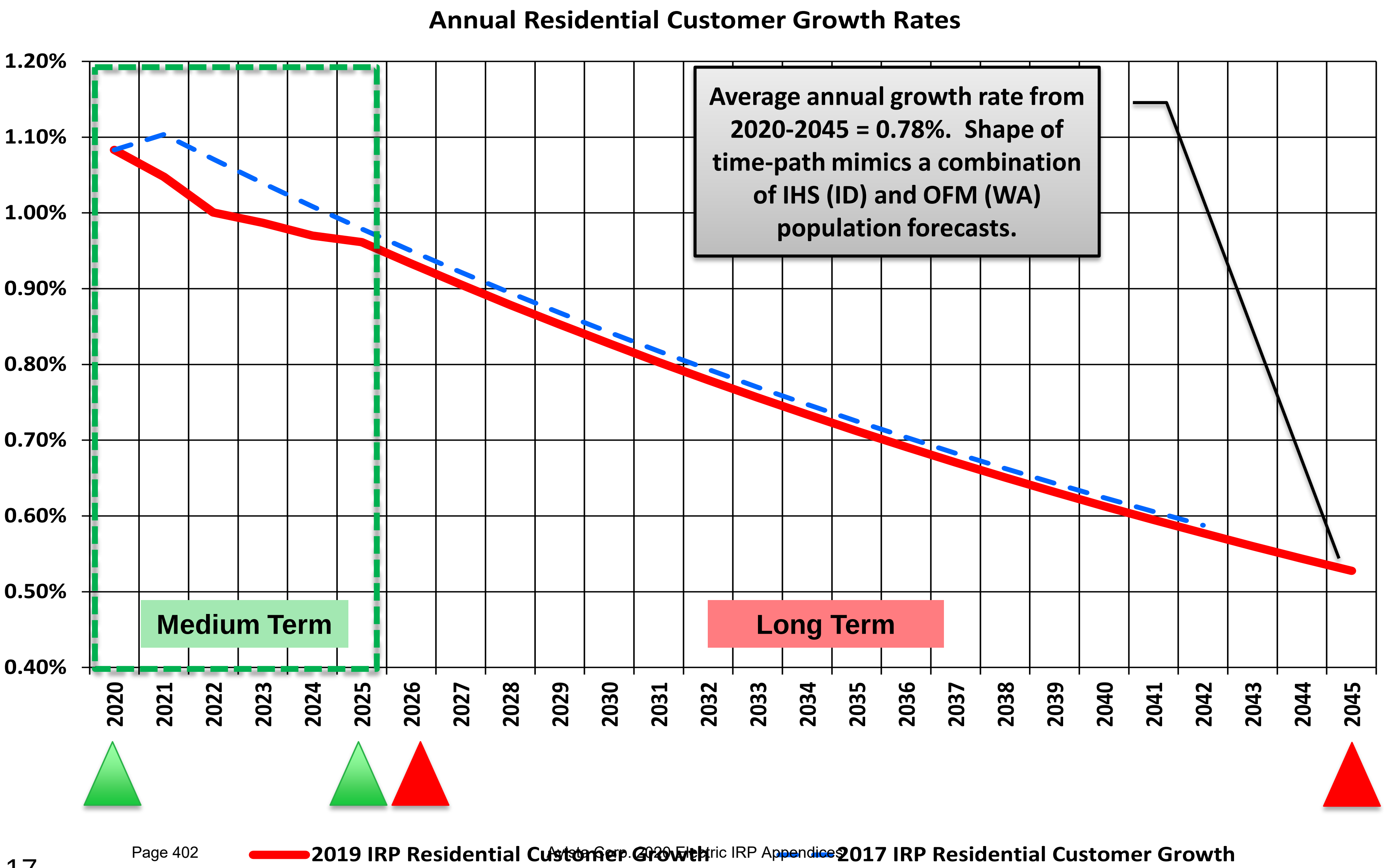
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

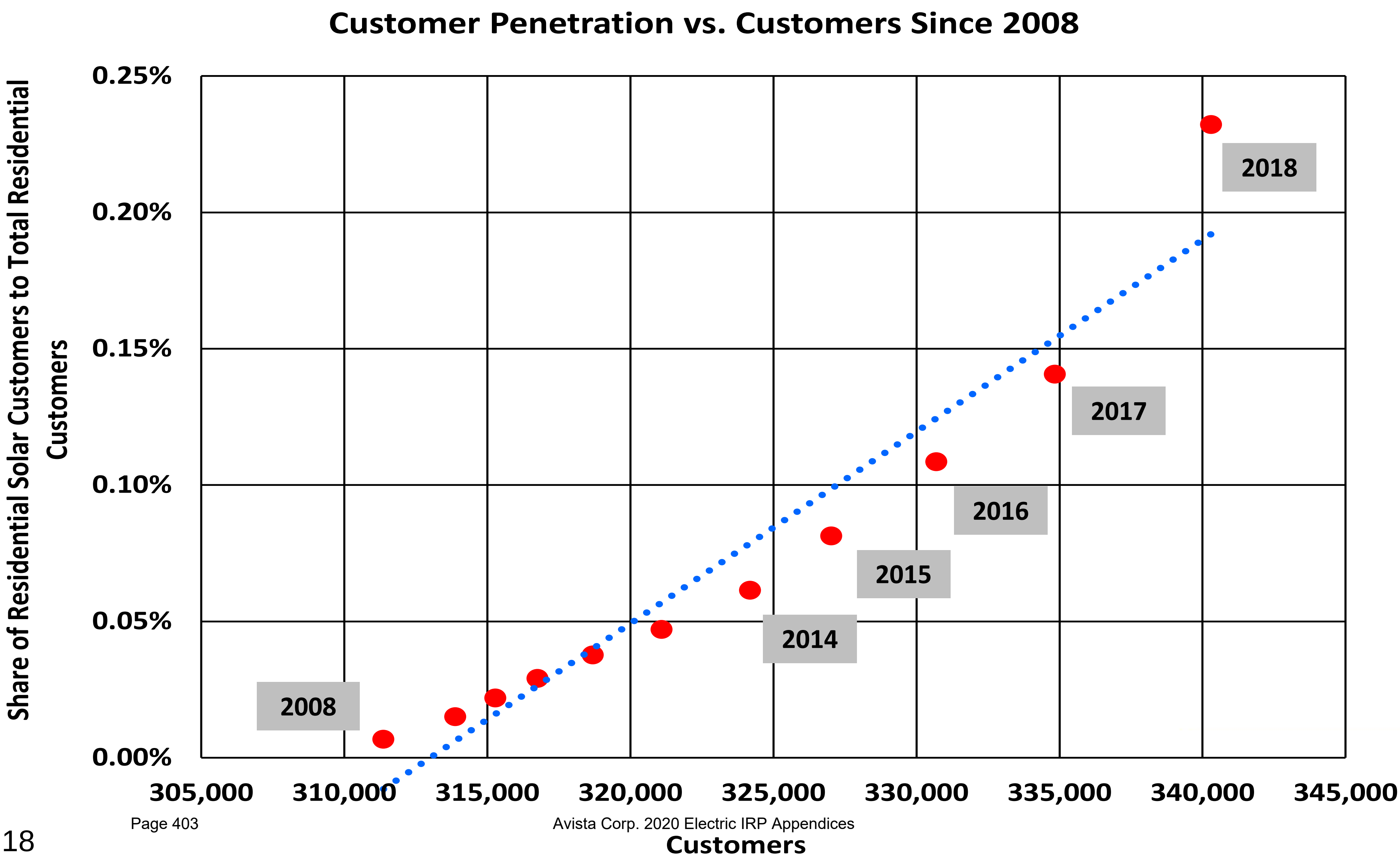
Assumed to be same as population growth, commercial growth will follow residential, and slow decline in industrial.

Assumed to be a function of multiple factors including renewable penetration, gas penetration, and EVs/PHEVs.

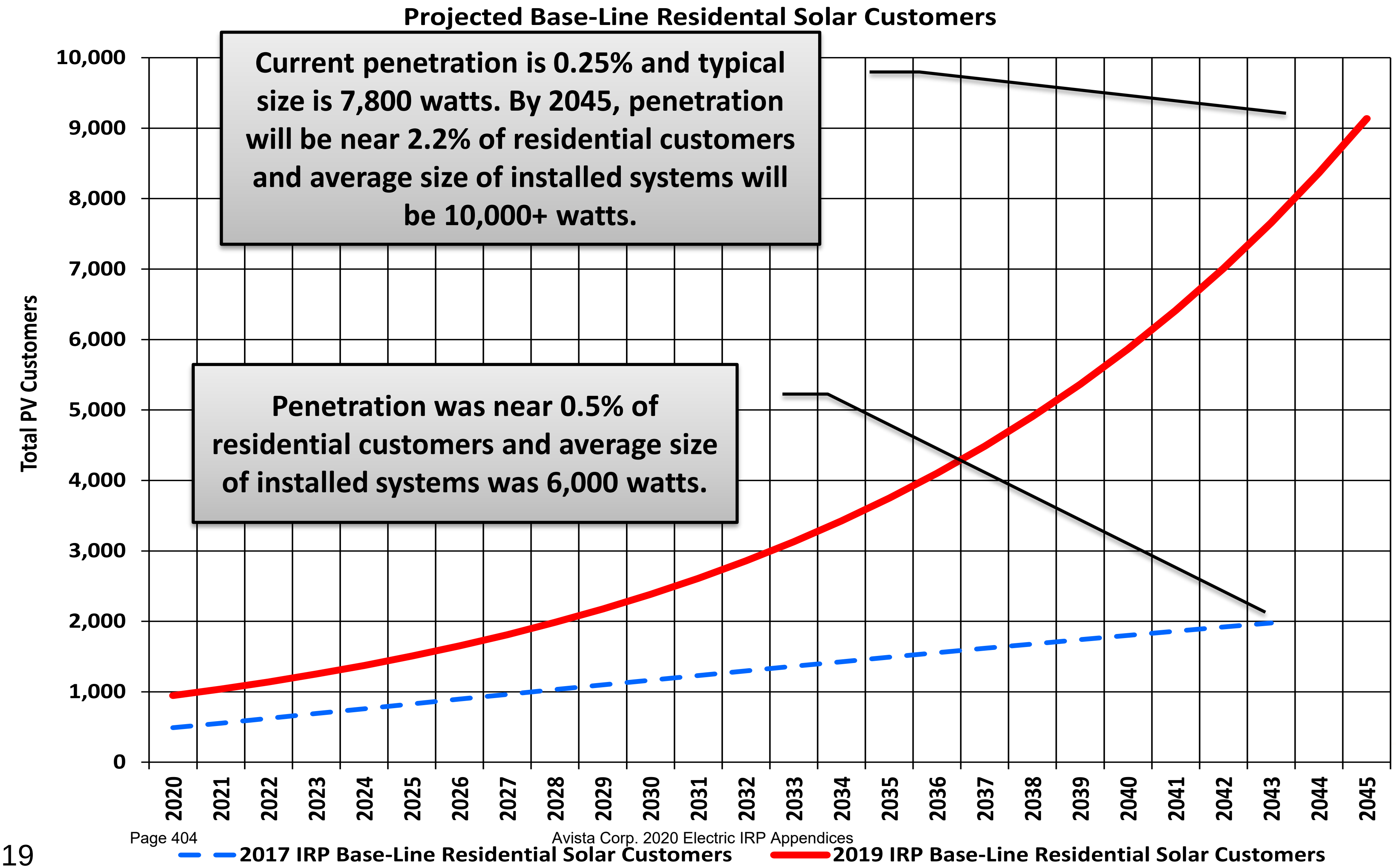
Residential Customer Growth, 2020-2045



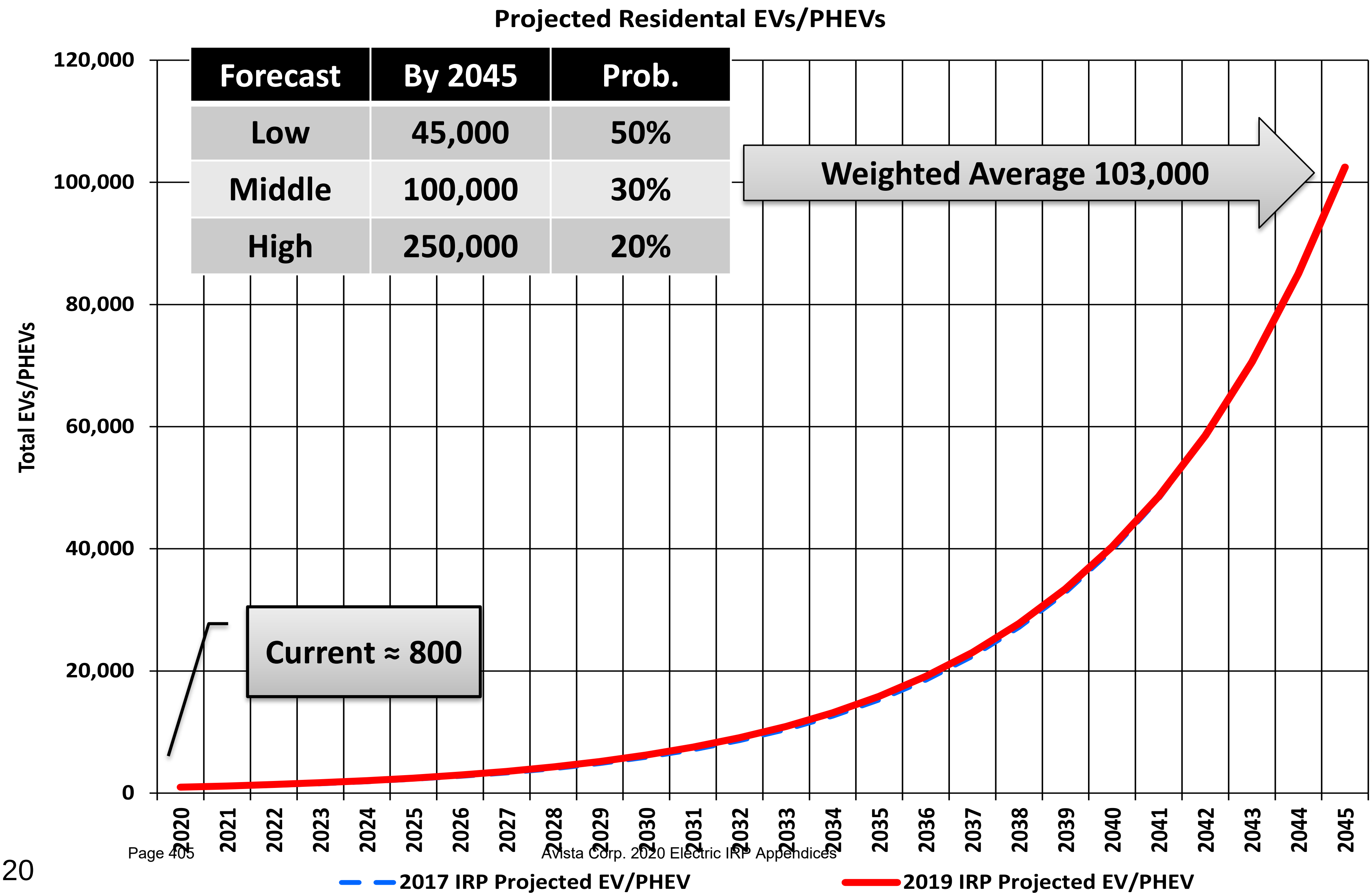
Residential Solar Penetration, 2008-2018



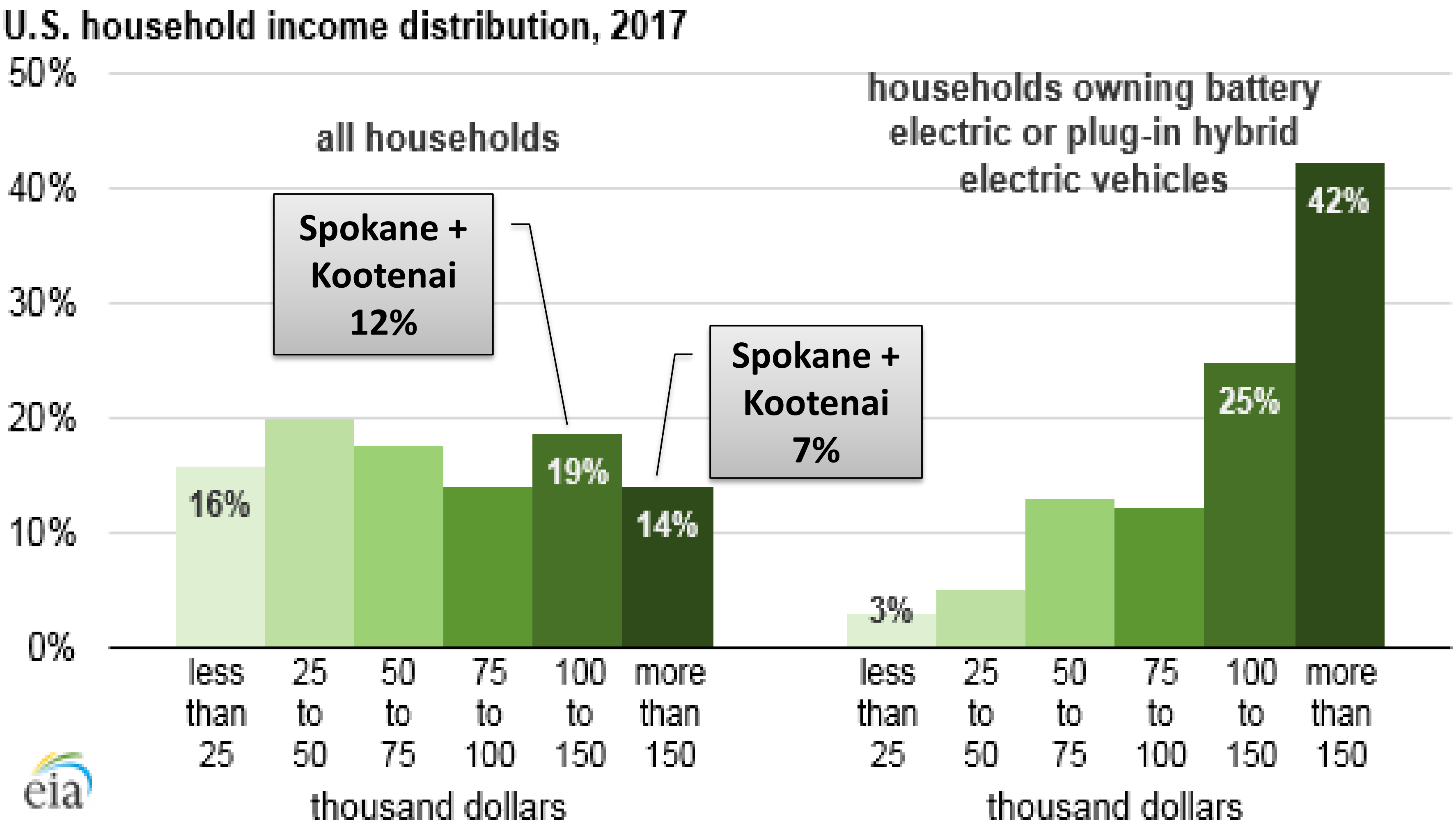
Residential Solar Penetration, 2020-2045



Residential EVs/PHEVs, 2020-2045

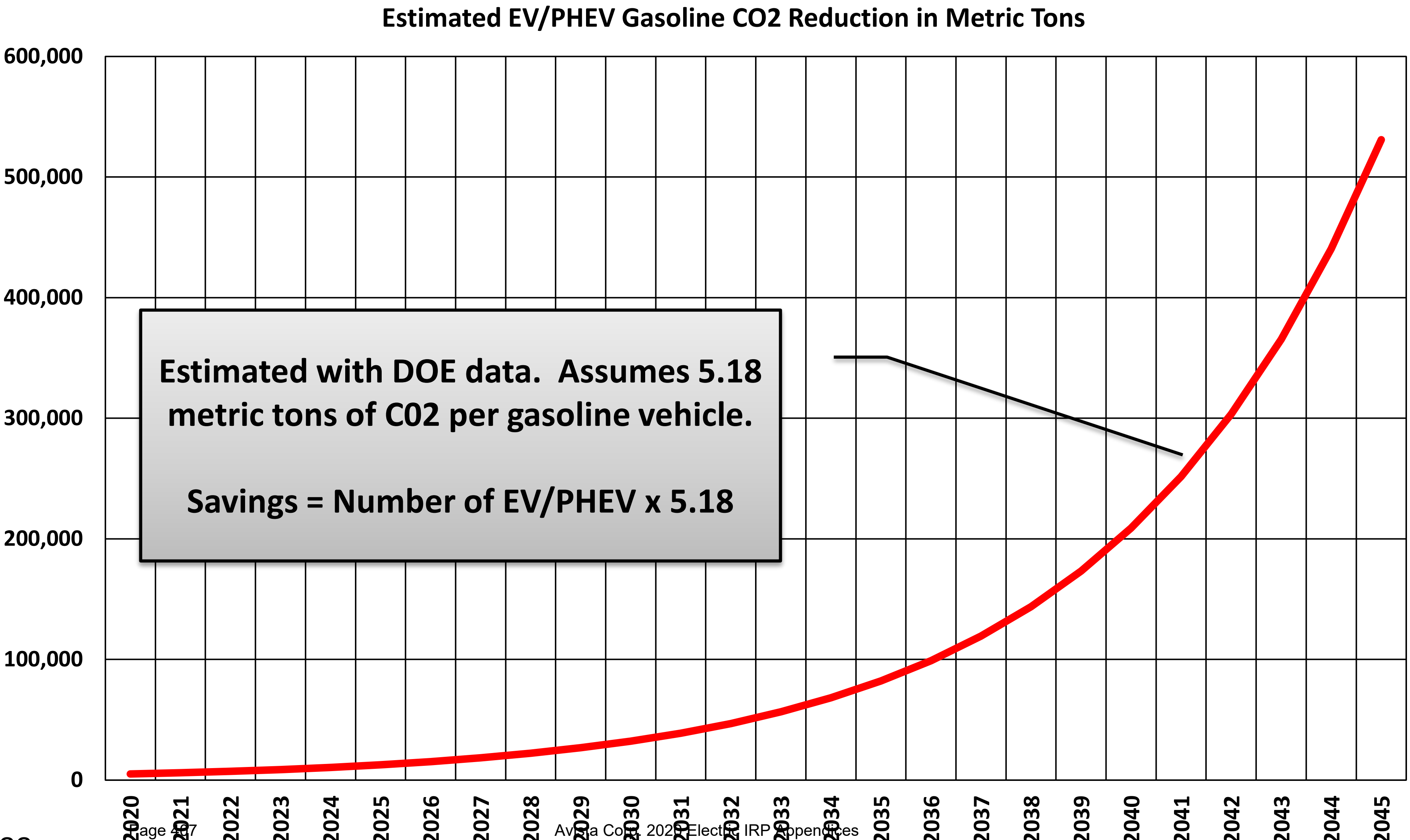


Residential EVs/PHEVs by Household Income

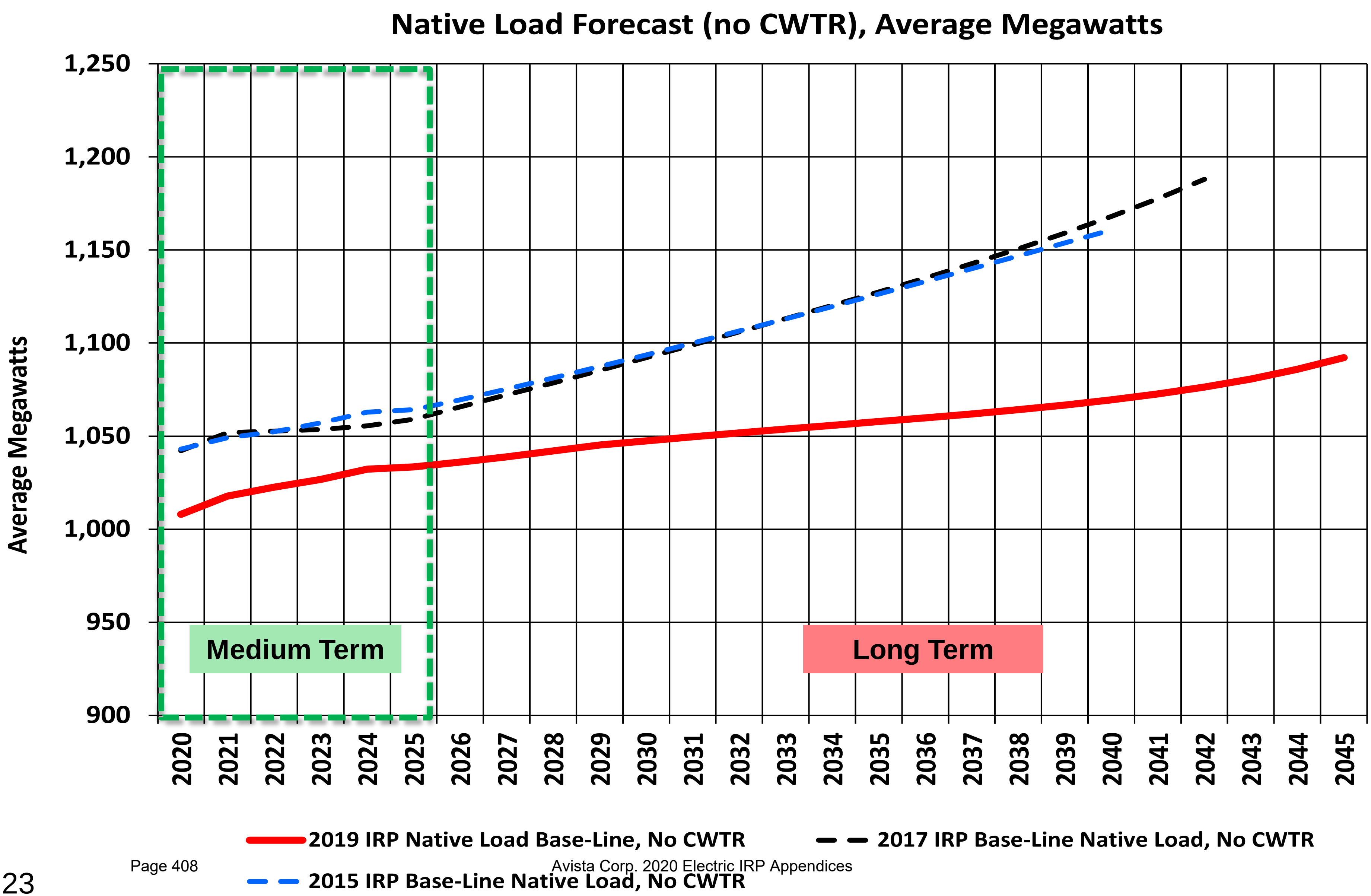


Source: EIA, *Today in Energy*, May 2018. Regional data from U.S. Census

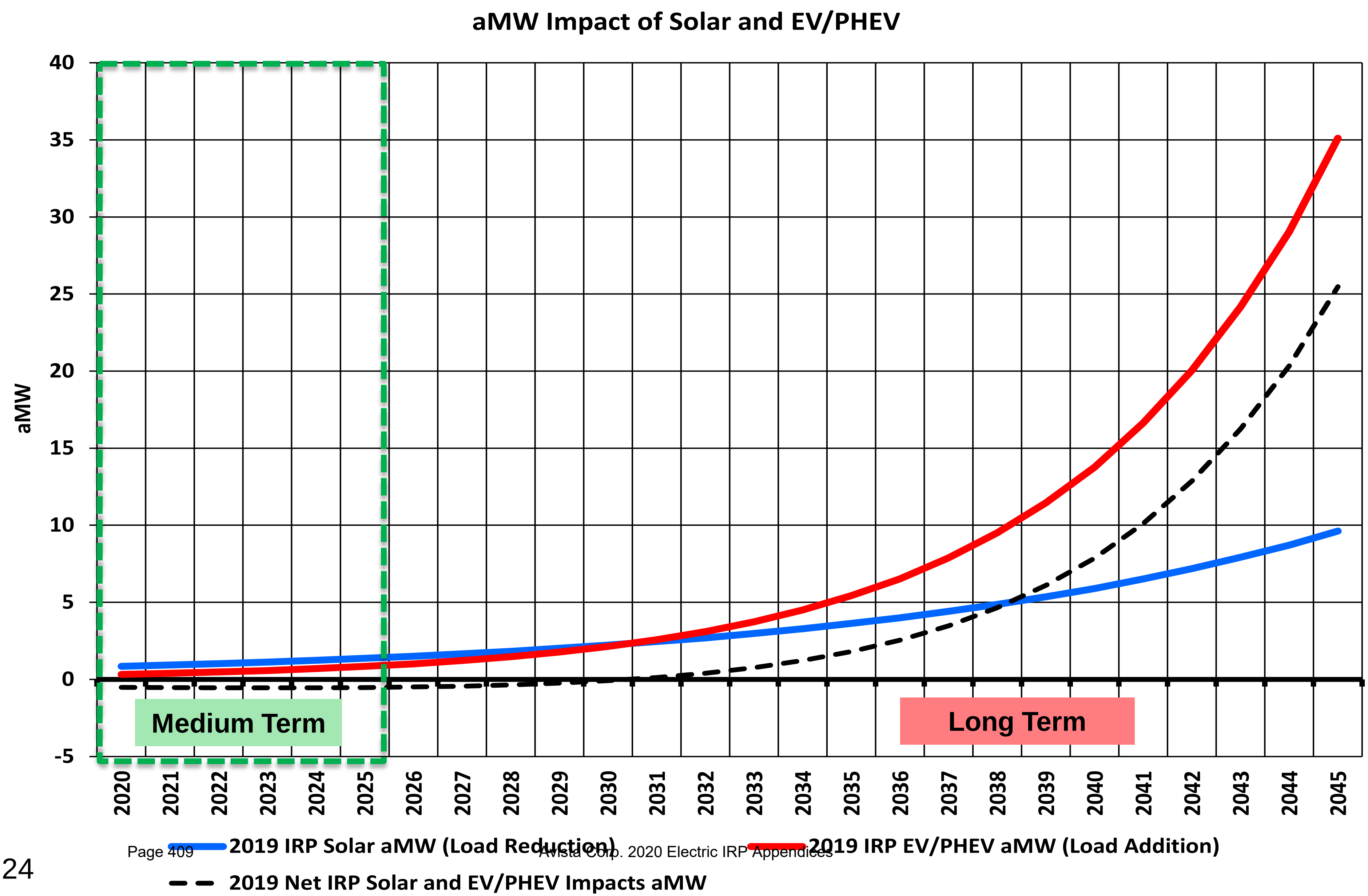
EV/PHEV Gasoline CO2 Savings Avista Service Territory



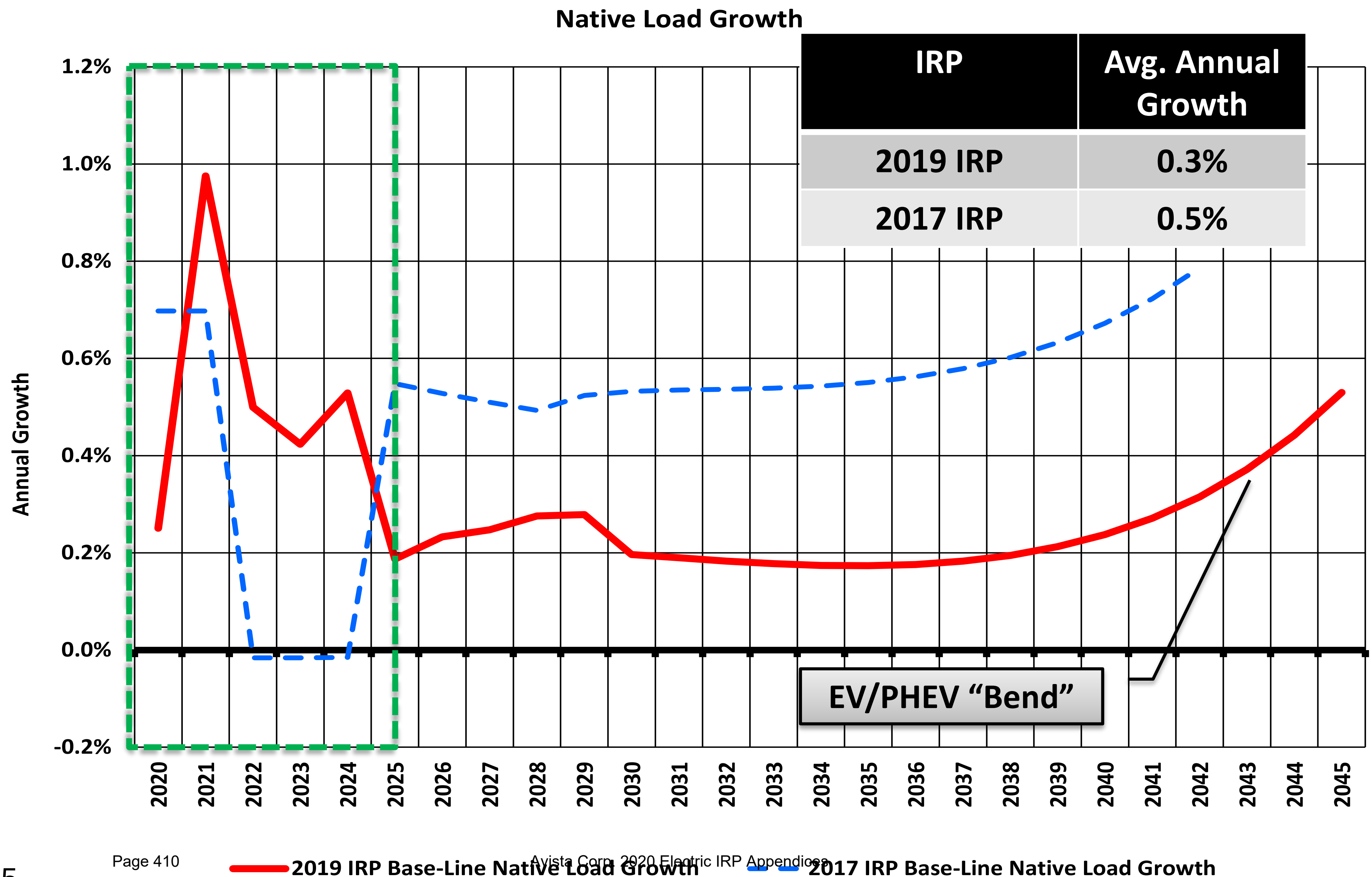
Native Load Forecast, 2020-2045



Net Solar and EV/PHEV Impact, 2020-2045

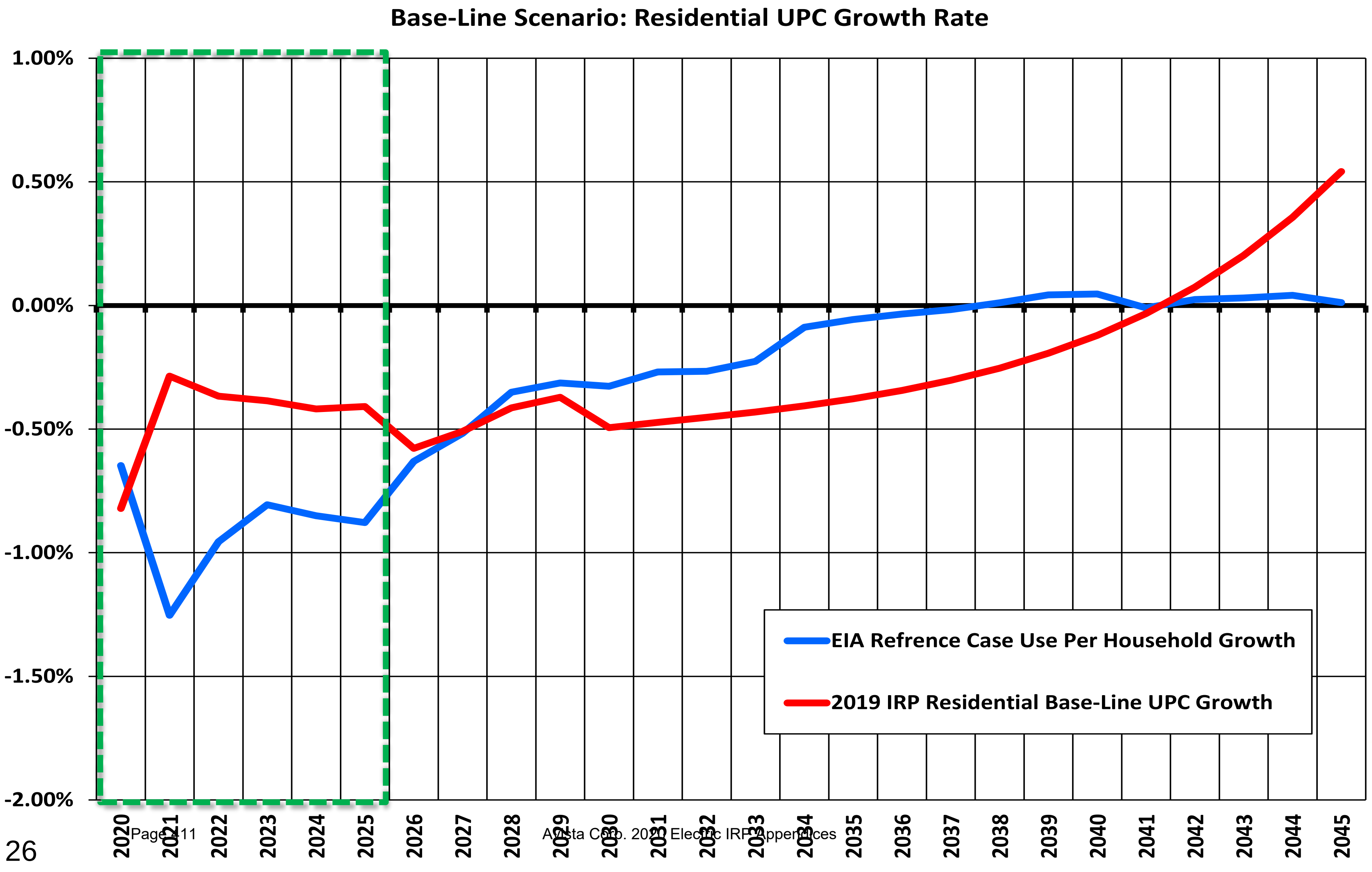


Native Load Growth Forecast, 2020-2045



IRP	Avg. Annual Growth
2019 IRP	0.3%
2017 IRP	0.5%

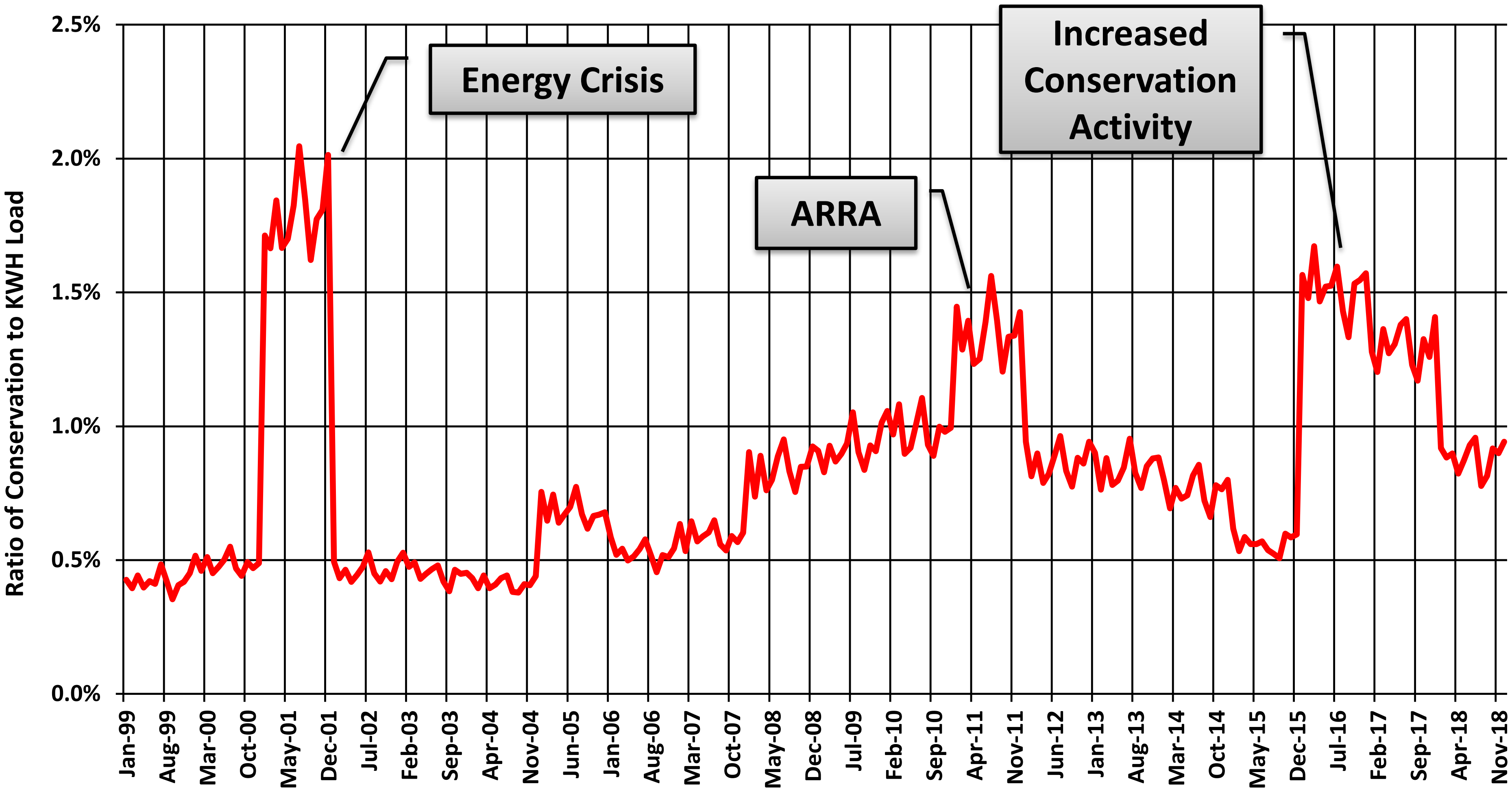
Residential UPC Growth: 2020-2045



Long-Term Load Forecast: Conservation Adjustment

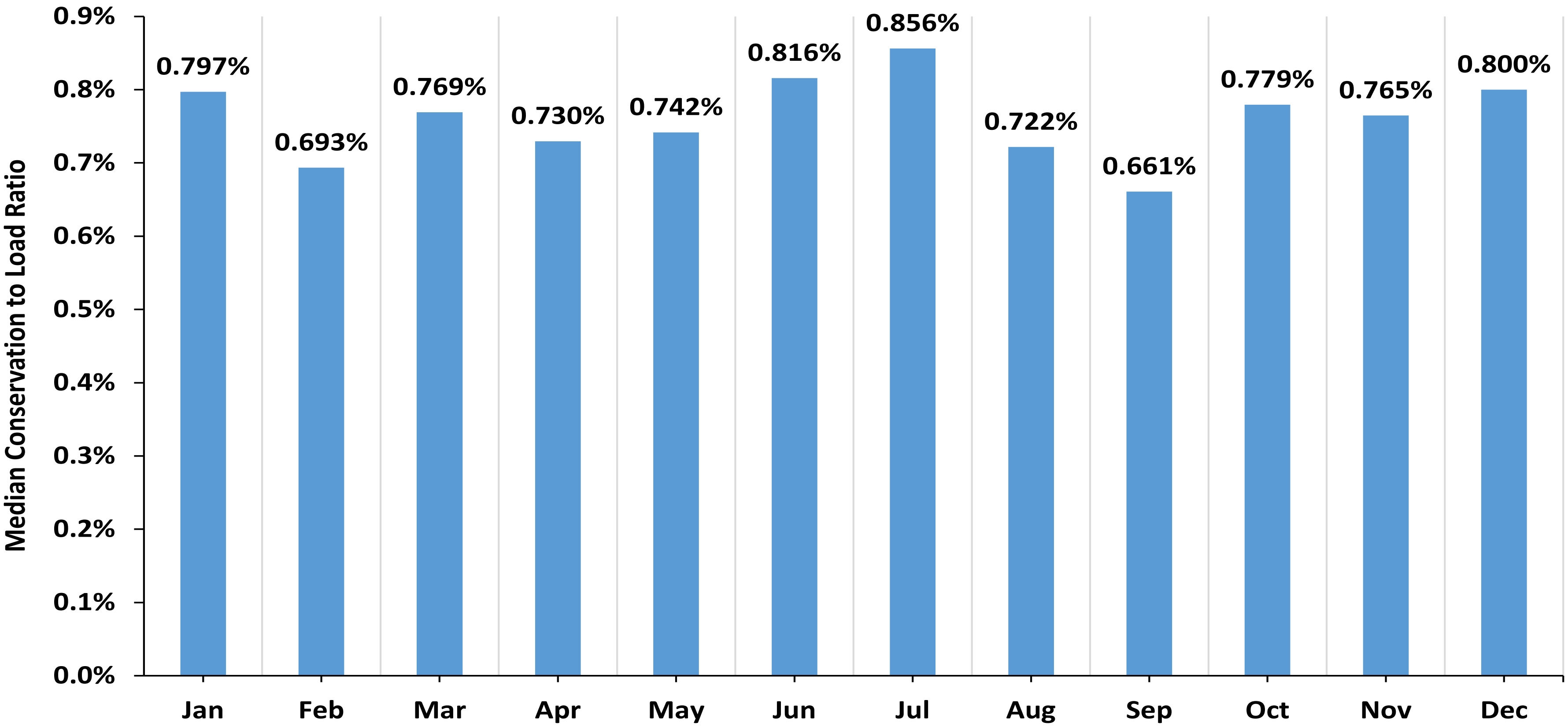
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



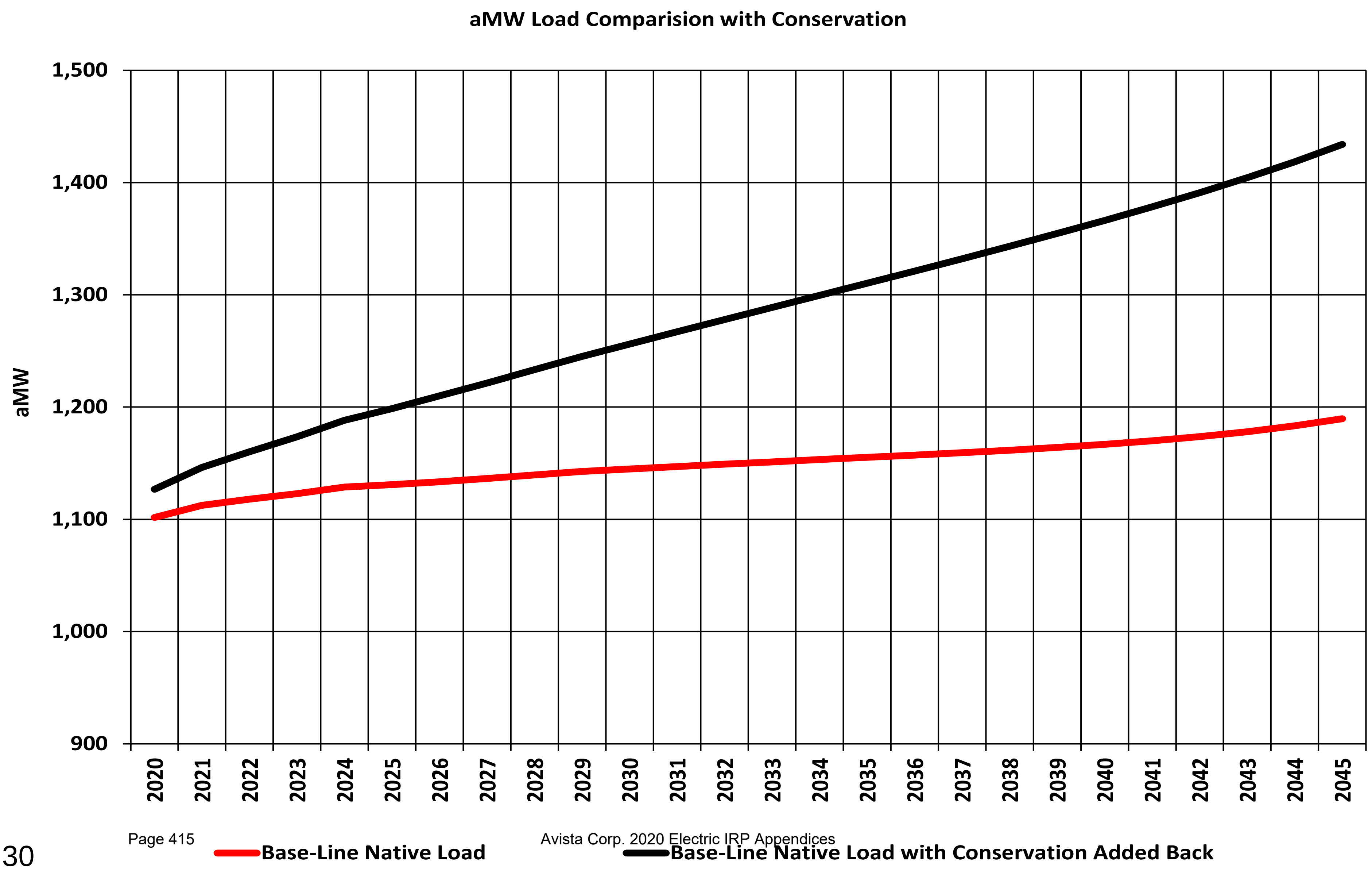
$$\text{Ratio} = \frac{Estimated\ Conservation\ Month\ t, Year\ y}{Actual\ KWH\ Load\ Month\ t, Year\ Y}$$

Median Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



$$Median\ Ratio\ Month\ t = Median\left(\frac{Estimated\ Conservation\ Month\ t}{Actual\ KWH\ Load\ Month\ t}\right),\ excluding\ 2001$$

Comparison of Native Load Forecasts, 2020-2045



Natural Gas

Tom Pardee, Manager of Natural Gas Planning
Fourth Technical Advisory Committee Meeting
August 6, 2019

Agenda

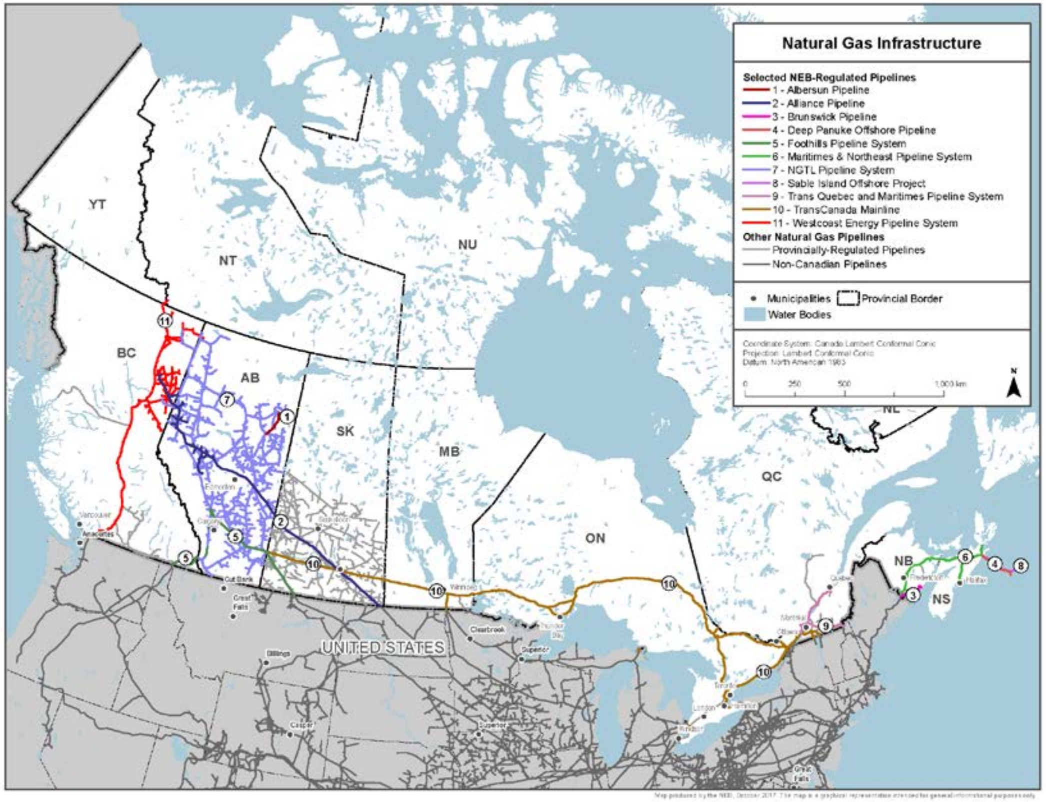
- Market Dynamics
- Pipeline Transportation
- Renewable Natural Gas (RNG)

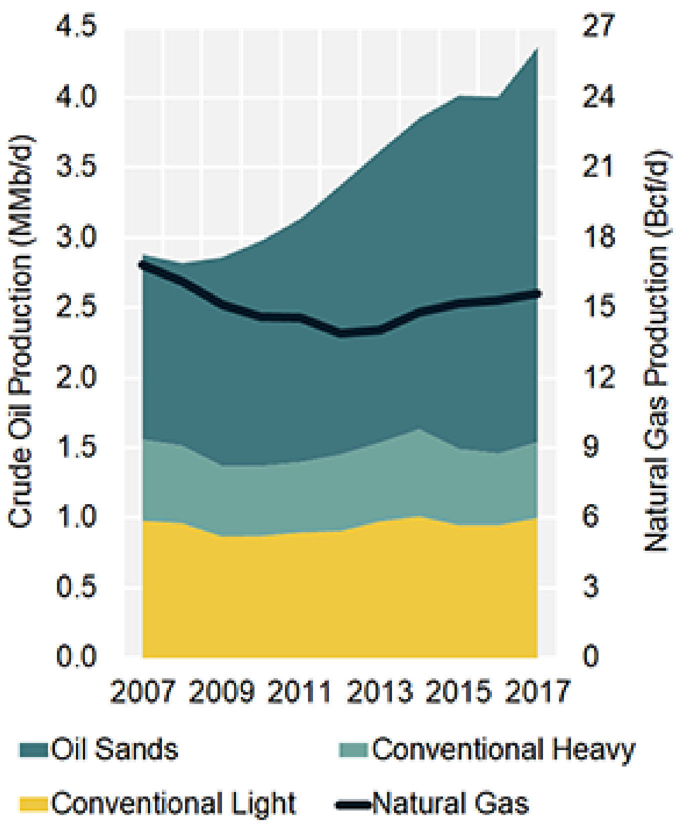
Avista Natural Gas Service Areas, Gas Fields, Trading Hubs and Major Pipelines

as of 3/31/2015

Canada

Canada Natural Gas Production

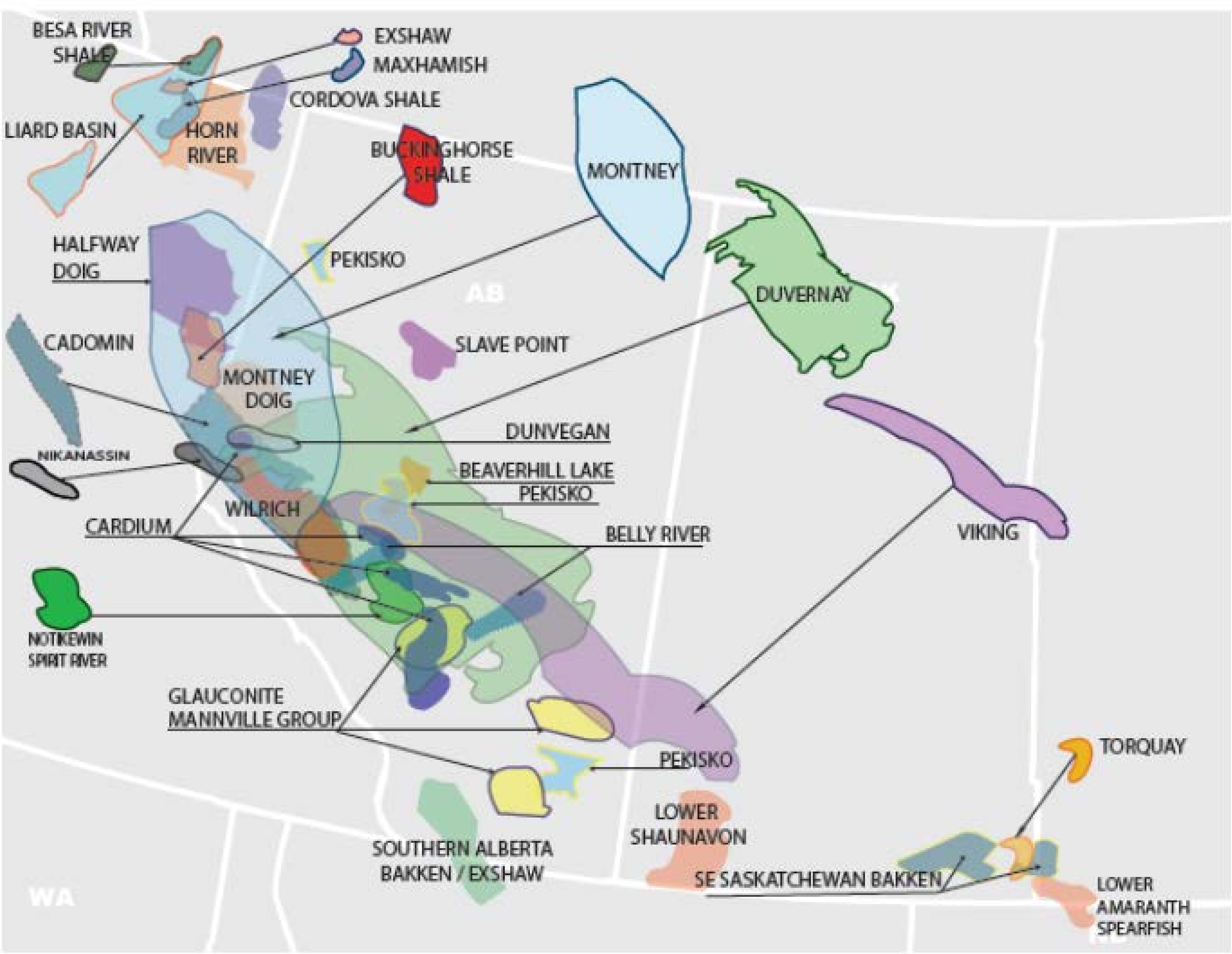




British Columbia
0.5 Bcf per day

Alberta 15
Bcf per day

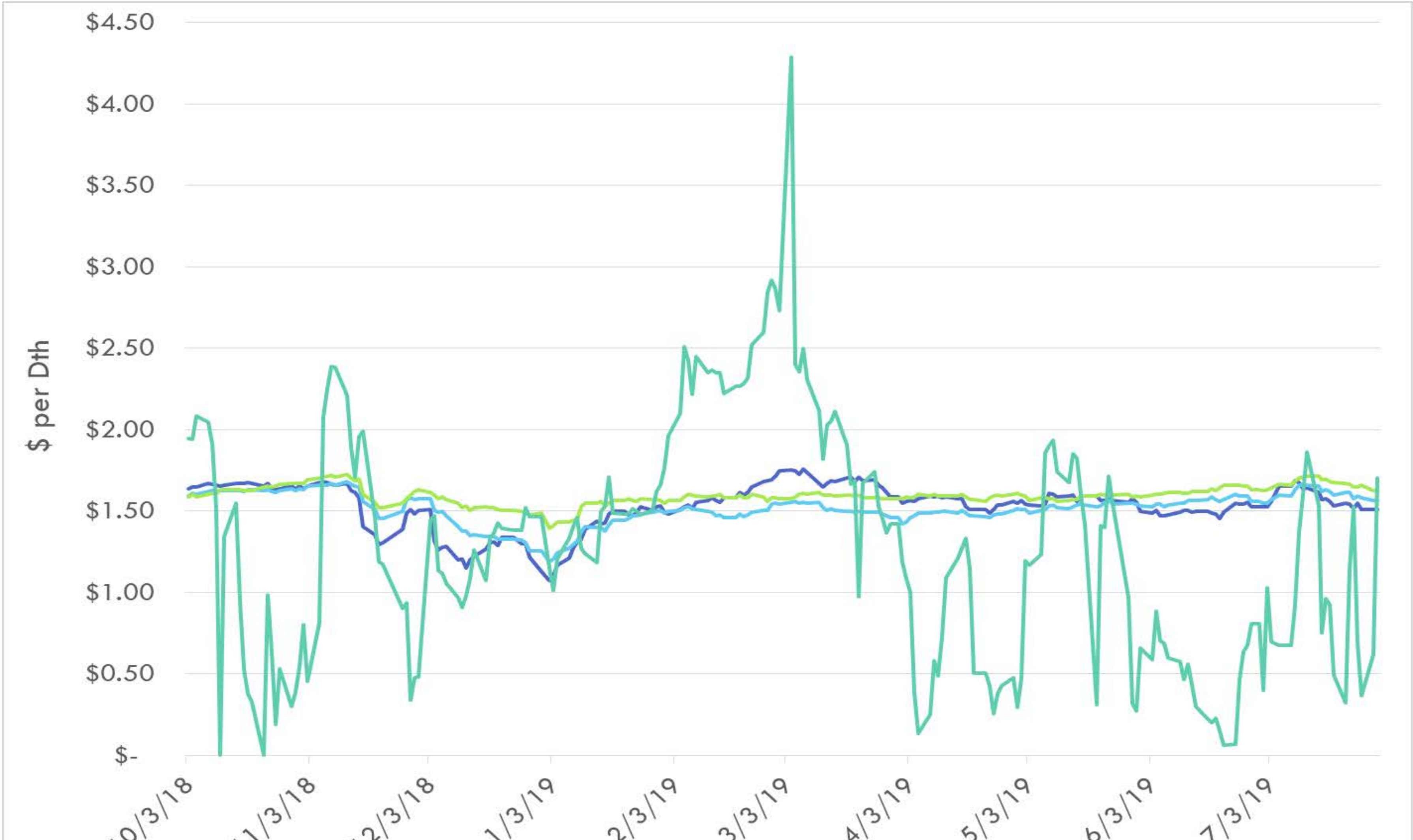
WESTERN CANADA RESOURCE PLAYS



300 Years of resources at current levels

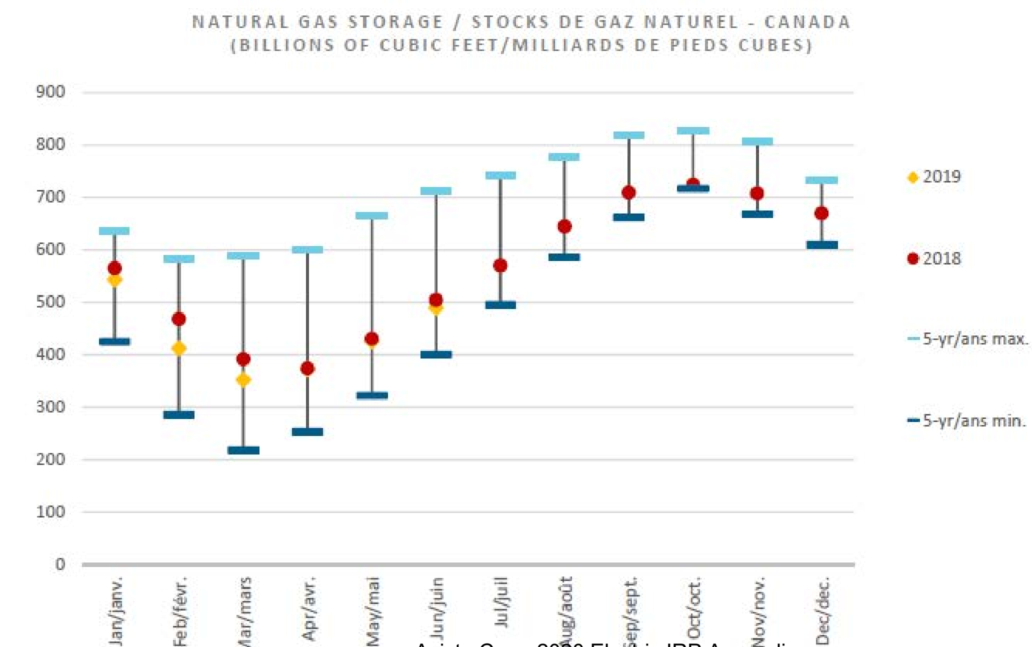
AVISTA

AECO cash vs. forwards



Canadian Natural Gas Storage

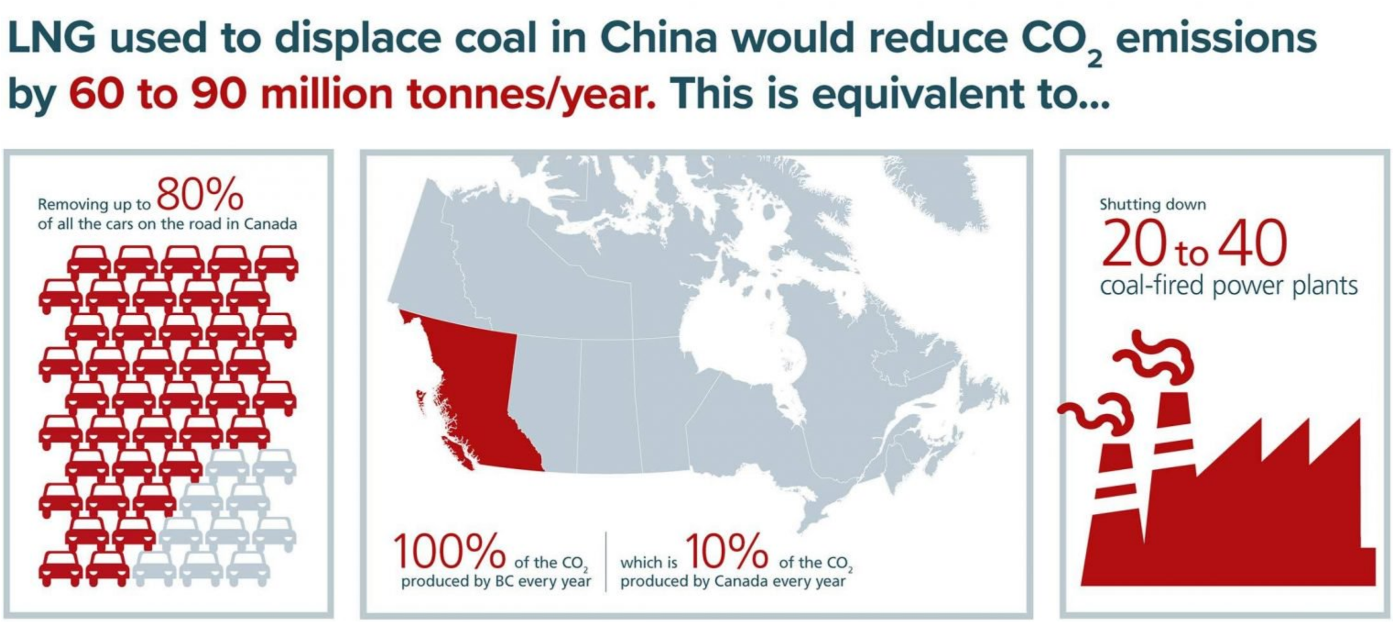
bcf/mpc	Jan/janv.	Feb/févr.	Mar/mars	Apr/avr.	May/mai	Jun/juin	Jul/juil	Aug/août	Sep/sept.	Oct/oct.	Nov/nov.	Dec/dec.
2019	543	412	352	372	426	490						
2018	565	468	391	374	431	504	570	644	709	724	707	669
2017	607	531	462	493	540	609	674	733	798	826	792	695
2016	635	583	589	601	664	712	740	776	818	815	807	704
2015	481	362	336	379	461	533	601	664	730	768	765	732
2014	425	286	218	253	322	401	495	586	662	717	668	610
2013	615	519	453	448	521	585	659	732	791	830	766	599
2012	658	596	594	607	668	708	729	769	812	819	793	725
5-yr/ans max.	635	583	589	601	664	712	740	776	818	826	807	732
5-yr/ans min.	425	286	218	253	322	401	495	586	662	717	668	610



Source: CGA

LNG Canada

Daily liquefaction:
3.5 Bcf Or
1,025,749 MWh

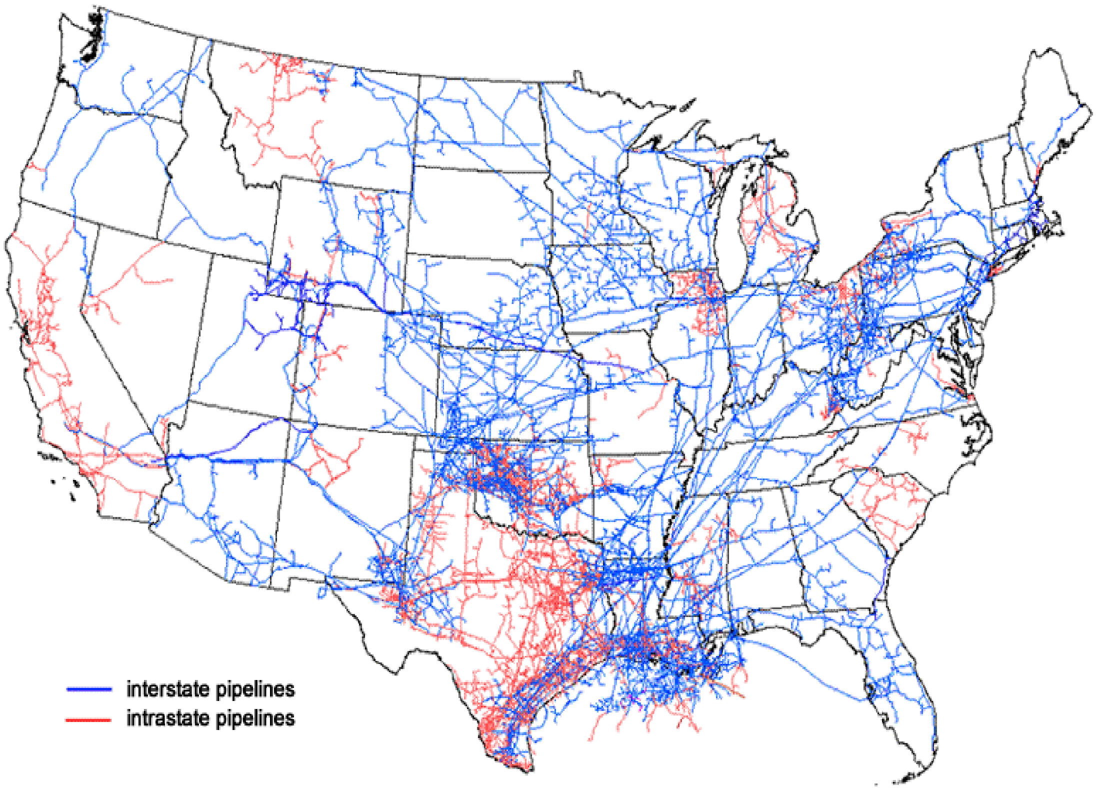


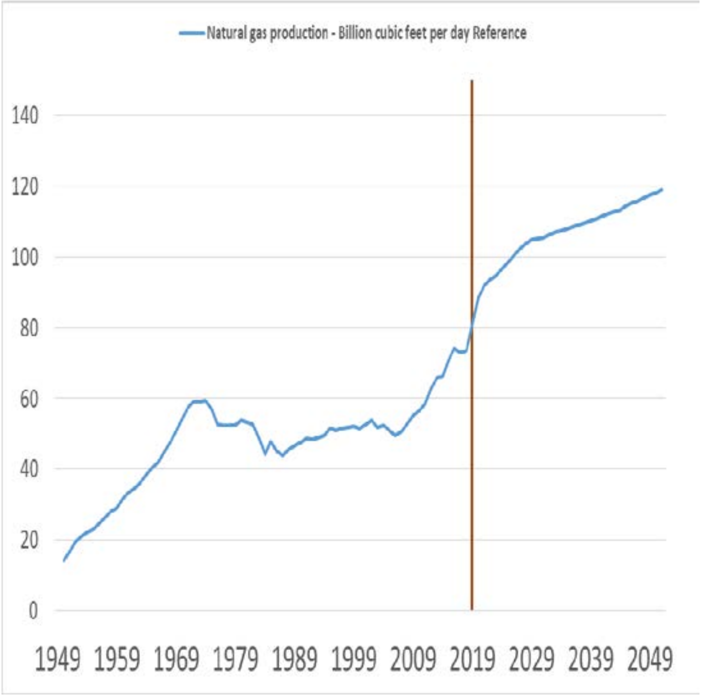
Source: https://www.lngcanada.ca/about-lng-canada/

US

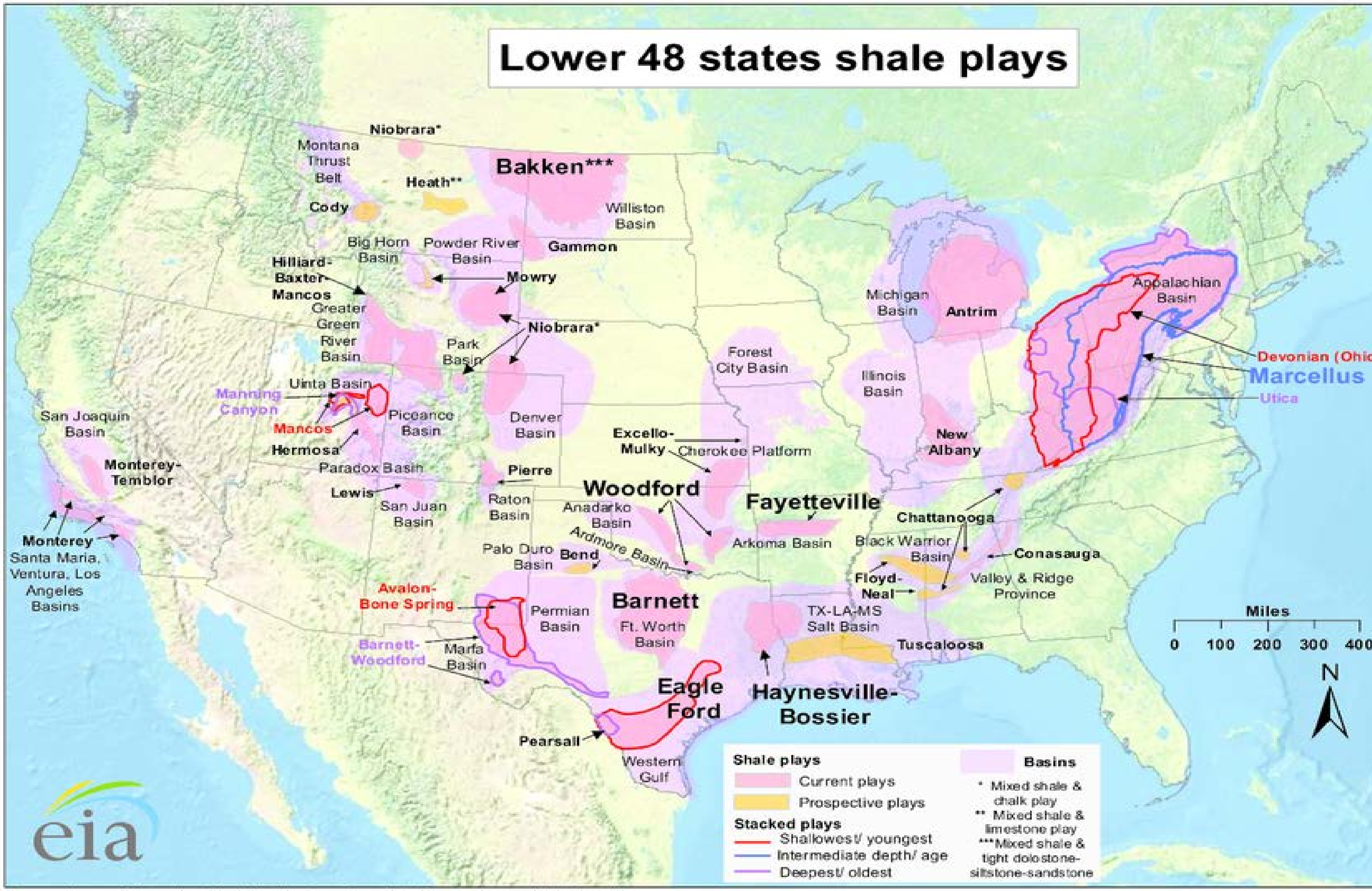
US Natural Gas Production

Map of U.S. interstate and intrastate natural gas pipelines





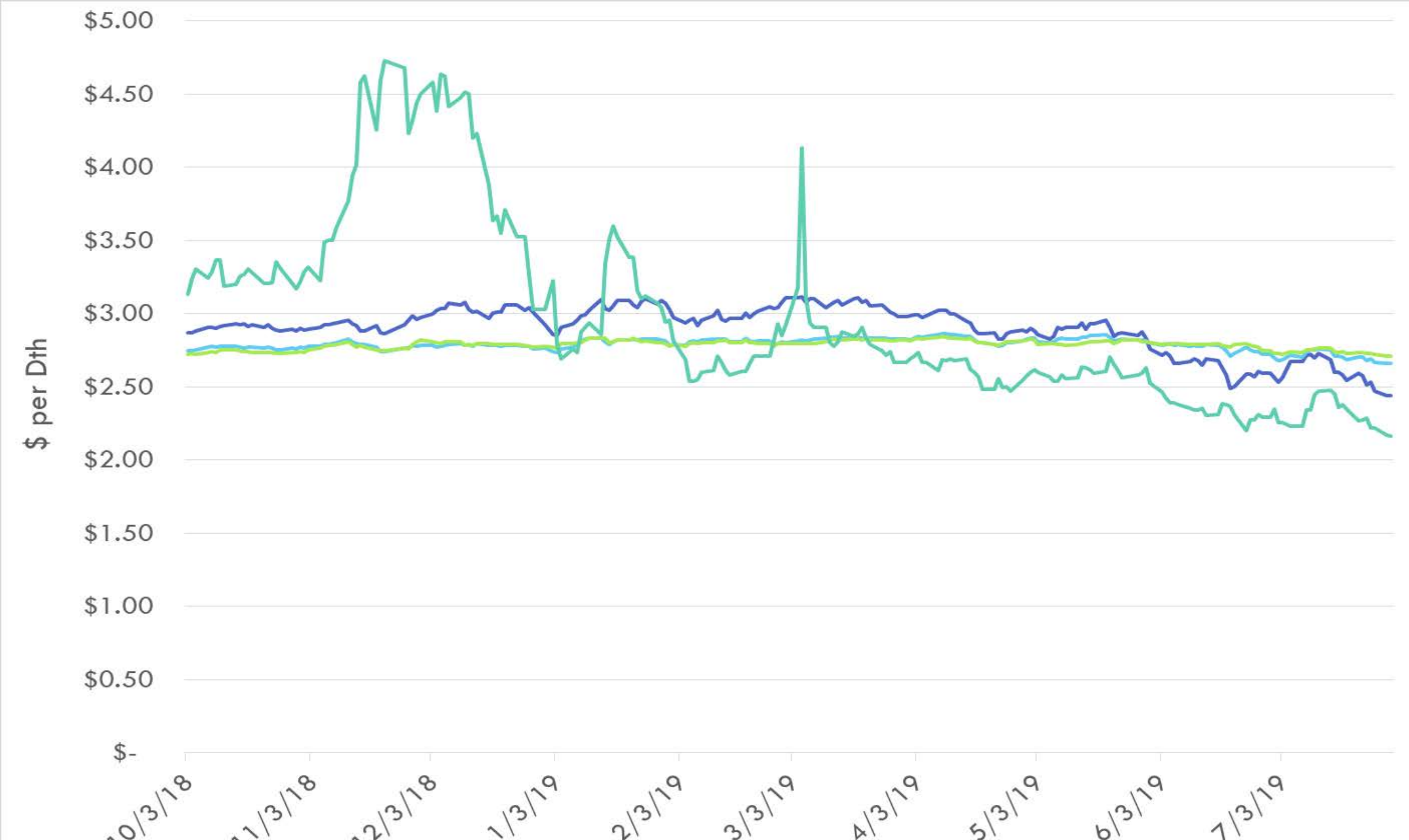
Source: EIA



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

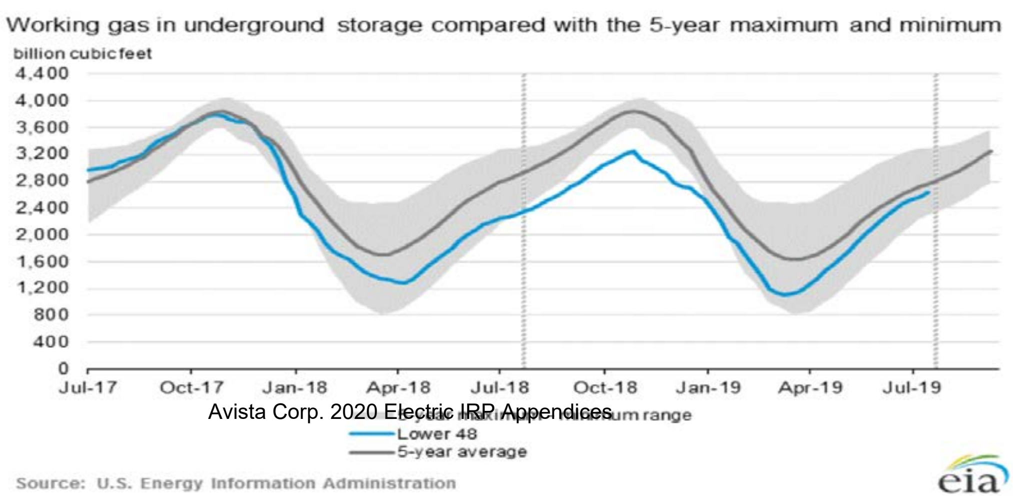
80 Years of resources at current levels

Henry Hub cash vs. forwards



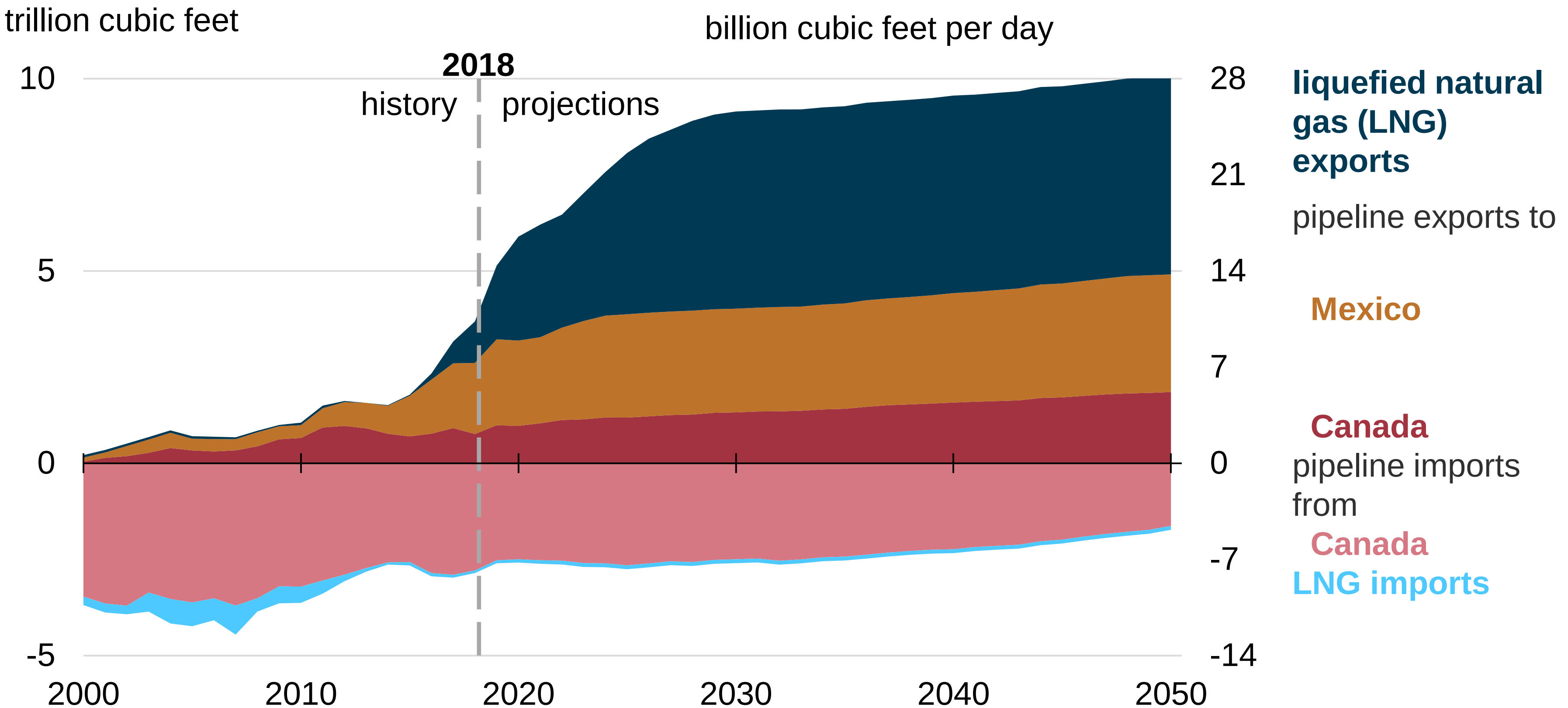
US Natural Gas Storage

	Stocks billion cubic feet (Bcf)				Historical Comparisons: Year ago (07/26/18)		Historical Comparisons: 5-year average (2014-18)	
Region	**07/26/19**	**07/19/19**	**net change**	**implied flow**	**Bcf**	**% change**	**Bcf**	**% change**
East	597	575	22	22	548	8.9	625	-4.5
Midwest	677	650	27	27	548	23.5	677	0.0
Mountain	156	151	5	5	146	6.8	174	-10.3
Pacific	270	271	-1	-1	250	8.0	294	-8.2
South Central	934	921	13	13	809	15.5	987	-5.4
Salt	226	229	-3	-3	207	9.2	268	-15.7
Nonsalt	708	692	16	16	602	17.6	719	-1.5
Total	**2,634**	**2,569**	**65**	**65**	**2,300**	**14.5**	**2,757**	**-4.5**



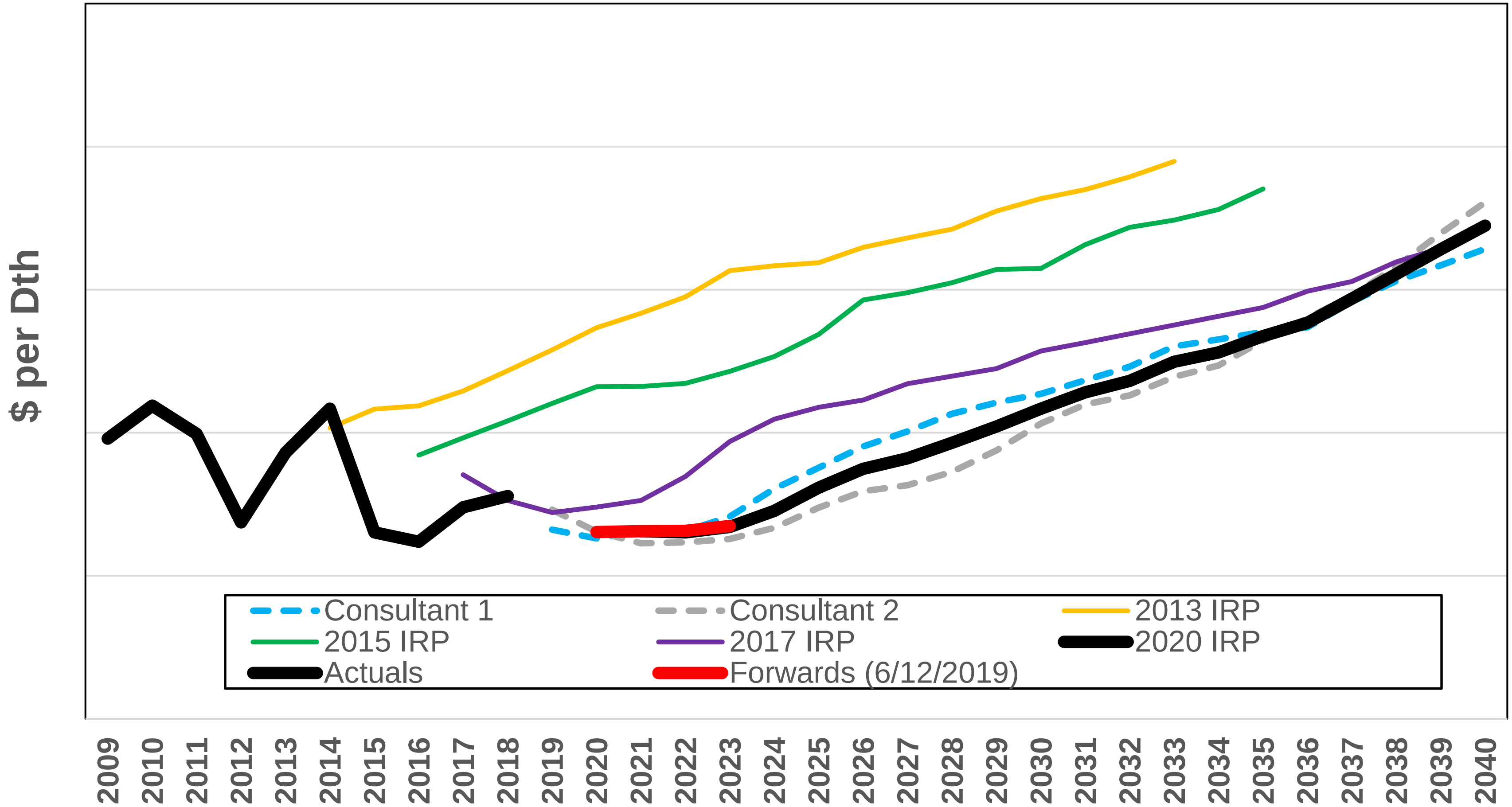
U.S. net exports of natural gas continue to grow in the Reference case—

Natural gas trade (Reference case)



Source: EIA AEO 2019

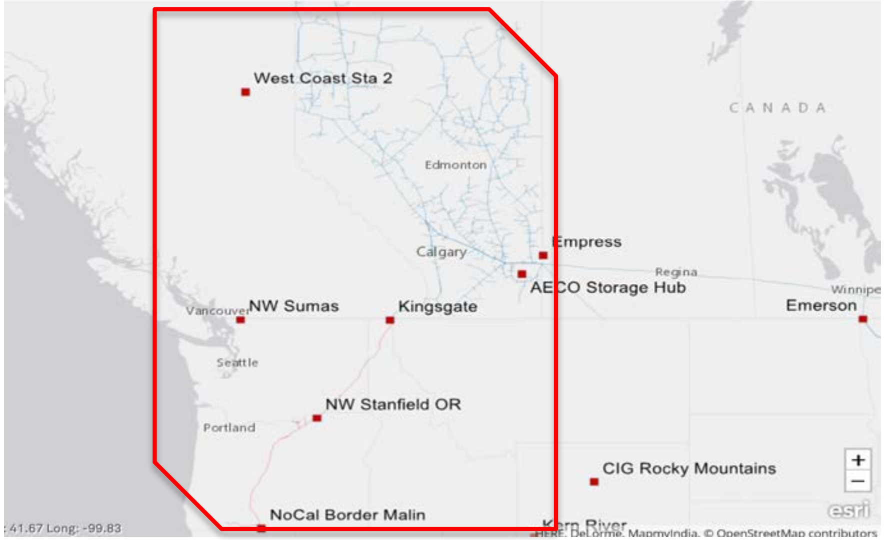
2020 IRP Henry Hub Natural Gas Price Forecast: 2021-2040: $3.99 per Dth



Pipeline Transportation

Fugitive Emissions

- Unintended emissions from facilities or activities (e.g., construction) that "could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening."



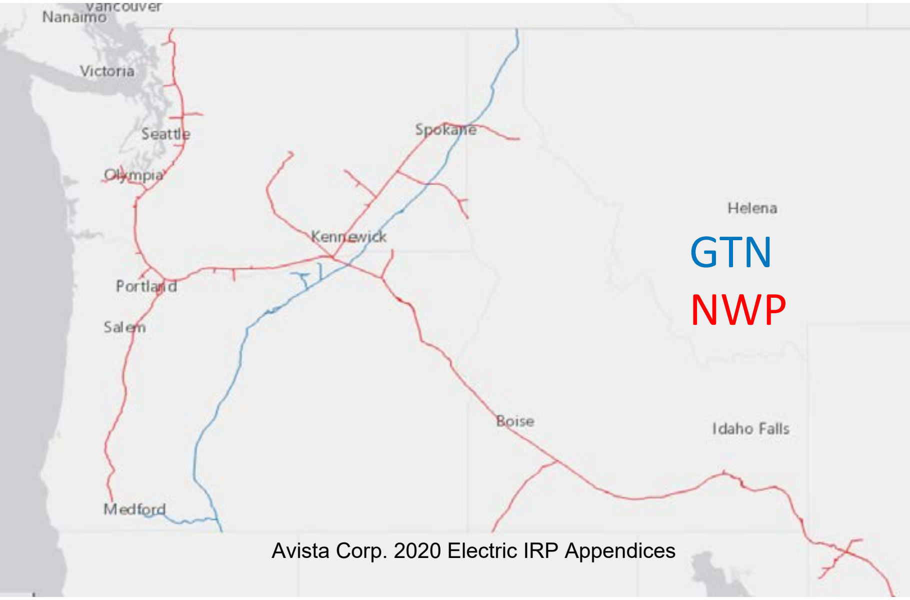
Fugitive emissions estimated at 0.783%

*This figure includes all emissions from production, transport & lost and unaccounted for gas

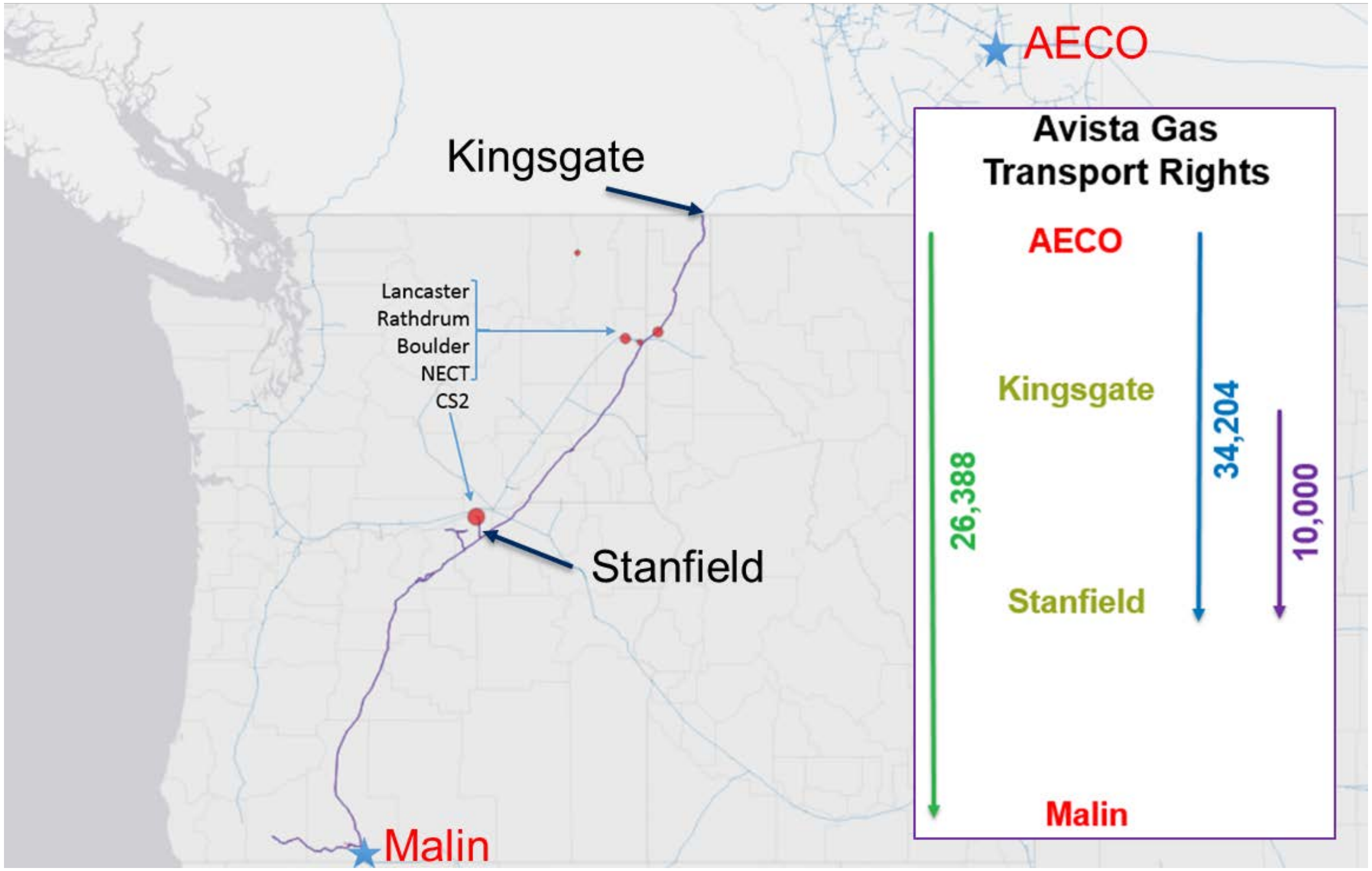
Source – NEB for Canadian infrastructure and EIA for US infrastructure

GTN & NWP Fully Subscribed

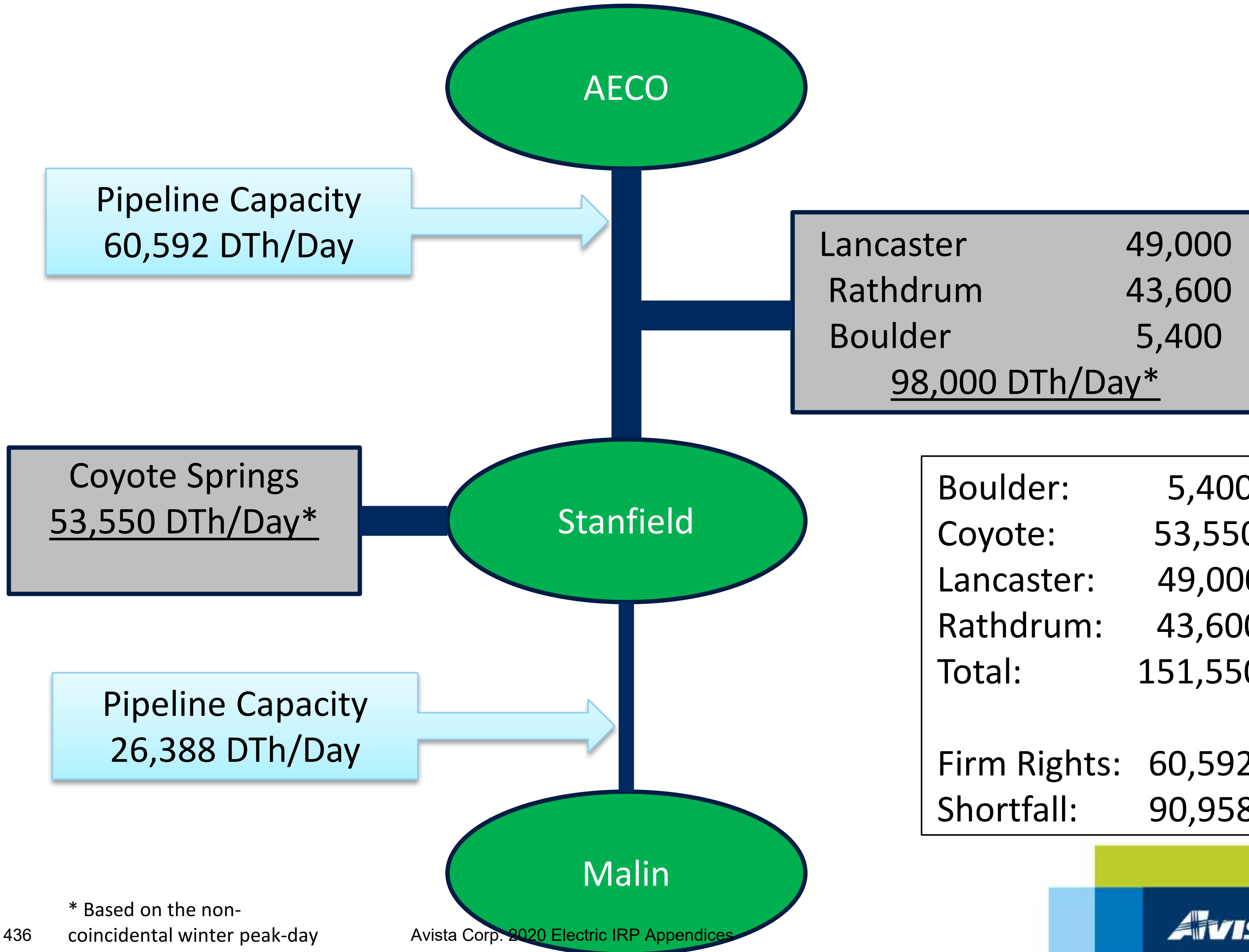
- Contractually both pipelines are now fully subscribed.
- Canadian producers signed up for new contracts in order to get natural gas out of Canada and into more lucrative markets.



Avista Transport for Electric Generation



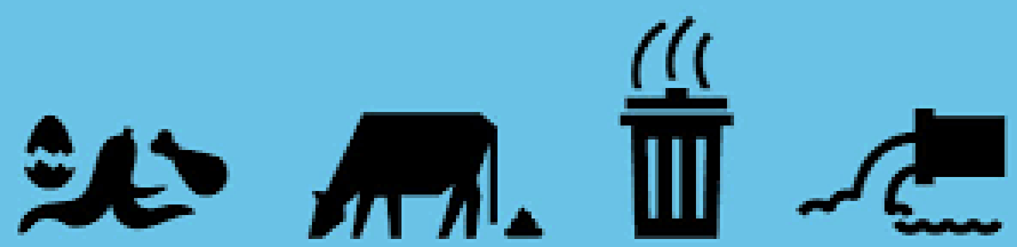
Current Transport & Gas Generation



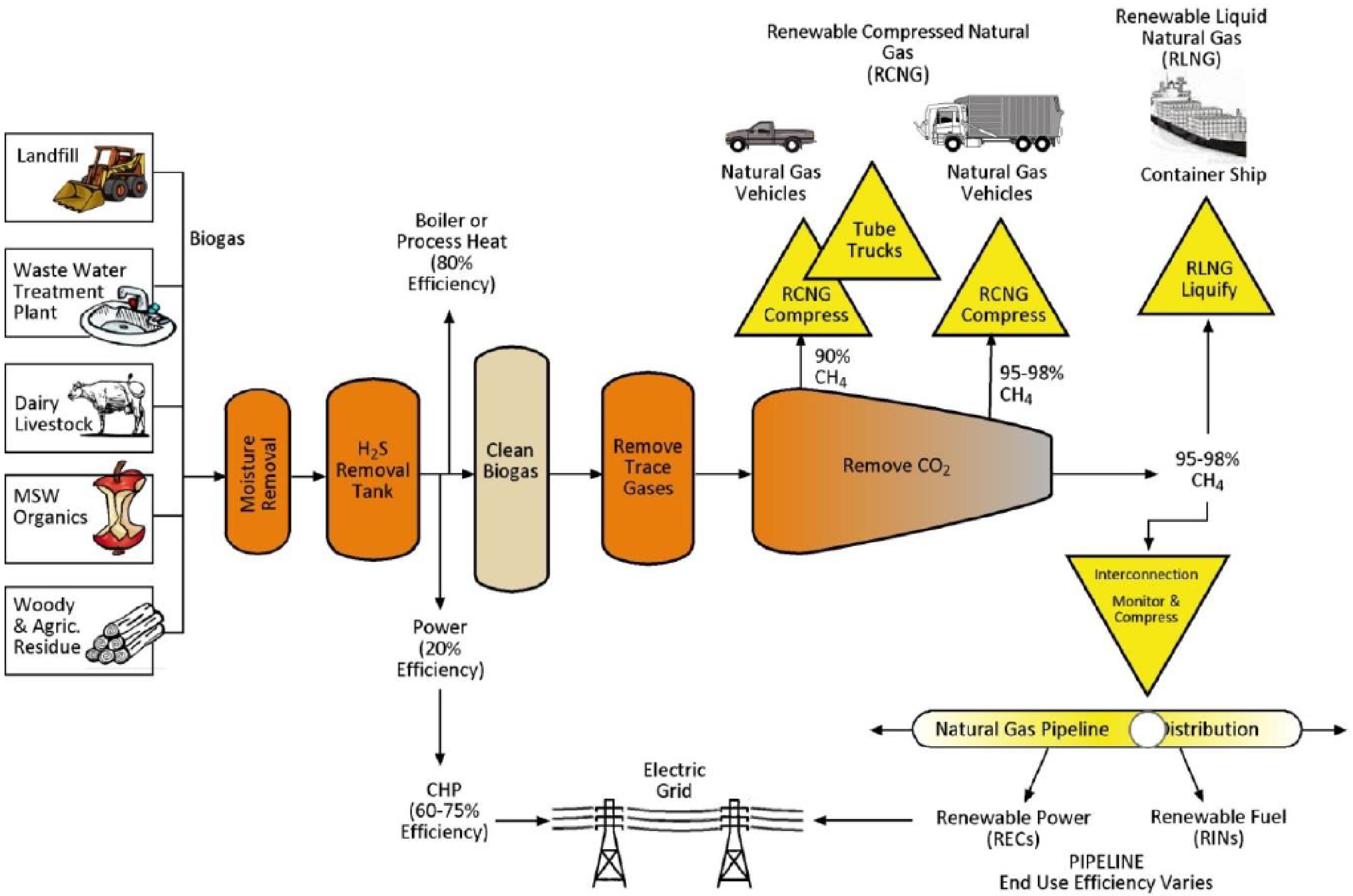
Boulder:	5,400
Coyote:	53,550
Lancaster:	49,000
Rathdrum:	43,600
Total:	151,550
Firm Rights:	60,592
Shortfall:	90,958

* Based on the non-coincidental winter peak-day

Renewable Natural Gas (RNG)

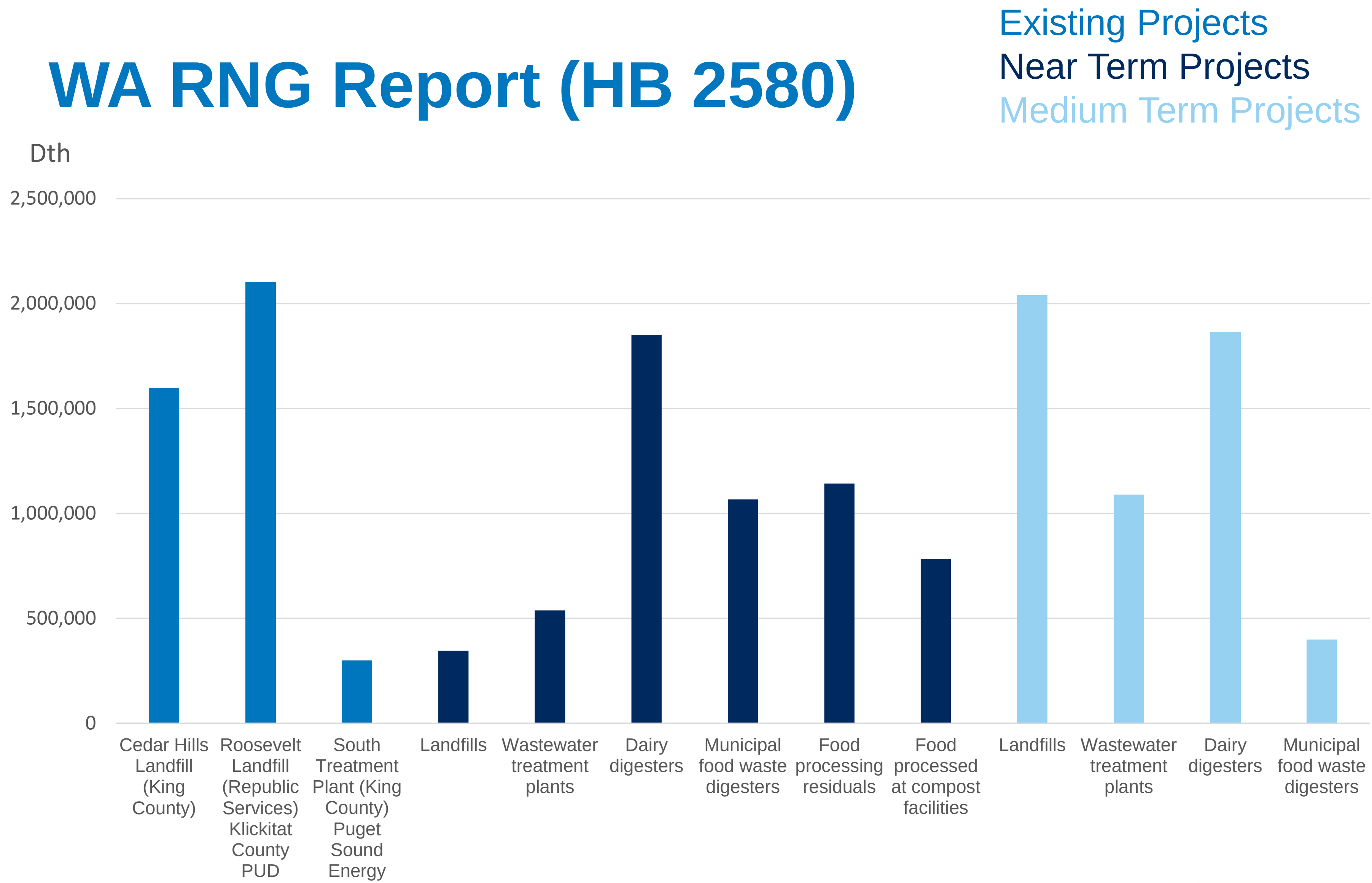


RNG Process Overview



Source: Promoting RNG in WA State

WA RNG Report (HB 2580)



WSU Energy Program, Harnessing Renewable Natural Gas for Low-Carbon Fuel: A Roadmap for Washington State

*Released December 1, 2018

Renewable Natural Gas Comparison to Non-Renewable Natural Gas Reserves

WA RNG Potential	Bcf	dth	dth/day
Current	3.9	4,002,400	10,965
Near-Term	5.2	5,395,010	14,781
Mid-Term	5.6	5,729,010	15,696
Total	14.7	15,126,420	41,442
Avista Natural Gas Consumption			
Avista Power Load 2018	23.4	24,114,712	66,068
Avista LDC Load 2018	33.4	34,456,500	94,401
Total Avista Consumption		58,571,212	160,469
Gas Consumption of CS2			50,000
North American Gas Reserves			
Canadian Gas Reserves (300 years)	1,828,891	1,885,586,517,900	
U.S. Gas Reserves (80 years)	2,459,000	2,535,229,000,000	
Total NA Gas Reserves	4,287,891	4,420,815,517,900	
WA RNG Potential Share of NA Gas Reserves			**0.0003%**

NREL Estimates – Idaho RNG

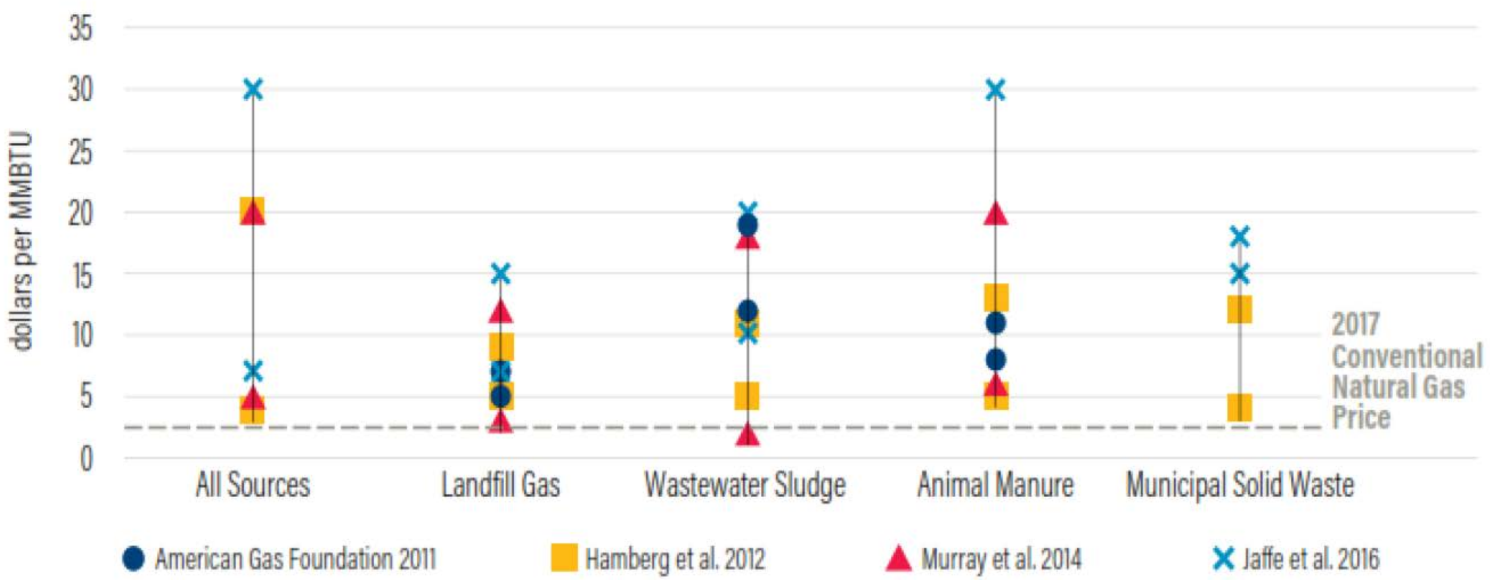
Total Potential Annual Production = 32 Bcf

Source – Anaerobic	MMBtu per Year
Landfills	3,712,221
Wastewater Treatment	6,196,531
Agriculture Manure	20,220,571
Source-Separated Organics (Solid Waste)	2,311,354
Total	**32,440,676**

National Renewable Energy Laboratory, NREL Biofuels Atlas

RNG $ per Dth/MMBtu

Avista Owned and Operated	ID - WA 2035 Premium Estimate ($ / Dth)
RNG - Landfills	$7 - $10
RNG - Waste Water Treatment Plants (WWTP)	$12 - $22
RNG - Agriculture Manure	$28 - $53
RNG - Food Waste	$29 - $53

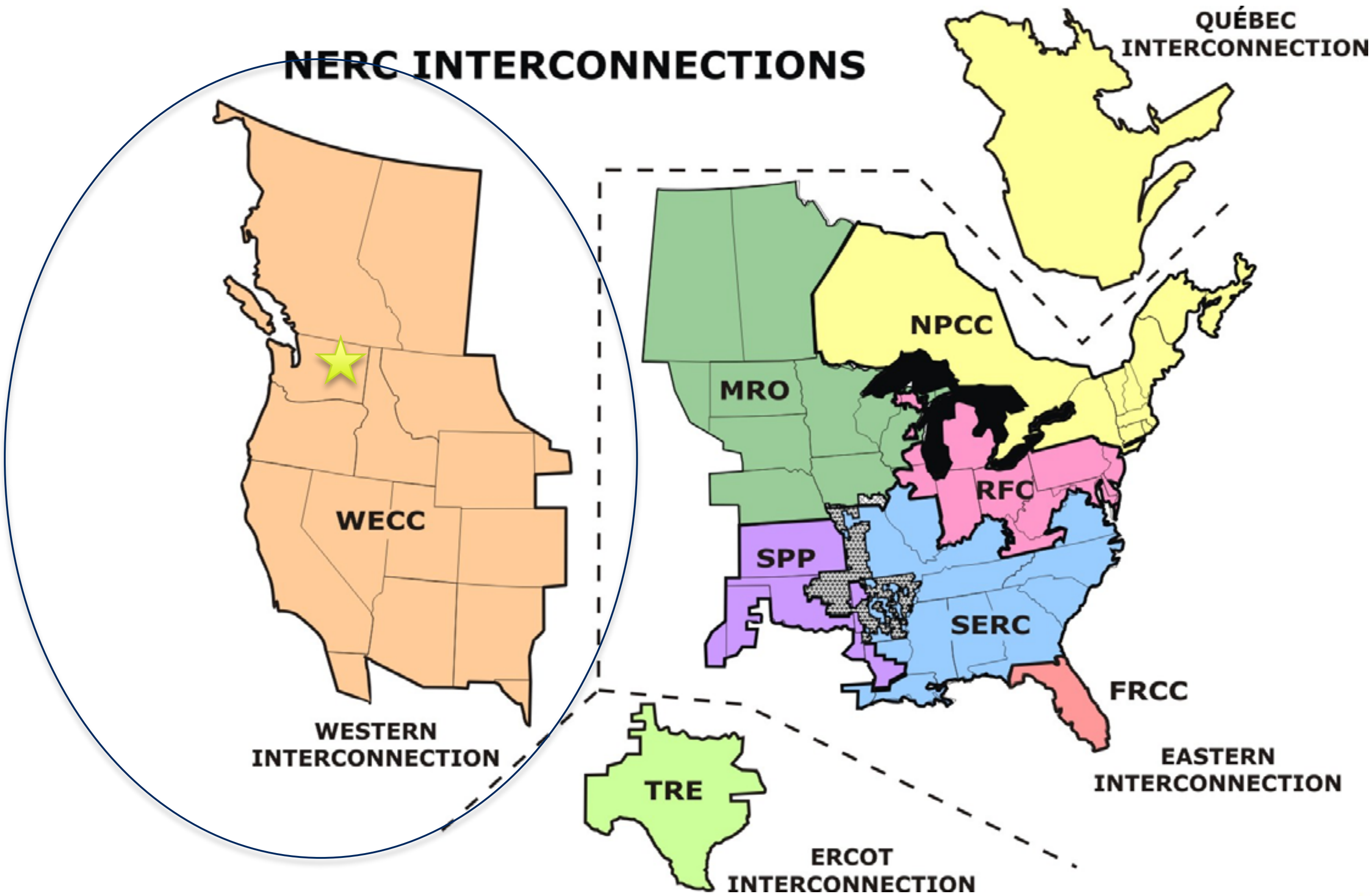


Source: Promoting RNG in WA State

2020 IRP Electric Market Price Forecast

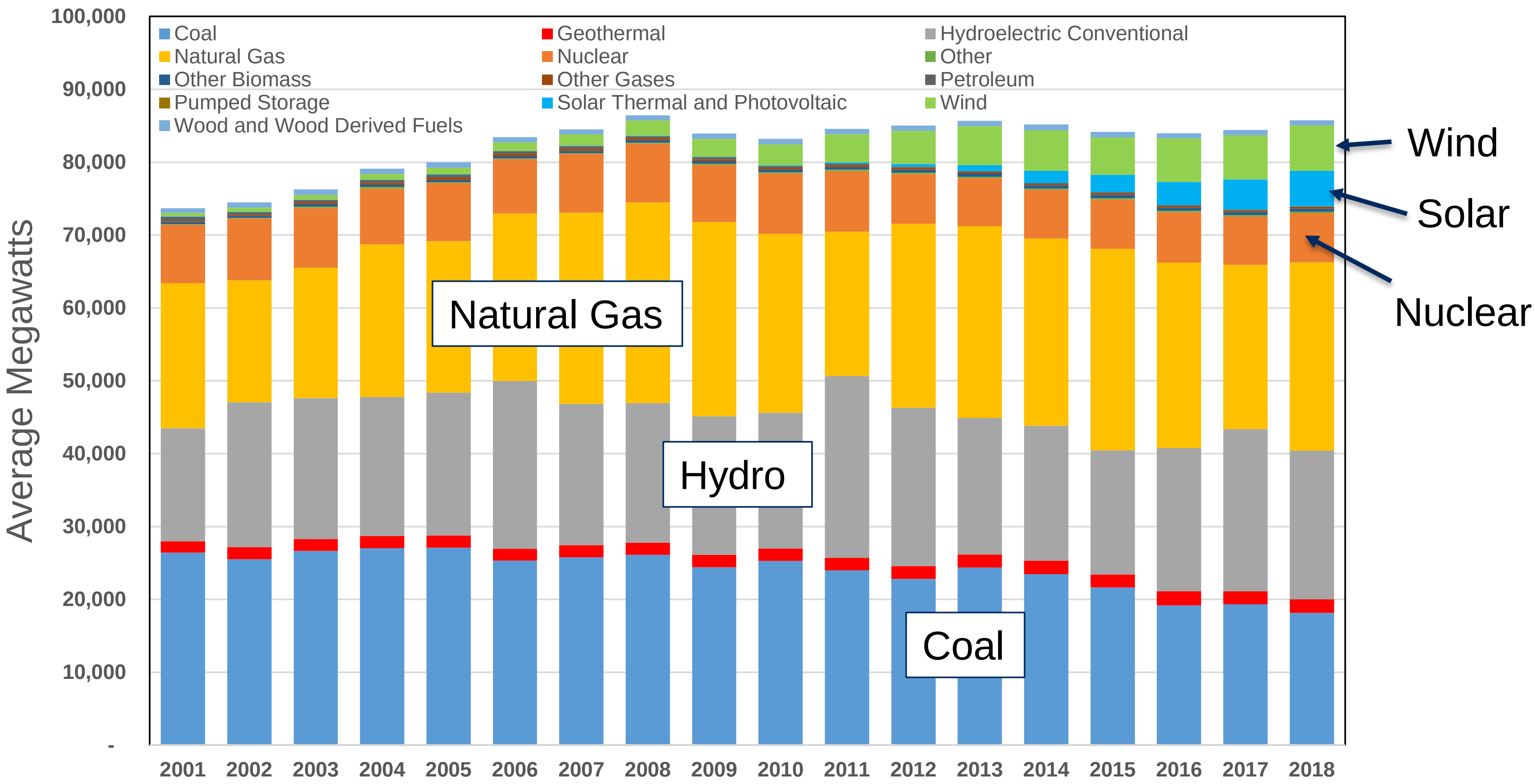
James Gall, IRP Manager
Fourth Technical Advisory Committee Meeting
August 6, 2019

Our Region



Source: NERC

US Western Interconnect Generation



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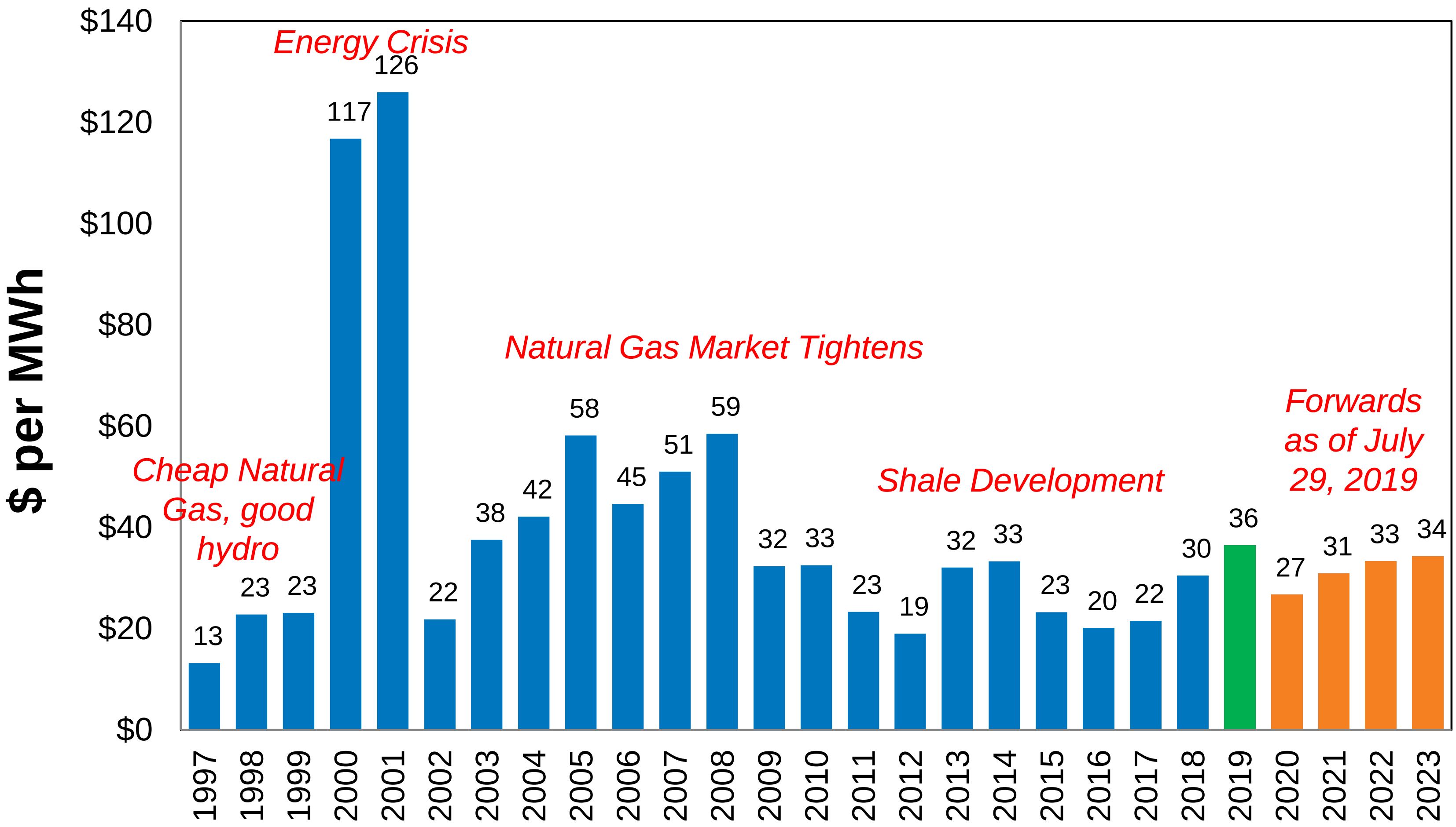
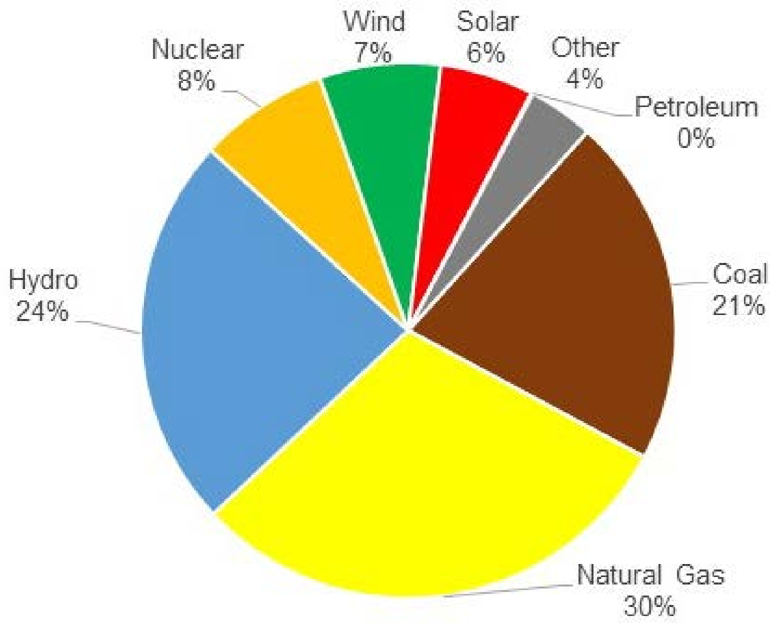
Source: EIA Data

Mid-Columbia Flat Firm Price Index History

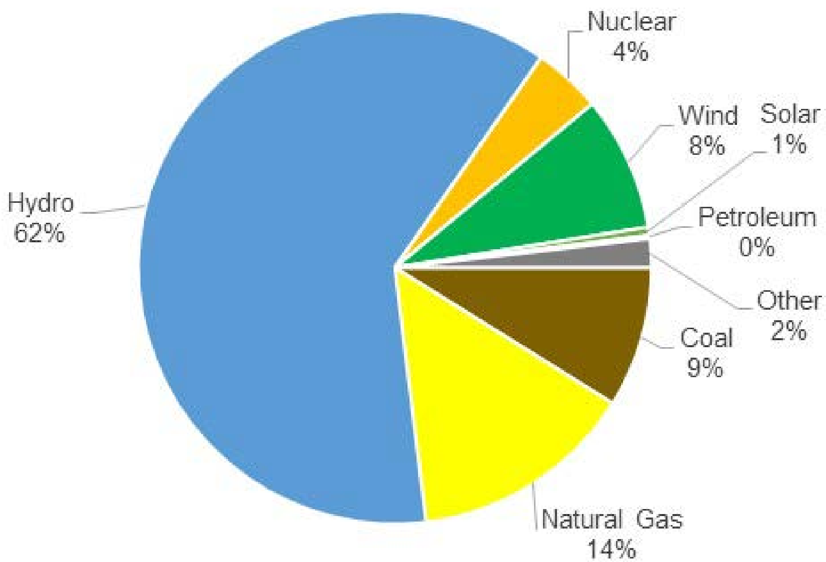


2018 Fuel Mix Comparison (NW vs West)

US Western Interconnect

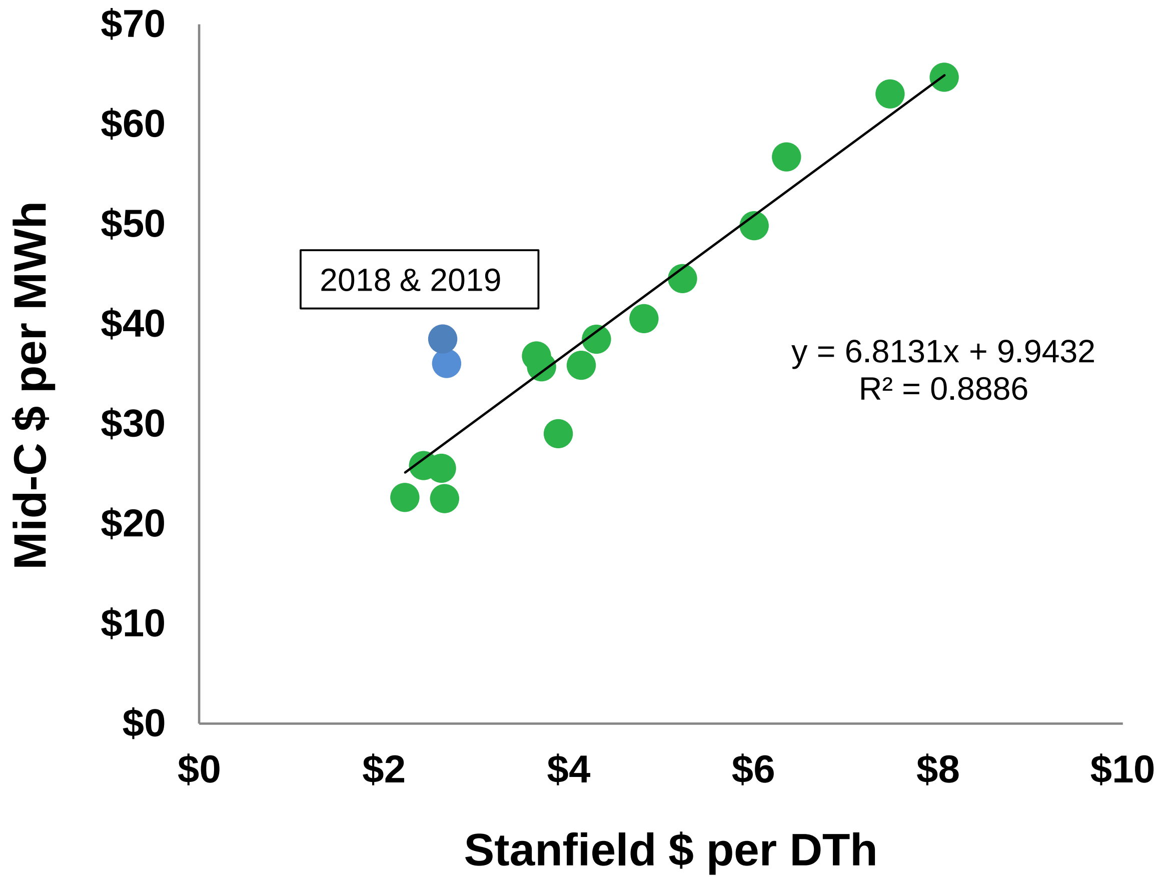


Northwest Four States

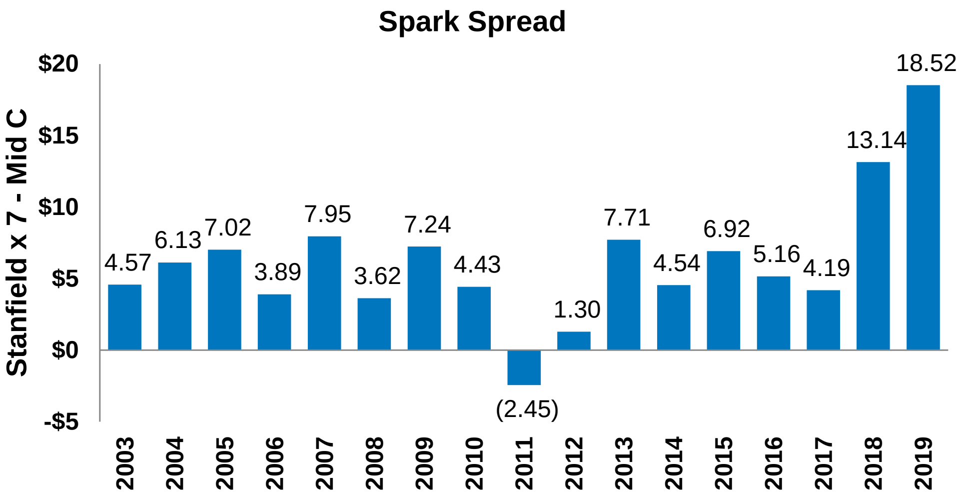


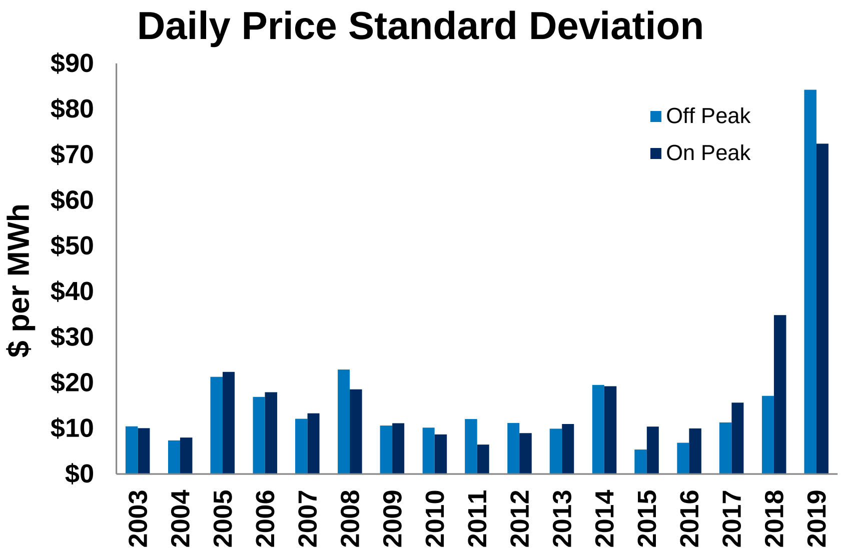
Source: EIA Data

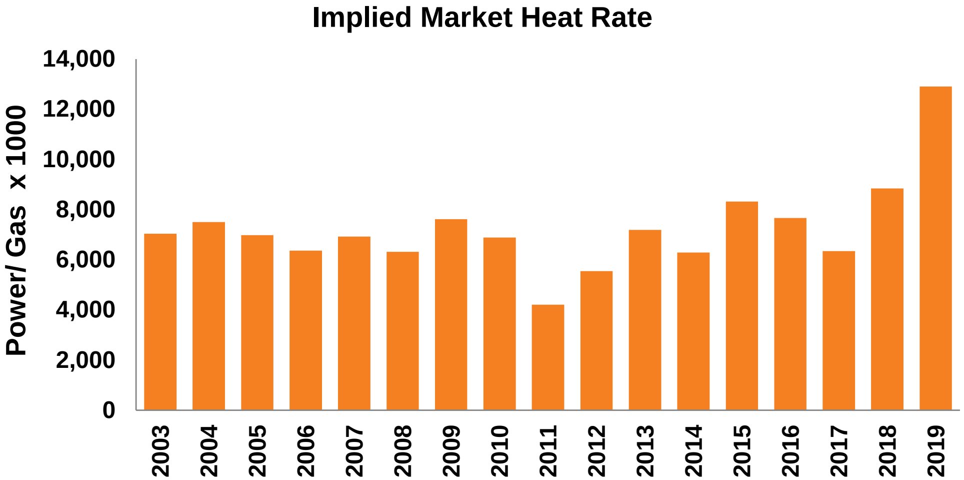
Natural Gas vs. On-Peak Electric Prices (2003-19)



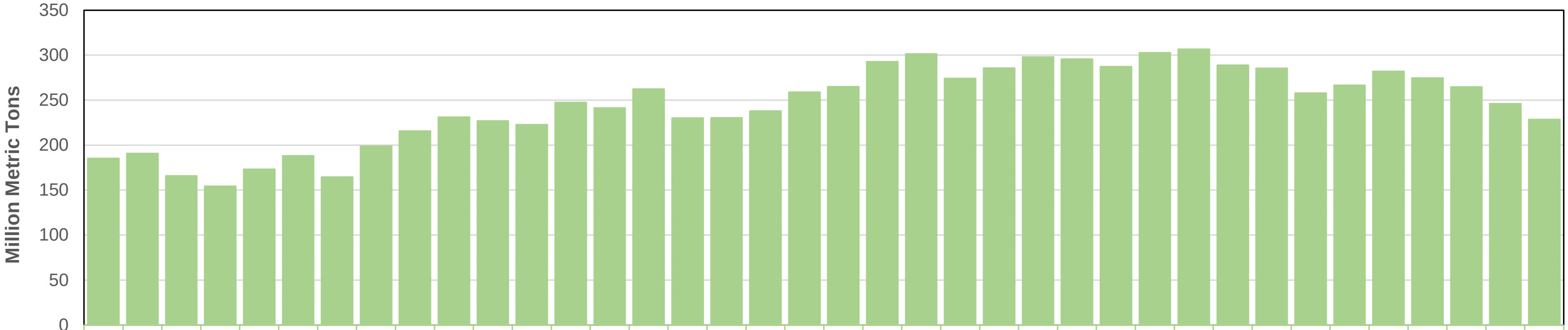
Market Indicators







Western Greenhouse Gas Emissions Power Industry

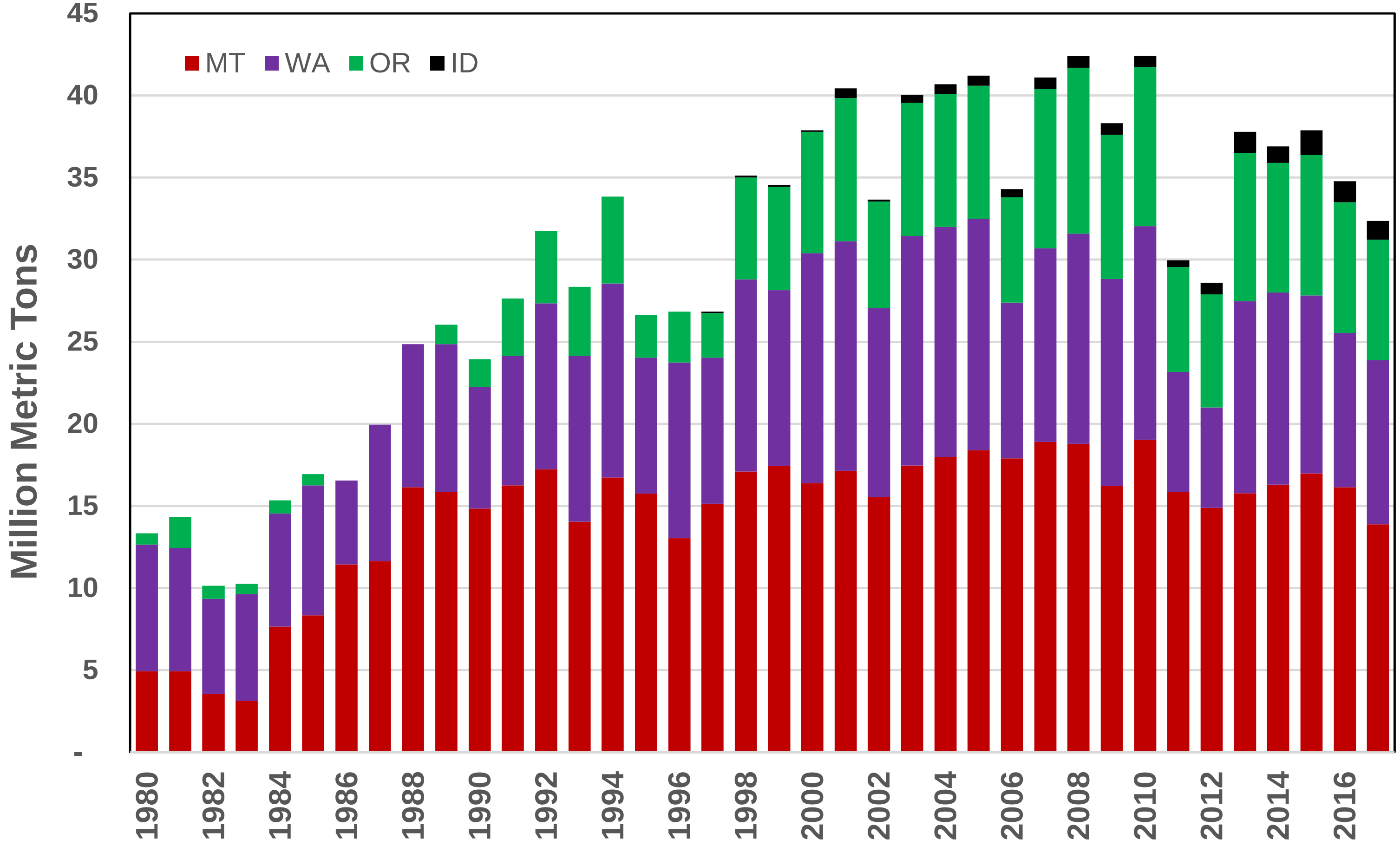


	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
WY	22	20	17	15	19	24	17	26	27	25	28	27	30	29	31	28	29	29	31	30	31	31	30	30	30	29	29	30	30	30	29	26	29	31	30	29	29	29
WA	8	8	6	7	7	8	5	8	9	9	7	8	10	10	12	8	11	9	12	11	14	14	12	14	14	14	10	12	13	13	13	7	6	12	12	11	9	10
UT	11	11	11	11	12	14	15	25	27	28	29	28	30	31	32	30	30	31	32	33	33	33	34	35	35	36	36	38	39	36	35	34	32	35	34	33	28	27
OR	1	2	1	1	1	1	-	-	-	1	2	4	4	4	5	3	3	3	6	6	7	9	7	8	8	8	6	10	10	9	10	6	7	9	8	9	8	7
NM	20	19	21	24	23	24	21	23	24	26	25	21	24	25	26	25	26	27	27	28	29	28	27	29	29	30	30	29	28	28	25	26	25	24	21	20	19	19
NV	11	13	14	13	15	12	16	15	18	17	17	18	19	18	20	18	20	19	21	22	25	24	21	23	25	26	17	17	18	18	17	15	15	15	16	14	14	12
MT	5	5	4	3	8	8	11	12	16	16	15	16	17	14	17	16	13	15	17	17	16	17	16	17	18	18	18	19	19	16	19	16	15	16	16	17	16	14
ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	1	0	1	1	1	1	1	1	1	1	0	1	1	1	1	1	1
CO	21	23	24	23	25	27	26	27	28	30	31	30	31	32	33	32	34	34	35	36	39	41	40	40	40	41	42	43	41	38	40	39	39	39	38	37	37	36
CA	61	59	38	31	34	40	27	37	37	44	40	38	46	42	50	37	33	36	39	43	53	58	44	43	46	42	47	50	51	48	44	36	48	46	46	44	37	28
AZ	25	31	31	26	29	31	25	27	29	35	33	33	35	37	38	32	32	35	38	40	45	46	45	46	52	51	53	55	58	52	54	52	51	55	53	50	47	45

1980: 185 MMT
1990: 227 MMT
2008: 307 MMT
2017: 228 MMT

Source: EPA
Adjusted for plants in the Western Interconnect system

Northwest Greenhouse Gas Emissions



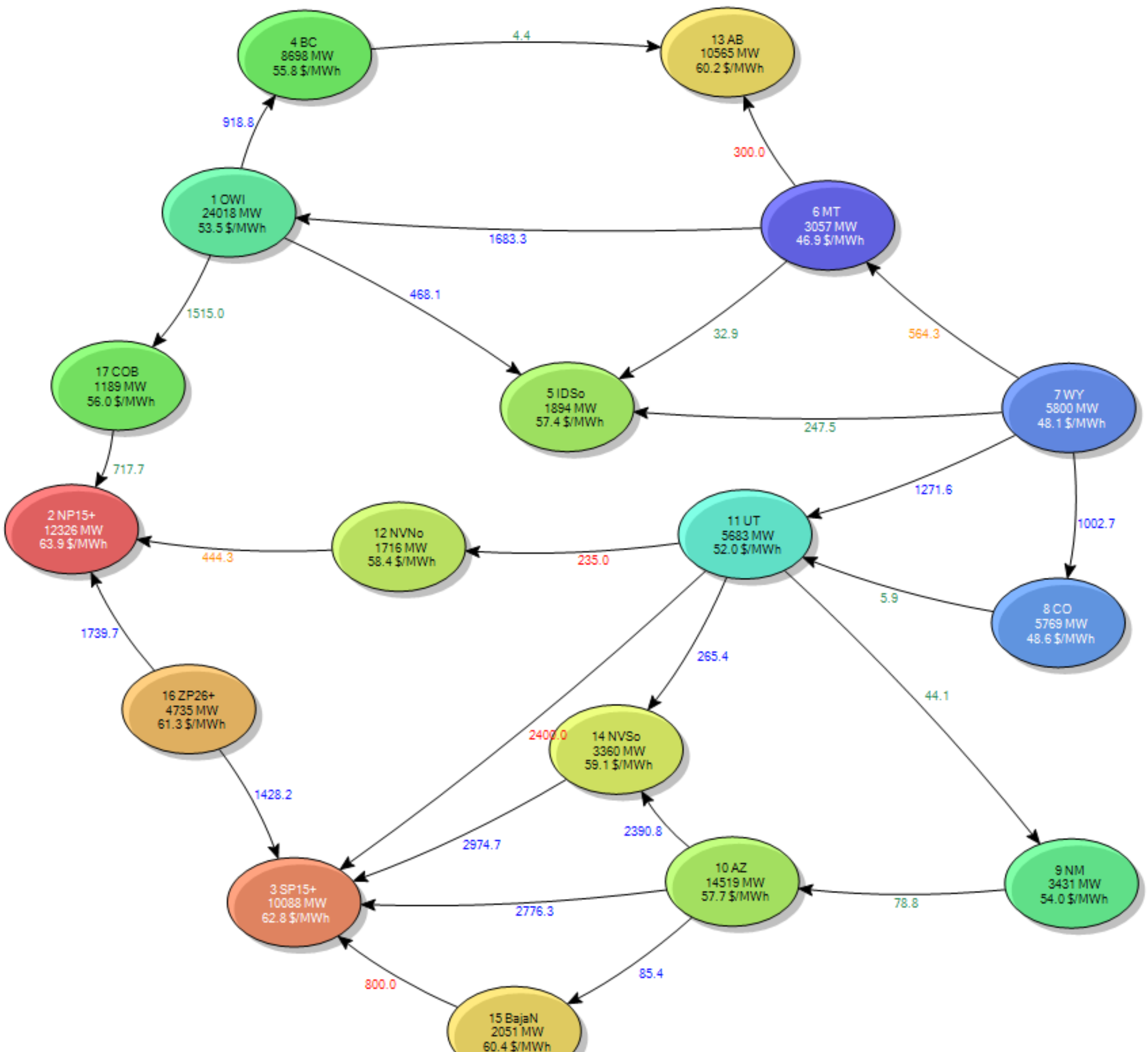
Electric Market Modeling

- 3rd party software- Aurora by Energy Exemplar
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet load
- Outputs:
  - Market prices (electric & emission)
  - Regional energy mix
  - Transmission usage
  - Greenhouse gas emissions
  - Power plant margins, generation levels, fuel costs
  - Avista's variable power supply costs

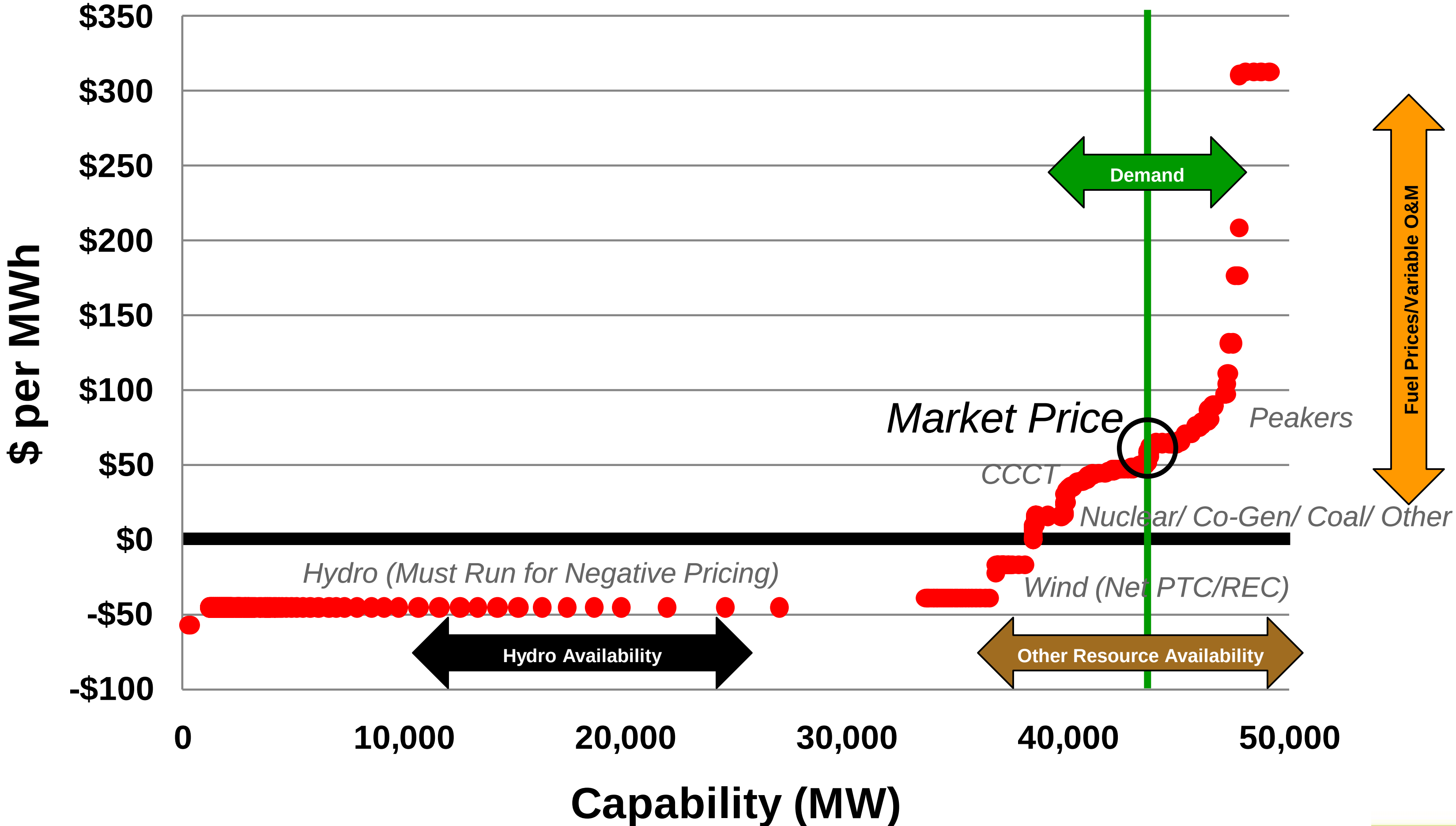
Stochastic Approach

- Simulate Western Electric market hourly for next 25 years (2021-45)
  - That is 175,248 hours for each study
- Model 500 potential outcomes
  - Variables include fuel prices, loads, wind, hydro, outages, and inflation
  - Simulating 87.6 million hours
- Run time is about 14+ days on 20 processors
- Why do we do this?
  - Allows for complete financial evaluation of resource alternatives
  - Without stochastic prices we cannot account for tail risk

Modeled Western Interconnect Topology



How Aurora derives hourly prices

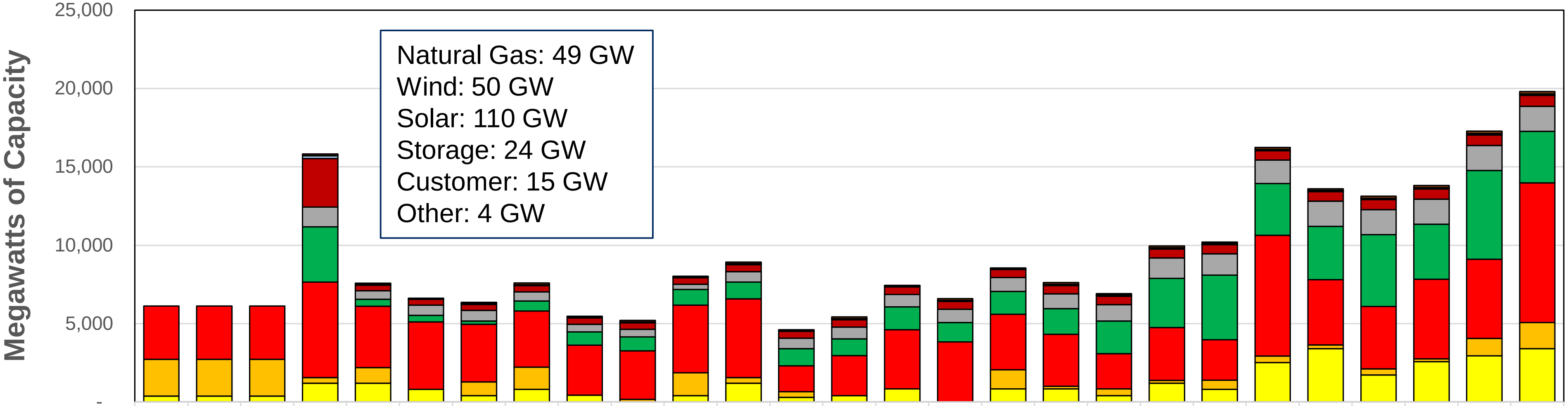


Note: minimum price is negative $25/ MWh (2018$)

Approach to New Resource Selection

- Baseline
  - 3rd party consultant new resource outlook
  - known retirements
- Policy Constraints
  - California, BC, and Alberta include CO_2 price adder
  - OR: Emissions Cap (3.6 million tons)
  - WA: CETA: resources & social cost of carbon
  - ID: Clean Power Plan Emission's Intensity (delayed)
  - No new coal-fired generation
  - Uses existing state Renewable Portfolio Standards
- Resource Adequacy
  - Achieve close to 1-in-20 loss of load probability (LOLP/LOLE)

New Resources Forecast- US West



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Geothermal	-	-	-	90	70	24	76	104	52	104	26	104	26
Biomass	-	-	-	18	11	35	36	35	37	35	36	36	36
Hydro	-	-	-	182	40	19	23	30	29	25	29	30	28
Consumer Gen	-	-	-	3,092	357	367	378	390	402	414	427	439	452
Storage	-	-	-	1,267	551	659	667	587	480	480	331	671	660
Wind	-	-	-	3,522	445	419	215	640	846	896	993	1,070	1,095
Solar	3,400	3,400	3,400	6,102	3,915	4,304	3,676	3,582	3,195	3,082	4,313	5,029	1,662
NG Peaker	2,353	2,353	2,353	350	988	-	880	1,422	-	175	1,467	350	350
NG CCCT	371	371	371	1,200	1,200	800	400	800	429	-	400	1,200	300

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Geothermal	104	26	104	26	104	76	114	86	124	96	134	140	156	160
Biomass	34	34	37	34	34	36	35	36	34	34	37	34	34	36
Hydro	40	31	36	39	58	51	56	54	51	58	56	56	56	58
Consumer Gen	466	480	494	510	525	541	557	574	592	610	628	647	667	687
Storage	748	795	849	897	941	1,050	1,308	1,358	1,500	1,600	1,598	1,600	1,601	1,600
Wind	1,070	1,462	1,236	1,450	1,632	2,078	3,145	4,127	3,308	3,399	4,576	3,510	5,656	3,294
Solar	2,562	3,778	3,834	3,539	3,320	2,240	3,367	2,583	7,705	4,168	3,985	5,079	5,052	8,910
NG Peaker	-	-	-	1,230	175	440	175	587	412	237	400	175	1,111	1,659
NG CCCT	400	829	-	829	829	400	1,200	800	2,516	3,403	1,716	2,574	2,945	3,403

Note 1: 2019-2021 additions are spread evenly between the 3 years, these are all added in 2021 for modeling purposes

Note 2: Storage is assumed to be a blend of technologies, average of 3 hours duration in 2021, ramping to 6 hours average duration by 2045

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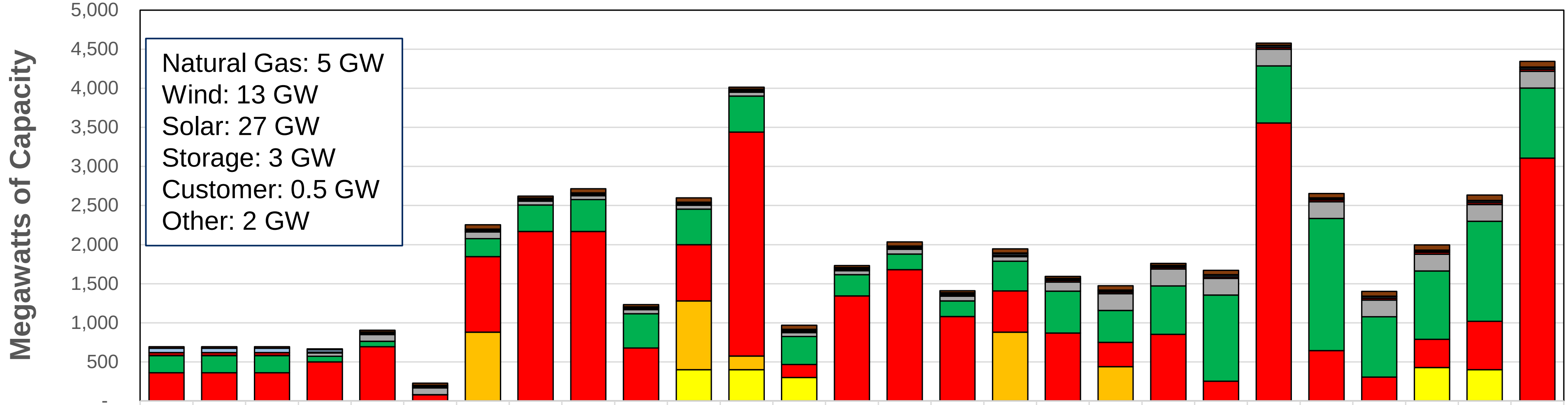
New Resources Forecast- Northwest States



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Geothermal	19	19	19	-	24	26	54	26	54	26	54	26	54	26	54	26	54	26	54	26	54	26	54	60	66	70	72
Biomass	-	-	-	11	11	10	11	11	11	10	12	10	10	10	11	10	10	10	11	10	10	10	11	10	10	10	11
Hydro	58	58	58	31	11	13	13	14	12	13	13	14	16	15	15	18	19	19	19	18	19	19	19	18	19	19	18
Consumer Gen	36	36	36	11	11	12	12	13	13	14	14	14	15	15	16	17	17	18	19	19	20	21	22	23	23	25	26
Storage	-	-	-	42	86	85	86	51	51	52	52	51	50	52	60	60	60	116	213	215	214	214	213	214	213	214	214
Wind	219	219	219	70	69	4	231	337	408	439	454	462	358	270	200	199	379	537	408	619	1,100	732	1,692	772	874	1,280	898
Solar	362	362	362	501	694	77	966	2,169	2,167	678	719	2,863	167	1,345	1,680	1,081	528	869	310	853	254	3,555	643	305	361	618	3,105
NG Peaker	-	-	-	-	-	-	880	-	-	-	880	175	-	-	-	-	880	-	440	-	-	-	-	-	-	-	-
NG CCCT	-	-	-	-	-	-	-	-	-	-	400	400	300	-	-	-	-	-	-	-	-	-	-	-	429	400	-

Note 1: 2019-2021 additions are spread evenly between the 3 years, these are all added in 2021 for modeling purposes

Note 2: Storage is assumed to be a blend of technologies, average of 3 hours duration in 2021, ramping to 6 hours average duration by 2045

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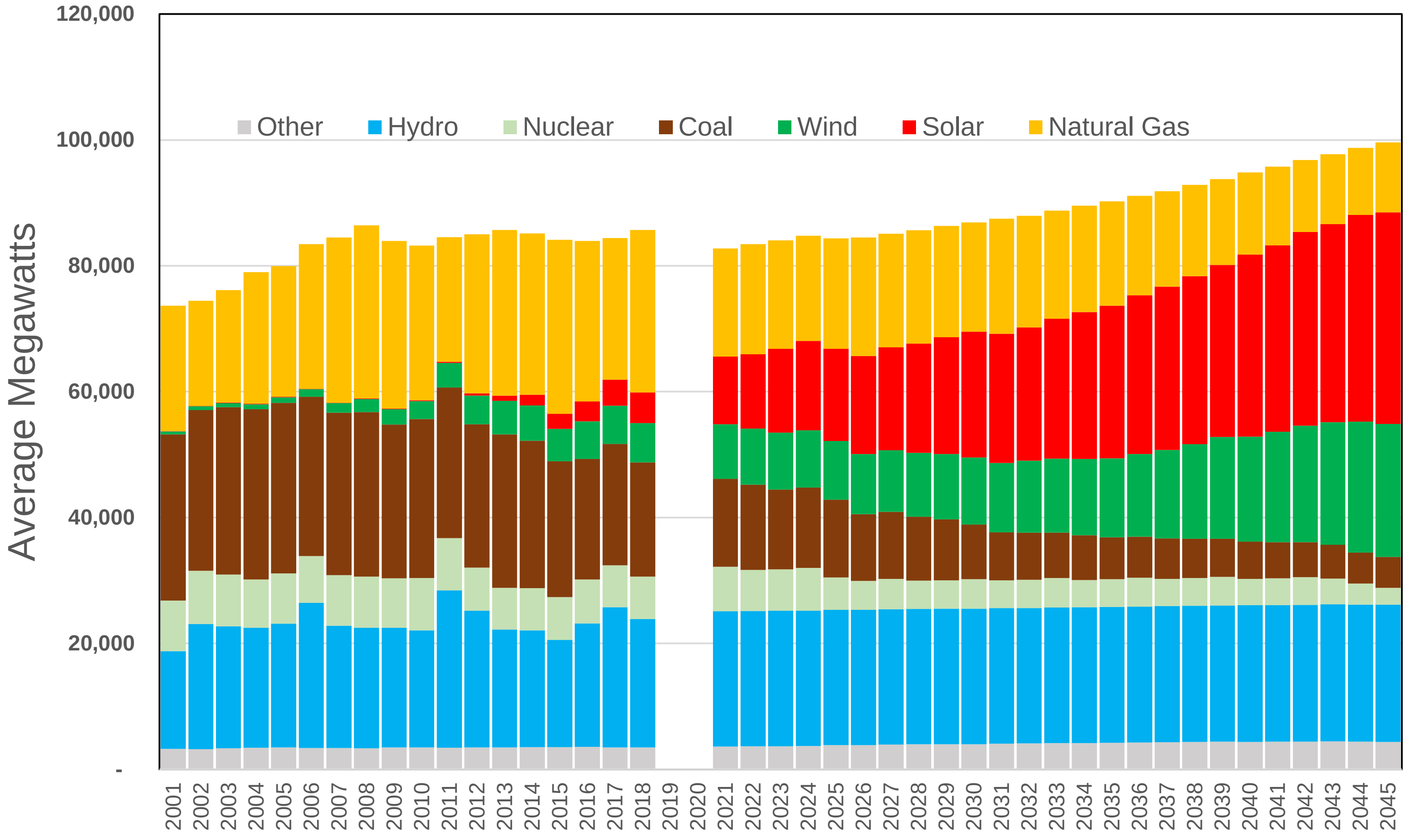
Resource Type Mix Forecast
(US Western Interconnect)



Fuel Type	2045 minus 2018 aGW
Natural Gas	-14.7
Hydro	+1.4
Solar	+28.7
Wind	+14.9
Other	+0.9
Coal	-13.2
Nuclear	-4.1

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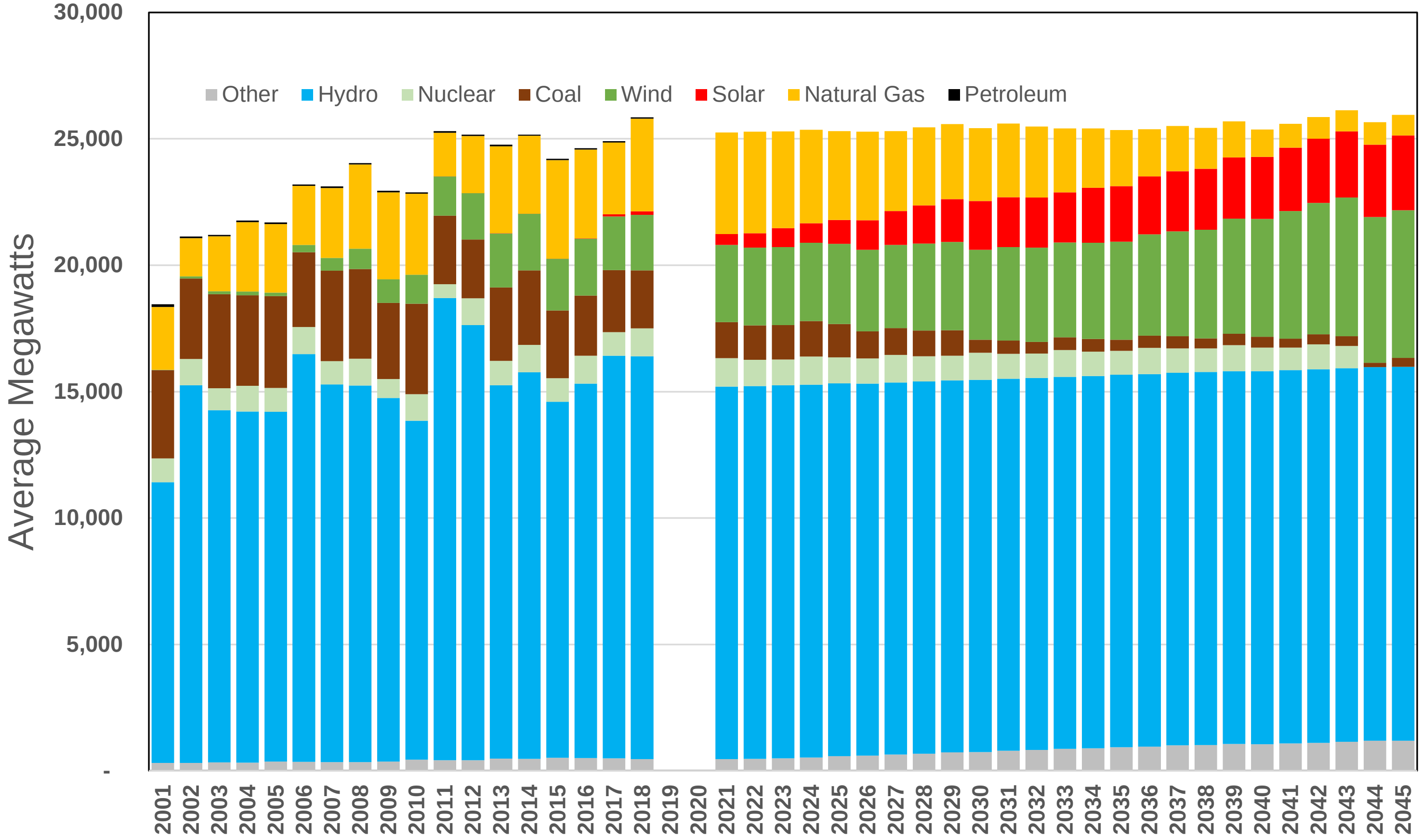
Resource Type Mix Forecast

(NW States)



Fuel Type	2045 minus 2018 aGW
Natural Gas	-2.8
Hydro*	-1.1
Solar	+2.8
Wind	+3.6
Other	+0.7
Coal	--1.9
Nuclear	-1.1

Note: Hydro change is due to actual hydro vs. average hydro

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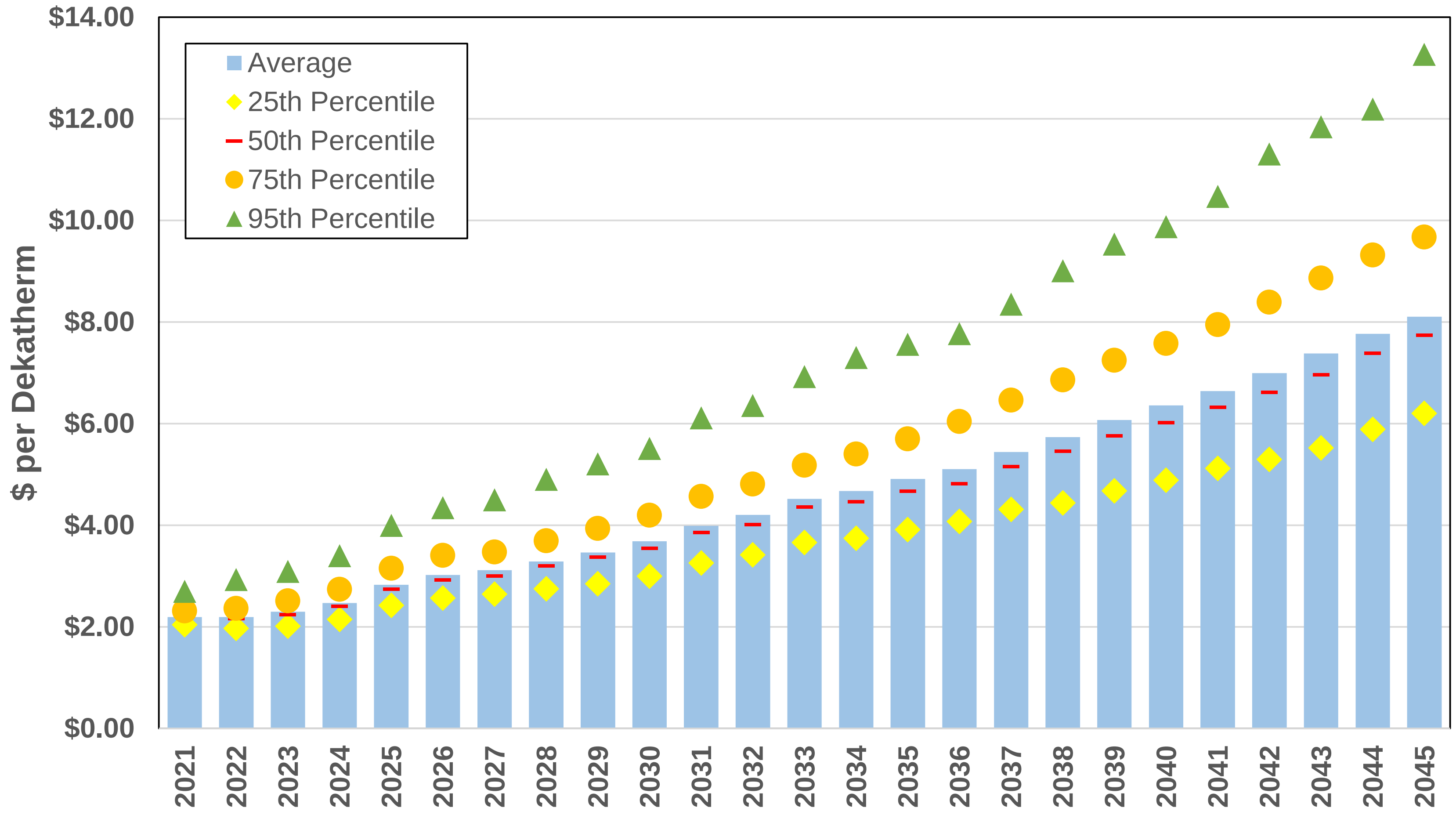
Stanfield Natural Gas Price Forecast



20-year levelized price: $3.98/Dth

25-year levelized price: $4.66/Dth

Note: Coefficient of variation (stdev/mean) in 2021 is 13%, in 2040, the volatility increases to 32%

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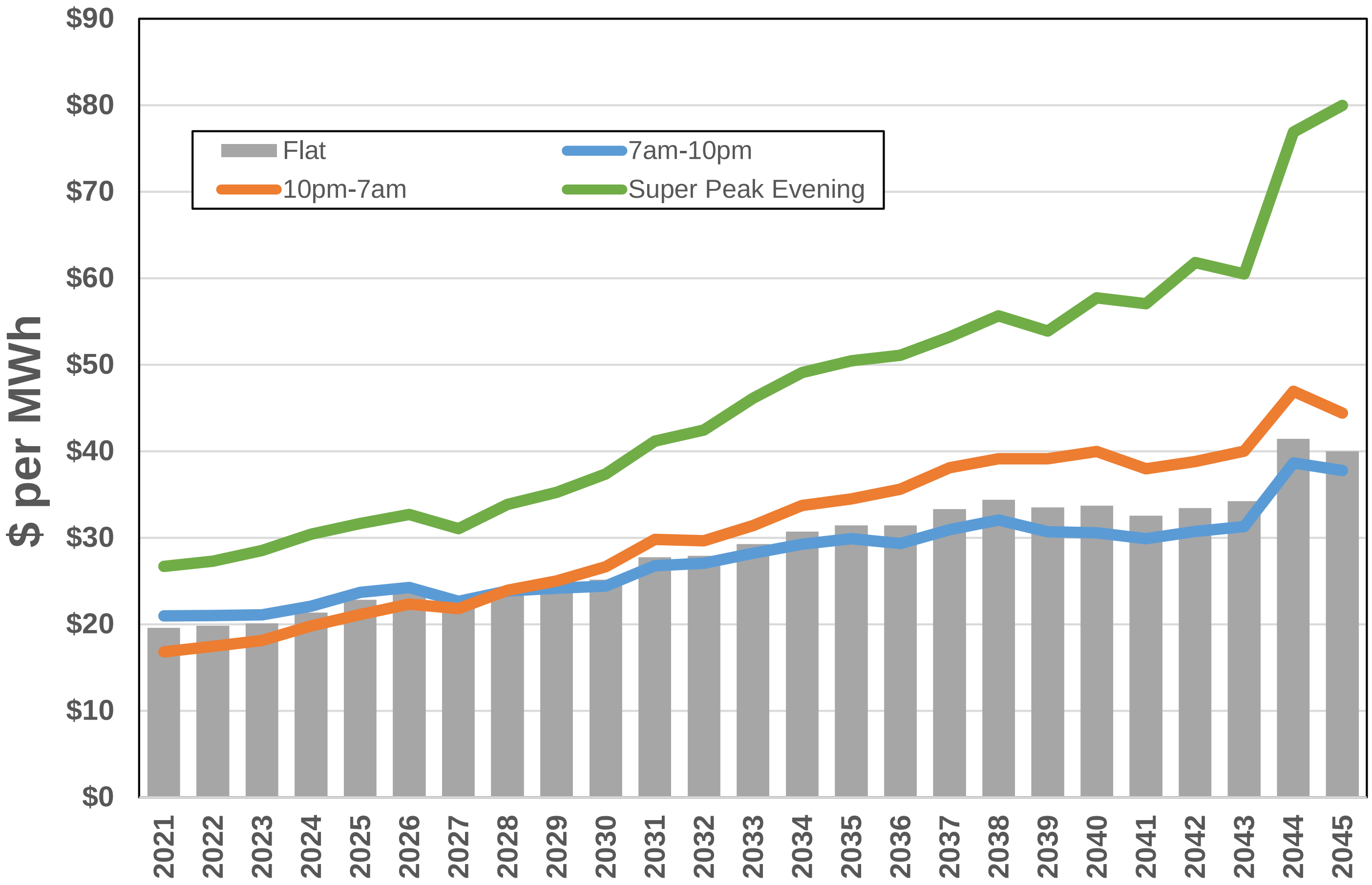
Mid-Columbia Electric Price Forecast
(Deterministic)



<u>Levelized Prices</u>

	20 year	25 year
Flat:	$25.03/MWh	$26.06/MWh
On Peak:	$25.07/MWh	$25.92/MWh
Off Peak:	$24.99/MWh	$26.25/MWh

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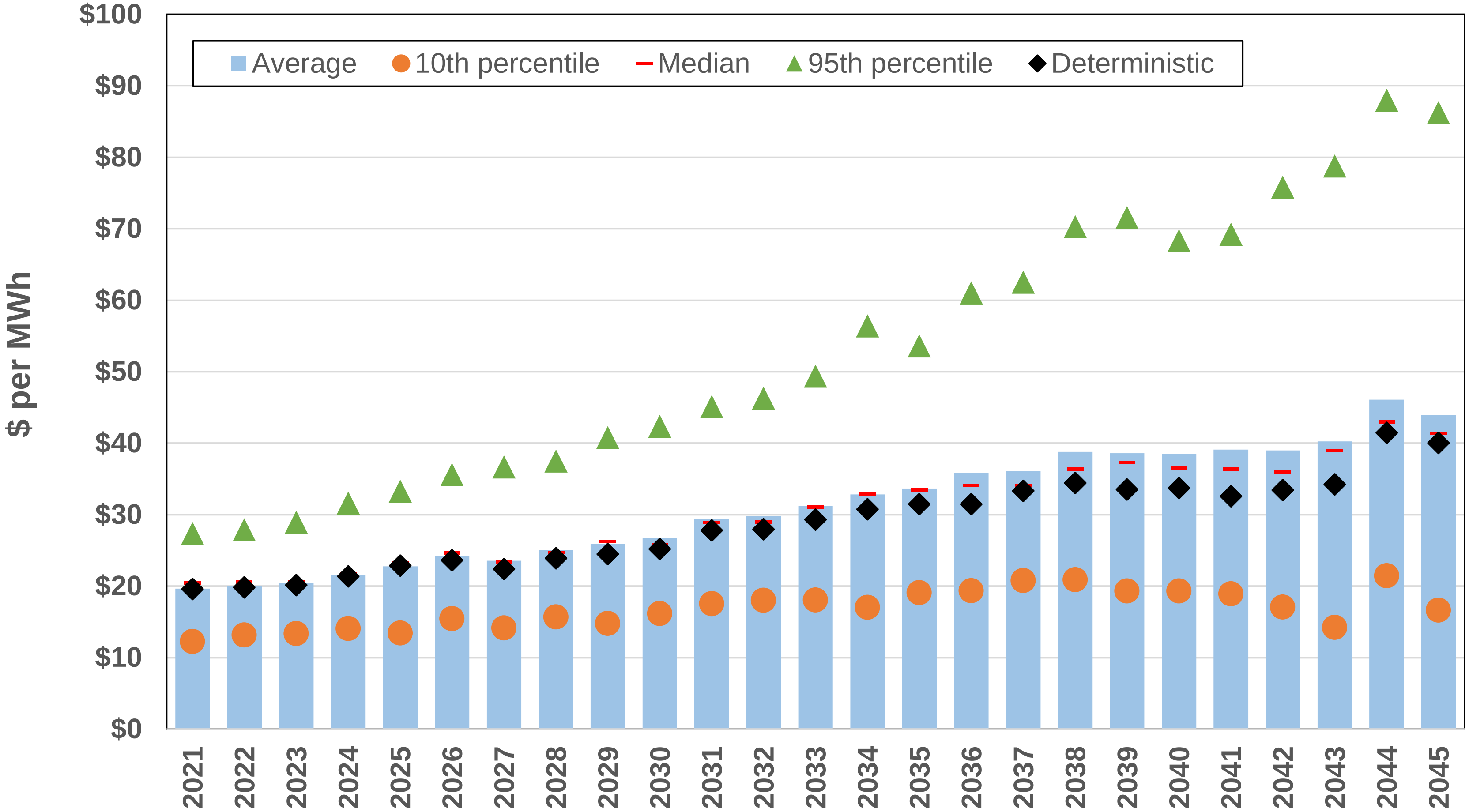
Mid-Columbia Electric Price Forecast

(Stochastic Flat Price Statistics)



20yr Levelized: $26.39 per MWh, 25 yr Levelized: $27.79 per MWh

Note: Coefficient of variation (stdev/mean) in 2021 is 28%, in 2040, the volatility increases to 42%

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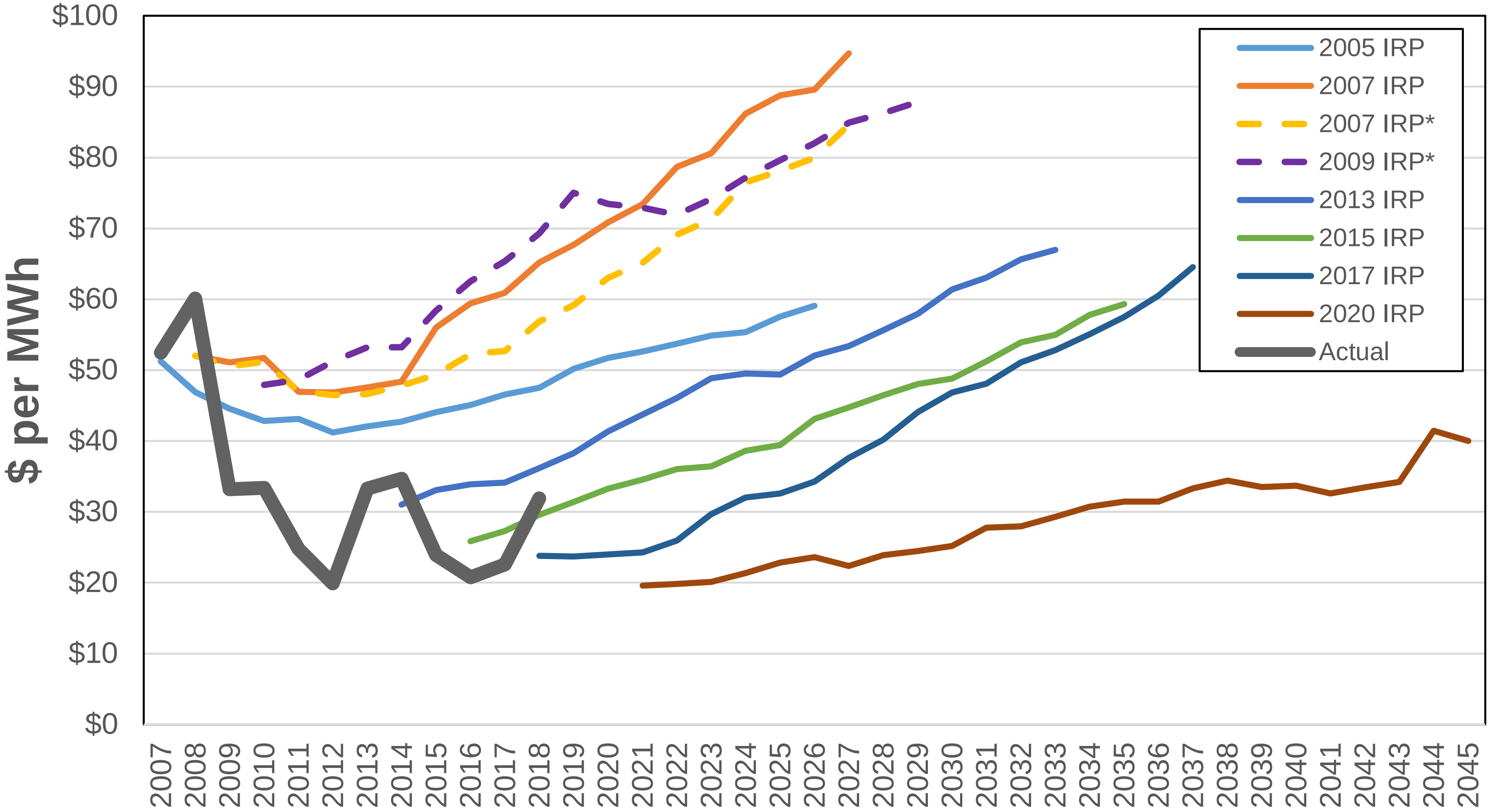
Historical IRP Price Forecasts (Annual Flat Prices)



Note: * Represents IRP forecast expected cases without carbon “taxes” in plant dispatch

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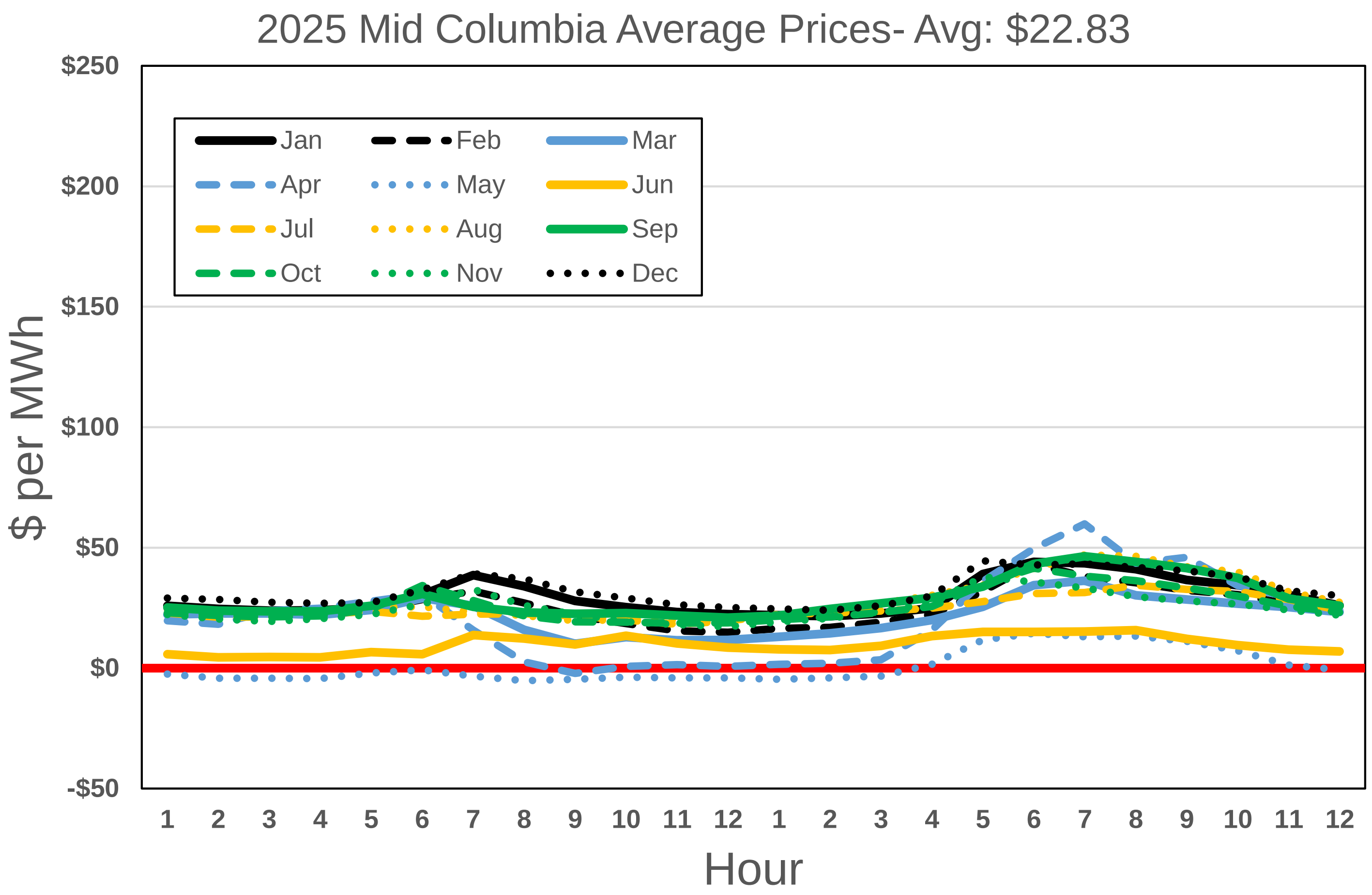
Hourly Price Shape



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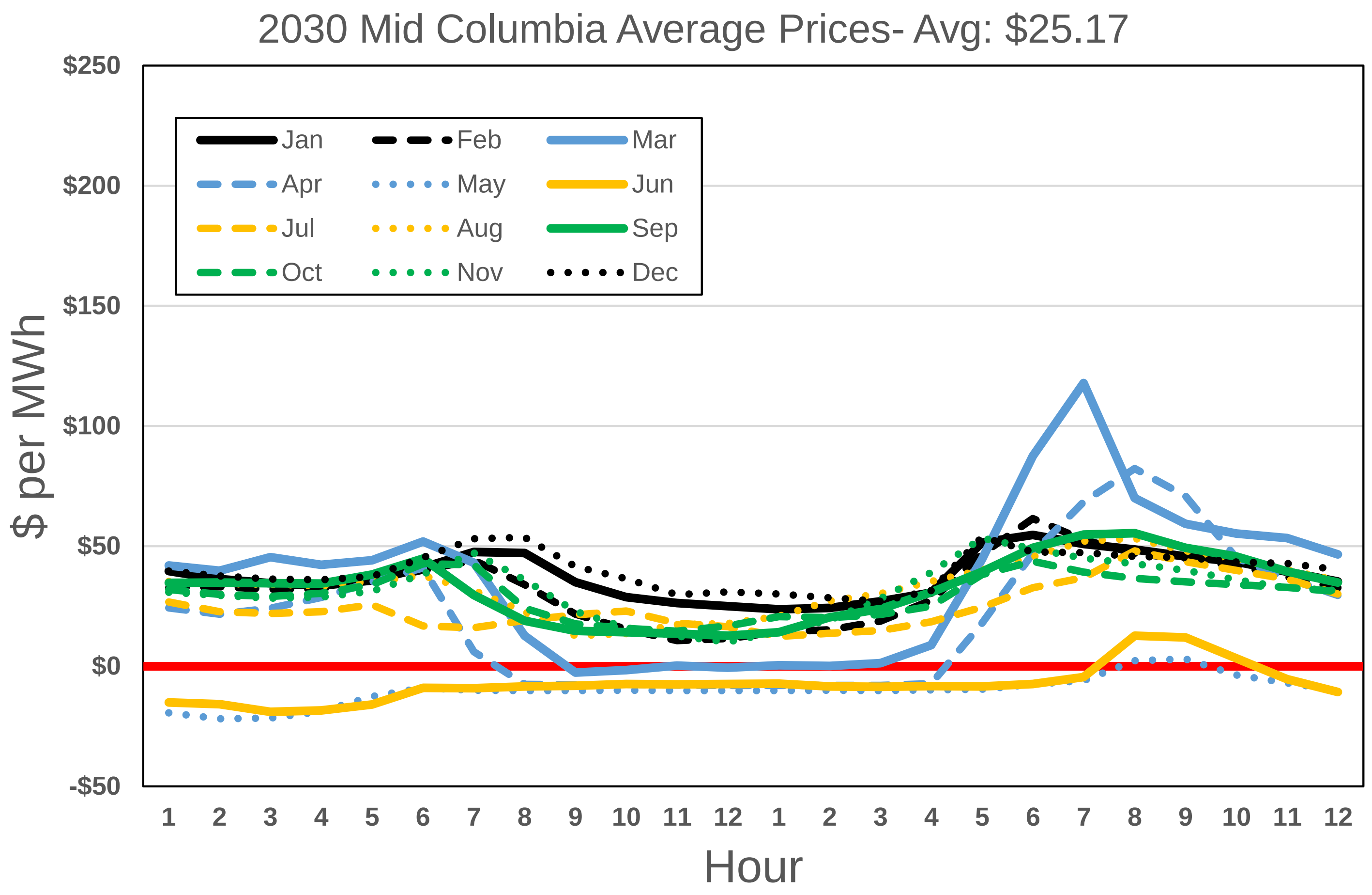
Hourly Price Shape



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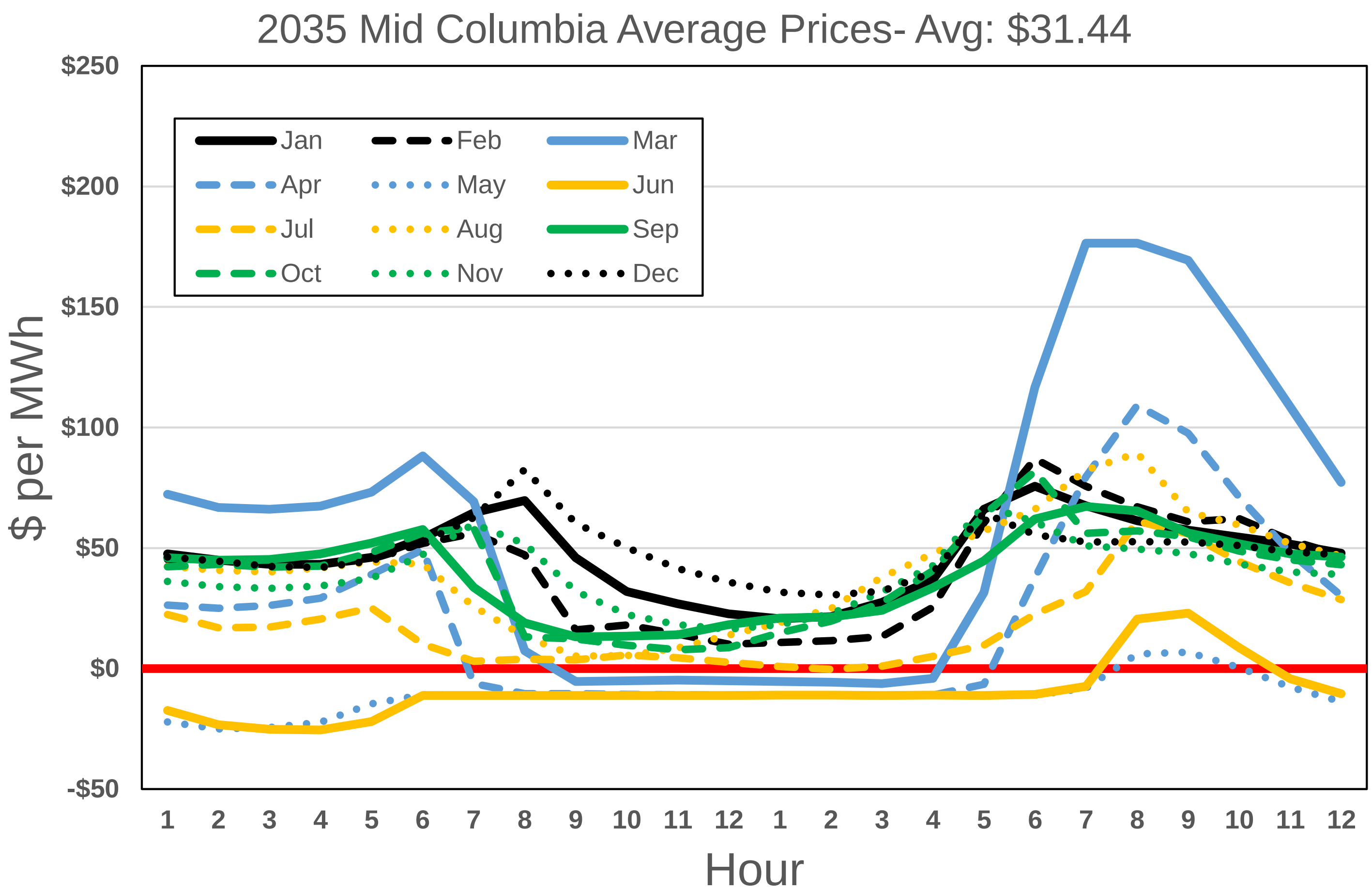
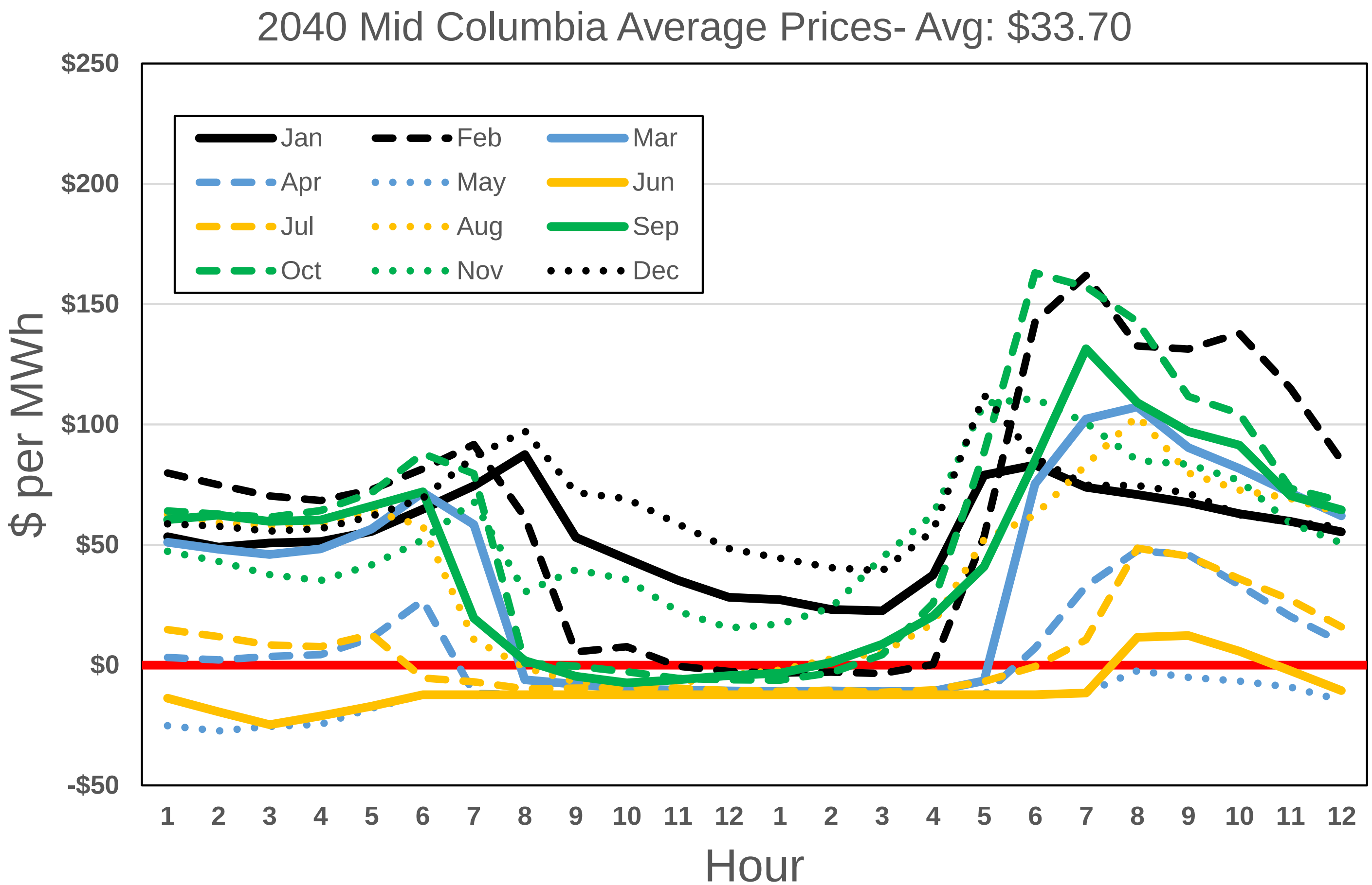
Hourly Price Shape



Hourly Price Shape



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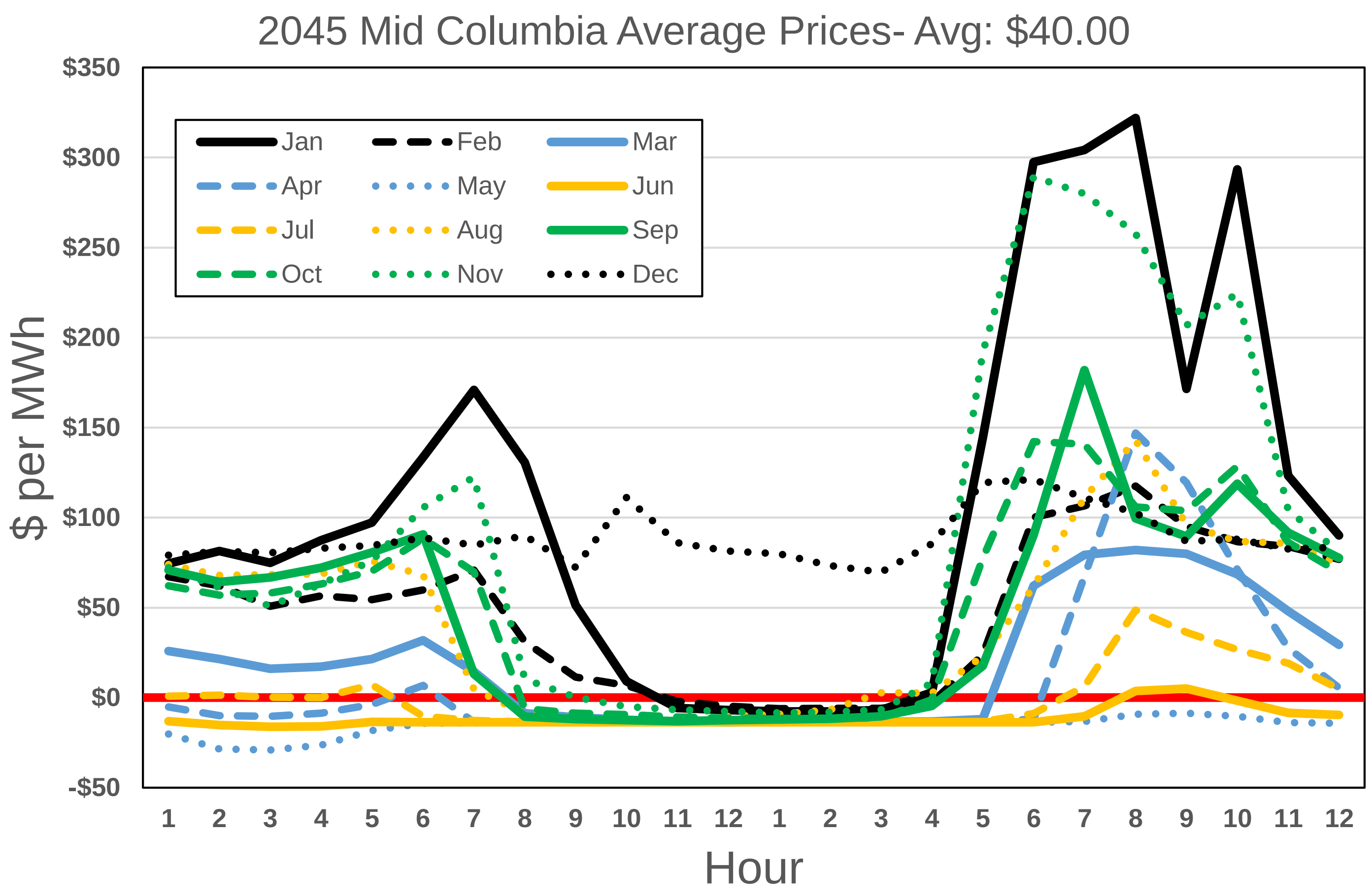
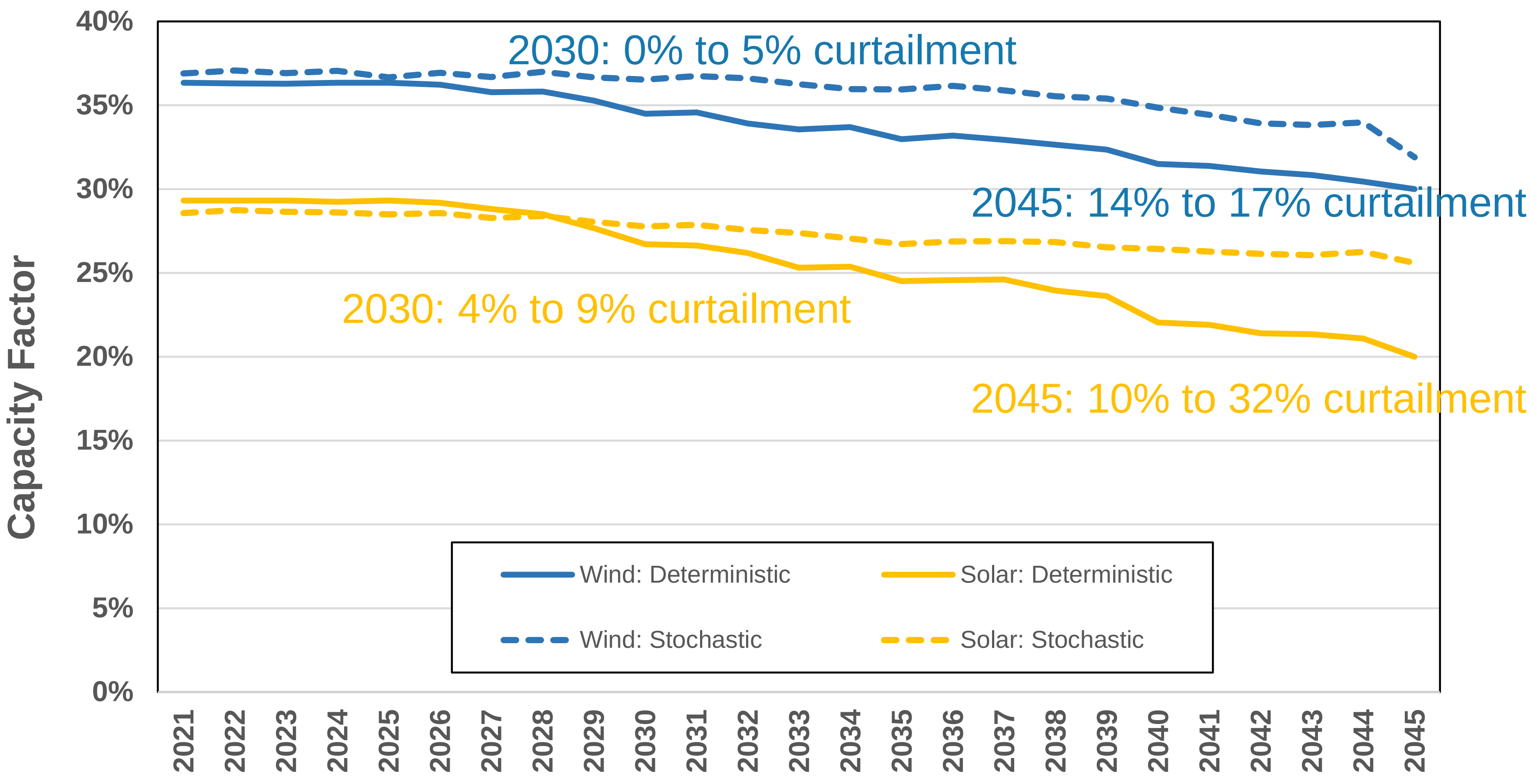
Hourly Price Shape



Renewable Curtailments



Note: Both wind and solar use a -$8.00/MWh + inflation variable charge + PTC if available

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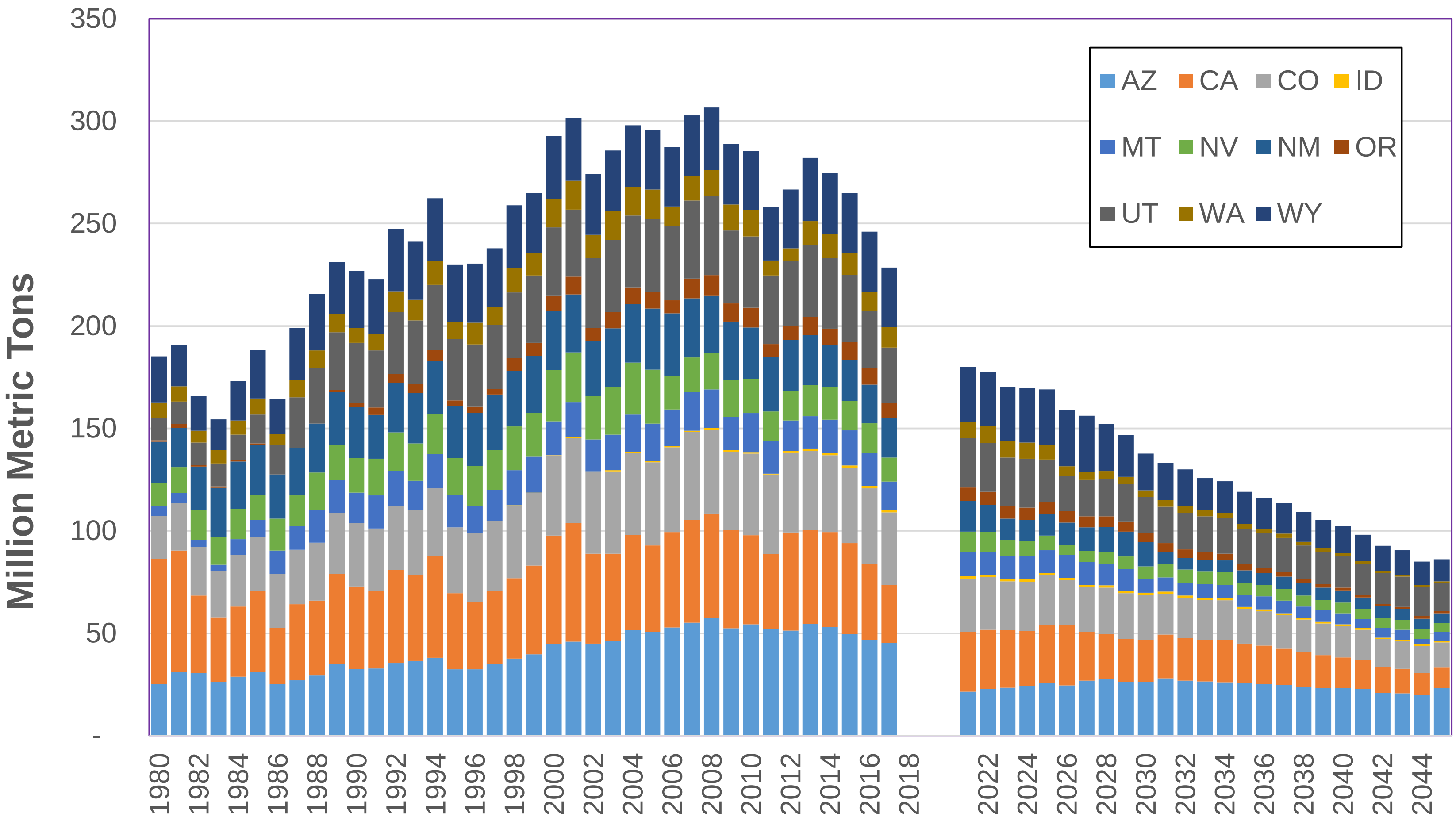
Greenhouse Gas Emissions Forecast

(US Western Interconnect Total)



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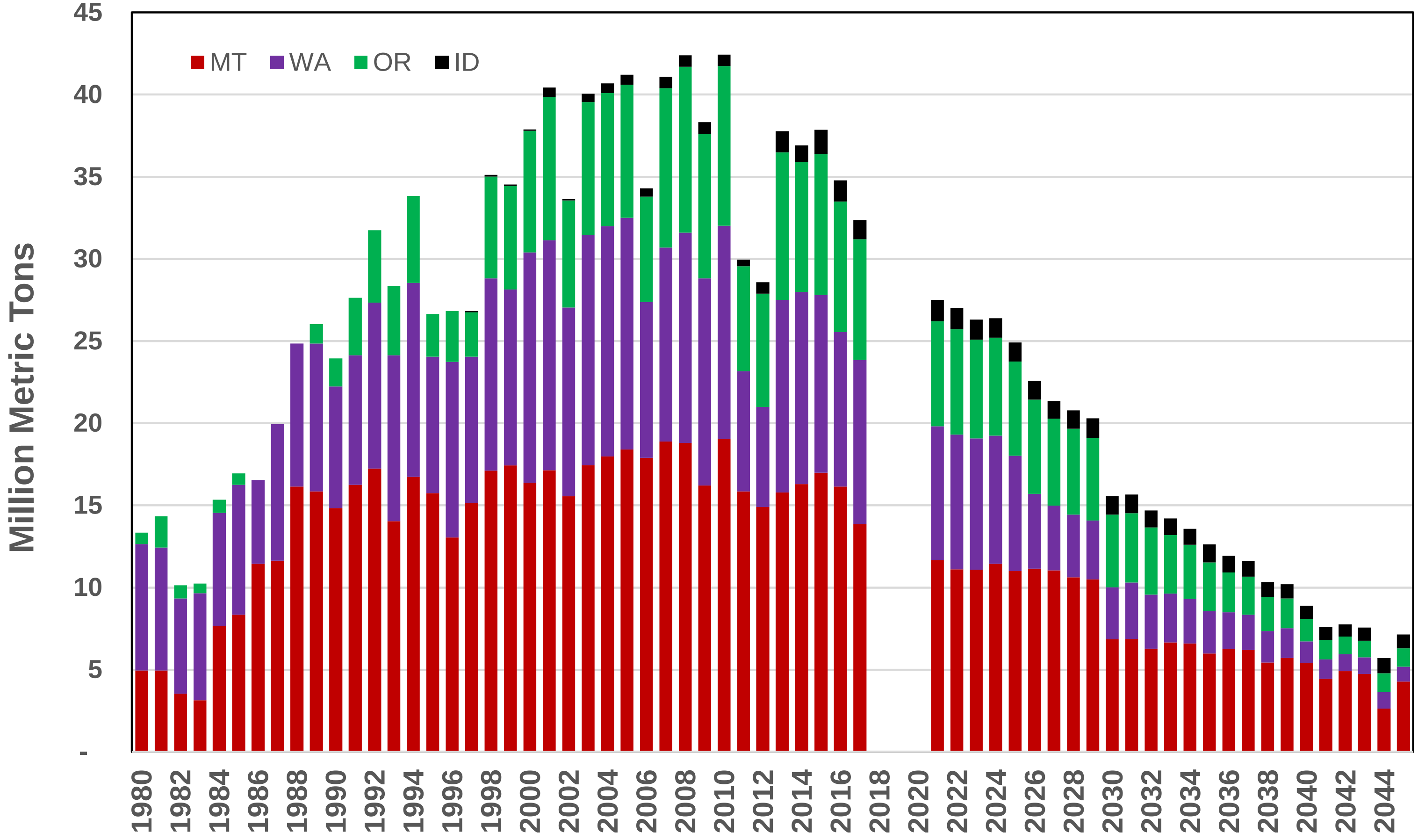
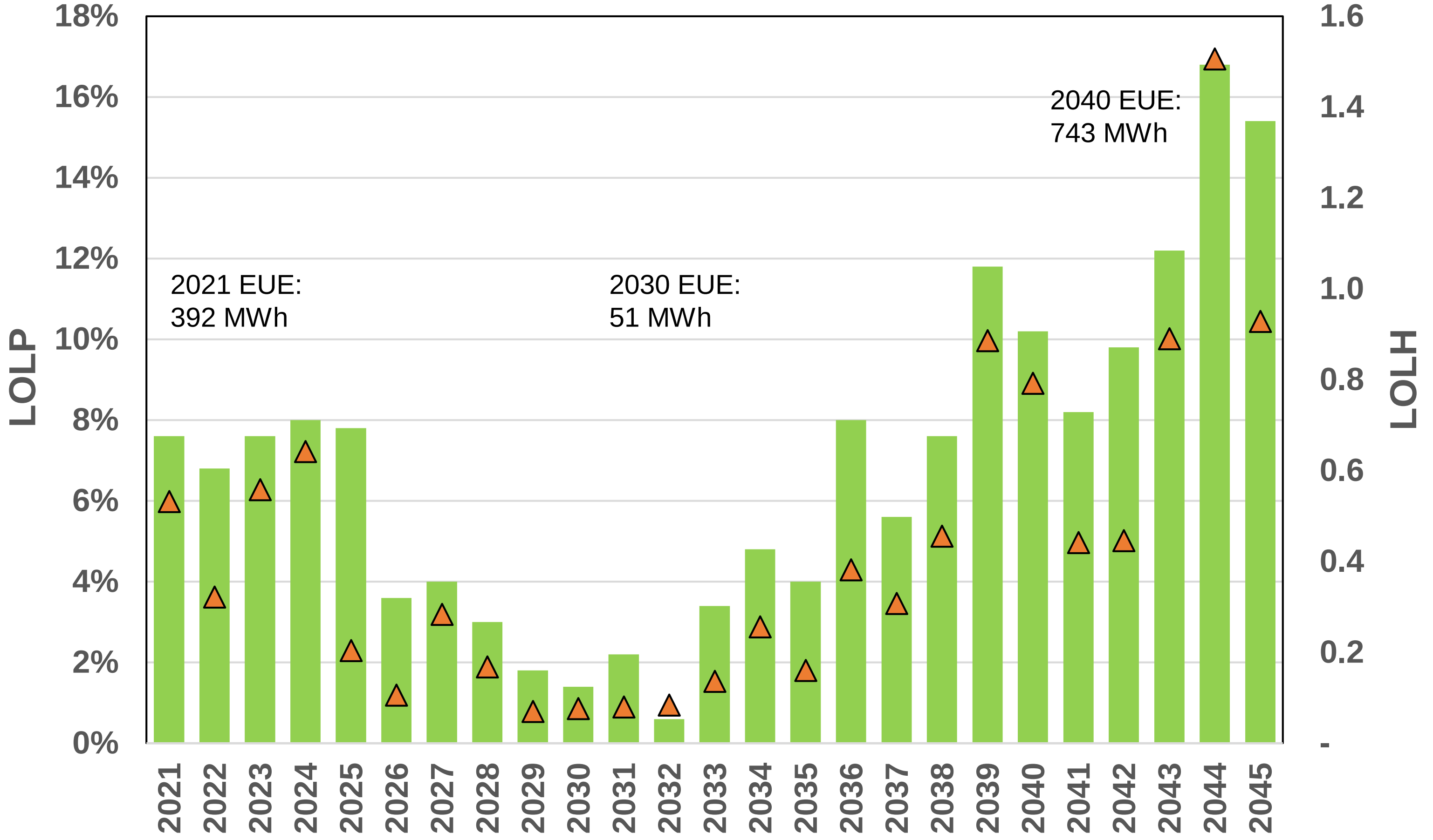
Greenhouse Gas Emissions Forecast
(Northwest- WA,OR,ID,MT)



Regional Resource Adequacy

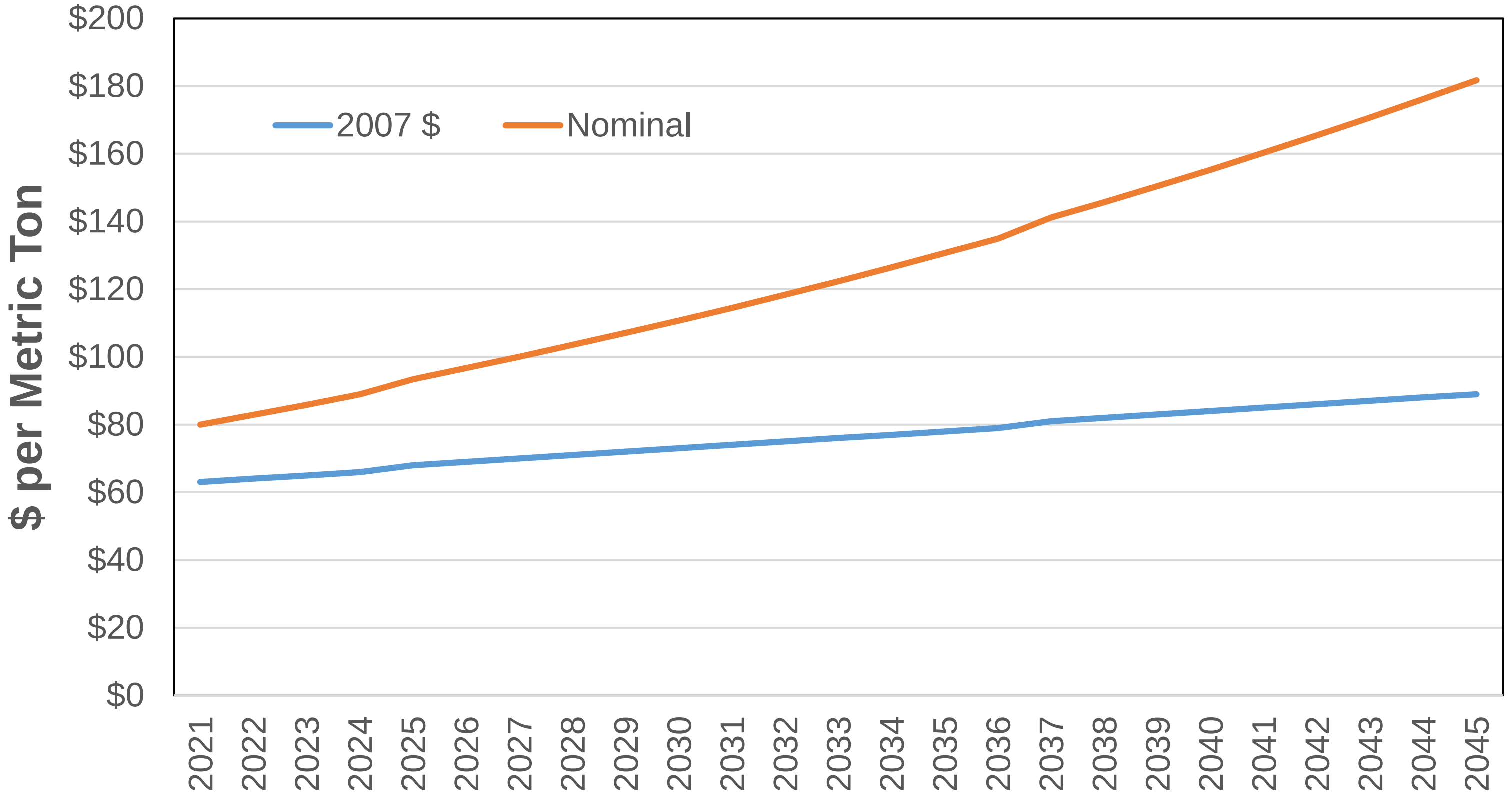


Resource adequacy results are not detailed enough to judge regional resource adequacy and are used for price forecasting only

Electric Price Forecast Scenarios

- Social Cost of Carbon in Dispatch
- No CETA resource build
- Low Natural Gas Prices
- High Natural Gas Prices

Social Cost of Carbon Price Forecast



Note: Inflation from 2007 uses CPI between 2007 and 2018, then 2% per year

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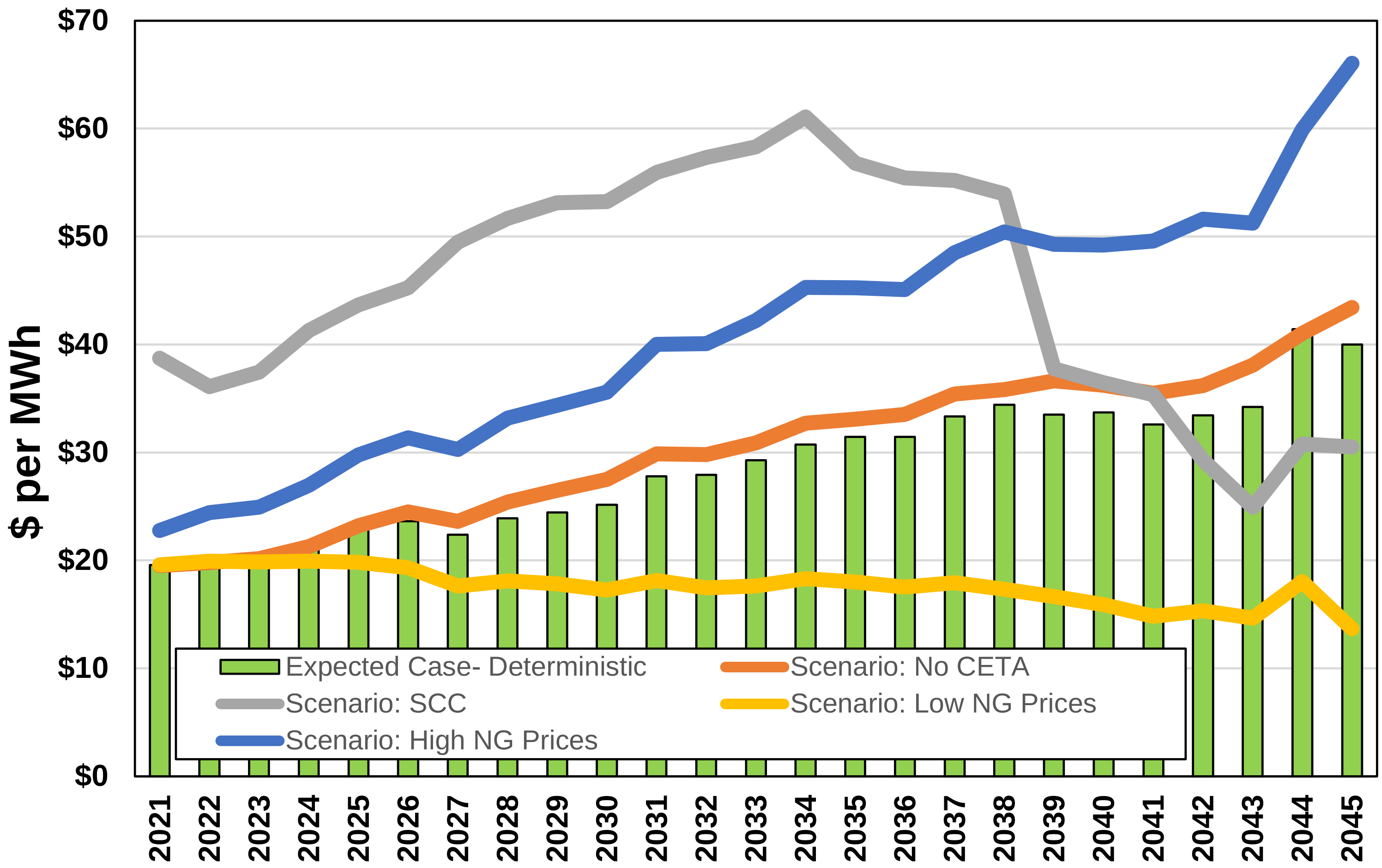
Scenario Price Forecast Results



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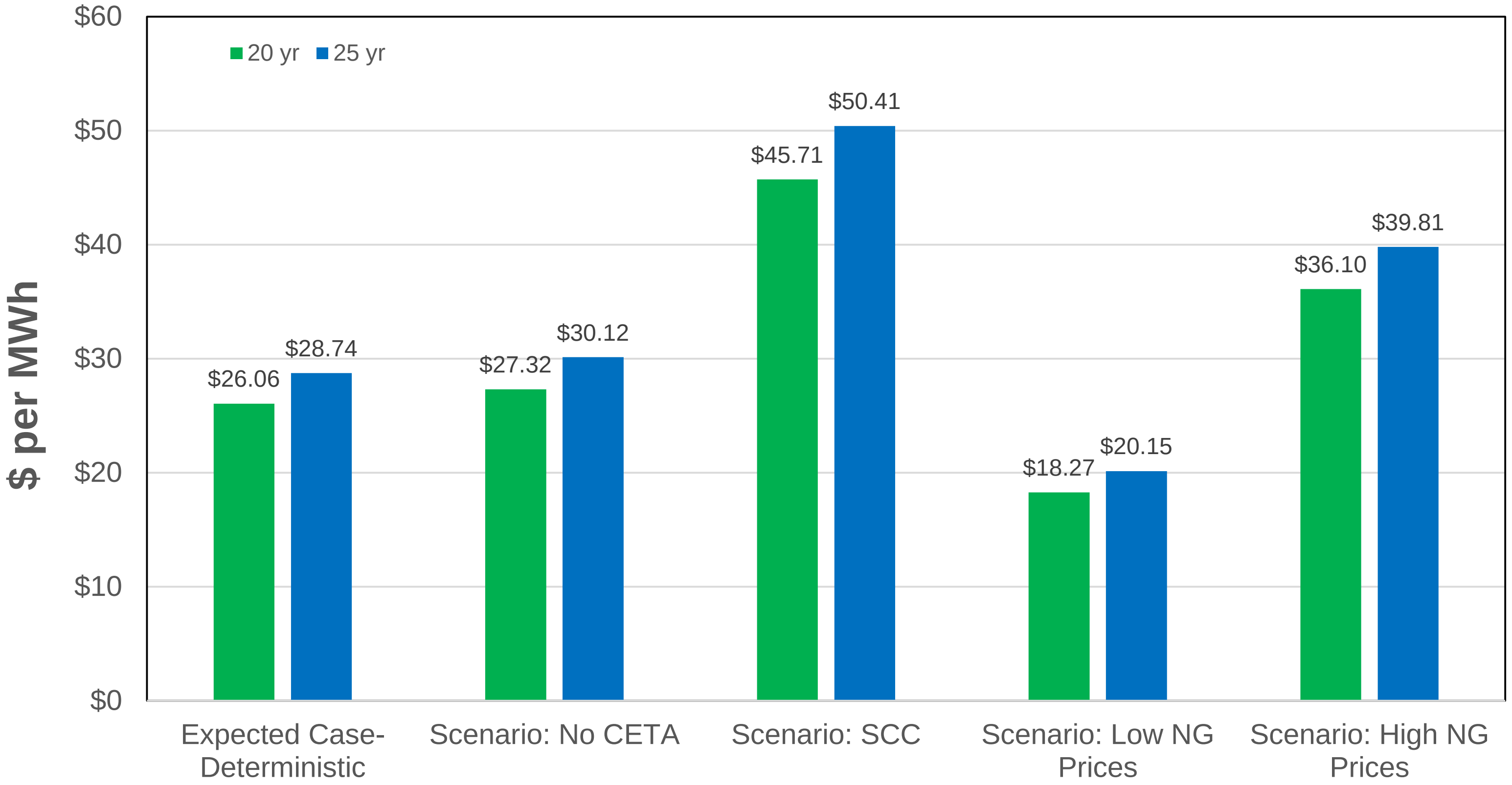
Scenario Levelized Prices



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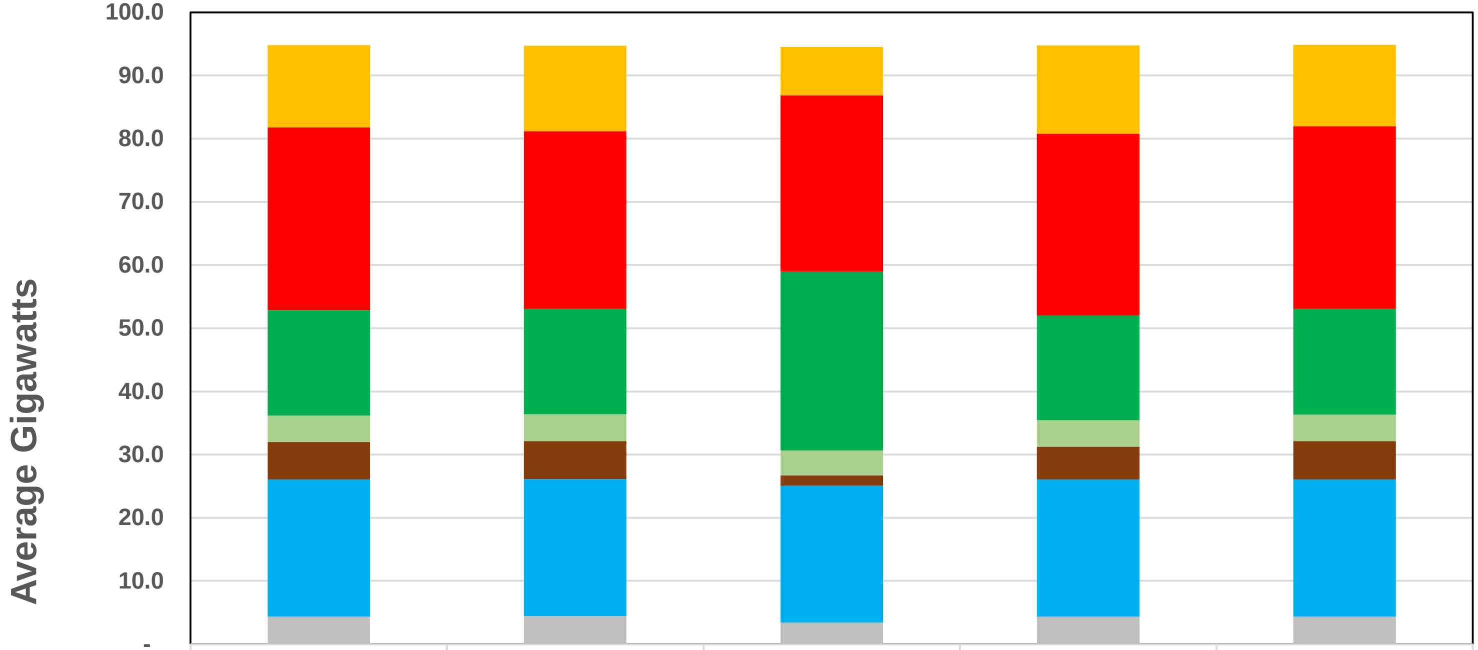
US Western Interconnect Generation Mix Forecast by Scenario (2040)



	Expected Case- Deterministic	Scenario: No CETA	Scenario: SCC	Scenario: Low NG Prices	Scenario: High NG Prices
Natural Gas	13.0	13.5	7.7	13.9	12.9
Solar	28.9	28.1	27.9	28.8	28.9
Wind	16.7	16.7	28.3	16.6	16.7
Nuclear	4.2	4.2	4.0	4.2	4.2
Coal	5.9	6.0	1.6	5.2	6.1
Hydro	21.7	21.7	21.7	21.7	21.7
Other	4.4	4.4	3.4	4.4	4.3

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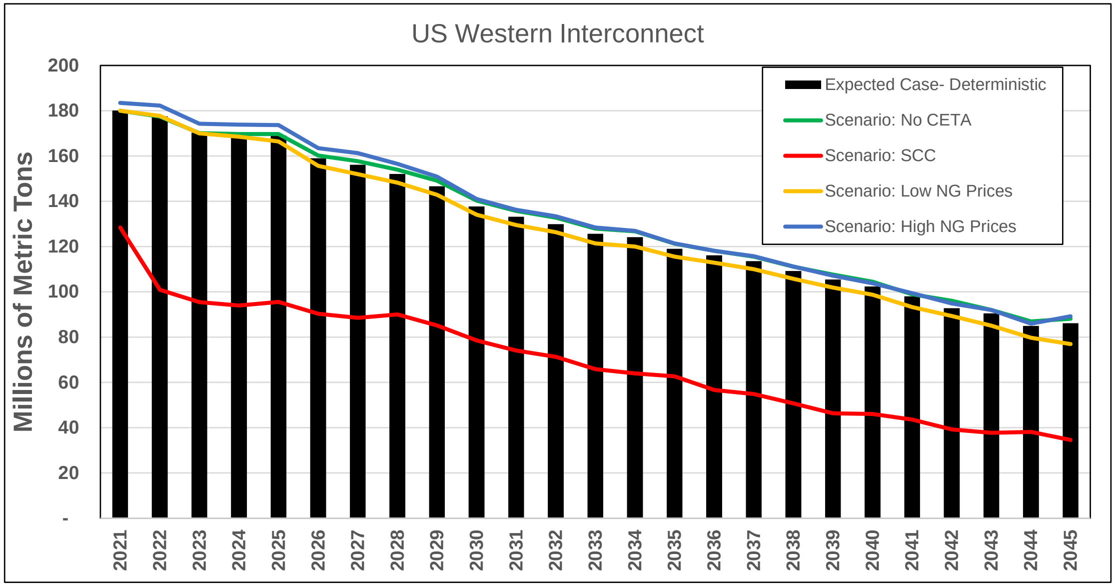
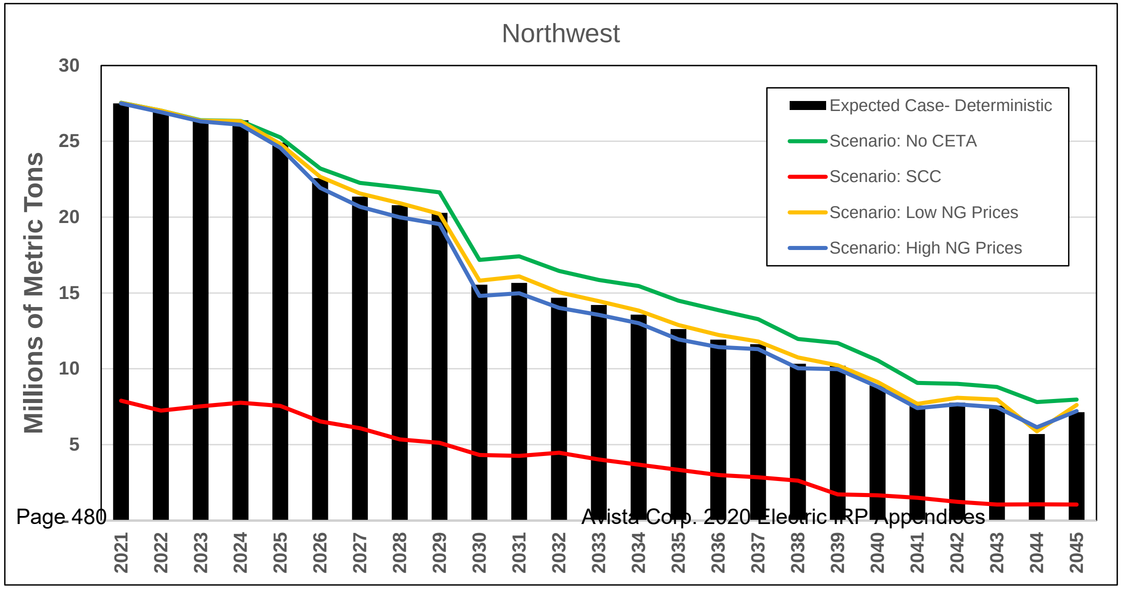
GHG Emission Forecast





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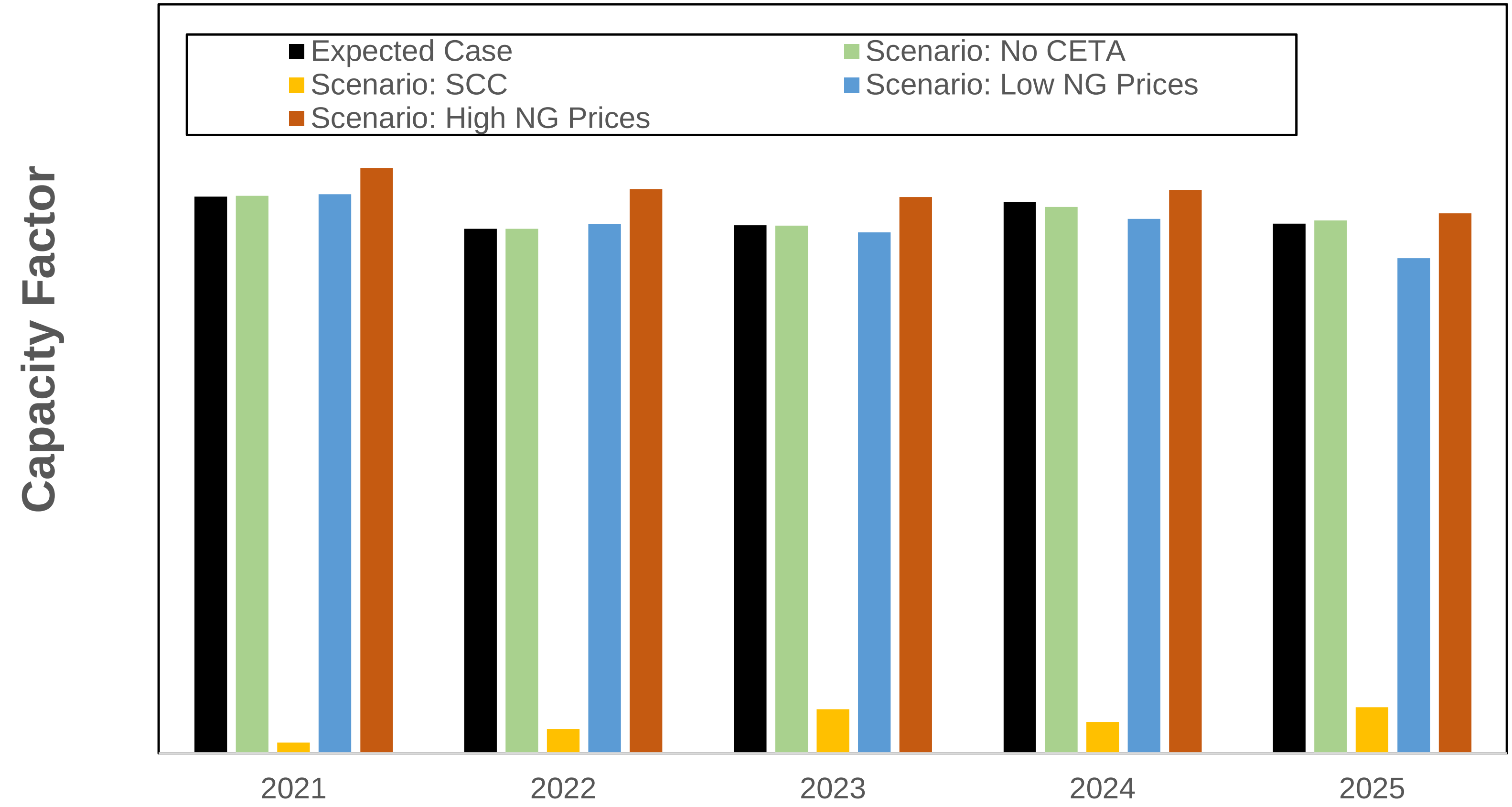
Colstrip Dispatch



Existing Thermal Resource Overview

Darrell Soyars, Manager of Corporate Environmental Compliance
John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
August 6, 2019

Purpose

- Review major environmental regulatory programs that may impact current and future operations
- This is not intended to be a discussion or debate about past practices or current approach to achieve compliance with these programs
- Questions are welcome within the scope of this presentation

Colstrip Environmental Considerations

Colstrip Ownership Information

Colstrip Basic Data			Colstrip Ownership Percentages					
Colstrip Unit #	Size (MW)	Year Online	Avista	NorthWestern Energy, LLC	PacifiCorp	Portland General Electric	Talen Energy, LLC	Puget Sound Energy
Unit #1	333	1975	0%	0%	0%	0%	50%	50%
Unit #2	333	1976	0%	0%	0%	0%	50%	50%
Unit #3	805	1984	15%	0%	10%	20%	30%	25%
Unit #4	805	1986	15%	30%	10%	20%	0%	25%
Total	2,094		11%	11%	7%	14%	25%	32%

- Generating Units 1 and 2: 333 MW each scheduled to shut down end of 2019, required to shut down by July 2022
- Generating Units 3 and 4: 805 MW each
    - Assumed to operate until 2040, depreciation varies by owner
    - Will not be serving Washington loads after 2025

Air Quality – Montana Mercury Rule

- Program established 2010, mercury site-wide annual average below 0.9 lb/Tbtu
- Colstrip installed mercury oxidizer/sorbent injection system in 2010
- MDEQ recently concurred with our pollution equipment technology review
- Units 3 & 4 operate in the 0.8 lb/Tbtu range
- No major changes expected

Air Quality – Mercury Air Toxics Rule

Mercury Air Toxics (MATS) Rule:

- Program established 2016
- Particulate Matter (PM) used as a surrogate for air toxics
- PM site-wide 30-day rolling average below 0.030 lb/MMBtu
- PM and mercury are controlled by existing wet scrubbing equipment with injection
- Units 3 & 4 typically operate in the 0.024 lb/MMBtu range
- Both units exceeded permit limitations during second quarter testing in June 2018
- Root cause analysis led to corrective actions; reachieved compliance in September 2018
- Expect MDEQ penalty for emissions exceedances
- No major changes expected

Air Quality – Regional Haze Rule

- Program established 1999, Improve visibility in Class 1 areas
- Federal plan for Montana was vacated by courts in 2015
- NOx is controlled by LoNOx burners, Overfire air and Smartburn
- MDEQ issued progress plan in 2017, now ready to take leadership of program
- Request for Colstrip analysis due in late 2019 for next planning period
- Regional unit shutdowns would indicate that emissions are below glide path
- No changes or additional pollution controls expected

Air Quality

- Affordable Clean Energy (ACE) Rule
  - Program established 9/16/19, replacement for Clean Power Plan (CPP)
    - Reduce CO_2 emissions by Heat Rate Improvements (HRI)
    - MDEQ will determine future limitations based on evaluation of HRI technologies
    - Cost and remaining useful life consideration
    - MDEQ must submit plan by July 2022, unit compliance by 2024
    - Impacts are unknown at this time

Water Use

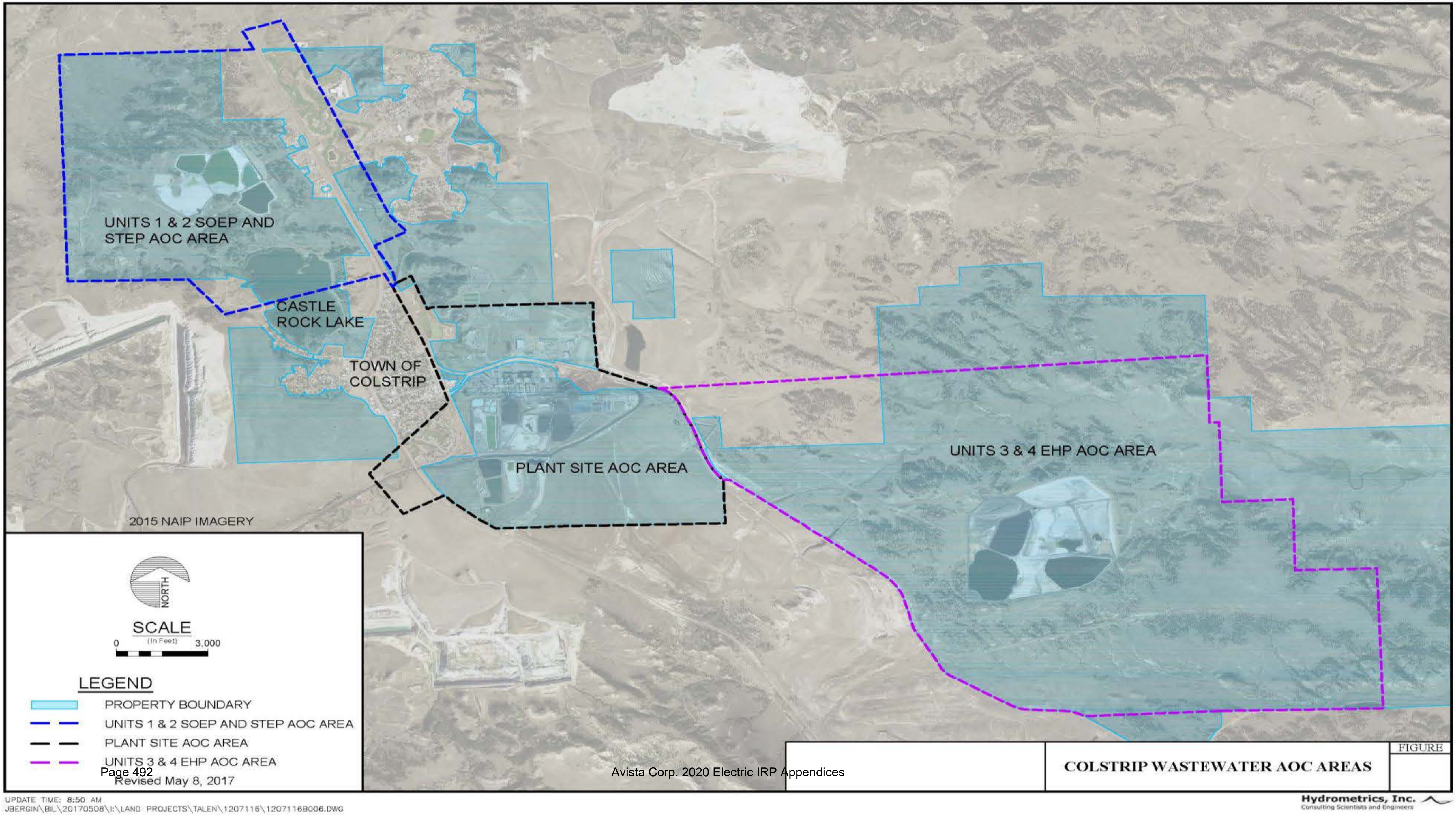
- Raw water is withdrawn from the Yellowstone River to Castle Rock Lake (a.k.a., the Surge Pond) via a 29-mile long pipeline.
- From the Surge Pond, water is piped to holding tanks at the Plant Site for use in boilers, cooling towers and scrubber systems.
- Fly ash from the scrubber system is transported to paste plants which remove excess water and deposit paste in disposal cells.
- Bottom ash is transported to holding ponds, dewatered, and then transported to disposal cells for evaporation.
- Clearwater from paste plants and dewatering is recirculated for reuse.
- All water is reused or lost through evaporation - Zero discharge facility.

Three Storage Areas

– The *Plant Site* contains Generating Units 1 through 4 and several associated ponds (Avista share)

– The *Units 3 & 4 EHP* contains several ponds for the disposal of fly ash scrubber slurry/paste from Generating Units 3 and 4, and bottom ash from Generating Units 1 through 4, and is located approximately 2.5 miles southeast of the Plant Site. (Avista share)

– The *Units 1 & 2 SOEP/STEP* contains several ponds for the disposal of fly ash scrubber slurry/paste from Generating Units 1 and 2, and is located approximately 2 miles northwest of the Plant Site. (No Avista share)


UNITS 1 & 2 SOEP AND
STEP AOC AREA
CASTLE
ROCK LAKE
TOWN OF
COLSTRIP
PLANT SITE AOC AREA
UNITS 3 & 4 EHP AOC AREA
2015 NAIP IMAGERY
NORTH
SCALE
0 (In Feet) 3,000
LEGEND
PROPERTY BOUNDARY
UNITS 1 & 2 SOEP AND STEP AOC AREA
PLANT SITE AOC AREA
UNITS 3 & 4 EHP AOC AREA
Revised May 8, 2017
COLSTRIP WASTEWATER AOC AREAS
FIGURE
UPDATE TIME: 8:50 AM
JBERGIN\BIL\20170508\I:\LAND PROJECTS\TALEN\1207116\1207116B006.DWG
Hydrometrics, Inc.
Consulting Scientists and Engineers

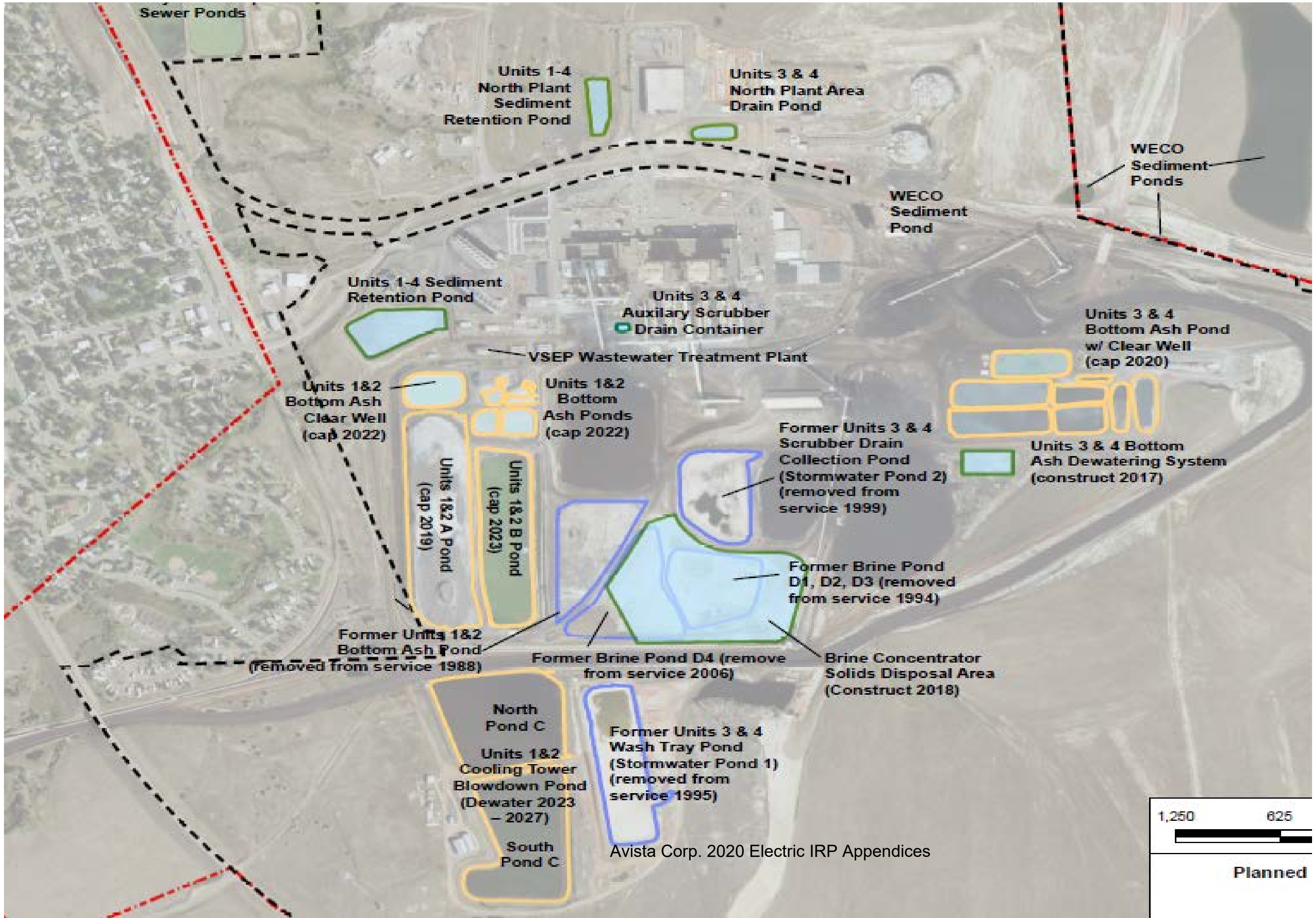
Management Drivers

- Regulatory programs
  - The Site Certificate originally issued including the amended 12(d) stipulation under the Major Facility Siting Act in Montana, Nov. 1975.
  - Administrative Order on Consent (AOC) Regarding Impacts Related to Wastewater Facilities, MDEQ (July 2012), Settlement agreement entered (2016).
  - Federal Coal Combustion Residual (CCR) Rule, 40 Code of Federal Regulations (CFR), April 2015.
- Operational facility
  - Units 1 and 2 announced early shutdown at the end of 2019.
  - Units 3 and 4 must maintain on-going operations
  - Convert to dry ash storage by the end of 2022.

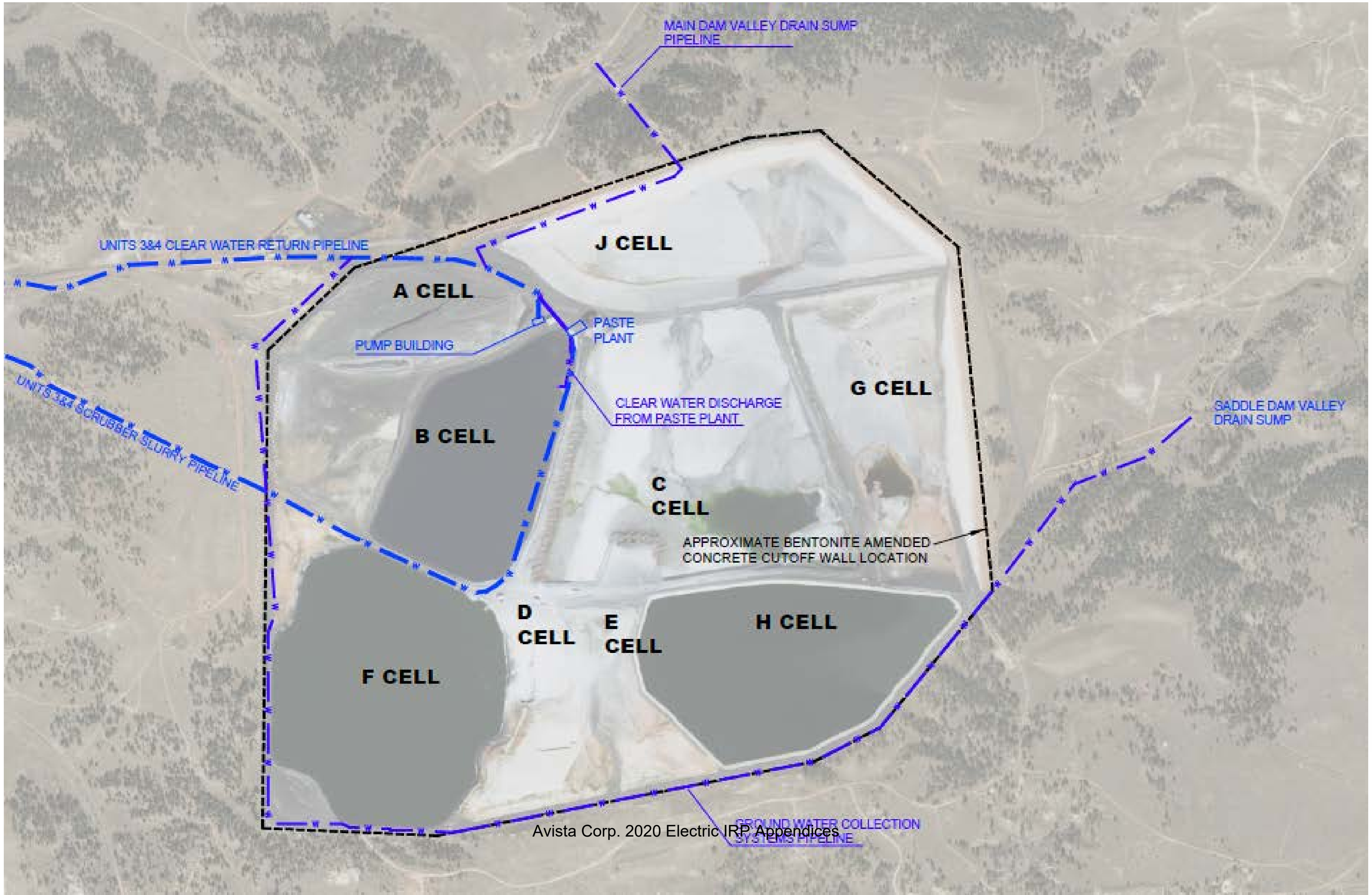
Strategic Water Planning

- Master Plan originally developed in November 2015, Executive Summary (Sept. 2016) is available on MDEQ-AOC website:
- http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation
- AOC public process will select actions to be performed and requires Financial Assurance (FA) of approved plan amounts.
- AOC Process>Site Characterization>Cleanup Criteria and Risk Assessment>Remedy Evaluation>Implement the selected remediation
- CCR Requirements tracking:
- https://www.talenenergy.com/generation/fossil-fuels/ccr-colstrip

Plant Site Ponds



Colstrip Units 3 & 4 Evaporative Ponds



Major Water Activities

- Must remove Boron, Chloride and Sulfate in groundwater
- Achieve source control
  - Close existing ash storage ponds
  - Build water treatment system
  - Dry ash storage
- Install and operate groundwater treatment system
- Achieve clean-up criteria
- Must take place regardless of plant operation

Avista's Financial Assurance Share

- Plant Site area
  - Remedy Plan – $5,841,000 posted 12/21/18
  - Closure Plan – $383,713 posted 2/1/19
- Units 3 & 4
  - Remedy Plan – currently under review, expected late 2019
  - Closure Plan – $6,793,050 posted 2/1/19
- Annual bond reconciliation required

Colstrip Fuel Contract

- Coal supplier has emerged from bankruptcy and agreed to honor the current contract, which ends 12/31/19
- New contract is being negotiated and results will be used to model Colstrip in this IRP

Modeled Colstrip Costs

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fixed O&M	10.3	9.4	9.7	10.1	11.2					
Coal Combustion Residuals O&M	0.4	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Existing Capital Revenue Requirement – WA	12.1	11.3	10.5	9.8	9.1	0.4				
Existing Capital Revenue Requirement – ID	5.9	5.5	5.1	4.8	4.5	4.2	3.9	0.2		
Traditional Capital Spending (Expensed)	9.4	3.2	4.2	9.5	6.4					
Asset Retirement Obligation Capital Revenue Requirement	1.7	1.7	1.6	1.6	1.5	1.5	1.4	1.4	1.3	1.3
Coal Combustion Residuals Master Plan Capital Revenue Requirement	0.5	0.6	0.9	1.1	1.1	1.0	1.0	1.0	0.9	0.9
Total	**40.3**	**32.3**	**32.9**	**37.8**	**34.7**	**8.0**	**7.2**	**3.5**	**3.1**	**3.1**

Table does not include fuel and variable O&M costs

Coal Combustion Residuals O&M and Master Plan Capital Revenue Requirement, and Asset Retirement Obligation Capital Revenue Requirement continue through 2045

Lancaster Power Purchase Agreement

- Current PPA ends in October 2026
- Directly connect to either AVA or BPA transmission system
- Avista controls firm GTN transportation rights
- This IRP will evaluate an extension of this contract

Thermal Plant Book Value and Remaining Depreciation

Thermal Plant	Book Value (millions)	Remaining Life (years)
Boulder Park	$ 17.4	20
Colstrip Units 3 and 4	$ 121.4	See Note
Coyote Springs 2	$ 124.8	21
Kettle Falls CT	$ 3.7	24
Northeast	$ 0.6	<2
Rathdrum	$ 36.5	14

- This table includes land, total generation and transmission/interconnection
- Remaining life is for the generation, transmission may differ
- Numbers are from the end of 2018 and may change as pieces depreciate or new capital is added
- Colstrip modeling will use a 2025 for Washington and 2027 for Idaho

2020 Electric IRP
Final Resource Need Assessment

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
August 6, 2019

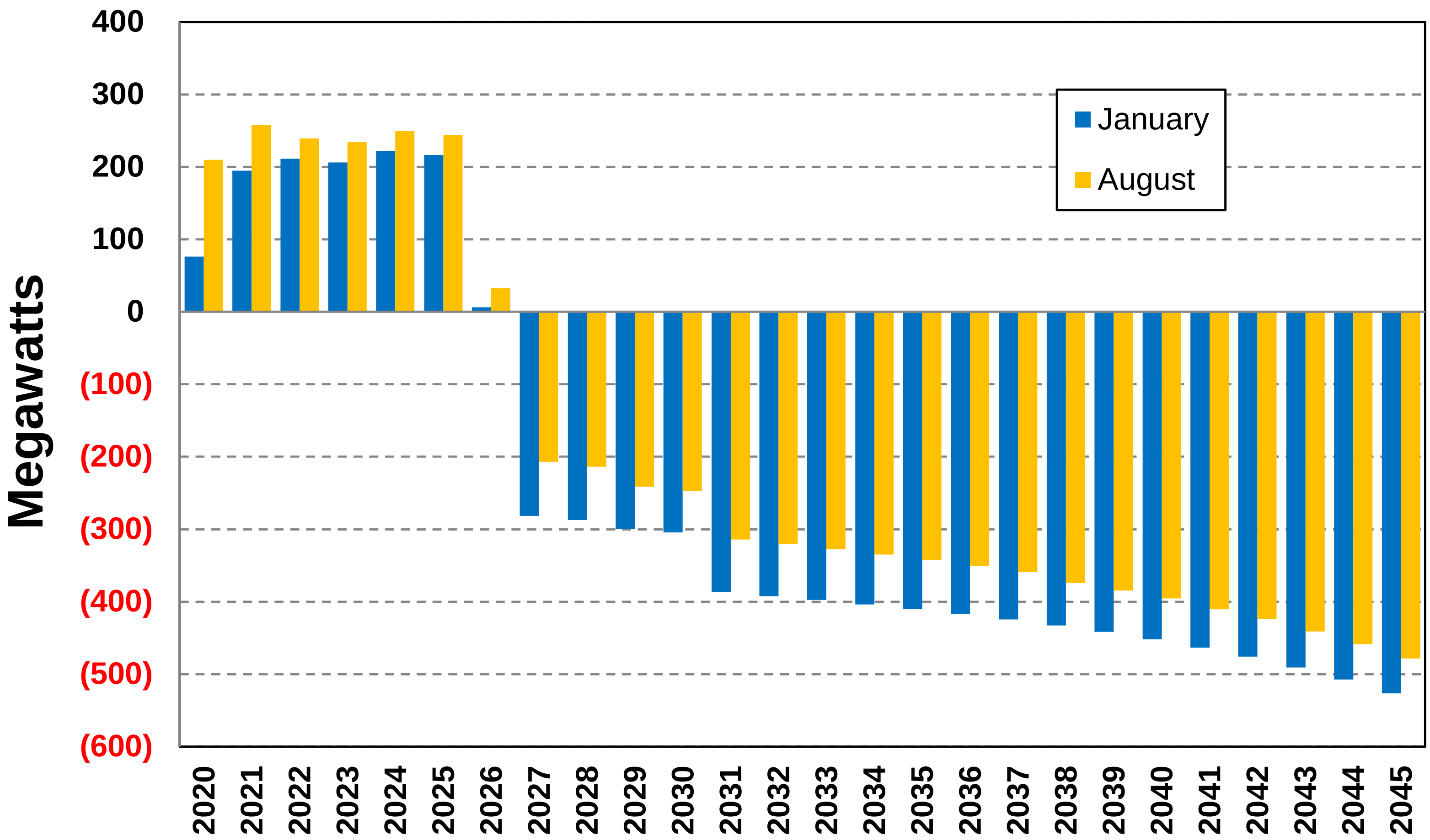
Agenda

- 2020 IRP Load & Resource Balance
- Avista's Clean Energy Goals
- Energy Independence Act Renewable Requirement Forecast
- Clean Energy Transformation Act Forecast

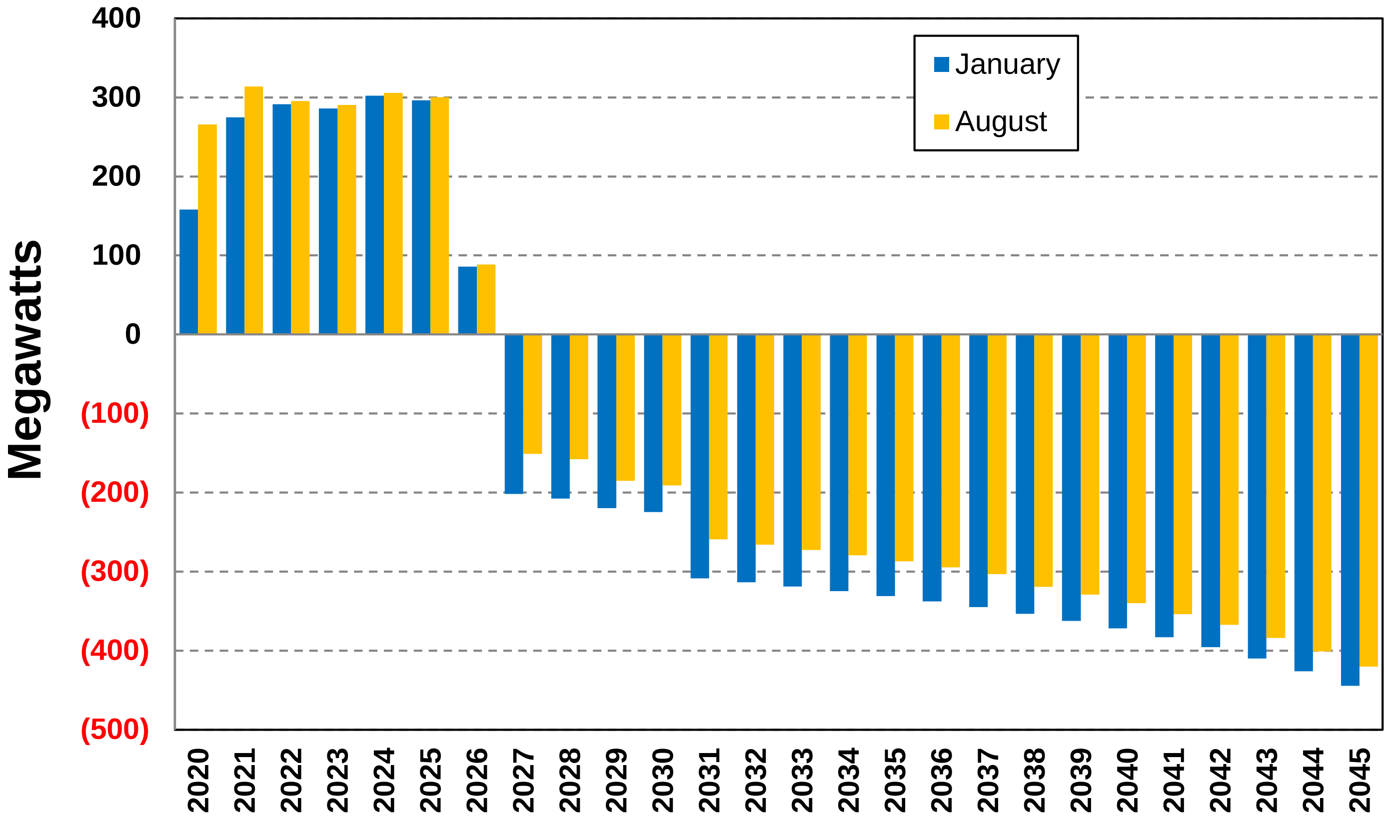
Load & Resource Methodology Review

- Sum resource capabilities against loads
- Resource plans are subject to 5% LOLP analysis – determines planning margins
- Capacity
  - Planning Margin (14% Winter, 7% Summer)
  - Operating Reserves and Regulation (~8%)
  - Reduced by planned outages for maintenance
  - Plant to largest deficit months between 1- and 18-hour analyses
- Energy
  - Reduced by planned and forced outages
  - Maximum *potential* thermal generation over the year
  - 80-year hydro average, adjusted down to 10^{th} percentile

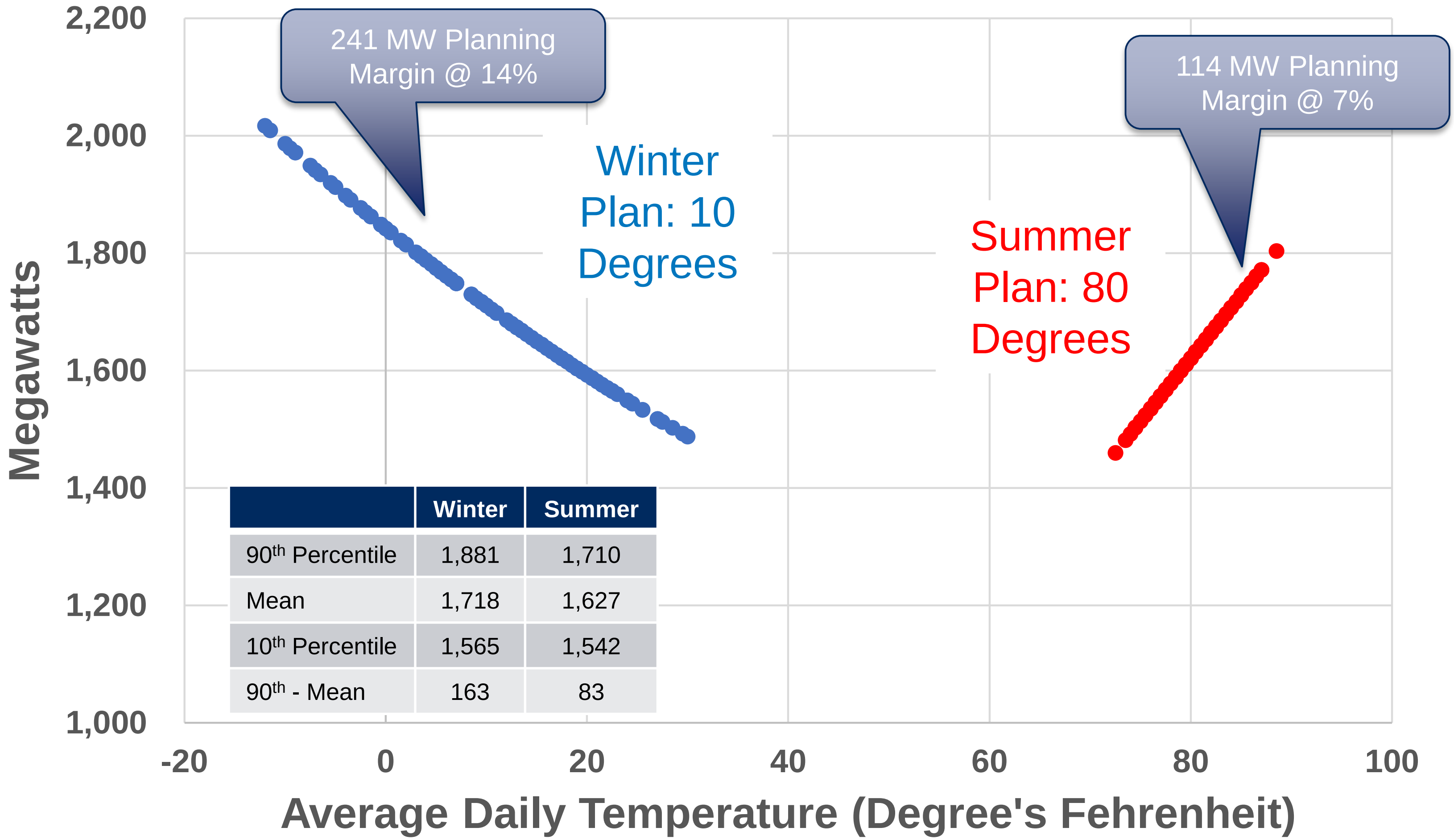
One Hour Peak Load & Resource Position



18-Hour Sustained Peak L&R

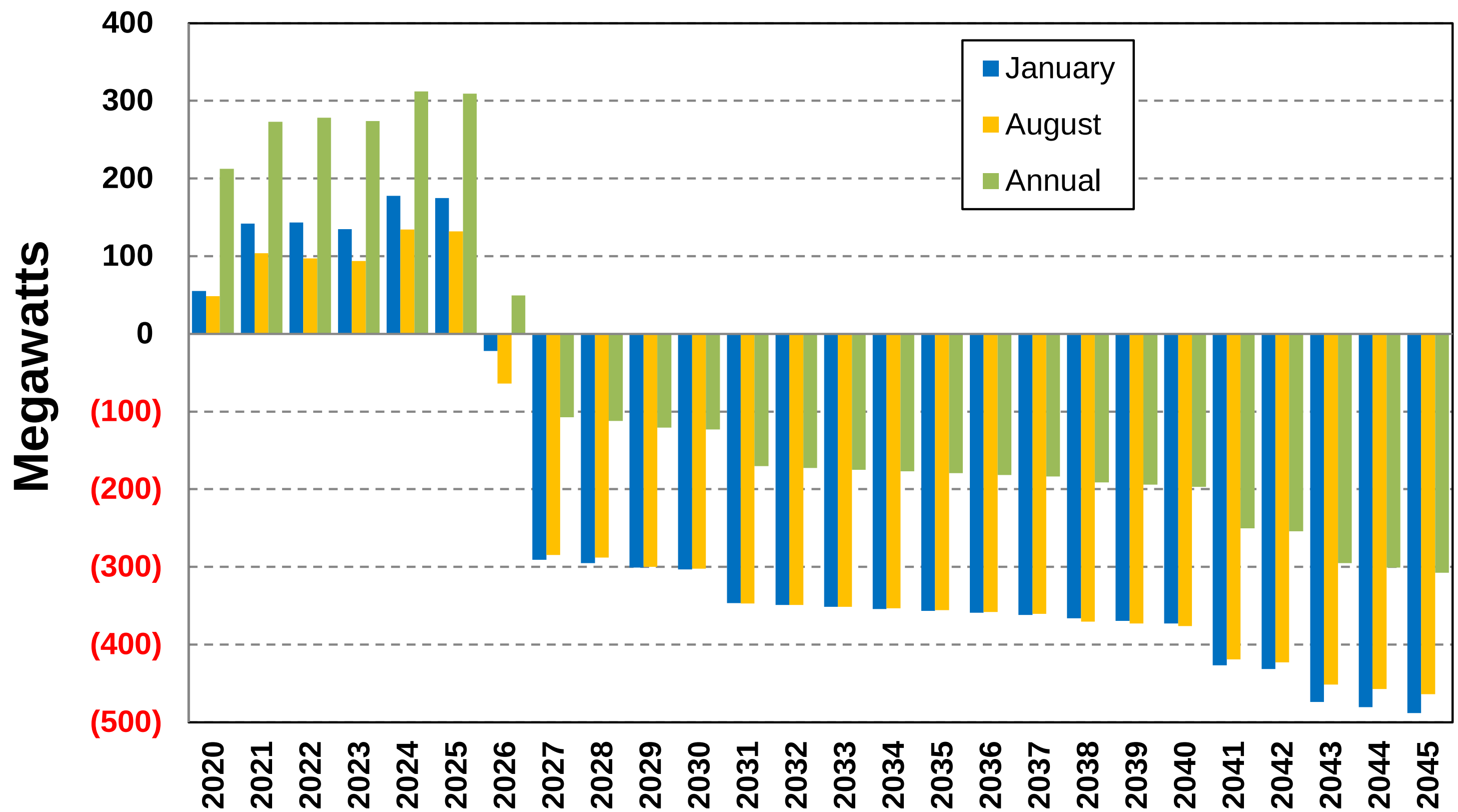


Load Variability (Temperature Variation)



	Winter	Summer
90th Percentile	1,881	1,710
Mean	1,718	1,627
10th Percentile	1,565	1,542
90th - Mean	163	83

Energy Load & Resource Position



Avista's Clean Energy Goal

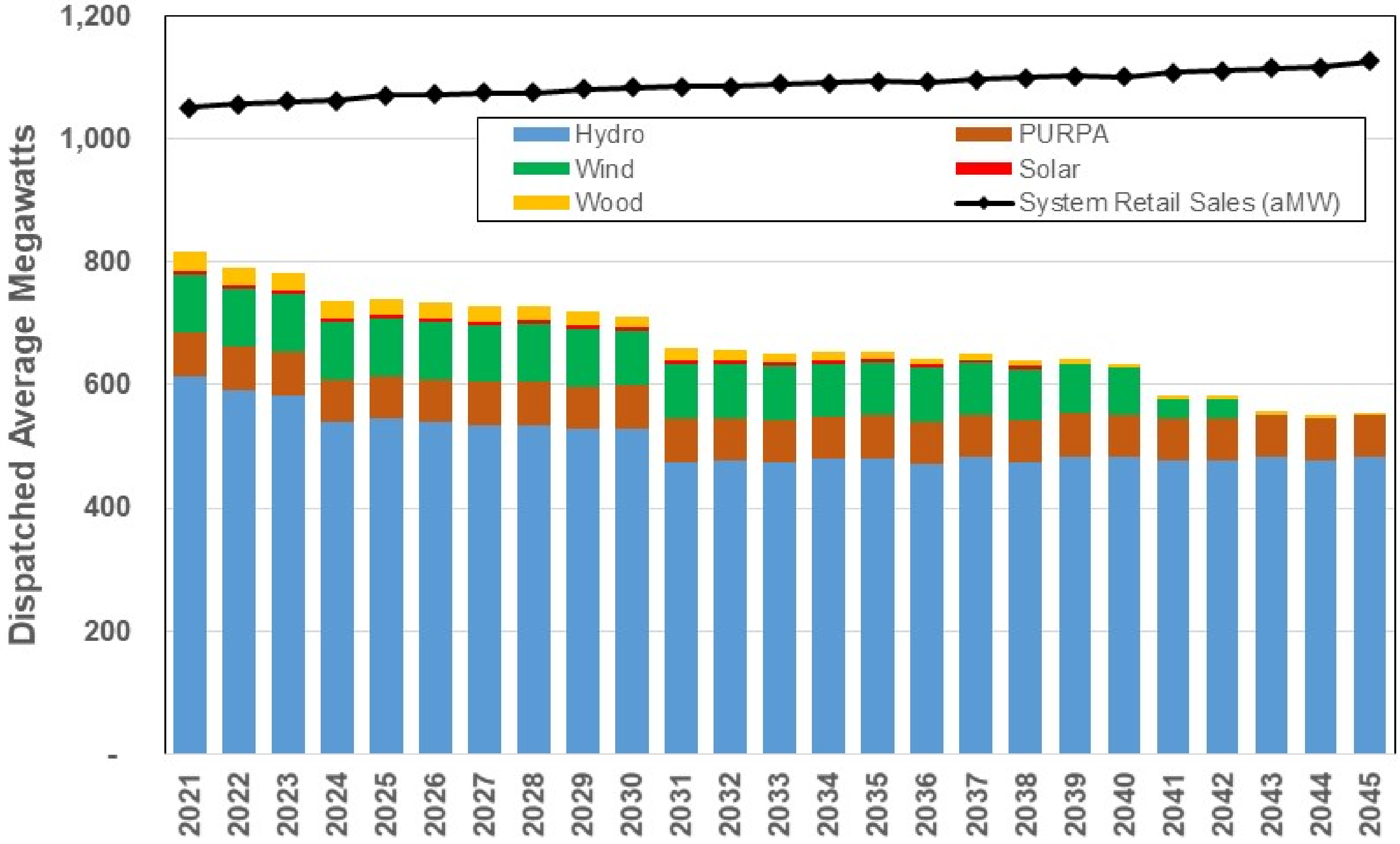
Goals

- 2027 – 100% carbon-neutral
- 2045 – 100% clean electricity

How we will get there

- It's not just about generation – various solutions are necessary
- Maintain focus on reliability and affordability
- Natural gas plays an important part of a clean energy future
- Cost effective technologies need to emerge and mature

Avista Corporate Clean Energy Goals

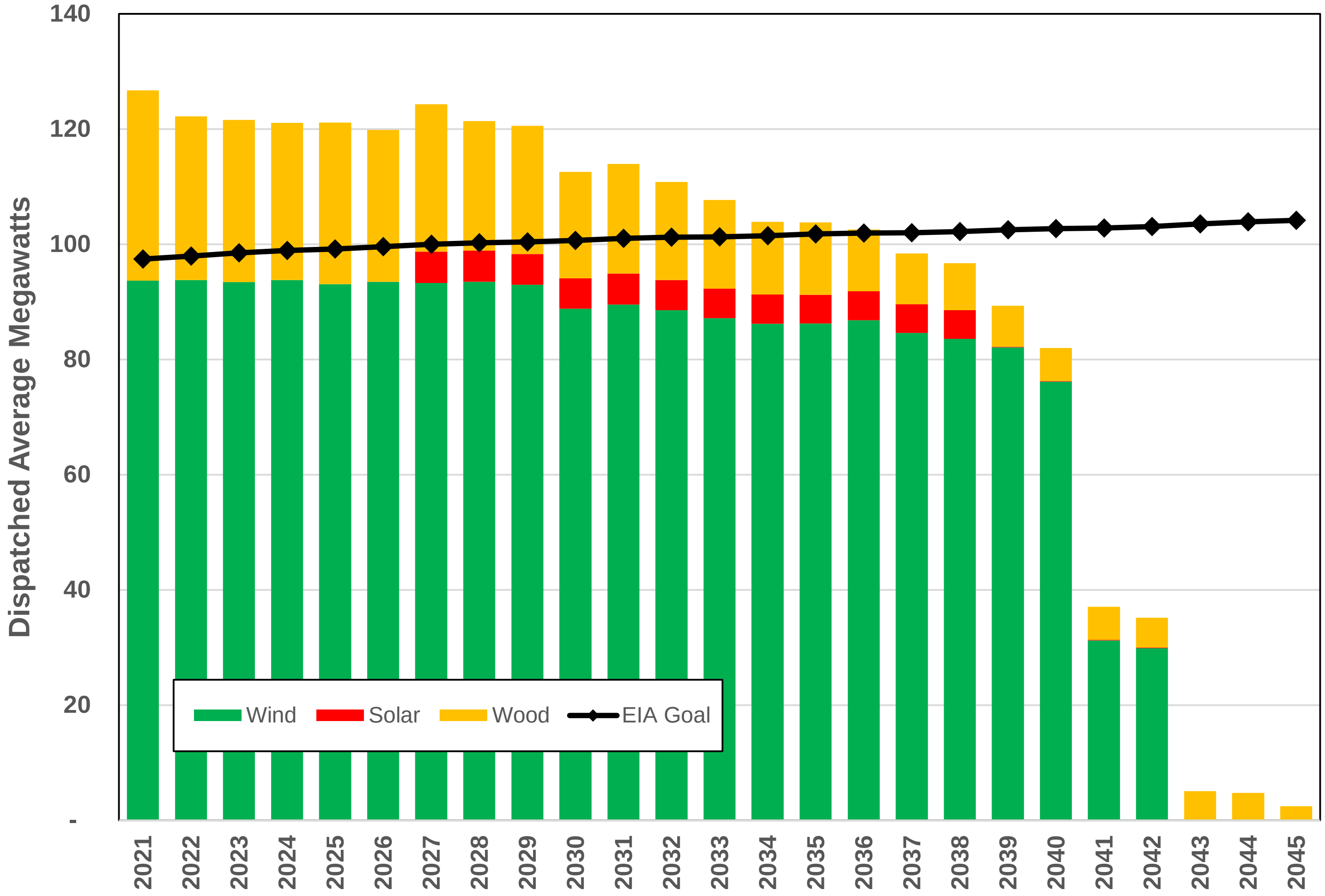


Washington State Clean Energy Goals

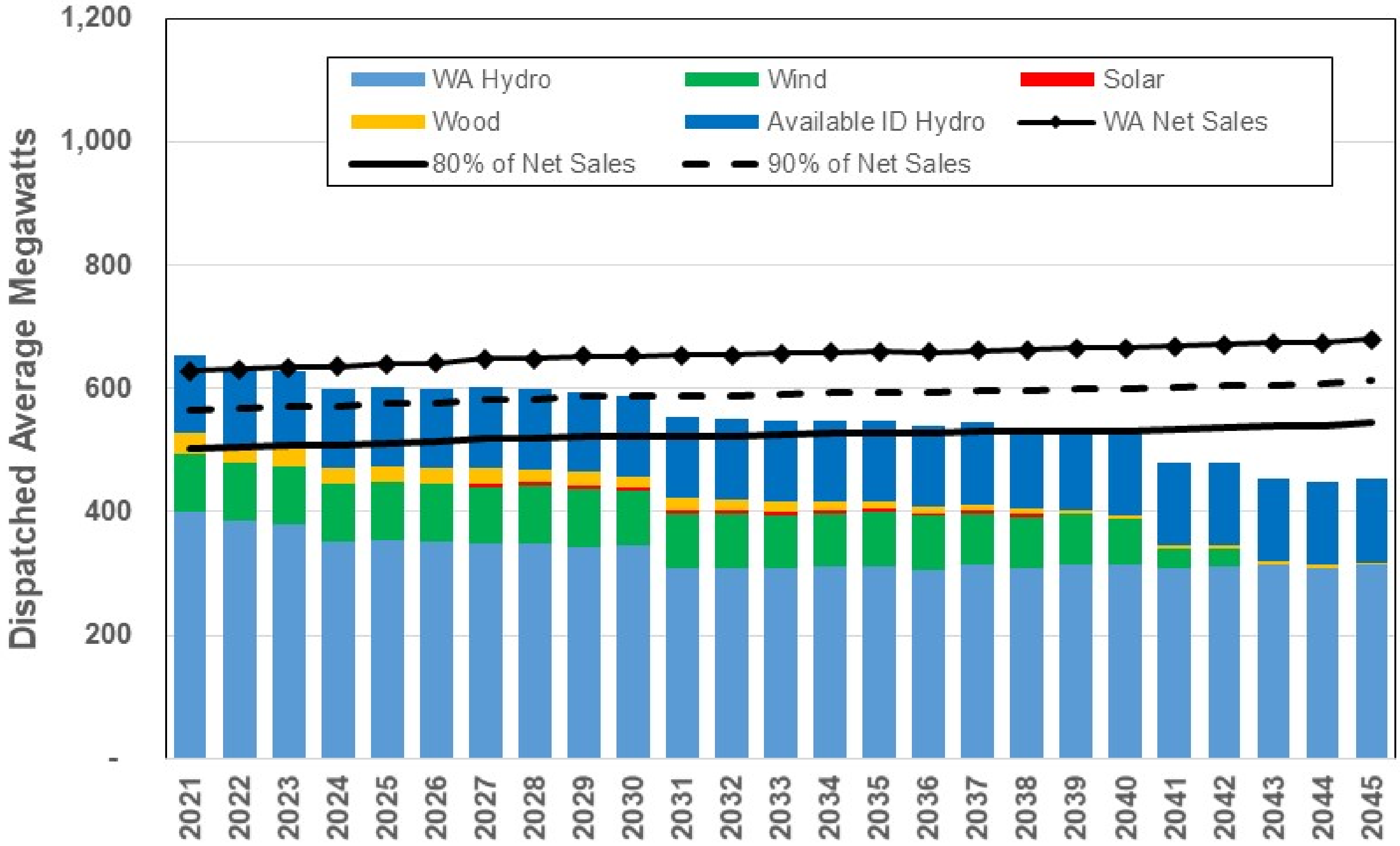
- Energy Independence Act or Initiative 937
  - 15% of Washington retail load after 2020
  - Qualifying resources less any forward sales obligations
  - Banking provisions mitigate year-to-year variation
  - Addition of qualifying BPA and Wanapum, which are not included in the chart. Will update when amounts are known.

- Clean Energy Transformation Act

Washington Energy Independence Act



Avista's Washington CETA Goals



Attendees: TAC 4, Tuesday, August 6, 2019 at Avista Headquarters in Spokane, Washington:

John Lyons, Avista; Thomas Dempsey, Avista; Steve Johnson, Washington UTC; Brian Parker, 350.org; Barry Kathrens, 350.org; Gerry Snow, Pacific Energy Research Associates; Michael Eldred, Idaho Public Utilities Commission; Terrence Browne, Avista; Greg Rahn, Avista; Ryan Ericksen, Avista; Mike Dillon, Avista; Ryan Finesilver, Avista; Jared Akins, Avista; Tom Pardee, Avista; Garrett Brown, Avista; Jaime Majure, Avista; Clint Kalich, Avista; Scott Kinney, Avista; Jennifer Snyder, Washington Utilities and Transportation Commission; Chris Zentz, National Grid; Kevin Davis, Inland Empire Paper; John Barber, Rockwood Retirement Communities; Dave Van Hersett, Residential Customer; Steve Wenke, Avista; Dennis Cakert, National Hydropower Association; Jose Phillips Rangel, Avista; Annie Gannon, Avista; and James Gall, Avista.

Phone Participants:

Kevin Keyt, Idaho Public Utilities Commission; Idaho Office of Energy; Shelby Herber, Idaho Conservation League; Tina Jayaweera, Northwest Power and Conservation Council ; Mike Starrett, Northwest Power and Conservation Council; Fred Heutte, Northwest Energy Coalition, and others who did not identify themselves.

These notes follow the progression of the meeting. The notes include summaries of the questions and comments from participants, Avista responses are in *italics*, and significant points raised by presenters that are not shown on the slides are also included.

Introductions and TAC 3 Recap and Washington SB 5116 and IRP Updates, John Lyons

Steve Johnson: Is this the specific avoided cost for peak summer hours. *Yes, avoided cost of energy and capacity or summer; i.e., $1 per kWh month.*

Clint Kalich: PRiSM technology allows us to calculate capacity values.

Steve Johnson: As we dispatch gas less, per unit increases so capacity value becomes more. Attract more developers to the Northwest by showing them a price.

James Gall: Duration problem, 6-hour vs. 2-hour peak contribution.

Steve Johnson: Hours and frequency.

Clint Kalich: Disincent new energy and incent capacity.

Jennifer Snyder: Really like to see an actual target in Demand Response (DR) in this IRP. *James Gall: We expect this, but things that provide energy and capacity might push DR out.*

Energy and Peak Load Forecast Update, Grant Forsyth

Dave Van Hersett: Is slide #6 a percentage scale. *Yes, now 8-9% above where we were in 2007.*

Steve Johnson: Does the model capture recession events? *Not really, timing is difficult and we haven't really beat the business cycle.*

Steve Johnson: Load forecasts have consistently been high. Action Item to keep in mind is to be responsive to economic downturns. Not saying that you need to change models, but consider the impact of these actions. *I now run the forecast twice a year to more quickly see changes in the forecast.*

Grant Forsyth: Slide #7 population growth is a proxy for customer growth. About 2011, the natural birth/death rate with very little in-migration.

Dave Van Hersett: Where are they coming from? *Mix of everywhere, but a lot from California based on driver's license surrenders. Also relocating business operations from the west side of the state.*

Greg Rahn: Does the blue bar [slide 7] imply more exposure to recessions. *Yes.*

Linda Gervais: How has DSM influenced summer/winter peak? *Still winter peaking, but summer peak is growing at a faster rate than winter because of a better economy, warmer summers and adopting more air conditioning.*

Steve Johnson: Data going back to 1890, is there some other explanation for the last 20 years? *May inform gas dispatch for the four-year plan and reshape hydro. There are not very good models for local temperature change. Imperfectly calculated risk.*

Clint Kalich: Can the data even be loaded from those models? Are other utilities looking at shorter periods [of weather data]? *It is hard to explain the oscillation of weather using historic data.*

James Gall: There is a risk if we exclude past peaks from shorter time periods. Bigger risk of missing a peak. Energy – short. Peak – capacity.

John Barber: New climate studies. Are they ready? *Starting to "downscale" global models, but no commonly accepted methodology to do this exists. Which study do you choose? Which downscaling method to you use? We don't know, but the University of Washington and Oregon State University are working on this issue. We went to 20-year average, but I'm still not comfortable enough with them yet to shift away from the moving average.*

Grant Forsyth: Slide 11 – actual, not weather normalized pre 2019.

James Gall: We plan for the tail events to maintain adequate supply.

Gerry Snow: Winter tail? *Summer looks more like a bell curve. Long tail at low temperatures, this is what we are worried about for capacity.*

James Gall: There is greater winter than summer variation.

Steve Johnson: There is a smaller area under the curve, so there may be fewer cold events. *NASA analysis for the 1950-1981 period for the temperature difference from average, shows a bigger summer than a winter shift.*

Steve Johnson: With EVs [electric vehicles], do you think you need more resources in the next five years or later? *No, our needs from resource retirements and contracts ending are a greater impact than EVs.*

Slide #15 – medium term forecast is now done twice yearly.

John Barber: Southerly parts of the country – looking at fleeing to places like here. May be looking at climate refugees. *Climate Council is looking at how climate and water is changing, but there is still a substantial investment in these areas so what will be spent on mitigation, so hard to work into the forecast.*

Barry Kathrens: Won't these impact us too? *May impact other areas. They would be impacted, but not as much. A lot of coastal regions are going to be going somewhere.*

Slide 19 – PV is rooftop solar.

John Barber (Slide 19): About a 2% penetration rate? *A generous forecast, but not unreasonable.*

Slide 20: About 13% electric vehicle penetration rate for residential.

Gerry Snow: Spokane transit may be the first big commercial EV customer.

Steve Johnson: Graph timing of EV. *Tough to calculate because small changes up front make huge changes later.*

Steve Johnson (Slide 21): Don't the wealthy buy most of the cars anyways? *Yes, but we also need a robust used market of EVs*. *Besides income, density is another predictor, probably because of range issues. This curtails regional uptake of EVs.*

Slide 22: Could have significant transportation emission savings. Still a net benefit per year with the switch to EVs.

Steve Johnson (Slide 26): I'm confused, difference in UPC winter vs. summer. *My guess is a disproportional effect on UPC on summer because of heating.*

Natural slowing of gas because of penetration, but not a specific cause.

Jim Le Tellier: Must be going to different meetings, because that is the next big thing for environmental groups.

James Gall: It's a very large cost for a small benefit with the extra cost of wiring.

Jim Le Tellier: Not an argument, just observing.

Steve Johnson: Price of gas falls, but price of electricity is going up.

Gerry Snow: It might be cheaper to decarbonize gas, rather than getting rid of it.

Steve Johnson: If the cost per unit is high, plus low greenhouse gas benefits, there may be a lot of pushback.

Steve Johnson: Strong enough population growth is overcoming no load growth.

Clint Kalich: Red bump on slide #25 (2023 to 2024), need to check why it is increasing.

Steve Johnson: Would like to leave feeling like he [Grant] can stand by the forecast. *Big forecasters still fundamentally different now. This is the best guess I've got now. All sorts of weird stuff can happen.*

Clint Kalich: We have low load growth and no immediate needs.

Steve Johnson: Lot of end use incentives. People want the service, not the thing. They want cold milk, not electricity. Would like to see more focus on the service. More DSM deployed and recognized. Tech geek out on the conservation side.

Jenifer Snyder: (Slide 26) 2020-2021 jump. Intermediate term probably enough correction process going from further out. Pushes more to the long term. *Price elasticity assumption – price not statistically significant anymore using academic studies. Longer term – no longer assume real price is constant, now increasing.*

Steve Johnson: Colstrip remediation costs also impacting

Dave Van Hersett: Small in comparison.

Steve Johnson: Can be significant. We'll see.

Substituting rising price for conservation in the long run.

Steve Johnson (Slide 29): Conservation adopted this year or actual effects. *This is the amount DSM said they got per month.*

Jennifer Snyder: Savings in that year. Grant cumulatively builds them in. *Persistence? Assumes going forward in time.*

Dave Van Hersett (slide 29): Is the 12% per year of 1%?

James Gall: More like 1% per year, the average of those.

Slide 30: Preliminary about 60% of black line.

Tina Jayaweera: How do codes and standards fit in?

James Gall: Transfers from programs to standards. Grant builds in a trend, pushed forward, but there is no specific variable to change.

Tina Jayaweera: About 2012, standards really increased. *Hard because of the timing.* We have some estimates that can be shared. *Yes, please.* Masood has these.

Natural Gas Price Forecast, Tom Pardee

Gerry Snow (Slide 3): Is Jackson Prairie a geologic formation. *Yes, an old aquifer. There are no salt domes available regionally.*

John Barber: Dth? *Dekatherm, million BTU or 10 therms.*

Fred Huette (slide 7): Numbers may be off a bit: 4.5 Bcf British Columbia and 10.5 Bcf Alberta. *The slide actually came from the Canadian government. We have all learned more about gas north of the boarder.*

Clint Kalich: Do you have statistics on the relative amounts of LNG vs. coal to China? *No.*

Fred Huette: If LNG is at 3.5 Bcf, any sense of price impacts? *Yes, in a few slides. Basically, their own pipeline, so will take away capacity potentially, but new filled so it lessens the impact to the AECO trading hub.*

Slide #11: 90 Bcf yesterday. About half to electric generation. 120 Bcf /day by 2050.

Slide #12: “Proved” reserves – fairly economic and could be extracted if need be.

Fred Huette: Not sure I would agree with reserves. Definitely a lot less, maybe better if we communicate offline about this. *On EIA as well, about 400 Tcf, about 360 Tcf last update.*

Steve Johnson: What if solar gets really cheap, cost per mmBtu for gas products? *Depends by area.* What does the curve look like? *Actually negative in the Permian where they are drilling for oil and natural gas is a byproduct. Marcellus is more of a dry gas with a higher marginal cost to extract.*

Jim Le Tellier: Could be a lot higher. Like solar curtailment, got to get rid of it. *Yes.* What is the long term production cost if they have to pay back Wall Street? *Typically, no free cash flow. Typically a hockey stick with high initial production in the first year, followed by less production, so they have to keep drilling. Now five days on average. Oil projects are long-term and large capital, not so much with [natural] gas only producers.*

Clint Kalich: Social policy might be more of a driver than investment.

Fred Huette: I have a somewhat different view. 80 years based on resources, not proved reserves. 464 Tcf, about 30 Tcf consumption. *We should probably get together on this offline.*

Grant Forsyth (Slide 15): Gas-fired generation in Canada? Or east?

Steve Johnson: What is driving increasing prices?

Fred Huette: What is your opinion or view of the differential between AECO and Henry Hub? Will it persist or is it temporary? *Never expect it to persist, but producers are trying to think about curtailing production to get closer to Henry Hub prices. Not sure why they can't, will seek normal returns.*

Clint Kalich: Oil is a bigger driver.

Steve Johnson: 2011 with falling prices, suppliers still want to do shorter contracts instead of long term. Is it because of fracked gas? *A lot of them do hedge 3 to 5 years, or less, to lock in margin.*

Barry Kathrens: Can't help thinking it might be a little low at 1 – 3%.

Gerry Snow: Is this based on CO_2 equivalent? *Yes, so different if flaring or leaking with a 28 times multiplier for leaking.*

Fred Huette: Interested again offline. It's a difficult question with a lot of information coming in. GWP [global warming potential] for 100 years is 33 or 36 times CO_2, 20-year is about 85. Atmospheric is 10 – 15 years, CO_2 is much longer.

Steve Johnson: Has Avista examined the methodologies? *No, haven't seen if methodology is available. It is set by the Canadian government and there is a tendency towards less reporting.*

Clint Kalich: So now we need to second guess federal studies?

Steve Johnson: The key is if you buy a product, you need to know it. Get a sense of risk if they are off. It may be hard to calculate and may not be very willing to report it. Not asking you to reinvent, but do you put a brand on it. Informing customers of what product they are getting. Could just say it in the IRP. If the methodology is self-reporting – it's a red flag. If spot measurement, that's better. Risk of non-cost effective conservation.

Jim Le Tellier: How did they build that [CO_2 reports]?

Clint Kalich: What do we do?

Tom Pardee: We have the date and documents. Should have a description of how they developed the numbers.

Fred Huette: I know a fair bit about this issue. Five years ago, it was based on a lot of engineering data. EDF managed a large research project on this issue and others, so more data is folding into it and the numbers are getting better. *Flaring is not a big issue in the northwest, but probably a little bit. Probably Bakken and Permian oil dominated by less gas infrastructure. Very little of this is coming to the Pacific Northwest. Data is reported to the states and to the feds. The industry has an incentive to reduce flaring, but the low prices don't incent it.*

Fred Huette (Slide 21): Able to cover almost all times in non-firm in the past when there was spare capacity, now no firm gas is left. *Jackson Prairie rights are on the LDC [local distribution company] side, so there is no interaction with it and generation.*

Gerry Snow: Have you investigated into renewables to hydrogen? *Yes, we also looked at hydrogen at the same time. Renewable about $40/Dth to hydrogen to a fuel cell in this IRP. It's very good for long-term storage. There is also methanization, but at a higher cost.*

Fred Huette: Unsure with pumped storage. Very big and limited places.

Electric Price Forecast, James Gall

Dave Van Hersett (Slide 7): At night, use something else than solar. *Every day's price and standard deviation of price (volatility).*

Slide 7: Implied market heat rate equation.

Steve Johnson: What is causing higher 2018-2019 prices? *Start up for fewer hours per day, etc.*

Fred Huette: In California last year, they are all out of range. Scarcity pricing for Aliso Canyon storage and pipeline issues. Persistently high prices. Will these continue? Much work is being done to calm down prices as things are fixed.

Fred Huette: Kevin Harris at Columbia Grid has studied the startup issue.

Fred Huette: High hydro, low gas burn, but fairly stable online.

Fred Huette: Will see higher emissions this year. Pretty stable market.

Clint Kalich (Slide 16): How do you reconcile resource need with the Council?

Jennifer Snyder (Slide 17): Does load growth include conservation? *Yes, low level of conservation assumed by the consultant.*

Thomas Dempsey: What is the 2045 percentage clean? *Over 80%, Northwest is 110%. Western Interconnect excludes Canada and Mexico. Assumes Colstrip out of Washington by 2025, but we assume there will likely be some generation out of Colstrip still for other areas.*

Fred Huette (Slide 17) Aurora inputs?

1. *Future resource cost projections from a consultant, can't tell you who, plus incentives; and the vendor of Aurora. NREL annual technology report just released 2019 update.*
2. *Solar, wind, storage. We can send out the cost assumptions. Solar plus storage.*

3. *Carbon pricing in model for future and existing resources. Washington uses the social cost of carbon. Other states/provinces include their own requirements – California, British Columbia, and Alberta.*
4. *Hydro modeling in Aurora is good, but not great. How do we modify it? 80-year energy input plus how flexible (Power Council factors) for hydro.*

Fred Huette (Slide 18): Are you doing anything to shock or perturb gas prices for unexpected conditions? *Yes, different hydro, load, gas prices, etc. for each of the 500 runs.*

Dave Van Hersett: Do rising gas prices raise electric prices? *Market prices are relatively flat in real terms.*

Fred Huette: What is the stochastic range? *Using randomized draws.*

Fred Huette (Slide 20): High load hours with 2026 being higher makes total sense. *I've actually studied the market in California. It is lower in the day than at night. The theory is that gas plants are bidding in the evening and recovering their costs then. May not shift total market revenue. Solar plus storage first reduces curtailment and then helps with the ramp.*

Steve Johnson: 8 to 16-hour is not relevant anymore.

Mike Dillon: Lot of seasonality, summer 20-21 hours for EIM buyers spike and it spikes aggressively. The value of flexibility and instant capacity is more.

Clint Kalich (Slide 22): Gas has collapsed showing most of this.

Steve Johnson: Price spike volatility in gas prices. Smaller gas exposure diminishes impact. *More impactful for winter than summer.*

Jim Le Tellier: This doesn't agree with the articles in the paper making statements about general shift of renewables blowing out bills.

Steve Johnson: The differential has collapsed, but capacity supply will explode in the other direction.

Clint Kalich: So suppose we now have 5 cents for energy and 2 cents for capacity, we will have 2 cents for energy and 5 cents for capacity in the future.

Steve Johnson (Slide 25): Why is March so high? *Probably because of the ramp spiking prices. Need to look at this. It is a penalty to turn back on. Not as much with higher loads.*

Fred Huette: A few slides ago, 2030/35/40. It is really great to see shifting prices and resource availability.

John Barber (Sldie 31) EUE? *Average load unserved.*

Clint Kalich: Energy that would have to be curtailed in the market.

Clint Kalich: PV [present value] of portfolios to run. *Didn't have to do the math or a levelized cost, wholesale prices are down and retail price up.*

Fred Huette: How did you apply the Social Cost of Carbon? *Applied the Social Cost of Carbon in dispatch for the entire Western Interconnect generation fleet.*

Phone: Is the 2020 and 2035 levelized cost for deterministic with California and British Columbia. *Yes, in Expected Case. Social Cost of Carbon case overrides.*

Existing Resource Overview, John Lyons

Gerry Snow: Limestone wet scrubbers? *Yes.*

Steve Johnson: There is a lot of water you can't get rid of if the plant is off. *The majority of the water leaves through the stack and evaporation. The remedy and closure plan gets to a net zero point about 30 years out on the current model.*

Jim Le Tellier: Sometimes the preliminary estimates are off. Article in the Billings Gazette was $700 million of cleanup costs [for contaminated water]. *That number is for all four units added together.*

Gerry Snow: If you stop bringing in more water? *About 470 million gallons on site now, it was about 700 million gallons.*

Fred Huette: What about the new [coal] contract? *It will be an all-party contract.*

Jennifer Snyder: Is Coyote Springs 2 getting a major redesign? *GSU [generation step up] transformer is the problem. Looking at breaking into individual phases outside of the IRP, but using the IRP to help evaluate because of losses to winter capacity. Already submitted a business case, but haven't made a decision yet.*

Final Resource Needs Assessment, John Lyons

Fred Huette: Tenth percentile for hydro? *We look at the tenth percentile, enough in nine out of 10 years. Others use critical water. One consistent month – 1937 was a bad winter, but an average summer.*

2019 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Tuesday, October 15, 2019
Conference Room 130

Topic	Time	Staff
Introductions, Updates and TAC 4 Recap	9:30	Lyons
Energy Imbalance Market Update	10:00	Kinney
Break	11:00	
Storage and Ancillary Service Analysis	11:15	Shane
Lunch	12:00	
Preliminary Preferred Resource Strategy	1:00	Gall
Break	2:00	
Preliminary Portfolio Scenario Results	2:15	Gall
Adjourn	3:30	

2020 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
October 15, 2019

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next twenty years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

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 while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - June 15, 2019 was the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

TAC #4 Recap – August 6, 2019

- Introductions and TAC 3 Recap, Lyons
- Washington SB 5116 and IRP Updates, Lyons
- Energy and Peak Load Forecast Update, Forsyth
- Natural Gas Price Forecast, Pardee
- Electric Price Forecast, Gall
- Existing Resource Overview, Lyons
- Final Resource Needs Assessment, Lyons

- Meeting minutes available on IRP web site at: https://www.myavista.com/about-us/our-company/integrated-resource-planning

Today's Agenda

9:30 – Introductions and TAC 4 Recap, Lyons

10:00 – Energy Imbalance Market Update, Kinney

11:00 – Break

11:15 – Storage and Ancillary Service Analysis, Shane

Noon – Lunch

1:00 – Preliminary Preferred Resource Strategy, Gall

2:00 – Break

2:15 – Preliminary Portfolio Scenario Results, Gall

3:30 – Adjourn

Future TAC Topics

- TAC 6: Tuesday, November 19, 2019
  - Review of final PRS
  - Market scenario results (continued)
  - Final Portfolio scenario results
  - Carbon cost abatement supply curves
  - 2020 IRP Action Items

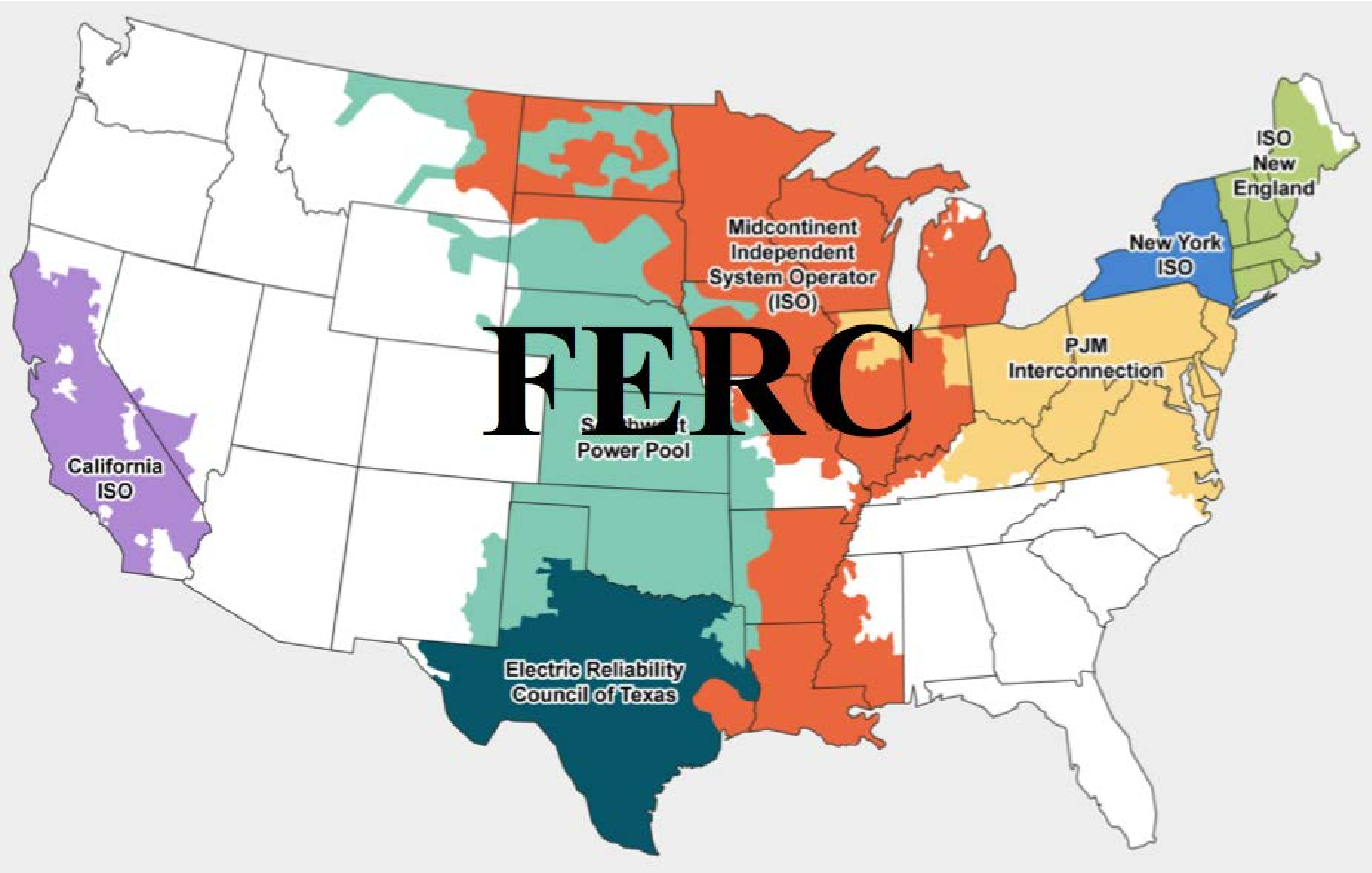
2020 Electric IRP
Energy Imbalance Market Update

Scott Kinney, Director of Power Supply
Fifth Technical Advisory Committee Meeting
October 15, 2019

Discussion

- Market Operations Today
  - NW bilateral market
  - California Independent System Operator (CAISO) market
- Western Energy Imbalance Market (EIM)
  - How the EIM works
  - Current participants
- Avista's Decision to join the EIM
  - Drivers
  - Costs and benefits
- Project Status

Organized Electric Markets



NW Bilateral Market

- No organized market
- Utilities operate individually
  - Buy/sell with counterparties or through electronic clearing house
    - Monthly, day ahead and hourly
  - Utilities hold extra resources to meet forecast error
    - Can't take advantage of regional load/resource diversity
  - Must meet all NERC compliance requirements
  - Perform transmission planning
  - Facilitate transmission tariff and sales
- Less efficient

The CAISO Market

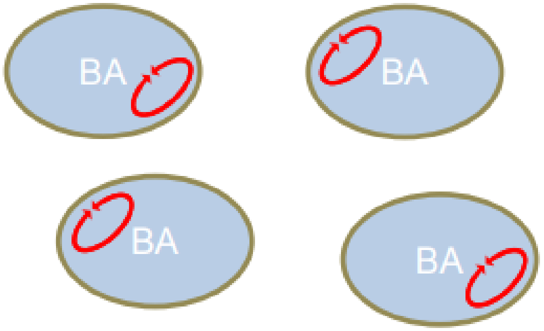
- The California Independent System Operator (CAISO) runs a full organized energy market in California
- Based in Folsom, CA, operational since 1998
- Utilities maintain ownership of generation and transmission assets
- CAISO ensures sufficient resources to meet CA load
  - Balancing Authority for members
  - Day ahead dispatch plan
  - Real-time resource dispatch
- Conducts long-term transmission planning
- Facilitates transmission tariff and sales

What is the Western Energy Imbalance Market?

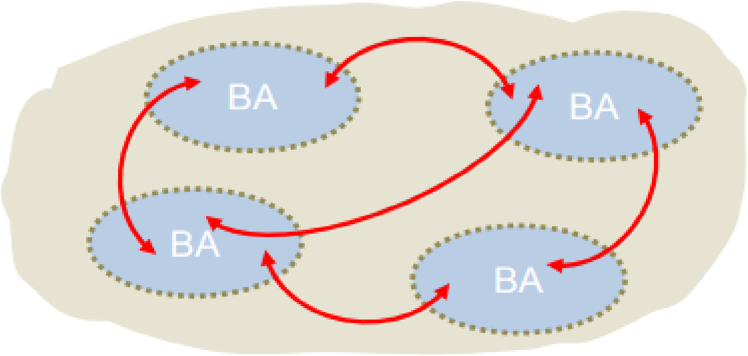
- Operational since 2014 – CAISO and PacifiCorp
- The EIM is an economic based 5 minute in-hour regional resource dispatch program
  - Allows participants to lower energy costs
    - Dispatch less expensive resources to meet in-hour load obligations
    - Increase revenue through the bidding of excess energy
    - Monetize resources traditionally held for regulating reserves
  - The EIM dispatches the most economic resource across its entire market footprint every 5 minutes based on bid prices to balance in-hour load and generation

Why EIM?

Prior to EIM:
Each BA must balance loads and resources w/in its borders.



In an EIM:
The market dispatches resources across BAs to balance energy



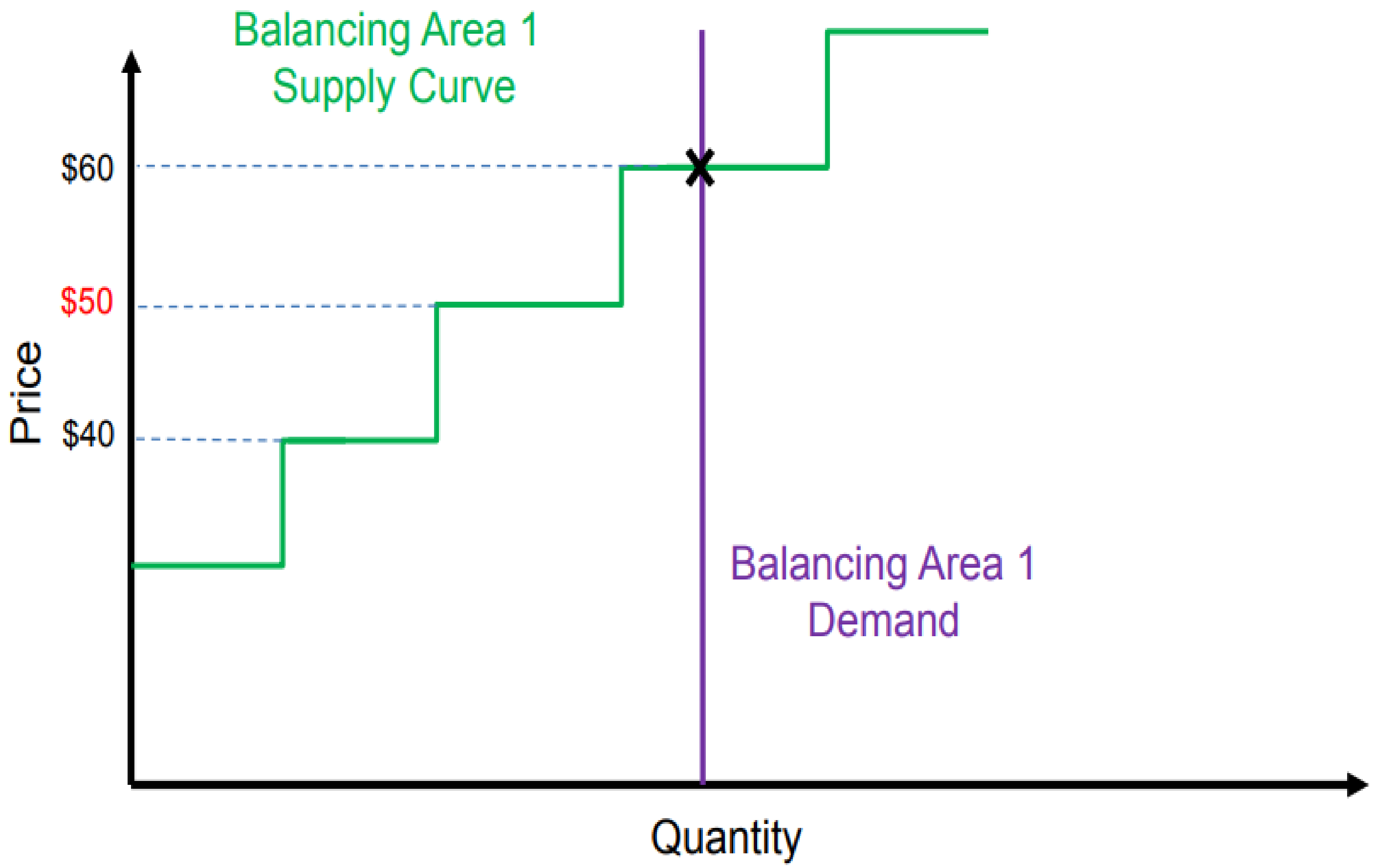
- Limited pool of balancing resources
- Inflexibility
- High levels of reserves
- Economic inefficiencies
- Increased costs to integrate wind/solar

- Diversity of balancing resources
- Increased flexibility
- Decreased flexible reserves
- More economically efficient
- Decreased integration costs

How the EIM Works

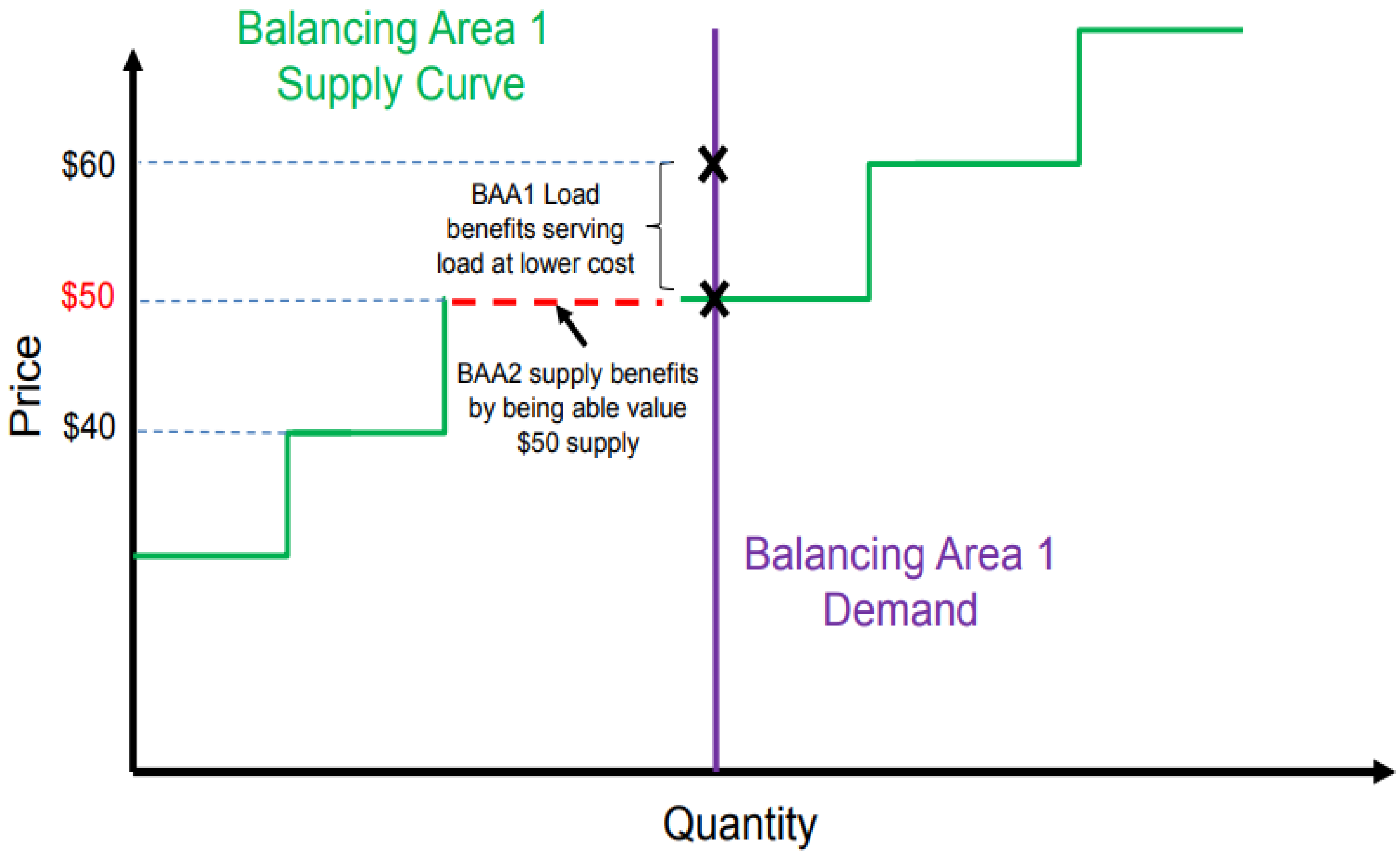
- Participants must show they can meet load obligations prior to the operating hour, no leaning on the market
- Participants voluntarily submit resource availability, min/max, ramp rates and price curves
- CAISO runs a security constraint (i.e. transmission) economic dispatch every 5 minutes to obtain the optimal economic and reliable resource solution for the EIM footprint
- Transmission congestion leads to price differentials
- CAISO sends a 5 minute dispatch request to selected resources to meet overall footprint load obligation
- Generators and load are assigned a locational marginal price based on the economic dispatch and transmission congestion

EIM Supply Transfers Benefit Both Areas



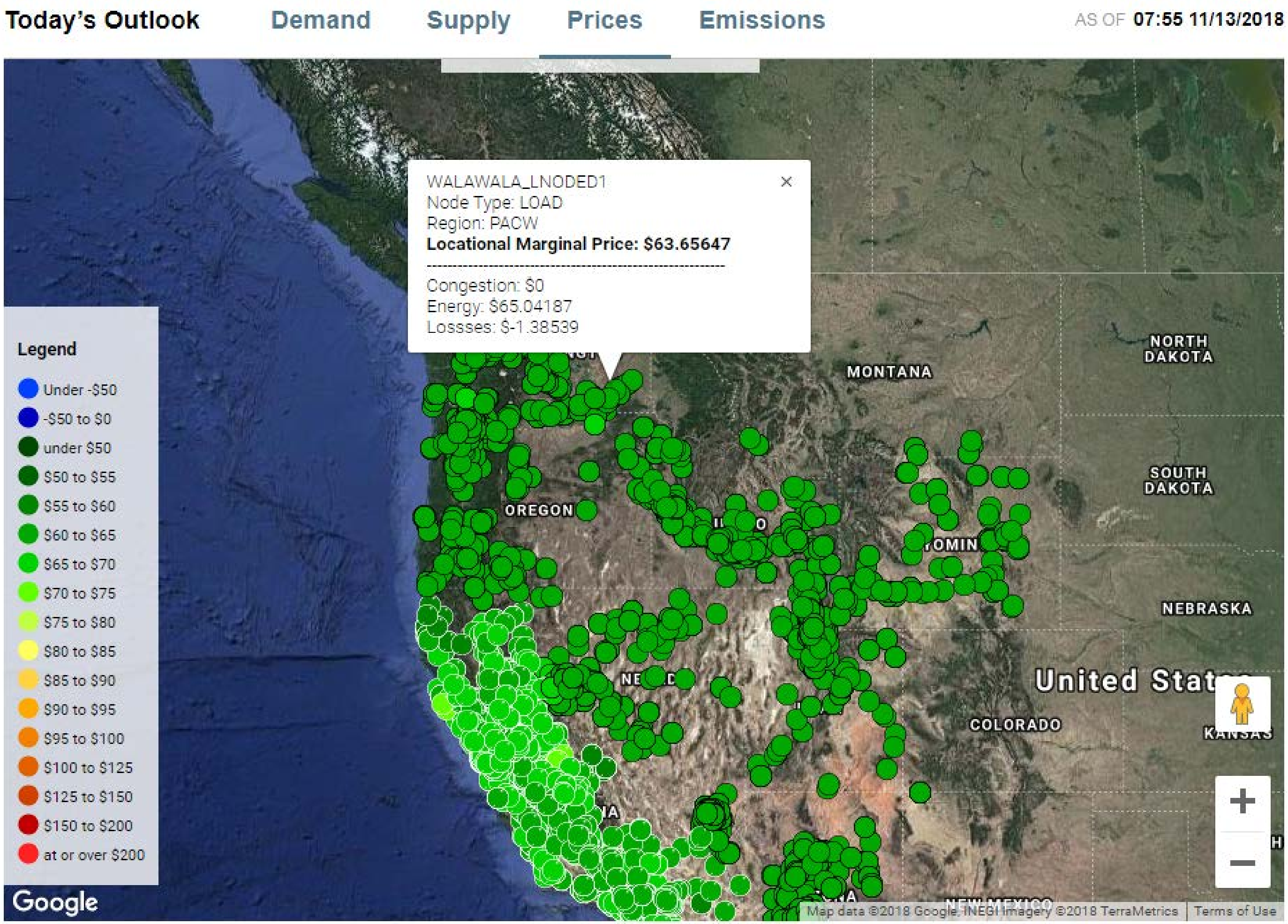
$50 supply from balancing area 2 displaces $60 supply in balancing area 1

EIM Supply Transfers Benefit Both Areas

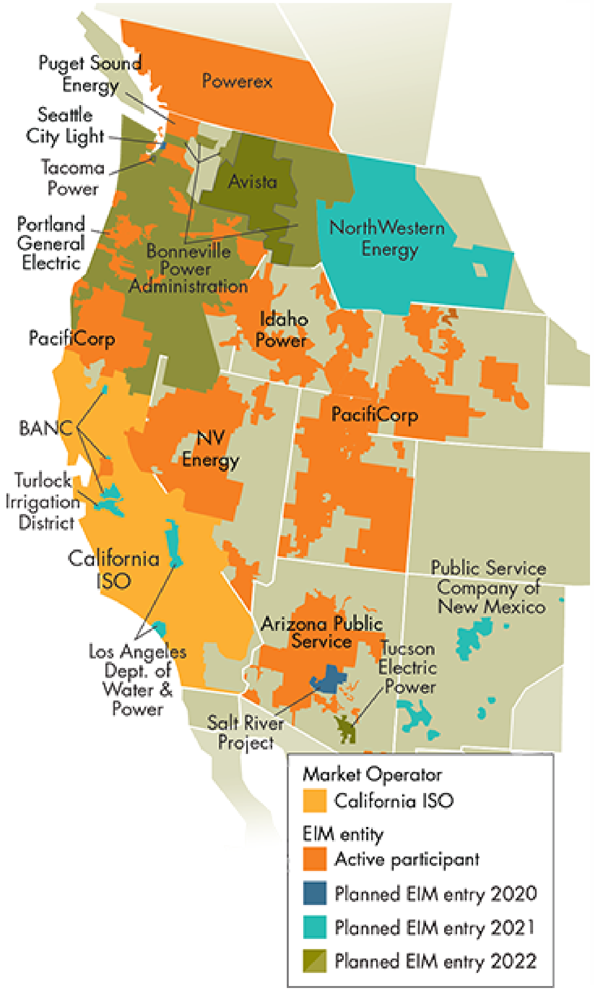


$50 supply from balancing area 2 displaces $60 supply in balancing area 1

http://www.caiso.com/TodaysOutlook/Pages/prices.aspx



EIM Participants



80% of WECC load

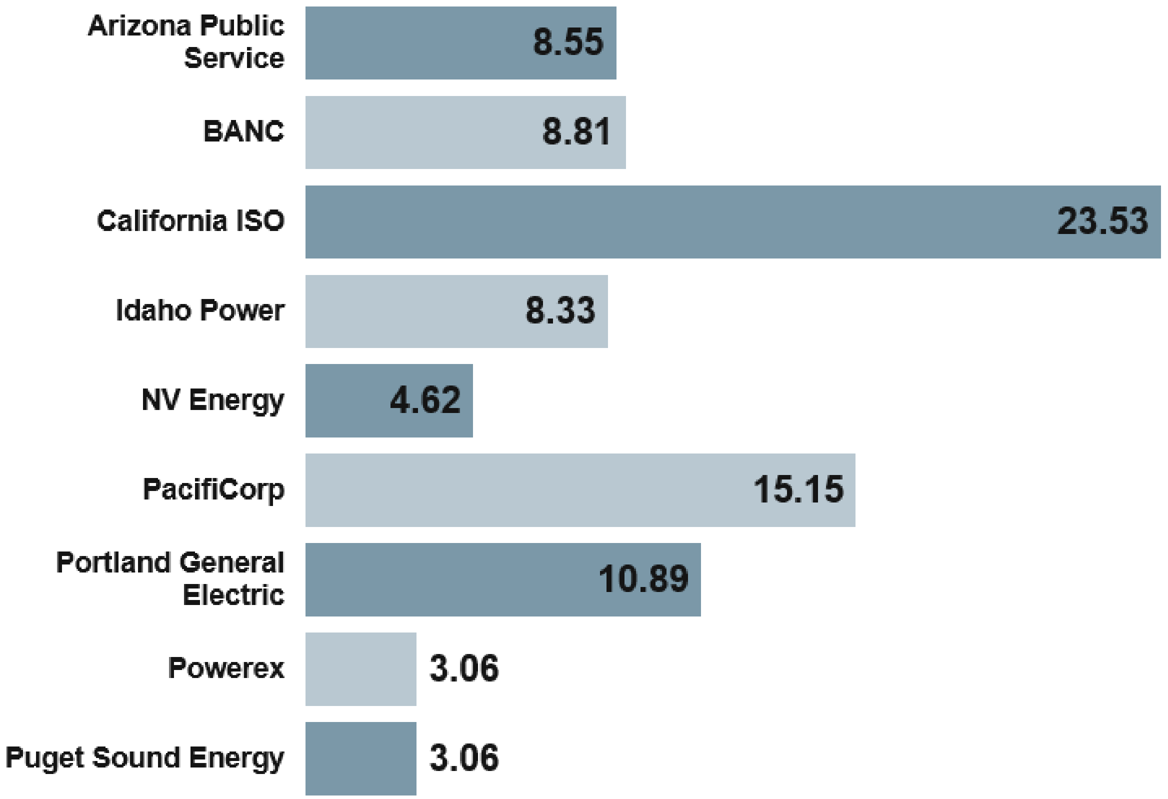
- Members - CAISO, PAC, NVE, PSE, APS, PGE, IPC, Powerex, BANC (SMUD)
- Committed
  - 2020 – SCL, SRP
  - 2021 – PNM, NWE, LADWP, TID
  - 2022 – Avista, TEC, Tacoma, BPA

EIM Gross Benefits

$86m savings in Q2 2019

Read full report >>   Read news release >>

(millions $)



TOTAL **$736.26m**
gross benefits since Nov 2014

Market Monitoring Phase 2015-2018

- Limited needs and risks
  - Small renewable penetration
  - Economics not compelling
  - Other large technology projects
- Monitor market development
  - Engage in public processes and meetings
- EIM Entity outreach and site visits
- CAISO Scheduling Coordinator certification
  - June 2016
- Infrastructure evaluation

Avista Decision Drivers and Risks

- In-hour market liquidity risks
  - 2018 summer issues
  - NWE joining in 2021, BPA planning to join in 2022
- Renewable energy integration
  - Rattlesnake Wind contract - 145 MWs end of 2020
  - Transmission interconnection queue >1000MW
  - Avista’s clean energy goals
  - State policies and regulations
    - WA Clean Energy Bill
    - WA PURPA changes

Avista Decision Drivers and Risks cont.

- Economics
  - Customer benefits
  - Risks of not joining
    - Reduction in current optimization opportunities
    - Higher resource dispatch costs

Avista EIM Costs and Benefits

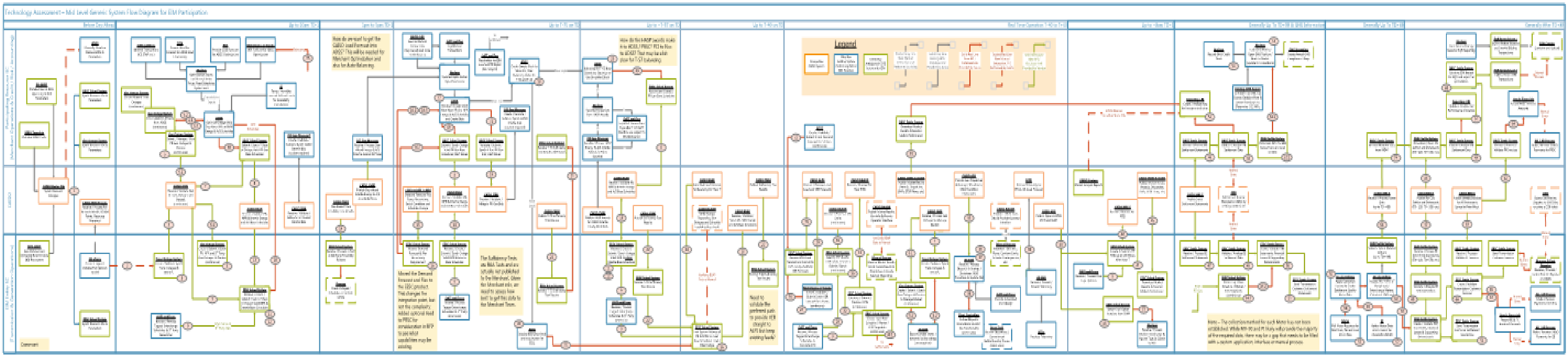
- Estimated EIM costs
  - $21 – 26 M start-up
  - $3.5 – 4.0 M on-going
- Anticipate 12+ new FTE for on-going support
- Estimated annual benefits
  - Full range $ 2 – 12 M
  - Expected range $3.5 - 9.2 M
  - Base $5.8 M

Utility EIM Cost/Benefit Comparison ($M)

	PAC	NVE	PSE	APS	PGE	IPC	AVA
Actual Costs	21.0	11.5+	22.0	16.0	22.0	12.0+	21.5
Studied Benefits	35.1	10.8	14.1	4.9	3.5	4.1	5.8
2018 Actual Benefits	61.7	25.6	13.7	45.3	27.6	26.9	?

Project Status

- Officer approval on April 15 to join EIM
  - Go-live April 1, 2022
- CAISO Contract
  - Signed Integration Agreement on April 25
- System Integrator – Utilicast
- Current efforts
  - Upgrade/replace meters and generation controls
  - Expand telecomm networks
  - Request For Proposals for EIM applications
    - Issued Outage Management RFP on August 13
    - Issued Bid to Bill RFP on September 17
  - ADSS enhancements
  - Staffing plan and training



2020 Electric IRP
Storage and Ancillary Services Analysis

Xin Shane, Senior Power Supply Analyst
Fifth Technical Advisory Committee Meeting
October 15, 2019

Challenges of Energy Storage Valuation

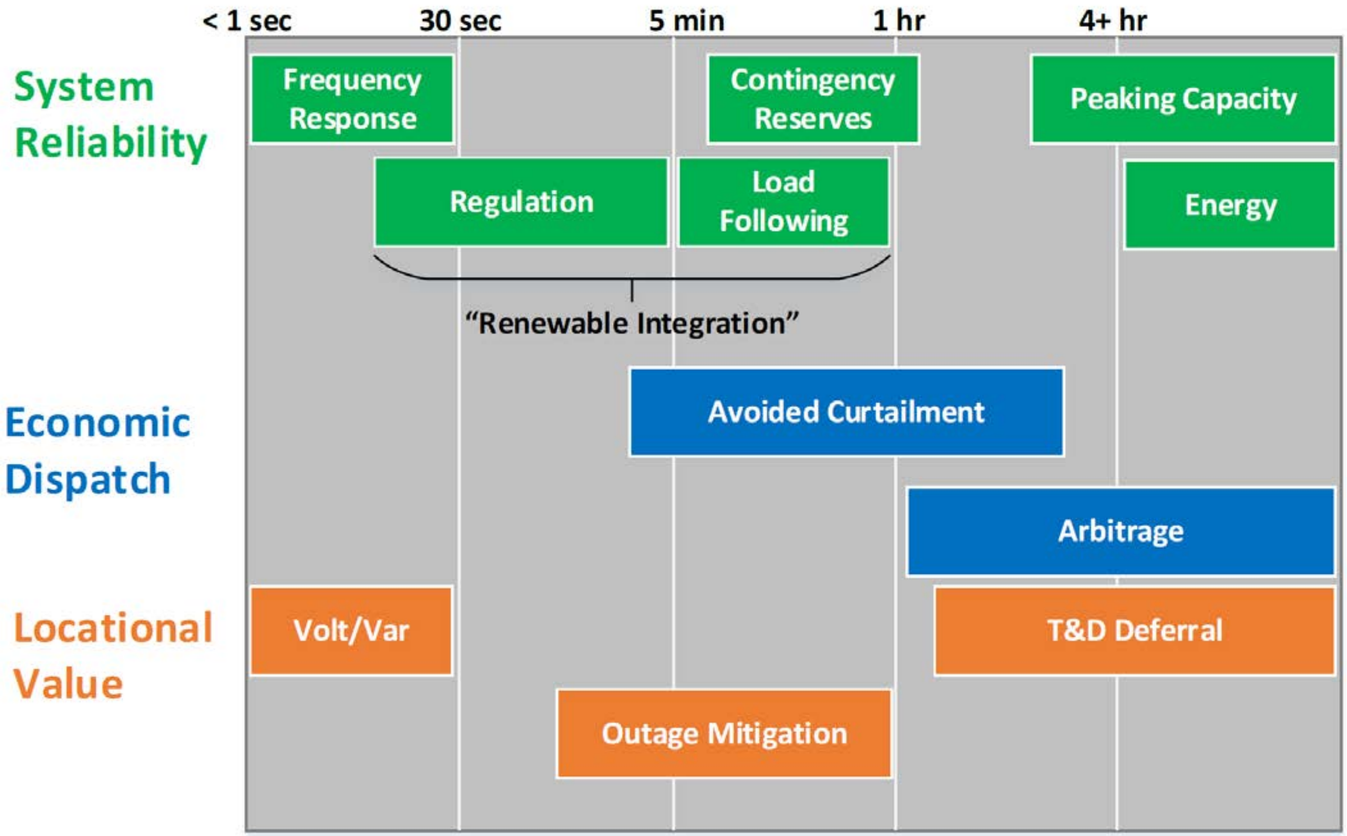


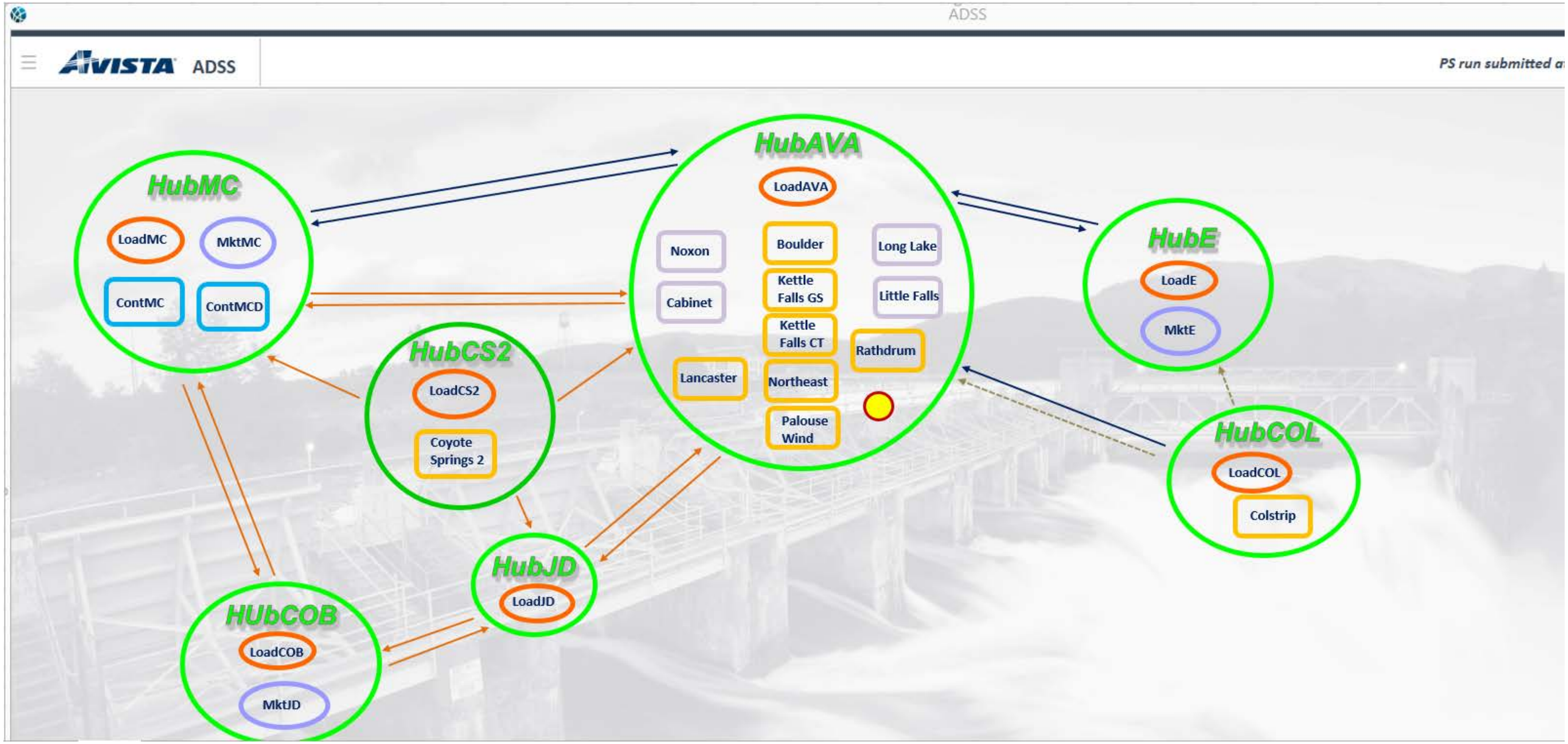
Figure 1: Key value streams within the power system and their associated timescales of action.

Source: Northwest Power and Conservation Council white paper on the value of energy storage to the future power system

Value Stream Definition

- **Frequency Response**: Automatic generator response to grid frequency excursions
- **Contingency Reserves**: Reserves available for grid emergencies
- **Regulation**: Instant response to system load fluctuations
- **Load Following**: Follows system load fluctuations
- **Arbitrage**: Store energy when price is low and discharge when price is high
- **Avoided Curtailment**: Storing energy during times of oversupply to avoid generation curtailment
- **Peaking Capacity**: Ensure sufficient capacity to meet forecast peak demand
- **Energy**: Optimizes energy timing to meet load
- **T&D Deferral**: Reduce loading on transmission paths and loading on distribution circuits during peak demand periods
- **Volt/Var:** Provide reactive power within the distribution system to maintain nominal grid voltage and enhance the power carrying capability of transmission system
- **Outage Mitigation:** Help with unplanned outages with back-up power for reliability and resilience

Avista Decision Support System



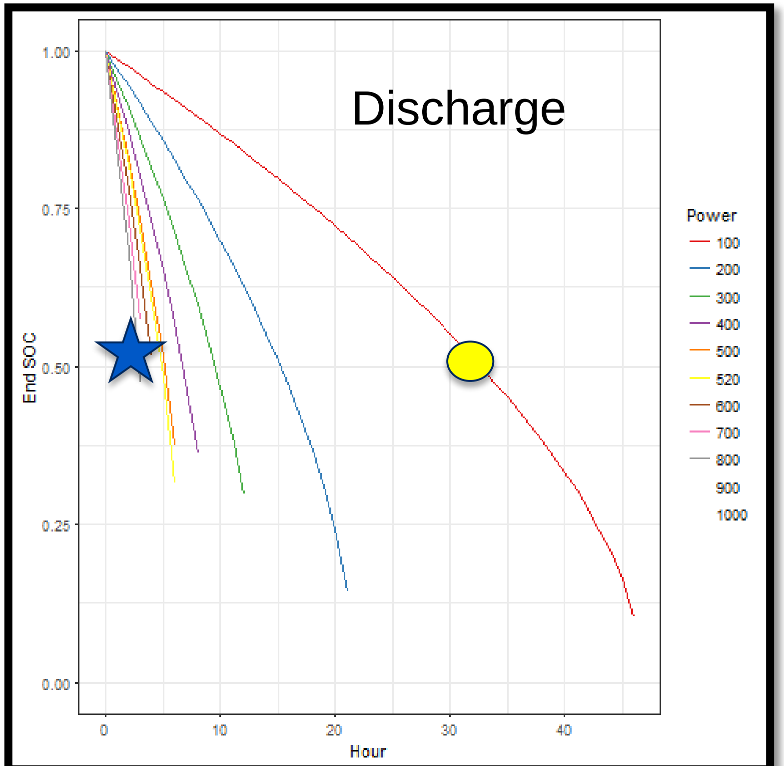
Battery Study Overview

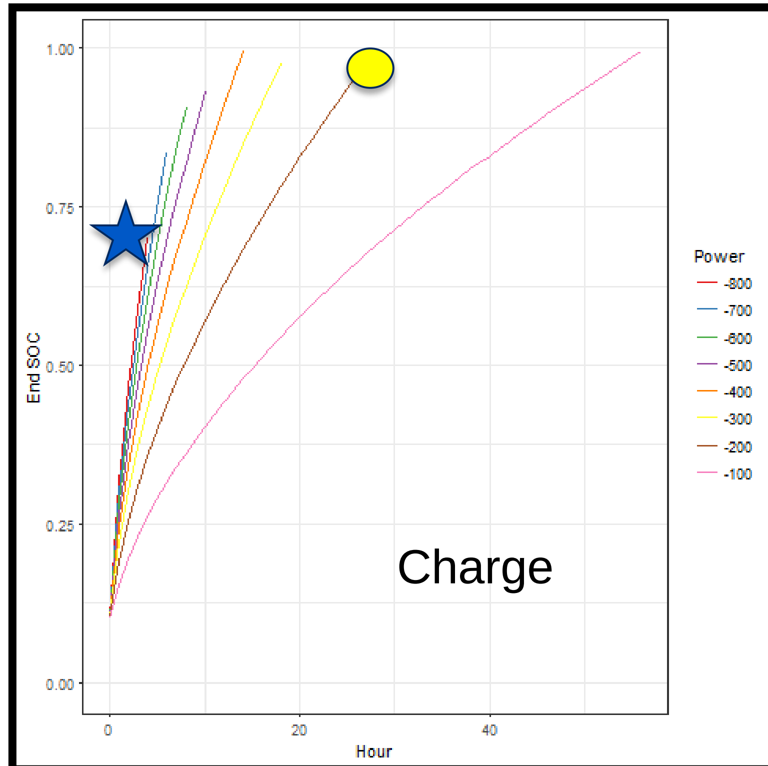
- Turner Energy Storage Project – 1 MW, 3.7 MWh vanadium redox flow battery
- Partnered with PNNL to study operational use cases for the Clean Energy Funds grant.
- Study focuses on regulation and reserves

Turner Energy Storage Project, Pullman, WA

AVISTA

Battery Operating Characteristics





State of Charge (SOC) – An expression of the present battery capacity as a percentage of maximum capacity.

Power – instantaneous kilowatts.

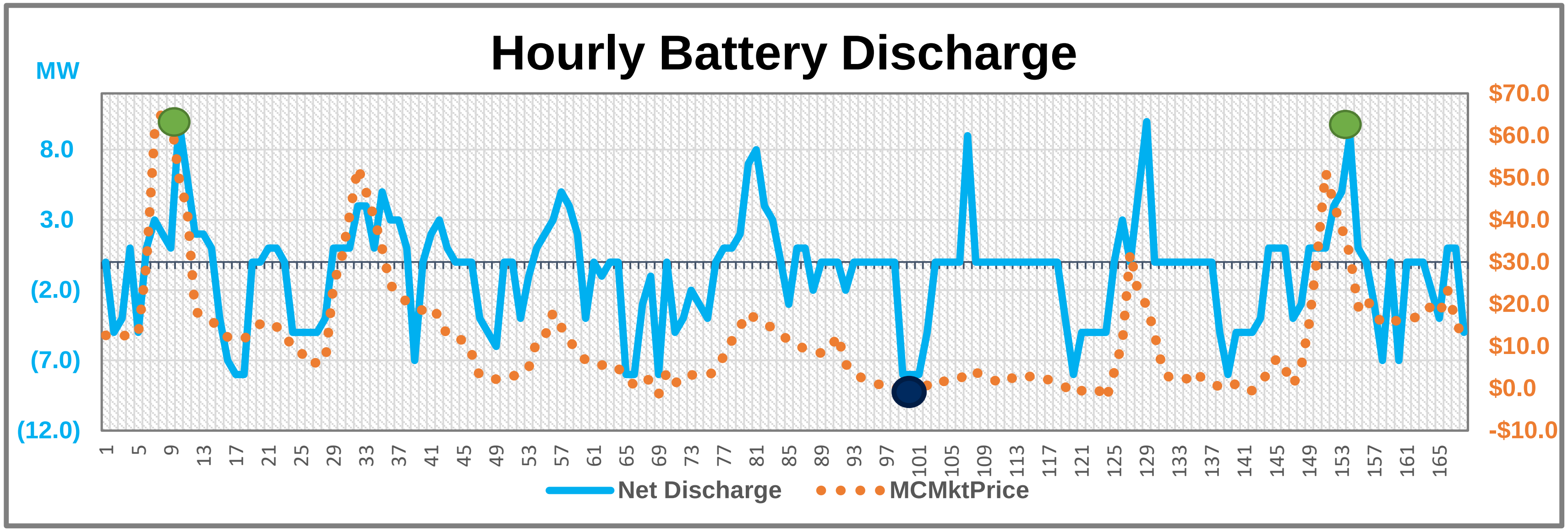
Modeling Overview

Targeted Battery Rating

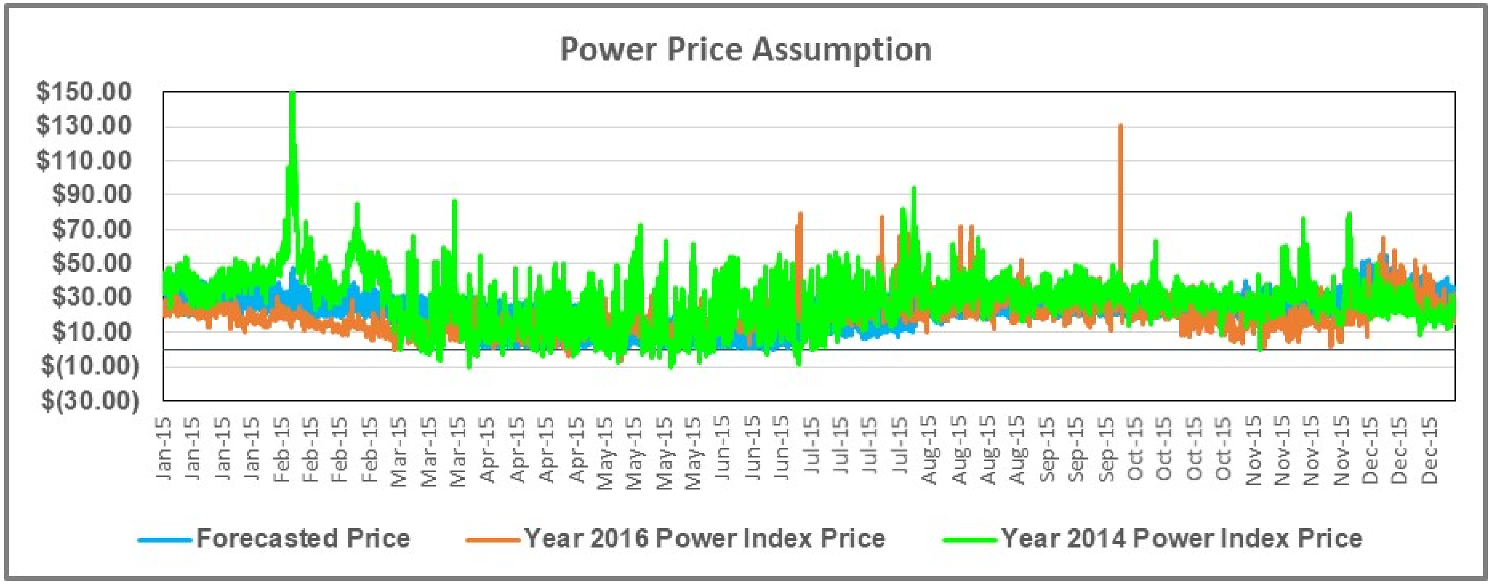
- Max Capacity – 1.0 MW
- Max Storage – 3.7 MWh

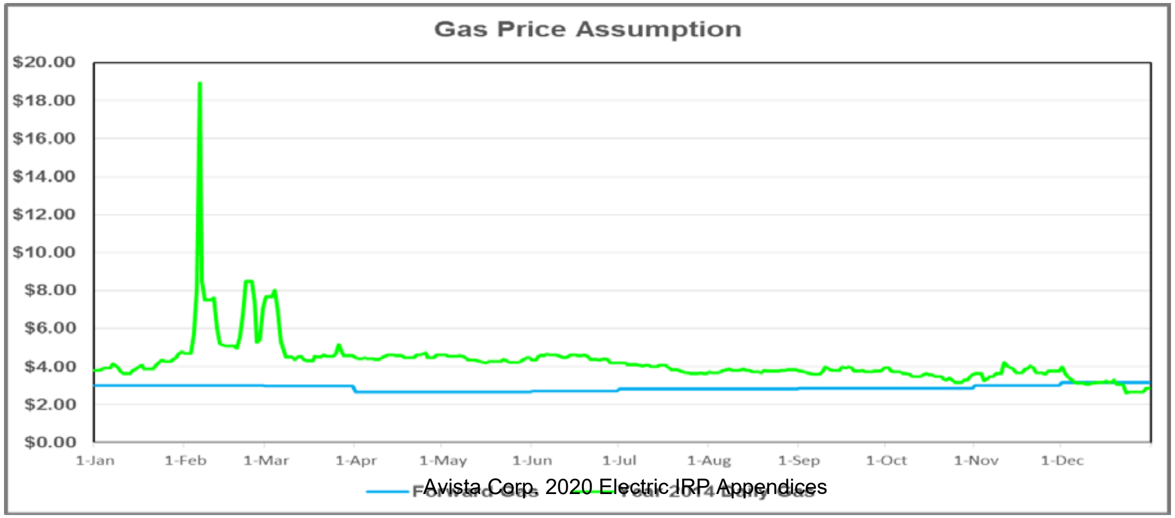
Applied Battery in Model

- Max Capacity – 10 MW
- Max Storage – 37 MWh



Price Volatility Impact





Benefit Evaluation

Scenario	Power Price	Gas Price	Benefits
1st Run	Forecasted	Monthly Forward	$5.00/kW-yr
2nd Run	Year 2016 Power Index Price	Monthly Forward	$6.63/kW-yr
3rd Run	Year 2014 Power Index Price	Year 2014 Daily	$36.32/kW-yr

Pumped Hydro Study

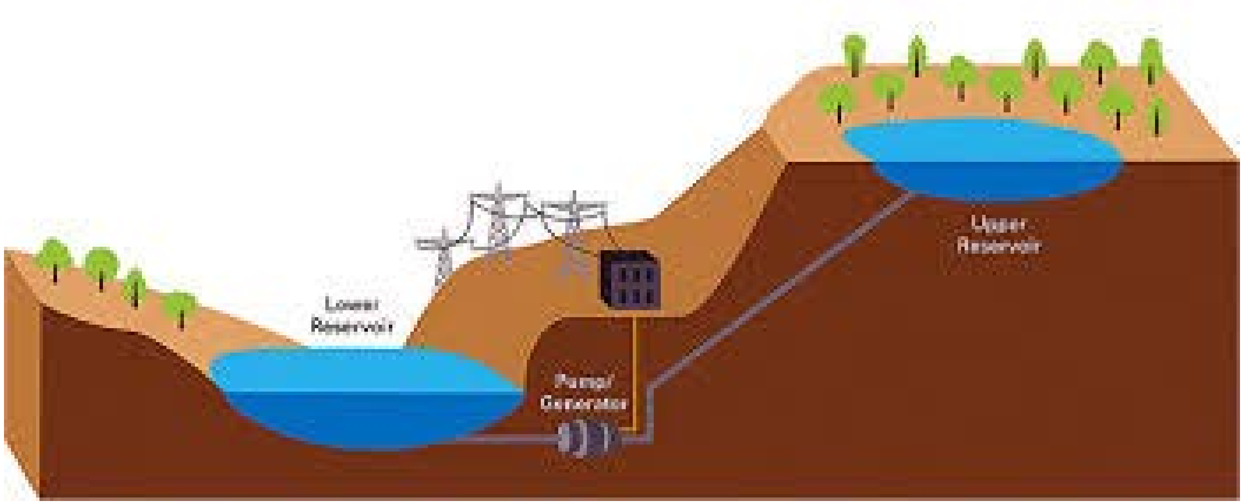
Operating Characteristics

Estimated Unit Pumping Efficiencies (3 × 400 MW)

Component	Efficiency
Pump	92.0%
Motor	98.5%
Transformer	99.0%
Total Station Pumping Efficiency	89.7%

Estimated Unit Generating Efficiencies (3 × 400 MW)

Flow (cfs)	Pump-Turbine	Generator-Motor	Transformer	Total Station Generating Efficiency
1,400	86.3%	98.5%	99.0%	84.2%
1,600	88.6%	98.5%	99.0%	86.4%
1,800	89.5%	98.5%	99.0%	87.2%
2,000	89.8%	98.5%	99.0%	87.5%
2,200	89.8%	98.5%	99.0%	87.6%
2,400	89.4%	98.5%	99.0%	87.1%

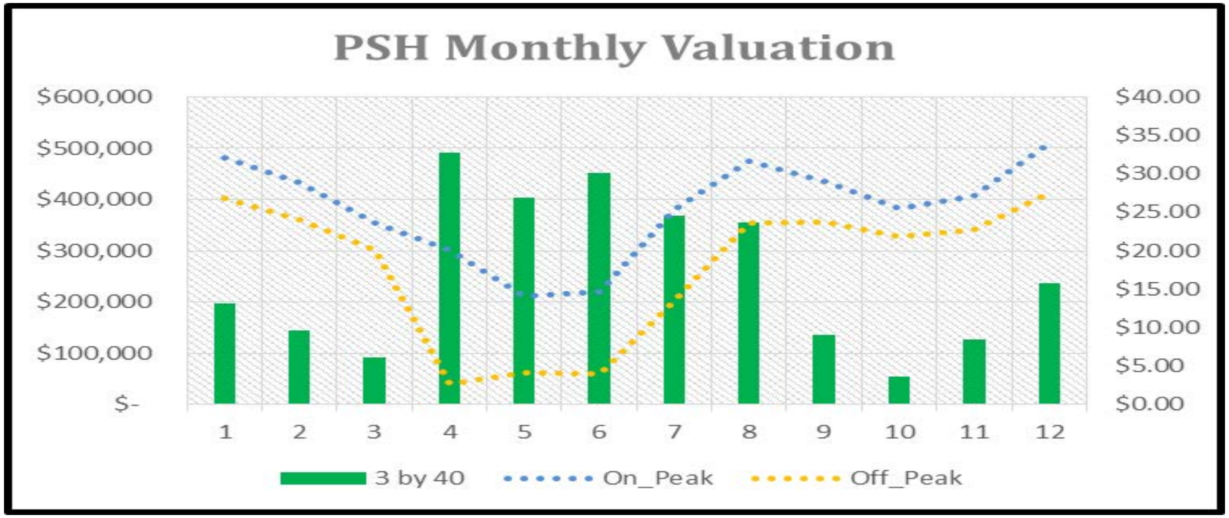


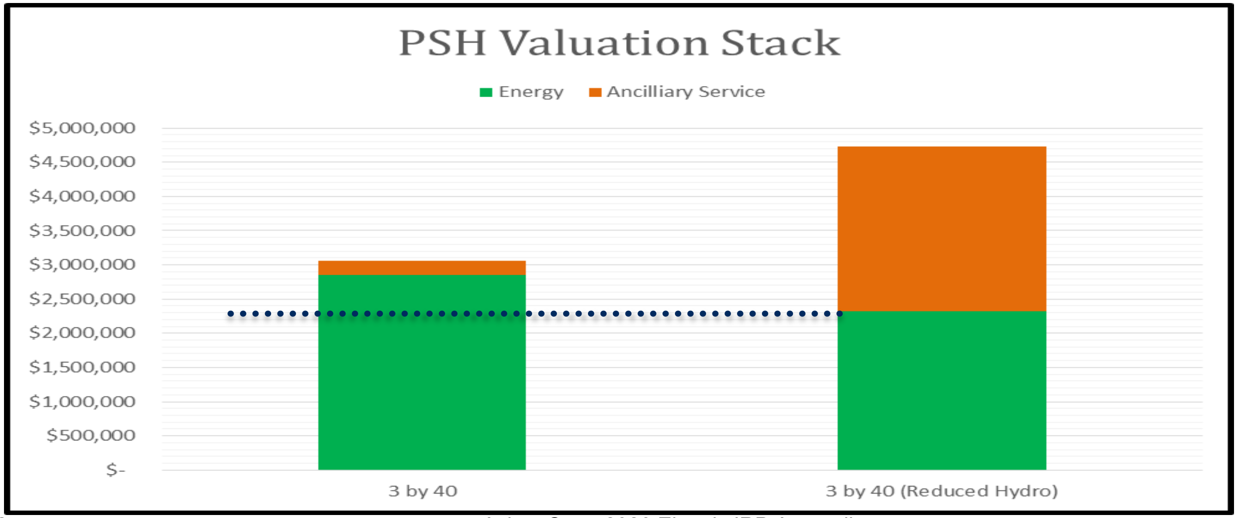
Pumped Hydro Scenarios and Results

System	Configuration	Target Project Scaling	Incremental Value ($)	Incremental Value ($/kw-yr)
Avista System	3 by 400 MW	100%	$19,412,500	$ 16.18
Avista System	3 by 100 MW	25%	$ 6,772,468	$ 22.57
Avista System	3 by 40 MW	10%	$ 3,057,399	$ 25.48
Avista System	3 by 20 MW	5%	$ 1,598,433	$ 26.64
Hydro Reduction	3 by 40 MW	10%	$ 4,730,827	$ 39.42

Noxon 1	120	Cabinet 1	65	Long Lake 1	22	Little Fall 1	8.5
Noxon 2	120	Cabinet 2	78	Long Lake 2	22	Little Fall 2	8.5
Noxon 3	120	Cabinet 3	79	Long Lake 3	22	Little Fall 3	8.5
Noxon 4	120	Cabinet 4	68	Long Lake 4	22	Little Fall 4	8.5
Noxon 5	135						

Pumped Hydro Incremental Value Results





Future Energy Storage Analyses

- Re-evaluate energy storage options in a shorter term energy market
- Analyze different energy storage technologies
- Updated pumped storage hydropower technologies
- Study with different levels of wind and solar penetration

2020 Electric Integrated Resource Plan DRAFT "Preferred" Resource Strategy

James Gall, IRP Manager

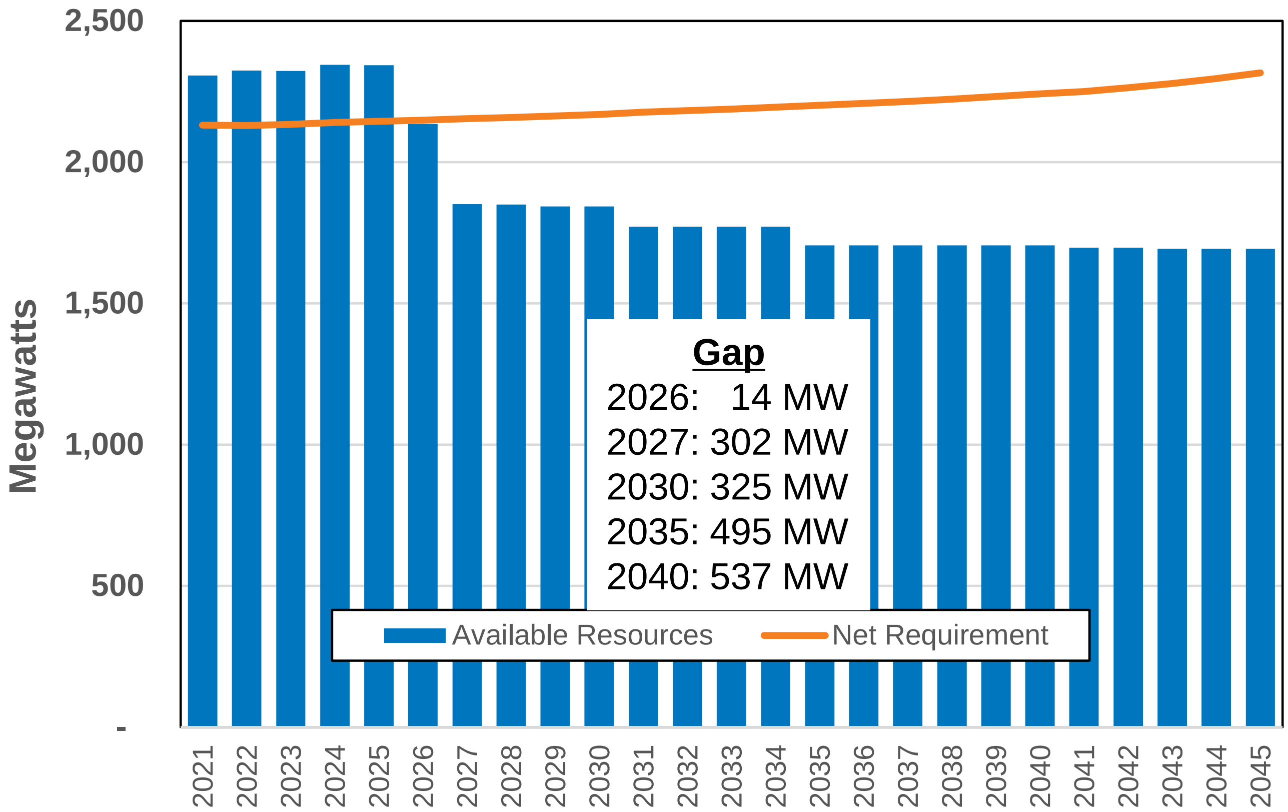
Fifth Technical Advisory Committee Meeting

October 15, 2019

DRAFT ONLY

What Are Avista's Physical Resource Needs?

Main focus: Winter Peak (e.g. cold week in January)



Key Losses:

Colstrip: 2025*

Lancaster: 2026

Mid-C: 2030

Northeast: 2035

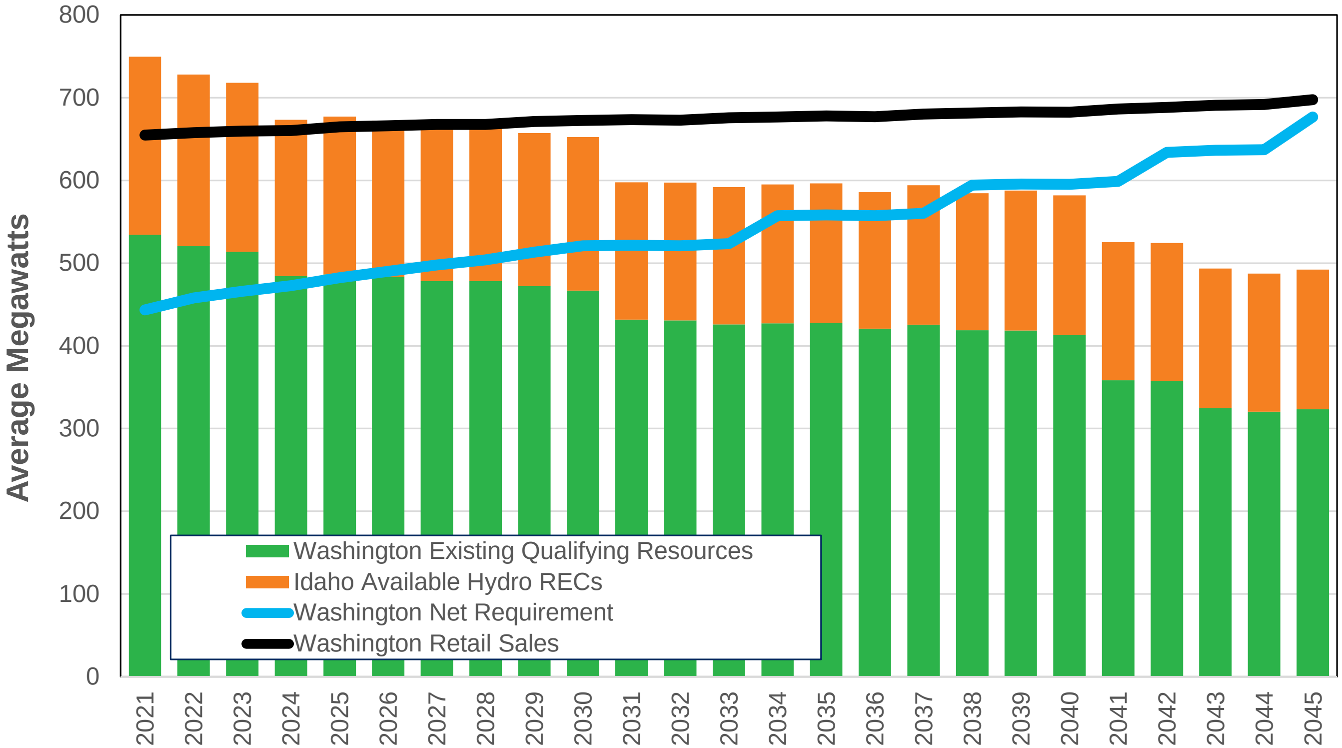
Avista is also short in summer and on an annual average basis beginning in 2027

* Colstrip is assumed offline at the end of 2025 for planning purposes only. Avista's ultimate decisions regarding Colstrip are still to be determined.

DRAFT ONLY

Washington SB5116 Clean Requirements

2026: Colstrip can no longer serve Washington Load
2030: 80% energy delivered over a four-year period is clean and 20% can be RECs
2045: Goal to be 100% clean (will require new technology to stay under cost cap)



Gap

2030: 54 aMW
2035: 130 aMW
2040: 182 aMW
2045: 353 aMW

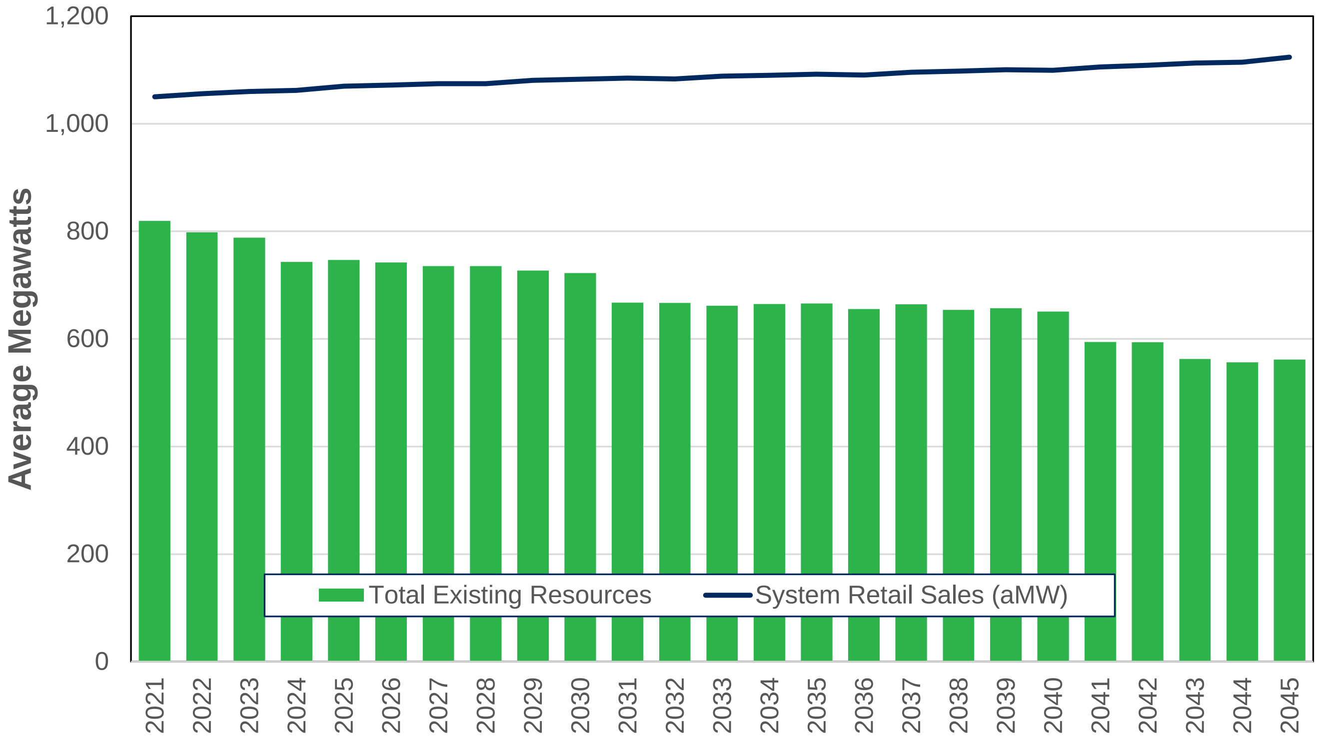
Key Losses:

Mid-C: 2030
Lind: 2039
Rattlesnake: 2040
Palouse: 2043

 Assumes: Idaho customers sell offsets to Washington Customers

Avista's Clean Electricity Goal

2027: 100% net clean portfolio wide (cost effective considerations)
2045: 100% clean (cost effective considerations and technology)



Gap

2027: 339 aMW
2030: 360 aMW
2035: 426 aMW
2040: 448 aMW
2045: 562 aMW

Resource Options

Clean

- Wind (WA/OR/MT)
- Solar (WA/ID/OR)
- Biomass (WA/ID)
- Hydro Upgrades (MS, LL)
- Hydro (Mid-C)
- ~~Hydro (BPA)~~
- Geothermal
- Nuclear
- Energy Efficiency
- Demand Response

Other

- Natural Gas CT
- Natural Gas CCCT
- Storage
  - Pumped hydro
  - Lithium-ion batteries
  - Liquid air
  - Hydrogen
  - Flow batteries
- ~~Regional Transmission~~

Preferred Resource Strategy Decision Process

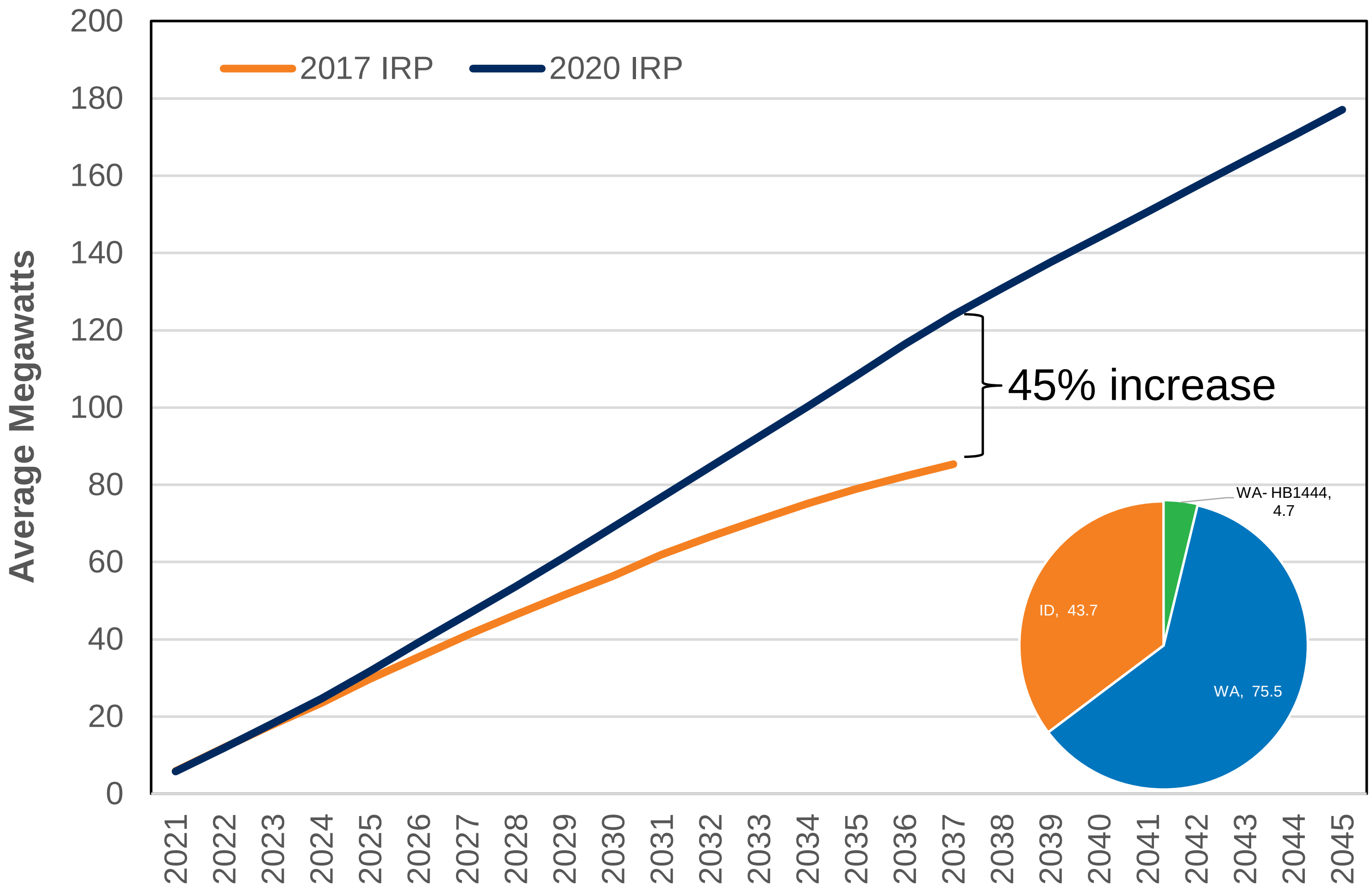
- Uses Mixed Integer Program (MIP) to find least cost solution meeting capacity, energy, and renewable constraints for the system between 2021 and 2045.

- Only known model with full co-optimization of energy efficiency and demand response with supply side resources.
  - Capable of co-optimization of T&D system with power system

- Accounts for societal preference Washington state planning criteria
  - (Social Cost of Carbon, 10% cost advantage from energy efficiency, upstream pipeline emissions, etc.)

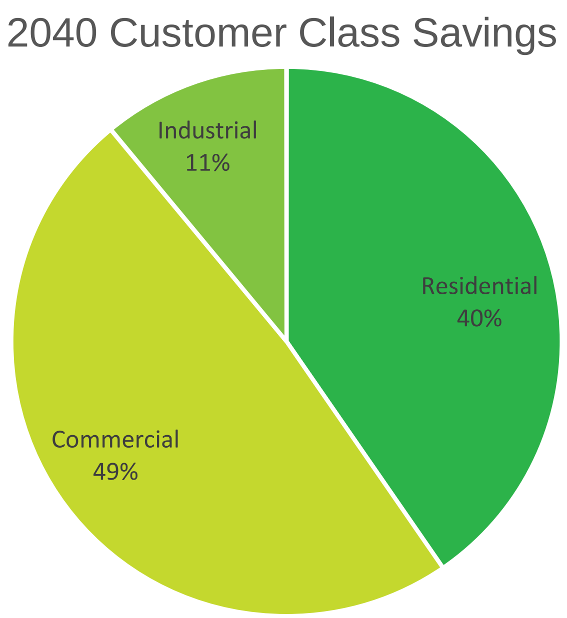
- Non-modeled utility revenue requirements assumes an increase of two percent per year.

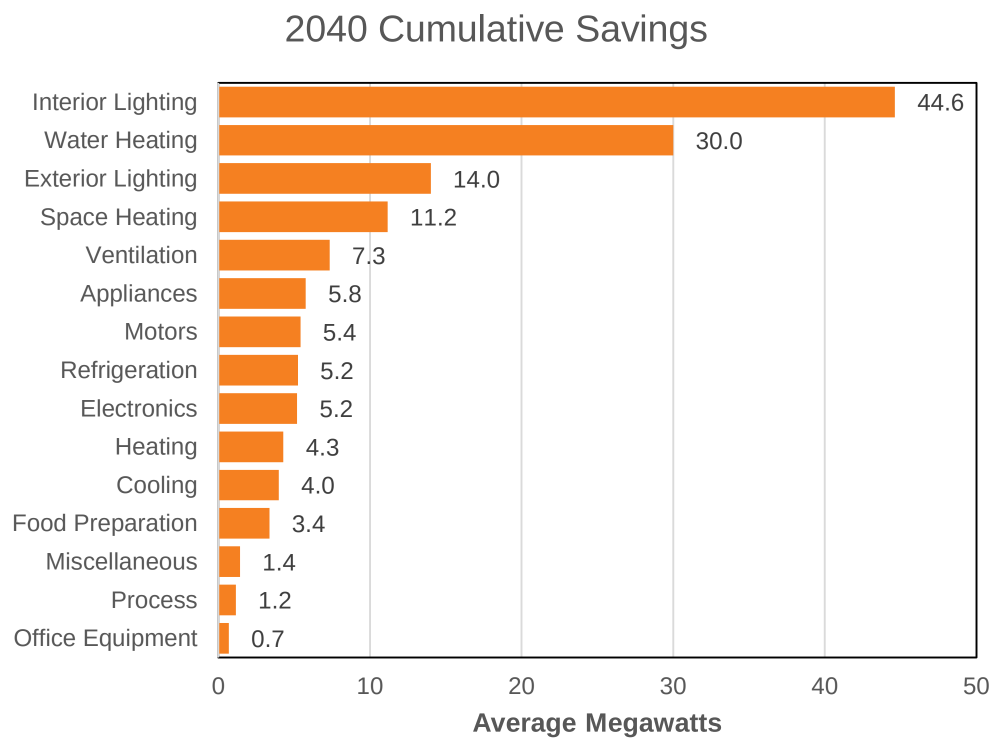
Energy Efficiency Results



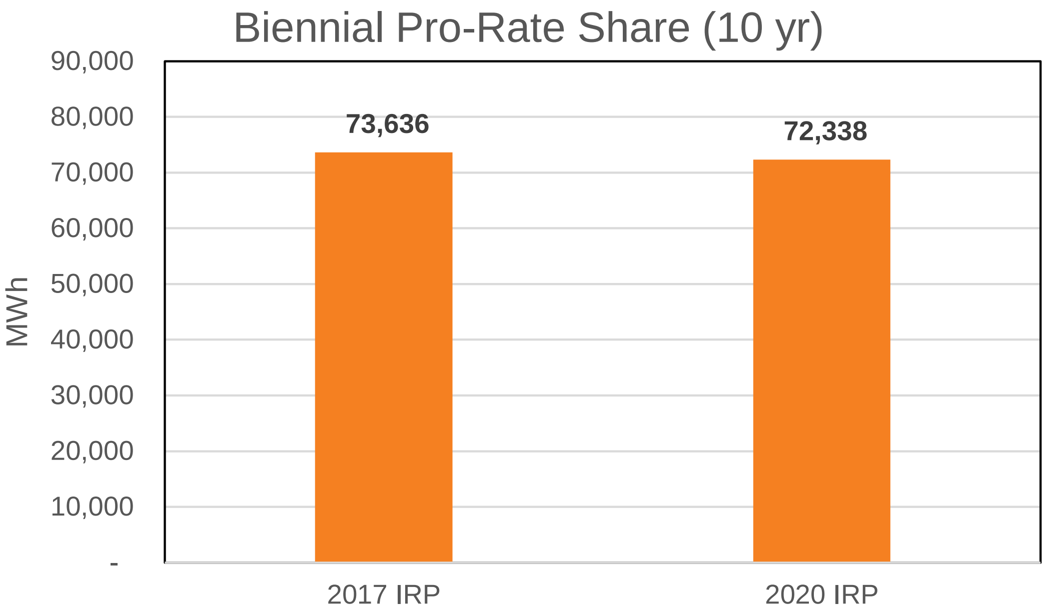
Note: excludes T&D losses

Where is the Cost Effective Energy Efficiency Savings?



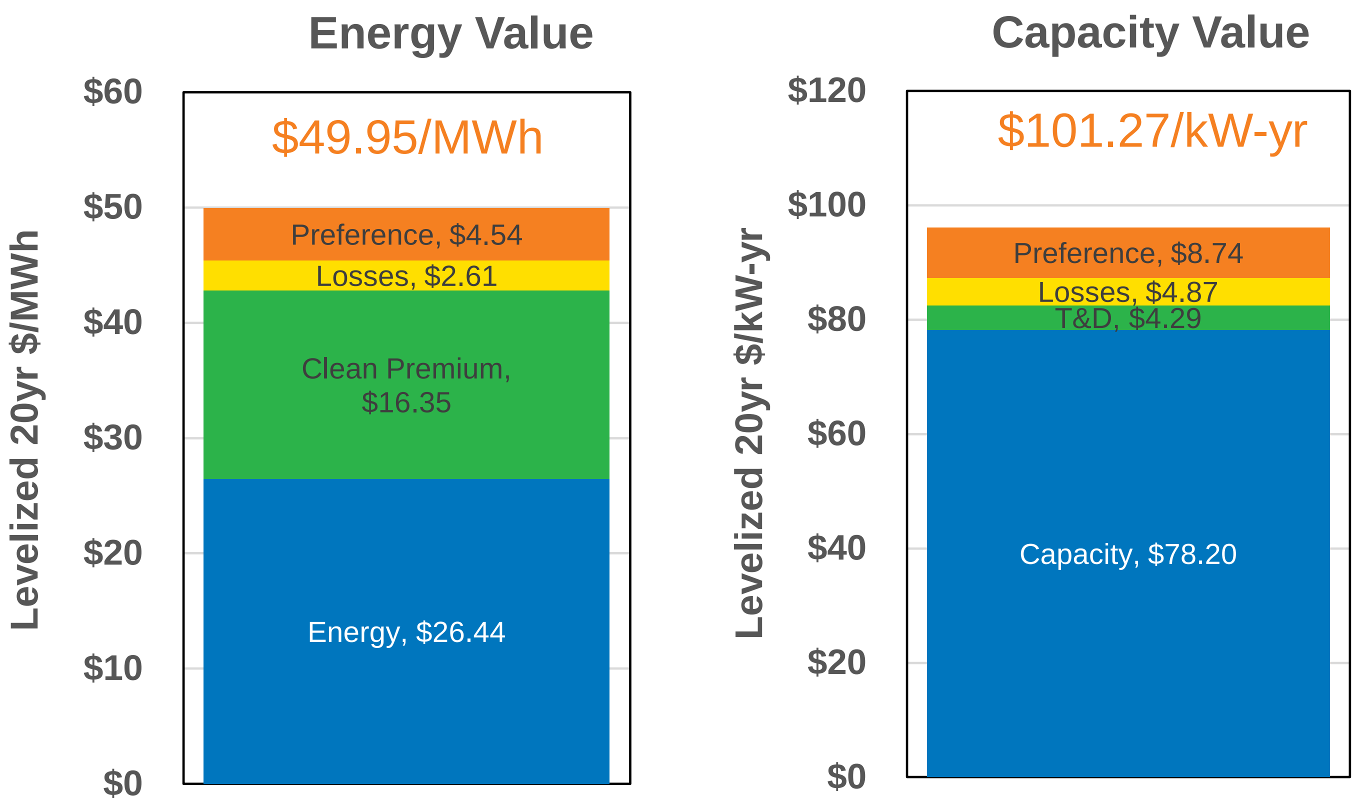


Washington Biennial EIA Energy Efficiency Goal (2021/22)

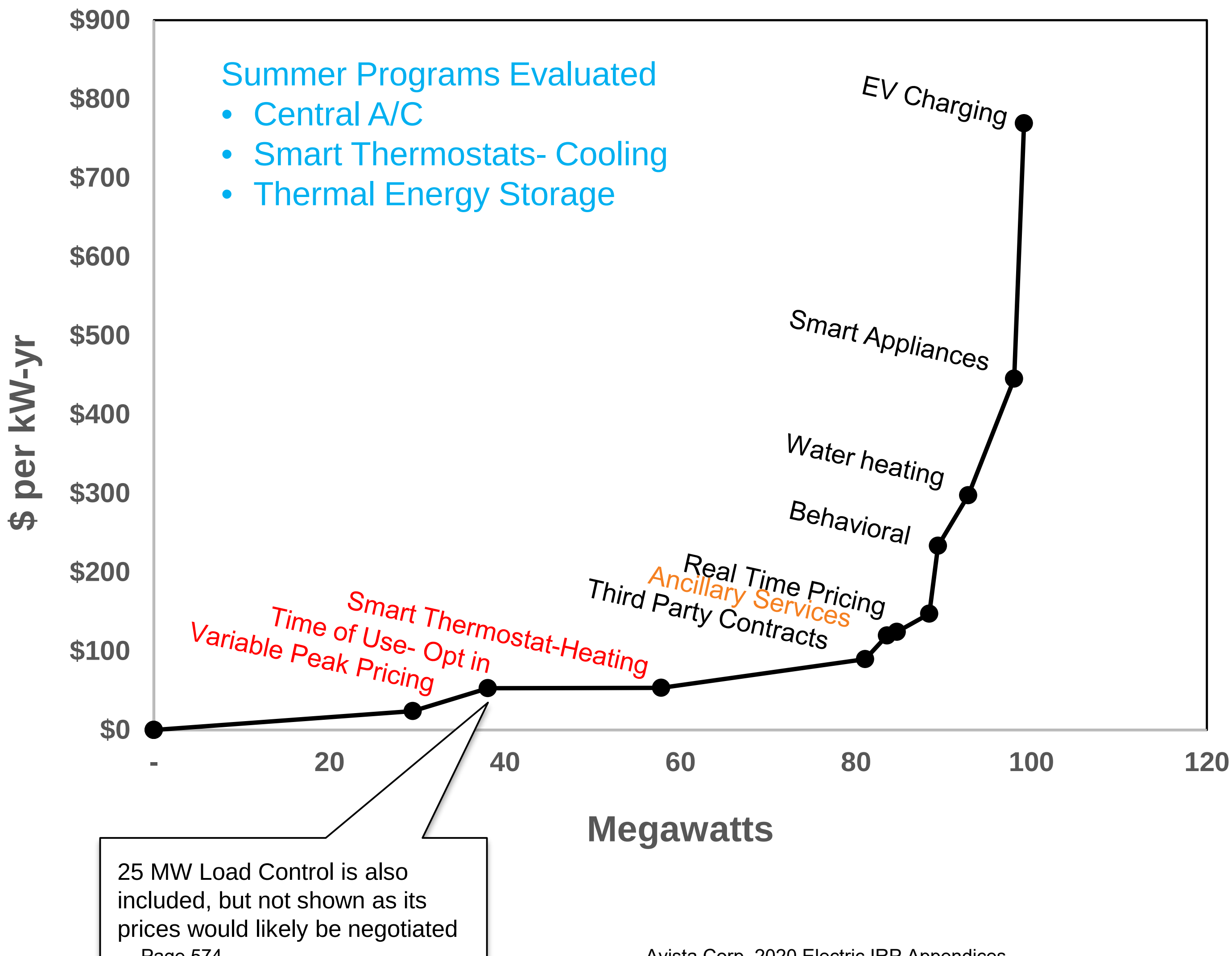


Biennial Conservation Approved Target (MWh)	Based on 2020 IRP	Based on 2017 IRP
CPA Pro-Rata Share	72,338	73,636
Behavioral Program Savings	N/A	15,386
Distribution and Street Light Efficiency	504	749
EIA Target	72,842	89,771
Decoupling Threshold	3,642	4,489
Total Utility Conservation Goal	76,484	94,260
Excluded Programs (NEEA)	-14,016	-9,986
Utility Specific Conservation Goal	62,468	84,274
Decoupling Threshold	-3,642	-4,489
EIA Penalty Threshold	58,826	79,785

Energy Efficiency Avoided Cost



Demand Response



Cost Effective Start Dates Shown in Red

2026: Variable Peak Pricing
2029: Time of Use
2029: Industrial Load Control
2030: Smart Thermostats
2043: Ancillary Services (TBD)

2022-2025 Generation Action Plan

- 2022- 2023 RFP
  - Early acquisition to take advantage of tax credits
  - Anticipate 300 MW Wind PPA (84 aMW)
    - 100 MW in MT and 200 MW in NW
    - locations depend on transmission availability
  - Solar could replace wind depending on pricing and future price shape forecasts
  - Potential for additional resource acquisitions in support of Avista's clean electricity goal subject to reliability and affordability considerations.
- 2024: Kettle Falls Upgrade
  - Incrementally increase Kettle Falls generating capability by installing larger sized equipment as part of modernization
- 2025: 222 MW, Colstrip removed
  - Per CETA, Colstrip will not serve Washington loads after 12/31/2025
  - The plants future for Idaho customers or wholesale transactions is yet to be determined

2026-2030 Generation Action Plan

- 2026: 150 MW, Pumped Hydro
  - Assumes low cost, <u>long duration</u> pumped hydro solution is available.
  - If resource is not available or price exceeds cost effectiveness tests, siting a similar sized NG peaker is the next least cost option.
  - Sizing will depend on reliability requirements of future power supply system.
- 2026: 24 MW, Rathdrum Upgrade
  - Increases each unit by 6 MW using a supplemental compression technology or alternative technology.
- 2026: Lancaster PPA expires in October
- 2027: 200 MW, MT Wind
  - Utilizes Colstrip transmission,
  - if not available additional NG and renewables are required.
- 2027: 8 MW, Post Falls Upgrade
  - Increase generating capability as part of modernization project to maintain FERC licensing requirements.

2031-2040 Generation Action Plan

- 2031: Attempt to renew Mid-C PPA contracts
- 2033: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2035: Northeast CT retires
- 2035: 68 MW Long Lake 2nd Powerhouse
  - Seek certification as an eligible resource
    - either as 2nd powerhouse and/or reconfiguration of single new powerhouse.
  - Begin licensing process
  - Optimize the site for cost, capacity, and environmental concerns
  - Earlier on-line date may be possible
  - NG Peaker and renewable resource would be alternative to this project
- 2036: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2038: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2039: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)

2040-45 Generation Action Plan

- 2041: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2042-2045: 300 MW Wind PPA Replacement
  - Existing PPAs begin to expire
  - Repowering is likely necessary
- 2043: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2042-2045: 250 MW x 4 hour, Lithium-ion (or lowest cost alternative)
- 2044: 50 MW, solar w/ 50 MW x 4 hour storage

DRAFT Preferred Resource Strategy

Load reduction of 152 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 150 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2026-2030: 85 MW, Demand Response
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2033: 25 MW x 16 hr Liquid Air Storage
- 2035: 55 MW, Northeast CT retires
- 2035: 68 MW, Long Lake 2nd Powerhouse
- 2036: 25 MW x 16 hr, Liquid Air Storage
- 2038: 25 MW x 16 hr, Liquid Air Storage
- 2039: 25 MW x 16 hr, Liquid Air Storage

2041-2045

- 2041: 25 MW x 16 hr, Liquid Air Storage
- 2042-2045: 300 MW Wind PPA Renew
- 2043: 25 MW x 16 hr, Liquid Air Storage
- 2043: 2.5 MW, Demand Response
- 2042-2045: 225 MW x 4 hr, Lithium-ion
- 2044: 50 MW, Solar w/ 50 MW x 4hr, Storage

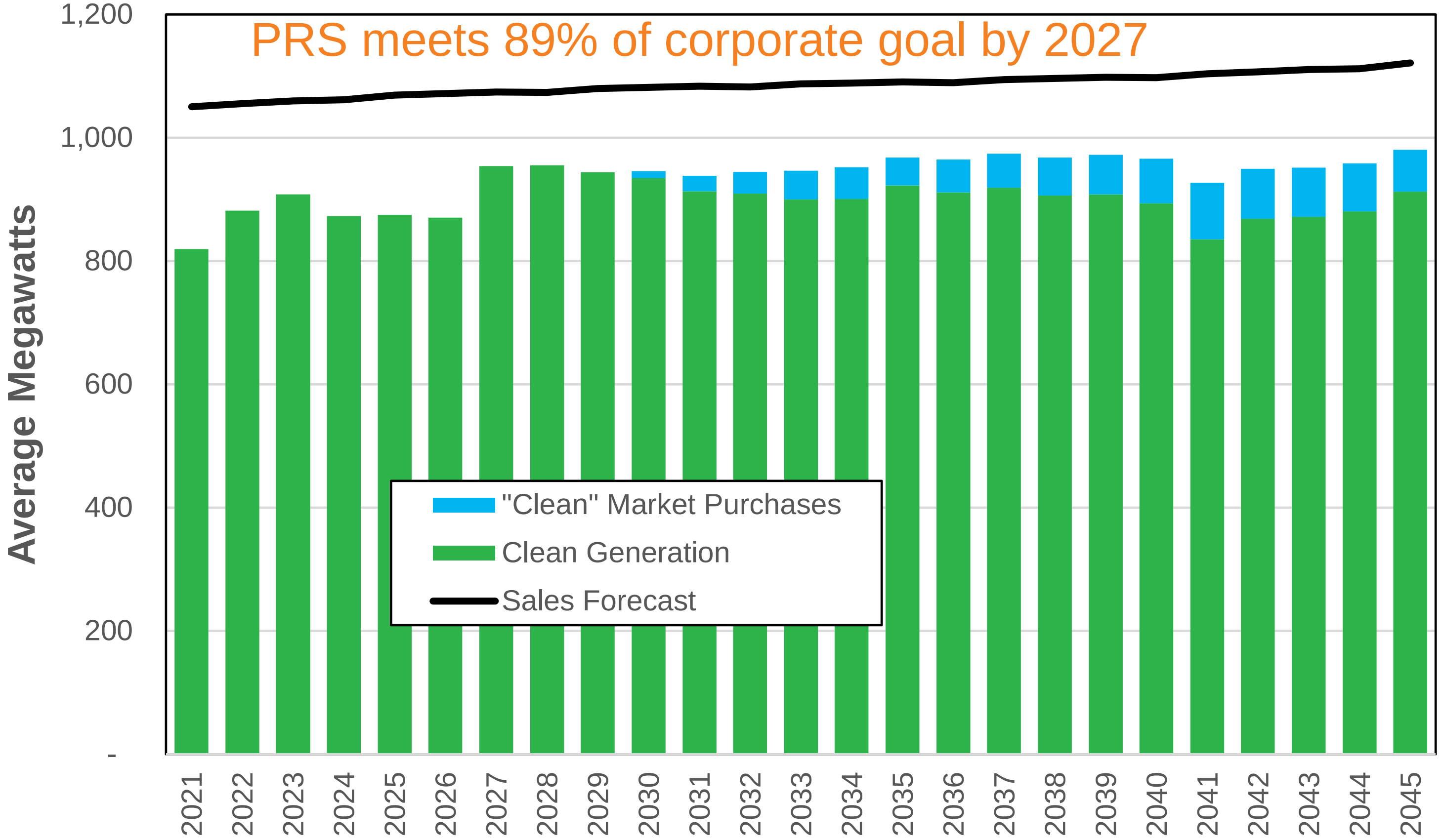
Reliability Study Results

- 14% planning margin without Colstrip and non-dispatchable resources is too low.
- LOLP analysis was re-studied without Colstrip to determine the required planning margin to achieve 5% LOLP with NG CTs- this resulted in a ~16% planning margin
- The resulting draft reliability metrics for the PRS are:

Reliability Metric	Draft PRS Result	TAC 2 Adequate System Result
LOLP	7.0%	4.9%
LOLH	3.10	1.85
LOLE	0.25	0.16
EUE	552.3 MWh	318.7 MWh

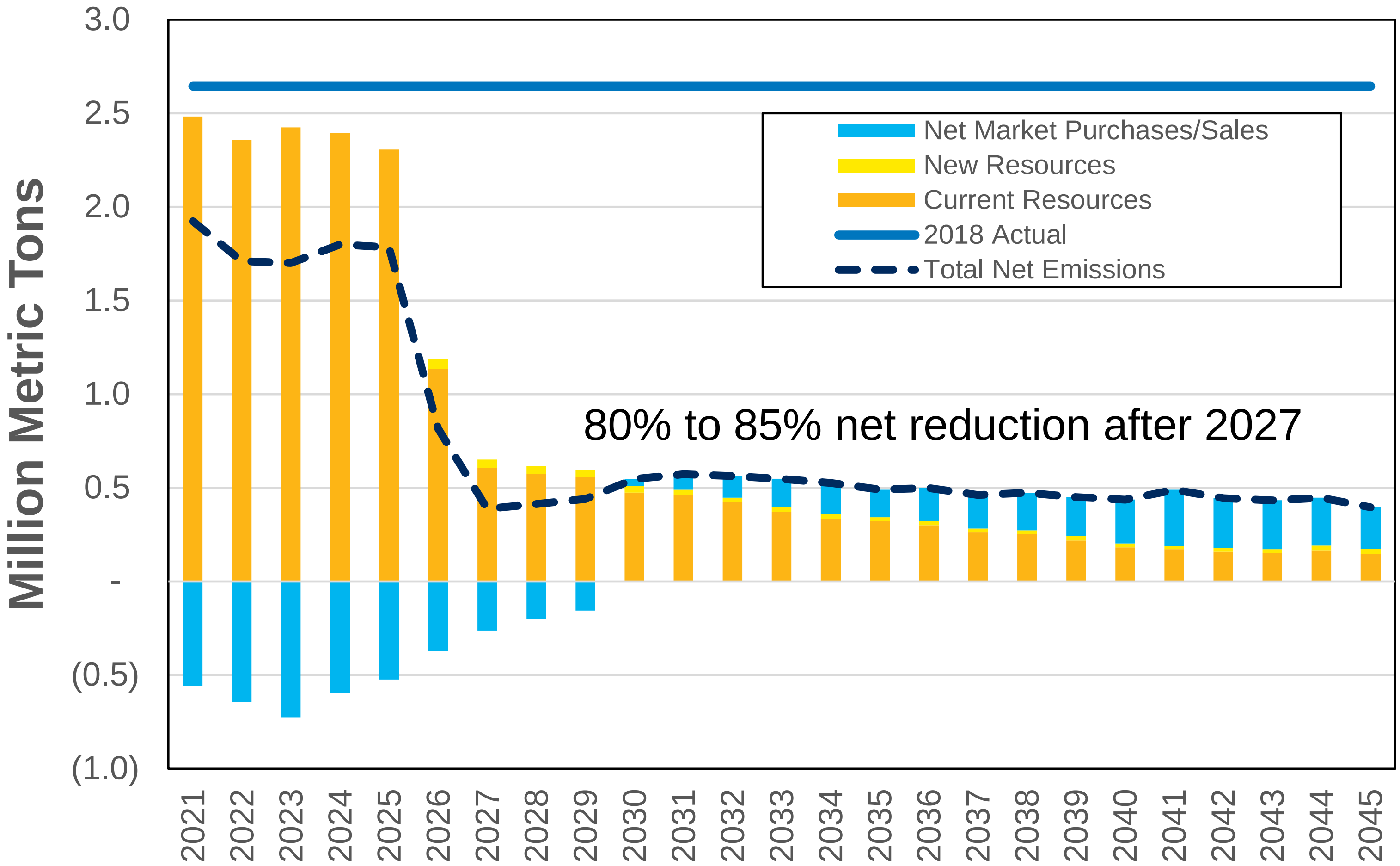
PRS Comparison to Corporate Clean Electricity Goal

Goal: Serve customers with 100% cost effective clean electricity

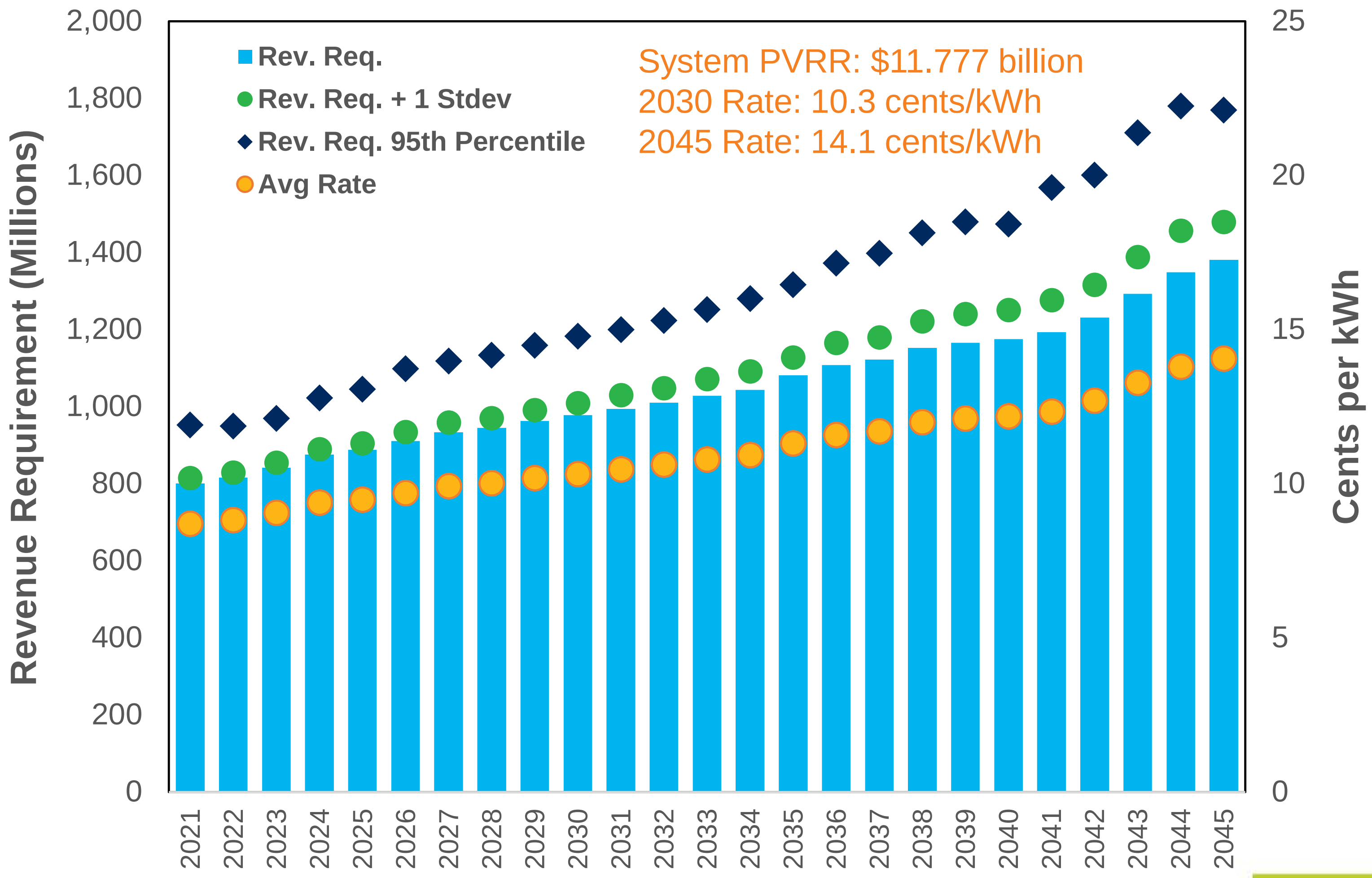


Notes:
1) Prior to 2030, Avista is a net energy seller to the market
2) "Clean" market purchases is measured as the regional generation mix's CO_2 mix compared to a CCCT

PRS: Greenhouse Gas Emissions Forecast

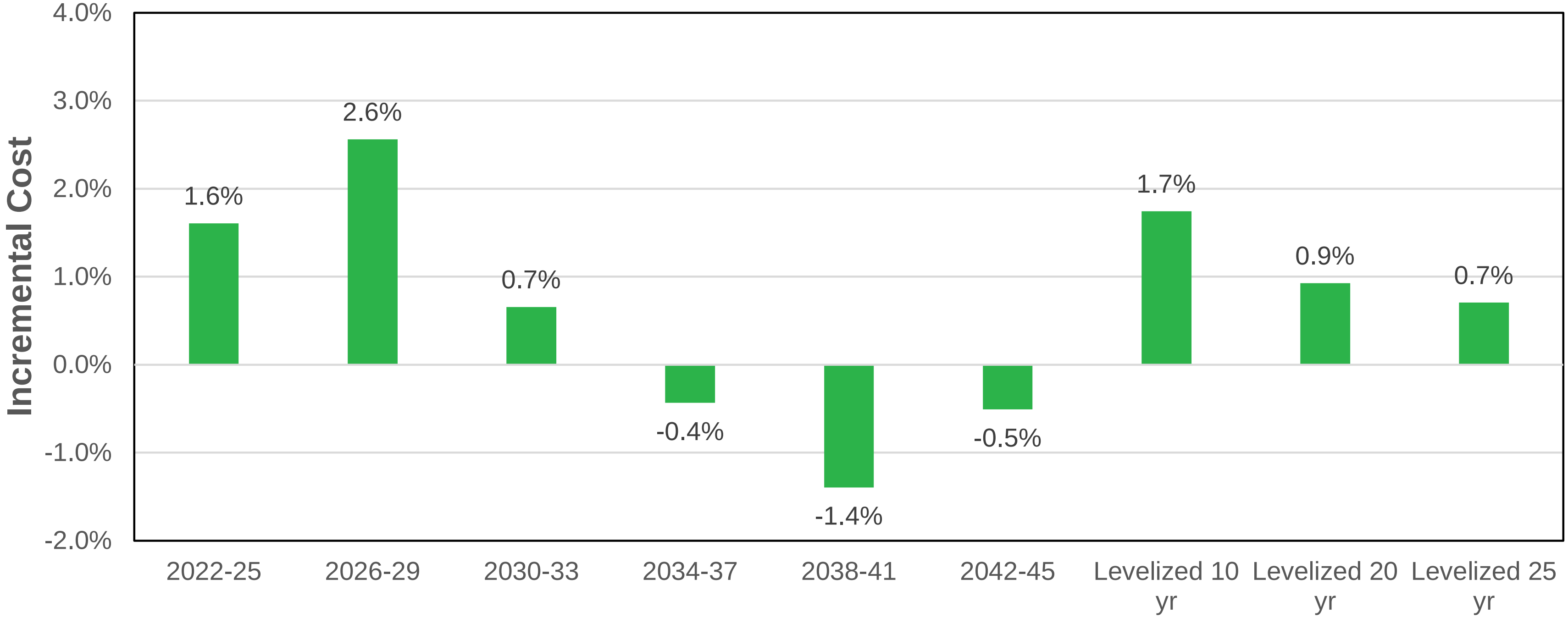


PRS: Cost/Rate Forecast



Note: Assumes non-power supply modelled costs escalate at 2 percent per year

Cost Comparison between PRS and LC Portfolio w/o CETA



Notes: State allocation factors and resource designation will affect these results for each state

Avoided Cost of Generation Calculation Methodology

- **Energy value:** hourly mark to market value of delivered energy in the wholesale market (i.e. Mid-C index).

- **Capacity value:** total portfolio revenue requirement difference between a portfolio meeting capacity targets versus a portfolio only relying on the spot energy market. The difference is divided by the added capacity additions (MW) to estimate $ per kW. Rates are levelized and tilted to begin with first deficit.

- **Clean premium:** total portfolio revenue requirement difference between a portfolio meeting CETA versus a portfolio only meeting the capacity requirements. This difference is divided by added generated MWh. Rates are levelized and tilted to begin with first expected acquisition year.

- **Clean premium with tax incentives:** Same as clean premium calculation except the federal tax subsidies continue.

Avoided Costs

Year	Energy Flat (S/MWh)	Energy On-Peak ($/MWh)	Energy Off-Peak ($/MWh)	Clean Premium ($/MWh)	Clean Premium (w/ Tax Incentive) ($/MWh)	Capacity ($/kW-year)
2021	19.67	22.64	15.71	0.00	0.00	0.0
2022	19.98	22.75	16.28	9.33	0.78	0.0
2023	20.44	23.05	16.98	9.52	0.79	0.0
2024	21.61	24.09	18.28	9.71	0.81	0.0
2025	22.76	25.19	19.50	9.90	0.83	0.0
2026	24.27	26.40	21.43	10.10	0.84	97.3
2027	23.57	25.27	21.30	10.30	0.86	99.3
2028	25.02	26.26	23.35	10.51	0.88	101.2
2029	25.92	26.80	24.73	10.72	0.89	103.3
2030	26.72	27.08	26.25	10.93	0.91	105.3
2031	29.46	29.66	29.21	11.15	0.93	107.4
2032	29.78	29.95	29.54	11.38	0.95	109.6
2033	31.22	30.74	31.89	11.60	0.97	111.8
2034	32.83	31.94	34.06	11.83	0.99	114.0
2035	33.66	32.64	35.05	12.07	1.01	116.3
2036	35.82	34.82	37.16	12.31	1.03	118.6
2037	36.12	34.58	38.19	12.56	1.05	121.0
2038	38.81	37.40	40.76	12.81	1.07	123.4
2039	38.60	37.13	40.57	13.07	1.09	125.9
2040	38.52	36.80	40.84	13.33	1.11	128.4
2041	39.09	37.74	40.92	13.59	1.13	131.0
2042	38.98	37.99	40.31	13.87	1.16	133.6
2043	40.24	39.51	41.21	14.14	1.18	136.2
2044	46.10	45.29	47.15	14.43	1.20	139.0
2045	43.94	43.11	45.05	14.71	1.23	141.8
15 yr Levelized	**24.58**	**26.11**	**22.55**	**9.38**	**0.78**	**58.5**
20 yr Levelized	**26.44**	**27.55**	**24.98**	**9.87**	**0.82**	**67.8**
25 yr Levelized	**27.86**	**28.77**	**26.66**	**10.27**	**0.86**	**74.3**

Challenges and Considerations

- Ultimate disposition of Colstrip
- State resource allocation
- Achieving Avista clean electricity goal
- Transmission needs and issues
  - Integration of transmission & distribution needs into a fully Integrated Resource Plan
  - System impacts of third party generation resources
- Storage issues
  - Physical requirements for resource adequacy and grid reliability
  - Economic needs for integration of renewable generation
  - Storage technology and cost improvements
- Rulemaking and permitting impacts on the preferred resource options
- Market development to accommodate increased variable generation and acquisition

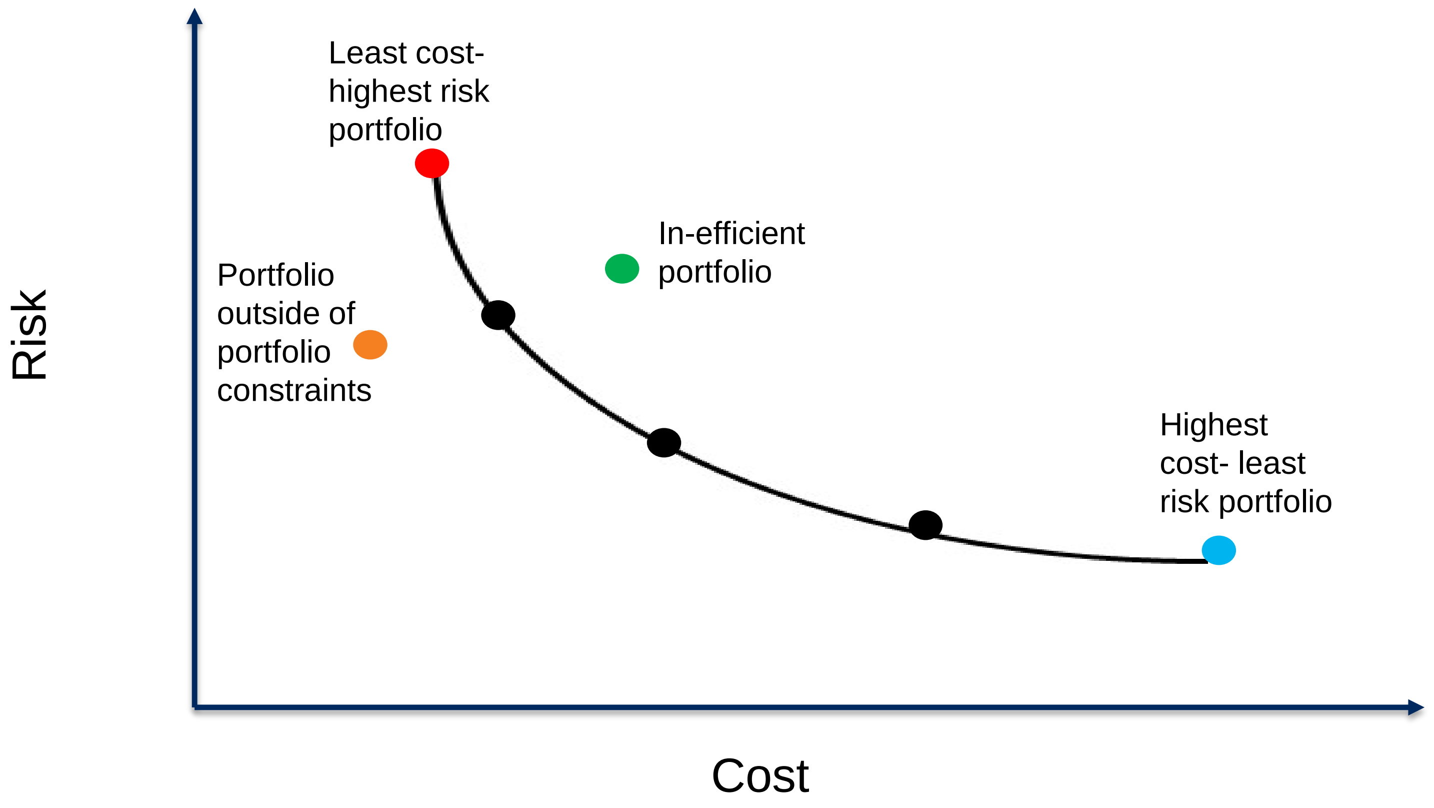
2020 Electric Integrated Resource Plan Draft Portfolio Scenario Analysis

James Gall, IRP Manager
Fifth Technical Advisory Committee Meeting
October 15, 2019

Scenario Overview

- Use same electric price forecast- but different resource assumptions.
- Use optimization to create portfolio, but use different <u>constraints</u> for each scenario.
- View financial results of each portfolio along with resource selection.
- Portfolio results with different market assumptions will be provided at the next TAC meeting.
- No reliability analysis are completed for portfolio scenarios.

Efficient Frontier Overview

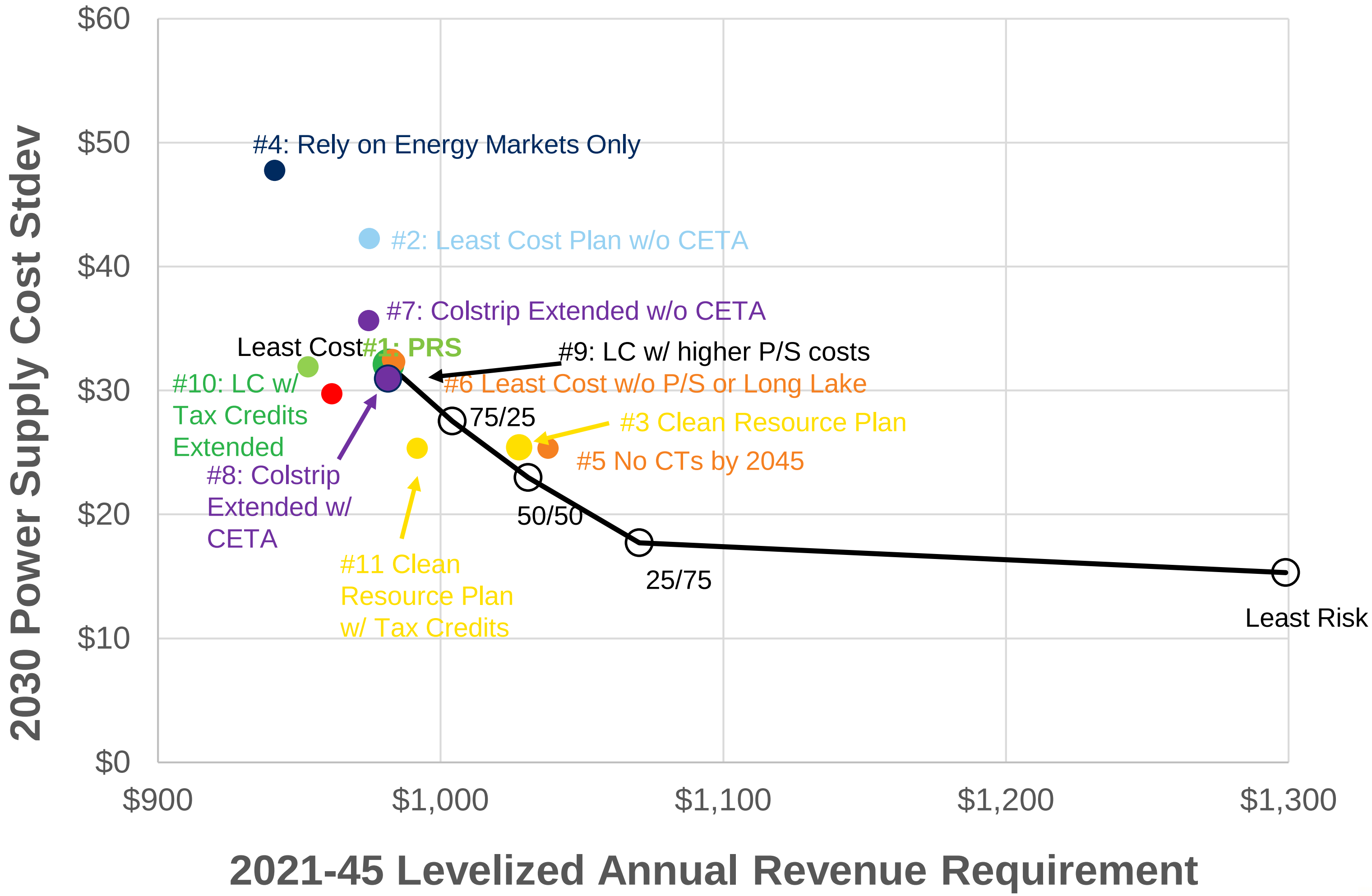


Scenarios

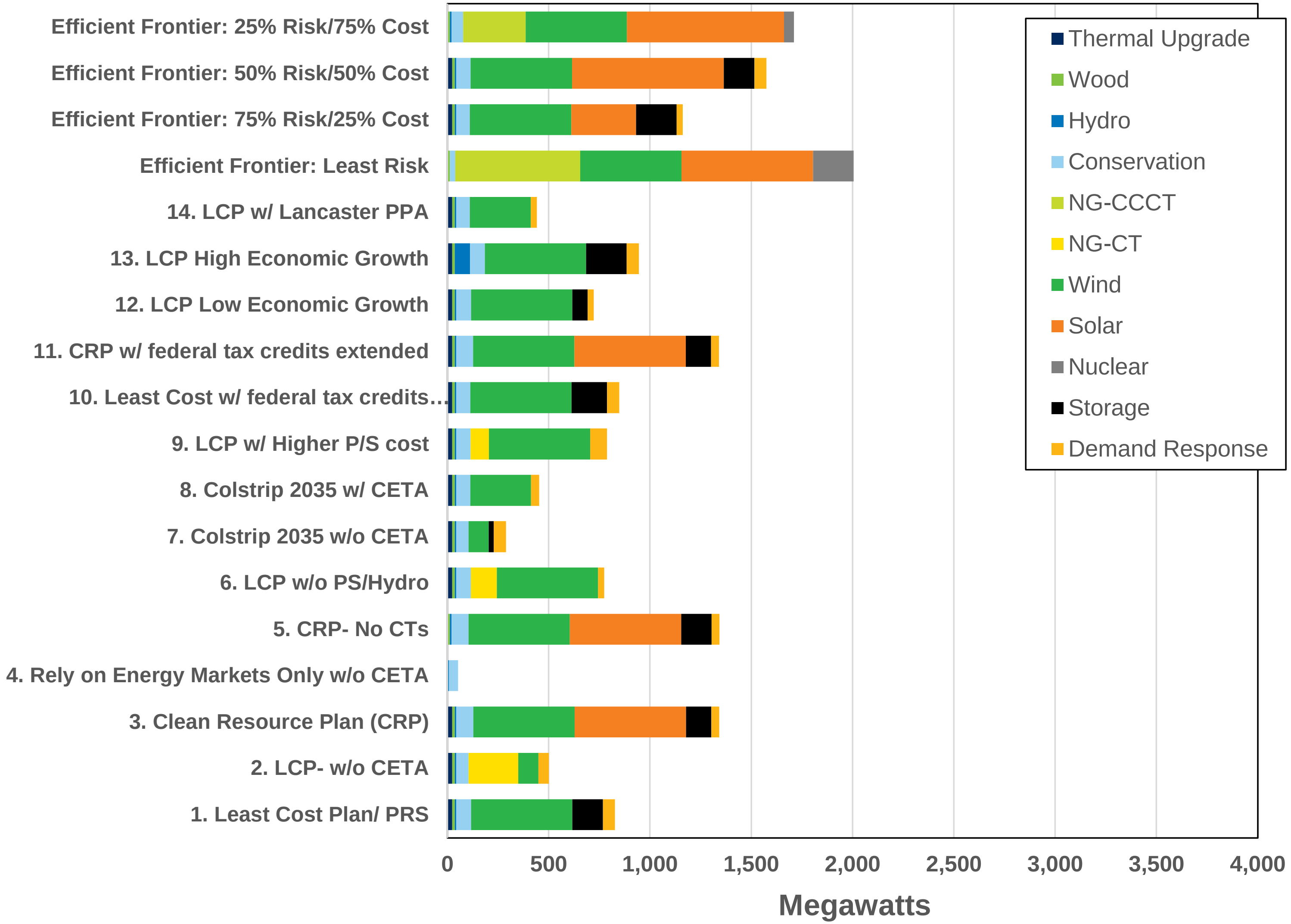
1. Preferred Resource Strategy
2. Least Cost Plan- w/o CETA
3. Clean Resource Plan: 100% net clean by 2027
4. Rely on energy markets only (no capacity or renewable additions) w/o CETA
5. 100% net clean by 2027, and no CTs by 2045
6. Least Cost Plan w/o pumped storage or Long Lake as options
7. Colstrip extended to 2035 w/o CETA
8. Colstrip extended to 2035 w/ CETA
9. Least Cost Plan w/ higher pumped storage cost
10. Least Cost w/ federal tax credits extended
11. Clean Resource Plan w/ federal tax credits extended
12. Least Cost Plan w/ low load growth (flat loads- low economic/population growth)
13. Least Cost Plan w/ high load growth (high economic/population growth)
14. Least Cost Plan w/ Lancaster PPA extended five years *(financials will not be public)*

Others: Efficient frontier portfolio (least risk, 75/25, 50/50, and 25/75)

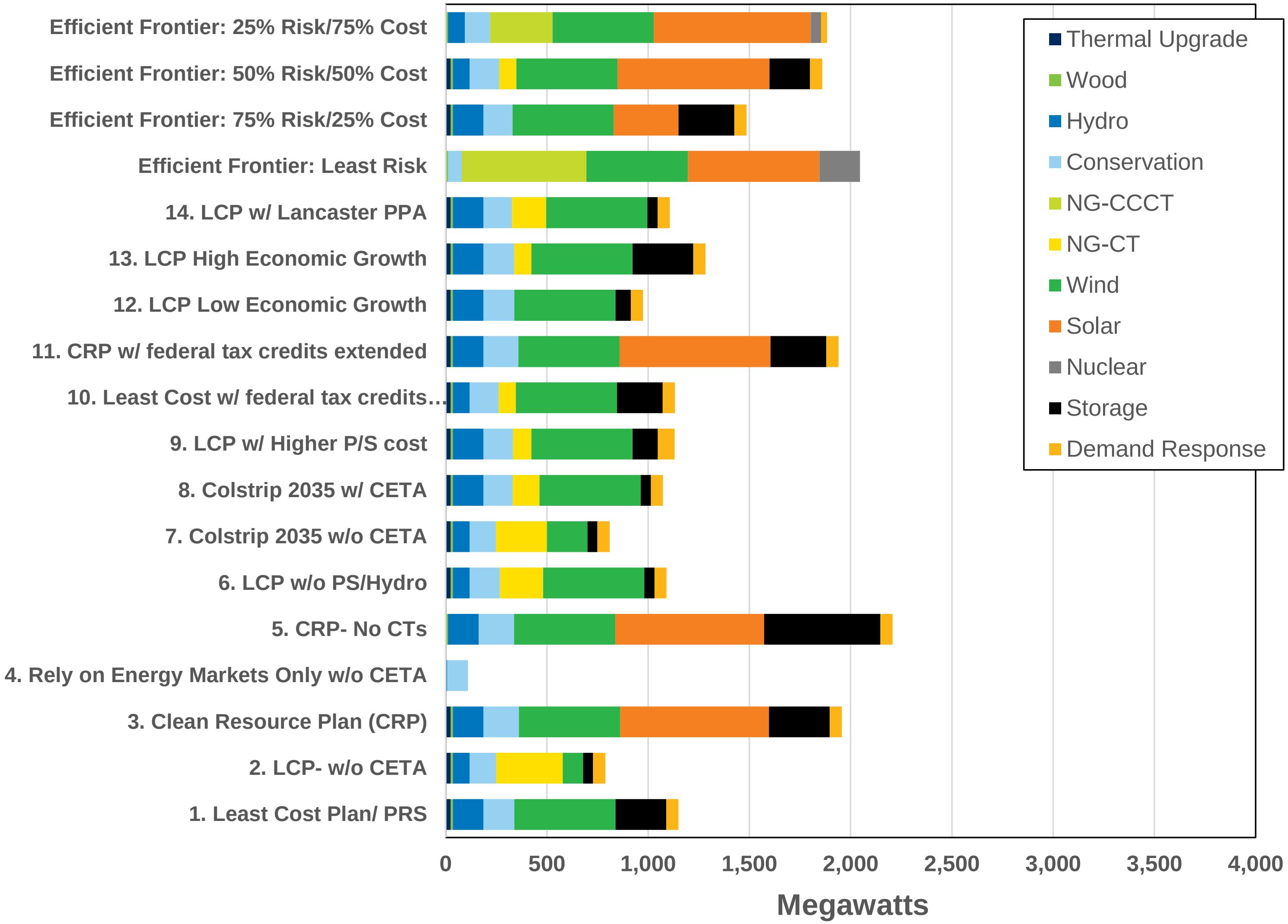
Efficient Frontier Results



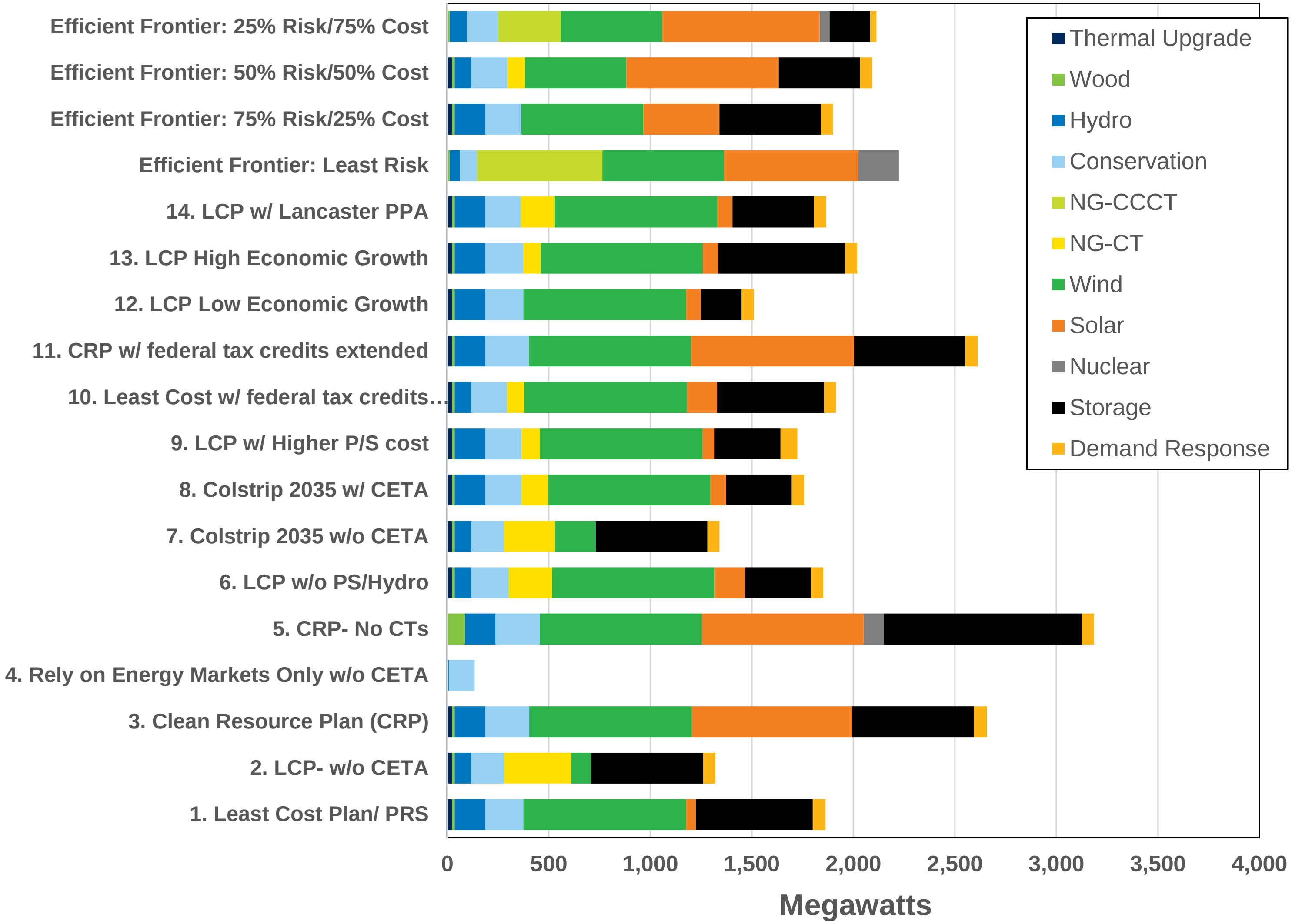
2030 Portfolio Resource Selection



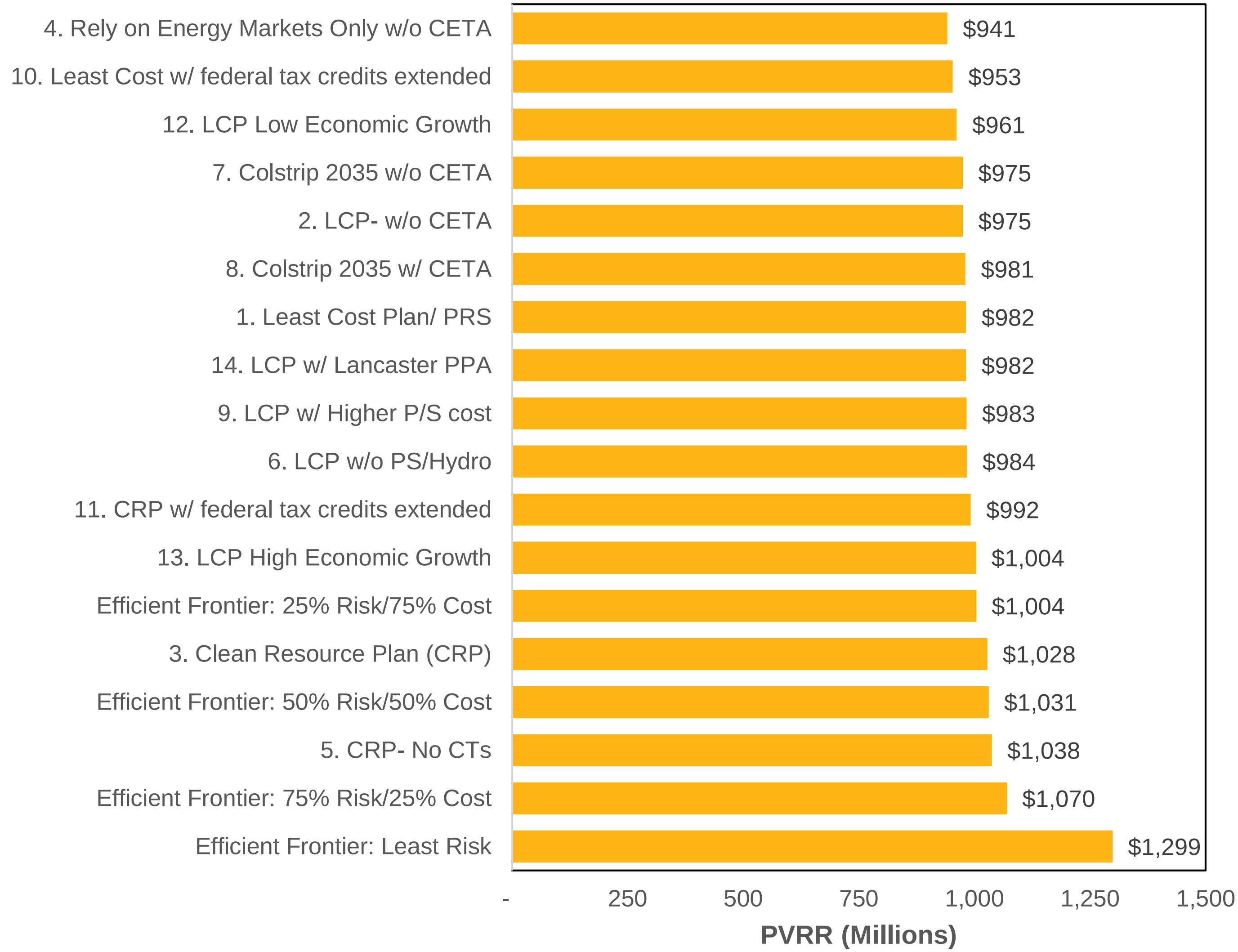
2040 Portfolio Resource Selection



2045 Portfolio Resource Selection

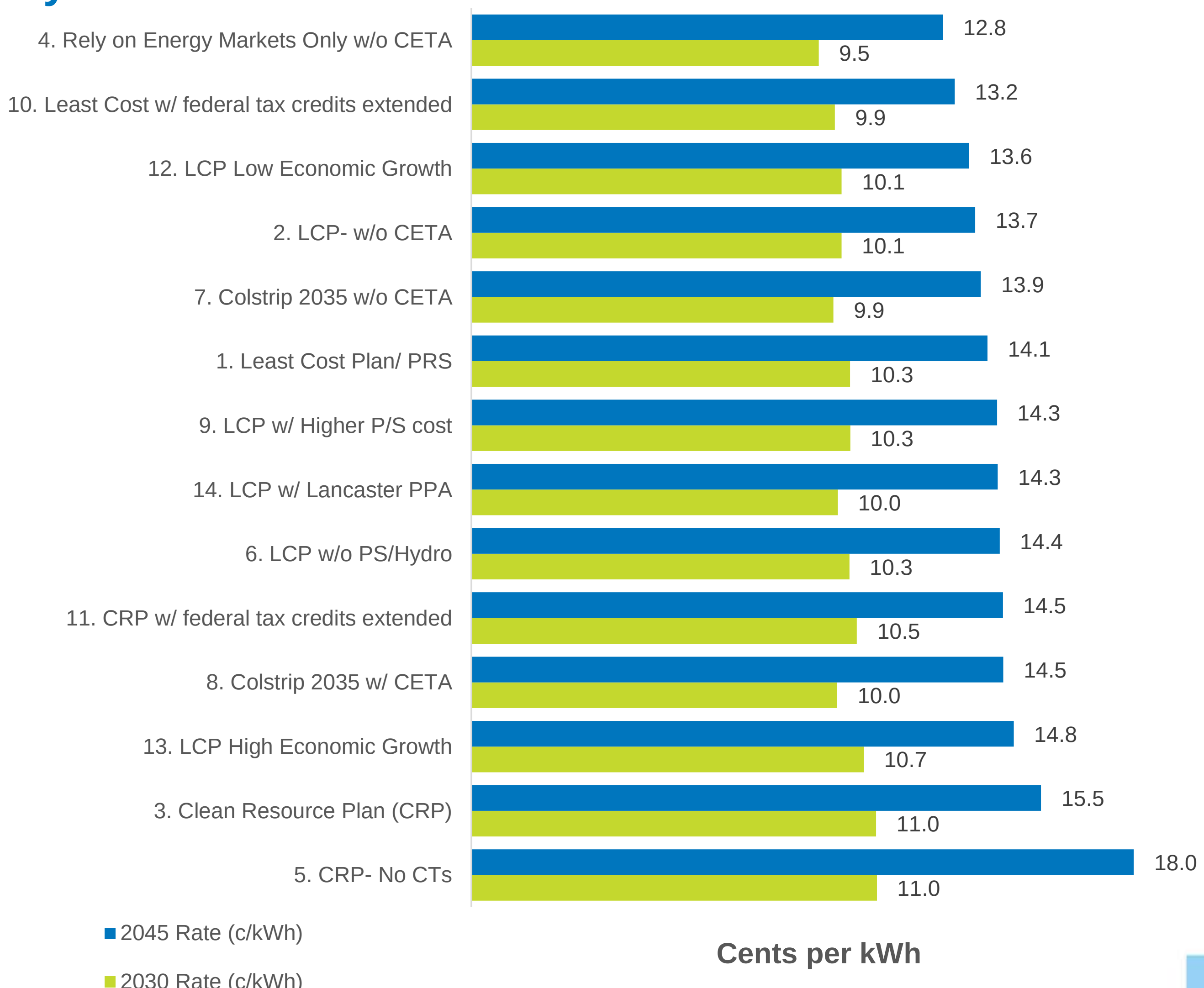


Annual Cost Comparison



Rate Comparison

sorted by 2045 rates



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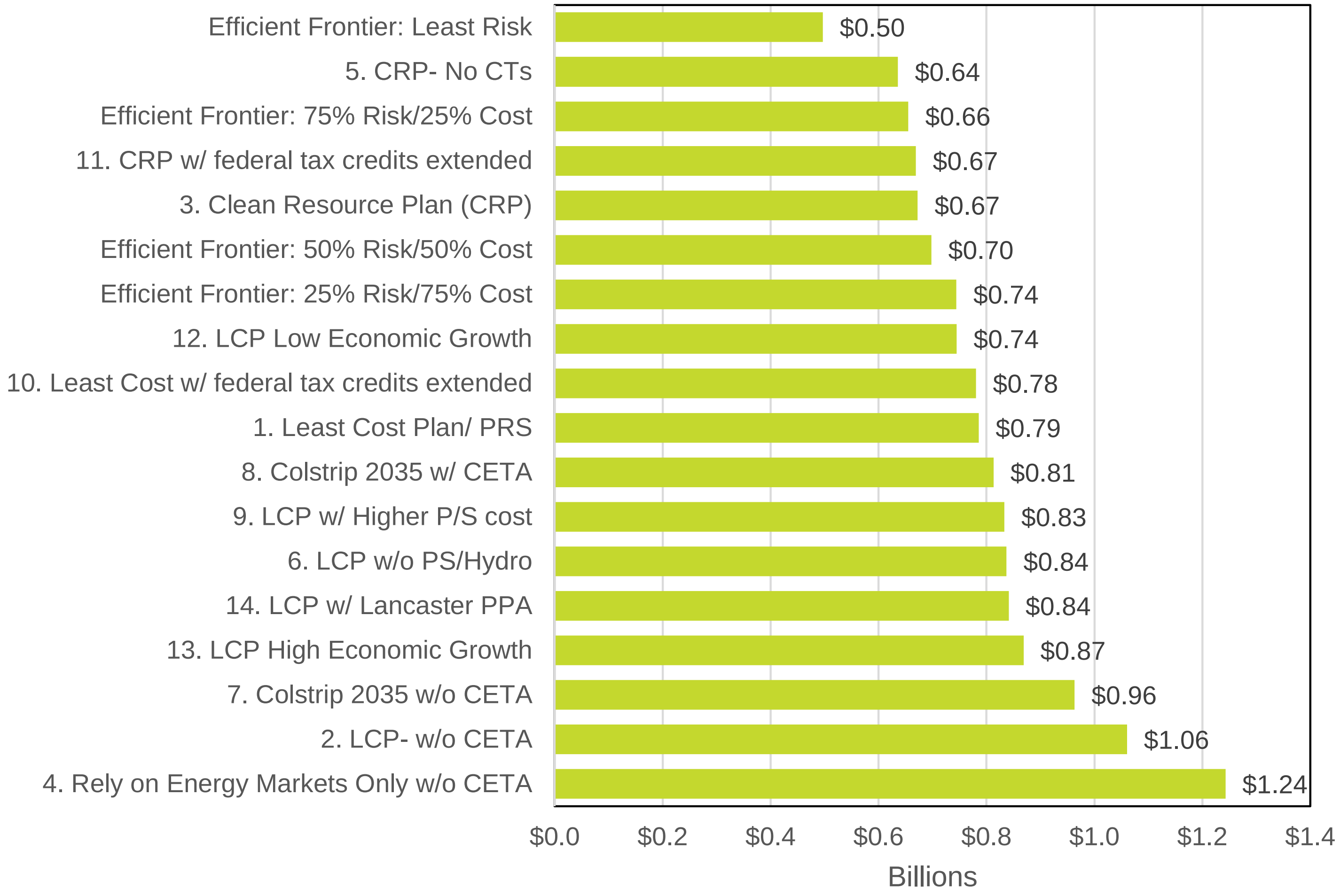
Portfolio Tail Risk

(95th percentile minus expected cost, excludes Social Cost of Carbon)



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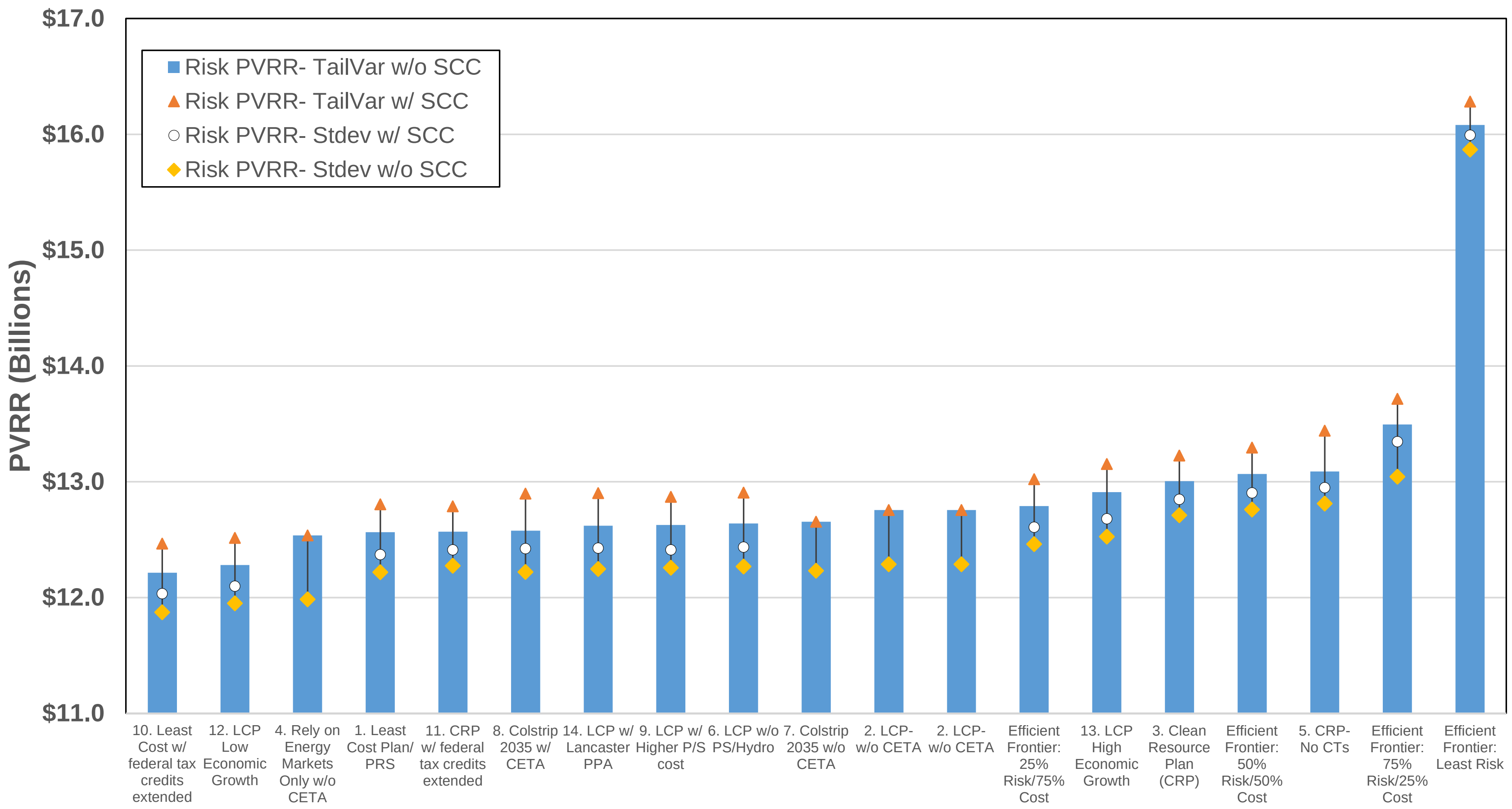
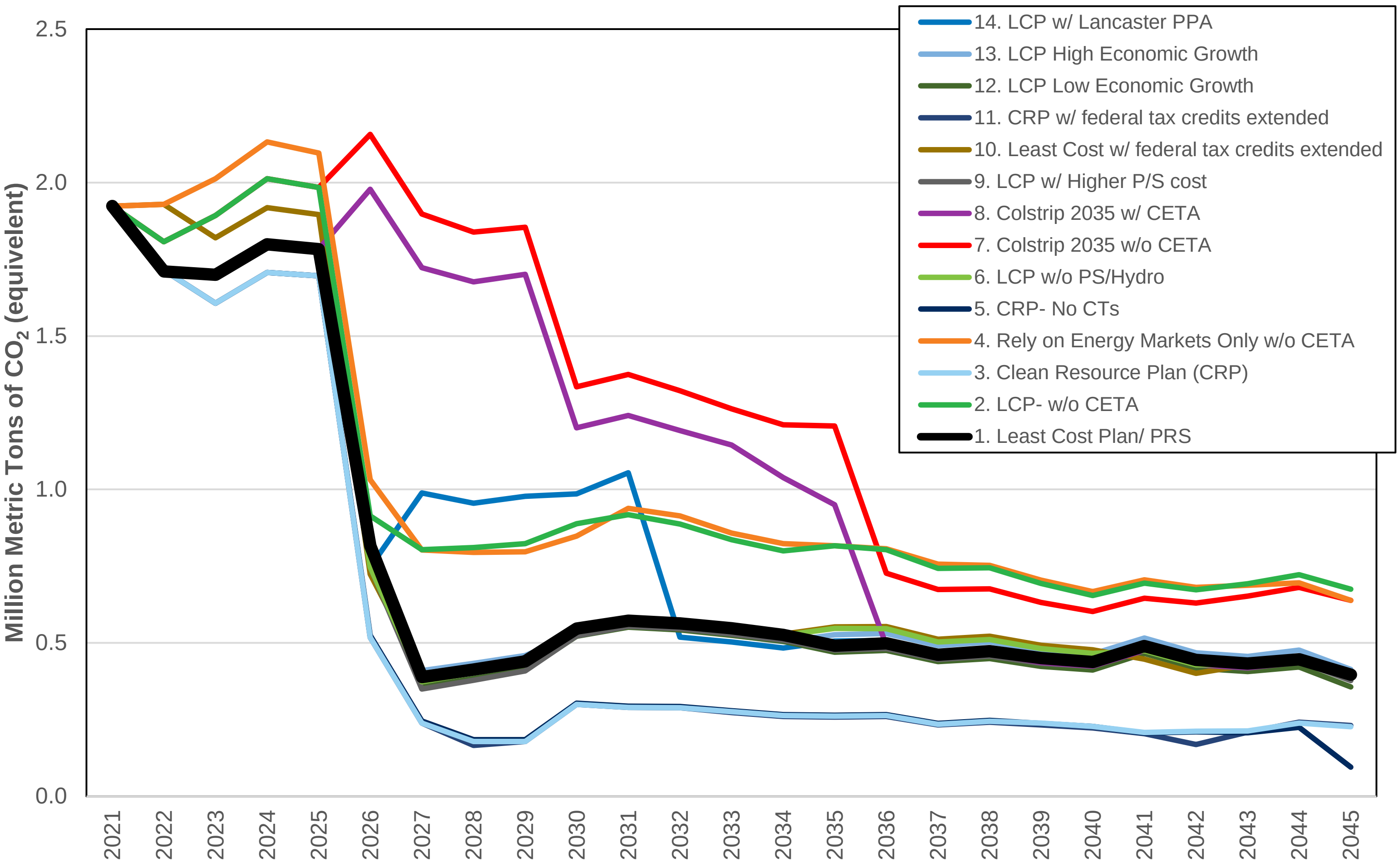
PVRR Risk Adjusted Comparison

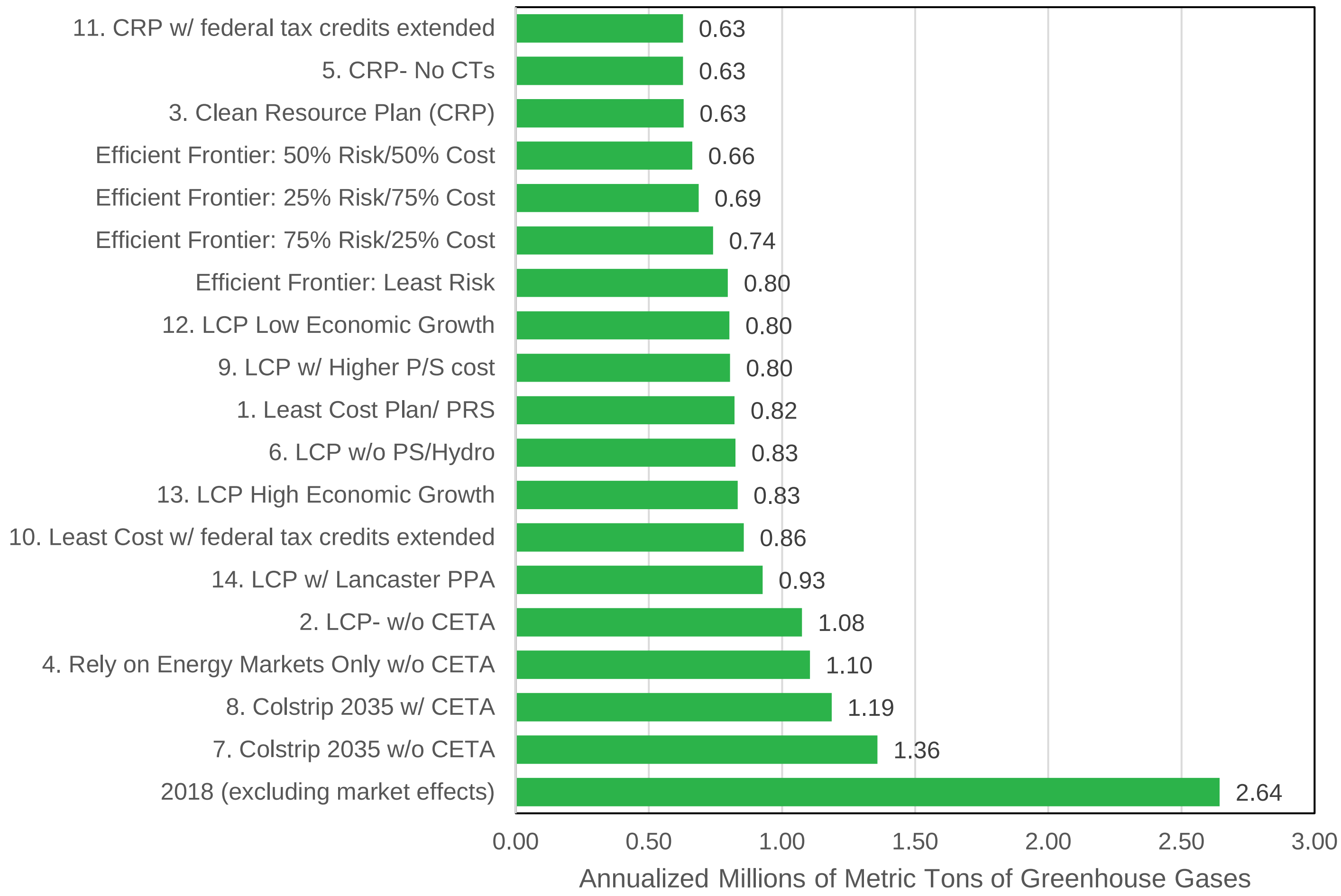
Sorted by TailVar w/o Social Cost of Carbon (SCC)



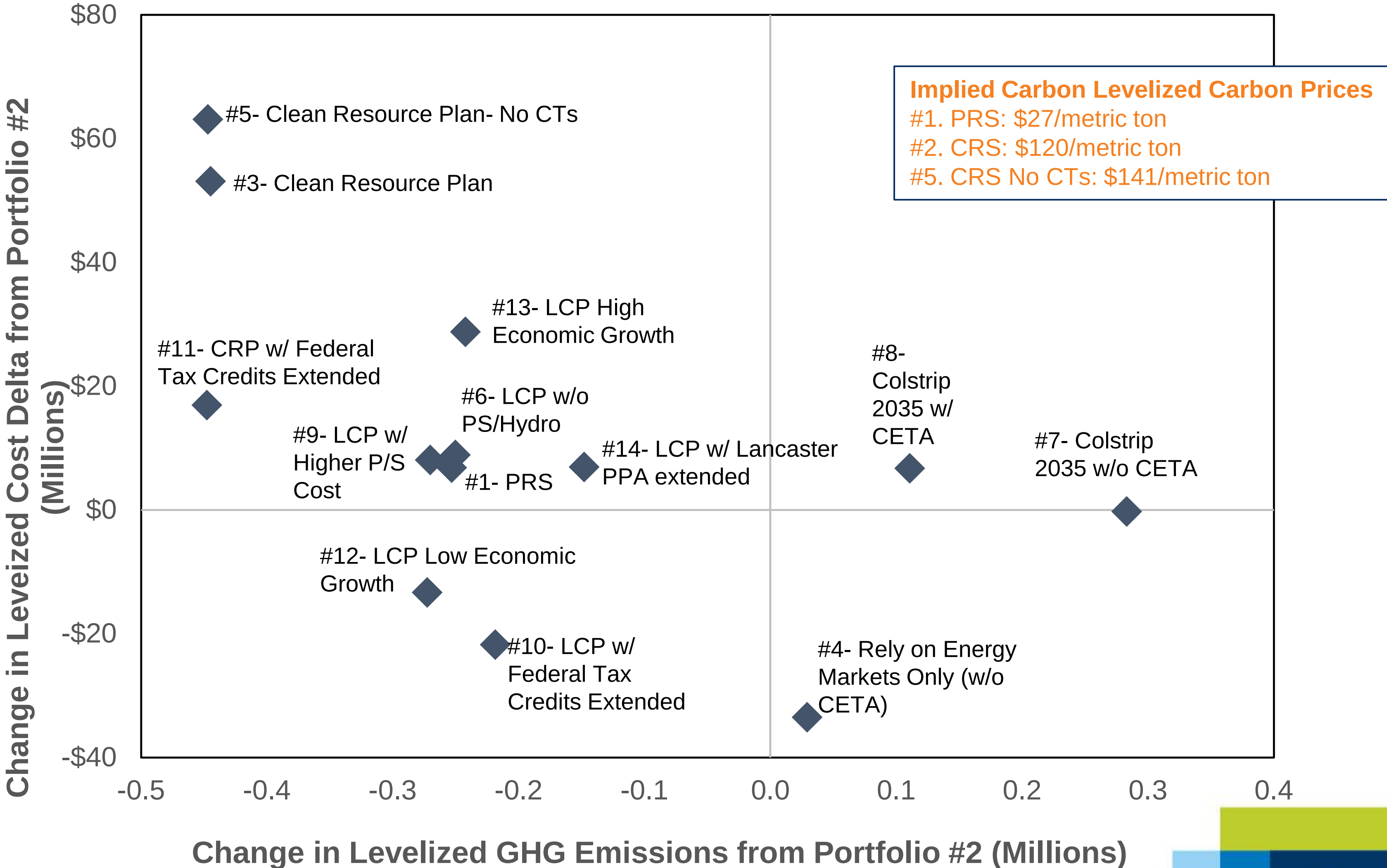
Annual Greenhouse Gas Comparison



Annalized Greenhouse Gas Emissions
(Levelized using 2.5% discount rate)



Cost vs GHG Emissions



Scenario Results Summary Table

Portfolio Number	Portfolio name	Cost 2021-2045 (PVRR) (millions)	Cost 2021-2030 (PVRR) (millions)	2030 Risk (millions)	2030 Rate (c/kWh)	2045 Rate (c/KWh)	Levelized R.R.
1	Preferred Resource Strategy	$11,777	$6,303	$32.1	10.3	14.1	981.7
2	Least Cost Plan- w/o CETA	$11,695	$6,195	$42.3	10.1	13.7	974.8
3	Clean Resource Plan: 100% net clean by 2027	$12,333	$6,447	$25.4	11.0	15.5	1,027.9
4	Rely on Energy Markets Only (no capacity or renewable additions)	$11,293	$6,058	$47.8	9.5	12.8	941.3
5	100% net clean by 2027, and no CTs by 2045	$12,452	$6,453	$25.3	11.0	18.0	1,037.9
6	Least Cost Plan w/o pumped storage or Long Lake as options	$11,802	$6,281	$32.3	10.3	14.4	983.7
7	Colstrip extended to 2035 w/o CETA	$11,692	$6,176	$35.6	9.9	13.9	974.6
8	Colstrip extended to 2035 w/ CETA	$11,764	$6,234	$30.9	10.0	14.5	980.6
9	Least Cost Plan w/ higher pumped storage cost	$11,792	$6,281	$32.5	10.3	14.3	982.9
10	Least Cost w/ federal tax credits extended	$11,434	$6,183	$31.9	9.9	13.2	953.1
11	Clean Resource Plan w/ federal tax credits extended	$11,898	$6,297	$25.4	10.5	14.5	991.8
12	Least Cost Plan w/ low economic growth	$11,535	$6,241	$29.7	10.1	13.6	961.5
13	Least Cost Plan w/ high economic growth	$12,041	$6,369	$34.4	10.7	14.8	1,003.6

Note: Costs do not include Social Cost of Carbon

Appendix

Detailed Resource Portfolios

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1) Preferred Resource Strategy

Least Reasonable Cost Plan

Load reduction of 152 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 150 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2026-2030: 85 MW, Demand Response
2027: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade

2031-2040

2031: 75 MW, Mid-C PPA Renew
2033: 25 MW x 16 hr, Liquid Air Storage
2035: 55 MW, Northeast CT retired
2035: 68 MW, Long Lake 2nd Powerhouse
2036: 25 MW x 16 hr, Liquid Air Storage
2038: 25 MW x 16 hr, Liquid Air Storage
2039: 25 MW x 16 hr, Liquid Air Storage

2041-2045

2041: 25 MW x 16 hr, Liquid Air Storage
2042-2045: 300 MW Wind PPA Renew
2043: 25 MW x 16 hr, Liquid Air Storage
2043: 2.5 MW, Demand Response
2042-2045: 225 MW x 4 hr, Lithium-ion
2044: 50 MW, Solar w/ 50 MW x 4hr, Storage

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2) Least Cost Plan

w/o CETA

Load reduction of 131 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2026: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2026-2030: 52 MW, Demand Response
- 2027: 8 MW, Post Falls Upgrade
- 2027: 245 MW, Natural Gas CT

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2033: 25 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2035: 84 MW, Natural Gas CT
- 2036: 9 MW, Demand Response
- 2038: 25 MW x 16 hr, Liquid Air Storage
- 2040: 25 MW x 16 hr, Liquid Air Storage

2041-2045

- 2041-2042: 50 MW x 16 hr, Liquid Air Storage
- 2043-2045: 450 MW x 4 hr, Lithium-ion

3) Clean Resource Plan

100% net clean by 2030

Load reduction of 175 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2022: 150 MW, NW Solar
2023: 200 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 125 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 200 MW, MT Wind
2026: 257 MW, Lancaster PPA expires
2025-2030: 39 MW, Demand Response
2027: 8 MW, Post Falls Upgrade
2027-2029: 300 MW, NW Solar
2028-2030: 100 MW, Solar

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031: 68 MW Long Lake 2nd Powerhouse
2033: 50 MW, NW Solar
2035: 55 MW, Northeast CT retired
2036-2040: 125 MW Solar w/ 125 MW x 4 hr. Storage
2038: 10 MW Solar
2039: 50 MW x 4 hr, Liquid Air Storage
2033-2040: 46 MW, Demand Response

2041-2045

2041-2043: 300 MW Wind PPA Renew
2042-2044: 75 MW x 16 hr Liquid Air Storage
2045: 5 MW Solar
2045: 50 MW Solar w/ 50 MW x 4 hr Storage
2045: 50 MW x 4 hr, Lithium-ion

4) Rely on Energy Markets Only

(no capacity or renewable additions)

Load reduction of 102 aMW due to Energy Efficiency by 2040

2021-2030

2026: 222 MW, Colstrip removed

2026: 257 MW, Lancaster PPA expires

2027: 8 MW, Post Falls Upgrade

2031-2040

2035: 55 MW, Northeast CT retired

2041-2045

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5) 100% Net Clean by 2027

and No CTs by 2045

Load reduction of 174 aMW due to Energy Efficiency by 2040

2021-2030

2022: 150 MW, Solar
2022: 100 MW, MT Wind
2023: 200 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 150 MW, Pumped Hydro
2026: 200 MW, MT Wind
2026: 257 MW, Lancaster PPA expires
2025-2027: 39 MW, Demand Response
2027: 8 MW, Post Falls Upgrade
2027-2029: 300 MW, NW Solar
2028-2030: 100 MW, NW Solar

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031: 68 MW, Long Lake 2nd Powerhouse
2033: 50 MW, NW Solar
2033-2035: 46 MW, Demand Response
2035: 55 MW, Northeast CT retired
2036-2040: 135 MW Solar w/ 125 MW x 4 hr, Storage
2039-2040: 250 MW x 16 hr Liquid Air Storage
2040: 50 MW Pumped Hydro
2035: 154 MW, Rathdrum CTs removed

2041-2045

2041-2043: 300 MW Wind PPA Renew
2043: 9 MW, Kettle Falls CT removed
2043: 25 MW, Boulder Park removed
2043-2045: 50 MW x 4 hr, Lithium-ion
2042-2044: 125 MW x 16 hr Liquid Air Storage
2045: 10 MW Solar
2045: 50 MW Solar w/ 50 MW x 4 hr, Storage
2045: 175 MW Pumped Hydro
2045: 100 MW Small Nuclear
2045: 75 MW Biomass
2045: 302 MW, Coyote Springs 2 removed

6) Least Cost Plan
w/o pumped storage or Long Lake

Load reduction of 149 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 129 MW, Natural Gas CT
- 2027: 30 MW, Demand Response
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031-2032: 55 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2035: 84 MW, Natural Gas CT
- 2039: 25 MW x 16 hr Liquid Air Storage
- 2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

- 2041-2045: 300 MW Wind PPA Renew
- 2042: 25 MW x 16 hr, Liquid Air Storage
- 2043-2045: 150 MW Solar w/ 150 MW x 4 hr, Storage
- 2044-2045: 75 MW x 4 hr, Lithium-ion
- 2044: 25 MW x 16 hr Liquid Air Storage

7) Colstrip Extended to 2035 w/o CETA

Load reduction of 129 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2026: 12 MW, Kettle Falls Upgrade
2026: 25 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 8 MW, Post Falls Upgrade
2028-2030: 61 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2035: 25 MW, Demand Response
2035: 55 MW, Northeast CT retired
2035: 222 MW, Colstrip removed
2035-2036: 252 MW, Natural Gas CT
2036: 100 MW, MT Wind
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041: 25 MW x 16 hr Liquid Air Storage
2042: 25 MW x 16 hr Liquid Air Storage
2042-2045: 450 MW x 4 hr, Lithium-ion

8) Colstrip Extended to 2035 w/ CETA

Load reduction of 143 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 8 MW, Post Falls Upgrade
2028: 39 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2032-2035: 46 MW, Demand Response
2035: 55 MW, Northeast CT retired
2035: 222 MW, Colstrip removed
2035: 68 MW, Long Lake 2nd Powerhouse
2036: 200 MW, MT Wind
2036: 132 MW, Natural Gas CT
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041: 25 MW x 16 hr Liquid Air Storage
2042-2045: 300 MW Wind PPA Renew
2043: 25 MW x 16 hr Liquid Air Storage
2042-2045: 75 MW, Solar w/ 75 MW x 4 hr, Storage
2042-2045: 125 MW x 4 hr, Lithium-ion Storage
2045: 25 MW x 16 hr Liquid Air Storage

9) Least Cost Plan
w/ higher pumped storage cost

Load reduction of 155 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2025-2028: 109 MW, Demand Response
- 2026: 222 MW, Colstrip removed
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 90 MW, Natural Gas CT
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2032: 25 MW x 16 hr Liquid Air Storage
- 2035: 55 MW, Northeast CT retired
- 2035: 68 MW, Long Lake 2nd Powerhouse
- 2035-2040: 100 MW x 16 hr Liquid Air Storage

2041-2045

- 2041: 25 MW x 16 hr Liquid Air Storage
- 2042-2045: 300 MW, Wind PPA Renew
- 2043: 25 MW x 16 hr Liquid Air Storage
- 2044: 25 MW x 16 hr Liquid Air Storage
- 2044: 10 MW, Solar
- 2044: 25 MW x 4 hr, Lithium-ion
- 2045: 50 MW x 4 hr, Lithium-ion
- 2045: 50 MW Solar w/ 50 MW x 4 hr Storage

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10) Least Cost Plan
w/ Federal Tax Credits Extended

Load reduction of 144 aMW due to Energy Efficiency by 2040

2021-2030

2023: 200 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2026: 200 MW, MT Wind
2026: 175 MW Pumped Hydro
2026: 283 MW, Lancaster PPA expires
2027: 100 MW, MT Wind
2027: 8 MW, Post Falls Upgrade
2027-2030: 60 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2032: 25 MW, Demand Response
2035: 84 MW, Natural Gas CT
2035: 55 MW, Northeast CT retired
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041: 25 MW x 16 hr Liquid Air Storage
2041-2042: 300 MW, Wind PPA Renew
2043: 25 MW, Pumped Hydro
2044-2045: 150 MW NW Solar
2044-2045: 150 MW, Solar w/ 150 MW x 4 hr Storage
2044-2045: 100 MW x 4 hr, Lithium-ion

11) Clean Resource Plan
w/ Federal Tax Credits Extended

Load reduction of 173 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 150 MW, NW Solar
- 2023: 200 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2025-2026: 39 MW, Demand Response
- 2026: 222 MW, Colstrip removed
- 2026: 200 MW, MT Wind
- 2026: 125 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027-2029: 300 MW, NW Solar
- 2027: 8 MW, Post Falls Upgrade
- 2028: 50 MW, Solar
- 2028: 50 MW, Solar

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031: 68 MW, Long Lake 2nd Powerhouse
- 2033: 60 MW, Solar
- 2033-2035: 46 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2036-2040: 135 MW, Solar w/ 125 MW x 4 hr Storage
- 2039: 25 MW x 16 hr Liquid Air Storage

2041-2045

- 2041-2042: 300 MW Wind PPA Renew
- 2043: 25 MW x 16 hr Liquid Air Storage
- 2043-2045: 200 MW x 4 hr, Lithium-ion
- 2045: 55 MW, Solar w/ 50 MW x 4 hr of Storage

12) Least Cost Plan
w/ Low Economic Growth

Load reduction of 152 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2025-2027: 55 MW, Demand Response
- 2026: 222 MW, Colstrip removed
- 2026: 75 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2035: 55 MW, Northeast CT retired
- 2035: 68 MW Long Lake 2nd Powerhouse
- 2038-2039: 30 MW Demand Response

2041-2045

- 2041: 25 MW x 4 hr, Lithium-ion
- 2042-2045: 300 MW Wind PPA Renew
- 2043: 25 MW x 16 hr Liquid Air Storage
- 2044-2045: 75 MW Solar w/ 75 MW x 4 hr Storage

13) Least Cost Plan
w/ High Economic Growth

Load reduction of 152 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2025-2029: 85 MW, Demand Response
- 2026: 222 MW, Colstrip removed
- 2026: 200 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade
- 2030: 68 MW Long Lake 2nd Powerhouse

2031-2040

- 2031-2033: 75 MW, Mid-C PPA Renew
- 2035: 84 MW Natural Gas CT
- 2035: 55 MW, Northeast CT retired
- 2037-2040: 100 MW x 16 hr Liquid Air Storage

2041-2045

- 2041-43: 100 MW x 16 hr Liquid Air Storage
- 2042-2045: 300 MW Wind PPA Renew
- 2043-2045: 125 MW x 4 hr, Lithium-ion
- 2044: 25 MW Pumped Hydro
- 2044-2045: 75 MW Solar w/ 75 MW x 4 hr Storage

14) Least Cost Plan w/ Lancaster PPA Extended Five Years

Load reduction of 141 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2027: 8 MW, Post Falls Upgrade
2030: 30 MW, Demand Response

2031-2040

2031-2032: 75 MW, Mid-C PPA Renew
2031-2032: 55 MW Demand Response
2032: 257 MW, Lancaster PPA expires
2032: 200 MW MT Wind
2032: 84 MW Natural Gas CT
2032: 68 MW Long Lake 2nd Powerhouse
2035: 55 MW, Northeast CT retired
2035: 84 MW Natural Gas CT
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041: 25 MW, Solar w/ 25 MW x 4 hr Storage
2041: 25 MW x 16 hr Liquid Air Storage
2042-2045: 300 MW, Wind PPA Renew
2042-2045: 225 MW x 4 hr, Lithium-ion
2043: 25 MW x 16 hr Liquid Air Storage
2044: 50 MW, Solar w/ 50 MW x 4 hr Storage
2045: 2.5 MW, Demand Response

Least Risk Plan

Load reduction of 67 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 150 MW, NW Solar
- 2022: 100 MW, MT Wind
- 2023: 200 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 257 MW, Lancaster PPA expires
- 2027: 308 MW, Natural Gas CCCT
- 2027-2028: 200 MW, MT Wind
- 2028-2030: 300 MW, NW Solar
- 2029-2030: 200 MW, NW Solar
- 2029-2030: 200 MW, Small Nuclear
- 2030: 308 MW, Natural Gas CCCT

2031-2040

- 2035: 55 MW, Northeast CT retired

2041-2045

- 2045: 5 MW, Solar
- 2045: 100 MW, NW Wind
- 2043-45: 50 MW, Mid-C PPA Renew

Note: The least Least Risk Portfolio minimizes risk for 2030

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25% Risk/ 75% Cost Plan

Load reduction of 143 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 50 MW, NW Solar
- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Solar
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 175 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 30 MW, Demand Response
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade
- 2030: 170 MW, Solar w/ 25 MW x 4 hr Storage

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2032: 55 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2035: 68 MW, Long Lake 2nd Powerhouse
- 2036: 25 MW x 16 hr Liquid Air Storage
- 2038: 25 MW x 16 hr Liquid Air Storage
- 2039: 25 MW x 16 hr Liquid Air Storage

2041-2045

- 2041: 25 MW x 16 hr Liquid Air Storage
- 2042: 25 MW x 16 hr Liquid Air Storage
- 2043: 25 MW, Pumped Hydro
- 2044: 5 MW
- 2044: 25 MW x 4 hr, Lithium-ion
- 2044: 25 MW x 16 hr Liquid Air Storage
- 2045: 50 MW, Solar w/ 50 MW x 4 hr Storage
- 2045: 100 MW, NW Wind
- 2045: 50 MW x 4 hr, Lithium-ion

50% Risk/ 50% Cost Plan

Load reduction of 146 aMW due to Energy Efficiency by 2040

2021-2030

2022: 100 MW, MT Wind
2022: 150 MW, NW Solar
2023: 200 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 150 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2026-2030: 60 MW, Demand Response
2027: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade
2028-2030: 300 MW, Solar w/ 300 MW x 4hr storage

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031: 25 MW, Demand Response
2035: 84 MW, Natural Gas CT
2035: 55 MW, Northeast CT retired
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041-2044: 100 MW x 16 hr Liquid Air Storage
2043-2044: 75 MW x 4 hr, Lithium-ion
2044: 50 MW, solar w/ 50 MW x 4hr storage
2045: 25 MW Pumped Hydro

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75% Risk/ 25% Cost Plan

Load reduction of 125 aMW due to Energy Efficiency by 2040

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 150 MW, NW Solar
- 2023: 200 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 25 MW, NW Solar
- 2026: 257 MW, Lancaster PPA expires
- 2027: 308 MW, Natural Gas CCT
- 2027: 200 MW, MT Wind
- 2027: 8 MW, Post Falls Upgrade
- 2028-2030: 300 MW, Solar w/ 300 MW x 4hr storage)
- 2030: 50 MW, Small Nuclear

2031-2040

- 2035-2039: 75 MW, Mid-C PPA Renew
- 2035: 55 MW, Northeast CT retired
- 2039: 30 MW, Demand Response

2041-2045

- 2042: 25 MW, Demand Response
- 2043: 25 MW, Pumped Hydro
- 2044: 150 MW x 4 hr, Lithium-ion
- 2045: 25 MW, Pumped Hydro

Future Scenarios For Next TAC meeting

- Alternative load forecasts
  - Electrification and roof top solar
  - Economic cycles
- Electric market price scenarios
  - Each of the previous scenarios w/ alternative prices
  - Least cost strategies w/ alternative prices
- Other scenarios?
  - For this IRP or the next

Carbon Abatement Curve Proposal

- Use “Expected Case” market forecast
    - No change to capacity build
    - Add generator/load in 100 MW in NW area
    - Estimate “system” emission reduction by difference between 2030 expected case and sensitivity
- Estimate cost of reduction concept
- Calculate the estimated societal $/metric ton
- Abatement options in Avista’s system
    - **Generation** sources:
        - Add: solar, wind, hydro, storage, storage + renewable
        - Remove: CCCT, CT, coal
    - **End uses:** water heater, furnaces, (to NG, away from NG), energy efficiency
    - **Transportation:** Electric vehicle vs gasoline/diesel
- Results at next TAC meeting

Attendees: TAC 5, Tuesday, October 15, 2019 at Avista Headquarters in Spokane, Washington:

Logan Callen, City of Spokane; Darrell Soyars, Avista; Terrence Browne, Avista; Garrett Brown, Avista; Zach Genta, Clenera; Clint Kalich, Avista; Linda Gervais, Avista; Justin Cowley, Clear Water Paper; John Barber, Rockwood Retirement Community; Dave Van Hersett, Customer; Kirsten G. Wilson, WA DES Energy Program; Jennifer Snyder, Washington Utilities and Transportation Commission; Jason Thackston, Avista; Cadie Olsen, City of Spokane; Kathlyn Kinney, Biomethane, LLC; Tom Pardee, Avista; James Gall, Avista; Collins Sprague, Avista; Greg Rahn, Avista; John Lyons, Avista; Rachelle Farnsworth, Idaho Public Utilities Commission; Amy Wheeless, Northwest Energy Coalition; Jim Le Tellier, 350 Spokane; David Howarth, National Grid Ventures; Michael Eldred, Idaho Public Utilities Commission; Barry Kathrens, 350 Spokane.org; and Grant Forsyth, Avista.

Phone Participants:

John Chatburn, Idaho Office of Energy and Mineral Resources; Damon Zentz, City of Spokane; Nancy Esteb, Renewable Energy Coalition; and remaining phone participants did not identify themselves.

These notes follow the progression of the meeting. The notes include summaries of the questions and comments from participants, Avista responses are in *italics*, and significant points raised by presenters that are not shown on the slides are also included.

Introductions, Updates and TAC 4 Recap, John Lyons

No additional notes or commentary.

Energy Imbalance Market Update, Scott Kinney

Dave Van Hersett: What is an organized market? *Will talk about organized markets later in the presentation.*

John Barber: Is this just a bunch of people calling back and forth? *Yes, but there is more electronic communication now.*

Dave Van Hersett: Kind of like the ICP? *Yes, going back quite a ways.*

Kathlyn Kinney: What percentage of electricity do we have to buy? *Depends. Spring, we are a net seller. Summer, we may go to market, usually at the Mid-Columbia trading prices. It changes depending on the company's needs and the market prices.*

Jim Le Tellier: Hydro percentage in mix? *About 50%.*

Dave Van Hersett: Is CAISO by hour? *It's a day ahead, 15 minute and a five minute market. Looking for optimized resources to impact dispatch cost. Readjust resources differently based on economics as we get closer to real time.*

Dave Van Hersett: Who owns CAISO? *A government agency with a board selected by the Governor of California.*

Dave Van Hersett: Easier to construct [new resources]? *Maybe, because it is looking at a bigger footprint.*

Dave Van Hersett: Savings? *Cost savings for customers based on a past operations.*

Dave Van Hersett: I'm struggling with what's the downside since ours is among the lowest cost in the region. Do we go up and others go down? *Will talk about that later, but we expect more revenues and cheaper dispatch.*

Jason Thackston (Slide 7): We do this already outside the day, but not inside the hour Since the 1980s we have been doing this on the hour.

Dave Van Hersett: Saying hour-by-hour, now into the 5 minute market? *Yes, good way of putting it.*

Cadie Olsen: What drove early adopters? *Renewable energy penetration. Lower dispatch (30 - 35%), load following costs, and some by Commissions and economics.*

Jim Le Tellier: Why did PacifiCorp join? *Utah, load pockets in Oregon. Better optimization between both utilities.*

Slide 13: A little bit optimistic numbers based on methodology, but they are indicative.

Dave Van Hersett: Gross revenue for Avista? *$800 to $900 million gross revenue requirement required. This is just the in-hour part.*

Jason Thackson: 3% of power supply expenses.

Jim Le Tellier: Does the entire EIM share a transmission grid? *Yes, participants still own their transmission. They allocate a percentage for market transactions. Allow anything to be used within the hour if not already paid for. Transmission is in effect free for EIM transactions.*

Dave Van Hersett: Will EIM reduce staff? *No, we are actually adding bodies. Technology and models allow us to trade within the hour.*

Slide 15 – It was getting difficult for us to find a trading partner around the summer of 2018. There was not enough market liquidity. All of the utilities around us – Northwestern Energy, BPA, Idaho Power – joined or are joining the EIM.

Jim Le Tellier: Where is Rattlesnake Wind located? *The Othello area, in Washington.*

Scott Kinney: PURPA changes. Recent changes in Washington expanded size qualifying for different costs and from 5 to 15 years. We have seen additional requests for PURPA. Prices are still falling, probably for a period of time as more renewables are added to the system.

Clint Kalich: Energy only. But, if bringing capacity, projects will get more benefit. Capacity over winter nights will be getting even more benefit.

Who do we talk to about PURPA? *Either Clint Kalich or Steve Silkworth.*

Dave Van Hersett: Is there a disadvantage to being in this group? *The large technology commitment is costly.* Do they get to call on our resources? *Only if we voluntarily bid in.*

Jennifer Snyder: How often? *Every five minutes. Hydro flex makes sense every hour.*

Dave Van Hersett: Typically, what is the technology needed for the EIM? *Outage management system, bidding system, and settlement system.*

Dave Van Hersett (slide 17): $6 million net. *No, gross. 8 to 9-year breakeven. Show chart 18. Most utilities actually seeing 3 to 5 times the study benefits.*

Jennifer Snyder: When was the study done? *2017 and updated in 2018; and cost done in 2015 and updated in 2018.*

Dave Van Hersett: If Avista keeps getting more renewables, does this help? *Absolutely, expect about a 35% reduction in costs to integrate renewables. Flex hour hydro allows us to bid in.*

Dave Van Hersett: In the long run, higher base of renewables might be better in the long term. *Yes, Idaho Power is similar to us and we see a similar market potential.*

Jim Le Tellier: Nice to have economic benefits, but many non-economic benefits that they might have even joined for.

Cadie Olsen: In the penultimate slide, how many city people are you interfacing with? Our citizens are our customers with 700 connections plus a generation interconnect. *Touchpoints at generators. Not anticipating city resources being bid into the EIM.*

Jim Le Tellier: As far as interconnection renewables, are they being drawn from other states? Wind from Montana? *Yes, includes renewables from other areas.*

Kirsten Wilson: Any preliminary evaluation of the shutdowns with PG&E? *Some assessment, but minimal from the EIM's perspective. More exposure in California with the only participant.*

Scott Kinney: More opportunity to integrate resources. Possibility depending on size and capability and controls. Costs may exceed benefits.

Jim Le Tellier: As Colstrip goes offline, will there be more gas or renewables? *James will be covering that later today.*

Logan Callen (Slide 18): PSE? *More aggressive air study assumption and not as integrated through BPA.*

Amy Wheeless: As Seattle comes online, will there be more benefit for PSE? *Yes, we would expect it.*

Dave Van Hersett: Does this affect our ability to stand alone? *No, we are required to be resource sufficient to be able to bid in to the EIM.*

Scott Kinney: People vs. algorithms. Dispatch is fully automated for dispatch changing but still have a final human check. This may change over time.

Storage and Ancillary Storage Analysis, Xin Shane

Dave Van Hersett: What is an example of an ancillary service? *Regulation.*

Dave Van Hersett: Can you get all out that you put in? *No, only about 70% round trip efficiency, which is the downfall of this type of storage.*

Clint Kalich (Slide 6): Only about 10% of the 1 MW cap to pull hard off system. Only a small amount of the total can be quickly used.

Barry Kathrens: Is capacity seasonal? *Did not consider it in this study. Engineers say there are many different factors like temperature.*

Rachelle Farnsworth: Is the typical performance for this type of battery to charge and recharge? *Yes, when price is high it is discharging and when low it is charging.*

John Barber: Was Avista's battery shut down? *Yes. It was the first one made by the manufacturer and was shut down for mechanical issues.*

Jason Thackston: The battery had a leak on a customer's premises, so we removed it.

Cadie Olsen: Did you learn anything different from other empirical studies? *Speed affecting overall efficiency, system setting comprehensive operational mod, testing linear model and refining it.*

Kirsten Wilson: Intent was to study quite a few (seven) operating scenarios and how batteries responded. *Different parts worked on different streams.*

David Howarth: When you say one third, is that equivalent to water availability or two thirds hydro? *Capped two units on Noxon Rapids and one unit on Cabinet Gorge – cascading system.*

Jim Le Tellier: Pumping from lower to higher levels? *Yes, that is what we are studying. Two reservoirs with a two way turbine.*

Dave Van Hersett: Two way is pump or generate? *Yes.*

Dave Van Hersett: Could we do that at Noxon Rapids?

Jason Thackston: Not a reservoir at Noxon. Hard when licensing is challenging, not a closed system.

Jim Le Tellier: With the EIM there could be pumped storage in other regions. Some in Montana is already permitted.

Jim Le Tellier: Astronomical starting cost, but a lot more benefit going forward to consider.

Clint Kalich: Some comments for the regulators in the room to consider on slide #12. It is difficult and complicated to do these studies. If we can create ancillary services, the value lies in arbitrage. The left 1/3 of hydro in the portfolio, and then saw the benefits of arbitrage. Most of the value is when we get energy in the system whether owned, PPA, or cheaper to just store renewables.

David Howarth: With the existing hydro flexibility on the system, wondering on a low hydro year how it affects flexibility. *Modestly ancillary benefit in low hydro years.*

Dave Van Hersett: Are we not looking at pumped storage yet? *Next presentation.*

Amy Wheeless: Not that many pumped storage projects in the northwest. *Got to wait until after lunch.*

Preliminary Preferred Resource Strategy, James Gall

Jim Le Tellier: Does Avista have an R&D department? *We keep up with developments and participate in new technologies. Idaho funds some R&D. We dabble, but are not focused on R&D.*

Jason Thackston: University District, Energy Impact Partners Fund investor and Clean Energy Grants.

Scott Kinney (Slide 3): How much could we drop the gap by renewing contracts as they expire, economic competition, and repowering of worn out wind projects?

Matt Nykiel: How are Idaho RECs managed and sold. *RECs are recorded and transferred in WREGIS.*

Jim Le Tellier: The goal doesn't sound real positive. If you have to have new technology, we want to see Avista as a leader.

Jason Thackston: We are working in the western US and using the Clean Energy Grant.

Jennifer Snyder: You are part of NEAA too.

Kathlyn Kinney: Does EIM help? *It helps us manage, but is not a capacity market.*

Scott Kinney: EIM participants have to show how they can meet their own resource needs.

Matt Nykiel (Slide 4): Are there asterisks to Avista's goals [100% clean] that we can read about?

Jason Thackston: The web site has a section. It is correct there is not a lot of detail on it. We need to see improvement on energy storage. 6 pm on a January night is our peak load and battery storage is not there yet. We are still working on it ourselves. Your definition of affordability may be different than mine. Hypothetically, is 15% worth it? Across the river from here, no. And we have to do this in a way that maintains reliability.

Matt Nykiel: Is Avista conducting a survey showing what is affordable?

Barry Kathrens: Is this a thing from the Nadine [Woodward mayoral] debate? *No, difference was between completely 100% renewable versus an aspirational goal. Sometimes the details in politics don't always line up.*

Amy Wheeless (Slide 5): Hydro from BPA, doesn't respond to an RFP? *We can't just assume BPA hydro availability. They have told us an RFP is not how they typically want to interact.*

Jim Le Tellier: BPA power is $90? *Yes, that is what they are required to sell at.*

Fred Huette: Transmission is a separate discussion. BPA hydro, know they have interest in a PGE capacity deal. *Difficulties in how to model it, but not leave an impression that we are not interested in it. Maybe we could model it as northwest capacity.*

Matt Nykiel: What is social cost of carbon cost? *$80 for Washington portion, see the last TAC meeting presentations for more details.*

Rachelle Farnsworth (Slide 6): How will you be excluding additional costs for Idaho? *Like the Social Cost of Carbon. Model solves for a peaker, only Washington has the cost. Then we allocate costs between the two states. Would depend on what we would do without the law. If Idaho needs wind, they pay their part. If not, all of the costs go to Washington. Also assign price of RECs, incremental cost of the resource over market, to transfer from Washington to Idaho.*

Rachelle Farnsworth: Building in costs. Need to keep track of additional costs that should not be attributed to Idaho.

Matt Nykiel: If the decision is made to keep it left open, how would Colstrip get allocated [after 2025]? *Not sure yet, it would be a Rates questions and handled outside of the IRP.*

Rachelle Farnsworth: Just because Washington doesn't take the electrons, there are still remediation costs they are responsible for.

Jennifer Snyder: Treating things as of today until 2025. After that, CETA allows recovery for remediation.

Matt Nykiel: Incremental Idaho costs post 2025.

Jim Le Tellier: On Colstrip, if Westmoreland completely goes under, do the five owners have other coal sources.

Jason Thackston: Six owners, but the air permit doesn't permit new coal. The new coal contract is being finalized.

Slide 11: Red is cost effective, black is not cost effective and orange maybe cost effective.

Amy Wheeless (Slide 11): Is this based on AEG? *Yes. Water heating does – with and without CETA required device. Not sure why yet. Didn't originally include. Added it back two weeks ago and will follow up later.*

Fred Huette: Not CETA, 1444, unless they (Commerce) grants some sort of extension. With a cost per kW-year well under $100/kW-year. What is the name of the consultant? *AEG.*

Jennifer Snyder: For variable peak pricing and time of use, are there plans to have pilots? *Still have to figure that out. Probably about 10 different things that will still have to be sorted out to make these happen.*

Fred Huette (Slide 13): Effectively, Montana wind is a 40% capacity value. *Yes, capacity contribution could be different. All sites are not equal. Also, if it is really cold here and in Montana, they [wind turbines] shut down about 25 degrees below zero. Probability of minus 25 in Montana and really cold here.*

Fred Huette: Really first of utilities putting direct value for Montana winter wind capacity. May consider across Montana. Appreciate the work.

Kathlyn Kinney: Where does renewable natural gas fit in? *Who gets it and at what cost. Levelized cost is $10 - $20 per Dth. You can sell the RIN to drive down the cost, but then the renewableness goes away. Can it clean up gas? Yes. Will it be available? Maybe, but will it go to power, the LDC, or will it even be developed? Not modeled yet, but as its gets closer to 100%, renewable natural gas competes.*

Jim Le Tellier: What is the problem with transmission? *Is it off, transmission rights allocation, and overbuilding wind. We own a portion of the line from Montana and have a BPA contract for the rest.*

David Howarth: What is long duration for storage? *40 hours per week.*

Amy Wheeless (Slide 13): Not too many sites [pumped hydro]? *Probably four to five sites and one with long duration. Will require more time and money to find other viable sites. What's available particularly for open loop?*

Fred Huette (Slide 14): Liquid air. Haven't hear much about it, but love the efficiency. *Yes, sub 70% efficiency, longer duration, long project life, and better if co-located with a thermal plant.*

Kirsten Wilson (Slide 15): Last round of the Clean Energy Grant funding went to Tacoma for Praxair for liquid air storage. *We tried for that funding too.*

Matt Nykiel: What is the risk of a stranded asset, like a gas plant in 2026 or will be required to be offset with RECs. *It looks at all costs. Mandate, no.*

Rachelle Farnsworth: How is the liquid air modeled? *Based on cost projections. Pumped hydro is number 1 for long duration, liquid air is number two for long duration and lithium ion is number 3 when paired with solar for the tax credit plus the value of short term storage.*

Slide 17: Reliability. This is where portfolio could change. Colstrip is two relatively small and significantly reliable units. 14% to 16% planning margin.

Fred Huette (Slide 17): Why does size make an impact on reliability? *Redundancy of two smaller units in the model. How much do we control versus how much we rely on our neighbors. Yes, now; later not so much. This is a regional, not just and Avista issue.*

Jennifer Snyder: Through 2045? *No, 2030 only on the reliability study. We are on the high side because of a single 320 MW resource out of 1,700 MW, the largest utility shaft risk for a single unit in the west.*

Scott Kinney (Slide 18): To clarify, this is system, not just Washington.

Clint Kalich: PURPA requires us to pay for energy and capacity, but we don't pay a clean premium under PURPA. We regard that as a put for the developer.

Matt Nykiel (Slide 24): Getting back to the transmission issue at Colstrip, there are at least five other utilities. Does Avista lose out if they don't make a decision? *We are contractually covered until the late 2020s.*

Preliminary Portfolio Scenario Results, James Gall

No notes to add.

2020 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 6 Agenda

Tuesday, November 19, 2019
Conference Room 130

Topic	Time	Staff
Introductions and TAC 5 Recap	9:30	Lyons
Review of PRS	9:45	Gall
Break	10:45	
Portfolio Scenario Results	11:00	Gall
Lunch	12:00	
Portfolio Scenario Results Continued	1:00	Gall
Break	2:00	
2020 IRP Action Items & Overview	2:15	Lyons
Adjourn	3:00	

2020 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Sixth Technical Advisory Committee Meeting
November 19, 2019

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next twenty years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

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 while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - June 15, 2019 was the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

TAC #5 Recap – October 15, 2019

- Introductions and TAC 4 Recap, Lyons
- Energy Imbalance Market Update, Kinney
- Storage and Ancillary Service Analysis, Shane
- Preliminary Preferred Resource Strategy, Gall
- Preliminary Portfolio Scenario Results, Gall

- Meeting minutes available on IRP web site at: https://www.myavista.com/about-us/our-company/integrated-resource-planning

Today’s Agenda

9:30 – Introductions and TAC 5 Recap, Lyons

9:45 – Review of PRS, Gall

10:45 – Break

11:00 – Portfolio Scenario Results, Gall

Noon – Lunch

1:00 – Portfolio Scenario Results Continued, Gall

2:00 – Break

2:15 – 2020 IRP Action Items and Overview, Lyons

3:00 – Adjourn

2020 IRP and 2021 IRP Key Dates

- Draft IRP released to TAC members December 18, 2019
- Comments from TAC members are to be returned to Avista by January 15, 2020
- IRP team will be available to address comments with individual TAC members or the entire group if needed
- This IRP will be published February 28, 2020
- Washington IRP due date moved for all IOUs: draft due January 1, 2021 and final IRP due April 1, 2021 to allow time for CETA rule making

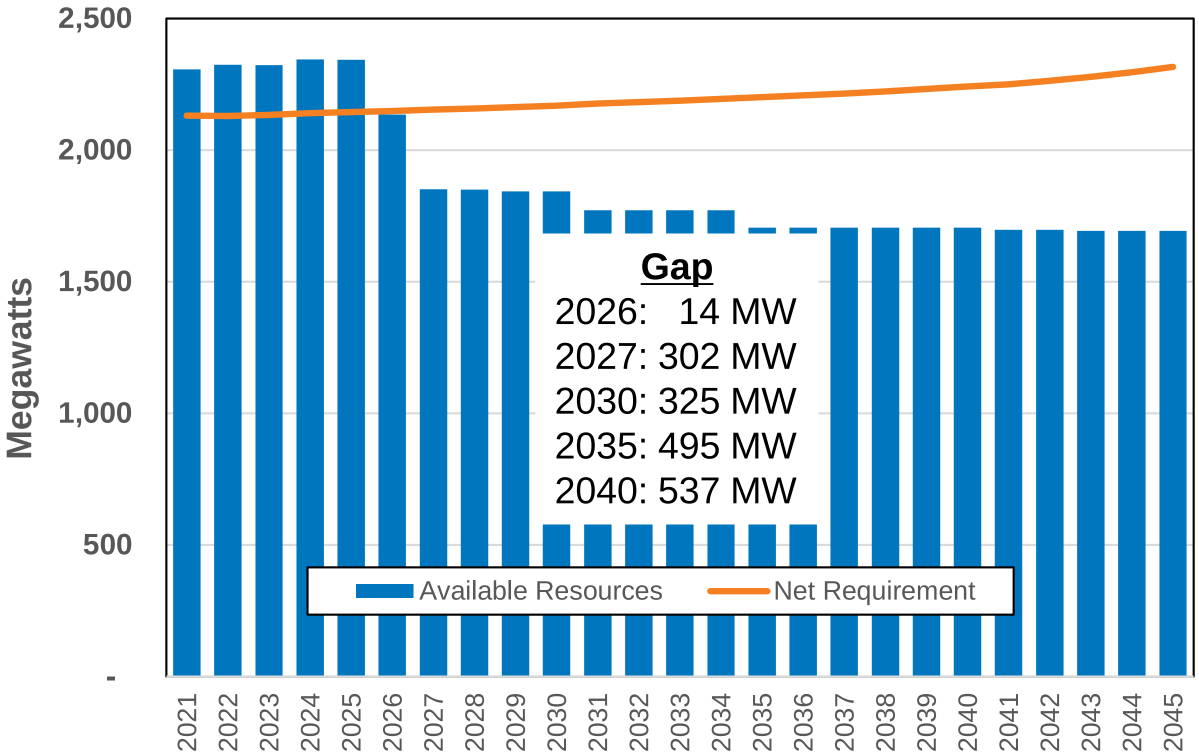
2020 Electric Integrated Resource Plan “Preferred” Resource Strategy

James Gall, IRP Manager
Sixth Technical Advisory Committee Meeting
November 19, 2019

What Are Avista's Physical Resource Needs?

Main focus: Winter Peak:

Includes 14% Planning Margin + Reserves



Key Losses:

Colstrip: 2025*

Lancaster: 2026

Mid-C: 2030

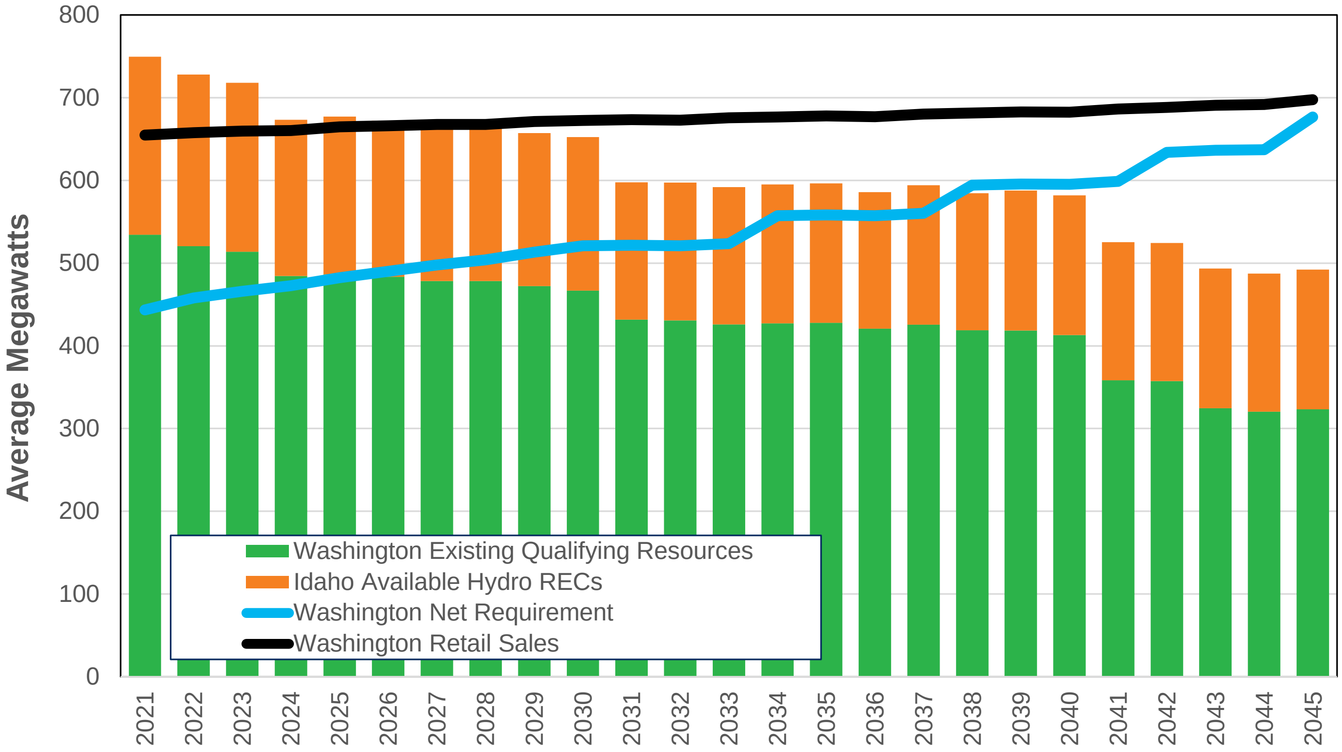
Northeast: 2035

Avista is also short in summer and on an annual average basis beginning in 2027

* Colstrip is assumed offline at the end of 2025 for planning purposes only. Avista's ultimate decisions regarding Colstrip are still to be determined.

Washington SB5116 Clean Requirements

2026: Colstrip can no longer serve Washington Load
2030: 80% energy delivered over a four-year period is clean and 20% can be RECs
2045: Goal to be 100% clean (will require new technology to stay under cost cap)



Gap

2030: 54 aMW
2035: 130 aMW
2040: 182 aMW
2045: 353 aMW

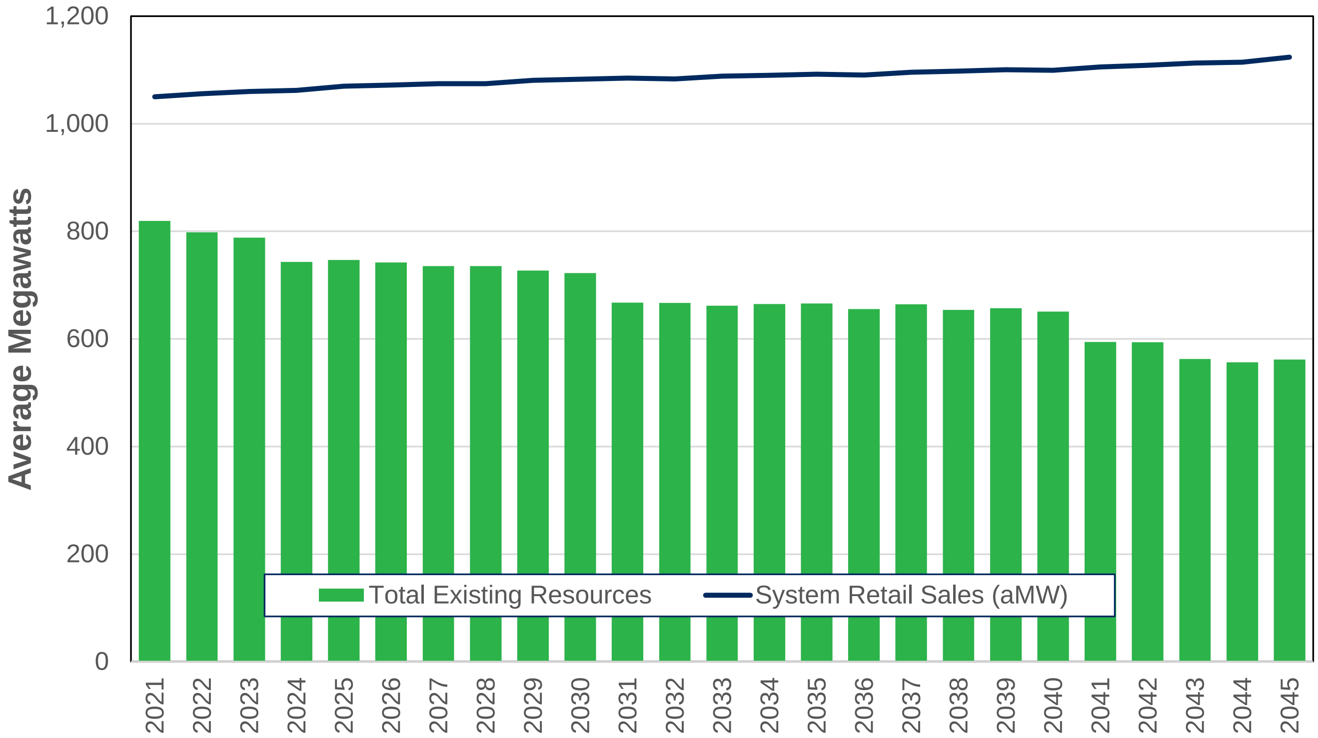
Key Losses:

Mid-C: 2030
Lind: 2039
Rattlesnake: 2040
Palouse: 2043

Assumes: Idaho customers sell offsets to Washington Customers

Avista's Clean Electricity Goal

2027: 100% net clean portfolio wide (cost effective considerations)
2045: 100% clean (cost effective considerations and technology)



Gap

2027: 339 aMW
2030: 360 aMW
2035: 426 aMW
2040: 448 aMW
2045: 562 aMW

Resource Options

Clean

- Wind (WA/OR/MT)
- Solar (WA/ID/OR)
- Biomass (WA/ID)
- Hydro Upgrades (MS, LL)
- Hydro (Mid-C)
- ~~Hydro (BPA)~~
- Geothermal
- Nuclear
- Energy Efficiency
- Demand Response

Other

- Natural Gas CT
- Natural Gas CCCT
- Storage
  - Pumped hydro
  - Lithium-ion batteries
  - Liquid air
  - Hydrogen
  - Flow batteries
- ~~Regional Transmission~~

Preferred Resource Strategy Decision Process

- Uses Mixed Integer Program (MIP) to find least cost solution meeting capacity, energy, and renewable constraints for the system between 2021 and 2045.

- Only known model with full co-optimization of energy efficiency and demand response with supply side resources.
  - Capable of co-optimization of T&D system with power system

- Accounts for societal preference Washington state planning criteria
  - (Social Cost of Carbon, 10% cost advantage from energy efficiency, upstream pipeline emissions, etc.)

- Non-modeled utility revenue requirements assumes an increase of two percent per year.

Changes Since Last TAC meeting

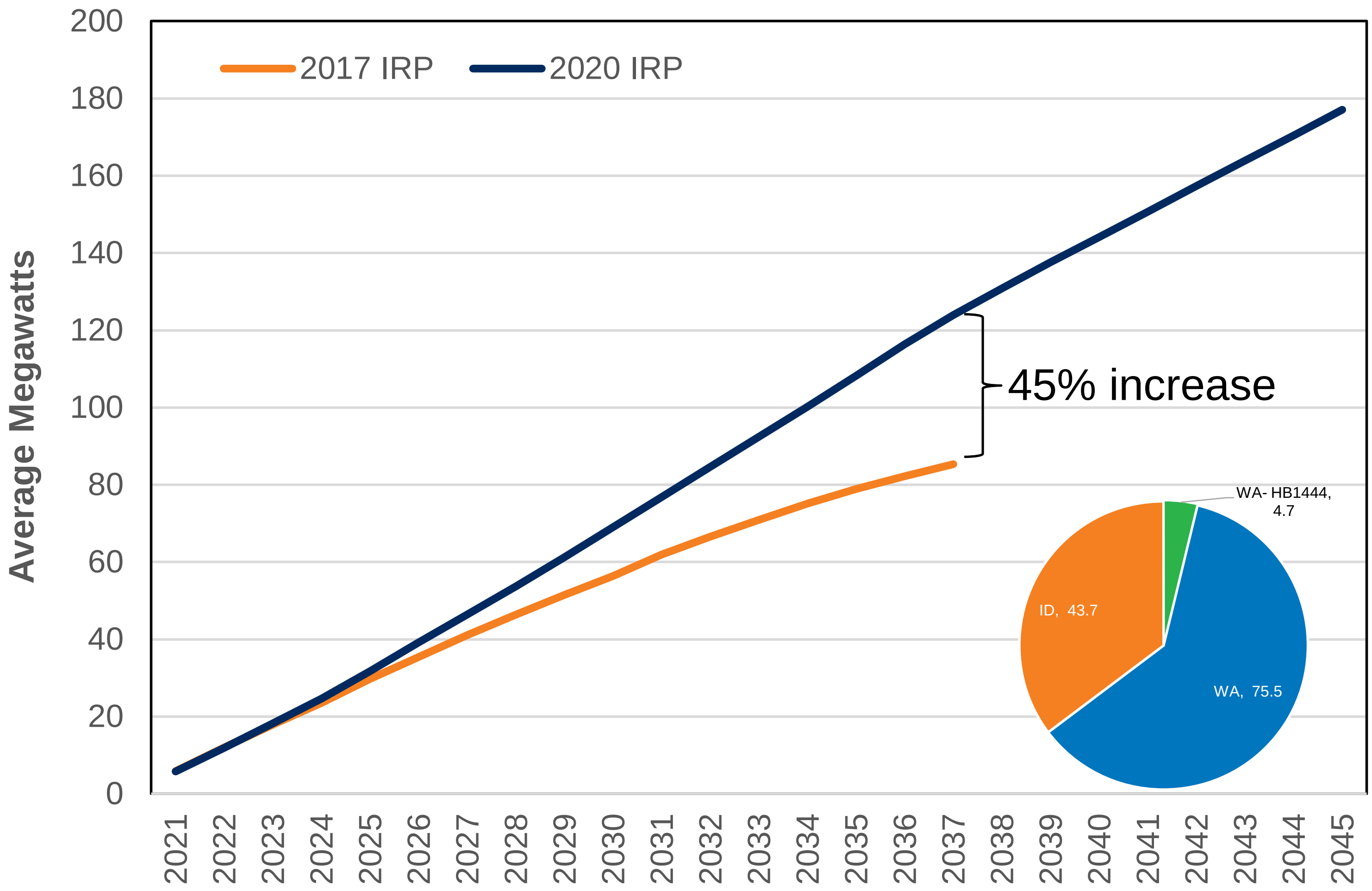
- Lowered Montana wind peak contribution due to transmission losses
- Increased long-duration pumped storage capacity contribution
- Increased planning margin in PRiSM to end with a reliable system

Reliability Study Results

- 22.6% planning margin (14% + reserves) without Colstrip and non-dispatchable resources is too low.
- The resulting draft reliability metrics for the PRS required an equivalent 24.6% planning margin (equivalent to 350 MW of CTs):

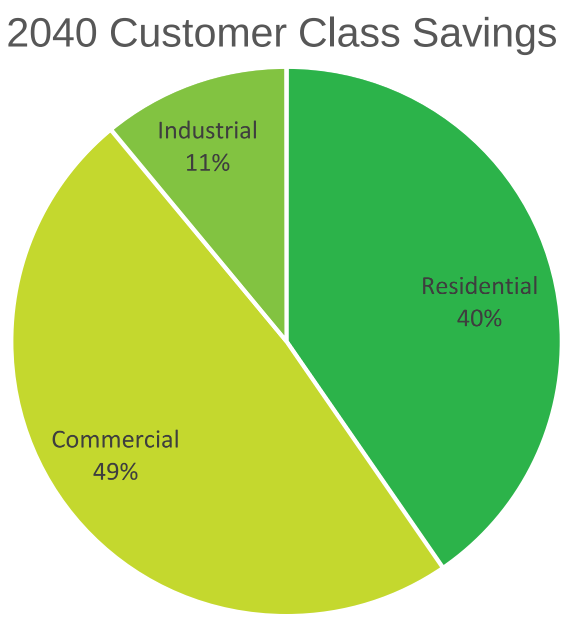
Reliability Metric	PRS (TAC 6)	PRS (TAC 5)	Updated Adequate System (w/o Colstrip & w/ CTs)	TAC 2 Adequate System Result (w/ Colstrip & CTs)
LOLP	5.3%	7.0%	5.2%	4.9%
LOLH	2.02	3.10	1.79	1.85
LOLE	0.17	0.25	0.14	0.16
EUE	330 MWh	552 MWh	264 MWh	318.7 MWh

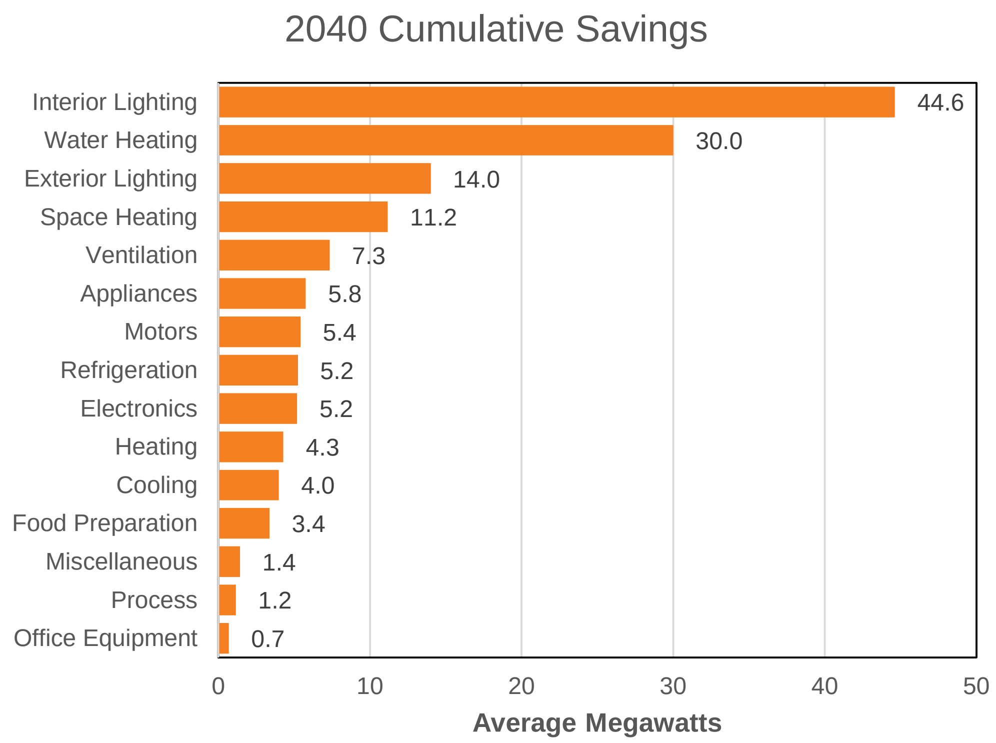
Energy Efficiency Results



Note: excludes T&D losses

Where is the Cost Effective Energy Efficiency Savings?





Preferred Resource Strategy

Load reduction of 187 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 175 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2025-2030: 76 MW, Demand Response
2026/27: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade

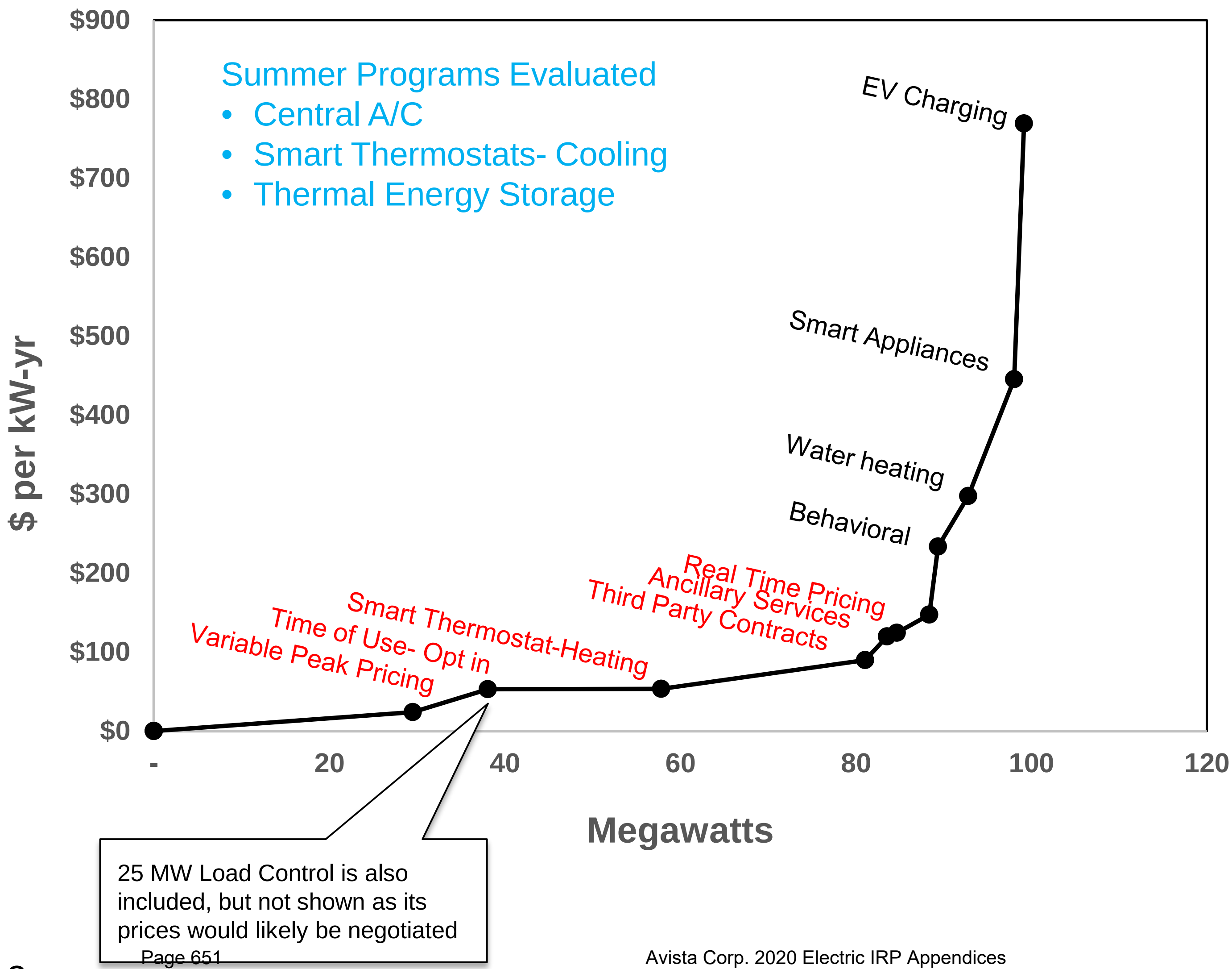
2031-2040

2031: 75 MW, Mid-C PPA Renew
2032: 32 MW, Demand Response
2035: 55 MW, Northeast CT retires
2035: 68 MW, Long Lake 2nd Powerhouse
2036-40: 75 MW x 16 hr, Liquid Air Storage
2037: 1 MW Demand Response

2041-2045

2041: 25 MW x 16 hr, Liquid Air Storage
2042: 2.5 MW, Demand Response
2042-2045: 300 MW Wind PPA Renew
2042-2045: 300 MW x 4 hr, Lithium-ion
2044: 55 MW, Solar w/ 50 MW x 4hr, Storage

Demand Response



Cost Effective Start Dates Shown in Red

2025: Variable Peak Pricing
2029: Smart Thermostats
2029: Industrial Load Control
2031: Time of Use
2031: Third Party Contracts
2037: Real Time Pricing
2042: Ancillary Services

2022-2025 Generation Action Plan

- 2022- 2023 RFP
  - Early acquisition to take advantage of federal tax credits
  - Anticipate 300 MW Wind PPA (84 aMW)
    - 100 MW in MT and 200 MW in NW
    - locations depend on transmission availability/price
  - Solar could replace wind depending on pricing and future price shape forecasts
  - Potential for additional resource acquisitions in support of Avista's clean electricity goal subject to reliability and affordability considerations.
- 2024: Kettle Falls Upgrade
  - Incrementally increase Kettle Falls generating capability by installing larger sized equipment as part of modernization
- 2025: 222 MW, Colstrip removed
  - Per CETA, Colstrip will not serve Washington loads after 12/31/2025
  - The plants future for Idaho customers or wholesale transactions is yet to be determined

2026-2030 Generation Action Plan

- 2026: 175 MW, Pumped Hydro
  - Assumes low cost, long duration pumped hydro solution is available.
  - If resource is not available or price exceeds cost effectiveness tests, siting a similar sized NG peaker is the next least cost option.
  - Sizing will depend on reliability requirements of future power supply system.
- 2026: 24 MW, Rathdrum Upgrade
  - Increases each unit by 12 MW using a supplemental compression technology or alternative technology.
- 2026: Lancaster PPA expires in October
- 2026/27: 200 MW, MT Wind
  - Utilizes Colstrip transmission,
  - If not available, additional NG and renewables are required.
- 2027: 8 MW, Post Falls Upgrade
  - Increase generating capability as part of modernization project to maintain FERC licensing requirements.

2031-2040 Generation Action Plan

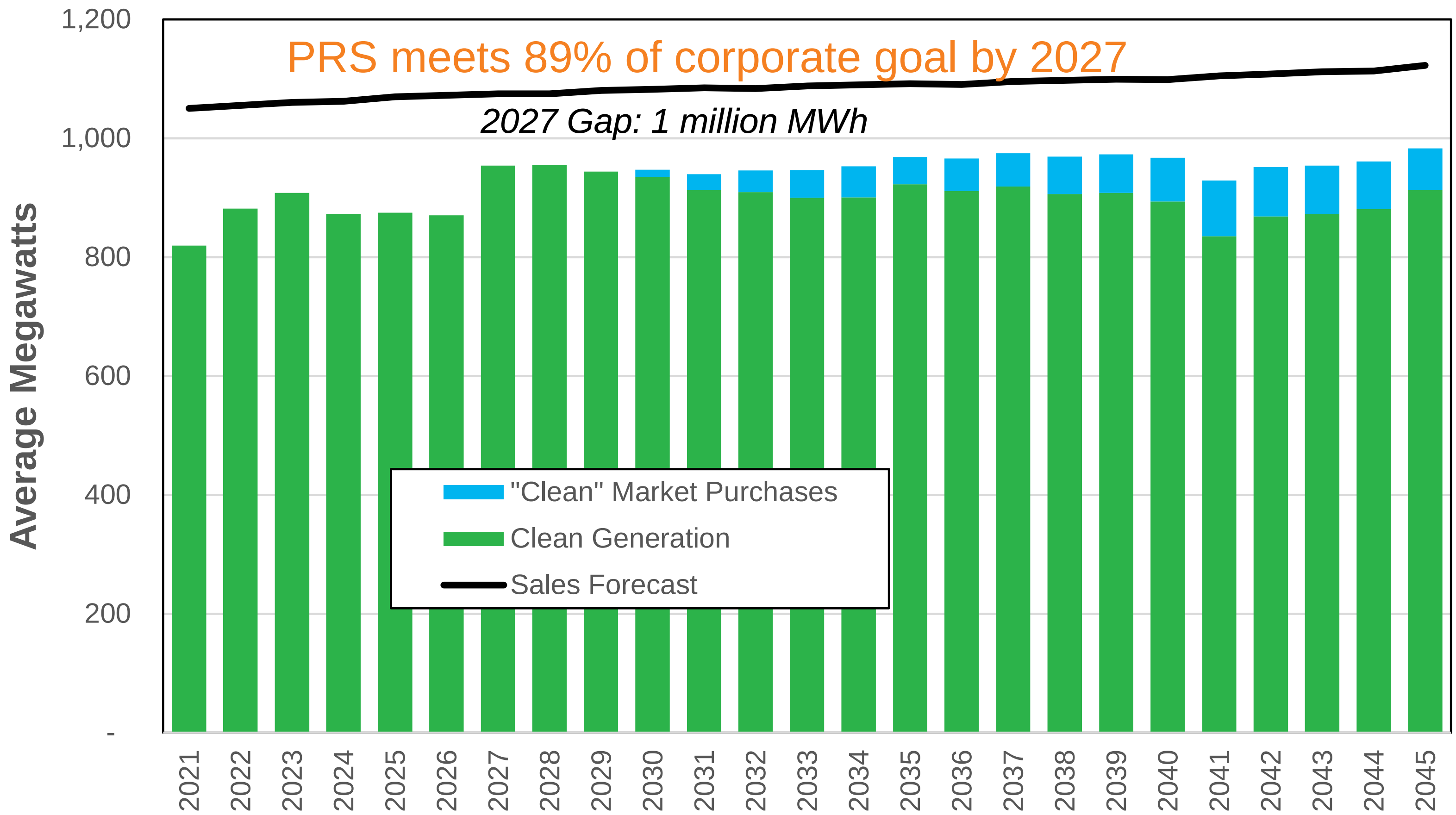
- 2031: Attempt to renew Mid-C PPA contracts
- 2035: Northeast CT retires
- 2035: 68 MW Long Lake 2nd Powerhouse
  - Seek CETA certification as an eligible resource
    - either as 2nd powerhouse and/or reconfiguration of single new powerhouse.
  - Begin licensing process
  - Optimize the site for cost, capacity, and environmental concerns
  - Earlier on-line date may be possible
  - NG Peaker and renewable resource would be alternative to this project
- 2036: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2038: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2040: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)

2040-45 Generation Action Plan

- 2041: 25 MW x 16 hour Liquid Air Storage (or lowest cost alternative)
- 2042-2045: 300 MW Wind PPA Replacement
  - Existing PPAs begin to expire
  - Repowering is likely necessary
- 2042-2045: 300 MW x 4 hour, Lithium-ion (or lowest cost alternative)
- 2044: 55 MW, solar w/ 50 MW x 4 hour storage

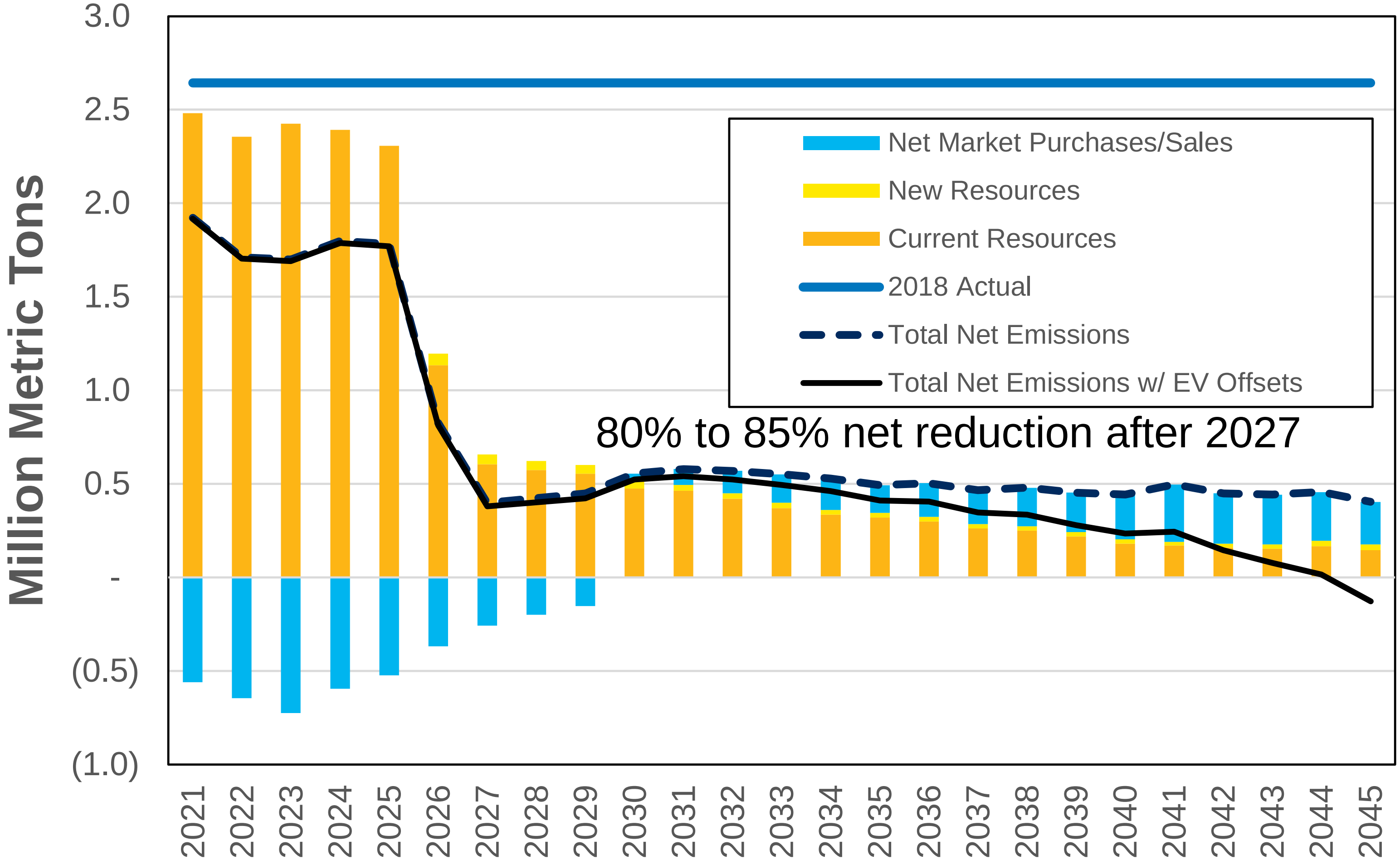
PRS Comparison to Corporate Clean Electricity Goal

Goal: Serve customers with 100% cost effective clean electricity



Notes:
1) Prior to 2030, Avista is a net energy seller to the market
2) “Clean” market purchases is measured as the regional generation mix’s CO_2 mix compared to a CCCT

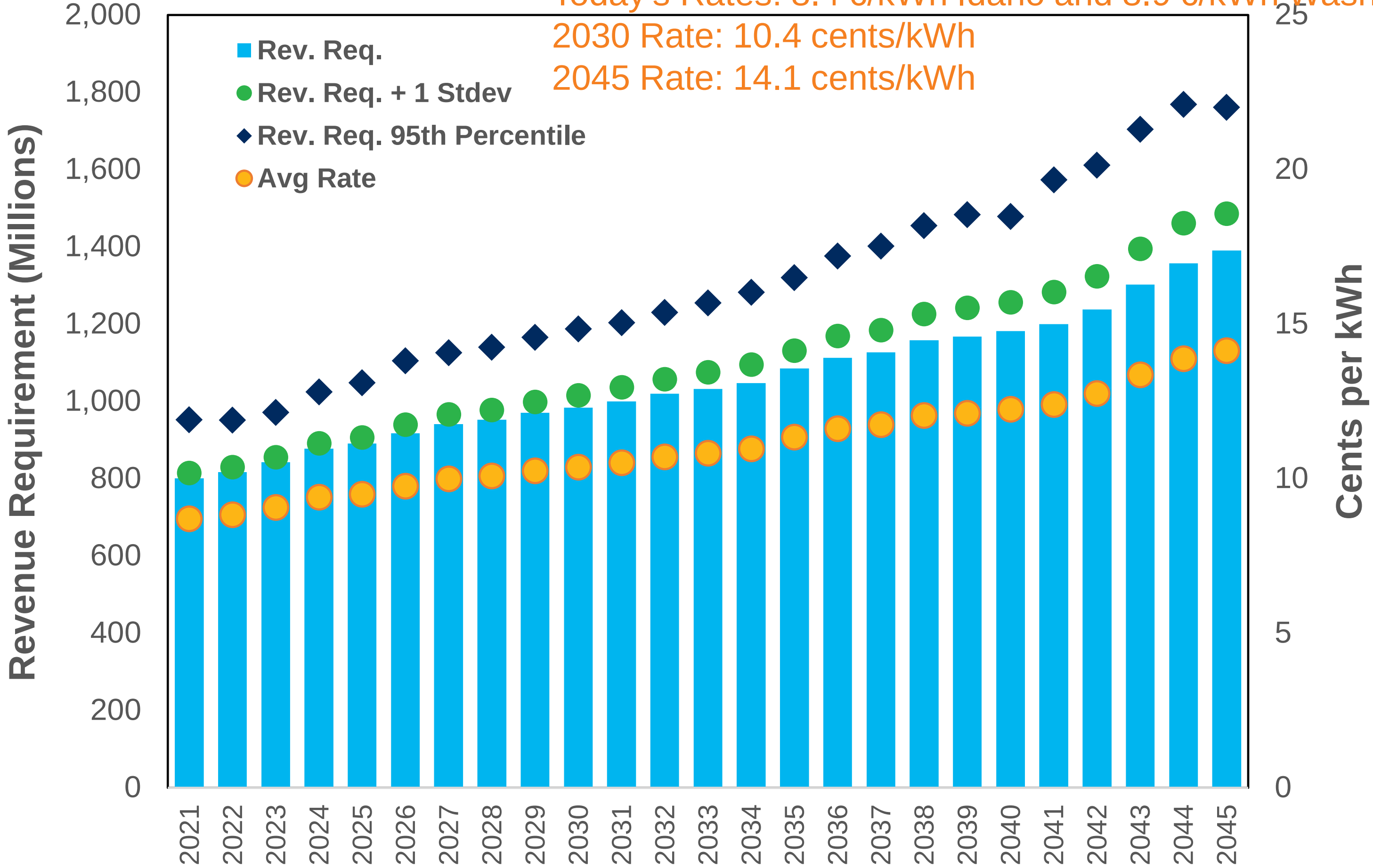
PRS: Greenhouse Gas Emissions Forecast



Note: Electrification of transportation lowers Avista's emissions below zero as offsetting petroleum emissions are lower then Avista's power related emissions

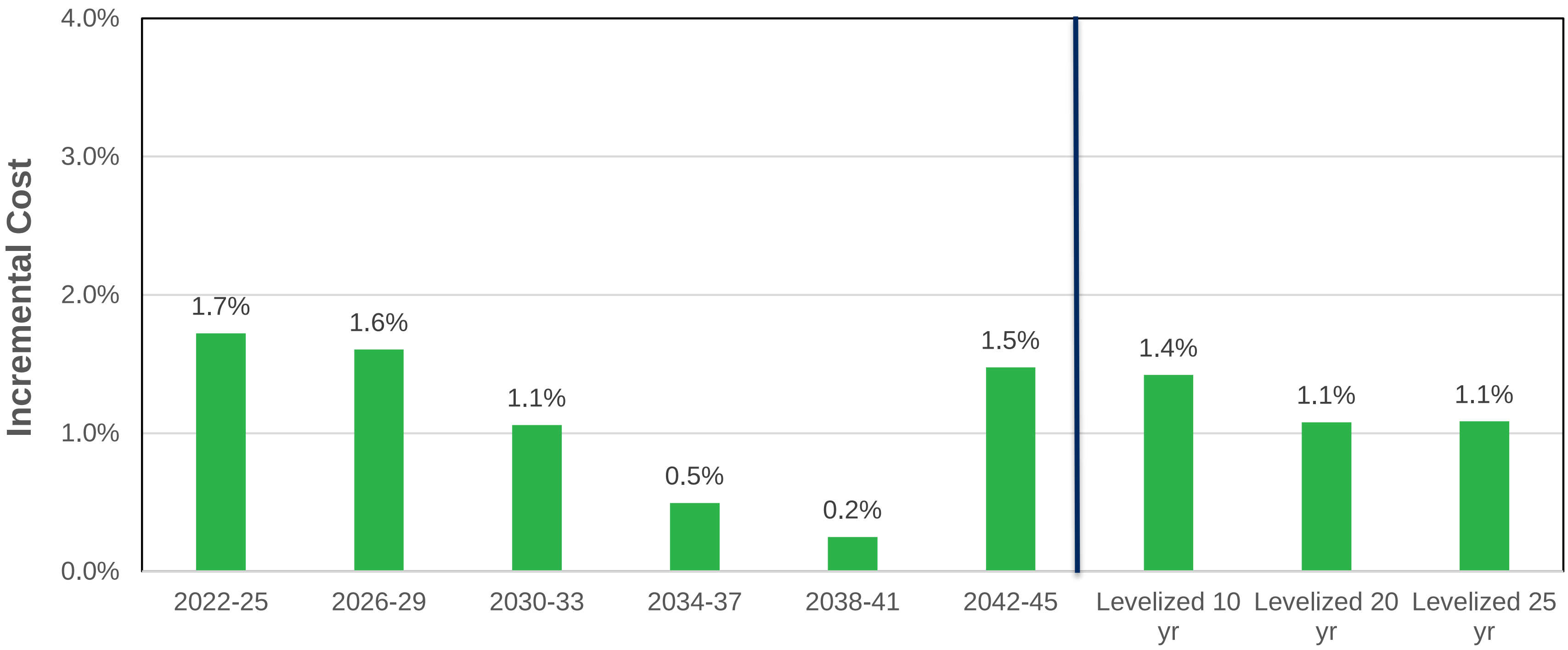
PRS: Cost/Rate Forecast

System PVRR: $11.83 billion
Today's Rates: 8.4 c/kWh Idaho and 8.9 c/kWh Washington
2030 Rate: 10.4 cents/kWh
2045 Rate: 14.1 cents/kWh



Note: Assumes non-power supply modelled costs escalate at 2 percent per year

Cost Comparison between PRS and LC Portfolio w/o CETA



Note: State allocation factors and resource designation will affect these results for each state

Avoided Costs- Power

Year	Energy Flat ($/MWh)	Energy On-Peak ($/MWh)	Energy Off-Peak ($/MWh)	Clean Premium ($/MWh)	Clean Premium (w/ Tax Incentive) ($/MWh)	Capacity ($/kW-Yr)
2021	19.67	22.64	15.71	0.00	0.00	0.0
2022	19.98	22.75	16.28	11.75	3.44	0.0
2023	20.44	23.05	16.98	11.99	3.50	0.0
2024	21.61	24.09	18.28	12.23	3.57	0.0
2025	22.76	25.19	19.50	12.47	3.65	0.0
2026	24.27	26.40	21.43	12.72	3.72	107.7
2027	23.57	25.27	21.30	12.97	3.79	109.9
2028	25.02	26.26	23.35	13.23	3.87	112.1
2029	25.92	26.80	24.73	13.50	3.95	114.3
2030	26.72	27.08	26.25	13.77	4.03	116.6
2031	29.46	29.66	29.21	14.04	4.11	118.9
2032	29.78	29.95	29.54	14.32	4.19	121.3
2033	31.22	30.74	31.89	14.61	4.27	123.7
2034	32.83	31.94	34.06	14.90	4.36	126.2
2035	33.66	32.64	35.05	15.20	4.44	128.7
2036	35.82	34.82	37.16	15.51	4.53	131.3
2037	36.12	34.58	38.19	15.82	4.62	133.9
2038	38.81	37.40	40.76	16.13	4.72	136.6
2039	38.60	37.13	40.57	16.45	4.81	139.3
2040	38.52	36.80	40.84	16.78	4.91	142.1
2041	39.09	37.74	40.92	17.12	5.01	145.0
2042	38.98	37.99	40.31	17.46	5.11	147.9
2043	40.24	39.51	41.21	17.81	5.21	150.8
2044	46.10	45.29	47.15	18.17	5.31	153.9
2045	43.94	43.11	45.05	18.53	5.42	156.9
15 yr Levelized	24.58	26.11	22.55	11.81	3.45	64.8
20 yr Levelized	26.44	27.55	24.98	12.43	3.63	75.1
25 yr Levelized	27.86	28.77	26.66	12.93	3.78	82.2

Methodology

Energy Prices: Electric market price forecast

Capacity Price: Cost difference between building resources to meet capacity needs as compared to not building any new capacity. This cost is divided by the amount of added capacity and is levelized and tilted (2% inflation) based on the first capacity deficit year.

Clean Premium: Difference in total cost of the PRS and the Least Cost Portfolio to meet capacity. This cost is divided by the amount of additional dispatch energy and is levelized and tilted (2% inflation) starting with the first year of renewable acquisition.

Clean Premium (w/ Tax Incentive): This shows the premium associated with renewables assuming the resource includes either the PTC or ITC.

2020 Electric Integrated Resource Plan Scenario and Sensitivity Analysis

James Gall, IRP Manager

Sixth Technical Advisory Committee Meeting

November 19, 2019

Agenda

- Portfolio analysis using the stochastic “expected case” market forecast
- Portfolio analysis with alternative market prices (deterministic)- sensitivity analysis
- Electrification scenario

Portfolio Scenarios

Portfolio Scenario Overview

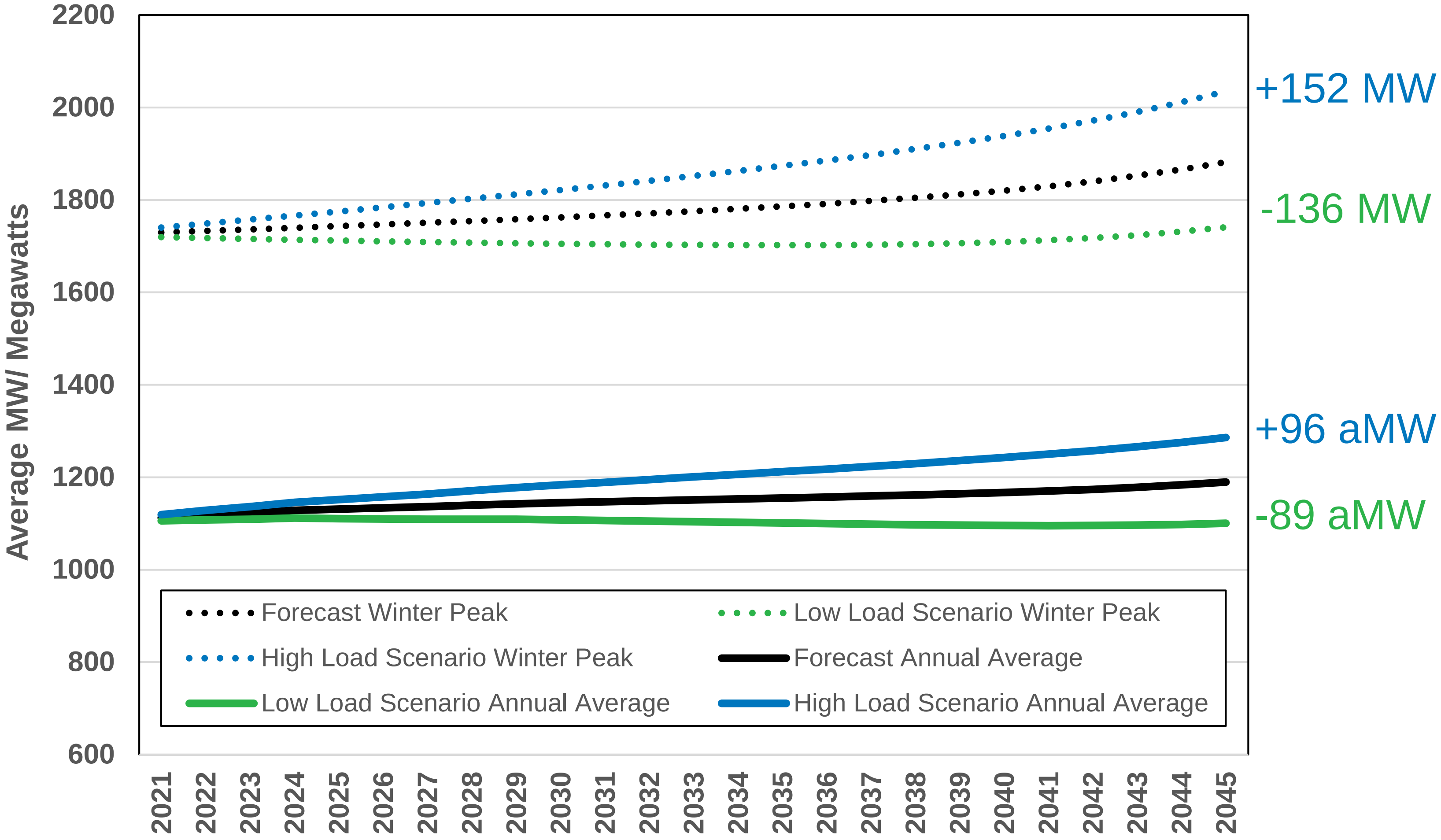
- Uses same electric price forecast, but different resource assumptions.
- Use optimization to create portfolio, but use different <u>constraints</u> for each scenario.
- View financial results of each portfolio along with resource selection.
- No reliability analyses are completed for portfolio scenarios.

Scenarios

1. Preferred Resource Strategy
2. Least Cost Plan- without CETA
3. Clean Resource Plan: 100% net clean by 2027
4. Rely on energy markets only (no capacity or renewable additions) without CETA
5. 100% net clean by 2027, and no CTs by 2045
6. Least Cost Plan without pumped storage or Long Lake as options
7. Colstrip extended to 2035 without CETA
8. Colstrip extended to 2035 with CETA
9. Least Cost Plan with higher pumped storage cost
10. Least Cost with federal tax credits extended
11. Clean Resource Plan with federal tax credits extended
12. Least Cost Plan with low load growth (flat loads- low economic/population growth)
13. Least Cost Plan with high load growth (high economic/population growth)
14. Least Cost Plan with Lancaster PPA extended five years *(financials will not be public)*
15. Least Cost Plan with one Colstrip unit operating through 2035

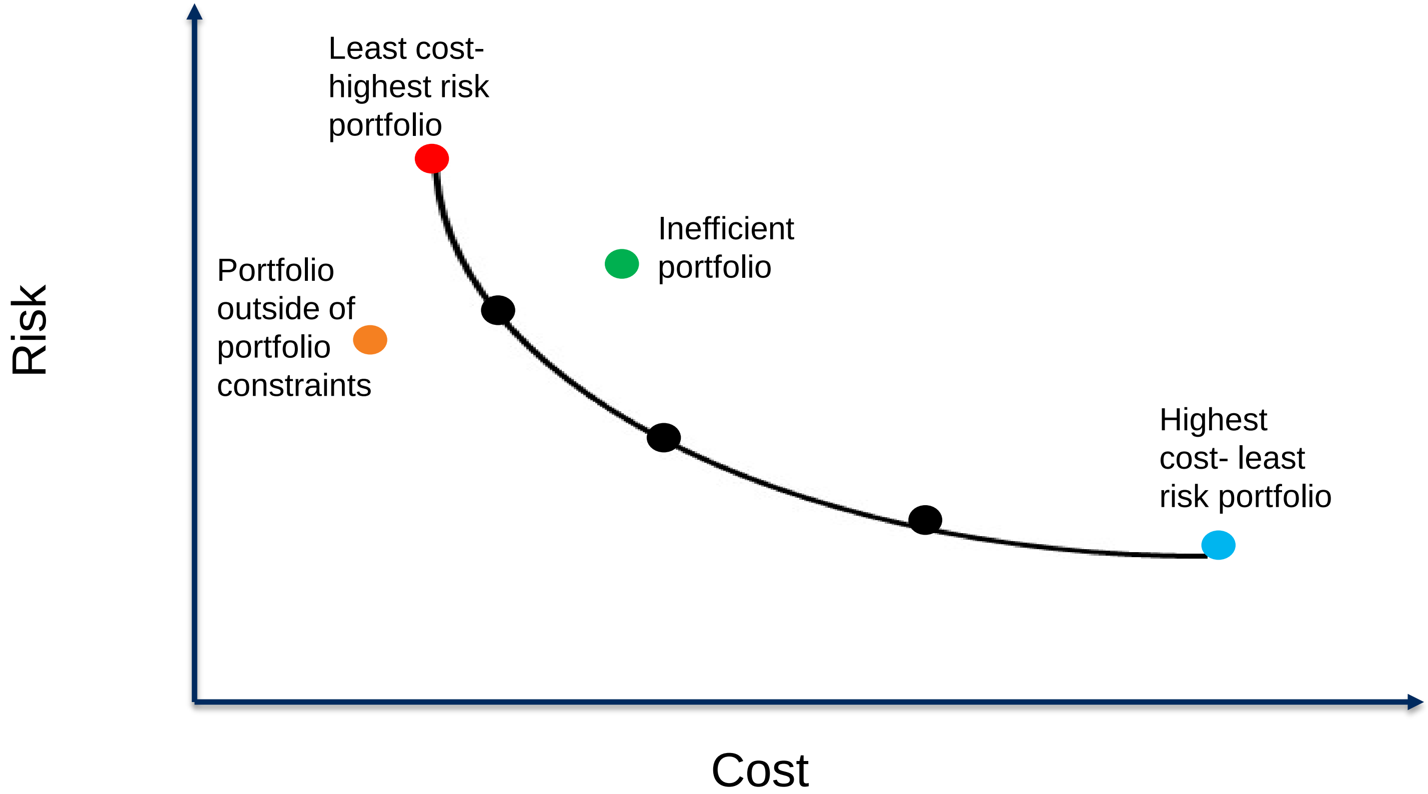
Others: Efficient Frontier portfolio (least risk, 75/25, 50/50, and 25/75)

Load Scenarios

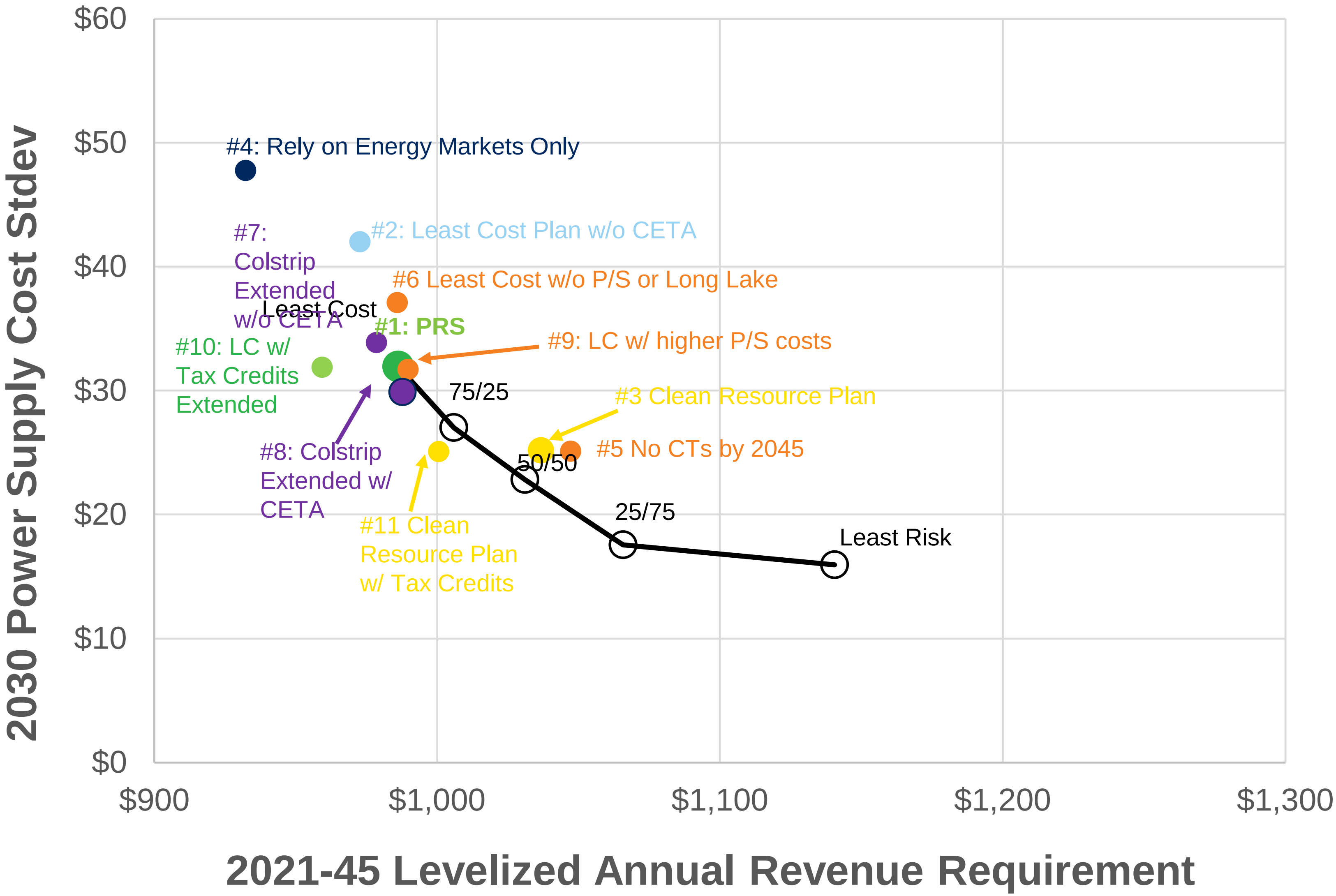


Scenarios are based on changing GDP assumptions: The change effects employment and population growth leading to load changes.

Efficient Frontier Overview

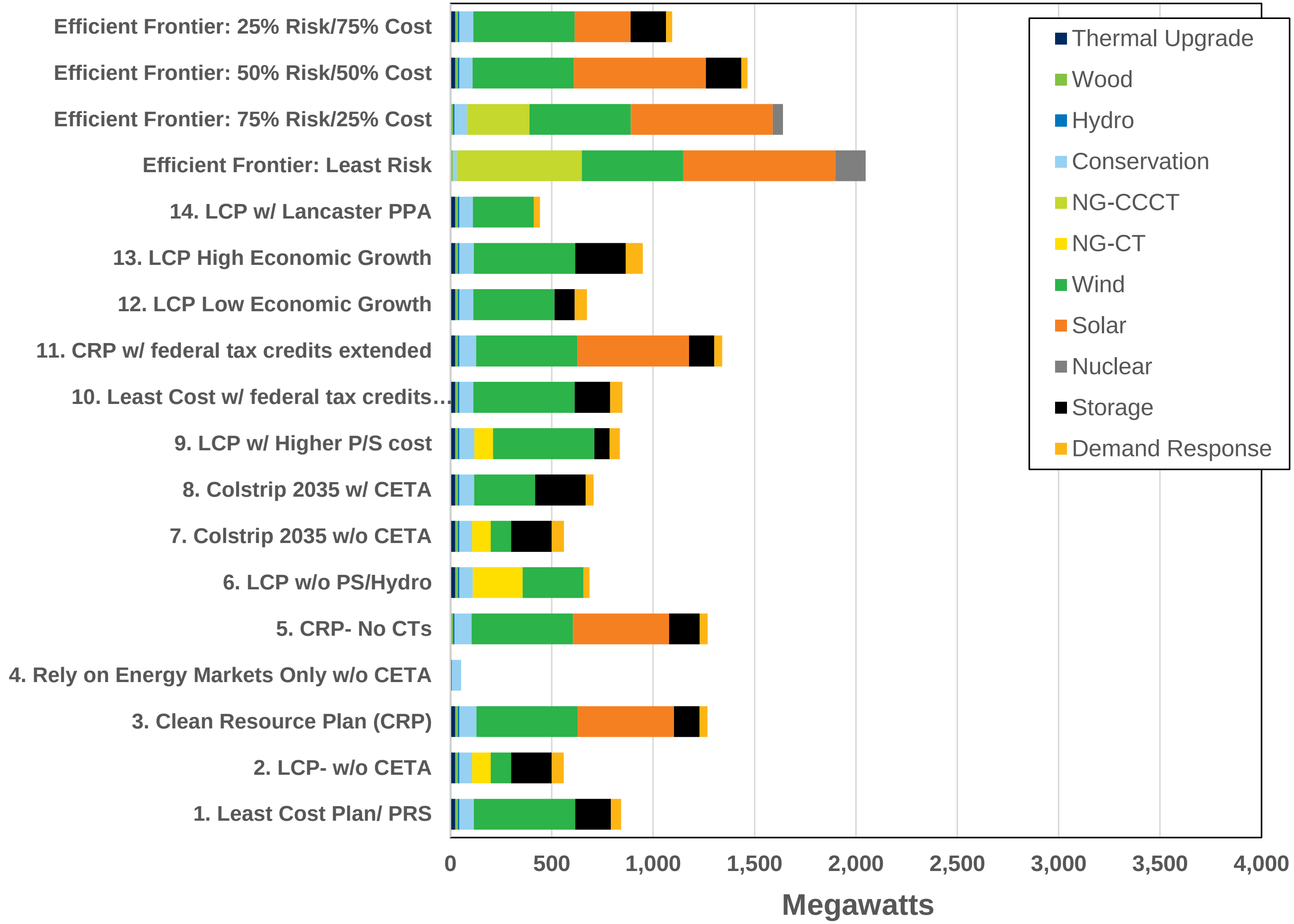


Efficient Frontier Results

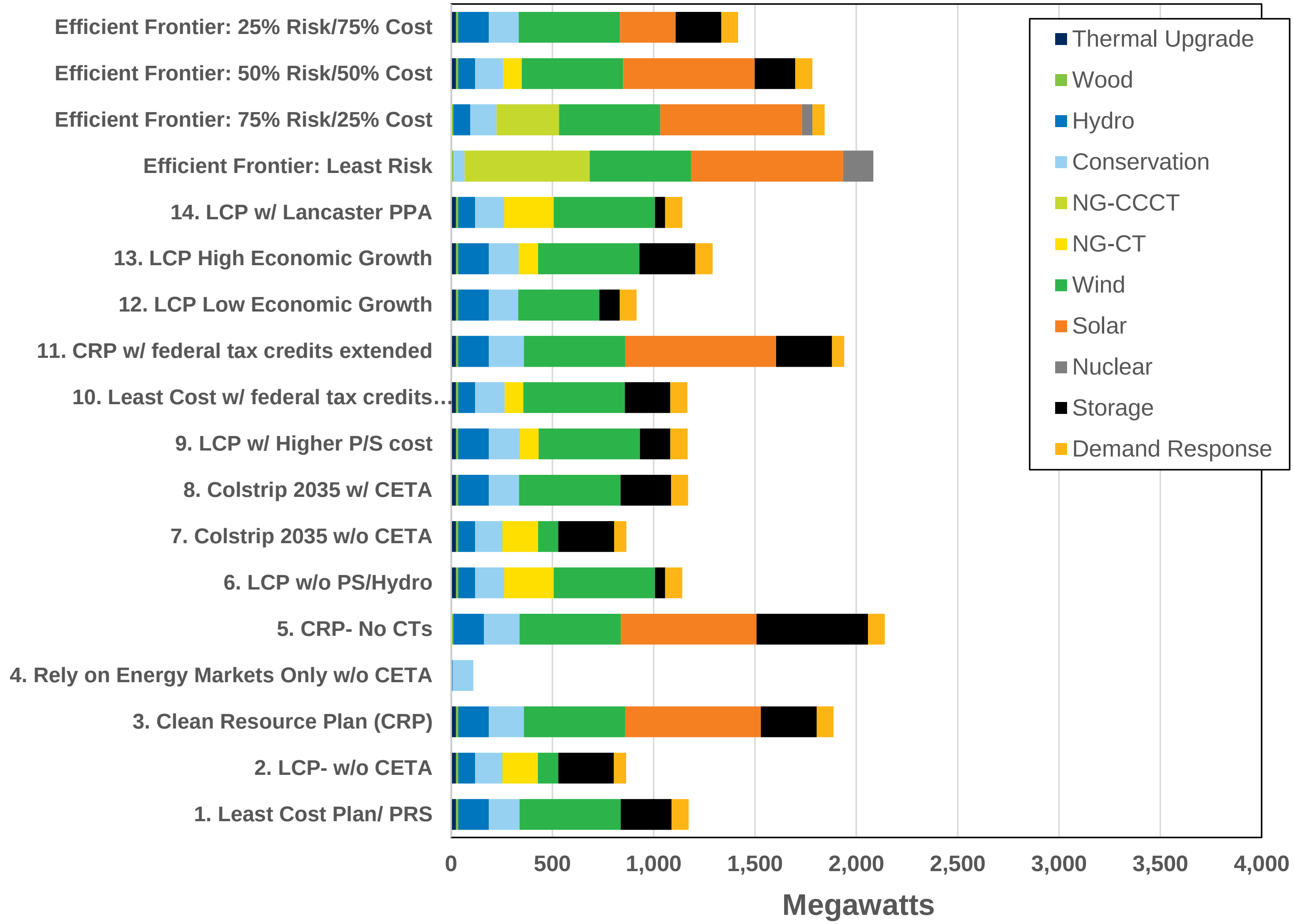


Note: excludes portfolios after #12

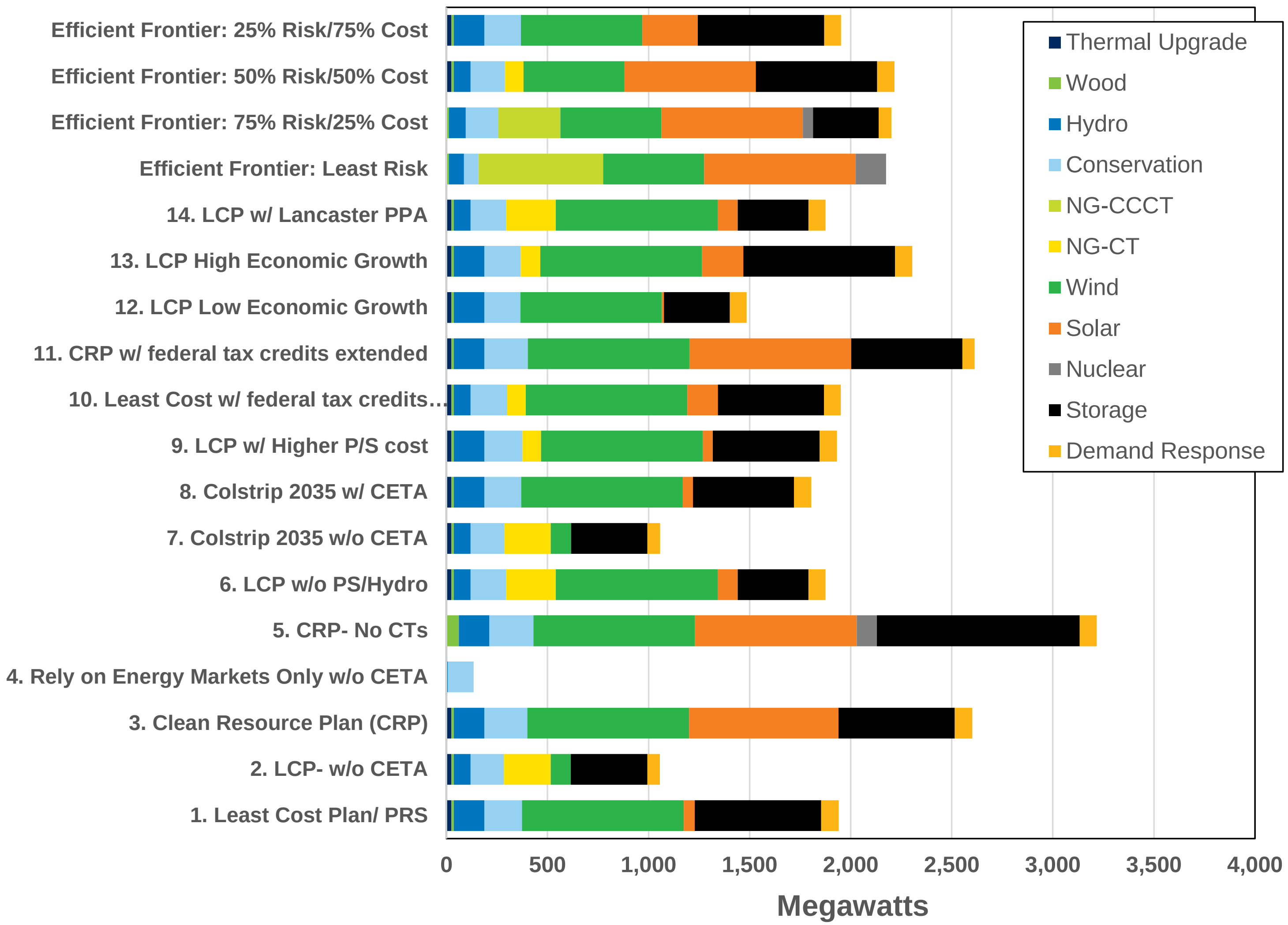
2030 Portfolio Resource Selection



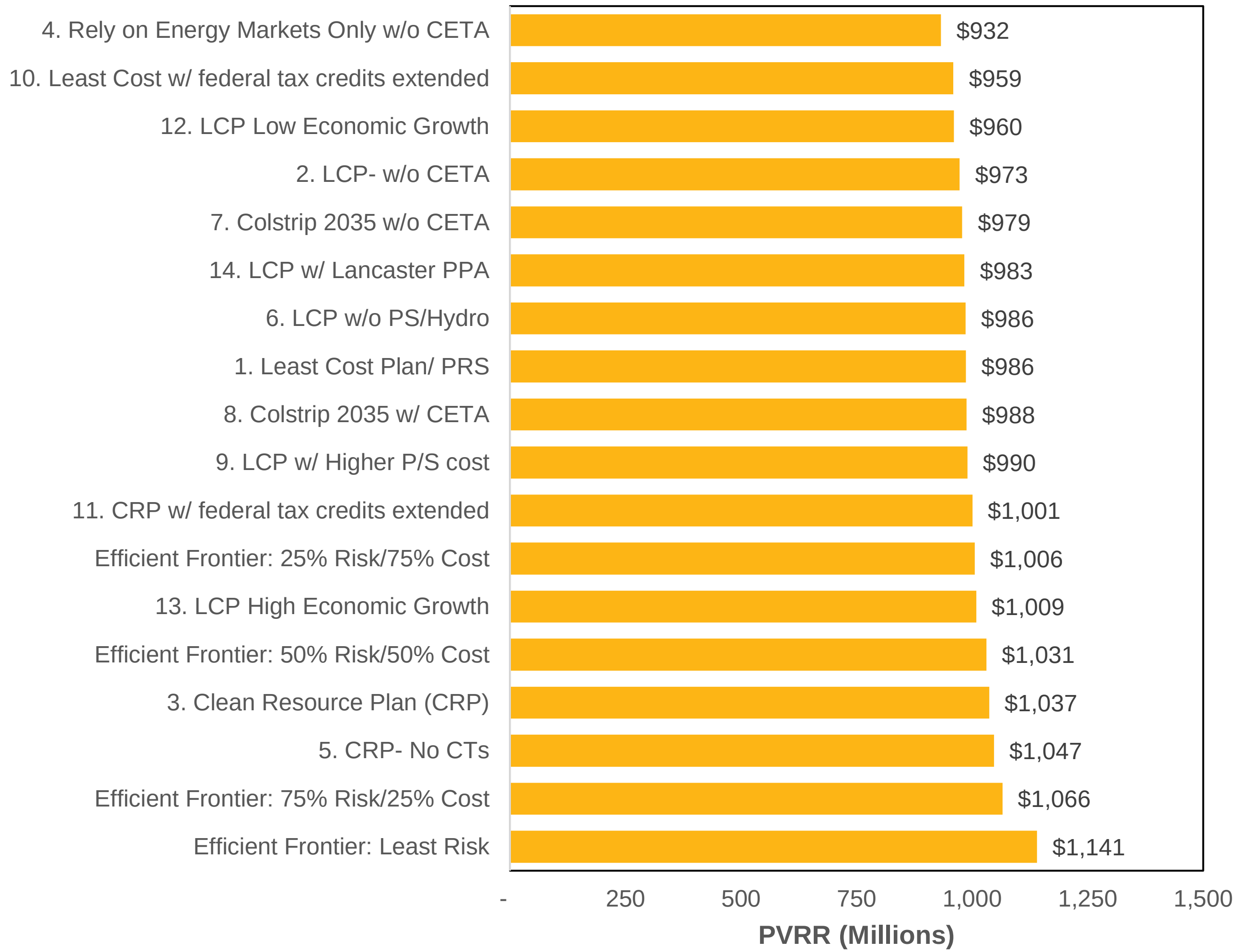
2040 Portfolio Resource Selection



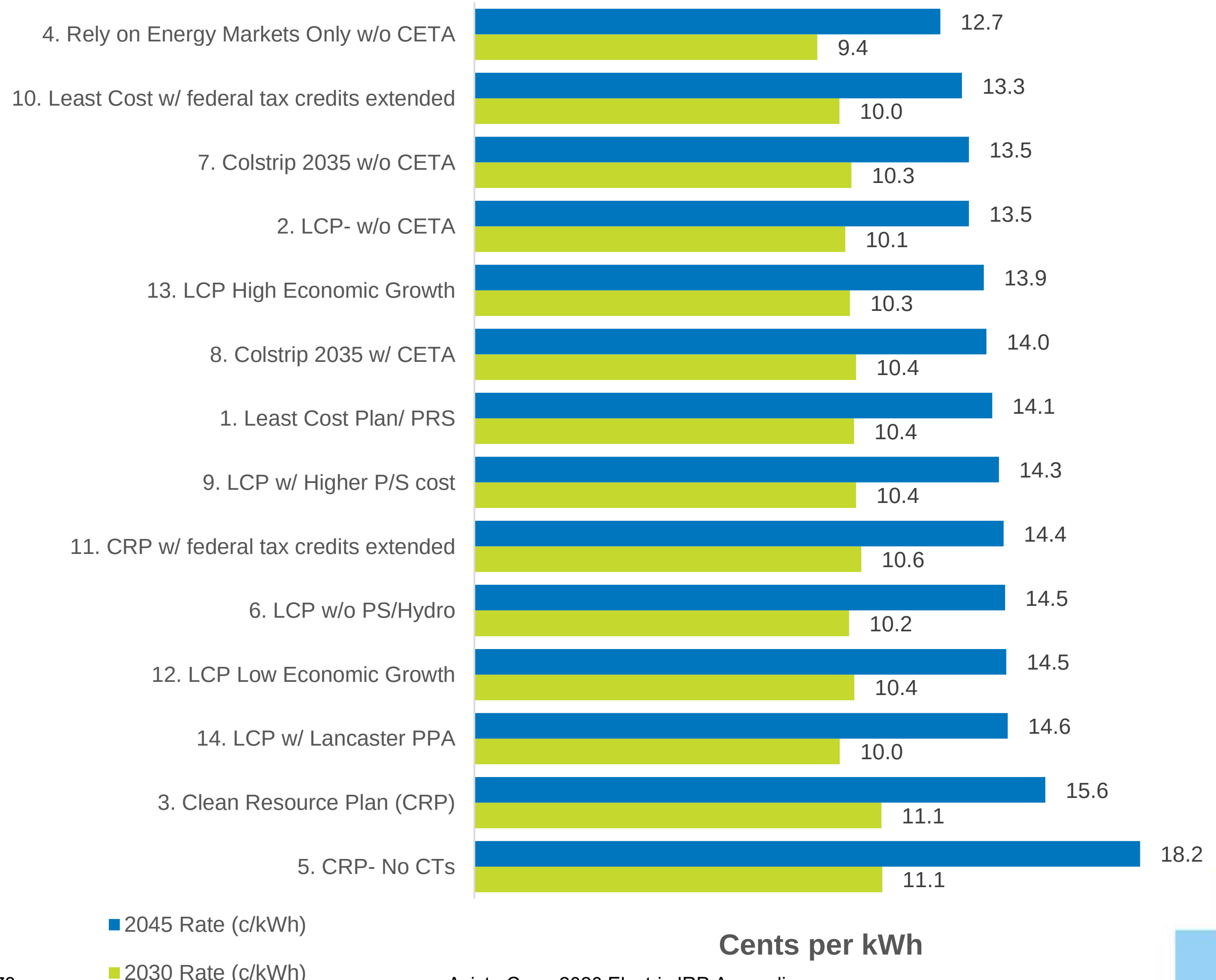
2045 Portfolio Resource Selection



Annual Cost Comparison

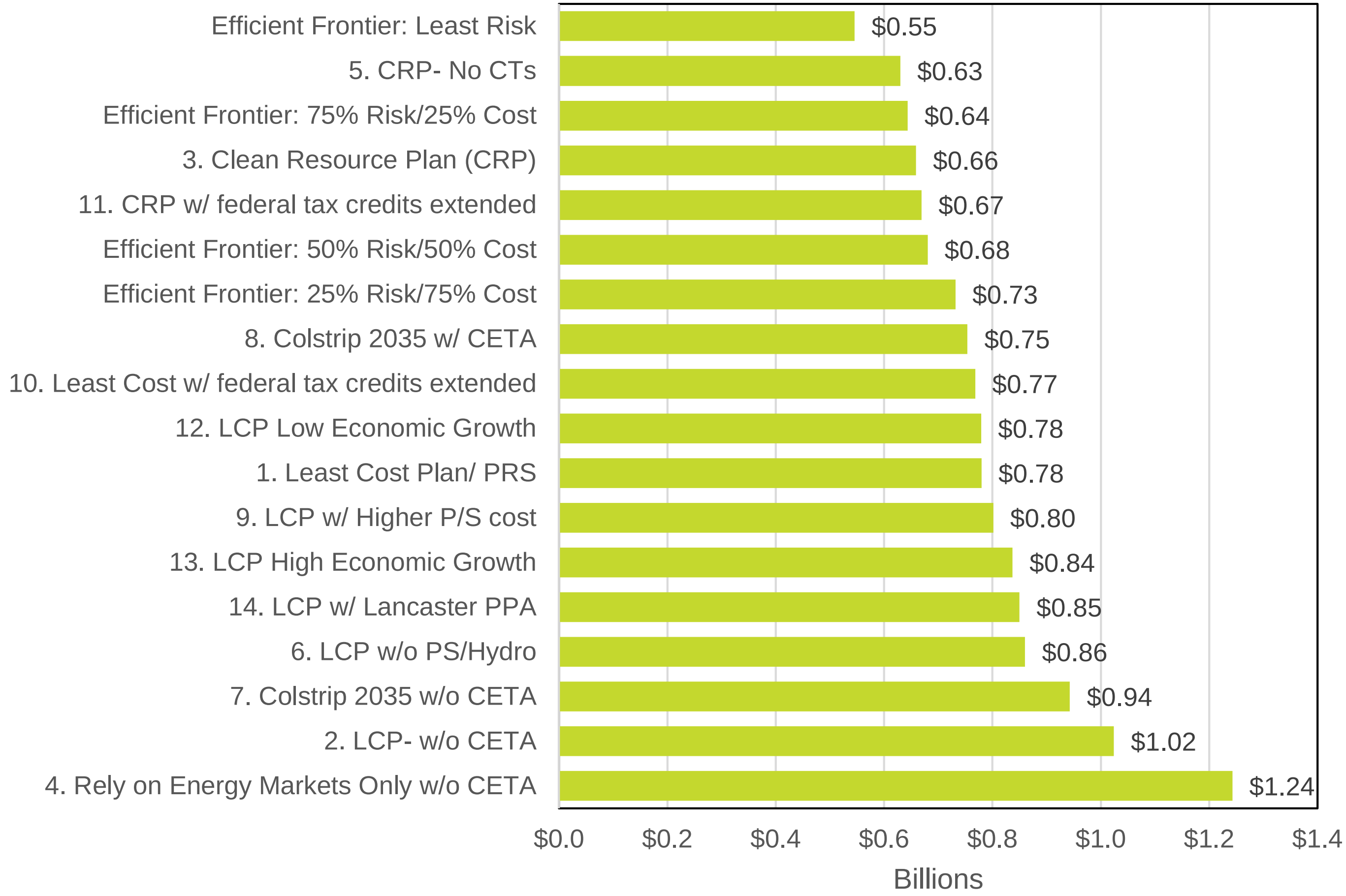


Rate Comparison
sorted by 2045 rates



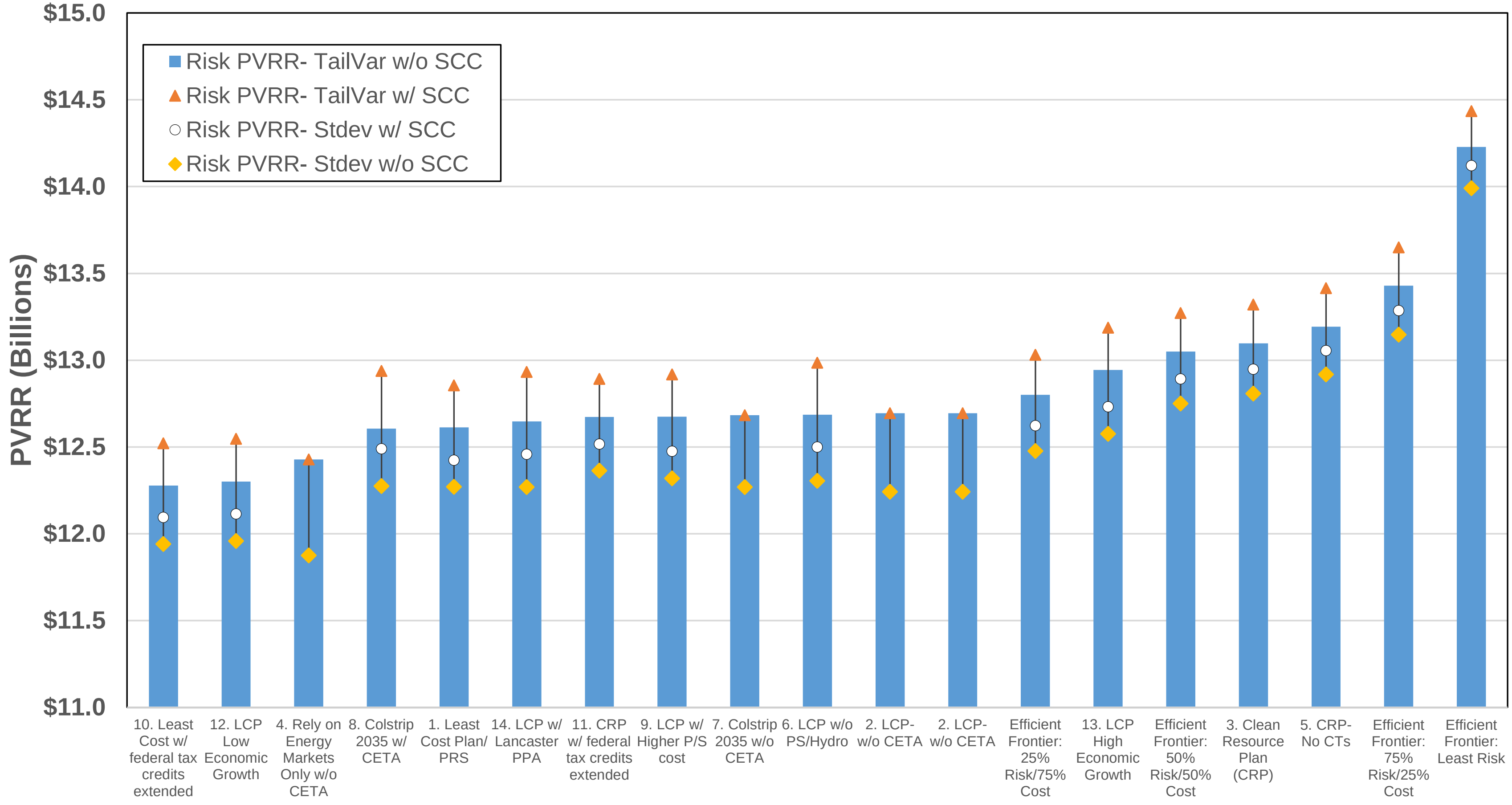
Portfolio Tail Risk

(95th percentile minus expected cost, excludes Social Cost of Carbon)

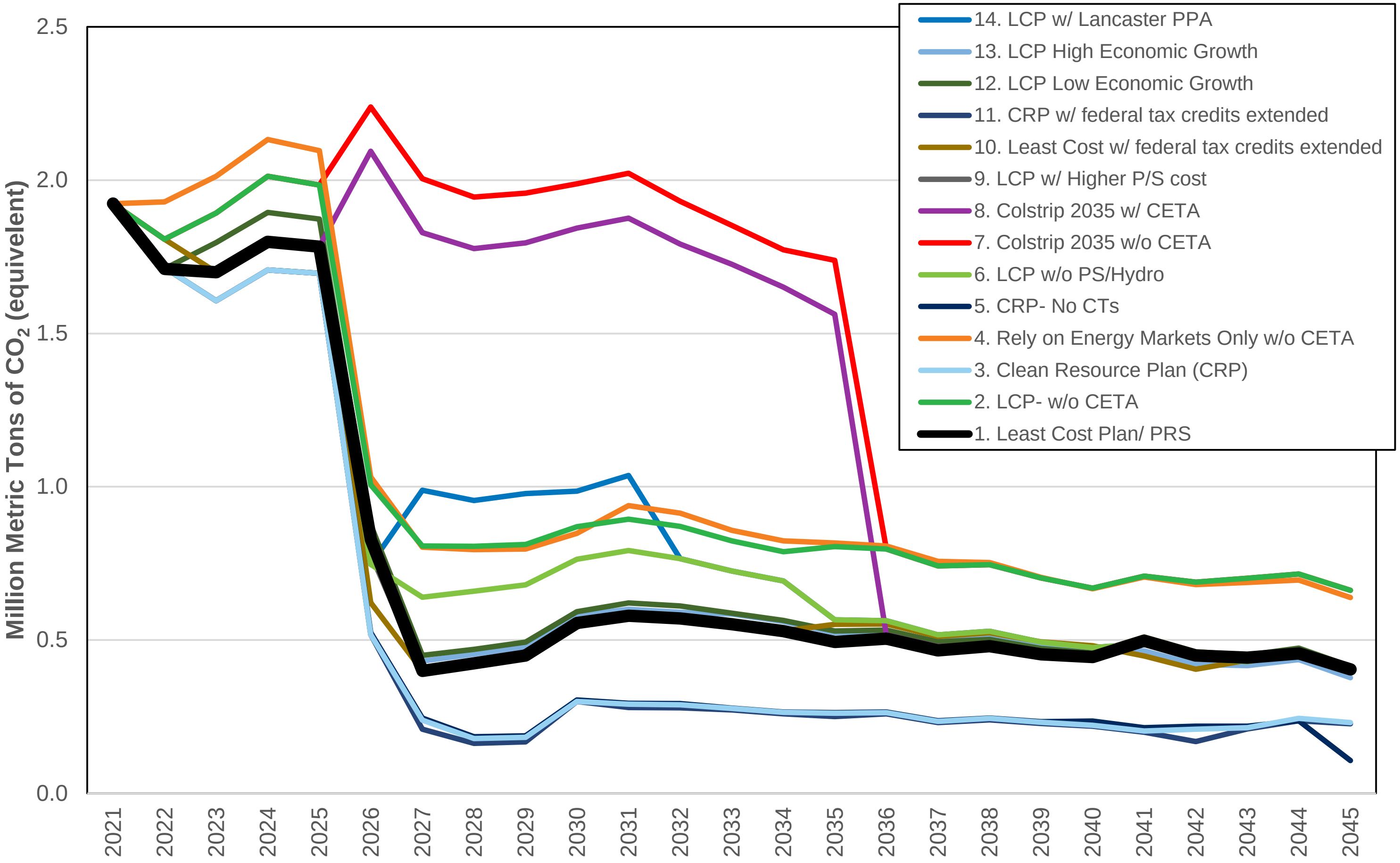


PVRR Risk Adjusted Comparison

Sorted by TailVar without Social Cost of Carbon (SCC)

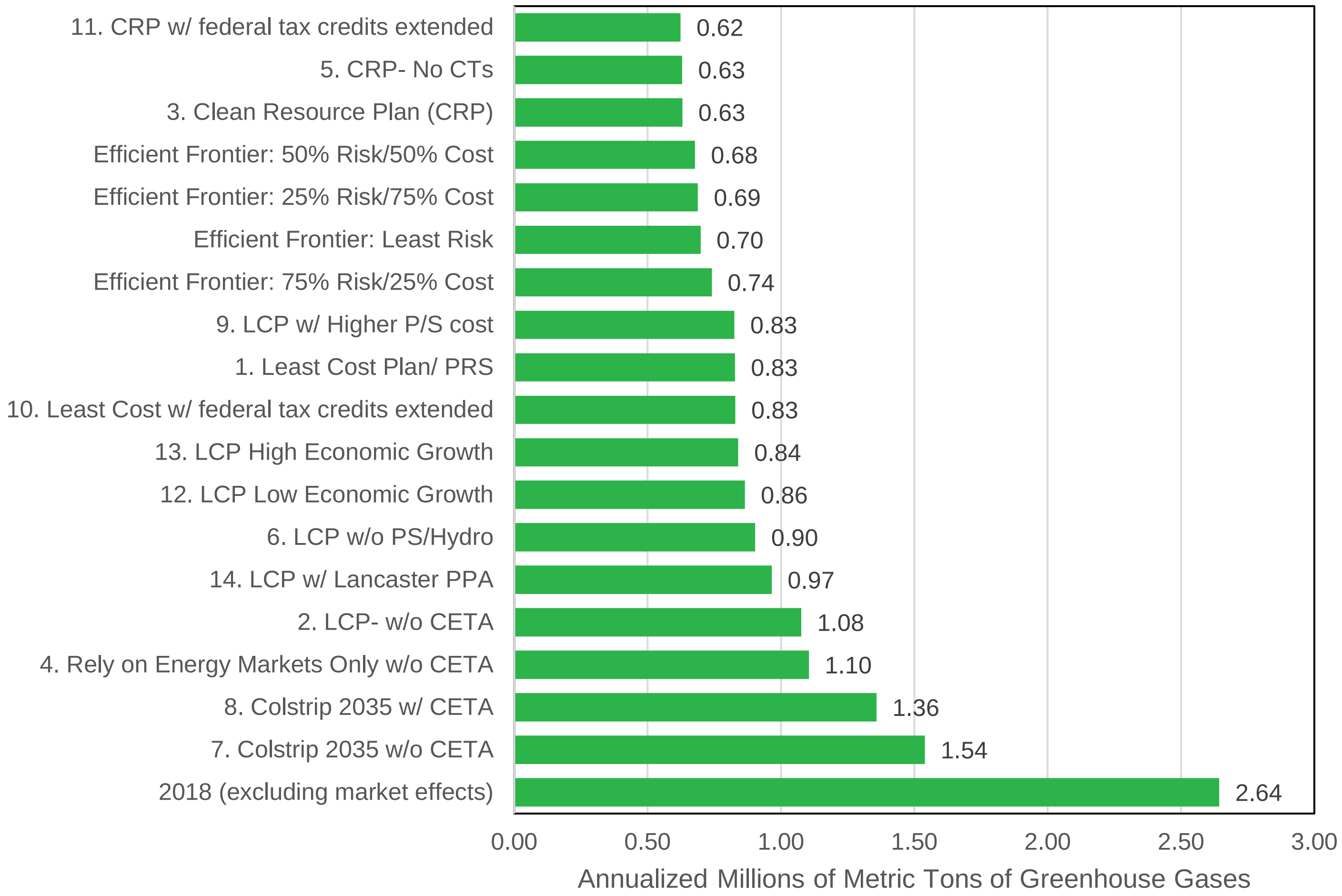


Annual Greenhouse Gas Comparison

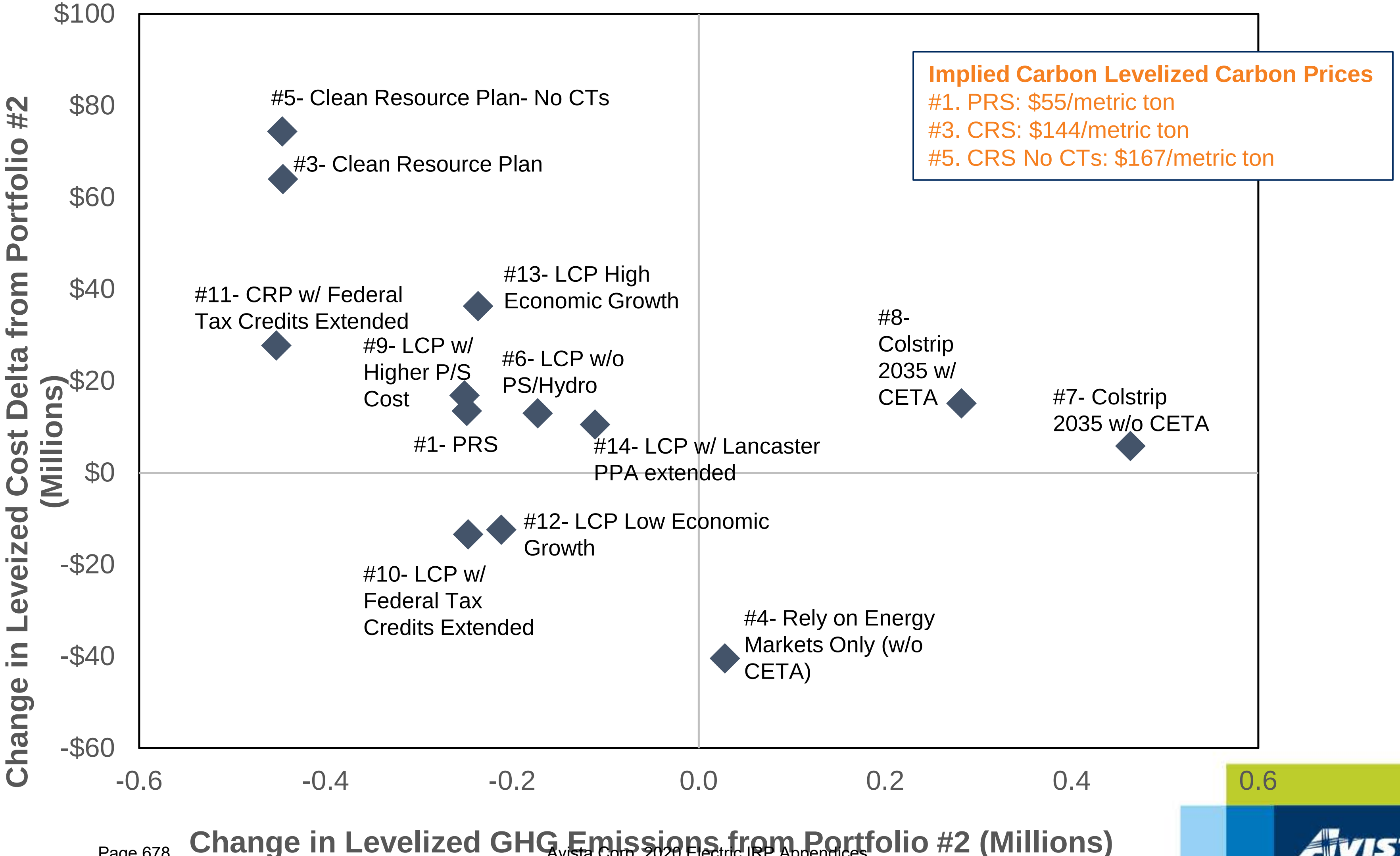


Annalized Greenhouse Gas Emissions

(Levelized using 2.5% discount rate)



Cost vs. GHG Emissions



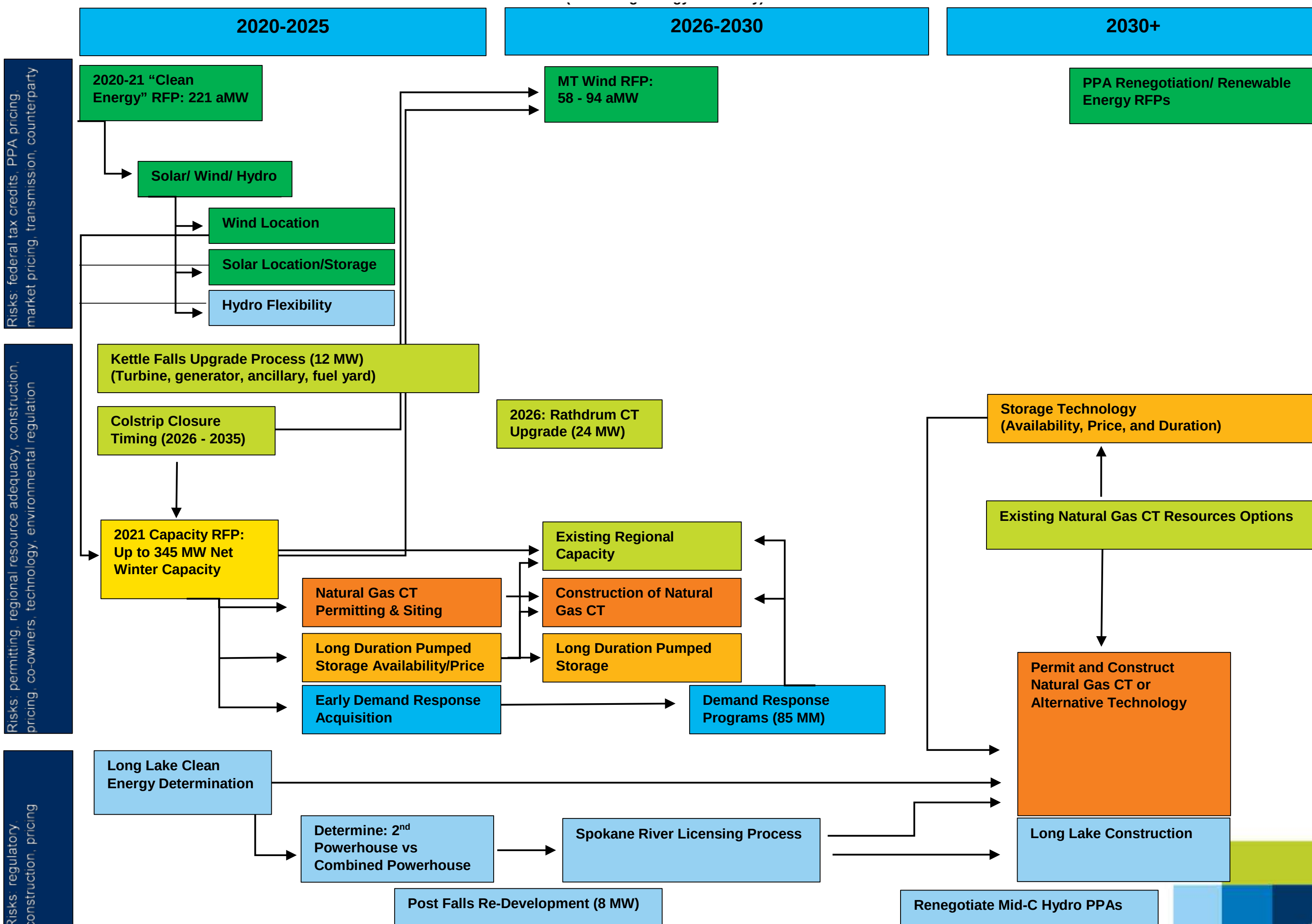
Scenario Results Summary Table

Portfolio Number	Portfolio name	Cost 2021-2045 (PVRR) (millions)	Cost 2021-2030 (PVRR) (millions)	2030 Risk (millions)	2030 Rate (c/kWh)	2045 Rate (c/KWh)	Levelized R.R.
1	Preferred Resource Strategy	$11,832	$6,329	$31.9	10.4	14.1	986.3
2	Least Cost Plan- w/o CETA	$11,670	$6,222	$42.0	10.1	13.5	972.7
3	Clean Resource Plan: 100% net clean by 2027	$12,439	$6,505	$25.2	11.1	15.6	1,036.8
4	Rely on Energy Markets Only (no capacity or renewable additions)	$11,185	$6,000	$47.8	9.4	12.7	932.3
5	100% net clean by 2027, and no CTs by 2045	$12,563	$6,511	$25.1	11.1	18.2	1,047.1
6	Least Cost Plan w/o pumped storage or Long Lake as options	$11,826	$6,270	$37.1	10.2	14.5	985.7
7	Colstrip extended to 2035 w/o CETA	$11,740	$6,252	$33.9	10.3	13.5	978.6
8	Colstrip extended to 2035 w/ CETA	$11,852	$6,346	$29.9	10.4	14.0	987.8
9	Least Cost Plan w/ higher pumped storage cost (+20%)	$11,873	$6,329	$31.7	10.4	14.3	989.6
10	Least Cost w/ federal tax credits extended	$11,510	$6,210	$31.9	10.0	13.3	959.4
11	Clean Resource Plan w/ federal tax credits extended	$12,004	$6,344	$25.1	10.6	14.4	1,000.5
12	Least Cost Plan w/ low economic growth	$11,521	$6,216	$31.9	10.4	14.5	960.3
13	Least Cost Plan w/ high economic growth	$12,106	$6,391	$34.4	10.3	13.9	1,009.1
15	Colstrip (Unit 4 until 2035)	$11,855	$6,343	$30.8	10.5	14.0	988.2

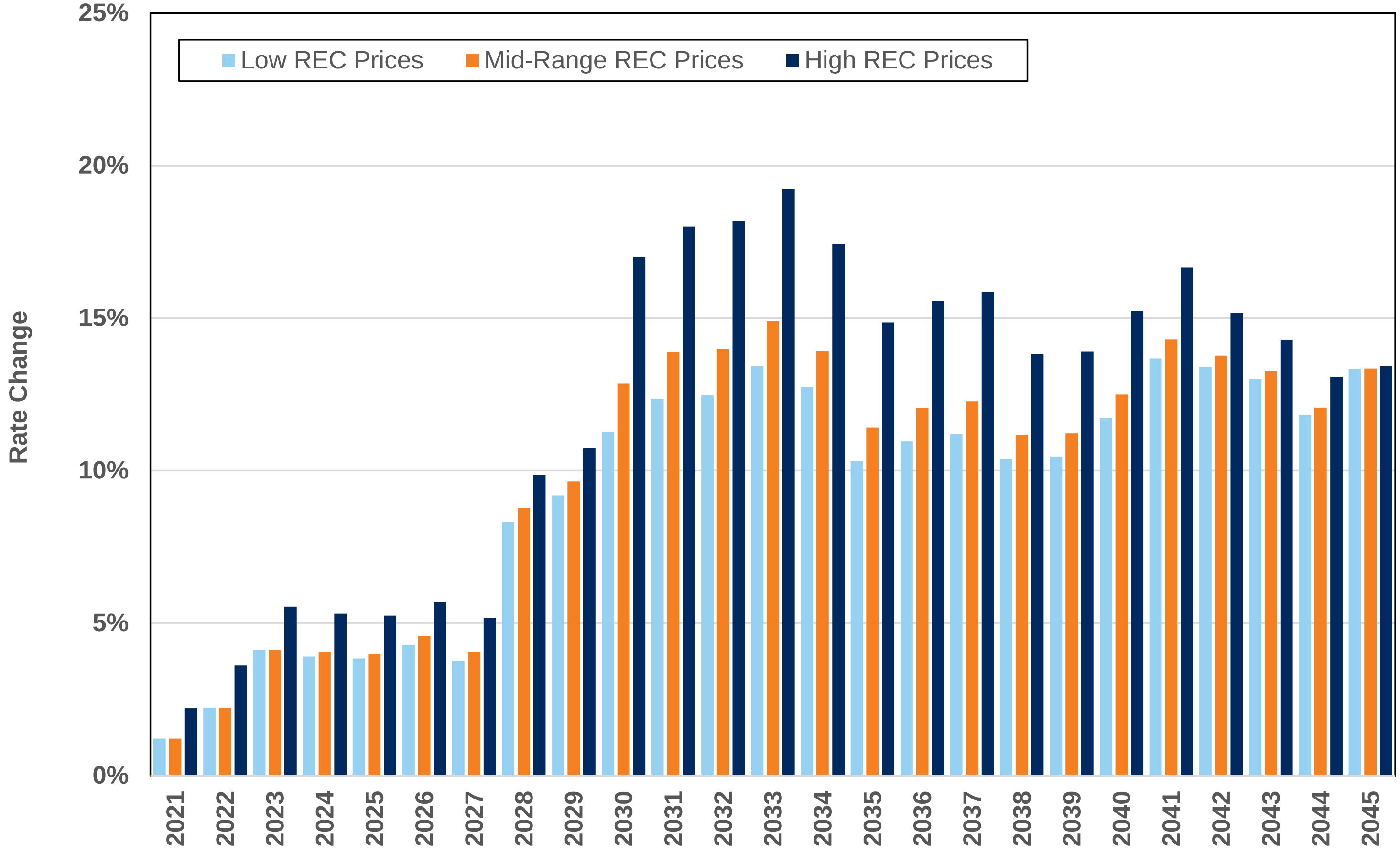
Note: Costs do not include Social Cost of Carbon, but included in optimization

Resource Acquisition Decision Chart

(Excluding Energy Efficiency)



Idaho Rate Impact for Clean Resource Strategy



Compares CRS (#3) cost to Idaho's LC strategy cost, then adjusts Costs down for REC sales at three different prices

Average Prices: Low- $4/REC, Mid- $6.40/REC, High- $15.40/REC

Observations

- Resource acquisitions and decisions are highly dependent on resource availability to be determined in a RFP.
- Colstrip continuing to 2035 is 0.3% higher cost then operating until 2025, (but rate per kWh is slightly lower due to changes in conservation). Keeping one unit running does not improve economics.
- CETA cost caps are likely to be in place closer to 2045.
- Idaho rates will be impacted by REC prices from its sales potential and how resources are allocated between states.
- Avista's GHG emissions will lower, but the amount depends on timing of resources and method for accounting for regional emissions.
- Low load scenario illustrates resource need if greater energy efficiency is gained.

Market Price Sensitivities

Market Price Sensitivity Analysis

- Use different market prices for each of the 14 portfolios
- Results in 70 sensitivities
- Market sensitivities include:
  - Expected Case (deterministic)
  - No CETA
  - Low natural gas prices
  - High natural gas prices
  - Social cost of carbon (west-wide dispatch- tax method)

Change in Cost (PVRR)

Sensitivity as Compared to Expected Case

Portfolios	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
1. Least Cost Plan/ PRS	0.6%	-3.0%	2.6%	10.5%
2. LCP- w/o CETA	0.8%	-4.4%	4.3%	15.5%
3. Clean Resource Plan (CRP)	0.1%	-2.3%	1.7%	7.6%
4. Rely on Energy Markets Only w/o CETA	0.4%	-5.8%	6.0%	19.5%
5. CRP- No CTs	0.2%	-2.0%	1.5%	7.6%
6. LCP w/o PS/Hydro	0.3%	-3.7%	3.5%	12.4%
7. Colstrip 2035 w/o CETA	0.7%	-3.8%	3.0%	14.8%
8. Colstrip 2035 w/ CETA	0.7%	-2.7%	2.2%	13.1%
9. LCP w/ Higher P/S cost	0.4%	-3.1%	2.8%	10.5%
10. Least Cost w/ federal tax credits extended	0.6%	-3.1%	5.4%	10.8%
11. CRP w/ federal tax credits extended	0.1%	-2.3%	1.8%	7.9%
12. LCP Low Economic Growth	0.4%	-3.0%	2.7%	11.3%
13. LCP High Economic Growth	0.8%	-3.2%	2.9%	10.9%
14. LCP w/ Lancaster PPA	0.2%	-3.7%	5.2%	12.6%
15. Colstrip Unit 4 through 2035	0.6%	-2.8%	2.4%	11.9%

Change in Cost (PVRR)

Portfolio as Compared to PRS

Portfolios	Expected Case (Stoch)	Expected Case (Det)	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
2. LCP- w/o CETA	-1.4%	-1.8%	-1.6%	-3.3%	-0.1%	2.7%
3. Clean Resource Plan (CRP)	5.1%	5.3%	4.7%	6.0%	4.4%	2.5%
4. Rely on Energy Markets Only w/o CETA	-5.5%	-6.4%	-6.6%	-9.1%	-3.3%	1.2%
5. CRP- No CTs	6.2%	6.4%	5.9%	7.4%	5.2%	3.5%
6. LCP w/o PS/Hydro	-0.1%	0.0%	-0.3%	-0.8%	0.9%	1.8%
7. Colstrip 2035 w/o CETA	-0.8%	-1.0%	-1.0%	-1.9%	-0.6%	2.9%
8. Colstrip 2035 w/ CETA	0.2%	0.3%	0.4%	0.6%	-0.1%	2.7%
9. LCP w/ Higher P/S cost	0.3%	0.3%	0.1%	0.1%	0.4%	0.3%
10. Least Cost w/ federal tax credits extended	-2.7%	-2.7%	-2.7%	-2.8%	0.0%	-2.4%
11. CRP w/ federal tax credits extended	1.4%	1.7%	1.1%	2.4%	0.8%	-0.7%
12. LCP Low Economic Growth	-2.6%	-2.8%	-3.1%	-2.9%	-2.7%	-2.2%
13. LCP High Economic Growth	2.3%	2.5%	2.6%	2.2%	2.8%	2.8%
14. LCP w/ Lancaster PPA	-0.3%	-0.2%	-0.6%	-1.0%	2.3%	1.7%
15. Colstrip Unit 4 through 2035	0.2%	0.3%	0.3%	0.4%	0.1%	1.6%

Change in Levelized GHG Emissions

Sensitivity as Compared to Expected Case

Portfolios	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
1. Least Cost Plan/ PRS	3.0%	8.7%	-1.1%	-36.8%
2. LCP- w/o CETA	5.2%	8.2%	-0.8%	-32.4%
3. Clean Resource Plan (CRP)	1.6%	11.2%	-1.1%	-43.9%
4. Rely on Energy Markets Only w/o CETA	2.7%	3.7%	-3.6%	-29.3%
5. CRP- No CTs	2.6%	11.2%	0.3%	-43.3%
6. LCP w/o PS/Hydro	1.9%	8.2%	-4.6%	-36.0%
7. Colstrip 2035 w/o CETA	4.2%	1.8%	0.0%	-53.6%
8. Colstrip 2035 w/ CETA	3.9%	2.0%	0.8%	-57.2%
9. LCP w/ Higher P/S cost	1.7%	7.9%	-2.9%	-37.2%
10. Least Cost w/ federal tax credits extended	2.7%	2.7%	-1.0%	-37.1%
11. CRP w/ federal tax credits extended	1.9%	11.6%	-0.8%	-44.3%
12. LCP Low Economic Growth	1.8%	6.8%	-2.7%	-35.3%
13. LCP High Economic Growth	4.0%	10.2%	4.0%	-37.4%
14. LCP w/ Lancaster PPA	2.6%	7.5%	-4.5%	-38.3%
15. Colstrip Unit 4 through 2035	3.6%	4.5%	0.2%	-49.8%

Change in Levelized GHG Emissions

Portfolio as Compared to PRS

Portfolios	Expected Case (Stoch)	Expected Case (Det)	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
2. LCP- w/o CETA	30.0%	24.1%	26.8%	23.6%	24.4%	32.9%
3. Clean Resource Plan (CRP)	-23.8%	-20.4%	-21.5%	-18.6%	-20.5%	-29.3%
4. Rely on Energy Markets Only w/o CETA	33.5%	26.5%	26.2%	20.7%	23.3%	41.5%
5. CRP- No CTs	-23.9%	-20.7%	-21.0%	-18.9%	-19.6%	-28.8%
6. LCP w/o PS/Hydro	9.2%	8.0%	6.9%	7.5%	4.2%	9.3%
7. Colstrip 2035 w/o CETA	86.0%	88.2%	90.5%	76.3%	90.2%	38.2%
8. Colstrip 2035 w/ CETA	64.1%	71.3%	72.8%	60.7%	74.5%	15.9%
9. LCP w/ Higher P/S cost	-0.3%	-0.8%	-2.1%	-1.5%	-2.7%	-1.3%
10. Least Cost w/ federal tax credits extended	0.2%	-0.1%	-0.4%	-5.6%	0.0%	-0.6%
11. CRP w/ federal tax credits extended	-24.6%	-21.1%	-21.9%	-19.0%	-20.9%	-30.4%
12. LCP Low Economic Growth	4.5%	2.7%	1.5%	1.0%	1.0%	5.1%
13. LCP High Economic Growth	1.5%	1.5%	2.5%	2.9%	6.7%	0.5%
14. LCP w/ Lancaster PPA	16.6%	15.7%	15.2%	14.4%	11.6%	12.9%
15. Colstrip Unit 4 through 2035	33.0%	36.2%	37.0%	31.0%	37.9%	8.3%

Sensitivity Observations

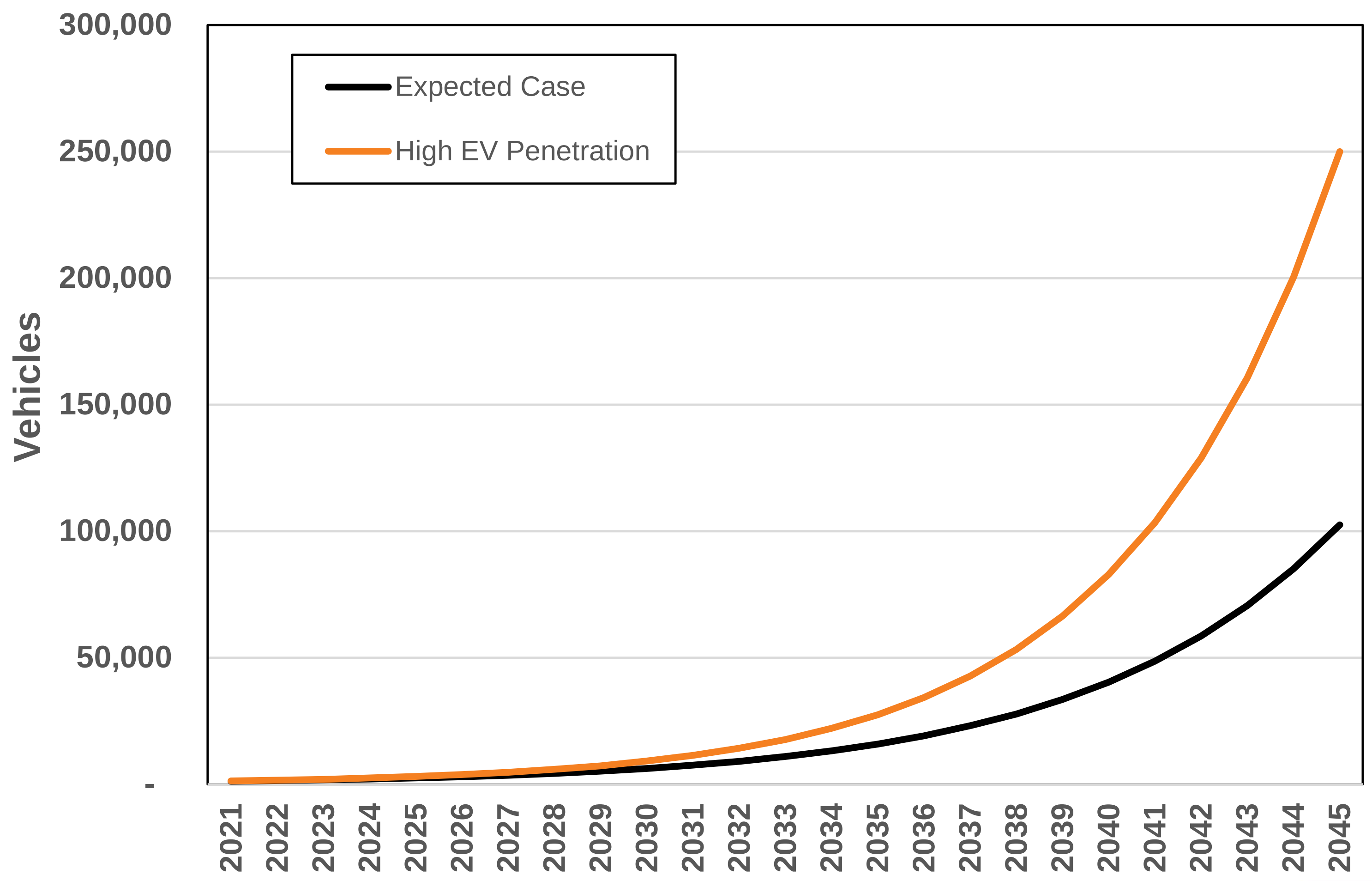
- Modeling the electric market place with and without CETA shows only modest changes in costs, but without CETA generally increases costs as electric market prices are higher.
- Low natural gas prices decrease portfolio costs and high natural gas prices increase costs, although scenarios with more gas turbines are more sensitive to gas prices changes- low natural gas prices are likely to increase Avista’s GHG emissions, while higher prices may not for Avista, but could for other markets.
- Modeling SCC as a tax increases Avista’s cost, but lowers Avista’s emissions. The PRS is still a lower cost alternative then other scenarios in this sensitivity.

Electrification Scenario

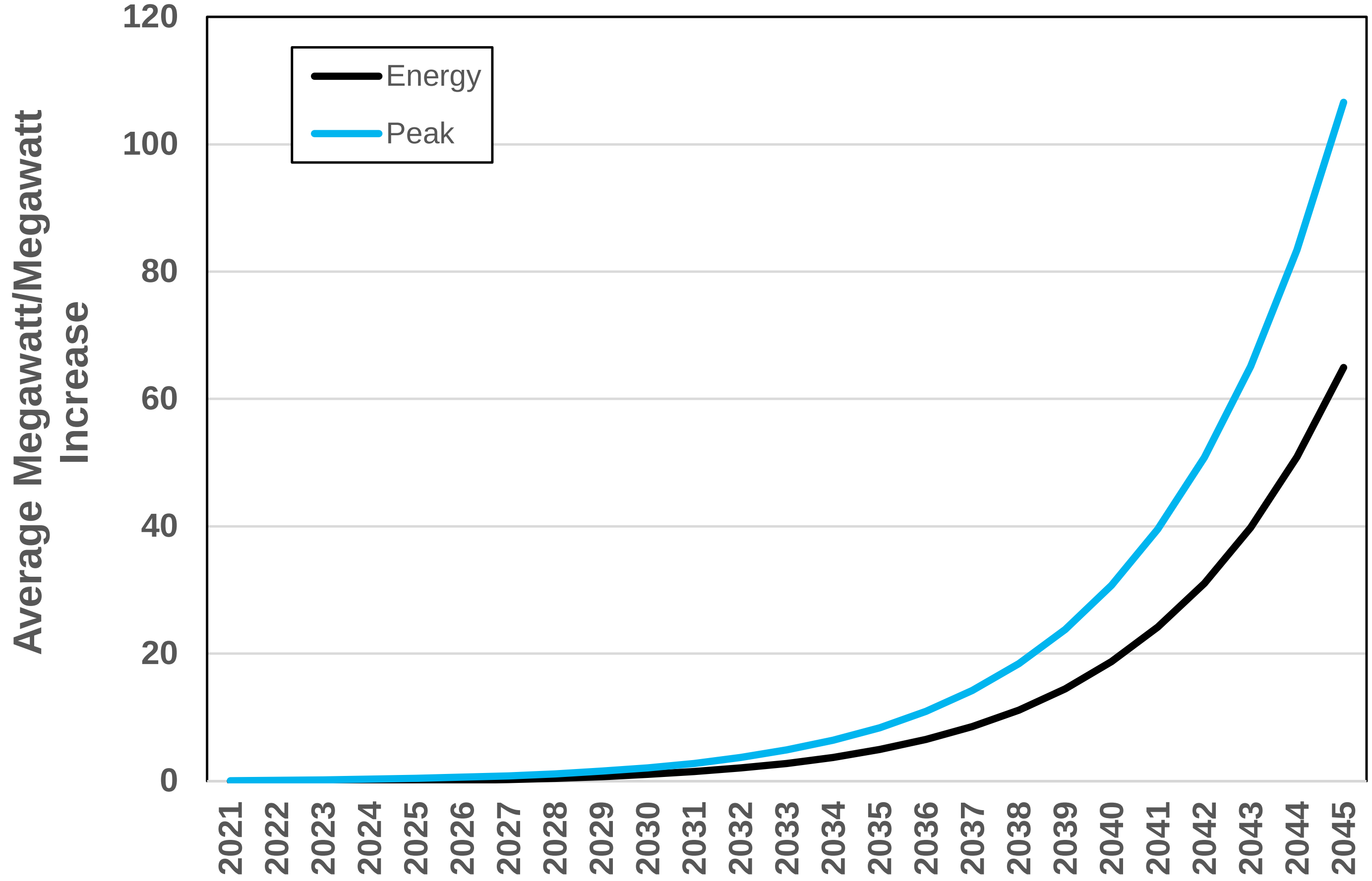
Electrification Scenario

- Increase electric vehicles
- Increase roof-top solar
- Reduction in end-use natural gas penetration

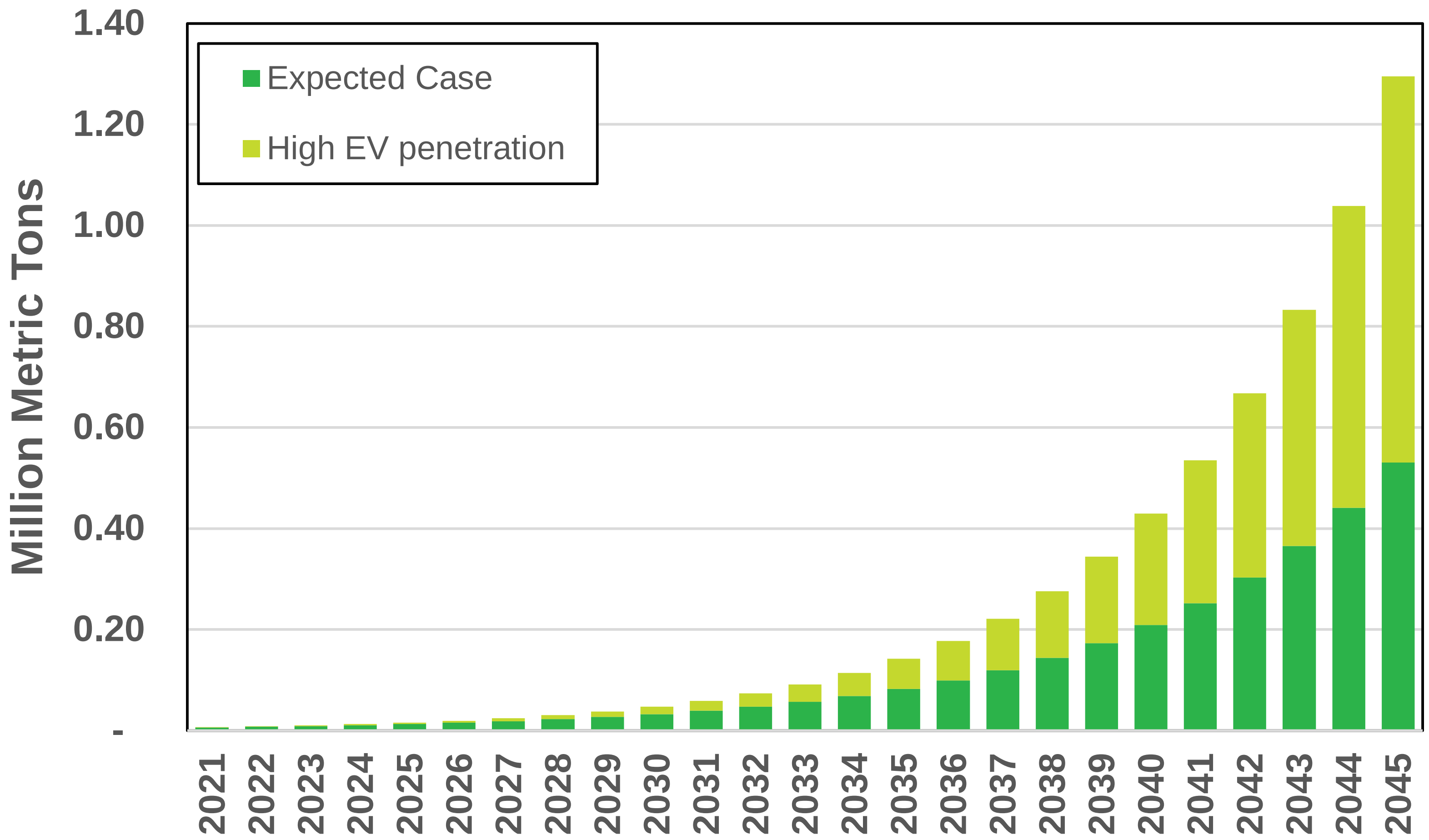
Service Territory Electric Vehicle Forecast



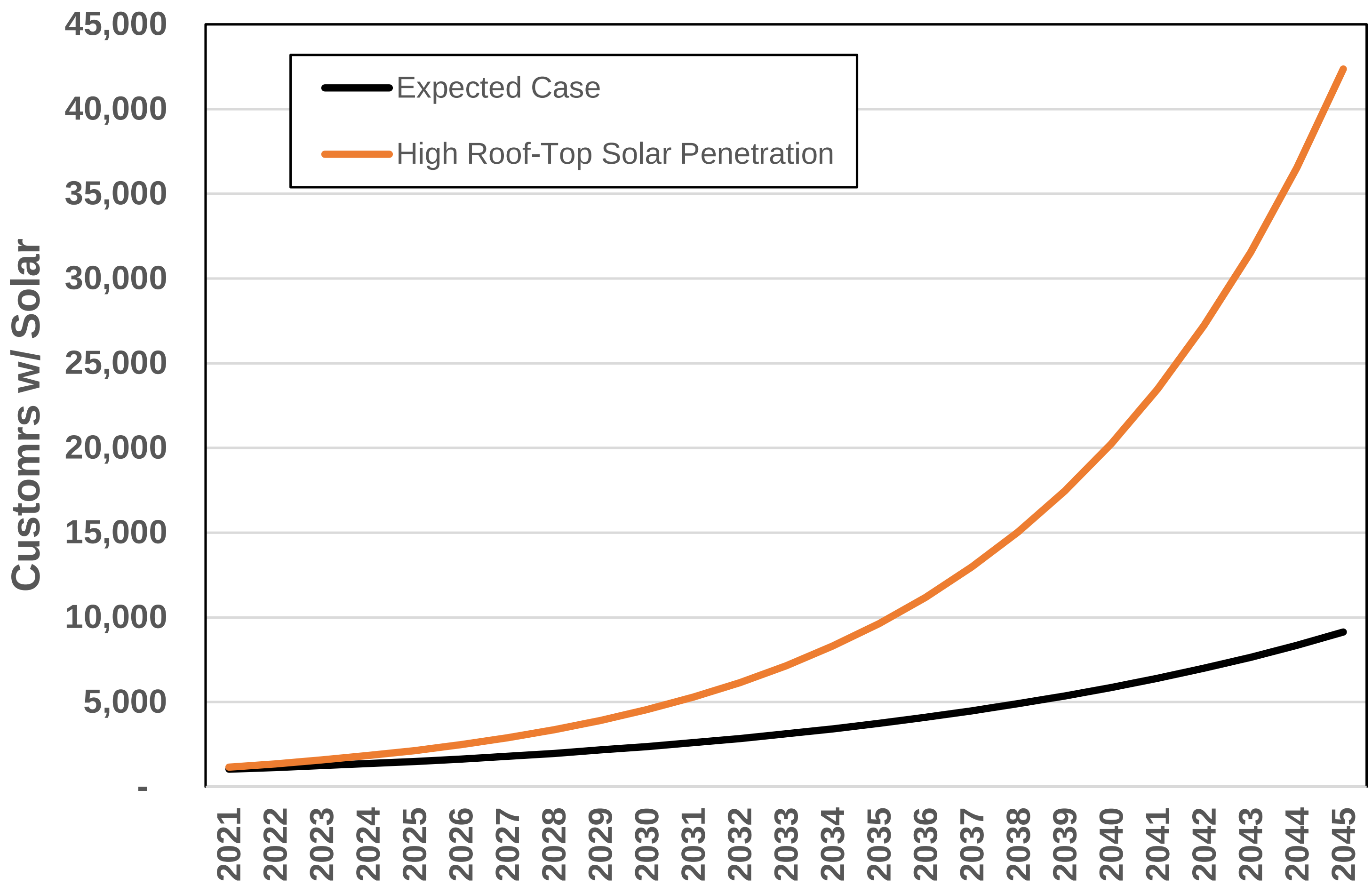
Electric Vehicle Impact to Peak & Energy Load Forecast



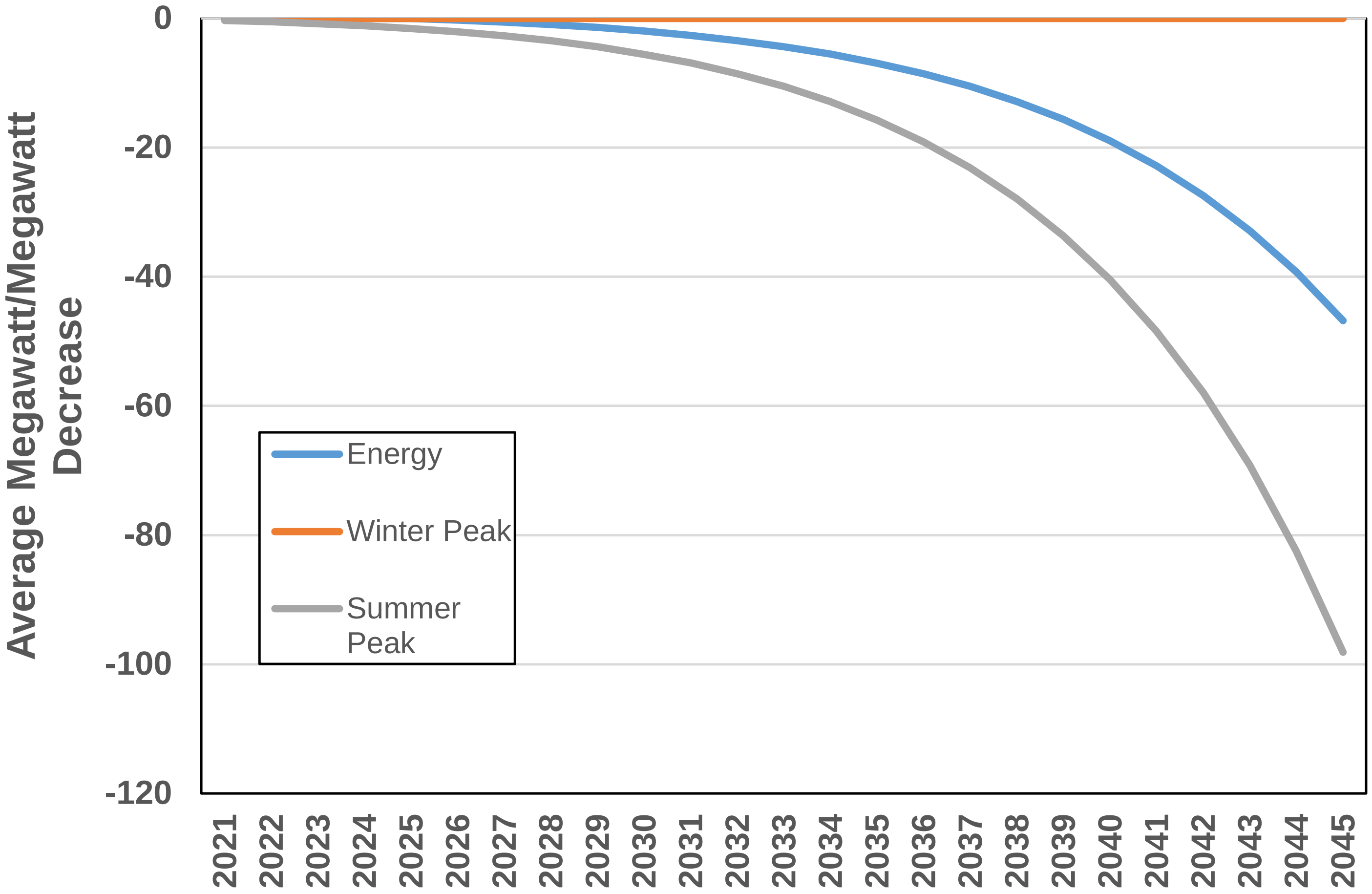
Avoided Direct Vehicle Emissions



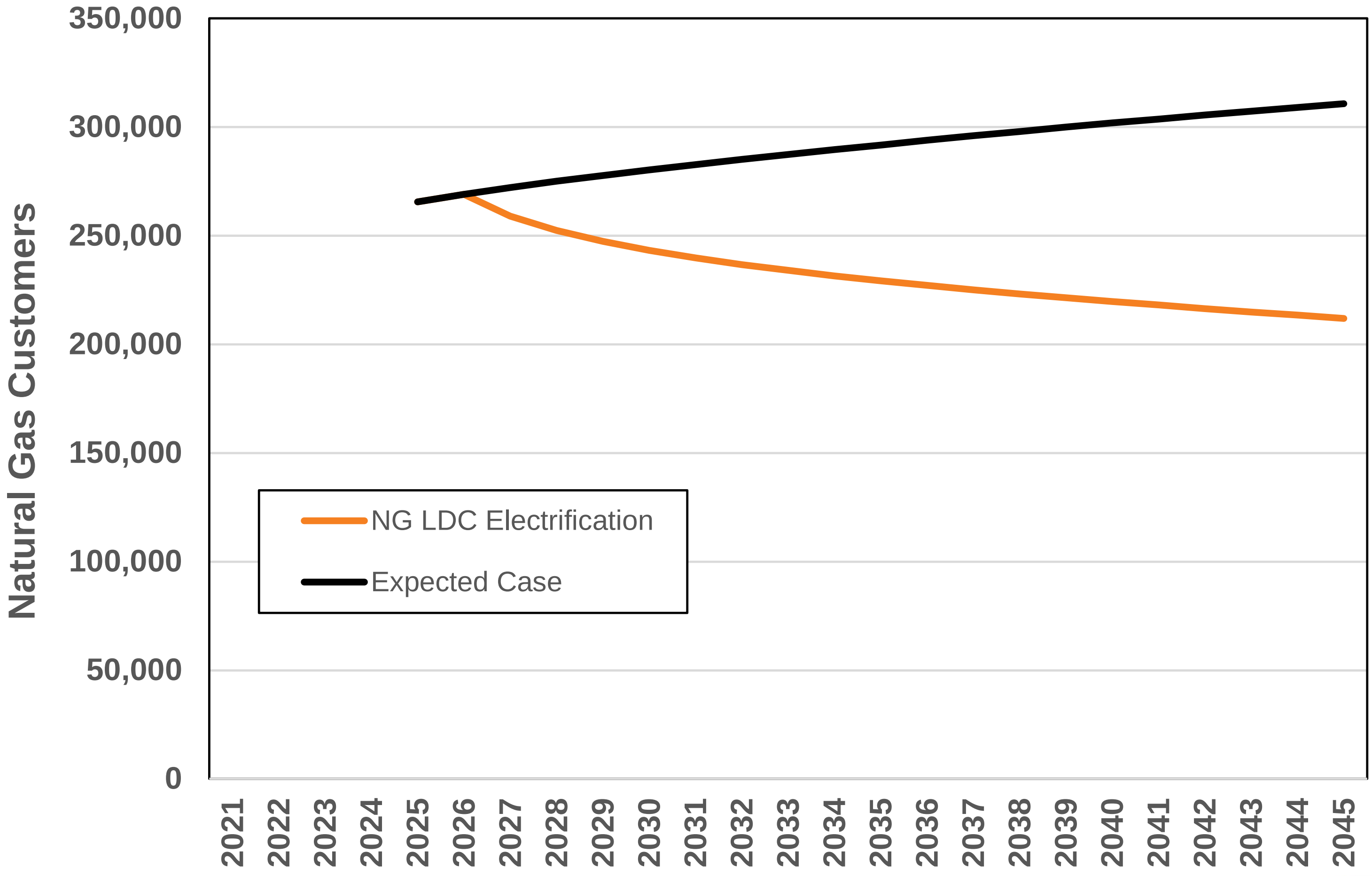
Customers with Roof-top Solar



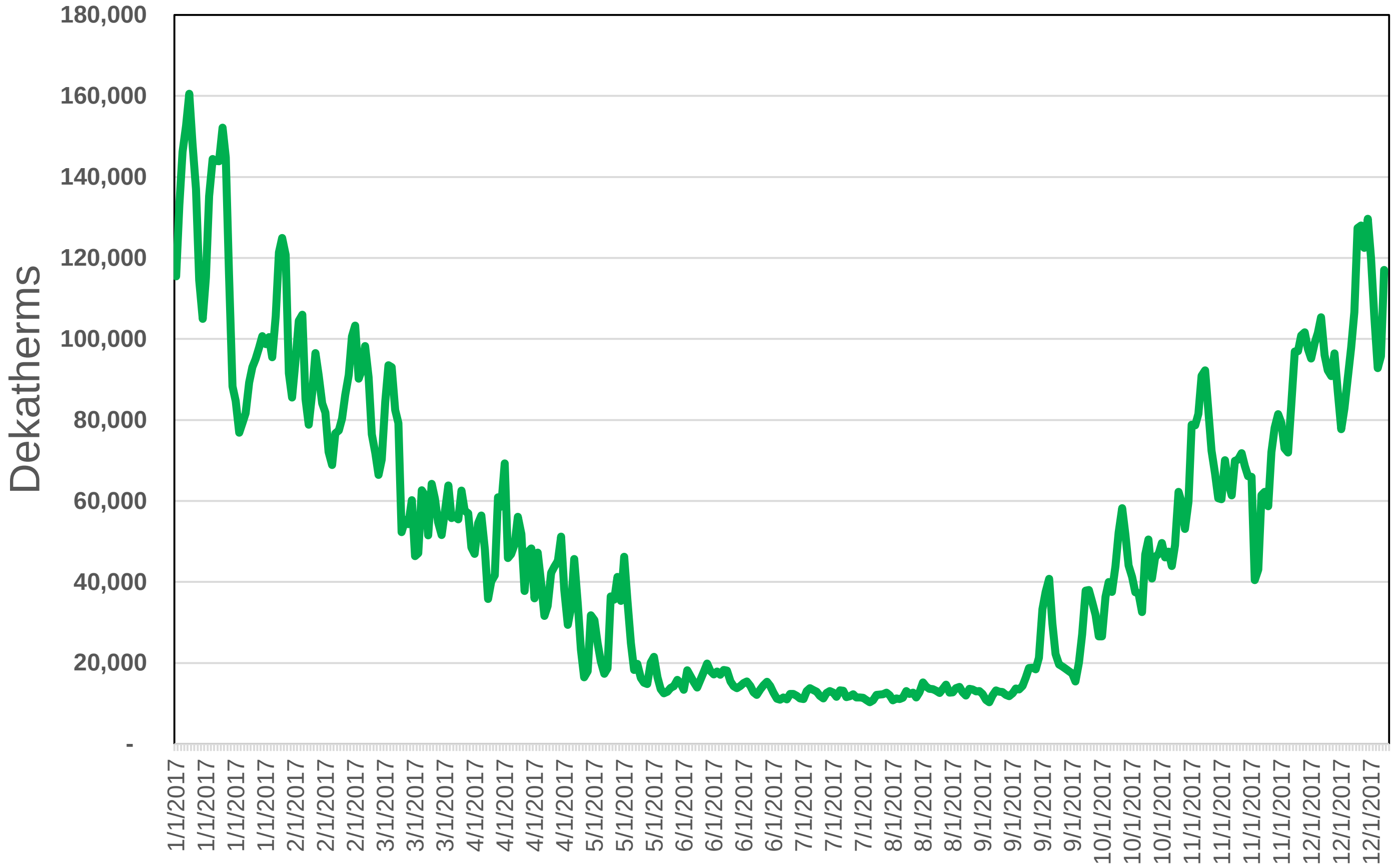
Roof-Top Solar Load Changes



End Use Natural Gas Penetration

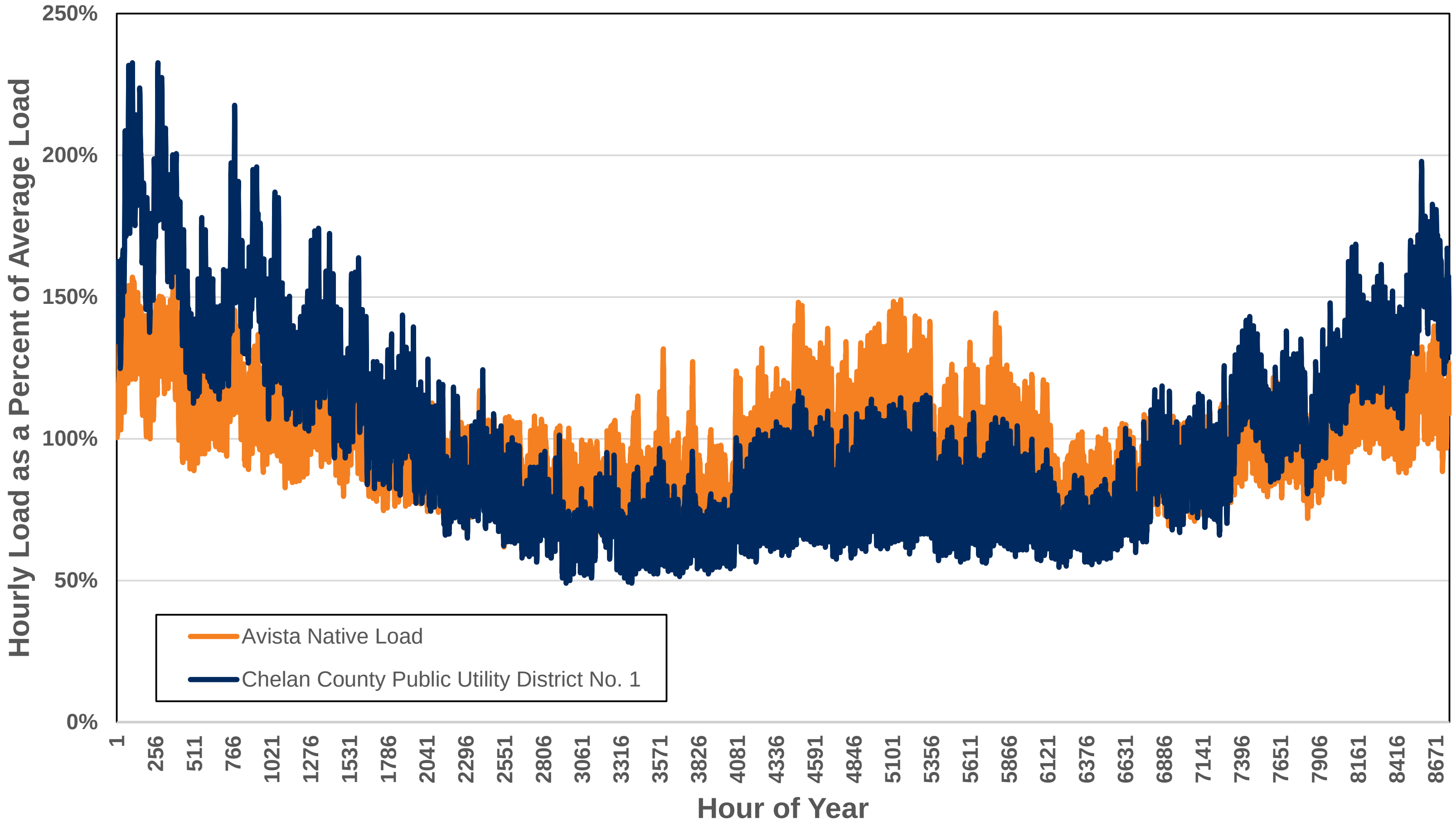


Avista's 2017 Natural Gas Daily Demand
(Core Washington Demand)



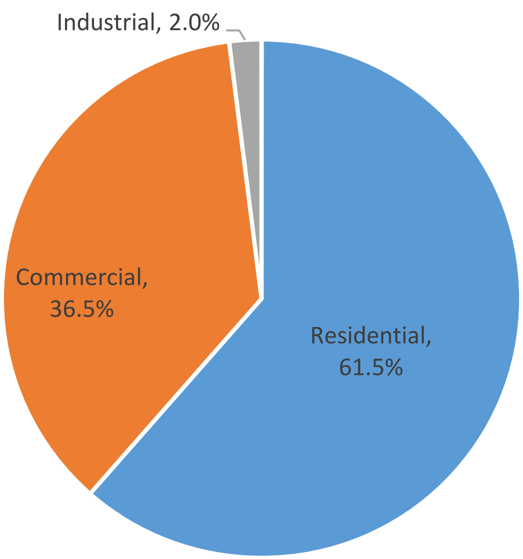
NW Electric Utility Load Shape

(All Electric vs. Mix Natural Gas/Electric)



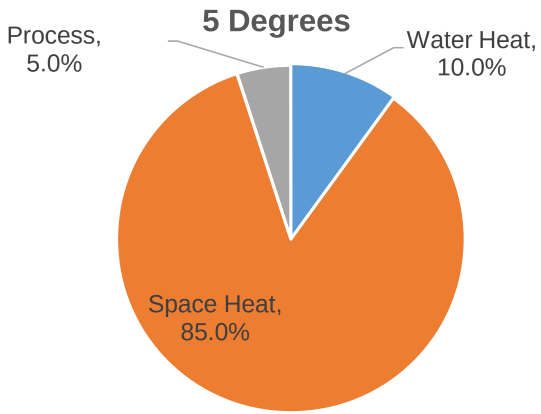
Converting Core Natural Gas to Electric

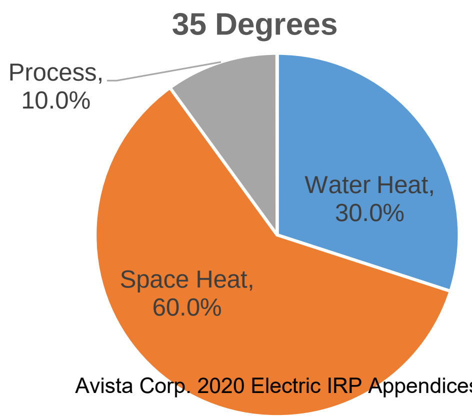
Annual customer type



End use by temperature

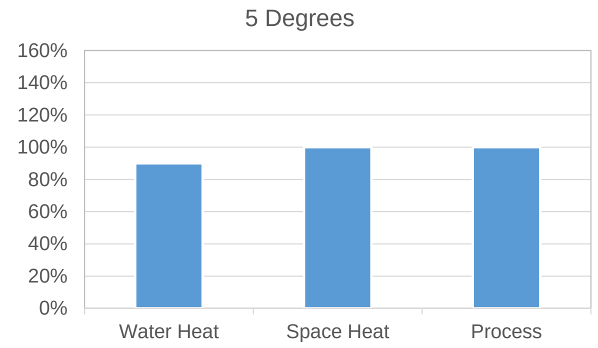
Residential Example

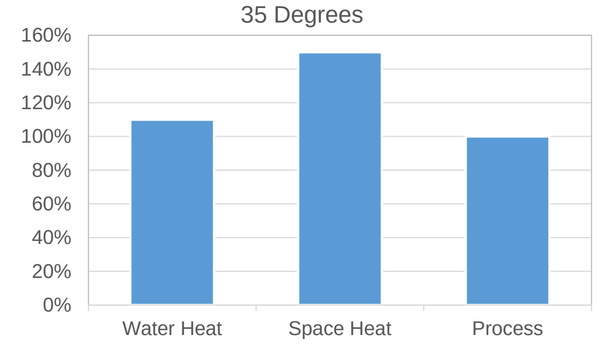




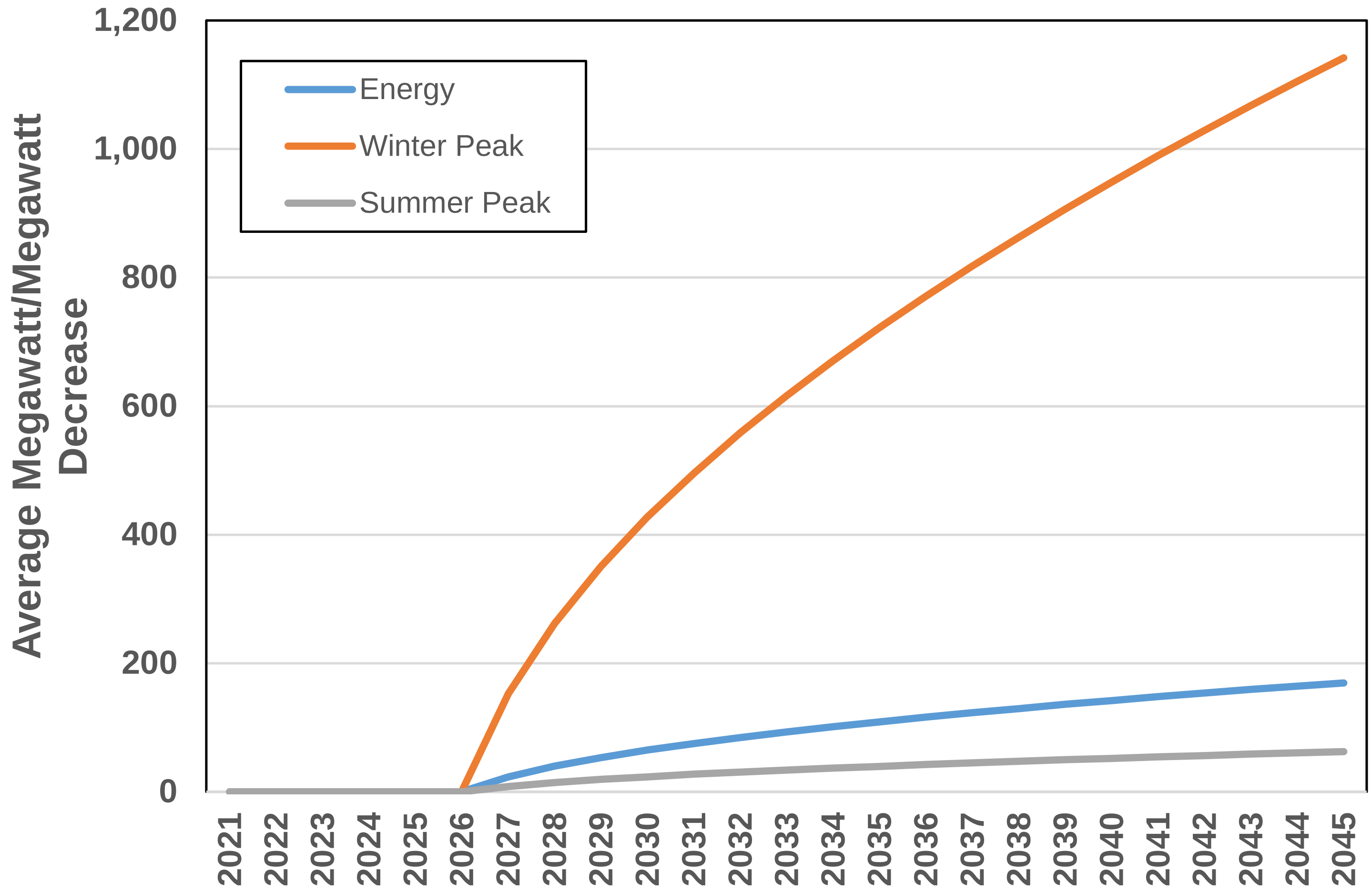
Efficiency by temperature

Residential Example



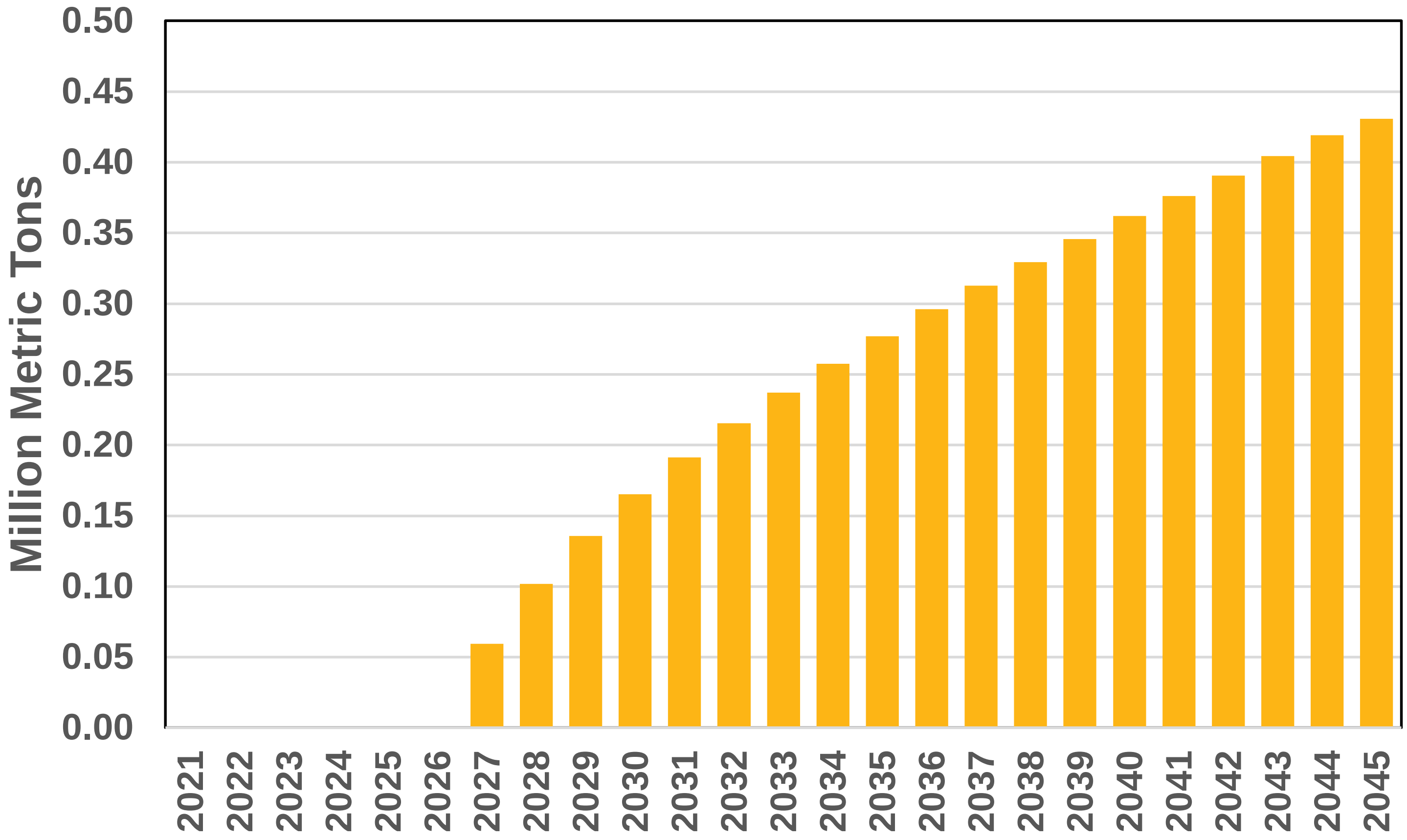


End-Use Natural Gas Load Changes

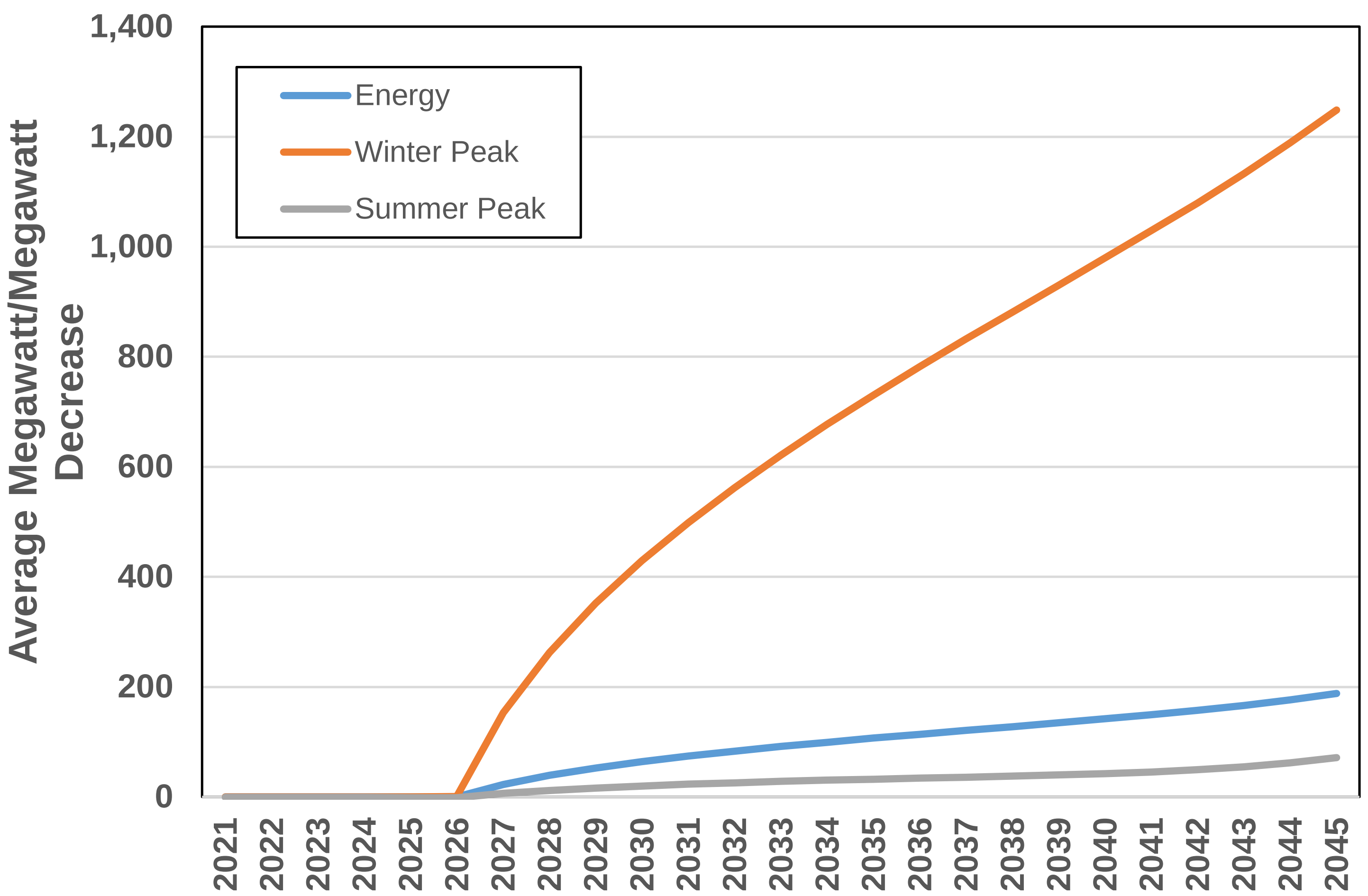


Associated Greenhouse Gas Emissions

From “Former” LDC Natural Gas Customers



Total Load Changes



2045 Cost Impacts

- Power System requires additional $365 million (25% increase)[1]
- Assumes an additional 1,080 MW new NG CT peakers, 520 MW Solar, 1,100 MW storage to meet new system peak load
- Greenhouse gas emissions

MMT	PRS + LDC NG	Electrification Scenario Change
Electric utility emissions	0.41	+0.28
Avoided petroleum emissions	-0.53	-0.76
LDC natural gas emissions	0.43	-0.43
Total emissions	0.31	-0.91

- Cost per metric ton: $397 per metric ton for the savings in 2045- over the 25 years the levelized cost of reduction is $1,942 per metric ton.
  - Does not include changes in Natural Gas LDC existing infrastructure costs
  - Does not include load related distribution/transmission investments (this will increase estimate)
  - Does not include EV incremental cost over petroleum alternative (this is unknown)
  - Does not include home owner equipment and wiring costs (this will increase estimate)

1) Estimate is net of natural gas commodity savings

Observations

- Electric vehicle penetration will have an impact on future resource needs- how customers use the energy will drive resource decisions.
- Electric vehicles will drive regional emissions lower, but Avista's emissions higher.
- Additional rooftop solar makes no material change in winter capacity planning, but lowers average energy and likely drives rates higher due to lower kWh sales.
- Electrification of natural gas space and water heating significantly increase winter load profiles.
- Additional heating electrification will likely result in natural gas peakers due to duration requirements and may costs result in modest savings of GHG emissions without significantly lowering storage costs.
- Heating electrification costs significantly exceed the Social Cost of Carbon.
- Externality costs can be significant: transmission, distribution, and direct home owner and should be considered in policy making.

Appendix

Detailed Resource Portfolios

Preferred Resource Strategy

Load reduction of 187 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 175 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2025-2030: 76 MW, Demand Response
2026/27: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade

2031-2040

2031: 75 MW, Mid-C PPA Renew
2032: 32 MW, Demand Response
2035: 55 MW, Northeast CT retires
2035: 68 MW, Long Lake 2nd Powerhouse
2036-40: 75 MW x 16 hr, Liquid Air Storage
2037: 1 MW Demand Response

2041-2045

2041: 25 MW x 16 hr, Liquid Air Storage
2042: 2.5 MW, Demand Response
2042-2045: 300 MW Wind PPA Renew
2042-2045: 300 MW x 4 hr, Lithium-ion
2044: 55 MW, Solar w/ 50 MW x 4hr, Storage

2) Least Cost Plan
without CETA

Load reduction of 166 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2026: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2026: 200 MW, Pumped Hydro
2026: 257 MW, Lancaster PPA expires
2026-2030: 85 MW, Demand Response
2027: 8 MW, Post Falls Upgrade
2027: 92 MW, Natural Gas CT

2031-2040

2031: 75 MW, Mid-C PPA Renew
2035: 55 MW, Northeast CT retired
2035: 84 MW, Natural Gas CT
2038: 25 MW x 16 hr, Liquid Air Storage
2039: 25 MW x 4 hr, Lithium-Ion
2040: 25 MW x 16 hr, Liquid Air Storage

2041-2045

2041-2042: 50 MW x 16 hr, Liquid Air Storage
2043: 55 MW Natural Gas CT
2045: 53 MW x 4 hr, Lithium-ion
2045: 3 MW Demand Response

3) Clean Resource Plan

100% net clean by 2030

Load reduction of 213 aMW due to Energy Efficiency by 2045

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 150 MW, NW Solar
- 2023: 200 MW, NW Wind
- 2023-2027: 64 MW, Demand Response
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 125 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 200 MW, MT Wind
- 2026: 257 MW, Lancaster PPA expires
- 2027: 8 MW, Post Falls Upgrade
- 2027-2030: 325 MW, Solar
- 2029: 20 MW Geothermal

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031: 68 MW Long Lake 2nd Powerhouse
- 2032: 21 MW Demand Response
- 2033-2040: 195 MW Solar w/ 150 MW x 4 hr. Storage
- 2035: 55 MW, Northeast CT retired
- 2037: 23 MW Demand Response

2041-2045

- 2041-2043: 300 MW Wind PPA Renew
- 2042: 25 MW x 16 hr Liquid Air Storage
- 2043-45: 225 MW x 4 hr, Lithium-ion
- 2040-45: 70 MW Solar w/ 50 MW x 4 hr. Storage
- 2045: 3 MW, Demand Response

4) Rely on Energy Markets Only
(no capacity or renewable additions)

Load reduction of 127 aMW due to Energy Efficiency by 2045

2021-2030

2026: 222 MW, Colstrip removed
2026: 257 MW, Lancaster PPA expires
2027: 8 MW, Post Falls Upgrade

2031-2040

2035: 55 MW, Northeast CT retired

2041-2045

5) 100% Net Clean by 2027

and No CTs by 2045

Load reduction of 214 aMW due to Energy Efficiency by 2045

2021-2030

- 2022: 150 MW, Solar
- 2022: 100 MW, MT Wind
- 2023: 200 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 222 MW, Colstrip removed
- 2026: 150 MW, Pumped Hydro
- 2026: 200 MW, MT Wind
- 2026: 257 MW, Lancaster PPA expires
- 2025-2027: 64 MW, Demand Response
- 2027: 8 MW, Post Falls Upgrade
- 2027-2028: 275 MW, NW Solar
- 2030: 50 MW, NW Solar
- 2029: 20 MW, Geothermal

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031: 68 MW, Long Lake 2nd Powerhouse
- 2031: 21 MW, Demand Response
- 2033: 55 MW, NW Solar
- 2035: 55 MW, Northeast CT retired
- 2036-2040: 140 MW Solar w/ 125 MW x 4 hr, Storage
- 2037: 23 MW, Demand Response
- 2040: 200 MW x 16 hr Liquid Air Storage
- 2040: 75 MW Pumped Hydro
- 2035: 154 MW, Rathdrum CTs removed

2041-2045

- 2041-2043: 300 MW Wind PPA Renew
- 2043: 9 MW, Kettle Falls CT removed
- 2043: 25 MW, Boulder Park removed
- 2042-2044: 125 MW x 16 hr Liquid Air Storage
- 2043-45: 28 MW x 4 hr, Lithium-ion
- 2045: 302 MW, Coyote Springs 2 removed
- 2045: 130 MW Solar w/ 75 MW x 4 hr, Storage
- 2045: 225 MW Pumped Hydro
- 2045: 100 MW Small Nuclear
- 2045: 50 MW Biomass

6) Least Cost Plan

w/o pumped storage or Long Lake, meeting CETA

Load reduction of 177 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 245 MW, Natural Gas CT
2027: 55 MW, Demand Response
2027: 8 MW, Post Falls Upgrade

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031-2035: 53 MW, Demand Response
2035: 55 MW, Northeast CT retired
2035: 200 MW, MT Wind
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041-2045: 300 MW Wind PPA Renew
2041: 25 MW x 16 hr, Liquid Air Storage
2044-2045: 150 MW x 4 hr, Lithium-ion
2044: 25 MW x 16 hr Liquid Air Storage
2045: 100 MW Solar w/ 100 MW x 4 hr, Storage
2045: 20 MW, Geothermal

7) Colstrip Extended to 2035 w/o CETA

Load reduction of 166 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2026: 12 MW, Kettle Falls Upgrade
2026: 200 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 92 MW, Natural Gas CT
2027: 8 MW, Post Falls Upgrade
2028-2030: 85 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2035: 55 MW, Northeast CT retired
2035: 222 MW, Colstrip removed
2035: 84 MW, Natural Gas CT
2038: 25 MW x 16 hr Liquid Air Storage
2039: 25 MW x 4 hr, Lithium-ion
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041: 25 MW x 16 hr Liquid Air Storage
2042: 25 MW x 16 hr Liquid Air Storage
2043: 55 MW, Natural Gas CT
2045: 53 MW x 4 hr, Lithium-ion
2045: 3 MW, Demand Response

8) Colstrip Extended to 2035 w/ CETA

Load reduction of 182 aMW due to Energy Efficiency by 2045

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 100 MW, NW Wind
- 2023: 100 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2026: 250 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027: 8 MW, Post Falls Upgrade
- 2028: 64 MW, Demand Response

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031-2032: 45 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2035: 222 MW, Colstrip removed
- 2035: 68 MW, Long Lake 2nd Powerhouse
- 2036: 200 MW, MT Wind

2041-2045

- 2042-2045: 300 MW Wind PPA Renew
- 2043: 25 MW x 16 hr Liquid Air Storage
- 2044: 50 MW, Solar w/ 50 MW x 4 hr, Storage
- 2045: 175 MW x 4 hr Lithium-ion
- 2045: 3 MW, Demand Response

9) Least Cost Plan

w/ 30 Percent higher pumped storage cost

Load reduction of 189 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 75 MW, Pumped Storage
2027: 92 MW, Natural Gas CT
2027: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade
2027-2030: 76 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031-32: 32 MW, Demand Response
2035: 55 MW, Northeast CT retired
2035: 68 MW, Long Lake 2nd Powerhouse
2036-2040: 75 MW x 16 hr Liquid Air Storage
2039: 3 MW, Demand Resonse

2041-2045

2041: 25 MW x 16 hr Liquid Air Storage
2042-2045: 300 MW, Wind PPA Renew
2042-45: 303 MW x 4 hr, Lithium-ion
2044: 50 MW Solar w/ 50 MW x 4 hr Storage

10) Least Cost Plan
w/ Federal Tax Credits Extended

Load reduction of 181 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2023: 200 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2026: 200 MW, MT Wind
2026: 175 MW Pumped Hydro
2026: 283 MW, Lancaster PPA expires
2027: 8 MW, Post Falls Upgrade
2025-2030: 85 MW, Demand Response

2031-2040

2031: 75 MW, Mid-C PPA Renew
2031: 23 MW, Demand Response
2035: 92 MW, Natural Gas CT
2035: 55 MW, Northeast CT retired
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041-2042: 300 MW, Wind PPA Renew
2042: 25 MW x 16 hr Liquid Air Storage
2043: 25 MW x 16 hr Liquid Air Storage
2044-2045: 150 MW, Solar w/ 150 MW x 4 hr Storage
2043-2045: 100 MW x 4 hr, Lithium-ion

11) Clean Resource Plan
w/ Federal Tax Credits Extended

Load reduction of 203 aMW due to Energy Efficiency by 2045

2021-2030

- 2022: 100 MW, MT Wind
- 2022: 150 MW, NW Solar
- 2023: 200 MW, NW Wind
- 2024: 12 MW, Kettle Falls Upgrade
- 2025-2027: 76 MW, Demand Response
- 2026: 222 MW, Colstrip removed
- 2026: 200 MW, MT Wind
- 2026: 125 MW, Pumped Hydro
- 2026: 24 MW, Rathdrum Upgrade
- 2026: 257 MW, Lancaster PPA expires
- 2027-2028: 300 MW, NW Solar
- 2027: 8 MW, Post Falls Upgrade
- 2029: 20 MW, Geothermal
- 2030: 25 MW, Solar

2031-2040

- 2031: 75 MW, Mid-C PPA Renew
- 2031: 68 MW, Long Lake 2nd Powerhouse
- 2033-2035: 32 MW, Demand Response
- 2035: 55 MW, Northeast CT retired
- 2033-2040: 250 MW, Solar w/ 225 MW x 4 hr Storage

2041-2045

- 2041-2042: 300 MW Wind PPA Renew
- 2043: 25 MW x 16 hr Liquid Air Storage
- 2042-2045: 225 MW x 4 hr, Lithium-ion
- 2044: 3 MW, Demand Response
- 2044-45: 75 MW, Solar w/ 75 MW x 4 hr of Storage

12) Least Cost Plan
with Low Economic Growth

Load reduction of 180 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2025-2027: 85 MW, Demand Response
2026: 222 MW, Colstrip removed
2026: 100 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade

2031-2040

2031: 75 MW, Mid-C PPA Renew
2035: 55 MW, Northeast CT retired
2035: 68 MW Long Lake 2nd Powerhouse
2038: 23 MW Demand Response

2041-2045

2042-2045: 300 MW Wind PPA Renew
2041-2045: 225 MW x 4 hr Storage
2045: 10 MW, Solar

13) Least Cost Plan
with High Economic Growth

Load reduction of 181 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2025-2040: 109 MW, Demand Response
2026: 111 MW, Colstrip Unit 3 removed
2026: 250 MW, Pumped Hydro
2026: 24 MW, Rathdrum Upgrade
2026: 257 MW, Lancaster PPA expires
2027: 200 MW, MT Wind
2027: 8 MW, Post Falls Upgrade

2031-2040

2031-2033: 75 MW, Mid-C PPA Renew
2033: 48 MW Natural Gas CT
2035: 68 MW Long Lake 2nd Powerhouse
2035: 55 MW, Northeast CT retired
2035: 111 MW, Colstrip Unit 4 removed
2037: 48 MW Natural Gas CT
2040: 25 MW x 16 hr Liquid Air Storage
2040: 3 MW, Demand Response

2041-2045

2041-43: 75 MW x 16 hr Liquid Air Storage
2041-2045: 205 MW Solar w/ 200 MW x 4 hr Storage
2042-2045: 300 MW Wind PPA Renew
2043-2044: 200 MW x 4 hr, Lithium-ion
2045: 20 MW, Geothermal

14) Least Cost Plan with Lancaster PPA Extended Five Years

Load reduction of 177 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 222 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2027: 8 MW, Post Falls Upgrade
2030: 30 MW, Demand Response

2031-2040

2031-2032: 75 MW, Mid-C PPA Renew
2031-2035: 78 MW Demand Response
2032: 257 MW, Lancaster PPA expires
2032: 245 MW Natural Gas CT
2035: 55 MW, Northeast CT retired
2035: 200 MW MT Wind
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041-2045: 300 MW, Wind PPA Renew
2042-2044: 150 MW x 4 hr, Lithium-ion
2041: 25 MW x 16 hr Liquid Air Storage
2043: 25 MW x 16 hr Liquid Air Storage
2045: 100 MW, Solar w/ 100 MW x 4 hr Storage
2045: 20 MW, Geothermal

15) Least Cost Plan with Colstrip Unit #4 extended until 2035

Load reduction of 178 aMW due to Energy Efficiency by 2045

2021-2030

2022: 100 MW, MT Wind
2022: 100 MW, NW Wind
2023: 100 MW, NW Wind
2024: 12 MW, Kettle Falls Upgrade
2026: 211 MW, Colstrip removed
2026: 24 MW, Rathdrum Upgrade
2027: 8 MW, Post Falls Upgrade
2030: 30 MW, Demand Response

2031-2040

2031-2032: 75 MW, Mid-C PPA Renew
2031-2035: 78 MW Demand Response
2032: 257 MW, Lancaster PPA expires
2032: 245 MW Natural Gas CT
2035: 55 MW, Northeast CT retired
2035: 200 MW MT Wind
2038: 25 MW x 16 hr Liquid Air Storage
2040: 25 MW x 16 hr Liquid Air Storage

2041-2045

2041-2045: 300 MW, Wind PPA Renew
2042-2044: 150 MW x 4 hr, Lithium-ion
2041: 25 MW x 16 hr Liquid Air Storage
2043: 25 MW x 16 hr Liquid Air Storage
2045: 100 MW, Solar w/ 100 MW x 4 hr Storage
2045: 20 MW, Geothermal

2020 Electric IRP
Action Items and IRP Chapter Overview

John Lyons, Ph.D.
Sixth Technical Advisory Committee Meeting
November 19, 2019

Analytical Action Items

- Determine ancillary services costs and benefits for intermittent and storage resources
- Research emission profiles for different types of resource construction and manufacturing
- Research the purchase of a third-party electric price forecast and then use that forecast to run our own dispatch analysis
- CETA issues and rulemaking:
  - Low income issues
  - Greenhouse gas emissions reporting
  - IRP requirements and future reporting
- Consider if IRP needs to be split between states because of timing and new requirements
- Consider the combination of the electric and natural gas IRPs
- Continued analysis for Colstrip post 2025

Resource Action Items

- Determine plan for Long Lake expansion and file with appropriate agencies concerning if the project meets CETA and licensing issues
- Continued pursuing pumped storage opportunities
- Conduct further transmission network studies for integration of renewables and contingency CTs
- 2020 RFP for renewable energy capacity (2022-2023 online)
- 2021 RFP for capacity resources (on-line by 2026)
- Additional studies for the eventual shutdown of Northeast CT

Other 2020 Action Items

- Other areas of concern or suggestions?
- Please call or email the planning team with any suggestions or added Action Items

2020 Electric IRP Chapters

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

2020 Electric IRP Chapters 1 – 3

- Chapter 1: Executive Summary
  - High level summary of 2020 IRP and PRS
- Chapter 2: Introduction, IRP Requirements, Stakeholder Involvement
  - TAC overview and rules guiding IRP development
- Chapter 3: Economic and Load Forecast
  - Economic conditions in Avista's service territory
  - Avista's energy and peak forecasts
  - Load forecast scenarios

2020 Electric IRP Chapters Ch. 4 – 6

- Chapter 4: Existing Supply Resources
  - Avista's resources
  - Contractual resources and obligations
  - Avista's natural gas pipeline overview

- Chapter 5: Energy Efficiency and Demand Response
  - Conservation Potential Assessment
  - Greenhouse gas offset calculation
  - Demand response opportunities

- Chapter 6: Long-Term Position
  - Reliability adequacy and reserve margins
  - Resource requirements
  - Reserves and flexibility requirements

2020 Electric IRP Chapters Ch. 7 – 8

- Chapter 7: Transmission and Distribution Planning
  - Overview of Avista's Transmission System
  - Future Upgrades and Interconnections
  - Transmission Construction Costs and Integration
  - Merchant Transmission Plan
  - Overview of Avista's Distribution System
  - Future Upgrades and Interconnections (includes project evaluated with DER alternative)

2020 Electric IRP Chapters Ch. 8 – 9

- Chapter 8: Generation and Storage Resource Options
  - New Resource Options
  - Avista Plant Upgrades

- Chapter 9: Market Analysis
  - Marketplace
  - Federal and State Environmental Policies
  - Fuel Price Forecasts
  - Market Price Forecast
  - Scenario Analysis

2020 Electric IRP Chapters Ch. 10 – 12

- Chapter 10: Preferred Resource Strategy
  - Resource Selection Process
  - Preferred Resource Strategy
  - Efficient Frontier Analysis
- Chapter 11: Portfolio Scenarios
  - Portfolio Scenarios
  - Resource Avoided Cost
- Chapter 12: Action Plan
  - 2017 Action Plan Summary
  - 2020 Action Plan

Remaining 2020 IRP Schedule

- December 18, 2019 – external draft released to TAC
- January 15, 2020 – external draft comments due
- February 28, 2020 – 2020 Electric IRP published and available to the public on Avista's web site
- Public comments period determined by the Commissions and posted on their respective web sites
- January 4, 2021 – Draft IRP due for Washington
- April 1, 2021 – File 2021 IRP in Washington
- Aug 31, 2021- File 2021 IRP in Idaho
- TAC schedule for next IRP(s) will be available after we determine if the IRP needs to be bifurcated between Idaho and Washington

Attendees: TAC 6, Tuesday, November 19, 2019 at Avista Headquarters in Spokane, Washington:

John Lyons, Avista; Xin Shane, Avista; Kevin Calhoun, Tyr Energy; Andrew Argetsinger, Tyr Energy; Barry Kathrens, 350.org; Michael Eldred, Idaho Public Utilities Commission; Clint Kalich, Avista; Shelby Herber, Idaho Conservation League; Matt Nykiel, Idaho Conservation League; John Barber, Rockwood Retirement Communities; Dave Van Hersett, Residential Customer; Kirsten Wilson, Washington State DES Energy; Cadie Olsen, City of Spokane; Jason Thackston, Avista; Rachelle Farnsworth, Idaho Public Utilities Commission; Darrell Soyars, Avista; Collins Sprague, Avista; Terrence Browne, Avista; Garrett Brown, Avista; Grant Forsyth, Avista; Logan Callen, City of Spokane; James Gall, Avista. David Howarth, National Grid; and Jaime Majure, Avista.

Phone Participants:

Jennifer Snyder, Washington UTC; Mike Starrett, Northwest Power and Conservation Council; Cassie Koerner, Idaho Public Utilities Commission; Amy Wheeless, Northwest Energy Coalition; Nancy Esteb, Renewable Energy Coalition; and several guest participants who did not identify themselves.

These notes follow the progression of the meeting. The notes include summaries of the questions and comments from participants, Avista responses from the presenter are in *italics*, and significant points raised by presenters that are not shown on the slides are also included. Bracketed comments provide additional details and updates.

Introductions and TAC 5 Recap, John Lyons

Matt Nykiel: Will the Idaho and Washington IRPs come back together? *Not sure, we will discuss later today and with both state Commissions.*

Cadie Olsen: With the limited availability of people to do economic analysis for CETA, has that slowed down the work?

John Lyons: Agencies have been working on it [CETA], but there have been staffing issues. The Washington UTC has a schedule laid out for the next few years for all of the rulemaking required for CETA.

Review of PRS, James Gall

Matt Nykiel: What is the status of the coal contract?

Jason Thackston: We haven’t signed the contract yet, but are very close and fully expect it to be signed by the end of the year. [Avista signed a new contract in early December 2016 for coal through the end of 2024.]

Clint Kalich: Can you clarify the statistic 70% green? *70% of our retail sales for Washington and Idaho.*

Matt Nykiel: A similar question as part of the RECs, Avista's goal is for both states. How will both be met since selling Idaho RECs to Washington makes it harder to meet the goal?

Jason Thackston (Slide 3): The purpose of this slide is to show the status of our ability to comply with the Washington law. That leads into the 100% goal.

Matt Nykiel: How does the model handle situations where it is rainy and windy in Spokane, but sunny in Montana? Let's factor in potential at other places, not just here at the office at Avista. *We apply a factor for different locations for availability.* 100% on average or net 100%? *We'll get to that later as well.*

James Gall (Slide 5): Solar includes bifacial panels with a single axis tracker. Hydro includes Long Lake and Post Falls upgrades. We removed the Monroe Street upgrade from the PRS discussed in the last TAC meeting. Wind includes offshore.

Clint Kalich: For BPA, is that federal hydro? *Price is based on a gas plant, but the actual generation may or may not be federal hydro.*

James Gall: Geothermal is not in our region; but is outside our region in southern Idaho, Nevada (in the last RFP), and in Utah that could get here. Nuclear is another option, but it is too big for Avista. Modular nuclear of 100 MW is clean and the right size, but will probably not be commercially available for quite some time. Energy efficiency has been used by Avista since the 1970s, we have saved over 200 MW on average.

Matt Nykiel: How are wind and solar being modeled? *All wind and solar are modeled as a PPA with different locations. On-system wind and solar have an interconnection cost and off-system locations have wheeling costs. Each resource type is assigned a peak credit for contribution to peak loads.*

James Gall: Liquid air storage is easy to scale, with long duration storage requiring more tanks – the same as hydrogen. Flow batteries are both four-hour for vanadium flow and zinc oxide batteries. Both of these are higher initial cost than lithium ion, but have a 20-year lifespan instead of 10 years. Regional transmission as a supply resource is crossed out because we don't know what will be on the other side of the transmission line in the future.

Matt Nykiel (Slide 6): Is the social cost of carbon $50 to $60? *$80 in 2021.* Can you explain how pipeline upstream emissions are modeled? *Losses* to *move gas on pipeline and releases from gas wells. We get all of our gas from Canada, mainly Alberta. The Canadians have a report that shows a little bit less than 1%, times the amount of gas. I don't know the name of the document, but it will be in the IRP document.*

Slide #7: The lower Montana wind capacity factor is used to account for transmission losses. We moved to the upper end of pumped hydro storage projects after talking more with developers. This makes it more reliable like a gas plant. And we added more planning margin.

Dave Van Hersett (Slide 7): How many hours [for pumped hydro]? *40 to 80 hours.*

Dave Van Hersett (Slide 10): Is water heating switching from electric to natural gas? *No, it is for heat pump water heaters. We will cover what you are talking about later today.*

Slide 11: Modeling versus actual acquisition. We think 100 MW from Montana and 100 MW from the Northwest, but anyone can bid into an RFP and provide the wind power.

Mike Starrett: Is the procedural expectation from the Washington Commission an acknowledgment? *The IRP is acknowledged and then any resources we acquire go into a future rate case. We show a need to answer the prudency question in a general rate case. CETA will have a Clean Energy Action Plan.*

Jennifer Snyder: Yes, as of right now, it is a rate case prudency question. Clean Energy Action Plan will be covered later.

Slide 11: Changed pumped hydro up from 150 MW to 175 MW in the PRS and increased demand response from 2021 to 2030.

Dave Van Hersett: DR is? *Demand response, we will get to that later.*

Mike Starrett: The presumption is that it goes away, but have you looked at attributes of Lancaster going forward? *Yes, we are showing that later.*

Matt Nykiel (Slide 12): Did you model opt in versus opt out? *Didn't model it, but about 50 percent more. We have an estimate of it. Dave, did this answer your question?* Yes.

Jason Thackston (Slide 13): 2022/23 acquisitions come online. Issue an RFP spring of next year. Online by at least 2022, but we will look at later dates in an RFP if they are better prices. We would rather do an RFP first, then the IRP. This is our best guess now. Colstrip cannot serve Washington customers after 2025, but could still serve Idaho's one third share or get other owners to agree to shut down.

Matt Nykiel: If it [Colstrip] is not cost effective, it is no longer prudent. *Colstrip could operate at minimums or we could sell it, but we could not unilaterally shut it down ourselves.*

John Barber: On the pumped hydro projects, are there others interested? *Yes, the projects are much bigger than we need. There are other parties interested and they would need even more participants.*

Matt Nykiel: With the cost effectiveness caveat, how does that make the business goal different than business as usual? *Other strategies are RECs with CTs [combustion turbines] to green up the portfolio. We don't want to jeopardize our customer's livelihood for an aspirational goal.*

Matt Nykiel: What is that cost effectiveness test?

Jason Thackston: Good question. We are struggling with that too. There was a lot of squirming in April. We continue to look at the impact of the goal while maintaining reliability. This goal is aligning ourselves internally. We totally get that from the business side of things. Gap with how it is marketed and caveats they signal are super important. Idaho resources are producing for Idaho customers, but are also going to Washington. There is a signal there so that customers can make an informed decision. This is good feedback. Thanks.

Dave Van Hersett: Increasing my bills is lowering my reliability.

Jason Thackston: The ideal outcome is 2025-2030. Our CFO always notes that hope is not a strategy. Rattlesnake Flat is a good example. It is a good alternative even though we didn't have a need expressly then.

James Gall: We will issue an RFP in the spring, if more resources come in that would lower rates; we will get the extra resources.

John Barber: With liquid air, is it taking it down to the Nitrogen or just the Oxygen? We w*ill need to ask Thomas Dempsey about this. [The liquid air doesn't separate out the gases, it uses ordinary air without separating the different gases].*

Clint Kalich: Can we retrofit the back end of our gas turbines? *We were going down that path, but last I heard it may not work. So, maybe.*

Barry Kathrens: If there is a positive balance, there is more available for [hydro] storage. *We only have two facilities with storage that are already being used. It is already serving the purpose you are describing.*

Jason Thackston: Some hydro can store over seasons, like in Juneau [Alaska]. Building more generation would force more water over spillways because there will still be the same amount of water over time.

Matt Nykiel (Slide 17): Back in 2026, Action Plans features for Idaho customers, the use of Colstrip for customers is undetermined. I'm grappling with it still being used. *You are talking about problems I think about every day. We are always going to run our system as a whole, but there is a cost allocation issue.*

Matt Nykiel: Easy answer from my point of view. *There is a balance that has to be maintained.*

Jason Thackston: You may think it is easy, but it is probably more complicated than you think.

Barry Kathrens: How does a state line affect climate policy? *It determines state energy policy.*

Dave Van Hersett (Slide 18): Emissions are less because you are getting rid of gas burning in my Corvette.

Matt Nykiel: Do other utilities model this [reduced car emissions] even though others made this choice? *CETA is working on this for incentives [on electrification of transportation].*

Clint Kalich: There is precedence in energy conservation. Absent that incentive, the conservation measure may not be installed.

Jason Thackston: Avista has already incented infrastructure for this to enable adoption. Someone chooses to fly and purchase offsets. Utilities are showing this.

John Lyons: This is the free rider problem. Did you purchase a particular energy efficient refrigerator for energy savings, the $50 rebate, or because it looks really good in your kitchen.

Garrett Brown (Slide 19): Is this just residential? *It is an average rate for all classes according.*

Matt Nykiel: Does it include the social cost of carbon? *It is included in the decision, but not in the rate. It is averaged all together.*

Darrell Soyars: Transmission and distribution – yes, assumes 2 percent growth.

Dave Van Hersett: About one third generation plus distribution plus one-third transmission on my bill. *There are four components with the common costs.*

Mike Starrett: When going through rates, it sounds like a composite rate. Can you characterize it for a single residential customer? *No, the best way is to look at it going bar to bar [on the graph]. We probably need to get more descriptive on that.* Is the cost consistent? *This slide is not getting into the scope of how to assign costs to different customer classes.*

Prewritten comments from Dave Van Hersett for his last TAC meeting:

November 19, 2019

Dave's Reflections on the IRP process 1989 to 2019:

I am 80 now and it is time for me to retire and spend more time chasing grandkids and my wife.

Quote from Mark Twain: "Twenty years from now you will more disappointed by the things you didn't do than by the ones you did do. So, throw off the bow lines. Sail away from the safe harbor. Catch the trade winds with your sails. Explore. Discover".

1. **Dave's: background**
    a. Fifth Generation Spokane Native
    b. North Central High School 1957, WSU 1962 Mechanical Engineering, MBA
    c. Veteran, USAF selected Outstanding Procurement Officer USAF 1966
    d. Avista residential customer since 1967.

e. Power Plant Developer: Coal, Gas Turbines and Renewable Biomass Fuels (wood, straw & garbage)
f. Commercial and Industrial Conservation Program Business Development
g. Professional Engineer Retired
h. Technical Advisory Committee Member for Avista's Biannual Integrated Resource Plan since 1989.

2. Utility is a Three leg stool: customers, capital & utility.

All three are dependent upon each other to be successful. Customers provide a steady market, investors require a secure and steady return to make an investment and a staff is the resource to make it happen.

3. Population dictates constant growth at 2% per year

For decades the population growth for the Inland Empire has been about 2% per year. This constant for long term planning and almost eliminates the risk of losing market or the customer load for the utility. Thus we have a risk free environment for both the utility and the investor.

4. Population: 1957, 2019, 2045 : World, USA, WA State, Spokane

POPULATION GROWTH (million)				
Year		1957	2019	2050
Spokane County		0.25	0.52	0.61
WA State		2.7	7.4	10
USA		172	329	438
World		2900	7400	9800
USA % of World		6%	4%	4%

5. World pollution contribution & competitive in USA and world

Points to consider:

a. The population growth is the driving factor for all future generation planning and the operations of the utility to provide services to its customers. A very low risk profile.
b. Note that the USA is a minority player in the world pollution production. Even if we reduced our pollution to zero the remaining world countries

would still be producing the majority of pollution. We only have a minor impact. Countries like China, India and Pakistan each with over a billion population have the major impact on the pollution to the world environment. The only result of our zero pollution is to eliminate our competitive advantage in the world market as a result of our higher production costs that incorporate significant environmental controls.

c. Nobody is addressing the uncontrolled population explosion on our planet. The population growth is the root of all demand for resources and generation of pollution.

6. **Utility has Lost objective to serve customers,**

I have observed that the utilities have lost their way on their path to serving their customers. The customers are the utilities life line and reason for existence. In the last 20 years there have been 13 towns in their service area that have lost their main source of existence, their forest service industries, or sawmills. The utilities have focused on meeting the concerns of the one percenters, like the Serria Club, instead of serving and meeting the needs of their customers.

Spokane, Post Falls, Coeur d'Alene, Newport, Sandpoint, Usk, Ione, Kettle Falls, Northport, Naples, Bonners Ferry, Samuels, Kellogg to name a few.

7. **Accommodate and kowtowing to the *one percenters* : Environmental groups and greenies.**

I have witnessed the domination of the Sierra Club at our IRP meetings. These representatives are not actual customers of Avista and only bring their message to go green with no liability on their part for the higher costs we customers will have to pay and the devastation to our natural resources. Note that less than 1% of the Avista customers actually participate in the environmental programs offered by Avista. Examples such as the higher cost Solar and Wind rates for power. Another example is when the Montana Greenies made a two hour presentation at the IRP meeting to lobby Avista to withdraw from Colstrip and utilize higher cost wind and solar. None of these presenters were actual customers of Avista and they came to Avista because they could not convince their Montana Legislature to terminate Colstrip. I call these Green parties ***the 1 percenters (1%)*** and that I have represent 99% of the Avista customers. These 1% have been accommodated by the Avista IRP staff to a much higher degree than they actually represent in the Avista customer base.

8. **East WA different from Western WA**

Eastern Washington population is more conservative than Western WA population. This is confirmed by the differences of the political representatives. Democrats in Western WA and Republican majority in Eastern WA. Eastern WA has a lower population density and the industry base is mining, forest products and farming. We harvest our natural resources with hard work and longtime husbanding of these natural resources.

9. **UTC to protect customers from utility**

In the three legs of the utility business the UTC protects the customers from abuses by the utilities. The UTC was brought about because of abuses by utilities over the years.

10. **UTC to differentiate between East and West WA on implementation of regulations.**

It is my contention that the UTC should take into account the differences between the East and Western Washington populations in their implementation of the regulations. We do not need nor do we want to include higher cost Green generation. We want lower cost and more reliable fossil fuel generation.

11. **Loss of forest products industry & towns since 1980's**

Since the 80's there has been a major loss of industry in the forest products area towns. 13 of these towns in Avista's service area have lost their sawmills, and the thousands of jobs they provided for the past 100 or more years. The utility catered to the environmental movement, (ie. 1%ers) and did not aggressively fight for their continued existence of the forest products industry and their longtime customer base.

12. **Installing High cost wind and solar, no benefits to customers, revenues go outside of customers.**

The utility is bending and accommodating the installation of higher cost wind and solar generation who's investment is bringing no real value to the Avista customer base. The costs to support these green generation resources sends our utility payments to investors outside of our service area. These green resources require subsidies to make them somewhat closer to the costs of traditional resources. The cost of green generation resources increases the overall cost of power to the customers.

13. Oppo**rtunity to revise forest products industry and improve forest production/reduce fire**

The May 2019 passage of the CETA act creates a market opportunity for the inland empire forests and barren lands. If one assumes that the Green Movement and population growth will continue into the future, we have the barren lands without population and forests that grow independent of politics that create a business opportunity for our area. We can develop Green generation resources for sale to other utilities utilizing our local natural resources and labor.

14. **Dark side of Green: cost and eliminates competitive position of PNW and customers.**

The Dark side of Green is the much higher cost and less reliable generation resources to replace the long time reliable fossil fuel generation resources. An analysis was prepared by several PNW utilities that concluded that the cost to implement the Green Resources by 2045 would result in increasing our power cost by three times. This cost information has not been included in the efforts of the 1%ers. Increasing our power costs by three times will eliminate our competitiveness of our industries here in the PNW and the world. This will then result in the further loss of jobs for our population and a weakening of Avista's customer base.

15. Cogeneration: small to large: approx. 100 mw.

The Avista load is approximately 1500 MW. The potential for cogeneration is in the order of 100 MW. This is minor part of the generation resources but is a major enhancement for the customer. The utility has bypassed the opportunity to create a customer based generation resource in favor of higher cost wind and solar. Implementing a customer based generation resources will build a stronger customer base by proving another revenue source for the customers investing and operating businesses in Avista's service area. It is to the advantage of all of the Avista customers to have a financially sound customer base. Instead the utility has focused on easier generation resources such as combustion turbines green power to provide for new load growth. The potential for customer based cogeneration is small percentage of total load and would require aggressive and cunning promotion by Avista. This is a proven skill of the Avista staff.

16. Use Renewable biomass generation to firm up wind and solar

We are fortunate to have established forests that can provide a renewable fuel supply for biomass generation for generations to come. These biomass plants are ideal for firming up wind and solar generation when the latter are not operational. We owe this to our customers.

17. Garbage is 50% biomass and renewable: 1 ton per person per year

Garbage has the same heating value as a fuel as forest residues. People generate 1 ton of garbage per year and it is renewable. 50% of the garbage is paper products. This is the same fuel as renewable forest residues. Garbage as a fuel supply will generate about 5% of the annual energy needs of the population. In turn using it as a fuel will eliminate long term creation of unusable lands created by the land fills that garbage is hauled to. We will need these lands for coming populations.

18. Never understood the Utility customer conservation programs.

One of my pet peeves is the utility conservation programs presented to the IRP meetings. I have been confused and could not understand the terminology used by the presenters to justify their projected conservation savings. There seemed to be a double standard for customer sponsored conservation projects as compared to inhouse improvements. Remember that the conservation funds come from the customer for the customer, not for the exclusive benefit of the utility. Example of double standard, Avista smart meters vs customer information system improvements to reduce energy consumption.

19. **IRP staff very skilled and very good. Just need their efforts directed to customer enhancement.**

The Avista Staff involved with the production of the IRP are very skilled and we are grateful that they are working on this product. They have to generate a viable 20 year plan taking into account all of the technical and political variables. This is not an easy task and they should be acknowledged and complemented for their fine work.

20. **Utility legacy for 2020's: dedicated to bring back forest products industry utilizing renewable forests, not leaving the forests for a fuel for forest fires.**

You have the opportunity to generate and leave a customer oriented legacy of utilizing our region renewable and natural resources to provide for future energy needs. You also have the opportunity to bring back the forest products industry to all of the towns in our region. The objectives of the ***one percenters*** is not in our best interests as their goals promote forest fires, degradation of our renewable forests and loss of jobs for our customers.

21. **Develop Limited potential of customer based generation and utilization of regions renewable biomass resources. Provides stronger customer base for all and benefits the utility and the capital providers.**

We should be continually working to enhance the viability of our customer base, the foundation and reason for the existence of the utility. Not kowtowing to the goals and demands of the 1%. The customer base has demonstrated and stated their desires by less than 1% participating in the conservation programs to utilize wind and solar options. Thus 99% want reliable low cost and reliable electric and gas service.

22. **What is your legacy going to be? Selling company for bonus or enhancing your customer base   by bringing back forest products industry? Providing employment for our children of the future or under utilizing our natural resources?**

My vision for your legacy would be to take advantage of the recent CETA legislation passed by the 1% to bring back our region forest natural resources, bringing back the jobs and economies of the past, restoring industry in the towns that have lost jobs, reduce the potential of destructive forest fires, improve the production of the forests. We know that we will have the need for more jobs every year and you have the resources and skills to make this happen. The customers need reliable and low cost energy services. The utility needs a stable and viable customer base. The capitalists need a reliable low risk market to attract their investments.

In closing it has been my privilege to participate in the IRP Process. I appreciate and thank you all for your efforts to integrate the demands and objectives of the

many interests wanting a piece of the requirement to provide long term reliable energy resources for your customers. Keep in mind that customers want low cost reliable energy supplies, the 1% have social goals in mind. Dave☺

Background for Presentation

- Population Growth Establishes Demand for Energy
    - *Slide #1of Population Growth of Spokane, WA state and World*
- Spokane current electric load is 300 Megawatts
- Inland Northwest Resources
    - Mining available Mineral Resources
    - Forests that grow renewable lumber products and biomass fuels annually
    - Garbage
- Utilities Regulated by Washington Utilities and Transportation Commission (WUTC)
    - Requires utilities to provide low cost, reliable electric power to customers
    - Monitors compliance with State and Federal regulations.
    - Requires a Biannual Integrated Resource Plan providing power for next 20 years.
- Clean Energy Transformation Act (CETA) May 7, 2019
    - Commits Washington to an electricity supply free of greenhouses gas emissions by 2045
    - Eliminate Coal and Carbon fuels.
    - Require Renewable Energy Resources such as Wind, Solar and Biomass (Wood)
    - **When fully implemented electric rates will triple**
- Less than 1% of Avista customers purchase higher cost Wind and Solar Electric rate option.
- Description of Wind Power Plant (Palouse Wind Project: 30 MW)
    - *Slide #2 comparing Wind Power Plant to Sea First Building.*
    - *Slide #3 with 556 Wind Power Plants located in Spokane*
    - Spokane Wind Power investment $450,000,000
- Description of Solar Power Plant (Lind Washington Solar Project: 28 MW, 170 acres)
    - *Slide #4 of 28 Megawatt Wind Solar Project located on 201 acres farm lands*
    - *Slide #5 of 860,000 solar panels on 2100 Acres in Spokane*
    - Spokane Solar Power investment $300,000,000
- Description of Avista's 53 MW Biomass Wood Fueled Project at Kettle Falls
    - *Slide #6 Avista's Project Brochure*
    - 250 Megawatt Biomass Project Investment: $625,000,000

Utilizing Inland Empire Biomass Forest residues for Electric Power Generation

- o Provide power when wind does not blow and sun does not shine
- o Harvest natures renewable biomass resource rather than letting it rot on ground
- o Reduce fuel for major forest fires
- o Bring back vibrant forest products industry, its jobs and towns to Inland Empire

Biomass Power potential from Inland Empire Forests – 670 Megawatts of Dispatchable Power

- o Hogg fuel steam generation (50 MW) Kettle Falls Power Plant
    - ▪ Slide #7 Hogged or ground up unused parts of sawmill production
    - ▪ Slide #8 Ground up logging residues
    - ▪ Historically burned in wigwam burners at sawmills
- o Logging residues (200 MW)
- o Thinning stagnant lodgepole stands (200 MW)
    - ▪ Timber growth from past forest fires, undesirable timber
- o Cogeneration at sawmills (90 to 150 MW)
- o Wheat Straw (add 10%)
- o Municipal Refuse (50 MW)
    - ▪ 1 ton garbage per person per year
    - ▪ 10,000 tons per year per megawatt
    - ▪ 500,000 population of Spokane area

Unique Economic Development Opportunity

- o We have large forest areas, dry land farming acreages, low population
- o A population that would favor development of its renewable and dispatchable resources.
- o Wind and solar additions to utility systems require a dispatchable resource to make wind and solar a reliable dispatchable resource.
- o Recent rash of forest fires makes a strong case to change the forest management practices of today to minimize the probability of and size of forest fires.
- o Power generated from a biomass fuel source qualifies as a Renewable Energy Credit (REC). This is a product that other utilities purchase to offset generation from non- renewable resources.

Implementation Plan

- o Put together a collation of Inland Empire elected officials, US Forest Service in Colville, area sawmills and Avista to sponsor a program to:
    - ▪ Produce a reliable Renewable Biomass Fuel Supply
    - ▪ Reduce likelihood of forest fires
    - ▪ Improve yield from our region forests
    - ▪ Bring back the forest products industry to the inland empire

- Seek Representative Cathy McMorris Rogers to assist in sponsoring legislation to make this happen. She is from Kettle Falls and knows the forest products industry.

Portfolio Scenario Results, James Gall

Matt Nykiel (Slide 5): Is Colstrip operating in portfolios 10 and 11? *Yes, those portfolios assume that CETA doesn't exist.*

Rachelle Farnsworth: Question on reliability for these portfolios. *I haven't validated them. They are likely close to being reliable, but cannot guarantee it. Numbers 4 and 5 are concerning, but the PRS is reliable. It was not as certain in the last TAC meeting, but the PRS is reliable now.*

Matt Nykiel: Do I understand right that numbers 2 through 15 have not been tested for reliability? *We are more comfortable with the plans that include all of the existing turbines. Taking reliable units away from a portfolio makes it more unreliable.*

Matt Nykiel: Is it a double counting issue?

Clint Kalich (Slide 6): Surplus capacity is benefitting renewables now. It will be different if we retire resources. As we add more renewables, diversity is a benefit. But, more renewables need more backstop.

Slide 14: At least some of them with the social cost of carbon. All except for the ones without CETA. Number 15 shows with the social cost of carbon – risk plus cost.

Dave Van Hersett (Slide 19): Are those are the retail rates that include transmission and distribution? *Correct.*

Garrett Brown (Slide 20): On top, what hydro is that? *BPA, Mid-C utilities bidding in.*

Slide 21: Shows what is the cost of Idaho keeping the RECs for themselves.

Clint Kalich (Slide 21): Are rates backwards? *No, losing the opportunity to sell RECs to Washington or to someone else.*

Dave Van Hersett: Haven't sold them [Idaho share of RECs] yet? *Right, this is the cost of keeping the RECs for Idaho.*

Garrett Brown: What happens to the RECs today? *Washington buys Idaho's share of qualifying hydro RECs from Idaho for I-937. Palouse RECs are sold in the market or to Washington customers for I-937. Rattlesnake Flat RECs will likely be sold in the early years.*

Matt Nykiel (Slide 19): For portfolios #15, 7 and 8; I assume the party's shares in costs for Colstrip remain the same. *Yes, we only pay for our share*. *If, in the highly unlikely situation where an owner didn't pay their share, the plant dispatch would be lowered by* *their ownership amount. Number 15 shows the scenario where all of the shared costs are paid for by one unit.*

Rachelle Farnsworth (Slide 19): Why is number 2 high risk? *There is no renewable acquisition in that scenario, so there is more variability. So #2 has a fixed price, but also includes fuel variability.*

Matt Nykiel: What are the Idaho risks with portfolio #3 – Avista's goal? *They are the economic cost of the clean energy goal.* So, Avista's goal should be 100% clean for Washington only.

Dave Van Hersett (Slide 25): When you say social cost of carbon, is that a tax? *This assumes it is a tax, but we don't know where it [the money] goes. It is an extra cost of generation that is borne by customers.*

David Howarth (Slide 27): Is this system wide or just in Washington? *This is just Avista emissions, but the wider market prices effect Avista's dispatch of resources.*

Barry Kathrens (Slide 33): What is the service territory population?

Grant Forsyth: About one million electric only with 1.9 cars per household.

Dave Van Hersett (Slide 34): Is that emissions net of generation? *Just the petroleum emissions avoided from more electric cars, we will talk about the rest of the emissions later.*

Grant Forsyth (Slide 37): The households we serve have about 70% natural gas penetration. *Assumes new homes are going all electric or switching from gas to electric when appliances fail.*

Mike Starrett (Slide 38): Assuming that is all powered by electric resistance heat? *Yes, we will get to that in the next slides.*

Dave Van Hersett (Slide 44): Is the arithmetic on the right side correct? [Slide fixed before posting].

Clint Kalich: It looks like the bigger bang for the buck is petroleum. Did you do a one off calculation on this? *No, but will if you direct me to since you're the boss.* No, you're still self-directed.

Mike Starrett: I don't disagree with the analysis; it is fundamentally balanced, wondering about new homes including air conditioning connection between the supply side and gas/electric? *A lot of our distribution feeders are peaking in the summer because of heat plus load. Then adding an EV [electric vehicle] is less of an issue in the winter. Air conditioning is about 7 kW and an electric furnace is about 11-12 kW.*

Dave Van Hersett: Will there be an all source RFP for capacity? *Yes, capacity and associated energy.*

Mike Starrett: Expand on previous opportunity for seasonal or term? *Winter focused need, but we do not limit by season.*

2020 IRP Action Items and Overview, John Lyons

No additional notes for this topic.

2020 Electric Integrated Resource Plan

Appendix B – 2020 Electric IRP Work Plan

Updated Work Plan for Avista's

2020 Electric Integrated Resource Plan

February 27, 2019

2020 Electric Integrated Resource Planning (IRP) Work Plan

The Company's updated work plan is submitted in compliance with Order 01 in Docket No. UE-180738 dated February 15, 2019. Due to the numerous legislative proposals in the States of Washington, Montana, and Oregon that will have major impacts on the regional electric market, Avista petitioned the Washington Utilities and Transportation Commission for a temporary exemption from WAC 480-100-238(4) to change the filing date of its next IRP from August 31, 2019, to February 28, 2020 with an updated work plan to be filed February 28, 2019.

This updated work plan outlines the process Avista will follow to develop its 2020 Electric IRP to be filed with the Washington and Idaho Commissions by February 28, 2020. Avista uses a public process to solicit technical expertise and feedback throughout the development of the IRP through a series of Technical Advisory Committee (TAC) meetings. Avista held the first TAC meeting for this IRP on July 25, 2018.

The 2020 IRP process will be similar to those used to produce the previous IRPs. Avista will use Aurora for electric market price forecasting, resource valuation and for conducting Monte-Carlo style risk analyses of the electric market place. Aurora modeling results will be used to select the Preferred Resource Strategy (PRS) and alternative scenario portfolios 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 involve separate analyses. Avista will utilize its proprietary Avista Decision Support System or ADSS model to conduct analyses to evaluate reserve products such as ancillary services and intermittent generation. Avista contracted with Applied Energy Group (AEG) to conduct conservation and demand response potential studies. Exhibit 1 shows the updated 2020 IRP 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 2020 IRP. The assumptions combine Avista's research of similar generating technologies, engineering studies, and the Northwest Power and Conservation Council's studies. Avista will rely on third party and consulting studies for storage resources. Avista will model renewable resources as power purchase agreements rather than utility-owned assets where it is more economic. This IRP will study renewable portfolio standards, environmental costs, sustained peaking requirements and resource adequacy, energy efficiency programs, energy storage and demand response. The IRP will develop a strategy that meets or exceeds renewable portfolio standards, greenhouse gas emissions regulations, or other regulations passed by our governing states.

Avista intends to create a PRS based on market and policy assumptions in the expected case based on the results of pending state energy legislation. The expected case is based on known or likely drivers affecting the company and energy industry. The IRP will include scenarios to address alternative futures in the electric market and public policy. TAC meetings help determine the underlying assumptions used in the expected case, market scenarios and portfolio studies. The IRP process is very technical and data intensive; public comments are welcome and we encourage timely input and participation for inclusion into the process so the plan can be submitted according to the 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 timeline and proposed agenda items for TAC meetings follows:

- **TAC 1: Completed on Thursday, July 25, 2018:**
  - TAC meeting expectations and IRP process overview,
  - Review of 2017 IRP acknowledgement & policy statements,
  - 2017 IRP action plan update,
  - Hydro One merger agreement's impact on the 2019 IRP,
  - Demand and economic forecast, and
  - Review the 2019 IRP draft Work Plan.

- **TAC 2: Completed on Tuesday, November 27, 2018**:
  - Modeling process overview, including Aurora and PRiSM,
  - Generation options (cost & assumptions),
  - Resource adequacy and effective load carrying capability (ELCC) analysis,
  - Overview of home heating technologies and efficiency,
  - Expected case key assumptions (regional loads, CO_2 regulation, etc.), and
  - Discuss market and portfolio scenarios.

- **TAC 3: Tuesday, April 16, 2019:**
  - Regional legislative update,
  - IRP Transmission planning studies,
  - Distribution planning within the IRP,
  - Pullman Smart Grid Demonstration Project review,
  - Pacific Northwest Pathways to 2050 Study,
  - Conservation Potential Assessment (AEG), and
  - Demand Response Potential Assessment (AEG).

- **TAC 4: Tuesday, August 6, 2019:**
  - Natural gas price forecast,
  - Electric market forecast,
  - Energy and peak load forecast,
  - Existing resource overview – Colstrip, Lancaster and other resources, and
  - Final resource needs assessment.

- **TAC 5: Tuesday, October 15, 2019:**
  - Ancillary services and intermittent generation analysis,
  - Energy Imbalance Market analysis,
  - Review Preliminary PRS,
  - Market scenario results,
  - Preliminary Portfolio scenario results,

- **TAC 6: Tuesday, November 19, 2019:**
  - Review of final PRS,
  - Market scenario results (continued),
  - Final Portfolio scenario results,
  - Carbon cost abatement supply curves, and
  - 2020 IRP Action Items.

- **Draft IRP released to TAC members December 1, 2019**. Comments from TAC members are to be returned to Avista by January 15, 2020. Avista's IRP team will be available for conference calls to address comments with individual TAC members or with the entire group if needed.

2020 Electric IRP Draft Outline

This section provides a draft outline of the major sections in the 2020 Electric IRP. This outline may change based on IRP study results and input from the TAC.

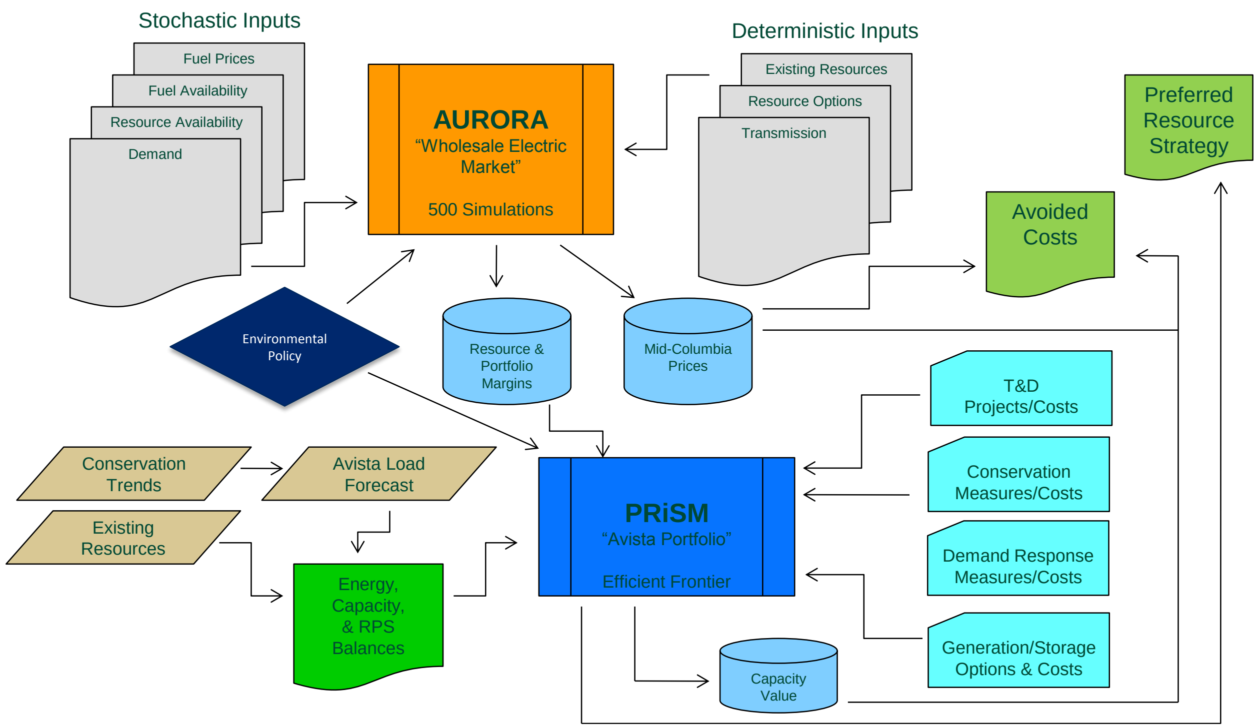
1. **Executive Summary**
2. **Introduction and Stakeholder Involvement**
3. **Economic and Load Forecast**
   a. Economic Conditions
   b. Avista Energy & Peak Load Forecasts
   c. Load Forecast Scenarios
4. **Existing Supply Resources**
   a. Avista Resources
   b. Contractual Resources and Obligations
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. **Transmission Planning**
   a. Overview of Avista's Transmission System
   b. Future Upgrades and Interconnections (includes project evaluated with DER alternative)
   c. Transmission Construction Costs and Integration
   d. Merchant Transmission Plan
8. **Distribution Planning**
   a. Overview of Avista's Distribution System
   b. Future Upgrades and Interconnections (includes project evaluated with DER alternative)
9. **Generation and Storage Resource Options**
   a. New Resource Options
   b. Avista Plant Upgrades

10. **Market Analysis**
    a. Marketplace
    b. Federal and State Environmental Policies
    c. Fuel Price Forecasts
    d. Market Price Forecast
    e. Scenario Analysis
11. **Preferred Resource Strategy**
    a. Resource Selection Process
    b. Preferred Resource Strategy
    c. Efficient Frontier Analysis
12. **Portfolio Scenarios**
    a. Portfolio Scenarios
    b. Resource Avoided Cost
    c. Carbon Cost Abatement Supply Curves
13. **Action Plan**[1]
    a. 2017 Action Plan Summary
    b. 2020 Action Plan

[1] The Action Plan chapter will become Chapter 14 and a new chapter will be added in the event state legislation requires additional documentation regarding clean energy.

Exhibit 1: 2020 Electric IRP Timeline	
Task	**Target Date**
Identify Avista's supply resource options (update as needed by July 2019)	Completed
Finalize demand response options & costs	Completed
Finalize energy efficiency options	April 2019
Transmission & Distribution studies due	April 2019
Determine portfolio & market future studies	June 2019
Begin Aurora market modeling	June 2019
Due date for study requests from TAC members	**June 15, 2019**
Finalize natural gas price forecast	July 1, 2019
Finalize datasets/statistics variables for risk studies	July 2019
Update and finalize energy & peak forecast	July 2019
Finalize PRiSM model assumptions	August 2019
Simulation of risk studies "futures" complete	September 2019
Simulate market scenarios in Aurora	September 2019
Evaluate resource strategies against market futures and scenarios	October 2019
Present preliminary study and PRS to TAC	November 2019
Writing Tasks	
File Updated 2020 IRP Work Plan	February 28, 2019
Prepare report and appendix outline	June 2019
Prepare text drafts	October 2019
Prepare charts and tables	October 2019
Internal draft released at Avista	October and November 2019
External draft released to the TAC	December 1, 2019
Comments and edits from TAC due	**January 15, 2020**
Final editing and printing	February 2020
Final IRP submission to Commissions and TAC	February 28, 2020

Exhibit 2: 2020 Electric IRP Modeling Process



Page 7

2020 Electric Integrated Resource Plan

Appendix C – Confidential Historical Generation Operating Data

Idaho – Confidential pursuant to Sections 74-109, Idaho Code

Washington – Confidential per WAC 480-07-160

2020 Electric Integrated Resource Plan

Appendix D – AEG Conservation Potential Assessment

AVISTA CONSERVATION POTENTIAL ASSESSMENT FOR 2021-2040

February 21, 2020

Report prepared for:
AVISTA CORPORATION

Energy Solutions. Delivered.

This work was performed by

Applied Energy Group, Inc. (AEG)
500 Ygnacio Valley Rd, Suite 250
Walnut Creek, CA 94596

Project Director: K. Kolnowski

Project Manager: K. Walter

Project Team: K. Marrin
B. Bushong
T. Williams

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

Avista Corporation (Avista) engaged Applied Energy Group (AEG) 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 2019 Integrated Resource Plan (IRP). AEG first performed an electricity CPA for Avista in 2013. We have also performed gas CPA studies in 2014 and 2016 and an assessment of demand-response potential in 2014. This study updates Avista's last electric CPA, which AEG performed in 2017.

Since 2017, additional information became available and there was also a desire for more granularity, corresponding to increasing sophistication in CPA studies. Therefore, this study provided enhanced analysis compared to the previous studies.

- The base-year for the analysis was brought forward from 2017 to 2017.
- 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 Northwest Energy Efficiency Alliance's (NEEA's) 2014 Residential Building Stock Assessment (RBSA) supplemented the GenPOP survey.
- For the commercial sector, analysis was performed for the major building types in the service territory. Results from the 2017 Commercial Building Stock Assessment (CBSA), including hospital and university data, 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 continue to drop in price and provide a significant opportunity for savings even under new market transformation assumptions by the RTF.
- Some measure data from the Seventh Power Plan (Seventh Plan) has been updated to reflect progress in the last two years.
- The study incorporates updated forecasting assumptions that line up with the most recent Avista load forecast.
- Analysis of economic potential was excluded from this study. Avista will screen for cost-effective opportunities directly within the IRP model. As such, economic potential and achievable potential have been replaced by a Technical Achievable Potential case.
- In addition to analyzing annual energy savings, the study also estimated the opportunity for reduction of summer and winter peak demand. This involved a full characterization by sector, segment and end use of peak demand in the base year.
- Finally, this year's study included an update to the 2017 assessment of demand-response potential, including analysis of residential programs as well as commercial and industrial (C&I), and options for both summer and winter demand reduction.

Since economic achievable potential is not included in this CPA, it is not possible to compare achievable potential results with CPAs prior to 2017. When making comparisons to the previous study we will focus on Technical Achievable Potential. Compared to the 2017 Study, 10-year technical achievable potential has increased to 110.1 aMW from 105.8 aMW. This is a net effect of changes in the measure list, market transformation, and baseline growth.

Abbreviations and Acronyms

Table 1-1 provides a list of abbreviations and acronyms used in this report, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
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
CFL	Compact fluorescent lamp
CPP	Critical Peak Pricing
C&I	Commercial and Industrial
DHW	Domestic Hot Water
DLC	Direct Load Control
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Estimated Useful Life
EUI	Energy Usage Intensity
FERC	Federal Energy Regulatory Commission
HH	Household
HID	High intensity discharge lamps
HVAC	Heating Ventilation and Air Conditioning
ICAP	Installed Capacity
IOU	Investor Owned Utility
LED	Light emitting diode lamp

Acronym	Explanation
LoadMAP	AEG's Load Management Analysis and Planning™ tool
LCOE	Levelized cost of energy
MW	Megawatt
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
RTU	Roof top unit
TRC	Total Resource Cost test
UEC	Unit Energy Consumption

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, 2017.
2. Develop a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2017 through 2039.
3. Define and characterize several hundred conservation measures to be applied to all sectors, segments, and end uses.
4. Estimate technical and Technical Achievable Potential at the measure level in terms of energy and peak demand impacts from conservation measures for 2021-2040.

LoadMAP Model

AEG used its Load Management Analysis and Planning tool (LoadMAP™) version 5.0 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 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.

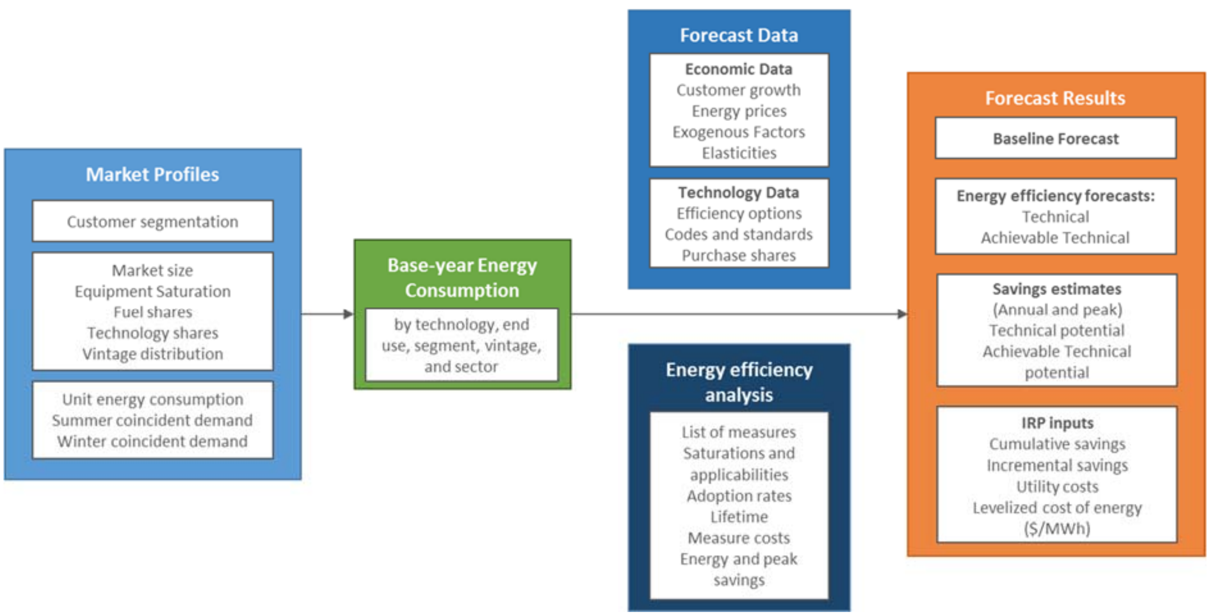
- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced 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).
- Can incorporate 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 two levels of potential: technical potential and Technical 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 efficient option available. In new construction, customers and developers also choose the most efficient equipment option.

  In new construction, customers and developers also choose the efficient equipment option relative to applicable codes and standards. Non-equipment measures which may be realistically installed apart from equipment replacements are implemented according to ramp rates developed by the NWPCC for its Seventh Power Plan, applied to 100% of the applicable market. This case is a theoretical construct and is provided primarily for planning and informational purposes.

- Technical Achievable Potential refines Technical Potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of DSM measures. We used achievability assumptions from the Council's Seventh Plan, adjusted for Avista's recent program accomplishments, as the customer adoption rates for this study. For the technical achievable case, ramp rates are applied to at most 85% of the applicable market, per Council methodology. This achievability factor represents potential which can reasonably be acquired by all mechanisms available, regardless of how conservation is achieved. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs.[2]

  Details regarding the market adoption factors appear in Appendix B.

Market Characterization

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, 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.

[2] Council's 7th Power Plan applicability assumptions reference an "Achievable Savings" report published August 1, 2007. http://www.nwcouncil.org/reports/2007/2007-13/

Table 2-1 Overview of Avista Analysis Segmentation Scheme

Dimension	Segmentation Variable	Description
1	Sector	Residential, commercial, industrial
2	Segment	**Residential**: single family, multifamily, 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 2017 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 index) describes the amount of energy consumed in 2017 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 2017. 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 2017.
- 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 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 2018 through 2040 by customer segment and end use without new utility programs. The end-use projection includes the impacts of relatively certain codes and standards which will unfold over the study timeframe. All such mandates that were defined as of September 2018 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.

Washington HB 1444

As this CPA neared its conclusion, the state of Washington passed HB 1444[3], which establishes new efficiency rules for several appliance and equipment categories. While the CPA models were not rebuilt to incorporate these new standards, we did estimate the impacts of these new standards in terms of measure potential that would be moved into the baseline by this ruling. We present the details of this estimate in Appendix D.

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 the Seventh Plan's updated ramp rates to identify technical achievable measure potential.

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 calculating the levelized cost of energy ($/MWh). 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

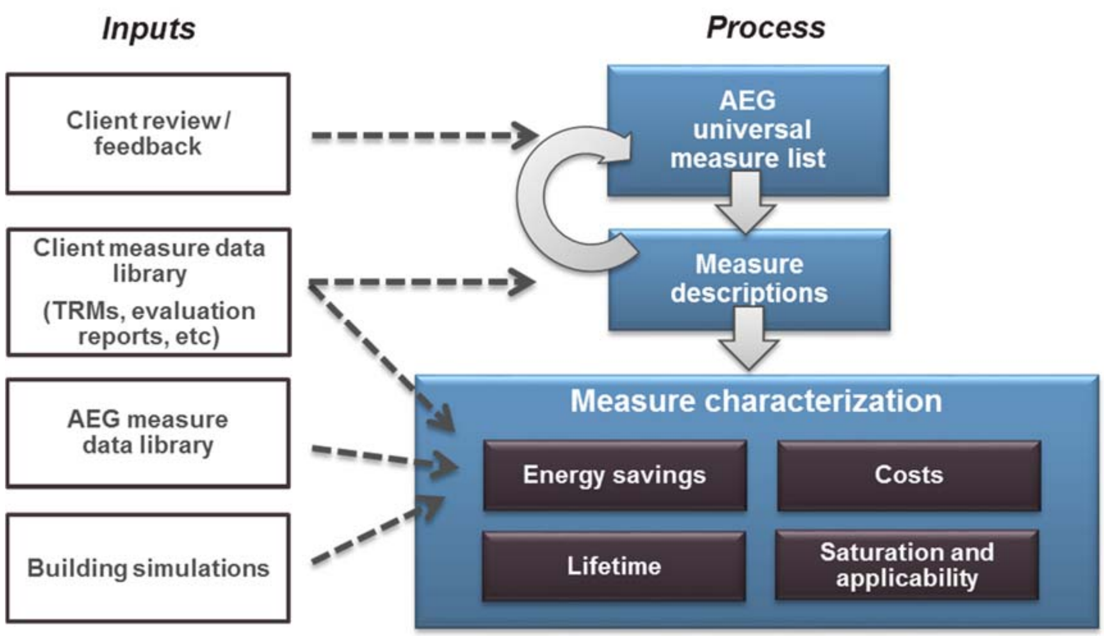
[3] https://app.leg.wa.gov/billsummary?BillNumber=1444&Year=2019&initiative=

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, the Regional Technical Forum (RTF), and the Seventh Plan deemed measures database, 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.

Since an economic screen was not performed in this Study, we have instead calculated the levelized cost of energy (LCOE) for each measure evaluated. This value, expressed in dollars per first-year megawatt hour (MWh) saved, can be used by Avista's IRP model to evaluate cost effectiveness. To calculate a measure's LCOE, first-year measure costs, annual non-energy benefits, and annual operations and maintenance (O&M) costs are levelized over a measure's lifetime, then divided by the first-year savings in MWh. Note that while non-energy benefits are typically included in the numerator of a traditional Total Resource Cost (TRC) economic screen, the LCOE benefits have not been monetized. Therefore, these benefits are instead subtracted from the costs portion of the test. These benefits are not included in the Utility Cost Test (UCT) used in Idaho.

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 21 unit. The Seventh Plan's "Lost Opportunity" ramp rates are primarily applied to equipment measures.

- **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. The Seventh Plan's "Retrofit" ramp rates are primarily applied to no-equipment measures. Non-equipment measures typically fall into one of the following categories:
    1. Building shell (windows, insulation, roofing material)
    2. Equipment controls (thermostat, compressor staging and controls)
    3. Equipment maintenance (cleaning filters, changing setpoints)
    4. Whole-building design (building orientation, advanced new construction designs)
    5. Lighting retrofits (assumed to be implemented alongside new LEDs at the equipment's normal end of life)
    6. Displacement measures (ceiling fan to reduce use of central air conditioners)
    7. Commissioning and retrocommissioning (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 Seventh Power Plan, the RTF deemed measure workbooks, simulation modeling, and other well-vetted sources as required.

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 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. Note that in this example no standards come into play and therefore all options are available throughout the forecast.

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 13.0	10 to 20	$2,097	1,383	2017	n/a
SEER 14.0	10 to 20	$2,505	1,284	2017	n/a
SEER 15.0	10 to 20	$2,913	1,199	2017	n/a
SEER 16.0	10 to 20	$3,321	1,124	2017	n/a
SEER 18.0	10 to 20	$4,140	999	2017	n/a
SEER 20.0	10 to 20	$4,955	899	2017	n/a

Table 2-3 lists some of the non-equipment measures applicable to a CAC in an existing single family home. LCOE values for all measures are evaluated based on the lifetime costs of the measure divided by the first-year savings. The total costs and savings are calculated for each year of the study and depend on the base year saturation of the measure, the applicability[4] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-3 Example Non-Equipment Measures – Single Family Home, Existing

End Use	Measure	Saturation in 2017	Applicability	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Cooling	Insulation - Ceiling Installation	0.00%	4.11%	45	$1,230.69	30.17%
Cooling	Insulation - Wall Cavity Installation	0.00%	5.73%	45	$2,622.52	6.10%
Cooling	Ducting - Repair and Sealing	22.84%	40.00%	20	$656.94	6.29%
Cooling	Windows - High Efficiency/ENERGY STAR	67.43%	75.00%	45	$3,966.55	9.63%
Cooling	Thermostat - Connected	4.00%	60.00%	5	$259.00	6.00%

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	88	176	704
Commercial	130	260	2,860
Industrial	111	222	222
Total Measures Evaluated	**329**	**658**	**3,786**

[4] 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.

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).[5] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying conservation potential. As described in Chapter 2, two types of potential were developed as part of this effort: Technical Potential and Technical 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 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. 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 LCOE ratio, with the measure with the lowest LCOE values (most likely to be cost effective) 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.
- Technical Achievable Potential refines Technical Potential by applying market adoption rates for each measure that estimate the percentage of customers who would be likely to select each measure, given consumer preferences (partially a function of incentive levels), retail energy rates, imperfect information, and real market barriers and conditions. These barriers tend to vary, depending on the customer sector, local energy market conditions, and other, hard-to-quantify factors. In addition to utility-sponsored programs, alternative acquisition methods, such as improved codes and standards and market transformation, can be used to capture portions of these resources, and are included within the Technical Achievable Potential, per 7th Power Plan methodology.

The calculation of Technical Potential is a straightforward algorithm. To develop estimates for Technical 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 Seventh Plan conservation workbooks but modified these to match Avista program history and service territory specifics. We examined historic program results for the most recent program years. We then adjusted the 2021 Technical Achievable Potential for these measures to approximately match the historical results. This provided a starting for 2021 potential that was aligned to historic results. In future years, the potential factors increased to a maximum of 85%, 55% for emerging technologies, to model increasing market acceptance and program improvements. For measures within the Seventh Plan, the Council's prescribed ramp rates were used. For measures outside the Seventh Plan, AEG assigned ramp rates comparable to similar measures within the Seventh Plan. The market adoption rates for each measure appear in Appendix B.

Results of all the potentials analysis are presented in Chapter 5.

[5] 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 well-vetted national or other regional secondary sources.

Data Sources

The data sources are organized into the following categories:

- Avista data
- Northwest Energy Efficiency Alliance data
- Northwest Power and Conservation Council 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 a discount rate and line loss factor. Avoided costs were not provided due to the economic screen being moved to the IRP model.
- **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, Residential Building Stock Assessment II**, Single-Family Homes Report 2016-2017, https://neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf
- **Northwest Energy Efficiency Alliance, Residential Building Stock Assessment II**, Manufactured Homes Report 2016-2017, https://neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Manufactured-Homes-Report-2016-2017.pdf
- **Northwest Energy Efficiency Alliance, Residential Building Stock Assessment II**, Multifamily Buildings Report 2016-2017, https://neea.org/img/documents/Residential-Building-Stock-Assessment-II-Multifamily-Homes-Report-2016-2017.pdf
- **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

- Northwest Energy Efficiency Alliance, 2014 Industrial Facilities Site Assessment, December 29, 2014, http://neea.org/docs/default-source/reports/2014-industrial-facilities-stock-assessment-final-report.pdf?sfvrsn=6

Northwest Power and Conservation Council 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.

- Regional Technical Forum Deemed Measures. The NWPCC Regional Technical Forum maintains databases of deemed measure savings data, available at http://www.nwcouncil.org/energy/rtf/measures/Default.asp .
- Northwest Power and Conservation Council Seventh Plan Conservation Supply Curve Workbooks. To develop its Seventh Power Plan, the Council used workbooks with detailed information about measures, available at https://nwcouncil.app.box.com/v/7thplanconservationdatafiles
- Northwest Power and Conservation Council, MC and Loadshape File, September 29, 2016. The Council's load shape library was utilized to convert CPA results into hourly conservation impacts for use in Avista's IRP process. Generalized Least Square (GLS) versions of these load shapes are available at https://nwcouncil.app.box.com/s/gacr21z8i89hh8ppk11rdzgm6fz4xlz3

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 DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- AEG's EnergyShape™: AEG's load shape database was used in addition to the Council's load shape database for comparative purposes. 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 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 EE 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[6].

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 2017 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 (CEE), the Environmental Protection Agency (EPA), and the American Council for an Energy-Efficient Economy (ACEEE).

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

[6] 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

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 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, NEEA's IFSA, 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 2017-2018
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 2017-2018 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
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	NWPCC RTF and Seventh Plan and RTF HVAC uses: BEST simulations using prototypes developed for Idaho Engineering analysis DEEM Recent AEG studies
Appliance/equipment age distribution	Age distribution for each technology	RTF and NWPCC Seventh Plan 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 2017-2018 DEER RTF and NWPCC Seventh Plan data Previous studies
Peak factors	Share of technology energy use that occurs during the peak hour	EnergyShape database

Table 2-6 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 2017-2018 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 and ENERGY STAR AEO 2017-2018 regional forecast assumptions[7] Appliance/efficiency standards analysis Avista program results and evaluation reports
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models AEO 2017-2018

In addition, we implemented assumptions for known future equipment standards as of September 2018, 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.

[7] We developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2016), 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 2-7 Residential Electric Equipment Standards[8]

End Use	Technology	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13.0								
	Room AC	EER 10.8								
Cooling/ Heating	Air-Source Heat Pump	SEER 13.0 / HSPF 8.2							SEER 14.0 / HSPF 9.0	
Water Heating	Water Heater (<=55 gallons)	EF 0.95								
	Water Heater (>55 gallons)	EF 2.0 (Heat Pump Water Heater)								
Lighting	General Service	Advanced Incandescent (~20 lumens/watt)			Advanced Incandescent (~45 lumens/watt)					
	Linear Fluorescent	T8 (92.5 lm/W lamp)								
Appliances	Refrigerator	25% more efficient than the 1997 Final Rule (62 FR 23102)								
	Freezer									
	Clothes Washer	IMEF 1.84 / WF 4.7								
	Clothes Dryer	3.73 Combined EF								
Miscellaneous	Furnace Fans	Conventional	ECM							

[8] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-8 Commercial Electric Equipment Standards[9]

<table>
<tr><th>End Use</th><th>Technology</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td rowspan="3">Cooling</td><td>Chillers</td><td colspan="9">2007 ASHRAE 90.1</td></tr>
<tr><td>RTUs</td><td colspan="9">EER 11.9/11.2</td></tr>
<tr><td>PTAC</td><td colspan="4">EER 9.8</td><td colspan="5">EER 11.0</td></tr>
<tr><td rowspan="2">Cooling/ Heating</td><td>Heat Pump</td><td colspan="2">EER 11.0/
COP 3.3</td><td colspan="7">EER 11.4/
COP 3.3</td></tr>
<tr><td>PTHP</td><td colspan="9">EER 10.4/COP 3.1</td></tr>
<tr><td>Ventilation</td><td>All</td><td colspan="9">Constant Air Volume/Variable Air Volume</td></tr>
<tr><td rowspan="3">Lighting</td><td>General Service</td><td colspan="3">Advanced Incandescent
(~20 lumens/watt)</td><td colspan="6">Advanced Incandescent
(~45 lumens/watt)</td></tr>
<tr><td>Linear Lighting</td><td colspan="9">T8 (82.5 lm/W lamp)</td></tr>
<tr><td>High Bay</td><td>51.2 lm/W</td><td colspan="8">Metal Halide (55.6 lm/W)</td></tr>
<tr><td rowspan="5">Refrigeration</td><td>Walk-In</td><td colspan="2">COP 3.2</td><td colspan="7">COP 6.1</td></tr>
<tr><td>Reach-In</td><td colspan="9">32 kWh/sqft</td></tr>
<tr><td>Glass Door</td><td colspan="9">12-28% more efficient than EPACT 2005</td></tr>
<tr><td>Open Display</td><td colspan="3">1,537 kWh/ft</td><td colspan="6">1,453 kWh/ft</td></tr>
<tr><td>Icemaker</td><td colspan="9">6.1 kWh/100 lbs.</td></tr>
<tr><td>Food Service</td><td>Pre-Rinse</td><td colspan="2">1.6 GPM</td><td colspan="7">1.0 GPM</td></tr>
<tr><td>Motors</td><td>All</td><td colspan="9">Expanded EISA 2007</td></tr>
</table>

[9] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Table 2-9 Industrial Electric Equipment Standards[10]

End Use	Technology	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Chillers	2007 ASHRAE 90.1								
	RTUs	EER 11.9/11.2								
	PTAC	EER 9.8				EER 11.0				
Cooling/ Heating	Heat Pump	EER 11.0/ COP 3.3		EER 11.4/ COP 3.3						
	PTHP	EER 10.4/COP 3.1								
Ventilation	All	Constant Air Volume/Variable Air Volume								
Lighting	General Service	Advanced Incandescent (~20 lumens/watt)			Advanced Incandescent (~45 lumens/watt)					
	Linear Lighting	T8 (82.5 lm/W lamp)								
	High Bay	51.2 lm/W	Metal Halide (55.6 lm/W)							
Motors	All	Expanded EISA 2007								

[10] 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 2-10 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 NWPCC workbooks, RTF NWPCC Seventh Plan conservation workbooks BEST AEG DEEM AEO 2017-2018 DEER 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 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 NWPCC workbooks, RTF NWPCC Seventh Plan conservation workbooks AEG DEEM AEO 2017-2018 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 NWPCC workbooks, RTF NWPCC Seventh Plan conservation workbooksAEG DEEM AEO 2017-2018 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 NWPCC workbooks, RTF NWPCC Seventh Plan conservation workbooks 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 Technical Achievable Potential

To estimate Technical 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. Like the 2016 CPA, we applied the "Retrofit" ramp rates from the Seventh Power Plan directly as diffusion curves. For technical potential, these rates summed up to 100% by the 20th year for most measures. Emerging technologies summed to 65% by the 20th year.
- **Adoption rates**. Customer adoption rates or take rates are applied to technical potential to estimate Technical Achievable Potential. For equipment measures, the Council's "Lost Opportunity" ramp rates were applied to technical potential with a maximum achievability of 85% for most measures and 55% for emerging technologies. For non-equipment measures, the Council's "Retrofit" ramp rates have already been applied to calculate technical diffusion. In this case, we multiply each of these by 85% for most measures and 55% for emerging technologies to calculate Technical Achievable Potential. Adoption rates are presented in Appendix B.

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, 2017. 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 2017 was 7,954 GWh; 5,311 GWh (WA) and 2,643 GWh (ID). As shown in the tables below, in both states the residential sector accounts for 49% of the annual energy use, followed by commercial at 41% of the annual energy use. In terms of winter peak demand, the total system peak in 2017 was 1,649 MW: 1,117 (WA) and 532 MW (ID). In both states, the residential sector contributes the most to the winter peak.

Figure 3-1 Sector-Level Electricity Use in Base Year 2017, Washington

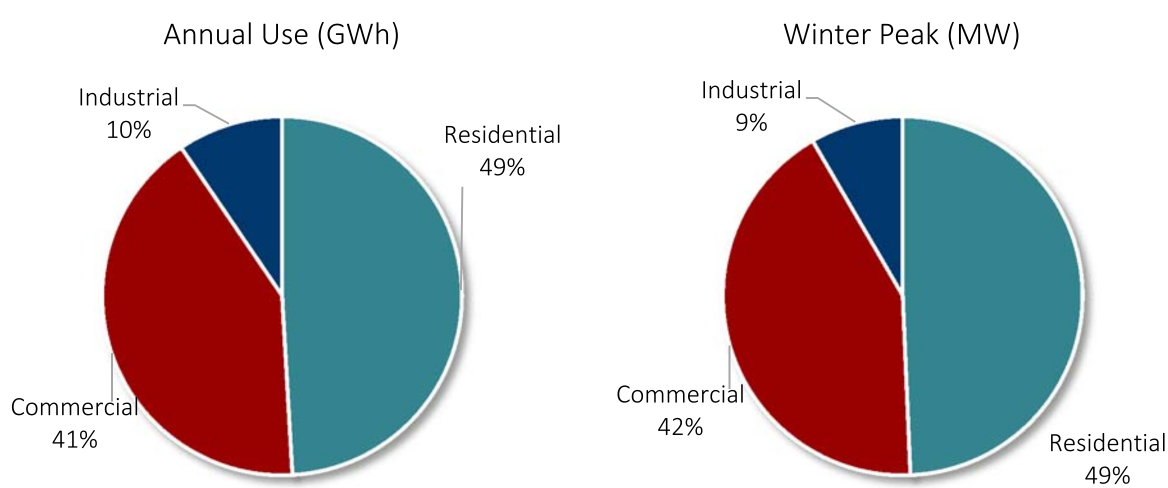


Table 3-1 Avista Sector Control Totals (2017), Washington

Sector	Annual Electricity Use (GWh)	% of Annual Use	Winter Peak Demand (MW)	% of Winter Peak
Residential	2,607	49%	551	49%
Commercial	2,200	41%	473	42%
Industrial	504	9%	93	8%
Total	**5,311**	**100%**	**1,117**	**100%**

Figure 3-2 Sector-Level Electricity Use in Base Year 2017, Idaho

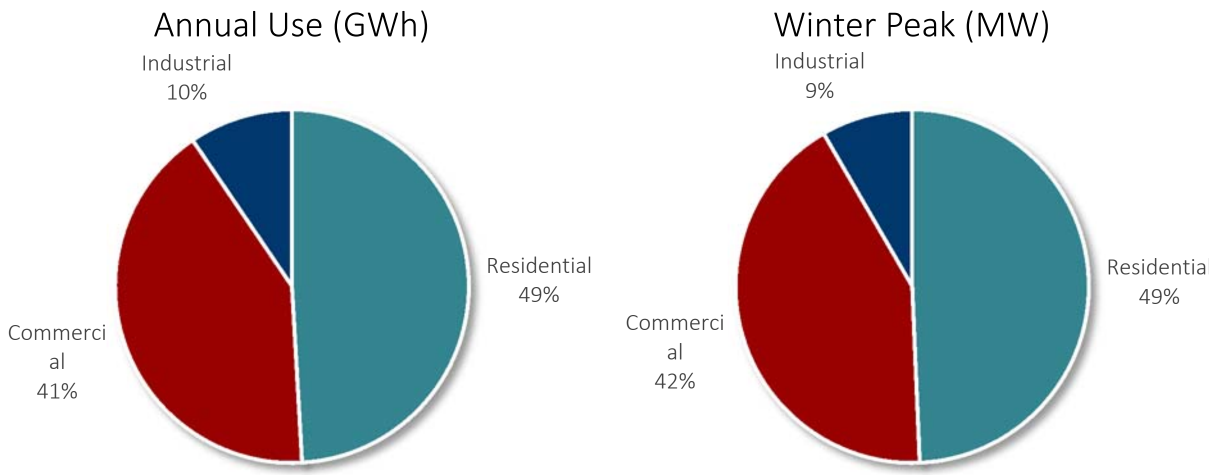


Table 3-2 Avista Sector Control Totals (2017), Idaho

Sector	Annual Electricity Use (GWh)	% of Annual Use	Winter Peak Demand (MW)	% of Winter Peak
Residential	1,250	47%	256	48%
Commercial	1,027	39%	200	38%
Industrial	366	14%	76	14%
Total	**2,643**	**100%**	**532**	**100%**

Residential Sector

The total number of households and electricity sales for the service territory were obtained from Avista's customer database. In 2017, there were 222,837 households in the state of Washington that used a total of 2,607 GWh with winter peak demand of 551 MW. Average use per customer (or household) at 11,699 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 2017, there were 112,001 households that used a total of 1,250 GWh with winter peak demand of 256 MW. Average use per customer (or household) was 11,158 kWh.

Table 3-3 Residential Sector Control Totals (2017), Washington

Segment	Number of Customers	Electricity Use	% of Annual	Annual Use/Customer (kWh/HH)	Winter Peak
Single Family	135,485	1,825	70%	13,473	378
Multifamily	12,479	101	4%	8,084	27
Mobile Home	8,022	97	4%	12,125	19
Low Income	66,851	583	22%	8,728	128
Total	**222,837**	**2,607**	**100%**	**11,699**	**551**

Table 3-4 Residential Sector Control Totals (2017), Idaho

Segment	Number of Customers	Electricity Use	% of Annual	Annual Use/Customer (kWh/HH)	Winter Peak
Single Family	68,097	873	70%	12,815	175
Multifamily	5,488	42	3%	7,681	11
Mobile Home	5,040	58	5%	11,522	11
Low Income	33,376	277	22%	8,293	60
Total	**112,001**	**1,250**	**100%**	**11,158**	**256**

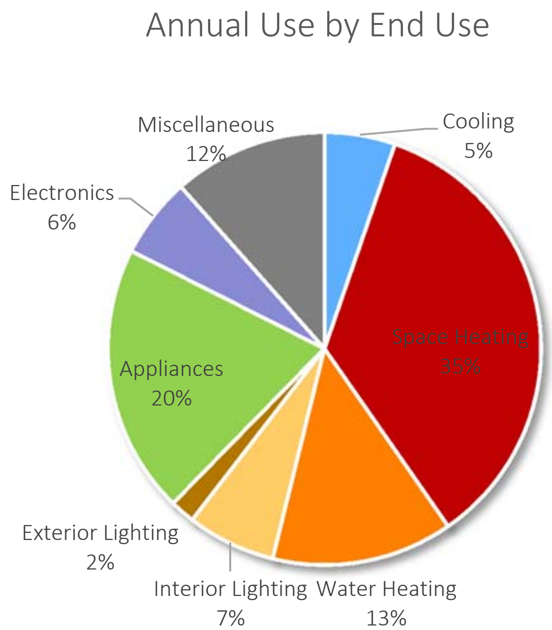
As we describe in the previous chapter, the market profiles provide the foundation for development of the baseline projection and the potential estimates. The average market profile for the residential sector is presented in Table 3-5 (WA) and Table 3-6 (ID). Segment-specific market profiles are presented 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 55% 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, electric vehicles, 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 winter peak demand by end use. As expected, heating is the largest contributor to winter peak demand, followed by appliances, lighting, and water heating.

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 13,473 kWh/year (WA) and 12,815 kWh/year (ID).

Figure 3-3 Residential Electricity Use and Winter Peak Demand by End Use (2017), Washington



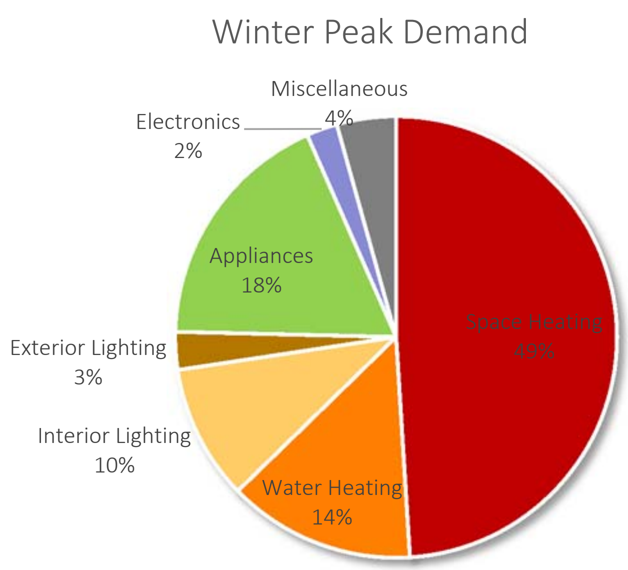
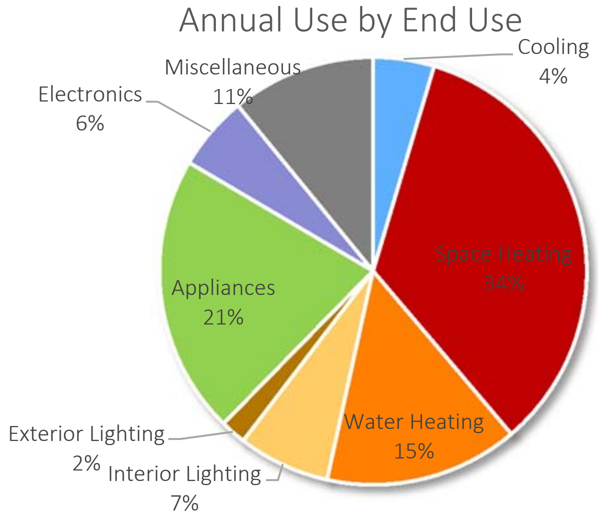


Figure 3-4 Residential Electricity Use and Winter Peak Demand by End Use (2017), Idaho



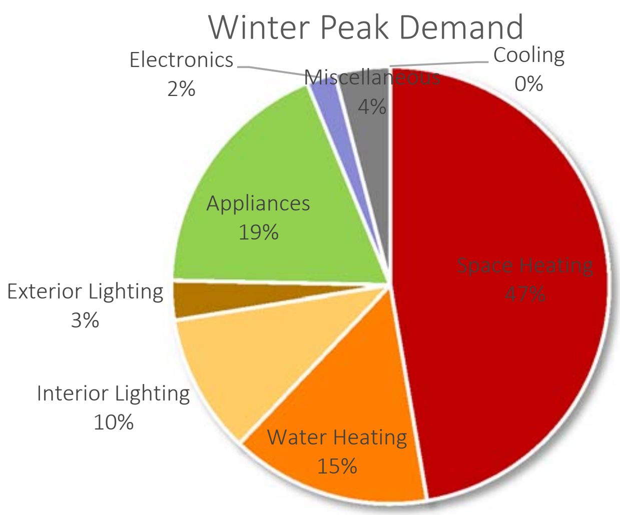


Figure 3-5 Residential Intensity by End Use and Segment (Annual kWh/HH, 2017), Washington

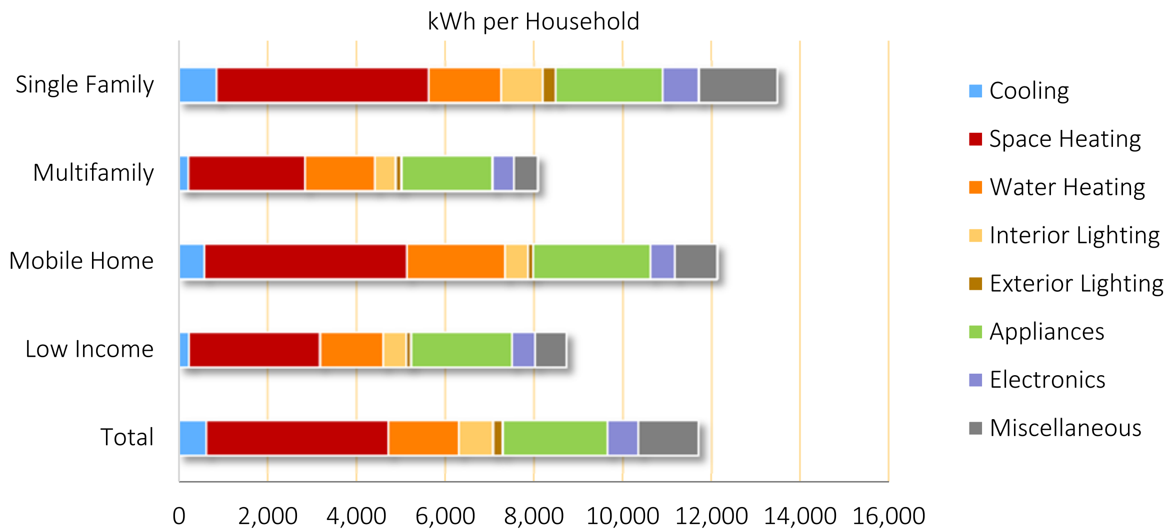


Figure 3-6 Residential Intensity by End Use and Segment (Annual kWh/HH, 2017), Idaho

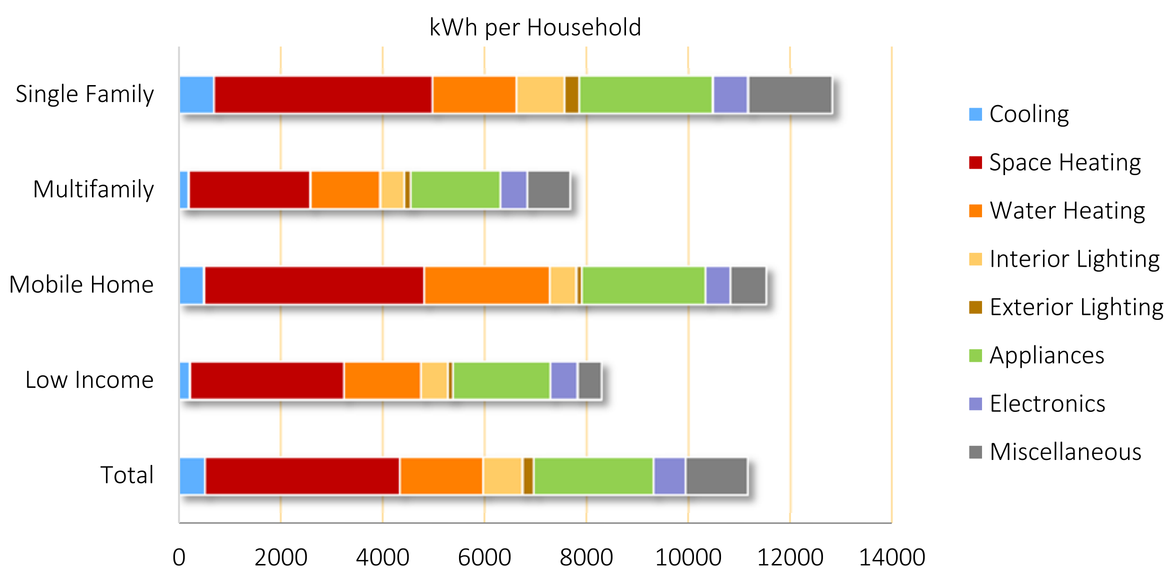


Table 3-5 Average Market Profile for the Residential Sector, 2017, Washington

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	30.6%	1,087	333	74.2
Cooling	Room AC	23.5%	401	95	21.1
Cooling	Air-Source Heat Pump	15.0%	1,178	176	39.3
Cooling	Geothermal Heat Pump	0.7%	1,139	7	1.7
Cooling	Evaporative AC	1.2%	533	6	1.4
Space Heating	Electric Room Heat	25.6%	5,176	1,325	295.2
Space Heating	Electric Furnace	9.1%	10,447	951	212.0
Space Heating	Air-Source Heat Pump	15.0%	10,485	1,570	349.9
Space Heating	Geothermal Heat Pump	0.7%	5,207	34	7.6
Space Heating	Secondary Heating	59.3%	371	220	49.0
Water Heating	Water Heater <= 55 Gal	53.3%	2,719	1,450	323.2
Water Heating	Water Heater > 55 Gal	3.8%	3,437	131	29.3
Interior Lighting	General Service Screw-in	100.0%	633	633	141.2
Interior Lighting	Linear Lighting	100.0%	98	98	21.8
Interior Lighting	Exempted Screw-In	100.0%	43	43	9.6
Exterior Lighting	Screw-in	100.0%	217	217	48.3
Appliances	Clothes Washer	92.0%	79	72	16.1
Appliances	Clothes Dryer	49.5%	735	364	81.0
Appliances	Dishwasher	77.2%	378	292	65.1
Appliances	Refrigerator	94.0%	705	663	147.7
Appliances	Freezer	55.5%	565	313	69.8
Appliances	Second Refrigerator	27.7%	812	225	50.0
Appliances	Stove/Oven	70.2%	440	309	68.9
Appliances	Microwave	94.8%	125	118	26.4
Electronics	Personal Computers	64.9%	161	105	23.3
Electronics	Monitor	129.6%	62	80	17.8
Electronics	Laptops	77.0%	42	33	7.2
Electronics	TVs	178.5%	114	203	45.3
Electronics	Printer/Fax/Copier	73.0%	42	31	6.9
Electronics	Set-top Boxes/DVRs	145.0%	99	143	31.9
Electronics	Devices and Gadgets	100.0%	108	108	24.0
Miscellaneous	Electric Vehicles	0.1%	4,324	6	1.3
Miscellaneous	Pool Pump	0.3%	3,500	12	2.7
Miscellaneous	Pool Heater	0.1%	3,517	3	0.7
Miscellaneous	Hot Tub / Spa	0.4%	2,032	8	1.9
Miscellaneous	Furnace Fan	59.6%	183	109	24.3
Miscellaneous	Well pump	1.5%	550	8	1.8
Miscellaneous	Miscellaneous	100.0%	1,204	1,204	268.2
Total				**11,699**	**2,606.9**

Table 3-6 Average Market Profile for the Residential Sector, 2017, Idaho

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	31.1%	1,045	326	36.5
Cooling	Room AC	17.6%	445	78	8.8
Cooling	Air-Source Heat Pump	8.6%	1,127	97	10.9
Cooling	Geothermal Heat Pump	0.5%	1,140	6	0.7
Cooling	Evaporative AC	1.5%	517	8	0.9
Space Heating	Electric Room Heat	23.5%	6,790	1,596	178.8
Space Heating	Electric Furnace	11.3%	9,715	1,099	123.1
Space Heating	Air-Source Heat Pump	8.6%	10,425	901	100.9
Space Heating	Geothermal Heat Pump	0.5%	5,487	29	3.2
Space Heating	Secondary Heating	48.0%	394	189	21.2
Water Heating	Water Heater <= 55 Gal	50.4%	2,921	1,472	164.9
Water Heating	Water Heater > 55 Gal	5.1%	3,227	163	18.3
Interior Lighting	General Service Screw-in	100.0%	634	634	71.0
Interior Lighting	Linear Lighting	100.0%	98	98	11.0
Interior Lighting	Exempted Screw-In	100.0%	43	43	4.8
Exterior Lighting	Screw-in	100.0%	216	216	24.2
Appliances	Clothes Washer	85.2%	82	69	7.8
Appliances	Clothes Dryer	60.2%	754	453	50.8
Appliances	Dishwasher	77.6%	381	296	33.2
Appliances	Refrigerator	93.2%	703	655	73.4
Appliances	Freezer	52.6%	563	296	33.2
Appliances	Second Refrigerator	27.8%	812	226	25.3
Appliances	Stove/Oven	63.3%	388	246	27.5
Appliances	Microwave	91.2%	126	115	12.9
Electronics	Personal Computers	57.1%	163	93	10.4
Electronics	Monitor	114.1%	62	71	7.9
Electronics	Laptops	79.7%	43	34	3.8
Electronics	TVs	175.6%	115	202	22.6
Electronics	Printer/Fax/Copier	67.1%	43	29	3.2
Electronics	Set-top Boxes/DVRs	92.8%	100	92	10.4
Electronics	Devices and Gadgets	100.0%	108	108	12.1
Miscellaneous	Electric Vehicles	0.1%	4,324	6	0.7
Miscellaneous	Pool Pump	0.1%	3,500	5	0.5
Miscellaneous	Pool Heater	0.0%	0	0	0.0
Miscellaneous	Hot Tub / Spa	0.5%	950	5	0.6
Miscellaneous	Furnace Fan	59.7%	458	274	30.6
Miscellaneous	Well pump	0.0%	0	0	0.0
Miscellaneous	Miscellaneous	100.0%	928	928	103.9
Total				**11,158**	**1,249.7**

Commercial Sector

The total electric energy consumed by commercial customers in Avista's service area in 2017 was 2,200 GWh (WA) and 1027 GWh (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). The average building intensities by segment are based on regional information from the CBSA, therefore the intensity is the same both states. However, due to the different mix of building types overall end use mix is different as shown in Figure 3-9 and Figure 3-10.

Table 3-7 Commercial Sector Control Totals (2017), Washington

Segment	Electricity Sales (GWh)	% of Total Usage	Intensity
Small Office	194	9%	16.4
Large Office	543	25%	19.3
Restaurant	111	5%	41.8
Retail	286	13%	13.1
Grocery	198	9%	46.3
College	94	4%	13.9
School	123	6%	8.0
Health	147	7%	29.9
Lodging	85	4%	12.7
Warehouse	104	5%	5.4
Miscellaneous	316	14%	10.4
Total	**2,200**	**100%**	**14.5**

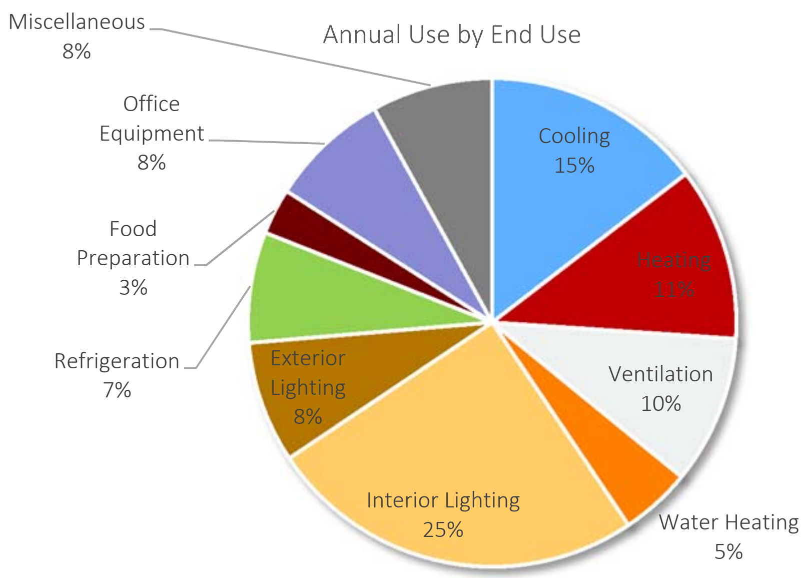
Table 3-8 Commercial Sector Control Totals (2017), Idaho

Segment	Electricity Sales (GWh)	% of Total Usage	Intensity
Small Office	91	4%	16.4
Large Office	253	12%	19.3
Restaurant	52	2%	41.8
Retail	134	6%	13.1
Grocery	92	4%	46.3
College	44	2%	13.9
School	57	3%	8.0
Health	68	3%	29.9
Lodging	40	2%	12.7
Warehouse	49	2%	5.4
Miscellaneous	147	7%	10.4
Total	**1,027**	**100%**	**14.5**

Figure 3-7 (WA) and Figure 3-8 (ID) show the distribution of annual electricity consumption and summer peak demand by end use across all commercial buildings. Electric usage is dominated by cooling and lighting, which comprise almost 48% of annual electricity usage. Winter peak demand is dominated by heating and lighting.

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 Electricity Use and Winter Peak Demand by End Use (2017), Washington



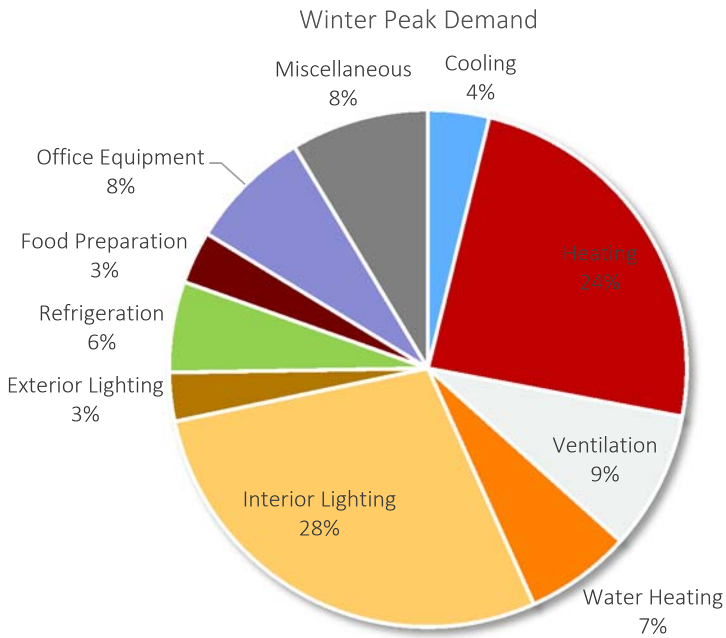
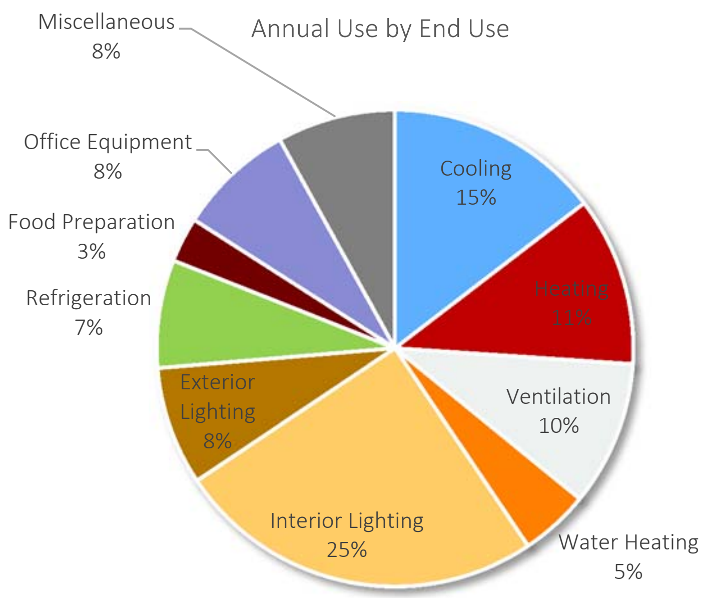


Figure 3-8 Commercial Electricity Use and Winter Peak Demand by End Use (2017), Idaho



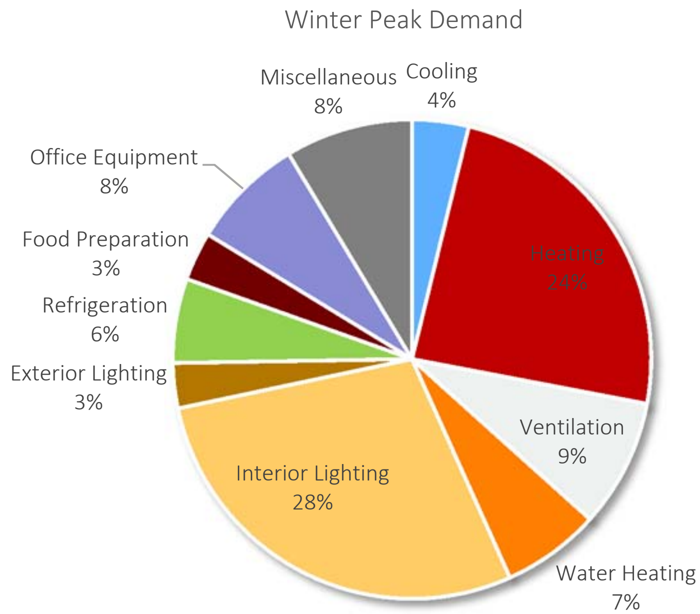


Figure 3-9 Commercial Electricity Usage by End Use Segment (GWh, 2017), Washington

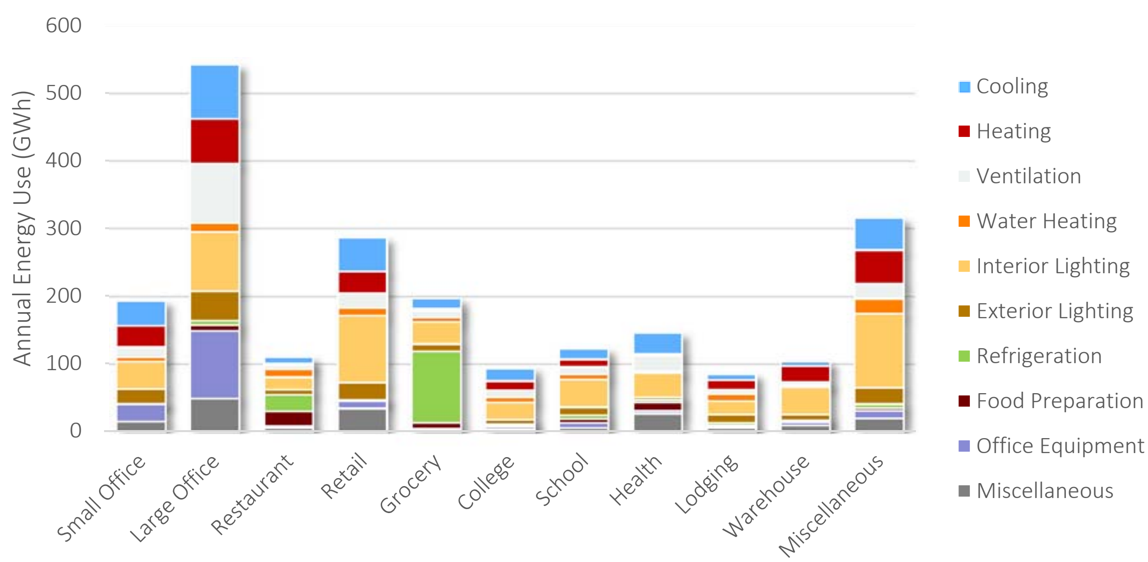


Figure 3-10 Commercial Electricity Usage by End Use Segment (GWh, 2017), Idaho

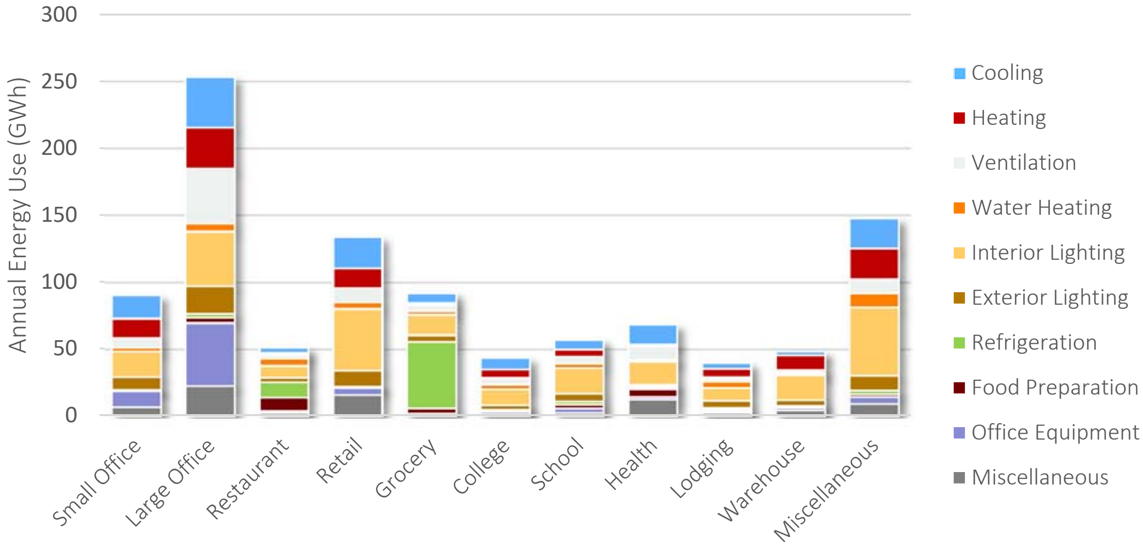


Table 3-9 (WA) and Table 3-10 (ID) show the average market profile for electricity of the commercial sector as a whole, representing a composite of all segments and buildings. Market profiles for each segment are presented in the appendix to this volume.

Table 3-9 Average Electric Market Profile for the Commercial Sector, 2017, Washington

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	8.6%	2.77	0.24	36.3
Cooling	Water-Cooled Chiller	5.0%	4.48	0.23	34.4
Cooling	RTU	46.4%	2.59	1.20	182.8
Cooling	PTAC	4.3%	2.37	0.10	15.5
Cooling	PTHP	1.7%	1.98	0.03	5.3
Cooling	Evaporative AC	0.1%	1.42	0.00	0.3
Cooling	Air-Source Heat Pump	8.6%	2.71	0.23	35.6
Cooling	Geothermal Heat Pump	4.3%	1.66	0.07	10.8
Heating	Electric Furnace	3.8%	5.54	0.21	32.2
Heating	Electric Room Heat	15.1%	5.38	0.81	123.9
Heating	PTHP	1.7%	3.60	0.06	9.6
Heating	Air-Source Heat Pump	8.6%	4.78	0.41	62.9
Heating	Geothermal Heat Pump	4.3%	3.66	0.16	23.8
Ventilation	Ventilation	100.0%	1.42	1.42	216.1
Water Heating	Water Heater	52.4%	1.29	0.68	103.0
Interior Lighting	General Service Lighting	100.0%	0.31	0.31	47.4
Interior Lighting	Exempted Lighting	100.0%	0.20	0.20	30.8
Interior Lighting	High-Bay Lighting	100.0%	1.44	1.44	219.0
Interior Lighting	Linear Lighting	100.0%	1.67	1.67	253.7
Exterior Lighting	General Service Lighting	100.0%	0.10	0.10	16.0
Exterior Lighting	Area Lighting	100.0%	0.87	0.87	131.6
Exterior Lighting	Linear Lighting	100.0%	0.19	0.19	29.4
Refrigeration	Walk-in Refrigerator/Freezer	7.8%	1.66	0.13	19.6
Refrigeration	Reach-in Refrigerator/Freezer	15.5%	0.14	0.02	3.4
Refrigeration	Glass Door Display	33.2%	0.33	0.11	16.8
Refrigeration	Open Display Case	33.2%	1.98	0.66	99.7
Refrigeration	Icemaker	32.8%	0.27	0.09	13.6
Refrigeration	Vending Machine	32.8%	0.16	0.05	8.2
Food Preparation	Oven	36.1%	0.18	0.06	9.7
Food Preparation	Fryer	35.5%	0.48	0.17	26.1
Food Preparation	Dishwasher	23.9%	0.51	0.12	18.6
Food Preparation	Hot Food Container	24.9%	0.08	0.02	3.1
Food Preparation	Steamer	22.3%	0.28	0.06	9.5
Office Equipment	Desktop Computer	100.0%	0.69	0.69	104.8
Office Equipment	Laptop	99.0%	0.10	0.10	15.1
Office Equipment	Server	88.4%	0.16	0.14	21.6
Office Equipment	Monitor	100.0%	0.12	0.12	18.5
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	10.8
Office Equipment	POS Terminal	57.1%	0.04	0.02	3.4
Miscellaneous	Non-HVAC Motors	58.4%	0.24	0.14	21.0
Miscellaneous	Pool Pump	8.8%	0.01	0.00	0.2
Miscellaneous	Pool Heater	3.1%	0.02	0.00	0.1
Miscellaneous	Clothes Washer	11.2%	0.02	0.00	0.3
Miscellaneous	Clothes Dryer	7.2%	0.05	0.00	0.6
Miscellaneous	Other Miscellaneous	100.0%	1.02	1.02	154.6
Total				**14.46**	**2,199.5**

Table 3-10 Average Electric Market Profile for the Commercial Sector, 2017, Idaho

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	8.6%	2.77	0.24	16.9
Cooling	Water-Cooled Chiller	5.0%	4.48	0.23	16.0
Cooling	RTU	46.4%	2.59	1.20	85.3
Cooling	PTAC	4.3%	2.37	0.10	7.2
Cooling	PTHP	1.7%	1.98	0.03	2.5
Cooling	Evaporative AC	0.1%	1.42	0.00	0.1
Cooling	Air-Source Heat Pump	8.6%	2.71	0.23	16.6
Cooling	Geothermal Heat Pump	4.3%	1.66	0.07	5.0
Heating	Electric Furnace	3.8%	5.54	0.21	15.0
Heating	Electric Room Heat	15.1%	5.38	0.81	57.8
Heating	PTHP	1.7%	3.60	0.06	4.5
Heating	Air-Source Heat Pump	8.6%	4.78	0.41	29.4
Heating	Geothermal Heat Pump	4.3%	3.66	0.16	11.1
Ventilation	Ventilation	100.0%	1.42	1.42	100.9
Water Heating	Water Heater	52.4%	1.29	0.68	48.1
Interior Lighting	General Service Lighting	100.0%	0.31	0.31	22.1
Interior Lighting	Exempted Lighting	100.0%	0.20	0.20	14.4
Interior Lighting	High-Bay Lighting	100.0%	1.44	1.44	102.2
Interior Lighting	Linear Lighting	100.0%	1.67	1.67	118.4
Exterior Lighting	General Service Lighting	100.0%	0.10	0.10	7.4
Exterior Lighting	Area Lighting	100.0%	0.87	0.87	61.4
Exterior Lighting	Linear Lighting	100.0%	0.19	0.19	13.7
Refrigeration	Walk-in Refrigerator/Freezer	7.8%	1.66	0.13	9.2
Refrigeration	Reach-in Refrigerator/Freezer	15.5%	0.14	0.02	1.6
Refrigeration	Glass Door Display	33.2%	0.33	0.11	7.9
Refrigeration	Open Display Case	33.2%	1.98	0.66	46.5
Refrigeration	Icemaker	32.8%	0.27	0.09	6.3
Refrigeration	Vending Machine	32.8%	0.16	0.05	3.8
Food Preparation	Oven	36.1%	0.18	0.06	4.5
Food Preparation	Fryer	35.5%	0.48	0.17	12.2
Food Preparation	Dishwasher	23.9%	0.51	0.12	8.7
Food Preparation	Hot Food Container	24.9%	0.08	0.02	1.5
Food Preparation	Steamer	22.3%	0.28	0.06	4.4
Office Equipment	Desktop Computer	100.0%	0.69	0.69	48.9
Office Equipment	Laptop	99.0%	0.10	0.10	7.0
Office Equipment	Server	88.4%	0.16	0.14	10.1
Office Equipment	Monitor	100.0%	0.12	0.12	8.6
Office Equipment	Printer/Copier/Fax	100.0%	0.07	0.07	5.1
Office Equipment	POS Terminal	57.1%	0.04	0.02	1.6
Miscellaneous	Non-HVAC Motors	58.4%	0.24	0.14	9.8
Miscellaneous	Pool Pump	8.8%	0.01	0.00	0.1
Miscellaneous	Pool Heater	3.1%	0.02	0.00	0.0
Miscellaneous	Clothes Washer	11.2%	0.02	0.00	0.1
Miscellaneous	Clothes Dryer	7.2%	0.05	0.00	0.3
Miscellaneous	Other Miscellaneous	100.0%	1.02	1.02	72.2
Total				**14.46**	**1,026.8**

Industrial Sector

The total electricity used in 2017 by Avista's industrial customers was 870 GWh; 504 GWh (WA) and 366 GWh (ID). Avista billing data and load forecast, NEEA's IFSA, 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.

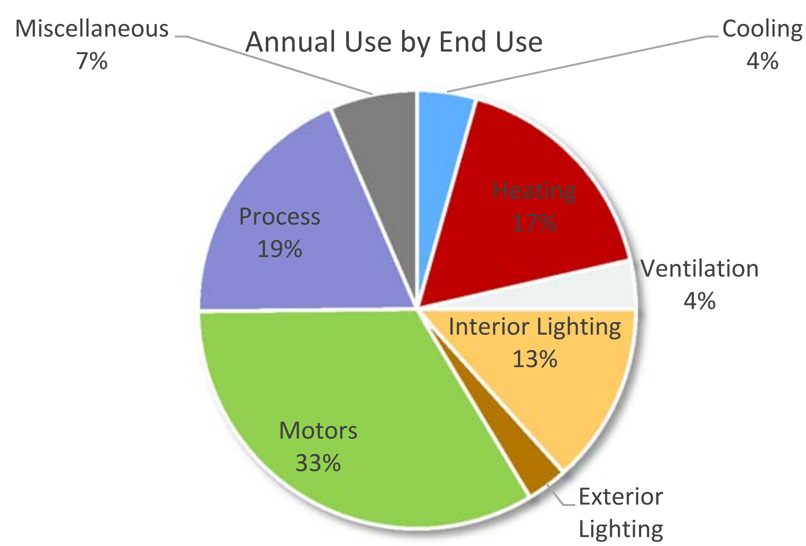
Table 3-11 Industrial Sector Control Totals (2017)

State	Electricity Sales (GWh)	Intensity (Annual kWh/employee)	Winter Peak (MW)
Washington	504	29,854	93
Idaho	366	67,257	76

Figure 3-12 shows the distribution of annual electricity consumption and summer peak demand by end use for all industrial customers. Motors are the largest overall end use for the industrial sector, accounting for 33% 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 19% 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.

Table 3-12 and Table 3-13 show the composite market profile for the industrial sector.

Figure 3-11 Industrial Electricity Use and Winter Peak Demand by End Use (2017), All Industries, WA



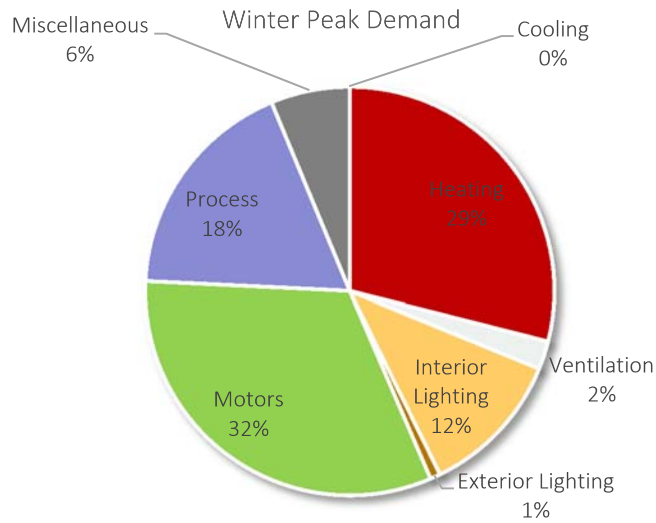
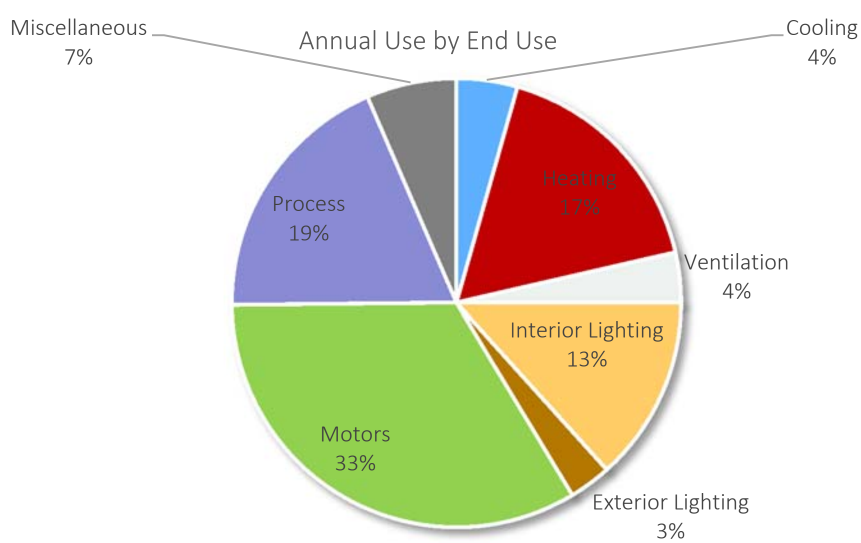


Figure 3-12 Industrial Electricity Use and Winter Peak Demand by End Use (2017), All Industries, ID



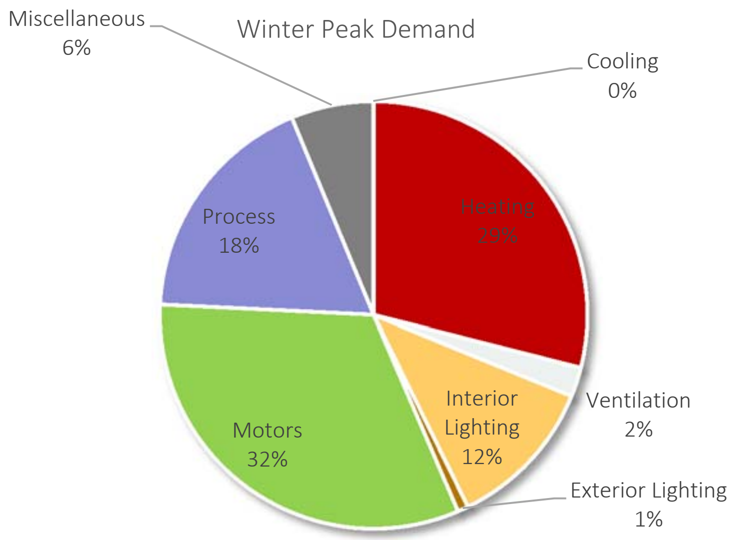

Winter Peak Demand
Miscellaneous
6%
Cooling
0%
Heating
29%
Process
18%
Ventilation
2%
Interior
Lighting
12%
Motors
32%
Exterior Lighting
1%

Table 3-12 Average Electric Market Profile for the Industrial Sector, 2017, Washington

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.5%	6,629.79	165.74	2.8
Cooling	Water-Cooled Chiller	2.5%	6,983.13	174.58	2.9
Cooling	RTU	11.4%	7,389.72	842.74	14.2
Cooling	Air-Source Heat Pump	1.7%	7,386.34	124.90	2.1
Cooling	Geothermal Heat Pump	0.0%	4,926.69	0.00	0.0
Heating	Electric Furnace	2.3%	32,574.73	747.28	12.6
Heating	Electric Room Heat	12.4%	31,023.55	3,849.55	65.0
Heating	Air-Source Heat Pump	1.7%	28,604.84	483.71	8.2
Heating	Geothermal Heat Pump	0.0%	19,079.43	0.00	0.0
Ventilation	Ventilation	100.0%	1,077.71	1,077.71	18.2
Interior Lighting	General Service Lighting	100.0%	206.68	206.68	3.5
Interior Lighting	High-Bay Lighting	100.0%	3,233.38	3,233.38	54.6
Interior Lighting	Linear Lighting	100.0%	537.49	537.49	9.1
Exterior Lighting	General Service Lighting	100.0%	38.05	38.05	0.6
Exterior Lighting	Area Lighting	100.0%	720.88	720.88	12.2
Exterior Lighting	Linear Lighting	100.0%	147.69	147.69	2.5
Motors	Pumps	100.0%	1,899.28	1,899.28	32.1
Motors	Fans & Blowers	100.0%	2,280.92	2,280.92	38.5
Motors	Compressed Air	100.0%	1,844.32	1,844.32	31.2
Motors	Material Handling	100.0%	3,900.92	3,900.92	65.9
Motors	Other Motors	100.0%	65.46	65.46	1.1
Process	Process Heating	100.0%	3,211.52	3,211.52	54.3
Process	Process Cooling	100.0%	843.19	843.19	14.2
Process	Process Refrigeration	100.0%	843.19	843.19	14.2
Process	Process Electrochemical	100.0%	324.59	324.59	5.5
Process	Process Other	100.0%	352.25	352.25	6.0
Miscellaneous	Miscellaneous	100.0%	1,937.76	1,937.76	32.7
Total				**29,853.79**	**504.4**

Table 3-13 Average Electric Market Profile for the Industrial Sector, 2017, Idaho

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.5%	14,936.14	373.40	2.0
Cooling	Water-Cooled Chiller	2.5%	15,732.18	393.30	2.1
Cooling	RTU	11.4%	16,648.18	1,898.60	10.3
Cooling	Air-Source Heat Pump	1.7%	16,640.58	281.39	1.5
Cooling	Geothermal Heat Pump	0.0%	11,099.27	0.00	0.0
Heating	Electric Furnace	2.3%	73,387.09	1,683.53	9.2
Heating	Electric Room Heat	12.4%	69,892.47	8,672.59	47.2
Heating	Air-Source Heat Pump	1.7%	64,443.40	1,089.73	5.9
Heating	Geothermal Heat Pump	0.0%	42,983.75	0.00	0.0
Ventilation	Ventilation	100.0%	2,427.96	2,427.96	13.2
Interior Lighting	General Service Lighting	100.0%	465.63	465.63	2.5
Interior Lighting	High-Bay Lighting	100.0%	7,284.44	7,284.44	39.6
Interior Lighting	Linear Lighting	100.0%	1,210.90	1,210.90	6.6
Exterior Lighting	General Service Lighting	100.0%	85.72	85.72	0.5
Exterior Lighting	Area Lighting	100.0%	1,624.05	1,624.05	8.8
Exterior Lighting	Linear Lighting	100.0%	332.72	332.72	1.8
Motors	Pumps	100.0%	4,278.85	4,278.85	23.3
Motors	Fans & Blowers	100.0%	5,138.64	5,138.64	28.0
Motors	Compressed Air	100.0%	4,155.05	4,155.05	22.6
Motors	Material Handling	100.0%	8,788.33	8,788.33	47.8
Motors	Other Motors	100.0%	147.48	147.48	0.8
Process	Process Heating	100.0%	7,235.19	7,235.19	39.4
Process	Process Cooling	100.0%	1,899.62	1,899.62	10.3
Process	Process Refrigeration	100.0%	1,899.62	1,899.62	10.3
Process	Process Electrochemical	100.0%	731.25	731.25	4.0
Process	Process Other	100.0%	793.59	793.59	4.3
Miscellaneous	Miscellaneous	100.0%	4,365.54	4,365.54	23.8
Total				**67,257.13**	**366.1**

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 Chapter 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 EE 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 peak demand in MW. We also present a summary across all sectors.

Please note that the base-year for the study is 2017. Annual energy use and summer peak demand values for 2017 reflect actual weather. 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 increase in energy use and peak demand in 2017 for the residential and commercial sectors. This results from the fact that 2017 was cooler than normal (e.g. more energy was required to heat a home in the Winter of 2017 than in an average year).

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 2,607 GWh in 2017 to 3,254 GWh in 2040, an increase of 25%. Residential use in Idaho increases from 1,250 GWh in 2017 to 1,628 GWh in 2040, an increase of 30%. This reflects a substantial 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. Heating usage increases over the forecast due to going from actual weather in 2017 to normal weather in 2018 and for the rest of the forecast.

Table 4-1 Residential Baseline Sales Projection by End Use (GWh), Washington

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	138	121	121	122	125	135	-2%
Space Heating	914	816	823	843	882	975	7%
Water Heating	352	347	345	342	345	366	4%
Interior Lighting	173	148	137	112	93	88	-49%
Exterior Lighting	48	40	37	31	26	24	-51%
Appliances	525	532	534	541	557	606	16%
Electronics	156	166	170	180	200	249	59%
Miscellaneous	301	345	361	411	514	810	169%
Total	**2,607**	**2,515**	**2,528**	**2,581**	**2,743**	**3,254**	**25%**

Figure 4-1 Residential Baseline Projection by End Use (GWh), Washington

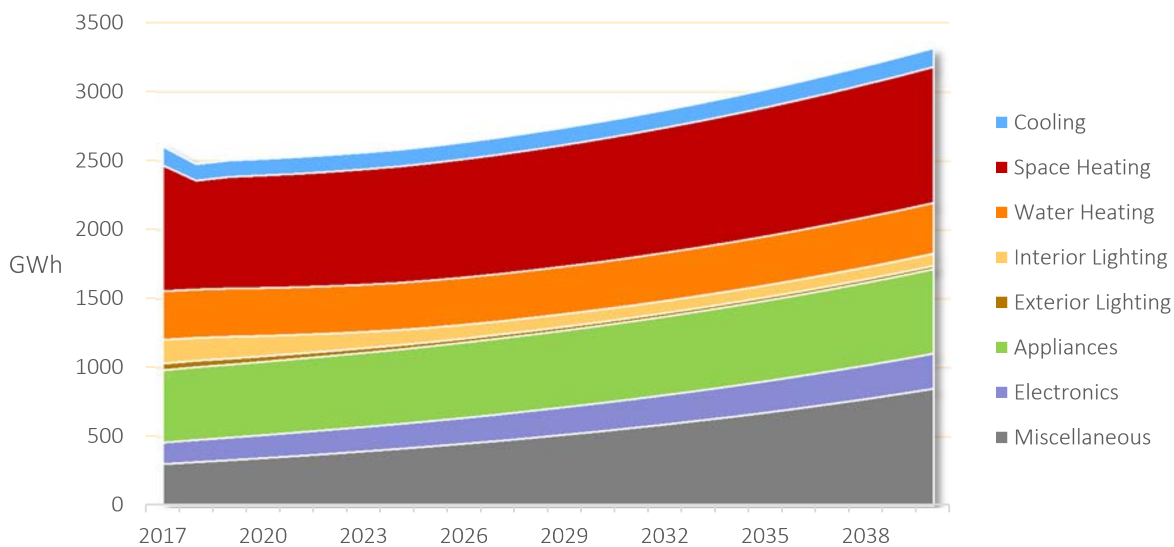


Figure 4-2 Residential Baseline Projection by End Use – Annual Use per Household, Washington

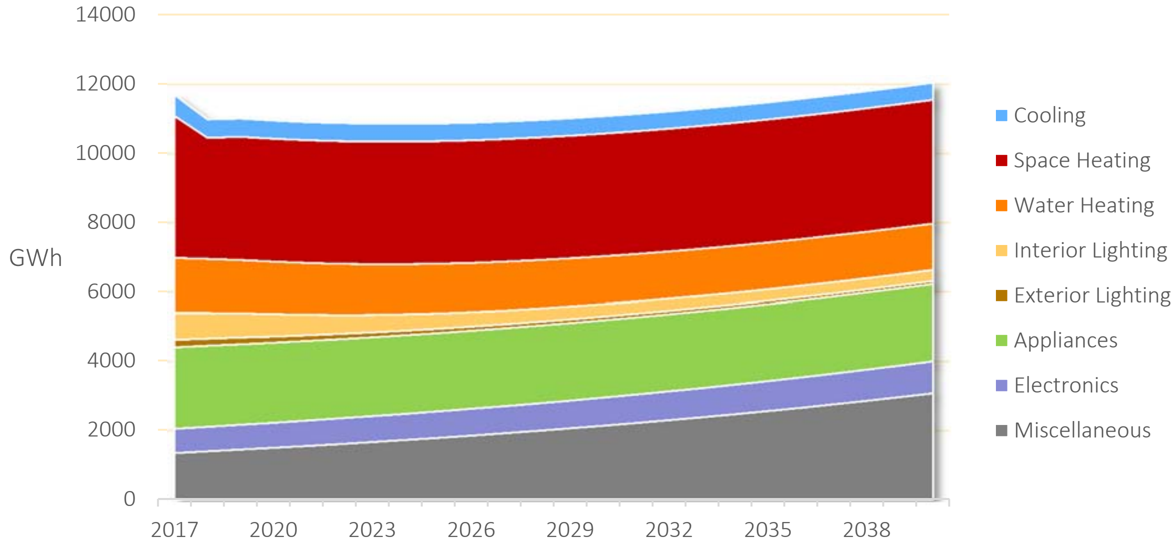


Table 4-2 Residential Baseline Sales Projection by End Use (GWh), Idaho

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	58	51	52	53	56	64	10%
Space Heating	427	386	390	404	430	489	14%
Water Heating	183	182	181	181	184	199	9%
Interior Lighting	87	75	70	58	50	50	-43%
Exterior Lighting	24	20	19	16	14	13	-46%
Appliances	264	270	272	278	291	326	24%
Electronics	70	76	78	83	95	123	75%
Miscellaneous	136	155	162	184	230	365	167%
Total	**1,250**	**1,215**	**1,223**	**1,256**	**1,348**	**1,628**	**30%**

Figure 4-3 Residential Baseline Projection by End Use (GWh), Idaho

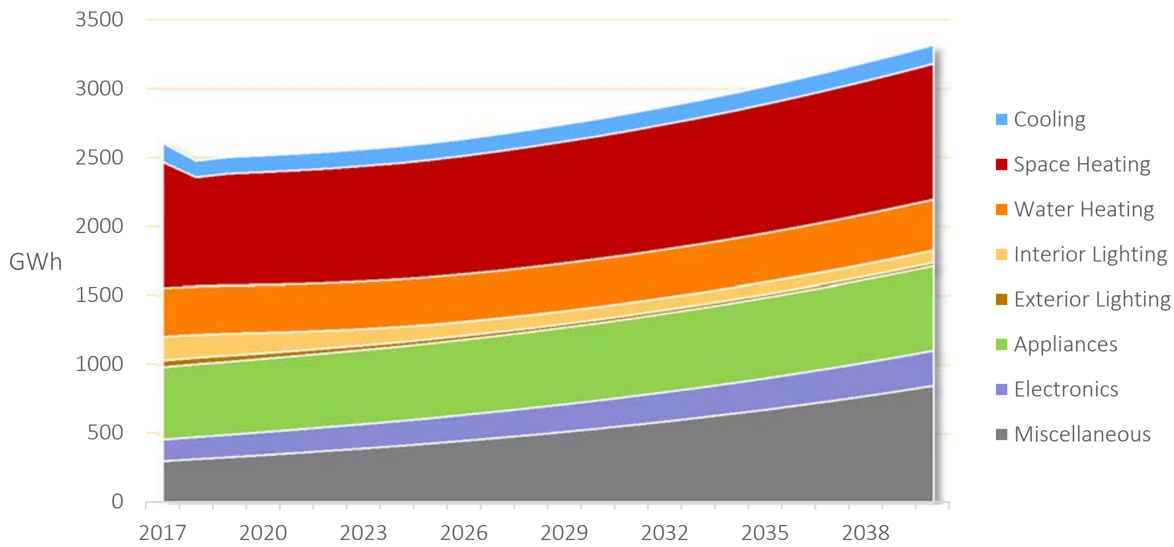
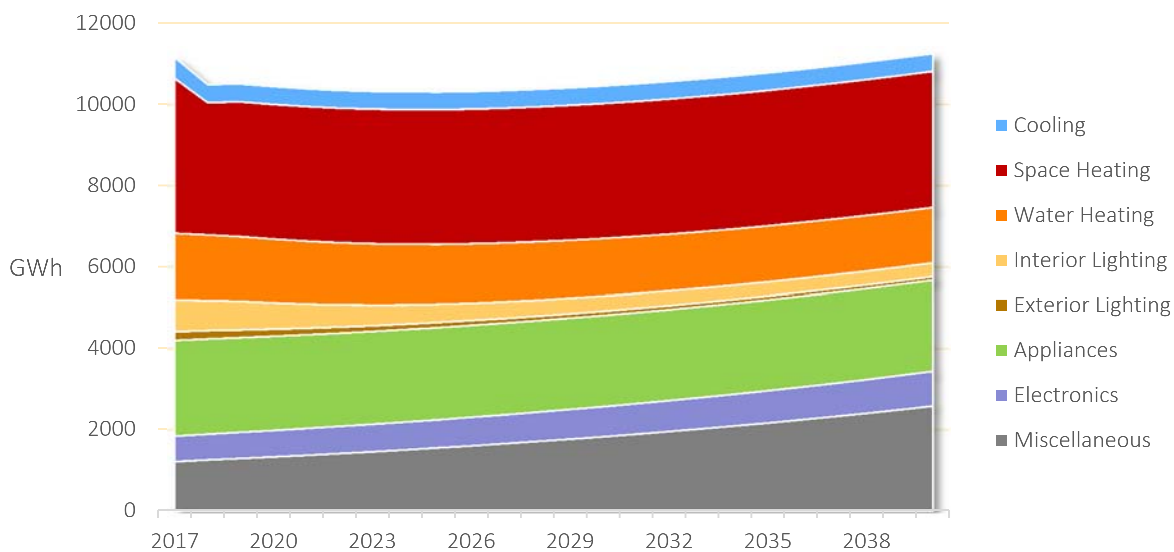


Figure 4-4 Residential Baseline Sales Projection by End Use – Annual Use per Household, Idaho



Commercial Sector Baseline Projections

Annual Use

In Washington, annual electricity use in the commercial sector grows during the overall forecast horizon, starting at 2,200 GWh in 2017, and increasing to 2,531 in 2040, an increase of 15%. In Idaho, annual electricity use grows from 1,027 GWh in 2017 to 1,159 GWh in 2040, an increase of 13%. 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 2017 to weather-normal in 2018 for the forecast.

Table 4-3 Commercial Baseline Sales Projection by End Use (GWh), Washington

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	321	276	275	271	266	267	-17%
Heating	252	245	246	249	256	275	9%
Ventilation	216	218	219	222	229	248	15%
Water Heating	103	103	103	104	108	119	15%
Interior Lighting	551	536	528	515	521	558	1%
Exterior Lighting	177	176	176	175	177	191	8%
Refrigeration	161	162	162	164	172	198	23%
Food Preparation	67	70	71	75	83	101	50%
Office Equipment	174	179	181	190	208	248	42%
Miscellaneous	177	193	199	217	251	327	85%
Total	**2,200**	**2,160**	**2,162**	**2,183**	**2,270**	**2,531**	**15%**

Table 4-4 Commercial Baseline Sales Projection by End Use (GWh), Idaho

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	150	129	129	127	125	127	-15%
Heating	118	115	115	117	120	129	10%
Ventilation	101	102	102	104	107	116	15%
Water Heating	48	49	49	50	52	57	19%
Interior Lighting	257	250	247	241	244	262	2%
Exterior Lighting	83	82	82	82	83	89	8%
Refrigeration	75	76	76	77	80	93	23%
Food Preparation	31	33	33	35	39	47	51%
Office Equipment	81	84	85	89	97	116	43%
Miscellaneous	82	90	93	102	109	122	47%
Total	**1,027**	**1,008**	**1,010**	**1,022**	**1,057**	**1,159**	**13%**

Figure 4-5 Commercial Baseline Projection by End Use, Washington

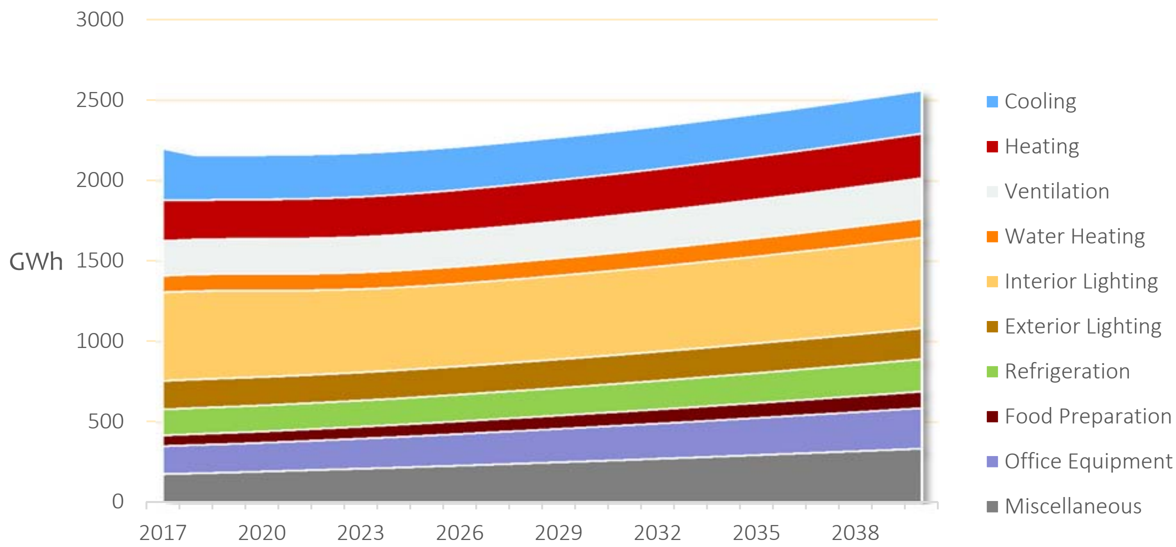
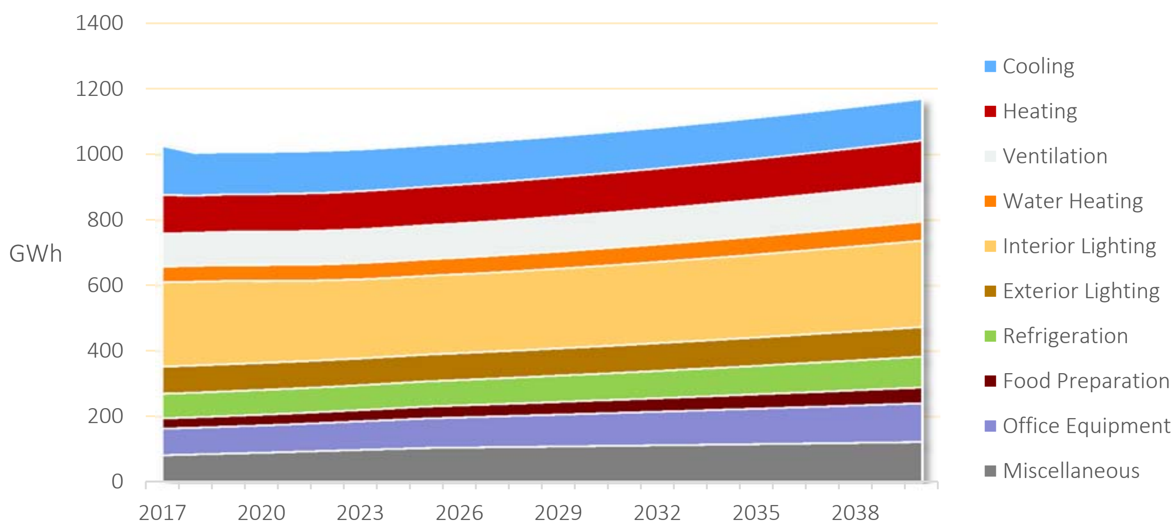


Figure 4-6 Commercial Baseline Projection by End Use, Idaho



Industrial Sector Baseline Projections

Annual Use

Annual industrial use increases by 25% through the forecast horizon, consistent with trends from Avista's industrial load forecast. The tables and graphs below present the projection at the end-use level. Overall in Washington, industrial annual electricity use increases from 504 GWh in 2017 to 683 GWh in 2040. In Idaho, annual electricity use increases from 366 GWh in 2017 to 406 GWh in 2040.

Table 4-5 Industrial Baseline Projection by End Use (GWh), Washington

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	22	24	24	25	26	28	29%
Heating	86	93	94	97	102	112	31%
Ventilation	18	20	20	20	21	23	29%
Interior Lighting	67	68	67	67	67	71	5%
Exterior Lighting	15	16	16	16	17	18	19%
Process	94	103	104	107	112	125	32%
Motors	169	184	186	191	202	223	32%
Miscellaneous	33	40	42	48	58	81	148%
Total	**504**	**548**	**553**	**571**	**605**	**683**	**35%**

Table 4-6 Industrial Baseline Projection by End Use (GWh), Idaho

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Cooling	16	15	15	15	15	15	-8%
Heating	62	65	65	65	65	65	4%
Ventilation	13	14	14	14	14	14	6%
Interior Lighting	49	50	49	47	45	43	-12%
Exterior Lighting	11	12	12	12	11	11	-1%
Process	68	75	75	75	75	75	10%
Motors	123	134	134	134	134	134	10%
Miscellaneous	24	29	30	34	39	49	108%
Total	**366**	**395**	**395**	**396**	**398**	**406**	**11%**

Figure 4-7 Industrial Baseline Projection by End Use (GWh), Washington

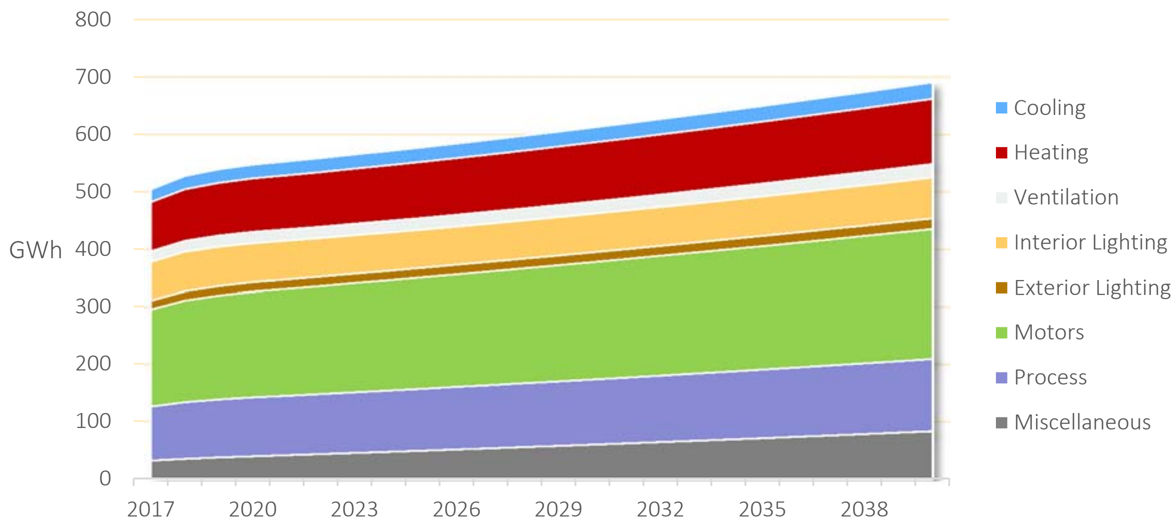
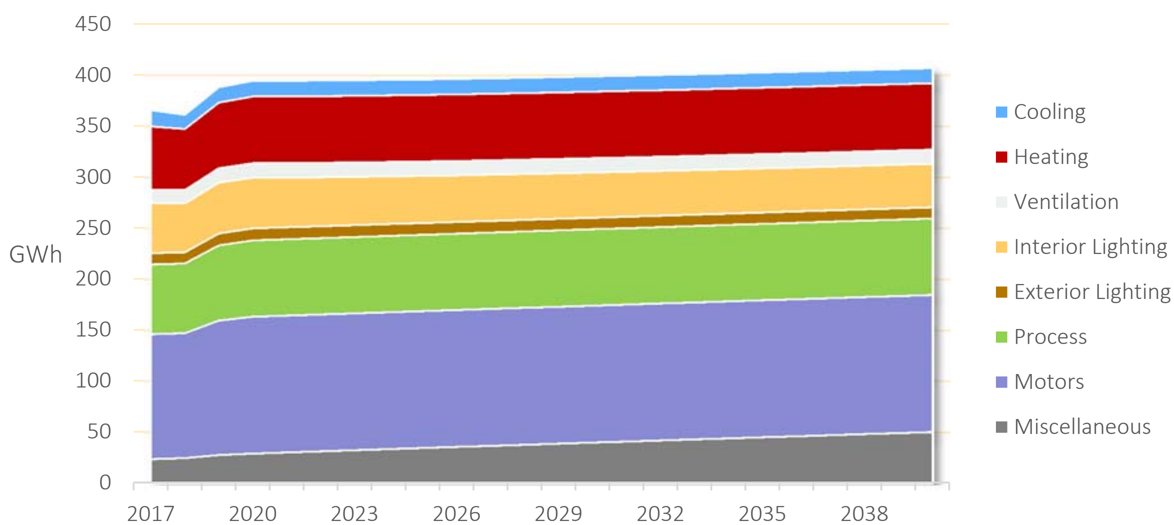


Figure 4-8 Industrial Baseline Projection by End Use (GWh), Idaho



Summary of Baseline Projections across Sectors and States

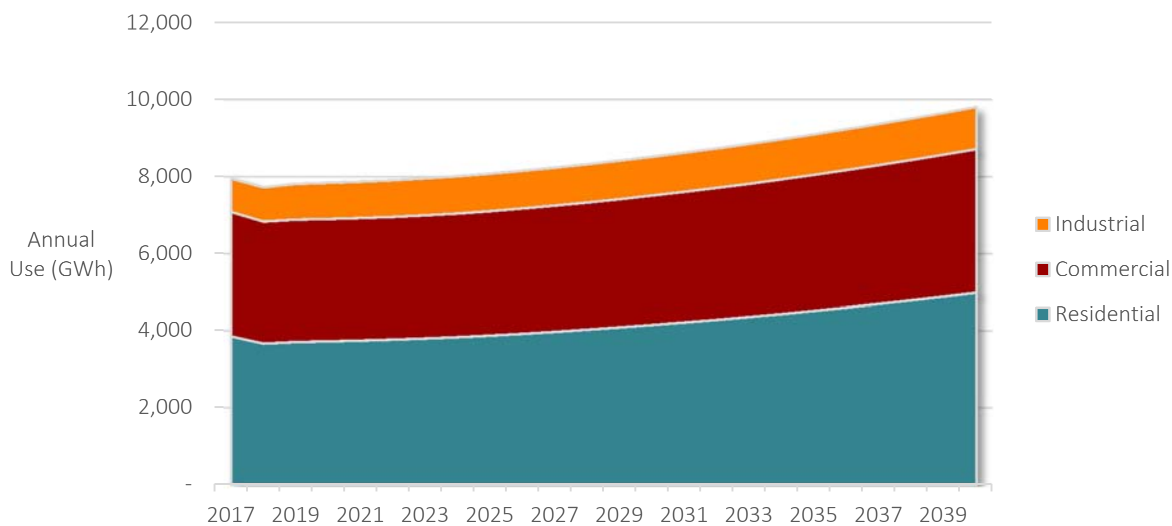
Annual Use

Table 4-7 and Figure 4-9 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 4-7 Baseline Projection Summary (GWh), WA and ID Combined

End Use	2017	2021	2022	2025	2030	2040	% Change ('17-'40)
Residential	3,857	3,731	3,751	3,838	4,090	4,882	27%
Commercial	3,226	3,168	3,171	3,205	3,327	3,690	14%
Industrial	871	942	948	967	1,004	1,089	25%
Total	**7,953**	**7,841**	**7,871**	**8,009**	**8,421**	**9,661**	**21%**

Figure 4-9 Baseline Projection Summary (GWh), WA and ID Combined



5

CONSERVATION POTENTIAL

This section presents the conservation potential for Avista. This includes every measure that is considered in the measure list, regardless of delivery mechanism (program implementation, NEEA initiatives, or momentum savings).

We present the annual energy savings in GWh and aMW, as well as the winter peak demand savings in MW, for selected years. 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 two levels of potential relative to the baseline projection. Figure 5-1(WA) and Figure 5-2 (ID) displays the two 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 102 GWh, or 2.0% of the baseline projection. Cumulative savings in 2040 are 1,607 GWh, or 24.5% of the baseline. For Idaho, first-year savings are 51 GWh, or 1.9% of the baseline projection. Cumulative savings in 2040 are 845 GWh, or 26.1% of the baseline.
- Technical Achievable Potential modifies Technical Potential by accounting for customer adoption constraints. In Washington, first-year savings are 47 GWh, or 0.9% of the baseline. In 2040, cumulative technical achievable savings reach 1,272 GWh, or 19.4% of the baseline projection. This results in average annual savings of 1.0% of the baseline each year. Technical Achievable Potential reflects 79% of Technical Potential throughout the forecast horizon. For Idaho, first year savings are 24 GWh or 0.9% of the baseline and by 2040 cumulative technical achievable savings reach 673 GWh, or 20.8% of the baseline. This results in average annual savings of 1% of the baseline each year. Technical Achievable Potential reflects 80% of Technical Potential throughout the forecast horizon.

Table 5-1 Summary of EE Potential (Annual Energy, GWh), Washington

	2021	2022	2023	2030	2040
Baseline projection (GWh)	5,243	5,268	5,300	5,687	6,572
Cumulative Savings (GWh)					
Technical Achievable Potential	47	100	158	636	1,272
Technical Potential	102	203	305	979	1,607
Cumulative Savings (aMW)					
Technical Achievable Potential	5	11	18	73	145
Technical Potential	12	23	35	112	183
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.9%	1.9%	3.0%	11.2%	19.4%
Technical Potential	2.0%	3.9%	5.8%	17.2%	24.5%

Table 5-2 Summary of EE Potential (Annual Energy, GWh), Idaho

	2021	2022	2023	2030	2040
Baseline projection (GWh)	2,628	2,640	2,656	2,834	3,241
Cumulative Savings (GWh)					
Technical Achievable Potential	24	50	80	328	673
Technical Potential	51	102	153	502	845
Cumulative Savings (aMW)					
Technical Achievable Potential	3	6	9	37	77
Technical Potential	6	12	17	57	96
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.9%	1.9%	3.0%	11.6%	20.8%
Technical Potential	1.9%	3.9%	5.8%	17.7%	26.1%

Figure 5-1 Summary of EE Potential as % of Baseline Projection (Annual Energy), Washington

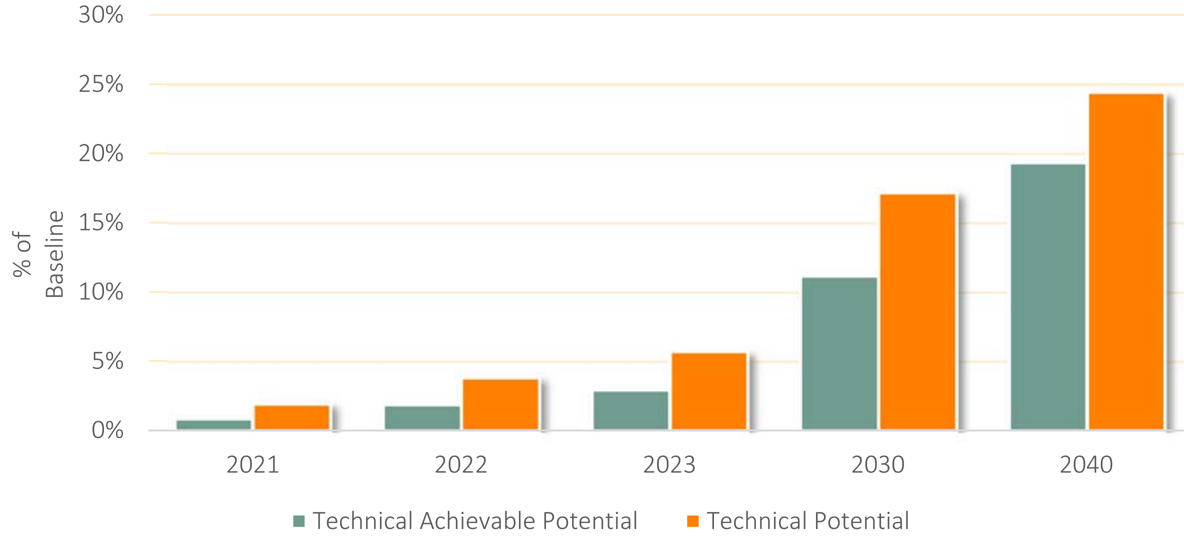


Figure 5-2 Summary of EE Potential as % of Baseline Projection (Annual Energy), Idaho

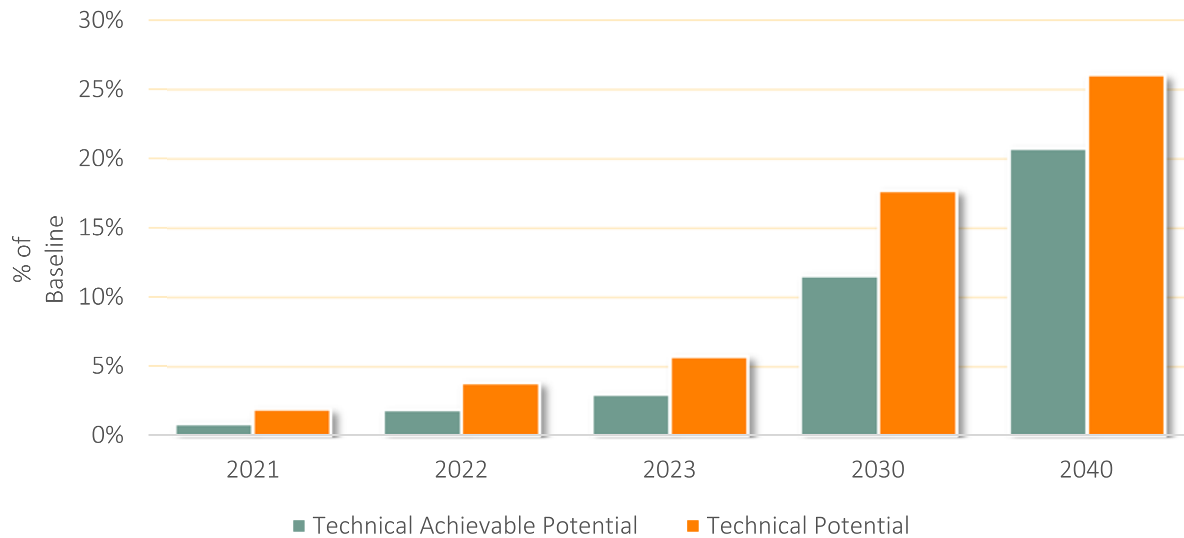


Figure 5-3 Baseline Projection and EE Forecast Summary (Annual Energy, GWh), Washington

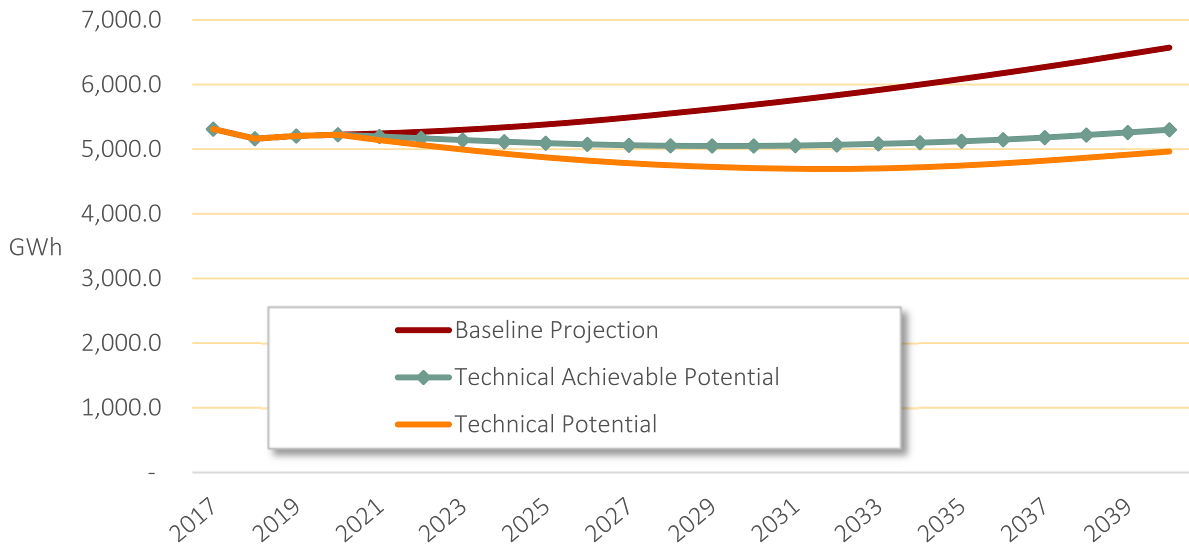
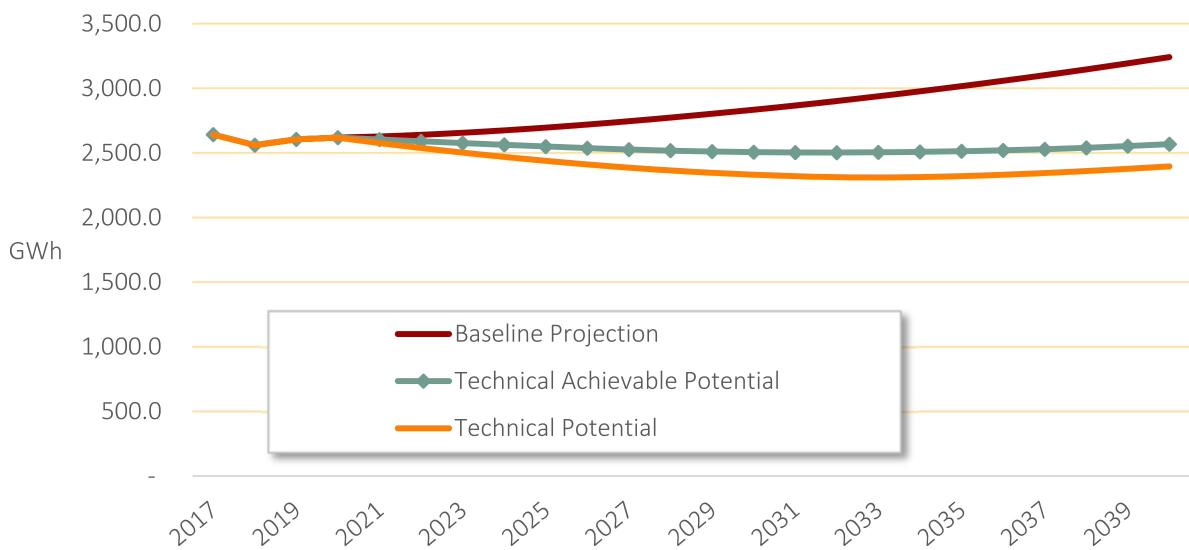


Figure 5-4 Baseline Projection and EE Forecast Summary (Annual Energy, GWh), Idaho



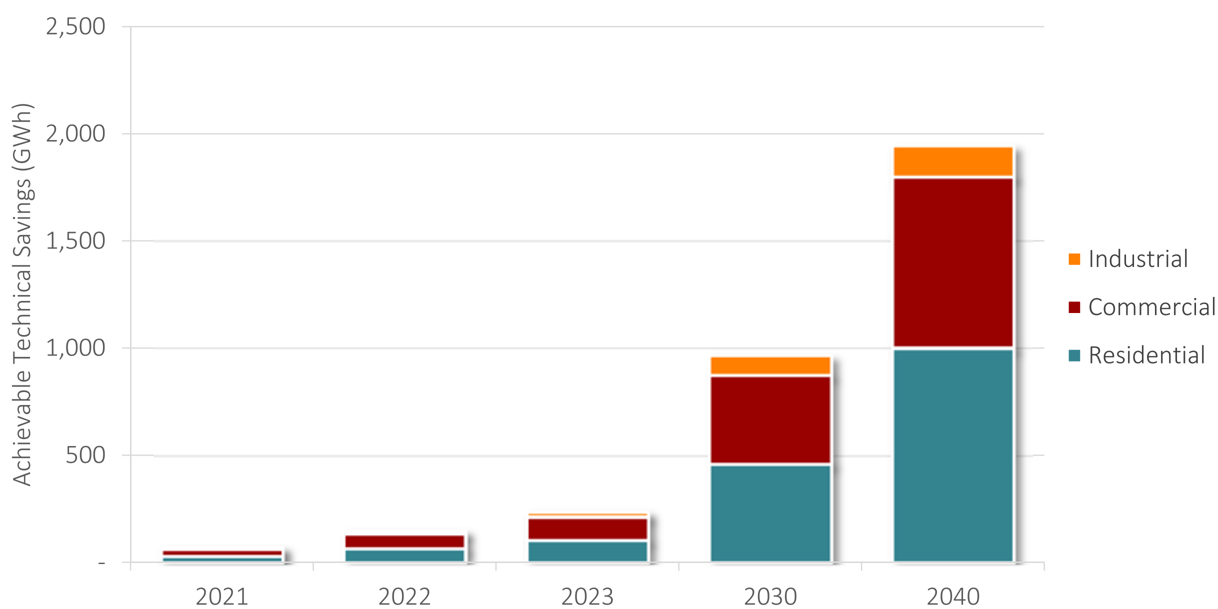
Summary of Conservation Potential by Sector

Table 5-3 and Figure 5-5 summarize the range of electric Technical Achievable Potential by sector, both states combined. The residential and commercial sectors contribute the most savings, but by 2040 the commercial sector potential begins to approach that of residential due to large lost opportunity lighting equipment and controls measures.

Table 5-3 Technical Achievable Conservation Potential by Sector (Annual Use), WA and ID

	2021	2022	2023	2030	2040
Cumulative Savings (GWh)					
Residential	31	66	106	461	1,000
Commercial	33	69	109	414	800
Industrial	7	15	24	89	145
Total	71	150	238	965	1,945
Cumulative Savings (aMW)					
Residential	4	8	12	53	114
Commercial	4	8	12	47	91
Industrial	1	2	3	10	17
Total	8	17	27	110	222

Figure 5-5 Technical Achievable Conservation Potential by Sector (Annual Energy, GWh)



Residential Conservation Potential

Table 5-4 (WA) and Table 5-5 (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 two levels of potential by year. For Washington, Technical Achievable Potential in the first year, 2021 is 21 GWh, or 0.8 % of the baseline projection. By 2040, cumulative technical achievable savings are 647 GWh, or 19.5% of the baseline projection. At this level, it represents over 82% of technical potential. For Idaho, first year technical achievable savings are 10 GWh or 0.8% of the baseline and by 2040 cumulative technical achievable savings reach 353 GWh, or 21.2% of the baseline. Technical Achievable Potential is 82% of technical potential in 2040.

Table 5-4 Residential Conservation Potential (Annual Energy), Washington

	2021	2022	2023	2030	2040
Baseline projection (GWh)	2,528	2,543	2,562	2,783	3,319
Cumulative Savings (GWh)					
Technical Achievable Potential	21	44	71	305	647
Technical Potential	48	96	144	475	791
Cumulative Savings (aMW)					
Technical Achievable Potential	2	5	8	35	74
Technical Potential	5	11	16	54	90
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.8%	1.7%	2.8%	11.0%	19.5%
Technical Potential	1.9%	3.8%	5.6%	17.1%	23.8%

Table 5-5 Residential Conservation Potential (Annual Energy), Idaho

	2021	2022	2023	2030	2040
Baseline projection (GWh)	1,223	1,233	1,244	1,370	1,663
Cumulative Savings (GWh)					
Technical Achievable Potential	10	22	35	157	353
Technical Potential	24	48	72	246	430
Cumulative Savings (aMW)					
Technical Achievable Potential	1	2	4	18	40
Technical Potential	3	5	8	28	49
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.8%	1.8%	2.8%	11.4%	21.2%
Technical Potential	1.9%	3.9%	5.8%	18.0%	25.9%

Figure 5-6 Residential Conservation Savings as a % of the Baseline Projection (Annual Energy), Washington

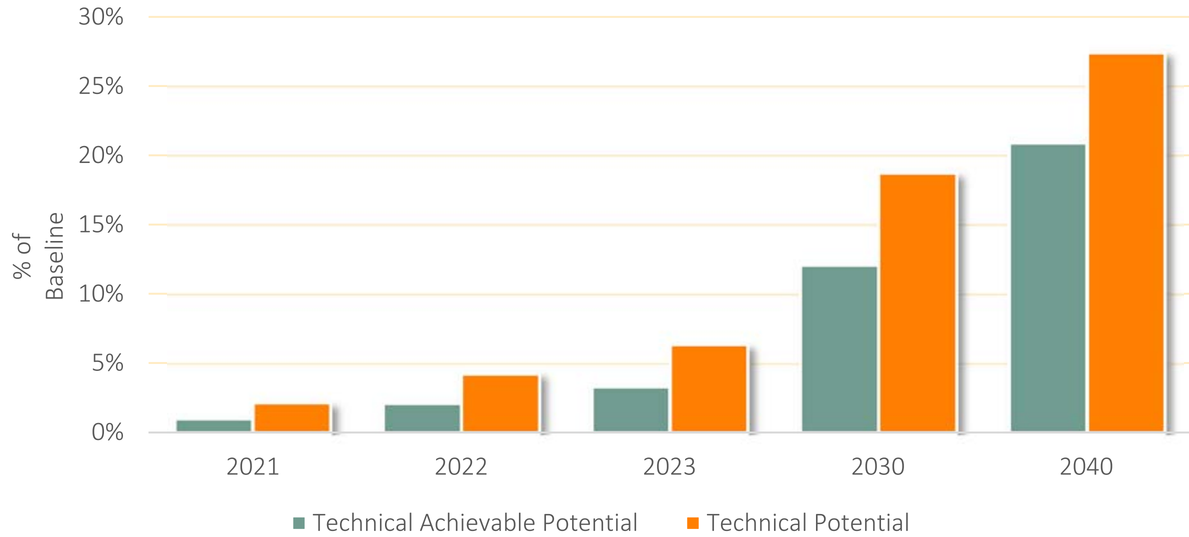
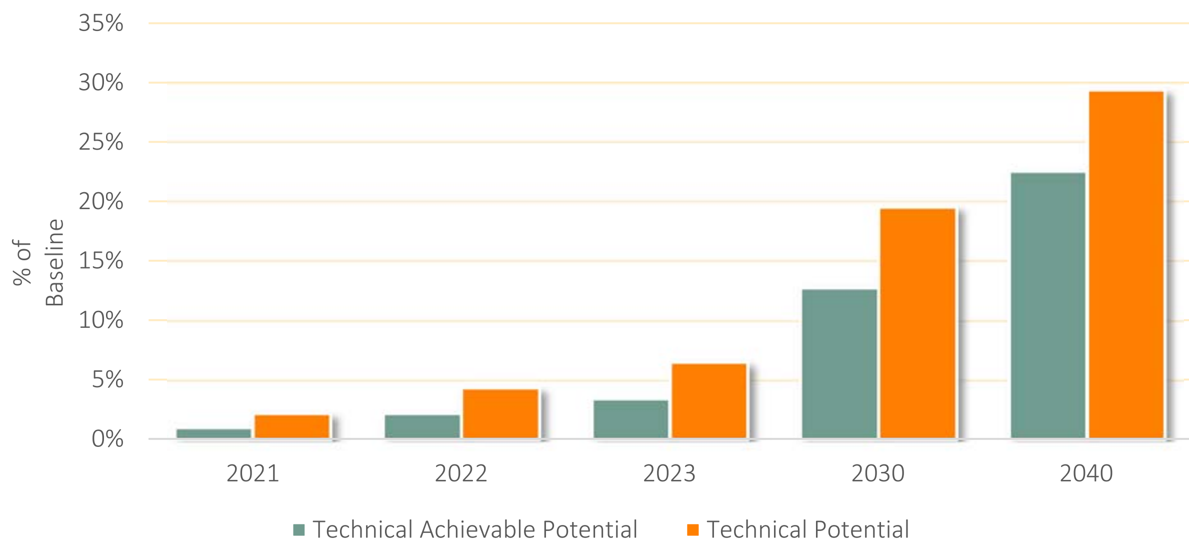


Figure 5-7 Residential Conservation Savings as a % of the Baseline Projection (Annual Energy), Idaho



Below, we present the top residential measures from the perspective of annual energy use. Table 5-6 identifies the top 20 residential measures from the perspective of annual energy savings in 2022 for Washington. The top three measures include Ductless Mini Split Heat Pumps (Ducted Forced Air), Water Heater – Low-Flow Showerheads, and Ductless Mini Split Heat Pump (Zonal). Note that technical achievable savings do not screen for cost effectiveness and some measures are expected to be screened out during the IRP process.

Table 5-6 Residential Top Measures in 2019 (Annual Energy, MWh), Washington

Rank	Residential Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Ductless Mini Split Heat Pump (Ducted Forced Air)	3,651	8%
2	Water Heater - Low-Flow Showerheads	2,834	6%
3	Ductless Mini Split Heat Pump (Zonal)	2,727	6%
4	Thermostat - Connected	2,303	5%
5	Windows - Low-e Storm Addition	2,011	5%
6	Building Shell - Infiltration Control	1,976	4%
7	Ducting - Repair and Sealing	1,832	4%
8	Windows - Cellular Shades	1,754	4%
9	Insulation - Floor Installation	1,668	4%
10	Furnace - Conversion to Air-Source Heat Pump	1,640	4%
11	Monitor	1,537	3%
12	Insulation - Ducting	1,472	3%
13	Windows - High Efficiency/ENERGY STAR	1,457	3%
14	General Service Screw-in	1,374	3%
15	Insulation - Wall Cavity Installation	1,080	2%
16	Doors - Storm and Thermal	873	2%
17	Exterior Lighting - Photosensor Control	802	2%
18	Insulation - Ceiling Installation	759	2%
19	Insulation - Radiant Barrier	751	2%
20	Water Heater - Pipe Insulation	645	1%
	Total of Top 20 Measures	**33,145**	**75%**
	Total Cumulative Savings	**44,428**	**100%**

Figure 5-8 presents forecasts of cumulative energy savings for Washington. Space heating and water heating account for a substantial portion of the savings throughout the forecast horizon. Weatherization, ductless heat pumps, heat pump water heaters, and LED lighting account for a large portion of potential over the 20-year study period.

Figure 5-8 Residential Technical Achievable Savings Forecast (Cumulative GWh), Washington

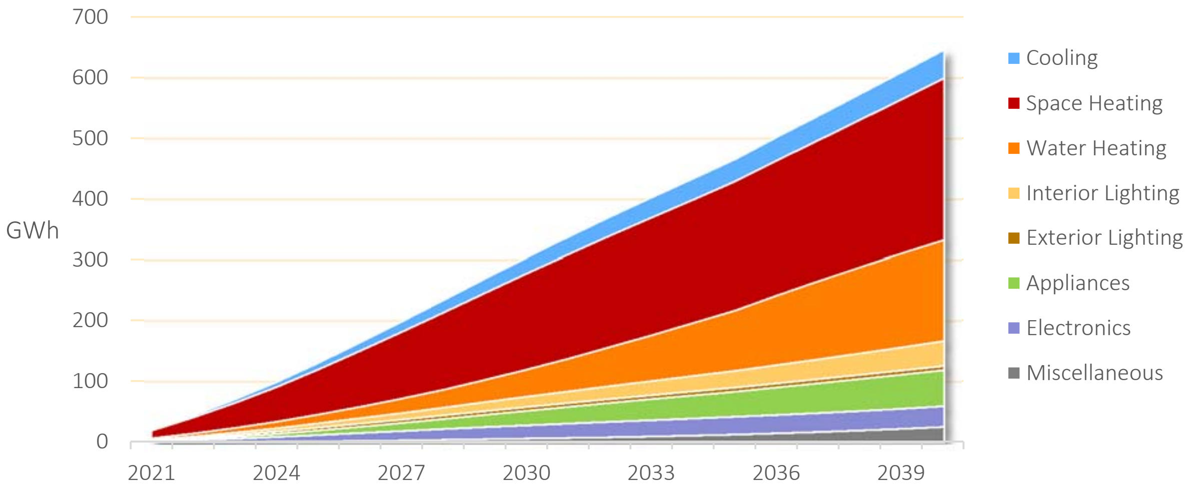


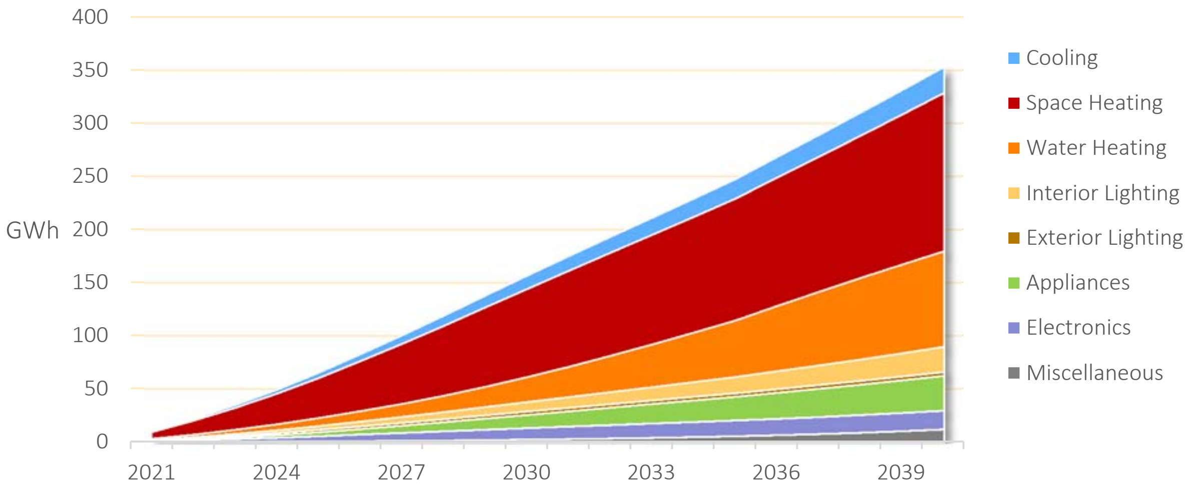
Table 5-7 shows the top residential measures from the perspective of annual energy use in Idaho in 2019. The top three measures are the same as Washington and include Ductless Mini Split Heat Pumps (Ducted Forced Air), Water Heater – Low-Flow Showerheads, and Ductless Mini Split Heat Pump (Zonal). Note that technical achievable savings do not screen for cost effectiveness and some measures are expected to be screened out during the IRP process.

Table 5-7 Residential Top Measures in 2019 (Annual Energy, MWh), Idaho

Rank	Residential Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Ductless Mini Split Heat Pump (Ducted Forced Air)	1,934	9%
2	Ductless Mini Split Heat Pump (Zonal)	1,467	7%
3	Water Heater - Low-Flow Showerheads	1,440	7%
4	Thermostat - Connected	1,086	5%
5	Windows - Low-e Storm Addition	921	4%
6	Building Shell - Infiltration Control	914	4%
7	Insulation - Floor Installation	893	4%
8	Furnace - Conversion to Air-Source Heat Pump	860	4%
9	Windows - Cellular Shades	829	4%
10	Insulation - Wall Cavity Installation	725	3%
11	Ducting - Repair and Sealing	716	3%
12	Monitor	697	3%
13	General Service Screw-in - LEDs	650	3%
14	Insulation - Ducting	597	3%
15	Insulation - Ceiling Installation	495	2%
16	Windows - High Efficiency/ENERGY STAR	420	2%
17	Doors - Storm and Thermal	395	2%
18	Exterior Lighting - Photosensor Control	386	2%
19	Insulation - Foundation	364	2%
20	Insulation - Radiant Barrier	354	2%
	Total of Top 20 Measures	**16,145**	**74%**
	Total Cumulative Savings	**21,726**	**100%**

Figure 5-9 presents forecasts of cumulative energy savings for Idaho. Results are similar to Washington where the majority of the savings come from heating and water heating measures.

Figure 5-9 Residential Technical Achievable Savings Forecast (Cumulative GWh), Idaho



Commercial Conservation Potential

Table 5-8 (WA) and Table 5-9 (ID) present estimates for the two levels of conservation potential for the commercial sector from the perspective of annual energy savings and average MW.

Table 5-8 Commercial Conservation Potential (Annual Energy), WA

	2021	2022	2023	2030	2040
Baseline projection (GWh)	2,162	2,166	2,173	2,292	2,562
Cumulative Savings (GWh)					
Technical Achievable Potential	22	47	73	278	536
Technical Potential	47	93	139	430	703
Cumulative Savings (aMW)					
Technical Achievable Potential	3	5	8	32	61
Technical Potential	5	11	16	49	80
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	1.0%	2.2%	3.4%	12.1%	20.9%
Technical Potential	2.2%	4.3%	6.4%	18.7%	27.4%

Table 5-9 Commercial Conservation Potential (Annual Energy), Idaho

	2021	2022	2023	2030	2040
Baseline projection (GWh)	1,010	1,012	1,016	1,065	1,171
Cumulative Savings (GWh)					
Technical Achievable Potential	11	22	35	136	264
Technical Potential	22	44	66	208	344
Cumulative Savings (aMW)					
Technical Achievable Potential	1	3	4	16	30
Technical Potential	3	5	8	24	39
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	1.0%	2.2%	3.5%	12.8%	22.6%
Technical Potential	2.2%	4.4%	6.5%	19.6%	29.4%

Figure 5-10 (WA) and Figure 5-11 (ID) display the two levels of potential by year. For Washington, the first year of the projection, Technical Achievable Potential is 22 GWh, or 1.0% of the baseline projection. By 2040, technical achievable savings are 536 GWh, or 20.9% of the baseline projection. Throughout the forecast horizon, Technical Achievable Potential represents about 76% of technical potential. For Idaho, first year technical achievable savings are 11 GWh or 1.0% of the baseline and by 2040 cumulative technical achievable savings reach 264 GWh, or 22.6% of the baseline. Throughout the forecast horizon, Technical Achievable Potential represents about 77% of technical potential.

Figure 5-10 Commercial Conservation Savings (Energy), Washington

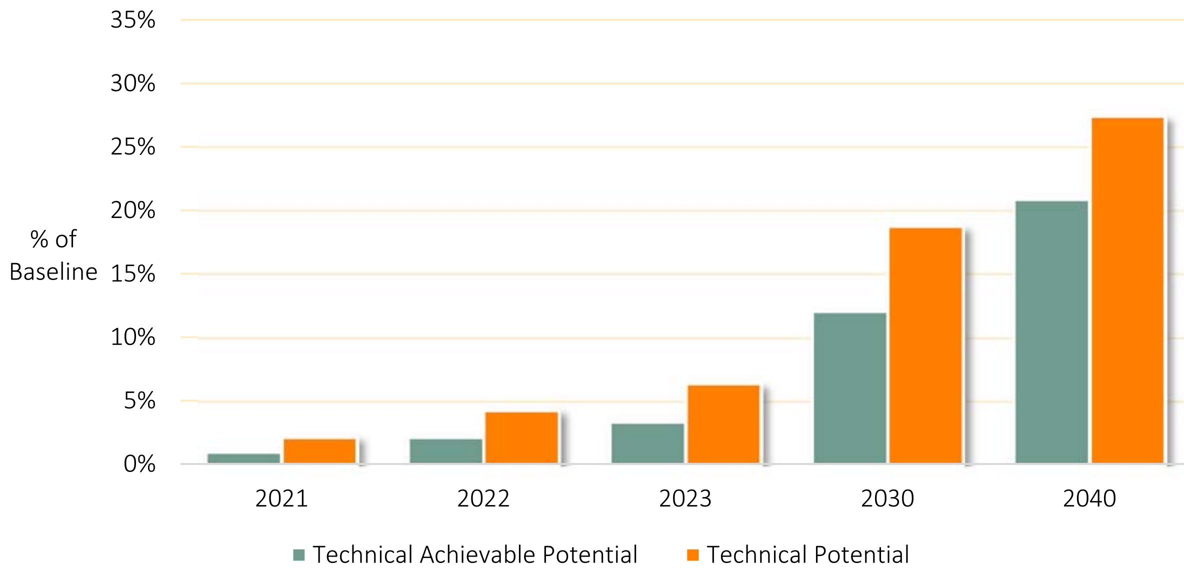
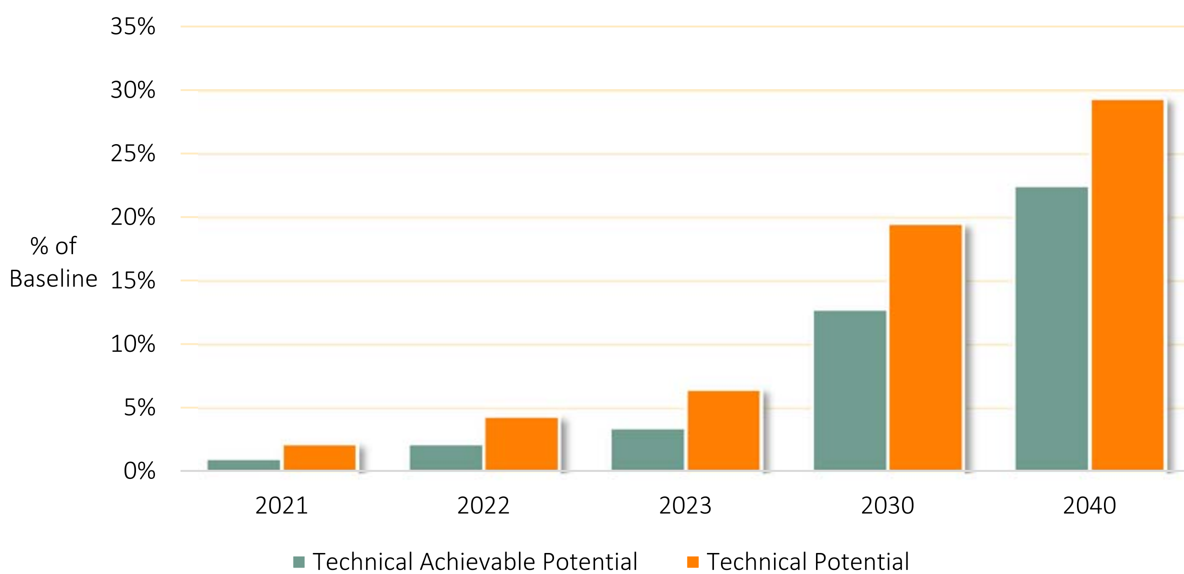


Figure 5-11 Commercial Conservation Savings (Energy), Idaho



Below, we present the top commercial measures from the perspective of annual energy use.

Table 5-10 (WA) and Table 5-11 (ID) identify the top 20 commercial-sector measures from the perspective of annual energy savings in 2019. In both states, lighting applications make up three out of the top five measures. Although the market has seen significant penetration of LEDs in some applications, newer systems – particularly those with built-in occupancy sensors or other controls – still represent significant savings opportunities.

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.

Table 5-10 Commercial Top Measures in 2019 (Annual Energy, MWh), Washington

Rank	Commercial Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Linear Lighting - LEDs	3,852	8%
2	High-Bay Lighting - LEDs	2,674	6%
3	Space Heating - Heat Recovery Ventilator	2,252	5%
4	Refrigeration - Evaporative Condenser	2,181	5%
5	Area Lighting - LEDs	1,908	4%
6	Chiller - Variable Flow Chilled Water Pump	1,714	4%
7	Refrigeration - Variable Speed Compressor	1,678	4%
8	Refrigeration - Replace Single-Compressor with Subcooled Multiplex	1,607	3%
9	HVAC - Dedicated Outdoor Air System (DOAS)	1,434	3%
10	Exterior Lighting - Bi-Level Parking Garage Fixture	1,407	3%
11	Exterior Lighting - Photovoltaic Installation	1,385	3%
12	Retrocommissioning	1,322	3%
13	Destratification Fans (HVLS)	1,207	3%
14	Refrigeration - High Efficiency Compressor	1,126	2%
15	Water Heater - Solar System	1,090	2%
16	Refrigeration - ECM Compressor Head Fan Motor	984	2%
17	Interior Lighting - Networked Fixture Controls	922	2%
18	Office Equipment - Advanced Power Strips	903	2%
19	Exterior Lighting - Enhanced Controls	691	1%
20	Water Heater - Pipe Insulation	664	1%
	Total of Top 20 Measures	**31,001**	**66%**
	Total Cumulative Savings	**46,666**	**100%**

Figure 5-12 Commercial Technical Achievable Savings Forecast (Cumulative GWh), Washington

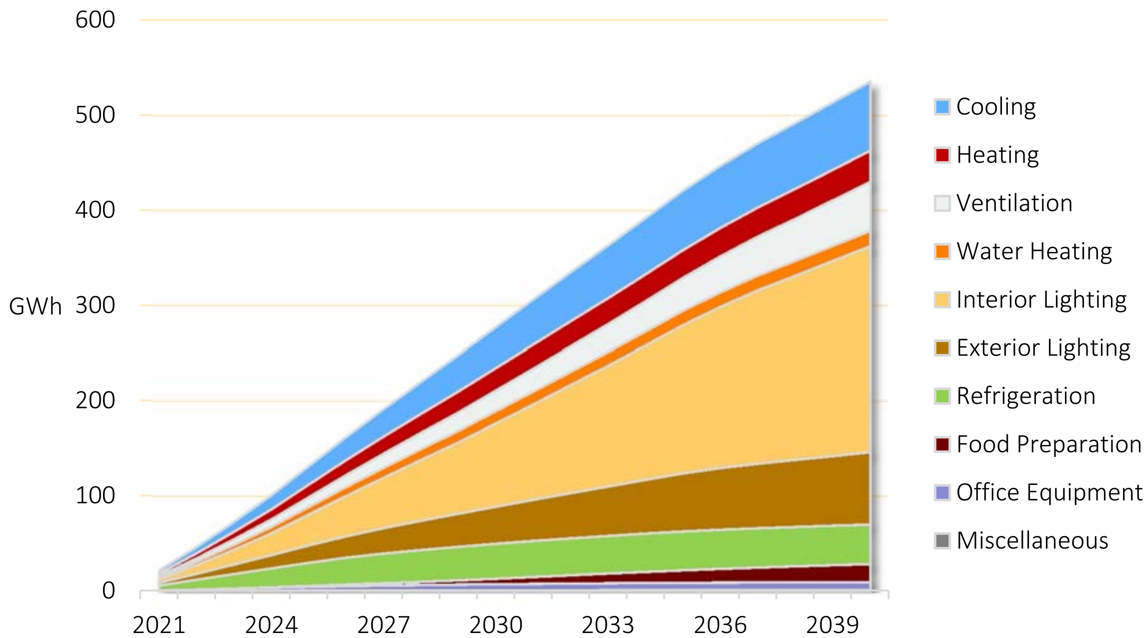
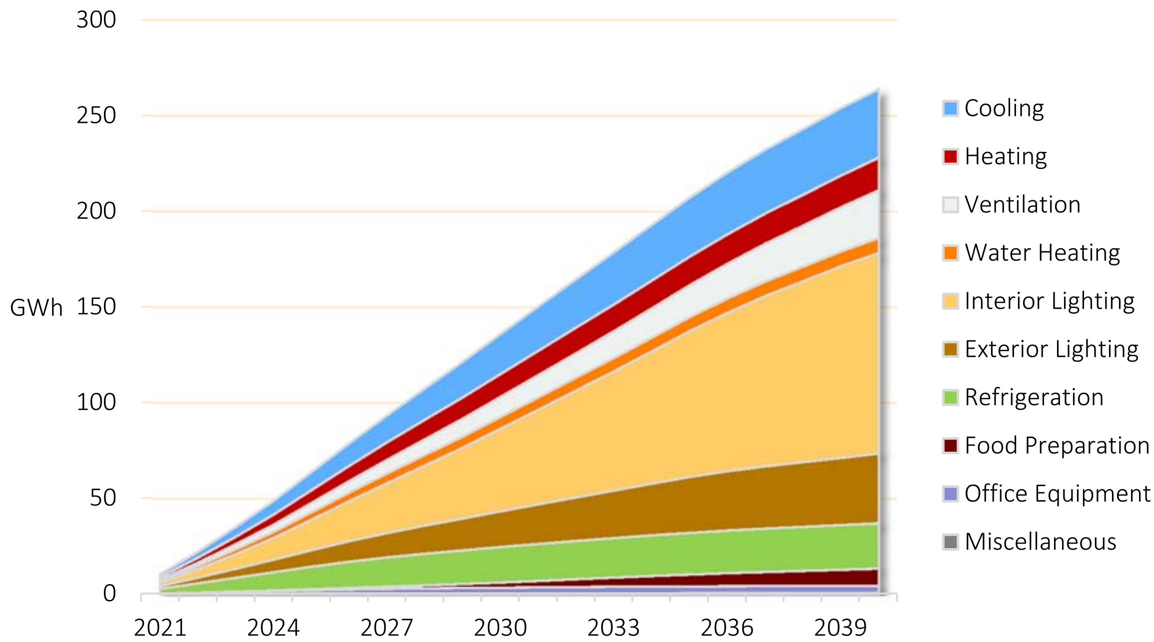


Table 5-11 Commercial Top Measures in 2019 (Annual Energy, MWh), Idaho

Rank	Commercial Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Linear Lighting – LEDs	1,809	8%
2	High-Bay Lighting - LEDs	1,256	6%
3	Space Heating - Heat Recovery Ventilator	1,165	5%
4	Refrigeration - Evaporative Condenser	1,018	5%
5	Area Lighting - LEDs	896	4%
6	Chiller - Variable Flow Chilled Water Pump	812	4%
7	Refrigeration - Variable Speed Compressor	791	4%
8	Refrigeration - Replace Single-Compressor with Subcooled Multiplex	750	3%
9	HVAC - Dedicated Outdoor Air System (DOAS)	668	3%
10	Retrocommissioning	659	3%
11	Exterior Lighting - Bi-Level Parking Garage Fixture	658	3%
12	Exterior Lighting - Photovoltaic Installation	647	3%
13	Destratification Fans (HVLS)	563	3%
14	Refrigeration - High Efficiency Compressor	530	2%
15	Water Heater - Solar System	517	2%
16	Refrigeration - ECM Compressor Head Fan Motor	456	2%
17	Interior Lighting - Networked Fixture Controls	432	2%
18	Office Equipment - Advanced Power Strips	421	2%
19	Exterior Lighting - Enhanced Controls	323	1%
20	Water Heater - Pipe Insulation	315	1%
	Total of Top 20 Measures	14,686	66%
	Total Cumulative Savings	22,325	100%

Figure 5-13 Commercial Technical Achievable Savings Forecast (Cumulative GWh), Idaho



Industrial Conservation Potential

Table 5-12 (WA) and Table 5-13 (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 two levels of potential by year. For Washington, technical achievable savings in the first year, 2021, are 4 GWh, or 0.8% of the baseline projection. In 2040, savings reach 89 GWh, or 12.9% of the baseline projection. For Idaho, technical achievable savings in the first year, 2021, are 3 GWh, or 0.7% of the baseline projection. In 2040, savings reach 56 GWh, or 13.7% of the baseline projection.

Table 5-12 Industrial Conservation Potential (Annual Energy), WA

	2021	2022	2023	2030	2040
Baseline projection (GWh)	553	559	565	612	691
Cumulative Savings (GWh)					
Technical Achievable Potential	4	9	14	54	89
Technical Potential	7	15	22	74	114
Cumulative Savings (aMW)					
Technical Achievable Potential	0	1	2	6	10
Technical Potential	1	2	3	8	13
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.8%	1.6%	2.5%	8.8%	12.9%
Technical Potential	1.3%	2.6%	3.9%	12.2%	16.4%

Table 5-13 Industrial Conservation Potential (Annual Energy), Idaho

	2021	2022	2023	2030	2040
Baseline projection (GWh)	395	395	395	399	407
Cumulative Savings (GWh)					
Technical Achievable Potential	3	6	10	35	56
Technical Potential	5	10	15	48	71
Cumulative Savings (aMW)					
Technical Achievable Potential	0	1	1	4	6
Technical Potential	1	1	2	5	8
Cumulative Savings as a % of Baseline					
Technical Achievable Potential	0.7%	1.6%	2.4%	8.9%	13.7%
Technical Potential	1.2%	2.4%	3.7%	12.0%	17.4%

Figure 5-14 Industrial Conservation Potential as a % of the Baseline Projection (Annual Energy), Washington

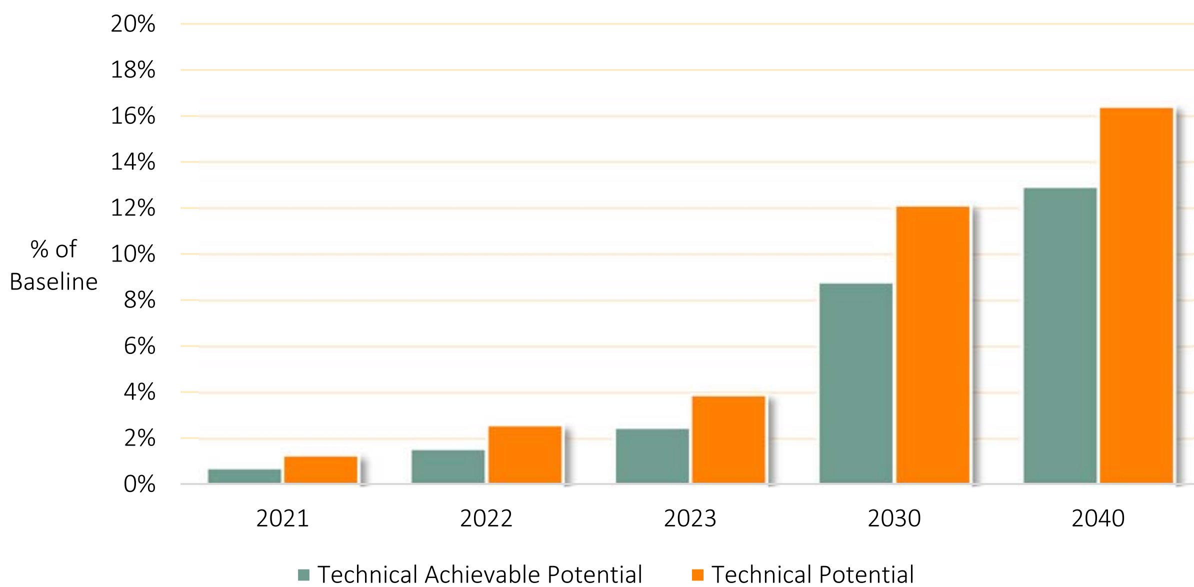
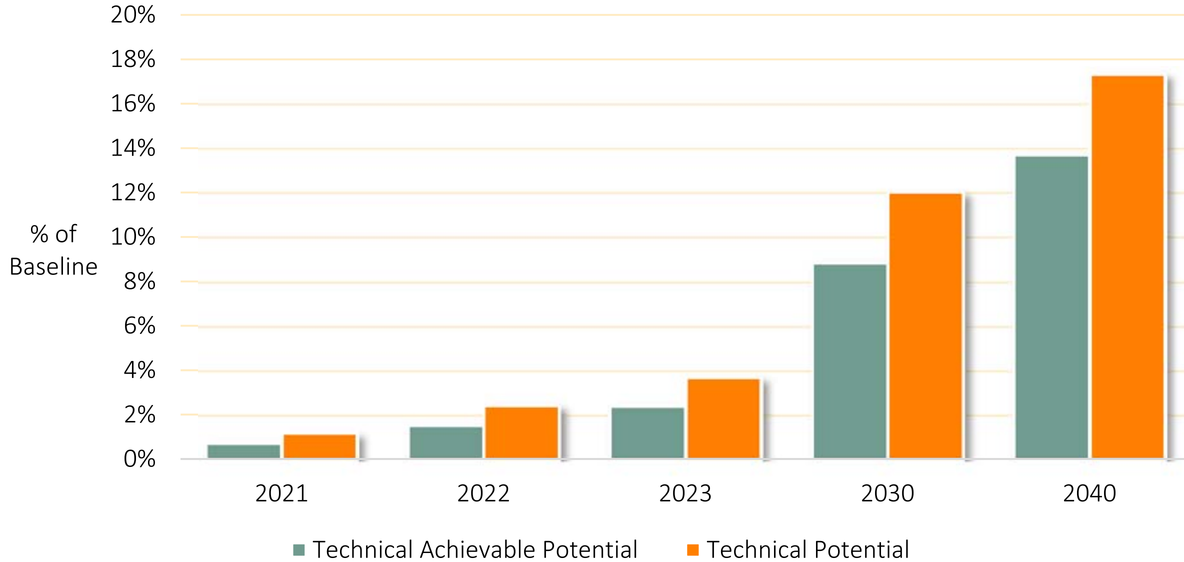


Figure 5-15 Industrial Conservation Potential as a % of the Baseline Projection (Annual Energy), Idaho



Below, we present the top industrial measures from the perspective of annual energy use.

Table 5-14 and Table 5-15 identify the top 20 industrial measures from the perspective of annual energy savings in 2020. For both states, the top measure is the instillation of destratification fans (HVLS). The measure with the second highest savings is the upgrade of compressed air equipment. Compressed air leak management program rounds out the top three in both states.

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. Various motor savings and lighting make up the majority of savings potential in the study horizon.

Table 5-14 Industrial Top Measures in 2019 (Annual Energy, GWh), Washington

Rank	Commercial Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Destratification Fans (HVLS)	1,263	14%
2	Compressed Air - Equipment Upgrade	746	8%
3	Compressed Air - Leak Management Program	728	8%
4	High-Bay Lighting - LEDs	673	8%
5	Pumping System - Equipment Upgrade	372	4%
6	Fan System - Equipment Upgrade	246	3%
7	Paper: Premium Control Large Material	221	2%
8	Material Handling - Variable Speed Drive	216	2%
9	Retrocommissioning	213	2%
10	Kraft: Efficient Agitator	203	2%
11	Fan System - Variable Speed Drive	192	2%
12	Area Lighting	184	2%
13	Compressed Air - Outside Air Intake	181	2%
14	Paper: Efficient Pulp Screen	178	2%
15	Exterior Lighting - Enhanced Controls	178	2%
16	Interior Lighting - Networked Fixture Controls	173	2%
17	Linear Lighting - LEDs	169	2%
18	Compressed Air - End Use Optimization	145	2%
19	Thermostat - Wi-Fi/Interactive	140	2%
20	Motors - Synchronous Belts	137	2%
	Total of Top 20 Measures	**6,560**	**74%**
	Total Cumulative Savings	**8,883**	**100%**

Figure 5-16 Industrial Technical Achievable Savings Forecast (Cumulative GWh), Washington

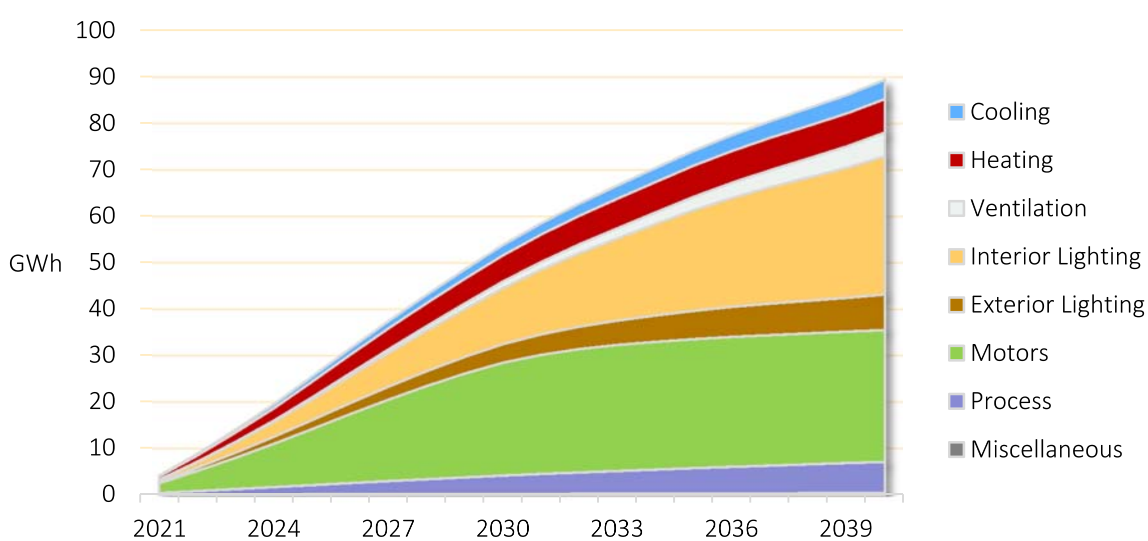
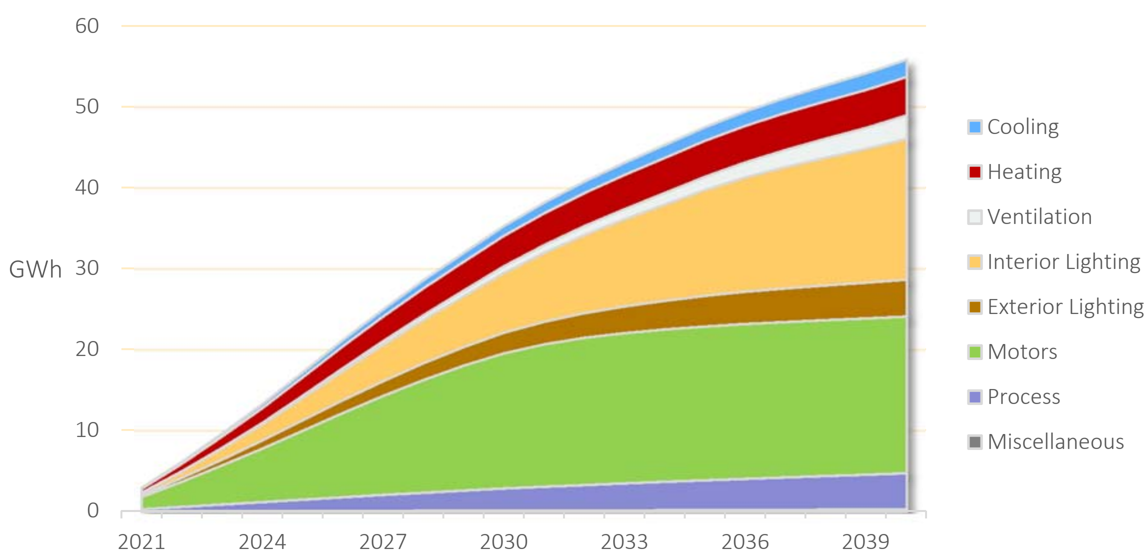


Table 5-15 Industrial Top Measures in 2019 (Annual Energy, GWh), Idaho

Rank	Commercial Measure	2022 Cumulative Energy Savings (MWh)	% of Total
1	Destratification Fans (HVLS)	863	14%
2	Compressed Air - Equipment Upgrade	537	9%
3	Compressed Air - Leak Management Program	524	9%
4	High-Bay Lighting	413	7%
5	Pumping System - Equipment Upgrade	268	4%
6	Fan System - Equipment Upgrade	177	3%
7	Paper: Premium Control Large Material	159	3%
8	Material Handling - Variable Speed Drive	155	3%
9	Retrocommissioning	155	3%
10	Kraft: Efficient Agitator	146	2%
11	Fan System - Variable Speed Drive	138	2%
12	Compressed Air - Outside Air Intake	130	2%
13	Exterior Lighting - Enhanced Controls	128	2%
14	Paper: Efficient Pulp Screen	128	2%
15	Area Lighting	113	2%
16	Interior Lighting - Networked Fixture Controls	112	2%
17	Linear Lighting	104	2%
18	Compressed Air - End Use Optimization	104	2%
19	Motors - Synchronous Belts	98	2%
20	Thermostat - Wi-Fi/Interactive	95	2%
	Total of Top 20 Measures	**4,547**	**74%**
	Total Cumulative Savings	**6,149**	**100%**

Figure 5-17 Industrial Technical Achievable Savings Forecast (Annual Energy, GWh), Idaho



6

DEMAND RESPONSE POTENTIAL

In 2014, AEG and The Brattle Group performed an assessment of winter demand response potential for Avista's commercial and industrial (C&I) sectors. As part of this conservation potential assessment, Avista asked AEG to update the DR analysis for C&I sectors in Washington and Idaho. In 2016, AEG provided an update to the 2014 assessment. This year, Avista asked that AEG include the demand response potential for their residential sector. In addition, since Avista is a dual-peaking utility, AEG was also asked to provide summer demand response potential.

The updated analysis provides demand response potential and cost estimates for the 20-year planning horizon of 2021-2040 to inform the development of Avista's 2019 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 analysis focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics that may hinder resource acquisition. DR analysis results will also be incorporated into subsequent DR planning and program development efforts.

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 residential service, general service, large general service, and extra-large general service 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 the relevant DR programs and develop assumptions on key program parameters for potential and cost analysis.
3. Assess achievable potential by DR program for the 2021-2040 planning period and estimate program budgets and levelized costs.

Market Characterization

The first step in the DR analysis was to segment customers by service class and develop characteristics for each segment. The two relevant characteristics for DR potential analysis are the number of eligible customers in each market segment and their coincident peak demand.

Market segmentation

Like the 2014 and 2016 studies, we used Avista's rate schedules as the basis for customer segmentation by state and customer class. Table 6-1 summarizes the market segmentation we developed for this study.

Table 6-1 Market Segmentation

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

We excluded Avista's two largest industrial customers from our analysis because they are so large and unique that a segment-based modeling approach is not appropriate. 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. We would also need to develop specific DR potential estimates for each customer. Avista may wish to engage with these large customers directly to gauge interest in participating in DR programs.

Customer Counts by Segment

Once the customer segments were defined, we developed customer counts and coincident peak demand values for the three C&I segments. We developed these estimates separately by state for Washington and Idaho. We considered 2017 as the base year for the study, since this is the most recent year with a full 12 months of available customer data. This also coincides with the base year used for the CPA study. The forecast years are 2018 to 2040.

Avista provided the number of customers by rate schedule for Washington and Idaho over the 2017-2023 timeframe. We used this data to calculate the average annual growth rate. We then applied these same average annual growth rates to develop customer projections over the rest of the study timeframe, 2024-2040. The average annual growth rate for all sectors is 1.1%. Table 6-2 below shows the number of customers by state and customer class for the base year and selected future years.

Table 6-2 Baseline C&I Customer Forecast by State and Customer Class

Customer Class	2017	2018	2019	2020	2027	2037
Washington						
Residential Service	222,837	225,529	227,521	229,618	243,398	245,335
General Service	22,415	22,716	22,945	23,202	25,002	27,783
Large General Service	1,835	1,845	1,844	1,844	1,844	1,844
Extra Large General Service	20	20	20	20	20	20

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

Customer Class	2017	2018	2019	2020	2027	2037
Idaho						
Residential Service	112,001	113,733	115,077	116,390	126,029	127,452
General Service	15,979	16,176	16,366	16,559	17,980	18,193
Large General Service	1,114	1,115	1,115	1,115	1,115	1,115
Extra Large General Service	11	11	11	11	11	11

Forecasts of Winter and Summer Peak Demand

System Peak Demand

Avista provided the 2017 system winter and summer peak values as well as annual energy forecasts through 2024. AEG used the annual energy growth rate by state and sector to forecast annual peak demands through 2040, Table 6-3 shows the winter and summer system peaks for the base year and selected futures years. These peaks exclude the demand for Avista's largest industrial customers. The winter and summer system peaks are each expected to increase by 4.1% by 2037, an average annual increase of 0.21%.

Table 6-3 Baseline System Winter Peak Forecast (MW @Meter) [12]

Peak Demand	2017	2018	2019	2020	2030	2037
Winter System Peak	1496	1468	1434	1440	1509	1559
Summer System Peak	1417	1389	1355	1362	1428	1477

Coincident Peak Demand by Segment

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 years 2017 through 2024. For the remaining years of the forecast, 2025 through 2040, we projected electricity sales using the average annual growth rate over the 2017 through 2021 timeframe.

Next, we relied on electricity sales and coincident peak demand values for 2010 provided in the 2010 load research study conducted by Avista to calculate the load factors for Residential Service, General Service, Large General Service, and Extra Large General Service customers for Washington and Idaho. We then applied the load factors to the 2017 electricity sales data to derive coincident peak demand estimates for the four segments. Table 6-4 and Table 6-5 below show the load factors and coincident peak values for the base year and selected future years.

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

Table 6-4 Winter Load Factors and Baseline Coincident Peak Forecast by Segment (MW @Meter)

Customer Class	Load Factor	2017	2018	2019	2020	2027	2037
Washington							
Residential	**0.63**	575	551	527	529	548	550
General Service	**0.60**	82	80	81	82	88	89
Large General Service	**0.60**	187	187	188	188	188	188
Extra Large General Service	**0.69**	83	87	86	86	85	85
Total		**928**	**905**	**882**	**885**	**910**	**913**
Idaho							
Residential	**0.65**	264	256	248	251	267	270
General Service	**0.66**	63	62	63	63	68	69
Large General Service	**0.66**	99	99	98	98	98	98
Extra Large General Service	**0.60**	52	56	56	55	54	54
Total		**477**	**473**	**464**	**467**	**487**	**490**

Table 6-5 Summer Load Factors and Baseline Coincident Peak Forecast by Segment (MW @Meter)

Customer Class	Load Factor	2017	2018	2019	2020	2027	2037
Washington							
Residential	**0.50**	568	544	520	523	525	528
General Service	**0.51**	76	74	74	75	81	82
Large General Service	**0.51**	173	173	173	173	174	174
Extra Large General Service	**0.57**	68	71	71	71	70	70
Total		**885**	**862**	**839**	**842**	**845**	**849**
Idaho							
Residential	**0.53**	254	246	239	241	243	246
General Service	**0.57**	57	57	57	57	58	59
Large General Service	**0.57**	89	90	89	89	88	89
Extra Large General Service	**0.53**	46	50	49	49	49	49
Total		**446**	**442**	**434**	**436**	**439**	**442**

System and Coincident Peak Forecasts by State

The next step in market characterization is to define the estimated peak load forecast for the study timeframe. This is done at the Avista system level, and also by state. We used Avista's peak demand data to develop the individual state contribution to the estimated coincident peak values. These represent a state's projected demand at the time of the system peak for both summer and winter.

Figure 6-1 shows the statewide contribution to the estimated system coincident summer peak, developed based on load forecast data provided by Avista. In the base year of analysis, 2017, system peak load for the summer is 1,374 MW at the grid or generator level. Washington contributes 66% of summer system peak while Idaho contributes 34%. Over the study period, summer coincident peak load is expected to grow by an average of 0.48% annually from 2021-2040.

Figure 6-1 Contribution to Estimated System Coincident Peak Forecast by State (Summer)

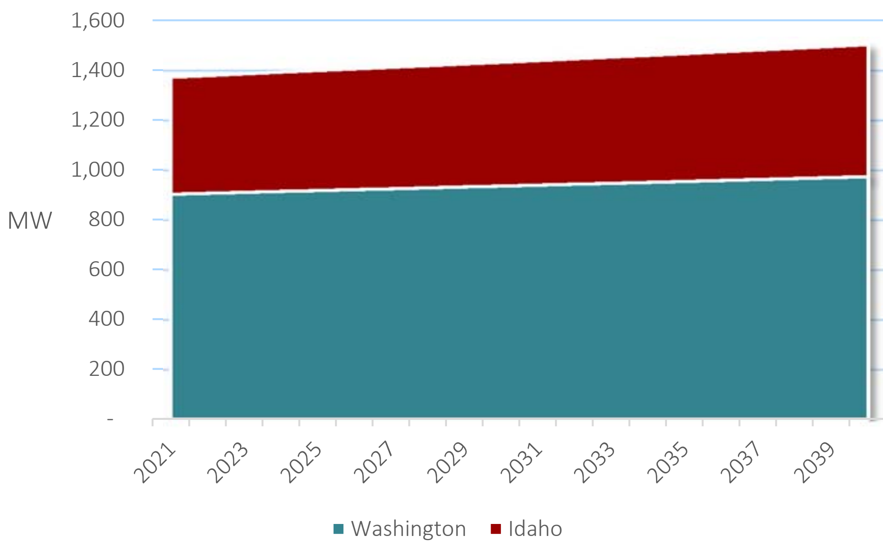
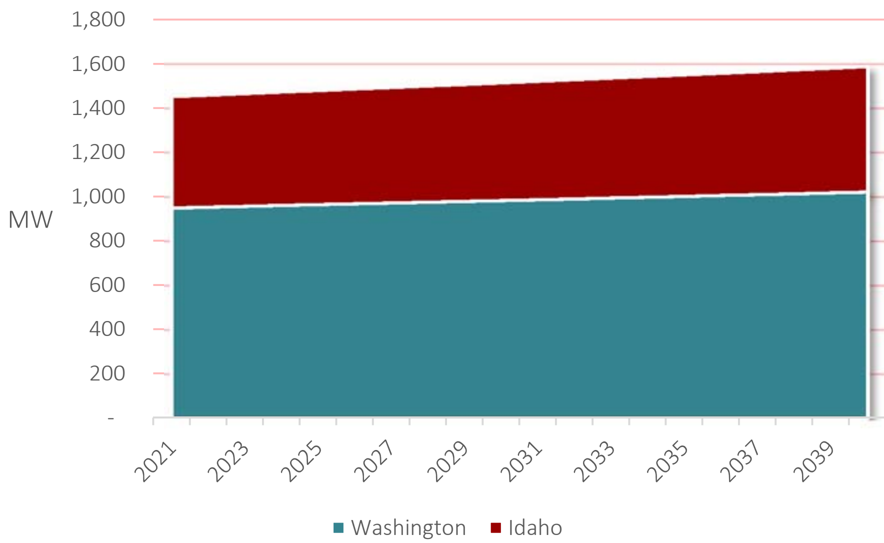


Figure 6-2 shows the jurisdictional contribution to the estimated system coincident winter peak forecast, developed based on load forecast data provided by PacifiCorp. In the base year of analysis, 2016, system peak load for the winter (a typical December weekday at 6:00 pm) is 8,170 MW at the grid or generator level. The winter system peak is about 18% lower than the summer peak. Utah contributes 38% of winter system peak, followed by Oregon at 32%, Wyoming at 15%, Washington 10%, and Idaho 3%, with California at 2%. Over the study period, winter coincident peak load is expected to grow by an average of 0.59% annually.

Figure 6-2 Contribution to Estimated System Coincident Peak Forecast by State (Winter)



Equipment End Use Saturation

Another key component of market characterization for DR analysis is end use saturation data. This is required to further segment the market and identify eligible customers for direct control of different equipment options. The relevant space heating equipment for DR analysis are electric furnaces and air-source heat pumps. We obtained C&I saturation data from the CPA study, which had updated figures from the 2014 NEEA Commercial Building Stock Assessment (CBSA). We obtained Residential saturation data from the 2016 NEEA Residential Building Stock Assessment (RBSA). Table 6-6 and Table 6-7 below show saturation estimates by state and customer class for Washington and Idaho respectively. We assume slight growth trends in Central AC, Space Heating, and Electric Vehicle saturations through 2040. AMI Saturations are new to the analysis this year. We assume 100% AMI Saturation in the residential sector from the start of the forecast horizon. Avista plans to have 100% AMI Saturation in the commercial sector by 2022 in Washington and by 2024 in Idaho. They plan to roll out each over the course of two years starting in 2020 in Washington and 2022 in Idaho.

Table 6-6 2017 End Use Saturations by Customer Class, Washington

End Use Saturation by Equipment Type	Residential	C&I
Space Heating Saturation		
Electric Furnace	7.4%	1.2%
Air-Source Heat Pump	19.4%	14.2%
Total (Applicable for DR Analysis)	***26.8%***	***15.5%***
Water Heating Saturation		
All equipment	42.2%	45.2%
Electric Vehicle Saturation		
All equipment	0.2%	-
Central AC Saturation		
All Equipment	38.4%	38.4%
AMI Saturation		
All Equipment	100.0%	0.0%
Appliance Saturation		
All Equipment	100.0%	-

Table 6-7 2017 End Use Saturation by Customer Class, Idaho

End Use Saturation by Equipment Type	Residential	C&I
Space Heating Saturation		
Electric Furnace	7.4%	1.2%
Air-Source Heat Pump	9.9%	14.2%
Total (Applicable for DR Analysis)	***17.3%***	***15.5%***
Water Heating Saturation		
All equipment	43.0%	45.2%
Electric Vehicle Saturation		
All equipment	0.2%	-
Central AC Saturation		
All Equipment	36.0%	36.0%
AMI Saturation		
All Equipment	100.0%	0.0%
Appliance Saturation		
All Equipment	100.0%	-

DSM Program Options

The next step in the analysis is to characterize the available DSM options for the Avista territory. We considered the characteristics and applicability of a comprehensive list of options available in the DSM marketplace today as well as those projected into the 20-year study time horizon. We included for quantitative analysis those options which have been deployed at scale such that reliable estimates exist for cost, lifetime, and performance. Each selected option is described briefly below.

Program Descriptions

Direct Load Control of Central Air Conditioners

The DLC Central AC program targets Avista's Residential and General Service customers in Washington and Idaho. This program directly controls Central AC load in summer through a load control switch placed on a customer's AC unit. During events, the AC units will be cycled on and off. Participation in the program is expected to be shared with the Smart Thermostat- Cooling Program in the integrated scenario since the programs are similar. However, if only one program is rolled out of the two, then participation would be expected to double for the program implemented. In the fully integrated case, we assume it would take three full time employees to manage all the DLC programs (five total).

Direct Load Control of Domestic Hot Water Heaters

The DLC Domestic Hot Water Heater program targets Avista's Residential and General Service customers in Washington and Idaho. This program directly controls water heating load throughout the year for these customers through a load control switch. Water heaters would be completely turned off during the DR event period. The event period is assumed to be 50 hours during the summer months and another 50 hours during winter months. Water heaters of all sizes are eligible for control. We assume a $160 cost to Avista for each switch, a $200 installation fee, and a permit and license cost of $100 for residential participants ($125 for general service participants).

Smart Thermostats DLC Heating/Cooling

This program uses the two-way communicating ability of smart thermostats to cycle them on and off during events. The Smart Thermostat program targets Avista's Residential and General Service customers in Washington and Idaho. We assume this will be a Bring your own Thermostat program (BYOT) and therefore assume no installation costs to Avista. Since the cooling and heating programs are quite different as far as impact assumptions and participation rates, we modeled them separately. As mentioned in the DLC Central AC program description, participation in the DLC Smart Thermostat Cooling program is expected to be split between the two programs in the integrated scenario.

Smart Appliances DLC

The Smart Appliances DLC program uses a Wi-Fi hub to connect smart Wi-Fi enabled appliances such as washers, dryers, refrigerators, and water heaters. During events throughout the year, the smart appliances will be cycled on and off. The Smart Appliances DLC program targets Avista's Residential and General Service customers in Washington and Idaho. We assume a low steady-state participation rate of 5% for this program.

Third Party Contracts

Third Party Contracts are assumed to be available for General Service, Large General Service, and Extra Large General Service customers year-round. For the Large and Extra Large General Service customers, we assume they will engage in firm curtailment. Under this program option, it is assumed that participating customers will agree to reduce demand by a specific amount or curtail their consumption to a predefined level at the time of an event. 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 the capacity payment typically varies with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction during events. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity requirements. Penalties may be assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by load aggregators and is most attractive for customers with maximum demand greater than 200 kW and flexibility in their operations. Industry experience indicates that aggregation of customers with smaller sized loads is less attractive financially due to lower economies of scale. In addition, 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.

For the general service customers, we simulate a demand buyback program. In a demand buyback program, customers volunteer to reduce what they can on a day-ahead or day-of basis during a predefined event window. Customers then receive an energy payment based on their performance during the events.

Electric Vehicle DLC Smart Chargers

DLC Smart Chargers for Electric Vehicles can be switched off during on-peak hours throughout the year to offset demand to off-peak hours. Avista currently has an Electric Vehicle Supply Equipment (EVSE) pilot program in place for residential, commercial electric vehicle fleets, and workplace charging locations. We also assume the DR program would only be available for residential service customers. The EVSE pilot called daily demand response events from 4-8 PM. The events yielded impacts of 0.41 kW per charger however the notifications only reached 82.5% of participants. Therefore, we assume a smaller impact per charger of 0.34 kW per charger for this study.

Time-of-Use Pricing

The Time-of-Use (TOU) pricing rate is a standard rate structure where rates are lower during off-peak hours and higher during peak hours during the day incentivizing participants to shift energy use to periods of lower grid stress. For the TOU rate, there are no events called and the structure does not change during the year. Therefore, it is a good default rate for customers that still offers some load shifting potential. We assume two scenarios for the TOU rate. An opt-in rate where participants will have to choose to go on the rate and an opt-out rate where participants will automatically be placed on the TOU rate and will need to request a rate change if required. We assume this rate will be available to all service classes.

Variable Peak Pricing

The Variable Peak Pricing (VPP) rate is composed of significantly higher prices during relatively short critical peak periods on event days to encourage customers to reduce their usage. VPP 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 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. We assume that this rate will be offered to all service classes.

Real Time Pricing

The Real Time Pricing rate is a dynamic rate that fluctuates throughout the day based on energy market prices. Since it is a dynamic rate that will involve shifting energy use depending on the different prices throughout the day, we assume only Large and Extra Large General Service customers will be able to utilize this rate.

Ancillary Services

Ancillary Services refer to functions that help grid operators maintain a reliable electricity system. Ancillary services maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. In systems with significant variable renewable energy penetration, additional ancillary services may be required to manage increased variability and uncertainty. We assume ancillary services demand response capabilities can be available in all sectors.

Thermal Energy Storage

Ice Energy Storage, a type of thermal energy storage, is an emerging technology that is being explored in many peak-shifting applications across the country. This technology involves cooling and freezing water in a storage container so that the energy can be used at a later time for space cooling. More specifically, the freezing water takes advantage of the large amount of latent energy associated with the phase change between ice and liquid water, which will absorb or release a large amount of thermal energy while maintaining a constant temperature at the freezing (or melting) point. An ice energy storage unit turns water into ice during off-peak times when price and demand for electricity is low, typically night time. During the day, at peak times, the stored ice is melted to meet all or some of the building's cooling requirements, allowing air conditioners to operate at reduced loads.

Ice energy storage is primarily being used in non-residential buildings and applications, as modeled in this analysis, but may see expansion in the future to encompass smaller, residential systems as well as emerging grid services for peak shaving and renewable integration. Since the ice energy storage is used for space cooling, we assume this program would be available during the summer months only.

Battery Energy Storage

This program provides the ability to shift peak loads using stored electrochemical energy. Currently the main battery storage equipment uses Lithium-Ion Batteries. They are the most cost-effective battery type on the market today. We assume the battery energy storage option will be available for all service classes with the size and cost of the battery varying depending upon the level of demand of the building.

Behavioral

Behavioral DR is structured like traditional demand response interventions, but it does not rely on enabling technologies nor does it offer financial incentives to participants. Participants are notified of an event and simply asked to reduce their consumption during the event window. Generally, notification occurs the day prior to the event and are deployed utilizing a phone call, email, or text message. The next day, customers may receive post-event feedback that includes personalized results and encouragement.

For this analysis, we assumed the Behavioral DR program would be offered as part of a Home Energy Reports program in a typical opt-out scenario. As such, we assume this program would be offered to residential customers only.

Program Assumptions and Characteristics

Table 6-8 lists the DSM options considered in the study, including the eligible sectors, the mechanism for deployment and the expected annual event hours (summer and winter hours combined if both seasons are considered). As shown below, this study update includes a multitude of options that were not considered in the previous study. Space Heating was considered as an additional option, however Avista ultimately decided the Smart Thermostat DLC Heating program would be sufficient for DLC space heating options. For cooling, both Central AC DLC and Smart Thermostats DLC were considered as options.

Table 6-8 Class 1 DSM Products Assessed in the Study

DSM Option	Eligible Sectors	Mechanism	Annual Event Hours
DLC of central air conditioners	Residential, General Service	Direct load control switch installed on customer's equipment	100
DLC of domestic hot water heaters (DHW)	Residential, General Service	Direct load control switch installed on customer's equipment	100
Smart Thermostats DLC Heating	Residential, General Service	Internet-enabled control of thermostat set points	36
Smart Thermostats DLC Cooling	Residential, General Service	Internet-enabled control of thermostat set points	36
Smart Appliances DLC	Residential, General Service	Internet-enabled control of operational cycles of white goods appliances	1056
Thermal Energy Storage	General Service, Large General Service, Extra Large General Service	Peak shifting of space cooling loads using stored ice	72
Third Party Contracts	General Service, Large General Service, Extra Large General Service	Customers enact their customized, mandatory curtailment plan. Penalties apply for non-performance.	60
Electric Vehicle DLC Smart Chargers	Residential	Automated, level 2 EV chargers that postpone or curtail charging during peak hours.	1056
Time-of-Use Pricing	All Sectors	Higher rate for a particular block of hours that occurs every day. Requires either on/off peak meters or AMI technology.	1056
Variable Peak Pricing	All Sectors	Much higher rate for a particular block of hours that occurs only on event days. Requires AMI technology.	80
Real Time Pricing	Large General Service, Extra Large General Service	Dynamic rate that fluctuates throughout the day based on energy market prices. Requires AMI technology.	72
Ancillary Services	All Sectors	Automated control of various building management systems or end-uses through one of the mechanisms already described	160
Thermal Energy Storage	General Service, Large General Service, Extra Large General Service	Peak shifting of primarily space cooling or heating loads using a thermal storage medium such as water or ice	72

DSM Option	Eligible Sectors	Mechanism	Annual Event Hours
Battery Energy Storage	All Sectors	Peak shifting of loads using stored electrochemical energy	72
Behavioral	Residential	Voluntary DR reductions in response to behavioral messaging. Example programs exist in CA and other states. Requires AMI technology.	80

The description of options below includes the key assumptions used for potential and levelized cost calculations. The development of these assumptions is based on findings from research and review of available information on the topic, including national program survey databases, evaluation studies, program reports, regulatory filings. The key parameters required to estimate potential for a DSM program are participation rate, per participant load reduction and program costs. We have described below our assumptions of these parameters.

Participation Rate Assumptions

Table 6-9 below shows the steady-state participation rate assumptions for each DSM option as well as the basis for the assumptions. As previously mentioned, the participation for space cooling is split between DLC Central AC and Smart Thermostat options.

Table 6-9 DSM Steady-State Participation Rates (% of eligible customers)

DSM Option	Residential Service	General Service	Large General Service	Extra Large General Service	Basis for Assumption
Direct Load Control (DLC) of central air conditioners	7%	7%	-	-	50/50 split between DLC Central AC and Smart Thermostats
DLC of domestic hot water heaters (DHW)	15%	5%	-	-	Industry Experience- Brattle Study
Smart Thermostats DLC Heating	12.5%	10%	-	-	Agreed Upon Estimate with Avista
Smart Thermostats DLC Cooling	7%	7%	-	-	Agreed Upon Estimate with Avista (See DLC Central AC)
Smart Appliances DLC	5%	5%	-	-	2017 ISACA IT Risk Reward Barometer – US Consumer Results, October 2017
Third Party Contracts	-	15%	22.1%	20.9%	Industry Experience
Electric Vehicle DLC Smart Chargers	25%	-	-	-	Industry Experience
Time-of-Use Pricing Opt-in	13%	13%	13%	13%	Best estimate based on industry experience; Winter impacts ½ of summer impacts
Time-of-Use Pricing Opt-out	74%	74%	74%	74%	
Variable Peak Pricing	25%	25%	25%	25%	OG&E 2017 Smart Hours Study
Real Time Pricing	-	-	3%	3%	Industry Experience
Ancillary Services	15%	7.5%	7.5%	7.5%	Industry Experience; C&I ½ of Residential
Thermal Energy Storage	-	0.5%	1.5%	1.5%	Industry Experience
Battery Energy Storage	0.5%	0.5%	0.5%	0.5%	Industry Experience
Behavioral	20%	-	-	-	PG&E rollout with six waves (2017)

Load Reduction Assumptions

Table 6-10 presents the per participant load reductions for each DSM option and explains the basis for these assumptions. The load reductions are shown on a kW basis for technology-based options and a percent load reduction otherwise.

Table 6-10 DSM Per Participant Impact Assumptions

DSM Option	Residential	General Service	Large General Service	Extra Large General Service	Basis for Assumption
Direct Load Control (DLC) of central air conditioners	0.5 kW	1.22 kW	-	-	Average CAC Impacts across WA and ID in Avista territory
DLC of domestic hot water heaters (DHW)	0.58 kW	1.46 kW	-	-	7th Plan, pg. 25 from Cadmus Report, Commercial: Res value multiplied by the CAC DLC ratio (small C&I impact /Res impact)
Smart Thermostats DLC Heating	1.5 kW	4 kW	-	-	Developed using the average of the 7th plan and the PSE 2010 DLC Pilot (WA), multiplied by ratio of HDD for the area
Smart Thermostats DLC Cooling	0.5 kW	1.22 kW	-	-	Average CAC Impacts across WA and ID in Avista territory
Smart Appliances DLC	0.14 kW	0.14 kW	-	-	Ghatikar, Rish. Demand Response Automation in Appliance and Equipment. Lawrence Berkley National Laboratory, 2017.
Third Party Contracts	-	10%	21%	21%	Impact Estimates from Aggregator Programs in California (Source: 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).
Electric Vehicle DLC Smart Chargers	0.34 kW	-	-	-	Avista EVSE DR Pilot Program for Residential-impact was 0.41 kW. 82.5% of customers received the DR notification so reducing to 0.34 kW.
Time-of-Use Pricing Opt-in	5.7%	0.2%	2.6%	3.1%	Best estimate based on industry experience; Winter impacts ½ of summer impacts
Time-of-Use Pricing Opt-out	3.4%	0.2%	2.6%	3.1%	
Variable Peak Pricing	10%	4%	4%	4%	OG&E 2017 Smart Hours Study; Summer Impacts Shown (Winter impacts ¾ summer)
Real Time Pricing	-	-	4%	4%	Industry Experience; Same as VPP Large and Extra Large General Service
Ancillary Services	4.8%	4.8%	4.8%	4.8%	Industry Experience

DSM Option	Residential	General Service	Large General Service	Extra Large General Service	Basis for Assumption
Thermal Energy Storage		1.68 kW	8.4 kW	8.4 kW	Ice Bear Tech Specifications, https://www.ice-energy.com/wp-content/uploads/2016/03/ICE-BEAR-30-Product-Sheet.pdf
Battery Energy Storage	2 kW	2 kW	15 kW	15 kW	Typical Battery size per segment
Behavioral	2%	-	-	-	Opower documentation for BDR with Consumers and Detroit Energy

Program Costs

Table 6-11 shows the annual marketing, recruitment, incentives, and program development costs associated with each DSM option.

Table 6-12 presents itemized cost assumptions for the DSM Options and the basis for the assumptions for the state of Washington. Table 6-11 shows the annual O&M costs per participant and per MW (Third Party Contracts only) and the Cost of Equipment and installation per participant and per kW (Thermal Energy Storage only).

Table 6-11 DSM Program Operations Maintenance, and Equipment Costs (Washington)

DSM Option	Annual O&M Cost Per Participant	Annual O&M Cost per MW	Cost of Equip + Install Per Participant	Cost of Equip + Install per kW
DLC Central AC	$13.00		$260.00	$0.00
DLC Water Heating	$23.63		$472.50	$0.00
DLC Smart Thermostats – Heating	$44.00		$0.00	$0.00
DLC Smart Thermostats - Cooling	$44.00		$0.00	$0.00
DLC Smart Appliances	$0.00		$300.00	$0.00
Third Party Contracts	$0.00	$80,000.00	$0.00	$0.00
DLC Electric Vehicle Charging	$11.00		$1,200.00	$0.00
Time-of-Use Opt-in	$0.00		$0.00	$0.00
Time-of-Use Opt-out	$0.00		$0.00	$0.00
Variable Peak Pricing Rates	$0.00		$0.00	$0.00
Real Time Pricing	$0.00		$0.00	$0.00
Ancillary Services	$0.00		$300.00	$0.00
Thermal Energy Storage	$308.00		$0.00	$6,160.00
Battery Energy Storage	$0.00		$27,897.60	$0.00
Behavioral	$3.25		$0.00	$0.00

Table 6-12 shows the annual marketing, recruitment, incentives, and program development costs associated with each DSM option.

Table 6-12 Marketing, Recruitment, Incentive, and Development Costs (Washington)

DSM Option	Annual Marketing/Recruitment Cost Per Participant	Annual Incentive Per Participant	Program Development Cost
DLC Central AC	$67.50	$29.00	$23,863.32
DLC Water Heating	$0.00	$24.00	$24,128.89
DLC Smart Thermostats - Heating	$67.50	$20.00	$23,963.15
DLC Smart Thermostats - Cooling	$67.50	$20.00	$23,863.32
DLC Smart Appliances	$50.00	$0.00	$24,084.70
Third Party Contracts	$0.00	$0.00	$0.00
DLC Electric Vehicle Charging	$50.00	$24.00	$49,135.60
Time-of-Use Opt-in	$57.50	$0.00	$12,315.14
Time-of-Use Opt-out	$57.50	$0.00	$12,281.26
Variable Peak Pricing Rates	$175.00	$0.00	$12,222.26
Real Time Pricing	$300.00	$0.00	$24,194.41
Ancillary Services	$0.00	$0.00	$11,700.67
Thermal Energy Storage	$100.00	$0.00	$14,994.78
Battery Energy Storage	$25.00	$0.00	$8,017.36
Behavioral	$0.00	$0.00	$66,055.68

Table 6-13 and *Table 6-14* present the equivalent cost tables for the state of Idaho.

Table 6-13 DSM Program Operations Maintenance, and Equipment Costs (Idaho)

DSM Option	Annual O&M Cost Per Participant	Annual O&M Cost per MW	Cost of Equip + Install Per Participant	Cost of Equip + Install per kW
DLC Central AC	$13.00		$260.00	$0.00
DLC Water Heating	$23.63		$472.50	$0.00
DLC Smart Thermostats – Heating	$44.00		$0.00	$0.00
DLC Smart Thermostats - Cooling	$44.00		$0.00	$0.00
DLC Smart Appliances	$0.00		$300.00	$0.00
Third Party Contracts	$0.00	$80,000.00	$0.00	$0.00
DLC Electric Vehicle Charging	$11.00		$1,200.00	$0.00
Time-of-Use Opt-in	$0.00		$0.00	$0.00
Time-of-Use Opt-out	$0.00		$0.00	$0.00
Variable Peak Pricing Rates	$0.00		$0.00	$0.00
Real Time Pricing	$0.00		$0.00	$0.00
Ancillary Services	$0.00		$300.00	$0.00
Thermal Energy Storage	$308.00		$0.00	$6,160.00
Battery Energy Storage	$0.00		$27,897.60	$0.00
Behavioral	$3.25		$0.00	$0.00

Table 6-14 Marketing, Recruitment, Incentive, and Development Costs (Idaho)

DSM Option	Annual Marketing/Recruitment Cost Per Participant	Annual Incentive Per Participant	Program Development Cost
DLC Central AC	$67.50	$29.00	$13,636.68
DLC Water Heating	$0.00	$24.00	$13,371.11
DLC Smart Thermostats - Heating	$67.50	$20.00	$13,536.85
DLC Smart Thermostats - Cooling	$67.50	$20.00	$13,636.68
DLC Smart Appliances	$50.00	$0.00	$13,415.30
Third Party Contracts	$0.00	$0.00	$0.00
DLC Electric Vehicle Charging	$50.00	$24.00	$25,864.40
Time-of-Use Opt-in	$69.00	$0.00	$6,434.86
Time-of-Use Opt-out	$69.00	$0.00	$6,468.74
Variable Peak Pricing Rates	$175.00	$0.00	$6,527.74
Real Time Pricing	$300.00	$0.00	$13,305.59
Ancillary Services	$0.00	$0.00	$7,049.33
Thermal Energy Storage	$100.00	$0.00	$10,005.22
Battery Energy Storage	$25.00	$0.00	$4,482.64
Behavioral	$0.00	$0.00	$33,944.32

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 5.21% 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.
- **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.

DR Potential and Cost Estimates

This section presents analysis results on demand savings and cost estimates for DR programs. We developed savings estimates in two ways:

- First, we present the integrated results. If Avista offers 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. For this study, we assumed a customer would not be on both a Central AC program and a Smart Thermostat program and would only be on a thermal energy storage program or battery energy storage program. The hierarchy of pricing rates is as follows: Time-of-Use, Variable Peak Pricing, and Real Time Pricing.
- At the very end of this section, we present high-level standalone results in 2040 without considering the integrated effects that occur if more than one DR option is offered to Avista customers. Standalone results represent an upper bound for each program individually and should not be added together as that would overstate the overall system level potential.

All potential results presented in this section represent capacity savings in terms of equivalent generation capacity.

Integrated Potential Results

The following sections separate out the integrated potential results for winter and summer for the Time-of-Use Opt-in and Time-of-Use Opt-out scenarios.

Winter TOU Opt-in Scenario

Figure 6-3 and Table 6-15 show the total winter demand savings from individual DR options for selected years of the analysis. These savings represent integrated savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- In the TOU opt-in scenario, participants are split more evenly across the available pricing options, leading to larger participation in the variable peak pricing rate and consequently a large VPP savings potential.
- The highest potential option is Third Party Contracts which is expected to reach a savings potential of 23.2 MW by 2040.
- Since most of the participants are likely to be on the VPP pricing rate in the TOU Opt-in scenario, the TOU potential is significantly lower than in the Opt-out case.
- After Third Party Contracts, the next three biggest potential options in winter include VPP, DLC Smart Thermostats- Heating, and DLC Water Heating all of which are projected to contribute over 19 MW by 2040.
- The total potential savings in the winter TOU Opt-in scenario are expected to increase from 13 MW in 2021 to nearly 107 MW by 2040. The respective increase in the percentage of system peak goes from 0.9% in 2021 to 6.7% by 2040.

Figure 6-3 Summary of Potential Analysis for Avista (TOU Opt-In Winter Peak MW @Generator)

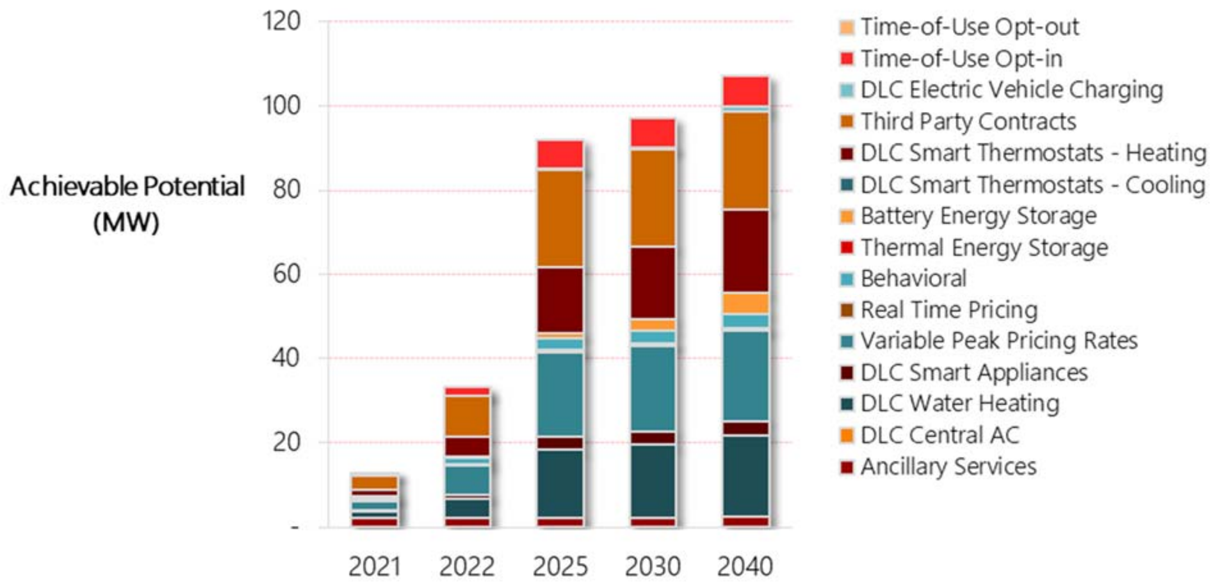


Table 6-15 Achievable DR Potential by Option (TOU Opt-In Winter MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (MW)	13.0	33.2	91.9	97.0	106.9
Market Potential (% of baseline)	0.9%	2.3%	6.2%	6.4%	6.7%
Potential Forecast	**1,440**	**1,427**	**1,389**	**1,418**	**1,482**
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	1.5	4.7	16.2	17.1	19.3
DLC Smart Thermostats - Heating	1.5	4.6	16.0	17.2	19.7
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.3	0.9	3.0	3.1	3.4
Third Party Contracts	3.4	9.5	23.0	23.0	23.2
DLC Electric Vehicle Charging	0.0	0.0	0.3	0.6	1.1
Time-of-Use Opt-in	0.7	2.2	6.7	6.9	7.2
Time-of-Use Opt-out	0.0	0.0	0.0	0.0	0.0
Variable Peak Pricing Rates	2.3	7.0	20.0	20.5	21.5
Real Time Pricing	0.1	0.3	0.6	0.6	0.6
Ancillary Services	2.2	2.2	2.2	2.3	2.5
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.1	0.3	1.0	2.8	5.2
Behavioral	0.8	1.6	2.9	3.0	3.2
Achievable Potential (% of Baseline)					
DLC Central AC	0.00%	0.00%	0.00%	0.00%	0.00%
DLC Water Heating	0.11%	0.32%	1.09%	1.13%	1.21%
DLC Smart Thermostats - Heating	0.10%	0.32%	1.08%	1.13%	1.24%
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.02%	0.06%	0.20%	0.21%	0.22%
Third Party Contracts	0.23%	0.65%	1.55%	1.52%	1.46%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.07%
Time-of-Use Opt-in	0.05%	0.15%	0.46%	0.45%	0.45%
Time-of-Use Opt-out	-	-	-	-	-
Variable Peak Pricing Rates	0.16%	0.48%	1.35%	1.35%	1.35%
Real Time Pricing	0.01%	0.02%	0.04%	0.04%	0.04%
Ancillary Services	0.15%	0.15%	0.15%	0.15%	0.16%
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.01%	0.02%	0.07%	0.18%	0.33%
Behavioral	0.06%	0.11%	0.20%	0.20%	0.20%

Table 6-16 and Table 6-17 show demand savings by individual DR option for the states of Washington and Idaho separately. Using the available DSM options, Washington is projected to save 68.78 MW (4.3% of winter system peak demand) by 2040 while Idaho is projected to save 38.16 MW (2.4% of winter system peak demand) by 2040.

Table 6-16 Achievable DR Potential by Option for Washington (TOU Opt-In Winter MW @Generator)

Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (MW)	9.09	23.06	59.79	62.92	68.78
Market Potential (% of System Peak)	0.6%	1.6%	4.0%	4.2%	4.3%
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	0.99	3.00	10.38	11.07	12.60
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.76	7.28	14.58	14.64	14.78
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in	0.49	1.49	4.50	4.57	4.72
Time-of-Use Opt-out	-	-	-	-	-
Variable Peak Pricing Rates	1.62	4.85	13.25	13.49	14.00
Real Time Pricing	0.07	0.17	0.38	0.38	0.38
Ancillary Services	1.35	1.36	1.39	1.44	1.55
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.55	1.07	1.96	2.00	2.08

Table 6-17 Achievable DR Potential by Option for Idaho (TOU Opt-In Winter MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (Winter MW)	3.87	10.15	32.07	34.11	38.16
Market Potential (% of System Peak)	0.3%	0.7%	2.2%	2.3%	2.4%
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	0.53	1.61	5.60	6.00	6.88
DLC Smart Thermostats - Heating	0.53	1.61	5.64	6.10	7.14
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.10	0.30	1.04	1.10	1.24
Third Party Contracts	0.64	2.25	8.37	8.40	8.47
DLC Electric Vehicle Charging	0.00	0.02	0.09	0.19	0.39
Time-of-Use Opt-in	0.22	0.67	2.24	2.32	2.47
Time-of-Use Opt-out					
Variable Peak Pricing Rates	0.70	2.16	6.73	6.97	7.48
Real Time Pricing	0.04	0.11	0.21	0.21	0.21
Ancillary Services	0.82	0.82	0.84	0.87	0.93
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.03	0.08	0.35	0.98	1.87
Behavioral	0.26	0.51	0.95	0.99	1.07

Cost Results

Table 6-18 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The Third Party Contracts option delivers the highest savings at approximately $74.8/kW-year cost. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third party contractor.
- The Variable Peak Pricing option has lowest levelized cost among all the DR options. It delivers 21.8 MW of savings in 2040 at $21.01/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of CPP deployment costs.

Table 6-18 DR Program Costs and Potential (TOU Opt-In Winter)

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Winter Potential MW in 2040
DLC Central AC	-	-	-	-
DLC Water Heating	$139.94	$138.67	$139.49	19.27
DLC Smart Thermostats - Heating	$46.17	$45.21	$45.83	19.74
DLC Smart Thermostats - Cooling	-	-	-	-
DLC Smart Appliances	$237.04	$240.63	$238.30	3.45
Third Party Contracts	$74.80	$74.80	$74.80	23.25
DLC Electric Vehicle Charging	$688.90	$698.35	$692.17	1.14
Time-of-Use Opt-in	$45.56	$54.73	$48.68	7.20
Time-of-Use Opt-out	-	-	-	-
Variable Peak Pricing Rates	$21.60	$22.81	$22.01	21.48
Real Time Pricing	$194.77	$191.22	$193.51	0.58
Ancillary Services	$90.19	$94.80	$91.74	2.48
Thermal Energy Storage	-	-	-	-
Battery Energy Storage	$389.31	$393.28	$390.70	5.21
Behavioral	$128.58	$134.97	$130.75	3.15

Winter TOU Opt-out Scenario

Figure 6-4 and Table 6-19 show the total winter demand savings from individual DR options for selected years of the analysis. These savings represent integrated savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- In the TOU opt-out scenario, customers are placed on the Time-of-Use rate by default and will need to go through an added step to switch rates. Therefore, the majority of savings among the rates are concentrated in TOU which is expected to reach 27.4 MW by 2040.
- In the Opt-out scenario, most of the participants are likely to be on the TOU pricing rate and we see a much lower savings potential for the VPP rate (6.6 MW by 2040).
- After TOU, the next three biggest potential options in winter include Third Party Contracts, DLC Smart Thermostats- Heating, and DLC Water Heating all of which are projected to contribute over 19 MW by 2040.
- The total potential savings in the winter TOU Opt-out scenario are expected to increase from 45.6 MW in 2021 to nearly 112 MW by 2040. The respective increase in the percentage of system peak goes from 3.1% in 2021 to 7.0% by 2040. In this scenario, the potential savings starts at a much faster rate than in the opt-in case as the participation in TOU will represent a much bigger portion initially.

Figure 6-4 Summary of Winter Potential Analysis for Avista (TOU Opt-Out MW @Generator)

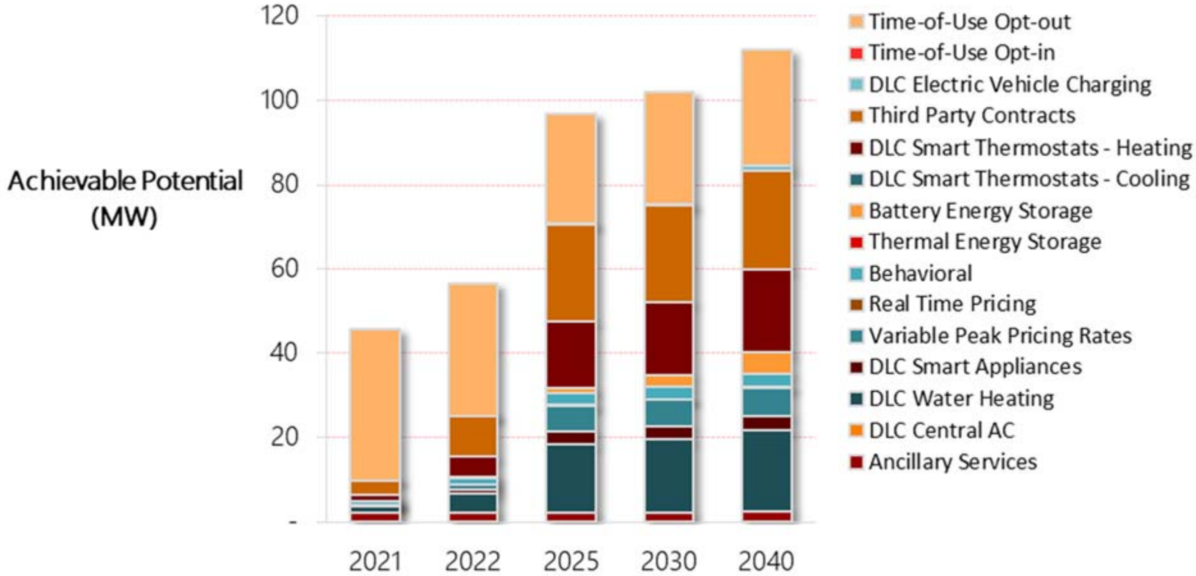


Table 6-19 Achievable DR Potential by Option – TOU Opt-Out (Winter MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (Winter MW)	45.6	56.7	96.8	101.9	111.9
Market Potential (% of baseline)	3.1%	3.9%	6.5%	6.7%	7.0%
Potential Forecast	**1,407**	**1,403**	**1,384**	**1,413**	**1,477**
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	1.5	4.7	16.2	17.1	19.3
DLC Smart Thermostats - Heating	1.5	4.6	16.0	17.2	19.7
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.3	0.9	3.0	3.1	3.4
Third Party Contracts	3.4	9.5	23.0	23.0	23.2
DLC Electric Vehicle Charging	0.0	0.0	0.3	0.6	1.1
Time-of-Use Opt-in	-	-	-	-	-
Time-of-Use Opt-out	35.7	31.7	25.9	26.4	27.4
Variable Peak Pricing Rates	0.1	1.2	6.1	6.3	6.6
Real Time Pricing	0.0	0.1	0.2	0.2	0.2
Ancillary Services	2.2	2.2	2.2	2.3	2.5
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.1	0.3	1.0	2.8	5.2
Behavioral	0.8	1.6	2.9	3.0	3.2
Achievable Potential (% of Baseline)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	0.11%	0.32%	1.09%	1.13%	1.21%
DLC Smart Thermostats - Heating	0.10%	0.32%	1.08%	1.13%	1.24%
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.02%	0.06%	0.20%	0.21%	0.22%
Third Party Contracts	0.23%	0.65%	1.55%	1.52%	1.46%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.07%
Time-of-Use Opt-in	-	-	-	-	-
Time-of-Use Opt-out	2.46%	2.17%	1.75%	1.74%	1.73%
Variable Peak Pricing Rates	0.01%	0.08%	0.41%	0.41%	0.41%
Real Time Pricing	0.00%	0.01%	0.01%	0.01%	0.01%
Ancillary Services	0.15%	0.15%	0.15%	0.15%	0.16%
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.01%	0.02%	0.07%	0.18%	0.33%
Behavioral	0.06%	0.11%	0.20%	0.20%	0.20%

Table 6-20 and Table 6-21 show demand savings by individual DR option for the states of Washington and Idaho separately.

Table 6-20 Achievable DR Potential by Option for Washington - TOU Opt-Out (MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (Winter MW)	8.39	21.45	55.77	58.77	64.34
Market Potential (% of System Peak)	0.6%	1.6%	4.0%	4.1%	4.3%
Achievable Potential (MW)					
DLC Central AC	0.39	1.19	4.04	4.32	4.92
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.39	1.20	4.15	4.44	5.06
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.44	6.50	13.04	13.10	13.23
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in	0.48	1.44	4.36	4.43	4.58
Time-of-Use Opt-out					
Variable Peak Pricing Rates	1.58	4.70	12.85	13.09	13.59
Real Time Pricing	0.06	0.16	0.34	0.34	0.33
Ancillary Services	1.21	1.22	1.25	1.30	1.40
Thermal Energy Storage	0.03	0.14	0.45	0.46	0.48
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.54	1.06	1.93	1.97	2.05

Table 6-21 Achievable DR Potential by Option for Idaho – TOU Opt-Out (MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (Winter MW)	3.56	9.40	30.20	31.80	35.64
Market Potential (% of System Peak)	0.3%	0.7%	2.2%	2.2%	2.4%
Achievable Potential (MW)					
DLC Central AC	0.22	0.65	2.28	2.43	2.85
DLC Water Heating	0.53	1.61	5.68	6.00	6.88
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.22	0.66	2.34	2.50	2.94
DLC Smart Appliances	0.10	0.30	1.06	1.10	1.24
Third Party Contracts	0.57	2.01	7.55	7.57	7.64
DLC Electric Vehicle Charging	0.00	0.02	0.11	0.19	0.39
Time-of-Use Opt-in	0.21	0.64	2.14	2.20	2.35
Time-of-Use Opt-out					
Variable Peak Pricing Rates	0.67	2.06	6.42	6.61	7.10
Real Time Pricing	0.04	0.10	0.19	0.19	0.19
Ancillary Services	0.74	0.74	0.77	0.79	0.85
Thermal Energy Storage	0.00	0.03	0.29	0.30	0.32
Battery Energy Storage	0.03	0.08	0.45	0.98	1.87
Behavioral	0.25	0.49	0.92	0.95	1.03

Cost Results

Table 6-22 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The TOU Opt-out option delivers the highest savings at approximately $62.87/kW-year cost and has the potential to contribute 27.42 MW of savings in 2040.
- The Third Party Contracts option delivers the second highest savings at approximately $74.8/kW-year cost. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third party contractor.
- The Variable Peak Pricing option has lowest levelized cost among all the DR options. It delivers 21.8 MW of savings in 2040 at $35.76/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of CPP deployment costs.

Table 6-22 DR Program Costs and Potential – TOU Opt Out Winter

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Winter Potential MW in 2040
DLC Central AC	-	-	-	-
DLC Water Heating	$139.94	$138.67	$139.49	19.27
DLC Smart Thermostats - Heating	$46.17	$45.21	$45.83	19.74
DLC Smart Thermostats - Cooling	-	-	-	-
DLC Smart Appliances	$237.04	$240.63	$238.30	3.45
Third Party Contracts	$74.80	$74.80	$74.80	23.25
DLC Electric Vehicle Charging	$688.90	$698.35	$692.17	1.14
Time-of-Use Opt-in	-	-	-	-
Time-of-Use Opt-out	$58.06	$72.18	$62.87	27.42
Variable Peak Pricing Rates	$35.30	$36.64	$35.76	6.59
Real Time Pricing	$659.87	$578.41	$193.51	0.18
Ancillary Services	$90.19	$94.80	$91.74	2.48
Thermal Energy Storage	-	-	-	-
Battery Energy Storage	$389.31	$393.28	$390.70	5.21
Behavioral	$128.58	$134.97	$130.75	3.15

Summer TOU Opt-in Scenario

Figure 6-5 and Table 6-23 show the total summer demand savings from individual DR options for selected years of the analysis. These savings represent integrated savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- Similar to the winter case, in the TOU opt-in scenario, many customers will choose to go on the variable peak pricing rate leading to a large VPP savings potential.
- The highest potential option is Third Party Contracts which is expected to reach a savings potential of 20.87 MW by 2040.
- Since most of the participants are likely to be on the VPP pricing rate in the TOU Opt-in scenario, the TOU potential is significantly lower than in the Opt-out case.
- After Third Party Contracts, the next two biggest potential options in summer include VPP, and DLC Water Heating each of which are projected to contribute over 19 MW by 2040. Space cooling options are split across DLC Smart Thermostat and DLC Central AC options. Together they contribute 15.78 MW by 2040.

- The total potential savings in the summer TOU Opt-in scenario are expected to increase from 11.9 MW in 2021 to 100 MW by 2040. The respective increase in the percentage of system peak goes from 0.9% in 2021 to 6.6% by 2040 (very similar to the winter percentages).

Figure 6-5 Summary of Summer Potential by Option (TOU Opt-In MW @Generator)

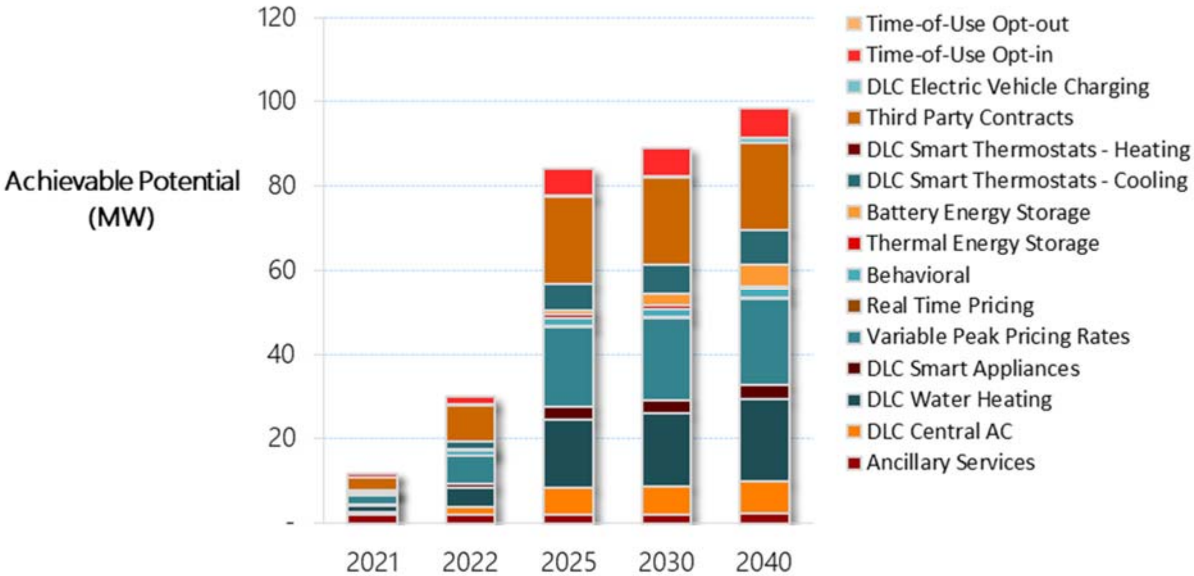


Table 6-23 Achievable DR Potential by Option TOU Opt-In (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (MW)	11.9	30.8	85.6	90.6	100.0
Market Potential (% of baseline)	0.9%	2.2%	6.1%	6.3%	6.6%
Potential Forecast	**1,362**	**1,350**	**1,315**	**1,343**	**1,405**
Achievable Potential (MW)					
DLC Central AC	0.61	1.84	6.32	6.75	7.78
DLC Water Heating	1.54	4.68	16.23	17.13	19.27
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.61	1.85	6.49	6.93	8.00
DLC Smart Appliances	0.29	0.88	3.01	3.14	3.45
Third Party Contracts	3.01	8.52	20.60	20.67	20.87
DLC Electric Vehicle Charging	0.01	0.05	0.30	0.55	1.14
Time-of-Use Opt-in	0.68	2.09	6.50	6.63	6.93
Time-of-Use Opt-out	-	-	-	-	-
Variable Peak Pricing Rates	2.25	6.76	19.27	19.70	20.69
Real Time Pricing	0.10	0.25	0.52	0.52	0.52
Ancillary Services	1.95	1.96	2.02	2.09	2.25
Thermal Energy Storage	0.03	0.17	0.74	0.76	0.80
Battery Energy Storage	0.08	0.26	1.10	2.77	5.21
Behavioral	0.79	1.55	2.85	2.92	3.08
Achievable Potential (% of Baseline)					
DLC Central AC	0.04%	0.13%	0.45%	0.47%	0.52%
DLC Water Heating	0.11%	0.34%	1.16%	1.19%	1.28%
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.04%	0.13%	0.46%	0.48%	0.53%
DLC Smart Appliances	0.02%	0.06%	0.22%	0.22%	0.23%
Third Party Contracts	0.22%	0.62%	1.47%	1.44%	1.39%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.08%
Time-of-Use Opt-in	0.05%	0.15%	0.46%	0.46%	0.46%
Time-of-Use Opt-out	-	-	-	-	-
Variable Peak Pricing Rates	0.16%	0.49%	1.38%	1.37%	1.37%
Real Time Pricing	0.01%	0.02%	0.04%	0.04%	0.03%
Ancillary Services	0.14%	0.14%	0.14%	0.15%	0.15%
Thermal Energy Storage	0.00%	0.01%	0.05%	0.05%	0.05%
Battery Energy Storage	0.01%	0.02%	0.08%	0.19%	0.35%
Behavioral	0.06%	0.11%	0.20%	0.20%	0.20%

Table 6-24 and Table 6-25 show demand savings by individual DR option for the states of Washington and Idaho separately.

Table 6-24 Achievable DR Potential by Option for WashingtonTOU Opt-In (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (MW)	8.39	21.45	55.77	58.77	64.34
Market Potential (% of System Peak)	0.6%	1.6%	4.0%	4.1%	4.3%
Achievable Potential (MW)					
DLC Central AC	0.39	1.19	4.04	4.32	4.92
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.39	1.20	4.15	4.44	5.06
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.44	6.50	13.04	13.10	13.23
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in	0.48	1.44	4.36	4.43	4.58
Time-of-Use Opt-out	-	-	-	-	-
Variable Peak Pricing Rates	1.58	4.70	12.85	13.09	13.59
Real Time Pricing	0.06	0.16	0.34	0.34	0.33
Ancillary Services	1.21	1.22	1.25	1.30	1.40
Thermal Energy Storage	0.03	0.14	0.45	0.46	0.48
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.54	1.06	1.93	1.97	2.05

Table 6-25 Achievable DR Potential by Option for Idaho TOU Opt-In (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Market Potential (MW)	3.56	9.40	30.20	31.80	35.64
Market Potential (% of System Peak)	0.3%	0.7%	2.2%	2.2%	2.4%
Achievable Potential (MW)					
DLC Central AC	0.22	0.65	2.28	2.43	2.85
DLC Water Heating	0.53	1.61	5.68	6.00	6.88
DLC Smart Thermostats - Heating	0.00	0.00	0.00	0.00	0.00
DLC Smart Thermostats - Cooling	0.22	0.66	2.34	2.50	2.94
DLC Smart Appliances	0.10	0.30	1.06	1.10	1.24
Third Party Contracts	0.57	2.01	7.55	7.57	7.64
DLC Electric Vehicle Charging	0.00	0.02	0.11	0.19	0.39
Time-of-Use Opt-in	0.21	0.64	2.14	2.20	2.35
Time-of-Use Opt-out					
Variable Peak Pricing Rates	0.67	2.06	6.42	6.61	7.10
Real Time Pricing	0.04	0.10	0.19	0.19	0.19
Ancillary Services	0.74	0.74	0.77	0.79	0.85
Thermal Energy Storage	0.00	0.03	0.29	0.30	0.32
Battery Energy Storage	0.03	0.08	0.45	0.98	1.87
Behavioral	0.25	0.49	0.92	0.95	1.03

Cost Results

Table 6-26 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The Third Party Contracts option delivers the highest savings at approximately $83.39/kW-year cost. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third party contractor.
- The Variable Peak Pricing option has the lowest levelized cost among all the DR options. It delivers 21.36 MW of savings in 2040 at $22.85/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of CPP deployment costs.

Table 6-26 DR Program Costs and Potential – Summer TOU Opt-In

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Summer Potential MW in 2040
DLC Central AC	$120.70	$118.55	$119.95	7.78
DLC Water Heating	$139.94	$138.67	$139.49	19.27
DLC Smart Thermostats - Heating	-	-	-	-
DLC Smart Thermostats - Cooling	$131.00	$127.06	$129.62	8.00
DLC Smart Appliances	$237.04	$240.63	$238.30	3.45
Third Party Contracts	$83.62	$82.98	$83.39	20.69
DLC Electric Vehicle Charging	$688.90	$698.35	$692.16	1.14
Time-of-Use Opt-in	$46.99	$57.66	$50.55	6.93
Time-of-Use Opt-out	-	-	-	-
Variable Peak Pricing Rates	$22.26	$24.05	$22.85	20.36
Real Time Pricing	$218.89	$212.35	$193.51	0.33
Ancillary Services	$99.98	$104.78	$101.56	2.25
Thermal Energy Storage	$610.99	$591.88	$603.36	0.80
Battery Energy Storage	$389.31	$393.28	$390.70	5.21
Behavioral	$130.16	$140.39	$133.57	2.05

Summer TOU Opt-out Scenario

Figure 6-6 and Table 6-27 show the total summer demand savings from individual DR options for selected years of the analysis. These savings represent integrated savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- In the TOU opt-out scenario, customers are placed on the Time-of-Use rate by default and will need to go through an added step to switch rates. Therefore, the majority of savings among the rates are concentrated in TOU which is expected to reach 26.2 MW by 2040.
- In the Opt-out scenario, most of the participants are likely to be on the TOU pricing rate and we see a much lower savings potential for the VPP rate (6.35 MW by 2040).
- After TOU Opt-out, the next two biggest potential options in summer include Third Party Contracts, and DLC Water Heating each of which are projected to contribute over 19 MW by 2040. Space cooling options are split across DLC Smart Thermostat and DLC Central AC options. Together they contribute 15.78 MW by 2040.
- The total potential savings in the summer TOU Opt-in scenario are expected to increase from 43.2 MW in 2021 to 104.5 MW by 2040. The respective increase in the percentage of system peak goes from 3.1% in 2021 to 6.9% by 2040 (very similar to the winter percentages for the TOU Opt-in case).

Figure 6-6 Summary of Summer Potential – TOU Opt-Out (MW @Generator)

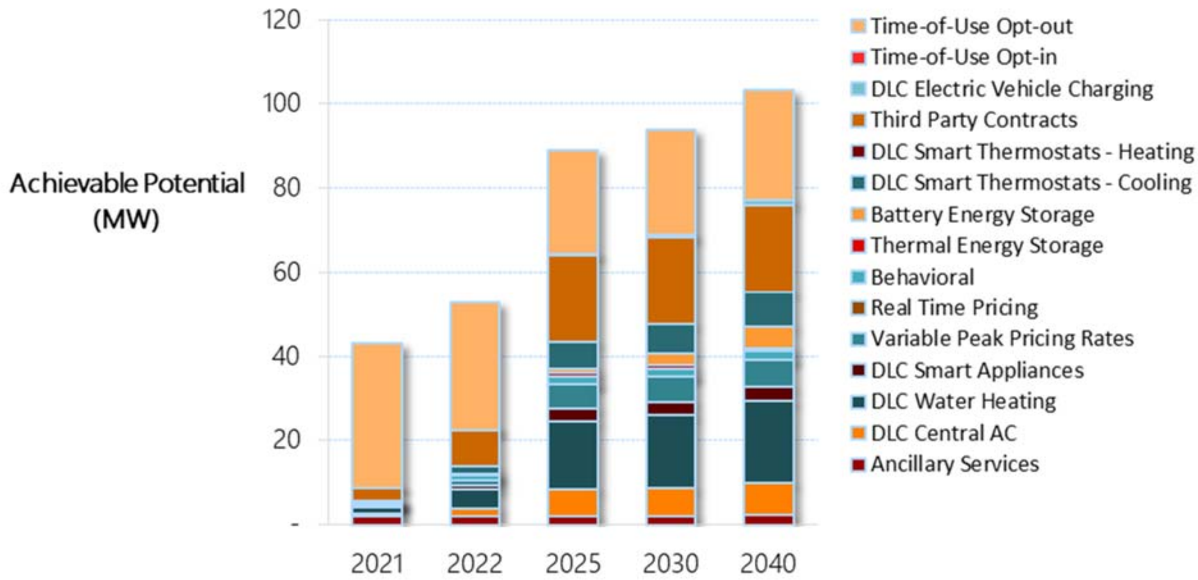


Table 6-27 Achievable DR Potential by Option – TOU Opt-Out (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (MW)	43.2	53.3	90.1	95.1	104.5
Market Potential (% of baseline)	3.1%	3.9%	6.4%	6.6%	6.9%
Potential Forecast	**1,330**	**1,327**	**1,310**	**1,339**	**1,400**
Achievable Potential (MW)					
DLC Central AC	0.61	1.84	6.29	6.75	7.78
DLC Water Heating	1.54	4.68	16.15	17.13	19.27
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.61	1.85	6.45	6.93	8.00
DLC Smart Appliances	0.29	0.88	3.00	3.14	3.45
Third Party Contracts	3.01	8.52	20.59	20.67	20.87
DLC Electric Vehicle Charging	0.01	0.05	0.28	0.55	1.14
Time-of-Use Opt-in	-	-	-	-	-
Time-of-Use Opt-out	34.18	30.26	24.70	25.18	26.20
Variable Peak Pricing Rates	0.08	1.17	5.90	6.05	6.35
Real Time Pricing	0.04	0.08	0.16	0.16	0.16
Ancillary Services	1.95	1.96	2.02	2.09	2.25
Thermal Energy Storage	0.03	0.17	0.74	0.76	0.80
Battery Energy Storage	0.08	0.26	1.00	2.77	5.21
Behavioral	0.79	1.55	2.84	2.92	3.08
Achievable Potential (% of Baseline)					
DLC Central AC	0.04%	0.13%	0.45%	0.47%	0.52%
DLC Water Heating	0.11%	0.34%	1.15%	1.19%	1.28%
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.04%	0.13%	0.46%	0.48%	0.53%
DLC Smart Appliances	0.02%	0.06%	0.21%	0.22%	0.23%
Third Party Contracts	0.22%	0.62%	1.47%	1.44%	1.39%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.08%
Time-of-Use Opt-in	-	-	-	-	-
Time-of-Use Opt-out	2.49%	2.19%	1.76%	1.76%	1.74%
Variable Peak Pricing Rates	0.01%	0.08%	0.42%	0.42%	0.42%
Real Time Pricing	0.00%	0.01%	0.01%	0.01%	0.01%
Ancillary Services	0.14%	0.14%	0.14%	0.15%	0.15%
Thermal Energy Storage	0.00%	0.01%	0.05%	0.05%	0.05%
Battery Energy Storage	0.01%	0.02%	0.07%	0.18%	0.33%
Behavioral	0.06%	0.11%	0.20%	0.20%	0.20%

Table 6-28 and Table 6-29 show demand savings by individual DR option for the states of Washington and Idaho separately.

Table 6-28 Achievable DR Potential by Option for Washington – TOU Opt-Out (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (MW)	30.37	37.02	58.77	61.78	67.36
Market Potential (% of System Peak)	2.2%	2.7%	4.2%	4.3%	4.5%
Achievable Potential (MW)					
DLC Central AC	0.39	1.19	4.04	4.32	4.92
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	0.00	0.00	0.00	0.00	0.00
DLC Smart Thermostats - Cooling	0.39	1.20	4.15	4.44	5.06
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.44	6.50	13.04	13.10	13.23
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in					
Time-of-Use Opt-out	24.02	21.09	16.50	16.75	17.26
Variable Peak Pricing Rates	0.07	0.76	3.94	4.02	4.17
Real Time Pricing	0.02	0.03	0.10	0.10	0.10
Ancillary Services	1.21	1.22	1.25	1.30	1.40
Thermal Energy Storage	0.03	0.14	0.45	0.46	0.48
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.54	1.06	1.93	1.97	2.05

Table 6-29 *Achievable DR Potential by Option for Idaho – TOU Opt-Out (Summer MW @Generator)*

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Market Potential (MW)	12.85	16.24	31.37	33.32	37.19
Market Potential (% of System Peak)	0.9%	1.2%	2.2%	2.3%	2.5%
Achievable Potential (MW)					
DLC Central AC	0.22	0.65	2.24	2.43	2.85
DLC Water Heating	0.53	1.61	5.60	6.00	6.88
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.22	0.66	2.30	2.50	2.94
DLC Smart Appliances	0.10	0.30	1.04	1.10	1.24
Third Party Contracts	0.57	2.01	7.55	7.57	7.64
DLC Electric Vehicle Charging	0.00	0.02	0.09	0.19	0.39
Time-of-Use Opt-in	-	-	-	-	-
Time-of-Use Opt-out	10.17	9.17	8.20	8.43	8.94
Variable Peak Pricing Rates	0.01	0.41	1.96	2.03	2.18
Real Time Pricing	0.02	0.05	0.06	0.06	0.06
Ancillary Services	0.74	0.74	0.76	0.79	0.85
Thermal Energy Storage	0.00	0.03	0.29	0.30	0.32
Battery Energy Storage	0.03	0.08	0.35	0.98	1.87
Behavioral	0.25	0.49	0.91	0.95	1.03

Cost Results

Table 6-30 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The Third Party Contracts option delivers the highest savings at approximately $83.39/kW-year cost. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third party contractor.
- The Variable Peak Pricing option has the lowest levelized cost among all the DR options. It delivers 6.25 MW of savings in 2040 at $37.14/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of CPP deployment costs.

Table 6-30 DR Program Costs and Potential – Summer TOU Opt-Out

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Summer Potential MW in 2040
DLC Central AC	$120.70	$118.55	$119.95	7.78
DLC Water Heating	$139.94	$138.67	$139.49	19.27
DLC Smart Thermostats - Heating	-	-	-	-
DLC Smart Thermostats - Cooling	$131.00	$127.06	$129.62	8.00
DLC Smart Appliances	$237.04	$240.63	$238.30	3.45
Third Party Contracts	$83.62	$82.98	$83.39	20.87
DLC Electric Vehicle Charging	$688.90	$698.35	$692.16	1.14
Time-of-Use Opt-in	-	-	-	-
Time-of-Use Opt-out	$60.46	$76.46	$65.81	26.20
Variable Peak Pricing Rates	$36.38	$38.66	$37.14	6.25
Real Time Pricing	$741.22	$641.72	$193.51	0.10
Ancillary Services	$99.98	$104.78	$101.56	2.25
Thermal Energy Storage	$610.99	$591.88	$603.36	0.80
Battery Energy Storage	$389.31	$393.28	$390.70	5.21
Behavioral	$130.16	$140.39	$133.57	2.05

Stand-alone Potential Results

The above results assume that the programs are offered on an integrated basis where participation across similar options do not overlap. However, it is also important to see the potential by option where each program is unaffected by participation in other options. This way, Avista can gauge the impact from implementing an individual program. For this scenario we do not combine the potential savings and only show individual potential contributions by program for each scenario.

Winter Results

Figure 6-7 and *Table 6-31* show the winter demand savings from individual DR options for selected years of the analysis. These savings represent stand-alone savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- When each TOU option is examined as an individual program, the Time-of-Use Opt-out option has a much larger potential savings then if participants could opt-in to the rate. The TOU Opt-out option makes up the largest savings potential in the stand-alone case and is expected to reach 32.9 MW by 2040.

- Since the different rate options are not allowed to influence other rates in the stand-alone scenario, each rate has a larger potential savings than in the Opt-out/Opt-in scenarios.
- After TOU Opt-in, the next two biggest potential options in winter include VPP and Third Party Contracts all of which are projected to contribute over 23 MW by 2040.

Figure 6-8 Summary of Potential Analysis for Avista (Winter Peak MW @Generator)

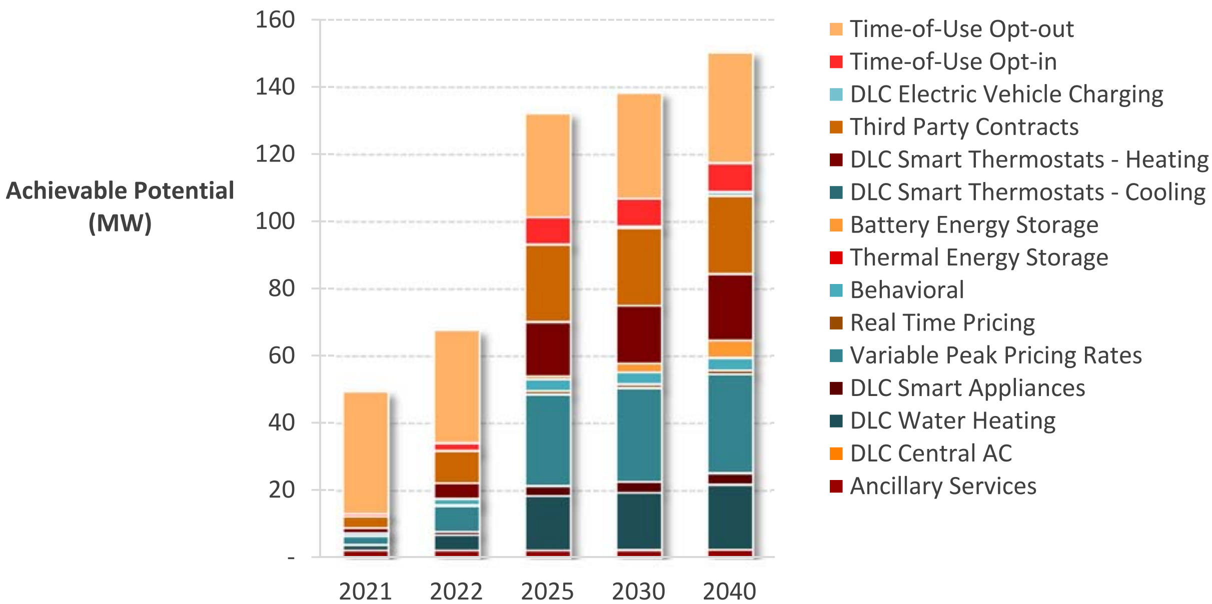


Table 6-32 Achievable DR Potential by Option (Winter MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,453**	**1,460**	**1,481**	**1,515**	**1,589**
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	1.5	4.7	16.2	17.1	19.3
DLC Smart Thermostats - Heating	1.5	4.6	16.0	17.2	19.7
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.3	0.9	3.0	3.1	3.4
Third Party Contracts	3.4	9.5	23.0	23.0	23.2
DLC Electric Vehicle Charging	0.0	0.0	0.3	0.6	1.1
Time-of-Use Opt-in	0.7	2.3	8.0	8.2	8.6
Time-of-Use Opt-out	36.5	33.6	30.9	31.6	32.9
Variable Peak Pricing Rates	2.4	7.7	27.2	27.9	29.5
Real Time Pricing	0.1	0.3	1.1	1.1	1.1
Ancillary Services	2.2	2.2	2.2	2.3	2.5
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.1	0.3	1.0	2.8	5.2
Behavioral	0.8	1.7	3.4	3.5	3.7
Achievable Potential (% of Baseline)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	0.11%	0.32%	1.09%	1.13%	1.21%
DLC Smart Thermostats - Heating	0.10%	0.32%	1.08%	1.13%	1.24%
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.02%	0.06%	0.20%	0.21%	0.22%
Third Party Contracts	0.23%	0.65%	1.55%	1.52%	1.46%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.07%
Time-of-Use Opt-in	0.05%	0.16%	0.54%	0.54%	0.54%
Time-of-Use Opt-out	2.51%	2.30%	2.09%	2.08%	2.07%
Variable Peak Pricing Rates	0.16%	0.53%	1.84%	1.84%	1.86%
Real Time Pricing	0.01%	0.02%	0.08%	0.08%	0.07%
Ancillary Services	0.15%	0.15%	0.15%	0.15%	0.16%
Thermal Energy Storage	0.00%	0.00%	0.00%	0.00%	0.00%
Battery Energy Storage	0.01%	0.02%	0.07%	0.18%	0.33%
Behavioral	0.06%	0.11%	0.23%	0.23%	0.23%

Table 6-33 and Table 6-34 show demand savings by individual DR option for the states of Washington and Idaho separately. As mentioned above, the programs with the largest potential savings are TOU Opt-out, VPP, and Third Party Contracts each individually contributing over 14.5 MW of savings in the Washington Territory alone.

Table 6-33 Achievable DR Potential by Option for Washington (Winter MW @Generator)

	2021	2022	2025	2030	2040
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	0.99	3.00	10.38	11.07	12.60
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.76	7.28	14.58	14.64	14.78
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in	0.50	1.58	5.32	5.42	5.63
Time-of-Use Opt-out	25.54	23.42	20.51	20.85	21.55
Variable Peak Pricing Rates	1.67	5.34	18.02	18.41	19.20
Real Time Pricing	0.07	0.22	0.73	0.73	0.73
Ancillary Services	1.35	1.36	1.39	1.44	1.55
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.56	1.12	2.28	2.33	2.44

Table 6-34 Achievable DR Potential by Option for Idaho (Winter MW @Generator)

	2021	2022	2025	2030	2040
Achievable Potential (MW)					
DLC Central AC	-	-	-	-	-
DLC Water Heating	0.53	1.61	5.60	6.00	6.88
DLC Smart Thermostats - Heating	0.53	1.61	5.64	6.10	7.14
DLC Smart Thermostats - Cooling	-	-	-	-	-
DLC Smart Appliances	0.10	0.30	1.04	1.10	1.24
Third Party Contracts	0.64	2.25	8.37	8.40	8.47
DLC Electric Vehicle Charging	0.00	0.02	0.09	0.19	0.39
Time-of-Use Opt-in	0.22	0.71	2.66	2.75	2.95
Time-of-Use Opt-out	10.93	10.20	10.41	10.72	11.38
Variable Peak Pricing Rates	0.72	2.35	9.19	9.54	10.29
Real Time Pricing	0.04	0.12	0.41	0.40	0.40
Ancillary Services	0.82	0.82	0.84	0.87	0.93
Thermal Energy Storage	-	-	-	-	-
Battery Energy Storage	0.03	0.08	0.35	0.98	1.87
Behavioral	0.27	0.54	1.10	1.15	1.26

Cost Results

Table 6-35 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The Variable Peak Pricing option has lowest levelized cost among all the DR options. It delivers 29.49 MW of savings in 2040 at $20.67/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.
- The second lowest levelized cost among all the DR options is DLC Smart Thermostats-Heating. It delivers 29.49 MW of savings in 2040 at $20.67/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.

Table 6-35 DR Program Costs and Potential (Winter)

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Winter Potential MW in 2040
DLC Central AC				
DLC Water Heating	$139.94	$138.67	$139.40	19.27
DLC Smart Thermostats - Heating	$46.17	$45.21	$45.83	19.74
DLC Smart Thermostats - Cooling				
DLC Smart Appliances	$237.04	$240.63	$238.56	3.45
Third Party Contracts	$74.80	$74.80	$74.80	23.25
DLC Electric Vehicle Charging	$688.90	$698.35	$692.17	1.14
Time-of-Use Opt-in	$43.07	$52.26	$46.40	8.58
Time-of-Use Opt-out	$51.59	$65.02	$56.45	32.93
Variable Peak Pricing Rates	$20.23	$21.38	$20.67	29.49
Real Time Pricing	$104.67	$104.18	$104.49	1.13
Ancillary Services	$90.19	$94.80	$91.95	2.48
Thermal Energy Storage				
Battery Energy Storage	$389.24	$393.20	$390.86	5.22
Behavioral	$120.61	$126.65	$122.66	3.70

Summer Results

Figure 6-9 and Table 6-36 show the summer demand savings from individual DR options for selected years of the analysis. These savings represent the individual stand-alone savings from all available DR options in Avista's Washington and Idaho service territories.

Key findings include:

- When each TOU option is examined as an individual program, the Time-of-Use Opt-out option has a much larger potential savings then if participants could opt-in to the rate. The TOU Opt-out option makes up the largest savings potential in the stand-alone case and is expected to reach 31.4 MW by 2040.
- Since the different rate options are not allowed to influence other rates in the stand-alone scenario, each rate has a larger potential savings than in the Opt-out/Opt-in scenarios.
- After TOU Opt-in, the next two biggest potential options in winter include VPP and Third Party Contracts all of which are projected to contribute over 20 MW by 2040. DLC Water Heating also has a high savings potential projected to reach 19.3 MW by 2040.

Figure 6-9 Summary of Summer Potential by Option (MW @Generator)

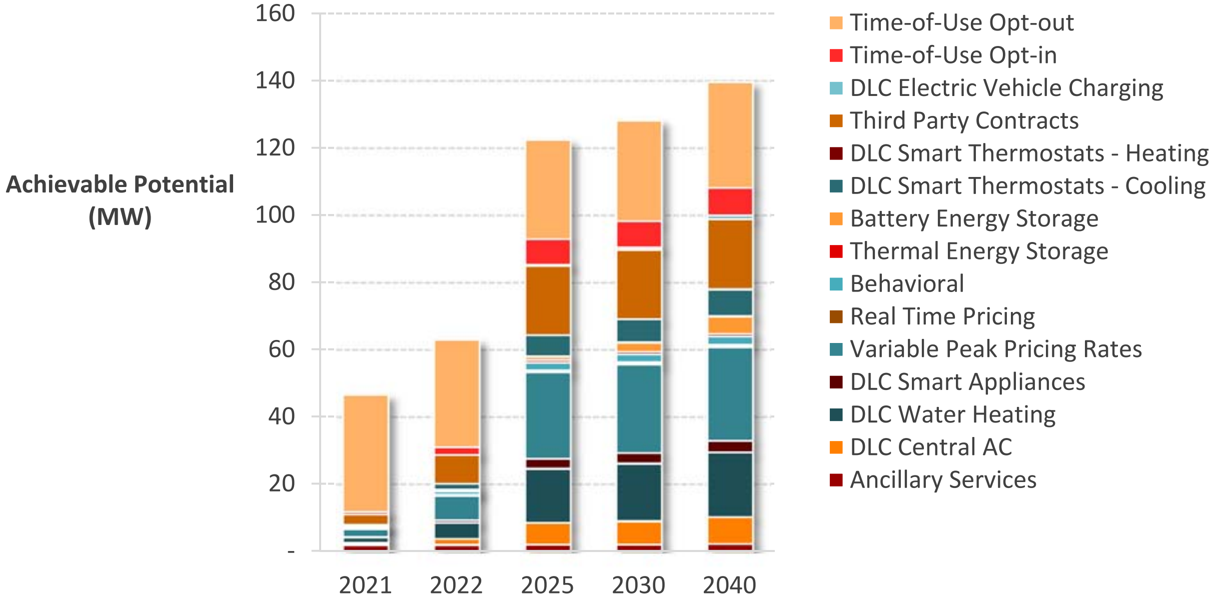


Table 6-36 Achievable DR Potential by Option (Summer MW @Generator)

	2021	2022	2025	2030	2040
Total System Peak (MW)	**1,374**	**1,380**	**1,400**	**1,434**	**1,505**
Achievable Potential (MW)					
DLC Central AC	0.6	1.9	6.5	6.9	8.0
DLC Water Heating	1.5	4.7	16.2	17.1	19.3
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.6	1.9	6.5	6.9	8.0
DLC Smart Appliances	0.3	0.9	3.0	3.1	3.4
Third Party Contracts	3.0	8.5	20.6	20.7	20.9
DLC Electric Vehicle Charging	0.0	0.0	0.3	0.6	1.1
Time-of-Use Opt-in	0.7	2.2	7.7	7.9	8.3
Time-of-Use Opt-out	34.9	32.1	29.4	30.1	31.4
Variable Peak Pricing Rates	2.3	7.3	25.7	26.4	27.9
Real Time Pricing	0.1	0.2	0.7	0.7	0.7
Ancillary Services	1.9	2.0	2.0	2.1	2.2
Thermal Energy Storage	0.6	1.1	2.2	2.3	2.4
Battery Energy Storage	0.0	0.2	0.8	0.8	0.8
Behavioral	0.1	0.3	1.0	2.8	5.2
Achievable Potential (% of Baseline)					
DLC Central AC	0.04%	0.13%	0.46%	0.48%	0.53%
DLC Water Heating	0.11%	0.34%	1.15%	1.19%	1.28%
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.04%	0.13%	0.46%	0.48%	0.53%
DLC Smart Appliances	0.02%	0.06%	0.21%	0.22%	0.23%
Third Party Contracts	0.22%	0.62%	1.47%	1.44%	1.39%
DLC Electric Vehicle Charging	0.00%	0.00%	0.02%	0.04%	0.08%
Time-of-Use Opt-in	0.05%	0.16%	0.55%	0.55%	0.55%
Time-of-Use Opt-out	2.54%	2.32%	2.10%	2.10%	2.09%
Variable Peak Pricing Rates	0.16%	0.53%	1.83%	1.84%	1.85%
Real Time Pricing	0.00%	0.01%	0.05%	0.05%	0.04%
Ancillary Services	0.14%	0.14%	0.14%	0.15%	0.15%
Thermal Energy Storage	0.04%	0.08%	0.16%	0.16%	0.16%
Battery Energy Storage	0.00%	0.01%	0.06%	0.06%	0.06%
Behavioral	0.01%	0.02%	0.07%	0.19%	0.35%

Table 6-37 and Table 6-38 show summer demand savings by individual DR option for the states of Washington and Idaho separately. As mentioned above, the programs with the largest potential savings are TOU Opt-out, VPP, and Third Party Contracts each individually contributing over 13 MW of savings in the Washington Territory alone.

Table 6-37 Achievable DR Potential by Option for Washington (Summer MW @Generator)

	2021	2022	2025	2030	2040
Achievable Potential (MW)					
DLC Central AC	0.39	1.20	4.15	4.44	5.06
DLC Water Heating	1.01	3.06	10.55	11.13	12.38
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.39	1.20	4.15	4.44	5.06
DLC Smart Appliances	0.19	0.57	1.96	2.04	2.21
Third Party Contracts	2.44	6.50	13.04	13.10	13.23
DLC Electric Vehicle Charging	0.01	0.03	0.19	0.37	0.74
Time-of-Use Opt-in	0.48	1.53	5.15	5.25	5.45
Time-of-Use Opt-out	24.52	22.43	19.65	19.98	20.68
Variable Peak Pricing Rates	1.63	5.17	17.46	17.84	18.62
Real Time Pricing	0.07	0.20	0.65	0.65	0.65
Ancillary Services	1.21	1.22	1.25	1.30	1.40
Thermal Energy Storage	0.03	0.14	0.47	0.48	0.50
Battery Energy Storage	0.05	0.17	0.65	1.79	3.34
Behavioral	0.55	1.11	2.25	2.30	2.41

Table 6-38 Achievable DR Potential by Option for Idaho (Summer MW @Generator)

	2021	2022	2025	2030	2040
Achievable Potential (MW)					
DLC Central AC	0.22	0.66	2.30	2.50	2.94
DLC Water Heating	0.53	1.61	5.60	6.00	6.88
DLC Smart Thermostats - Heating	-	-	-	-	-
DLC Smart Thermostats - Cooling	0.22	0.66	2.30	2.50	2.94
DLC Smart Appliances	0.10	0.30	1.04	1.10	1.24
Third Party Contracts	0.57	2.01	7.55	7.57	7.64
DLC Electric Vehicle Charging	0.00	0.02	0.09	0.19	0.39
Time-of-Use Opt-in	0.21	0.67	2.52	2.61	2.80
Time-of-Use Opt-out	10.37	9.65	9.80	10.09	10.74
Variable Peak Pricing Rates	0.69	2.24	8.70	9.04	9.75
Real Time Pricing	0.04	0.11	0.37	0.36	0.36
Ancillary Services	0.74	0.74	0.76	0.79	0.85
Thermal Energy Storage	0.00	0.03	0.31	0.32	0.34
Battery Energy Storage	0.03	0.08	0.35	0.98	1.87
Behavioral	0.26	0.52	1.06	1.11	1.21

Cost Results

- The Variable Peak Pricing option has lowest levelized cost among all the DR options. It delivers 27.89 MW of savings in 2040 at $21.44/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.
- The second lowest levelized cost option is the TOU Opt-in rate. It delivers 8.25 MW of savings in 2040 at $44.49/kW-year system wide.

Table 6-39 presents the levelized costs per kW of equivalent generation capacity over 2021-2040 for both Washington and Idaho as well as the system weighted average levelized costs across both states. In addition, we show the 2040 savings potential from DR options for reference purposes.

Key findings include:

- The Variable Peak Pricing option has lowest levelized cost among all the DR options. It delivers 27.89 MW of savings in 2040 at $21.44/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.
- The second lowest levelized cost option is the TOU Opt-in rate. It delivers 8.25 MW of savings in 2040 at $44.49/kW-year system wide.

Table 6-39 DR Program Costs and Potential – Summer

DR Option	Washington 2021-2040 Levelized Cost ($/kW-year)	Idaho 2021-2040 Levelized Cost ($/kW-year)	System Weighted Average Levelized Cost ($/kW-year)	System Summer Potential MW in 2040
DLC Central AC	$120.31	$118.14	$119.55	8.00
DLC Water Heating	$139.94	$138.67	$139.49	19.27
DLC Smart Thermostats - Heating	-	-	-	-
DLC Smart Thermostats - Cooling	$131.00	$127.06	$129.62	8.00
DLC Smart Appliances	$237.04	$240.63	$238.30	3.45
Third Party Contracts	$83.62	$82.98	$83.39	20.87
DLC Electric Vehicle Charging	$688.90	$698.35	$692.16	1.14
Time-of-Use Opt-in	$44.49	$55.11	$48.03	8.25
Time-of-Use Opt-out	$53.81	$68.96	$58.88	31.42
Variable Peak Pricing Rates	$20.87	$22.57	$21.44	27.89
Real Time Pricing	$117.58	$115.69	$116.90	0.65
Ancillary Services	$99.98	$104.78	$101.56	2.25
Thermal Energy Storage	$122.10	$131.73	$125.31	2.41
Battery Energy Storage	$593.83	$573.63	$585.74	0.84
Behavioral	$389.24	$393.20	$390.63	5.22

A

MARKET PROFILES

This appendix presents the market profiles for each sector and segment for Washington, followed by Idaho.

Begins on Next page.

Table A-1 Washington Residential Single Family Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	38.4%	1,271	488	66.1
Cooling	Room AC	12.3%	691	85	11.5
Cooling	Air-Source Heat Pump	19.4%	1,332	258	34.9
Cooling	Geothermal Heat Pump	1.0%	1,176	12	1.6
Cooling	Evaporative AC	1.3%	647	8	1.1
Space Heating	Electric Room Heat	6.3%	14,299	904	122.4
Space Heating	Electric Furnace	7.4%	16,116	1,195	162.0
Space Heating	Air-Source Heat Pump	19.4%	12,257	2,373	321.5
Space Heating	Geothermal Heat Pump	1.0%	5,402	55	7.5
Space Heating	Secondary Heating	66.5%	372	248	33.6
Water Heating	Water Heater <= 55 Gal	42.2%	3,362	1,419	192.3
Water Heating	Water Heater > 55 Gal	5.8%	3,554	205	27.8
Interior Lighting	General Service Screw-in	100.0%	761	761	103.1
Interior Lighting	Linear Lighting	100.0%	124	124	16.8
Interior Lighting	Exempted Screw-In	100.0%	58	58	7.8
Exterior Lighting	Screw-in	100.0%	284	284	38.5
Appliances	Clothes Washer	96.4%	77	74	10.1
Appliances	Clothes Dryer	38.6%	741	286	38.8
Appliances	Dishwasher	80.9%	377	305	41.3
Appliances	Refrigerator	94.6%	705	667	90.4
Appliances	Freezer	59.1%	564	333	45.2
Appliances	Second Refrigerator	39.7%	829	329	44.6
Appliances	Stove/Oven	66.9%	443	296	40.2
Appliances	Microwave	95.6%	124	119	16.1
Electronics	Personal Computers	80.5%	161	130	17.5
Electronics	Monitor	161.4%	61	99	13.4
Electronics	Laptops	94.4%	42	40	5.4
Electronics	TVs	205.8%	114	234	31.7
Electronics	Printer/Fax/Copier	85.5%	42	36	4.9
Electronics	Set-top Boxes/DVRs	175.4%	99	173	23.4
Electronics	Devices and Gadgets	100.0%	108	108	14.6
Miscellaneous	Electric Vehicles	0.2%	4,324	9	1.2
Miscellaneous	Pool Pump	0.5%	3,500	19	2.5
Miscellaneous	Pool Heater	0.1%	3,517	5	0.7
Miscellaneous	Hot Tub / Spa	0.7%	2,032	13	1.8
Miscellaneous	Furnace Fan	75.8%	205	156	21.1
Miscellaneous	Well pump	2.0%	561	11	1.5
Miscellaneous	Miscellaneous	100.0%	1,554	1,554	210.5
Total				**13,473**	**1,825.3**

Table A-2 Washington Residential Multi Family Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	16.3%	426	70	0.9
Cooling	Room AC	49.0%	258	127	1.6
Cooling	Air-Source Heat Pump	2.9%	426	12	0.2
Cooling	Geothermal Heat Pump	0.0%	376	0	0.0
Cooling	Evaporative AC	0.9%	320	3	0.0
Space Heating	Electric Room Heat	72.8%	2,937	2,139	26.7
Space Heating	Electric Furnace	7.6%	3,143	239	3.0
Space Heating	Air-Source Heat Pump	2.9%	1,831	53	0.7
Space Heating	Geothermal Heat Pump	0.0%	807	0	0.0
Space Heating	Secondary Heating	44.8%	443	199	2.5
Water Heating	Water Heater <= 55 Gal	74.2%	2,100	1,558	19.4
Water Heating	Water Heater > 55 Gal	0.5%	2,220	10	0.1
Interior Lighting	General Service Screw-in	100.0%	405	405	5.1
Interior Lighting	Linear Lighting	100.0%	33	33	0.4
Interior Lighting	Exempted Screw-In	100.0%	33	33	0.4
Exterior Lighting	Screw-in	100.0%	130	130	1.6
Appliances	Clothes Washer	82.7%	75	62	0.8
Appliances	Clothes Dryer	69.1%	586	405	5.1
Appliances	Dishwasher	70.9%	375	266	3.3
Appliances	Refrigerator	92.7%	701	650	8.1
Appliances	Freezer	46.4%	562	261	3.3
Appliances	Second Refrigerator	3.9%	660	25	0.3
Appliances	Stove/Oven	74.5%	357	266	3.3
Appliances	Microwave	93.6%	124	117	1.5
Electronics	Personal Computers	35.5%	161	57	0.7
Electronics	Monitor	72.8%	61	45	0.6
Electronics	Laptops	41.9%	42	18	0.2
Electronics	TVs	124.7%	114	142	1.8
Electronics	Printer/Fax/Copier	49.5%	42	21	0.3
Electronics	Set-top Boxes/DVRs	91.4%	99	90	1.1
Electronics	Devices and Gadgets	100.0%	108	108	1.3
Miscellaneous	Electric Vehicles	0.0%	4,324	0	0.0
Miscellaneous	Pool Pump	0.0%	3,500	0	0.0
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.0%	2,032	0	0.0
Miscellaneous	Furnace Fan	18.9%	73	14	0.2
Miscellaneous	Well pump	0.0%	556	0	0.0
Miscellaneous	Miscellaneous	100.0%	529	529	6.6
Total				**8,084**	**100.9**

Table A-3 Washington Residential Mobile Home Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	19.6%	1,001	196	1.6
Cooling	Room AC	18.5%	531	98	0.8
Cooling	Air-Source Heat Pump	26.9%	1,001	269	2.2
Cooling	Geothermal Heat Pump	0.0%	881	0	0.0
Cooling	Evaporative AC	1.7%	499	9	0.1
Space Heating	Electric Room Heat	0.0%	7,208	0	0.0
Space Heating	Electric Furnace	32.1%	7,715	2,478	19.9
Space Heating	Air-Source Heat Pump	26.9%	6,752	1,813	14.5
Space Heating	Geothermal Heat Pump	0.0%	3,094	0	0.0
Space Heating	Secondary Heating	54.2%	493	267	2.1
Water Heating	Water Heater <= 55 Gal	67.3%	3,288	2,214	17.8
Water Heating	Water Heater > 55 Gal	0.0%	3,476	0	0.0
Interior Lighting	General Service Screw-in	100.0%	441	441	3.5
Interior Lighting	Linear Lighting	100.0%	62	62	0.5
Interior Lighting	Exempted Screw-In	100.0%	19	19	0.2
Exterior Lighting	Screw-in	100.0%	109	109	0.9
Appliances	Clothes Washer	91.2%	77	70	0.6
Appliances	Clothes Dryer	66.7%	924	616	4.9
Appliances	Dishwasher	70.2%	377	265	2.1
Appliances	Refrigerator	93.0%	700	651	5.2
Appliances	Freezer	61.4%	565	347	2.8
Appliances	Second Refrigerator	18.2%	742	135	1.1
Appliances	Stove/Oven	82.5%	537	443	3.6
Appliances	Microwave	93.0%	124	116	0.9
Electronics	Personal Computers	45.8%	161	74	0.6
Electronics	Monitor	77.1%	61	47	0.4
Electronics	Laptops	66.7%	42	28	0.2
Electronics	TVs	156.3%	114	177	1.4
Electronics	Printer/Fax/Copier	58.3%	42	25	0.2
Electronics	Set-top Boxes/DVRs	91.7%	99	90	0.7
Electronics	Devices and Gadgets	100.0%	108	108	0.9
Miscellaneous	Electric Vehicles	0.0%	4,324	0	0.0
Miscellaneous	Pool Pump	0.0%	3,500	0	0.0
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.0%	2,032	0	0.0
Miscellaneous	Furnace Fan	84.6%	157	132	1.1
Miscellaneous	Well pump	3.4%	451	15	0.1
Miscellaneous	Miscellaneous	100.0%	811	811	6.5
Total				**12,125**	**97.3**

Table A-4 Washington Residential Low-Income Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	18.9%	444	84	5.6
Cooling	Room AC	42.3%	255	108	7.2
Cooling	Air-Source Heat Pump	6.9%	449	31	2.1
Cooling	Geothermal Heat Pump	0.1%	396	0	0.0
Cooling	Evaporative AC	1.0%	284	3	0.2
Space Heating	Electric Room Heat	58.9%	3,709	2,185	146.1
Space Heating	Electric Furnace	10.0%	4,043	406	27.1
Space Heating	Air-Source Heat Pump	6.9%	2,851	197	13.2
Space Heating	Geothermal Heat Pump	0.1%	1,269	1	0.1
Space Heating	Secondary Heating	47.9%	337	162	10.8
Water Heating	Water Heater <= 55 Gal	70.3%	1,993	1,401	93.7
Water Heating	Water Heater > 55 Gal	1.0%	2,107	20	1.3
Interior Lighting	General Service Screw-in	100.0%	441	441	29.5
Interior Lighting	Linear Lighting	100.0%	62	62	4.1
Interior Lighting	Exempted Screw-In	100.0%	19	19	1.3
Exterior Lighting	Screw-in	100.0%	109	109	7.3
Appliances	Clothes Washer	84.9%	83	70	4.7
Appliances	Clothes Dryer	65.8%	734	483	32.3
Appliances	Dishwasher	71.8%	382	275	18.4
Appliances	Refrigerator	92.9%	707	658	44.0
Appliances	Freezer	49.1%	566	278	18.6
Appliances	Second Refrigerator	8.9%	685	61	4.1
Appliances	Stove/Oven	74.6%	438	327	21.8
Appliances	Microwave	93.8%	126	118	7.9
Electronics	Personal Computers	41.0%	163	67	4.5
Electronics	Monitor	82.1%	62	51	3.4
Electronics	Laptops	49.7%	43	21	1.4
Electronics	TVs	136.0%	115	156	10.4
Electronics	Printer/Fax/Copier	54.0%	43	23	1.5
Electronics	Set-top Boxes/DVRs	99.8%	100	100	6.7
Electronics	Devices and Gadgets	100.0%	108	108	7.2
Miscellaneous	Electric Vehicles	0.0%	4,324	1	0.1
Miscellaneous	Pool Pump	0.1%	3,500	2	0.1
Miscellaneous	Pool Heater	0.0%	3,517	1	0.0
Miscellaneous	Hot Tub / Spa	0.1%	2,032	1	0.1
Miscellaneous	Furnace Fan	31.2%	95	30	2.0
Miscellaneous	Well pump	0.5%	546	3	0.2
Miscellaneous	Miscellaneous	100.0%	668	668	44.6
Total				**8,728**	**583.5**

Table A-5 Washington Commercial Large Office Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.7%	3.08	0.42	11.9
Cooling	Water-Cooled Chiller	8.5%	3.37	0.28	8.0
Cooling	RTU	44.5%	3.22	1.43	40.4
Cooling	PTAC	2.4%	3.80	0.09	2.5
Cooling	PTHP	0.7%	3.22	0.02	0.7
Cooling	Evaporative AC	0.0%	1.29	0.00	0.0
Cooling	Air-Source Heat Pump	14.2%	3.22	0.46	12.9
Cooling	Geothermal Heat Pump	7.6%	1.96	0.15	4.2
Heating	Electric Furnace	1.2%	5.64	0.07	2.0
Heating	Electric Room Heat	23.8%	5.37	1.28	36.0
Heating	PTHP	0.7%	4.29	0.03	0.9
Heating	Air-Source Heat Pump	14.2%	4.77	0.68	19.1
Heating	Geothermal Heat Pump	7.6%	3.85	0.29	8.3
Ventilation	Ventilation	100.0%	3.11	3.11	87.7
Water Heating	Water Heater	45.2%	1.04	0.47	13.2
Interior Lighting	General Service Lighting	100.0%	0.25	0.25	7.0
Interior Lighting	Exempted Lighting	100.0%	0.10	0.10	2.9
Interior Lighting	High-Bay Lighting	100.0%	1.01	1.01	28.4
Interior Lighting	Linear Lighting	100.0%	1.72	1.72	48.6
Exterior Lighting	General Service Lighting	100.0%	0.10	0.10	2.7
Exterior Lighting	Area Lighting	100.0%	1.28	1.28	36.0
Exterior Lighting	Linear Lighting	100.0%	0.18	0.18	5.1
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	0.14	0.00	0.1
Refrigeration	Reach-in Refrigerator/Freezer	14.0%	0.03	0.00	0.1
Refrigeration	Glass Door Display	77.4%	0.03	0.03	0.7
Refrigeration	Open Display Case	77.4%	0.19	0.15	4.2
Refrigeration	Icemaker	44.9%	0.05	0.02	0.7
Refrigeration	Vending Machine	44.9%	0.05	0.02	0.6
Food Preparation	Oven	66.0%	0.09	0.06	1.6
Food Preparation	Fryer	76.4%	0.13	0.10	2.7
Food Preparation	Dishwasher	43.1%	0.18	0.08	2.1
Food Preparation	Hot Food Container	43.1%	0.02	0.01	0.3
Food Preparation	Steamer	43.1%	0.13	0.06	1.6
Office Equipment	Desktop Computer	100.0%	2.35	2.35	66.1
Office Equipment	Laptop	100.0%	0.36	0.36	10.2
Office Equipment	Server	100.0%	0.23	0.23	6.5
Office Equipment	Monitor	100.0%	0.41	0.41	11.7
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	6.0
Office Equipment	POS Terminal	40.0%	0.03	0.01	0.3
Miscellaneous	Non-HVAC Motors	89.6%	0.35	0.31	8.8
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.42	1.42	39.9
Total				**19.27**	**542.8**

Table A-6 Washington Commercial Small Office Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	3.17	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	3.45	0.00	0.0
Cooling	RTU	65.6%	3.61	2.37	28.0
Cooling	PTAC	2.3%	4.25	0.10	1.2
Cooling	PTHP	0.7%	3.61	0.03	0.3
Cooling	Evaporative AC	0.0%	1.44	0.00	0.0
Cooling	Air-Source Heat Pump	14.0%	3.61	0.50	6.0
Cooling	Geothermal Heat Pump	7.5%	2.20	0.16	1.9
Heating	Electric Furnace	1.1%	6.82	0.08	0.9
Heating	Electric Room Heat	21.9%	6.49	1.42	16.8
Heating	PTHP	0.7%	5.16	0.04	0.4
Heating	Air-Source Heat Pump	14.0%	5.73	0.80	9.5
Heating	Geothermal Heat Pump	7.5%	4.44	0.33	3.9
Ventilation	Ventilation	100.0%	1.25	1.25	14.7
Water Heating	Water Heater	60.0%	0.94	0.56	6.6
Interior Lighting	General Service Lighting	100.0%	0.25	0.25	2.9
Interior Lighting	Exempted Lighting	100.0%	0.13	0.13	1.6
Interior Lighting	High-Bay Lighting	100.0%	1.51	1.51	17.8
Interior Lighting	Linear Lighting	100.0%	1.54	1.54	18.2
Exterior Lighting	General Service Lighting	100.0%	0.16	0.16	1.9
Exterior Lighting	Area Lighting	100.0%	1.58	1.58	18.6
Exterior Lighting	Linear Lighting	100.0%	0.07	0.07	0.9
Refrigeration	Walk-in Refrigerator/Freezer	0.0%	0.66	0.00	0.0
Refrigeration	Reach-in Refrigerator/Freezer	8.8%	0.15	0.01	0.2
Refrigeration	Glass Door Display	0.0%	0.15	0.00	0.0
Refrigeration	Open Display Case	0.0%	0.90	0.00	0.0
Refrigeration	Icemaker	5.1%	0.25	0.01	0.2
Refrigeration	Vending Machine	5.1%	0.12	0.01	0.1
Food Preparation	Oven	3.6%	0.19	0.01	0.1
Food Preparation	Fryer	3.6%	0.27	0.01	0.1
Food Preparation	Dishwasher	3.6%	0.37	0.01	0.2
Food Preparation	Hot Food Container	3.6%	0.05	0.00	0.0
Food Preparation	Steamer	3.6%	0.27	0.01	0.1
Office Equipment	Desktop Computer	100.0%	1.24	1.24	14.7
Office Equipment	Laptop	100.0%	0.19	0.19	2.3
Office Equipment	Server	100.0%	0.36	0.36	4.3
Office Equipment	Monitor	100.0%	0.22	0.22	2.6
Office Equipment	Printer/Copier/Fax	100.0%	0.17	0.17	2.0
Office Equipment	POS Terminal	20.0%	0.10	0.02	0.2
Miscellaneous	Non-HVAC Motors	22.0%	0.28	0.06	0.7
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.19	1.19	14.0
Total				**16.41**	**193.9**

Table A-7 Washington Commercial Retail Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	2.19	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	2.39	0.00	0.0
Cooling	RTU	67.0%	2.50	1.67	36.6
Cooling	PTAC	2.4%	2.62	0.06	1.4
Cooling	PTHP	0.8%	2.49	0.02	0.4
Cooling	Evaporative AC	0.0%	1.00	0.00	0.0
Cooling	Air-Source Heat Pump	14.3%	2.49	0.36	7.8
Cooling	Geothermal Heat Pump	7.7%	1.52	0.12	2.5
Heating	Electric Furnace	0.5%	6.04	0.03	0.7
Heating	Electric Room Heat	9.6%	5.75	0.55	12.1
Heating	PTHP	0.8%	4.03	0.03	0.7
Heating	Air-Source Heat Pump	14.3%	4.47	0.64	14.0
Heating	Geothermal Heat Pump	7.7%	3.04	0.23	5.1
Ventilation	Ventilation	100.0%	1.01	1.01	22.1
Water Heating	Water Heater	61.8%	0.82	0.50	11.0
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	8.3
Interior Lighting	Exempted Lighting	100.0%	0.36	0.36	7.9
Interior Lighting	High-Bay Lighting	100.0%	1.51	1.51	33.1
Interior Lighting	Linear Lighting	100.0%	2.28	2.28	49.9
Exterior Lighting	General Service Lighting	100.0%	0.24	0.24	5.2
Exterior Lighting	Area Lighting	100.0%	0.84	0.84	18.5
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	1.7
Refrigeration	Walk-in Refrigerator/Freezer	0.0%	0.42	0.00	0.0
Refrigeration	Reach-in Refrigerator/Freezer	5.4%	0.09	0.01	0.1
Refrigeration	Glass Door Display	5.4%	0.10	0.01	0.1
Refrigeration	Open Display Case	5.4%	0.57	0.03	0.7
Refrigeration	Icemaker	5.1%	0.32	0.02	0.4
Refrigeration	Vending Machine	5.1%	0.15	0.01	0.2
Food Preparation	Oven	3.6%	0.17	0.01	0.1
Food Preparation	Fryer	3.6%	0.25	0.01	0.2
Food Preparation	Dishwasher	3.6%	0.35	0.01	0.3
Food Preparation	Hot Food Container	3.6%	0.05	0.00	0.0
Food Preparation	Steamer	3.6%	0.25	0.01	0.2
Office Equipment	Desktop Computer	100.0%	0.18	0.18	3.9
Office Equipment	Laptop	100.0%	0.03	0.03	0.6
Office Equipment	Server	82.0%	0.21	0.17	3.8
Office Equipment	Monitor	100.0%	0.03	0.03	0.7
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.4
Office Equipment	POS Terminal	100.0%	0.06	0.06	1.2
Miscellaneous	Non-HVAC Motors	40.2%	0.34	0.13	3.0
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	7.0%	0.01	0.00	0.0
Miscellaneous	Clothes Dryer	4.0%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.43	1.43	31.4
Total				**13.09**	**286.3**

Table A-8 Washington Commercial Restaurant Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	3.49	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	3.52	0.00	0.0
Cooling	RTU	72.9%	3.99	2.91	7.7
Cooling	PTAC	2.7%	4.69	0.13	0.3
Cooling	PTHP	1.9%	3.98	0.08	0.2
Cooling	Evaporative AC	3.3%	1.59	0.05	0.1
Cooling	Air-Source Heat Pump	8.2%	3.98	0.33	0.9
Cooling	Geothermal Heat Pump	0.0%	2.43	0.00	0.0
Heating	Electric Furnace	19.1%	4.81	0.92	2.4
Heating	Electric Room Heat	1.7%	4.58	0.08	0.2
Heating	PTHP	1.9%	3.01	0.06	0.2
Heating	Air-Source Heat Pump	8.2%	3.35	0.28	0.7
Heating	Geothermal Heat Pump	0.0%	2.37	0.00	0.0
Ventilation	Ventilation	100.0%	1.98	1.98	5.2
Water Heating	Water Heater	57.9%	7.75	4.49	11.9
Interior Lighting	General Service Lighting	100.0%	1.34	1.34	3.5
Interior Lighting	Exempted Lighting	100.0%	0.94	0.94	2.5
Interior Lighting	High-Bay Lighting	100.0%	2.92	2.92	7.7
Interior Lighting	Linear Lighting	100.0%	1.87	1.87	4.9
Exterior Lighting	General Service Lighting	100.0%	0.28	0.28	0.7
Exterior Lighting	Area Lighting	100.0%	2.14	2.14	5.7
Exterior Lighting	Linear Lighting	100.0%	0.40	0.40	1.1
Refrigeration	Walk-in Refrigerator/Freezer	74.0%	6.59	4.88	12.9
Refrigeration	Reach-in Refrigerator/Freezer	7.0%	2.96	0.21	0.5
Refrigeration	Glass Door Display	5.2%	1.52	0.08	0.2
Refrigeration	Open Display Case	5.2%	9.00	0.47	1.2
Refrigeration	Icemaker	97.3%	2.49	2.42	6.4
Refrigeration	Vending Machine	97.3%	1.17	1.14	3.0
Food Preparation	Oven	21.0%	3.95	0.83	2.2
Food Preparation	Fryer	82.0%	5.71	4.68	12.4
Food Preparation	Dishwasher	52.5%	3.93	2.06	5.5
Food Preparation	Hot Food Container	84.0%	0.54	0.45	1.2
Food Preparation	Steamer	16.0%	2.88	0.46	1.2
Office Equipment	Desktop Computer	100.0%	0.29	0.29	0.8
Office Equipment	Laptop	100.0%	0.04	0.04	0.1
Office Equipment	Server	50.0%	0.34	0.17	0.5
Office Equipment	Monitor	100.0%	0.05	0.05	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.2
Office Equipment	POS Terminal	100.0%	0.09	0.09	0.2
Miscellaneous	Non-HVAC Motors	20.0%	0.54	0.11	0.3
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.15	2.15	5.7
Total				**41.80**	**110.5**

Table A-9 Washington Commercial Grocery Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.5%	3.98	0.02	0.1
Cooling	Water-Cooled Chiller	0.3%	4.33	0.01	0.1
Cooling	RTU	71.3%	4.53	3.23	13.8
Cooling	PTAC	2.1%	5.33	0.11	0.5
Cooling	PTHP	0.6%	4.15	0.03	0.1
Cooling	Evaporative AC	1.2%	1.81	0.02	0.1
Cooling	Air-Source Heat Pump	7.2%	4.15	0.30	1.3
Cooling	Geothermal Heat Pump	0.0%	1.41	0.00	0.0
Heating	Electric Furnace	6.4%	7.41	0.47	2.0
Heating	Electric Room Heat	1.2%	7.06	0.08	0.4
Heating	PTHP	0.6%	3.42	0.02	0.1
Heating	Air-Source Heat Pump	7.2%	3.80	0.27	1.2
Heating	Geothermal Heat Pump	0.0%	2.65	0.00	0.0
Ventilation	Ventilation	100.0%	2.18	2.18	9.3
Water Heating	Water Heater	62.5%	2.29	1.43	6.1
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	1.6
Interior Lighting	Exempted Lighting	100.0%	0.30	0.30	1.3
Interior Lighting	High-Bay Lighting	100.0%	2.02	2.02	8.6
Interior Lighting	Linear Lighting	100.0%	5.01	5.01	21.4
Exterior Lighting	General Service Lighting	100.0%	0.36	0.36	1.5
Exterior Lighting	Area Lighting	100.0%	1.78	1.78	7.6
Exterior Lighting	Linear Lighting	100.0%	0.38	0.38	1.6
Refrigeration	Walk-in Refrigerator/Freezer	16.0%	5.38	0.86	3.7
Refrigeration	Reach-in Refrigerator/Freezer	83.1%	0.34	0.29	1.2
Refrigeration	Glass Door Display	94.9%	3.54	3.36	14.3
Refrigeration	Open Display Case	94.9%	20.97	19.90	84.9
Refrigeration	Icemaker	98.9%	0.29	0.29	1.2
Refrigeration	Vending Machine	98.9%	0.27	0.27	1.1
Food Preparation	Oven	11.0%	0.64	0.07	0.3
Food Preparation	Fryer	87.0%	0.92	0.80	3.4
Food Preparation	Dishwasher	54.9%	1.27	0.70	3.0
Food Preparation	Hot Food Container	73.0%	0.17	0.13	0.5
Food Preparation	Steamer	20.0%	0.93	0.19	0.8
Office Equipment	Desktop Computer	100.0%	0.16	0.16	0.7
Office Equipment	Laptop	64.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.09	0.09	0.4
Office Equipment	Monitor	100.0%	0.03	0.03	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.1
Office Equipment	POS Terminal	100.0%	0.06	0.06	0.3
Miscellaneous	Non-HVAC Motors	34.6%	0.20	0.07	0.3
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.63	0.63	2.7
Total				**46.35**	**197.8**

Table A-10 Washington Commercial Health Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	16.7%	5.60	0.93	4.6
Cooling	Water-Cooled Chiller	66.7%	7.13	4.76	23.3
Cooling	RTU	11.0%	5.57	0.61	3.0
Cooling	PTAC	0.4%	6.56	0.03	0.1
Cooling	PTHP	0.0%	5.56	0.00	0.0
Cooling	Evaporative AC	0.0%	2.23	0.00	0.0
Cooling	Air-Source Heat Pump	0.6%	5.56	0.03	0.2
Cooling	Geothermal Heat Pump	0.9%	3.38	0.03	0.1
Heating	Electric Furnace	3.0%	17.22	0.51	2.5
Heating	Electric Room Heat	0.1%	16.40	0.01	0.0
Heating	PTHP	0.0%	10.10	0.00	0.0
Heating	Air-Source Heat Pump	0.6%	11.22	0.06	0.3
Heating	Geothermal Heat Pump	0.9%	7.92	0.07	0.3
Ventilation	Ventilation	100.0%	4.56	4.56	22.3
Water Heating	Water Heater	12.6%	4.56	0.57	2.8
Interior Lighting	General Service Lighting	100.0%	0.55	0.55	2.7
Interior Lighting	Exempted Lighting	100.0%	0.23	0.23	1.1
Interior Lighting	High-Bay Lighting	100.0%	2.59	2.59	12.7
Interior Lighting	Linear Lighting	100.0%	4.04	4.04	19.8
Exterior Lighting	General Service Lighting	100.0%	0.04	0.04	0.2
Exterior Lighting	Area Lighting	100.0%	0.66	0.66	3.3
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	0.4
Refrigeration	Walk-in Refrigerator/Freezer	33.0%	0.27	0.09	0.4
Refrigeration	Reach-in Refrigerator/Freezer	50.0%	0.06	0.03	0.2
Refrigeration	Glass Door Display	90.4%	0.06	0.06	0.3
Refrigeration	Open Display Case	90.4%	0.38	0.34	1.7
Refrigeration	Icemaker	90.4%	0.21	0.19	0.9
Refrigeration	Vending Machine	90.4%	0.10	0.09	0.4
Food Preparation	Oven	69.7%	0.64	0.45	2.2
Food Preparation	Fryer	80.7%	0.93	0.75	3.7
Food Preparation	Dishwasher	53.5%	1.28	0.68	3.3
Food Preparation	Hot Food Container	53.5%	0.17	0.09	0.5
Food Preparation	Steamer	53.5%	0.93	0.50	2.4
Office Equipment	Desktop Computer	100.0%	0.56	0.56	2.7
Office Equipment	Laptop	100.0%	0.03	0.03	0.2
Office Equipment	Server	100.0%	0.07	0.07	0.3
Office Equipment	Monitor	100.0%	0.10	0.10	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.3
Office Equipment	POS Terminal	100.0%	0.04	0.04	0.2
Miscellaneous	Non-HVAC Motors	74.1%	0.63	0.47	2.3
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	63.0%	0.04	0.02	0.1
Miscellaneous	Clothes Dryer	58.0%	0.12	0.07	0.3
Miscellaneous	Other Miscellaneous	100.0%	4.89	4.89	23.9
Total				**29.95**	**146.7**

Table A-11 Washington Commercial College Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	28.5%	4.25	1.21	8.2
Cooling	Water-Cooled Chiller	0.0%	5.34	0.00	0.0
Cooling	RTU	46.8%	2.49	1.16	7.9
Cooling	PTAC	3.0%	2.93	0.09	0.6
Cooling	PTHP	2.1%	2.48	0.05	0.4
Cooling	Evaporative AC	0.0%	1.00	0.00	0.0
Cooling	Air-Source Heat Pump	7.9%	2.48	0.20	1.3
Cooling	Geothermal Heat Pump	5.7%	1.51	0.09	0.6
Heating	Electric Furnace	0.0%	11.87	0.00	0.0
Heating	Electric Room Heat	8.1%	11.31	0.91	6.2
Heating	PTHP	2.1%	7.12	0.15	1.0
Heating	Air-Source Heat Pump	7.9%	7.92	0.63	4.2
Heating	Geothermal Heat Pump	5.7%	5.95	0.34	2.3
Ventilation	Ventilation	100.0%	1.52	1.52	10.3
Water Heating	Water Heater	55.3%	2.08	1.15	7.8
Interior Lighting	General Service Lighting	100.0%	0.09	0.09	0.6
Interior Lighting	Exempted Lighting	100.0%	0.04	0.04	0.3
Interior Lighting	High-Bay Lighting	100.0%	1.42	1.42	9.6
Interior Lighting	Linear Lighting	100.0%	2.19	2.19	14.8
Exterior Lighting	General Service Lighting	100.0%	0.02	0.02	0.1
Exterior Lighting	Area Lighting	100.0%	0.29	0.29	1.9
Exterior Lighting	Linear Lighting	100.0%	0.75	0.75	5.1
Refrigeration	Walk-in Refrigerator/Freezer	7.7%	0.16	0.01	0.1
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.07	0.01	0.1
Refrigeration	Glass Door Display	26.6%	0.04	0.01	0.1
Refrigeration	Open Display Case	26.6%	0.22	0.06	0.4
Refrigeration	Icemaker	26.6%	0.12	0.03	0.2
Refrigeration	Vending Machine	26.6%	0.06	0.02	0.1
Food Preparation	Oven	21.0%	0.24	0.05	0.3
Food Preparation	Fryer	21.0%	0.34	0.07	0.5
Food Preparation	Dishwasher	21.0%	0.47	0.10	0.7
Food Preparation	Hot Food Container	21.0%	0.06	0.01	0.1
Food Preparation	Steamer	21.0%	0.35	0.07	0.5
Office Equipment	Desktop Computer	100.0%	0.47	0.47	3.2
Office Equipment	Laptop	100.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.06	0.06	0.4
Office Equipment	Monitor	100.0%	0.08	0.08	0.6
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.4
Office Equipment	POS Terminal	100.0%	0.02	0.02	0.1
Miscellaneous	Non-HVAC Motors	88.8%	0.08	0.07	0.5
Miscellaneous	Pool Pump	90.3%	0.01	0.01	0.1
Miscellaneous	Pool Heater	36.2%	0.02	0.01	0.0
Miscellaneous	Clothes Washer	15.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	11.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.35	0.35	2.4
Total				**13.91**	**93.9**

Table A-12 Washington Commercial School Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	22.1%	1.97	0.43	6.7
Cooling	Water-Cooled Chiller	0.0%	2.47	0.00	0.0
Cooling	RTU	36.2%	1.15	0.42	6.4
Cooling	PTAC	2.4%	1.35	0.03	0.5
Cooling	PTHP	1.6%	1.15	0.02	0.3
Cooling	Evaporative AC	0.0%	0.46	0.00	0.0
Cooling	Air-Source Heat Pump	6.1%	1.15	0.07	1.1
Cooling	Geothermal Heat Pump	4.4%	0.70	0.03	0.5
Heating	Electric Furnace	0.0%	6.44	0.00	0.0
Heating	Electric Room Heat	4.4%	6.13	0.27	4.2
Heating	PTHP	1.6%	3.86	0.06	1.0
Heating	Air-Source Heat Pump	6.1%	4.29	0.26	4.1
Heating	Geothermal Heat Pump	4.4%	3.23	0.14	2.2
Ventilation	Ventilation	100.0%	0.71	0.71	11.0
Water Heating	Water Heater	50.0%	0.99	0.50	7.6
Interior Lighting	General Service Lighting	100.0%	0.16	0.16	2.5
Interior Lighting	Exempted Lighting	100.0%	0.18	0.18	2.8
Interior Lighting	High-Bay Lighting	100.0%	0.81	0.81	12.5
Interior Lighting	Linear Lighting	100.0%	1.51	1.51	23.3
Exterior Lighting	General Service Lighting	100.0%	0.00	0.00	0.1
Exterior Lighting	Area Lighting	100.0%	0.12	0.12	1.8
Exterior Lighting	Linear Lighting	100.0%	0.66	0.66	10.1
Refrigeration	Walk-in Refrigerator/Freezer	19.0%	0.17	0.03	0.5
Refrigeration	Reach-in Refrigerator/Freezer	33.0%	0.08	0.02	0.4
Refrigeration	Glass Door Display	65.7%	0.04	0.03	0.4
Refrigeration	Open Display Case	65.7%	0.23	0.15	2.3
Refrigeration	Icemaker	65.7%	0.13	0.08	1.3
Refrigeration	Vending Machine	65.7%	0.06	0.04	0.6
Food Preparation	Oven	64.8%	0.11	0.07	1.1
Food Preparation	Fryer	58.6%	0.16	0.09	1.5
Food Preparation	Dishwasher	52.3%	0.22	0.12	1.8
Food Preparation	Hot Food Container	52.3%	0.03	0.02	0.2
Food Preparation	Steamer	52.3%	0.16	0.08	1.3
Office Equipment	Desktop Computer	100.0%	0.29	0.29	4.5
Office Equipment	Laptop	100.0%	0.02	0.02	0.3
Office Equipment	Server	100.0%	0.07	0.07	1.1
Office Equipment	Monitor	100.0%	0.05	0.05	0.8
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.5
Office Equipment	POS Terminal	36.0%	0.01	0.00	0.1
Miscellaneous	Non-HVAC Motors	43.7%	0.07	0.03	0.5
Miscellaneous	Pool Pump	6.0%	0.02	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Clothes Washer	15.0%	0.01	0.00	0.0
Miscellaneous	Clothes Dryer	11.0%	0.02	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.33	0.33	5.0
Total				**7.96**	**122.7**

Table A-13 Washington Commercial Lodging Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.0%	0.49	0.01	0.1
Cooling	Water-Cooled Chiller	7.3%	0.62	0.05	0.3
Cooling	RTU	15.8%	1.52	0.24	1.6
Cooling	PTAC	38.8%	1.79	0.70	4.7
Cooling	PTHP	13.0%	1.52	0.20	1.3
Cooling	Evaporative AC	0.5%	0.61	0.00	0.0
Cooling	Air-Source Heat Pump	5.1%	1.52	0.08	0.5
Cooling	Geothermal Heat Pump	5.5%	1.44	0.08	0.5
Heating	Electric Furnace	1.4%	3.02	0.04	0.3
Heating	Electric Room Heat	51.1%	2.88	1.47	9.9
Heating	PTHP	13.0%	2.42	0.32	2.1
Heating	Air-Source Heat Pump	5.1%	2.69	0.14	0.9
Heating	Geothermal Heat Pump	5.5%	1.90	0.10	0.7
Ventilation	Ventilation	100.0%	0.94	0.94	6.4
Water Heating	Water Heater	50.0%	3.20	1.60	10.8
Interior Lighting	General Service Lighting	100.0%	0.81	0.81	5.4
Interior Lighting	Exempted Lighting	100.0%	0.43	0.43	2.9
Interior Lighting	High-Bay Lighting	100.0%	1.29	1.29	8.7
Interior Lighting	Linear Lighting	100.0%	0.46	0.46	3.1
Exterior Lighting	General Service Lighting	100.0%	0.04	0.04	0.3
Exterior Lighting	Area Lighting	100.0%	1.73	1.73	11.6
Exterior Lighting	Linear Lighting	100.0%	0.03	0.03	0.2
Refrigeration	Walk-in Refrigerator/Freezer	3.0%	0.39	0.01	0.1
Refrigeration	Reach-in Refrigerator/Freezer	19.0%	0.09	0.02	0.1
Refrigeration	Glass Door Display	58.9%	0.09	0.05	0.4
Refrigeration	Open Display Case	58.9%	0.54	0.32	2.1
Refrigeration	Icemaker	58.9%	0.15	0.09	0.6
Refrigeration	Vending Machine	58.9%	0.14	0.08	0.6
Food Preparation	Oven	13.8%	0.26	0.04	0.2
Food Preparation	Fryer	21.0%	0.37	0.08	0.5
Food Preparation	Dishwasher	30.0%	0.51	0.15	1.0
Food Preparation	Hot Food Container	30.0%	0.07	0.02	0.1
Food Preparation	Steamer	30.0%	0.38	0.11	0.8
Office Equipment	Desktop Computer	100.0%	0.08	0.08	0.6
Office Equipment	Laptop	100.0%	0.01	0.01	0.1
Office Equipment	Server	100.0%	0.05	0.05	0.3
Office Equipment	Monitor	100.0%	0.01	0.01	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.1
Office Equipment	POS Terminal	58.0%	0.01	0.01	0.1
Miscellaneous	Non-HVAC Motors	91.3%	0.14	0.12	0.8
Miscellaneous	Pool Pump	76.0%	0.01	0.01	0.1
Miscellaneous	Pool Heater	27.0%	0.02	0.00	0.0
Miscellaneous	Clothes Washer	67.0%	0.02	0.01	0.1
Miscellaneous	Clothes Dryer	26.0%	0.07	0.02	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.63	0.63	4.2
Total				**12.69**	**85.3**

Table A-14 Washington Commercial Warehouse Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	1.59	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	1.68	0.00	0.0
Cooling	RTU	16.0%	1.78	0.28	5.5
Cooling	PTAC	1.1%	2.09	0.02	0.4
Cooling	PTHP	0.3%	1.78	0.01	0.1
Cooling	Evaporative AC	0.0%	0.71	0.00	0.0
Cooling	Air-Source Heat Pump	1.7%	1.78	0.03	0.6
Cooling	Geothermal Heat Pump	0.0%	1.08	0.00	0.0
Heating	Electric Furnace	2.3%	7.84	0.18	3.5
Heating	Electric Room Heat	12.4%	7.46	0.93	17.8
Heating	PTHP	0.3%	6.19	0.02	0.4
Heating	Air-Source Heat Pump	1.7%	6.88	0.12	2.2
Heating	Geothermal Heat Pump	0.0%	5.93	0.00	0.0
Ventilation	Ventilation	100.0%	0.26	0.26	5.0
Water Heating	Water Heater	55.3%	0.26	0.15	2.8
Interior Lighting	General Service Lighting	100.0%	0.07	0.07	1.4
Interior Lighting	Exempted Lighting	100.0%	0.04	0.04	0.7
Interior Lighting	High-Bay Lighting	100.0%	1.69	1.69	32.6
Interior Lighting	Linear Lighting	100.0%	0.28	0.28	5.4
Exterior Lighting	General Service Lighting	100.0%	0.02	0.02	0.4
Exterior Lighting	Area Lighting	100.0%	0.38	0.38	7.3
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	1.5
Refrigeration	Walk-in Refrigerator/Freezer	1.1%	0.49	0.01	0.1
Refrigeration	Reach-in Refrigerator/Freezer	2.0%	0.11	0.00	0.0
Refrigeration	Glass Door Display	10.1%	0.11	0.01	0.2
Refrigeration	Open Display Case	10.1%	0.67	0.07	1.3
Refrigeration	Icemaker	10.1%	0.19	0.02	0.4
Refrigeration	Vending Machine	10.1%	0.09	0.01	0.2
Food Preparation	Oven	2.3%	0.03	0.00	0.0
Food Preparation	Fryer	2.3%	0.05	0.00	0.0
Food Preparation	Dishwasher	2.3%	0.07	0.00	0.0
Food Preparation	Hot Food Container	2.3%	0.01	0.00	0.0
Food Preparation	Steamer	2.3%	0.05	0.00	0.0
Office Equipment	Desktop Computer	100.0%	0.09	0.09	1.7
Office Equipment	Laptop	100.0%	0.01	0.01	0.2
Office Equipment	Server	89.0%	0.10	0.09	1.8
Office Equipment	Monitor	100.0%	0.02	0.02	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.2
Office Equipment	POS Terminal	77.0%	0.03	0.02	0.4
Miscellaneous	Non-HVAC Motors	49.9%	0.12	0.06	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	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.43	0.43	8.3
Total				**5.40**	**104.0**

Table A-15 Washington Commercial Miscellaneous Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	9.7%	1.64	0.16	4.8
Cooling	Water-Cooled Chiller	5.0%	1.78	0.09	2.7
Cooling	RTU	56.8%	1.86	1.06	32.0
Cooling	PTAC	5.1%	2.19	0.11	3.4
Cooling	PTHP	2.6%	1.86	0.05	1.5
Cooling	Evaporative AC	0.0%	0.74	0.00	0.0
Cooling	Air-Source Heat Pump	5.5%	1.86	0.10	3.1
Cooling	Geothermal Heat Pump	1.0%	1.13	0.01	0.4
Heating	Electric Furnace	12.5%	4.77	0.59	18.0
Heating	Electric Room Heat	14.8%	4.55	0.67	20.3
Heating	PTHP	2.6%	3.61	0.09	2.8
Heating	Air-Source Heat Pump	5.5%	4.01	0.22	6.7
Heating	Geothermal Heat Pump	1.0%	3.13	0.03	1.0
Ventilation	Ventilation	100.0%	0.73	0.73	22.1
Water Heating	Water Heater	53.0%	1.39	0.74	22.3
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	11.4
Interior Lighting	Exempted Lighting	100.0%	0.23	0.23	6.9
Interior Lighting	High-Bay Lighting	100.0%	1.56	1.56	47.2
Interior Lighting	Linear Lighting	100.0%	1.46	1.46	44.3
Exterior Lighting	General Service Lighting	100.0%	0.09	0.09	2.8
Exterior Lighting	Area Lighting	100.0%	0.64	0.64	19.3
Exterior Lighting	Linear Lighting	100.0%	0.06	0.06	1.8
Refrigeration	Walk-in Refrigerator/Freezer	10.3%	0.58	0.06	1.8
Refrigeration	Reach-in Refrigerator/Freezer	12.1%	0.13	0.02	0.5
Refrigeration	Glass Door Display	3.4%	0.13	0.00	0.1
Refrigeration	Open Display Case	3.4%	0.79	0.03	0.8
Refrigeration	Icemaker	21.6%	0.22	0.05	1.4
Refrigeration	Vending Machine	21.6%	0.20	0.04	1.3
Food Preparation	Oven	58.9%	0.08	0.05	1.5
Food Preparation	Fryer	29.9%	0.12	0.04	1.1
Food Preparation	Dishwasher	15.4%	0.17	0.03	0.8
Food Preparation	Hot Food Container	15.4%	0.02	0.00	0.1
Food Preparation	Steamer	15.4%	0.12	0.02	0.6
Office Equipment	Desktop Computer	100.0%	0.20	0.20	6.0
Office Equipment	Laptop	100.0%	0.03	0.03	0.9
Office Equipment	Server	66.0%	0.12	0.08	2.3
Office Equipment	Monitor	100.0%	0.03	0.03	1.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.7
Office Equipment	POS Terminal	28.0%	0.03	0.01	0.3
Miscellaneous	Non-HVAC Motors	59.9%	0.15	0.09	2.6
Miscellaneous	Pool Pump	4.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Clothes Washer	15.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	10.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.57	0.57	17.1
Total				**10.43**	**315.8**

Table A-16 Washington Industrial Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.5%	6,629.79	165.74	2.8
Cooling	Water-Cooled Chiller	2.5%	6,983.13	174.58	2.9
Cooling	RTU	11.4%	7,389.72	842.74	14.2
Cooling	Air-Source Heat Pump	1.7%	7,386.34	124.90	2.1
Cooling	Geothermal Heat Pump	0.0%	4,926.69	0.00	0.0
Heating	Electric Furnace	2.3%	32,574.73	747.28	12.6
Heating	Electric Room Heat	12.4%	31,023.55	3,849.55	65.0
Heating	Air-Source Heat Pump	1.7%	28,604.84	483.71	8.2
Heating	Geothermal Heat Pump	0.0%	19,079.43	0.00	0.0
Ventilation	Ventilation	100.0%	1,077.71	1,077.71	18.2
Interior Lighting	General Service Lighting	100.0%	206.68	206.68	3.5
Interior Lighting	High-Bay Lighting	100.0%	3,233.38	3,233.38	54.6
Interior Lighting	Linear Lighting	100.0%	537.49	537.49	9.1
Exterior Lighting	General Service Lighting	100.0%	38.05	38.05	0.6
Exterior Lighting	Area Lighting	100.0%	720.88	720.88	12.2
Exterior Lighting	Linear Lighting	100.0%	147.69	147.69	2.5
Motors	Pumps	100.0%	1,899.28	1,899.28	32.1
Motors	Fans & Blowers	100.0%	2,280.92	2,280.92	38.5
Motors	Compressed Air	100.0%	1,844.32	1,844.32	31.2
Motors	Material Handling	100.0%	3,900.92	3,900.92	65.9
Motors	Other Motors	100.0%	65.46	65.46	1.1
Process	Process Heating	100.0%	3,211.52	3,211.52	54.3
Process	Process Cooling	100.0%	843.19	843.19	14.2
Process	Process Refrigeration	100.0%	843.19	843.19	14.2
Process	Process Electrochemical	100.0%	324.59	324.59	5.5
Process	Process Other	100.0%	352.25	352.25	6.0
Miscellaneous	Miscellaneous	100.0%	1,937.76	1,937.76	32.7
Total				**29,853.79**	**504.4**

Table A-17 Idaho Residential Single Family Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	36.0%	1,271	458	31.2
Cooling	Room AC	11.6%	691	80	5.5
Cooling	Air-Source Heat Pump	9.9%	1,332	132	9.0
Cooling	Geothermal Heat Pump	0.8%	1,176	10	0.7
Cooling	Evaporative AC	1.6%	647	10	0.7
Space Heating	Electric Room Heat	9.8%	15,052	1,470	100.1
Space Heating	Electric Furnace	7.4%	16,964	1,262	86.0
Space Heating	Air-Source Heat Pump	9.9%	12,902	1,277	87.0
Space Heating	Geothermal Heat Pump	0.8%	5,686	47	3.2
Space Heating	Secondary Heating	57.2%	392	224	15.3
Water Heating	Water Heater <= 55 Gal	43.0%	3,362	1,445	98.4
Water Heating	Water Heater > 55 Gal	5.9%	3,554	209	14.2
Interior Lighting	General Service Screw-in	100.0%	761	761	51.8
Interior Lighting	Linear Lighting	100.0%	124	124	8.4
Interior Lighting	Exempted Screw-In	100.0%	58	58	3.9
Exterior Lighting	Screw-in	100.0%	284	284	19.4
Appliances	Clothes Washer	95.5%	83	79	5.4
Appliances	Clothes Dryer	65.6%	734	482	32.8
Appliances	Dishwasher	80.1%	382	306	20.8
Appliances	Refrigerator	95.5%	707	676	46.0
Appliances	Freezer	66.3%	566	376	25.6
Appliances	Second Refrigerator	39.7%	829	329	22.4
Appliances	Stove/Oven	58.4%	438	256	17.4
Appliances	Microwave	93.1%	126	117	8.0
Electronics	Personal Computers	63.3%	163	103	7.0
Electronics	Monitor	126.9%	62	79	5.4
Electronics	Laptops	85.7%	43	36	2.5
Electronics	TVs	199.0%	115	228	15.5
Electronics	Printer/Fax/Copier	76.9%	43	33	2.2
Electronics	Set-top Boxes/DVRs	105.8%	100	105	7.2
Electronics	Devices and Gadgets	100.0%	108	108	7.3
Miscellaneous	Electric Vehicles	0.2%	4,324	9	0.6
Miscellaneous	Pool Pump	0.0%	3,500	0	0.0
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.8%	950	8	0.5
Miscellaneous	Furnace Fan	70.2%	541	380	25.9
Miscellaneous	Well pump	0.0%	561	0	0.0
Miscellaneous	Miscellaneous	100.0%	1,254	1,254	85.4
Total				**12,815**	**872.7**

Table A-18 Idaho Residential Multi Family Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	22.6%	426	96	0.5
Cooling	Room AC	32.0%	258	83	0.5
Cooling	Air-Source Heat Pump	1.3%	426	6	0.0
Cooling	Geothermal Heat Pump	0.0%	376	0	0.0
Cooling	Evaporative AC	1.9%	320	6	0.0
Space Heating	Electric Room Heat	58.5%	2,937	1,718	9.4
Space Heating	Electric Furnace	16.4%	3,143	515	2.8
Space Heating	Air-Source Heat Pump	1.3%	1,831	24	0.1
Space Heating	Geothermal Heat Pump	0.0%	807	0	0.0
Space Heating	Secondary Heating	30.0%	443	133	0.7
Water Heating	Water Heater <= 55 Gal	60.4%	2,100	1,269	7.0
Water Heating	Water Heater > 55 Gal	4.6%	2,220	101	0.6
Interior Lighting	General Service Screw-in	100.0%	405	405	2.2
Interior Lighting	Linear Lighting	100.0%	33	33	0.2
Interior Lighting	Exempted Screw-In	100.0%	33	33	0.2
Exterior Lighting	Screw-in	100.0%	130	130	0.7
Appliances	Clothes Washer	59.6%	78	47	0.3
Appliances	Clothes Dryer	42.3%	785	332	1.8
Appliances	Dishwasher	73.1%	379	277	1.5
Appliances	Refrigerator	90.4%	691	624	3.4
Appliances	Freezer	23.1%	548	127	0.7
Appliances	Second Refrigerator	3.9%	660	25	0.1
Appliances	Stove/Oven	69.2%	317	219	1.2
Appliances	Microwave	86.5%	126	109	0.6
Electronics	Personal Computers	46.3%	163	75	0.4
Electronics	Monitor	94.9%	62	59	0.3
Electronics	Laptops	74.1%	43	32	0.2
Electronics	TVs	140.7%	115	162	0.9
Electronics	Printer/Fax/Copier	51.9%	43	22	0.1
Electronics	Set-top Boxes/DVRs	64.8%	100	65	0.4
Electronics	Devices and Gadgets	100.0%	108	108	0.6
Miscellaneous	Electric Vehicles	0.0%	4,324	0	0.0
Miscellaneous	Pool Pump	0.0%	3,500	0	0.0
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.0%	950	0	0.0
Miscellaneous	Furnace Fan	33.3%	196	65	0.4
Miscellaneous	Well pump	0.0%	556	0	0.0
Miscellaneous	Miscellaneous	100.0%	783	783	4.3
Total				**7,681**	**42.2**

Table A-19 Idaho Residential Mobile Home Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	22.5%	890	201	1.0
Cooling	Room AC	12.9%	472	61	0.3
Cooling	Air-Source Heat Pump	26.1%	890	232	1.2
Cooling	Geothermal Heat Pump	0.0%	783	0	0.0
Cooling	Evaporative AC	0.0%	443	0	0.0
Space Heating	Electric Room Heat	6.2%	7,208	447	2.3
Space Heating	Electric Furnace	24.8%	7,715	1,915	9.7
Space Heating	Air-Source Heat Pump	26.1%	6,752	1,763	8.9
Space Heating	Geothermal Heat Pump	0.0%	3,094	0	0.0
Space Heating	Secondary Heating	38.5%	493	190	1.0
Water Heating	Water Heater <= 55 Gal	75.0%	3,288	2,466	12.4
Water Heating	Water Heater > 55 Gal	0.0%	3,476	0	0.0
Interior Lighting	General Service Screw-in	100.0%	441	441	2.2
Interior Lighting	Linear Lighting	100.0%	62	62	0.3
Interior Lighting	Exempted Screw-In	100.0%	19	19	0.1
Exterior Lighting	Screw-in	100.0%	109	109	0.5
Appliances	Clothes Washer	94.9%	82	78	0.4
Appliances	Clothes Dryer	82.1%	830	681	3.4
Appliances	Dishwasher	74.4%	384	286	1.4
Appliances	Refrigerator	84.6%	705	597	3.0
Appliances	Freezer	48.7%	567	276	1.4
Appliances	Second Refrigerator	18.2%	742	135	0.7
Appliances	Stove/Oven	82.1%	312	256	1.3
Appliances	Microwave	92.3%	126	116	0.6
Electronics	Personal Computers	46.4%	163	76	0.4
Electronics	Monitor	78.1%	62	48	0.2
Electronics	Laptops	50.0%	43	21	0.1
Electronics	TVs	110.7%	115	127	0.6
Electronics	Printer/Fax/Copier	42.9%	43	18	0.1
Electronics	Set-top Boxes/DVRs	89.3%	100	89	0.4
Electronics	Devices and Gadgets	100.0%	108	108	0.5
Miscellaneous	Electric Vehicles	0.0%	4,324	0	0.0
Miscellaneous	Pool Pump	1.8%	3,500	65	0.3
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.0%	950	0	0.0
Miscellaneous	Furnace Fan	71.4%	310	222	1.1
Miscellaneous	Well pump	0.0%	451	0	0.0
Miscellaneous	Miscellaneous	100.0%	418	418	2.1
Total				**11,522**	**58.1**

Table A-20 Idaho Residential Low-Income Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	23.9%	470	112	3.8
Cooling	Room AC	28.0%	270	76	2.5
Cooling	Air-Source Heat Pump	4.7%	476	22	0.7
Cooling	Geothermal Heat Pump	0.1%	420	0	0.0
Cooling	Evaporative AC	1.6%	300	5	0.2
Space Heating	Electric Room Heat	48.4%	4,146	2,006	67.0
Space Heating	Electric Furnace	16.3%	4,519	738	24.6
Space Heating	Air-Source Heat Pump	4.7%	3,187	148	4.9
Space Heating	Geothermal Heat Pump	0.1%	1,419	1	0.0
Space Heating	Secondary Heating	33.5%	377	126	4.2
Water Heating	Water Heater <= 55 Gal	60.2%	2,345	1,411	47.1
Water Heating	Water Heater > 55 Gal	4.2%	2,479	105	3.5
Interior Lighting	General Service Screw-in	100.0%	441	441	14.7
Interior Lighting	Linear Lighting	100.0%	62	62	2.1
Interior Lighting	Exempted Screw-In	100.0%	19	19	0.6
Exterior Lighting	Screw-in	100.0%	109	109	3.6
Appliances	Clothes Washer	66.7%	79	53	1.8
Appliances	Clothes Dryer	48.6%	784	381	12.7
Appliances	Dishwasher	73.9%	379	280	9.4
Appliances	Refrigerator	90.3%	694	627	20.9
Appliances	Freezer	30.0%	552	165	5.5
Appliances	Second Refrigerator	8.9%	685	61	2.0
Appliances	Stove/Oven	69.4%	328	228	7.6
Appliances	Microwave	87.8%	126	111	3.7
Electronics	Personal Computers	48.0%	163	78	2.6
Electronics	Monitor	96.4%	62	60	2.0
Electronics	Laptops	72.8%	43	31	1.0
Electronics	TVs	143.6%	115	165	5.5
Electronics	Printer/Fax/Copier	53.5%	43	23	0.8
Electronics	Set-top Boxes/DVRs	71.4%	100	71	2.4
Electronics	Devices and Gadgets	100.0%	108	108	3.6
Miscellaneous	Electric Vehicles	0.0%	4,324	1	0.0
Miscellaneous	Pool Pump	0.2%	3,500	6	0.2
Miscellaneous	Pool Heater	0.0%	3,517	0	0.0
Miscellaneous	Hot Tub / Spa	0.1%	950	1	0.0
Miscellaneous	Furnace Fan	40.8%	242	99	3.3
Miscellaneous	Well pump	0.0%	546	0	0.0
Miscellaneous	Miscellaneous	100.0%	364	364	12.1
Total				**8,293**	**276.8**

Table A-21 Idaho Commercial Large Office Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	13.7%	3.08	0.42	5.6
Cooling	Water-Cooled Chiller	8.5%	3.37	0.28	3.7
Cooling	RTU	44.5%	3.22	1.43	18.9
Cooling	PTAC	2.4%	3.80	0.09	1.2
Cooling	PTHP	0.7%	3.22	0.02	0.3
Cooling	Evaporative AC	0.0%	1.29	0.00	0.0
Cooling	Air-Source Heat Pump	14.2%	3.22	0.46	6.0
Cooling	Geothermal Heat Pump	7.6%	1.96	0.15	2.0
Heating	Electric Furnace	1.2%	5.64	0.07	0.9
Heating	Electric Room Heat	23.8%	5.37	1.28	16.8
Heating	PTHP	0.7%	4.29	0.03	0.4
Heating	Air-Source Heat Pump	14.2%	4.77	0.68	8.9
Heating	Geothermal Heat Pump	7.6%	3.85	0.29	3.9
Ventilation	Ventilation	100.0%	3.11	3.11	40.9
Water Heating	Water Heater	45.2%	1.04	0.47	6.2
Interior Lighting	General Service Lighting	100.0%	0.25	0.25	3.3
Interior Lighting	Exempted Lighting	100.0%	0.10	0.10	1.4
Interior Lighting	High-Bay Lighting	100.0%	1.01	1.01	13.3
Interior Lighting	Linear Lighting	100.0%	1.72	1.72	22.7
Exterior Lighting	General Service Lighting	100.0%	0.10	0.10	1.3
Exterior Lighting	Area Lighting	100.0%	1.28	1.28	16.8
Exterior Lighting	Linear Lighting	100.0%	0.18	0.18	2.4
Refrigeration	Walk-in Refrigerator/Freezer	2.0%	0.14	0.00	0.0
Refrigeration	Reach-in Refrigerator/Freezer	14.0%	0.03	0.00	0.1
Refrigeration	Glass Door Display	77.4%	0.03	0.03	0.3
Refrigeration	Open Display Case	77.4%	0.19	0.15	2.0
Refrigeration	Icemaker	44.9%	0.05	0.02	0.3
Refrigeration	Vending Machine	44.9%	0.05	0.02	0.3
Food Preparation	Oven	66.0%	0.09	0.06	0.8
Food Preparation	Fryer	76.4%	0.13	0.10	1.3
Food Preparation	Dishwasher	43.1%	0.18	0.08	1.0
Food Preparation	Hot Food Container	43.1%	0.02	0.01	0.1
Food Preparation	Steamer	43.1%	0.13	0.06	0.7
Office Equipment	Desktop Computer	100.0%	2.35	2.35	30.9
Office Equipment	Laptop	100.0%	0.36	0.36	4.8
Office Equipment	Server	100.0%	0.23	0.23	3.0
Office Equipment	Monitor	100.0%	0.41	0.41	5.4
Office Equipment	Printer/Copier/Fax	100.0%	0.21	0.21	2.8
Office Equipment	POS Terminal	40.0%	0.03	0.01	0.2
Miscellaneous	Non-HVAC Motors	89.6%	0.35	0.31	4.1
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.42	1.42	18.6
Total				**19.27**	**253.4**

Table A-22 Idaho Commercial Small Office Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	3.17	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	3.45	0.00	0.0
Cooling	RTU	65.6%	3.61	2.37	13.0
Cooling	PTAC	2.3%	4.25	0.10	0.5
Cooling	PTHP	0.7%	3.61	0.03	0.1
Cooling	Evaporative AC	0.0%	1.44	0.00	0.0
Cooling	Air-Source Heat Pump	14.0%	3.61	0.50	2.8
Cooling	Geothermal Heat Pump	7.5%	2.20	0.16	0.9
Heating	Electric Furnace	1.1%	6.82	0.08	0.4
Heating	Electric Room Heat	21.9%	6.49	1.42	7.8
Heating	PTHP	0.7%	5.16	0.04	0.2
Heating	Air-Source Heat Pump	14.0%	5.73	0.80	4.4
Heating	Geothermal Heat Pump	7.5%	4.44	0.33	1.8
Ventilation	Ventilation	100.0%	1.25	1.25	6.9
Water Heating	Water Heater	60.0%	0.94	0.56	3.1
Interior Lighting	General Service Lighting	100.0%	0.25	0.25	1.4
Interior Lighting	Exempted Lighting	100.0%	0.13	0.13	0.7
Interior Lighting	High-Bay Lighting	100.0%	1.51	1.51	8.3
Interior Lighting	Linear Lighting	100.0%	1.54	1.54	8.5
Exterior Lighting	General Service Lighting	100.0%	0.16	0.16	0.9
Exterior Lighting	Area Lighting	100.0%	1.58	1.58	8.7
Exterior Lighting	Linear Lighting	100.0%	0.07	0.07	0.4
Refrigeration	Walk-in Refrigerator/Freezer	0.0%	0.66	0.00	0.0
Refrigeration	Reach-in Refrigerator/Freezer	8.8%	0.15	0.01	0.1
Refrigeration	Glass Door Display	0.0%	0.15	0.00	0.0
Refrigeration	Open Display Case	0.0%	0.90	0.00	0.0
Refrigeration	Icemaker	5.1%	0.25	0.01	0.1
Refrigeration	Vending Machine	5.1%	0.12	0.01	0.0
Food Preparation	Oven	3.6%	0.19	0.01	0.0
Food Preparation	Fryer	3.6%	0.27	0.01	0.1
Food Preparation	Dishwasher	3.6%	0.37	0.01	0.1
Food Preparation	Hot Food Container	3.6%	0.05	0.00	0.0
Food Preparation	Steamer	3.6%	0.27	0.01	0.1
Office Equipment	Desktop Computer	100.0%	1.24	1.24	6.8
Office Equipment	Laptop	100.0%	0.19	0.19	1.1
Office Equipment	Server	100.0%	0.36	0.36	2.0
Office Equipment	Monitor	100.0%	0.22	0.22	1.2
Office Equipment	Printer/Copier/Fax	100.0%	0.17	0.17	0.9
Office Equipment	POS Terminal	20.0%	0.10	0.02	0.1
Miscellaneous	Non-HVAC Motors	22.0%	0.28	0.06	0.3
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.19	1.19	6.5
Total				**16.41**	**90.5**

Table A-23 Idaho Commercial Retail Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	2.19	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	2.39	0.00	0.0
Cooling	RTU	67.0%	2.50	1.67	17.1
Cooling	PTAC	2.4%	2.62	0.06	0.6
Cooling	PTHP	0.8%	2.49	0.02	0.2
Cooling	Evaporative AC	0.0%	1.00	0.00	0.0
Cooling	Air-Source Heat Pump	14.3%	2.49	0.36	3.6
Cooling	Geothermal Heat Pump	7.7%	1.52	0.12	1.2
Heating	Electric Furnace	0.5%	6.04	0.03	0.3
Heating	Electric Room Heat	9.6%	5.75	0.55	5.6
Heating	PTHP	0.8%	4.03	0.03	0.3
Heating	Air-Source Heat Pump	14.3%	4.47	0.64	6.5
Heating	Geothermal Heat Pump	7.7%	3.04	0.23	2.4
Ventilation	Ventilation	100.0%	1.01	1.01	10.3
Water Heating	Water Heater	61.8%	0.82	0.50	5.1
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	3.9
Interior Lighting	Exempted Lighting	100.0%	0.36	0.36	3.7
Interior Lighting	High-Bay Lighting	100.0%	1.51	1.51	15.4
Interior Lighting	Linear Lighting	100.0%	2.28	2.28	23.3
Exterior Lighting	General Service Lighting	100.0%	0.24	0.24	2.4
Exterior Lighting	Area Lighting	100.0%	0.84	0.84	8.6
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	0.8
Refrigeration	Walk-in Refrigerator/Freezer	0.0%	0.42	0.00	0.0
Refrigeration	Reach-in Refrigerator/Freezer	5.4%	0.09	0.01	0.1
Refrigeration	Glass Door Display	5.4%	0.10	0.01	0.1
Refrigeration	Open Display Case	5.4%	0.57	0.03	0.3
Refrigeration	Icemaker	5.1%	0.32	0.02	0.2
Refrigeration	Vending Machine	5.1%	0.15	0.01	0.1
Food Preparation	Oven	3.6%	0.17	0.01	0.1
Food Preparation	Fryer	3.6%	0.25	0.01	0.1
Food Preparation	Dishwasher	3.6%	0.35	0.01	0.1
Food Preparation	Hot Food Container	3.6%	0.05	0.00	0.0
Food Preparation	Steamer	3.6%	0.25	0.01	0.1
Office Equipment	Desktop Computer	100.0%	0.18	0.18	1.8
Office Equipment	Laptop	100.0%	0.03	0.03	0.3
Office Equipment	Server	82.0%	0.21	0.17	1.8
Office Equipment	Monitor	100.0%	0.03	0.03	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.2
Office Equipment	POS Terminal	100.0%	0.06	0.06	0.6
Miscellaneous	Non-HVAC Motors	40.2%	0.34	0.13	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	Clothes Washer	7.0%	0.01	0.00	0.0
Miscellaneous	Clothes Dryer	4.0%	0.03	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	1.43	1.43	14.6
Total				**13.09**	**133.6**

Table A-24 Idaho Commercial Restaurant Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	3.49	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	3.52	0.00	0.0
Cooling	RTU	72.9%	3.99	2.91	3.6
Cooling	PTAC	2.7%	4.69	0.13	0.2
Cooling	PTHP	1.9%	3.98	0.08	0.1
Cooling	Evaporative AC	3.3%	1.59	0.05	0.1
Cooling	Air-Source Heat Pump	8.2%	3.98	0.33	0.4
Cooling	Geothermal Heat Pump	0.0%	2.43	0.00	0.0
Heating	Electric Furnace	19.1%	4.81	0.92	1.1
Heating	Electric Room Heat	1.7%	4.58	0.08	0.1
Heating	PTHP	1.9%	3.01	0.06	0.1
Heating	Air-Source Heat Pump	8.2%	3.35	0.28	0.3
Heating	Geothermal Heat Pump	0.0%	2.37	0.00	0.0
Ventilation	Ventilation	100.0%	1.98	1.98	2.4
Water Heating	Water Heater	57.9%	7.75	4.49	5.5
Interior Lighting	General Service Lighting	100.0%	1.34	1.34	1.7
Interior Lighting	Exempted Lighting	100.0%	0.94	0.94	1.2
Interior Lighting	High-Bay Lighting	100.0%	2.92	2.92	3.6
Interior Lighting	Linear Lighting	100.0%	1.87	1.87	2.3
Exterior Lighting	General Service Lighting	100.0%	0.28	0.28	0.3
Exterior Lighting	Area Lighting	100.0%	2.14	2.14	2.6
Exterior Lighting	Linear Lighting	100.0%	0.40	0.40	0.5
Refrigeration	Walk-in Refrigerator/Freezer	74.0%	6.59	4.88	6.0
Refrigeration	Reach-in Refrigerator/Freezer	7.0%	2.96	0.21	0.3
Refrigeration	Glass Door Display	5.2%	1.52	0.08	0.1
Refrigeration	Open Display Case	5.2%	9.00	0.47	0.6
Refrigeration	Icemaker	97.3%	2.49	2.42	3.0
Refrigeration	Vending Machine	97.3%	1.17	1.14	1.4
Food Preparation	Oven	21.0%	3.95	0.83	1.0
Food Preparation	Fryer	82.0%	5.71	4.68	5.8
Food Preparation	Dishwasher	52.5%	3.93	2.06	2.5
Food Preparation	Hot Food Container	84.0%	0.54	0.45	0.6
Food Preparation	Steamer	16.0%	2.88	0.46	0.6
Office Equipment	Desktop Computer	100.0%	0.29	0.29	0.4
Office Equipment	Laptop	100.0%	0.04	0.04	0.0
Office Equipment	Server	50.0%	0.34	0.17	0.2
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%	0.54	0.11	0.1
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	2.15	2.15	2.7
Total				**41.80**	**51.6**

Table A-25 Idaho Commercial Grocery Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.5%	3.98	0.02	0.0
Cooling	Water-Cooled Chiller	0.3%	4.33	0.01	0.0
Cooling	RTU	71.3%	4.53	3.23	6.4
Cooling	PTAC	2.1%	5.33	0.11	0.2
Cooling	PTHP	0.6%	4.15	0.03	0.1
Cooling	Evaporative AC	1.2%	1.81	0.02	0.0
Cooling	Air-Source Heat Pump	7.2%	4.15	0.30	0.6
Cooling	Geothermal Heat Pump	0.0%	1.41	0.00	0.0
Heating	Electric Furnace	6.4%	7.41	0.47	0.9
Heating	Electric Room Heat	1.2%	7.06	0.08	0.2
Heating	PTHP	0.6%	3.42	0.02	0.0
Heating	Air-Source Heat Pump	7.2%	3.80	0.27	0.5
Heating	Geothermal Heat Pump	0.0%	2.65	0.00	0.0
Ventilation	Ventilation	100.0%	2.18	2.18	4.3
Water Heating	Water Heater	62.5%	2.29	1.43	2.9
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	0.8
Interior Lighting	Exempted Lighting	100.0%	0.30	0.30	0.6
Interior Lighting	High-Bay Lighting	100.0%	2.02	2.02	4.0
Interior Lighting	Linear Lighting	100.0%	5.01	5.01	10.0
Exterior Lighting	General Service Lighting	100.0%	0.36	0.36	0.7
Exterior Lighting	Area Lighting	100.0%	1.78	1.78	3.6
Exterior Lighting	Linear Lighting	100.0%	0.38	0.38	0.8
Refrigeration	Walk-in Refrigerator/Freezer	16.0%	5.38	0.86	1.7
Refrigeration	Reach-in Refrigerator/Freezer	83.1%	0.34	0.29	0.6
Refrigeration	Glass Door Display	94.9%	3.54	3.36	6.7
Refrigeration	Open Display Case	94.9%	20.97	19.90	39.6
Refrigeration	Icemaker	98.9%	0.29	0.29	0.6
Refrigeration	Vending Machine	98.9%	0.27	0.27	0.5
Food Preparation	Oven	11.0%	0.64	0.07	0.1
Food Preparation	Fryer	87.0%	0.92	0.80	1.6
Food Preparation	Dishwasher	54.9%	1.27	0.70	1.4
Food Preparation	Hot Food Container	73.0%	0.17	0.13	0.3
Food Preparation	Steamer	20.0%	0.93	0.19	0.4
Office Equipment	Desktop Computer	100.0%	0.16	0.16	0.3
Office Equipment	Laptop	64.0%	0.02	0.02	0.0
Office Equipment	Server	100.0%	0.09	0.09	0.2
Office Equipment	Monitor	100.0%	0.03	0.03	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.0
Office Equipment	POS Terminal	100.0%	0.06	0.06	0.1
Miscellaneous	Non-HVAC Motors	34.6%	0.20	0.07	0.1
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.63	0.63	1.3
Total				**46.35**	**92.3**

Table A-26 Idaho Commercial Health Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	16.7%	5.60	0.93	2.1
Cooling	Water-Cooled Chiller	66.7%	7.13	4.76	10.9
Cooling	RTU	11.0%	5.57	0.61	1.4
Cooling	PTAC	0.4%	6.56	0.03	0.1
Cooling	PTHP	0.0%	5.56	0.00	0.0
Cooling	Evaporative AC	0.0%	2.23	0.00	0.0
Cooling	Air-Source Heat Pump	0.6%	5.56	0.03	0.1
Cooling	Geothermal Heat Pump	0.9%	3.38	0.03	0.1
Heating	Electric Furnace	3.0%	17.22	0.51	1.2
Heating	Electric Room Heat	0.1%	16.40	0.01	0.0
Heating	PTHP	0.0%	10.10	0.00	0.0
Heating	Air-Source Heat Pump	0.6%	11.22	0.06	0.1
Heating	Geothermal Heat Pump	0.9%	7.92	0.07	0.2
Ventilation	Ventilation	100.0%	4.56	4.56	10.4
Water Heating	Water Heater	12.6%	4.56	0.57	1.3
Interior Lighting	General Service Lighting	100.0%	0.55	0.55	1.3
Interior Lighting	Exempted Lighting	100.0%	0.23	0.23	0.5
Interior Lighting	High-Bay Lighting	100.0%	2.59	2.59	5.9
Interior Lighting	Linear Lighting	100.0%	4.04	4.04	9.2
Exterior Lighting	General Service Lighting	100.0%	0.04	0.04	0.1
Exterior Lighting	Area Lighting	100.0%	0.66	0.66	1.5
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	0.2
Refrigeration	Walk-in Refrigerator/Freezer	33.0%	0.27	0.09	0.2
Refrigeration	Reach-in Refrigerator/Freezer	50.0%	0.06	0.03	0.1
Refrigeration	Glass Door Display	90.4%	0.06	0.06	0.1
Refrigeration	Open Display Case	90.4%	0.38	0.34	0.8
Refrigeration	Icemaker	90.4%	0.21	0.19	0.4
Refrigeration	Vending Machine	90.4%	0.10	0.09	0.2
Food Preparation	Oven	69.7%	0.64	0.45	1.0
Food Preparation	Fryer	80.7%	0.93	0.75	1.7
Food Preparation	Dishwasher	53.5%	1.28	0.68	1.6
Food Preparation	Hot Food Container	53.5%	0.17	0.09	0.2
Food Preparation	Steamer	53.5%	0.93	0.50	1.1
Office Equipment	Desktop Computer	100.0%	0.56	0.56	1.3
Office Equipment	Laptop	100.0%	0.03	0.03	0.1
Office Equipment	Server	100.0%	0.07	0.07	0.1
Office Equipment	Monitor	100.0%	0.10	0.10	0.2
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.1
Office Equipment	POS Terminal	100.0%	0.04	0.04	0.1
Miscellaneous	Non-HVAC Motors	74.1%	0.63	0.47	1.1
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	63.0%	0.04	0.02	0.1
Miscellaneous	Clothes Dryer	58.0%	0.12	0.07	0.2
Miscellaneous	Other Miscellaneous	100.0%	4.89	4.89	11.2
Total				**29.95**	**68.5**

Table A-27 Idaho Commercial College Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	28.5%	4.25	1.21	3.8
Cooling	Water-Cooled Chiller	0.0%	5.34	0.00	0.0
Cooling	RTU	46.8%	2.49	1.16	3.7
Cooling	PTAC	3.0%	2.93	0.09	0.3
Cooling	PTHP	2.1%	2.48	0.05	0.2
Cooling	Evaporative AC	0.0%	1.00	0.00	0.0
Cooling	Air-Source Heat Pump	7.9%	2.48	0.20	0.6
Cooling	Geothermal Heat Pump	5.7%	1.51	0.09	0.3
Heating	Electric Furnace	0.0%	11.87	0.00	0.0
Heating	Electric Room Heat	8.1%	11.31	0.91	2.9
Heating	PTHP	2.1%	7.12	0.15	0.5
Heating	Air-Source Heat Pump	7.9%	7.92	0.63	2.0
Heating	Geothermal Heat Pump	5.7%	5.95	0.34	1.1
Ventilation	Ventilation	100.0%	1.52	1.52	4.8
Water Heating	Water Heater	55.3%	2.08	1.15	3.6
Interior Lighting	General Service Lighting	100.0%	0.09	0.09	0.3
Interior Lighting	Exempted Lighting	100.0%	0.04	0.04	0.1
Interior Lighting	High-Bay Lighting	100.0%	1.42	1.42	4.5
Interior Lighting	Linear Lighting	100.0%	2.19	2.19	6.9
Exterior Lighting	General Service Lighting	100.0%	0.02	0.02	0.1
Exterior Lighting	Area Lighting	100.0%	0.29	0.29	0.9
Exterior Lighting	Linear Lighting	100.0%	0.75	0.75	2.4
Refrigeration	Walk-in Refrigerator/Freezer	7.7%	0.16	0.01	0.0
Refrigeration	Reach-in Refrigerator/Freezer	13.4%	0.07	0.01	0.0
Refrigeration	Glass Door Display	26.6%	0.04	0.01	0.0
Refrigeration	Open Display Case	26.6%	0.22	0.06	0.2
Refrigeration	Icemaker	26.6%	0.12	0.03	0.1
Refrigeration	Vending Machine	26.6%	0.06	0.02	0.0
Food Preparation	Oven	21.0%	0.24	0.05	0.2
Food Preparation	Fryer	21.0%	0.34	0.07	0.2
Food Preparation	Dishwasher	21.0%	0.47	0.10	0.3
Food Preparation	Hot Food Container	21.0%	0.06	0.01	0.0
Food Preparation	Steamer	21.0%	0.35	0.07	0.2
Office Equipment	Desktop Computer	100.0%	0.47	0.47	1.5
Office Equipment	Laptop	100.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.06	0.06	0.2
Office Equipment	Monitor	100.0%	0.08	0.08	0.3
Office Equipment	Printer/Copier/Fax	100.0%	0.06	0.06	0.2
Office Equipment	POS Terminal	100.0%	0.02	0.02	0.1
Miscellaneous	Non-HVAC Motors	88.8%	0.08	0.07	0.2
Miscellaneous	Pool Pump	90.3%	0.01	0.01	0.0
Miscellaneous	Pool Heater	36.2%	0.02	0.01	0.0
Miscellaneous	Clothes Washer	15.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	11.0%	0.01	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.35	0.35	1.1
Total				**13.91**	**43.8**

Table A-28 Idaho Commercial School Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	22.1%	1.97	0.43	3.1
Cooling	Water-Cooled Chiller	0.0%	2.47	0.00	0.0
Cooling	RTU	36.2%	1.15	0.42	3.0
Cooling	PTAC	2.4%	1.35	0.03	0.2
Cooling	PTHP	1.6%	1.15	0.02	0.1
Cooling	Evaporative AC	0.0%	0.46	0.00	0.0
Cooling	Air-Source Heat Pump	6.1%	1.15	0.07	0.5
Cooling	Geothermal Heat Pump	4.4%	0.70	0.03	0.2
Heating	Electric Furnace	0.0%	6.44	0.00	0.0
Heating	Electric Room Heat	4.4%	6.13	0.27	2.0
Heating	PTHP	1.6%	3.86	0.06	0.5
Heating	Air-Source Heat Pump	6.1%	4.29	0.26	1.9
Heating	Geothermal Heat Pump	4.4%	3.23	0.14	1.0
Ventilation	Ventilation	100.0%	0.71	0.71	5.1
Water Heating	Water Heater	50.0%	0.99	0.50	3.6
Interior Lighting	General Service Lighting	100.0%	0.16	0.16	1.2
Interior Lighting	Exempted Lighting	100.0%	0.18	0.18	1.3
Interior Lighting	High-Bay Lighting	100.0%	0.81	0.81	5.8
Interior Lighting	Linear Lighting	100.0%	1.51	1.51	10.9
Exterior Lighting	General Service Lighting	100.0%	0.00	0.00	0.0
Exterior Lighting	Area Lighting	100.0%	0.12	0.12	0.9
Exterior Lighting	Linear Lighting	100.0%	0.66	0.66	4.7
Refrigeration	Walk-in Refrigerator/Freezer	19.0%	0.17	0.03	0.2
Refrigeration	Reach-in Refrigerator/Freezer	33.0%	0.08	0.02	0.2
Refrigeration	Glass Door Display	65.7%	0.04	0.03	0.2
Refrigeration	Open Display Case	65.7%	0.23	0.15	1.1
Refrigeration	Icemaker	65.7%	0.13	0.08	0.6
Refrigeration	Vending Machine	65.7%	0.06	0.04	0.3
Food Preparation	Oven	64.8%	0.11	0.07	0.5
Food Preparation	Fryer	58.6%	0.16	0.09	0.7
Food Preparation	Dishwasher	52.3%	0.22	0.12	0.8
Food Preparation	Hot Food Container	52.3%	0.03	0.02	0.1
Food Preparation	Steamer	52.3%	0.16	0.08	0.6
Office Equipment	Desktop Computer	100.0%	0.29	0.29	2.1
Office Equipment	Laptop	100.0%	0.02	0.02	0.1
Office Equipment	Server	100.0%	0.07	0.07	0.5
Office Equipment	Monitor	100.0%	0.05	0.05	0.4
Office Equipment	Printer/Copier/Fax	100.0%	0.03	0.03	0.2
Office Equipment	POS Terminal	36.0%	0.01	0.00	0.0
Miscellaneous	Non-HVAC Motors	43.7%	0.07	0.03	0.2
Miscellaneous	Pool Pump	6.0%	0.02	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Clothes Washer	15.0%	0.01	0.00	0.0
Miscellaneous	Clothes Dryer	11.0%	0.02	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.33	0.33	2.4
Total				**7.96**	**57.3**

Table A-29 Idaho Commercial Lodging Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.0%	0.49	0.01	0.0
Cooling	Water-Cooled Chiller	7.3%	0.62	0.05	0.1
Cooling	RTU	15.8%	1.52	0.24	0.8
Cooling	PTAC	38.8%	1.79	0.70	2.2
Cooling	PTHP	13.0%	1.52	0.20	0.6
Cooling	Evaporative AC	0.5%	0.61	0.00	0.0
Cooling	Air-Source Heat Pump	5.1%	1.52	0.08	0.2
Cooling	Geothermal Heat Pump	5.5%	1.44	0.08	0.2
Heating	Electric Furnace	1.4%	3.02	0.04	0.1
Heating	Electric Room Heat	51.1%	2.88	1.47	4.6
Heating	PTHP	13.0%	2.42	0.32	1.0
Heating	Air-Source Heat Pump	5.1%	2.69	0.14	0.4
Heating	Geothermal Heat Pump	5.5%	1.90	0.10	0.3
Ventilation	Ventilation	100.0%	0.94	0.94	3.0
Water Heating	Water Heater	50.0%	3.20	1.60	5.0
Interior Lighting	General Service Lighting	100.0%	0.81	0.81	2.5
Interior Lighting	Exempted Lighting	100.0%	0.43	0.43	1.3
Interior Lighting	High-Bay Lighting	100.0%	1.29	1.29	4.0
Interior Lighting	Linear Lighting	100.0%	0.46	0.46	1.4
Exterior Lighting	General Service Lighting	100.0%	0.04	0.04	0.1
Exterior Lighting	Area Lighting	100.0%	1.73	1.73	5.4
Exterior Lighting	Linear Lighting	100.0%	0.03	0.03	0.1
Refrigeration	Walk-in Refrigerator/Freezer	3.0%	0.39	0.01	0.0
Refrigeration	Reach-in Refrigerator/Freezer	19.0%	0.09	0.02	0.1
Refrigeration	Glass Door Display	58.9%	0.09	0.05	0.2
Refrigeration	Open Display Case	58.9%	0.54	0.32	1.0
Refrigeration	Icemaker	58.9%	0.15	0.09	0.3
Refrigeration	Vending Machine	58.9%	0.14	0.08	0.3
Food Preparation	Oven	13.8%	0.26	0.04	0.1
Food Preparation	Fryer	21.0%	0.37	0.08	0.2
Food Preparation	Dishwasher	30.0%	0.51	0.15	0.5
Food Preparation	Hot Food Container	30.0%	0.07	0.02	0.1
Food Preparation	Steamer	30.0%	0.38	0.11	0.4
Office Equipment	Desktop Computer	100.0%	0.08	0.08	0.3
Office Equipment	Laptop	100.0%	0.01	0.01	0.0
Office Equipment	Server	100.0%	0.05	0.05	0.2
Office Equipment	Monitor	100.0%	0.01	0.01	0.0
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.0
Office Equipment	POS Terminal	58.0%	0.01	0.01	0.0
Miscellaneous	Non-HVAC Motors	91.3%	0.14	0.12	0.4
Miscellaneous	Pool Pump	76.0%	0.01	0.01	0.0
Miscellaneous	Pool Heater	27.0%	0.02	0.00	0.0
Miscellaneous	Clothes Washer	67.0%	0.02	0.01	0.0
Miscellaneous	Clothes Dryer	26.0%	0.07	0.02	0.1
Miscellaneous	Other Miscellaneous	100.0%	0.63	0.63	2.0
Total				**12.69**	**39.8**

Table A-30 Idaho Commercial Warehouse Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	0.0%	1.59	0.00	0.0
Cooling	Water-Cooled Chiller	0.0%	1.68	0.00	0.0
Cooling	RTU	16.0%	1.78	0.28	2.6
Cooling	PTAC	1.1%	2.09	0.02	0.2
Cooling	PTHP	0.3%	1.78	0.01	0.0
Cooling	Evaporative AC	0.0%	0.71	0.00	0.0
Cooling	Air-Source Heat Pump	1.7%	1.78	0.03	0.3
Cooling	Geothermal Heat Pump	0.0%	1.08	0.00	0.0
Heating	Electric Furnace	2.3%	7.84	0.18	1.6
Heating	Electric Room Heat	12.4%	7.46	0.93	8.3
Heating	PTHP	0.3%	6.19	0.02	0.2
Heating	Air-Source Heat Pump	1.7%	6.88	0.12	1.0
Heating	Geothermal Heat Pump	0.0%	5.93	0.00	0.0
Ventilation	Ventilation	100.0%	0.26	0.26	2.3
Water Heating	Water Heater	55.3%	0.26	0.15	1.3
Interior Lighting	General Service Lighting	100.0%	0.07	0.07	0.7
Interior Lighting	Exempted Lighting	100.0%	0.04	0.04	0.3
Interior Lighting	High-Bay Lighting	100.0%	1.69	1.69	15.2
Interior Lighting	Linear Lighting	100.0%	0.28	0.28	2.5
Exterior Lighting	General Service Lighting	100.0%	0.02	0.02	0.2
Exterior Lighting	Area Lighting	100.0%	0.38	0.38	3.4
Exterior Lighting	Linear Lighting	100.0%	0.08	0.08	0.7
Refrigeration	Walk-in Refrigerator/Freezer	1.1%	0.49	0.01	0.0
Refrigeration	Reach-in Refrigerator/Freezer	2.0%	0.11	0.00	0.0
Refrigeration	Glass Door Display	10.1%	0.11	0.01	0.1
Refrigeration	Open Display Case	10.1%	0.67	0.07	0.6
Refrigeration	Icemaker	10.1%	0.19	0.02	0.2
Refrigeration	Vending Machine	10.1%	0.09	0.01	0.1
Food Preparation	Oven	2.3%	0.03	0.00	0.0
Food Preparation	Fryer	2.3%	0.05	0.00	0.0
Food Preparation	Dishwasher	2.3%	0.07	0.00	0.0
Food Preparation	Hot Food Container	2.3%	0.01	0.00	0.0
Food Preparation	Steamer	2.3%	0.05	0.00	0.0
Office Equipment	Desktop Computer	100.0%	0.09	0.09	0.8
Office Equipment	Laptop	100.0%	0.01	0.01	0.1
Office Equipment	Server	89.0%	0.10	0.09	0.8
Office Equipment	Monitor	100.0%	0.02	0.02	0.1
Office Equipment	Printer/Copier/Fax	100.0%	0.01	0.01	0.1
Office Equipment	POS Terminal	77.0%	0.03	0.02	0.2
Miscellaneous	Non-HVAC Motors	49.9%	0.12	0.06	0.6
Miscellaneous	Pool Pump	0.0%	0.00	0.00	0.0
Miscellaneous	Pool Heater	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Washer	0.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	0.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.43	0.43	3.9
Total				**5.40**	**48.5**

Table A-31 Idaho Commercial Miscellaneous Market Profile

End Use	Technology	Saturation	EUI (kWh/Sq.Ft.)	Intensity (kWh/Sq.Ft.)	Usage (GWh)
Cooling	Air-Cooled Chiller	9.7%	1.64	0.16	2.2
Cooling	Water-Cooled Chiller	5.0%	1.78	0.09	1.3
Cooling	RTU	56.8%	1.86	1.06	14.9
Cooling	PTAC	5.1%	2.19	0.11	1.6
Cooling	PTHP	2.6%	1.86	0.05	0.7
Cooling	Evaporative AC	0.0%	0.74	0.00	0.0
Cooling	Air-Source Heat Pump	5.5%	1.86	0.10	1.4
Cooling	Geothermal Heat Pump	1.0%	1.13	0.01	0.2
Heating	Electric Furnace	12.5%	4.77	0.59	8.4
Heating	Electric Room Heat	14.8%	4.55	0.67	9.5
Heating	PTHP	2.6%	3.61	0.09	1.3
Heating	Air-Source Heat Pump	5.5%	4.01	0.22	3.1
Heating	Geothermal Heat Pump	1.0%	3.13	0.03	0.5
Ventilation	Ventilation	100.0%	0.73	0.73	10.3
Water Heating	Water Heater	53.0%	1.39	0.74	10.4
Interior Lighting	General Service Lighting	100.0%	0.38	0.38	5.3
Interior Lighting	Exempted Lighting	100.0%	0.23	0.23	3.2
Interior Lighting	High-Bay Lighting	100.0%	1.56	1.56	22.0
Interior Lighting	Linear Lighting	100.0%	1.46	1.46	20.7
Exterior Lighting	General Service Lighting	100.0%	0.09	0.09	1.3
Exterior Lighting	Area Lighting	100.0%	0.64	0.64	9.0
Exterior Lighting	Linear Lighting	100.0%	0.06	0.06	0.8
Refrigeration	Walk-in Refrigerator/Freezer	10.3%	0.58	0.06	0.8
Refrigeration	Reach-in Refrigerator/Freezer	12.1%	0.13	0.02	0.2
Refrigeration	Glass Door Display	3.4%	0.13	0.00	0.1
Refrigeration	Open Display Case	3.4%	0.79	0.03	0.4
Refrigeration	Icemaker	21.6%	0.22	0.05	0.7
Refrigeration	Vending Machine	21.6%	0.20	0.04	0.6
Food Preparation	Oven	58.9%	0.08	0.05	0.7
Food Preparation	Fryer	29.9%	0.12	0.04	0.5
Food Preparation	Dishwasher	15.4%	0.17	0.03	0.4
Food Preparation	Hot Food Container	15.4%	0.02	0.00	0.0
Food Preparation	Steamer	15.4%	0.12	0.02	0.3
Office Equipment	Desktop Computer	100.0%	0.20	0.20	2.8
Office Equipment	Laptop	100.0%	0.03	0.03	0.4
Office Equipment	Server	66.0%	0.12	0.08	1.1
Office Equipment	Monitor	100.0%	0.03	0.03	0.5
Office Equipment	Printer/Copier/Fax	100.0%	0.02	0.02	0.3
Office Equipment	POS Terminal	28.0%	0.03	0.01	0.1
Miscellaneous	Non-HVAC Motors	59.9%	0.15	0.09	1.2
Miscellaneous	Pool Pump	4.0%	0.01	0.00	0.0
Miscellaneous	Pool Heater	1.0%	0.01	0.00	0.0
Miscellaneous	Clothes Washer	15.0%	0.00	0.00	0.0
Miscellaneous	Clothes Dryer	10.0%	0.00	0.00	0.0
Miscellaneous	Other Miscellaneous	100.0%	0.57	0.57	8.0
Total				**10.43**	**147.4**

Table A-32 Idaho Industrial Market Profile

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Employee)	Usage (GWh)
Cooling	Air-Cooled Chiller	2.5%	14,936.14	373.40	2.0
Cooling	Water-Cooled Chiller	2.5%	15,732.18	393.30	2.1
Cooling	RTU	11.4%	16,648.18	1,898.60	10.3
Cooling	Air-Source Heat Pump	1.7%	16,640.58	281.39	1.5
Cooling	Geothermal Heat Pump	0.0%	11,099.27	0.00	0.0
Heating	Electric Furnace	2.3%	73,387.09	1,683.53	9.2
Heating	Electric Room Heat	12.4%	69,892.47	8,672.59	47.2
Heating	Air-Source Heat Pump	1.7%	64,443.40	1,089.73	5.9
Heating	Geothermal Heat Pump	0.0%	42,983.75	0.00	0.0
Ventilation	Ventilation	100.0%	2,427.96	2,427.96	13.2
Interior Lighting	General Service Lighting	100.0%	465.63	465.63	2.5
Interior Lighting	High-Bay Lighting	100.0%	7,284.44	7,284.44	39.6
Interior Lighting	Linear Lighting	100.0%	1,210.90	1,210.90	6.6
Exterior Lighting	General Service Lighting	100.0%	85.72	85.72	0.5
Exterior Lighting	Area Lighting	100.0%	1,624.05	1,624.05	8.8
Exterior Lighting	Linear Lighting	100.0%	332.72	332.72	1.8
Motors	Pumps	100.0%	4,278.85	4,278.85	23.3
Motors	Fans & Blowers	100.0%	5,138.64	5,138.64	28.0
Motors	Compressed Air	100.0%	4,155.05	4,155.05	22.6
Motors	Material Handling	100.0%	8,788.33	8,788.33	47.8
Motors	Other Motors	100.0%	147.48	147.48	0.8
Process	Process Heating	100.0%	7,235.19	7,235.19	39.4
Process	Process Cooling	100.0%	1,899.62	1,899.62	10.3
Process	Process Refrigeration	100.0%	1,899.62	1,899.62	10.3
Process	Process Electrochemical	100.0%	731.25	731.25	4.0
Process	Process Other	100.0%	793.59	793.59	4.3
Miscellaneous	Miscellaneous	100.0%	4,365.54	4,365.54	23.8
Total				**67,257.13**	**366.1**

B

MARKET ADOPTION (RAMP) RATES

This appendix presents the Power Council's 7th Plan ramp rates we applied to technical potential to estimate Technical Achievable Potential.

Table B-1 Measure Ramp Rates Used in CPA

Key	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LO12Med	9%	19%	28%	37%	47%	55%	62%	67%	71%	75%	78%	80%	82%	83%	84%	85%	85%	85%	85%	85%
LO5Med	4%	8%	13%	20%	27%	35%	45%	54%	63%	71%	76%	81%	83%	84%	85%	85%	85%	85%	85%	85%
LO1Slow	0%	1%	1%	3%	5%	7%	11%	16%	22%	29%	37%	46%	54%	62%	69%	75%	79%	82%	84%	85%
LO50Fast	38%	56%	68%	76%	81%	83%	84%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
LO20Fast	19%	32%	42%	49%	55%	61%	65%	69%	72%	75%	78%	79%	81%	82%	83%	84%	84%	84%	85%	85%
LOEven20	4%	9%	13%	17%	21%	26%	30%	34%	38%	43%	47%	51%	55%	60%	64%	68%	72%	77%	81%	85%
LOMax60	1%	3%	5%	8%	12%	16%	20%	24%	28%	31%	34%	37%	40%	42%	45%	47%	49%	51%	53%	55%
LO3Slow	0%	1%	3%	5%	9%	15%	22%	31%	40%	49%	57%	65%	71%	75%	79%	81%	83%	84%	85%	85%
Retro12Med	11%	11%	11%	11%	11%	10%	8%	6%	5%	4%	3%	3%	2%	2%	1%	1%	0%	0%	0%	0%
Retro5Med	4%	5%	6%	7%	8%	10%	11%	11%	10%	9%	7%	5%	3%	1%	1%	0%	0%	0%	0%	0%
Retro1Slow	0%	1%	1%	1%	2%	3%	4%	6%	7%	8%	9%	10%	10%	9%	8%	7%	5%	3%	2%	1%
Retro50Fast	45%	21%	14%	9%	6%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Retro20Fast	22%	16%	11%	8%	7%	6%	5%	5%	4%	3%	3%	2%	2%	1%	1%	1%	1%	0%	0%	0%
RetroEven20	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
RetroMax60	1%	2%	3%	4%	5%	5%	5%	4%	4%	4%	4%	3%	3%	3%	3%	3%	3%	2%	2%	2%
Retro3Slow	1%	1%	2%	3%	5%	7%	8%	10%	11%	11%	10%	9%	7%	6%	4%	3%	2%	1%	1%	0%

* Assumption of 55% maximum achievability from Council's 7th Power Plan

C

MEASURE DATA

Measure level assumptions and data are available in the "Avista 2019 DSM Potential Study Measure Assumptions" workbook provided to Avista alongside this file.

D

HB 1444 IMPACT ANALYSIS

In April 2019, the Washington State Legislature passed HB 1444, which established new energy efficiency requirements for some consumer technologies sold in Washington, particularly water-using equipment, commercial kitchen equipment, and desktop computing equipment. These devices have associated savings potential within the CPA which would be affected by this legislation, in that the savings would become part of the baseline, or "naturally occurring" efficiency.

AEG did not reconfigure and rerun the CPA to include the impacts of this legislation, as the standards were not yet in place at the time the study was designed and developed, however, an estimate of the likely impacts is provided in Table D-1 below. AEG estimates that 5% - 7% of Avista's Washington Technical Achievable Potential for the biennium period could be moved into the baseline by HB 1444.

Table D-1 Impacts of HB 1444 on EE Potential[13]

Technical Achievable Potential MWh - CPA Total	2022	2030	2040
Idaho	50,201	328,073	673,115
Washington	99,977	636,490	1,271,968
Total	**150,178**	**964,564**	**1,945,083**

HB 1444 Affected Measures - TAP MWh	2022	2030	2040
Residential			
Monitor	1,537	7,994	8,552
Personal Computers	634	2,846	2,913
Water Heater - Faucet Aerators	19	693	821
Water Heater - Low-Flow Showerheads	2,834	10,144	7,814
Commercial			
Desktop Computer	418	2,285	2,600
Dishwasher	24	756	2,461
ENERGY STAR Water Cooler	80	433	879
Fryer	40	1,256	2,937
Hot Food Container	18	537	2,005
Monitor	67	300	319
Steamer	44	2,010	8,070
Water Heater - Faucet Aerators/Low Flow Nozzles	442	990	1,044
Water Heater - Low-Flow Showerheads	242	536	562
Total	**6,400**	**30,779**	**40,977**
% of WA	*6.4%*	*4.8%*	*3.2%*
% of Total	*4.3%*	*3.2%*	*2.1%*

[13] Note: HB 1444 also requires direct load control switches to be present on storage water heaters, which would affect the *cost* of the Residential Water Heating DLC program described in Chapter 6, but AEG did not assume a change in participation or potential as a result

Applied Energy Group, Inc.
500 Ygnacio Valley Rd, Suite 250
Walnut Creek, CA 94596

P: 510.982.3525

2020 Electric Integrated Resource Plan

Appendix E – Conservation Potential Assessment Measure Assumptions

Please see attached spreadsheet

2020 Electric Integrated Resource Plan

Appendix F – Resource Adequacy in the Pacific Northwest by E3

Resource Adequacy in the Pacific Northwest

March 2019

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

March 2019

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project Team:
Zach Ming
Arne Olson
Huai Jiang
Manohar Mogadali
Nick Schlag

Table of Contents

Study Sponsors

This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy, and the Public Generating Pool (PGP). PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington: Chelan County PUD, Clark Public Utilities, Cowlitz County PUD, Eugene Water and Electric Board, Klickitat PUD, Grant County PUD, Lewis County PUD, Tacoma Power, Snohomish County PUD, and Benton PUD.

Acknowledgements

E3 thanks the staff of the Northwest Power and Conservation Council (NWPCC) for providing data and technical review.

Conventions

The following conventions are used throughout this report:

+ All costs are reported in **2016 dollars.**
+ All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).

Acronyms

CONE	Cost of New Entry
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GENESYS	NWPCC's Generation Evaluation System Model
GHG	Greenhouse Gas
ISO	Independent System Operator
LOLE	Loss-of-Load Expectation
LOLF	Loss-of-Load Frequency
LOLP	Loss-of-Load Probability
MISO	Midwest Independent System Operator
MMT	Million Metric Ton
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
RA	Resource Adequacy
RECAP	E3's Renewable Energy Capacity Planning Model
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

Executive Summary

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

Background and Approach

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

+ How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
+ How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?
+ How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
+ How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;

- Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
- Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
- Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.

2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;

- Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.

3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.

4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;

- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy.

1 Introduction

1.1 Study Background & Context

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

1.2 Prior Studies

In 2017-2018, E3 completed a series of studies[1] for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon. These studies were conducted using E3's RESOLVE model, which is a dispatch and investment model that identifies optimal long-term generation and transmission investments in the electric system to meet various decarbonization and renewable energy targets. The studies found that the least-cost pathway to reduce greenhouse gases from electricity generation is to replace coal generation with a mix of energy efficiency, renewables, and natural gas generation. While these studies examined in great detail the economics of new resources needed to achieve decarbonization, including the type, quantity, and location of these resources, they did not look in-depth at reliability and Resource Adequacy.

1.3 Purpose of Study

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

- How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
- How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?

[1] https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

1.4 Report Contents

The remainder of this report is organized as follows:

- Section 2 introduces Resource Adequacy and current practices in the Northwest
- Section 3 describes the study's modeling approach
- Section 4 highlights key inputs and assumptions used in the modeling
- Section 5 presents results across a variety of time horizons and resource portfolios
- Section 6 discusses implications of the results
- Section 7 summarizes the study's conclusions and lessons learned

2 Resource Adequacy in the Northwest

2.1 What is Resource Adequacy?

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run standard on the maximum frequency of reliability events where generation is insufficient to serve all load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Council (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy but have no formal governing role.

While a variety of approaches are used, the industry best practice is to establish a standard for resource adequacy using a two-step process:

+ **Loss-of-load-probability (LOLP) modeling:** LOLP modeling uses statistical techniques and/or Monte Carlo approaches to simulate the capability of a generation portfolio to produce sufficient generation to meet loads across a wide range of different conditions. Utilities plan the system to meet a specific reliability standard that is measured through LOLP modeling such as the expected frequency and/or size of reliability events; a relatively common standard used in LOLP modeling is "one day in ten years," which is often translated to an expectation of 24 hours of lost load every ten years, or 2.4 hours per year.[2]

+ **Planning reserve margin (PRM) requirements:** Utilities then determine the required PRM necessary to ensure that the system will meet the specific the reliability standard from the LOLP modeling. A PRM establishes a total requirement for capacity based on the peak demand of an electric system plus some reserve margin to account for unexpected outages and extreme conditions; reserve margin requirements typically vary among utilities between 12-19% above peak demand. To meet this need, capacity from resources that can produce their full power on demand (e.g., nuclear, gas, coal) are typically counted at or near 100%, whereas resources that are constrained in their availability or ability to dispatch (e.g., hydro, storage, wind, solar) are typically de-rated below full capacity.

While LOLP modeling is more technically rigorous, most utilities perform LOLP modeling relatively infrequently and use a PRM requirement to heuristically ensure compliance with a specific reliability standard due to its relative simplicity and ease of implementation. The concept and application of a PRM to measure resource adequacy has historically worked well in a paradigm in which most generation capacity is "firm"; that is, the resource will be available to dispatch to full capacity, except in the event of unexpected forced outages. Under this paradigm, as long as the system has sufficient capacity to meet its peak demand (plus some reserve margin for extreme weather and unexpected forced outages), it will be capable of serving load throughout the rest of the year as well.

However, growing penetrations of variable (e.g., wind and solar) and energy-limited (e.g., hydro, electric energy storage, and demand response) resources require the application of increasingly sophisticated modeling tools to determine the appropriate PRM and to measure the contribution of each resource towards resource adequacy. Because wind and solar do not always generate during the system peak and because storage may run out of charge while it is serving the system peak, these resources are often de-

[2] Other common interpretations of the "one day in ten year" standard include 1 "event" (of unspecified duration) in ten years or "one hour in ten years" i.e., 0.1 hrs/yr

rated below the capability of a fully dispatchable thermal generator when counted toward meeting the PRM.

2.2 Planning Practices in the Northwest

A number of entities within the Northwest conduct analysis and planning for resource adequacy within the region. Under its charter to ensure prudent management of the region's federal hydro system while balancing environmental and energy needs, the Northwest Power and Conservation Council (NWPCC) conducts regular assessments of the resource adequacy position for the portion of the Northwest region served by the Bonneville Power Administration. The NWPCC has established an informal reliability target for the region of 5% annual loss of load probability[3]—a metric that ensures that the region will experience reliability events in fewer than one in twenty years—and uses GENESYS, a stochastic LOLP model with a robust treatment of the resource's variable hydroelectric conditions and capabilities, to examine whether regional resources are sufficient to meet this target on a five-year ahead basis.[4] These studies provide valuable information referenced by regulators and utilities throughout the region.

While the work of the Council is widely regarded as the most complete regional assessment of resource adequacy for the smaller region, the Council itself holds no formal decision-making authority to prescribe new capacity procurement or to enforce its reliability standards. Instead, the ultimate administration of resource adequacy lies in the hands of individual utilities, often subject to the oversight of state commissions. Most resource adequacy planning occurs within the planning and procurement processes

[3] This Council's standard, which focuses only on whether a reliability event occurred within a year, is unique to the Northwest and is not widely used throughout the rest of the North America

[4] The most recent of these reports, the Pacific Northwest Power Supply Adequacy Assessment for 2023, is available at: **https://www.nwcouncil.org/sites/default/files/2018-7.pdf** (accessed January 18, 2019).

of utilities: individual utilities submit integrated resource plans (IRPs) that consider long-term resource adequacy needs and conduct resource solicitations to satisfy those needs.

Utilities rely on a combination of self-owned generation, bilateral contracts, and front-office transactions (FOTs) to satisfy their resource adequacy requirements. FOTs represent short-term firm market purchases for physical power delivery. FOTs are contracted on both a month-ahead, day-ahead and hour-ahead basis. A survey of the utility IRPs in the Northwest reveals that most of the utilities expect to meet a significant portion of their peak capacity requirements in using FOTs.

FOTs may be available to utilities for several potential reasons including 1) the region as a whole has a capacity surplus and some generators are uncontracted to a specific utility or 2) natural load diversity between utilities such that one utility may have excess generation during another's peak load conditions and vice versa. The use of FOTs in place of designated firm resources can result in lower costs of providing electric service, as the cost of contracting with existing resources is generally lower than the cost of constructing new resources.

However, as loads grow in the region and coal generation retires, the region's capacity surplus is shrinking, and questions are emerging about whether sufficient resources will be available for utilities to contract with for month-ahead and day-ahead capacity products. In a market with tight load-resource balance, extensive reliance on FOTs risks under-investment in the firm capacity resources needed for reliable load service.

Table 1: Contribution of FOTs Toward Peak Capacity Requirements in 2018 in the Northwest

Utility	Capacity Requirement (MW)	Front Office Transactions (MW)	% of Capacity Requirement from FOTs
Puget Sound[5]	6,100	1,800	30%
Avista[6]	2,150	-	0%
Idaho Power[7]	3,078	313	10%
PacifiCorp[8]	11,645	462	4%
BPA[9]	11,506	-	0%
PGE[10]	4,209	106	3%
NorthWestern[11]	1,205	503	42%

[5] Figure 6-7: Available Mid C Tx plus Additional Mid-C Tx w/ renewals in PSE 2017 IRP: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf?la=en&revision=bb9e004c-9da0-4f75-a594-6c30dd6223f4&hash=75800198E4E8517954C63B3D01E498F2C5AC10C2
[6] Figure 6.1 (for peak load), Chapter 4 Tables for resources in Avista 2017 IRP: https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2017-electric-irp-final.pdf?la=en
[7] Table 9.11 in Idaho Power 2017 IRP: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf
[8] Table 5.2 in PacifiCorp 2017 IRP (Interruptible Contracts + Purchases): https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf
[9] Bottom of the page in BPA fact sheet: https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf
[10] PGE 2016 IRP Table P-1 Spot Market Purchases (rounded from 106), Capacity Need : https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp
[11] Table 2-2 for peak load and netted out existing resources (Ch. 8) @ 12%PRM from NorthWestern Energy 2015 IRP: https://www.northwesternenergy.com/our-company/regulatory-environment/2015-electricity-supply-resource-procurement-plan

3 Modeling Approach

3.1 Renewable Energy Capacity Planning (RECAP) Model

3.1.1 MODEL OVERVIEW

This study assesses the resource adequacy of electric generating resource portfolios for different decarbonization scenarios in the Northwest region using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida.

RECAP calculates a number of reliability metrics which are used to assess the resource adequacy for an electricity system with a given set of loads and generating resources.

- **Loss of Load Expectation (hrs/yr) – LOLE**
  - The total number of hours in a year where load + reserves exceeds generation
- **Expected Unserved Energy (MWh/yr) – EUE**
  - The total quantity of unserved energy in a year when load + reserves exceeds generation
- **Loss of Load Probability (%/yr) – LOLP**
  - The probability in a year that load + reserves exceeds generation at any time
- **Effective Load Carrying Capability (%) – ELCC**
  - The additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage, hydro, and demand response). Equivalently, this is the quantity of perfectly dispatchable

generation that could be removed from the system by an incremental dispatch-limited generator

- **Planning Reserve Margin (%) – PRM**
  - The resource margin above a 1-in-2 peak load, in %, that is required in order to meet a specific reliability standard (such as 2.4 hrs./yr. LOLE)

This study uses 2.4 hrs./yr. LOLE reliability standard which is based on a commonly accepted 1-day-in-10-year standard. All portfolios that are developed by RECAP in this analysis for resource adequacy are designed to meet a 2.4 hrs./yr. LOLE standard.

RECAP calculates reliability statistics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE and other reliability statistics.

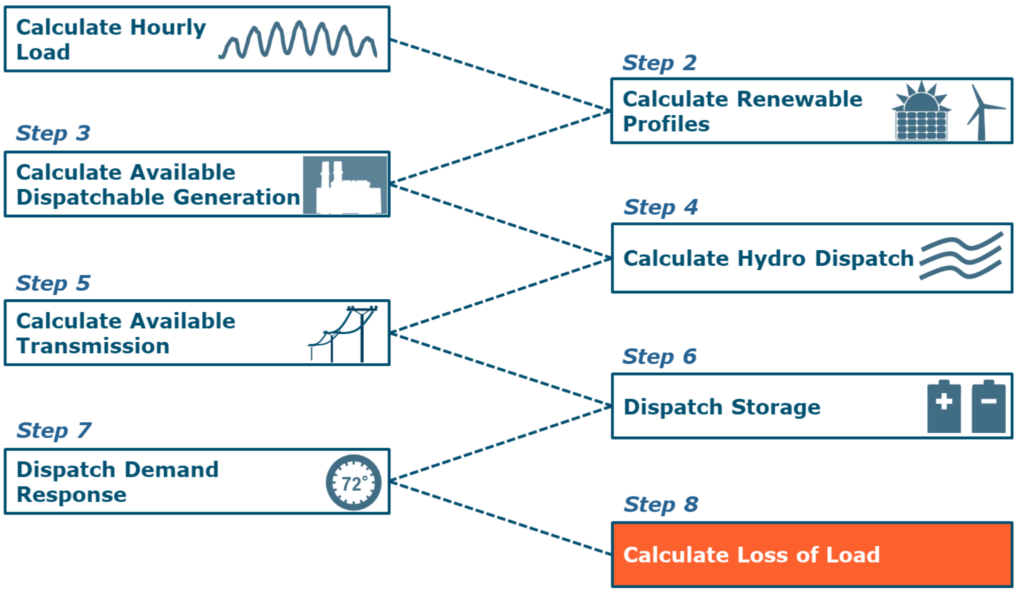
RECAP was specifically designed to calculate the reliability of electric systems operating under high penetrations of renewable energy and storage. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response.

3.1.2 MODEL METHODOLOGY

The steps of the RECAP modeling process are shown below in Figure 1. RECAP calculates long-run resource availability through Monte Carlo simulation of electricity system resource availability using weather conditions from 1948-2017. Each simulation begins on January 1, 1948 and runs hourly through December 31, 2017. Hourly electric loads for 1948-2017 are synthesized using statistical analysis of actual load shapes and weather conditions for 2014-2017 combined with recorded historical weather conditions.

Then, hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory (NREL) and paired with historical weather days through an E3-created day-matching algorithm. Next, nameplate capacity and forced outage rates (FOR) for thermal generation are drawn from various sources including the GENESYS database and the Western Electric Coordinating Council's Anchor Data Set. Hydro is dispatched based on the load net of renewable and thermal generation. Annual hydro generation values are drawn randomly from 1929-2008 water years and shaped to calendar months and weeks based on the Northwest Power and Conservation Council's GENESYS model. For each hydro year, we identify all the hydro dispatch constraints including maximum and minimum power capacity, 2-hour to 10-hour sustained peaking limits, and hydro budget, specific to the randomly-drawn hydro condition. For each x-hour sustained peaking limit (where x = 2, 4, and 10), RECAP dispatches hydro so that the average capacity over consecutive x hours does not exceed the sustained peaking capability. Overall, hydro is dispatched to minimize the post-hydro net load subject to the above constraints. In other words, hydro is used within assumed constraints to meet peak load needs while minimizing loss-of-load. Finally, RECAP uses storage and demand response to tackle the loss-of-load hours and storage is only discharged during loss-of-load hours. A more detailed description of the RECAP model is in Appendix B.2.

Figure 1: Overview of RECAP Model



3.1.3 PORTFOLIO DEVELOPMENT

RECAP is used in this study to both test the reliability of the existing 2018 Greater Northwest electricity system as well as to determine a total capacity need in 2030 and to develop portfolios in 2050 under various levels of decarbonization that meet a 1-day-in-10-year reliability standard of 2.4 hrs./yr.

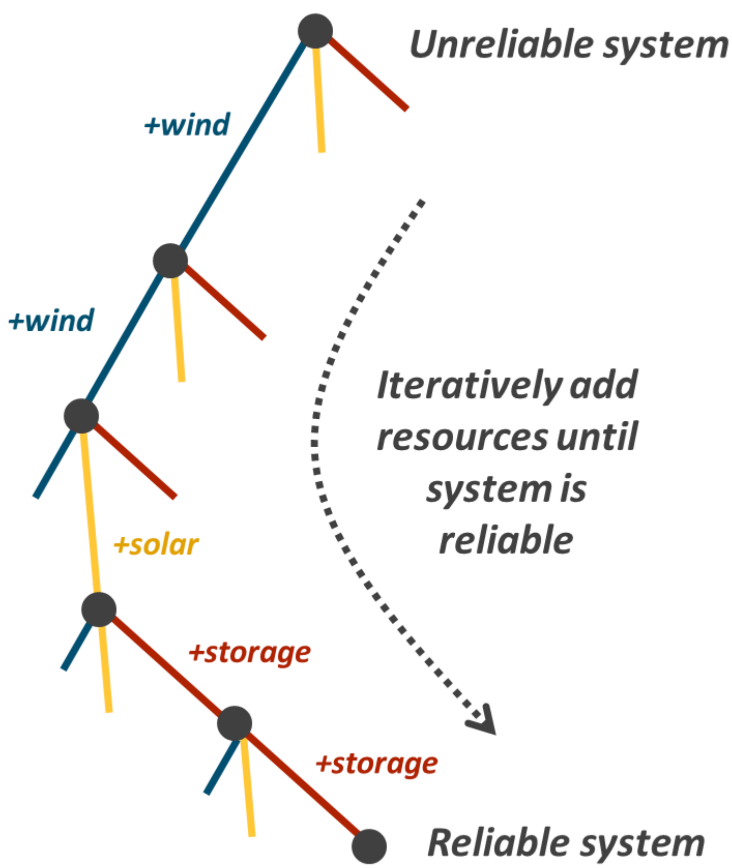
To develop each 2050 decarbonization portfolio, RECAP calculates the reliability of the system in 2050 after forecasted load growth and the removal of all fossil generation but the maintenance of all existing carbon-free resources. Unsurprisingly, these portfolios are significantly less reliable than the required 2.4 hrs./yr. nor do they deliver enough carbon-free generation to meet the various decarbonization targets. To improve the reliability and increase GHG-free generation of these portfolios, RECAP tests the contribution of small, equal-cost increments of candidate GHG-free resources. The seven candidate resources in this study are:

+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ Solar (based on an assumed diverse mix of resources from each state)
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

The resource that improves reliability the most (as measured in loss-of-load-expectation) is then added to the system. This process is repeated until the delivered GHG-free generation is sufficient to meet the GHG target (e.g., 80% reduction) for each particular scenario. Once a portfolio has achieved the objective GHG target, RECAP calculates the residual quantity of perfect firm capacity that is needed to bring the portfolio in compliance with a reliability standard of 2.4 hrs./yr. This perfect firm MW capacity is converted to MW of natural gas capacity by grossing up by 5% to account for forced outages. Natural gas capacity is used because it is the most economic source of firm capacity. To the extent that other carbon-free resources can substitute for natural gas capacity, this is reflected in deeper decarbonization portfolios that have higher quantities of wind, solar, and storage along with a smaller residual requirement for firm natural gas capacity.

Figure 2 illustrates a simple example of this portfolio development process where RECAP has 3 candidate resources: wind, solar, and storage. The model evaluates the contribution to reliability of equal-cost increments of the three candidate resources and selects the resource that improves reliability the most. From that new portfolio, the process is repeated until either the system reaches a reliability standard of 2.4 or a particular GHG target is achieved.

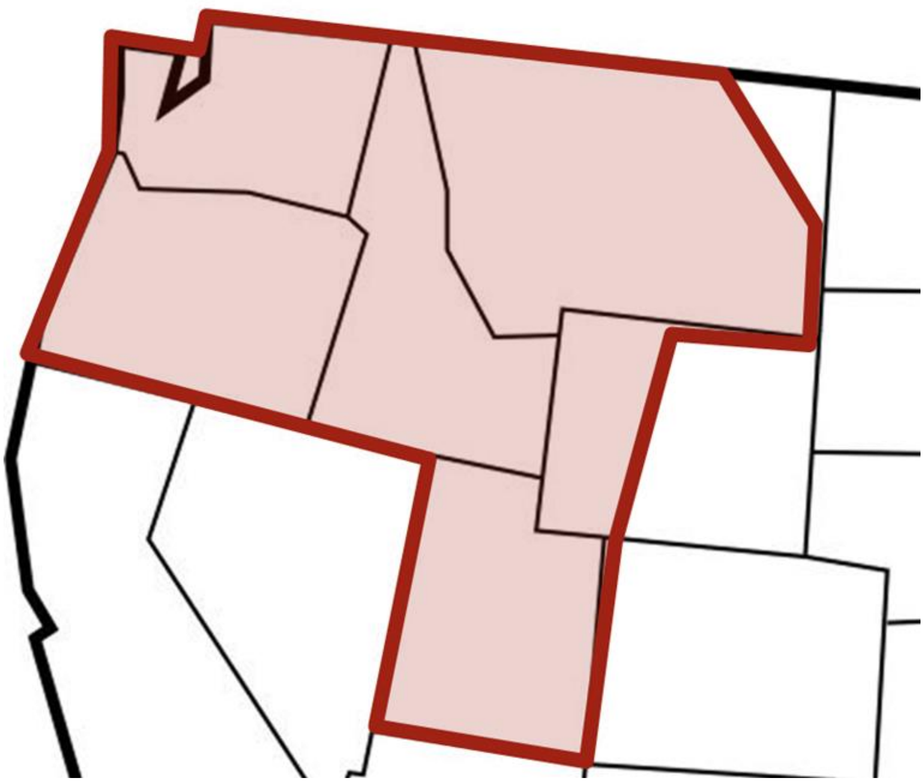
Figure 2: RECAP Portfolio Development Process



3.2 Study Region

The geographic region for this study consists of the U.S. portion of the Northwest Power Pool (NWPP), excluding Nevada, which this study refers to as the "Greater Northwest". This region includes the states of Washington, Oregon, Idaho, Utah, and parts of Montana and Wyoming.

Figure 3: The study region - The Greater Northwest



It is important to note that this is a larger region than was analyzed in the prior E3 decarbonization work in the Northwest which only analyzed a "Core Northwest" region consisting of Oregon, Washington, northern Idaho and Western Montana. The larger footprint encompasses the utilities that have traditionally coordinated operational efficiencies through programs under the Northwest Power Pool and includes utilities that typically transact with each other to maintain resource adequacy and optimize resource portfolios. The larger region also incorporates a footprint that allows for diversity of both load and resources which minimizes the need for firm capacity. The Balancing Authority Areas (BAAs) that were included in this Greater Northwest study region are listed in Table 2.

Table 2: List of Balancing Authorities Included in Study

Balancing Authority Areas Included in Greater Northwest Study Region		
Avista	Bonneville Power Administration	Chelan County PUD
Douglas County PUD	Grant County PUD	Idaho Power
NorthWestern	PacifiCorp East	PacifiCorp West
Portland General Electric	Puget Sound Energy	Seattle City Light
Tacoma Power	Western Area Power Administration Upper Great Plains	

3.3 Scenarios & Sensitivities

This study examines the resource adequacy requirements of the Greater Northwest region across multiple timeframes and decarbonization scenarios.

+ **Near-term (2018)** reliability statistics are calculated for today's system based on 2018 existing loads and resources. These results are presented to give the reader a sense of existing challenges and as a reference for other scenario results.
+ **Medium-term (2030)** reliability statistics are calculated in 2030 for two scenarios: a *Reference* scenario and a *No Coal* scenario. The *Reference* scenario includes the impact of expected load growth and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants. The *No Coal* scenario assumes that all coal is retired.
+ **Long-term (2050)** reliability statistics are calculated in 2050 for multiple scenarios including a *Reference* scenario and for a range of decarbonization targets. The *Reference* scenario includes the impact of load growth, growth in renewable capacity to meet current RPS policy goals, and the retirement of all coal. Decarbonization scenarios assume GHG emissions are reduced to 60%, 80%, 90%, 98% and 100% below 1990 GHG levels through the addition of wind, solar, and electric energy storage.

These scenarios are summarized in Table 3.

Table 3: List of Scenarios and Descriptions

Analysis Period	Scenario	Description
Near-term (2018)	Reference	2018 Existing Loads and Resources
Medium-Term (2030)	Reference	Includes load growth through 2030 and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants
	No Coal	Same as 2030 reference but all coal generation in the region is retired (11 GW)
Long-Term (2050)	Reference	Includes load growth through 2050, renewable capacity additions to meet RPS targets, and ***retirement of all coal generation*** (11 GW)
	60% GHG Reduction	Scenarios achieve specified greenhouse gas reduction (relative to 1990 levels) through addition of solar, wind, and energy storage; sufficient gas generating capacity is maintained to ensure reliability (except in 100% GHG Reduction)
	80% GHG Reduction	
	90% GHG Reduction	
	98% GHG Reduction	
	100% GHG Reduction	

This study further explores the potential resource adequacy needs of a 100% carbon free electricity system in 2050 recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. To better understand how those technologies might impact the viability of achieving this ambitious goal, the study includes several sensitivity analyses of the 100% GHG Reduction scenario that assume the wide-scale availability of several such emerging technology options. These sensitivities are described in Table 4.

Table 4: 100% GHG Reduction in 2050 Sensitivities

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

3.4 Key Portfolio Metrics

Each of the scenarios is evaluated using several different metrics which are defined below:

3.4.1 CLEAN ENERGY METRICS

A number of metrics are used to characterize the greenhouse gas content of generation within the region in each of the scenarios. These are:

+ **Greenhouse Gas Emissions (MMT CO2):** the annual quantity of greenhouse gas emissions attributed to ratepayers of the Greater Northwest region, measured in million metric tons.
+ **Greenhouse Gas Reduction (%):** the reduction below 1990 emission levels (approximately 60 million metric tons) for the Greater Northwest region.
+ **Clean Portfolio Standard (%):** the total quantity of GHG-free generation (including renewable, hydro, and nuclear) divided by retail electricity sales. Because this metric allows the region to retain the clean attribute for exported electricity and offset in-region or imported natural gas

generation, this metric can achieve or exceed 100% without reducing GHGs to zero. This metric is presented because it is a common policy target metric across many jurisdictions to measure clean energy progress and is the near-universal metric used for state-level Renewables Portfolio Standards. This metric is consistent with California's SB 100 which mandates 100% clean energy by 2045.

+ **GHG-Free Generation (%):** the total quantity of GHG-free generation, minus exported GHG-free generation, divided by total wholesale load. For this metric, exported clean energy cannot be netted against in-region or imported natural gas generation. When this metric reaches 100%, GHG emissions have been reduced to zero.

3.4.2 COST METRICS

+ **Renewable Curtailment (%):** the total quantity of wind and solar generation that cannot be delivered to loads in the region or exported, expressed as a share of total available potential generation from wind and solar resources.
+ **Annual Cost Delta ($B)** is the annual cost in 2050 of decarbonization scenarios relative to the 2050 Reference scenario. While the 2050 Reference scenario will require significant costs to meet load growth, this metric only evaluates the *change* in costs for each decarbonization scenario relative to the Reference scenario. By definition, the 2050 Reference scenario has an annual cost delta of zero. The annual cost delta is calculated by comparing the incremental cost of new wind, solar, and storage resources to the avoided cost of natural gas capital and operational costs.
+ **Additional Cost ($/MWh)** is the total annual cost delta ($B) divided by total wholesale load, which provides an average measure of the incremental rate impact borne by ratepayers within the region. While this metric helps to contextualize the annual cost delta, it is important to note that the incremental cost will not be borne equally by all load within the Greater Northwest region and some utilities may experience higher additional costs.

3.5 Study Caveats

3.5.1 COST RESULTS

The study reports the incremental costs of achieving various GHG targets relative to the cost of the reference scenario. While the method used to estimate capital and dispatch costs is robust, it does not entail optimization and the results should be regarded as high-level estimates. For this reason, a range of potential incremental costs are reported rather than a point estimate. The range is determined by varying the cost of wind, solar, energy storage and natural gas.

3.5.2 HYDRO DISPATCH

For this study, RECAP utilizes a range of hydro conditions based on NWPCC data covering the time period 1929 – 2008. Within each hydro year, hydroelectric energy "budgets" for each month are allocated to individual weeks and then dispatched to minimize net load, subject to sustained peaking limit constraints that are appropriate for the water conditions. Hydro resources are dispatched optimally within each week with perfect foresight. There are many real-life issues such as biological conditions, flood control, coordination between different project operators, and others that may constrain hydro operations further than what is assumed for this study.

3.5.3 TRANSMISSION CONSTRAINTS

This analysis treats the Greater Northwest region as one zone with no internal transmission constraints or transactional friction. In reality, there are constraints in the region that may prevent a resource in one corner of the region from being able to serve load in another corner. To the extent that constraints exist, the Greater Northwest region may be less resource adequate than is calculated in this study and additional effective capacity would be required to achieve the calculated level of resource adequacy. It is assumed that new transmission can be developed to deliver energy from new renewable resources to wherever it is needed, for a cost that is represented by the generic transmission cost adder applied to resources in different locations.

3.5.4 INDIVIDUAL UTILITY RESULTS

Cost and resource results in this study are presented from the system perspective and represent an aggregation of the entire Greater Northwest region. These societal costs include all capital investment costs (i.e., “steel in the ground”) and operational costs (i.e., fuel and operation and maintenance) that are incurred in the region. The question of how these societal costs are allocated between individual utilities is not addressed in this study, but costs for individual utilities may be higher or lower compared to the region as a whole. Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources.

Resource adequacy needs will also be different for each utility as individual systems will need a higher planning reserve margin than the Greater Northwest region as a whole due to smaller size and less diversity. The capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production.

3.5.5 RENEWABLE RESOURCE AVALIBILITY AND LAND USE

The renewable resource availability assumed for this study is based on technical potential as assessed by NREL. It is assumed wind and solar generation can be developed in each location modeled in this study up to the technical potential. However, the land consumption is significant for some scenarios and it is not clear whether enough suitable sites can be found to develop the large quantities of resources needed for some scenarios. Land use is also a significant concern for the new transmission corridors that would be required.

4 Key Inputs & Assumptions

4.1 Load Forecast

The Greater Northwest region had an annual load of 247 TWh and peak load of 43 GW in 2017. This data was obtained by aggregating hourly load data from the Western Electric Coordinating Council (WECC) for each of the selected balancing authority areas in the Greater Northwest region.

This study assumes annual load growth of **1.3% pre-energy efficiency** and **0.7% post-energy efficiency**. This assumption is consistent with the previous E3 decarbonization work for Oregon and Washington and is benchmarked to multiple long-term publicly available projections listed in Table 5. The post-energy efficiency growth rate includes the impact of all cost-effective energy efficiency identified by the NWPCC, scaled up to the full Greater Northwest region and assumed to continue beyond the end of the Council's time horizon. Electrification of vehicles and buildings is only included to the extent that it is reflected in these load growth forecasts. For example, the NWPCC forecast includes the impact of 1.1 million electric vehicles by 2030.

In general, E3 believes these load growth forecasts are conservatively low because they exclude the effect of vehicle and building electrification that would be expected in a deeply decarbonized economy. To the extent that electrification is higher than forecasted in this study, resource adequacy requirements would also increase. In this study, total loads increase 25% by 2050, whereas other studies[12] that have comprehensively examined cost-effective strategies for economy-wide decarbonization include

[12] https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

significant quantities of building, vehicle, and industry electrification that cause electricity-sector loads to grow by upwards of 60% by 2050 even with significant investments in energy efficiency.

Table 5. Annual load growth forecasts for the Northwest

Source	Pre EE	Post EE
PNUCC Load Forecast	1.7%	0.9%
BPA White Book	1.1%	-
NWPCC 7th Plan	0.9%	0.0%
WECC TEPPC 2026 Common Case	-	1.3%
E3 Assumption	**1.3%**	**0.7%**

Hourly load profiles are assumed to be constant through the analysis period and do not account for any potential impact due to electrification of loads or climate change. The Greater Northwest system is a winter peaking system with loads that are highest during cold snaps on December and January mornings and evenings. An illustration of the average month/hour load profile for the Greater Northwest is shown in Figure 4.

Figure 4: Month/Hour Average Hourly Load in the Greater Northwest (GW)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
Mar	24	23	23	23	24	25	28	30	30	30	30	29	29	28	28	27	27	28	28	29	29	28	27	25
Apr	22	22	21	22	22	24	27	28	28	28	28	27	27	27	26	26	26	26	27	27	28	27	25	23
May	22	21	21	21	21	22	24	26	26	27	27	27	27	27	27	27	27	27	27	27	27	27	25	23
Jun	23	22	21	21	22	22	24	26	27	27	28	28	29	29	29	29	29	29	29	29	28	28	26	24
Jul	24	23	22	22	22	23	24	26	27	28	29	30	31	31	32	32	32	32	32	31	30	30	28	26
Aug	23	22	21	21	21	22	24	25	26	27	28	29	29	30	30	31	31	31	30	30	30	28	26	24
Sep	21	20	20	20	20	22	24	25	26	26	26	27	27	27	27	27	27	28	27	28	27	26	24	22
Oct	21	21	20	20	21	23	25	26	27	27	27	27	27	26	26	26	26	27	27	28	27	26	24	22
Nov	24	23	23	23	23	24	26	28	30	30	30	29	29	28	28	28	28	29	31	30	30	29	28	26
Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

Projecting these hourly loads using the post-energy efficiency load growth forecasts yields the following load projections in 2030 and 2050.

Table 6. Load projections in 2030 and 2050 for the Greater NW Region

Load	2018	2030	2050
Median Peak Load (GW)	43	47	54
Annual Energy Load (TWh)	247	269	309

To evaluate the reliability of the Greater Northwest system under a range of weather conditions, hourly load forecasts for 2030 and 2050 are developed over seventy years of weather conditions (1948-2017). Historical weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA) for the following sites in the Greater Northwest region.

Table 7: List of NOAA Sites for Historical Temperature Data

City	Site ID
Billings, MT	USW00024033
Boise, ID	USW00024131
Portland, OR	USW00024229
Salt Lake City, UT	USW00024127
Seattle, WA	USW00024233
Spokane, WA	USW00024157

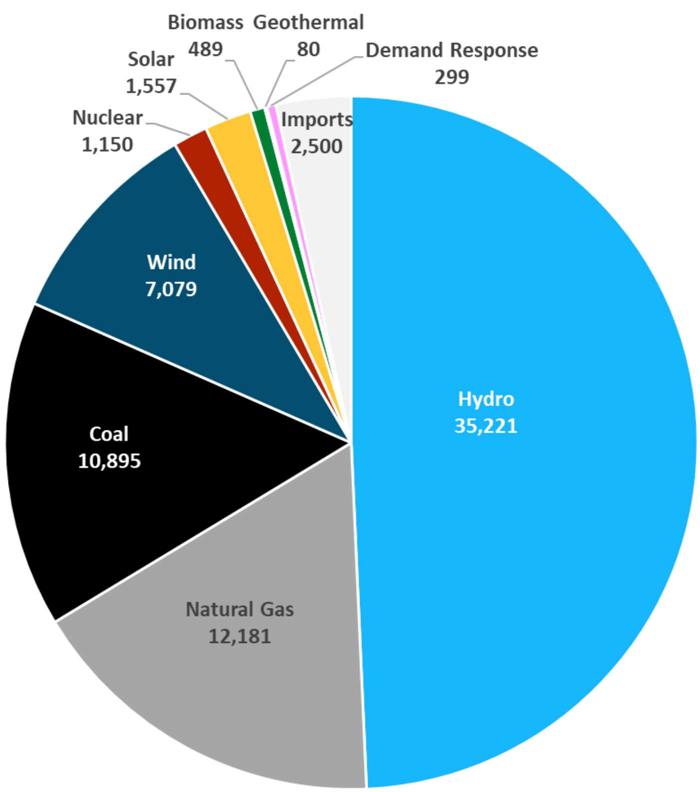
4.2 Existing Resources

A dataset of existing generating resources in the Greater Northwest was derived from two sources: 1) the NWPCC's GENESYS model, used to characterize all plants within the Council's planning footprint; and 2) the WECC's Anchor Data Set, used to gather input data for all existing plants in areas outside of the NWPCC's footprint. For each resource, the dataset contains:

+ Dependable capacity (MW)
+ Location
+ Commission and announced retirement date
+ Forced outage rate (FOR) and mean time to repair (MTTR)

A breakdown of existing resources by type is shown in Figure 5.

Figure 5: Existing 2018 Installed Capacity (MW) by Resource Type



Several power plants have announced plans to retire one or more units. The table below lists the notable coal and natural gas planned retirements through 2030.

Table 8: Planned Coal and Natural Gas Retirements

Power Plant	Resource Type	Capacity (MW)
Boardman	Coal	522
Centralia	Coal	1,340
Colstrip 1 & 2	Coal	614
North Valmy	Coal	261
Naughton	Natural Gas	330

4.2.1 WIND AND SOLAR PROFILES

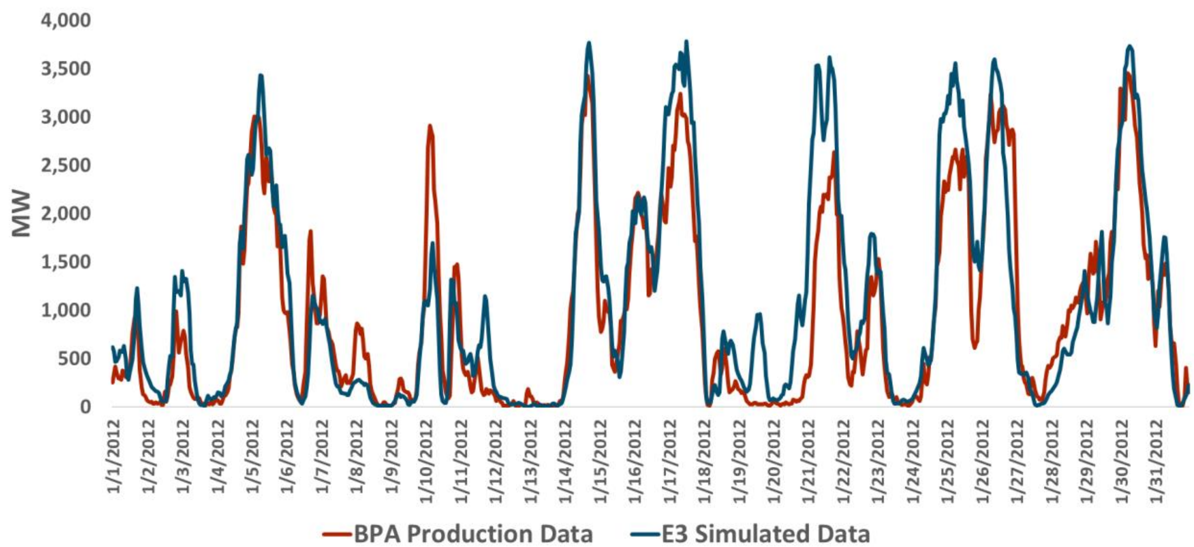
Hourly wind and solar data were collected for each existing resource in the combined dataset at the location of the resource. For wind, NREL's Wind Integration National Dataset Toolkit was used which includes historical hourly wind speed data from 2007-2012. For solar, NREL's Solar Prospector Database was used which includes historical hourly solar insolation data from 1998-2012. These hourly wind speeds and solar insolation values were then converted into power generation values using the NREL System Advisor Model (SAM) under assumptions for wind turbine characteristics (turbine power curve and hub height) and solar panel characteristics (solar inverter ratio). RECAP simulates future electricity generation from existing wind and solar resources using the historical wind speed data and solar insolation data respectively.

Simulated wind generation from existing wind plants within BPA territory was benchmarked to historical wind production data[13]. To simulate wind generation from existing plants accurately, wind turbine

[13] BPA publishes production from wind plants within its Balancing Authority Area in 5-min increments: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

technology (power curve and hub height) varies for each existing wind farm, based on the year of installation. Figure 6 shows how the simulated wind production compares to historical wind production in BPA territory in January 2012.

Figure 6: Comparison of historical wind generation to simulated wind production for January 2012



A detailed description of the renewable profile simulation process is described in Appendix C.

4.2.2 HYDRO

Hydro availability is based on a random distribution of the historical hydro record using the water years from 1929-2008. This data was obtained from the NWPCC's GENESYS model. Future electricity generation from existing hydro resources is simulated using the historical hydro availability. Available hydro energy is dispatched in RECAP subject to sustained peaking limits (1-hr, 2-hr, 4-hr, 10-hr) and minimum output levels. The sustained peaking limits are based on detailed hydrological models developed by NWPCC. Available hydro budgets, sustained peaking limits, and minimum output levels are shown for three hydro years – 1937 (critical hydro year), 1996 (high hydro year), and 2007 (typical hydro year). The 10-hour sustained peaking limits for each month represent the maximum average generation for any continuous 10-hour period within the month.

Figure 7: Monthly budgets, sustained peaking limits and minimum outputs levels for 1937 (critical hydro)

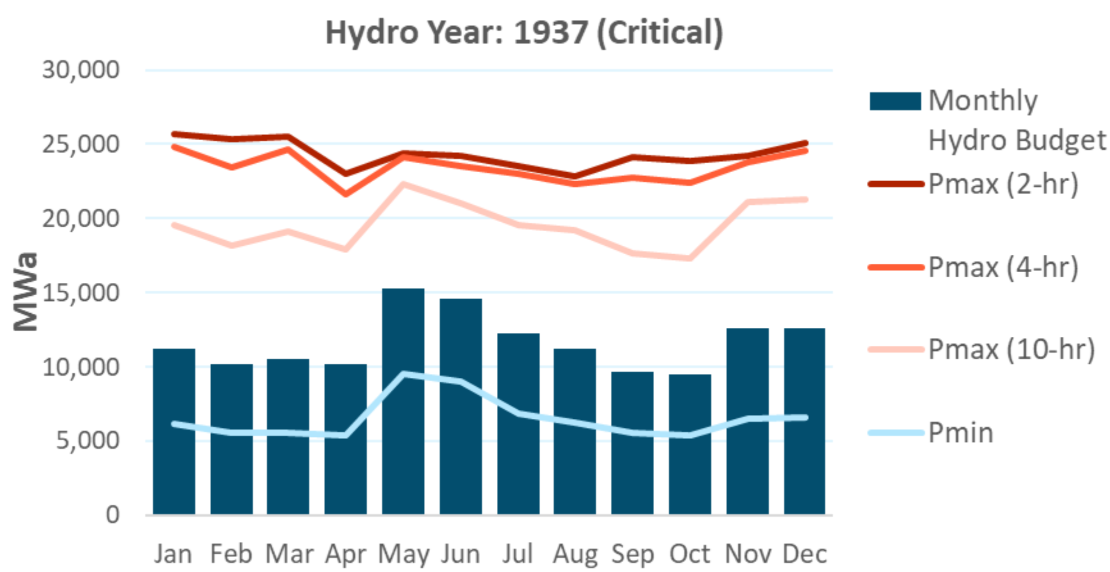


Figure 8: Monthly budgets, sustained peaking limits and minimum outputs levels for 1996 (high hydro)

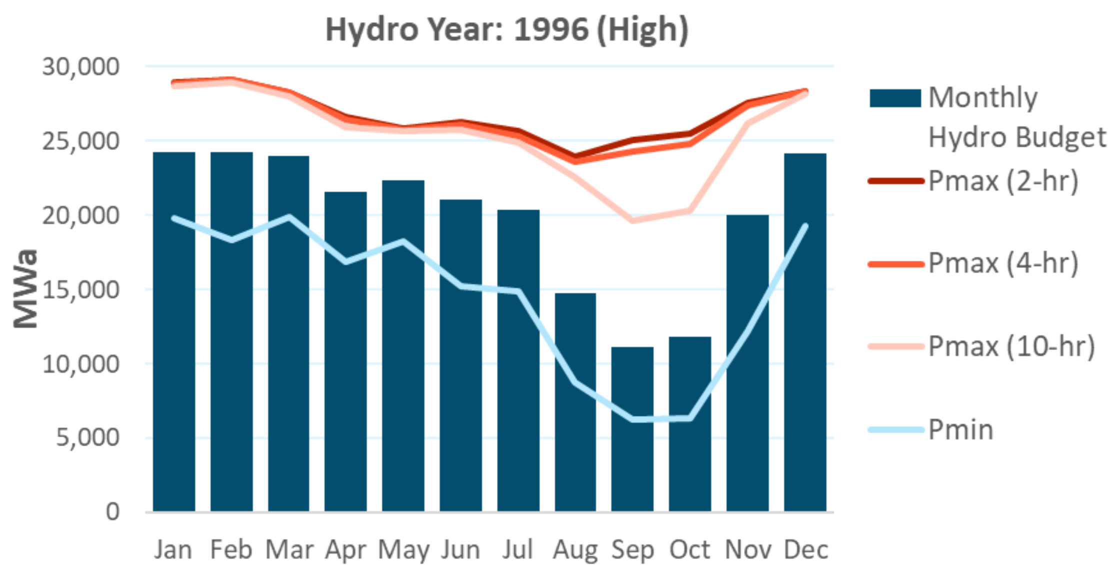
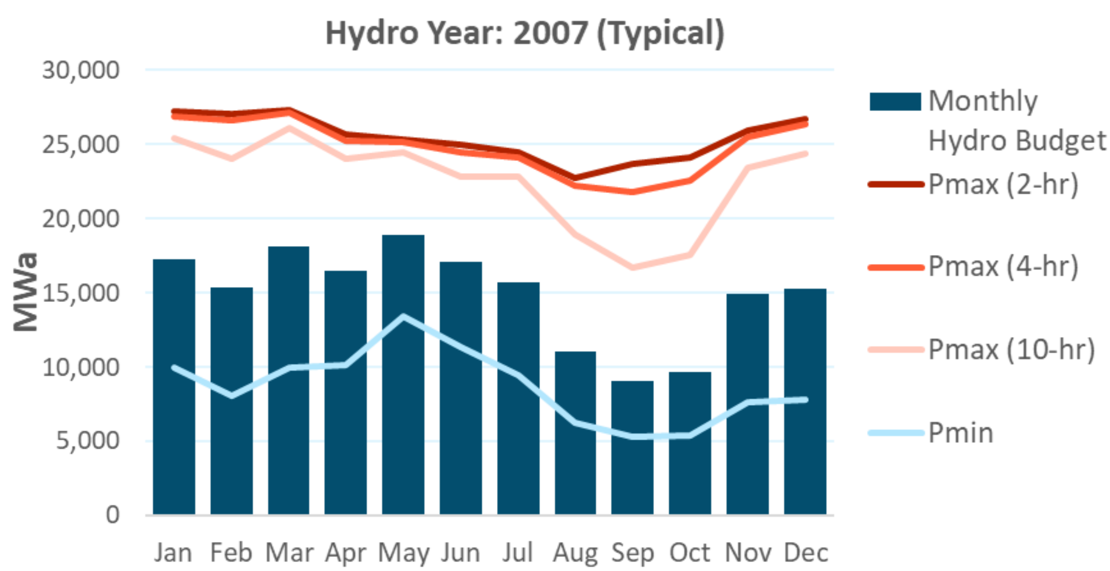


Figure 9: Monthly budgets, sustained peaking limits and minimum outputs levels for 2007 (typical hydro)



4.2.3 IMPORTS/EXPORTS

The Greater Northwest region is treated as one zone within the model, but it does have the ability to import and export energy with neighboring regions, notably California, Canada, Rocky Mountains, and the Southwest. Import and export assumptions used in this model are consistent with the NWPCC's GENESYS model and are listed in Table 9. Monthly and hourly import availabilities are additive but in no hour can exceed the simultaneous import limit of 3,400 MW. In the 100% GHG Reduction scenarios, import availability is set to zero to prevent the region from relying on fossil fuel imports.

Table 9: Import Limits

Import Type	Availability	MW
Monthly Imports	Nov – Mar	2,500
	Oct	1,250
	Apr – Sep	-
Hourly Imports	HE 22 – HE 5	3,000
	HE 5 – HE 22	-
Simultaneous Import Limit	**All Hours**	**3,400**

For the purposes of calculating the CPS % metric i.e., "clean portfolio standard", the model assumes an instantaneous exports limit of 7,200 MW in all hours.

Table 10: Export Limit

Export Type	Availability	MW
Simultaneous Export Limit	**All Hours**	**7,200**

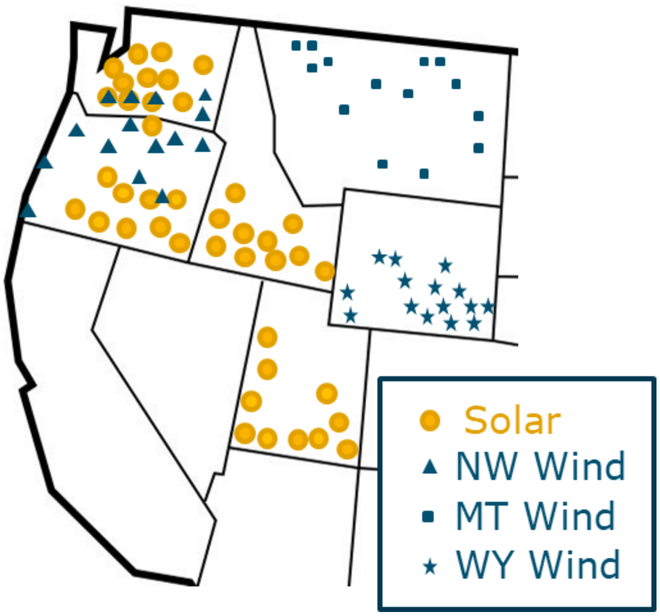
4.3 Candidate Resources

Candidate resources are used to develop portfolios of resources in 2050 to both achieve GHG reduction targets or ensure acceptable reliability of 2.4 hrs./yr. LOLE. For a more detailed description of the portfolio development process, see Section 3.1.3. The 7 candidate resources are:

+ Solar (geographically diverse across Greater Northwest)
+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

Natural gas generation is also added as needed to meet any remaining reliability gaps after the GHG reduction target is met. The new renewable candidate resources (solar, NW wind, MT wind, WY wind) are assumed to be added proportionally across a geographically diverse footprint which has a strong impact on the ability of variable renewable resources to provide reliable power that can substitute for firm generation. Figure 10 illustrates the location of new candidate renewable resources. When a resource is added, it is added proportionally at each of the locations shown in the figure below.

Figure 10: New Renewable Candidate Resources



The generation output profile for each location was simulated by gathering hourly wind speed and solar insolation data from NREL's Wind Integration National Dataset Toolkit and Solar Prospector Database and converting to power output using NREL's System Advisor Model. The wind profiles used in this study are based on 135 GW of underlying wind production data from hundreds of sites. The solar profiles used in this study are based on 80 GW of underlying solar production data across four states. This process is described in more detail in Appendix C.

New storage resources are available to the model in different increments of duration at different costs which provide different value in terms of both reliability and renewable integration for GHG reduction. Note that the model can choose different quantities of each storage duration which results in a fleet-wide storage duration that is different than any individual storage candidate resource. Because storage is modeled in terms of capacity charge/discharge and duration, many different storage technologies could provide this capability. The cost forecast trajectory for Li-Ion battery storage was used to estimate costs, but any storage technology that could provide equivalent capacity and duration, such as pumped hydro or flow batteries, could substitute for the storage included in the portfolio results of this study.

New renewable portfolios are within the bounds of current technical potential estimates published in NREL.

Table 11. NREL Technical Potential (GW)

State	Wind Technical Potential (GW)
Washington	18
Oregon	27
Idaho	18
Montana	944
Wyoming	552
Utah	13
Total	**1,588**

4.3.1.1 Resource Costs

All costs in this study are presented in 2016 dollars. The average cost of each resource over the 2018-2050 timeframe is shown in Table 12 while the annual cost trajectories from 2018-2050 are shown in Figure 11.

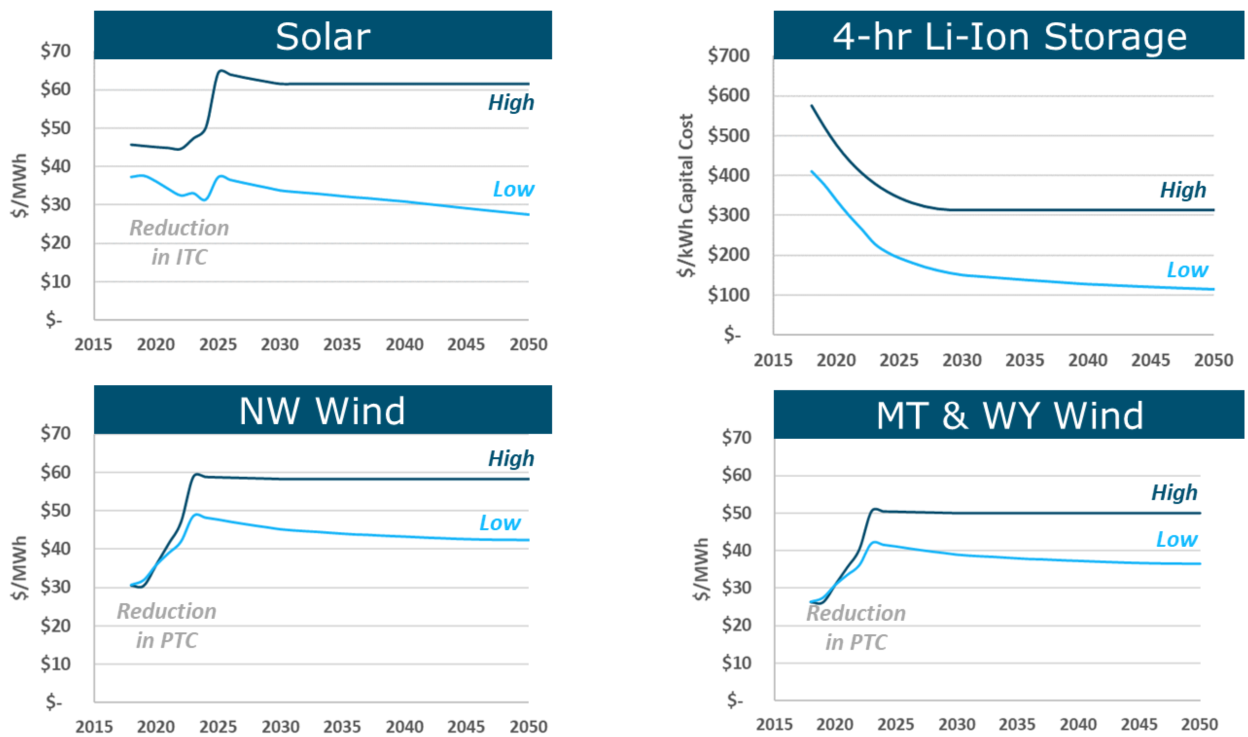
Table 12. Resource Cost Assumptions (2016 $)

Technology	Unit	High[14]	Low[15]	Transmission	Notes
Solar PV	$/MWh	$59	$32	$8	Capacity factor = 27%
NW Wind	$/MWh	$55	$43	$6	Capacity factor = 37%
MT/WY Wind	$/MWh	$48	$37	$19	Capacity factor = 43%
4-hr Battery	$/kW-yr	$194	$97		

[14] Source for high prices: 2017 E3 PGP Decarbonization Study
[15] Source for low prices: NREL 2018 ATB Mid case for wind and solar; Lazard LCOS Mid case 4.0 for batteries

Technology	Unit	High[14]	Low[15]	Transmission	Notes
8-hr Battery	$/kW-yr	$358	$189		
16-hr Battery	$/kW-yr	$686	$373		
Natural Gas Capacity	$/kW-yr	$150	$150		7,000 Btu/kWh heat rate; $5/MWh variable O&M
Gas Price	$/MMBtu	$4	$2		
Biogas Price	$/MMBtu	$39	$39		

Figure 11: Cost trajectories over the 2018-2050 timeframe (2016 $)



4.4 Estimating Cost and GHG Metrics

The cost of the future electricity portfolios consists of (1) fixed capital costs for building new resources, and (2) operating costs for running both existing and new resources. For new wind and new solar resources, the cost of generation is calculated using their respective levelized costs (see Table 12). Cost of electricity generation from natural gas plants includes both the capital cost for new natural gas plants and the operating costs (fuel costs and variable operating costs). All the natural gas plants are assumed to operate at a heat rate of 7,000 Btu/kWh, with the price of natural gas varying from \$2 to \$4 per MMBtu (see Table 12). Storage resources are assumed to have only fixed cost, but no operating cost. All exports are assumed to yield revenues of \$30 per MWh.

In this study, annual GHG emissions are compared against 1990 emission levels, when the emissions for the Greater Northwest region was 60 million metric tons. GHG emissions are calculated for each thermal resource depending on the fuel type. For natural gas plants, an emission rate of 117 lb. of CO_2 per MMBtu of natural gas is assumed, yielding 0.371 metric tons of CO_2 per MWh of electricity generated from natural gas (assumed 7,000 Btu/kWh heat rate). For coal plants, an emission rate of 1.0 ton of CO_2 per MWh of electricity generated from coal is assumed.

5 Results

5.1 Short-Term Outlook (2018)

The 2018 system (today's system) in the study region is supplied by a mix of various resources, as described in Section 4.2. The annual electricity load for the study region is 247 TWh with a winter peak demand of 43 GW. Hydro energy provides the plurality of generation capacity with significant contributions from natural gas, coal and wind generation.

Resource adequacy conclusions vary depending on what metric is used for evaluation. The region has sufficient capacity to meet the current standard used by the NWPCC of 5% annual loss of load probability (LOLP). The region does not have sufficient capacity to meet the 2.4 hrs./yr. LOLE standard used in this study. In other words, most loss of load is concentrated in a few number of years which matches intuition for a system that is dependent upon the annual hydro cycle and susceptible to drought conditions. Full reliability statistics for the Greater Northwest region are shown in Table 13.

Table 13. 2018 Reliability Statistics

Metric	Units	Value
Annual LOLP (%)	%	3.7%
Loss of Load Expectation (LOLE)	hrs/yr	**6.5**
Expected Unserved Energy (EUE)	MWh/yr	5,777
Normalized EUE	%	0.003%
1-in-2 Peak Load	GW	43
PRM Requirement	% of peak	12%
Total Effective Capacity Requirement	GW	48

Table 14. 2018 Load and Resource Balance

Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

In order to meet an LOLE target of 2.4 hrs./yr., a planning reserve margin (PRM) of 12% is required. The PRM is calculated by dividing the quantity of effective capacity needed to meet the LOLE target by the median peak load, then subtracting one. This result is lower than many individual utilities currently hold within the region (typical PRM ~15%) due to the load and resource diversity across the geographically large Greater Northwest region. As shown in Table 14, the total effective capacity (47 GW) available is slightly lower than the total capacity requirement (48 GW) which is consistent with the finding that the system is not sufficiently reliable to meet a 2.4 hrs./yr. LOLE target. The effective capacity percent contributions from wind and solar are shown to be 7% and 12%, respectively. These relatively low values stem primarily from the non-coincidence of wind and solar production during high load events in the Greater Northwest region, notably very cold winter mornings and evenings.

It should be noted that the effectiveness of firm capacity is set to 100% by convention in calculating a PRM. The contribution of variable resources is then measured relative to firm capacity, incorporating the effect of forced outage rates for firm resources.

5.2 Medium-Term Outlook (2030)

The Greater Northwest system in 2030 is examined under two scenarios:

+ **Reference**
    - Planned coal retirements; new gas gen for reliability
+ **No Coal**
    - All coal retired; new gas gen for reliability

The resulting generation portfolios in both scenarios (both of which meet the 2.4 hrs./yr. LOLE reliability standard) are shown in Figure 12 alongside the 2018 system for context. To account for the load growth by 2030, 5 GW of net new capacity is required to maintain reliability. In the *Reference* Scenario where 3 GW of coal is retired, 8 GW of new firm capacity is needed by 2030 for reliability. Similarly, the *No Coal* Scenario (where all 11 GW of coal is retired) results in 16 GW of new firm capacity need by 2030. The study assumes all the new capacity in the 2030 timeframe need is met through additional natural gas build. It should be noted that regardless of what resource mix is built to replace the retirement of coal, the siting, permitting, and construction of these new resources will take significant time so planning for these resources needs to begin well before actual need. The portfolio tables for each scenario are summarized in Appendix A.2.

Figure 12: Generation Portfolios in 2030

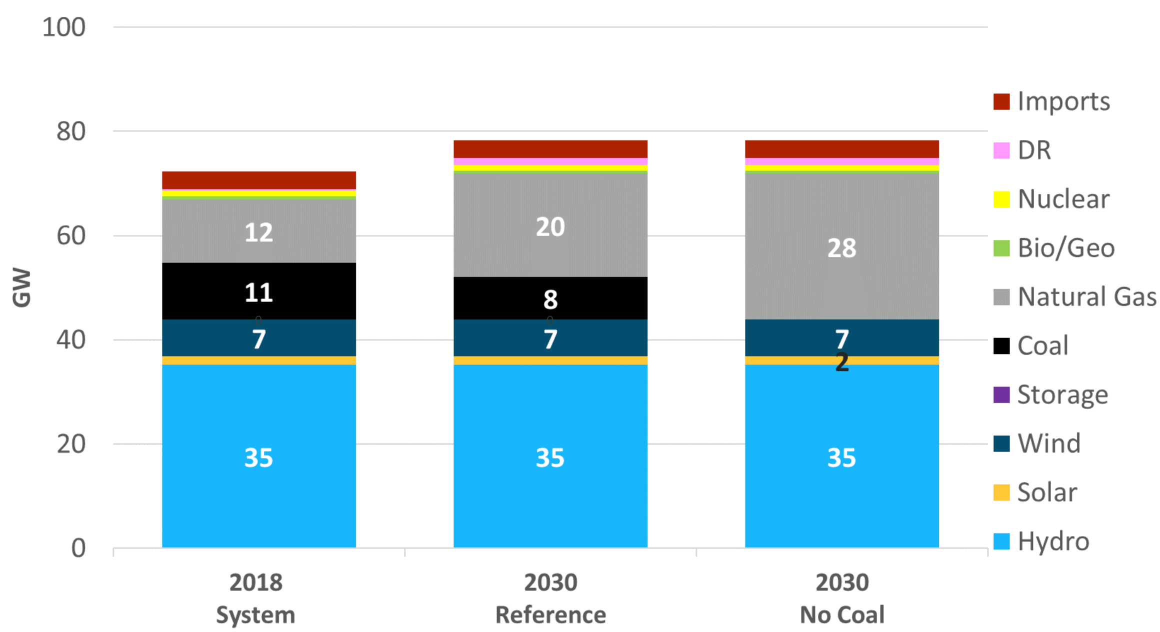


Table 15. 2030 Generation Portfolio: Key Metrics

Metric	2030 Reference	2030 No Coal
GHG-Free Generation (%)	61%	61%
GHG Emissions (MMT CO_2 / year)	67	42
% GHG Reduction from 1990 Level	-12%[16]	31%

[16] Negative value for %GHG reduction from 1990 level indicates that emissions are above 1990 level

As these metrics show, without either natural gas replacement of coal capacity or significant increase in renewable energy, GHG emissions are forecasted to rise in the 2030 timeframe. However, repowering coal with natural gas has the potential to reduce GHG emissions by 31% below 1990 levels.

In order to meet an LOLE target of 2.4 hrs/yr, the region requires a planning reserve margin (PRM) in 2030 of 12%.

Table 16. 2030 Load and Resource Balance, Reference Scenario

Load			Load MW
Peak Load			45.9
Firm Exports			1.1
PRM (12%)			5.8
Total Requirement			**52.9**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	8.2	100%	8.2
Gas	19.9	100%	19.9
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	2.2	45%	1.0
Hydro	35.2	53%	18.7
Wind	7.1	9%	0.6
Solar	1.6	14%	0.2
Storage	0	—	0
Total Internal Generation	**76.1**		**50.5**
Firm Imports	3.4	74%	2.5
Total Supply	**79.5**		**52.9**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3 Long-Term Outlook (2050)

The Greater Northwest system in 2050 is examined under a range of decarbonization scenarios, relative to 1990 emissions.

- 60% GHG Reduction
- 80% GHG Reduction
- 90% GHG Reduction
- 98% GHG Reduction
- 100% GHG Reduction

The portfolio for each decarbonization scenario was developed using the methodology described in Section 3.1.3. To summarize this process, RECAP iteratively adds carbon-free resources (wind, solar storage) to reduce GHG in a manner that maximizes the effective capacity of these carbon-free resources, thus minimizing the residual need for firm natural gas capacity. Once a cost-effective portfolio of carbon-free resources has been added to ensure requisite GHG reductions, the residual need for natural gas generation capacity is calculated to ensure the entire portfolio meets a 2.4 hrs./yr. LOLE standard.

5.3.1 ELECTRICITY GENERATION PORTFOLIOS

All the 2050 decarbonization portfolios are shown together in Figure 13. Higher quantities of renewable and energy storage are required to achieve deeper levels of decarbonization, which in turn provide effective capacity to the system and allow for a reduction in residual firm natural gas capacity need, relative to the reference case. Detailed portfolio results tables for each scenario are provided in Appendix A.2.

Figure 13: Generation Portfolios for 2050 Scenarios

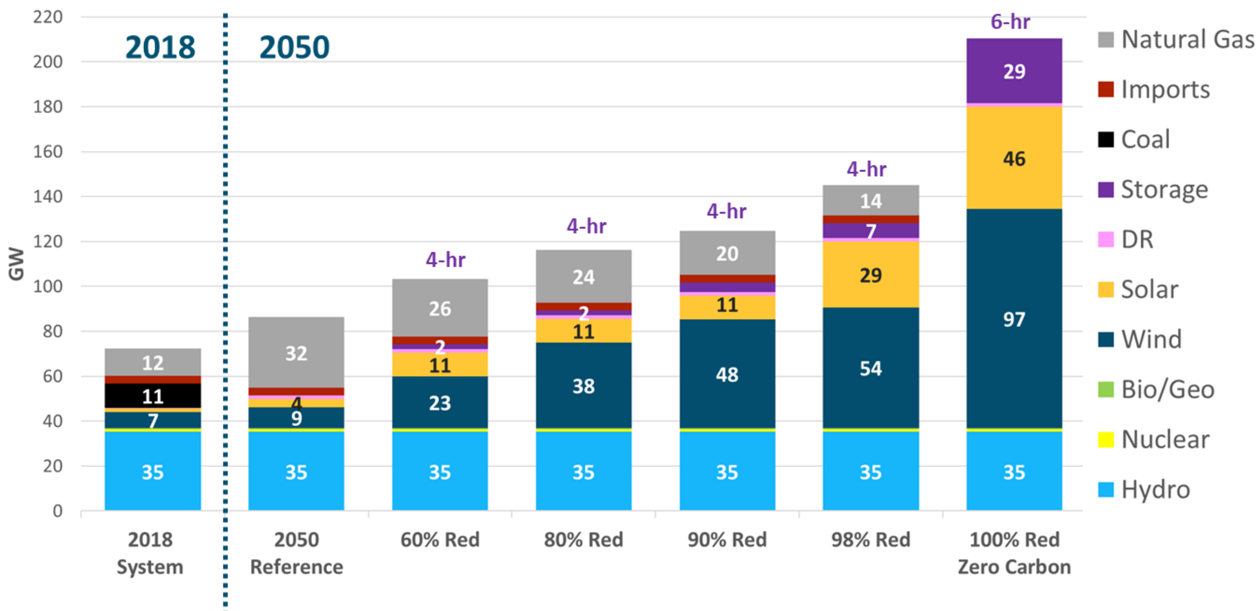


Table 17. 2050 Decarbonization Scenarios: Key Generation Metrics

Metric	Units	Reference Scenario	GHG Reduction Scenarios				
			60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
GHG Emissions	MMT/yr	50	25	12	6	1	0
GHG Reductions	% below 1990	16%	60%	80%	90%	98%	100%
GHG-Free Generation	% of load	60%	80%	90%	95%	99%	100%
Clean Portfolio Standard	% of sales	63%	86%	100%	108%	117%	123%
Annual Renewable Curtailment	% of potential	Low	Low	4%	10%	21%	47%

Table 17 evaluates the performance of each decarbonization portfolio along several key generation metrics that were described in detail in Section 3.4.

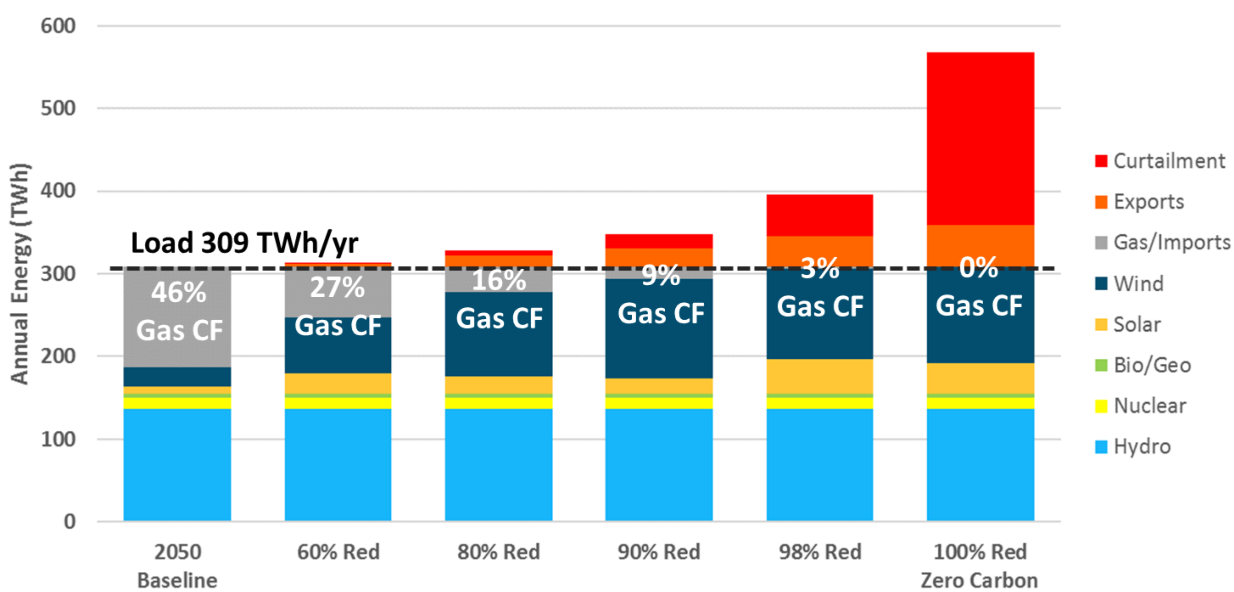
Analyzing the portfolio of each decarbonization scenario and resulting performance metrics yields several interesting observations.

+ On retiring all 11 GW of coal by 2050 in the *Reference* scenario, the Greater Northwest system requires 20 GW of new capacity in order to meet the 2.4 hrs./yr. LOLE standard used in the study. This suggests that 9 GW of net new firm capacity is needed to account for load growth through 2050.
+ The integration of more renewables and conservation policies provides the energy needed to serve loads in a deeply decarbonized future, but new gas-fired generation capacity is needed for relatively short, multi-day events with low renewable generation, high loads, and low hydro availability.
+ To reduce GHG emissions to 80% below 1990 levels, RECAP chooses to build 38 GW of wind, 11 GW of solar, and 2 GW of 4-hour storage. In addition to this renewable build, 12 GW of new firm capacity is required for reliability (after retaining all the existing natural gas plants) which is assumed to be met through natural gas build. The generation portfolio under 80% Reduction Scenario results in a 100% clean portfolio standard and 90% GHG-free generation.
+ RECAP achieves deeper levels of decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) by overbuilding renewables with 54 GW of wind, 29 GW of solar, and 7 GW of 4-hour storage. Annual renewable oversupply becomes significant (at 21%). Nevertheless, the system still requires an additional gas build of 2 GW after retaining all existing natural gas plants, to ensure reliability during periods of low renewable generation. The capacity factor for these gas plants is extremely low (3%), underlining their importance for reliability.
+ The 100% GHG Reduction Scenario (Zero Carbon Scenario) results in no GHG emissions from the electricity sector. The generation portfolio consists only of renewables (97 GW of wind and 46 GW of solar) and energy storage (29 GW of 6-hour storage). Ensuring a reliable system using only renewables and energy storage requires a significant amount of renewable overbuild – resulting

in nearly half of all the generated renewable energy to be curtailed. Compared to the 98% GHG Reduction Scenario (which results in 99% GHG-free generation), the Zero Carbon Scenario requires almost double the quantity of renewables and even greater quantity of energy storage.

With increases in renewable generation, generation from natural gas plants decreases. Due to negligible operating costs associated with renewable production, it is cost optimal to use as much renewable generation as the system can. During periods of prolonged low renewable generation when energy storage is depleted, natural gas plants can ramp up to provide the required firm capacity to avoid loss-of-load events. In the deep decarbonization scenarios, gas is utilized sparingly and even results in very low capacity factors (such as 9% and 3%). However, RECAP chooses to retain (and even build) natural gas as the most cost-effective resource to provide reliable firm capacity. Renewable overbuild also results in significant amounts of curtailment.

Figure 14: Annual generation mix across the scenarios



A planning reserve margin of 7% to 9% is required to meet the 1-in-10 reliability standard in 2050 depending on the scenario. Accounting for a planning reserve margin, the total capacity requirement (load plus planning reserve margin) in 2050 is 57-59 GW. As shown in Table 18, this capacity requirement is met through a diverse mix of resources. Variable or energy-limited resources such as hydro, wind, solar and storage contribute only a portion of their entire nameplate capacity (ELCC) towards resource adequacy. Load and resource tables for the 80% and 100% Reduction scenarios are shown below.

Table 18. 2050 Load and Resource Balance, 80% Reduction scenario

Load			Load MW
Peak Load			52.8
Firm Exports			1.1
PRM (9%)			4.9
Total Requirement			**58.8**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	23.5	100%	23.5
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	53%	18.7
Wind	38.0	19%	7.2
Solar	10.6	19%	2.0
Storage	2.2	73%	1.6
Total Internal Generation	**116.8**		**56.3**
Firm Imports	3.4	74%	2.5
Total Supply	**120.2**		**58.8**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

Table 19. 2050 Load and Resource Balance, 100% Reduction scenario

Load			Load MW
Peak Load			52.8
Firm Exports			1.1
PRM (7%)			4.0
Total Requirement			**58.0**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	0	—	0
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	57%	20.1
Wind	97.4	22%	21.5
Solar	45.6	16%	7.3
Storage	28.7	20%	5.7
Total Internal Generation	**214.2**		**58.0**
Firm Imports	0	—	0
Total Supply	**214.2**		**58.0**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3.2 ELECTRIC SYSTEM COSTS

System costs are estimated using the methodology and cost assumptions described in Section 4.3.1.1 and Section 4.4. Electric system costs represent the cost of decarbonization relative to the 2050 *Reference* scenario, and so by definition all annual and unit cost increases in this scenario are zero. The 2050 *Reference* scenario does require significant investment in new resources in order to reliably meet load growth and existing RPS policy targets, so the zero incremental cost is not meant to make any assessment on the absolute change (or lack thereof) in total electric system costs or rates by 2050.

Table 20 evaluates the performance of 2050 decarbonization scenarios along two cost metrics for both a low and high set of cost assumptions.

Table 20: 2050 Decarbonization Scenarios: Key Cost Metrics

Metric		Units	Reference Scenario	GHG Reduction Scenarios 60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
Annual Cost Increase	Lo	$BB/yr *(vs. Ref)*	—	$0	$1	$2	$3	$16
	Hi			$2	$4	$5	$9	$28
Unit Cost Increase	Lo	$/MWh *(vs. Ref)*	—	$0	$3	$5	$10	$52
	Hi			$7	$14	$18	$28	$89

Analyzing the cost results for each decarbonization scenario yields several interesting observations

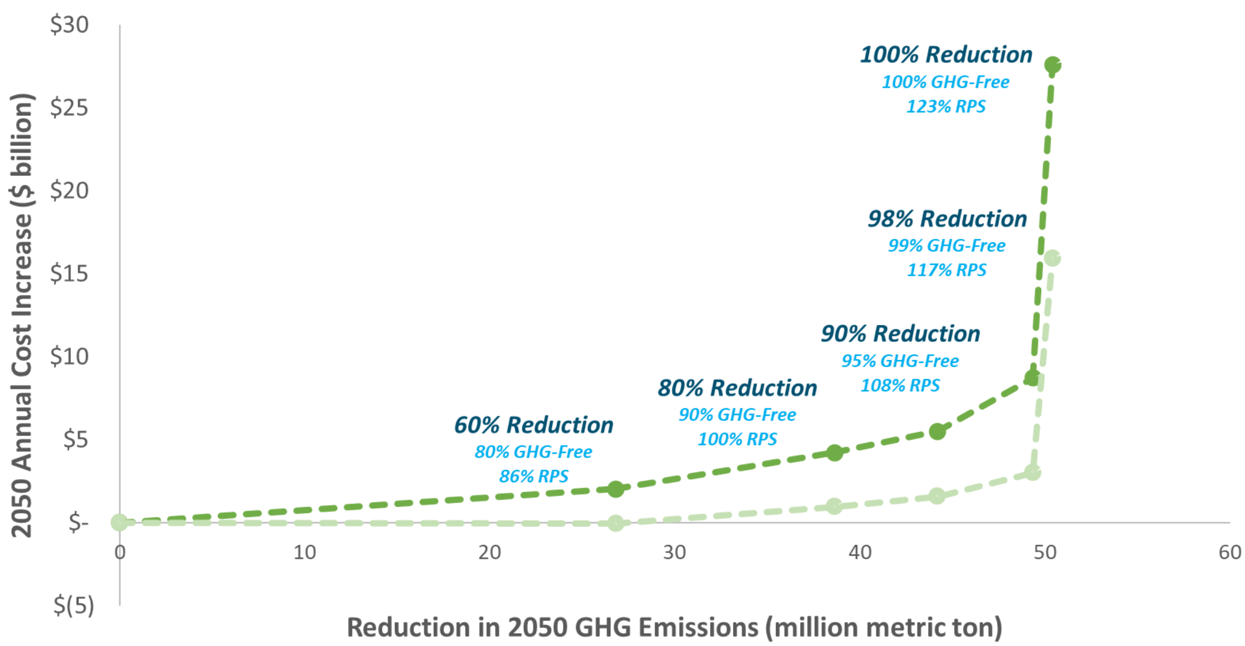
+ To reduce GHG emissions to 80% below 1990 levels, a portfolio of wind/solar/storage can be obtained at an additional annual cost of $1 to $4 billion ($3 to $14/MWh) after accounting for the avoided costs of new gas build and utilization. Assuming an existing average retail rate of $0.10/kWh, this implies an increase of 3%-14% in real terms relative to the *Reference* Scenario. Because the 80% reduction scenario achieves a 100% clean portfolio standard (as shown in Section 5.3.1), this scenario is compelling from both a policy perspective and a cost perspective in balancing multiple objectives across the Greater Northwest region.

+ Deep decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) of the Greater Northwest system can be obtained at an additional annual cost of $3 to $9 billion ($10 to $28/MWh), i.e., the average retail rates increase 10%-28% in real terms relative to the *Reference* Scenario. This suggests that deep decarbonization of the Greater Northwest system can be achieved at moderate additional costs, assuming that natural gas capacity is available as a resource option to maintain reliability during prolonged periods of low renewable production.
+ The 100% GHG Reduction Scenario requires a significant increase in wind, solar and storage to eliminate the final 1% of GHG-emitting generation. An additional upfront investment of $100 billion to $170 billion is required, relative to the 98% GHG Reduction scenario. Compared to the *Reference* Scenario, the Zero Carbon Scenario requires an additional annual cost of $16 to $28 billion ($52 to $89/MWh), i.e., the average retail rates nearly double.

Costs for individual utilities will vary and may be higher or lower than the region as a whole. This report does not address allocation of cost between utilities.

As shown in Figure 15, the cost increases of achieving deeper levels of decarbonization become increasingly large as GHG emissions approach zero. This is primarily due to the level of renewable overbuild that is required to ensure reliability and the increasing quantities of energy storage required to integrate the renewable energy.

Figure 15: Cost of GHG reduction



The marginal cost of GHG reduction represents the incremental cost of additional GHG reductions at various levels of decarbonization. Figure 16 and Figure 17 both show the increasing marginal cost of GHG abatement at each level of decarbonization. At very deep levels of GHG reductions, the marginal cost of carbon abatement greatly exceeds the societal cost of carbon emissions, which generally ranges from $50/ton to $250/ton[17], although some academic estimates range up to $800/ton[18].

[17] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[18] https://www.nature.com/articles/s41558-018-0282-y

Figure 16: Marginal Cost of GHG Reduction: 60% Reduction To 98% Reduction

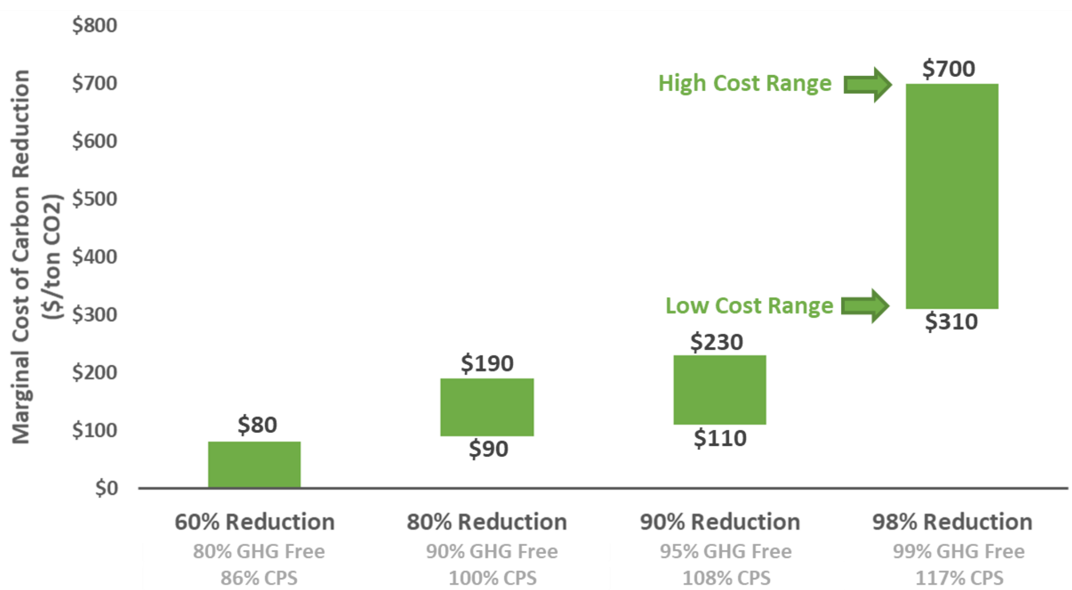
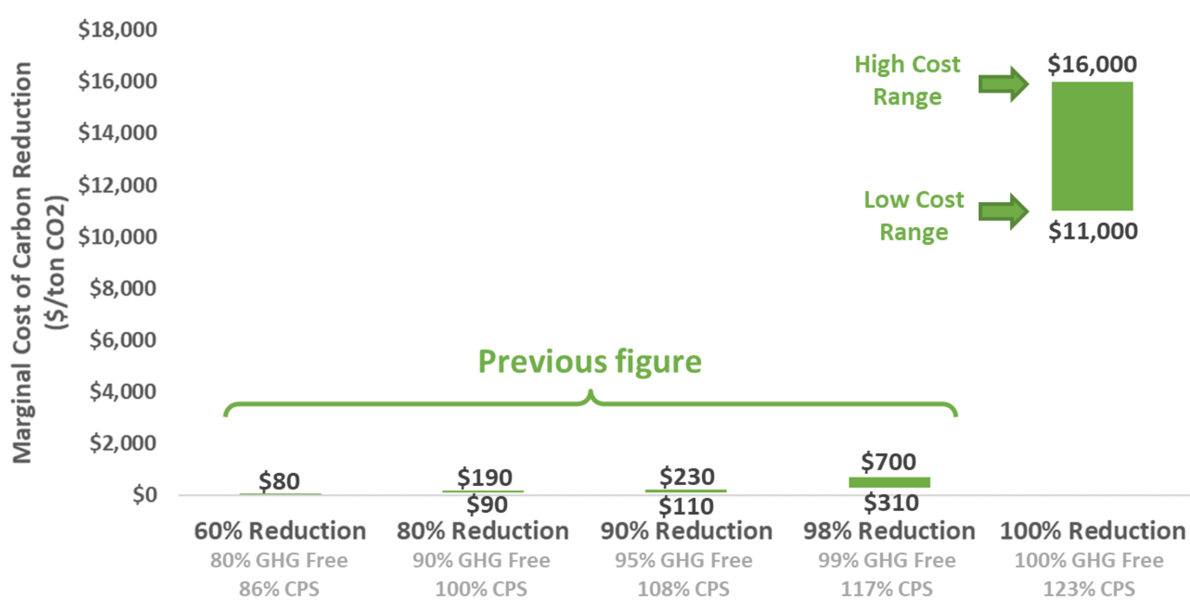


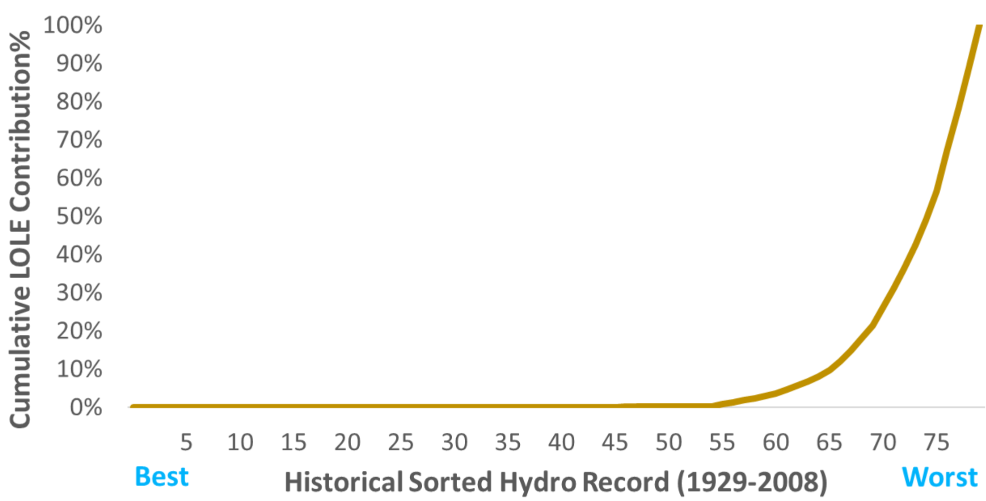
Figure 17: Marginal Cost of GHG Reduction: 60% Reduction to 100% Reduction



5.3.3 DRIVERS OF RELIABILITY CHALLENGES

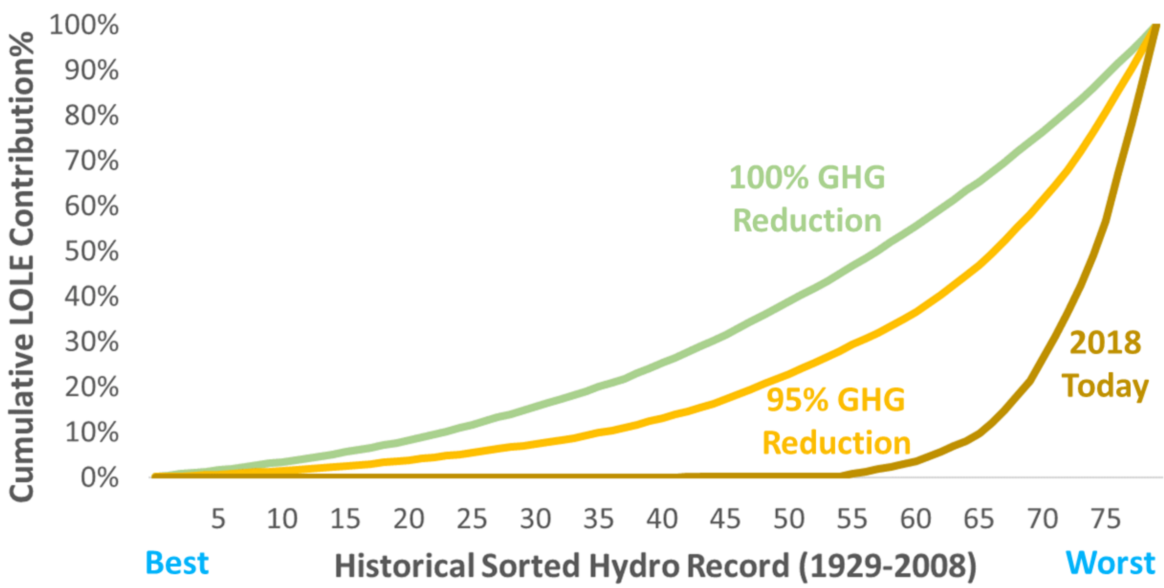
The major drivers of loss of load in the Greater Northwest system include high load events, prolonged low renewable generation events, and drought hydro conditions. In today's system where most generation is dispatchable, prolonged low renewable generation events do not constitute a large cause of loss-of-load events. Rather, the largest cause of loss-of-load events stem from the combination of high load events and drought hydro conditions. This relationship between contribution to LOLE and hydro conditions is highlighted in Figure 18 which shows nearly all loss of load events concentrated in the worst 25% of hydro years.

Figure 18. 2018 System Loss-of-Load Under Various Hydro Conditions



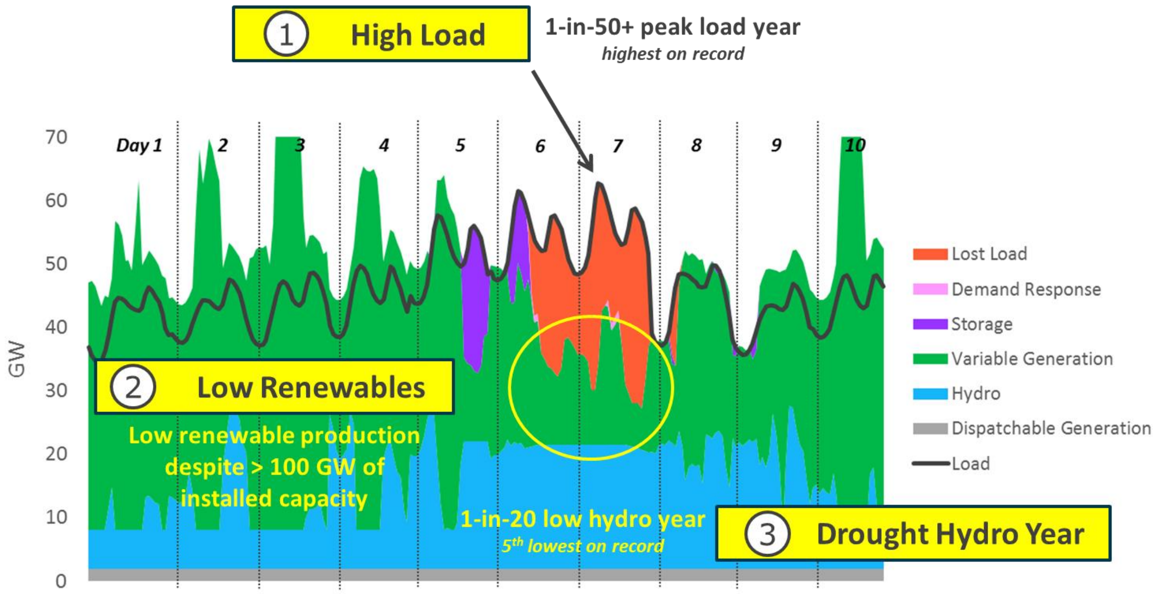
At very high renewable penetrations, in contrast, prolonged low renewable generation events usurp drought hydro conditions as the primary driver of reliability challenges. Figure 19 shows that at high levels of GHG reductions, loss-of-load is much less concentrated in the worst hydro years as prolonged low renewable generation events can create loss-of-load conditions in any year.

Figure 19. 2018 System GHG Reduction Scenarios Loss-of-Load Under Various Hydro Conditions



In practice, these prolonged periods of low renewable output manifest via multi-day winter storms that inhibit solar production over very wide geographic areas or large-scale high-pressure systems associated with low wind output. Figure 20 presents an example of multiday loss-of-load in a sample week in 2050 in the 100% GHG Reduction scenario. In a system without available dispatchable resources to call during such events, low solar radiation and wind speed can often give rise to severe loss-of-load events, especially when renewable generation may be insufficient to serve all load and storage quickly depletes. As shown in the example, over 100 GW of total installed renewables can only produce less than 10 GW of output in some hours. It is the confluence of events like these that drive the need for renewable overbuild to mitigate these events, which in turn leads to the very high costs associated with ultra-deep decarbonization.

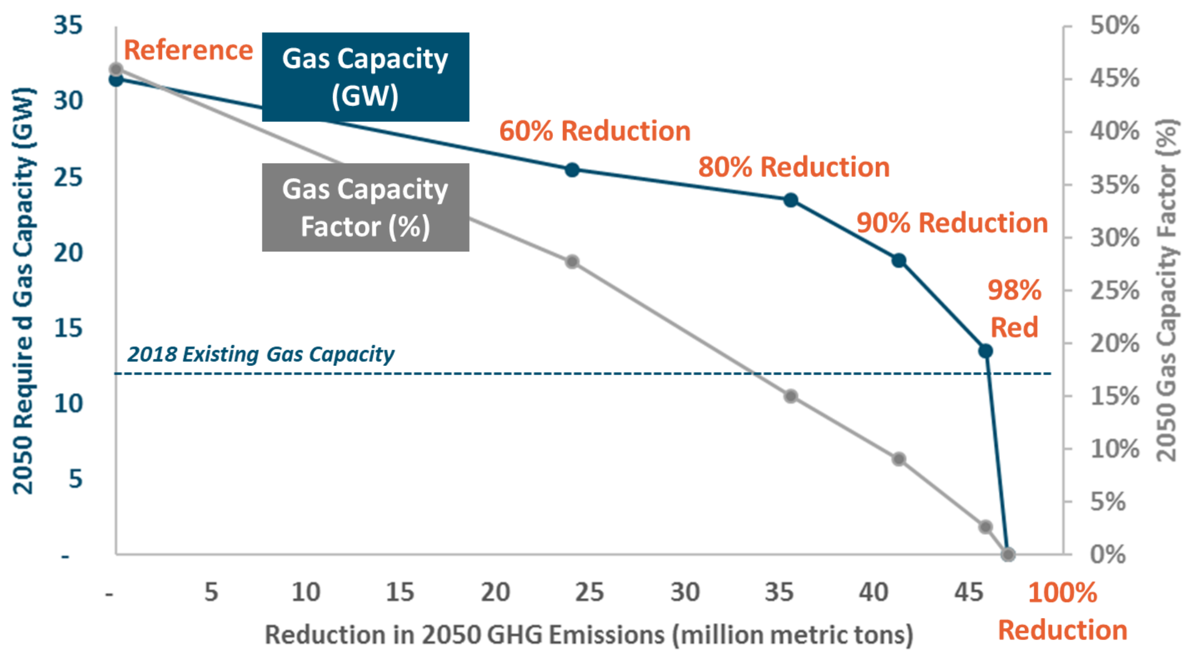
Figure 20: Loss-of-load Example in a Sample Week



5.3.4 ROLE OF NATURAL GAS GENERATION CAPACITY

The significant buildout of renewables and storage to meet decarbonization targets contributes to the resource adequacy needs of the system and reduces the need for thermal generation. However, despite the very large quantities of storage and renewables in all the high GHG reduction scenarios, a significant amount of natural gas capacity is still needed for reliability (except for the 100% GHG Reduction scenario where natural gas combustion is prohibited). Even though the system retains significant quantities of gas generation capacity for reliability, the capacity factor utilization of the gas fleet decreases substantially at higher levels of GHG reductions as illustrated in Figure 21. It is noteworthy that all scenarios except 100% GHG reductions require more gas capacity than exists in 2018, assuming all coal (11 GW) is retired.

Figure 21: Natural Gas Required Capacity in Different 2050 Scenarios



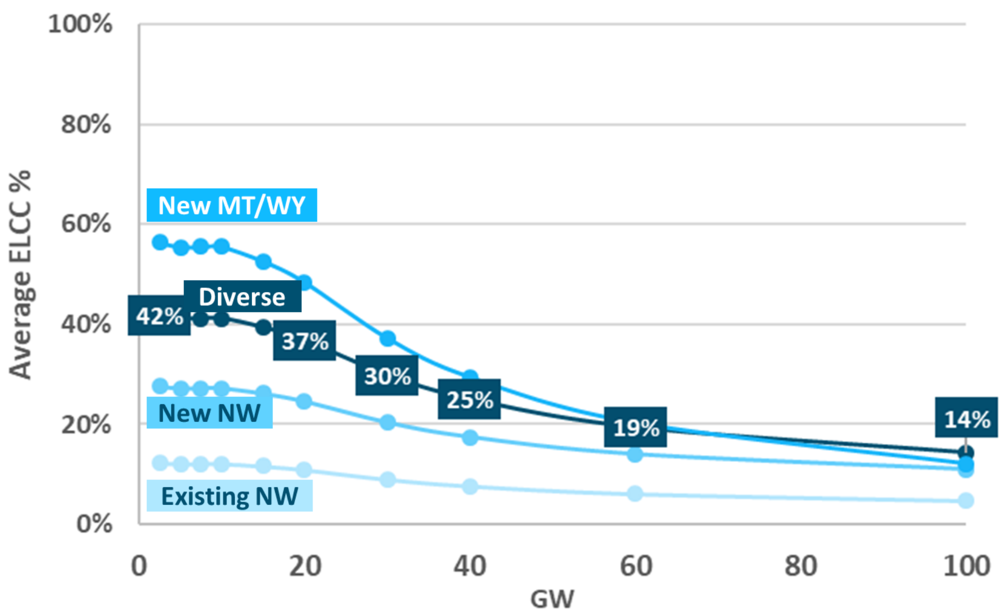
5.3.5 EFFECTIVE LOAD CARRYING CAPABILITY

Effective Load Carrying Capability (ELCC) is a metric used in the electricity industry to quantify the additional load that can be met by an incremental generator while maintaining the same level of system reliability. Equivalently, ELCC is a measure of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, storage, or demand response.

5.3.5.1 Wind ELCC

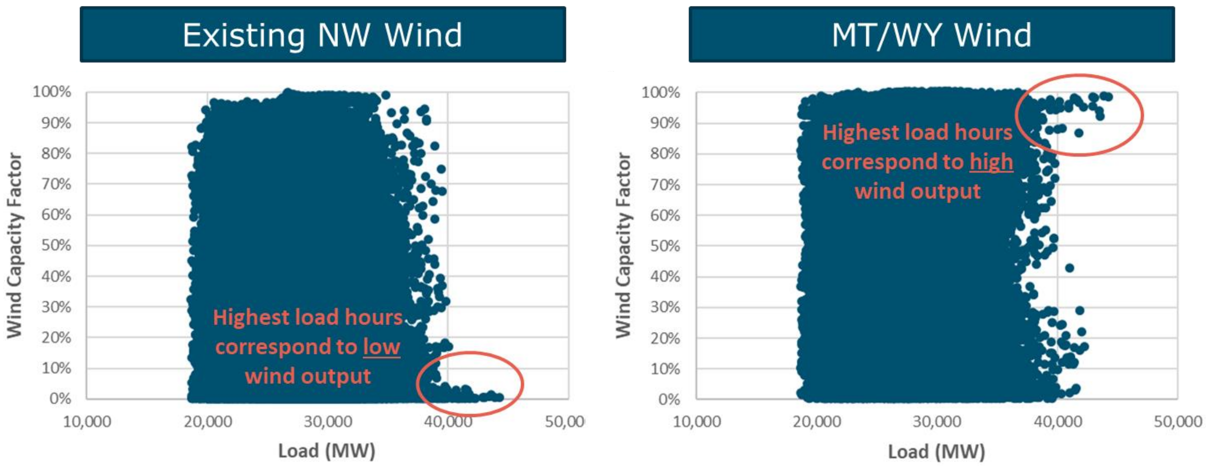
Wind resources in this study are grouped and represented as existing Northwest (Oregon and Washington) wind, new Northwest wind, and new Wyoming and Montana wind. The ELCC curves of each representative wind resource and as well as the combination of all three resources (i.e., “Diverse”) are shown in Figure 22.

Figure 22: Wind ELCC at Various Penetrations



These results are primarily driven by the coincidence of wind production and high load events. Existing wind in the Northwest today, primarily in the Columbia River Gorge, has a strong negative correlation with peak load events that are driven by low pressures and cold temperatures. Conversely, Montana and Wyoming wind does not exhibit this same correlation and many of the highest load hours are positively correlated with high wind output as illustrated in Figure 23.

Figure 23: Load and Wind Correlation (Existing NW Wind and New MT/WY Wind)



Comparing and contrasting the ELCC of different wind resources yields several interesting findings:

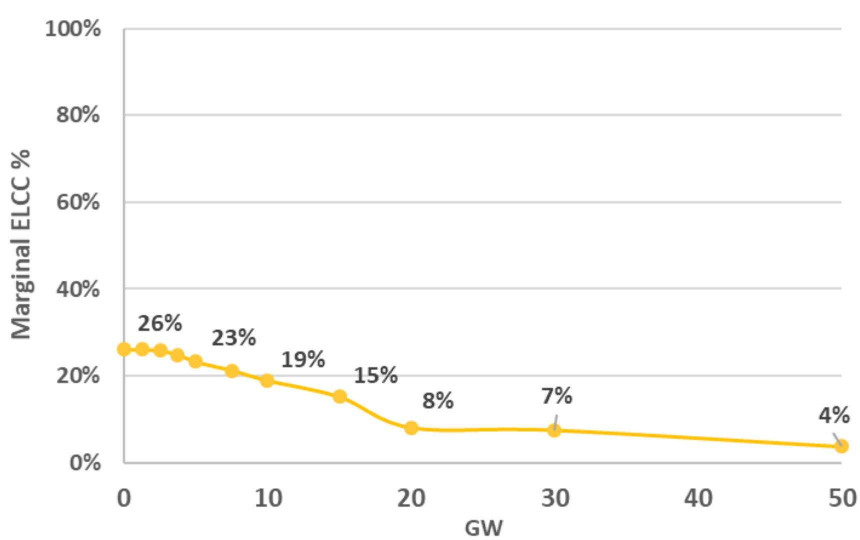
- The wide discrepancy between the "worst" wind resource (existing NW) and the "best" wind resource (new MT/WY) is primarily driven by the correlation of the wind production and peak load events in Washington and Oregon. Existing NW wind is almost entirely located within the Columbia River Gorge which tends to have very low wind output during the high-pressure weather systems associated with the Greater Northwest cold snaps that drive peak load events. Conversely, MY/WY wind is much less affected by this phenomenon due largely to geographic distance, and wind output tends to be highest during the winter months when the Northwest is most likely to experience peak load events.
- All wind resources experience significant diminishing returns at high levels of penetration. While wind may generate significant energy during the system peak, ultimately the net load peak that drives ELCC will shift to an hour with low wind production and reduce the effectiveness with which wind can provide ELCC. Diversity mitigates the rate of decline of ELCC.
- New NW wind has notably higher ELCC values than existing NW wind due to both improvements in turbine technology but also through larger geographic diversity of wind development within the Northwest region but outside of the Columbia River Gorge.

+ Diverse wind (combination of all three wind groups) yields the highest ELCC values at high penetrations. This is because even the best wind resources experience periods of low production and additional geographic diversity can help to mitigate these events and improve ELCC.

5.3.5.2 Solar ELCC

Solar resources in this study are grouped and represented as existing solar and new solar which is built across the geographically diverse area of Idaho, Washington, Oregon, and Utah. In general, solar provides lower capacity value than wind due to the negative correlation between winter peak load events and solar generation which tends to be highest in the summer. Like wind, solar ELCC also diminishes as more capacity is added. Figure 24 shows this information for the ELCC of new solar in the Greater Northwest region.

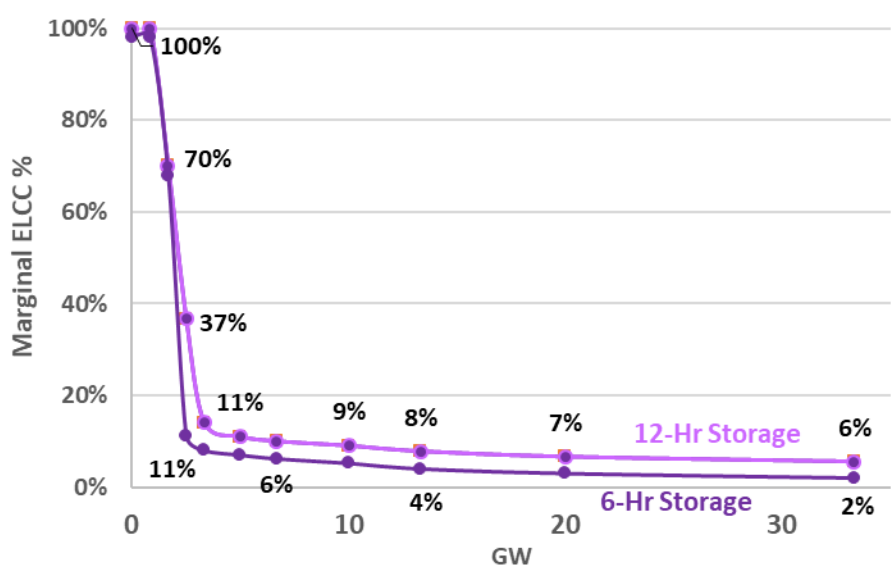
Figure 24: Solar ELCC at Various Penetrations



5.3.5.3 Storage ELCC

At small initial penetrations, energy storage can provide nearly 100% ELCC as a substitute for peaking generation that only needs to discharge for a small number of hours. However, at higher penetrations, the required duration for storage to continue to provide ELCC to the system diminishes significantly. This is primarily due to the fact that storage does not generate energy and ELCC is a measure of perfect capacity which can reliably generate energy. This result holds true for both shorter duration (6-hr) and longer duration (12-hr) storage which represents the upper end of duration for commercially available storage technologies. Figure 25 highlights the steep diminishing returns of storage toward ELCC.

Figure 25: Storage ELCC at Various Penetrations



This steeply-declining ELCC value for diurnal energy storage is particularly acute in the Pacific Northwest. This has to do with the fact that there is a significant quantity of energy storage implicit with the 35-GW hydro system in the region. The Federal Columbia River Power System is already optimized over multiple days, weeks and months within the bounds of non-power constraints such as flood control, navigation and fish & wildlife protections. Significant quantities of energy are stored in hydroelectric reservoirs today and dispatched when needed to meet peak loads. Thus, additional energy storage has less value for providing resource adequacy in the Northwest than it does in regions that have little or no energy storage today.

5.3.5.4 Demand Response ELCC

Demand response (DR) represents a resource where the system operator can call on certain customers during times of system stress to reduce their load and prevent system-wide loss-of-load events. However, DR programs have limitations on how often they can be called and how long participants respond when they are called. DR in this study is represented as having a maximum of 10 calls per year with each call lasting a maximum of 4 hours. This is a relatively standard format for DR programs, although practice varies widely across the country. This study also assumes perfect foresight of the system operator such that a DR call is never "wasted" when it wasn't actually needed for system reliability.

Figure 26: Cumulative and Marginal ELCC of DR

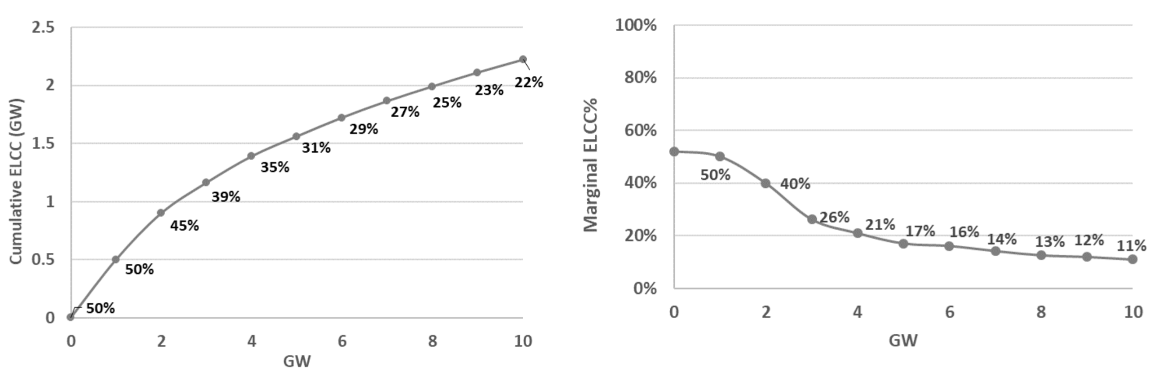


Figure 26 shows the cumulative and marginal ELCC of DR at increasing levels of penetration. Due to the limitations on the number of calls and duration of each call, DR has an initial ELCC of approximately 50%. Similar to energy storage, conventional 4-hour DR has less value in the Pacific Northwest than in other regions due to the flexibility inherent in the hydro system. Also, the capacity value of DR declines as the need for duration becomes longer and longer.

5.3.5.5 ELCC Portfolio Effects

Grouping different types of renewable resources, energy storage, and DR together often creates synergies between the different resources such that the combined ELCC of the entire portfolio is more than the sum of any resource's individual contribution. For example, solar generation can provide the energy that storage needs to be effective and storage can provide the on-demand dispatchability that solar needs to be effective. This resulting increase in ELCC is referred to as the diversity benefit.

Figure 27 shows the average ELCC for each resource type both on a stand-alone basis and also with a diversity allocation that accrues to each resource when they are added to a portfolio together.

Figure 27: ELCC of Solar, Wind, and Storage with Diversity Benefits

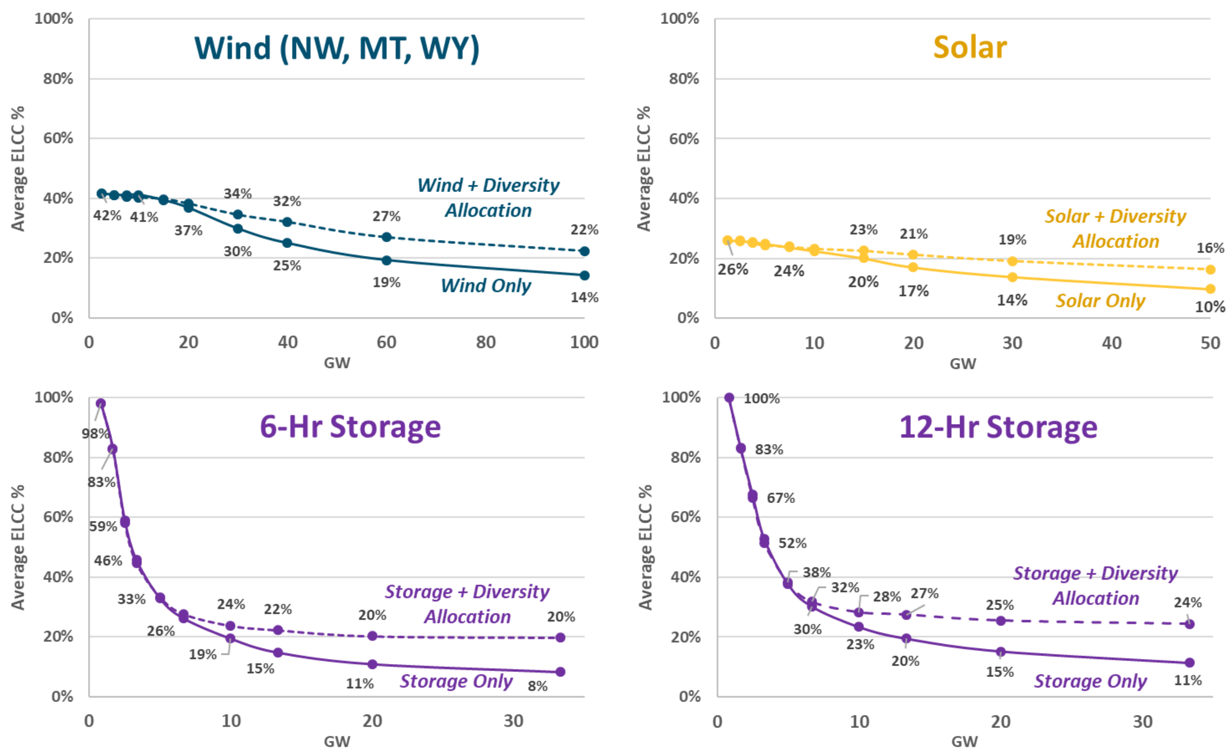
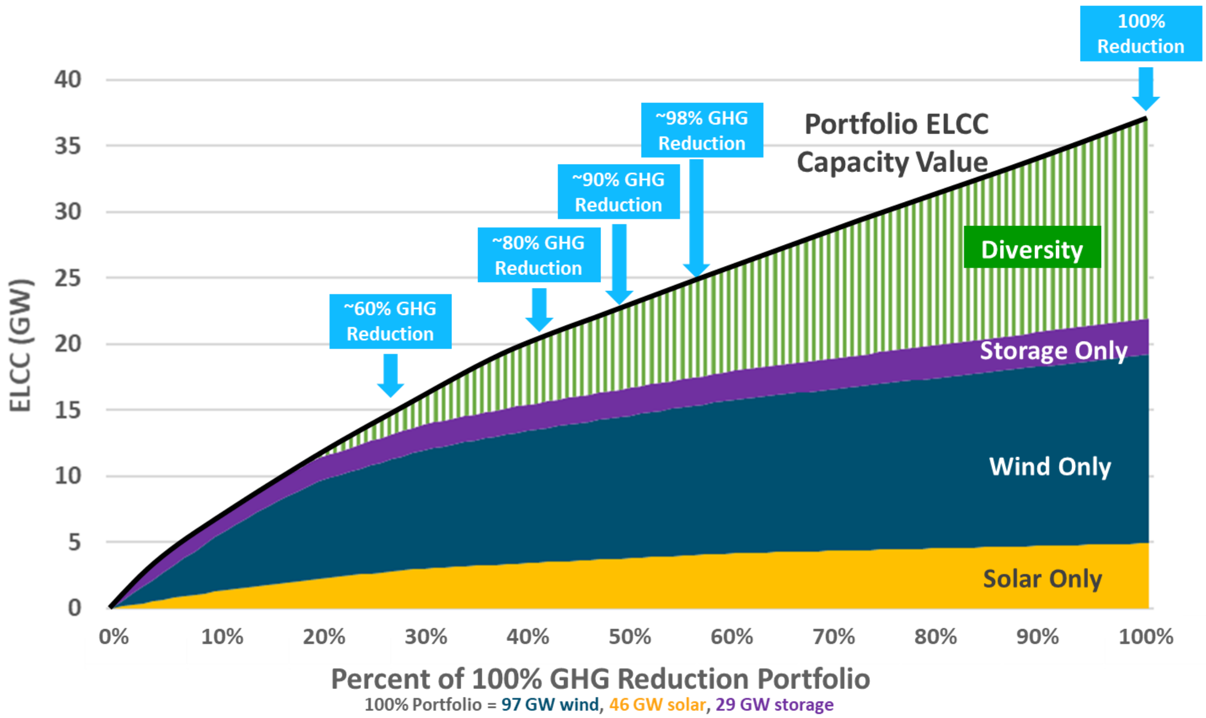


Figure 28 presents the cumulative portfolio ELCC of wind, solar, and storage up to the penetrations required to reliably serve load in a 100% GHG Reduction scenario. At high penetrations of renewables and storage, most of the ELCC is realized through diversity, although it still requires approximately 170 GW of nameplate renewable and storage resources to provide an equivalent of 37 GW of firm ELCC capacity that is required to retire all fossil generation. However, unlike adding these resources on a standalone basis, a combined portfolio continues to provide incremental ELCC value of approximately 20% of nameplate even at very high levels of penetration.

Figure 28: ELCC of Different Portfolios in 2050



5.3.6 SENSITIVITY ANALYSIS

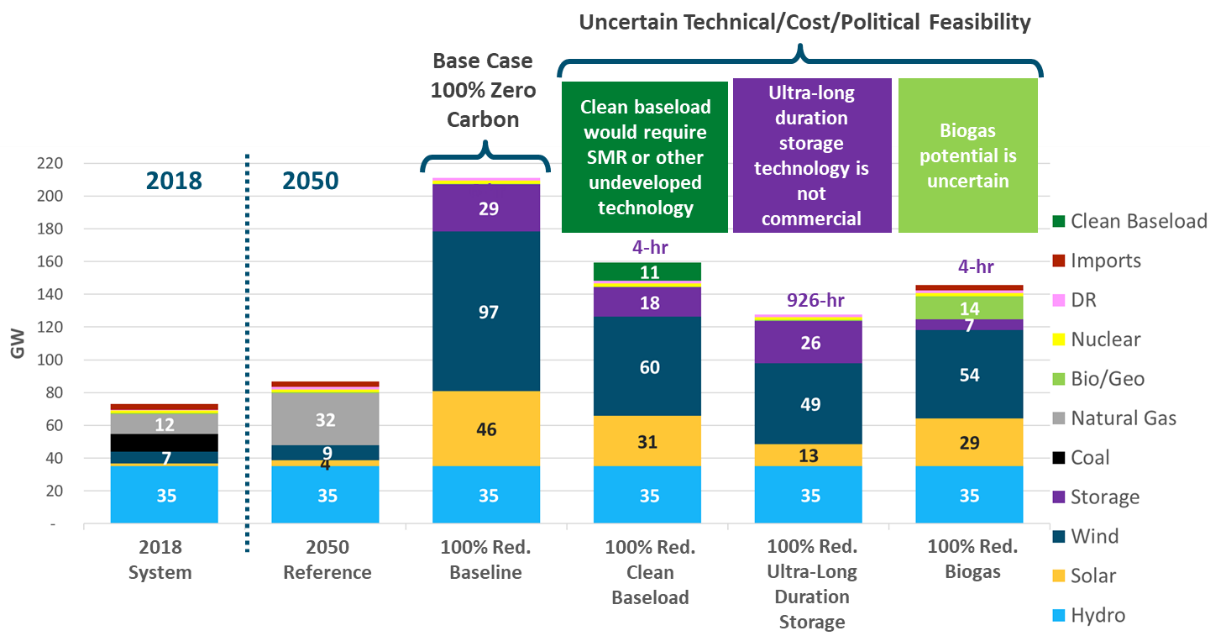
This study also explores the potential resource adequacy needs of a 100% GHG free electricity system recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. Specifically, the alternative resources analyzed are: clean baseload, ultra-long duration storage, and biogas which are further described in Table 21.

Table 21: Sensitivity Descriptions

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

All three of these alternative technology options have the potential to greatly reduce the required renewable overbuild of the system as shown in Figure 29. This is achieved because each of these technologies is dispatchable and can generate energy during prolonged periods of low wind and solar production when short-duration energy storage would become depleted.

Figure 29: 2050 100% GHG Reduction Sensitivity Portfolio Results



While these alternative technologies clearly highlight the benefits, there are significant technical feasibility, economic, and political feasibility hurdles that stand in the way of large-scale adoption of these alternatives at the present time. In particular, clean baseload would require some technology such as small modular nuclear reactors which is not yet commercially available. Geothermal could provide a clean baseload resources but is limited in technical potential across the region. Fossil generation with carbon capture and sequestration (CCS) is another potential candidate, but the technology is not widely deployed, the cost at scale is uncertain, and current CCS technologies do not achieve a 100% capture rate. Ultra-long duration storage (926 hours) is not commercially available at reasonable cost assuming the technology is limited to battery storage or other commercially proven technologies. Biogas potential is also uncertain and there will be competition from other sectors in the economy to utilize what may be available. A detailed table of installed nameplate capacity for each portfolio is summarized in Appendix A.2.

Table 22 shows key cost metrics for the 100% GHG Reduction sensitivity scenarios. For consistency with the base case scenarios, all costs are relative to the 2050 *Reference* scenario.

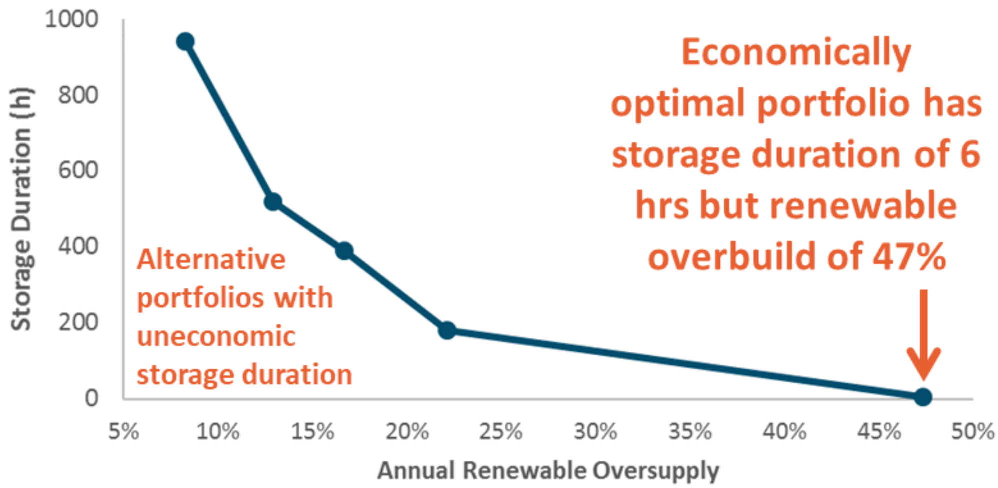
Table 22. 100% GHG Reduction Sensitivity Key Cost Metrics

Metric	100% GHG Reduction Baseline	100% GHG Reduction Clean Baseload	100% GHG Reduction Ultra-Long Duration Storage	100% GHG Reduction Biogas
Carbon Emissions (MMT CO_2 / year)	0	0	0	0
Annual Incremental Cost ($B)	$12- $28	$11-$22	$370-$920	$2 - $10
Annual Incremental Cost ($/MWh)	$39-$91	$36-$70	$1,200-$3,000	$5 - $32

Analyzing the portfolio and key cost metrics for each of the 100% GHG Reduction sensitivity cases yields several notable observations.

+ In the Clean Baseload sensitivity, the availability of a carbon-free source of baseload generation dramatically reduces the amount of investment in variable renewables and storage needed to maintain reliability: adding 11 GW of clean baseload resource displaces a portfolio of 15 GW solar, 37 GW wind, and 11 GW of storage. In the context of a highly renewable grid, baseload resources that produce energy round-the-clock—including during periods when variable resources are not available—provide significant reliability value to the system. However, at an assumed price of $91/MWh, the scenario still results in considerable additional costs to ratepayers of between $11-22 billion per year relative to the Reference Scenario.
+ The Ultra-Long Duration Storage sensitivity illustrates a stark direct relationship between the magnitude of renewable overbuild and the storage capability of the system: limiting renewable curtailment while simultaneously serving load with zero carbon generation reliability requires energy storage capability of a duration far beyond today's commercial applications (this relationship is further explored in Figure 30 below). Without significant breakthrough in storage technologies, such a portfolio is beyond both technical and economic limits of feasibility.

Figure 30: Tradeoff between Renewable Curtailment and Storage Duration



- The Biogas sensitivity demonstrates the relatively high value of the potential option to combust renewable natural gas in existing gas infrastructure. In this scenario, 14 GW of existing and new gas generation capacity is retained by 2050, serving as a reliability backstop for the system during periods of prolonged low renewable output by burning renewable gas. This sensitivity offers the lowest apparent cost pathway to a zero-carbon electric system because biogas generation does not require significant additional capital investments. While the biogas fuel is assumed to be quite expensive on a unit cost basis, the system doesn't require very much fuel, so the total cost remains reasonable. Moreover, biogas generation uses the same natural gas delivery and generation infrastructure as the Reference Case, significantly reducing the capital investments required. However, the availability of sufficient biomass feedstock to meet the full needs of the electric sector remains an uncertainty. Moreover, there may be competing uses for biogas in the building and industrial sectors that inhibit the viability of this approach.

6 Discussion & Implications

6.1 Land Use Implications of High Renewable Scenarios

Renewables such as wind and solar generation require much greater land area to generate equivalent energy compared to generation sources such as natural gas and nuclear. In the deep decarbonization scenarios, significant amount of land area is required for renewable development. In the 100% GHG Reduction Scenario, estimates of total land use vary from 3 million acres to 14 million acres which is equivalent to 20 to 100 times the land area of Portland and Seattle combined. This is almost three times the land use required under the 80% GHG Reduction scenario.

Table 23. Renewable Land Use in 2050

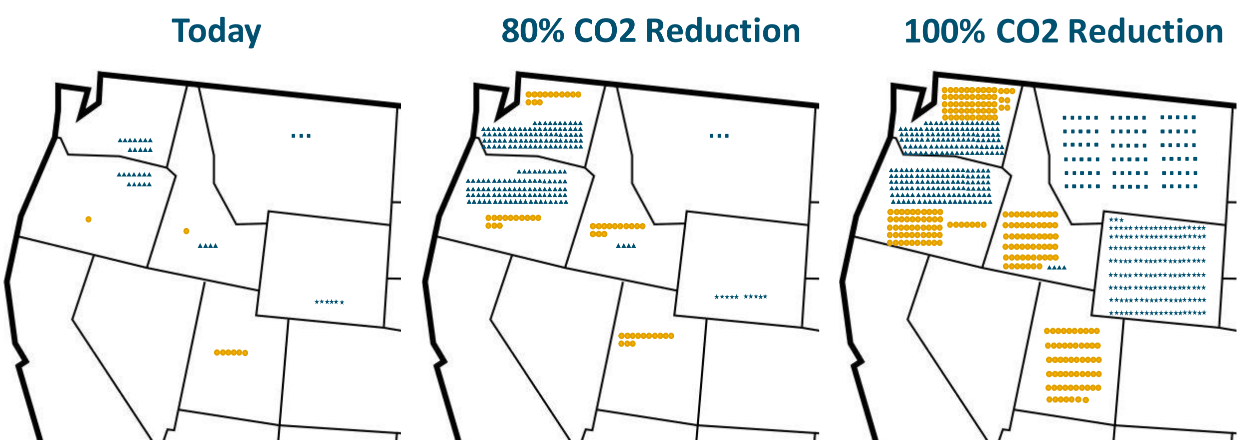
2050 Scenario	Units	Solar Total Land Use	Wind – Direct Land[19] Use	Wind – Total Land[20] Use
80% GHG Reduction	Thousand acres	84	94	1,135 – 5,337
100% GHG Reduction	Thousand acres	361	241	2,913 – 13,701

Even though such vast expanses of land are available, achieving very high levels of decarbonization would require extensive land usage for such large renewable development. Additionally, significant quantities of land would be required to site the necessary transmission to deliver the renewable energy.

[19] Direct land use is defined as disturbed land due to physical infrastructure development and includes wind turbine pads, access roads, substations and other infrastructure
[20] Total land use is defined as the project footprint as a whole and is the more commonly cited land-use metric associated with wind plants. They vary with project and hence as presented as a range
Both direct and total land use for wind is sourced from NREL's technical report: **https://www.nrel.gov/docs/fy09osti/45834.pdf**
Land use for solar is sourced from NREL's technical report: **https://www.nrel.gov/docs/fy13osti/56290.pdf**

Figure 31 highlights the scale of renewable development that would be required to achieve 100% GHG reductions via only wind, solar, and storage. Each dot in the map represents a 200 MW wind or solar farm. Note that sites are not to scale or indicative of site location.

Figure 31: Map of Renewable Land Use Today and in 80% and 100% GHG Reduction Scenario. Each dot represents one 200 MW power plant (blue = wind, yellow = solar)



6.2 Reliability Standards

Determining the reliability standard to which each electricity system plans its resource adequacy is the task of each individual Balancing Authority as there is no mandatory or voluntary national standard. There are several generally accepted standards used in resource adequacy across North America, with the most common being the "1-in-10" standard. There is, however, a range of significant interpretations for this metric. Some interpret it as one loss-of-load ***day*** every ten years. Some interpret it as one loss-of-load ***event*** every ten years. And some interpret it as one loss-of-load ***hour*** every ten years. The translation of these interpretations into measurable reliability metrics further compounds inconsistency across jurisdictions. However, the ultimate interpretation of most jurisdictions ultimately boils down to the use of one of four reliability metrics:

+ **Annual Loss of Load Probability (aLOLP)**
    - The probability in a year that load + reserves exceed generation at any time
+ **Loss of Load Frequency (LOLF)**
    - The total number of events in a year where load + reserves exceed generation
+ **Loss of Load Expectation (LOLE)**
    - The total number of hours in a year where load + reserves exceed generation
+ **Expected Unserved Energy (EUE)**
    - The total quantity of unserved energy in a year when load + reserves exceed generation

Each of these metrics provides unique insight into the reliability of the electric system and provides information that cannot be ascertained by simply using the other metrics. At the same time, each of the metrics is blind to many of the factors that are ascertained through the other metrics.

The NWPCC sets reliability standards for the Pacific Northwest to have an annual loss of load probability (aLOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, this metric does not provide any information on the number of events, duration of events, or magnitude of events that occur during years that experience loss of load. While this metric has generally served the region well when considering that the biggest reliability drive (hydro) was on an annual cycle, this metric becomes increasingly precarious when measuring a system that is more and more dependent upon renewables.

This study uses loss of load expectation (LOLE), because it is a more common metric that is used by utilities and jurisdictions across the country. Unlike aLOLP, LOLE does yield insight on the duration of events which can help to provide greater detail whether or not a system is adequately reliable.

However, LOLE does not capture the magnitude of events when they occur and thus misses a potentially large measure of reliability as compared to a metric such as EUE. EUE captures the total quantity of energy that is expected to go unserved each year. While this metric is not perfect, it is likely the most robust metric in terms of measuring the true reliability of an electric system, particularly in a system that is energy-constrained. Despite these attributes, EUE is not commonly used as a reliability metric in the industry today.

RECAP calculates all the aforementioned reliability metrics and can be used to compare and contrast their performance across different portfolios. Table 24 shows the four reliability metrics across different 2050 decarbonization scenarios.

Table 24: Reliability Statistics Across 2050 Decarbonization Portfolios

Reliability Metric	Units	2050 Reference	80% GHG Red.	100% GHG Red.
aLOLP	%/yr	3.6%	8.1%	10.5%
LOLF	#/yr	0.16	0.29	0.13
LOLE	hrs/yr	2.4	2.4	2.4
EUE	GWh/yr	1.0	2.0	19.0

Because the portfolios were calibrated to meet a 2.4 hrs./yr. LOLE standard, all portfolios yield exactly this result. However, this does not mean that all portfolios are equally reliable. Notably, the 100% GHG Reduction scenario has nearly 20 times the quantity of expected unserved energy (EUE) as compared to the reference scenario. The value of unserved energy varies widely depending on the customer type and outage duration; studies typically put the value between $5,000 and $50,000/MWh. This means that the economic cost of unserved energy in the 2050 Reference Scenario is between $5 million and $50 million per year. However, in the 100% GHG Reduction Scenario, which meets the same target for LOLE, the value of unserved energy could be nearly $1 billion annually.

This gives an important insight to some of the qualities of a system that is highly dependent upon dispatch-limited resources. For a traditional system that is composed mainly of dispatchable generation (coal, natural gas, nuclear, etc.), the primary reliability challenge is whether there is enough capacity to serve peak load. Even if the peak is slightly higher than expected or power plants experience forced outages and are unavailable to serve load, the difference between available generation and total load should be relatively small. Conversely, for a system that is highly dependent upon variable generation and other dispatch limited generation, there is a much greater chance that the sum of total generation could be *significantly* lower than total load. This phenomenon was highlighted in Section 5.3.3. The reliability statistics above confirm this intuition by highlighting how aLOLP, LOLF, and LOLE are each uniquely inadequate to fully capture the reliability of a system that is highly dependent upon variable renewable energy. For a system that is heavily dependent on variable generation, EUE may be a more useful reliability metric than the conventional LOLE metrics.

6.3 Benefits of Reserve Sharing

One of the simplifying assumptions made in this study to examine reliability across the Greater Northwest is the existence of a fully coordinated planning and operating regime within the region. In reality, however, responsibility for maintaining reliability within the system is distributed among individual utilities and balancing authorities with oversight from state utility commissions. The current distributed approach to reliability planning has two interrelated shortcomings:

1) Because the region's utilities each plan to meet their own needs, they may not rigorously account for the natural load and resource diversity that exists across the footprint. If each utility built physical resources to meet its own need, the quantity of resources in the region would greatly exceed what would be needed to meet industry standards for loss-of-load.

2) As an informal mechanism for taking advantage of the load and resource diversity that exists in the region, many utilities rely on front-office transactions (FOTs) or market purchases instead of physical resources, as was discussed in Section 2. This helps to reduce costs to ratepayers of maintaining reliability by avoiding the construction of capacity resources. However, as the region transitions from a period of capacity surplus to one of capacity deficit, and because there is no uniform standard for capacity accreditation, there is a risk that overreliance on FOTs could lead to underinvestment in resources needed to meet reliability standards.

Formal regional planning reserve sharing could offer multiple benefits in the Greater Northwest by taking advantage of load and resource diversity that exists across the region. A system in which each utility builds physical assets to meet its own needs could result in overcapacity, because not every system peaks at the same time. Planning to meet regional coincident peak loads requires less capacity than meeting each individual utility's peak loads. Further, surplus resources in one area could be utilized to meet a deficit in a neighboring area. Larger systems require lower reserve margins because they are less vulnerable to individual, large contingencies. A regional entity could adopt more sophisticated practices and computer models than individual utilities and manage capacity obligation requirements independent from the utilities.

Table 25 provides a high-level estimate of the benefits that could accrue if the Northwest employed a formal planning reserve sharing system. The benefits are divided into (1) benefits due to switching from individual utility peak to regional peak and (2) benefits due to lower target PRM.

A regional planning reserve sharing system could be established in the Greater Northwest. A regional entity could be created as a voluntary organization of utilities and states/provinces. The regional entity would perform loss-of-load studies for the region and calculate the regional PRM and develop accurate methods for estimating capacity credit of hydro and renewables. The entity would create a forward capacity procurement obligation based on studies and allocate responsibility based on their share of the regional requirement.

Table 25. Possible Benefits from a Regional Planning Reserve Sharing System in the Northwest[21]

Capacity Requirement	BPA + Area	NWPP (US)
Individual Utility Peak + 15% PRM (MW)	33,574	46,398
Regional Peak + 15% PRM (MW)	32,833	42,896
Reduction (MW)	741	3,502
Savings ($MM/year)	***$89***	***$420***
	BPA + Area	**NWPP (US)**
Regional Peak + 12% PRM (MW)	31,977	41,777
Reduction (MW)	1,597	4,621
Savings ($MM/year)	***$192***	***$555***

Rules similar to other markets could be made for standardized capacity accreditation of individual resources such as dispatchable generation, hydro generation, variable generation, demand response and energy storage. Tradable capacity products could be defined based on the accredited capacity.

A regional entity could be formed by voluntary association in the Greater Northwest. It could be governed by independent or stakeholder board. Alternatively, new functionality could be added to the existing reserve sharing groups such as Northwest Power Pool (NWPP) and Southwest Reserve Sharing Group, which expand their operating reserve sharing to include planning reserve sharing. It would not require setting up a regional system operator immediately and PRM sharing could be folded into a regional system operator if and when it forms.

[21] Calculated regional and non-coincident peaks using WECC hourly load data averaged over 2006-2012. Savings value estimated using capacity cost of $120/kW-yr. Assumes no transmission constraints within the region. Ignores savings already being achieved through bilateral contracts

7 Conclusions

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

7.1 Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
   - Natural gas generation is the most economic source of firm capacity today;
   - Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
   - Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
   - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.
2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;
   - Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.
3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.
4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;
- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

Appendix A. Assumption Development Documentation

A.1 Baseline Resources

Table 26. NW Baseline Resources Installed Nameplate Capacity (MW) by Year.

Category	Resource Class	2018	2030	2050
Thermal	Natural Gas	12,181	19,850	31,500
	Coal	10,895	8,158	0
	Nuclear	1,150	1,150	1,150
	Total	**24,813**	**29,745**	**33,237**
Firm Renewable	Geothermal	79.6	79.6	79.6
	Biomass	489.2	489.2	489.2
Variable Renewables	Wind	7,079	7,079	9,205
	Solar	1,557	1,557	3,593
Hydro	Hydro	35,221	35,221	35,221
Storage	Storage	0	0	0
DR	Shed Demand Response	600	2,200	5,500
Imports	Imports*	3,400	3,400	3,400

*Imports consist of market purchases and non-summer firm imports. For more details, please refer to Imports section.

A.2 Portfolios of Different Scenarios

Table 27. Portfolios for 2030 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	No Coal
Solar	1.6	1.6
Wind	7.1	7.1
DR	2.2	2.2
Hydro	35.2	35.2
Coal	8.2	-
Natural Gas	19.9	28.0
Nuclear	1.2	1.2
Bio/Geo	0.6	0.6
Storage	-	-
Imports	3.4	3.4

Table 28. Portfolios for 2050 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	60% GHG Reduction	80% GHG Reduction	90% GHG Reduction	98% GHG Reduction	100% GHG Reduction
Solar	3.6	10.6	10.6	10.6	29.2	45.6
Wind	9.2	22.9	38.0	48.2	53.8	97.4
DR	5.5	5.5	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2	35.2	35.2
Coal	-	-	-	-	-	-
Natural Gas	31.5	25.5	23.5	19.5	13.5	-
Nuclear	1.2	1.2	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6	0.6	0.6
Storage	-	2.2 (4-hr)	2.2 (4-hr)	4.4 (4-hr)	6.7 (4-hr)	28.7 (6-hr)
Imports	3.4	3.4	3.4	3.4	3.4	-

Table 29. Zero Carbon Sensitivity Portfolios in 2050– Installed Nameplate Capacity (GW) by Scenario

Resource Class	100% GHG Reduction Renewables	100% GHG Reduction Baseload Tech	100% GHG Reduction Long Duration Storage	100% GHG Reduction Biogas
Solar	45.6	30.7	13.5	29.2
Wind	97.4	60.5	49.2	53.8
DR	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2
Coal	-	-	-	-
Natural Gas	-	-	-	13.5
Nuclear	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6
Storage	28.7 (6-hr)	18.0 (4-hr)	25.9 (926-hr)	6.7 (4-hr)
Clean Baseload	-	11.3	-	-
Imports	-	-	-	-

Appendix B. RECAP Model Documentation

B.1 Background

RECAP is a loss-of-load-probability model developed by E3 to examine the reliability of electricity systems under high penetrations of renewable energy and storage. In this study, RECAP is used to assess reliability using the *loss-of-load expectation* (LOLE) metric. LOLE measures the expected number of hours/yr when load exceeds generation, leading to a loss-of-load event.

LOLE is one of the most commonly used metrics within the industry across North America to measure the resource adequacy of the electricity system. LOLE represents the reliability over many years and does not necessarily imply that a system will experience loss-of-load every single year. For example, if an electricity system is expected to have two 5-hour loss-of-load events over a ten-year period, the system LOLE would be 1.0 hr./yr LOLE (10 hours of lost load over 10 years).

There is no formalized standard for LOLE sufficiency promulgated by the North American Electric Reliability Coordinating Council (NERC), and the issue is state-jurisdictional in most places expect in organized capacity markets. In order to ensure reliability in the electricity system, the Northwest Power and Conservation Council (NWPCC) set reliability standards for the Pacific Northwest. The current reliability standard requires the electricity system to have an annual loss of load probability (annual LOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, in a system with high renewables, LOLE is a more robust reliability metric.

B.2 Model Overview

RECAP calculates LOLE by simulating the electric system with a specific set of generating resources and economic conditions under a wide variety of weather years, renewable generation years, hydro years, and stochastics forced outages of generation and transmission resources, while accounting for the correlation and relationships between these. By simulating the system thousands of times under different combinations of these conditions, RECAP is able to provide a statistically significant estimation of LOLE.

B.2.1 LOAD

E3 modeled hourly load for the northwest under current economic conditions using the weather years 1948-2017 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

- Max and min daily temperature (including one and two-day lag)
- Month (+/- 15 calendar days)
- Day-type (weekday/weekend/holiday)
- Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1948-2017) under current economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (10 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1948-2017 under today's economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This 'base' load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource in Section 0.

Operating reserves of 1,250 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 1,250 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

B.2.2 DISPATCHABLE GENERATION

Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states developed using NWPCC data. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).

B.2.3 TRANSMISSION

RECAP is a zonal model that models the northwest system as one zone without any internal transmission constraints. Imports are assumed to be available as mentioned in Imports Section 4.2.3.

B.2.4 WIND AND SOLAR PROFILES

Hourly wind and solar profiles were simulated at all wind and solar sites across the northwest. Wind speed and solar insolation data was obtained from the NREL Western Wind Toolkit[22] and the NREL Solar Prospector Database[23], respectively and transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2014.

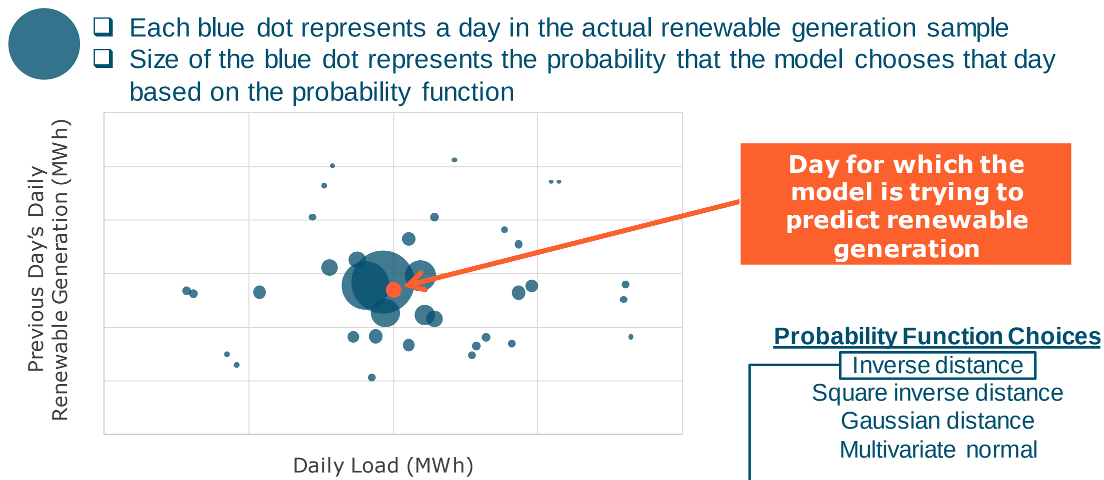
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data i.e., years with available renewable data. For each day in the historical load profile (1948-2017), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

+ Season (+/- 15 days)
    - Probability is 1 inside this range and 0 outside of this range
+ Load
    - For winter peaking systems like the northwest, high load days tend to have low solar output
+ Previous Day's Renewable Generation
    - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 32

[22] https://www.nrel.gov/grid/wind-toolkit.html
[23] https://nsrdb.nrel.gov/

Figure 32: Renewable Profile Selection Process



$$\text{Probability of sample i being selected} = \frac{\frac{1}{Distance_i}}{\sum_{j=1}^{n} \frac{1}{Distance_j}} \qquad \text{Where distance}_i = \text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$$

B.2.5 HYDRO DISPATCH

Dispatchable hydro generation is a hybrid resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. It is important to differentiate this resource from non-dispatchable hydro such as many run-of-river systems that produce energy when there is hydro available, similar to variable wind and solar facilities, especially in a system like northwest which has an abundance of hydro generation.

To determine hydro availability, the model uses a monthly historical record of hydro production data from NWPCC's records from 1929 – 2008. The same data is used to model hydro generation in NWPCC's GENESYS model. For every simulated load year, a hydro year is chosen stochastically from the historical database. The study assumes no significant hydro build in the future and no correlation with temperature, load or renewable generation. Once the hydro year is selected, the monthly hydro budgets denote the amount of energy generated from hydro resources in that month. Since RECAP optimizes the hydro dispatch to minimize loss-of-load, providing only monthly budgets can dispatch hydro extremely flexibly. For example, some of the hydro can be held back to be dispatched during generator outages. Such high flexibility in hydro dispatch is not representative of the current northwest hydro system. Therefore, the monthly budget is further divided into weekly budgets to ensure hydro dispatch is in line with operating practices in the northwest.

In addition to hydro budgets, hydro dispatch has other upstream and downstream hydrological and physical constraints that are modeled in a hydrological model by NWPCC. RECAP does not model the complete hydrological flow but incorporates all the major constraints such as sustained peaking (maximum generation and minimum generation) limits. Sustained peaking maximum generation constraint results in the average hydro dispatch over a fixed duration to be under the limit. Similarly, minimum generation constraints ensure average dispatch over a fixed duration is above the minimum generation sustainable limits. Sustainable limits are provided over 1-hour, 2-hour, 4-hour and 10-hour durations.

The weekly budgets and sustained peaking limits together make the hydro generation within RECAP representative of the actual practices associated with hydro generation in the northwest. Output from RECAP are benchmarked against hydro outputs from NWPCC's GENESYS model.

B.2.6 STORAGE

The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.)

B.2.7 DEMAND RESPONSE

The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

B.2.8 LOSS-OF-LOAD

The final step in the model calculates loss-of-load if there is insufficient available dispatchable generation, renewables, hydro, storage, and demand response to serve load + operating reserves.

Appendix C. Renewable Profile Development

The electricity grid in the Greater Northwest consists of significant quantities of existing wind and solar generation. Significant new renewable build is expected to be built in the future, as explored in this study. Representing the electricity generation from both existing and future renewable (solar and wind) resources is fundamental to the analysis in this study. In this appendix section, the process of developing these renewable profiles for both existing and new renewable resources is elaborated.

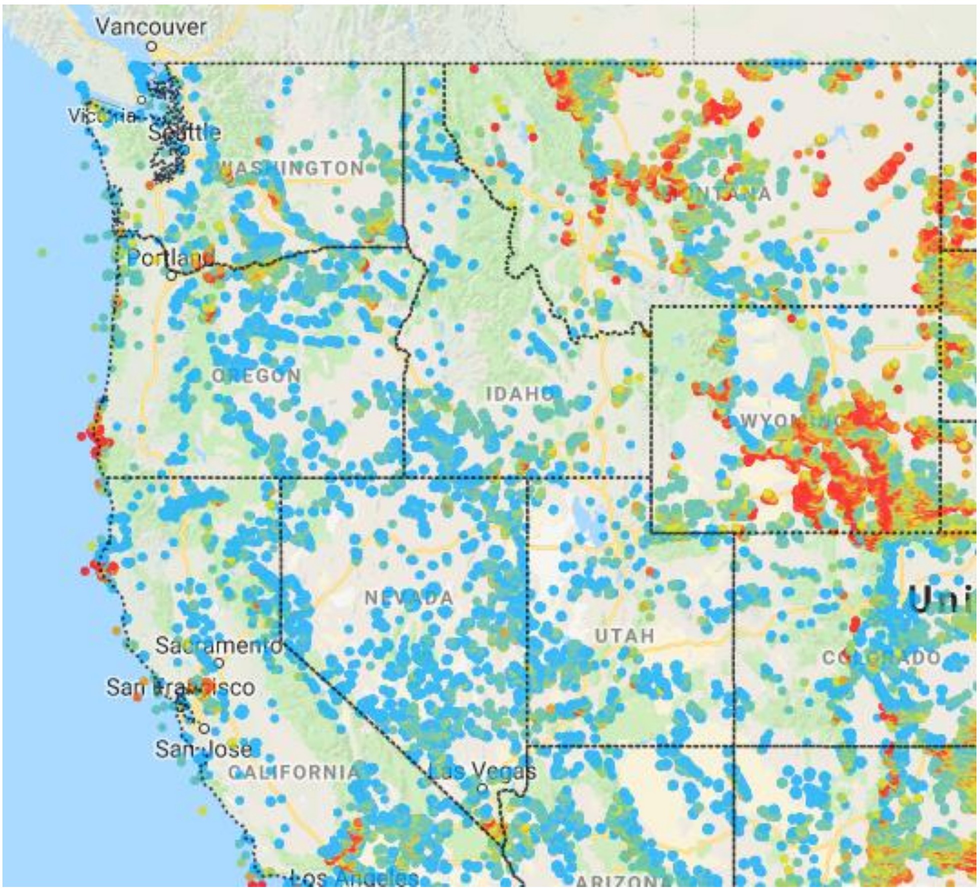
C.1 Wind Profiles

C.1.1 SITE SELECTION

Existing wind site locations (latitude and longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. New candidate wind sites are identified based on the highest average wind speed locations across the Greater Northwest region using data published by NREL[24] (see Figure 33).

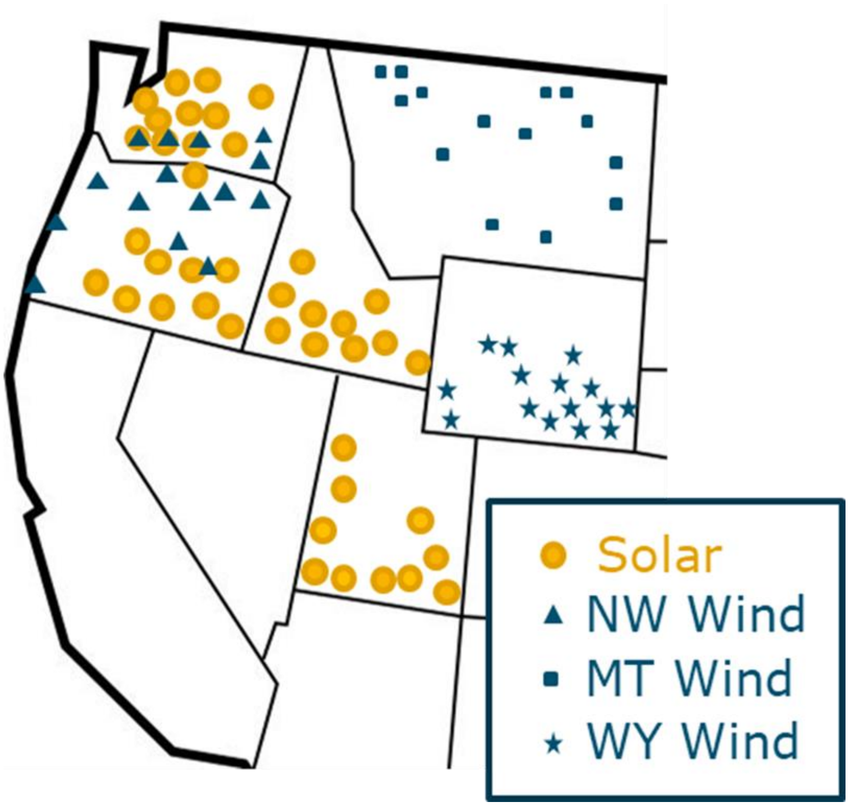
[24] https://maps.nrel.gov/wind-prospector/

Figure 33: Wind speed data in the northwest (Source: NREL)



While striving to place new candidate wind sites in the windiest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in wind generation (e.g. the likelihood that the wind will be blowing in one location even when it is not in another). The new candidate sites used in this study are shown in Figure 34. New sites were aggregated geographically into three single resources that were used in the study modeling: Northwest, Montana, and Wyoming. For example, Montana wind in the study is represented as a single profile with new wind turbines installed proportionally across the various "blue squares" shown in Figure 34.

Figure 34: New Candidate Solar and Wind Sites



C.1.2 PROFILE SIMULATION

NREL's Wind Integration National Dataset (WIND) Toolkit[25] contains historical hourly wind speed data from 2007-2012 for every 2-km x 2-km grid cell in the continental United States. This data is downloaded for each selected site location (both existing and new sites).

[25] https://www.nrel.gov/grid/wind-toolkit.html

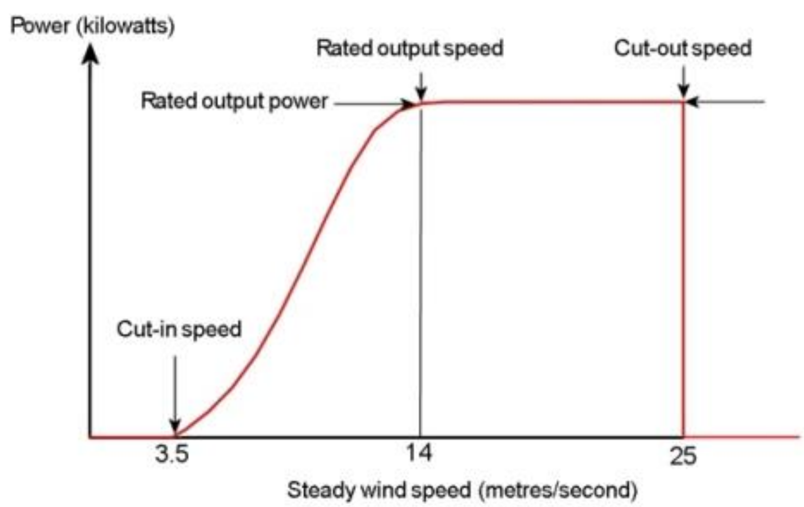
The amount of electricity generated from a wind turbine is a function of wind speed and turbine characteristics, such as the turbine hub height (height above the ground), and the turbine power curve (the mapping of the windspeed to the corresponding power output). Wind speeds increase with height above the ground. Since all NREL WIND data is reported at 100-meters, the wind profile power law is used to scale wind speeds to different heights, depending on the height of the turbine being modeled. This relationship is modeled as:

$$\frac{wind\ speed\ at\ height\ x}{wind\ speed\ at\ heigh\ y} = \left(\frac{height\ x}{height\ y}\right)^{wind\ shear\ coefficient}$$

A wind shear coefficient of 0.143 is used in this study.

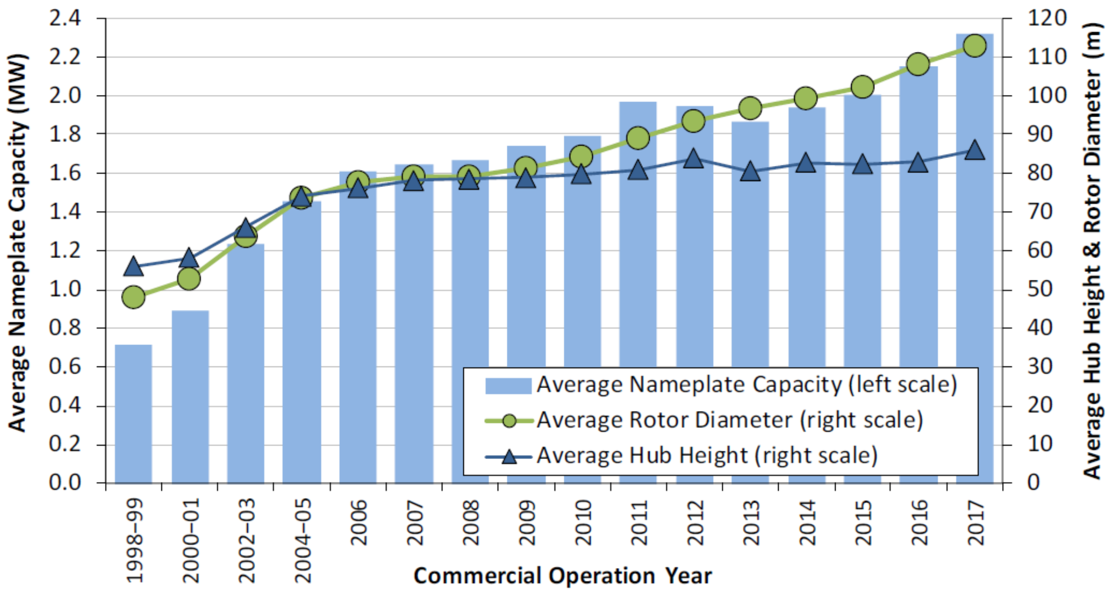
A typical power curve is shown in Figure 35. Turbine power curves define the cut-in speed (minimum windspeed for power generation), rated speed (minimum wind speed to achieve maximum turbine output), cut-out speed (maximum wind speed for power generation) and power generation between the cut-in speed and rated speed.

Figure 35: Typical Wind Turbine Power Curve



With the advancement of wind turbine technology, hub heights have increased over the years (see Figure 36). For existing wind resources, the hub heights are assumed to be the annual average hub height based on the install year. For new turbines, hub height is assumed to be 100 meters.

Figure 36: Average turbine nameplate capacity, rotor diameter and hub height for land-based wind project in the US



For existing turbines, *Nordic 1000 54m 1 MW (MT)* turbine power curve generates wind profiles that benchmark well to the historical generation profiles. The validation process of turbine power curve selection is described in greater detail in Section C.1.3. For new turbines, NREL standard power turbine curves are used to produce future wind profiles.

The wind generation profiles simulation process can be performed for each 2 km X 2 km grid cell and are usually limited to maximum power of 8 - 16 MW due to land constraints and the number of turbines that can fit within that area. However, each wind site that is selected as described in Section C.1.1 (shown in Figure 34), was modeled as 3 GW of nameplate installed wind capacity and encompasses hundreds of adjacent grid cells from the NREL WIND Toolkit database. Note that the actual installed wind capacity varies by scenario in the study and so these 3 GW profiles were scaled up and down to match the installed capacity of each specific scenario. The adjacent grid cells are chosen such that they are the closest in geographical distance from the first wind site location (first grid cell). Representing a single wind site using hundreds of grid cells represents wind production more accurately and irons out any local production spikes that are limited to only a few grid cells in the NREL WIND Toolkit database.

C.1.3 VALIDATION

BPA publishes historical wind production data[26] in its service territory. This data is used to identify a turbine power curve that best benchmarks wind energy production from existing projects as simulated using historical wind speed data. Three turbine power curves were tested – *GE 1.5SLE 77m 1.5mW (MG)*, *Nordic 1000 54m 1Mw (MT)*, and *NREL standard.* Based on annual capacity factors and hourly generation matching, *Nordic 1000 54m 1Mw (MT)* turbine was selected to represent existing wind turbines in the study. These benchmarking results are illustrated in Figure 37 and Figure 38.

[26] https://transmission.bpa.gov/business/operations/wind/

Figure 37: Comparison of Annual Wind Capacity Factors for Benchmarking

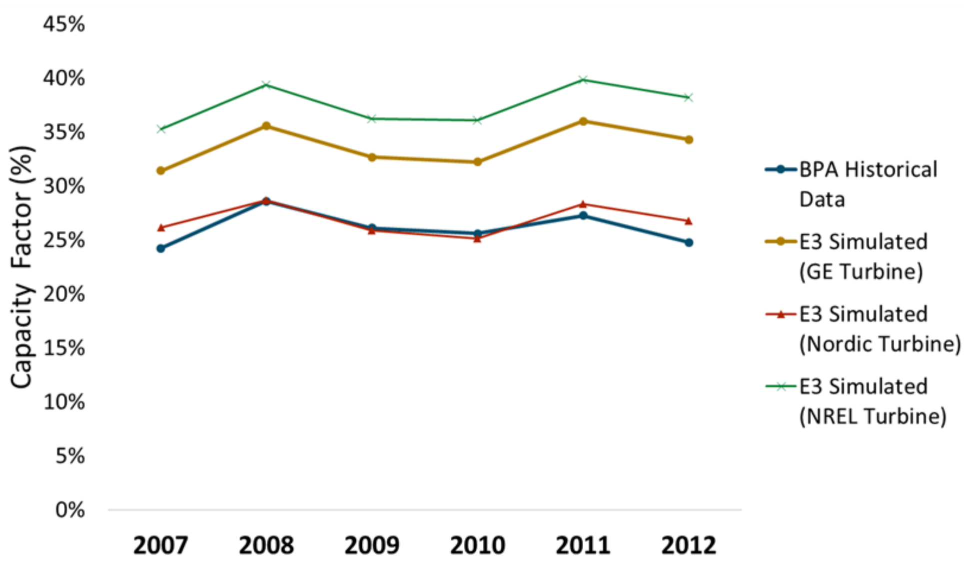
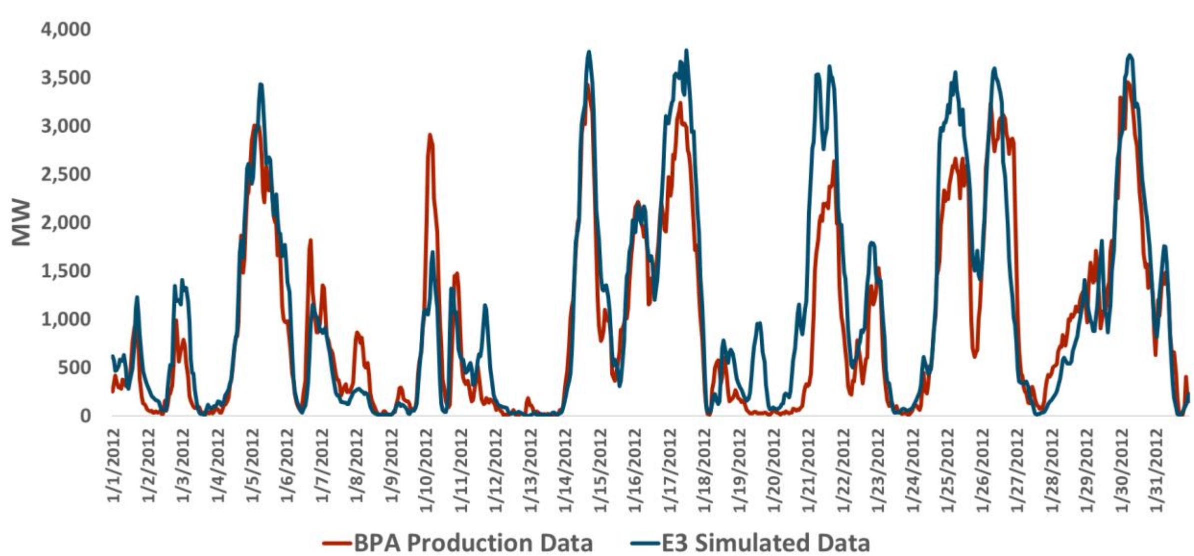


Figure 38: Comparison of Hourly Historical Wind Generation to Simulated Wind Generation for January 2012



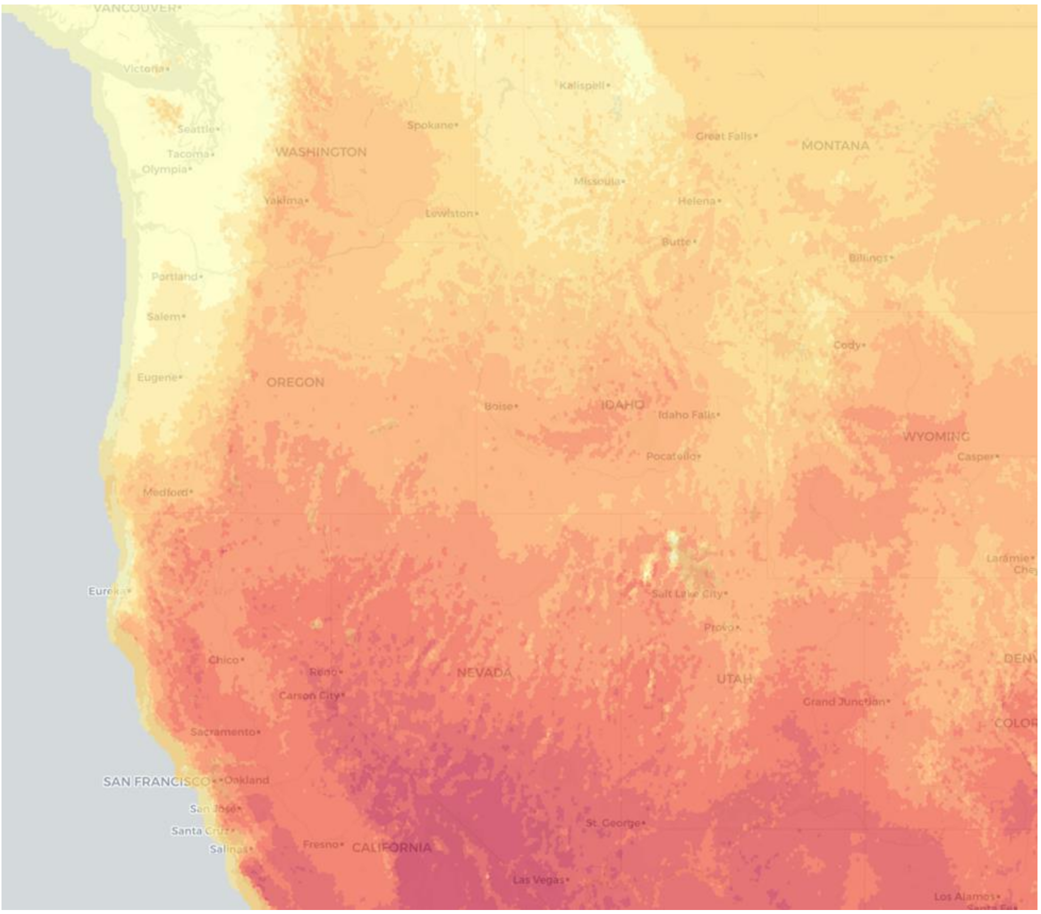
C.2 Solar Profiles

C.2.1 SITE SELECTION

Existing solar site locations (latitude, longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. To build new candidate solar resources in the future, the best solar sites in the region are identified based on the highest insolation from the solar maps published by NREL[27] (see Figure 39). While striving to place new candidate wind sites in the sunniest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in solar generation (e.g. the likelihood that the sun will be shining in one location even when it is not in another). The future solar sites used in this study are shown in Figure 34.

[27] https://maps.nrel.gov/nsrdb-viewer/

Figure 39: Solar insolation data in the northwest (Source: NREL)



C.2.2 PROFILE SIMULATION

NREL Solar Prospector Database [28] includes historical hourly solar insolation data: global horizontal irradiance (GHI), direct normal irradiance (DNI), diffuse horizontal irradiance (DHI), and solar zenith angle from 1998-2014. This data is downloaded for all each selected site location (both existing and new).

[28] https://nsrdb.nrel.gov/

The hourly insolation data is then converted to hourly production profiles using the NREL System Advisor Model (SAM) simulator. Additional inputs used are tilt, inverter loading ratio and tracking type. All panels are assumed to have a tilt equal to the latitude of their location. The study assumes an inverter loading ratio of 1.3 and that all solar systems are assumed to be single-axis tracking. The NREL SAM simulator produces an hourly time series of generation data that is used to represent the electricity generation from the solar sites in this study.

Forty sites are aggregated to represent the solar candidate resource used in this study. These sites are evenly distributed in the four states of Oregon, Washington, Idaho, and Utah as shown in Figure 34.

2020 Electric Integrated Resource Plan

Appendix G – New Resource Table for Transmission

Appendix G

New Resource Table For Transmission

Resource	Note	Resource Location	POR	POD	Start	Stop	Capacity MW	Year Total
Wind		Avista System	AVA.SYS	AVA.SYS	1/1/2022	Indefinite	100.0	
Wind		Montana	AVAT.NWMT	AVA.SYS	1/1/2022	Indefinite	100.0	200.0
Wind		Avista System	AVA.SYS	AVA.SYS	1/1/2023	Indefinite	100.0	100.0
Kettle Falls		Kettle Falls, WA	AVA.SYS	AVA.SYS	1/1/2024	Indefinite	12.0	12.0
Pumped Hydro		Mid-C	MIDC	AVA.SYS	1/1/2026	Indefinite	175.0	
Rathdrum		Rathdrum, WA	AVA.SYS	AVA.SYS	1/1/2026	Indefinite	24.0	199.0
Wind		Off-System	Colstrip/BPA	AVA.SYS	1/1/2027	Indefinite	200.0	
Post Falls		Post Falls	AVA.SYS	AVA.SYS	1/1/2027	Indefinite	8.0	208.0
Hydro		Mid-C	MIDC	AVA.SYS	1/1/2031	Indefinite	75.0	75.0
Hydro		Long Lake	AVA.SYS	AVA.SYS	1/1/2035	Indefinite	68.0	68.0
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2036	Indefinite	25.0	25.0
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2038	Indefinite	25.0	25.0
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2040	Indefinite	25.0	25.0
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2041	Indefinite	25.0	25.0
Wind		TBD	AVA.SYS	AVA.SYS	1/1/2042	Indefinite	100.0	
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2042	Indefinite	25.0	125.0
Wind		TBD	AVA.SYS	AVA.SYS	1/1/2043	Indefinite	100.0	
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2043	Indefinite	100.0	
Solar		TBD	AVA.SYS	AVA.SYS	1/1/2043	Indefinite	5.0	205.0
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2044	Indefinite	75.0	
Wind		TBD	AVA.SYS	AVA.SYS	1/1/2044	Indefinite	50.0	
Solar		TBD	AVA.SYS	AVA.SYS	1/1/2044	Indefinite	50.0	175.0
Wind		TBD	AVA.SYS	AVA.SYS	1/1/2045	Indefinite	100.0	
Storage		TBD	AVA.SYS	AVA.SYS	1/1/2043	Indefinite	100.0	200.0
						Total	1667.0	1667.0

2020 Electric Integrated Resource Plan

Appendix H – New Resource Cost Assumptions

Please see Appendix H spreadsheet

2020 Electric Integrated Resource Plan

Appendix I – Black and Veatch Renewable Resource and Storage Study

BLACK & VEATCH

James Gall
Avista Corporation
1411 E. Mission Ave.
Spokane, WA 99202

Subject: 2019 Avista Integrated Resource Plan Renewable Energy Assumptions

Dear Mr. Gall:

Black & Veatch Corporation (Black & Veatch) is providing this letter to summarize its review of the inputs for renewable energy and energy storage used in the Avista 2019 Integrated Resource Plan (IRP) process.

Background

Avista Corporation (Avista) retained Black & Veatch to provide independent third-party services to review assumptions used for renewable energy and energy storage resources in the 2019 IRP process. Black & Veatch reviewed Avista's supply side resource option inputs workbook, which includes estimates for values such as capital costs, operating costs, performance characteristics, maintenance requirements, emissions, Power Purchase Agreement (PPA) analyses, etc. for both conventional and renewable energy sources.

Specifically, Avista asked Black & Veatch to review the workbook assumptions for upfront capital expenditures (CAPEX), operating & maintenance (O&M) costs, performance, and technology improvement curves for solar, wind, and energy storage resource categories. The purpose of the review was for Black & Veatch to opine on the reasonableness and suggest potential changes if necessary.

To assist with the analysis, Black & Veatch used internal knowledge from projects with which it is aware in the Northwest, as well as publicly-available information from industry publications.

Supply Side Renewable Energy Resource Categories

The list of supply side resources considered for the review are listed in Table 1.

Table 1: Supply Side Renewable Energy Resource Categories

CATEGORY	TECHNOLOGY	OWNERSHIP
NW Wind On System (101.2 MW)	Wind	PPA
NW Wind Off System (101.2 MW)	Wind	PPA

CATEGORY	TECHNOLOGY	OWNERSHIP
Wind Montana (101.2 MW)	Wind	PPA
Off Shore Wind (100 MW)	Wind	PPA
Solar PV, Fixed Array (5 MW AC)	Solar	PPA
Solar PV, Single Axis Tracking (100 MW AC)	Solar	PPA
Southern NW Solar PV, Single Axis Tracking (100 MW AC)	Solar	PPA
Solar PV, Single Axis Tracking (100 MW AC *plus* 50 MW/200 MWh Lithium-ion)	Solar/Storage	PPA
Distribution Scale 4hr Lithium-Ion	Storage	Utility
Distribution Scale 8hr Lithium-Ion	Storage	Utility
4hr Lithium-Ion	Storage	Utility
8hr Lithium-Ion	Storage	Utility
16hr Lithium-Ion	Storage	Utility
40hr Lithium-Ion	Storage	Utility
4 hr Vanadium Flow Battery	Storage	Utility
4 hr Zinc Bromide Flow Battery	Storage	Utility

Capex Assumptions

The CAPEX assumptions for supply side resources are listed in Table 2. All CAPEX values are 2018 nominal dollars.

Table 2: Supply Side Renewable Energy CAPEX Assumptions

CATEGORY	CAPEX* ($/KW$_{AC}$)
NW Wind On System (101.2 MW)	1,533
NW Wind Off System (101.2 MW)	1,426
Wind Montana (101.2 MW)	1,426
Off Shore Wind (100 MW)	3,500
Solar PV, Fixed Array (5 MW AC)	1,400
Solar PV, Single Axis Tracking (100 MW AC)	1,157
Southern NW Solar PV, Single Axis Tracking (100 MW AC)	1,157

CATEGORY	CAPEX* ($/KWAC)
Solar PV, Single Axis Tracking (100 MW AC *plus* 50 MW/200 MWh Lithium-ion)	1,504
Distribution Scale 4hr Lithium-Ion	1,950
Distribution Scale 8hr Lithium-Ion	3,822
4hr Lithium-Ion	1,438
8hr Lithium-Ion	2,818
16hr Lithium-Ion	5,578
40hr Lithium-Ion	13,858
4 hr Vanadium Flow Battery	1,600
4 hr Zinc Bromide Flow Battery	1,800
* Excludes AFUDC	

Black & Veatch notes that there has been limited development of offshore wind projects in the United States, so cost estimates are subject to a higher degree of uncertainty. In addition, most energy storage technologies are undergoing significant development and commercialization, for which CAPEX estimates should also be considered with a higher degree of uncertainty.

Overall, the CAPEX assumptions appear reasonable.

O&M Assumptions

The O&M assumptions for supply side resources are listed in Table 2. All CAPEX values are 2018 nominal dollars.

Table 3: Supply Side Renewable Energy CAPEX Assumptions

CATEGORY	O&M COSTS ($/KW-YR)
NW Wind On System (101.2 MW)	35.0
NW Wind Off System (101.2 MW)	35.0
Wind Montana (101.2 MW)	35.0
Off Shore Wind (100 MW)	90.0
Solar PV, Fixed Array (5 MW AC)	10.0
Solar PV, Single Axis Tracking (100 MW AC)	8.0

CATEGORY	O&M COSTS ($/KW-YR)
Southern NW Solar PV, Single Axis Tracking (100 MW AC)	8.0
Solar PV, Single Axis Tracking (100 MW AC *plus* 50 MW/200 MWh Lithium-ion)	72.0
Distribution Scale 4hr Lithium-Ion	68.3
Distribution Scale 8hr Lithium-Ion	133.8
4hr Lithium-Ion	50.3
8hr Lithium-Ion	98.6
16hr Lithium-Ion	195.2
40hr Lithium-Ion	485.0
4 hr Vanadium Flow Battery	56.0
4 hr Zinc Bromide Flow Battery	63.0

As noted previously, there has been limited development of offshore wind projects or battery energy storage projects in the United States, so O&M estimates are subject to a higher degree of uncertainty.

Overall, the O&M assumptions appear reasonable.

Performance Assumptions

The capacity factor and round-trip efficiency values (for energy storage only) assumptions for supply side resources are listed in Table 3.

Table 4: Supply Side Renewable Energy Resource Performance Assumptions

CATEGORY	CAPACITY FACTOR (%)	ROUND-TRIP EFFICIENCY (%)
NW Wind On System (101.2 MW)	37.0	n/a
NW Wind Off System (101.2 MW)	37.0	n/a
Wind Montana (101.2 MW)	48.0	n/a
Off Shore Wind (100 MW)	50.0	n/a
Solar PV, Fixed Array (5 MW AC)	25.0	n/a
Solar PV, Single Axis Tracking (100 MW AC)	27.0	n/a

CATEGORY	CAPACITY FACTOR (%)	ROUND-TRIP EFFICIENCY (%)
Southern NW Solar PV, Single Axis Tracking (100 MW AC)	30.0	n/a
Solar PV, Single Axis Tracking (100 MW AC *plus* 50 MW/200 MWh Lithium-ion)	27.0	n/a
Distribution Scale 4hr Lithium-Ion	n/a	88
Distribution Scale 8hr Lithium-Ion	n/a	88
4hr Lithium-Ion	n/a	88
8hr Lithium-Ion	n/a	88
16hr Lithium-Ion	n/a	88
40hr Lithium-Ion	n/a	88
4 hr Vanadium Flow Battery	n/a	70
4 hr Zinc Bromide Flow Battery	n/a	67

Actual capacity factor results for renewable energy resources are highly site-dependent and depend on factors such as weather patterns and site topography. However, the values used by Avista fall within expected ranges.

Overall, the performance assumptions appear reasonable.

Technology Improvement Assumptions

The technology improvement assumptions for supply side resources are listed in Table 4. These values refer to the aggregate industry learning curve of improving technology efficiency from experience and Research & Development efforts.

Table 5: Supply Side Renewable Energy Resource Technology Improvement Assumptions

CATEGORY	ANNUAL TECHNOLOGY IMPROVEMENT (%)
NW Wind On System (101.2 MW)	0.3
NW Wind Off System (101.2 MW)	0.3
Wind Montana (101.2 MW)	0.3
Off Shore Wind (100 MW)	0.3
Solar PV, Fixed Array (5 MW AC)	0.3

CATEGORY	ANNUAL TECHNOLOGY IMPROVEMENT (%)
Solar PV, Single Axis Tracking (100 MW AC)	0.3
Southern NW Solar PV, Single Axis Tracking (100 MW AC)	0.3
Solar PV, Single Axis Tracking (100 MW AC *plus* 50 MW/200 MWh Lithium-ion)	0.3
Distribution Scale 4hr Lithium-Ion	2.1 to 10.6
Distribution Scale 8hr Lithium-Ion	2.3 to 11.4
4hr Lithium-Ion	2.1 to 10.6
8hr Lithium-Ion	2.3 to 11.4
16hr Lithium-Ion	2.6 to 12.3
40hr Lithium-Ion	3.1 to 14.1
4 hr Vanadium Flow Battery	1.0 to 5.0
4 hr Zinc Bromide Flow Battery	1.0 to 8.0

Black & Veatch notes that solar, wind, and energy storage technologies have all experienced technical improvements over the past decade. While the rate of technology improvement is sometimes uneven, the general industry expectation is that renewable energy and energy storage technologies will continue to advance down the learning curve in future years. In general, the energy storage field is in earlier stages of development and commercialization, and is considered to be more likely to experience faster technological improvements compared to more mature technologies such as wind turbines and PV modules.

Overall, the technology improvement assumptions appear reasonable.

Conclusions

Black & Veatch reviewed the inputs for renewable energy and energy storage used in the Avista 2019 Integrated Resource Plan (IRP) process. The values used for CAPEX, O&M performance, and technology improvement assumptions appear reasonable and within the range expected for similar facilities.

2020 Electric Integrated Resource Plan

Appendix J – Confidential Report of Portfolio #14

Idaho – Confidential pursuant to Sections 74-109, Idaho Code

Washington – Confidential per WAC 480-07-160