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

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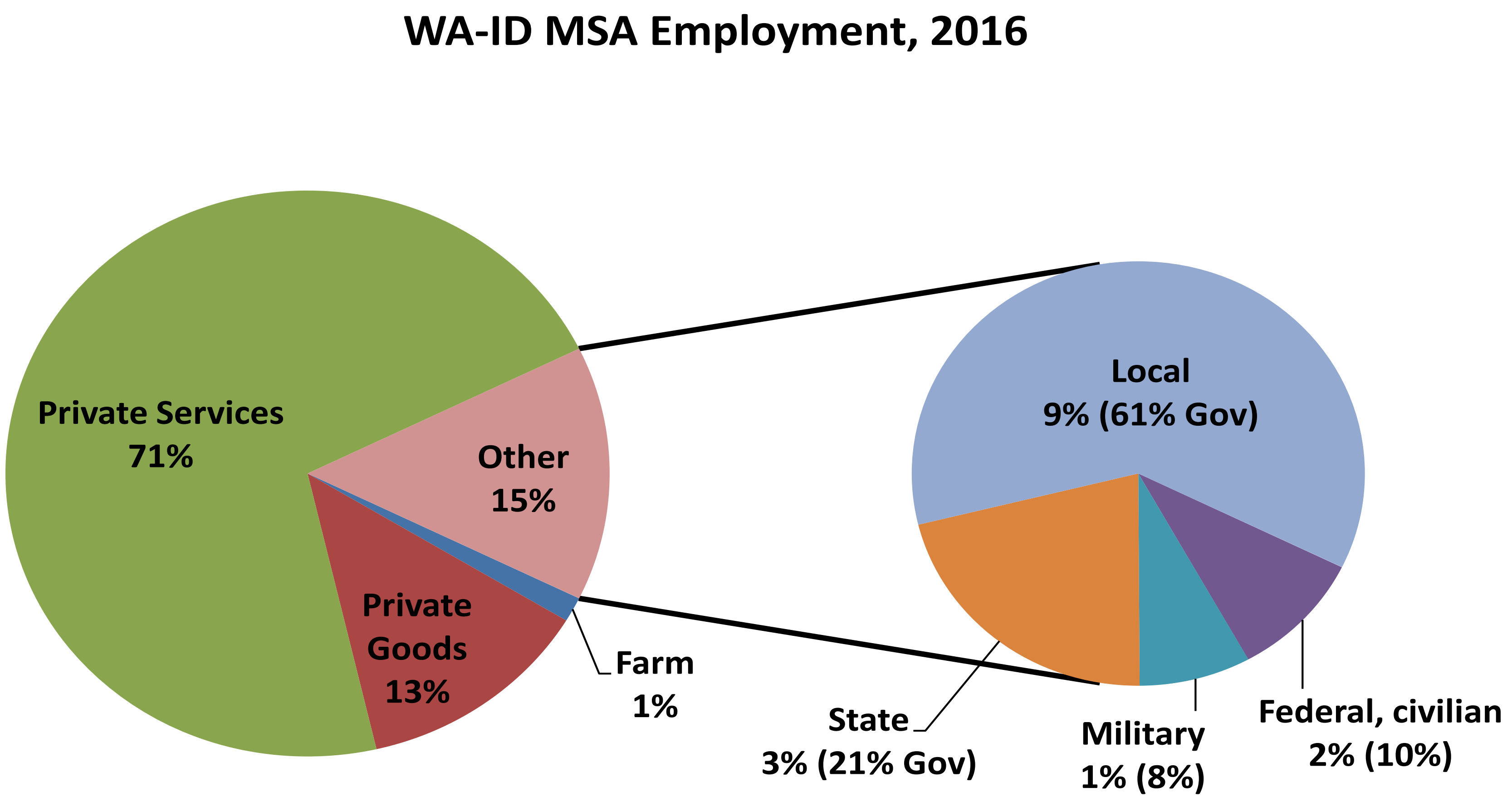
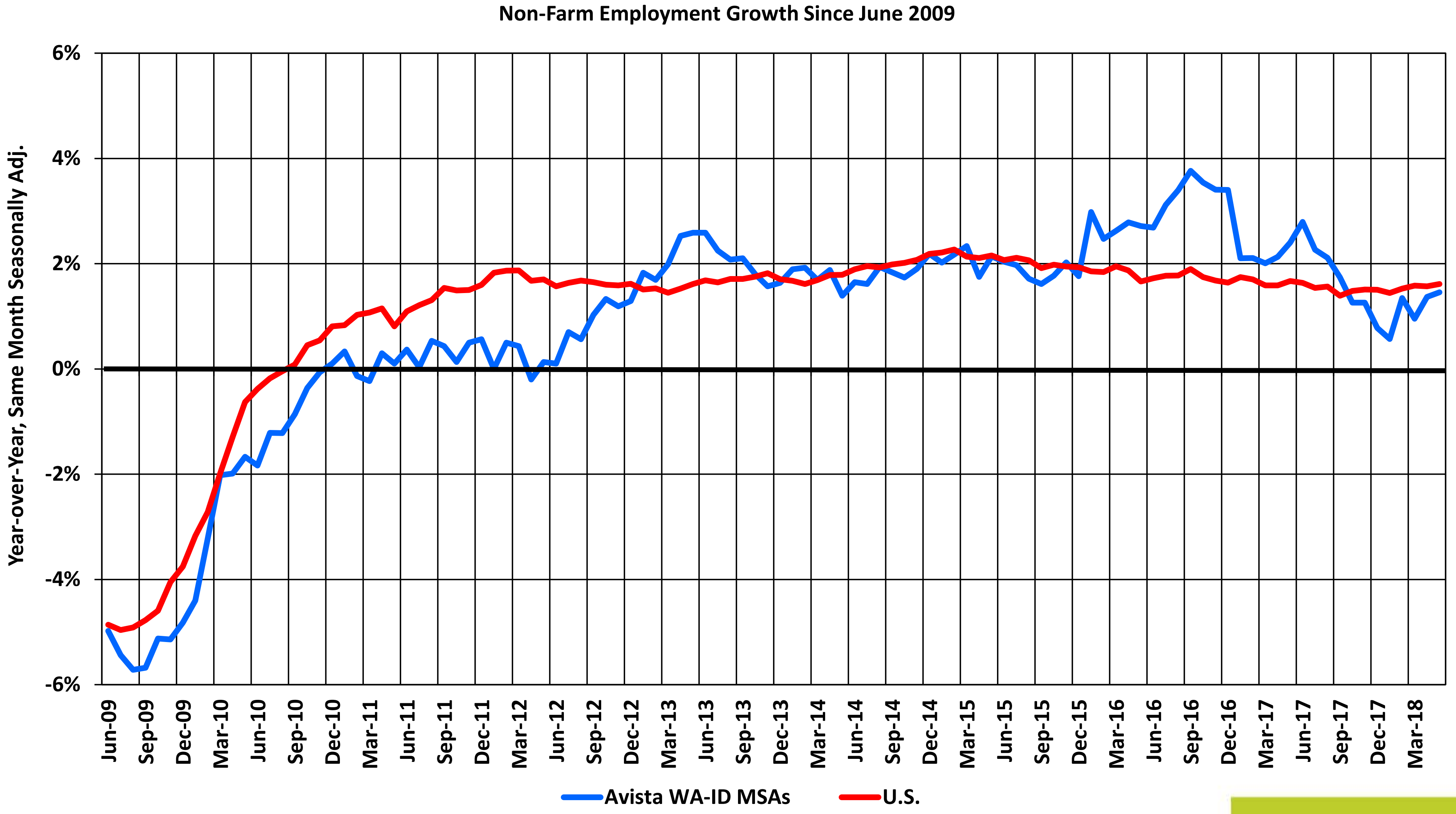
Distribution of Employment: Services and Government are Dominant



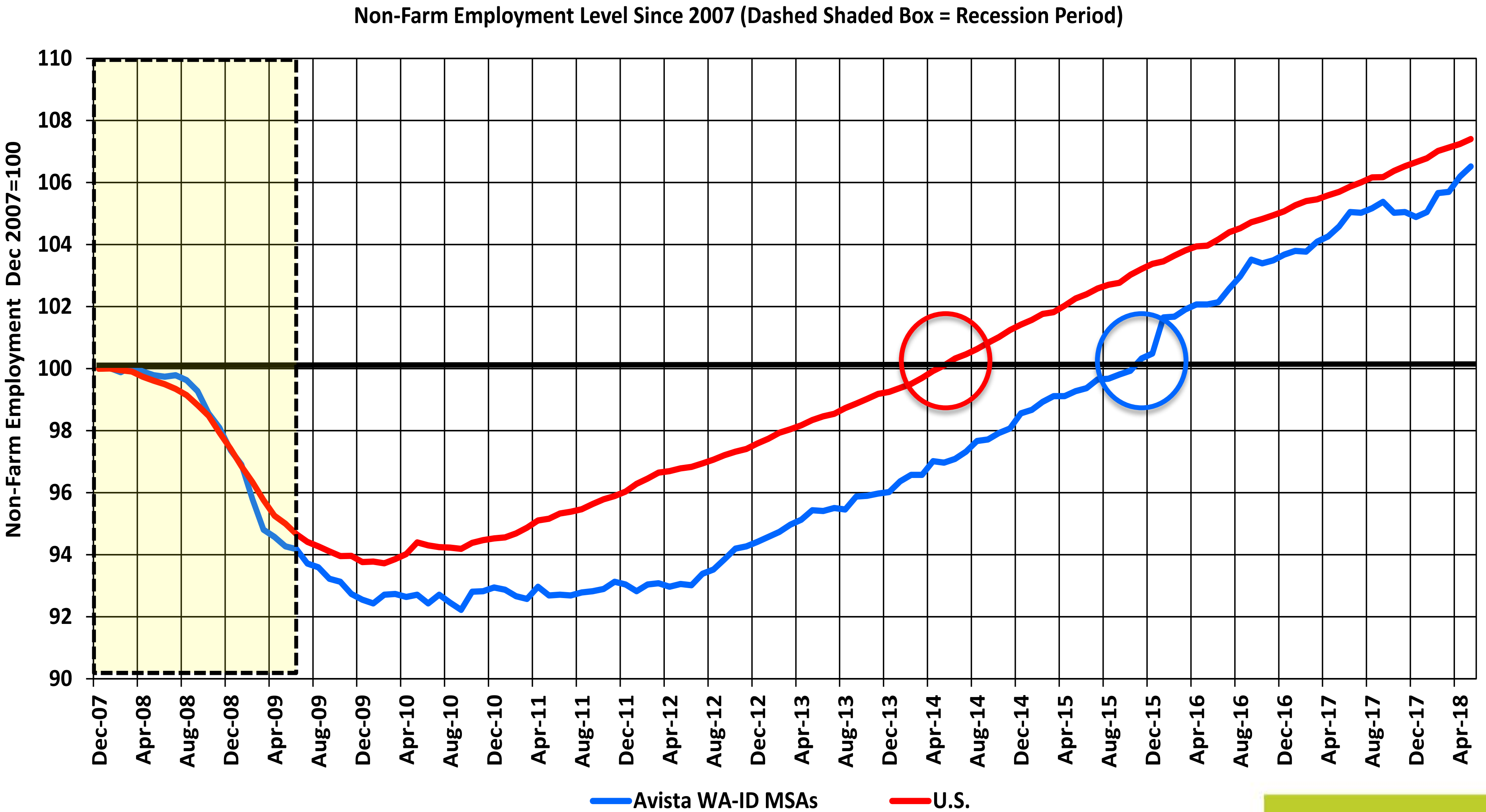
Source: BEA and author's calculations.

Non-Farm Employment Growth, 2009-2018



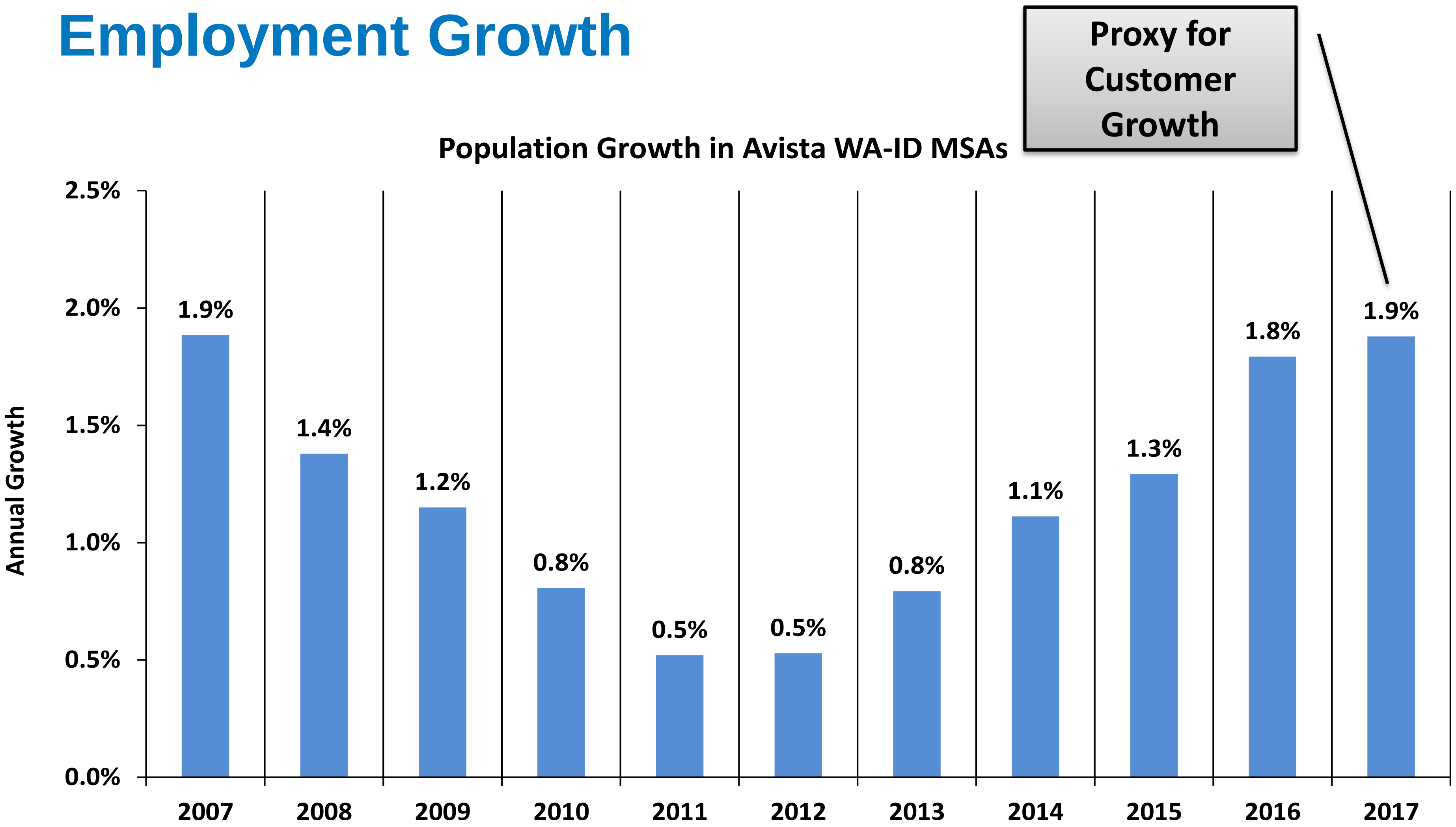
Source: BLS and author’s calculations.

Non-Farm Employment: Finally Catching Up



Source: BLS and author’s calculations.

Population Growth: Recovering with Employment Growth



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

Peak Load Forecast

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The Basic Model

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

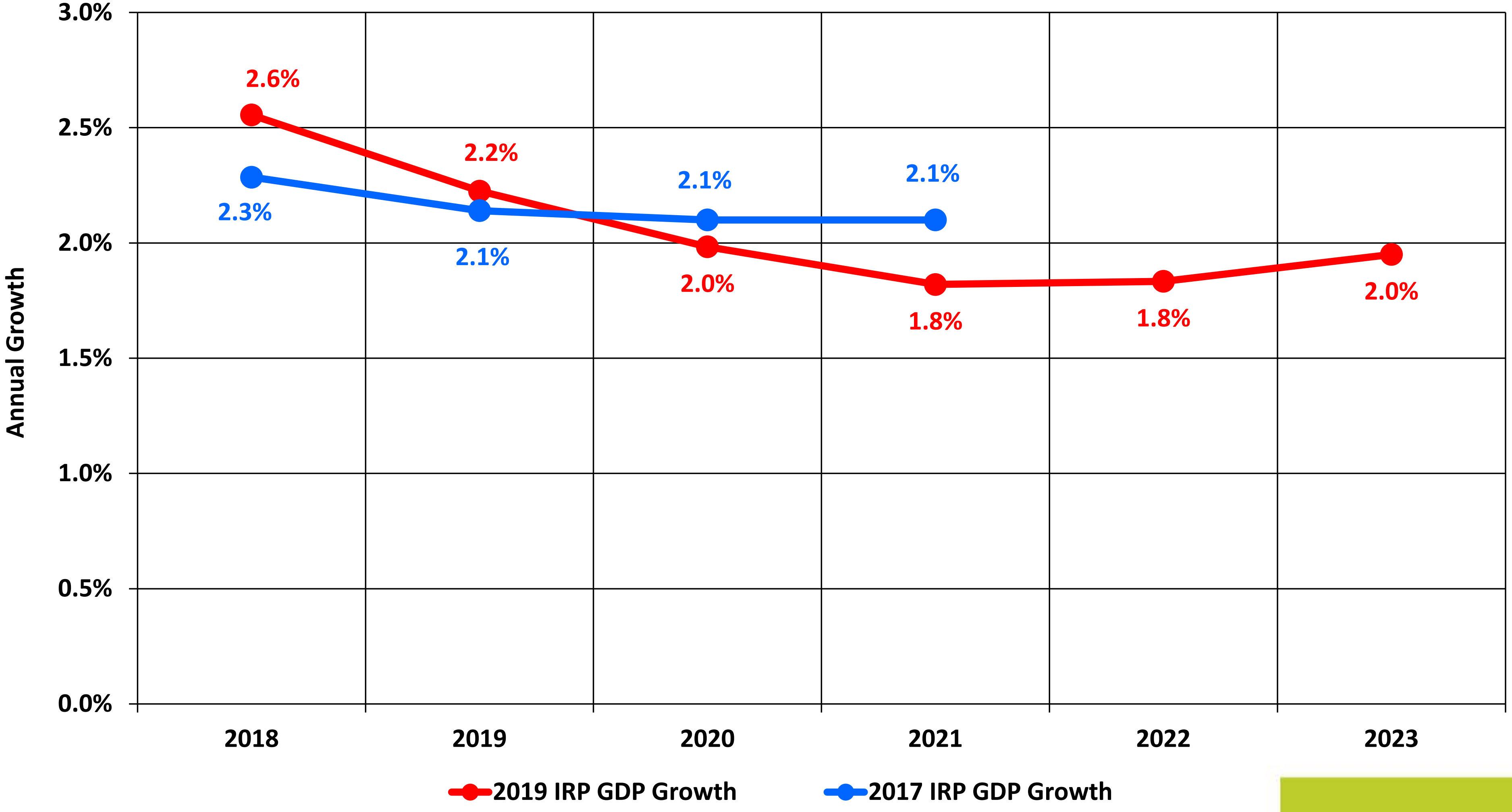
- **Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.**

- **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.**

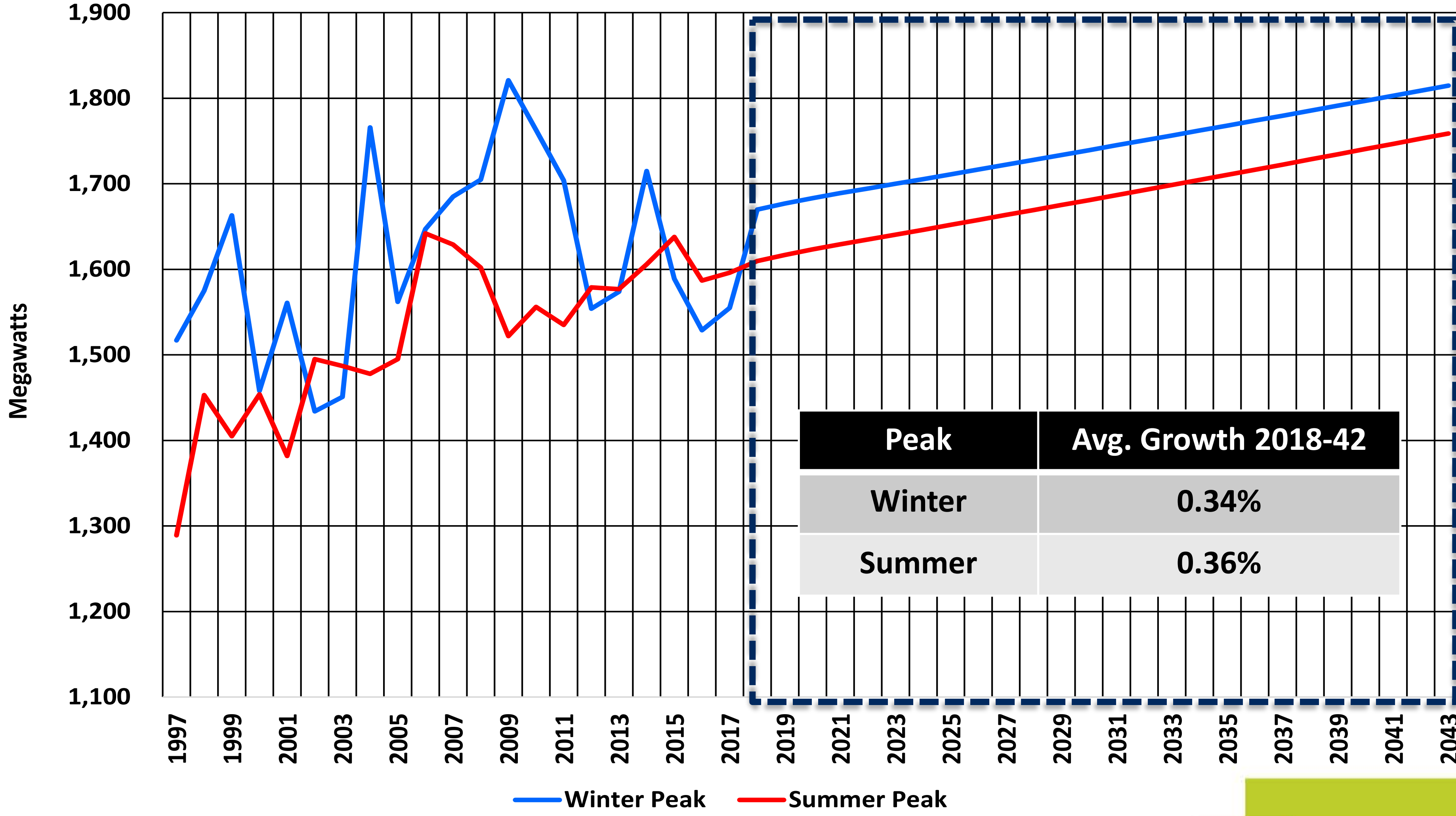
- **The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "*ceteris paribus*" assumption for weather and other factors.**

GDP Growth Assumptions: 2015 IRP vs. 2017 IRP



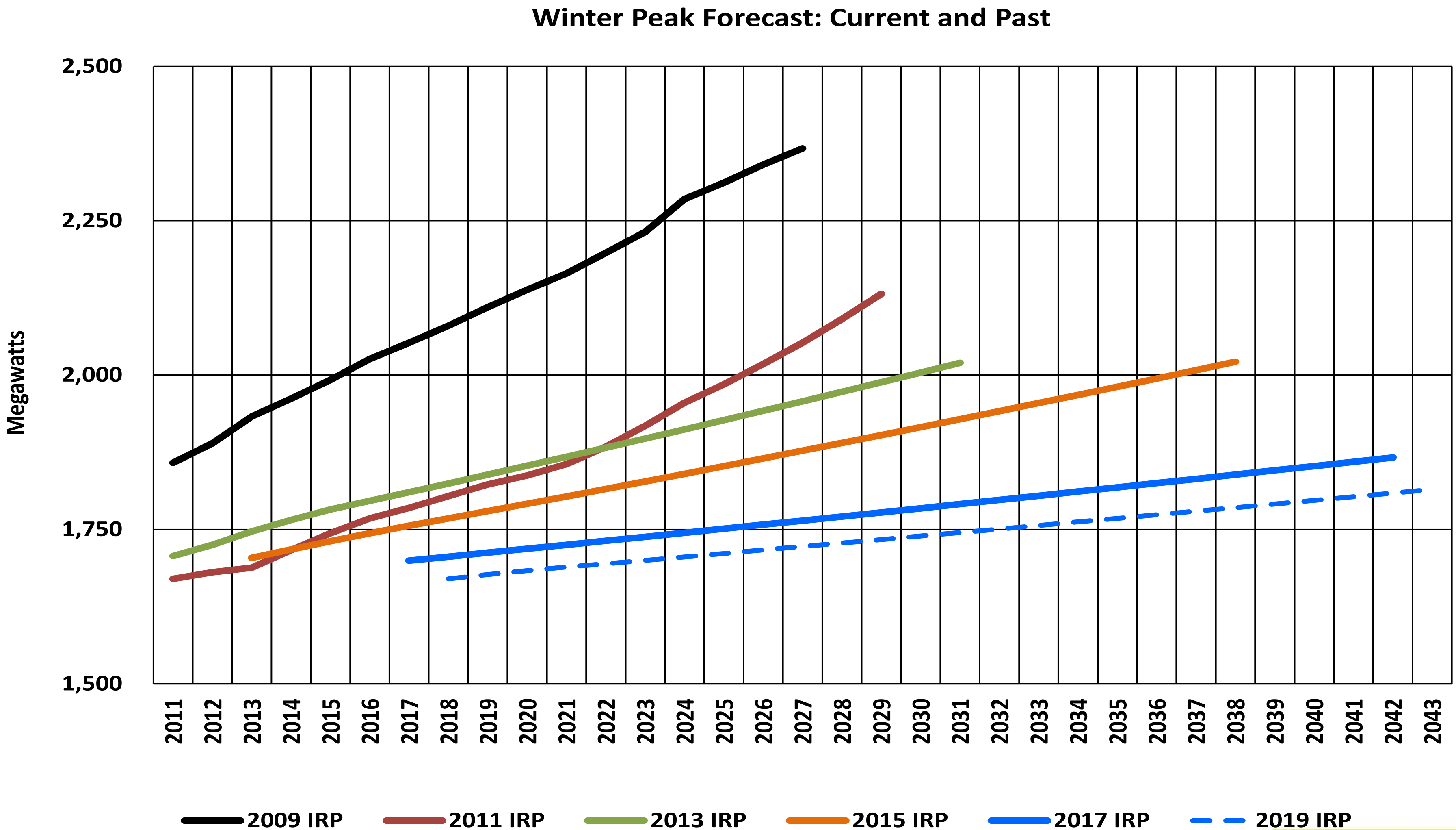
Source: Various and author's calculations.

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

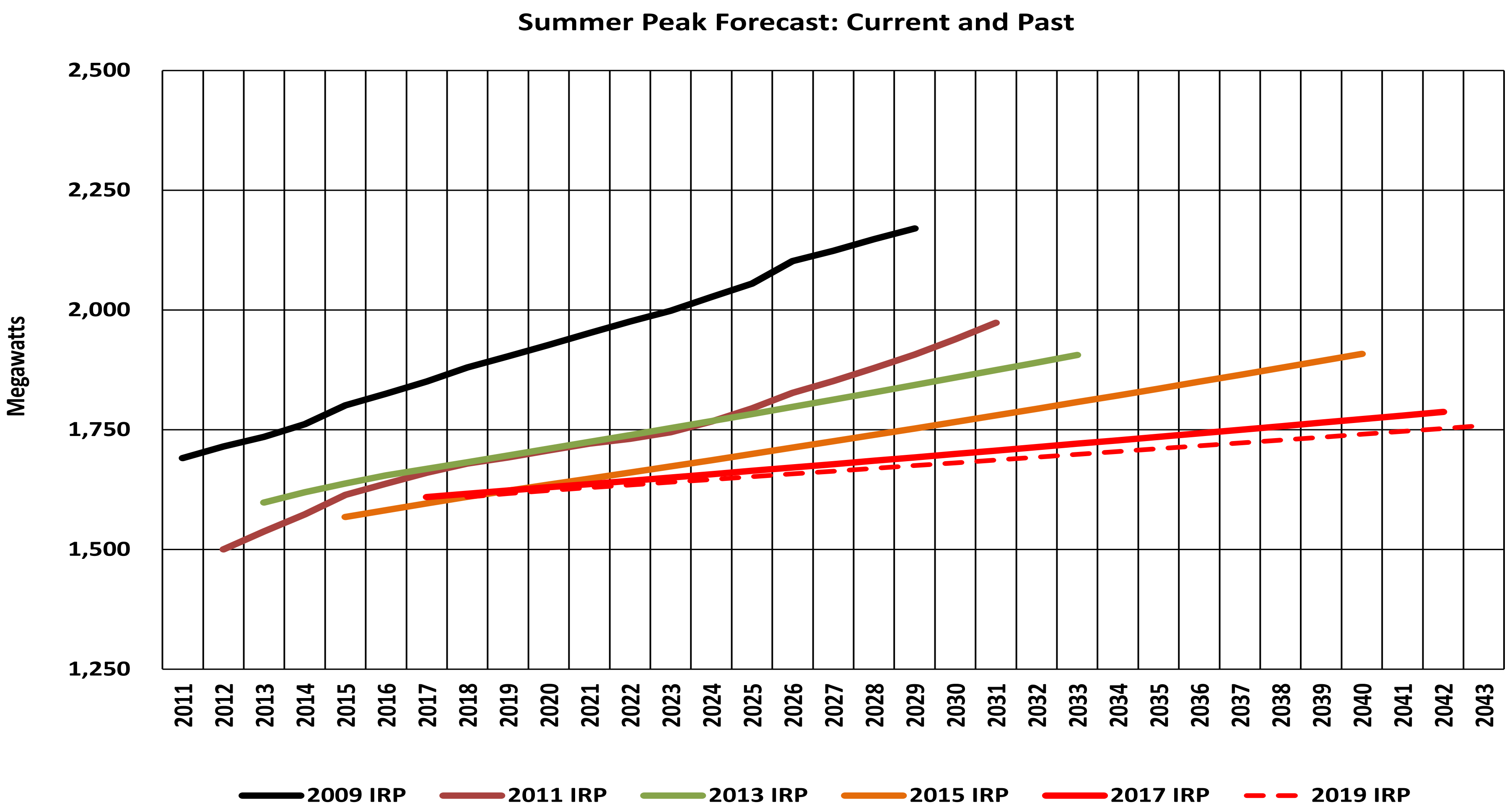


Peak	Avg. Growth 2018-42
Winter	0.34%
Summer	0.36%

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

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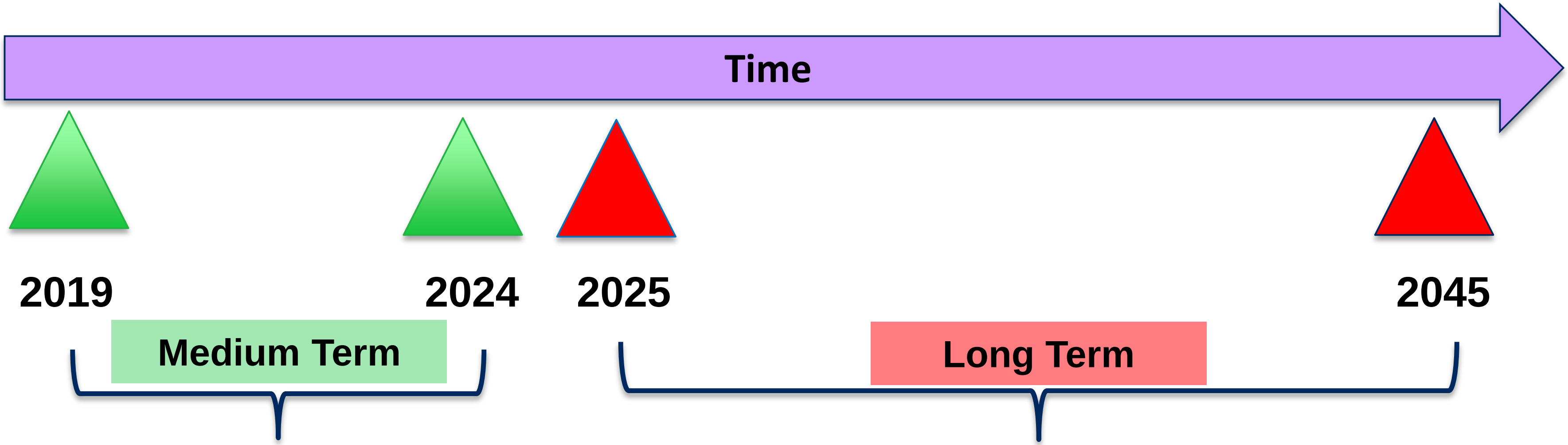
Basic Forecast Approach



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

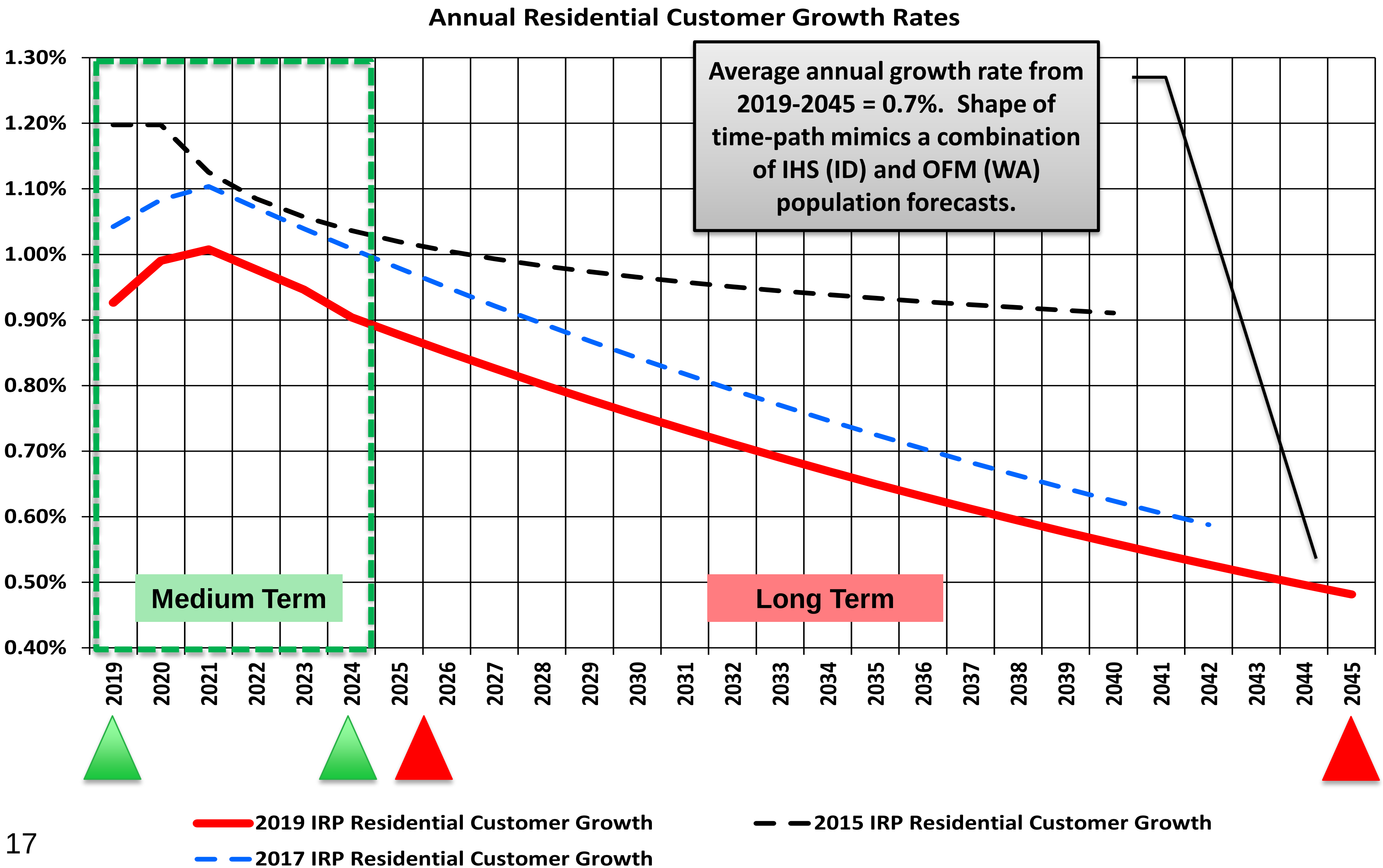
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

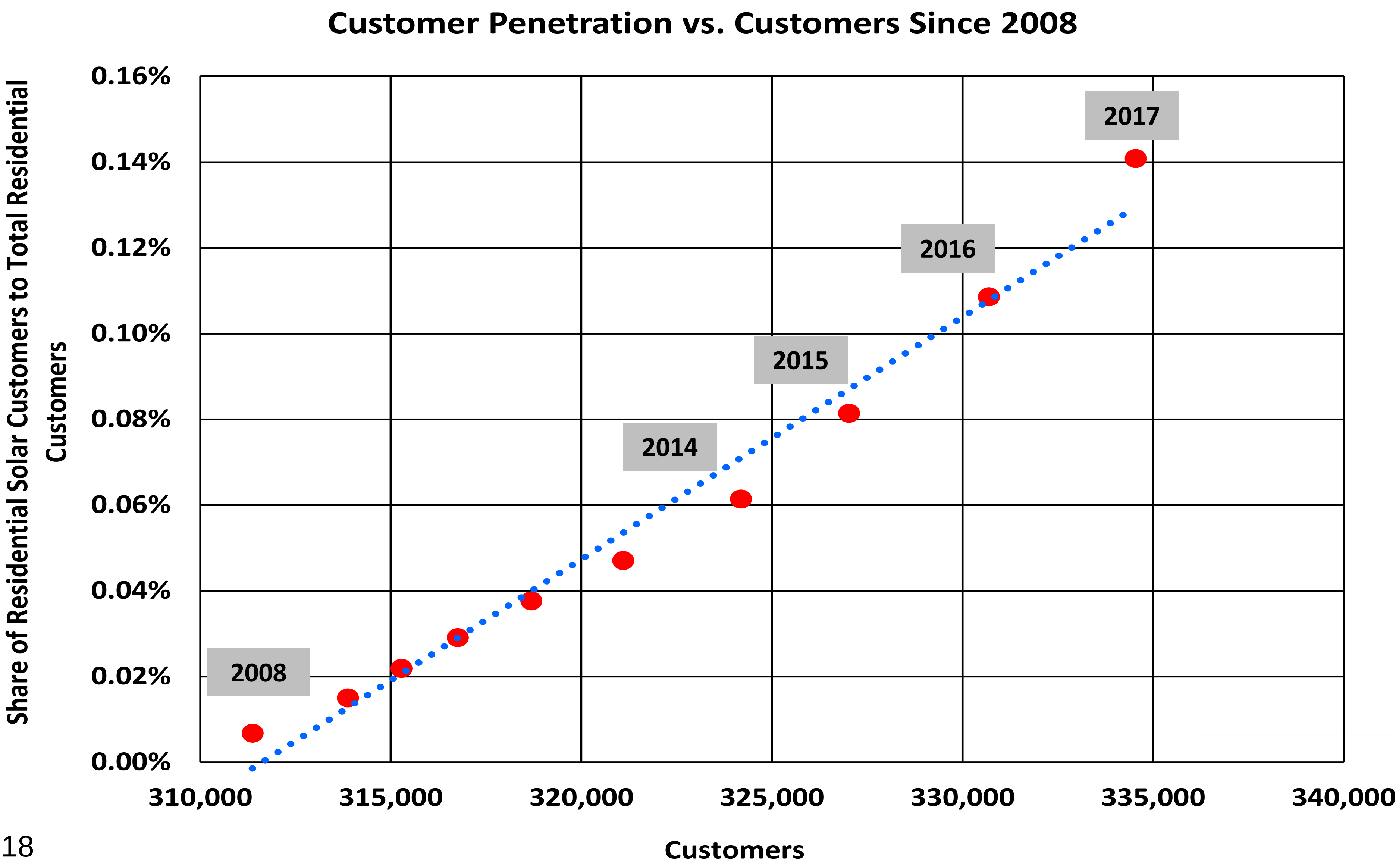
Assumed to be same as population growth, commercial growth will follow residential, and slow decline in industrial.

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

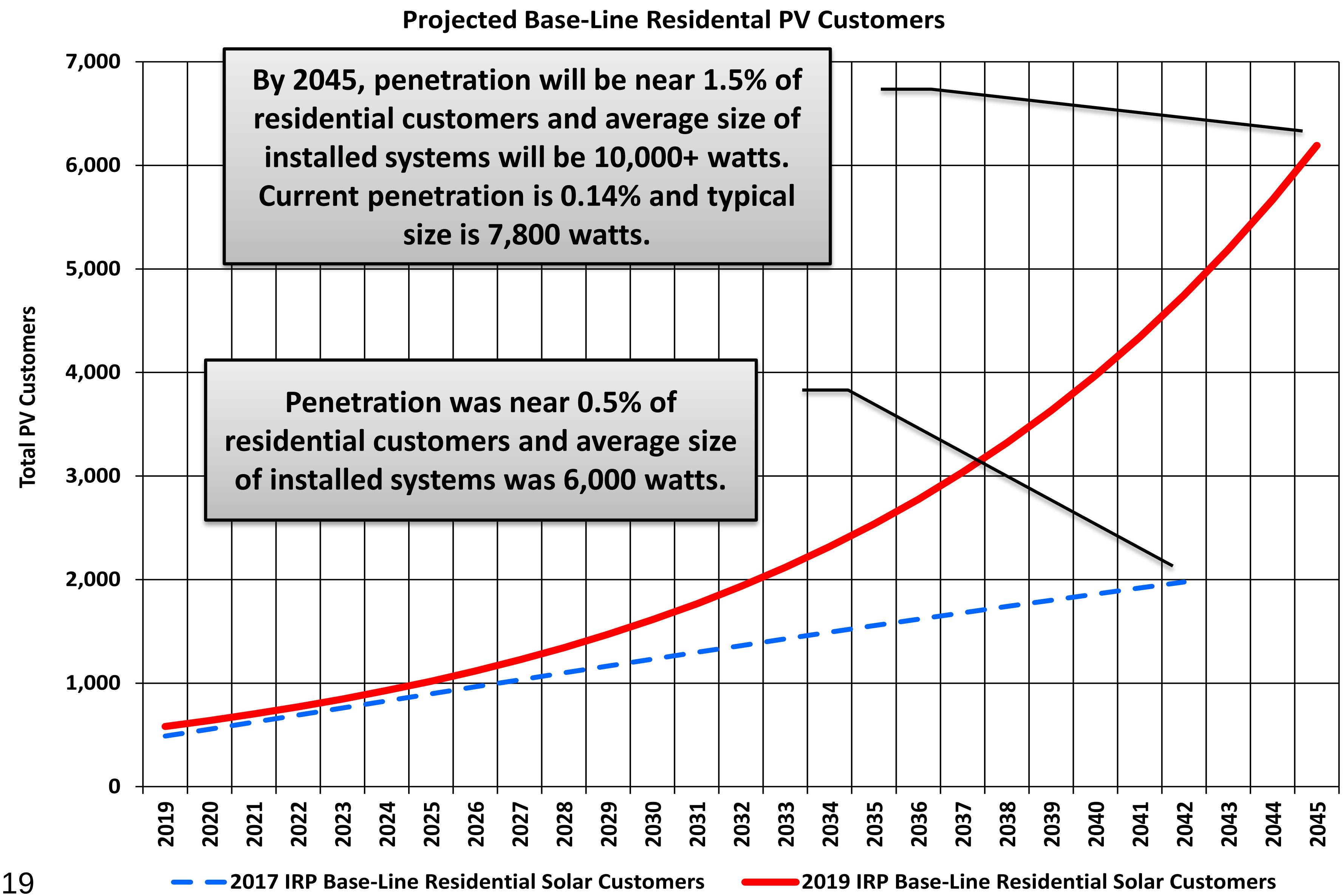
Residential Customer Growth, 2019-2045



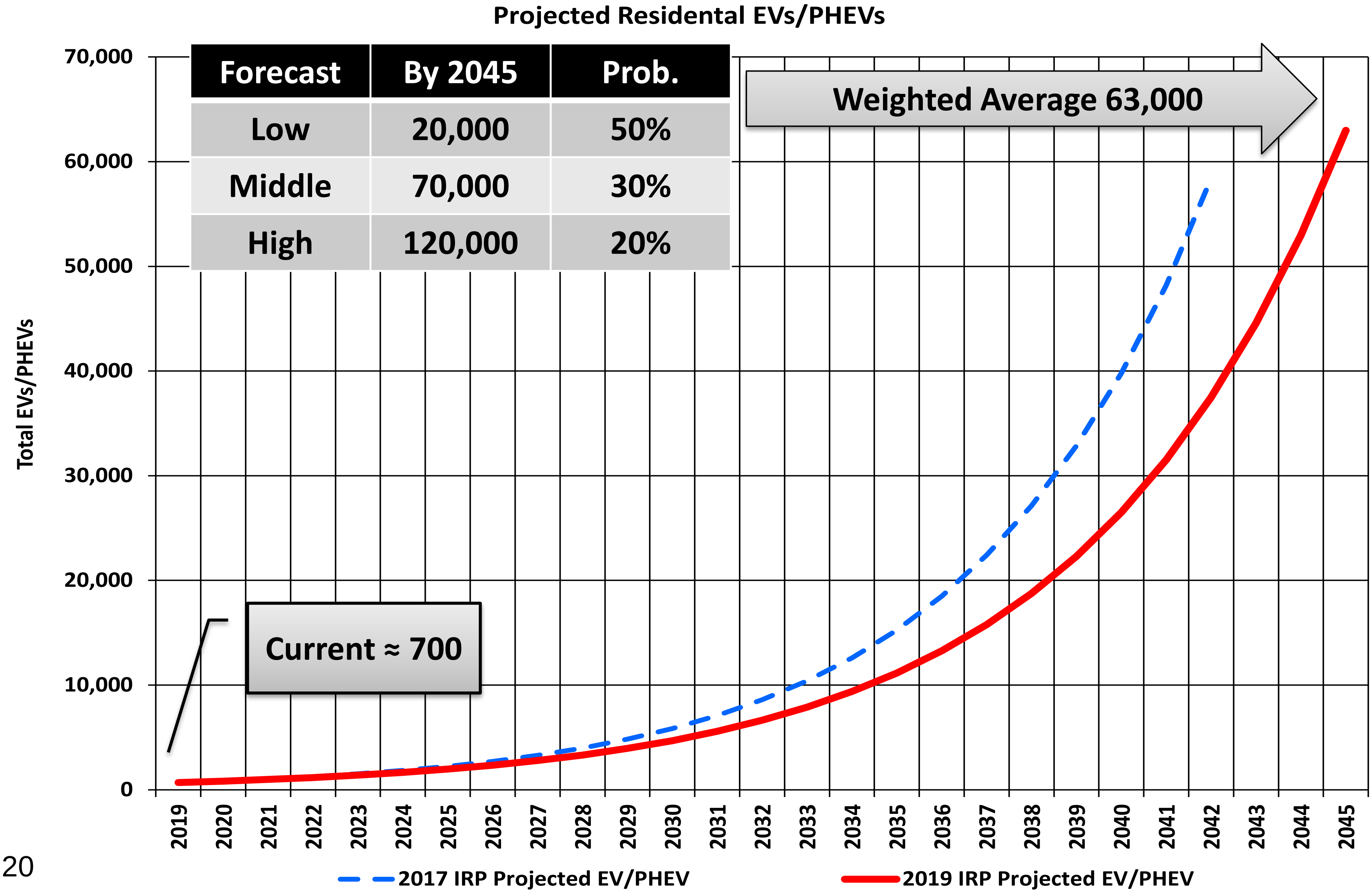
Residential Solar Penetration, 2008-2017



Residential Solar Penetration, 2019-2045

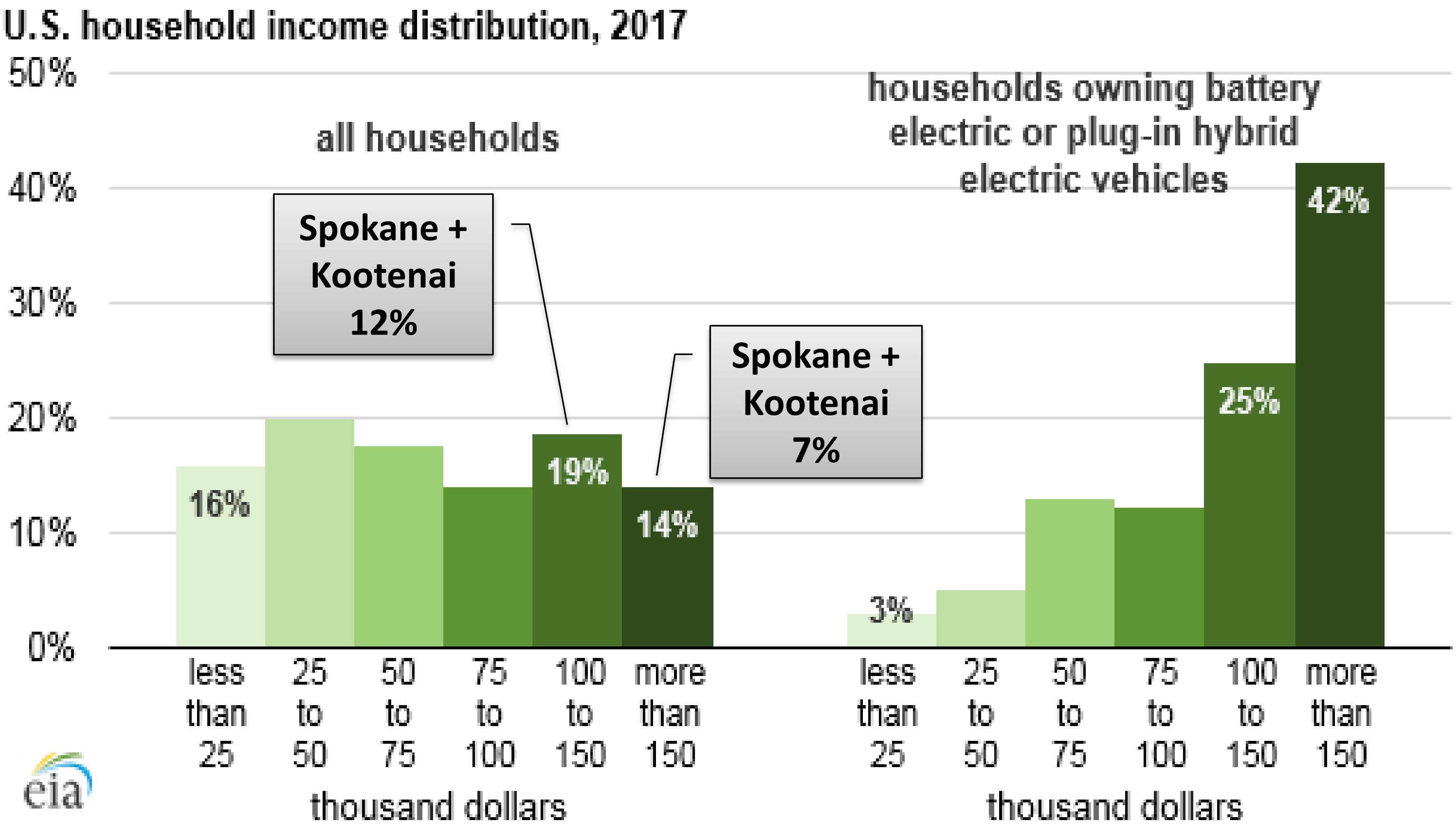


Residential EVs/PHEVs, 2019-2045



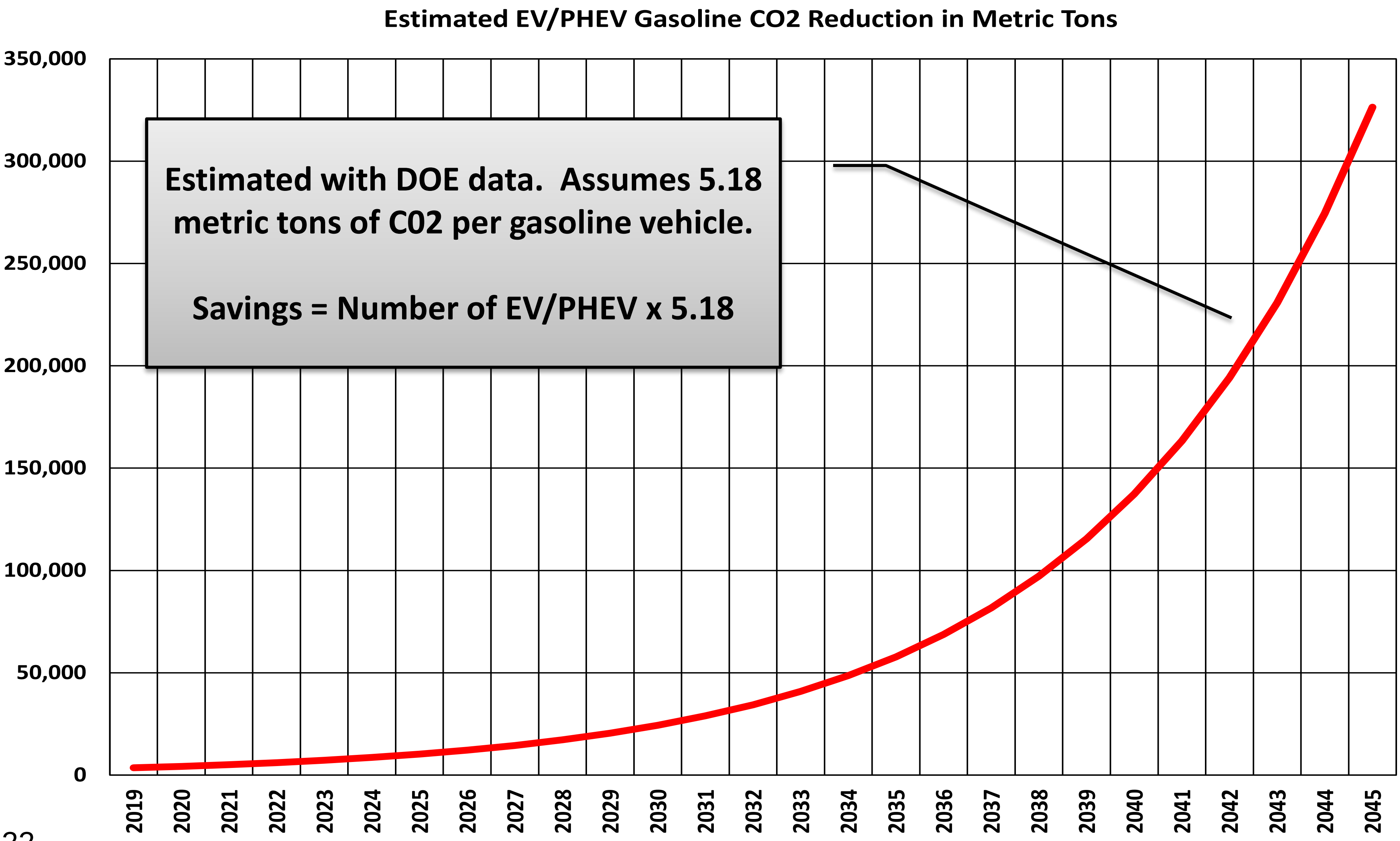
Forecast	By 2045	Prob.
Low	20,000	50%
Middle	70,000	30%
High	120,000	20%

Residential EVs/PHEVs by Household Income

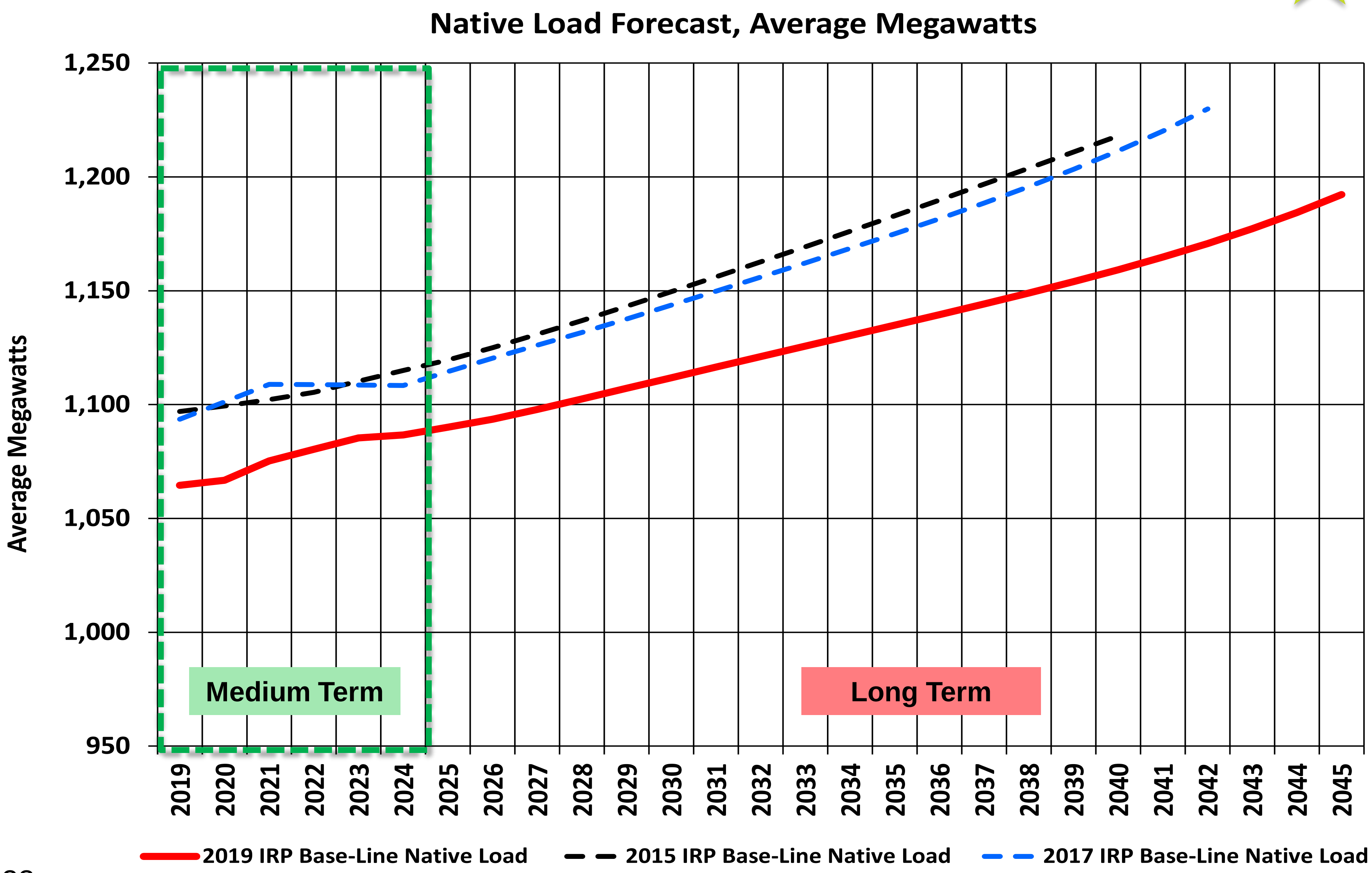


Source: EIA, *Today in Energy*, May 2018. Regional data from U.S. Census

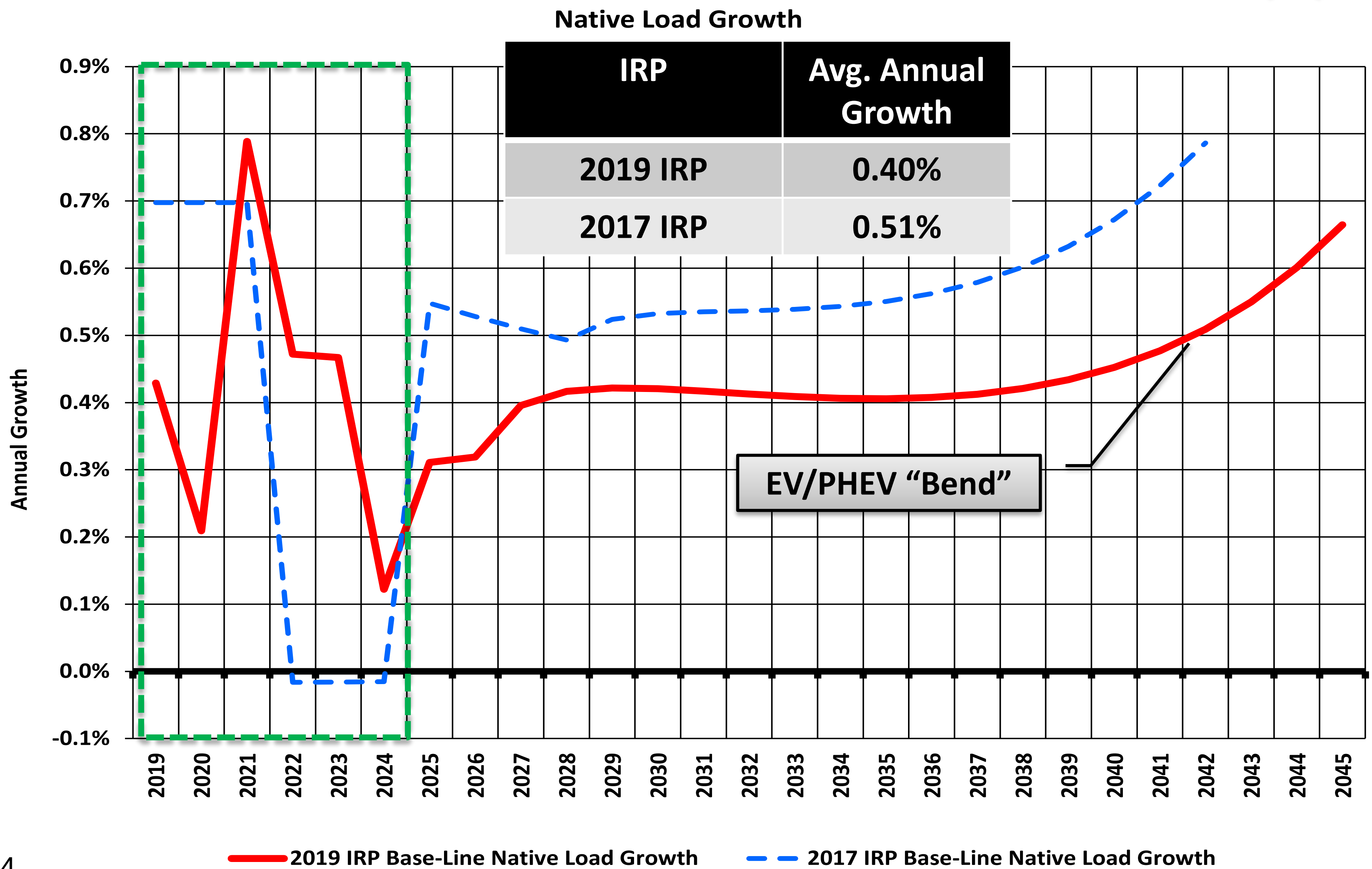
EV/PHEV Gasoline CO2 Savings Avista Service Territory



Native Load Forecast, 2019-2045

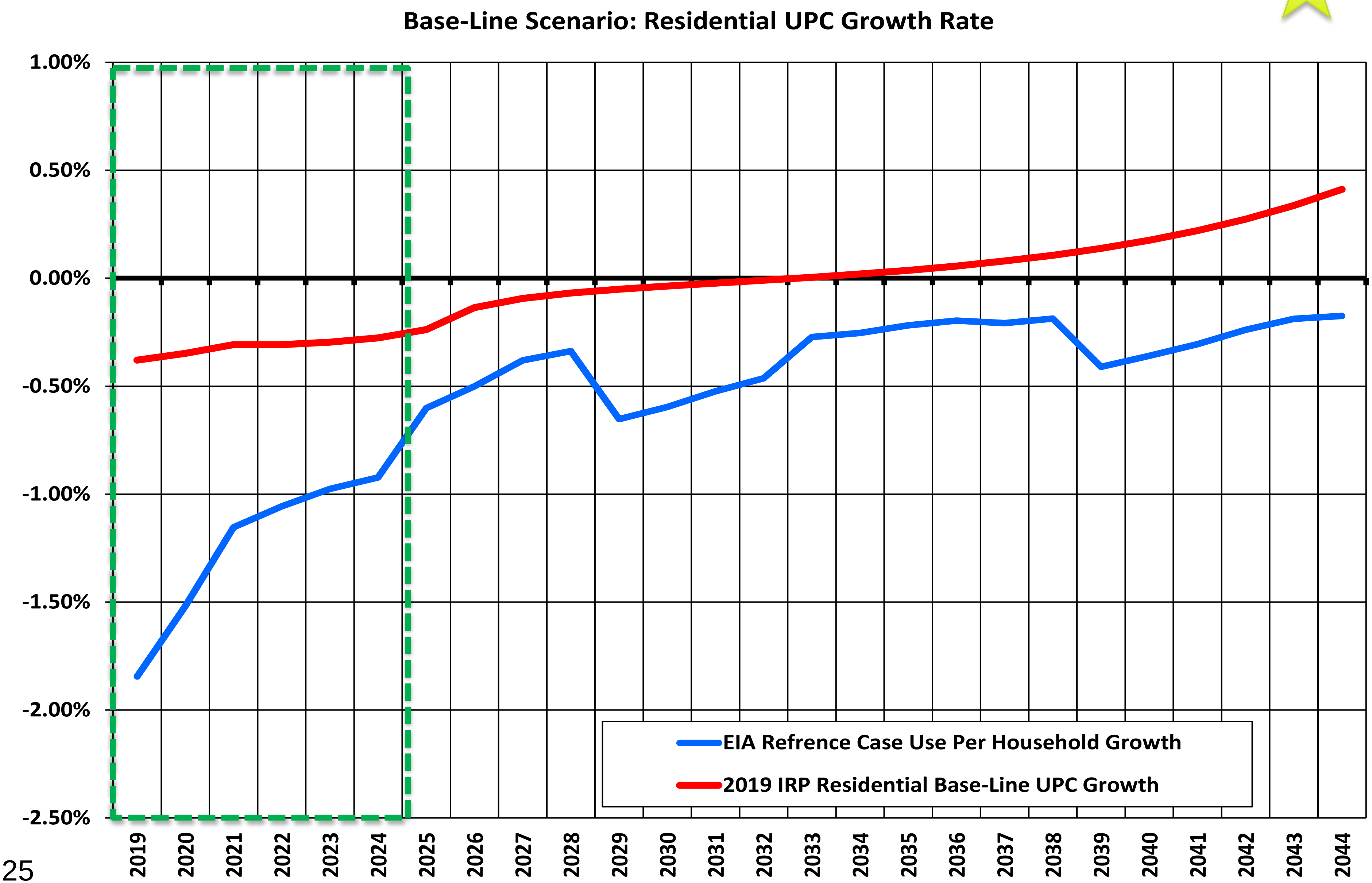


Native Load Growth Forecast, 2019-2045



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

Residential UPC Growth: 2019-2045



Long-Term Load Forecast: Conservation Adjustment

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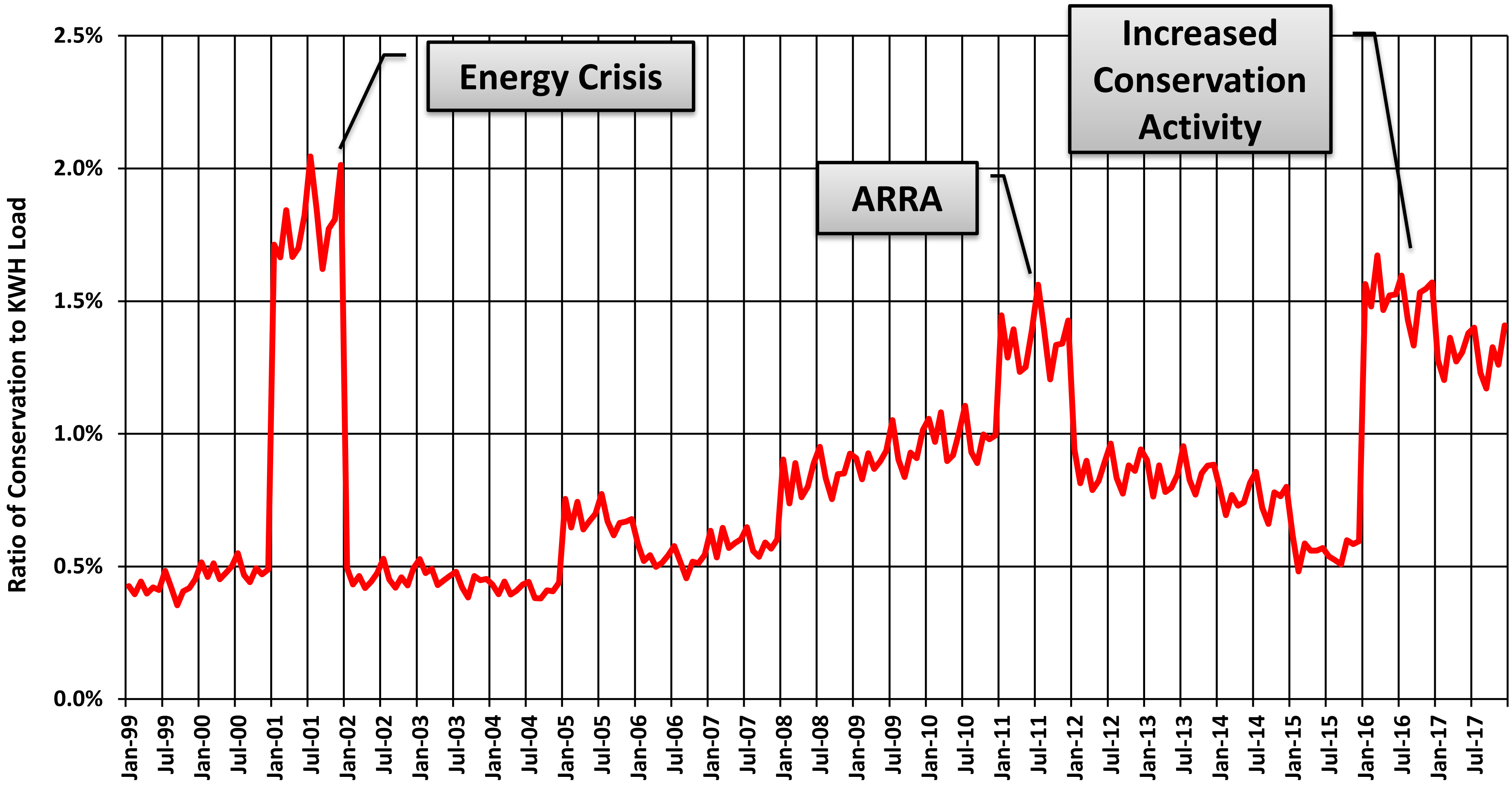
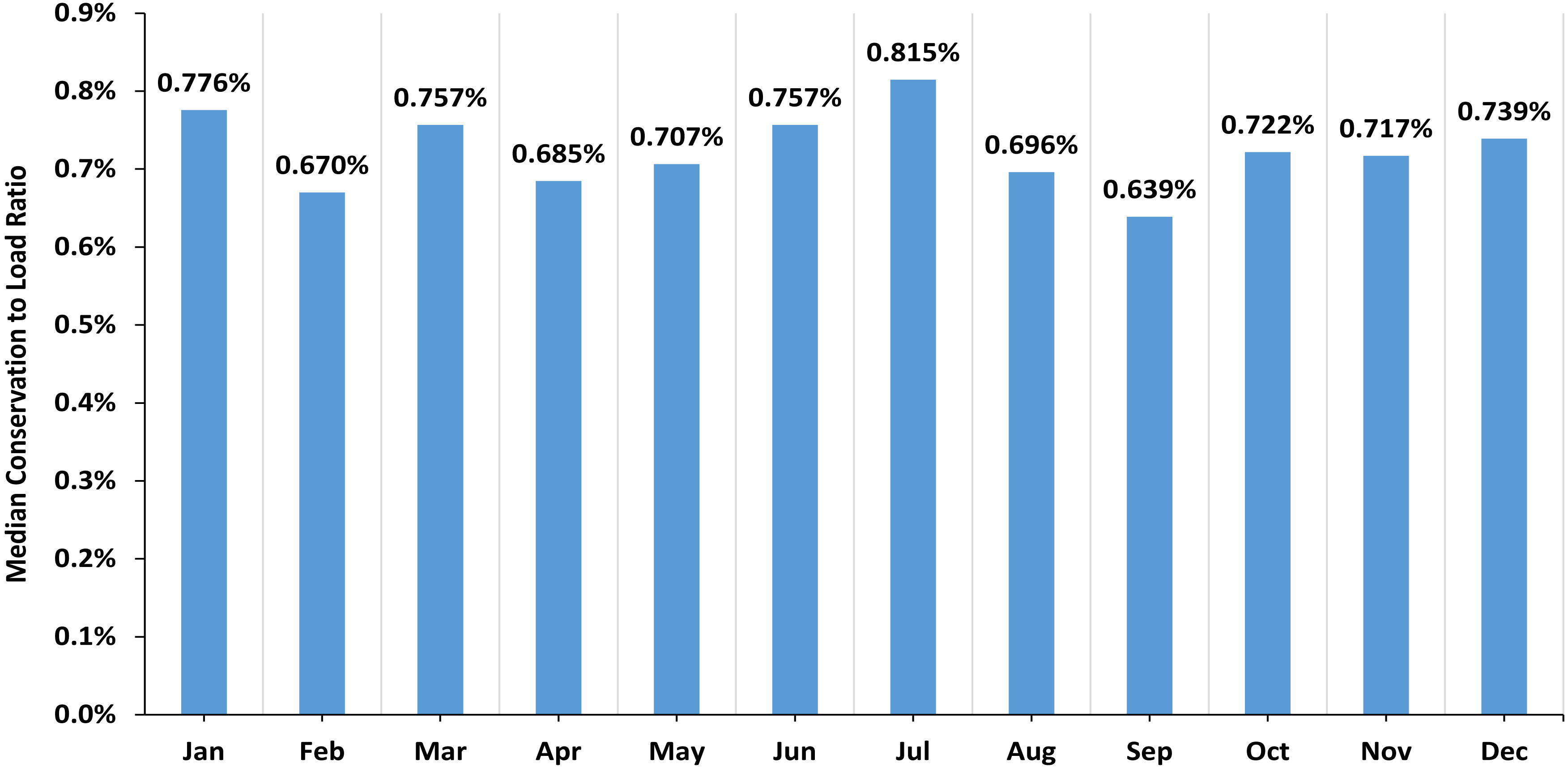
Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



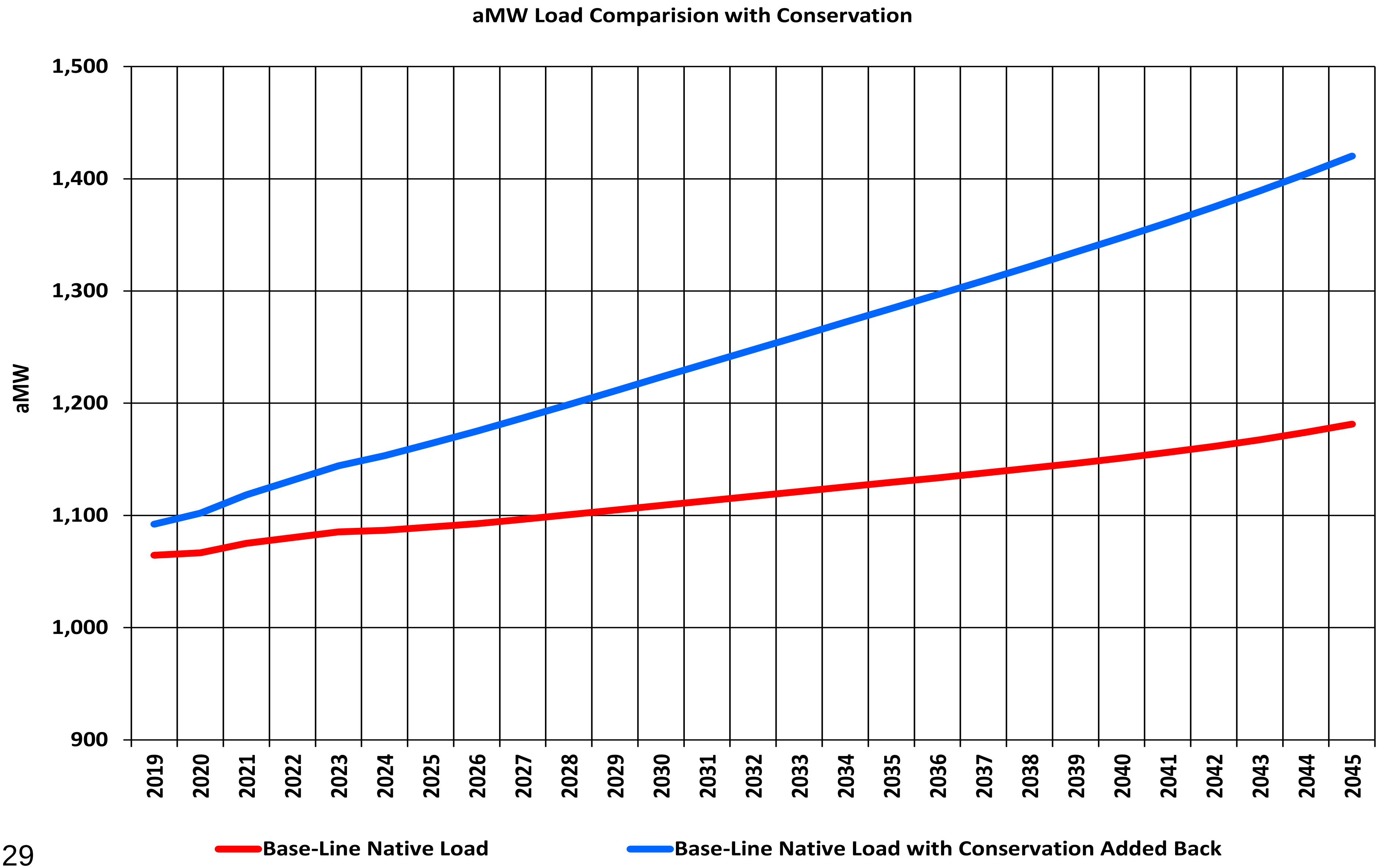
$$\text{Ratio} = \frac{\textit{Estimated Conservation Month } t, \textit{Year } y}{\textit{Actual KWH Load Month } t, \textit{Year } Y}$$

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.

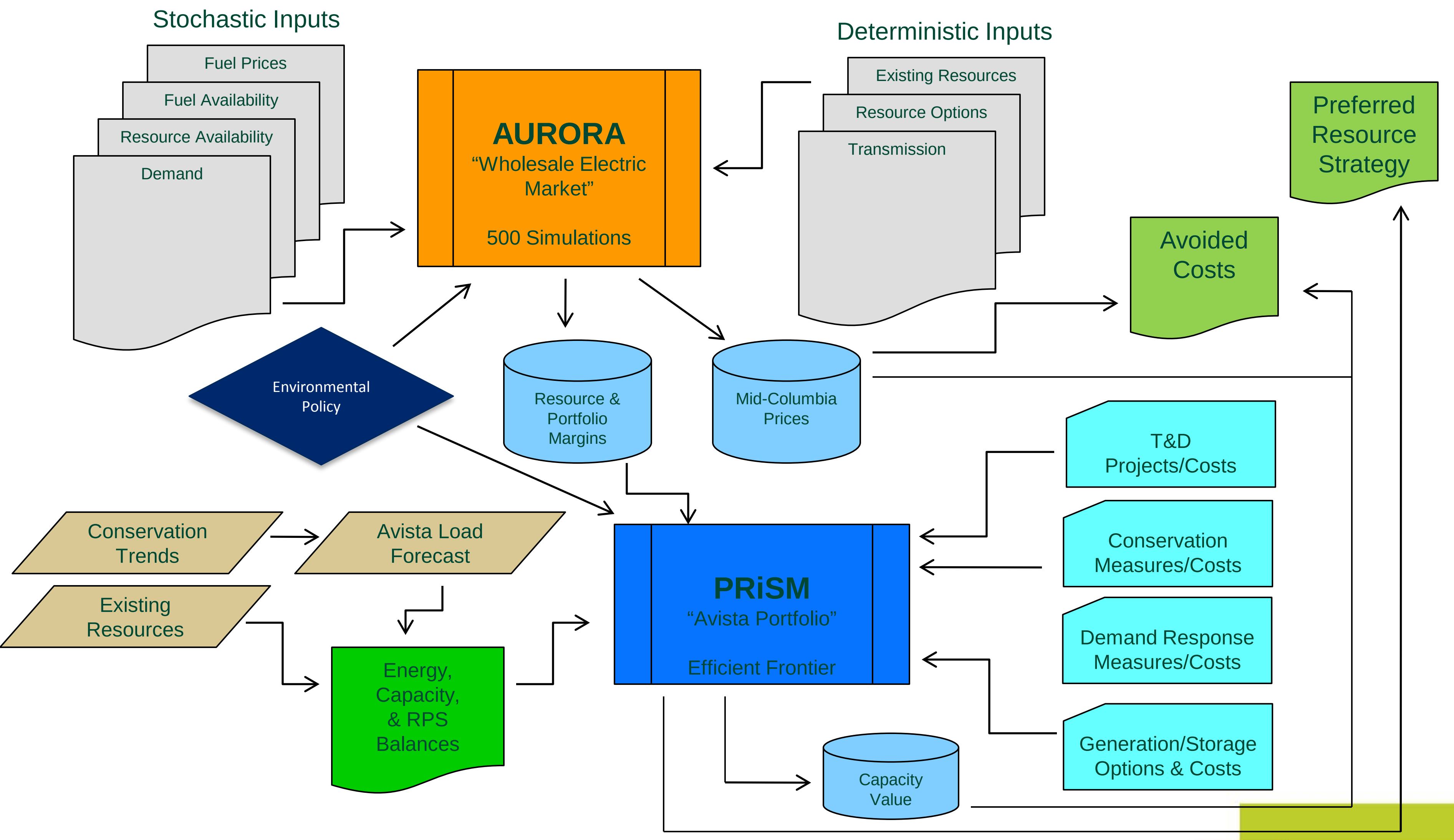
2019 Draft Electric IRP Timeline

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

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

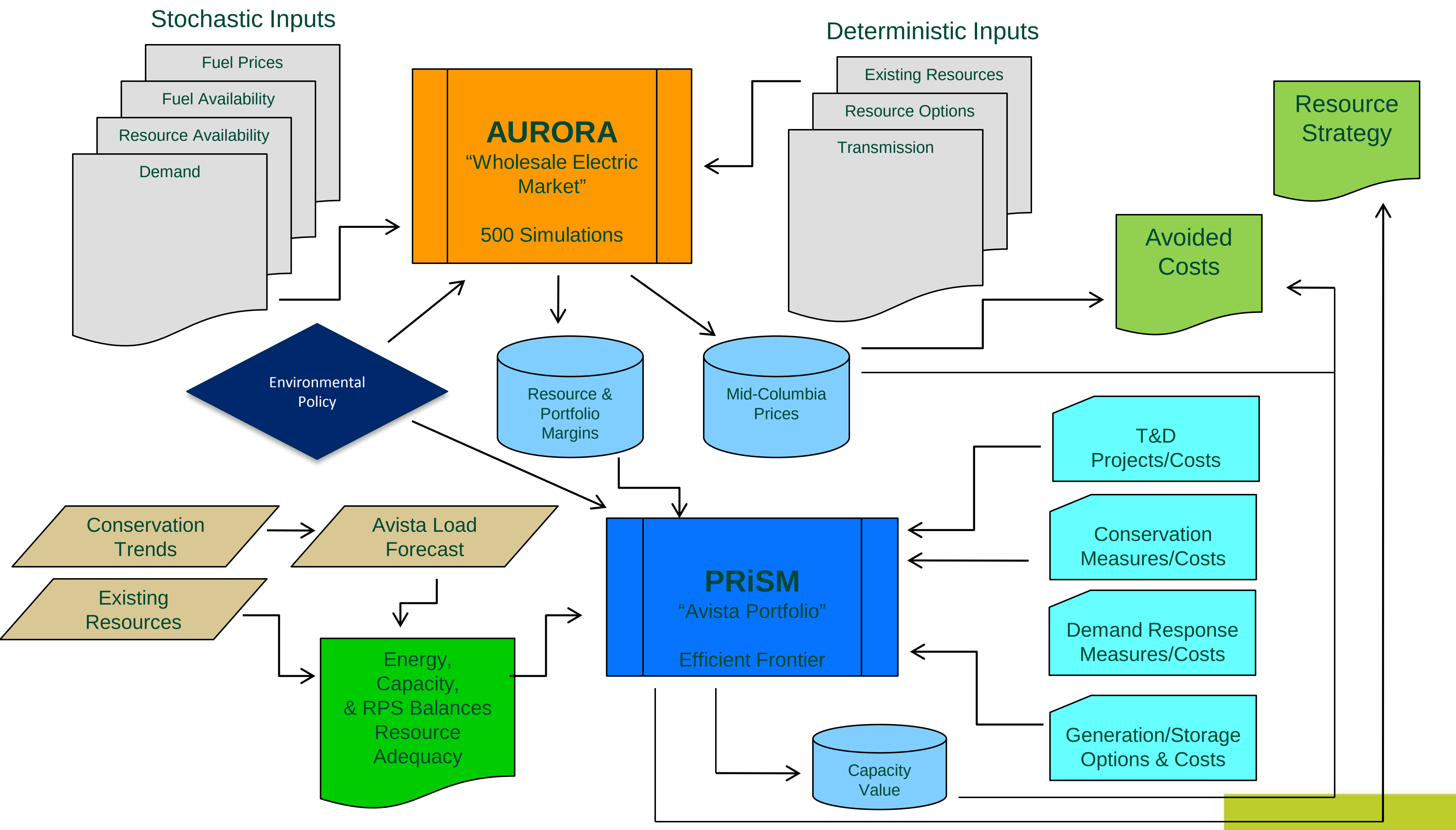
2019 IRP Modeling Process Overview

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

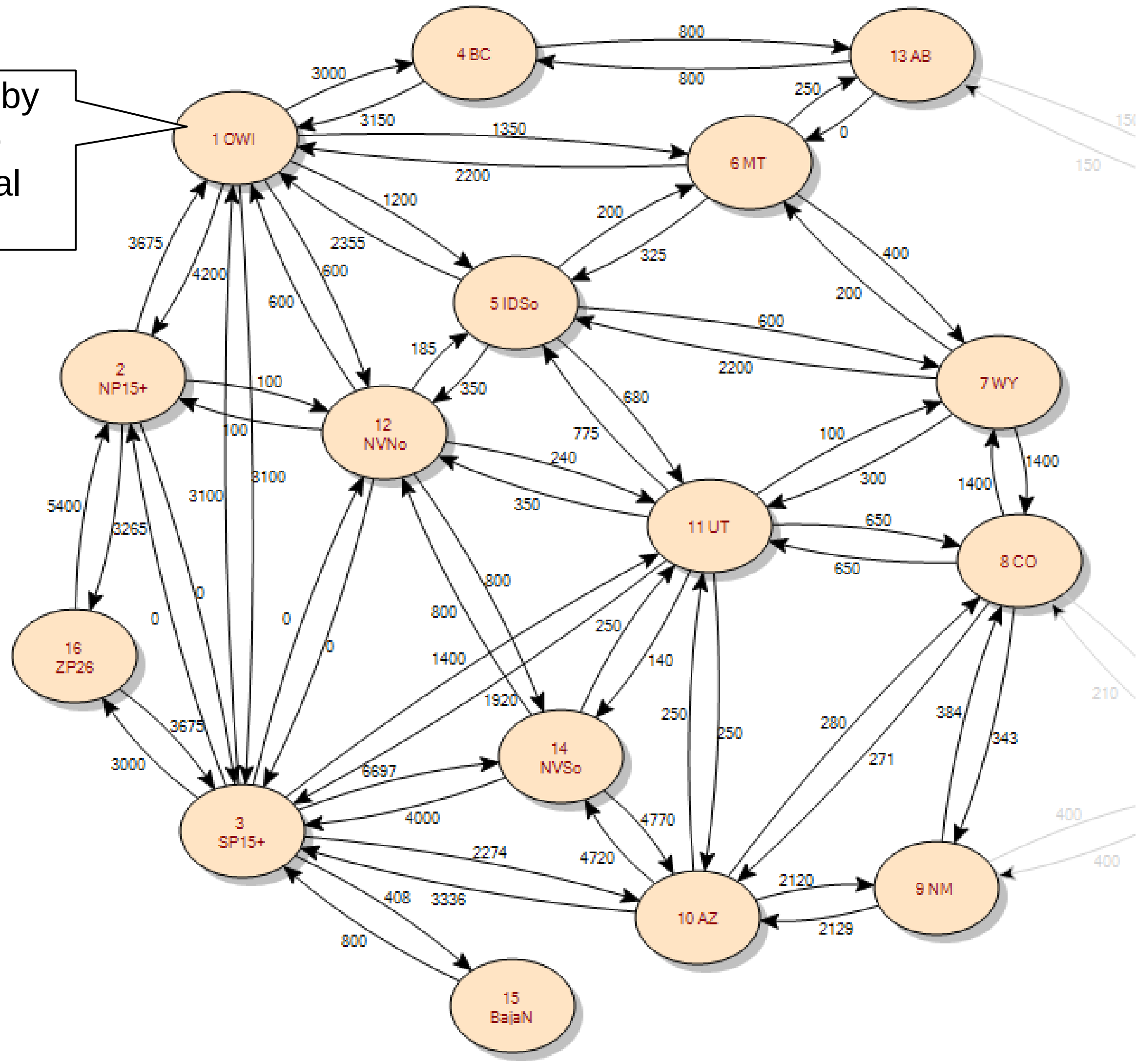
Outputs:
- Market prices
- Energy mix
- Transmission usage
- Emissions
- Power plant margins, generation levels, fuel costs
- Avista's variable power supply costs

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)

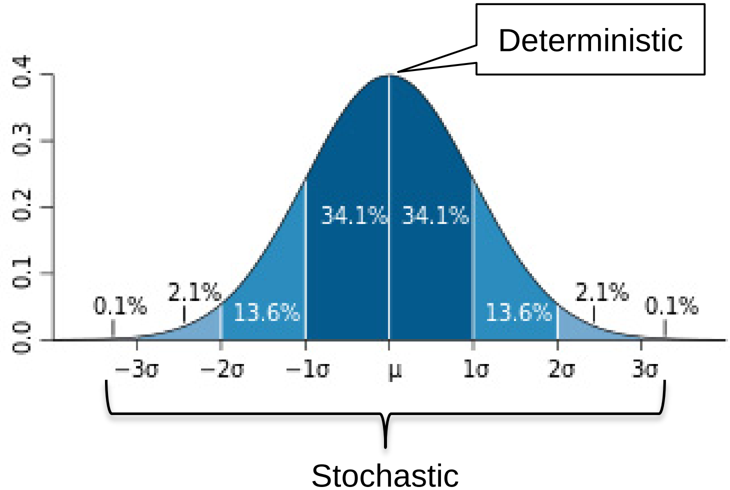
Aurora Load Area Topology

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

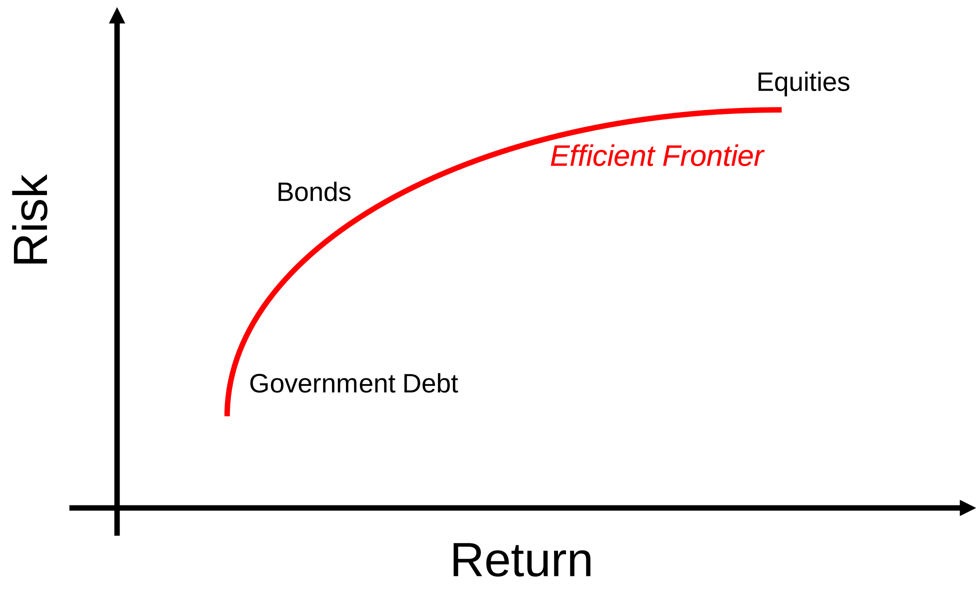
PRiSM

- 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

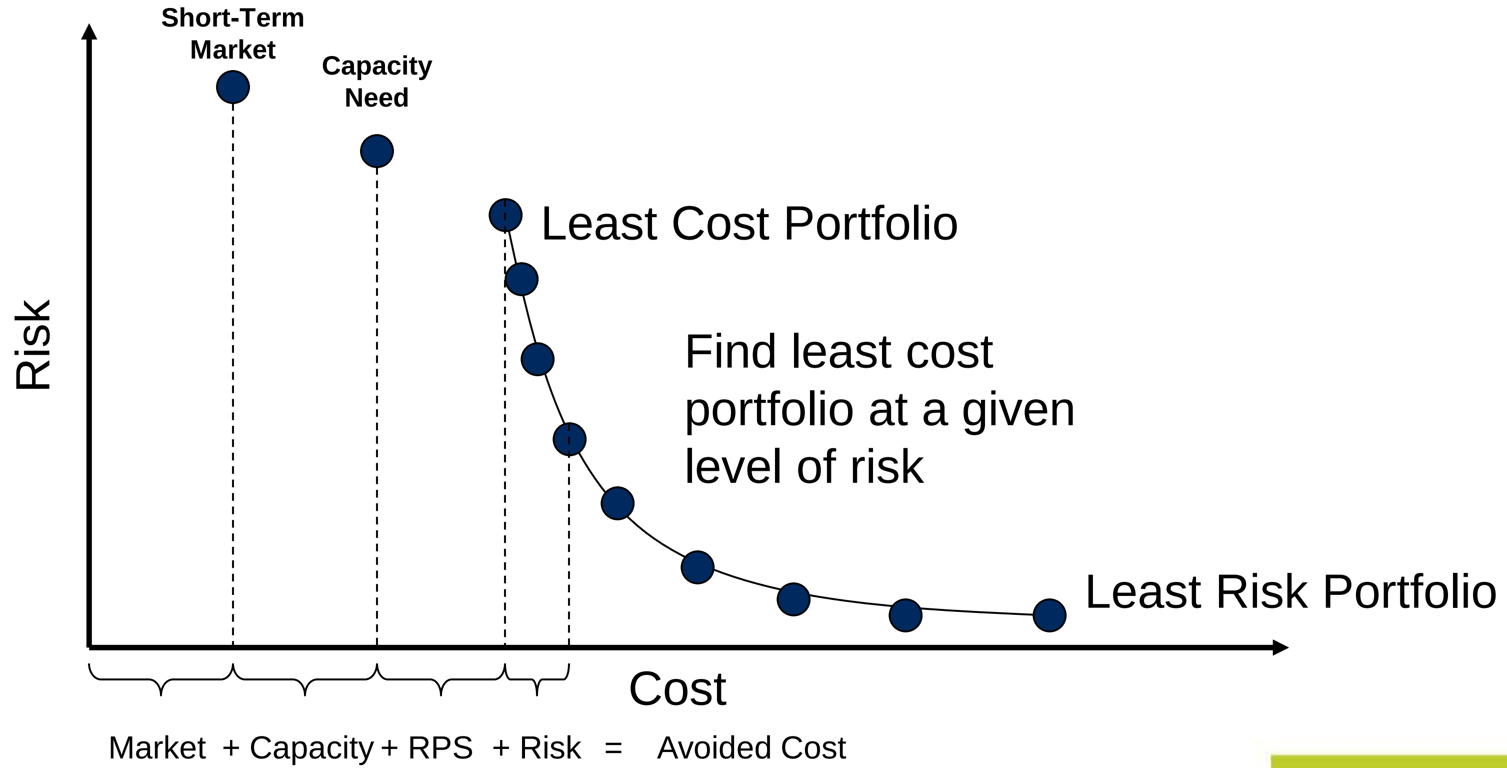
- Does not find the optimal portfolio, only the optimal portfolio for a given level of risk.
- Used in investment finance for portfolio management.

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

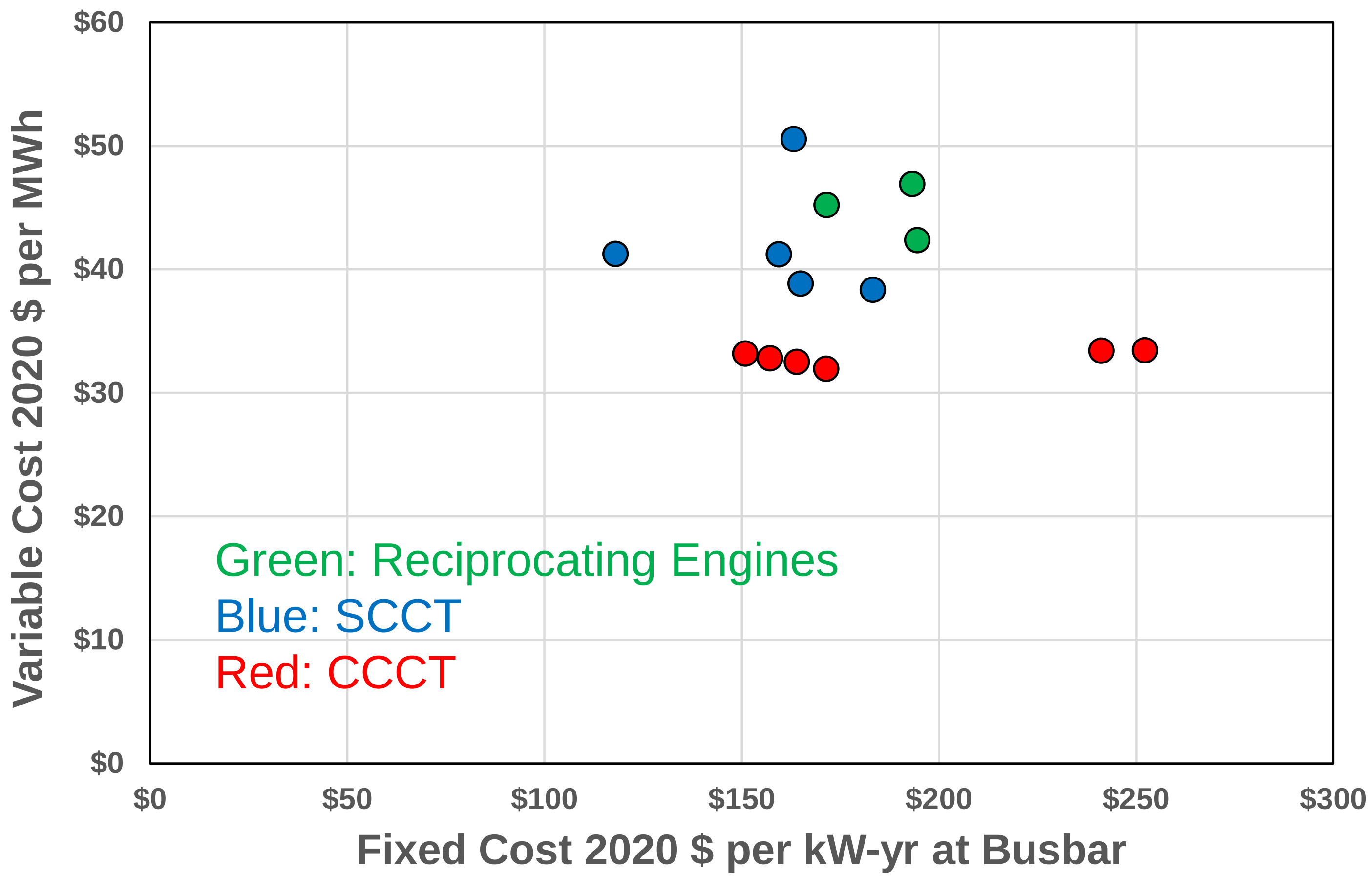
Other Storage Options

- 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

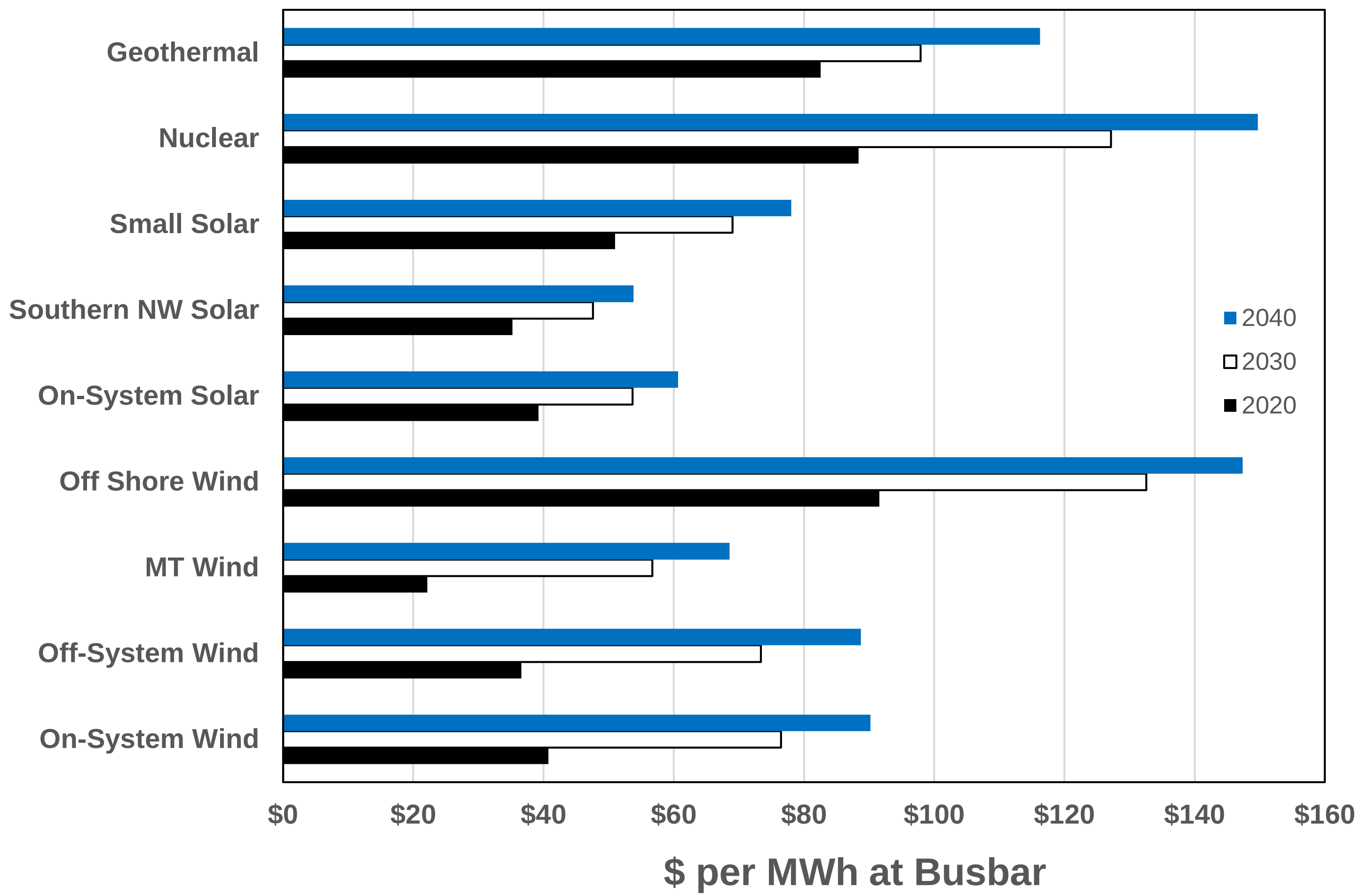
Resource Upgrades

- **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



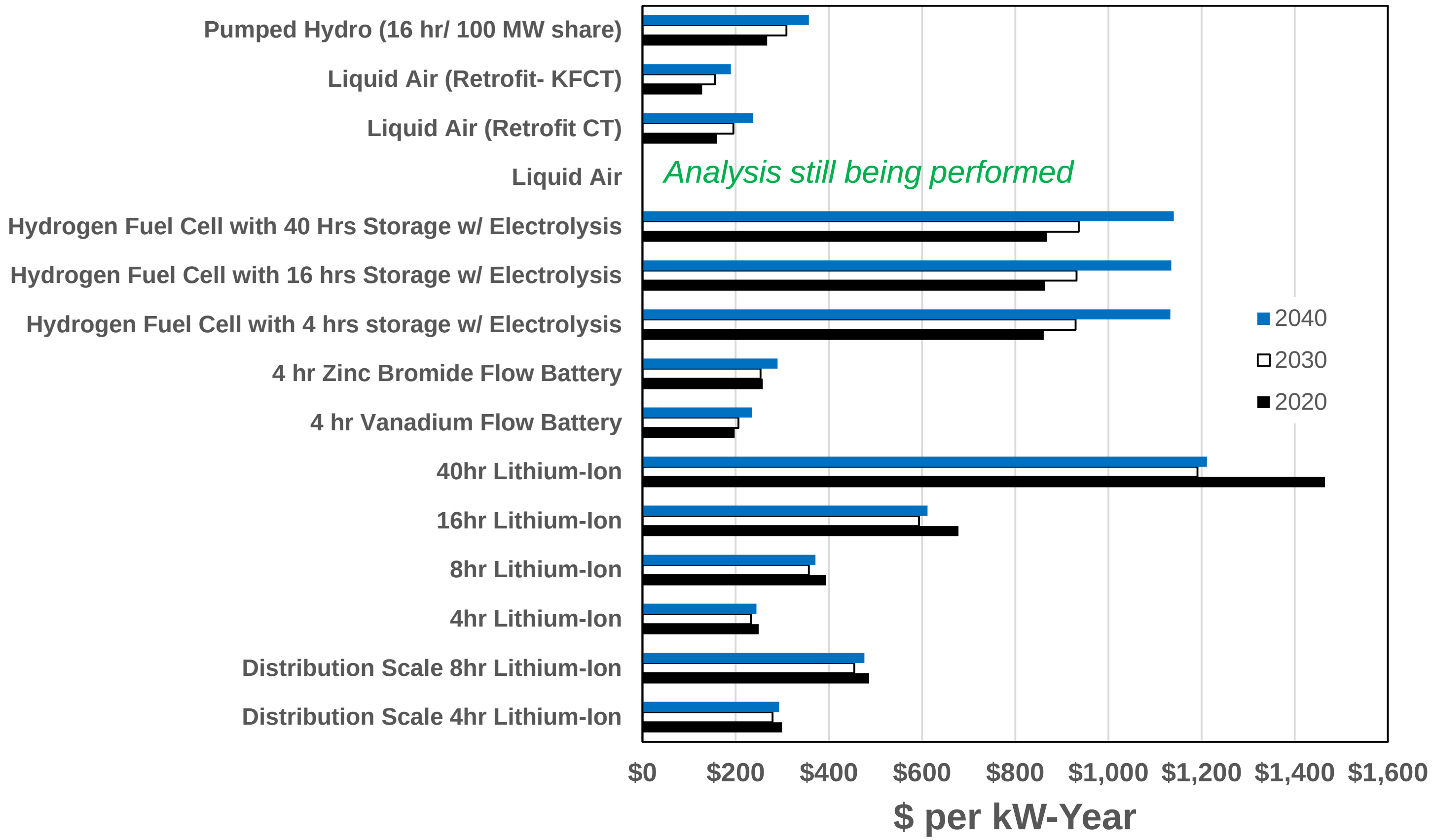
PPA Resource Cost Analysis



Prices include utility loading such as variability integration and revenue taxes

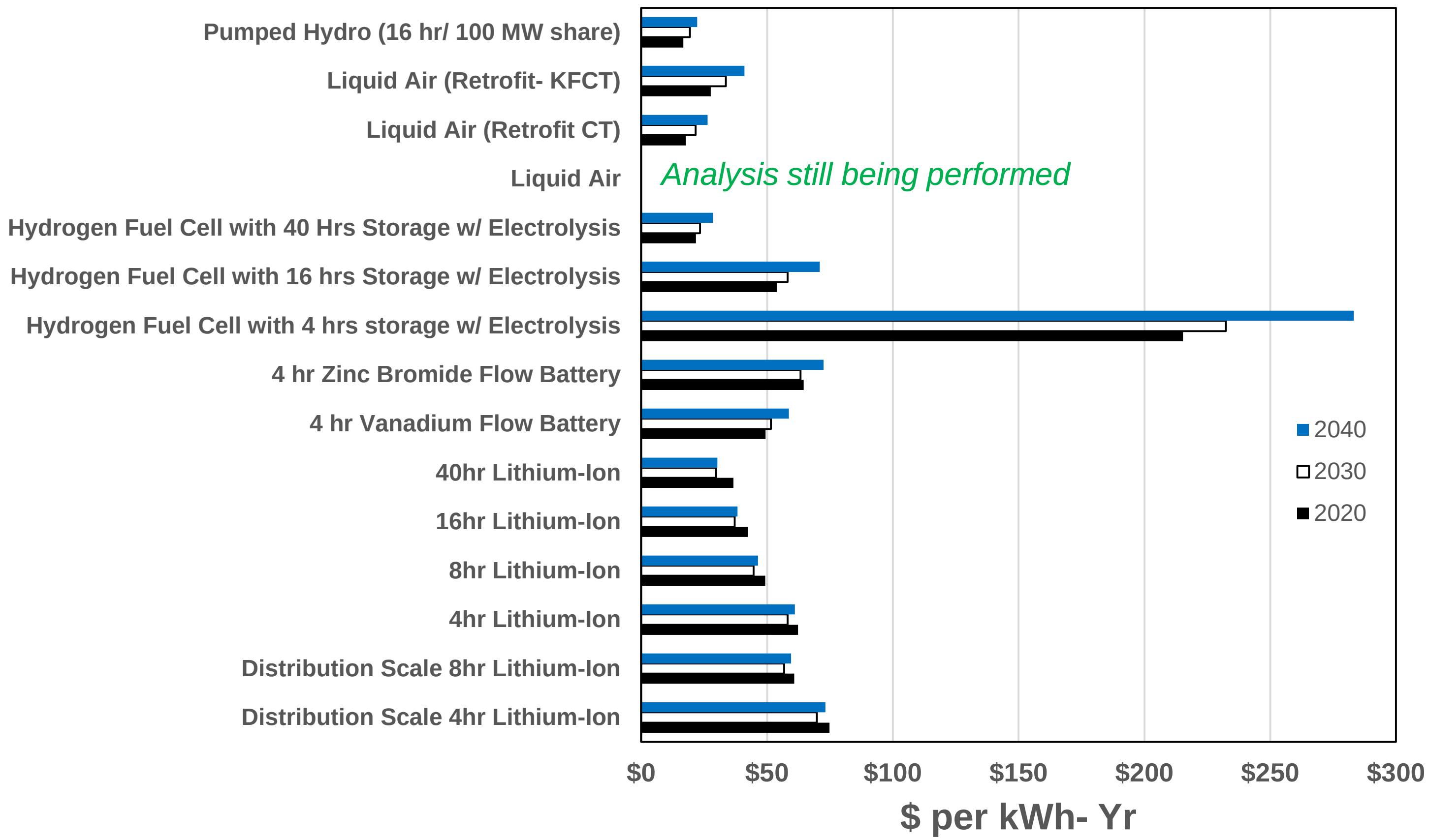
Storage Costs

Capacity based cost analysis

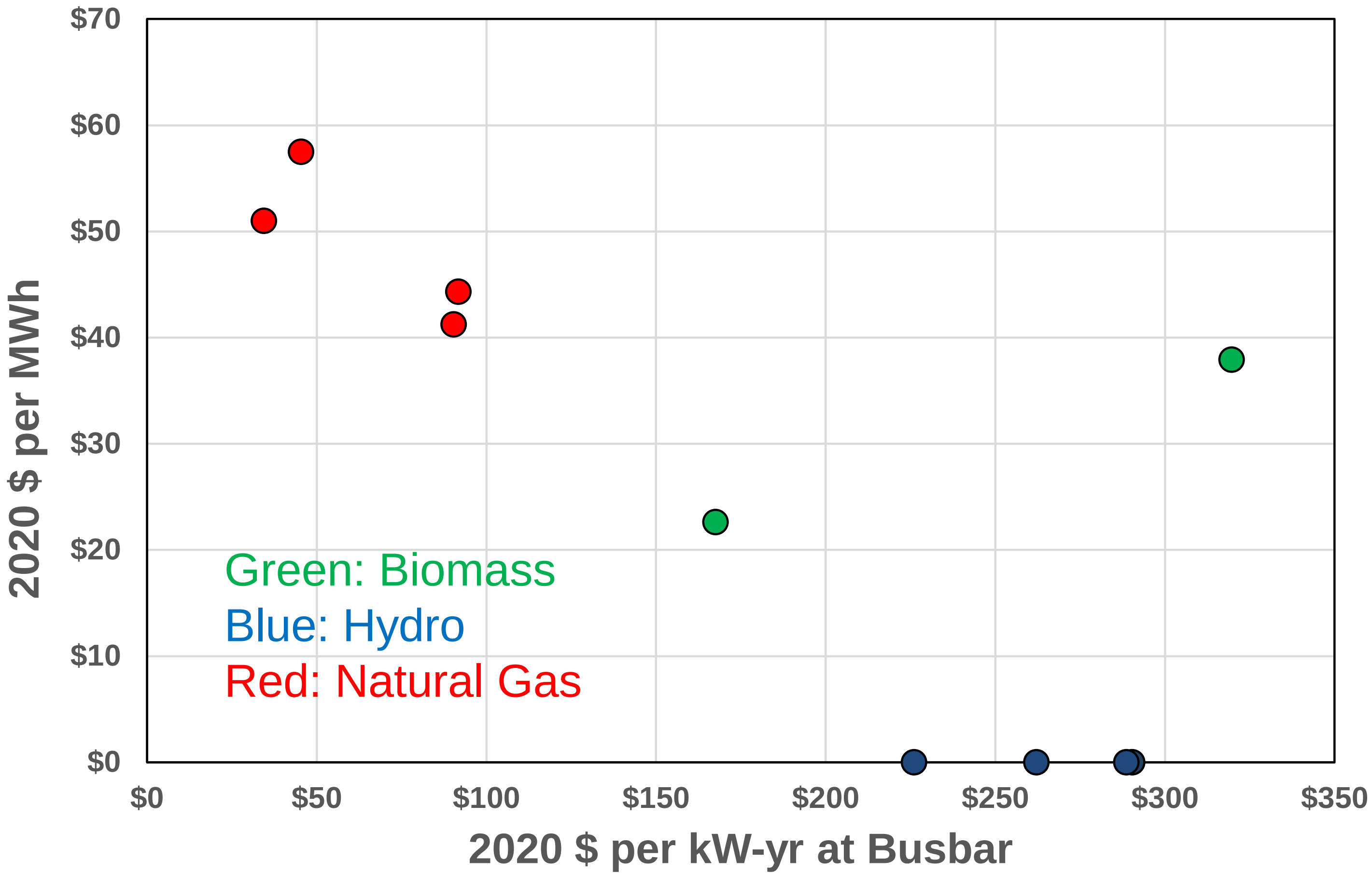


Storage Costs

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

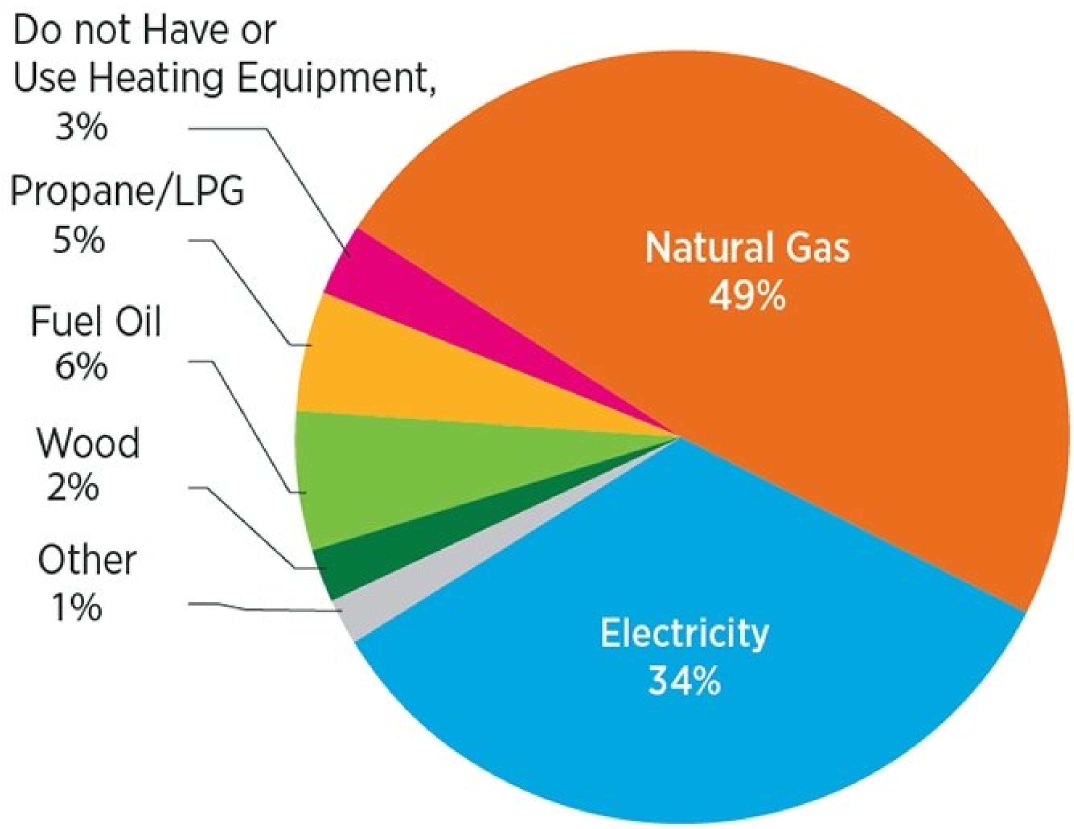
Home Heating Technologies Overview

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.

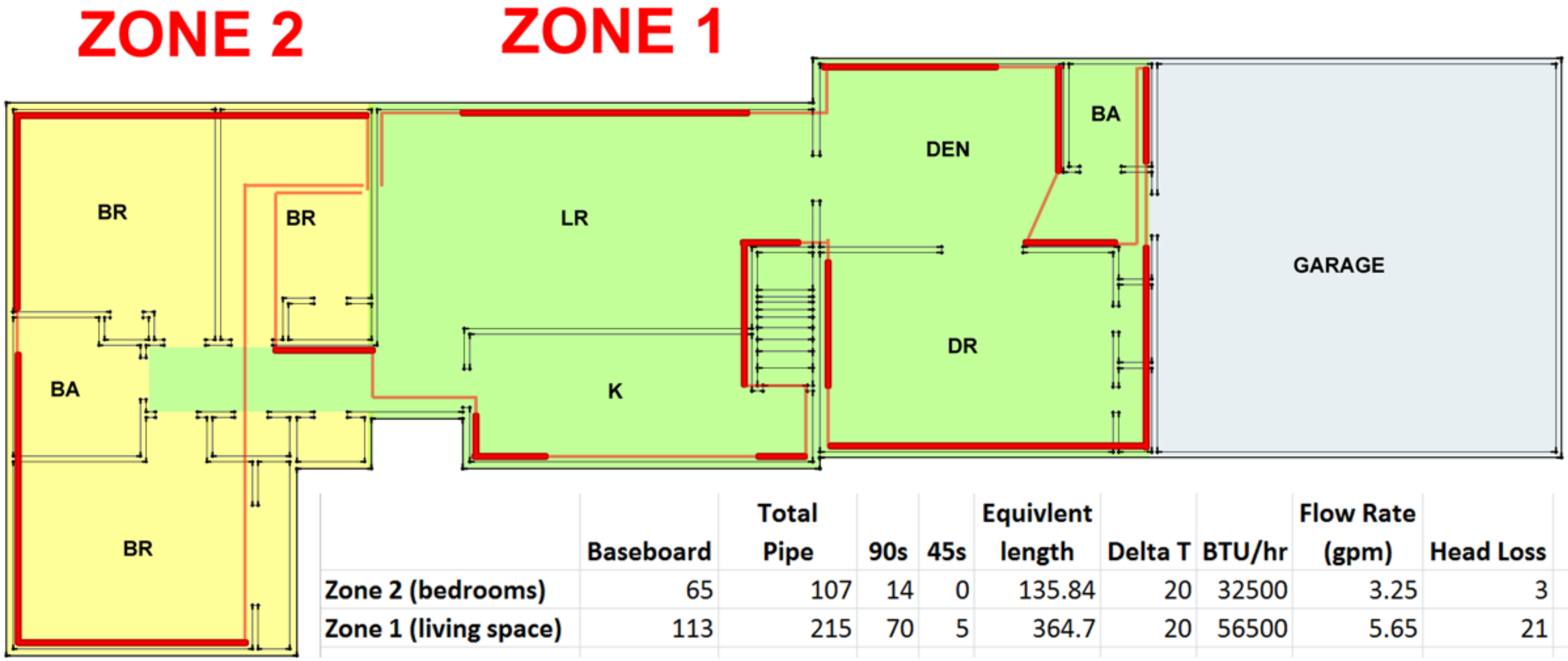
Zoning

- 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.

AVISTA

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.

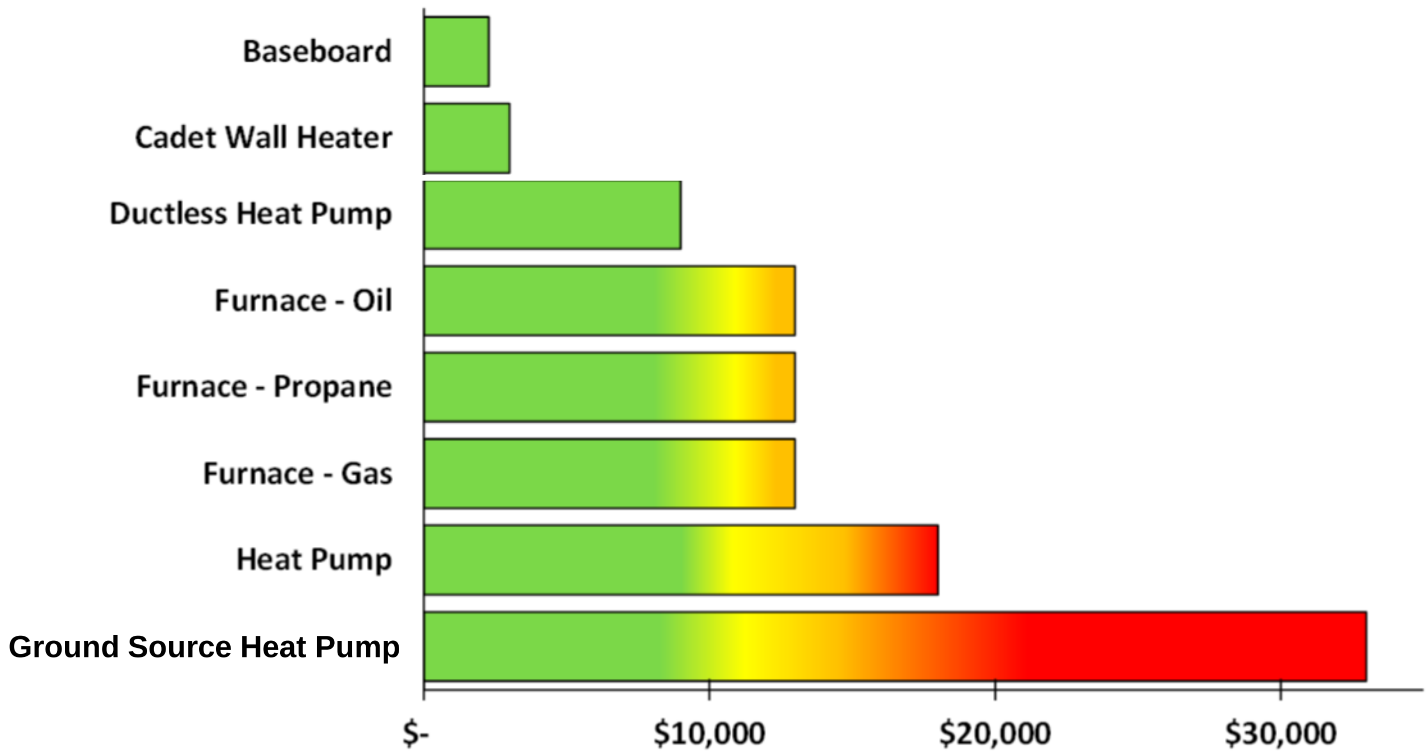
First Cost of Technologies

- 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

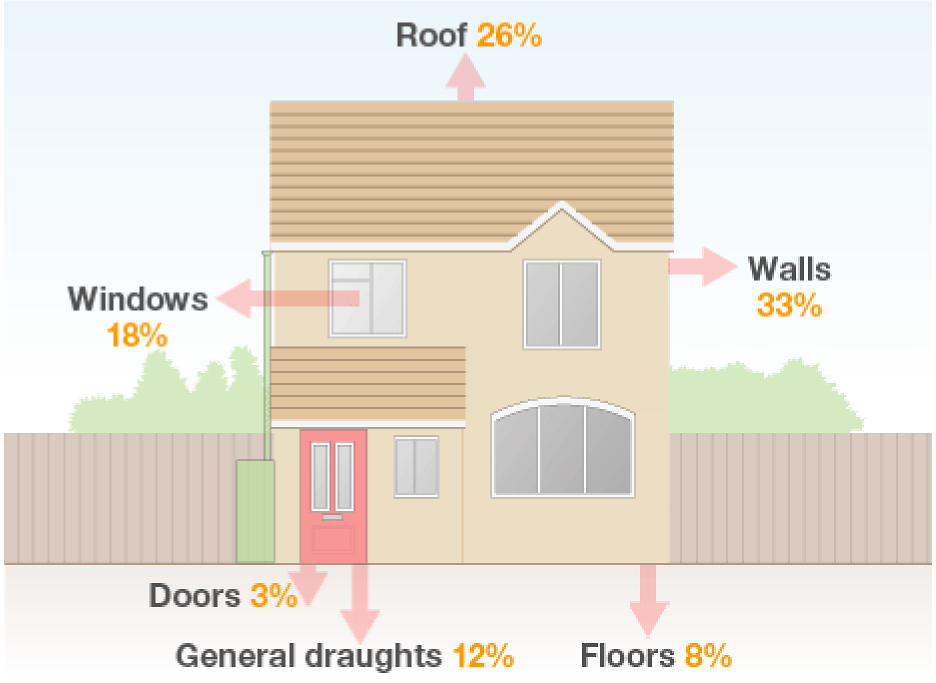


Baseboard
Cadet Wall Heater
Ductless Heat Pump
Furnace - Oil
Furnace - Propane
Furnace - Gas
Heat Pump
Ground Source Heat Pump
$-
$10,000
$20,000
$30,000

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

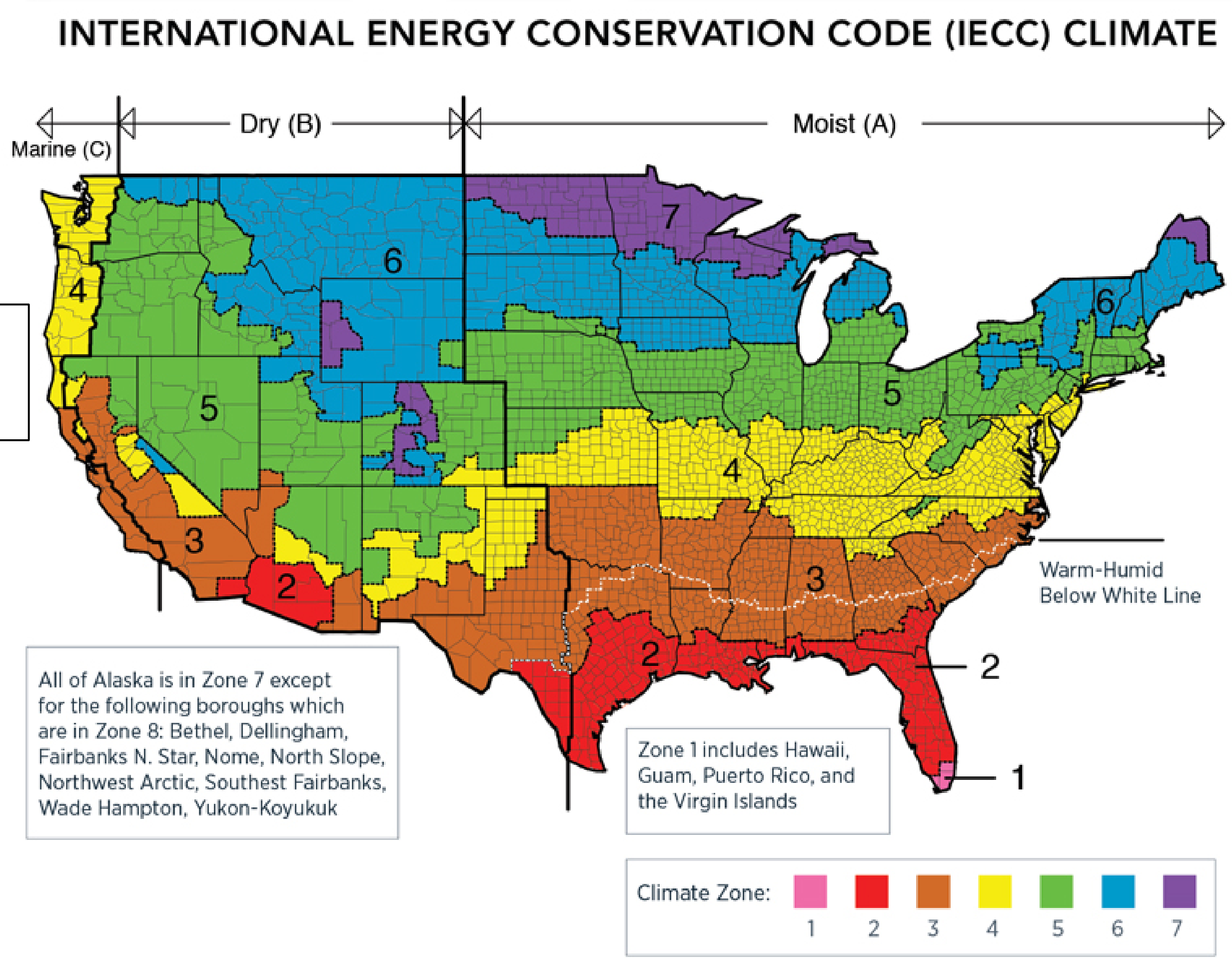
Home Heat Loss



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

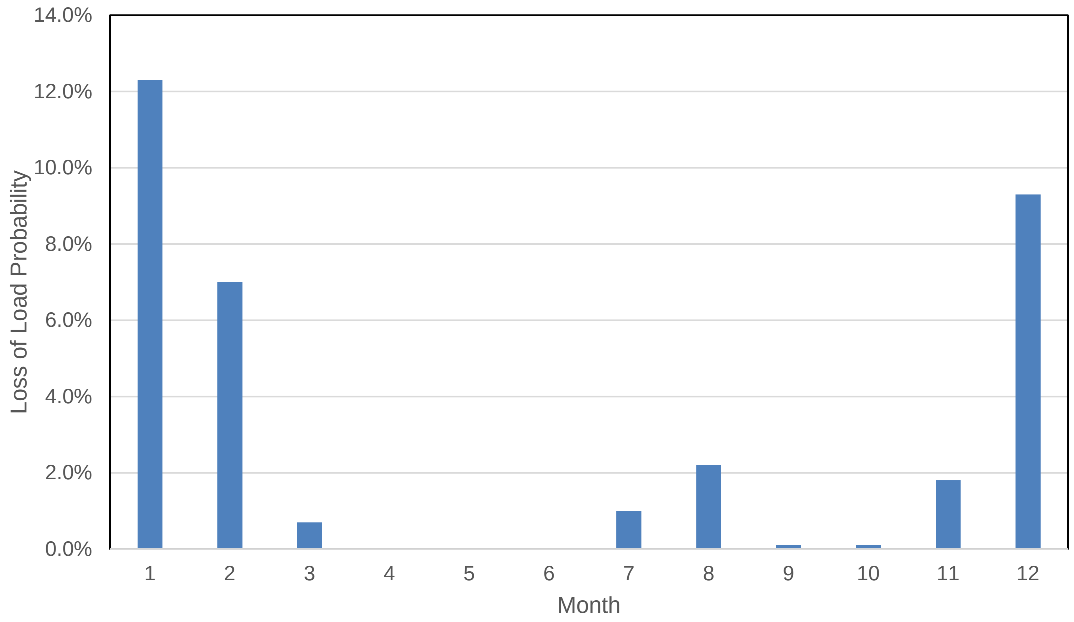
The Model

- 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

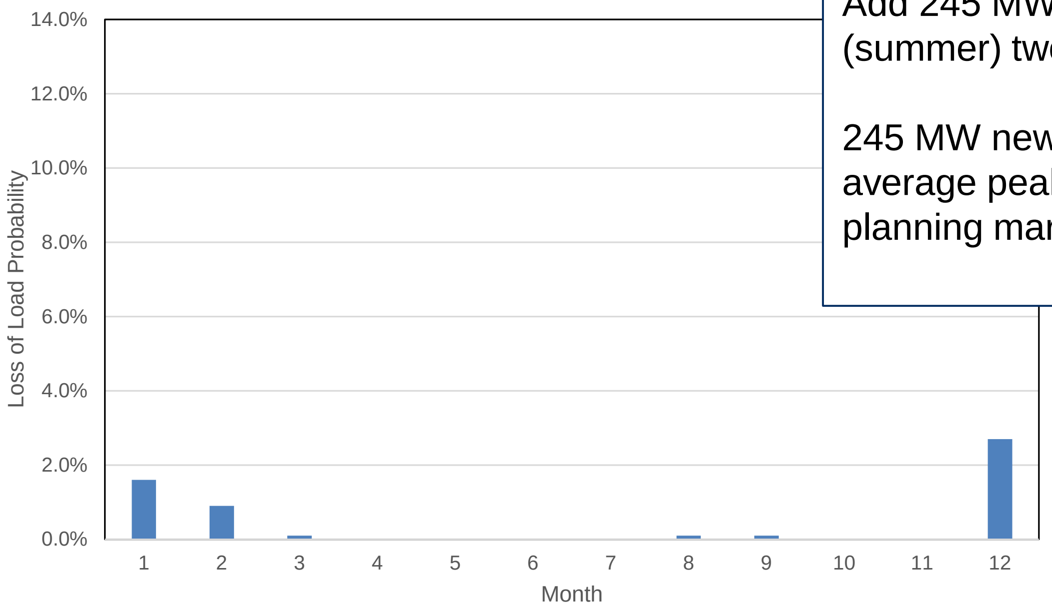
- 2030 load and resources
- Average peak load: 1,778 MW (Winter), 1,636 MW (Summer)
- Average hourly load: 1,081 MW
- Major resource changes from today: No Lancaster, less Mid-C, no WNP-3 contract
- Off-peak market purchases limited to 1,000 MW
- On-peak market purchase limited to 400 MW
- When daily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

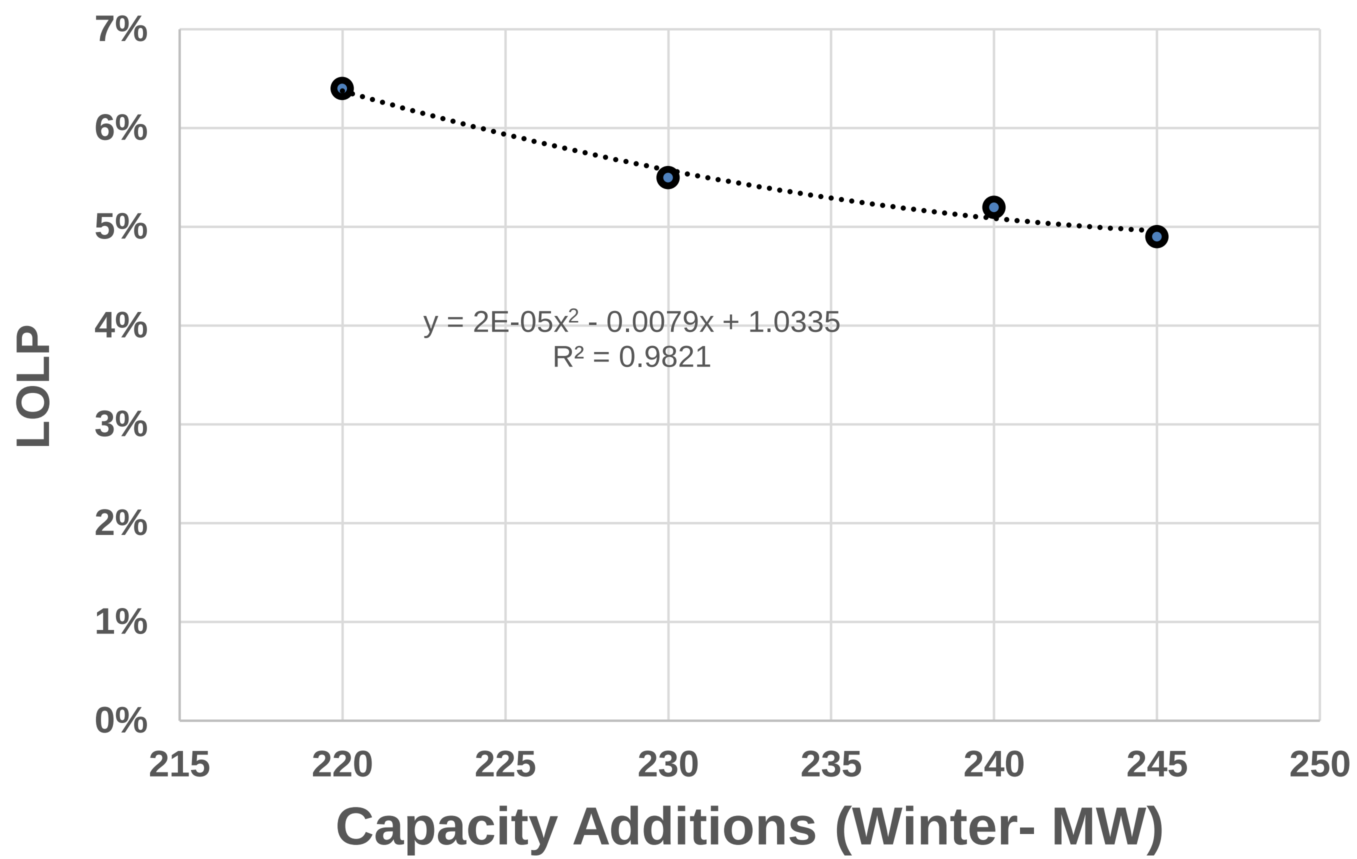


Add 245 MW (winter) / 182 MW (summer) two unit CT

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: $30/metric ton (Can$)

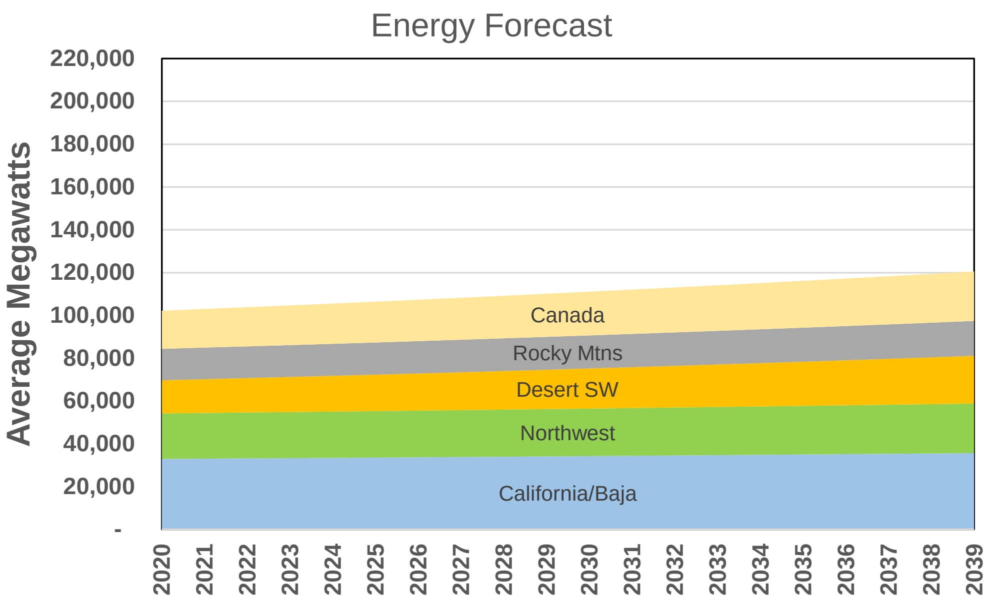
Aurora Inputs

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

Regional Loads

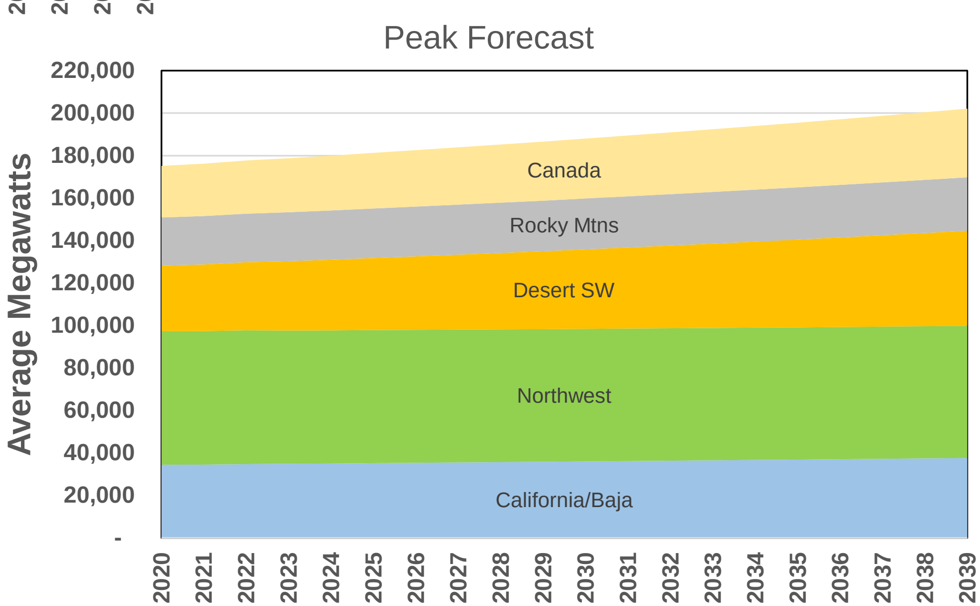
- Forecast load growth for all Western Interconnect regions
- Consider both peak and energy growth
- Use latest load forecast from Epis
- Stochastic modeling simulates load changes due to weather and considers regional correlation of weather patterns
- Economically driven load changes are difficult to 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



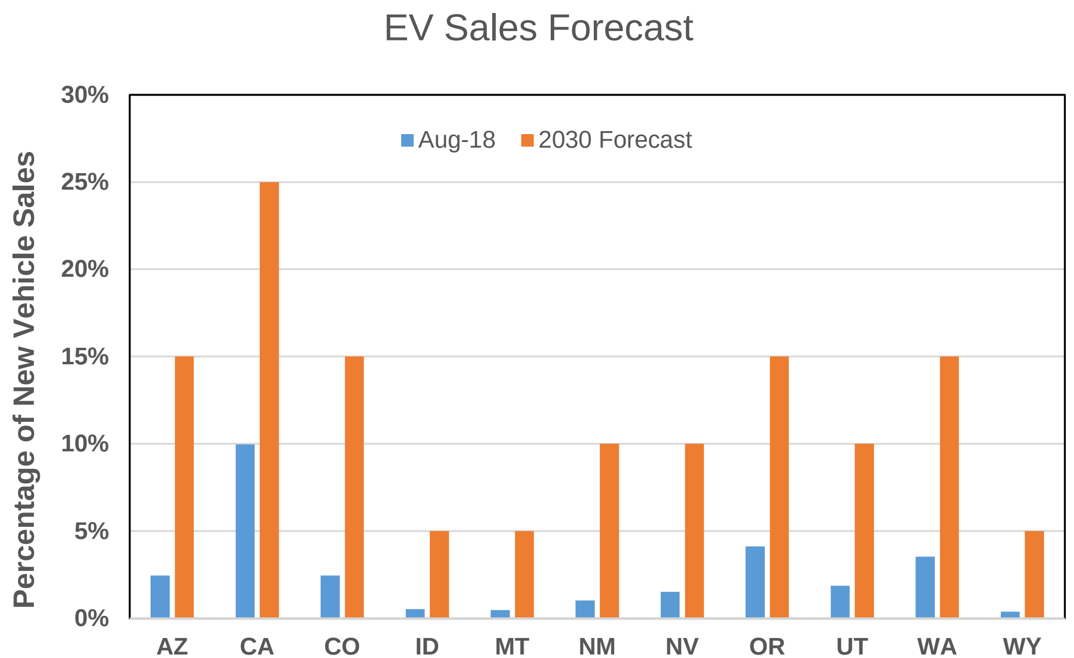
Energy	AAGR	Change
Canada	1.32%	
Rocky Mtns.	0.53%	
Desert SW	1.84%	
California	0.40%	
Northwest	0.42%	
Total	0.83%	

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)

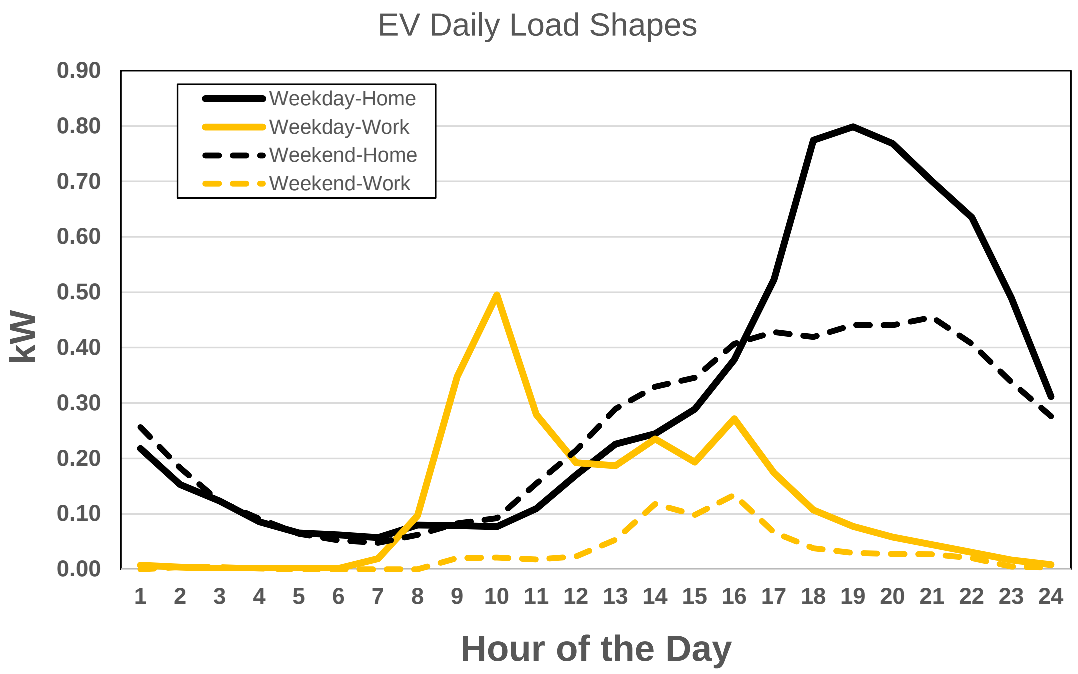
- Current load shapes have low EV penetration, but by 2030, load shapes will differ due to EV and behind the meter solar
- EV percentage of new vehicle sales forecast by 2030
- After 2030, EV growth equals traditional vehicle growth (half of population growth)



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

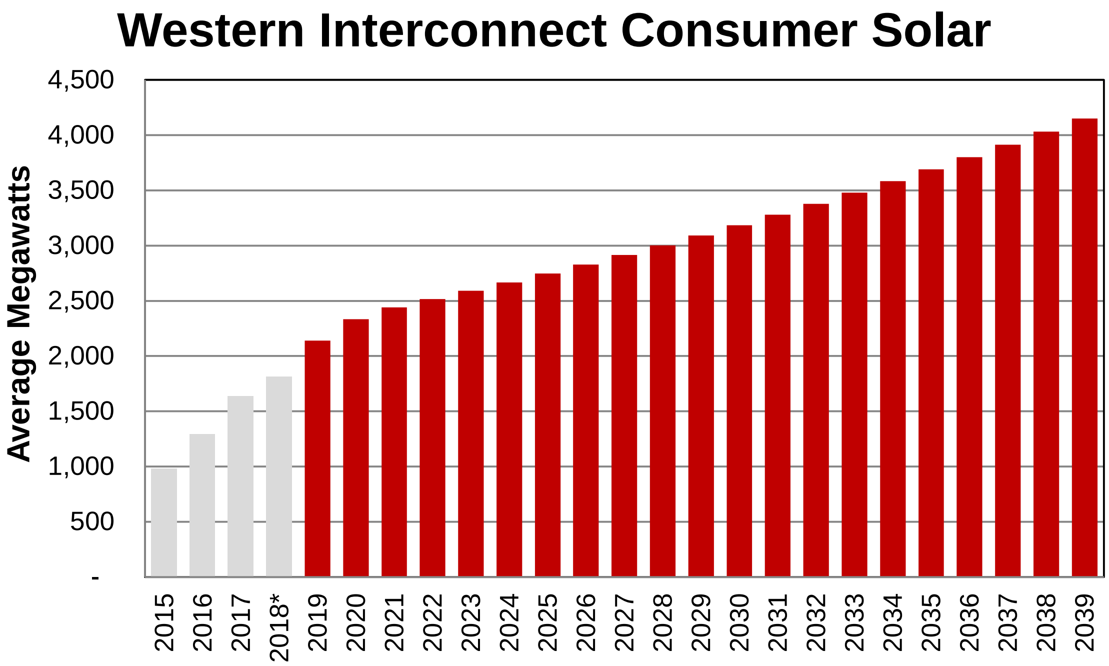
EV Load Shaping

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



Rooftop Solar

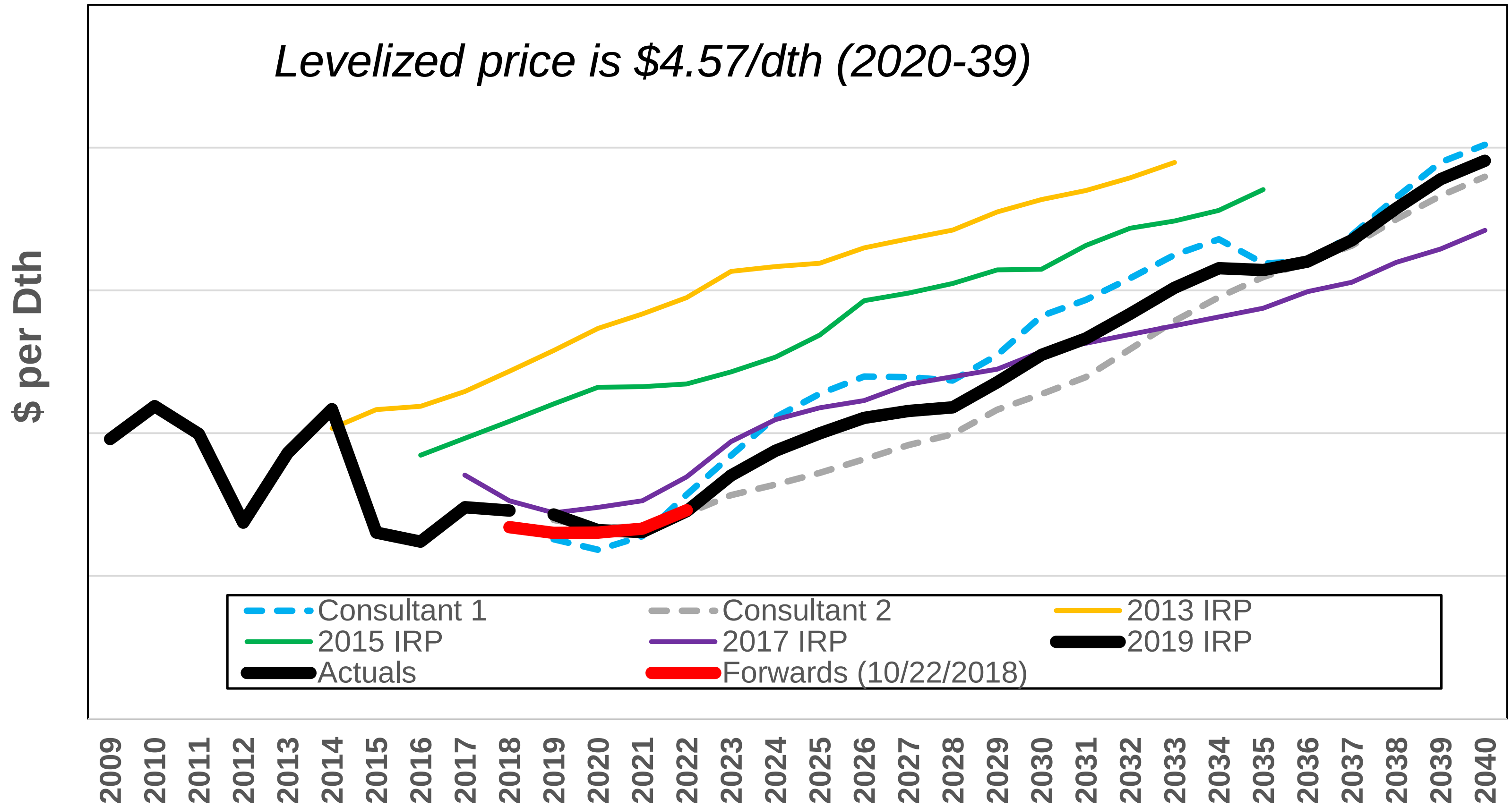
- Rooftop solar impacts future load growth and changes its hourly profile
- Future rooftop solar growth depends on policy choices
- Assumes 20-30% growth, before leveling off to 3% long run growth in 2020s



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**

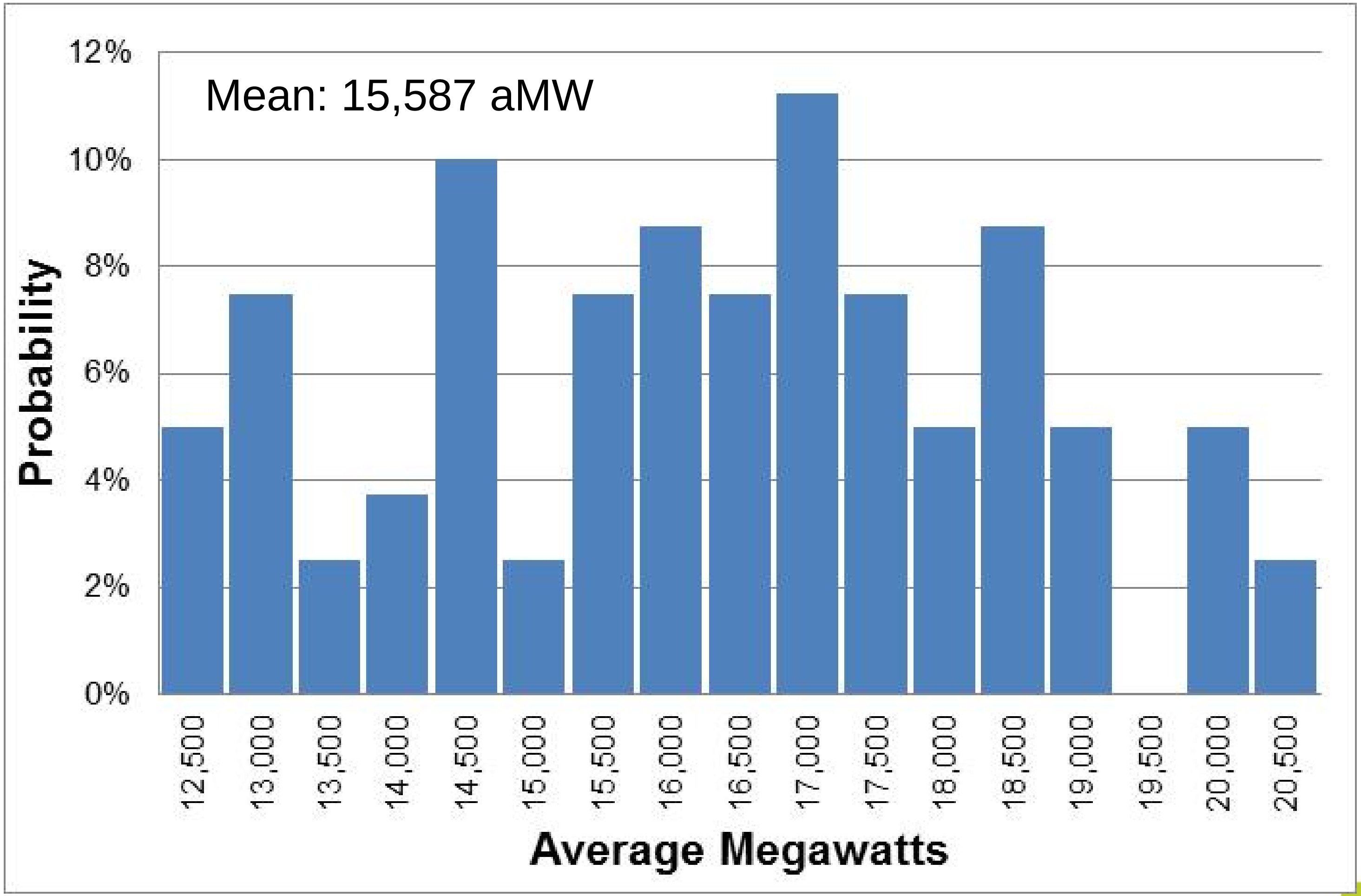
Coal Prices

- 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

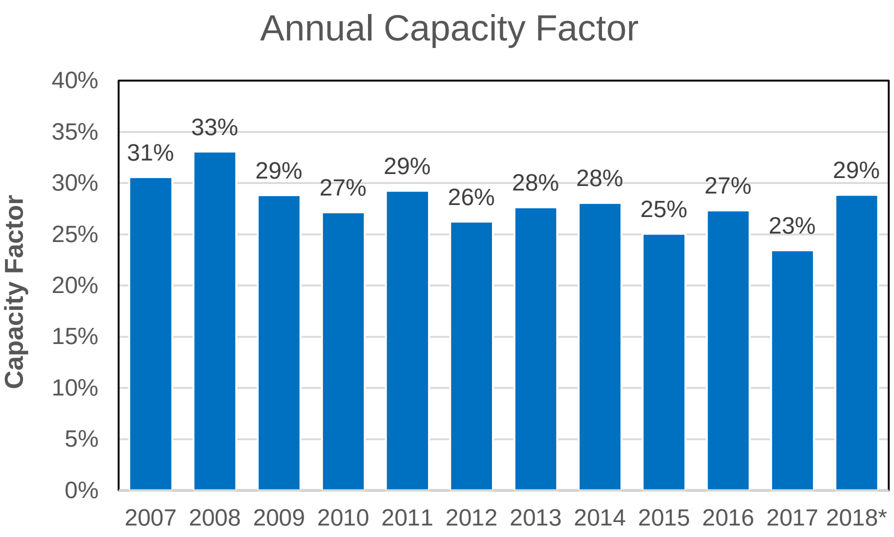


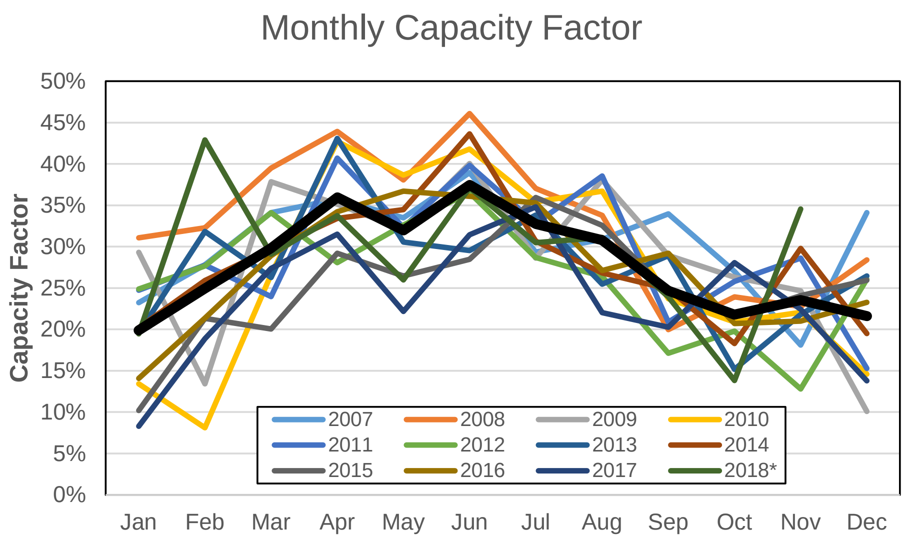
Wind

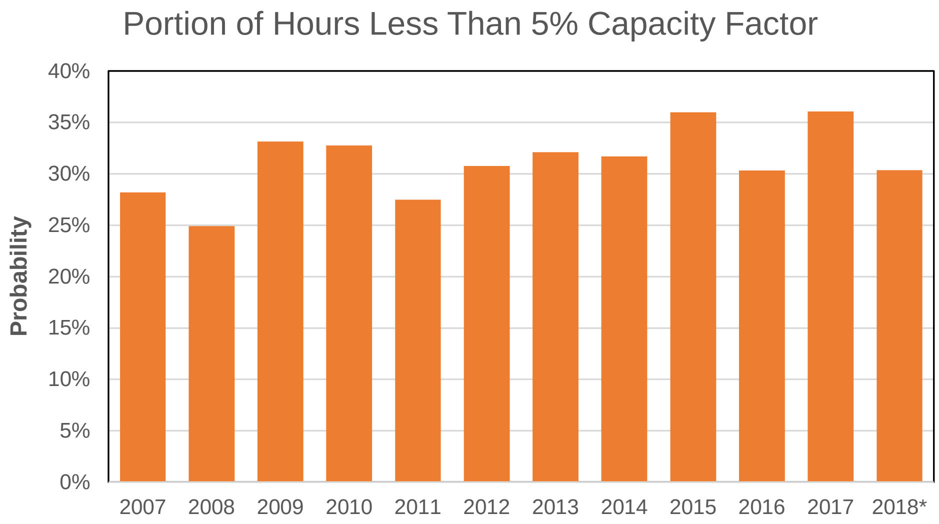
- Modeling technique
  - Autoregressive technique to simulate output in similar to reported data available from BPA, CAISO, and other publically available data sources- also considers correlation between regions
  - For stochastic studies several wind curves, will be drawn from to simulate variation 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







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 <u>futures</u> 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:

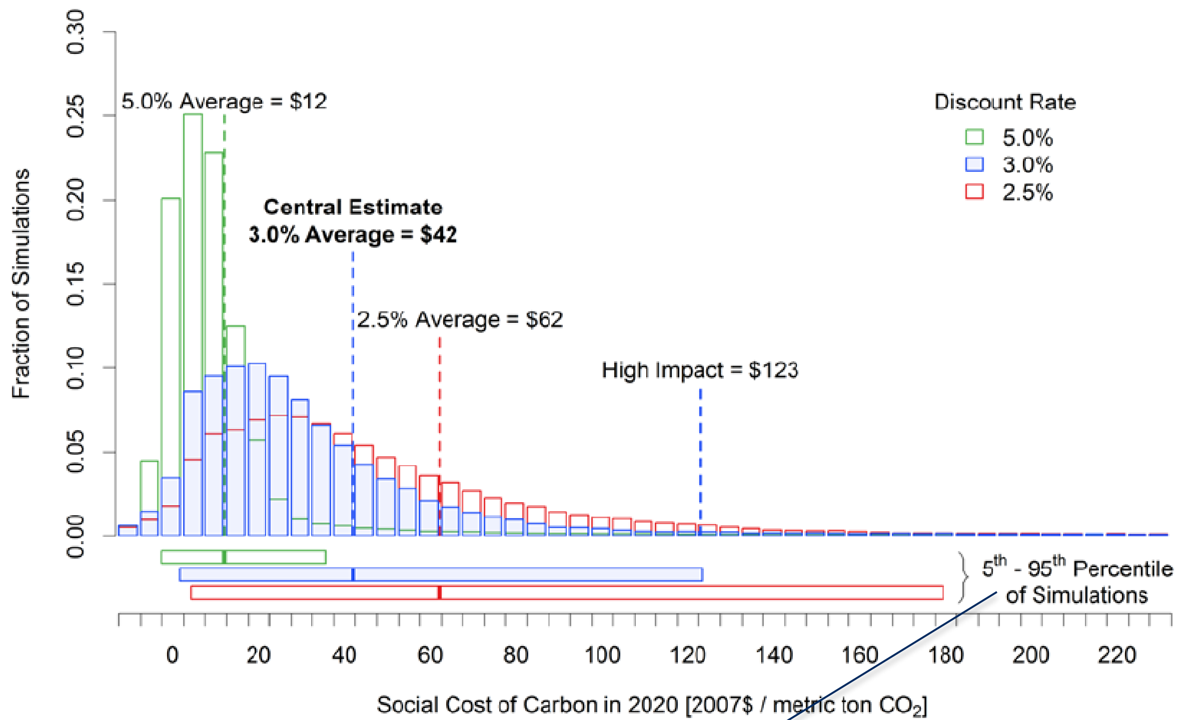
- 1/3 probability of no pricing
- 1/3 probability of $10/metric ton (2018$) escalating at 2.5% year
  - Begins in 2025
  - Applies to all of Western Interconnect resources
- 1/3 probability of cap and trade of 20% below 1990 levels
  - 20% goal by 2030
  - 40% goal by 2040
  - Applies to all of Western 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 (90^{th} Confidence Level)
  - 1/3 probability of 3.0% discount rate pricing distribution (90^{th} Confidence Level)
  - 1/3 probability of 2.5% discount rate pricing distribution (90^{th} Confidence Level)
- SCC will be applied to the Washington portion of load service for Avista resource portfolios

Social Cost of Carbon Pricing Distribution From

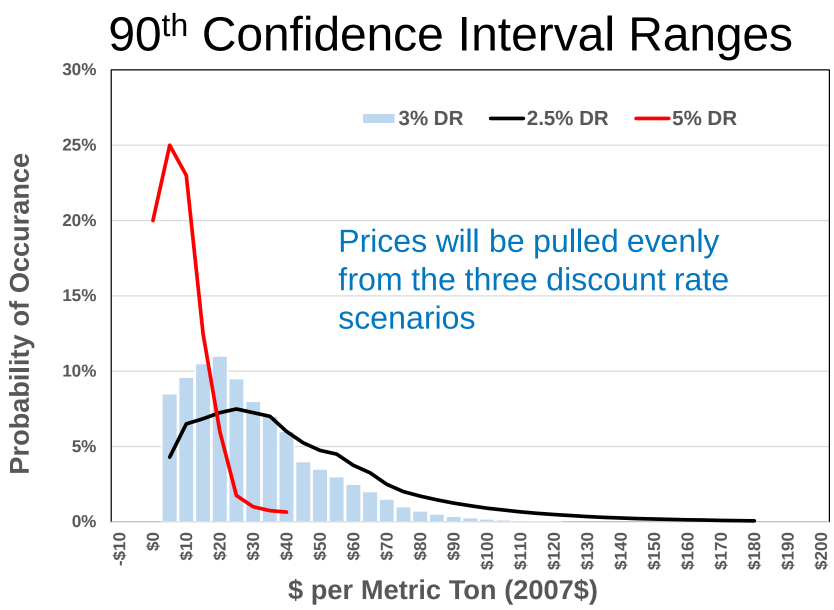
Figure ES-1: Frequency Distribution of SC-CO_2 Estimates for 2020[3]

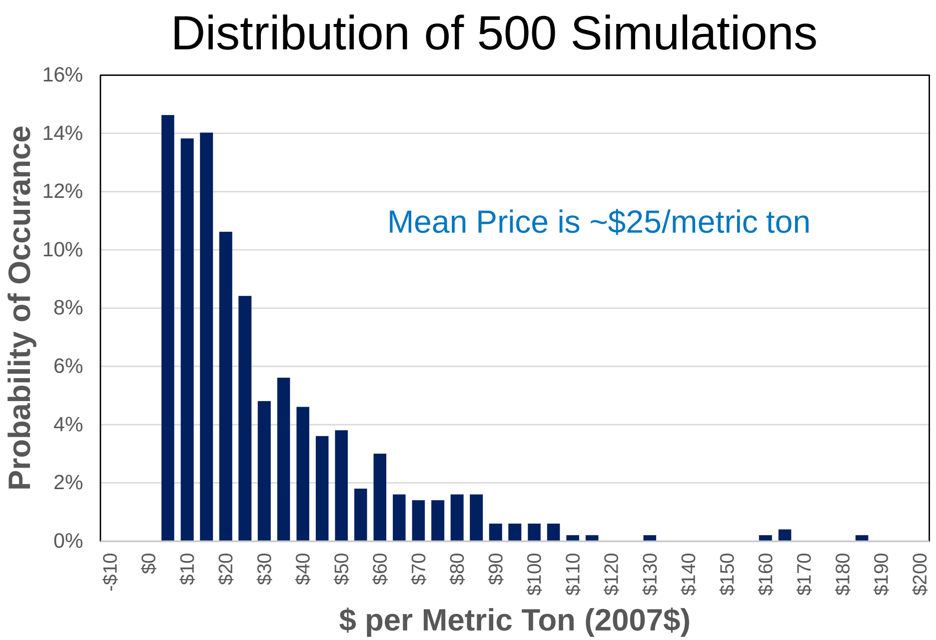


Use 90th confidence interval for each of the three distributions for the 500 simulations

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

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

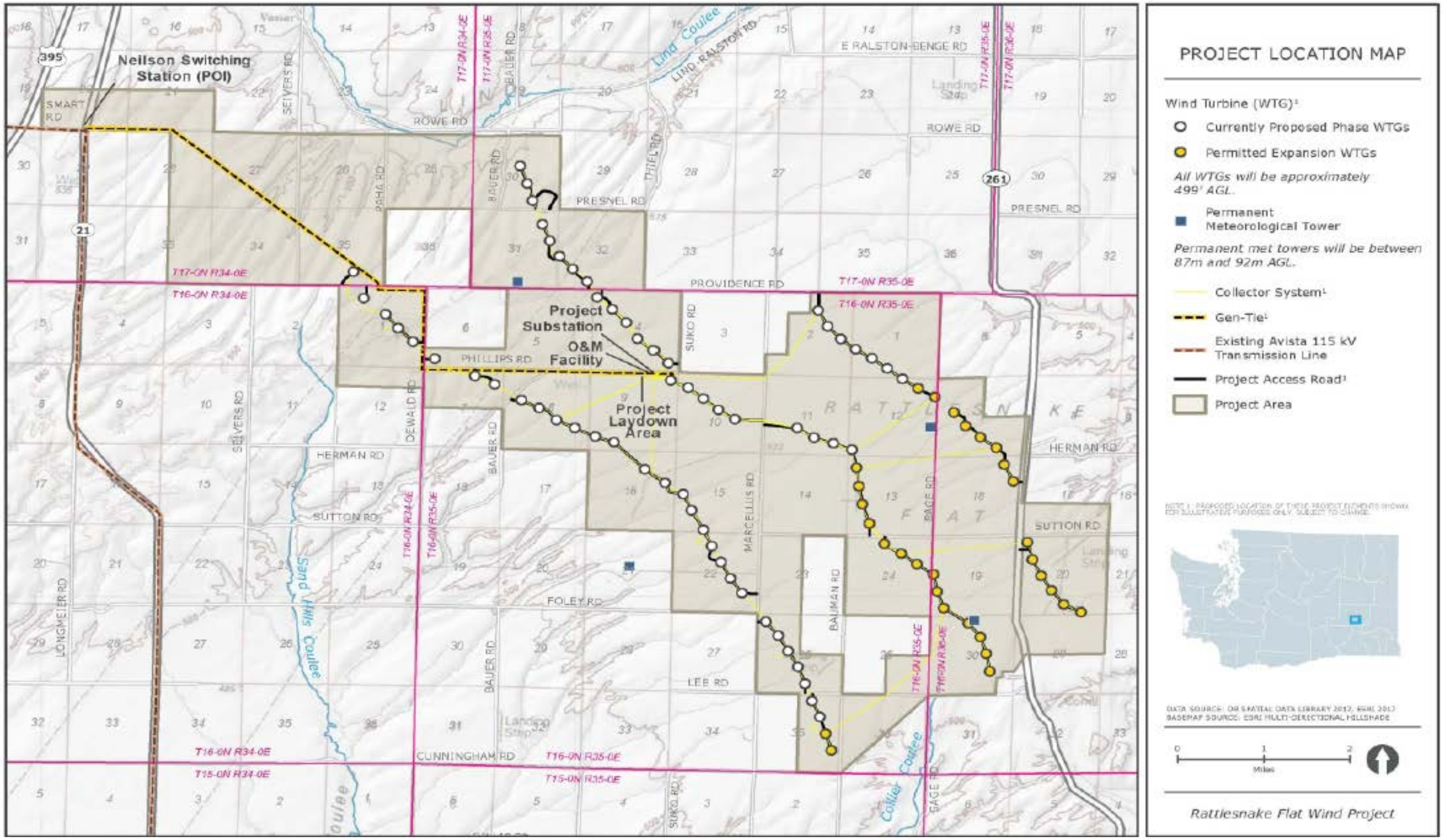
TAC #2 Recap – November 27, 2018

- 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 *<u>significantly</u>* 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

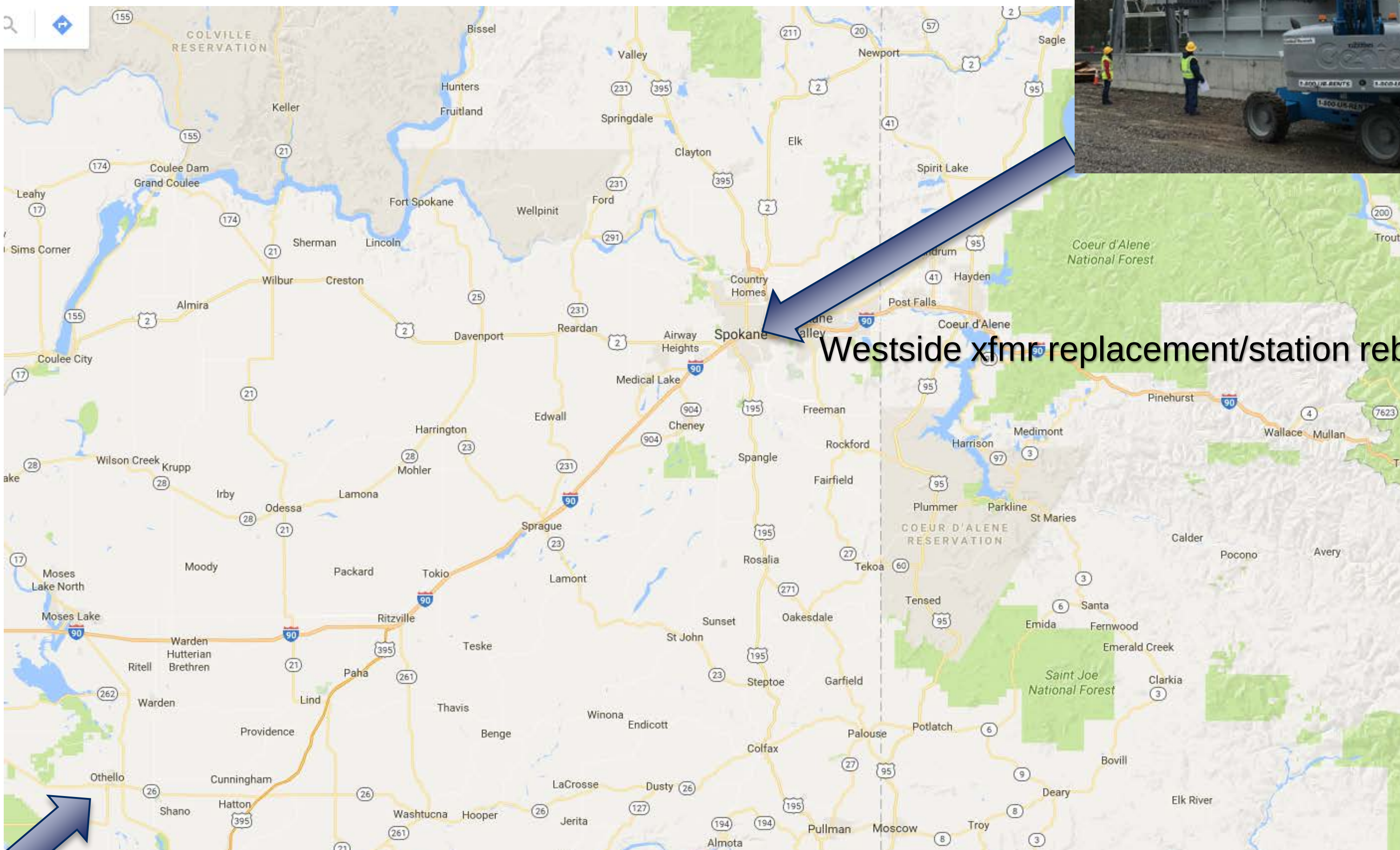
We Are Recovering From This…

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)

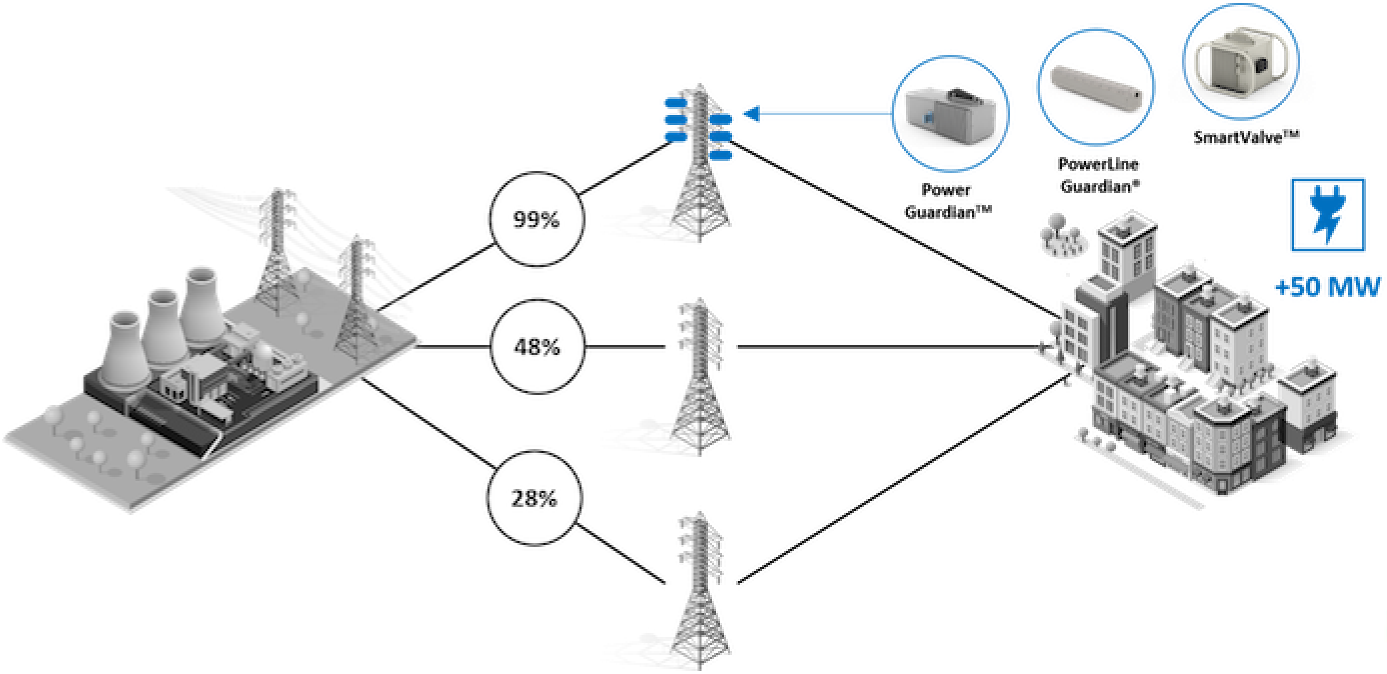
Non Wires (or perhaps no new wires)

- 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

AVISTA

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	

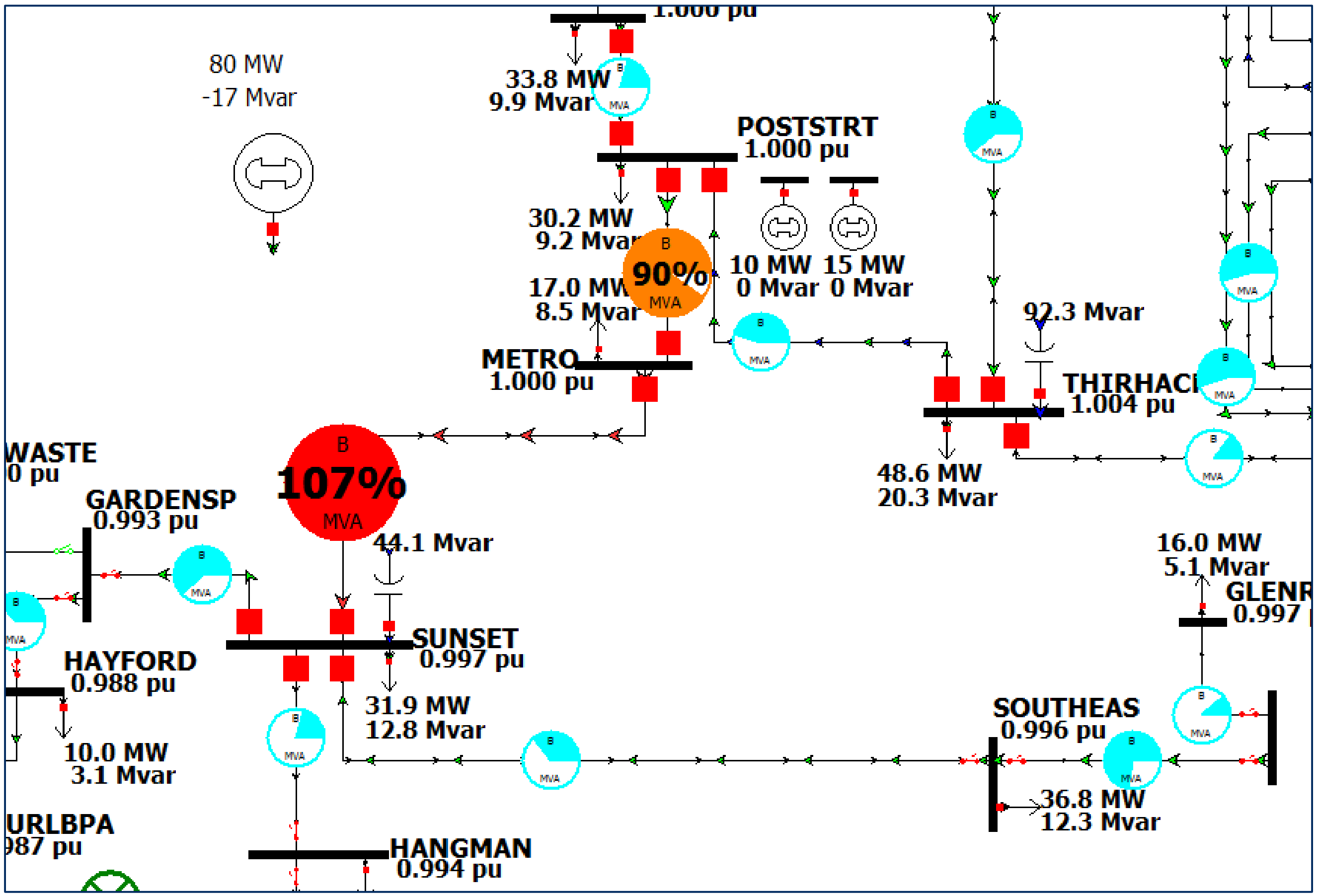
Study reports (listed under column P) are available upon request. Contact Randy Gnaedinger @ 509-495-2047 or Randy.Gnaedinger@Avistacorp.com to request a copy of a report. Reports may contain Critical Energy Infrastructure Information ("CEII") and may require the requestor to sign a CEII Non-Disclosure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

Glossary of terms

Construction	Construction phase

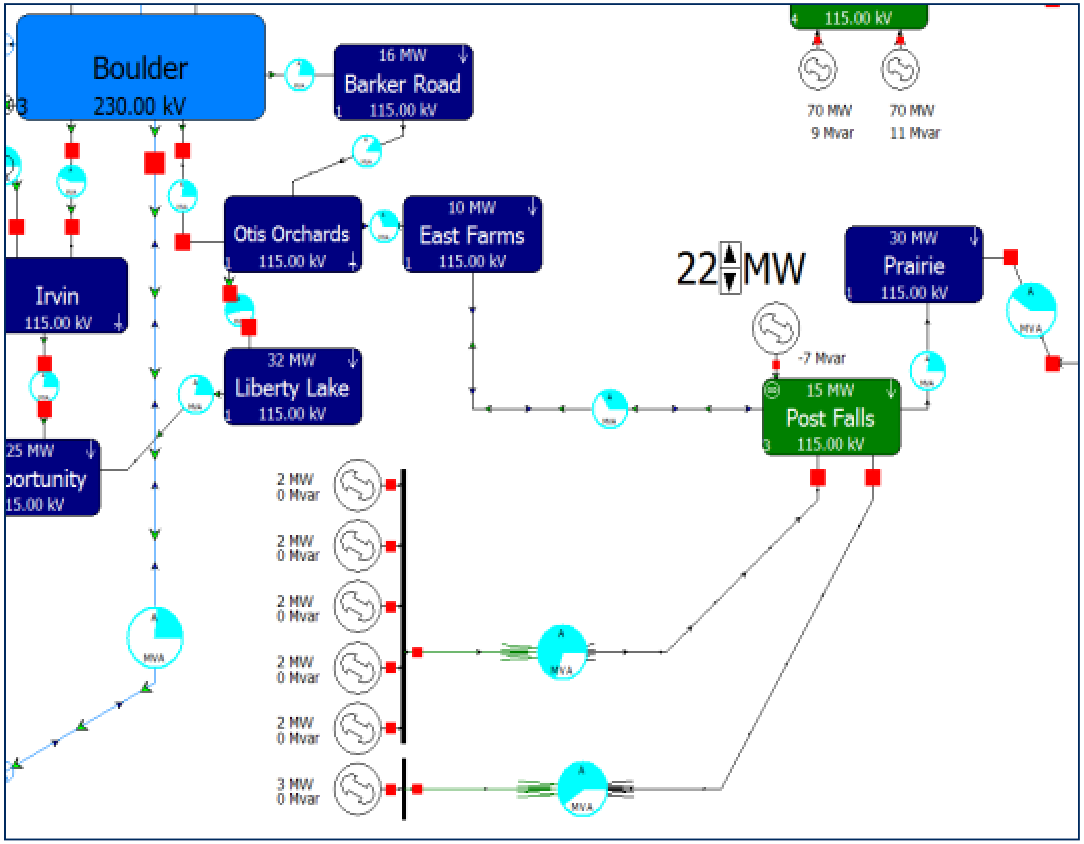
Monroe Street: 80 MW

- 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

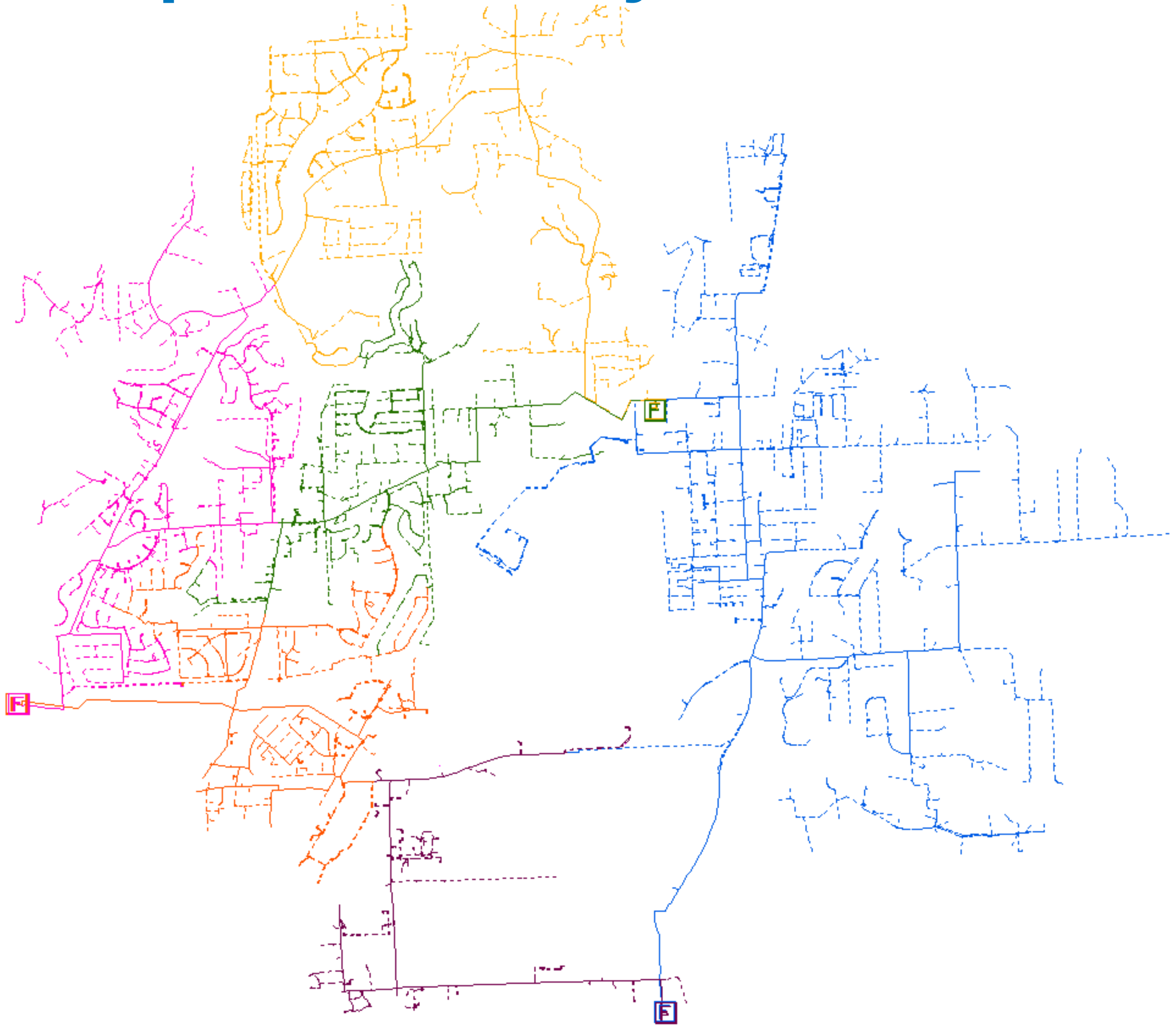
Electric Distribution Within the IRP

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

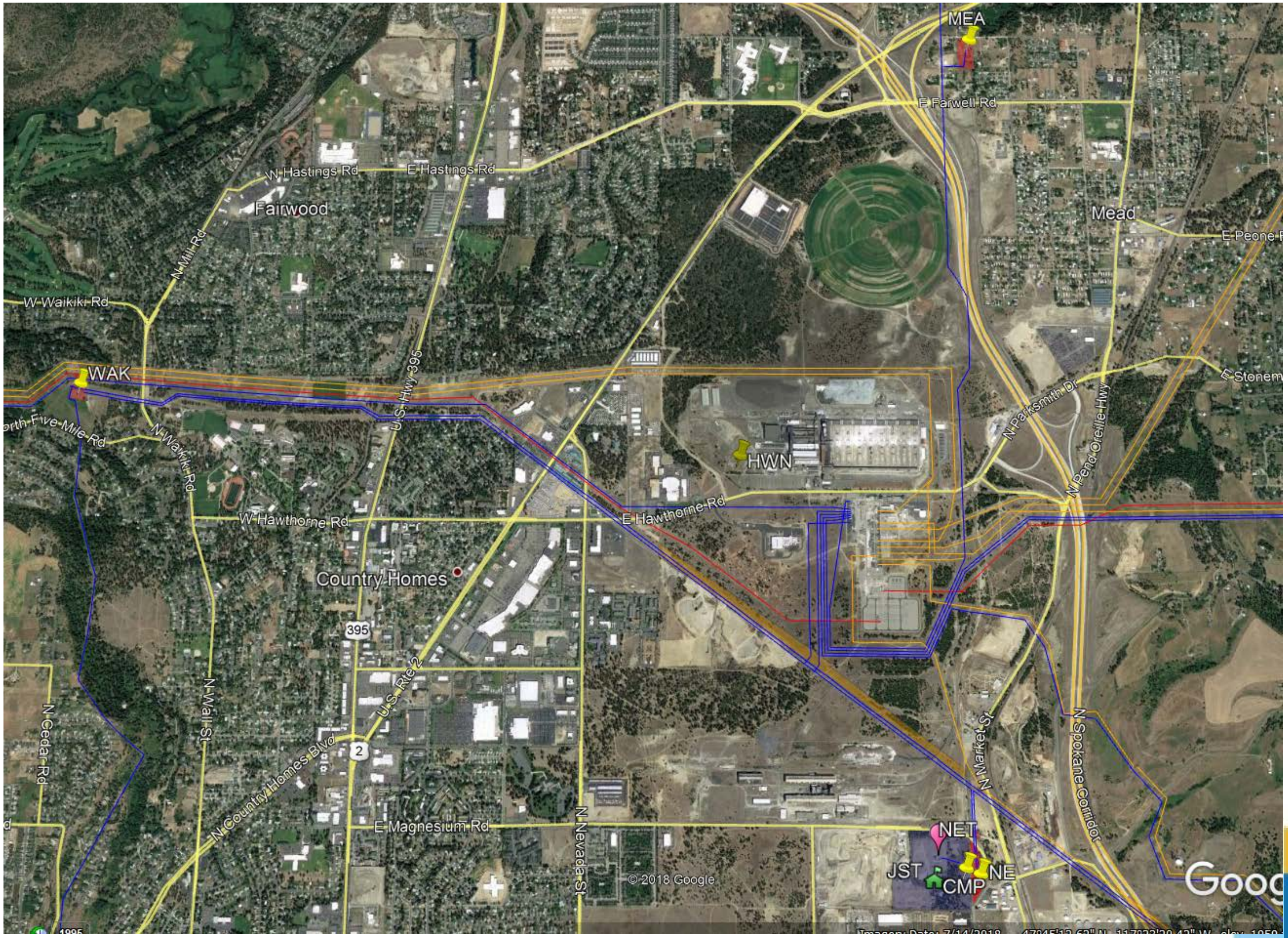
Goals of Electric Distribution Planning

- 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

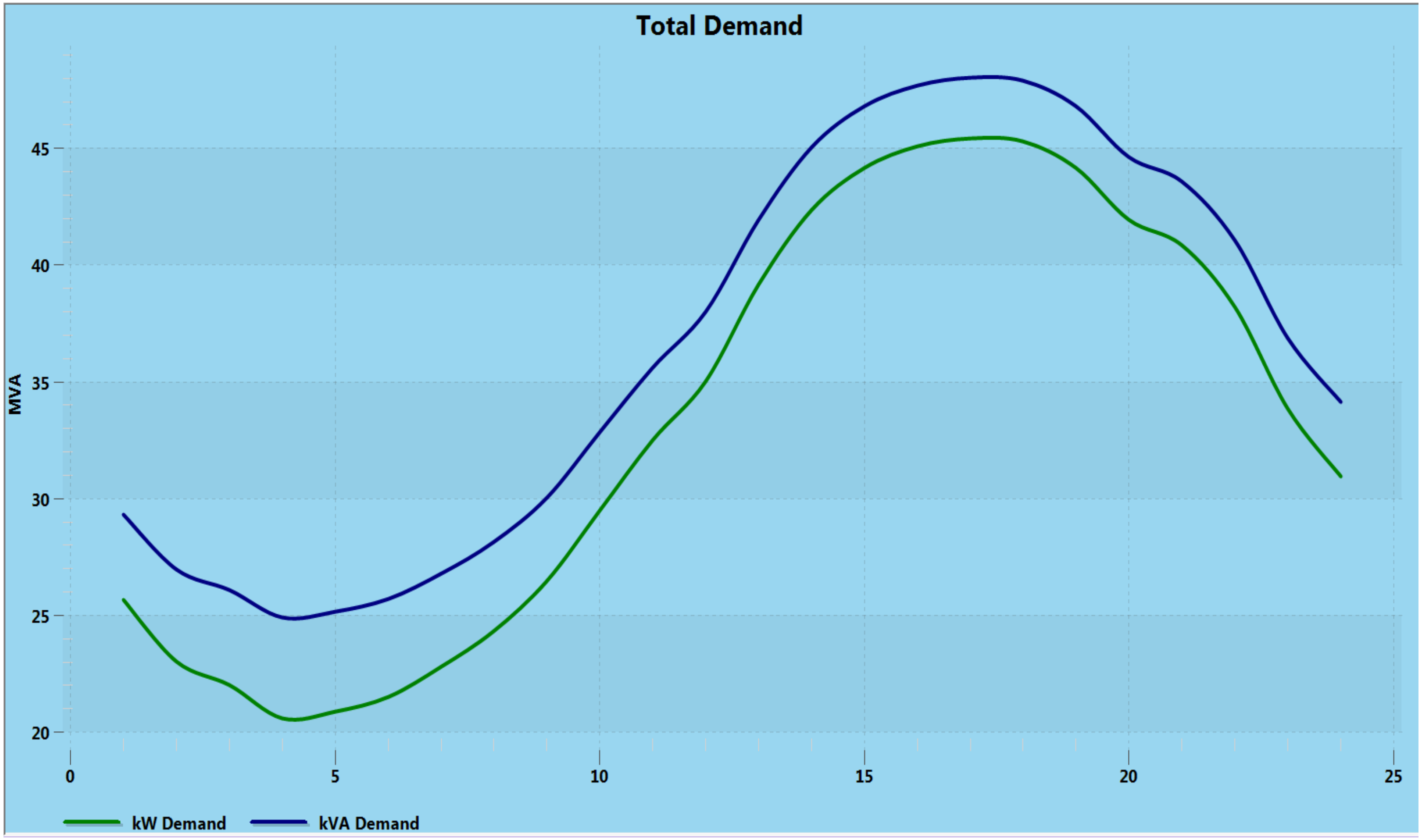
North Spokane Study



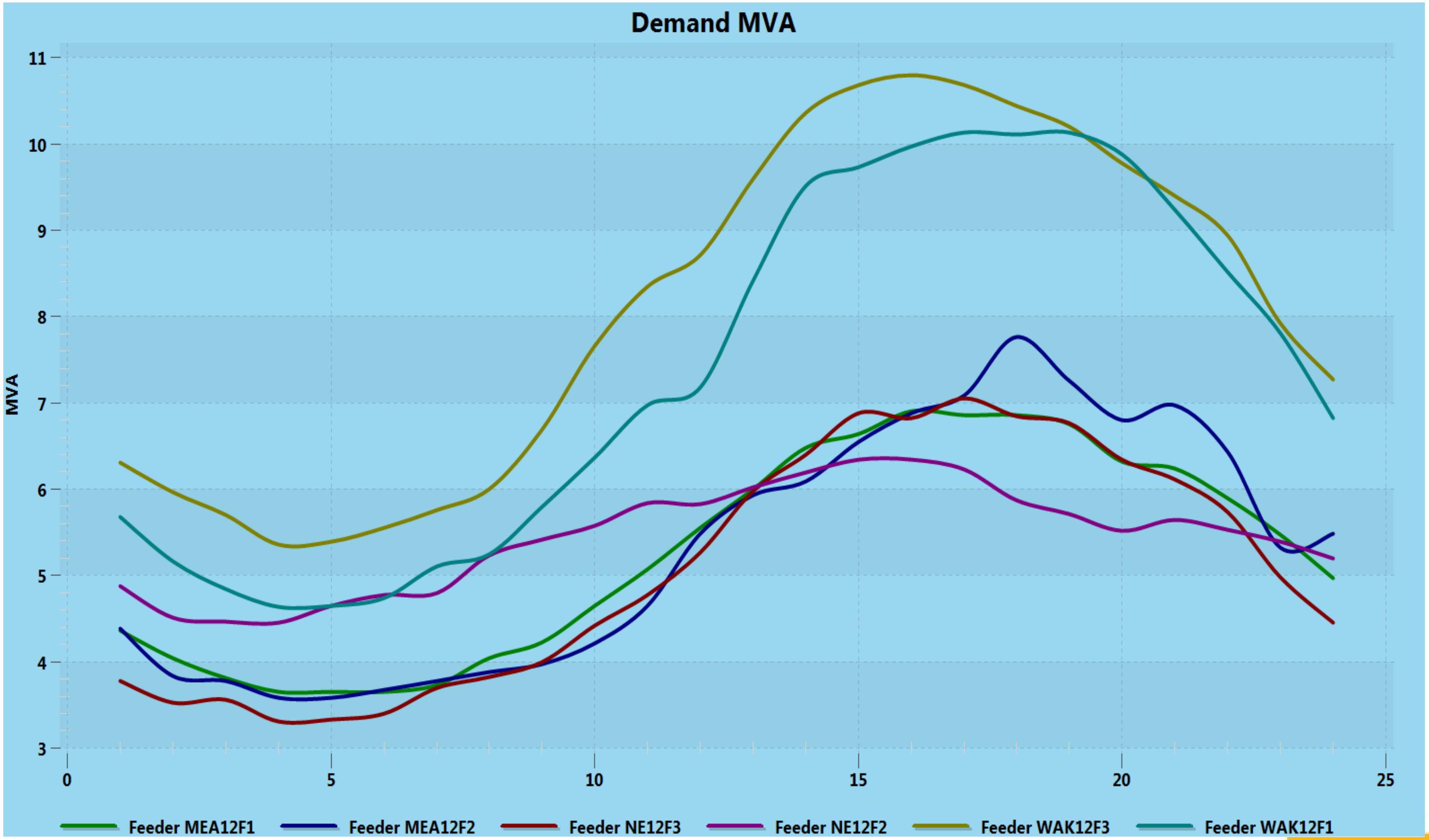
Study Area Map



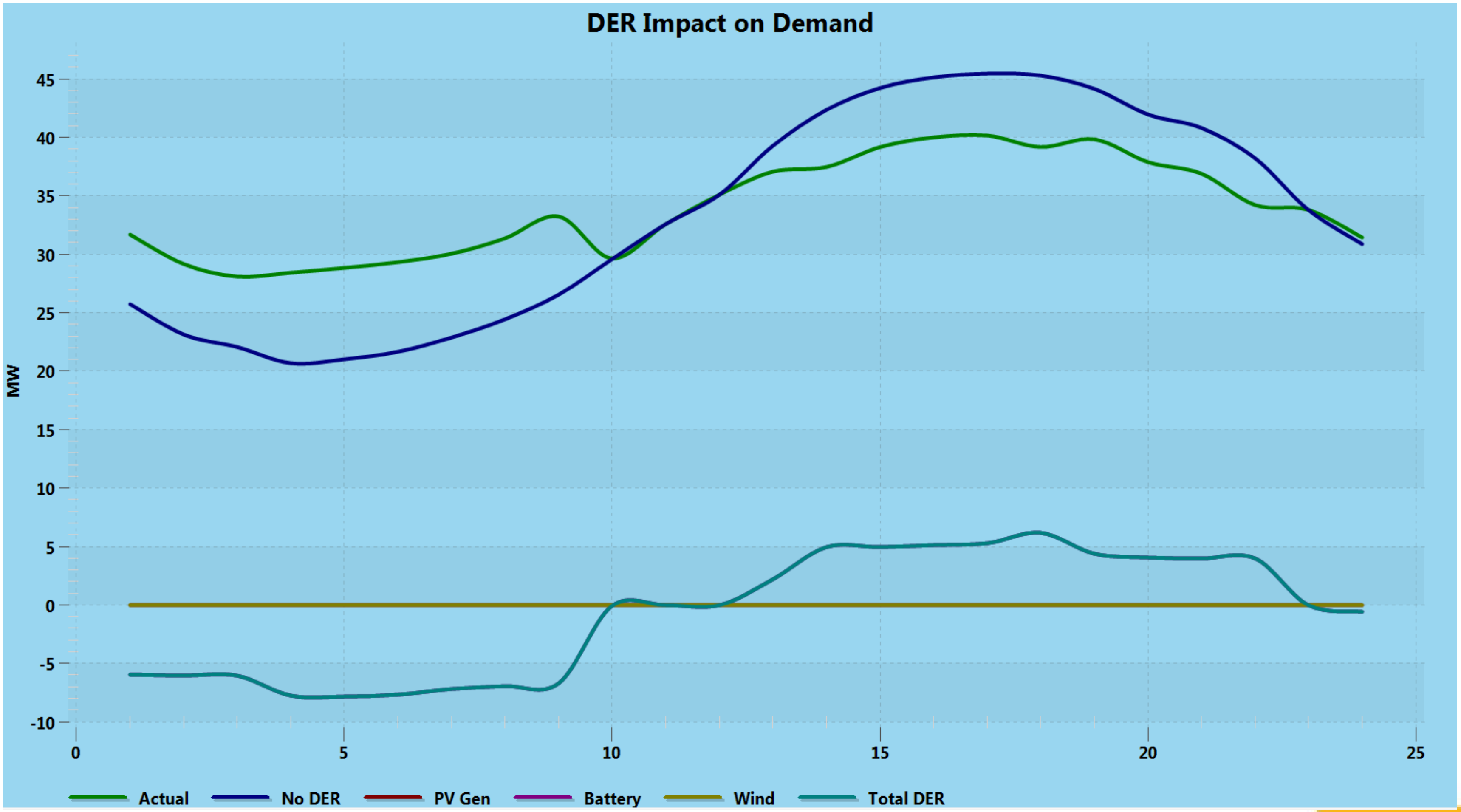
Total Area Demand 8/10/18



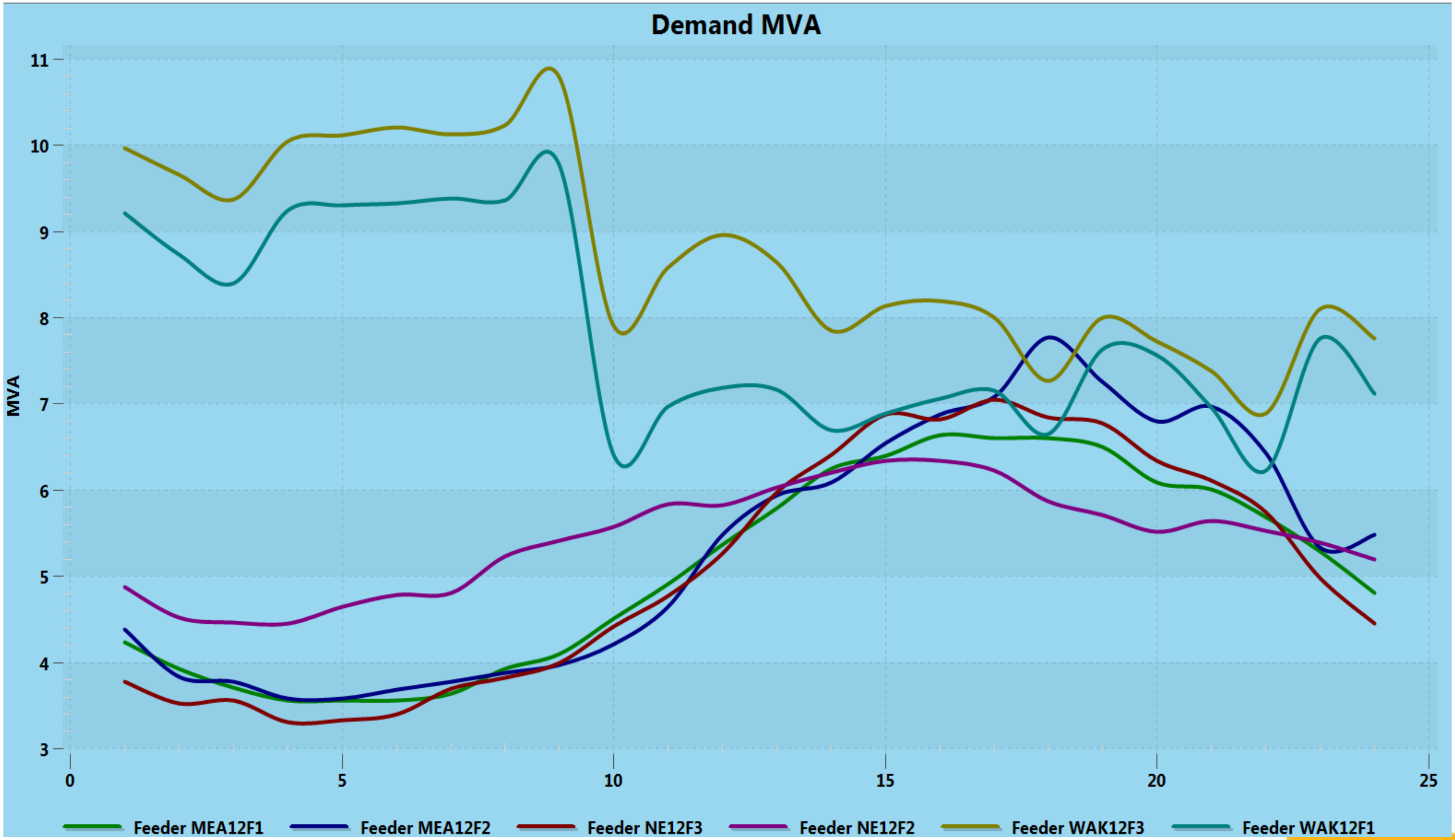
Feeder Demand 8/10/18



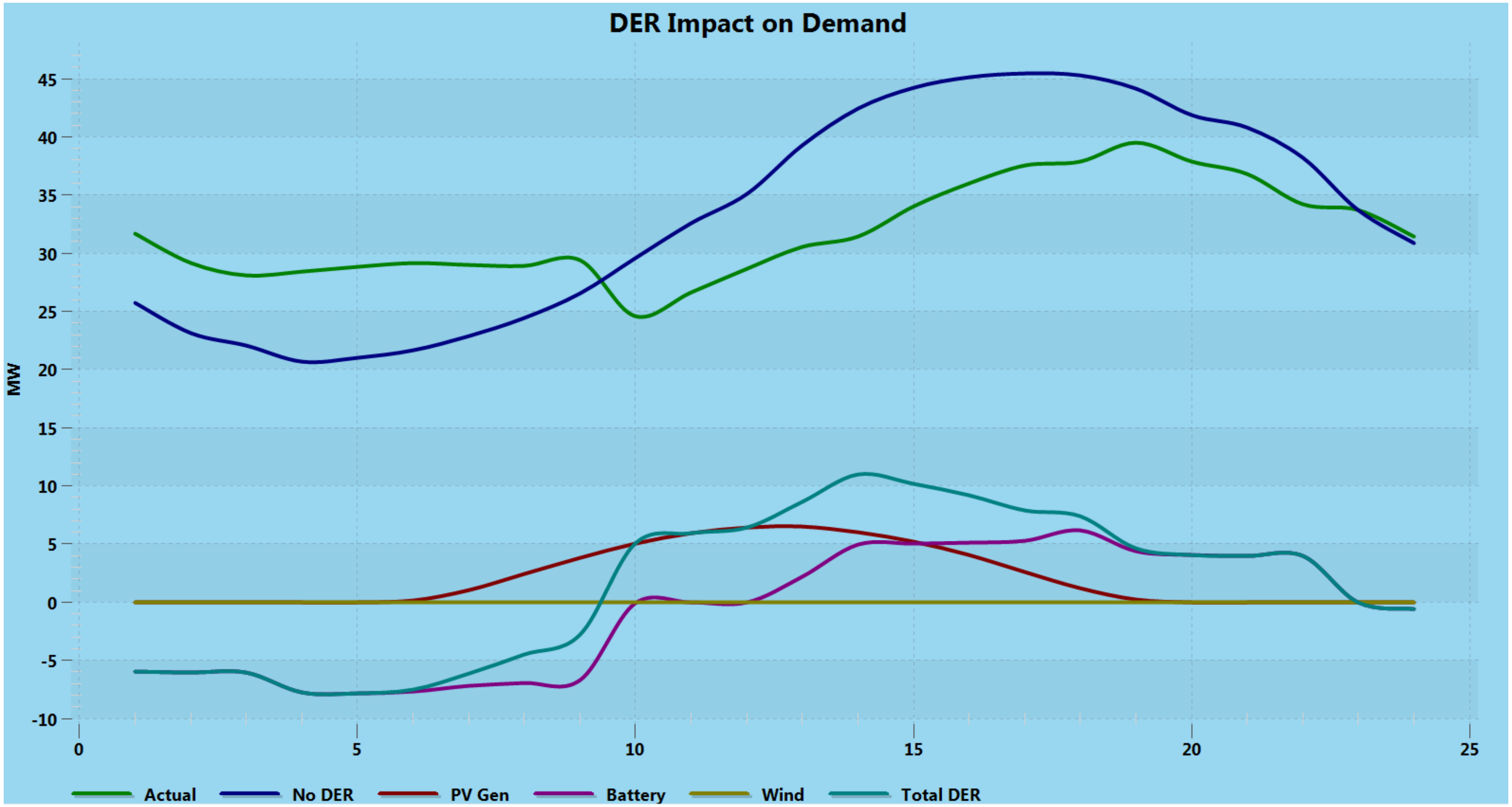
Add two 5MW 6 Hour Batteries



Feeder Demand with Batteries

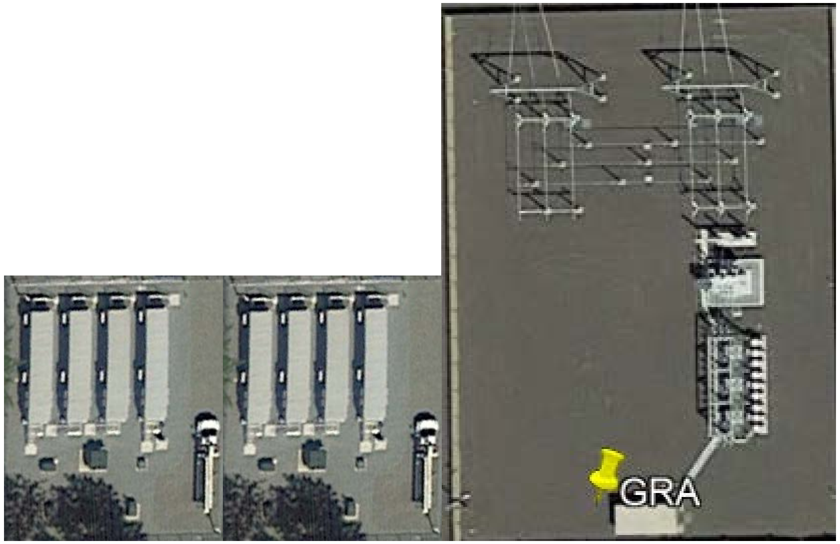


Modest Solar Installation



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

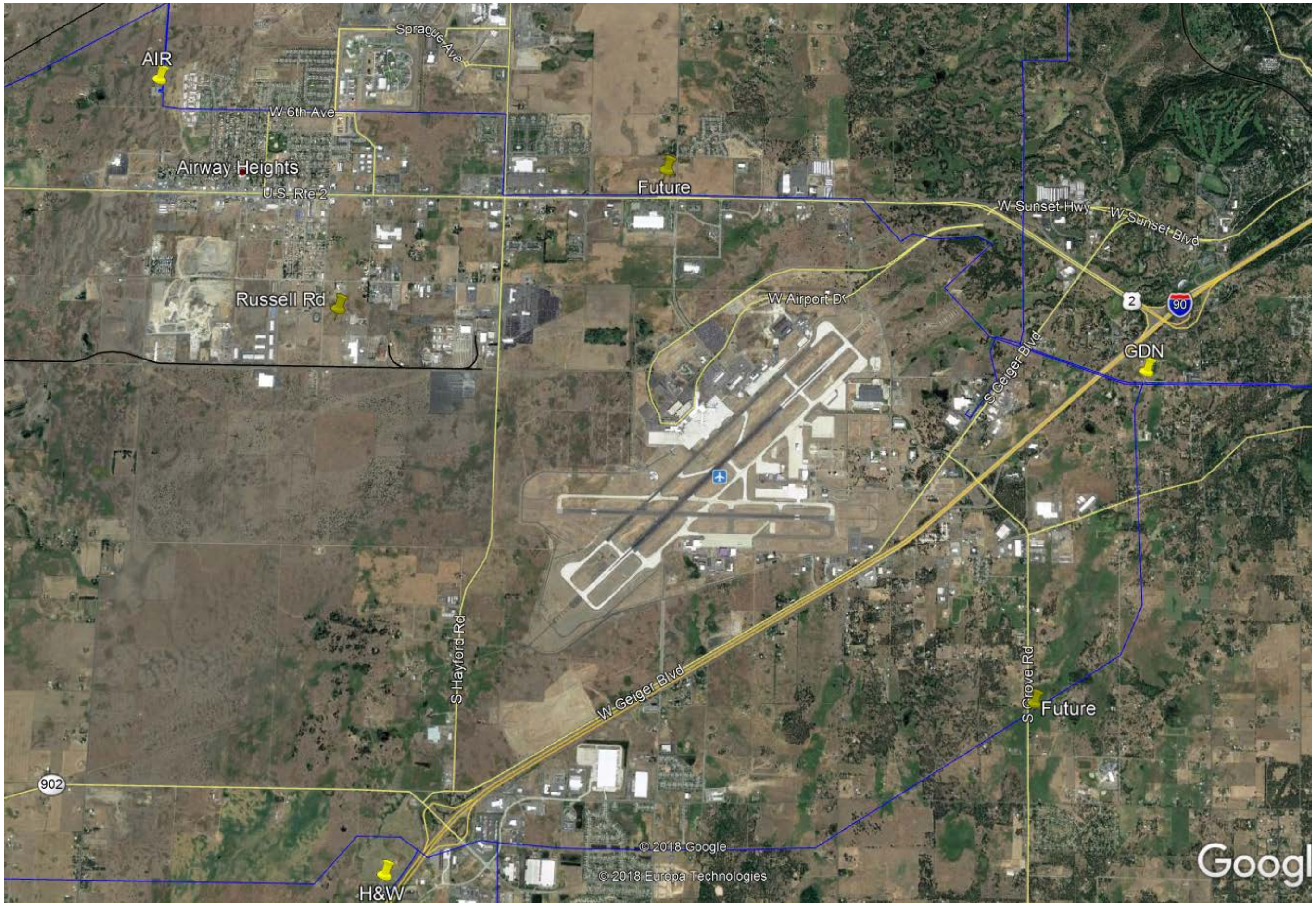
Substation/Transmission- $5 Million
Batteries (10MW with 6 hours)- ~$25 Million

Distribution Battery Benefits

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

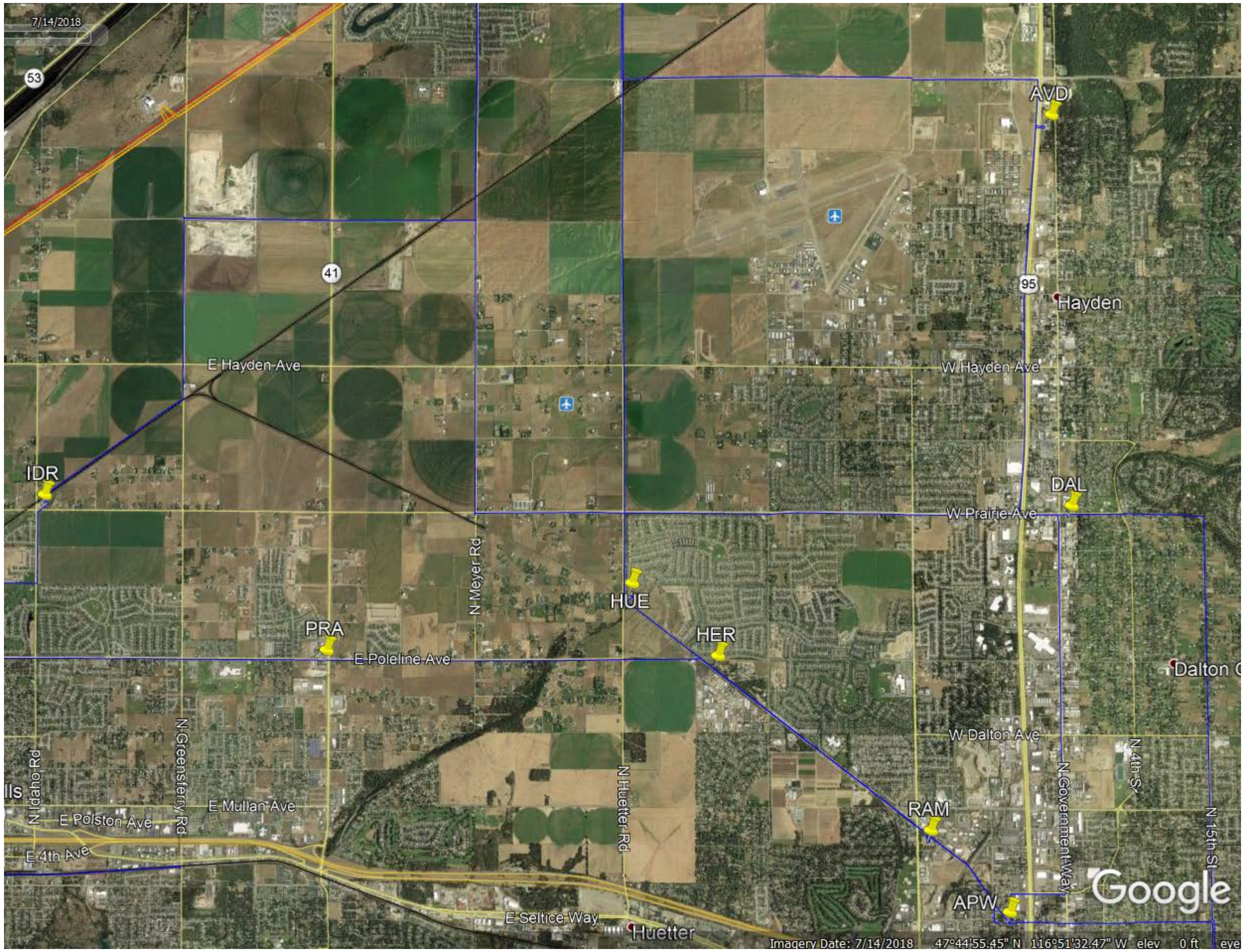
Other Projects

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



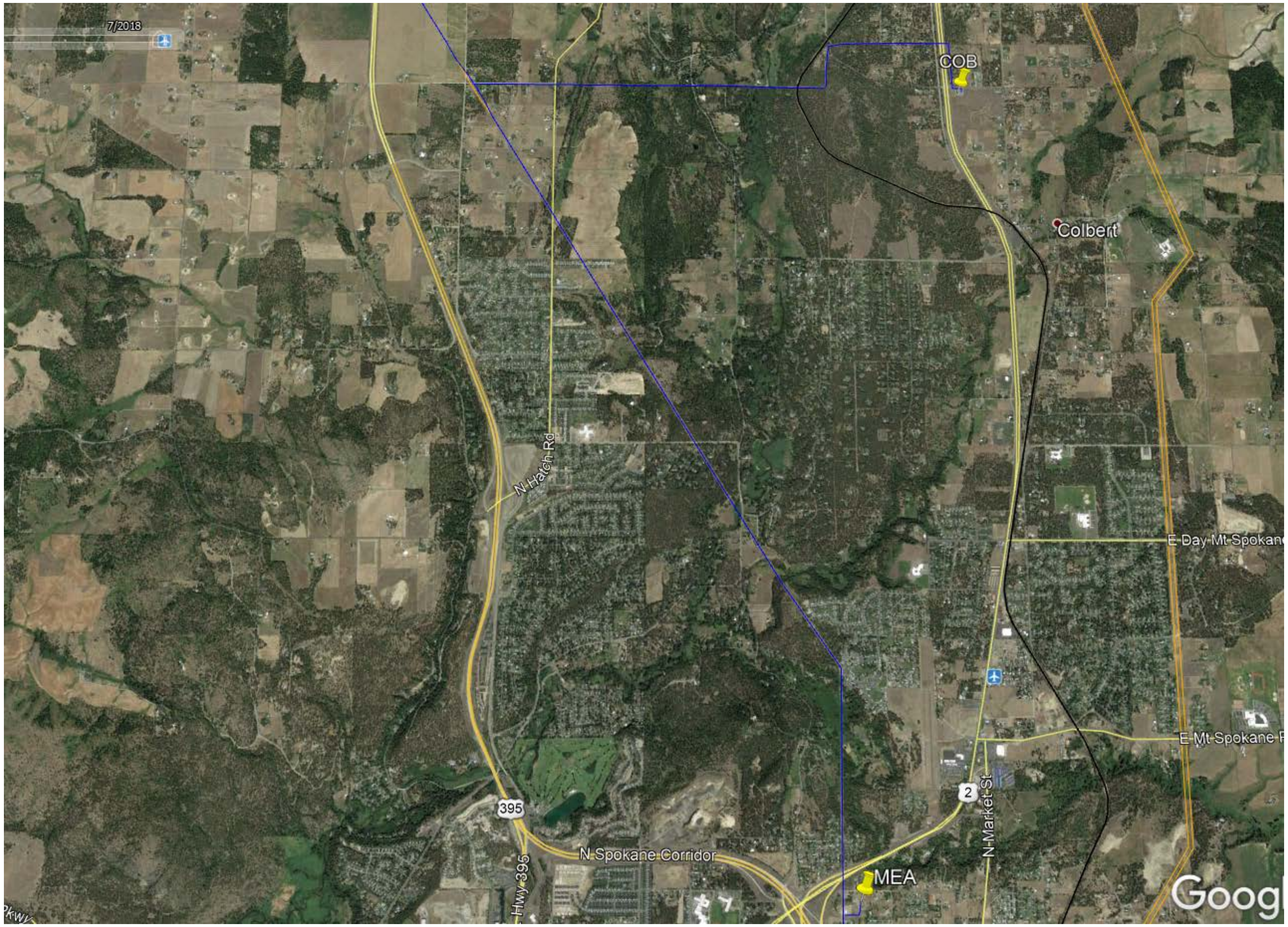
Other Projects

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

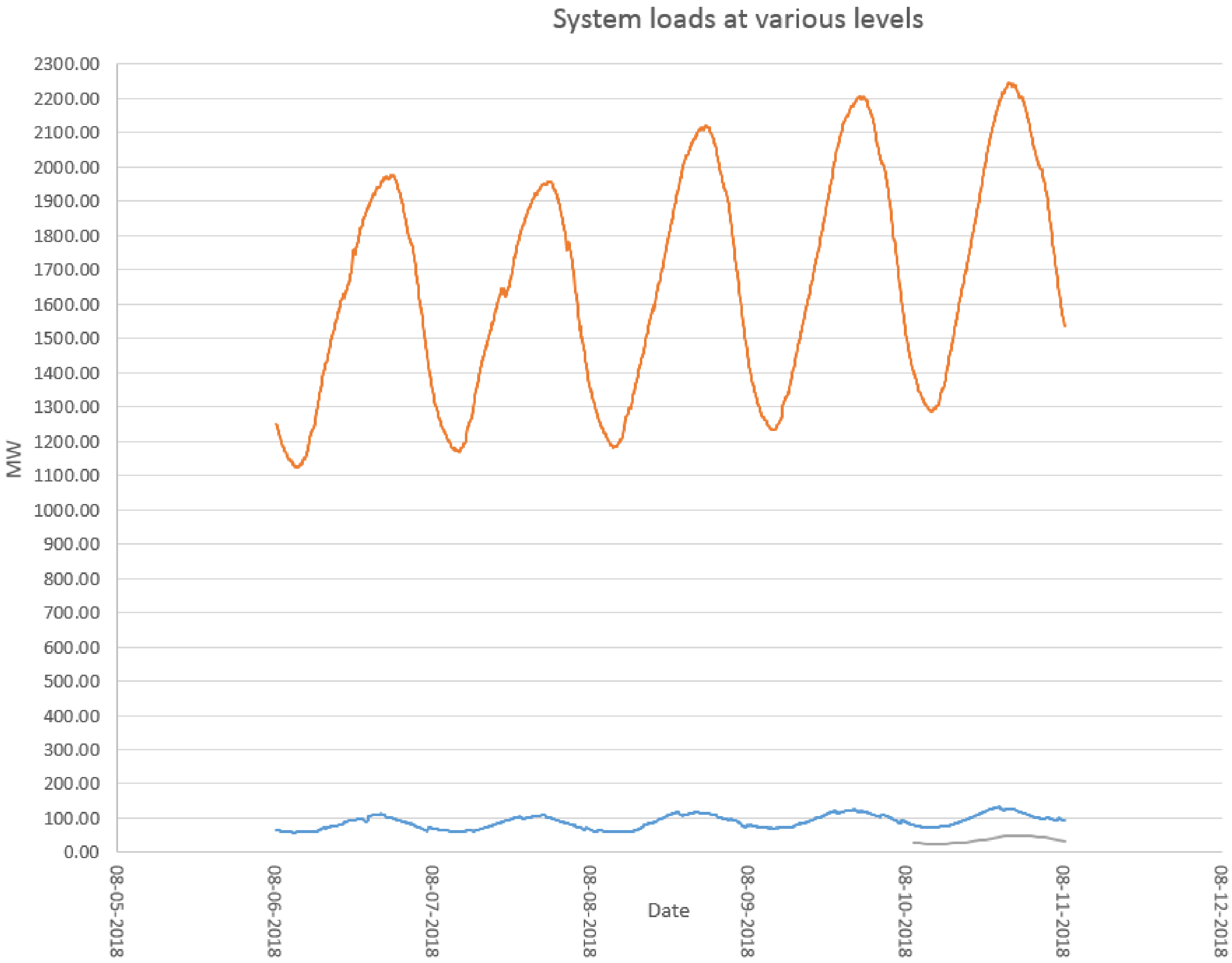


Other Projects

- New Colbert Substation
  - Offload overloaded Colbert Feeders



Conclusion


System loads at various levels
MW
Date
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
08-05-2018
08-06-2018
08-07-2018
08-08-2018
08-09-2018
08-10-2018
08-11-2018
08-12-2018

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

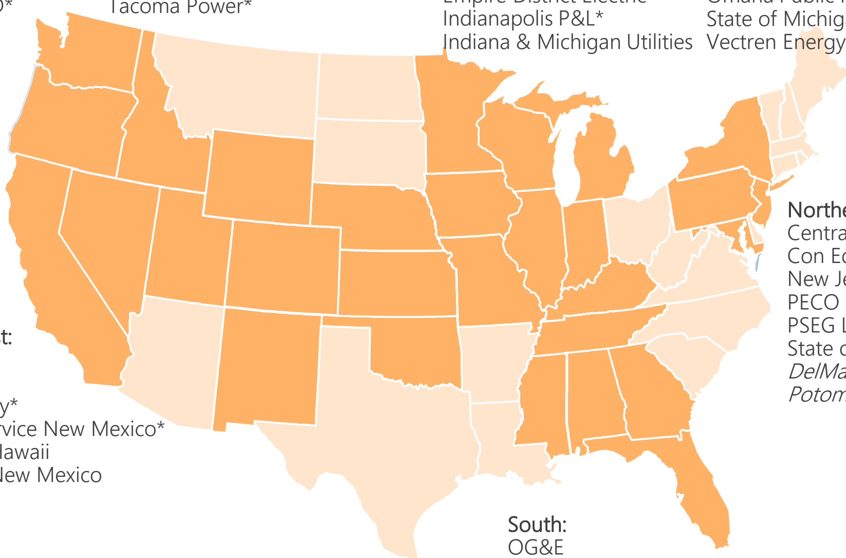
Full DSM lifecycle tracking & reporting

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

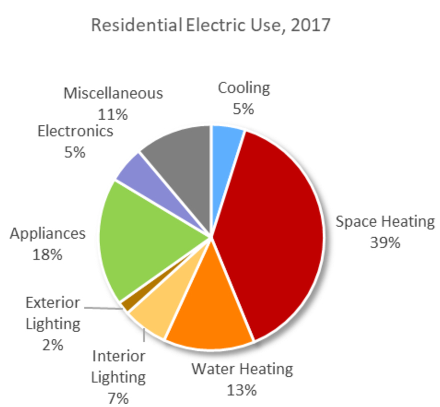
Overview

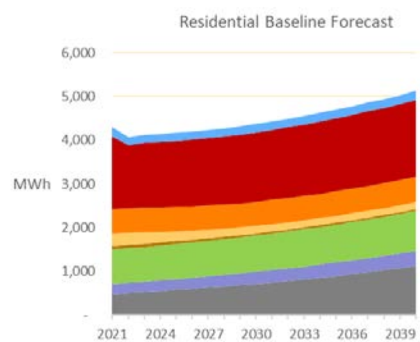
Market Characterization
- Avista control totals
- Customer account data
- Secondary data
- Avista market research

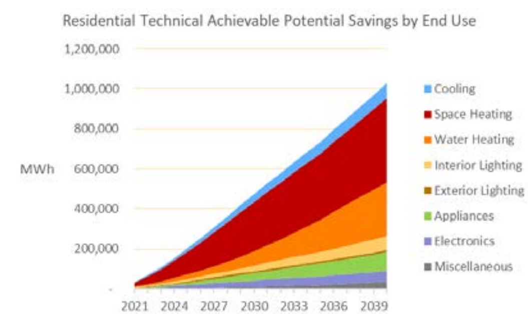
Identify Demand-Side Resources
- EE technologies
- EE measures
- Emerging

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

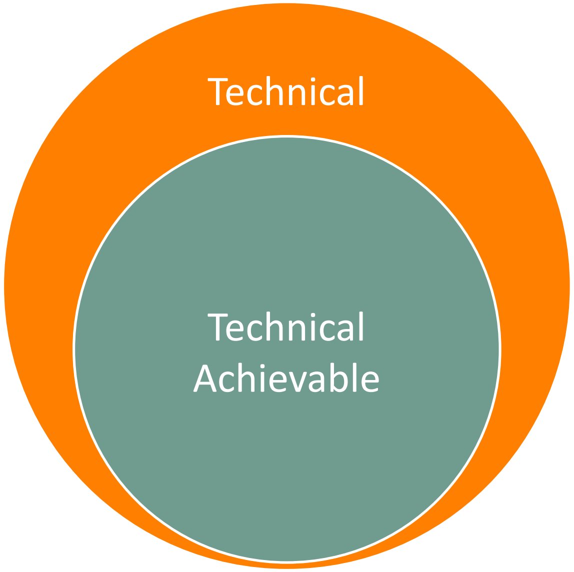
Additional sources include:

- 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

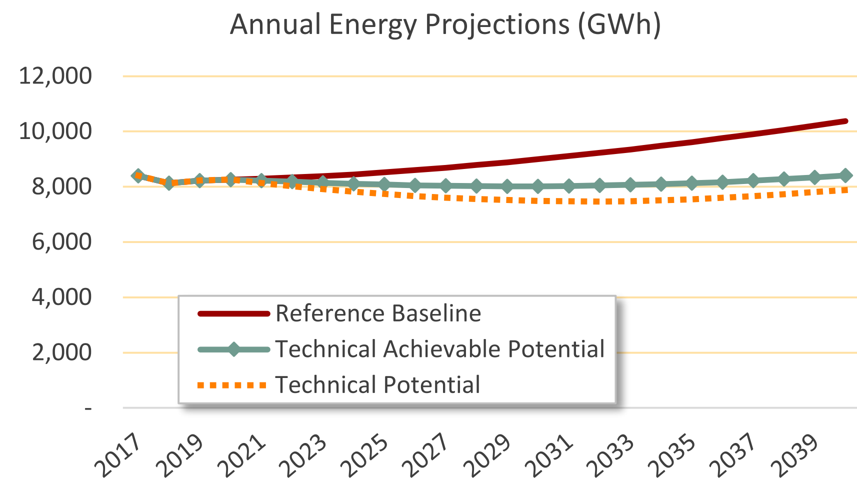
Summary of Findings

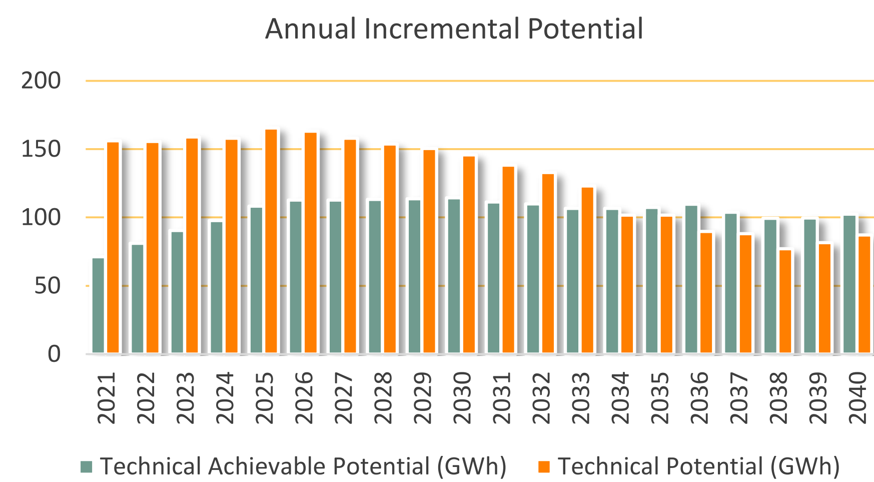
ENERGY EFFICIENCY POTENTIAL

Potential Summary –WA & ID All Sectors

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

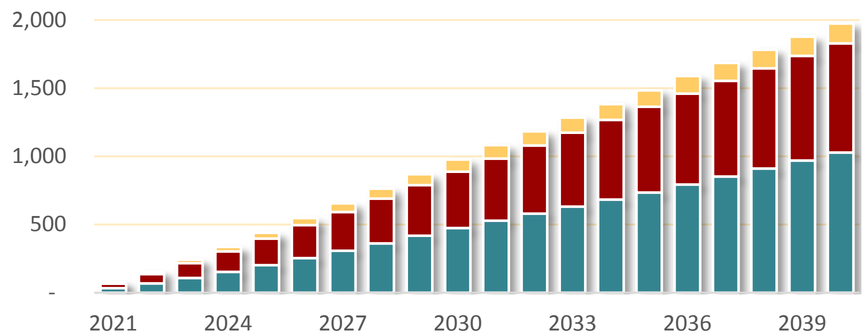
- 152 GWh (17 aMW) in biennium period (2021-2022)
- 976 GWh (111 aMW) by 2030
- This level of savings offsets future load growth

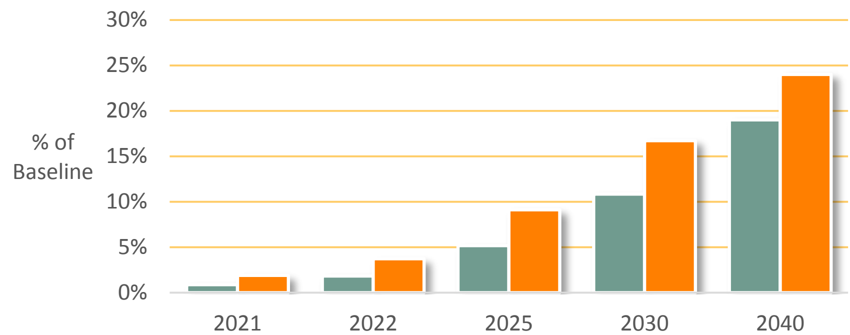




EE POTENTIAL, CONTINUED

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

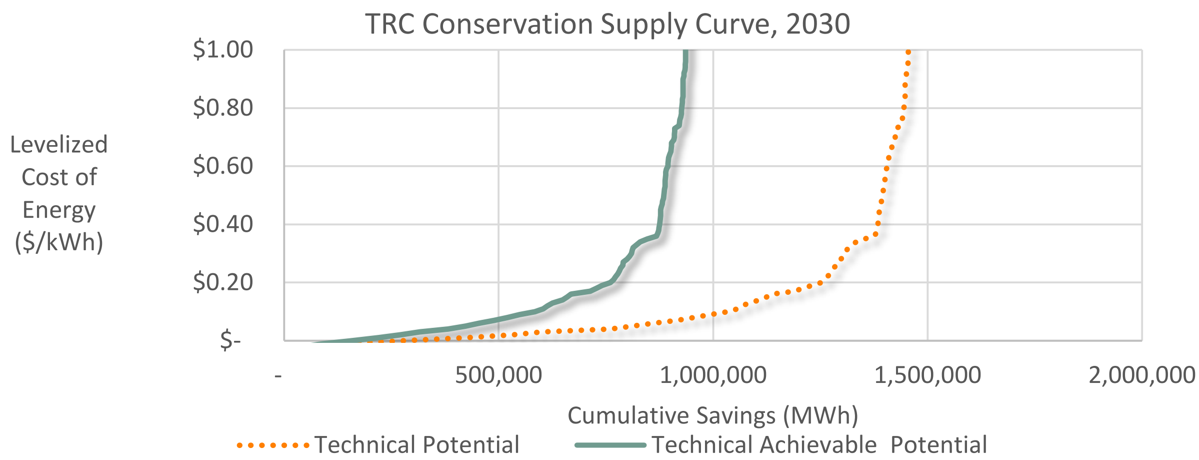
Peak Impacts – Technical Achievable Potential

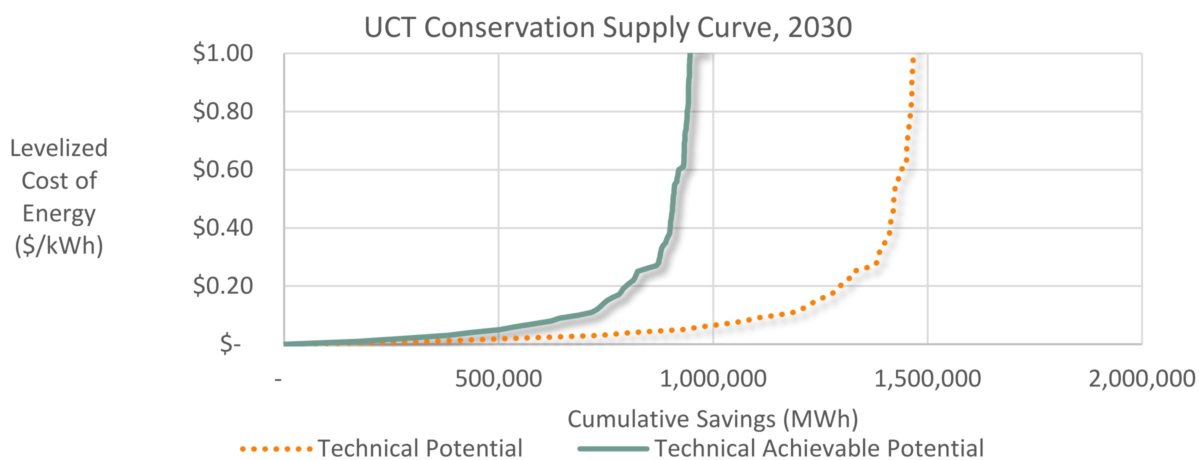
	Top Measures - Winter Peak (MW) Reduction by 2030	2030 MW	% of Total
1	Commercial - Linear Lighting	6.5	6.2%
2	Residential - ENERGY STAR Home Design	5.8	5.5%
3	Commercial - High-Bay Lighting	4.9	4.7%
4	Residential - Thermostat - Connected	4.7	4.4%
5	Residential - Windows - Cellular Shades	3.9	3.7%
6	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

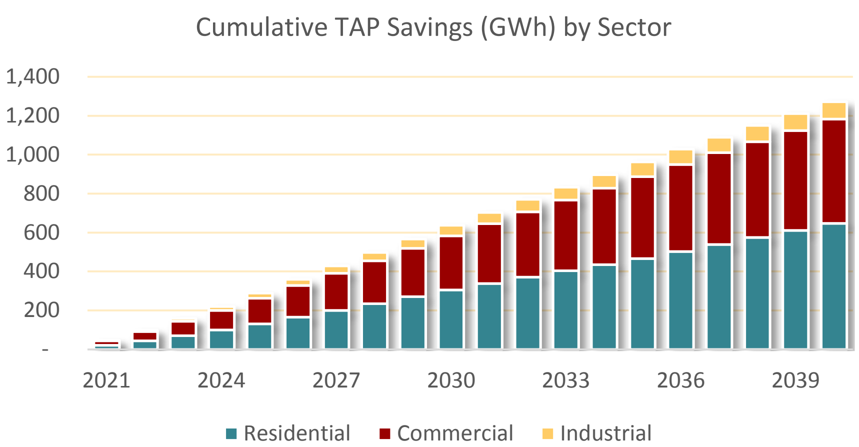
WA & ID Technical Achievable Potential by 2030

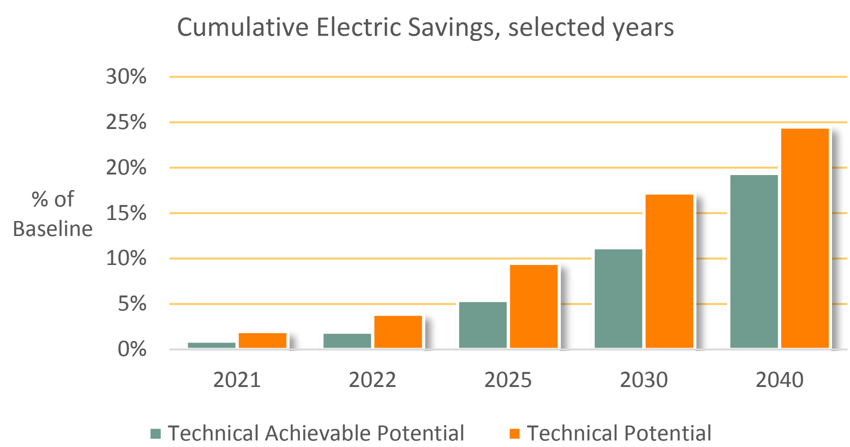




EE POTENTIAL, CONTINUED

Potential Summary – Washington, All Sectors

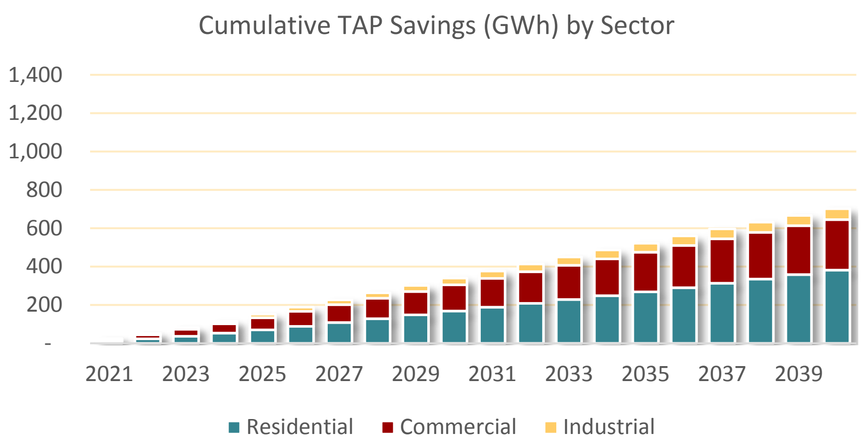


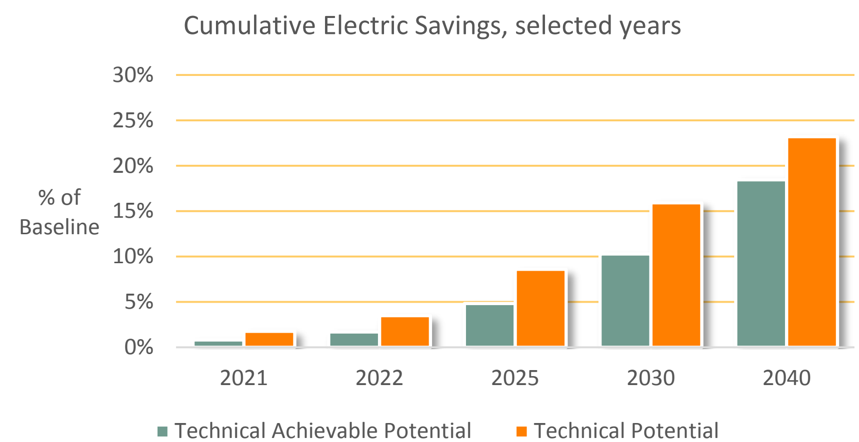


Summary of Energy Savings (GWh), Selected Years	2021	2022	2025	2030	2040
Reference Baseline (GWh)	5,243.2	5,268.4	5,381.1	5,686.8	6,571.8
Cumulative Savings (GWh)					
Technical Achievable Potential	47.2	100.0	288.5	636.5	1,272.0
Technical Potential	102.5	203.4	508.2	979.2	1,607.3
Energy Savings (% of 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

AEG
Applied Energy Group

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 <u>calendar years</u>, rather than <u>study years</u> 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 <u>removed</u> 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

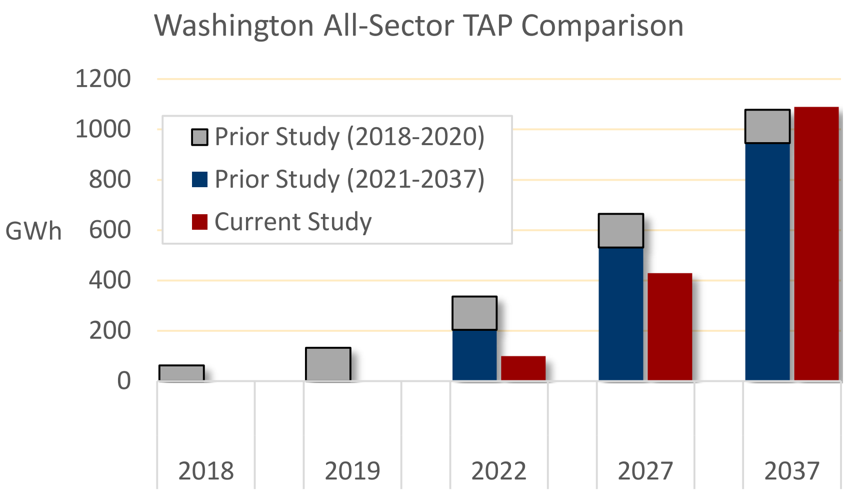
The previous study's 20-year look ended in 2037, therefore we must <u>remove</u> 2038-2040 from the comparison

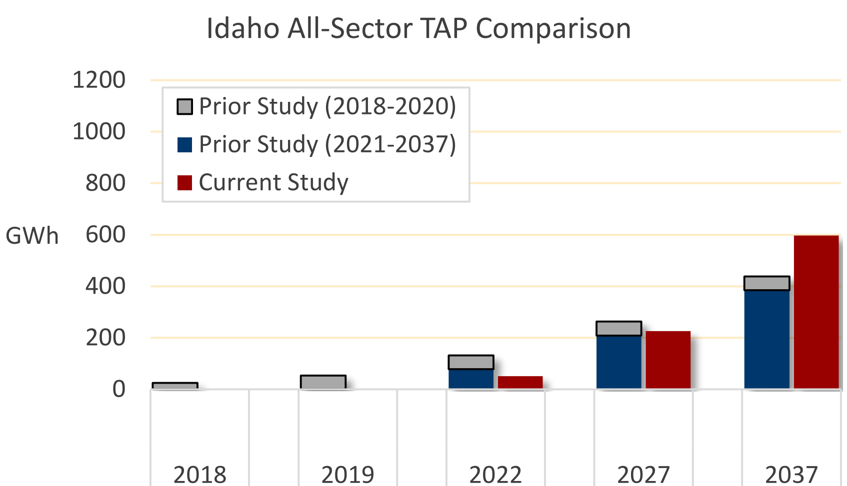
- **Cumulative Potential Comparisons** – 2021 through year 2036
  - This should have a minimal impact on potential since retrofits are mainly captured prior to this point

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

ACHIEVABLE POTENTIAL COMPARISON

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

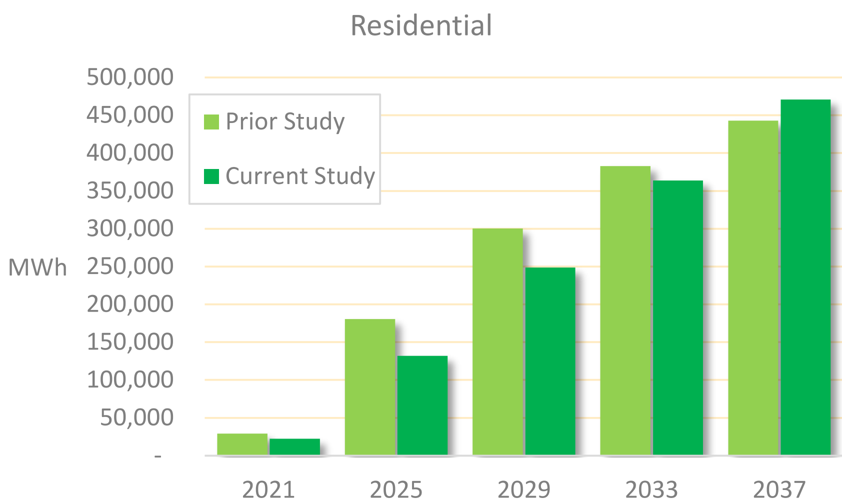


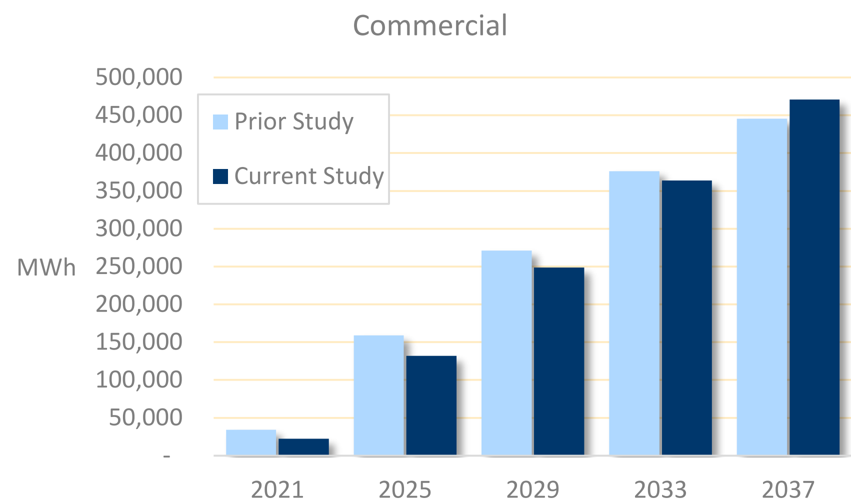


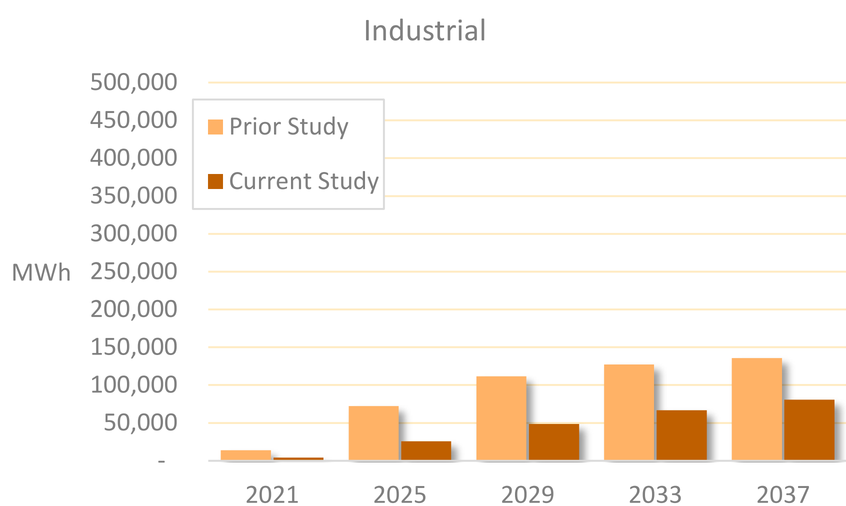
Sector (All States)	End Use	Prior CPA 2037 MWh	Current Study 2037 MWh	Diff.
Residential	Cooling	44,269	63,188	18,919
	Heating	242,917	366,549	123,632
	Water Heating	191,988	206,932	14,944
	Interior Lighting	43,555	55,064	11,509
	Exterior Lighting	8,102	10,986	2,884
	Appliances	72,894	76,363	3,469
	Electronics	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**

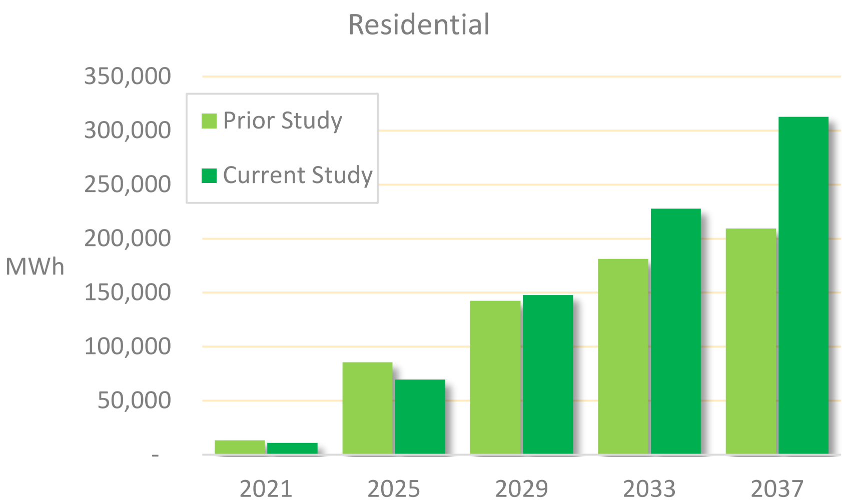


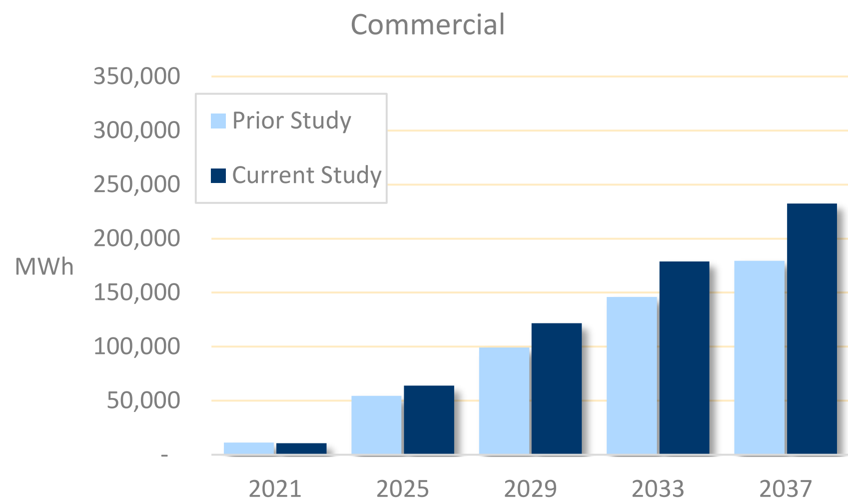


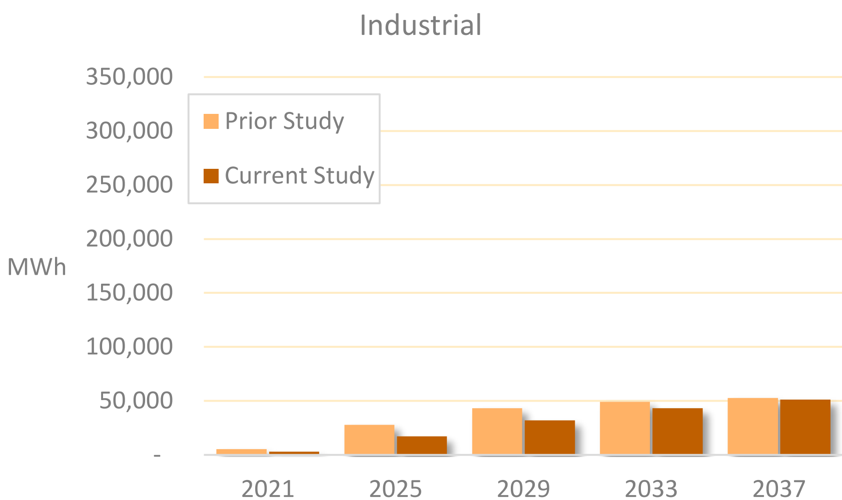


- 2018-2020 already removed from prior study values

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

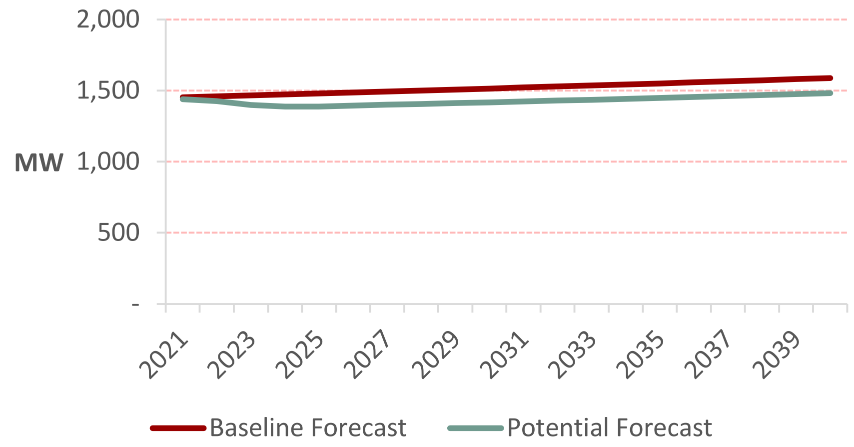
Industrial:

- 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

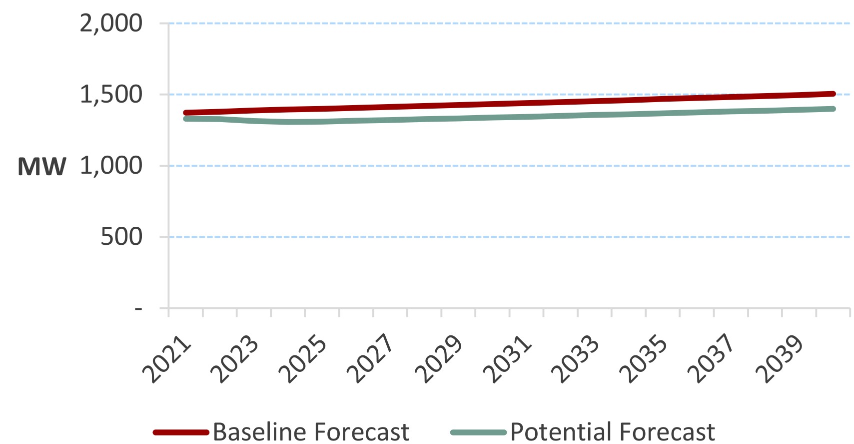
DR Potential Results

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



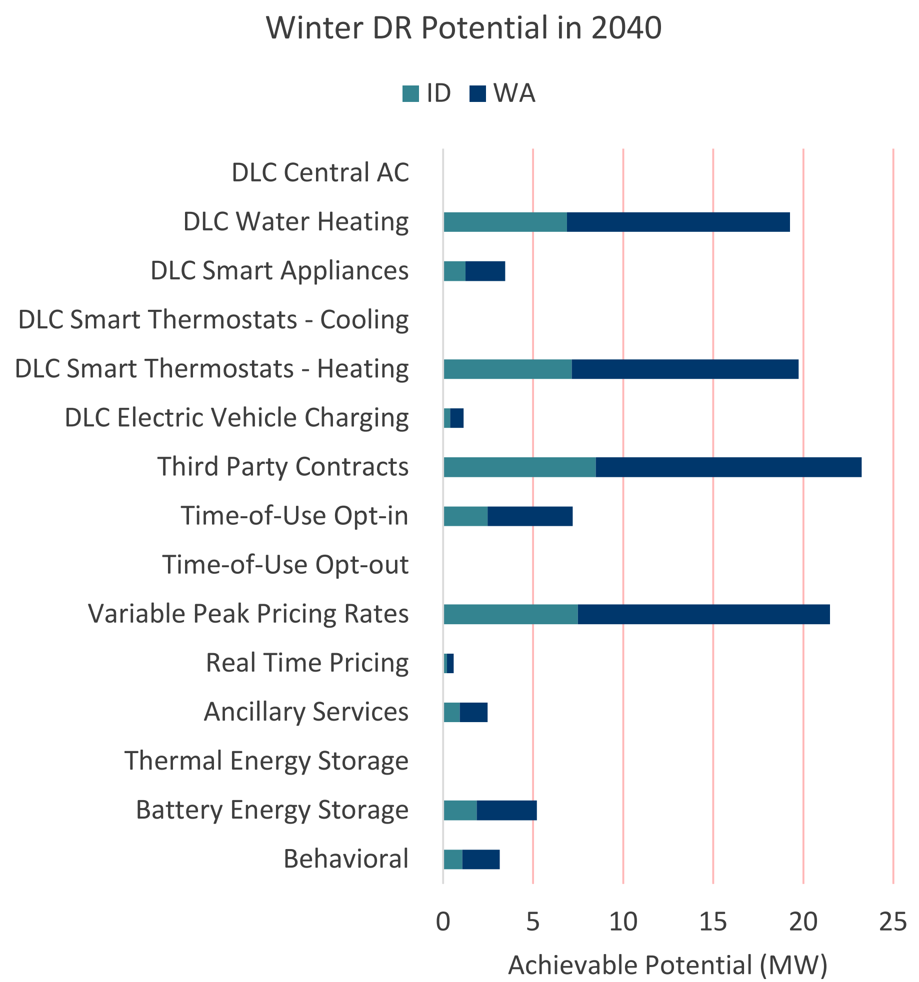
Summer Peak MW	2021	2022	2025	2030	2040
Baseline Projection	1,374	1,380	1,400	1,434	1,505
Market Potential	11.9	30.8	85.6	90.6	100.0
Potential (% of baseline)	0.9%	2.2%	6.1%	6.3%	6.6%
Potential Projection	1,362	1,350	1,315	1,343	1,405



WINTER PEAK MW REDUCTIONS

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

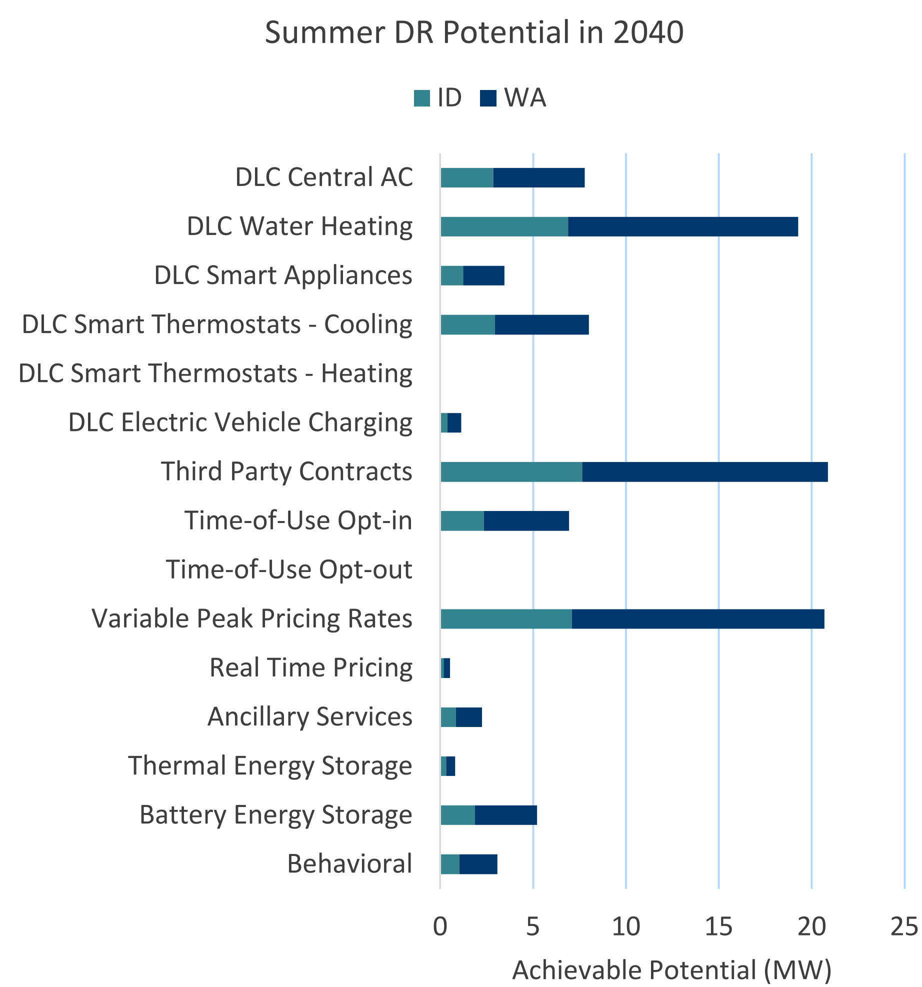
Winter Potential in 2040	ID	WA	Grand Total
DLC			
DLC Central AC	0.00	0.00	0.00
DLC Water Heating	6.88	12.38	19.27
DLC Smart Thermostats - Cooling	0.00	0.00	0.00
DLC Smart Thermostats - Heating	7.14	12.60	19.74
DLC Smart Appliances	1.24	2.21	3.45
DLC Electric Vehicle Charging	0.39	0.74	1.14
Third Party 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**



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

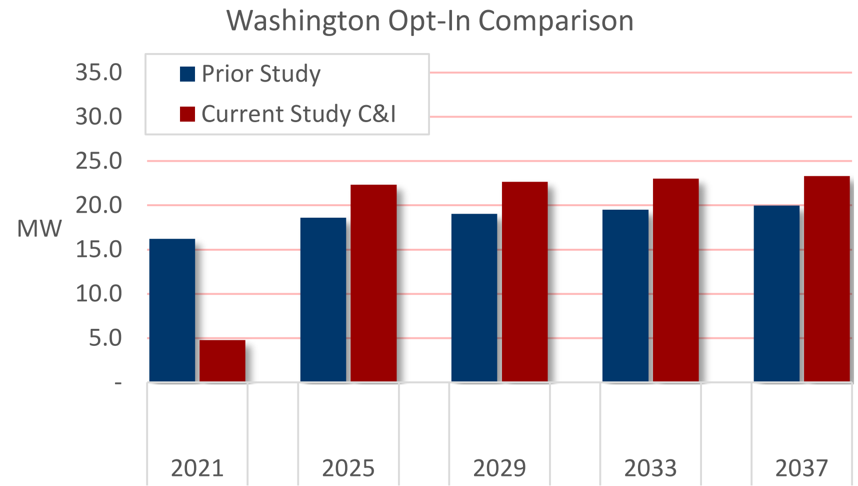
- Note: Comparison between calendar years for DR does not remove previous year impacts like the EE comparison

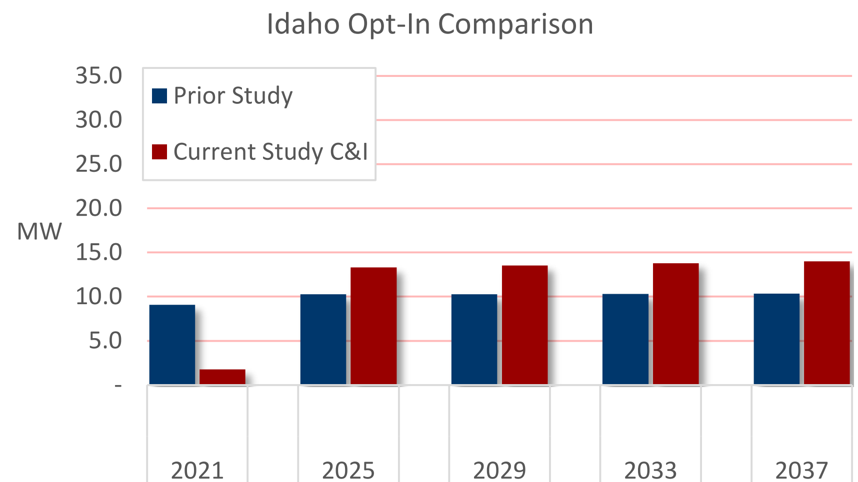
DR POTENTIAL COMPARISON OPT-IN

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!

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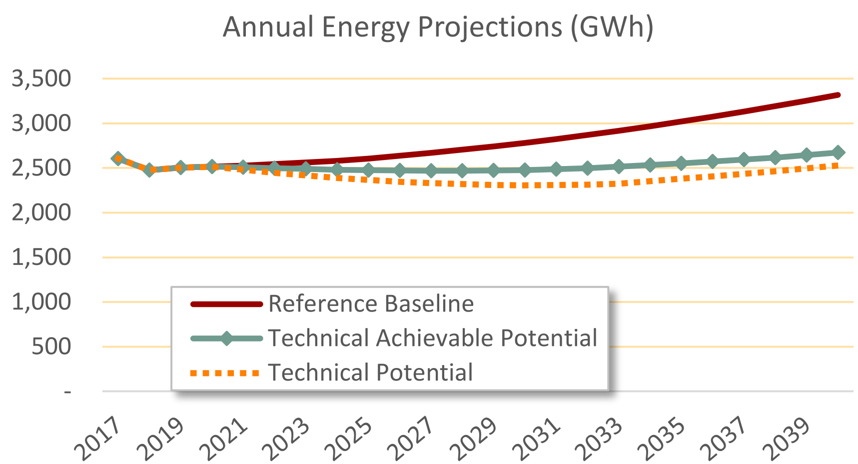
Sector EE Results

ENERGY EFFICIENCY POTENTIAL

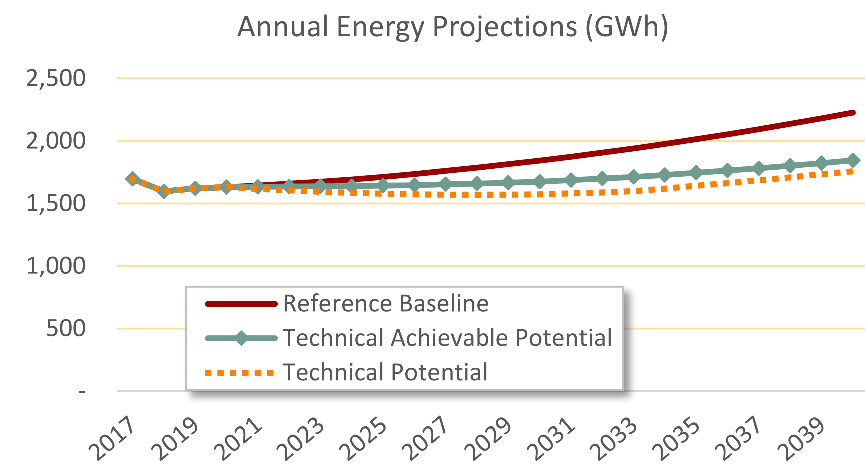
Potential Summary – Residential

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

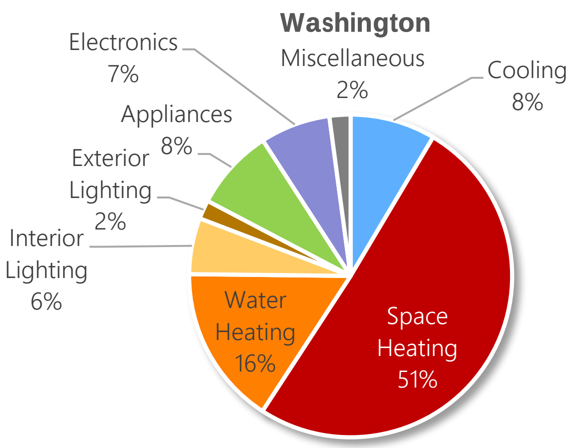
Idaho

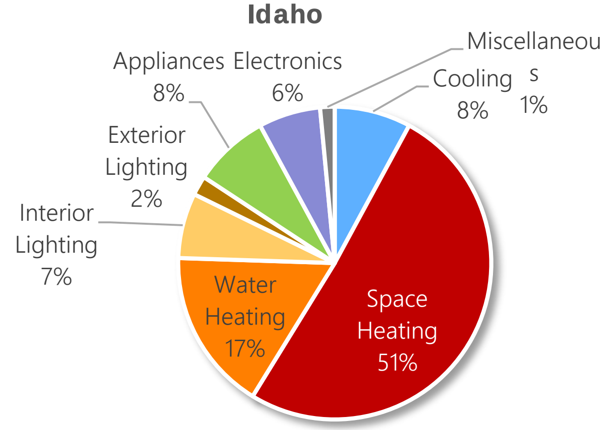


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	1,644	1,658	1,713	1,844	2,226
Potential Forecasts (GWh)					
Technical Achievable Potential	1,633	1,635	1,643	1,675	1,845
Technical Potential	1,618	1,605	1,579	1,574	1,758
Cumulative Savings (GWh)					
Technical Achievable Potential	11	23	70	168	382
Technical 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





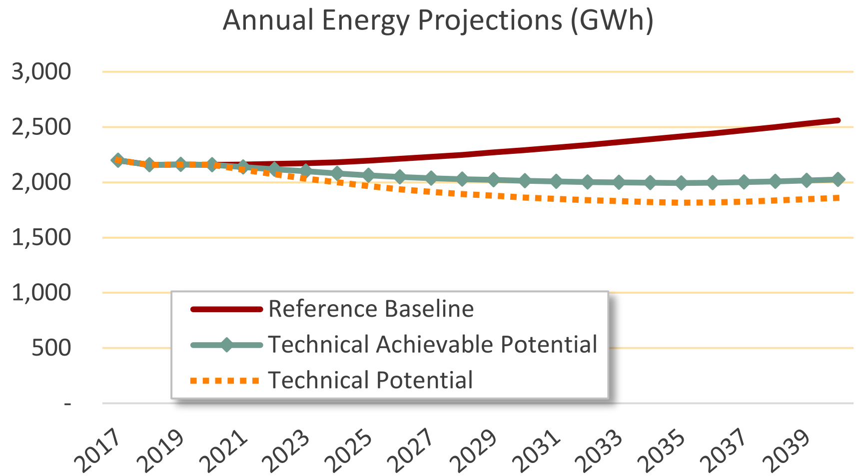
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Ductless Mini Split Heat Pump (Ducted Forced Air)	3,651	11,941	30,156	9.9%
2	Ductless Mini Split Heat Pump (Zonal)	2,727	8,760	21,357	7.0%
3	Water Heater (<= 55 Gal)	215	2,270	20,804	6.8%
4	Thermostat - Connected	2,303	7,472	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

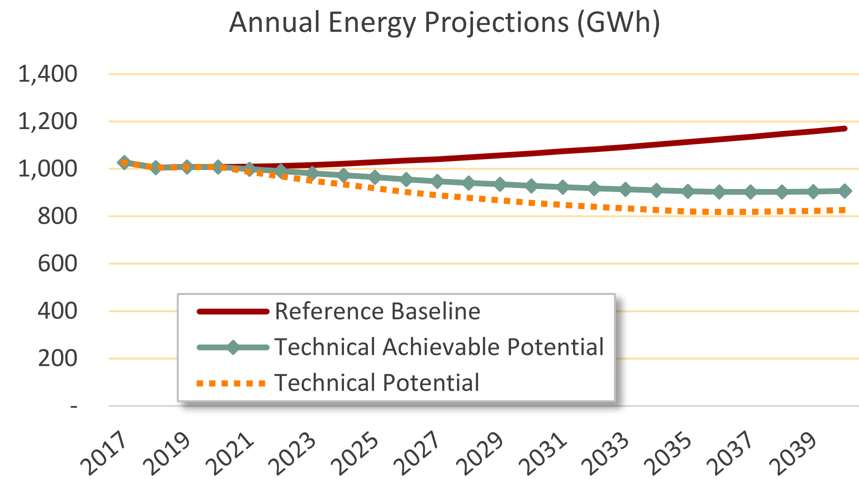
Potential Summary – Commercial

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

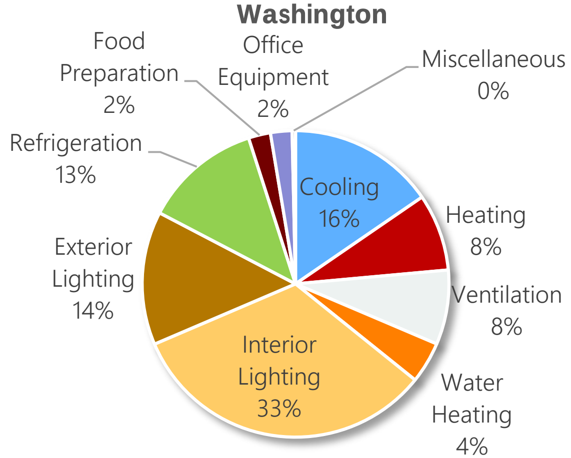
Idaho

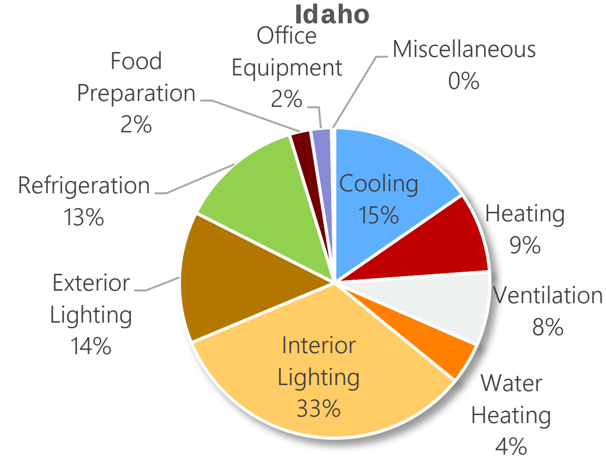


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	1,010	1,012	1,029	1,065	1,171
Potential Forecasts (GWh)					
Technical Achievable Potential	999	990	965	929	906
Technical Potential	987	968	918	857	826
Cumulative Savings (GWh)					
Technical Achievable Potential	11	22	64	136	264
Technical Potential	22	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





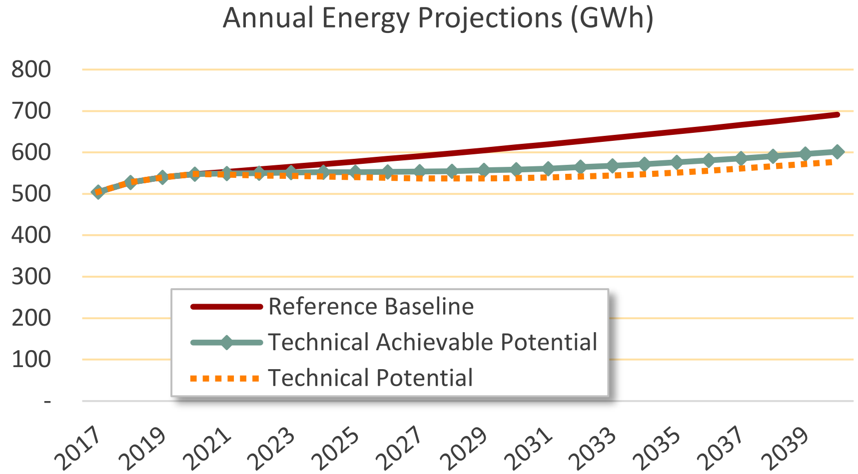
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	Linear Lighting	3,852	15,024	43,235	15.6%
2	High-Bay Lighting	2,674	10,375	30,106	10.8%
3	Area Lighting	1,908	7,347	21,034	7.6%
4	Ventilation	525	2,546	8,984	3.2%
5	Space Heating - Heat Recovery Ventilator	2,252	5,394	8,208	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

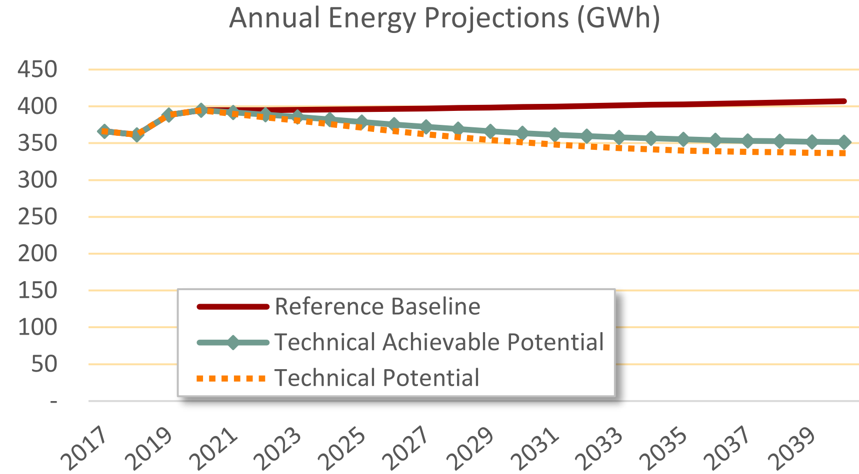
Potential Summary – Industrial

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

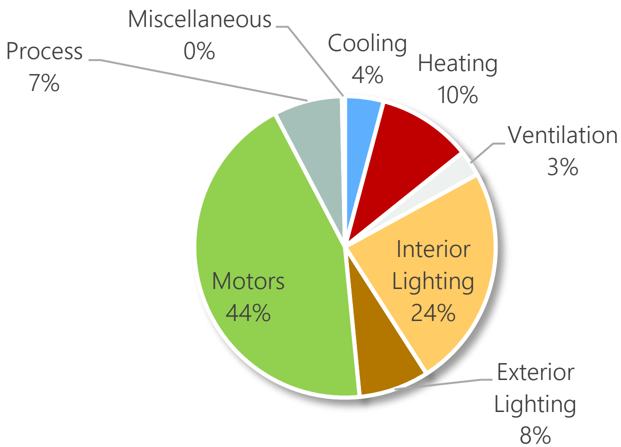


	2021	2022	2025	2030	2040
Reference Baseline (GWh)	395	395	396	399	407
Potential Forecasts (GWh)					
Technical Achievable Potential	392	389	379	364	351
Technical Potential	390	385	371	351	336
Cumulative Savings (GWh)					
Technical Achievable Potential	3	6	17	35	56
Technical Potential	5	10	25	48	71
Energy 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

EE POTENTIAL - CONTINUED

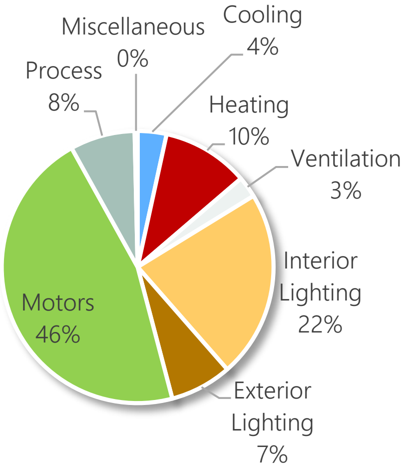
Top Measures – Industrial, Technical Achievable Potential

Washington



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%**

Idaho



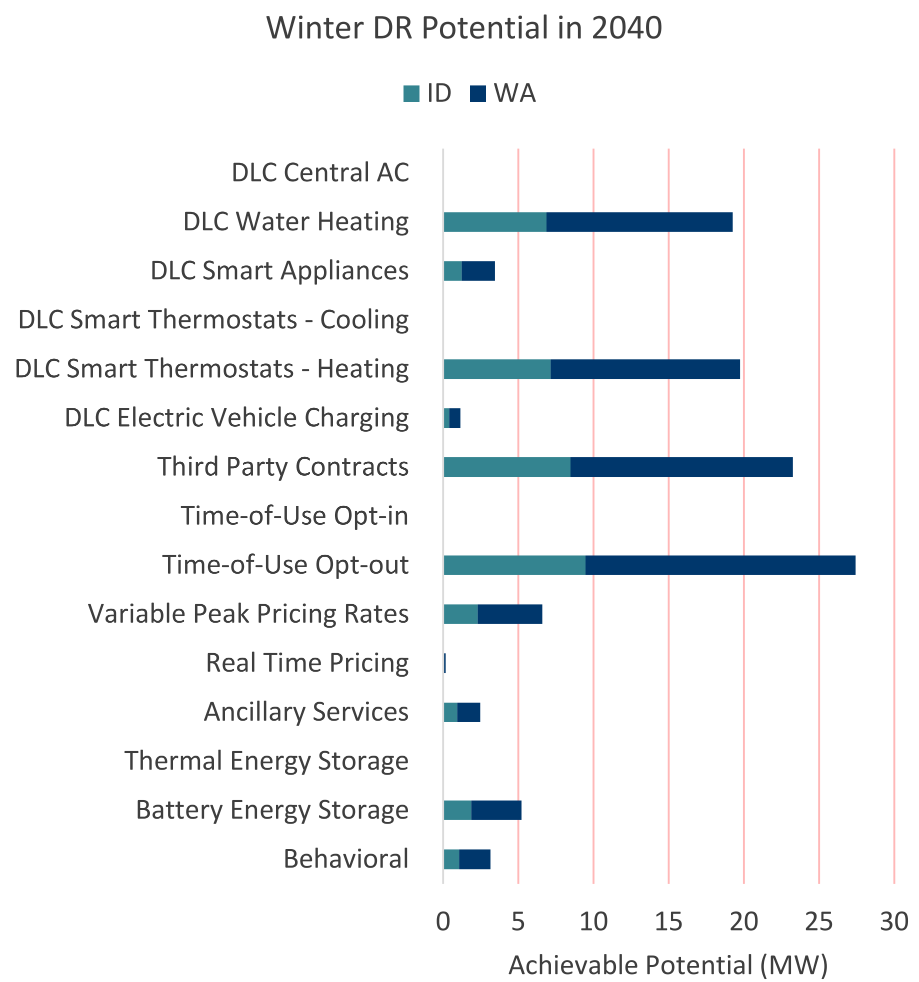
Rank	Measure / Technology (Technical Achievable MWh)	2022	2025	2030	% of Total
1	High-Bay Lighting	413	1,600	4,642	13.1%
2	Destratification Fans (HVLS)	863	2,149	3,426	9.7%
3	Compressed Air - Equipment Upgrade	537	1,338	2,136	6.0%
4	Compressed Air - Leak Management Program	524	1,297	2,058	5.8%
5	Material 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

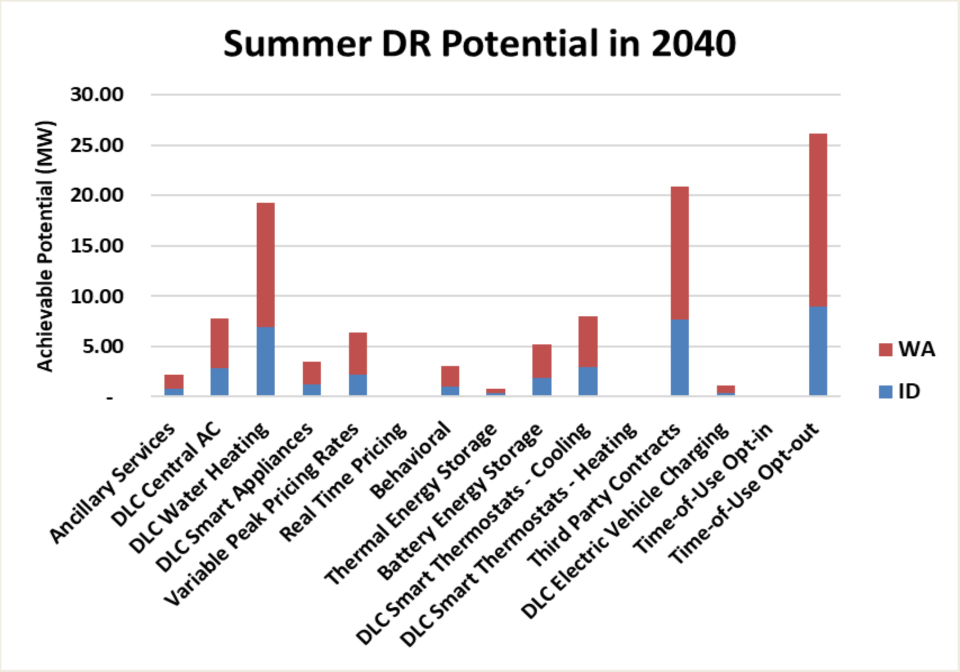
By 2040, by State and Option, TOU Opt-out Scenario

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)

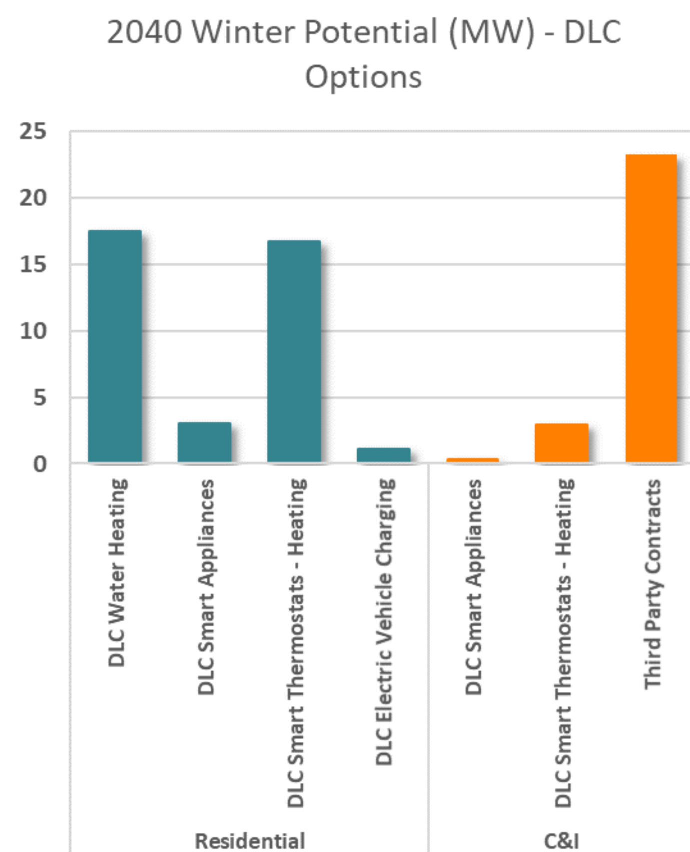
Summer Potential in 2040	ID	WA	Grand Total
Ancillary Services	0.8	1.4	2.2
DLC Central AC	2.9	4.9	7.8
DLC Water Heating	6.9	12.4	19.3
DLC Smart Appliances	1.2	2.2	3.4
Variable Peak Pricing Rates	2.2	4.2	6.3
Real Time Pricing	0.1	0.1	0.2
Behavioral	1.0	2.1	3.1
Thermal Energy Storage	0.3	0.5	0.8
Battery 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

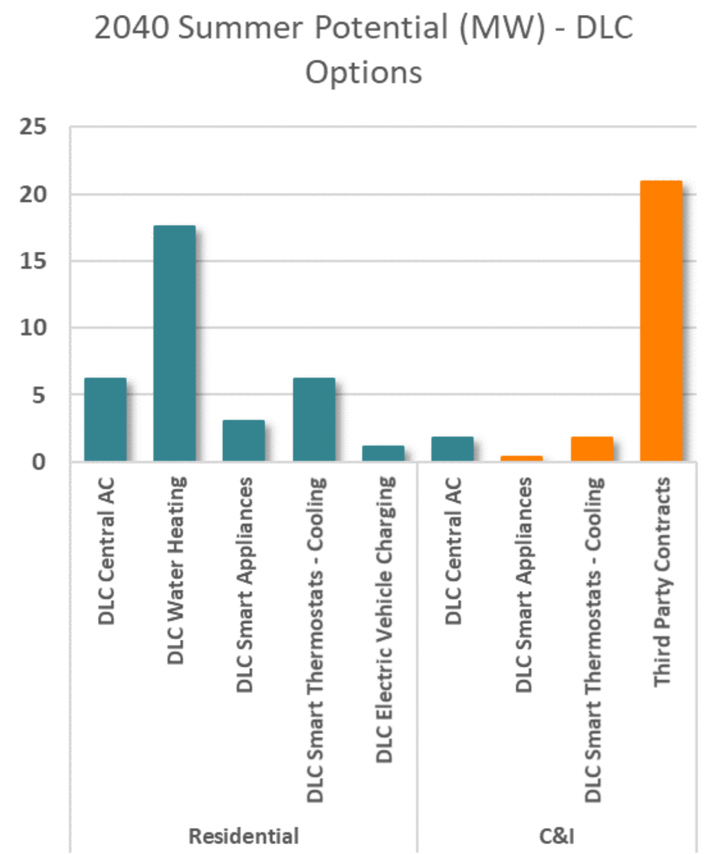
MW BY OPTION – WINTER DLC

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



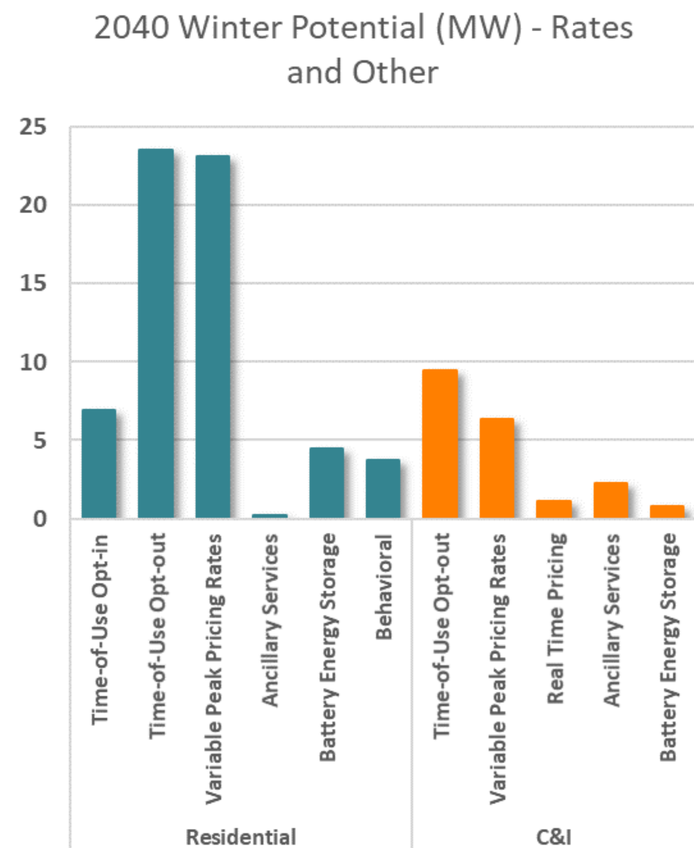
MW BY OPTION – SUMMER DLC

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



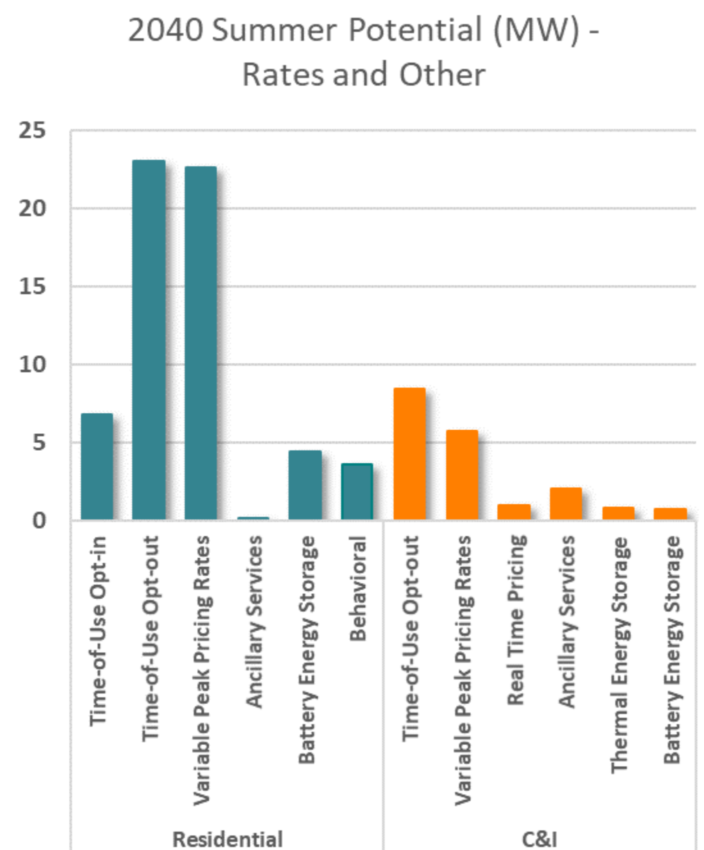
MW BY OPTION – WINTER RATES AND OTHER OPTIONS

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

Washington State University

World Class. Face to Face.

Spirae

AVISTA

Transactive System

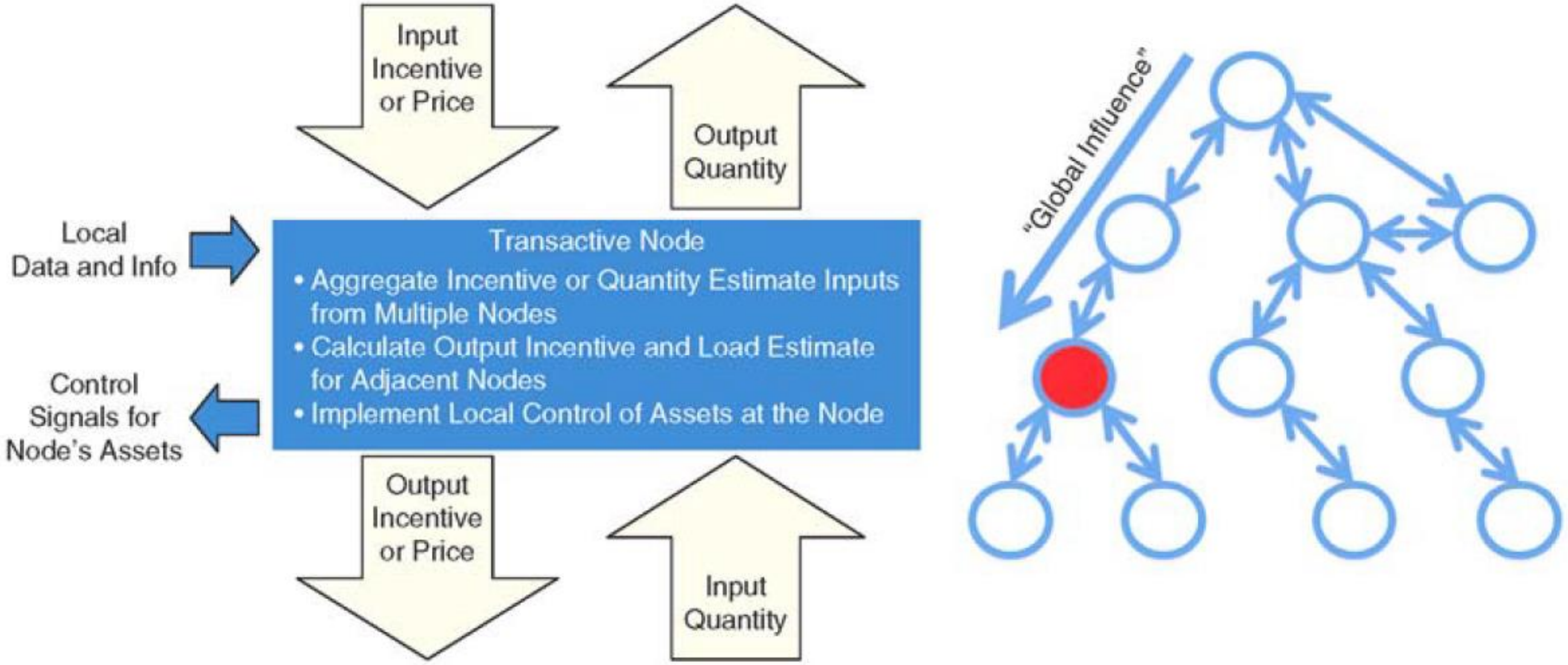


Figure courtesy of PNNL study Transactive System, December 2017

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

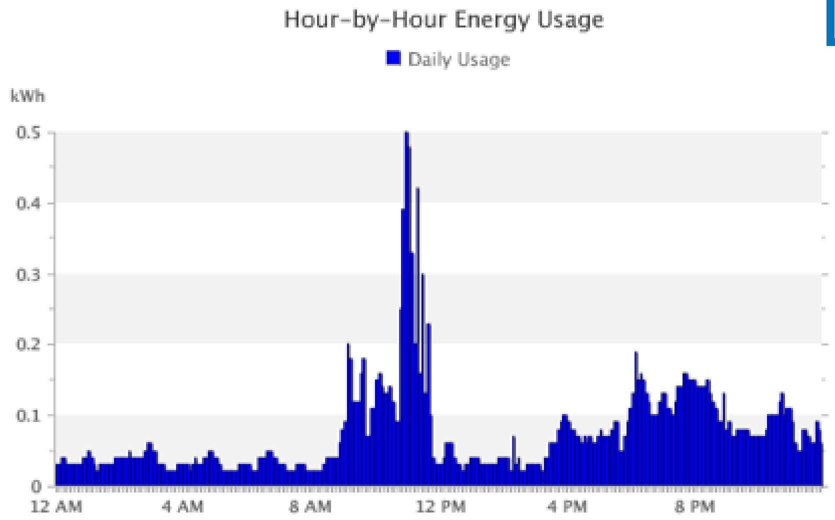
You are 16 days into your billing cycle.

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.



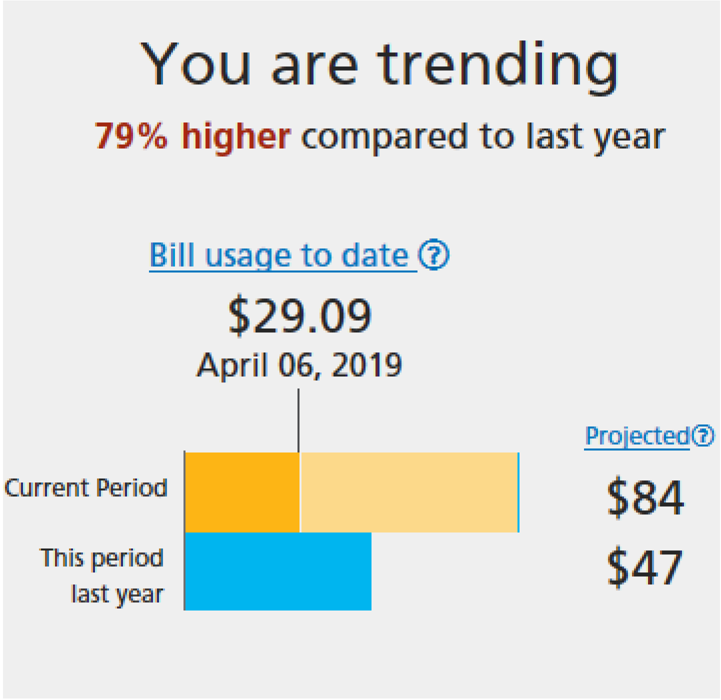
Usage notifications & alerts between bills

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

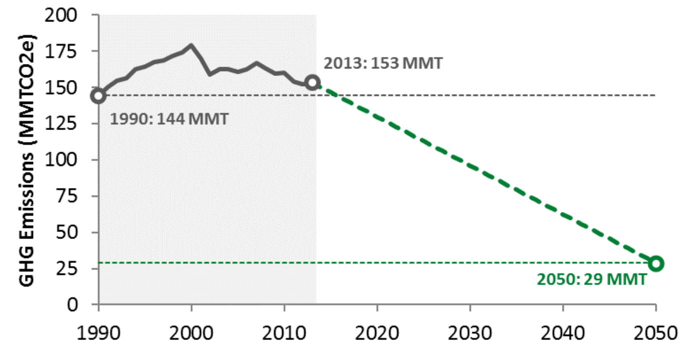
Energy+Environmental Economics

STUDY BACKGROUND & METHODOLOGY

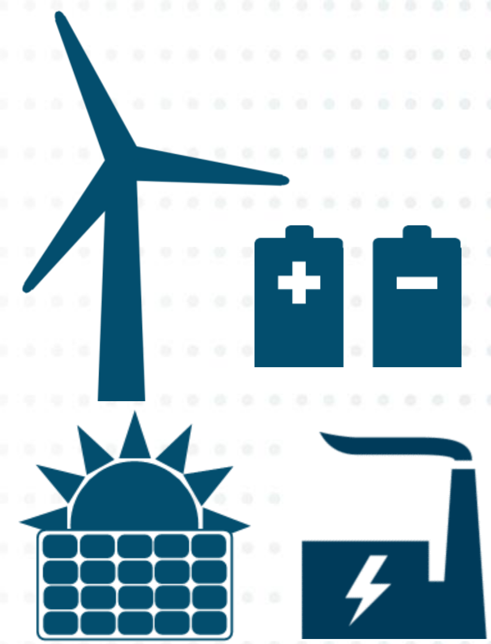
About This Study

+ **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

Historical and Projected GHG Emissions for OR and WA



+ **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



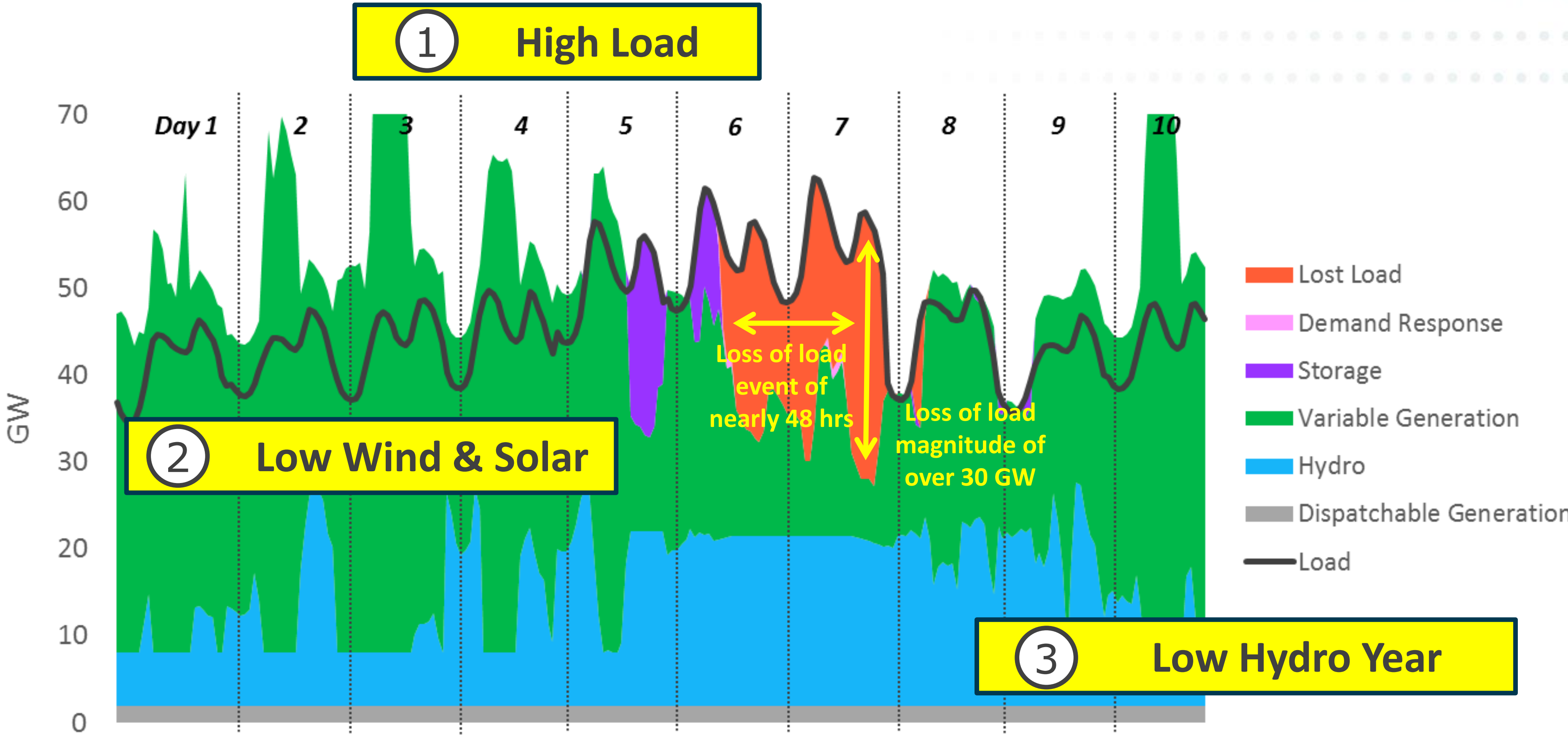
Study Sponsors

+ **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

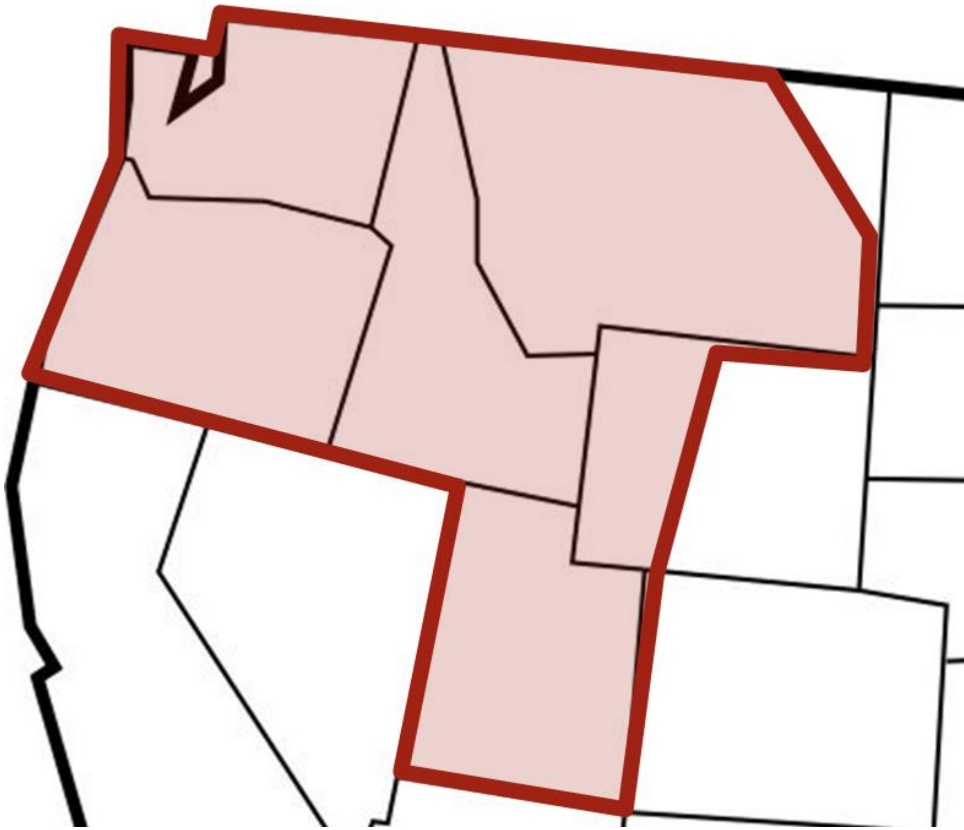


Long-run Reliability and Resource Adequacy

- **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

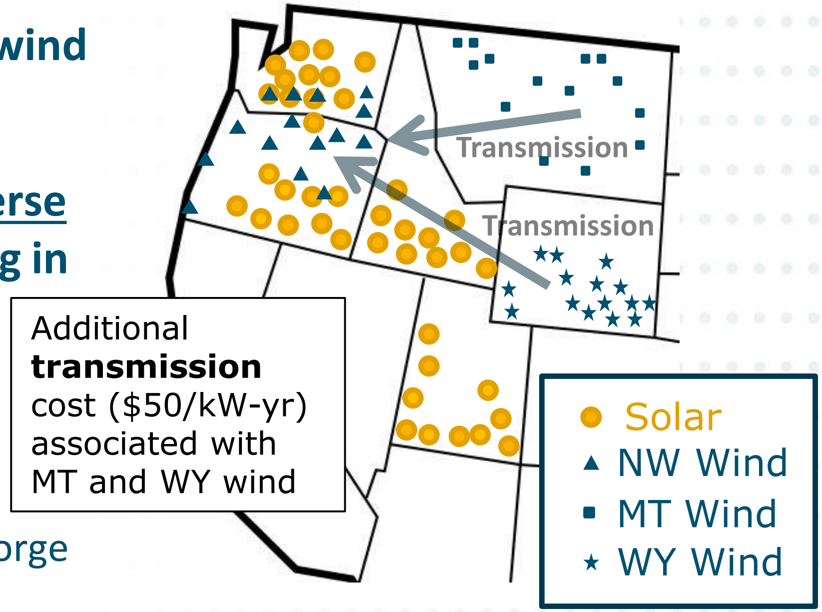
- **The study region consists of the U.S. portion of the Northwest Power Pool (excluding Nevada)**
- **It is assumed that any resource in any area can serve any need throughout the Greater NW region**
  - Study assumes no transmission constraints or transactional friction
  - Study assumes full benefits 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 significantly more diverse 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

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

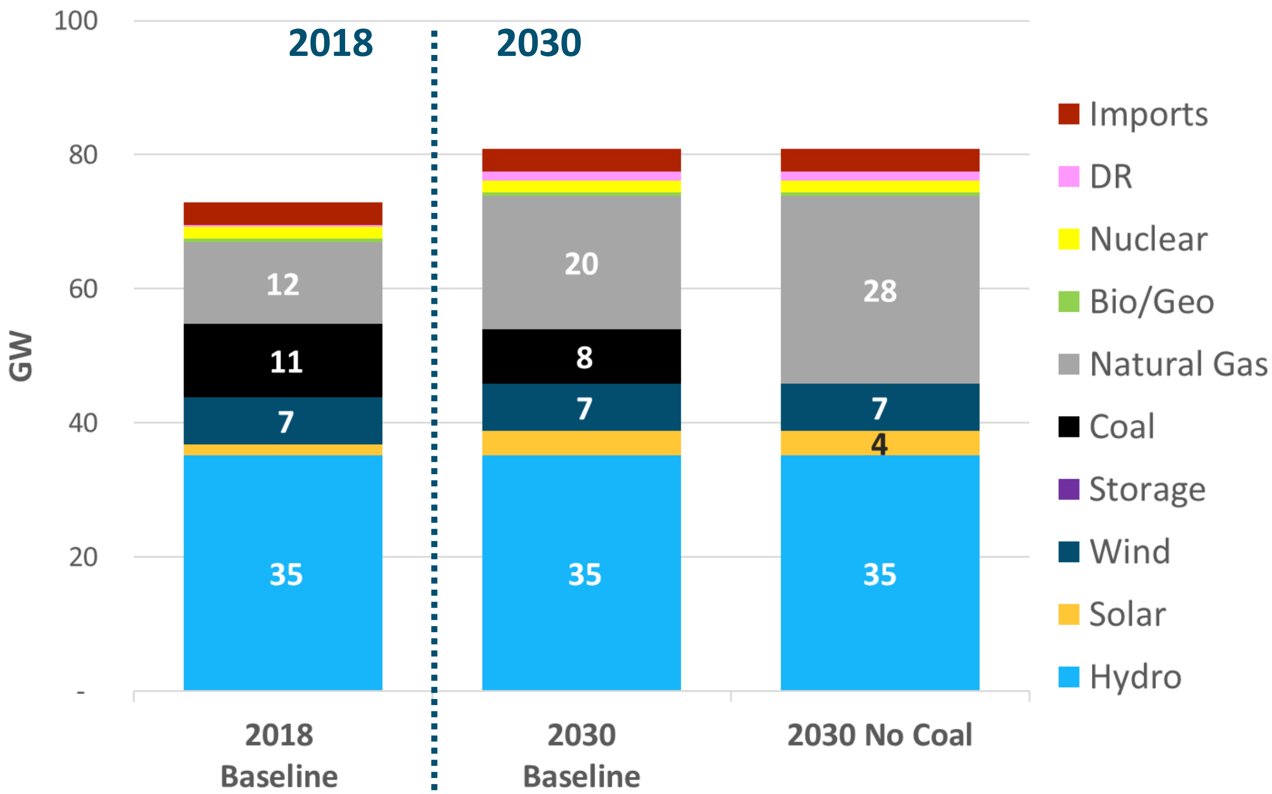
[1]Greater NW Region 1990 electricity sector emissions = 60 MMT/yr.
[2]GHG-Free Generation % = renewable + hydro + nuclear generation, minus exports, divided by total wholesale load
[3]CPS % = renewable + hydro + nuclear generation divided by retail electricity sales
[4]2018 and 2030 cases assumes coal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

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

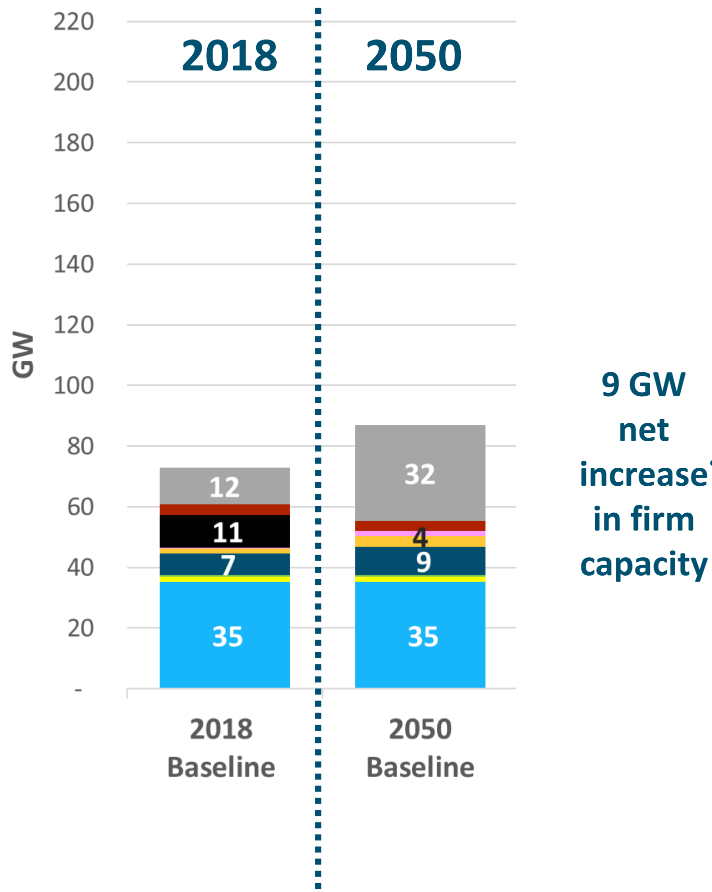
- The 2030 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2030 system does not meet standard for Annual LOLP (5%)
- Load growth and planned coal retirements lead to the need for 8 GW of new effective capacity by 2030

	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%

Energy+Environmental Economics

2050 RESULTS

Scenario Summary
Greater NW System in 2050



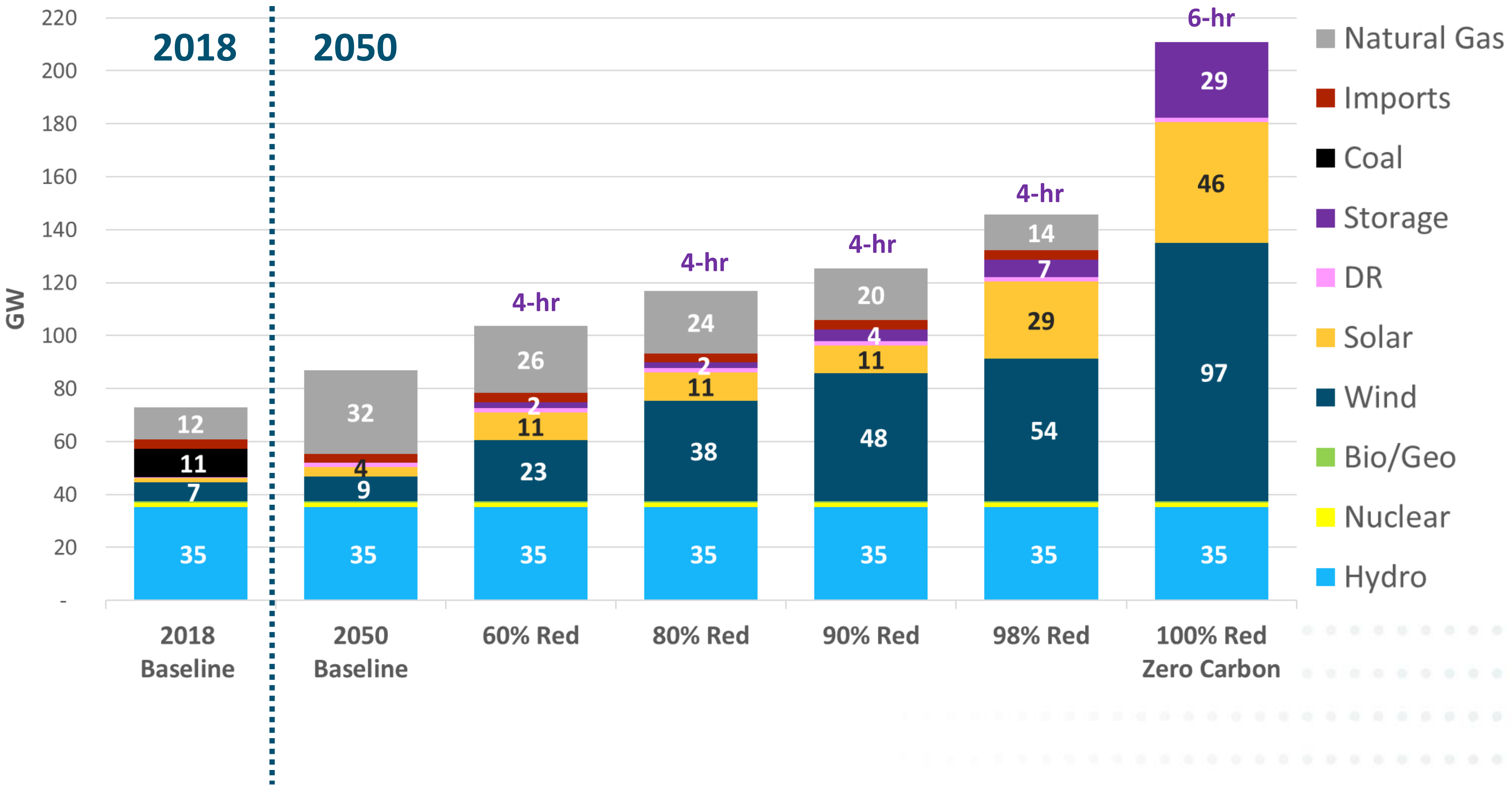
2050 Reference Scenario

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

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

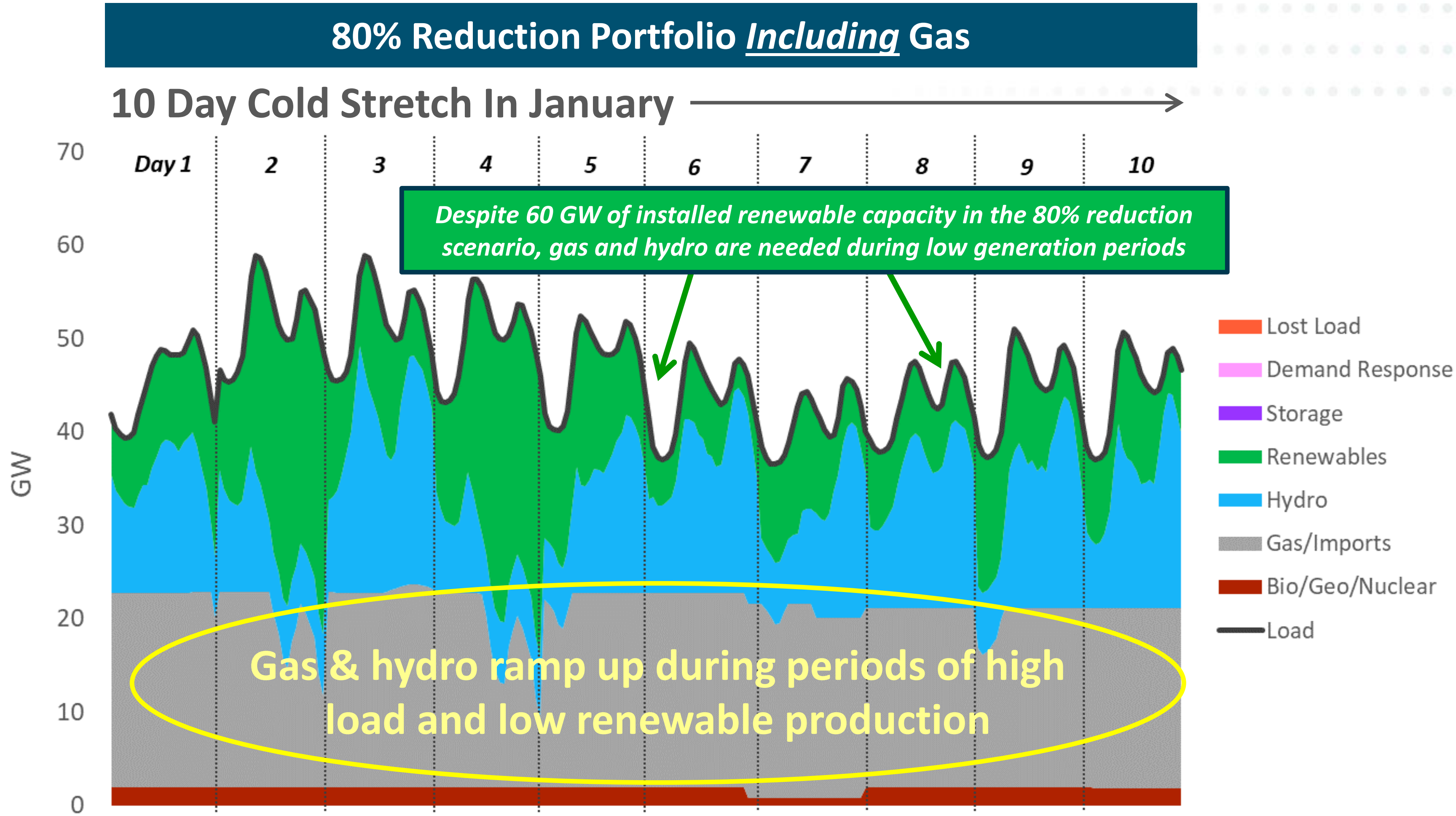
[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary
Greater NW System in 2050



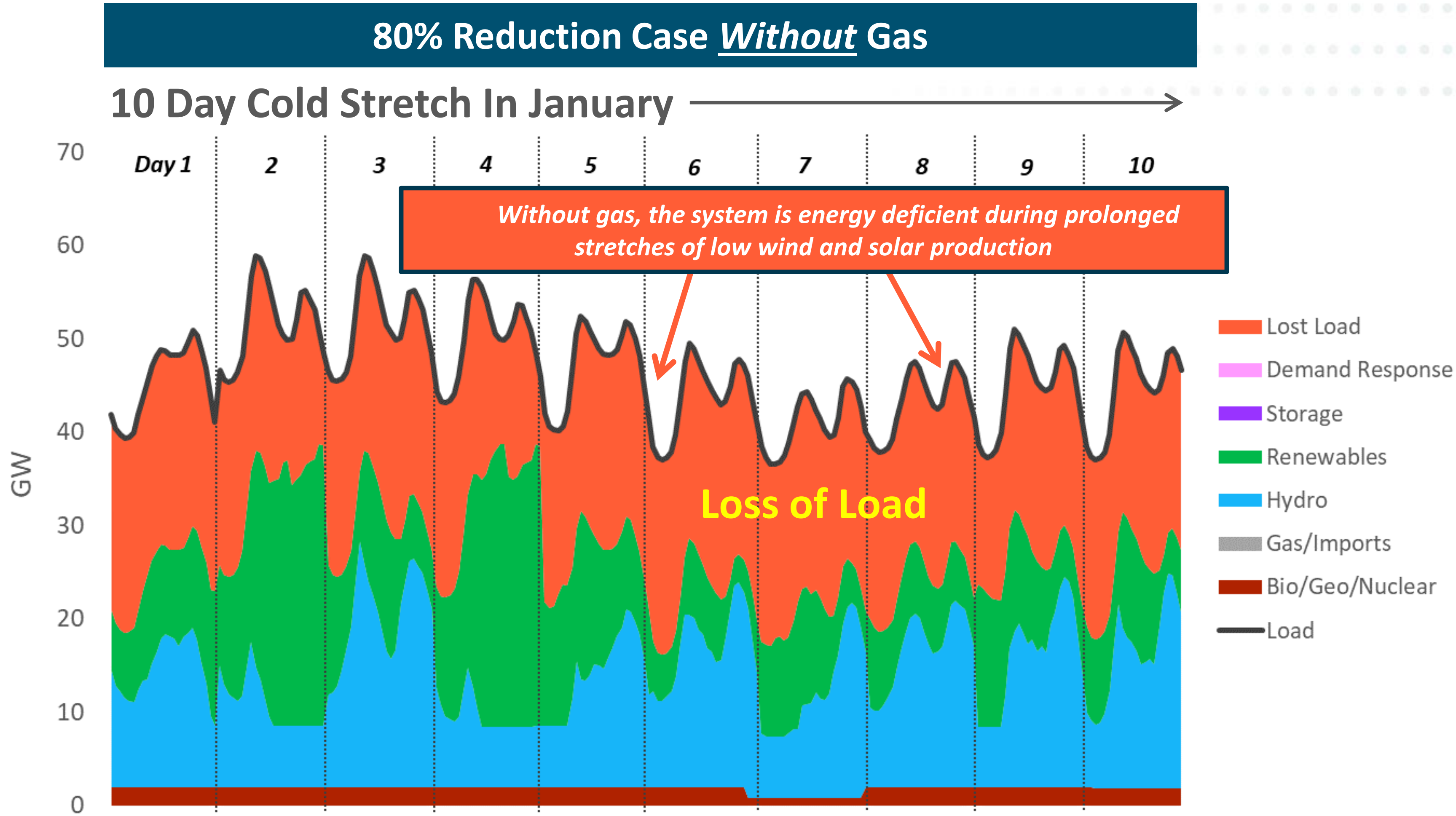
[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Illustrating the Need for Firm Capacity – January

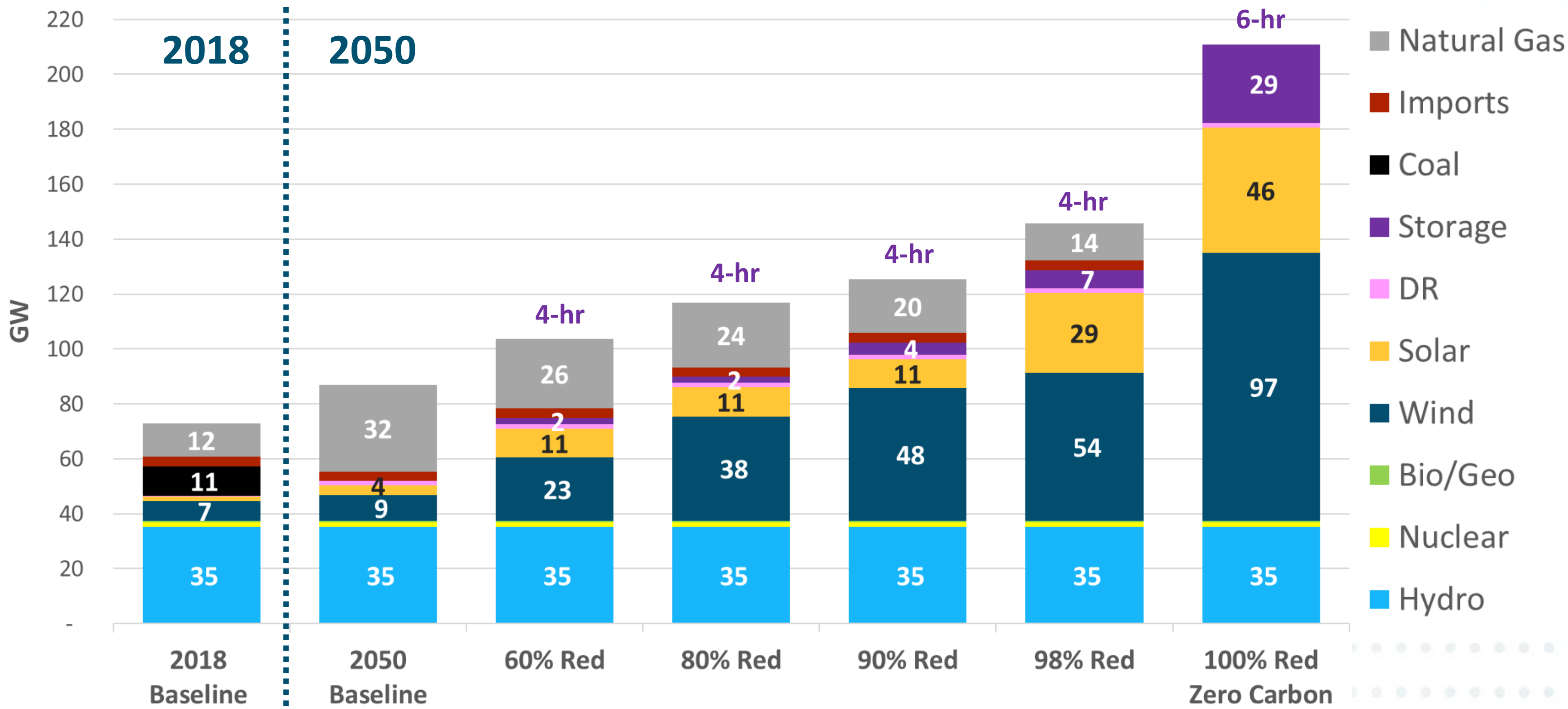


Energy+Environmental Economics

Illustrating the Need for Firm Capacity – January



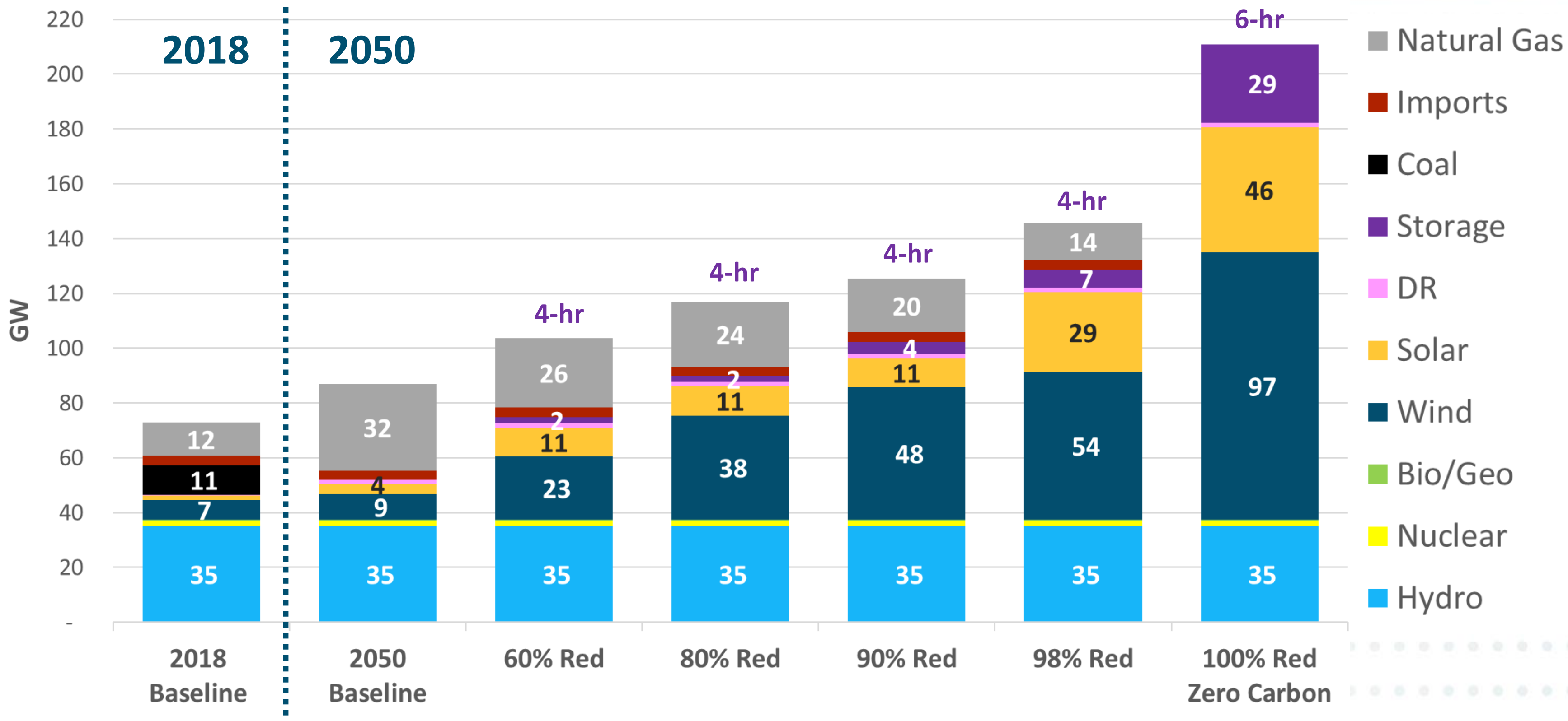
Scenario Summary
2050 Emissions Reductions



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

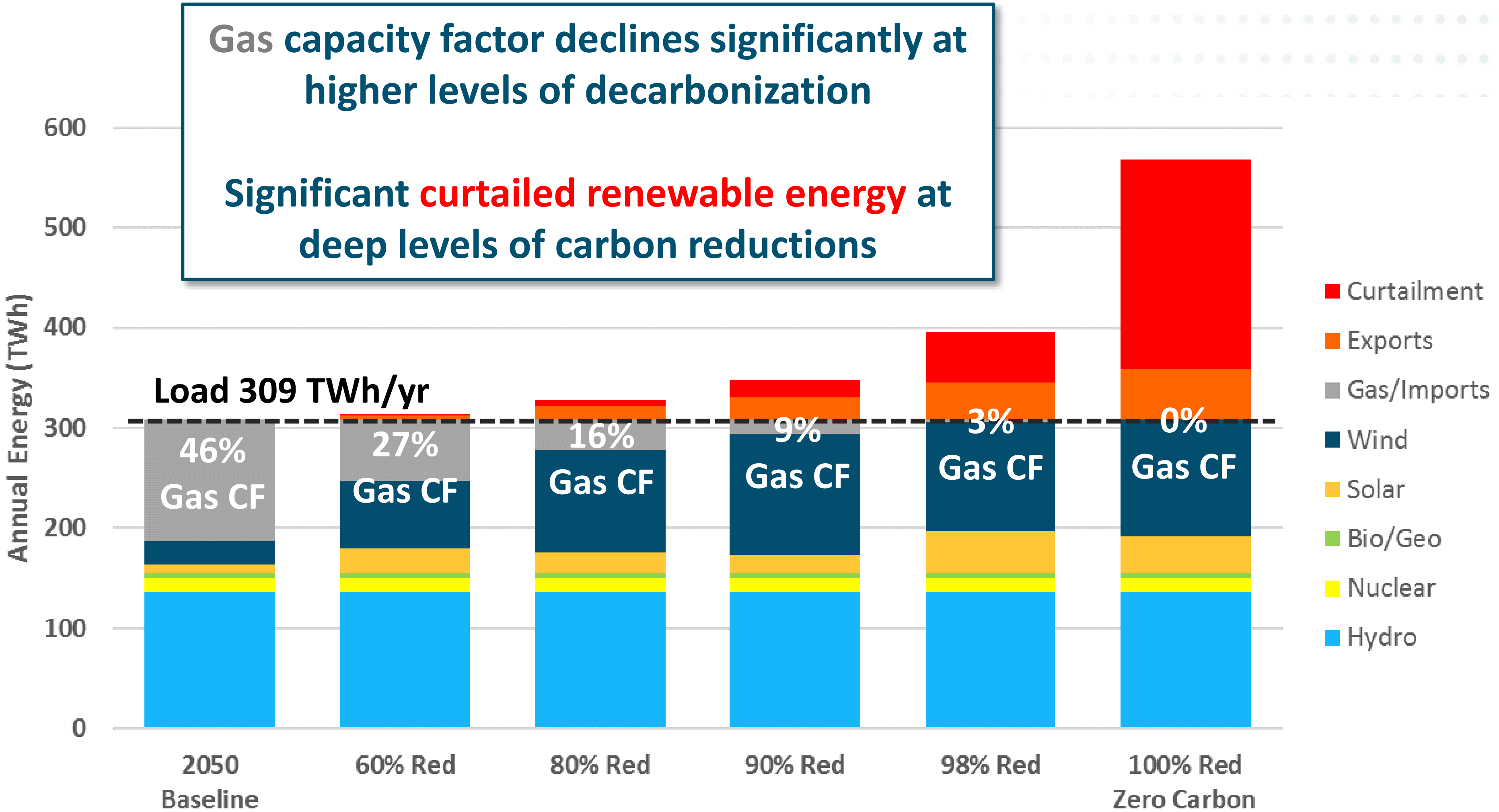
Scenario Summary
2050 Resource Use



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%

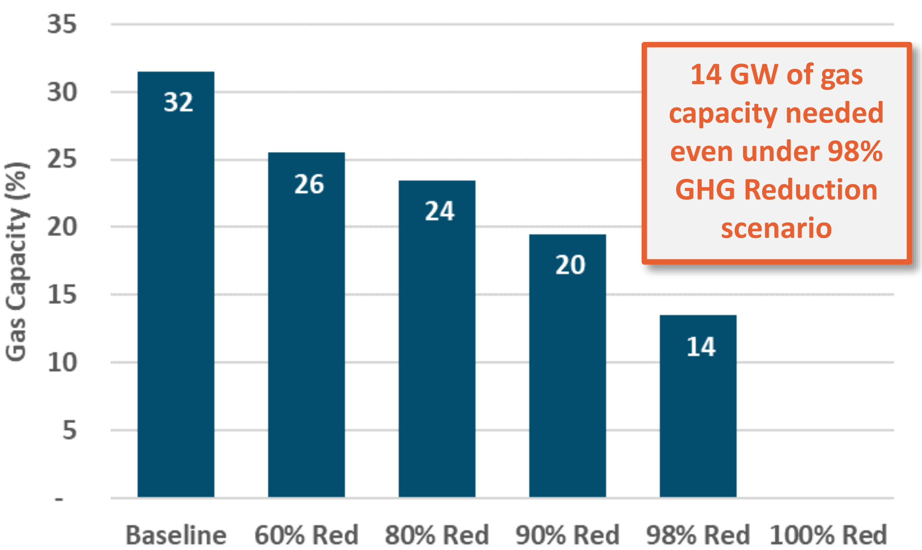
[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

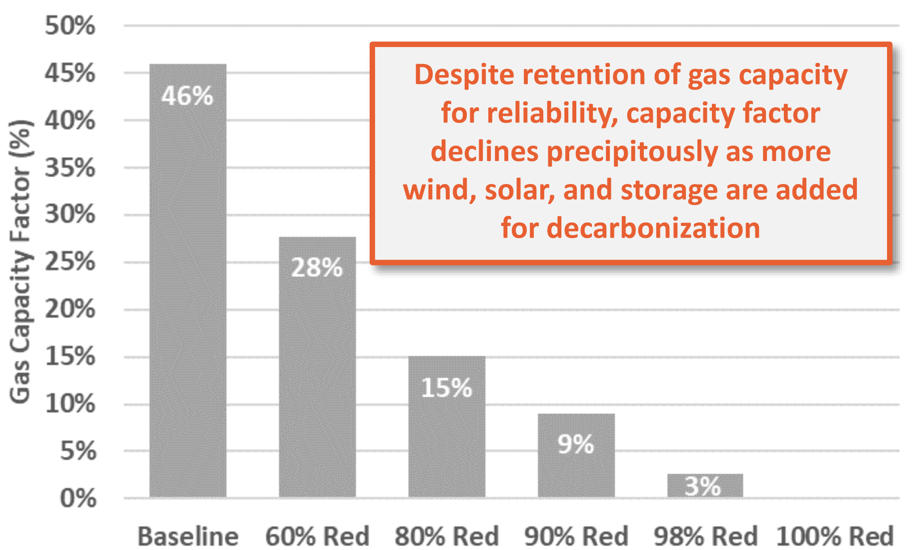
2050 Annual Energy Balance



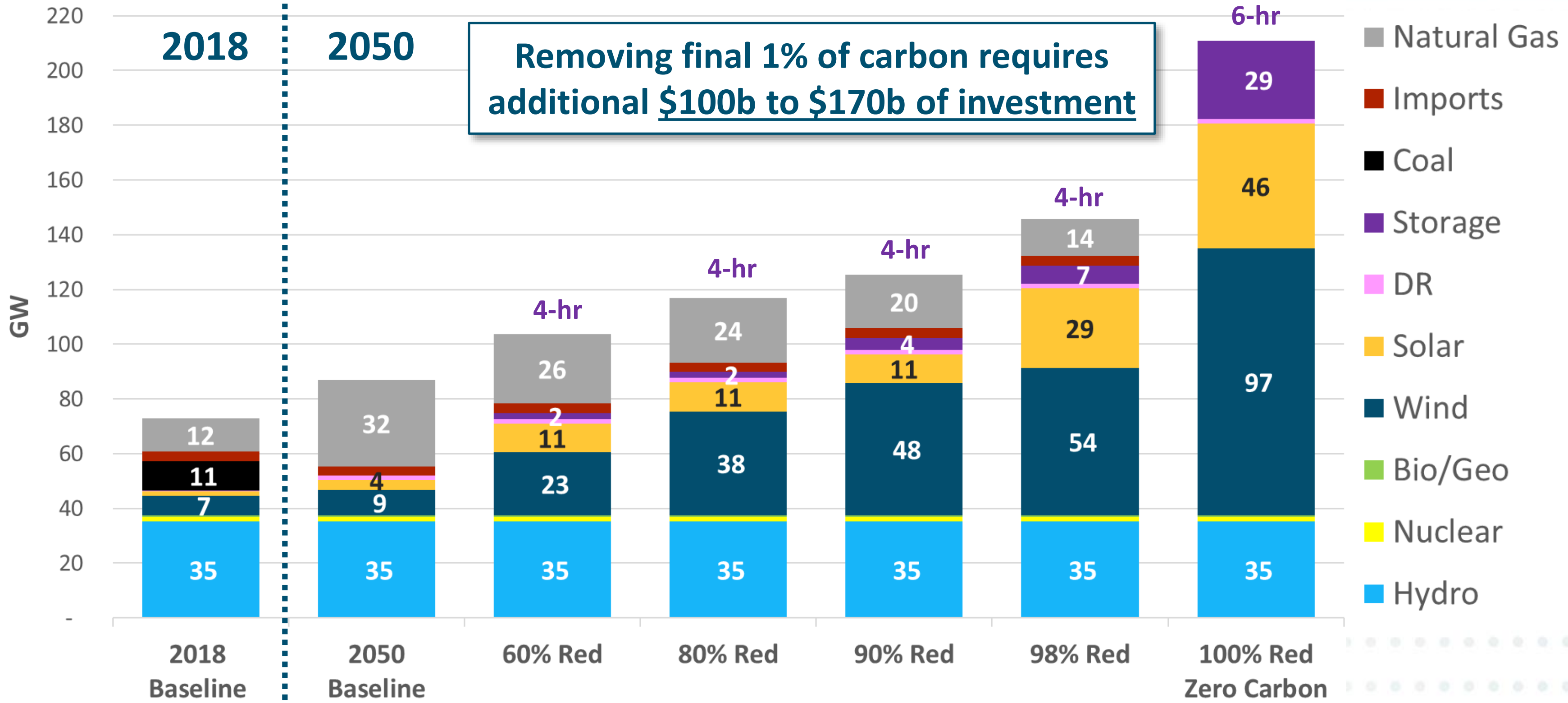
Firm capacity is still needed for reliability under deep decarbonization despite much lower utilization

- 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

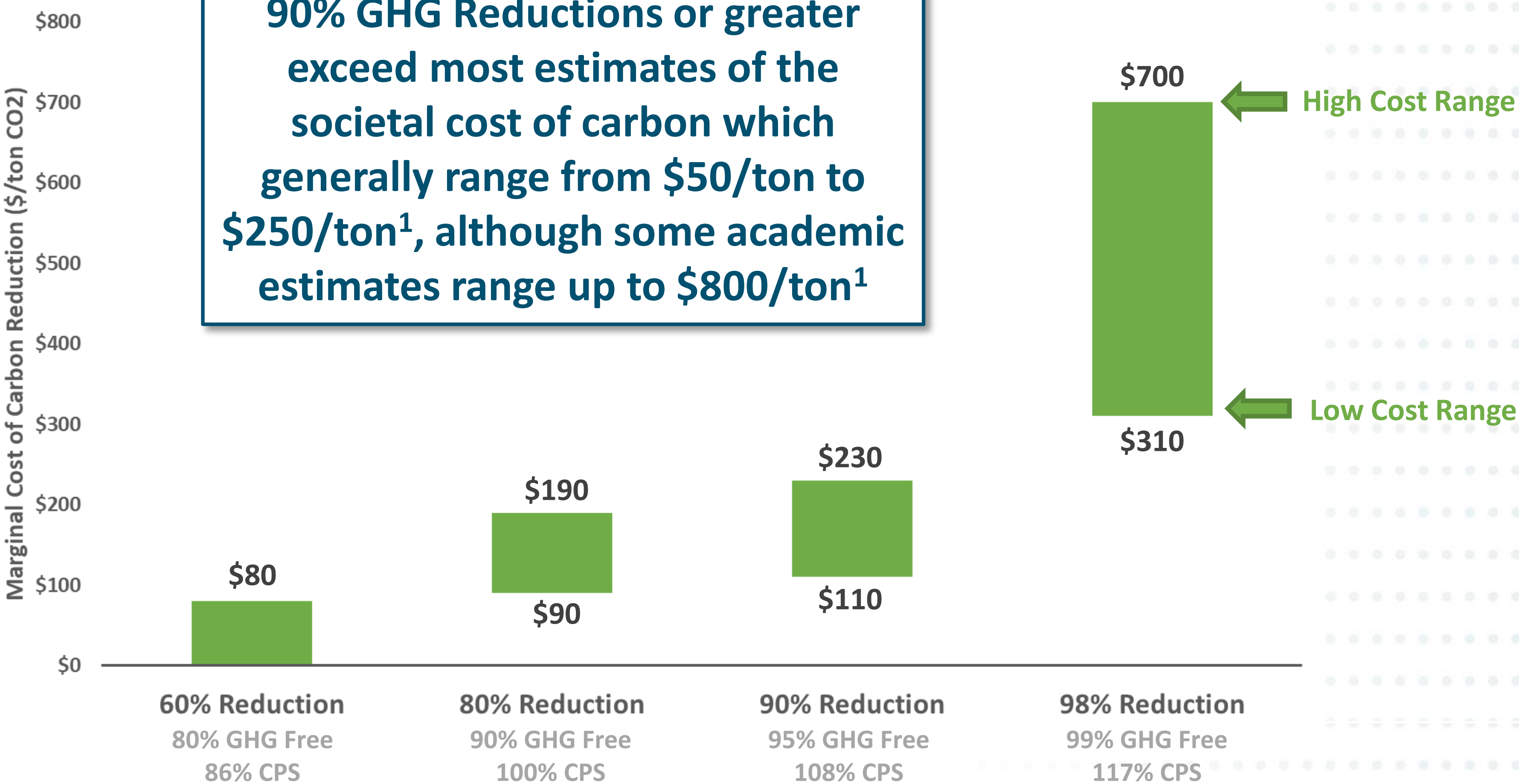


Marginal Carbon Reduction Cost ($/Metric Ton)	Base	$0 - $80	$90 - $190	$110 - $230	$310 - $700	$11,000 – $16,000
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89

[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*

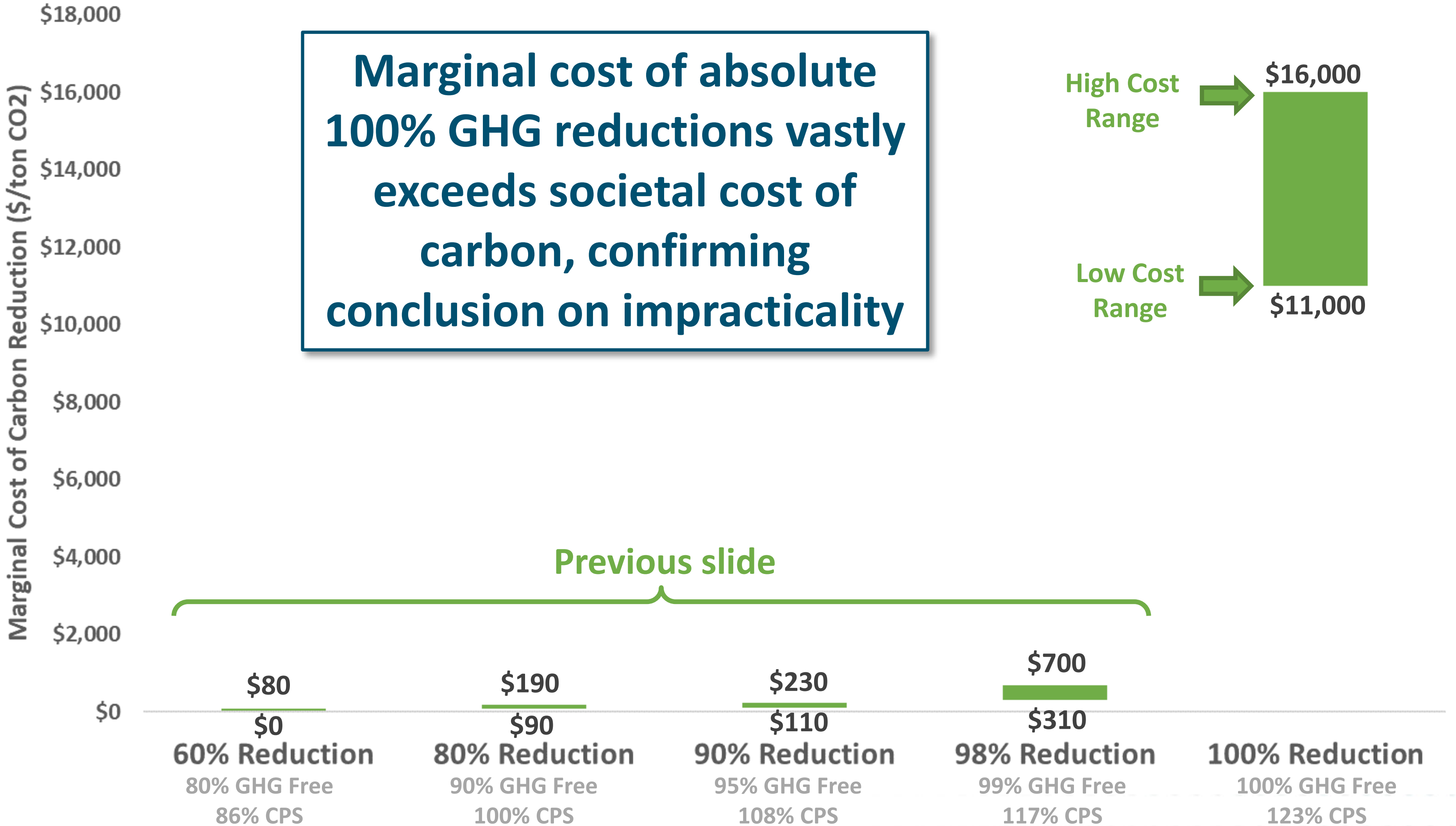
Marginal Cost of GHG Reduction

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]



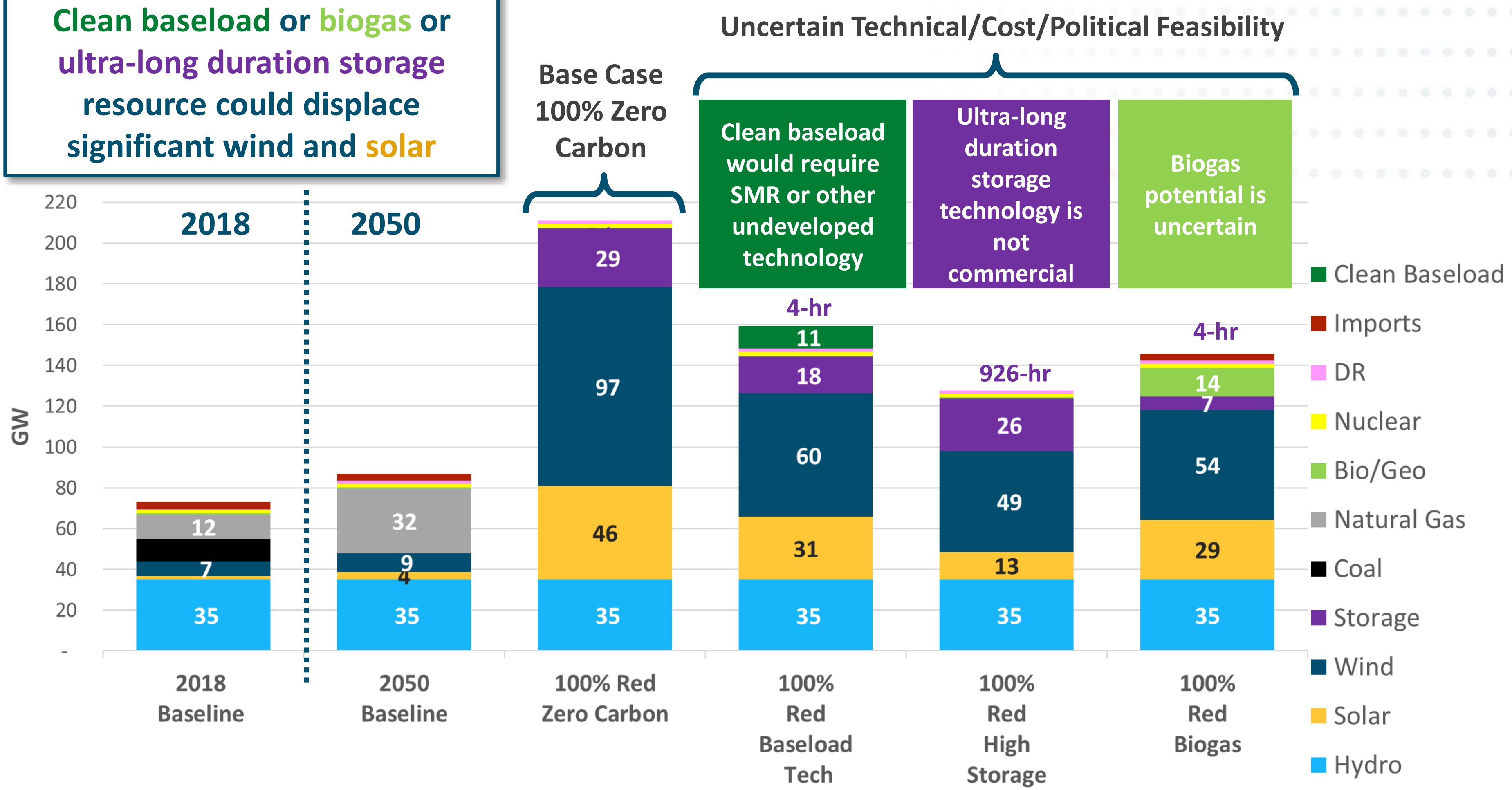
[1] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html; https://www.nature.com/articles/s41558-018-0282-y

Marginal Cost of GHG Reduction



100% Reduction Portfolio Alternatives in 2050

Clean baseload or biogas or ultra-long duration storage resource could display significant wind and solar



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

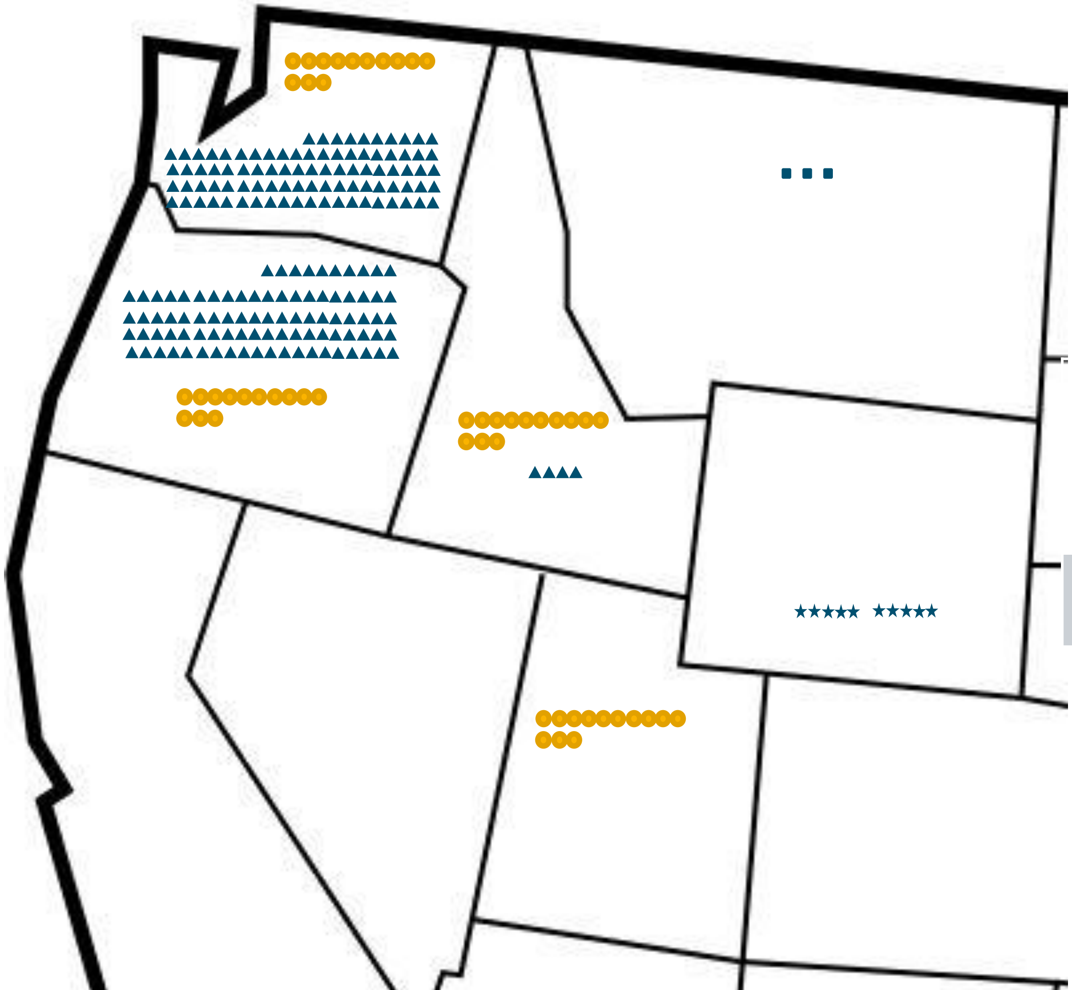
1.6 to 7.5x

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



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

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

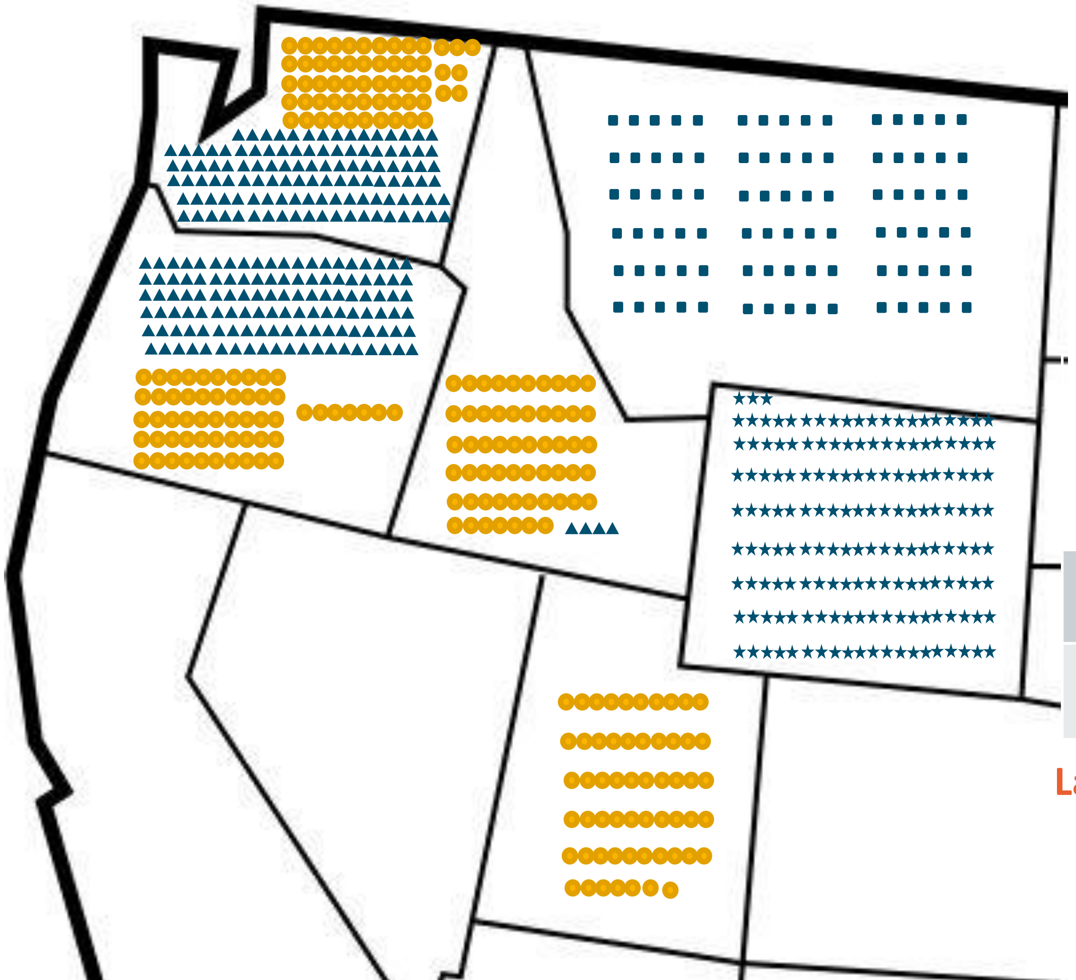
8 to 37x

the area of Portland and Seattle combined

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

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

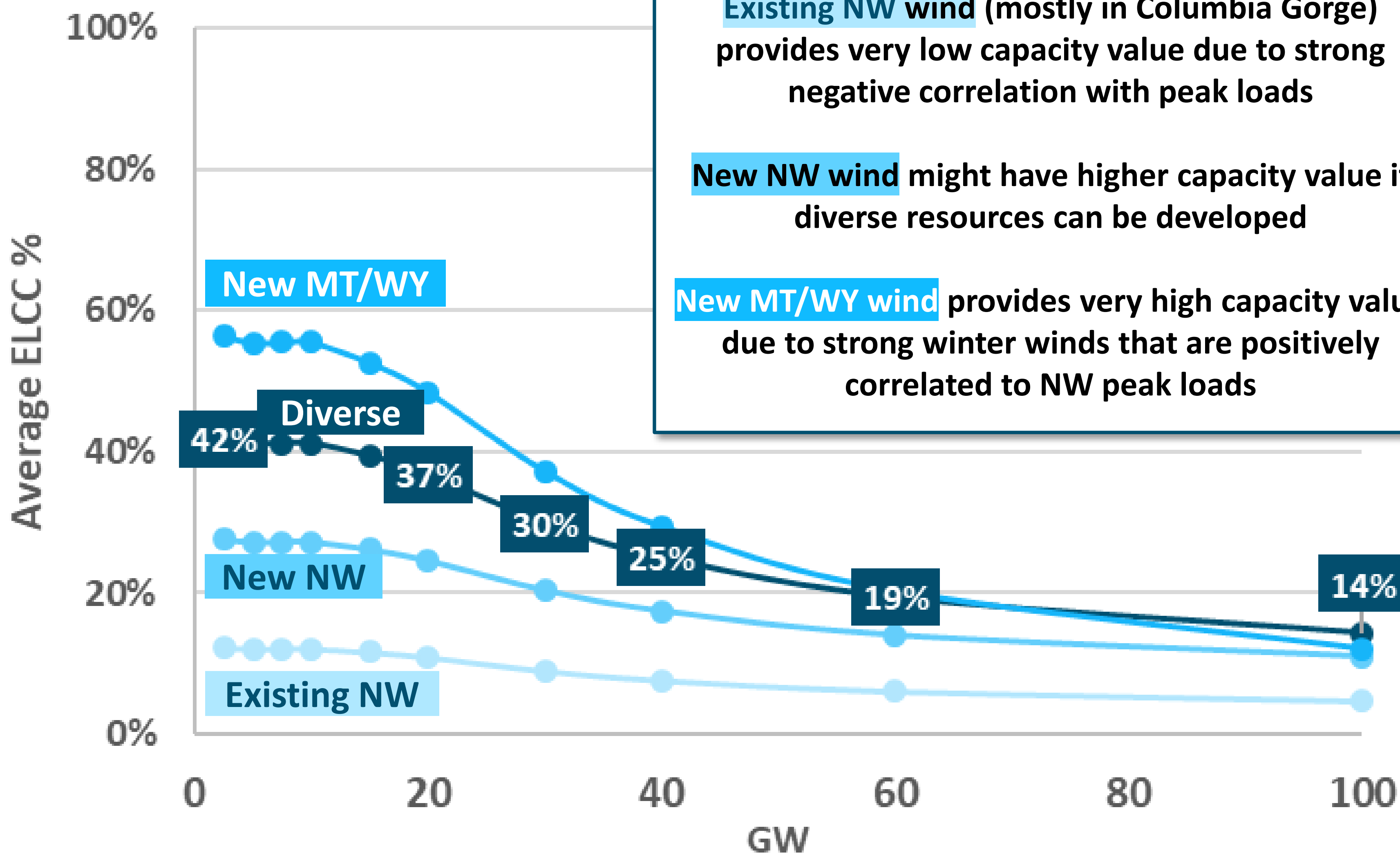
20 to 100x

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

Wind ELCC varies widely by location

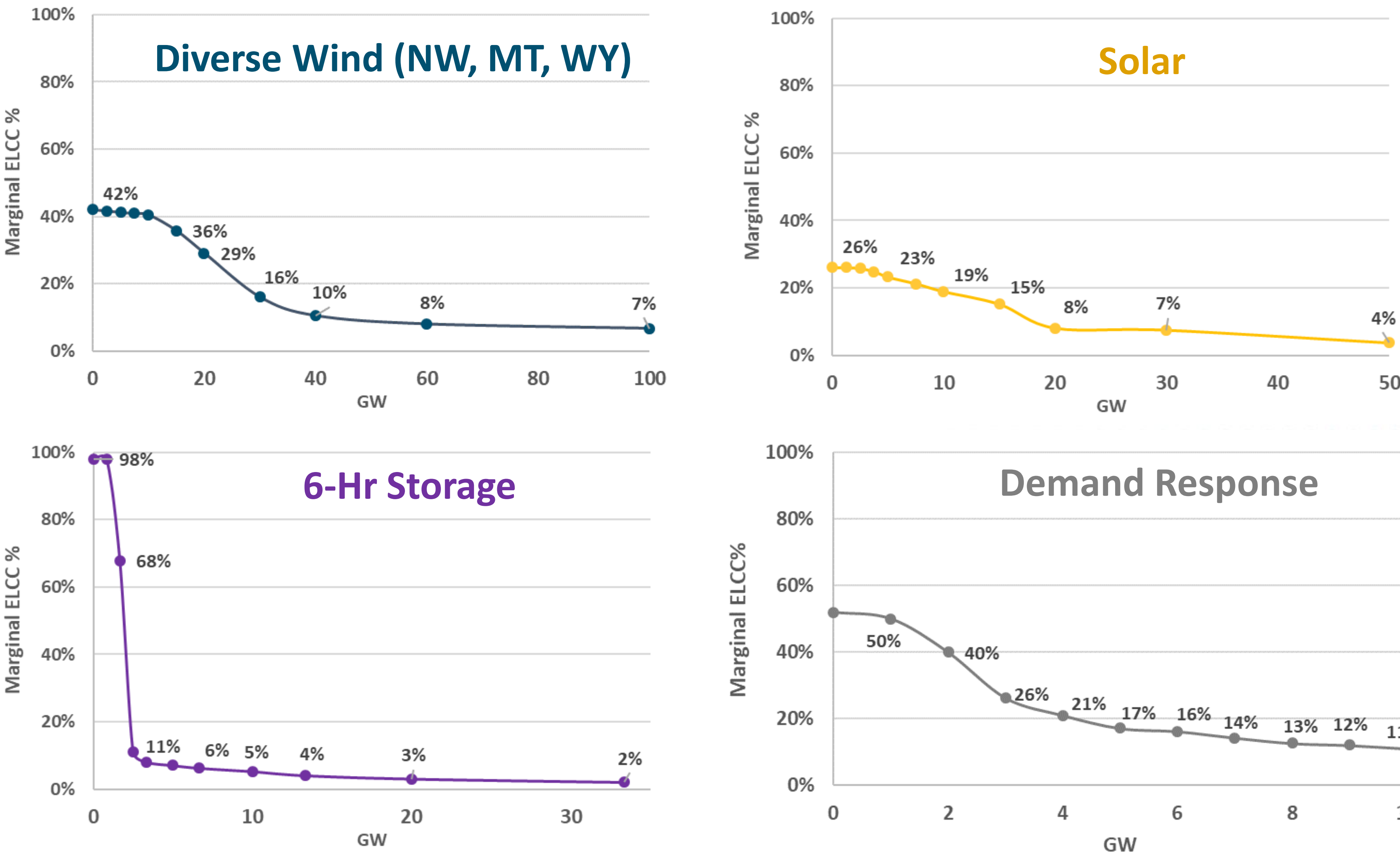


Existing NW wind (mostly in Columbia Gorge) provides very low capacity value due to strong negative correlation with peak loads

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

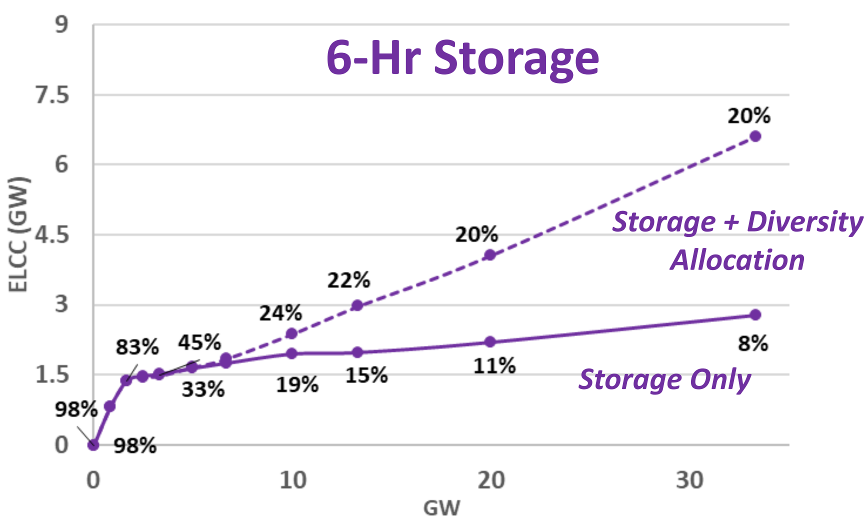
Effective capacity from wind, solar, storage, and demand response is limited due to saturation effects

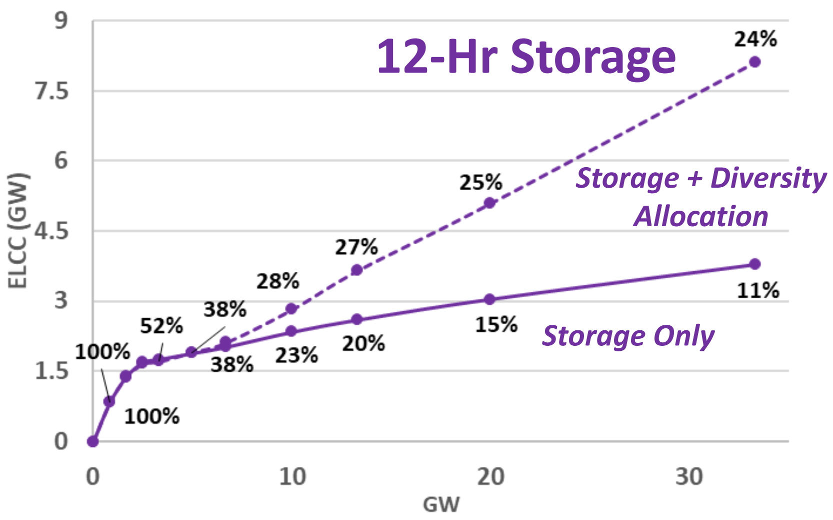


ELCC = Effective Load Carrying Capability = firm contribution to system peak load

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

Energy+Environmental Economics

Thank You!

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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/

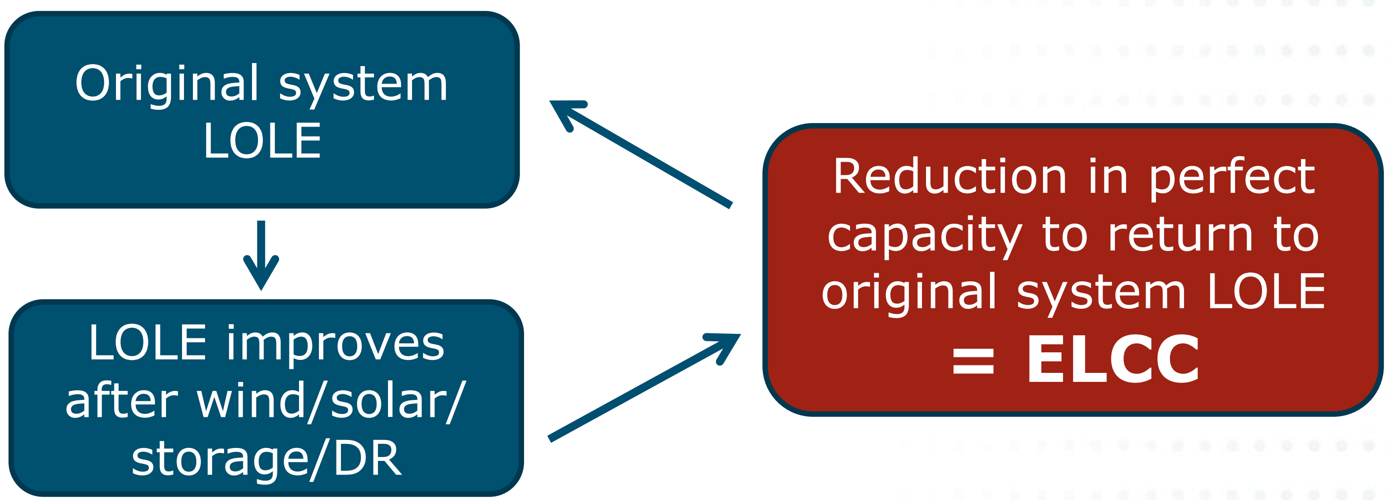
RECAP calculates a number of metrics that are useful for resource planning

- **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 <u>2050 80% GHG Reduction Scenario</u> 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%*

**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)			
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
Wind	7	11	21
Solar	2.0	2.2	7.5
Storage	1.6	1.8	5.8
Total Supply	59	59	57

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

	Nameplate Capacity (GW)			ELCC (%)			Capacity Factor (%)		
	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.
Hydro	*35*	*35*	*35*	*58%*	*58%*	*57%*	*44%*	*44%*	*44%*
Wind	*38*	*48*	*96*	*19%*	*22%*	*22%*	*35%*	*36%*	*37%*
Solar	*11*	*11*	*46*	*19%*	*21%*	*16%*	*27%*	*27%*	*27%*
Storage	*2.2*	*4.4*	*29*	*71%*	*41%*	*20%*	*N/A*	*N/A*	*N/A*

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

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

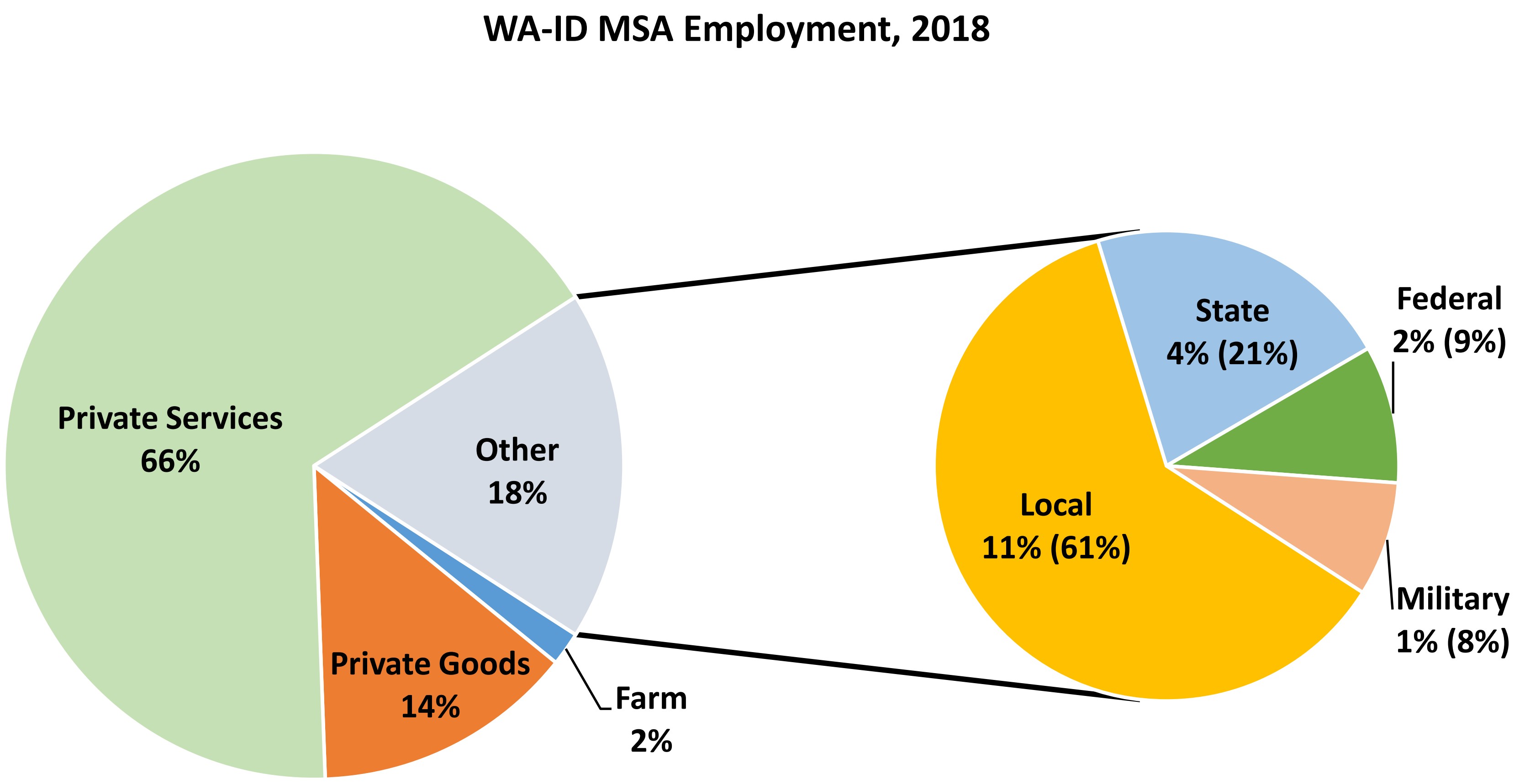
- **Service Area Economy**
- **Peak Load Forecast**
- **Long-run Forecast**

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

Service Area Economy

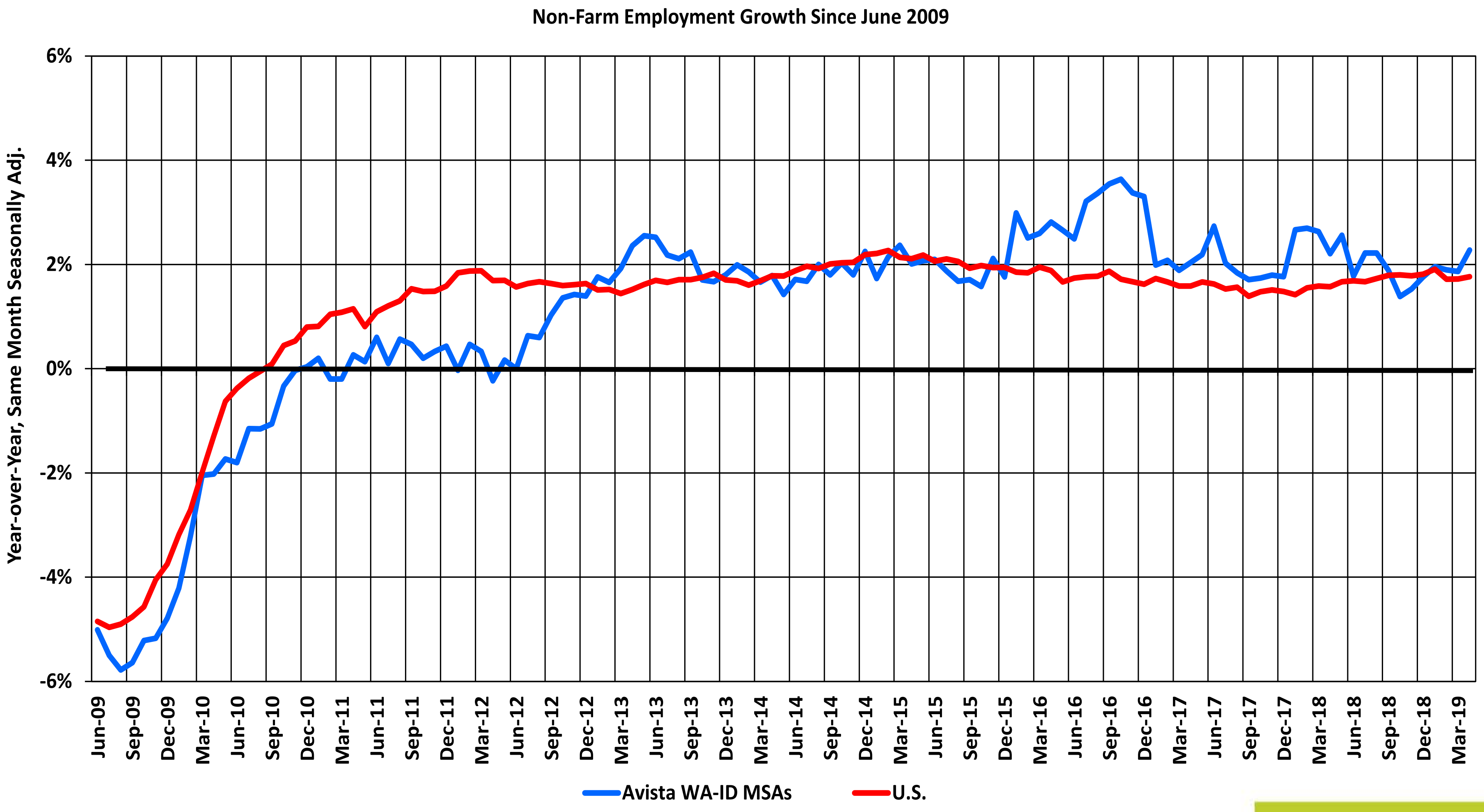
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Distribution of Employment: Services and Government are Dominant



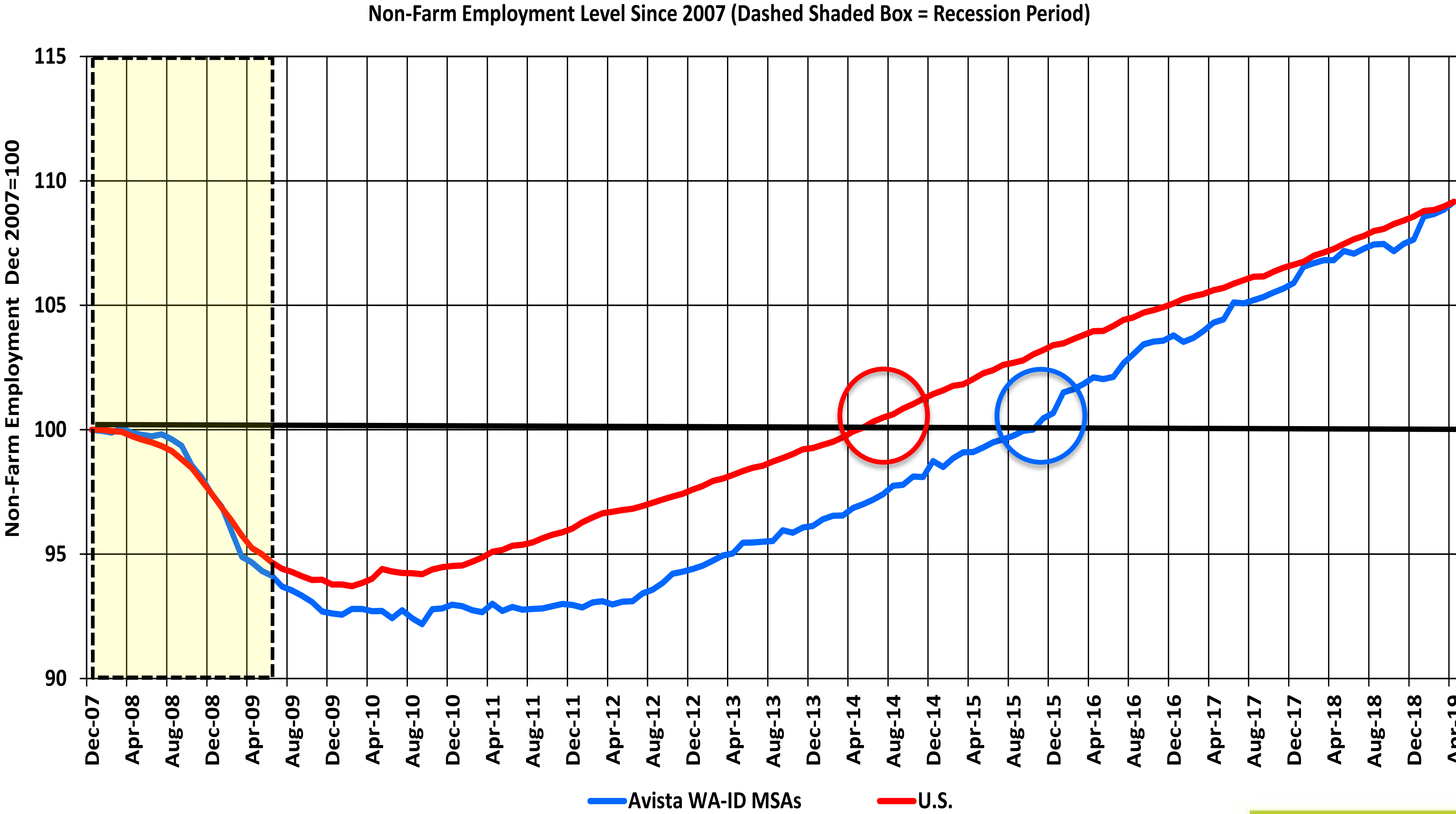
Source: BLS, BEA and author's calculations.

Non-Farm Employment Growth, 2009-2019



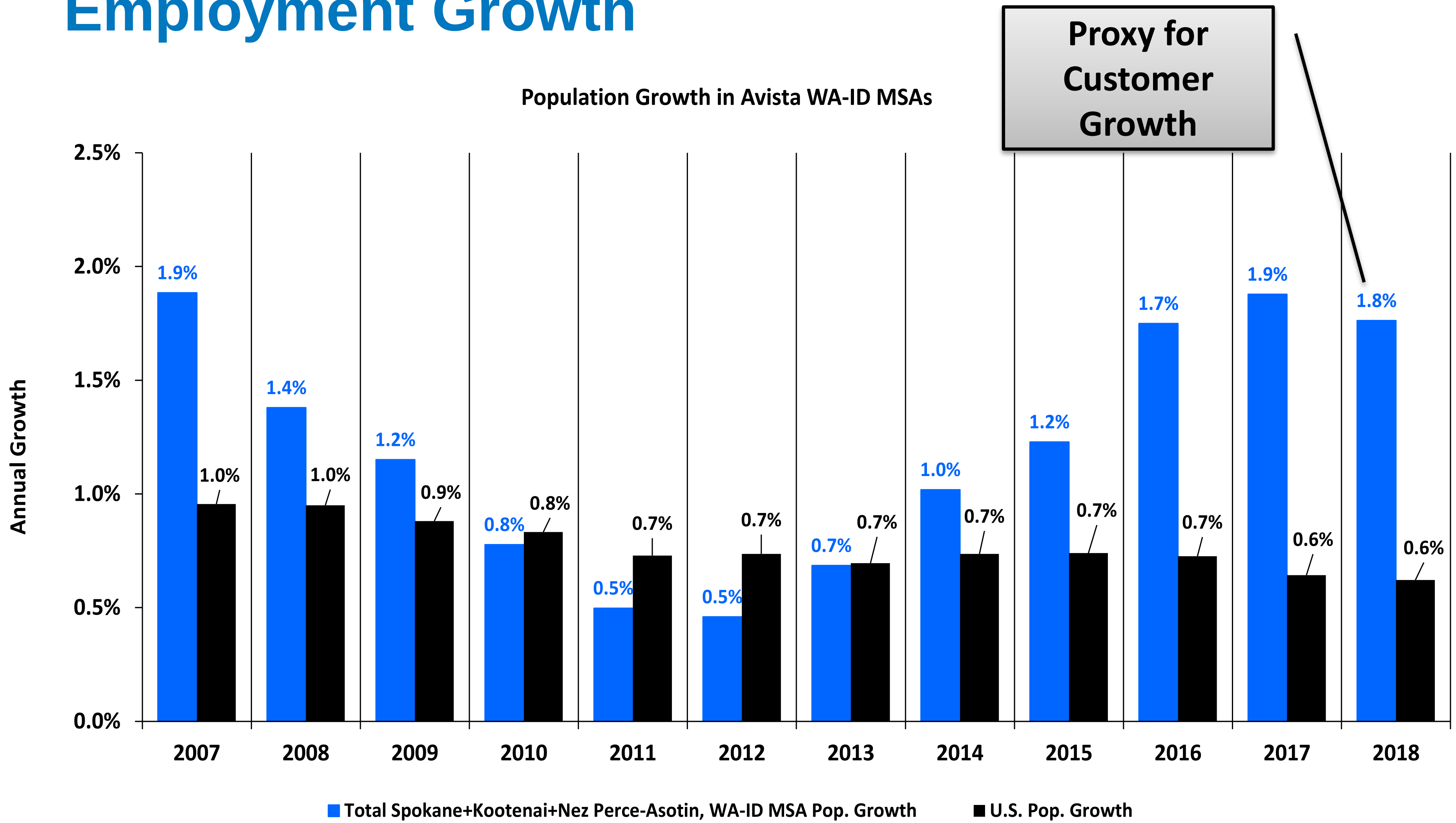
Source: BLS and author’s calculations.

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.**

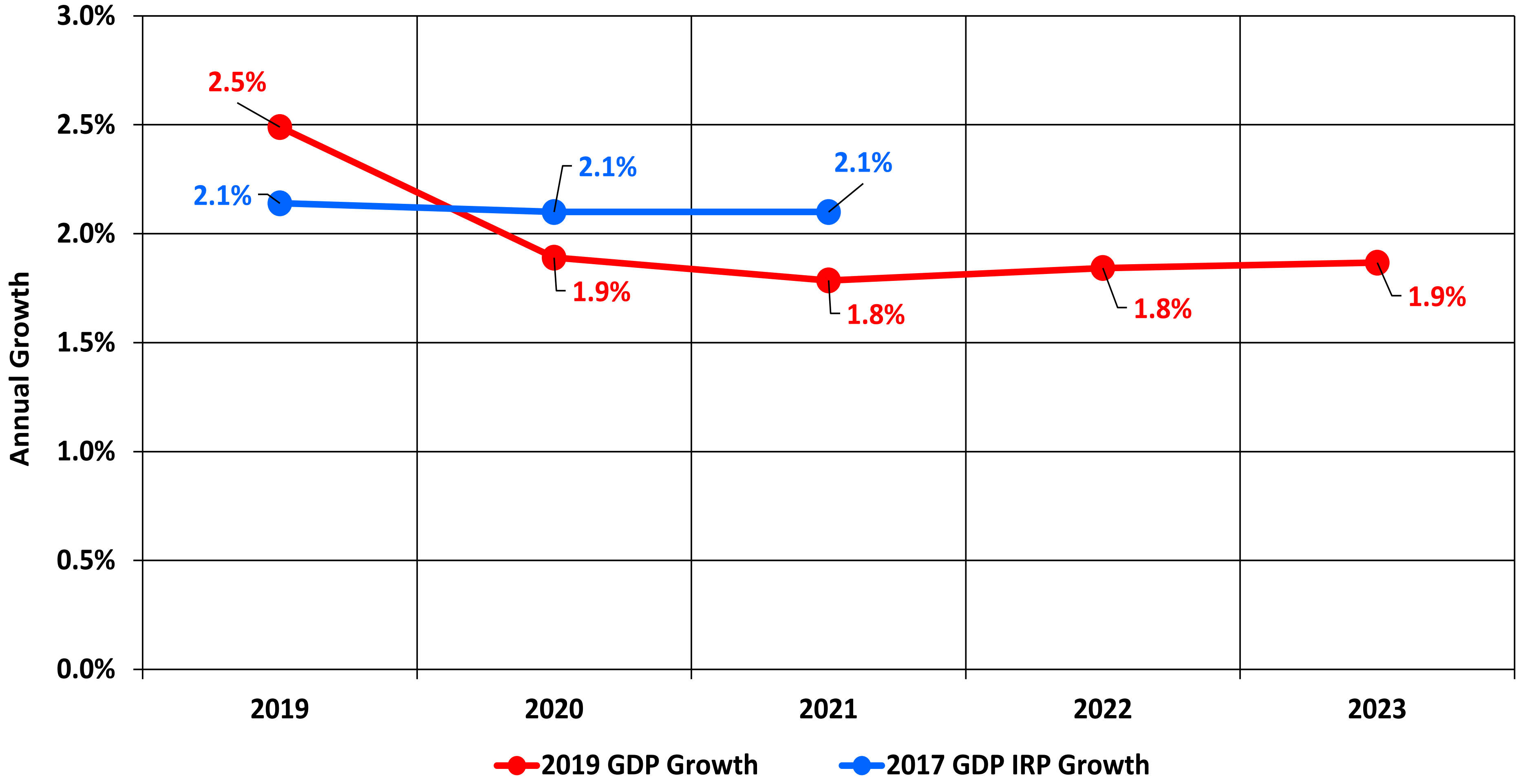
- **Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.**

- **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.**

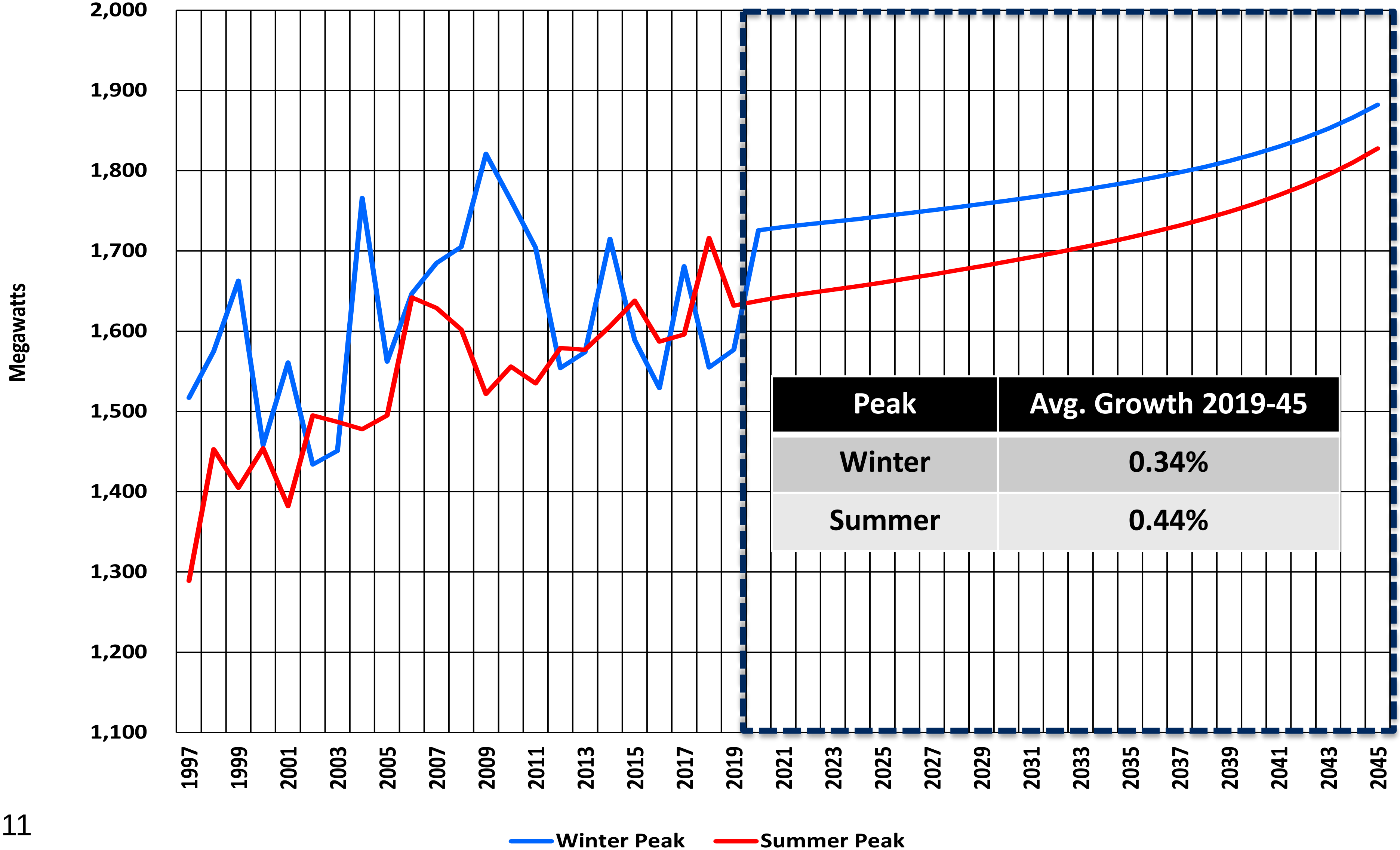
- **The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "*ceteris paribus*" assumption for weather and other factors.**

GDP Growth Assumptions: 2019 IRP vs. 2017 IRP



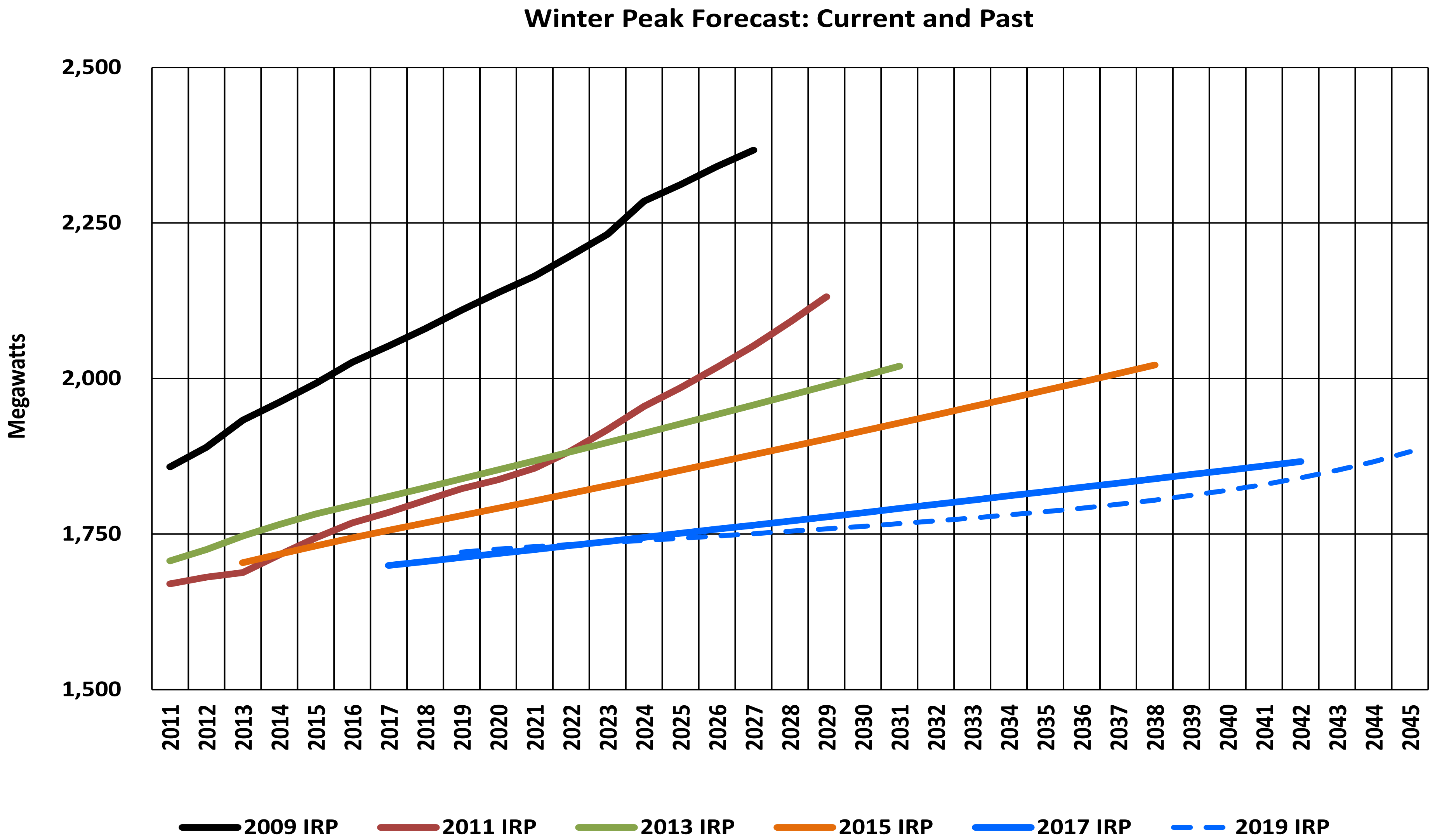
Source: Various and author’s calculations.

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

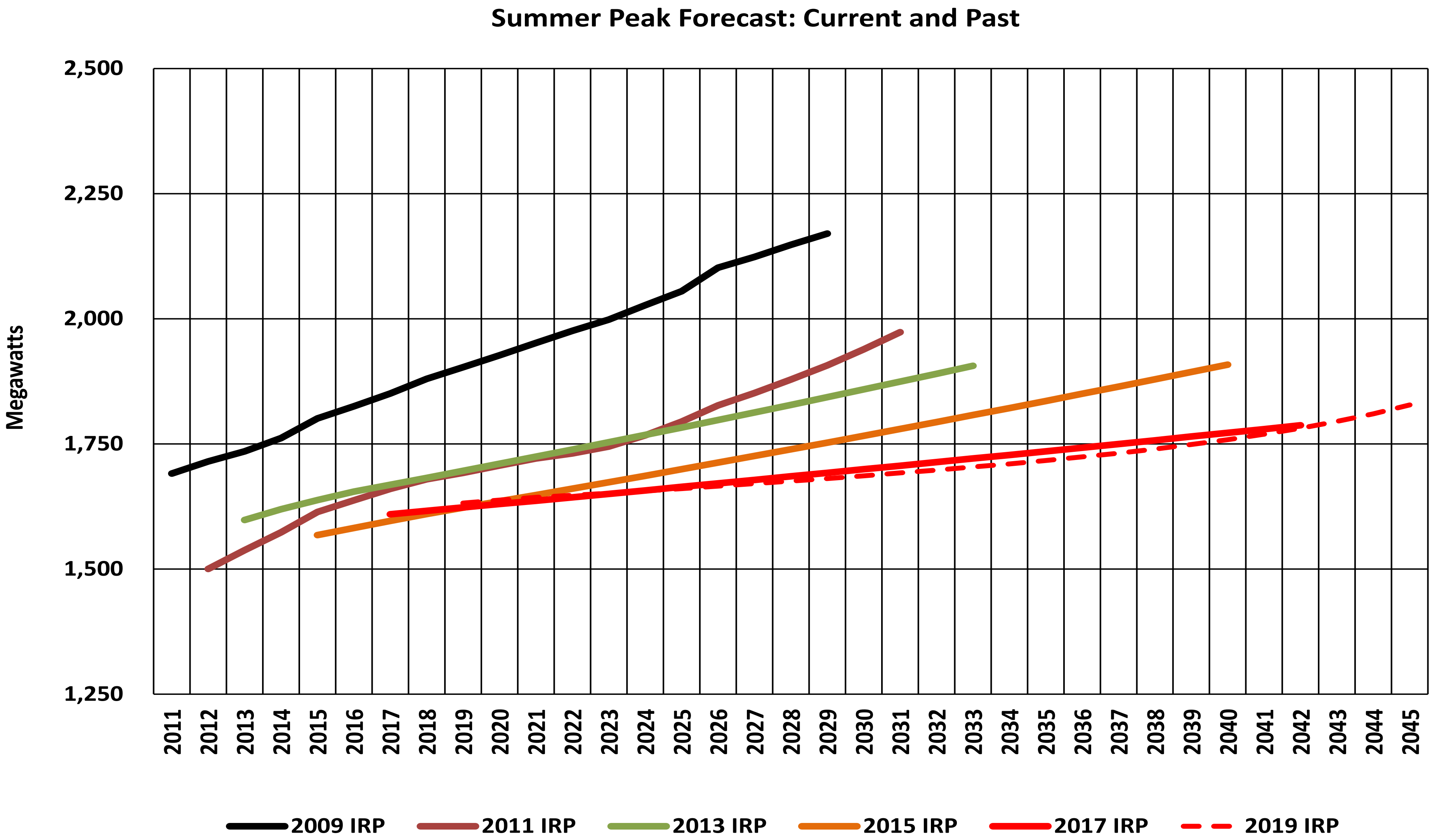


Peak	Avg. Growth 2019-45
Winter	0.34%
Summer	0.44%

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

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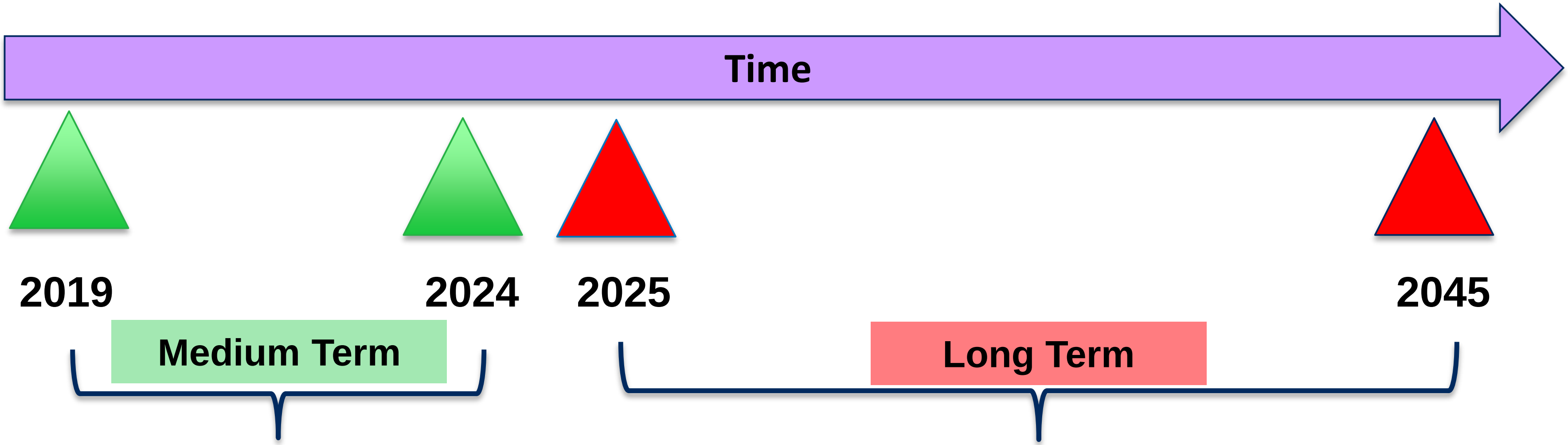
Grant.Forsyth@avistacorp.com

Basic Forecast Approach



Medium Term

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.

Long Term

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

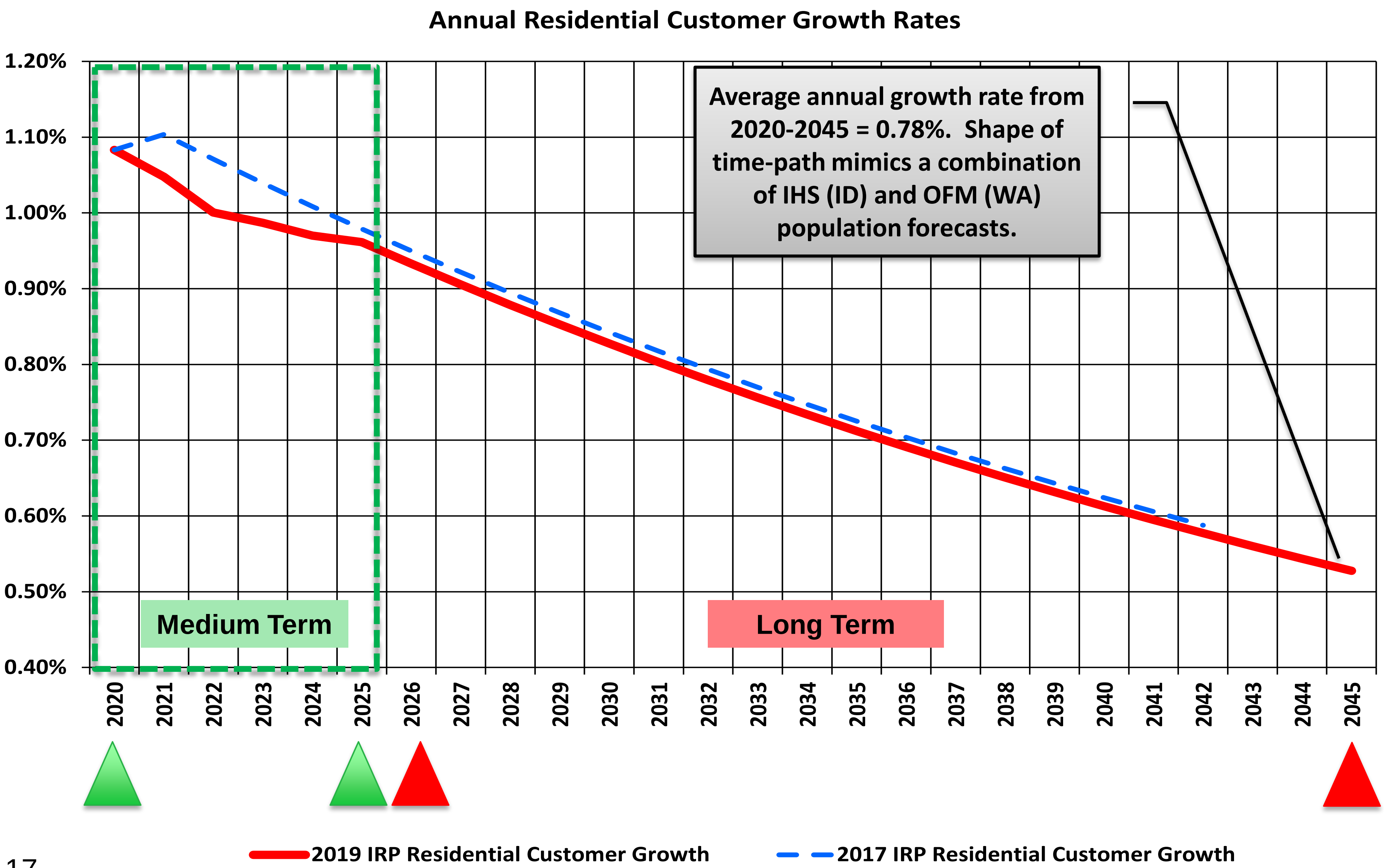
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

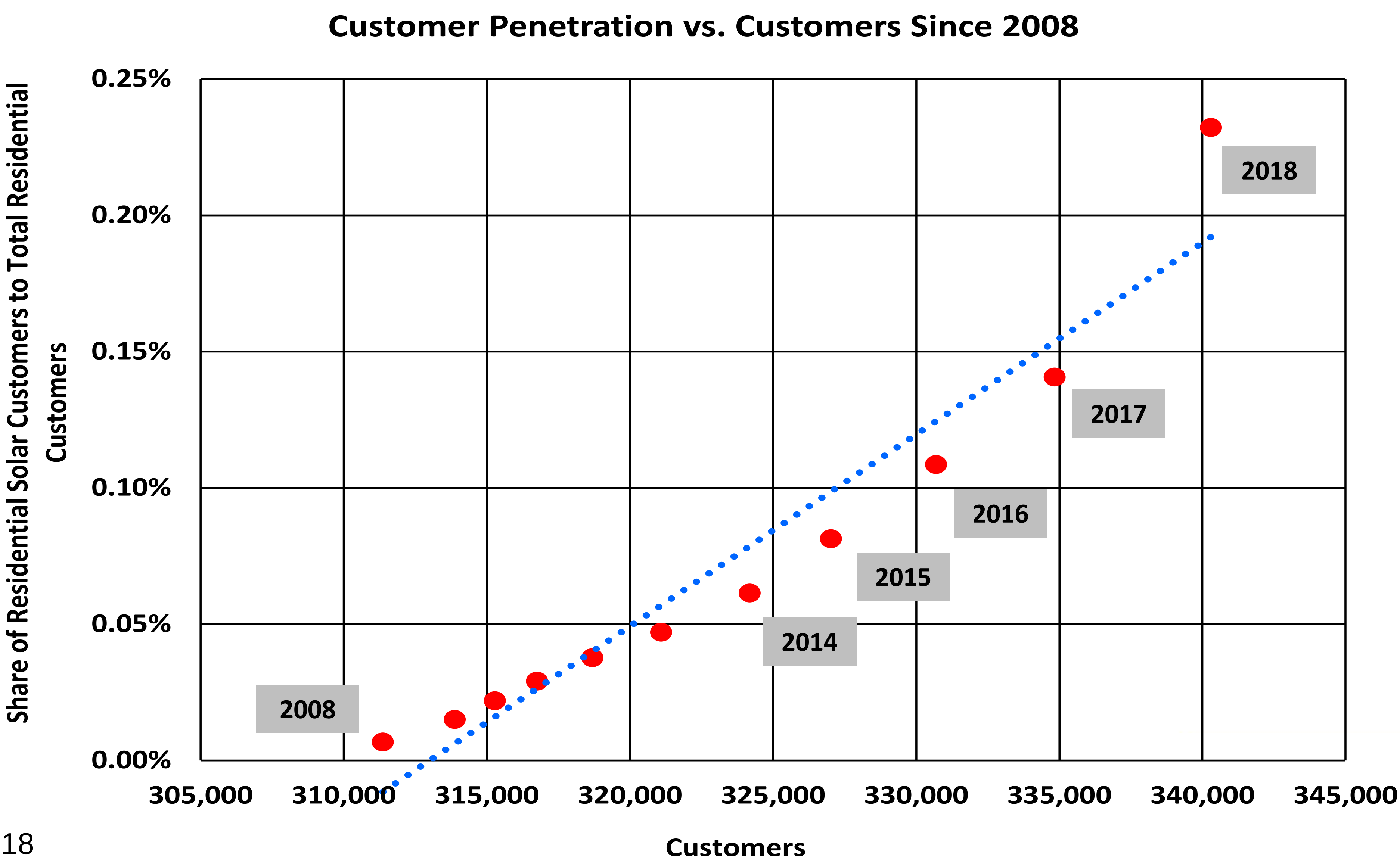
Assumed to be same as population growth, commercial growth will follow residential, and slow decline in industrial.

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

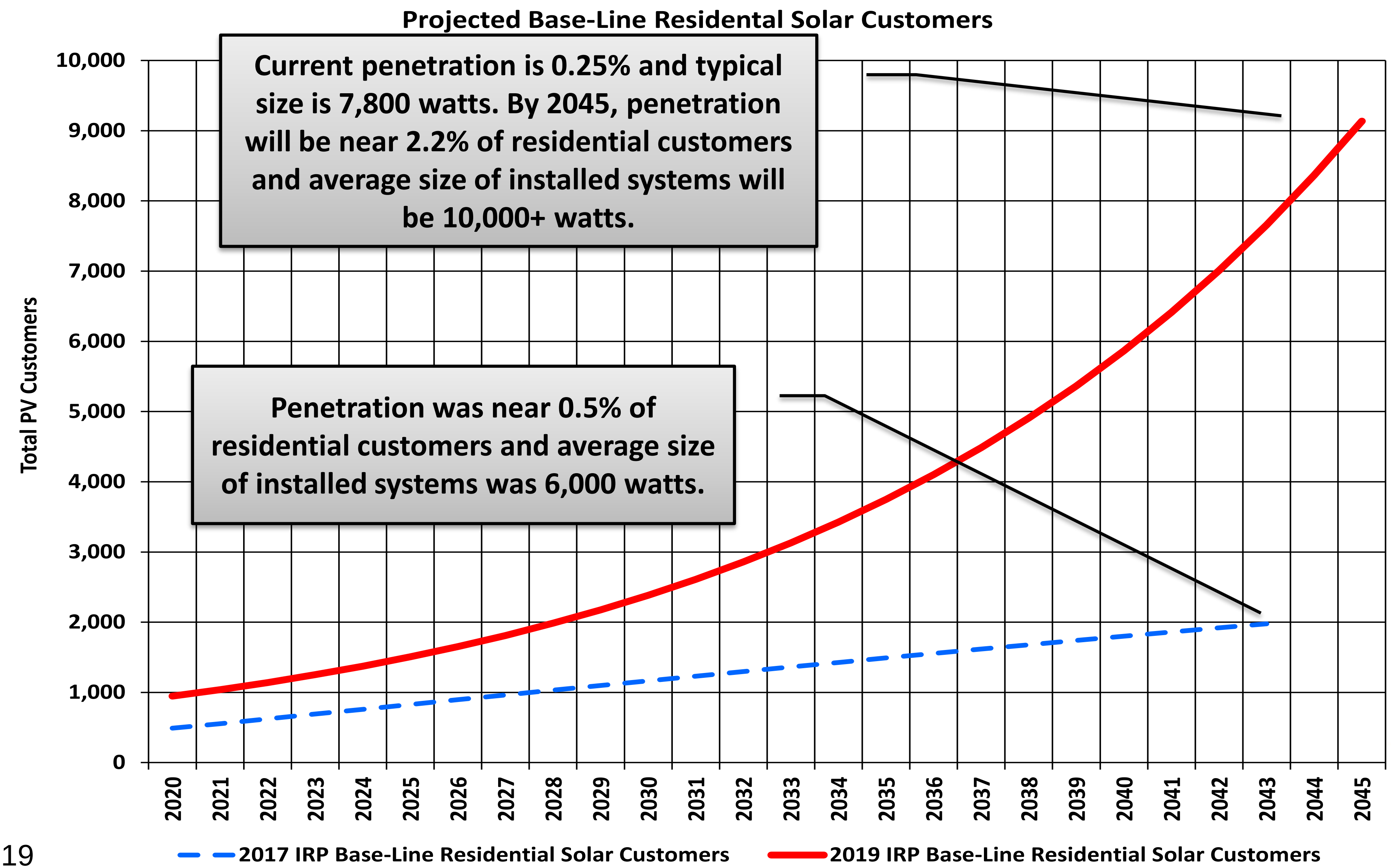
Residential Customer Growth, 2020-2045



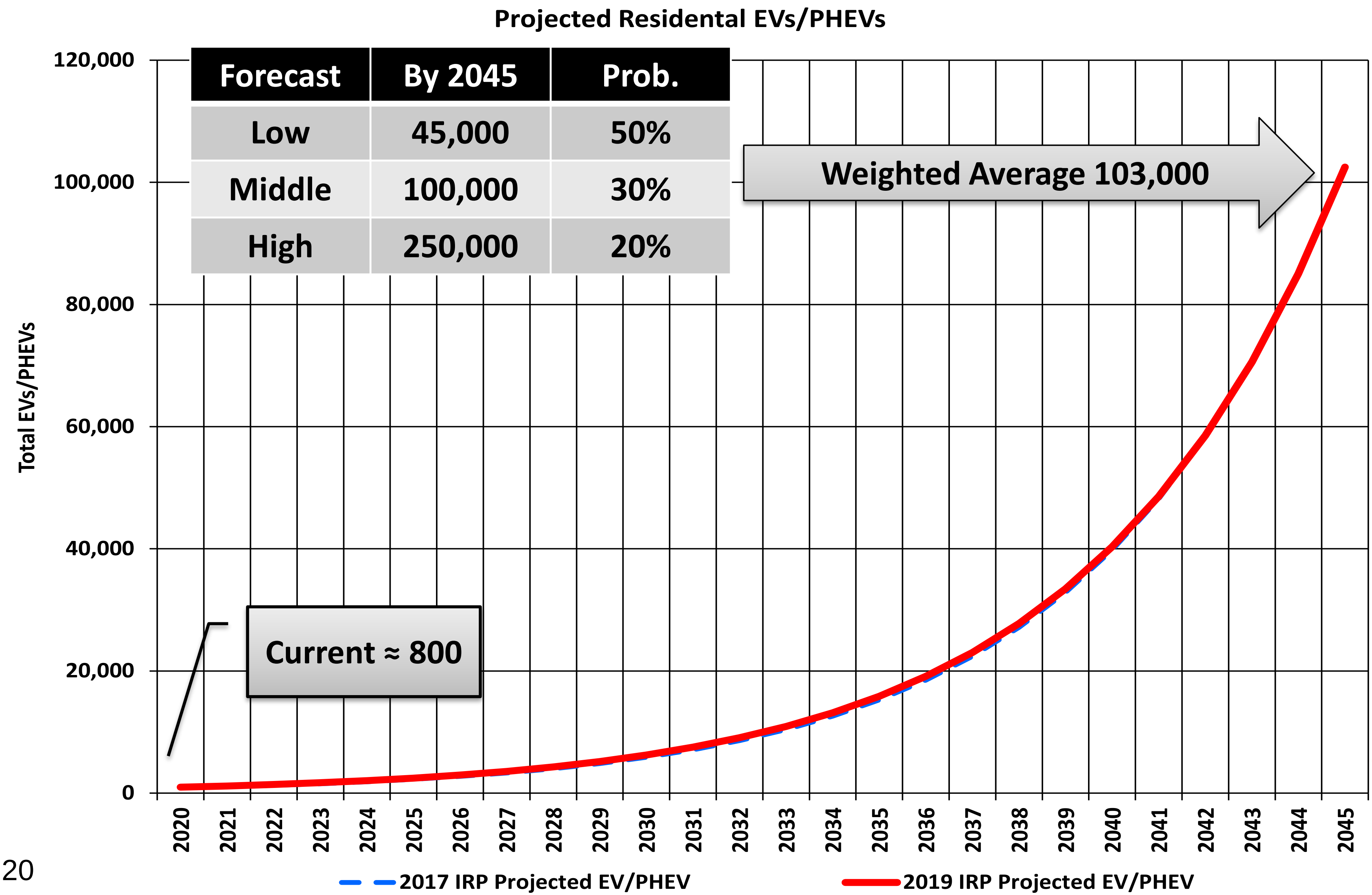
Residential Solar Penetration, 2008-2018



Residential Solar Penetration, 2020-2045

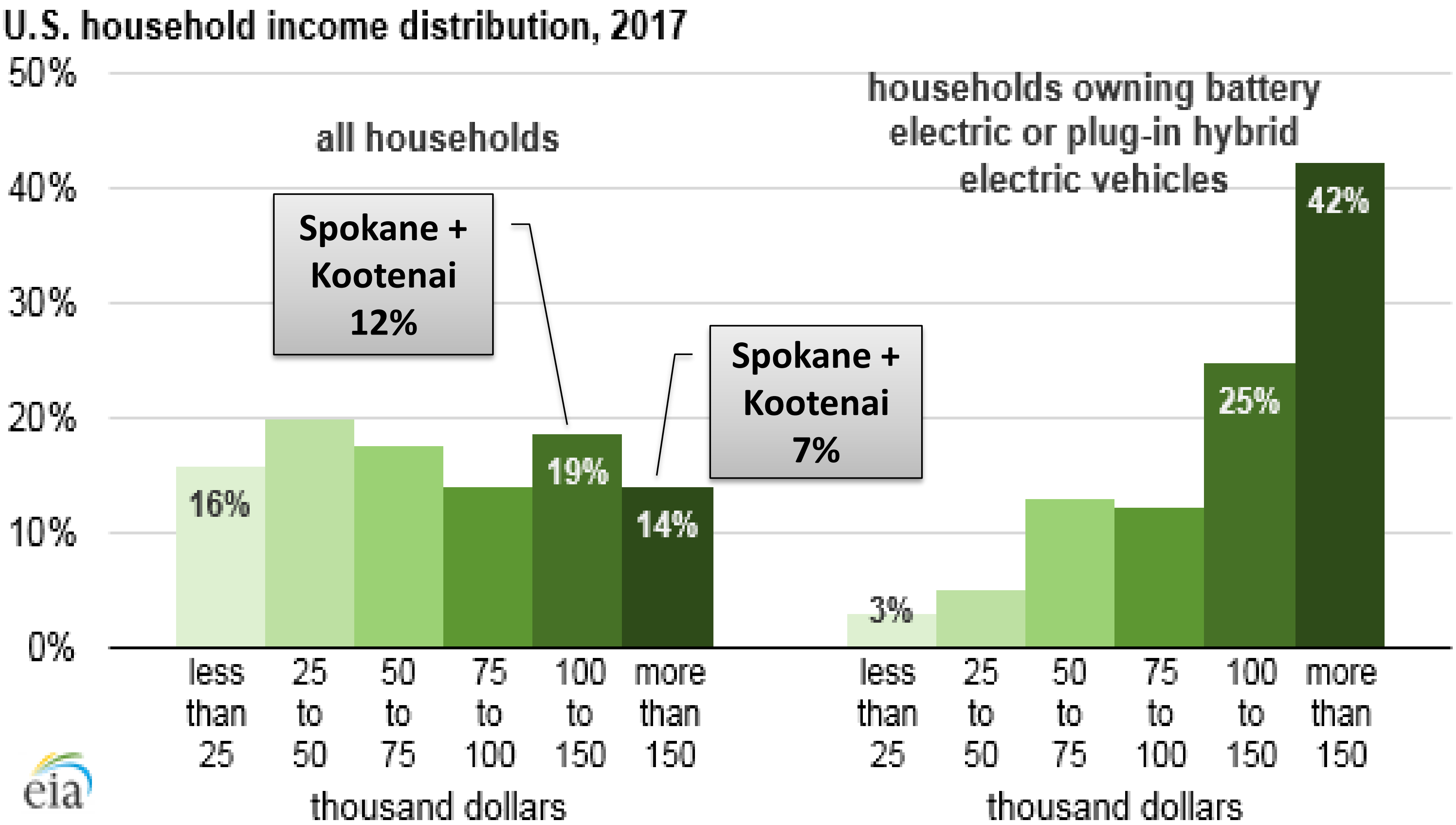


Residential EVs/PHEVs, 2020-2045



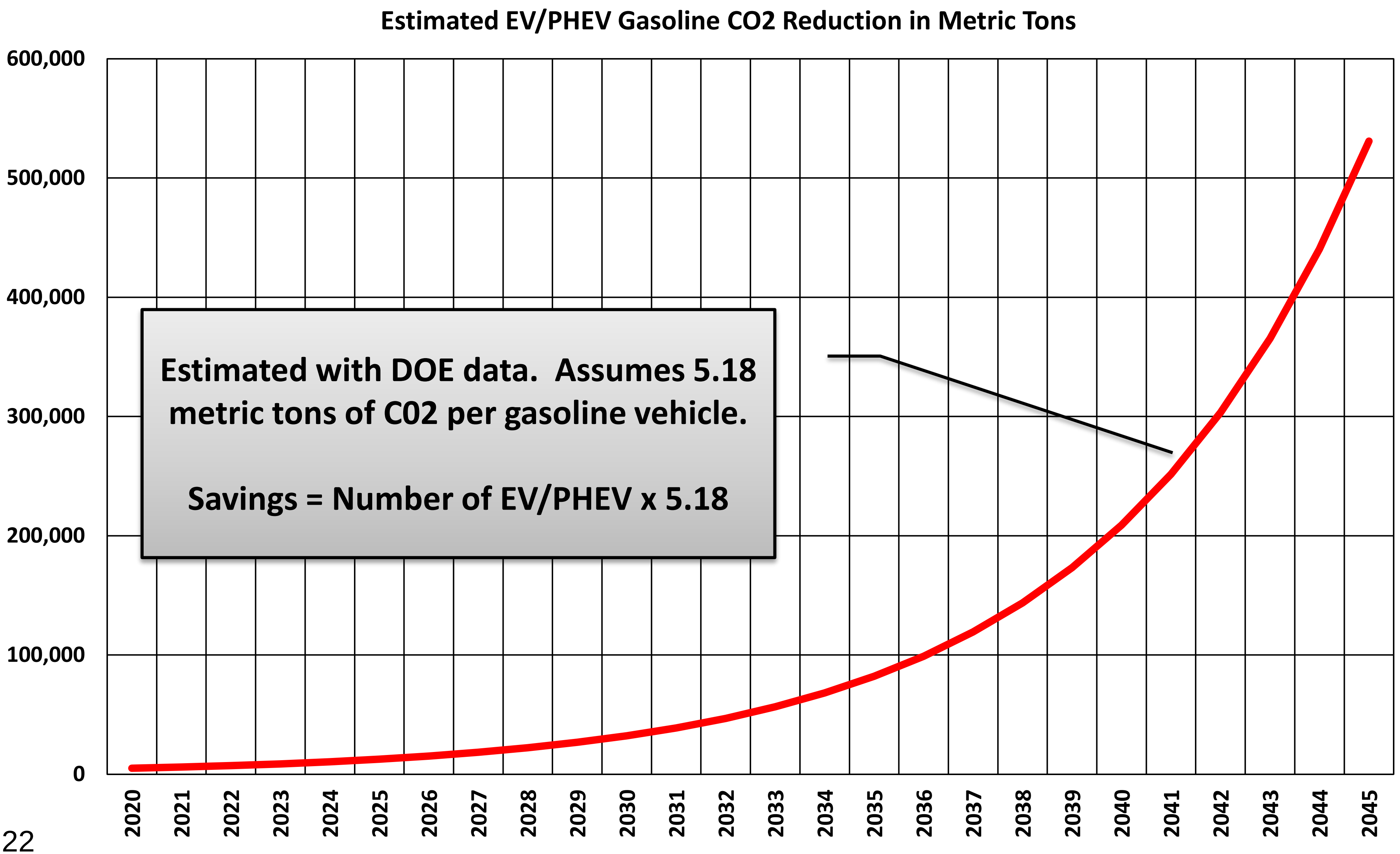
Forecast	By 2045	Prob.
Low	45,000	50%
Middle	100,000	30%
High	250,000	20%

Residential EVs/PHEVs by Household Income

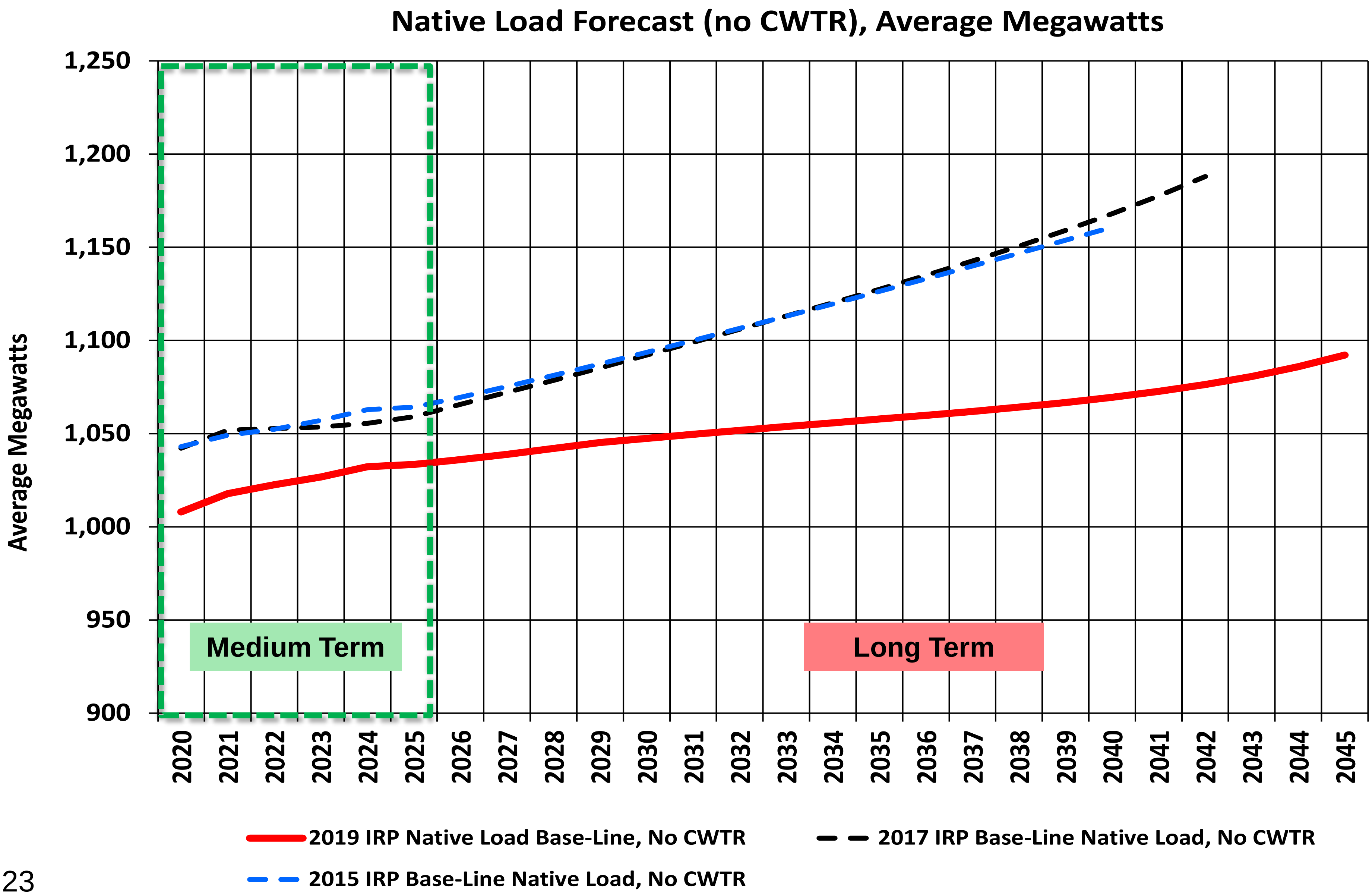


Source: EIA, *Today in Energy*, May 2018. Regional data from U.S. Census

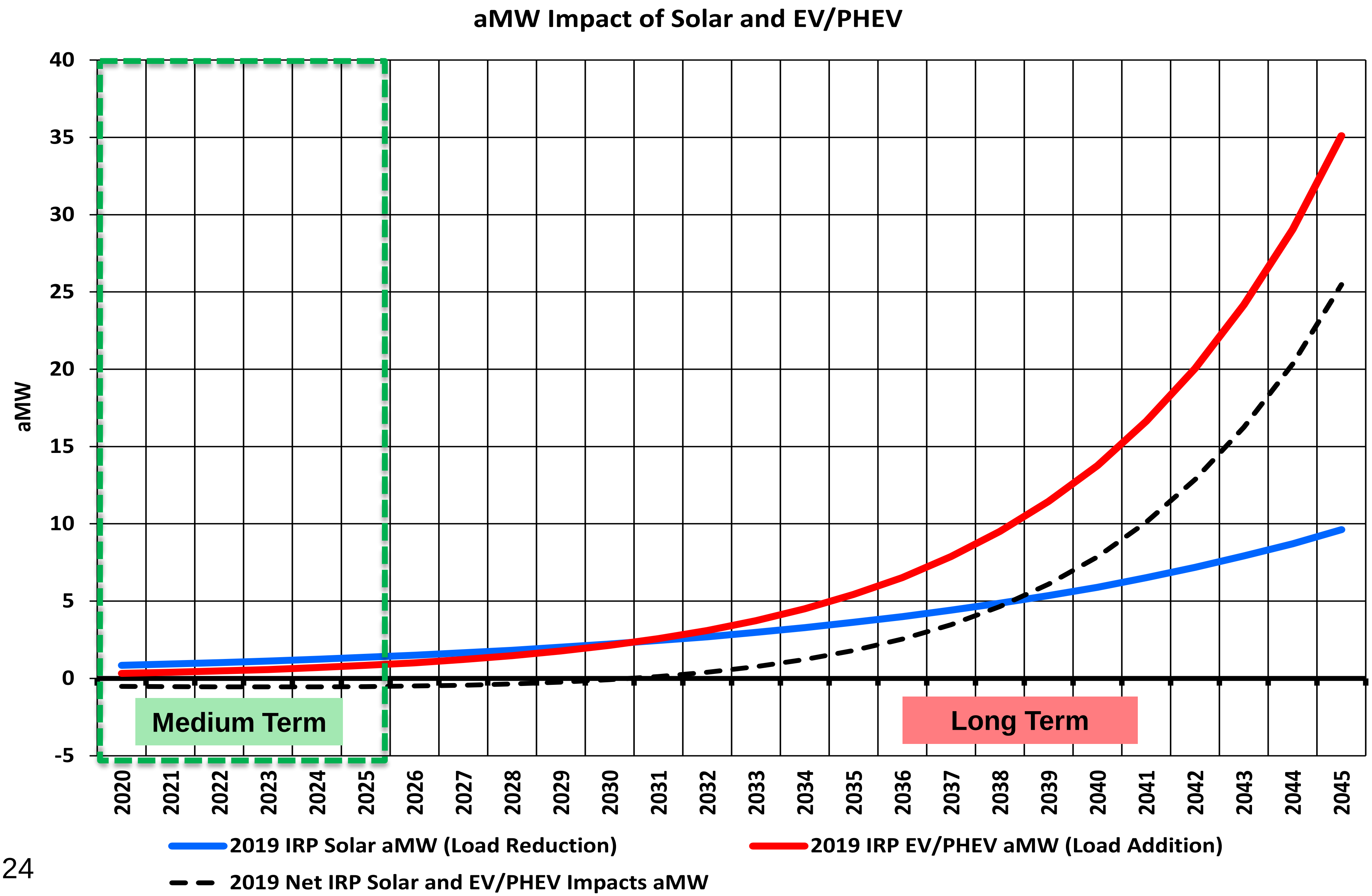
EV/PHEV Gasoline CO2 Savings Avista Service Territory



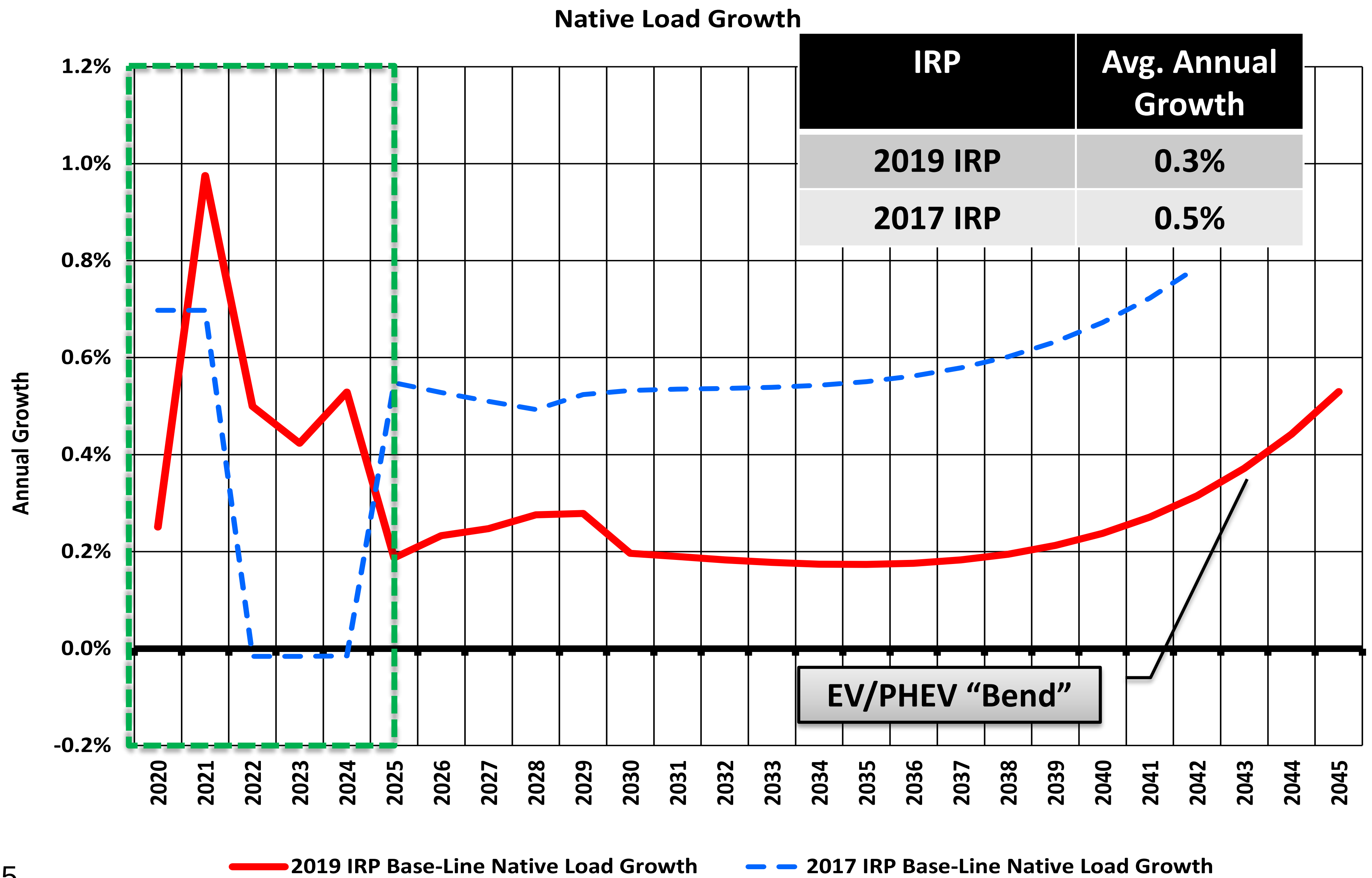
Native Load Forecast, 2020-2045



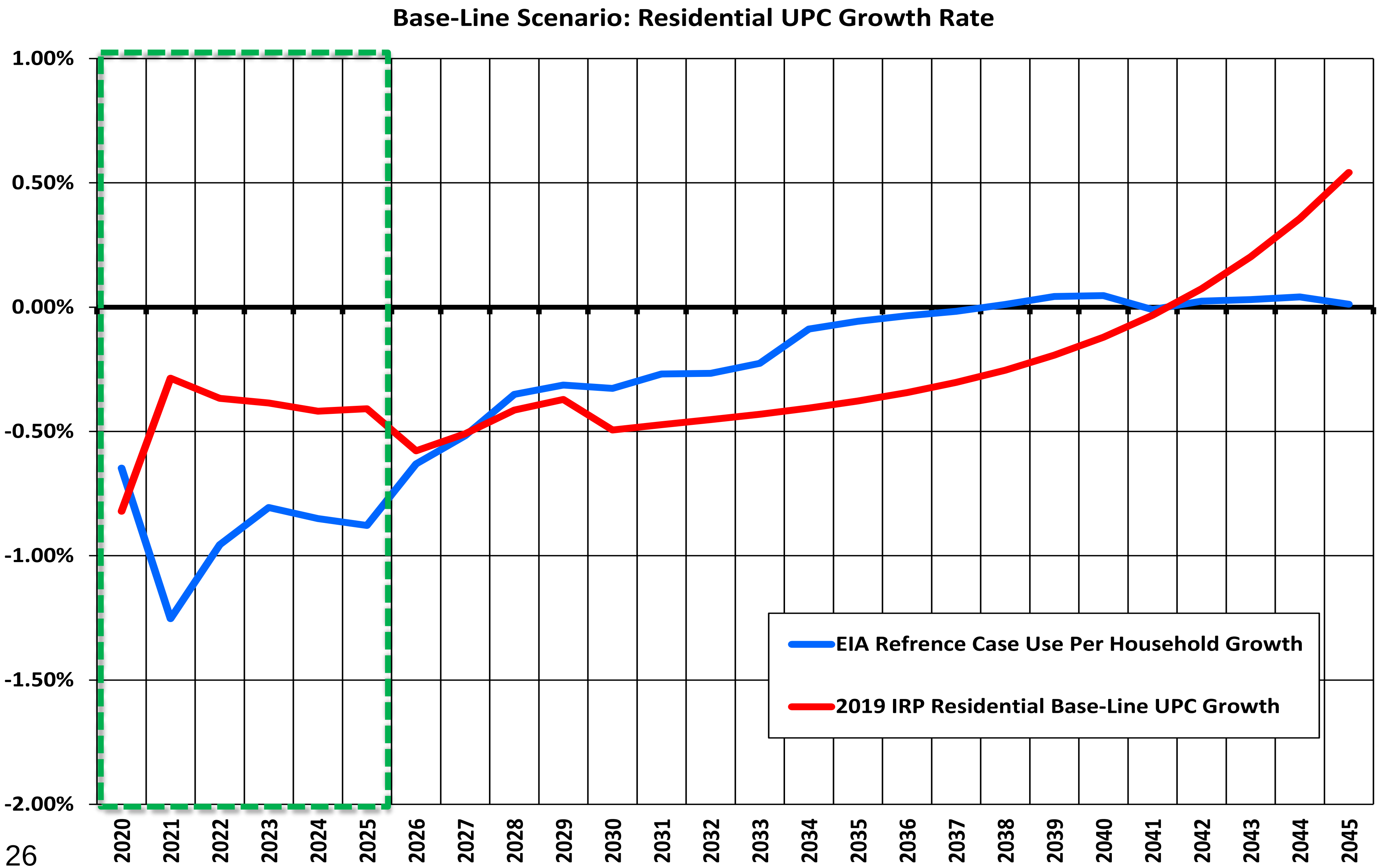
Net Solar and EV/PHEV Impact, 2020-2045



Native Load Growth Forecast, 2020-2045



Residential UPC Growth: 2020-2045



Long-Term Load Forecast: Conservation Adjustment

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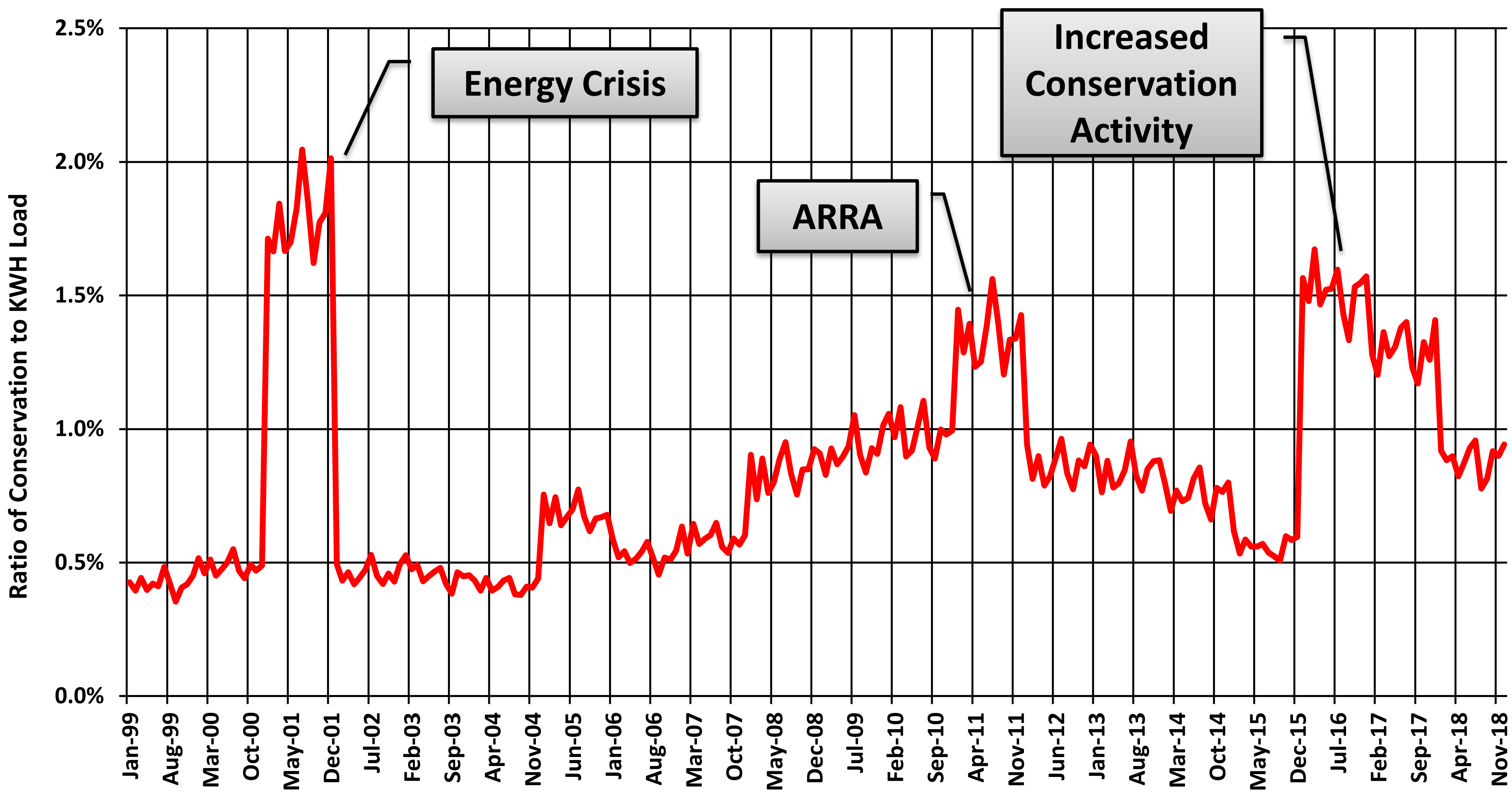
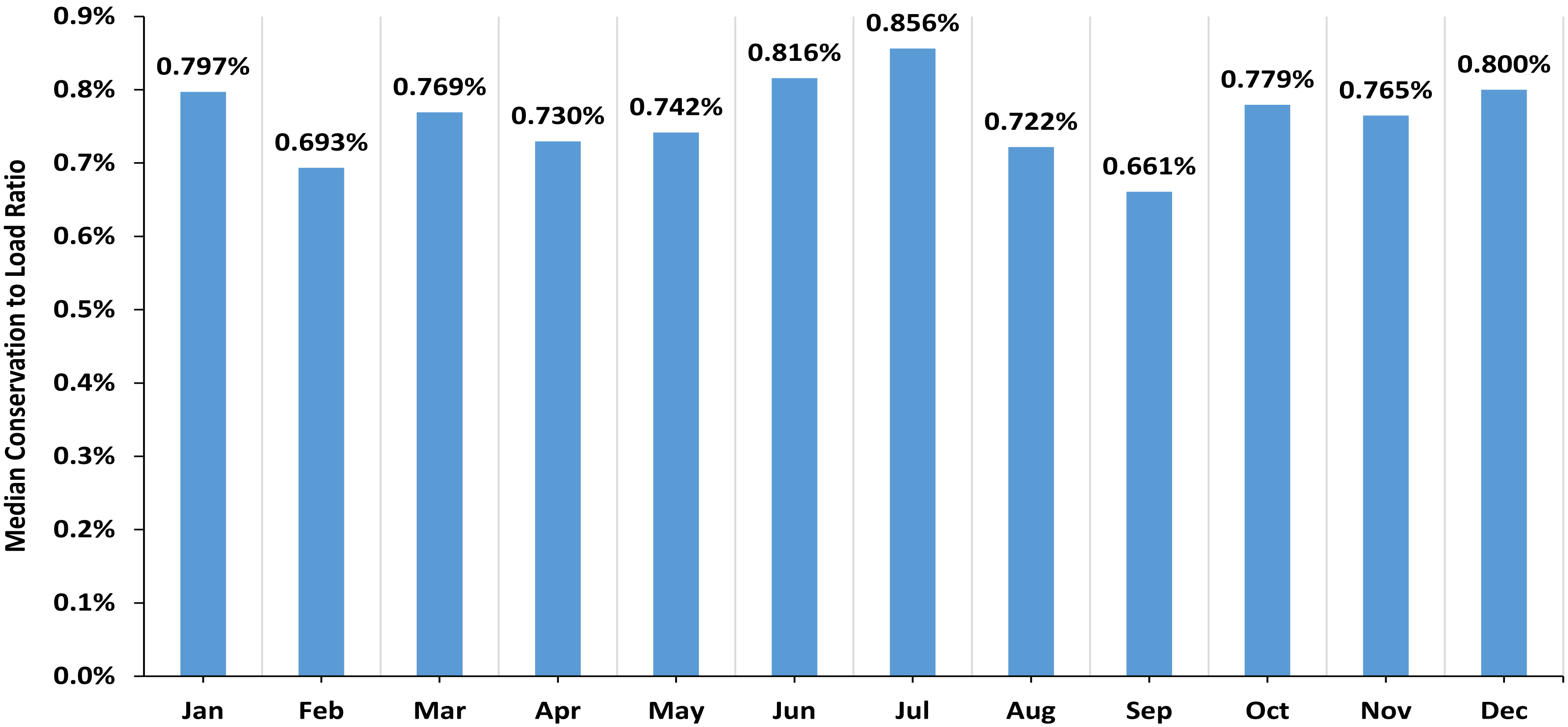
Monthly Conservation as a Share of Total Actual Retail Load: Navigant Estimates



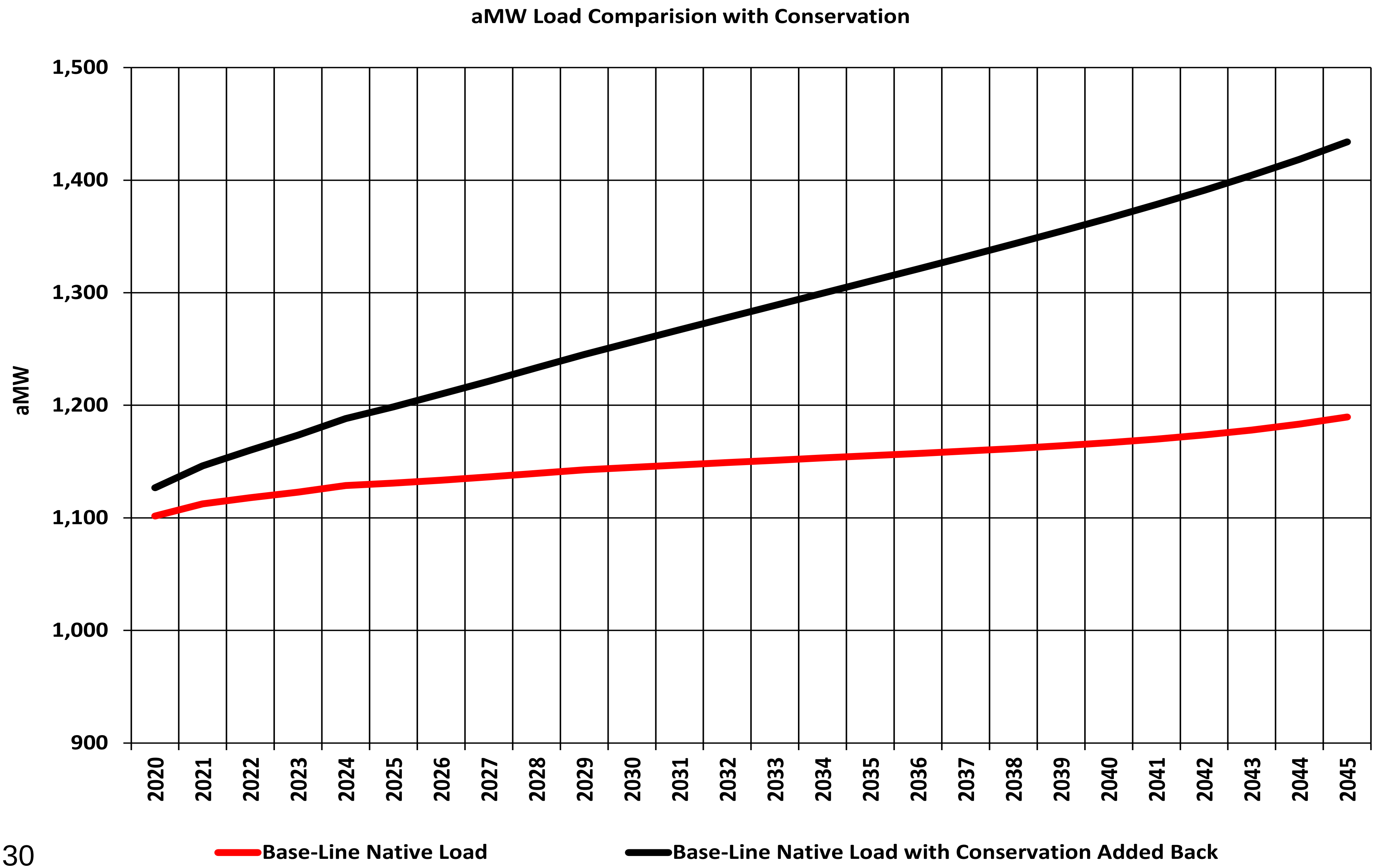
$$\text{Ratio} = \frac{Estimated\ Conservation\ Month\ t, Year\ y}{Actual\ KWH\ Load\ Month\ t, Year\ Y}$$

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



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

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

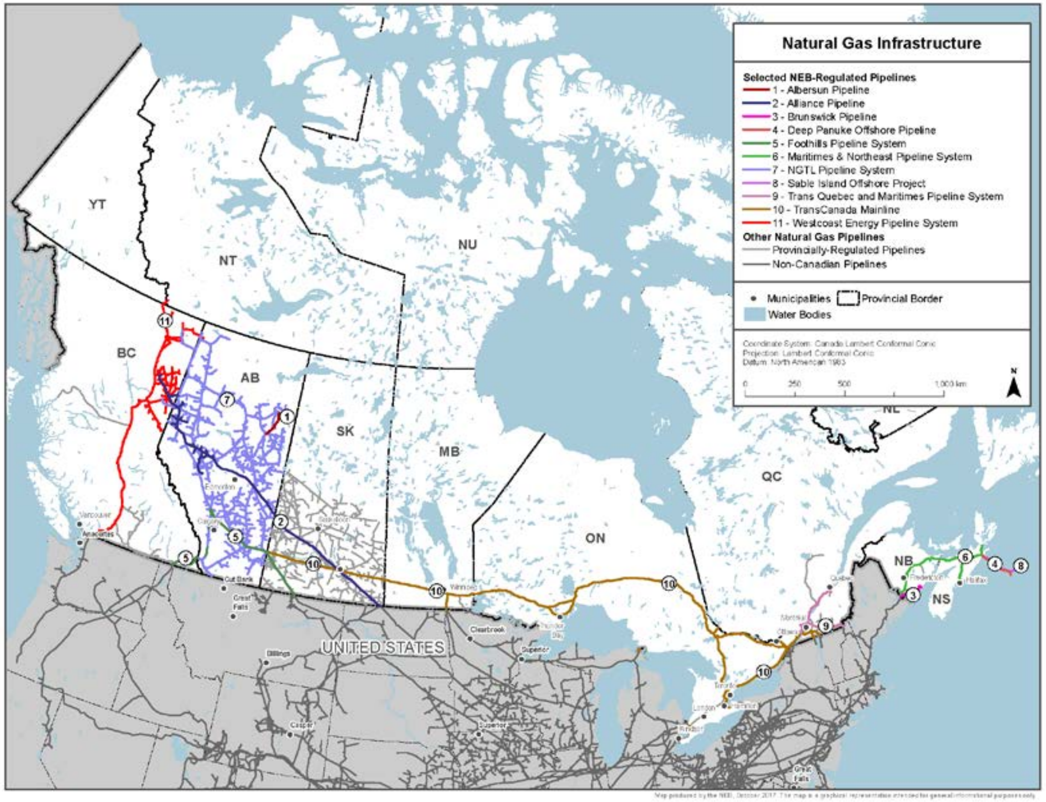
- Market Dynamics
- Pipeline Transportation
- Renewable Natural Gas (RNG)

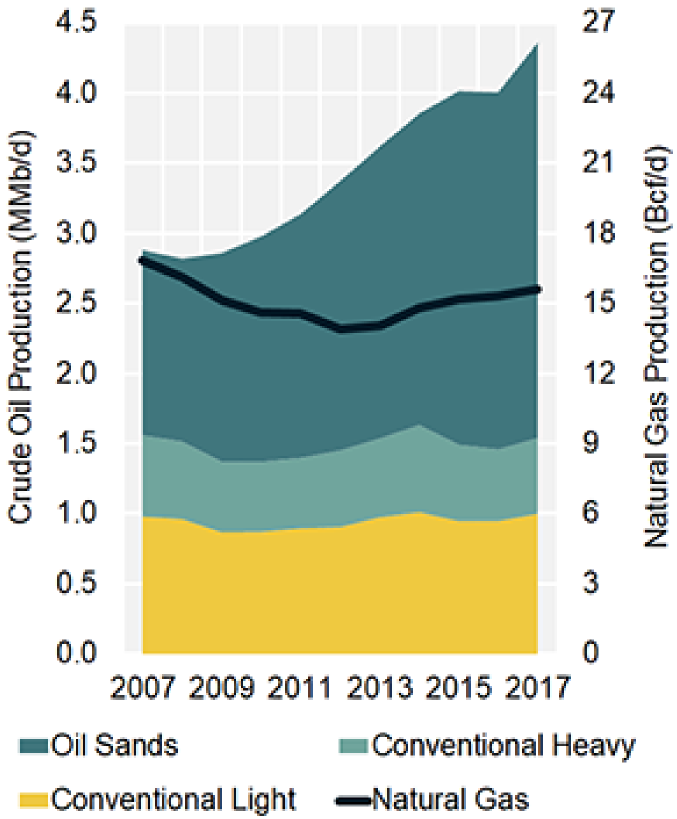
Avista Natural Gas Service Areas, Gas Fields, Trading Hubs and Major Pipelines

as of 3/31/2015

Canada

Canada Natural Gas Production

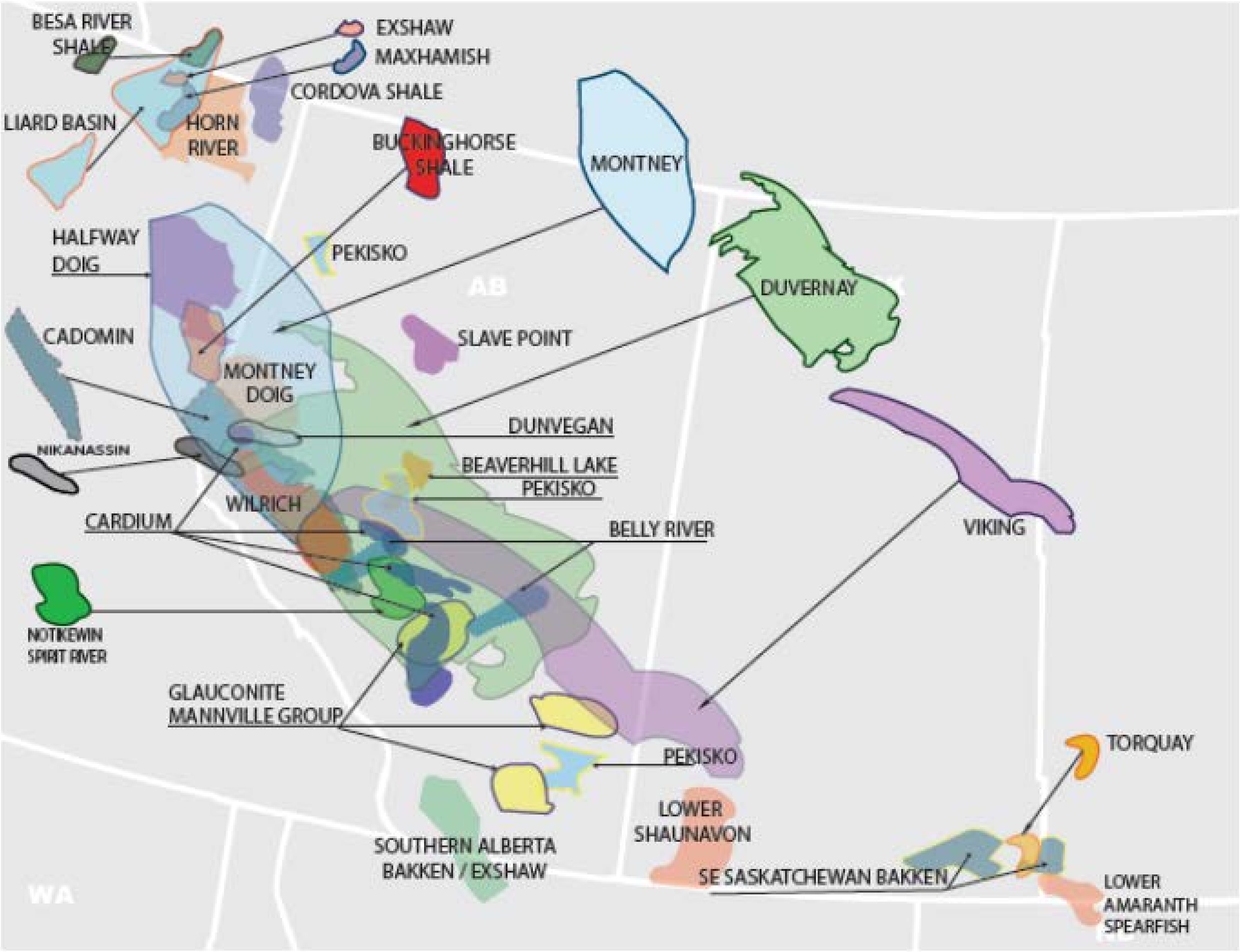




British Columbia 0.5 Bcf per day

Alberta 15 Bcf per day

WESTERN CANADA RESOURCE PLAYS

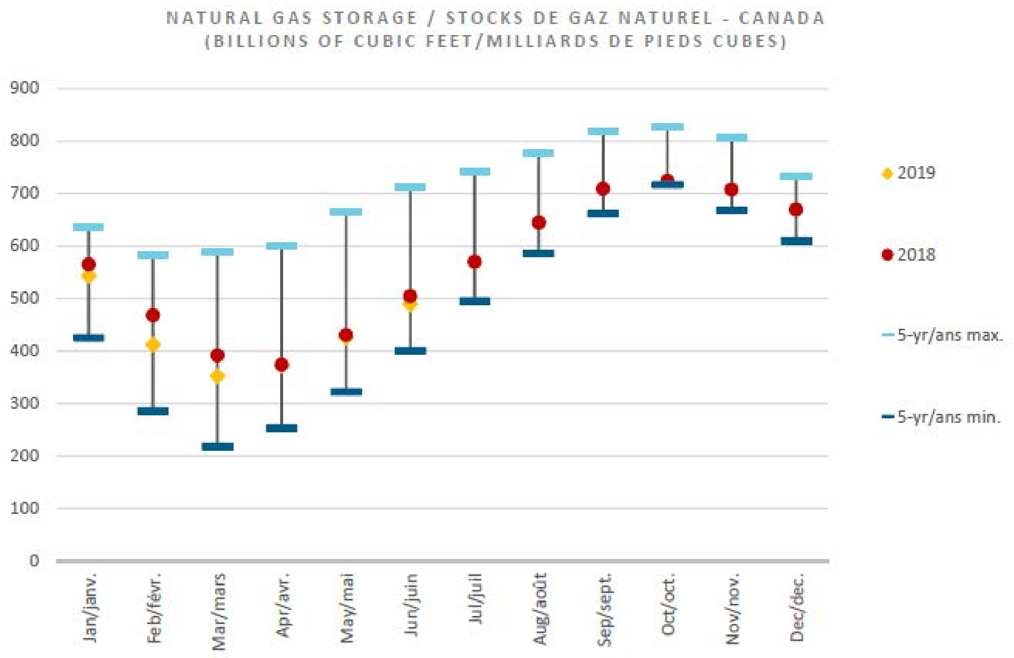


<u>300 Years </u>of resources at current levels

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



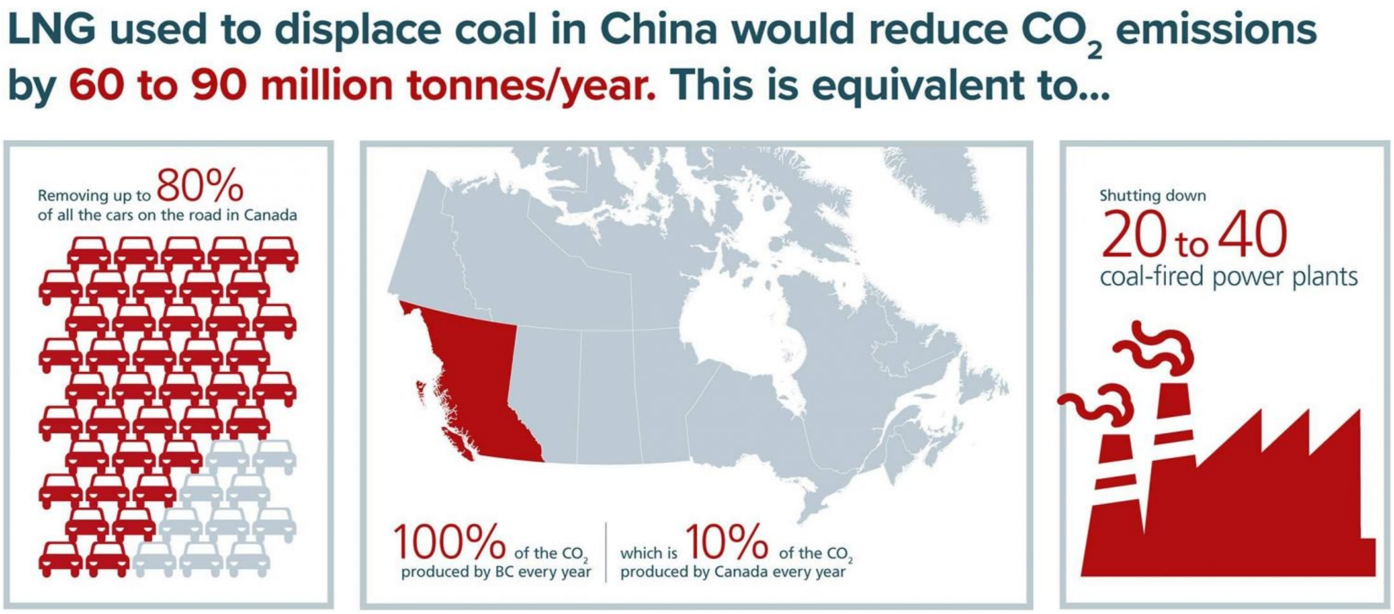
Source: CGA

LNG Canada

Daily liquefaction:

3.5 Bcf Or

1,025,749 MWh

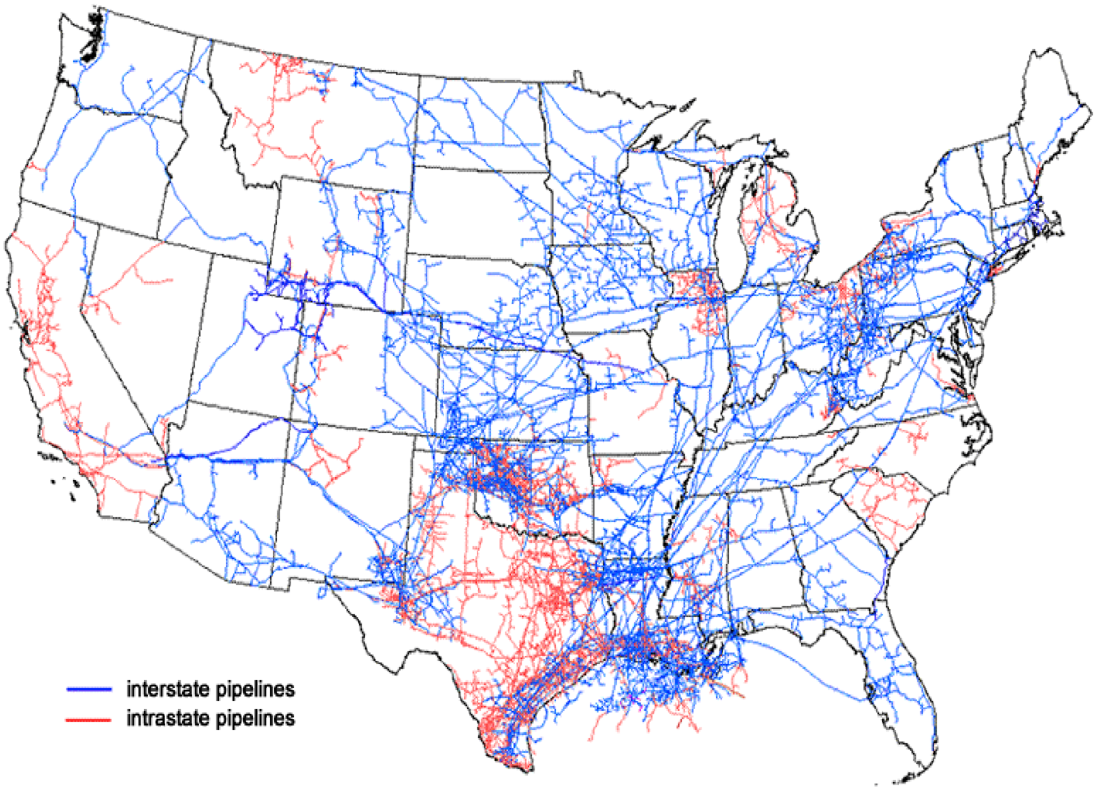


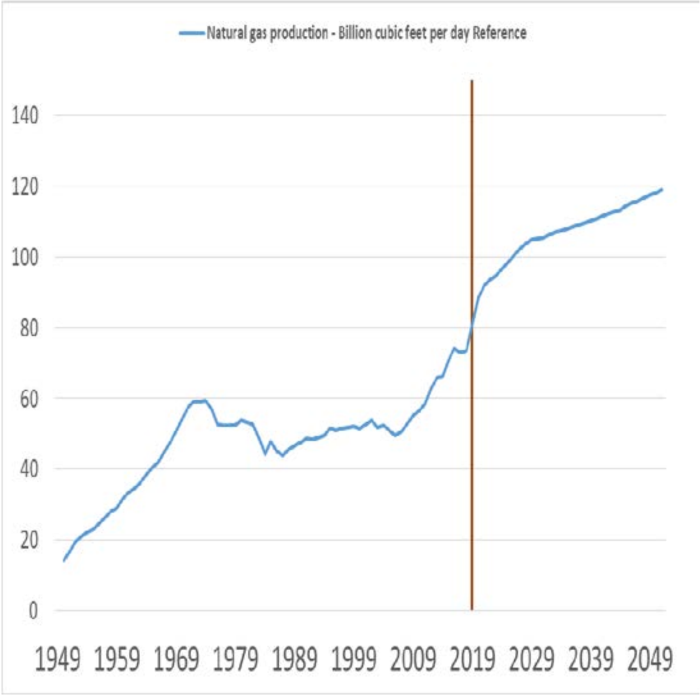
Source: https://www.lngcanada.ca/about-lng-canada/

US

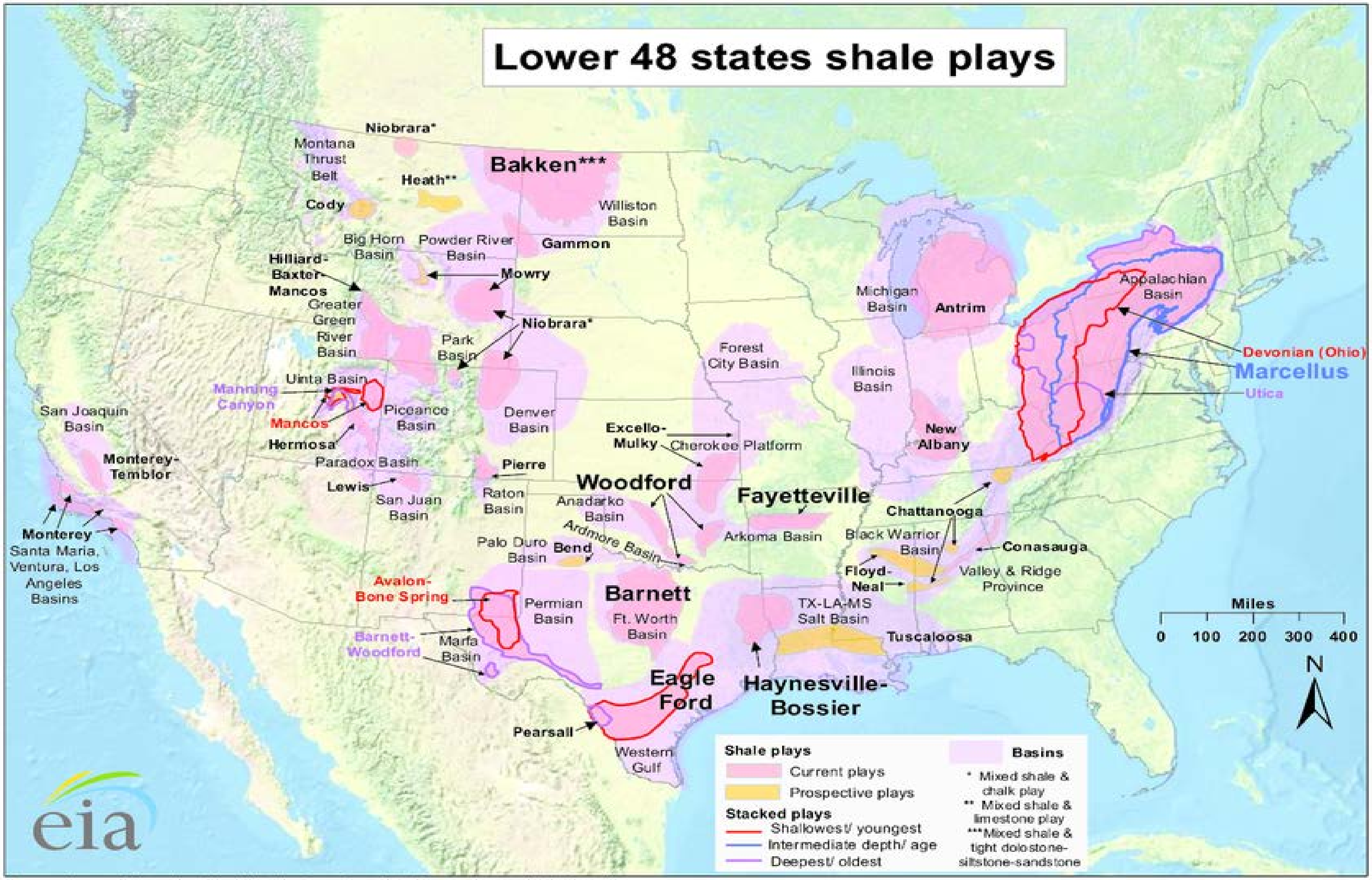
US Natural Gas Production

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





Source: EIA

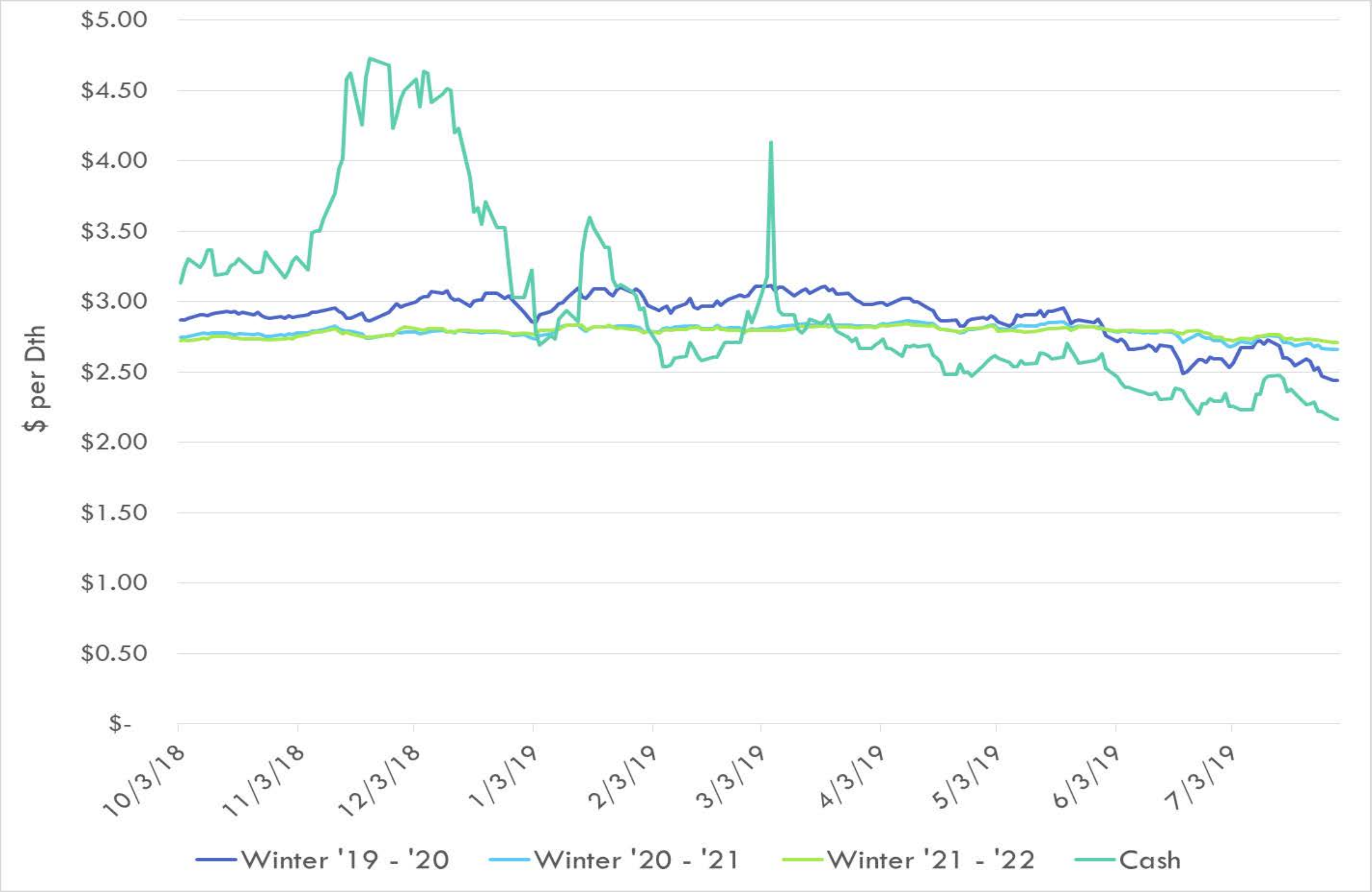


Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

<u>80 Years</u> of resources at current levels

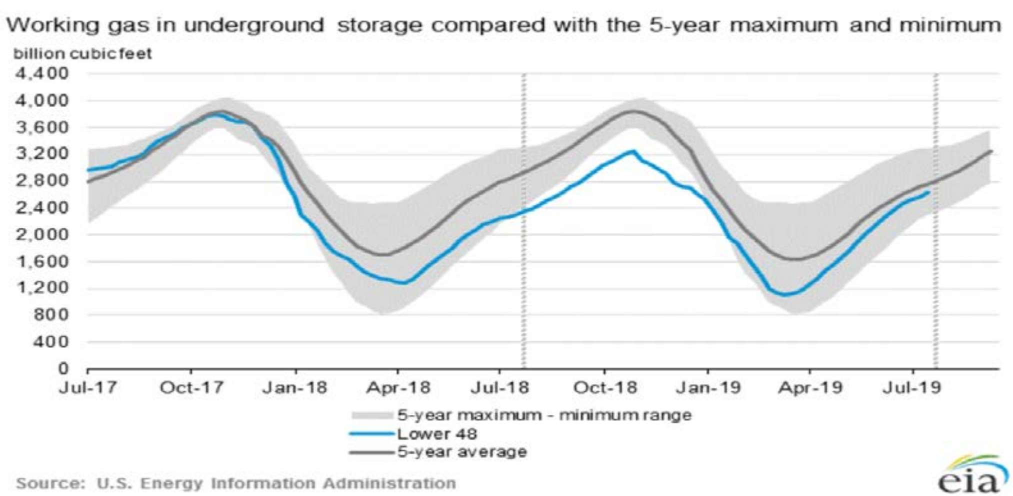
AVISTA

Henry Hub cash vs. forwards

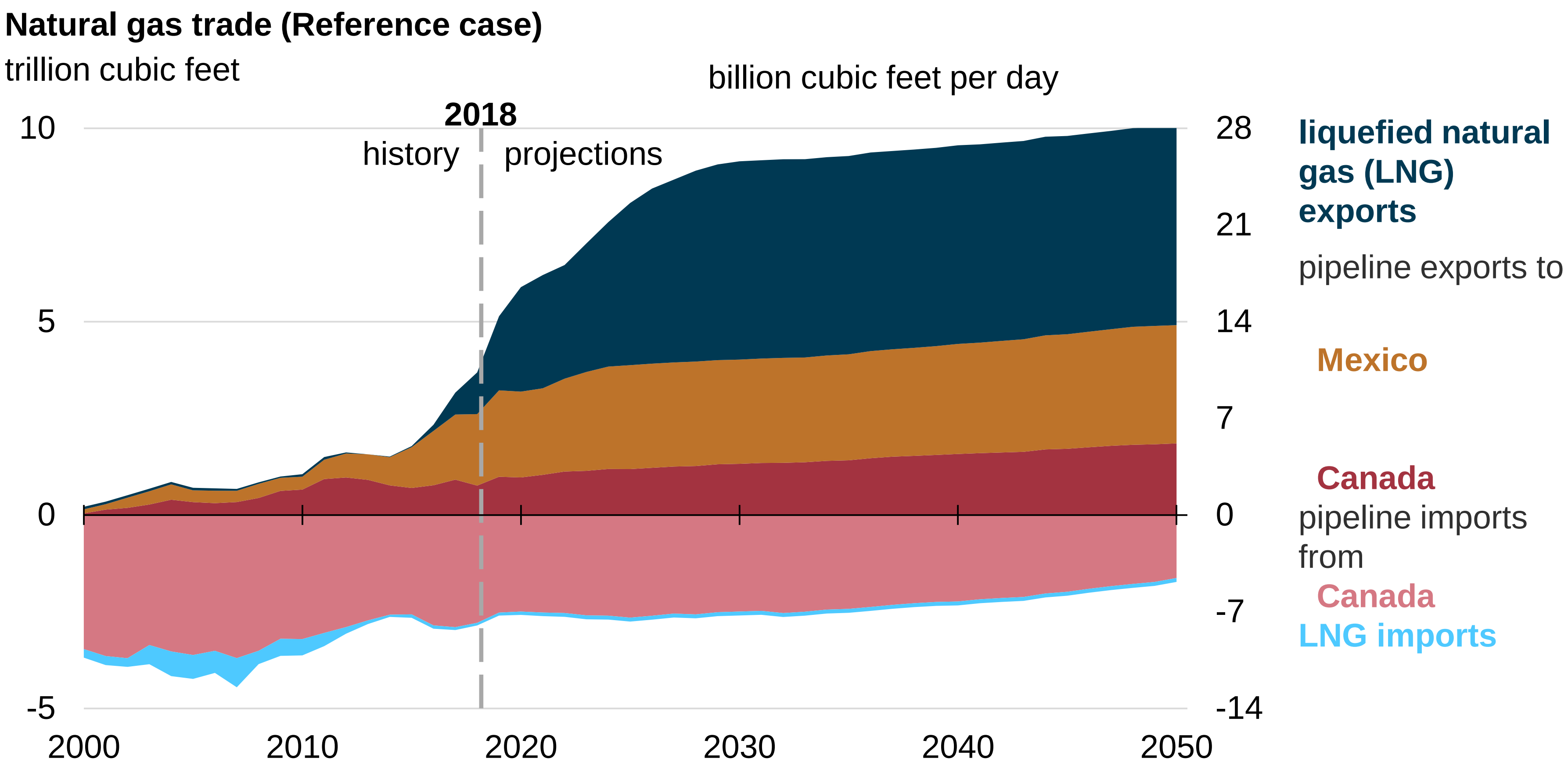


US Natural Gas Storage

Region	Stocks billion cubic feet (Bcf) 07/26/19	07/19/19	net change	implied flow	Historical Comparisons: Year ago (07/26/18) Bcf	% change	5-year average (2014-18) 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**

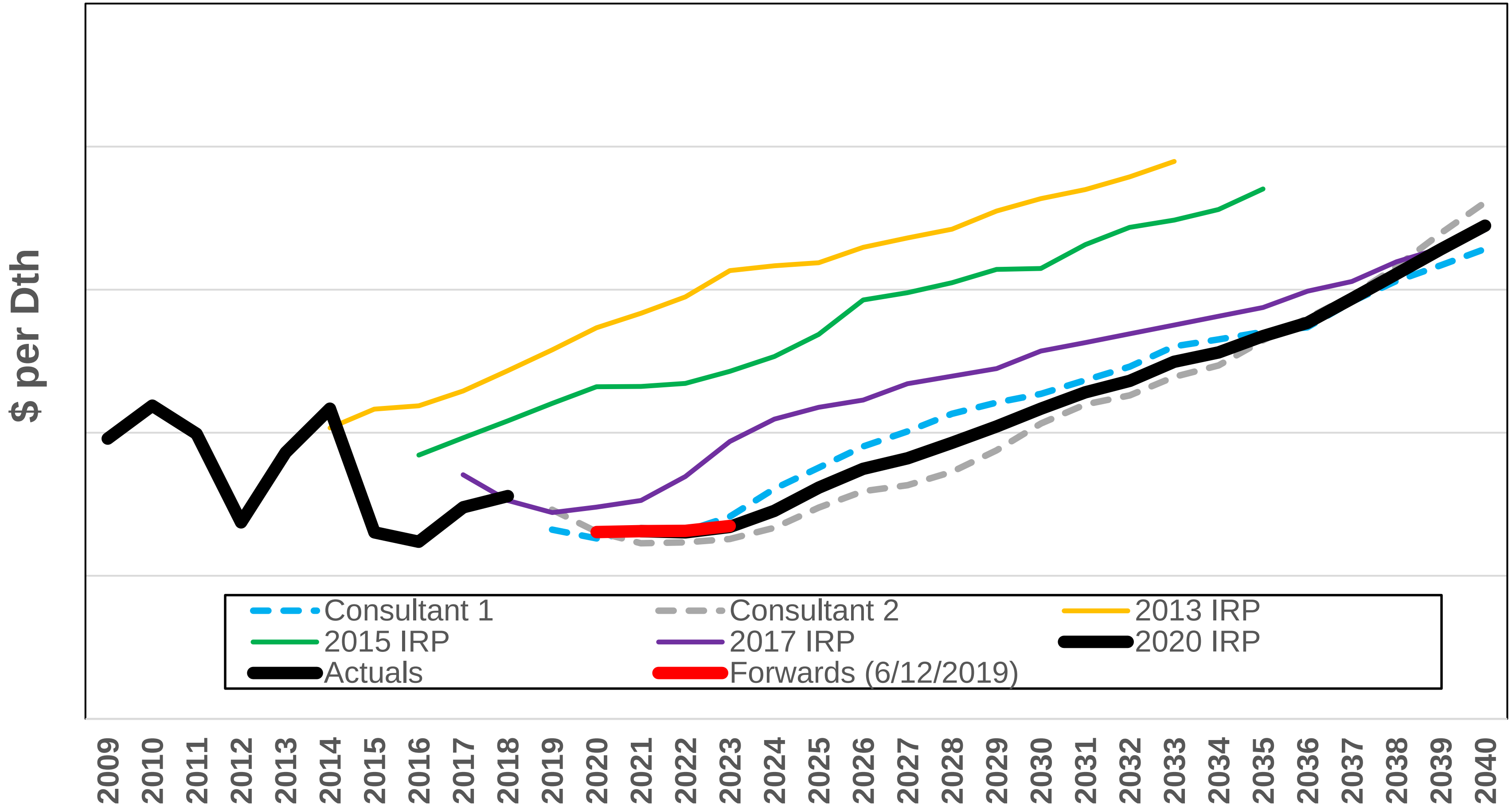


U.S. net exports of natural gas continue to grow in the Reference case—



Source: EIA AEO 2019

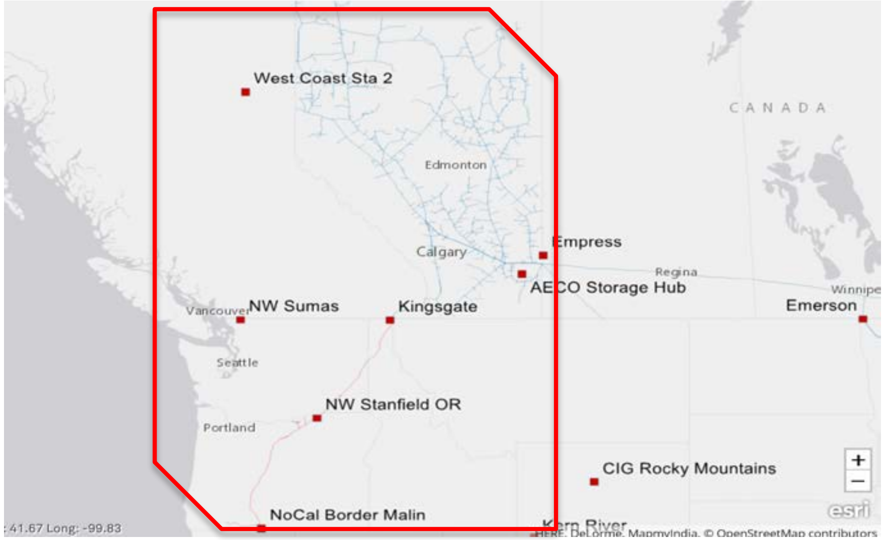
2020 IRP Henry Hub Natural Gas Price Forecast: 2021-2040: $3.99 per Dth



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."



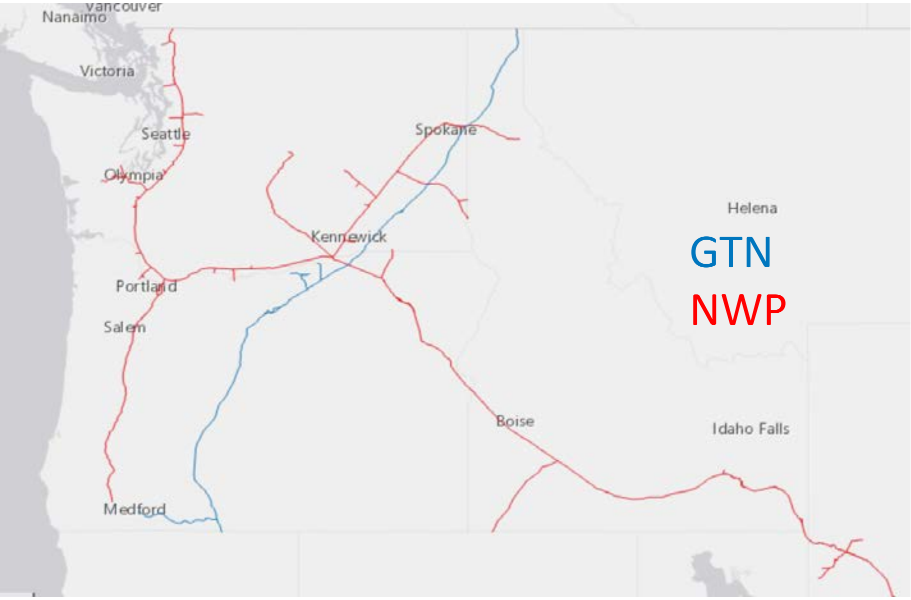
Fugitive emissions estimated at 0.783%

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

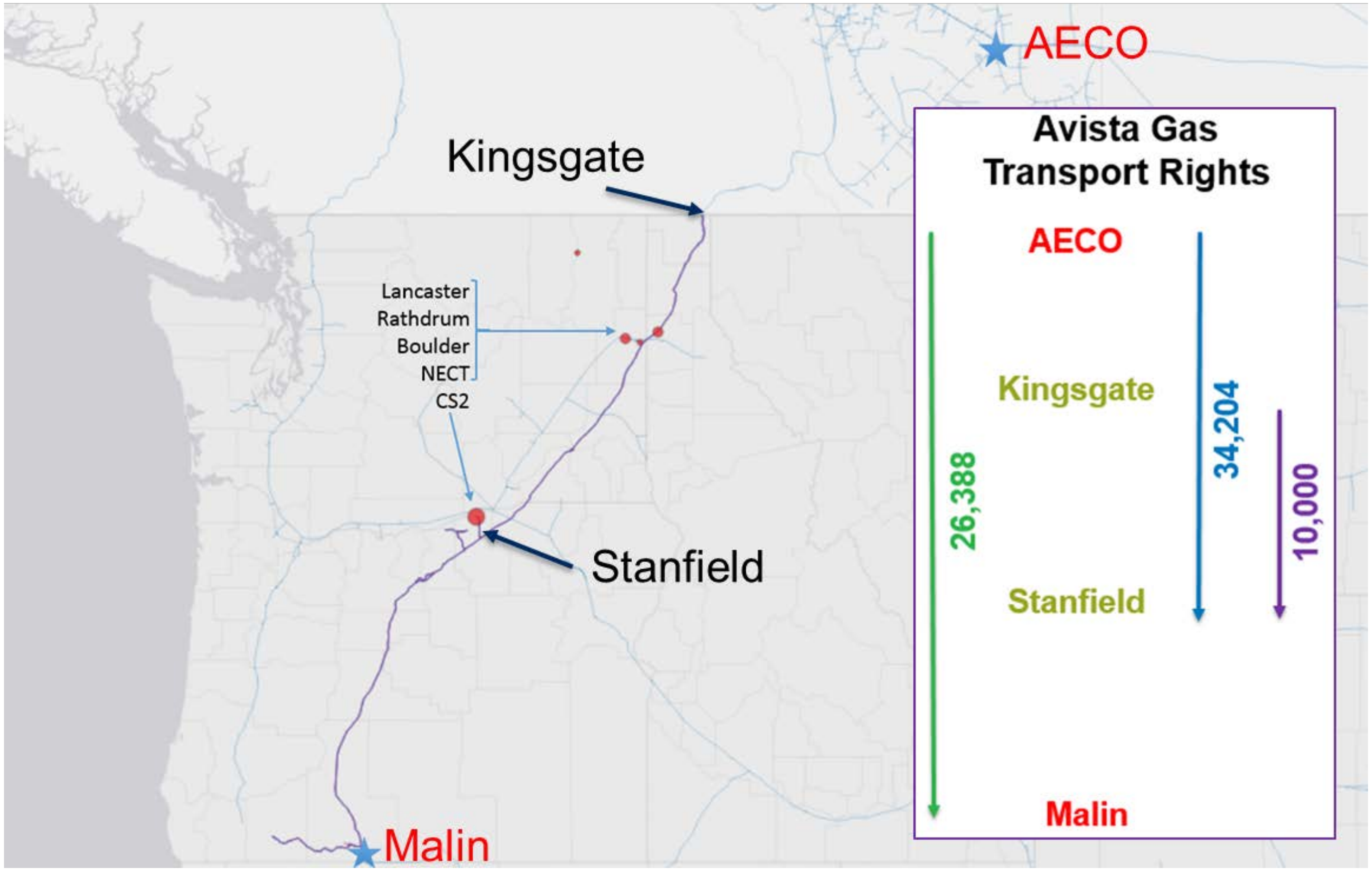
Source – NEB for Canadian infrastructure and EIA for US infrastructure

GTN & NWP Fully Subscribed

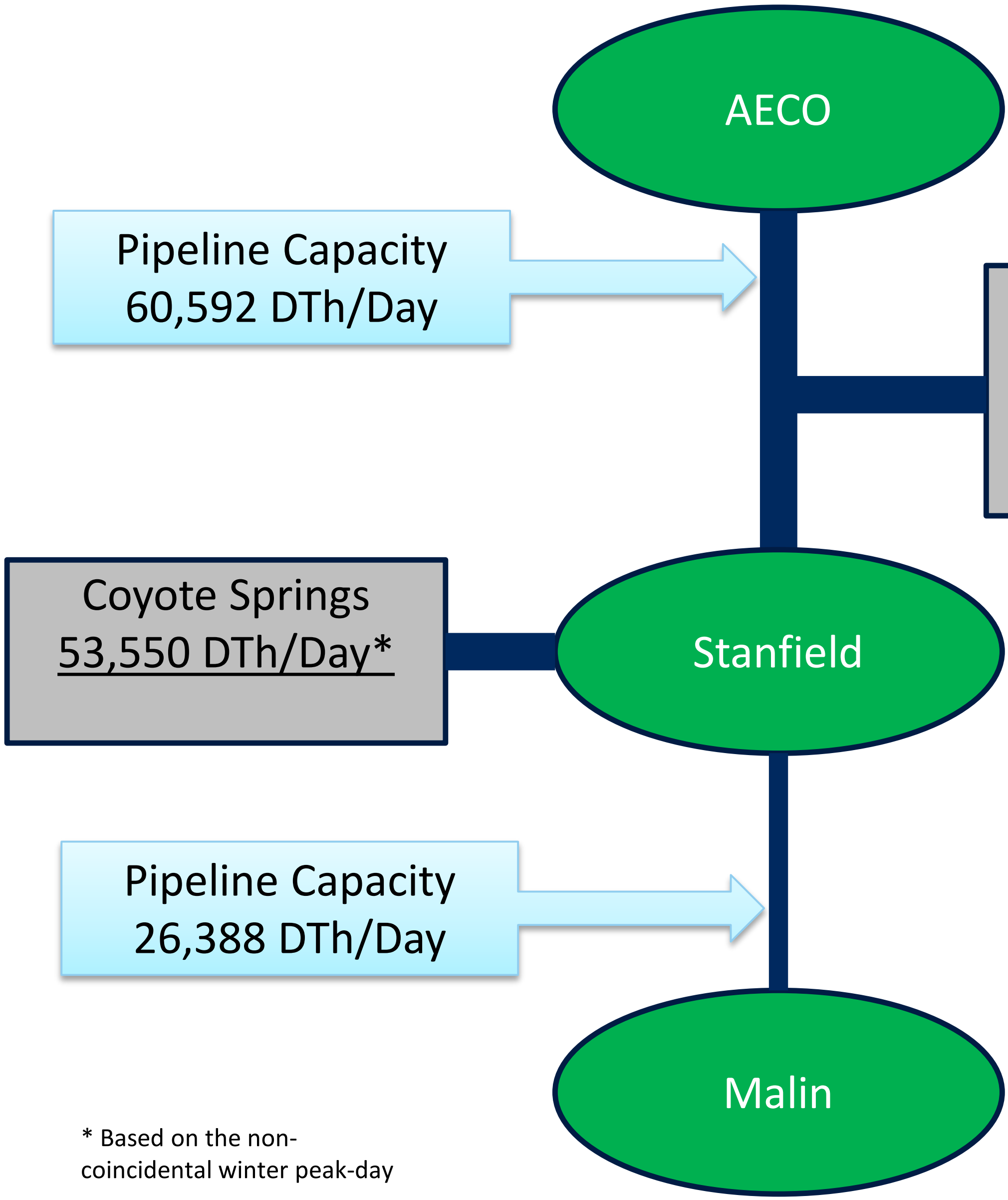
- Contractually both pipelines are now fully subscribed.
- Canadian producers signed up for new contracts in order to get natural gas out of Canada and into more lucrative markets.



Avista Transport for Electric Generation



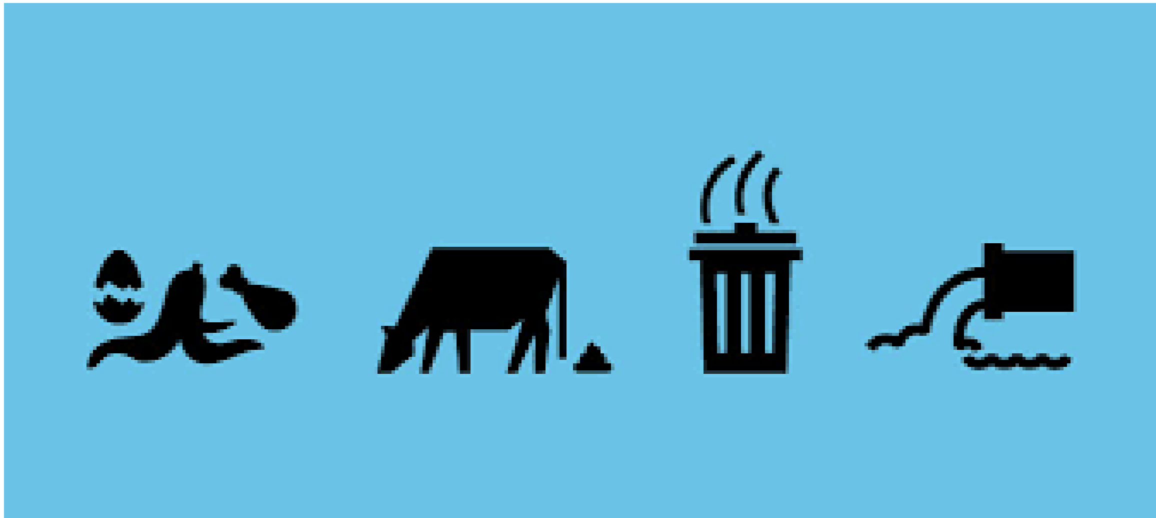
Current Transport & Gas Generation



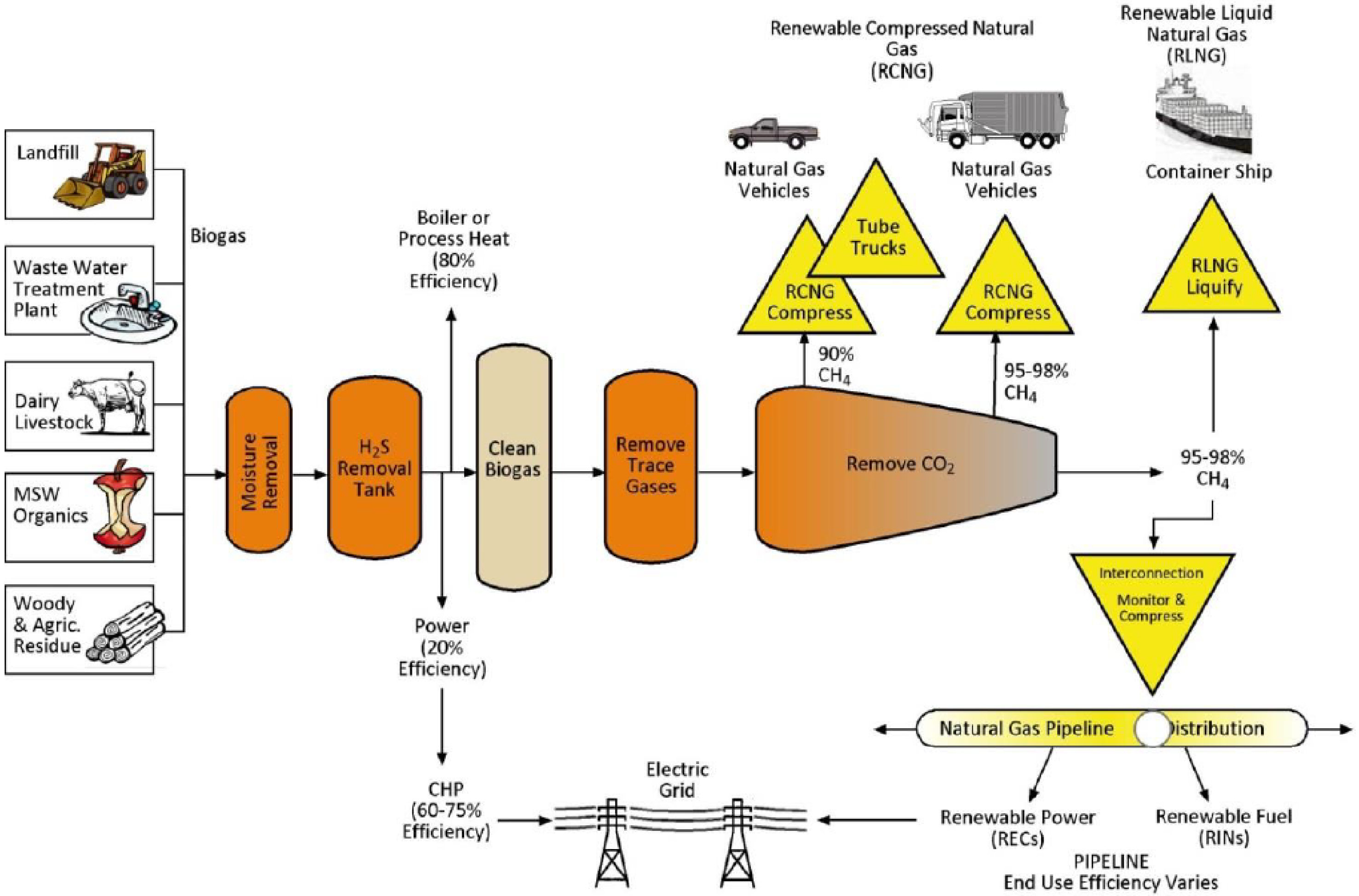
Boulder:	5,400
Coyote:	53,550
Lancaster:	49,000
Rathdrum:	43,600
Total:	151,550
Firm Rights:	60,592
Shortfall:	90,958

* Based on the non-coincidental winter peak-day

Renewable Natural Gas (RNG)



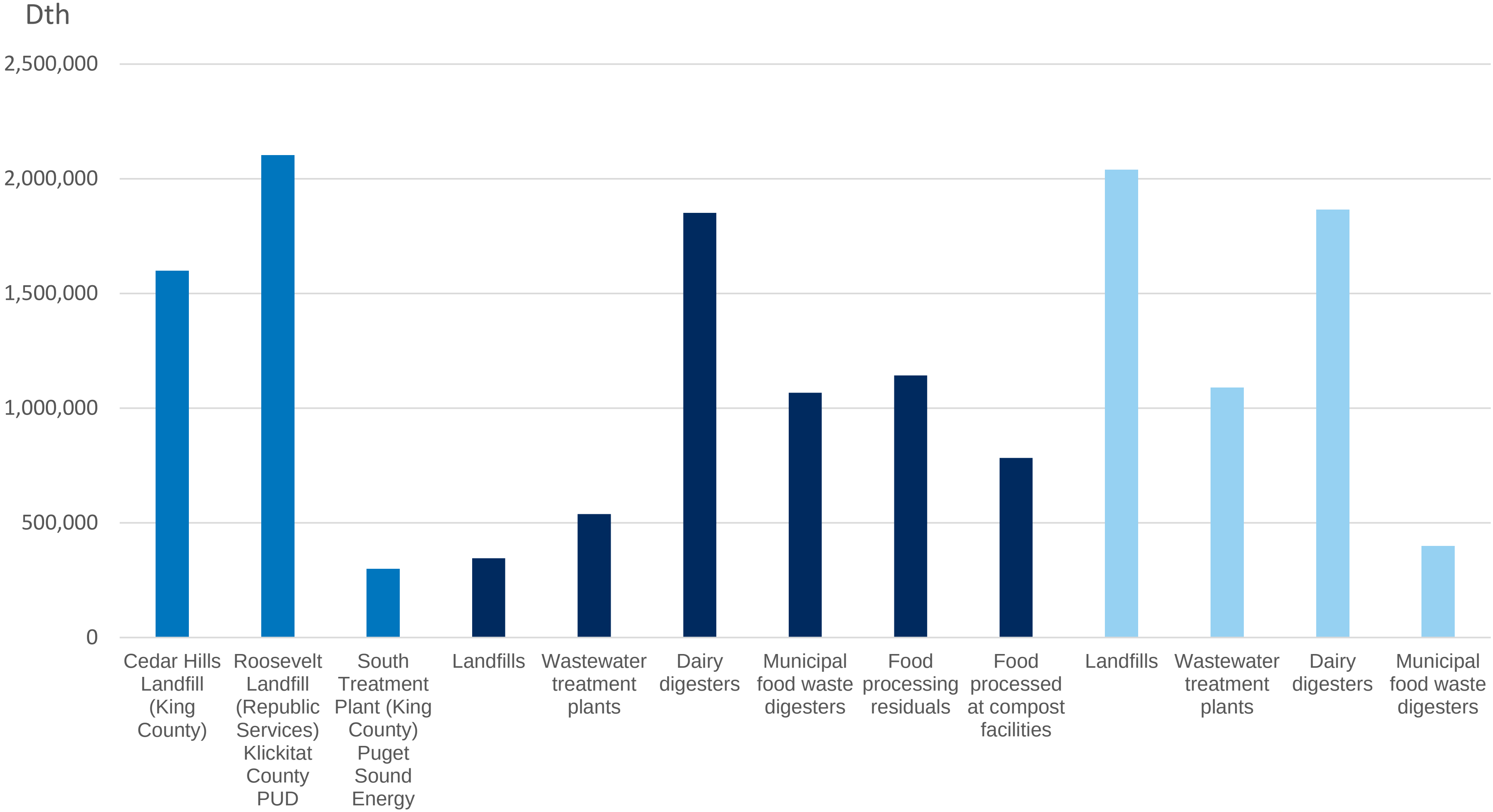
RNG Process Overview



Source: Promoting RNG in WA State

WA RNG Report (HB 2580)

Existing Projects
Near Term Projects
Medium Term Projects



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

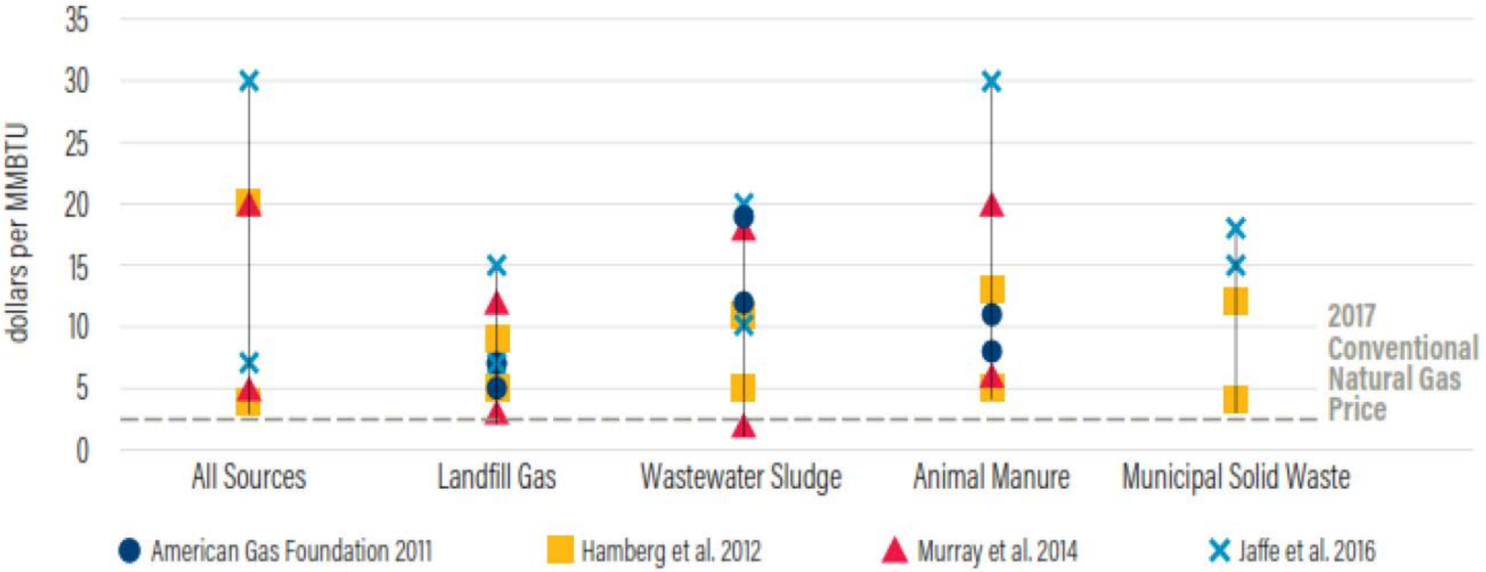
Total Potential Annual Production = 32 Bcf

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

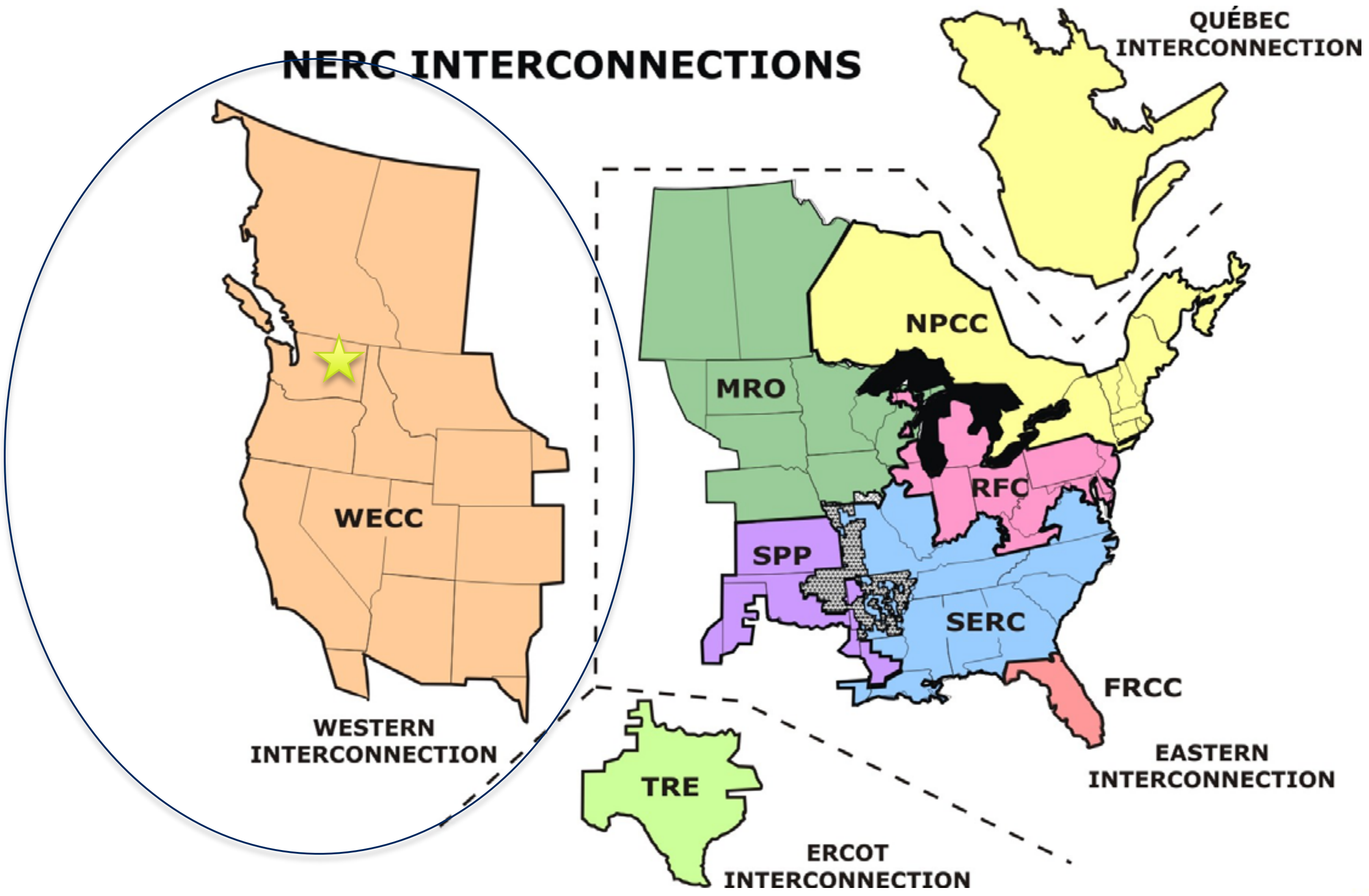


Source: Promoting RNG in WA State

2020 IRP Electric Market Price Forecast

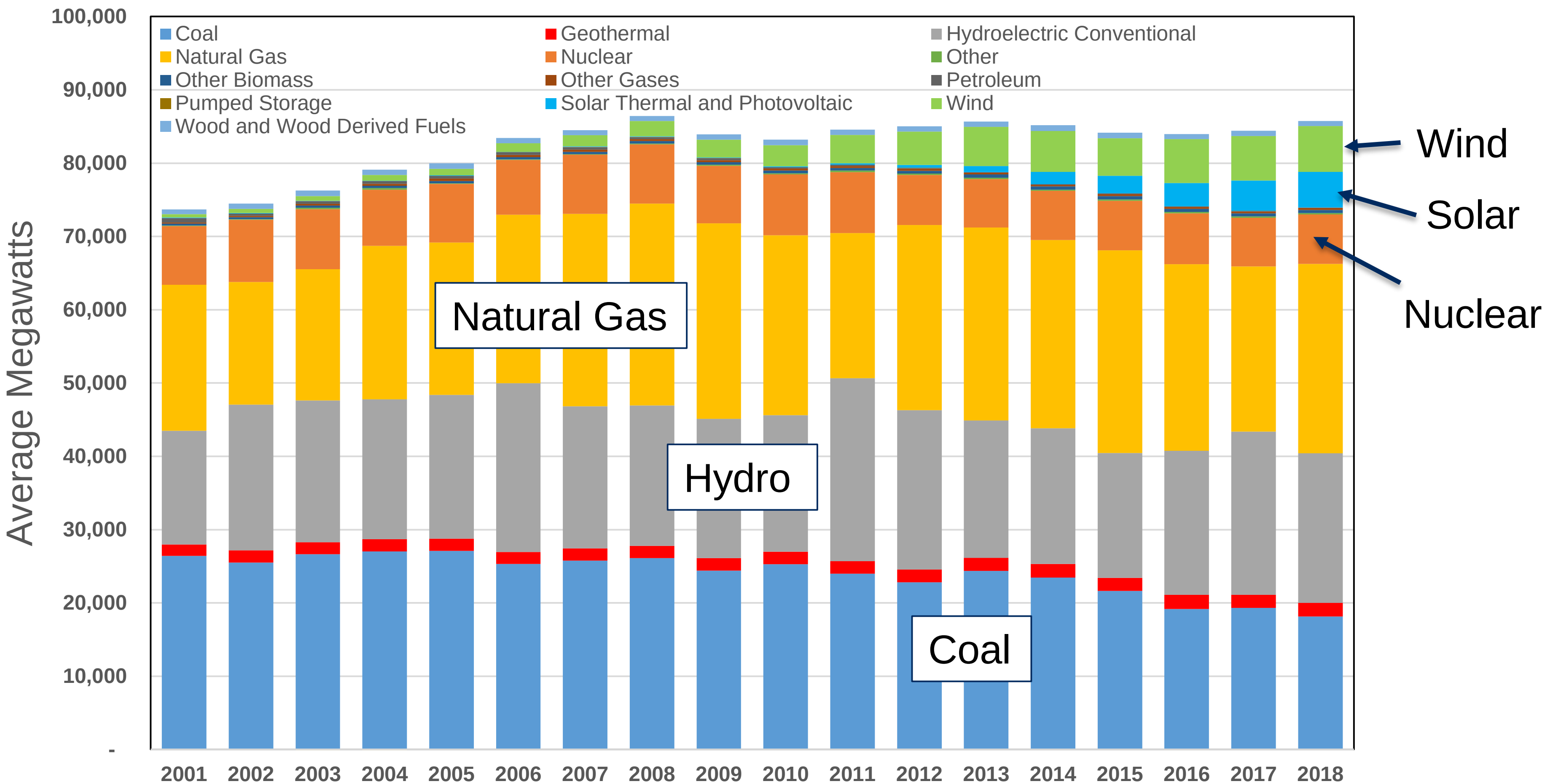
James Gall, IRP Manager
Fourth Technical Advisory Committee Meeting
August 6, 2019

Our Region



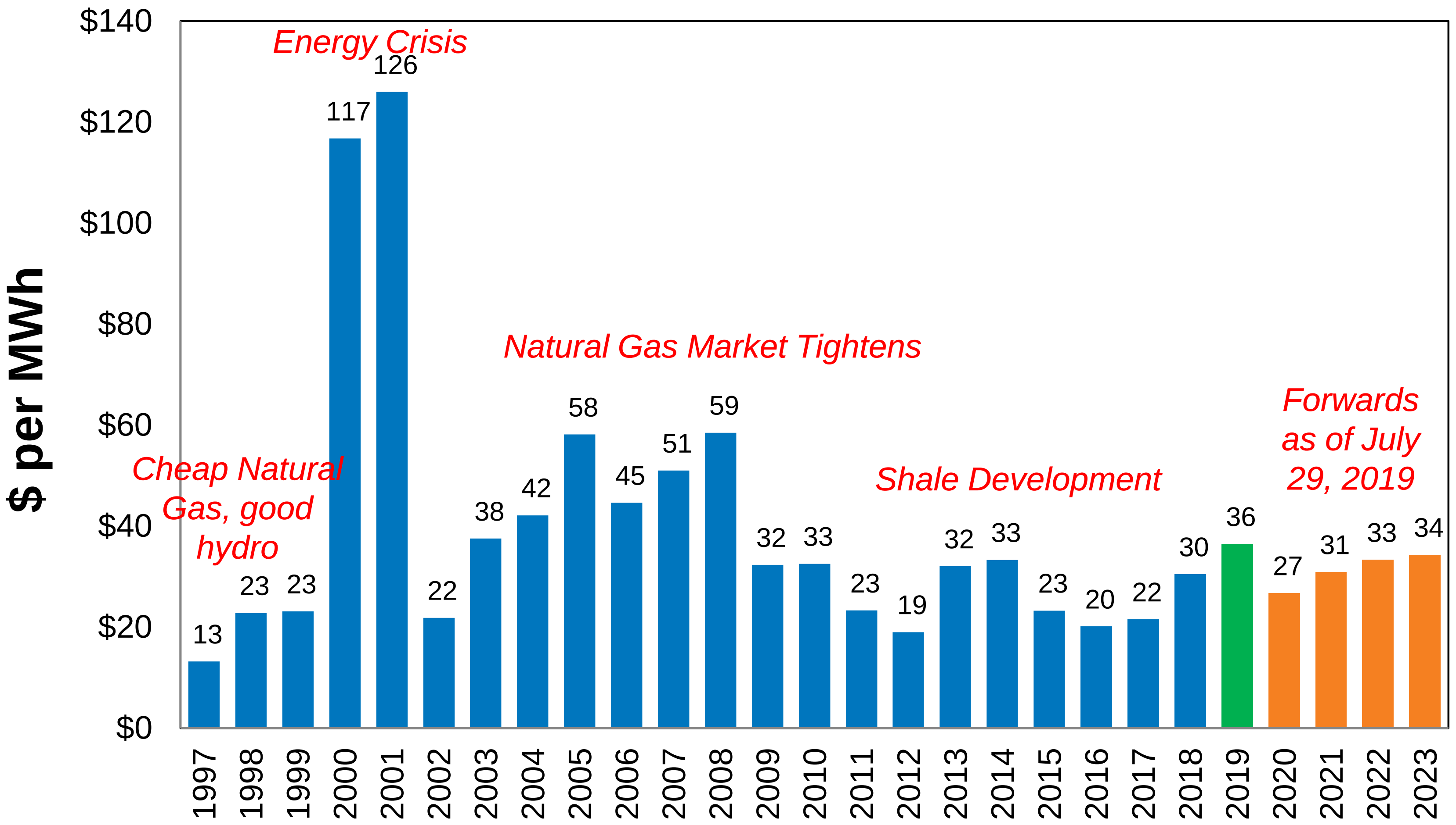
Source: NERC

US Western Interconnect Generation



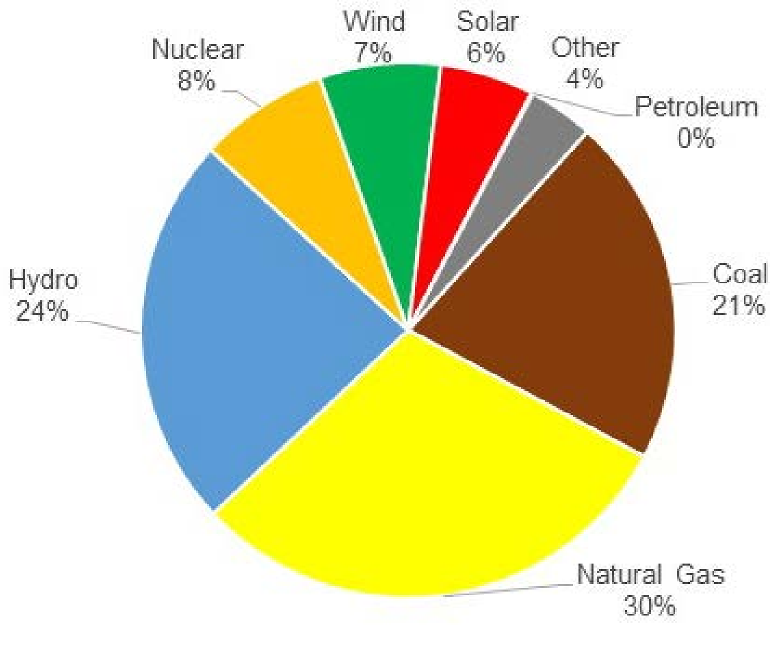
Source: EIA Data

Mid-Columbia Flat Firm Price Index History

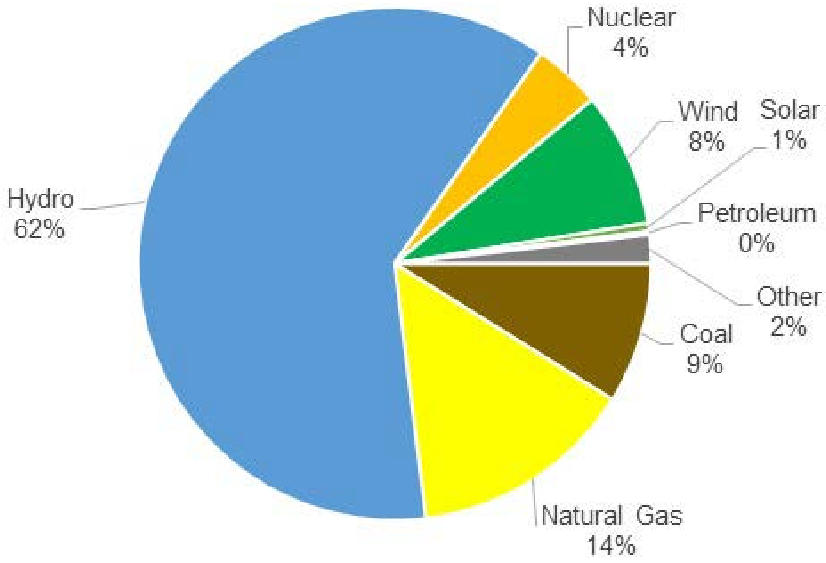


2018 Fuel Mix Comparison (NW vs West)

US Western Interconnect

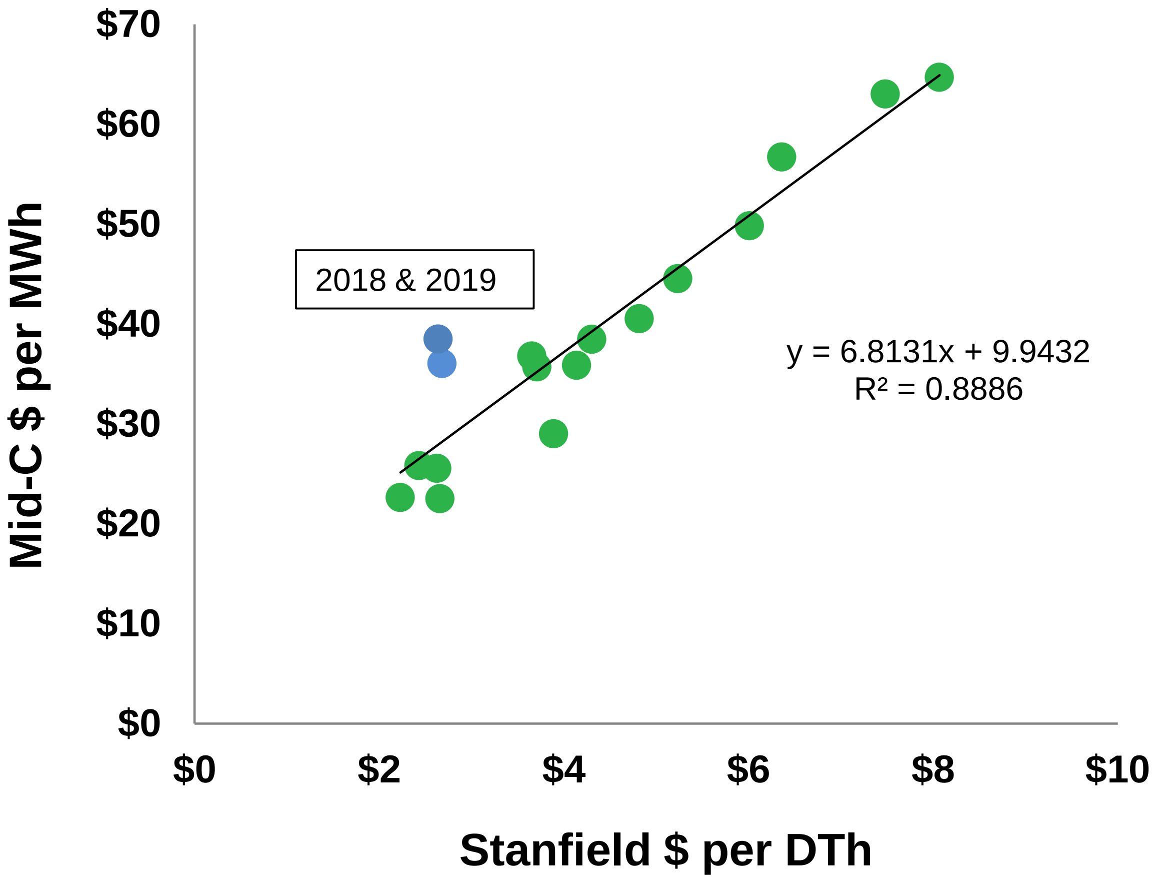


Northwest Four States

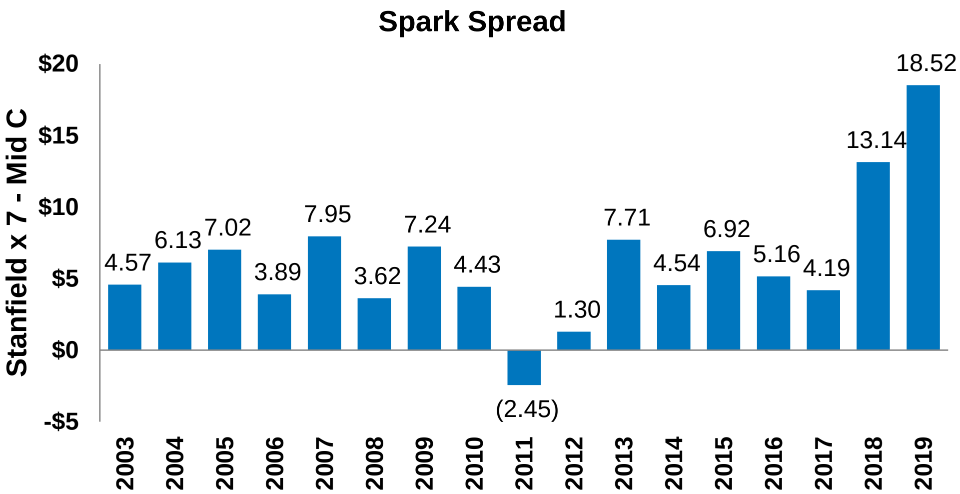


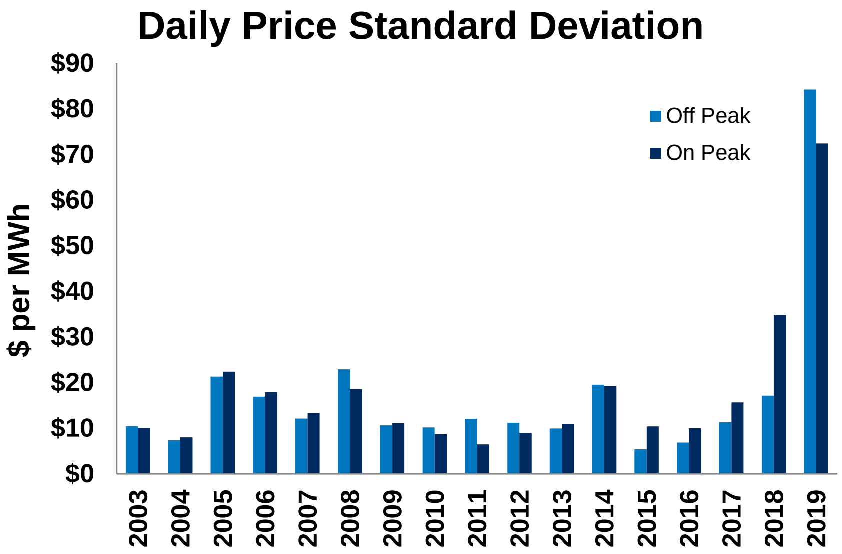
Source: EIA Data

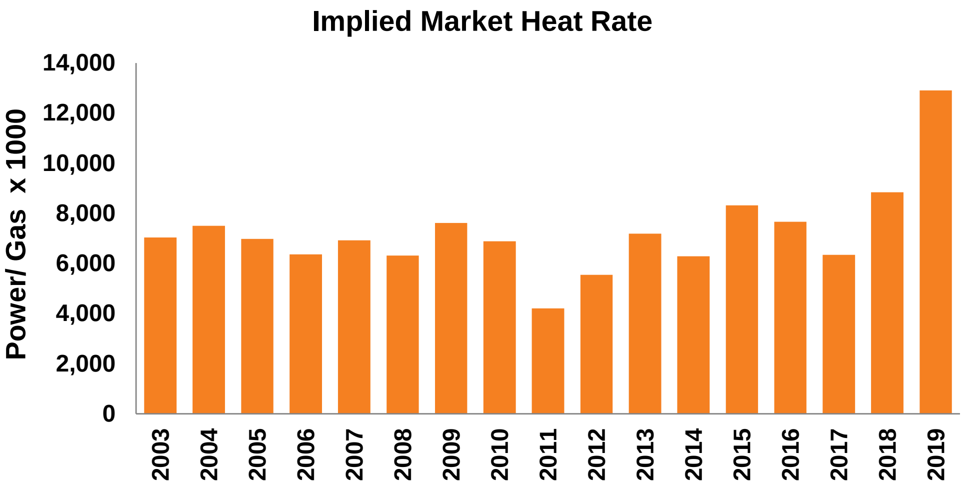
Natural Gas vs. On-Peak Electric Prices (2003-19)



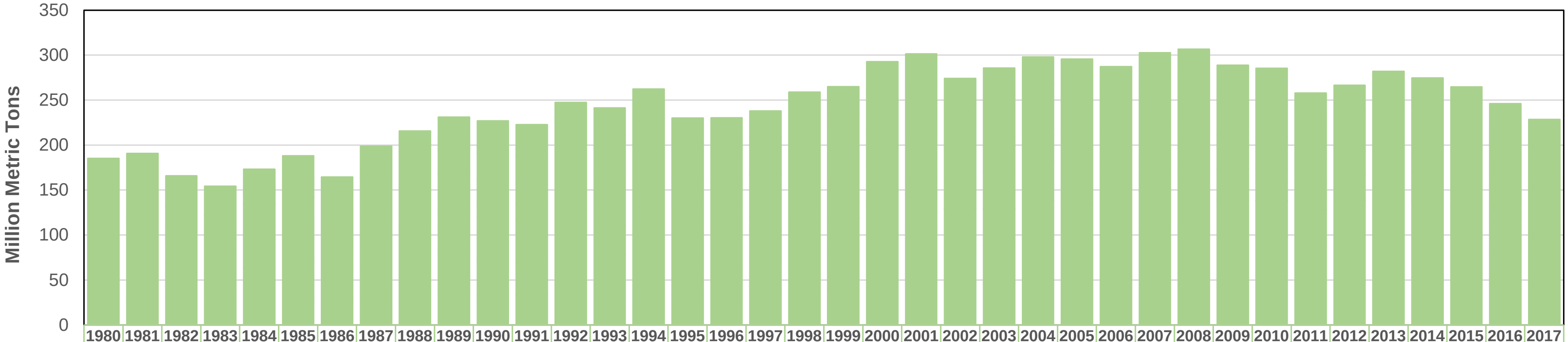
Market Indicators







Western Greenhouse Gas Emissions Power Industry

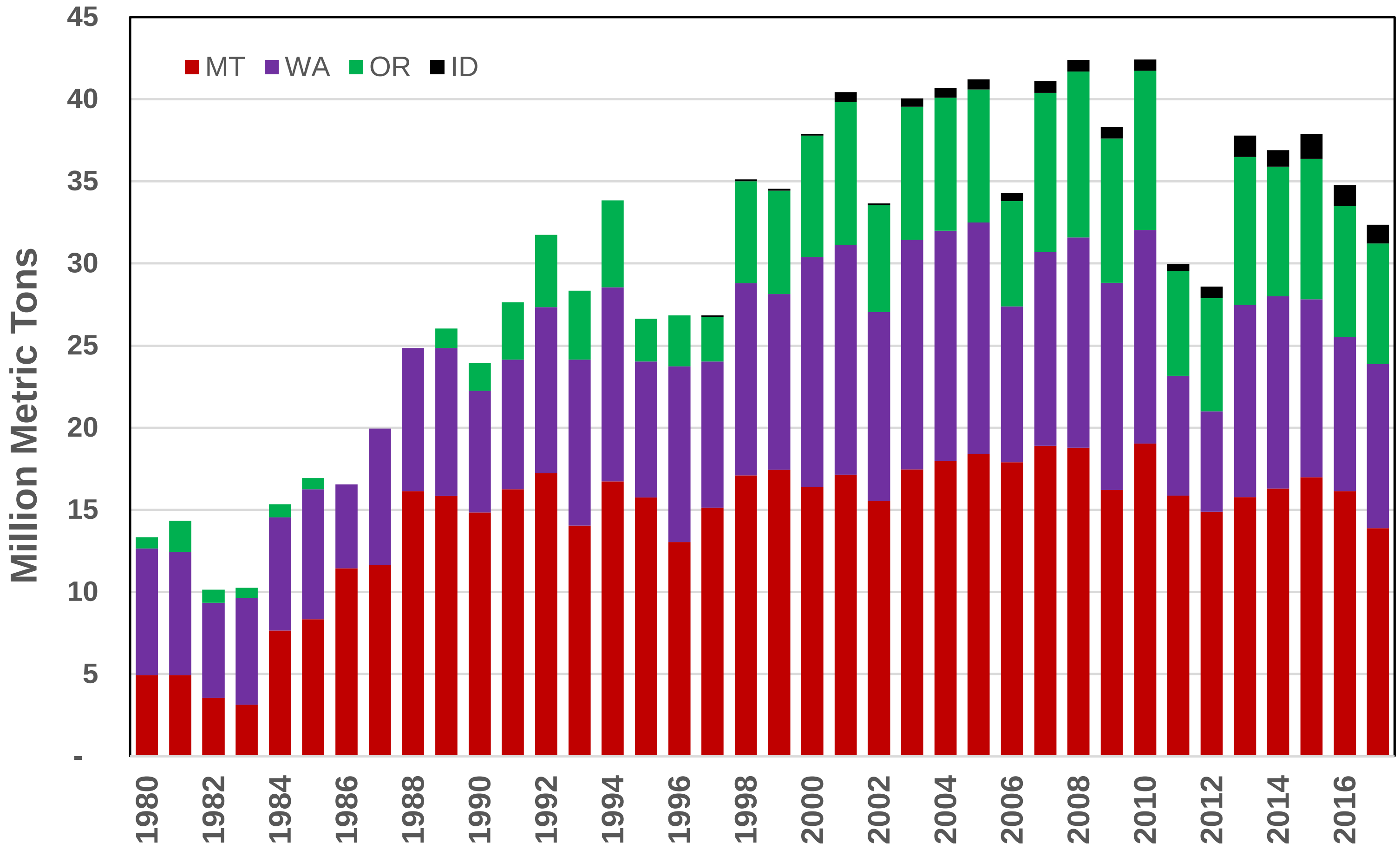


	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
WY	22	20	17	15	19	24	17	26	27	25	28	27	30	29	31	28	29	29	31	30	31	31	30	30	30	29	29	30	30	30	29	26	29	31	30	29	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



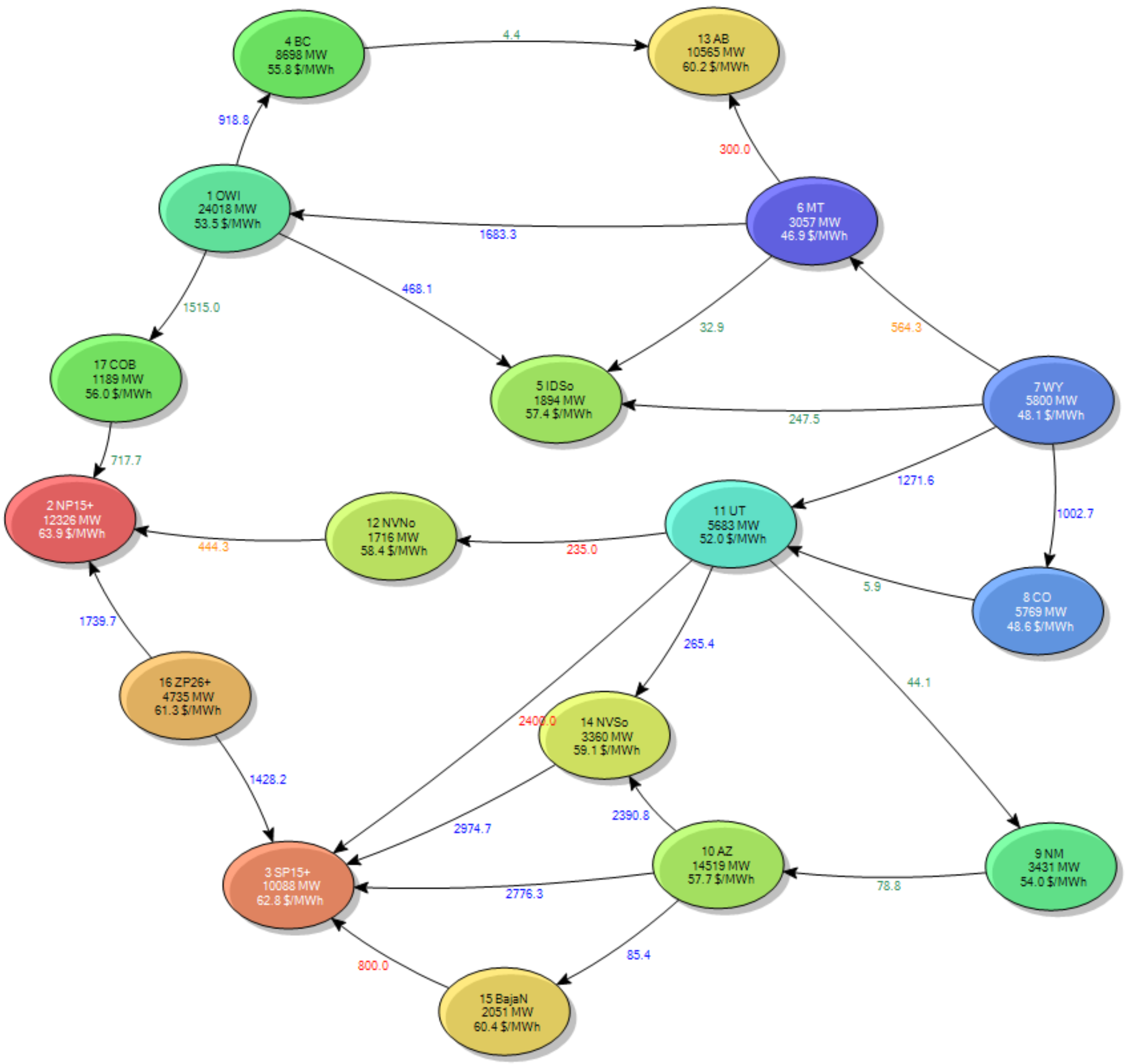
Electric Market Modeling

- 3^{rd} 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

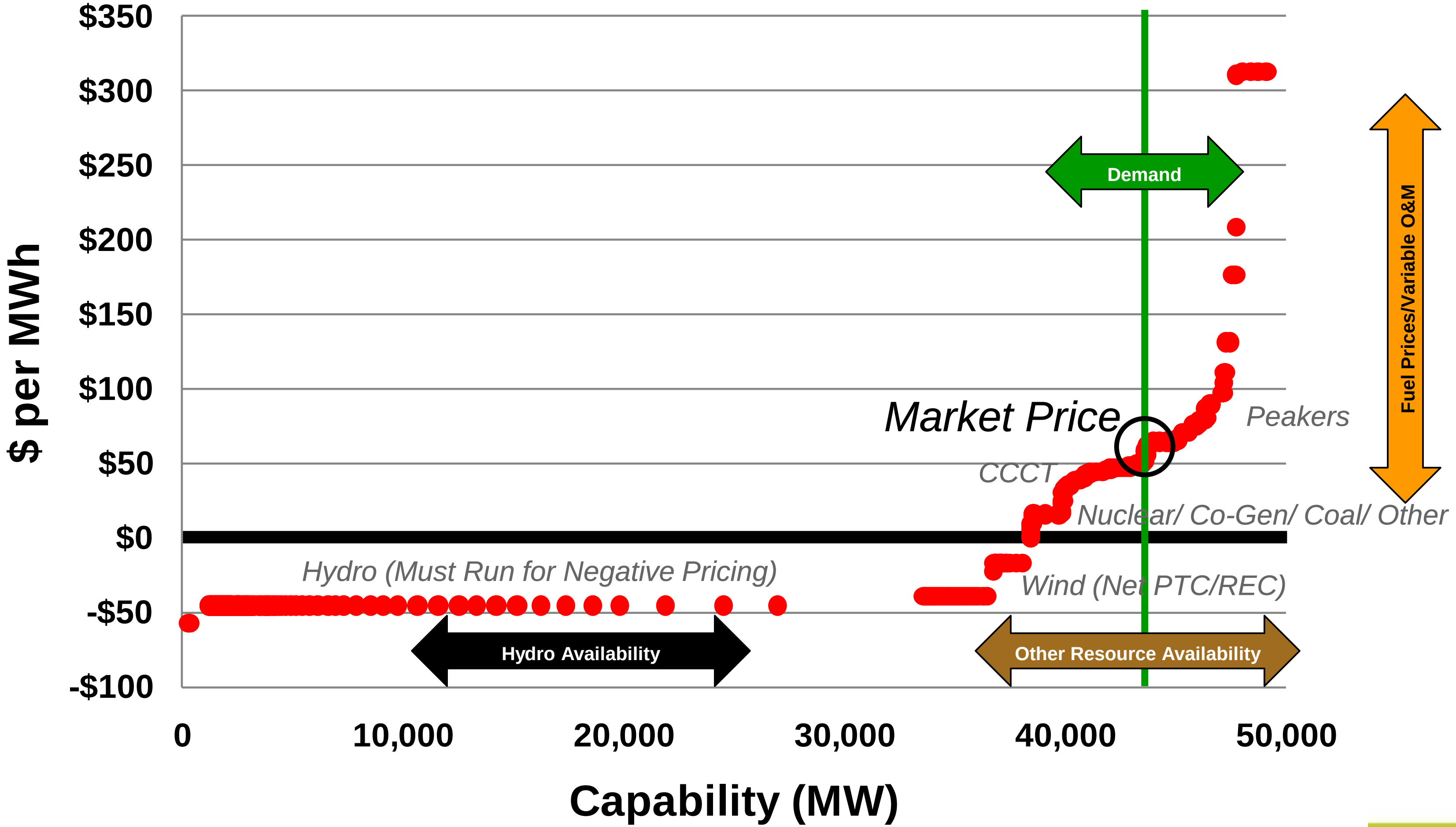
Stochastic Approach

- 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)

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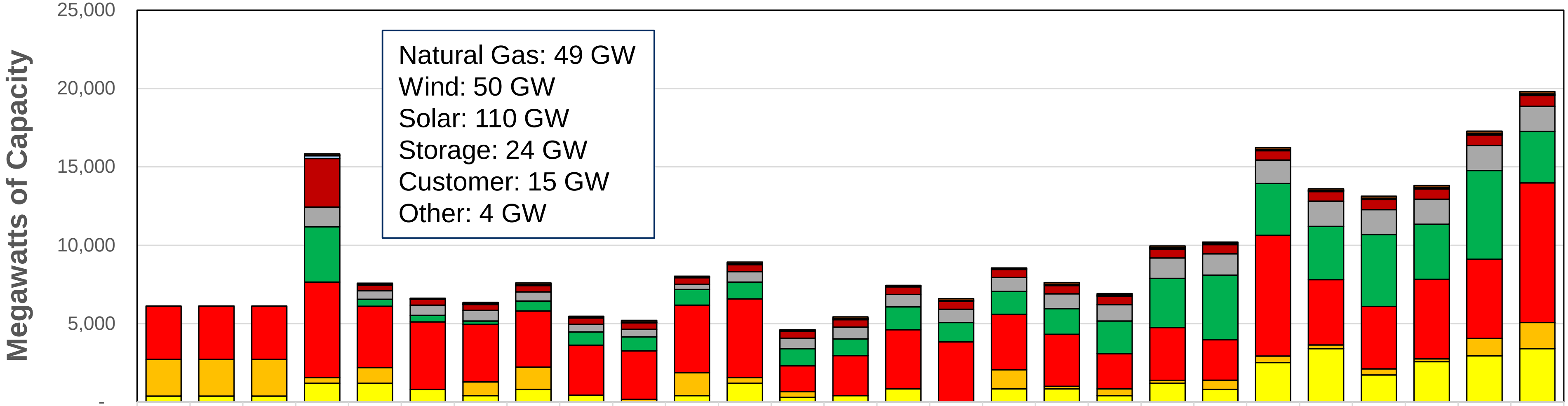
New Resources Forecast- US West



	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	-	-	-	90	70	24	76	104	52	104	26	104	26	104	26	104	26	104	76	114	86	124	96	134	140	156	160
Biomass	-	-	-	18	11	35	36	35	37	35	36	36	36	34	34	37	34	34	36	35	36	34	34	37	34	34	36
Hydro	-	-	-	182	40	19	23	30	29	25	29	30	28	40	31	36	39	58	51	56	54	51	58	56	56	56	58
Consumer Gen	-	-	-	3,092	357	367	378	390	402	414	427	439	452	466	480	494	510	525	541	557	574	592	610	628	647	667	687
Storage	-	-	-	1,267	551	659	667	587	480	480	331	671	660	748	795	849	897	941	1,050	1,308	1,358	1,500	1,600	1,598	1,600	1,601	1,600
Wind	-	-	-	3,522	445	419	215	640	846	896	993	1,070	1,095	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	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	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	2,353	2,353	2,353	350	988	-	880	1,422	-	175	1,467	350	350	-	-	-	1,230	175	440	175	587	412	237	400	175	1,111	1,659
NG CCCT	371	371	371	1,200	1,200	800	400	800	429	-	400	1,200	300	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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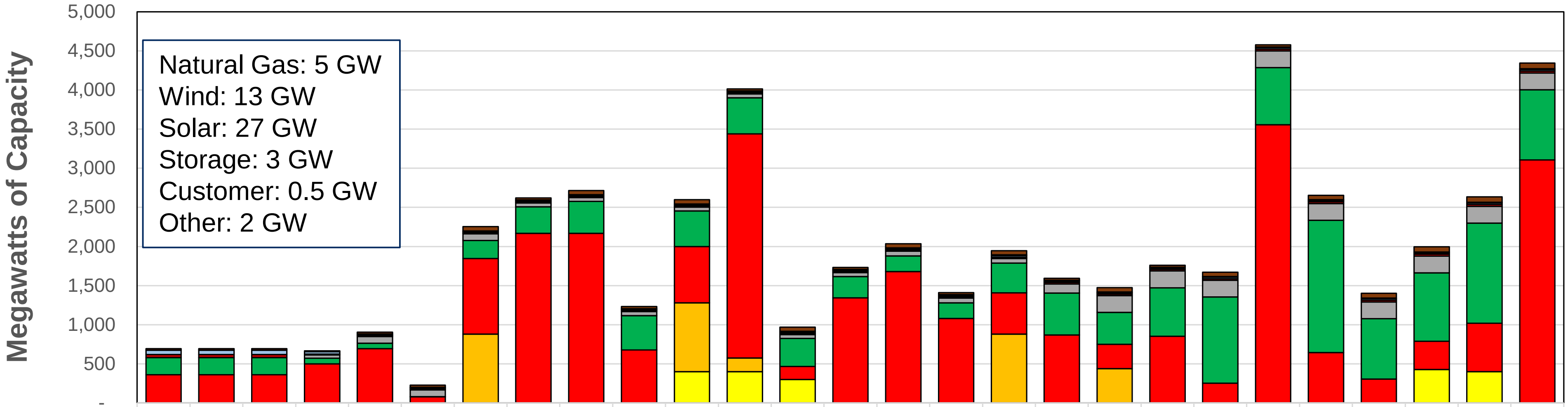
New Resources Forecast- Northwest States



	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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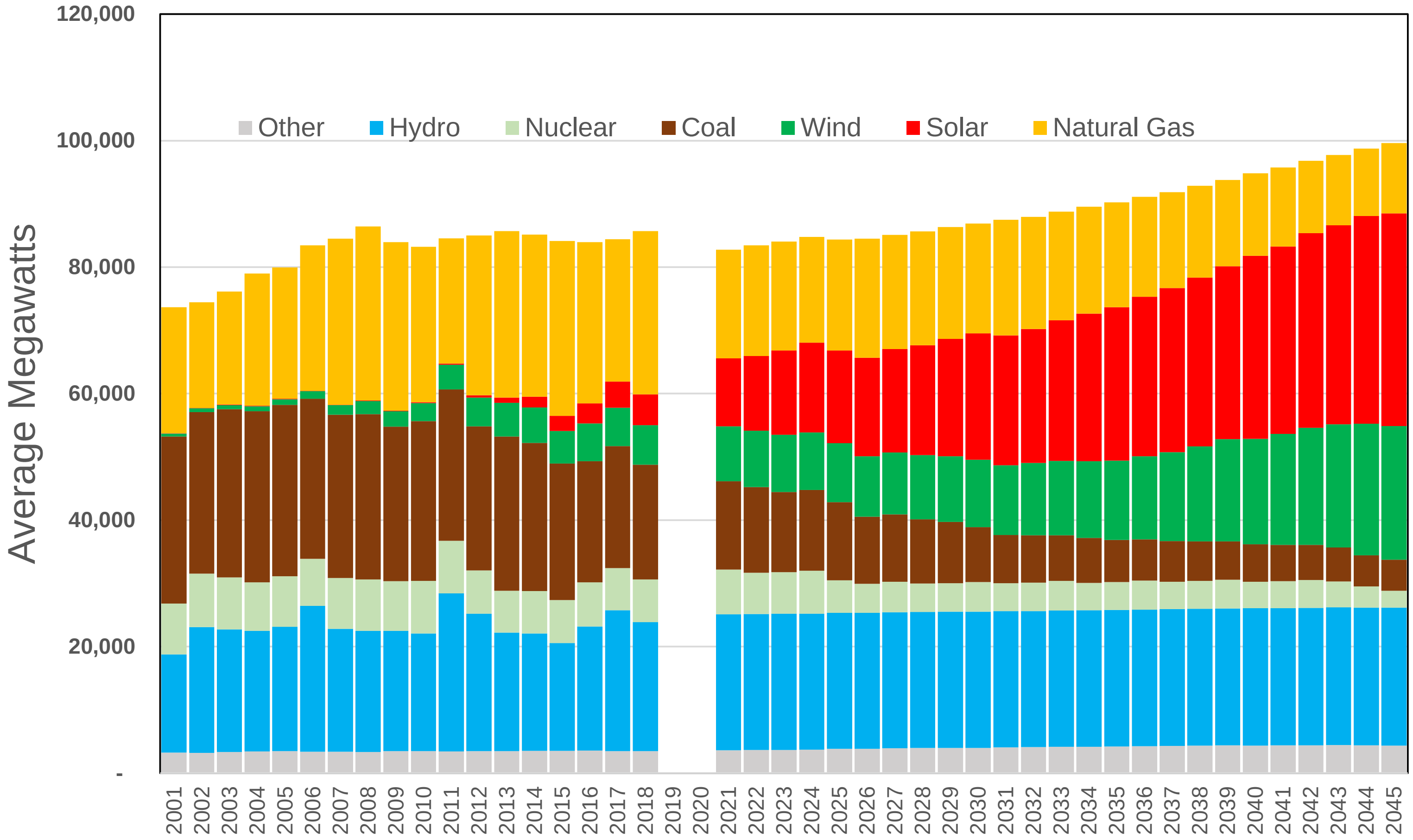
Resource Type Mix Forecast
(US Western Interconnect)



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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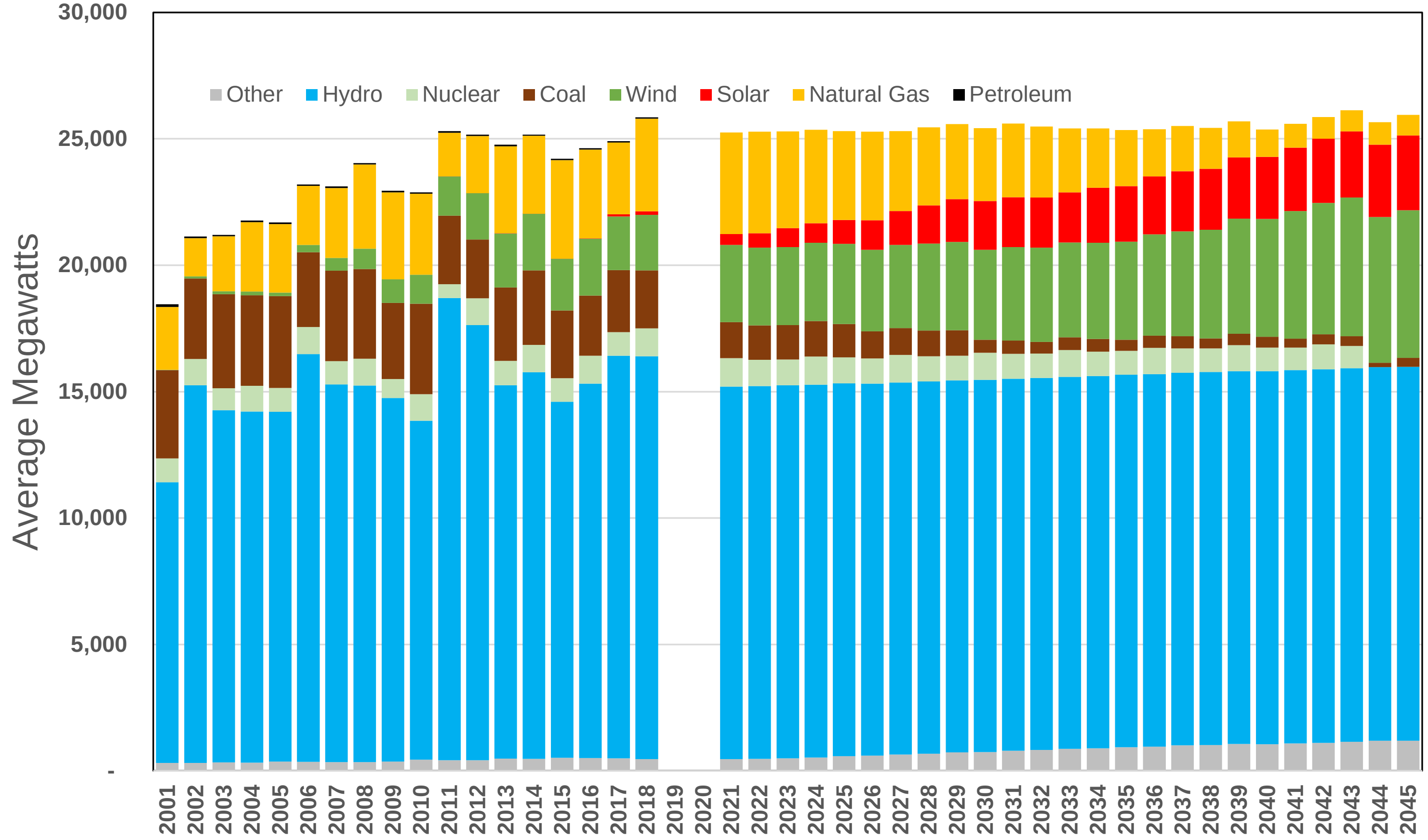
Resource Type Mix Forecast
(NW States)



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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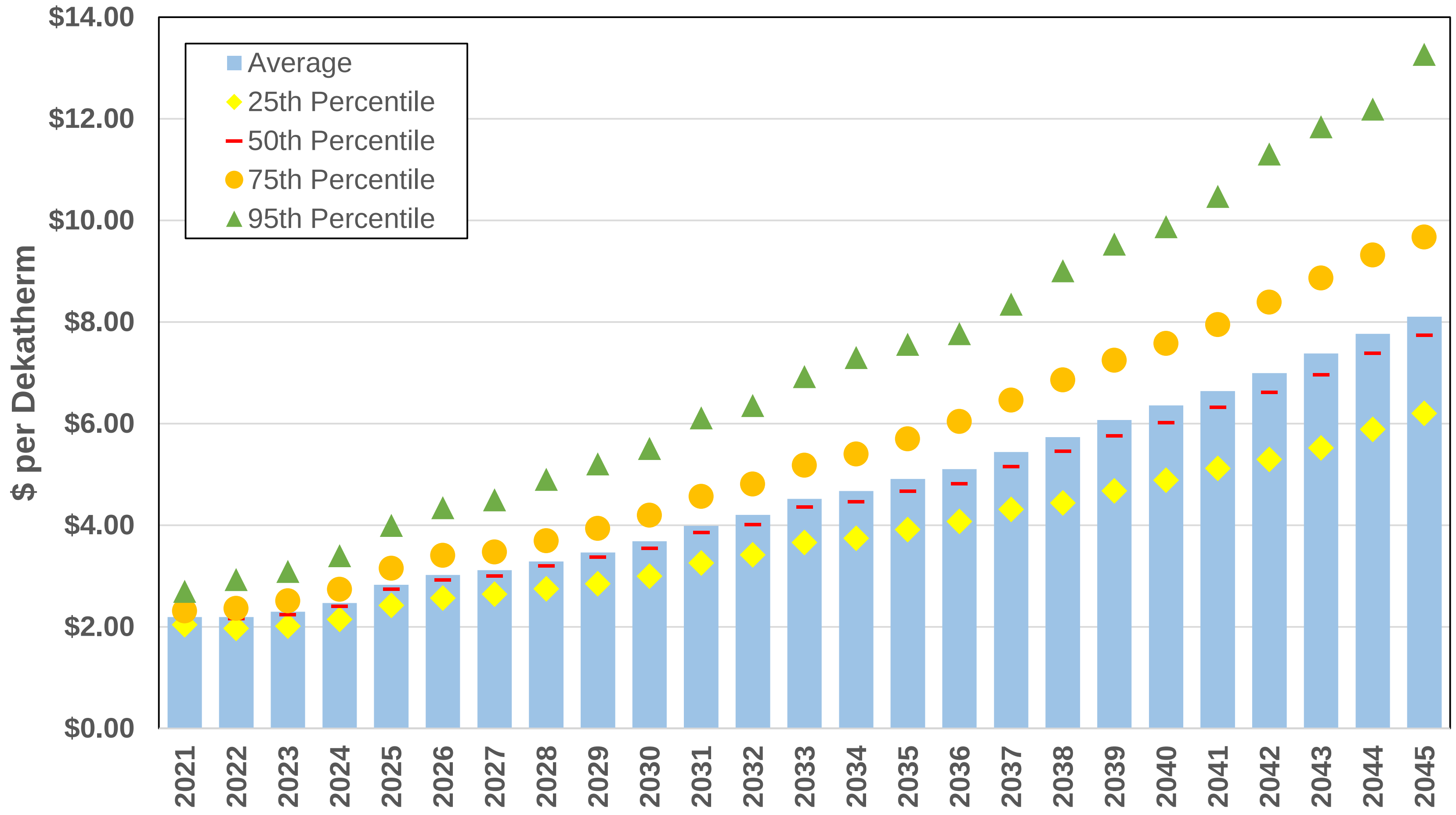
Stanfield Natural Gas Price Forecast



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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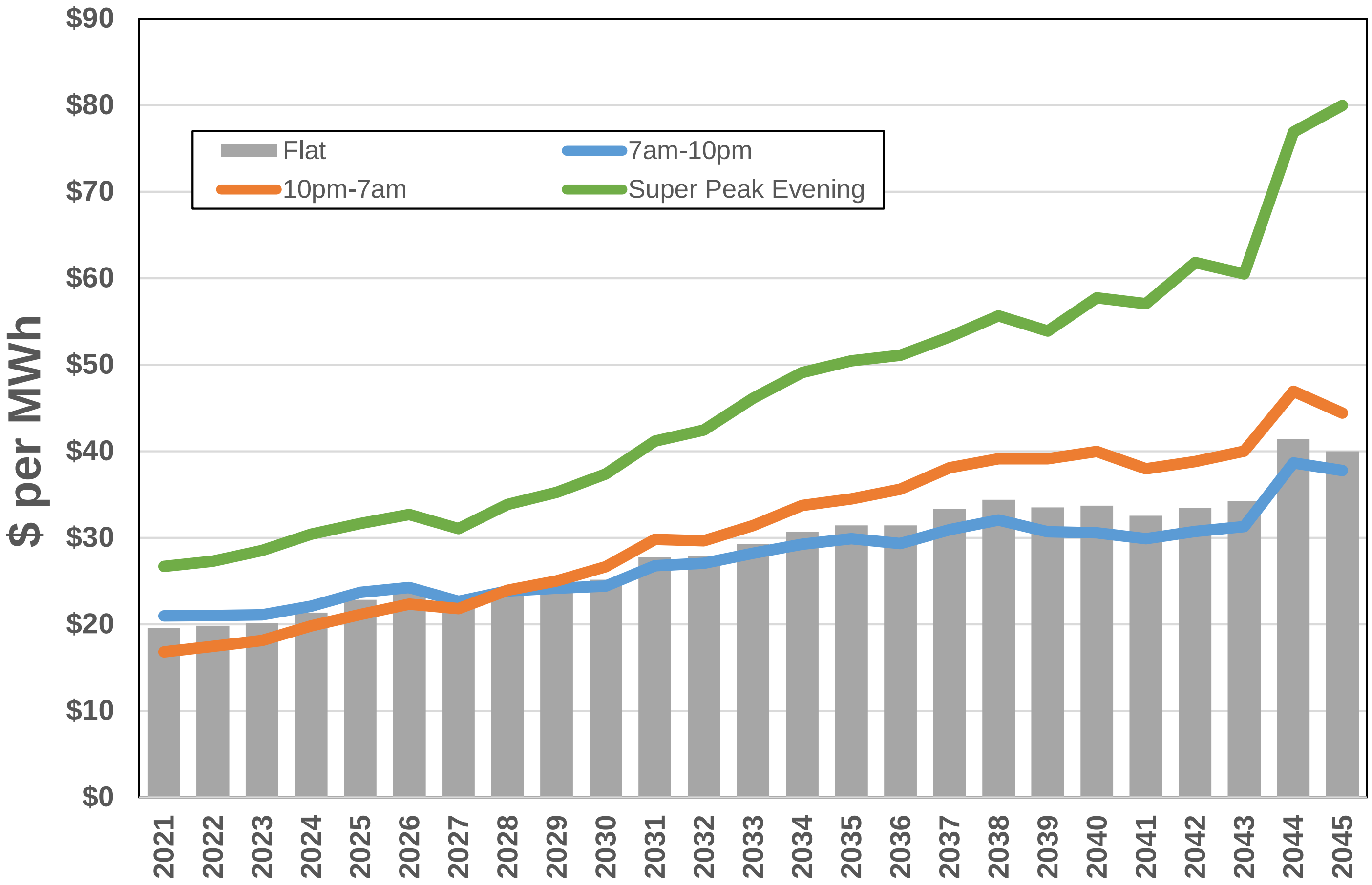
Mid-Columbia Electric Price Forecast
(Deterministic)



<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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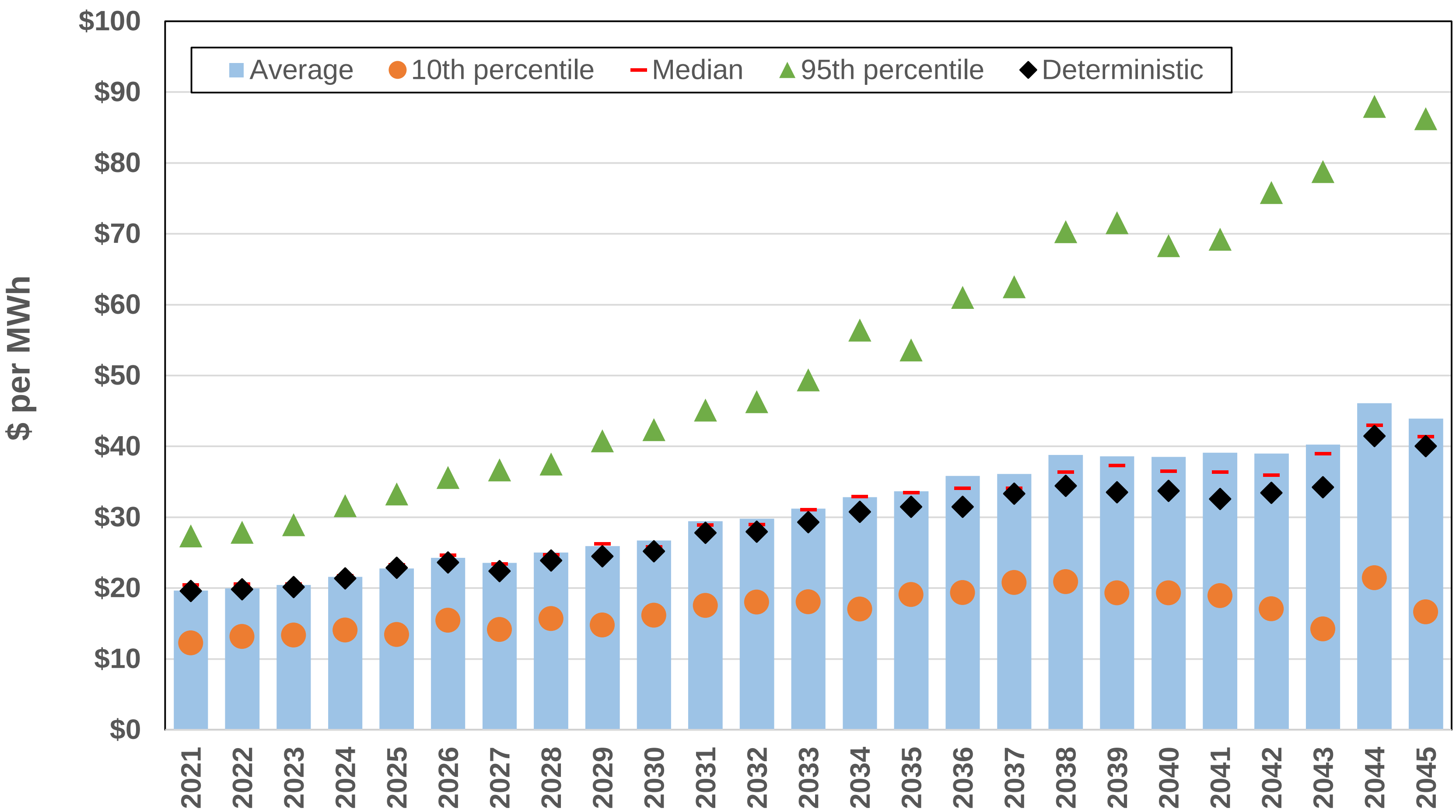
Mid-Columbia Electric Price Forecast

(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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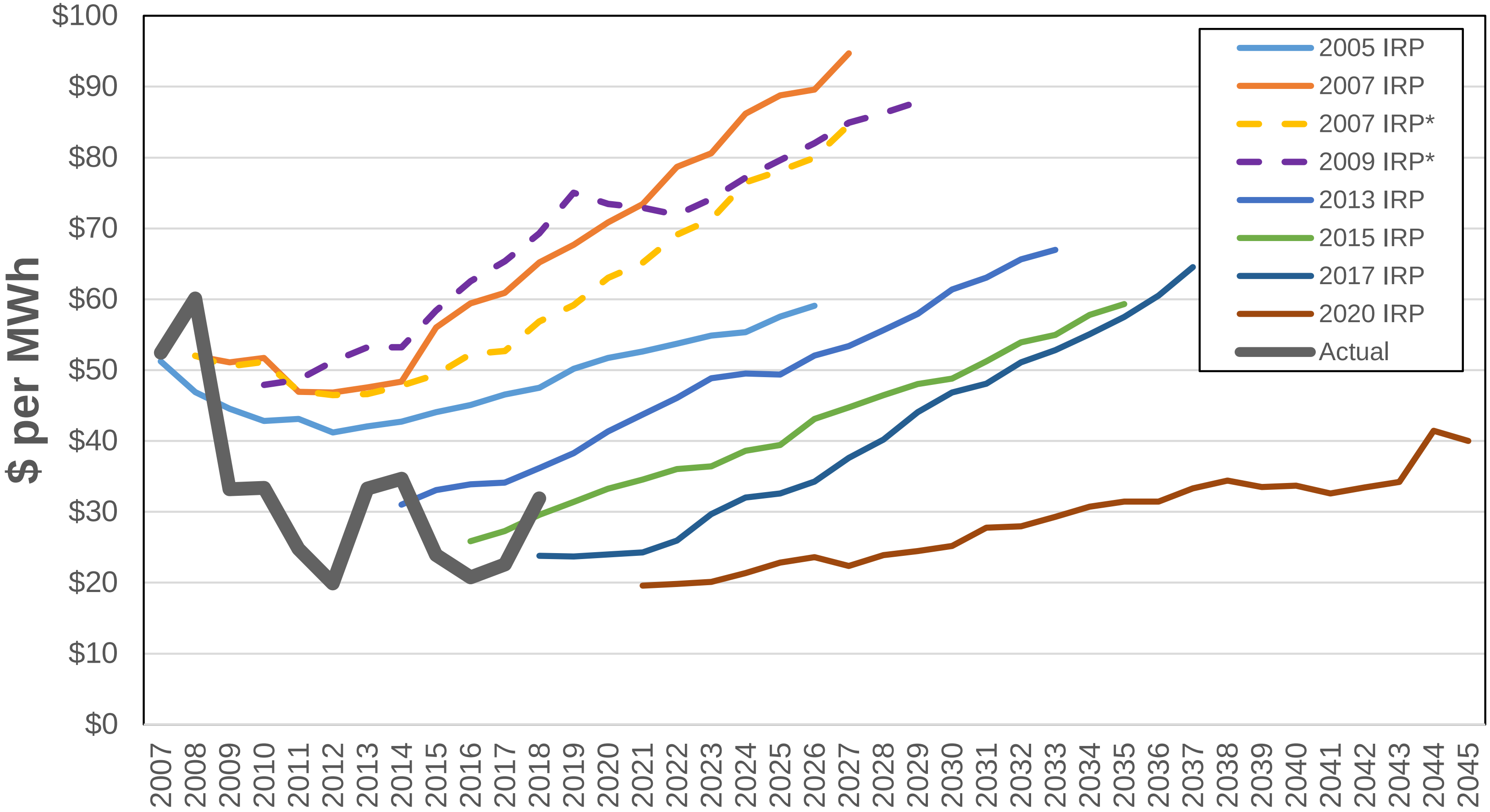
Historical IRP Price Forecasts (Annual Flat Prices)



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

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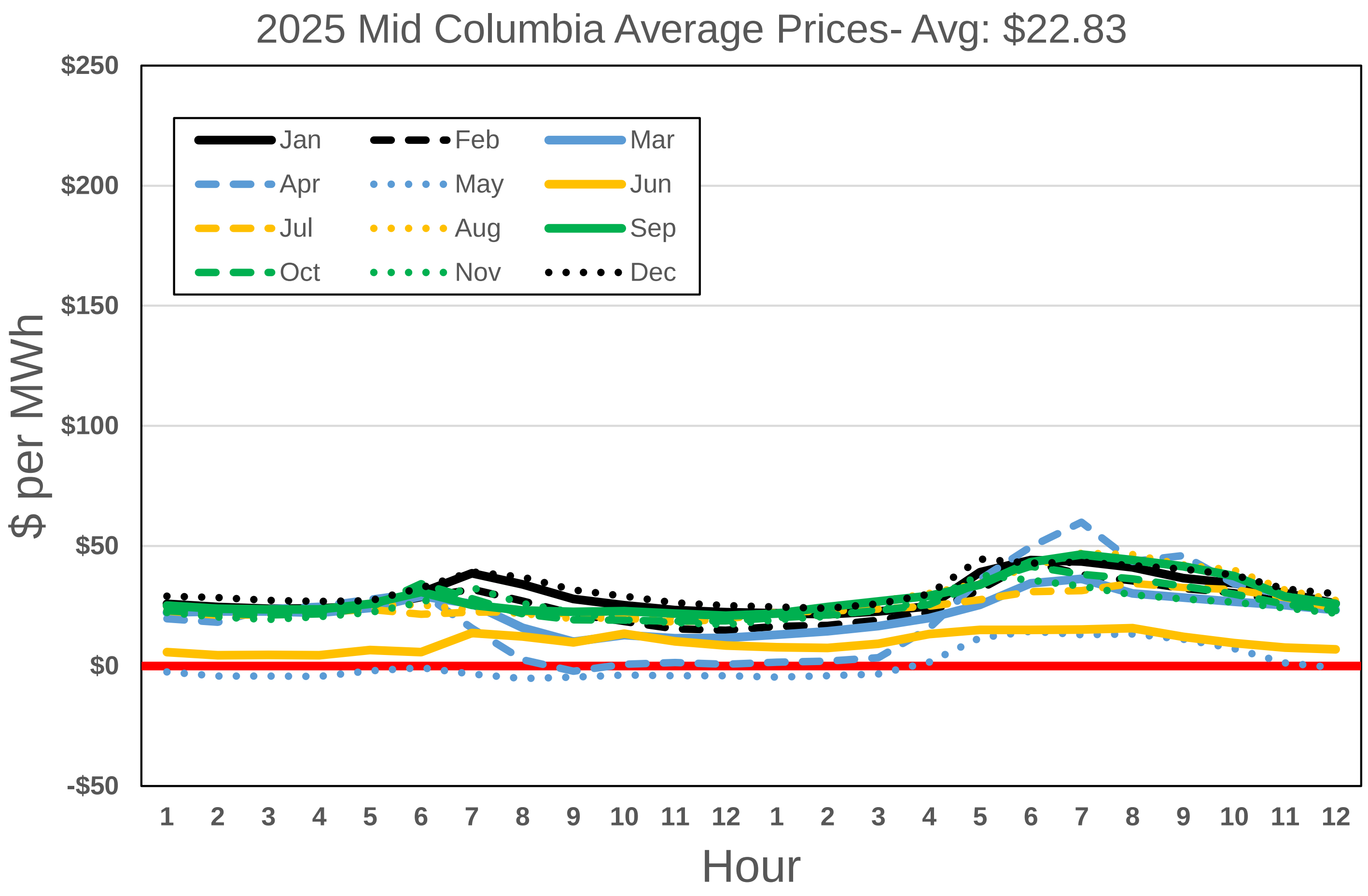
Hourly Price Shape



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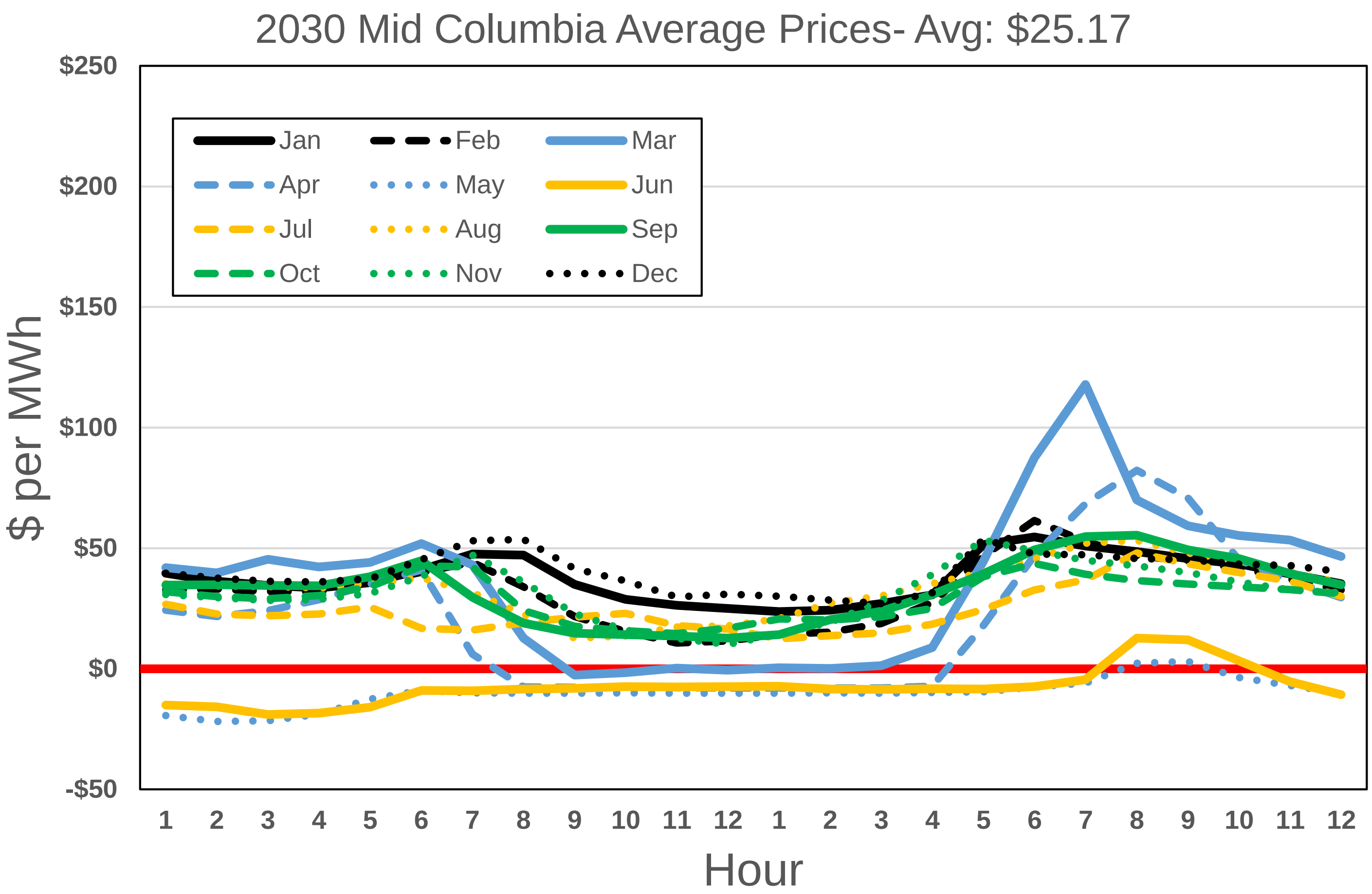
Hourly Price Shape



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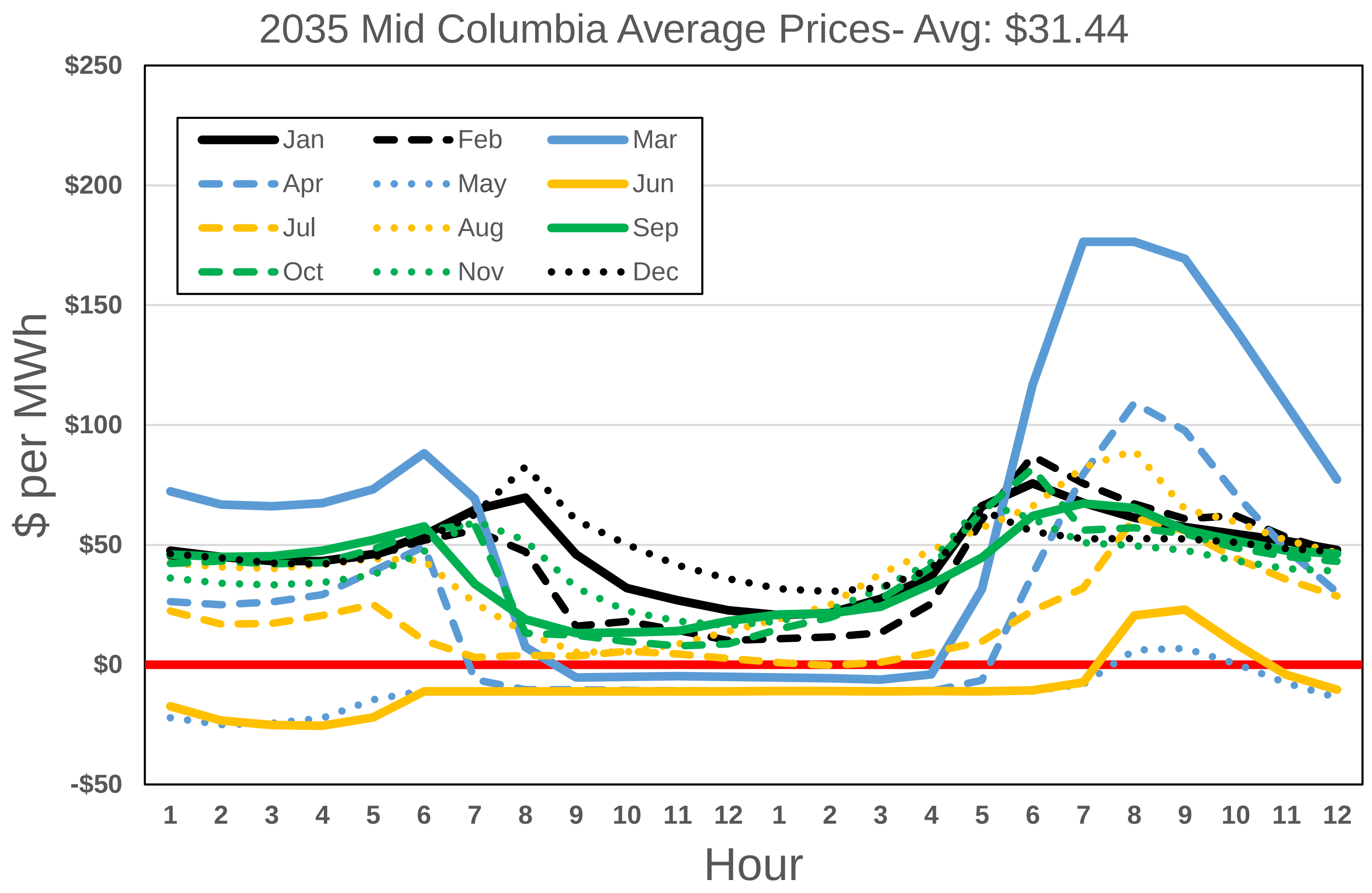
Hourly Price Shape



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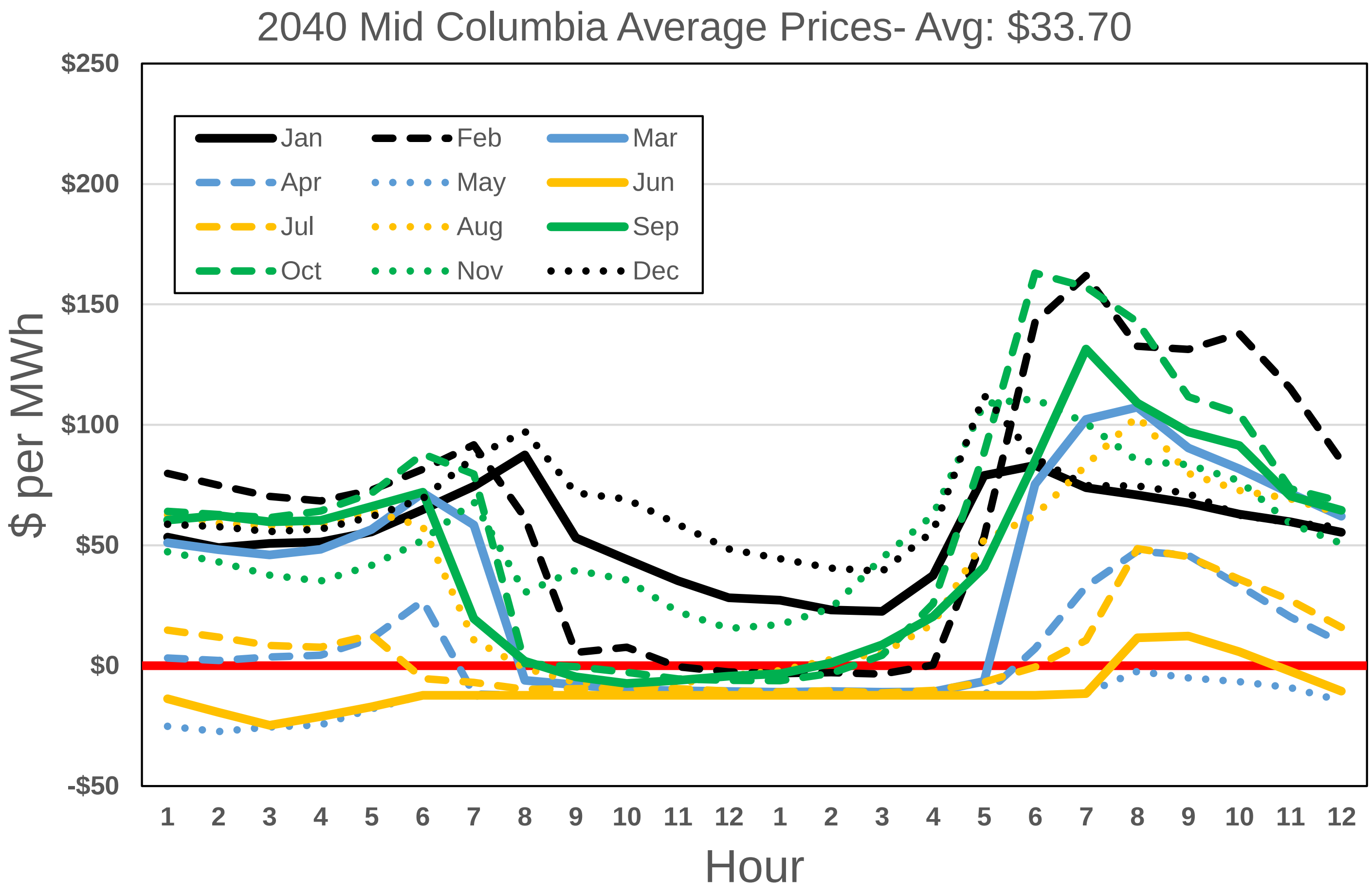
Hourly Price Shape



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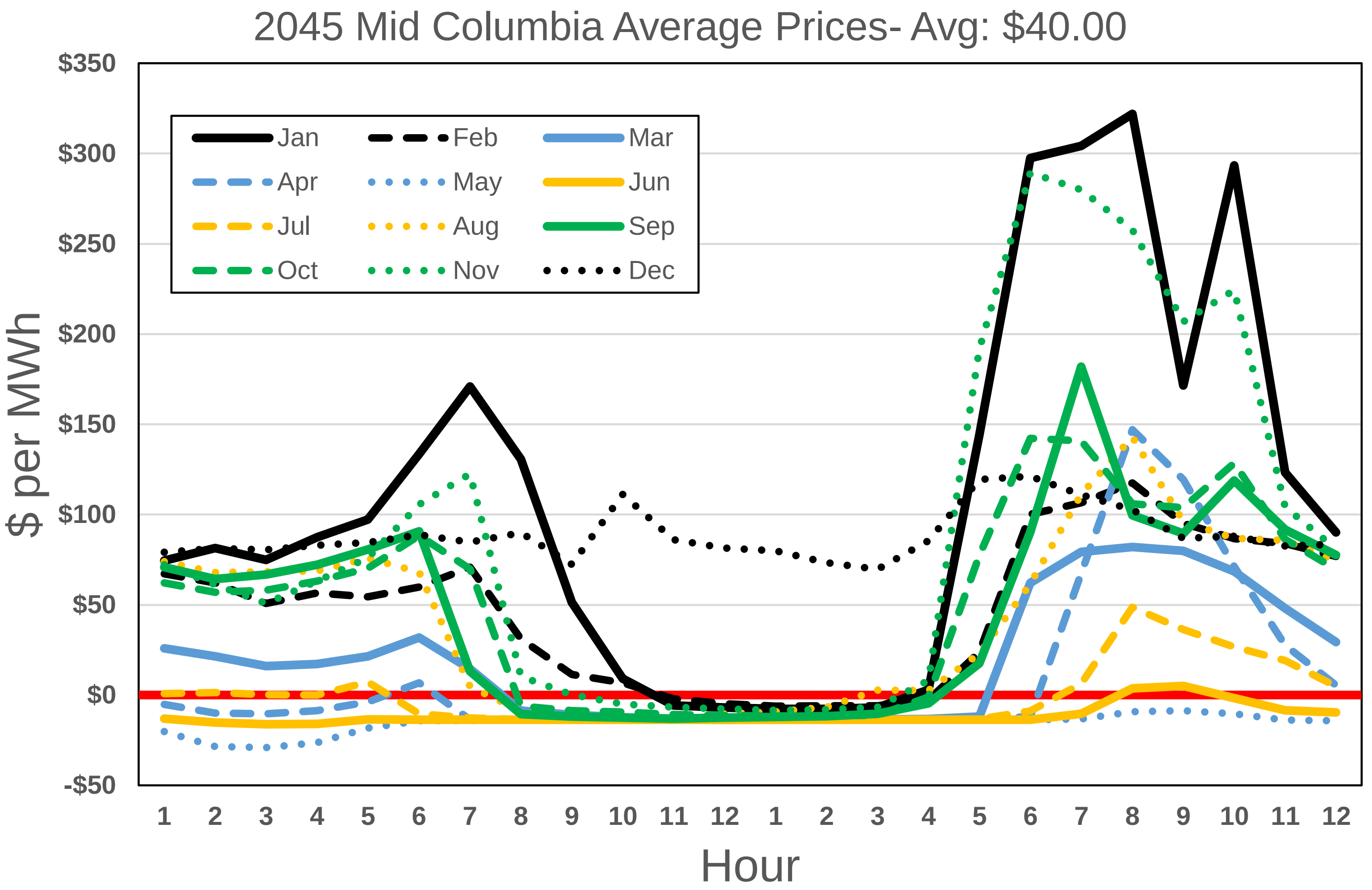
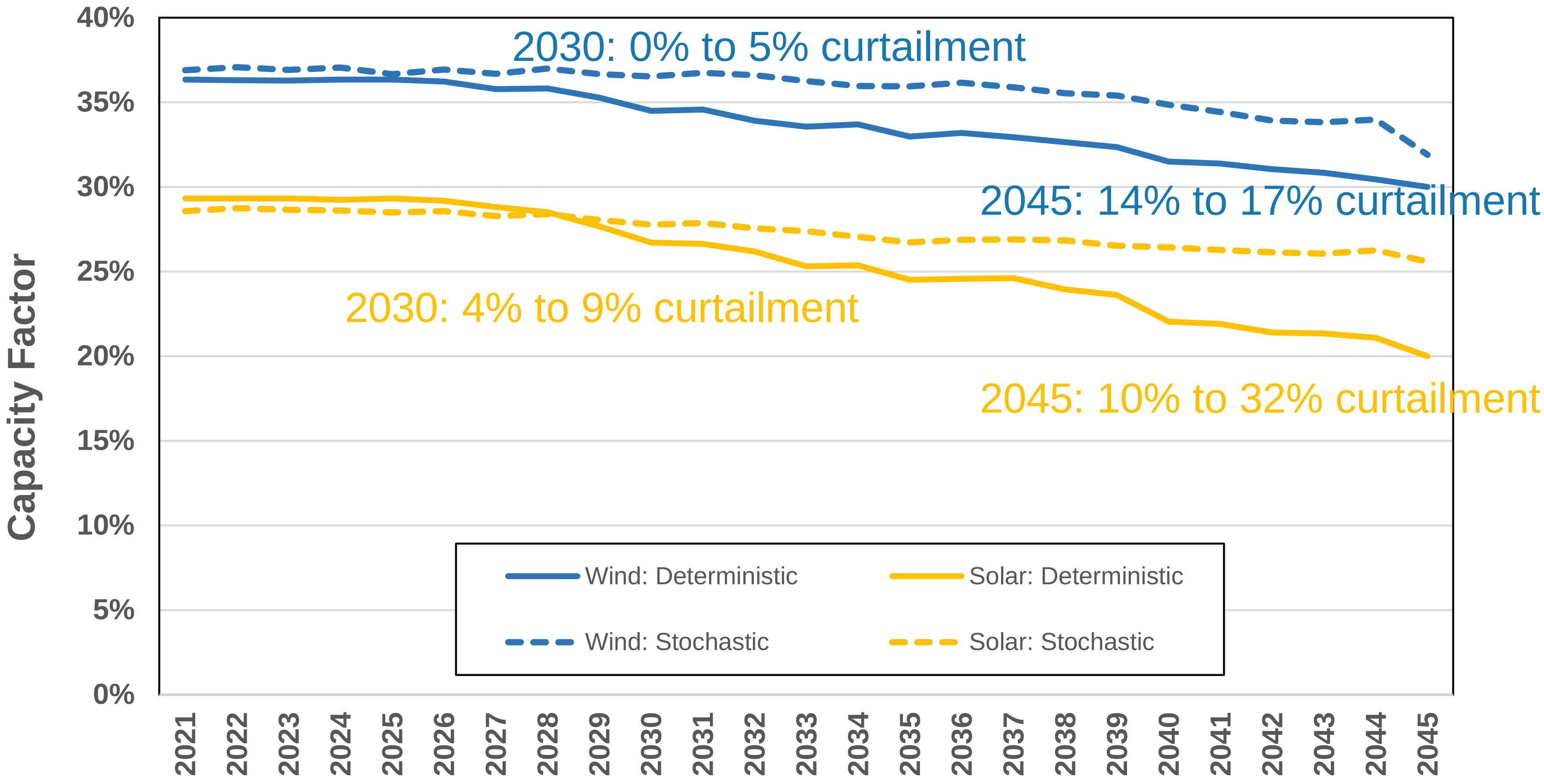
Hourly Price Shape



Renewable Curtailments



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

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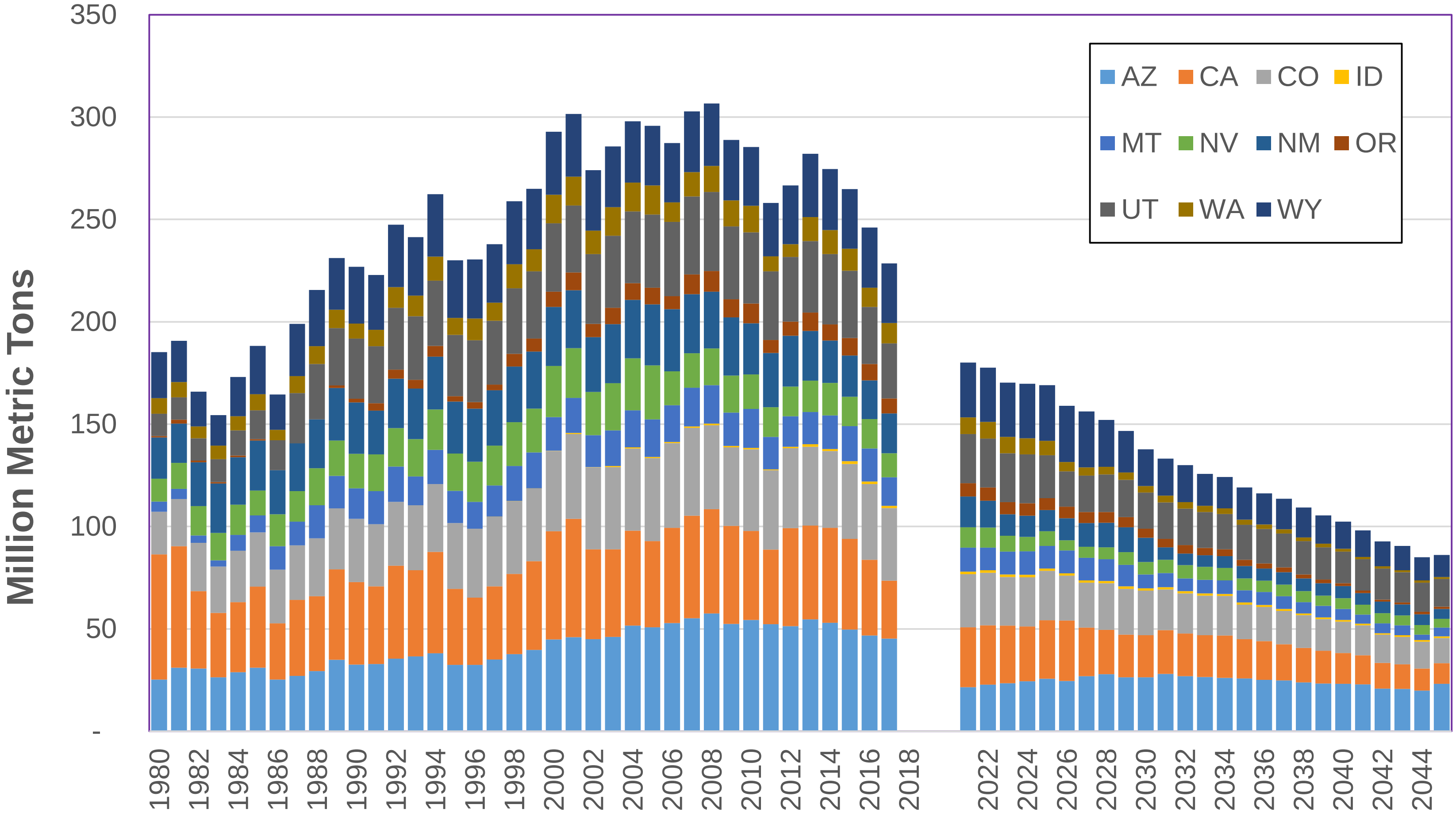
Greenhouse Gas Emissions Forecast
(US Western Interconnect Total)



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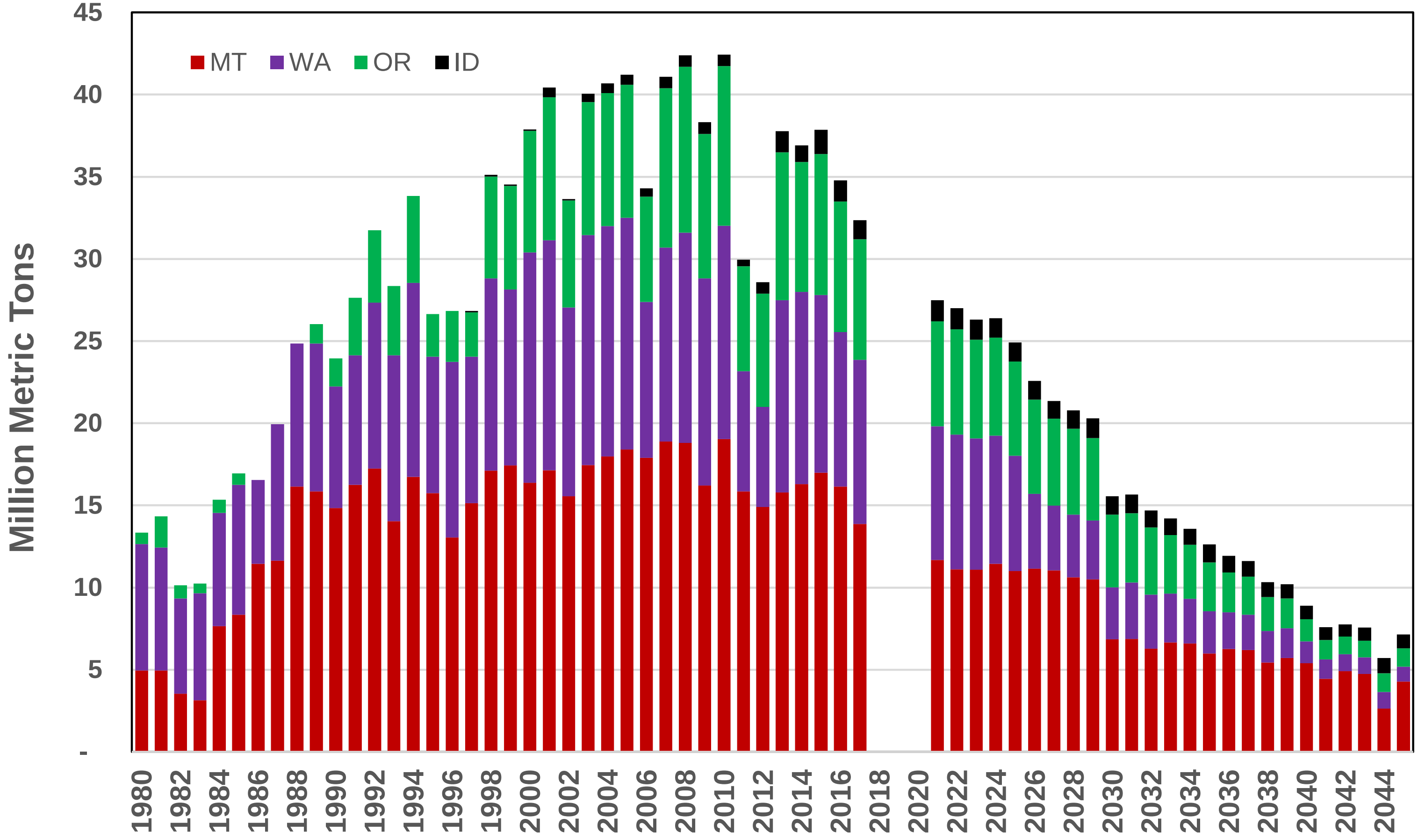
Greenhouse Gas Emissions Forecast

(Northwest- WA,OR,ID,MT)



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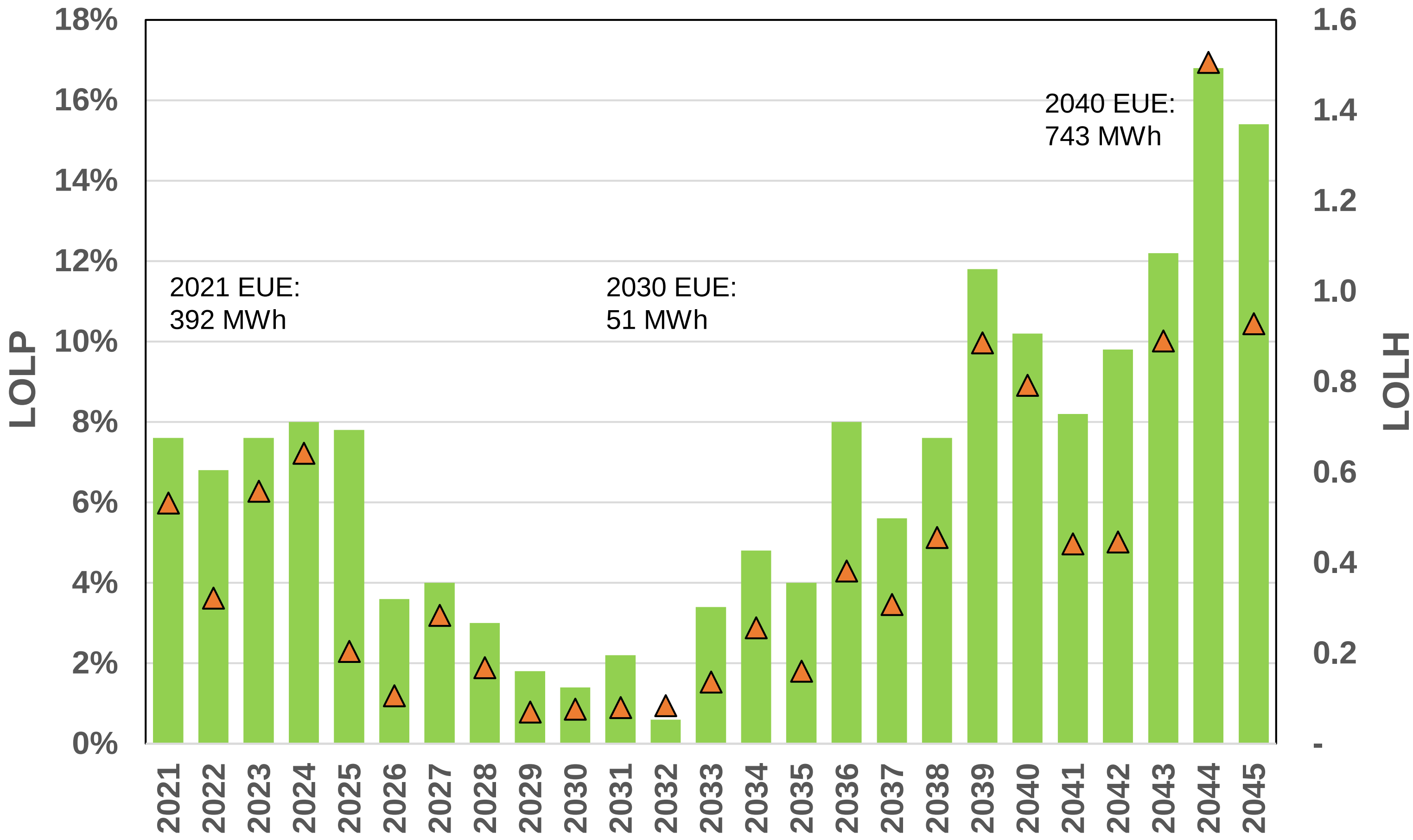
Regional Resource Adequacy

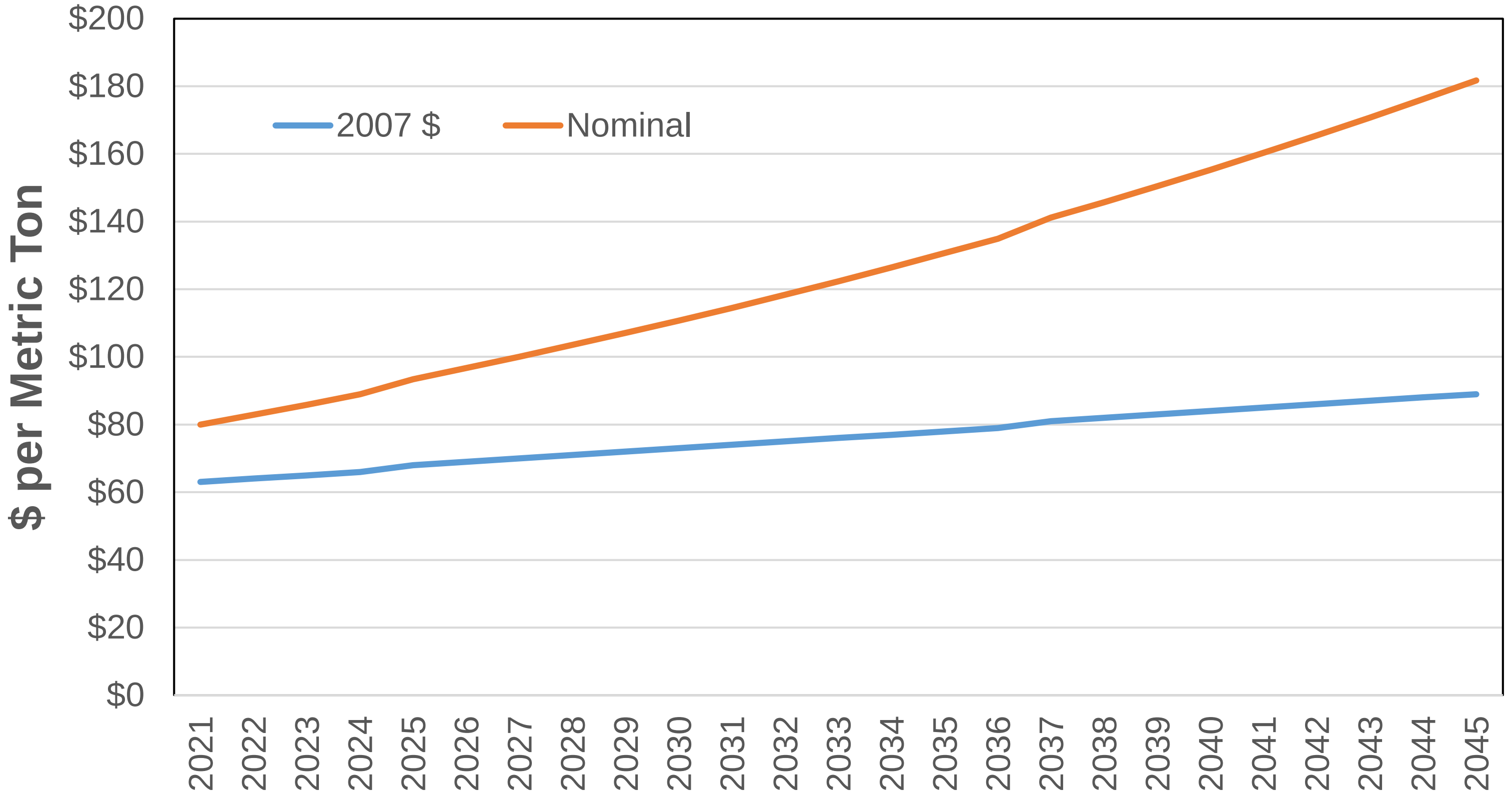


Resource adequacy results are not detailed enough to judge regional resource adequacy and are used for price forecasting only

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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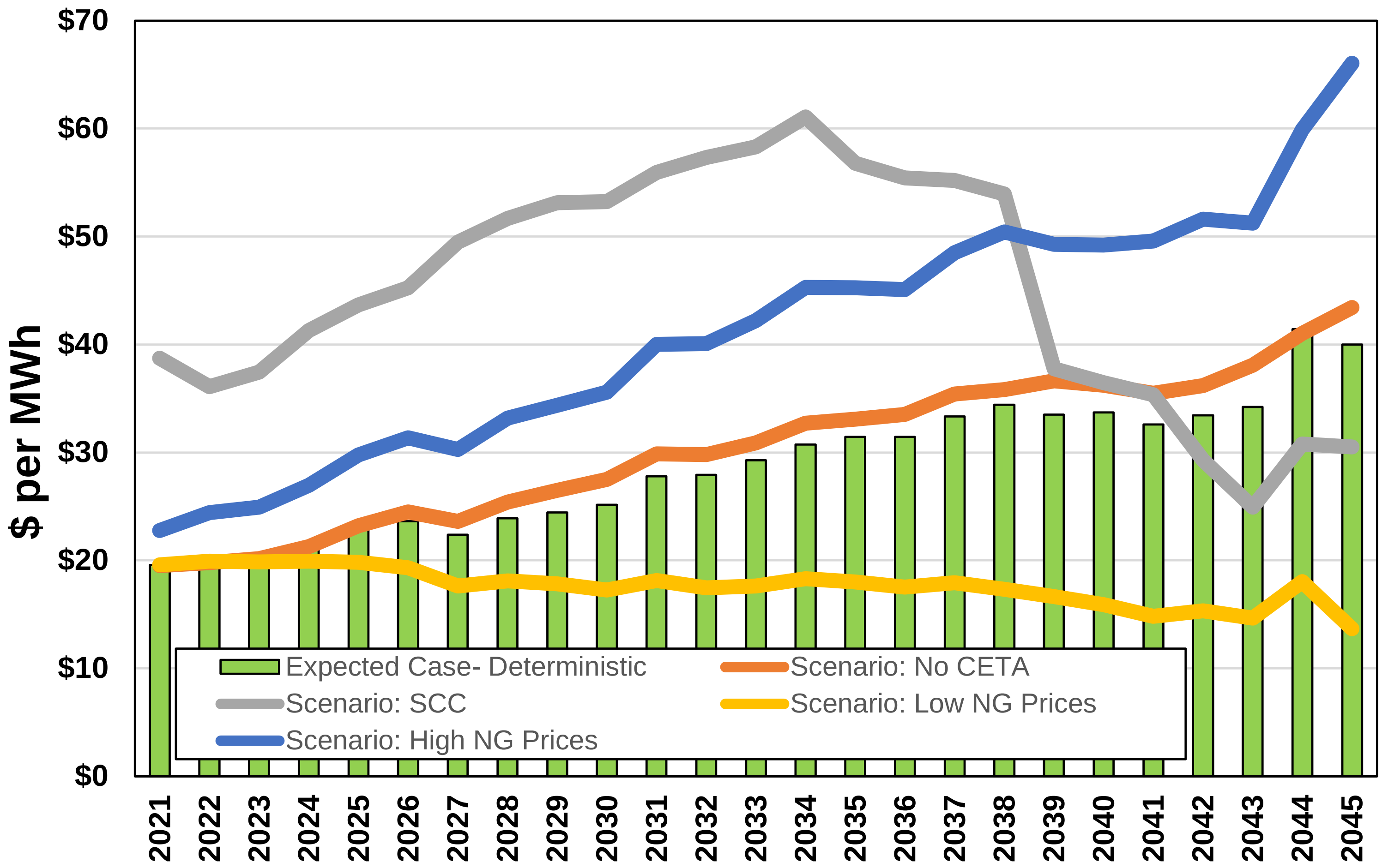
Scenario Price Forecast Results



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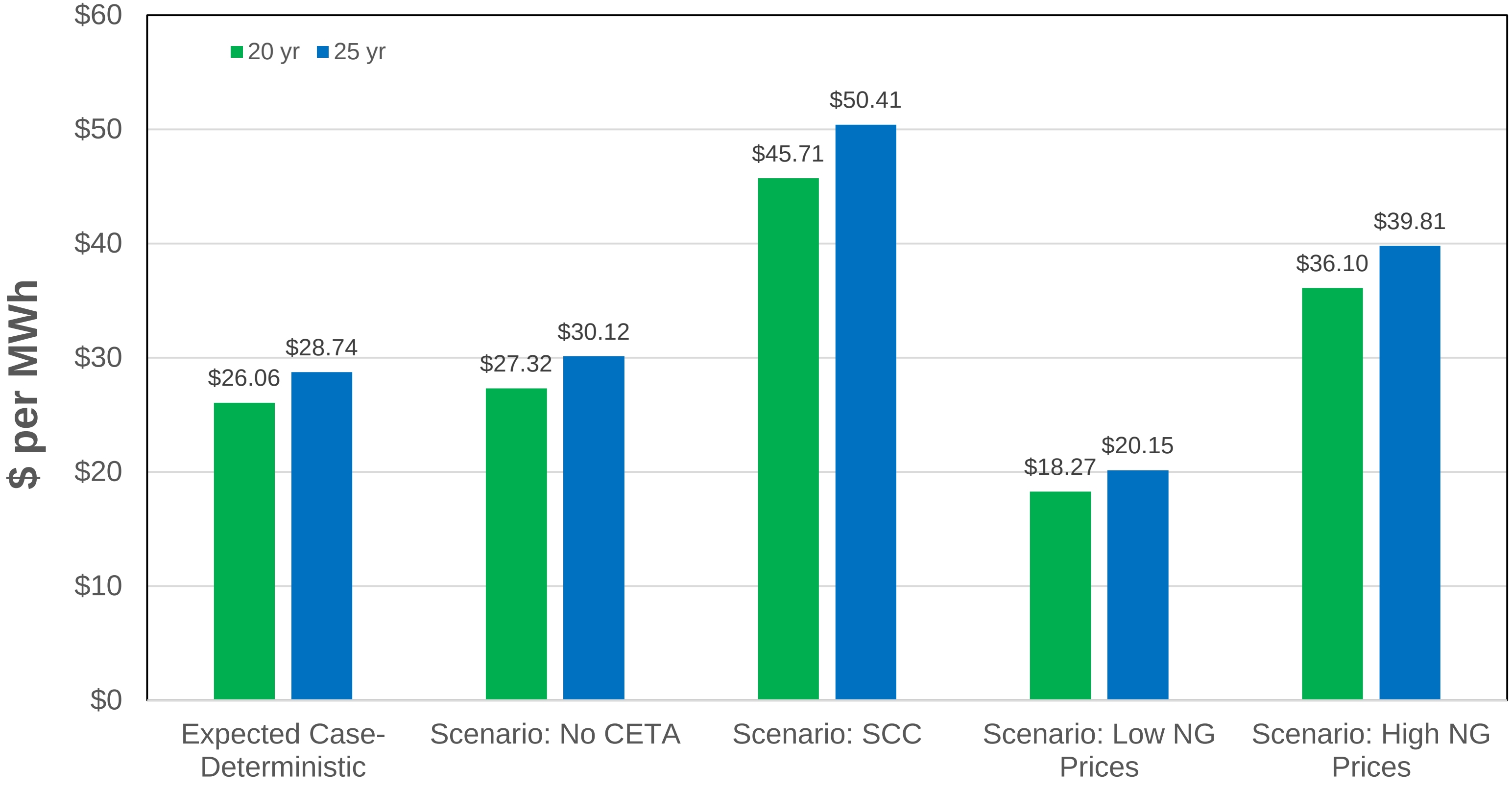
Scenario Levelized Prices



US Western Interconnect Generation Mix Forecast by Scenario (2040)

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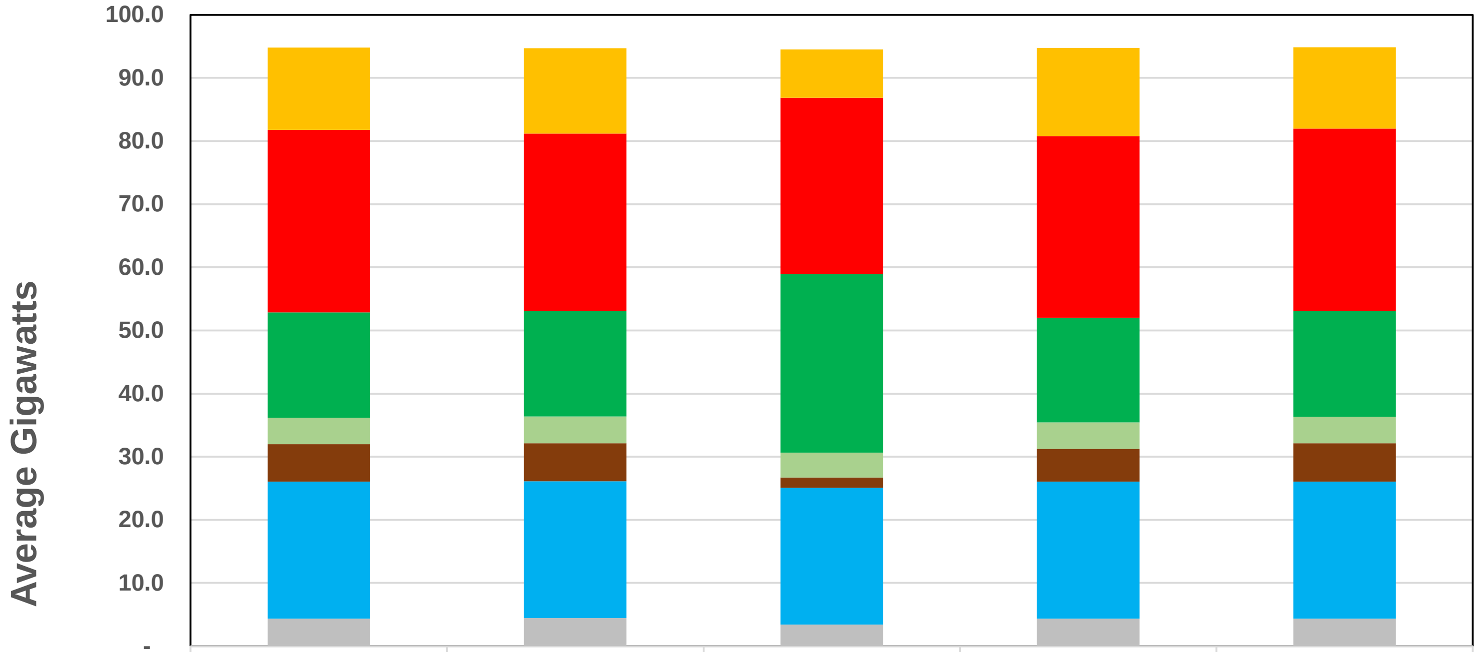
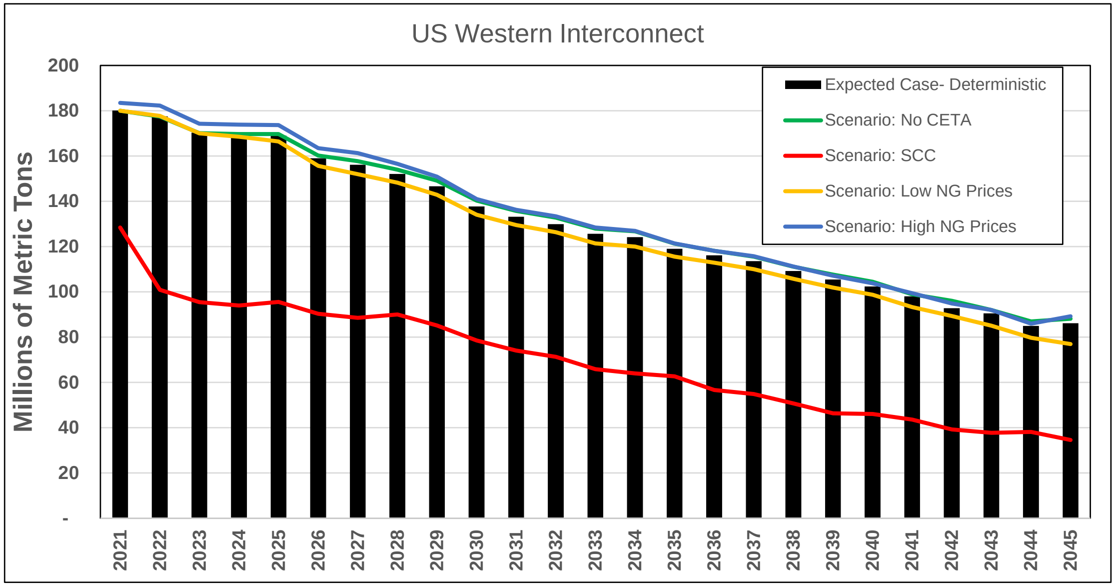
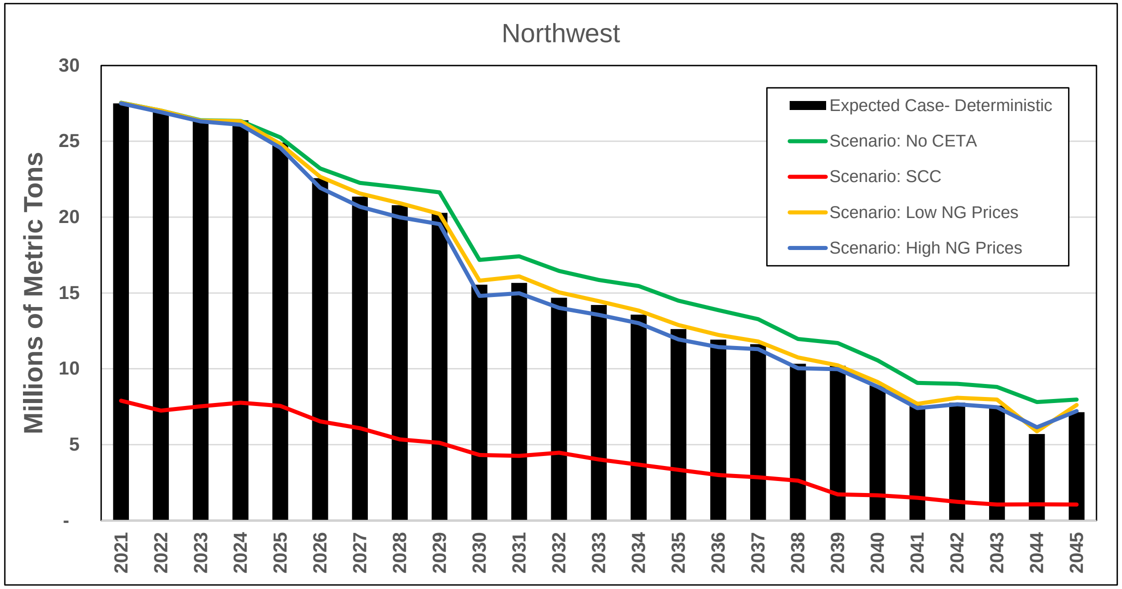


	Expected Case-Deterministic	Scenario: No CETA	Scenario: SCC	Scenario: Low NG Prices	Scenario: High NG Prices
Natural Gas	13.0	13.5	7.7	13.9	12.9
Solar	28.9	28.1	27.9	28.8	28.9
Wind	16.7	16.7	28.3	16.6	16.7
Nuclear	4.2	4.2	4.0	4.2	4.2
Coal	5.9	6.0	1.6	5.2	6.1
Hydro	21.7	21.7	21.7	21.7	21.7
Other	4.4	4.4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

GHG Emission Forecast





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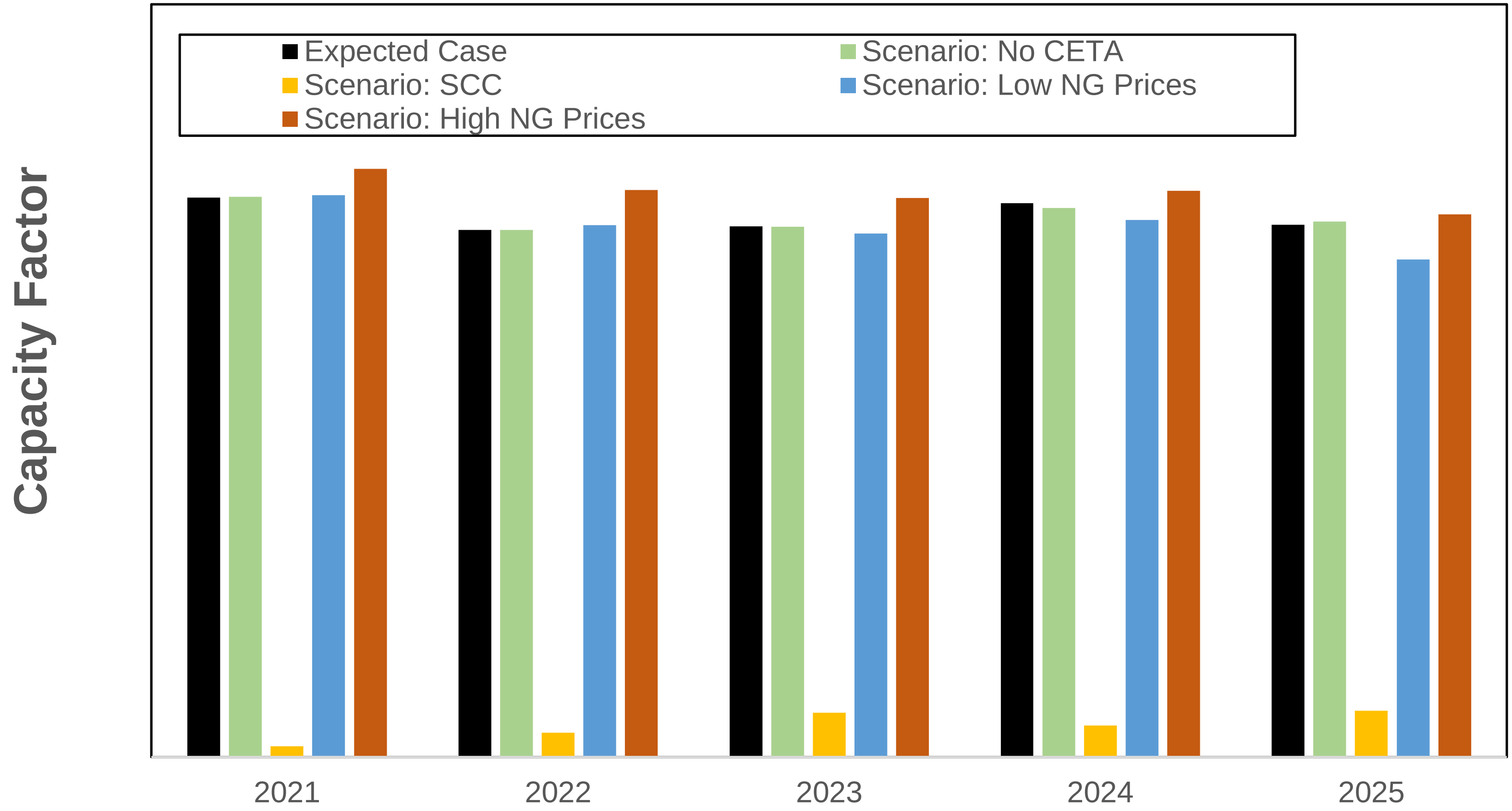
Colstrip Dispatch



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

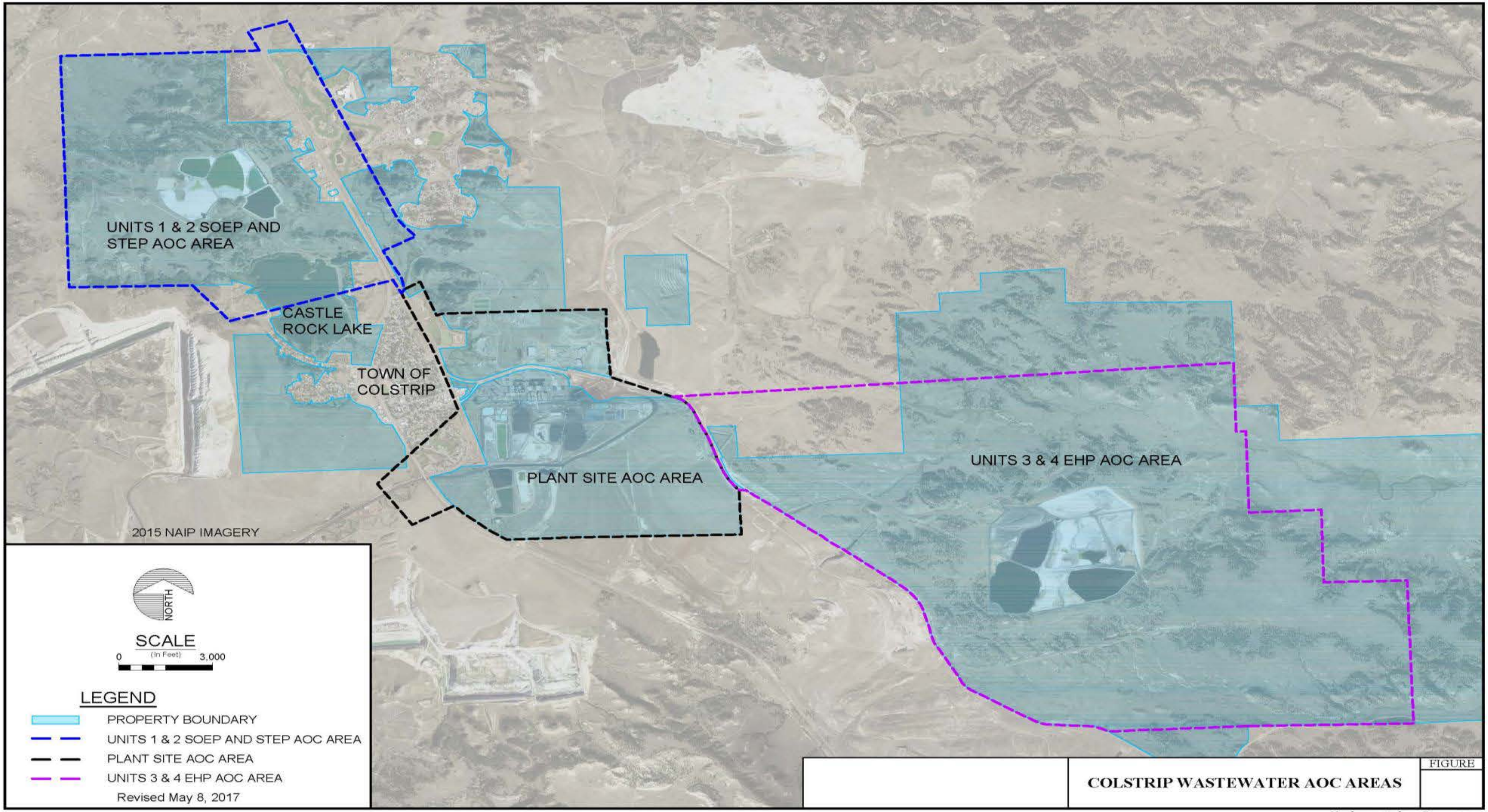
- Raw water is withdrawn from the Yellowstone River to Castle Rock Lake (a.k.a., the Surge Pond) via a 29-mile long pipeline.
- From the Surge Pond, water is piped to holding tanks at the Plant Site for use in boilers, cooling towers and scrubber systems.
- Fly ash from the scrubber system is transported 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)



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Hydrometrics, Inc.
Consulting Scientists and Engineers

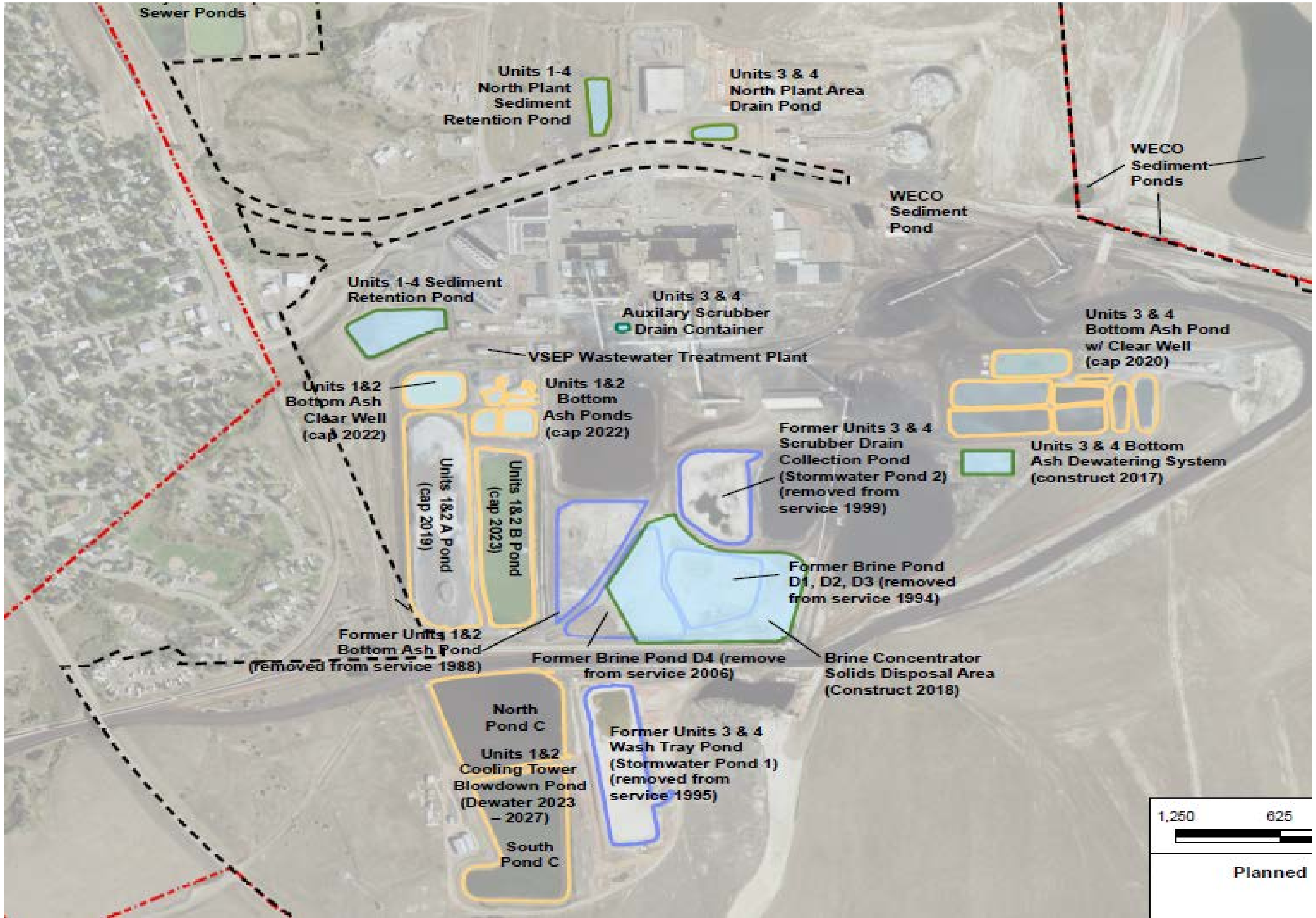
Management Drivers

- 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.

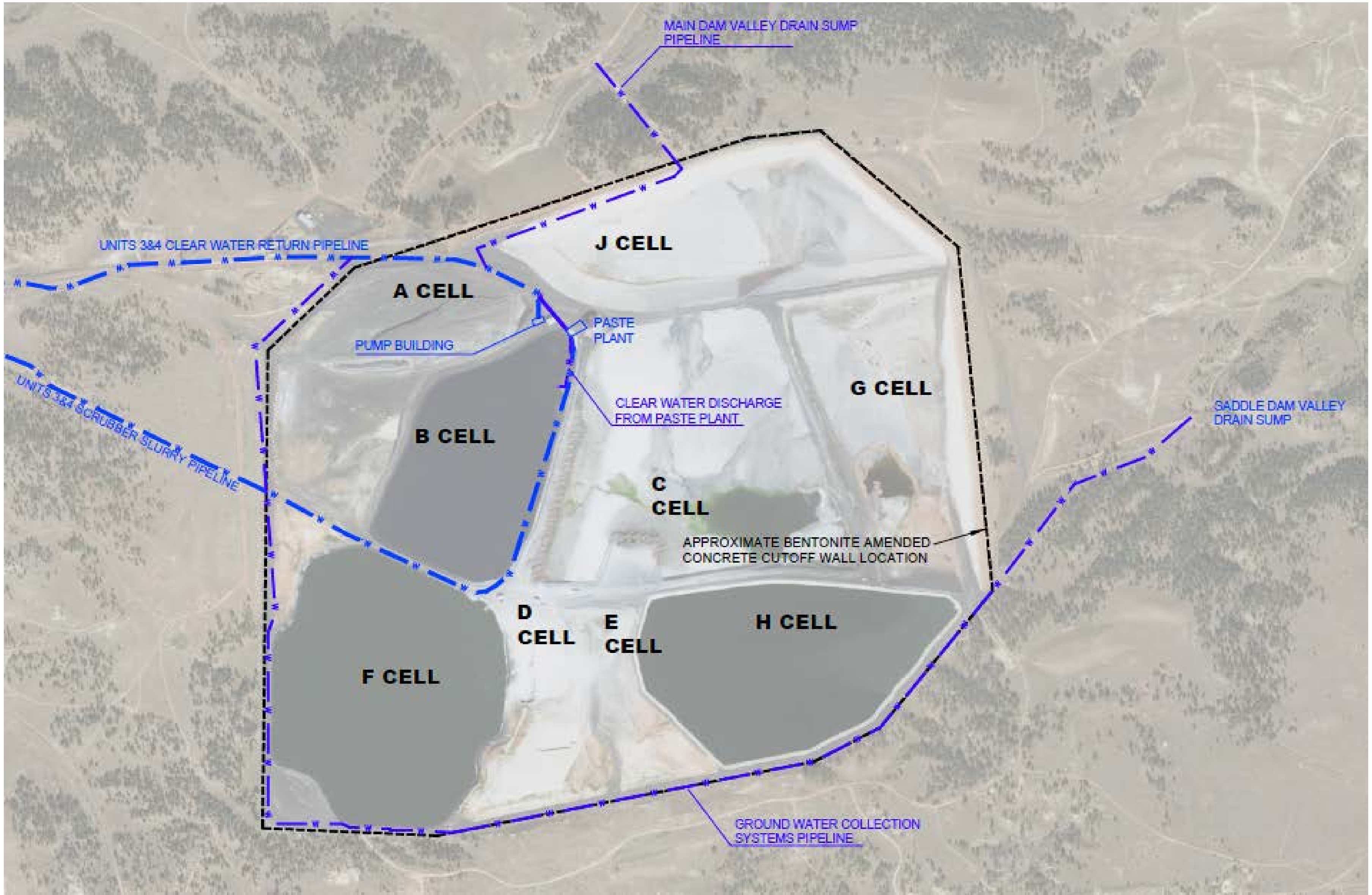
Strategic Water Planning

- 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

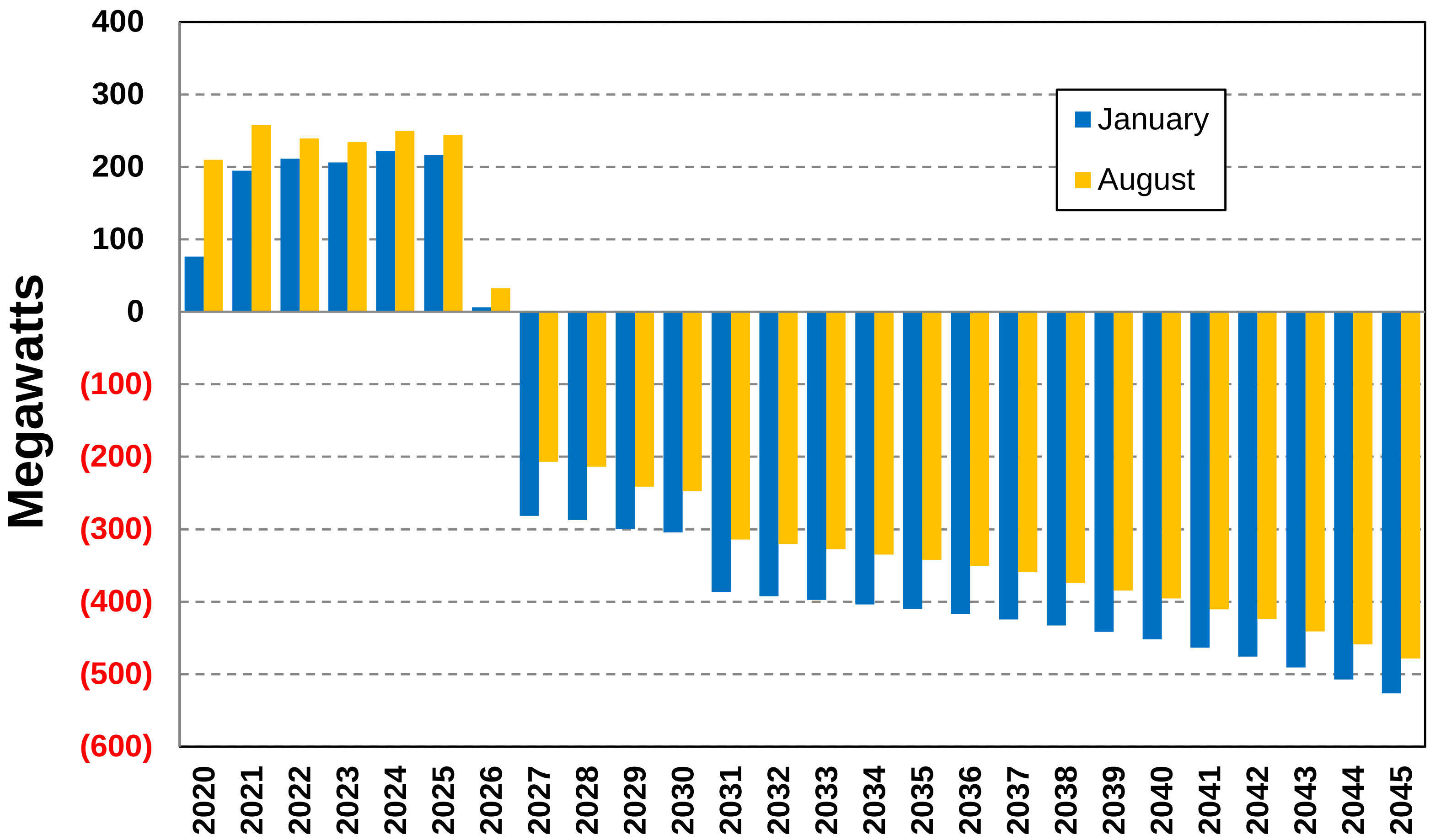
Agenda

- 2020 IRP Load & Resource Balance
- Avista's Clean Energy Goals
- Energy Independence Act Renewable Requirement Forecast
- Clean Energy Transformation Act Forecast

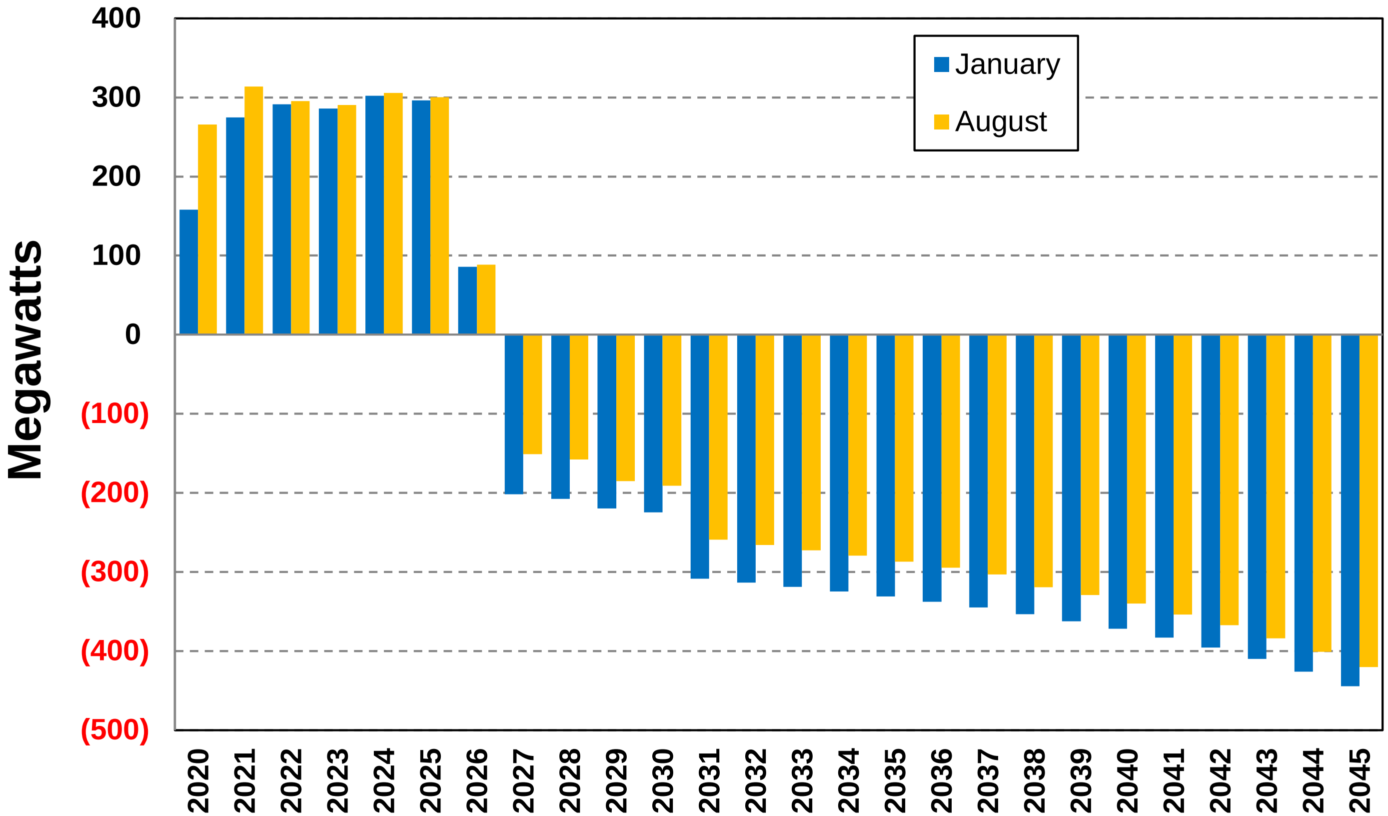
Load & Resource Methodology Review

- 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 10th percentile

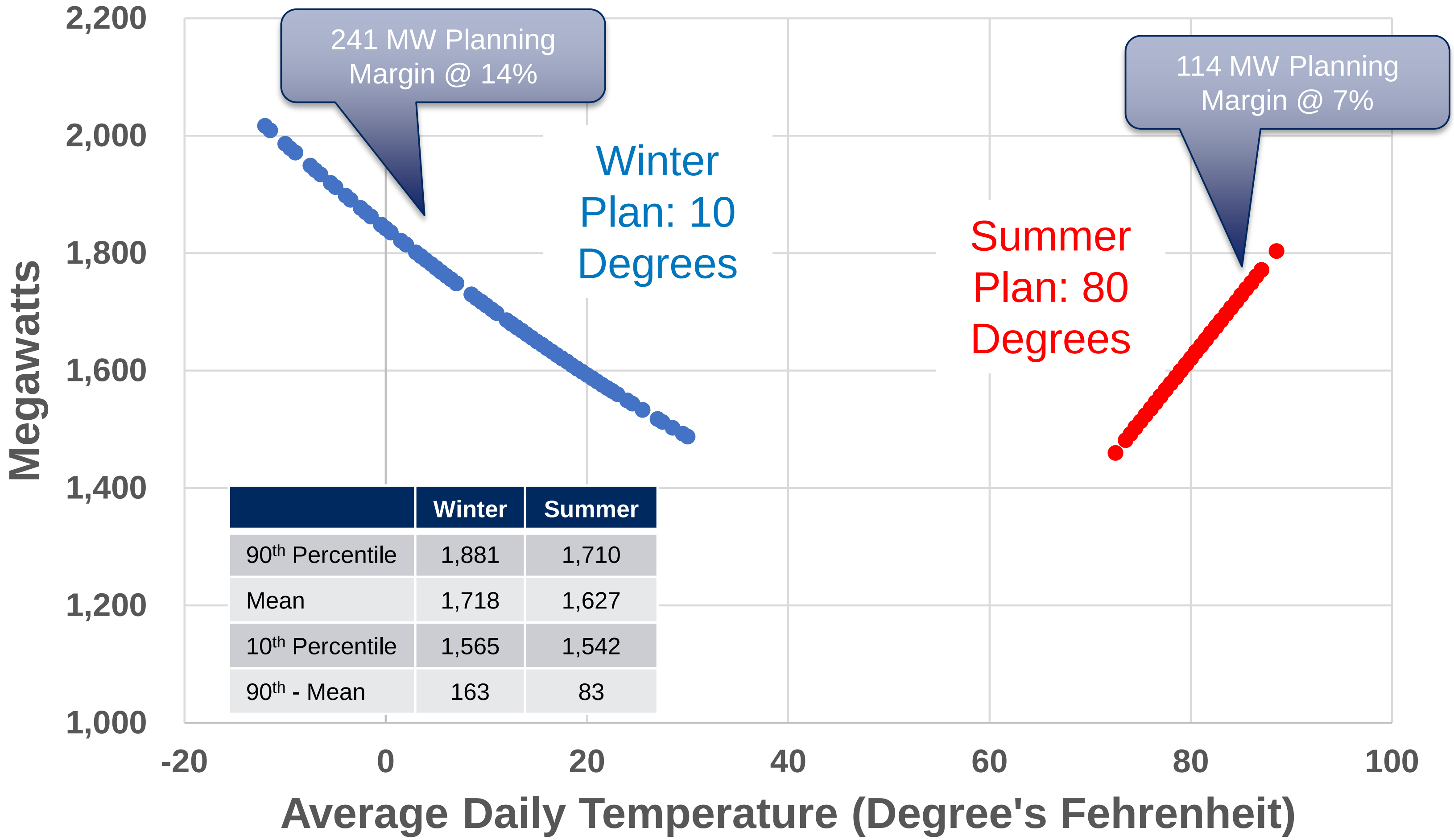
One Hour Peak Load & Resource Position



18-Hour Sustained Peak L&R

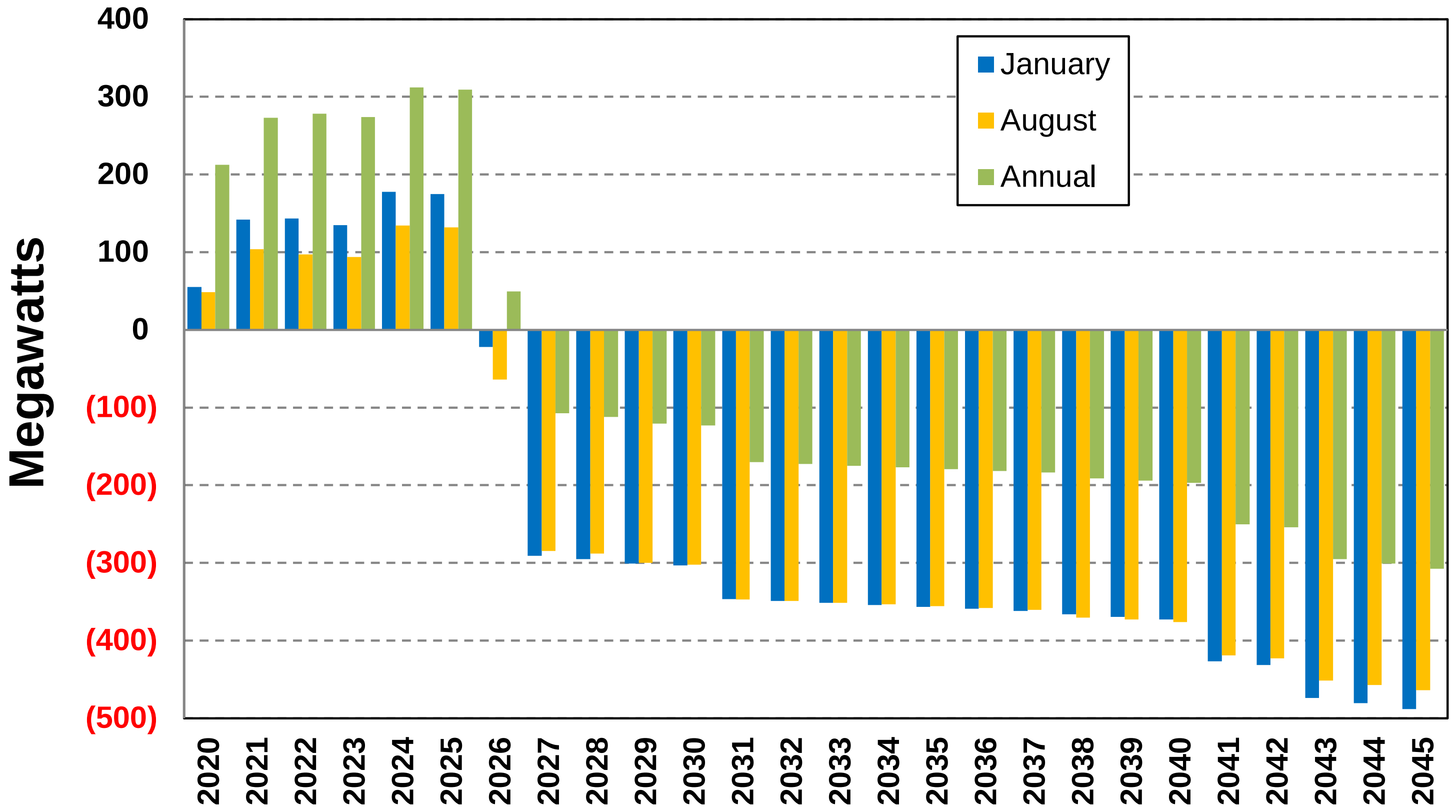


Load Variability (Temperature Variation)



	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

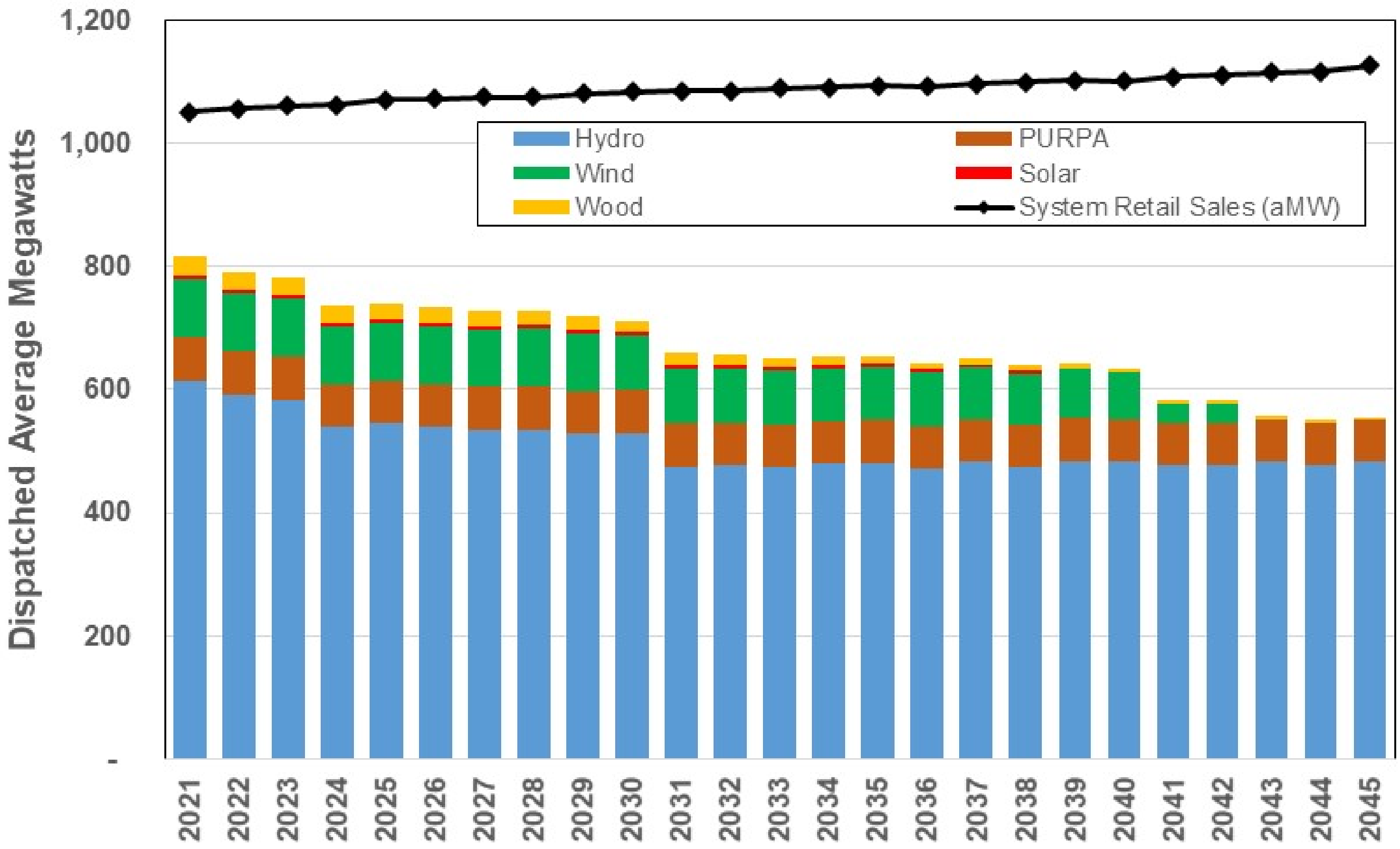
Goals

- 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

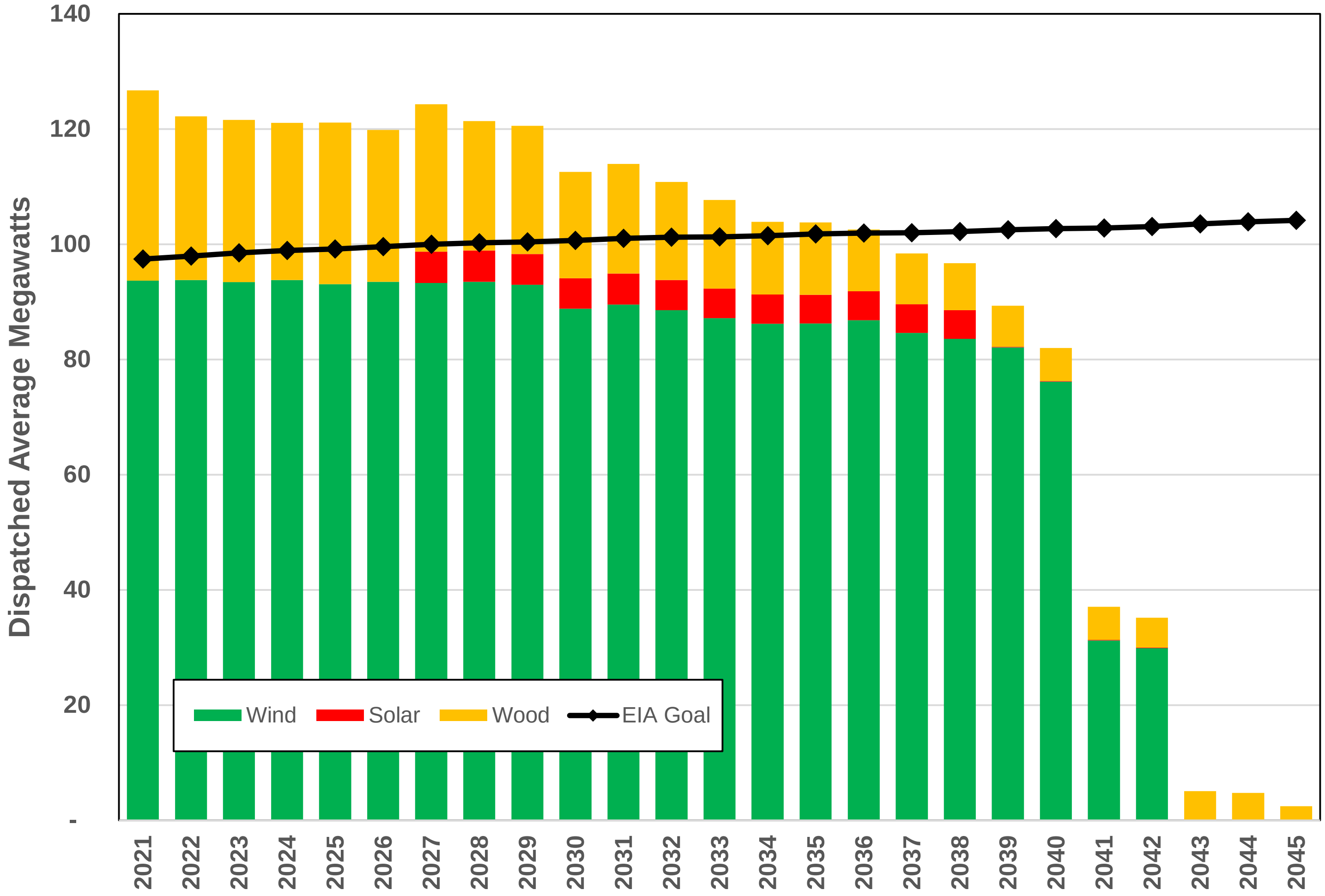


Washington State Clean Energy Goals

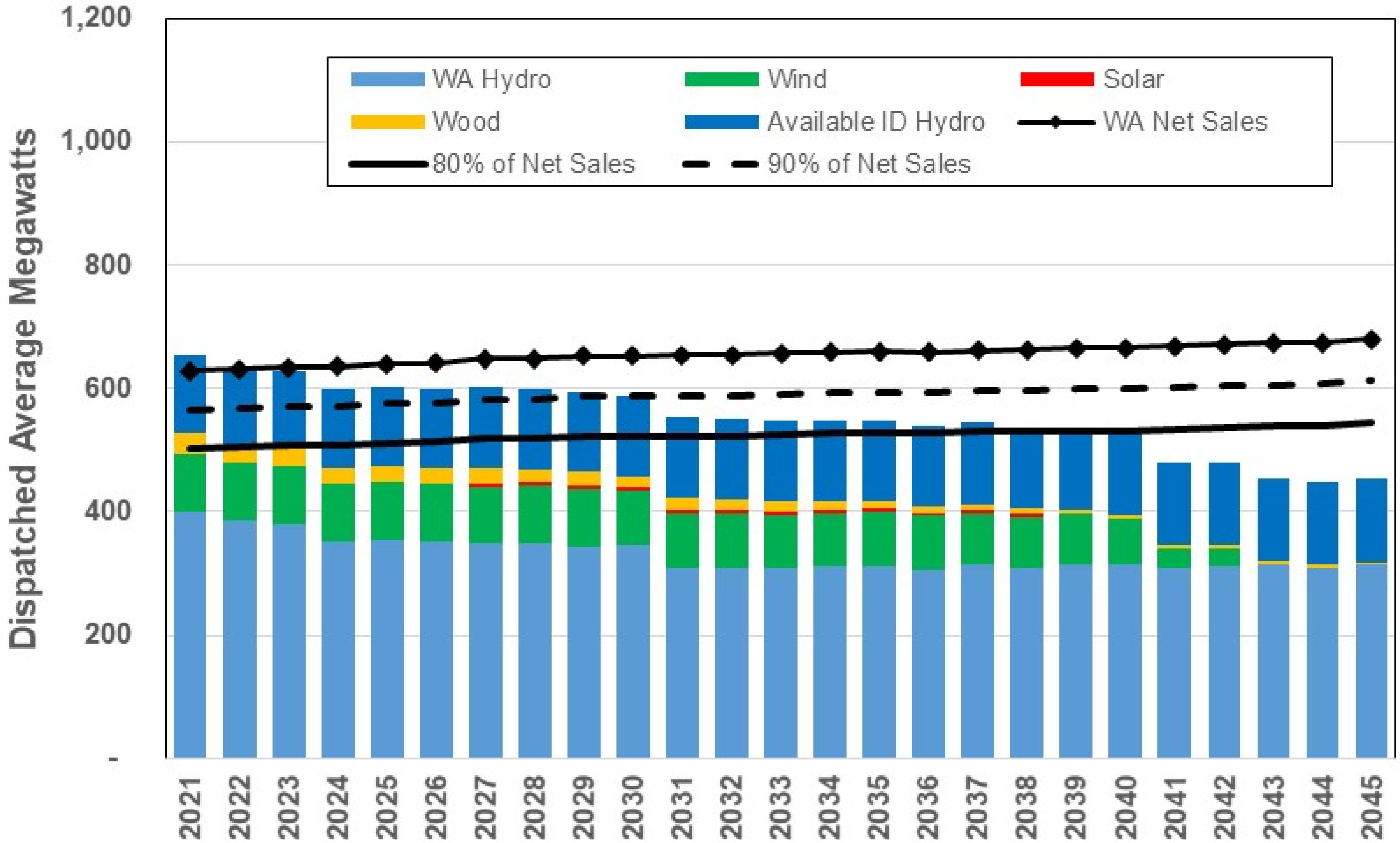
- Energy Independence Act or Initiative 937
  - 15% of Washington retail load after 2020
  - Qualifying resources less any forward sales obligations
  - Banking provisions mitigate year-to-year variation
  - Addition of qualifying BPA and Wanapum, which are not included in the chart. Will update when amounts are known.

- Clean Energy Transformation Act

Washington Energy Independence Act



Avista's Washington CETA Goals



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

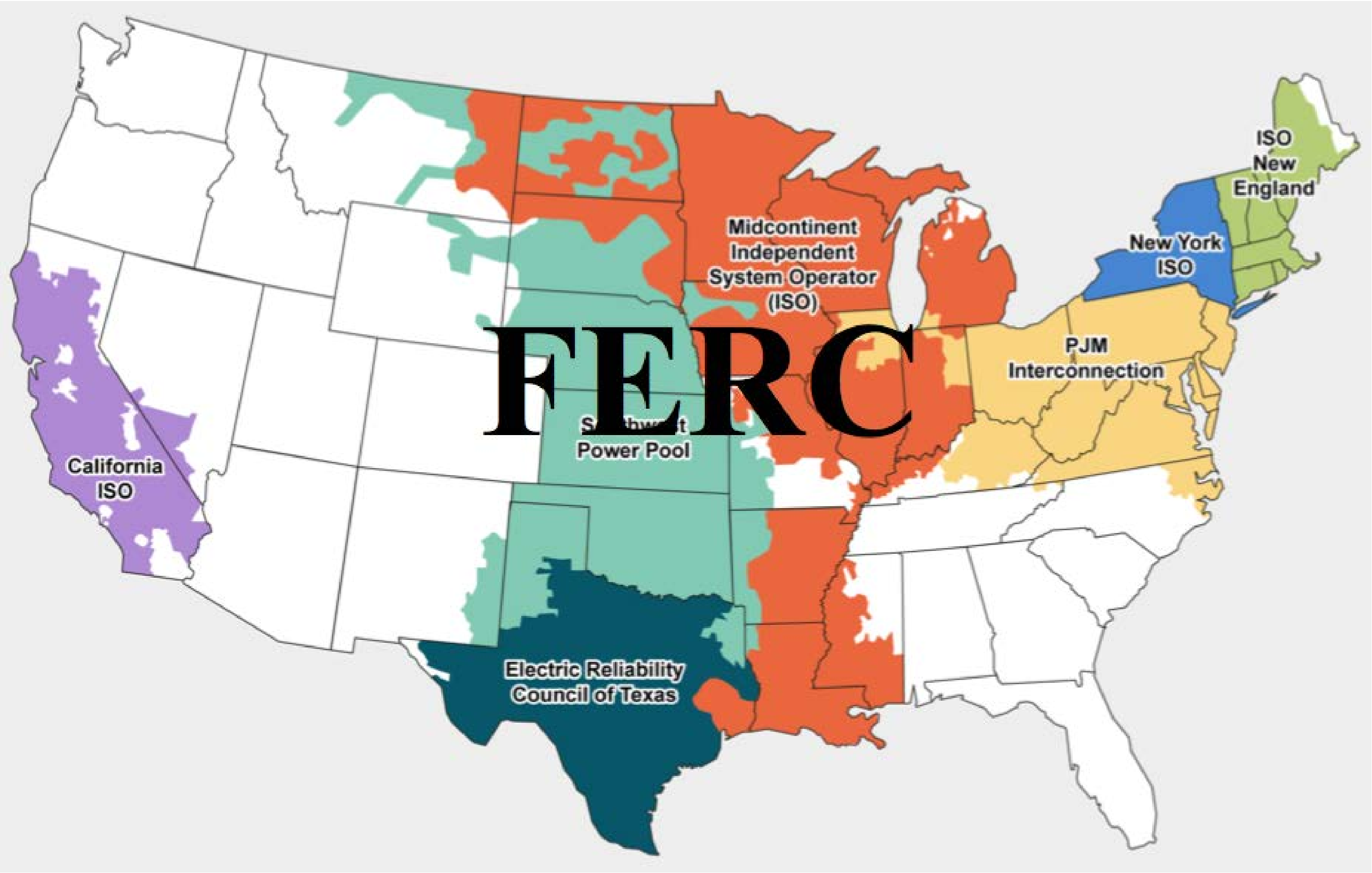
2020 Electric IRP
Energy Imbalance Market Update

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

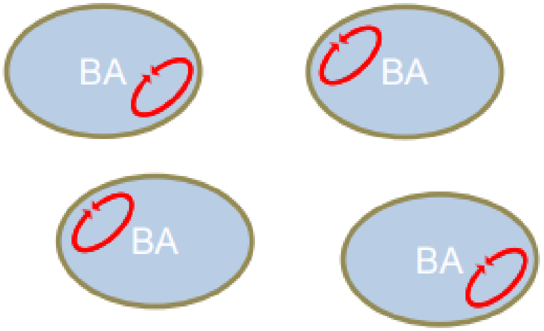
- The California Independent System Operator (CAISO) runs a full organized energy market in California
- Based in Folsom, CA, operational since 1998
- Utilities maintain ownership of generation and transmission assets
- CAISO ensures sufficient resources to meet CA load
  - Balancing Authority for members
  - 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

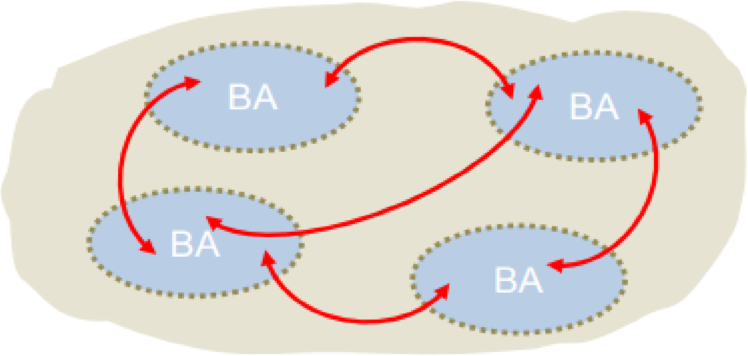
Why EIM?

Prior to EIM:
Each BA must balance loads and resources w/in its borders.



- Limited pool of balancing resources
- Inflexibility
- High levels of reserves
- Economic inefficiencies
- Increased costs to integrate wind/solar

In an EIM:
The market dispatches resources across BAs to balance energy

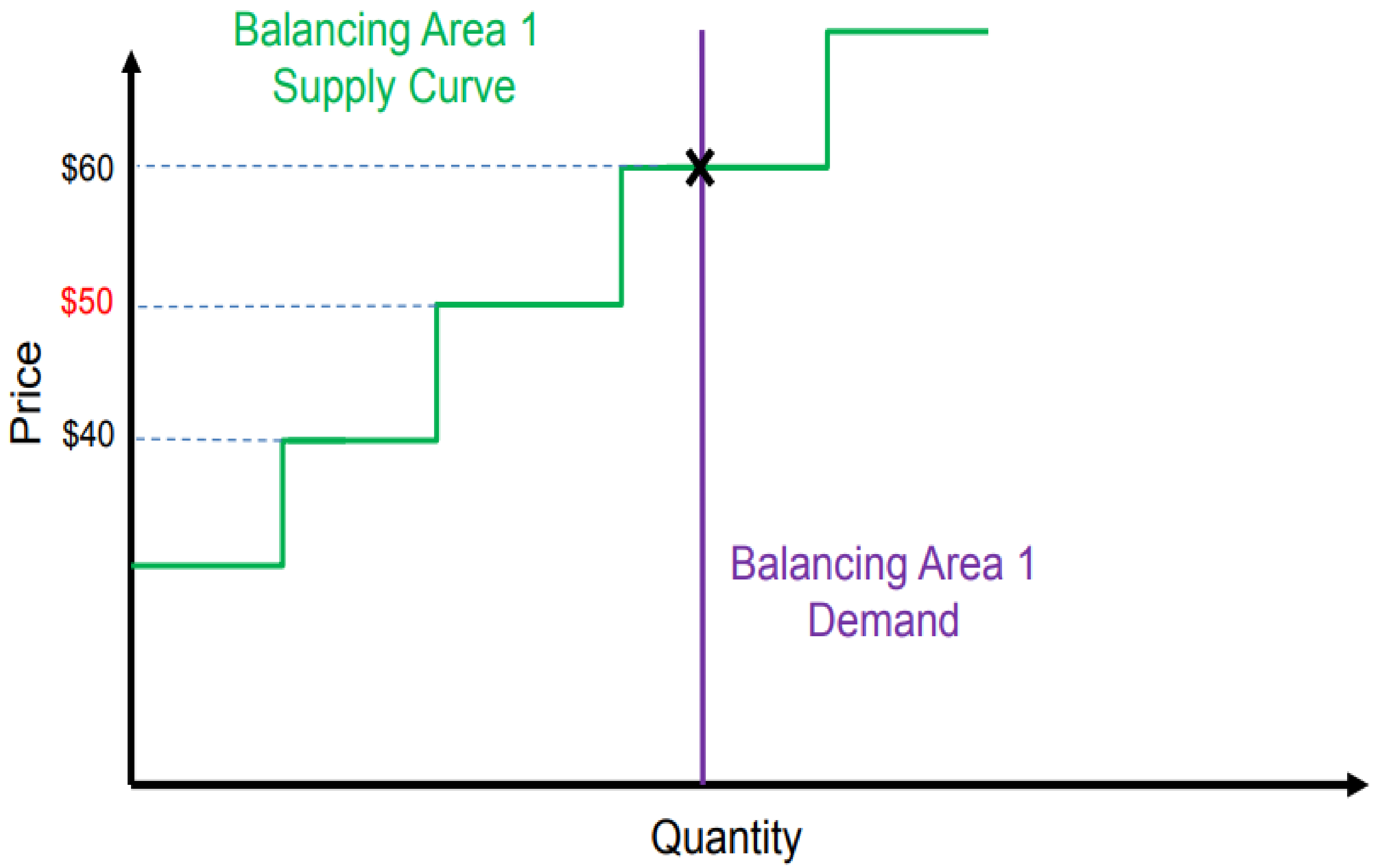


- Diversity of balancing resources
- Increased flexibility
- Decreased flexible reserves
- More economically efficient
- Decreased integration costs

How the EIM Works

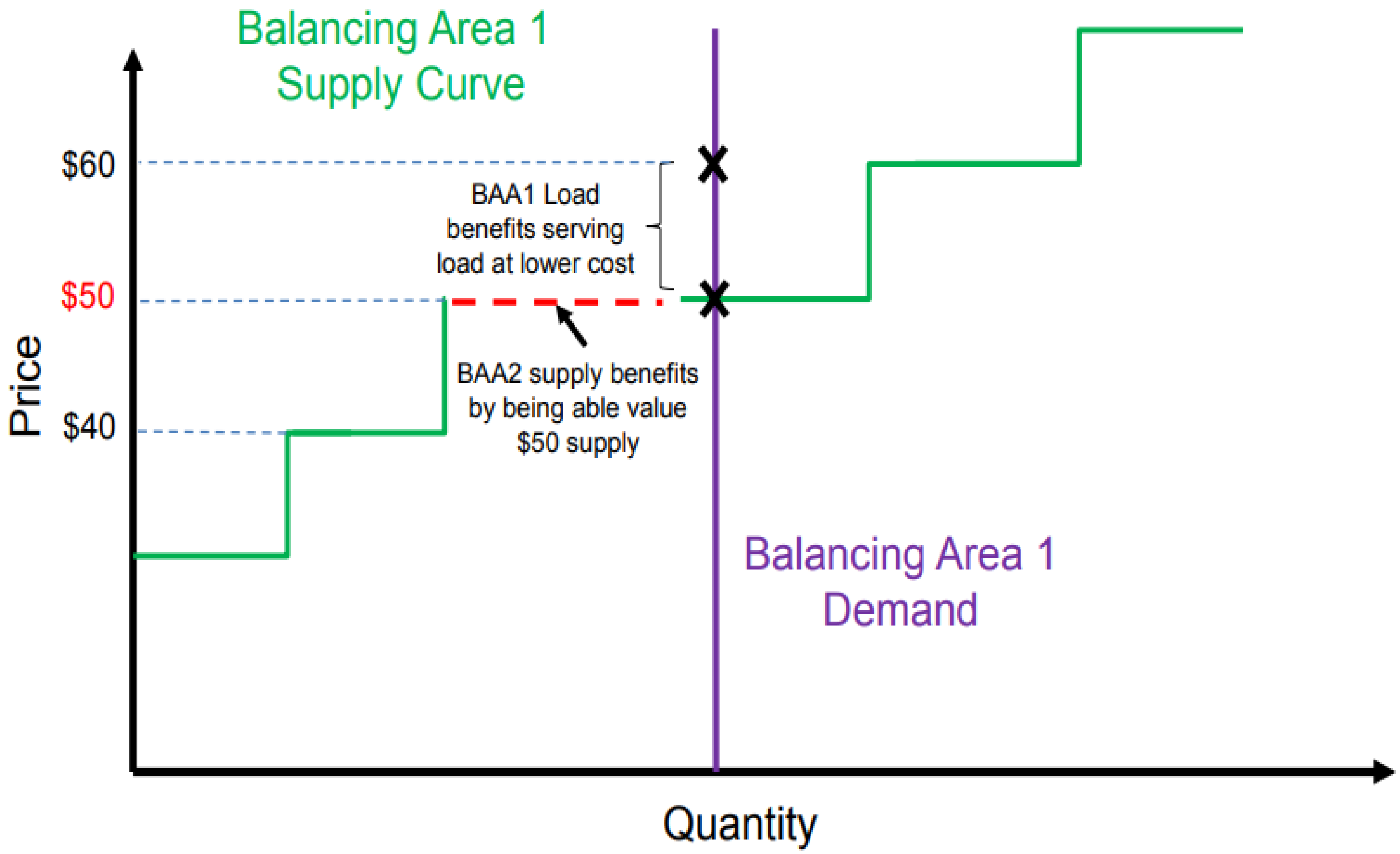
- Participants must show they can meet load obligations prior to the operating hour, no leaning on the market
- Participants voluntarily submit resource availability, min/max, ramp rates and price curves
- CAISO runs a security constraint (i.e. transmission) economic dispatch every 5 minutes to obtain 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



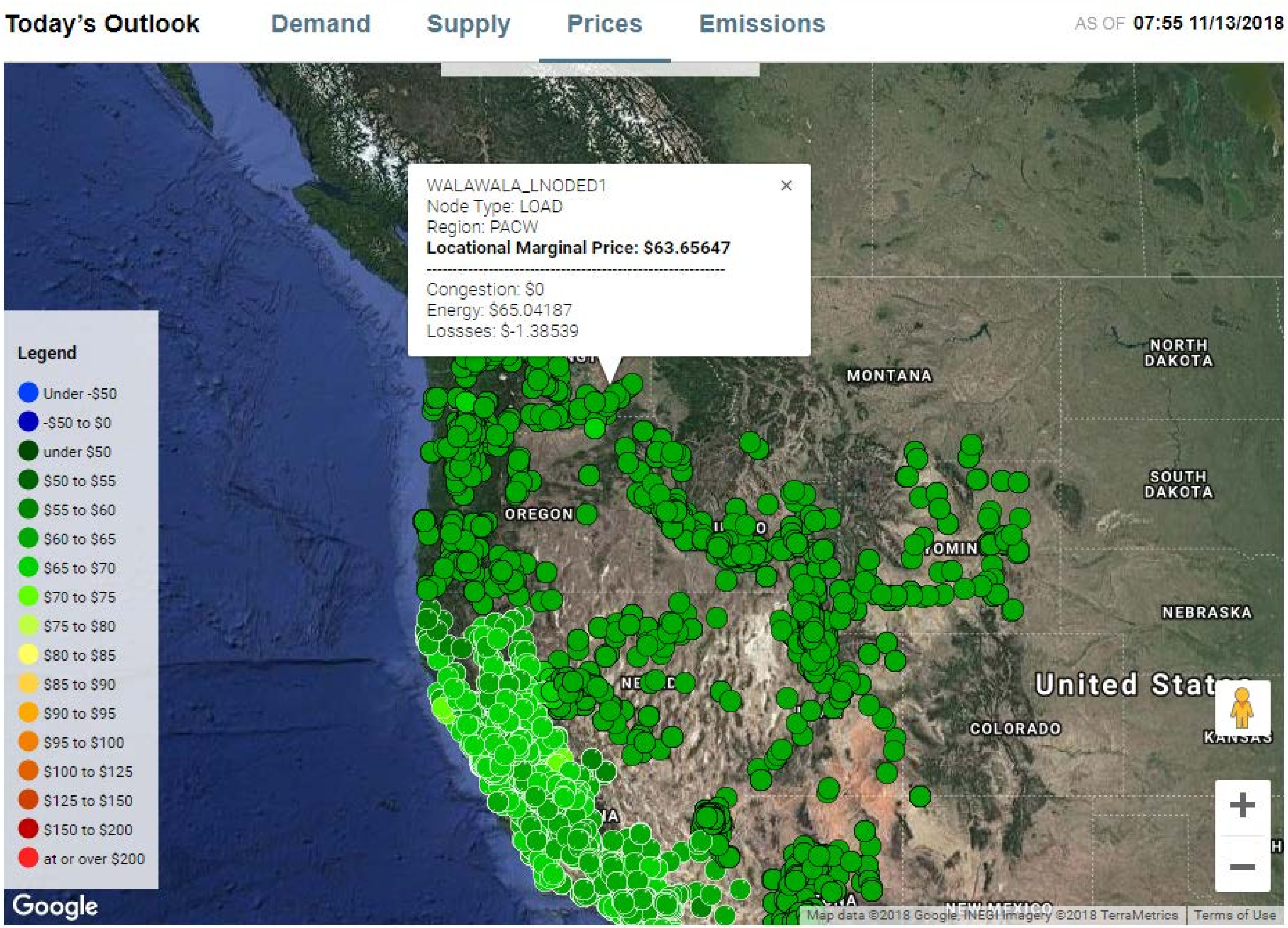
$50 supply from balancing area 2 displaces $60 supply in balancing area 1

EIM Supply Transfers Benefit Both Areas

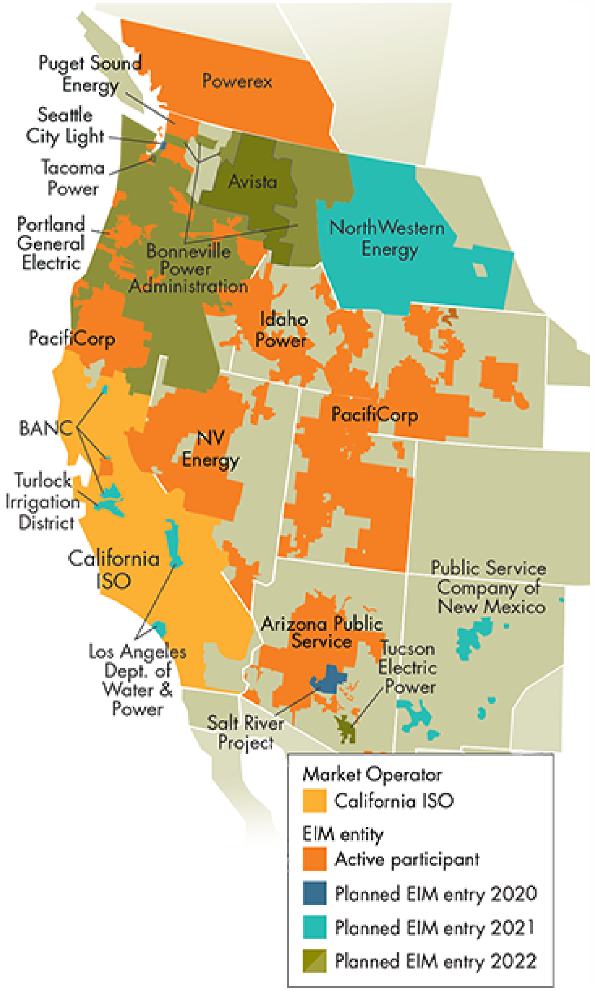


$50 supply from balancing area 2 displaces $60 supply in balancing area 1

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

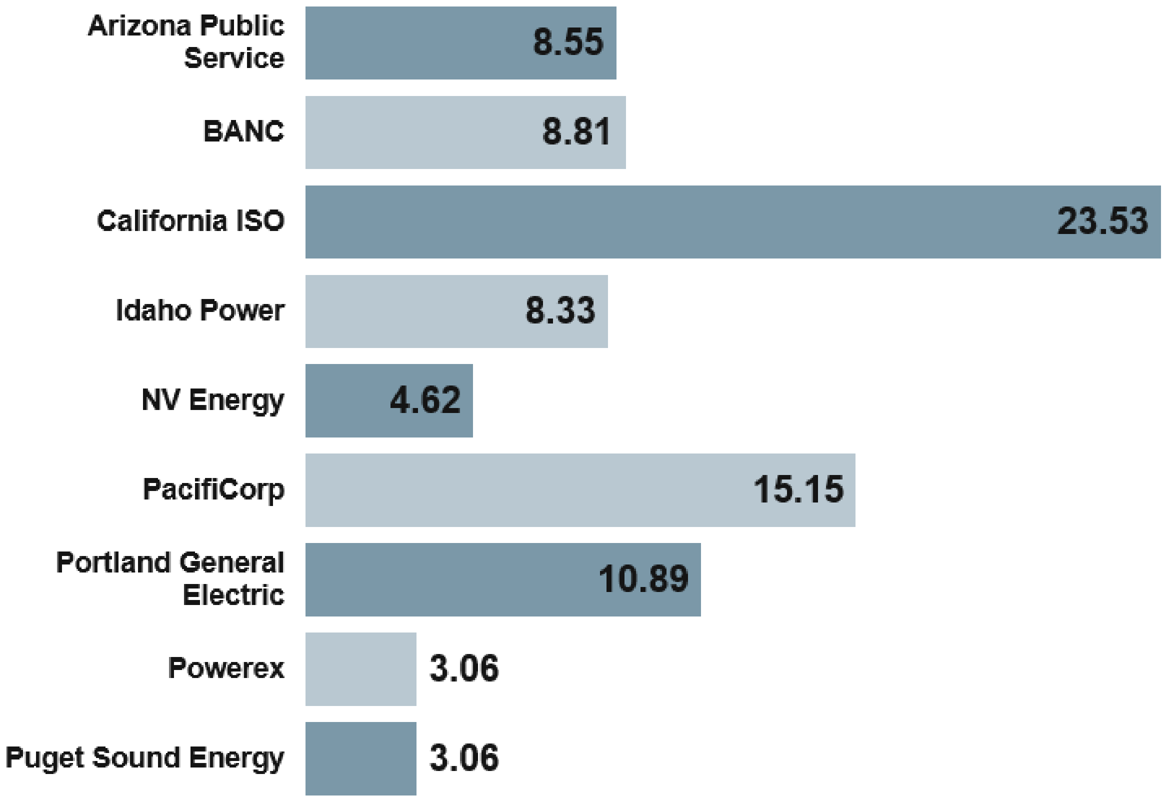
EIM Gross Benefits

$86m savings in Q2 2019

Read full report >>   Read news release >>

TOTAL **$736.26m**
gross benefits since Nov 2014

(millions $)



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

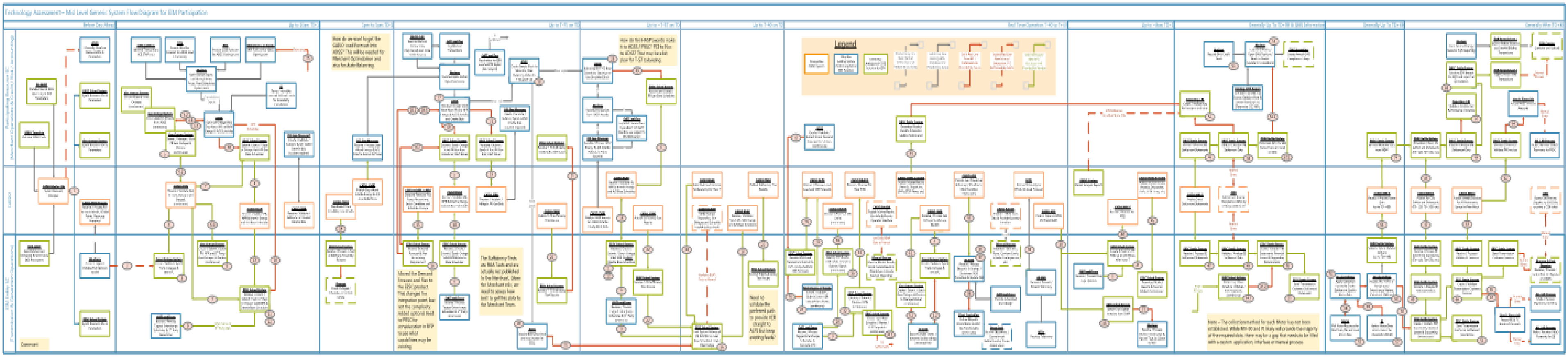
- Estimated EIM costs
  - $21 – 26 M start-up
  - $3.5 – 4.0 M on-going
- Anticipate 12+ new FTE for on-going support
- Estimated annual benefits
  - Full range $ 2 – 12 M
  - Expected range $3.5 - 9.2 M
  - Base $5.8 M

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


Technology Assessment – Mid-Level Generic System Flow Diagram for EIM Participation

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

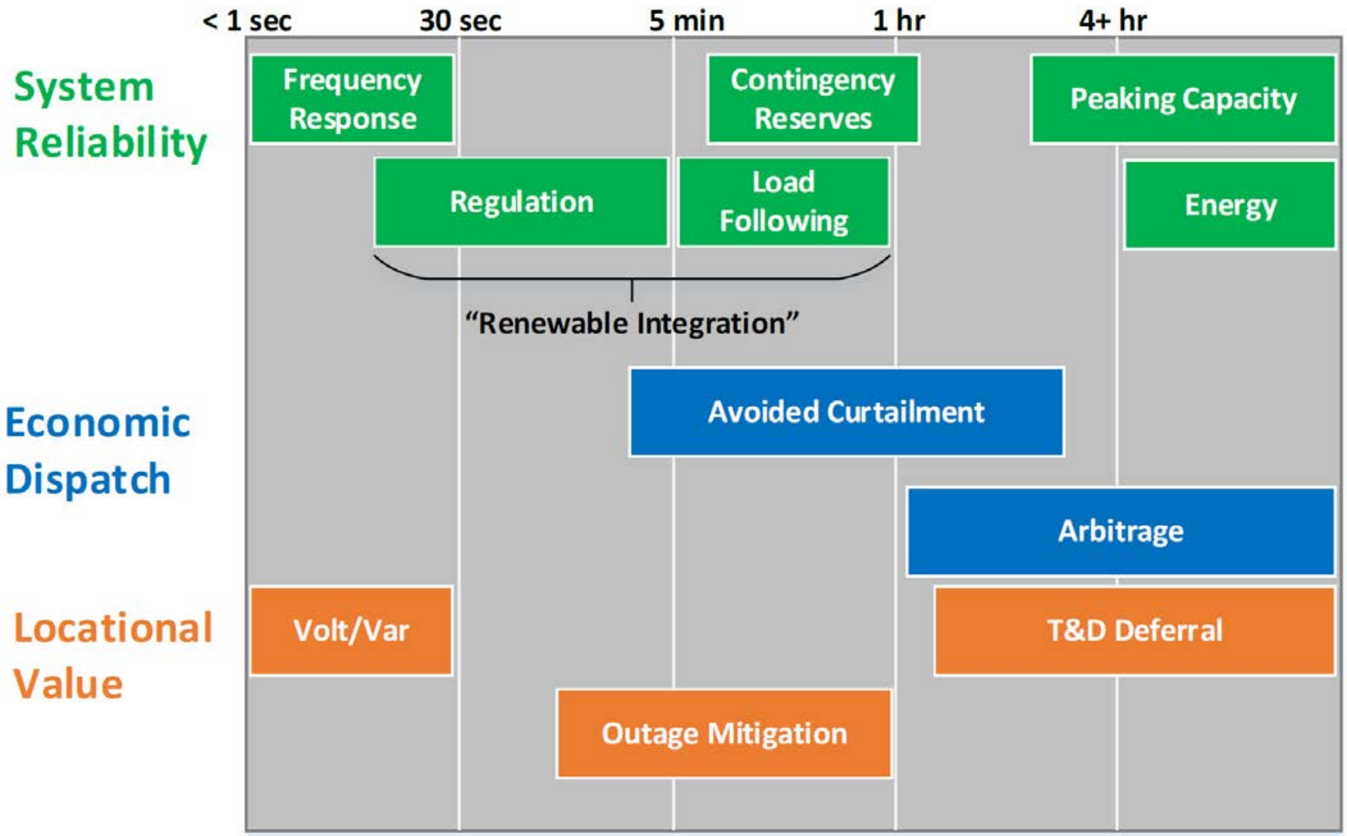


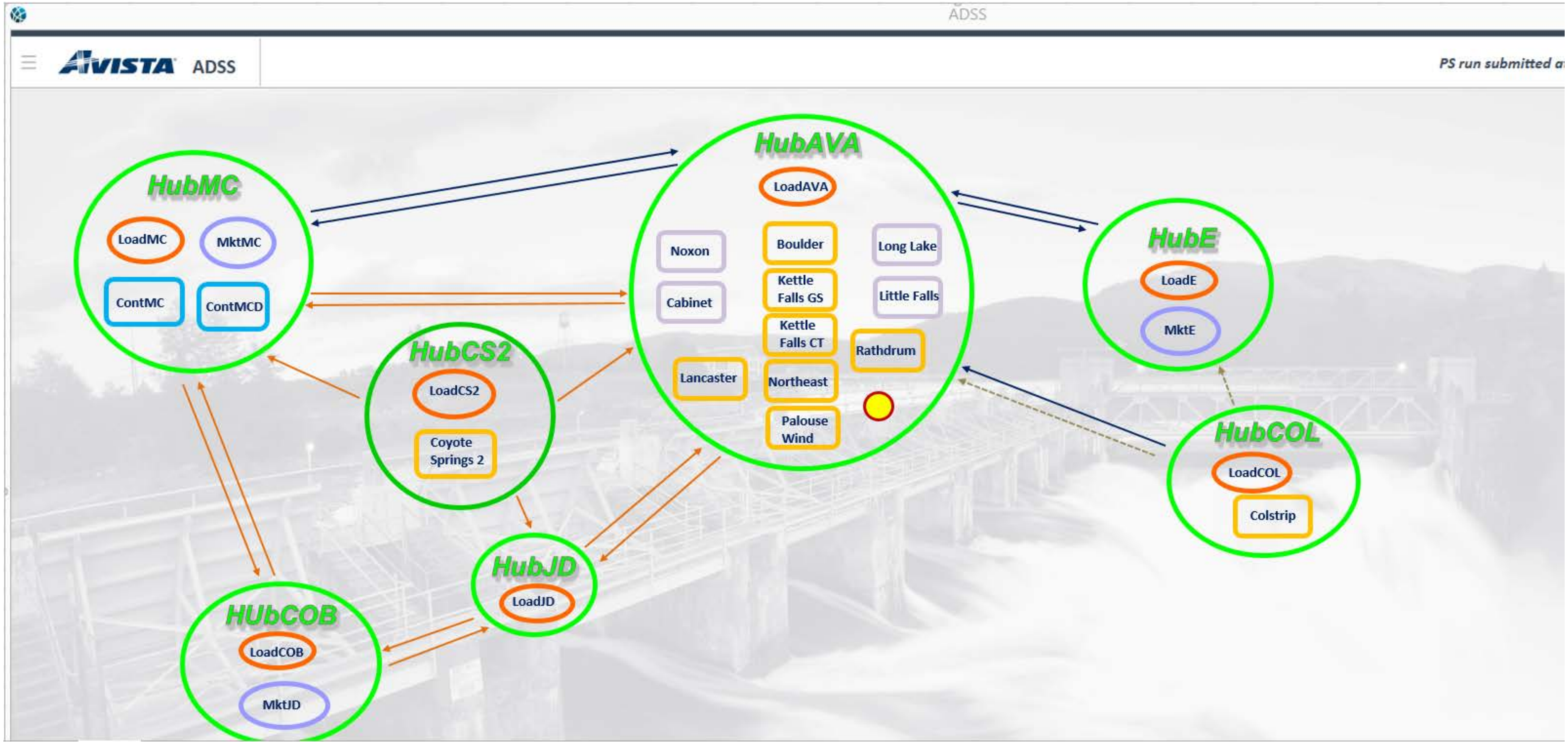
Figure 1: Key value streams within the power system and their associated timescales of action.

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

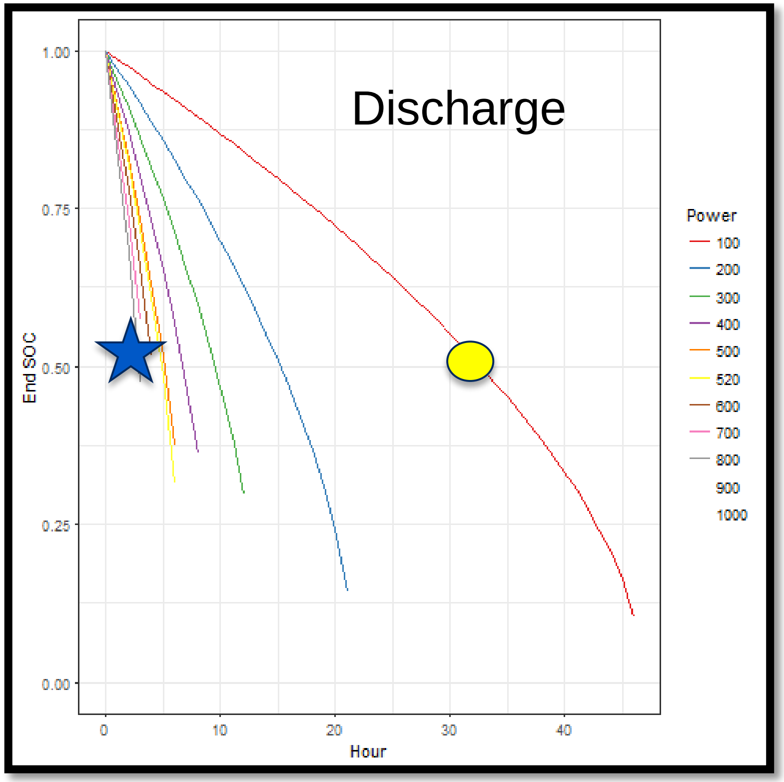


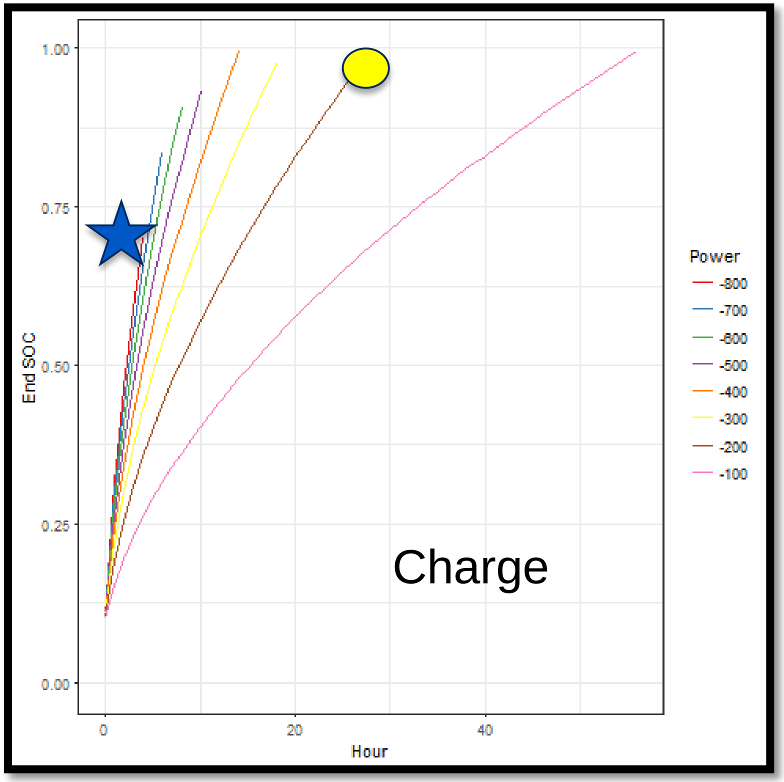
Battery Study Overview

- 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

Battery Operating Characteristics





State of Charge (SOC) – An expression of the present battery capacity as a percentage of maximum capacity.

Power – instantaneous kilowatts.

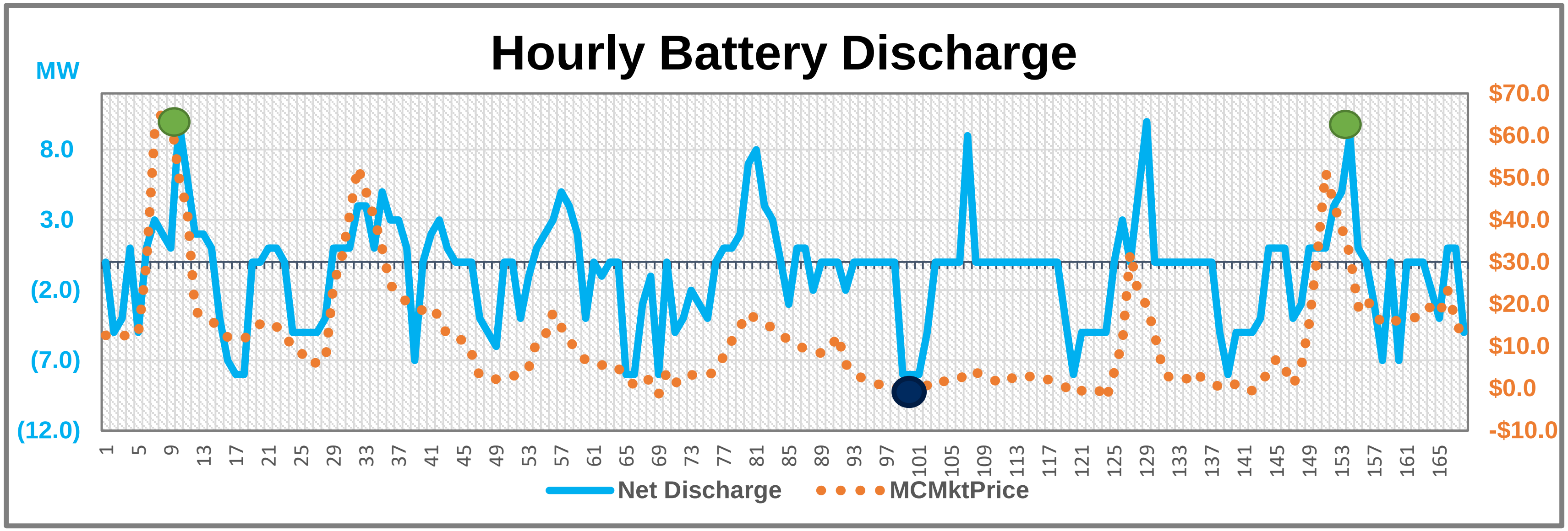
Modeling Overview

Targeted Battery Rating

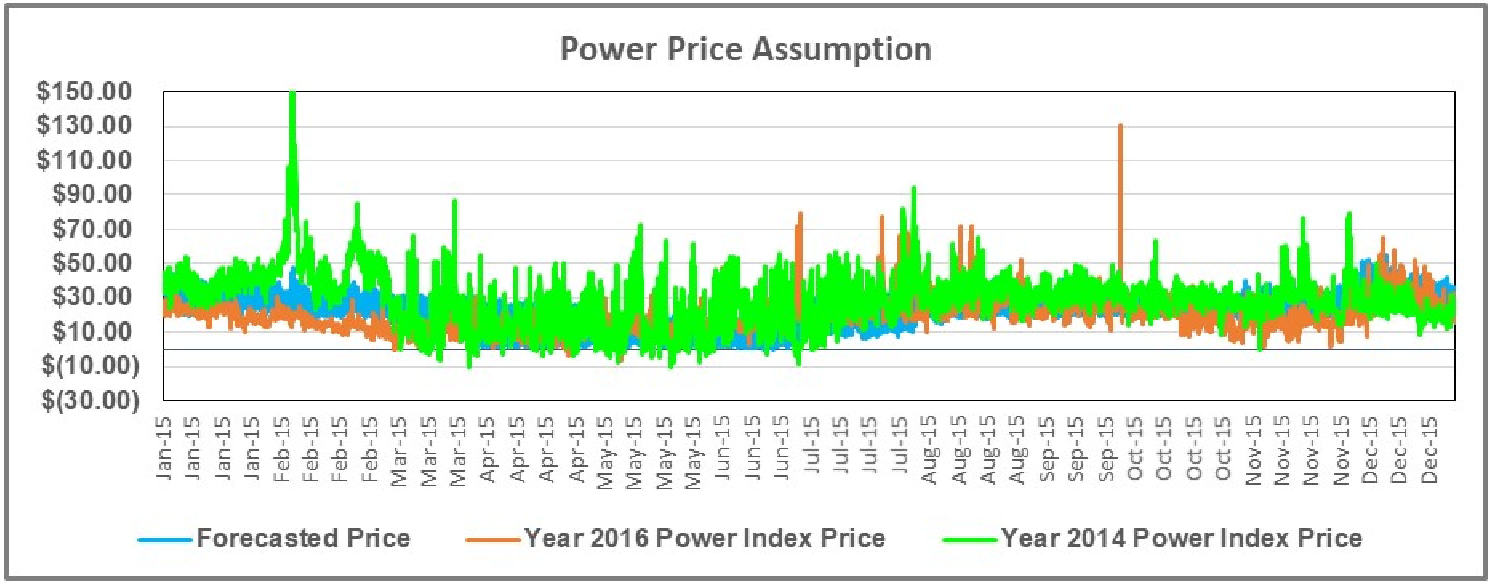
- Max Capacity – 1.0 MW
- Max Storage – 3.7 MWh

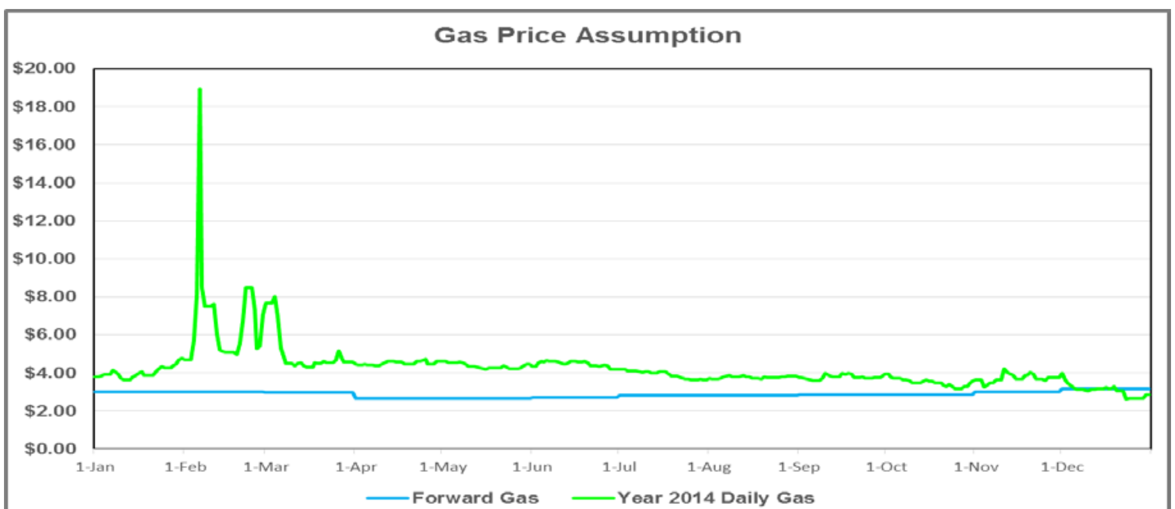
Applied Battery in Model

- 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

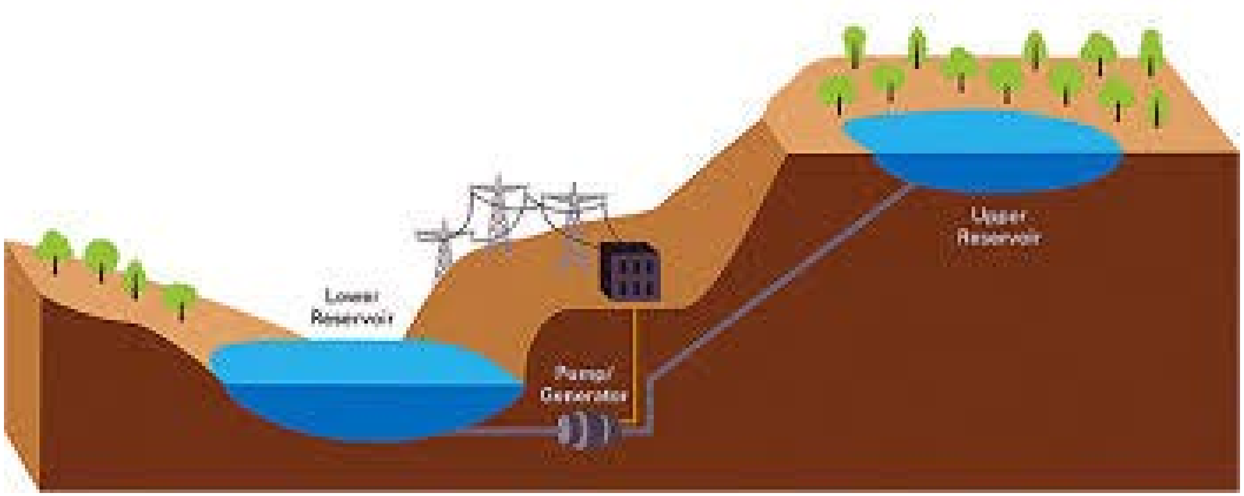
Operating Characteristics

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%



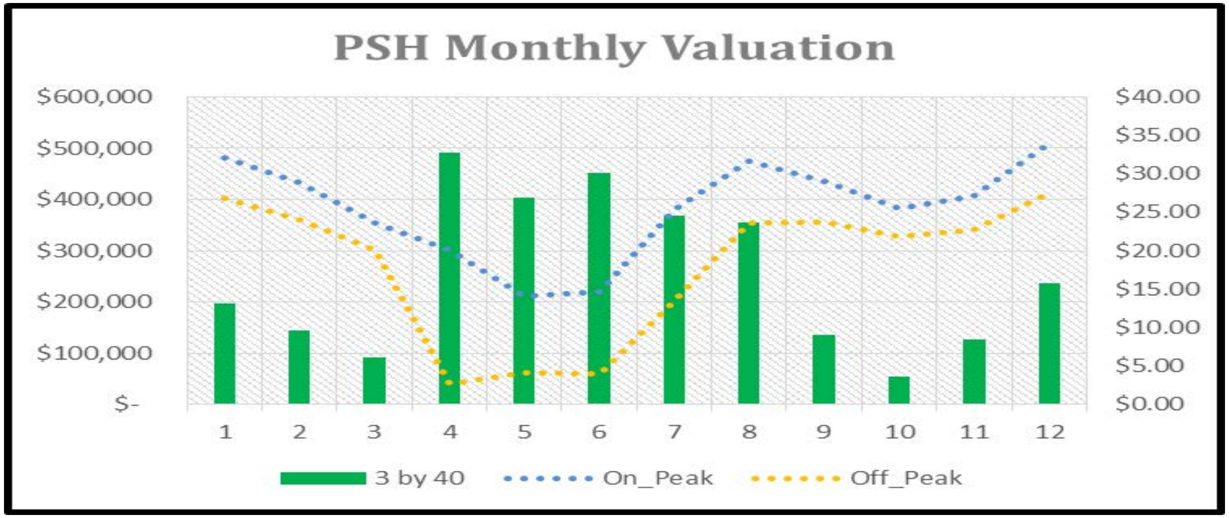
Pumped Hydro Scenarios and Results

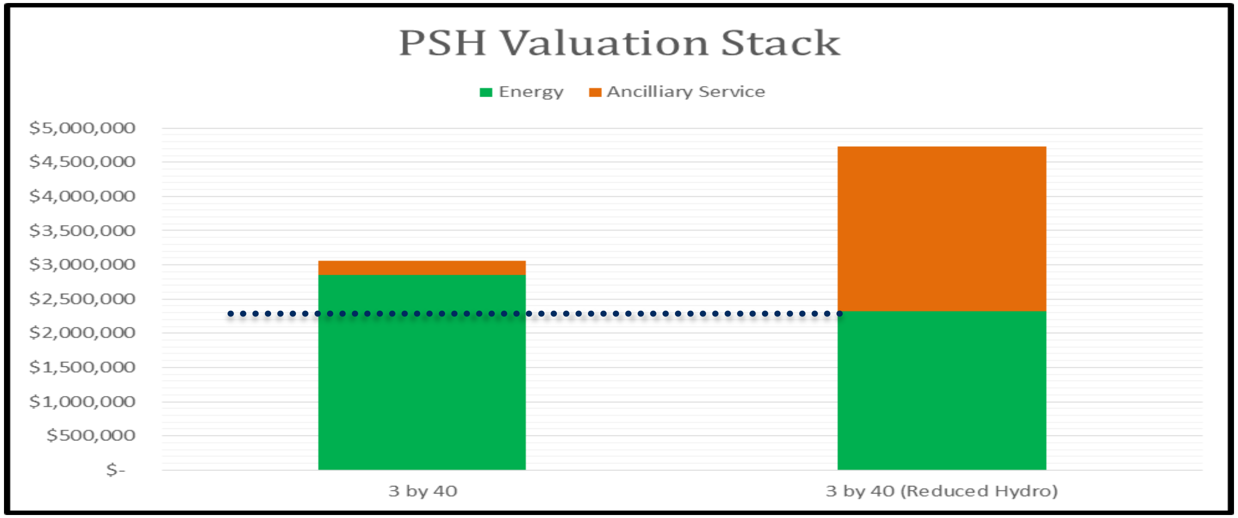
System	Configuration	Target Project Scaling	Incremental Value ($)	Incremental Value ($/kw-yr)
Avista System	3 by 400 MW	100%	$19,412,500	$ 16.18
Avista System	3 by 100 MW	25%	$ 6,772,468	$ 22.57
Avista System	3 by 40 MW	10%	$ 3,057,399	$ 25.48
Avista System	3 by 20 MW	5%	$ 1,598,433	$ 26.64
Hydro Reduction	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						

AVISTA

Pumped Hydro Incremental Value Results





Future Energy Storage Analyses

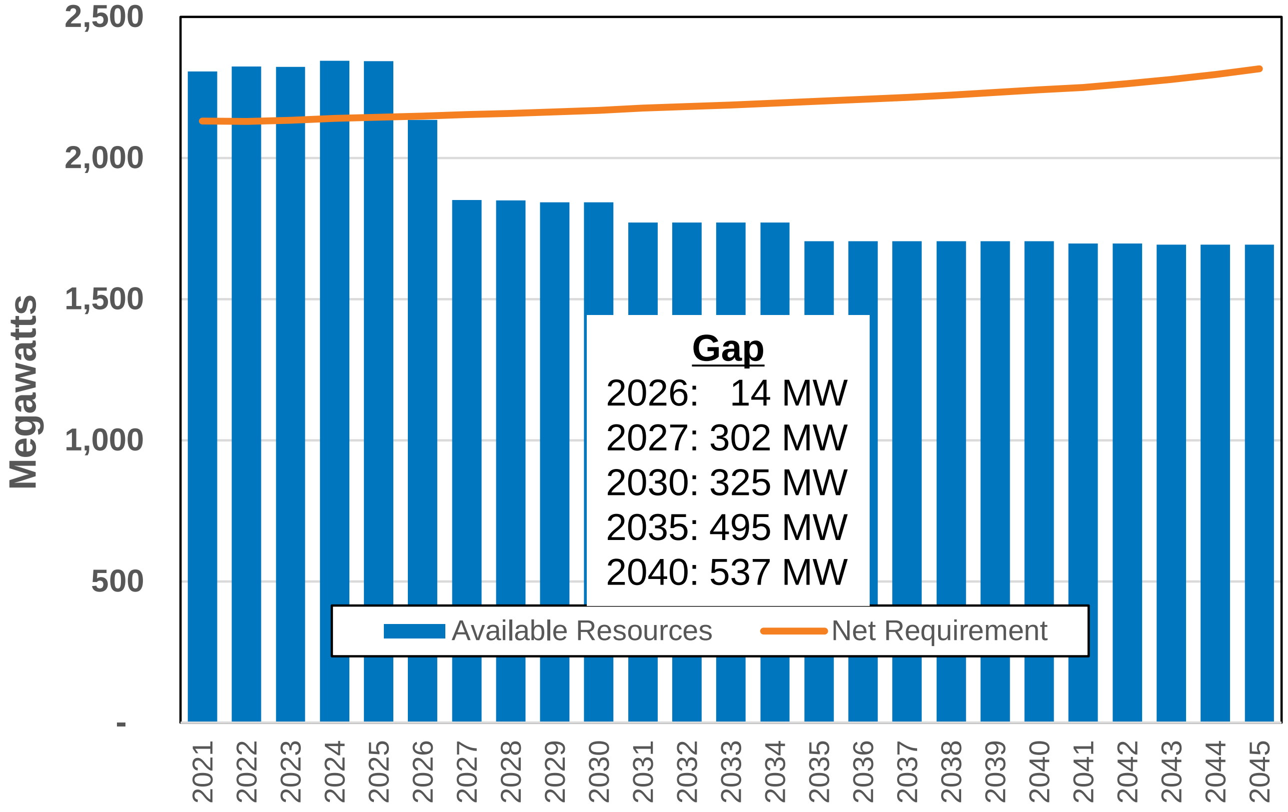
- Re-evaluate energy storage options in a shorter term energy market
- Analyze different energy storage technologies
- Updated pumped storage hydropower technologies
- Study with different levels of wind and solar penetration

2020 Electric Integrated Resource Plan DRAFT “Preferred” Resource Strategy

James Gall, IRP Manager
Fifth Technical Advisory Committee Meeting
October 15, 2019

What Are Avista's Physical Resource Needs?

Main focus: Winter Peak (e.g. cold week in January)



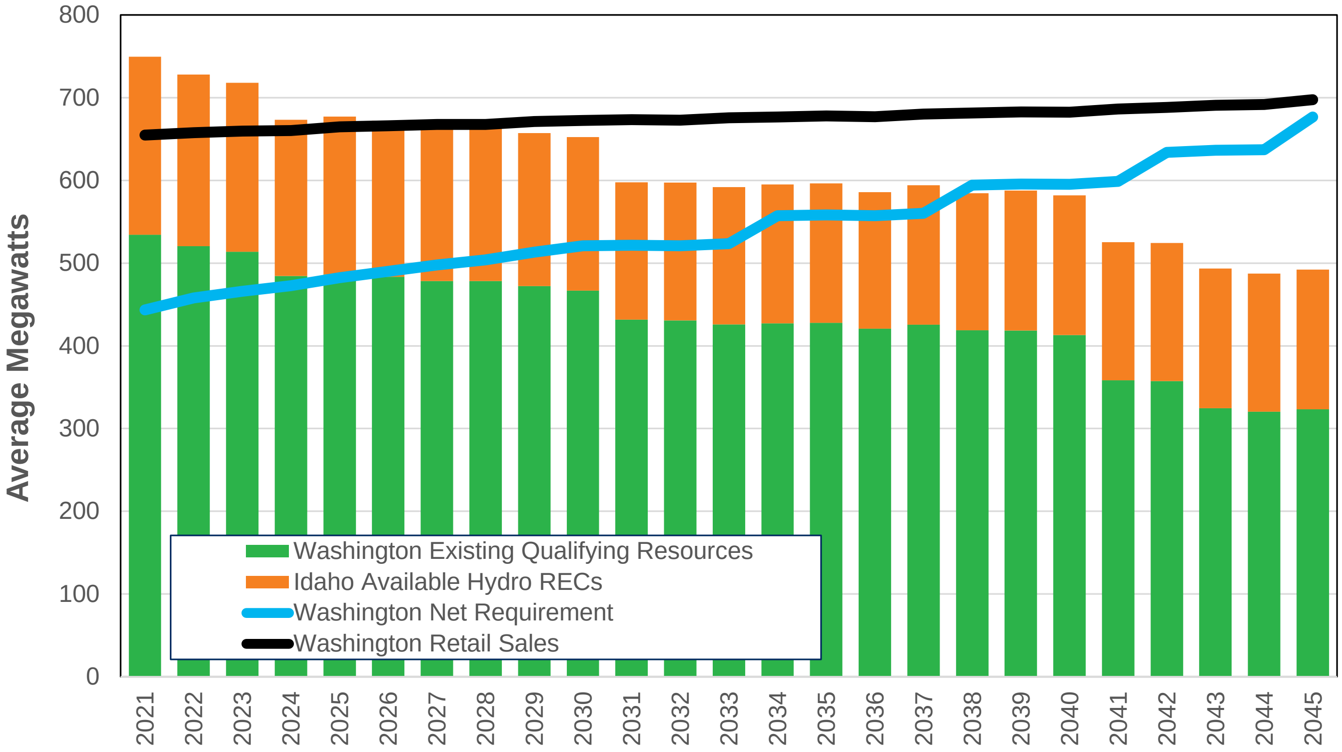
Key Losses:
Colstrip: 2025*
Lancaster: 2026
Mid-C: 2030
Northeast: 2035

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.

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)



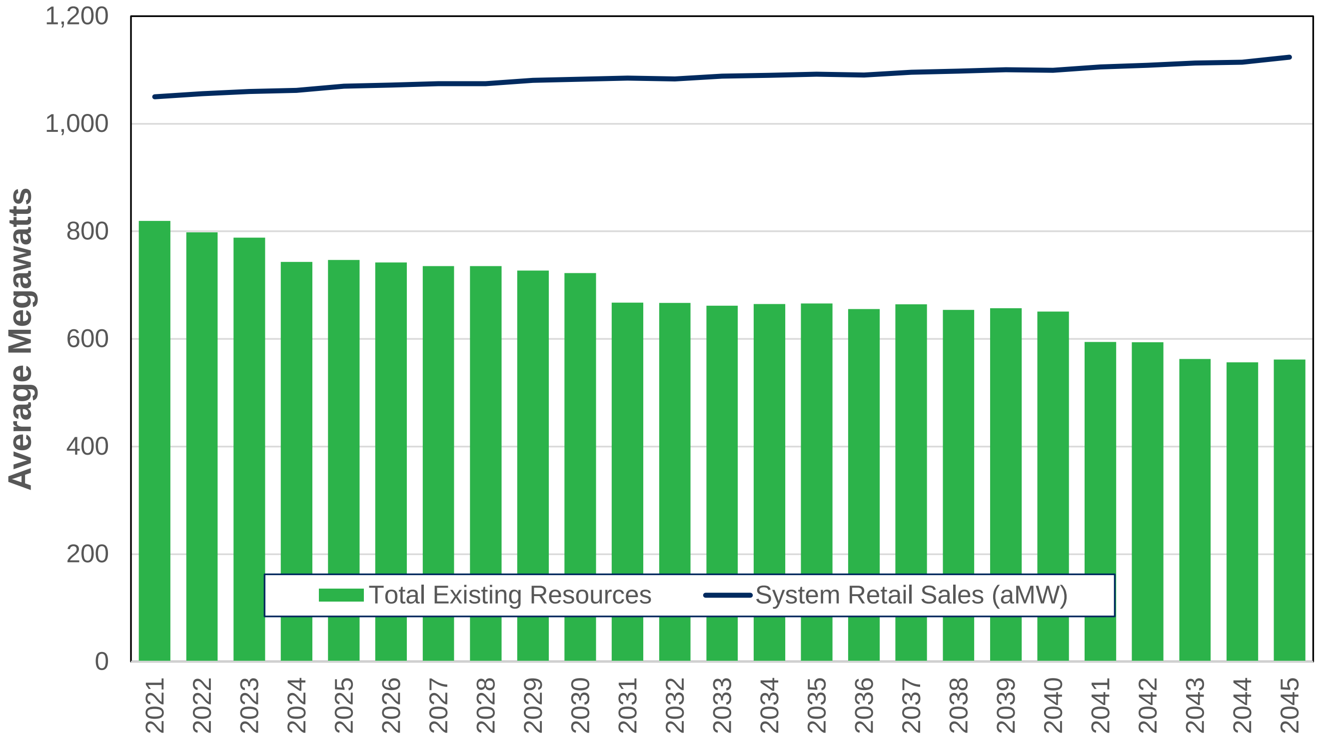
Gap
2030: 54 aMW
2035: 130 aMW
2040: 182 aMW
2045: 353 aMW

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)



<u>Gap</u>

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

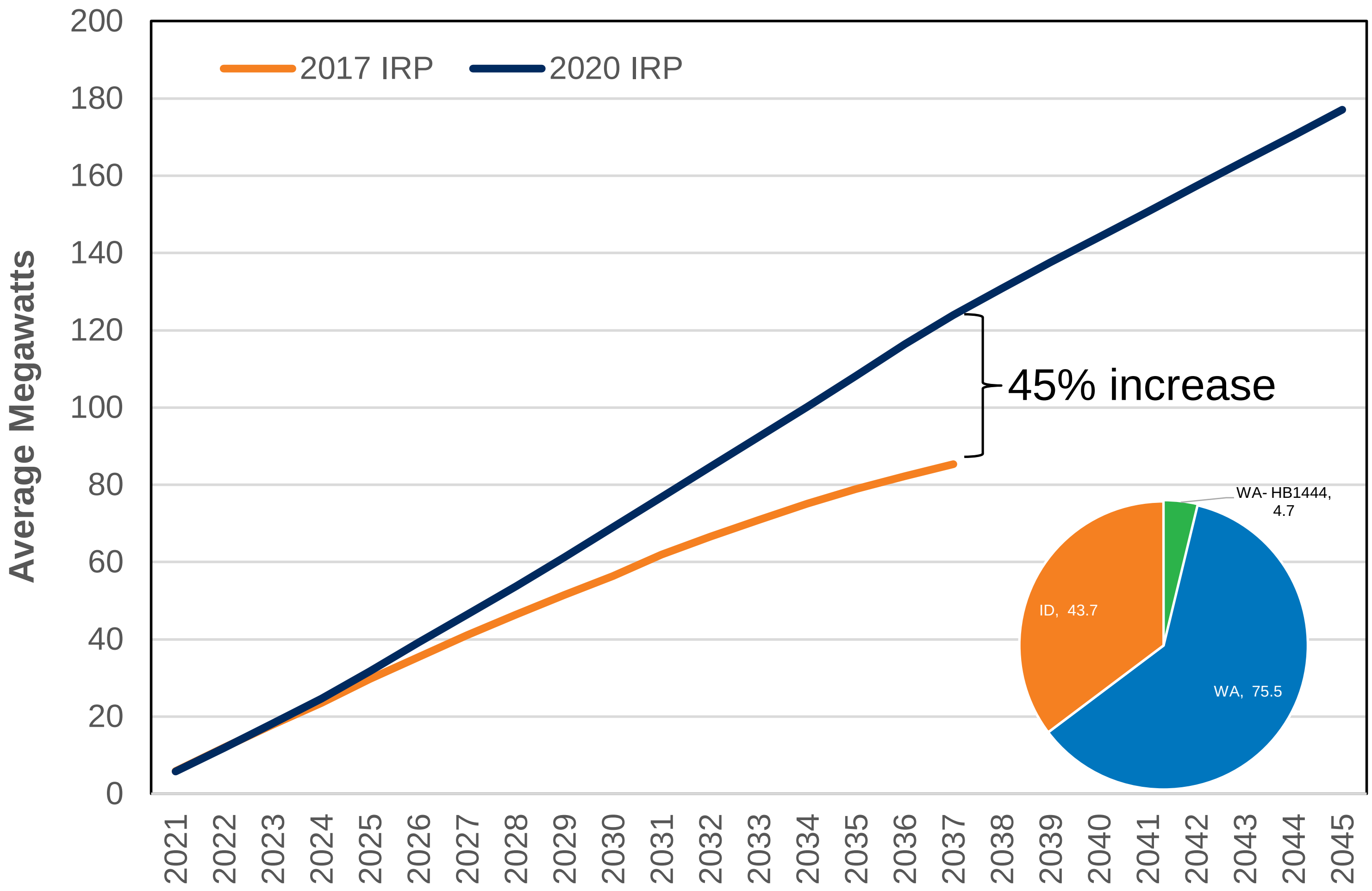
- Uses Mixed Integer Program (MIP) to find least cost solution meeting capacity, energy, and renewable constraints for the system between 2021 and 2045.

- 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.)

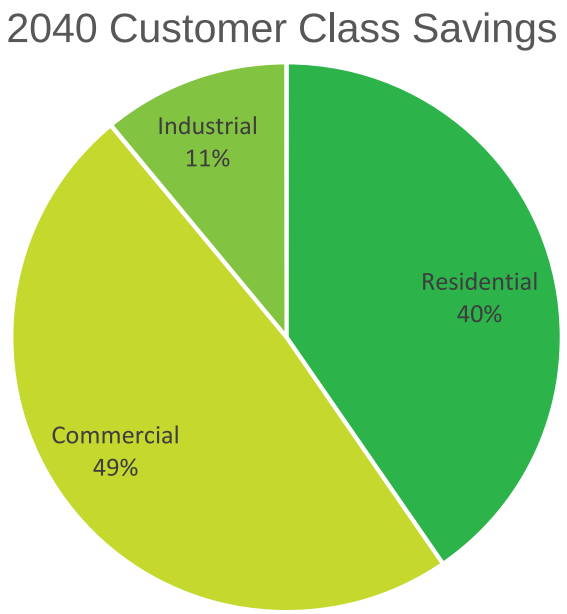
- Non-modeled utility revenue requirements assumes an increase of two percent per year.

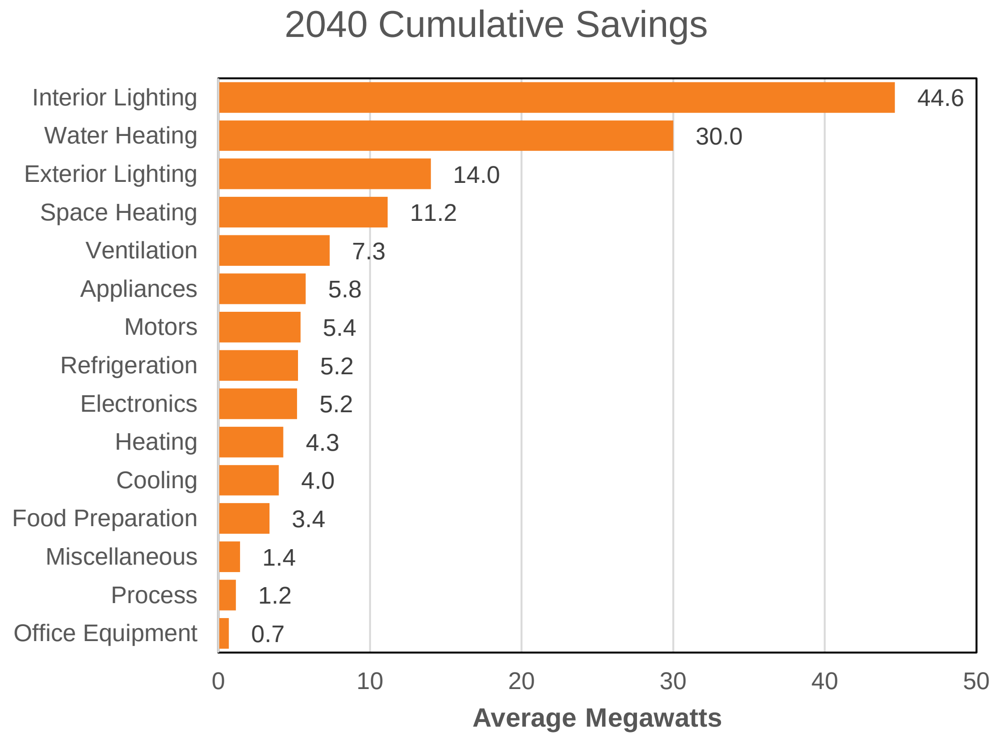
Energy Efficiency Results



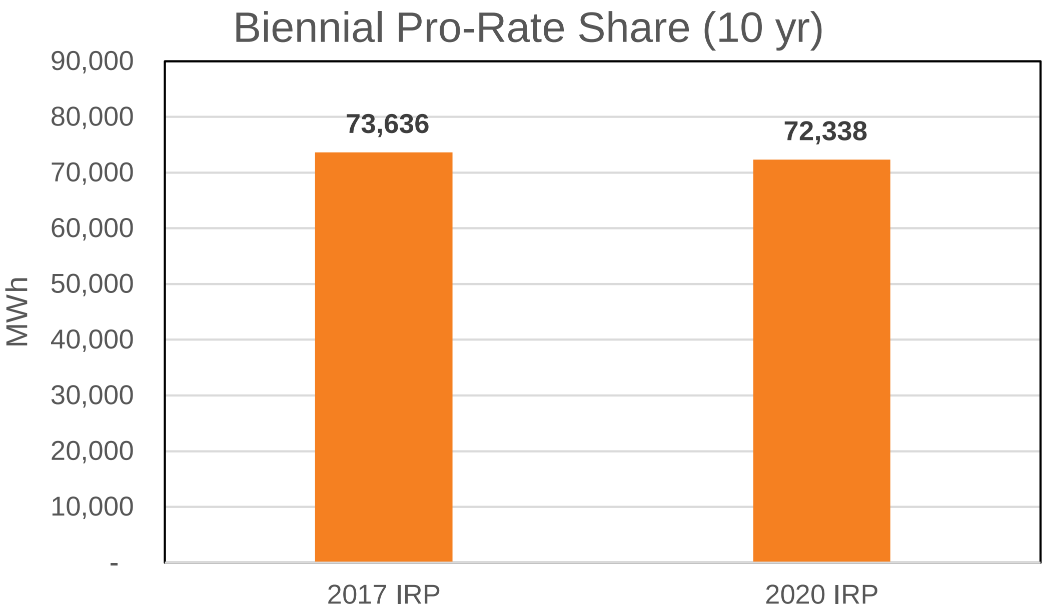
Note: excludes T&D losses

Where is the Cost Effective Energy Efficiency Savings?



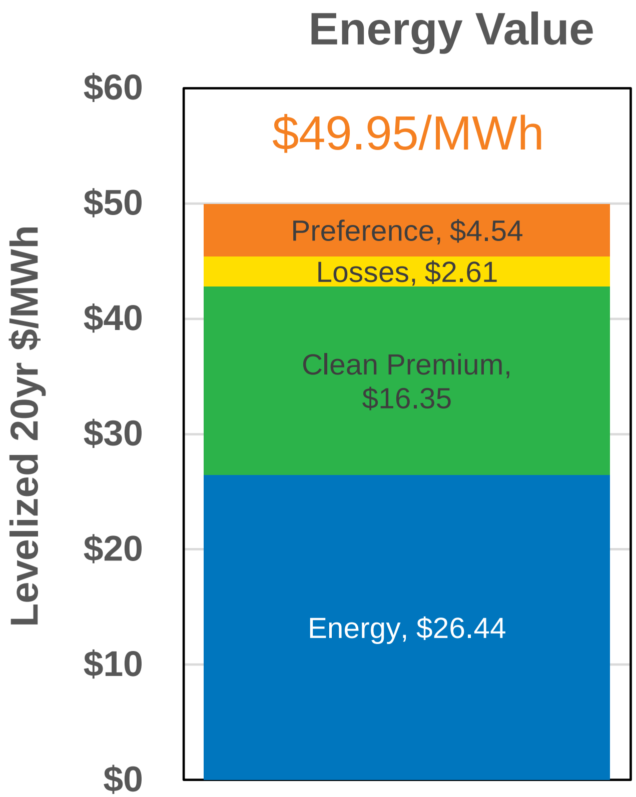


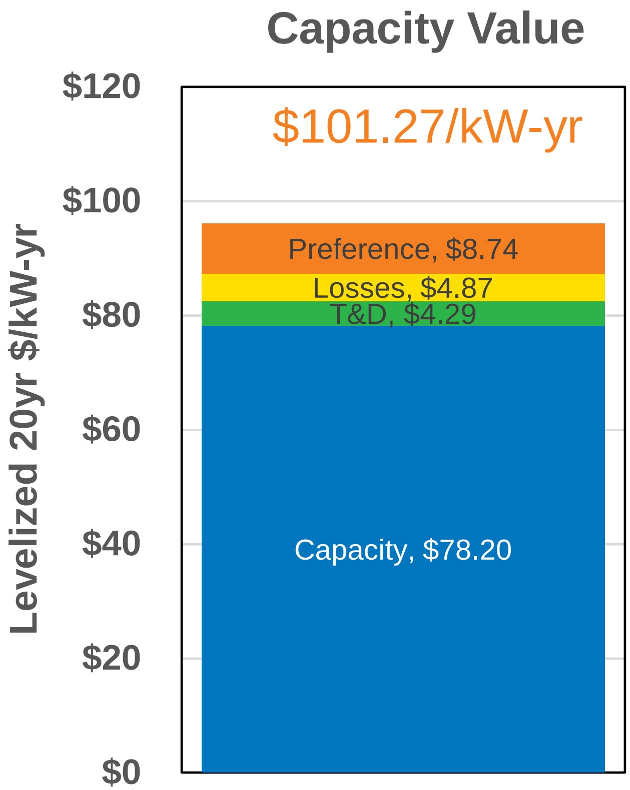
Washington Biennial EIA Energy Efficiency Goal (2021/22)



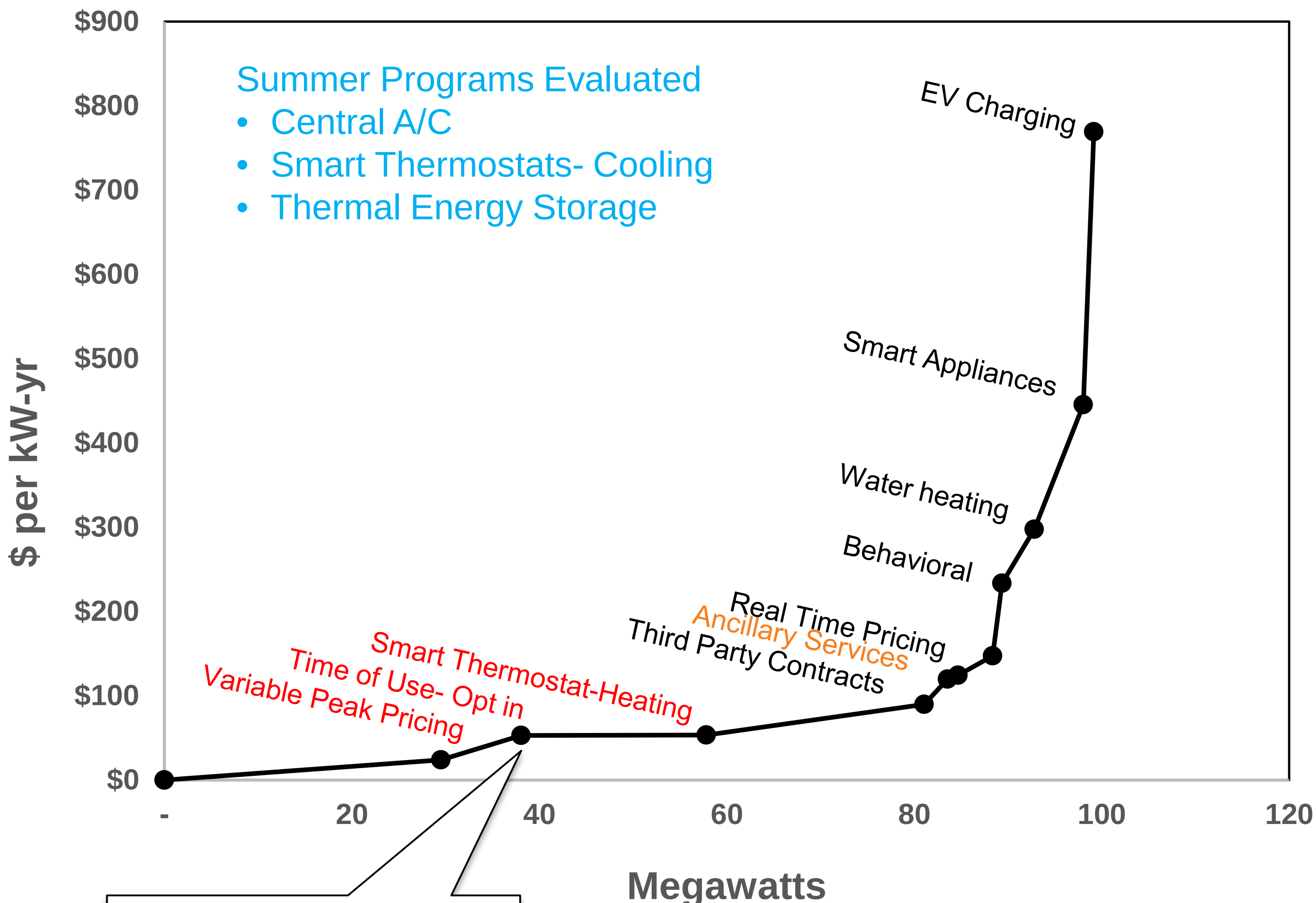
Biennial Conservation Approved Target (MWh)	Based on 2020 IRP	Based on 2017 IRP
CPA Pro-Rata Share	72,338	73,636
Behavioral Program Savings	N/A	15,386
Distribution and Street Light Efficiency	504	749
EIA Target	72,842	89,771
Decoupling Threshold	3,642	4,489
Total Utility Conservation Goal	76,484	94,260
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



25 MW Load Control is also included, but not shown as its prices would likely be negotiated

<u>Cost Effective Start Dates Shown in Red</u>

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, 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 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

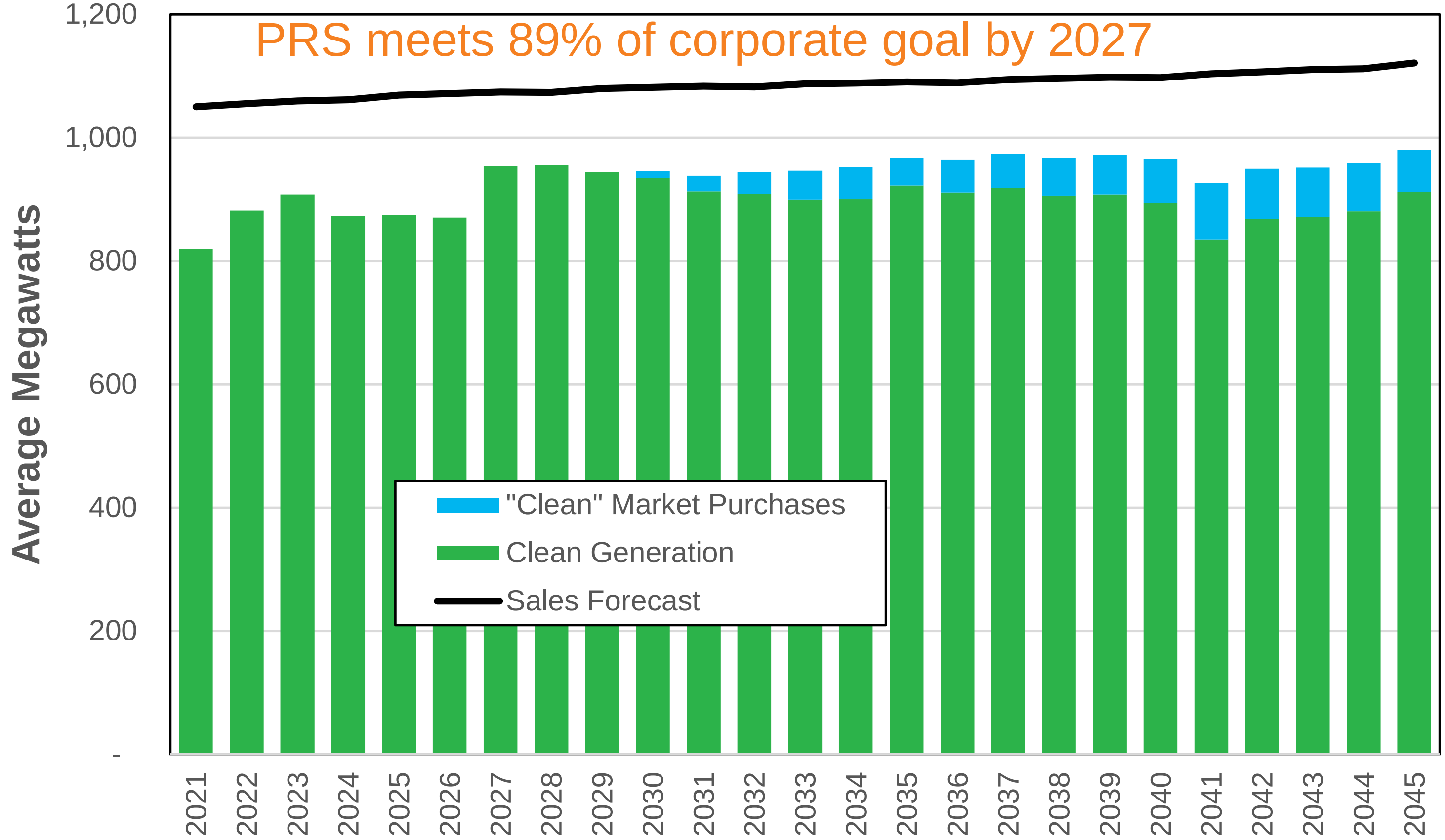
- 14% planning margin without Colstrip and non-dispatchable resources is too low.
- LOLP analysis was re-studied without Colstrip to determine the required planning margin to achieve 5% LOLP with NG CTs- this resulted in a ~16% planning margin
- The resulting draft reliability metrics for the PRS are:

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

DRAFT ONLY

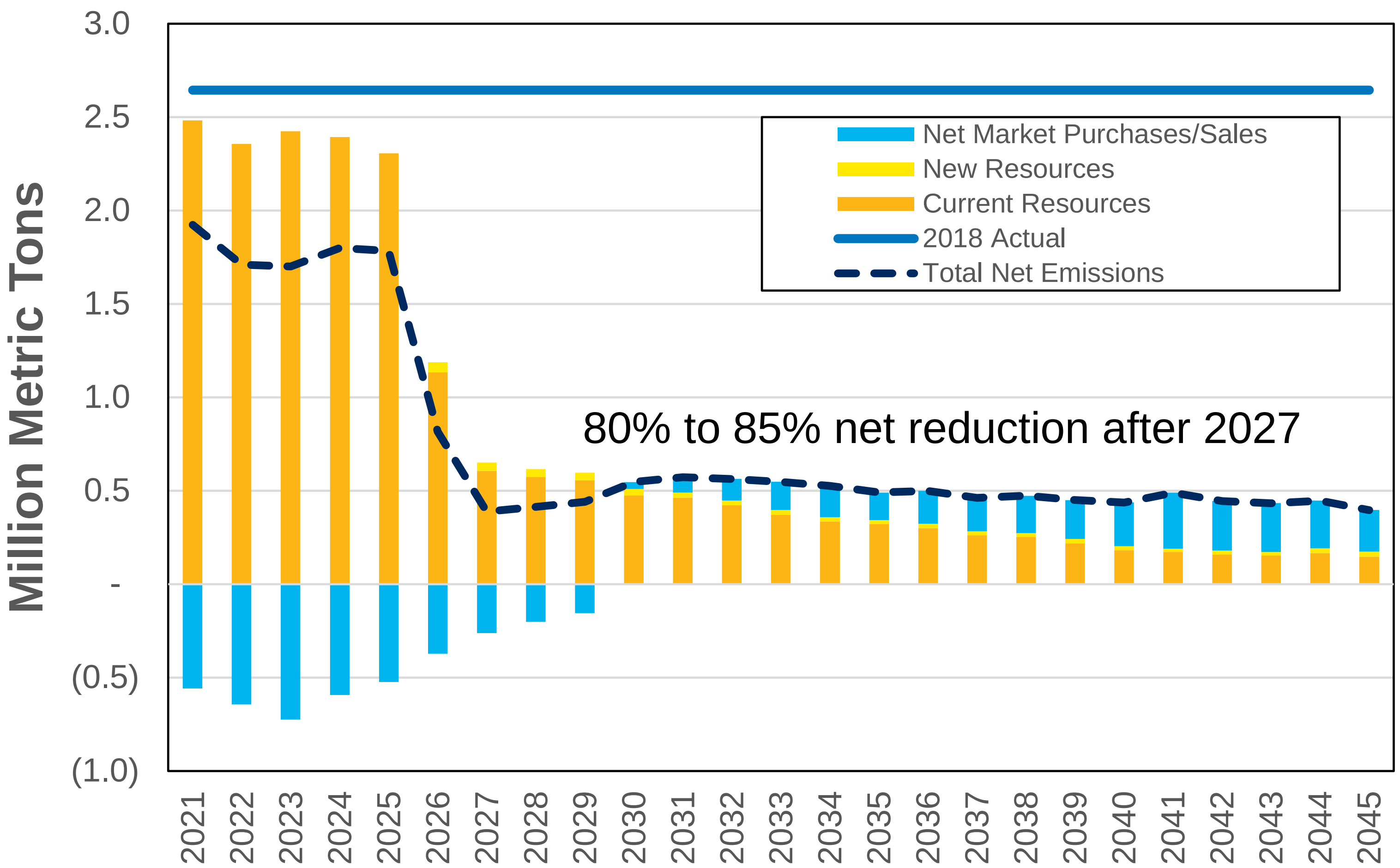
PRS Comparison to Corporate Clean Electricity Goal

Goal: Serve customers with 100% cost effective clean electricity

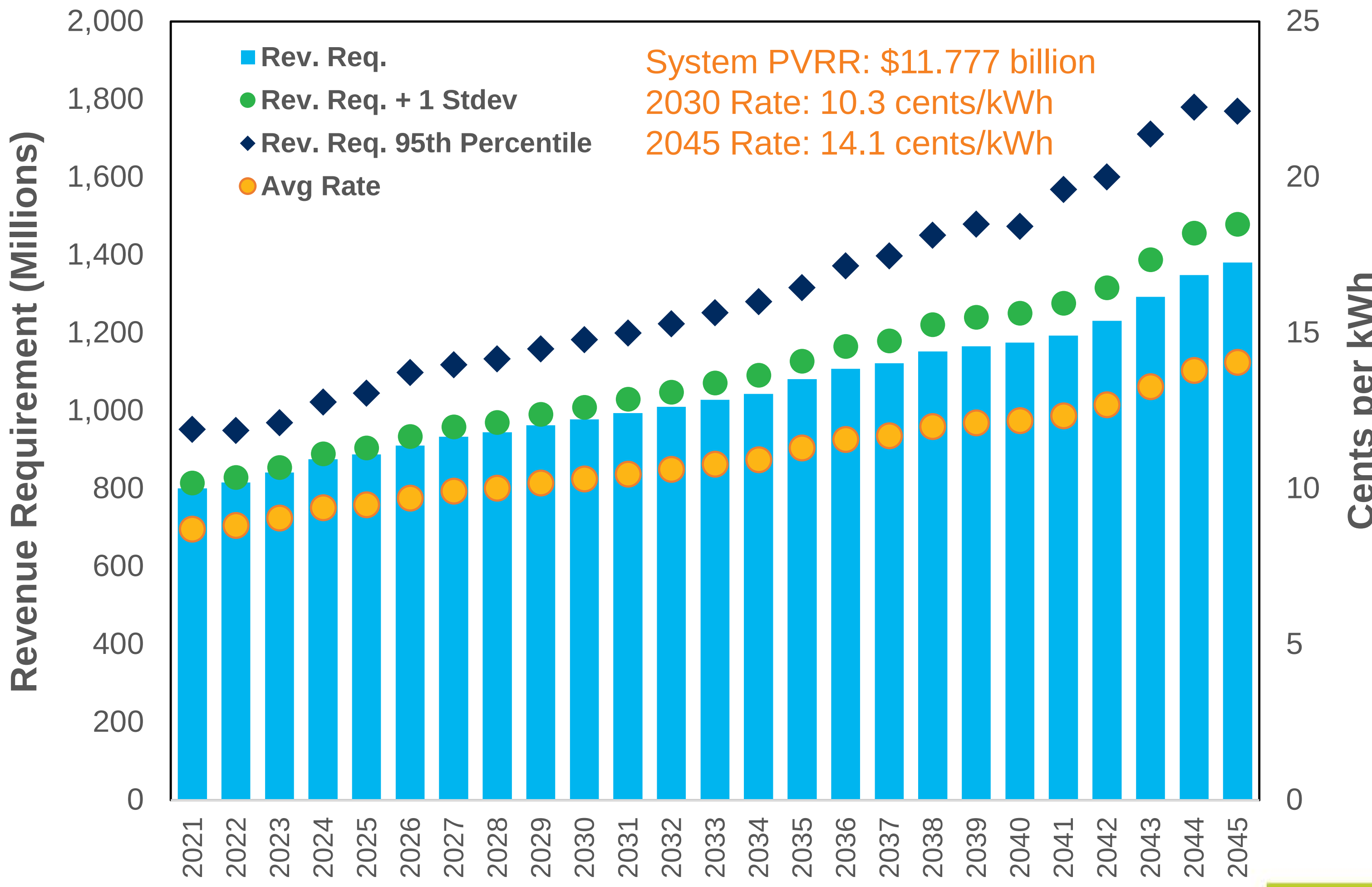


Notes:
1) Prior to 2030, Avista is a net energy seller to the market
2) "Clean" market purchases is measured as the regional generation mix's CO_2 mix compared to a CCCT

PRS: Greenhouse Gas Emissions Forecast

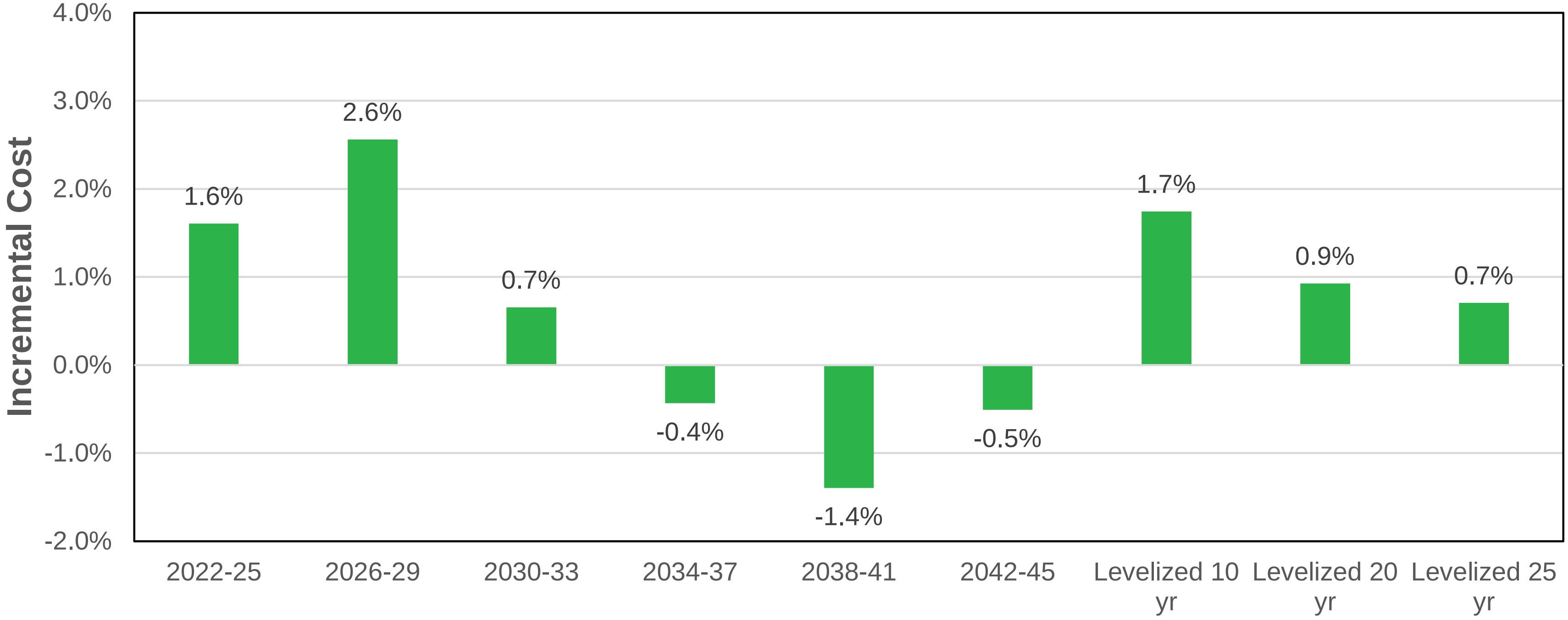


PRS: Cost/Rate Forecast



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

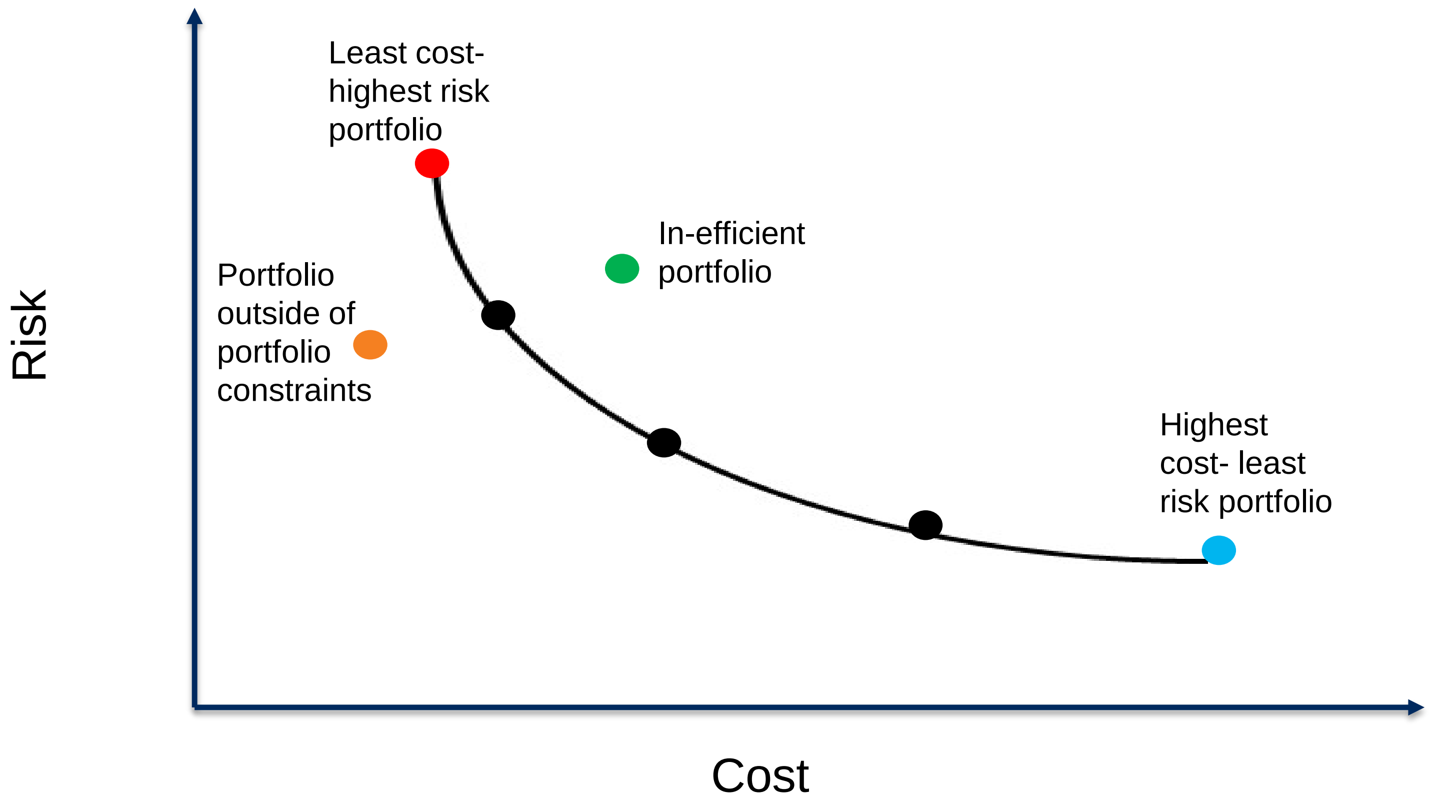
2020 Electric Integrated Resource Plan
Draft Portfolio Scenario Analysis

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 constraints 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

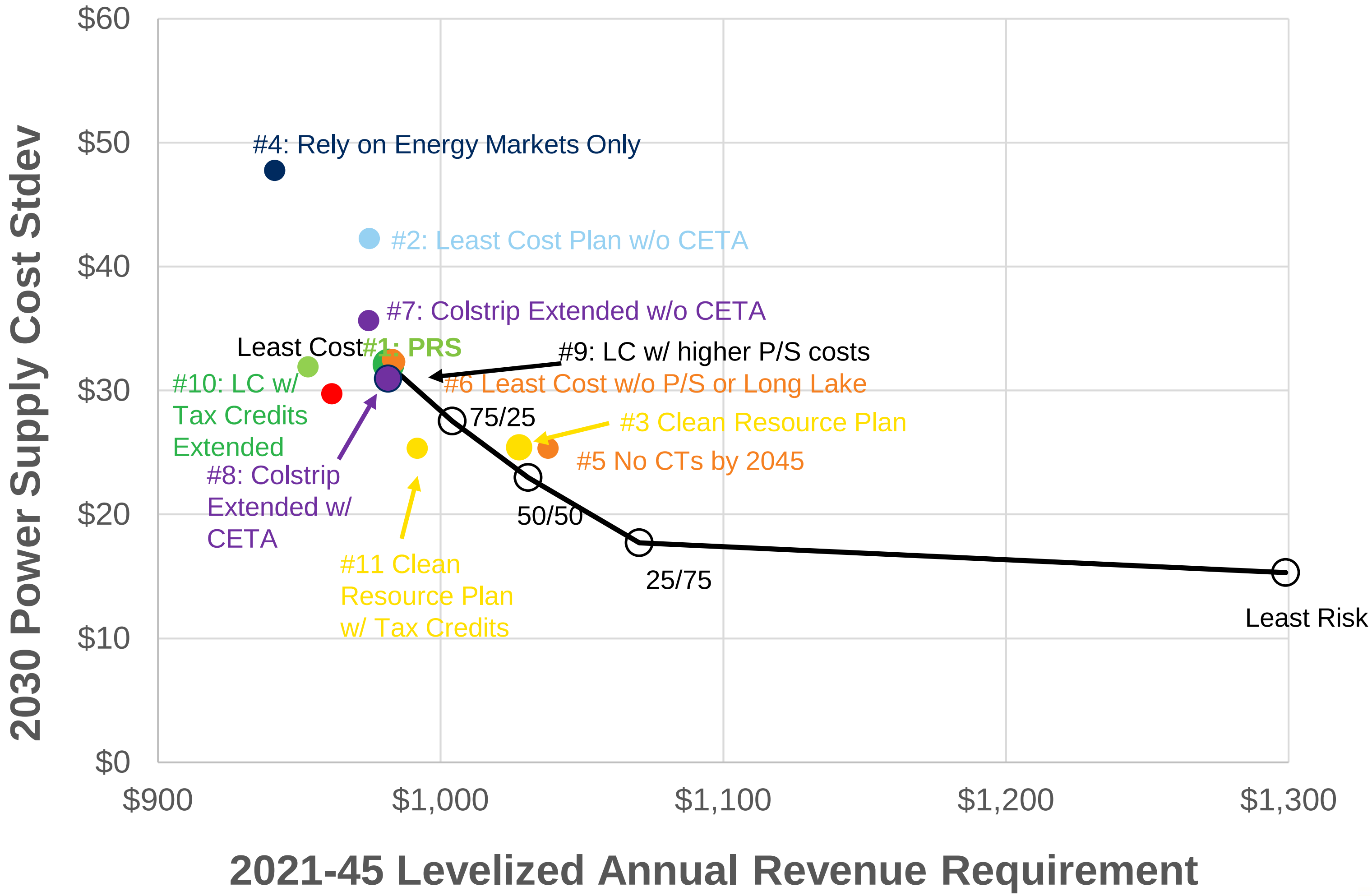


Scenarios

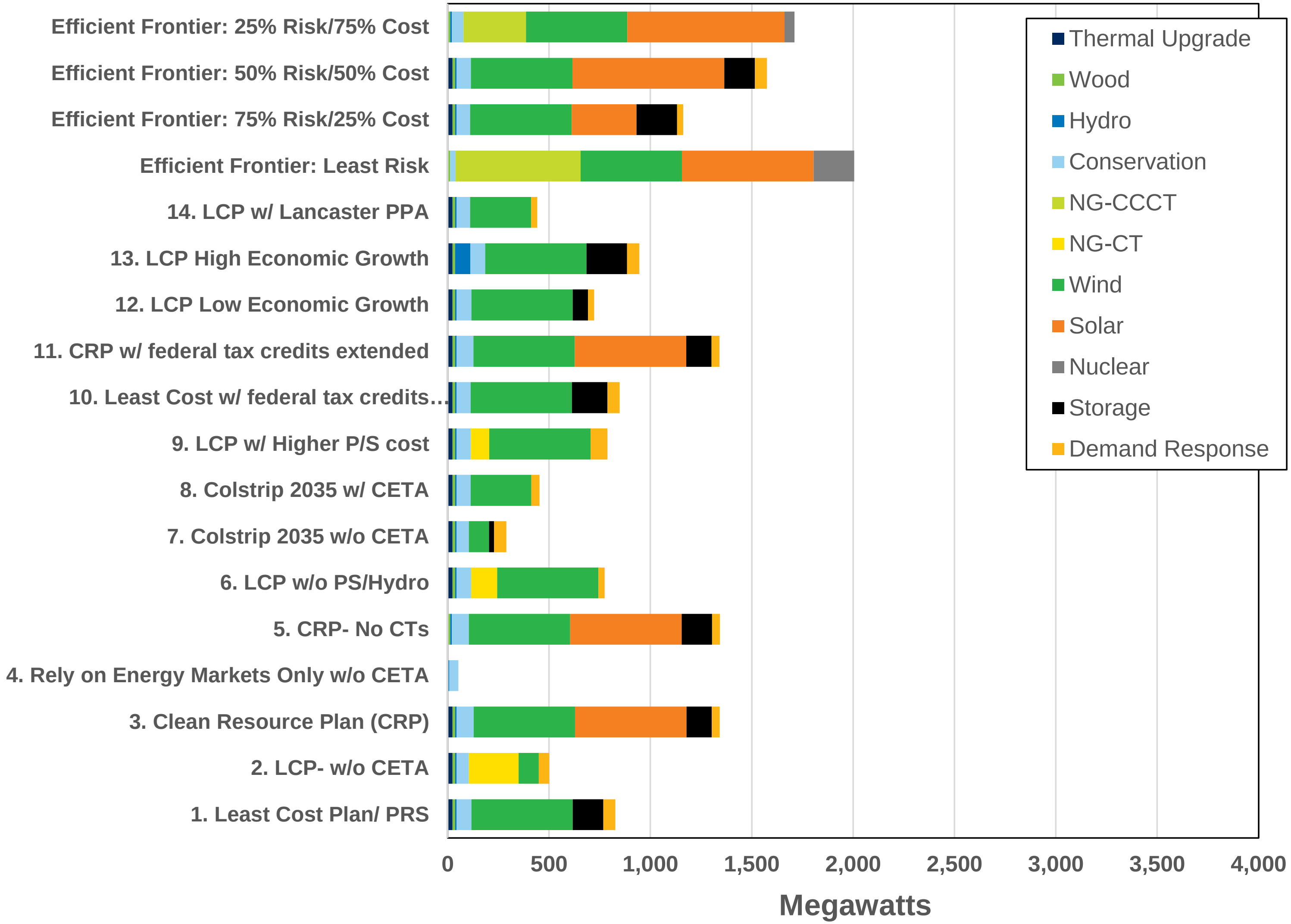
1. Preferred Resource Strategy
2. Least Cost Plan- w/o CETA
3. Clean Resource Plan: 100% net clean by 2027
4. Rely on energy markets only (no capacity or renewable additions) w/o CETA
5. 100% net clean by 2027, and no CTs by 2045
6. Least Cost Plan w/o pumped storage or Long Lake as options
7. Colstrip 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)

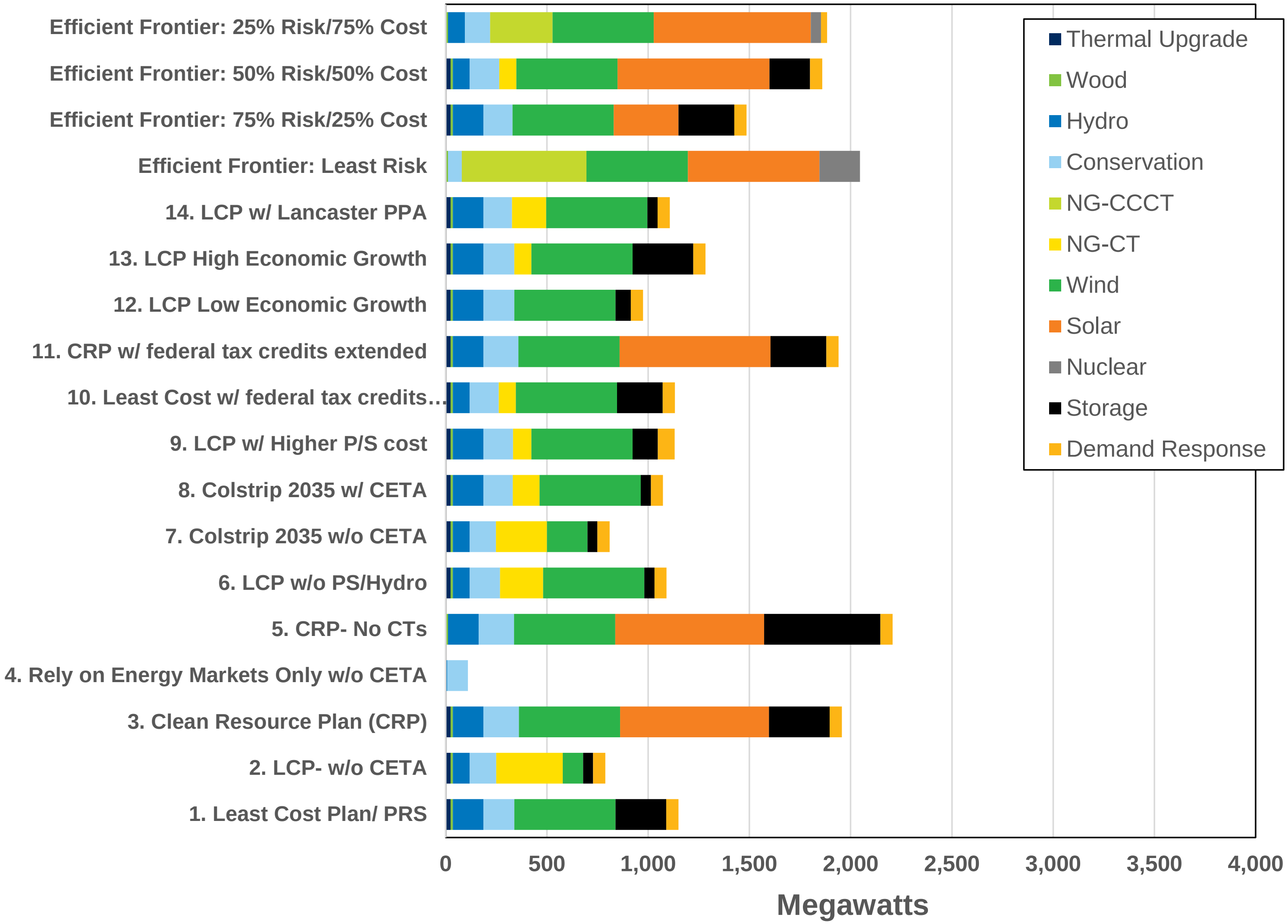
Efficient Frontier Results



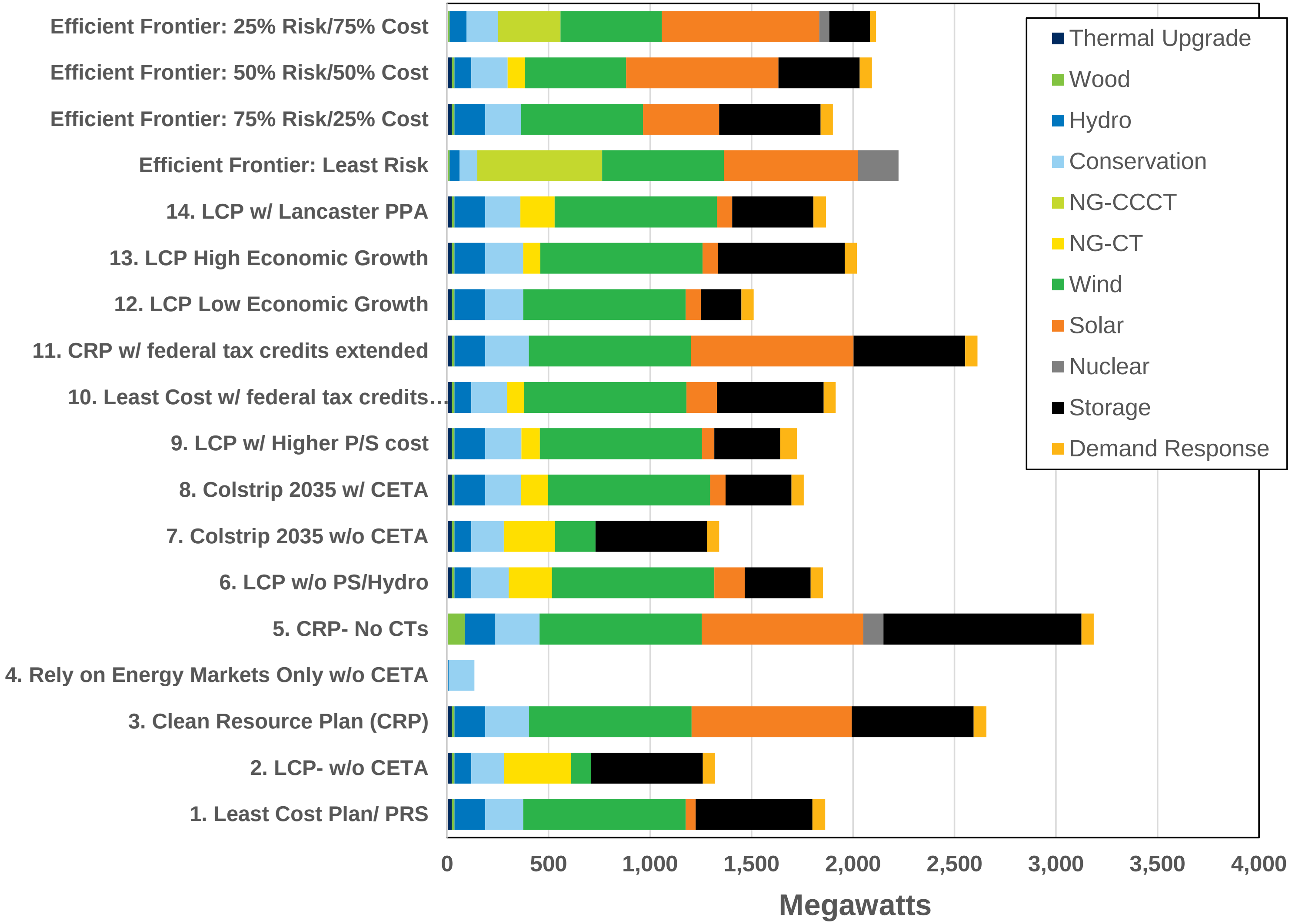
2030 Portfolio Resource Selection



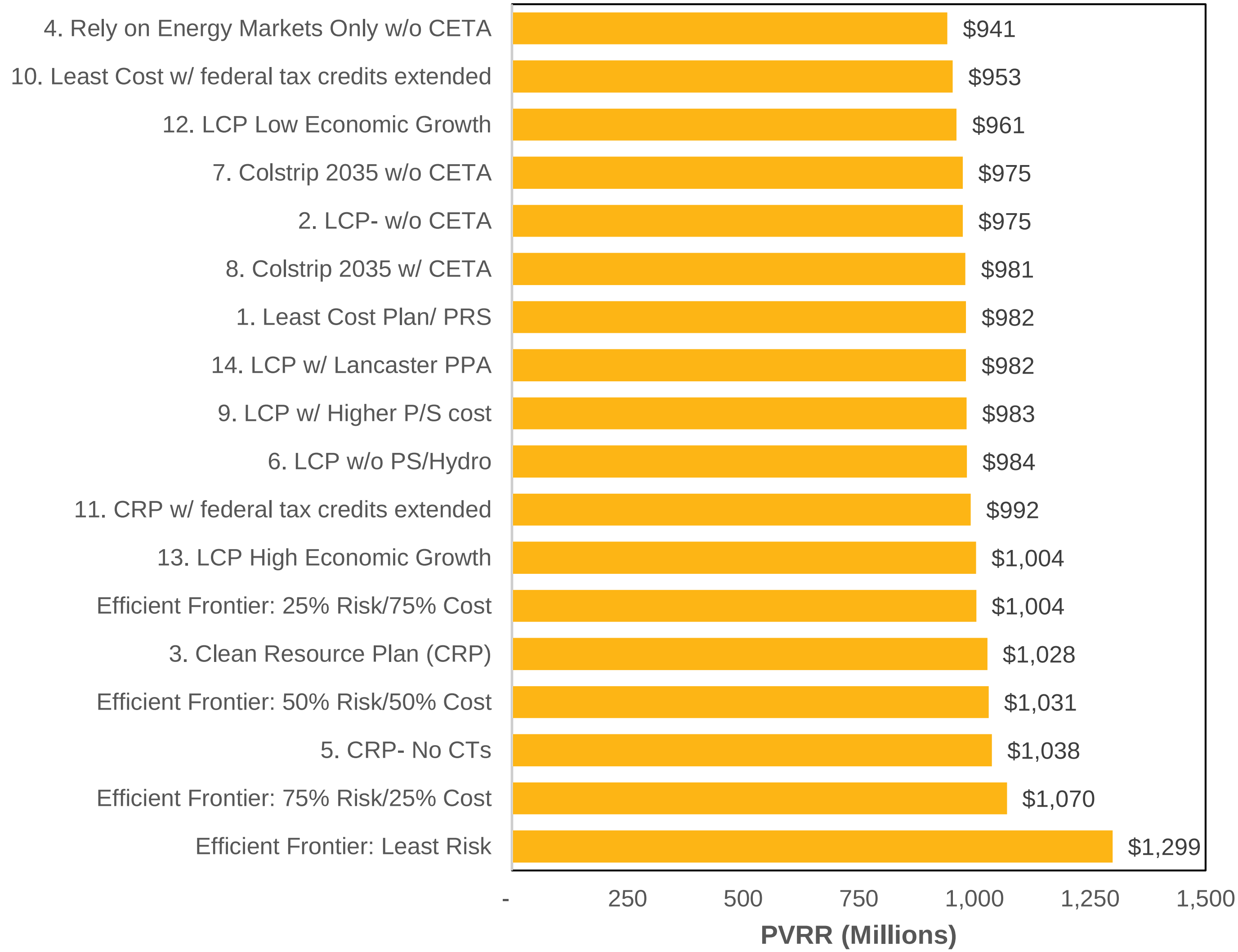
2040 Portfolio Resource Selection



2045 Portfolio Resource Selection

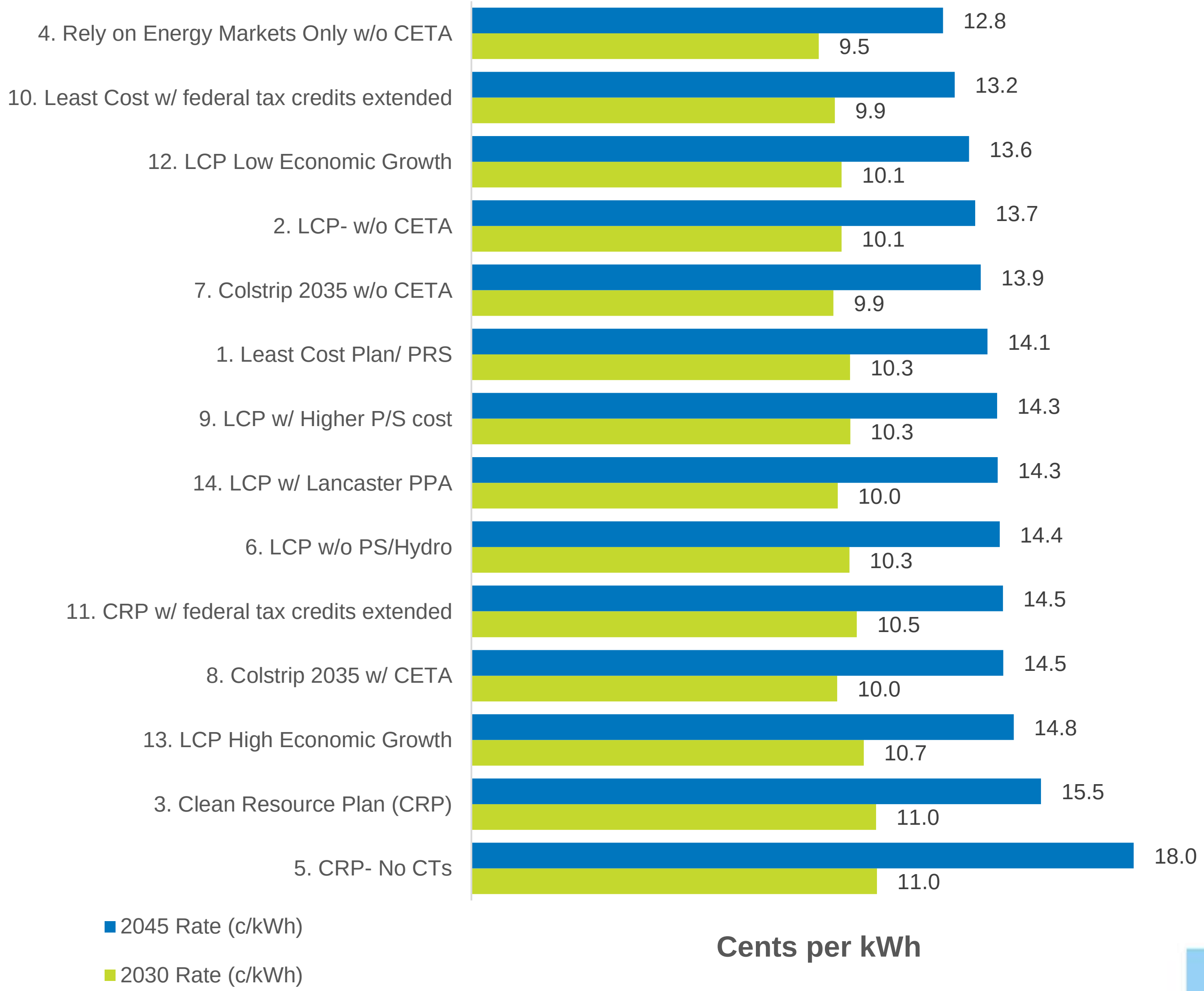


Annual Cost Comparison



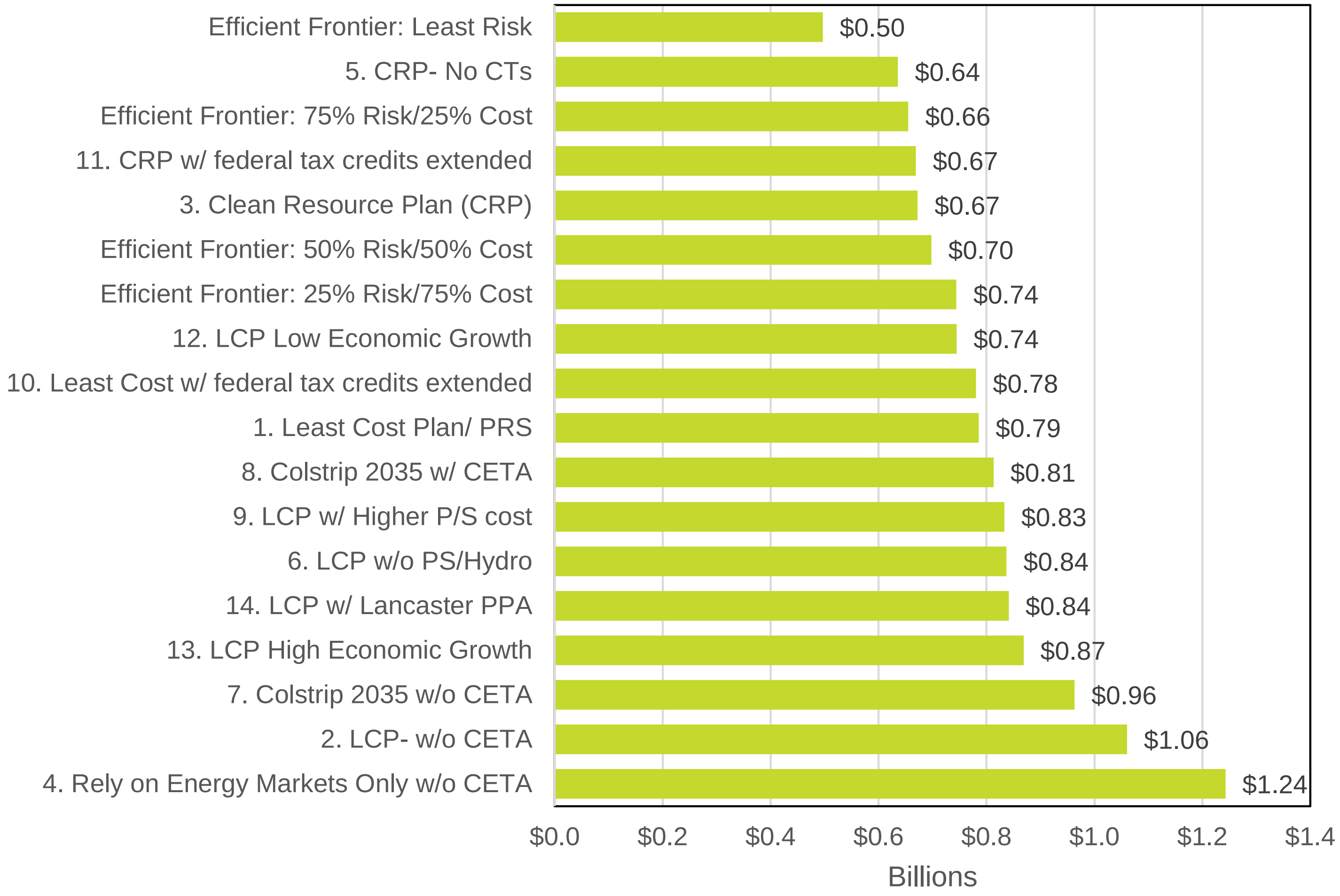
Rate Comparison

sorted by 2045 rates



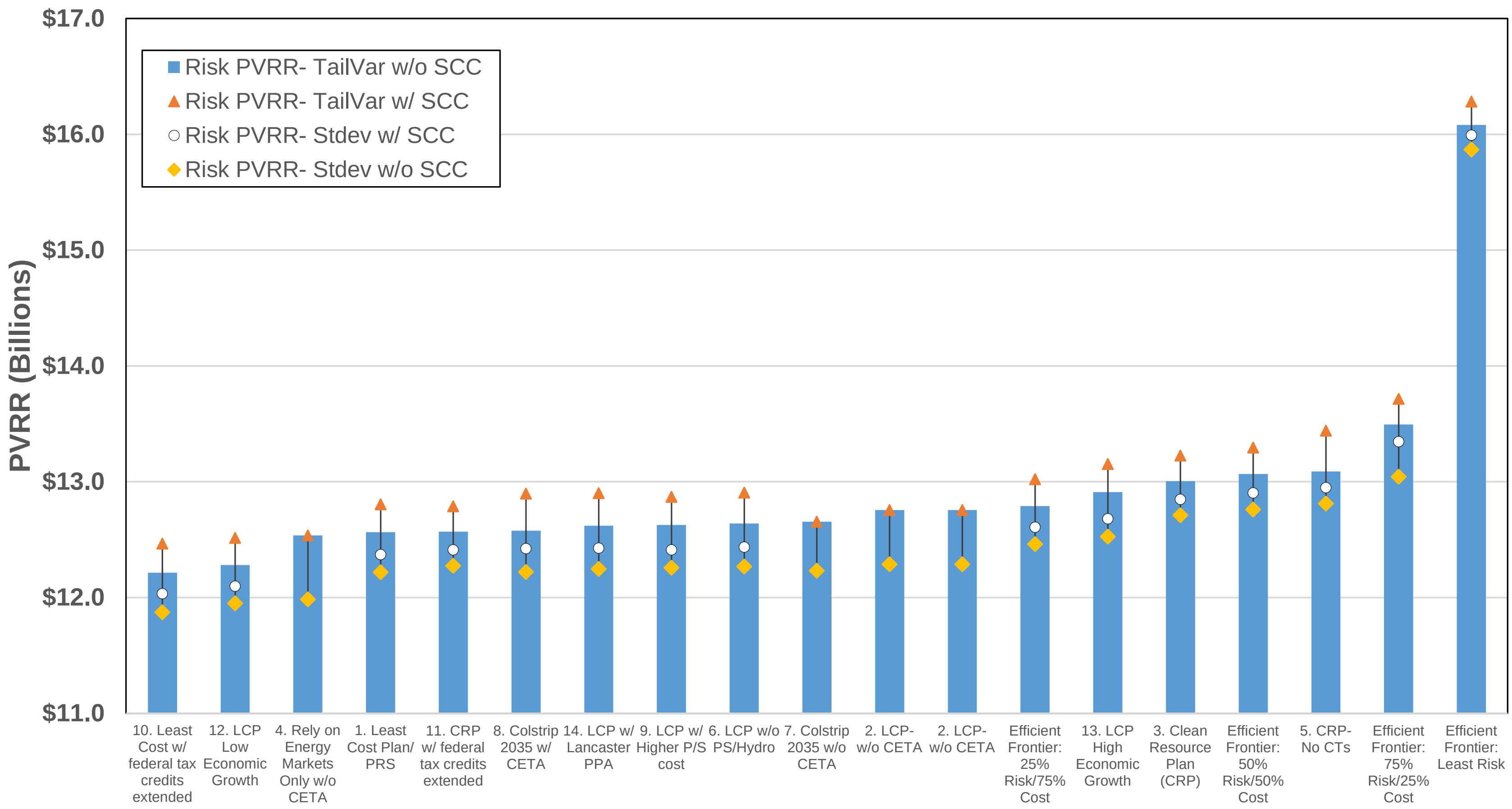
Portfolio Tail Risk

(95th percentile minus expected cost, excludes Social Cost of Carbon)

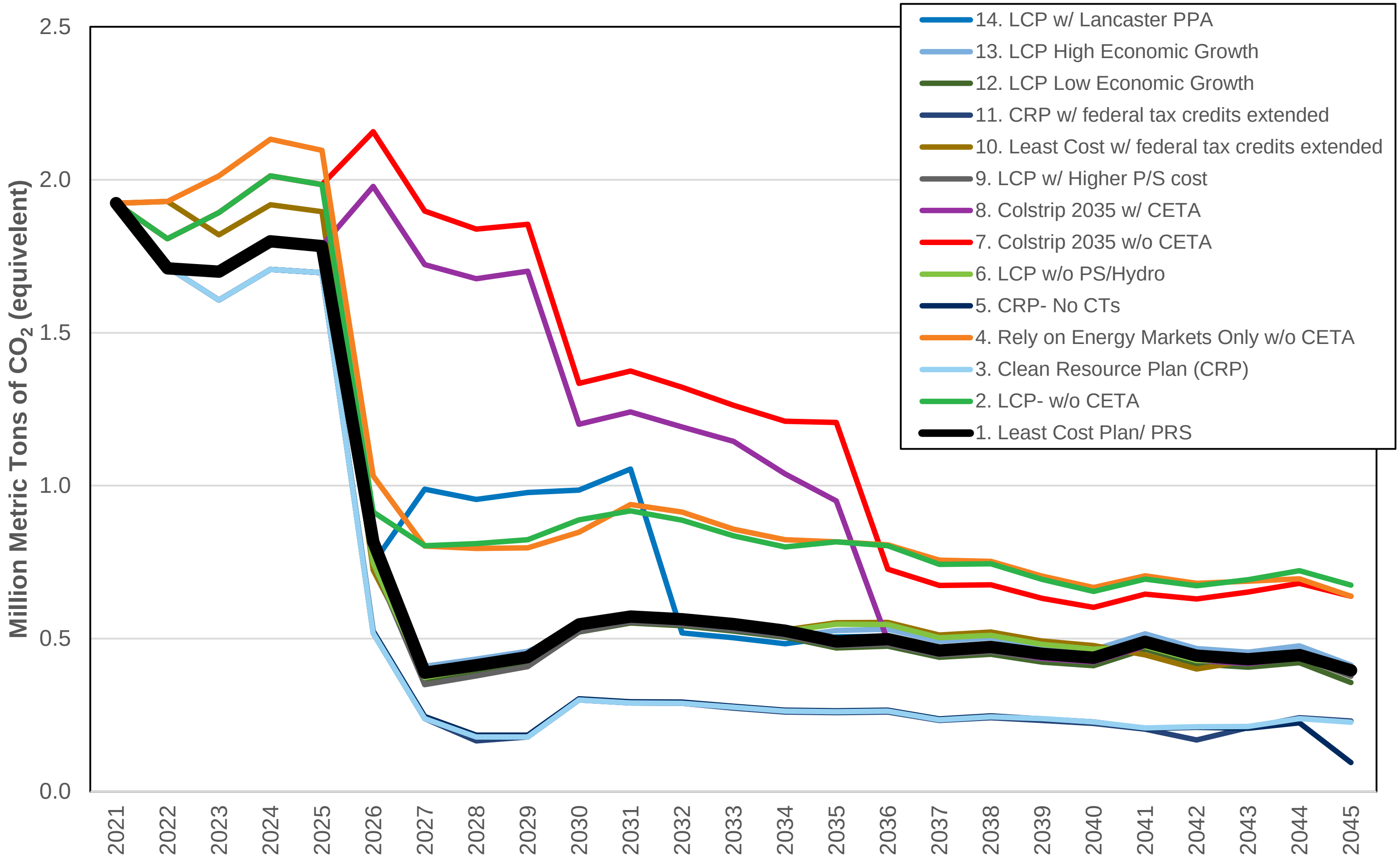


PVRR Risk Adjusted Comparison

Sorted by TailVar w/o Social Cost of Carbon (SCC)



Annual Greenhouse Gas Comparison



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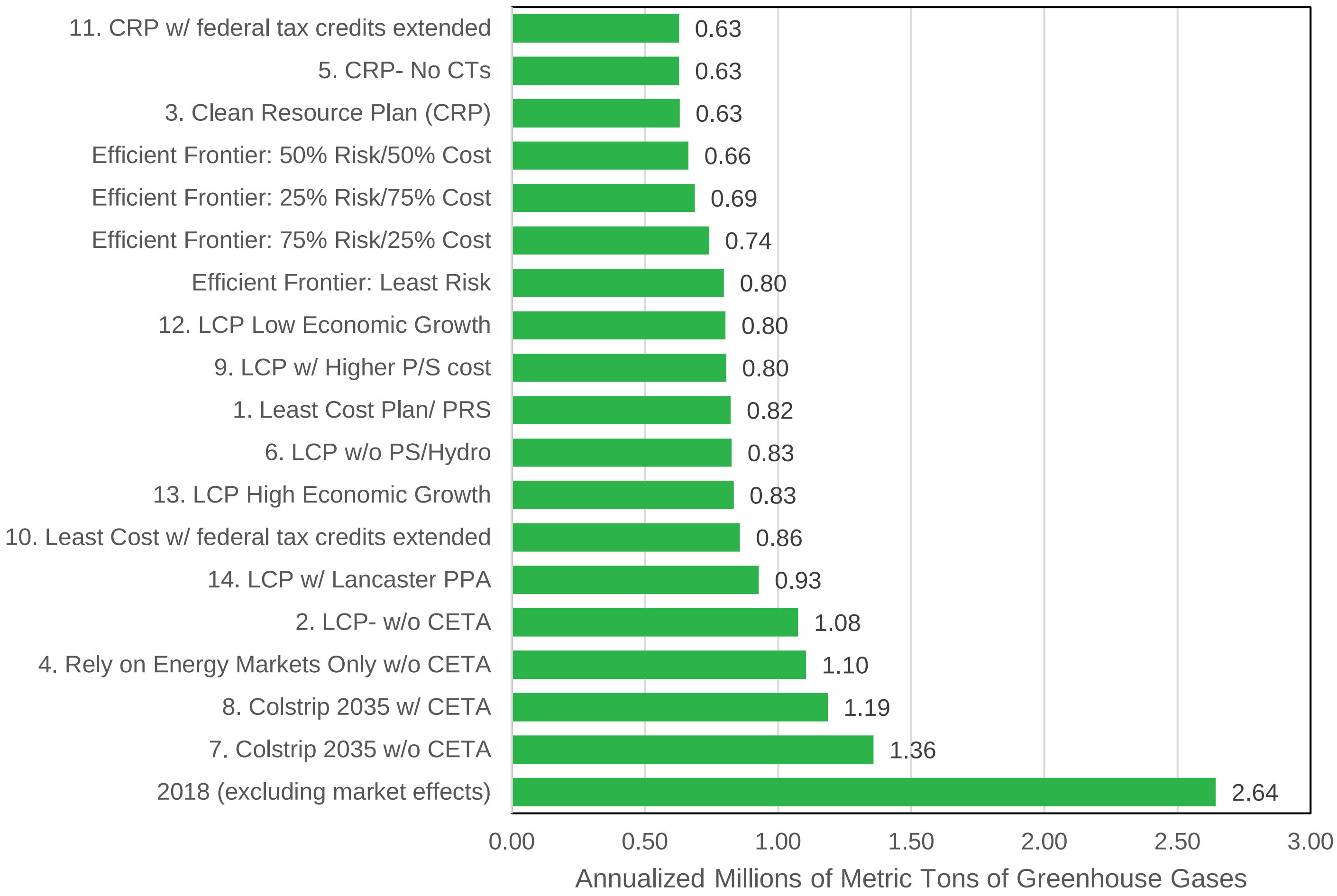
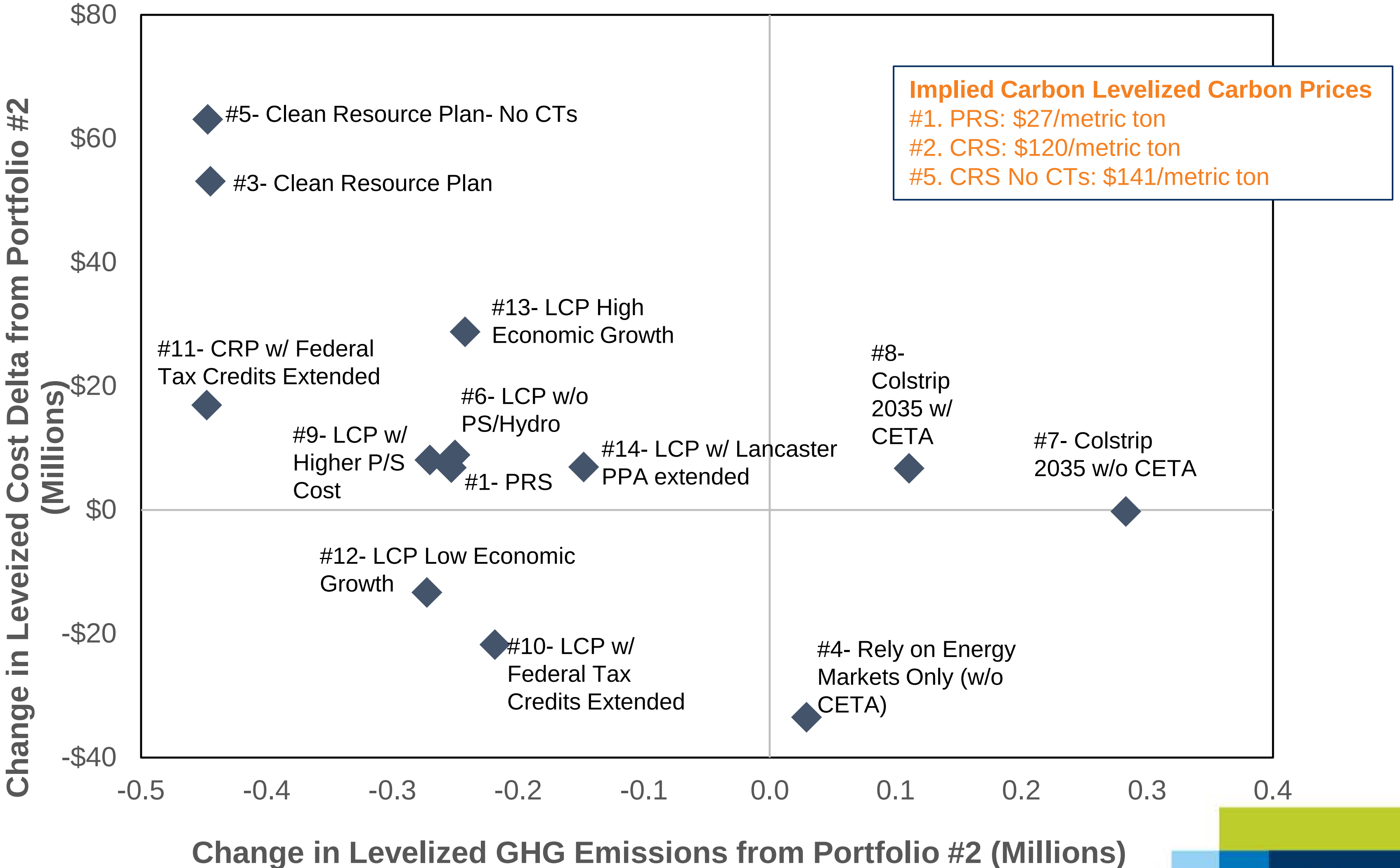
Annualized Greenhouse Gas Emissions
(Levelized using 2.5% discount rate)



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

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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

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

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

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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

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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

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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

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

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