2020 Avista Natural Gas IRP

Technical Advisory Committee Meeting
June 17, 2020

2020 Natural Gas IRP schedule

•**TAC 1: Wednesday, June 17, 2020**: TAC meeting expectations, 2020 IRP process and schedule, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits, Demand, Weather Analysis and a Weather Planning Standard, and an energy efficiency update.

•**TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

•**TAC 3: Wednesday, September 30, 2020:** Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

•**TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

•**TAC 5: February 2021:** TAC final review meeting (if necessary)

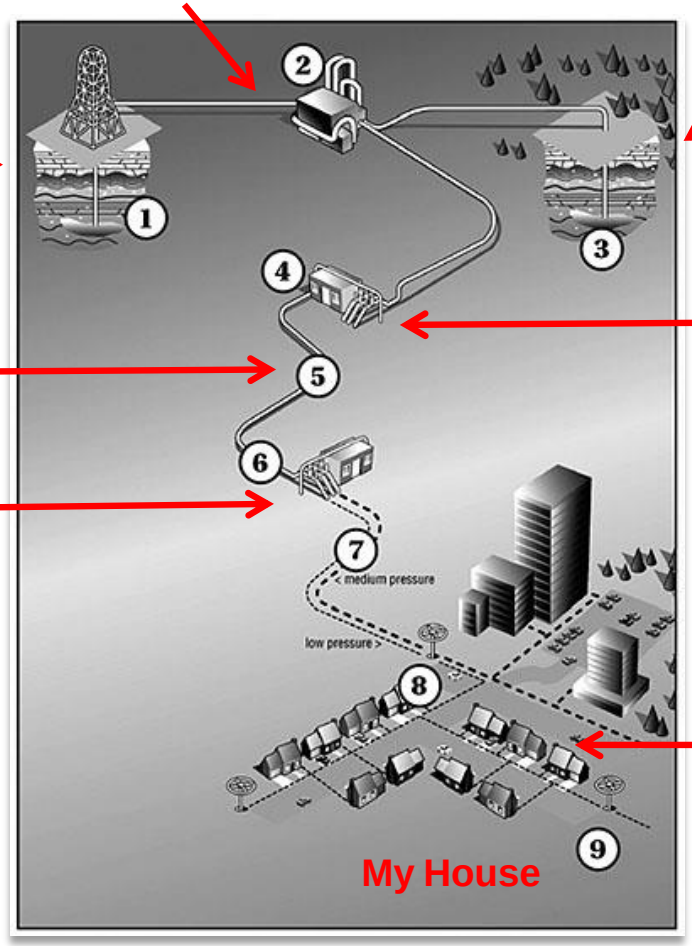
Agenda

- TAC meeting expectations
- 2020 IRP process and schedule
- Actions from 2018 IRP
- Winter of 2018-2019 review
- Demand
- Demand Forecast Methodology
- Weather Analysis
- Weather Planning Standard
- Procurement Plan
- Resource Optimization benefits
- Energy efficiency update

Avista's IRP Process

- Comprehensive analysis bringing demand forecasting and existing and potential supply-side and demand-side resources together into a 20-year, risk adjusted least-cost plan
- Considers:
  - Customer growth and usage
  - Weather planning standard
  - Demand-side management opportunities
  - Existing and potential supply-side resource options
  - Risk
  - Public participation through Technical Advisory Committee meetings (TAC)
  - Distribution upgrades
- 2018 IRP filed in all three jurisdictions on August 31, 2018 and acknowledged

The Natural Gas System



2018 Avista Natural Gas IRP – Action Plan

1. Avista's 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
2. Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.
3. Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.
4. Revisit coldest on record planning standard and discuss with TAC for prudency.
5. Provide additional information on resource optimization benefits and analyze risk exposure.
6. DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.
7. Carbon Costs – consult Washington State Commission's Acknowledgement Letter Attachment in its 2017 Electric IRP (Docket UE-161036), where emissions price modeling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.
8. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.

2018 Avista Natural Gas IRP Action Plan cont.

- 9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:
- • Natural gas infrastructure investment not included as discrete projects in IRP
- – Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
- • Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
- – Anticipated PHMSA guidance or rules related to 49 CFR Part § 192 that will likely requires additional capital to comply
- • Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
- – Construction of gas infrastructure associated with growth
- – Other special contract projects not known at the time the IRP was published
- • Other non-IRP investments common to all jurisdictions that are ongoing, for example:
- – Enterprise technology projects & programs
- – Corporate facilities capital maintenance and improvements

- An updated table 8.4 for those distribution projects in Oregon:
- Location
- Klamath Falls, OR
- Sutherlin, OR

- 10. Avista will work with members of the OPUC to determine an alternative stochastic approach to Monte Carlo analysis prior to Avista's 2020 IRP and share any recommendations with the TAC members.

That Could Never Happen!

Gas Supply Winter 2018-2019

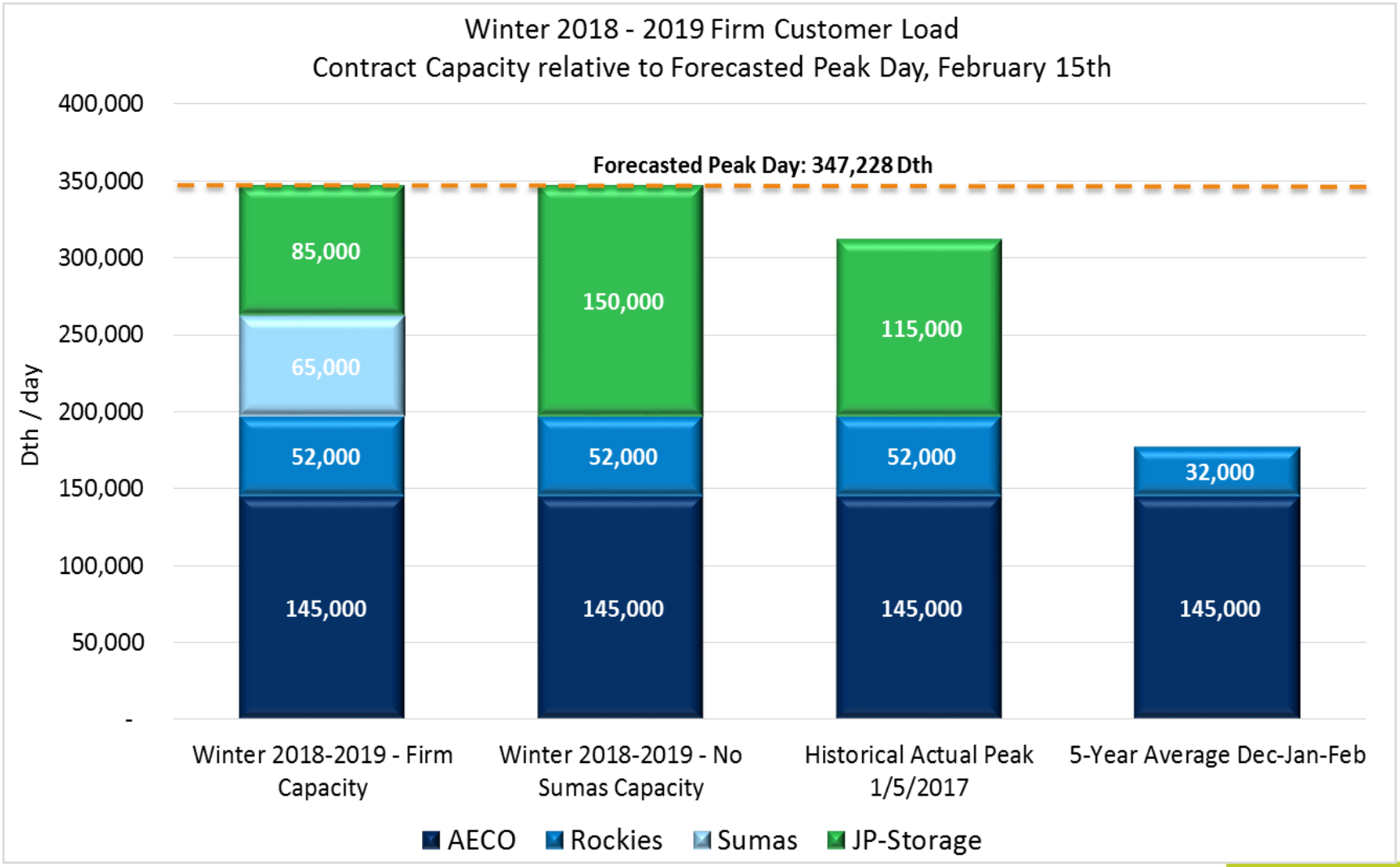
Enbridge Pipeline Rupture

Pipeline ruptured October 9th

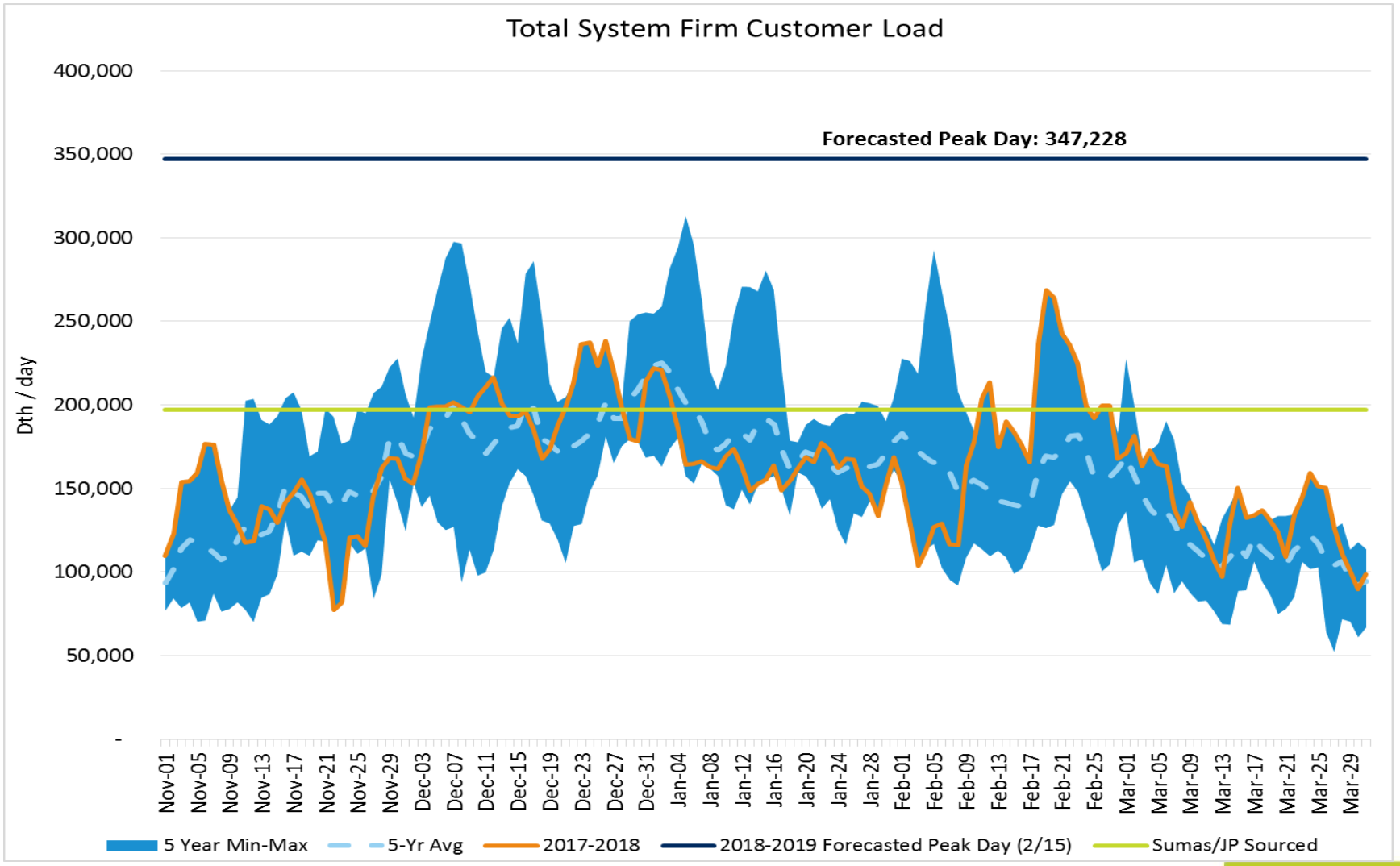
- 2.4 Bcf off the system
- Jackson Prairie Storage - down
- **NWP Roosevelt** compressor maintenance
- Within 24 hours, 50% of demand came off
- Moderate temperatures across Pacific NW
- Average gas prices < $3/Dth
- Gas rebate deferral balances growing

Source: NWGA 2017 Annual Outlook

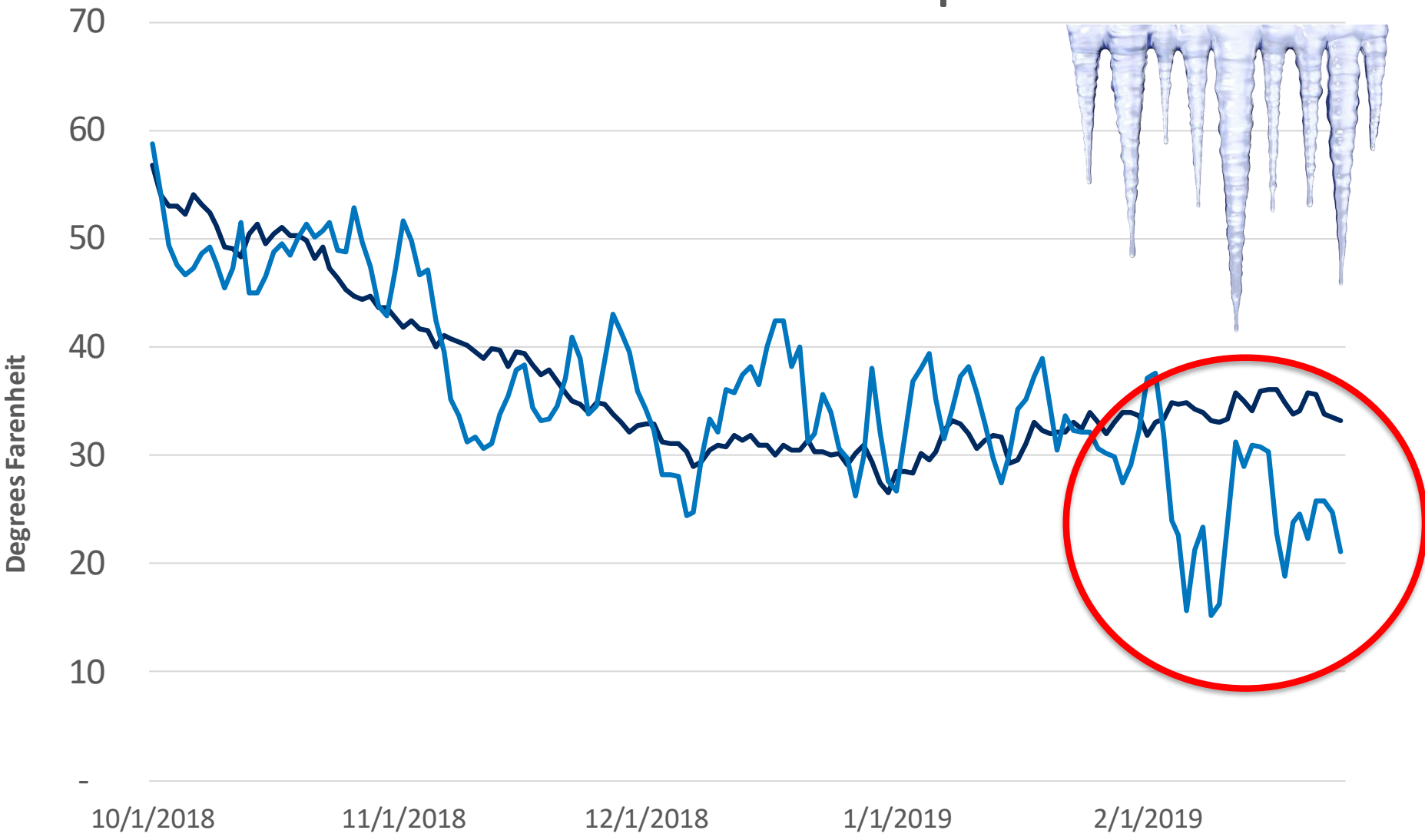
Winter 2018-2019 Outlook



Historical Winter Firm Customer Load



Winter '18 - '19 Blended Temps



*Avg. weather

Operation Flow Order (OFO)

- **Northwest Pipeline (NWP) Operational Flow Order**

An OFO is declared to provide the needed displacement on NWP's system to meet firm commitments. When scheduled quantities exceed physical capacity, NWP is in a potential OFO situation. In other words,

****Avista must flow gas from west to east.****

US Storage

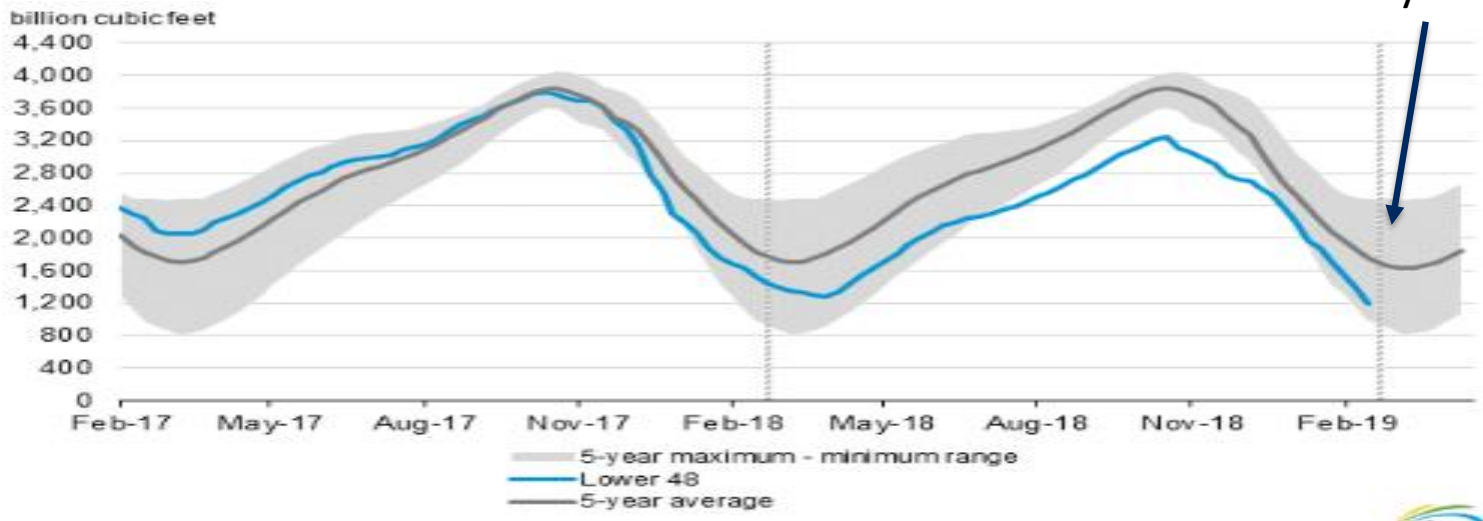
Working gas in underground storage, Lower 48 states

Summary text | CSV | JSN

	Stocks billion cubic feet (Bcf)				Historical Comparisons: Year ago (03/08/18)		5-year average (2014-18)	
Region	03/08/19	03/01/19	net change	implied flow	Bcf	% change	Bcf	% change
East	262	311	-49	-49	320	-18.1	338	-22.5
Midwest	287	338	-51	-51	354	-18.9	398	-27.9
Mountain	66	73	-7	-7	94	-29.8	116	-43.1
Pacific	102	112	-10	-10	170	-40.0	199	-48.7
South Central	469	557	-88	-88	607	-22.7	705	-33.5
Salt	129	180	-51	-51	186	-30.6	195	-33.8
Nonsalt	340	377	-37	-37	420	-19.0	510	-33.3
Total	1,186	1,390	-204	-204	1,545	-23.2	1,755	-32.4

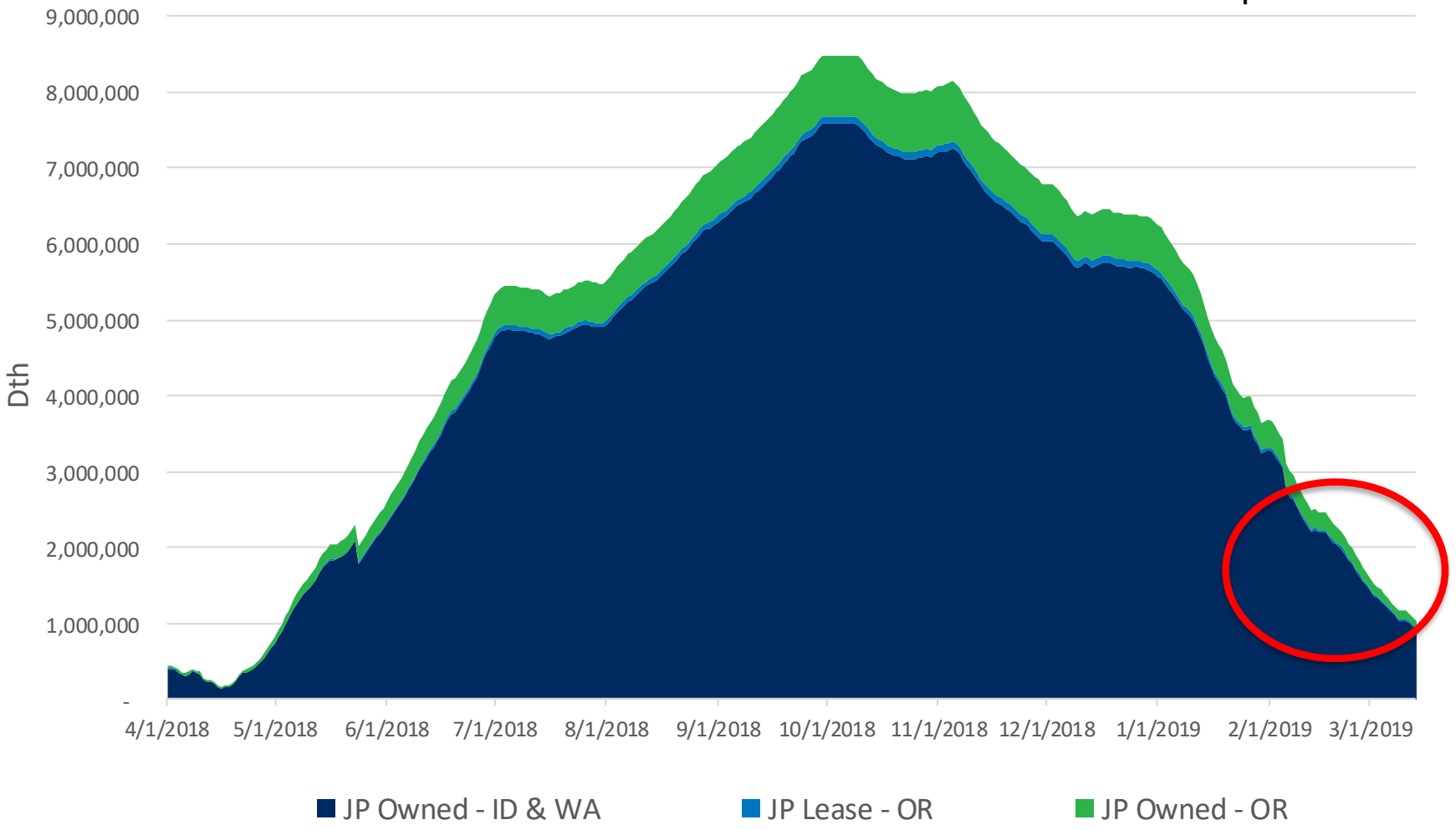
Totals may not equal sum of components because of independent rounding.

569 Bcf below 5 yr avg

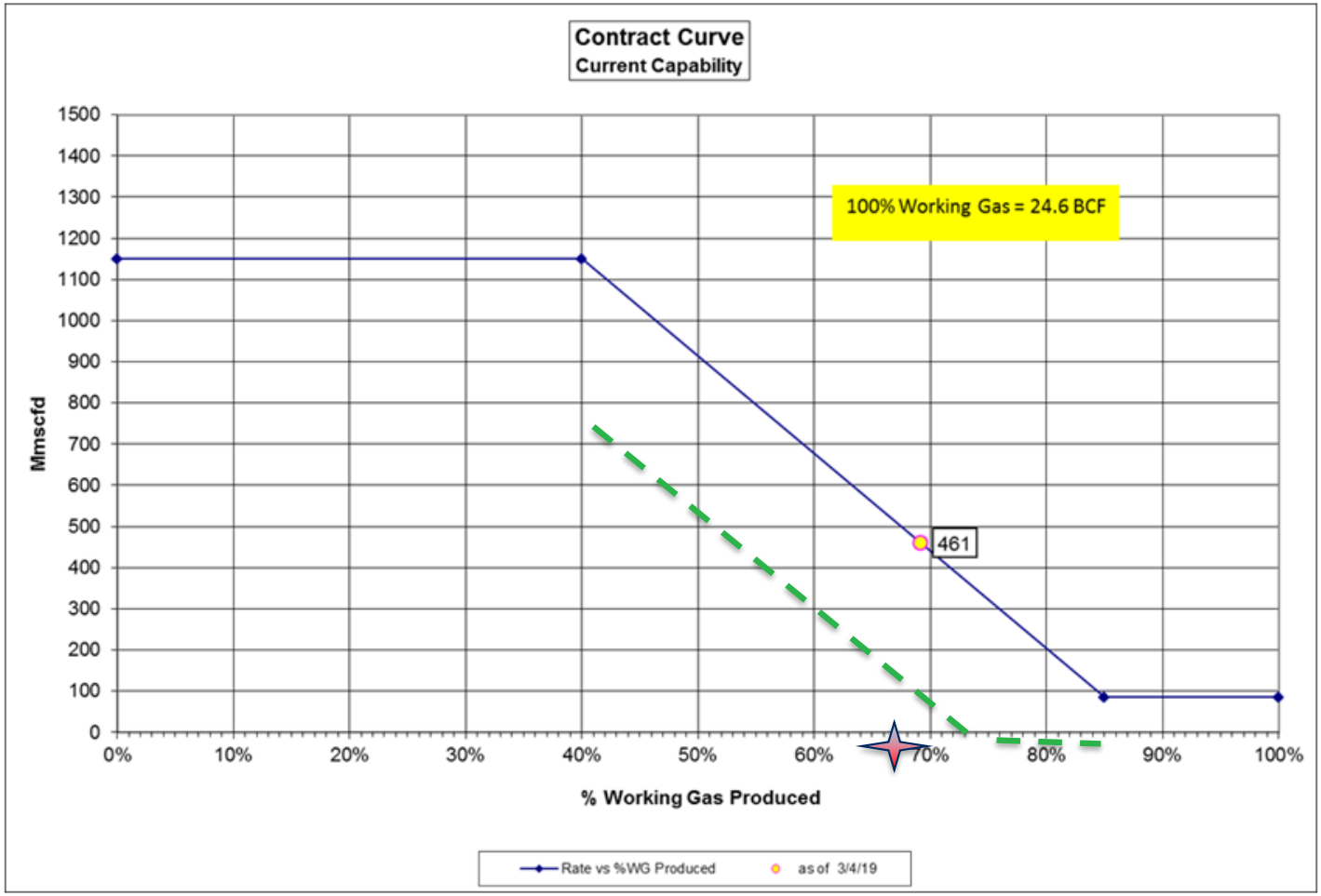


JP Storage Levels

Avista – 1.0 bcf
Puget – 2.2 bcf
Nwp – 3.5 bcf



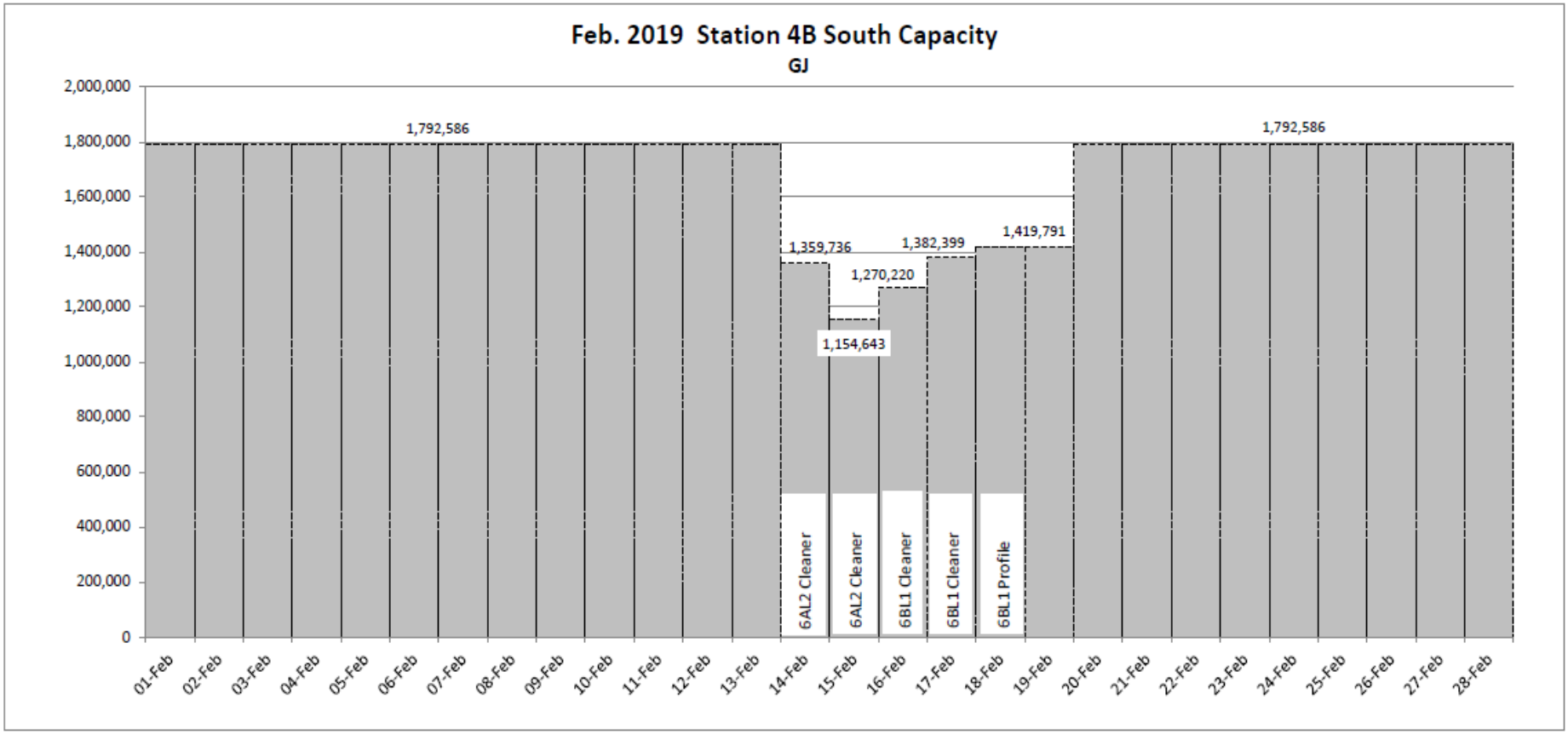
Jackson Prairie Compressor C-9



Compressor Failed 2/10/19

Reduction of withdrawal capability by approx. 200-300 MMscfd
Avista withdrawal ability < 90 MMscfd (JP demand 50 – 90 MMscfd)

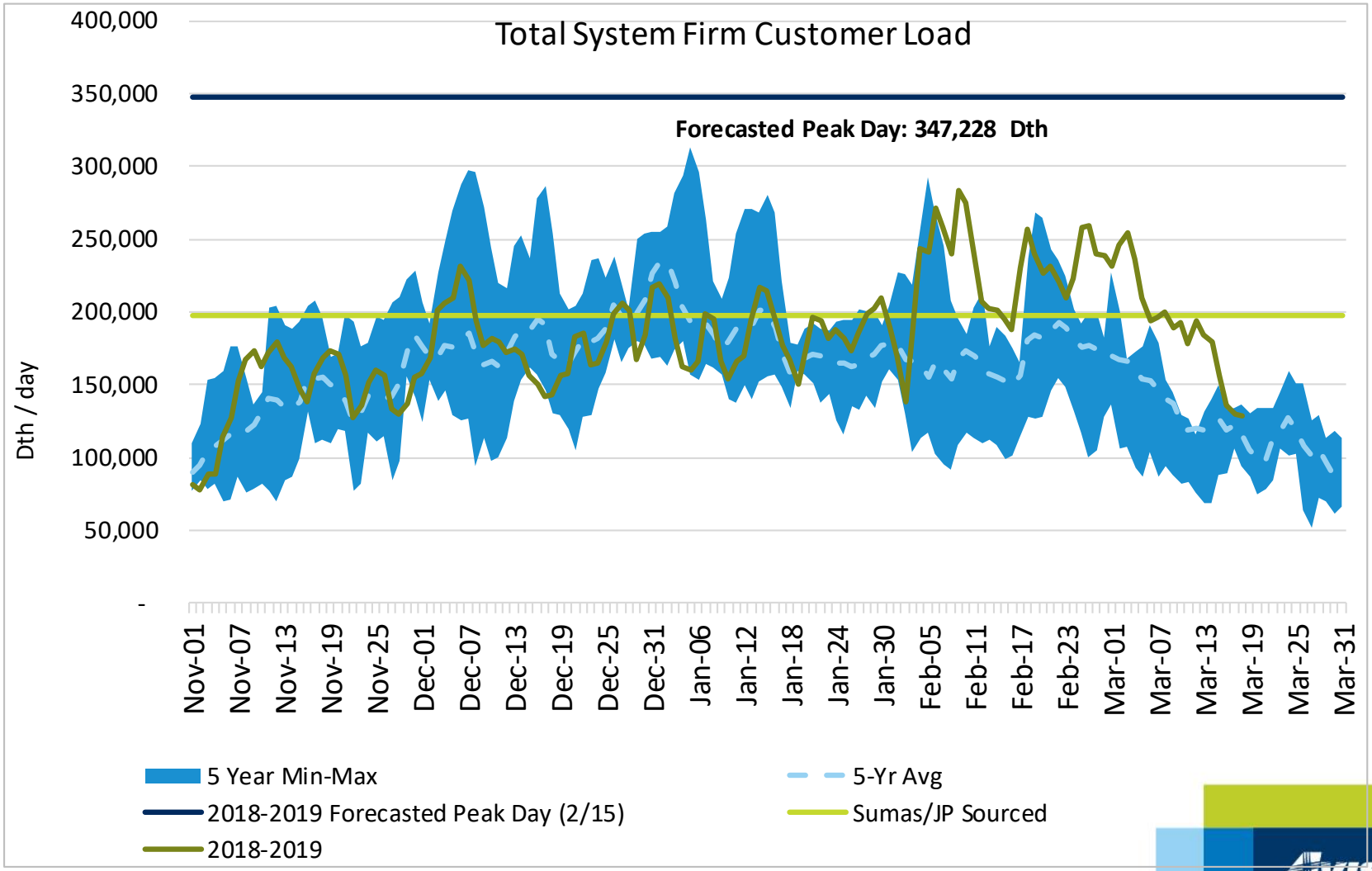
Enbridge Capacity Cuts



Pipeline Entitlements

- Entitlements are used to balance demand
  - Entitlement tolerances are tiered
    - 13%, 8%, 5%, 3% depending on severity of issue
  - Overrun entitlement
    - Total demand must not exceed nominations by the prescribed level
    - Example: Avista nominates 150,000 Dth on pipeline, demand must be AT MOST 169,500 Dth
  - Entitlement penalties
    - Greater of $10.00/ dth or 4x the highest midpoint price in region

Historical and Current Winter Loads



Planning Outcomes changes

- In order to reduce the risk around not being able to serve load on a peak day with late winter weather Avista is moving it's peak day from 2/15 to 2/28 for the WA/ID and La Grande

Avista's Demand Overview

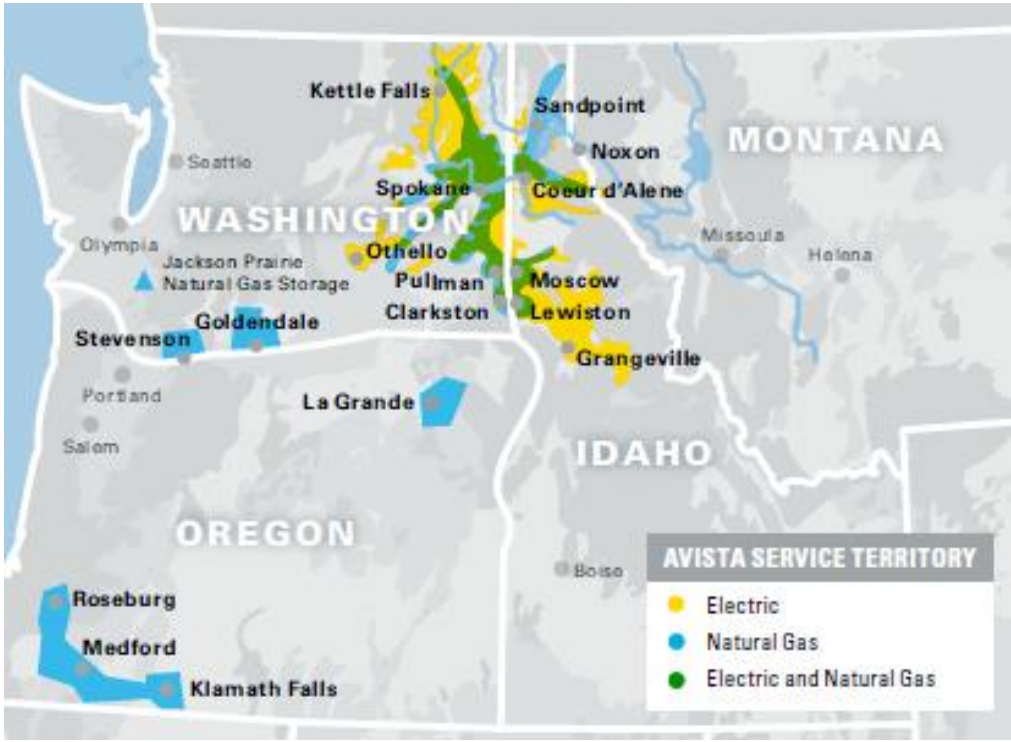
Tom Pardee
Manager of Natural Gas Planning

Service Territory and Customer Overview

- Serves electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in southern and eastern Oregon
  - Population of service area 1.5 million
    - 385,000 electric customers
    - 360,000 natural gas customers

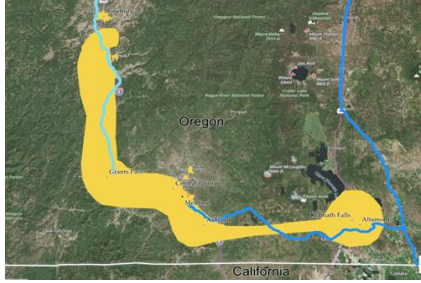
- Has one of the smallest carbon footprints among America's 100 largest investor-owned utilities

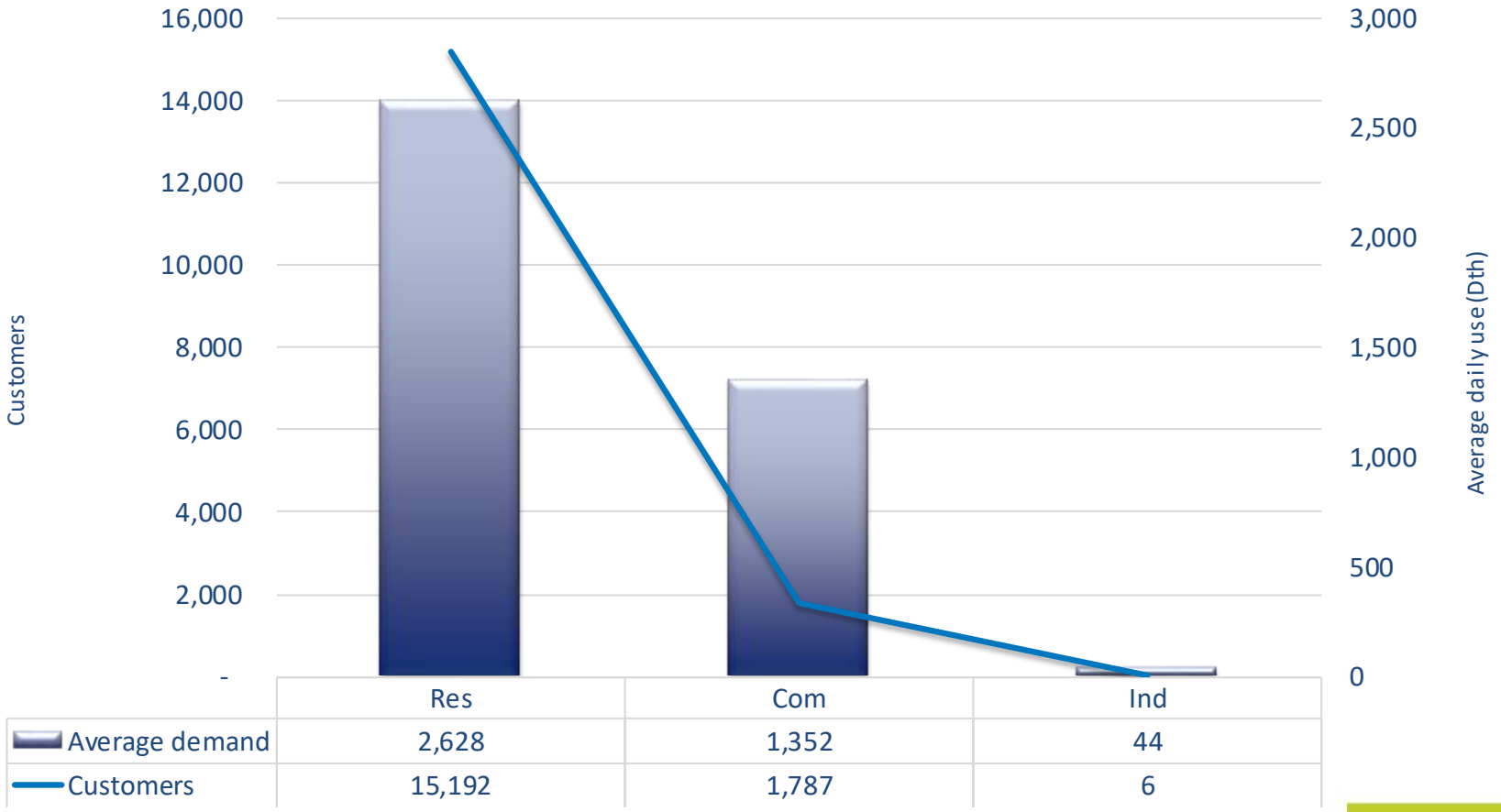
- Committed to environmental stewardship and efficient use of resources



State	Total Customers	% of Total
Washington	170,000	47%
Oregon	103,000	29%
Idaho	87,000	24%
Total	360,000	100%

Klamath Falls

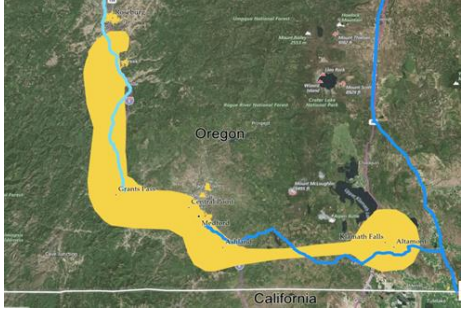


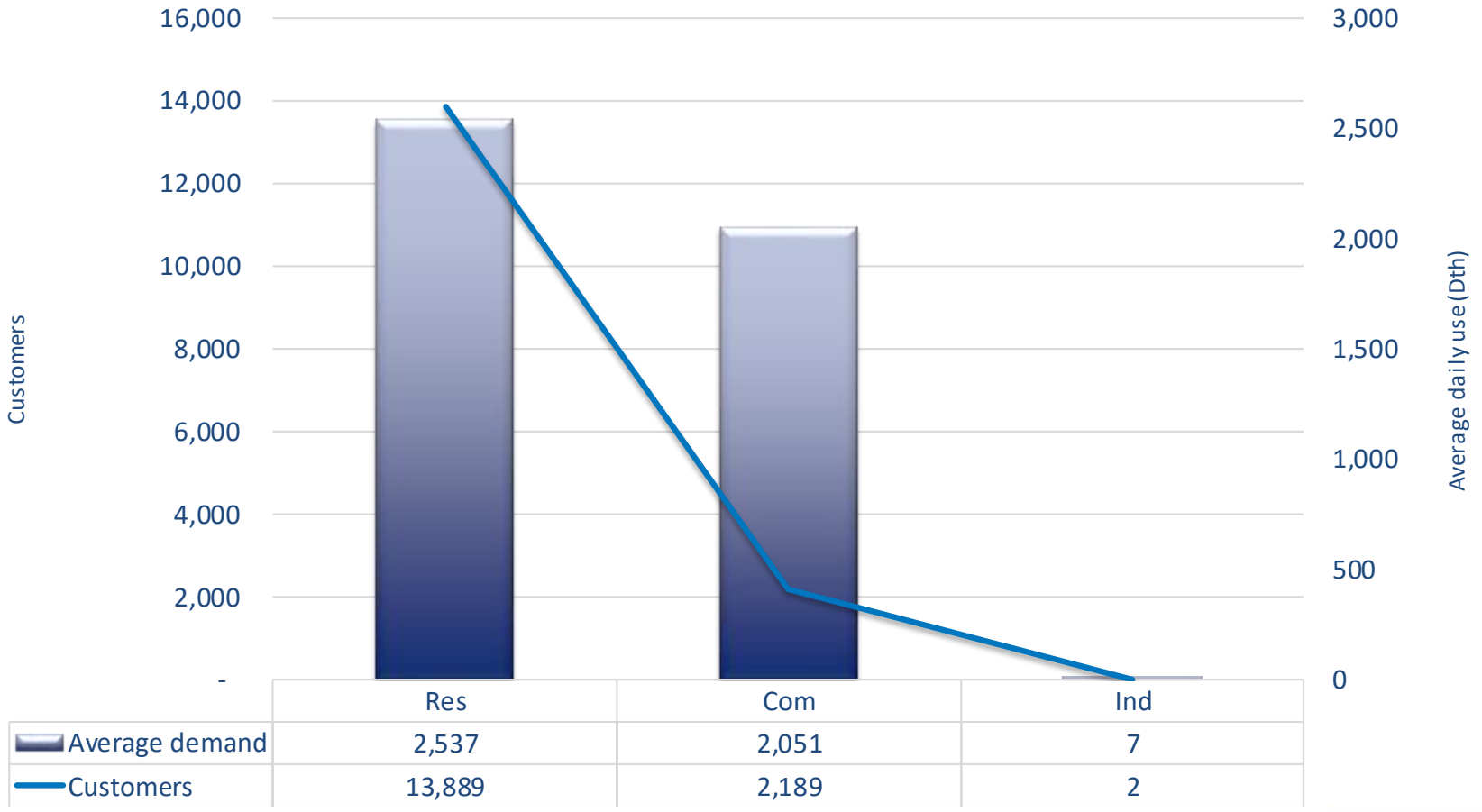


	Res	Com	Ind
Average demand	2,628	1,352	44
Customers	15,192	1,787	6

Average 2019 Temp Fahrenheit 47

Roseburg

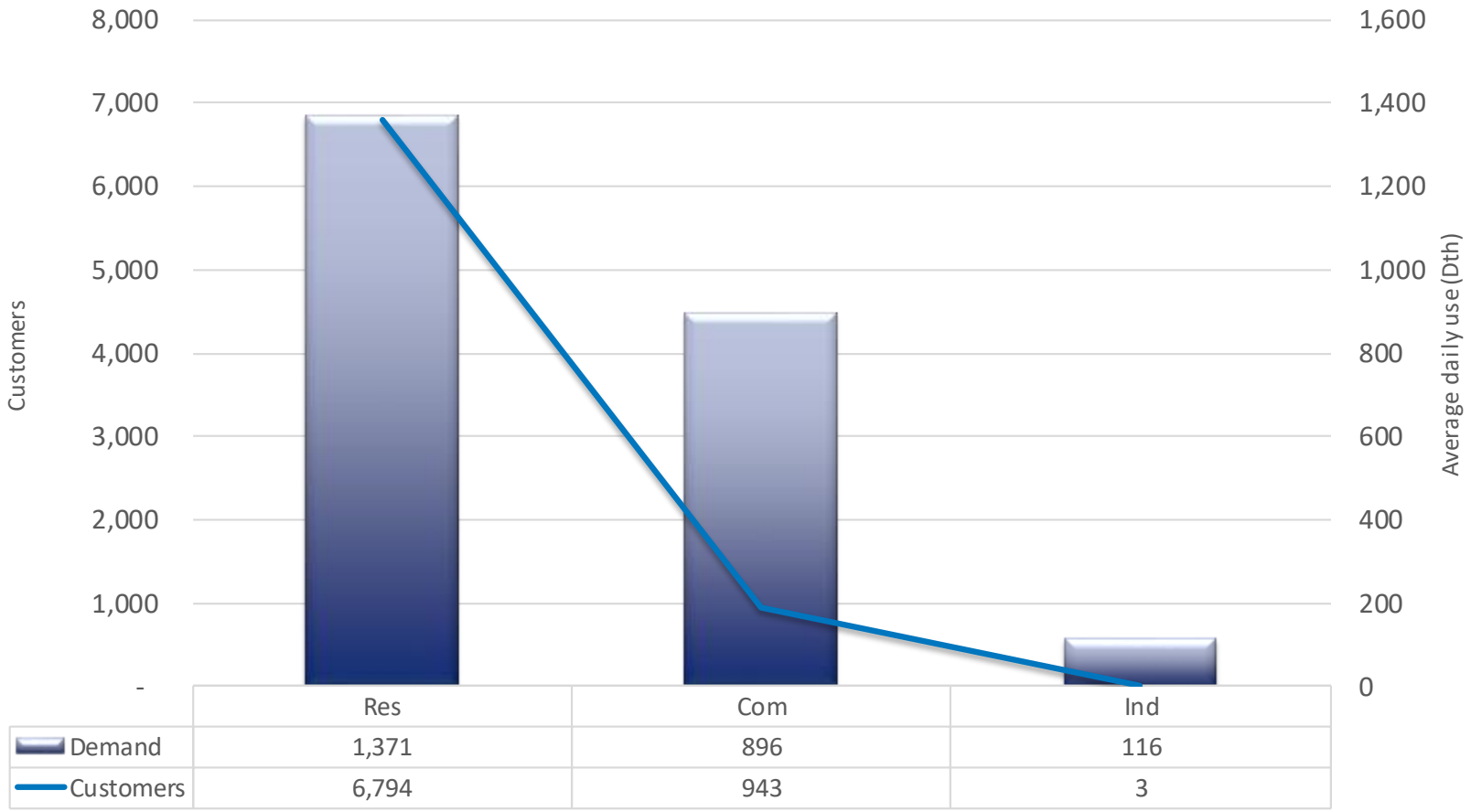




	Res	Com	Ind
Average demand	2,537	2,051	7
Customers	13,889	2,189	2

Average 2019 Temp Fahrenheit 55

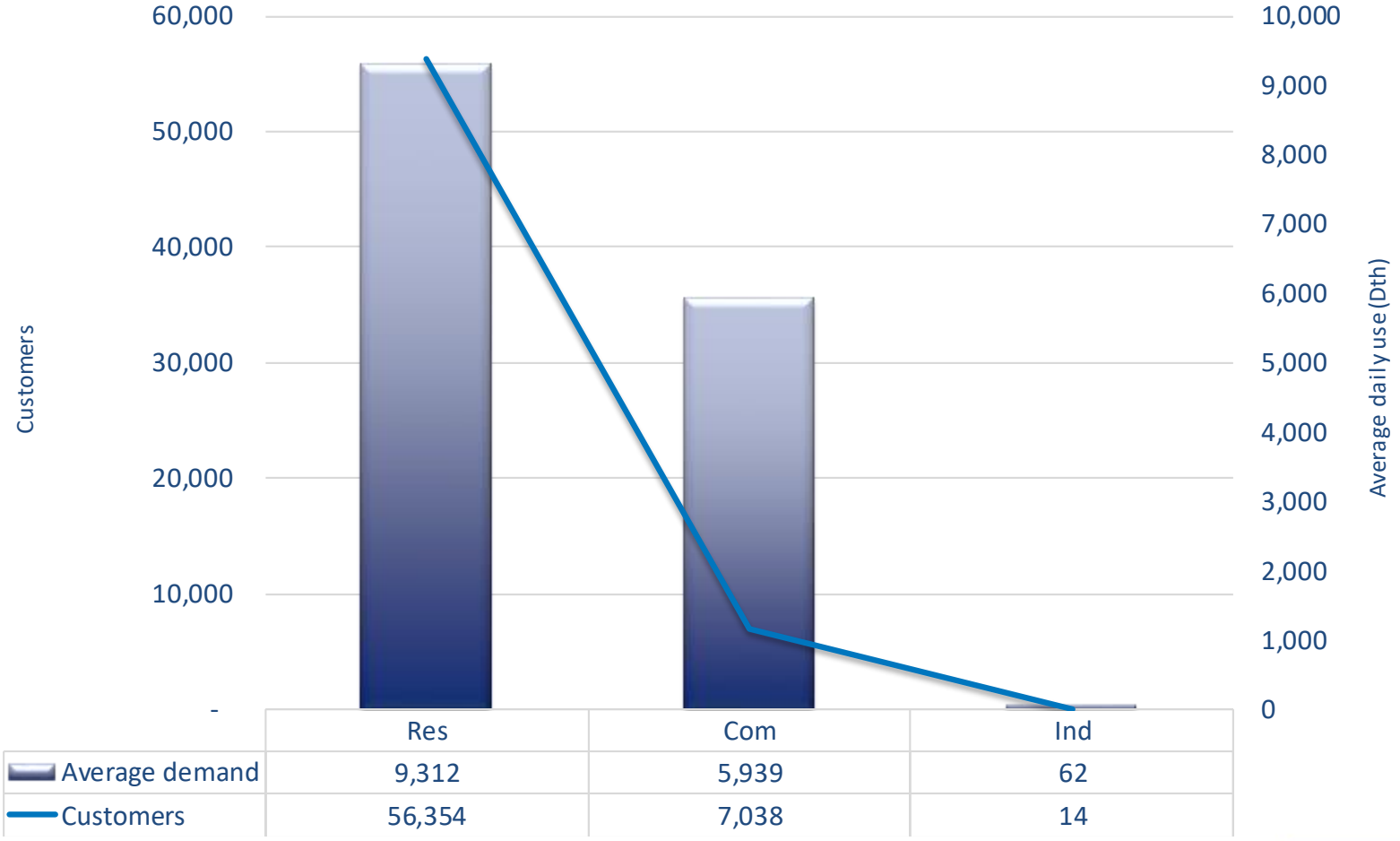
La Grande



	Res	Com	Ind
Demand	1,371	896	116
Customers	6,794	943	3

Average 2019 Temp Fahrenheit 47

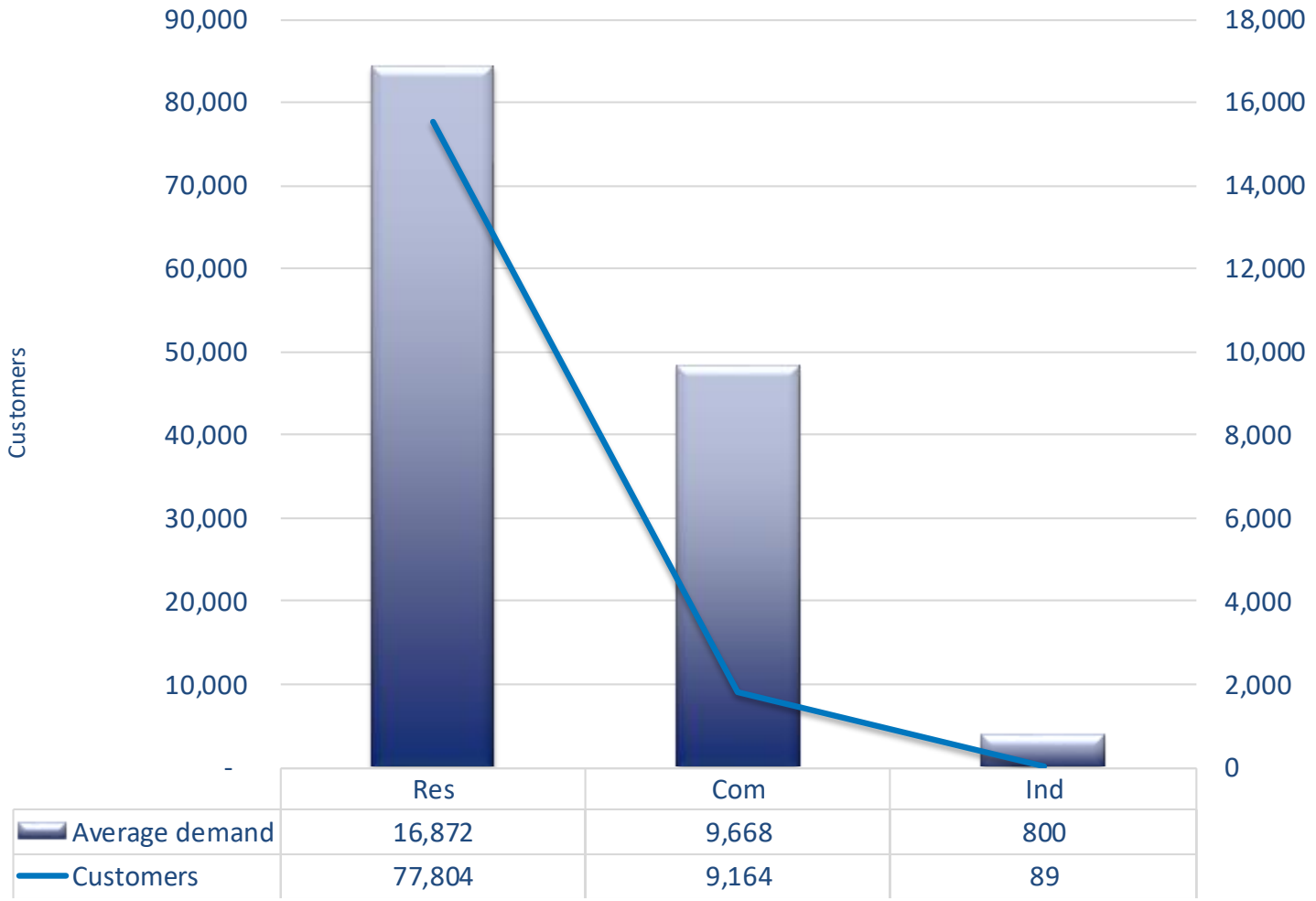
Medford



	Res	Com	Ind
Average demand	9,312	5,939	62
Customers	56,354	7,038	14

Average 2019 Temp Fahrenheit 55

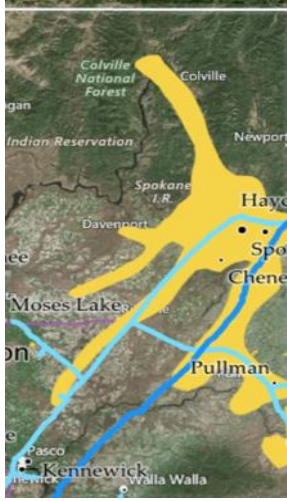
Idaho

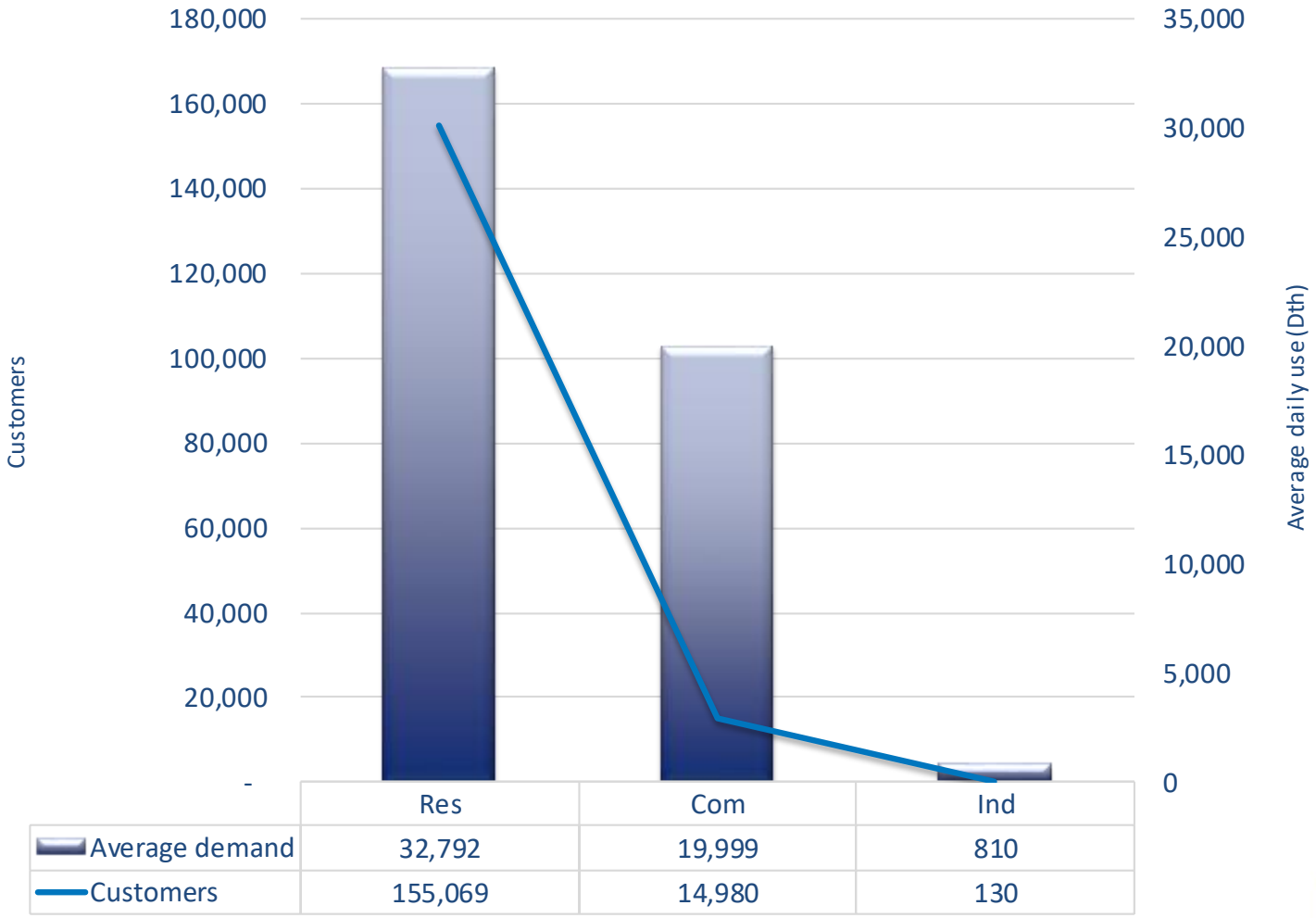


	Res	Com	Ind
Average demand	16,872	9,668	800
Customers	77,804	9,164	89

Average 2019 Temp Fahrenheit 47

Washington

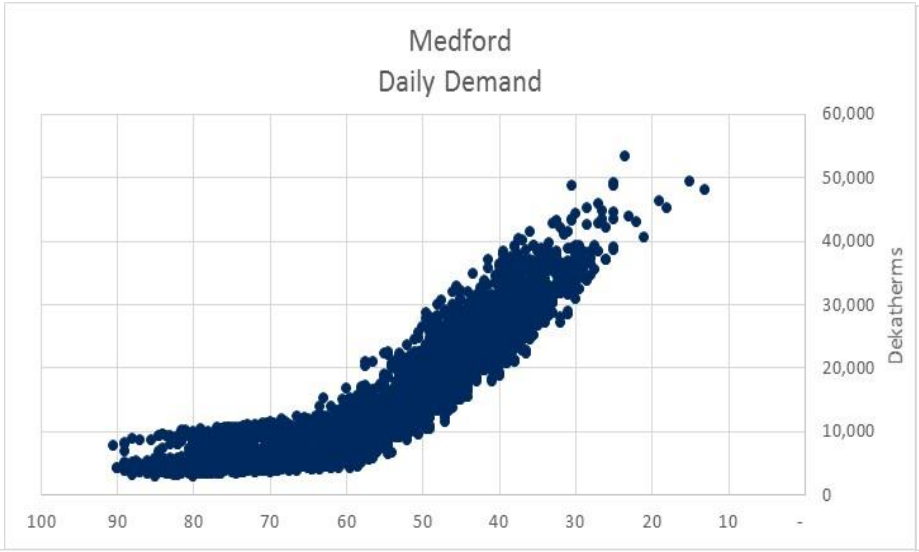


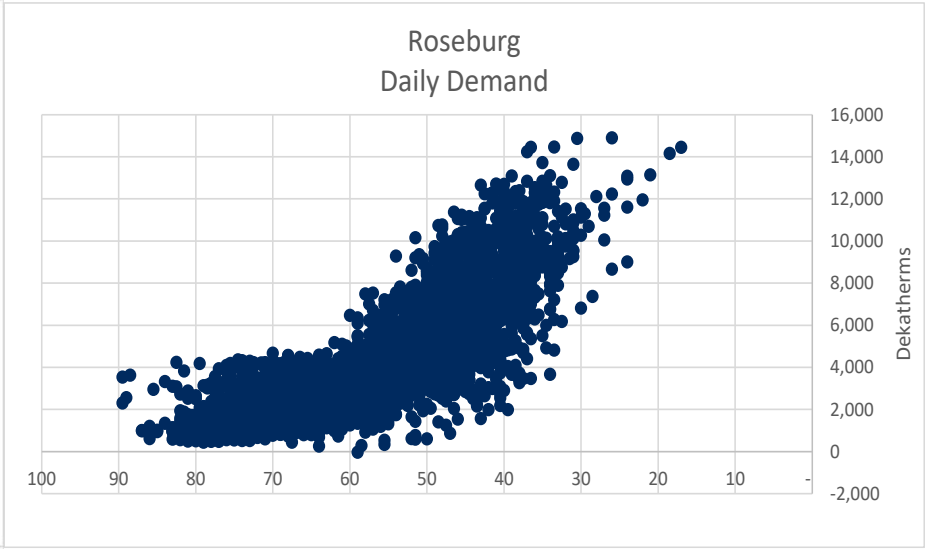


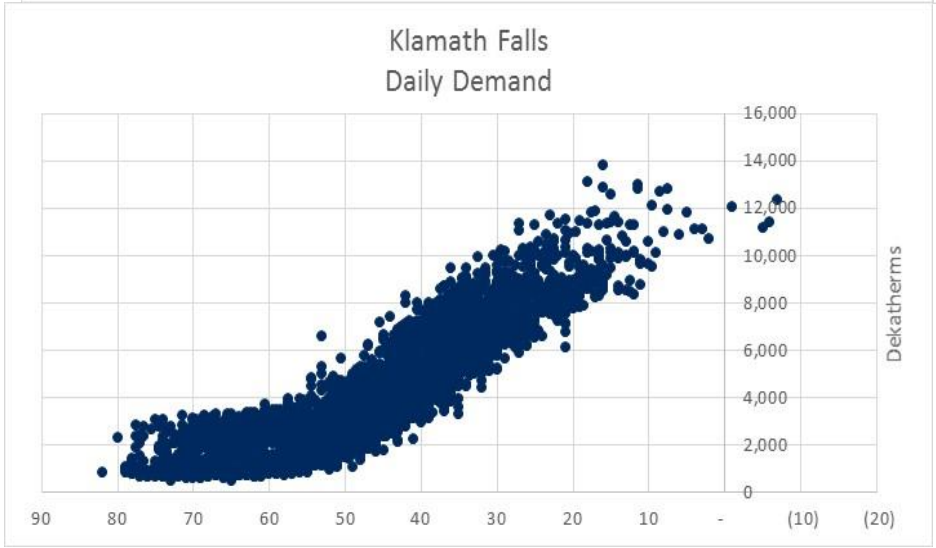
	Res	Com	Ind
Average demand	32,792	19,999	810
Customers	155,069	14,980	130

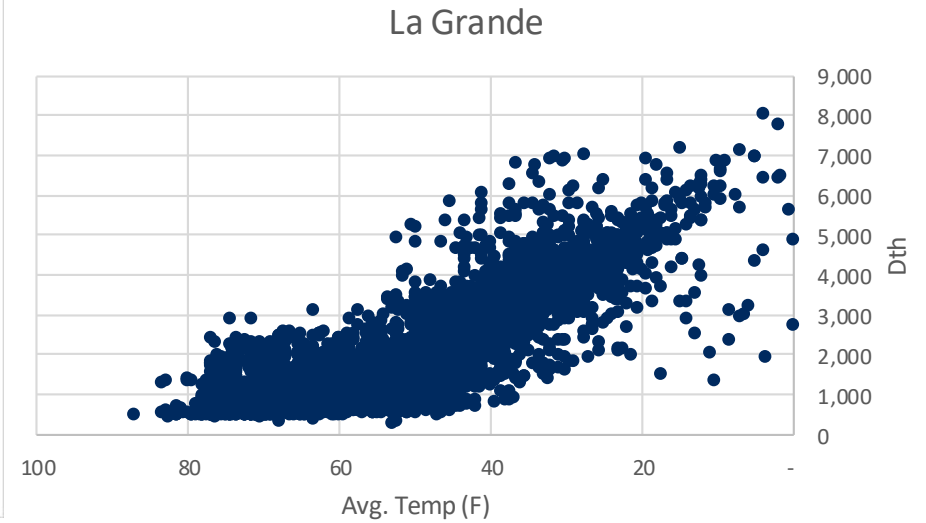
Average 2019 Temp Fahrenheit 47

OR Daily Demand Profiles

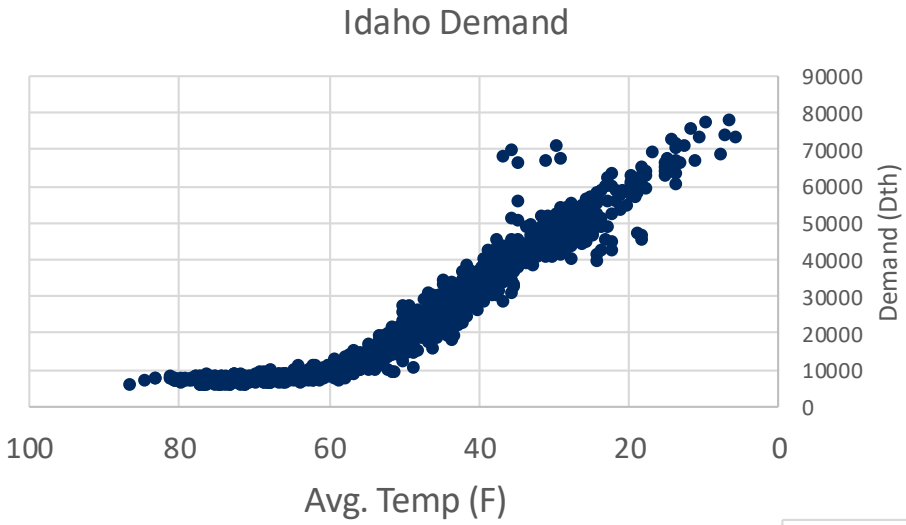


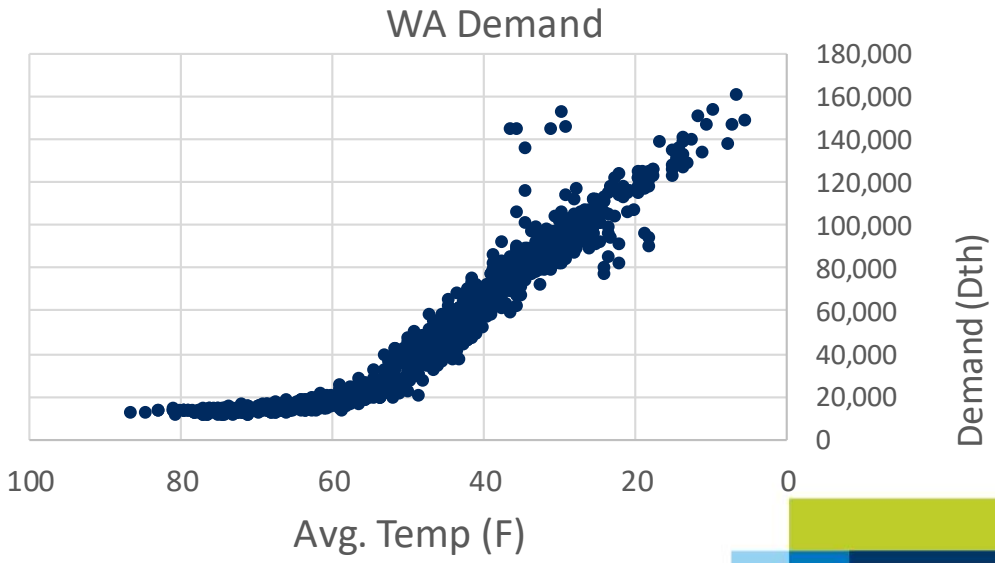






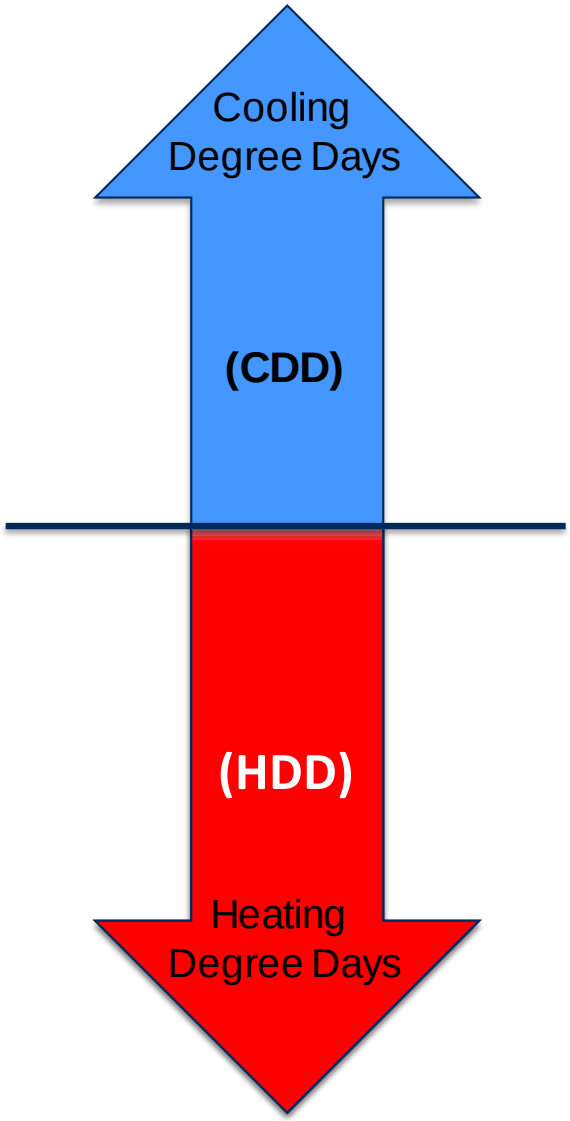
WA-ID Daily Demand Profiles





Demand Forecast Methodology

Temperature & Degree Days



Temp (°F)		Degree Days
100	=	35
90	=	25
80	=	15
70	=	5
65	=	0
60	=	5
50	=	15
40	=	25
30	=	35
20	=	45
10	=	55
0	=	65
-10	=	75
-20	=	85

Weather

- NOAA 20 year actual average daily HDD's (2000-2019)
- Peak weather includes two winter storms (5 day duration), one in December and one in February
- Planning Standard
- Sensitivity around planning standard including
  - Normal/Average
  - Monte Carlo simulation

Base Coefficients

Planning Area - Residential Class	2 year	3 year	5 year
Roseburg (Oregon)	0.041949146	0.040148823	0.03765259
Medford (Oregon)	0.04748832	0.047701223	0.04716918
La Grande (Oregon)	0.069994892	0.068986632	0.073506326
Klamath Falls (Oregon)	0.035881027	0.034536108	0.033843554
Idaho	0.048375922	0.046698825	0.046092068
Washington	0.047248771	0.046575066	0.047525773

*Base Coefficients

*Historic Data - July and August Average

Heat Coefficients

Planning Area - Residential Class	2 Year	3 Year	5 Year
Roseburg (Oregon)	0.008829	0.008046	0.00699
Medford (Oregon)	0.00639	0.0065	0.006068
La Grande (Oregon)	0.006223	0.007297	0.00665
Klamath Falls (Oregon)	0.005284	0.005268	0.004902
Idaho	0.006445	0.006344	0.005896
Washington	0.006307	0.006313	0.005957

*Avg. of monthly heat coefficient

*Historic Data – adjusted by price elasticity and DSM

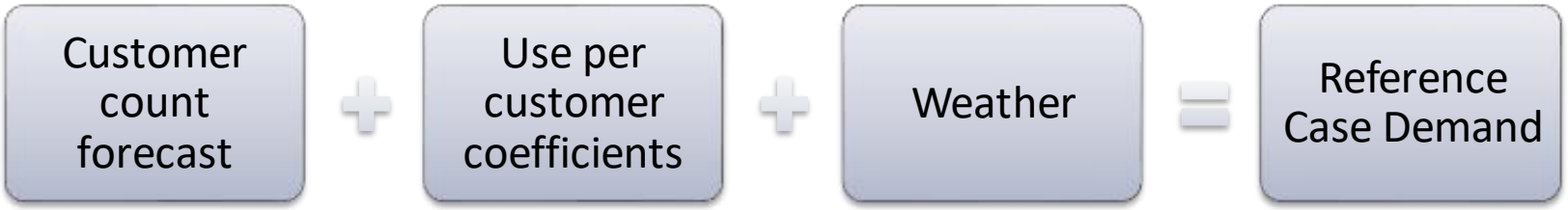
Demand Modeling Equation – a closer look

SENDOUT® requires inputs expressed in the below format to compute daily demand in dekatherms. The **base** and **weather sensitive** usage (degree-day usage) factors are developed outside the model and capture a variety of demand usage assumptions.

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer
Plus
# of customers **x** Daily **weather sensitive** usage / customer

Developing a Reference Case

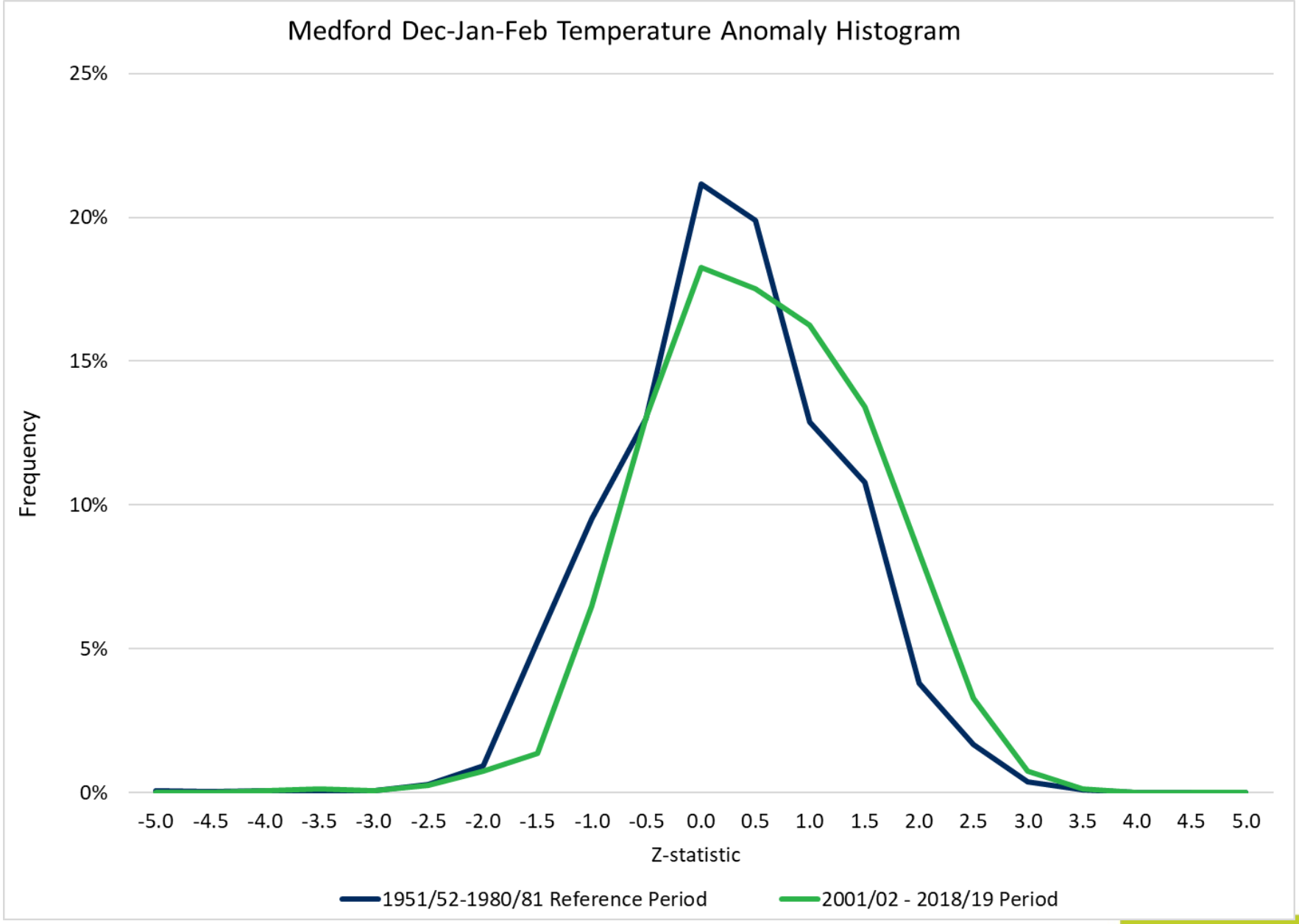


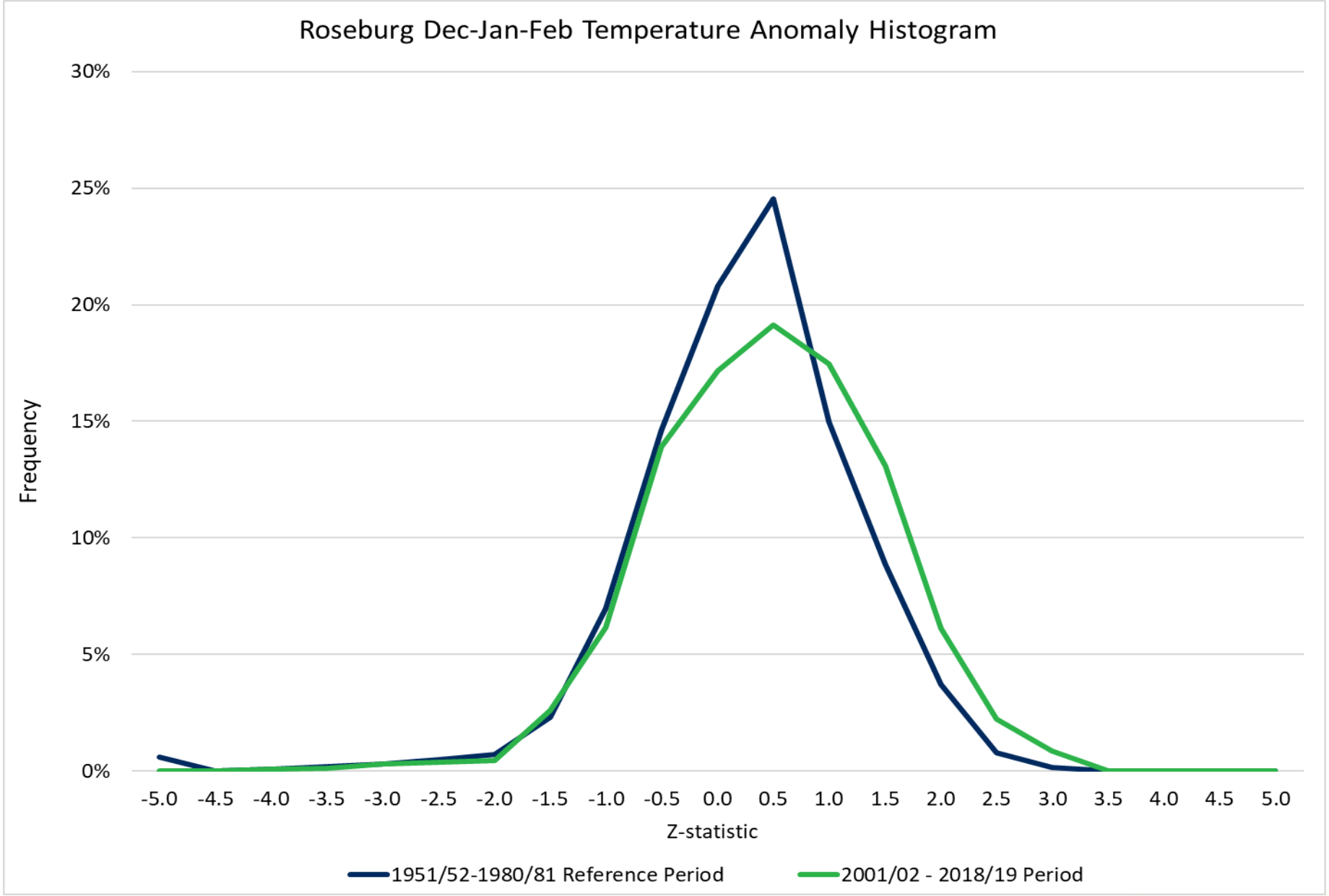
1. Expected customer count forecast by each of the 6 areas
2. Use per customer coefficients –5 year, 3 year or last 2 year average use per HDD per customer
3. Current weather planning standard

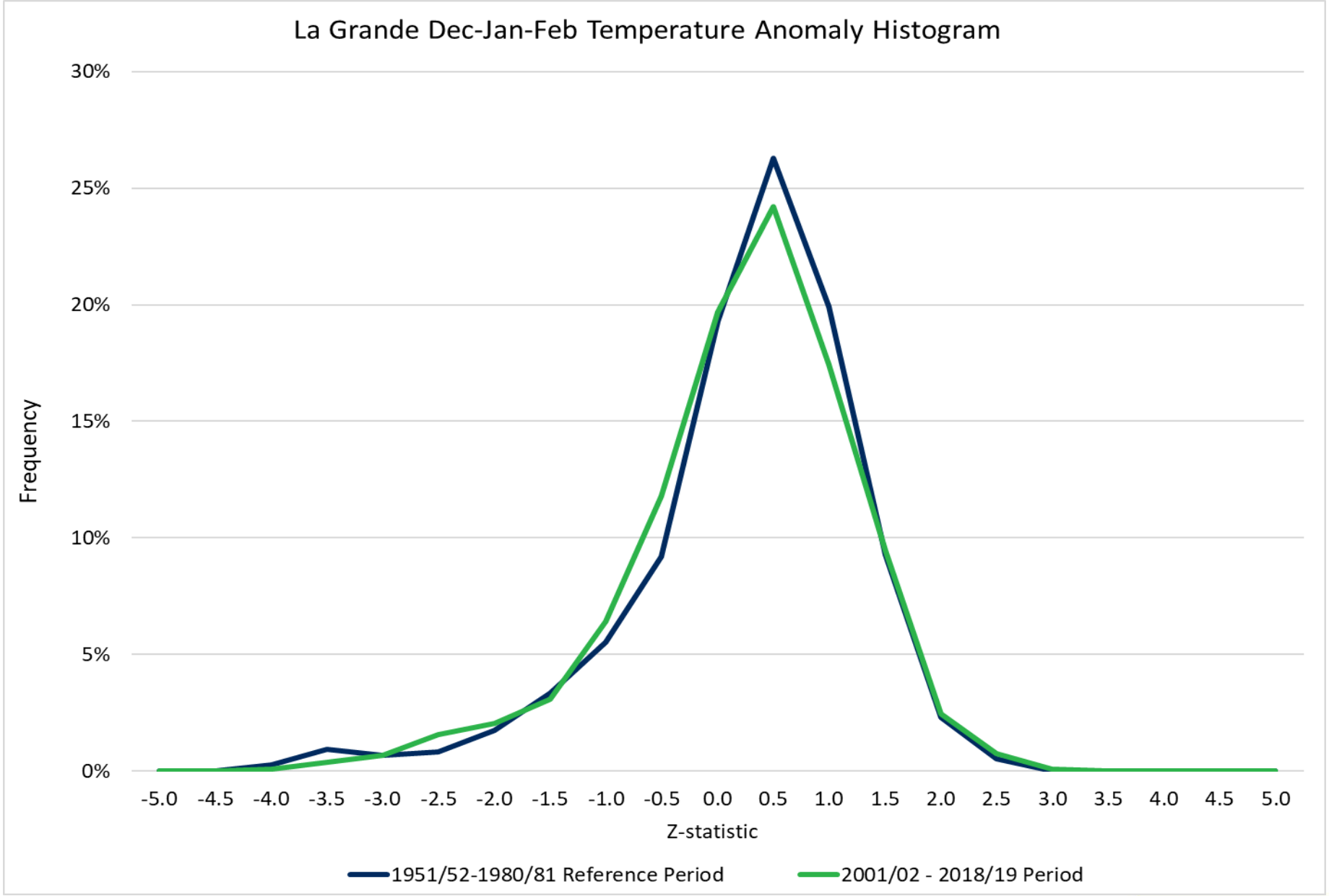
Weather Analysis

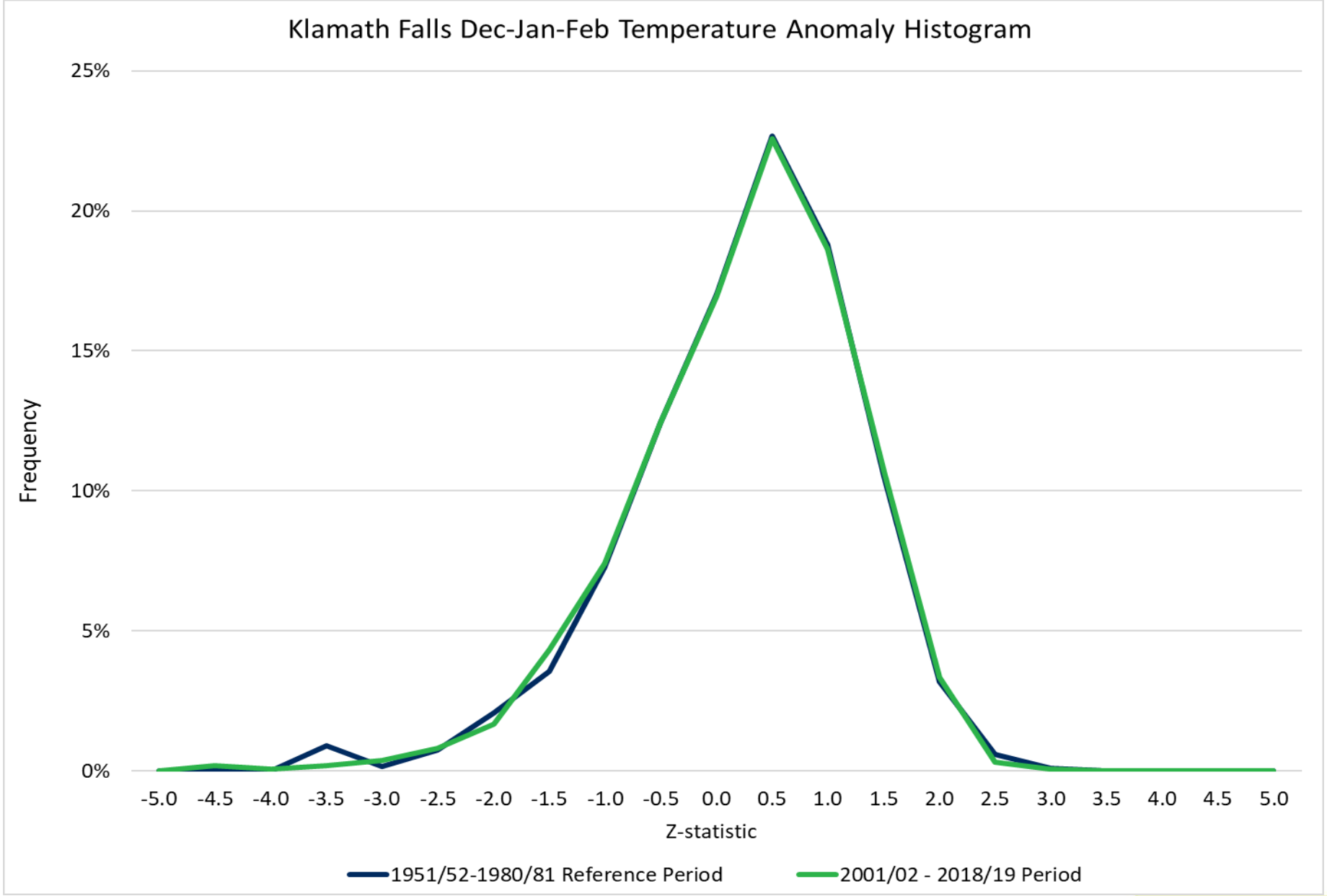
Z-Stat

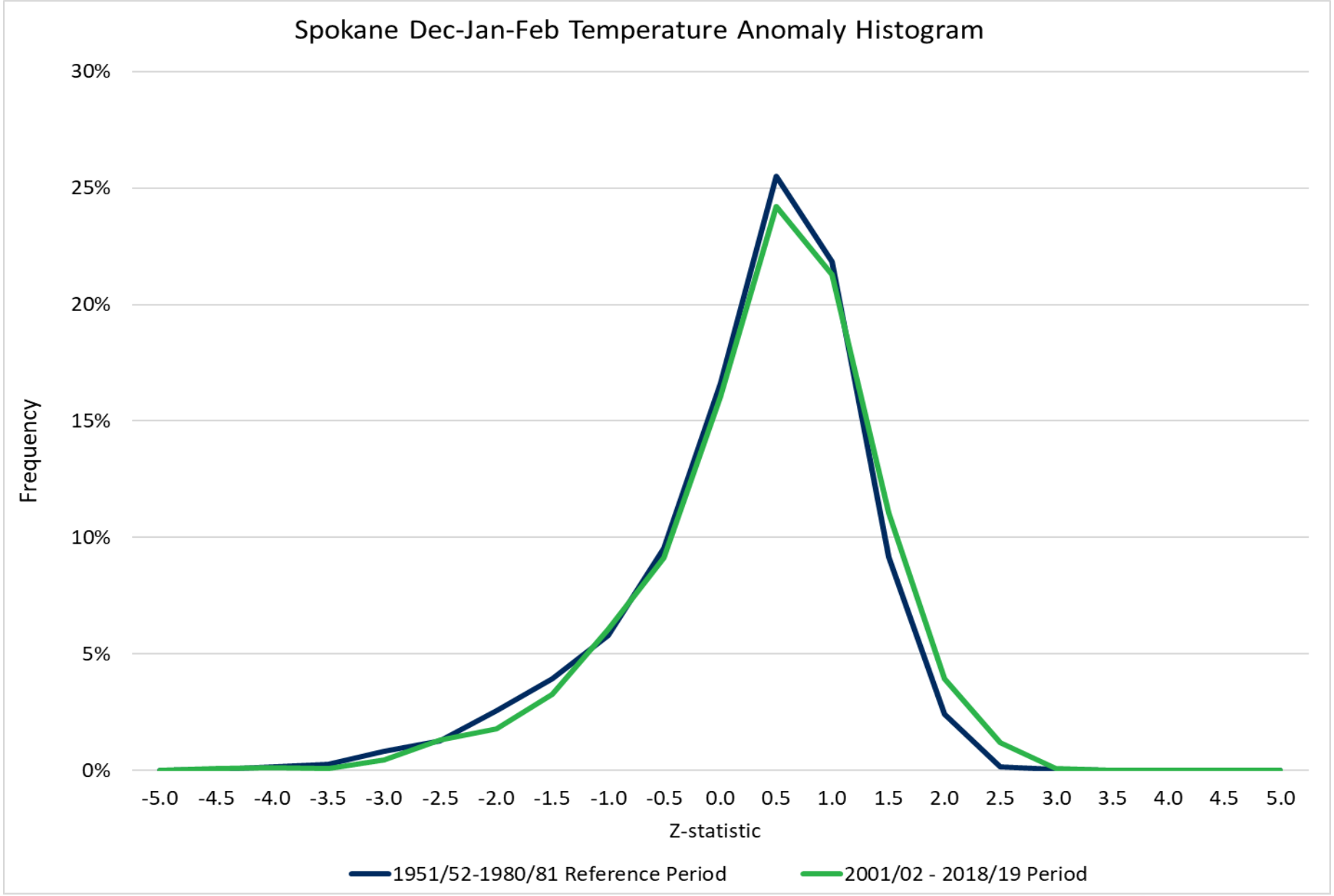
- Compare one period to another
- Shows how far from the average the data point falls


Medford Dec-Jan-Feb Temperature Anomaly Histogram
25%
20%
15%
10%
5%
0%
Frequency
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period


Roseburg Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period


La Grande Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period


Klamath Falls Dec-Jan-Feb Temperature Anomaly Histogram
25%
20%
15%
10%
5%
0%
Frequency
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period


Spokane Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
Z-statistic
1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period

Summary

- Avista's warmer climate locations, Roseburg and Medford, continue to see a shift in temperatures vs. the reference period

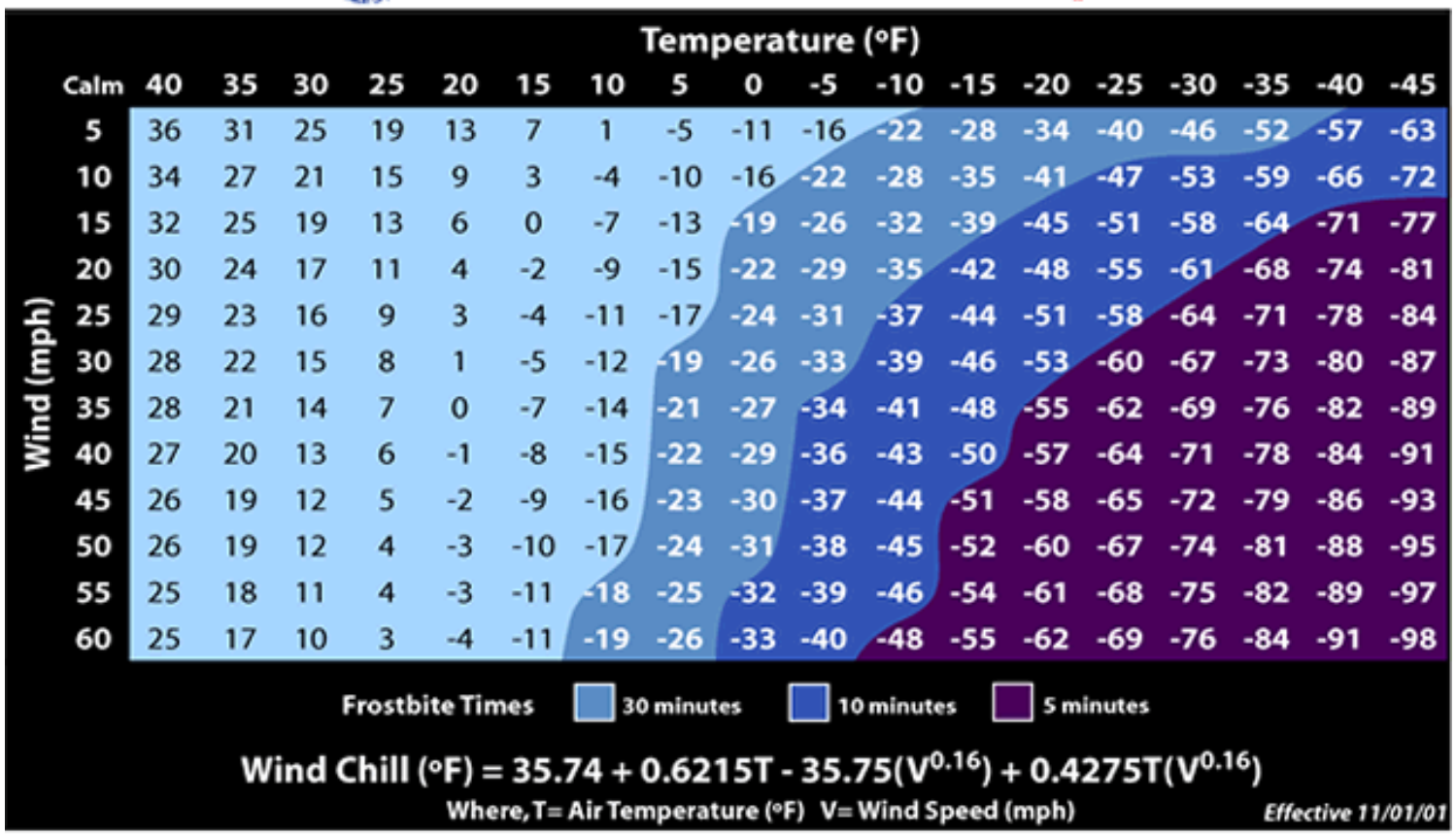
- The colder weather climate locations, Klamath Falls, La Grande, Spokane (ID, WA), have maintained the general shape and remain consistent vs. the reference period

Weather Planning Standard

Weather Standard

- Has the potential to significantly change timing of resource needs
- Significant qualitative considerations
  - No infrastructure response time if standard exceeded
  - Significant safety and property damage risks
- Current Peak HDD Planning Standards
  - WA/ID 82
  - Medford 61
  - Roseburg 55
  - Klamath 72
  - La Grande 75

Wind Chill Chart



Wind (mph) \ Temperature (°F)	Calm	40	35	30	25	20	15	10	5	0	-5	-10	-15	-20	-25	-30	-35	-40	-45
5		36	31	25	19	13	7	1	-5	-11	-16	-22	-28	-34	-40	-46	-52	-57	-63
10		34	27	21	15	9	3	-4	-10	-16	-22	-28	-35	-41	-47	-53	-59	-66	-72
15		32	25	19	13	6	0	-7	-13	-19	-26	-32	-39	-45	-51	-58	-64	-71	-77
20		30	24	17	11	4	-2	-9	-15	-22	-29	-35	-42	-48	-55	-61	-68	-74	-81
25		29	23	16	9	3	-4	-11	-17	-24	-31	-37	-44	-51	-58	-64	-71	-78	-84
30		28	22	15	8	1	-5	-12	-19	-26	-33	-39	-46	-53	-60	-67	-73	-80	-87
35		28	21	14	7	0	-7	-14	-21	-27	-34	-41	-48	-55	-62	-69	-76	-82	-89
40		27	20	13	6	-1	-8	-15	-22	-29	-36	-43	-50	-57	-64	-71	-78	-84	-91
45		26	19	12	5	-2	-9	-16	-23	-30	-37	-44	-51	-58	-65	-72	-79	-86	-93
50		26	19	12	4	-3	-10	-17	-24	-31	-38	-45	-52	-60	-67	-74	-81	-88	-95
55		25	18	11	4	-3	-11	-18	-25	-32	-39	-46	-54	-61	-68	-75	-82	-89	-97
60		25	17	10	3	-4	-11	-19	-26	-33	-40	-48	-55	-62	-69	-76	-84	-91	-98

Frostbite Times — 30 minutes — 10 minutes — 5 minutes

$$\text{Wind Chill (°F)} = 35.74 + 0.6215T - 35.75(V^{0.16}) + 0.4275T(V^{0.16})$$

Where, T= Air Temperature (°F) V= Wind Speed (mph)

Effective 11/01/01

Wind chill effects

- Wind on homes causes two effects. One is wind chill on the exterior of the building and the other is infiltration increases due to the pressure difference caused by wind blowing past the home.
- The greatest effect of wind on heating is low humidity in the home which makes the customers feel like the temperature is 64 degrees when they have the thermostat set at 72 if their humidity is lower than 10% Relative Humidity.

Weather Peak Planning Day alternative

- Coldest Average Day, each year, for the past 30 years combined with a 99% probability

Area	Coldest on Record	99% Probability Avg. Temp	99% Probability Avg. Temp & Wind Chill*
La Grande	-10	-11	-23
Klamath Falls	-7	-9	-16
Medford	4	11	9
Roseburg	10	14	16
Spokane	-17	-12	-26

*this was done with the recent 20 years of data combined with windspeed for example purposes

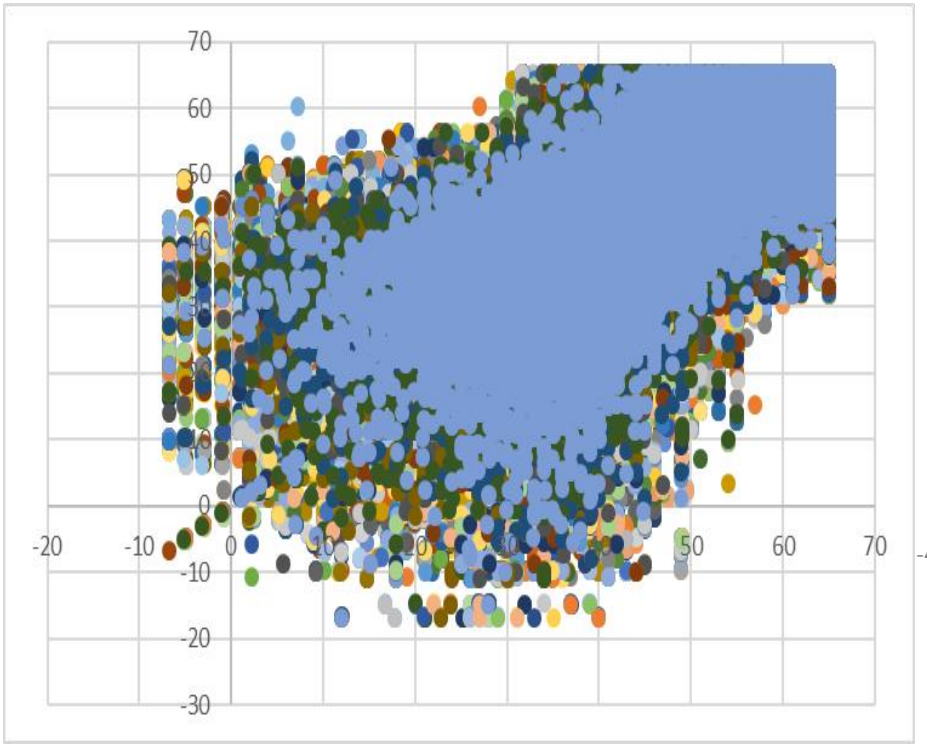
Risks

- Using wind chill effects combined with a 99% probability produces some drastic changes in peak day planning and may require a large amount of capital to meet those design criteria

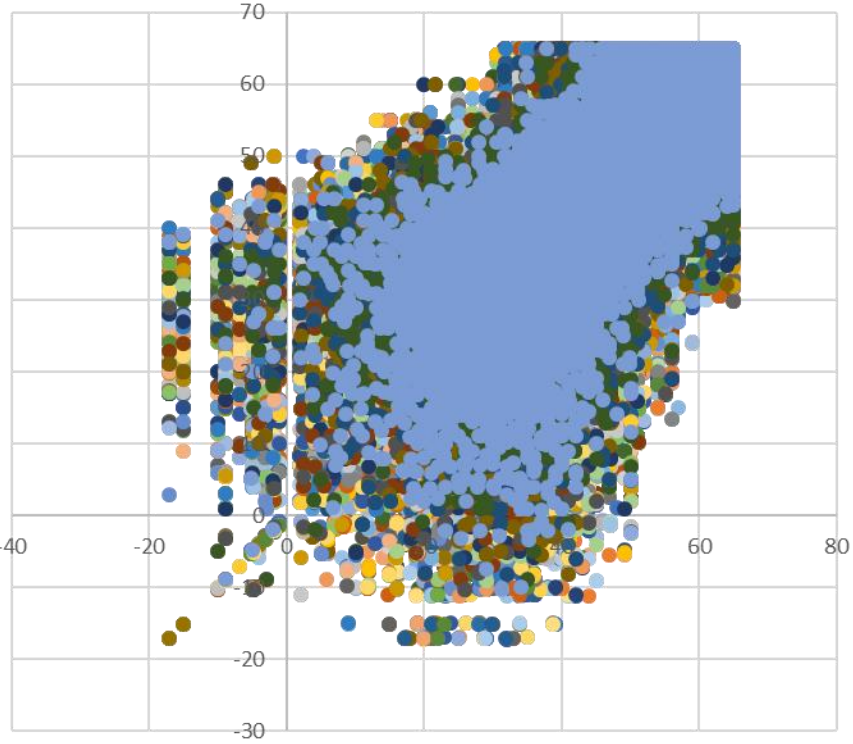
- Utilizing a 99% probability means there is a 1 in 100 event where Avista may not be able to meet the demand

Risk around moving WA and ID peak day temps (1,000 simulated futures run)

Draws 1 - 200



Draws 201 - 400



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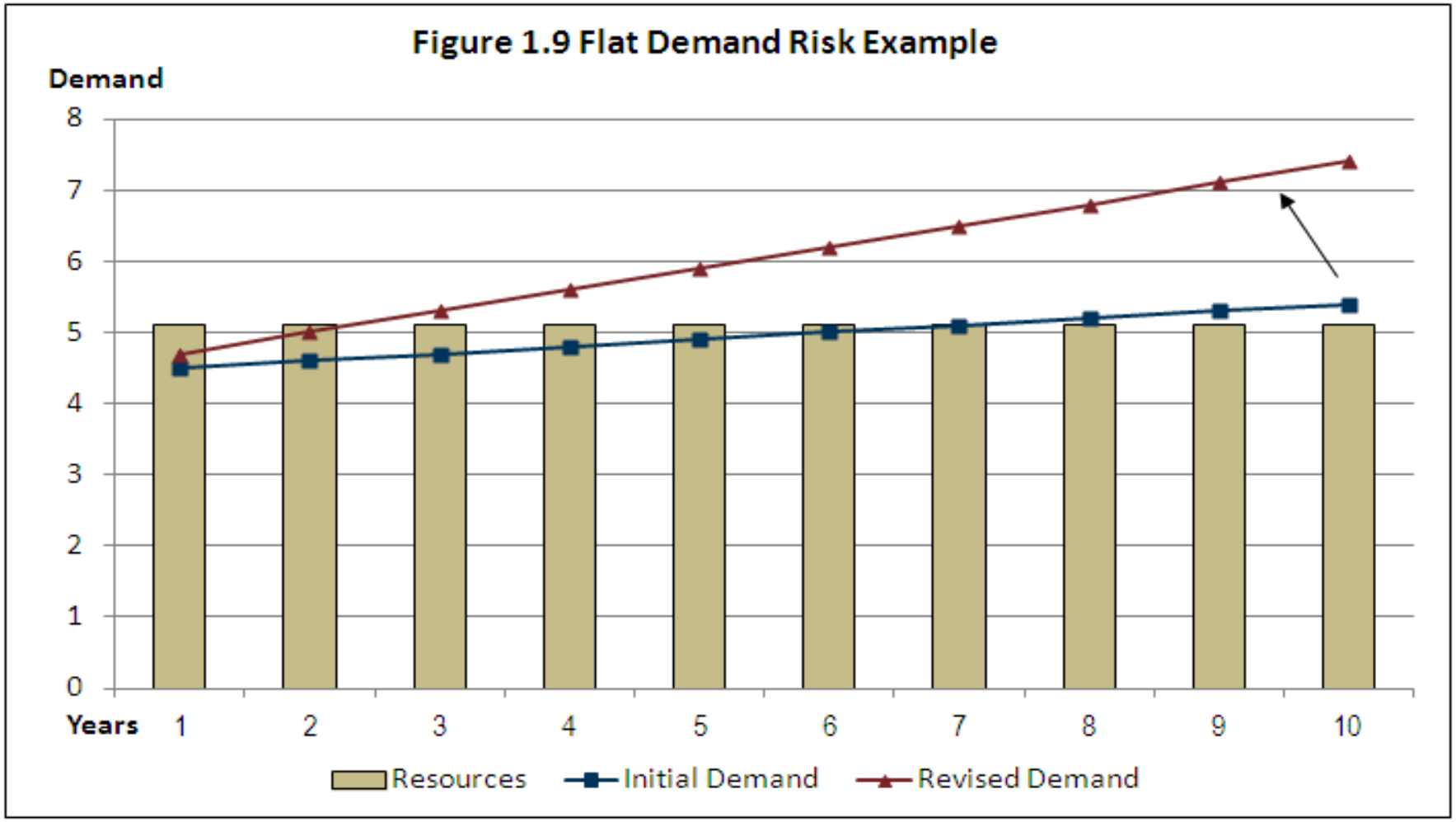
Coldest on Record Peak Days
(82 HDD's, or -17 Avg. Temp Fahrenheit)

“Flat Demand” Risk



Avista Weather Recommendation

- Utilize coldest day for each of the past 30 years with a 99% probability supply can be fulfilled

Area	99% Probability Avg. Temp
La Grande	-11
Klamath Falls	-9
Medford	11
Roseburg	14
Spokane	-12

Procurement Plan

Hedging Objectives and Goals

Mission

To provide a diversified portfolio of reliable supply and a level of price certainty in volatile markets.

- Avista cannot predict future market prices, however we use experience, market intelligence, and fundamental market analysis to structure and guide our procurement strategies.
- Avista's goal is to develop a plan that utilizes customer resources (storage and transportation), layers in pricing over time for stability (time averaging), allows discretion to take advantage of pricing opportunities should they arise, and appropriately manages risk.

Oversight and Control

Risk Management Committee (RMC)

- Comprised of Executive Officers & Sr. Management
- Responsible for the Risk Management Policy
- Provides oversight and guidance on natural gas procurement plan

Strategic Oversight Group (SOG)

- Cross functional group consisting of:
  - Credit, Electric/Gas Supply, Rates, Resource Accounting, Risk
- Co-develops the Procurement Plan
- Meets regularly

Natural Gas Supply

- Monitors and manages the Procurement Plan on a daily basis
- Leads in the annual Procurement Plan review and modification

Commission Update

- Semi-Annual Update
- New Procurement Plan is communicated semi-annually in the fall and spring
- Intra-year changes communicated to staff on an ad-hoc basis

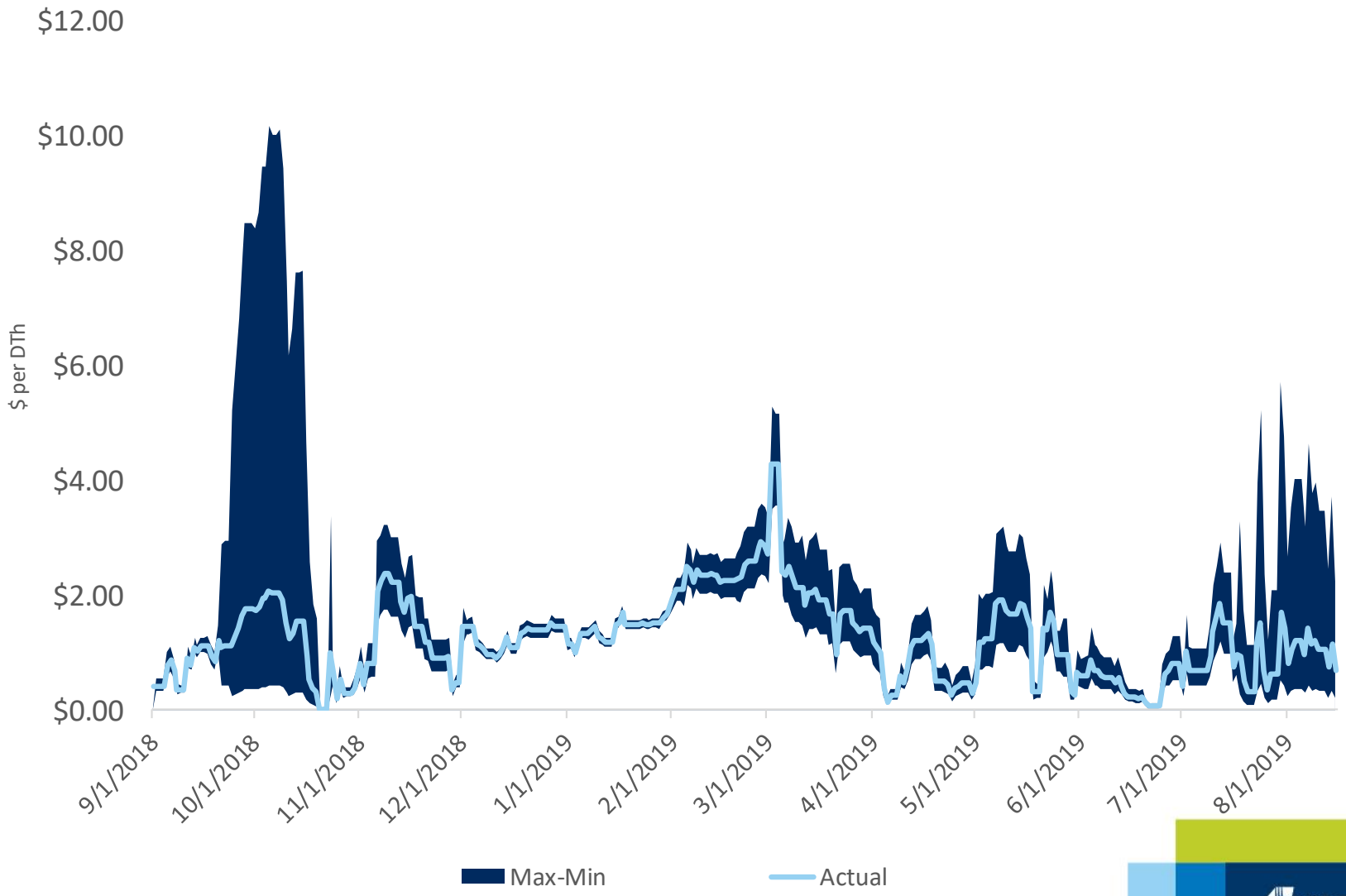
Comprehensive Annual Review of Previous Plan

Review conducted with SOG includes:

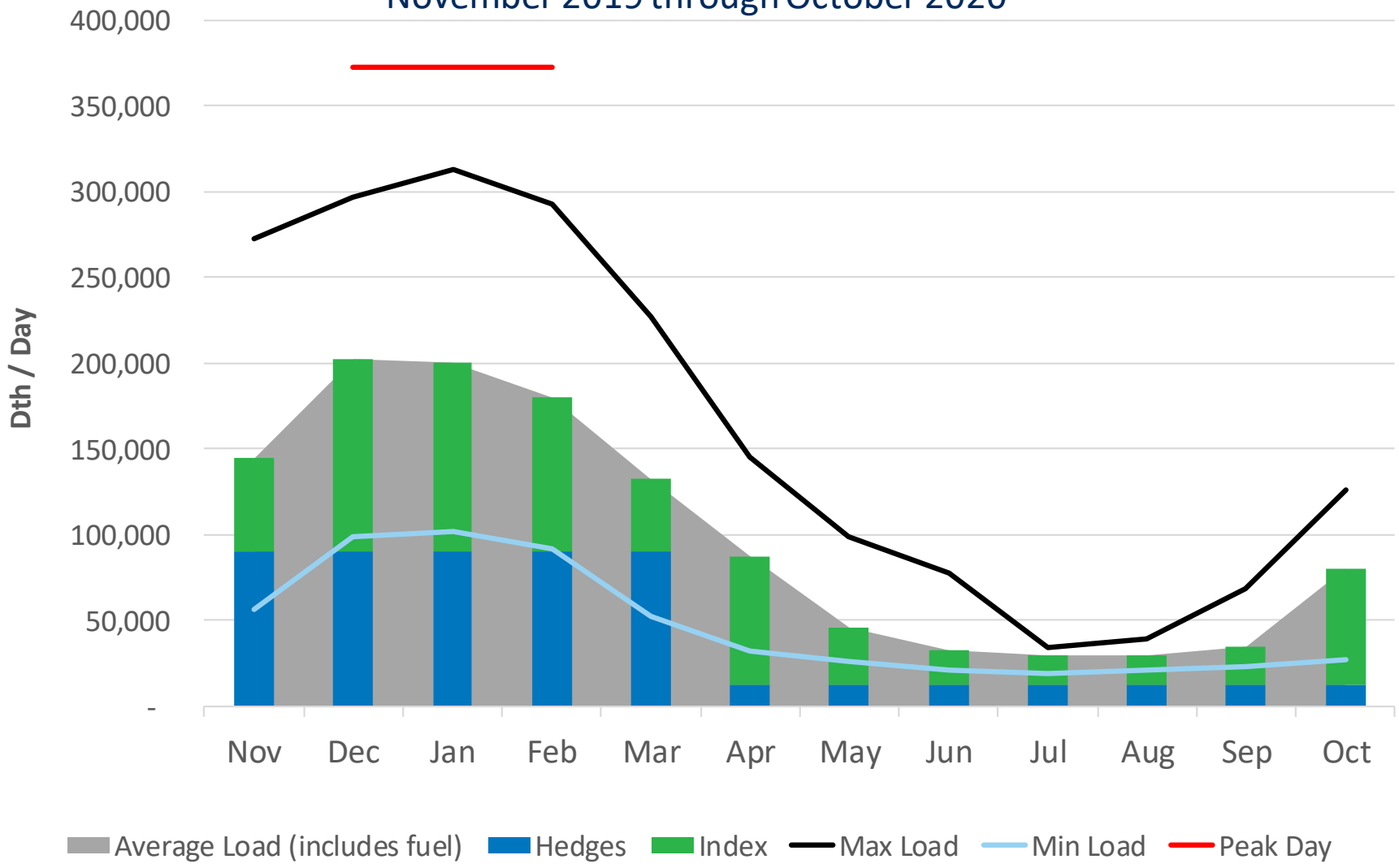
- Mission statement and approach
- Current and future market dynamics
- Hedge percentage
- Operative Boundary
- Resources available (i.e. storage and transportation)
- Hedge windows and quantity (how many, how long)
- Storage utilization
- Analysis (volatility, past performance, scenarios, risk)

A Thorough Evaluation of Risks

AECO Daily Volatility



Natural Gas Procurement Plan vs. System Demand
November 2019 through October 2020



*As of 10/9/2019

Plan Overview

Dynamic Window Hedge (DWH) Plan

- Manages hedges based on average volumetric load
- Firm local distribution customers only
- **Delivery Periods:** Hedges up to 3 years out into the future from the prompt month in monthly and/or seasonal timeframes
- **Supply Basins:** Windows will use VAR as a way to determine the best basin for a hedge. (AECO, Rockies, Sumas).

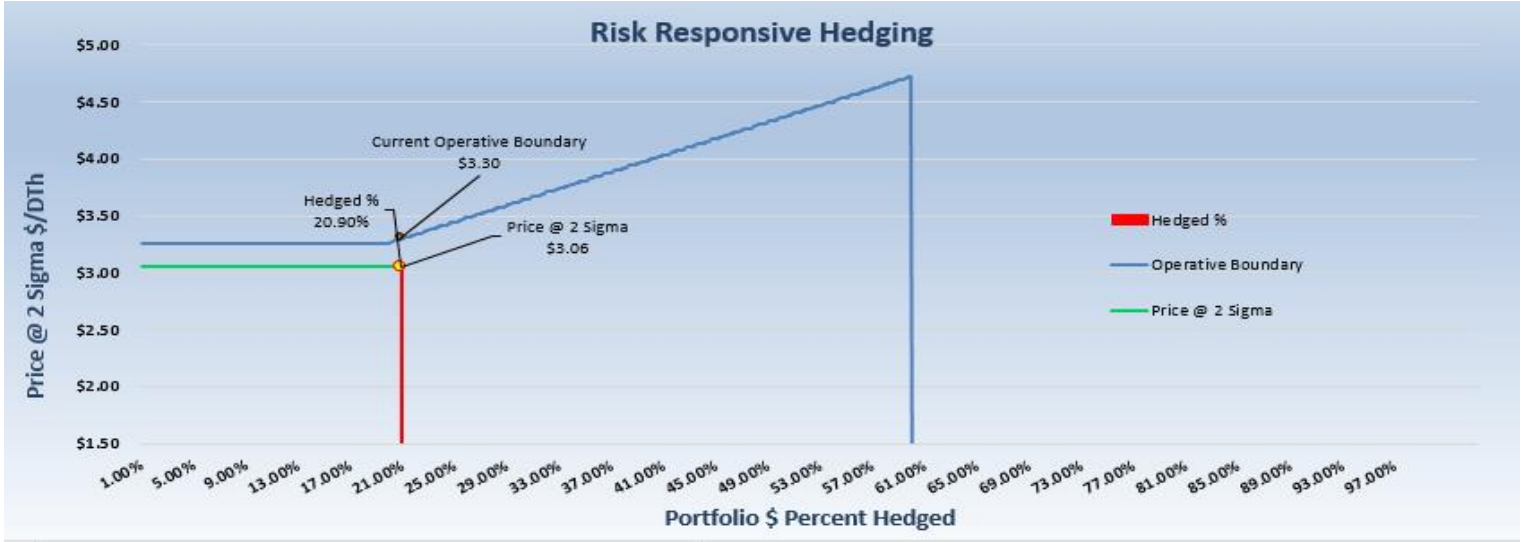
Risk Responsive Hedging Tool (RRHT)

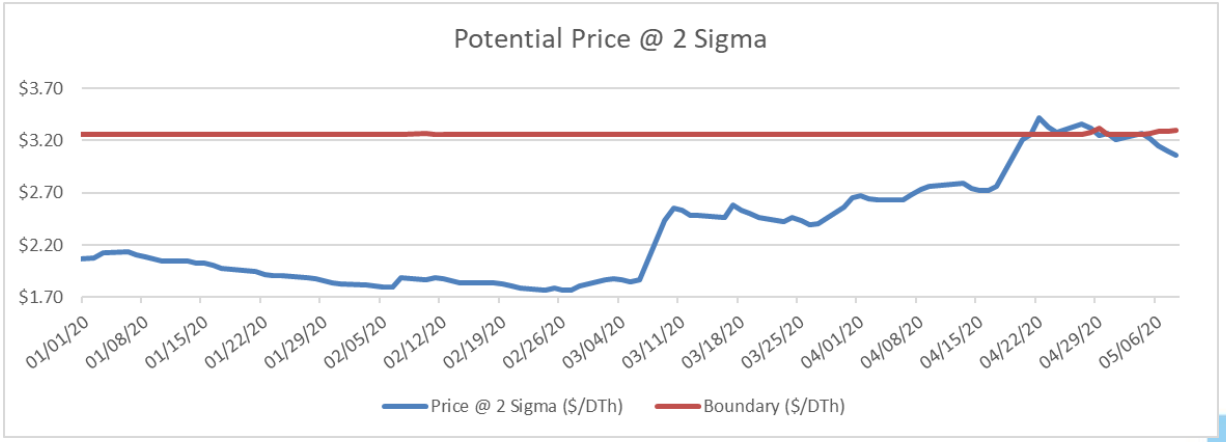
- Manages all hedges in the portfolio based on a financial position
  - Transport optimization hedges
  - Storage optimization hedges
  - LDC hedges from the DWH program
- Incorporates the financial value at risk (VaR) as a daily position based on current firm supply side assets combined with price volatility at each futures market basin

Dynamic Window Hedging

	May 8, 2020												
	Physical Positions			Dynamic Window Hedging									
	Load Estimate (DTh/Day)	Completed Hedges (DTh/Day)	Net Position (DTh/Day)	Window Hedging Threshold	Load Hedged (%)	Hedges Left	Set Date	Expire Date	Low Price Trigger ($/DTh)	Today's Price ($/DTh)	High Price Trigger ($/DTh)	Hedge Required (DTh/Day)	Preferred Basin
June-20	-33,221	12,500	-20,721	40%	38%	0							
July-20	-29,585	12,500	-17,085	40%	42%	0							
August-20	-29,623	12,500	-17,123	40%	42%	0							
September-20	-37,700	15,000	-22,700	40%	40%	0							
October-20	-84,793	27,500	-57,293	40%	32%	3	05/01/20	06/11/20	1.52	1.67	2.08		AECO
Nov20-Mar21	-169,784	85,000	-84,784	33%	50%	0							
Apr21-Oct21	-52,143	12,500	-39,643	23%	24%	0							
Nov21-Mar22	-175,136	37,500	-137,636	33%	21%	8	04/22/20	06/27/20	1.86	2.01	2.22		AECO
Apr22-Oct22	-52,700	5,000	-47,700	23%	9%	3	04/23/20	12/05/20	1.34	1.59	1.93		AECO
Nov22-Mar23	-177,261	2,500	-174,761	33%	1%	22	04/09/20	05/20/20	1.78	1.86	1.95		AECO

Risk Responsive Hedging Tool





Optimization

Avista Gas Supply Asset Optimization

- Storage Optimization.
  - Utilize Avista owned portion of Jackson Prairie storage facility
  - Maintain a peak day capability in order to serve needed demand from the facility during a peak event.
  - Optimize excess capacity through arbitrage between daily prices and forward months as well as between different forward months.
- Transport Optimization.
  - Avista owns transport capacity sufficient to serve peak day load. Unused capacity is optimized by purchasing/selling gas at different hubs to capture locational price spreads.

Storage Optimization Examples

- Day ahead market arbitrage with forward month

  Purchase: daily sumas 75,000 dth for $1.45/dth.

  Sale: 75,000 dth October 2020 Sumas for $2.48/dth.

  Realized arbitrage value: $1.03*75,000 = $77,250

- Arbitrage between different forward months

  Purchase: Q3 2020 sumas 225,000 dth for $1.81

  Sale: Q1 2021 sumas 225,000 dth for $3.47

  Realized arbitrage value : $1.66*225,000 = $373,500

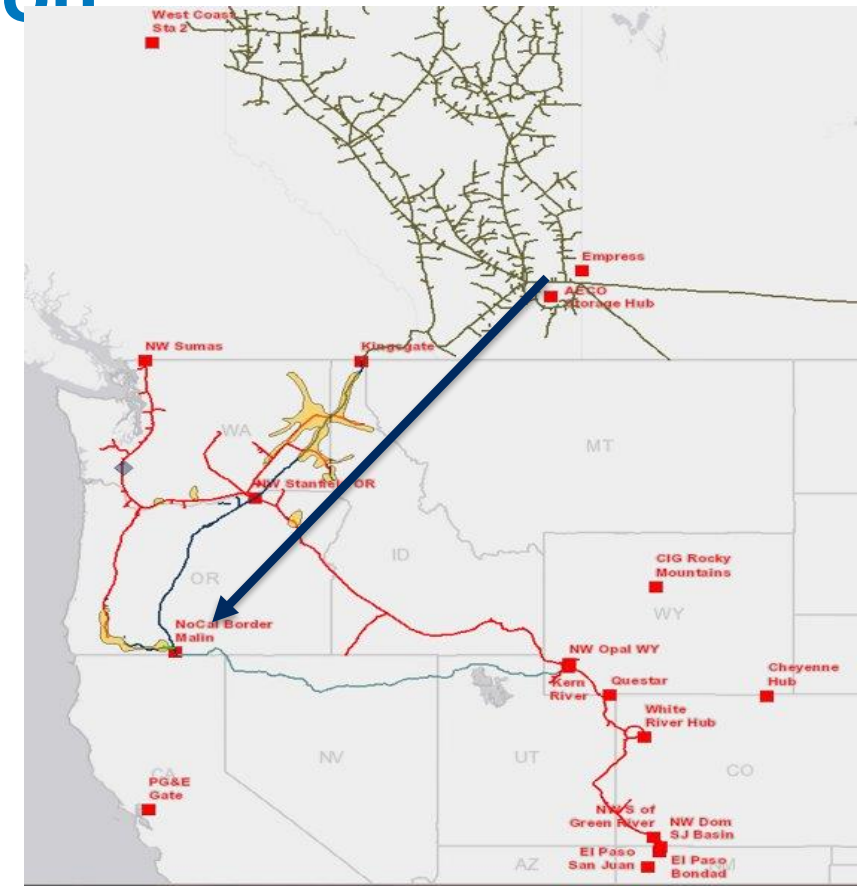
Transport Optimization

- Transport Capacity in excess of Avista core load can be optimized to reduce customer costs.
- Optimization can be done in either the daily or forward markets

Example:

Purchase: 30,000 dth AECO for $2.00/dth

Sale: 30,000 dth Malin for $2.30/dth
Realized cost reduction to customers:
$0.30*30,000 = $9,000



Risks

- Operational Flow Orders:
  - NW Pipeline may require the use of JP storage gas to satisfy OFO's.
  - May require additional purchases from market to replace storage inventory.
- Unplanned maintenance:
  - Unexpected reductions to pipeline capacity or reduced access to storage may limit optimization activity
- Damage or failure of infrastructure

2020 Natural Gas IRP
Energy Efficiency

Ryan Finesilver – Energy Efficiency Planning and Analytics Manager

First Technical Advisory Committee Meeting

Team Roles

Planning & Analytics Team

Applied Energy Group (AEG)

Gas Supply

ACP

CPA

IRP

Oregon DSM Programs

Alphabet Soup

- CPA: Conservation Potential Assessment
- IRP: Integrated Resource Plan
- AEG: Applied Energy Group
- IPUC: Idaho Public Utility Commission
- TRC: Total Resource Cost Test
- UCT: Utility Cost Test
- UTC: Utilities and Transportation Commission

The CPA within the IRP is done by AEG and as per the UTC, is according to the TRC but the IPUC requires the UCT.

Who Energy Efficiency Serves

Three Jurisdictions

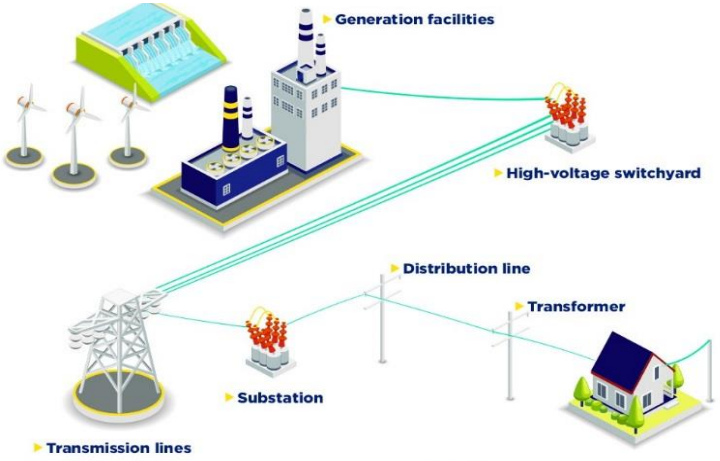
- Washington
- Idaho
- Oregon (ETO except for Low-Income)

Multiple Customer Segments

- Residential
- Industrial/Commercial
- Low-Income Residential

The Company's Infrastructure

- Aids in reducing overall capacity
- Defers capital investments



Energy Efficiency Funding – Natural Gas

SCHEDULE 191

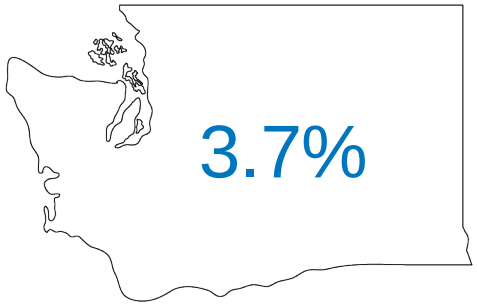
DEMAND SIDE MANAGEMENT RATE ADJUSTMENT - WASHINGTON

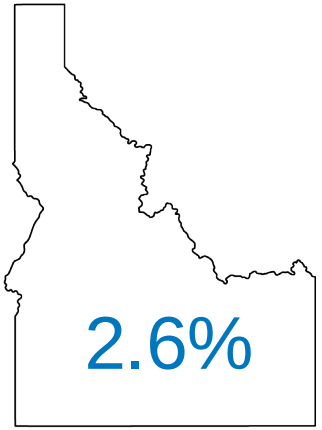
APPLICABLE:
To Customers in the State of Washington where the Company has natural gas service available. This Demand Side Management Rate Adjustment or Rate Adjustment shall be applicable to all retail customers taking service under Schedules 101, 111, 112, 121, 122, 131, and 132. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing Demand Side Management services and programs to customers.

MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:

Schedule 101	$0.03472 per Therm
Schedule 111 & 112	$0.02475 per Therm

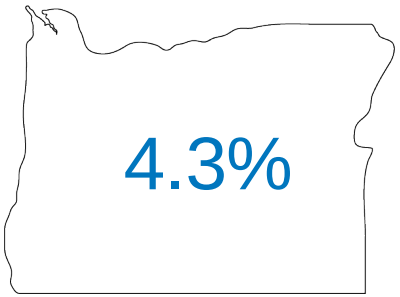
Tariff percentage of customer bill by state:



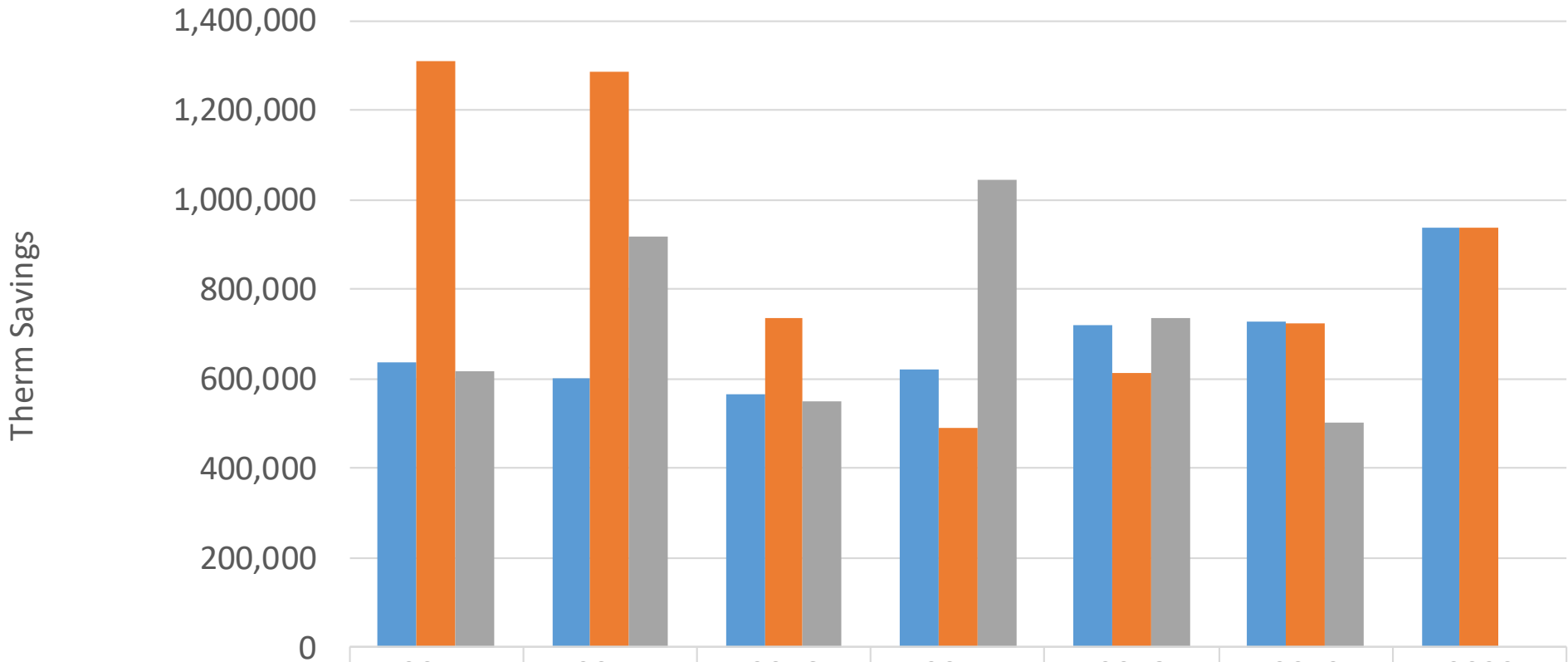


$8.4 Million Annual Funding

(2019)

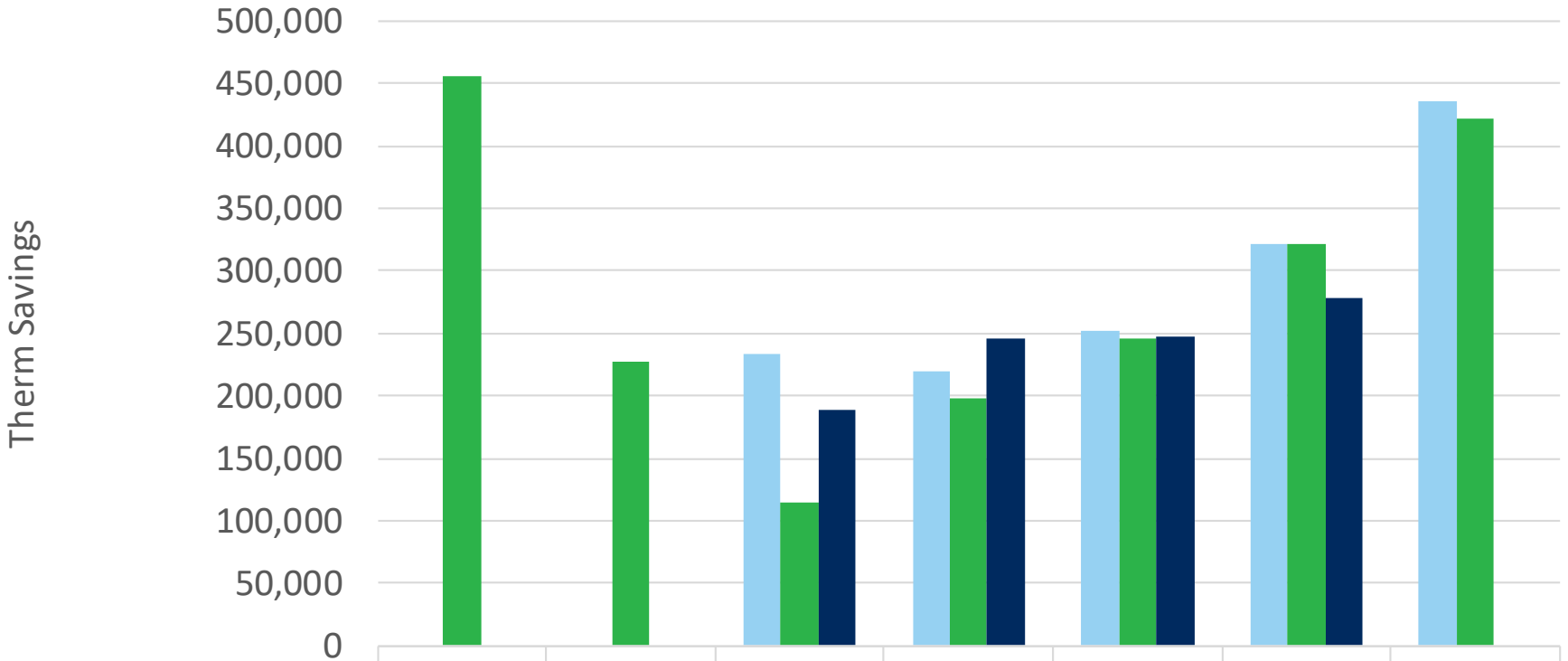


WA Gas Targets to Actual Savings



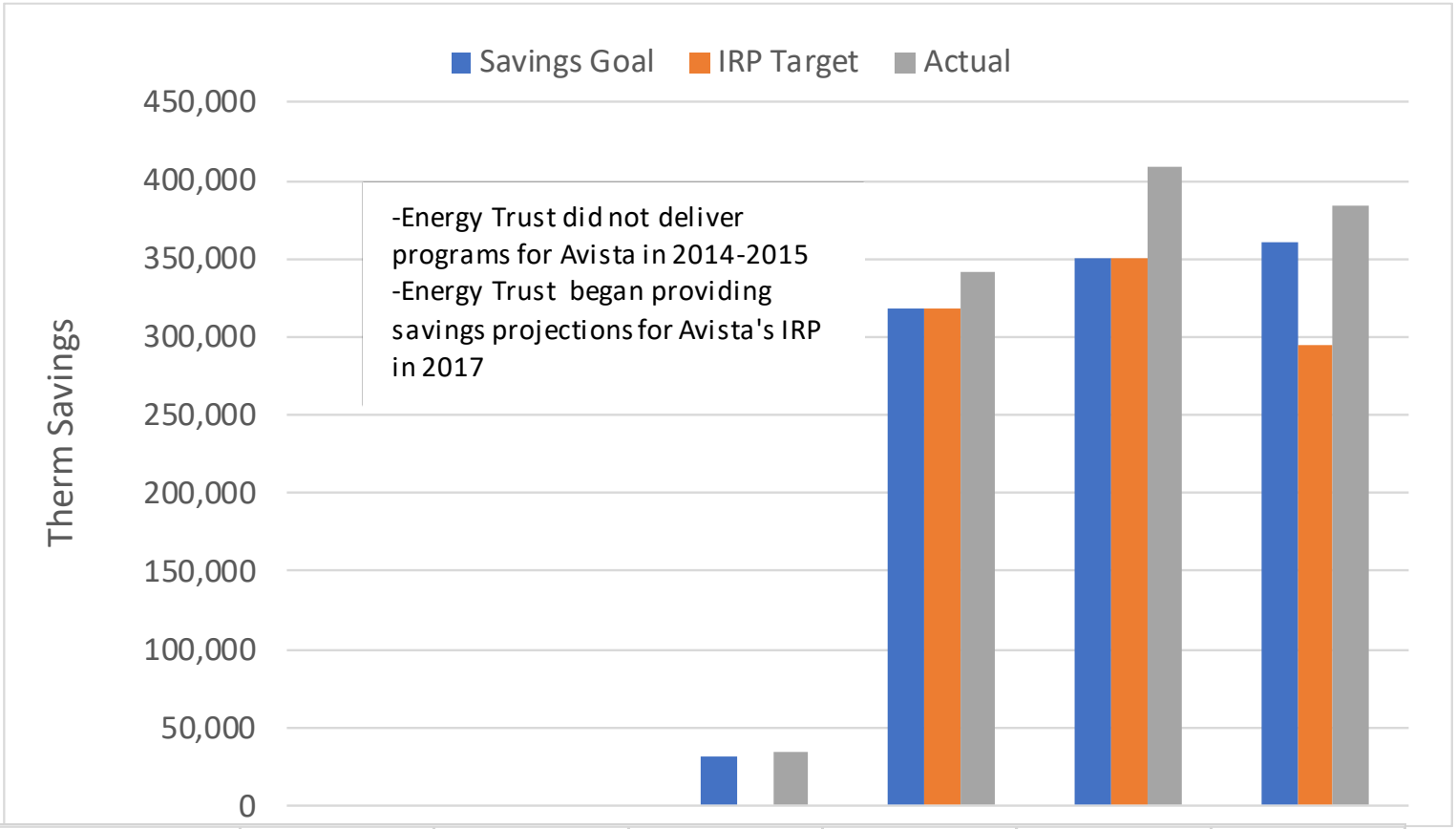
	2014	2015	2016	2017	2018	2019	2020
Business Plan Target	637,042	602,010	567,653	620,310	719,451	726,128	937,402
IRP Target	1,310,000	1,287,000	737,000	489,110	612,830	725,180	936,350
Actual	615,418	919,892	548,756	1,046,356	736,985	504,113	

ID Gas Targets to Actual Savings



	2014	2015	2016	2017	2018	2019	2020
Business Plan Target	0	0	232,737	219,272	252,712	321,120	436,405
IRP Target	456,000	228,000	114,000	197,640	246,440	320,830	421,270
Actual	0	0	189,295	245,747	247,756	278,922	

OR Energy Trust Gas Targets to Actual Savings



	2014	2015	2016	2017	2018	2019
Savings Goal			31,574	318,332	349,520	360,682
IRP Target				318,332	349,520	294,720
Actual			34,708	340,738	409,128	384,599

Energy Efficiency Business Planning

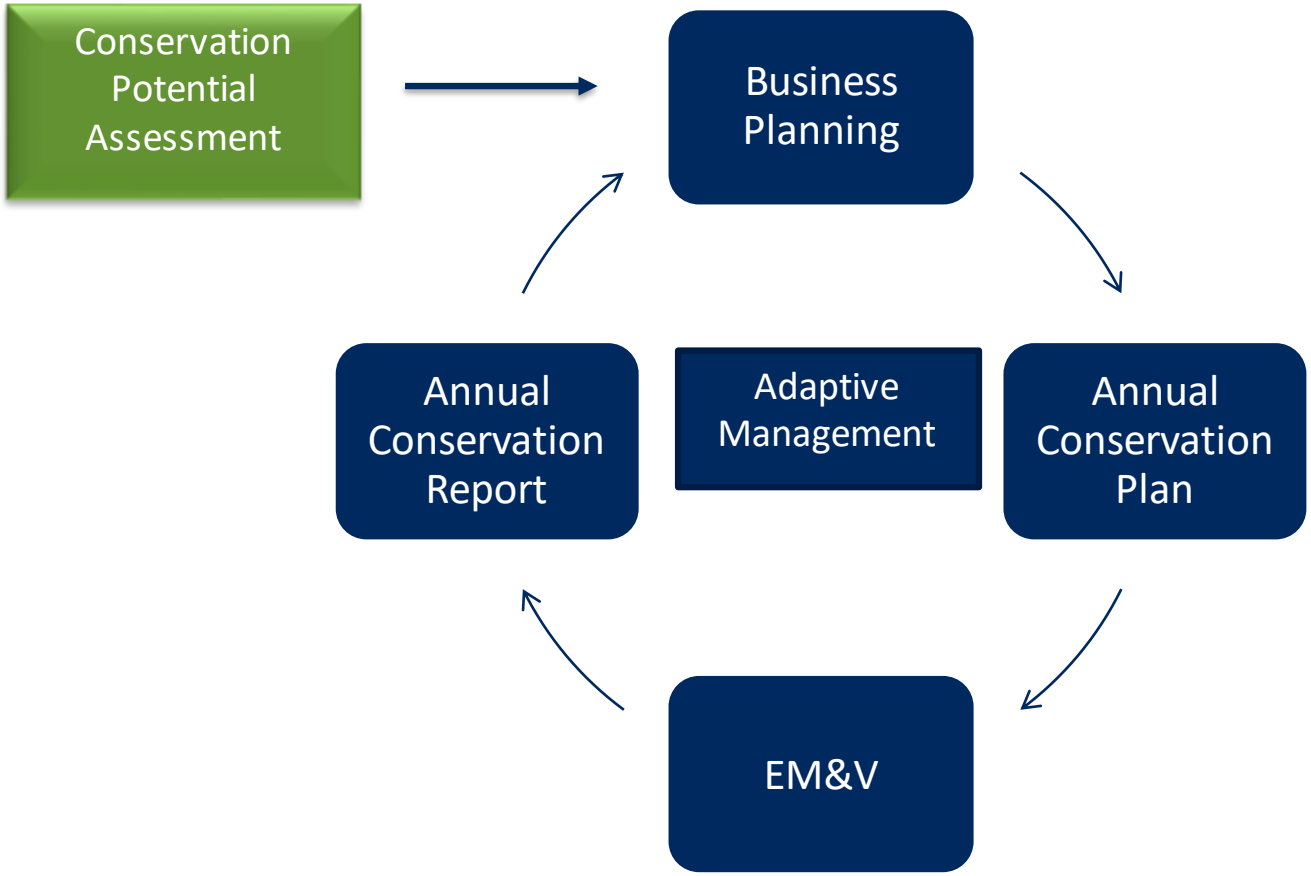
Conservation Potential Assessment (CPA)

- Primary Objectives
  - Meet legislative and regulatory requirements
  - Support integrated resource planning
  - Identify opportunities for savings; key measures in target segments
- Key Deliverables
  - 20-year conservation potential
  - Individual measures
  - IRP target

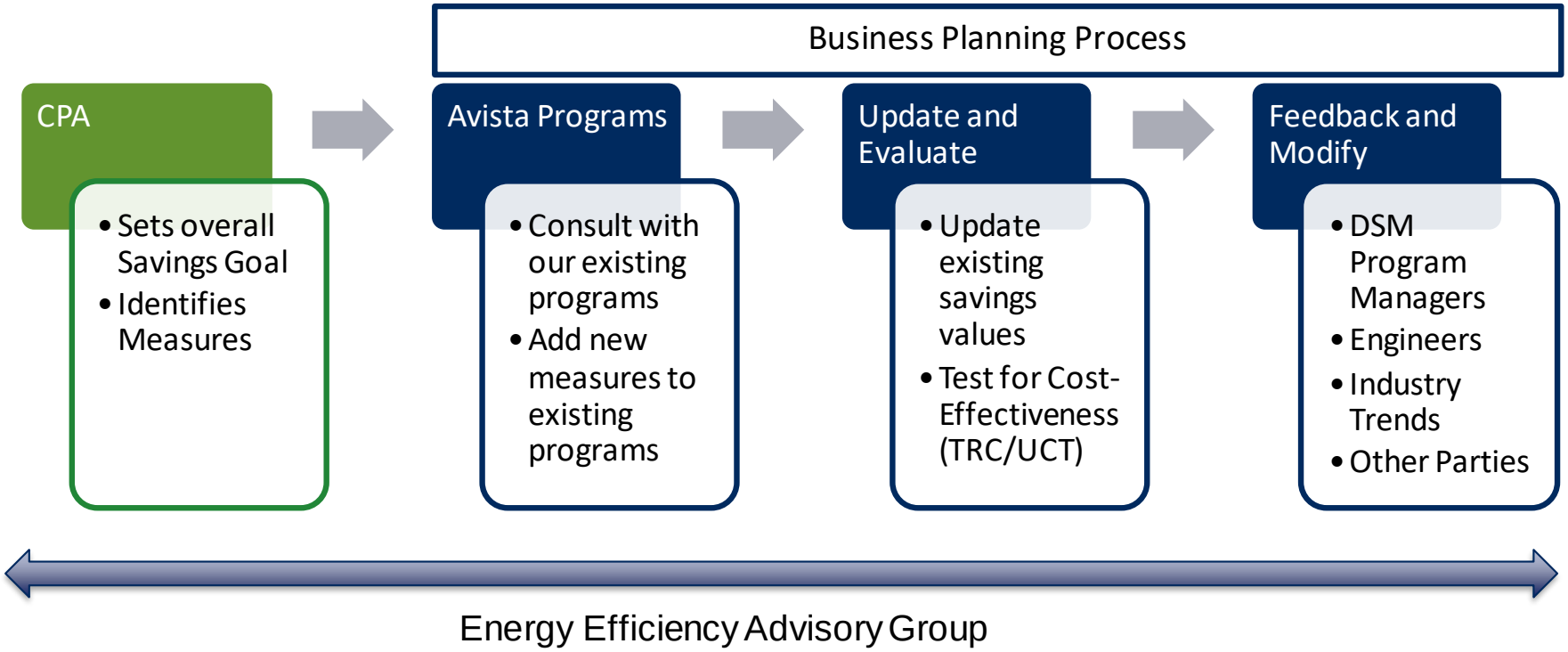
Conservation Potential Assessment

Technical Potential	• Theoretical upper limit of conservation • All efficiency measures are phased in regardless of cost
Achievable Technical Potential	• Realistically achievable, accounting for adoption rates and how quickly programs can be implemented • Does not consider cost-effectiveness of measures
Achievable Potential	• Includes economic screening of measures (cost effectiveness) • Sets our conservation target

Business Planning Process



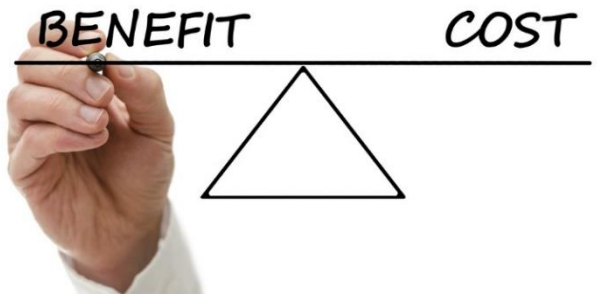
Business Planning Process



Incentive Setting

Cost-Effective Test

Utility Cost Test (UCT) Total Resource Cost (TRC)	Must have a B/E ratio of 1.0 or Higher



Decide Incentive Level

$3 per Therm	70% of CIC	CE Impact	Portfolio Alignment

Significant Costs and Benefits

COSTS

- **Administration**

  (e.g., program design, development, operations, maintenance, overhead, customer service, marketing & outreach, sales, IT infrastructure, customer education, program evaluation, measurement & verification)

- **Measure (Capital) Costs**

  (equipment costs incurred by the utility and participants)

- **Incentives**

- **Revenue Loss**

  (bill reductions)

- **Participant Costs**

  (Other than capital costs – value of service lost & transaction costs)

BENEFITS

- **Avoided Costs**

  (complex)

- **Tax Credits**

  (currently available for DG only)

- **Market/Reliability Benefits**

- **Non-energy benefits**

- **Incentives**

- **Bill reductions**

From Cost-effectiveness training (3/6/15) Powerpoint
http://www.cpuc.ca.gov/General.aspx?id=5267

Energy Trust's Resource Assessment Model

- What is a resource assessment model?
  - Energy Trust's version of a Conservation Potential Assessment
  - Model that provides an estimate of energy efficiency resource potential achievable over a 20-year period
  - 'Bottom-up' approach to estimate potential starting at the measure level and scaling to a service territory
- Energy Trust uses a Model that calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential
  - Final program/IRP targets are established via a deployment forecast in a separate tool
- We provide a 20-year energy efficiency forecast for utility IRPs about every two years.

Energy Trust's Resource Assessment Model is "Living Model"

- Energy Trust makes continuous improvements to the model
- Measures in the model are updated on an ongoing basis to reflect changing market conditions and savings estimates
- Emerging technologies are added to the model as data availability and product viability allows
- Cost-effective potential may be realized through programs, market transformation and/or codes and standards
- Under discussion: use of a "large project adder" to account for large, unexpected projects

Energy Trust Resource Assessment Model Inputs

Measure Level Inputs

Measure Definition and Application:
- Baseline/Efficient equip. definition
- Applicable customer segments
- Installation type (RET/ROB/NEW)*
- Measure Life

Measure Savings

Measure Cost
- Incremental cost for ROB/NEW measures
- Full cost for retrofit measures

Market Data (for scaling)
- Units per site
- Baseline/efficient equipment saturations
- Suitability

Utility 'Global' Inputs

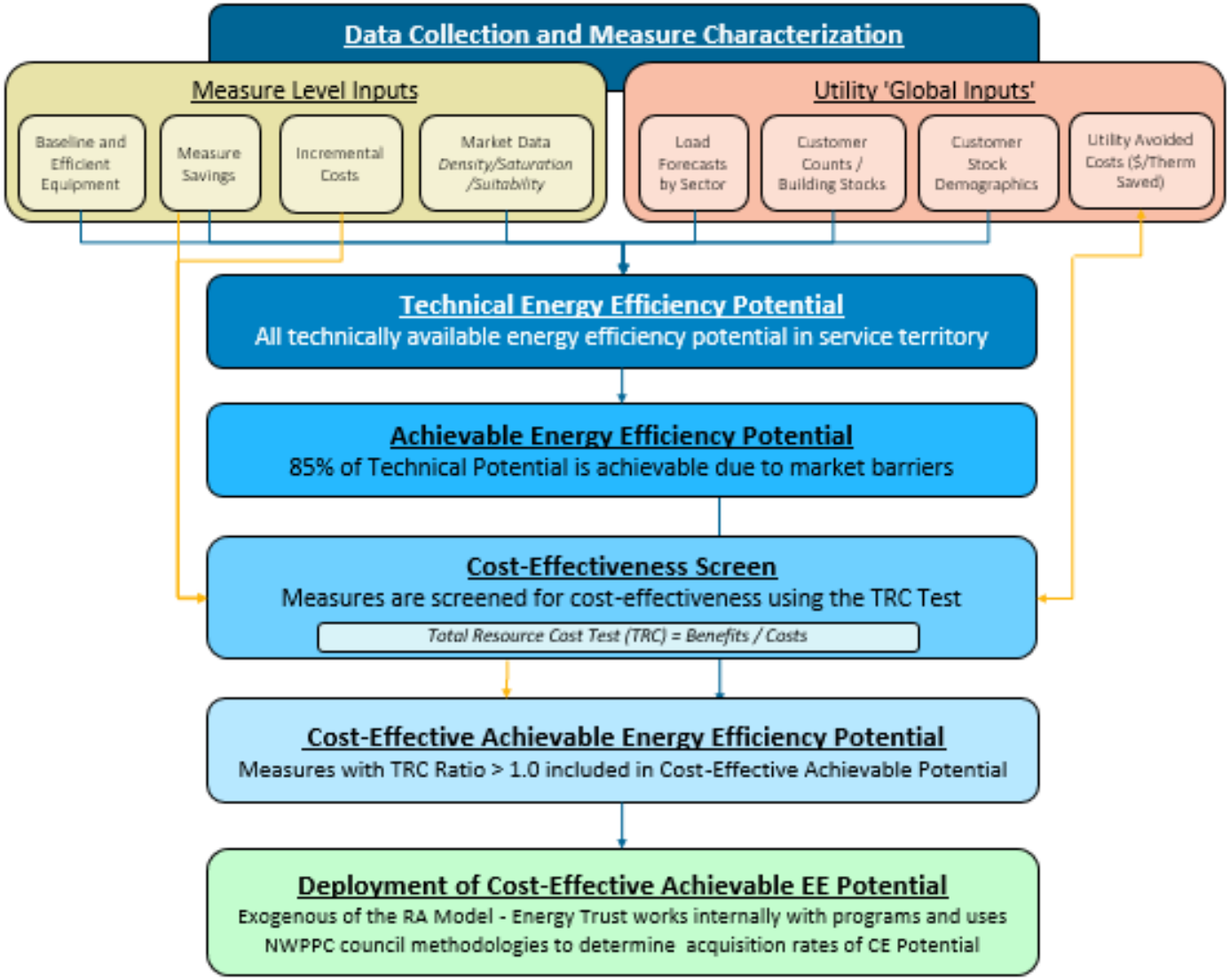
Customer and Load Forecasts
- Used to scale measure level savings to a service territory
  - Residential Stocks: # of homes
  - Commercial Stocks: 1000s of Sq.Ft.
  - Industrial Stocks: Customer load

Avoided Costs

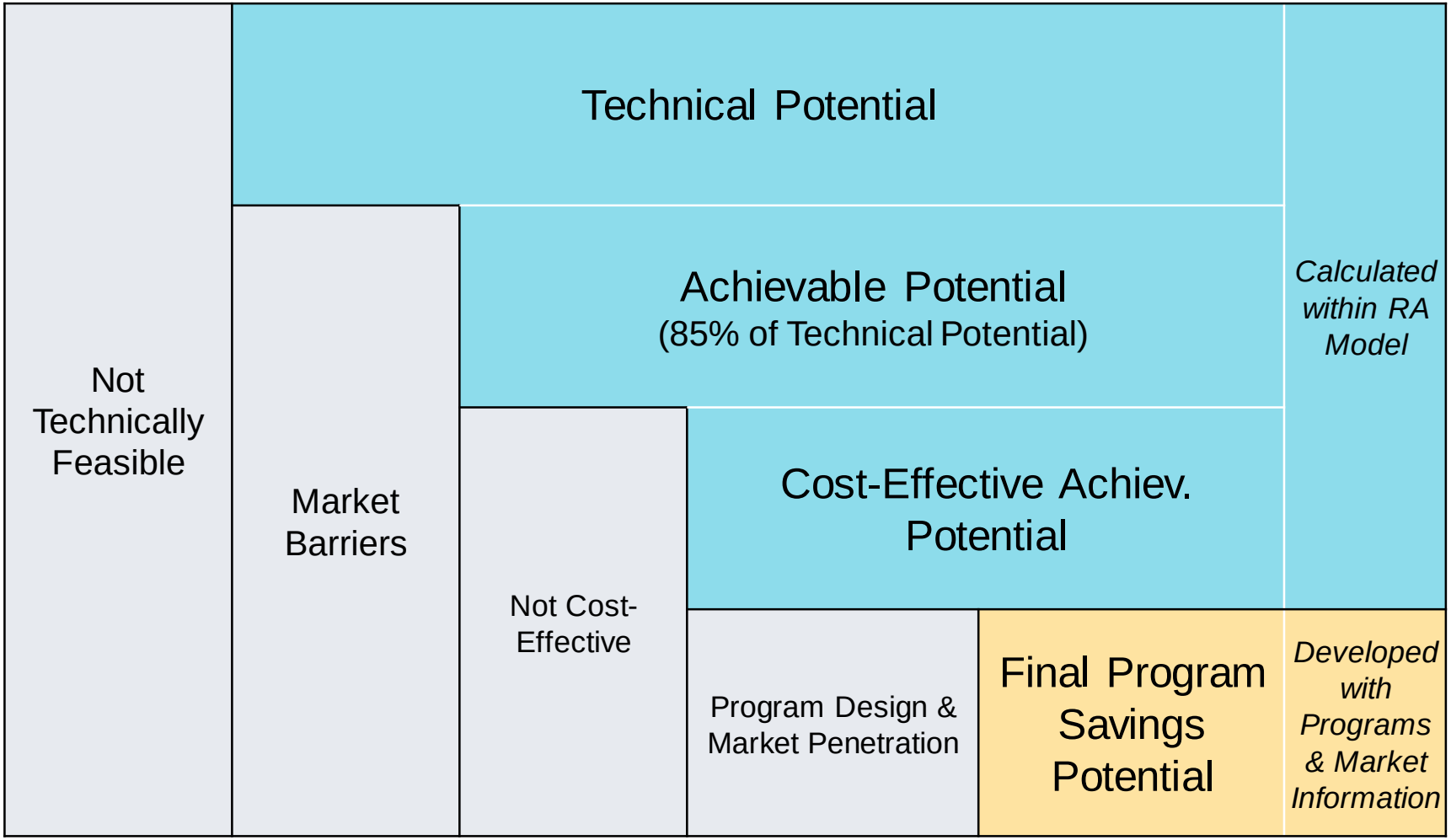
Customer Stock Demographics:
- Heating fuel splits
- Water heat fuel splits

** RET = Retrofit; ROB = Replace on Burnout; NEW = New Construction*

Energy Trust 20-Year IRP EE Forecast Flow Chart



Energy Trust Forecasted Potential Types



Energy Trust Cost-Effectiveness Screen For RA Modeling

- Energy Trust utilizes the Total Resource Cost (TRC) test to screen measures in the model for cost effectiveness

$$TRC = \frac{Measure\ Benefits}{Total\ Measure\ Cost}$$

- If TRC is > 1.0, it is cost-effective and the resources is included in cost-effective achievable potential
- Measure Benefits:
  - Avoided Costs
    - Annual measure savings x NPV avoided costs per therm or kWh
  - Quantifiable Non-Energy Benefits
    - Water savings, etc.
- Total Measure Costs:
  - The customer cost of installing an EE measure (full cost if retrofit, incremental over baseline if replacement)

- Some gas measures are forced into the model if they have exceptions from the OPUC under the criteria established via UM 551

Energy Trust Deployment

- The RA model results represent the maximum savings potential in a given year.
- Ramp rates are an estimate of how much of that available potential will come off Avista's system in a given year.
- Energy Trust ramp rates are based on NWPCC methods and ramp rates, but calibrated to be specific to Energy Trust.

Energy Trust Final Savings Projection Methodology

Energy Trust calibrates the first five years of energy efficiency acquisition ramp rates to program performance and budget goals.

Years 1-2

- Program forecasts – they know what is happening short term best

Years 3-5

- Planning and Programs work together to create forecast

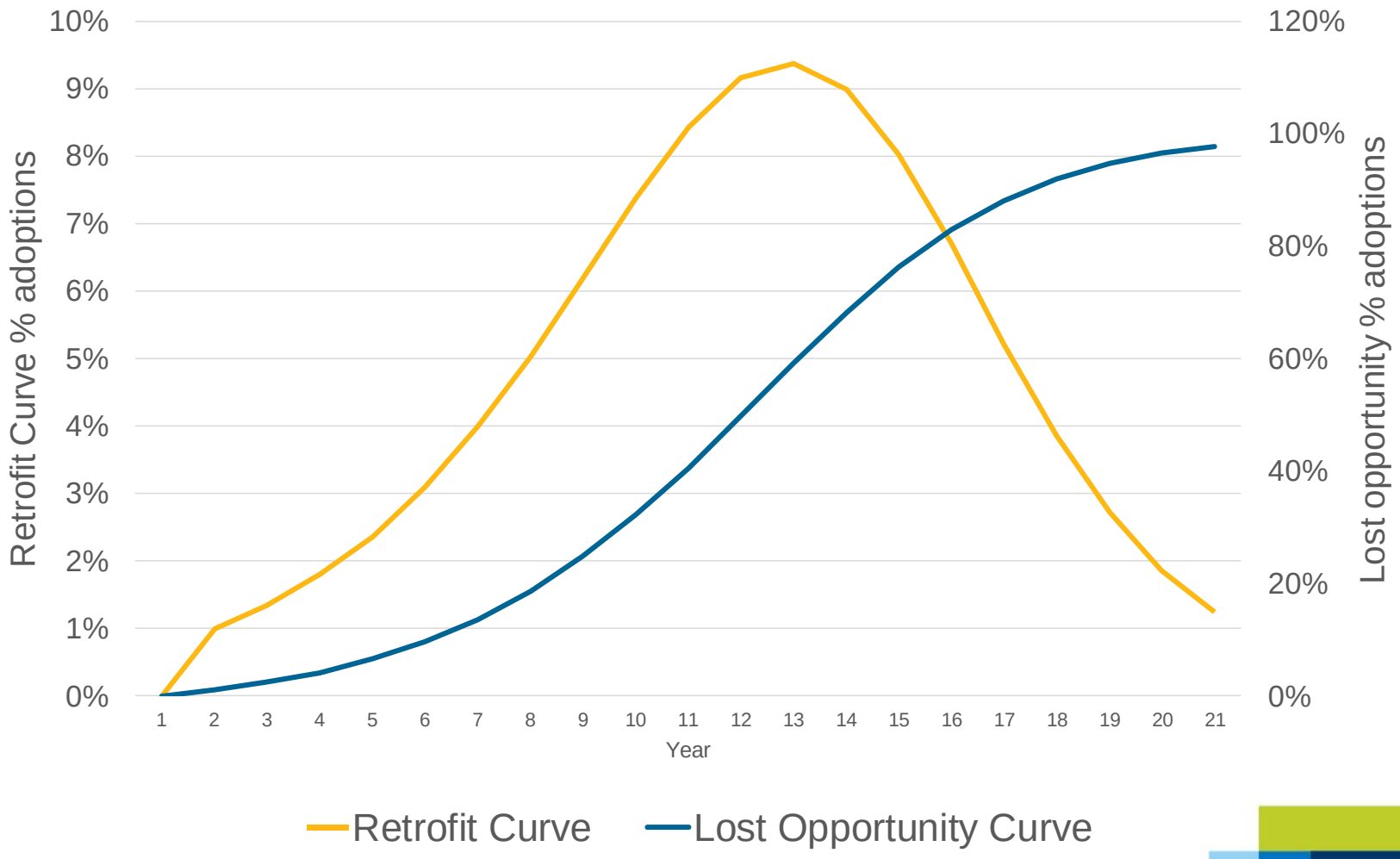
Years 6-20

- Planning forecasts long-term acquisition rate to generally align NWPCC

Energy Trust Ramp Rate Overview

- Total RA Model cost-effective potential is different depending on the measure type.
  - **Retrofit measure savings** are 100% of all potential in every year, therefore must be distributed in a curve that adds to 100% over the forecast timeframe (bell curve)
  - **Lost opportunity measure savings** are the savings available in that year only and deployment rates are what % of that available potential rate can be achieved – results in an s-curve
- Generally follows the NWPCC deployment methodology
  - 100% cumulative penetration for retrofit measures over 20-year forecast
  - 100% annual penetration for lost opportunity by end of 20-year forecast (program or code achieved)
  - Hard to reach measures or emerging technologies do not ramp to 100%

Energy Trust Ramp Rate Examples



Avista's OR IRP Savings Targets Influence Annual Energy Trust Savings Goals and Budgets

- The savings forecasts that Avista incorporates into their IRPs is a reference point for setting annual Energy Trust savings goals and budgets
- Likewise, the Energy Trust savings goals from the last budget cycle inform the early years of the next IRP forecast
- This results in a cycle of iterative updates to savings projections based on the most recent market intelligence
- In addition, Energy Trust's measure development process uses the Utility Cost Test to screen measures for cost-effectiveness
  - This test sets an upper bound on the incentive that can be offered and this factors into the budget process

Questions?

2020 Natural Gas IRP schedule

•**TAC 1: Wednesday, June 17, 2020**: TAC meeting expectations, 2020 IRP process and schedule, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits, Demand, Weather Analysis and a Weather Planning Standard, and an energy efficiency update.

•**TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

•**TAC 3: Wednesday, September 30, 2020:** Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

•**TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

•**TAC 5: February 2021:** TAC final review meeting (if necessary)