Provider of Choice Workshop:

System Augmentation Cost Analysis

December 1, 2022

Today’s Workshop

Michelle Lichtenfels, Program Manager, Provider of Choice

Agenda

Time Start	Time End	Topic	Presenter(s)
9:00 a.m.	9:05 a.m.	Intro and Expectations	Michelle Lichtenfels
9:05 a.m.	9:15 a.m.	Overview	Daniel Fisher
9:15 a.m.	10:00 a.m.	Resource Selection Methodology	Eric Graessley and Brian Dombeck
10:00 a.m.	**10:15 a.m.**	**Break**	
10:15 a.m.	11:00 a.m.	Rates Impact Analysis	Brian Dombeck and Daniel Fisher
11:00 a.m.	11:45 a.m.	Discussion	All
11:45 a.m.	12:00 p.m.	Wrap-Up	Michelle Lichtenfels

Format

- Presenters will take pauses for questions.
- There is scheduled Q & A time.
- If a question arises during a presentation, please:
  - Hold your question until a pause, or
  - Write your question in the Webex chat with the corresponding slide number.
- Chat questions will be addressed in the order received.
- We will call on raised hands. You can unmute/mute yourself.
  - **Please state your name and organization.**

Workshop Roles & Expectations: BPA

- Distribute workshop materials a minimum of 48 hours in advance via email and/or post on BPA website.
  - Materials will not be printed.
- Start and end workshops on time.
- Facilitate and moderate conversations with an eye on workshop objectives and scope.
- Provide open and inclusive opportunities for feedback, both within and following workshops.
- Respect others and assume good intentions.
- Bring a constructive mentality.

Workshop Roles & Expectations: Participants

- Come prepared by reviewing materials in advance of workshops.
- Participants are empowered to represent utility or organization, as applicable.
- Share your perspective and provide feedback.
- Limit discussion to the scope of each workshop. Don’t start side conversations.
- Respect others and assume good intentions.
- Bring a constructive mentality.

Overview

Daniel Fisher

Today’s Topics

- Describe portfolio selection methodologies.
- Characterize cost estimation and estimated rates impact.
- Highlight rate design analysis and tool.

Goals of Today’s Discussion

- Provide an overview of how BPA views current resource costs.
- Explore how resource portfolio decisions may need to be different from current practices.
- Apply acquisition cost estimations to the rate constructs discussed at the Oct. 12 workshop.

Recap

- Provider of Choice discussions have considered how augmentation may impact the existing federal system looking at up to 500 to 1,000 average megawatts of augmentation.
- BPA looked at the expected cost of various resource-acquisition portfolios and calculated a back-of-the-envelope rate impact of incremental system augmentation.
- Subsequent analysis may involve BPA's 2024 Resource Program.

Key Takeaways

- Increasing system size is more challenging and costly than simply acquiring annual average energy at the lowest levelized cost of energy (LCOE).
- Future acquisitions to meet new load growth may be more expensive and complex, involving a mix of energy and capacity resources.
- Additional conversations are needed around the rate design and potential impacts to customers to move forward with a policy construct.

Caveats and Disclaimers

- This analysis is for informational purposes only.
  - The scenario shown here is hypothetical.
- This analysis should not be interpreted as a signal of any future acquisition strategy by BPA.
- This is not a customer specific rate analysis.
- There is uncertainty in cost inputs and around any long-term projections i.e. technological progress, forward cost curves, load growth and transmission capacity.

Resource Selection Methodology

Eric Graessley and Brian Dombeck

High Level Overview

- Least cost portfolios were chosen to meet *incremental needs* associated with assumed system growth trajectory.
  - Large initial 500 aMW augmentation
- Assess sensitivity of resource selections from varying market reliance and/or capacity mix requirements.
- Costs of selected resource solutions were determined and evaluated under various rate design constructs.

Predicting the Future is Hard

Risk	Severity
Costs: ➢ Fixed and variable costs ranges ➢ Inflation reduction act provisions ➢ Financing ➢ Additional ancillary services/ Transmission	Moderate ➢ Many of these can be minimized in PPA / contracting phase of resource acquisition.
Resource Capacity Factors ➢ Specific siting of renewables can significantly alter generation profiles ➢ Renewables have multiple scales of temporal variability (hourly, daily, monthly, seasonal)	High ➢ Annual average capacity factors often over stated in LCOE ➢ Higher granularity required to ensure reliability
Energy Market Prices ➢ Augmentation purchases ➢ Surplus sales ➢ Vary with PNW hydro conditions ➢ Carbon prices and market design	High ➢ By definition during low hydro, $$$ ➢ Market designs need to incorporate REC accounting, or be treated as "brown" ➢ Markets covering large geographic expanse prevent overbuild.
Needs ➢ Shape of obligations ➢ Levels of acceptable market reliance ➢ How much capacity backing is needed	Critical ➢ Key determinant of both resource selection and portfolio cost

MicroFin

- Cost curves obtained from NWPCC’s publicly available Excel-based MicroFin model used in the 2021 Power Plan.

- MicroFin:
  - Produces revenue requirements, levelized costs, and other data for a selected resource using data inputs including:
    - Development/construction costs with potential to adjust for technological improvement.
    - Fuel, integration, O&M, and carbon costs.
    - Financial assumptions.
  - Inputs calibrated to reflect BPA-specific financial assumptions, transmission/integration rates from BP24-IP, ITC schedule from IRA.

Resources Overview

Characteristic	Solar PV - East of Cascades	Solar + Battery Storage (4 hour)	Battery Storage (6 hour)	Onshore Wind - Columbia Gorge/SE WA	SMR	CGS EPU (With relicense)
Nameplate (MW)	100	100	100	216	684	170
Technology Type	100MWac Mono PERC c-SI w/ single axis tracker	100MWac Solar co-located w/ DC-coupled 100MW/ 400MWh lithium ion	100MW/600MWh Lithium Ion	3.6MW, 105m hub height WTG	SMR NuScale 720 MW gross	Extended Power Uprate
Overnight Capital Cost ($2021/kW)	$ 1,518	$ 2,887	$ 2,203	$ 1,630	$ 6,070	$ 3,502
Real Levelized Fixed Cost ($2021/kw-yr)	$ 87.96	$ 165.74	$ 127.58	$ 118.92	$ 452.61	$ 238.72
Real LCOE ($2021/MWh)	$ 31.36	$ 59.08	#N/A	$ 33.09	$ 85.14	$ 30.04
Development Period (Years)	1	1	1	1	2	6
Construction Period (Years)	1	1	1	1	3	3
Maximum Build-Out Potential (# units)	50	50	10	25	5	1
Maximum Build-Out Potential (MW)	5,000	5,000	1,000	5,400	3,420	170

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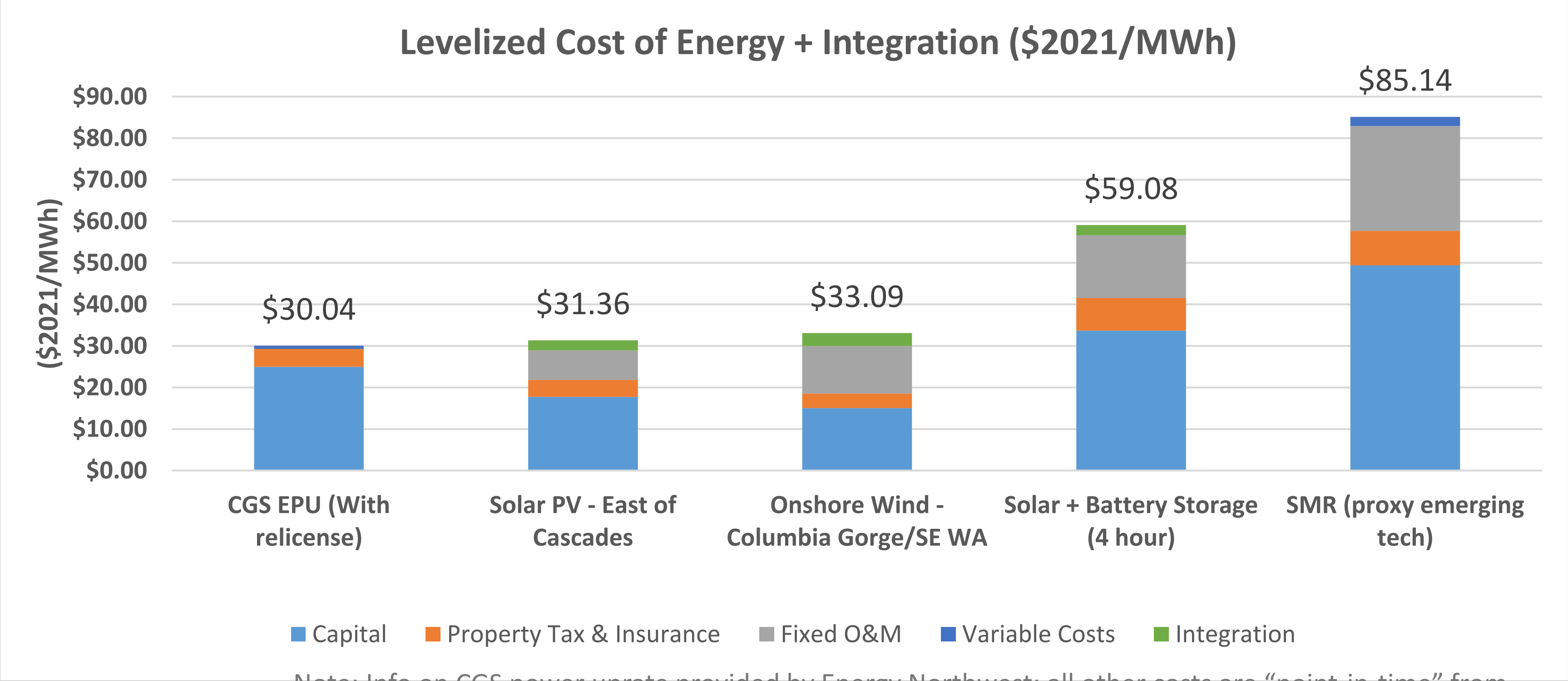
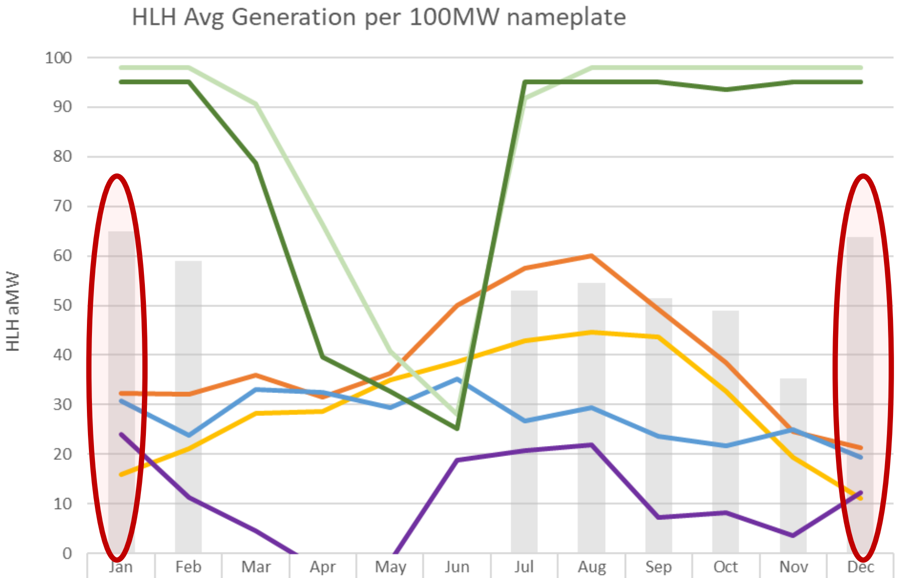
Note: Info on CGS power uprate provided by Energy Northwest; all other costs are “point-in-time” from the NWPCC’s MicroFin. Forecasts vary by consultants/ agencies, and are inherently difficult to predict.

LCOE Comparison



Note: Info on CGS power uprate provided by Energy Northwest; all other costs are “point-in-time” from the NWPCC’s MicroFin. Forecasts vary by consultants/ agencies, and are inherently difficult to predict.

Differences in Needs and Resources



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Inc. Need Shape	65	59					53	55	51	49	35	64
Solar	16	21	28	29	35	39	43	45	44	33	19	11
Solar plus 4hr Storage	32	32	36	31	36	50	57	60	49	38	25	21
Wind	31	24	33	32	29	35	27	29	24	22	25	19
CGS uprate	98	98	91	66	41	28	92	98	98	98	98	98
6hr Storage	24	11	5	-4	-2	19	21	22	7	8	4	12
SMR	95	95	79	40	33	25	95	95	95	94	95	95

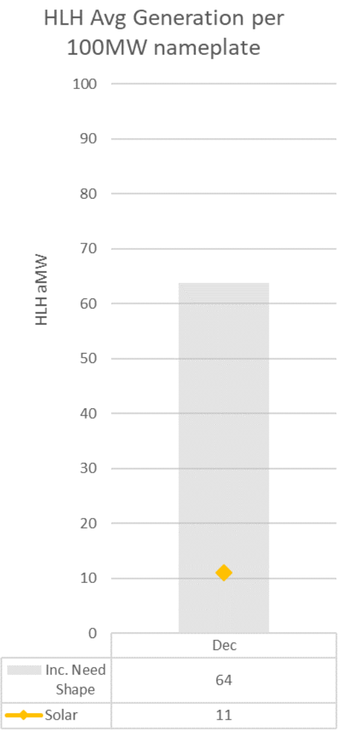
We want back-of-the-envelope, reasonable estimates of potential resource acquisitions.

While solar provides the lowest expected cost per MWh of energy, incorporating **differences between our expected incremental needs and monthly resource generation** suggest other resources or significantly more resources are required to grow the system.

*The needs reflect the *shape* of an additional 500 aMW of load, scaled down to 50 aMW for ease of comparison.

Differences in Needs and Resources, December

- What it takes to meet December HLH energy needs associated with increasing firm obligation by 500 aMW using only solar:
  - The associated December HLH energy need is about 640 aMW.
  - Solar can be expected to provide about 11 aMW per 100 MW nameplate capacity in December.
  - Without relying on the market, this would suggest we need about 5,800 MW of solar nameplate capacity, or about 1,200 aMW of solar energy, in order to grow the system by 500 aMW.
- The team produced a simplified selection method to give ballpark estimates of what actual acquisition strategies might reasonably look like after accounting for these differences of needs and resources.



Selection Methodology

Leverage

Use existing analysis and assumptions from the 2022 Resource Program base case:

- Monthly HLH energy needs
- Resource characteristics
- Market prices

Simplify

- Only consider one representative year (2028)
- Evaluate *incremental* monthly HLH needs
- Reduce candidate set to supply-side resources in overview slide

Solve

Find the least cost set of resources that increase system size by 500 aMW and satisfy BPA's expected energy needs with varying degrees of market reliance and capacity mixes.

1. 'Full Market' business as usual with full market reliance and no capacity.
2. 'Mixed' partial clean and firm with half market reliance and half capacity.
3. 'No Market' full clean and full capacity (no market reliance).

Reminder: **energy needs** rely on monthly diurnal averages, **capacity needs** evaluate the system under extreme weather events—peak needs and peak resource capabilities using BPA's 18-hour capacity metrics (highest 6-hour needs over 3 consecutive days in summer and winter). There are no market options modeled for capacity**. All solutions ensure energy and capacity needs are met**, while respecting market reliance limits.

Results

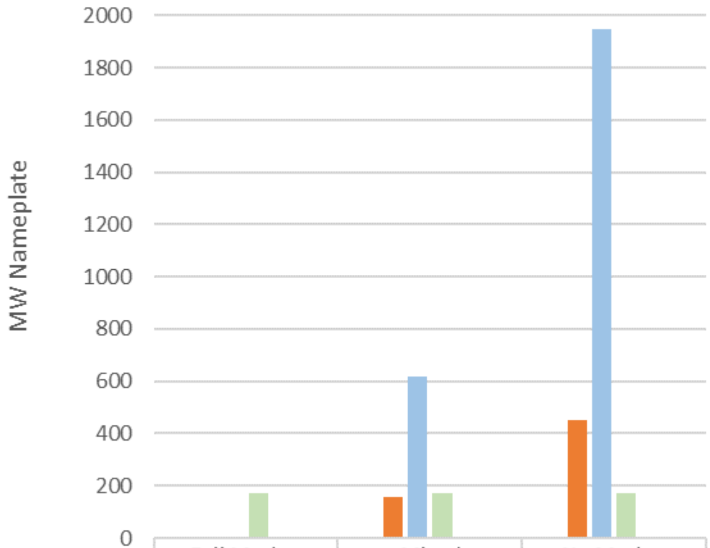
Growing the system by using a business as usual approach (acquire some resources and rely heavily on the market) results in selection of the Columbia Generating Station uprate* with a total annual average portfolio cost of ~$250 million.

Reducing the market reliance by half and ensuring half of the needs are backed by capacity results in additional acquisitions of wind and solar + storage with a total annual average cost of ~$275 million.

Eliminating market reliance and ensuring all incremental needs are backed by capacity results in additional acquisitions of wind and solar + storage with a total annual average cost of ~$400 million. Only relying on solar + storage would increase this cost to over $500 million, annually.

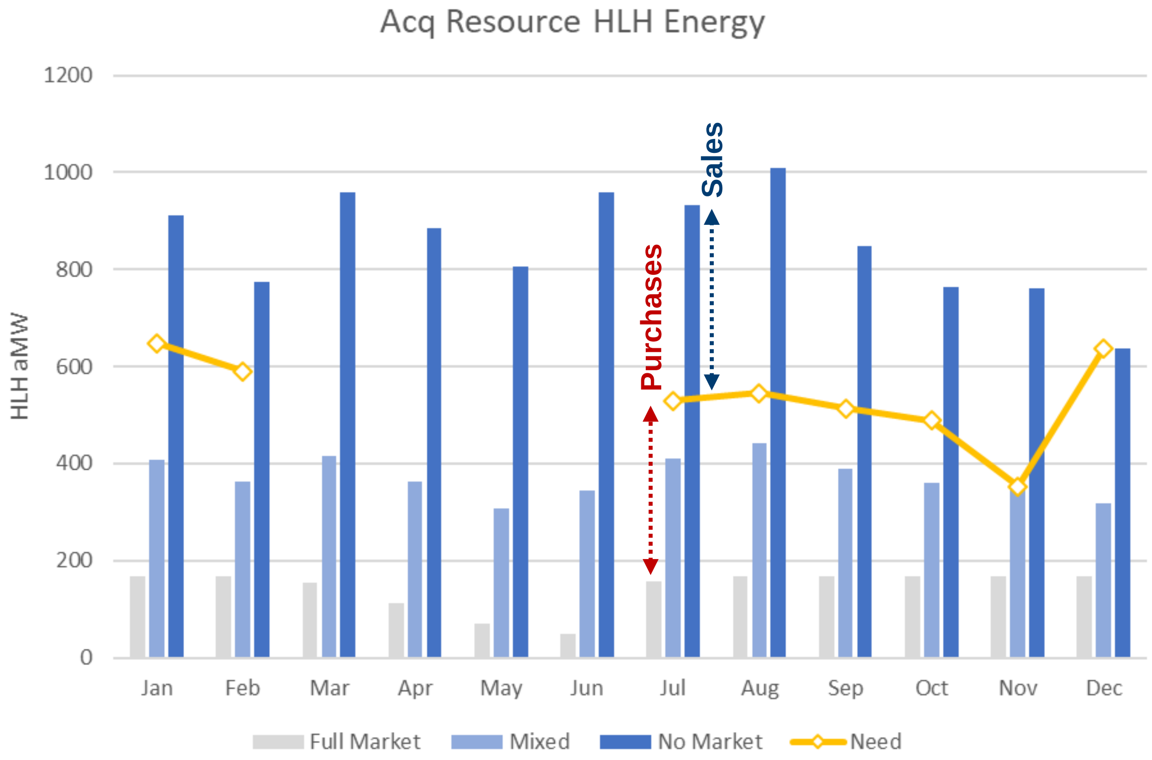
*The Columbia Generating Station uprate is not expected to be available in 2028, but this analysis is only using 2028 as a representative LT year. All dollar values are real 2021.

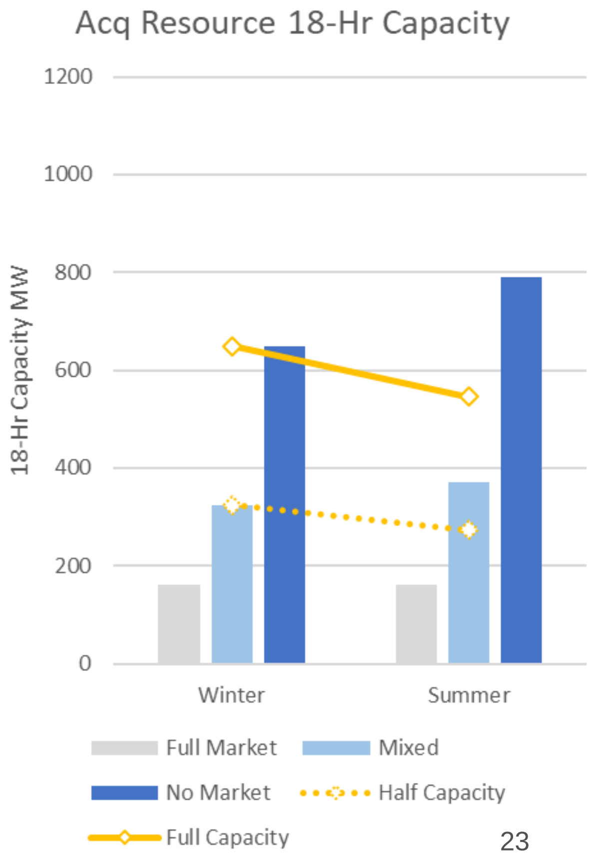
Acquired Nameplate Capacity (MW)



	Full Market	Mixed	No Market
Solar	0	0	0
Solar plus 4hr Storage	0	156	451
Wind	0	618	1945
CGS uprate	170	170	170
6hr Storage	0	0	0
SMR	0	0	0

Acquired Energy & Capacity vs Needs

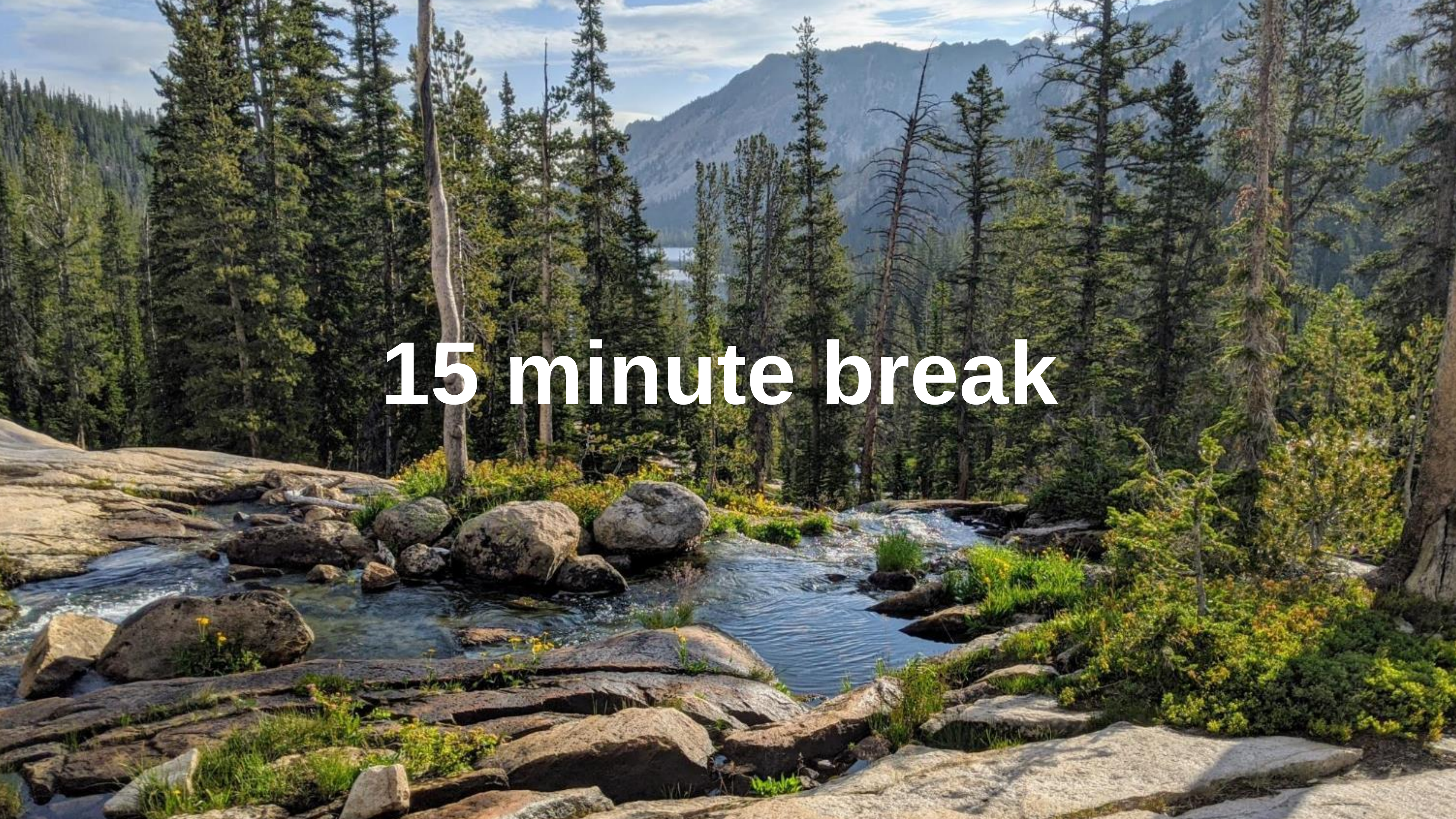




Not Included in This Analysis

- Consideration of expected changes over time for:
  - Needs
  - Resource costs
  - Market landscape and energy prices
- Does not explicitly factor in renewable energy credit value / zero emissions credits / WA carbon policy.
- Detailed evaluations of increasing forecast error and how system needs might evolve with more renewable/variable resource saturation
- WRAP requirements / capabilities
- Locational needs / transmission expense / availability + potential resources outside of BPA BA
- Consideration of resource cost uncertainty

DISCUSSION


15 minute break

Rates Impact Analysis

Brian Dombeck and Daniel Fisher

Calculating Portfolio Cost

- Focus on impact from initial 2028 load shock (but robust to consideration of additional growth in out-years).
- Selected portfolios fed into PortfolioCraft to determine *portfolio costs* ($) associated with project development, construction, and operations on yearly basis.
- *Net secondary revenue (NSR, $)* calculated from monthly diurnal data on incremental needs, portfolio generation profile, and LT2022 market price forecasts.
  - Surplus/deficit determined from incremental needs and portfolio generation profile.
  - Incremental load-resource balancing through sales into market (at *average rate*) and* purchases (at *P90 rate*).*
- Recover costs on firm basis with accounting for expected NSR.

$$Portfolio\ Costs\ (\$/MWh)_t = \frac{Portfolio\ Costs\ (Development, Construction, Operations)_t - NSR_t}{Cumulative\ Load\ Shock_t}$$

**Note: Market prices are exogenous to the implied incremental demand/supply shifts.*

Rates Impact

- All dollar values are real and reported in 2021$.
- Portfolio cost is the sum of delivered costs less transmission and credited for annual NSR from using market to balance incremental loads-and-resources.
- Expected costs of portfolio rise from $55.82/MWh with no market purchase limits to $91.03/MWh with zero market reliance.

PortfolioCraft Rates Impact Comparison				
	Unit	Full Market	Mixed	No Market
Total Delivered	2021$	$58.74 M	$231.44 M	$590.14 M
Electric Transmission	2021$	$4.00 M	$22.24 M	$60.44 M
NSR	2021$	($190.42 M)	($68.04 M)	$129.89 M
Portfolio Cost	2021$	$245.15 M	$277.24 M	$399.81 M
Solar	MW	0	0	0
Solar + 4-hr Battery	MW	0	156	451
Wind	MW	0	618	1945
CGS EPU	MW	170	170	170
6hr Storage	MW	0	0	0
SMR	MW	0	0	0
Total New Acquisitions/Billing Credits	aMW	500	500	500
Existing System	aMW	7000	7000	7000
New Cost	2021$/MWh	$55.82	$63.12	$91.03
Existing Cost	2021$/MWh	$35.00	$35.00	$35.00
Weighted Cost	2021$/MWh	$36.39	$36.87	$38.74
Rate Impact	2021$	$1.39	$1.87	$3.74
Rate Impact	%	3.97%	5.36%	10.67%

****Results are preliminary. Data may change from methodological or data input changes.*

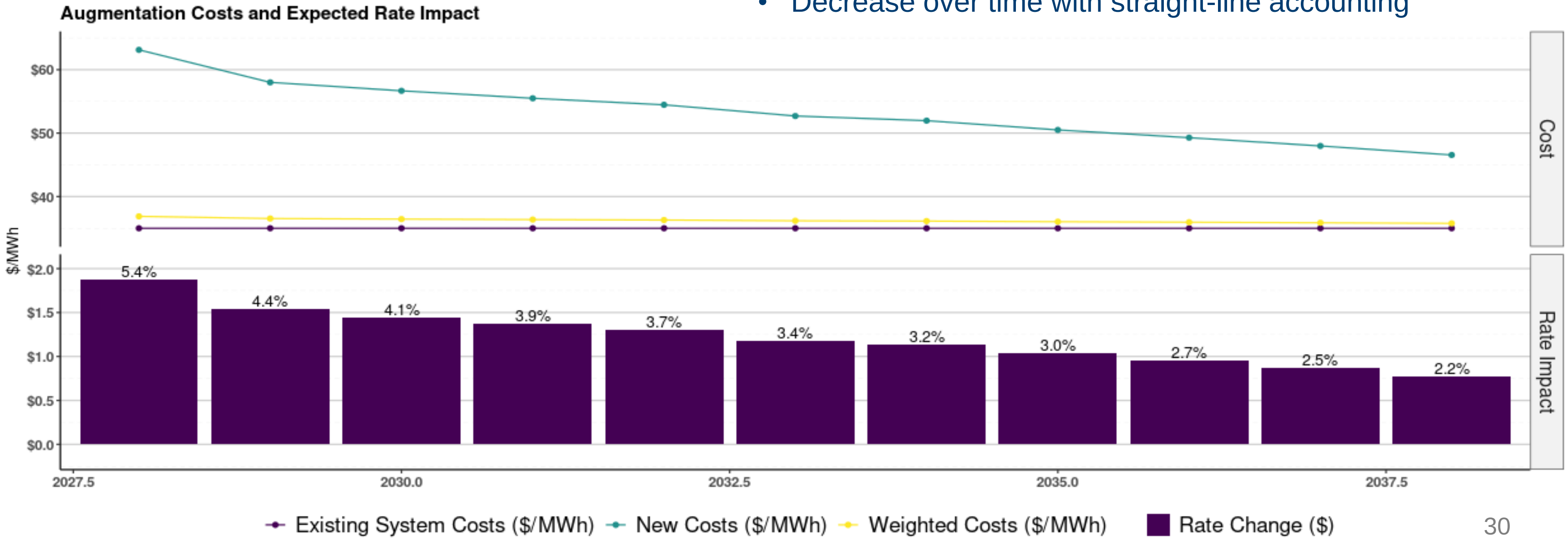
Rates Impact: Half Market Reliance & Half Capacity Backing

Acquisition Details:

- 156 MW solar + 4-hr storage
- 618 MW onshore wind
- 170 MW CGS uprate
- 944 MW total nameplate

Rate Impacts:

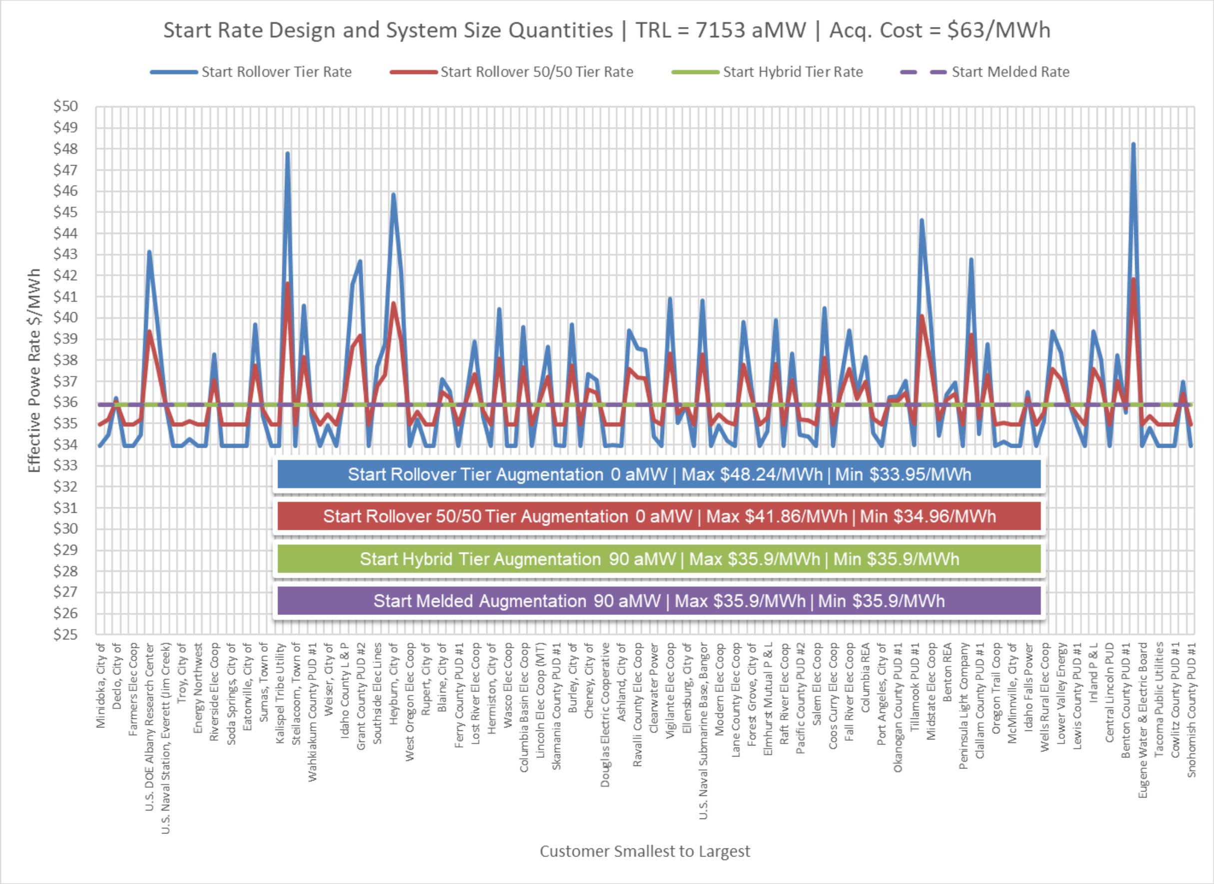
- In 2028:
  - Portfolio cost is $63.12/MWh.
  - Weighted cost is $36.87/MWh.
  - Rate impact is $1.87 (5.36%), *an increase.*
- Decrease over time with straight-line accounting



System Size and Rate Design Tool

- BPA created a tool that aids in the evaluation of different rate designs and system sizes.
- The tool uses BP-24 RHWM information as its starting point and calculates an effective rate by customer assuming no other rate design features (demand, LDD, IRD, energy shaping, *etc.*).
- Above-RHWM is assumed to be the same cost regardless of whether BPA or the customers is serving the load obligation.
- The tool considers four different approaches.
  - Rollover of current design.
  - Rollover of current design but partially reduce Above-RHWM exposure and partially reduce Unused-RHWM.
  - A hybrid design that augments the system to remove all Above-RHWM exposure and leaves Unused-RHWM.
  - A melded rate design.
- The tool also evaluates an “end” state after load growth is applied to each customer.
  - At this point, the load growth is random and is applied to evaluate patterns under various different hypothetical scenarios on how customers could be impacted.
  - **The “end” state analysis is not a customer-specific rate impact tool.**

Start with BP-24 RHWM data as base:



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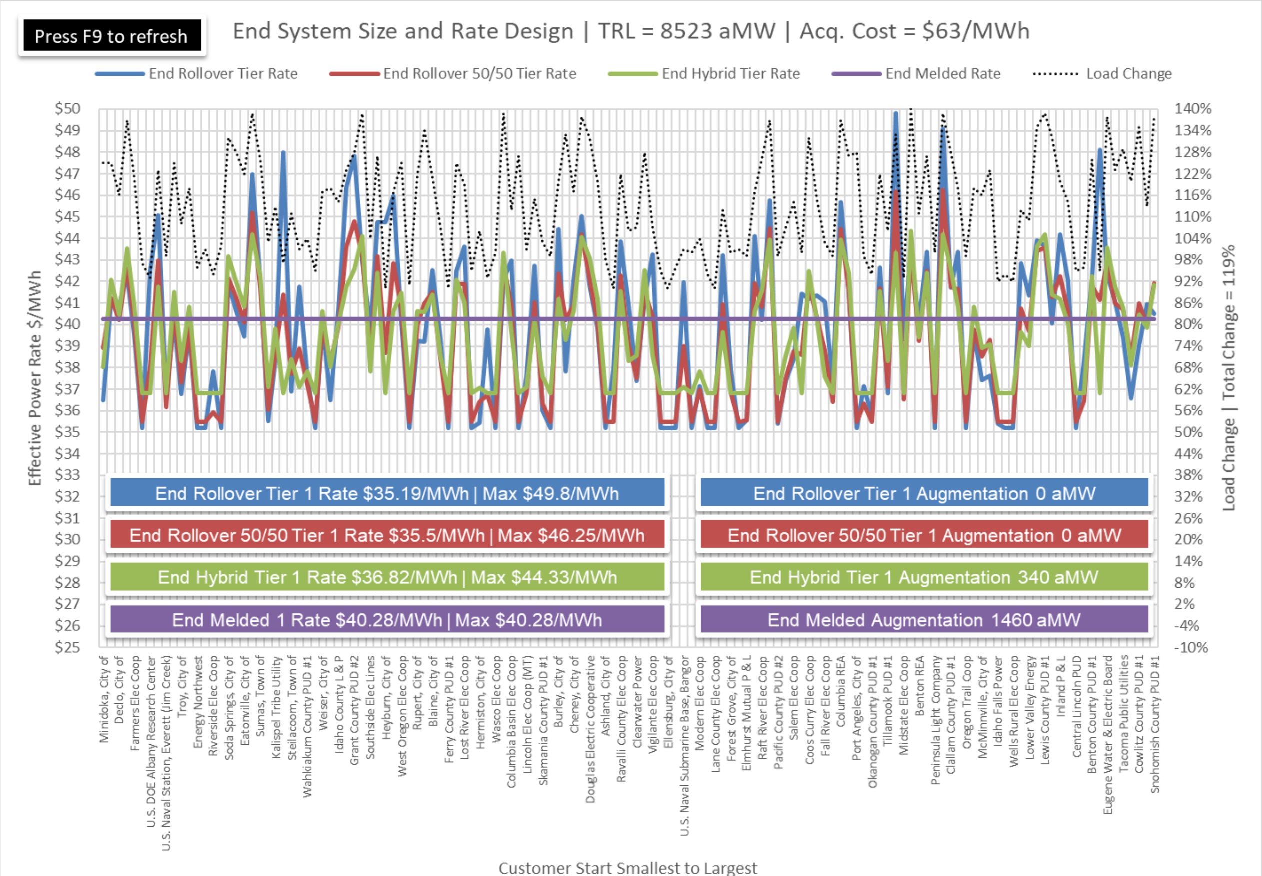
End state with random load growth applied:



Note:
This is not a customer-specific rate tool.

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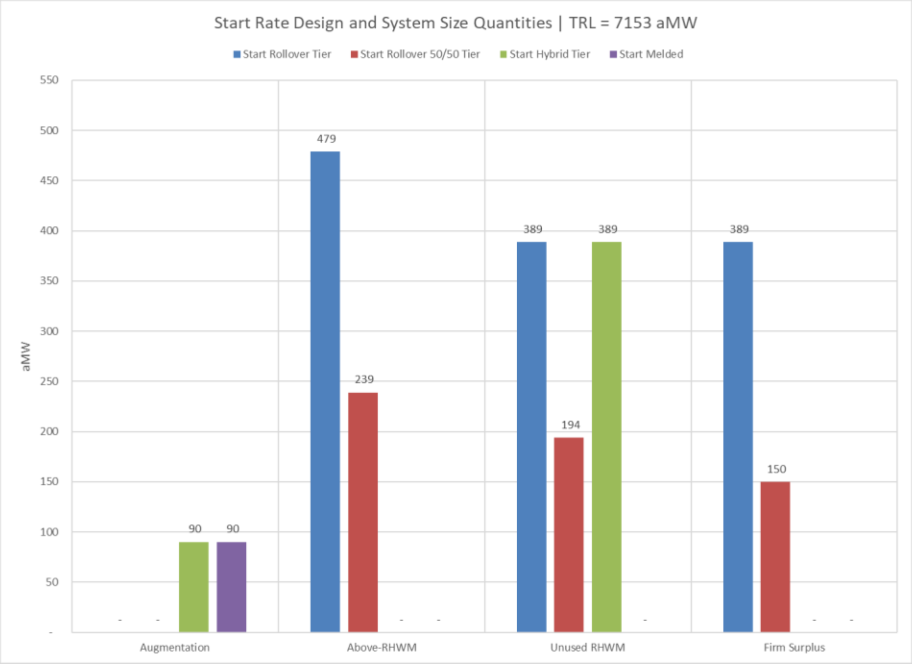
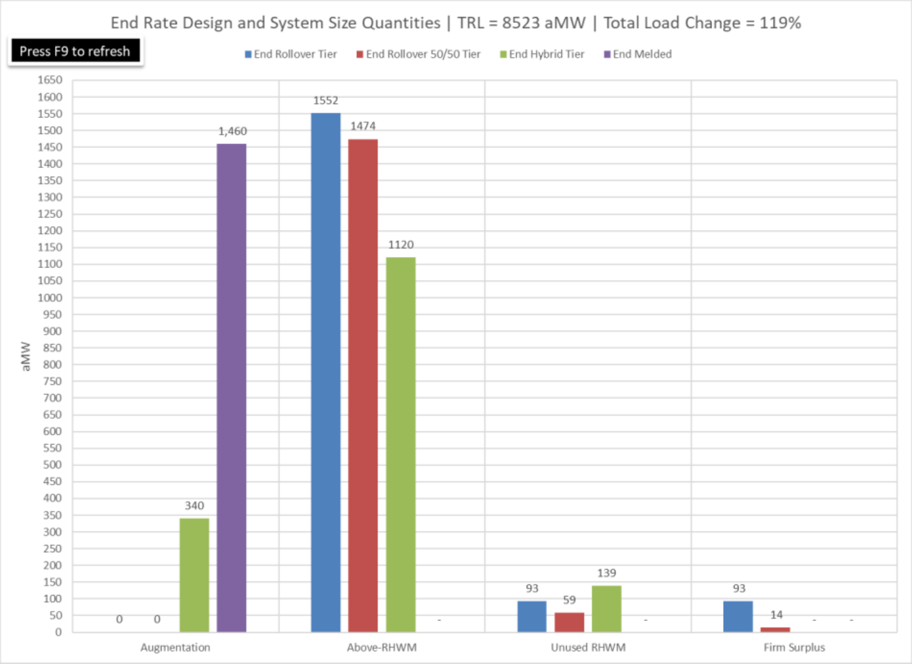
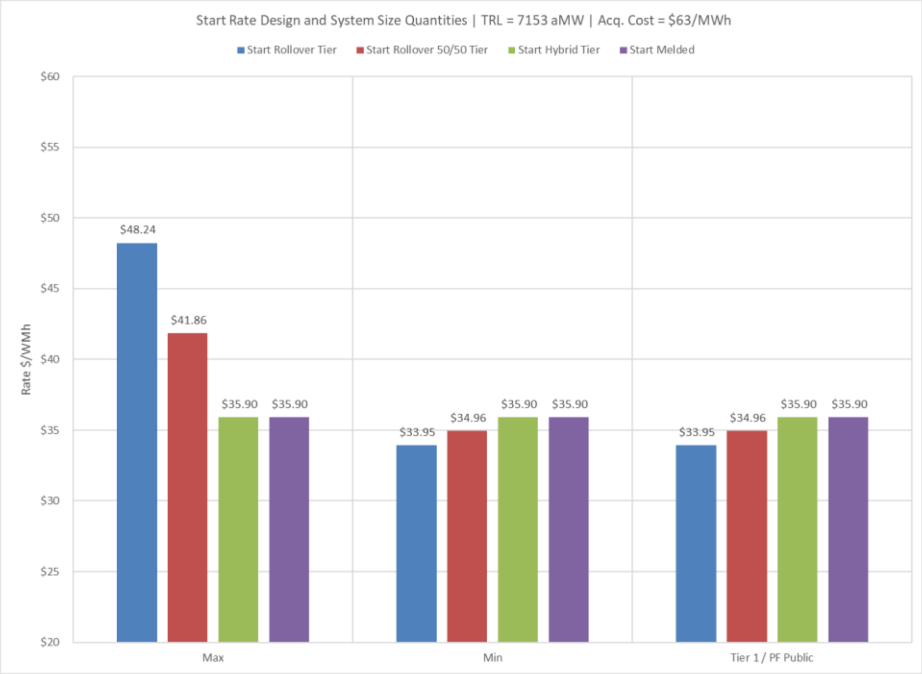
Start Energy Measurements



End Energy Measurements

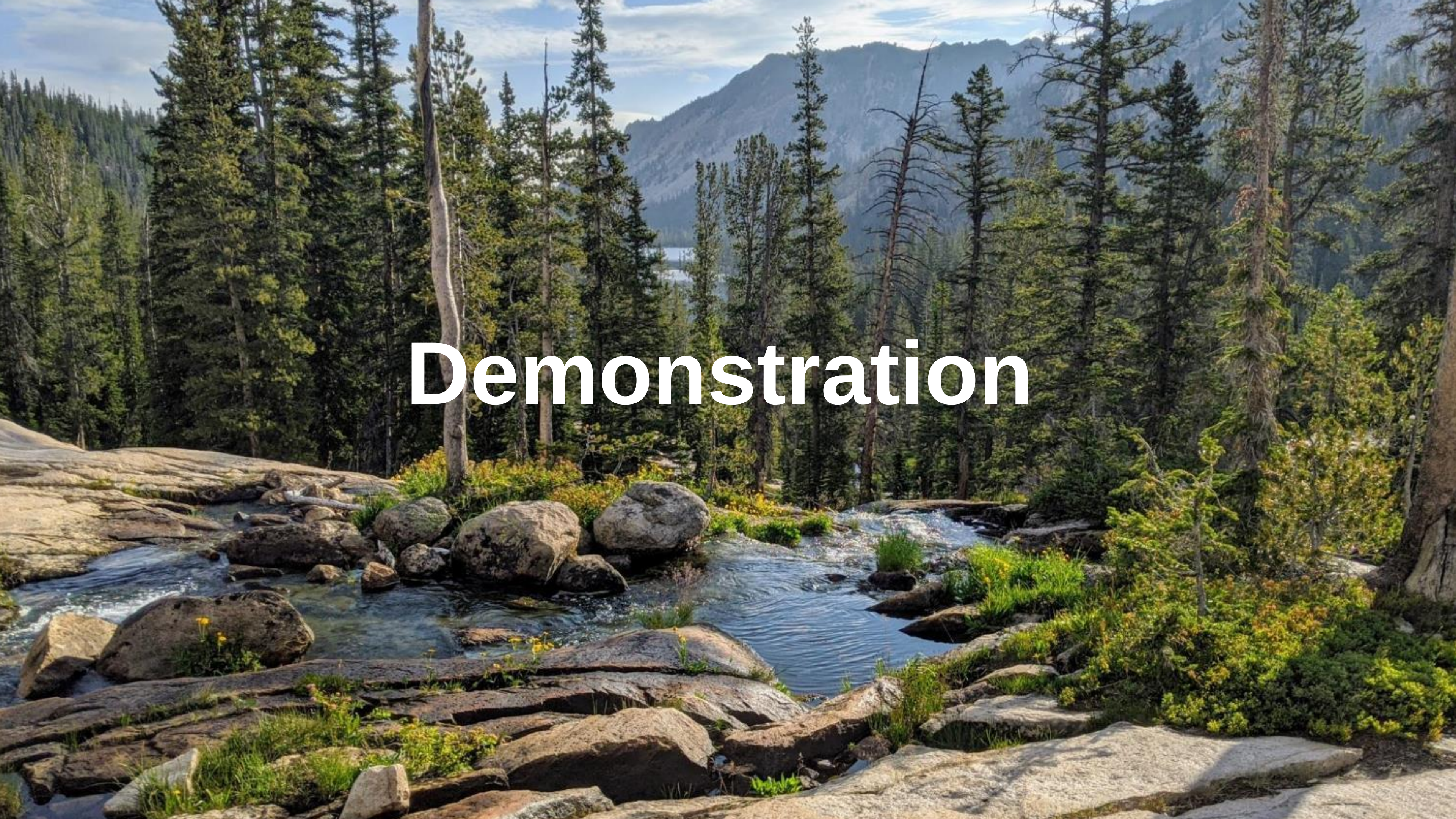


Start Effective Rates $/MWh



End Effective Rates $/MWh

Demonstration



Key Takeaways

- **Increasing system size** is more challenging and costly than simply acquiring annual average energy at the lowest levelized cost of energy (LCOE).
- **Future acquisitions** to meet new load growth may be more expensive and complex, involving a mix of energy and capacity resources
- Additional conversations are needed around the **rate design and potential impacts** to customers to move forward with a policy construct.

Next Steps

- Further analysis would require additional clarity on the load obligation that is expected in the future and who is serving that load.
- Further policy conversations are needed to establish that detail including:
  - Aligning on a tiered rate construct with awareness of potential rate consequences discussed today.
  - Determining who is taking on load obligation going forward – is the approach to offer customer flexibility to develop non-federal resources or is BPA taking on that obligation?
  - Defining the Tier 1 system size and if there is augmentation, assuming moving forward with tiered rate construct.

DISCUSSION

Schedule & Feedback

Michelle Lichtenfels, Program Manager, Provider of Choice

Mark Your Calendar

Date	Time	Workshop Topics
December 8, 2022	9am – 4pm; BPA Rates Hearing Room and Webex	• Executive Overview (2 hours) - Executive remarks from Suzanne Cooper, Senior Vice President of Power Services and Kim Thompson, Vice President of Northwest Requirements Marketing - Open Q & A • Preference products overview and discussion
December 14, 2022	9am – 3pm; Webex	• Overviews: LDD, IRD, NLSL, Transfer • Customer presentations/proposals
2023		• In planning

BPA Event Calendar: https://www.bpa.gov/learn-and-participate/public-involvement-decisions/event-calendar

Feedback

Informal comments accepted and feedback requested:

- Send requests to present at the December 14 workshop to **Post2028@bpa.gov** by **Dec. 7**.
- Share feedback by **December 14** with your Power AE and/or **Post2028@bpa.gov** with a copy to your Power AE.
- Please note that direct responses will not be provided.

Thank You.

Provider of Choice Lead Sponsor:

Kim Thompson, Vice President, Northwest Requirements Marketing

Provider of Choice Team Leads:

Sarah Burczak, Policy Lead

Kelly Olive, Contract Lead

Michelle Lichtenfels, Program Manager

Provider of Choice Website:

https://www.bpa.gov/energy-and-services/power/provider-of-choice