Northwest **Power** and **Conservation** Council

June 3, 2025

MEMORANDUM

TO: **Council Members**

FROM: **Joe Walderman, Energy Resource Analyst**

SUBJECT: **Proposed Demand Response Resources for the Ninth Plan (Part 2) – Draft Supply Curves**

BACKGROUND:

Presenter: Joe Walderman

Summary: This presentation is the second and final of a two-part series that describes the demand response resource potential being developed for the Ninth Power Plan. Staff are in the finishing stages of completing the demand response supply curve, an aggregation of the 28 distinct demand response products being considered for the Ninth Plan. Demand response products are represented in the supply curves by total potential savings (megawatts) and levelized cost (dollars per kilowatt-year). The products are assessed for both their summer peak and winter peak potential. The total demand response resource is just over 4,100 MW of summer potential (up from 3,700 MW in the 2021 Plan) and just over 3,500 MW of winter potential (up from ~2,750 MW in the 2021 Plan).The increased demand response potential comes in large part from the addition of new demand response products like behind-the-meter batteries, the incorporation of the latest electric vehicle forecast, and expanded thermostat programs. Staff will discuss potential and levelized costs for individual demand response products grouped by the end uses they impact—such as HVAC, water heating, EV charging, and irrigation—and then will discuss supply curves as a whole. The supply curve represents the entirety of

the demand response resource potential to be ultimately modeled against other resources in the OptGen modeling.

Relevance: Over the past year staff has been conducting research, improving assessment models, and conferring with the Demand Response Advisory Committee to build out the spreadsheets and assumptions that define our DR products. These product definitions are important for accurately comparing the suite of resource options available to the region when conducting the optimization modeling for the Ninth Power Plan.

Workplan: B.4. Develop demand side supply curves and related assumptions for plan analysis.

More info: Staff presented draft supply curve results to the Demand Response Advisory Committee on May 30, 2025:

- May2025 DRAC Draft Supply Curves for the 9th Plan

Staff also presented a Primer on DR for the Ninth Plan in July of last year as well as Part One of the proposed demand response resources in May 2025:

- Supply Curve Primer for DR in the Ninth Plan (September 2024)
- Proposed Demand Response Resources for the Ninth Plan (Part 1) (May 2025)

Demand Response Supply Curves for the 9th Power Plan

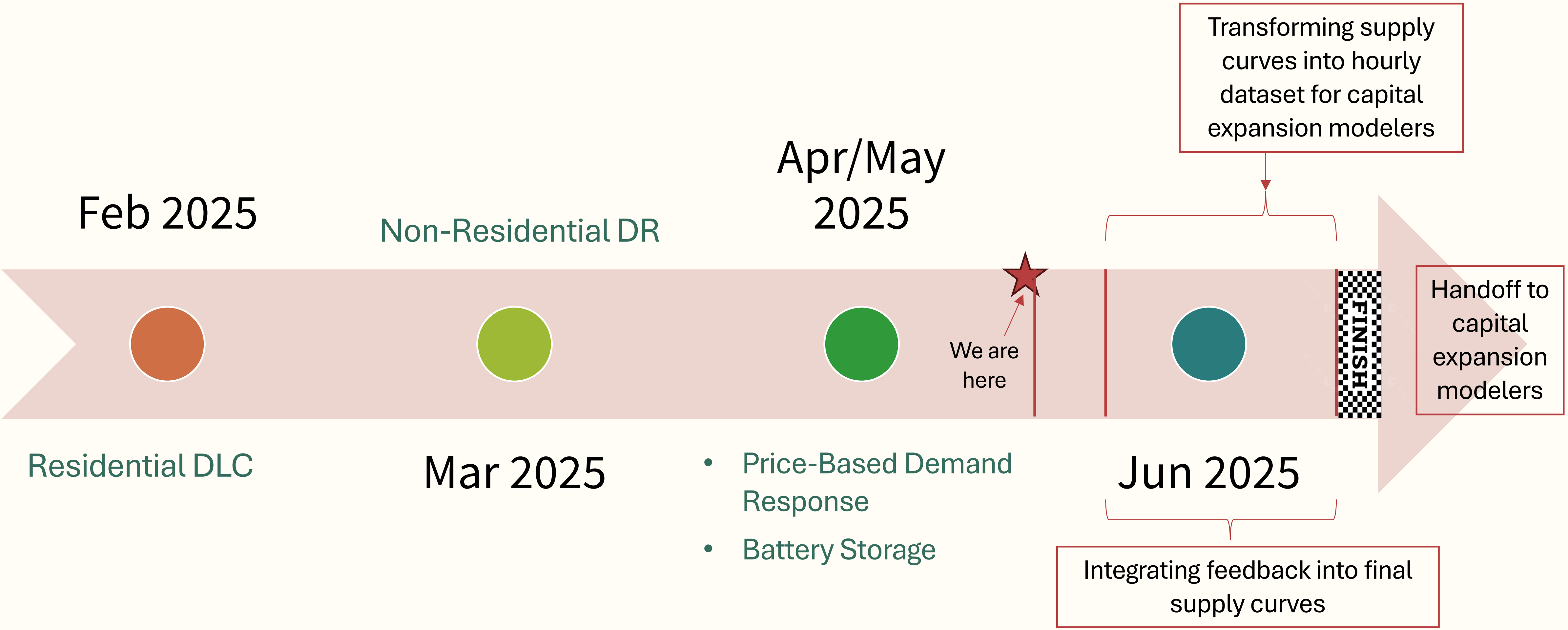
June 11, 2025 Council Meeting

Joe Walderman

Agenda/Overview

- Demand Response in the 8th and 9th Plans
- Levelized Cost Development
- Potential and Costs by End Use and Sector
- Demand Response Supply Curves
- Dispatch and Binning
- Final Steps

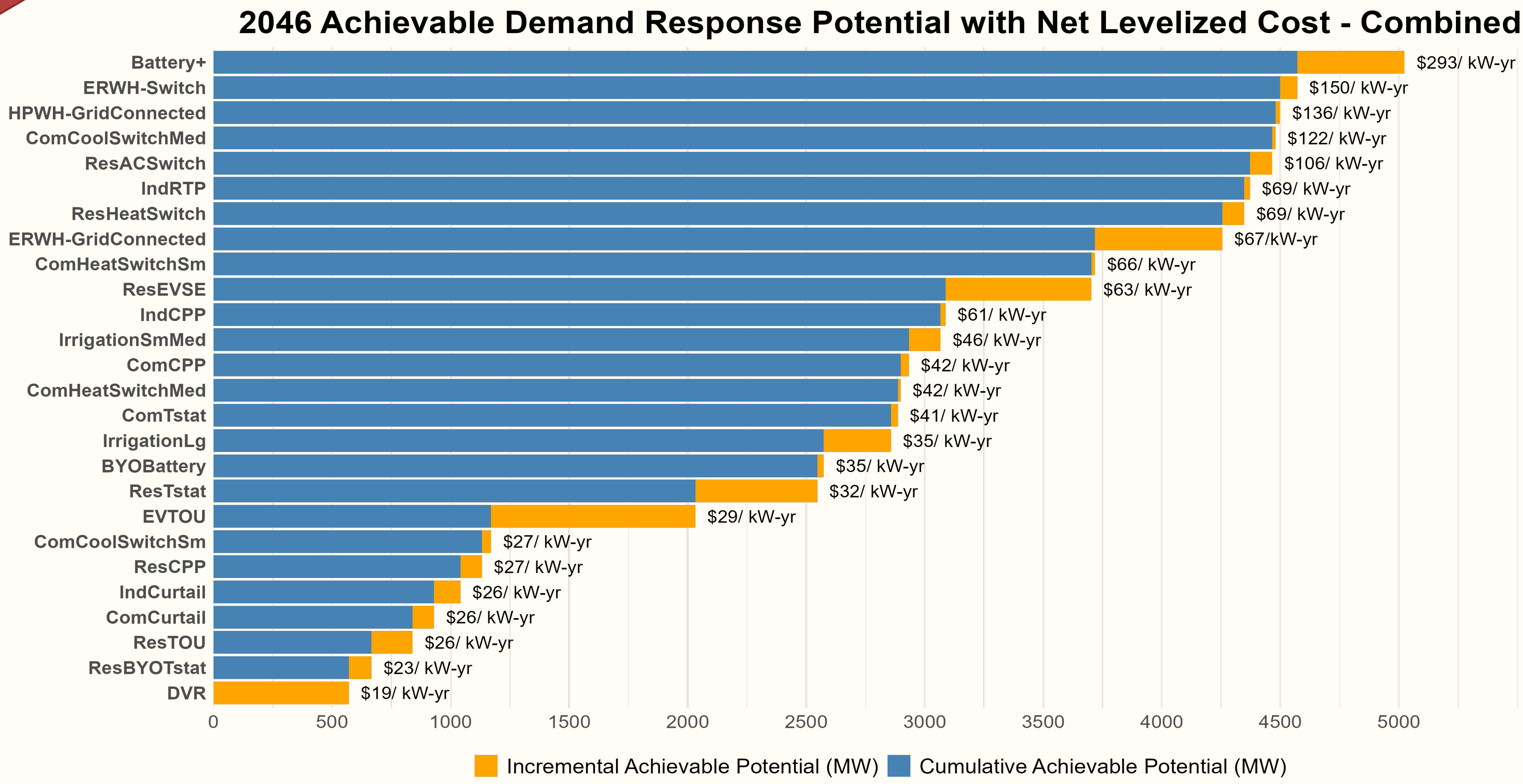
Demand Response Advisory Committee Timeline



Demand Response Advisory Committee

- A big THANK YOU to DRAC participants, for the Plan, they have helped:
  - Determine DR product list
  - Estimate key product inputs, including: cost, impacts, applicability, and participation
  - Provide guidance on challenging questions, such as: calculating levelized cost, determining deployment capabilities, incorporating variable versus fixed costs
  - Review draft assumptions/results

Supply Curve Preview



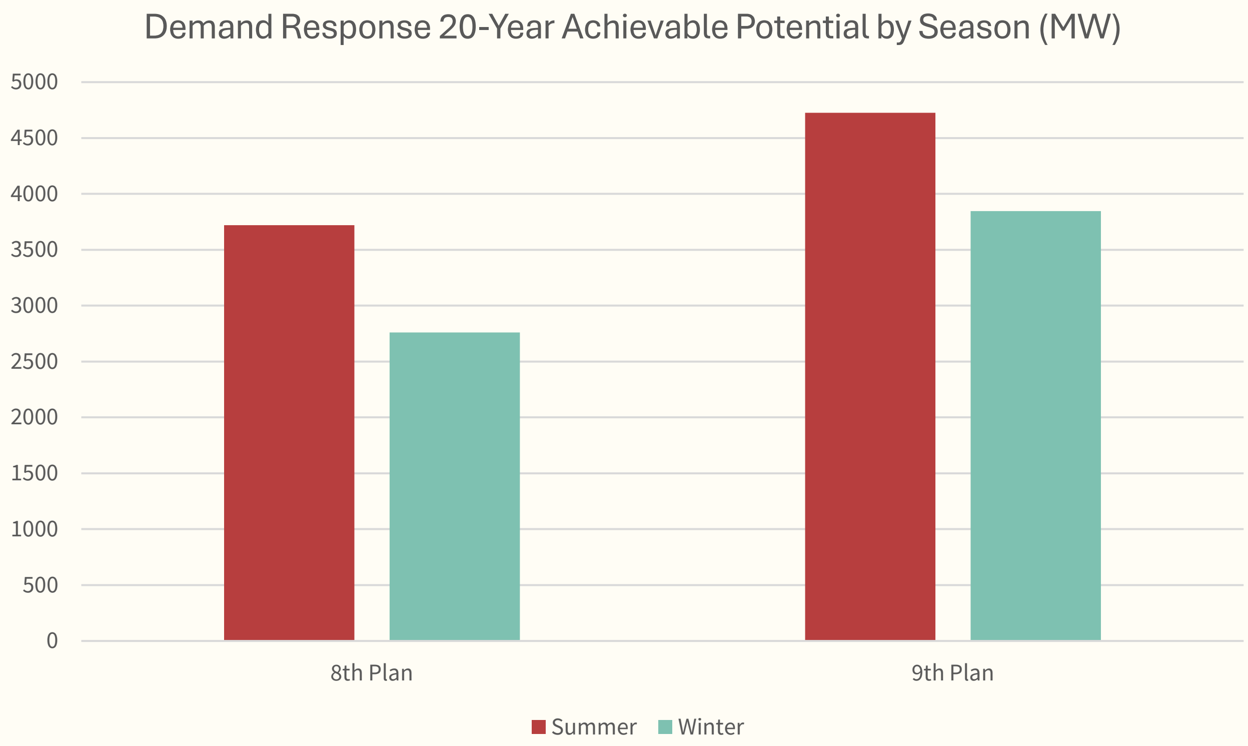
General Modeling Steps

1. Define Demand Response Products
2. Estimate Technical Potential
3. Estimate Achievable Potential
4. Calculate Levelized Costs
5. Develop Supply Curves

DR in 8th Plan vs 9th Plan

Updated Potential Drivers and Insights

- EV demand response greatly increased due to incorporation of new EV forecast and addition of EV TOU rate
- New battery demand response products add 500 MW of potential
- Water heating potential moderately decreased due to lower observed peak load impact
- Irrigation demand response derated by the 328 MW of existing capacity



Levelized Cost

- Setup, equipment, marketing, O&M, and incentive costs unique to each DR product (may differ by zone)
- Levelized costs developed for each zone and a weighted average cost is developed for the region
- Still working on developing T&D deferral credit approach for DR
  - Demand response with limited deployment capability may not be able to fully defer T&D upgrade needs

Implementation Costs

Enablement Costs

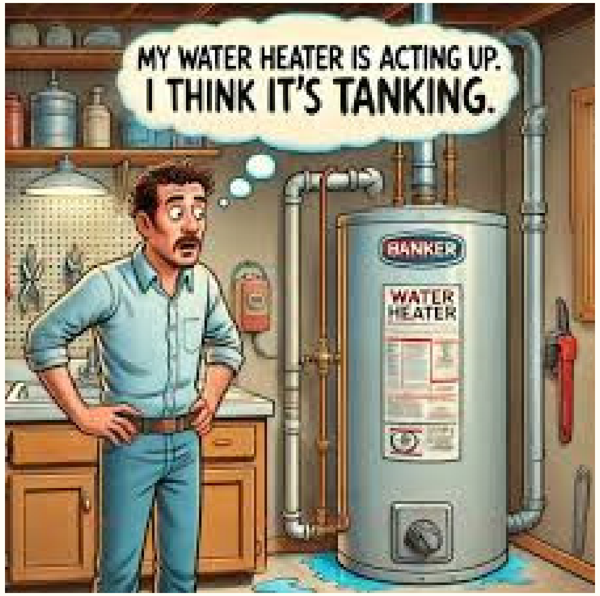
Incentives/Value of Lost Service

Deferred T&D

Regional: $31/kw-year
West: $39/kw-year
East: $16/kw-year

Water Heating

- Most electric water heaters are grid-enabled with CTA-2045 port by end of plan timeline
- Cost driven mostly by grid modules and cellular fee
- Potential subject to change based on EE measure adoption
  - ex. If HPWH gets adopted, DR potential for HPWH increases and potential for ERWH decreases

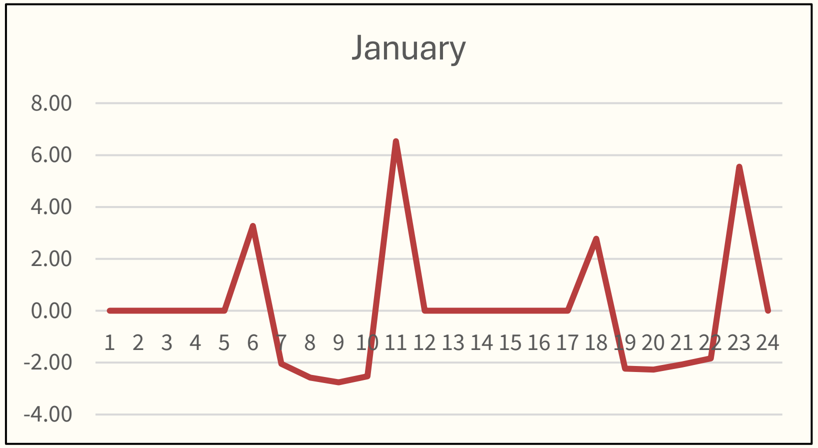


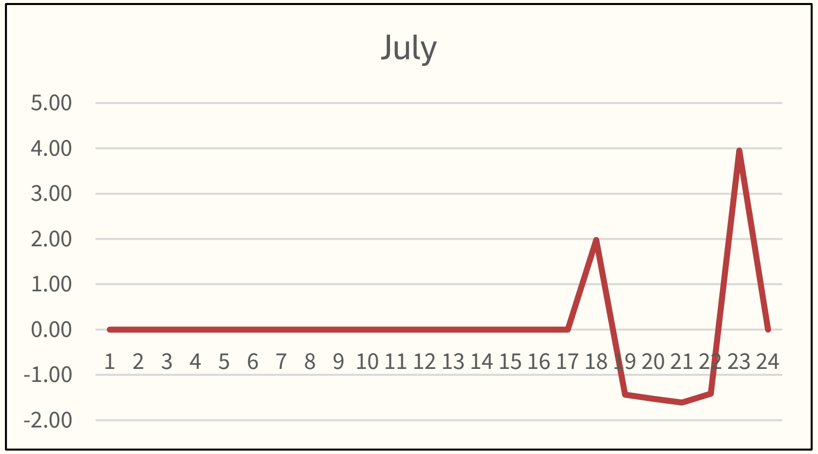
DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
ERWH-GridConnected	537	$67/kW-yr
ERWH-Switch	53	$136/kW-yr
HPWH-GridConnected	29	$148/kW-yr
Total	**549**	

Peak load impact per water heater is 0.4 kW for ERWHs and 0.2 kW for HPWH

Grid-Connected ERWH Deployment Assumptions

- Assumed frequent deployment, treated as daily load modifier
- Grid-connected module allows preheating in advance of DR load shedding events
- Achievable potential assigned to highest average hour and scaled down based on load shape





EV Charging

- EV loads are highly flexible
- 78% of LDVs on the road in 2046 are EVs based on plan forecast, with annual program eligibility based on forecast stock
- 40% participation in EV programs shared between active managed charging and EV TOU
- EV demand response programs are assumed frequently deployable

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
EV TOU	862	$29/kW-yr
Active Managed Charging	614	$63/kW-yr
Total	1,476	

HVAC – Residential

- **Smart Thermostats**: Uses WiFi-enabled thermostats to change setpoint temperature on heating or cooling systems to preheat/precool and then adjust during peak events to lower energy demand. Divided into two DR products:
  - BYO Tstat: Relies on existing smart thermostat saturation from RBSA (~14%) and modest 1.7% annual adoption rate (no equipment cost)
  - Res Tstat**:** Remaining population with central heating and/or cooling included in potential with $170 equipment cost
- **Load Switch**: Directly curtails central AC or heat load through a load control switch placed on a customer's air conditioning or heating unit
  - AC Switch
  - Heat Switch

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
BYO Tstat	119	$22/kW-yr
ResTstat	499	$29/kW-yr
ResACHeatSwitch	79	$68/kW-yr
ResHeatSwitch	165	$105/kW-yr

HVAC – Commercial

- Thermostat and load switch demand response products
- Focused primarily on office and retail customers
- Larger customers covered by C&I curtailment DR products

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
CommercialTstat	30	$35/kW-yr
CommercialHeatSwitch	Medium: 16 Small: 15	Medium: $42/kW-yr Small: $66/kW-yr
CommercialCoolSwitch	Medium: 38 Small: 18	Medium: $37/kW-yr Small: $122/kW-yr
Total	**117**	

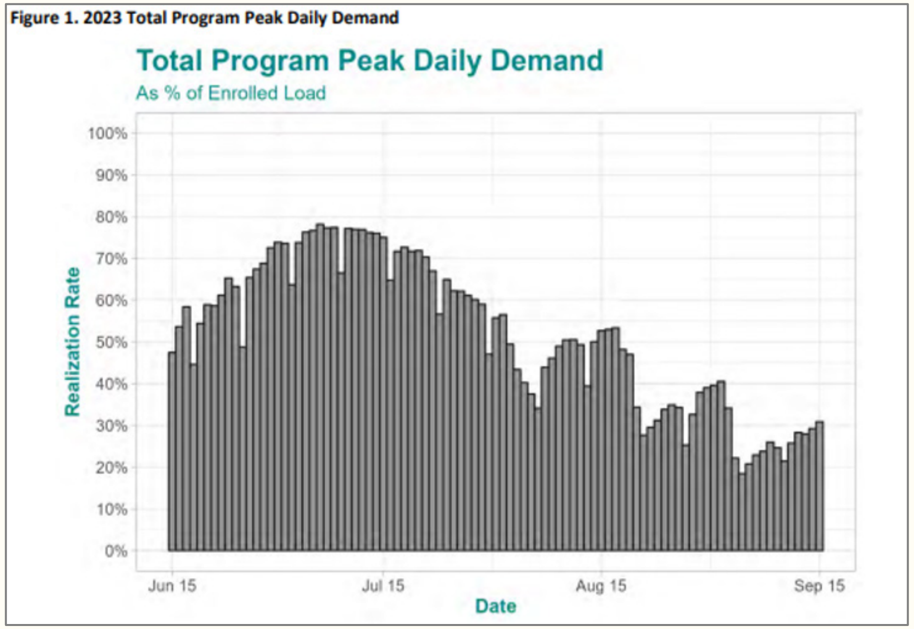
C&I Curtailment

- Targets large commercial and industrial customers, providing incentives for custom load curtailment strategies and event-based energy shifts
- The offering is technology agonistic and flexible, with a mix of behavioral/manual participants and other customers who opt for direct load control
- Products for commercial as well as industrial
- Assumes participants nominate 25% of their load for curtailment

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
IndCurtail	111	$26/kW-yr
ComCurtail	90	$27/kW-yr
Total	201	

Irrigation

- 417 MW of irrigation potential
  - Idaho Power and PacifiCorp programs have been around for years and total 328 MW capacity. Maturity of these programs mean they are baked into our load forecast, and the capacity will be removed from the total potential
  - Final regional irrigation potential is **89MW**
- DR products broken between large farms (>2,000 acres) and small/medium farms (<2,000 acres)
- Potential peaks in first half of the summer, dying off after harvests

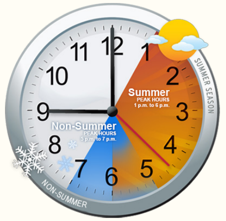


Source: Idaho Power

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
IrrigationLg	60	$35/kW-yr
IrrigationSmMed	29	$46/kW-yr
Total	89	

Price-Based and System Demand Response

- Setup cost of price-based DR increased to $500,000 to partly cover the cost of billing and IT upgrades needed
- AMI saturation and deployment plans used to define eligibility
- Smaller potential means fixed costs have outsized impact on levelized cost
- All price-based products are opt-in



Time of Use (Residential)	A residential time-varying rate designed to encourage customers to shift their energy use to off-peak times, reducing overall demand during peak periods
Critical Peak Pricing (Residential, Commercial, and Industrial)	Higher prices during peak events (called), lower prices during other times
Real Time Pricing (Industrial)	Hourly (generally) electricity prices set day-ahead •Includes $4,000 per participant equipment cost for real time monitoring and information sharing
Demand Voltage Regulation (All)	DVR uses voltage regulation to reduce demand and manage voltages in power systems during peaks

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
DVR	571	$19/kW-yr
ResTOU	173	$32/kW-yr
ResCPP	91	$39/kW-yr
ComCPP	36	$42/kW-yr
IndCPP	22	$61/kW-yr
IndRTP	24	$69/kW-yr
Total	935	

Batteries

- BYO Battery: Uses existing customer owned battery to shift peak loads, charging with solar in the afternoon and dispatching during evening peaks
  - Battery adoption is not forecast for plan, so eligibility is based on frozen distributed solar forecast and an assumed 8% storage attachment rate
  - Assume 80% of battery capacity enrolled in the program, providing 4 kW of peak load impact per battery
  - 30 deployments per year
- Battery+:
  - Expands potential for battery-based DR to potential homes that *could* have a battery
  - Includes full $9,400 cost of distributed battery procurement
  - Frequently deployable demand response

DR Product	20-Year Achievable Potential (MW)	Net Levelized Cost
BYO Battery	47	$26/kW-yr
Battery+	452	$293/kW-yr
Total	499	

Summary Results

Sector	Combined 20-Year Achievable Potential (MW)
Residential	3,554
Non-Residential	570
DVR	571
Grand Total	**4,695**

NOTE: All values presented are DRAFT. The review and revision process will continue through June 2025.

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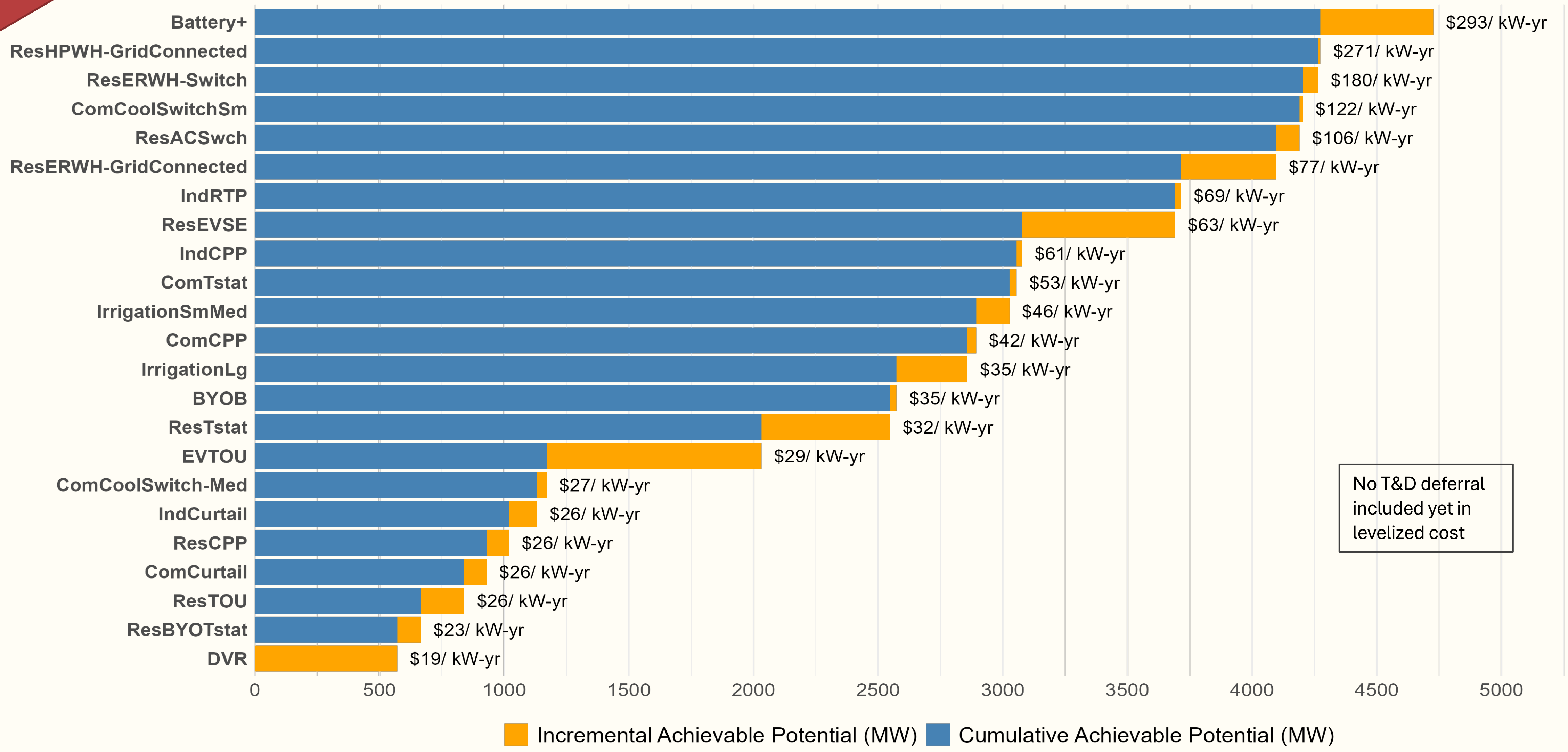
2046 Achievable Demand Response Potential with Net Levelized Cost - Summer



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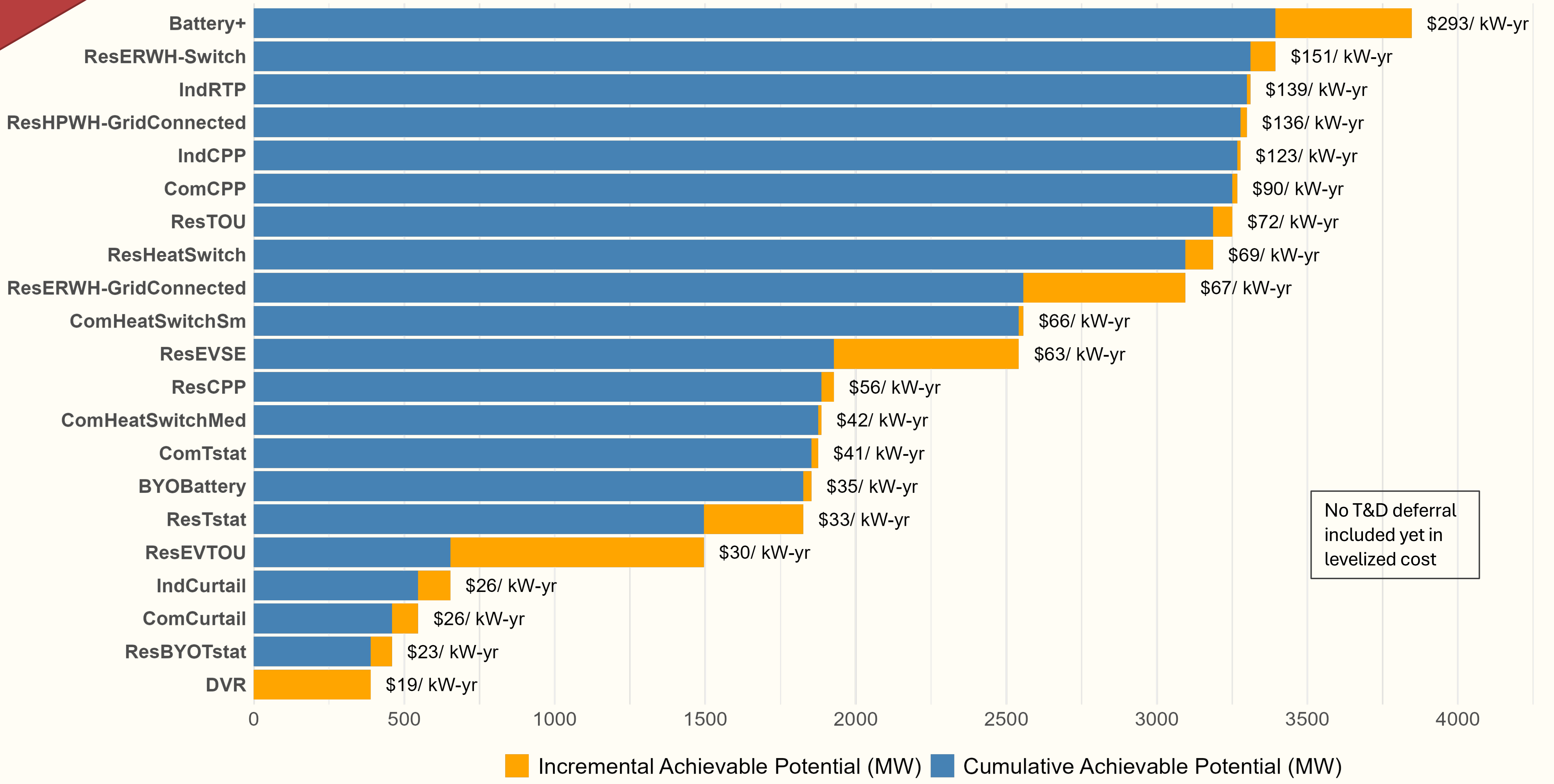
2046 Achievable Demand Response Potential with Net Levelized Cost - Winter



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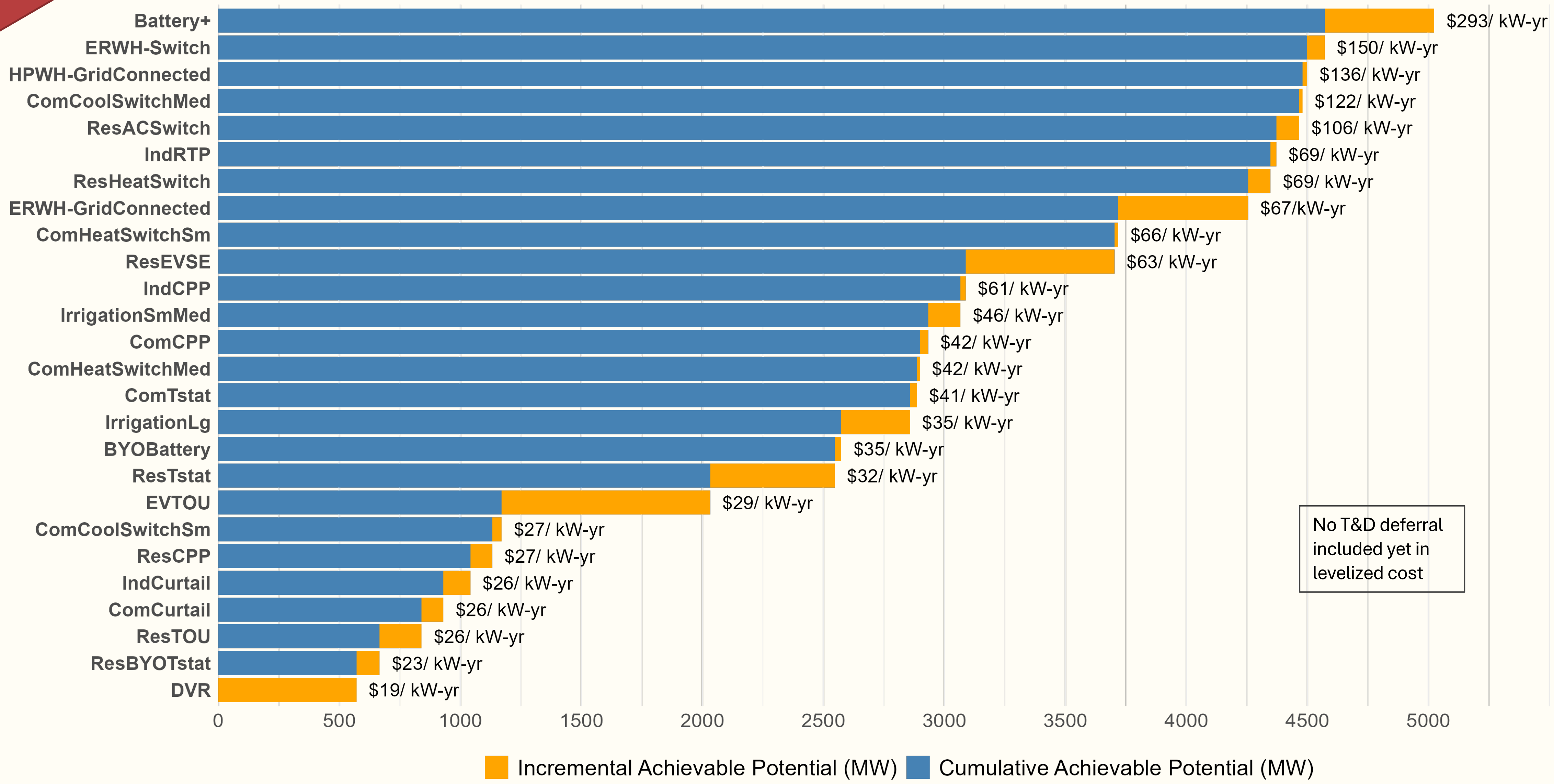
2046 Achievable Demand Response Potential with Net Levelized Cost - Combined



How to Bin?

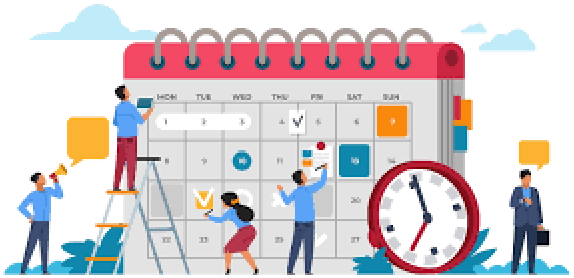
- Cost largest driver
  - Want minimal variance in costs across products in a bin
- Deployment capability
  - Limited and frequent deployment DR may have to be binned and modeled separately
- Seasonal availability

Dispatch Assumptions

Event-Based

10-15 events per season lasting 3-8 hours in duration

- HVAC
- Irrigation
- BYO Battery
- Critical Peak Pricing
- Non-Res Curtailment

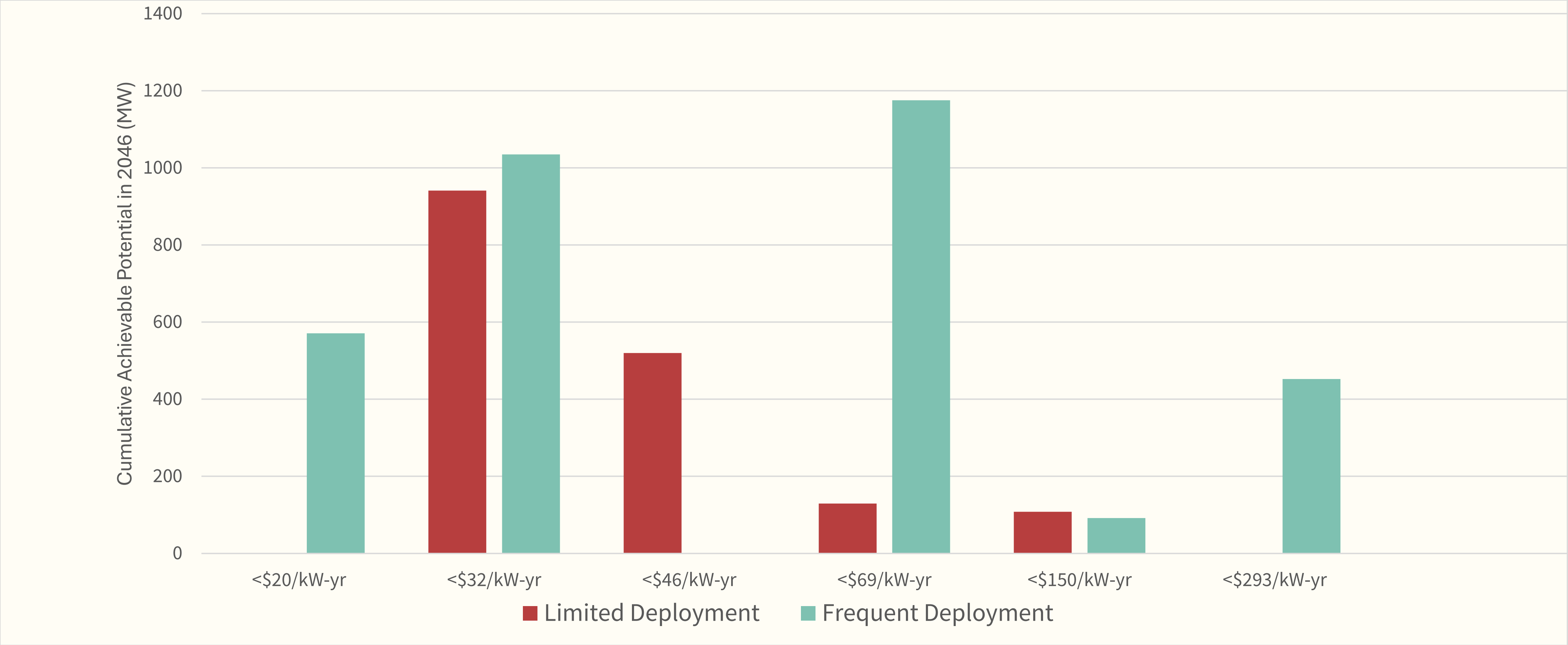


Frequently Deployable

Utilized almost every day for energy shifting

- Water Heating
- EV Charging
- Time of Use
- DVR
- Real Time Pricing
- Battery+

Total Potential By Cost and Deployment Type



Next Steps to Finalize in June

- Finalize T&D deferral credit approach and provide finalized supply curves
- Incorporate extra tiers of EV charging demand response
  - Added participation with increased incentives
  - Commercial EV charging demand response as an emerging technology
- Develop hourly shapes and bundle supply curves into bins for OptGen
- Staff will share with the Council any changes and a final summary after complete of these updates

Thanks!

For questions or suggestions please contact:

jwalderman@nwcouncil.org

Cost Parameters

Setup Costs	O&M Costs	Equipment Cost	Marketing Cost	Value of Lost Service (Derived from incentive)
$	*$/ participant* or *$/ year*	*$/ new participant*	*$/ new participant*	*$/ new participant*
• A one-time cost associated with setting up the demand response program in its first year	• An ongoing cost, either a $ per year or $ per participant per year basis. This represents the ongoing operations and maintenance cost for the DR program, including labor and materials, and administrative overhead	• An estimate of the incremental cost of any equipment required to enable DR connectivity with an end use	• An estimate of the cost required to spread awareness, adoption, and satisfaction with a DR program	• Service or utility lost from participation in the demand response program • Derived as percentage of incentive, the cost of one-time enrollment and ongoing annual compensation paid to host load for participation in the demand response program

Impact Parameters

Eligibility	Program Participation	Event Participation	Peak Load Impact	Ramp Period	Attrition
% of customer count or *% of end use load* • Percent of customers in the region that are eligible for a given demand response program based on load class or equipment saturation	*% of eligible customers* or *eligible end use load* • Estimate of the percentage of eligible customers that will be enrolled in a given program when fully ramped	*% success rate* • Estimate of the percentage of enrolled and participating customers in the program that will be participating in a given demand response event (eg customer override, switch failure, connectivity issues)	*kW per participant* or *% of end use load* • Average kW of demand reduction per participant observed at the meter for a given demand response event	*Years* • Number of years to reach maximum achievable potential	*% of existing participants per year* • Estimated percentage of existing participants dropped from the program per year

Model Inputs

The model can be modified to accommodate varied approaches and inputs.

Some data points come from sources such as NEEA, and utilities, while others come from Plan processes such as our load forecast

Parameters	Units
Set up Cost	$
O&M Cost	$ per year
Equipment Cost	$ per new participant or kW
Marketing Cost	$ per new participant or new kW
Incentives (annual)	$ per participant per year or per kW
Incentives (one time)	$ per new participant or per kW
Attrition	% of existing participants per year
Population	**Customer count**
Eligibility	**% of customer count (e.g. equipment saturation)**
Peak Load Impact	kW per participant (at meter) or % of eligible end use load
Program Participation	% of eligible customers
Event Participation	% (switch success rate)
Ramp Period	Number of years to reach maximum achievable potential

Really, the value of lost service (% of incentive)

From load forecast

From Residential Building Stock Assessment or stock forecast

BYO Battery Assumptions

Input Type	Proposed Assumptions	Sources
O&M Cost ($ per participant per year)	**$80**	Brattle Value of Virtual Power Report: $80 Michigan DTE: $75
Equipment Cost ($/new participant)	$0	
Marketing Cost ($/new participant)	$50	Brattle Value of Virtual Power Report: $50
Incentives – Annual ($/participant/yr)	$550	PGE: $1.70/kWh *10.8 kWh * $1.70/kWh * 30 deployments per year = $550* PSE: $500
Eligibility (% of population)	~0.4%	Based on frozen distributed solar forecast and an 8% attachment rate
Peak Load Impact (kW per participant at meter)	4 kW	5 kW battery with 80% of capacity enrolled
Program Participation (% of eligible customers)	20%	Brattle: 20%
Event Participation	90%	

Battery+ Assumptions

Input Type	Proposed Assumptions	Sources
O&M Cost ($ per participant per year)	$80	Brattle Value of Virtual Power Report: $80 Michigan DTE: $75
Equipment Cost ($/new participant)	$9,400	Includes 30% Investment Tac Credit
Marketing Cost ($/new participant)	$50	Brattle Value of Virtual Power Report: $50
Incentives – Annual ($/participant/yr)	$0	
Eligibility (% of population)	~3%	Based on distributed solar potential
Peak Load Impact (kW per participant at meter)	4 kW	5 kW battery with 80% of capacity enrolled
Program Participation (% of eligible customers)	20%	Brattle: 20%
Event Participation	100%	