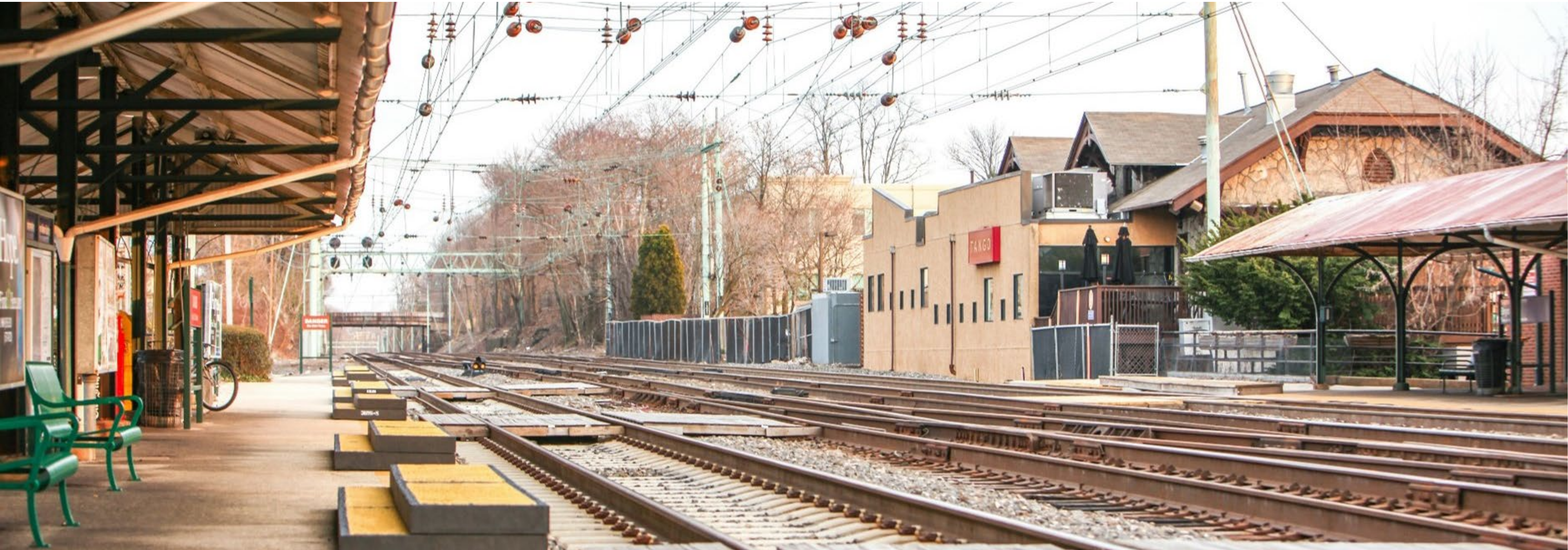
Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Demand Response Potential Study For Act 129 Phase V

January 29, 2025



Presenter Introductions

Jesse Smith

Partner

Jesse Smith is an applied statistician whose work is focused on estimating the impacts and economics of clean energy technologies and policies.

- Core member of the SWE team since 2011
- Founded Demand Side Analytics in 2016
- Third time leading the Act 129 DR potential study
- Managed the Avoided Cost of Transmission and Distribution Capacity Study
- Author of the DR chapter of the Pennsylvania Evaluation Framework

He holds a BS in Psychology from the University of North Carolina at Chapel Hill and a MS degree in Applied Statistics from Kennesaw State University.

Davis Farr

Consultant

Davis Farr is a resource economist with experience managing demand response evaluations and planning studies in multiple states.

- Member of the SWE team since 2021
- Conducted DR audit activities for several EDCs in Phase III
- Led the Pennsylvania Demand Reduction Induced Price Effects (DRIPE) Study in 2024
- Supported Commission Staff in developing the 2026 TRC Test Order
- Performed the program design simulations and optimization analysis

He holds a BA in Economics from the University of Georgia and a MA degree in Economics from the University of Texas at Austin.

PROGRAM DESIGN

A Brief History of Act 129 Demand Response

Act 129 Phase	Included DR Programming?	Event Trigger	Wholesale Recognition Pathway
Phase I	Yes	Top 100 Hours	Demand resource, not formally recognized
Phase II	No	Not defined	N/A
Phase III	Yes	PJM day-ahead forecast ≥ 96% of annual peak load forecast	Demand resource, not formally recognized
Phase IV	No	Temperature Humidity Index (THI)	Peak Shaving Adjustment

- The magnitude and cost of DR potential is heavily dependent on program design
  - ➢ Absent an existing program design, we must first establish a recommended DR framework to model
  - ➢ The Commission needs to clearly spell out the DR performance definition associated with proposed targets
- By what mechanism are peak load reductions intended to be reflected at the wholesale level and generate benefits for the Commonwealth?

Wholesale Recognition Pathway

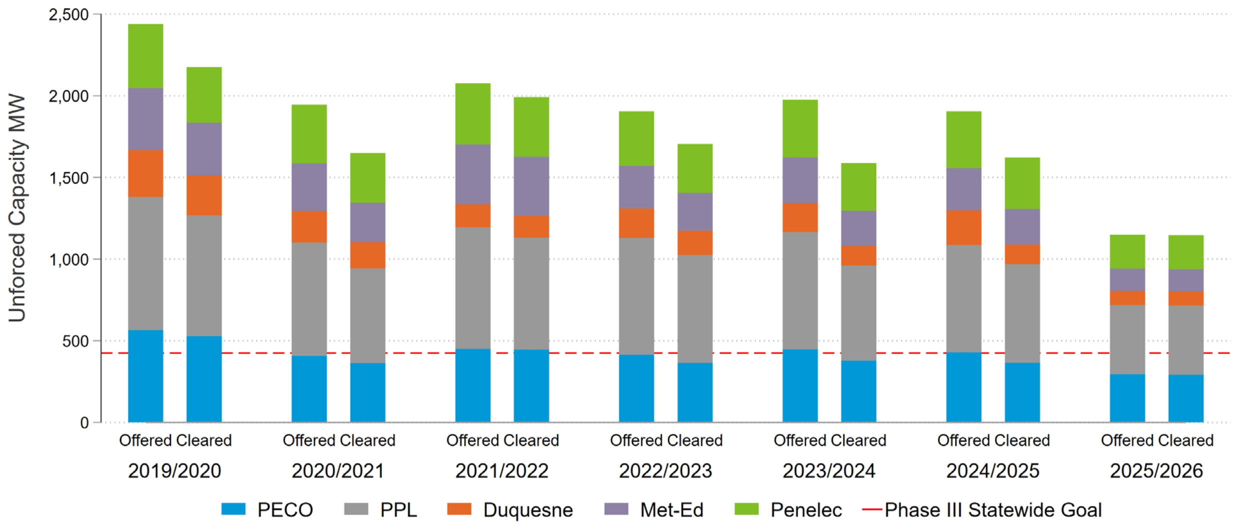
Supply Resource (Capacity)

- Formally recognized as supply in the capacity market alongside traditional generation types
- Dispatch instructions come from PJM based on grid conditions
- Value lies in availability
- Forward capacity market creates timing issues for Act 129 at the beginning and end of phases

Demand Resource (Shadow DR)

- EDCs target reductions during high system load hours
- This places downward pressure on peak load forecasts and lowers future capacity obligations
- Valuation is more complex and requires events to be called
- Dispatch criteria must be set by the PUC in an Implementation Order or proposed by EDCs in the EE&C plans

Pennsylvania DR Resources Offered and Cleared by Delivery Year



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

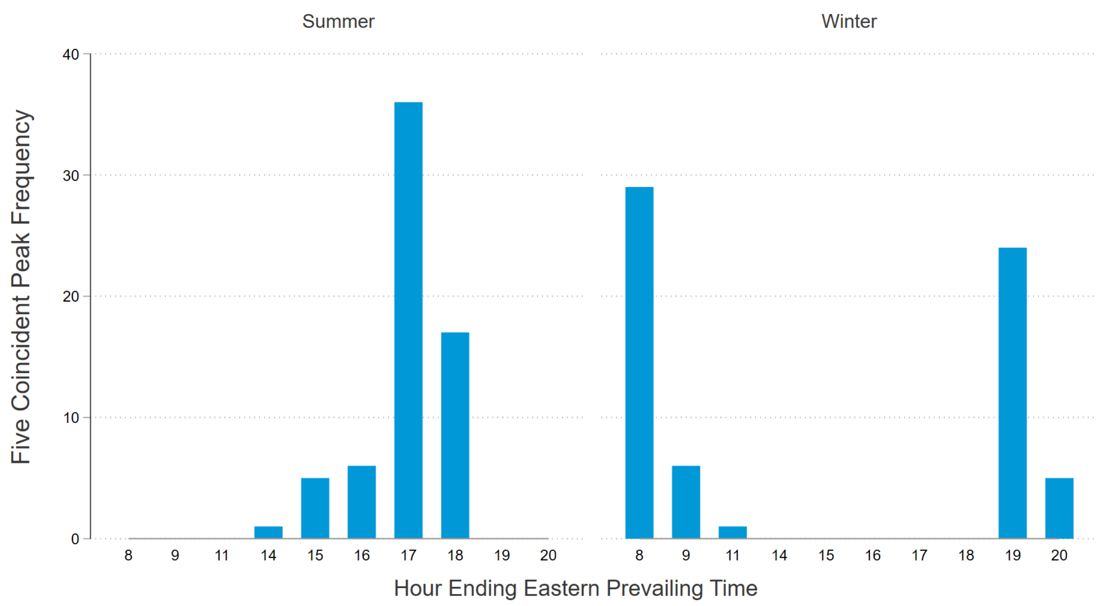
A Simulation Process Was Used to Select the Recommended Program Design

- Compare the effectiveness of different program designs
  - Zonal load and weather data 2011-2023
  - Simulate DR events and compute metrics
- Design parameters
  - **Dispatch trigger** - weather conditions or daily?
  - **Event start time** – what time will events begin?
  - **Event duration** – how long does each event last?
  - **Program operation period** – what set of month define the active season for DR programs?

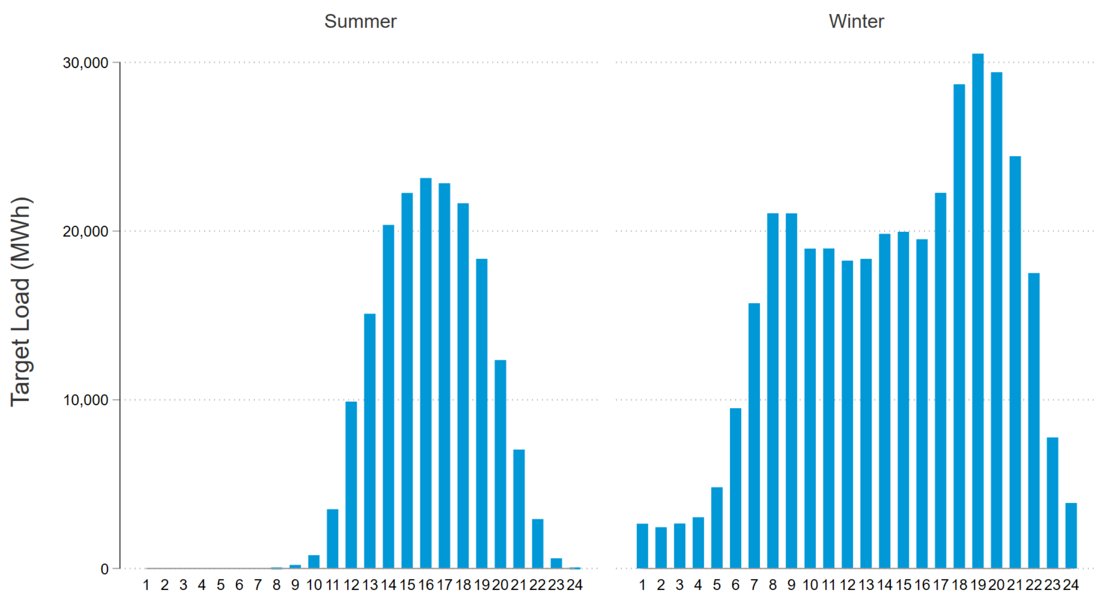
1) **Five Coincident Peak** (5CP) – The five days and hours of highest peak load by season. Performance is expressed as the percentage of the five system peak hours that are captured by DR performance hours in each scenario. The system peak hours are defined RTO-wide and represent the five hours with the highest system demand for a given delivery year and season, which must occur on five different days.
2) **Effective Load Carrying Capacity** (ELCC) – A measure of the relative importance of hours of availability for DR dispatch. The SWE calculated the ELCC metric for this study as the percentage of target load that is captured by a simulated DR event. The target load is all demand above 90% of the forecast system peak for a given year and season. Hours with higher demand contribute more to the total target load and thus weigh more heavily in the calculation of ELCC. The embedded assumption is that these hours/loads are driving the peak load forecast for the zone.

The 5CP Metric Places More Emphasis On Correctly Hitting The Single Hours Of Highest Load. The ELCC Metric Looks More Broadly at the Hours that Influence Peak Load Forecasts.

5CP Frequency by Season and Hour Ending



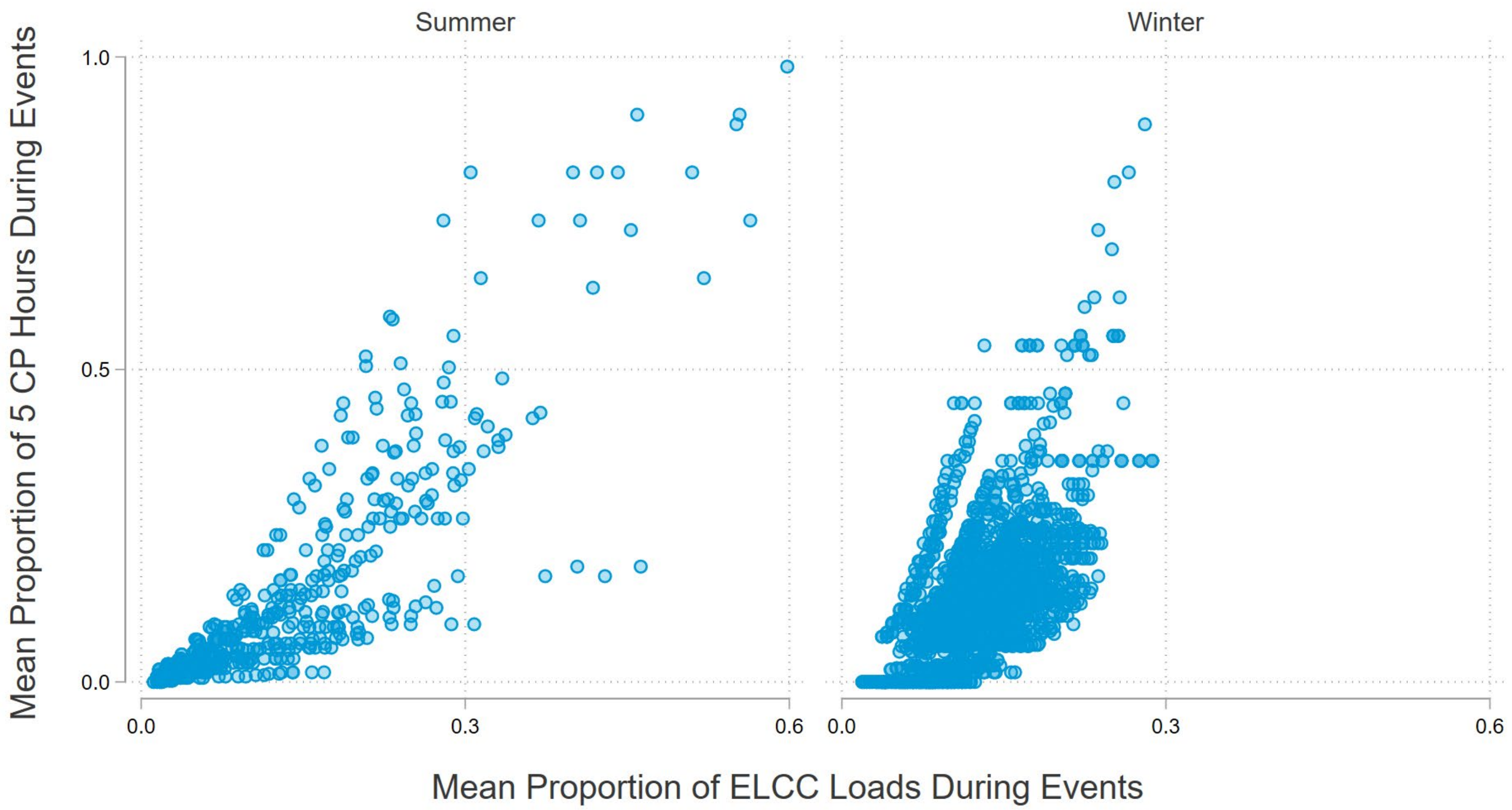
ELCC Target Load by Season and Hour Ending



Winter loads tend to be flatter than summer with peaks spread across both the morning and evening hours

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

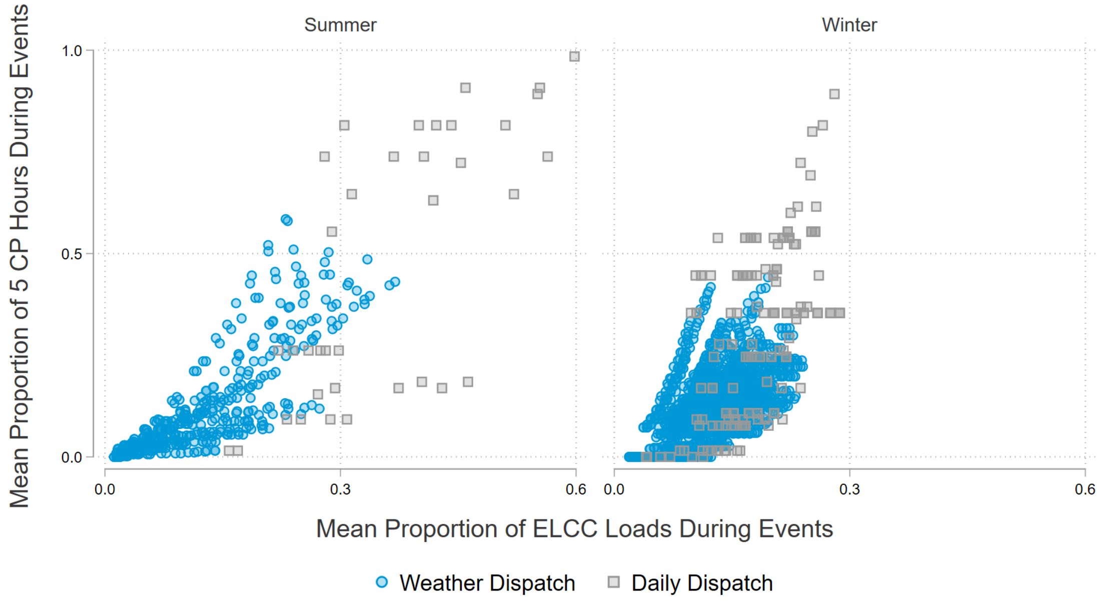
INTERPRETING SIMULATION RESULTS



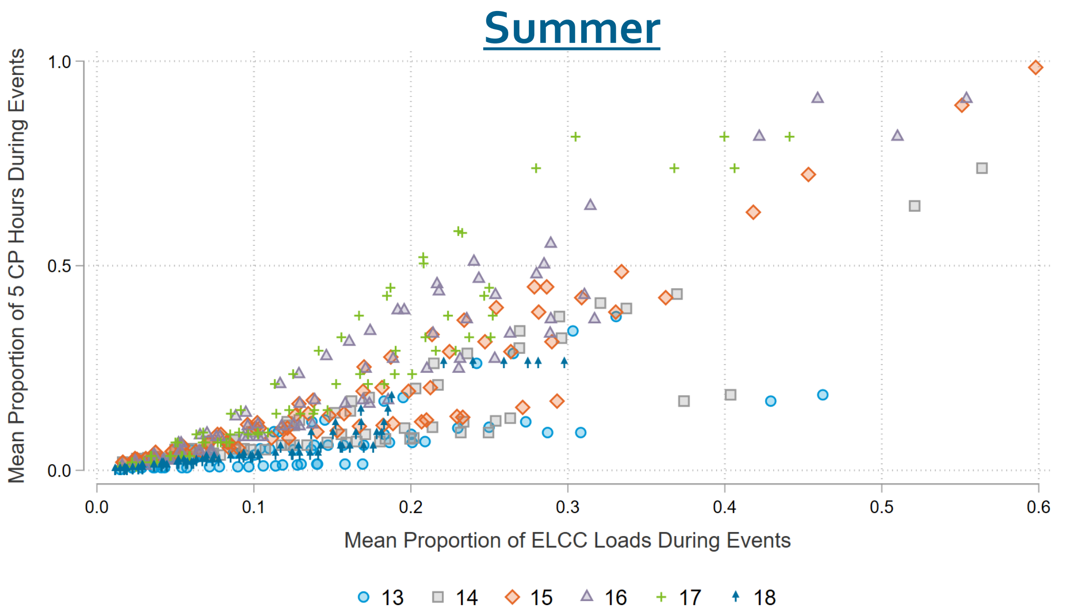
- Designs in the upper right quadrant are most effective
- Most candidate designs score higher on the 5CP metric than the ELCC metric
- ELCC scores are much higher in the summer because peaks are concentrated in the late afternoon and early evening

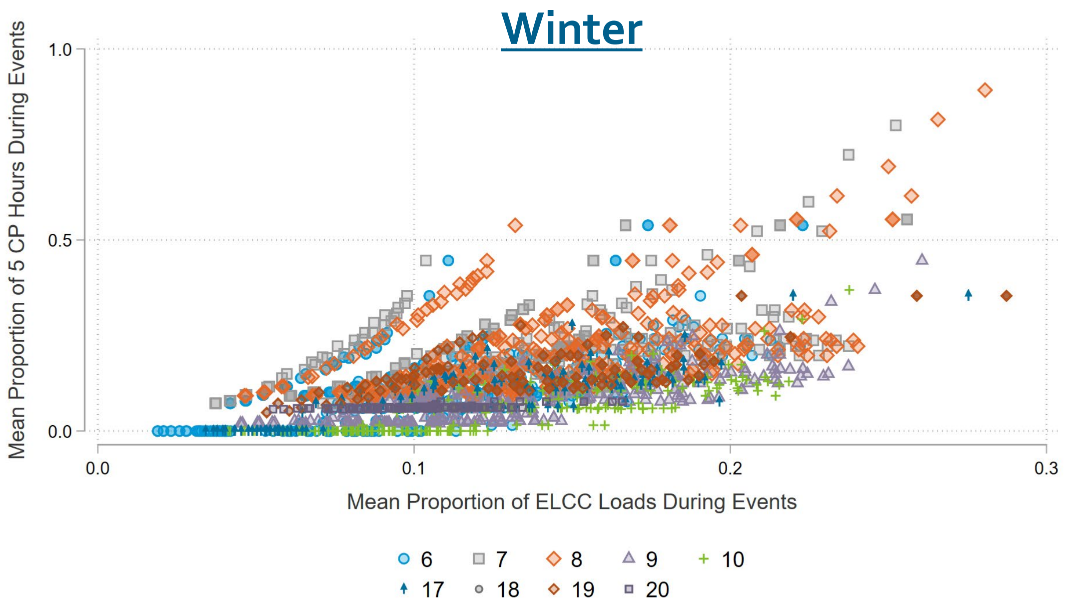
Dispatch Trigger and Event Start Time

Daily Dispatch Outperforms Weather Dispatch



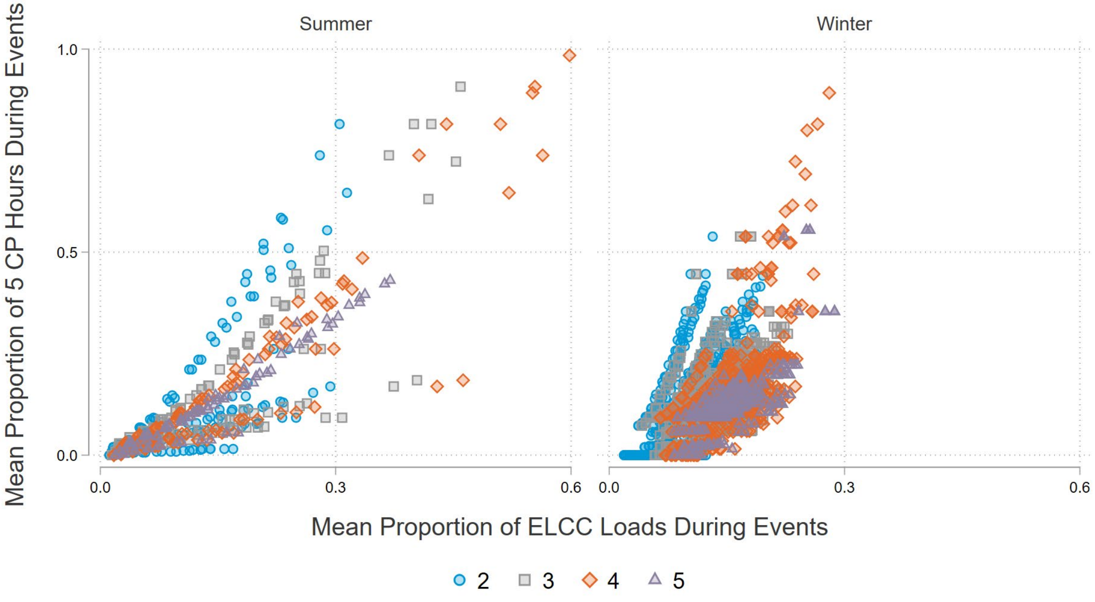
Not surprising given weather dispatch designs were limited to 24 hours per season



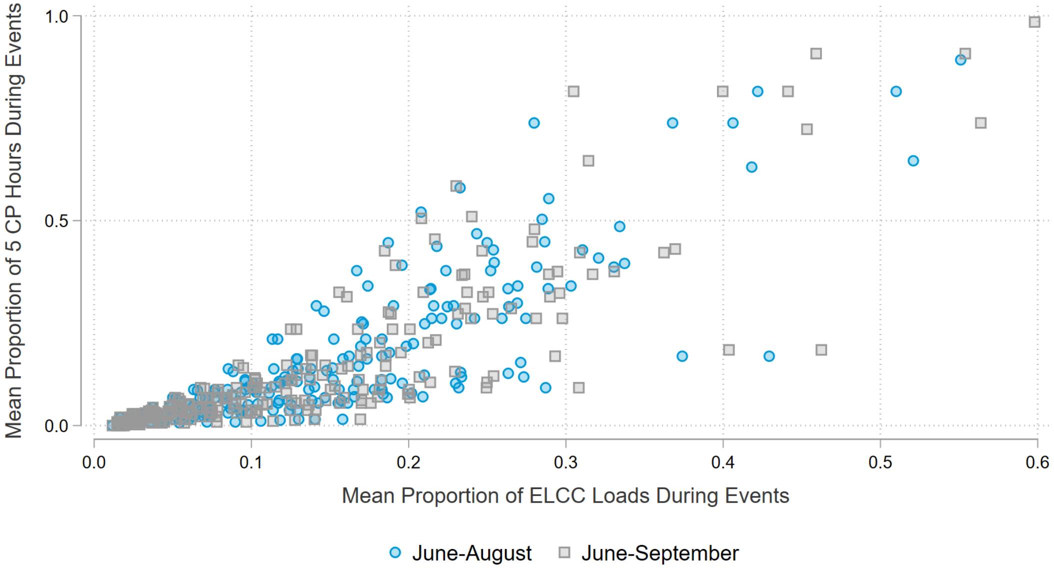


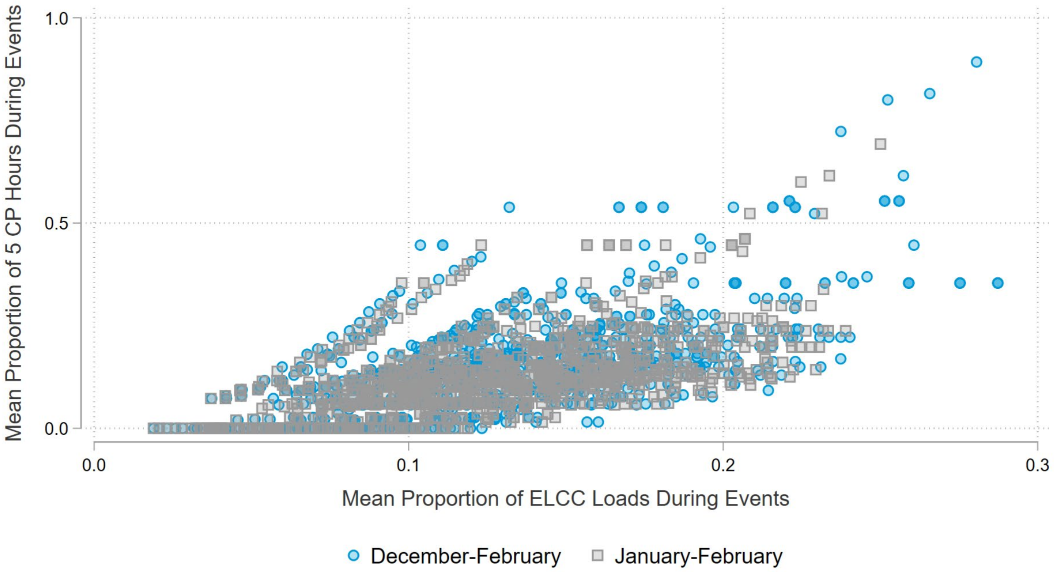
Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Event Duration and Operation Period



Four-hour events score the highest on both metrics. Including December and September in the seasonal definitions improve metrics slightly



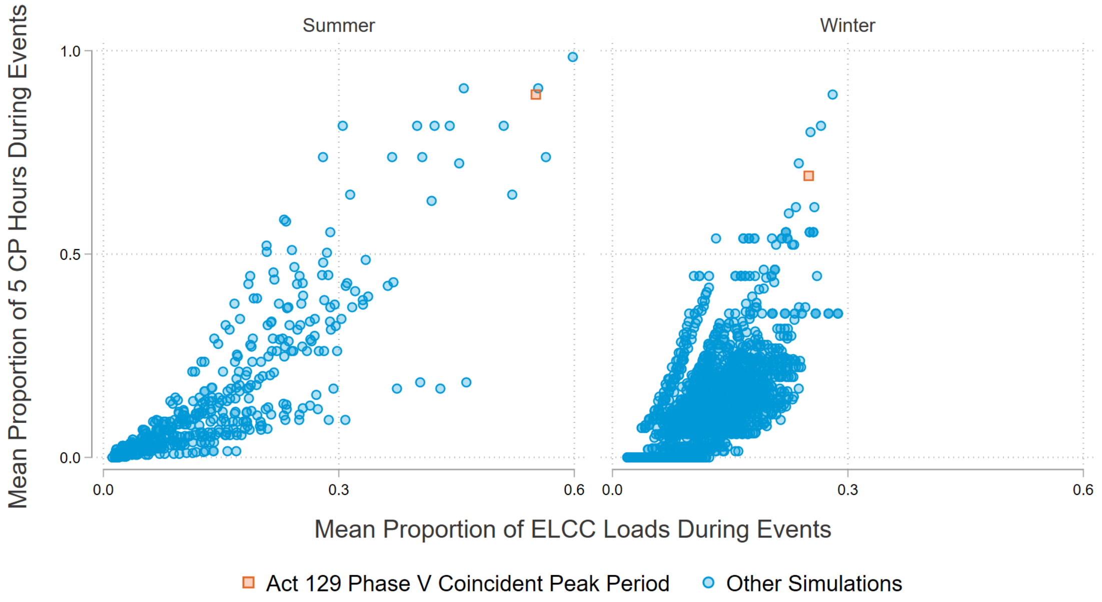


RECOMMENDED PROGRAM DESIGN

- Align daily dispatch performance definition with the Act 129 definition for coincident demand reductions from energy efficiency

Parameter Name	Description	Summer Recommendation	Winter Recommendation
Dispatch Trigger	Weather-based versus daily dispatch on all non-holiday weekdays	Daily	Daily
Performance Hours (Hour Ending EPT)	The hours that are targeted by DR programs. The hours over which load reductions would be measured to assess goal achievement and estimate cost-effectiveness	15, 16, 17, 18	8, 9, 19, 20
Program Operation Period	Set of months that define the operations season for DR programs	June-August	January-February

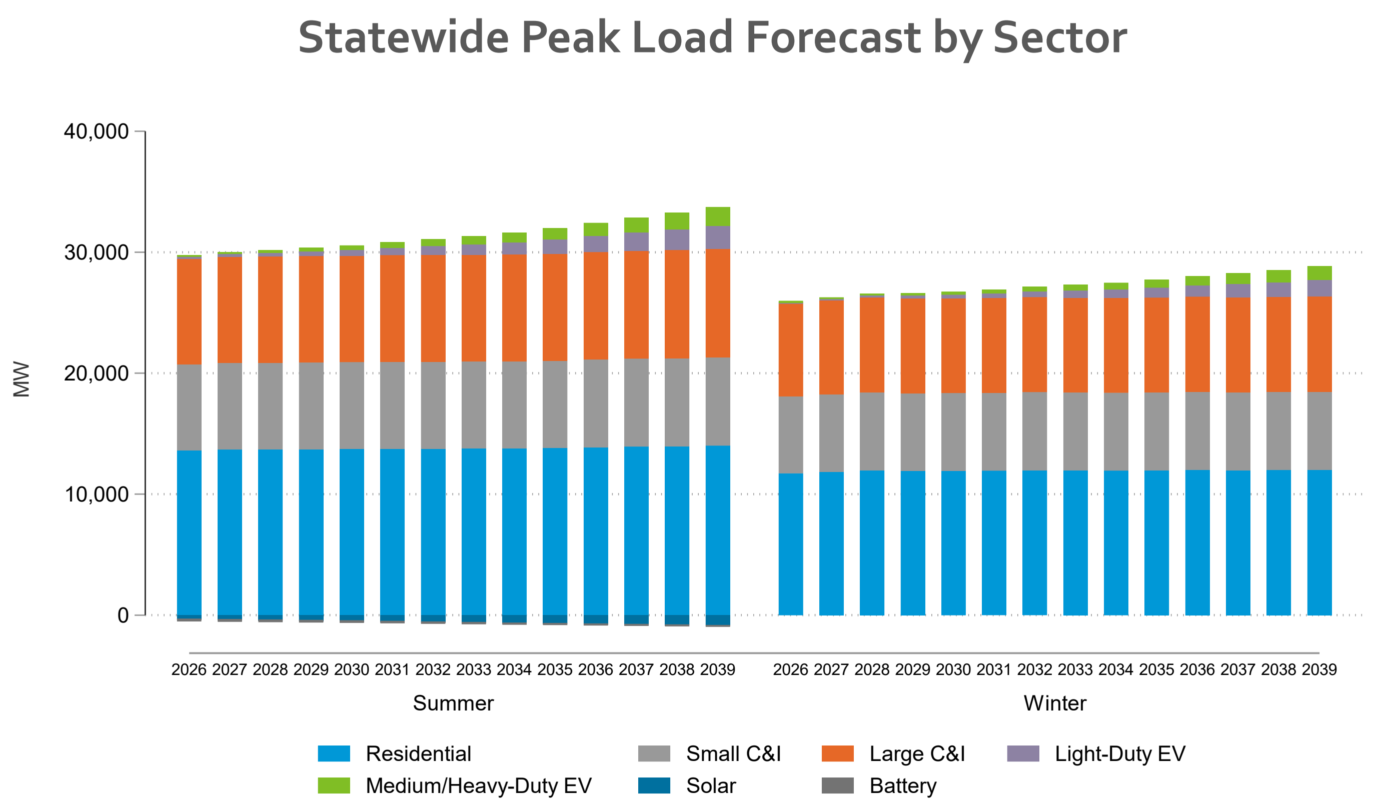
- A common definition for EE and DR would allow the Commission to set peak demand reduction goals that could be satisfied with either program type, affording the EDCs considerable flexibility in their EE&C plan design process



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

METHODS

The Study Forecast Was Anchored to the 2024 PJM Load Forecast Report



320 MW of APS data center load allocated to West Penn Power. Unclear if the planned 800 MW is in PA, MD, Virginia, or West Virginia

- Zonal level projections
  - Penn Power and West Penn Power are subsets of ATSI and APS
- PJM does not list EV, solar, and battery adjustments to winter peak
  - Assumed solar and battery adjustments only applied to summer and calculated winter-to-summer ratio to isolate winter EV adjustment
- PJM does not distinguish load by sector
  - Utilized EGS settlement resources and EDC-provided peak demand data from the SWE baseline study

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Types of Potential Modeled

Maximum Achievable Potential (MAP): An aggressive projection of future DR programming, achieved by offering more generous incentives and allocating more program budget to marketing and recruitment efforts. Incentive levels are allowed to equal or even exceed the expected marginal benefits from participation. The aggregate DR potential in megawatts (MWs) is larger with MAP, but the programs are less cost-effective.

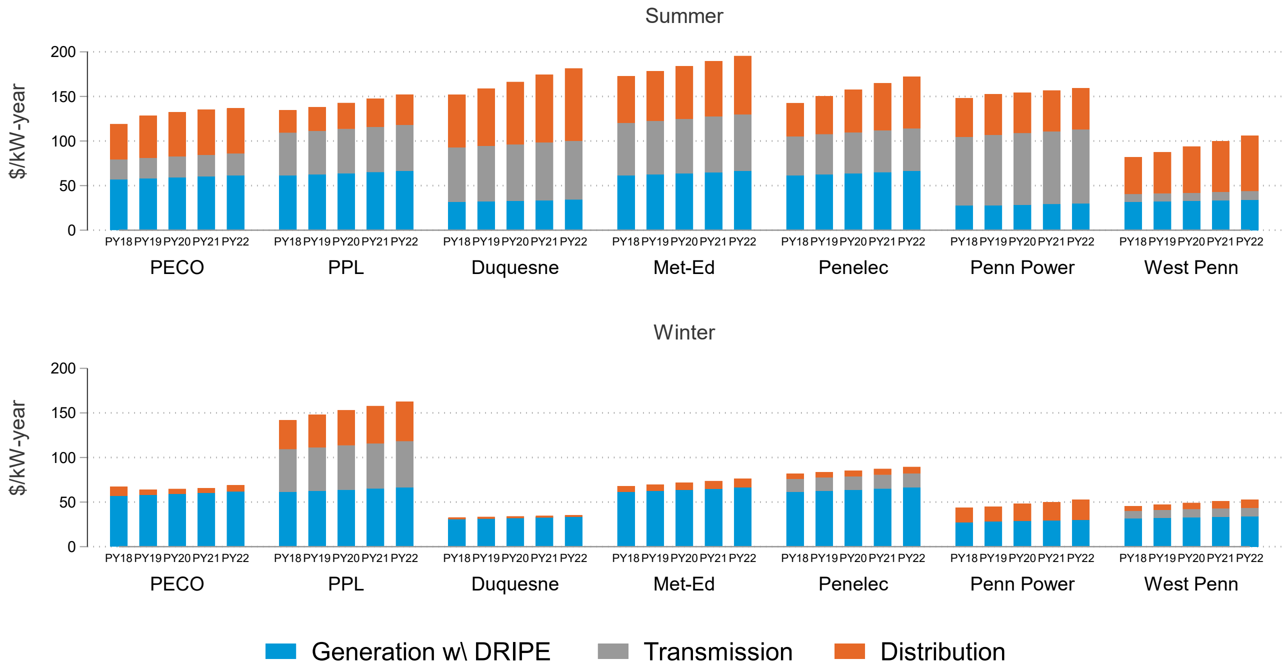
Realistic Achievable Potential (RAP): A projection of future DR potential at typical industry incentive rates and marketing levels. Incentive levels are sufficient to drive some amount of participation, but low enough so that the marginal costs are lower than the marginal benefits to generate net benefits. The assumed load impacts are also set to typical industry levels that balance participant comfort and disruption.

Phase V Potential: Subset of RAP made up of economically viable program options. The MW reductions and TRC Test results are identical to RAP for the selected programs.

Using the TRC Test for Demand Response – 2026 TRC Test Order Assumptions

- No distribution capacity benefits for Large C&I
- No derate for daily load shifting
- 75% of incentives as TRC Cost
- Measure life capped by Phase length if incentives are recurring
- CSP fees as a proxy for incentives if EDC lacks visibility

Avoided Cost of Capacity Forecast



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Program Costs and Budgets

Cost Category	Description
Fixed Program Startup	The upfront cost to design and launch a DR program. Independent of enrollment so does not vary for RAP and MAP
Fixed Recurring Program Administration	Annual overhead and administration costs to deliver a program. Varies by EDC size, but not across RAP and MAP
Volumetric One-Time	Upfront costs of marketing, customer acquisition, equipment, installation, and enrollment incentives. Costs are a function of enrollment, so they are higher for MAP than RAP
Volumetric Recurring	Costs incurred each year that a program is active. Includes recurring participation incentives, equipment API fees, and CSP fees.

$/kW-Phase acquisition cost metric

1) **Estimate the five-year budget requirement of the DR program in nominal dollars**. This is the numerator of the acquisition cost metric.

2) **Calculate the average summer and winter demand reduction at the system-level over the five program years in Phase V**. Since most programs ramp up over the course of the phase, these values are lower than the expected performance of the programs by the end of Phase V.

3) **Take a simple average of the summer and winter Phase V demand reduction values from Step #2.** Combining the summer and winter values returns an annualized kW metric.

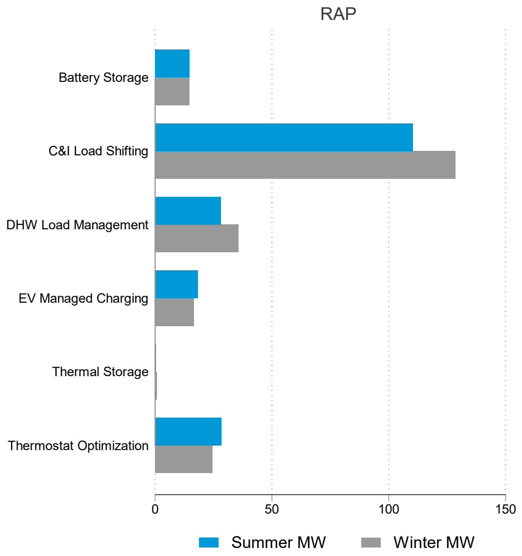
4) **Divide the budget requirement from Step #1 by the annualized Phase V demand reduction metric from Step #3.** The result of this calculation is a $/kW value that can be compared with the acquisition cost of coincident demand reductions from the EE potential study or historic Act 129 program activity.

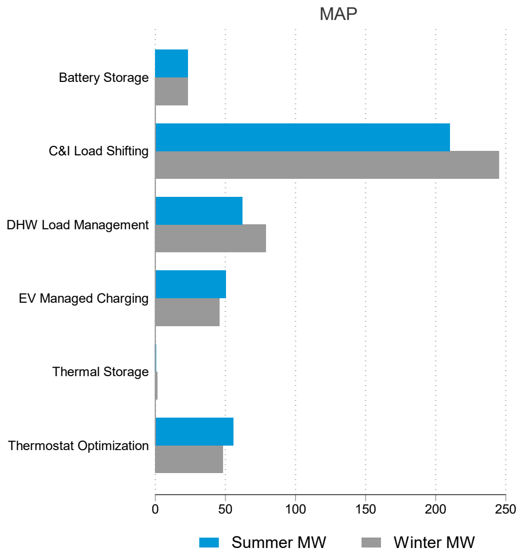
STUDY OUTPUTS AND COMBINATION WITH EE MPS

Combining Results to Estimate Phase V Potential

- C&I Daily Load Shifting
- Connected Thermostat Optimization
- Water Heating Load Management
- EV Managed Charging
- Behind-the-Meter Storage

We Estimate 210 MW Of RAP And 420 MW Of MAP, But Not All Of It Is Economically Viable





- The Executive Summary of the DR MPS report directs readers to the RAP results for programs with a TRC ratio above 0.8

Program	RAP TRC Ratio	MAP TRC Ratio
Battery Storage	0.62	0.57
C&I Load Shifting	**1.66**	1.21
DHW Load Management	0.60	0.57
EV Managed Charging	**0.89**	0.58
Thermal Storage	0.09	0.08
Thermostat Optimization	**1.23**	0.97

This Subset Of RAP Is Used To Examine Tradeoffs Associated With Allocating Phase V Budget To DR Instead Of EE

Phase V DR Potential by EDC						
EDC	Summer DR Potential (Phase V MW)	Winter DR Potential (Phase V MW)	TRC Costs ($1,000)	TRC Benefits ($1,000)	PVNB ($1,000)	TRC Ratio
PECO	44.1	39.0	$28,919	$32,995	$4,077	1.14
PPL	36.3	48.0	$24,828	$51,229	$26,401	2.06
Duquesne	15.5	13.1	$10,454	$11,921	$1,467	1.14
FirstEnergy	60.8	69.4	$41,636	$52,892	$11,257	1.27
Statewide	**156.8**	**169.5**	**$105,837**	**$149,038**	**$43,201**	**1.41**

Required Budget by EDC ($833/kW-phase)					
EDC	Phase V MW	Percent Reduction vs. 2007/2008 Baseline	EDC Budget Requirement for Program Potential ($1,000)	Phase V Funding ($1,000)	Share of Phase V Budget
PECO	41.6	0.53%	$36,541	$427,386	8.5%
PPL	42.2	0.64%	$32,261	$307,507	10.5%
Duquesne	14.3	0.57%	$13,307	$97,730	13.6%
FirstEnergy	65.1	0.68%	$53,797	$390,320	13.8%
Statewide	**163.1**	**0.62%**	**$135,906**	**$1,222,943**	**11.1%**

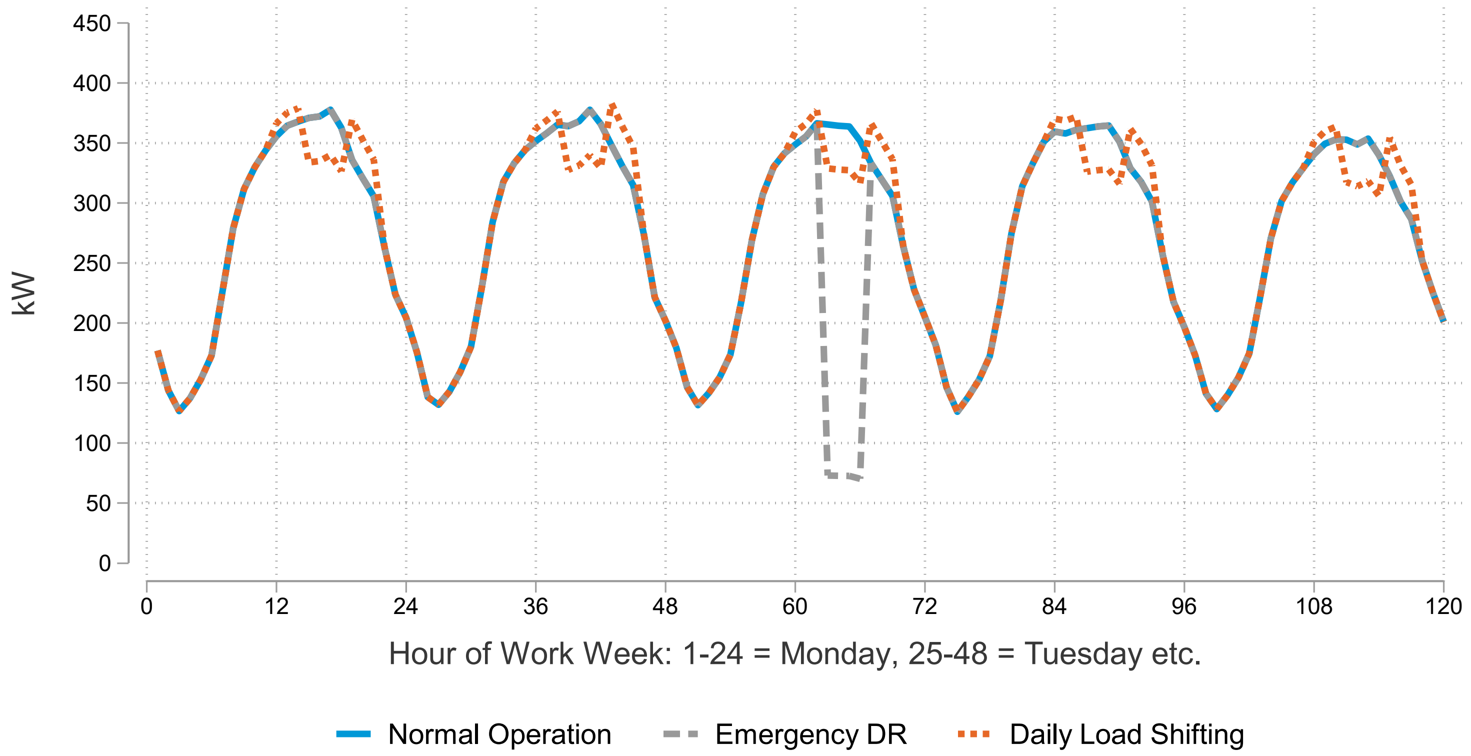
C&I LOAD SHIFTING

A Different Style of Curtailment

Program Overview

- Pennsylvania has mature participation in PJM load management offerings
  - Large commitments with the expectation of infrequent dispatch
  - Much of it in the form of behind-the-meter generation or curtailment of manufacturing operations
- Daily shift encourages the movement of energy consumption away from periods of high demand
  - Subtler changes implemented more frequently
  - Avoids double-dipping concerns

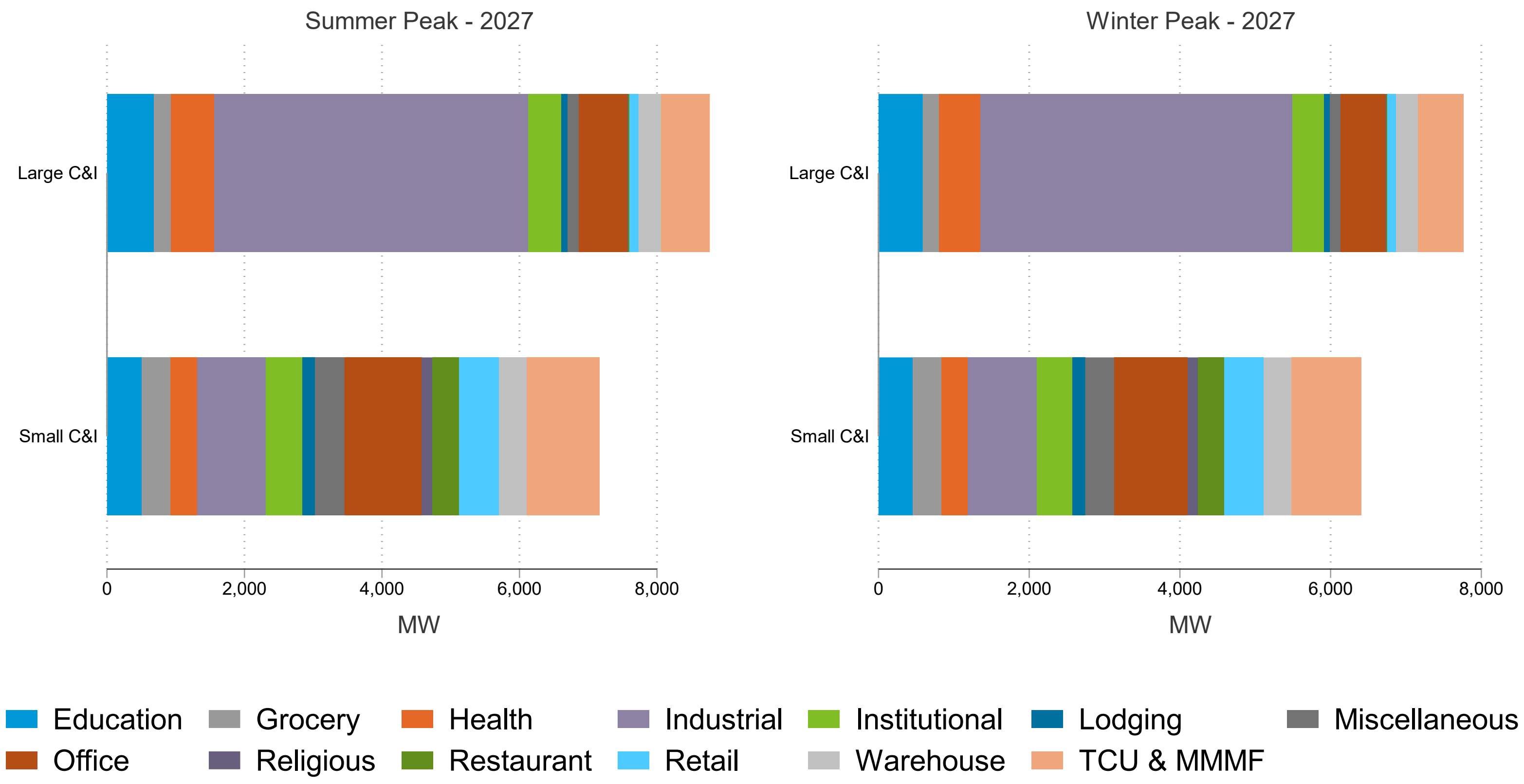
Comparison of Emergency DR and Daily Load Shifting



These options align with the "Shed" and "Shift" categories in the LBNL DR-Path Modeling Framework

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Peak Load Forecast Disaggregation

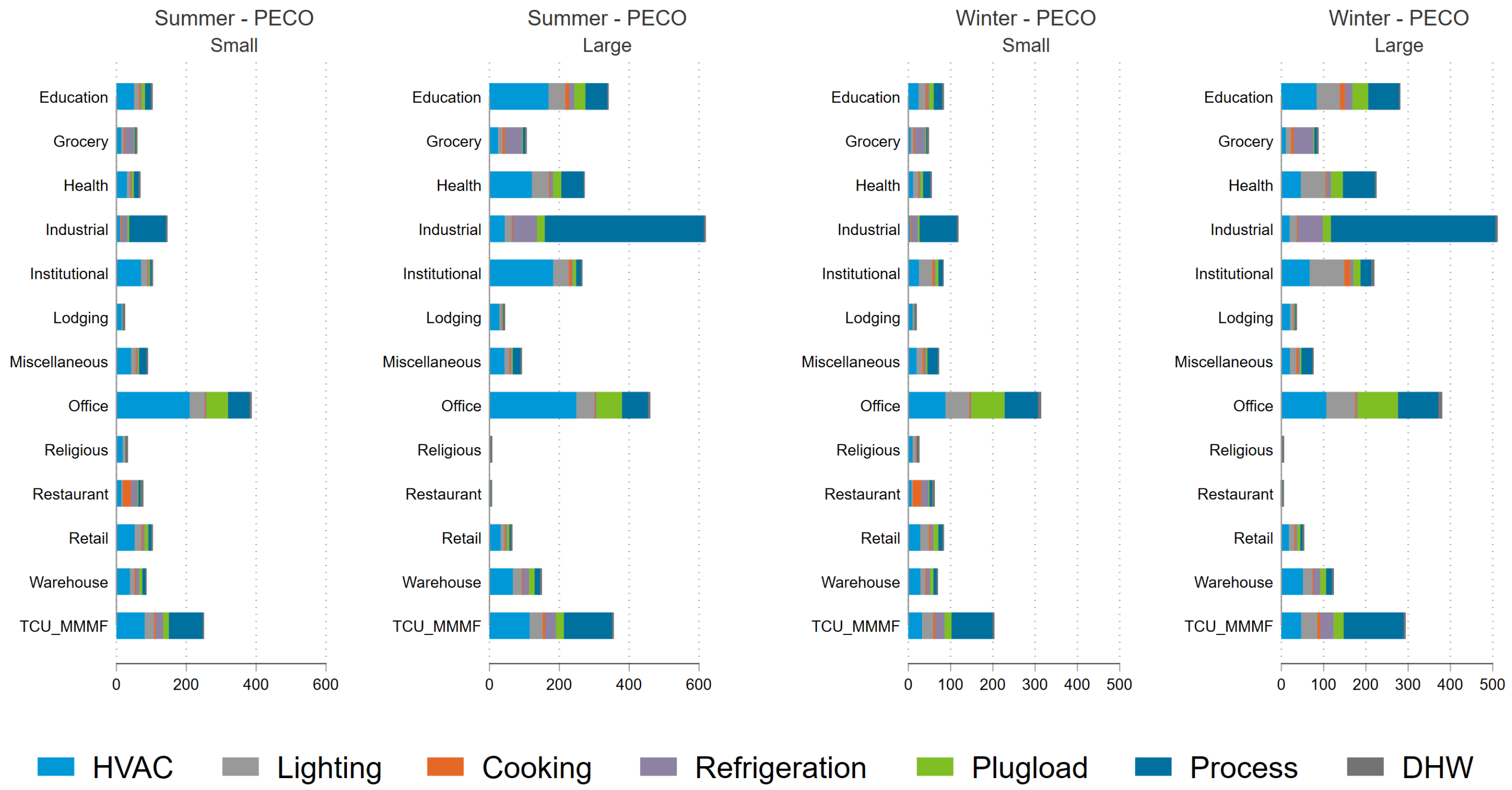


- Summer and winter peak loads for the Small C&I and Large C&I sectors are distributed across **thirteen industry segments**
- This step built off the 2023 Non-Residential Baseline Study analysis
- The Industrial segment within the Large C&I sector accounts for one-fourth of all non-residential peak load
  - Approximately 4,000 MW

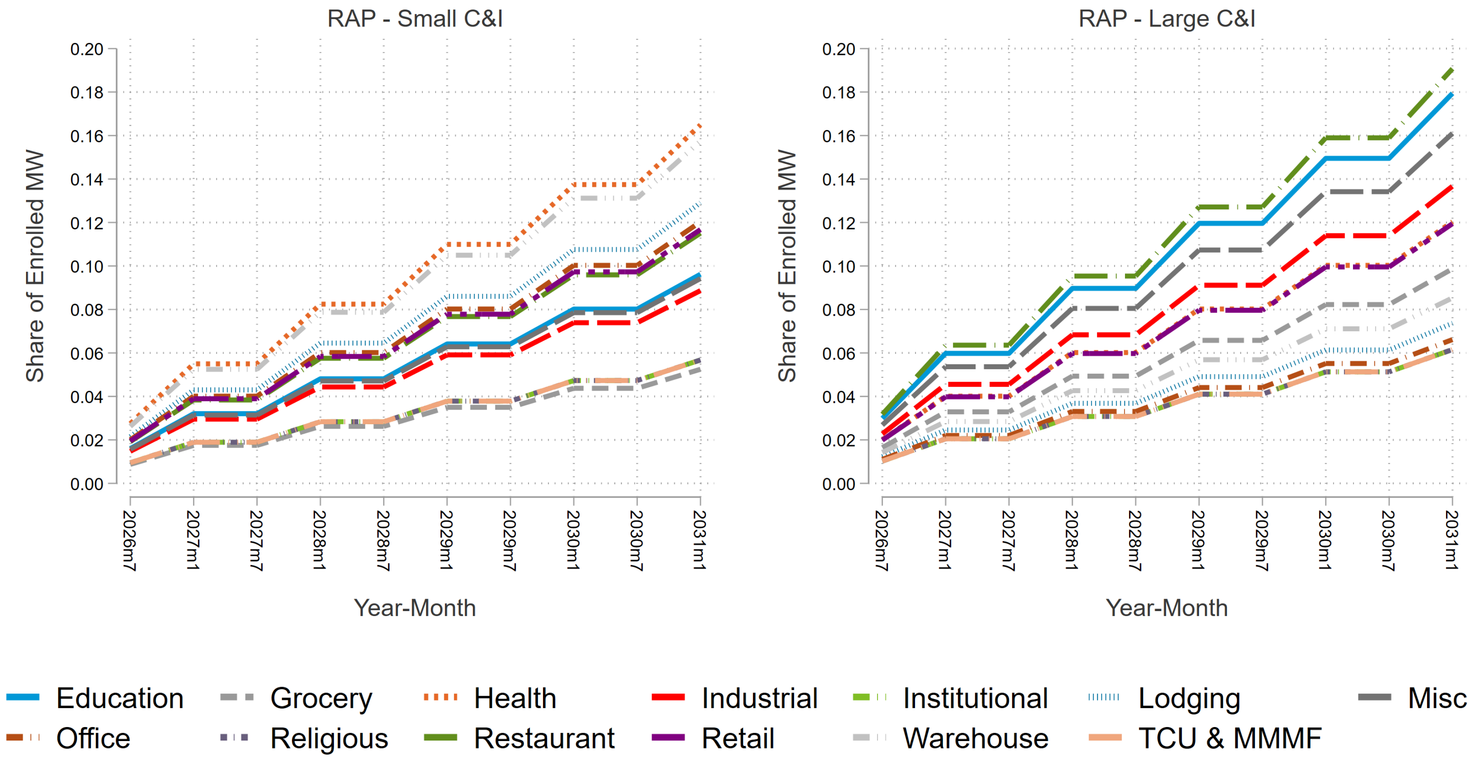
Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Peak Load Forecast Disaggregation

- Within each EDC, sector, segment, and season peak loads were assigned to **seven end uses**
  - Heating Ventilation and Air Conditioning (HVAC)
  - Lighting
  - Cooking
  - Refrigeration
  - Plug Load
  - Process
  - Domestic Hot Water (DHW)



Enrollment Rates



- Estimated using fractional probit regression models from the LBNL DR-Path model
  - Models were trained on California DR program enrollment data
- Enrollment function varies based on sector, segment, and incentive level
- We treat the LBNL enrollment rates as a maximum reachable share over a 20-year horizon
  - Linear growth rate from 2026 to 2045 means Phase V enrollment levels only reach 25% of the modeled estimates

Load Impacts Are Applied Top-Down to the Disaggregated Forecast

Shed Fraction by End Use

- Catalog the four-hour Shed fractions from the LBNL DR-Path model
- Estimated percent reduction in end-use demand
- Assume a conservative value for the cooking end use since it is not included in the LBNL modeling assumptions

Calibrate Shed Fractions to Shift

- The LBNL fractions are for 'Shed' DR and the Phase V design is 'Shift', so an adjustment is required
- Use the ratio of aggregate Shift potential to Shed potential as the calibration factor
  - RAP uses the 2025 ratio (0.313)
  - MAP uses the 2030 ratio (0.565)

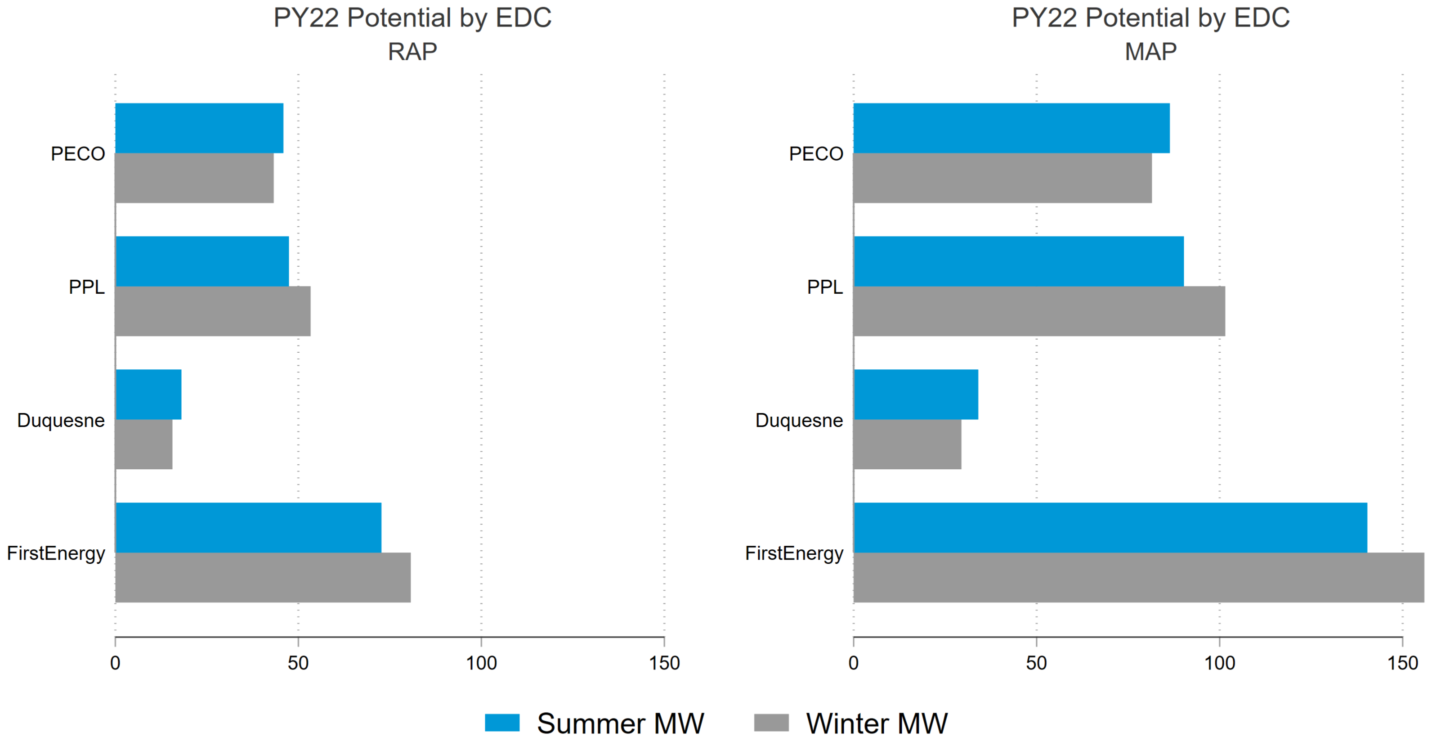
End Use	RAP	MAP
DHW	12.5%	22.6%
HVAC	15.7%	28.3%
Lighting	11.0%	19.8%
Plug Load	4.7%	8.5%
Process	17.2%	31.1%
Refrigeration	15.7%	28.3%
Cooking	6.3%	11.3%

Apply a Performance Factor

- An 85% performance factor was applied to address several practical considerations
  - Participating sites won't have their full PLC available each day of the DR season
  - Some amount of underperformance relative to nomination is expected over a season
- The performance adjustment is applied *after the calculation of incentive costs*

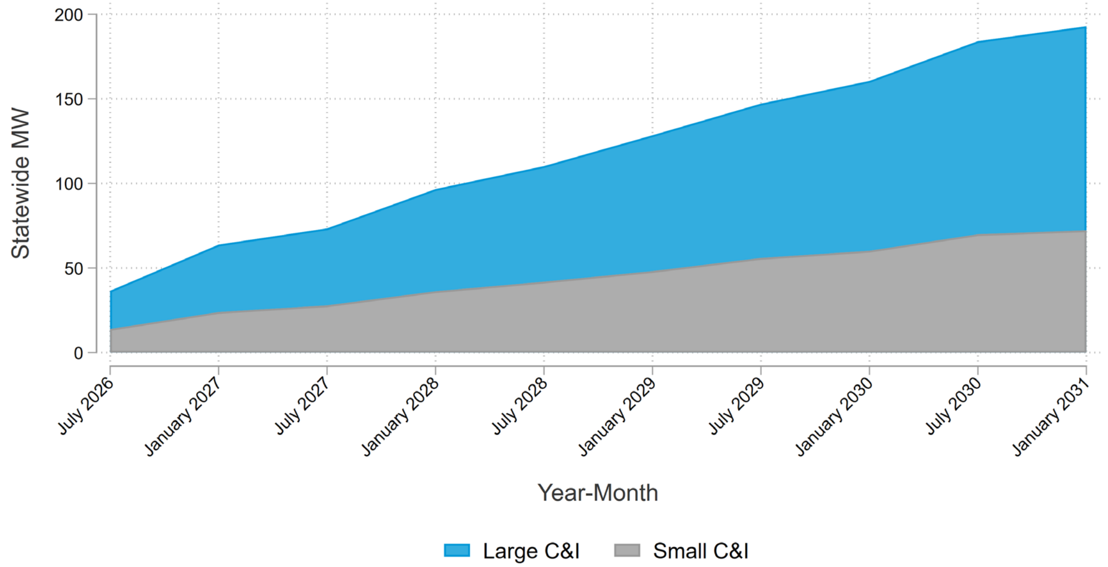
Cumulative Potential by EDC, Scenario, and Season

- PECO and Duquesne have slightly higher potential in the summer season
- PPL and FirstEnergy have slightly higher potential in the winter season
- Winter has an enrollment advantage by falling six months later in each program year

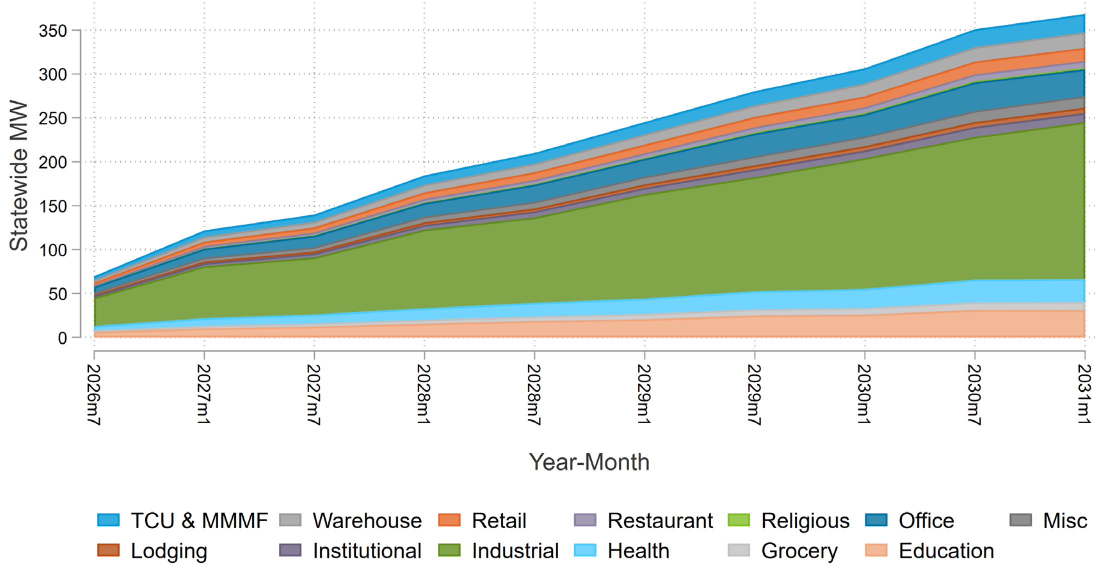


Time Series Estimates by Sector and Segment

RAP by Sector



MAP by Segment



Approximately 60% of the non-residential potential lies in the Large C&I sector

Almost 50% of the non-residential potential comes from the Industrial segment

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Realistic Achievable Potential by EDC and Season

Summer

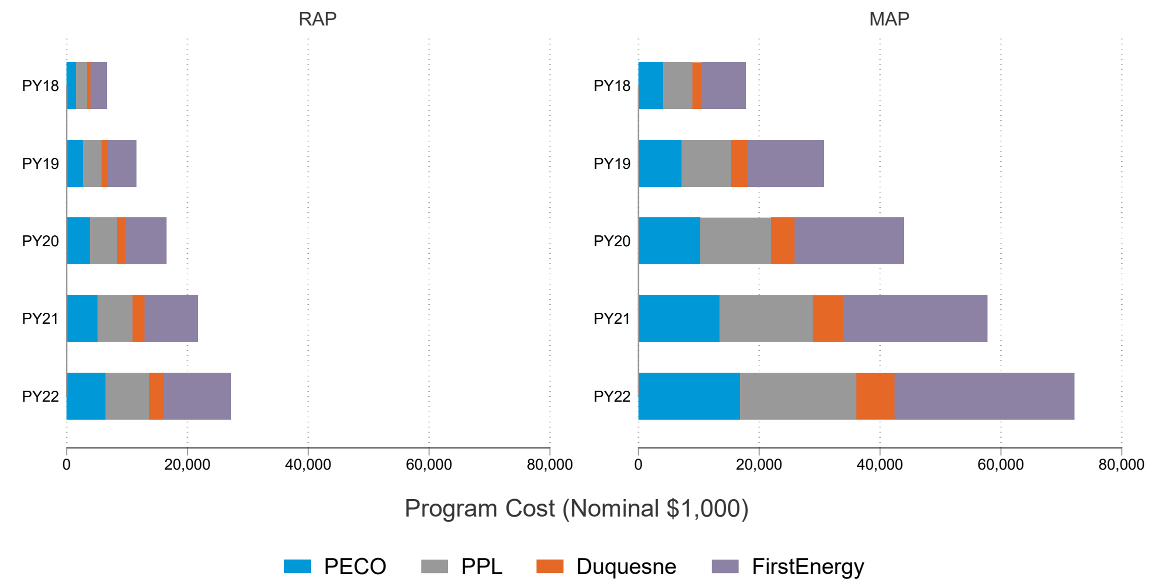
EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	9.1	18.3	27.5	36.7	45.9	27.5
PPL	9.5	19.0	28.4	37.9	47.4	28.4
Duquesne	3.6	7.2	10.8	14.5	18.1	10.8
FirstEnergy	14.3	28.9	43.5	58.1	72.7	43.5
Statewide	**36.5**	**73.4**	**110.2**	**147.1**	**184.1**	**110.3**

Winter

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	14.4	21.7	28.8	36.0	43.3	28.8
PPL	17.8	26.9	35.6	44.5	53.3	35.6
Duquesne	5.2	7.8	10.4	13.0	15.6	10.4
FirstEnergy	26.4	40.2	53.6	67.1	80.7	53.6
Statewide	**63.8**	**96.6**	**128.5**	**160.6**	**192.9**	**128.5**

Economic Results

Program Expenditures by EDC



RAP Cost-Effectiveness Metrics

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$20,039	$14,302	$5,737	1.40
PPL	$37,533	$16,282	$21,251	2.31
Duquesne	$7,941	$5,392	$2,549	1.47
FirstEnergy	$35,278	$24,665	$10,613	1.43
Statewide	**$100,791**	**$60,641**	**$40,150**	**1.66**

MAP Cost-Effectiveness Metrics

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$37,616	$36,869	$747	1.02
PPL	$71,080	$42,422	$28,658	1.68
Duquesne	$14,885	$13,924	$961	1.07
FirstEnergy	$67,736	$65,235	$2,500	1.04
Statewide	**$191,317**	**$158,450**	**$32,867**	**1.21**

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Acquisition Cost by EDC and Scenario

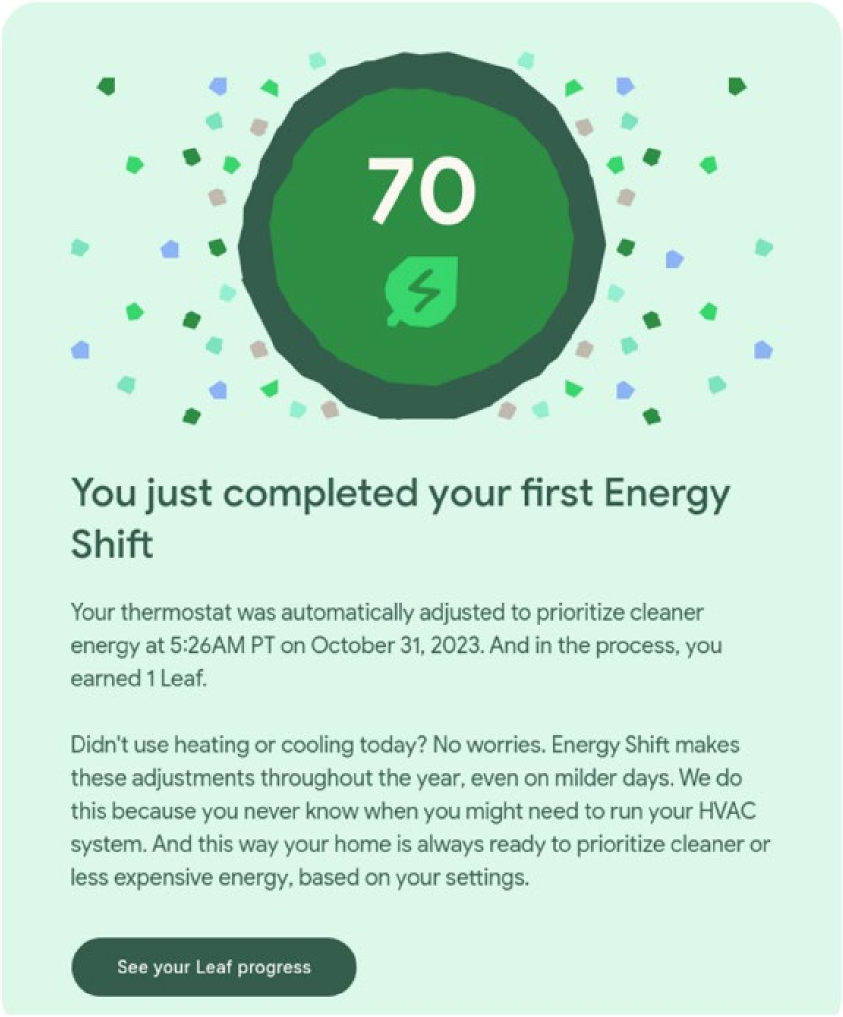
EDC	Scenario	Phase V MW	EDC Spend ($1,000)	Acquisition Cost ($/kW-Phase)
PECO	RAP	28.2	$19,740	$701
PPL	RAP	32.0	$22,463	$701
Duquesne	RAP	10.6	$7,443	$700
FirstEnergy	RAP	48.5	$34,041	$701
Statewide	**RAP**	**119.4**	**$83,687**	**$701**
PECO	MAP	53.0	$51,755	$976
PPL	MAP	60.9	$59,522	$977
Duquesne	MAP	20.0	$19,547	$976
FirstEnergy	MAP	93.7	$91,562	$977
Statewide	**MAP**	**227.8**	**$222,386**	**$976**

RAP spend would equal 6.8% of Phase V funding
MAP spend would equal 18.2% of Phase V funding

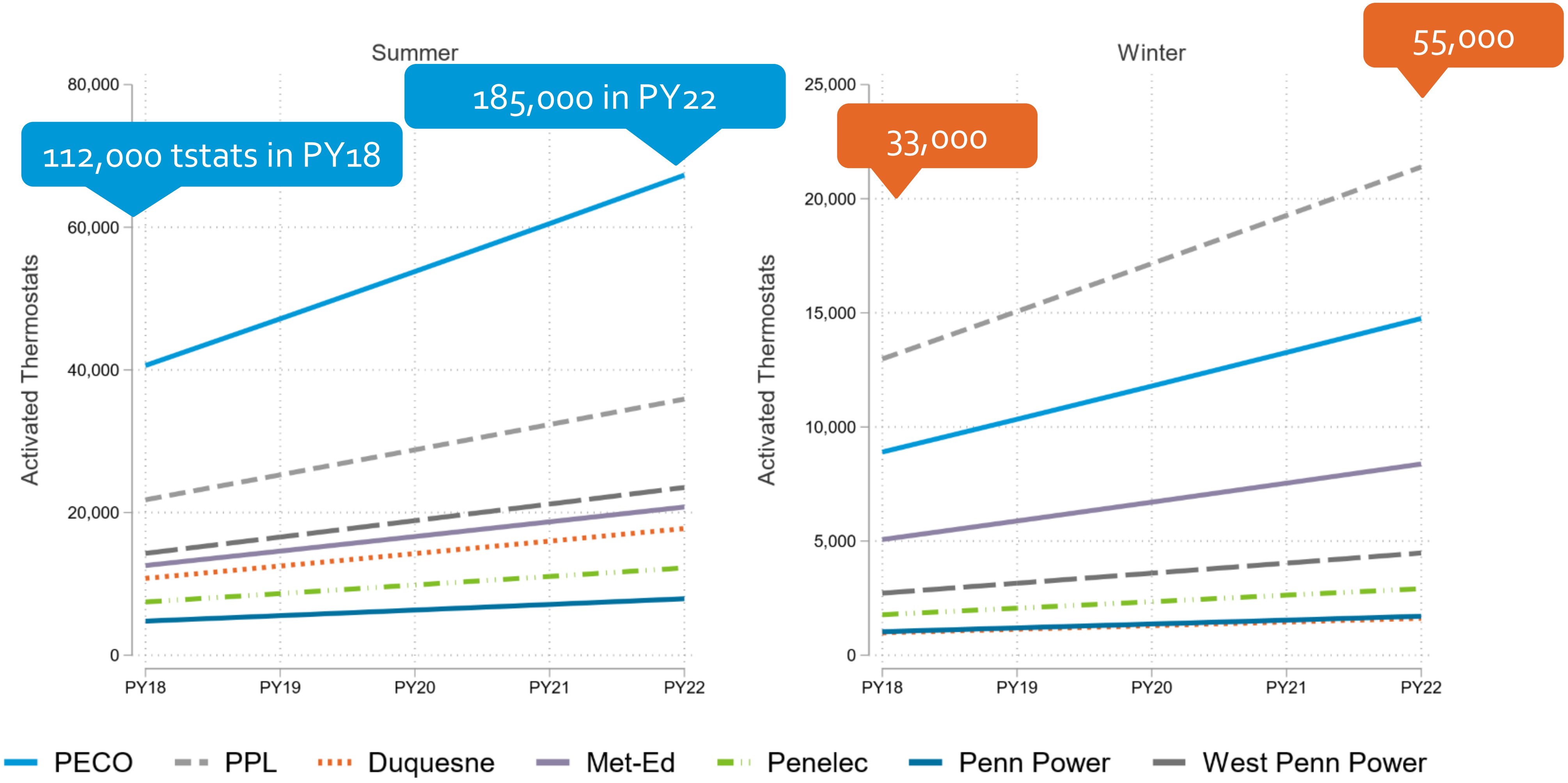
CONNECTED THERMOSTAT OPTIMIZATION

Overview of the Program

- **Targeted Load:** residential heating and cooling
- **Program Design:** Opt-in program where small, daily adjustments to Wi-Fi-connected thermostats to modify the cooling or heating setpoint during peak hours
  - No up-front or participation incentive to the participant
  - Per-participant fee paid to the CSP administering the adjustments



Active Thermostat Count by EDC and Season (RAP)



Connected Thermostat Per-Customer PLC and Potential

Peak Load Contribution (kW)	Seasonal Load Relief Potential (kW)

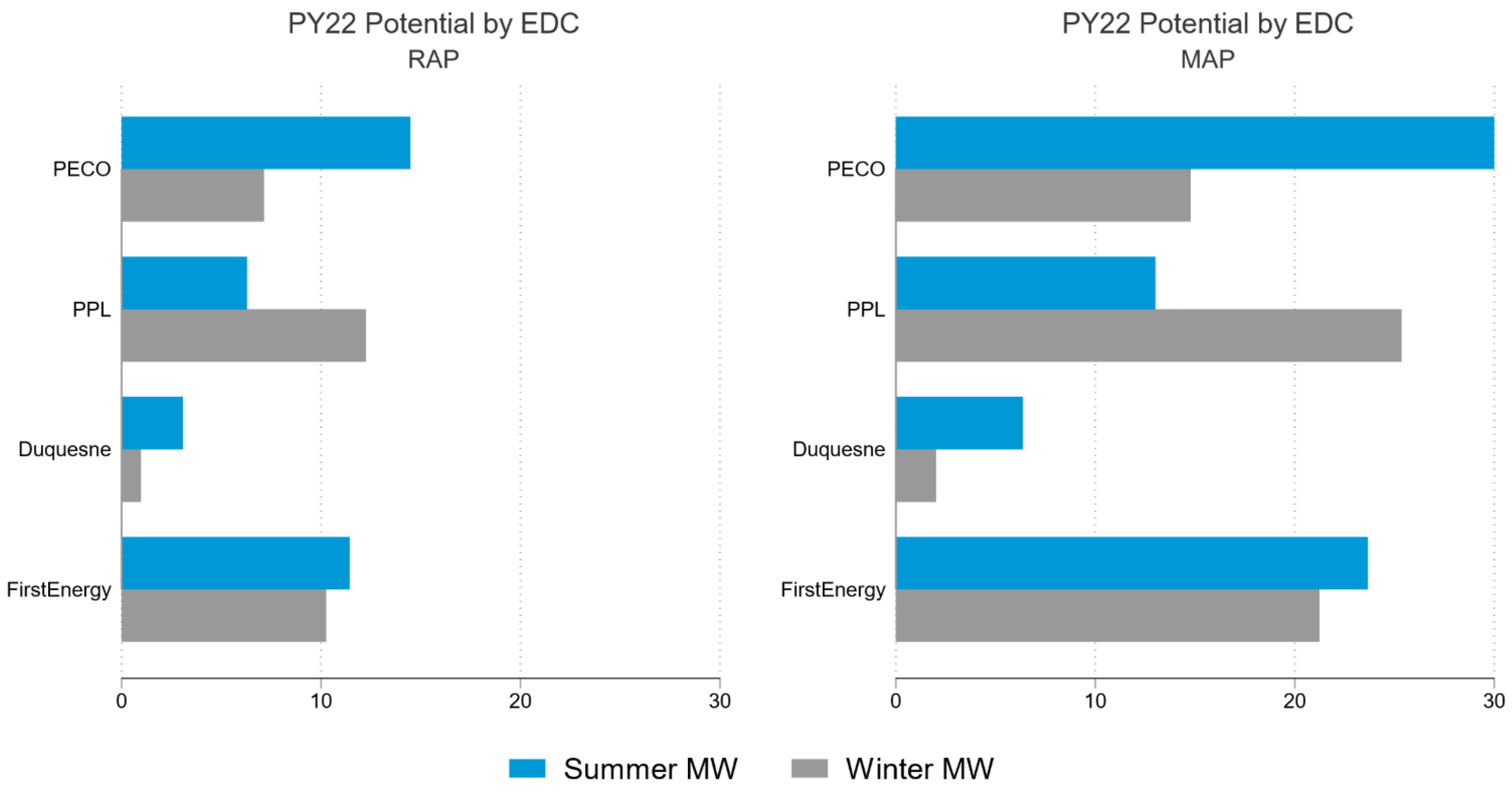
- Baseline PLC of residential thermostat-controllable HVAC loads are grounded in the 2026 TRM algorithm and the capacity and efficiency values reported in the 2023 Residential Baseline Study.
- Avg. per-customer PLC of thermostat-controllable HVAC equipment is 1.1 kW in summer to 3.6 kW in winter.

Season	kW	
	RAP	MAP
Summer	0.16	0.22
Winter	0.54	0.72

- Avg. seasonal load relief per participant varies by EDC and season (statewide avg. shown here)
- 15% load shifted for RAP; 20% for MAP
- While per-device impacts are larger in the winter, there are fewer eligible devices due to limited saturation of electric heat

Results: PY22 Seasonal Potential by EDC

- PY22 Potential statewide in the RAP scenario is 35 MW
- Total summer MW is slightly higher than winter MW due to a larger portion of eligible cooling systems
- PPL and FirstEnergy have more homes with electric heat, which leads to increased winter potential



Economics: RAP Spending & Cost-effectiveness Results

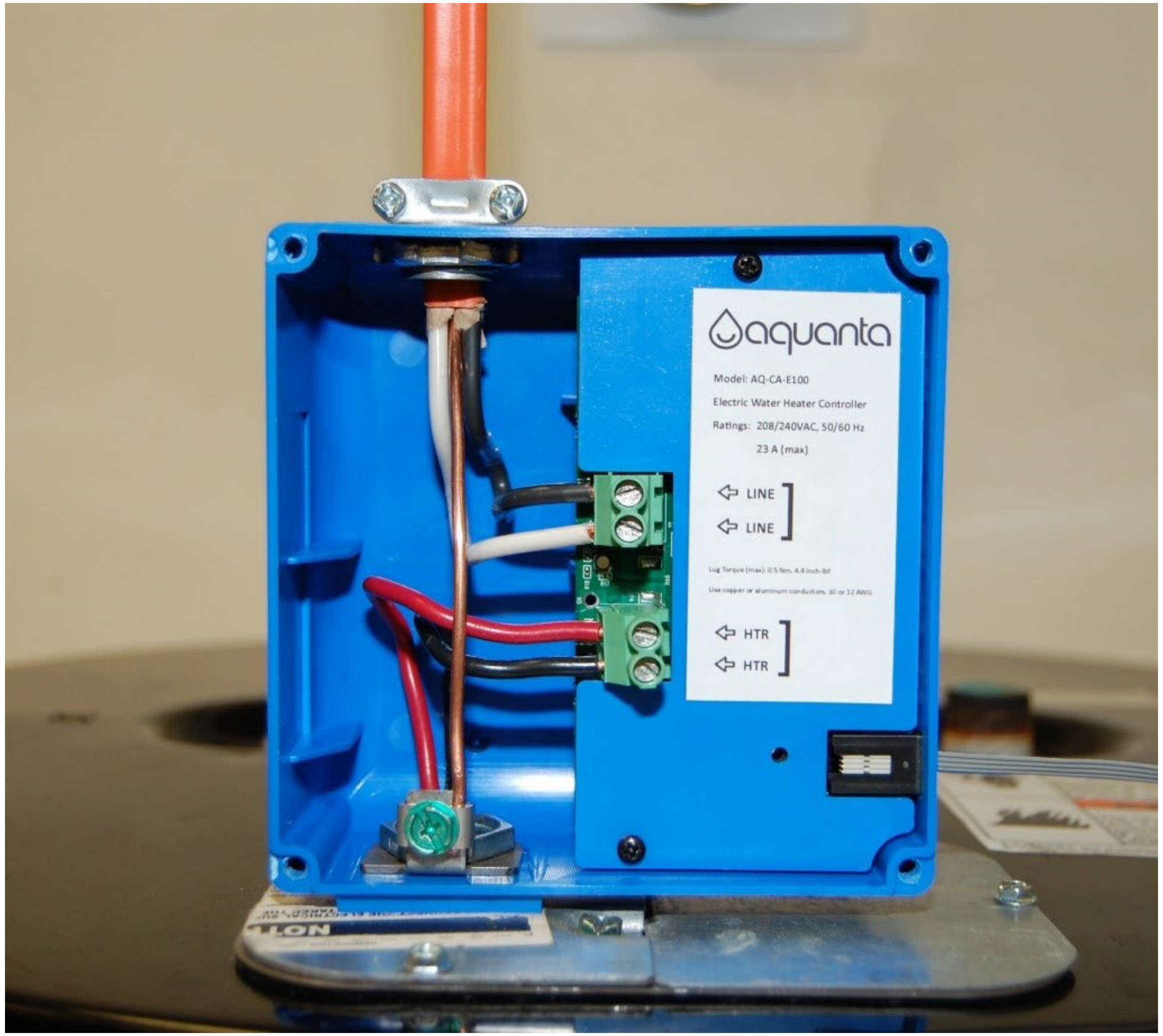
EDC	MW Potential	Phase V Spending ($1,000)	Acquisition Cost ($/kW-Phase)	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	8.7	$9,384	$1,085	$8,519	$8,437	$82	1.01
PPL	7.4	$5,298	$712	$10,034	$4,770	$5,264	2.10
Duquesne	1.6	$2,565	$1,575	$1,981	$2,308	$(327)	0.86
FirstEnergy	8.7	$9,197	$1,057	$8,644	$8,274	$369	1.04
Statewide	**26.4**	**$26,443**	**$1,001**	**$29,179**	**$23,789**	**$5,389**	**1.23**

- PPL incurs 97% of the net benefits and 2.1 TRC ratio due to higher ratio of eligible heating systems in the PPL service territory relative to cooling systems
- MAP TRC Ratio (not shown) is 0.97 statewide

DOMESTIC HOT WATER LOAD MANAGEMENT

Overview of the Program

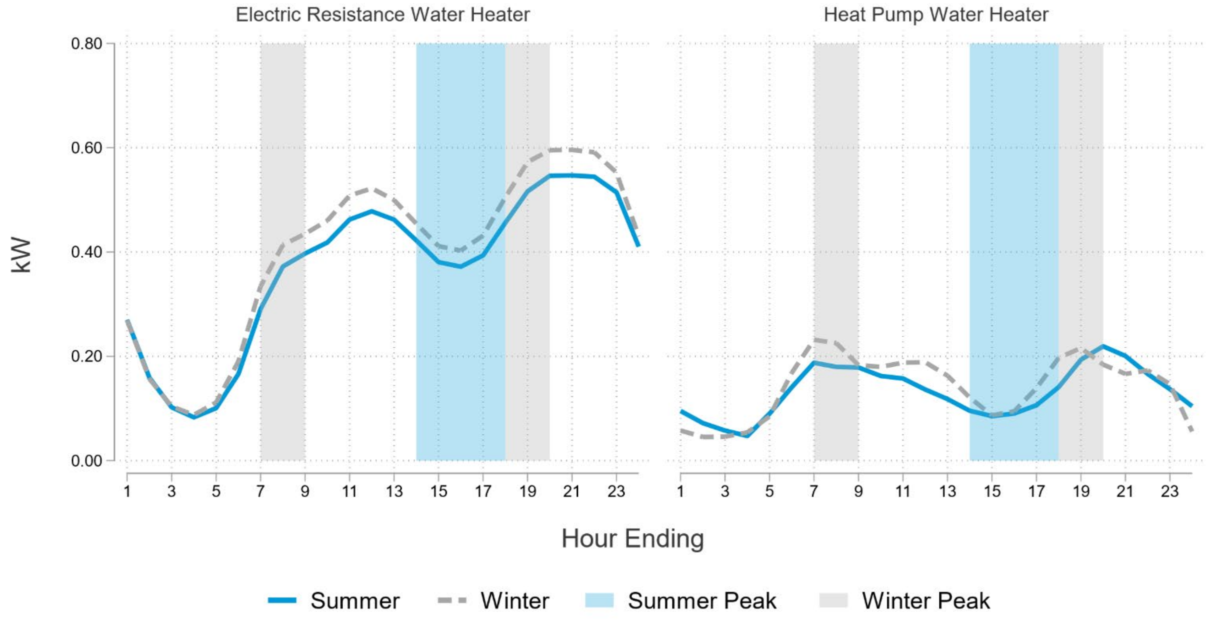
- **Targeted Load:** residential hot water demand
- **Program Design:** Opt-in program where Wi-Fi-connected add-on devices and/or native WH functionality can reduce or shift water heating loads during peak periods by shifting into storage-only mode
  - ➢ Water heaters can run on preconfigured schedules or communicate with utility systems and third-party aggregators



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Domestic Water Heating Per-Customer PLC and Potential

Peak Load Contribution (kW)



- Baseline PLC ranges from 0.1 to 0.5 kW depending on season and WH type

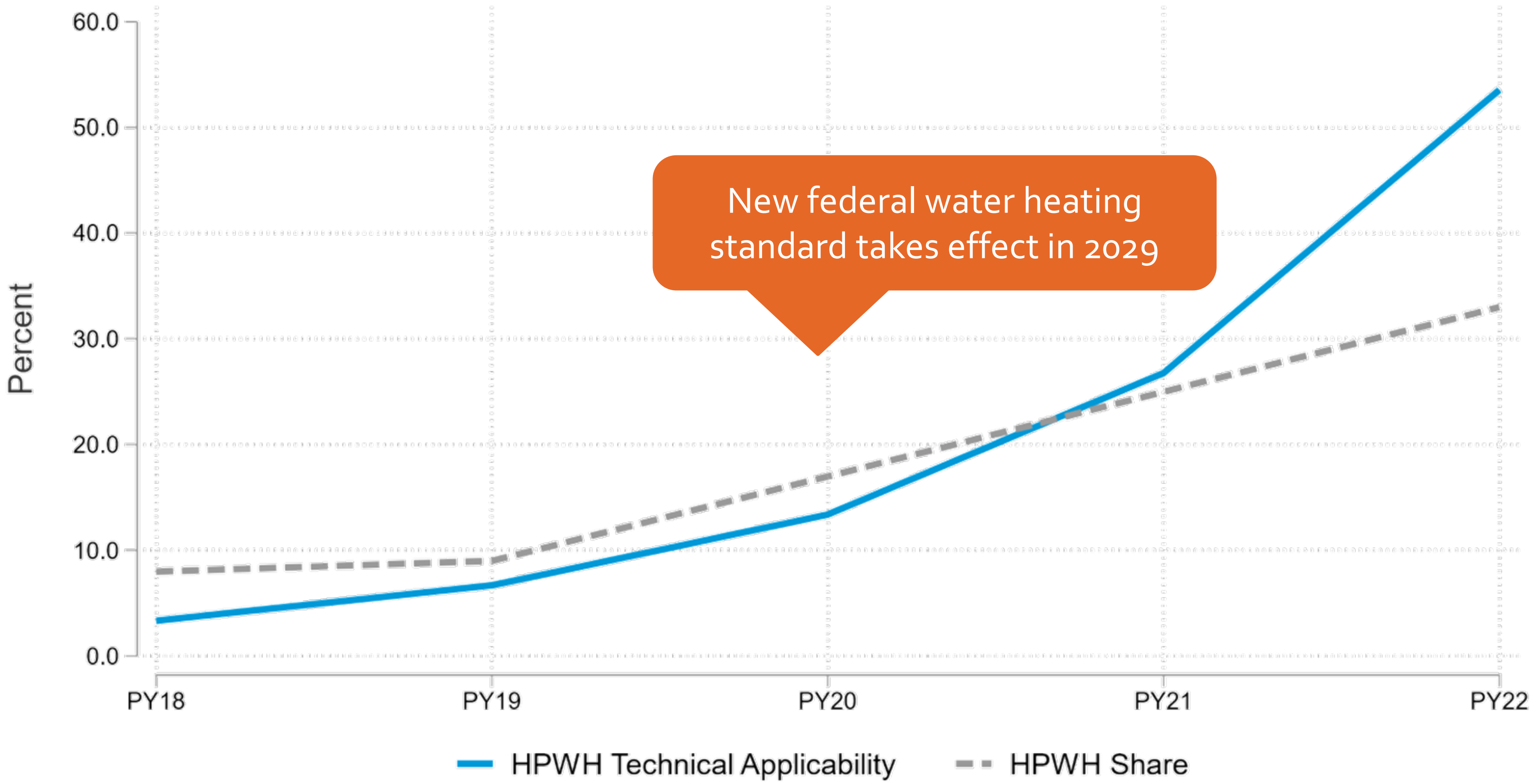
Seasonal Load Relief Potential (kW)

Season	DHW Technology	kW	
		RAP	MAP
Summer	Resistance	0.36	0.40
	HPWH	0.10	0.11
Winter	Resistance	0.45	0.50
	HPWH	0.18	0.20

- 90% load shifted outside of peak hours for RAP; 100% for MAP

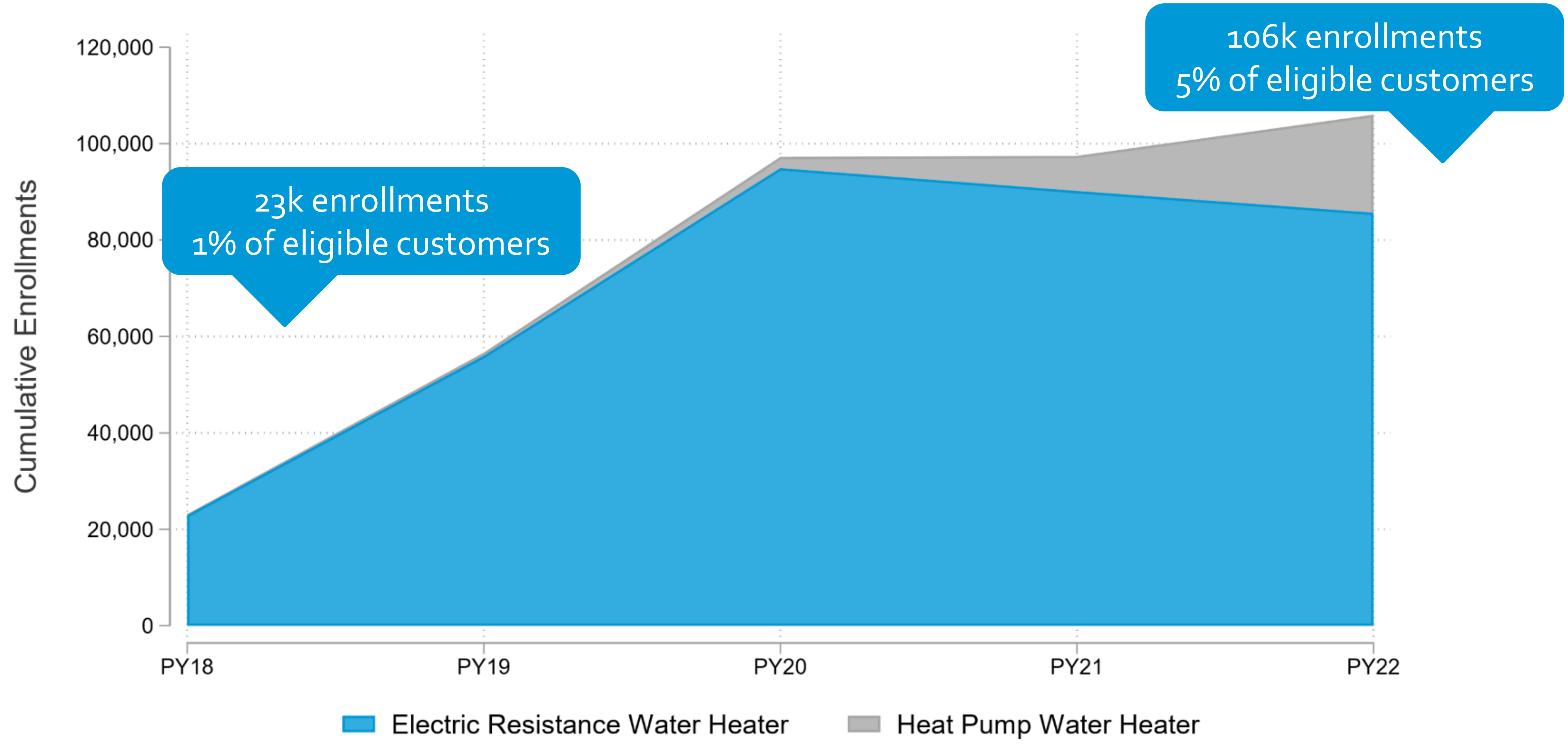
Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

HPWH Share And Technical Applicability By Year



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

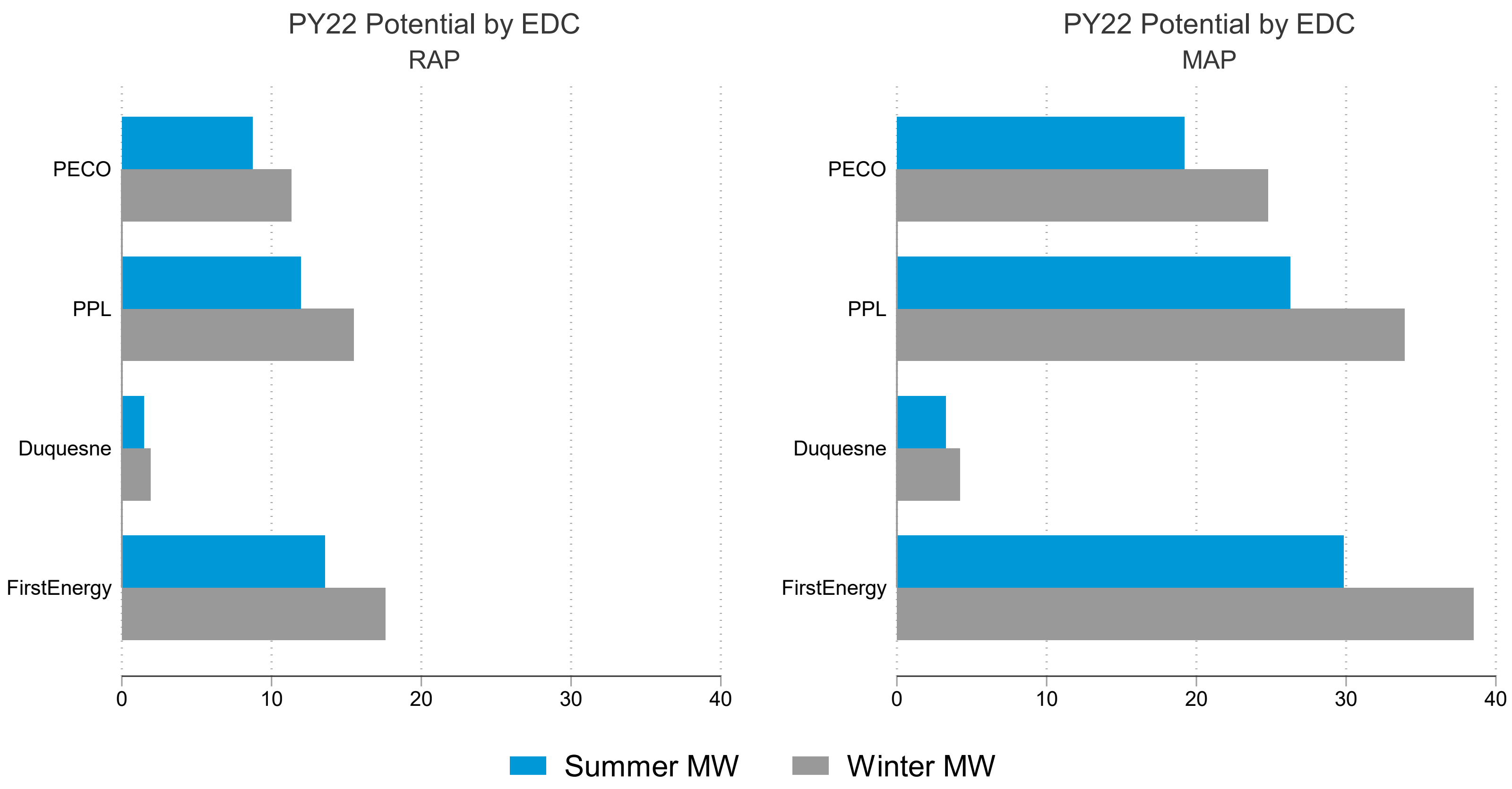
Cumulative Enrollments by DHW Technology Type



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Results: PY22 Seasonal Potential by EDC

- PY22 Potential statewide in the RAP scenario is 32 MW
  - Average of summer and winter
- Winter MW is higher than summer due to higher baseline water heating demand during winter



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Economics: RAP Spending and Cost-effectiveness Results

EDC	MW Potential	Phase V Spending ($1,000)	Acquisition Cost ($/kW-Phase)	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	7.8	$16,023	$2,058	$6,825	$14,226	$(7,401)	0.48
PPL	10.7	$21,303	$1,997	$14,592	$18,899	$(4,307)	0.77
Duquesne	1.3	$2,904	$2,196	$1,142	$2,584	$(1,442)	0.44
FirstEnergy	12.1	$24,253	$2,001	$11,999	$21,523	$(9,524)	0.56
Statewide	**31.9**	**$64,484**	**$2,022**	**$34,559**	**$57,232**	**$(22,673**	**0.60**

- Net TRC benefits statewide are approximately negative $23 million, with negative benefits across all EDCs, and a statewide TRC ratio of 0.60.
- MAP TRC Ratio (not shown) is 0.57 statewide

Resistance and HPWH Contributions To Impacts and Costs

- Resistance units are more cost effective despite higher per-project costs due to per-customer impacts 2-5X that of HPWHs.

Scenario	Technology	Total Impact (MW)		% of Scenario Impact	
		Summer	Winter	Summer	Winter
RAP	Resist	27.4	34.5	98%	97%
	HPWH	0.6	1.2	2%	3%
MAP	Resist	60.9	76.7	98%	97%
	HPWH	1.2	2.3	2%	3%

Scenario	Technology	Statewide Phase V Spend ($1,000)	% of Scenario Spend	TRC Net Benefits ($1,000)	Standalone TRC Ratio
RAP	Resist	$59,325	92%	$(19,597)	0.67
	HPWH	$5,159	8%	$(3,076)	0.40
MAP	Resist	$147,021	94%	$(52,811)	0.64
	HPWH	$9,384	6%	$(5,230)	0.44

EV MANAGED CHARGING

Overview of the Program

- Background
  - Rapid EV adoption is projected across the Commonwealth in Phase V
  - With unmanaged charging, EV charging demand coincides with the summer peak period, and to a slightly lesser extent, the winter peak period
- Managed charging programs
  - A non-rate-based method of reducing EV demand during these peak periods by incentivizing off-peak charging
  - Can work either by direct load control of the charger (called “active managed charging”) or through behavioral nudges, such as offering an incentive for charging off-peak (“passive managed charging”)
  - Modeled both a light-duty EV (LDEV) program and a medium- and heavy-duty EV (MHDEV) program targeted toward companies managing commercial MHDEV electrified fleets

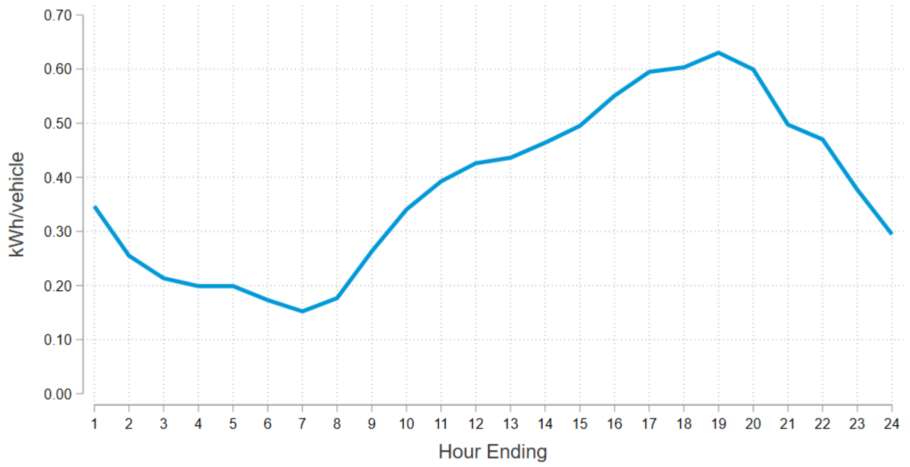
Reference Load

- Aligned with the Act 129 Avoided T&D Study and 2024 PJM Load Forecast Report EV energy totals
- Leveraged PJM hourly charging shapes for LDEV and MHDEV in 2024 that were derated slightly
- The expected daily kWh consumption per LDEV and MHDEV are 9.2 and 72.8 kWh respectively

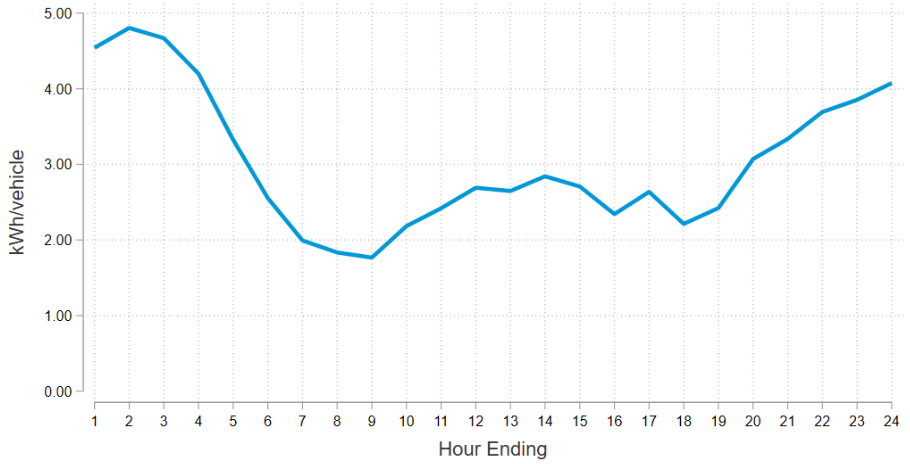
Per-EV PLC (kW) by Technology and Season

Technology	Summer	Winter
LDEV	0.56	0.42
MHDEV	2.48	2.27

Unmanaged LDEV 24-Hour Load Shape



Unmanaged MHDEV 24-Hour Load Shape



Note: The original PJM load shapes were multiplied by a factor of 0.8915 so that the assumed yearly energy consumption, multiplied by the PJM EV forecast, matched the electric vehicle energy totals published by PJM.

Eligible Electric Vehicle Forecast

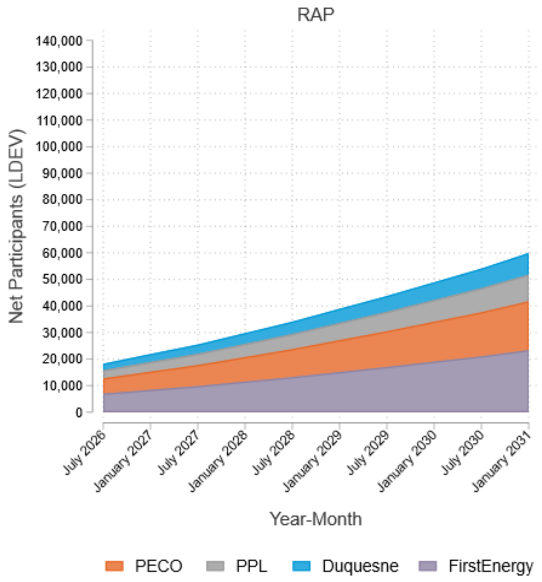
Program Year	Season	PECO		PPL		Duquesne		FirstEnergy	
		LDEV	MHDEV	LDEV	MHDEV	LDEV	MHDEV	LDEV	MHDEV
PY18	Summer	57,402	4,912	30,482	3,063	24,837	2,027	70,054	13,975
PY18	Winter	69,863	6,144	37,402	3,832	30,451	2,536	86,243	17,488
PY19	Summer	82,325	7,377	44,323	4,603	36,065	3,045	102,433	21,004
PY19	Winter	96,043	8,838	51,920	5,519	42,225	3,646	120,191	25,156
PY20	Summer	109,760	10,299	59,517	6,435	48,385	4,248	137,948	29,310
PY20	Winter	125,073	11,986	68,015	7,510	55,275	4,950	157,935	34,197
PY21	Summer	140,386	13,673	76,513	8,584	62,165	5,651	177,922	39,085
PY21	Winter	156,957	15,429	85,649	9,714	69,509	6,379	199,040	44,049
PY22	Summer	173,528	17,185	94,786	10,844	76,853	7,109	220,159	49,017
PY22	Winter	192,252	19,060	105,219	12,076	85,277	7,904	244,519	54,619

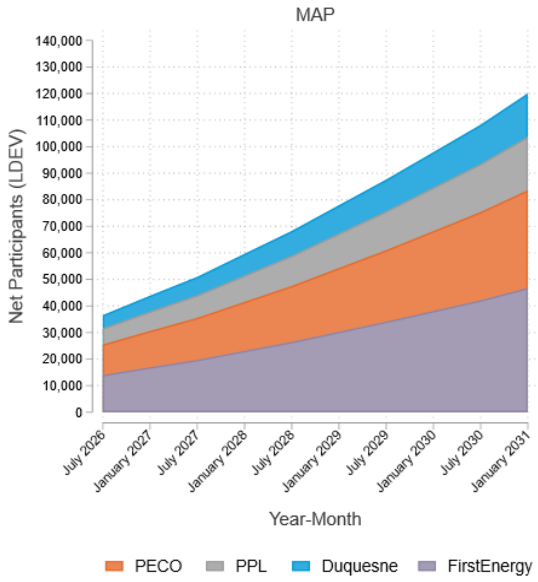
- LDEV forecast is assumed to be 65% BEV
  - BEVs provide more DR potential than PHEV
  - Approximately 35% of LDEVs in Pennsylvania are plug-in hybrids based on PennDOT registrations
  - Used zero-emissions vehicle registration data from the Pennsylvania Department of Transportation (PennDOT)
  - Multiplied the LDEV forecasts by 0.65 to create a BEV-only forecast.
- MHDEV forecast is assumed to be 95% BEV
  - There is little data on the BEV/PHEV split for MHDEV, but nearly all MHDEV research anticipates MHDEV stock to be primarily BEV
- PJM forecast is yearly and represents summer counts (August)
  - Winter counts are estimated as the average of the previous and following summer counts

Enrollment Rates and Load Reductions

Enrollment Rates

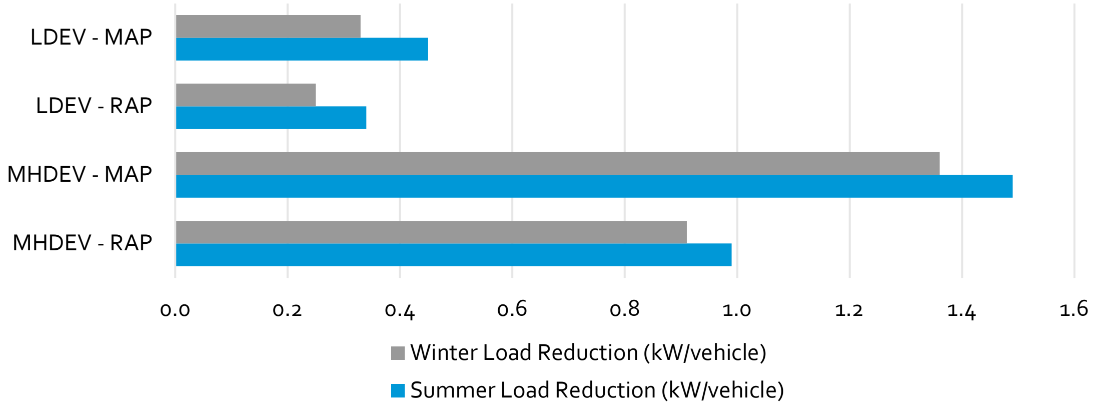
- RAP = 10%, MAP = 20% of eligible vehicles
  - ➢ Higher enrollment for MAP due to higher incentives





Load Reductions

- LDEV peak load reductions are highly variable across existing studies, moderate peak load reductions were assumed
  - ➢ RAP = 60% peak load reduction, MAP = 80% peak load reduction
- Less data available on MHDEV managed charging so we assume lower percent peak load reduction
  - ➢ RAP = 40%, MAP = 60% PLC reduction



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

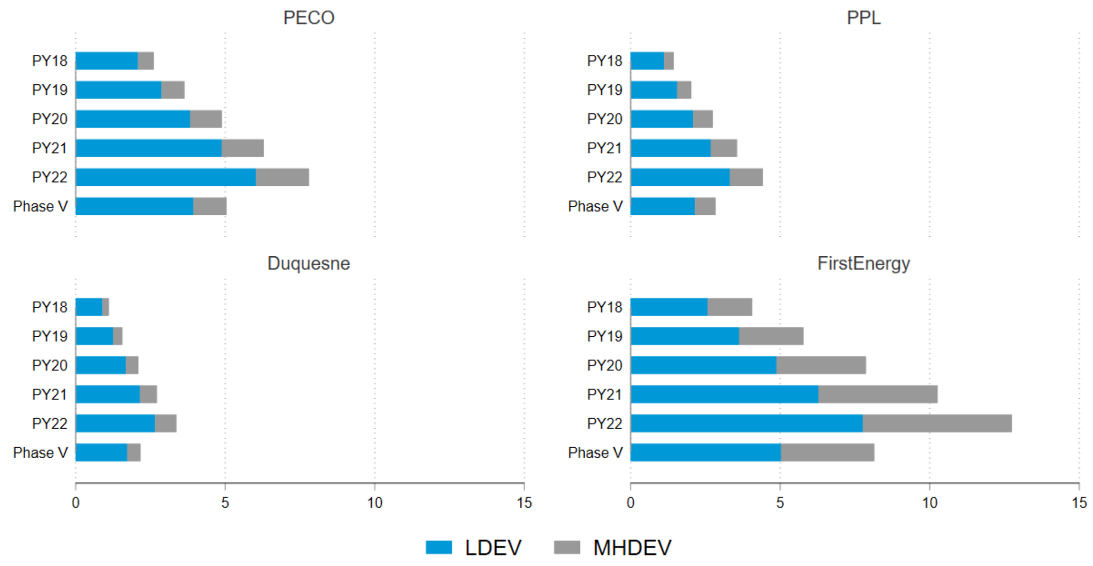
Program Costs

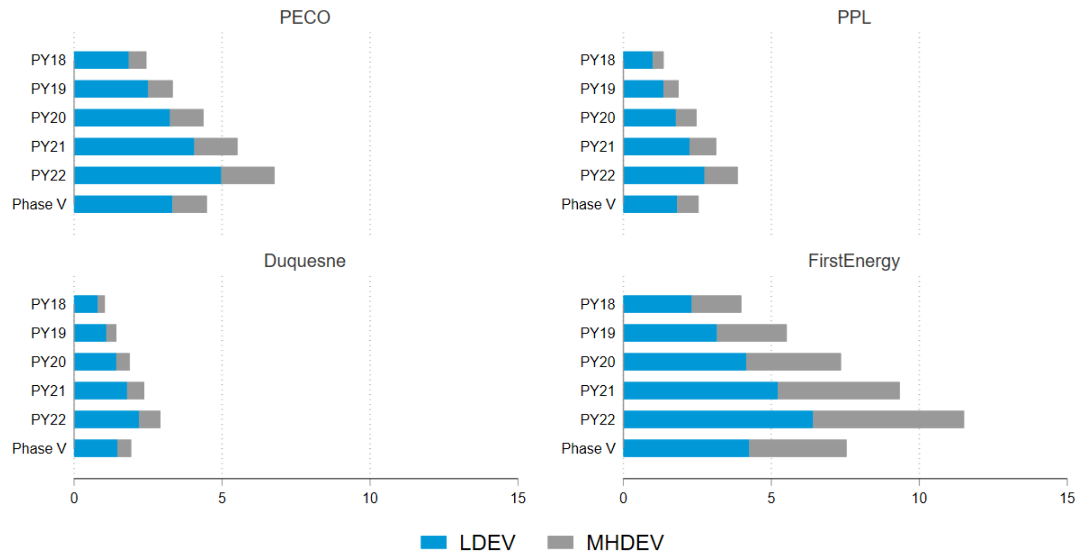
- Fixed Costs
  - One-time program startup ($175k statewide). Varies by EDC
  - Recurring administration ($350k statewide)
  - Economic efficiency from running both LDEV and MHDEV
- Volumetric Costs
  - Common assumptions across EDCs
  - TRC cost is 75% of EDC cost for incentive categories
  - The MAP scenario includes an additional volumetric one-time cost category – "Participant Sign-up Bonus"

Scenario	Technology	Category	Cost Description	Amount ($2026)	TRC Cost
RAP	LDEV	Volumetric One-Time	Marketing/Recruitment	$25	$25
RAP	LDEV	Volumetric Recurring	Annual Participant Incentive	$60	$45
RAP	LDEV	Volumetric Recurring	Vendor Fee	$25	$25
RAP	MHDEV	Volumetric One-Time	Marketing/Recruitment	$100	$100
RAP	MHDEV	Volumetric Recurring	Annual Participant Incentive	$80	$60
RAP	MHDEV	Volumetric Recurring	Vendor Fee	$40	$40
MAP	LDEV	Volumetric One-Time	Marketing/Recruitment	$50	$50
MAP	LDEV	Volumetric One-Time	Participant Sign-up Bonus	$200	$150
MAP	LDEV	Volumetric Recurring	Annual Participant Incentive	$120	$90
MAP	LDEV	Volumetric Recurring	Vendor Fee	$25	$25
MAP	MHDEV	Volumetric One-Time	Marketing/Recruitment	$100	$100
MAP	MHDEV	Volumetric One-Time	Participant Sign-up Bonus	$500	$375
MAP	MHDEV	Volumetric Recurring	Annual Participant Incentive	$160	$120
MAP	MHDEV	Volumetric Recurring	Vendor Fee	$40	$40

Achievable Potential

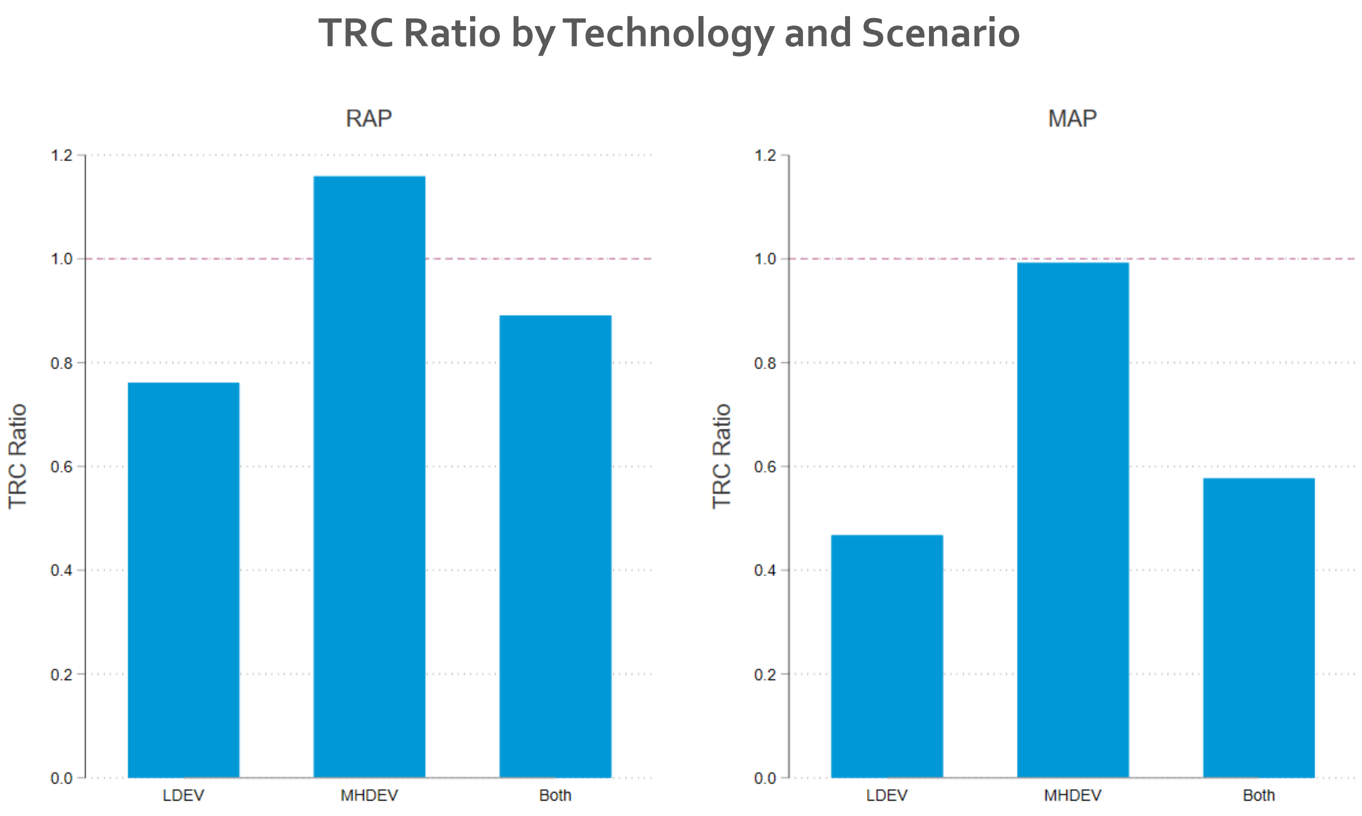
Summer RAP (MW)	Winter RAP (MW)





- Statewide MAP is approximately 2.5 times RAP in PY22 (78 MW vs. 28 MW)
  - Increased enrollment and larger per-vehicle kW impacts
- Summer MW is slightly larger than winter MW due to unmanaged charging load shape
- FirstEnergy has the largest share of forecasted MHDEV

Economics



- The combined program does not pass the TRC test under either scenario, but RAP is close
  - TRC > 1.0 for FirstEnergy
- LDEV cost-effectiveness is lower than MHDEV due to lower per-vehicle PLC
- TRC Test results compare the cost of managing EV load to serving the load via traditional supply-side options
  - Does not compare against non-Act 129 options

Other EV Activity In Pennsylvania

Public Charging

Policy Statement: In November 2018, the Commission adopted a Policy Statement aimed at promoting increased investment in EV charging infrastructure in the Commonwealth

Pilot Programs: PECO and Duquesne submitted EV pilot programs aimed at promoting the installation of publicly available and workplace-accessible DC fast charging (DCFC) stations

EV Rate Design

Final Policy Statement Order: In December 2024, the PUC adopted the Order supporting EV adoption and encouraging EDCs to develop charging tariffs that promote more efficient capacity utilization.

Pilot Programs: Outside of Act 129, several EDCs, including PECO, Duquesne, and FirstEnergy, have implemented opt-in EV time-of-use (EV-TOU) pilot programs

BEHIND THE METER STORAGE

Overview of the Program

Overview:

- Behind-the-meter (BTM) storage allows consumers to store excess energy during low demand periods and discharge when demand is high.

Functionality:

- During periods of low demand, low-cost energy can be stored by batteries.
- Resiliency benefits for participants.
- "Firming" solar PV with storage is more beneficial to the grid than the current net metering framework.

Program Design:

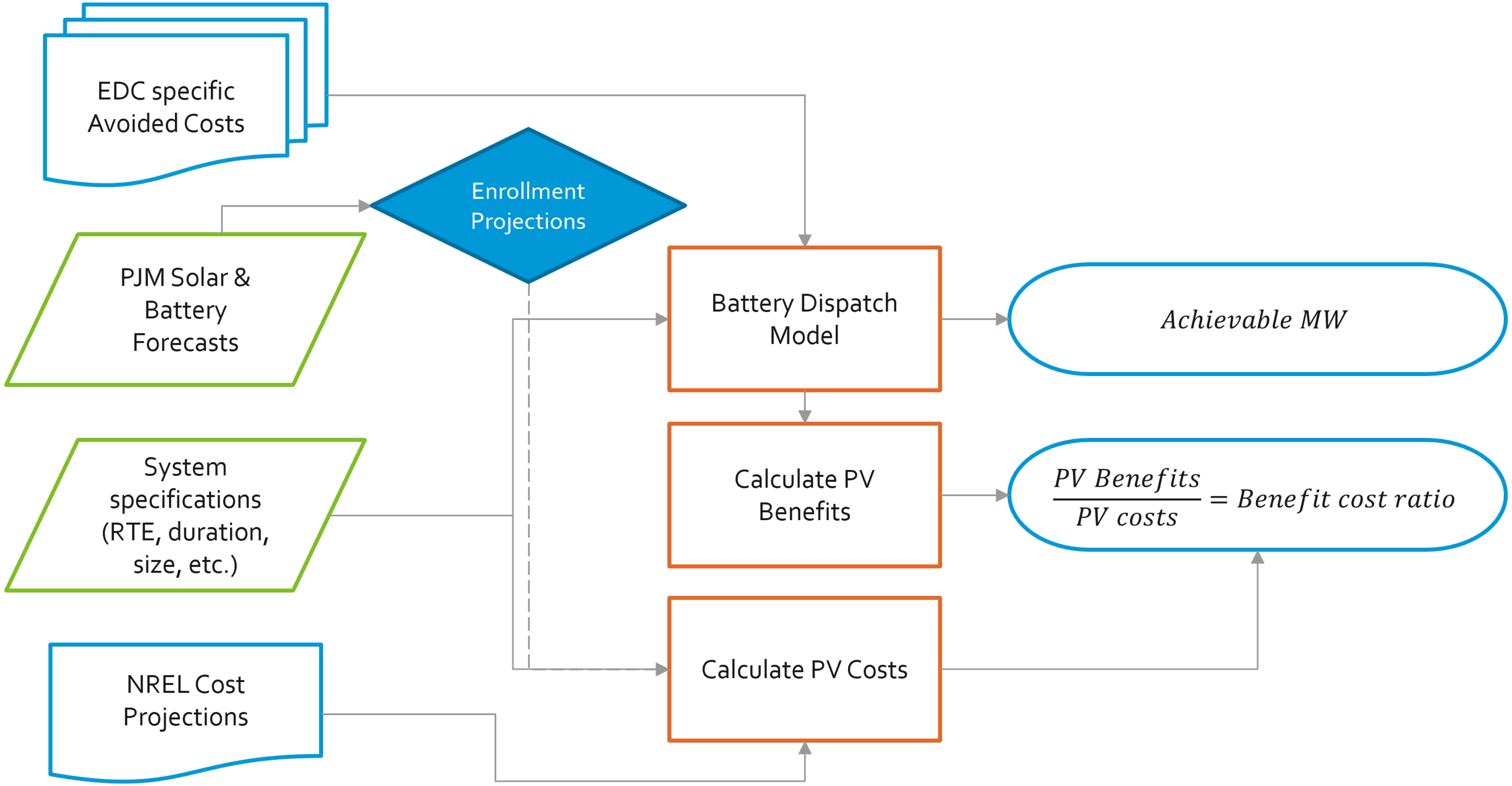
- Focus on lithium-ion batteries used for daily cycling.
- Targets customers with solar PV systems, allowing surplus clean energy to be harnessed and used at a times that benefit the grid.

External Influences on Battery Adoption

- The adoption of battery storage systems in the United States has seen a notable expansion in recent years
  - California Independent System Operator (CAISO) increased the capacity from ~ 6,320 MW in Q2-2023 to over 9,867 MW by Q2-2024
  - The Energy Reliability Council of Texas (ERCOT) doubled its capacity from around 3,287 MW in Q2-2023 to 7,740 MW in Q2-2024.
  - New England (ISO-NE) and the Midcontinent (MISO), have also seen noticeable increases in their battery capacity
- Policies like the federal Inflation Reduction Act (IRA) are poised to accelerate this growth
  - Granting significant tax benefits for residential and commercial customers installing batteries paired with solar systems
- Pennsylvania solar generation is expected to expand by approximately 3 GW in the next five years

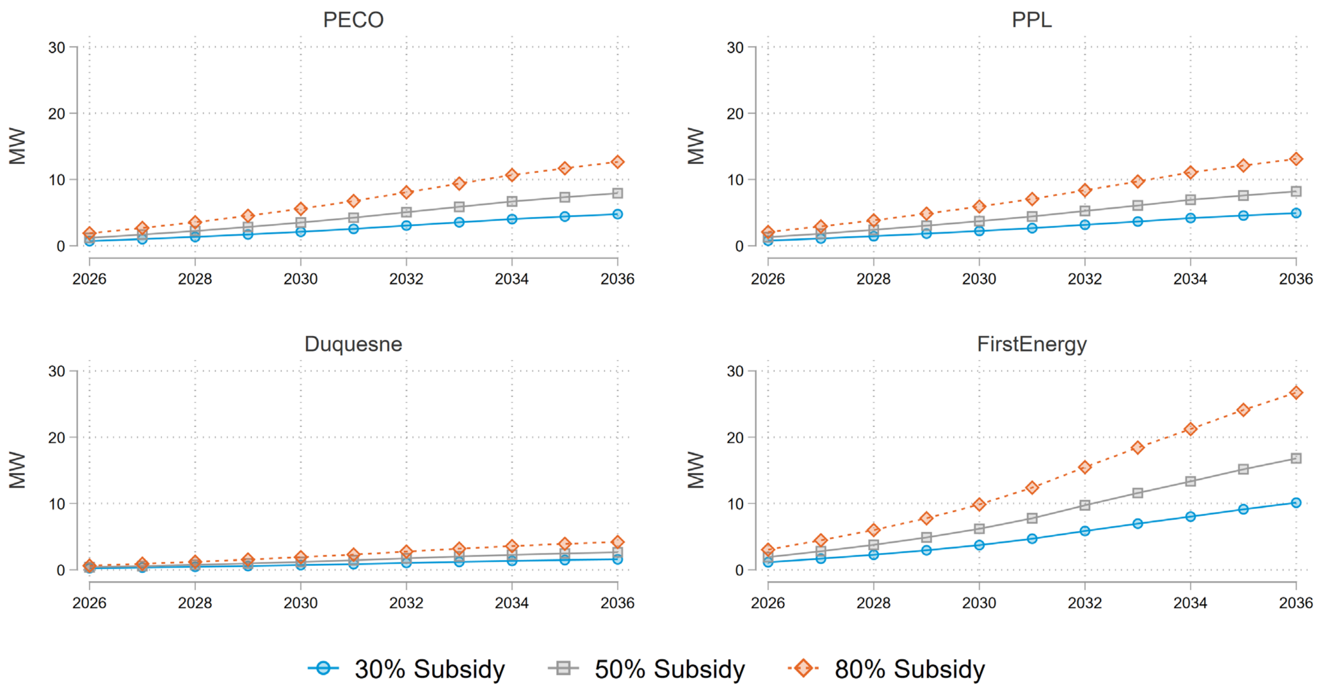
Utility	Program Name(s)	Capacity (MW)	Dispatch Frequency	Incentives
Green Mountain Power	Energy Storage System Lease	30	Daily	10-year lease of a Telsa Powerwall for $55/month
Hawaiian Electric	Battery Bonus Program	55	Daily	$850 upfront, $5/kW monthly
Holy Cross Energy	Power+ Program	3	Event Based	Battery paid by utility, paid back with a 0% interest monthly charge, offset by energy credits received by the customer
National Grid	Connected Solutions - Residential	21	Event Based	$275/kW performance-based payment
Pacific Gas & Electric	Peak Power Rewards	32	Daily	$750 upfront
Sacramento Municipal Utility District	Partner+	10	Daily	$250/kWh up to $2,500 upfront
Rocky Mountain Power	WattSmart Battery	20	Daily	$600/kW upfront plus a $15/kW bill credit

Methodology



Enrollment Projections

Additional Battery Capacity (MW) by Incentive Level

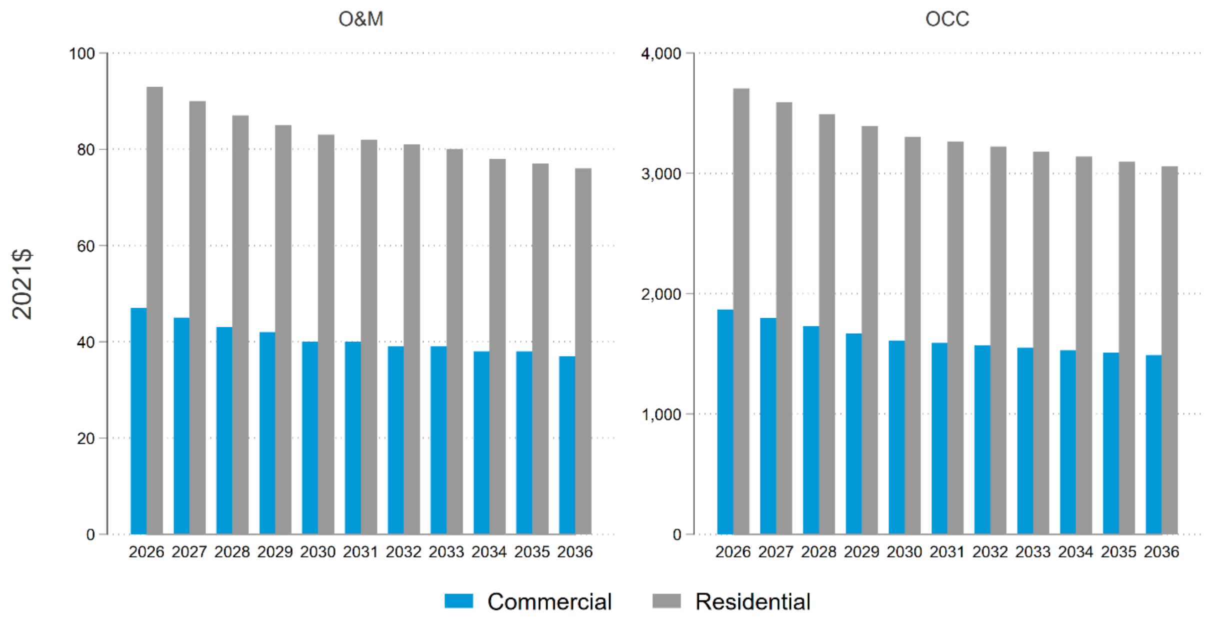


1. Identify the base population of potential battery adopters:	Calculate the target solar population by assessing the difference between Nameplate MW (total installed capacity) and Peak MW (actual peak generation)
2. Identify the forecasted level of battery penetration:	Calculate the current battery share by dividing the installed Battery Nameplate MW by the Target Solar Capacity.
3. Establish a baseline for adoption without any external influences:	Use the Bass-Diffusion model to estimate the shape parameters assuming no changes in external influence.
4. Simulate how different incentive levels might accelerate battery adoption:	Increase the external influence factor in the Bass-Diffusion model proportionally to the level of incentives provided.
5. Quantify the expected increase in battery capacity under different scenarios:	Translate the output from the model (expressed as a percentage of solar capacity that adopts batteries) into MW projections of battery installations

TRC Costs

- Cost projections from the NREL Annual Technology Baseline (ATB) for lithium-ion battery systems
  - Advanced: the lowest cost estimates
  - Conservative: the highest projections
  - Moderate: the median value
- Overnight Capital Costs (OCC)
  - Total capital expenditures required to install the battery during the year of installation, covering materials, labor, and development costs ($/kW)
- Fixed Operation and Maintenance (O&M) Costs
  - Recurring expenses associated with operating and maintaining the battery ($/kW-yr)
- Administrative Costs and Incentives

Moderate Cost Projections of 4-Hour Battery Systems by Sector



Administrative Costs and Incentives – RAP versus MAP

Scenario	Administrative Costs	EDC Incentives (% of OCC Paid)	IRA Incentives (% of OCC Paid)
RAP	$20/kW	30%	20%
MAP	$80/kW	50%	30%

TRC Benefits

Avoided Capacity Costs

- When battery systems discharge during peak demand periods, they reduce the need for additional generation, transmission, and distribution capacity
- This study uses the system-wide avoided cost of distribution capacity values from 2026 ACC
- However, EDCs might choose to target BTM battery installations in constrained areas of their distribution system, where the true avoided cost of distribution capacity is higher than the system-wide averages

Energy Arbitrage Benefits

- Charging the battery when marginal prices are low and discharge when prices are higher
- We need to factor in the round-trip efficiency (RTE) of the battery system. The assumed 85% RTE means 15% of the energy charging the battery is lost during the process
- Negative energy savings, but positive (albeit small) energy benefits thanks to the on-peak / off-peak differential in 2026 ACC

Achievable Potential and Economics

- The total achievable from batteries is modest
- Not cost-effective during Phase V in either scenario
- MAP scenario shows lower cost-effectiveness than RAP
  - More aggressive outreach and administration
- While the TRC is marginal, the *EDC acquisition* cost is lower than other DR options
  - IRA tax credits

Behind the Meter Battery Storage – Realistic Achievable Potential

EDC	MW Potential	Program Cost ($1,000)	Acquisition Costs ($/kW)	NPV Benefits ($1000)	NPV Costs ($1000)	Net Benefits ($1000)	TRC Ratio
PECO	3.50	$2,527	$722	$4,102	$8,080	($3,978)	0.51
PPL	3.71	$2,679	$722	$6,847	$8,565	($1,717)	0.80
Duquesne	1.19	$857	$722	$1,637	$2,741	($1,104)	0.60
FirstEnergy	6.18	$4,461	$722	$8,115	$14,264	($6,148)	0.57
Statewide	**14.58**	**$10,524**	**$722**	**$20,701**	**$33,650**	**($12,947)**	**0.62**

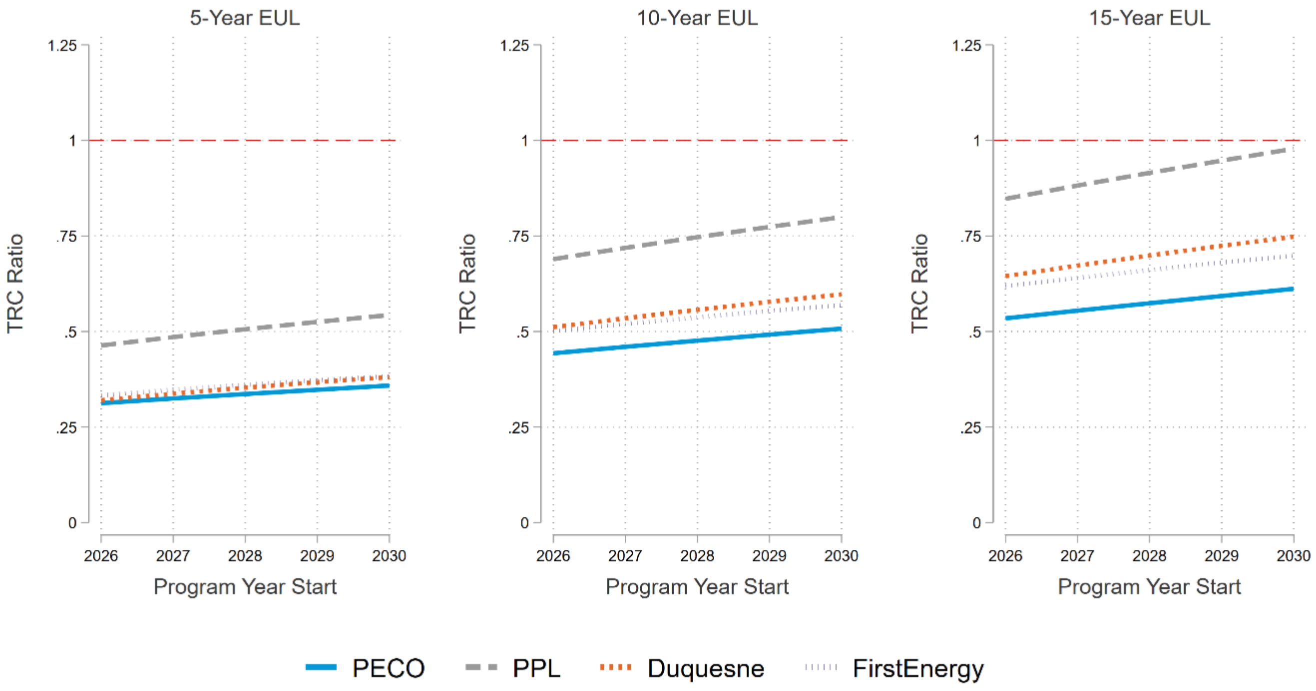
Behind the Meter Battery Storage – Maximum Achievable Potential

EDC	MW Potential	Program Cost ($1,000)	Acquisition Costs ($/kW)	NPV Benefits ($1000)	NPV Costs ($1000)	Net Benefits ($1000)	TRC Ratio
PECO	5.58	$5,619	$1,006	$6,539	$13,925	($7,386)	0.47
PPL	5.92	$5,960	$1,006	$10,923	$14,772	($3,848)	0.74
Duquesne	1.89	$1,906	$1,006	$2,610	$4,724	($2,114)	0.55
FirstEnergy	9.85	$9,917	$1,006	$12,936	$24,577	($11,641)	0.53
Statewide	**23.24**	**$23,402**	**$1,006**	**$33,008**	**$57,998**	**($24,989)**	**0.57**

Measure Life Sensitivity

- TRC ratios improve as the assumed battery lifespan increases
  - ➢ More lifetime benefits to offset the upfront cost incurred in the year of installation
- According to the 2026 TRC Test Order, the measure life of a program is set to equal the agreed-upon participation term with the program participant
  - ➢ EDCs could structure agreements with longer durations, matching the technical life of the battery and not constrained by the length of Phase V

TRC Ratios Under Varying EUL Assumptions

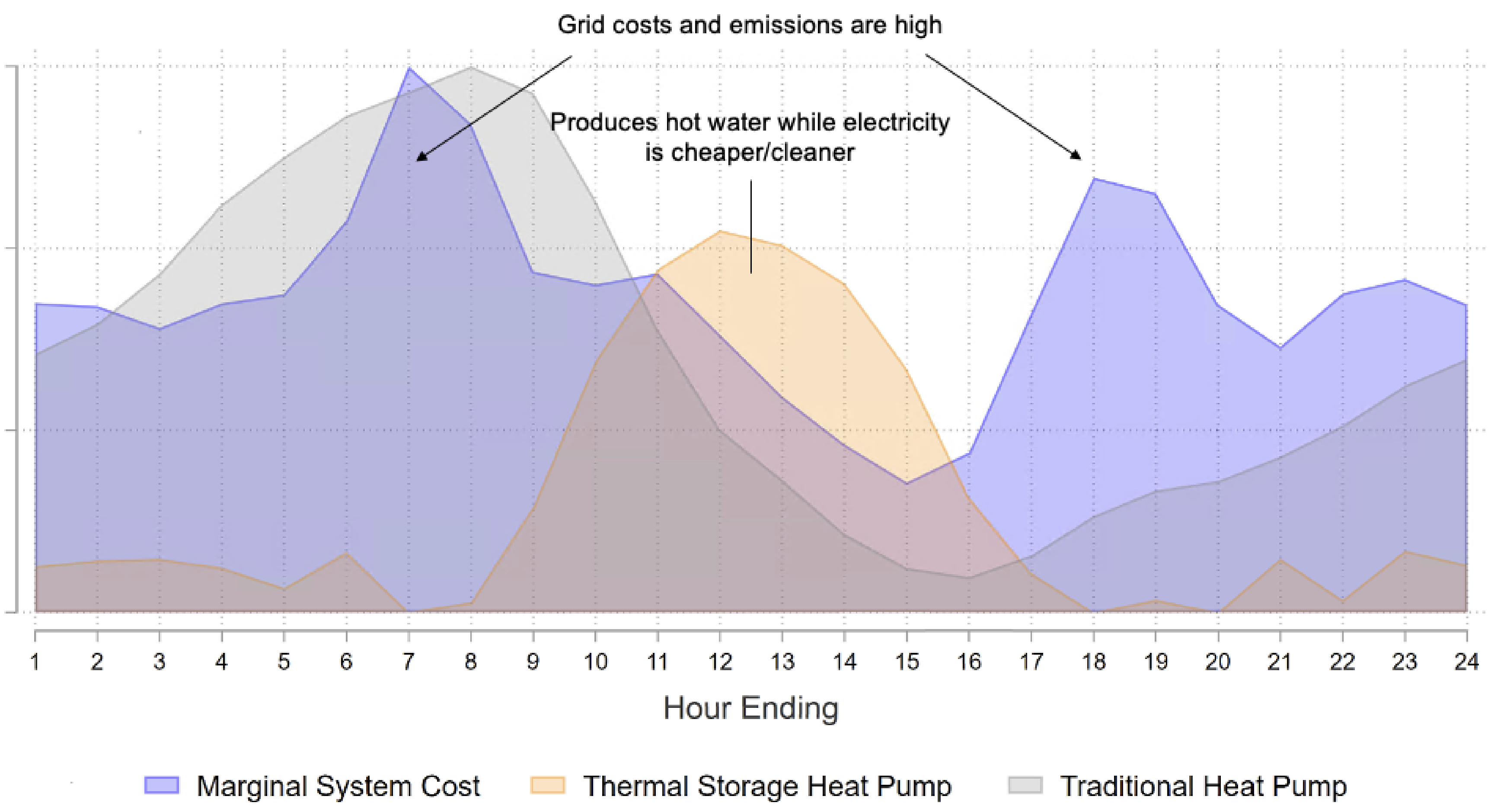


Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

THERMAL STORAGE WITH HEAT PUMP

OVERVIEW OF THE PROGRAM

- **Targeted Load:** residential space heating and water heating
- **Program Design:** Water is heated and stored outside of the peak demand window when costs and emissions are lower, then accessed for space heating and DHW needs during peaks.



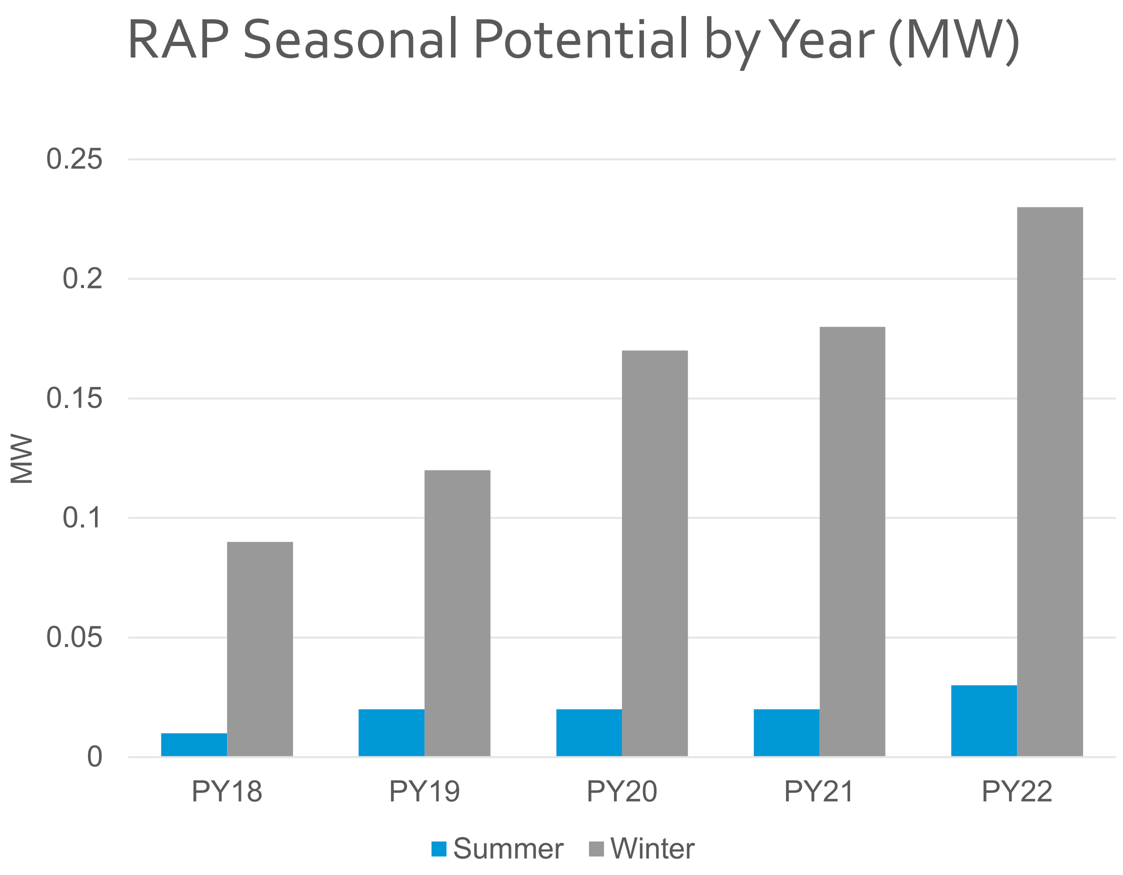
Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

MODELING ASSUMPTIONS

Input	Assumption
Peak Load Contribution	Combined heat pump space heating and DHW
Enrollment Rates	Eligible cooling system share, heat pump shares from baseline study., For the existing heat pump thermal battery add-on rate and new heat pump thermal battery add-on rate, MAP is double RAP.
Load Impacts	91% - based on commercially available thermal battery product.
Participation Incentive	RAP: \$2,000 for Heat Pump, \$500 for HPWH MAP: 30% of project cost
Program Admin Costs, fixed	\$50-175k annually, scaled to EDC residential customer count
Program Admin Costs, volumetric	One-time recruiting and marketing costs between \$20-\$0 per customer, and incentives between 33-75% of equipment costs depending on scenario
Other Key Inputs	Avoided costs, Inflation rate, Opt-out rate of 5% annually

Results: RAP Seasonal Potential

- Statewide Phase V potential (MW) is 0.46 MW
  - Average of Summer/Winter
  - Winter is much higher



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Economics: RAP Spending & Cost-effectiveness Results

EDC	MW Potential	Phase V Spending ($1,000)	Acquisition Cost ($/kW-Phase)	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	0.13	$4,134	$32,534	$211	$3,698	($3,487)	0.06
PPL	0.11	$3,418	$29,900	$452	$3,060	($2,608)	0.15
Duquesne	0.05	$1,448	$28,128	$71	$1,295	($1,224)	0.05
FirstEnergy	0.17	$4,866	$28,454	$326	$4,354	($4,028)	0.07
Statewide	**0.46**	**$13,865**	**$29,892**	**$1,059**	**$12,406**	**($11,347)**	**0.09**

- The thermal storage offering results in negative net TRC benefits for all EDCs, for both scenarios.
- MAP TRC Ratio (not shown) is 0.08 statewide

Phase V Planning Timeline

2/20/2025
- Tentative Implementation Order on Public Meeting Agenda

4/7/2025
- Comments due on Tentative Implementation Order

4/22/2025
- Reply comments due on Tentative Implementation Order

6/18/2025
- Final Implementation Order on Public Meeting Agenda

11/1/2025
- EDCs file Phase V EE&C Plans

6/1/2026
- Phase V EE&C Programs Begin

QUESTIONS?

Jesse Smith
Partner
Demand Side Analytics
jsmith@demandsideanalytics.com
770.401.9018

Davis Farr
Consultant
Demand Side Analytics
dfarr@demandsideanalytics.com
706.816.3585