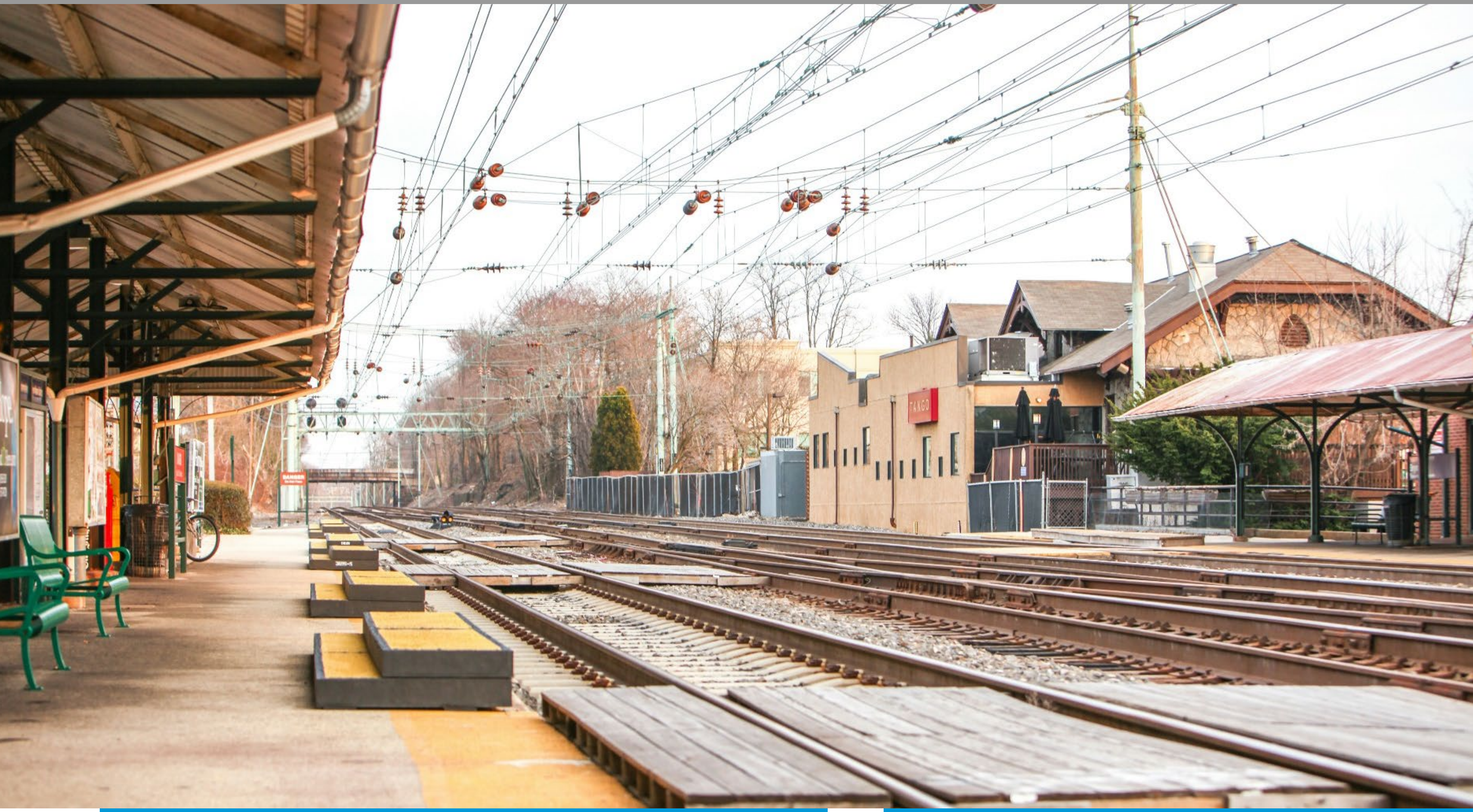
Phase V Demand Response Potential Study



Prepared for the Pennsylvania Public Utility Commission
February 2025

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

PHASE V DEMAND RESPONSE POTENTIAL STUDY

Pennsylvania's Statewide Evaluator performed an assessment of the DR potential for each of the four electric distribution companies - PECO, PPL, Duquesne, and FirstEnergy. This study also examines the costs and benefits of statewide policies to encourage the development and deployment of DR resources during Phase V of Act 129.

New Considerations for Phase V

- **Winter potential**
- **Consolidated results for the FirstEnergy**
- **Daily dispatch on non-holiday weekdays during peak season**

✓

- Aligns with EE peak demand definition
- Eliminates the need for de-rating benefits
- Differs from PJM and avoids dual enrollment concerns
- Reduces uncertainty around dispatch

X

- More disruptive to participants due to high volume of performance hours
- Smaller load impacts per participant
- More challenging to measure impacts due to lack of adjacent non-event days to use as a baseline

Act 129 Phase	Includes DR Programming	Event Trigger
I	✓	Top 100 Hours
II	X	Not defined
III	✓	PJM day-ahead forecast ≥ 96% of annual peak load forecast
IV	X	Temperature Humidity Index (THI)
V	?	*Daily dispatch on non-holiday weekdays during peak season*

Realistic Achievable Potential by Program

C&I Daily Load Shifting **119.4 MW**

Connected Thermostat Optimization **26.43 MW**

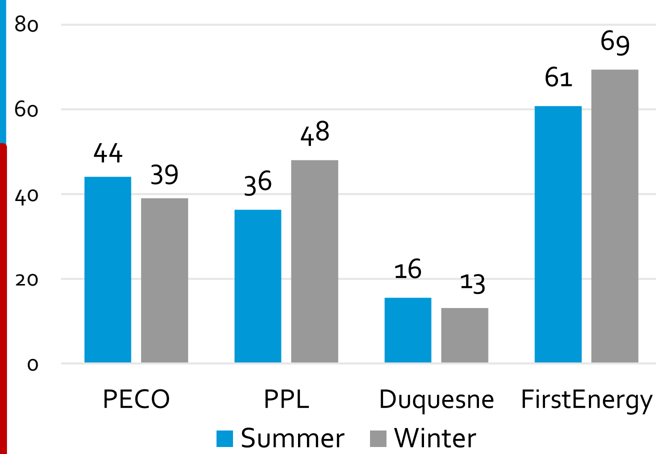
EV Managed Charging **17.34 MW**

Above / Below — TRC cutoff = 0.8 — Above / Below

Water Heating Load Management **31.9 MW**

Behind-the-Meter Storage **15.05 MW**

DR Potential by EDC and Season
(Phase V MW)



Acquisition Cost

$167/kW-year
Or $833/kW-phase

(EDC budget requirement to acquire modeled DR potential)

EDC Phase V budget requirement

11.1%

($136 Million of $1.22 Billion in statewide funding for the phase)

Statewide TRC

1.41

$149M of TRC benefits against $106M of TRC Cost.

ACKNOWLEDGEMENTS

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This study was made possible by the efforts and cooperation of staff at the electric distribution companies highlighted in this report. Their assistance in providing the necessary data on customer segmentation and consumption was instrumental in the design and execution of the study.

TABLE OF CONTENTS

Figures

Tables

1 EXECUTIVE SUMMARY

NMR Group, Inc. (NMR) and a team of subcontractors – collectively known as the Statewide Evaluator (SWE)– have been contracted by the Pennsylvania Public Utility Commission (PUC) to provide audit and planning consulting services for Phase IV of the Commonwealth's Act 129 Energy Efficiency and Conservation (EE&C) programs. Part of the SWE's scope is to perform a demand response (DR) potential assessment for possible Phase V of Act 129 programs. The four electric distribution companies (EDCs) subject to Act 129 and included as part of this study are as follows:

- PECO Energy Company (PECO)
- PPL Electric Utilities (PPL)
- Duquesne Light Company (Duquesne)
- FirstEnergy Pennsylvania Electric Company (FirstEnergy)

During the execution of this study, the Commission approved the consolidation of the four legacy FirstEnergy EDCs (Met-Ed, Penelec, Penn Power, and West Penn Power) into rate districts of a single FirstEnergy EDC. All study results are shown for the FirstEnergy EDC because this is how the PUC would establish Phase V goals. However, due to the timing of the consolidation, much of the technical research to characterize Phase V DR opportunities was conducted separately for the four legacy FirstEnergy EDCs. The SWE consolidated results for the four legacy EDCs during the reporting process, but many of the tables and figures in this report show study inputs and assumptions separately. The separate input assumptions shown for the legacy FirstEnergy EDCs reflect the underlying technical and economic characterization research and modeling procedures.

Demand Response is a demand-side management (DSM) tool for electric utilities. It is designed to reduce system reliability costs and meet capacity needs by lowering electric load during peak hours. The primary objectives of the study are as follows:

1) Estimate the DR potential in each EDC service territory over a five-year period, beginning June 1, 2026, and ending May 31, 2031.
2) Examine the costs and benefits of statewide policies to encourage the development and deployment of DR resources during Phase V of Act 129.

1.1 PEAK LOAD CONSUMPTION

All estimates of DR potential are presented at the system-level, meaning load impacts at the customer meter have been scaled up to reflect transmission and distribution system losses. This is consistent with how DR targets have been established in prior phases of Act 129. The line loss factors used to scale impacts from meter level to system level are specific to each EDC and sector. These are taken from Table 1-5 of the 2026 Pennsylvania Technical Reference Manual (TRM).[1]

[1] *See* 2026 TRM, Volume 1, Docket No. M-2023-3044491 (Entered September 12, 2024) Weblink. Page 13.

Modeling efforts for this study build on PJM Interconnection's (PJM's) peak demand forecast for the first delivery year of Phase V, as presented in the 2024 Load Forecast Report.[2] This contemporary forecast is useful for considering the relative impact of Phase V DR on peak loads in the Commonwealth and is discussed in detail in Section 3. Figure 1 shows the total forecast for the four EDCs subject to Act 129 disaggregated to the sector by the SWE.[3] Electric vehicle (EV) charging load is shown separately to highlight the projected growth over the next 15 years. Behind-the-meter solar has a negative contribution to peak demand in the summer but does not provide the same benefit for the winter peak demand forecast.

Figure 1: Statewide Peak Demand Forecast by EDC, Sector, and Year

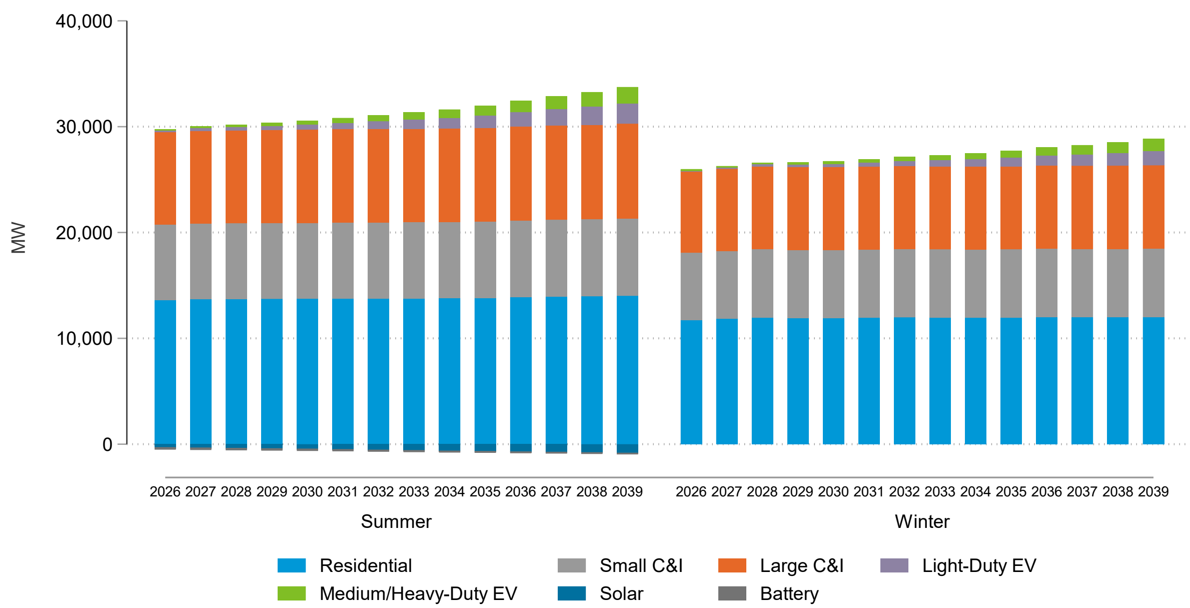


Figure 1 shows that summer peak demand is expected to exceed 30,000 MW statewide during Phase V of Act 129. However, for the purposes of comparing modeled Phase V percent reductions to prior phases of Act 129, the SWE used the original peak demand values that were used to establish Phase I targets. This legacy peak demand baseline was based on each EDC's peak load for the June 1, 2007, through September 30, 2008, delivery year and is shown in Table 1.

[2] *See* PJM Load Forecast Report, January 2024 Weblink. As discussed in Section 3, the values in the Load Forecast Report were further processed by the SWE to account for EDCs that do not serve an entire PJM zone.
[3] PJM does not publish sector level peak load forecasts. Section 3 describes the approach used to allocate zonal peak demand into the Residential, Small C&I, and Large C&I sectors.

Table 1: Peak Demand Baseline by EDC

EDC	2007-2008 Peak Demand (MW)
PECO	7,899
PPL	6,592
Duquesne Light	2,518
FirstEnergy	9,515
Statewide	**26,524**

The peak demand baseline for the FirstEnergy EDC shown in Table 1 is the peak demand during the 2007-2008 delivery year for Met-Ed, Penelec, Penn Power, and West Penn Power. FirstEnergy was granted approval for consolidation of the four independent Pennsylvania EDCs it owned by the PUC at the December 7, 2023, Public Meeting.

1.2 TYPE OF POTENTIAL MODELED

Energy efficiency (EE) potential modeling follows an established series of four stages: (1) technical, (2) economic, (3) achievable, and (4) program potential. There is no clear analogue for technical potential for DR. All demand for electricity can be temporarily curtailed or shifted, so DR technical potential is not a meaningful output. This DR potential study also does not explicitly report economic potential or what the potential would be if all customers adopted all cost-effective DR measures because the measure list for a DR potential study is much shorter and more nuanced than that of an EE potential study measure list. While economic screening for EE is just a comparison of a technology's incremental cost to its expected savings, a given DR offering may be cost-effective under one configuration but not under another. Enrollment rates also play a key role in DR cost-effectiveness because the SWE models the fixed and variable administrative costs as part of the economic analysis.

The fundamental question for a DR potential study is how much peak demand can be reduced at a cost that is lower than the supply-side options to serve the load. To answer this question, we must first consider the avoided costs in place and the incentive and administrative costs of operating a DR program. Incentive levels are a primary driver of DR adoption and potential for many DR solutions, so, once incentive levels are determined, we can estimate DR potential at those incentive levels.

The modeling in this report considers two achievable potential scenarios. The details vary slightly by DR strategy, but the general definitions are as follows:

- **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 (TRC benefits minus TRC costs). The assumed load impacts are also set to typical industry levels that balance participant comfort and disruption with the program goal of lowering peak demand.

- **Maximum Achievable Potential (MAP)**: A more aggressive projection of future DR programming, achieved by offering more generous incentives and allocating more program budget to marketing and recruitment efforts. The assumed per-participant load impacts are also higher than RAP because the objective of the program is to maximize reductions in peak demand. 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.

The SWE believes the RAP modeling perspective and results are more relevant for goal setting and program design. The MAP perspective is less practical in a funding-constrained environment like Act 129, because any allocation of funding to DR means decreased funding for EE programs. Reaching MAP projections within a five-year phase would also be challenging, because Phase IV did not include DR targets and EDCs do not have existing DR programs upon which to build. The SWE encourages the Commission and readers to focus on the RAP scenario outputs.

Several of the programs considered are not cost-effective (TRC ratio < 1.0), even under the RAP modeling perspective. Including DR offerings with poor economics in the overall study totals would harm the financial outlook of including DR in Phase V, so it is necessary to exclude a subset of programs. The economic screening for DR differs from EE measure screening because the DR potential models account for program administration costs. This raises an interesting policy question regarding the combination of EE and DR potential study results and establishing Phase V goals, because a DR offering with a TRC ratio of 1.0 is more economically viable than an EE measure with a TRC ratio of 1.0. The core study results shown in Section 1.5 reflect a TRC screening criteria of 0.8 to balance the differential handling of program administration costs within the modeling frameworks of the EE and DR potential studies.

1.3 PROGRAM DESIGN

DR potential, and the cost to acquire it, are heavily influenced by program design. The event dispatch trigger, the expected frequency and duration of DR events, and the amount of notification time participants receive prior to events are key parameters. Program design is also a function of the mechanism by which the program administrator seeks to have the peak load reductions reflected at the wholesale level. Table 2 summarizes the history of Act 129 DR program designs and the recommended design for Phase V. Since there is no current Act 129 DR program design to model, the SWE must first establish a recommended program design to model DR potential. The Commission also needs to clearly spell out the DR performance definition when establishing targets. While the EDCs have flexibility to design their own DR programs, invariably, their programs will be designed to deliver peak demand reductions over the hours that the Commission intends to measure compliance with those targets.

Table 2: Act 129 DR Overview by Phase

Act 129 Phase	Includes 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
Phase V	*To Be Determined*	*Daily dispatch on non-holiday weekdays during peak season*	*Demand resource, not formally recognized*

To choose the specific DR program design to model in this study, the SWE created a simulation to test hundreds of combinations of program design parameters for the summer and winter seasons separately. The set of parameters used in the simulation included:

- **Dispatch Trigger**: Weather versus Daily
  - Weather dispatch triggers decide whether to initiate an event for a given day based on expected seasonal weather variables by load zone.
  - Daily dispatch triggers initiate events on each non-holiday weekday of the DR season regardless of weather conditions.
- **Event Start Time**: The time that events start on event days.
- **Event Duration**: The duration of events on event days.
- **Program Operation Period**: Set of months that define the operations season for DR programs.

Section 2.3 details the mechanics of the simulation and the effects of varying each parameter individually. Daily dispatch designs were clearly more effective at controlling load during high-value hours, and a few event windows were shown to consistently outperform others. The SWE also considered the administrative advantages of DR program designs before making a final design recommendation. Daily load shifting is fundamentally different from the event-based DR programs offered by PJM. This difference avoids the dual participation concerns that have plagued Act 129 DR in prior phases. Aligning the DR program design with the Act 129 peak demand period definitions for EE would avoid capacity benefit derates and provide the Commission with flexibility in setting Phase V demand reduction goals. A daily load-shifting design would also complement time-of-use (TOU) rates if they become more widespread in Pennsylvania. A daily load-shifting DR program that encourages customers to shift consumption away from peak periods is conceptually like a TOU rate with a higher volumetric rate during peak periods and a lower volumetric rate off-peak.

The recommended designs for summer and winter programs were among the top performers in the simulations, based on quantitative metrics, and offer a unique administrative synergy for establishing peak demand reduction goals that could be achieved via either DR or coincident impacts from EE. This efficacy is offset by the frequency of events and load impact, and enrollment assumptions had to be calibrated to reflect the fact that participants will experience close to 100 events annually. Table 3 shows the final recommended program design parameters for summer and winter DR programs. The estimates of DR potential presented in this report are based on the recommended design. Similar offerings might return very different levels of DR potential under an alternative design.

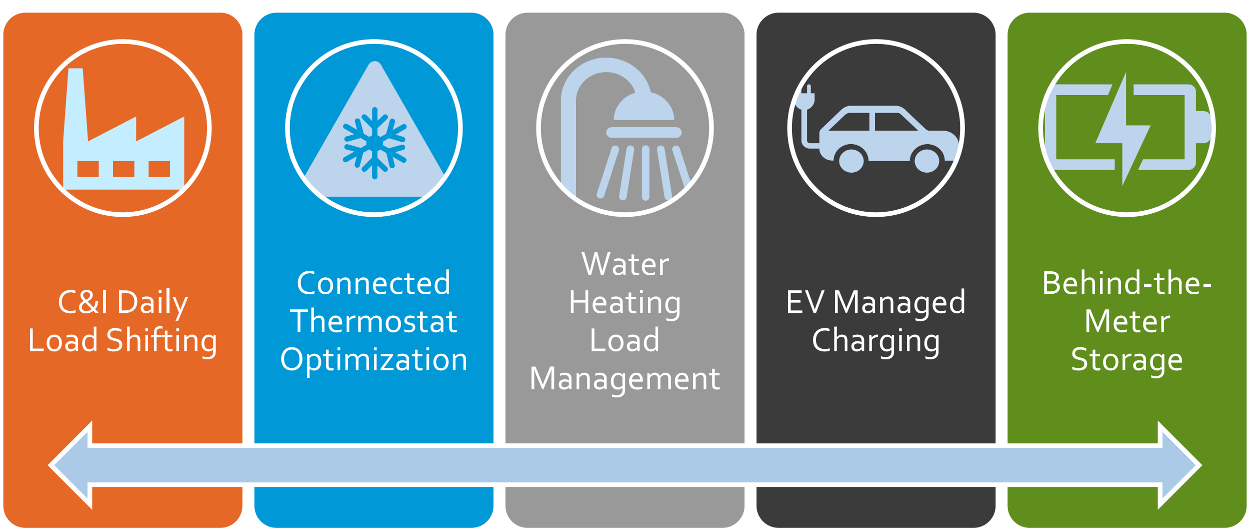
Table 3: Recommended DR Program Design Parameters

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 Eastern Prevailing Time)	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

1.4 PROGRAMS MODELED

Figure 2 shows the DR program strategies modeled in this potential study. Short descriptions of the programs follow the figure. These different offerings represent likely strategies, or solutions the EDCs might adopt if the PUC elects to establish peak demand reduction targets for Phase V. This report uses the term "program" for simplicity, but EDCs have the flexibility to define and organize programs as they wish as part of the EE&C plan design process. For example, an EDC could define a single "Residential DR" program that includes both connected thermostat optimization and EV managed charging.

Figure 2: DR Program List



- **Commercial and Industrial (C&I) Daily Load Shifting:** A popular method for curtailing peak loads that involves arrangements with C&I customers who have the flexibility to flatten their demand during peak periods. The SWE models the achievable potential and economics of daily load shifting for a program in which non-residential customers are incentivized to reschedule high-intensity activities to off-peak periods. This program relies on a top-down modeling approach applied to disaggregated peak demand forecast with enrollment and percent reductions assumptions that vary by sector, segment, and end use.

- **Connected Thermostat Optimization:** Air conditioning is the largest contributor to residential peak demand in the summer and electric heating is the largest contributor to winter peaks. The SWE modeled the impacts of a daily automated DR program in which Wi-Fi enabled thermostat vendors optimize heating and cooling loads to reduce demand during performance hours. Scenarios were modeled for both summer and winter to reflect the seasonal conditions that drive HVAC demand.

- **Domestic Hot Water Load Management:** Almost 50% of Pennsylvania households use electricity to heat water for showers, cooking, and other domestic functions. Residential water heating can have a large effect on aggregate loads. The SWE modeled daily control of both existing electric resistance units and high-efficiency heat pump water heaters. Heat pump water heaters are required by federal code by the end of Phase V and ENERGY STAR units are expected to come DR-enabled from the manufacturer.

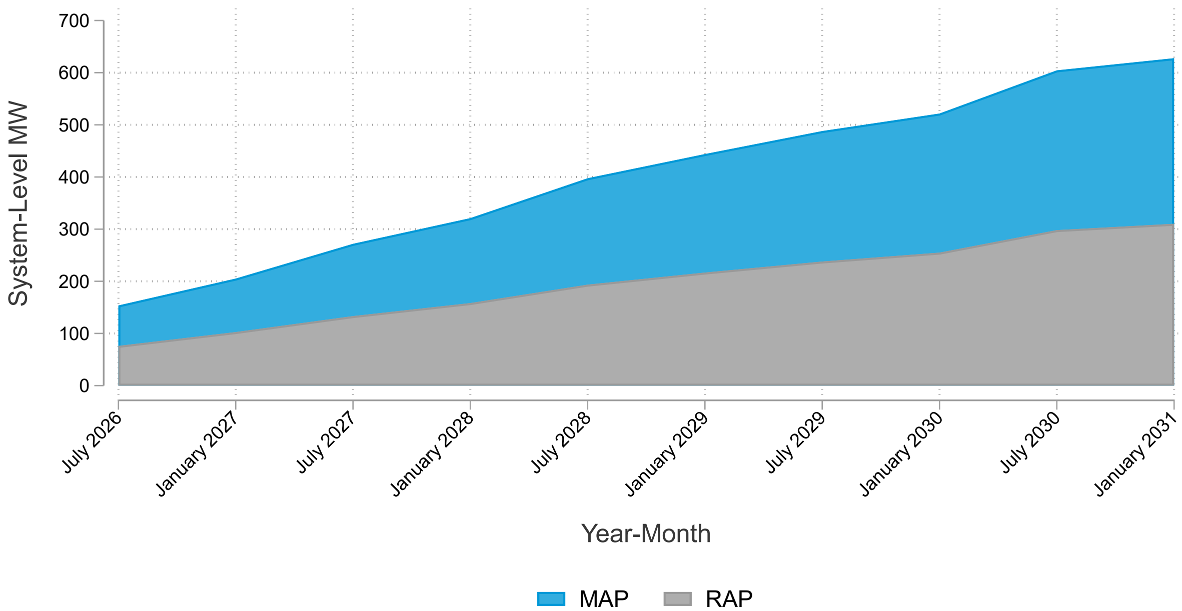
- **EV Managed Charging**: Electrification of the transportation sector is expected to bring considerable load growth to Pennsylvania over the study horizon. The SWE modeled managed charging programs for both light duty and medium-heavy duty vehicles where EDCs incentivize participants to charge during off-peak periods.

- **Behind the Meter Storage:** The primary solution consists of battery storage paired with solar photovoltaic systems. Solar adoption is projected to increase significantly in Pennsylvania over the study horizon but provides limited demand reduction for summer peaks and almost no winter peak load reduction due to the timing of peaks and path of the sun. Battery storage allows solar production to be stored when it is plentiful and discharged when the grid is more constrained. The SWE also modeled a thermal storage and heat pump pairing, where water is heated electrically off-peak and then used to meet the heating and water heating needs of a home during the peak period instead of grid-supplied electricity.

1.5 PHASE V POTENTIAL

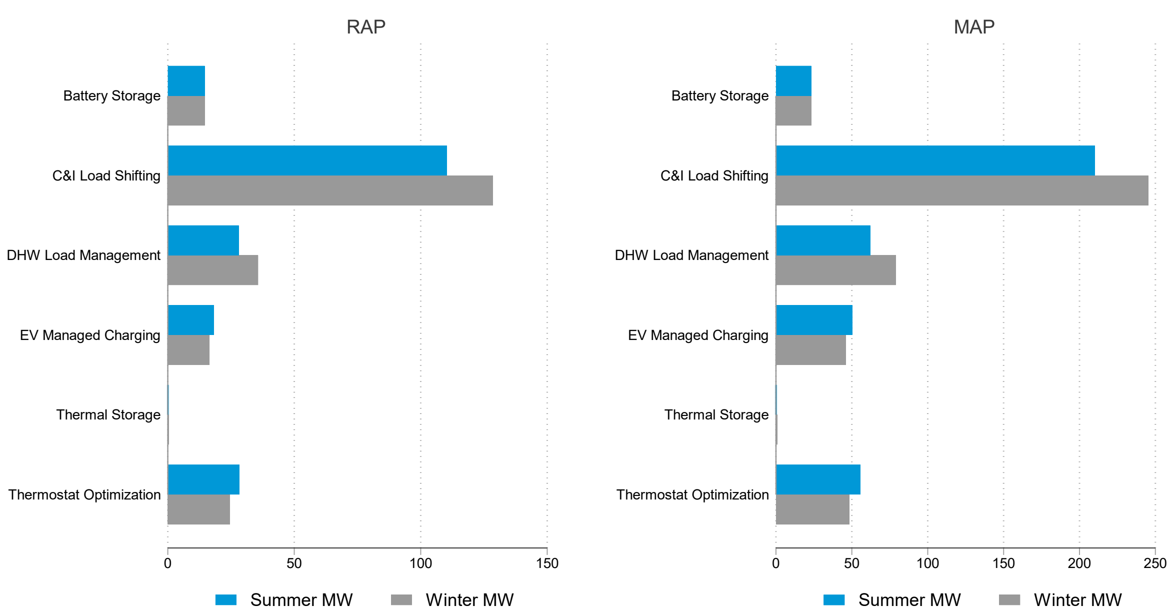
Figure 3 shows the total RAP and MAP over the Phase V study horizon across all modeled programs without consideration of cost-effectiveness. The achievable potential grows gradually across Phase V as programs mature and the adoption of the relevant technologies increases. The DR programs considered in the study have different capabilities by season, which interact with the varying heating and water heating fuel shares of the EDCs. PECO and Duquesne have more potential in the summer season while PPL and FirstEnergy have higher potential in the winter. Summer falls at the beginning of each Act 129 program year (PY) so the winter season has the benefit of an extra six months of marketing and enrollment efforts within a given program year.

Figure 3: Phase V Achievable Potential Time Series Without Cost-Effectiveness Filter



For reporting simplicity and to make the peak demand reduction potential from DR more directly comparable to the coincident demand reductions from EE programs, values from the five years of the study horizon are averaged to create a "Phase V MW" metric. The Phase V MW values are higher than the potential in PY18 (June 2026 to May 2027) and lower than the potential in PY22 (June 2030 to May 2031). Figure 4 shows the summer and winter Phase V potential by program and achievable potential scenario.

Figure 4: Phase V DR Potential by Scenario, Season, and Program



The benefits and costs for each program were modeled using the Total Resource Cost (TRC) Test perspective according to the guidelines established in the 2026 TRC Test Order.[4] Section 4 of the report describes the economic analysis and assumptions. Table 4 shows the TRC ratio for each program by achievable potential scenario. A TRC ratio greater than 1.0 indicates that the expected benefits to the Commonwealth outweigh the costs, while a TRC ratio less than 1.0 indicates that the expected benefits are less than the costs.

Table 4: TRC Ratios by Program and Scenario

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

Ultimately the outputs of this DR potential study must be combined with the outputs of the companion EE potential study to inform proposed targets for Phase V. As described in Section 1.2, the SWE recommends the PUC make this comparison based on an economically viable subset of programs. Table 5 shows those results by EDC and statewide along with relevant financial outputs. The estimates of DR potential are an average annual value over the five-year phase and the financials are five-year totals. The table values reflect the RAP modeling perspective and are limited to the three programs with a statewide TRC ratio of 0.8 or higher: C&I Load Shifting, Connected Thermostat Optimization, and EV Managed Charging. TRC costs, TRC benefits, and Present Value of Net Benefits (PVNB) are shown in 2026 dollars and reflect a nominal discount rate of 5%.

Table 5: Phase V Demand Response 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**

Table 6 shows the estimated cost to acquire the potential shown in Table 5. The MW values in Table 6 are a simple average of the summer and winter potential. The percent reduction column compares the estimated potential to the baseline levels from Table 1. The budget requirement is shown in nominal dollars and compared to each EDC's total funding limit for a five-year Phase V. Pursuit of the RAP opportunities for daily load-shifting would require approximately 11% of Phase V budgets statewide.

[4] *See* the *2026 TRC Test Final Order*, Docket No. M-2024-3048998 (entered November 7, 2024) at Weblink.

Table 6: Required Budget by EDC

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%**

The acquisition cost implied by the values in Table 6 ranges from $765 per kW-Phase at PPL to $930 per kW-Phase at Duquesne. The statewide average is $833 per kW-Phase. In PY15, the statewide acquisition cost for summer peak demand from EE programs was $1,647 per kW. This highlights a basic finding regarding DR and EE programming. DR programs deliver peak demand reductions at a lower unit cost than EE programs. However, EE programs lower energy consumption along with reducing peak demand. Allocation of Phase V funding to DR programming would allow for higher peak demand reduction targets but at the expense of lower conservation targets. Excluding DR performance from the first summer or first program year of Phase V, as the PUC did for Phase III, would reduce budget requirements, and the MW potential would increase. Omitting the first season(s) from the performance definition for Phase V removes the year with the lowest potential from the calculation, and the average potential for the remaining years would rise slightly.

2 DEMAND RESPONSE PROGRAM DESIGN

Demand Response potential and its cost are heavily influenced by program design. In particular, the expected frequency and duration of DR events and the amount of notification time participants receive prior to events play an important role in customer willingness to enroll in DR and influence the expected incentive levels for participation. Since there is no current Act 129 DR program design to model, the SWE must first establish a recommended program design before it is possible to model DR potential. The Commission also needs to clearly spell out the DR performance definition when establishing targets. While the EDCs have the flexibility to design their own DR programs, inevitably their programs will be designed to deliver peak demand reductions over the hours that the Commission intends to measure compliance with those targets.

2.1 A BRIEF HISTORY OF ACT 129 DEMAND RESPONSE

DR activity in Act 129 EE&C programs has been intermittent since the legislation was enacted in 2008. The language below, from House Bill 2200[5] (Act 129 of 2008), established the initial targets for peak demand reduction:

> *By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008.*

The noteworthy aspects of the Phase I peak demand reduction are as follows:

- **Dispatchable DR programs or EE measures that reduce demand coincident with the system peak could meet the 4.5% peak demand reduction**. Act 129 also established a mandatory 3% reduction in energy consumption. On average, EE measures tend to produce similar percentage reductions in energy consumption and peak demand. As a result, EDCs achieved approximately 54% of Phase I peak demand reduction as a byproduct of the EE measures installed to meet the 3% consumption reduction target.[6] Dispatchable DR programs delivered the remaining peak demand reductions.

- **The measurement period for Phase I goals was summer 2012**. Because Pennsylvania observes its highest system loads during summer months and the legislation called for reductions by May 2013, the performance period was summer 2012. Other than for testing and planning, EDCs did not operate DR programs during the first three years of Phase I.

- **The Top 100 Hours performance definition was operationally challenging**. EDCs faced significant uncertainty in predicting which hours would be part of the Top 100. Load

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[5] *See Act 129 of 2008.* November 14, 2008. Weblink. Page 55.

[6] *See* the *SWE Phase I Final Report*, Table 3-25 at Weblink.

reductions also had to be added back to metered loads to reconstitute system loads.[7] EDCs faced two primary risks:

- Dispatching DR programs during hours that were ultimately not part of the top 100 hours. In this scenario, the EDC incurs costs but generates no benefits.

- Not dispatching DR programs during hours that are ultimately part of the top 100 hours. Summer 2012 started off very hot and then cooled off in early August. The EDCs found themselves reserving DR resources for hot days that never arrived.

- **Cost-effectiveness was poor**. Table 7 shows the TRC costs, TRC benefits, and TRC ratios for each EDCs' Phase I DR offerings.

Table 7: Phase I Demand Response Cost-Effectiveness, by EDC

EDC	TRC Cost ($1,000)	TRC Benefits ($1,000)	TRC Ratio
PECO	$21,364	$6,197	0.29
PPL	$15,744	$5,943	0.38
Duquesne	$1,864	$155	0.08
Met-Ed	$21,191	$4,186	0.20
Penelec	$14,095	$4,104	0.29
Penn Power	$2,183	$1,978	0.91
West Penn Power	$6,426	$6,661	1.04
Statewide	**$82,867**	**$29,224**	**0.35**

Phase II of Act 129 did not include any DR targets or programs. Phase I DR program activity occurred at the end of the phase, in parallel with planning activities for Phase II of Act 129. The timing of activities did not allow for a full assessment of Phase I DR performance and cost-effectiveness in time for findings to be incorporated in Phase II goal setting. As a result, the Commission established a relatively short Phase II (three years), with only consumption reduction targets.

To inform future DR offerings, the Commission directed the SWE to study the cost-effectiveness of Phase I and potential future DR programs. On November 1, 2013, the SWE's Act 129 Demand Response Study was released.[8] This study included a retrospective assessment of the effectiveness of the Phase I design and compared the Phase I design with how DR is implemented and evaluated in other jurisdictions. On February 27, 2015, the SWE's Phase III Demand Response Potential Study was released.[9] The 2015 Demand Response Potential Study was prospective in nature, recommended an

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[7] Section 4 of the 2012 Pennsylvania TRM provides a detailed discussion of the demand reduction calculations under the "Top 100 hours" framework. *See* Weblink.

[8] *See* Act 129 SWE Demand Response Study Final Report – Amended November 1, 2013. Docket Nos. M-2012-2289411 and M-2008-2069887. Weblink.

[9] *See Act 129 Statewide Evaluator Demand Response Potential for Pennsylvania - Final Report.* Weblink. The *DR Potential Study* is dated February 25, 2015, and was released February 27, 2015, at Docket No. M-2014-2424864.

alternative Act 129 program design, and included estimates of DR potential and cost that formed the basis of Phase III DR targets.

Phase III of Act 129 began on June 1, 2016, and ended May 31, 2021. Key features of the Phase III DR program design and EDC targets included the following:

- **DR program activity for four of the five summers in Phase III**. The Commission determined that the timing of the Phase III Implementation Order and EE&C Plan filings for Phase III did not allow EDCs adequate time to ramp up DR programs for PY8 (summer 2016). The Phase III performance period initially included the four summers associated with PY9 through PY12.
    - DR performance from the fifth summer of Phase III was excluded from compliance calculation due to the COVID-19 pandemic and concerns that participants would not be able to supply their committed load reductions due to reduced operations.[10]
- **Demand reduction targets were for DR only**. Coincident peak (CP) demand reductions from EE measures did not count toward Phase III EDC compliance targets.
    - The EDCs achieved 540 MW of verified peak demand reduction via dispatchable DR programs, against a 425 MW target. The 904 MW of gross verified coincident summer peak demand reduction from EE programs did not count towards Phase III goals. However, the peak demand reductions from EE were used to calculate capacity benefits in the TRC Test.
- **A narrower performance period with dispatch guidelines to manage EDC risk**. Phase III DR programs were limited to 24 hours per summer (no more than six events, with a duration of four hours each). The Phase III performance definition that determined when EDCs called events was as follows:
    - Curtailment events were limited to the months of June through September and lasted four consecutive hours.
    - Curtailment events were triggered when PJM's day-ahead forecast for the PJM Regional Transmission Organization (RTO) was greater than 96% of the PJM RTO summer peak demand forecast for the year.
    - Once six curtailment events had been called in a program year, the peak demand reduction program was suspended for that program year.
    - The reductions attributable to a curtailment event were based on the average MW reduction achieved during each hour of an event.

[10] See *Phase III Modification Order*, Docket No. M-2014-2424864. Entered June 3, 2020. Weblink

- Compliance was determined based on the average MW reductions achieved from events called in the four years of DR program activity. As noted above, the Commission excluded the fourth year of DR program activity (PY12 / Summer 2020) from compliance determination due to the COVID-19 pandemic. Despite the exclusion of PY12 DR impacts from compliance calculations, the EDCs achieved 439 MW of DR performance in PY12, exceeding the Phase III target of 425 MW.

For both Phase I and Phase III of Act 129 DR programs, EDCs were permitted to enroll participants with existing capacity commitments in PJM's emergency load response program (ELRP). In the Phase III Implementation Order, the Commission clarified that "*The EDCs, in their plans, must demonstrate that the cost to acquire MWs from customers who participate in PJM's ELRP is no more than half the cost to acquire MWs from customers in the same rate class that are not participating in PJM's ELRP.*"[11]

The TRC test results of Phase III DR programs were much higher than the Phase I DR programs. Table 8 shows the TRC costs, TRC benefits, and TRC ratios for each EDC in Phase III. The narrower definition of peak demand for Phase III, relative to Phase I, and the reduced risk regarding which hours were performance hours, were major factors in the improved DR economics of Phase III.

Table 8: Phase III DR Cost-Effectiveness

EDC	TRC Costs ($1,000)	TRC Benefits ($1,000)	TRC Ratio
PECO	$35,067	$32,033	1.09
PPL	$16,792	$7,397	2.27
Duquesne	$17,235	$6,263	2.75
Met-Ed	$11,203	$6,179	1.81
Penelec	$0	$0	N/A
Penn Power	$7,302	$2,246$	3.25
West Penn Power	$21,813	$7,360	2.96
Statewide	**$109,412**	**$61,478**	**1.78**

The Phase III TRC ratio of 1.78 for DR programs was higher than the Phase III TRC ratio for EE programs of 1.39. One reason Phase III DR programs showed favorable benefit-cost results was the assignment of full avoided capacity cost to peak demand reductions from DR in the 2016 TRC Test Order. The Commission altered its position on this topic in the 2021 TRC Test Order and set forth a valuation approach for Phase IV whereby MW impacts from DR were derated when estimating capacity benefits in the TRC Test.[12] Specifically, EDCs were directed to use a 60% derate factor when calculating avoided transmission and distribution benefits from Phase IV and an EDC-specific derate factor when calculating the avoided cost of generation capacity.

[11] *See* the *Phase III Final Implementation Order*, Docket No. M-2014-2424864 (entered June 19, 2015), page 44 at Weblink.
[12] *See* the *2021 TRC Test Final Order*, Docket No. M-2019-3006868 (entered December 19, 2019), pgs. 86-97, at Weblink.

The derate factors, or the extent to which a MW of Act 129 dispatchable DR lowers resource requirements for an EDC, was a key theme of the Phase IV DR Potential Study.[13] The SWE elected to model Phase IV DR potential under a coordinated design which leveraged PJM's recently created Peak Shaving Adjustment (PSA) mechanism. The PSA mechanism relies on a temperature-humidity index (THI) trigger to determine when DR programs are dispatched. This weather-based event trigger was a departure from the load-based trigger used for Phase III of Act 129, although in practice, elevated loads are a function of extreme temperatures.

The Phase IV DR potential study identified approximately 198 MW/year of dispatchable summer DR potential statewide with an estimated TRC ratio of 1.54.[14] However, the Commission ultimately elected to set Phase IV peak demand reduction targets that must be satisfied by coincident demand reductions from EE measures. This decision was based on the expected net benefits to the Commonwealth as described in the Phase IV Implementation Order. "*A Phase IV design which pursues both EE and peak demand reductions without utilizing DDR would achieve $35 million more net benefits to the Commonwealth than a Phase IV design which includes DDR*."[15] The exclusion of DR from Phase IV of Act 129 meant that peak demand reduction targets were based on the expected magnitude of summer peak demand reduction associated with 100% allocation of Phase IV budgets to EE programming. The statewide peak demand reduction target for Phase IV is 809 MW.

Each phase of Act 129 has taken a different position on DR program design and on whether investment in DR programming is a prudent use of limited Act 129 budgets. The Commission will undoubtedly face a similar decision following the release of this DR Potential Study and companion EE Potential Study. The SWE approached the central questions of wholesale recognition and event trigger anew, based on market development since the 2019 DR potential study. The Commission's decision to expand the Pennsylvania TRM and TRC Test Order to consider winter peak in addition to summer peak demand adds an additional layer of complexity, which must be considered in the DR program design for Phase V of Act 129.

2.2 WHOLESALE RECOGNITION OF ACT 129

The mechanism by which peak demand reductions are reflected at the wholesale level in the organized regional markets operated by PJM is perhaps the most fundamental program design question for Act 129 DR program offerings. In Phase I and Phase III, Act 129 DR programs were operated independently of the PJM markets. In Phase IV, the SWE elected to model a more coordinated Act 129 DR program design that leveraged the PSA mechanism, developed by PJM in 2019. This change provided a clear mechanism for Act 129 DR to be recognized and monetized, but drastically reduced Act 129 DR potential from the Large Commercial and Industrial (LCI) customer class, because it effectively prohibited dual participation in Act 129 DR and PJM's capacity market.

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[13] *See* the *Pennsylvania Act 129 Phase IV Demand Response Potential Study*, Docket No. M-2020-3015229 (entered March 2, 2020). Weblink.
[14] Ibid, page 16
[15] *See* the *Phase IV Final Implementation Order*, Docket No. M-2020-3015228 (entered June 18, 2020), page 60 at Weblink.

The first step in developing a program design for Phase V is to decide whether DR should be recognized through the PJM market, or whether it should be operated independent of the PJM market. This recognition pathway will determine how the DR program is designed, how events are triggered, and how the EDCs calculate the benefits of DR. Figure 5 compares the two broad pathways by which Act 129 peak demand reductions could be reflected at the wholesale level.

Figure 5: Overview of Recognition Pathways

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)

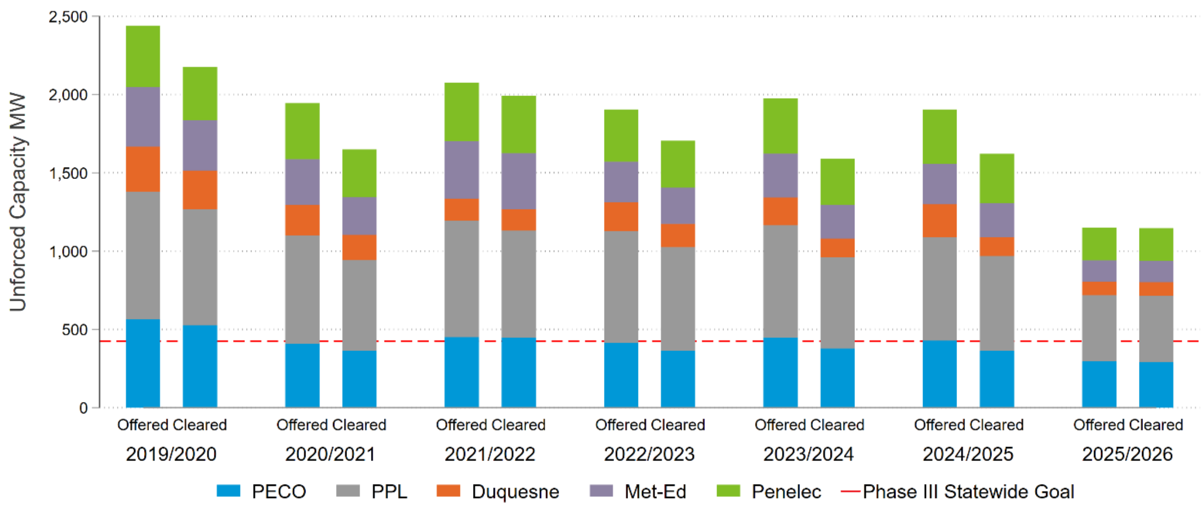
- EDCs target reductions during high system load hours
- This places downward pressure on peak load forecasts and lowers future capacity obligations
- Valuation is more complex and requires events to be called
- Dispatch criteria must be set by the PUC in an Implementation Order or proposed by EDCs in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

Most DR in the PJM system enters the market as supply in the Emergency and Pre-Emergency Load Response program and is compensated at the capacity clearing price. While it is the most common form of DR in the PJM system, this pathway has not been used to date for Act 129 DR. Under this model, valuation is straightforward and dispatch instructions are all handled by PJM, which means the Commission does not need to establish a trigger for dispatching DR resources. Cleared resources are simply paid to be available and obligated to respond when PJM initiates DR. However, formal recognition of Act 129 DR as a supply resource poses several administrative challenges for Act 129 programming. First, the market is quite mature in Pennsylvania, and many Large C&I customers participate in PJM DR either directly or through a Curtailment Service Provider.

Figure 6 depicts the demand resources offered and cleared in the Base Residual Auction (BRA) over time for five of the seven legacy EDCs.[16] The quantity of demand resources offered and cleared varies from year-to-year based on market prices and rules. However, consistently 1,000-2,000 MW of DR resources cleared for the past seven BRAs for the five EDCs considered. This is significantly more than the Phase III statewide DR goal of 425 MW. If Act 129 DR followed the supply resource pathway, it would create competition between the EDCs and CSPs over the same customers, and it is unclear whether EDC involvement would lead to the enrollment of more DR resources.

[16] Penn Power and West Penn Power both fall under multi-state zones and their auction results are not reported separately, therefore they are not depicted in the figure.

Figure 6: Pennsylvania DR Resources Offered and Cleared by Delivery Year



The second administrative challenge with recognizing Act 129 DR as a supply resource in PJM's Forward Capacity Market is the timeline. Current delays notwithstanding, the BRA for a delivery year is typically held in the spring, three years prior to the delivery year. This advanced schedule means that, by the time the EDCs have a Phase V DR target and an approved EE&C plan, all but two BRAs for Phase V program years will have passed. A similar issue exists after the phase because the EDCs would need to commit resources into the BRA without an approved Act 129 EE&C plan to fund their efforts.

Financial penalties for underperformance are a third administrative challenge with formal recognition of Act 129 DR as a supply resource. In PJM's capacity market, parties who fail to deliver the nominated demand reductions are penalized financially. The question of who bears this risk and responsibility (the EDC or the program participant) is challenging from a policy standpoint.

Section 2.2.1 discusses a specific type of wholesale recognition, Price Responsive Demand (PRD), that has historically attracted load reductions primarily from the residential sector. Most of the general challenges with formal wholesale recognition also apply to PRD, but the PRD mechanism has some unique features that merit a separate discussion.

The demand resource, or shadow DR, pathway avoids the administrative issues discussed above but is not without its own challenges. DR programs that operated during Phase I and Phase III of Act 129 leveraged the demand resource pathway. Under this recognition pathway, demand response programs target reductions during high system load hours, which drive peak load forecasting and cost allocation. Consider an EDC with a 5,000 MW summer peak zonal load. If the EDC dispatches 100 MW of unrecognized DR each hot summer day for several years, the econometric load forecast used by PJM will start to view that zone as a 4,900 MW system in the summer, and the ratepayers will experience the cost savings associated with a 100 MW lower capacity obligation. Practically speaking, the goal of this type of DR program is to reduce load during the five coincident peak (5CP) load hours. Under this recognition pathway, the value of DR is derived from its ability to reduce future capacity obligations. To be beneficial, this pathway requires EDCs to call events. If DR event calls successfully hit the 5CP hours, program participants will be assigned a lower peak load contribution (PLC) and reap the associated reduction in their retail energy costs. In fact, some savvy customers engage in this type of peak-shaving behavior absent programmatic encouragement.

Valuation is significantly more complex under a shadow DR design and requires assumptions about the impact of observed reductions on future peak load forecasts. Modeling efforts from the Phase IV DR potential study showed that this relationship is less than 1:1, meaning a 1 MW reduction in peak demand lowers the peak demand forecast for the zone by less than 1 MW. Under this design some level of derate is needed, but the exact impact and the number of years that impact persists is challenging to estimate. The other key complexity with this recognition pathway is that, historically, the EDCs have had to initiate DR events rather than taking dispatch instructions from PJM. By extension, this means the Commission must carefully define in its Phase V Implementation Order the following program parameters:

- The mechanism that triggers DR events
- The duration of DR events
- The number of events called per summer, per winter, or per year
- How much notice will participants be given prior to an event

Alternatively, the Commission could direct the EDCs to define these parameters in their Phase V EE&C plans. However, because each parameter directly impacts the amount of DR potential available and the cost to acquire it, this could create a disconnect between the assumptions used to set targets and the specifics of an EDC's program design.

In the Phase IV DR potential study, the SWE modeled a formally coordinated demand resource mechanism that leveraged the PSA mechanism developed by PJM in 2019. The PSA mechanism allows EDCs to formally declare their demand resources and have them directly reflected in regional planning parameters. Importantly, the PSA mechanism does not allow dual enrollment of sites with supply commitments, and thus significantly reduces DR potential in the Large C&I sector. The PSA mechanism also faces many of the same timeline challenges as formal recognition of DR as a supply resource because PJM planning occurs three years ahead of each delivery year. Since Act 129 planning and funding occurs in phases, EDCs will typically lack the regulatory certainty in time to put forth resources in the early delivery years of an Act 129 phase.

The demand resource pathway is not unlike the way most coincident demand reductions from EE are considered within Act 129. Aside from a small portion of Phase IV demand reductions which were nominated at PJM, demand reductions from EE are assumed to be incorporated in PJM peak load forecasts and lower future capacity needs over the useful life of the equipment. One option for Phase V DR is to focus on daily load-shifting resources for DR rather than event-based resources. This eliminates the risk of dispatching on the incorrect day and makes the demand impacts of DR programs essentially interchangeable with coincident demand reductions from EE. If DR programs shift customer load daily, then there is a much higher chance that the EDC will have a lower load during the 5CP hours and other top load days and will receive a lower capacity obligation. This pathway would avoid the need to derate resources based on dispatch frequency, as well as allow administrative flexibility for program operations that are not currently allowed through the PSA pathway.

Daily load-shifting programs also come with the advantage of seasonal flexibility. Currently, PSA programs in PJM are only considered for their effects in the summer season. Programs that target demand reductions in the winter months are not able to be valued at all through this mechanism. While this would not have been an issue in past phases of Act 129, which only targeted demand reductions during the summer, it could pose a complication for Phase V of Act 129. In the 2026 TRM Final Order,[17] the Commission chose to bifurcate the Act 129 peak demand definition to include both summer peak and winter peak. This means that the Implementation Order for Phase V may include both summer and winter peak demand reduction targets. While no formal decisions have been made on which seasons to target for demand reductions, daily load-shifting programs, unlike PSA-based programs, would allow for seasonal flexibility to meet those targets.

In addition, daily load-shifting programs remove EDC uncertainty about the number of events or when events will be dispatched. The number of performance days and hours is known in advance simply by counting the number of non-holiday weekdays in the season, as the resources are dispatched every day during their targeted seasons. A daily load-shifting design could also complement time-of-use (TOU) rates if they become more widespread in Pennsylvania. Programmatic interventions that encourage customers to shift consumption away from peak periods are conceptually similar to a TOU rate with a higher volumetric rate during peak periods and a lower volumetric rate off-peak.

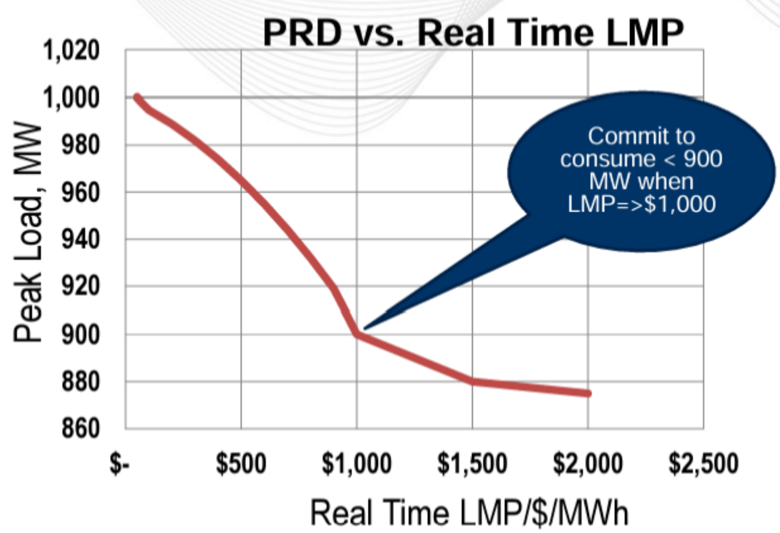
However, there are some drawbacks that accompany daily load-shifting. First, there is a real threat of customer fatigue if the reductions are too severe, or the disruption is too great. Second, the impacts would be more challenging to measure because there are no adjacent non-event days to use as a baseline. Third, attribution of impacts between Act 129 programs and TOU rates would be challenging if homes or businesses enrolled in both an Act 129 DR program and a TOU rate.

2.2.1 PRICE RESPONSIVE DEMAND

PRD is a specific type of wholesale recognition that captures the expected response of retail customers to wholesale prices. It requires the PRD provider, typically the EDC, to have automation in place to orchestrate response to real-time Locational Marginal Prices (LMPs). PRD providers that commit capacity must detail a price-responsiveness plan to reduce energy use by a defined amount in response to prices. Figure 7 shows an illustrative PRD "price curve" from PJM training materials.[18]

[17] See 2026 TRM Final Order at Page 7-8. Weblink
[18] Price Responsive Demand Overview and DR Hub Implementation. Weblink

Figure 7: Illustration of PRD



Load that will automatically respond to energy prices and be off the grid during a PJM emergency will receive a lower capacity requirement.

Prior to each BRA, PRD providers also submit a PRD election that indicates the nominal PRD value in MWs that the PRD provider is willing to commit at different reservation prices ($/MW-day). Once the BRA occurs and the clearing price is established, the PRD commitment becomes binding. PJM credits the provider at the cleared PRD the adjusted zonal clearing price of the zone in which they cleared. The PRD credits are charged to the load of those zone(s) by inclusion in the RPM net load price. PRD providers are required to decrease load to, or below, the agreed-upon service level when an Emergency Action is triggered or LMPs exceed the price threshold.

A total of 210 MW of PRD cleared in the 2025/2026 BRA, all of it located in the Pepco, BGE, and DPL zones, and predominantly coming from the state of Maryland.[19] PRD requires customers to face a dynamic retail rate, or a contractual arrangement linked to PJM real-time LMP triggers. Maryland electric utilities BGE, Pepco, and Delmarva rely on the latter option by offering "peak time rebate" programs, where residential customers receive a bill credit if their usage during performance hours is lower than the baseline calculated from recent similar days. Customers are enrolled in the program by default but can opt out if they wish. If a home does not voluntarily lower its usage and their consumption is higher than their baseline, no bill credit is issued for that day. Duquesne recently added an opt-in peak time rebate rider that is branded the Residential Behavioral Load Management Pilot. The Duquesne pilot is open to up to 7,500 customers. Participants will be notified of an event in advance and can earn per kilowatt-hour (kWh) incentives if their consumption during an event is lower than their baseline.[20] The Duquesne peak time rebate offering is not recognized as PRD by PJM.

The SWE explored the PRD mechanism and does not recommend it as a wholesale recognition strategy for Phase V for several reasons:

[19] 2025/2026 Base Residual Auction Report. Weblink. Page 14.
[20] Duquesne Light Schedule of Rates. Weblink Page 57

- The same timing considerations that create challenges for Emergency and Pre-Emergency Load Response DR participation at PJM also apply to PRD. In a normal BRA schedule, PRD plans are due 3.5 years prior to the beginning of a delivery year. Under the status quo Act 129 phase planning cycle, an EDC would not have an approved EE&C plan in time to register PRD resources for the initial years of a phase. Similarly, EDCs would not have the certainty of an Implementation Order and approved EE&C plan to register PRD beyond the end of a current phase. The Commission could potentially provide some form of cross-phase certainty with respect to cost recovery, but to date each Act 129 phase has remained an isolated effort.

- PRD cannot be uncommitted or replaced by another available resource and there are penalties for non-performance. Like the capacity DR options discussed in Section 2.2, this raises administrative questions about risk-sharing between the EDCs and participants.

- Time-varying rates are still relatively uncommon for residential customers in Pennsylvania. While Act 129 required EDCs to submit one or more proposed time-of-use rate and real-time price plans by January 1, 2010, very few residential households in the Commonwealth currently face a dynamic retail rate. This is further complicated by competitive electric supply. According to EIA Form 861 data for 2023, over 1.2 million residential customers of the EDCs subject to Act 129 take delivery only from the EDC and take electric supply from a different provider.[21]

- Costs are predominantly volumetric, meaning that the cost of operating the program each year depends on how many events are called. This uncertainty would create budget challenges for EDCs because the cost of the program might swing considerably from year to year, depending on the number of event calls.

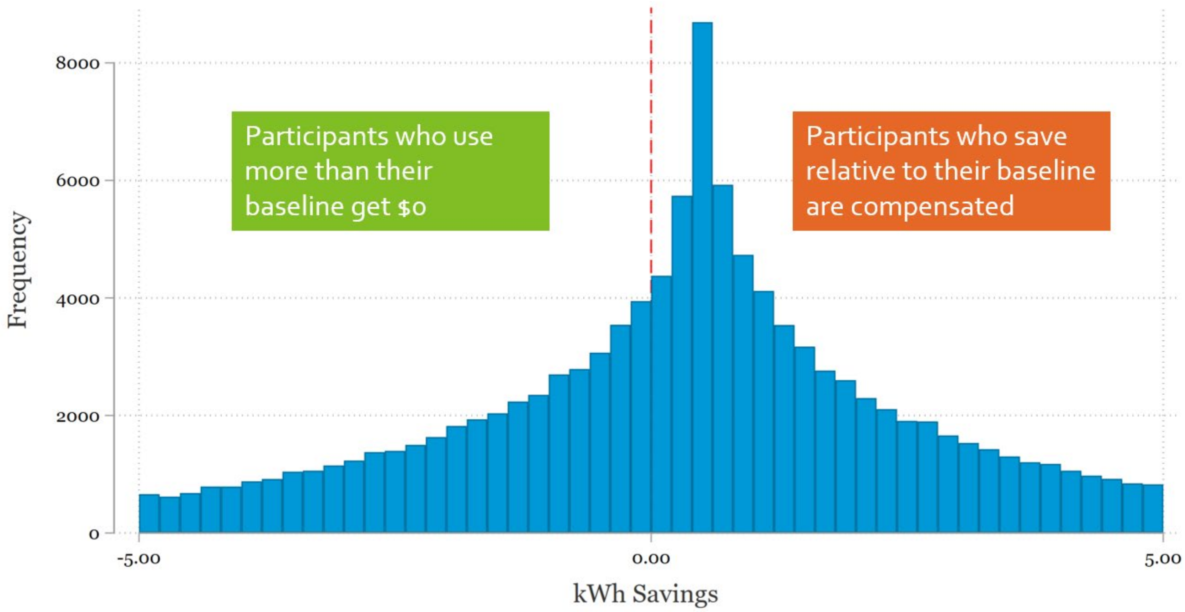
- PRD must be managed by pricing point or substation. This means an EDC might need to dispatch participants in one area of its service territory, but not others. Historically, the EDCs have unanimously opposed spatial targeting or locational differentiating within their Act 129 programs.

- Without widespread dynamic pricing, EDCs would need to offer peak time rebate programs to satisfy the price responsiveness requirement of PRD. While peak time rebate programs are attractive to customers because there is no risk of bill increases, the payment asymmetry makes them economically inefficient. Because settlement occurs at the individual customer level, the performance estimates are inherently noisy. Zeroing out this noise so that participants can only receive credits or no payment, biases the measurement and leads to program costs that far exceed the actual impact. Figure 8 shows a simulated distribution of peak time rebate load impacts across many homes. The mean savings are 0.3 kWh over a four-hour period. The mean allows negative and positive impacts to cancel out and converge on the central tendency. However, because payment is asymmetrical and

[21] EIA Form 861 Sales to Ultimate Customers Report 2023. Weblink

negative impacts are zeroed out for settlement, the average impact used for settlement is 0.97 kWh. This means an EDC will pay for approximately three times the aggregated load impact that the program actually delivers. The payment asymmetry issue is particularly acute with default enrollment because the average impact is so close to zero.

Figure 8: Distribution of Peak Time Rebate Settlement Impacts



2.3 DATA AND METHODOLOGY

Each of the potential pathways to wholesale recognition could create economic benefits for Pennsylvania ratepayers from DR activities. Choosing the best pathway requires analysis of many factors that affect DR performance and alignment with other Act 129 activities to maximize these benefits. Due to the administrative challenges associated with supply side DR resources in PJM, this section focuses only on potential demand resource (shadow DR) program designs.

This section details the analysis of DR program design factors through a simulation. The goal of the simulation was to understand the effectiveness of the many different DR program designs available. This was done by varying a set of program parameters and simulating the event outcomes if those parameters had been used to call DR events over the last 13 years (from 2011 – 2023). The set of parameters used in the simulation included:

- **Dispatch Trigger**: Weather versus Daily
  - Weather dispatch triggers decide whether to initiate an event based on expected seasonal weather variables by load zone.
  - Daily dispatch triggers initiate events in each day of the DR season regardless of expected weather.
- **Event Start Time**: The time that events start on event days.
- **Event Duration**: The duration of events on event days.

- **Program Operation Period**: Set of months that define the operations season for DR programs.

The weather data for event triggers uses the zonal weather station weights derived from the PJM Load Forecast Supplement.[22] The SWE calculated the THI and the Winter Weather Parameter (WWP) for the summer and winter months respectively in each hour of every year. The THI variable accounts for both dry bulb temperature and humidity levels and is highly correlated with summer loads. WWP on the other hand, accounts for both dry bulb temperature and wind speed. The WWP variable is essentially a measure of temperature and wind chill, which has a high negative correlation to winter loads. The load data, spanning from 2011 to 2023, for the simulations, was retrieved for each zone from PJM Data Miner 2.[23] The SWE also collected the forecasted system peak load for each zone and the 5CP days and hours from PJM.[24] PJM zones and EDC service territories are highly related, but not interchangeable. Table 9 maps the seven legacy EDCs subject to Act 129 to the relevant PJM zones. This study presents consolidated results for the FirstEnergy EDC, but this portion of the analysis considered the legacy FirstEnergy EDCs separately as they each fall into different PJM zones.

Table 9: Mapping Table of EDC Territory to PJM Zone Mapping

EDC	PJM Zone	Notes
PECO	PE	
PPL	PL	
Duquesne	DUQ	
Met-Ed	METED	PJM zones also include some small co-op and municipal utility load
Penelec	PN	
Penn Power	ATSI	Most American Transmission Systems, Inc. (ATSI) load is in Ohio. Penn Power is a small subset of ATSI load
West Penn Power	APS	Allegheny Power System (APS) zone also includes areas of Maryland and West Virginia served by FirstEnergy

In all figures included in this report, hour values are presented in hour ending format. This means hour 1 represents the period from midnight to 1:00 am. Table 10 provides a legend to facilitate interpretation of the hour ending time convention. Time is also always listed presented in Eastern Prevailing Time. This means that in the winter, time is in Eastern Standard Time (GMT-5) and in the summer, time is in Eastern Daylight Time (GMT-4).

[22] *See* Weblink. Page 9
[23] *See* Weblink.
[24] *See* Weblink.

Table 10: Hour Ending Time Convention

Hour	Definition	Hour	Definition	Hour	Definition
1	Midnight to 1:00 am	**9**	8:00 am to 9:00 am	**17**	4:00 pm to 5:00 pm
2	1:00 am to 2:00 am	**10**	9:00 am to 10:00 am	**18**	5:00 pm to 6:00 pm
3	2:00 am to 3:00 am	**11**	10:00 am to 11:00 am	**19**	6:00 pm to 7:00 pm
4	3:00 am to 4:00 am	**12**	11:00 am to Noon	**20**	7:00 pm to 8:00 pm
5	4:00 am to 5:00 am	**13**	Noon to 1:00 pm	**21**	8:00 pm to 9:00 pm
6	5:00 am to 6:00 am	**14**	1:00 pm to 2:00 pm	**22**	9:00 pm to 10:00 pm
7	6:00 am to 7:00 am	**15**	2:00 pm to 3:00 pm	**23**	10:00 pm to 11:00 pm
8	7:00 am to 8:00 am	**16**	3:00 pm to 4:00 pm	**24**	11:00 pm to Midnight

To compare the multitude of potential program designs available, common metrics must be used to quantify program effectiveness. Ultimately, an effective DR program is meant to lower loads during times when the grid is most constrained, which is when resources are most valuable. In practical terms, for shadow DR programs, the goal is to lower future load forecasts at PJM. If the zonal load forecasts are lower, then overall cost to load is reduced. The SWE cannot directly model the load forecasting done at PJM, which means that proxy metrics must be used to quantify the extent to which different program designs are able to lower future load forecasts. For each program design scenario, the SWE-defined performance based on two criteria:

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.

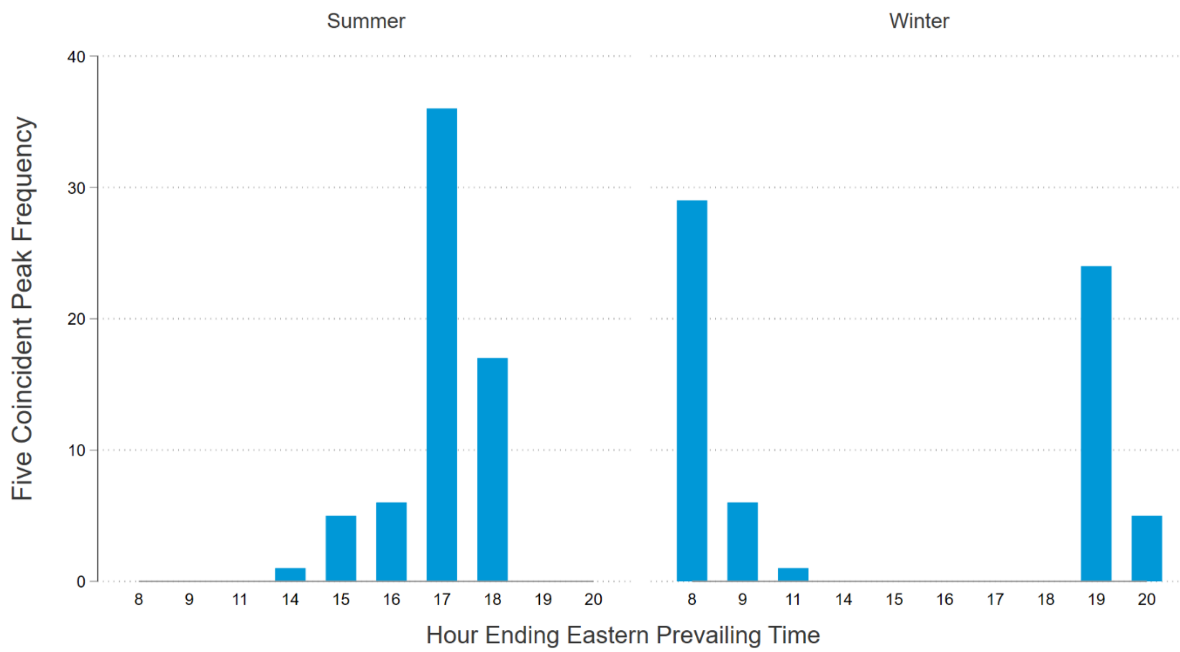
2) **Effective Load Carrying Capacity**[25] **(ELCC)** – A measure of the relative importance of hours of availability for DR dispatch. The SWE calculated the ELCC metric for this study as the percentage of target load that is captured by a simulated DR event. The target load is all demand above 90% of the forecast system peak for a given year and season. Thus, if the forecasted system peak for a zone in summer 2023 was 10,000 MW, any hour with more than 9,000 MW of demand would contribute to the target load for the summer DR programs. 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 SWE believes that these metrics adequately capture DR's ability to reduce PJM peak load forecasts and are directly comparable across all scenarios. The 5CP metric places more emphasis on correctly

[25] PJM uses the term Effective Load Carrying Capability to define a similar idea to the one described by Effective Load Carrying Capacity in this report. While the terms are not the same, they both are used to quantify the extent to which resources can serve load during the hours of highest need. *See* PJM Manual 20: Section 5. Weblink

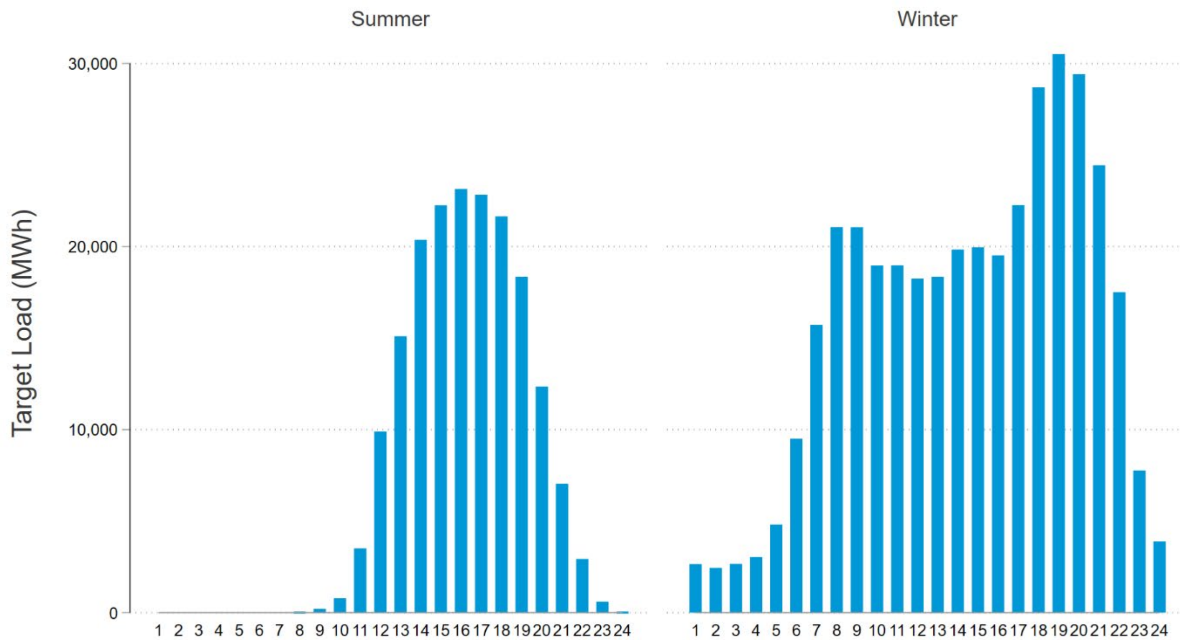
hitting the single hours of highest load, whereas ELCC is based on total target load covered. The 5CP metric also likely translates well to the participant's perceived value, because their consumption during the 5CP hours is often used to calculate their PLC and allocate capacity costs. Figure 9 shows the frequency at which certain hours are classified as 5CP hours over the simulated timeframe. There is a clear window of peak hours in the summer season, while the winter season window is split between the morning and evening hours.

Figure 9: Five Coincident Peak Frequency by Season and Hour Ending



The target load, described above, that is captured under the different program design scenarios contributes to the ELCC metric used to measure scenario performance. Target load represents load available for DR, not necessarily the peak shaving that would be achieved. The *captured load* is the sum of target load during all performance hours for that scenario. ELCC is then the ratio of captured load to total target load for each zone-year. Figure 10 shows the yearly average available target load by season and hour over the simulated timeframe. Because target load is a function of the seasonal load forecast, the generally flatter nature of winter load shapes leads to more target load being available for the winter programs.

Figure 10: Hourly Target Load by Season and Hour Ending



The SWE ran simulations for all seven legacy EDCs, varying each of the parameters and evaluating the performance of the different event scenarios in both summer and winter using the average performance across each EDC. To limit the number of possible scenarios and focus efforts on the most realistic designs, the simulation was restricted to scenarios with 24 or fewer performance hours per season when using weather dispatch triggers, or a total of four or fewer performance hours per day for daily dispatch.

For each scenario, days were first flagged as event days based on the dispatch trigger being tested. For daily dispatch, this meant that each non-holiday weekday of summer and winter season was tagged as an event day. For weather-based dispatch in the summer, each day with a maximum THI value above the scenario threshold was flagged. In the winter, each day with a minimum WWP value below the scenario threshold was flagged. For each flagged event day, the event start hour and event duration parameters of the scenario dictated the performance hours.

Table 11 shows the summer DR program parameters and their value ranges which were simulated. The THI variable accounts for both dry bulb temperature and humidity levels and is highly correlated with summer loads. Using a higher THI value as an event dispatch trigger will correspond to fewer summer events.

Table 11: Summer DR Program Simulation Parameters

Parameter Name	Description	Value Range		
		Minimum	Interval	Maximum
Dispatch Trigger	Weather Dispatch: Value of the daily maximum THI at which a DR event will be triggered.	75	0.5	85
	Daily Dispatch: DR events triggered on each eligible day.	-	-	-
Event Start Time	What time will the event start?	12:00 pm	1	5:00 pm
Event Duration	How long does each event last (in hours)?	2	1	5
Program Operation Period	Set of months that define the operations season for DR programs?	June-August	-	June-September

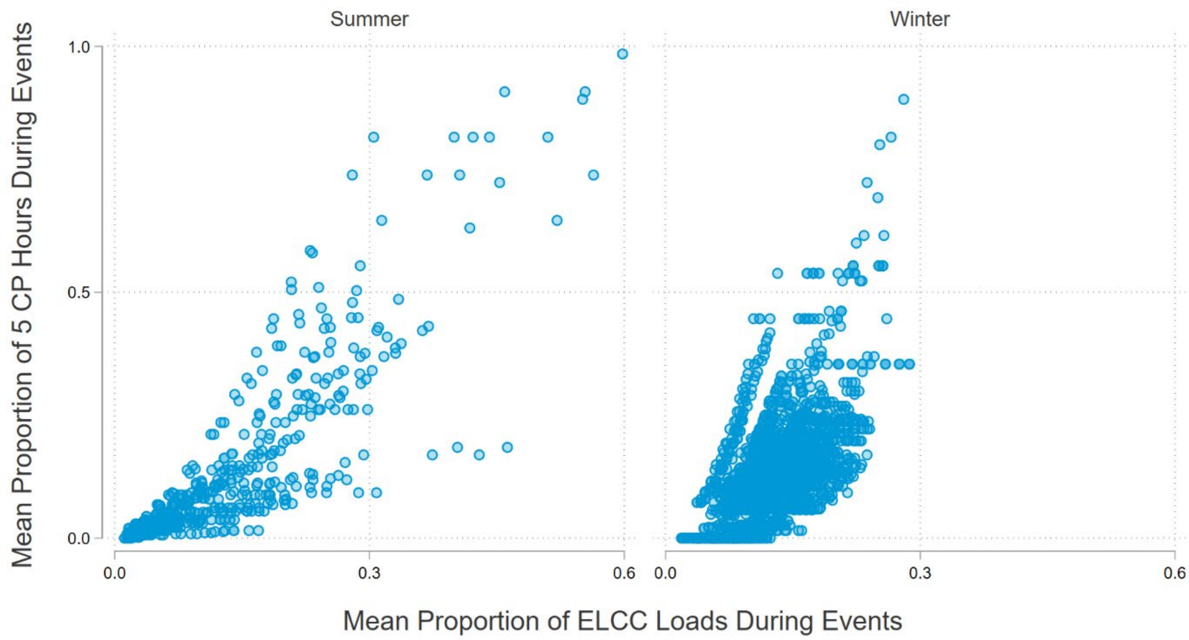
Table 12 shows the winter DR program parameters and their value ranges, which were simulated. WWP on the other hand, accounts for both dry bulb temperature and wind speed. The WWP variable is essentially a measure of temperature and wind chill, which has a high negative correlation to winter loads. Using a lower WWP value as an event dispatch trigger will correspond to fewer winter events. Historically, in winter, the 5CP and high load periods are spread across a wide range of hours in both the morning and evening hours. This means that a winter program design, which only allows for a few consecutive hours per day to be controlled, will be less likely to hit those high-value hours. In an attempt to hit the highest-value hours possible, the simulation allows for "split" events in the winter, meaning that performance hours on an event day do not have to be continuous and can be split into two groups. For example, there could be performance hours from hours ending 8 and 9 in the morning and the hours ending 19 and 20 in the evening of the same day. These split events must still be under four hours of total control in a single day for daily dispatch.

Table 12: Winter DR Program Simulation Parameters

Parameter Name	Description	Value Range		
		Minimum	Interval	Maximum
Dispatch Trigger	Weather Dispatch: Value of the daily minimum WWP at which a DR event will be triggered.	0	1	20
	Daily Dispatch: DR events triggered on each eligible day.	-	-	-
Event Start Time 1	What time will the first event window start?	5:00 am	1	10:00 am
Event Start Time 2	What time will the second event window start?	4:00 pm	1	8:00 pm
Event Duration	How long does each event last (in hours)?	2	1	4
Program Operation Period	Set of months that define the operations season for DR programs?	January-February	-	December-February

Figure 11 shows a scatter plot of the simulation event performance for all scenarios by season. Each dot represents the simple average yearly performance across the Pennsylvania EDCs in a single simulation. Outcomes closer to the top right side of the figure mean that the set of program parameters led to capturing a greater share of high-value hours. There is a wide range of outcomes for 5CP in both summer and winter. ELCC also varies substantially by scenario in summer, but in winter it is relatively low overall and more tightly grouped. Generally, the simulations perform better on the 5CP metric than ELCC on average. Due to the wider range of hours covered by the ELCC target load, it is more difficult to capture than the 5CP hours. Both metrics are just proxies for grid and program value. While they are generally correlated with each other, some designs favor one or the other. There are, however, some clear scenarios of program parameters that outperform others. The effects of varying each program parameter individually will be explored in the following sections.

Figure 11: EDC Average 5CP versus ELCC by Season



2.3.1 Dispatch Trigger

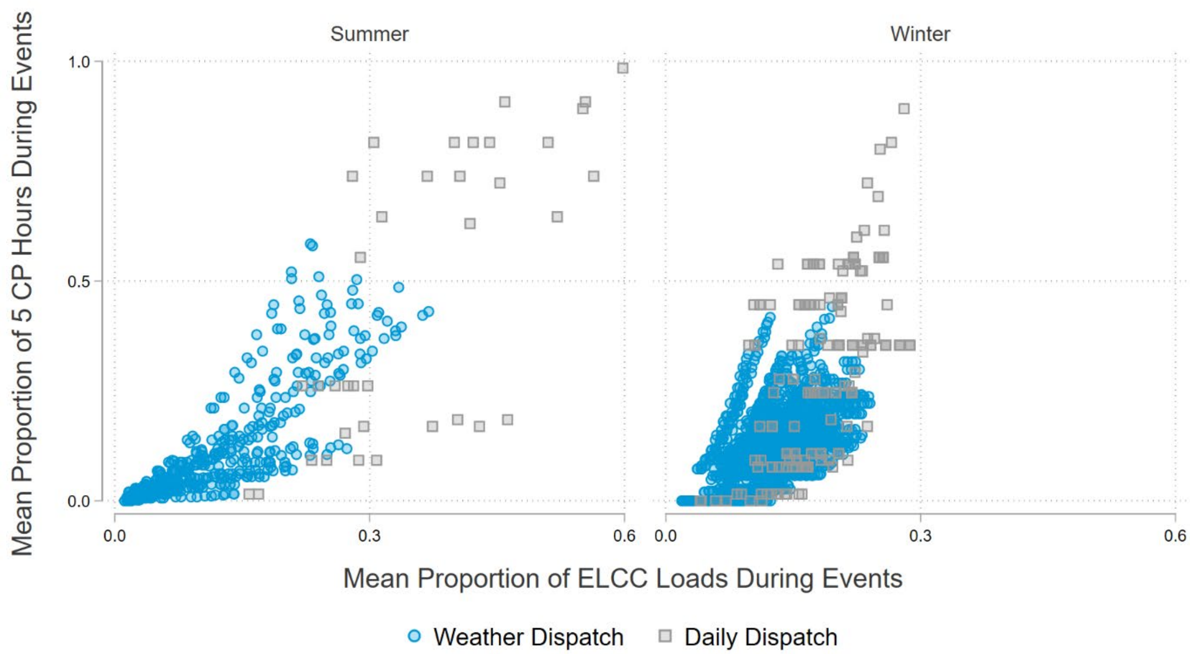
The dispatch trigger parameter varies the mechanism used to decide which days should be event days in the simulation. The two categories for this parameter are weather dispatch and daily dispatch. The weather dispatch trigger determines whether each day should be an event day, based upon a seasonal weather variable that is calculated separately each day for each EDC's load zone. In the summer, the weather dispatch trigger was based on the daily maximum THI for the zone. If the daily maximum THI was above the threshold set by the simulation, then an event was called for that zone on that day. In the winter, the weather dispatch trigger was based on the minimum WWP for the zone. If the daily minimum WWP was below the threshold set by the simulation, then an event was called for that zone on that day. In total, 20 different weather variable thresholds were tested for both summer and winter events.

Daily dispatch triggers, instead, assume that each non-holiday weekday of the season will be an event day with events starting and ending at the same time each day of a given scenario. This approach allows for simplifications to both program administration and planning. The program will incentivize participants to reduce loads on each day of either the summer or the winter, with clear advance notice on exactly which days and hours will be considered performance hours.

The effectiveness of DR programs in reducing peak loads is constrained by practical considerations, which limit the total number of performance hours a program should call in a season. For weather-based dispatchable programs, many DR events could exhaust budgets, and participants may suffer event fatigue if called repeatedly or for long durations. Weather based dispatchable events are more burdensome for participants to plan for due to the uncertain nature of dispatches across the season. Daily dispatch programs suffer less from this issue, due to the ability for participants to plan for daily events more easily, but there are still the same practical considerations of budgets and participant fatigue present.

Figure 12 shows the average 5CP and ELCC performance for each season, for both the weather dispatch trigger and daily dispatch trigger simulations. Each dot represents the average yearly performance across the EDCs in a single simulation.

Figure 12: EDC Average 5CP versus ELCC by Season and Dispatch Trigger



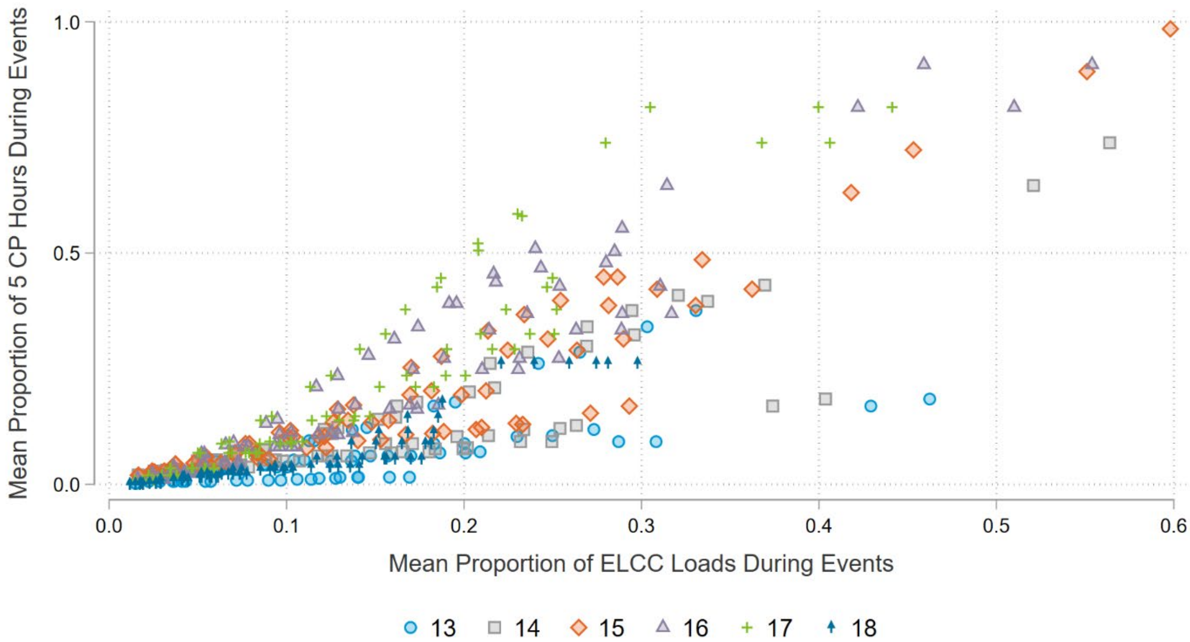
Unsurprisingly, based on the number of performance hours in the summer, the daily dispatch trigger strategy outperforms the weather dispatch triggers in hitting the 5CP days as well as capturing the high-value ELCC hours. PJM 5CP and ELCC hours tend to be tightly concentrated in a few afternoon hours during the summer season, and if events are called each day during that time, there is a very high chance that the program will be controlling during the most important hours.

The daily dispatch trigger is also more effective than a weather-based trigger in the winter, but to a lesser extent. Historically, in winter, the 5CP and high-value ELCC hours are spread across a wide range of hours in both the morning and evening. This means that a program design that only allows four hours per day to be controlled will be unable to capture many high-value hours.

2.3.2 Event Start Hour

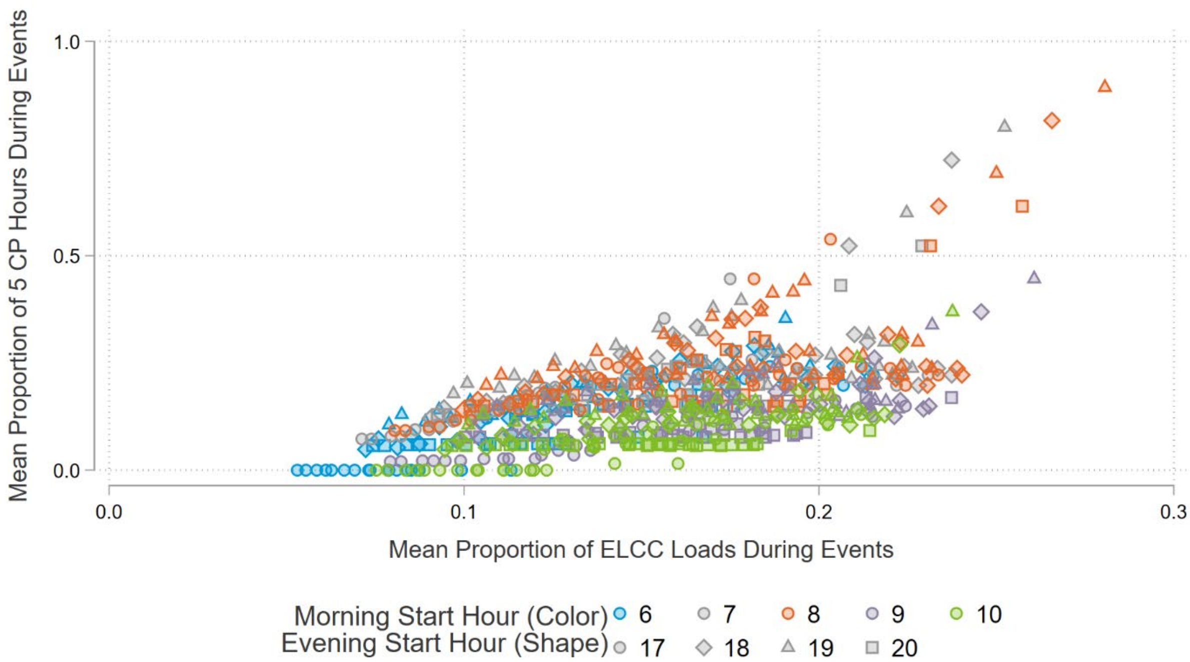
The event start hour dictates the time on event days when participants are instructed to begin load reduction. As expected, the optimal start hour depends on the event duration, but there are still some start times that clearly allow for better event performance than others. Figure 13 shows the average EDC event performance for the summer season by event start hour. The top performing simulations, those in the top right of the figure, start in hour ending 14, 15, and 16.

Figure 13: EDC Average Summer 5CP versus ELCC by Event Start Time



Winter events are allowed to be split between the morning and evening hours. This means that, on event days, there could be performance hours in both the morning and evening. If split events are not allowed, the dual-peaking nature of the winter season makes it difficult for any program design to capture a high number of valuable hours. Figure 14 shows the results of the winter program simulations, split by morning and evening event start times. The morning event start time is indicated by the color of the dot, while the evening event start time is represented by the shape. The best-performing set of start times is hour ending 8 in the morning and hour ending 19 in the evening.

Figure 14: EDC Average Winter 5CP versus ELCC by Event Start Time



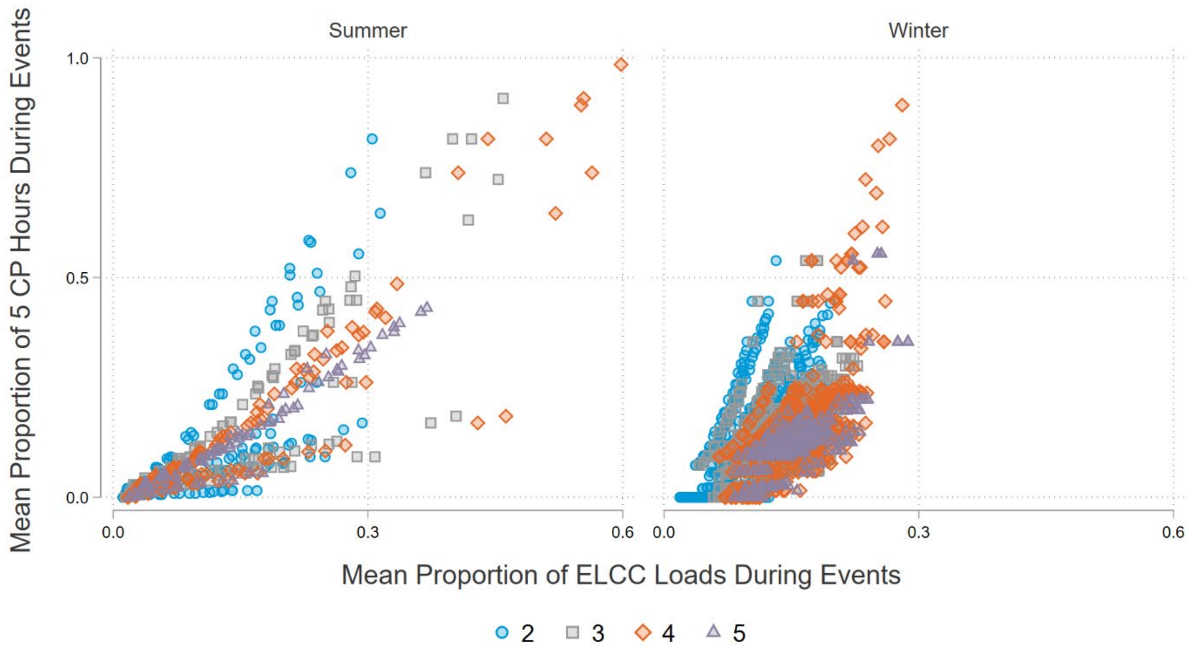
2.3.3 Event Duration

The most effective event duration for each season varies mostly based on the dispatch trigger. If simulating a daily load-shifting program, the optimal event duration for any given start hour is four hours, the longest allowed in the simulation. This is because, in the model, there are no trade-offs when going from two-hour to three-hour or three-hour to four-hour events for daily designs. If the events are called for longer periods, they will always capture at least as many, if not more, high-value hours than when they are called for shorter periods, when looking at daily dispatch.

Weather-based dispatch, however, does come with a trade-off. Because the simulation model caps average yearly performance hours at 24 when using weather dispatch, increases in event duration can sometimes push certain scenarios over the hours cap. When this happens, that scenario is no longer considered as an option. This means that there is a trade-off between event duration and program viability for program designs with a weather-based trigger.

Figure 15 shows simulation outcomes by season and event duration. In both summer and winter, the four-hour event duration performs the best. This is mostly attributed to the four-hour cap on the daily dispatch designs. All the five-hour event duration scenarios use a weather-based dispatch but capture fewer of the high-value hours due to the yearly performance hour cap.

Figure 15: EDC Average 5CP versus ELCC by Season and Event Duration



2.3.4 PROGRAM OPERATION PERIOD

The Program Operation Period parameter dictates the months during which the simulated DR programs are active. For summer programs, this can be either June – August or June – September, while winter programs can be either December – February or January – February. Increasing the operation month windows can increase the amount of 5CP hours and ELCC load available for control, but that comes at the expense of an increase in overall program performance hours.

Figure 16 shows the simulation results for summer by program operation period. Generally, including September in the DR program season improves performance. The differences are more significant for the ELCC metric than the 5CP metric because, historically, relatively few 5CP hours have occurred in September. That said, including September does yield an increase in the average number of performance hours. The marginal increase in ELCC performance may not make the entire extra month of events worth it for program administrators or participants, especially without a large increase in the 5CP hours hit.

Figure 16: EDC Average Summer 5CP versus ELCC by Program Operation Period

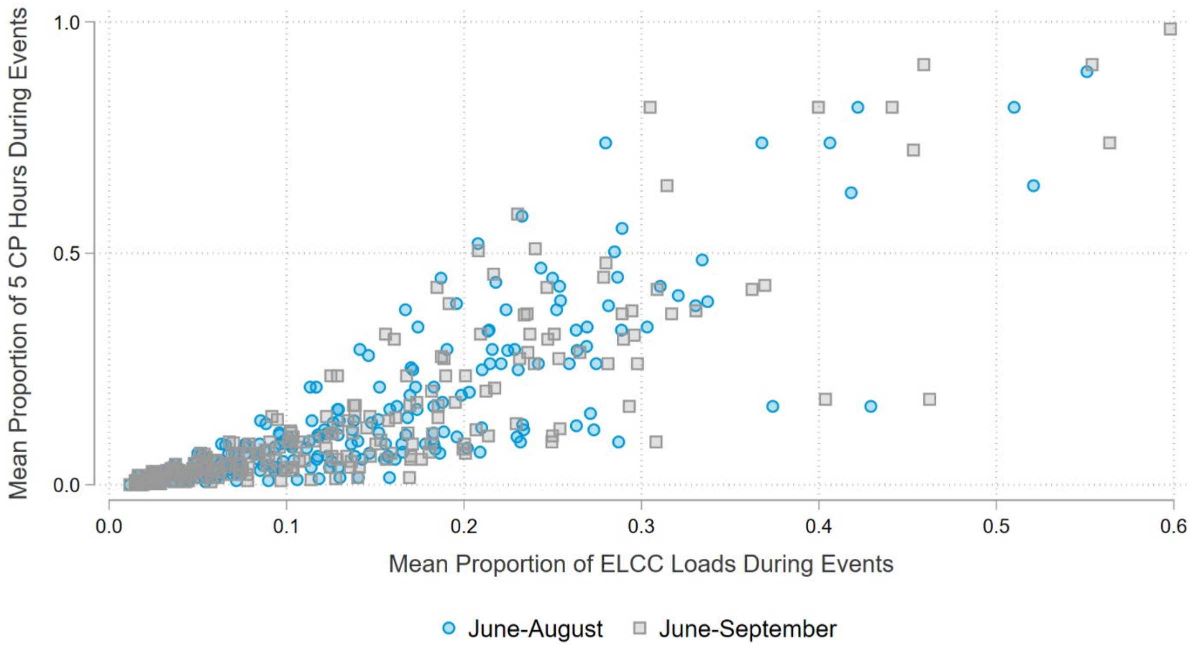
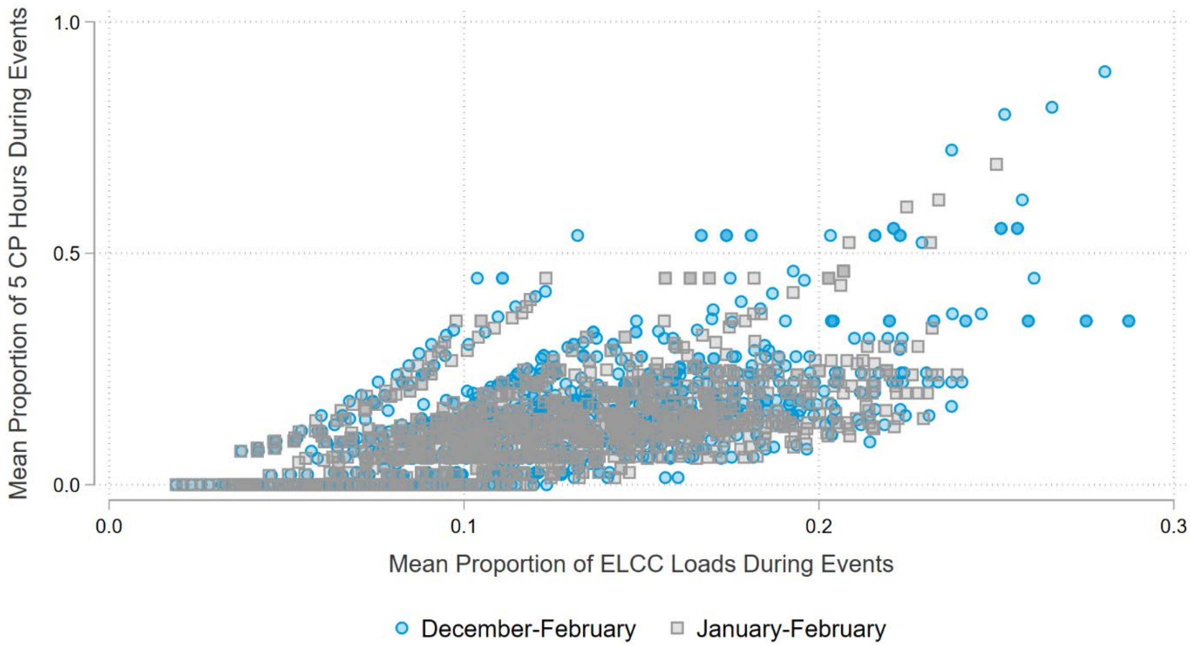


Figure 17 shows the simulation results for winter by program operation period. Like September in the summer season, including December in the DR program season improves performance. There are significant gains in both the 5CP and ELCC metrics when including the extra month in program operations. But there is a trade-off when including an extra month of program operations. A larger budget is required when operating a DR program for longer periods of time, and potentially poor participant experience can cause higher attrition rates. If a program design that relies on longer operations periods is chosen, the trade-offs will need to be carefully considered.

Figure 17: EDC Average Winter 5CP versus ELCC by Program Operation Period



2.4 RECOMMENDED PROGRAM DESIGN

The 5CP and ELCC metrics are both quantitative proxy metrics for the value of a DR resource. They are proxy metrics because the SWE cannot directly model how decreasing loads on these days would affect future peak load forecasts. While these quantitative metrics are helpful when considering different program designs, they do not tell the complete story. Administrative factors must also be considered for all Act 129 activities. All things being equal, a simple design is preferrable to a more complex design.

The dispatch trigger was the most influential program parameter in the simulations. Figure 12 shows the simulation outcomes split by season and dispatch trigger. The daily dispatch program designs outperform weather-based dispatch on both 5CP and ELCC metrics in most cases and produces all the highest performing designs. This is expected due to the number of hours covered by daily dispatch programs in comparison to weather-based dispatch programs. Daily dispatch program designs also come with several administrative advantages over weather-based dispatch programs. Because daily dispatch programs call events each day, there is no need to derate capacity benefits due to event uncertainty, as outlined in the 2026 TRC Test Order.[26] Choosing daily programs over dispatchable programs also removes the need for the administrative work of tracking dispatch triggers and event notification. Conversely, a daily design means high event frequency, so the load impact and enrollment assumptions must be lowered to reflect the fact that participants will experience close to 100 events annually.

[26] See 2026 TRC Test Final Order at Docket No. M-2024-3048998, entered November 7, 2024. Weblink. Page 89-93

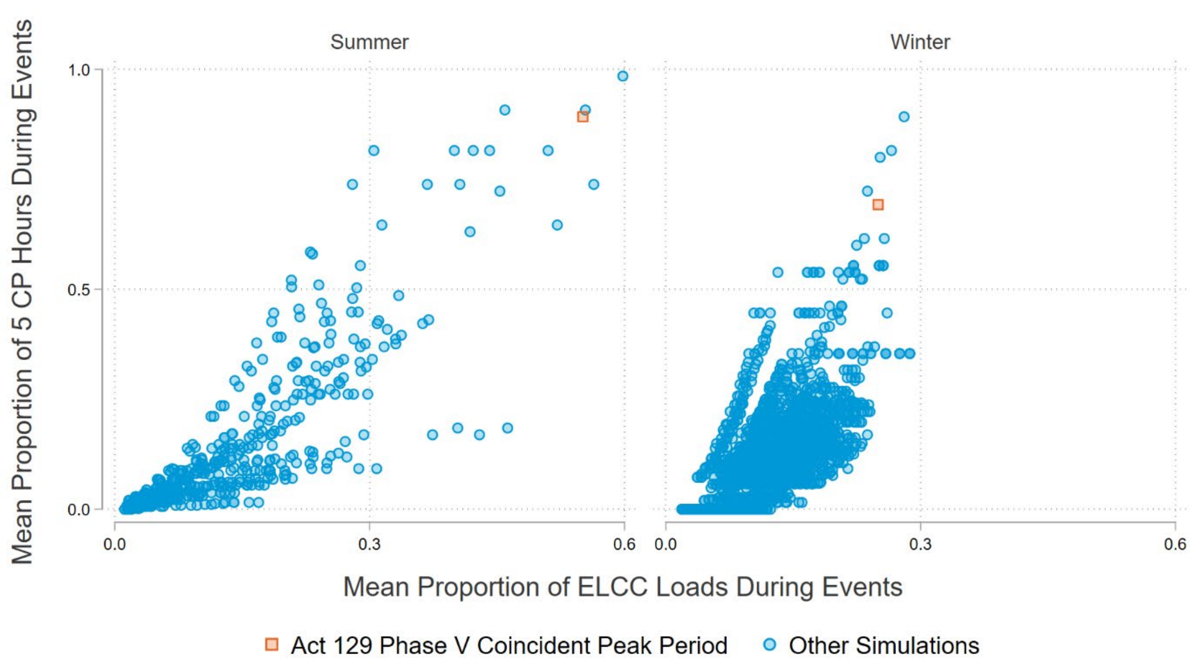
The Act 129 2026 TRM Volume 1[27] sets the definition for coincident peak demand savings for Phase V of Act 129 related activities. Table 13 shows the specific coincident peak period definitions laid out in the TRM. During Phase IV of Act 129 EDCs were only able to meet demand reduction goals through coincident demand reductions from EE. The SWE recommends that the Commission allow Phase V demand reduction goals to be satisfied through either coincident demand reductions from EE or demand reductions from daily load shifting. To facilitate flexibility and interchangeability EE&C program planning, aligning the DR performance definition with the coincident peak window defined in the 2026 TRM is desirable.

Table 13: Phase V of Act 129 Periods for Coincident Peak Demand Savings

Period	Summer	Winter
Months	June, July, and August	January and February
Day Types	Non-Holiday Weekdays	
Hour Ending (Eastern Prevailing Time)	15-18	8-9 and 19-20

The specific coincident peak performance windows defined in the 2026 TRM were among the daily dispatch trigger simulations roster. Figure 18 highlights the 5CP and ELCC performance of those specific program designs. They are near the top in performance among program designs for both the summer and winter.

Figure 18: EDC Average 5CP versus ELCC by Season for the Act 129 Phase V Coincident Peak Period



The SWE sees a clear administrative advantage in aligning a daily load-shifting DR program performance definition with the coincident peak definition for EE defined in the 2026 TRM. A common

[27] See 2026 TRM Volume 1 at Docket No. M-2023-3044491, entered September 12, 2024. Weblink. Page 10

definition for EE and DR would allow the Commission to set peak demand reduction goals that could be satisfied with either program type, thereby affording the EDCs considerable flexibility in their EE&C plan design process. Although the TRM peak demand window is based on PJM definitions for the capacity market and EE as a wholesale resource is no longer going to be allowed in the capacity market,[28] our simulations show that it is among the most effective designs according to the 5CP and ELCC metrics. Table 14 shows the recommended program design parameters for summer and winter.

Table 14: Recommended DR Program Design Parameters

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 Eastern Prevailing Time)	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

Both the summer and winter program designs assume performance on each non-holiday weekday for the duration of the program operation period. All DR potential modeling in this study is based on the recommended program design. The estimates of potential are a function of this design. The same program types would likely return different estimates of achievable potential and show different economics under an alternative design.

[28] *See* FERC filing. November 5, 2024. Weblink

3 PENNSYLVANIA PEAK LOAD FORECAST

System peak loads drive the costs of generation capacity and determine the need for expansion of transmission and distribution facilities. A successful Act 129 DR program will lower peak forecasts and, as a result, reduce the amount of generation capacity that must be secured by PJM on behalf of the EDCs. Pennsylvania has summer and winter peaking loads,[29] and PJM produces seasonal peak load forecasts for each zone. West Penn Power and Penn Power are subsets of broader PJM zones, so it was necessary to determine the EDC share of APS and ATSI zone served by these two legacy EDCs. Table 15 and Table 16 show peak load forecasts by EDC for summer and winter. In Phase V, all EDCs are expected to see a slight increase in peak demand during both summer and winter.[30] The peak load forecast for the consolidated FirstEnergy EDC is simply the sum of Met-Ed, Penelec, Penn Power, and West Penn Power. Table 16 shows winter peaks labeled by the year the winter begins, so the row where the year equals 2026 refers to the winter that begins in 2026 and ends in 2027.

Table 15: Summer Peak Load Forecast (MW) at System Level

Year	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	WPP	Statewide
2026	8,640	7,196	2,716	3,141	2,885	991	3,778	29,347
2027	8,679	7,218	2,727	3,205	2,892	993	3,873	29,587
2028	8,716	7,227	2,737	3,256	2,897	993	3,888	29,714
2029	8,754	7,241	2,754	3,323	2,903	995	3,900	29,870
2030	8,796	7,266	2,767	3,383	2,913	996	3,907	30,028
2031	8,852	7,306	2,787	3,454	2,930	997	3,912	30,238
2032	8,907	7,331	2,803	3,538	2,940	998	3,914	30,431
2033	8,972	7,357	2,826	3,620	2,955	1,001	3,922	30,654
2034	9,031	7,382	2,855	3,715	2,970	1,005	3,939	30,898
2035	9,113	7,427	2,888	3,824	2,996	1,011	3,959	31,218
2036	9,233	7,497	2,924	3,942	3,032	1,017	3,984	31,629
2037	9,326	7,567	2,962	4,077	3,072	1,025	4,000	32,029
2038	9,409	7,621	3,004	4,200	3,102	1,032	4,017	32,384
2039	9,519	7,687	3,050	4,343	3,137	1,040	4,040	32,816

[29] Summer peak loads typically occur in June, July, August. Winter peak loads typically occur in December, January, February.

[30] 2024 PJM Load Forecast Report. Weblink.

Table 16: Winter Peak Load Forecast (MW) at System Level

Year	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	WPP	Statewide
2026	6,616	7,353	2,001	2,799	2,815	875	3,470	25,930
2027	6,664	7,379	2,016	2,859	2,820	880	3,635	26,253
2028	6,729	7,425	2,035	2,946	2,836	886	3,735	26,593
2029	6,733	7,395	2,046	2,987	2,828	888	3,745	26,622
2030	6,768	7,400	2,056	3,054	2,826	889	3,752	26,745
2031	6,812	7,421	2,075	3,122	2,837	891	3,766	26,925
2032	6,878	7,444	2,095	3,210	2,862	895	3,780	27,164
2033	6,916	7,449	2,114	3,281	2,859	897	3,786	27,302
2034	6,967	7,450	2,133	3,365	2,869	900	3,795	27,479
2035	7,026	7,477	2,159	3,464	2,886	905	3,811	27,728
2036	7,102	7,514	2,183	3,580	2,919	909	3,832	28,039
2037	7,152	7,546	2,212	3,672	2,926	913	3,841	28,262
2038	7,211	7,577	2,242	3,786	2,942	917	3,855	28,530
2039	7,285	7,617	2,270	3,912	2,967	923	3,875	28,848

Three important characteristics of the PJM forecasts are that: (1) they are at the zonal level; (2) they do not list EV, solar, and battery adjustments to winter peak; (3) they do not distinguish load by sector.

PECO, PPL, Met-Ed, Penelec, and Duquesne have dedicated PJM zones; however, some adjustments for load served by municipal and cooperative utilities were necessary. West Penn Power and Penn Power are subsets of broader PJM zones, so it was necessary to determine the EDC share of APS and ATSI zone served by these two legacy FirstEnergy EDCs. To calculate the Pennsylvania share of Penn Power, the SWE used the Penn Power-specific peak provided by FirstEnergy divided by the broader ATSI zonal peak from the PJM 2024 Load Forecast Report. The average share over 15 years (2024 – 2039) was calculated for both summer and winter, resulting in 7.97% for summer and 8.48% for winter. The SWE applied a similar approach to calculate the share for West Penn Power using West Penn Power-specific and broader APS zonal peaks. The average share over the same 15-year period (2024 – 2039) was 40.38% for summer and 36.94% for winter.

The DR potential study considers summer and winter separately. PJM lists EV, solar, and battery adjustments for summer peak but not for winter peak. The SWE assumed that solar and battery adjustments only applied to summer. To isolate EV adjustments from winter peak, the SWE employed a winter-to-summer ratio approach. By applying this ratio to the EV summer peak, the SWE calculated the winter adjustments. In an appendix to the 2024 Load Forecast Report, PJM released a forecast of EV counts by zone for 2024 – 2039, as well as normalized load shapes for 2024 and 2039 for Light-Duty Electric Vehicles (LDEVs) and Medium-Heavy Duty Electric Vehicles (MHDEVs) during the summer.[31] The SWE assumed that the winter load shape was identical to the summer load shape. Given the long-term nature of the projection, the SWE averaged the 2024 and 2039 load shapes to create a single load shape for all forecasted years. Based on the normalized load shape, the SWE calculated the ratio of average winter peak to average summer peak across peak hours for each vehicle type. However, this

[31] PJM Electric Vehicle Totals. February 2024. Link

ratio is unweighted, meaning it does not account for the different contributions of LDEVs and MHDEVs. To address this, the SWE first calculated total usage for EV charging by applying yearly vehicle miles traveled (VMT) and efficiency assumptions to the vehicle count forecasts from PJM. Since the VMT and efficiency assumptions used by PJM were not publicly available, the SWE assumed that an LDEV consumes 3,748 kWh/year and an MHDEV consumes 29,820 kWh/year. For LDEVs, counts were multiplied by 3,748 kWh/year assumptions, resulting in total LDEV usage per year. For MHDEVs, counts were multiplied by 29,820 kWh/year, resulting in total MHDEV usage per year. The SWE then applied the unweighted winter-to-summer ratio to the total usage for each vehicle type. By dividing the total usage with the unweighted ratio applied by the total usage of both vehicle types, the SWE obtained the weighted winter-to-summer ratio for each EDC and year. Finally, the SWE multiplied this weighted ratio by the EV adjustment for the summer peak to determine the EV adjustment for winter.

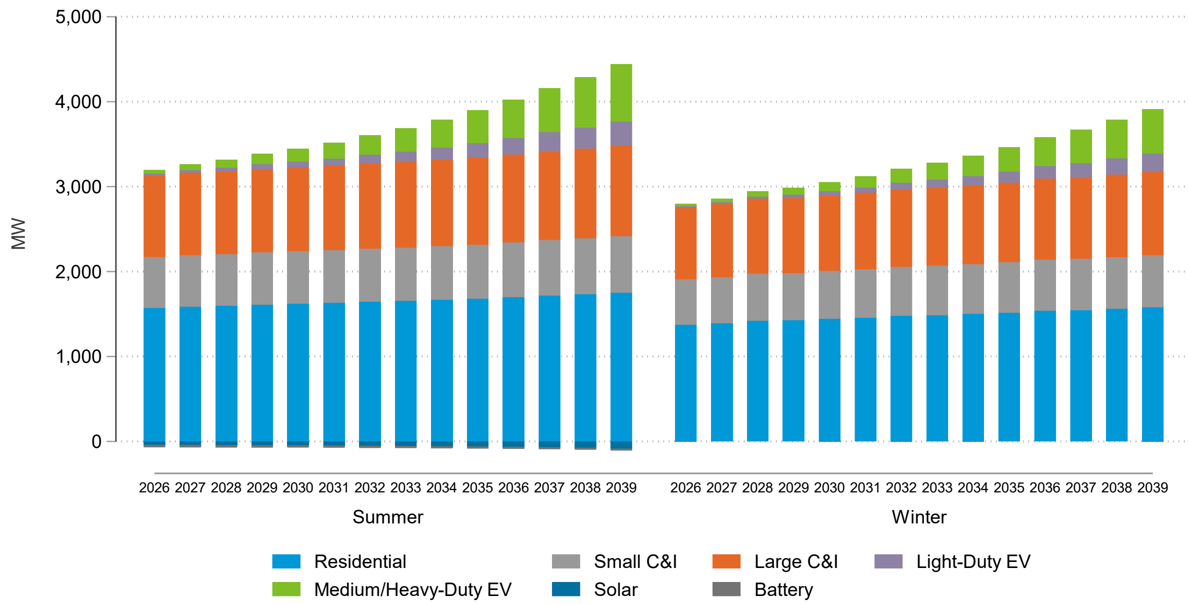
Disaggregation of native peak load forecasts to the sector level is an important precursor to the DR potential assessment. The native peak load forecast excludes data for EVs, solar, and batteries. Table 17 shows the percentage of the total system native load attributed to each customer class by season. The SWE developed these percentages using market data available to support the Commonwealth's Electric Generation Suppliers, customer level peak demand data provided by the EDCs in response to the SWE's baseline study data request, and discussions with EDC technical staff.

Table 17: Shares of Native Peak Load by Sector and Season

EDC	Season	Residential	SCI	LCI
PECO	Summer	50.41%	17.54%	32.05%
PECO	Winter	46.78%	18.60%	34.62%
PPL	Summer	43.81%	31.96%	24.23%
PPL	Winter	46.00%	30.99%	23.00%
Duquesne	Summer	37.80%	35.12%	27.08%
Duquesne	Winter	37.25%	34.36%	28.39%
Met-Ed	Summer	50.25%	19.10%	30.66%
Met-Ed	Winter	49.78%	19.37%	30.84%
Penelec	Summer	40.08%	24.51%	35.41%
Penelec	Winter	39.67%	24.76%	35.57%
Penn Power	Summer	48.69%	23.24%	28.07%
Penn Power	Winter	48.67%	23.60%	27.73%
West Penn Power	Summer	47.87%	20.94%	31.19%
West Penn Power	Winter	47.28%	21.58%	31.13%

By applying the shares associated with each sector to the forecasts, the SWE estimated the sector-specific peak load for each EDC and season. It is worth noting that this rests on the assumption that the growth rates are uniform across sectors. In other words, any load growth or decline is allocated according to the same percentages. Figure 19 provides an example using Met-Ed, illustrating the disaggregation of the total peak demand forecast across seven sectors.

Figure 19: Met-Ed Peak Forecast Demand by Sector



The original Act 129 legislation established Phase I peak demand reduction targets at 4.5% of the EDC peak loads from the June 2007 to May 2008 delivery year. Table 18 shows the values, by EDC, from that forecast. When DR potential estimates are shown as a percentage reduction, the convention in this report is to use the 2007 – 2008 peak demand values for ease of comparison with prior phases. These legacy values are lower than the contemporary summer peak demand forecasts shown in Table 15 and comparable to the contemporary winter peak demand forecasts shown in Table 16 at the statewide level.

Table 18: 2007-2008 Peak Demand Values Used to Establish Phase I Targets

EDC	Peak Demand (MW)
PECO	7,899
PPL	6,592
Duquesne	2,518
FirstEnergy	9,515
Statewide Total	**26,524**

4 ECONOMIC ANALYSIS OF DEMAND RESPONSE

Cost-effectiveness analysis in Pennsylvania is performed using the TRC Test. The SWE's assumptions are guided by the technical and policy directives in the 2026 TRC Test Order.[32] Table 19 provides an overview of the key cross-cutting modeling inputs and the sections that follow provide additional detail.

Table 19: Key Cross-Cutting Modeling Inputs

Modeling Input	Description
Peak Performance Hours	Aligned with the Act 129 peak demand definition for EE. Non-holiday weekdays in January, February, June, July, and August. Summer performance hours are 2pm – 6pm and winter performance hours are 7am – 9am and 6pm – 8pm.
Avoided Cost of Generation Capacity	Equal values for summer and winter ranging from $28/kW-season to $66/kW-season and averaging $49/kW-season. These values are inclusive of capacity DRIPE.
Avoided Transmission Capacity	Summer value ranges from $23/kW-season to $83/kW-season. Winter values are lower, averaging $10/kW-season with several EDCs having zero winter value.
Avoided Distribution Capacity	Generally higher in the summer than winter with values ranging from $12/kW-season to $81/kW-season. Not applied to the LCI sector.
Avoided Energy Costs ($/Megawatt-Hour or $/MWh)	The differential between the avoided cost of on-peak and off-peak energy. This equates to an average arbitrage value of $24/MWh in the summer and $12/MWh in the winter.
Discount Rate	5% nominal discount rate.
Line Losses	EDC-specific line loss factors are from the 2026 TRM. Line losses are not applicable to C&I Load Shifting as all modeling is done "top down" from system-level forecasts inclusive of losses.

Section 4.1 summarizes general considerations for the TRC Test perspective as it relates to DR. Assumptions about the supply costs avoided by DR are required to calculate benefits and to model the economics of DR. Section 4.2 provides an overview of the avoided cost assumptions used to model DR potential. Section 4.3 discusses the basis for assumptions about program delivery costs and incentive amounts, and Section 4.4 examines EDC budget considerations.

4.1 USING THE TRC TEST FOR DEMAND RESPONSE

The primary goal of the TRC Test is to assess whether the total economic benefits of a program outweigh its total costs. Unlike other benefit-cost tests that focus on specific stakeholders, the TRC Test considers the perspective of the Commonwealth as a whole. It accounts for all costs and benefits, regardless of who pays for or receives them. For DR, the primary costs are typically tied to program administration, participation incentives, and equipment and installation costs. Benefits primarily stem

[32] *See* the *2026 TRC Test Final Order*, Docket No. M-2024-3048998 (entered November 7, 2024) at Weblink.

from avoided capacity costs, but also include some avoided energy costs associated with shifting energy consumption from periods with higher marginal cost to periods with lower marginal cost.

Consistent with the 2026 TRC Test Order, this study calculated demand reductions during peak periods for summer and winter. As described in Section 2, this DR potential study for Phase V models a significant change from infrequent, event-based dispatch to a daily load-shifting model, managing load for each weekday during the summer and winter peak seasons. Because daily load-shifting aligns more closely with the coincident demand reductions seen in EE measures, the Commission directed in the 2026 TRC Test Order that no derate factor be applied to verified DR when estimating the capacity benefits of daily load-shifting programs.

Treatment of incentives is another key assumption when implementing the TRC Test for DR. For EE, incentives are considered transfer payments and excluded from the TRC costs and benefits. For DR, incentives are also considered transfer payments but are additionally used as a proxy for the sacrifice participants make by forgoing the use of electricity. In the 2026 TRC Test Order,[33] the Commission retained the 75% participant cost assumption set forth in California's DR Cost-Effectiveness Protocols.[34] This policy directive takes the perspective that customers are generally rational and would likely only participate in a DR program if they felt the benefits of participation outweighed the costs. All economic modeling in this study uses 75% of incentives as TRC cost.

The Commission's disposition regarding DR measure life in Section G.4 of the 2026 TRC Test Order is critically important to understanding the cost-effectiveness of several of the DR programs considered in the study.[35]

> *FirstEnergy's comment highlights an important consideration regarding the measure life of DR programs. While the measure life of a DR offering that relies on recurring participation incentives should not exceed the length of Phase V, it is not equal to the length of Phase V by default. The Commission agrees with FirstEnergy that the measure life for a DR offering should be governed by the program design. For Phase V of Act 129, the EDCs are directed to use a one-year measure life for behavioral DR programs and load curtailment or daily load-shifting programs in the C&I sector. For equipment-based DR programs, the measure life shall equal the agreed-upon participation term with the program participant.*

This guidance limits the number of years of TRC benefits a DR measure can accrue to the number of years remaining in the phase, if the program has recurring participation incentives. DR programs that involve the installation of load management equipment typically have very front-loaded cost profiles, because the equipment and installation costs occur in the first year. Ongoing costs in future years are much lower, so DR measures often need many years when the benefits exceed the recurring costs to overcome the first-year capital costs. The 2026 TRC Test effectively caps DR measure lives at five years, and the economics of installing new load management equipment worsen each year of the phase because there are fewer remaining years to capture TRC benefits. Because of this phenomenon, the SWE assumes no new installation of domestic hot water load management equipment after PY20. The

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[33] *See* the *2026 TRC Test Final Order*, Docket No. M-2024-3048998 (entered November 7, 2024) at Weblink.
[34] *See* 2016 Demand Response Cost Effectiveness Protocols. Weblink. California refers to this component as the "value of service lost."
[35] *See* the *2026 TRC Test Final Order* at page 97. Weblink.

truncated measure life issue also led the SWE to structure the connected thermostat and EV managed charging program designs to avoid upfront capital costs of new thermostats and chargers, due to the economic challenges of recovering the upfront costs within Phase V. The storage programs in Section 9 and Section 10 sidestep this issue by assuming all EDC incentives are upfront to offset the cost of the equipment. In exchange for that subsidy, participants agree to operate their systems in a way that delivers load reductions.

4.2 AVOIDED COSTS

The following sections discuss the financial assumptions used to monetize the grid benefits of DR. Due to the daily load-shifting framework presented in this study, the modeling perspective is like EE, in that the full avoided cost of generation, transmission, and distribution (GT&D) capacity is used to monetize peak demand reductions. All avoided cost assumptions are consistent between this DR potential study and the companion EE potential study.

4.2.1 CAPACITY BENEFITS

Generation capacity for Pennsylvania is secured through PJM's forward capacity auction process – the Reliability Pricing Model. BRAs for generation capacity occur approximately three years prior to the beginning of each delivery year. The avoided cost of generation capacity assumptions used to monetize DR impacts are based on the 2026 TRC Test Order and were developed by the SWE using the 2026 Avoided Cost Calculator (ACC). The five-year average called for in the 2026 TRC Test Order relied on results of the BRA for the five delivery years listed below:

- 2025/2026
- 2024/2025
- 2023/2024
- 2022/2023
- 2021/2022

The avoided cost of generation capacity values also include estimates of Demand Reduction Induced Price Effects (DRIPE). DRIPE benefits capture the cost savings across all remaining capacity purchases in the Commonwealth attributable to the downward pressure on clearing prices created by Act 129 peak demand reductions. DRIPE benefits are only assumed to last for four years and vary in magnitude across that four-year period. This means that the DRIPE benefit per kW-year in PY20 varies depending on whether a measure was installed in PY18, PY19, or PY20. Table 20 shows the summer avoided cost of generation capacity assumptions used to model DR benefits, by EDC, inclusive of the DRIPE benefit stream, for PY18. The drop off in the 2030/2031 delivery year is due to the four-year duration for capacity DRIPE benefits.

Table 20: PY18 Avoided Cost of Generation Capacity Forecast Including DRIPE - Summer

Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$57.06	$61.32	$31.65	$61.32	$61.32	$27.60	$31.65
2027/2028	$58.20	$62.54	$32.28	$62.54	$62.54	$28.15	$32.28
2028/2029	$59.35	$63.79	$32.92	$63.79	$63.79	$28.71	$32.92
2029/2030	$60.53	$65.06	$33.57	$65.06	$65.06	$29.27	$33.57
2030/2031	$25.19	$23.95	$20.69	$23.95	$23.95	$21.93	$20.69

Table 21 shows the corresponding forecast for the winter season, which is identical to summer due to the Commission's decision in the 2026 TRC Test Order to split annual generation capacity values evenly between summer and winter.

Table 21: PY18 Avoided Cost of Generation Capacity Forecast Including DRIPE - Winter

Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$57.06	$61.32	$31.65	$61.32	$61.32	$27.60	$31.65
2027/2028	$58.20	$62.54	$32.28	$62.54	$62.54	$28.15	$32.28
2028/2029	$59.35	$63.79	$32.92	$63.79	$63.79	$28.71	$32.92
2029/2030	$60.53	$65.06	$33.57	$65.06	$65.06	$29.27	$33.57
2030/2031	$25.19	$23.95	$20.69	$23.95	$23.95	$21.93	$20.69

Table 22 and Table 23 show the avoided cost of transmission capacity values used to estimate TRC benefits across all programs. The values used for this study come directly from 2026 ACC and are based on the outputs of the SWE's Avoided Cost of Transmission and Distribution Capacity Study.[36] The forecast is independent of the installation year and generally higher for summer than winter.

[36] See Exhibit 4 to the 2026 TRC Test Final Order: The Avoided Cost of Transmission and Distribution Capacity Study. Docket No. M-2024-3048998 (entered November 7, 2024) at Weblink.

Table 22: Avoided Cost of Transmission Capacity Forecast by EDC - Summer

Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$22.48	$48.00	$61.07	$58.92	$44.19	$77.10	$8.83
2027/2028	$22.92	$48.94	$62.27	$60.08	$45.06	$78.62	$9.00
2028/2029	$23.37	$49.91	$63.51	$61.27	$45.95	$80.18	$9.18
2029/2030	$23.84	$50.90	$64.76	$62.48	$46.86	$81.76	$9.36
2030/2031	$24.31	$51.91	$66.04	$63.72	$47.79	$83.38	$9.55

Table 23: Avoided Cost of Transmission Capacity Forecast by EDC - Winter

Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$0.00	$48.00	$0.00	$0.00	$14.73	$0.00	$8.83
2027/2028	$0.00	$48.94	$0.00	$0.00	$15.02	$0.00	$9.00
2028/2029	$0.00	$49.91	$0.00	$0.00	$15.32	$0.00	$9.18
2029/2030	$0.00	$50.90	$0.00	$0.00	$15.62	$0.00	$9.36
2030/2031	$0.00	$51.91	$0.00	$0.00	$15.93	$0.00	$9.55

Finally, Table 24 and Table 25 show the avoided cost of distribution capacity forecast by EDC. Most values fall between $50 and $70/kW-year combined across summer and winter. Only PPL has higher values in the winter season than in the summer season.

Table 24: Avoided Cost of Distribution Capacity Forecast by EDC - Winter

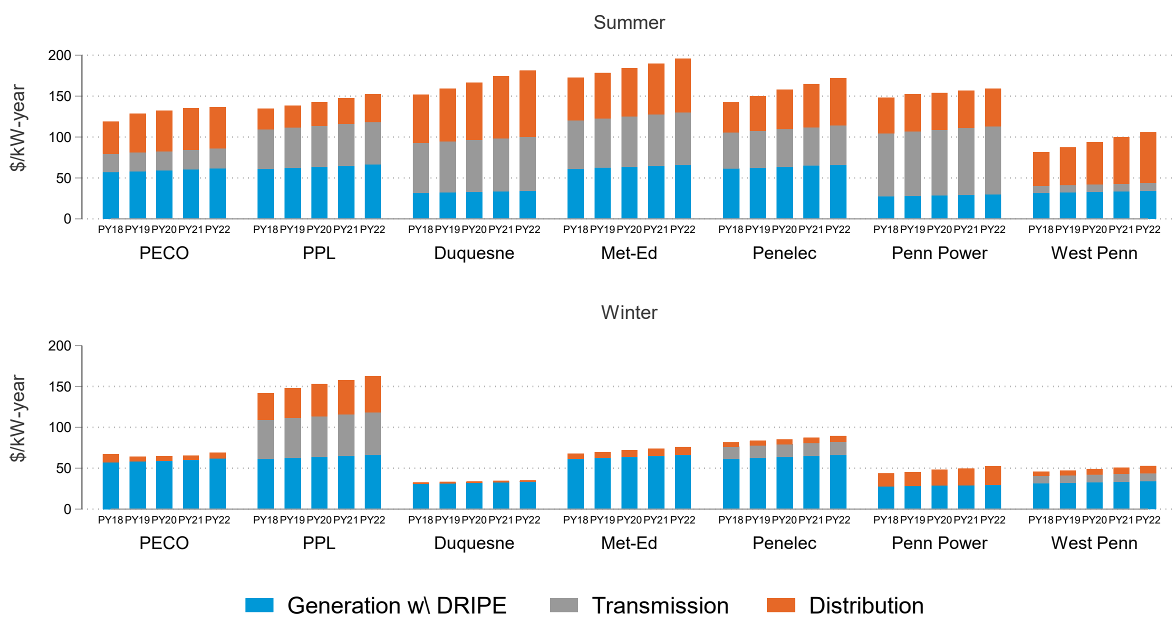
Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$39.61	$25.11	$59.28	$52.46	$37.18	$43.52	$41.25
2027/2028	$47.21	$26.68	$64.43	$55.82	$42.64	$45.52	$46.27
2028/2029	$49.64	$29.00	$69.93	$58.95	$47.98	$45.17	$51.89
2029/2030	$51.04	$31.55	$76.21	$62.16	$53.05	$45.79	$56.92
2030/2031	$50.53	$33.94	$81.30	$65.41	$57.97	$45.98	$62.19

Table 25: Avoided Cost of Distribution Capacity Forecast by EDC - Winter

Delivery Year	EDC (Nominal $/kW-year)						
	PECO	PPL	Duquesne	Met-Ed	Penelec	Penn Power	West Penn
2026/2027	$10.26	$32.44	$0.21	$6.70	$5.79	$16.27	$5.05
2027/2028	$5.67	$36.48	$0.12	$7.21	$5.97	$16.76	$6.06
2028/2029	$5.54	$39.40	$0.18	$8.16	$6.24	$19.33	$7.01
2029/2030	$5.08	$41.88	$0.18	$8.64	$6.58	$20.57	$7.93
2030/2031	$7.16	$44.30	$0.29	$9.68	$7.24	$22.70	$9.02

Figure 20 shows the GT&D benefits stacked by EDC and season for each program year of Phase V. The values in the figure represent year 1 of the effective useful life (EUL) of a measure installed in each program year, so the generation capacity benefits are inclusive of DRIPE for all program years. In practice, most of the DR solutions considered in this study have a single-year EUL, so these are the most relevant values. Consistent with the 2026 TRC Test Order, demand reductions from the Large C&I sector are not assigned any distribution capacity benefits.

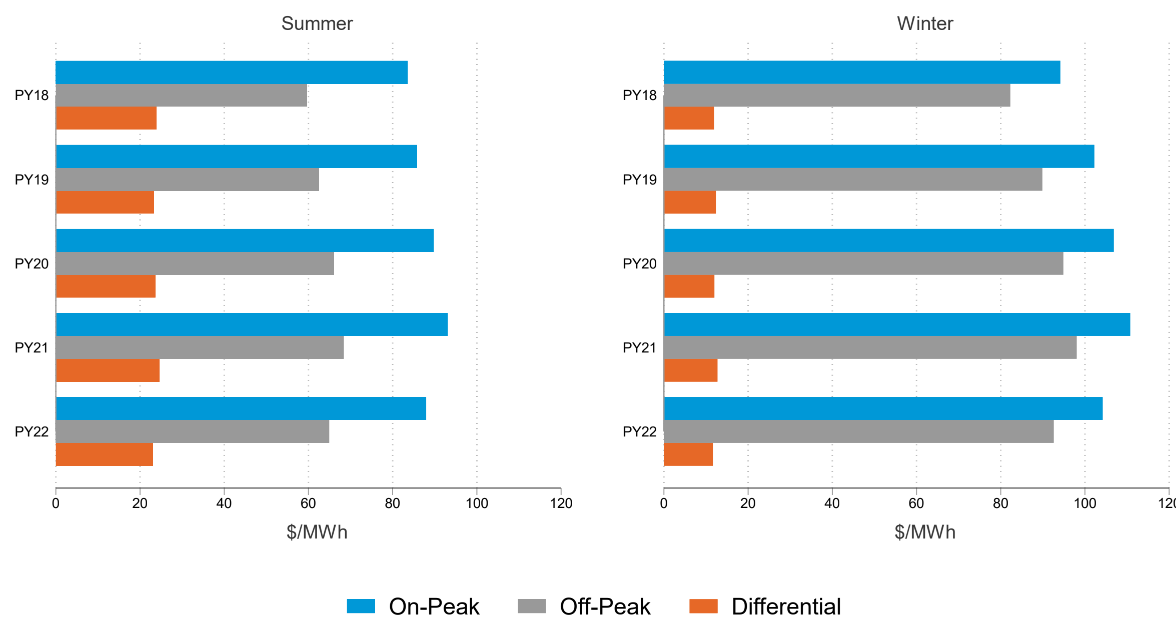
Figure 20: Capacity Benefits for EUL Year 1 by EDC, Season, and Program Year



4.2.2 Energy Benefits

The DR strategies examined in this report are primarily assumed to be energy neutral, in that the reduced energy consumption during performance hours is offset by increased energy usage outside of the DR event hours. To monetize this shift in consumption timing, the SWE calculated the differential between the seasonal on and off-peak avoided cost of electric energy forecast by EDC and year. The avoided energy forecast for this study was developed in fall 2024 using the 2026 ACC and values are similar across EDCs. Figure 21 shows the average on-peak (blue) and off-peak (grey) values by season and program year, along with the differential in orange. This differential is multiplied by the number of performance hours and expected load impact to calculate the energy benefits. This energy arbitrage benefit captures the wholesale benefits of moving energy consumption to periods when the grid is less constrained and marginal costs are lower. In today's PJM system, this likely means a combined-cycle plant on the margin instead of a combustion turbine. The differential between on-peak and off-peak energy is larger in the summer than in the winter, and the summer performance period includes three months rather than two, so energy arbitrage benefits are larger for the summer season. However, capacity benefits are the dominant stream for DR and the energy benefits account for less than 1% of the total TRC benefits across the study.

Figure 21: Statewide Average Avoided Cost of Energy by Year and Costing Period



The 2026 TRC Test Order recognizes energy DRIPE as well as capacity DRIPE and the estimated DRIPE benefit is embedded in the avoided cost of energy for the first four years. Energy DRIPE occurs when reduced demand lowers the market clearing price and thus reduces the cost of the remaining energy purchased in the market. Figure 21 shows the first year of an EUL for each program year, so all values include energy DRIPE. Phase V avoided costs include a $/MWh adder for low-income programs to capture the benefit of reduced arrearage and collection costs. Figure 21 shows the market rate avoided costs, but since the low-income adder is the same during both the on-peak and off-peak periods, the resulting differential would be the same if it were calculated using the avoided cost forecast for low-income programs.

4.3 PROGRAM DELIVERY AND INCENTIVE COSTS

Modeling assumptions about the fixed and volumetric costs of delivering DR programs are documented in the strategy-specific chapters of this report. Generally, the SWE relied on Pennsylvania-specific data, where available and applicable, and supplemented with cost assumptions from other jurisdictions and professional judgement where necessary.

4.4 PROGRAM BUDGETS AND ACQUISITION COST

Pennsylvania's Act 129 EE&C programs are budget constrained, with each EDC's funding capped at 2% of 2006 revenues.[37] Table 26 shows the Phase V funding amounts by EDC, as well as an estimate of annual budget. The annualized budget is simply the five-year budget divided by five. The budget for FirstEnergy is the sum of the annual budget limits for the legacy FirstEnergy EDCs (Met-Ed, Penelec, Penn Power, and West Penn Power).

Table 26: Phase V Funding Limits, by EDC

EDC	Five-Year EE&C Funding ($1,000)	Annual Budget ($1,000)
PECO	$427,386	$85,477
PPL	$307,507	$61,501
Duquesne Light	$97,730	$19,546
FirstEnergy	$390,320	$78,064
Statewide	**$1,222,943**	**$244,589**

In addition to the cost-effectiveness results, such as TRC benefits, TRC costs, and TRC net benefits, this report presents estimates of the EDC budget requirement to deliver DR programs. EE&C plans are funded and recovered in the current year's dollars, so estimates of EDC budget requirements are presented in nominal dollars. The budget limits in Table 26 encompass both EE and DR program spending, so every program dollar allocated to DR is a dollar not invested in EE, and vice versa. To help inform policy decisions about the trade-offs of investing program funds in different program types, and to facilitate goal setting in the Phase V Implementation Order, the SWE combines the estimates of achievable potential and program spending into a unitized acquisition cost metric. The capacity acquisition cost metric for DR programs is calculated as follows:

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

[37] *See* House Bill No. 2200, Session of 2008, of the General Assembly of Pennsylvania, An Act Amending Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes, page 59.

the acquisition cost of coincident demand reductions from the EE potential study or historic Act 129 program activity.

The resulting estimates represent the program cost to acquire five years of capacity reduction. The SWE selected this approach rather than summing the demand impacts across the five years of Phase V, because it is more comparable to the $/kW metric that comes out of the EE potential study. In the EE potential study, acquisition costs are computed using first-year kWh and kW in the denominator, because Act 129 goals have historically been based on first-year incremental annual savings. Since most EE measures last 5 to 15 years, the SWE felt this $/kW-Phase metric for DR would create a more "apples-to-apples" comparison between EE and DR. Typically, we expect DR programs to deliver capacity savings at a lower cost than EE programs, since they do not also produce meaningful energy savings. A $/kW-Phase metric is also useful if the Commission elects to propose peak demand reduction goals that can be satisfied by either daily load-shifting DR programs or coincident demand reductions from EE programs. Under such a design, the SWE's recommendation would be to define DR performance as the average performance across all peak seasons of the Phase.

The steps below illustrate the acquisition cost calculation for a hypothetical DR program.

- Expected MW impacts of 3, 4, 5, 6, and 7 MW across the five summers of Phase V
    - Mean = 5 MW of summer demand reduction
- Expected MW impacts of 1, 2, 3, 4, and 5 MW across the five winters of Phase V
    - Mean = 3 MW of winter demand reduction
- Average MW impact across seasons of (5 + 3) / 2 = 4 MW
- Modeled EDC program expenditure of $4.4 million over the five-year phase.
- Acquisition cost = $4,400,000 / 4,000 kW = $1,100/kW-Phase
- To calculate a more traditional $/kW-year metric value, the $/kW-Phase values would simply be divided by five. In this example, the result would be $220/kW-year.

The storage offerings presented in Section 9 and Section 10 are an exception to the $/kW-Phase DR acquisition metric described above. Since the SWE assumes storage technologies are paired with solar and subsidized through upfront equipment incentives, the demand impacts are even more analogous to EE and can just be expressed on a $ per first-year kW basis. There is an upfront incentive paid by the EDCs to lower the equipment cost to the participants in exchange for a commitment to operate the system in a way that is beneficial to the grid over its useful life. The expected demand reductions are not dependent on a recurring annual incentive.

5 C&I LOAD SHIFTING

Curtailment of non-essential electric loads in the Small Commercial & Industrial (Small C&I or SCI) and Large Commercial & Industrial (Large C&I or LCI) sectors is one of the most common and reliable forms of electric demand response. Most DR impacts statewide during Phase I and Phase III of Act 129 came from C&I facilities interrupting their normal business operations during event hours. Similarly, the SCI and LCI sectors represent the majority of Load Management MW in the PJM capacity market. Table 27 shows the distribution of capacity MW based on PJM's 2024 Demand Response Operations Markets Activity Report.[38]

Table 27: Share of Nominated Capacity MW by Business Segment

Business Segment	Share of Nominated Capacity MW
Manufacturing	51%
Schools	11%
Transportation, Communication, and Utilities	9%
Office Building	6%
Hospitals	5%
Retail	5%
Services	4%
Mining	4%
Residential	3%
Data Center with Crypto Mining	1%
Other	1%

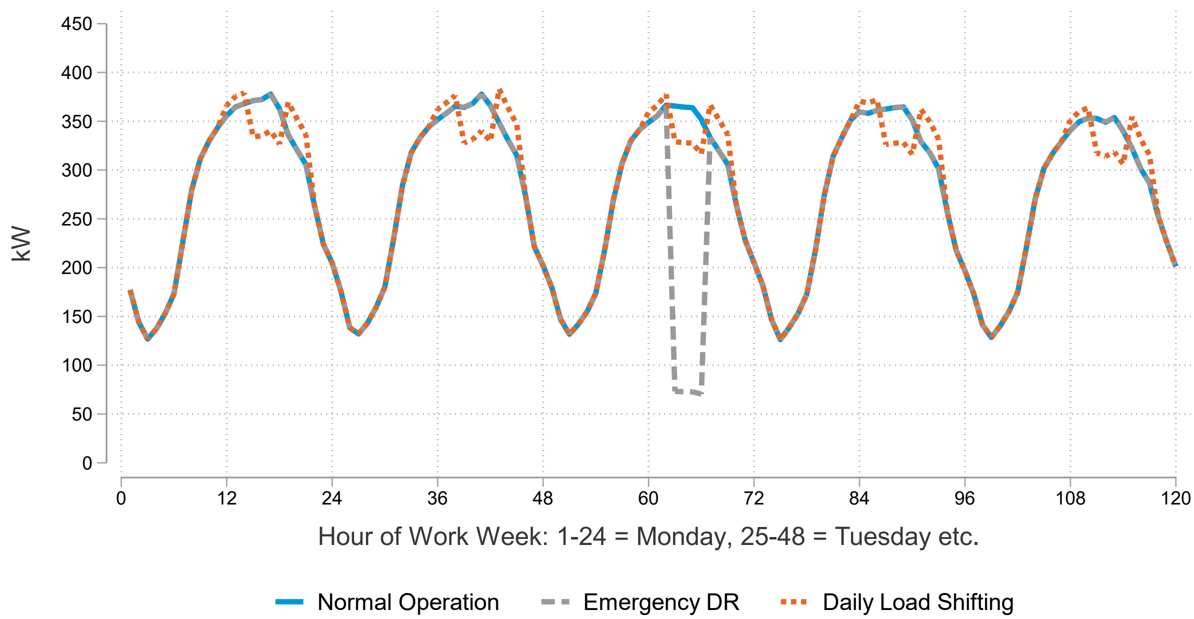
Much of the C&I DR registered at PJM and acquired by the EDCs in prior Act 129 phases involves significant curtailment of energy intensive operations or activation of behind-the-meter generators (typically diesel-powered). These strategies generate significant reductions in demand but are often disruptive to the business. However, the design is viable when events are infrequent, and participants are well compensated.

The C&I daily load-shifting program explored in this section considers less disruptive but far more frequent modifications to electric demand. Whereas a manufacturing sector participant in a traditional interruptible or C&I load curtailment program might largely suspend operations for several hours in response to an emergency DR event call, the site might operate equipment at lower levels or speeds during peak hours, or schedule energy intensive activities to occur off-peak in a daily load-shifting program. Figure 22 compares the two designs for a hypothetical facility over the course of a summer work week. In this example, an emergency DR event (grey line) is called on Wednesday afternoon, and the participant sheds load aggressively (80% reduction) to a minimum operating level. In all other hours of the week, the facility operates normally as indicated by the alignment of the grey and blue lines. The daily load shifting program (orange line) dispatches each weekday afternoon, but the change is far more subtle with a reduction of approximately 10%. Additionally, the facility loads are higher than

[38] 2024 Demand Response Operations Markets Activity Report: November 2024. Weblink. Figure 6

normal during the hours immediately preceding and following each afternoon peak period. Participants facing a non-coincident peak billing determinant would need to be careful not to create an artificially large power draw outside of the on-peak period, as this could lead to adverse bill impacts.

Figure 22: Comparison of Emergency DR and Daily Load Shifting



The SWE's analysis of daily load shifting potential in the SCI and LCI sectors leverages work conducted by Lawrence Berkeley National Laboratory (LBNL) on behalf of the California Public Utilities Commission (CPUC).[39] The LBNL modeling framework organizes DR services into the four categories shown in Table 28 that address different needs of the electric grid.

[39] To date LBNL has completed four phases of DR potential modeling for California with Phase 1 published in 2016 and Phase 4 published in 2024. Weblink

Table 28: LBNL DR Categories

DR Category	Description	Grid Product(s)
Shed	Market integrated DR that curtails loads to provide peak reductions and support the system during emergency or contingency events with a range in dispatch advance notice times.	Capacity
Shape	DR that reshapes customer load profiles during significant portions of the year through price response or behavioral campaigns with advance notice of months, days, or even hours.	Capacity and Energy
Shift	DR that encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of variable renewable energy generation.	Capacity and Energy
Shimmy	Involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.	Ancillary Services

The PJM emergency load management product where many Pennsylvania businesses have existing capacity commitments maps squarely to the "Shed" product category. The daily load shifting offering considered by this study aligns most closely with the "Shift" category but also has elements of "Shape." While the penetration of intermittent renewable generation in Pennsylvania is nowhere near as high as California, many of the same concepts apply. There are periods of time when marginal system costs are predictably higher and lower. Shifting loads from the days and hours when the grid is constrained can also help avoid or defer the need for capacity expansion. This is especially salient given the expected load growth and number of planned generator retirements across the PJM footprint in the next decade.[40]

Importantly, facilities with a capacity commitment at PJM could also engage in Act 129 daily load shifting without raising the "double dipping" concerns that have been a policy concern in prior phases. Dually enrolled participants would need to consider the implications for their PJM baseline. Daily load shifting would lower the site's PLC and in turn their share of capacity costs. However, that lower PLC would also limit the available load for curtailment during a PJM emergency.

While the daily load shifting program design could target the same participants as PJM emergency DR, it would likely target different loads within the facility. Target loads for a daily load-shifting program are flexible processes that can be scheduled, typically via a building management system or other automated controls, to occur outside of the peak periods. Examples of automated daily shifting strategies include:

- Staging manufacturing processes to initiate the most energy-intensive processes outside of the peak period when facility demand is otherwise lower.
- Lowering lighting levels in commercial settings.
- Shifting cooling or heating loads to run more intensely before and after the peak period.

[40] The PJM system could see 40 GW of retirements by 2030. Energy Transition in PJM: Resource Retirements, Replacements & Risks. February 2023. Weblink. Page 5.

- Avoiding charging of battery-powered forklifts during peak hours.
- Ramping down fan and pump speeds or cycling them off during peak periods.
- Manipulating refrigeration settings to lower temperatures prior to the peak period to limit consumption during peak as a form of thermal storage.

Charging of EV fleets or medium/heavy duty electric vehicles are modeled separately in Section 8 of the study.

5.1 METHODS

Table 29 provides an overview of the key model inputs and assumptions for the C&I daily load-shifting program. The sections that follow discuss each component in detail.

Table 29: Summary of Modeling Assumptions

Input Variable	Key Assumptions and Notes
Program Design (number of events, start time, and event duration)	Aligned with Act 129 peak demand definition for EE. Non-holiday weekdays in January, February, June, July, and August. Summer performance hours are 2pm-6pm and winter performance hours are 7am-9am and 6pm-8pm.
Peak Load Forecast	The zonal 50/50 summer and winter forecasts from PJM's 2024 Load Forecast Report disaggregated to the sector, segment, and end use.
Enrollment Rates	Linear ramp rate approaching cumulative limits estimated using fractional regression coefficients from LBNL DR-Path model inputs.
Load Impacts	End use shed fractions from LBNL DR-Path model inputs calibrated to a daily load-shifting design.
Performance Factor	An 85% multiplier (or 15% derate factor) applied prior to calculating achievable potential and TRC benefits but after computing participant incentives. Accounts for sites having less available load than their PLC on a given day and underdelivering their expected load reduction over the course of DR season.
Participant Incentive	$80/kW-year (RAP) and $120/kW-year (MAP). Equivalent to $40/kW-season (RAP) and $60/kW-season (MAP).
Program Management Budget (Non-Incentive Costs)	Recurring annual 30% adder to participant incentives for RAP and 40% adder to participant incentives for MAP.
Avoided Cost of Generation Capacity	Equal values for summer and winter ranging from $28/kW-season to $66/kW-season and averaging $49/kW-season. These values are inclusive of capacity DRIPE.
Avoided Transmission and Distribution Capacity	Summer value ranges from $23/kW-season to $83/kW-season. Winter values are lower, averaging $10/kW-season with several EDCs having zero winter value.
Avoided Transmission and Distribution Capacity	Not applied to the LCI sector. Generally higher in the summer than winter with values ranging from $12/kW-season to $81/kW-season.

Input Variable	Key Assumptions and Notes
Avoided Energy Costs ($/MWh)	The differential between the on-peak and off-peak avoided cost of energy. Average arbitrage value of $24/MWh in the summer and $12/MWh in the winter.
Discount Rate	5% nominal discount rate.
Line Losses	Not applicable as all modeling is done "top down" from system-level forecasts inclusive of losses.

5.1.1 Peak Load Forecast Disaggregation

The SWE relied on a top-down modeling approach for daily load-shifting potential in the SCI and LCI sectors. Section 3 of this report describes the disaggregation of summer and winter peak demand forecasts to the sector level, by EDC. The sector-level forecasts were then further disaggregated by segment and end use. This disaggregation leveraged the data collection and analysis of the 2023 Pennsylvania Non-Residential Baseline Study.[41] Table 30 introduces the thirteen segments across which all summer and winter peak demand from the SCI and LCI sectors was assigned.

Table 30: Non-Residential Building Categories

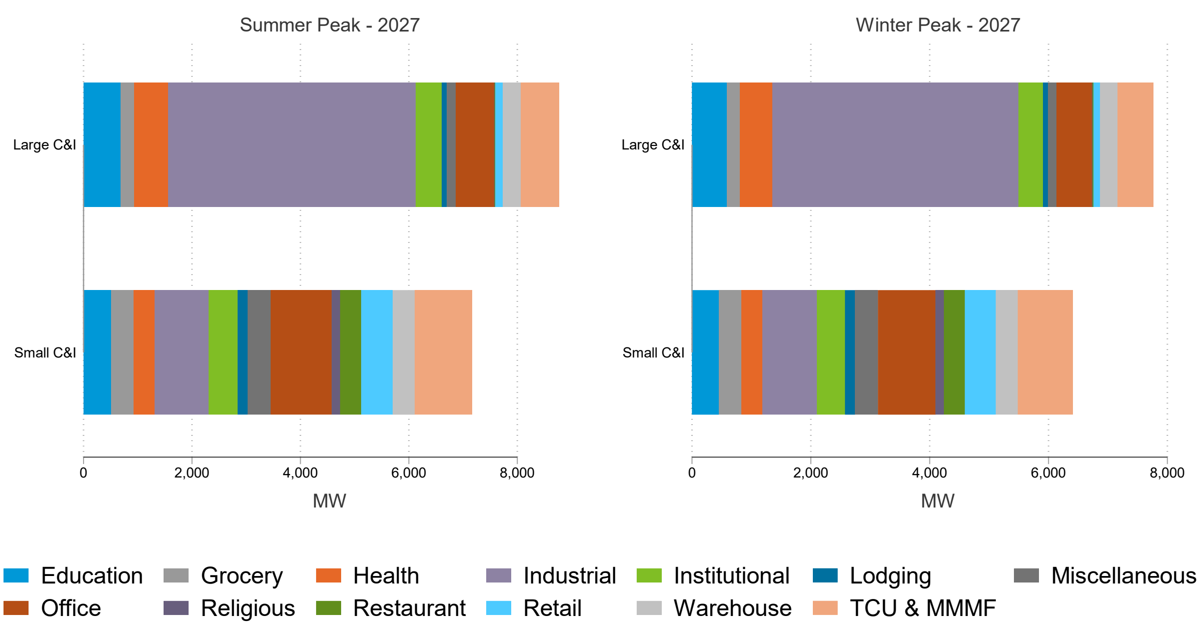
Segment	Definition and Examples
Education	Institutions supporting academic studies, including K-12 schools, colleges and libraries, as well as childcare centers.
Grocery	Facilities where perishable food items are sold, generally with large refrigeration loads, including grocery stores, convenience stores, and gas stations. Also includes big-box stores that sell groceries.
Health	Institutions that support physical and mental health, including hospitals, medical and dental offices, assisted living centers, and gyms.
Industrial	Facilities that create, process, and refine goods.
Institutional	Government and non-profit facilities, such as town halls, courthouses, federal/state offices, police stations, and emergency services. Also includes municipal water treatment systems, which are extremely energy intense.
Lodging	Facilities offering temporary accommodation, such as hotels, motels, and campgrounds.
Miscellaneous	Other facilities with higher energy usage than traditional offices or retail stores, including personal services (salons, laundromats, dry cleaners, etc.), auto repair, and entertainment (theaters, recreational facilities).
Office	Private offices, such as office buildings, law offices, and financial institutions.
Religious	Places of worship, not including church-run schools.
Restaurant	Food service facilities, including full-service and fast-service restaurants, bars, coffee shops, and catering facilities.

[41] 2023 Pennsylvania Statewide Act 129 Non-Residential Baseline Study. Submitted March 25, 2024, at Docket No: M-2023-304490. Weblink.

Segment	Definition and Examples
Retail	Retail establishments not included in the Grocery or Miscellaneous segments, such as clothing, hardware, electronics, furniture, and sporting goods stores.
TCU and MMMF	Transportation, Communications, and Utilities (TCU) accounts are numerous but often small and include cell towers, signs, utility infrastructure and railroads. Master-Metered Multifamily (MMMF) are residential housing units with shared meters.
Warehouse	Facilities for storage, shipping, and wholesale trade, including refrigerated warehouses.

Figure 23 shows the distribution of summer and winter PLC within the SCI and LCI sectors across the 13 study segments. The Industrial segment within the LCI sector accounts for approximately 4,000 MW statewide, or one-fourth of the non-residential peak load statewide.

Figure 23: Peak Load Contribution by Sector, Segment, Season



The EDC peak load forecasts were then further disaggregated by end use within each sector and segment. The disaggregation was based on the segment-specific energy use intensity values from the 2023 Non-Residential Baseline Study. The seven end uses considered were:

- **Heating, Ventilation, and Air Conditioning (HVAC):** Electricity used for heating, cooling, and dehumidification of buildings for the comfort and safety of the occupants.
- **Lighting**: Fixtures and lamps used to illuminate indoor and outdoor spaces.
- **Cooking**: Electric food service equipment such as ovens, fryers, and griddles.
- **Refrigeration**: Commercial freezers and refrigerators, mostly concentrated in the Grocery, Restaurant, and Warehouse segments.

- **Plug Load**: Various devices that are not part of the building's mechanical systems but plug into outlets and contribute to overall facility demand.
- **Process:** Motors, drives, and other equipment used to power manufacturing and other business processes.
- **Domestic Hot Water (DHW):** Electric demand for heating water for various applications.

Figure 24 shows the statewide breakdown of the Health segment across the seven end uses. The winter HVAC contribution is smaller than the summer's due to the saturation of fossil fuel heating.

Figure 24: Peak Load Contribution by End Use for Health Segment

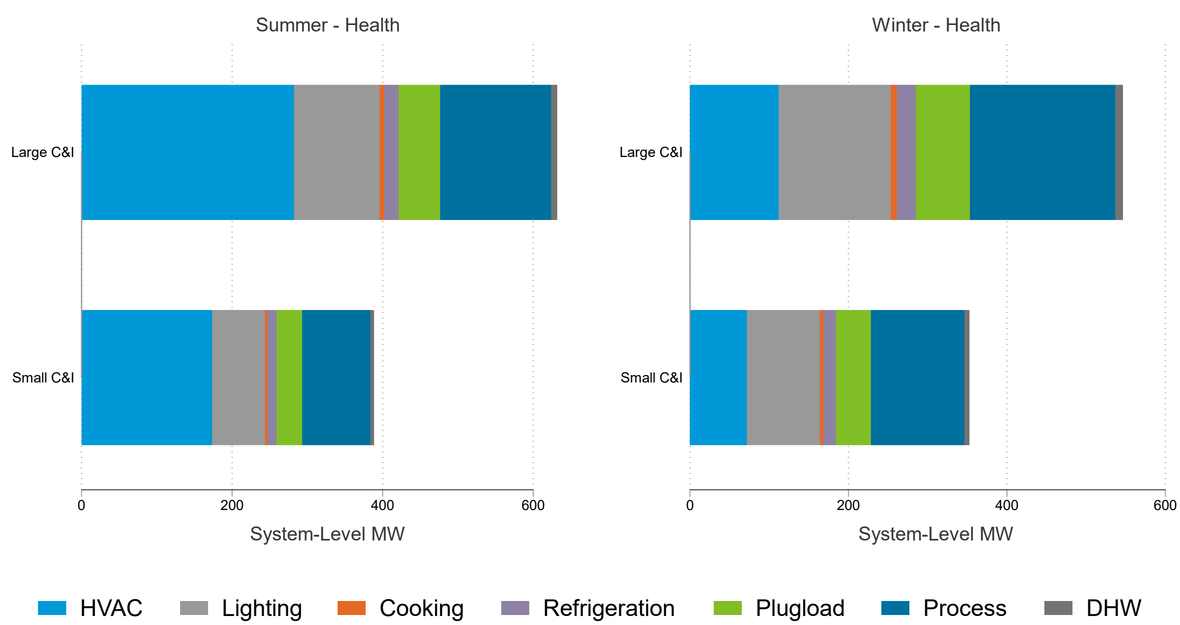
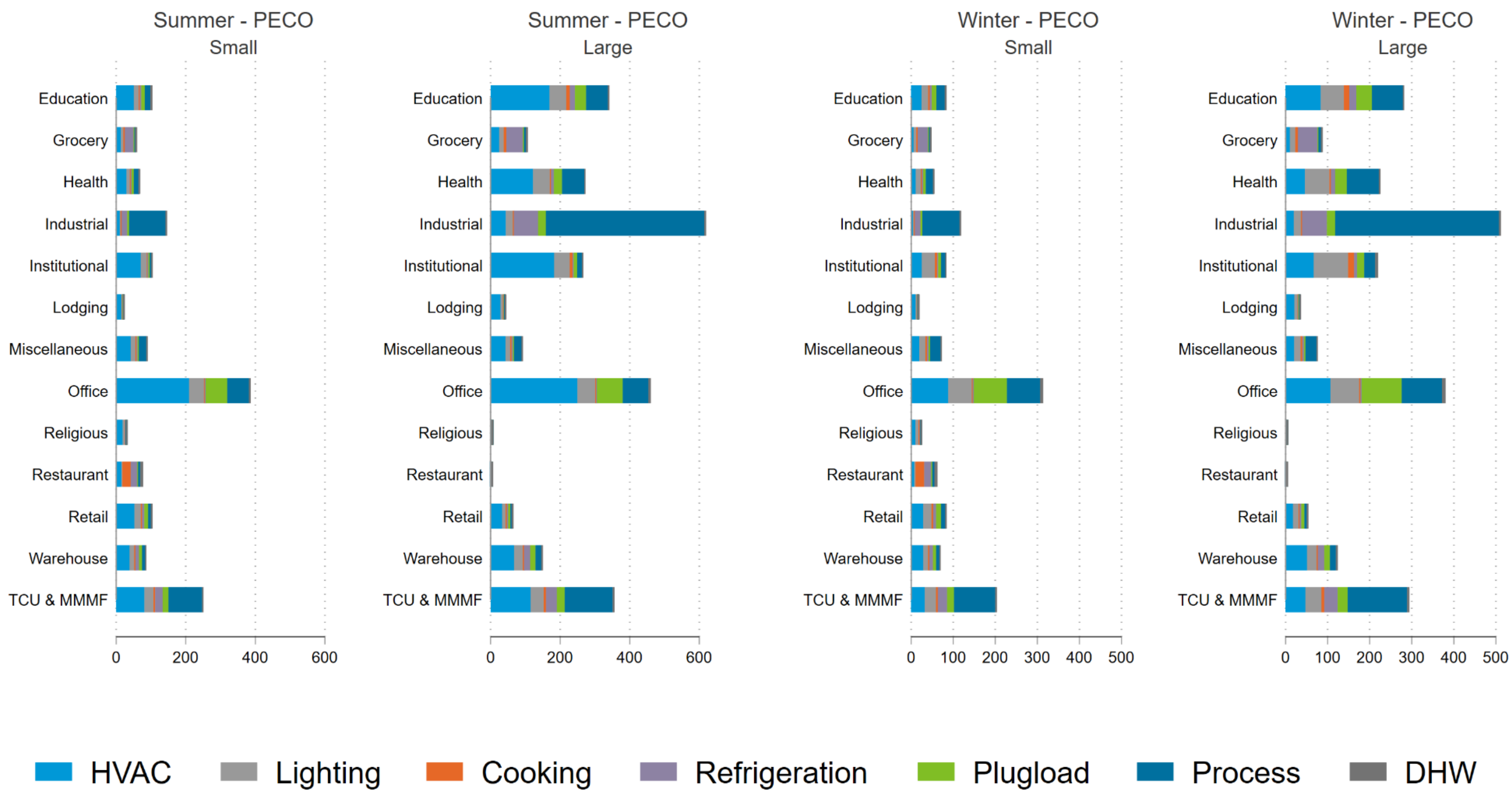


Figure 25 illustrates the culmination of the peak disaggregation task for PECO. The SWE estimated the PLC (in MW) of each end use within each segment for each EDC, season, and year of the forecast horizon. This granular disaggregation allowed for varying participation and load impact assumptions to be applied across business types and end uses.

Figure 25: PECO Seasonal Peak Load Forecast (MW) by Sector, Segment, and End Use



5.1.2 ENROLLMENT RATES

The share of non-residential peak load that is expected to enroll in daily load shifting is a key driver of the achievable potential. Since there is little Pennsylvania-specific history to draw from for this type of program offering, the SWE leveraged the enrollment modeling module of LBNL's DR-Path toolset.[42] The LBNL DR-Path model relies on fractional probit regression models trained on real program enrollment data to predict cumulative enrollment as a function of:

- **Incentive level ($/kW-year):** this leads to higher enrollment rates for the MAP scenario than RAP, because incentive levels are higher under the MAP perspective. The SWE assumes an annual incentive of $80/kW-year for RAP and $120/kW-year for MAP. Since the study considers both summer and winter peak demand, this is equal to $40/kW-season for RAP and $60/kW-season for MAP.

- **Sector:** The DR-Path model differentiates between commercial and industrial customers. The SWE maps industrial enrollment assumptions to the Industrial segment and commercial enrollment assumptions to all other segments.

- **Size:** The LBNL modeling provides separate estimates for Small (< 75 kW), Medium (75-500 kW), and Large (> 500 kW) accounts. The SWE applies model coefficients for Large businesses to the LCI sector and applies the model coefficients for Medium businesses to the SCI sector. One exception to this mapping is the Health/Medical segment, which is not included in the DR-Path commercial enrollment probabilities for Large businesses. For Health, the SWE applies coefficients for Medium businesses to LCI and map Small business enrollment coefficients to SCI.

- **Climate Region:** The DR-Path enrollment module includes separate assumptions for the Marine, Hot-Dry, and Cold climate regions of California. This study uses an average of the three.

Table 31 shows the enrollment coefficients adapted from the LBNL DR-Path model to Pennsylvania sectors and segments. These coefficients are used to estimate enrollment rates using Equation 1. Since the LBNL study did not include building types that map clearly to the Religious, Institutional, or TCU segments, the SWE applied a conservative assumption of half of the sector-level average for these three building types.

Equation 1: Enrollment Rate Equation Using Probit Coefficients

$$Enrollment\ Rate = \frac{1}{(1 + exp^{-(\beta_0 + \beta_1 + \beta_2 * Incentive\ Rate)})}$$

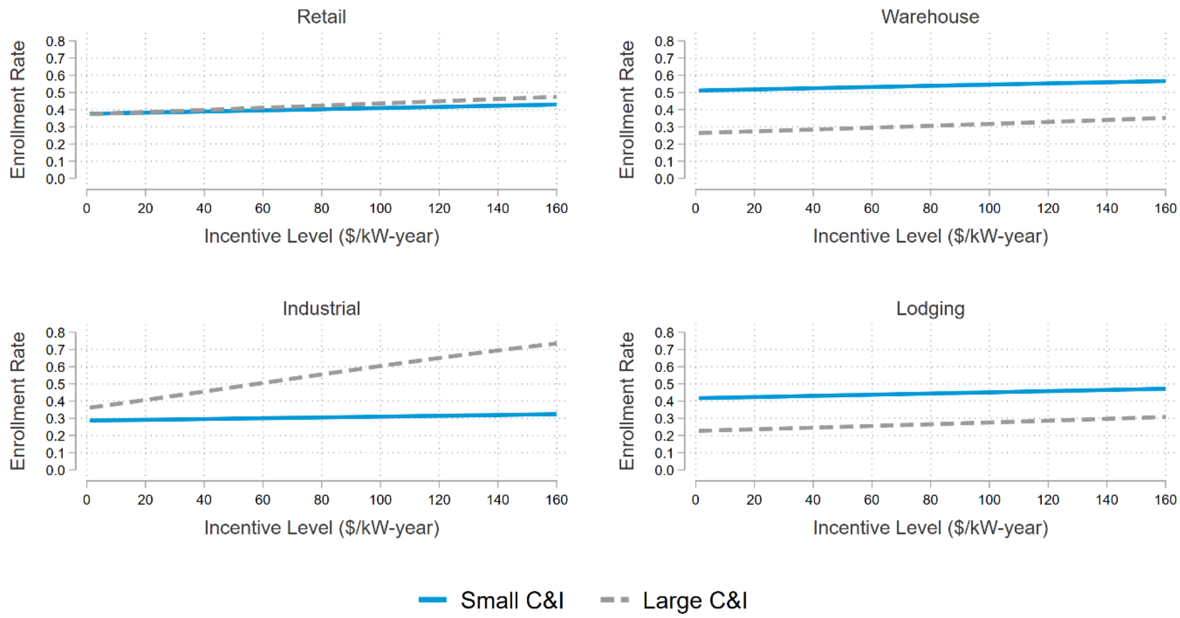
[42] California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources. https://eta-publications.lbl.gov/sites/default/files/appendices_2024-05-21.pdf. The enrollment model is described in Appendix B of the Phase 4 Report. Page 53.

Table 31: Enrollment Probit Coefficients

Sector	Segment	Intercept (β_0)	Segment Coefficient (β_1)	Incentive Coefficient (β_2)
Large	Education	-0.2667	0.560	0.0026
Small	Education	-0.6267	-0.180	0.0014
Large	Grocery	-0.2667	-0.550	0.0026
Small	Grocery	-0.6267	-0.980	0.0014
Small	Health	-0.6267	0.380	0.0026
Large	Health	-0.2843	0.170	0.0014
Large	Industrial	-0.9278	0.350	0.0100
Small	Industrial	-0.9278	0.016	0.0011
Large	Lodging	-0.2667	-0.960	0.0026
Small	Lodging	-0.6267	0.290	0.0014
Large	Miscellaneous	-0.2667	0.310	0.0026
Small	Miscellaneous	-0.6267	-0.210	0.0014
Large	Office	-0.2667	-1.100	0.0026
Small	Office	-0.6267	0.170	0.0014
Large	Restaurant	-0.2667	0.720	0.0026
Small	Restaurant	-0.6267	0.097	0.0014
Large	Retail	-0.2667	-0.250	0.0026
Small	Retail	-0.6267	0.120	0.0014
Large	Warehouse	-0.2667	-0.760	0.0026
Small	Warehouse	-0.6267	0.670	0.0014

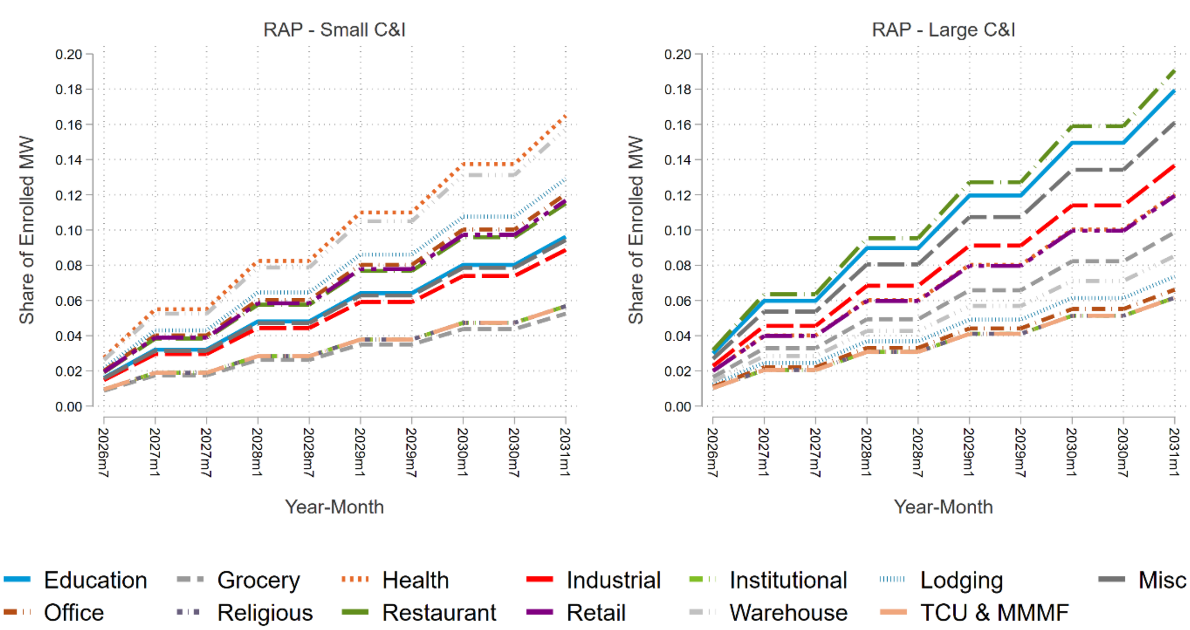
Figure 26 shows the resulting curves, by sector, for the Retail, Warehouse, Industrial, and Lodging segments. For each sector-segment pairing, the estimated enrollment share grows as the incentive rate increases, but there are strong assumptions about natural adoption propensity across segments and sectors. Importantly, the DR-Path enrollment functions are designed to estimate long-run cumulative enrollment rates in Shift DR.

Figure 26: Long-Run Enrollment Rate Versus Incentive Level



The SWE treated the estimated enrollment rates for mature DR programs as maximum reachable shares of peak load that can be enrolled over a 20-year horizon and modeled a linear ramp rate from the first year of the study horizon (2026) to the 20th year (2045). Since the Phase V modeling horizon is only five years, the calculated share of enrolled MW in this study only reaches 25% of the long-term enrollment rates predicted by the model coefficients. Figure 27 shows the results for the RAP scenario. The MAP enrollment rates are slightly higher due to the elevated incentive rate.

Figure 27: Time Series Enrollment Rates by Segment and Sector - RAP



5.1.3 Load Impacts

Load impacts are the expected reduction in peak load conditional on program enrollment. The SWE leveraged the LBNL DR-Path modeling assumptions to create a set of assumed percent reductions by end use and scenario. The assumed percent reductions are the same for a given end use across the summer and winter peak seasons, but they are applied to the season-specific peak loads described in Section 5.1.1. The initial load impact assumptions were developed through the following steps:

1) **Catalog the average four-hour shed fraction for each end use category**. These values represent the estimated percentage reduction in end-use load electric demand achievable over a DR event lasting event last four hours.[43] Importantly, these assumptions pertain to the "Shed" DR category rather than the "Shift."
2) **Address the Cooking End Use**. Since this end use category was not included in the DR-Path inputs, the SWE set a conservative value of 20%, lower than each of the other end uses except for plug loads.
3) **Use the ratio of business-as-usual achievable potential to calibrate the fractions to Shift DR**. Since end use shed fractions are not presented in the LBNL report for Shift DR, the SWE derates the shed fractions using the ratio of aggregate Shift DR potential to Shed DR potential.[44] The SWE used the 2025 ratio of 31.3% (0.72 GW of Shift to 2.3 GW of Shed) for the RAP scenario, and the 2030 ratio of 56.5% (1.3 GW of Shift and 2.3 GW of Shed) for the MAP scenario.
4) **Multiply the initial shed fraction by the applicable derate factor**. This step combines the output of the first three steps to create the set of distinct values by end use and scenario shown in Table 32.

Table 32: End Use Percent Load Impacts by Scenario – Prior to Performance Adjustment

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%

Finally, the SWE included a performance factor of 85% to account for sites having less available load than their PLC on a given day and for underdelivering their expected load reduction over the course of

[43] California Demand Response Potential Study, Phase 4: Appendices to Report on Shed and Shift Resources. Weblink. Commercial end use shed fractions are presented in Table C-13 and Industrial shed fractions are presented in Table C-16.

[44] The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050. Weblink. Shed potential is presented in Table 12 and Shift potential is presented in Table 17.

the DR season. This performance adjustment is applied after the calculation of participant incentives. For example:

- **Participation Nomination**: 100 kW in both summer and winter
- **Incentive Rate**: $120/year consistent with study assumptions for the MAP scenario
- **Incentive Cost to the EDC**: $12,000 annually ($120 * 100)
- **kW impact adjusted for performance**: 85 kW (100 kW * 85% performance factor)
- **Performance adjusted EDC incentive cost**: $141.18 per kW/year

The implication of the performance factor and how it is used in the modeling process is that kW impacts, after adjustment for performance, are used to estimate TRC benefits, while the kW impacts prior to adjustment are used to estimate EDC costs and TRC costs.

Equation 2 shows the final formula used to estimate achievable potential for each scenario, sector, segment, and end use. The calculations are performed separately for each year of the study horizon to account for the variations in PLC and growth in the cumulative enrollment rate.

Equation 2: Achievable Potential Calculation

$$Achievable\ Potential = PLC * Enrollment\ Probablility * Load\ Impact * Performance\ Factor$$

The system-level estimates of achievable potential are then used to calculate the costs and benefits of the daily load-shifting program offering.

5.1.4 Program Costs and TRC Costs

The C&I daily load shifting solution was modeled with a one-year EUL. This simplifies the modeling framework, as all benefits and costs occur in the same year. For reporting purposes, the costs and benefits from each year of the study horizon are discounted to 2026 dollars using a 5% nominal discount rate. From an operational standpoint, this means that participants would enter into a participation agreement for one or more years with the EDC and be paid an incentive based on the amount of summer and winter demand they commit to shift.

The cost assumptions for the C&I daily load shifting program are straightforward volumetric recurring amounts based on the quantity of kW committed. Table 33 shows the incentive and overhead rates for the RAP and MAP scenario. Incentive levels are at the system-level and increase by a 2% annual inflation rate over the study horizon. The administration rate calculation is higher for the MAP scenario to allow for more aggressive marketing and outreach efforts by the EDCs and their CSPs.

Table 33: C&I Load Shifting Cost Components

Scenario	Incentive Level ($2026/kW-year)	Administration Rate
RAP	$80	30%
MAP	$120	40%

For a hypothetical C&I load-shifting program with 500 kW of summer nomination and 400 kW of winter nomination for the RAP scenario, the annual total program cost is calculated as:

$$Program\ Spend = \left(\frac{\$80}{2} * 500 + \frac{\$80}{2} * 400\right) * (1 + 0.3)$$

$$Program\ Spend = (\$36{,}000) * (1.3) = \$46{,}800$$

In this example the participant incentives equal $36,000, and the administration and overhead expenses equal $10,800. These two cost centers are handled differently for the purposes of TRC costs. The 2026 TRC Test Order[45] directs EDCs:

> "*to include 75% of the customer incentive payment as a TRC Cost for all dispatchable DR or daily load-shifting programs. The 75% assumption acts as a proxy for the participant's cost of sacrificing electric consumption during performance hours.*"

In the hypothetical example above, the participant cost equals $27,000. Administration and overhead costs are included as TRC costs in full so the total TRC cost for this example is the sum of the administration cost and participant, or $37,800.

5.1.5 TRC Benefits

Estimation of the TRC benefits of a C&I daily load-shifting program follows the general process and assumptions described in the Section 4.2. In the SCI sector, estimates of summer and winter achievable potential are multiplied by the season and EDC-specific avoided cost of GT&D capacity for each year. As directed in the 2026 TRC Test Order, peak demand reductions in the LCI sector only receive the avoided cost of generation and transmission capacity, because most accounts take service at primary voltage and largely bypass the EDC distribution system. We assume that C&I load shifting is energy neutral over the course of a day and the energy conserved on-peak is recovered off-peak. Energy benefits are calculated by multiplying the achievable potential by the number of performance hours and the on/off-peak differential in the season-specific avoided cost of energy. This energy arbitrage benefit stream accounts for 0.18% of the TRC benefits in the SCI sector and 0.26% of the TRC benefits in the LCI sector statewide.

All avoided cost assumptions are derived from EDC-specific implementations of the 2026 ACC, developed in the fall 2024. The SWE modeled the four legacy FirstEnergy EDCs separately, using distinct avoided costs and disaggregated peak load forecasts, and then combined the results for reporting.

[45] 2026 TRC Test Final Order, Docket No. M-2024-3048998 (entered November 7, 2024) at Weblink. Page 95

5.2 RESULTS

5.2.1 ACHIEVABLE POTENTIAL

Figure 28 shows the achievable estimates for the final year of the study horizon (PY22).

Figure 28: Cumulative Potential by EDC, Scenario, and Season

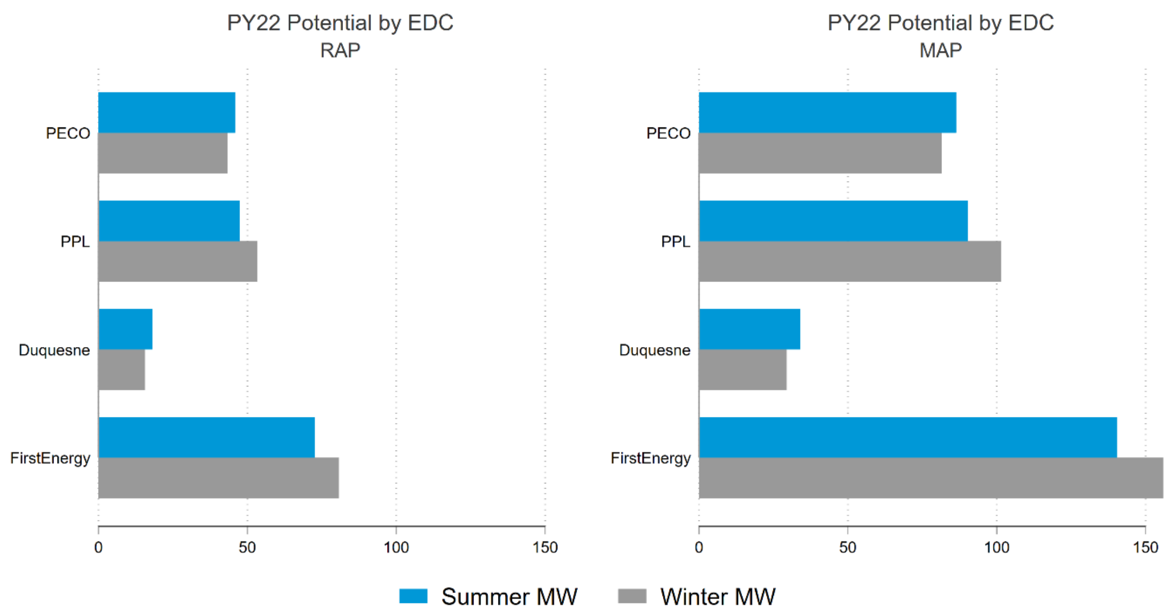


Table 34 and Table 35 show the RAP results by EDC and program year separately for the summer and winter season in system-level MW. The Phase V column represents the average of the five program years. This column would be used for target-setting if the Commission elects to establish peak demand reductions goals that can be satisfied with daily load-shifting, with performance measured as the average over the phase.

Table 34: Realistic Achievable Potential by EDC – Summer (MW)

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**

Table 35: Realistic Achievable Potential by EDC – Winter (MW)

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**

The estimated MW impacts grow gradually over the phase as enrollment increases. Because the summer season falls at the beginning of each Act 129 program year and the winter season falls later in the program year, the estimated demand reduction potential is generally higher for winter within a given program year. Figure 29 shows statewide RAP for both seasons in a single time-series. Summer values are shown each July, and winter values are shown each January. Approximately 60% of the potential comes from the LCI sector, and the other 40% comes from the SCI sector.

Figure 29: Statewide RAP Time Series by Sector

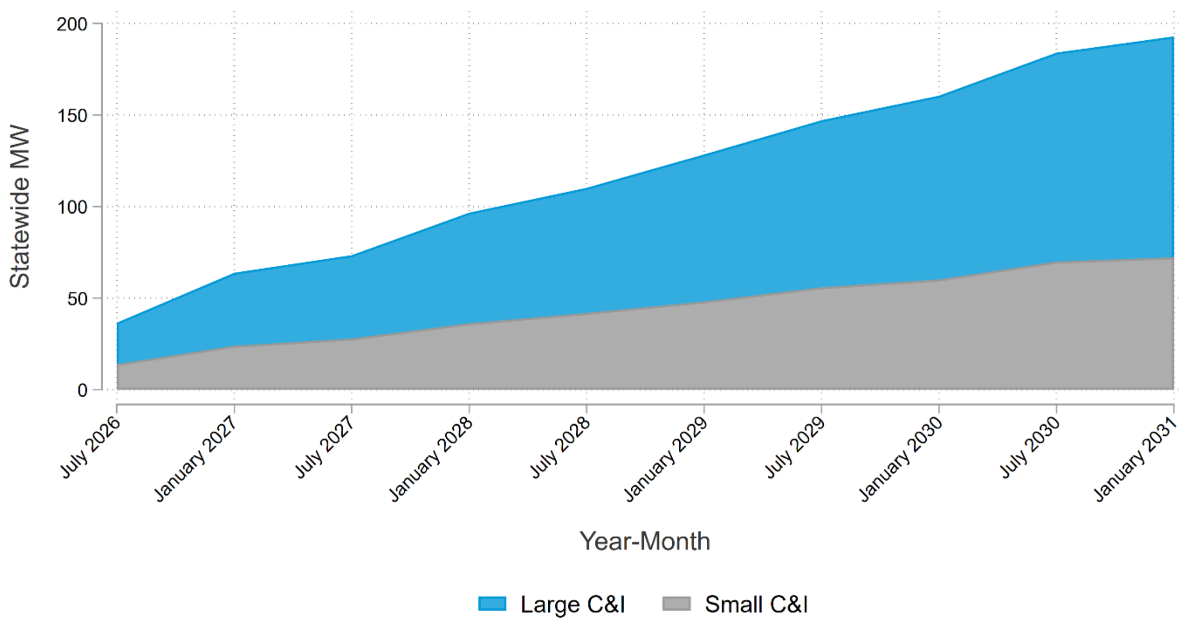


Table 36 and Table 37 show the corresponding MAP results. FirstEnergy has the largest potential in both the summer and winter seasons, because FirstEnergy has the most summer and winter non-residential peak load of the four EDCs. Statewide MAP is almost twice as high as RAP, due to the increased incentives, load impacts, and enrollment rates.

Table 36: Maximum Achievable Potential by EDC – Summer (MW)

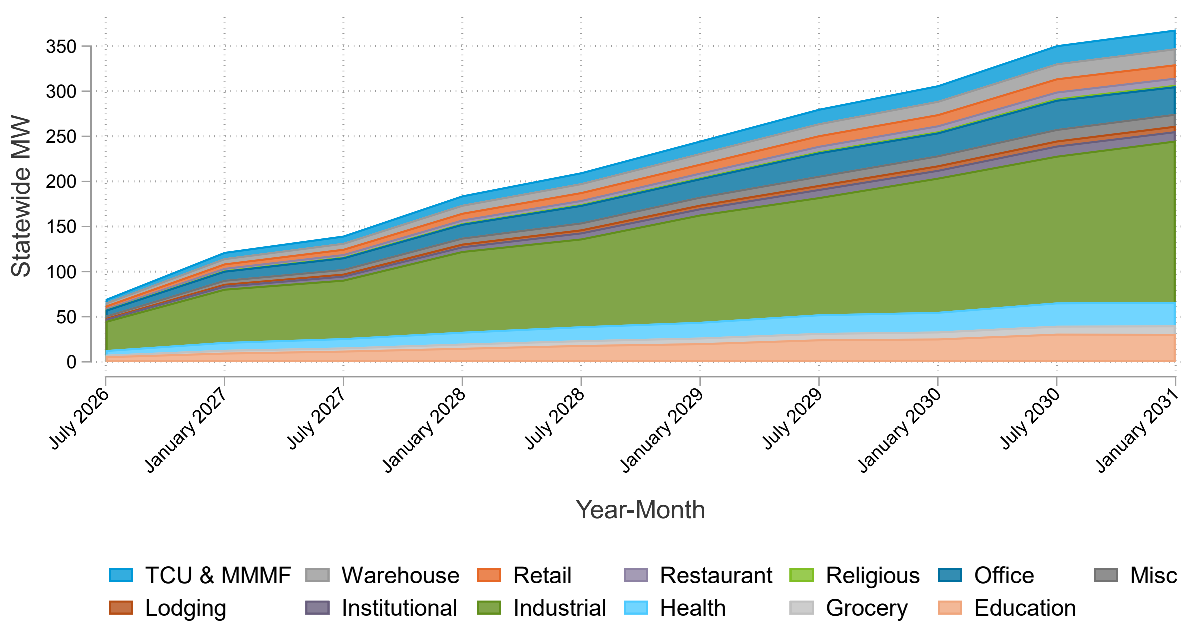
EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	17.2	34.4	51.7	69.0	86.4	51.7
PPL	18.0	36.1	54.1	72.1	90.2	54.1
Duquesne	6.8	13.6	20.4	27.3	34.0	20.4
FirstEnergy	27.6	55.8	83.9	112.1	140.3	83.9
Statewide	**69.6**	**140.0**	**210.1**	**280.5**	**350.9**	**210.2**

Table 37: Maximum Achievable Potential by EDC – Winter (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	27.1	40.9	54.3	67.9	81.5	54.3
PPL	34.0	51.2	67.8	84.6	101.5	67.8
Duquesne	9.8	14.8	19.7	24.5	29.4	19.6
FirstEnergy	51.0	77.7	103.5	129.6	155.9	103.5
Statewide	**121.8**	**184.5**	**245.2**	**306.5**	**368.3**	**245.3**

Figure 30 shows statewide MAP for both seasons in a single time-series. Summer values are shown each July, and winter values are shown each January. The segment values are stacked in the figure, so that the total height across all 13 segments equals the statewide MAP. Almost 50% of the potential comes from the Industrial segment.

Figure 30: Statewide MAP Time Series by Segment



5.2.2 ECONOMICS

Table 38 shows the cost-effectiveness results for the RAP scenario. All TRC costs and benefits are expressed in 2026 dollars. The net benefits (benefits minus costs) statewide are approximately $40 million, and the TRC ratio is comfortably above 1.0 for each EDC.

Table 38: TRC Results by EDC - RAP

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**

Table 39: TRC Results by EDC - MAP

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**

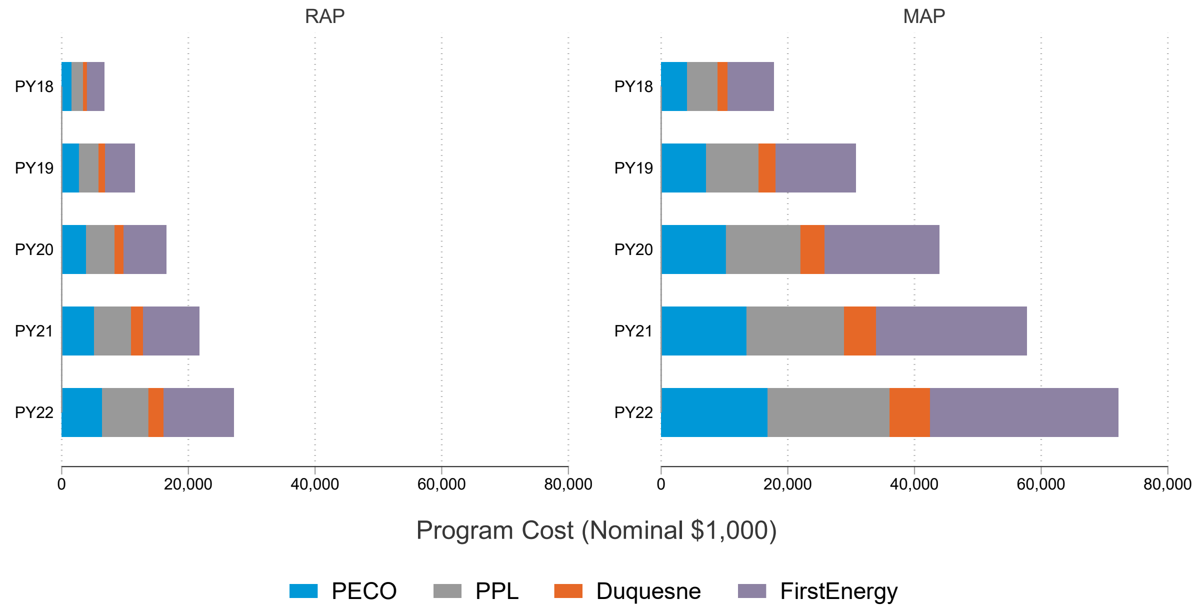
As described in Section 5.1.4, the TRC costs of a DR program are different from the program costs incurred by an EDC to administer the program. In addition to the 75% participant cost assumption, program budgets are in nominal dollars, so there is no discount rate applied to expenditures in PY19-PY22. Table 40 shows the five-year total program expenditure modeled for each EDC and statewide for the RAP and MAP scenarios.

Table 40: Phase V Program Expenditures by EDC - Nominal

EDC	RAP Spending ($1,000)	MAP Spending ($1,000)
PECO	$19,740	$51,755
PPL	$22,463	$59,522
Duquesne	$7,443	$19,547
FirstEnergy	$34,041	$91,562
Statewide	**$83,687**	**$222,386**

Due to the gradual ramp-up in enrollment for this new program design and the fact that all costs are volumetric, Phase V expenditures for the C&I daily load-shifting offering are concentrated toward the second half of the phase. Figure 31 shows the details by year, EDC, and scenario. Almost 60% of the Phase V spending is projected to occur during the last two years of the phase.

Figure 31: Program Spend by Year and EDC



While the MAP scenario has approximately twice the summer and winter MW of RAP, the cost of the MAP scenario is almost 2.7 times higher. Table 41 combines the estimates of achievable potential with the Phase V program expenditures in a unitized acquisition cost metric. The "Phase V MW" column represents the average of the summer and winter Phase V MW values from Section 5.2.1. Importantly, this is the cost of acquiring five years of MW savings, with the intent of creating a metric more analogous to the coincident peak demand reductions from EE that last multiple years. On a $/kW-year basis, the values would be approximately one-fifth of the values shown in the table, or $140/kW-year for RAP and $195/kW-year for MAP.

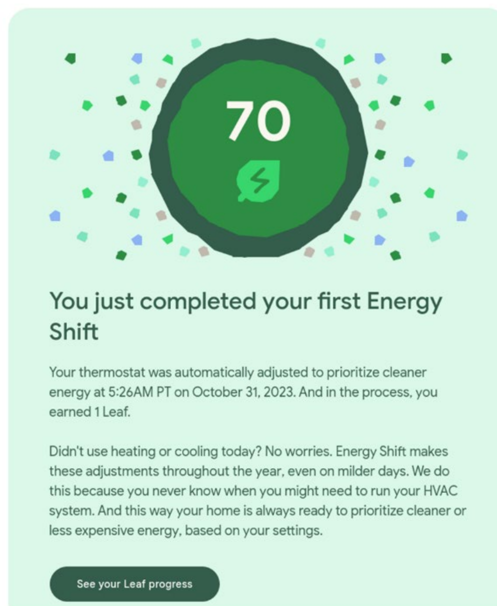
Table 41: Acquisition Cost by EDC and Scenario

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**

6 CONNECTED THERMOSTAT OPTIMIZATION

Residential HVAC load is one of the primary drivers of system peaking conditions in Pennsylvania. During hot summer afternoons and cold winter mornings and evenings, HVAC loads ramp up to maintain comfortable indoor temperatures. Reductions in residential heating and cooling loads through Wi-Fi-connected thermostats can provide substantial amounts of DR, as small reductions per household are aggregated over thousands of customers.

The SWE modeled the DR potential of residential connected thermostats optimized in aggregate daily. Customers with Wi-Fi-connected thermostats opt into an optimization feature where the EDC or its CSP (possibly the thermostat manufacturer) modifies the cooling or heating setpoint during peak hours. Examples of this type of program include Google Nest Renew or Ecobee eco+, where small adjustments are made to thermostats throughout the day to provide participants with less expensive or cleaner energy. While event-based thermostat DR programs typically incentivize participation through rebates or bill credits, in this case, the SWE assumes that the EDC does not subsidize any of the upfront cost of the thermostat or provide an incentive directly to the participant. Instead, the EDC pays a per-participant fee to the CSP. The image to the right is an example of customer communication affirming participation and rewarding a non-monetary incentive in the form of eco-friendly "leaves." This type of daily load-shifting feature is common in areas with widespread TOU rates, where it helps lower customer bills. However, the same algorithms can be applied to avoid emissions or reduce grid strain.



Connected thermostat optimization DR offerings are modeled for each summer and winter of Phase V. New and existing thermostats are treated slightly differently regarding assumptions around costs and enrollment rates. RAP and MAP scenarios differ by opt-in rates, per-participant vendor fees, and load impacts per thermostat.

6.1 METHODS

Table 42 shows the key factors used to model potential load relief and cost effectiveness of the connected thermostat offering.

Table 42: Summary of Connected Thermostat Optimization Modeling Assumptions

Input Variable	Key Assumptions and Notes
Program Design	An opt-in program where small adjustments are made to thermostat set points throughout the day to shift usage out of peak periods.
Peak Load Contribution	Estimated consistent with the connected thermostat measure in the 2026 TRM and 2023 Residential Baseline Study findings. Average per-customer PLC of thermostat-controllable HVAC equipment is 1.1 kW in summer and 3.6 kW in winter.
Participation Rates	Participation is limited to residential customers with eligible cooling and heating systems and connected thermostats. Start year acceptance rates range from 15%-30%, and subsequent year incremental enrollment is between 1%-3%, depending on thermostat vintage and scenario (higher opt-in rates for new thermostats). More aggressive spending and higher opt-in rates are assumed for the MAP scenario.
Load Impacts	15% of baseline peak load shifted for RAP and 20% for MAP. Average seasonal load relief per participant is 0.16-0.22 kW in summer and 0.54-0.72 kW in winter.
Participant Incentive	None. Customers agree to participate in bill savings and/or environmental impact.
Program Administration Costs (Non-incentive), Fixed	Fixed one-time startup costs and fixed annual recurring administrative costs of between \$50k-\$175k, scaled to EDC residential customer count. For this program, fixed recurring costs are assumed equal to startup costs.
Program Administration Costs (Non-incentive), Volumetric	Volumetric recurring costs include annual program admin costs and annual vendor fees totaling between \$30-\$55 per customer. MAP scenario models more aggressive program spending.
Other Key Inputs	Avoided costs from 2026 Avoided Cost Calculator. Inflation rate of 2% from 2026 TRC Test Order. Annual opt-out rate of 5% (assumption).

6.1.1 Peak Load Contribution

The baseline PLCs of residential thermostat-controllable HVAC loads are grounded in the capacity and efficiency values reported in the 2023 Residential Baseline Study. These values are combined with other parameters in the 2026 TRM algorithms for Central Air Conditioner (CAC), Air Source Heat Pump (ASHP), and electric furnace equipment to estimate typical baseline demand during the summer and winter peak periods. Table 43 shows the key parameters.

Table 43: Key Parameters used to Calculate Baseline Peak Load Contribution

Parameter	Units	Source
Capacity, cooling	kBTU/h	2023 Residential Baseline Study
Capacity, heat pump	kBTU/h	2023 Residential Baseline Study
Capacity, furnace	kBTU/h	2026 TRM
Seasonal EE Ratio	BTU/Wh	2026 TRM
Heating Seasonal Performance Factor	BTU/Wh	2026 TRM
Duct Efficiency	fraction	2026 TRM
Summer Coincidence Factor	fraction	EDC-specific calculation based on 2026 TRM assumptions by weather station (Table 44)
Winter Coincidence factor	fraction	

Table 44 shows the EDC-specific residential HVAC coincidence factor assumptions calculated based on the climate region weights from Volume 1 of the 2026 TRM.

Table 44: Weighted EDC Residential HVAC Coincidence Factors

EDC	Summer CF	Winter CF
PECO	0.48	0.30
PPL	0.42	0.36
Duquesne	0.37	0.38
Met-Ed	0.44	0.34
Penelec	0.33	0.40
Penn Power	0.35	0.39
West Penn Power	0.37	0.38

Baseline household demand is multiplied by these coincidence factors to estimate baseline PLC per customer (kW) for the summer and winter seasons. Table 45 shows the average seasonal per-customer PLC eligible for shifting through connected thermostats.

Table 45: Seasonal Baseline Peak Load Contribution per Customer by EDC

EDC	Summer kW	Winter kW
PECO	1.33	2.99
PPL	1.07	3.51
Duquesne	1.08	3.75
Met-Ed	1.21	3.30
Penelec	0.90	3.95
Penn Power	1.03	3.78
West Penn Power	1.08	3.77

6.1.2 Participation Rates

Potential estimates are limited to residential customers with eligible electric cooling and heating systems and connected thermostats. Eligible HVAC system shares come from the 2023 Residential Baseline Study, with eligible cooling systems comprised of Central AC and ASHP, and heating systems comprising only ASHP. Table 46 shows the share of residential households in each EDC territory with eligible heating and cooling systems. Thermostat optimization is most cost-effective for homes with eligible heating and cooling equipment because the program acquires both summer and winter peak demand. PPL has the most advantageous HVAC shares with almost 60% of eligible cooling systems also eligible for the heating season. Duquesne falls at the other end of the spectrum with only approximately 10% of eligible cooling systems also eligible for winter DR.

Table 46: Eligible HVAC Shares by EDC

EDC	Eligible Cooling System Share	Eligible Heating System Share
PECO	73%	16%
PPL	47%	28%
Duquesne	55%	5%
Met-Ed	67%	27%
Penelec	42%	10%
Penn Power	88%	19%
West Penn Power	63%	12%
Statewide	**60%**	**18%**

Connected thermostat share is based on the sum of the smart thermostat and Wi-Fi thermostat share at the time of the 2023 Residential Baseline Study, with an assumed annual growth rate of two percent. Table 47 shows the shares of households with eligible HVAC equipment assumed to have a connected thermostat by program year.

Table 47: Connected Thermostat Share

Program Year	Connected Thermostat Share
PY18	23%
PY19	25%
PY20	27%
PY21	29%
PY22	31%

Table 48 shows the number of eligible households for each EDC in PY18. The eligible households are the product of the number of residential households and the shares from Table 46 and Table 47.

Table 48: First-Year Eligible Customers, by EDC (PY18)

EDC	Residential Households	Eligible Customers, Summer	Eligible Customers, Winter
PECO	1,567,247	263,141	57,675
PPL	1,305,977	141,176	84,105
Duquesne	552,105	69,841	6,349
Met-Ed	528,593	81,456	32,826
Penelec	500,293	48,328	11,507
Penn Power	153,063	30,980	6,689
West Penn Power	638,374	92,500	17,619
Statewide	**5,245,652**	**727,423**	**216,769**

Figure 32 and the tables that follow show participating thermostats for the summer and winter seasons. By PY22, nearly 20% of eligible residential thermostats are actively managed for the season(s) they are eligible. This equals 3% of all residential households during summer, and 1% of all residential households during winter. Customers are assumed to leave the program at a rate of 5% per year in both scenarios.

Figure 32: Thermostat Count by EDC and Season (RAP)

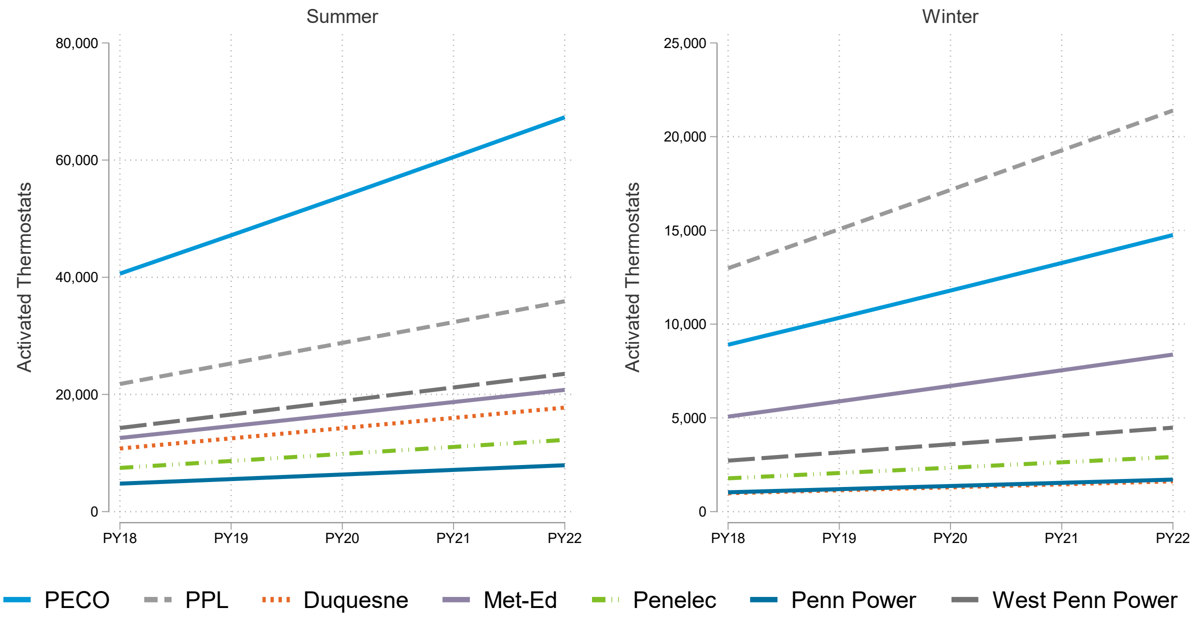


Table 49: Time Series Activated Thermostats by EDC (RAP) (Summer)

EDC	PY18	PY19	PY20	PY21	PY22
PECO	40,615	47,167	53,800	60,514	67,310
PPL	21,790	25,286	28,802	32,343	35,907
Duquesne	10,780	12,509	14,249	15,998	17,759
Met-Ed	12,573	14,596	16,640	18,703	20,784
Penelec	7,459	8,651	9,846	11,045	12,246
Penn Power	4,782	5,553	6,332	7,121	7,918
West Penn Power	14,277	16,567	18,872	21,190	23,524
Statewide	**112,276**	**130,329**	**148,541**	**166,914**	**185,448**

Table 50: Time Series Activated Thermostats by EDC (RAP) (Winter)

EDC	PY18	PY19	PY20	PY21	PY22
PECO	8,902	10,338	11,792	13,263	14,753
PPL	12,981	15,063	17,158	19,268	21,392
Duquesne	980	1,137	1,295	1,454	1,615
Met-Ed	5,067	5,883	6,707	7,538	8,377
Penelec	1,776	2,060	2,345	2,631	2,916
Penn Power	1,032	1,198	1,366	1,537	1,709
West Penn Power	2,719	3,155	3,594	4,036	4,480
Statewide	**33,457**	**38,834**	**44,257**	**49,728**	**55,242**

6.1.3 Load Impacts

Table 51 shows the estimated first-year load impacts per customer, broken down by season. The SWE assumed that 15% of baseline peak load would be shifted for RAP and 20% for MAP, based on similar program benchmarks. The average seasonal load relief per participant is 0.16-0.22 (RAP/MAP) kW in the summer and 0.54-0.72 kW in winter.

Table 51: Seasonal Load Relief Potential per Participant by EDC (kW)

EDC	Summer		Winter	
	RAP	MAP	RAP	MAP
PECO	0.20	0.27	0.45	0.60
PPL	0.16	0.21	0.53	0.70
Duquesne	0.16	0.22	0.56	0.75
Met-Ed	0.18	0.24	0.49	0.66
Penelec	0.13	0.18	0.59	0.79
Penn Power	0.15	0.21	0.57	0.76
West Penn Power	0.16	0.22	0.57	0.75

6.1.4 Program Costs and TRC Costs

The SWE organized the connected thermostat optimization program into three cost categories for modeling. The costs listed below are for PY18. An annual inflation rate of 2% was applied to calculate program budget requirements in PY19-PY22.

1) **Fixed program administration costs**: The SWE assumed this connected thermostat offering will require $150,000 of fixed program administration costs for PECO (including EDC staffing, CSP set-up fees, tracking system integration, and EM&V costs), with the other EDC costs scaled from this assumption based on residential customer count.

2) **Volumetric recurring costs**: Other aspects of program delivery scale proportionately with program size. Connected thermostat manufacturers generally assess application programming interface (API) fees on a per-device basis. Marketing costs and other CSP fees have a linear relationship with the number of program participants. The SWE assumed $30 per device of recurring annual cost for RAP, and $55 for MAP. The vendor fee portion of these costs are pro-rated to 75% for TRC purposes in accordance with the 2026 TRC Test Order for a scenario where an EDC pays a CSP for turnkey DR program delivery.

There are no one-time volumetric costs for this program, as no equipment or installation incentives are provided.

6.2 RESULTS

6.2.1 ACHIEVABLE POTENTIAL

Figure 33 shows the achievable estimates for connected thermostats for the final year of the study horizon (PY22).

Figure 33: Cumulative Potential by EDC, Scenario, and Season

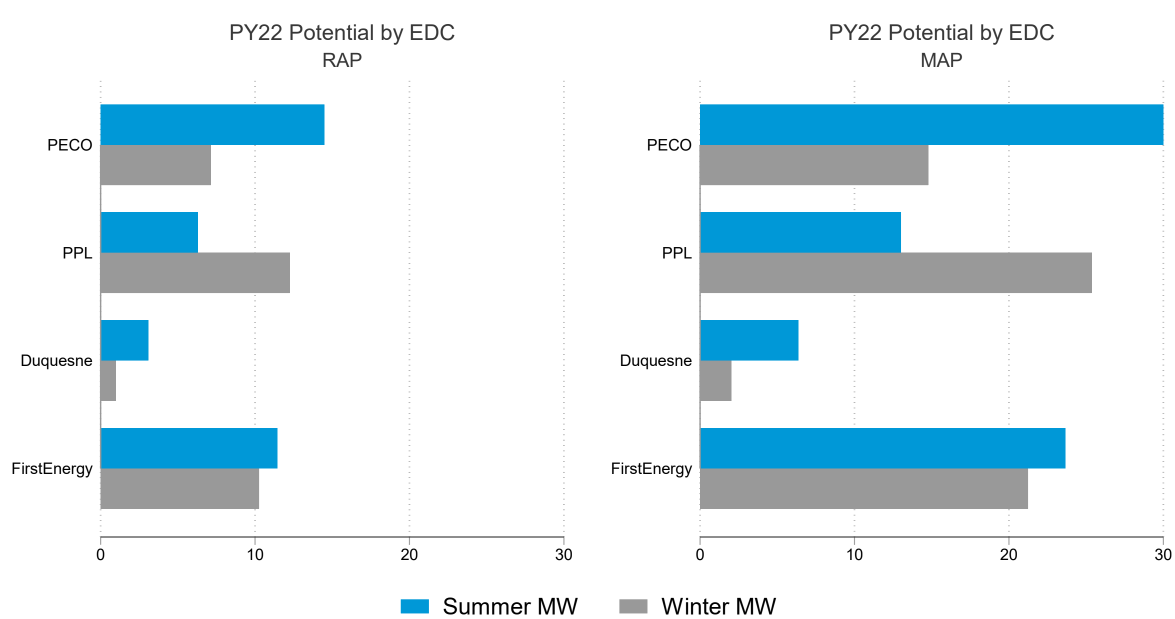


Table 52 and Table 53 show the summer and winter RAP results by EDC for each program year. The Phase V column is the average of the five program years. Potential load relief increases over the phase as enrollment increases. PY22 potential statewide in the RAP scenario is 35 MW, and average RAP over Phase V is 28 MW. Despite per-customer load relief being higher for winter heating loads, total summer MW is slightly higher than winter MW due to a larger portion of eligible cooling systems (see Table 46 earlier in this section). For instance, FirstEnergy's eligible cooling system share is 60%, while the eligible heating system share is only 16 percent.

Table 52: Realistic Achievable Potential by EDC – Summer (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	8.7	10.1	11.6	13.0	14.5	11.6
PPL	3.8	4.4	5.0	5.7	6.3	5.0
Duquesne	1.9	2.2	2.5	2.8	3.1	2.5
FirstEnergy	6.9	8.0	9.2	10.3	11.4	9.2
Statewide	**21.4**	**24.8**	**28.3**	**31.8**	**35.3**	**28.3**

Table 53: Realistic Achievable Potential by EDC – Winter (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	4.3	5.0	5.7	6.4	7.1	5.7
PPL	7.4	8.6	9.8	11.0	12.3	9.8
Duquesne	0.6	0.7	0.8	0.9	1.0	0.8
FirstEnergy	6.2	7.2	8.2	9.2	10.3	8.2
Statewide	**18.6**	**21.5**	**24.5**	**27.6**	**30.6**	**24.6**

Table 54 and Table 55 show the corresponding MAP results. For each season, MAP is approximately double RAP. Higher MAP is driven by higher participation rates and larger per-participant load impacts.

Table 54: Summer MAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	15.8	19.2	22.8	26.3	30.0	22.8
PPL	6.9	8.4	9.9	11.5	13.0	9.9
Duquesne	3.4	4.1	4.9	5.6	6.4	4.9
FirstEnergy	12.5	15.2	18.0	20.8	23.7	18.0
Statewide	**38.5**	**47.0**	**55.6**	**64.2**	**73.0**	**55.7**

Table 55: Winter MAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	7.8	9.5	11.2	13.0	14.8	11.2
PPL	13.4	16.3	19.3	22.3	25.4	19.3
Duquesne	1.1	1.3	1.5	1.8	2.0	1.5
FirstEnergy	11.2	13.7	16.2	18.7	21.2	16.2
Statewide	**33.4**	**40.8**	**48.2**	**55.8**	**63.4**	**48.3**

6.2.2 ECONOMICS

Table 56 shows RAP cost-effectiveness results for the connected thermostat optimization offering. The RAP TRC ratio is positive at 1.23, with net TRC benefits statewide of approximately $5.4M. This is driven mostly by PPL, who incurs 97% of the net benefits and has a highly favorable TRC ratio of 2.1, due to the relatively higher ratio of eligible heating systems in the PPL service territory (28%) relative to eligible cooling systems (47%). Duquesne is the only EDC in the RAP scenario with a TRC ratio below 1.0.

Table 56: TRC Results by EDC - RAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$8,519	$8,437	$82	1.01
PPL	$10,034	$4,770	$5,264	2.10
Duquesne	$1,981	$2,308	$(327)	0.86
FirstEnergy	$8,644	$8,274	$369	1.04
Statewide	**$29,179**	**$23,789**	**$5,389**	**1.23**

Table 57 shows the equivalent MAP TRC results. There is a similar pattern across EDCs, but the net benefits from PPL are not enough to pull the statewide TRC ratio above 1.0 for Phase V. These results suggest that there is more benefit to the Commonwealth in running a smaller, less expensive program, and that the economic viability of the program is highly correlated with electric heating shares.

Table 57: TRC Results by EDC - MAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$16,745	$21,330	$(4,585)	0.79
PPL	$19,720	$11,663	$8,057	1.69
Duquesne	$3,896	$5,717	$(1,821)	0.68
FirstEnergy	$17,001	$20,645	$(3,645)	0.82
Statewide	**$57,361**	**$59,355**	**$(1,994)**	**0.97**

Table 58 shows the five-year total connected thermostat program expenditures modeled for each EDC and statewide for the RAP and MAP scenarios. The MAP scenario results in spending approximately three times RAP spending.

Table 58: Phase V Program Expenditures by EDC - Nominal

EDC	RAP Spending ($1,000)	MAP Spending ($1,000)
PECO	$9,384	$23,837
PPL	$5,298	$13,023
Duquesne	$2,565	$6,386
FirstEnergy	$9,197	$23,063
Statewide	**$26,443**	**$66,308**

As Figure 34 shows, program spending gradually increases over Phase V as volumetric costs increase in line with growing enrollment. In the RAP scenario, PY22 costs statewide are about $6.6 million, while MAP costs are just under $18 million.

Figure 34: Program Spend by Year and EDC

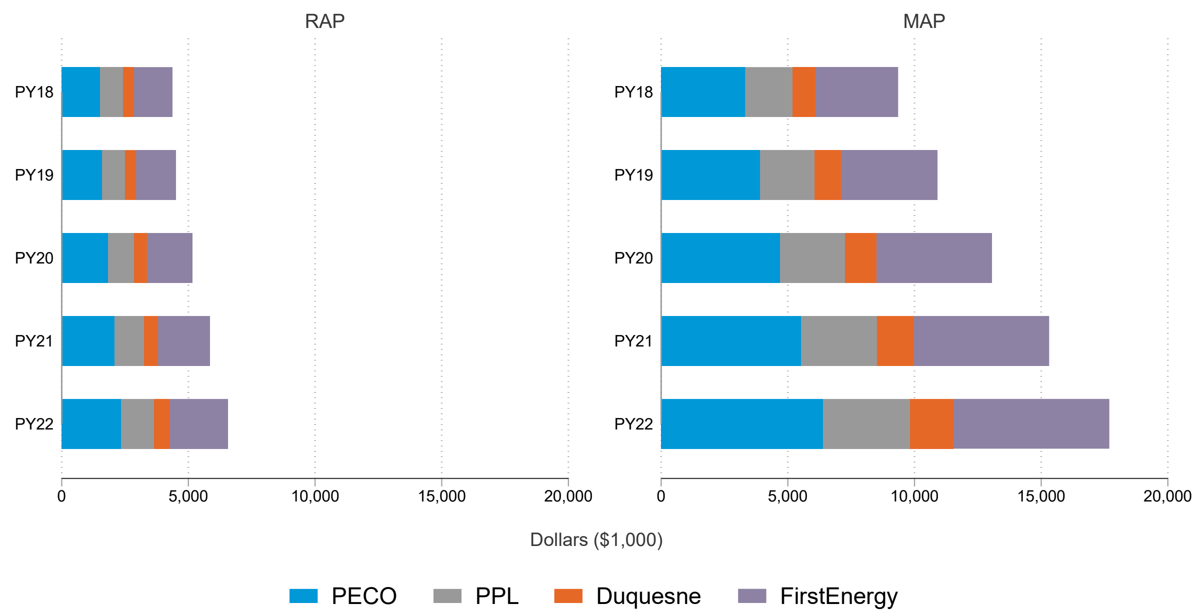


Table 59 presents achievable potential estimates alongside Phase V spending estimates and acquisition costs. The "Phase V MW" column represents the average of the summer and winter Phase V MW values from Section 6.2.1. MAP acquisition costs statewide are about 120% of RAP.

Table 59: Acquisition Costs by EDC and Scenario

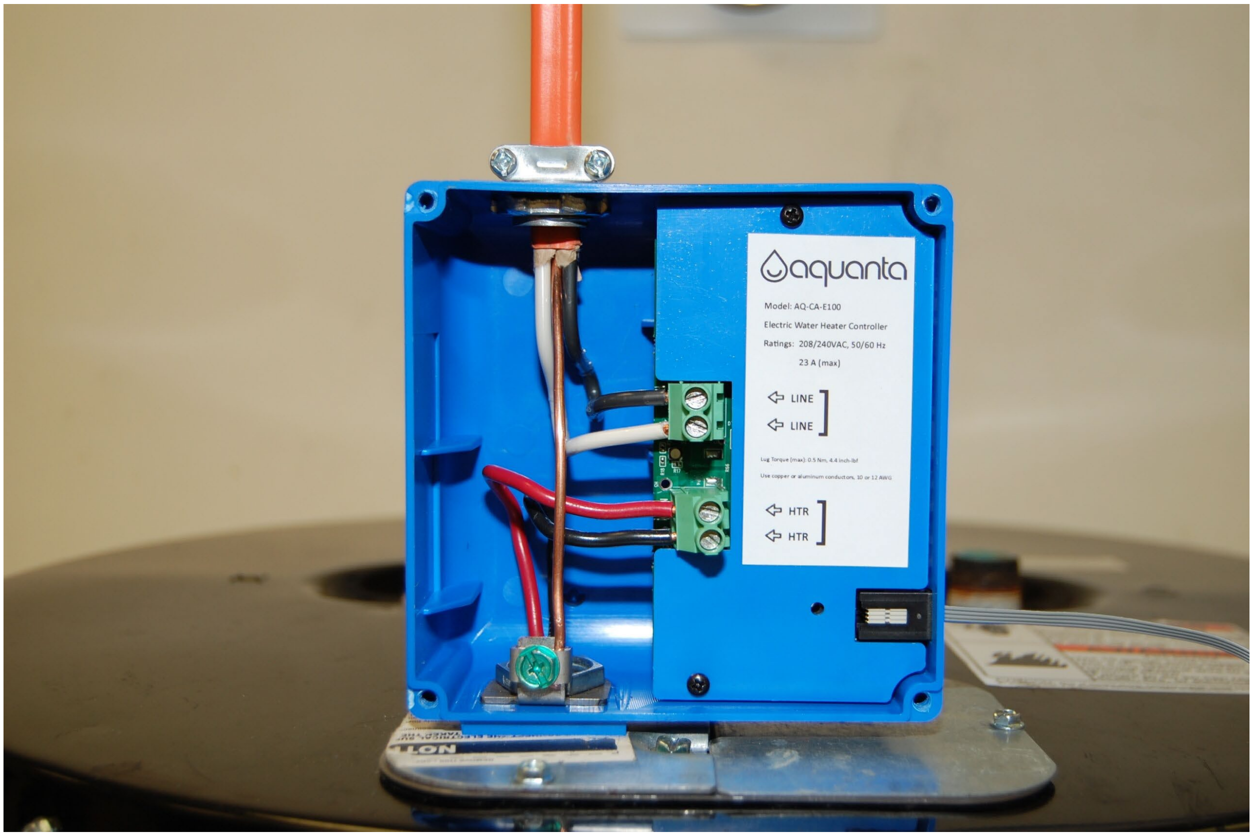
EDC	Scenario	Phase V MW	EDC Spend ($1,000)	Acquisition Cost ($/kW-Phase)
PECO	RAP	8.7	$9,384	$1,085
PPL	RAP	7.4	$5,298	$712
Duquesne	RAP	1.6	$2,565	$1,575
FirstEnergy	RAP	8.7	$9,197	$1,057
Statewide	**RAP**	**26.4**	**$26,443**	**$1,001**
PECO	MAP	17.0	$23,837	$1,400
PPL	MAP	14.6	$13,023	$890
Duquesne	MAP	3.2	$6,386	$1,994
FirstEnergy	MAP	17.1	$23,063	$1,347
Statewide	**MAP**	**52.0**	**$66,308**	**$1,275**

7 DOMESTIC HOT WATER LOAD MANAGEMENT

Domestic hot water (DHW) load is another significant contributor to residential energy use, particularly during morning and evening peak times when household demand for hot water is highest. By leveraging Wi-Fi-connected add-on devices and/or native water heater DR functionality, EDCs can reduce or shift water heating loads during peak periods. DHW loads can be optimized to avoid system peaks by adjusting the timing or intensity of water heating, without compromising customer comfort or access to hot water.

DR capabilities in water heaters are enabled by internet-connected add-on controllers or built-in capabilities to run on preconfigured schedules and/or communicate with utility systems and third-party aggregators. Water heater savings potential is modeled here for daily, ongoing optimization to shift usage out of peak hours.

Figure 35: Photo of Water Heater Controller Unit[46]



7.1 METHODS

The key factors affecting the potential load relief and cost effectiveness of the DHW load management offering are included in Table 60.

[46] Source: aquanta.io

Table 60: Summary of DHW Load Management Modeling Assumptions

Input Variable	Key Assumptions and Notes
Program Design	Add-on water heater controller device or native WH technology shifts WH into storage-only mode to the extent possible during peak hours, while retaining DHW capacity for customers.
Peak Load Contribution	Estimated using National Renewable Energy Laboratory (NREL) and Database of Energy Efficiency Resources (DEER) data to develop hourly load shapes overlaid with the study peak demand periods.
Enrollment Rates	Enrollment is limited to customers with electric water heating. Both resistance and heat pump water heaters are eligible, and HPWHs must have native DR capability. The portion of DR-capable HPWHs grows from 3% to 54% over Phase V.
Load Impacts	Assumed 90% shift out of peak periods for RAP, 100% for MAP using benchmark from 2019 Water Heater DR Evaluation.[47]
Participant Incentive	Equipment and installation incentives are provided for add-on resistance WH controllers. No equipment incentives are offered for HPWHs with native DR capabilities. Recurring costs include annual participation incentives and CSP fees. More aggressive spending assumed for MAP.
Program Admin Costs (Non-incentive), Fixed	Fixed one-time startup costs and fixed annual recurring administrative costs of between \$50k-\$175k, scaled to EDC residential customer count. For this program, fixed recurring costs are assumed equal to startup costs.
Program Admin Costs (Non-incentive), Volumetric	Volumetric one-time costs include recruiting and marketing per-participant costs, as well as controller and installation costs for resistance controllers. Volumetric recurring costs include annual vendor fees totaling between \$55-\$90 per customer. MAP scenario assumes more aggressive program spending.
Other Key Inputs	Avoided costs from the 2026 Avoided Cost Calculator. Inflation rate of 2% from the 2026 TRC Test Order. Annual participant attrition rate of 5% (assumption).

7.1.1 Peak Load Contribution

Resistance and heat pump water heaters are modeled in parallel, with separate assumptions, through the peak load forecasting, enrollment, impact, and costing steps of the potential modeling process. The impacts and economics reported later in this chapter are shown in aggregate. Baseline PLCs are estimated using NREL and DEER equipment-specific load. The SWE sourced resistance water heater load profiles for a representative residential unit in Pennsylvania using NREL ResStock.[48] Each seasonal load shape represents a weighted average of resistance water heater load across housing unit types.

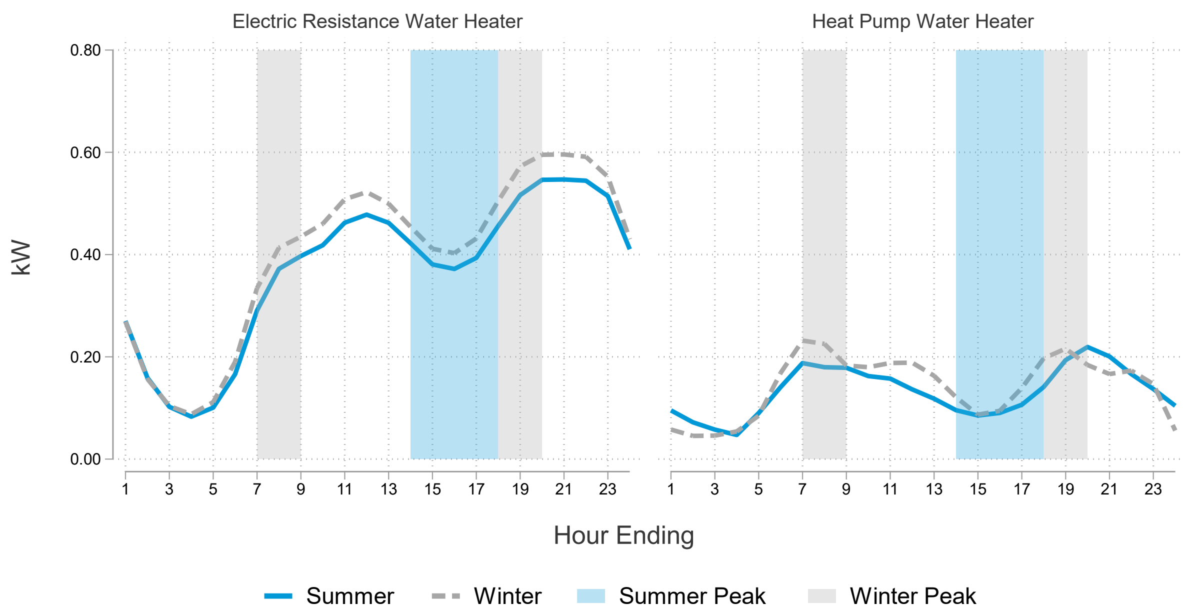
[47] Illume Advising (2019). Water Heater Demand Response Pilot Final Evaluation Report on behalf of Georgia Power Company. Weblink

[48] End-Use Load Profiles for the U.S. Building Stock. National Renewable Energy Laboratory. Load profiles are available under the 'Dataset Access' webpage, but require some user processing. Weblink

The SWE sourced heat pump water heater load shapes from California's DEER.[49] Heat pump water heater load shapes are scaled to create a load profile by assuming annual kWh consumption consistent with the HPWH measure in the 2026 TRM. These seasonal 24-hour load shapes are overlaid with the peak demand periods for the study (see Figure 36) to estimate seasonal PLC per customer for resistance and heat pump water heaters, as shown in Figure 37. DHW loads are higher overall in the winter because the water coming into the home is colder and more energy is required to raise it to the desired temperature.

Figure 36: Domestic Water Heating Baseline Load Shapes

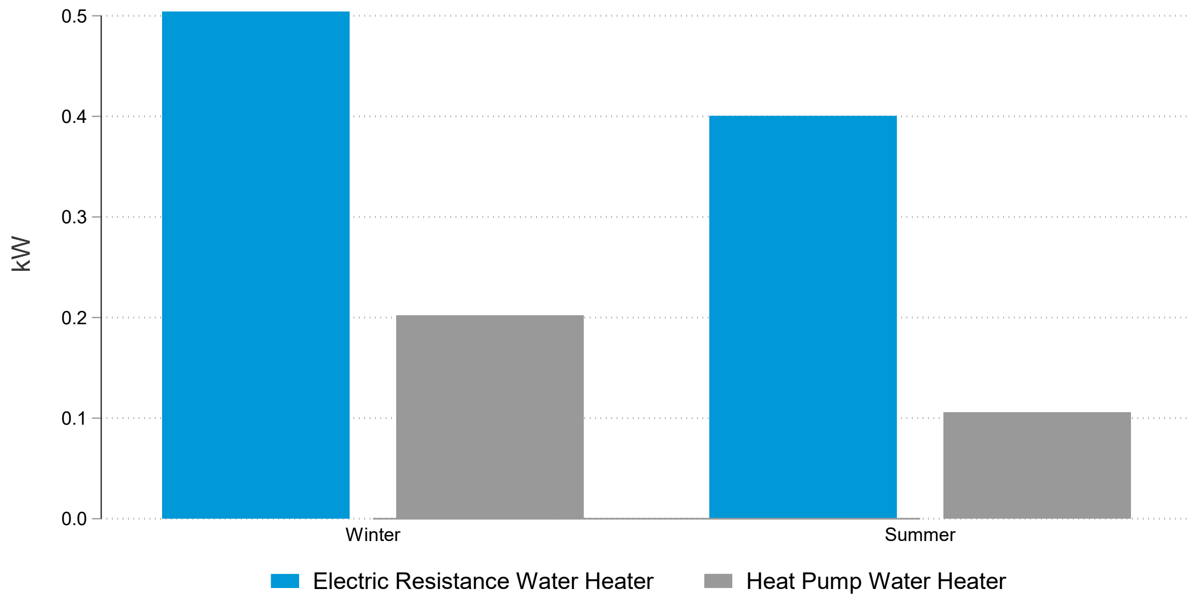
Baseline PLC ranges from 0.1 to 0.5 kW depending on the season and technology type. PLC from each resistance water heater is between 2.5-4 times the PLC from each h



eat pump water heater. This differential illustrates the efficiency difference between HPWH and resistance water heaters and what makes HPWH such a promising EE measure. However, the high efficiency of HPWH works against the technology as a DR measure, because there is less load available to shift.

[49] Database of Energy Efficiency Resources. California Public Utilities Commission. Load profiles are available via the 'LoadShapeSystem_Examples' download, but require some user processing. Weblink

Figure 37: Per-Customer Baseline Peak Load Contribution by Season (kW)



7.1.2 Enrollment Rates

Modeled enrollment in the DHW load management program is limited to residential customers with electric water heating. Figure 38 shows the electric water heating fuel shares by EDC from the 2023 Residential Baseline Study.

Figure 38: Electric Water Heating Fuel Share by EDC

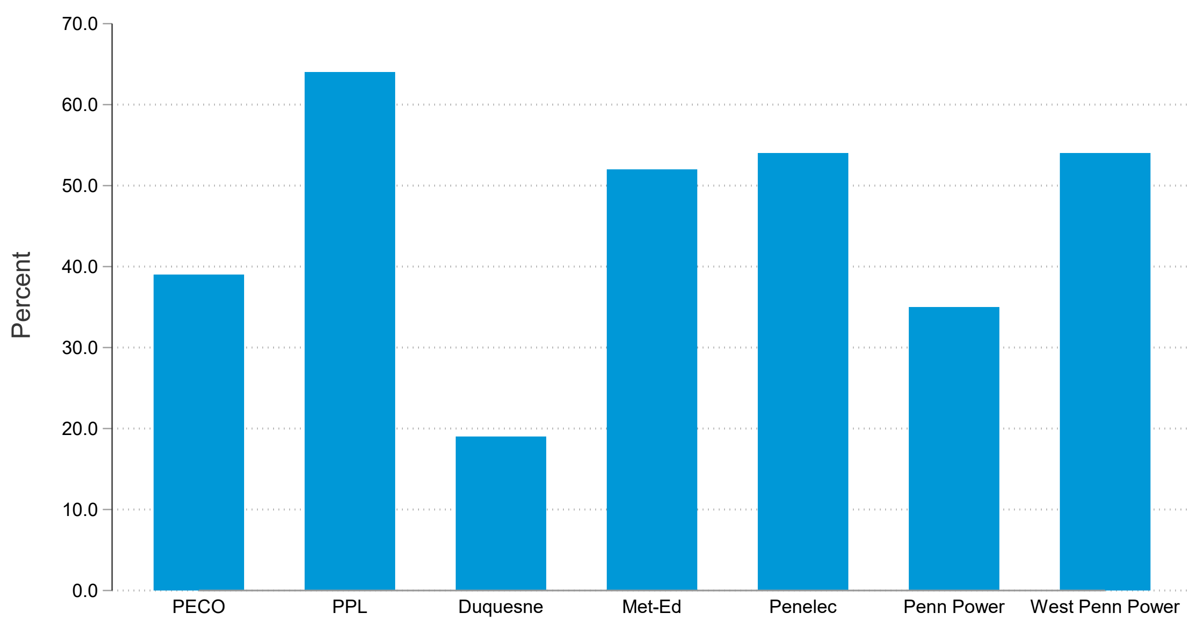


Table 61 shows HPWH share of electric water heaters (vs. traditional electric resistance) and technical applicability assumptions during Phase V. In 2029 (PY20), a new federal standard takes effect that will require heat pump technology to comply with minimum efficiency levels. This is reflected in the growing HPWH share as a portion of electric water heaters (HPWH Share). While add-on controllers are available for most resistance water heaters, only a few HPWHs (about 2%) currently have built-in DR load-shifting capabilities. Typically, DR-enabling technology in HPWHs includes the same scheduling and event functions as the add-on controllers and is designed for compatibility with standard DR communication protocols like OpenADR and CTA-2045. HPWH technical applicability, for purposes of estimating potential, is based on the percentage of HPWHs in the ENERGY STAR qualified product list with DR capability in 2024, extrapolated over the study period. As shown in Table 61, by PY22, 54% of new HPWHs are assumed to have built-in DR load shifting capabilities.

Table 61: HPWH Share of Electric Water Heaters and Technical Applicability by Year

Program Year	HPWH Share	HPWH Technical Applicability
PY18	8%	3%
PY19	9%	7%
PY20	17%	13%
PY21	25%	27%
PY22	33%	54%

Figure 39 shows the two primary limitations for HPWH potential and how they grow to enable more HPWH DR over Phase V.

Figure 39: HPWH Share and Technical Applicability by Year

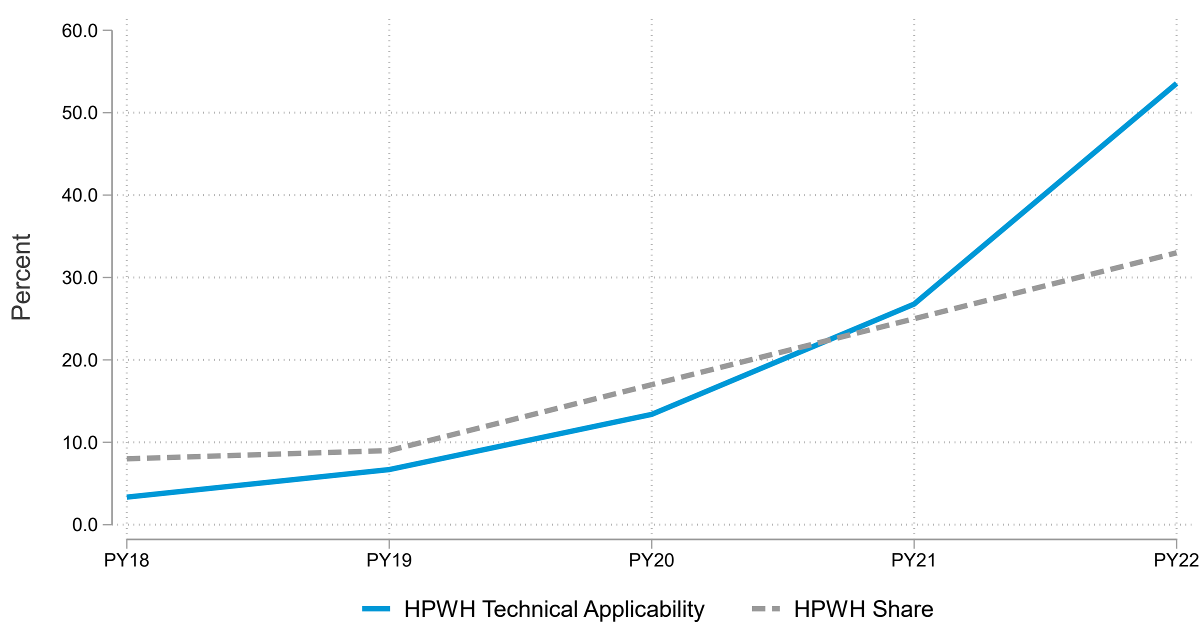


Table 62 shows projected electric water heaters by technology type in PY18, based on electric heating fuel, HPWH share, and HPWH technical applicability (DR capability). By PY22 (not shown), the statewide number of eligible resistance water heaters is projected to decrease to about 1.7 million, and the number of eligible heat pump water heaters is projected to grow to nearly 450,000.

Table 62: First-Year Eligible Water Heaters, by EDC (PY18)

EDC	Residential Households	Eligible Resistance WH	Eligible HPWH
PECO	1,567,247	562,328	1,637
PPL	1,305,977	768,959	2,238
Duquesne	552,105	96,508	281
Met-Ed	528,593	252,879	736
Penelec	500,293	248,546	723
Penn Power	153,063	49,286	143
West Penn Power	638,374	317,144	923
Statewide	**5,245,652**	**2,295,650**	**6,682**

Figure 40 and Figure 41 show projected enrollments by EDC and technology type for the RAP scenario. In PY18, 1% of residential customers with an eligible electric water heater are enrolled (about 23,000 customers), and this increases to 5% (10,600 customers) by PY22. Over the same period PY18-PY22, heat pump water heaters increase from 1% – 19% of enrollments.

Figure 40: DHW Time Series Enrollments by EDC (RAP)

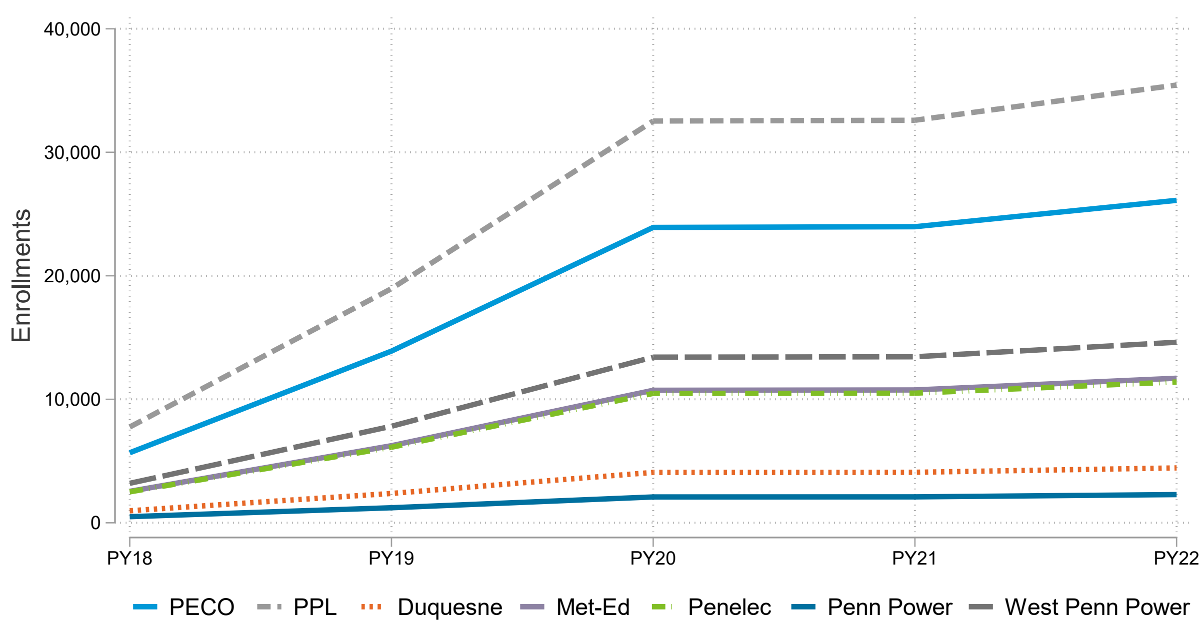
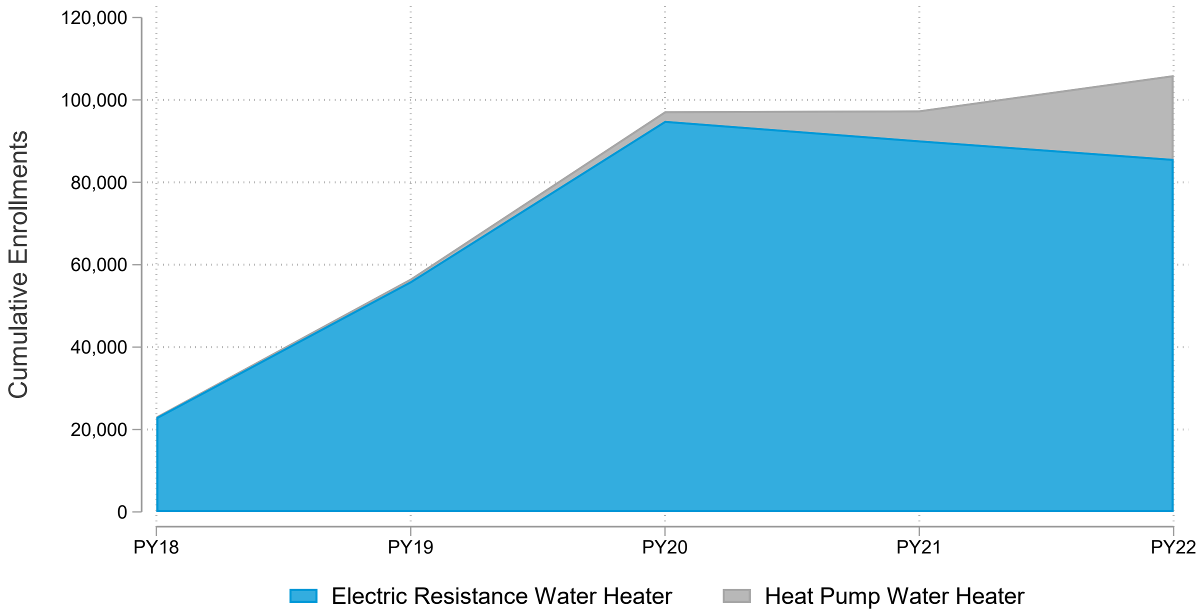


Figure 41: Cumulative Enrollments by DHW Technology Type



7.1.3 Load Impacts

The SWE assumes 90% load shift outside of peak hours for RAP and 100% shift for MAP. Table 63 shows estimated seasonal peak load impacts per customer, by scenario.

Table 63: Seasonal Peak Load Impacts per Customer, by Scenario (kW)

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

7.1.4 Program Costs and TRC Costs

The SWE organized the DHW load management program into three cost categories for modeling. The cost assumptions listed below are for PY18. An annual inflation rate of 2% was applied to calculate program budget requirements in PY19 – PY22.

1) **Fixed program admin costs**: The SWE assumed this DHW load management offering will require $150,000 of fixed program administration cost annually for PECO, with the other EDC costs scaled from this assumption based on residential customer count.

2) **Volumetric one-time costs:** Recruiting/marketing, equipment, and installation costs are estimated for resistance WH controllers. For HPWHs, native DR capability means no equipment or installation costs. The SWE assumed higher recruiting and marketing costs for MAP across

both DHW technology types. Cost assumptions are \$10 – \$50 per participant for recruiting and marketing (depending on scenario and WH type), \$127 for equipment (the average of equipment costs across three devices in the market), and \$250 for professional installation for 50% of resistance controllers purchased. Incentives are pro-rated to 75% for TRC purposes in accordance with the 2026 TRC Test Order.

3) **Volumetric recurring costs**: Other aspects of program delivery scale in proportion to program size. DHW DR service providers generally charge a per-customer fee. In this case the assumption came from multiple vendors included in a 2020 pilot evaluated by the SWE, adjusted for inflation. Marketing costs and CSP fees have an approximately linear relationship with the number of program participants. The SWE assumed \$49 – \$55 per device (varies by technology type) of recurring annual cost for RAP, and \$74-80 for MAP.

7.2 RESULTS

7.2.1 ACHIEVABLE POTENTIAL

Figure 42 shows achievable potential estimates for DHW load management for the final year of the study horizon (PY22).

Figure 42: Cumulative Potential by EDC, Scenario, and Season

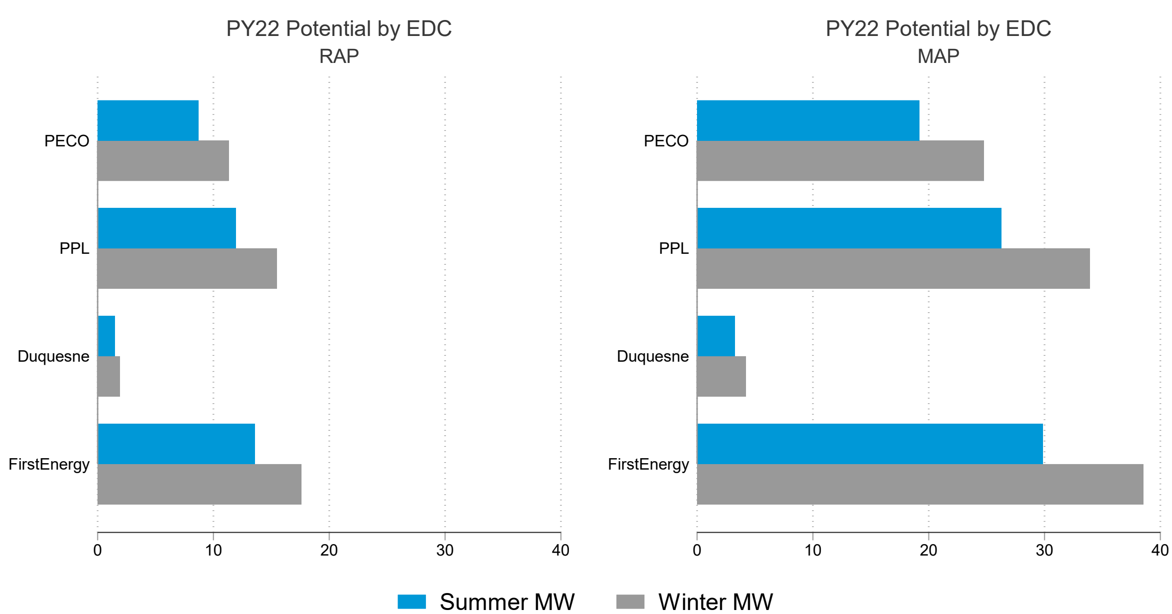


Table 64 and Table 65 show the summer and winter RAP results by EDC for each program year. The Phase V column is the average of the five program years. In both scenarios, the winter MW is higher than summer due to higher baseline PLCs during winter.

Table 64: Realistic Achievable Potential by EDC – Summer (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	2.2	5.4	9.1	8.8	8.7	6.8
PPL	3.0	7.4	12.5	12.1	11.9	9.4
Duquesne	0.4	0.9	1.6	1.5	1.5	1.2
FirstEnergy	3.4	8.4	14.2	13.7	13.6	10.7
Statewide	**9.0**	**22.0**	**37.5**	**36.1**	**35.7**	**28.1**

Table 65: Realistic Achievable Potential by EDC – Winter (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	2.8	6.8	11.5	11.2	11.3	8.7
PPL	3.8	9.3	15.8	15.4	15.5	12.0
Duquesne	0.5	1.2	2.0	1.9	1.9	1.5
FirstEnergy	4.3	10.6	18.0	17.5	17.6	13.6
Statewide	**11.4**	**27.8**	**47.3**	**45.9**	**46.3**	**35.7**

MW potential increases over the phase as enrollment increases. The SWE assumed between 1% – 5% incremental annual enrollment of eligible electric water heating customers, depending on scenario and WH technology type, with program enrollment plateauing after PY20 when there are fewer remaining years in the phase to accrue benefits and offset upfront costs. Section 4.1 discusses this truncated measure life issue and the challenges it creates for capital investments in DR in more detail. Customers opt out of the program at a rate of 5% per year in both scenarios.

Table 66 and Table 67 show corresponding MAP results for the DHW load management offering. MAP MW is about two times the RAP MW for both scenarios. Much like the connected thermostat optimization offering, higher MAP potential is driven by higher enrollment rates and larger per-participant load impacts.

Table 66: Maximum Achievable Potential by EDC – Summer (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	4.9	11.9	20.3	19.5	19.2	15.2
PPL	6.7	16.4	27.8	26.7	26.3	20.8
Duquesne	0.8	2.0	3.4	3.3	3.3	2.6
FirstEnergy	7.6	18.6	31.6	30.4	29.8	23.6
Statewide	**20.0**	**48.9**	**83.2**	**80.0**	**78.5**	**62.1**

Table 67: Maximum Achievable Potential by EDC – Winter (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	6.1	15.0	25.6	24.8	24.8	19.3
PPL	8.5	20.6	35.1	34.0	33.9	26.4
Duquesne	1.0	2.6	4.3	4.2	4.2	3.3
FirstEnergy	9.6	23.4	39.9	38.6	38.5	30.0
Statewide	**25.2**	**61.6**	**104.9**	**101.5**	**101.4**	**78.9**

7.2.2 Economics

Table 68 includes RAP cost-effectiveness results for the DHW load management program. Net TRC benefits statewide are approximately negative $23 million, with negative benefits across all EDCs, and a statewide TRC ratio of 0.60. Negative totals are shown in parentheses.

Table 68: TRC Results by EDC - RAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$6,825	$14,226	$(7,401)	0.48
PPL	$14,592	$18,899	$(4,307)	0.77
Duquesne	$1,142	$2,584	$(1,442)	0.44
FirstEnergy	$11,999	$21,523	$(9,524)	0.56
Statewide	**$34,559**	**$57,232**	**$(22,673)**	**0.60**

MAP TRC results result in approximately 2.5 times the negative net benefits of RAP and a slightly lower TRC ratio of 0.57.

Table 69: TRC Results by EDC - MAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$15,100	$33,224	$(18,124)	0.45
PPL	$32,273	$44,741	$(12,468)	0.72
Duquesne	$2,529	$5,827	$(3,299)	0.43
FirstEnergy	$26,544	$50,695	$(24,151)	0.52
Statewide	**$76,446**	**$134,487**	**$(58,041)**	**0.57**

Table 70 shows the five-year total DHW load management program expenditures modeled for each EDC and statewide for the RAP and MAP scenarios. MAP scenario spending is in line with savings potential at approximately double the spending for RAP.

Table 70: Phase V Program Expenditures by EDC - Nominal

EDC	RAP Spending ($1,000)	MAP Spending ($1,000)
PECO	$16,023	$38,630
PPL	$21,303	$52,051
Duquesne	$2,904	$6,763
FirstEnergy	$24,253	$58,962
Statewide	**$64,484**	**$156,405**

Figure 43 illustrates how Phase V program spending for the DHW offering is heaviest in PY20, when installation of new controllers is heaviest. Average spending per year over Phase V in the RAP scenario is about $13M, and for MAP, it is just above $31M.

Figure 43: Program Spend by Year and EDC

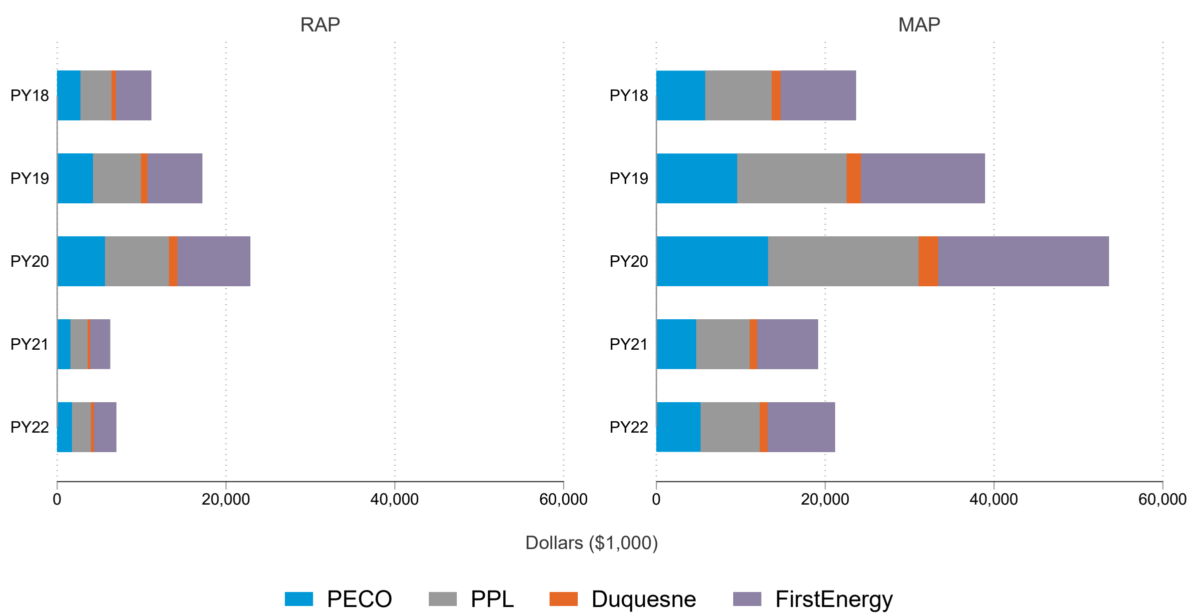


Table 71: Acquisition Costs by EDC and Scenario

EDC	Scenario	Phase V MW	EDC Spend ($1,000)	Acquisition Cost ($/kW-Phase)
PECO	RAP	7.8	$16,023	$2,058
PPL	RAP	10.7	$21,303	$1,997
Duquesne	RAP	1.3	$2,904	$2,196
FirstEnergy	RAP	12.1	$24,253	$2,001
Statewide	**RAP**	**31.9**	**$64,484**	**$2,022**
PECO	MAP	17.2	$38,630	$2,244
PPL	MAP	23.6	$52,051	$2,206
Duquesne	MAP	2.9	$6,763	$2,312
FirstEnergy	MAP	26.8	$58,962	$2,200
Statewide	**MAP**	**70.5**	**$156,405**	**$2,217**

7.2.3 Resistance and HPWH Contributions to Program Impacts and Costs

The two water heating technologies included in potential modeling, HPWH and traditional electric resistance water heaters, have widely different per-customer impacts and costs. DHW load management is a more expensive add-on for resistance water heaters due to the need to add an aftermarket controller; therefore, the SWE assumes lower enrollment for resistance water heaters. Resistance units also contribute more to baseline peak load and demand response potential, both on a per-unit and overall basis, as most electric water heaters statewide are resistance units. The SWE estimates resistance water heaters at 92% of the Pennsylvania electric water heating equipment stock in PY18, dropping to 67% by PY22 once new federal standards take effect.

Table 72 and Table 73 show how resistance water heating dominates total impacts and spending in both scenarios, even as HPWH enrollment grows as a portion of the program over Phase V. Resistance water heaters are more cost effective despite higher per-project costs due to peak load impacts per customer on the order of two to five times that of HPWHs and (see Table 63 in the prior section).

Table 72: Seasonal Impacts by Scenario, by DHW Technology

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%

Table 73: Key Economic Indicators by DHW Technology

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

8 ELECTRIC VEHICLE MANAGED CHARGING

Electric vehicle charging load is a key driver of the forecasted growth in peak demand presented in Section 3 of this study. While EV charging load has not been a significant contributor to peak demand historically, rapid EV adoption is forecasted to take place across the Commonwealth.

Conventional wisdom among utility planners is that without behavioral or rate-based interventions, EV owners, particularly light-duty EV (LDEV) owners that do most charging at home, tend to plug in and begin charging in the early evening hours (referred to as an "unmanaged" charging shape). This is reflected in the load shape assumed by PJM in its peak load forecast for the region, as the LDEV load shape peaks in hour ending (HE) 19 (Figure 44). With unmanaged charging, the highest EV demand coincides largely with the summer peak period, and to a slightly lesser extent, the winter peak period. Managed charging programs are a non-rate-based method of reducing EV demand during these peak periods by incentivizing off-peak charging. Managed charging programs 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").

For the scope of this study, the SWE modeled a program that gives participants a monthly incentive for enrollment, but that is not necessarily either "passive" or "active." The SWE modeled both an LDEV program and a medium- and heavy-duty EV (MHDEV) program targeted toward companies managing commercial MHDEV fleets.

It is worth noting that other types of EV load management, such as EV time-of-use rates, have been considered and tested in the Commonwealth. This study only focuses on the DR potential of managed charging programs in Pennsylvania and does not look at other types of EV load management. Ultimately, the Commission and EDCs will need to decide whether the forecasted growth in transportation load is best managed through Act 129, managed through rates, or not managed at all.

8.1 MODELING ASSUMPTIONS

The assumptions used to develop the EV managed charging model were benchmarked against several past evaluations of managed charging programs from across the country. Fundamental assumptions such as load shapes and vehicle count forecasts come from PJM's load forecast.

8.1.1 Reference Load

The reference load assumption is crucial to the EV managed charging model because the only load with potential to be shifted is that of unmanaged, "natural" EV charging behaviors. To align with the Act 129 Avoided Cost of Transmission and Distribution Capacity Study,[50] the SWE leveraged PJM hourly charging shapes for LDEVs and MHDEVs in 2024 that were derated slightly[51] to align with 2024 PJM Load Forecast Report EV energy totals.[52] Figure 44 shows the unmanaged LDEV daily load shape.

[50] Act 129 Avoided Cost of Transmission and Distribution Capacity Study Prepared for PA PUC. July 2024. Weblink.
[51] The original PJM load shapes were multiplied by a factor of 0.8915 so that the assumed yearly energy consumption, multiplied by the PJM vehicle forecast, matched the electric vehicle energy totals published by PJM.
[52] Table E-4, referenced at: Weblink

Figure 45 shows the unmanaged MHDEV daily load shape. The expected daily kWh consumed per MHDEV is considerably higher than the LDEV estimate at 72.8 and 9.2 kWh per day, respectively.

Figure 44: Unmanaged LDEV 24-Hour Load Shape

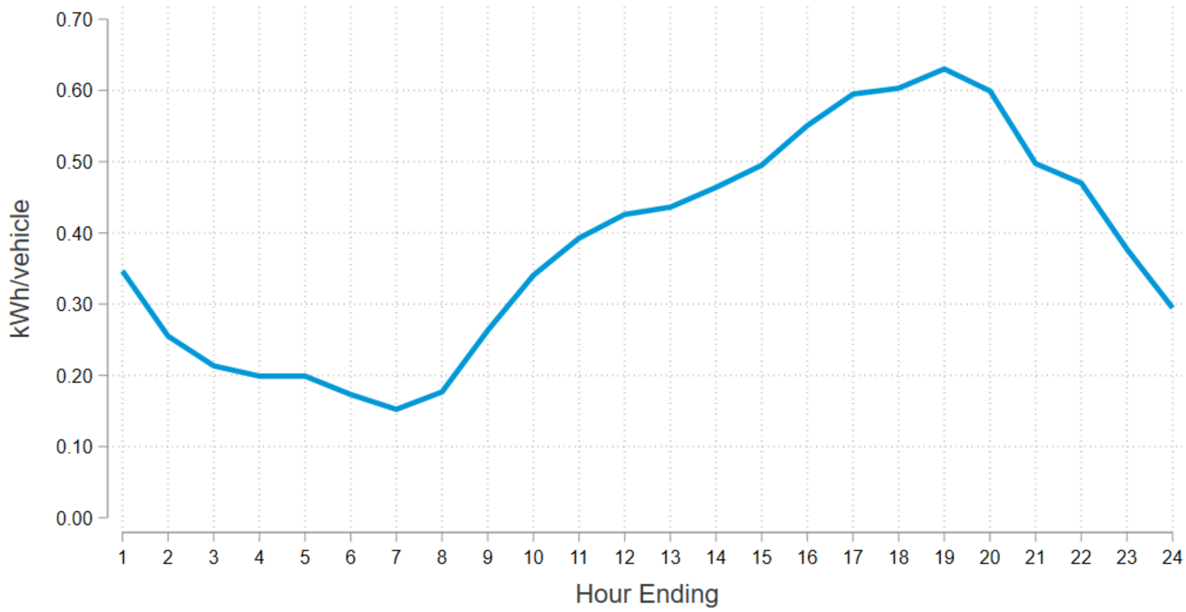
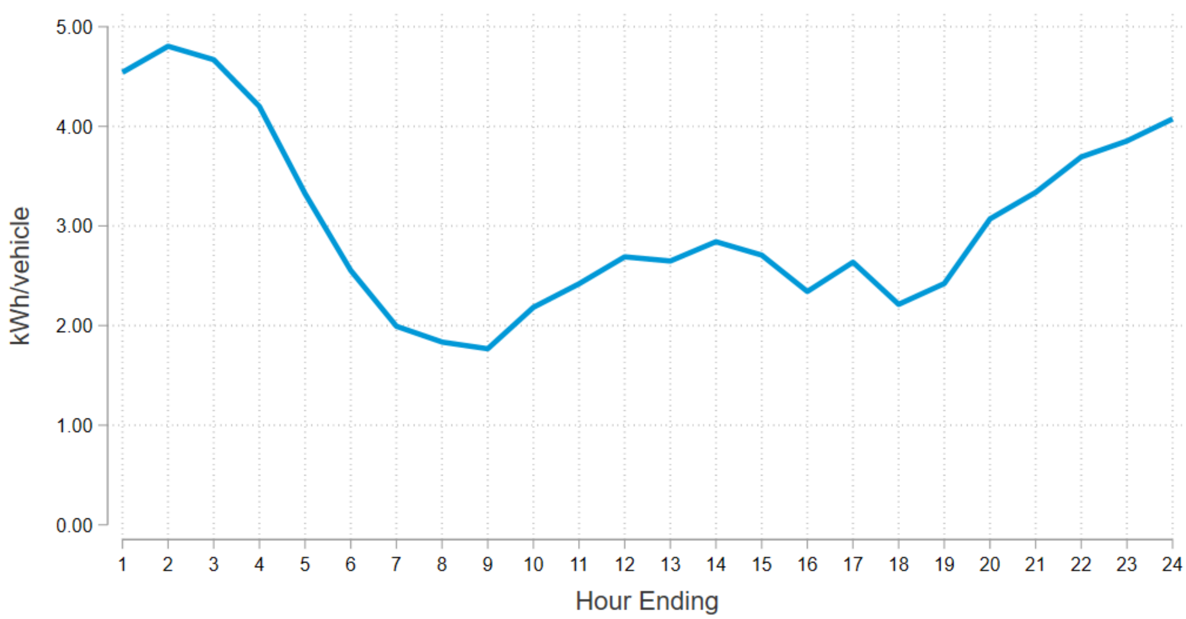


Figure 45: Unmanaged MHDEV 24-Hour Load Shape



Most LDEV charging happens in the evening hours, while projected MHDEV charging is heaviest in the very early morning and ramps up in the late evening. Table 74 shows the per-vehicle PLC, measured at the meter, for the summer and winter peak definitions by technology.

Table 74: Per-Vehicle PLC (kW) by Technology and Season

Technology	Summer	Winter
LDEV	0.56	0.42
MHDEV	2.48	2.27

8.1.2 Load Impacts

The SWE reviewed evaluations of both active and passive managed charging programs to benchmark load impact assumptions. The results vary by jurisdiction, but active managed charging typically results in greater peak load reductions per vehicle because the charger is remotely throttled to slow charging when vehicles are plugged in during peak hours. In contrast, passive managed charging results in lesser peak load reductions, as participants can charge freely during peak hours but risk losing their program incentives.

From the review of LDEV managed charging evaluations, the SWE found that passive managed charging programs saw load reductions of about 0.25 kW/vehicle during peak hours, while active managed charging programs saw load reductions ranging from 0.40 to as high as 1.74 kW/vehicle. Considering the large variance in reported managed charging load reductions, the SWE adopted values approximately in the middle of the range observed in other jurisdictions. The SWE assumed an 80% load reduction for the MAP scenario and a 60% load reduction for the RAP scenario. With LDEV having a 0.57 kW summer PLC, these percentage impacts equate to 0.46 kW/vehicle and 0.35 kW/ vehicle, respectively.

There is much less industry literature on MHDEV managed charging programs, as these programs are still very new and are typically in their pilot phases, with program impacts yet to be evaluated. To account for uncertainty about what types of demand reductions can be expected for programs targeting these types of vehicles, the SWE used lower load reduction percentages for MHDEVs. Table 75 documents the load reduction assumptions by season, vehicle type, and scenario. Even with the lower assumed percent load reductions, MHDEV managed charging load reductions are larger than for LDEVs because the per-vehicle PLC is so much higher for MHDEV.

Table 75: Load Impact Assumptions

Technology	Scenario	Percent Impact	Summer Impact (kW/vehicle)	Winter Impact (kW/vehicle)
LDEV	MAP	80%	0.45	0.33
	RAP	60%	0.34	0.25
MHDEV	MAP	60%	1.49	1.36
	RAP	40%	0.99	0.91

8.1.3 Vehicle Forecast

To determine the scale of the potential managed charging programs, the SWE used a publicly available PJM electric vehicle count forecast, published alongside their 2024 Load Forecast Report. The forecast contains the number of both LDEVs and MHDEVs by load zone within the PJM footprint for the years 2024 through 2039. For the APS and ATSI zones, which include the legacy FirstEnergy territories of West Penn Power and Penn Power but do not map 1:1 to those rate districts, vehicle counts were multiplied by the ratio of the rate district peak to the zonal peak (about 43% for West Penn Power/APS and about 7% for Penn Power/ATSI) to estimate counts by rate district.

Since the PJM electric vehicle forecast represents both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV), the forecasts were derated slightly to better represent the number of vehicles eligible for a managed charging program. Since BEVs have a higher yearly kWh consumption and typically charge at higher power levels than PHEVs, those are the vehicles that provide the most demand response potential and are more frequently enrolled in managed charging programs. Using zero-emissions vehicle registration data from the Pennsylvania Department of Transportation (PennDOT), the SWE estimated that approximately 35% of LDEVs registered in Pennsylvania are PHEVs. Thus, the SWE multiplied the LDEV forecasts by 0.65 to create a BEV-only forecast. However, very little data was available on medium- and heavy-duty PHEVs and BEVs. For MHDEVs, the SWE assumed a far smaller portion of vehicles would be plug-in hybrids, as MHDEVs primarily consists of utility vehicles rather than passenger or consumer vehicles; therefore, the PJM forecast was multiplied by 0.95. Since the PJM forecast was yearly and represented summer counts, the SWE calculated winter counts as the average of the summer counts before and after each winter in Phase V. Table 76 shows the EV forecast used in the model, by EDC, for each summer and winter of the five years of Phase V. The legacy FirstEnergy EDCs, or rate districts, are combined.

Table 76: 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

8.1.4 Enrollment Rates

The number of vehicles participating in the managed charging program at any given time is determined by the vehicle forecast documented above, enrollment rate assumptions, and an assumed attrition rate. The program gains participants by enrolling some percentage of the new EVs on the system in each season. The enrollment rate of these incremental vehicles depends on the selected scenario. The SWE found in their review of relevant literature that the most successful opt-in managed charging programs had enrollment rates of only 20% among eligible customers. Thus, a 20% enrollment rate was set as the benchmark for participation in the MAP scenario. In the RAP scenario, which assumes lower incentives, the assumed enrollment rate is 10%. The assumed enrollment rates do not vary for LDEVs and MHDEVs, nor do these rates change over time. Table 77 shows enrollment rates by technology, scenario, and program year. The growth in program enrollment over time is driven by the growth in the number of EVs in each EDC territory.

Table 77: Enrollment Rates

Program Year	LDEV		MHDEV	
	MAP	RAP	MAP	RAP
PY18	20%	10%	20%	10%
PY19	20%	10%	20%	10%
PY20	20%	10%	20%	10%
PY21	20%	10%	20%	10%
PY22	20%	10%	20%	10%

The program also loses a small number of participants in each season through attrition. In each year, the SWE assumes that 5% of the cumulative enrollments in the program elect to leave the program. This could be because they close their account, purchase a new vehicle, or simply no longer wish to allow their EDC to influence their charging behavior. The 5% attrition rate assumption is consistent with other demand response potential studies. Figure 46 shows the net LDEV managed charging participants for each EDC over the five years of Phase V by scenario. Figure 47 shows the net MHDEV managed charging participants for each EDC over the five years of Phase V by scenario. Note that LDEV participant counts are about seven times the MHDEV participant counts. For each technology, MAP participant counts are about double that of RAP, due to the doubled enrollment rates.

Figure 46: Participating LDEV by Scenario

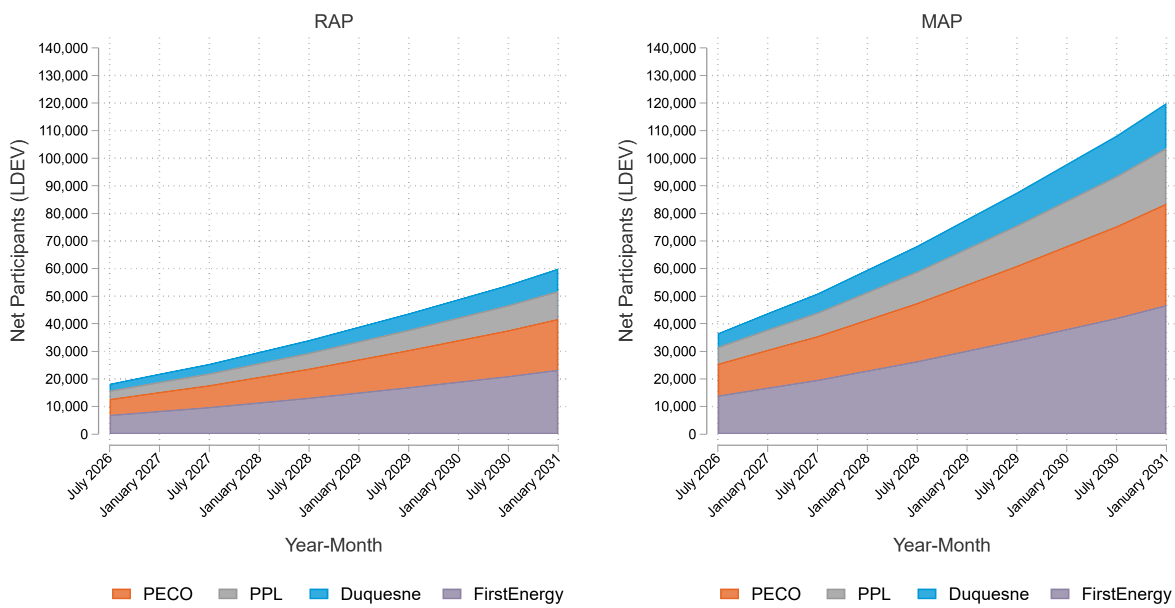
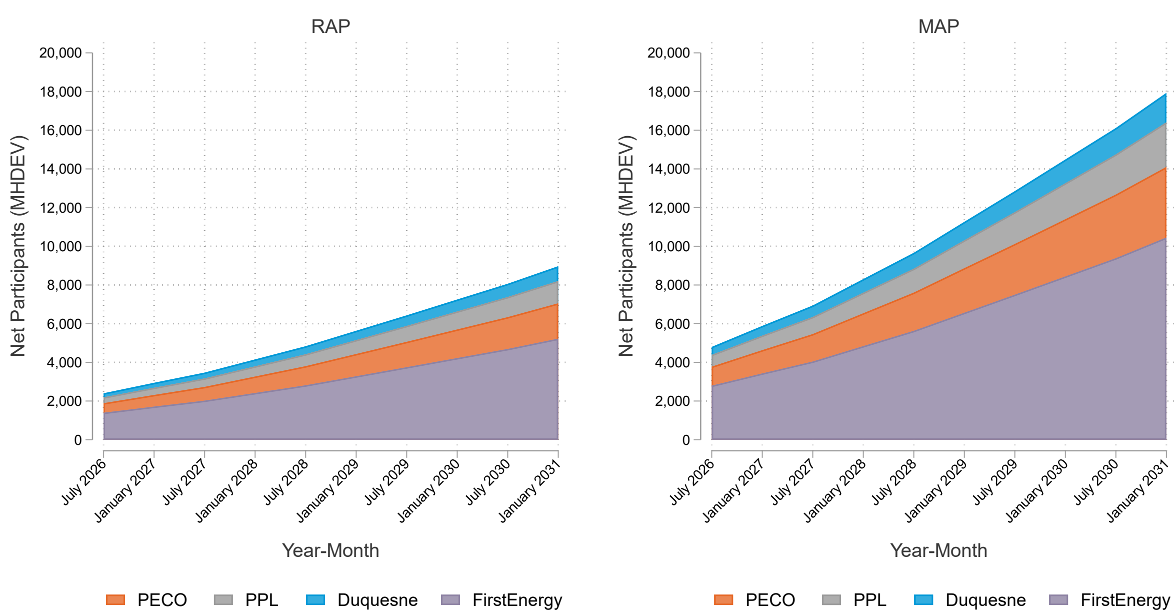


Figure 47: Participating MHDEV by Scenario



8.1.5 Program Costs

For modeling, program costs were split into four categories: fixed one-time, fixed recurring, volumetric one-time, and volumetric recurring. All volumetric costs were modeled separately for LDEV and MHDEV as the incentive structures are different. Fixed costs, however, such as program administration costs, were largely the same for these technologies, as running each type of program is likely quite similar. The largest portion of recurring costs are participant incentives and vendor fees. Participant incentives go to participants every year that they are enrolled, and vendor fees need to be paid on a recurring basis to have access to telemetry or charger data to verify that participants are complying with the program and reducing their on-peak charging. All participant incentive amounts were benchmarked against existing managed charging offerings.

Table 78 documents the per-participant volumetric costs as well as TRC costs by technology and scenario. The per-unit volumetric costs in the managed charging model do not vary by EDC. For costs that go directly to participants, the TRC cost is 75% of the cost to the EDC. The MAP scenario includes an additional volumetric one-time cost category that is not included in the RAP scenario. This "Participant Sign-up Bonus" is intended to entice EV owners to join the program and even help with the upfront cost of the charging equipment. The extra cost category is a key reason why the assumed enrollment rates and costs are higher for MAP.

Table 78: Volumetric Costs by Technology and Scenario

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

Table 79 documents the statewide total fixed costs by scenario and technology. These costs do vary by EDC based on their relative sizes. The TRC cost is equal to the EDC cost for these administrative cost categories. The budget amounts in the table are for PY18, and the first program year is assigned both the one-time and recurring costs. An annual inflation rate of 2% was applied to calculate program fixed recurring budget requirements in PY19-PY22. The SWE assumes economies of scale for an EDC that operates a managed charging program for both LDEV and MHDEV, so the fixed costs of the "Both" technology rows are less than the sum of the corresponding LDEV and MHDEV rows.

Table 79: Fixed Costs by Technology

Program Technology	Category	Cost Description	Amount ($2026)
LDEV	Fixed One-Time	Program Startup	$175,000 statewide, varies by EDC
LDEV	Fixed Recurring	Program Admin	$350,000 statewide, varies by EDC
MHDEV	Fixed One-Time	Program Startup	$175,000 statewide, varies by EDC
MHDEV	Fixed Recurring	Program Admin	$350,000 statewide, varies by EDC
Both	Fixed One-Time	Program Startup	$262,500 statewide, varies by EDC
Both	Fixed Recurring	Program Admin	$525,000 statewide, varies by EDC

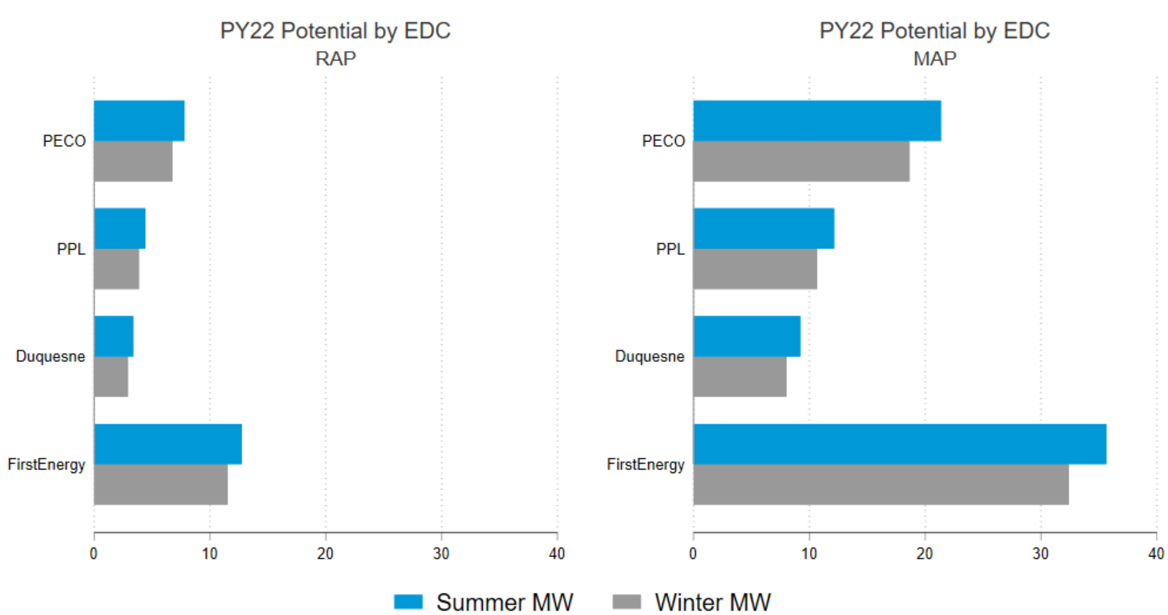
8.2 RESULTS

The managed charging model considered two technologies: LDEV managed charging and MHDEV managed charging. This chapter summarizes the results for a combined program as well as results broken out by the separate technologies.

8.2.1 Achievable Potential

Figure 48 shows the combined program (LDEV and MHDEV) potential estimates for the last year of the study horizon (PY22) by EDC, scenario, and season.

Figure 48: Cumulative Potential by EDC, Scenario, and Season



The difference in statewide MAP (78 MW in PY22) and RAP (28 MW in PY22) is due to the combined effects of increased enrollment and larger per-vehicle kW impacts. The MAP incremental enrollment rate is double that of the RAP scenario, and the MAP per-vehicle load impacts are 33% larger and 50%

larger than RAP for LDEV and MHDEV, respectively. This translates to more vehicles with charging loads to curtail and more charging loads being curtailed by each vehicle. FirstEnergy leads the other three EDCs in terms of managed charging potential, primarily due to having the largest forecasted number of vehicles in their service territory. For all EDCs, summer MW is slightly larger than winter MW, due to the higher summer PLC. For both LDEV and MHDEV, more of the unmanaged load coincides with the summer peak period than the winter peak period.

Statewide, about two-thirds of the combined program potential comes from LDEV managed charging, and one-third comes from MHDEV, although this split varies by EDC. Figure 49 shows the LDEV and MHDEV contributions to the total summer MW under the RAP scenario, by year and EDC. Table 80 displays the combined LDEV and MHDEV MW, as well as the statewide total. Phase V potential is simply the average potential across the five years of the phase.

Figure 49: LDEV and MHDEV RAP – Summer MW

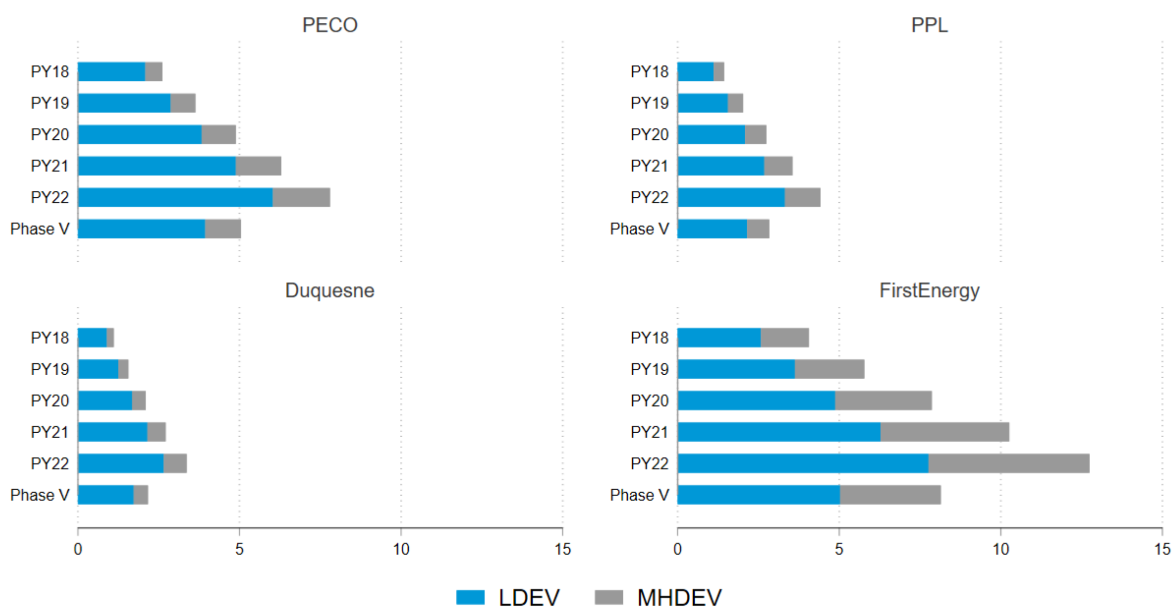


Table 80: Summer RAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	2.6	3.6	4.9	6.3	7.8	5.0
PPL	1.4	2.0	2.7	3.6	4.4	2.8
Duquesne	1.1	1.6	2.1	2.7	3.4	2.2
FirstEnergy	4.1	5.8	7.9	10.3	12.7	8.1
Statewide	**9.2**	**13.0**	**17.6**	**22.8**	**28.3**	**18.2**

Figure 50 shows the LDEV and MHDEV contributions to the total winter MW under the RAP scenario, broken down by year and EDC. Table 81 displays the combined LDEV and MHDEV MW as well, as the statewide total.

Figure 50: LDEV and MHDEV Realistic Achievable Potential – Winter (MW)

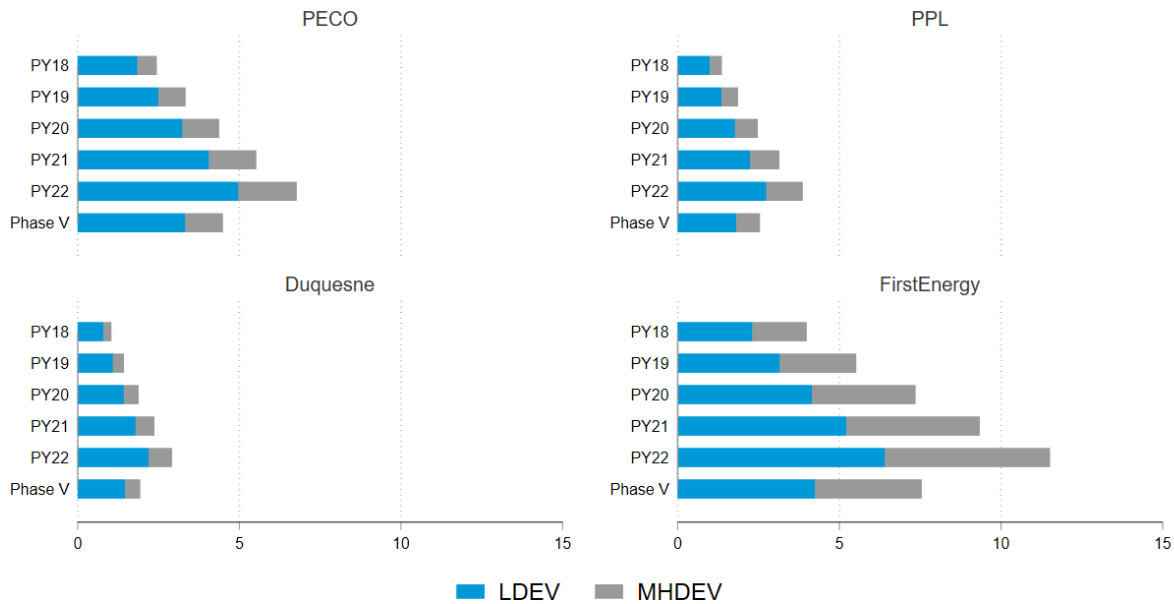


Table 81: Winter RAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	2.4	3.3	4.4	5.5	6.8	4.5
PPL	1.4	1.9	2.5	3.1	3.9	2.5
Duquesne	1.0	1.4	1.9	2.4	2.9	1.9
FirstEnergy	4.0	5.5	7.4	9.3	11.5	7.5
Statewide	**8.8**	**12.1**	**16.1**	**20.4**	**25.1**	**16.5**

Figure 51 shows the LDEV and MHDEV contributions to the total summer MW under the MAP scenario, broken down by year and EDC. Table 82 displays the combined LDEV and MHDEV MW, as well as the statewide total.

Figure 51: LDEV and MHDEV Maximum Achievable Potential – Summer (MW)

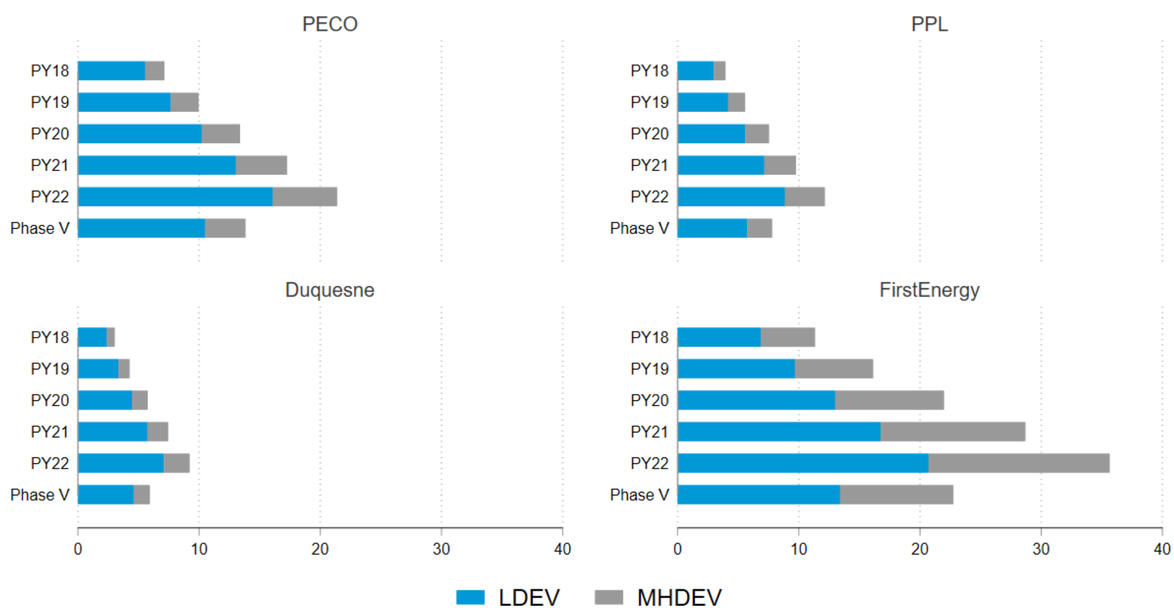


Table 82: Summer MAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	7.1	9.9	13.4	17.2	21.4	13.8
PPL	3.9	5.6	7.5	9.8	12.1	7.8
Duquesne	3.0	4.3	5.7	7.4	9.2	5.9
FirstEnergy	11.3	16.1	22.0	28.7	35.6	22.7
Statewide	**25.4**	**35.9**	**48.6**	**63.1**	**78.4**	**50.3**

Figure 52 shows the LDEV and MHDEV contributions to the total winter MW under the MAP scenario, broken down by year and EDC. Table 83 displays the combined LDEV and MHDEV MW, as well as the statewide total.

Figure 52: LDEV and MHDEV Maximum Achievable Potential – Winter (MW)

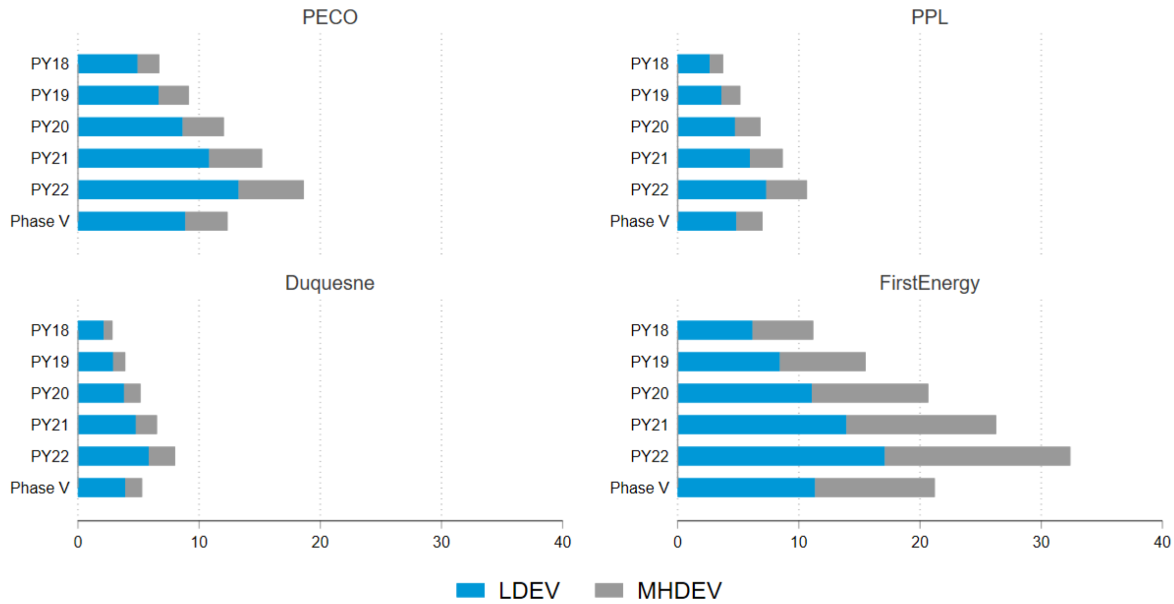


Table 83: Winter MAP by EDC and Program Year (MW)

EDC	PY18	PY19	PY20	PY21	PY22	Phase V
PECO	6.7	9.2	12.0	15.2	18.6	12.3
PPL	3.8	5.2	6.8	8.7	10.7	7.0
Duquesne	2.9	3.9	5.2	6.5	8.0	5.3
FirstEnergy	11.2	15.5	20.7	26.3	32.4	21.2
Statewide	**24.5**	**33.7**	**44.7**	**56.7**	**69.7**	**45.9**

8.2.2 ECONOMICS

Table 84 shows the cost-effectiveness results for the combined program (LDEV and MHDEV) under the RAP scenario. All TRC costs and benefits are expressed in 2026 dollars. Statewide, the costs exceed the benefits by approximately $2.3 million. With a statewide TRC ratio of 0.89, the program is not cost-effective as modeled. The only EDC where benefits outweigh costs is FirstEnergy, which has net benefits of $275,000 and a TRC ratio of 1.03.

Table 84: TRC Results by EDC – RAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$4,438	$6,180	($1,742)	0.72
PPL	$3,662	$3,777	($114)	0.97
Duquesne	$1,999	$2,754	($756)	0.73
FirstEnergy	$8,970	$8,696	$275	1.03
Statewide	**$19,069**	**$21,407**	**($2,338)**	**0.89**

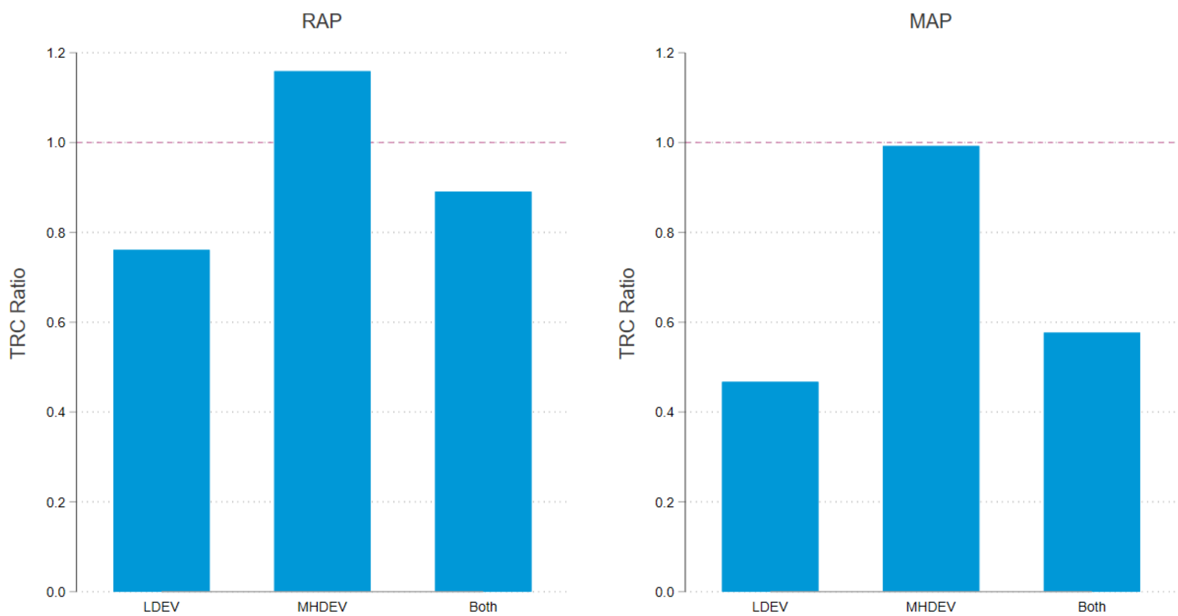
Table 85 shows the cost-effectiveness results for the combined program (LDEV and MHDEV) under the MAP scenario. All TRC costs and benefits are expressed in 2026 dollars. Statewide, the costs exceed the benefits by approximately $39 million. While the MAP scenario produces much more load reduction than the RAP scenario, it does so through much higher participant incentives, which ultimately cost more than the benefits they provide.

Table 85: TRC Results by EDC – MAP

EDC	TRC Benefits ($1,000)	TRC Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	$12,173	$26,434	($14,261)	0.46
PPL	$10,083	$15,038	($4,955)	0.67
Duquesne	$5,468	$11,633	($6,164)	0.47
FirstEnergy	$25,146	$38,563	($13,417)	0.65
Statewide	**$52,871**	**$91,668**	**($38,798)**	**0.58**

Despite the combined program not passing the TRC test under either scenario, the MHDEV program on its own passes under the RAP scenario with a TRC ratio of 1.16 statewide. The LDEV program on its own does not pass with a TRC ratio of 0.76. Under the MAP scenario, the MHDEV program on its own lies right on the threshold of cost-effectiveness with a TRC ratio of 0.99. The LDEV program on its own does not pass with a TRC ratio of 0.47. Figure 53 shows the TRC ratio by technology under the RAP and MAP scenarios.

Figure 53: TRC Ratio by Technology and Scenario



The economic results shown above are based on the current rate designs in the Commonwealth. If time-varying pricing becomes widespread, either for vehicle charging specifically or whole homes and businesses, the expected load reduction from managed charging would decrease and the economics of a managed charging program would presumably suffer. From a policy standpoint, the Commission should likely pursue managed charging through Act 129, or EV TOU rates, but not both. The following section summarizes Pennsylvania EV activity outside of Act 129.

8.3 OTHER ELECTRIC VEHICLE ACTIVITY IN PENNSYLVANIA

The managed charging model is an attempt to estimate the DR potential of one approach to EV load management. However, many other approaches exist, and the PUC and EDCs have been proactive in adopting policies to encourage prudent transportation electrification. As consumer interest and demand for EVs has grown, the Commission has recognized the importance of eliminating regulatory uncertainties that could impede investment and deployment in this sector. In recent years, the Commission has adopted several policy statements and approved pilot programs focused on deploying public charging stations and designing smart EV rates.

These programs are designed to allow EV drivers to save money over the life of their vehicles by shifting their electricity usage to off-peak hours. This shift can reduce greenhouse gas emissions and put downward pressure on electricity rates for all customers. Additionally, it maximizes the use of existing grid assets during off-peak periods for both generation and transmission, making the grid more efficient and resilient.

8.3.1 PUBLIC CHARGING

In November 2018, the Commission adopted a Policy Statement aimed at promoting increased investment in EV charging infrastructure in the Commonwealth. The Policy Statement emphasizes that the service provided by an EV charging facility open to the public for the sole purpose of recharging an EV battery should not be construed as a sale of electricity to a residential consumer, and that EDCs are required to expressly address EV charging stations in their tariffs. Following the adoption of this policy, PECO and Duquesne submitted EV pilot programs aimed at promoting the installation of publicly available and workplace-accessible DC fast charging (DCFC) stations.

PECO's pilot program offers a discount on distribution charges to commercial customers installing fast charging infrastructure for public or workplace use. The primary objective of this program is to encourage the development of public DCFC stations by mitigating demand charges during the early adoption period. PECO applies a fixed demand credit, initially equal to 50% of the DCFC nameplate capacity, for a period of 36 months or until the pilot expires at the end of 2025. Pilot participants are required to provide data on all DCFCs connected to the PECO system, whether separately metered or not, to aid in capacity planning and future rate design. As of the end of January 2023, 29 sites had enrolled in the rider, totaling 197 DCFC plugs, with 28 of these sites designated for public charging. PECO has also received over 50 additional service and meter applications for sites under development, accounting for approximately 350 more DCFC plugs.

Duquesne launched its EV ChargeUp Pilot in January 2019, with a focus on deploying Level 2 charging stations and developing DC fast charging stations for use by Duquesne and the Port Authority of Allegheny County. From March 2020 to February 2021, the pilot successfully deployed 49 Level 2 dual port charging stations across nine publicly accessible customer sites, with each site hosting a minimum of four such stations. Customer site hosts reported that the rebate covered about one-third of the project costs, although some observed a decline in parking facility usage following electrification. Additionally, the pilot installed two DC fast charging stations at a Port Authority location for electric buses and company fleet vehicles, with the stations becoming operational in early 2020.

Further expanding its efforts, Duquesne introduced a Transportation Electrification program, which was approved by the Commission in December 2021. This comprehensive program includes components for public, workplace, multi-unit dwelling, fleet, and transit system charging. It also emphasizes outreach to low-income communities and service providers. The fleet portion of the pilot supports infrastructure installation, capped at ten new customers per year, while the transit component aids Pittsburgh Regional Transit's bus fleet electrification efforts by installing infrastructure and providing rebates for DC fast charging stations. Additionally, Duquesne offers programs focused on awareness, education, and engagement to further support EV adoption and the broader goals of transportation electrification.

8.3.2 EV Rate Design

Increased penetration of EVs presents both challenges and opportunities for regulators and utilities. Without appropriate policies, the widespread adoption of these technologies could lower capacity utilization on an EDC's distribution system. Moreover, adding EV charging loads to existing peak demand periods could strain resource adequacy and put upward pressure on the clearing price of generation capacity.

In February 2022, ChargEVC-PA, a coalition supporting EV adoption, petitioned the PUC to initiate a proceeding that would result in a Policy Statement on EV charging rate design. Following comments from 23 informal working group participants, the PUC adopted and entered the Order in May 2023. With this Order, the Commission continued its review of this subject by entering, for comment, a Proposed Policy Statement in October 2023. In December 2024, the PUC adopted the Final Policy Statement Order[53] supporting EV adoption and encouraging EDCs to develop charging tariffs that promote more efficient capacity utilization.

Three noteworthy aspects of the Final Policy Statement Order are listed below:

1) **EDCs are encouraged to develop tariffs containing distribution and default service generation rates with the specific purpose of addressing EV-charging customers.** These rates should reflect cost-of-service principles and the cost of electricity, maintenance, and administrative expenses in a manner that avoids unreasonable cross-subsidization between customers.
2) **EDCs are advised to efficiently use EV-charging infrastructure to manage electric grid demand by creating rates for EV customers that encourage consideration of load factors and charging time adjustments to accommodate system needs.** Considerations for rate design include following of cost-of-service principles to align with the Commonwealth's policy goals, minimizing system stress and maximizing network capacity utilization, addressing rates for direct current fast chargers, and reflecting generation services costs during system stress. Additionally, the Commission recommends that electric vehicle charging rates be flexible and periodically reviewed to ensure fairness, cost-effectiveness, and efficiency.
3) **The Commission recommends EDCs promote fairness and equity as they design EV charging distribution and default service generation rates.** Such principles include avoiding unreasonable preference or advantages for certain EVs or drivers, and considering impacts on low-income and disadvantaged communities. Additionally, the Final Policy Statement Order underscores the importance of educating consumers on the efficient and effective use of EV charging infrastructure and available rates.

Outside of Act 129, several EDCs, including PECO, Duquesne, and FirstEnergy, have implemented opt-in EV time-of-use (EV-TOU) pilot programs. EV-TOU pilot programs cater to residential customers, with some extending to Small C&I customers. These programs feature electricity supply rates that fluctuate throughout the day, offering higher rates on-peak, lower rates for off-peak, and the lowest rates for super off-peak time periods. Importantly, these rate schedules remain consistent regardless of weekends, holidays, or seasonal changes. Customers who opt into the EV-TOU rate program receive TOU pricing for all electricity usage through their existing smart meters.

To facilitate customer participation and comprehension of the EV-TOU programs, the EDCs provide a range of tools and resources. For example, an online rate calculator helps customers evaluate potential savings from driving EVs and enrolling in the EV-TOU program. Following enrollment, Duquesne offers participants additional support by sending monthly and weekly emails that summarize their electricity usage. These communications help customers better understand their consumption patterns and offer strategies for shifting usage to off-peak periods. Furthermore, participants can track their electricity

[53] Electric Utility Rate Design for Electric Vehicle Charging Final Policy Statement Order. Entered January 7, 2025 at Docket M-2023-3040755. Weblink

usage through the electric usage online portal, which provides real-time insights into their energy consumption.

The results of these pilot programs have been promising. As of February 2023, PECO reported that 1,621 customers had enrolled in their EV-TOU program, with 1,611 of those being residential customers. Between June 2021 and December 2022, 465 Duquesne customers actively participated in the EV-TOU program. Both EDCs reported that customers experienced bill savings relative to the standard offer rates for generation service. Importantly, these rates require customers to take generation service from their EDC rather than a competitive electricity generation supplier.

To improve the program, Duquesne conducted a survey to gather feedback from participants. The survey results revealed that most respondents found the educational tools provided by the utility to be helpful. However, more than half of the respondents expressed a preference for an EV-TOU rate that applies solely to EV charging, rather than a rate that covers the entire home's electricity usage. Of course, this would require a second utility meter. How the capital and O&M costs of a second meter installation as a tool to manage EV load growth compares to a managing charging approach under Act 129 is outside the scope of this study.

To improve the situational awareness of the EDCs as to where the EV charging will take place, Pennsylvania launched Pennsylvania Alternative Fuel Vehicle (AFV) Rebates which provides rebates to Commonwealth residents for the purchase of new and pre-owned BEV and PHEV. PECO and Duquesne offer a $50 EV bonus to customers when they are notified that the customer owns or leases an EV. Similarly, PECO offered an incentive of $50 per car for customers who report that they purchased a plug-in EV.

9 BEHIND THE METER BATTERY STORAGE

Behind-the-meter (BTM) storage is a technology capable of shaving peaks and filling valleys to flatten energy demand, much like other DR applications. While most DR applications consist of avoiding energy use during peak hours or shifting demand to off-peak hours, BTM storage can be used to flatten loads by charging during periods of low demand (essentially storing lower-cost energy) and discharging during periods of high prices and demand. The SWE explored two storage solutions in this study: 1) lithium-ion battery packs, and 2) thermal storage paired with heat pumps, presented in Section 10. Both offerings are assumed to be co-located at homes or businesses with solar PV to allow surplus clean energy production from solar to be harnessed and used at a time that benefits the grid. This section discusses the policy landscape for BTM lithium-ion battery storage systems in Pennsylvania, as well as the DR potential and cost-effectiveness.

9.1 INFLUENCES ON BATTERY ADOPTION

The adoption of battery storage systems in the United States has seen a notable expansion in recent years. Recent data on regional battery storage in the U.S. reveals significant growth across multiple regions.[54] The California Independent System Operator (CAISO) leads the way, with capacity increasing from around 6,320 MW in Q2-2023 to over 9,867 MW by Q2-2024. The Energy Reliability Council of Texas (ERCOT) has also shown substantial growth, more than doubling its capacity from around 3,287 MW in Q2-2023 to 7,740 MW in Q2-2024. Other regions, such as New England (ISO-NE) and the Midcontinent (MISO), have also seen noticeable increases in their battery capacity, though on a smaller scale.

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.[55] Moreover, utility programs are increasingly developing incentive programs for BTM batteries, offering upfront payments, monthly credits, or performance-based incentives for participation in demand response and other grid services. Table 86 provides a summary of utility programs for BTM battery storage.

[54] See: S&P Global Commodity Insights – Electric Power. August 13, 2024. Weblink

[55] The IRA provides up to a 30% tax credit for both residential and commercial customers who decide to install an on-site battery storage system. See: Weblink

Table 86: Example Battery Programs Throughout the United States

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

The growth of BTM solar PV generation in Pennsylvania also creates favorable conditions for BTM battery adoption. With Pennsylvania set to expand its solar generation by approximately 3 GW in the next five years, battery installations are likely to surge, as it is common to couple these systems with solar installations.[56] The EDCs plan to spend almost $80 million on solar incentives in Phase IV and acquire over 100 MW of summer peak demand reduction toward their Phase IV demand reduction targets. As battery technology improves and policies support expansion, BTM batteries are poised to become a viable option for both individual consumers and the grid.

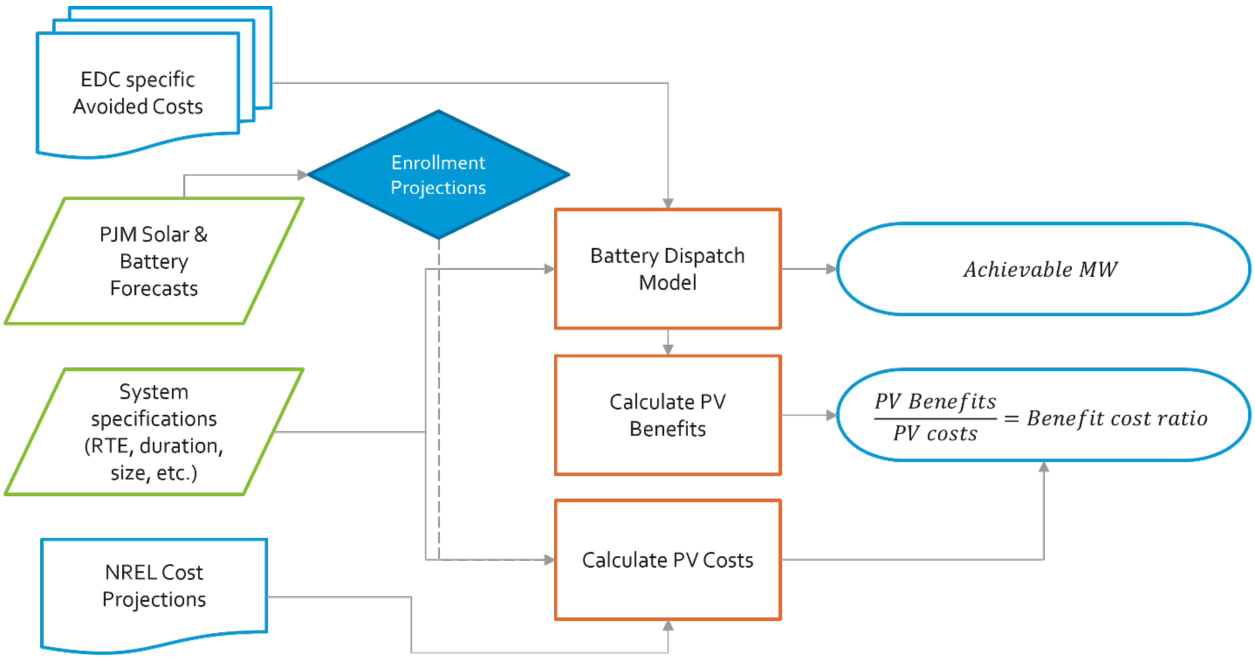
9.2 METHODOLOGY

The purpose of the battery storage potential analysis was to understand the peak demand reduction potential and net benefits associated with battery storage systems. This analysis incorporates avoided costs from the 2026 ACC, detailed in Section 4, and installation and recurring costs over a ten-year measure life. Our modeling assumed that battery systems would be paired with pre-existing solar installations, acknowledging the unique appeal for battery systems for these customers.[57] Each program year within Phase V was evaluated independently to account for the changing costs, benefits, and enrollment assumptions. Figure 54 provides an overview of the process used to calculate the overall TRC ratios and achievable potential for each EDC and program year.

[56] Solar Energy Industries Association State Overview – Pennsylvania: Weblink

[57] Battery storage systems are appealing to solar customers because they allow for greater use of the energy generated by their solar panels. Since solar panels produce electricity during the day, which may not match when energy is most needed, batteries can store excess energy for use later, such as in the evening or during cloudy periods. This reduces dependence on the grid, lowers energy costs, and provides backup power during outages.

Figure 54: Benefit-Cost and Achievable Potential Model for Battery Storage



9.2.1 BATTERY DISPATCH MODEL AND TECHNOLOGY ASSUMPTIONS

SWE assumed a maximum dispatch of four hours per day during peak demand periods, with all charging assumed to occur outside of the peak demand performance hours. The SWE additionally assumed that only 90% of the battery's capacity was available for dispatch, so a portion of the battery may be reserved for reliability and charging efficiency. Multiple EUL scenarios were modeled (5-year, 10-year, and 15-year), with the 10-year EUL used for the primary analysis. The SWE used the estimate for PY22 to assess the overall cost-effectiveness, recognizing that enrollments accrue cumulatively over the phase. By using the final year as the ultimate measure of cost-effectiveness and potential, the SWE captures the full extent of the program's impact for Phase V.

9.2.2 ENROLLMENT PROJECTIONS

To forecast customer adoption, the SWE utilized a Bass-Diffusion model in conjunction with PJM forecasts for solar and battery capacity. The Bass-Diffusion model is typically used for modeling how new technologies spread through a market. It accounts for two primary factors: external influence (innovation), driven by marketing and early adoption, and internal market momentum (imitation), driven by social influences.

The model was first calibrated separately for each EDC to estimate coefficients of internal and external influences, assuming a business-as-usual case with no Act 129 incentives. To evaluate how Act 129 incentives may accelerate adoption, the model was then adjusted by increasing the external influence in proportion to incentive levels offered (% of the battery paid for by outside sources). This adjustment enabled the model to simulate different scenarios, demonstrating how varying levels of incentives could shift adoption over time.

The model's upper bound for battery adoption was tied to PJM solar MW forecasts for each EDC.[58] To define the full potential for battery installations, the model used the difference between the total nameplate solar MW and the peak solar MW, with the maximum achievable scenario being battery MW equaling 100% of this difference. For example, consider a hypothetical EDC with a forecasted nameplate capacity of 10 MW but with a projected summer peak contribution of 1 MW. With sufficient battery installations, the seasonal peak contribution could be increased to 10 MW by storing and discharging the full nameplate capacity of the solar. This effectively "firms" the solar generation and brings its PLC up to its full nameplate capacity. In this example, the full battery potential is 9 MW—the difference between the 10 MW of solar nameplate capacity and the 1 MW of peak solar generation. The process for estimating battery enrollments for each EDC is explained in further detail in Table 87.

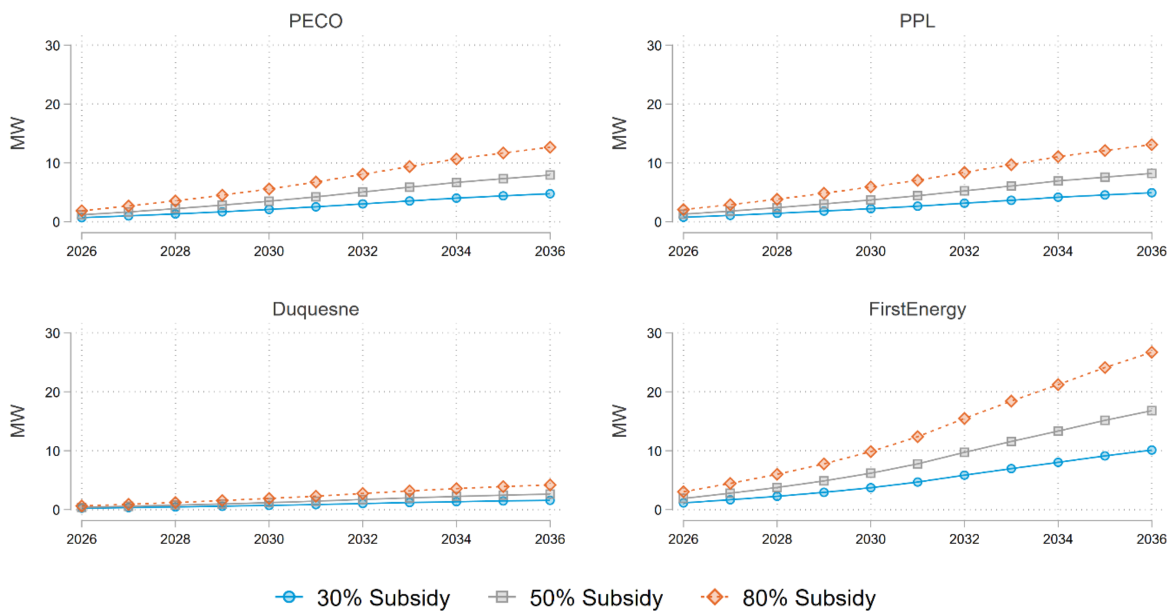
Table 87: Enrollment Estimation Process

Objective	Description
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.

Figure 55 shows the additional battery capacity that was estimated at different subsidy levels. The estimated adoption rate increases as the battery cost to the participant net of incentives goes down.

[58] PJM's load forecast and development materials provides additional detail on the solar and battery forecasts in the 2024 Load Forecast Report. Weblink

Figure 55: Additional Battery Capacity (MW) by Incentive Level



A key aspect of the analysis was the distinction between commercial and residential customers, as the costs of battery storage systems differ significantly between these sectors due to the scale in which battery systems are applied, highlighted in Section 9.2.3. The SWE assumed a blend of 80% of commercial systems and 20% residential. This 80-20 split was based on projected Phase IV solar savings provided by the EDCs to the SWE during summer 2024. Non-residential installations are expected to account for approximately 80% of total solar capacity incentivized statewide through Phase IV EE&C plans.

9.2.3 TRC Costs

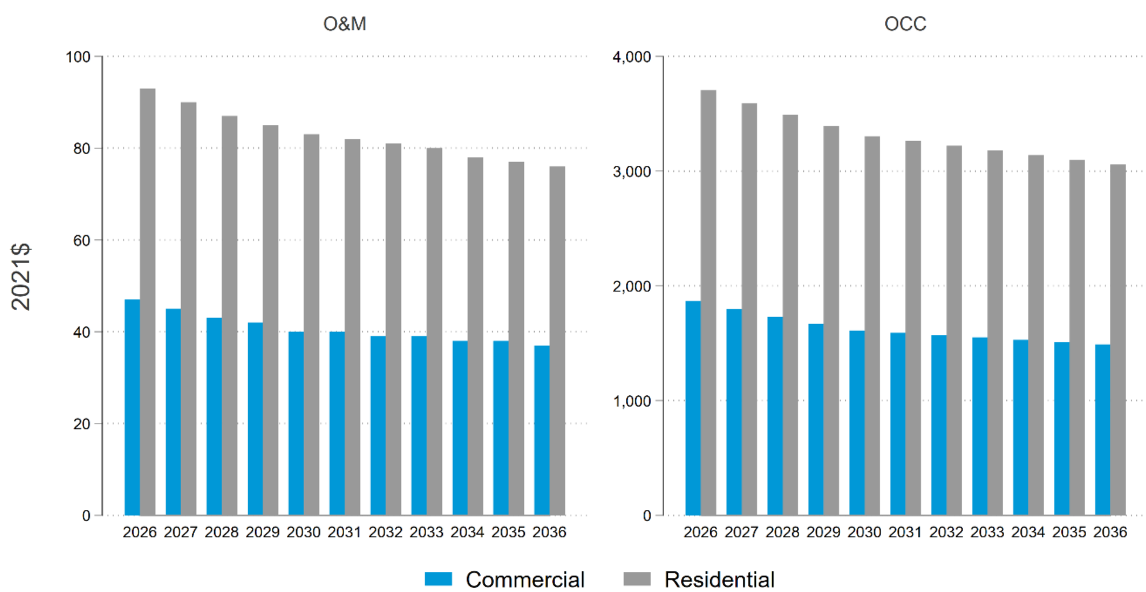
Lithium-ion battery system costs have declined in recent years and are expected to continue to decrease. These costs can be divided into different components, which, at a high level, include the costs of battery equipment, inverters, as well as labor costs associated with installation and maintenance. Systems additionally incur annual operation and maintenance costs for each year the system is in operation.

To develop cost projections for battery storage in this analysis, the SWE utilized cost projections from the NREL Annual Technology Baseline (ATB) for lithium-ion battery systems, released in June 2023.[59] These projections include three scenarios—Advanced, Conservative, and Moderate—based on a literature review of 14 publications. These scenarios reflect a range of cost forecasts, with the Conservative scenario indicating the highest projections among the reviewed publications, Moderate representing the median value, and Advanced showcasing the lowest cost estimates.

[59] Electricity Annual Technology Baseline (ATB) Data Download. Weblink. Documentation for the estimates is provided at Weblink.

Figure 56 shows cost projections under the Moderate scenario for the two cost categories: Overnight Capital Costs (OCC) and Fixed Operation and Maintenance (O&M) Costs. OCC represents the total capital expenditures required to install the battery during the year of installation, covering materials, labor, and development costs ($/kW). O&M Costs are the recurring expenses associated with operating and maintaining the battery, including administrative fees, taxes, general maintenance, and the replacement of large components over time ($/kW-yr). Both OCC and O&M costs are projected to decline over Phase V in real dollars.

Figure 56: Moderate Cost Projections of 4-Hour Battery Systems by Sector



Residential battery storage systems generally have higher costs per kW than commercial systems due to economies of scale. Commercial battery systems are typically much larger, allowing fixed costs like installation, maintenance, and system integration to be spread across a greater capacity, resulting in lower per-kW costs. According to the NREL cost calculations for 2026, small-scale residential systems (up to 10 kW) have an OCC of approximately $3,200/kW, while larger commercial and industrial systems (up to 1 MW) see costs drop to approximately $1,600/kW.

In addition to installation and maintenance costs, battery programs naturally incur other expenses, including incentives provided by the utility and program administration costs. While incentives reduce the out-of-pocket costs for consumers, making the technology more accessible and appealing, they are a program cost to the EDC. Program administration costs, which encompass the resources needed to manage and operate the program, such as marketing, customer support, and regulatory compliance, further add to the overall expense. In the benefit-cost scenarios modeled by the SWE, it is assumed that the EDC pays for a portion of the battery OCC, shifting the cost burden away from the customer as an incentive. Since the TRC test does not differentiate between who pays for the equipment, the incentives under this cost-sharing model do not impact the TRC ratios. However, acquisition costs are tied to the share of the cost borne by the EDCs, so greater incentives will ultimately increase program expenditures per MW of capacity enrolled.

Table 88 shows the cost assumptions used under the RAP and MAP scenarios. Higher administrative costs are attributed to the MAP scenario, assuming more extensive outreach efforts and greater per-customer involvement, helping customers access other incentives such as the IRA subsidy. In contrast, the RAP scenario assumes lower administrative costs, reflecting more conservative estimates of the achievable participation with limited additional outreach efforts. The SWE assumes the full 30% IRA credit in the MAP scenario. In the RAP scenario, we assume some participants do not receive the full IRA tax credit and set the IRA subsidy to 20%.

Table 88: 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%

9.2.4 TRC BENEFITS

Behind-the-meter battery storage offers multiple streams of benefits, with the most significant stemming from the avoided GT&D capacity costs. The SWE also modeled energy arbitrage benefits based on the battery system's ability to shift consumption from periods of high demand and high-cost energy to periods of low demand and low-cost energy.

Avoided capacity costs represent the primary source of economic value for these systems. When battery systems discharge during peak demand periods, they reduce the need for utilities to invest in additional GT&D capacity. This study uses the system-wide avoided cost of distribution capacity values called for in the 2026 TRC Test Order and documented in the 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 from 2026 ACC.

Energy arbitrage refers to the practice of charging the battery when marginal prices are low and discharging the stored energy when wholesale prices are higher. However, it is important to factor in the round-trip efficiency (RTE) of the battery system, assumed to be 85%.[60] This means that 15% of the energy charging the battery is lost during the charging and discharging process. As a result, while energy arbitrage offers savings, the inefficiency of the battery system must be accounted for, as it increases the total energy required to achieve these benefits.

There are certain economic implications for individual participants that may further incentivize them to adopt a BTM battery. However, this will not be accounted for in the TRC Test. Depending on their tariff, customers may further benefit from discharging their batteries during peak periods by lowering their peak billing determinants. However, under Pennsylvania's current net metering rules, there is not a strong incentive to store surplus energy for later use rather than exporting to the grid, as excess generation is credited back at the full retail rate. If Pennsylvania's net metering rules were to change, BTM battery storage would become more economically attractive to homes and businesses with solar.

[60] NREL researchers have identified 85% as being a representative metric for RTE. Weblink

9.3 RESULTS

9.3.1 ACHIEVABLE POTENTIAL AND ECONOMICS

Table 89 and Table 90 show the results for the RAP and MAP scenarios, respectively. The MAP scenario, with more aggressive outreach and administration, showed lower cost-effectiveness than the RAP scenario. TRC ratios ranged between approximately 0.5 and 0.8, with higher TRC ratios being driven by higher avoided capacity cost forecasts. In either scenario, the program would not be cost effective during Phase V. However, the acquisition costs for battery installations are low respective to coincident demand reductions from EE and most of the DR programs in this report. While the total achievable from batteries is modest, if the Commission chooses to establish peak demand reduction goals for Phase V, battery storage would be among the lowest-cost ways to achieve the goal, thanks in part to the IRA tax credits.

Table 89: 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**

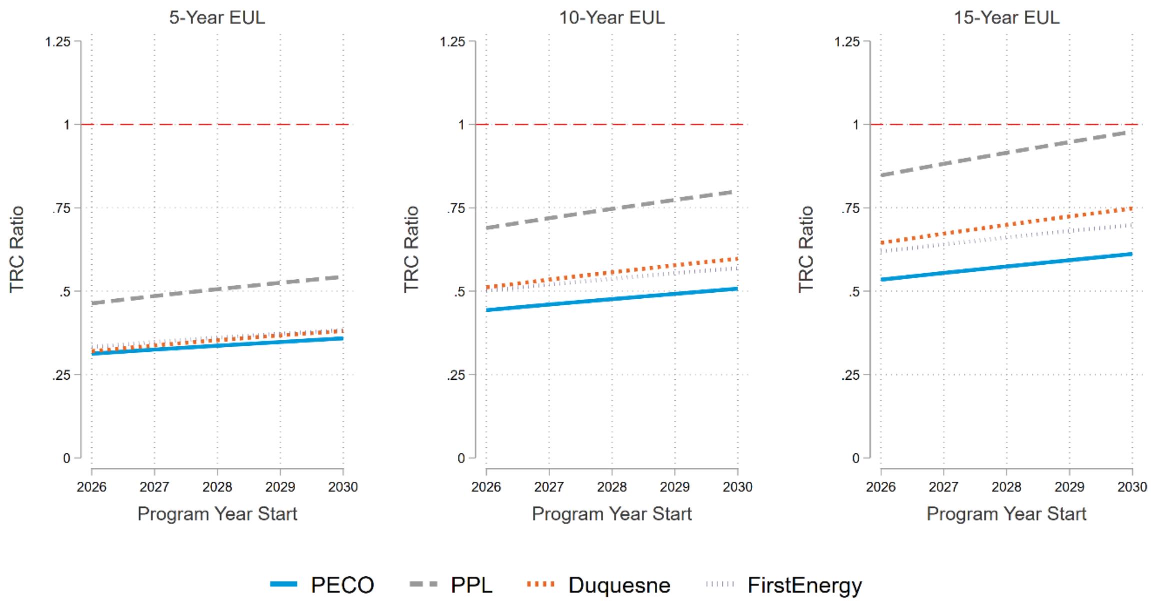
Table 90: Behind the Meter Battery Storage – Maximum Achievable Potential

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**

9.3.2 MEASURE LIFE SENSITIVITY

The analysis of varying EUL assumptions demonstrated that the TRC ratios improve as the assumed battery lifespan increases. This is driven by the ability of the efficiency technology to accrue more benefits over an extended period, offsetting the higher upfront costs 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. This creates an avenue for the EDCs to structure agreements with longer durations, matching the technical life of the battery and not constrained by the length of Phase V. By designing programs with longer contract periods, EDCs can realize additional value from behind-the-meter battery installations. This makes daily dispatch battery storage paired with solar similar to an EE measure with respect to program accounting and goal attainment.

Figure 57: TRC Ratios Under Varying EUL Assumptions

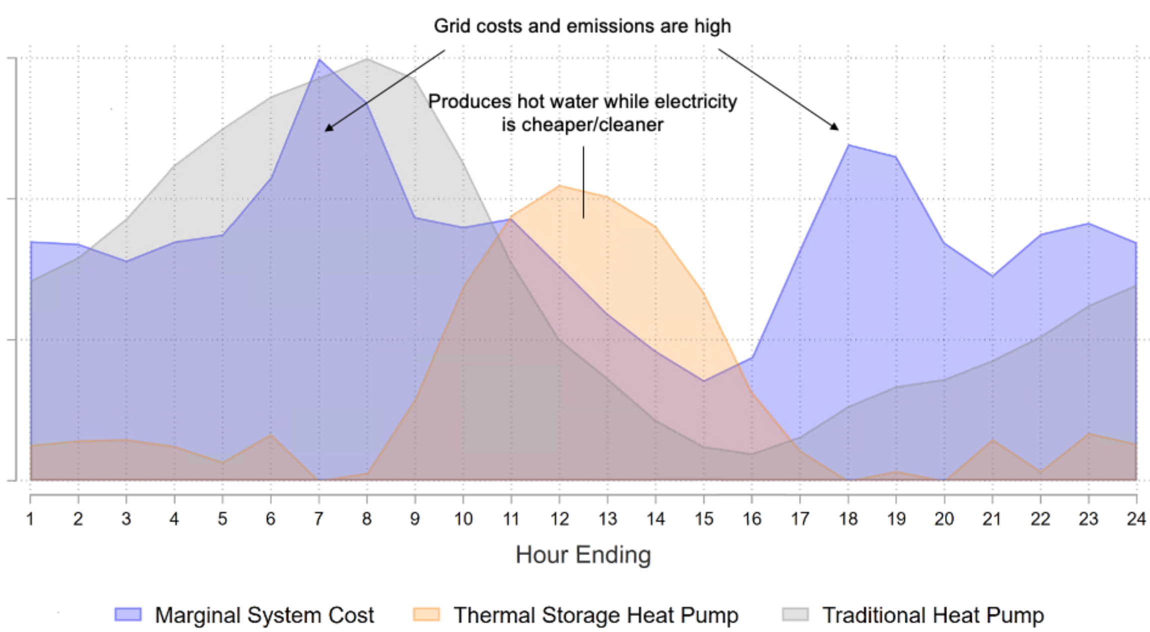


10 THERMAL STORAGE WITH HEAT PUMP

Thermal storage systems can help manage demand by storing thermal energy for heating or cooling, allowing HVAC and DHW systems to draw less power during peak periods. These systems store energy as hot or cold water, for example, then use it later. The program offering modeled here consists of a thermal battery (hot water tank) and a smart controller, coupled with a heat pump and HPWH to provide space heating and hot water. The SWE assumes heat pump energy usage for cooling remains unchanged. The system heats the water in a storage tank (charges the "thermal battery") when electricity is less expensive or cleaner, then accesses that thermal storage when space heating or hot water is needed. For modeling purposes, the SWE assumes that the customer is either purchasing a new HVAC heat pump at the time of thermal battery installation or, less commonly, retrofitting the thermal battery components to an existing HVAC heat pump system. Either way, the customer is also assumed to purchase a new efficient HPWH at the time of thermal battery installation.

Figure 58 shows how the thermal storage system produces hot water or "charges" when electricity is cheaper/cleaner, to "discharge" that preheated water during peaks when grid costs and emissions are high. This solution would be most viable for homes with solar PV because the surplus solar energy during the middle of the day could be used to charge the thermal battery and provide decarbonized heating and water heating when the sun is not shining.

Figure 58: Thermal Storage Load Shifting Example



Beyond heat pump and hot water storage systems, other types of commercially-available thermal storage—such as ice storage, essentially the opposite approach—also offer opportunities for demand shifting and energy cost savings. The cost-effectiveness and viability of these technologies depends on the application, scale, and regional energy pricing. For instance, ice storage is more popular in commercial and industrial buildings due to relatively low operational cost and compatibility with existing HVAC systems. The thermal storage with heat pump system modeled here is still a nascent technology with high add-on costs and practical barriers to entry such as the requirement for a large storage tank and room for an air handling unit. This is reflected in the low enrollment assumptions and low TRC ratios in the SWE models.

10.1 METHODS

The key factors affecting the potential load relief and cost effectiveness of the thermal storage with heat pump offering are included in Table 91.

Table 91: Summary of Thermal Storage + Heat Pump Modeling Assumptions

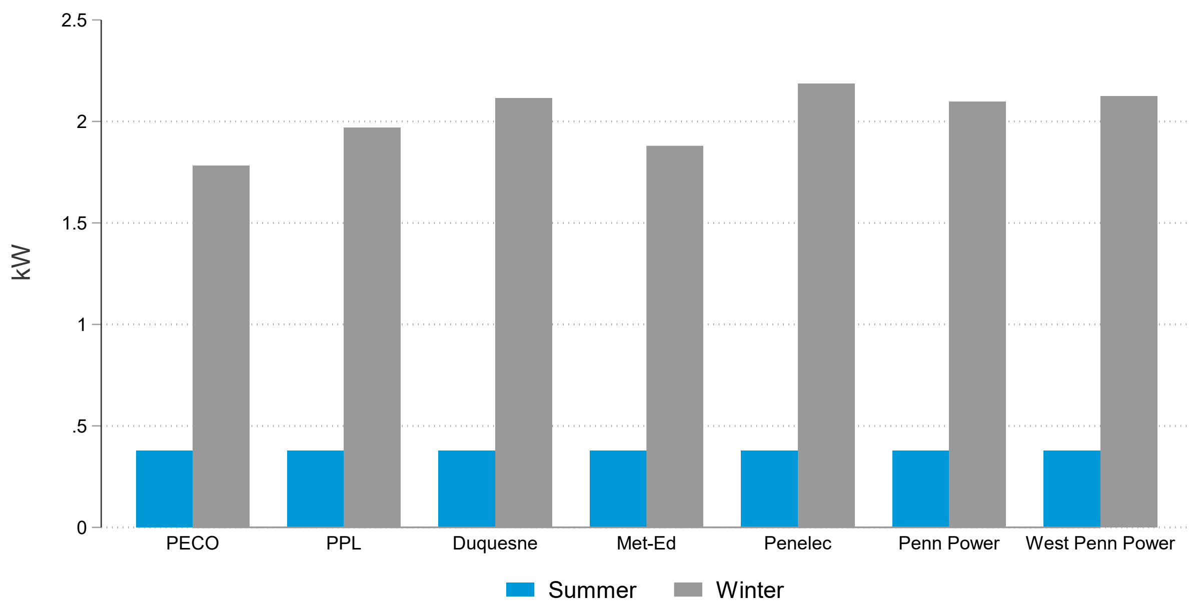
Input Variable	Key Assumptions and Notes
Program Design	Water is heated and stored outside of the peak demand window when costs and emissions are lower, then accesses the thermal energy of that stored hot water for space heating and DHW needs during peaks.
Peak Load Contribution	Combined heat pump heating and DHW demand relies on the same methods used for the Connected Thermostats and Domestic Hot Water Load Management programs
Enrollment Rates	Eligible cooling system share, heat pump share, existing heat pump thermal battery add-on rate, new heat pump thermal battery add-on rate. MAP is double RAP.
Load Impacts	91% - Average of Nominal Heating Load Shifting percentage for 40 degree Fahrenheit Design Temp, 119-gallon storage tank, 36 kBTU/hour Design Load, based on Harvest Open product. Assumed DHW load shift is the same.
Participant Incentive	RAP: 33% of project cost MAP: 75% of project cost
Program Admin Costs (Non-incentive), Fixed	Fixed one-time startup costs and fixed annual recurring administrative costs of between $50k-$175k, scaled to EDC residential customer count. For this program, fixed recurring costs are assumed equal to startup costs.
Program Admin Costs (Non-incentive), Volumetric	Volumetric one-time costs include recruiting/marketing costs of between $20-$40 per customer, depending on scenario. The MAP scenario models more aggressive program spending to achieve a higher enrollment rate.
Other Key Inputs	Avoided costs from 2026 ACC Heat Pump EUL from 2026 TRM (15 years), used to determine turnover rate and lifetime benefits.

10.1.1 PEAK LOAD CONTRIBUTION

Thermal storage systems of this type enable shifting of both space heating and water heating demand out of peak periods. Figure 59 shows baseline PLC per customer for combined HVAC and DHW loads eligible for thermal storage. HVAC PLC varies by EDC in accordance with the assumptions outlined in

Section 6.1.1 for heat pumps.[61] There is no differentiation between EDCs for baseline DHW load, so assumptions are identical across EDCs for summer kW. This figure shows the PY18 assumptions, but the eligible per-customer DHW contribution to peak load decreases slightly over the study period as resistance water heaters across the Commonwealth are displaced by more efficient heat pump water heaters.

Figure 59: Seasonal Thermal Storage Baseline Peak Load Contribution by Customer



10.1.2 Enrollment Rates

There are two basic paths for enrollment in the thermal storage offering: customers can retrofit the thermal battery/hot water storage system to their existing heat pump system or purchase and install it when they purchase a new heat pump. For customers to be eligible, they must have electric heating. The SWE assumed that a thermal storage system is technically feasible among 60% of heat pump installations, based on the installation requirements including room for a slightly larger-than-standard hot water tank and an air handler for forced-air systems. Table 92 shows key eligibility assumptions for this program offering.

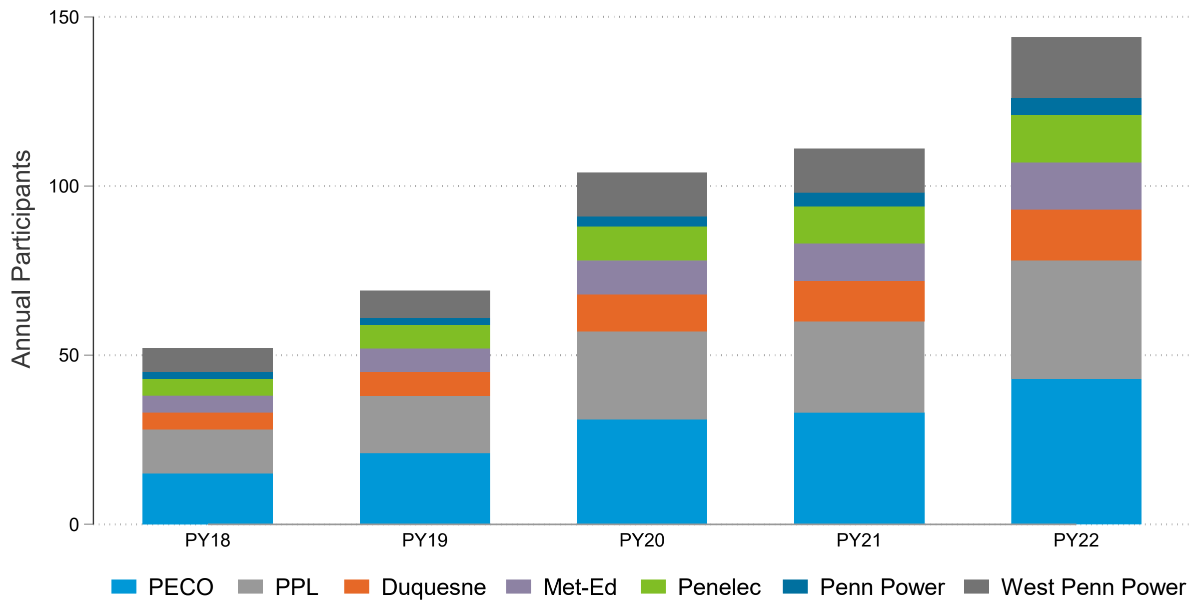
Table 92: Key Eligibility Parameters for Thermal Storage Add-On

Input	Value
Electric heating share	16%
Heat pump share (for retrofit applications) (EDC-specific)	5%-28%
Technical feasibility	60%

[61] The winter PLCs for the connected thermostat optimization include both the heat pump compressor and some auxiliary electric resistance heat based on electric furnace assumptions in the 2026 TRM. This measure considers only the heat pump and assumes any supplemental heat would be unaffected.

The SWE assumed different enrollment rates for the retrofit and new add-on paths, with new heat pump thermal battery add-ons taking place at a higher pace than retrofits to existing systems. For the RAP scenario, in PY18, 1 out of every 200 new heat pump purchasers chooses to add a thermal storage system, increasing to 4 out of 200 by PY22. These rates are doubled for MAP. Figure 60 shows modeled RAP enrollment over Phase V. Total participation statewide is 52 homes in PY18 and 144 homes in PY22.

Figure 60: Thermal Storage Time Series Annual Participants by EDC (RAP)



10.1.3 Load Impacts

Load impact assumptions are borrowed from manufacturer technical specifications using a 40 degree Fahrenheit design temperature, 119-gallon storage tank, and 36 kBTU/hour design load during the hours of 5:00 am – 9:00 am and 3:00 pm – 12:00 am. The estimate assumes that 86% of demand is shifted outside of peak periods for both heating and DHW end uses.[62]

10.1.4 Program Costs and TRC Costs

The SWE organized this program into two cost categories for modeling. The cost assumptions listed below are for PY18. An annual inflation rate of 2% was applied to calculate program budget requirements in Py19 – Py22.

1. **Fixed program administration costs:** The SWE assumed this DHW load management offering will require $150,000 of fixed program administration cost annually for PECO, with the other EDC costs scaled from this assumption based on residential customer count.
2. **Volumetric one-time costs:** Recruiting and marketing costs are assumed to be $20-$40 per customer depending on scenario. Incremental equipment costs are $8,000, or the cost

[62] Harvest Technical Specifications, pg. 12 Weblink

of a HPWH + thermal battery system, as the ASHP costs are incurred with or without the thermal storage add-on. The per-customer incentive is 33% of project cost for RAP and 75% of project cost for MAP.

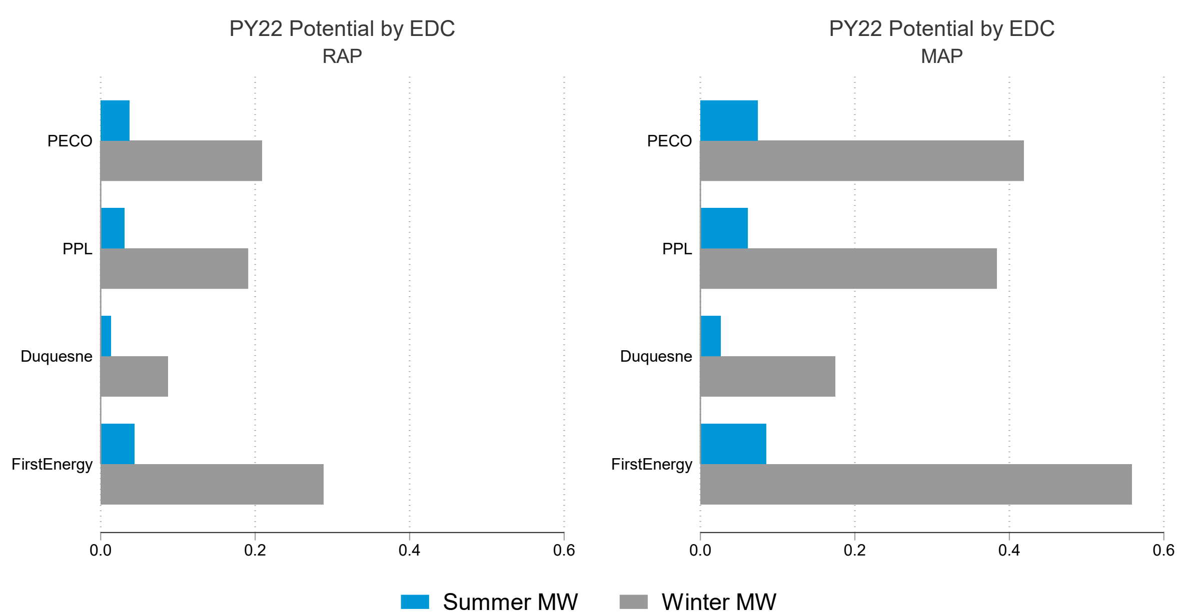
There are no volumetric recurring costs in the form of ongoing incentives or vendor fees for this program offering.

10.2 RESULTS

10.2.1 ACHIEVABLE POTENTIAL

Figure 61 shows the achievable estimates for Phase V. This heating-specific technology has a considerable degree of seasonality, with winter potential being around six times that of summer, as summer impacts are limited to summer DHW load reductions.

Figure 61: Thermal Storage Cumulative Potential by EDC, Scenario, and Season



The MW Potential columns in Table 93 and Table 94 are averages of Phase V cumulative potential for summer and winter, for each EDC and statewide. Because of the incremental annual accounting, the Phase V column represents the sum of the demand reductions acquired across the five years, rather than the average. The thermal storage offering results in negative net TRC benefits for all EDCs.

Table 93: Thermal Storage with Heat Pump - Realistic Achievable Potential

EDC	MW Potential	Program Cost ($1,000)	Acquisition Costs ($/kW)	NPV Benefits ($1,000)	NPV 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**

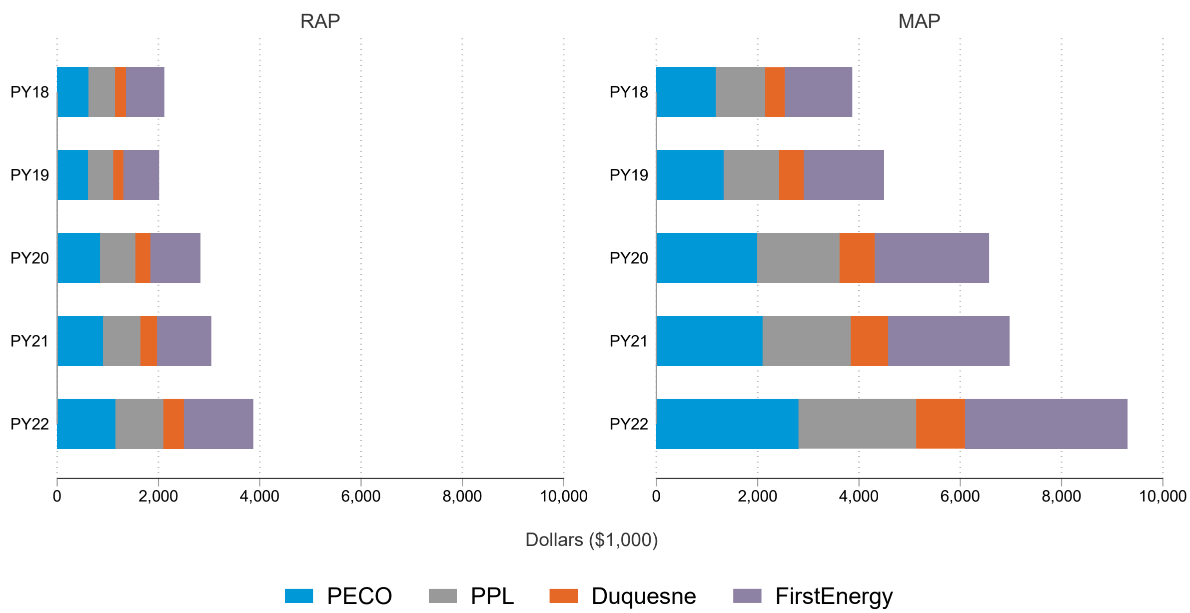
MAP impacts are approximately twice the RAP impacts for each EDC. Statewide load relief does not reach 1 MW in Phase V for either scenario.

Table 94: Thermal Storage with Heat Pump - Maximum Achievable Potential

EDC	MW Potential	Program Cost ($1,000)	Acquisition Costs ($/kW)	NPV Benefits ($1,000)	NPV Costs ($1,000)	Net Benefits ($1,000)	TRC Ratio
PECO	0.25	$9,397	$36,853	$423	$8,365	($7,942)	0.05
PPL	0.23	$7,767	$33,842	$907	$6,915	($6,008)	0.13
Duquesne	0.10	$3,278	$31,820	$141	$2,918	($2,776)	0.05
FirstEnergy	0.33	$10,756	$32,451	$633	$9,578	($8,945)	0.07
Statewide	**0.92**	**$31,198**	**$33,949**	**$2,104**	**$27,776**	**($25,672)**	**0.08**

Figure 62 shows the modeled spending by program year and EDC. The projected program costs grow over the phase as adoption of this emerging technology increases.

Figure 62: Program Spend by Year and EDC



APPENDIX A – TABLE OF ACRONYMS

Table 95 lists each of the acronyms used in this report and the phrase it is used to represent.

Table 95: Table of Acronyms

Acronym	Phrase
API	Application Programming Interface
APS	Allegheny Power Systems
ASHP	Air Source Heat Pump
ATSI	American Transmission Systems, Inc.
BRA	Base Residual Auction
CAC	Central Air Conditioner, or Central Air Conditioning
C&I	Commercial and Industrial
CP	Coincident Peak
DEER	Database of Energy Efficiency Resources
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effects
DSM	Demand-Side Management
EDC	Electric Distribution Company
EE	Energy Efficiency
EE&C	Energy Efficiency and Conservation
ELCC	Effective Load Carrying Capacity
ELRP	Emergency Load Response Program
EV	Electric Vehicle
GT&D	Generation, Transmission, and Distribution
kW	Kilowatt
kWh	Kilowatt Hour
LCI	Large Commercial & Industrial
LDEV	Light Duty Electric Vehicle
LMP	Locational Marginal Price
MAP	Maximum Achievable Potential
Met-Ed	Metropolitan Edison Company (FirstEnergy)
MHDEV	Medium-Heavy Duty Electric Vehicle
MW	Megawatt
MWh	Megawatt Hour
NMR	NMR Group, Inc.
NREL	National Renewable Energy Laboratory

O&M	Operation and Maintenance
OCC	Overnight Capital Costs
PECO	PECO Energy Company
Penelec	Pennsylvania Electric Company (FirstEnergy)
Penn Power	Pennsylvania Power Company (FirstEnergy)
PJM	PJM Interconnection, LLC
PLC	Peak Load Contribution
PPL	PPL Electric Utilities
PRD	Price Responsive Demand
PSA	Peak Shaving Adjustment
PUC	Public Utility Commission
PVNB	Present Value of Net Benefits
PY	Program Year
RAP	Realistic Achievable Potential
RTO	Regional Transmission Organization
SCI	Small Commercial & Industrial
SWE	Statewide Evaluator
THI	Temperature Humidity Index
TRC	Total Resource Cost
TRM	Technical Reference Manual
West Penn, WPP	West Penn Power Company (FirstEnergy)
WWP	Winter Weather Parameter