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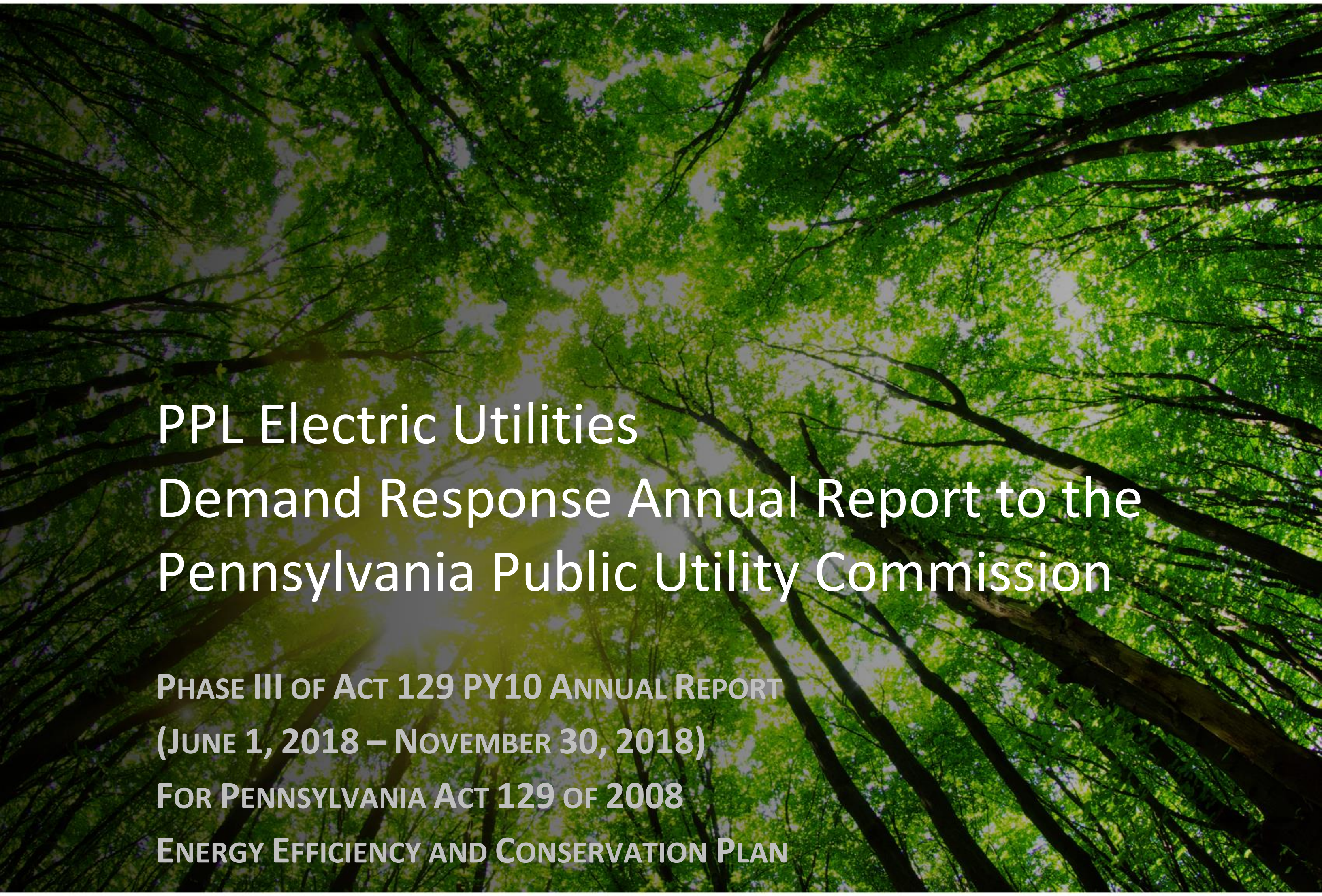

PPL Electric Utilities
Demand Response Annual Report to the Pennsylvania Public Utility Commission

PHASE III OF ACT 129 PY10 ANNUAL REPORT
(JUNE 1, 2018 – NOVEMBER 30, 2018)
FOR PENNSYLVANIA ACT 129 OF 2008
ENERGY EFFICIENCY AND CONSERVATION PLAN

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Table of Contents

Figures

Tables

Acronyms

AMI	Advanced Metering Infrastructure
BDR	Behavioral Demand Response
C&I	Commercial and Industrial
CBL	Customer Baseline
CFL	Compact Fluorescent Lamp
CHP	Combined Heat and Power
CP	Coincident Peak
CSP	Conservation Service Provider or Curtailment Service Provider
CV	Coefficient of Variation
DLC	Direct Load Control
DR	Demand Response
EDC	Electric Distribution Company
EDT	Eastern Daylight Time
EE&C	Energy Efficiency and Conservation
EM&V	Evaluation, Measurement, and Verification
EISA	Energy Independence and Security Act
EUL	Effective Useful Life
GHI	Global Horizontal Irradiance
GNE	Government, Nonprofit, Educational
HER	Home Energy Report
HIM	High Impact Measure
HOU	Hours of Use
HVAC	Heating, Ventilating, and Air Conditioning
ICSP	Implementation Conservation Service Provider
IPMVP	International Performance Measurement and Verification Protocol
kW	Kilowatt
kWh	Kilowatt-hour
KPI	Key Performance Indicator
LED	Light-Emitting Diode
LIURP	Low-Income Usage Reduction Program
M&V	Measurement and Verification
MAPE	Mean Absolute Percentage Error
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
NTG	Net-to-Gross

O&M	Operations and Maintenance
P3TD	Phase III to Date
PA PUC	Pennsylvania Public Utility Commission
PSA	Phase III to Date Preliminary Savings Achieved; equal to VTD + PYRTD
PSA+CO	PSA savings plus Carryover from Phase II
PY	Program Year: for example, PY8, from June 1, 2016, to May 31, 2017
PYRTD	Program Year Reported to Date
PYVTD	Program Year Verified to Date
PYTD	Program Year to Date
QA/QC	Quality Assurance/Quality Control
RMSE	Root Mean Square Error
RTD	Phase III to Date Reported Gross Savings
SEER	Seasonal Energy Efficiency Rating
SWE	Statewide Evaluator
T&D	Transmission and Distribution
THI	Temperature Humidity Index
TRC	Total Resource Cost
TRM	Technical Reference Manual
VTD	Phase III to Date Verified Gross Savings
WRAP	Weatherization Relief Assistance Program

Types of Savings

Gross Savings: The change in energy consumption and/or peak demand that results directly from program-related actions taken by participants in an EE&C program, regardless of why they participated.

Net Savings: The total change in energy consumption and/or peak demand that is attributable to an EE&C program. Depending on the program delivery model and evaluation methodology, the net savings estimates may differ from the gross savings estimate due to adjustments for the effects of free riders, changes in codes and standards, market effects, participant and nonparticipant spillover, and other causes of changes in energy consumption or demand not directly attributable to the EE&C program.

Reported Gross: Also referred to as *ex ante* (Latin for “beforehand”) savings. The energy and peak demand savings values calculated by the EDC or its program Implementation Conservation Service Providers (ICSP), and stored in the program tracking system.

Unverified Reported Gross: The Phase III Evaluation Framework allows EDCs and the evaluation contractors the flexibility to not evaluate each program every year. If an EE&C program is being evaluated over a multi-year cycle, the reported savings for a program year where evaluated results are not available are characterized as unverified reported gross until the impact evaluation is completed and verified savings can be calculated and reported.

Verified Gross: Also referred to as *ex post* (Latin for “from something done afterward”) gross savings. The energy and peak demand savings estimates reported by the independent evaluation contractor after the gross impact evaluation and associated M&V efforts have been completed.

Verified Net: Also referred to as *ex post* net savings. The energy and peak demand savings estimates reported by the independent evaluation contractor after application of the results of the net impact evaluation. Typically calculated by multiplying the verified gross savings by a net-to-gross (NTG) ratio.

Annual Savings: Energy and demand savings expressed on an annual basis, or the amount of energy and/or peak demand an EE&C measure or program can be expected to save over the course of a typical year. Annualized savings are noted as MWh/year or MW/year. The Pennsylvania (PA) Phase III technical reference manual (TRM), hereafter referenced as the PA TRM, provides algorithms and assumptions to calculate annual savings, and Act 129 compliance targets for consumption reduction are based on the sum of the annual savings estimates of installed measures or behavior change.

Lifetime Savings: Energy and demand savings expressed in terms of the total expected savings over the useful life of the measure. Typically calculated by multiplying the annual savings of a measure by its effective useful life. The TRC Test uses savings from the full lifetime of a measure to calculate the cost-effectiveness of EE&C programs.

Program Year Reported to Date (PYRTD): The reported gross energy and peak demand savings achieved by an EE&C program or portfolio within the current program year. PYTD values for energy efficiency will always be reported gross savings in a semi-annual or preliminary annual report.

Program Year Verified to Date (PYVTD): The verified gross energy and peak demand savings achieved by an EE&C program or portfolio within the current program year as determined by the impact evaluation findings of the independent evaluation contractor.

Phase III to Date (P3TD): The energy and peak demand savings achieved by an EE&C program or portfolio within Phase III of Act 129. Reported in several permutations described below.

- **Phase III to Date Reported (RTD):** The sum of the reported gross savings recorded to date in Phase III of Act 129 for an EE&C program or portfolio.
- **Phase III to Date Verified (VTD):** The sum of the verified gross savings recorded to date in Phase III of Act 129 for an EE&C program or portfolio, as determined by the impact evaluation finding of the independent evaluation contractor.
- **Phase III to Date Preliminary Savings Achieved (PSA):** The sum of the verified gross savings (VTD) from previous program years in Phase III where the impact evaluation is complete plus the reported gross savings from the current program year (PYTD).
- **Phase III to Date Preliminary Savings Achieved + Carryover (PSA+CO):** The sum of the verified gross savings from previous program years in Phase III plus the reported gross savings from the current program year plus any verified gross carryover savings from Phase II of Act 129. This is the best estimate of an EDC’s progress toward the Phase III compliance targets.
- **Phase III to Date Verified + Carryover (VTD + CO):** The sum of the verified gross savings recorded to date in Phase III plus any verified gross carryover savings from Phase II of Act 129.

DEMAND RESPONSE

Through participation in the Demand Response Program, commercial and industrial (C&I) customers and government, nonprofit, and education (GNE) customers reduce electricity demand during Act 129 demand response events, helping PPL Electric Utilities manage its peak demand.

VERIFIED DEMAND REDUCTION

Phase III has so far saved an average of **116.6 MW**

127% of Act 129 target

121% of Act 129 target

PY10 saved an average of **111.5 MW**

PROGRAM SATISFACTION

8 in 12 Satisfied with overall program

9 in 12 satisfied with the **timing of event notifications**

8 in 11 satified with the **online enrollment process**

8 in 12 satisfied with the **ICSP**

PY10 PARTICIPATION

A total of **6** events with **60** unique particpants:

58 participants curtailed 105.9 MW in July 2, 2018 event

58 participants curtailed 109.5 MW in July 3, 2018 event

58 participants curtailed 116.2 MW in August 6, 2018 event

54 participants curtailed 120.2 MW in August 28, 2018 event

50 participants curtailed 114.6 MW in September 4, 2018 event

50 participants curtailed 102.6 MW in September 5, 2018 event

ACTUAL EXPENDITURES ($1,000)

Phase III expenditures through PY10 **$4,550**

37% of projected

67% of projected

PY10 expenditures **$2,167**

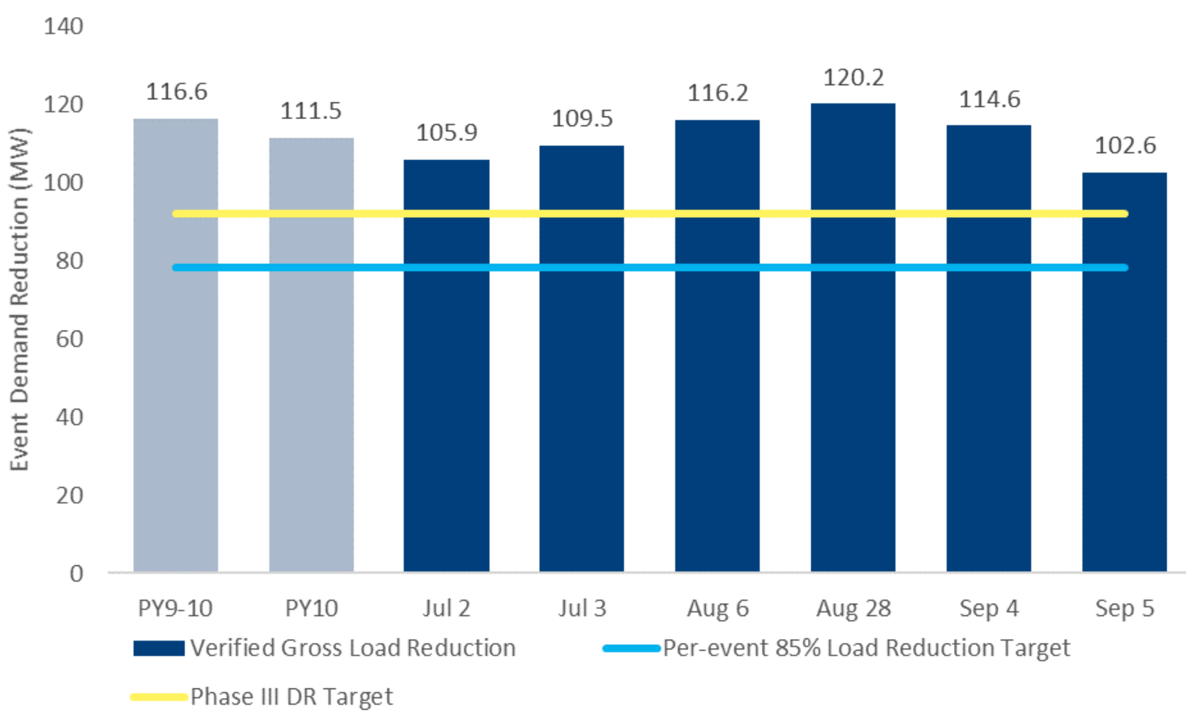
1 Demand Response Program

1.1 Executive Summary

In PY10, PPL Electric Utilities' Act 129 Demand Response Program operated with 24 participating customers representing 60 participating facilities. According to the Act 129 Phase III Implementation Order, a maximum of six events can be called per program year.[1] In PY10, six events were called, and the last event occurred on September 5, 2018.

PPL Electric Utilities is on track to meet its Phase III Act 129 Demand Reduction compliance target specified in the Implementation Order. Figure 1 shows the PY10 evaluation impact findings. In PY10, verified peak load reductions were 111.5 MW (equal to the average demand reduction over the six demand response events). The P3TD verified peak load reductions were 116.6 MW (the average load reduction over PY9 and PY10 event hours), which exceeds the Phase III compliance target of 92 MW. In addition, PPL Electric Utilities met its per-event compliance target of at least 78.2 MW (85% of the total compliance target) in each demand response event.

Figure 1. Gross Verified Savings in Comparison to Act 129 Targets



Note: These reported load impacts are based on Cadmus analysis of participant AMI consumption data and have been grossed up to reflect transmission and distribution losses.

1 Phase III Final Implementation Order. From the Public Meeting of June 11, 2015. Pennsylvania Public Utility Commission. Docket No. M-2014-2424864. Available at http://www.puc.pa.gov/pcdocs/1367313.doc.

1.2 Background

1.2.1 Compliance Targets

To comply with the Pennsylvania Public Utility Commission's Act 129 Phase III demand response compliance targets, PPL Electric Utilities' Demand Response Program must reduce its system load by an average of 92 MW (measured at the generator level) overall demand response events during the last four years of Phase III (PY9–PY12).[2] In addition, PPL Electric Utilities is required to achieve a minimum of 85% of the 92 MW compliance target, or 78.2 MW, during each event.

Compliance targets for demand response programs were established at the generator level, which means load reductions measured at the customer meter must be increased to reflect transmission and distribution losses (line losses). The peak demand impact estimates presented in this report have been adjusted for these line losses. PPL Electric Utilities uses the following line loss percentages and/or multipliers by sector:

- Small C&I = [8.75% or 1.0875]
- Large C&I = [4.2% or 1.0420]

Demand response events were initiated in accordance with Act 129 Phase III Implementation Order, which requires a four-hour event on the following day when at least one hour of the PJM Interconnection regional transmission organization (RTO) day-ahead forecast exceeds 96% of its forecast of summer peak demand. According to the order, there can be a maximum of six events per program year, and in PY10 all six events were called by September 5, 2018.

1.2.2 PY10 Activities

During Phase III, PPL Electric Utilities operates the Demand Response Program for commercial and industrial (C&I) customers and for government, nonprofit, and education (GNE) customers. PPL Electric Utilities manages the implementation conservation service provider (ICSP) and provides overall strategic direction for the program.

CPower, the ICSP, enrolls and contracts with customers to reduce electricity demand during Act 129 demand response events.[3] After the summer season, the ICSP makes performance-based payments to participating customers.[4]

In PY10, PPL Electric Utilities initiated six load curtailment events, including two pairs of back-to-back events. Each event occurred on a non-holiday weekday between 2:00 p.m. and 6:00 p.m.

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2 Program objectives are stipulated on PPL Electric Utilities' revised EE&C Plan (Docket No. M-2015-2515642) filed with the Pennsylvania PUC in July 2018 and approved in November 2018.

3 CPower, the ICSP, contracted with four PPL Electric Utilities' customer facilities through the demand response aggregators NRG and Direct Energy.

4 In PY10, 28 customers representing 64 facilities enrolled in PY10; however, four customers representing four facilities did not participate in any events.

The ICSP notified participating customers between 10:30 a.m. and 11:15 a.m. on the day before each event. Before the event started, customers confirmed their participation for specific event hours by logging into the ICSP's online platform. Customers had the option of participating in all or a subset of event hours. In PY10, among 60 participant facilities and across six events, there were 106 instances of a facility participating for fewer than four hours of an event.

1.3 Progress Toward Phase III Projected Savings

In Phase III, PPL Electric Utilities designed the Demand Response Program to achieve approximately 115 MW of capacity and to exceed its 92 MW Act 129 demand response compliance targets. It protected against various operational and evaluation uncertainties by overenrolling capacity. In PY10, PPL Electric Utilities achieved verified peak demand reductions that averaged 111.5 MW over all event hours, approximately 21% greater than the 92 MW target for Phase III.

Table 1 shows the program's verified gross peak demand reductions and progress toward its Phase III totals, as filed in PPL Electric Utilities' Energy Efficiency and Conservation (EE&C) Plan.[5]

Table 1. PY10 Demand Response Program Projected and Verified Savings

Event	PY9 Only	PY10 Only			Phase III: PY8–PY12 (1)		
	Verified (MW)	Projected (2) (MW)	Verified (3) (MW)	Percentage of Projected	Projected (2) (MW)	Verified (4) (MW)	Percentage of Projected
Demand response capacity	126.7	115	111.5	97.3%	115	116.6	101.4%

(1) All demand reductions are averages across all events. The planned reductions are not summed across years, since the sum of demand reductions across years is not a meaningful concept.
(2) Planned savings are based on PPL Electric Utilities' revised EE&C plan (Docket No. 2015-2515642) filed with the Pennsylvania PUC July 2018 and approved in November 2018. Estimated demand reduction is shown per event hour.
(3) Verified savings are the average demand response savings per event during the July 2, July 3, August 6, August 28, September 4, and September 5, 2018, Act 129 events.
(4) Phase III verified MW are averaged across all nine events (three from PY9 and six from PY10), for the average event day MW.

1.4 Participation and Reported Savings by Customer Segment

1.4.1 Definition of a Participant

A participant in the Demand Response Program in PY10 is defined as a customer facility that participated in at least one of PPL Electric Utilities' Act 129 demand response events. The ICSP enrolled 64 customers in PY10. During PY10, a total of 24 customers with 60 participating facility sites participated in at least one Act 129 demand response event.

[5] Pennsylvania Public Utility Commission, *Energy Efficiency and Conservation Program Implementation Order*, at Docket No. M-2014-2424864 (*Phase III Implementation Order*), entered June 11, 2015.

1.4.2 Program Participation and Reported Impacts

Table 2 presents the participation counts, reported demand reduction, and incentive payments for the Demand Response Program in PY10 by customer segment and Act 129 event. In PY10 (summer of 2018), the program reported demand savings of approximately 106 MW on July 2, 109 MW on July 3, 121 MW on August 6, 106 MW on August 28, 119 MW on September 4, and 107 MW on September 5. Large C&I customers accounted for between 92% and 97% of the reported demand savings for these events.

Table 2. PY10 Demand Response Program Participation and Reported Demand Reductions

Parameter	Small C&I (Non-GNE)	Large C&I (Non-GNE)	GNE	Total (1)
PYTD Number of Participants (2)	30	20	10	60
Event 1, July 2, 2018, Reported MW	0.5	102.0	3.8	106.3
Event 2, July 3, 2018, Reported MW	0.4	104.0	4.0	108.5
Event 3, August 6, 2018, Reported MW	1.2	114.4	5.5	121.1
Event 4, August 28, 2018, Reported MW	0.9	102.1	2.9	106.0
Event 5, September 4, 2018, Reported MW	2.1	115.4	1.7	119.1
Event 6, September 5, 2018, Reported MW	1.6	103.7	1.7	106.6
Total Average Reported MW	**1.1**	**106.9**	**3.2**	**111.3**
PY10 Incentives ($1000) (3)	$21,100	$1,803,400	$54,100	$1,878,600

Note: The load impacts reported in this table have been grossed up to reflect transmission and distribution losses.
(1) Total may not equal total of row due to rounding.
(2) Number of participant who participated in at least one event.
(3) Refers to total savings across all events and all event hours

A dual-enrolled participant is a facility that participated in PPL Electric Utilities' Demand Response Program and a PJM demand response program. In PY10, all PPL Electric Utilities demand response program participants were dual-enrolled participants. Table 3 reports the number of these participating facilities and the incentives paid.

Table 3. Dual-Enrolled Participants

Dual-Enrolled Customer Facilities	Act 129-Only Customer Facilities	Incentives Paid to Dual-Enrolled Customers	Incentives Paid to Act 129-Only Customers
60	0	$1,878,600	$0

Dual-enrolled customers were enrolled in PPL Electric Utilities' Act 129 Demand Response Program and PJM demand response programs in PY10.

1.4.3 Gross Impact Evaluation

The impact evaluation sampling strategy is shown in Table 4. Cadmus analyzed consumption data to estimate Act 129 load impacts for the population of participants (that is, there was no sampling). However, for three facilities, it was not possible to estimate event savings for one or two events because the interval kWh meter readings during the event were estimated, not actual.[6] The number and

[6] This affected one small C&I customer during two events and two small C&I customers, each for one event.

composition of participants varied between events, because the ICSP called upon different sets of customers for each event.

Table 4. PY10 Demand Response Program Gross Impact Sample Design

Stratum	Event	Population Size	Assumed Proportion or Cv in Sample Design	Achieved Sample Size	PYRTD MW	Impact Evaluation Activity
Small C&I	July 2, 2018	30	N/A (Census)	30	0.5	Analysis of individual participating facility loads was performed for each event hour.
	July 3, 2018	30	N/A (Census)	30	0.4	
	August 6, 2018	30	N/A (Census)	29	1.2	
	August 28, 2018	30	N/A (Census)	29	0.9	
	September 4, 2018	30	N/A (Census)	29	2.1	
	September 5, 2018	30	N/A (Census)	29	1.6	
Large C&I	July 2, 2018	19	N/A (Census)	19	102.0	
	July 3, 2018	20	N/A (Census)	20	104.0	
	August 6, 2018	18	N/A (Census)	18	114.4	
	August 28, 2018	18	N/A (Census)	18	102.1	
	September 4, 2018	18	N/A (Census)	18	115.4	
	September 5, 2018	17	N/A (Census)	17	103.7	
GNE	July 2, 2018	9	N/A (Census)	9	3.8	
	July 3, 2018	8	N/A (Census)	8	4.0	
	August 6, 2018	10	N/A (Census)	10	5.5	
	August 28, 2018	6	N/A (Census)	6	2.9	
	September 4, 2018	2	N/A (Census)	2	1.7	
	September 5, 2018	3	N/A (Census)	3	1.7	
Program Total (1)	**July 2, 2018**	**58**	**N/A (Census)**	**58**	**106.3**	
	July 3, 2018	**58**	**N/A (Census)**	**58**	**108.5**	
	August 6, 2018	**58**	**N/A (Census)**	**57**	**121.1**	
	August 28, 2018	**54**	**N/A (Census)**	**53**	**106.0**	
	September 4, 2018	**50**	**N/A (Census)**	**49**	**119.1**	
	September 5, 2018	**50**	**N/A (Census)**	**49**	**106.6**	

The load impacts reported in this table have been grossed up to reflect transmission and distribution losses.
(1) Totals may not sum due to rounding.

Cadmus evaluated each facility's demand savings by comparing the facility's metered demand during event hours with an estimated baseline. The baseline was estimated using either regression analysis or a day-matching method.[7] For each participant, Cadmus analyzed interval consumption data to identify the most accurate baseline calculation method. Additional details about the evaluation and baseline selection methodology are in *Appendix A*.

7 Cadmus applied standard day-matching baseline calculation methods such as selecting the seven days of the previous 10 with highest average demand in accordance with SWE guidelines.

Table 5 shows that in PY10 that the Demand Response Program achieved 111.5 MW verified average demand reduction, a realization rate of 100.2% relative to the reported (*ex ante*) load reduction. The verified average demand savings exceeded PPL Electric Utilities' Act 129 target for Phase III by 20 MW.

Table 5. PY10 Demand Response Program Gross Impact Results for Demand

Stratum	Event	PYRTD MW	Demand Realization Rate	PYVTD MW [1]	Standard Error	Relative Precision at 90% C.L. [2]
Small C&I	Event 1	0.5	371%	1.9	0.08	7%
	Event 2	0.4	308%	1.4	0.08	10%
	Event 3	1.2	149%	1.8	0.08	7%
	Event 4	0.9	168%	1.6	0.08	8%
	Event 5	2.1	92%	1.9	0.08	7%
	Event 6	1.6	115%	1.8	0.08	7%
Large C&I	Event 1	102.0	95%	97.2	4.63	8%
	Event 2	104.0	98%	101.8	4.61	7%
	Event 3	114.4	94%	108.1	4.36	7%
	Event 4	102.1	112%	114.5	4.51	6%
	Event 5	115.4	96%	110.9	4.52	7%
	Event 6	103.7	96%	99.2	4.50	7%
GNE	Event 1	3.8	179%	6.8	0.30	7%
	Event 2	4.0	156%	6.3	0.29	8%
	Event 3	5.5	114%	6.3	0.29	8%
	Event 4	2.9	142%	4.1	0.28	11%
	Event 5	1.7	108%	1.8	0.23	21%
	Event 6	1.7	122%	1.6	0.20	15%
Event [3]	**Event 1**	**106.3**	**100%**	**105.9**	**4.64**	**8%**
	Event 2	**108.5**	**101%**	**109.5**	**4.62**	**7%**
	Event 3	**121.1**	**96%**	**116.2**	**4.37**	**6%**
	Event 4	**106.0**	**113%**	**120.2**	**4.52**	**6%**
	Event 5	**119.1**	**96%**	**114.6**	**4.52**	**6%**
	Event 6	**106.6**	**96%**	**102.6**	**4.51**	**7%**
Average		**111.3**	**100%**	**111.5**	**1.85**	**3%**

[1] Based on Cadmus' analysis of participant AMI consumption data. MW were grossed up to reflect transmission and distribution losses.
[2] Precision accounts for covariances of savings across hours of each event but not between events.

The following factors may have contributed to differences between the reported and verified savings and the realization rates that deviated from 100%:

- **Estimated interval consumption readings.** Cadmus could not estimate demand savings for three small C&I facilities during one or two events because the interval kWh readings for event hours were estimated and not actual readings.[8]
- **Allowance of event notification days in basis window.** Cadmus excluded event notification days from consideration for the basis window when calculating customer baselines. This exclusion was justified because Cadmus' analysis of load impacts on notification days in the PY9 evaluation suggested that many customers increased or decreased their loads in response to event notifications. The ICSP did not exclude event notification days when calculating customer baselines.
- **Different treatment of estimated readings**. PPL Electric Utilities estimated about 1% of all hourly interval readings for participating facilities on event or weekdays that were not holidays or notification days between April 1, 2018, and September 15, 2018. Cadmus replaced these estimated readings with missing values and did not include them in the analysis sample.
- **Different methods for calculating customer baselines.** To the extent possible, the ICSP attempted to align its baseline calculation method with Cadmus' method. However, for all small C&I facilities, 90% of GNE facilities, and 20% of large C&I facilities, Cadmus employed regression analysis to calculate the baseline whereas the ICSP employed day-matching. The ICSP employed day-matching because it is transparent and easier for participants to understand than regression. Cadmus used regression after determining it yielded more accurate savings estimates than day-matching.

1.5 Verified Savings Estimates

Table 6 shows the verified PYTD and P3TD demand savings, which were calculated by analyzing individual participant facility loads and estimating savings for individual facilities during each event hour. Cadmus averaged the PY9 and PY10 estimates of verified demand reduction for individual events to calculate the Phase III (P3VTD) program impacts.

[8] The affected events (with number of affected facilities in parentheses) were August 6, 2018 (1), August 28, 2018 (1), September 4, 2018 (1), and September 5, 2018 (1).

Table 6. PYTD and P3TD Demand Savings Summary

Savings Type	Demand (MW)
PYRTD	111.3
PYVTD Gross	111.5
PYVTD Net [3]	-
P3RTD [1]	112.7
P3VTD Gross [2]	116.6
P3VTD Net [3]	-

(1) Savings are calculated as the average of demand reductions for the July 2, July 3, August 6, August 28, September 4, and September 5 Act 129 events in 2018.
(2) Savings are calculated as the average of the demand reductions for individual Act 129 demand response events in PY9 and PY10.
(3) There are no net savings because neither free riders nor spillover apply to this program. C&I and GNE participants are not expected to curtail their loads without notification of PPL Electric Utilities system peaks and without compensation.

1.6 Process Evaluation

1.6.1 Research Objectives

The process evaluation assessed program implementation and customer satisfaction. The main research objectives focused on these areas:

- Event implementation successes and challenges
- Customer response to event notifications and the event enrollment process
- Customer response to events and participation challenges, especially with back-to-back events
- Customer satisfaction with the incentive amount, the ICSP, and the overall program

1.6.2 Evaluation Activities

The PY10 process evaluation activities for the Demand Response Program featured interviews with PPL Electric Utilities and ICSP program managers and online surveys of participants.

Table 7 lists the process evaluation sampling strategy. The process evaluation’s survey activity did not count participants in the same way as the impact evaluation. The impact evaluation counted the number of customer facilities that participated in at least one event in PY10 (n=60 facilities). For the survey as part of the process evaluation, a participant was defined as an enrolled company contracted by the ICSP (n=25 unique companies which had 64 facilities). This company did not have to participate in an event in PY10 to qualify for the survey, but it did have to have been enrolled for the PY10 program and received the event notifications.

Table 7. PY10 Process Evaluation Sampling Strategy

Stratum	Stratum Boundaries	Mode	Population Size	Assumed Proportion or Cv in Sample Design	Target Sample Size	Achieved Sample Size	Number of Records Selected for Sample Frame [1]	Percent of Sample Frame Contacted to Achieve Sample [2]
PPL Electric Utilities Program and ICSP Staff	Staff	Telephone in-depth Interview	2	N/A	2	2	2	N/A
Participant Surveys	Enrolled Companies Contracted by CPower	Online survey	25 [3]	N/A	12	12	25	100%
Program Total			**27**	**N/A**	**14**	**14**	**27**	**N/A**

[1] Sample frame is the enrolled customer companies with contact information that were asked to complete the survey. The final sample frame includes unique records in the PPL Electric Utilities tracking database.
[2] Percent contacted means the percentage of the sample frame that were emailed to complete surveys.
[3] There were 25 unique companies contracted by CPower, the ICSP, that enrolled in the PY10 Demand Response Program. Cadmus included enrolled companies that did not participate in any events in its survey population. Cadmus did not survey the companies under contract with the demand response aggregators NRG and Direct Energy because it did not have customer contact information. The survey's population count of participants, therefore, differs from the impact evaluation's participant count. The impact evaluation counts as participants the number of customer facilities that participated in at least one event.

1.6.2.1 Program Staff and ICSP Interview Methodology

In early November 2018, Cadmus interviewed the program managers from PPL Electric Utilities and the ICSP. The interviews covered program operations, event implementation, and event performance outcomes as well as any program changes, areas working well, and areas experiencing challenges.

1.6.2.2 Survey Methodology

Between mid-November and early December 2018, Cadmus contacted all 25 enrolled companies, even if they did not participate in any events, to ask them to complete an online survey.[9]

The email was directed to the person who authorized the events at each company, typically an energy manager. The survey sought 12 completes out of the 25 companies, with no subquotas based on customer segment or level of event participation to ensure that survey responses were representative of all.

Cadmus coordinated with PPL Electric Utilities program staff and key account managers and the ICSP on the survey. The ICSP sent an email notifying enrolled customers of the survey one day before Cadmus sent the invitation email. One week before the survey closed, PPL Electric Utilities' key account managers emailed the remaining customers who had not yet responded to encourage completion of the survey.

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[9] Cadmus did not survey the four enrolled customers under contract with the demand response aggregators NRG and Direct Energy because it did not have customer contact information.

Table 8 lists total contacts, the outcome (final disposition) of each record, and response rate.

Table 8. PY10 Demand Response Participant Survey Sample Attrition Table

Description of Online Survey Outcomes	Count
Population (number of CPower, NRG, and Direct Energy enrolled facilities)	**64**
Removed: NRG and Direct Energy contracted facilities	4
Removed: Duplicate facility contacts	35
Sample Frame (number of unique companies)	**25**
Survey Sample Frame (used for online surveys)	**25**
Not started	13
Opted out	0
Partial complete (not included in survey findings analysis)	0
Completed Surveys	**12**
Response Rate (completed surveys divided by number of records)	**48%**

Because of the small number of respondents (n=12), the expected confidence and precision levels for survey data are not reported here. Therefore, data gathered from the participant surveys should be viewed more qualitatively than quantitatively.

1.6.3 Process Evaluation Findings

1.6.3.1 Program Delivery

In PY10, PPL Electric Utilities and the ICSP successfully implemented six events, including two pairs of back-to-back events. This was twice as many events as in PY9, which had one pair of back-to-back events. The Demand Response Program recruited four new companies in PY10 and retained around 90% of the participants from PY9. PPL Electric Utilities and the ICSP operated the program the same as in PY9.

The Demand Response Program's successful event implementation and strong performance can be attributed to three factors:

- **Having a familiar and clear set of operational procedures.** PPL Electric Utilities, the ICSP, and participating customers were prepared to handle the greater number of events in PY10 because operational procedures were kept the same as in PY9. Moreover, in early June 2018 the ICSP held a seasonal readiness webinar to educate any new participating customers and remind repeat participating customers of the event procedures and expectations.
- **Knowing which participating customers could fill in load performance gaps.** PPL Electric Utilities expressed concern regarding one of its large capacity customers and its ability to meet load reductions if this customer was not able to participate in an event or deliver on its enrolled load expectation. The ICSP addressed this concern by reviewing the operations and previous event performance of customers and identifying the ones that could compensate for the underperformance of a large capacity customer. The ICSP acted on this information in PY10 when one of the large capacity customers was not able to deliver.

- **Oversubscribing the number of participating customers.** As a performance gap backup plan, the ICSP enrolled more customers than the program needed to meet the capacity projections. Rather than place customers on a program wait list, the ICSP added any interested, qualified customers. These additional customers could provide the additional MW load reduction needed should a large capacity customer not be able to deliver.

PPL Electric Utilities and the ICSP noted one challenge in PY10: the two pairs of back-to-back events occurred on a Monday and following a Monday holiday, which meant event notifications were sent out on a Sunday and on Labor Day Monday, respectively. PPL Electric Utilities believed this timing would inconvenience participating customers. However, that was not the case. Participating customers responded to the event notifications and enrolled in events, albeit event enrollment was slower than on a normal weekday.

1.6.3.2 Participant Profile

Of the 25 enrolled companies (contracted by CPower, the ICSP), 80% had one facility enrolled in the PY10 program, 68% were manufacturing facilities, 52% participated in all six events, and 84% participated in back-to-back events. As shown in Table 9, the online surveys captured a fairly representative sample of enrolled companies. The 12 survey respondents represented approximately 53% of the 111.5 MW average peak load reduction in PY10.

Table 9. PY10 Demand Response Enrolled Company and Survey Respondent Profile

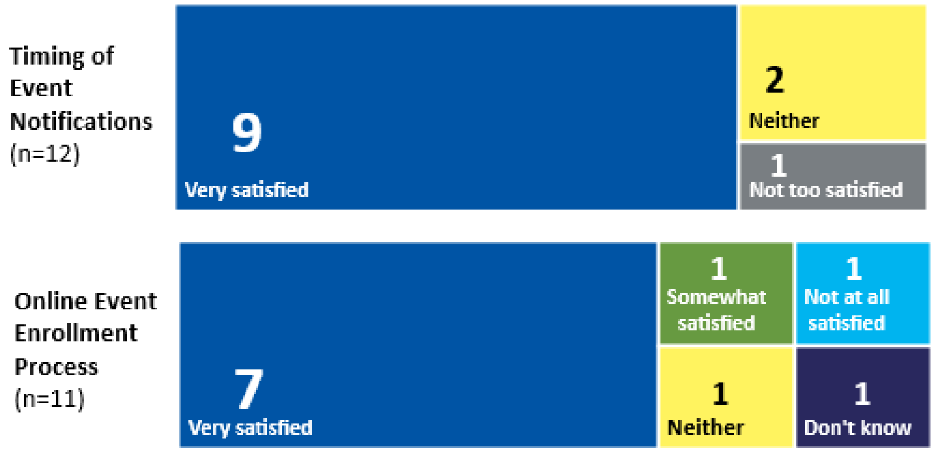
Characteristic	All Enrolled Customers (Population n=25)	Surveyed Customers (Sample n=12)
One Facility vs. Multiple Facilities		
Customer had one facility enrolled in the program	80%	67%
Customer had multiple facilities enrolled in the program	20%	33%
Facility Type		
Manufacturing Facility	68%	75%
School/University	12%	8%
Office	8%	0%
Retail	8%	8%
Medical/Health	4%	8%
Event Participation Count		
Six Events	52%	58%
Five Events	16%	17%
Four Events	4%	0%
Three Events	8%	8%
Two Events	4%	8%
One Event	0%	0%
Zero Events	16%	8%
Participation in Back-to-Back Events		
Yes	84%	92%
No	16%	8%
Note: All percentages based on analysis of customer and facility data provided by the ICSP.		

1.6.3.3 Event Notifications and Enrollment

Most respondents were satisfied with the timing of event notifications and the online event enrollment process. Nine of the 12 respondents were *very satisfied* with the amount of time between the notifications and the start of the events. Eight of 11 respondents (one did not answer the question) were satisfied with the online event enrollment process; seven said they were *very satisfied* and one was *somewhat satisfied*. Figure 2 shows respondents' satisfaction with the timing of event notifications and the online event enrollment process.

For these two items, the survey did not ask respondents who said they were less than satisfied to explain their reasons. Instead, the survey asked everyone for suggestions on ways to improve the event notifications and the online event enrollment process. Only one respondent offered a suggestion. This respondent disliked having to go through the event enrollment process more than once a week and suggested a one-time enrollment instead of having to enroll in each event individually.

Figure 2. Satisfaction with Timing of Event Notifications and Online Event Enrollment Process



Source: Survey question, "CPower notified you in advance of upcoming PPL Act 129 Program Events. You should have received a notification between 10:10 a.m. and noon on days before events. How satisfied were you with the amount of time between the advance notification and the start of the event?" and "You enrolled in events and specified the hours of participation through CPower's online website. How satisfied were you with the online event enrollment process?"

1.6.3.4 Event Experience and Participation Challenges

In general, most respondents found it easy to participate in the PY10 events. Of 11 respondents (the respondent who did not answer the question did not participate in any events), three respondents said it was *very easy* and five said it was *somewhat easy* to participate. In contrast, most respondents found it difficult to participate in the back-to-back events. Seven said it was *somewhat difficult* and one said it was *very difficult*. Table 10 shows the number of respondents who said it was easy or difficult to participate in general and back-to-back events.

Table 10. Ease/Difficulty of Participating in PY10 Events

Events in General (n=11)	Vs.	Back-to-Back Events (n=11)
3	Very easy	1
5	Somewhat easy	2
0	Neither	0
2	Somewhat difficult	7
1	Very difficult	1

Source: Survey question, "How easy or difficult was it for your facility/facilities to participate in the PPL events this summer?" and "How easy or difficult was it for your facility/facilities to participate in back-to-back PPL events this summer?"

The survey asked those respondents who participated in fewer than six events why their facilities were unable to participate in all events. Of the six respondents asked this question, three said not having enough benefits to outweigh the costs, two said there were too many interruptions to business operations, and one said an event had coincided with the annual facility shutdown.

Similarly, the survey asked respondents what was difficult about participating in the back-to-back events. Of 10 respondents who answered, six said the back-to-back events impacted their production and three said occupant comfort was affected from shortening HVAC runtimes.

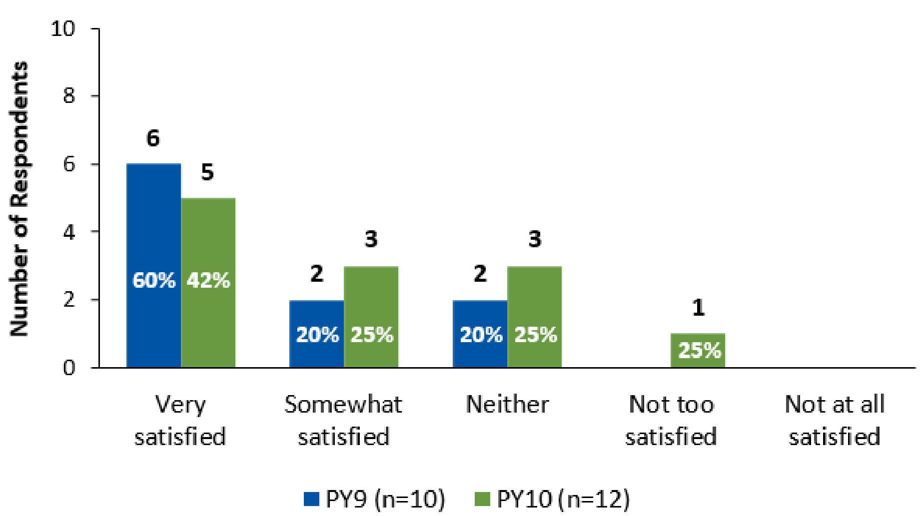
When asked what would make it easier to participate in events, six of eight respondents said increasing the amount of the incentive. Other suggestions were providing more communication outside of event days and having access to historical meter data.

1.6.3.5 Participant Satisfaction

In PY10, eight of 12 respondents were satisfied with the Demand Response Program—five were *very satisfied* and three were *somewhat satisfied*. One respondent who was *not too satisfied* did not provide a reason. Responses to other questions revealed this respondent's dissatisfaction with the timing of event notifications, the online event enrollment process, the incentive amount, and the ICSP. Despite reporting dissatisfaction with the program, this respondent's company nonetheless participated in all six events.

Figure 3 compares overall satisfaction with the program in PY9 and PY10. In PY9, eight of 10 respondents were satisfied; in PY10, eight of 12 respondents were satisfied. When expressed as a percentage, satisfaction appears to have decreased from 80% in PY9 to 67% in PY10; however, this may be misleading because of the small sample sizes. These small sample sizes also means that confidence and precision of the survey data cannot be estimated. It is possible that any decrease in satisfaction may be due to the greater number of events in PY10, but because of the small sample sizes, this explanation cannot be supported with confidence. Another difference is that the PY9 survey was conducted by telephone and the PY10 survey was online. Each survey mode has its set of biases and strengths, such as self-selection bias, interviewer bias, and respondent anonymity that can influence responses.

Figure 3. Overall Satisfaction with Demand Response Program



Source: Survey question, "How would you rate your overall satisfaction with the Demand Response Program?"

Six of 12 respondents were neither satisfied nor dissatisfied with the incentive amount, and two were *very satisfied* and two were *somewhat satisfied*. Only one respondent was *not too satisfied*. Note that when Cadmus administered the surveys, participating customers had not received their incentive payments, but they had been informed of the amount they would be receiving. Figure 4 shows the response breakdown on satisfaction with the incentive amount.

Figure 4. Satisfaction with the Incentive Amount

Source: Survey question, "How would you rate your satisfaction with the incentive amount you will receive?"

During the staff interviews, PPL Electric Utilities acknowledged the issue with the timing of incentive payments. Incentive payments are made approximately 90 days after the end of the event season. PPL Electric Utilities needs this time to review and approve the incentives and for the ICSP to process and send out the incentives. In the PY9 evaluation report, Cadmus recommended that the ICSP advise customers when they could expect to receive the incentive payment. The ICSP implemented this recommendation by specifying the timing of the payment in the customer's contract. During the interview, the ICSP noted that in PY10 it received one complaint about the timing of the incentive payment and worked with this participating customer to resolve it.

In PY10, eight of 12 respondents were satisfied with the ICSP—five were *very satisfied* and three were *somewhat satisfied*. One respondent was *not at all satisfied* because of difficulties with the event enrollment website and that the ICSP had not responded to emails in a timely manner. Figure 5 shows the response breakdown on overall satisfaction with the ICSP.

Figure 5. Overall Satisfaction with the ICSP

Source: Survey question, "Thinking about your interactions with CPower, how would you rate your overall satisfaction with CPower?"

1.6.4 Cost-Effectiveness Reporting

Cadmus will include a detailed breakdown of Demand Response Program finances and cost-effectiveness in the PY10 Annual Report due November 15, 2019, when program costs are finalized.

1.7 Recommendations

Overall, in PY10 the Demand Response Program exceeded the Act 129 compliance target of 92 MW for all event hours by 21% and is on track to meet the Act 129 projected demand reduction for Phase III. Most participating customers were satisfied with the timing of the event notifications, the online event enrollment process, the ICSP, and the program overall.

Recommendations are provided in Table 11, along with a summary of how PPL Electric Utilities plans to address the recommendations.

Finding: The program achieved an average peak load reduction of 111.5 MW in PY10, exceeding the Act 129 compliance target of 92 MW for all event hours (see section *1.3 Progress Toward Phase III Projected Savings* and Table 1). For Phase III, the program achieved an average peak load reduction of 116.6 MW, putting the program on track to exceed the Act 129 compliance target.

Finding: The program met its per-event compliance target of at least 78.2 MW, or 85% of the total 92 MW compliance target, in each of the six events (see Figure 1 in the *Executive Summary*).

Conclusion: PPL Electric Utilities and the ICSP successfully reduced peak demand in PY10 as the program met its per-event compliance target and remains on track to exceed the Phase III compliance target of 92 MW.

Finding: In PY10, PPL Electric Utilities, the ICSP, and participants experienced six events, including two pairs of back-to-back events. This was twice as many events as in PY9, which had only one pair of back-to-back events (see section *1.6.3.1 Program Delivery*).

Finding: PY10 had fewer participating facilities, 60 facilities compared to 93 in PY9; nevertheless, the program still met the Act 129 compliance target (see Table 2).[10]

Finding: PY10 had lower enrolled demand response capacity (124.0 MW) than PY9 (141.8 MW) and still met the Act 129 compliance target (see Figure A-1 in *Appendix A*). [11]

Finding: The ICSP had a load performance backup plan in place on the chance one of the large load capacity customers was unable to participate in an event. The backup plan involved enrolling more

[10] Cadmus. *Annual Report to the Pennsylvania Public Utility Commission.* November 15, 2018. Prepared for PPL Electric Utilities.

[11] Ibid.

customers in the program than needed and identifying which of the enrolled customers could make up the difference of a large load capacity customer (see section *1.6.3.1 Program Delivery*).

Conclusion: PPL Electric Utilities and the ICSP had a resilient program in PY10 that overcame participation and capacity adversities by exercising the backup plan in place.

Recommendation #1: Maintain the robust backup plan for a variety of participation and capacity scenarios to manage program risks and challenges.

Finding: The two pairs of back-to-back events occurred on a Monday and following a Monday holiday, which meant event notifications were sent out on a Sunday and Labor Day Monday. PPL Electric Utilities expressed concern that back-to-back events would inconvenience the participating customers (see section *1.6.3.1 Program Delivery*).

Finding: Eight of 11 participating customers reported finding it difficult to participate in the back-to-back events. Of the 10 respondents who explained the difficulties, six said the events impacted production and three said the events impacted occupant comfort (see section *1.6.3.4 Event Experience and Participation Challenges*).

Finding: Customers who participated in fewer than six events gave these reasons for opting out of the event: three said not enough benefits to outweigh the costs, two said too many interruptions to business operations, and one said that an event coincided with the annual facility shutdown (see section *1.6.3.4 Event Experience and Participation Challenges*).

Finding: Participants exceeded the 78.2 MW per-event compliance target for the two pairs of back-to-back events. On average, participants reduced 106.8 MW and 109.7 MW on July 2 and July 3, respectively, and 116.4 MW and 104.1 MW on September 4 and September 5, respectively (see Figure 1 in the *Executive Summary*).

Finding: Eight of 12 respondents were satisfied with the program—five were *very satisfied* and three were *somewhat satisfied*. One respondent was *not too satisfied*, yet the company still participated in all six events (see section *1.6.3.5 Participant Satisfaction*).

Conclusion: Despite participants' reporting difficulty with back-to-back event participation, the program achieved the per-event compliance target for the two pairs of back-to-back events and observed no event fatigue or low program satisfaction.

Recommendation #2: Consider providing customers with year-to-year performance results and a historical summary of past events on the ICSP's online event enrollment website. Performance results can include the customer's load reduction amount and incentive earned. The historical summary of past events can include the number of events and the event date. Displaying such information can help customers understand how they perform, plan for future events, and highlight their achievements that will encourage participation in future events and mediate satisfaction.

1.7.1 Status of Recommendations

Table 11 contains the status of each PY10 recommendation made to PPL Electric Utilities.

Table 11. Status of Recommendations for the Demand Response Program

Demand Response Program		
Recommendation Number	**Recommendation**	**EDC Status of Recommendation (Implemented, Being Considered, Rejected and Explanation of Action Taken by EDC)**
1	Maintain the robust backup plan for a variety of participation and capacity scenarios to manage program risks and challenges.	Implemented.
2	Consider providing customers with year-to-year performance results and a historical summary of past events on the ICSP's online event enrollment website.	Rejected. Customer have the ability to see past performance in the portal. Customers who do have real-time loggers will not have access to historical portal data.

Appendix A. Evaluation Detail – Demand Response Program

A.1 Gross Impact Evaluation

This appendix describes the methodology for estimating savings and program load impacts.

A.1.1 Methodology

Evaluation Sampling Approach

In PY10, 60 facilities operated by 24 customers of PPL Electric Utilities participated in one or more Act 129 demand response events. Table A-1 shows the number of participating facilities by customer stratum. Half of the participants were small commercial and industrial (C&I) facilities, one-third were large C&I customers, and the remaining were GNE customers. Cadmus estimated load impacts for all participant facilities for one or more events.

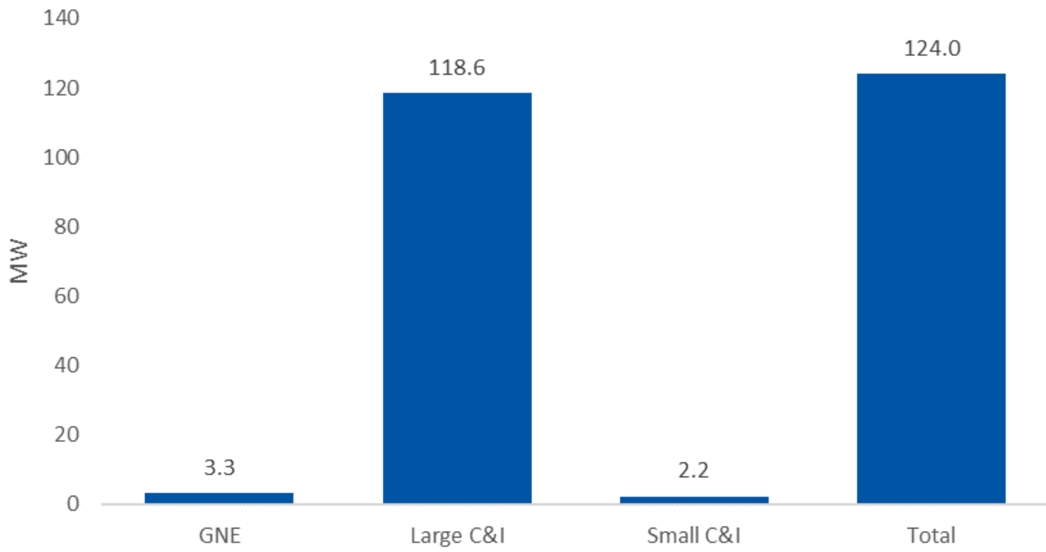
Table A-1. PY10 Program Sampling Strategy

Stratum	Population Size (Facilities)	Target Levels of Confidence & Precision	Target Sample Size	Achieved Sample Size	Evaluation Activity
Small C&I	30	N/A	30	30	Analysis of load impact data
Large C&I	20	N/A	20	20	Analysis of load impact data
GNE	10	N/A	10	10	Analysis of load impact data
Program Total	**60**	**N/A**	**60**	**60**	**Analysis of load impact data**

As Figure A-1 shows, although representing 50% of participant facilities, small C&I facilities contracted for only 2.2 MW or 1.8% of the program's enrolled capacity.[12] Large C&I customers contracted for 118.6 MW or 95.6% of the program's enrolled capacity. GNE customers contracted for the remaining capacity of 3.3 MW.

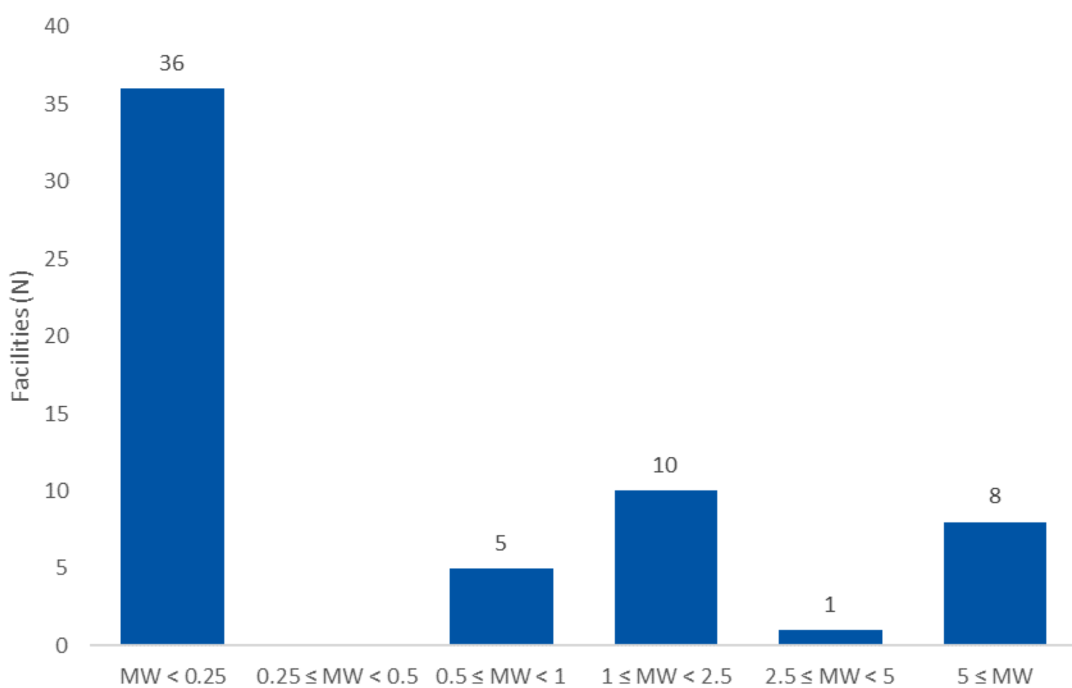
[12] Contracted capacity refers to the capacity committed by the facility to the ICSP and enrolled in the program. The capacity provided by the facility during Act 129 events may have differed from the contracted amount. The capacities of four facilities that did not participate in a PY10 demand response event are not included in the 124 MW total. In PY10, the total capacity of the four nonparticipant facilities was 1.9 MW.

Figure A-1. Enrolled Demand Response Capacity by Customer Segment



As Figure A-2 shows, most enrolled demand response capacity was provided by a small number of facilities. Of 60 participating facilities, 36, or 60%, each contracted for less than 250 kW; 19 facilities contracted to supply one or more megawatts. These 19 facilities contracted for 95% of the program's enrolled capacity.

Figure A-2. Distribution of Demand Response Program Enrolled Capacity



To protect the identity of participants, this figure does not display bins above 5 MW.

Ex Post *Verified Savings Methodology*

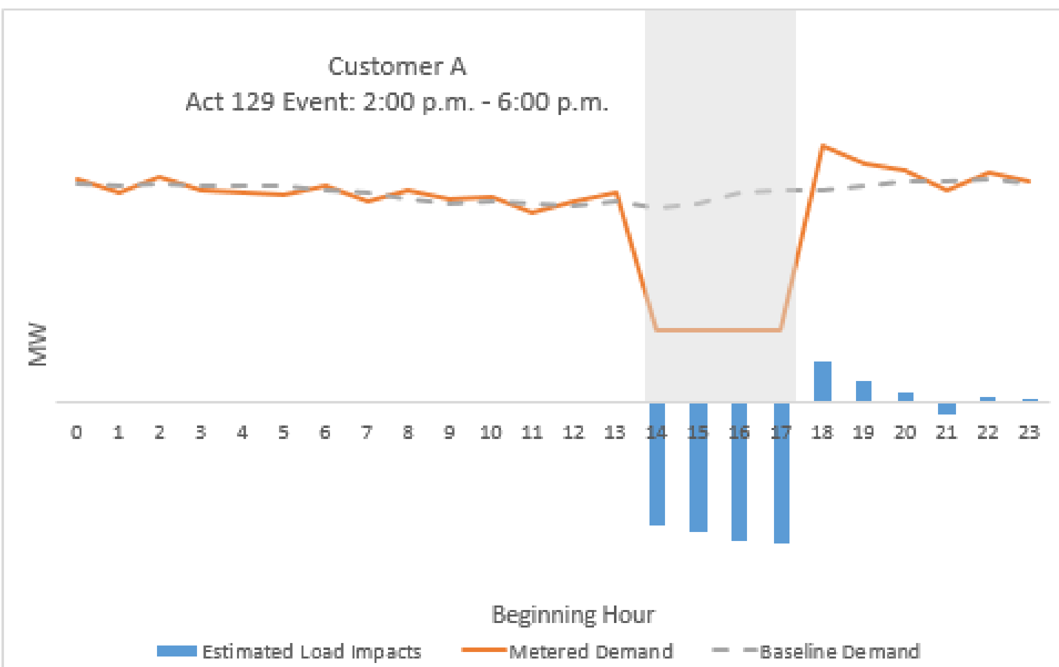
Cadmus analyzed advanced metering infrastructure (AMI) interval consumption data for each participating facility. A facility was defined as the area over which the participating customer's electricity consumption was metered and the load reductions measured during PY10 Demand Response Program period (June 1, 2018, through September 30, 2018). Cadmus estimated the facility load impacts as the difference between baseline electricity demand and metered demand, as shown in this equation:

$$\text{kW impact} = \text{Baseline kW} - \text{Metered kW}$$

Baseline demand is a counterfactual and represents what the facility's load would have been if the load curtailment event had not been called. The baseline is unobservable and must be estimated. Accurate estimation of load impacts requires establishing a valid method for estimating the baseline.

Figure A-3 illustrates the demand response event savings estimation for a hypothetical participant facility (Customer A). The shaded area shows the event window between 2:00 p.m. and 6:00 p.m. The solid line shows the metered consumption, and the gray dashed line shows the estimated baseline. The demand savings shown as blue bars represent the reduction in demand relative to the baseline caused by the event. The average demand savings per event hour are calculated as the average of the estimated hourly load reductions between 2:00 p.m. and 6:00 p.m.

Figure A-3. Demand Response Program Savings



Note: The shading shows event hours. This figure also depicts an increase in load, or snapback, after the event, shown as metered load lying above the baseline during hours 18 through 20. For the PY10 evaluation, Cadmus did not report snapback load impact estimates. In the PY9 evaluation, Cadmus documented snapback for small C&I and GNE facilities and no snapback for large C&I facilities. Large C&I facilities did not resume normal energy consumption until the following day.

Data Collection

Cadmus collected data from several sources to evaluate the PY10 Demand Response Program impacts. Table A-2 lists the data and sources.

Table A-2. Data Sources

Data	Population	Period	Variables	Source
Customer information system data	Demand Response Program participant facilities	From beginning of enrollment to end of summer 2018	Customer name, account number, business segment, ICSP baseline calculation method, enrolled MW, event hour participation indicators and reported load reductions, advance notification times, PJM economic market participation dates	CPower (ICSP)
PJM day-ahead forecasts and Act 129 event dates and hours	PPL Electric Utilities Demand Response Program participants	Summer 2018	Event dates and hours	PJM Interconnection LLC website
Facility interval consumption data	PPL Electric Utilities Demand Response Program participants	April 1, 2018–September 15, 2018	15 minute or hour interval kWh, estimated read indicator	PPL Electric Utilities
Weather	11 weather stations in PPL Electric Utilities service area	April 1, 2018–September 15, 2018	Dry-bulb temperature	NOAA
Solar radiation	Penn State, Pennsylvania SURFRAD site	April 1, 2018-September 15, 2018	Global horizontal irradiance	NOAA ESRL GMD
Line losses	Commercial and industrial electric utility customers	Phase III Act 129	Line loss factor	PA Technical Resource Manual (2016), Table 1-4

PPL Electric Utilities provided 15-minute or one-hour interval consumption data between April 1, 2018, and September 15, 2018, for 60 participating facilities. Cadmus aggregated all facility 15-minute interval data to the hour level. A small percentage of intervals was estimated or included one or more estimated or missing 15-minute intervals. Cadmus flagged these observations and set them to missing for the analysis. Estimated readings were not used in the calculation of facility baselines or in estimating savings. It was not possible to estimate demand savings of three small commercial facilities during one or two events because the interval kWh readings for event hours were estimated and not actual readings.

Cadmus also screened the data for outliers but did not remove any observations. A number of big box stores had negative readings during midday hours. Cadmus inferred from the time of day and outside temperature as well as corroborating articles in the press about solar panel installations by participating big box store chains that these probably represented negative net demand for utility-supplied electricity because of on-site solar generation of electricity.

Table A-3 summarizes the outcome of the kWh data-cleaning process.

Table A-3. Energy Data Summary

Observations	Number	Percentage [1]
Participating Facilities	60	N/A
Total Hourly Observations	241,920	N/A
Total Hourly Observations after Removing Excluded Days	168,480	100%
Observations with Missing kWh Readings	0	0%
Observations with Estimated kWh Readings	1,052	0.6%
Observations in Final Analysis Sample	167,428	99.4%

[1] Percentages reported relative to total hourly observations after removing excluded days (weekends, holidays).

The ICSP provided Cadmus information about each participating facility's business segment, customer baseline calculation method, enrolled megawatts, participation in each event hour, customer incentive payments, and event advance notification times. The ICSP also provided information about facilities that had participated in the PJM economic market. During PY10, two Act 129 participating facilities participated in the PJM economic energy market.

Cadmus located the closest National Oceanic and Atmospheric Administration (NOAA) weather station and mapped hourly temperature and humidity data to the kWh data. Cadmus mapped weather data to participating facilities from 11 stations across the PPL Electric Utility service area. The average temperature during event hours was 93.0°F.

Table A-4 shows summary statistics for the analysis sample, including weekday event and non-event hours between 2:00 p.m. and 6:00 p.m. for all facilities and by customer segment. Participants consumed an average of 1.77 MWh per event hour per facility, although there was variation in consumption between customer segments. Large C&I facilities consumed about 4.4 MWh per hour per facility, while small C&I participants consumed less than one-tenth of this amount.

Table A-4. Sample Summary Statistics

	All Facilities	GNE	Large C&I	Small C&I
Panel A: Event Hours				
kWh	1,768.8	923.2	4,434.4	228.7
	(4,181.7)	(1,483.8)	(6,301.6)	(110.4)
Outside Temperature (°F)	93.0	94.5	93.4	92.3
	(3.4)	(2.5)	(3.0)	(3.7)
Event Participation (=1 if Yes, =0 if No)	0.77	0.60	0.90	0.73
	(0.42)	(0.49)	(0.30)	(0.44)
PJM Economic Participation	0.003	0	0.008	0
	(0.053)	(0.0)	(0.091)	(0.0)
N	1,440	240	480	720
Panel B: Non-event Hours				
kWh/hour	3,362.3	1,061.9	9,177.0	221.6
	(6,538.1)	(1,430.6)	(8,686.3)	(105.6)
Outside Temperature (°F)	75.5	76.6	75.8	74.9
	(12.8)	(12.7)	(12.8)	(12.9)
Event Participation (=1 if Yes, =0 if No)	N/A	N/A	N/A	N/A
	N/A	N/A	N/A	N/A
PJM Economic Participation	0.002	0	0.005	0
	(0.042)	(0.0)	(0.073)	(0.0)
N	26,640	4,440	8,880	13,320
Note: All summary statistics are averages for hours between 2:00 p.m. and 6:00 p.m. on event or non-event days, non-holiday weekdays between April 1, 2018, and September 15, 2018. Sample standard deviations in parentheses.				

Figure A-4 and Figure A-5 show the average kWh per hour per facility for GNE, large C&I, and small C&I facilities on event days; all non-holiday weekdays between June 1, 2018, and September 15, 2018, that were not notification days; and "almost Act 129 event days."

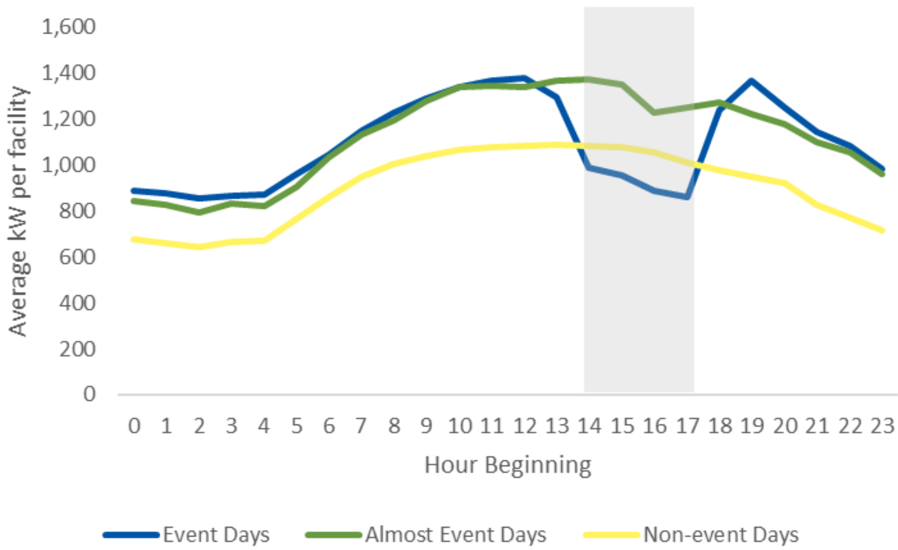
Almost-event days were the two non-notification, non-holiday weekdays with the highest PJM RTO day-ahead load forecasts that did not qualify as event days. These days (June 18, 2018, and August 29, 2018) had the highest day-ahead PJM forecasts that did not qualify them as Act 129 days and which provided a natural baseline for assessing the impact of Act 129 events.[13] These figures show demand at the meter and do not account for line losses.

For GNE facilities, the Act 129 event impacts between 2:00 p.m. and 6:00 p.m. (shaded in Figure A-4) are evident as a reduction in load relative to baseline demand on almost-event days. There was a steep reduction in load at 2 p.m., and loads continued to decrease during the event. At 6:00 p.m., loads rebounded sharply and exceeded normal levels. The figure also shows that average demand on all non-event days was less than was demand on event or almost-event days, and the difference was

[13] The peak day-ahead forecasts for June 18, 2018 and August 29, 2018 were, respectively, 95.8% and 95.1% of the PJM summer peak demand.

greatest during the late morning and early afternoon. Event days tended to be warmer, and space conditioning was a major electricity end use in GNE facilities. The difference between event and non-event days suggests that many of the non-event days may not provide an accurate baseline for event days.

Figure A-4. Average kW per GNE Participant Facility



The impacts of Act 129 events between 2:00 p.m. and 6:00 p.m. on loads of large C&I facilities are also evident in Figure A-5. During non-event hours (outside the shaded 2:00 p.m. to 6:00 p.m. window), average demand per facility was less on event days than on non-event days or almost-event days. This suggests that at least some participating facilities may have reduced their loads in in response to receiving event notifications or that participating facilities were attempting to manage 5CP (five highest one-hour system coincident peak) peak demand charges. Also, on non-event days, average demand per facility was constant across hours, suggesting demand was not sensitive to weather.

On almost-event days, there was a reduction in load relative to non-event days between 2:00 p.m. and 6:00 p.m. Again, this may have been the result of PJM market economic program participation by several Act 129 participants or by customers attempting to manage their demand to reduce 5CP peak demand charges. Two large C&I customers with more than 20 MW of combined enrolled demand response capacity participated in the PJM market on August 29.

Figure A-5. Average kW per Large C&I Participant Facility in PY10

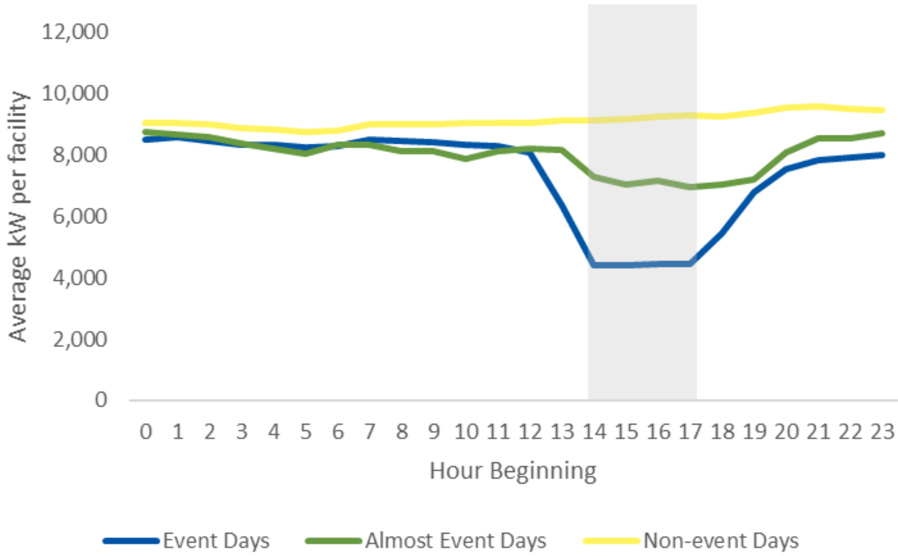
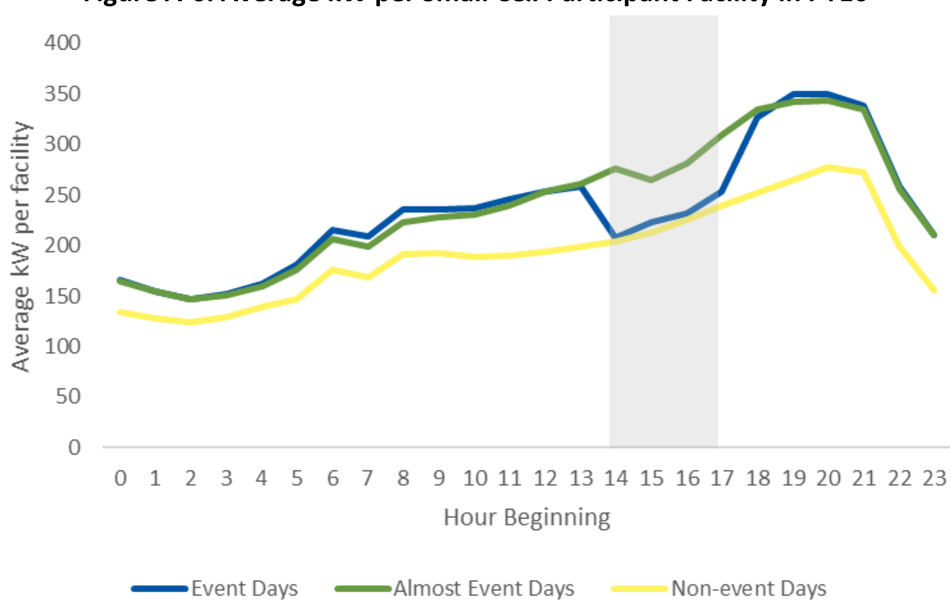


Figure A-6 shows loads for small C&I facilities on event days, non-event days, and almost-event days. Comparison of event and almost-event days demonstrates the load impacts of the Act 129 events and that loads increased modestly above normal levels after the end of events. Loads on non-event days were lower than those on event or almost-event days, again suggesting that loads on some non-event days may not provide a valid baseline. Also, loads increased over daytime hours, which suggests growing energy consumption for air conditioning.

Figure A-6. Average kW per Small C&I Participant Facility in PY10



Baseline Calculation Approach

Day-Matching Customer Baselines and Regression Baselines

Cadmus estimated individual consumption baselines for each participating facility and event using either a day-matching approach or regression. Day-matching identifies a set of nearby, non-event, non-holiday weekdays for each event day, referred to as the basis window. For each event hour, the baseline is the average consumption during the same hour of the days or subset of days in the basis window. Cadmus considered and tested the accuracy of a variety of general day-matching methods for estimating the baselines of participating facilities:

- *Y Previous Days*: This is the average load of Y previous days in the CBL (customer baseline) basis window.
- *X Highest of Y Previous Days*: This is the average load of the X days with highest loads of Y previous days in the basis window.
- *Y Previous Days of Same Day Type*: This is the average load of Y previous days of the same day type (e.g., Wednesday) in the basis window. For example, if Y=3 and the event occurs on a Wednesday, the CBL basis window would only include three previous Wednesdays.

When applying a day-matching method, Cadmus excluded the following types of days from the basis window:

- Weekend days
- Days with average load between 2 p.m. and 6 p.m. less than 25% of the average load of all days in the baseline window. This exclusion follows PJM protocol and should result in the exclusion of most days when a facility had abnormally low consumption. Cadmus replaced excluded days with the next closest permissible day.
- Holidays
- Facility closures
- Previous event days[14]
- Weekdays more than 45 days before the event day
- PJM economic participation days
- Act 129 notification days

Cadmus did not make any adjustments to the estimated day-matching baselines based on the difference between the baseline and the metered load during hours preceding the event. Adjustments of this kind were not permitted because PPL Electric Utilities' Demand Response Program involved day-ahead

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[14] Cadmus also excluded June 26, 2018 from basis windows as the ICSP informed Cadmus that PJM conducted a demand response test event.

notification of Act 129 events.[15] In the PY9 evaluation, Cadmus provides evidence that some participating facilities appear to have adjusted their loads in response to the advance notifications.

The ICSP employed day-matching to estimate impacts and make settlement calculations. By aligning, to the extent possible and without sacrificing accuracy, its day-matching baseline calculation methods with ICSP's, Cadmus eliminated a possible source of difference between the reported and evaluated impact estimates.

Cadmus employed regression analysis as the second baseline calculation approach. Regression involves estimating an equation to predict hourly consumption as a function of multiple independent variables such as day of the week, hour of the day, and weather. Regression controls for the impacts of weather on energy consumption better than day-matching and is expected to be superior to day-matching especially for facilities with weather-sensitive loads. Cadmus estimated a separate regression model for each facility using data for hours between 2:00 p.m. and 6:00 p.m. on the 30 non-holiday weekdays between June 1, 2018, and September 15, 2018, with the highest day-ahead PJM RTO forecasts that did not qualify as Act 129 event or notification days.[16]

Selection of Facility Baseline Calculation Methods

Before PY9 for previous Demand Response Program participants or before the start of PY10 for new participants, Cadmus assigned each facility to one of the following day-matching baseline calculation method or regression:

- 2 previous days
- 3 previous days
- 4 previous days
- 5 previous days
- 10 previous days
- 3 of 5 previous days with highest average load during event hours
- 4 of 5 previous days with highest average load during event hours
- 7 of 10 previous days with highest average load during event hours
- 3 previous days of the same day type (e.g., Wednesdays)
- 4 previous days of the same day type
- Regressions (one of 81 models)

15 See Goldberg, Miriam, and G. Kennedy Agnew. *Measurement and Verification for Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group. 2013. The exception to this rule would be an adjustment based on an exogenous variable such as weather or the PJM day-ahead forecast of load or actual load.

16 The PJM RTO day-ahead forecast for these 30 days ranged between 82.1% and 95.8% of the PJM RTO summer peak demand forecast.

Cadmus selected the most accurate baseline calculation method for each participating facility based on tests of predictive accuracy.[17] Cadmus tested baseline calculation methods using AMI meter data from summer 2016 for previous (PY9) participants and from summer 2017 for (PY10) participants. For facilities assigned a regression baseline calculation method, Cadmus tested an expanded set of 81 regression models. These models included various combinations of date, time, and weather regressors including dry-bulb-temperature (temp), cooling degree hour variables with 70°F and 75°F base temperatures (CDH70, CDH75), a cooling degree buildup variable (CDH_buildup), temperature humidity index (THI), and a solar radiation measure of global horizontal irradiance (GHI).[18] GHI was included to improve the predictive accuracy of regression baseline calculations for facilities with on-site solar generation.

For each regression facility, Cadmus tested the predictive accuracy of these 81 regression model specifications using load data between 2:00 p.m. and 6:00 p.m. for the 45 non-holiday weekdays in 2018 that had highest PJM day-ahead forecasts but that did not qualify as Act 129 demand response days or notification days. Cadmus randomly selected 30 of 45 days to use as baseline days, with the remaining 15 days held out as test days. Using the baseline day data, Cadmus estimated each of the 81 different regression models and calculated prediction errors for test day hours between 2:00 p.m. and 6:00 p.m. Cadmus then repeated the random selection of baseline and test days and estimation of prediction errors nine additional times. Cadmus calculated prediction errors statistics and selected the regression model with the highest predictive accuracy. The regression specifications are described in Table A-5.

Table A-5. Baseline Regression Model Specifications

Model	Dependent Variable	Class Variables	Independent Variables
1	kWh/Hour	Day Hour	Day*Hour Temp $Temp^2$ $Temp^3$
2	kWh/Hour	Day Hour	Day*Hour CDD70 CDD70_Buildup
3	kWh/Hour	Day	Day
4	kWh/Hour	Day Hour	Hour Day
5	kWh/Hour	Day Hour	Hour Day CDD70
6	kWh/Hour	Day Hour	Hour Day CDD70_Buildup
7	kWh/Hour	Day	Day CDD70
8	kWh/Hour	Day	Day CDD70 CDD70_Buildup
9	kWh/Hour	Day	Day CDD70_Buildup
10	kWh/Hour	Hour	Hour

[17] Cadmus performed a separate analysis for each facility, selecting the day-matching or regression baseline method that performed best in terms of accuracy, bias, and variability (risk). It assessed the accuracy of the baseline using relative root mean squared error (RRMSE), bias using mean absolute percentage error (MAPE) and median percentage prediction error, and variability using the distribution of errors. Cadmus calculated and plotted the distribution of errors to see if there were a small number of hours where models predicted poorly.

[18] The heat buildup variable was the weighted average of CDHs in the preceding 24 hours. The weights were normalized to sum to one and the weight assigned to hour t-1 was 90% of the weight assigned to hour t, so that more recent hours received greater weight.

Model	Dependent Variable	Class Variables	Independent Variables
11	kWh/Hour	Hour	Hour CDD70
12	kWh/Hour	Hour	Hour CDD70_Buildup
13	kWh/Hour	Hour	Hour CDD70 CDD70_Buildup
14	kWh/Hour		CDD75
15	kWh/Hour		CDD75 CDD70_Buildup
16	kWh/Hour		CDD70_Buildup
17	kWh/Hour	Day Hour	Day Hour CDD70 CDD70_Buildup
18	kWh/Hour	Day Hour	HOUR DAY THI
19	kWh/Hour	Day	Day THI
20	kWh/Hour	Hour	Hour THI
21	kWh/Hour		THI
22	kWh/Hour	Day Hour	Hour Day THI GHI
23	kWh/Hour	Day	DAY THI GHI
24	kWh/Hour	Hour	HOUR THI GHI
25	kWh/Hour		THI GHI
26	kWh/Hour	Day Hour	DAY*HOUR TEMP TEMP_SQ TEMP_CU GHI
27	kWh/Hour	Day Hour	DAY*HOUR CDD70 CDD70_BUILDUP_9_10 GHI
28	kWh/Hour	Day	DAY GHI
29	kWh/Hour	Day Hour	HOUR DAY GHI
30	kWh/Hour	Day Hour	HOUR DAY CDD70 GHI
31	kWh/Hour	Hour	HOUR DAY CDD70_BUILDUP_9_10 GHI
32	kWh/Hour	Day	DAY CDD70 GHI
33	kWh/Hour	Day	DAY CDD70 CDD70_BUILDUP_9_10 GHI
34	kWh/Hour	Day	DAY CDD70_BUILDUP_9_10 GHI
35	kWh/Hour	Hour	HOUR GHI
36	kWh/Hour	Hour	HOUR CDD70 GHI
37	kWh/Hour	Hour	HOUR CDD70_BUILDUP_9_10 GHI
38	kWh/Hour	Hour	HOUR CDD70 CDD70_BUILDUP_9_10 GHI
39	kWh/Hour		CDD70 GHI
40	kWh/Hour		CDD70 CDD70_BUILDUP_9_10 GHI
41	kWh/Hour		CDD70_BUILDUP_9_10 GHI
42	kWh/Hour	Day Hour	DAY HOUR CDD70 CDD70_BUILDUP_9_10 GHI
43	kWh/Hour	Day Hour	HOUR DAY GHI
44	kWh/Hour	Day	DAY GHI
45	kWh/Hour	Hour	HOUR GHI
46	kWh/Hour	Hour	HOUR CDD70 CDD70_BUILDUP_9_10 GHI HOUR*GHI
47	kWh/Hour	Hour	CDD70 CDD70_BUILDUP_9_10 HOUR*GHI
48	kWh/Hour	Hour	HOUR THI GHI HOUR*GHI
49	kWh/Hour	Hour	THI HOUR*GHI
50	kWh/Hour	Hour	HOUR CDD75 GHI GHI*HOUR
51	kWh/Hour	Hour	CDD75 GHI*HOUR

Model	Dependent Variable	Class Variables	Independent Variables
52	kWh/Hour	Day Hour	DAY*HOUR CDD75 CDD75_BUILDUP_9_10
53	kWh/Hour	Day Hour	HOUR DAY CDD75
54	kWh/Hour	Day Hour	HOUR DAY CDD75_BUILDUP_9_10
55	kWh/Hour	Day	DAY CDD75
56	kWh/Hour	Day	DAY CDD75 CDD75_BUILDUP_9_10
57	kWh/Hour	Day	DAY CDD75_BUILDUP_9_10
58	kWh/Hour	Hour	HOUR CDD75
59	kWh/Hour	Hour	HOUR CDD75_BUILDUP_9_10
60	kWh/Hour	Hour	HOUR CDD75 CDD75_BUILDUP_9_10
61	kWh/Hour		CDD75
62	kWh/Hour		CDD75 CDD75_BUILDUP_9_10
63	kWh/Hour		CDD75_BUILDUP_9_10
64	kWh/Hour	Day Hour	DAY HOUR CDD75 CDD75_BUILDUP_9_10
65	kWh/Hour	Day Hour	DAY*HOUR CDD75 CDD75_BUILDUP_9_10 GHI
66	kWh/Hour	Day Hour	HOUR DAY CDD75 GHI
67	kWh/Hour	Day Hour	HOUR DAY CDD75_BUILDUP_9_10 GHI
68	kWh/Hour	Day	DAY CDD75 GHI
69	kWh/Hour	Day	DAY CDD75 CDD75_BUILDUP_9_10 GHI
70	kWh/Hour	Day	DAY CDD75_BUILDUP_9_10 GHI
71	kWh/Hour	Hour	HOUR CDD75 GHI
72	kWh/Hour	Hour	HOUR CDD75_BUILDUP_9_10 GHI
73	kWh/Hour	Hour	HOUR CDD75 CDD75_BUILDUP_9_10 GHI
74	kWh/Hour		CDD75 GHI
75	kWh/Hour		CDD75 CDD75_BUILDUP_9_10 GHI
76	kWh/Hour		CDD75_BUILDUP_9_10 GHI
77	kWh/Hour	Day Hour	DAY HOUR CDD75 CDD75_BUILDUP_9_10 GHI
78	kWh/Hour	Hour	HOUR CDD75 CDD75_BUILDUP_9_10 GHI HOUR*GHI
79	kWh/Hour	Hour	CDD75 CDD75_BUILDUP_9_10 HOUR*GHI
80	kWh/Hour	Hour	HOUR CDD75 GHI GHI*HOUR
81	kWh/Hour	Hour	CDD75 GHI*HOUR

Table A-6 shows counts of participating facilities by final baseline modeling approach for all facilities, by customer segment, and for 19 facilities with capacity enrollments greater than or equal to 1 MW. These 19 facilities accounted for 95% of enrolled capacity.

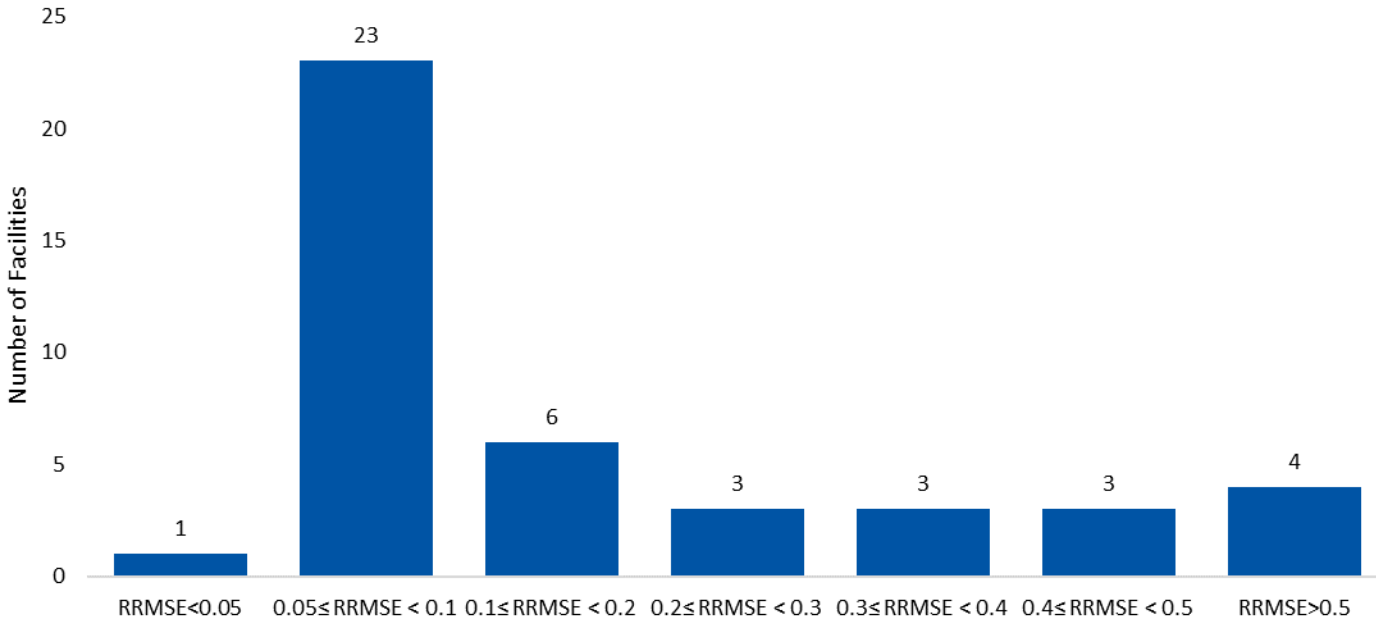
Table A-6. Number of Facilities by Baseline Modeling Approach

Baseline	All Facilities	GNE	Large C&I	Small C&I	DR Capacity ≥ 1 MW
2 OF 2	3	0	3	0	3
3 OF 3	1	0	1	0	1
3 OF 5	1	0	1	0	1
4 OF 4	0	0	0	0	0
4 OF 5	1	0	1	0	1
5 OF 5	1	0	1	0	1
7 OF 10	6	1	5	0	5
10 OF 10	2	0	2	0	2
Day of Week 4 of 4	2	0	2	0	2
Day of Week 3 of 3	0	0	0	0	0
Regression	43	9	4	30	3
Total	**60**	**10**	**20**	**30**	**19**

Many large C&I facilities used day-matching approaches because they had near constant or highly variable day-to-day consumption between 2:00 p.m. and 6:00 p.m., and regression did not predict better than day-matching methods. For these facilities, the best predictor of consumption was consumption in recent previous days, so many large C&I facilities selected X-of-Y-previous-day baseline methods.

Cadmus estimated the predictive accuracy of selected baseline methods on non-event, non-holiday, and non-notification weekdays in summer 2018 for hours between 2:00 p.m. and 6:00 p.m. For facilities with regression baselines, the RRMSEs were obtained from the prediction errors of the testing procedure used to select the regression model specification.

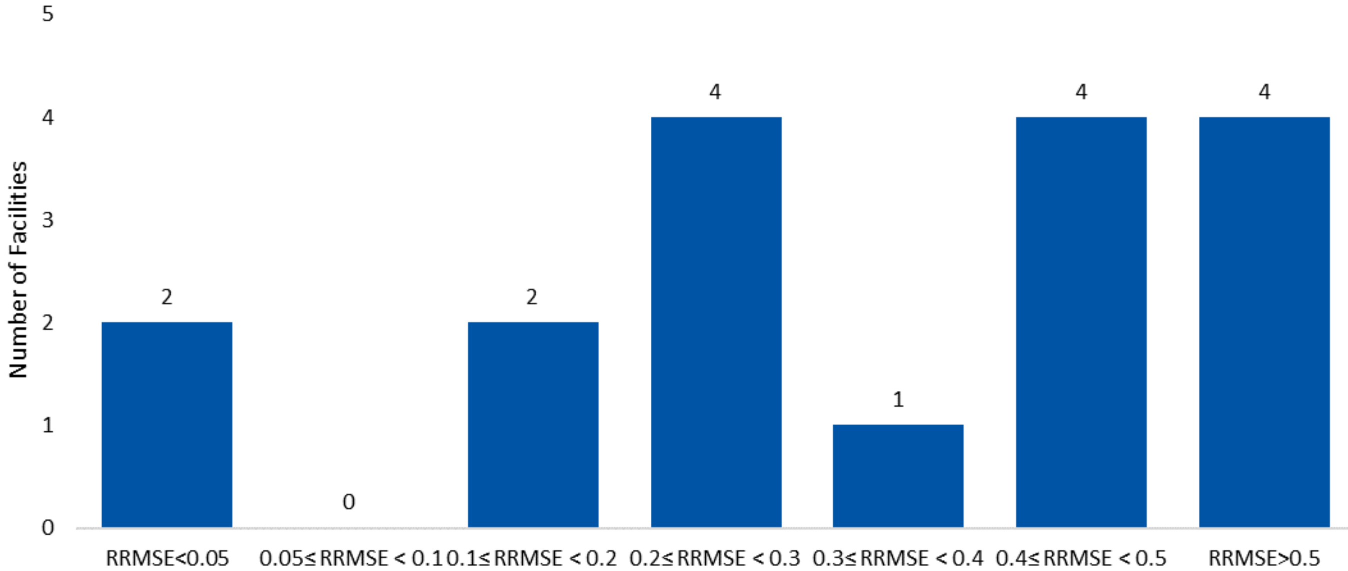
Figure A-7. Predictive Accuracy of Regression Baseline Facilities



As Figure A-7 shows, of 43 participant facilities with regression baselines, 30 had RRMSE less than 0.2, which is considered the upper bound of the desired range. Six of the 13 remaining facilities had RRMSE between 0.2 and 0.4, slightly higher than what is considered desirable. Overall, the regressions used to predict baseline consumption demonstrated high predictive accuracy.

Figure A-8 shows the RRMSEs for day-matching facilities. For facilities with day-matching baselines, the RRMSE was obtained from prediction errors calculated for all non-holiday weekdays between June 1, 2018, and September 15, 2018, that did not qualify as event or notification days. The predictive accuracy of the day-matching baselines was not as high as that for the regression baselines. Nine of 17 facilities had RRMSE less than 0.4, but four facilities had RRMSE greater than 0.5. However, although the predictive accuracy of the day-matching baselines for these four facilities was less than desired, the day-matching baselines still provided greater accuracy than regression baselines.

Figure A-8. Predictive Accuracy of Day-Matching Baseline Facilities



Standard Errors of Demand Savings Estimates

Cadmus calculated 90% confidence intervals for the Demand Response Program gross verified demand savings from the standard errors for the savings estimates of individual facilities.[19] For facilities with regression baselines, Cadmus obtained the standard errors for the hourly demand savings estimates from the regression coefficient standard errors. For facilities with day-matching baselines, Cadmus followed the SWE's and the PJM's guidance to predict loads on non-event days in 2018 and to estimate the margin of error at the 90% confidence level as the RMSE. Cadmus calculated the RMSE for the day-matching baseline using baseline predictions for hours between 2:00 p.m. and 6:00 p.m. on non-holiday, non-event, and non-notification days between June 1, 2018, and September 15, 2018.

Act 129 Events in Program Year 10

Table A-7 presents the Act 129 event dates, hours, advance notification date and times, and the average outside temperature during events in PY10.

[19] The standard errors for the event savings estimates do not account for the covariance of a facility's savings across event hours, i.e., the calculation assumes the errors were independent. Calculation of event savings as the average of the event hour savings (instead of as the average of facility savings across event hours) complicates the calculation of the standard errors. However, ignoring the covariance of facility savings across event hours has little effect. Cadmus performed a separate calculation of the event savings as the average of individual facility event savings and the standard errors that account for the covariance of facility savings across event hours was only 6% larger for the July 2, 2018, event, 3% larger for the July 3, 2018, event, 4% larger for the August 6, 2018, event, 1% larger for the August 28, 2018, event, 1% larger for the September 4, 2018, event, and 1% larger for the September 5, 2018, event.

Table A-7. PY10 Act 129 Events Dates and Times

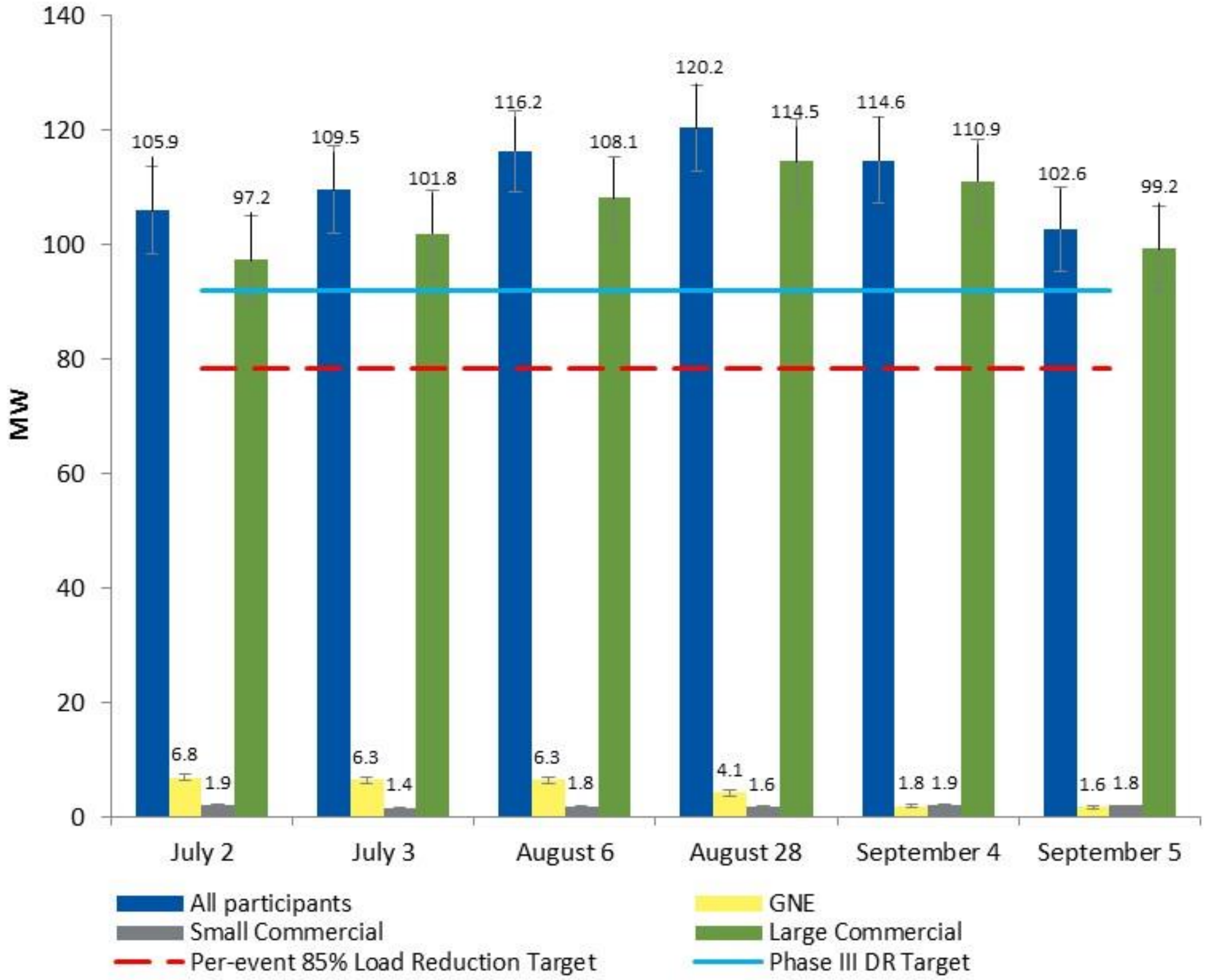
Event Date	Event Hours	Advance Notification Date and Time	Average Outside Temperature (°F) During Event
Monday, July 2, 2018	2:00 p.m. - 6:00 p.m.	Sunday, July 1, 2018, 10:29 a.m.	96
Tuesday, July 3, 2018	2:00 p.m. - 6:00 p.m.	Monday, July 2, 2018, 11:03 a.m.	96
Monday, August 6, 2018	2:00 p.m. - 6:00 p.m.	Sunday, August 5, 2018, 10:48 a.m.	91
Tuesday, August 28, 2018	2:00 p.m. - 6:00 p.m.	Monday, August 27, 2018, 10:36 a.m.	92
Tuesday, September 4, 2018	2:00 p.m. - 6:00 p.m.	Monday, September 3, 2018, 10:30 a.m.	91
Wednesday, September 5, 2018	2:00 p.m. - 6:00 p.m.	Tuesday, September 4, 2018, 11:04 a.m.	91
Note: Advance notification times were obtained from CPower, the ICSP, through Cadmus data request.			

A.1.2 Results and Discussion

The estimates of program and customer segment demand savings by PY10 Act 129 event date are presented in Figure 1 and Table 5 in the main content of this report. In Figure A-9, Cadmus presents the results graphically. Unless noted otherwise, all demand load impacts have been adjusted for line losses.

Across the six events, PPL Electric Utilities averaged 112 MW, and averages 117 MW for Phase III event, putting the program on track to exceed PPL Electric Utilities’ target of 92 MW for Phase III of Act 129. PPL Electric Utilities achieved the maximum event demand savings of 120.2 MW on August 28 and the minimum event demand savings of 102.6 MW on September 5. As Figure A-9 shows, large C&I customers were responsible for more than 95% of the demand response savings.

Figure A-9**. PPL Electric Utilities Act 129 Gross Verified Demand Savings, PY10**



Notes: Estimates based on Cadmus analysis of AMI interval consumption data for participant facilities. Error bars show 90% confidence intervals. The Phase III demand response target for PPL Electric Utilities is 92 MW. All savings estimates were adjusted for line losses.

Table A-8 reports the evaluation estimated demand savings, metered demand, estimated baseline demand, and the percentage demand savings by event for each customer segment and the program.

Small C&I customers saved between 1.4 and 1.9 MW per event, large C&I customers saved between 97.2 and 114.5 MW per event, and GNE customers saved between 1.8 and 6.8 MW per event. The wide range of savings across events for GNE customers is due to the resumption of schools and limited participation of these customers in late summer events.

During event hours, the program saved about 59% of participant electricity demand. Large C&I customers saved more demand as a percentage of the baseline (about 62%) than small C&I customers (about 23%) and GNE customers (about 45%).

Table A-8. Event Demand Savings and Baseline Demand

Stratum	Event	Demand Savings (MW/hour)	Metered Demand (MW/hour)	Baseline Demand (MW/hour)	Relative Precision at 90% C.L.	Percentage Demand Savings
Small C&I	7/2/2018	1.9	5.9	7.8	7%	24%
	7/3/2018	1.4	5.9	7.3	10%	19%
	8/6/2018	1.8	5.6	7.5	7%	25%
	8/28/2018	1.6	5.5	7.1	8%	23%
	9/4/2018	1.9	5.3	7.2	7%	26%
	9/5/2018	1.8	5.8	7.6	7%	24%
Large C&I	7/2/2018	97.2	92.8	189.9	8%	51%
	7/3/2018	101.8	92.5	194.3	7%	52%
	8/6/2018	108.1	49.9	158.0	7%	68%
	8/28/2018	114.5	49.1	163.6	6%	70%
	9/4/2018	110.9	50.5	161.5	7%	69%
	9/5/2018	99.2	60.9	160.0	7%	62%
GNE	7/2/2018	6.8	7.8	14.6	7%	47%
	7/3/2018	6.3	7.3	13.5	8%	46%
	8/6/2018	6.3	7.1	13.4	8%	47%
	8/28/2018	4.1	7.6	11.7	11%	35%
	9/4/2018	1.8	5.7	7.6	21%	24%
	9/5/2018	1.6	0.6	2.1	15%	72%
Event	**7/2/2018**	**105.9**	**106.5**	**212.4**	**7%**	**50%**
	7/3/2018	**109.5**	**105.6**	**215.1**	**7%**	**51%**
	8/6/2018	**116.2**	**62.7**	**178.8**	**6%**	**65%**
	8/28/2018	**120.2**	**62.2**	**182.4**	**6%**	**66%**
	9/4/2018	**114.6**	**61.6**	**176.2**	**6%**	**65%**
	9/5/2018	**102.6**	**67.3**	**169.8**	**7%**	**60%**
Average		**111.5**	**77.6**	**189.1**	**3%**	**59%**

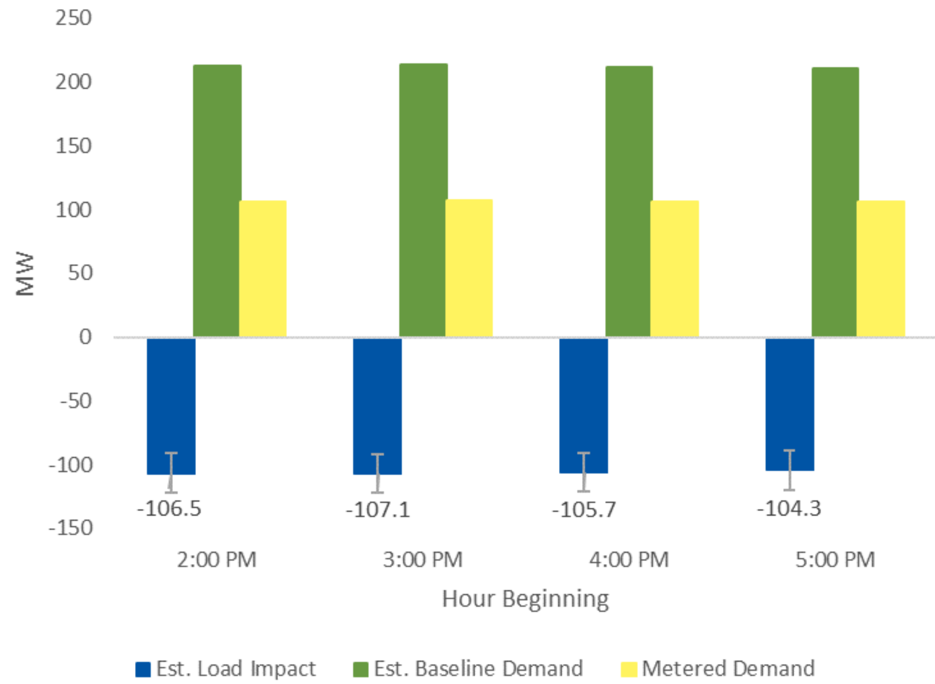
Notes: Estimates based on Cadmus analysis of AMI interval consumption data for participant facilities. Percentage demand savings were estimated as the ratio of the estimated demand savings to estimated baseline demand. Sums of columns or rows may not equal totals due to rounding error.

A.1.3 Load Impacts by Event Day

Figure A-10 through Figure A-15 present metered demand, the estimated baseline demand, and the estimated load impacts of participant facilities by hour of the day for the six Act 129 demand response event days, across the four event hours. The error bars for the load impacts show 90% confidence intervals.

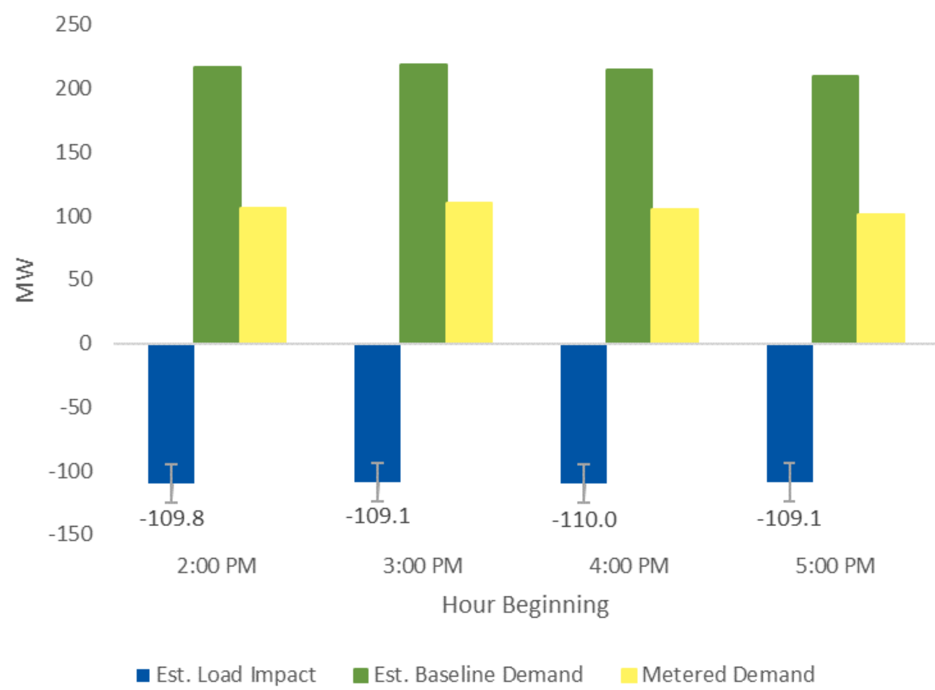
During the July 2 event the average demand reduction per hour was 105.9 MW, exceeding the Act 129 event minimum of 78.2 MW by about 28 MW (Figure A-10).

Figure A-10. July 2, 2018 – Hourly Load Impacts



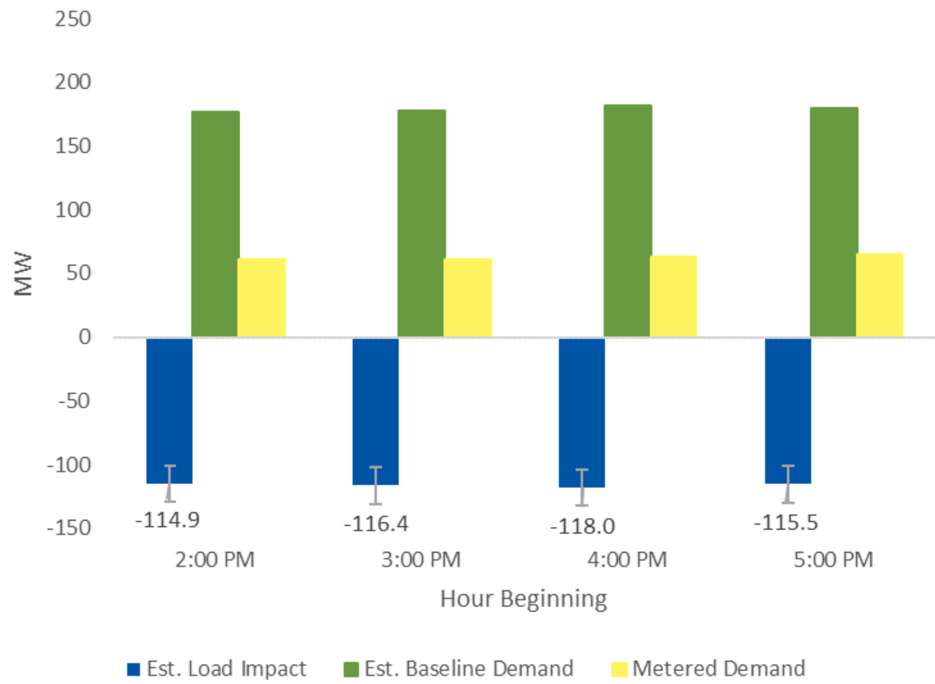
The load impacts on July 3 were approximately equal to those on July 2. The average demand reduction for July 3 was 109.5 MW (Figure A-11).

Figure A-11. July 3, 2018 – Hourly Load Impacts



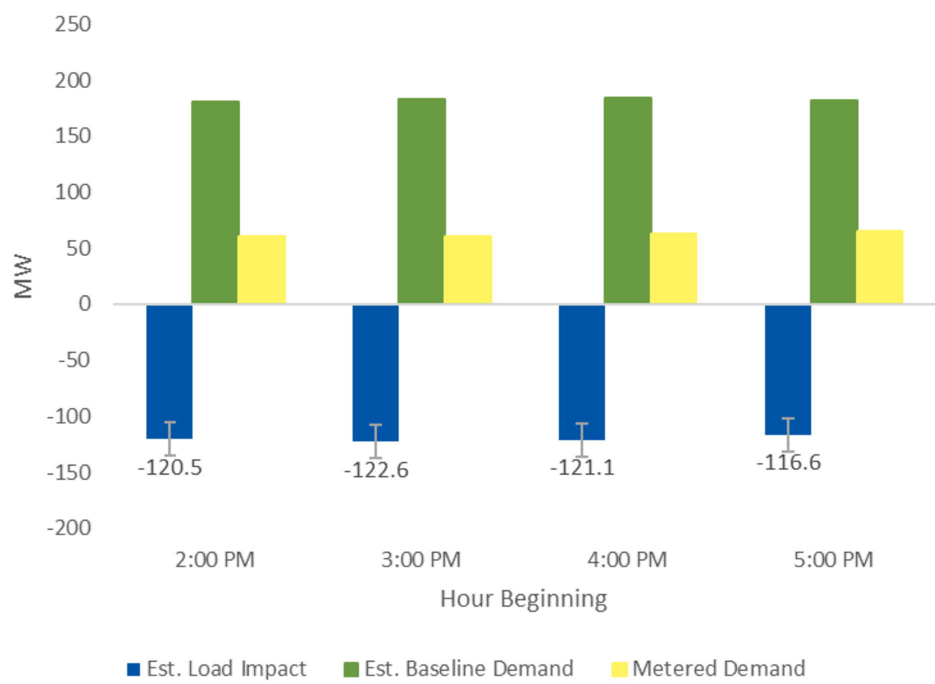
During the August 6 event, the average demand reduction was 116.2 MW (Figure A-12).

Figure A-12. August 6, 2018 – Hourly Load Impacts



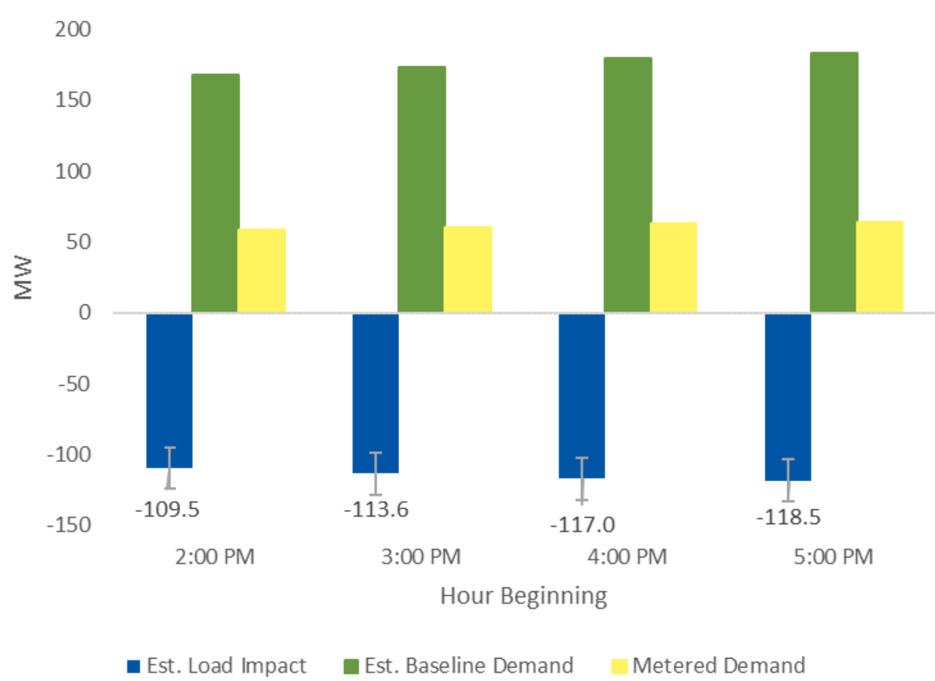
During the August 28 event, the average demand reduction was 120.2 MW. the highest average demand reduction of all six events in PY10 (Figure A-13).

Figure A-13. August 28, 2018 – Hourly Load Impacts



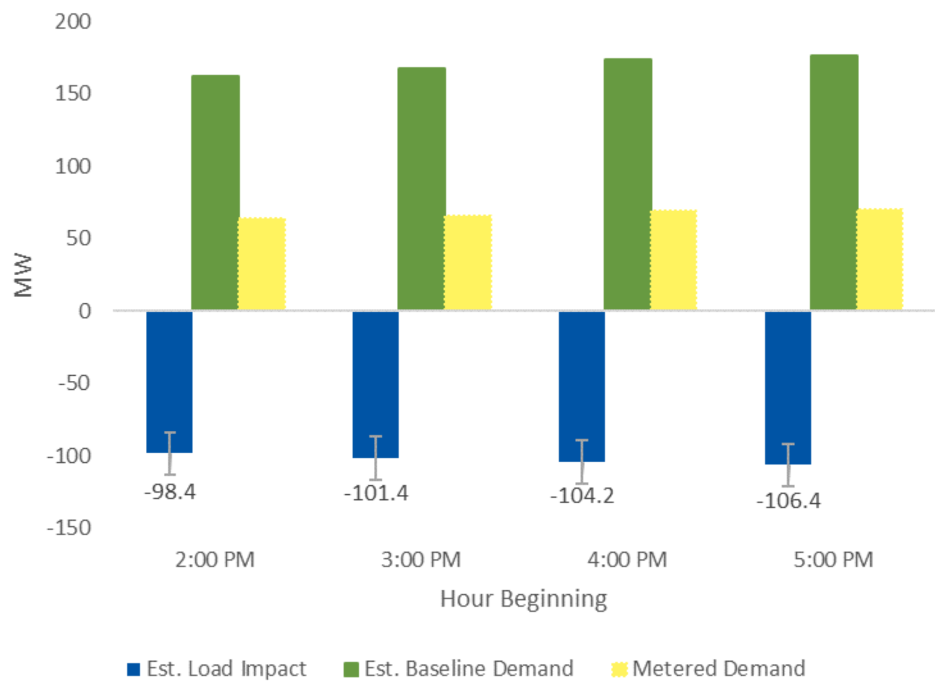
During the September 4 event, the average demand reduction per hour was 114.6 MW (Figure A-14).

Figure A-14. September 4, 2018 – Hourly Load Impacts



During the final event of September 5, the average demand reduction per hour was 102.6 MW, the lowest average demand reduction among the six event days (Figure A-15).

Figure A-15. September 5, 2018 – Hourly Load Impacts



A.1.4 Event Day Load Impacts by Customer Segment

Figure A-16 through Figure A-21 show the load impacts by hour of each event day for GNE, large C&I, and small C&I participant customers.

Figure A-16. July 2, 2018 – GNE Participants

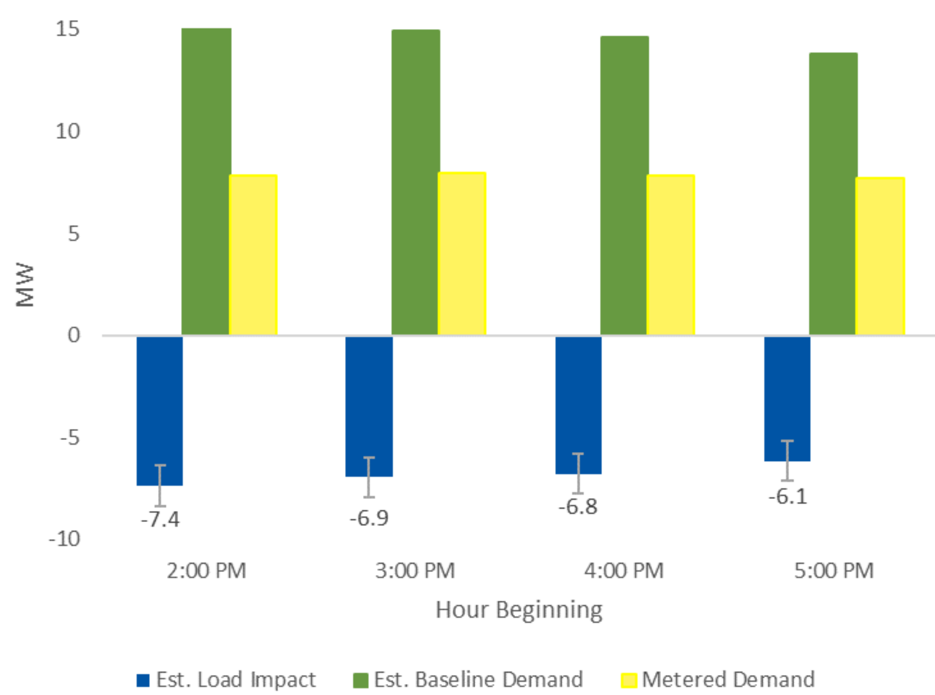


Figure A-17. July 3, 2018 – GNE Participants

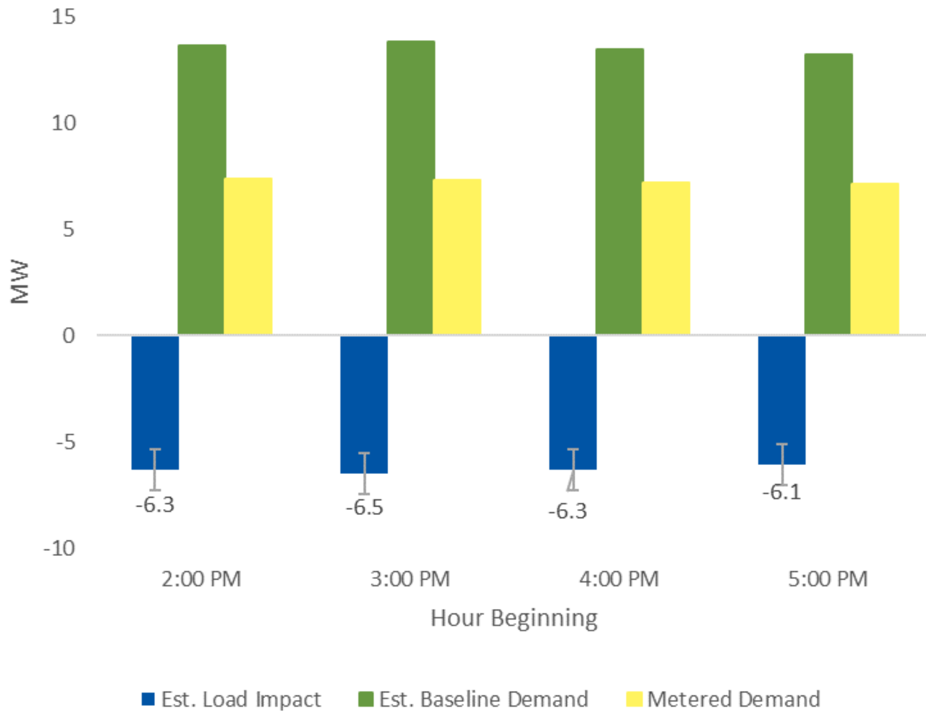


Figure A-18. August 6, 2018 – GNE Participants

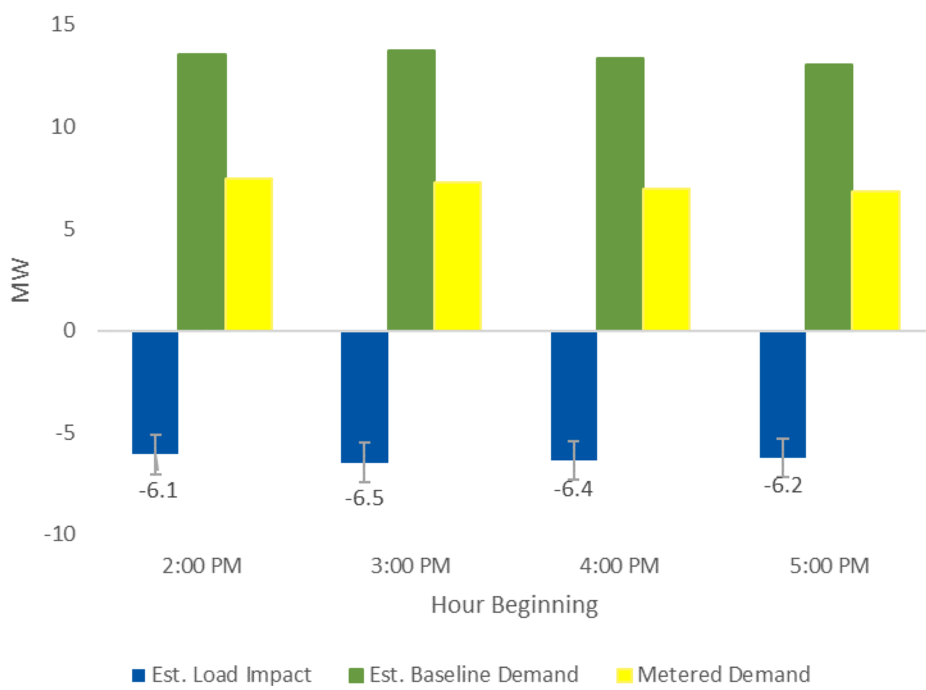


Figure A-19. August 28, 2018 – GNE Participants

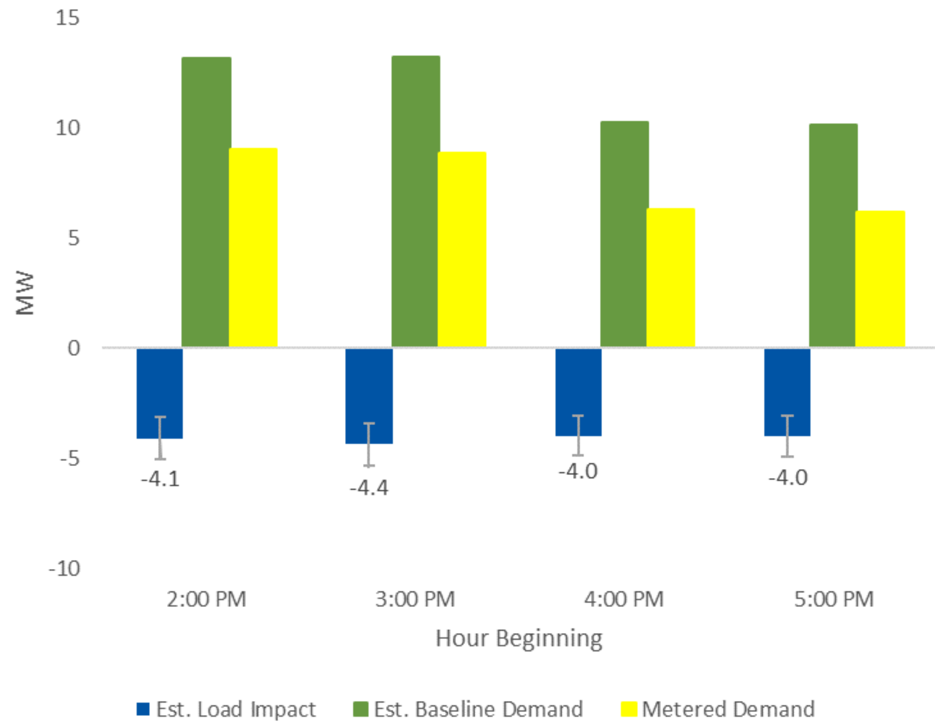


Figure A-20. September 4, 2018 – GNE Participants

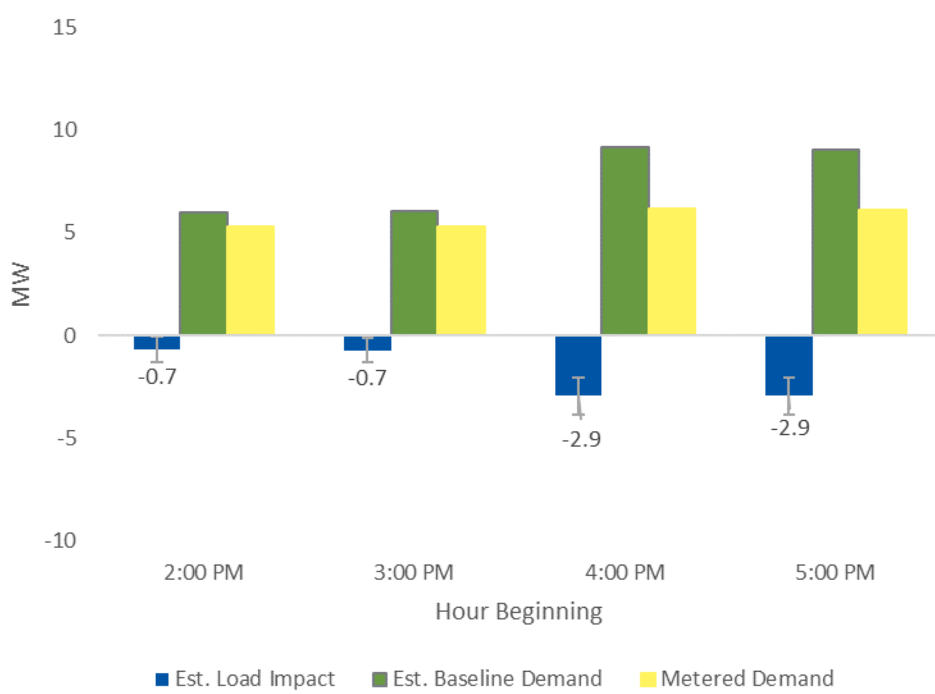
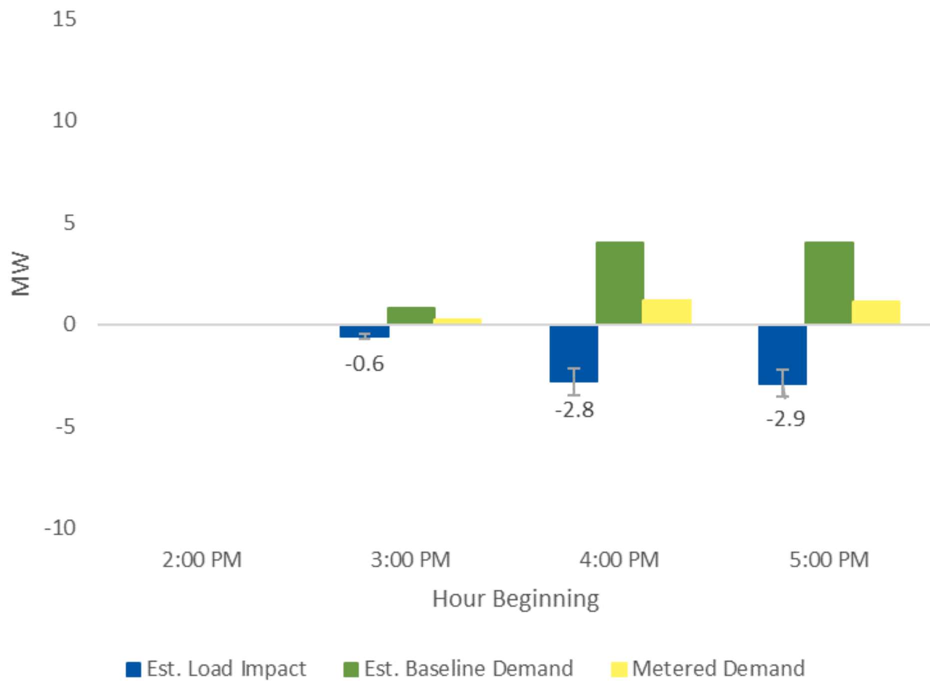


Figure A-21. September 5, 2018 – GNE Participants



Note: No GNE customers participated in the 2:00 p.m. hour of September 5, 2018 event.

Figure A-22 through Figure A-27 show the load impacts for small C&I customers across all six events. All figures show that electricity consumption was reduced during the event. The reductions or increases in metered demand and the estimate baseline demand after 4:00 p.m. reflect the participation of some retail big box store facilities for only two of four event hours.

Figure A-22. July 2, 2018 – Small C&I Participants

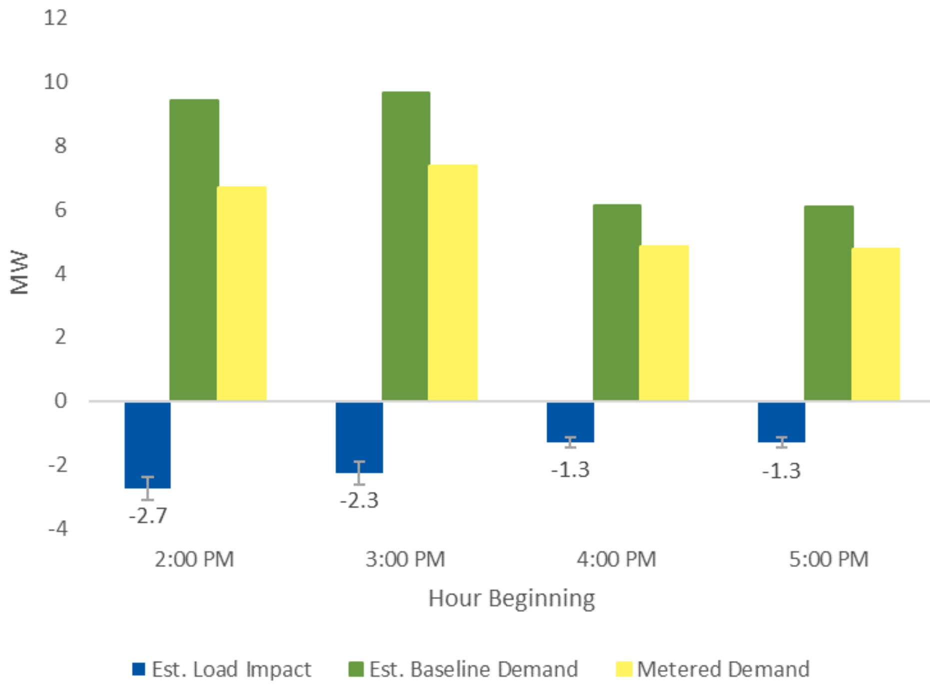


Figure A-23. July 3, 2018 – Small C&I Participants

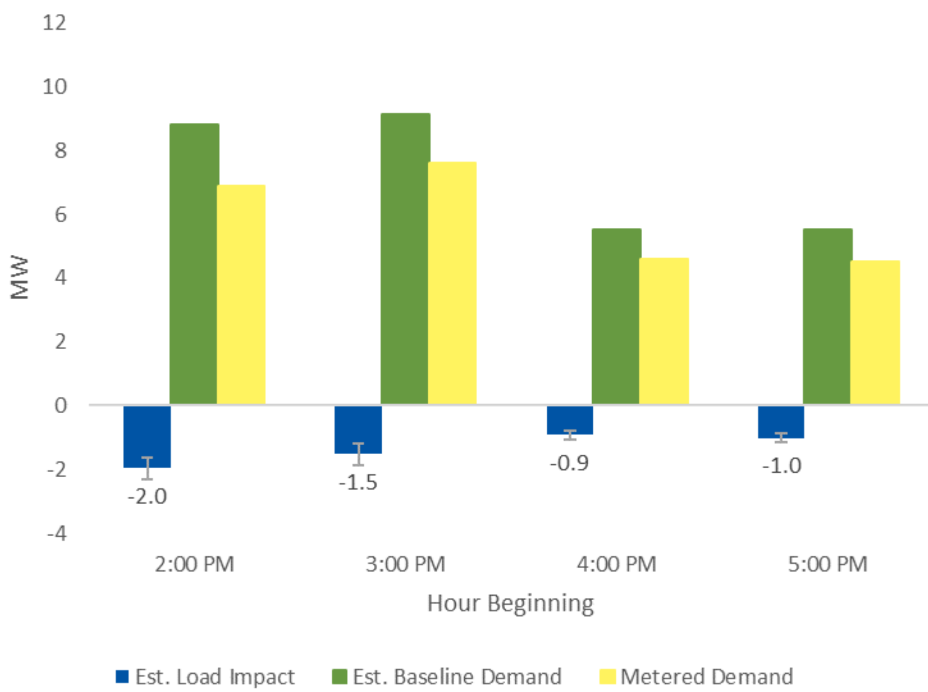


Figure A-24. August 6, 2018 – Small C&I Participants

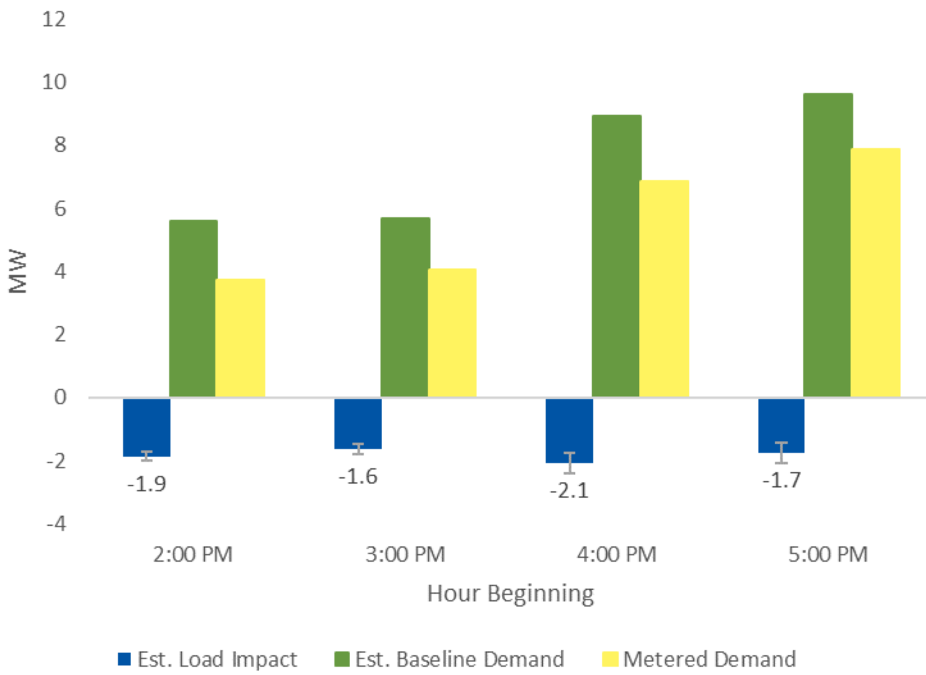


Figure A-25. August 28, 2018 – Small C&I Participants

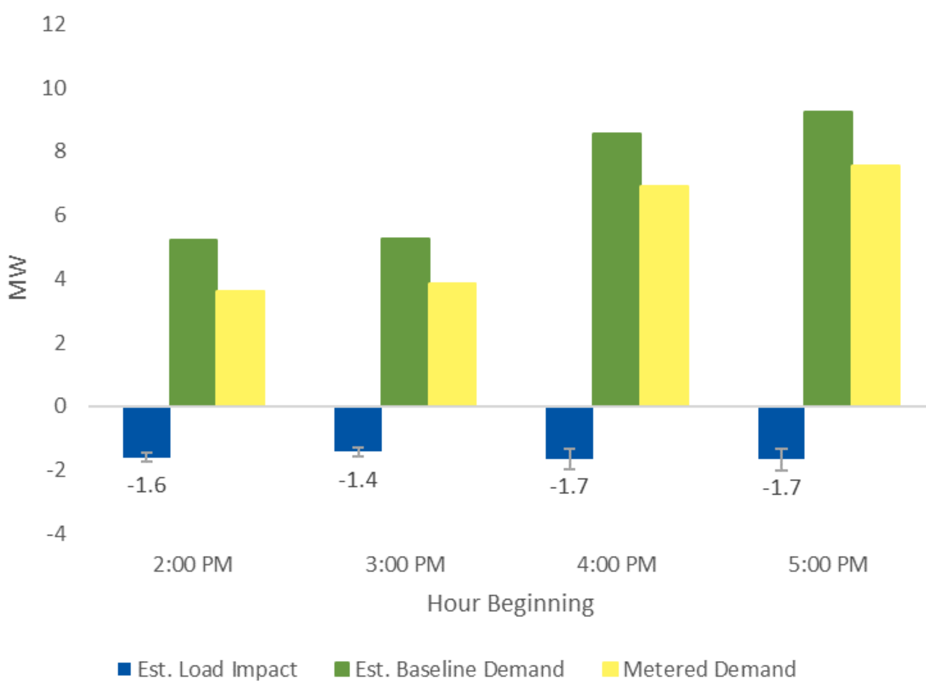


Figure A-26. September 4, 2018 – Small C&I Participants

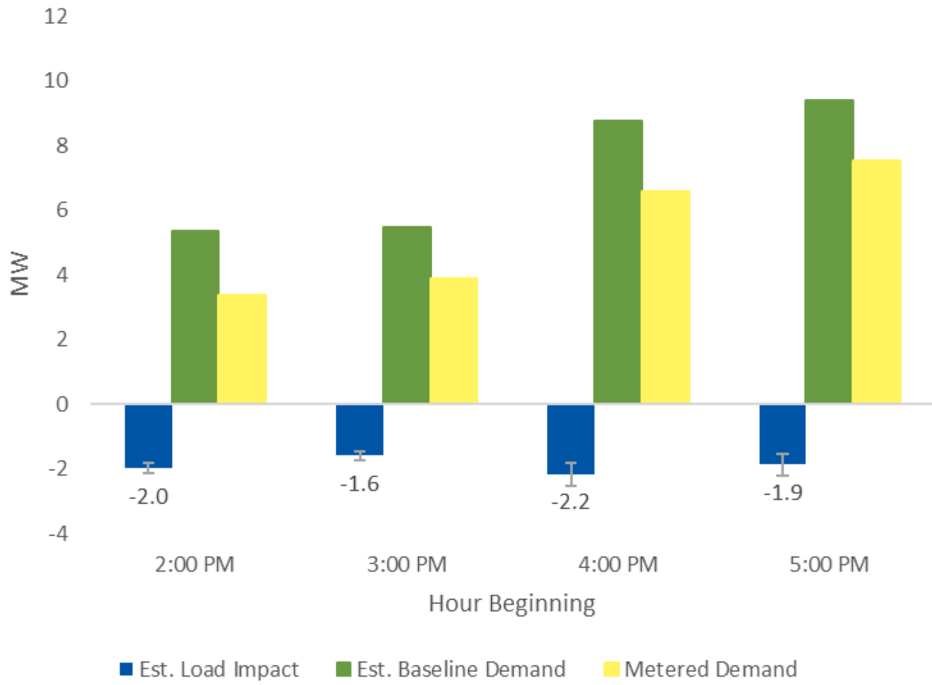


Figure A-27. September 5, 2018 – Small C&I Participants

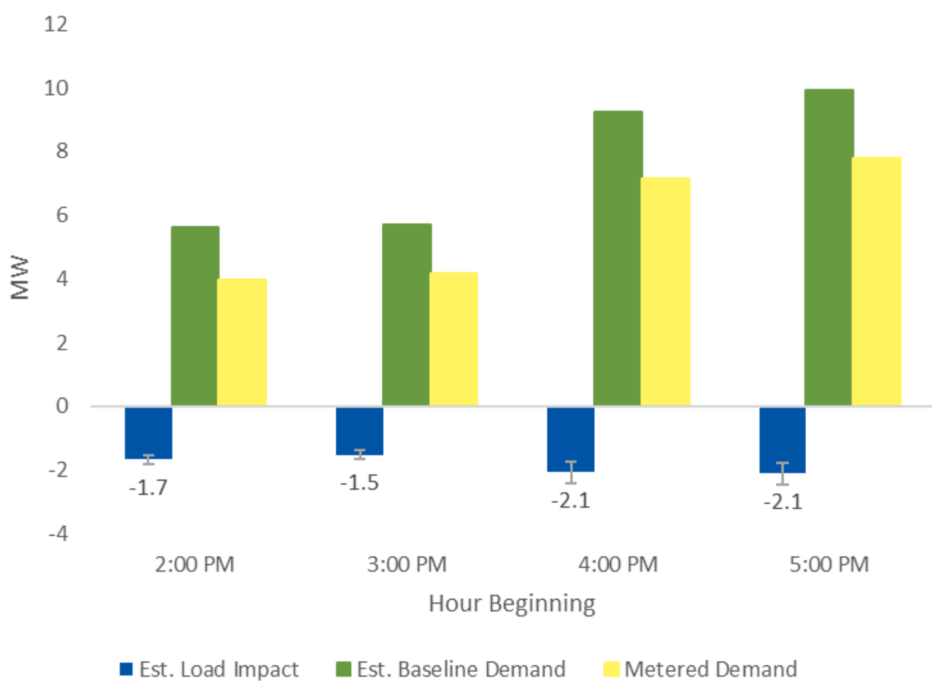


Figure A-28 through Figure A-33 show load impacts for large C&I participating facilities. These accounted for 95% of the event demand savings. As expected, the loads of large C&I customers do not appear very weather-sensitive. Loads trended up only slightly across hours of the day.

Figure A-28. July 2, 2018 – Large C&I Participants

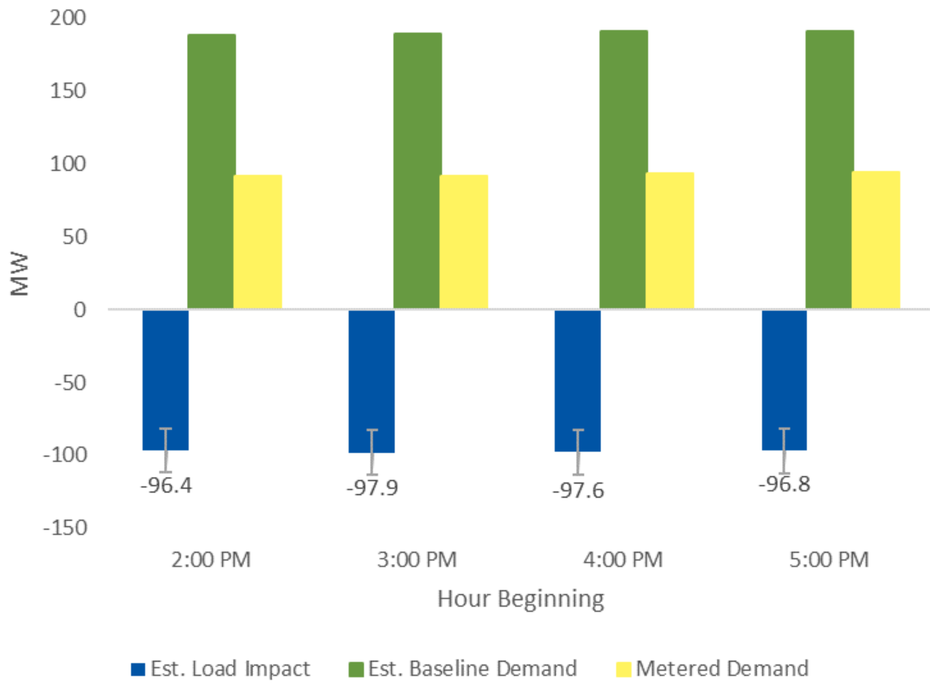


Figure A-29. July 3, 2018 – Large C&I Participants

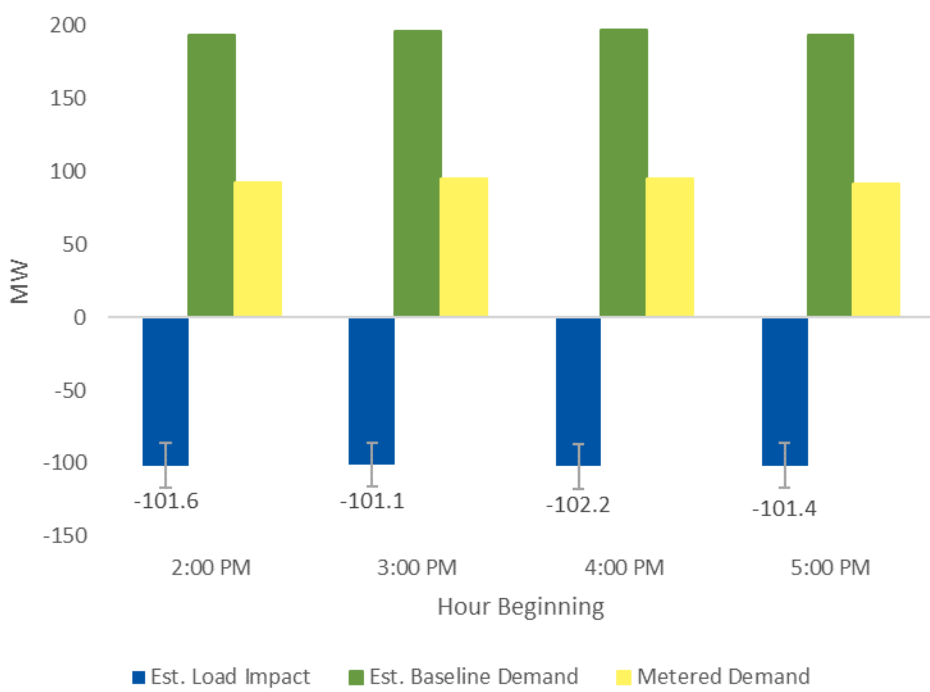


Figure A-30. August 6, 2018 – Large C&I Participants

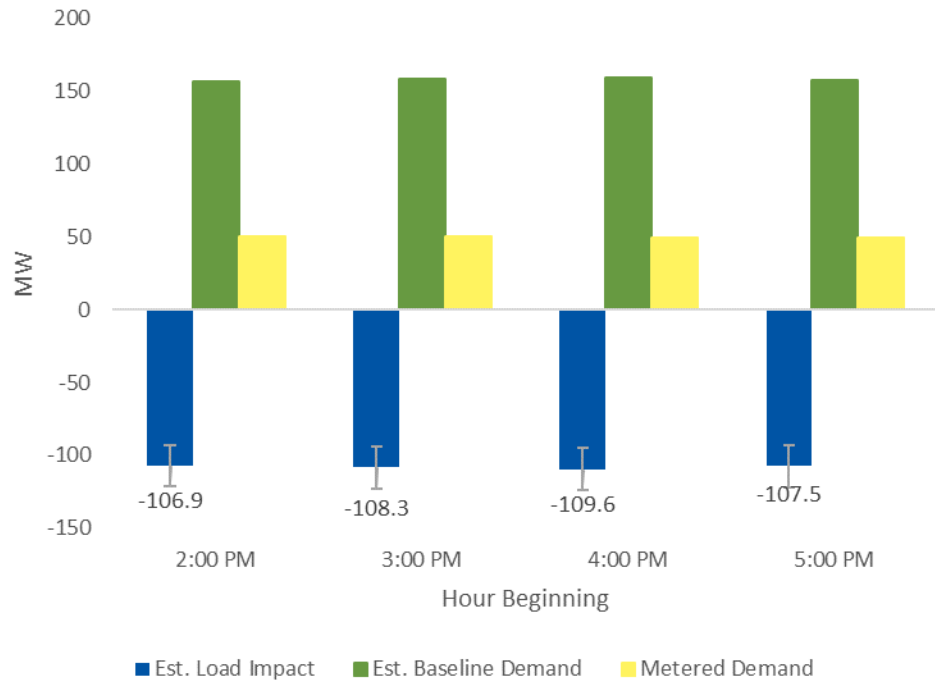


Figure A-31. August 28, 2018 – Large C&I Participants

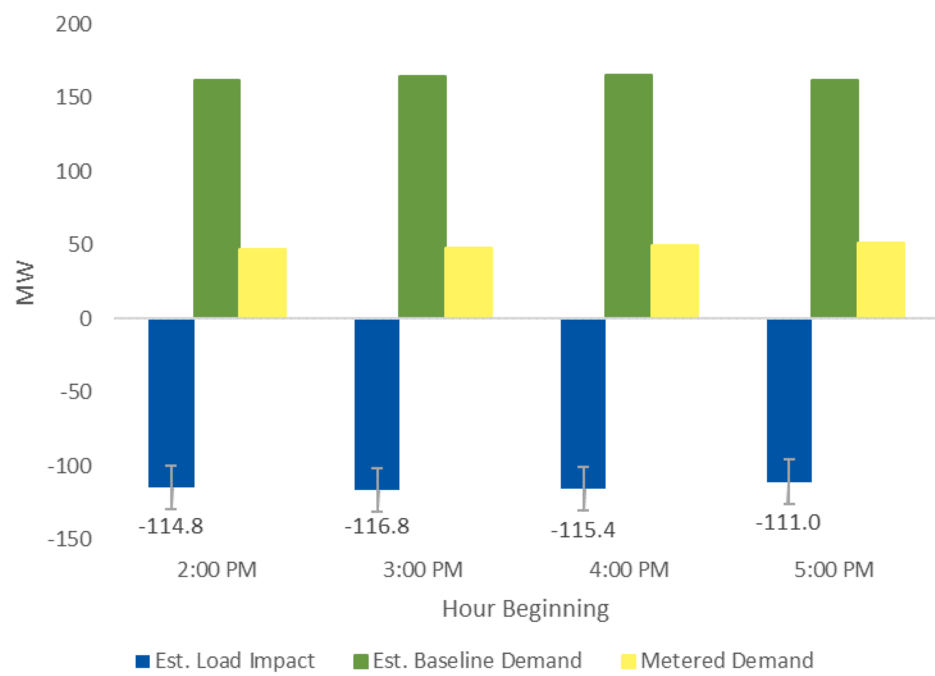


Figure A-32. September 4, 2018 – Large C&I Participants

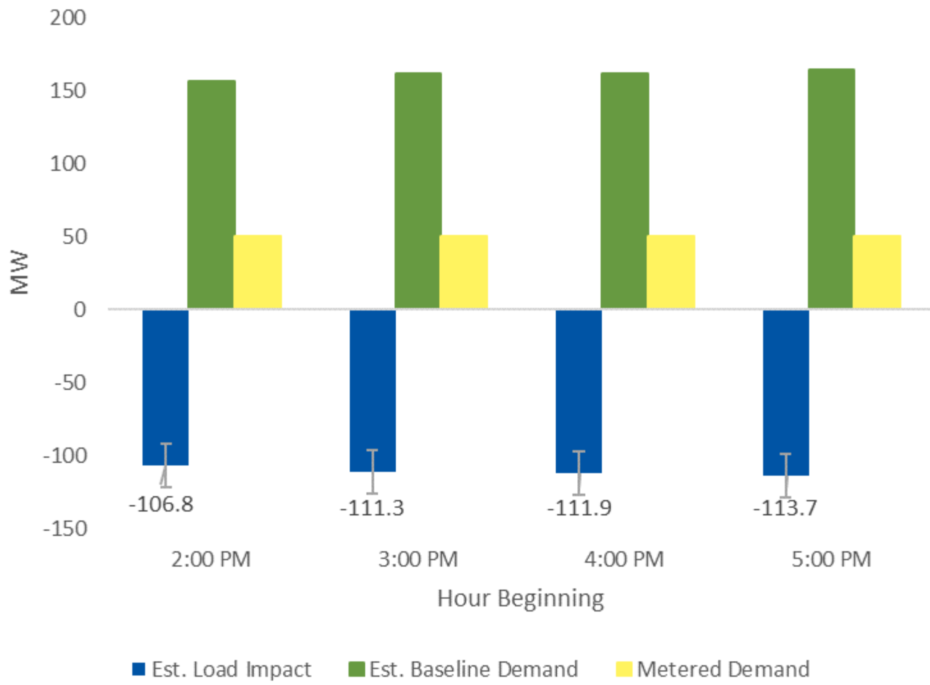
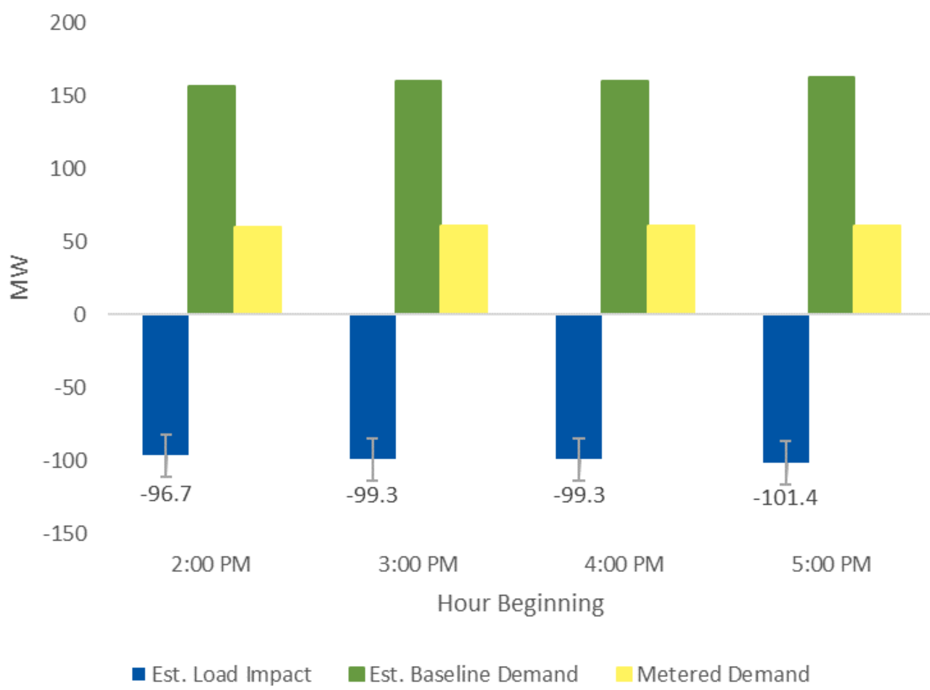


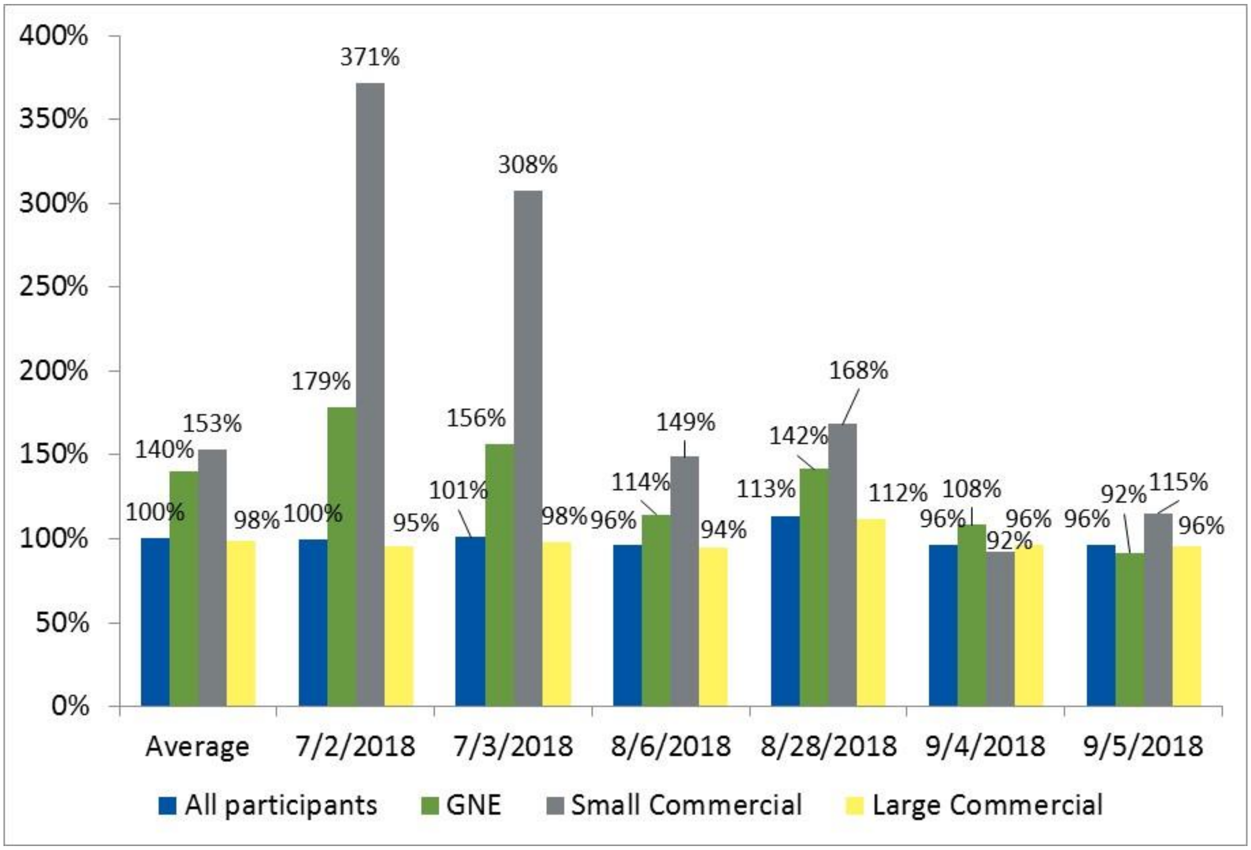
Figure A-33. September 5, 2018 – Large C&I Participants



A.1.5 Realization Rate Findings

Figure A-34 shows that the savings realization rate—the ratio of gross verified to gross reported savings—for each Act 129 event and the average across events was 100%. Cadmus evaluated average savings of 111.5 MW compared to reported savings of 111.3 MW. The realization rates ranged from 96% for the August 6 event to 113% for the August 28 event.

Figure A-34. Event Savings Realization Rates



Note: Realization rates estimated based on Cadmus analysis of AMI interval consumption data for participant facilities and ICSP reported demand savings.

The largest discrepancies between gross reported and verified savings occurred for GNE and small C&I participants. The average savings realization rates were 140% for GNE and 153% for small C&I. For example, for the July 2 event, Cadmus estimated savings of 6.8 MW for GNE participants while the ICSP estimated savings of 3.8 MW. Similarly, for the same event, Cadmus estimated savings of 1.9 MW for small C&I participants while the ICSP estimated savings of 0.5 MW.

It is likely that Cadmus estimated higher savings for GNE and small C&I facilities because it used regression analysis instead of day-matching to estimate the baseline. With temperature, CDH, or THI variables included as explanatory variables in regressions, baselines for facilities with air conditioning loads will reflect the effect of temperature on electricity demand. However, day-matching estimators such as those used by the ICSP do not explicitly adjust the baseline for differences in weather and may substantially under-predict baseline demand.