PACIFIC POWER.
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

April 1, 2024

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: ADV 1383 / Advice 22-004—PacifiCorp's 2023 Demand Response Programs Report

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits the attached 2023 Demand Response Programs Report. On March 28, 2022, the Company filed Advice 22-004 to introduce a new broadly enabling Schedule 106 for Demand Response Programs, cancel the Irrigation Load Control Pilot Program, Schedule 105, and propose an expanded irrigation demand response program to replace the pilot program using the provisions of Schedule 106. Advice 22-004 was approved on May 5, 2022. Since then, the Commission has approved two additional demand response programs[1] using the provisions of Schedule 106.

PacifiCorp's 2023 Demand Response Programs Report provides an update on the following Oregon Demand Response Programs authorized under Schedule 106:

- Irrigation Load Control Program
- Commercial & Industrial Demand Response Program
- Residential Demand Response Program

PacifiCorp requests that all formal information requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

[1] Advice 22-011, filed on October 14, 2022, introduced a program for commercial and industrial customers and was approved on November 15, 2022. Advice 23-010, filed on April 11, 2023, introduced a program for residential customers and was approved on May 16, 2023.

IRRIGATION LOAD CONTROL PROGRAM

2023 Irrigation Load Control Program in Oregon

Issued April 1, 2024

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Report Navigation

In its Pilot Program application, PacifiCorp identified key elements that would be provided annually, and the expanded program outlined the plan to continue to utilize the same reporting format. The following table describes where each of these elements is addressed in this report:

Overview

This report describes activity and outcomes from 2023, the first full year of implementation of the state-wide Irrigation Load Control Program.

In 2023, 57 customers representing 251 pumps were active during the season. After the season, another 13 pumps were added, for a total of 264 pumps enrolled by year-end.

PacifiCorp called five events in 2023: one in June, one in July, and three in August, for a total duration of 15.5 hours.

Key Findings

Key findings from 2023 focus on recruitment and retention, performance, impact of water availability, delivery costs and the retrospective TRC ratio for 2023.

<u>Recruitment and Retention</u>

There was strong grower interest across the state in the expanded program. PacifiCorp and Connected Energy grew the program from 40 pumps at the end of 2022 to 264 pumps by the end of 2023. This is evidence that the existing incentive options are compelling, and marketing approaches effective.

Few growers appeared sensitive to the length of notice time offered, with 71% of pumps participating in the 22.5 minute tier. Another 22% participated in the hour-ahead option, and the remainder in the day-ahead option.

Participants seem satisfied with the program design, given the 100% rate of retention of participants from previous years.

<u>Demand Response Performance</u>

In 2023, the program delivered an average load reduction of 2.15 MW across 5 days when events were scheduled (total of six events). This load reduction was an increase of 372% from the 2022 average of 578 kW. The nearly 4 times increase in available load reduction was due to significant program expansion in 2023.

<u>Water Availability</u>

Weather and water availability had a limited impact on program performance. Despite the region again seeing higher than average temperatures, and water restrictions continuing in the Klamath basin, PacifiCorp was able to leverage the ILC resource for three consecutive 4-hour curtailments in mid-August, with high performance and minimal opt-outs. Only two customers, representing a collective 12 pumps, opted out of any events. One customer opted four pumps out of the August 14 event, and together the two customers opted 12 pumps out of both the August 15 and August 16 events.

<u>Delivery Costs</u>

Because the program expanded significantly in 2023, an unusually high percentage of the devices active during the season (84% of 251 devices) were newly installed in 2023, and an additional 13 devices were installed post season. The full cost of the device plus the labor to install it is incurred by the program in the installation year only, while capacity benefits continue year over year. In 2023, installation costs accounted for 46% of all program costs.

Assessing Costs and Benefits

In addition to the high installation costs, because installs were distributed over the season and into post-season, the program did not have the full capacity benefit from many of the newly installed devices. This high cost and relatively lower benefit contributed to the low retrospective TRC ratio of 0.13 for the year. PacifiCorp expects that in future years, new installs will represent a steadily decreasing proportion of devices, and higher capacity from existing devices will begin to offset installation costs, increasing the TRC.

Background

On May 3, 2016, the Public Utility Commission of Oregon (Commission or OPUC) approved PacifiCorp's request to implement a pilot irrigation load control program for customers within the Oregon portion of the Klamath Basin. Over the period 2016 to 2022, the pilot experimented with recruitment and retention of participants, creating notification and dispatch options, and expanding the season, frequency and duration of demand response events. Based on the success of the pilot, the Company filed Advice 22-004 to introduce a new broadly enabling Schedule 106 for Demand Response Programs, cancel the Pilot Program, Schedule 105, and propose an expanded irrigation demand response program to replace the Pilot Program using the provisions of Schedule 106. The expanded program was approved on May 5, 2022.[1] Advice 22-004 expanded the program to all Oregon irrigation customers and added a new incentive option for curtailing loads with shorter notice.

2023 Program Implementation

2023 was the first full year of implementation of the expanded program. Throughout the year, PacifiCorp worked with the implementer, Connected Energy to deliver the program. PacifiCorp is responsible for program oversight, communication with regulators and stakeholders, maintaining the program website, addressing any customer questions delivered through the call center or Regional Business Managers, and issuing annual incentives. PacifiCorp also schedules and calls demand response events.

Connected Energy is responsible for marketing the program, enrollments, installing and maintaining the control device at customer pumps, maintaining the CNRG portal, issuing notifications to customers once an event has been scheduled, issuing the signals to switch pumps off and then back on at beginning and end of events, collecting usage data, evaluating participant performance and calculating incentives.

Program Parameters /Design

PacifiCorp did not change any aspects of the program design from 2022 to 2023. The parameters for dispatch and incentive levels approved in Advice 22-004 were applicable to the 2023 season. These parameters are described in Table 1.

[1] See Oregon Public Utility Commission Advice No. 22-004. Available online: https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf

Table 1. 2023 Irrigation Load Control Program Parameters

Program Parameters	Description
Eligible Customers	Irrigation Customers on Schedules 41 or 48 in and around targeted areas posted on the Company web site.
Program Period	Week including June 1 through week including September 15.
Program Hours	All days 12:00 p.m. to 10:00 p.m. Pacific Time.
Dispatch Limitations	52 hours per year, 20 events per year, up to 4 hours per event or 12 hours per week.
Dispatch notification	Day ahead, hour ahead and 22.5 minute ahead
Incentive Rate	Day ahead at $18/kW per year. Hour ahead at $30/kW per year. 22.5 minute ahead at $45/kW per year
Opt-Outs	Participants may opt out of dispatches. Opting out will lower participation payments proportionally.
Incentive Payments	The incentive payment is calculated at the end of the irrigation season and paid to each participant after the season ends. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).

Additional information about 2023 customers, dispatch events, incentive rates and payments, and event opt-outs is provided in Appendix One.

Marketing and Outreach

PacifiCorp and Connected Energy collaborated with the Energy Trust of Oregon to launch the Irrigation Roadshow – a series of local events consisting of presentations about available programs from ETO and PacifiCorp for irrigation growers. These 5 presentations in four locations (Pendleton, Lebanon, Redmond, and Klamath Falls) in March 2023 had over 2,000 attendees, and directly led to over 100 pumps being enrolled.

In addition to the Roadshow events, Connected Energy implemented several outreach campaigns during the 2023 program year, using both email and postcards. Table 2 shows the frequency of these campaigns.

Table 2. ILC Marketing Campaigns in 2023

Date	Media Type	Description
2/7/2023	Email	New enrollment opportunity
3/16/2023	Postcard mailing	"Enroll today to save"
4/25/2023	Email	New enrollment opportunity
5/18/2023	Postcard mailing	"Enroll today to save"
6/20/2023	Email	New enrollment opportunity
10/6/2023	Postcard mailing	"This is your 1st chance to save"
10/10/2023	Email	New enrollment opportunity
11/7/2023	Email	New enrollment opportunity

Demand Response Performance

Availability

Availability increased in 2023 due to the substantial increase in the number of pumps participating, and the popularity of the reduced-notice products. Table 2 shows number of pumps by incentive tier during the 2023 season. After the season, another 13 pumps were added, mostly in the 22.5 minute tier.

Table 3. Number of Pumps by Incentive Tier Active During 2023 Season

Advance Notice Period	Annual Incentive Payment ($/kW)	Devices Installed at End of Season by Notice Period
22.5 Minutes	$45	179
1 Hour	$30	54*
1 Day	$18	18

* Includes 4 pumps that are operated manually (without a Connected Energy control device) in response to events.

Events

PacifiCorp called five events in 2023, for varying lengths of time, as shown in Table 3. The hour-ahead tier and the 22.5 min tier were called separately on August 14, and these are listed as two separate events.

Table 4. 2023 Curtailment Events

Date	Advance Notification	Start Time	End Time	Duration (Hrs)	Capacity (MWs)
June 30	6 hours, 19 minutes	15:45	16:15	0.5	1,939
July 14	9 hours, 16 minutes	17:00	20:00	3.0	2,867
August 14	8 hours, 30 minutes	17:00	21:00	4.0	389
August 14	22 minutes	18:05	21:00	3.0	1,727
August 15	5 hours, 9 minutes	16:00	20:00	4.0	1,886
August 16	3 hours, 53 minutes	16:00	20:00	4.0	1,952

Resource Performance

The average kW available from all events was 2,152 kW, an increase compared to 578 in 2022. All customers participated in the June and July events. One customer opted 4 pumps out of the August 14 event, and that same customer plus another opted a combined 12 pumps out of the events on August 15 and 16. All load control equipment performed as expected.

Table 5. Oregon Irrigation Load Control –2022-2023 Performance

	2022	2023
Proxy/Available kW	787	2,588
Curtailed kW (average all events)	578	2,152

Notes for Table 5

- kW values are at customer site
- Available kW value represents the average daily peak value during all program hours.

Program Costs

Program costs in 2023 are shown in Table 3. Costs to implement the program included an annual fee per device to operate previously connected devices, equipment, labor, and fees to install and operate new devices, administration fees to Connected Energy, marketing expenses, PacifiCorp labor costs and incentives to participants for the 2023 season. Costs are lower than the filed costs because program ramp up, while substantial, has not kept pace with the forecast.

Table 6. Irrigation Load Control –2022-2023 Program Year Costs

	2022	2023
Program Costs (corrections for in red text)	~~$312,056~~ $350,402	$991,284

Notes for Table 5

- Costs for a program year include all costs directly attributable to outcomes in a given year, such as equipment and labor costs for devices reported installed in the year, monthly administrative costs, and incentives for the program year. Cost corrections for 2022 include device installs for participants incurred in late 2022 and annual incentives that were posted in 2023, but apply to the 2022 season.

Appendix 1: 2023 Connected Energy Pacific Power Irrigation Load Control Program Report

Appendix 1
2023 Connected Energy Pacific Power Irrigation Load Control Program Report

In support of Pacific Power's regulatory activities related to the Irrigation Load Control Program in Oregon, Connected Energy prepares an annual report on program activities including total program enrollment, sites added, customer outreach, crops, weather data, and any available information on water restrictions, incentive payments, load control events and key observations. Connected Energy's report is provided as Appendix 1 to this report.

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2023 Pacific Power Irrigation
Oregon Load Control Program Report

Connected Energy
651 Holiday Drive
Foster Plaza 5, Suite 400
Pittsburgh, PA 15220
www.connectedenergy.com

Pacific Power
825 NE Multnomah
Portland, OR 97232
www.pacificorp.com

Date: March 20, 2024

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Overview of the 2023 Irrigation Load Control Program

This report provides an overview of the Irrigation Load Control (ILC) Program for Pacific Power in the state of Oregon. The program was initially rolled out as a pilot program focused on the Klamath Falls, Oregon region of the PacifiCorp service area, but has since been expanded to include the entire state of Oregon. The program was implemented and administered by Connected Energy for the 2023 irrigation season. Connected Energy has been the program implementer since 2018. This report is intended to document program results, accomplishments, and challenges, including lessons learned that will be leveraged to enhance the program going forward.

Regulatory approval for the Irrigation Load Control (ILC) pilot program in Oregon was initially granted by the Oregon Public Utility Commission (OPUC) on May 4, 2016. The ILC pilot program was transitioned to Connected Energy in 2018 and was initially made available to irrigation loads in the Klamath Falls, Oregon region of the PacifiCorp service area for customers that were not already participating in the time of use program. On February 14, 2020, the pilot program was approved to expand to areas beyond Klamath Falls and to provide for dispatch load control events with shorter notification.

On May 5, 2022, the ILC program was approved by the OPUC to transition from a pilot to a fully operational load control program across the entire Oregon service area of Pacific Power.[2] All customers that have participated in the program since its inception in 2016 have remained in the program through the 2023 irrigation season.

In 2023, the program delivered an average load reduction of 2.15 MW across 5 days when events were scheduled (total of six events). This load reduction was an increase of 372% from the 2022 average of 578 kW. The nearly 4 times increase in available load reduction was due to significant program expansion in 2023.

During the 2023 irrigation season, the program grew to include 192 participating pumps with load control devices (plus 4 large medium voltage pumps with manual control) across 57 different participating irrigators.[3] Maximum load available for curtailment was 3.78 MW and occurred on August 10, 2023, between 6:00 PM and 7:00 PM. Participating sites were compensated for allowing PacifiCorp to shut off irrigation loads for specific time periods determined by PacifiCorp

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[2] OPUC. Staff Report. Public Meeting Date: May 5, 2022. Docket No. ADV 1382 / Advice No. 22-004. Available online: https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf

[3] Due to customer operation of the pumps and growing practices, not all pumps enrolled in the program logged run times during program hours, and some operated at reduced levels. Connected pumps that do not run at all during the season are deemed nonparticipants for that season, and do not receive any incentive. Pumps that run at reduced levels during program hours receive proportional reductions to season incentives.

and were provided either day ahead, hour ahead, or 22.5-minute notice of load control events, based on participant's notification option selection.

During 2023, 77.5% of customers selected 22.5-minute notice, 19.5% of customers selected hour-ahead notice, and 3% selected day-ahead notice. In addition, participants had the opportunity to opt-out of (i.e., choose not to have their pumps curtailed) events as necessary to suit their day-to-day business operations.

Participant incentives in the ILC program are based on the site level average available load during load control program hours adjusted for the number of opt outs or non-participation in load control events. For 2023, the program hours were maintained as 12:00 PM to 10:00 PM Pacific Daylight Time (PDT) for all days (weekends and holidays included) from May 29, 2023, through and including September 17, 2023.

PacifiCorp initiated load control events during the 2023 load control season on the following dates and times:

- June 30, 2023, during the hours of 3:45 PM – 4:15 PM
- July 14, 2023, during the hours of 5:00 PM – 8:00 PM
- August 14, 2023, during the hours of 5:00 PM – 9:00 PM (Hour Ahead Group only)
- August 14, 2023, during the hours of 6:05 PM – 9:00 PM (22.5 Minute Group only)
- August 15, 2023, during the hours of 4:00 PM – 8:00 PM
- August 16, 2022, during the hours of 4:00 PM – 8:00 PM

Load reductions for the events are calculated using five-minute interval metering data from Connected Energy's direct load control devices and from PacifiCorp billing data for the one large customer with medium voltage (2300V) pumps.

Review of 2023 Customer Enrollment and Enablement

Customer Payment Structure

Participants get compensated by the program for their voluntary participation in load curtailment events. The participant payment is based on the amount of load able to be curtailed as well as the notice period that the participant agrees to in advance. In 2023, the same as 2022, the program offered three different notice levels and associated incentive payments based on the customer selected notice period:

Advance Notice Period	Annual Incentive Payment ($/kW)	Devices Installed at End of Season by Notice Period
22.5 Minutes	$45	179
1 Hour	$30	54*
1 Day	$18	18

*- Includes 4 pumps that are operated manually in response to events.

For the 2023 irrigation season and as seen in the table above, 71% of participants selected the 22.5-minute notice option, 22% selected hour ahead notice, while the remaining 7% selected the day ahead notice.

The incentive payment provided to participants was based on the measured available load for curtailment throughout the program season adjusted for any opt outs or non-performance in load control events. This payment structure is designed to provide fair and consistent treatment for all sites. For the six events called by PacifiCorp in 2023, five were initiated with at least an hour ahead notice and one was initiated with at least a 22.5-minute notice.

Enrolled Customers

Connected Energy enrolled customers and installed 228 new devices during the calendar year. Of those 228 devices, 215 were installed during the irrigation season, with 13 additional installed after the season ended. Connected Energy started marketing activities early in the program year and continued marketing the program benefits to irrigators throughout the season.

All previously installed customers remained active in the program in 2023. Previous participants, along with new installations resulted in a total of 247 active irrigation load control pumps (plus 4 large medium voltage pumps with manual control) available during the irrigation season. These pumps were distributed across 57 different irrigation customers.

Data Quality

Connected Energy's load control devices are designed with an integrated metering chip that provides near real-time interval metering data during both Irrigation Load Control events and normal operation of the customer participating loads. This metered data is used to validate when the pump is running and when the pump has been successfully curtailed. Thus, there is no need to create a statistical methodology or tool to validate participation of enrolled loads in the program. In cases where participants power down pumps when they are not being used, Connected Energy will see no metering data coming into the platform and will treat that load as being powered off. When the load is powered up again, we will then either see positive load data (load is running) or zero load data (load is not running).

Connected Energy's load control devices utilize 4G (LTE) cellular communications which provides added benefits as the minimum projected network life for 4G (LTE) is currently year end 2032.

Review of 2023 Program Participants and Performance

Customer Crop/Operations and Pumping Equipment

For the 2023 Irrigation Load Control season, customer crop types/operations included alfalfa, potatoes, and grass fields for cattle and livestock grazing as well as pumping into reservoirs. Pump sizes at these locations ranged from 25 HP to 750 HP.

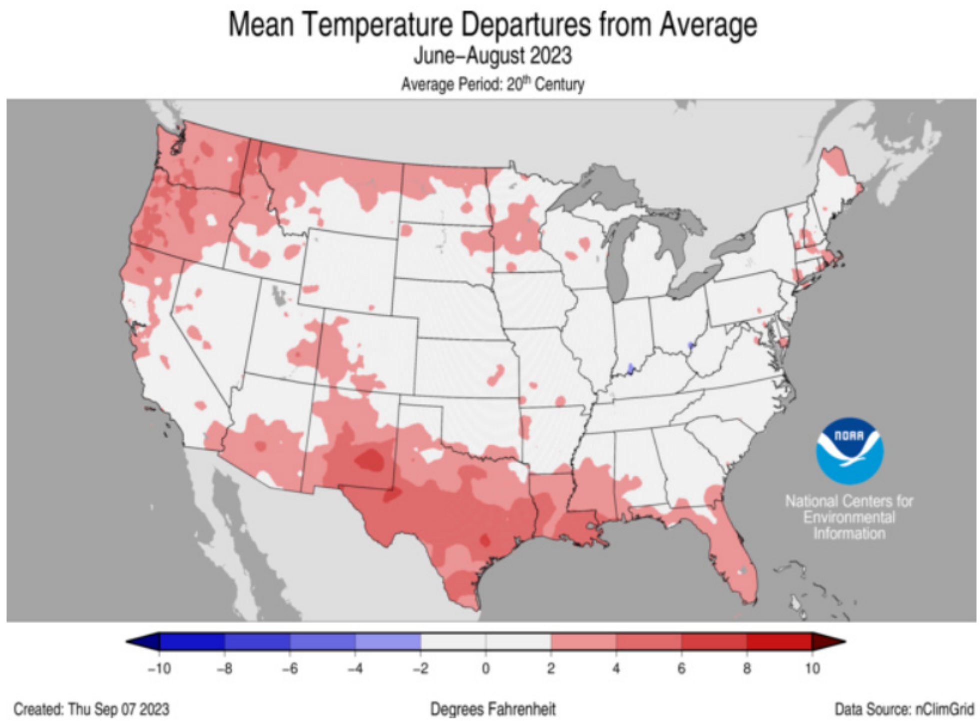
Impact of Irrigation Technology and Water Availability

While pump size is a clear determinant of total load availability in the Irrigation Load Control program, irrigation technology and water availability also impact irrigation pump run-time and thus can affect customer success in the Irrigation Load Control program. Pivot irrigation systems are operationally easier to manage for load control events than a wheel line or hand line irrigation system. During the 2023 season, participants continued to have concerns related to major water restrictions throughout the Klamath Basin. These water restrictions resulted in several participants experiencing reduced pumping loads due to the lack of water to pump.

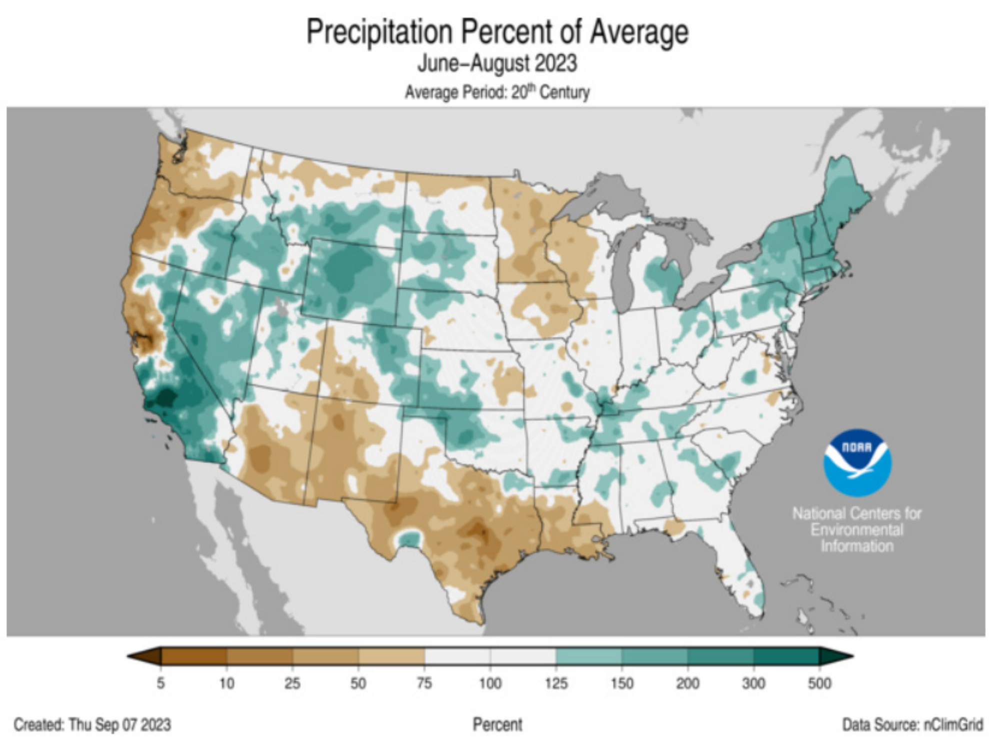
Weather & Drought Impact

Similar to the previous five years, 2023 was warmer than normal (including a record-breaking heat wave in August 2023) in the Irrigation Load Control geographical area, leading to greater irrigation needs. Similar to the previous 4 out of 5 years, precipitation levels were below average in the Irrigation Load Control geographical area. Along with below average levels of precipitation, water restrictions remained in place and resulted in lower pump loads versus historical averages.

The two images below highlight the above average temperatures and average to slightly below average precipitation across much of the western part of the country including the ILC program region during the 2023 program season.



Source: NOAA Mean Temperature Departures from Average (June-August) and Precipitation Percent of Average (June-August), available online: https://www.ncdc.noaa.gov/sotc/national/202008#season-precip



Source: NOAA Mean Temperature Departures from Average (June-August) and Precipitation Percent of Average (June-August), available online: https://www.ncdc.noaa.gov/sotc/national/202008#season-precip

Available Load Reduction

The Oregon Irrigation Load Control program is evaluated based upon average available load reduction (kW) during the 2023 program year, which ran from May 29, 2023, through September 17, 2023 (a total of 112 days).

The two charts below are provided for comparative purposes between the 2023 and 2022 program years.

For the 2023 program year the portfolio average available load reduction for the operating season was 2,588 kW (see Figure 1 below) with a maximum of 3,775 kW occurring on August 10, 2023. The chart below shows daily available demand during active program hours (12:00 PM – 10:00 PM, all days) and active program months in 2023.

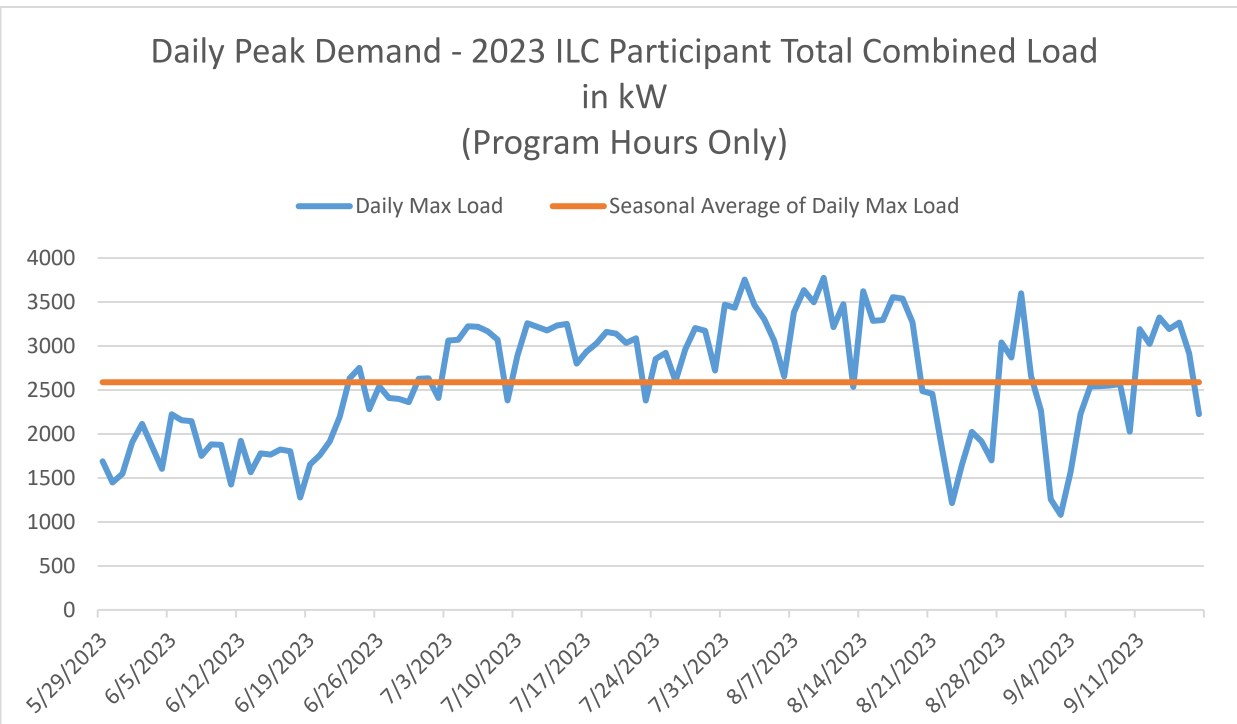


Figure 1 – 2023 ILC Participant Total Combined Load in kW for Program Hours Only

By comparison, for the 2022 program year, the portfolio average available load reduction was 550 kW (see Figure 2 below), with a maximum of 787 kW which occurred on August 24, 2022.

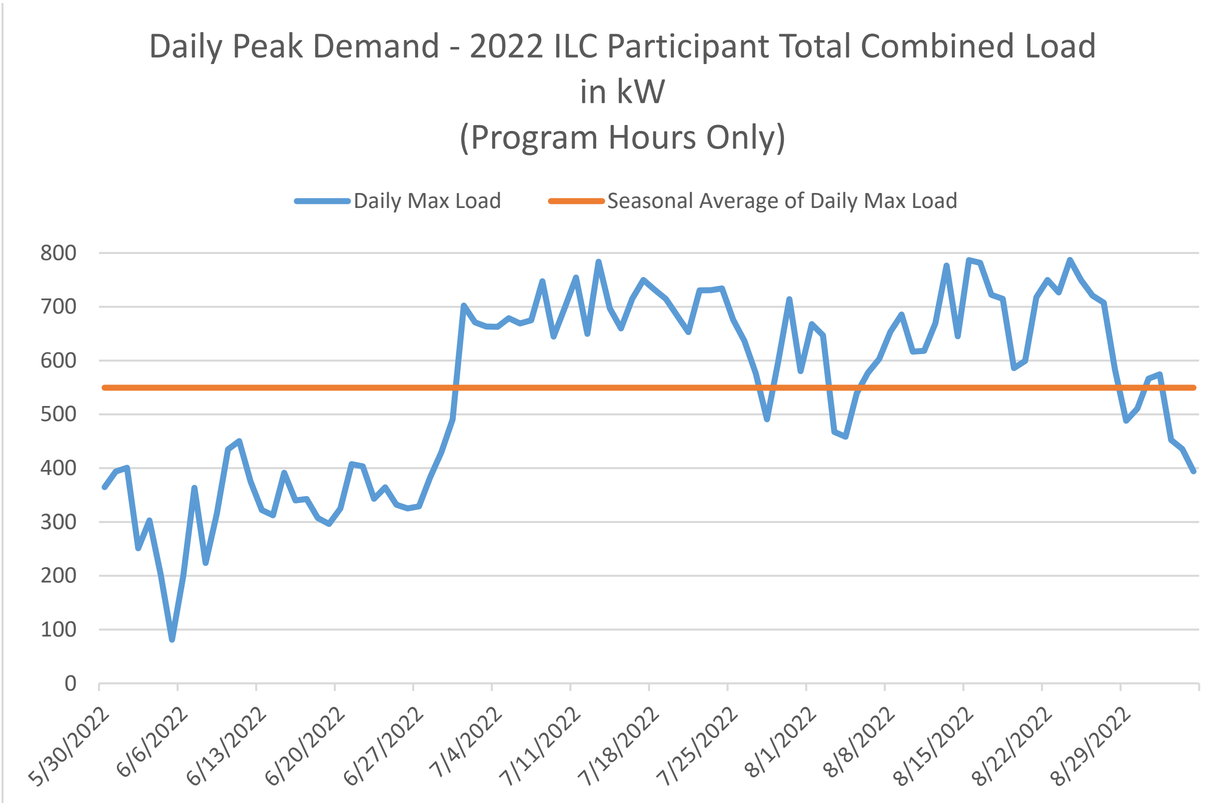


Figure 2 – 2021 ILC Participant Total Combined Load in kW for Program Hours Only

Load Control Events

PacifiCorp activated the Irrigation Load Control program a total of six times during 2023:

- June 30, 2023, during the hours of 3:45 PM – 4:15 PM
- July 14, 2023, during the hours of 5:00 PM – 8:00 PM
- August 14, 2023, during the hours of 5:00 PM – 9:00 PM (Hour Ahead Group only)
- August 14, 2023, during the hours of 6:05 PM – 9:00 PM (22.5 Minute Group only)
- August 15, 2023, during the hours of 4:00 PM – 8:00 PM
- August 16, 2022, during the hours of 4:00 PM – 8:00 PM

Event notice times are as follows:

Event Date	Event Time	Event Notice Sent	Notice Provided
6/30/23	3:45 PM – 4:15 PM	6/30/23 @ 9:26 AM	6 hours, 19 minutes
7/14/23	5:00 PM – 8:00 PM	7/14/23 @ 7:44 AM	9 hours, 16 minutes
8/14/23	5:00 PM – 9:00 PM	8/14/23 @ 8:30 AM	8 hours, 30 minutes
8/14/23	6:05 PM – 9:00 PM	8/14/23 @ 5:43 PM	22 minutes
8/15/23	4:00 PM – 8:00 PM	8/15/23 @ 10:51 AM	5 hours, 9 minutes
8/16/23	4:00 PM – 8:00 PM	8/16/23 @ 12:07 PM	3 hours, 53 minutes

Note that a combined single event was called for both the 22.5-minute and hour ahead notice groups on June 30, July 14, August 15, and August 16, while 2 separate events were called on August 14 (one for the hour ahead group and a second event for the 22.5-minute group). This resulted in a total of six called events over 5 event days.

Load reduction was measured as the difference between actual demand remaining on the system during the event and baseline demand. Baseline demand is the average demand during program hours (12pm to 10pm) on the most recent non-event, program day. Detailed Baseline Charts are provided in Appendix C for each event. Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from Connected Energy's field installed equipment at customers' sites and 5-minute PacifiCorp data for the one customer with medium voltage equipment.

The 2023 portfolio delivered an average of 2,152 kW across the 6 called load control events. The Load Reduction Performance Factor (LRPF), the measure of actual load reduction compared to baseline demand, was 92% for the portfolio in 2023.

Figures 3 through 8 below are graphs showing the Event Peak Load data for each of the 6 called events. The red line on each graph shows the 5-minute Peak Load Data on the day of the event and the blue line shows the Average Peak Load During Program Hours for the baseline day.[4] The

[4] Note - the baseline period is the same day (August 13, 2023) for each of the events on August 14, August 15, and August 16. Pacific Power is reviewing the methodology used for baseline calculations, as the utilized baseline for these three events was significantly lower than available loads on each of event days.

difference between the lines shows the amount of curtailed load achieved by the event.

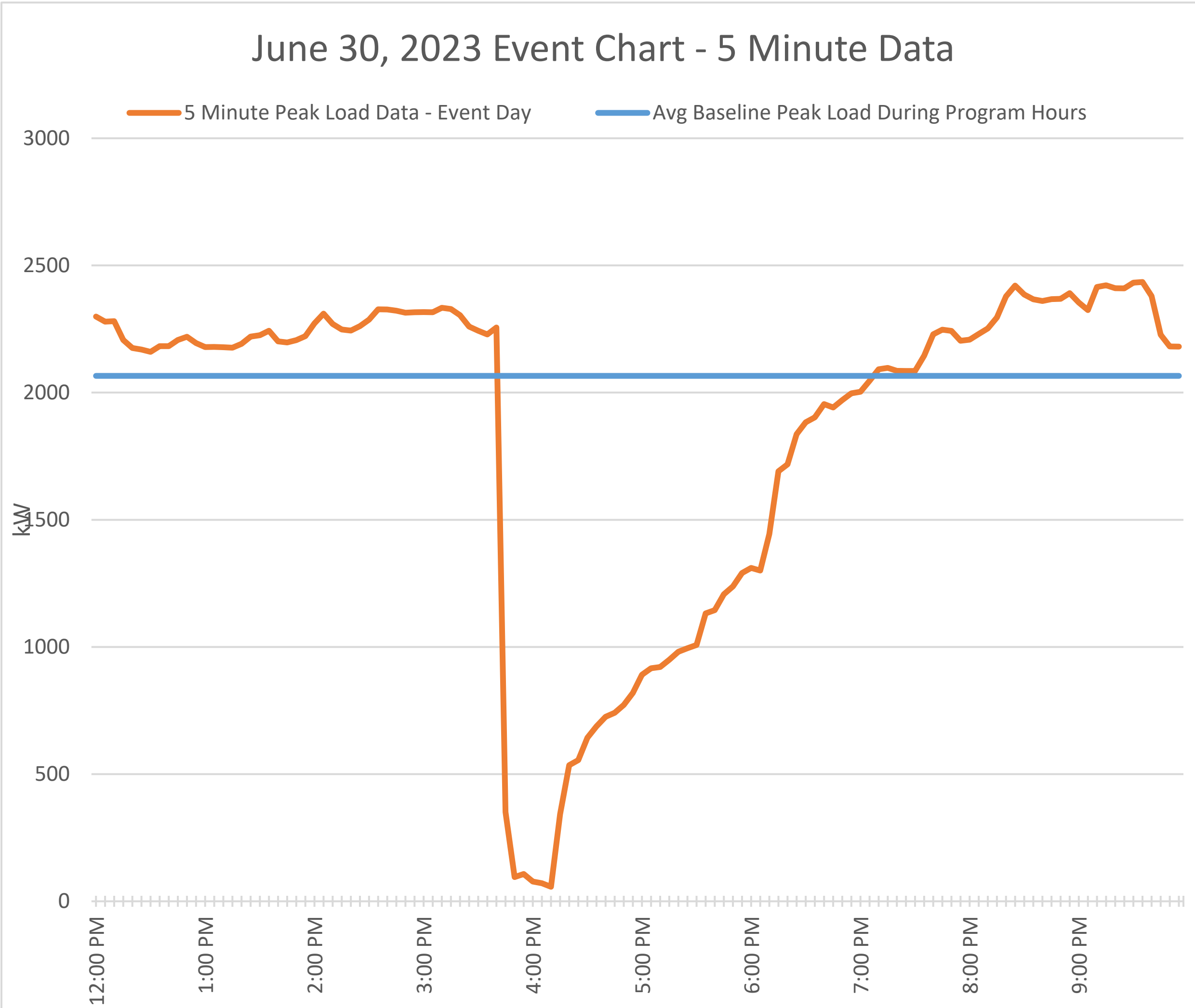


Figure 3 – June 30, 2023 Event Chart

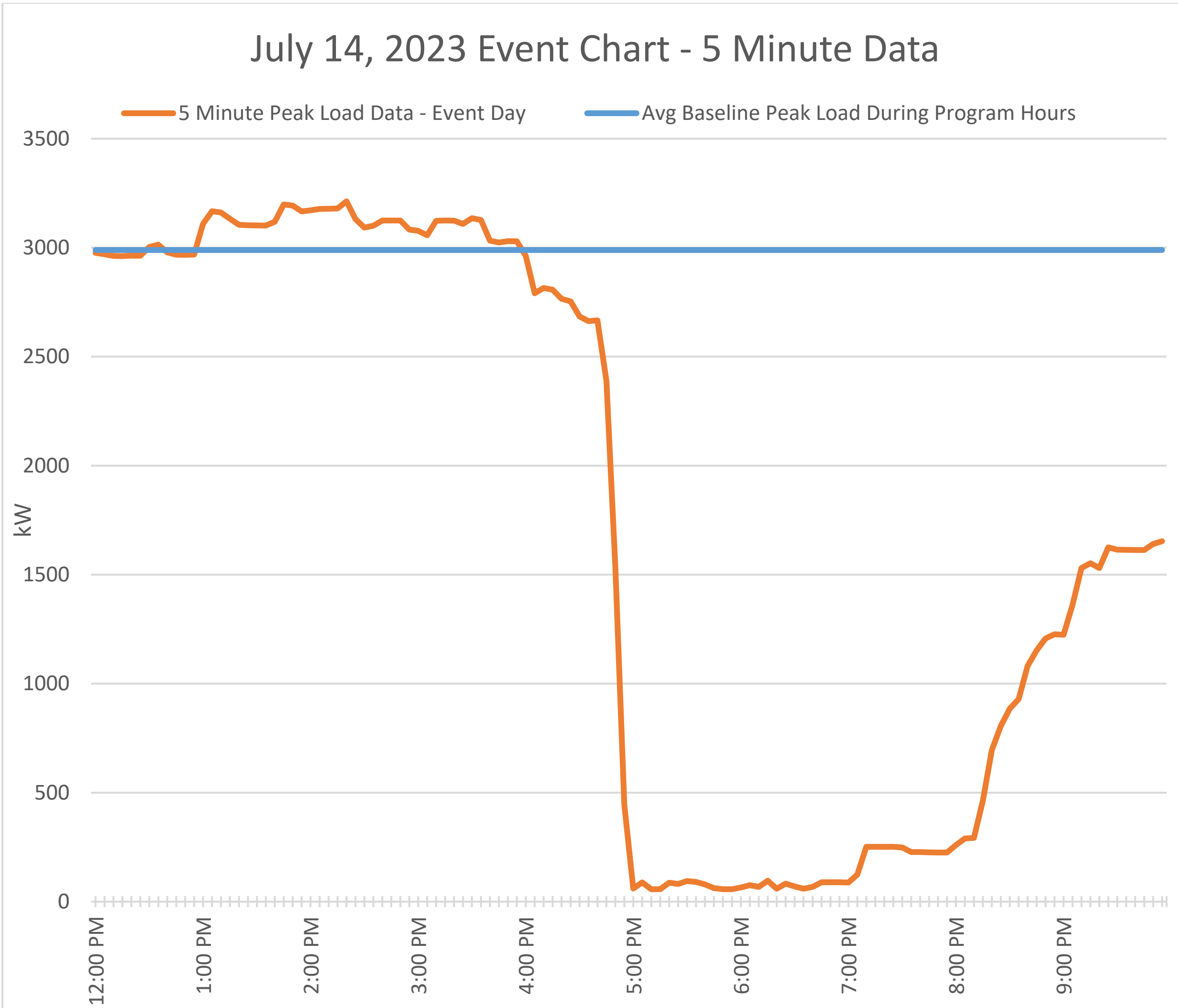


Figure 4 – July 14, 2023 Event Chart

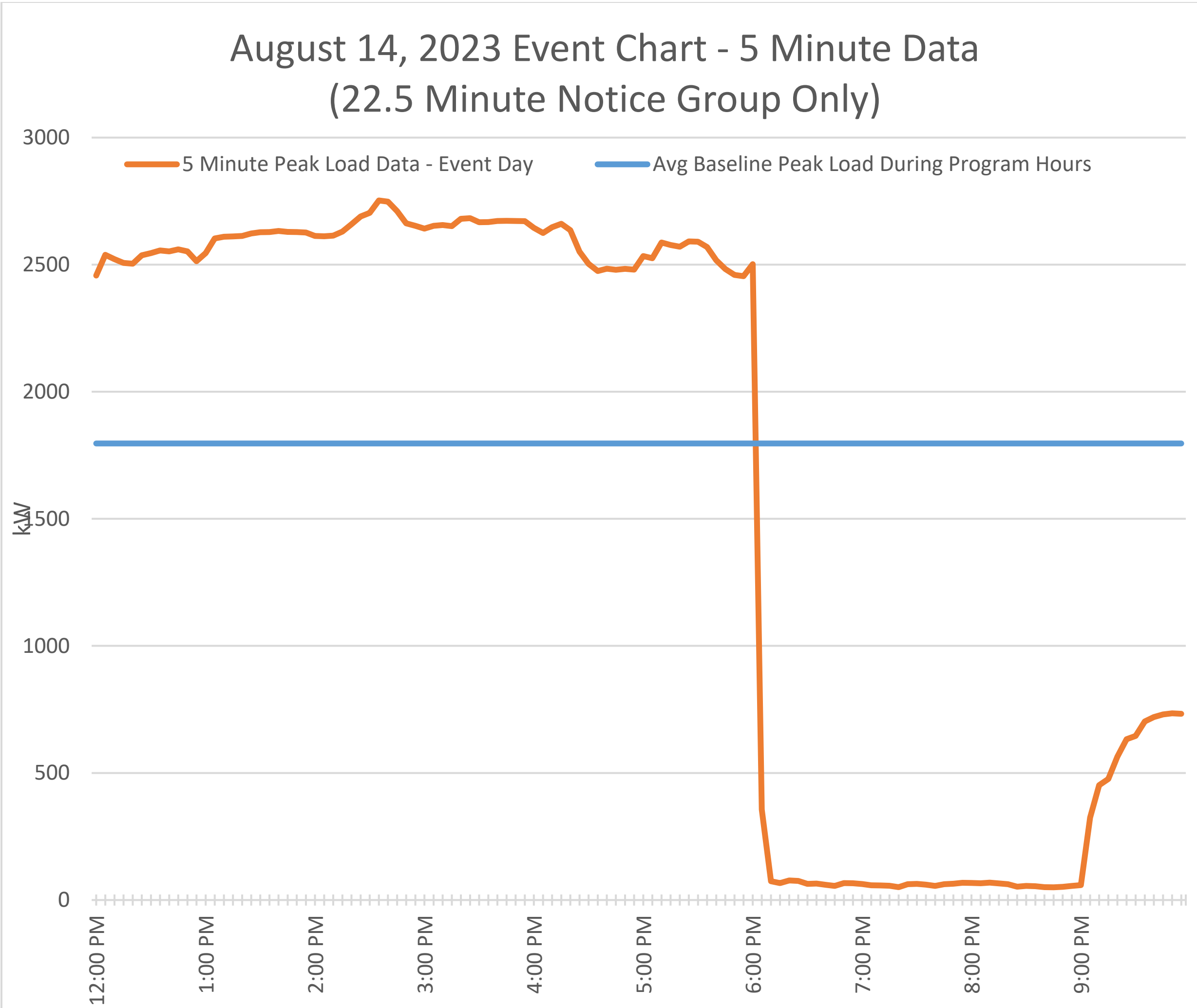


Figure 5 – August 14, 2023 Event Chart (22.5-Minute Notice Group)

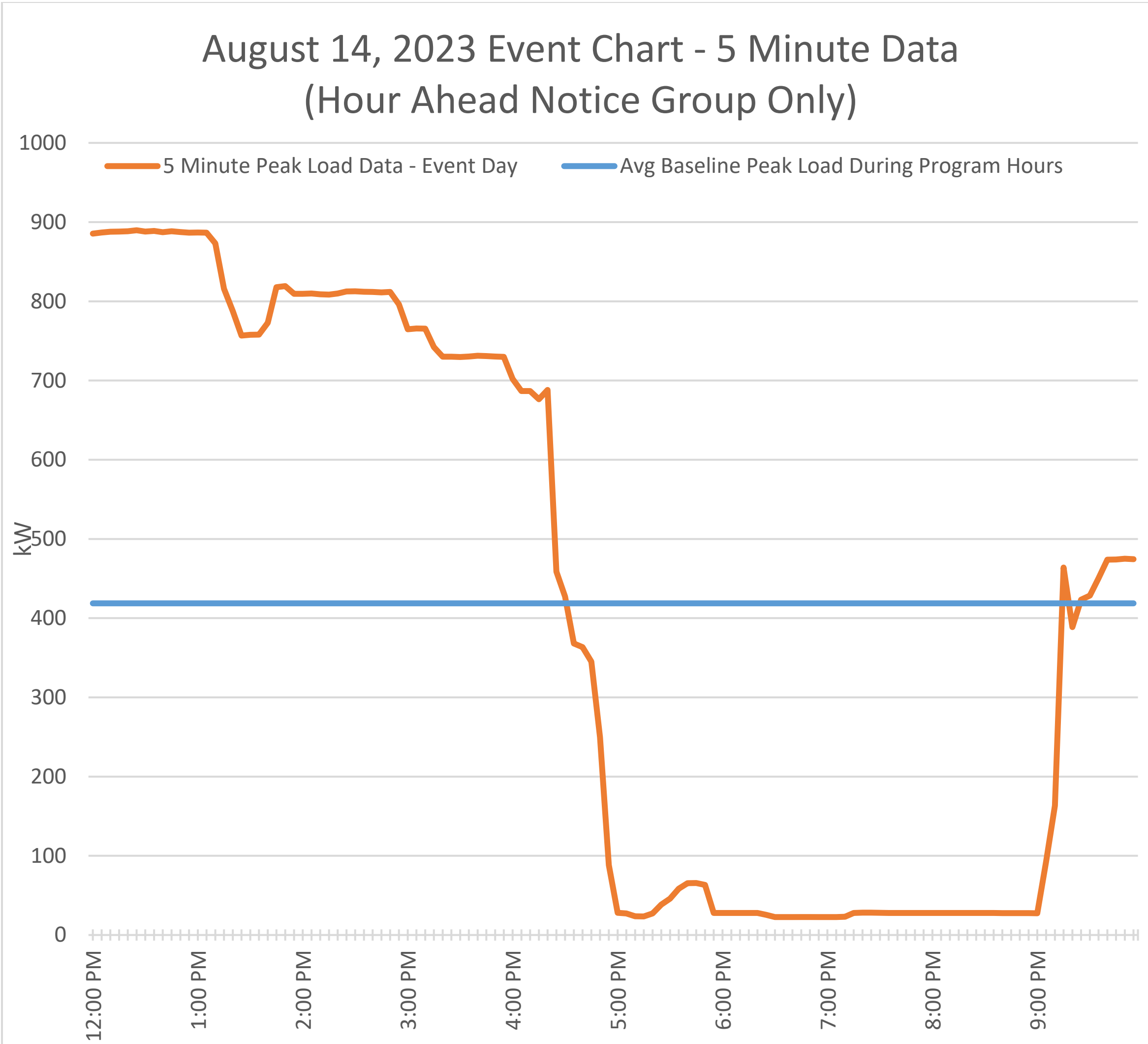


Figure 6 – August 14, 2023 Event Chart (Hour Ahead Notice Group)

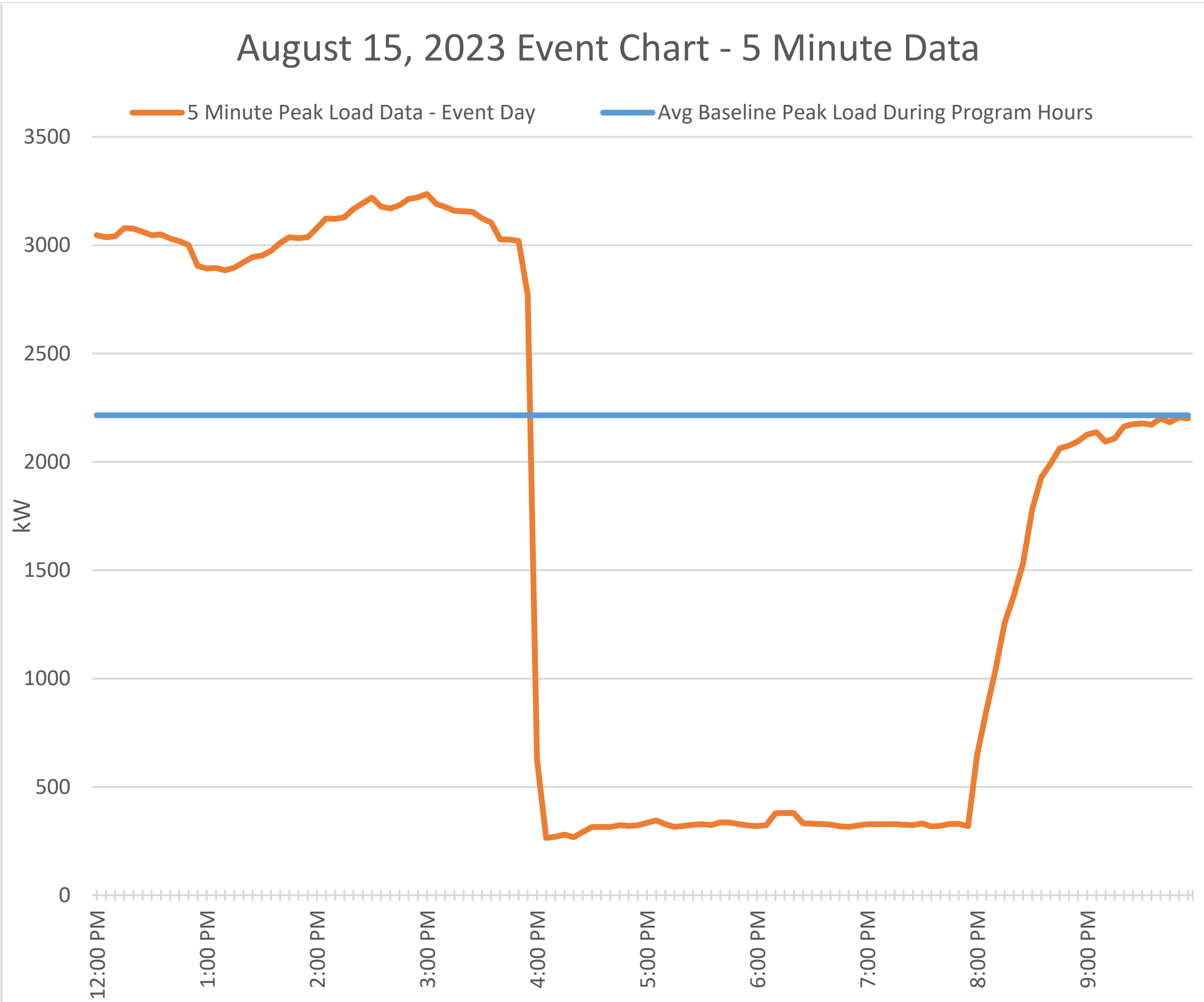


Figure 7 – August 15, 2023 Event Chart

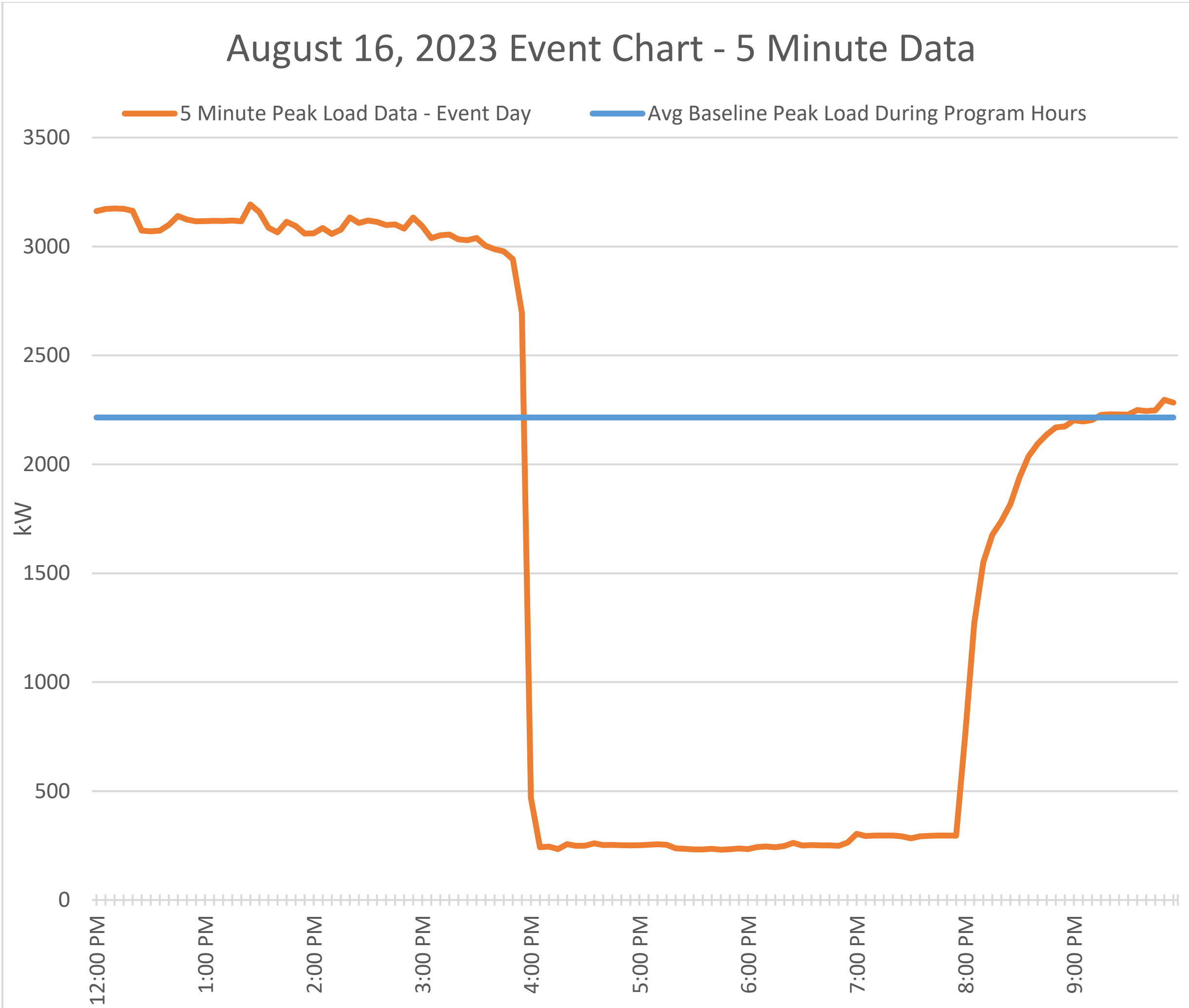


Figure 8 – August 16, 2023 Event Chart

Load Control Event Results

Table 1 below shows the summary detail for each of the six called events. Included is the actual load reduction (defined as Baseline Demand minus the amount of load remaining on the system), baseline demand, and performance factor (Actual Load Reduction / Baseline Demand) for each of the six called events.

Date	Notice Groups Called	Event Time	Actual Load Reduction (kW) *	Baseline Demand (kW) *	Load Reduction Perf Factor (%) *
June 30 2023	**1,2**	**3:45 PM - 4:15 PM**	1,939	2,066	93.88%
July 14 2023	**1,2**	**5:00 PM - 8:00 PM**	2,867	2,989	95.93%
August 14 2023	**2**	**5:00 PM - 9:00 PM**	389	419	92.79%
August 14 2023	**1**	**6:05 PM - 9:00 PM**	1,727	1,796	96.11%
August 15 2023	**1,2**	**4:00 PM - 8:00 PM**	1,886	2,215	85.12%
August 16 2023	**1,2**	**4:00 PM - 8:00 PM**	1,952	2,215	88.12%
Avg of 6 Events			2,152	2,340	91.99%

Notice Group 1 – 22.5 Minute Notice Provided
Notice Group 2 – One Hour Notice Provided

Table 1: Actual Load Reduction, Baseline Demand, and Performance Factor, by Event and Region

* Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from Connected Energy's equipment at customers' sites and 5-minute data from the PacifiCorp system, for the one customer with medium voltage equipment. These measurements may or may not correspond to realized load reduction on Pacific Power's system.

Customer Opt-outs of Called Events

Pacific Power's ILC program is a voluntary program that allows customers to opt out of any or all called events during the season. If customers do opt out of an event(s), their incentive amount is reduced proportionally based on the number of events called and the number of events opted out of by the customer.

During the 2023 program year, only 2 customers opted out of any called events. The opt outs occurred on August 14, August 15, and August 16, during an extended record-breaking heat wave in the Pacific Northwest.

Event Date	# of Customer Opt-Outs	# of Devices Opted Out
6/30/23	0	0
7/14/23	0	0
8/14/23	1	4
8/15/23	2	12
8/16/23	2	12

Key Lessons Learned from 2023

- The 22.5-minute notice option continues to be well received by participants, with more than 75% of customers selecting that notice option by year-end, which also provides a higher program incentive billing credit.

- Of the six called events in 2023, five events were initiated with at least a one-hour notice prior to the start of the event, and one event was initiated with at least a 22.5-minute notice prior to the start of the event. Shorter notice times generally provide higher economic market value for Pacific Power.

Event Date	Event Time	Event Notice Sent	Notice Provided
6/30/23	3:45 PM – 4:15 PM	6/30/23 @ 9:26 AM	6 hours, 19 minutes
7/14/23	5:00 PM – 8:00 PM	7/14/23 @ 7:44 AM	9 hours, 16 minutes
8/14/23	5:00 PM – 9:00 PM	8/14/23 @ 8:30 AM	8 hours, 30 minutes
8/14/23	6:05 PM – 9:00 PM	8/14/23 @ 5:43 PM	22 minutes
8/15/23	4:00 PM – 8:00 PM	8/15/23 @ 10:51 AM	5 hours, 9 minutes
8/16/23	4:00 PM – 8:00 PM	8/16/23 @ 12:07 PM	3 hours, 53 minutes

- Calling multiple events in succession (events call on August 14, 15, 16) along with record breaking heat wave resulted in 2 customers opting out of at least 2 of those back to back to back events.

- Continued program marketing efforts via multiple emails, postcards, outbound calling, and participation in the Irrigation Load Control Roadshow (late March of 2023) were key in gaining program exposure and increased participation through added enrollments.

    -

APPENDIX A: Customer-Facing Irrigation Load Control Activity

Listed below are the major activities involving program participants that occurred in 2023.

	Activity	Date	Description
1	**Email**	2/7/23	New enrollment opportunity email to solicit new customers into the program.
2	**Postcard Mailing**	3/16/23	"Enroll today to save" postcard sent to potential participants to continue to provide program exposure
3	**Irrigation Load Control Roadshow**	3/21/23 – 3/25/23	PacifiCorp and Connected Energy toured key areas of Oregon promoting the Irrigation Load Control (ILC) program. Areas included Pendleton, Lebanon, Klamath Falls, and Redmond.
4	**Email**	4/25/23	New enrollment opportunity email to solicit new customers into the program.
5	**Postcard Mailing**	5/18/23	"Enroll today to save" postcard sent to potential participants to continue to provide program exposure
6	**Email**	6/20/23	New enrollment opportunity email to solicit new customers into the program.
7	**Postcard Mailing**	10/6/23	"This is your 1st chance to save" postcard sent to potential participants introducing the ILC program for 2024.
8	**Email**	10/10/23	New enrollment opportunity email to solicit new customers into the program.
9	**Email**	11/7/23	New enrollment opportunity email to solicit new customers into the program.

APPENDIX B: Customer Payments

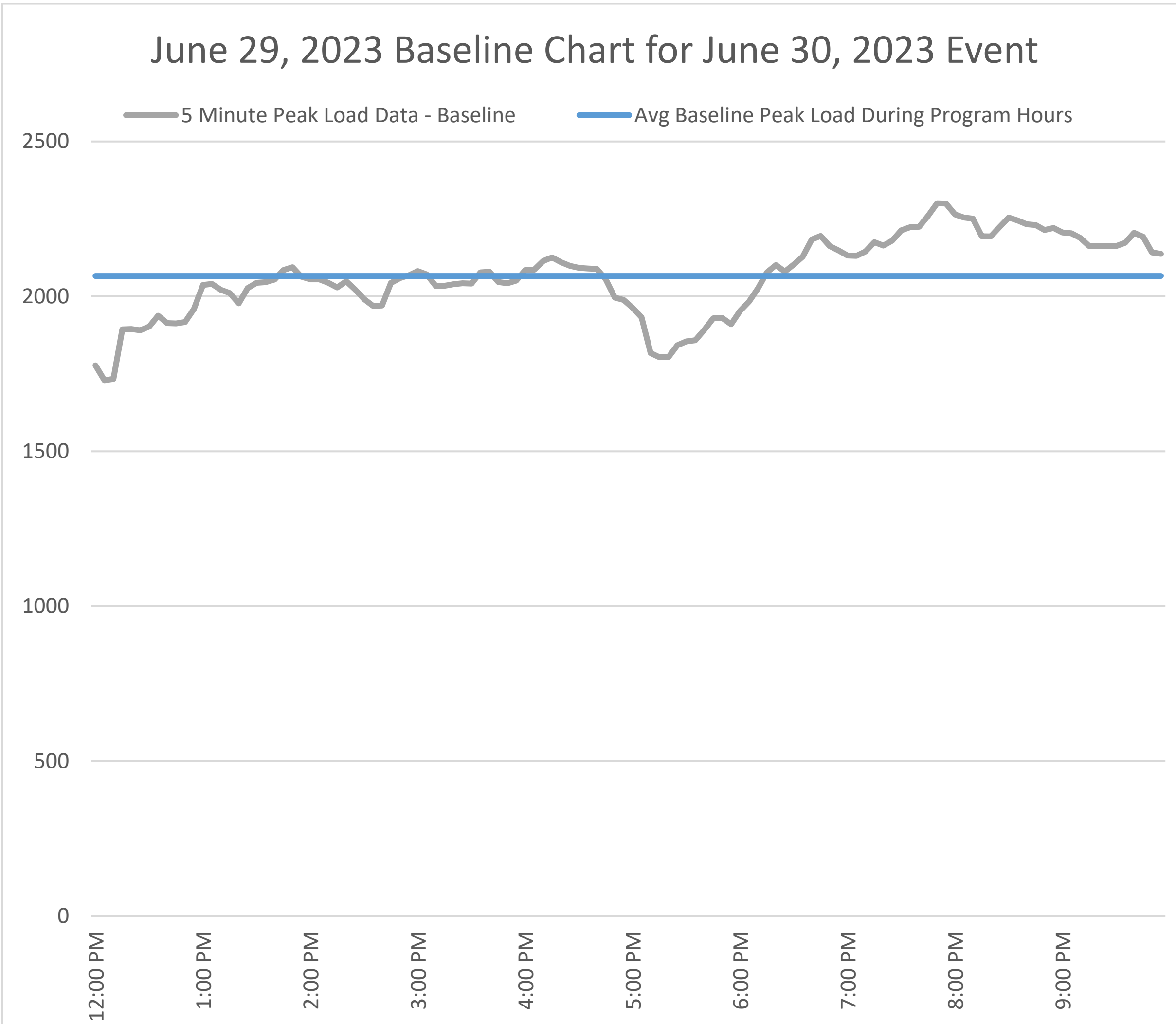
In 2023 the Irrigation Load Control program was modified to provide customer incentive payments via a billing credit posted to the customer's account after the season had concluded. In previous years when the number of participating customers was significantly smaller, incentive payments were made via a bank check.

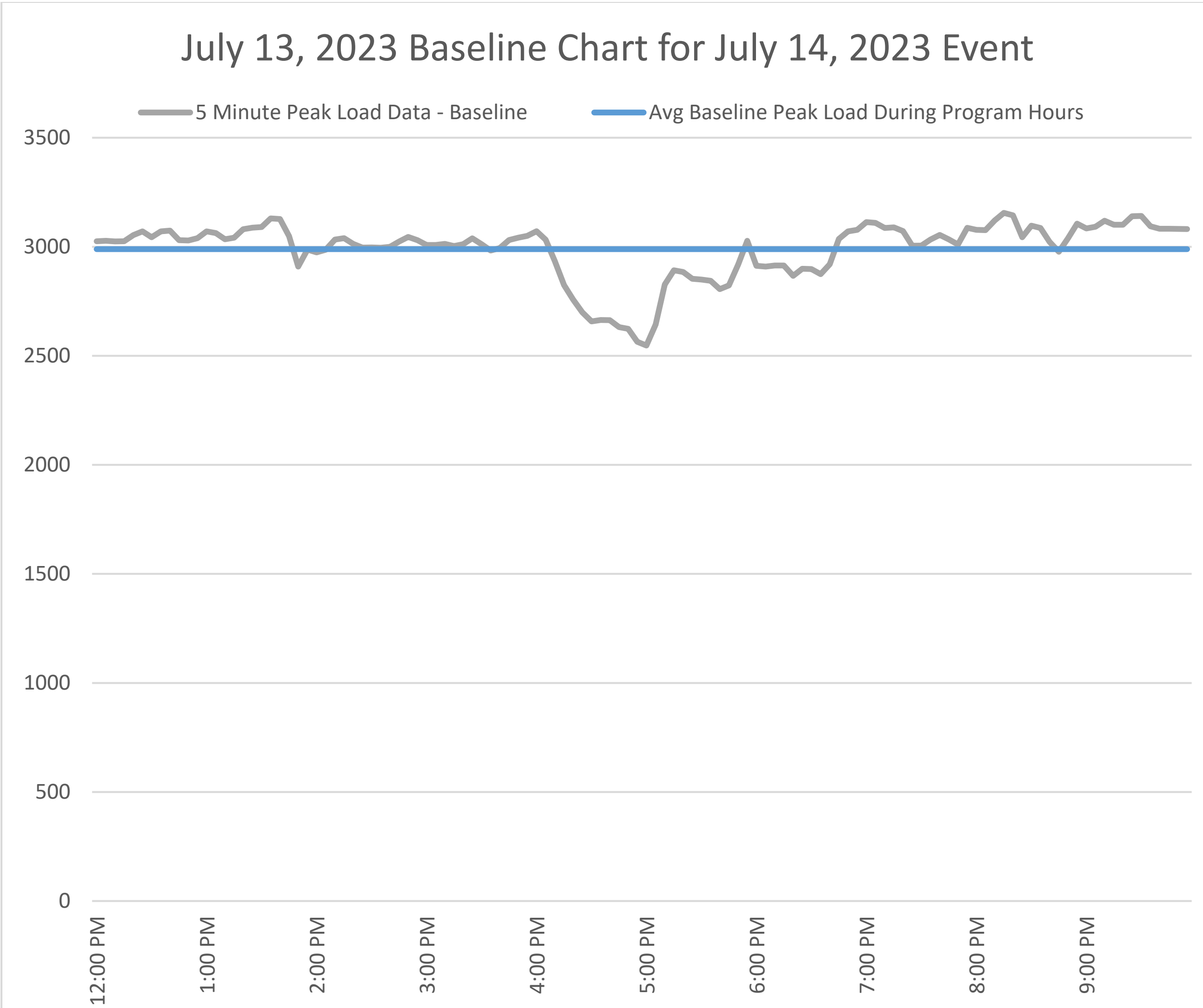
A total of 57 customers with 249 connected devices were potentially eligible for an incentive bill credit in 2023. Once the final analysis was completed, 55 of those connected devices were determined to be ineligible to receive an incentive due to insufficient run time during the program hours of 12:00 PM – 10:00 PM.

Incentive bill credits totaling $90,780.76 were issued to participating customers at the end of the 2023 irrigation season. The breakout of incentive payments based on customer selected notice period is as follows:

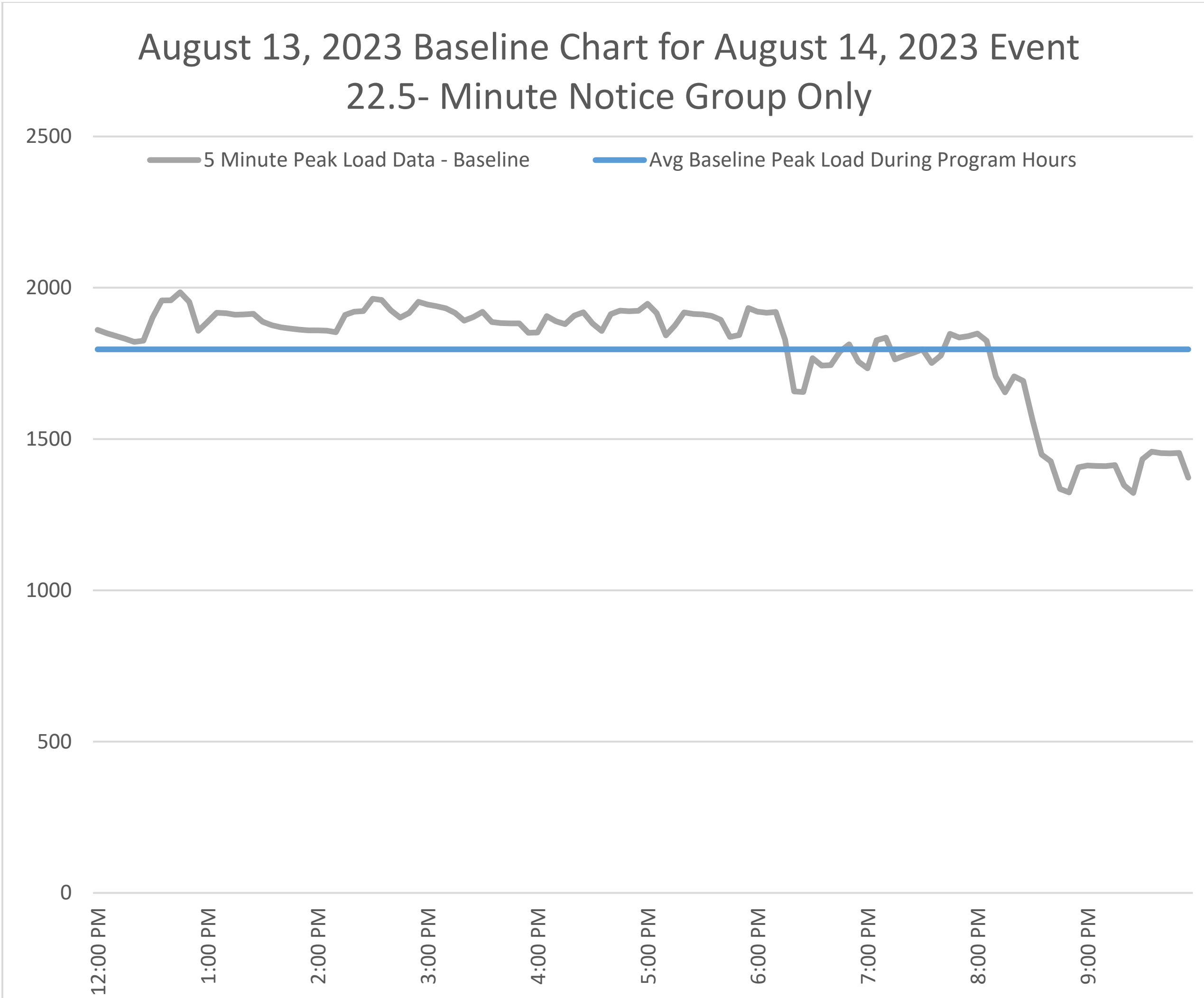
- 22.5 Minute Notice - $76,274.22
- Hour Ahead Notice - $13,375.78
- Day Ahead Notice - $1,230.76

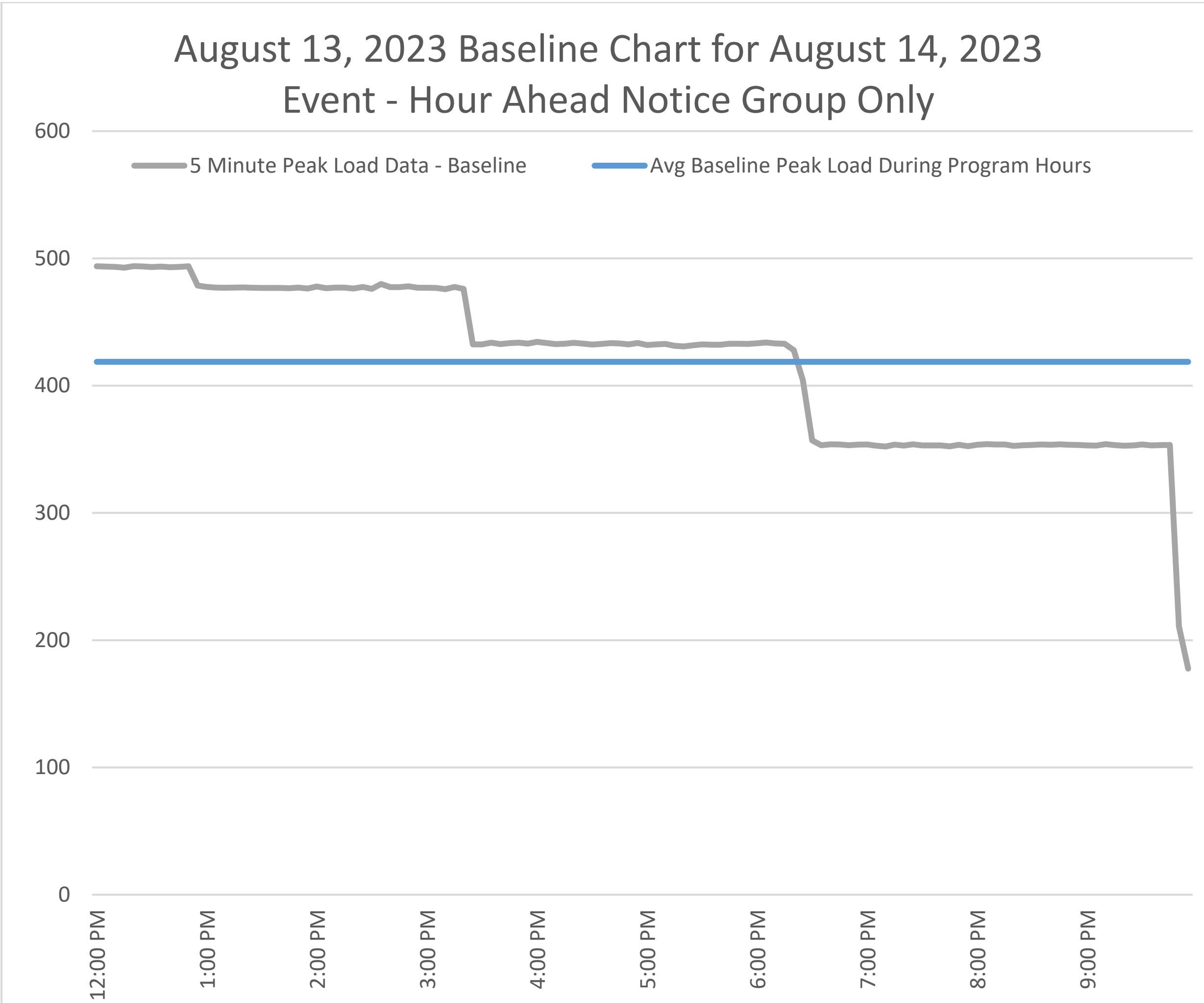
APPENDIX C: Detailed Baseline Charts

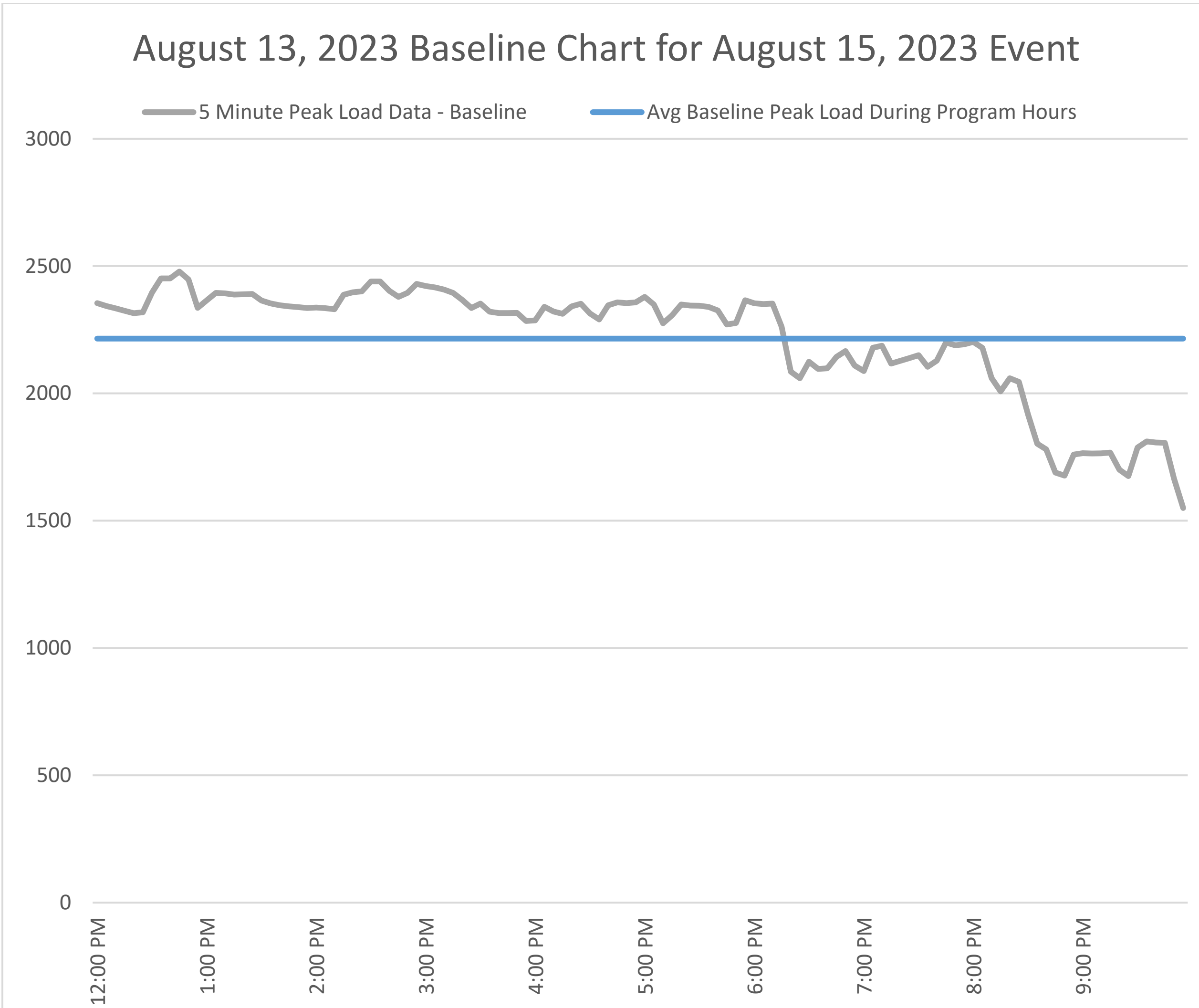




July 13, 2023 Baseline Chart for July 14, 2023 Event
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
3500
3000
2500
2000
1500
1000
500
0
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM


August 13, 2023 Baseline Chart for August 14, 2023 Event
22.5- Minute Notice Group Only
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
2500
2000
1500
1000
500
0
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM


August 13, 2023 Baseline Chart for August 14, 2023
Event - Hour Ahead Notice Group Only
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
600
500
400
300
200
100
0
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM


August 13, 2023 Baseline Chart for August 15, 2023 Event
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
3000
2500
2000
1500
1000
500
0
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2:00 PM
3:00 PM
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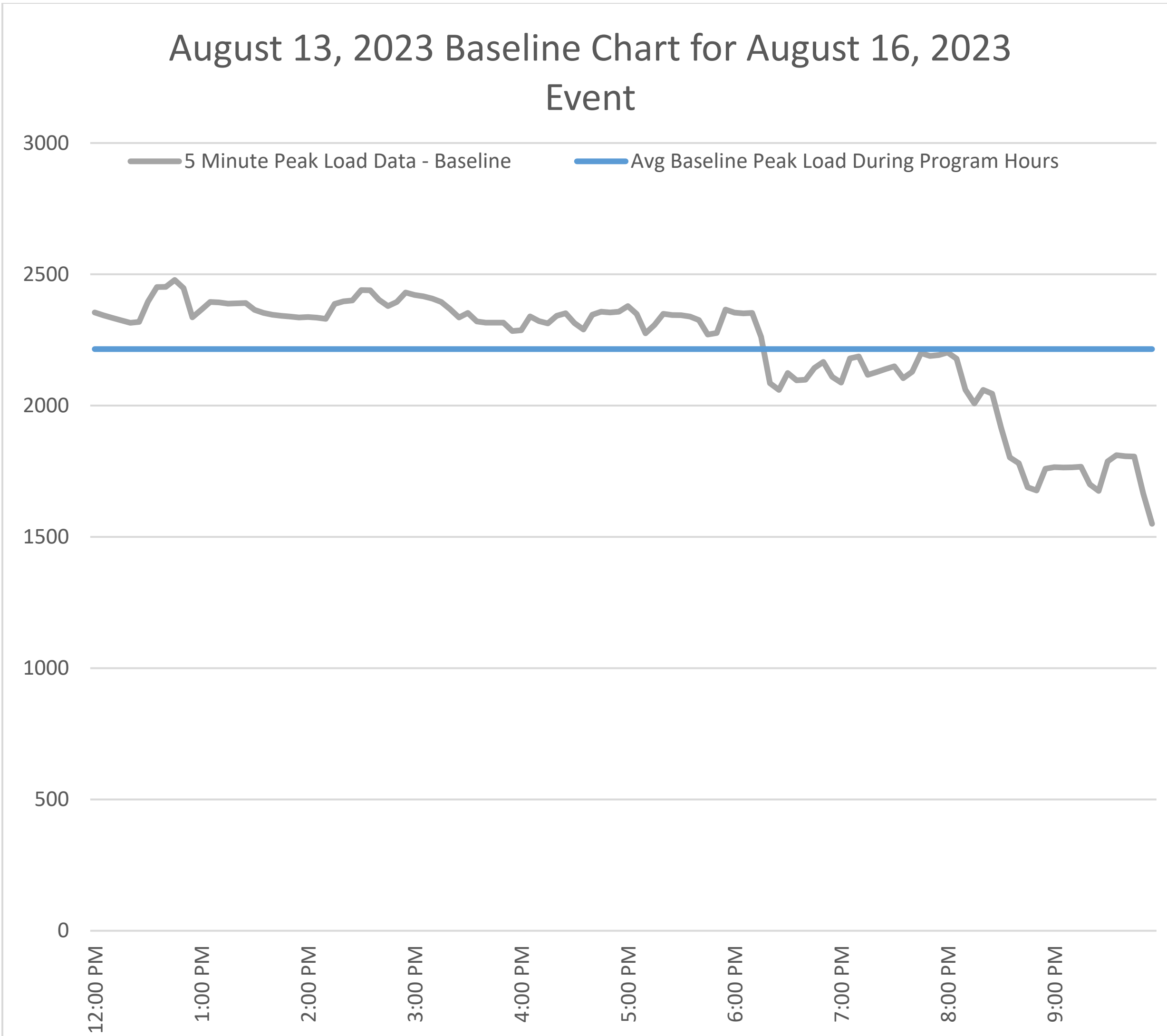
8:00 PM
9:00 PM


August 13, 2023 Baseline Chart for August 16, 2023 Event
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
3000
2500
2000
1500
1000
500
0
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM

Appendix 2: Cost Effectiveness - Benefits and Costs Discussion

For the first full year of implementation of the ILC DR Program, PacifiCorp updated the cost-effectiveness analysis to use the same methodology used to estimate cost-effectiveness in ADV 22-011, updated to reflect the costs and MW capacity from the single most recent implementation year.

As recommended by Commission Staff Report in Advice No. 16-04, PacifiCorp continued to apply the discount factors from the California Public Utilities Commission Distributed Energy Resource Avoided Cost Framework, Appendix A.[5]

For the retrospective cost-effectiveness analysis for the 2023 program year, PacifiCorp assessed the cost effectiveness of each incentive tier, and the program as a whole. Benefits were calculated using a 10 year levelized benefit of the program based on the capacity dispatched and actual energy prices in 2023. Total dispatched events for the levelized benefit in 2023 are based on 2023 actual dispatched hours and actual peak prices during 2023, using EIM scalar prices. Beyond 2023, a convergence of program availability hours and peak prices were used to simulate dispatch for the levelized benefit. Capacity amounts per dispatch were based on the average 2023 load reduction from each tier, adjusted for line losses. The day-ahead product was not called for any of the events in 2023, and therefore was allocated 0 benefits. In the original program filing, PacifiCorp included reserve benefits expected to accrue from registering the 22.5-minute tier in the CAISO EIM market. PacifiCorp did not complete this registration in 2023, and therefore CAISO EIM reserve value benefit is excluded from the analysis.

Program costs included actual equipment and installation labor for devices enrolled in each tier, while program level costs such as administration and PacifiCorp internal costs were allocated across tiers based on the proportion of capacity availability delivered by the tier. Delivery costs to administer the ILC Program include an annual fee per device to operate previously connected devices; equipment, labor, and fees to install and operate new devices; administration fees to Connected Energy; marketing expenses and incentives to participants. PacifiCorp internal costs are those directly attributable to the program operation.

Participant costs represent the value of service lost, transaction costs, additional management, and other costs that participants might experience as a result of enrolling and participating in the program. These costs are highly variable across participants and are difficult to observe or measure. At the same time, the fact that participants are willing to participate in the program provides some evidence that the maximum participant cost is some value less than the direct benefit they experience. Using this assumption, PacifiCorp modeled participant costs as 75% of participant incentives.

Over time, the annual program cost effectiveness improves because the most significant program costs – the equipment and labor to install devices – are incurred only once for each device. Reflecting the significant expansion in 2023, 84% of the 251 devices active during the 2023 season were installed during the year. Program costs include costs for 13 additional devices installed post-season. In total, 46% of 2023 program costs are for new device installation. Going

[5] *2015 Demand Response Cost Effectiveness Protocols,* California Public Utilities Commission. 2015.

forward, PacifiCorp expects that the majority of devices on the system will have been installed in previous years, and those costs will not apply to the program year even as capacity from those devices continues to provide a benefit.

Cost-effectiveness results for 2023 are shown in Table 7.

Table 7. Cost Effectiveness for 2023 Program Year

Parameter	2023	Day-Ahead	Hour-Ahead	22.5 Minute
Avg. Curtailed Load (MW)*	**2.3**	**0.0**	**0.5**	**1.8**
Total Avoided Costs w B, C Factor	$125,144	$0	$25,798	$99,346
Incentives	$90,781	$1,231	$13,276	$76,274
Delivery	$824,328	$50,289	$148,786	$625,252
EM&V Costs	$0	$0	$0	$0
PacifiCorp Internal Costs	$76,175	$2,350	$15,229	$58,596
Participant costs (value of service lost, transaction costs, capital cost, etc.)	$68,086	$923	$9,957	$57,206
Utility Cost Test	**0.13**	**0.00**	**0.15**	**0.13**
Total Resource Cost Test	**0.13**	**0.00**	**0.15**	**0.13**

*Capacity at generation.

Below, is a summary of each of the components using in the calculation of benefits for the program. The benefits used in the for this analysis generally follow guidelines outlined in the California Public Utility Commission (CPUC) 2016 DR cost-effectiveness protocols, where applicable. The following information is used for valuation of demand response benefits:

1. *Avoided Generation Capacity Costs*

For the purposes of this analysis, the Company relied on the most recent approved generation capacity deferral values from OPUC docket UM 1893[6]. The avoided generation capacity benefit is spread across the hours of dispatch and then adjusted for the estimated capacity contribution. The ILC program's estimated capacity contribution is assumed to be equivalent to a 4-hr maximum duration summer only demand response resource in the 2021 IRP.

2. *Avoided Energy Costs*

For the purposes of this report, energy value is reported based on the amounts shed, relative to the prior day baseline, without any adjustments related to shifting. For the 2023 valuation, the value of avoided energy is based on the avoided energy during event hours, with day-ahead, hour-ahead, and 22.5-minute-ahead option value being reflected in the market capacity estimate.

[6] State of Oregon: Public Utility Commission of Oregon

Avoided energy during event hours for 2023 is based on Energy Imbalance Market 15-minute market prices for PacifiCorp West, blended using the same values applied to qualifying facilities and adopted in the Resource Value of Solar proceeding. Because energy volumes reflect metered loads, it is appropriate to account for the value of avoided line losses that would otherwise have been incurred to serve those loads.

3. *Avoided Transmission and Distribution Costs*

Assigning transmission and/or distribution deferral value(s) to load management is consistent with the Company's IRP, the Northwest Power Planning and Conservation Council's 7th Power Plan7 and Oregon's Resource Value of Solar (UM 1910). Similar to generation capacity deferral values, transmission and distribution deferral values and their application in this analysis are derived from the most recent approved avoided cost values in UM 1893. These values are adjusted to reflect the expected capacity contribution of a 4-hr summer only demand response resource in the 2021 IRP.

4. *Line Losses*

For valuation purposes, the hourly line loss factor methodology developed for the Oregon GRC was used, based on a 2018 study. The value of avoided line losses is included in avoided energy and capacity costs. Avoided line losses are based on the average energy loss factors for irrigation customers on Oregon Schedule 41, as applied in the 2018 Line Loss Study. Avoided losses represent a roughly 7.55 percent increase in savings.

5. *Adjustment Factors (based on 2016 CPUC CR protocol).*

Notification Time (B Factor)
Avoided costs are discounted depending on notification time to account for visibility and foresight into system need. Often the need for DR is based on conditions (particularly weather), which can change in the course of 24 hours. The longer notification of an event the less predictable the conditions driving an event need are. As a result, the Company makes the value discounts to avoided cost to reflect this logic.

Table 8 Factor B Adjustments

Notification Time	B Factor
30 minutes or less	100%
Day Of, greater than 30 minutes	94%
Day Ahead or greater	88%

In 2023, the program required no less than 22.5-minute- and no more than one day-ahead notification with the majority of customers being enrolled in the hour ahead or 22.5 minute products.

[7] 7th Power Plan applies transmission deferral value only.

Trigger (C Factor)
The C factor accounts for the triggers or conditions that permit the Company to call each DR program. In general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions. Therefore, an adjustment should be determined so that programs with less flexible triggers can be de-rated. For programs with limited flexibility the avoided costs are derated by 5%.

Irrigation load control events can be called at the discretion of utility (within the specified months, weeks, days, hours). The Company considers this a limited-flexibility resource, and accordingly derated capacity by 5%. The 2023 events were triggered by a forecast for higher than typical power prices for the super peak period. In addition, hot weather was forecast for the period.

COMMERICAL & INDUSTRIAL DEMAND RESPONSE PROGRAM

2023 Commercial and Industrial Demand Response Program in Oregon

Issued April 1, 2024

PACIFIC POWER
A DIVISION OF PACIFICORP

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Overview

On October 14, 2022, PacifiCorp filed Advice 22-011 to introduce a demand response program for commercial and industrial customers using the provisions of the recently approved Schedule 106. The advice filing was approved with an effective date of November 16, 2022.

2023 marked the first full year of implementation of the program. During the year, PacifiCorp and its partner began recruiting for four distinct demand response products to customers. The program contracted for over 50 MW of capacity, and enabled over 12 MW of capacity. The Company utilized the available resource 5 times over the summer months, achieving an average of 3.1 MW, over 12 hours of curtailment.

PacifiCorp and Enel X also designed and nearly completed development of an interface between the Enel X platform and PacifiCorp's central grid management system to improve response time for the PAC 7M (responds within 7 minutes) and the PAC RT product (instant and fully automated dispatch for frequency response.)

Key Findings

<u>Participant behavior</u>

Customer response to all four product offers was extremely positive, with customers contracting for over 50 MW of capacity. Customers appear less sensitive to the difference between notice time of 60 minutes and 20 minutes than expected, with the PAC 20M product being the most popular of the four. (Customer response to the PAC 7M and RT products is still somewhat untested, since recruitment and enablement were paused early in the year to allow further system build-out.)

<u>Logistics</u>

The program encountered challenges procuring and installing necessary meter upgrades (KYZ pulse boards) to support enabling contracted customers. Supply scarcity issues were resolved in Q3, by which time a substantial backlog of contracted customers awaited enablement. The KYZ pulse installations were completed by PacifiCorp meter technicians. As meter upgrades ramped up in the end of the year, the meter technicians, PacifiCorp program staff and Enel X identified and implemented a number of process improvements to streamline the process. Regardless, given the extremely rapid pace of contracting, 21 customers representing about 37 MW were still awaiting enrollment at the end of the year.

<u>Product Performance</u>

PacifiCorp dispatched the PAC 60M product 5 times in the summer of 2023. Performance (ability of participants to curtail the full amount they nominated into the program) for multi-hour events was initially low but increased steadily with each successive event, as customers became more adept at implementing their curtailment plans.

Additionally, in November of 2023, PacifiCorp paused further recruitment in the PAC 20M product. The product was more popular than initially anticipated, and PacifiCorp wanted to preserve an opportunity to ensure the product use case remains viable going forward, and to assess whether and how to achieve a more balanced distribution of capacity across available products, each of which has a unique use case.

Delivery Costs

Program costs for the CIDR program for 2022 and 2023 are shown in Table 1. Costs for 2023 increased substantially over the 2022 costs, as the program only operated for a few weeks in 2022. In 2023, costs to implement the program included delivery fees, PacifiCorp internal labor, equipment purchases, and incentives. See Appendix 2: Cost Effectiveness - Benefits and Costs Discussion for a more detailed breakout of 2023 costs.

Table 1. CIDR Annual Program Costs

	2022	**2023**
Program Costs	$4,628	$530,757

Incentives represented the single largest cast category in 2023, followed closely by procurement and labor costs for meter upgrades. This is expected for the first year, since the program is focused on installing new customers. In future years, meter upgrades as a proportion of total costs is expected to decline, while incentives and delivery costs are expected to increase as program capacity increases.

Assessing Costs and Benefits

In this start-up year, the program was not cost-effective. This result is not unexpected, since this program requires higher capacity to offset program costs. The program has a strong pipeline, and expects significant increase in capacity in 2024. For the retrospective cost-effectiveness analysis, PacifiCorp made two additional changes to the methodology used in the program filing that reduced the final TRC. The analysis used the average curtailed load from 2023, rather than the maximum available load used in planning. In addition, the analysis removed CAISO EIM reserve benefit, since PacifiCorp did not register any capacity in the CAISO.

Additional Detail

Appendix 1 provides a full discussion of the implementation activities, outcomes, lessons learned and recommendations for the coming year.

Appendix 2 provides a discussion of potential benefits utilizing demand response cost-effectiveness protocols from California.

Appendix 1: Enel X Annual Report for the 2023 Oregon Commercial and Industrial Demand Response Program

Pacific Power C&I Demand Response Program

2023 Annual Report - Oregon

Prepared for:
Pacific Power

Prepared by:
Enel North America
100 Brickstone Sq.
Andover, MA 0810

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List of Tables & Figures

Executive Summary

2023 was the first full program year and the first year with active participants in the Pacific Power Commercial and Industrial Demand Response (CIDR) program. In 2023, PacifiCorp and Enel X field-tested the program offer to customers, contracting and enrollment processes, and dispatch and reporting protocols for the first time. Customer response was positive, and led to customers contracting for over 50 MW of capacity. In addition, Pacific Power's Energy Supply Management group was able to use the available 60-minute capacity several times during the summer season.

There were also important lessons learned during the year. Delays in hardware procurement, changing understanding of optimal product design, and the need to build up and refine standardized operating and reporting procedures impacted overall program performance. The key takeaways from this program year are:

1) Maximize the capacity resource with Enel monitoring equipment to improve performance and customer experience.

2) Focus on shortening the performance and settlement feedback loop to improve performance and customer experience.

3) Review and refine the use case for the 20-minute product, and potentially revise product characteristics.

4) Leverage the centralized enablement control process to improve collaboration between organizations and ultimately decrease the overall enablement timeline.

All tables and figures in this report are specific to the state of Oregon unless otherwise stated. Total participation through the end of 2023 is shown in Table 1.

Table 2. 2023 Participation by Customers and Capacity

Product	Customers	Capacity (MW)
60-minute Ahead	9	7.91
20-minute Ahead	7	5.03
7-minute Ahead	0	0
Real Time	0	0
TOTAL CIDR	**16**	**12.94**

In addition to the 16 customers and almost 13 MW of capacity fully enrolled and available for dispatch by the end of the year, another 41 customers representing 37 MW of capacity had signed participant agreements and were awaiting enrollment. Overall, the program enrollment saw customers from the following industries: government (4), education (2), retail (2), water and sewage services (1), transportation and storage (1), business and consumer services (1), manufacturing (1), metal products manufacturing (1), energy and utilities (1), and other industries (2).

Program Overview

The Pacific Power Oregon Commercial and Industrial Demand Response (CIDR) Program provides incentives to participating customers in exchange for granting Pacific Power the right to curtail participating customers' loads at certain times within the dispatch parameters and during the dispatch period. Pacific Power contracts with Enel X as the program administrator to deliver the CIDR program; Enel X oversees the enrollment of participating customers, delivers dispatch notifications, and calls dispatch events on behalf of Pacific Power. The ability to curtail these loads provides Pacific Power with curtailment, regulation reserve, contingency reserve, and frequency response grid services. The four demand response product offerings (DR products) are the Pacific Power 60-min Ahead (PAC 60M), Pacific Power 20-min Ahead (PAC 20M), Pacific Power 7-min Ahead (PAC 7M), Pacific Power Real Time (PAC RT), which vary by dispatch notification length, and other parameters.

Enel X is responsible for recruiting customers, managing the enrollment of participating customers, installing Enel X energy monitoring devices where necessary, maintaining the Enel X utility portal that allows dispatches to be scheduled, maintaining the Enel X participant applications that allow participants to access their own energy and participation data, delivering dispatch notifications and calling dispatch events scheduled by PacifiCorp, reporting on program performance and calculating and delivering customer incentives. PacifiCorp is responsible for general program oversight, procuring and installing KYZ pulse boards and other equipment necessary to provide a pulse signal to the Enel X device (where installed), providing customer usage data where no Enel X monitoring device is installed, and scheduling dispatch events for the PAC 60M, PAC20M and PAC 7M products.

Customer Eligibility

Eligible customers and relevant load criteria are included in Table 2 below. Eligible customers who meet the criteria and agree to participate are participating customers. Participating customers are required to sign a standard agreement with the Enel X to initiate participation. The agreement is perpetual (unless terminated by either party), and does not need to be re-signed at the start of each year. Customers are eligible to dual enroll in one of the following PAC 60M, PAC 20M, PAC 7M, and the PAC RT product. Customers are not allowed to dual enroll between PAC 60M, PAC 20M, and PAC 7M.

Table 3: Customer Eligibility Requirements

Category	Description
Eligible Customer	All commercial and industrial customers on Delivery Service Schedules 23,28,30, 47 and 48.
Criteria	Interval meter installed 500 kW or more of curtailable load as determined by Program Administrator for Customers participating in 7 minute and Real Time Dispatch Notification

Incentives

Incentives, summarized in Table 3 below are available on a $/kilowatt (kW) per year basis and vary by DR product. Participants earn an equal incentive rate for each hour and month under the PAC 60M product. Under the PAC 20M and PAC 7M products customers earn a variably incentive rate across each month during the year based on value of the demand response capacity resource in each month. In each month, all hours for the PAC 20M product are equal and under the PAC 7M product the incentive is weighted by time of day, where the hours between 9am – 9pm provide a higher incentive rate than 9pm – 9am. The $/kW incentive rate for the PAC RT product is equal across all hours of the year.

Using data from Enel X installed equipment, loads available for curtailment (kW) during the hours, days and months of the dispatch period are averaged to arrive at an average available load which will be multiplied by participant performance during applicable dispatch events and the Incentive rate depending on the product offering selected. Loads opted out are removed from the connected load calculations and reduce the Incentive payment to the participating customer. In 2023, incentives were paid on an annual basis, though in future years, the PAC 60M product will be paid at the end of the season and all other products will be paid quarterly. In the event Pacific Power does not call a dispatch event, participating customers receive incentives based on the availability of load reduction.

Table 4: Incentives by DR Product

DR Product		Incentive Rates											
PAC 60M		Annual Rate ($/kW):		$30.00									
		Monthly Rate											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		N/A	N/A	N/A	N/A	$6.00	$6.00	$6.00	$6.00	$6.00	N/A	N/A	N/A
PAC 20M		Annual Rate ($/kW):		$55.00									
		Monthly Rate											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		$5.50	$4.13	$2.75	$2.75	$2.75	$4.13	$8.25	$8.25	$5.50	$2.75	$2.75	$5.50
PAC 7M		Annual Rate ($/kW):		$75.00									
		Monthly Rate											
	Hours	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	9am - 9pm	$5.63	$4.22	$2.81	$2.81	$2.81	$4.22	$8.44	$8.44	$5.63	$2.81	$2.81	$5.63
	9pm - 9am	$1.88	$1.41	$0.94	$0.94	$0.94	$1.41	$2.81	$2.81	$1.88	$0.94	$0.94	$1.88
PAC RT		Annual Rate ($/kW):			$85.04								
		All annual hours equal ($/kW):			$0.00971								

Dispatch Parameters

The dispatch parameters for the four CIDR products are summarized in Table 4 below. The PAC 60M product is a summer only (May – September) product. All others are available year-round. The PAC 20M and PAC 60M are only available on non-holiday business days during their respective dispatch periods. The PAC 7M and PAC RT products are available every day of the year.

Table 5: DR Product Dispatch Parameters

	DR Product			
Dispatch Parameter	PAC 60M	PAC 20M	PAC 7M	PAC RT
Dispatch Period	May 1 - Sep 30	Jan 1 - Dec 31	Jan 1 - Dec 31	Jan 1 - Dec 31
Dispatch Days	Weekdays, non-holidays during Dispatch Period	Weekdays, non-holidays during Dispatch Period	Monday - Sunday during Dispatch Period	Monday - Sunday during Dispatch Period
Available Dispatch Hours	3:00 p.m. to 9:00 p.m. Pacific Time on all Dispatch Days	8:00 am to 9:00 p.m. Pacific Time on all Dispatch Days	24 hours/day on all Dispatch Days	24 hours/day on all Dispatch Days
Maximum Dispatch Hours	40 hours	60 hours	60 hours	5 hours
Maximum Dispatch Events	1 event/day	1 event/day	25 events/year	50 events/year
Dispatch Durations	up to 3 hours	up to 4 hours	up to 4 hours	up to 15 minutes
Dispatch Notification (minimum)	60 minutes	20 minutes	7 minutes	None

Marketing

For 2023, Enel and Pacific Power coordinated to develop the following marketing materials and campaigns:

- Frequently Asked Questions in print and online at Pacific Power's and Enel's websites. Spanish version is available on Pacific Power's website.
- Marketing and sales slide presentations.
- Informational sessions with Pacific Power's Regional Business Managers about the Pacific Power C&I Demand Response program, target customers and collaboration framework

Pacific Power and Enel also introduced the CIDR program to Energy Trust of Oregon (Trust) staff, discussed initial customer lessons learned, and fielded questions about the DR program from the Trust.

Recruiting and Enablement

Recruitment

The Recruitment process is the set of activities that allows Enel to identify and contract with eligible commercial and industrial customers. Primary activities of this process include, but are not limited to:

- marketing and prospecting across various market sources to include utility data sources from Pacific Power for eligible customers.
- defining customer needs through interviews and applying customer analogs from market experience.
- evaluating which DR product is the best customer fit based on operations, historical load data, and financial incentives.
- contracting with the customer for the agreed site(s) and DR product(s).

Once the customer has fully executed a contract with Enel, they are ready to begin the enablement process.

Program recruitment contacts and activities through year-end 2023 are summarized in Table 5 below. Contacted is the number of unique customers contacted. Engaged is the number of unique customers with whom Enel had at least an initial meeting. Meetings is the total number of meetings had with customers.

Table 6: 2023 Annual Recruitment Summary

Contacted Customers	Engaged Customers	Meetings
155	141	200

Table 6 shows the number of customers and capacity contracted. Contracted customers and capacity from late December 2022 are included in the 2023 results since the 2023 report is the first year published. Contracted customers is the number of customers who signed an Enel demand response order form agreeing to participate in one, or more, DR product. Contracted MWs is a sum of the number of MWs per site that were detailed on the Enel DR order form for all customers contracted.

Table 7: Contracted Customers and Capacity through December 2023

	PAC 60M	PAC 20M	PAC 7M	PAC RT	Total
Customers Contracted	15	22	4	4	45
MWs contracted	14.47	28.59	3.84	3.34	50.24

Recruitment through the end of 2023 was a significant success. The PAC 20M product was the most popular, with 22 customers signing up almost 29 MW. The product appeared to hit a “sweet spot” for customers. It offers a higher incentive than the PAC 60M peak shaving product, but as a reserve product, would likely be used for shorter curtailment events. Compared to the PAC 7M and RT products, the PAC 20M product is more attainable, because it does not have a minimum 500kw threshold, and customers can participate with manual curtailment rather than automation.

While customer interest in the PAC 20M product was an overall positive outcome, PacifiCorp paused further recruitment into this product in November 2023 for several reasons. First, PacifiCorp’s program design assumes a more balanced distribution of capacity across the four products. The Company wanted time to assess the potential implications of the unexpected concentration of capacity in the PAC 20M product, while minimizing any potential negative impacts to customers if the product is modified. In addition, in the second half of 2023, the Company started to identify potential challenges with utilization of the PAC 20M product in its primary use case, as regulation reserve (see **Event Performance** for further discussion). Following the pause in recruitment, Enel X continued to enable customers already contracted for this product. In addition, the resource remained available for dispatch, and PacifiCorp continued to monitor for opportunities to use the resource under the existing parameters. At the same time, PacifiCorp began to explore possible revisions to the product that would improve functionality for PacifiCorp, and be compatible with customer operations.

The second highest contracted DR product was the PAC 60M product, which is also expected as it is the simplest program to participate in due to the longer notification time, lower dispatch expectations and lower enablement burden. All customers contracted into the PAC RT product are contracted as dual-enrolled into either the PAC 20M or PAC 7M as well. The final results for the PAC 7M and PAC RT products does not represent a complete year of activities as recruitment was paused for these products while PacifiCorp and Enel X integrated dispatch capability for these products into the central grid management system. Therefore, the number of customers and capacity contracted may not accurately reflect the market response to the DR products.

2023 was the first full year of recruitment and the initial outreach revealed a few general trends about the customer base. First, participants who use conditioned spaces, or HVAC loads, to participate typically make up a much larger portion of a traditional summer peak-shaving demand response program, like the PAC 60M product. However, it was difficult to find participants with consistent available load for the duration of the product’s active hours, 3:00 PM to 9:00 PM. Many of the potential participants with conditioned space loads, including schools, colleges/universities, and offices set back their temperature settings too early, generally between 5 – 6 pm.

Second, potential updates to program design and implementation of the PAC RT, PAC 20M, and PAC 7M products impacted the recruitment effort as well. Initially, the PAC RT product had two options localized and centralized. The localized option was intended to be dispatched at the site level and responded to local grid frequency deviations. On further review, PacifiCorp’s energy supply management group indicated a strong preference to manage frequency on a system wide basis using a predictive algorithm that would dispatch all frequency resources at the same time. The localized option was ultimately removed, but after customers signed contracts to participate in this option of the PAC RT product. Work continues with these customers to help them better understand how often frequency events might be called with a system wide signal and whether they want to continue the enablement process.

During the 2023 program year, there was an extended period of defining and development work for the PAC RT product. Development of the platform integration began in 2023 but was not complete by the end of the year. Enel paused the recruitment process for the remainder of 2023 for the PAC RT product until dispatch capability was fully operational.

The PAC 7M product was designed during the RFP and negotiation process to qualify as contingency reserve capacity. However, to speed up the dispatch process and allow Pacificorp to qualify these demand response resources as contingency reserve capacity the location of executing a dispatch event was moved from the Enel Flex platform to the Pacificorp Energy Management System (EMS). The requirement to dispatch the PAC 7M product from the Pacificorp EMS was a requirement uncovered during 2023. The product development work for the PAC 7M product followed the same timeline as the PAC RT product. Additionally, Enel had originally expected non-emergency generators to be eligible capacity for the PAC 7M product. Pacific Power decided to exclude these resources in 2023, which reduced the potential market.

Enablement

The Enablement process is the set of activities that enable a newly sold customer site to participate in their respective DR product. Primary activities in this process include, but are not limited to:

- upgrade of the utility meter where required to enable connection of the Enel monitoring device, by installing a KYZ pulse board. Some customers, dependent on the DR product requirements may not be monitored by an Enel device.
- Installation and configuration of the Enel monitoring device to provide the customer with near real-time access to energy usage, as well as control signals for energy curtailment.
- Platform testing and validation to ensure data accuracy.
- Customer preparation including additional education, software training, and DR testing as a practice dispatch event.
- (As needed) Capital project management for customers who need significant changes/updates to their operation such as building management systems upgrades, etc.

PacifiCorp is responsible for procuring and installing the KYZ boards. A KYZ pulse allows the utility meter to communicate with the Enel monitoring device and provide near real-time energy demand data to the customer, utility, and Enel. Enel X oversees the remainder of the enablement process.

Once a customer is fully enabled and has completed a demand response test, they are ready for enrollment into the program. The enablement results for 2023 are summarized in Table 7 below.

Table 8: Enabled Customers and Capacity through December 2023

	PAC 60M	PAC 20M	PAC 7M	PAC RT
Customers Enabled	9	7	0	0
Sites Enabled	47	14	0	0
MW	7.91	5.03	0.00	0.00

Although it was not the most popular product, the PAC 60M had the highest rate of enablement. Since the PAC 60M product is a summer-only program, early 2023 was focused on enabling customers in that DR product to ensure the participants could participate for as much of the program season as possible. Additionally, the scarcity of KYZ pulse boards (discussed in more detail below) was not as prohibitive for the PAC 60M product as for the other three DR products. For smaller PAC 60M participants, typically below 200 kW, that generally have simpler end use loads and lower capacity nominations, and have an AMI meter, energy monitoring is not necessary. These participants were able to enroll in the PAC 60M product without the KYZ board or monitoring device, and Enel used AMI interval data to determine performance.

The higher enablement numbers in PAC 60M and PAC 20M also reflect the higher volume of customers recruited for those respective DR products. 2023 saw no enabled customers/sites in the PAC 7M and PAC RT products because the platform integration project discussed in the next section paused enablement for customers recruited to participate in these products.

As mentioned previously, an important factor impacting enablement generally in 2023 was the lack of available KYZ pulse boards, due to national supply constraints. It took the program nine months to procure meaningful quantities of the required KYZ pulse hardware. The initial order of KYZ pulse boards was submitted in January of 2023. The hardware began arriving in the second half of 2023, with the order not being completely fulfilled until the end of 2023.

The KYZ pulse install is completed by a PacifiCorp meter technician, and requires coordination across multiple units within at least three organizations – PacifiCorp, Enel and the customer. Initial pulse requests were hampered by poor communication, meter technicians declining to prioritize pulse installs over competing responsibilities, unexpected meter configurations requiring alternative equipment, and conditions on site that required special solutions. As requests for pulse installs increased in the fall and winter months, PacifiCorp program staff and Enel worked with meter technicians to document and share the program and device metering requirements, and establish a centralized control process for managing the workflow across organizations. In addition, the team developed solutions to execute customer meter setups in some less common configurations. Significant process improvements were made during 2023, but the initial learning curve resulted in lower enablement.

In addition to supply chain and installation delays, the platform integration work, detailed in the Flex Platform Development section below, delayed enablement in the same manner as recruitment.

Enrollment and DR Event Performance

Enrollment

Final enrollment represents the customers, sites, and MWs available for dispatch in each respective DR product at the end of the program year (December), or in the case of the PAC 60M product, end of the program season (September). There were no removals or lowering of enrolled MWs in the state of Oregon during 2023. Final enrollment is summarized in Table 8 by DR product, number of unique customers, number of unique sites, and number of MWs. Table 9 provides a customer breakdown by industry type. Final enrollment by product and site is represented geographically in Figure 1.

Table 9: Final Program Enrollment

	PAC 60M	PAC 20M	PAC 7M	PAC RT
Number of Customers	9	7	0	0
Number of Sites	47	14	0	0
MWs	7.91	5.03	0.00	0.00

Table 10: Enrolled Customers by Industry

	PAC 60M	PAC 20M	PAC 7M	PAC RT
Government	2	2	0	0
Education	1	1	0	0
Retail	2	0	0	0
Water and Sewage Services	1	0	0	0
Transportation and Storage	1	0	0	0
Other	1	1	0	0
Business and Consumer Services	1	0	0	0
Manufacturing	0	1	0	0
Metal Products Manufacturing	0	1	0	0
Energy and Utilities	0	1	0	0

Figure 1: Map of Pacific Power C&I Demand Response Enrolled Sites[1]

Enrollment trends match closely to the enablement results because 2023 is the first program year with enrolled customers. The underlying trends are the same as those discussed previously in the **Enablement** section.

<u>Event Performance</u>

PAC 60M Event Performance

A summary of all 2023 PAC 60M events are provided below. The available load varied from 1.8 to 7.7MWs and delivered MWs ranged from 1.4 to 5.0MWs. The highest performance of the season was during the June 24th event at 77.9%. The lowest performance was during the July 23rd event. Dispatch events ranged from one to three hours. Available and participating customers increased as the season progressed as enrollment increased. Overall, the program saw all events dispatched in the late afternoon and evening hours as expected coinciding with the Pacific Power summer peaking hours. Customers received a minimum 60-minute notice for all events.

[1] While this report discusses CIDR implementation in Oregon, Enel X manages CI DR in both Oregon and Washington. While this map includes sites in both programs, sites in OR are clearly delineated.

Table 11: PAC 60M Event Performance in 2023

Event Date	Jun-30	Jul-14	Aug-11	Aug-14	Aug-16
Notification to customer	10:01 AM	4:01 PM	3:01 PM	3:01 PM	2:01 PM
Event Start	5:30 PM	6:00 PM	5:00 PM	5:00 PM	4:00 PM
Event End	6:30 PM	8:00 PM	8:00 PM	8:00 PM	7:00 PM
Event Length (hrs)	1	2	3	3	3
Available Customers	19	47	47	47	47
Participating Customers	19	29	47	47	47
Available MWs	1.820	7.906	7.581	7.581	7.743
Delivered MWs	1.417	1.659	1.842	3.602	5.035
Performance %	77.9%	21.0%	24.3%	47.5%	65.0%

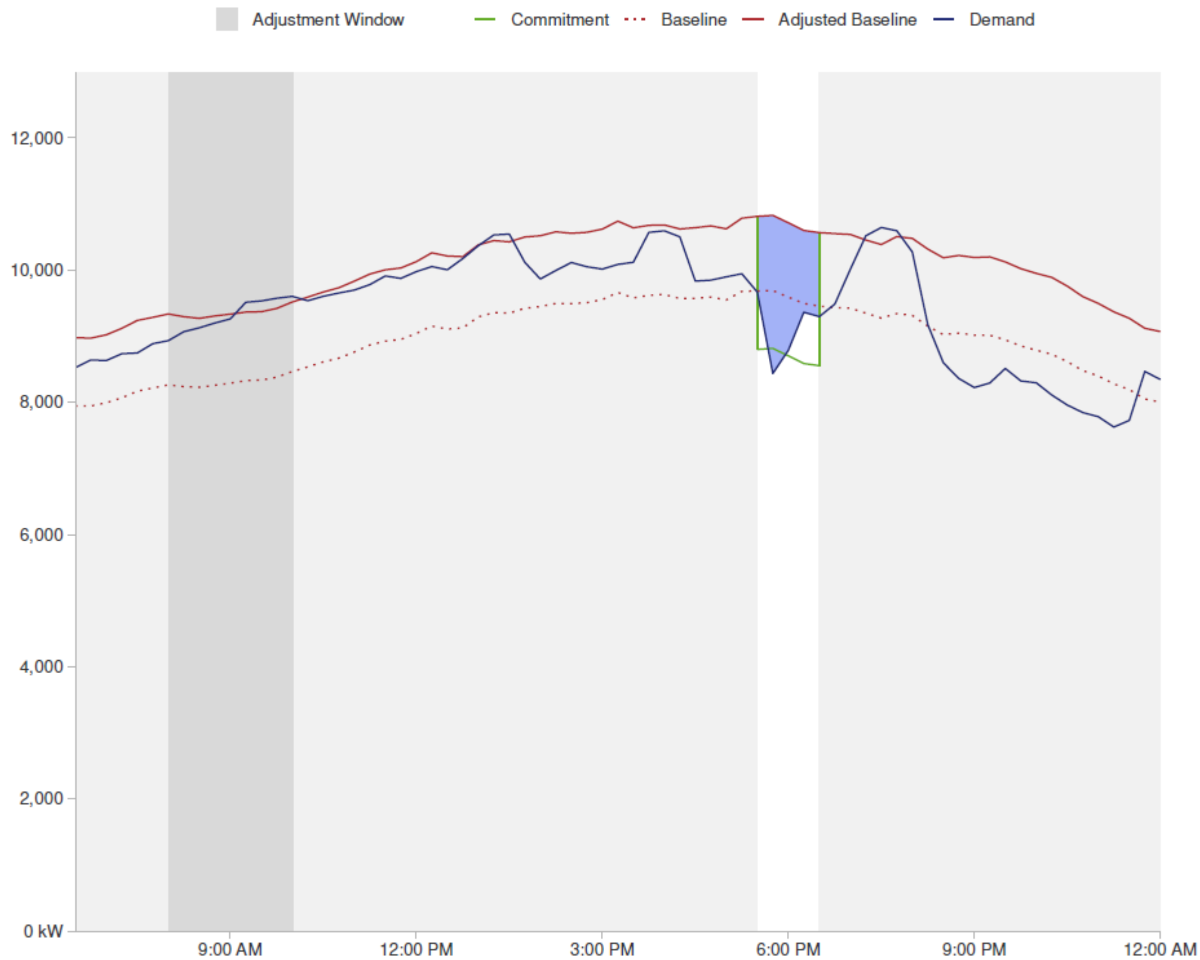
In general, the performance in 2023 was lower than expected. The main contributing factor was the lack of Enel devices installed at customers' sites due to the procurement and supply chain issues discussed in the **Enablement** section. Without installed devices, customers receive no real-time feedback via the Flex platform on how they are performing relative to their available load. When devices are installed, and streaming energy demand to the Flex platform, Enel can leverage this data to provide feedback to underperforming customers via email and SMS communications as well as contact customers via phone to coach them to better performance.

Another contributing factor is that 2023 is the first year of the program. Many of the customers are participating for the first time in a demand response program. Executing the customers' curtailment plan, providing a highly accurate available kW/MW load, and optimizing performance all require some learning to do well. This learning process likely explains the increasing performance for the three August events.

The higher performance during the June 24th event is likely due to the short event time. For longer events, customers' curtailment starts to taper as the event goes on and shorter events lessen that impact. A visual representation of the June 24th event is depicted in Figure 2. [2] The Commitment (green) is the portfolio's capacity obligation subtracted from the Adjusted Baseline for each interval during the dispatch event window. The Baseline (dotted red line) is the unadjusted baseline measured as the average of the four highest energy demand days of the previous five non-event business days. The Adjusted Baseline (solid red line) is a result of comparing the current day's demand during the Adjustment Window (dark gray region) against the Baseline and factoring it up or down accordingly. Demand (solid blue line) is an aggregation of all participants' energy demand.

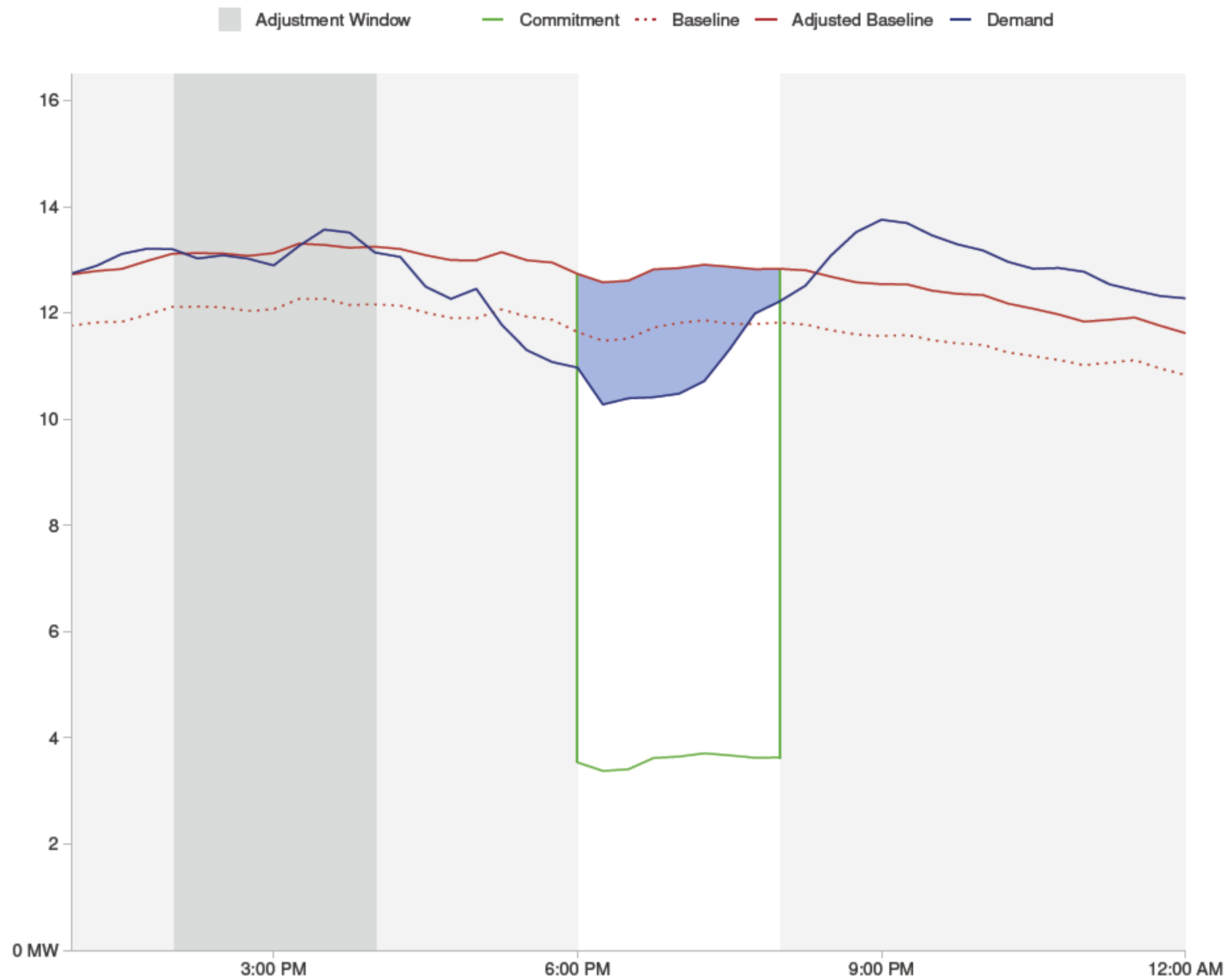
[2] Enel X and PacifiCorp developed the ESM scheduling capability to dispatch both Oregon and Washington resources simultaneously to manage grid needs at the balancing authority level. During the initial year of operation, the visualization provided included both states.

Figure 2: June 30th Event Performance Graph for Oregon and Washington



The July 14th event saw the lowest performance of the season at 21.0%. In addition to the general trends discussed above, one issue that caused low performance in this event was a platform error that failed to include 19 customer sites in the event. These customers were not notified of the event by the Enel Flex platform. Therefore, their energy demand during the event was not included in the delivered MWs for the program. This error was resolved after the event and did not repeat for the remainder of the season, nor is it expected to occur in the future. For incentive purposes, this subset of customers was not penalized and was credited full participation for this event. A visual representation of the July 14th event is depicted in Figure 3.

Figure 3: July 14th Event Performance Graph for Oregon and Washington



Visual representations of each August event are depicted in Figure 4, Figure 5, and Figure 6. Performance started low on August 11 but improved over the next two events.

Figure 4: August 11th Event Performance Graph for Oregon and Washington

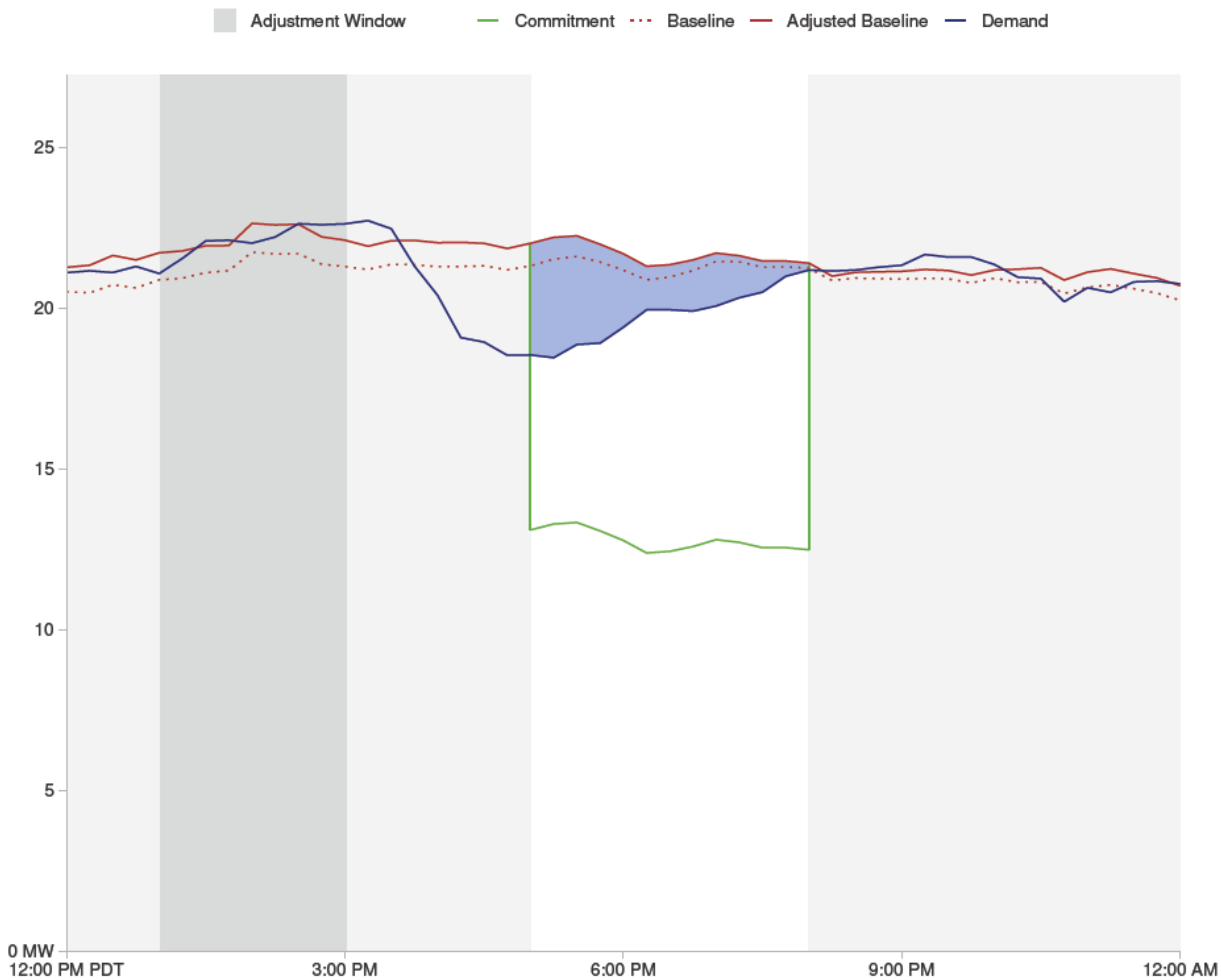


Figure 5: August 14th Event Performance Graph for Oregon and Washington

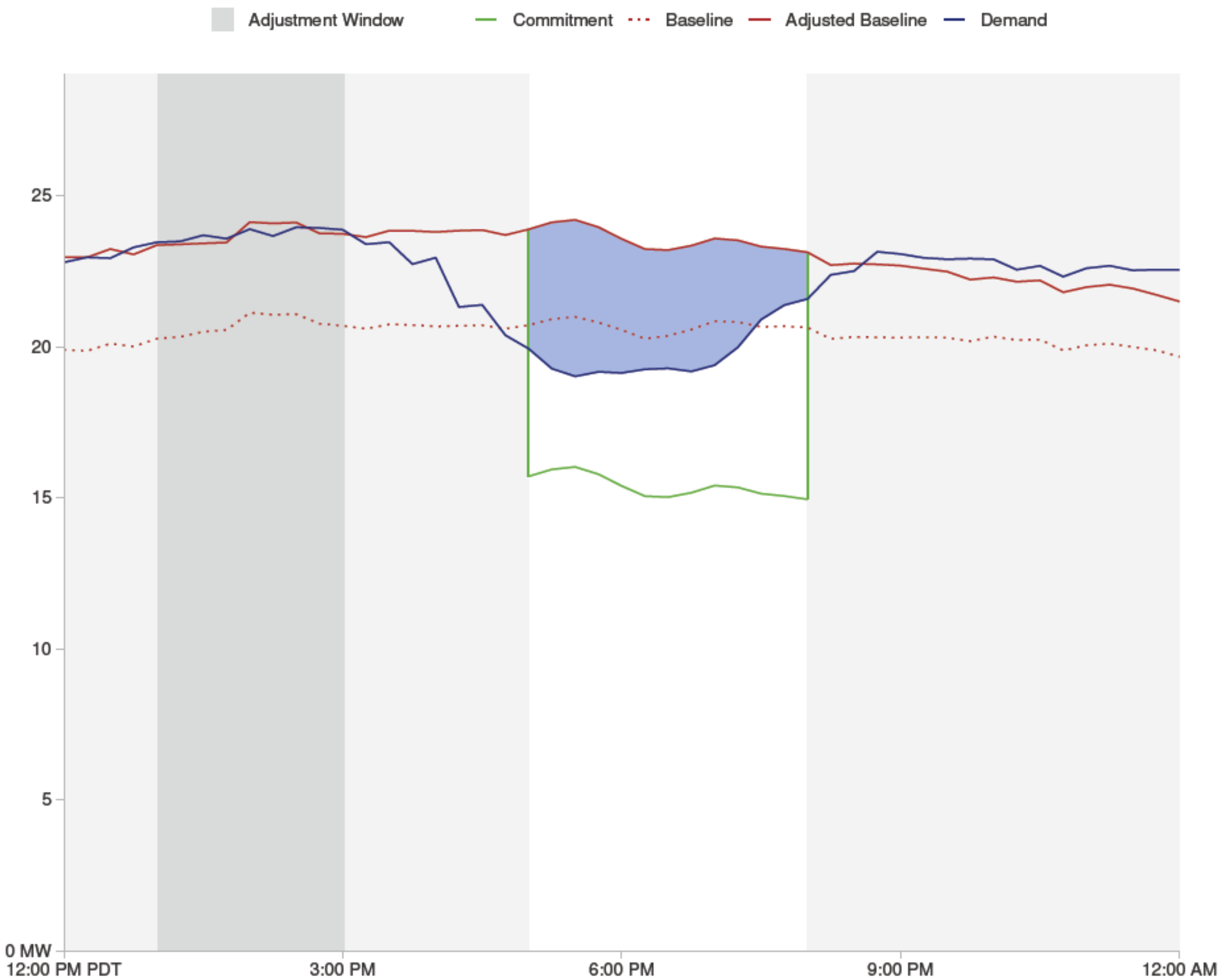
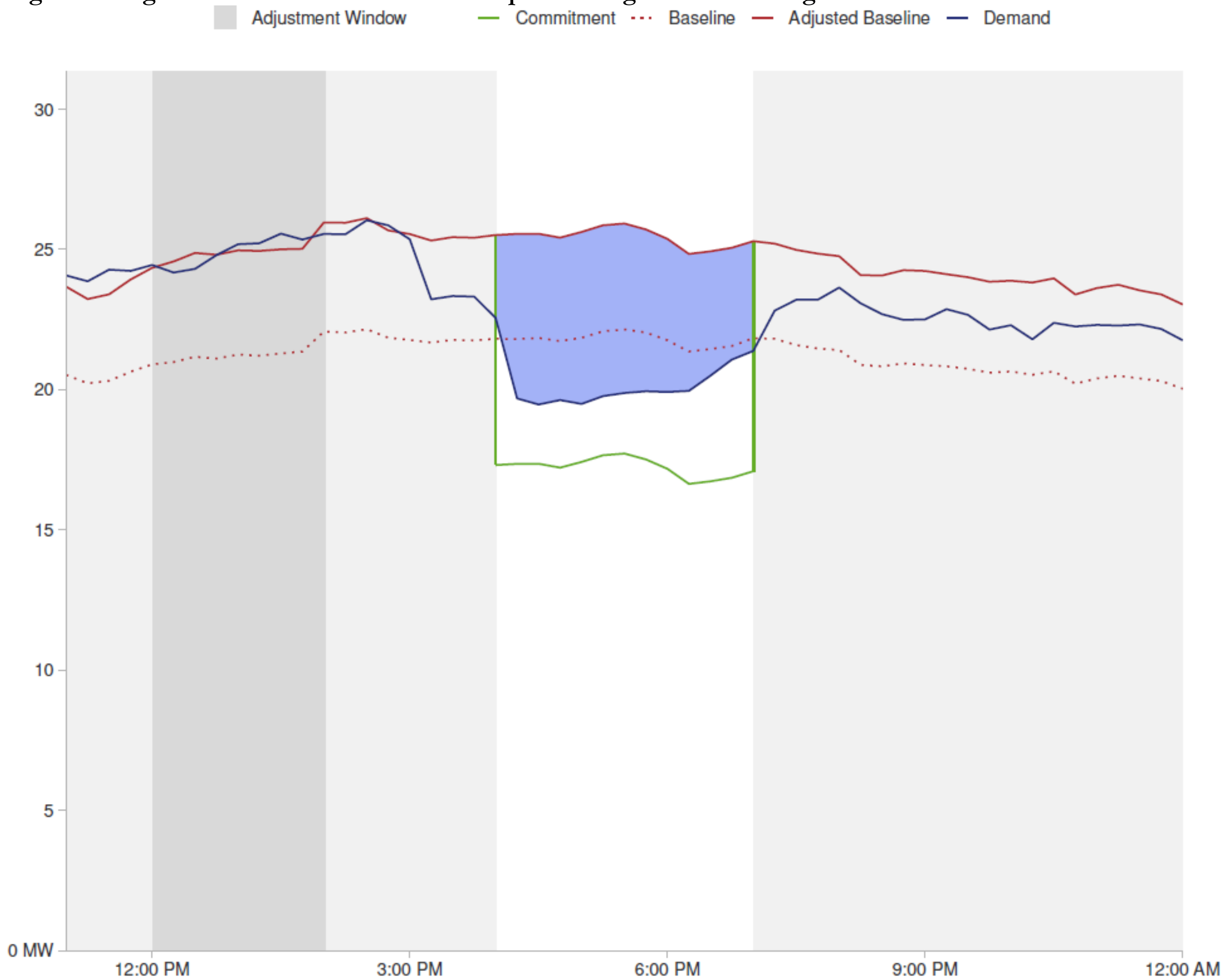


Figure 6: August 16th Event Performance Graph for Oregon and Washington



PAC 20M Event Performance

There were no dispatch events for the PAC 20M product in 2023. Customer loads were first available in August of 2023, and the DR product ended the year with 5.03 MW available.

The PAC 20M product was initially designed primarily as a reserve product able to respond inside the 30-minute response time allowed by the Control Performance Standard (CPS).[3] At the time, PacifiCorp anticipated a growing need for resources with this response capability. However, grid needs and available resources have been changing at a rapid pace since the product was designed in 2021. Throughout 2023, energy supply management staff had other resources available to maintain the CPS, including resources that could respond within 15 minutes. Energy supply management staff has a strong preference for resources available within 15 minutes to ensure they have time to implement a second recovery strategy if the initial strategy is not sufficient. Given this result for 2023, PacifiCorp is evaluating the potential for the PAC 20M to be utilized under BAL-001-2 in the future, other potential use cases for the existing product, and possible changes to the product that might improve the usability for 2024 and beyond.

PAC 7M Event Performance

The PAC 7M product had no available load during the 2023 program year, and therefore no dispatch events.

PAC Real Time Event Performance

The PAC RT product had no available load during the 2023 program year, and therefore no dispatch events.

[3] NERC Reliability Standard BAL-001-2. https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

Incentive Payments

Overview

Customers were issued incentive payments for each month in which they were enrolled. Enel issues a capacity payment in respect of each hour during the given month in the amount of the following:

- If there were no dispatch events within the month, the customer's available load during each hour of the month, multiplied by the DR product capacity payment rate for the respective month/hour, or
- If there were dispatch events within a given month, the customer's available load during each hour of the month, multiplied by the customer's event performance during the given time period, multiplied by the DR product capacity payment rate for the respective month/hour.

Incentive Payments for 2023

2023 customer incentive payments were issued in February and March of 2024 after all customer data was received, and performance was finalized. The delay for PAC 60M customer incentive payments was due to customer data acquisition delays due to occasional glitches in the new automated reporting system PacifiCorp established to support this program, and additional time needed to finalize performance measurement and verification. Similar delays in the future program years are not expected. Customer incentive payment amounts are summarized in Table 11 below.

Table 12: 2023 Customer Incentives by DR Product

DR Product	PAC 60M	PAC 20M	PAC 7M	PAC RT	2023 Total
Incentive Amount	$ 76,775.86	$ 110,393.25	$ -	$ -	$ 187,169.11

Incentive payments were highest in the PAC 20M product for multiple reasons. First, the PAC 20M product has a higher annual incentive rate of $55/kW. Second, the PAC 20M saw the most months with available load, from August – December, in contrast to just under four months for the PAC 60M product, which is only active in summer. Finally, incentive payments for the PAC 60M customers were adversely impacted by the low-performance trends discussed in the Event Performance section.

No incentive payments were issued to PAC 7M or PAC RT customers because there were no enrolled customers or available load during the 2023 program year.

Customer Experience

Motivations for customer participation in the Pacific Power C&I Demand Response program are multi-faceted. First, it is an opportunity to earn revenue. Participating in the Pacific Power C&I Demand Response program opens up additional revenue streams not previously accessed. Second, the Enel energy monitoring device provides near real-time and historical insight into energy demand. Customers are able to leverage this data to reduce their energy use overall, and lower costs on goods and operating expenses. Less money spent on operating increases revenues and allows for additional opportunities. However, customers participate for other reasons outside of financial incentives.

Supporting a community is a significant motivator. Customers continue to see the impacts of constrained grid conditions and are driven to be good community partners during those times. Related to community support is sustainability. A majority of customers now have corporate sustainability goals. Enel and Pacific Power help customers achieve those goals through demand response participation. One trend not as prevalent in the Pacific Power program as in others is operational reliability. Many customers engaged during recruitment have not, or rarely experience outages. If a customer has not experienced outages, then the motivation to prevent them is not as impactful.

While 2023 recruitment was a success, customers did provide some feedback. Customers appeared to be impacted by the initial learnings the program went through during its first full program year. Delays to enablement, changes to DR product use, and delays to payments negatively impacted customers. The extended gap between a signed contract and installation work at the customer's site negatively impacts a customer's trust and motivation to participate in the program. With some customers, after the enablement process was able to resume, it required some re-education on the program and how it works. Customers who contracted for the PAC RT product also required re-education when the product options changed. The recruitment team was required to revisit all customers who signed contracts for the PAC RT product and determine if the customer was still interested and could meet the dispatch requirements of the DR product.

The other area of customer feedback was the delay in performance results and incentive payments. The delays in acquiring customer interval data and finalizing performance negatively impacted the customer experience during the program season. Enel was unable to provide feedback to all participants on their performance between dispatch events in the PAC 60M product. Providing performance feedback during the inter-event period is critical to improving customer performance within the program season. These delays also resulted in customers contacting Enel to inquire about when they should expect incentive payments. Enel planned to issue incentive payments within the 2023 calendar year, but the causes discussed in the Incentive Payments section delayed the payments until Q1 of 2024.

Flex Platform Development

Flex Platform

The Enel Flex platform provides various resources to all demand response participants. All participants can view their past event performance, historical earnings, manage their capacity obligations and other aspects of their enrollment. Customers with an Enel monitoring device are able to view their real time and historical energy demand anytime. They can also monitor their real-time performance during a demand response event. The Flex platform provides this wide range of functionality while utilizing robust cyber security controls.

The Flex platform enables Enel, as the demand response service provider, to implement demand response programs on behalf of Pacific Power by aggregating a heterogenous portfolio of participants into a single demand response resource. It allows Pacific Power to create, edit, monitor, and review demand response events across all DR products. The Flex platform allows the utility to view near real-time energy demand at multiple levels from site to program level for the utility. During a demand response event, the platform enables Enel to notify participants according to their preferences, optimize performance by synthesizing real-time data, and provide feedback and coaching to all participants.

The creation of a demand response event in the Flex platform is a manual process which allows Pacific Power the flexibility of selecting various event parameters. However, tor the PAC 7M and PAC RT products, this manual process is not fast enough. To meet PacifiCorp's need for faster response, Enel developed an open market interface, which PacifiCorp IT staff integrated to PacifiCorp's central energy management system (EMS).

PacifiCorp Open Market Interface

Overview

During the 2023 program year, Enel, Pacific Power, Rocky Mountain Power, and PacifiCorp collaborated to develop an open market interface between Enel's Flex platform and the PacifiCorp EMS. The PacifiCorp open market interface is an API endpoint that provides PacifiCorp a robust, always available, low-latency solution to self-create and end demand response events. The initial purpose was to provide a software solution configured to curtail loads within 30 seconds of Enel receiving an automated dispatch signal from PacifiCorp via the PAC RT product. During the requirements gathering process, the scope was expanded to include dispatching the PAC 7M product as well. PAC 7M product was changed to this dispatch mechanism to reduce the time required to dispatch the DR product and satisfy contingency reserve capacity requirements.

For the PAC RT product, the open market interface enabled PacifiCorp to automate demand response events and satisfy the BAL-003 requirement for tertiary frequency response. An automated signal is sent from the PacifiCorp EMS, the signal is processed in the Enel Flex platform, a demand response dispatch event is created with start time, end time, selection of customers, performance expectations and reporting via the Enel Flex platform. Then communications are sent to the participating customers within 30 seconds of Enel's receipt of the signal.

For the PAC 7M product, the open market interface enables PacifiCorp to use the Pacific Power available load as contingency reserve capacity. A manual signal is sent from the PacifiCorp EMS to create a demand response event for seven minutes from the current time and automate the creation of a demand response dispatch event is created with start time, end time, selection of customers, performance expectations and reporting via the Enel Flex platform, and communications to participating customers.

Timeline

The initial investigation into this product solution began in February 2023. Several alternatives were explored such as using different communication protocols, user software interfaces, and reporting requirements. The scope and technical approach of the project was agreed upon in June. From there, specific business requirements for each functional area of the open market interface began. After discussions between Enel and PacifiCorp, the requirements were agreed upon in September. At this point Enel and PacifiCorp's IT team began platform development work in parallel. Development work for the testing version of the integration took place in October. After testing was complete Enel and PacifiCorp completed the final development work and released the integration in December. Development tasks including the user interface configuration and end date updates continued into the 2024 program year.

Conclusions

2023 was a critical learning year for the Pacific Power C&I Demand Response program. It was a year of launching four brand new C&I demand response products, where none existed prior. This first year of experience resulted in a strong start to building demand response capacity in the C&I sector, as well as several lessons learned that can improve implementation in future years. The recommendations for 2024 are:

1) Maximize the capacity resource with Enel monitoring equipment. Enel's experience in other markets shows that when customers and Enel have access to near real-time energy demand data program performance and customer experience significantly improves.
2) Focus on shortening the performance and settlement feedback loop. 2023 provided the program team the ability to experience a full program year from enrollment to incentive payments, as well as establish processes and procedures for data acquisition, data validation, and measurement and validation. The program can now shift to improving the time it takes to execute these tasks.
3) Review and refine the use case for the 20-minute product, and potentially revise product characteristics.
4) Leverage the centralized enablement control process. After overcoming supply chain issues for KYZ pulse boards and developing a standardized process for installation, Enel and Pacific Power should focus on utilizing this process to improve collaboration between organizations and drive down the time required from customer contracted to initial enrollment date.

Appendix 2: Cost Effectiveness - Benefits and Costs Discussion

This Appendix provides discussion of the costs and benefits of the 2023 CI DR program year. As the Company does for its other demand response programs, PacifiCorp applied the California Public Utilities Commission Distributed Energy Resource Avoided Cost Framework ("Framework") as a guide when conducting the program year retrospective analysis.

For the retrospective cost-effectiveness analysis for the 2023 program year, PacifiCorp assessed the cost effectiveness of each product that had enrolled capacity in 2023, and the program as a whole. Only the PAC 60M product was involved in events in 2023, and therefore benefits were only allocated to this product. Capacity amounts per dispatch were based on the 2023 average load reduction, adjusted for line losses. Benefits were calculated using a 10 year levelized benefit of the program based on the capacity dispatched and actual energy prices in 2023. Total dispatched events for the levelized benefit in 2023 are based on 2023 actual dispatched hours and actual peak prices during 2023, using EIM scalar prices. Beyond 2023, a convergence of program availability hours and peak prices were used to simulate dispatch for the levelized benefit.

Delivery costs included customer recruitment and enrollment, all software and integration services, dispatch notification, calling events on behalf of PacifiCorp, and monitoring and coaching of participants, data tracking, incentive analysis and delivery, and reporting. PacifiCorp internal costs included contract oversight and program management, as well as procurement and installation of KYZ pulse boards at participant meters.

Participant costs represent the value of service lost, transaction costs, additional management, and other costs that participants might experience as a result of enrolling and participating in the program. These costs are highly variable across participants and are difficult to observe or measure. At the same time, the fact that participants are willing to participate in the program provides some evidence that the maximum participant cost is some value less than the direct benefit they experience. Using this assumption, PacifiCorp modeled participant costs as 75% of participant incentives.

The TRC ratio for Oregon CIDR in 2023 was 0.44. Detailed cost-effectiveness results for 2023 are shown in Table .

Table 13. Summary of 2023 Retrospective Cost-effectiveness Results

Parameter	CIDR 2023	PAC 60M	PAC 20M
Avg. Curtailed Load (MW)*	3.24	3.24	0
Total Avoided Costs	$213,929	$213,929	$0
Incentives	$187,169	$76,776	$110,393
Delivery	$96,394	$58,924	$37,470
EM&V Costs	$0	$0	$0
Pulse meter installment/upgrade costs	$182,078	$140,290	$41,788
PacifiCorp Internal Costs	$65,116	$39,804	$25,312
Participant Costs **	$140,377	$57,582	$82,795
Utility Cost Test	**0.40**	**0.68**	**0.00**
Total Resource Cost Test	**0.44**	**0.72**	**0.00**

In 2023, cost-effectiveness was negatively impacted by several factors that will likely diminish going forward. Avoided costs were reduced because the curtailed load (3.24 MW) was significantly less than enrolled load (12.94 MW). In the PAC 60M product, this was in part due to poor performance by new participants, and in part a result of a large proportion of capacity coming online later in the year, after all the curtailment events for 2023 had taken place. Both of these impacts are related to supply chain delays in 2023. Because the KYZ pulse boards needed for monitoring were unavailable for much of the year, many of the customers that participated in 2023 did not have real-time visibility of their load. As a result, they were less able to control their performance during events. Going forward, a greater proportion of participants will have KYZ pulse and other monitoring equipment installed, and will have better visibility and control. Also, in 2024 the program will be actively working to enable the backlog of capacity contracted in 2023 that chose not to participate without monitoring equipment installed (over 37MW). A significant proportion of new capacity in 2024 should come on earlier in the year and, together with existing capacity from 2023, have more opportunities to participate in an event.

PacifiCorp also expects pulse equipment costs to decline in 2024. PacifiCorp included all KYZ procurement completed in 2023 as a 2023 cost; however, less than half of the inventory the Company has purchased had been installed by the end of 2023. The remainder will be installed in 2024, but without impacting the 2024 cost-effectiveness. Although this is a major cost item in 2023, that is more a result of other values being unusually low. Going forward KYZ procurement should be a minor line item relative to other costs and benefits regardless of what year it is claimed.

For the PAC 20M product, no benefits are incorporated because there were no curtailment events in 2023. Additionally, in the original program filing, PacifiCorp included reserve benefits expected to accrue from registering this product in the CAISO EIM market. PacifiCorp did not complete this registration in 2023, and therefor CAISO EIM reserve value benefit is excluded from the analysis.

Below, is a summary of each of the components using in the calculation of benefits for the program. The benefits used in the for this analysis generally follow guidelines outlined in the California Public Utility Commission (CPUC) 2016 DR cost-effectiveness protocols, where applicable. The following information is used for valuation of demand response benefits:

1. *Avoided Generation Capacity Costs*

The Company relied on the most recent approved generation capacity deferral values from OPUC docket UM 1893[4]. The avoided generation capacity benefit is spread across the hours of dispatch and then adjusted for the estimated capacity contribution. The C&I program's estimated capacity contribution is assumed to be equivalent to a 3-hr annual demand response resource in the 2021 IRP.

2. *Avoided Energy Costs*

For the purposes of this report, energy value is reported based on the amounts shed, relative to the prior day baseline, without any adjustments related to shifting. For the 2023 valuation, the value of avoided energy is based on the avoided energy during event hours, with the hour-ahead, value being reflected in the market capacity estimate as it was the only product dispatched in 2023.

Avoided energy during event hours for 2023 is based on Energy Imbalance Market 15-minute market prices for PacifiCorp West, blended using the same values applied to qualifying facilities and adopted in the Resource Value of Solar proceeding. Because energy volumes reflect metered loads, it is appropriate to account for the value of avoided line losses that would otherwise have been incurred to serve those loads.

3. *Avoided Transmission and Distribution Costs*

Assigning transmission and/or distribution deferral value(s) to load management is consistent with the Company's IRP, the Northwest Power Planning and Conservation Council's 7th Power Plan and Oregon's Resource Value of Solar (UM 1910). Similar to generation capacity deferral values, transmission and distribution deferral values and their application in this analysis are derived from the most recent approved avoided cost values in UM 1893. These values are adjusted to reflect the expected capacity contribution of a 3-hr annual demand response resource in the 2021 IRP.

4. *Line Losses*

For valuation purposes, the hourly line loss factor methodology developed for the Oregon GRC was used, based on a 2018 study. The value of avoided line losses is included in avoided energy and capacity costs. Avoided line losses are based on the average energy loss factors for

[4] State of Oregon: Public Utility Commission of Oregon

commercial and industrial customers in Oregon, as applied in the 2018 Line Loss Study. Avoided losses represent a roughly 6.95 percent increase in savings.

5. *Adjustment Factors (based on 2016 CPUC CR protocol).*

Notification Time (B Factor)
Avoided costs are discounted depending on notification time to account for visibility and foresight into system need. Often the need for DR is based on conditions (particularly weather), which can change in the course of 24 hours. The longer notification of an event the less predictable the conditions driving an event need are. As a result, the Company makes the value discounts to avoided cost to reflect this logic.

Table 14 Factor B Adjustments

Notification Time	**B Factor**
30 minutes or less	100%
Day Of, greater than 30 minutes	94%
Day Ahead or greater	88%

In 2023, the program had notification times of hour ahead, 20 minute ahead, 7 minute ahead, and real time. As previously mentioned, on the hour ahead product was called upon in 2023.

Trigger (C Factor)
The C factor accounts for the triggers or conditions that permit the Company to call each DR program. In general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions. Therefore, an adjustment should be determined so that programs with less flexible triggers can be de-rated. For programs with limited flexibility the avoided costs are derated by 5%.

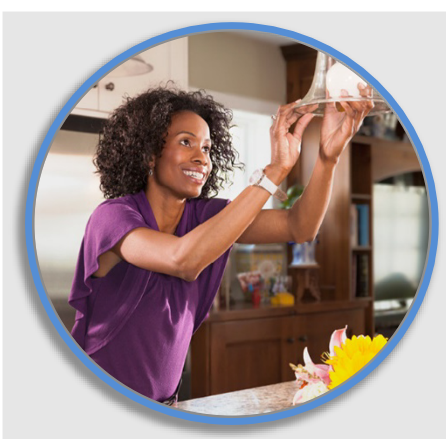
Irrigation load control events can be called at the discretion of utility (within the specified months, weeks, days, hours). The 2023 events were triggered by a forecast for higher than typical power prices for the super peak period. In addition, hot weather was forecast for the period.

RESIDENTIAL
DEMAND RESPONSE PROGRAM

Optimal Time Rewards Program in Oregon

2023 Annual Report

Issued April 1, 2024



PACIFIC POWER
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Overview

This report provides a description of start-up activities in 2023 for the Optimal Time Rewards program which was approved on May 16, 2023.[1] Because PacifiCorp did not complete system development until the end of the year, there was no engagement with customers, enrolled load, or curtailment activity in 2023. As a result, there are no key findings regarding program effectiveness. Information on program performance and effectiveness will be provided in the 2024 annual report.

Program Parameters/Design

Optimal Time Rewards (OTR) is a demand response program targeted to the residential sector, enabling aggregation of electric water heater and heating and cooling loads. OTR is part of an overall equity approach by PacifiCorp to make demand response programs available to all customer classes. Participants receive an immediate benefit in the form of an incentive. The availability of flexible load benefits all customers including non-participants by reducing costs of utility operations. The program focuses on water heaters in multi-family buildings and smart thermostats controlling compressor-based cooling and/or heating equipment in single-family homes. The program requires installation of a WiFi-enabled control device to enable monitoring and control of electric water heaters. Smart thermostats are controlled through integration with manufacturers' cloud-based software platforms.

PacifiCorp selected OATI and their partner Armada Power to implement this program. OATI and Armada Power are responsible for the aggregation of smart thermostats using the capabilities of the equipment manufacturer software; directing customers to existing online technical resources to assist with installation of new thermostats; installation, operation, and maintenance of the load control devices on water heaters; enabling dispatch of the devices as directed by the PacifiCorp ; managing enrollment and customer participation; customer service; and issuing customer incentives.

To aggregate smart thermostats, OATI contracts directly with four original equipment manufacturers (OEMs): Google Nest, ecobee, Honeywell (Honeywell Home and Honeywell Total Connect Comfort brands), and Copeland Sensi. Armada Power installs its own proprietary device on electric resistance tank water heaters, and uses a SkyCentrics device to connect CTA-2045 enabled heat pump water heaters.

Customers earn incentives for both enrollment and continuing annual participation for both the water heater option and the smart thermostat option. Table 1 shows the available incentives for each device enrolled.

[1] See Oregon Public Utility Commission Advice No. 23-010. Available online: ADV 1496 23-010 PAC Eff 5-17-23 filed 4-11-23 CA2_encrypted_.pdf (state.or.us)

Table 1. Customer Incentives

Device	Enrollment	Annual Participation
Water Heaters		
Property Manager – multi-metered or single-family	$5	n/a
Tenant – multi-metered or single-family	$20	$25
Property Manager – master metered	$25	$25
Smart Thermostats	$50	$25

PacifiCorp energy supply management staff will have access to curtail the aggregated load from enrolled devices as needed to support system operations. Key dispatch parameters approved by the Oregon Public Utility Commission are shown in Table 2.

Table 2. Key Dispatch Parameters for OTR

Device	Requirements
Water Heaters	
Notice Time	None
Dispatch Period, Days and Times	Anytime
Frequency	Maximum 1 event per day, 2 events per week
Duration	Maximum 2 hours
Smart Thermostats	
Notice Time	20 Minutes
Dispatch Period, Days and Times	Year round, weekdays, 12 pm – 9 pm
Frequency	Maximum 1 event per day, 3 events per week, 30 events per year
Duration	Maximum 4 hours

2023 Activities

During 2023, OATI and its partner Armada Power worked with PacifiCorp to finalize details of the program design. The OATI team also developed the software infrastructure for the program, necessary legal and operational resources, marketing plans and materials, and contributed to regulatory approval and stakeholder engagement activities.

Software Customization

OATI completed significant software customization efforts in 2023, including identifying user requirements , coding, and implementing customization of existing OATI systems to enable both smart thermostat and water heater demand response operations.

Software development efforts included many changes and customizations within the OATI webSmartEnergy DERMS system in order to meet PacifiCorp's system use requirements. For example, OATI added a system enhancement to receive, store and apply data exports from PacifiCorp's customer database to automatically validate incoming enrollments.

OATI's software customization efforts included successful integration, including setup, configuration and testing, with the following demand response headends (and the communication type for each):

- Google Nest Smart Thermostat (REST API)
- ecobee Smart Thermostat (REST API)
- Honeywell Home Smart Thermostat (REST API)
- Honeywell TCC Smart Thermostat (REST API)
- Emerson/Copeland Sensi Smart Thermostat (REST API)
- Armada Power Water Heater Control (REST API and SFTP)
- SkyCentrics CTA-2045-compatible Water Heater Control (OpenADR)

During 2023, PacifiCorp determined the internal timeline to enable two-way OpenADR integration with demand response resources on the PacifiCorp enterprise distributed energy resource management system (DERMS) would be extended. Absent this capability, OATI was not able to integrate their platform with the DERMS to allow PacifiCorp energy management staff control of the demand response resources. PacifiCorp and OATI identified an alternative approach, by granting PacifiCorp staff direct access to OATI's cloud-based platform, and creating special program-specific interfaces. This additional programming work extended the timeline, but could occur on a parallel track with other start-up activities and was the shortest path to a fully operational software platform.

OATI conducted significant and repeated testing on all functionalities of the PacifiCorp customization of its webSmartEnergy DERMS system throughout project development. OATI also conducted formalized internal testing of integrations and DERMS functionalities. OATI's formal internal system testing for smart thermostat functionality commenced on September 18, 2023. Formal internal system testing for water heater functionality commenced on October 1, 2023. Testing for both continued into 2024.

Development System user credentials for PacifiCorp grid operatives were created on October 23, 2023. Development System access was granted in 2024.

Go-Live planning and testing was substantively complete by the end of 2023. Go-Live occurred in 2024.

Creating Operational Resources

In 2023, OATI configured reporting on enrollments, events, and availability forecasting generated from the webSmartEnergy DERMS system based on PacifiCorp's requirements. The availability forecasting is created in coordination with Armada Power, and is calculated internally for the Smart Thermostat headends and SkyCentrics. OATI facilitated the creation of Terms and Conditions for both Smart Thermostats and Armada Power. The substantive creation of the Terms and Conditions was conducted by PacifiCorp and Armada Power legal teams with a focus on customer consent and data protections.

In coordination with PacifiCorp, OATI ensured that all necessary documentation was provided to the Smart Thermostat headends including final versions of the Terms and Conditions, and documentation of cyber security and program parameters.

Marketing

PacifiCorp developed the program website, with pages targeted to residential customers (focused on the smart thermostat option) and to property manager (focused on the water heater option). PacifiCorp also worked with the OATI team to develop a detailed Frequently Asked Questions (FAQ).

To manage to program cost-effectiveness, OATI and PacifiCorp planned to rely on the free, targeted messaging provided by the OEMs for smart thermostats. For water heaters, the primary outreach channel is direct marketing to property managers. Armada Power developed a marketing strategy, materials for distribution, giveaway and engagement collateral, and outreach planning for potential water heater host communities, community residents, and single-family home participants. These materials were reviewed by both OATI and PacifiCorp and ultimately approved for print and distribution by PacifiCorp.

Armada Power utilized these marketing materials while leveraging existing resources for conducting outreach to property managers. In 2023, this comprised of messaging and collateral being sent to over 100 of the largest property managers in Oregon with buildings in the PacifiCorp territory to build initial program awareness, including available incentives. Several property managers responded with initial indications of interest and were scheduled for follow-up calls.

2023 Program Costs

Program costs in 2023 included costs for administration, program delivery and marketing. The total costs are shown in Table 3.

Table 3. 2023 Program Costs

PacifiCorp Administration	$22,731
Delivery	$242,137
Marketing	$9,060
Total	**$273,927**