PACIFIC POWER
A DIVISION OF PACIFICORP

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March 29, 2019

VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: Advice 16-04—Compliance Filing—2018 Report on Pacific Power's Irrigation Load Control Pilot Program

PacifiCorp d/b/a Pacific Power submits the attached 2018 Irrigation Load Control Pilot Program Report. The report is provided in compliance with the terms of PacifiCorp's Irrigation Load Control Pilot Program that was approved by the Public Utility Commission of Oregon on May 4, 2016.

Pacific Power 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, Suite 2000
Portland, OR 97232

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

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

2018 Irrigation Load Control Pilot Program in Oregon

Issued March 29, 2019

PACIFIC POWER
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Overview

PacifiCorp has operated an irrigation load control program in Idaho since 2003 and in Utah since 2007. These voluntary direct load reduction programs allow PacifiCorp to better manage summer peak loads by providing incentives to customers that allow the company to interrupt their irrigation service under certain conditions.

On May 3, 2016, the Public Utility Commission of Oregon (Commission) approved PacifiCorp's d/b/a Pacific Power request to implement a pilot irrigation load control program for customers within the Oregon portion of the Klamath Basin. The Irrigation Load Control Pilot Program (pilot program) was filed to test the design characteristics of the company's existing irrigation load control program for its Oregon customers.

In 2016, the pilot program focused on enrolling a small number of initial participants, testing and related logistics and one two-hour event was called during the season. In 2017, the focus was on maintaining engagement with enrolled growers, increasing the number and duration of events during the season, and seeking updated market pricing for program delivery beyond the 2017 season.

In 2018, PacifiCorp focused on transitioning the program to the new delivery provider, Connected Energy. Selection of this firm was the result of the competitive procurement process described in the 2017 report.

This report summarizes 2018 pilot program activity and presents the key findings from the third program year. In its pilot program application, PacifiCorp identified key elements that would be provided annually. The following table describes where each of these elements is addressed in this report:

Element	Start Page	Section
1. Review of annual enrollment		
a. Total program enrollment	18	Enrolled Customers
b. Sites added and removed	18	Enrolled Customers
c. Customer outreach	9	2018 Activities …Challenges From 2017
d. Crop(s)	19	Customer Crop/ Operations and Pumping Equipment
e. Weather data from local weather station(s)	20	Weather and Drought Impact
f. Available information on water restrictions	20	Impact of Irrigation Technology and Water Availability
2. Customer satisfaction a. Customer requests for retirement b. Site reassignment management	5	Participant Behavior *There were no customer requests for retirement or reassignments in 2018
3. Incentive payments	18 31	Customer Payment Structure Appendix B: Customer Payments
4. Review of annual program performance		
a. Weekly available load reduction	23	Available Load Reduction
b. Load control events	24	Load Control Events
c. Availability and load reduction comparison	8	Availability
5. Key observations	5	Key Findings

In 2018, the same small group of customers participated as in 2017. The existing EnerNOC-provided switches were replaced with Connected Energy-provided switches as part of the transition to the new delivery provider. Ongoing efforts were made to enroll the one customer with medium voltage equipment that was identified but not enabled during the prior seasons. Four events were called in August of 2018: three three-hour events and one four-hour event for a total of thirteen event hours. Key findings from 2018 focus on participant behavior, event logistics and transitioning customers to the new provider.

Key Findings

Participant behavior

Grower interest and engagement was maintained between the second and third year of the pilot and the transition to the new provider. The small number of initial participants remain engaged and willing to participate in 2018 even when being asked to sign replacement participation agreements and have replacement switches installed on their equipment. The 2018 program year included four events. Three events were called in one week, which provides additional insight into the propensity for growers to opt out of events. The growers participated in all events and fulfilled their commitment to curtail irrigation usage. Similar to the 2017 season, participants did not indicate concerns about water availability for the current season.

Logistics

The 2018 events were three or four hours and in close proximity to each other; Monday, Wednesday, and Friday of the same week and further support the learning from prior years indicating the resource (kW available for load control events) can be ramped up quickly and is reliable with an experienced delivery provider and an engaged grower community. Elapsed time between contract signing and completed transition for existing customers (new participation agreements and switches installed) was comparatively fast.

Event notification was successful and customers participated when called (i.e., did not opt out of events). Event information including baseline, load curtailed, and post event load was successfully captured by program devices and the network operations center. Data on connected load for these sites during the irrigation season were also transmitted from the devices and archived at the network operations center. During the final event, the full amount of load was not curtailed. Investigation discovered that the curtailment relay was not properly wired upon installation and the customer was manually curtailing the load which masked the installation problem until the fourth curtailment event, where the customer did not manually curtail the load. Wiring corrections were made within days of discovering the problem.

Delivery Costs

PacifiCorp negotiated a new delivery contract with Connected Energy in 2018. The new delivery contract replaced the Oregon portion of the EnerNOC delivery contract utilized for the first two years of the pilot. The updated delivery pricing was more aligned with the smaller focused efforts inherent in this pilot and utilizes a combination of fixed pricing for infrastructure and unit pricing for equipment installations. This is a change from the pricing structure in the prior contract, which subsequently proved not to be sustainable for the delivery provider (a key learning reported in the prior reports).

Assessing Costs and Benefits

The pilot program is intended to test designs, provide market feedback, and generate information about delivery. PacifiCorp continues to monitor the pilot costs and potential benefits to understand the feasibility of expansion or alternate delivery models in Oregon beyond this initial pilot phase.

Appendix 2 provides a discussion of potential benefits and initial findings related to the pilot objectives, including a discussion of potential benefits utilizing demand response cost-effectiveness protocols from California.

Background

The pilot, filed as Advice 16-04 was approved by the Oregon Public Utility Commission on May 3, 2016 and has operated for three growing seasons. Activities in the prior two seasons were outlined in the annual reports filed on March 31, 2017 and March 30, 2018. On May 1, 2018, PacifiCorp filed the 2017 Integrated Resource Plan update and included the potential impacts of the irrigation load control pilot program[1]. The 2018 timeline of key program activities is outlined below.

2018 Timeline

April 24	EnerNOC program transition letter (and follow-up phone calls) to existing customers.
May 22	New contract signed with Connected Energy
June 4	Website message updated to 2018 season offer
July 26	New switch installations complete
August 6	Event notification to participating customers for August 7 event
August 7	Four hour event conducted between 4pm-8pm, Pacific time
August 10	Event notification (Friday) to participating customers for August 13 event (Monday)
August 13	Three hour event conducted between 5pm-8pm, Pacific time
August 14	Event notification to participating customers for August 15 event
August 15	Three hour event conducted between 5pm-8pm, Pacific time
August 16	Event notification to participating customers for August 17 event
August 17	Three hour event conducted between 4pm-7pm, Pacific time
August 17	End of regular season (mandatory events)
September 30	End of season (including voluntary event window). Season end communication to participating customers
January 2019	Incentives paid to participating customers

Anticipated Pilot Size

PacifiCorp's 2015 IRP helped inform the 3 MW size of the pilot program. Year 3 (2018) availability was comparable to prior years, which is consistent with having the same set of customers and equipment enrolled over the three year period. The primary focus in 2018 was to complete a successful transition between the outgoing and new delivery provider.

Anticipated Duration

PacifiCorp proposed a five-year pilot period to provide sufficient time to test a variety of parameters and align with grower input favoring a multi-year program.

[1] 2017 Integrated Resource Plan Update, Table 4.4, page 34.

Program Parameters/Design

Participation in the Pilot Program requires irrigators to allow their pumps to be interrupted under conditions specified in Schedule 105 and summarized in Table 1.

Table 1. Irrigation Load Control Pilot Program Parameters

Program Parameters	**Description**
Eligible Customers	Irrigation Customers on Schedules 41 or 48 in and around Klamath Falls.
Program Period	Week including June 1 through week including August 15[2].
Program Hours	Weekdays, 12 p.m. to 8 p.m. Pacific Time.
Dispatch Limitations	52 hours per year, 20 events per year, up to 4 hours per event or twelve hours per week.
Incentive Rate	Estimated at $23-$27/kw per year. The program vendor may adjust the incentive rate based upon the needs of the program.
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 in the Fall. 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 2018 customers, dispatch events, incentive rates and payments, and event opt-outs is provided in Appendix One.

2018 Performance

<u>Availability</u>

Program availability in 2018 was more closely aligned with initial estimates for Year 1 and actual performance for Year 1 and Year 2 than with initial estimates for Year 3 shown in Table 2. Delivery cost challenges to expansion are outlined in the Year 2 report and while the new delivery contract in Year 3 addressed these challenges, the primary focus was a successful transition of existing customers to the new provider. This focus resulted in the same customer set delivering approximately the same impacts as the prior years.

Four events were called in August 2018, three events of three hours and one four-hour event for a total of thirteen hours. The average kW available from all events was 258 kW. There was 100% customer participation in all events. Load control equipment performed as expected with

[2] In addition, voluntary events may be dispatched separately through September 30.

exception of the one switch with the wiring problem described above, that was discovered during the final season event and lowered the kW average for the events.

Table 2. Oregon Irrigation Load Control Pilot – 2016 - 2017 Performance

	Year 1 (2016)	Year 2 (2017)	Year 3	Year 4	Year 5
Estimated kW	0 - 2,000	3,000	3,000	3,000	3,000
Proxy/Available kW	565	546	563		
kW (average all events)	281	432	258		

* kW values are at customer site

For 2018, the five-minute interval data from the Connected Energy replacement devices was available from July 26 to the end of the season. The available kW value represents the highest value during program hours when the switches were installed.

For the 2017 season, five-minute interval data was available for all enabled customers for the entire season. Available kW represents the highest five-minute interval demand reading during all program hours for the season.

For the 2016 program season only, average available load was set at customers; peak demand from June 2015 as a proxy for available load given the event occurred at the end of the season and a lack of five-minute interval load data until customers were enabled with site specific hardware.

<u>Program Costs</u>
Program costs in 2018 shown in Table 3 were associated with the new Connected Energy delivery contract and included delivery provider start-up costs in addition to equipment costs, customer incentives and customer engagement expenses.

Table 3. Irrigation Load Control Pilot 2016 - 2018 Costs

	Year 1 (2016)	Year 2 (2017)	Year 3 (2018)	Year 4	Year 5
Estimated Program Costs (Calendar Year)	$150,000	$225,000	$225,000	$225,000	$225,000
Actual Program Costs	$150,000	$125,000	$179,634		

2018 includes approximately $60,000 in start-up which includes costs for approximately 15 switches yet to be installed

2018 Activities to Address Key Challenges From 2017

PacifiCorp negotiated a new delivery contract with Connected Energy in 2018. The new contract was the end result of a competitive procurement process initiated in 2017 to secure updated market pricing. The new delivery contract replaced the Oregon portion of the EnerNOC delivery contract utilized for the first two years of the pilot. Pricing in the new contract is more aligned with the smaller focused efforts inherent in this pilot and utilizes a combination of fixed pricing for infrastructure and unit pricing for equipment installations. This is a change from the fixed pricing in the prior contract which subsequently proved not to be sustainable for the original delivery provider (a key learning reported in the prior reports). In early 2018, prior to signing the contract PacifiCorp provided Commission staff with a high level briefing on options under consideration, the identifiable value based on avoided peak energy and trends (outward push) surrounding capacity needs in the west as identified in the company IRPs. The general direction received was that there was still value in capacity management tools and that continuation of the program with a new provider appeared to be an appropriate course of action.

Efforts to enable the one customer with medium voltage equipment enrolled in prior periods did not come to fruition during 2018, but valuable information on a path forward was acquired. This equipment is owned by a federal entity and operated by a local irrigation district. The federal entity is responsible for equipment modifications (including the addition of upgraded utility metering and load control switches). The irrigation district is responsible for utility bills for this equipment and managing overall water movement for the benefit of their members. Prior conversations between the delivery provider and the customer focused on adding metering communications equipment so that traditional load control equipment could be installed. Conversations during the 2018 season with the owner's technical and operational staff (instead of the contract personnel as in prior years) revealed a very low tolerance for any added equipment to be installed. These conversations also identified a customer willingness to manually control the equipment in response to event notifications. The customer willingness to control combined with PacifiCorp's recently enabled AMI technology may provide an alternate way to have the customer's load participate in the program going forward. As outlined in prior reports, these ongoing conversations reinforce the need for a multi-year pilot so these complex ownership and operational issues can be better understood and addressed, where possible. If they can, then this equipment can serve as a resource. If the challenges are insurmountable, then there is knowledge this equipment should not be considered an available load control resource.

Post Year Three Recommendation

Recommendations (from staff report in Advice 16-04 dated April 26, 2016)

1. Given the length of the proposed Pilot Program, Staff recommends that after the third year of the pilot that if PacifiCorp anticipates that the program should *not* be expanded to all of its agricultural customers for the next irrigation season, then it should explain in detail why the pilot program appears to be unsuccessful in that regard and what additional information would be obtained in the remaining years of the pilot that would justify its continuance.

PacifiCorp recommends the program be expanded to include irrigation customers beyond the Klamath Basin, but proposes the expansion be targeted to focus on areas with potential to defer traditional investments in sub-station upgrades. PacifiCorp also recommends changes in the days and weeks during which events can be called and to provide an option for a higher incentive for shortening the event notice period. Expanded hours and shorter notice is a direct response in the need for increased resource flexibility, driven by the Energy Imbalance Market and needs identified by the company's Energy Supply Management group. This added flexibility should help generate higher value from quickly curtailable resources. The expansion is designed to intentionally see if localized deferral values can be achieved and is intended to do so by adding selected areas and customers to the program.

The recommendation stops short of expanding to all customers as an intentional tactic to help manage delivery costs and provide for a sustainable delivery model for PacifiCorp and its third party delivery partner. This recommendation is directly responsive to the challenges faced during the first two program years when the original provider identified the legacy contract structure as unsustainable for its current business objectives. The unsustainable nature of the delivery contract functionally precluded meaningful expansion within the Klamath Basin during the first three years. Targeted delivery within the company's extensive rural territory is an important tool to control costs and concentrate potential benefits.

The expansion recommendation reflects changes in company planning efforts and results. During the pilot period, West system demand response capacity resources identified by PacifiCorp's Integrated Resource Plans (IRP) and updates[3] have consistently moved further into the future. If this trend was moving in the opposite direction, (i.e., if demand response resources were being selected sooner) it would provide support for an immediate expansion to all customers.

At the same time system wide selections are moving out, there is an increased focus on planning for and deploying added tools and analysis to identify localized values and solutions. The Distributed Energy Resources Alternatives process and tool provides a consistent way to compare costs and benefits of facility upgrades with the cost and benefits of various non-wire solutions including load management[4]. Localized deferral value may be higher in select areas than the system wide values in the 2017 IRP[5]. These two trends, support the targeted expansion to customers in areas with potential localized deferral value.

Expanding and increasing the flexibility of this resource as outlined in these recommendations maintains a presence in the demand response space in Oregon and will provide flexibility to respond to changes triggered by legislation on carbon, increasing renewable resource penetration, or potential economic coal retirements.

Incorporating these recommendations will require modifications to Schedule 105 to amend the expiration date, available areas, dispatch period, hours, and notification in addition to other language changes that may be necessary to implement the proposed changes. PacifiCorp intends to file these modifications to make them available for the 2019 growing season, if approved.

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[3] 2015 IRP Update, 2017 IRP and 2017 IRP Update.
[4] 2017 Smart Grid Report – Appendix E https://edocs.puc.state.or.us/efdocs/HAQ/um1667haq11754.pdf.
[5] 2017 IRP – T&D deferral value - $13.57/kW which reflects a utilization factor. For a substation with a need, the 100% utilization value for D from the 2017 IRP is $15.60/kW.

Additional detail on PacifiCorp's recommendations is provided below.

- Expand beyond Klamath Basin starting with the 2019 growing season. Extend the end date to 2023. Maintain the pilot status to permit the continued focus on innovation.
- Target installations to customers in locations where there may exist additional localized value. Eligible areas will be posted on the company web site starting in 2020. For 2019, areas will be posted when regulatory approval is received. Once an area is identified and customers participate, they will be eligible to participate as long as the program is active.
- Utilize AMI data to test participation options for select large customers.
  Increased renewable energy penetration and greater swings in supply have increased the value of added flexibility in the energy supply market. This recommendation includes changes to expand the event hours and shorten the notice which should help drive greater value from participating customers.
  - Test grower acceptance of shorter notice period and hold day-of resources as spinning reserve. Modify tariff language to incorporate the following program and event changes to increase flexibility. Maintain limit on 52 hours/season
  - Extend season end date from August 15 to September 1 (week including)
  - Extend last daily dispatch hour from 8:00 PM to 10:00 PM
  - Remove weekend and holiday exemptions. All days during season are possible dispatch days.

- Differentiate notice requirements and align incentives with notice.
  - Day ahead: $18/kW-yr.
  - Hour ahead: $30/kW-yr.
  - Incentives will be paid based on weekly available (enrolled) kW – average of connected kW (measured by switches) for 12:00 PM to 10:00 PM for each day (not including dispatch days) which will be expanded to include approximately two more weeks (the last half of August). Weekends and holidays will now be eligible dispatch days.
  - Event impacts will be measured against prior day average for day ahead and prior hour average for hour ahead.
  - Growers choice on which option for which site (equipment controlled by one device). Enrollment by option is for the season. Pilot off-ramp feature: Growers with hour ahead may move to day ahead during the season, but incentives for season will be paid at lower rate.

Distributed Energy Resources (DER) Alternative Solutions can identify increased localized value

As outlined in PacifiCorp's 2017 Smart Grid report during the pilot period, Pacific Power has recognized the role that DERs may play in the deferral or offset of traditional poles and wires infrastructure investments and created a tool for transmission and distribution planners to compare alternative DERs solutions to traditional solutions. The irrigation load control resource is one of many resources available for circuits or substations with constraints during summer hours and a reasonable concentration of irrigation customers. In addition, PacifiCorp's development of tools that facilitate queries of customers by substation or feeder has improved the analytical tools available since the pilot was first filed. When customers are identified, their billing information can be queried and the range of capacity impacts can be more fully understood. Insight on a per-customer basis is valuable when planning deployment of load control switches.

As of the date of this report, PacifiCorp has identified select areas in southern Oregon and central Oregon with summer conditions suggesting targeted irrigation load control may provide additional system value. Each of the areas are predicted to reach their summer capacity constraints in the 2027-2029 timeframe, which would require initial engineering design work to begin no later than 2026 in order to deliver a traditional capacity increase solution (e.g. new substation or large power transformer). The seven year period before a traditional capacity increase solution would need to be initiated makes these areas ideal for additional testing of irrigation load control. The areas have relatively low growth rates, making long-term deferral through irrigation load control a possibility.

The focus on locational need will also provide an opportunity to explore alternate dispatch protocols. The current practice of having PacifiCorp's Energy Supply Management group call events based on forecasted weather or economics will continue and incorporate switches installed on substations with locational value. The impact of this approach will be measured during annual DER planning cycles when information on load growth and constraints is updated. PacifiCorp is working with the grid operations group to explore whether an additional dispatch portal (provided by Connected Energy) could be used by the group to implement direct load control in response to local grid conditions.

Added hours and shorter notice increase value in the Energy Imbalance Market

Since the Energy Imbalance Market (EIM) was implemented on November 1, 2014 it has delivered substantial benefits through (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint. Irrigation load control resources may have some increased value in the EIM arena if the availability (months, days, hours) can be expanded and the notice period shortened. The primary barrier to grower acceptance is expected to be the shortened notice period, which is why

PacifiCorp is proposing an elective option so that growers may decide which option is likely to work best for their operations.

Automated Meter Infrastructure (AMI) provides alternate control options for selected loads

AMI deployment started in Oregon during the 2018 season and is expected to be complete in 2019. While AMI equipment is not capable of controlling (stopping and starting) three phase irrigation equipment, the infrastructure can provide an alternate means to acquiring information on connected load without installing a load control switch. PacifiCorp has identified this AMI capability as a potential solution for customers with unique configurations, specifically the large (750 HP) medium voltage pumps in the Klamath Basin. While this customer is interested in participating, installing load control equipment on their equipment is prohibitive from a logistical and operations perspective.

The customer has expressed a willingness to control the equipment in response to event notifications provided by PacifiCorp's load control implementation contractor. The implementation contractor has indicated a willingness to integrate AMI provided data into their system that provides real time information on kW available for dispatch. It is expected there will be a lag (up to one day) on information uploaded this way compared to the intra-hour data acquired through a load control switch. This lag and the dependence on operator (vs. automated) control are reasons PacifiCorp would limit the use of this option to installations meeting the following criteria a) technical barriers to installation of conventional equipment, b) loads ≥ 500 kW, c) loads with relatively low intraday variability, and d) in-place operational personnel and/or systems or to control the equipment.

Impacts for these sites would be validated using AMI data and incentives would be paid based on the validated kW curtailed relative to the baseline. While this alternate approach is not likely to provide the certainty needed to defer infrastructure investments, successful performance during events will generate some arbitrage value and provide an opportunity for testing a new method of dispatch and data analysis.

Appendix 1
2018 Connected Energy Pacific Power Irrigation Load Control Program Report

In support of PacifiCorp'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.

CONNECTED ENERGY

PACIFIC POWER
A DIVISION OF PACIFICORP

2018 Pacific Power Irrigation Load Control Program Report

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Contents

Overview of the 2018 Irrigation Load Control Program

This report provides an overview of the Irrigation Load Control (ILC) Program in the Klamath Falls, Oregon region of the Pacific Power service territory as implemented and administered by Connected Energy. This report is intended to document program results, accomplishments, and challenges, including lessons learned that will be leveraged to enhance program going forward.

Regulatory approval for the ILC program in Oregon was initially granted by the Public Utility Commission of Oregon on May 4, 2016. The Irrigation Load Control program transitioned to Connected Energy in 2018 and was made available to irrigation loads in the Klamath Falls, Oregon region of the Pacific Power service territory for customers that were not already participating in the time of use program and that had participated in the program in 2016 and/or 2017. Installation of direct load control equipment was initiated in late July with devices coming online on or about July 24, 2018.

Three customers with a total of five sites and ten pumps participated in the program in 2018. Total connected program load for 2018 was approximately 650 kW in irrigation pumps. Participating sites were compensated for shutting off irrigation load for specific time periods determined by Pacific Power, and were provided day-ahead notice of load control events. Customers had the opportunity to opt-out of (i.e., choose not to have their pumps curtailed) for events as necessary to suit their day-to-day business operations.

Customer 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. The program hours are 12:00 PM to 8:00 PM Pacific Daylight Time (PDT), Monday through Friday, not including holidays.

Per Oregon Schedule 105, the load control season starts on the Monday of the week including June 1st and ends on the Friday of the week including August 15th. For the 2018 load control season, the first day of the program season was Tuesday, May 29th as Monday, May 28th was the Memorial Day holiday and, thus, not an eligible program day. The program season ended on Friday August 17th. Pacific Power may additionally call voluntary events from June 1st to September 30th each year. Voluntary events allow customers to earn payments for their real-time reductions during such events, but their participation or lack of participation does not impact their regular season capacity payments. No voluntary events were called by Pacific Power in 2018.

Pacific Power initiated four load control events during the 2018 load control season on the following dates and times:

- August 7, 2018 between hours of 4:00PM - 8:00PM
- August 13, 2018 between hours of 5:00PM - 8:00PM
- August 15, 2018 between hours of 5:00PM - 8:00PM
- August 17, 2018 between hours of 4:00PM - 7:00PM

Load reductions for the events are calculated using five-minute interval metering data from Connected Energy's direct load control devices. The participation factor for all customers for all events was 100%, which indicates that all 10 irrigation pumps across the three customers participated in each load control event with no opt- outs. There was an equipment factor that affected event performance during the final event which is more fully described later in this report.

Review of 2018 Customer Enrollment and Enablement

Customer Payment Structure

All participants are paid the same incentive rate based on measured available load for curtailment throughout the program season adjusted for any opt outs or non-performance in load control events[1]. In 2018, all participants were paid at the $23/kW rate. This payment structure is designed to provide fair and consistent treatment for all sites.

Enrolled Customers

For the 2018 load control season, Connected Energy enrolled and installed advanced load control devices on equipment for 3 customers across 5 site locations serving 10 pump loads.

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, whereas legacy devices were based on 3G technology. The current 3G network is nearing end of life with provider plans calling for the 3G network to be shut down by the end of 2020. Utilizing 4G (LTE) load control switches provides added benefits as the minimum projected network life for 4G (LTE) is currently year end 2028.

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[1] In 2018, the program transitioned to Connected Energy from a legacy vendor. Customer billing data was used from season start until the week of July 23rd when the switches were installed and then device data for the remainder of the season.

Review of 2018 Program Participants and Performance

Customer Crop/Operations and Pumping Equipment

For the 2018 Irrigation Load Control season, customer crop types/operations included alfalfa, potatoes, and grass fields for cattle and livestock grazing. Pump sizes at these locations ranged for 40 HP to 200 HP.

Impact of Crop Type

Connected Energy's experience in other programs has shown that crop type can typically be a predictor of customer willingness and ability to successfully participate in the Irrigation Load Control program. Irrigators in Klamath Falls most commonly grow alfalfa, hay, potatoes, or some combination thereof over the course of a multi-year planting schedule. In addition, some irrigators water fields for cattle and livestock grazing.

- **Alfalfa** is typically grown on a five to seven-year planting cycle and is watered consistently across the season. Prices trended up in 2018 from 2017 and appear to be further increasing into 2019. Typically, alfalfa crops have the flexibility to participate in events due to a tolerance for shifts in watering schedules. However, the load profile of alfalfa irrigation is intermittent. Pumps watering alfalfa are typically shut off for two periods each load control season for harvest. These harvest periods can last a week or more, resulting in significantly reduced availability.

- **Potatoes** are a water-intensive crop that typically stays in the ground for one to three years, and is often rotated with wheat. Potatoes are significantly more sensitive to irrigation schedule interruptions than wheat or alfalfa. Irrigation Load Control participants with potato crops will have high availability but likely a reduced flexibility to participate in load control events. Potatoes will also be particularly sensitive in drought years, further impacting event participation.

- **Fields watered for livestock pasture** have less consistent or predictable irrigation schedules, and are mostly found on dairy farms.

As irrigators change and rotate crops across fields, it is difficult to predict the impact that will result in available irrigation load. At a minimum, there would need to be information related to crop specifics to provide some estimate of impact on crop rotation.

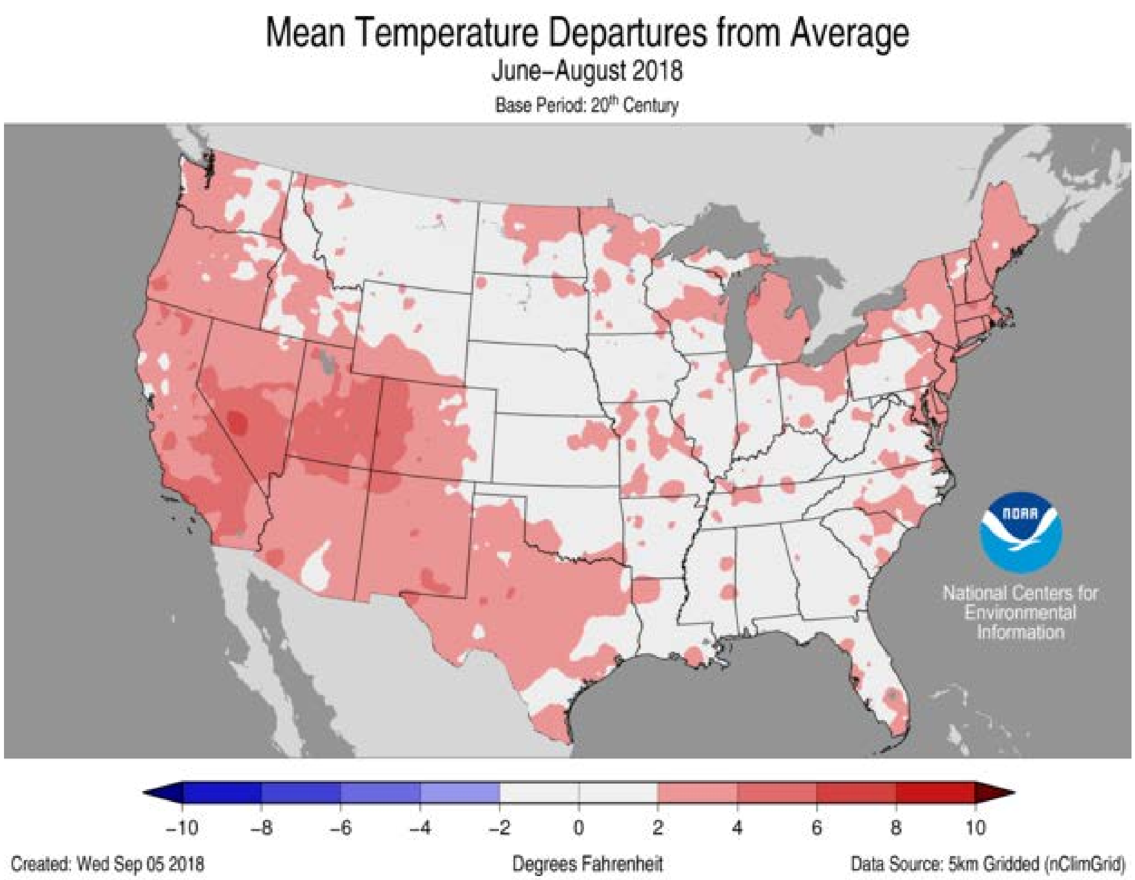
Impact of Irrigation Technology and Water Availability

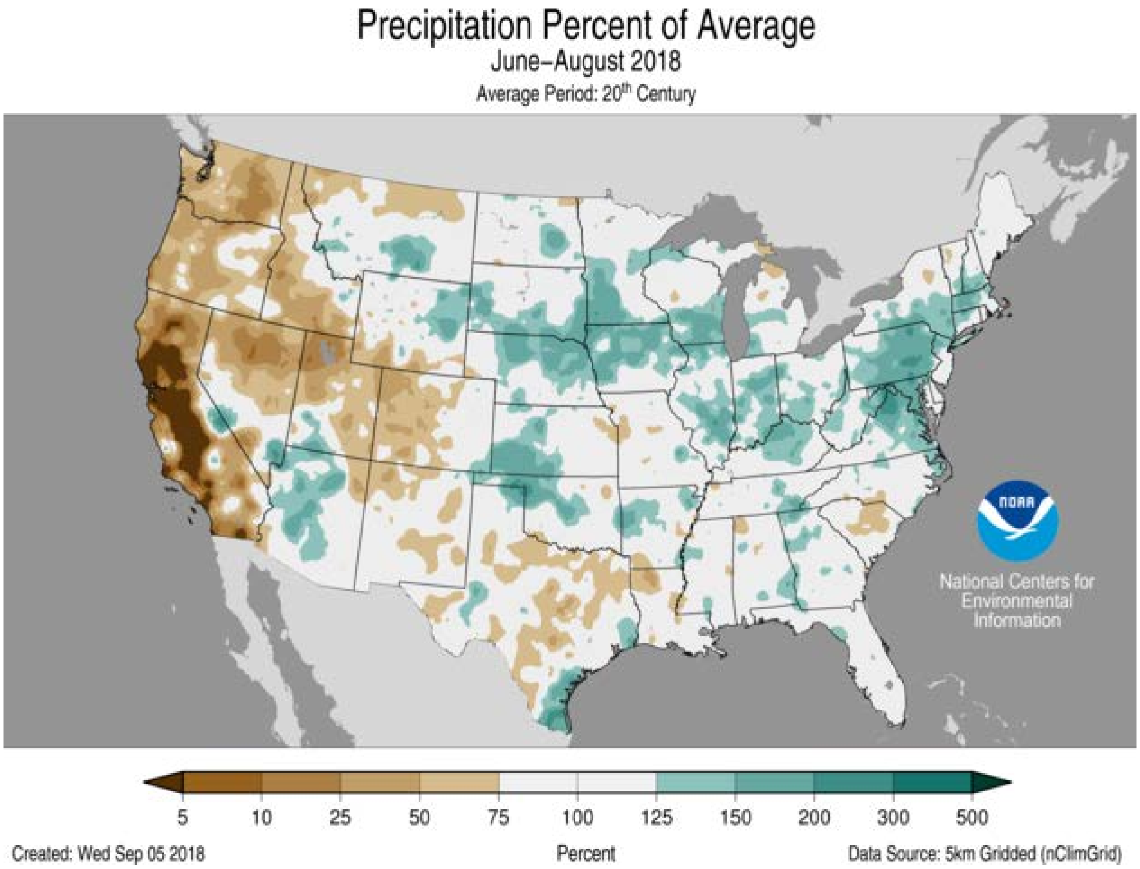
While pump size is a clear determinant of total availability in the Irrigation Load Control program, irrigation technology and water availability also impact irrigation pump run-time and thus can affect customer success in the Irrigation Load Control program. Pivot irrigation systems are operationally easier to manage for load control events than a wheel line or hand line irrigation system. During the 2018 season irrigators did not raise issues or questions about current or potential future water restrictions impacting their ability to participate in the program.

Weather & Drought Impact

Similar to 2017, 2018 was warmer and dryer than normal, especially in July and August.[2] Warmer and dryer conditions, likely led to greater irrigation needs and higher available loads versus historical averages. However, given the mix of billed and interval data from the transition to Connected Energy, definitive conclusions about higher average loads based on a comparison with historical interval data cannot be made.

The two images below highlight the above average temperatures and below average precipitation across much of the western part of the country including the ILC program region during the 2017 program season.





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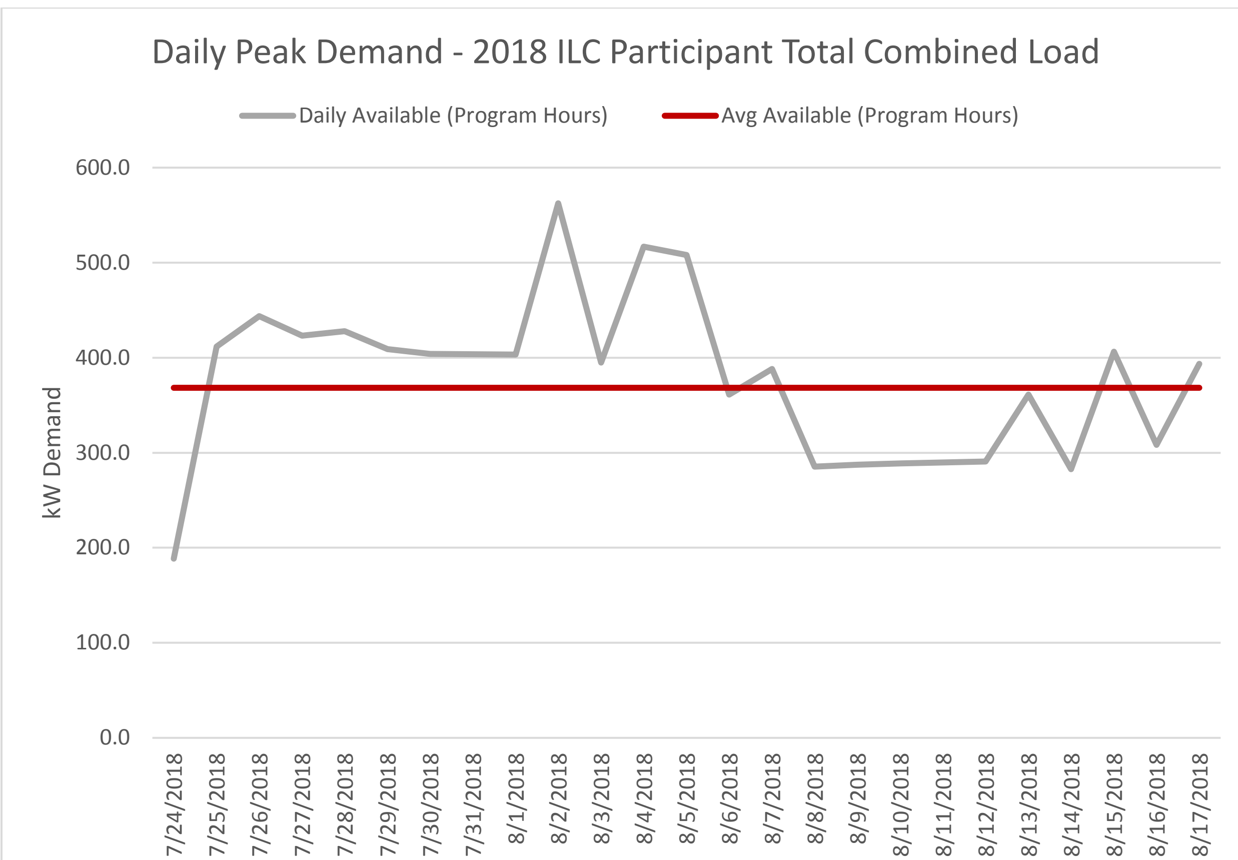
2 Source: NOAA Mean Temperature Departures from Average (June-August) and Precipitation Percent of Average (June-August), available online: https://www.ncdc.noaa.gov/sotc/national/201808.

Available Load Reduction

The Oregon Irrigation Load Control program is evaluated based upon average available load reduction (kW) between the nearest Monday on or before June 1st and the nearest Friday on or after August 15th during program hours from 12:00 PM to 8:00 PM Pacific Daylight Time, non-holidays. In 2018, the program was active between Tuesday, May 29th and Friday, August 17th. Due to the transition of vendors in 2018, the load control devices were not available to participate in load events until July 25, 2018. From July 24th until the program year-end on August 17th, the portfolio average available load reduction was 368 kW (with a peak available load reduction of 563 kW on August 2, 2018.[3]

The chart below shows daily available demand (as well as average available demand) during active program hours (12:00 PM – 8:00 PM, excluding weekends and holidays) and active program months in 2018. Consistent with previous years, customers stopped their irrigation activities in line with the end of the growing season in early October with load dropping to ~0 kW on October 3rd and remaining at ~0 kW for the remainder of the year. The shape of the seasonal load curve is in keeping with expectations that the highest load should align with the active growing season and the warmest seasonal periods.



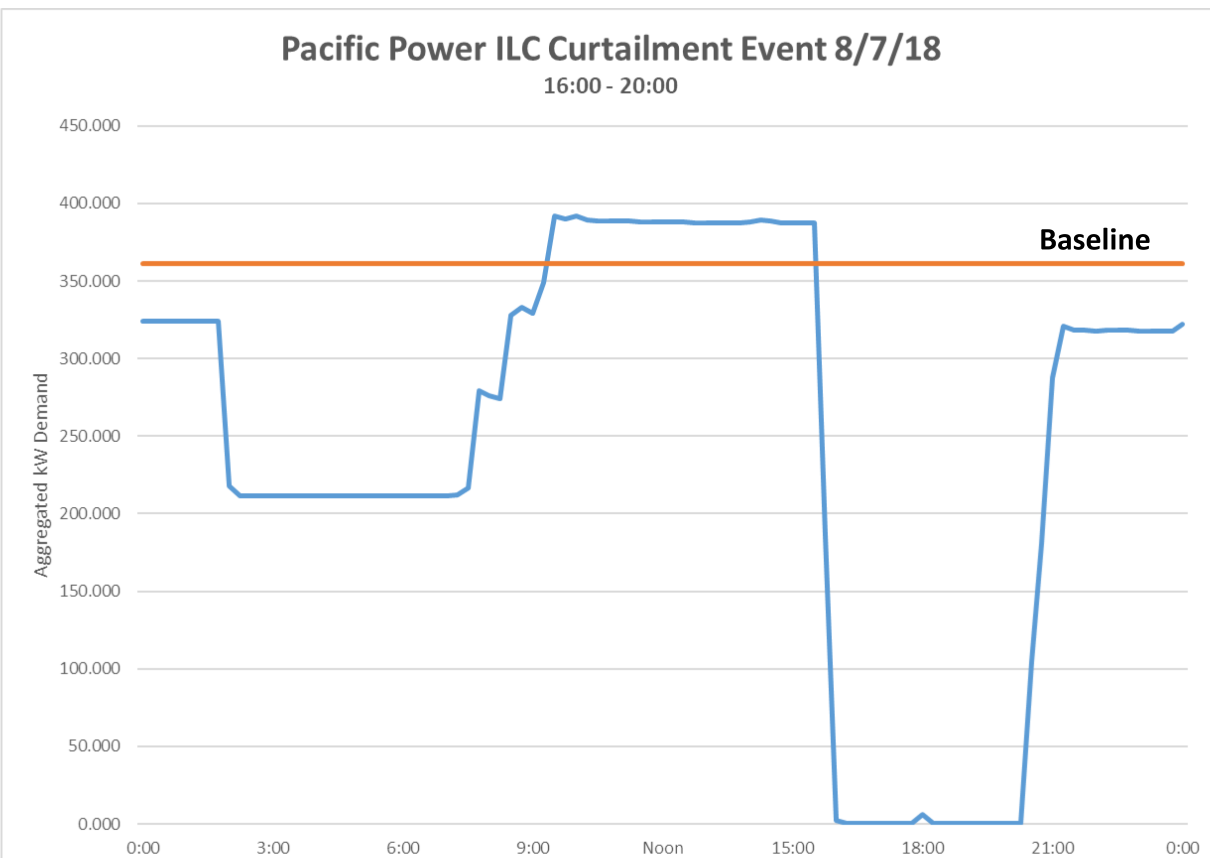
[3] Monday, May 28th was the Memorial Day holiday, which moved the start of the program season to the next non-holiday weekday, which was Tuesday, May 29th.

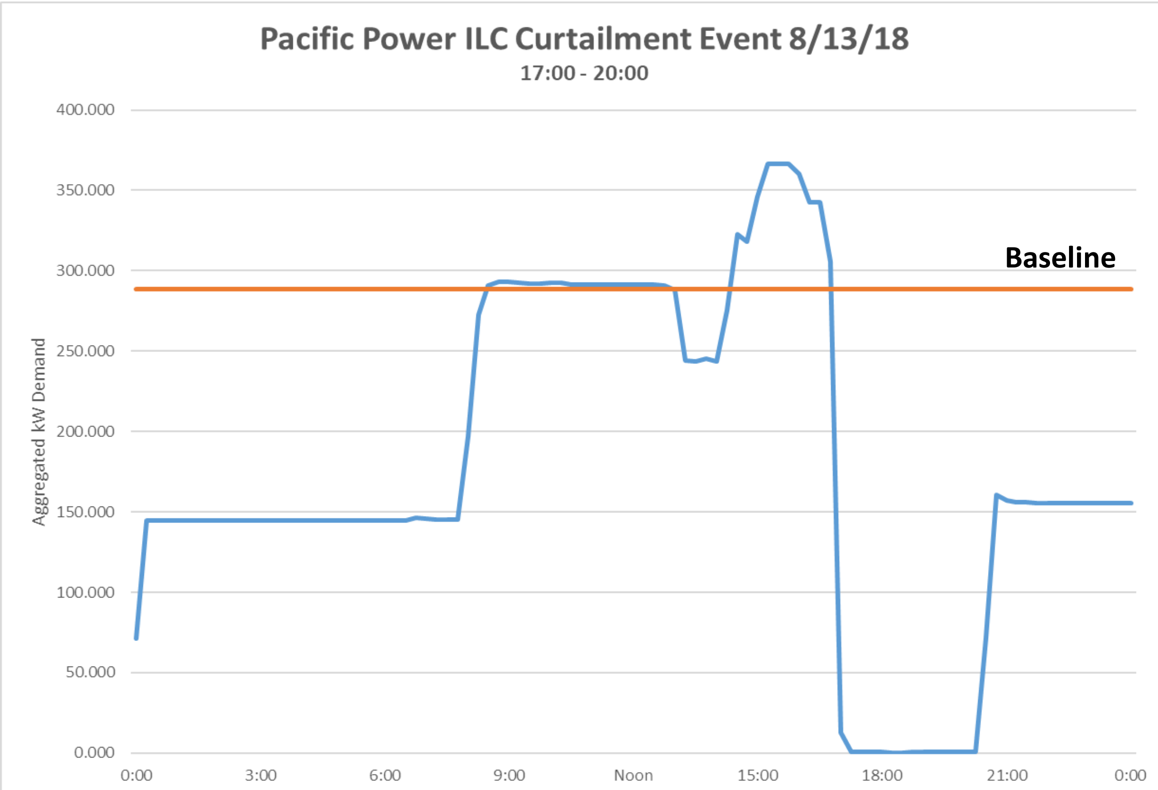
Load Control Events

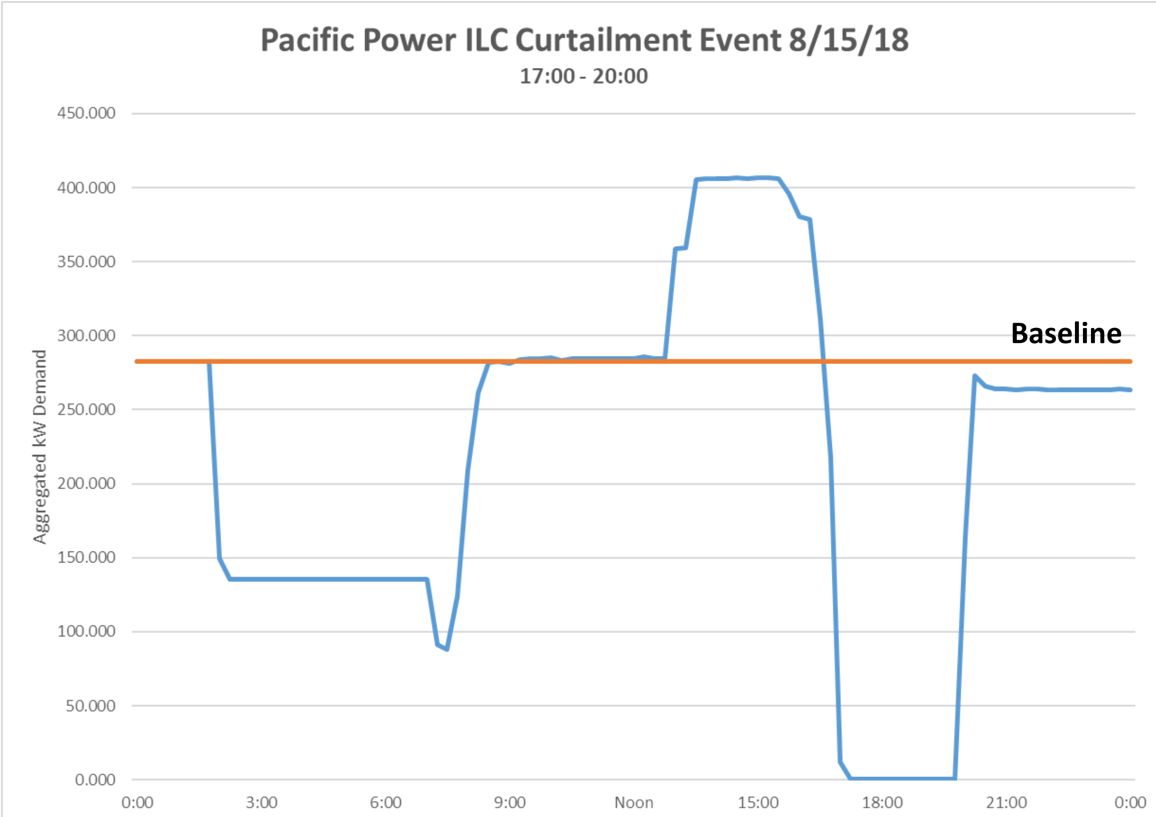
Pacific Power activated the Irrigation Load Control program for four mandatory irrigation load control events in 2018. Actual load reduction was measured as the difference between actual demand remaining on the system during the event and baseline demand. Baseline demand is the average demand during program hours (12 to 8pm PT) on the most recent non-event, program day. 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.

The 2018 portfolio delivered an average of 258 kW across the 4 mandatory load control events called during the 2018 program season. Load Reduction Performance Factor, the measure of actual load reduction compared to baseline demand, was 89% for the portfolio. A customer participation factor is also calculated for each participating site and is designed to measure customers' choices to opt-out of participating in events. This customer participation factor is used to adjust availability payments in accordance with the pay-for-performance nature of the program. In the 2018 program season, the customer participation factor was 100%.

Images below are visual representations of the 4 load control events showing the participating load's demand relative to baseline:




Pacific Power ILC Curtailment Event 8/13/18
17:00 - 20:00
Baseline
Aggregated kW Demand
400.000
350.000
300.000
250.000
200.000
150.000
100.000
50.000
0.000
0:00
3:00
6:00
9:00
Noon
15:00
18:00
21:00
0:00


Pacific Power ILC Curtailment Event 8/15/18
17:00 - 20:00
Baseline
Aggregated kW Demand
450.000
400.000
350.000
300.000
250.000
200.000
150.000
100.000
50.000
0.000
0:00
3:00
6:00
9:00
Noon
15:00
18:00
21:00
0:00

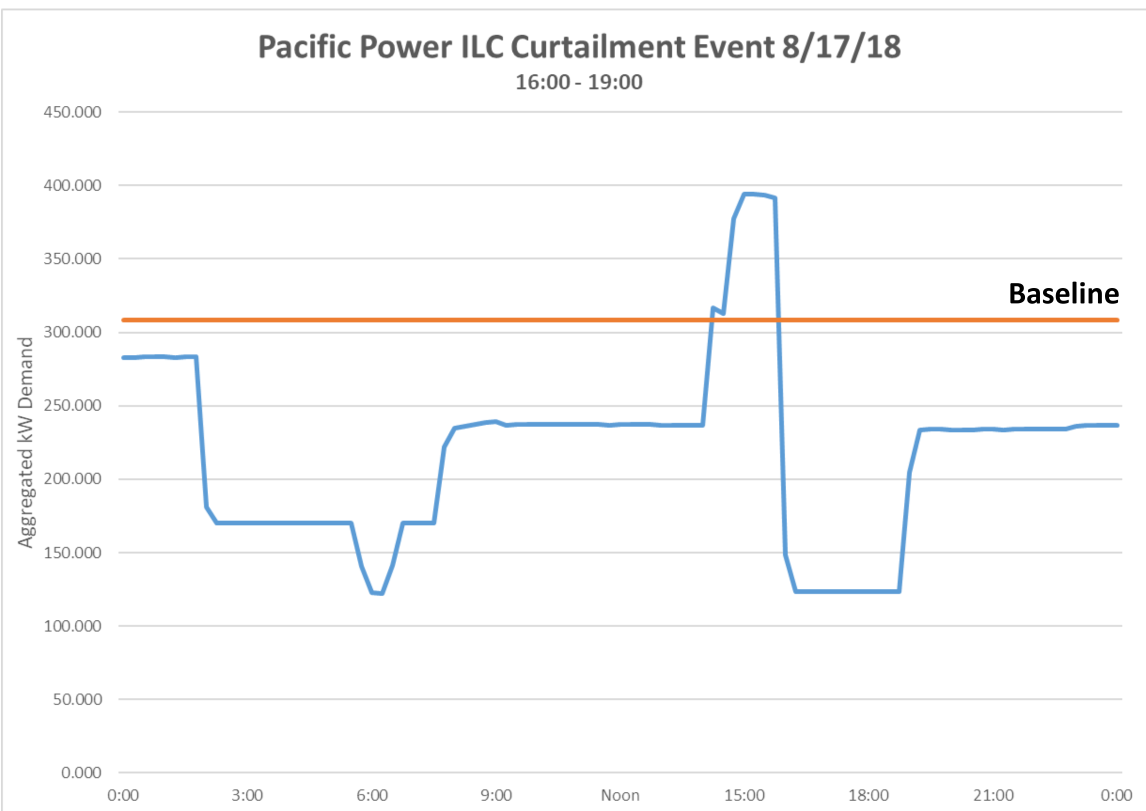

Pacific Power ILC Curtailment Event 8/17/18
16:00 - 19:00
Baseline
Aggregated kW Demand
450.000
400.000
350.000
300.000
250.000
200.000
150.000
100.000
50.000
0.000
0:00
3:00
6:00
9:00
Noon
15:00
18:00
21:00
0:00

Figure 2 below details the actual load reduction, baseline demand, and performance factor for each of the four called mandatory events.

Figure 2: Actual Load Reduction, Baseline Demand, and Performance Factor, by Event and Region

Date	Region	Actual Load Reduction (kW)*	Baseline Demand (kW)*	Load Reduction Performance Factor (%)*
8/7/2018	Oregon	329.55 kW	329.55 kW	100%
8/13/18	Oregon	281.94 kW	281.94 kW	100%
8/15/18	Oregon	257.71 kW	257.71 kW	100%
**8/17/18 ** **	Oregon	164.52 kW	289.85 kW	56.7%
Avg of 4 Events	Oregon	258.43 kW	289.76 kW	89.2%

* 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. These measurements may or may not correspond to realized load reduction on Pacific Power's system.

** Full amount of load was not curtailed for final event. Investigation discovered that the curtailment relay was not properly wired upon installation and the customer was manually curtailing the load which masked the installation problem until the fourth curtailment event, where the customer failed to manually curtail the load.

Figure 3 below, provides details for each of the mandatory events in 2018. No events were called and then subsequently cancelled in 2018. Additionally, there were no voluntary events in 2018.

Figure 3: List of 2018 Event Activity

Event Type	Start Time (PDT)	End Time (PDT)	Notes / Comments
Mandatory	8/7/18 16:00	8/7/18 20:00	• Baseline demand was 329.55 kW • Total load reduction was 329.55 kW • Performance factor was 100%
Mandatory	8/13/18 17:00	8/13/18 20:00	• Baseline demand was 281.94 kW • Total load reduction was 281.94 kW • Performance factor was 100%
Mandatory	8/15/18 17:00	8/15/18 20:00	• Baseline demand was 257.71 kW • Total load reduction was 257.71 kW • Performance factor was 100%
Mandatory**	8/17/18 16:00	8/17/18 19:00	• Baseline demand was 289.85 kW • Total load reduction was 164.52 kW • Performance factor was 56.7%

** Full amount of load was not curtailed for final event. Investigation discovered that the curtailment relay was not properly wired upon installation and the customer was manually curtailing the load which masked the installation problem until the fourth curtailment event, where the customer failed to manually curtail the load.

Key Lessons Learned from 2018

2018 was a transitional year for the Pacific Power Irrigation Load Control Pilot Program as it moved from the legacy vendor to Connected Energy's advanced technology. Connected Energy operated within a compressed schedule to get new customer agreement signed and install new switches for existing participants. Customer were amenable to the transition to a new provider and were cooperative is signing new agreements and arranging access for new switch installations. Even with the compressed schedule, four events were still called during the later part of the season. As we enter the 2019 season, we are better prepared to identify irrigators and install equipment at those sites that can deliver maximum value for Pacific Power.

1. With 100% participation in four events in 2018 from customers that participated in both 2016 and 2017, it indicates strong interest and willingness for irrigators in the Klamath region to continue to participate in an irrigation load control program.

2. Customer recruitment will begin in the first quarter of 2019 to ensure that

we can identify sufficient irrigators to meet the program enrollment objectives for 2019.

3. Customers that require non-standard enablement pose a participation challenge. Prior conversations with the public entity with the large medium voltage pumps focused on adding metering communications equipment so that traditional load control equipment could be installed. Conversations during this season with the owner's technical and operational staff (instead of the contract personnel as in prior years) revealed a very low tolerance for any added equipment to be installed. These conversations also identified a customer willingness to manually control the equipment in response to event notifications. The customer willingness combined with Pacific Power's recently enabled AMI technology may provide an alternate way to have these load participate in the program going forward.

APPENDIX A: Customer-Facing Irrigation Load Control Activity

The table below lists all activity involving program participants related to the Irrigation Load Control program that occurred in 2018, excluding Irrigation Load Control events.

See figures 2 and 3 above for dates and detail related to those events.

Figure 4: Participant-Facing Irrigation Load Control Activity in 2017

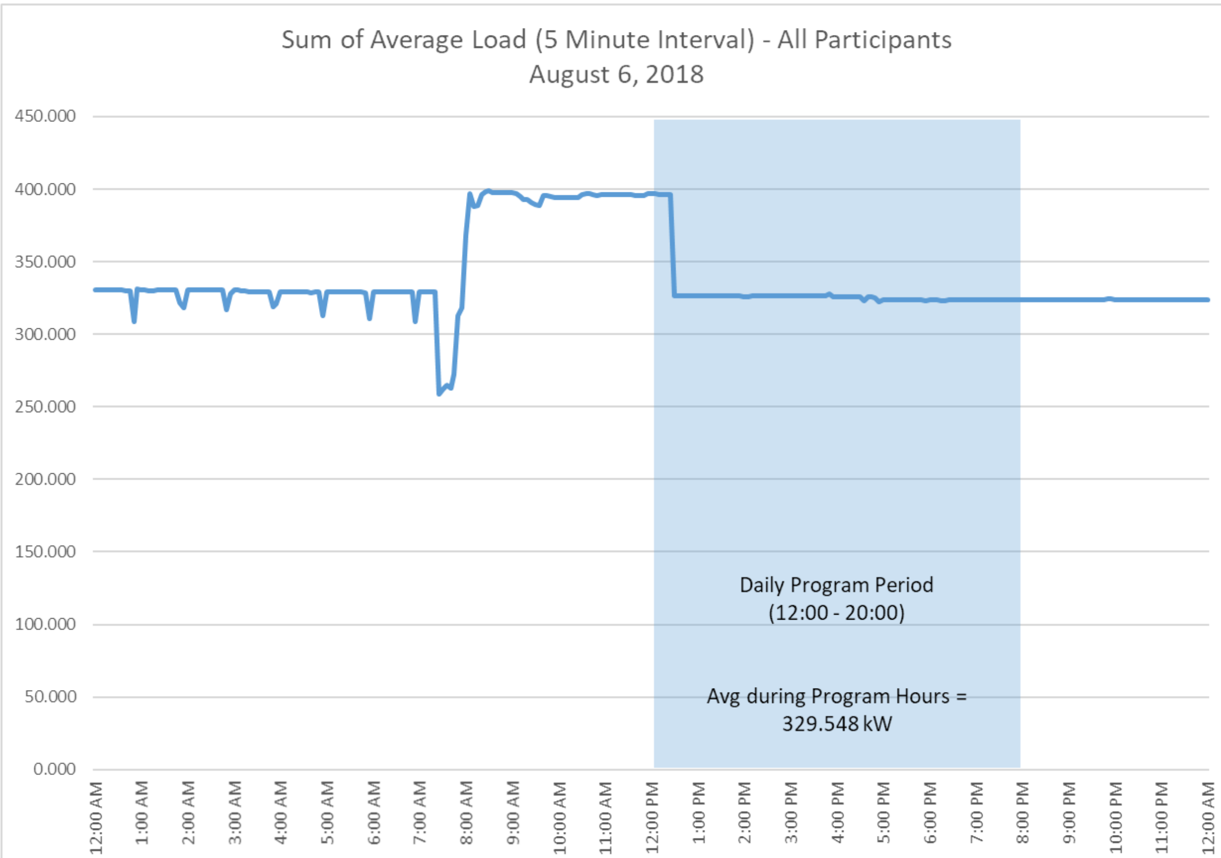
	Activity	Date	Description
1	**Welcome Letter sent to previous year participants**	Friday, July 13, 2018	Connected Energy forwarded welcome letters to previous participants advising them of the continuation of the program with the invitation to enroll with Connected Energy for 2018. All previous year participants were pleased that the program was continuing and welcomed to the chance to enroll.
2	**New equipment installation**	Week of July 23, 2018	Connected Energy Field Service Engineer met with program participants and our installation contractor to perform installation of field equipment to enable participation in ILC program.
3	**Courtesy calls to customers in advance of events**	Prior to each event	Connected Energy placed phone calls to each participant in advance of an event (in addition to electronic day ahead notifications) to ensure they were aware of scheduled events
4	**Incentive payments mailed to participants**	Week of January 28, 2019	Incentive checks were mailed to enrolled customers for participation in the 2018 Load Control program.

APPENDIX B: Customer Payments

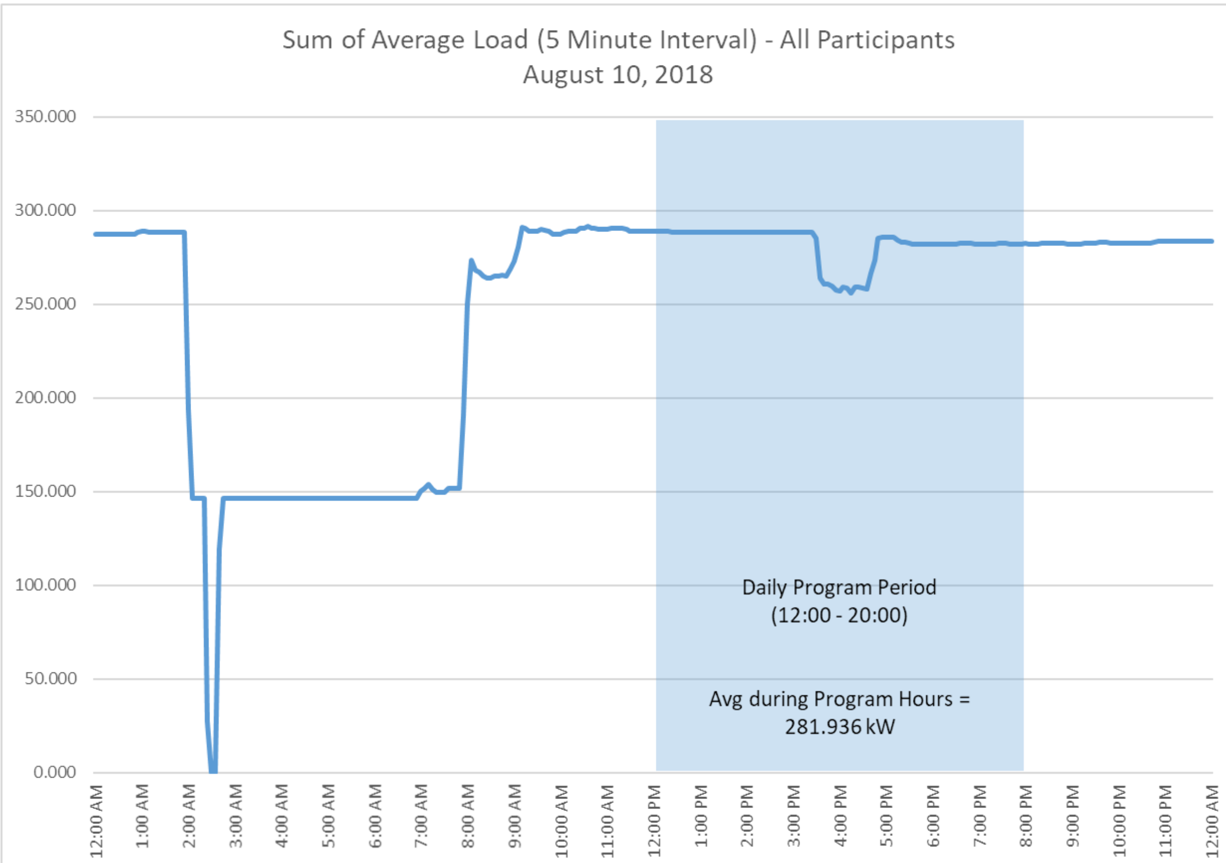
Three customers received incentive payments for their participation in the 2018 ILC program season. Incentives payments totaled $10,833.84 and were based on weekly available load that could participate in events multiplied by the participation factor. 2018 customer billing data was used for portion of the season prior to switch installations. Device data was used for the balance of the season. The customer participation factor was 100% for all customers and all customer incentives were calculated utilizing a $23/kW rate.

APPENDIX C: Detailed Baseline Charts

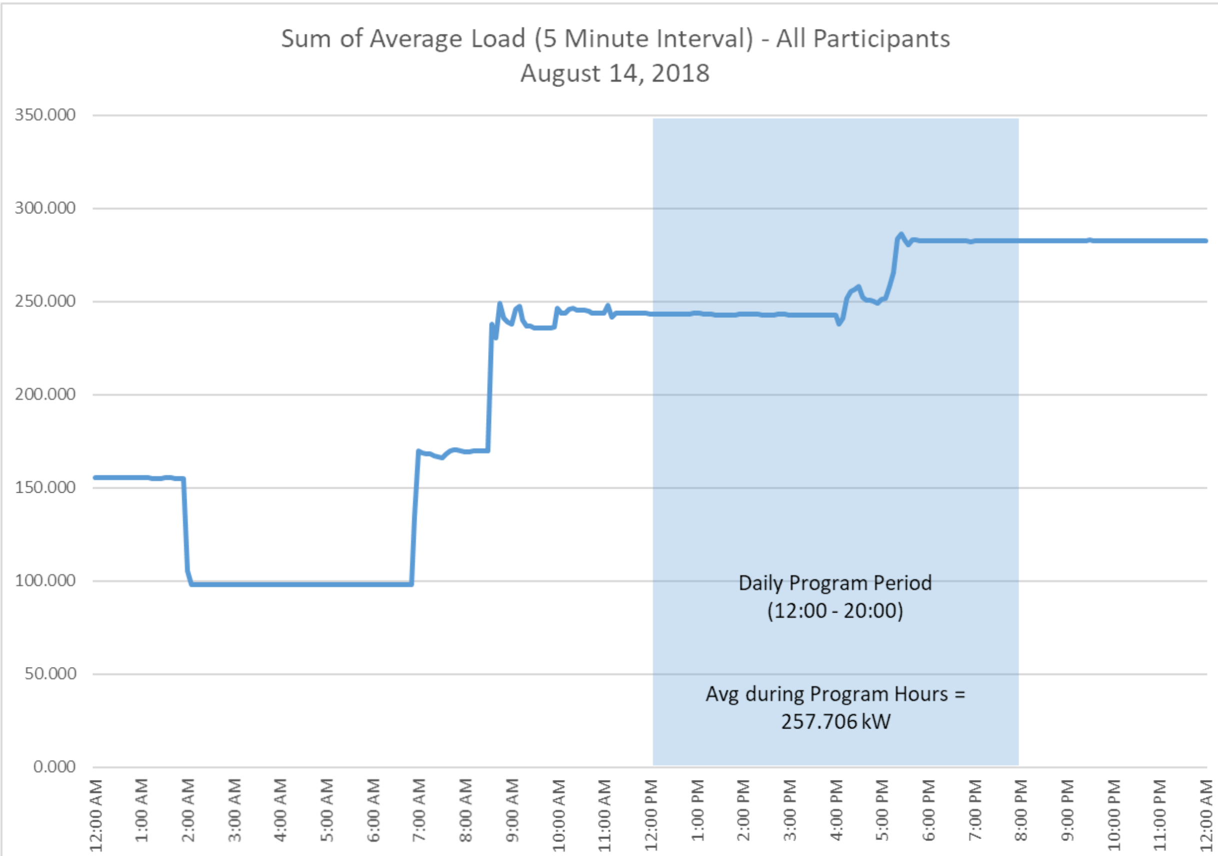
August 6, 2018 Baseline Chart for August 7, 2018 Event



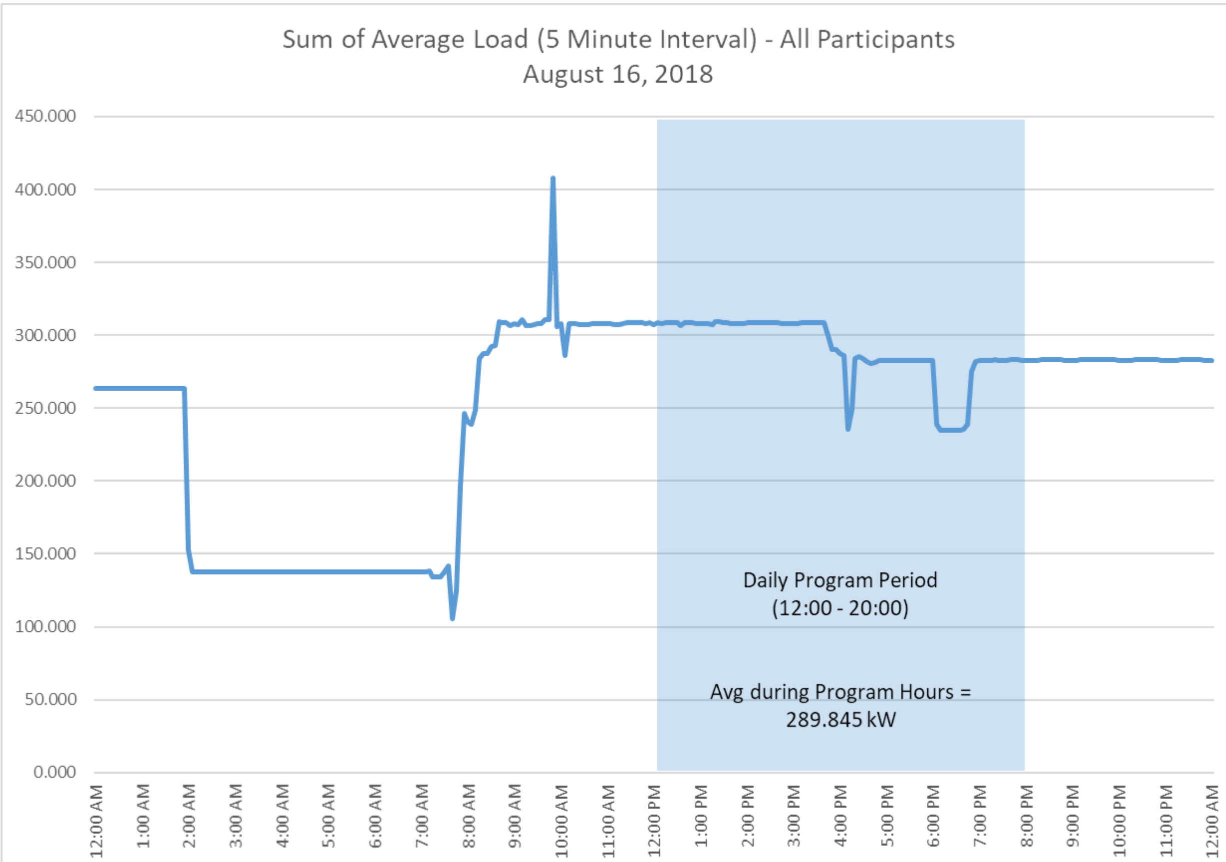
August 10, 2018 Baseline Chart for August 13, 2018 Event



August 14, 2018 Baseline Chart for August 15, 2018 Event



August 16, 2018 Baseline Chart for August 17, 2018 Event



Appendix 2

Oregon Pilot Program year three - benefits and costs discussion

The Oregon pilot program is intended to test designs, provide market feedback, and generate information about delivery logistics and costs. PacifiCorp will monitor the costs and benefits to understand the feasibility of expanding the load control program beyond the pilot stage in Oregon.

This Appendix provides discussion of the costs and benefits of the 2018 program developed in response to Recommendation No. 3 in the April 26, 2016 Commission staff memo in Advice No. 16-04 to utilize the California Public Utilities Commission Distributed Energy Resource Avoided Cost Framework ("Framework") as a guide when conducting the post-season assessment.

Appendix A of the Framework, 2015 Demand Response Cost Effectiveness Protocols (Protocols) is dated November 2015.[6] It is important to note that these protocols are not directly applicable to pilots: "These protocols are not designed to measure 'pilot' programs, which are done for experimental or research purposes, technical assistance, educational or marketing and outreach activities which promote DR or other energy-saving activities in general...[7]" Although these Protocols are not directly applicable to pilots, they are being used here as an initial guide to help discuss the pilot program as it moves forward.

To utilize the Protocols as a guide, information from pages 11 and 12 of Appendix A is provided below, italicized; Protocol references to California utilities have been removed. 2018 program information is provided below each Protocol topic and labeled "Pilot" for the purposes of this discussion.

1. *Avoided Generation Capacity Costs*
   Pilot: For 2018, PacifiCorp's marginal capacity resource was Front Office Transactions (i.e. market purchases), which typically have a minimum increment of 25 MW. While this resource was too small to avoid a market transaction, the avoided energy costs below are calculated assuming that market transactions are avoided on a kW for kW basis.

2. *Avoided Energy Costs*
   Pilot: A review of the loads preceding and following each event indicate a mixture of load shedding (loads not fully restored after events and or load shifting (loads returning following the event) or a hybrid (some but not all load returning after events) This review provides additional information to that gathered in the last two seasons and continues to suggest a

[6] *2015 Demand Response Cost Effectiveness Protocols,* California Public Utilities Commission. 2015.
[7] *Id*, page 7.

mixture of shedding and shifting but provides no definitive conclusion about load shifting or shedding as the primary impact.

Because day-ahead notice is required for curtailment, for valuation purposes the pilot program was assumed to allow day-ahead on-peak market purchases to be avoided. However, day-ahead on-peak purchases typically span a standard 16 hour block, rather than the four-hour curtailment associated with the pilot program. As a result, purchases may be necessary during the hours in which the irrigation loads are not being curtailed. The 2018 valuation is based on the highest cost day-ahead purchase transaction entered by PacifiCorp, net of costs in non-curtailment hours based on Energy Imbalance Market (EIM)[8] prices.

3. *Avoided Transmission and Distribution Costs*
   Pilot: Assigning transmission and/or distribution deferral value(s) to load management is consistent with the 2017 IRP, the Northwest Power Planning and Conservation Council's 7th Power Plan[9] and Oregon's Resource Value of Solar (UM-1910). Deferral values and their application in this analysis are from the 2017 IRP. Available information indicates enabled load control equipment is connected to four separate distribution substations. In 2018, none of these substations were identified as needing import capacity upgrades and no transmission deferral value was assigned. In 2018, one device controlling approximately 15 kW of irrigation load was connected to a distribution substation identified for an upgrade if block load additions materialize in the future. While no future block loads were identified in 2018, for the purposes of this analysis, the deferral value of $15.60 kw-year was utilized to estimate a potential distribution deferral benefit of $234.

4. *Avoided Environmental Costs for Greenhouse Gases (GHG)*
   Pilot: There are no published costs for GHG that are applicable to this analysis. There are no Oregon explicit avoided environmental cost associated with GHG reductions.

5. *Line Losses*
   Pilot: For valuation purposes, the hourly line loss factor methodology developed for UM-1910 was used. Under that methodology, avoided line losses are highest during peak load periods, and as a result, the avoided line losses during the 2018 curtailment events is estimated at 10.13%. The value of avoided line losses is included in avoided energy costs.

6. *Weighted Average Cost of Capital (WACC)*
   Pilot: Not applicable for contemporaneous recovery of these pilot costs.

[8] For more information on EIM, see www.westerneim.com/pages/default.aspx.
[9] 7th Power Plan applies transmission deferral value only.

The LSE will specify the following quantitative information relevant to the evaluation of each program, following the procedures outlined in these protocols:

1. *Load Impacts, in MW*
   Pilot: The average MW reduction across the four 2018 events was 0.258 MW at site. Applying the 10.13% estimated line loss, the load impacts at the generator are 0.284 MW.

2. *Expected call hours of the program (used to determine energy savings)*
   Pilot: Program was called for 13 hours in 2018. This is 25% of 52 maximum annual dispatch hours.

3. *Administrative Costs*
   Pilot: Administrative (non-incentive) costs paid in 2018 to Connected Energy include start-up, delivery and equipment installation costs for the third year of the pilot.

4. *Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)*
   Pilot: Participants do not incur capital costs to participate.

5. *Capital Costs and Amortization Period, both to the LSE and to the Participant (should be specified for each investment)*
   Pilot: There are no unamortized capital costs to recover over an amortization period. 2018 program expenses were paid through 2018 and are being recovered contemporaneously through Schedule 95.

6. *Revenues from participation in CAISO Markets (such as ancillary services or proxy demand resource)*
   - *CAISO Markets Entered*
   - *Average megawatts (MWs) and hours bid into those*
   - *Average market price received*
     Pilot: This resource was not large enough to change any portion of PacifiCorp's participation in CAISO markets.

7. *Bill reductions and increases*
   Pilot: 2018 participants' bills were not analyzed for changes since it was unlikely the thirteen event hours combined with a mixture of load shedding and load shifting around those events would have had an impact on total bills for the season.

8. *Incentives paid*
   Pilot: 2018 incentive payments were $10,834.

9. *Increased supply costs*
   Pilot: The resource is too small to change supply costs.

10. *Revenue gain/loss from changes in sales (usually assumed to be the same as bill reductions and increases)*
    Pilot: See No. 7 above.

11. *Adjustment Factors (if not required to use default values).*

    - *Data need to calculate Availability (A Factor)*
      Pilot: The portion of the capacity value that can be captured by the program based on availability (daily, monthly), frequency and duration of calls permitted. While this program is likely to be coincident with generation capacity constraints in the summer, it is not necessarily available during all hours (weekends, before June 1st that a generation constraint could occur.

    - *Notification Time (B Factor)*
      Pilot: This program has day ahead notification.

    - *Trigger (C Factor)*
      Pilot: Events can be called at the discretion of utility (within the specified months, weeks, days, hours). Other than that there are no restrictions. The 2018 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.

    - *Distribution (D Factor)*
      Pilot: The D factor can be summarized as "right time", "right place", "right certainty" and "right reliability". The pilot was not designed to avoid specific local investments.

    - *Energy Price (E Factor)*
      Pilot: Valuation for the avoided energy during the four events was performed internally by same team involved in other Oregon work; solar and avoided costs. Events require day ahead notification, so they are assumed to avoid day-ahead on-peak market energy purchases (16 hour blocks). The cost of replacing the portion of the 16 hour block not covered by the 3 or 4 hour curtailment event is estimated based on EIM price results. The small size of the current program makes it unlikely to actually avoid a day-ahead market transaction (typically 25MW increments). Estimated value based on day-ahead PacifiCorp transactions and EIM prices during the four events in 2018 was $1,988.

    - *Flexibility (F Factor)*
      Pilot: The pilot is too small for PacifiCorp to assess possible F Factor value.

    - *Geographical/local avoided generation capacity (G Factor)*
      Pilot: Not applicable.

The LSE may also add the following optional inputs:

1. *Social non-energy benefits, such as environmental benefits (in addition to the avoided*

GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
Pilot: Not applicable.

2. *Utility non-energy benefits, such as fewer customer calls and improved customer relations.*
   Pilot: Not applicable.

3. *Participant non-energy benefits, such as improved ability to manage energy use and "feeling green."*
   Pilot: Not applicable

4. *Market benefits, such as market power mitigation and market transformation benefits*
   Pilot: Not applicable.