Portland General Electric Company
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September 21, 2017

Email
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High St., SE, Ste. 100
P. O. Box 1088
Salem, OR 97308-1088

Attn: OPUC Filing Center

Re: UM-1514 PGE's Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response

Enclosed for filing is Portland General Electric Company's application for reauthorization of deferral of incremental costs associated with Non-Residential Demand Response, with an effective date of January 1, 2018.

PGE originally received permission for deferral of incremental costs associated with Non-Residential Demand Response through Commission Order No. 11-182. A Notice of Application regarding the filing of this application has been served by electronic mail to the OPUC Docket UE 319 and UM 1514 service lists.

Thank you for your assistance in this matter. If you have any questions or require further information, please call Alex Tooman at (503) 464-7623.

Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

encls.
cc: Bob Jenks, CUB
Tyler Pepple, ICNU
Jason Klotz, OPUC
Service List: UE 319 / UM 1514

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1514

In the Matter of the Application of Portland General Electric Company for an Order Reauthorizing the Deferral of Incremental Costs Associated with Non-Residential Demand Response	**Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response**

Pursuant to ORS 757.259, OAR 860-027-0300, and Public Utility Commission of Oregon (Commission) Order Nos. 16-037 and 17-105, Portland General Electric Company (PGE) hereby requests approval for the continuance of the deferral that is subject to an automatic adjustment clause rate schedule and is associated with the Non-Residential Demand Response Pilots (Non-Res DR Pilots or pilots). PGE also requests that the proposed pilots be included in the UM 1514 deferral, when Schedules 25 and 26 become effective.

I. Deferral History

PGE filed an application for deferral of incremental costs associated with an automated demand response (ADR or Energy Partner) pilot on December 29, 2010, seeking deferral from January 1 through December 31, 2011. This deferral and cost recovery tariff (Advice 10-29, Schedule 135) was approved by Commission Order No. 11-182 on June 1, 2011.

As discussed in PGE's report submitted April 28, 2016, with the second ADR evaluation, the pilot in its current form had fallen short of its nomination goal of 25 MW, with only 10.6 MW nominated for the summer of 2017. In addition, PGE's third-party provider, EnerNOC, informed PGE earlier this year that they were leaving the Pacific Northwest market and that as of September 30, 2017, they would be terminating their contract to provide the aggregator demand response (DR) services under the ADR pilot. PGE has taken this opportunity to review the existing ADR pilot along with Schedule 77[1] and revised them to create two pilots able to meet PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products.

The new pilots are based upon the results of the Energy Partner evaluations conducted by Itron (provided previously under Docket No. UM 1514), market research from Hansa (provided as Attachment D), customer interviews, focus groups, and Navigant report (provided as Attachment E). Across that research, some common themes emerged:

- No one offer will suffice for all customers. Thus, PGE needs to provide a variety of offerings:
- There needs to be more flexibility in programs;
- Important segments of our customer base (particularly in the commercial sector) are under-served;
- There are opportunities for additional demand response from direct access customers who are not eligible for this program; and
- Offerings need to better address customer business needs.

By addressing these issues, we believe the new pilot program will be successful and will help PGE meet its 819 MW capacity deficit projected for 2021.[2] However, because the Non-Res DR effort is in transition, PGE proposes to continue its deferred accounting.

To date, PGE filed and received reauthorization for this deferral, as shown in Table 1 below. PGE seeks reauthorization for deferral of incremental costs associated with the revised Non-Res DR Pilots for the period beginning January 1 through December 31, 2018, and asks that

[1] Firm Load Reduction Program, which has only one customer.
[2] PGE 2016 Integrated Resource Plan (IRP), Docket No. LC 66, page 113.

the proposed pilots be included in the UM 1514 deferral, when Schedules 25 and 26 become effective.

Table 1
UM 1514 Authorizations

Filing Date	Renewal Period	Order No.	Approval Date
12/29/2010		11-182	06-01-2011
12/23/2011	1/01/2012 – 12/31/2012	12-062	02-28-2012
12-27-2012	1/01/2013 – 12/31/2013	13-059	02-26-2013
12-11-2013	1/01/2014 – 12/31/2014	14-019	01-22-2014
12-24-2014	1/01/2015 – 12/31/2015	15-022	01-28-2015
12-18-2015	1/01/2016 – 12/31/2016	16-037	01-26-2016
12-15-2016	1/01/2017 – 12/31/2017	17-105	03-21-2017

II. <u>Current Proposal</u>

Overview

PGE proposes to implement the Non-Res DR Pilots to replace the current ADR pilot and PGE's Schedule 77, Firm Load Reduction Program. To do so, we will submit Schedule 25, Non-residential Direct Load Control Pilot and Schedule 26, Non-residential Demand Response Pilot (provided as Attachments A and B). We believe that customers on the current ADR pilot and Schedule 77 will enroll in Schedule 26 and will continue providing demand response to PGE. Both pilots are expected to be conducted through September 30, 2020. As we had intended with the earlier versions of ADR, after the pilots have stabilized, we plan to move them into power costs as capacity resources and continue them as a long-term program.

In contrast to ADR, the proposed pilots will be administered directly by PGE to its customers, with support from a program implementer and a technology integrator / demand response management system (DRMS) provider. PGE took this approach primarily to allow us the flexibility to offer a variety of products and potentially adjustment those products in the future. The previous EnerNOC program was inflexible in its parameters, which was identified as one of the barriers to adoption. The secondary reason for PGE to work directly with customers is to ensure resilience of the portfolio. With the loss of EnerNOC in 2017, new contracts and new technology will need to be put in place for our current participants. By administering the program, PGE hopes to ensure that we will not lose a third party provider again and, thereby, avoid adversely affecting the ongoing operation of nonresidential DR. Administering the program also gives PGE and its implementer the ability to better bundle and/or cross-market the program with other offerings, such as energy efficiency, renewables, storage, and dispatchable standby generation.

The revised proposal will be offered through two new tariffs, which we discuss in more detail below. This new program design and its accompanying tariffs will open up new opportunities to expand the market. Existing and new customers that were previously averse to the long availability windows (10 hours under EnerNOC) and/or short notification window (10 minutes previously) will be able to have increased capacity commitments under less onerous conditions. Small and medium-sized businesses will be able to participate through either a turnkey thermostat offering or through the curtailable tariff with the flexibility that meets their needs. Campuses, a historically underserved market segment, will be able to aggregate their meters to participate without having to incur significant up-front costs across numerous smaller sites.

In order to run these pilots, PGE has contracted with CLEAResult to administer the marketing, sales, and implementation. Enbala Corporation has been separately contracted to provide the technology integration and the DRMS. Both contractors were selected through an open Request for Proposals. These contractors were also selected for the multi-family water heater DR pilot,[3] potentially providing synergies in multi-tenant buildings.

Evaluations

PGE will submit two pilot evaluations to the Commission and stakeholders:

- The first evaluation will be submitted during the third quarter of 2019, after the first three operating seasons. This will allow for adequate time and events to provide meaningful results.
- A final evaluation will be submitted in the second quarter of 2021, after the next three operating seasons and the planned end of the pilots.

The evaluations will include various metrics on customer participation, demand response capacity, and data gaps that emerge from the program. In order to ensure that we have results to evaluate, even during seasons with mild weather or minimal need for DR curtailment, PGE will call a minimum of one event per agreement year.[4]

While PGE is interested in pursuing pricing options for nonresidential customers there are several barriers to implementing them at this time. For instance, the first evaluation will not be available until 2019. More importantly, the new customer information system (CIS)[5] will not be implemented until the second quarter of 2018. We will submit a detailed pricing offering after the CIS is operational and as part of the discussion regarding the move to fully scalable DR programs.

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[3] See Docket No. UM 1827.
[4] As currently specified on Schedule 77.
[5] See PGE Exhibit 900 in Docket No. UE 319, PGE's 2018 general rate case for a discussion of the new CIS.

Schedule 25

Schedule 25, Non-Residential Direct Load Control Pilot, provides nonresidential customers with a turnkey, direct load control program, similar to Schedule 5 for our residential customers. This will provide an easy opportunity for our commercial customers to participate, while getting the value added services associated with one or more smart thermostats.

More specifically, the direct load control pilot offers incentives to allow PGE to control up to 10,000 qualified thermostats during direct load control events while providing for customer override. Eligible customers must have a PGE network meter and must also have a qualified thermostat[6] connected to the internet and their heating or cooling systems. To participate in winter event seasons, customers must have a ducted heat pump or electric forced air heating. To participate in the summer event seasons, the customers must have central air conditioning or a ducted heat pump.

Direct load control events will occur for one to five hours. PGE may call two events per day, but will not exceed five cumulative hours for the day. During direct load control events (initiated with event notification), customers allow PGE to control their thermostat for the duration of the event, although customers have the option to not participate by overriding via their thermostat. Additional details regarding the direct load control events and pilot incentives are included in the draft Schedule 25, provided as Attachment A.

Schedule 26

Schedule 26, Non-Residential Demand Response Pilot, resembles Schedule 77, PGE's current curtailable tariff. Schedule 26, however, provides a much greater diversity of participation levels, allowing customers to select differing availability periods, notification times,

[6] Qualified thermostats are provided as an incentive.

and maximum event hours. Schedule 26 will also allow customers with multiple points of delivery (POD) the ability to self-aggregate their PODs.

Schedule 26 allows a customer to participate in summer, winter or both seasons. Schedule 26 also makes several firm load reduction options available to customers including: maximum event hours per season, notification periods, and event windows. For each season, the Customer chooses one option for maximum event hours per season and one notification period. The Customer also chooses whether or not to participate in each event window (time period for an event) per season.

Participating customers will receive reservation payments based on their qualified load reduction (kW) multiplied by the sum of each applicable reservation price ($/kW as specified by Schedule 26) based on the options selected. Participating customers will also receive an energy payment based on the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex.

The load reduction, on which the payments are made, will be calculated on a customer's baseline load profile. The profile will be based upon the average hourly load of the five highest load days in the last ten typical operational days for the event period with adjustments specific to the day-of operational characteristics leading up to the event. Additional details regarding the pilot's options, baseline measurements, notifications, etc. are included in the draft Schedule 26, provided as Attachment B.

Cost Effectiveness

The cost effectiveness of the Non-Residential Demand Response proposals is based on the methodology proposed in Navigant's 2016 memo, *A Proposed Cost-Effectiveness Approach for Demand Response*, and is provided as Attachment C. A significant aspect of the cost effectiveness is the de-rate or discount factors used to reflect the operational differences between a dispatchable supply-side resource (based on the levelized fixed costs per kW of a simple cycle frame resource) and demand response (as described by the pilots' parameters).

The most accurate approach for determining this de-rate factor would be to run PGE's loss of load probability, Renewable Energy Capacity Planning (RECAP), model with the DR parameters. Both time constraints and the maturity of the model, however, impeded this approach. As an alternative, PGE reviewed de-rate factors used in DR programs elsewhere and selected those from programs with the most similar parameters. Based on this review and the proposed range of the pilots' participation options, PGE employed the following factors to produce a blended A factor of 47%:[7]

- Southern California Edison's Commercial Base Summer Discount Plan. This is limited to 90 annual event hours with six-hour event duration (A factor 44.8%).
- Southern California Edison's Critical Peak Pricing. This is limited to 12 events per year, 48 hours per month, with four-hour event duration (A factor 26.1%).
- Southern California Edison's Residential Summer Discount Plan. This is limited to 180 hours per year with six-hour event duration (A factor 65.7%).

PGE then applied the blended A factor across the pilots' offerings in the cost effectiveness tests (see Attachment C, "Benefit Details", for additional details regarding the calculation and application of the A factor).

PGE also applied additional discounting of a blended B factor (94.6%) based on the length of notification option. By combining the de-rating factors along with the cost of the baseline supply-side resource, PGE calculated the avoided capacity costs for use in its cost-effectiveness calculation as shown in Table 2, below.

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[7] This de-rate factor is more conservative (i.e., lower) than was employed for ADR, which this pilot replaces.

Table 2
Avoided Capacity Cost

Avoided capacity cost; 2016 IRP	$123.19
Grossed up for line losses (8.91%)	$135.24
De-rate availability, A factor	47.0%
De-rate notification, B factor	94.6%
De-rated avoided capacity cost	$60.18

Loss of Load Probability

In PGE's 2016 Integrated Resource Plan, PGE's reliability target was that our loss of load probability (LOLP) not exceed one day in 10 years (i.e., 2.4 hours per year). To address this, PGE used the RECAP model to calculate PGE's existing LOLP for each month/day-type/hour of a test year (2021), taking into account load shapes, wind and solar hourly generation profiles, hydro capacity values, and thermal resource output according to monthly average temperatures and forced outage rates. The RECAP study concluded that PGE's 2021 loss of load expectation (LOLE) is 253 hours per year if no additional resources are acquired (versus the target of 2.4 hours). The study also produced a heat map of the seasonal and hourly shape of the LOLE. This heat map indicates that capacity shortages are not evenly spread, but rather cluster in winter morning and evening hours, and in the summer afternoon and evening hours.

For Schedule 26, PGE aggregated the LOLE heat map hourly values into the tariff windows. Winter season windows total 11 hours per day; summer season windows total 15 hours per day. Because the two program seasons cover eight of 12 months, the seasonal windows cover 91% of the LOLE hours in the 2021 test year.

In order to allocate the derated avoided capacity cost across the windows, PGE grossed up the sum of all windows from 91% to 100%, and multiplied each window's share of the LOLE by the derated avoided capacity cost ($60.18, as discussed above). More valuable windows indicate time periods in which PGE's LOLE is the highest, which occur both in summer and winter between 4:00 and 8:00 pm.

III. OAR 860-027-0300 Requirements

The following is provided pursuant to OAR 860-027-0300(3):

a. Description of Amounts

Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with the Non-Res DR pilots. The approval of the Application will support the continued use of an automatic adjustment clause rate schedule, which will provide for recovery of the incremental costs associated with the pilots through tariff Schedule 135.

In accordance with the stipulated AMI Conditions (Docket No. UE 189), PGE has endeavored to develop a demand response program for up to 25 MW of peaking capacity in aggregate among our commercial and industrial customers. The decision in UM 1514 approved PGE's application for deferral of incremental costs associated with the ADR pilot. PGE requests that: 1) the revised pilots be included in the UM 1514 deferral, when Schedules 25 and 26 become effective; and 2) the deferral be renewed for an additional year beginning January 1, 2018, and be amortized under Schedule 135, subject to Commission Order.

b. Reasons for Deferral

Pursuant to ORS 757.259(2)(e), for the reasons discussed above, PGE seeks to continue deferred accounting treatment for the incremental costs associated with the Non-Res DR pilots. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Without reauthorization, the current authorization to defer costs will expire on December 31, 2017. PGE is filing this reauthorization application for the period January 1 through December 31, 2018.

c. Proposed Accounting

PGE proposes to record the pilots' deferred costs in FERC Account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131, (Cash). In the absence of deferral reauthorization, PGE would not receive revenues to recover the pilots' costs. Consequently, PGE would discontinue the pilots and incur no additional costs.

d. Estimate of Amounts

PGE estimates the amounts to be deferred for the pilots in 2018 to be approximately $2.5 million.

e. Notice

A copy of the notice of application for reauthorization of the deferred accounting treatment is attached to the application as Attachment F. In compliance with the provisions of 860-027-0300(6), PGE is serving the Notice of Application on the UE 319 Service List, PGE's last general rate case.

IV. The following is provided pursuant to OAR 860-027-0300(4)

a. Description of deferred account entries

Please see section II (c) above.

b. The reason for continuing deferred accounting

Please see Section II (b) above. PGE is seeking approval to continue the approved deferred accounting treatment for incremental Non-Res DR Pilots' costs pursuant to Commissioner Order No. 17-105 as described above.

V. PGE Contacts

Communications regarding this reauthorization application should be addressed to:

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In addition to the names and addresses above the following are to receive notices and communications via the e-mail service list:

Alex Tooman, Project Manager, Regulatory Affairs
E-mail: alex.tooman@pgn.com.

VI. Summary of Filing Conditions

a. Earnings Review

The cost recovery the Non-Res DR pilots will be subject to an automatic adjustment clause rate schedule and would not be subject to an earnings review under ORS 757.259. When the pilots are complete and the nominated capacity level is stable, PGE proposes that the subsequent pilots' costs flow through PGE's Annual Power Cost Update (AUT – Schedule 125) and Power Cost Adjustment Mechanism (PCAM – Schedule 126). These costs would then be subject to the earnings review contained within the PCAM.

b. Prudence Review

The methodology used to evaluate the pilots remains sound. PGE will continue to evaluate demand response resources against the supply-side capacity resource alternatives, such as a simple-cycle combustion turbine. This is consistent with the discussion in Commission Order

No. 05-584 and is consistent with other PGE analyses for demand side capacity resources in recent years.

c. Sharing

As discussed in Section V (a), above under the earnings review, when the pilots are completed, then the proposal is for subsequent costs to flow through PGE's AUT and PCAM. The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.

d. Rate Spread/Rate Design

Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the pilots on the basis of an equal percent of forecast generation revenues.

e. Three percent test (ORS 757.259(6))

The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. PGE's deferral amortizations are currently within the 3% limit and this is expected to continue throughout 2018.

VII. Conclusion

For the reasons stated above, PGE requests permission to continue to defer for later rate-making treatment incremental costs associated with the Non-Residential Demand Response Pilots effective January 1 through December 31, 2018. PGE also requests that the proposed pilots be included in the UM 1514 deferral, when Schedules 25 and 26 become effective.

DATED this September 21, 2017.

Respectfully Submitted,

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UM 1514

Attachment A

Draft Schedule 25

SCHEDULE 25
NONRESIDENTIAL DIRECT LOAD CONTROL PILOT

PURPOSE

This direct load control pilot is a demand response option for eligible nonresidential Customers. The direct load control pilot offers incentives to allow the Company to control thermostats during Direct Load Control Events while providing a customer override. The Company provides advance notice to participating Customers for Direct Load Control Events. The pilot is expected to be conducted from November 1, 2017 through September 30, 2020.

DEFINITIONS

Central Air Conditioning – air conditioner tied into a central ducted forced air system.

Direct Load Control – a remotely controllable switch that allows the utility to operate an appliance, often by cycling. In terms of this pilot, direct load control allows the Company to change the set point or cycle the Customer's heating or cooling through the Customer's Qualified Thermostat in order to reduce the Customer's energy demand.

Direct Load Control Event – a period of time in which the Company will provide direct load control.

Ducted Heat Pump – heat pump heating and cooling system hooked into a central ducted forced air system.

Electric Forced Air Heating – an electrical resistance heating system tied into a central ducted forced air system.

Event Notification – the Company will issue a notification of a Direct Load Control Event to participating Customers. Participating Customers must choose at least one method for receipt of notification. Notification methods may include email, text, auto-dialer phone call, on thermostat display screen, or via mobile app notification. Notification may also be available on the Company's website.

Event Season – the pilot has two event seasons: the Summer Event Season and the Winter Event Season.

Holidays – the following are holidays for purposes of the pilot: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

SCHEDULE 25 (Continued)

DEFINITIONS (Continued)

Summer Event Season – the summer event season includes the successive calendar months June through September.

Winter Event Season – the winter event season includes the successive calendar months November through February.

Qualified Thermostat – thermostats that are Company-approved and listed on PortlandGeneral.com.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Subject to selection by the Company, up to 10,000 Qualified Thermostats from eligible nonresidential Customers may elect to participate in the pilot. The Company will limit participation to 10,000 Qualified Thermostats. This program is available to eligible Customers on nonresidential schedules that elect to enroll. Customers will remain on their base schedule and will be eligible for the incentives described in this schedule.

ELIGIBILITY

Eligible Customers must have a Network Meter. Customers must have a Qualified Thermostat connected to the internet and the heating or cooling system at the Customer's expense, except as provided in the Incentives section of this schedule. To participate in the Winter Event Season, the Customer must have a Ducted Heat Pump or Electric Forced Air Heating. To participate in the Summer Event Season, the Customer must have Central Air Conditioning or a Ducted Heat Pump.

DIRECT LOAD CONTROL EVENT

Direct Load Control Events occur for one to five hours. The Company may call two events per day, but will not exceed five cumulative hours for the day. During Direct Load Control Events the Customer may allow the Company to control their thermostat for the duration of the event. The Customer has the option not to participate by overriding via the thermostat. The Company initiates Direct Load Control Events with Event Notification. The Company will call Direct Load Control Events only in the following months: November, December, January, February, June, July, August, and September. Direct Load Control Events will not be called on weekends or Holidays. Reasons for calling events may include, but are not limited to: energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 or below 32, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. The Company will call no more than 150 event hours per Event Season.

SCHEDULE 25 (Continued)

ENROLLMENT

The Customer may enroll at any time, but must participate for the minimum number of hours described in the incentive section.

INCENTIVE

Participating Customers receive a Qualified Thermostat for signing up for the direct load control pilot. A Customer may receive multiple Qualified Thermostats for separate spaces subject to verification by the Company. In addition, Customers receive $60 per Qualified Thermostat for each Event Season they participate. A Customer participating in all Event Seasons receives $120 per Qualified Thermostat per pilot year. Incentives are paid to the Customer with a check, bill credit, or generic gift card. To receive payment for an Event Season, the Customer must participate in at least 50% of the event hours for which the Customer is eligible to participate in that Event Season.

SPECIAL CONDITIONS

1. The Customer may terminate service under this pilot at the next regularly scheduled meter reading if the Customer provides the Company two weeks' notice prior to the next regularly scheduled meter read date.

2. Customers that reenroll in the program are not eligible for a second Qualified Thermostat for signing up. A Customer continuing service at a new location is not considered a new enrollment.

3. If the participating Customer moves to a different location, the Customer may continue participation if the new location meets the eligibility requirements.

4. The Company will defer and seek recovery of all pilot costs not otherwise included in rates.

5. The Company is not responsible for any direct, consequential, incidental, punitive, exemplary, or indirect damages to the participating Customer or third parties that result from AC Cycling or changing the thermostat set point.

6. The Company shall have the right to select the cycling schedule and the percentage of the Customer's heating or cooling systems to cycle at any one time, up to 100%, at its sole discretion.

7. The provisions of this schedule do not apply for any time period that the Company interrupts the Customer's load for a system emergency or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular service schedule and associated charges.

SCHEDULE 25 (Continued)

SPECIAL CONDITIONS (Continued)

8. PGE has the right to remove a Customer from the pilot when good cause is shown including, but not limited to, for poor customer responsiveness, consistent customer non-participation in called events, or issues with customer equipment that impact customer's participation.

TERM

This pilot term is November 1, 2017 through September 30, 2020.

UM 1514

Attachment B

Draft Schedule 26

SCHEDULE 26
NONRESIDENTIAL DEMAND RESPONSE PILOT PROGRAM

PURPOSE

This schedule is an optional supplemental service that provides participating Large Nonresidential Customers incentives for reducing a committed amount of load at the request of the Company. Under this tariff, the Customer provides a Firm Load Reduction Commitment that the Company calls at any time according to the conditions listed below. The pilot is expected to be conducted from November 1, 2017 through September 30, 2020.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Nonresidential Customers served under Schedules 32, 38, 47, 49, 75, 83, 85, 89, and 90. Participating Customers must execute a Schedule 26, Firm Load Reduction Agreement (Agreement) to participate in this program. The Agreement specifies the Customer's Firm Load Reduction Commitment and selected Firm Load Reduction Options.

CUSTOMER ENROLLMENT

Qualified Customers must enroll at least one week prior to the Participation Month.

At the time of enrollment, for each event window, the Customer chooses the load reduction amount, advance-notice option, and maximum event hours per season option. First-time participants can also opt-in for a commissioning test.

Within five days of enrollment, the Company will confirm receipt of the PODID(s) the Customer intends to enroll under this schedule and the Company or its representatives will send a signed Agreement to the Customer's representative. The Customer may choose to aggregate PODIDs.

Each Agreement will automatically renew for successive annual terms on January 1st of subsequent calendar years unless the Customer elects to terminate such Agreement by notifying PGE prior to January 1st or this Schedule is withdrawn, revoked or otherwise terminated. A customer may also choose to change their contracted participation options by notifying PGE prior to January 1st.

SCHEDULE 26 (Continued)

CUSTOMER PARTICIPATION OPTIONS

Customers are offered three participation options: Option 1 provides that the Customer participates for all eight months of the contracted program year. Options two and three offer the Customer summer or winter seasonal participation. In the second option the Customer participates for four months in the summer – June, July, August and September. The third option is the Customer participates for four months in the winter – November, December, January and February. Customers select one of the three options at the time of enrollment.

Customer Option	Participation Months	Number of Months Participating
1	Nov, Dec, Jan, Feb, Jun, Jul, Aug, Sep	Eight-month – both seasons
2	Jun, Jul, Aug, Sep	Four-month seasonal – summer
3	Nov, Dec, Jan, Feb	Four-month seasonal – winter

FIRM LOAD REDUCTION OPTIONS

Several firm load reduction options are available to Customers in the Reservation Price Section: Options include differing maximum event hours per season, notification periods, and event windows. For each event window (time period for an event) per season, the Customer must choose only one option or choose not to participate in that event window. For example, for the summer 11 am to 4 pm event window, the Customer can choose an 18 hour ahead notification period with a maximum of 20 event hours per season, but cannot make any other selections for the summer 11 am to 4 pm event window.

RESERVATION PRICE

20 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Period		
	18 hours	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$1.68	$1.80	$1.91
4 pm - 8 pm	$1.95	$2.08	$2.22
8 pm - 10 pm	$0.39	$0.42	$0.45
All summer windows	$4.02	$4.30	$4.57
Winter (November - February)			
7 am - 11 am	$1.27	$1.35	$1.44
11 am -4 pm	$0.73	$0.78	$0.83
4 pm - 8 pm	$2.07	$2.22	$2.36
8 pm - 10 pm	$0.73	$0.78	$0.83
All winter windows	$4.80	$5.13	$5.46

SCHEDULE 26 (Continued)

RESERVATION PRICE (Continued)

40 Event Hours per Season
Monthly Payment per kW

	Notification Period		
Windows	**18 hours**	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$2.52	$2.69	$2.87
4 pm - 8 pm	$2.92	$3.12	$3.32
8 pm - 10 pm	$0.59	$0.63	$0.67
All summer windows	$6.04	$6.45	$6.86
Winter (November - February)			
7 am - 11 am	$1.90	$2.03	$2.16
11 am -4 pm	$1.09	$1.17	$1.24
4 pm - 8 pm	$3.11	$3.32	$3.54
8 pm - 10 pm	$1.09	$1.17	$1.24
All winter windows	$7.20	$7.70	$8.19

80 Event Hours Maximum per Season
Monthly Payment per kW

	Notification Period		
	18 hours	**4 hours**	**10 minutes**
Summer (June - September)			
11 am -4 pm	$3.35	$3.58	$3.81
4 pm - 8 pm	$3.89	$4.16	$4.42
8 pm - 10 pm	$0.79	$0.84	$0.89
All summer windows	$8.03	$8.58	$9.12
Winter (November - February)			
7 am - 11 am	$2.53	$2.70	$2.87
11 am -4 pm	$1.46	$1.56	$1.65
4 pm - 8 pm	$4.14	$4.42	$4.70
8 pm - 10 pm	$1.46	$1.56	$1.65
All winter windows	$9.58	$10.23	$10.89

SCHEDULE 26 (Continued)

COMMITTED LOAD REDUCTION

If a Customer has completed a test event, but not participated in actual events, their Committed Load Reduction will be based on nominated load identified in the agreement. If a Customer has completed only one event, their Committed Load Reduction will be the higher of either their nominated load or their first event performance. If a Customer has participated in more than one event, their Committed Load Reduction will be based on an average of actual load reductions during event hours. The Customer, at its discretion, may choose to increase its nomination above the levels described above.

QUALIFIED LOAD REDUCTION

If no events are called in a Participation Month, the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for the full Reservation Payment during a month with events, the Customer must provide a minimum of 90% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month. If the Customer qualifies for the full Reservation Payment; the Qualified Load Reduction is the Committed Load Reduction.

In order to qualify for a proportional reservation payment during a month with events, the Customer must deliver a minimum of 70% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month. If the Customer qualifies for a reduced reservation payment; the Qualified Load Reduction is the average load reduction for all event hours during that month.

If the Customer fails to deliver a minimum of 70% of the Committed Load Reduction for each and every hour during an event for which the Customer is enrolled during events in that month, the Customer is not eligible for the Energy Reduction Payment for that Event and the Reservation Payment for that month. If other Load Reduction Events are called in the same month, and the Customer complies, the corresponding Energy Reduction Payments are paid for each event that the Customer delivers a minimum of 70% of the Committed Load Reduction for each and every hour for which the Customer is enrolled during events in that month.

RESERVATION PAYMENTS

The Reservation Payment is the Customer’s Qualified Load Reduction (kW) multiplied by the sum of each applicable Reservation Price ($/kW) based on the Options selected by the Customer adjusted for losses based on the Customer’s delivery voltage. For each event window (time period for an event) per season, only one price is applicable. The Reservation Payment is made to the Customer no later than 60 days after the month in which they participated.

SCHEDULE 26 (Continued)

ENERGY PAYMENTS

The Energy Payment is the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction Amount can be up to 120% of the commitment.

The monthly prices for energy per MWh are:

Nov 2017	Dec 2017	Jan 2018	Feb 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018
$29.95	$36.30	$29.88	$27.99	$18.17	$26.02	$29.24	$27.01

The Firm Energy Reduction Payment rates will be updated annually by December 1st for the next calendar year. Evaluation and settlement of the Firm Energy Reduction Payment will occur within 60 days of the Firm Load Reduction Event.

*Holidays are New Year's Day (January 1), President's Day (February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a holiday. If a holiday falls on Sunday, the following Monday is designated a holiday.

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

LOAD REDUCTION MEASUREMENT

Load Reduction is measured as a reduction of Demand from a Customer Baseline Load calculation during each hour of the Load Reduction Event. Although the Firm Load Reduction Agreement shall specify the Customer Baseline Load calculation methodology to be used, PGE generally uses the following baseline methodology:

Baseline Load Profile

The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical Operational Days for the Event period. For Customers choosing the four-hour or 10-minute notification options there is an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Event if the Event starts at 11 am or later. This adjustment is the difference between the Event day load and the average load of the five highest days used in the load profile above during the two-hour period ending four hours prior to the start of the Event.

SCHEDULE 26 (Continued)

LOAD REDUCTION MEASUREMENT (Continued)

Typical Operational Days

Typical Operational Days exclude days that a Customer has participated in a Firm Load Reduction Event or pre-scheduled opt-out days as defined in the Special Conditions. Typical Operational Days for the baseline calculation are defined as the ten applicable days closest to the Load Reduction Event. Typical Operational Days may exclude Saturdays, Sundays and WECC holidays.

The Company may decline the Customer's enrollment application when the Company determines the Customer's energy usage is highly variable and the Company is not able to verify that a reduction will be made when called upon.

FIRM ENERGY REDUCTION

The Firm Energy Reduction amount is the difference between the Customer's Baseline Energy profile and the Customer's measured hourly energy usage during the Load Reduction Event.

LOAD REDUCTION EVENT

The Company, at its discretion, initiates a Load Reduction Event by providing the participating Customer with the appropriate notification consistent with the Customer's selected Firm Load Reduction Option. The Customer reduces its Demand served by the Company, for each hour of the Load Reduction Event to achieve its Committed Load Reduction. Each load reduction event will last from one to five hours in duration. For pilot purposes, the Company will call at least one event per season.

The Company initiates Load Reduction Events during January, February, June, July, August, September, November, and December.

EVENT NOTIFICATION

The Company notifies the participating Customer of a Load Reduction Event using a mutually agreed upon method at the time of enrollment. The Company's notification includes a time and date by which the Customer must reduce the committed Demand for each period of the Load Reduction Event.

The Customer is responsible to notify the Company if the Customer's contact information specified at the time of the enrollment changes as soon as such change occurs.

FIRST-TIME PARTICIPANT OPTIONAL COMMISSION TEST

A commissioning test is available to Customers who are participating on this schedule for the first time. Interested participants will work with the Company to learn the details of this process.

SCHEDULE 26 (Continued)

SPECIAL CONDITIONS

1. Customers cannot use on-site generation equipment for load reductions to meet load reduction commitments under this tariff.

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, or 590 will be withdrawn from this program.

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Reduction Event or the Customer's effort to reduce Energy in response to a Firm Load Reduction Event.

5. This tariff is not applicable when the Company requests or initiates Load Reduction affecting a Customer PODID under system emergency conditions described in Rule N or Rule C(2)(B).

6. The Company will not cancel or shorten the duration of a Firm Reduction Event once notification has been provided.

7. The Company will file any adjustment to the Reservation Rate by August 1st for the next program year.

8. Participating Customers are required to have interval metering and meter communication in place prior to initiation of service under this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage.

9. If the Customer experiences operational changes or a service disconnection that impairs the ability of the customer to provide the Firm Load Reduction as requested under this schedule, the agreement will be terminated.

10. If the Company is not allowed to recover any costs of this program by the Commission, the Company may at its option terminate service under this agreement with 30-day notice.

SCHEDULE 26 (Continued)

SPECIAL CONDITIONS (Continued)

11. The Customer may pre-schedule four opt-out days per season at nomination and indicated in the Agreement. If the Company calls a Load Reduction Event on a pre-scheduled opt-out day, the Customer is exempt from providing load reduction and receives no Firm Energy Reduction Payment, whether or not they choose to operate. The Customer will receive the Reservation payment if otherwise eligible. An opt-out day will not be included in the calculation of the Baseline Demand Profile.

12. Customers who opt for this Schedule may be placed on a calendar monthly billing cycle.

TERM

This pilot term is November 1, 2017 through September 30, 2020.

UM 1514

Attachment C

Costs Effectiveness

Schedules 25 and 26 Nonresidential Demand Response Cost Effectiveness

The analysis estimates the cost effectiveness of three commercial Demand Response (DR) programs that will replace PGE's Energy Partner program in fall 2017. Current program enrollment assumptions, cost, and benefit estimates indicate a positive preliminary benefit: cost ratio of 1.03 for the Total Resource Cost Test. This is the primary metric used by the OPUC.[1]

Total Resource Cost Test			
Cost/Benefit Category	**Costs**	**Benefit**	
Administrative costs	$6,600,000		
Avoided costs of supplying electricity		$20,460,000	
Bill Reductions			
Equipment costs to utility	$4,810,000		
Environmental benefits		$20,000	
Incentives paid			
Revenue loss from reduced sales			
Transaction costs to participant (25%)	$4,190,000		
Value of service lost (25%)	$4,190,000		
	$19,790,000	$20,480,000	
Benefit Cost Ratio			**1.03**

Costs and benefits reported in the above table are the net present value of a 20-year stream of revenue and expenses.[2] Three additional tests are included on the final page of this report.

The general approach employed in this analysis is to align with recent PGE analyses of DR programs. PGE expects that upcoming dockets with the Oregon Public Utility Commission and stakeholders will refine the methodological approach to calculating program cost effectiveness, and analyses of future programs (as well as post-pilot analyses of existing programs) may look different and thus conclude different results.

Key Programmatic Assumptions

- This analysis encompasses three commercial DR program structures, all of which will be implemented by the same vendor team and through a single contract:
    1. Small Business (Schedule 25). Incentives consist of a free thermostat and $60 annual payment. Events are limited to 80 hours per year; five hours per event. The hours in which events may be called are delineated in the tariff. Event notification is provided four hours in advance.

[1] The application of this test to the Commercial and Industrial Demand Response program follow the methodology proposed in Navigant's 2016 memo, *A Proposed Cost-Effectiveness Approach for Demand Response*.
[2] Annual costs and benefits were discounted using the weighted average cost of capital of 7.18% (September 2017 update).

2. Standard (Schedule 26). Participants receive capacity and energy payments per kW nominated for curtailment and kWh reduced during events. Events are limited to 80 hours per year; five hours per event. The hours in which events may be called are delineated in the tariff. Event notification is provided four hours in advance.
3. Custom (Schedule 26). Participants select the hours in which they will participate, the notification timeframe, and maximum hours per year. Capacity incentive per kW nominated is adjusted accordingly. Energy payments reflect actual kWh curtailed during events.

Cost benefit modeling averages incentives across program types and anticipated participation levels.

- Program participation increases over three years to achieve PGE's goal of 27 MW by 2020 (AAGR of 40%).
- In years 6-20, the program is modeled to grow more slowly at 3% annually, achieving 42 MW of demand reduction by 2036. This is a conservative growth estimate; vendor contracts are for five years only. This cost estimation approach accounts for program expansion and maintenance as well as equipment replacement as (5-10 year) asset life is exceeded.

Goals of Pilot Project

- Grow all DR programs into sustainable, long-term programs incorporated into the PGE dispatchable resource stack.
- Future program evaluation anticipates repeating these tests and replacing assumptions with both observed results and any program adjustments that may occur due to participant feedback. These inputs may include:
  - Customer adoption rates and distribution across program options.
  - Allocation of payment across variable (energy) and fixed (capacity) components.
  - Updated vendor costs (program administration and equipment).
  - Realization of participant kW nominated for curtailment.

Cost Details

- **Administrative and Equipment Costs**. Vendors CLEAResult and Enbala are under contract as third party implementers of these programs. Administrative and equipment costs reflect all labor and expenses. All costs are to be expensed; no equipment will be capitalized. The Enbala contract will support multiple programs; costs were assigned to this program as total proposed cost minus costs previously negotiated for the Water Heater pilot.
- **Transaction Costs to Participants**. Transaction costs reflect the inconvenience/intrusion associated with the installation process, program education, and program audit and evaluation. Costs are considered indirect, and defined as a percentage of the incentive provided. C&I DR modeling currently assumes 25% or low transaction costs, consistent with Navigant's 2016 review of the Energy Partner program. This percentage was assigned to total estimated annual incentives paid.

- **Value of Lost Service**. Loss of service costs are intended to reflect productivity and comfort losses, and are also calculated as a percentage of the incentive payment. The model assumes the service loss equates of 25% of the incentive payment, consistent with Navigant's 2016 review of the Energy Partner program.

Benefit Details

- **Avoided Cost of Supplying Electricity**. Typically three value streams are included.
  1. Avoided Cost of Capacity. Demand response reduces PGE's need for capacity by reducing demand. To estimate the value (or cost) of the capacity avoided, this analysis multiplies the average net reduction in demand (kW) per participant x the number of participants x the value of one kW of additional capacity. The value of capacity is based on the real levelized fixed cost of a simple cycle combustion turbine (1x0 GE 7F.05). PGE's 2016 IRP found this to be the least cost dispatchable unit at an estimated $125.70/kW-year (2018 dollars). Total fixed cost includes capital ($58.19), fixed O&M wheeling ($29.46), and fixed gas transport ($38.04). This value is then grossed up for line losses (6.85% per PGE secondary delivery voltage adjustment factor + 2.06% to reflect marginal peak vs. average line loss).
     - Discount Factors. The Avoided Cost of Capacity is then discounted to reflect the operational differences between a dispatchable thermal resource and demand response (as described by this program's parameters). The most influential discount factor employed in the analysis is the A factor. Navigant describes the A factor as the percent of overlap between program availability hours and forecasted periods of highest demand or load loss. The most accurate approach for determining this factor would be to run PGE's loss of load probability model (RECAP) with the DR program parameters. Both time constraints and the maturity of the model inhibited this approach. As an alternative, A factors used in similar D&R programs elsewhere were reviewed, and applied from the program with most similar parameters. Because this program offers a broad range of participation options, a blend of A factors was employed:
       - Southern California Edison's Commercial Base Summer Discount Plan is limited to 90 annual event hours with six hour event duration (A factor 44.8%). This was applied to the Small Business, Standard, and 45% of Custom participants (on the assumption that 45% of Custom participants select a cap of 80 hours annually).
       - Southern California Edison's CPP is limited to 12 events per year, 48 hours per month, with four hour event duration (A factor 26.1%). This was applied to 10% of Custom participants (on the assumption they select a cap of 40 hours annually).
       - Southern California Edison's Residential Summer Discount Plan is limited to 180 hours per year with six hour event duration (A factor 65.7%). This was applied to 45% of Custom participants (on the assumption they select a cap of 160 hours annually).

The resulting blended A factor, applied across the three program offerings, is 47%. This is a more conservative assignment than was employed for the Energy Partner program, which this C&I program replaces. Navigant reviewed that program and found that its parameters were most similar to PG&E's PeakChoice program (maximum 75 hours), for which the A factor was widely estimated at between 41% and 82%, depending on the assumptions around historical load hours. Given the broad range, Navigant assumed a mid A factor value of 60% for the Energy Partner program.

Discount factors were applied as follows:

A Availability	47%
B Notification	95%
C Trigger	100%
D Distribution – adder	0%
Total de-rate:	45%

Notification is modeled as 95%, also a blend across programs of the 4-hour notification time frame (94%), 18 hour notification time frame (88%), and 10 minute notification timeframe (100%). The Small Business and Standard programs both require a four hour notification; Custom participants can select their notification timeframe.

No discount was applied for trigger, because the tariff will not identify required conditions (or triggers) for an event to be called. No distribution adder was modeled, as the program does not allow for distribution investment deferrals.

The end result is an Avoided Cost of Capacity of $60.18 per kW in 2017. See the end of this memo for a table detailing the blending of A and B factors across program types, and the calculation of incentive per kW hour for each program and participation selection.

2. Avoided Cost of Distribution. This program claims no locational benefits that would defer additional investment in transmission or distribution infrastructure. It is also not expected to adjust a participant's kW of monthly on peak demand, the basis of transmission and distribution charges for large nonresidential customers (Schedule 85), given a limited number of calls per season. Therefore no avoided cost of transmission and distribution benefits was assigned.
3. Avoided Cost of Electricity is the final component of the Avoided Cost of Supplying Electricity. This was calculated by multiplying the target MW capacity reduction per year x estimated average event duration (three hours) x estimated number of annual events (15) x estimated net change in energy usage times x energy cost (on-peak Aurora pricing, consistent with 2016 IRP, without CO_2). Snapback – or the extent to which energy is shifted, rather than reduced – is estimated at 90%, meaning the net energy change would be fairly minimal at

10%. The total Avoided Cost of Electricity comprises less than 1% of the Avoided Cost of Supplying Electricity.

- **Environmental Benefits**. This is defined as the CO2 tax that is avoided when decreased demand results in decreased energy usage. In accordance with PGE's 2016 IRP, CO2 tax is expected to be realized in 2022; only energy reductions in that date or later receive this benefit. This benefit comprises less than 1% of the total benefit in the Total Resource Cost Test.

Program Assumptions						Capacity Payment				
	Participants	**MW**	**Avg Nomination (kW)**	**E savings (kW)**	**Customer Share**	**Capacity $ per kW**	**Avg Annual per participant**	**A Factor**	**Southern California Edison DR Program - basis of A factor selection***	**B factor***
Small	89	4	45	1,808	100%	1.33	60	44.8%	SDP Non-Res Base program. 90 hours/year, 6 hour/day	94%
Standard	167	15	90	3,615	100%	52.52	4,727	44.8%	SDP Non-Res Base program. 90 hours/year, 6 hour/day	94%
Custom								0.0%		
20 hours	*1.30*	*0.8*			*10%*	*40.12*		26.1%	CPP. 12 events per year, max of 48 hours per month, 4 hours/day	88%
40 hours	*5.85*	*3.6*			*45%*	*60.18*		44.8%	SDP Non-Res Base program. 90 hours/year, 6 hour/day	94%
80 hours	*5.85*	*3.6*			*45%*	*80.05*		65.7%	SDP Res. 180 hours/year, 6 hours/day	100%
Custom average	13	8	600	24,102	100%	67.12	40,270	0.0%		
	269	27	735	29,525		49.26	4,903	47.0%	*Demand Response Measurement and Evaluation, Program Enrollment and Load Impacts, Cost-Effectiveness, and Ratemaking Proposal	94.6%
						"100%" participation value			Soutern California Edison , March 1, 2011	
									*B factor driven by varying notification periods per PGE program options	

Total Resource Cost Test

Cost/Benefit Category	Costs	Benefit	
Administrative costs	$6,600,000		
Avoided costs of supplying electricity		$20,460,000	
Bill Reductions			
Equipment costs to utility	$4,810,000		
Environmental benefits		$20,000	
Incentives paid			
Revenue loss from reduced sales			
Transaction costs to participant (25%)	$4,190,000		
Value of service lost (25%)	$4,190,000		
	$19,790,000	$20,480,000	
Benefit Cost Ratio			**1.03**

Program Administrator Cost Test

Cost/Benefit Category	Cost	Benefit	
Administrative costs	$6,600,000		
Avoided costs of supplying electricity		$20,460,000	
Bill Reductions			
Equipment costs to utility	$4,810,000		
Environmental benefits			
Incentives paid	$17,820,000		
Revenue loss from reduced sales			
Transaction costs to participant			
Value of service lost			
	$29,230,000	$20,460,000	
			0.70

Rate Impact Measure Test

Cost/Benefit Category	Cost	Benefit	
Administrative costs	$6,600,000		
Avoided costs of supplying electricity		$20,460,000	
Bill Reductions			
Equipment costs to utility	$4,810,000		
Environmental benefits			
Incentives paid	$17,820,000		
Revenue loss from reduced sales	$100,000		
Transaction costs to participant			
Value of service lost			
	$29,330,000	$20,460,000	
			0.70

Participant Cost Test

Cost/Benefit Category	Costs	Benefit	
Administrative costs			
Avoided costs of supplying electricity			
Bill Reductions		$100,000	
Equipment costs to utility			
Environmental benefits			
Incentives paid		$17,820,000	
Revenue loss from reduced sales			
Transaction costs to participant	$4,190,000		
Value of service lost	$4,190,000		
	$8,380,000	$17,920,000	
			2.14

UM 1514

Attachment D

Demand Response Final Report and Presentation from Hansa

PGE

Demand Response Final Report and Presentation

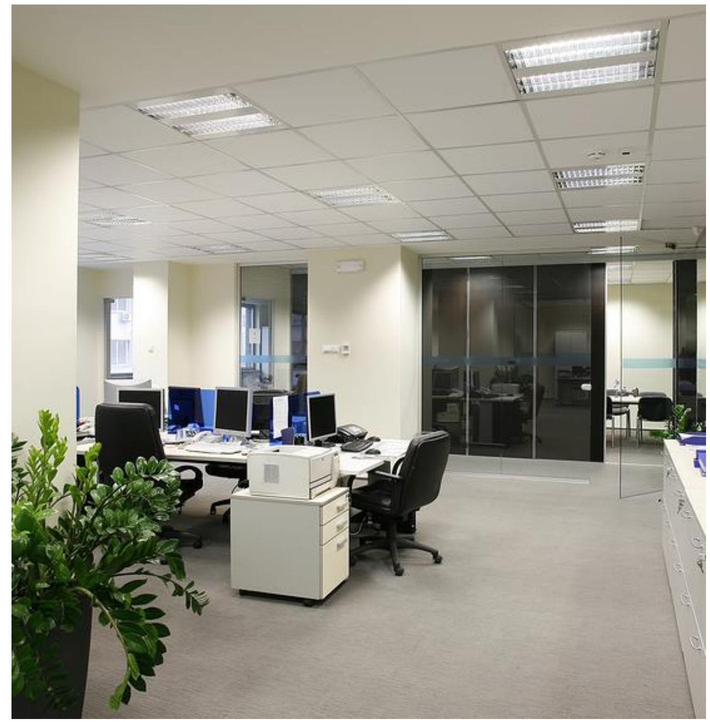
13 April, 2015

HANSA

Engagement #6531

Contents

- Background:
  Objectives and Methodology
- Executive Summary
- What Is Energy Partner^{SM}?
- Communicating with the Customer
- The Last Word
- Interpretations and Conclusions

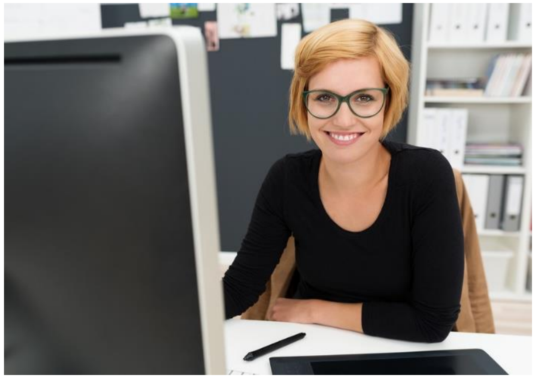


Objectives and Methodology

- Primary goal: Pick marketing communication messaging that will strengthen the Energy Partner[SM] brand and increase participation in demand response programs.

  Core objectives:

  - Find messaging that resonates, without jargon
  - Test which messaging resonates with different customer groups (facility, sustainability, finance/executive)
  - Rank key messages in order of importance to customer groups



- In-depth interviews:
  - 30 participant interviews
  - 30 minutes in length
  - Conducted face to face or by phone (21 by phone, 9 face to face)
  - Recruited from PGE lists

Respondent Profile: Good Mix of Roles and Industries

- Decision-makers for energy efficiency programs in a mix of industries within Energy Partner[SM]'s sweet spot
- Research participants met minimum thresholds for power use

Industry	**Interviews**
Food & Beverage	7
Water/Waste Water	6
Industrial Manufacturing	6
Tech/Data Center	4
Commercial Real Estate	7
Total	**30**

Sample Job Responsibilities

- CEO/Principal
- Production
- Operations
- Controller
- Store manager
- Property manager
- Maintenance
- Farm manager

Sample Businesses

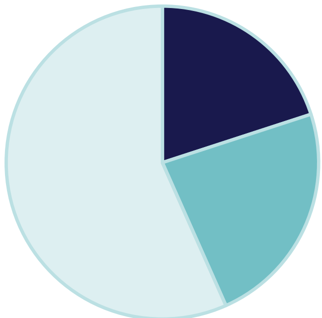
- Grass seed growing and storage
- Apparel manufacturing
- Woodworking
- Storage facility management
- Egg producer
- Grocery store

Respondent Profile: Low Overall Awareness of Energy Partner^{SM}

- Nearly half of customers who participated say they are not at all aware of demand response programs.
- More customers say they are very knowledgeable about PGE's Energy Partner^{SM} than about demand response programs in general, illustrating the importance of using customer-centric language.

Awareness Level	Demand response programs	PGE's Energy Partner^{SM}
Very knowledgeable	1	6
Knowledgeable	6	0
Somewhat aware	9	7
Not aware	14	17*

Energy Partner^{SM}
n=30



*S04A. PGE has a program called Energy Partner where business customers can get paid to make small reductions in their energy use on hot summer and cold winter days when we're all using more electricity, putting pressure on the grid. Are you aware of this program, or anything like it? Sometimes utilities call this kind of program "demand response." READ LIST.

S04B. If at least somewhat aware at S04A: What is your level of knowledge of PGE's Energy Partner Program?

Includes 14 who said "not aware" to demand response question (and were not asked the follow-up question).

Executive Summary: Energy Partner^{SM} is Appealing

- Two-thirds of participants have at least some interest in Energy Partner^{SM}.
  - Saving energy and getting paid for it is an appealing combination as long as there is no hidden rate hike to pay for the compensation.
  - It's essential for each company to maintain control of how and when they participate in Energy Partner^{SM}.

- Customer perception of an energy reduction energy event translates to a high-usage period where Energy Partners ease strain.
  - Understanding of the length of an event varies from hours to days or more.

Executive Summary: Strong Concerns Limit Participation

- While the idea of cash for participation attracts positive attention, customers have worries about being an Energy Partner℠.
  - Continuing to meet business and customer commitments is a prime concern.
  - Businesses also worry about losing control of their access to the power they need. Is it really their choice or PGE's choice?
  - Some see a Big Brother aspect, thinking PGE will know too much about power use and move to mandates about how power is used.
  - The specter of regulatory requirements and how they may be at cross purposes with Energy Partner℠ looms large for those in heavily-regulated industries.

Executive Summary: Multi-Step Communications Required

- Customers want to know more about Energy Partner[SM] and have suggestions about how they would like to be approached.
  - Email is the logical first step for outreach with a follow up by phone or in person so PGE and the customer can learn more.
  - Getting buy-in from industry leaders and industry organizations will give Energy Partner[SM] validity and encourage others.
- Customers confess to not knowing much about energy saving programs in general, let alone programs like Energy Partner[SM].
  - They are uncertain about where to look for new programs.
  - Confusion exists about how Energy Star, Energy Trust and LEED programs relate to PGE programs.

Detailed Findings: What Is Energy Partner[SM]?

Energy Partner℠: What Is It?

To serve as background for consistent understanding across interviews, customers heard the following description of Energy Partner℠ at the beginning of the interview:

- *During hot summer and cold winter days, we all use more electricity, putting pressure on the grid, energy prices and the environment. To help keep power reliable, affordable and sustainable, PGE pays business customers to reduce or shift their energy needs during these peak periods.*
- *In other words, for every kilowatt you don't use, you get paid.*
- *Being an Energy Partner℠ doesn't mean "turning off the power" or interrupting business. Instead, PGE works with you to identify ways to make small changes, customized for your business, that add up to real savings. Whether it's changing when you charge equipment, or turning the thermostat up or down by a degree or two, <u>you</u> choose the solutions that work best for your business – and in return, you get a check from PGE.*
- *It's your plan, and you stay in control.*
- *On a high-demand day, PGE alerts your business that an energy reduction event is starting. The strategies you selected can go into effect automatically, or you can choose to opt out that day with no penalties. It's always up to you.*

Energy Partner℠: In the Words of the Customer

What Is Energy Partner℠?

"There's a possibility of saving money during peak usage times, where you adjust the way you do business during those times to save energy."

"It's a program designed to induce you to save energy when possible and you get compensated in the process."

"It's partnering with PGE to manage our energy use with specific things we can do, by season or day, to reduce energy usage and save money."

A word about word clouds: The size of a word indicates the frequency of use for that word across respondents as they describe Energy Partner℠. Word color and placement are randomly assigned.

Energy Partner[SM]: Would a Program Like This Appeal to You?

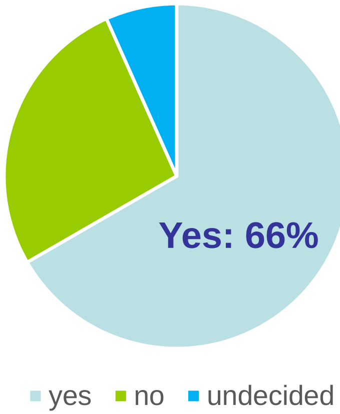
Sounds Good

It's good for us

- *"If there is a way to save money or it brings a check from PGE, I would welcome that but I don't always have the luxury to be able to do that."*
- *"If it's free, I would want to be in it so we could see what our usage is and study it. It's a way for us to see what we're using so we can see what can be done to save."*
- *"It would be worth looking into. I like reducing costs, and right now we spend about $250k a year on electricity."*

It's good for the environment

- *"We like to consider ourselves a green company, so we would be interested in looking at anything that could help."*
- *"I'm environmental and that appeals to me. Getting a rebate check is always nice too."*
- *"I think it's good for the environment and for other users so that everybody is conscious of what's going on."*



Not for Us

Interferes with business

- *I don't think it would work too great because most of our electricity is for irrigating, and when it's hot we need to irrigate."*

Beyond our control

- *"Being a big store, we have doors opening and closing and we just can't control the cold air that blows in."*
- *"That's hard because our energy use goes up and down depending on how much we're receiving or selling, how our motors are running and so on." It doesn't really fit us."*

Too little energy to matter

- *"We're a small office, it would be very minimal to try to do something like that."*

Doesn't fit our lifestyle

- *"But you can't adjust times in an office. You're 7-5, 8-5, or whatever the hours are, and at 5-6pm there's a herd of people heading for the front door."*

On the Fence

What else can we do?

"We've already done work with Energy Trust. I don't know what more can be done. It would be nice to be more efficient but I don't know how."

We don't want to endanger our business

"The largest [concern]: our type of operation is difficult to adjust."

Energy Partner^{SM}: In the Words of the Customer

What Is an Event?

Customers describe an event through several lenses: power usage, community and business involvement, and power reduction.

Power Usage

- *"You're asking partners to use less power during that time, if possible."*
- *"I think that means cutting back on power usage in some manner."*

Community and Business Involvement

- *"When there's high demand due to heat or cold and the grid is stressed people need to start working for the good of the community."*
- *"PGE is asking businesses to reduce their power usage to help mitigate the peak usage for a given day."*

Power Reduction

- *"A way of lowering the power needs in the building for that time period."*
- *"On a peak demand time you get notified and they want you to reduce your peak."*

The occasional customer sees a loss of control.

- *"Someone other than myself has control of the energy and is reducing or manipulating whatever parameters to create an energy reduction."*

How long is an event?

Given what they knew about Energy Partner^{SM}, customers speculate on the length of an event.

A matter of hours …

- *"Probably a business day from 8:00 to 5:00."*
- *"Four hours of less."*

Weeks? Or Months?

- *"A week or longer."*
- *"One to three hours at the peak time of day."*
- *"A week or a month"*

Even More

- *"A full season."*
- *"All summer when it's really hot. Shorter in the winter, maybe?"*

Energy Partner℠: Benefits of Participation Not Just Financial

What Do Customers Get?

Customers focus on saving money but they also mention reducing power use, enhancing corporate image and preserving the environment.

Reduced Power Cost

- *“I'm going to say that if we can save money and reduce the cost of energy, that is the ultimate benefit.”*
- *“It comes down to dollars and cents. If it's something that can affect the bottom line positively, then I'm all for it.”*
- *“Potential lower cost, not only in near-term but also in the long term.”*
- *“The company saves money, and we’re always looking for ways to save.”*

Responsible Energy Use

- *“Overall this program would help with electrical use because it would spread out the usage instead of peaks and valleys.”*
- *“Increased awareness of energy use onsite.”*

Building an Image of Responsibility

- *“A personal reward, knowing you did something good for the environment.”*
- *“The biggest is your public image. It’s being able to put an icon on our literature saying we're part of this Energy Partner℠ program so we're working to promote sustainable energy practices.”*

Environmental Benefits

- *“It's green like dollars to us, but also green like saving the forest.”*

Compensation No Matter What

Customers like the idea of a monthly check, but wonder if there’s a catch.

- *“I like getting compensated even without an event. Where is the money coming from though? Will they raise the price on something else to cover that?”*
- *“That sounds like a win/win; how they can afford that?”*
- *“I don't understand how you could compensate people if there are no events. How do you compensate someone for not actually participating or saving energy. That just doesn't make sense.”*
- *“I don't think you should be compensated for signing up. That doesn't sound financially prudent to me. It sounds a little wasteful.”*

Energy Partner℠: Barriers Rooted in Fear, Lack of Understanding

Why Not Participate?

PGE's customers tend to think about their commitments to their own customers and employees. They also have trouble visualizing how the program applies to them, and they wonder how much work it will be to implement. Some are concerned about PGE having too much information about how they operate, or too much control over how they do so.

Business Commitments

- *"Our equipment can't really be turned off."*
- *"My customers couldn't be affected."*
- *"My clients' comfort level is big."*
- *"We want out employees to be happy and satisfied."*

Doesn't Seem to Apply to Us

- *"I don't know what we could turn off or turn down to help out. I wonder if it's applicable to us, and I just don't know where we'd make our cuts."*
- *"It just doesn't seem practical for a grocery store."*
- *"Our equipment runs to make us money."*

Too Much Work

- *"Is there an extra layer of accounting?"*
- *"We don't know how to do it."*
- *"Are there forms, surveys, paperwork?"*

Big Brother

- *"If you put yourself under the spotlight of a program that puts more of a focus or scrutiny on what you do, is it going to put you in a predicament where you get involved with mandates?"*
- *"So there is always a risk that if you open your doors to opportunities that you might also be opening your doors for an unanticipated outcome."*
- *"The utility companies make money every time they come up with a new program, and that justifies increased rates."*

Compliance Concerns Are Significant Barriers

Companies in the food and water quality industries or companies that touch on those areas think first and always about regulatory and legal compliance.

They cannot modify their environment without reassurance they will not run into regulatory problems, legal risk or endanger the public.

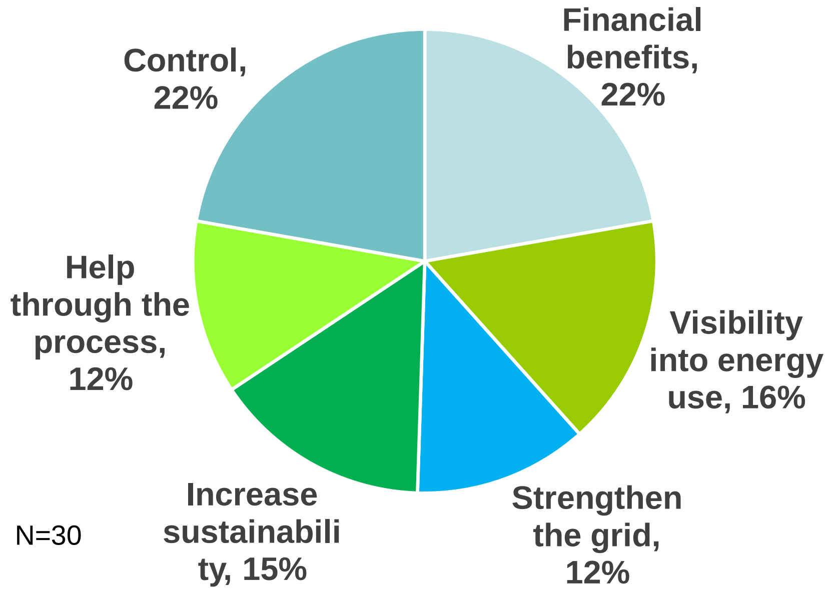
- *"Under FDA regulations there are temperatures we have to maintain to protect food safety."*
- *"We have to watch out for public health and the environment and if it means we have to run during high peak times that's what are required to do by law."*
- *"Violating legal mandates."*

Detailed Findings: Communicating with the Customer

Communicating with the Customer: All Themes Resonate

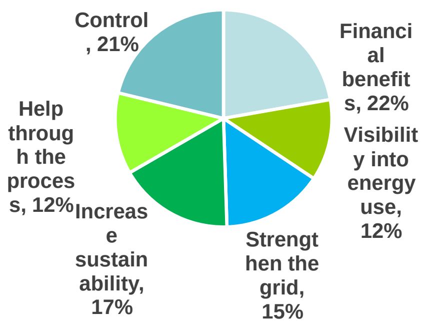
Customers considered six themes related to Energy Partner[SM]. They were given 100 points to allocate among the themes, assigning points to show the relative importance of each theme to participation in Energy Partner[SM].

Overall, reactions to the themes split into three tiers with Financial Benefits and Control at the top, followed by Sustainability and Visibility. Help Through the Process and Strengthen the Grid sit at the bottom for importance.

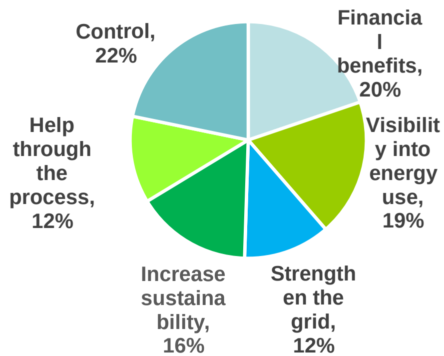


Communicating with the Customer: Themes by Industry

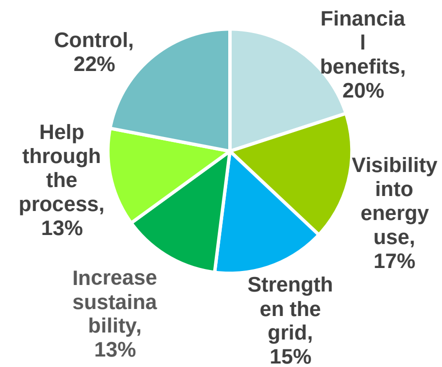
Although the relative importance of the themes is fairly consistent across industries, Industrial Manufacturing stands out among the groups for interest in Financial Benefits, and Control resonates with Water and Waste Water Storage organizations.



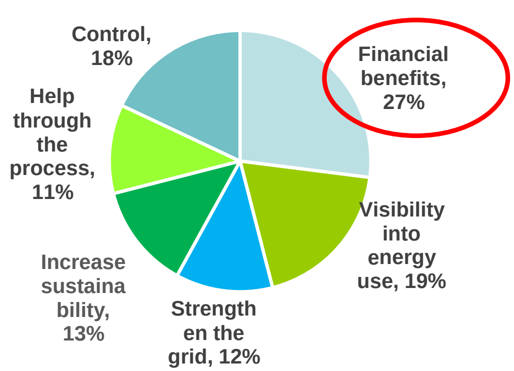
Commercial Real Estate, n=7



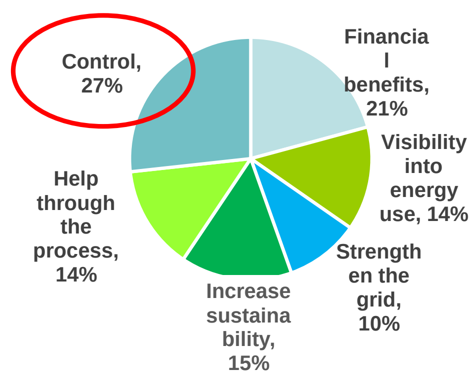
Food & Beverage/ Cold Storage, n=7



High Tech/ Data Centers, n=4



Industrial Manufacturing, n=6



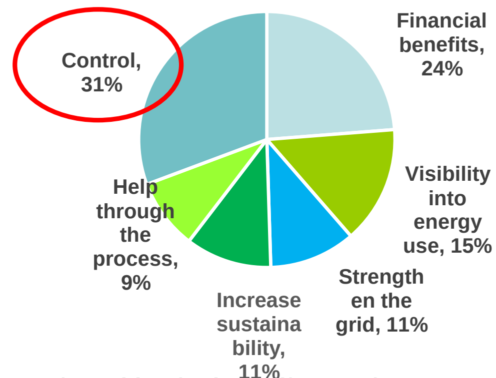
Water & Waste Water Storage, n=6

Communicating with the Customer: Themes by Job Title

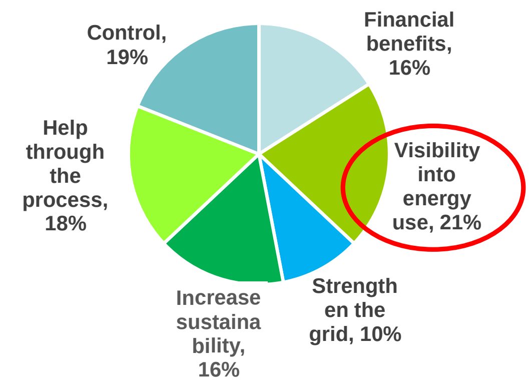
Who Is Interested in What?

Using job title as a lens, each set of job titles has a unique focus.

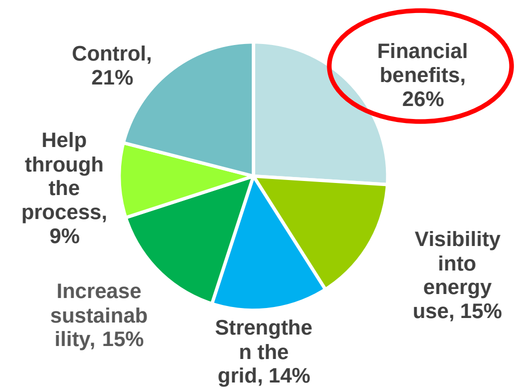
- Control is the outstanding theme for the CEO segment
- CFOs find Visibility into Energy Use the most compelling theme
- Facility and Operations Managers look most closely at the Financial Benefits theme



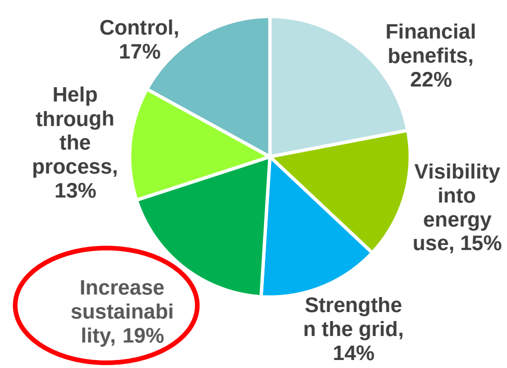
CEO/ President/ Principal/ Owner/GM, n=8



CFO/Controller/Finance Manager/VP Finance, n=7



Facility/ Operations Manager/ Plant Manager, n=7



Other Titles, n=7
(includes Property Manager, Maintenance Director, Systems Admin, Store Manager and Sustainability Manager)

Communicating with the Customer: Top Phrases Strong

Customers heard a series of phrases that support the Energy Partner^{SM} themes and selected the phrase that best supported each theme. The following phrases are the most-often selected phrases by theme. Two-thirds of the customers selected the phrase that emphasizes PGE's commitment to partnership.

Theme: Financial benefits - You get a check

√ Get paid for managing your energy use (Selected by 13 customers)

Theme: Visibility into energy use – Tools to shine a light on your energy usage patterns

√ Get a no-cost assessment of your facility's energy use and operations (Selected by 16 customers)

Theme: Strengthen the grid - It's good for everyone

√ Businesses like you are supporting their community while improving their bottom line (Selected by 13 customers)

Theme: Increase sustainability – Your company is part of the solution

√ By being an Energy Partner^{SM}, you help create a greener tomorrow (Selected by 12 customers)

Theme: Help through the process - PGE makes participation easy

√ PGE works with you to identify a customized solution for your business (Selected by 20 customers)

Theme: Control - You're in control

√ You choose the solutions that work best for your business (Selected by 10 customers)
√ The strategies you select can go into effect automatically, or you can choose to opt out that day with no penalty (Selected by 10 customers)

Detailed Findings: The Last Word

Communicating with the Customer: Talk to Me

Email is the choice for first, introductory contact for Energy Partner℠. Once a connection has been established, then a more direct method such as **face to face, phone or detailed information sources** move the process forward.

Step One:

- *"Email so I **don't have to look too hard**."*
- *"Email with a **link**."*
- *"Emails to **build it up**."*

Step Two:

- *"A **phone call** to the right people."*
- *"Face to face to **get to know our business**."*
- *"**Directions to the web site for more information** or information packets to read and absorb when we have time."*

For some industries, customers suggest taking a group approach. They recommend forging a **partnership between PGE and an industry organization or influential users** to show validity and encourage participation.

- *"**Pick some of the largest users** and schedule meetings to go over the program. Let them assist with ideas for the program."*
- *"**Get active with the movers and shakers in the industry**. These are the people who recognize the advantages."*
- *"**Partner with organizations like BOMA** and offer continuing education hours as an incentive to listen."*
- *"**Notifications in professional publications and newsletters would attract attention** and get the message out to a wider audience."*

Energy Partner^{SM}: Specifics Will Interest Customers

Customers are interested in Energy Partner^{SM}, but … unanswered questions hinder full acceptance. In short, customers want to be sure Energy Partner^{SM} will not interfere with business as usual. And they don't want to retrace the steps they have taken with other energy efficiency programs.

What about my industry?

- *"I need to know how this fits for farms."*
- *"PGE needs to demonstrate they understand our business needs and challenges."*
- *"They're going to have to survey our site and show they can definitely save us money."*

What's my part?

- *"What specifically are we being asked to do?"*
- *"We'll need help determining what we need to do."*

How does this affect the way I do business?

- *"We don't want to upset the apple cart of the organization."*
- *"We need some way of visualizing a way to do it that doesn't directly impact our ability to do business."*

What if we already participate in other energy programs?

- *"Explain to me how this is different from the other energy programs. We're heading into a saturation of energy programs. Participating in Energy Star and LEED is not inexpensive and it's time consuming. Why should we do this, too?"*

Interpretations and Conclusions

Interpretations and Conclusions

- Customers see their business through the lenses of serving their customers and maintaining service standards and regulatory compliance.
  - They need to know what changes they can make that would not affect customer comfort or detract from the way they do business.
  - Customers hear the message they will be in control, but they need solid reasons to believe in the promise of total control.
- Customers are ready to hear about real numbers with regard to how much they will save, how much they have to contribute and the real extent of what they must commit to.
  - Emphasizing PGE's energy assessment and small changes is important to increasing participation.

Interpretations and Conclusions

- Showing real results and benefits of Energy Partner℠ based on the experiences of existing participants will open the door for many businesses to take a closer look.
  - Industry-specific case studies that focus on the kind of changes that make a difference and their effect on the bottom line, including estimates of what a monthly check can be, will help customers look at Energy Partner℠.

- Partnerships with industry leaders and organizations along with the support and cooperation with recognized energy saving programs will appeal to businesses that may be uncertain about participation.
  - Energy Partner℠ is a community program; having the support of community and industry leaders emphasizes the nature of the program.

Interpretations and Conclusions

- Messages that emphasize financial benefits and customer control of Energy Partner^{SM} are most effective in communicating the value of the program to customers.
  - In support of the financial benefits theme, customers prefer phrasing that puts the customer first and cites customer management that leads to rewards. *"Get paid for managing your energy use."*
  - Similarly, customers are drawn to *"You choose the solutions that work best for your business"*, emphasizing customer choice to describe control of the program.
- Visibility into energy use and sustainability follow financial benefits and control in order of importance to customers.
  - The opportunity for a *"no cost assessment of energy use"* is appealing.
  - Customers like knowing they can demonstrate they care about a *"greener tomorrow".*

Interpretations and Conclusions

- Audience segments react differently to Energy Partner℠ themes, suggesting the value of varied approaches by audience.
  - CEOs want to know they will be in control.
  - CFOs like the idea of having new visibility into their company's energy use.
  - The financial benefits theme makes sense to facility and operations managers.
  - Not surprisingly, sustainability managers are in the group that wants to hear about the sustainability benefits of Energy Partner℠.

Thank you!

Q&A

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About Hansa

Hansa GCR is a full-service market research and consulting firm. Looking through the lens of the customer experience and applying psychological principles of human motivation, it offers best-in-class services in areas relating to Customer Relationship Equity, Market Assessment, Branding, and Product/Service Innovation. Hansa GCR is part of R K SWAMY HANSA, an emerging global group with 1,500+ professionals offering Creative Communication, Market Research, Data Analytics, Brand Consulting, Interactive and Healthcare Communication services.

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UM 1514

Attachment E

Commercial & Industrial Demand Response Program Redesign from Navigant

Commercial & Industrial Demand Response Program Redesign

Presented to:

Portland General Electric

Portland General Electric

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March 23 2017

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Table of Contents

Executive Summary

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[1] with a significant portion coming from the commercial and industrial (C&I) sectors. However, PGE has faced challenges building C&I DR capacity through its existing C&I DR portfolio, consisting of the Energy Partner program and Schedule 77. This study identifies recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

Findings

Since the program's inception in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. PGE's service area is a difficult one to develop an effective C&I DR resource, due to a variety of factors including limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. Compounding this difficult business environment, the program's aim to deliver a firm and valuable resource to the Company has resulted in relatively strict rules for participation and performance that have limited enrollment and the number of MW that customers are willing and able to contribute.

The following are specific findings relating to 1) the PGE customer base and operating environment, 2) the Energy Partner program structure, and 3) the program delivery.

PGE Customer Base and Operating Environment:

1. PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.
2. PGE is losing potential large C&I demand response opportunities due to large customers choosing alternative providers.
3. Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation.
4. PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.

Program Structure:

1. Current participants are satisfied with most aspects of the program.
2. Having dual peaks creates unique and significant challenges for implementing demand response.
3. The duration of the event windows presents a challenge for the program implementer and some customers.
4. PGE's peak hours are not necessarily coincident with C&I customer peak hours.
5. The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.
6. The 10-minute notification time is not a significant barrier for customers in practice.
7. Enabling more customers with automated curtailment would increase the curtailment

[1] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.

available from both non-participants and participants alike, although at a higher program cost.

Program Delivery:

1. Corporate social responsibility and “doing the right thing” is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.
2. The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.
3. Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.
4. Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.
5. Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.
6. Opportunities exist for impactful coordination with the Energy Trust of Oregon’s Strategic Energy Management (SEM), but require strategic effort from PGE.
7. KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.

Recommendations

The recommended changes in the design of PGE’s C&I DR program offerings reflect changes in PGE’s priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

The following are specific findings relating to 1) the target market, 2) the proposed program structure, and 3) the program delivery.

Target Market:

PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. Non-industrial/process loads at large C&I customers, such as lighting and HVAC
2. Medium-size C&I customers (200 kW to 1+ MW peak load)
3. Small-size C&I customers (<200 kW peak load)
4. Site aggregation
5. Direct access customers

Program Structure:

1. Allow more flexibility across seasons and within seasons.
2. Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.
3. Facilitate partial credit for partial participation.
4. Relax the notification time requirement for participation.
5. Emphasize automated curtailment, where possible, but continue to support both manual and

automated curtailment.

6. Revisit the methodology used for determining a customer's baseline to avoid penalizing customers with variable load.

Program Delivery:

1. Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.
2. Focus the program marketing and delivery around the benefits to the customers.
3. Enhance education for both participants and non-participants.
4. Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust's day-to-day processes with minimal overhead.
5. Increase marketing to medium-size customers (200 kW to 1+ MW peak load).
6. Evaluate options for using existing interval meters to lower program equipment costs.
7. To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.
8. Leverage existing and new channels for broader and more continuous customer engagement.

Section I Introduction

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[2] with a significant portion coming from the commercial and industrial (C&I) sectors. PGE's C&I DR portfolio currently consists of the Energy Partner program with 10-15 megawatts (MW)[3] and Schedule 77 with 1.8 MW. Since the inception of the Energy Partner program in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. Given the challenges that PGE has encountered with achieving target DR capacity from the C&I sectors, the objectives of this study are to identify recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

To support the findings in this study, Navigant conducted interviews with the following stakeholders:

- PGE program staff
- Energy Partner program manager at the program implementer (EnerNOC)
- Strategic Energy Management (SEM) program manager at the Energy Trust of Oregon (Energy Trust)
- 10 participants
- 10 non-participants, including 5 customers currently participating in the SEM program, 4 customers who had previously declined to participate in the program, and 1 former participant
- This study is organized into the following sections: **Section II: Findings** presents the findings from the interviews noted above, as well as Navigant's review of relevant secondary

[2] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.
[3] EnerNOC's expected nominations for the Energy Partner program are 13.5 MW for Winter 2016/2017 and 11.3 for Summer 2017.

resources from PGE and other jurisdictions, including benchmarking results comparing PGE's C&I customer base with other utilities around the country.

- **Section III: Recommendations** discusses recommendations for refining PGE's C&I DR program offerings, based on the findings in Section II and best practice programs at other utilities, as well as recommendations for conducting the procurement process.
- **Section IV: Summary** provides a summary overview of the issues and recommendations.

Section II Findings

PGE initially designed the Energy Partner and Schedule 77 programs to maximize the value of the resource to PGE's system, with fast response time and comprehensive windows of availability, as shown in Figure 1. For the reasons discussed in this section, these objectives are difficult to achieve in a robust, cost-effective program within PGE's service area.

A key theme expressed by both PGE and customers was the desire for more flexibility within the program design and eligibility requirements to facilitate broader customer participation and increased customer satisfaction. In other words, moving from a "one size fits all" program to one with more options for when and how customers participate.

Figure 1. Philosophy of Program Design: Current Program

Source: Navigant, 2017.

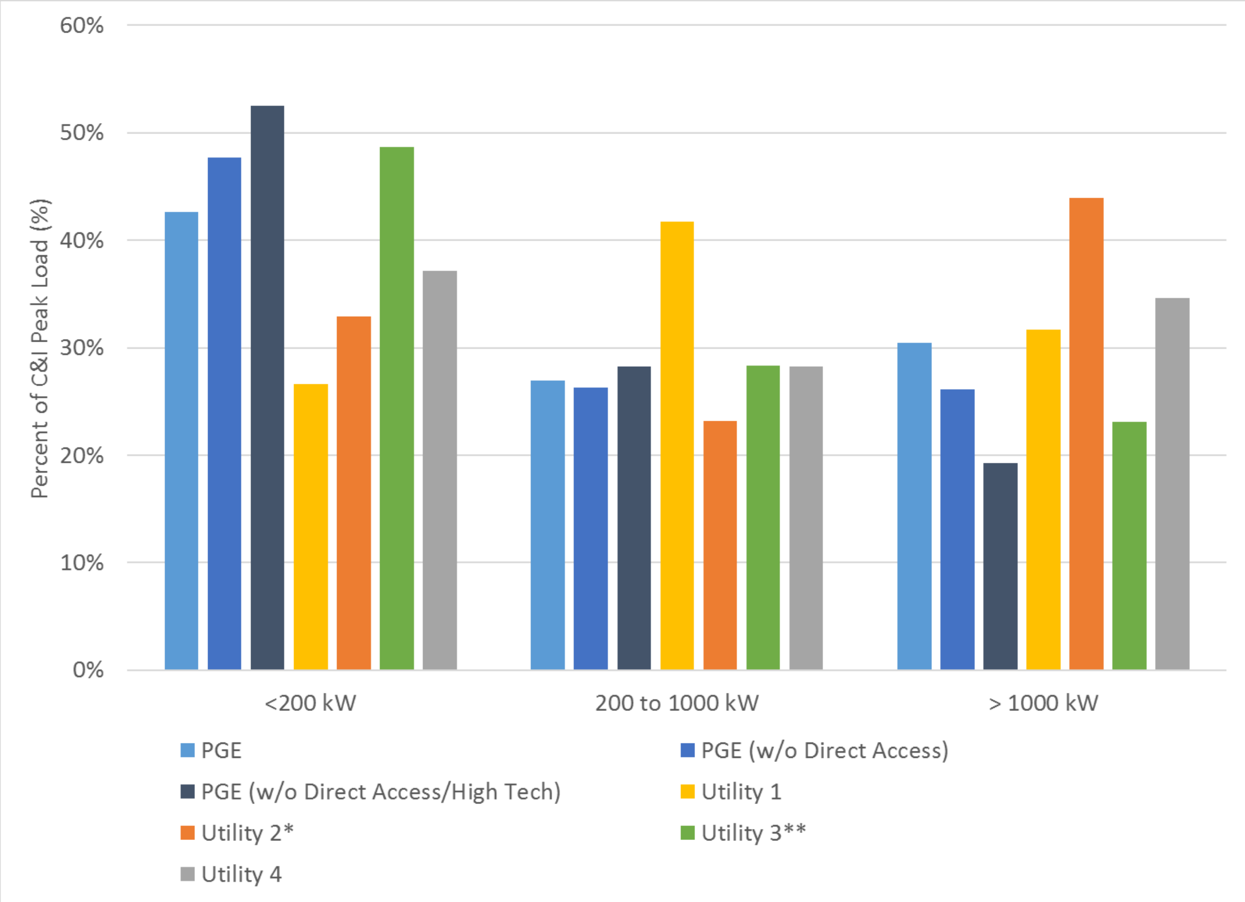
2.1 PGE Customer Base and Operating Environment

The following section discusses the finding relating to the market characteristics and system requirements within which the Energy Partner program operates.

1. **PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.** Other utility programs around the country often rely on just a few very large customers to provide the bulk of curtailment. For example, Xcel Energy Colorado currently has roughly 200 MW out of the 300 MW available from their C&I program through just two customers. Similarly, Oncor's early-stage C&I DR program had 9 MW of 11 MW from a single customer. Compared to these other regions, PGE's customer base has fewer large industrial customers who can shift or shed load during PGE's peak times. For example, one-third of PGE's demand from customers with greater than 1 MW peak load is from high-tech manufacturing customers. These customers have significant load and would be prime candidates for participation; however, they are generally reluctant to participate due to the limited options available for participation without impacting production, the high consequences of production disruption, and the relatively limited benefits of participation in comparison to these factors. Similar barriers exist for hospitals. Navigant has seen these challenges with enrolling high-tech manufacturing and hospitals in other service areas, as well.

Figure 2 shows the percent of PGE's C&I customers by size compared to other utilities with C&I DR programs. After factoring out high-tech manufacturing and direct access (discussed in below) customers who are unable to participate, PGE has a significantly smaller proportion of large C&I customers than other utilities.

Figure 2. Benchmarking Comparison of PGE C&I Peak Load to Other Utilities by Size



Source: Navigant, 2017 and utility data.

** Utility 2 based on Average Monthly Load data and size breakdowns of <500kW, 500-1000 kW and >1000 kW*

*** Utility 3 based on size breakdowns of <300 kW, 300-1000 kW and >1000 kW*

2. **C&I load is declining due to large customers choosing alternative providers**. As an example, two customers recently left the program when their companies switched to direct access and were no longer eligible for the program. Based on their experience in other jurisdictions, EnerNOC contends that these customers and potentially other national chains would return to the program if direct access customers were eligible; however, PGE would need to work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers. Figure 2 indicates the magnitude of impact from excluding direct access customers.
3. **Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation**. EnerNOC does not currently permit aggregation of metered locations on a customer site below a certain size threshold, due to the cost of installing the separate meters that EnerNOC requires for participation at each metered location on the customer site. This presents a significant barrier for the participation of certain customers, such as campus-like customers with multiple smaller facilities on a single site.

4. **PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.** Within PJM's entire DR portfolio, generators alone comprise 12 percent of nominated capacity.[4] As another example, within Duke Energy Progress's C&I Demand Response Automation Program, generators comprise more than 75 percent of their summer DR impacts and more than 90 percent of their winter DR impacts.[5] PGE recently changed the program rules, such that the Energy Partner program may be marketed to customers who also participate in PGE's DSG program. However, the customer is only permitted to participate in Energy Partner with load, rather than the generators. EnerNOC estimated that the additional curtailment that could be achieved if EPA compliant generators were eligible is between 3 and 4.5 MW. While PGE does not plan to permit the use of generators for DR, it is worth noting that the exclusion of this resource limits available MW, relative to other DR programs. The limitation of generation also impacts participation from segments with sensitive loads like hospitals and high-tech customers, who are reticent to curtail end use loads.

2.2 Program Structure

The following section discusses findings related to the structure of PGE's existing Energy Partner program, including program parameters like event timing and duration.

1. **Current participants are satisfied with most aspects of the program.** Participants responded with an average of 8.4 when asked how satisfied they are with the Energy Partner, where a 0 meant they are extremely dissatisfied and a 10 meant they are extremely satisfied. Customers also expressed general satisfaction in their interactions with EnerNOC, PGE, and their KCM.

2. **Having dual peaks creates unique and significant challenges for implementing demand response.** PGE's demand response targets are similar in the winter and the summer through at least 2021. Thus, PGE's current program requires customers to enroll for both winter and summer. While customers are able to nominate different load amounts in each season, it is hard for some customers to offer curtailment in both summer and winter. As an example, three of the four prospective non-participants interviewed mentioned that participation would be significantly harder for them in the winter than in the summer.

   Implementers must enroll customers who are able to curtail in both seasons or incur additional costs enrolling customers who can only participate in one season. Although program delivery costs increase by as much as 40 percent when providing curtailment in both summer and winter, PGE's avoided costs are split across seasons, which means that an implementer must be able to provide almost double the curtailment for half of the avoided cost value.

3. **The duration of the event windows presents a challenge for the program implementer and some customers.**[6] The duration of the event window is much larger than in most other programs (i.e., typically two to four hours), although the vast majority of PGE's events over the past several years have occurred in the 4-7 p.m. timeframe. The broad event windows limit the pool of candidates who are available to curtail across all possible event hours and incurs additional costs on the part of the program implementer to identify those candidates or bear the risk that less-suitable companies will not be able to provide sufficient demand reduction if events are called outside of the 4-7 p.m. timeframe.

4. **PGE's peak hours are not necessarily coincident with C&I customer peak hours.** PGE's

[4] http://pjm.com/~/media/markets-ops/dsr/2016-demand-response-activity-report.ashx
[5] Navigant analysis, Duke Energy Progress Commercial, Industrial and Governmental Demand Response Automation Program, Program Year 2015.
[6] During the summer and winter periods, program events may be called: 1) during non-holiday weekdays from 12 p.m. to 10 p.m. Pacific Time for the summer period; and 2) during non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. Pacific Time for the winter period.

peak occurs later in the day than for many utilities with large C&I DR programs. The 4-7 p.m. timeframe works well for some C&I customers that are changing shifts during this time or have fewer customer occupancy concerns outside of their core business hours. However, it also limits participation from customers, particularly commercial, who operate primarily 9 a.m. to 5 p.m. and either have limited load available to curtail or would need to pay someone overtime to manage the event curtailment. As discussed in the recommendations below, some customers thought that automated curtailment could help minimize this barrier.

None of the participants expressed concerns about participating in morning events, which is likely due to the fact that PGE has only called one morning event in the history of the program. However, the requirement that customers must be available to participate in both the morning and evening means that the program heavily favors 24/7 customers and can present a perceived barrier for non-participants.

5. **The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.** Requiring the ability to curtail within ten minutes limits the pool of customers eligible for the program and increases program delivery costs through increased automation needs, added risk absorbed by the implementer, and more limited enrollment options. Several non-participants said that they would need at least an hour to curtail load, particularly without automation.
6. **The 10-minute notification time is not a significant barrier for customers in practice.** In practice, EnerNOC generally provides customers with an alert that an event may be coming, then gives customers at least three hours of advance notice. EnerNOC tells customers to expect two to four hour notice, but they may need to perform in ten minutes in rare circumstances. Current participants generally seem satisfied with this arrangement.
7. **Enabling more customers with automated curtailment would increase the curtailment available from both non-participants and participants alike, although at a higher program cost.** Manual curtailment with 10-minute notification is challenging for many customers, who are shutting down multiple loads, and a perceived barrier for non-participants. Furthermore, the late afternoon and evening timing for PGE's events means that many C&I customers need to pay someone overtime to manually curtail load during events. With automation, these customers could potentially still participate after the main business hours.

   Half of the non-participants interviewed said that automation would increase the chances of their participation. PGE also recently worked with a customer interested in participating in Energy Partner who ultimately decided not to participate because they wanted automation and were not able to make it pencil out with PGE and the Energy Trust.

2.3 Program Delivery

The following section discusses the findings related to the program delivery, including marketing and outreach strategies, as well as contracting considerations.

1. **Corporate social responsibility and "doing the right thing" is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.** Only two of the ten participants interviewed responded that financial benefit is their primary driver for participation. Thus, the financial incentive is an important factor, but is not the only factor driving customers to participate, and often it is not sufficient to serve as the sole benefit to customers.
2. **The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.** Non-participants also expressed concern with the costs of enablement, occupant comfort, and staff time during events. For example, the Energy Trust of Oregon cited that their SEM customers historically do not see enough upside benefit from the program for them to spend time setting up DR at their site. This fits with EnerNOC's findings that reasons provided by customers who are "not interested" in the program included: *too much work*, *too disruptive*, *does not see how it fits into operations*, and *not worth it*. It should

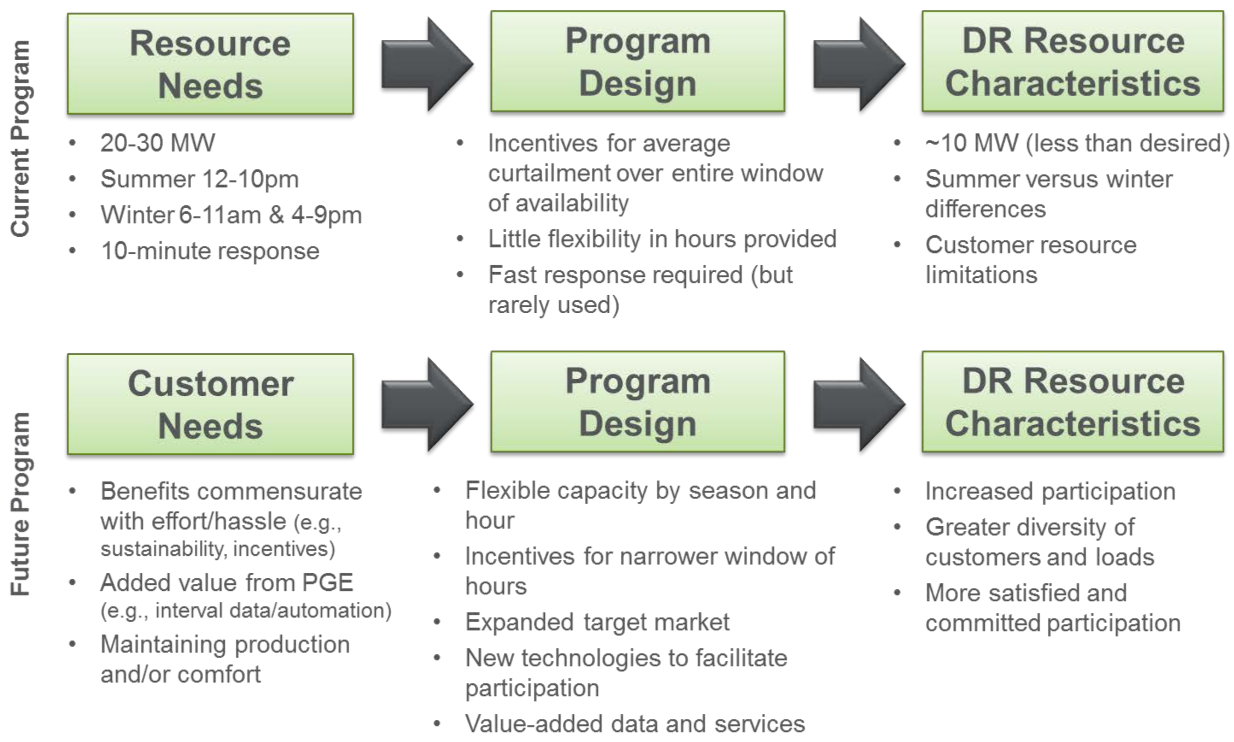
be noted that some customers are unlikely to participate, regardless of the financial value proposition that the program offers, such as customers with sensitive 24/7 operations.

3. **Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.** Both participants and non-participants alike expressed interest in having more resources available to help them and their stakeholders (i.e., customers, staff, and internal management) understand a range of topics, including how the program works; the value of the program to their organization and society; the potential drawbacks and costs of participating; and how to optimize their curtailment strategy. This lack of education might also be a key driver for the customer perceptions discussed in #2 above.
4. **Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.** Half of the participants interviewed reported revising their initial curtailment strategy to lower targets and some reported still having issues meeting their targets. Part of these changes resulted from changes in the customer's operation, while part of these changes resulted from customers learning more about DR and how it affects their facility. For example, one customer had been initially unaware of how their curtailment strategy would be impacted in the winter versus the summer.
5. **Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.** EnerNOC currently requires that customers install a separate meter for participation, even if customers already have an interval meter. This separate meter provides customers with near-real-time energy information, as opposed to the next-day information that PGE's existing interval meters would provide. During interviews, only three of the ten participants mentioned using the system in real-time during events. The other comments from participants suggest that a system providing next-day information would largely suit customers' needs.
6. **Opportunities exist for impactful coordination with the Energy Trust of Oregon's Strategic Energy Management (SEM), but require strategic effort from PGE.** Energy Trust of Oregon and PGE concur that the SEM program is a good channel for informing C&I customers about DR, given that SEM participants tend to have high acceptance and awareness of energy-related opportunities. One Energy Partner participant even said that the change in their organization's culture and thinking about energy use through the SEM program paved the way for them to enroll in Energy Partner. However, successful collaboration with the SEM program will need to overcome barriers relating to limited staff time, customer and contractor education, customer fatigue, and technical integration. Recommendations for overcoming each of these are discussed in Section 3.3 below.
7. **KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.** KCMs currently manage about half of the current participants, with the other half unmanaged. EnerNOC leads the enrollment process, with a hand-off mechanism between the KCMs and EnerNOC. With training, clearly defined expectations, and aligned incentives, KCMs could likely play an enhanced role in engaging customers in the program.

Section III Recommendations

The section below discusses recommended changes in the design of PGE's C&I DR program offerings to reflect changes in PGE's priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

Figure 3. Philosophy of Program Design: Future Program



Source: Navigant, 2017.

3.1 Target Market

Historically, the target market for the Energy Partner program has been larger C&I customers, particularly in the industrial sector. Expanding the targeted reach of the program to additional market segments can contribute to significant incremental DR capacity if certain barriers are removed. PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. **Non-industrial/process loads at large C&I customers, such as lighting and HVAC:** Enabling additional types of load at the customer site could increase nominations from existing participants and entice participation from customers with sensitive processes that might not otherwise participate. For example, three of the ten participants interviewed responded that they could potentially curtail more load at their facility by expanding their curtailment strategy beyond process equipment to other loads like lighting, particularly with automation or assistance upgrading equipment. Hospitals and high-tech customers, who are otherwise unwilling or unable to participate by curtailing process-related loads, may consider curtailing non-essential HVAC and lighting in office spaces with the appropriate value proposition for doing so.

2. **Medium-size C&I customers (200 kW to 1+ MW peak load):** PGE has roughly the same amount of load from medium-size C&I customers as from larger customers with 1+ MW (see Figure 2). New strategies are emerging for engaging these customers in DR, as vendors and utilities around the country are looking beyond large C&I customers. These implementation strategies include distributed, networked, high-tech, relatively low-cost communication and control technologies that can communicate back to a central control center. One example of a vendor that participates in this market is Encycle. Smart thermostats might also be used as a value-add to the customer, as well as for enabling communications and control. While the “jury is still out” to some degree on the cost-effectiveness and efficacy of these new strategies, PGE should evaluate options for engaging with this segment during the

procurement process.

3. **Small-size C&I customers (<200 kW peak load):** More than 40 percent of PGE's C&I load comes from C&I customers with less than 200 kW peak load (see Figure 2). While this segment has traditionally been challenging for C&I DR programs, it is worth exploring with vendors during the procurement process to understand options available for that segment. Expanding into this segment would require allowing customer nominations of less than 75 kW and may warrant a separate program or tariff structure. Vendors may approach this segment as an extension of the medium-size C&I market, with distributed low-cost communications and control technologies to 50-200 kW customers, or as a mass market program, which could be an extension of PGE's Nest thermostat program to small commercial.
4. **Site aggregation:** Use of existing interval meters and allowing the aggregation of multiple meters would enable more customers to participate and lower program equipment costs. In EnerNOC's view, site aggregation "is what is needed for PGE's program, if [PGE] could get it cost effectively." The ability to facilitate site aggregation will largely be dependent on the vendor's capabilities and requirements.
5. **Direct access customers:** Work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers for participation in a C&I DR program.

3.2 Program Structure

The following section discusses recommendations for reframing the structure of PGE's C&I DR program, including program parameters like event timing and duration.

1. **Allow more flexibility across seasons and within seasons.** To maximize customer eligibility, PGE should allow differences in nominations within seasons and allow customers to participate in only one season.[7]
2. **Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.** DR programs often fail when they try to cast too wide of a net. PGE should prioritize the top two to four most important hours needed for generation capacity deferral in each season as the required hours that a customer must be available to be eligible for the program. Enrollment for any hours outside of this window could be optional, based on the customer's operational needs. PGE could facilitate this by breaking the existing event windows up into more discrete windows (e.g., winter morning, winter evening, etc.) and providing a different value for each window. ERCOT's programs function similarly to this, with three seasonal program periods and multiple daily windows within each season that can be bid into separately —with a different price for each period.
3. **Facilitate partial credit for partial participation.** Under the current program structure, customers who can curtail for only a portion of the event window do not get payment, which discourages customers from participating in the event at all. PGE should explore ways to provide compensation to customers for partial participation, such as providing a reduced incentive of allowing customers to participate for just one hour at a time.
4. **Relax the notification time requirement for participation.** Given that PGE's primary objective for the C&I DR resource (i.e., generation capacity deferral) does not require 10 minute notification, Navigant recommends that PGE change the program requirements to a more traditional 2 or 4 hour notification. While EnerNOC currently operates the Energy Partner program with 2-4 hour notification in practice, lifting this requirement will help decrease program delivery costs by broadening the pool of eligible customers, decreasing automation needs, and reducing the amount of risk absorbed by the implementer.
5. **Emphasize automated curtailment, where possible, but continue to support both manual and automated curtailment.** Allowing both manual and automated curtailment reaches the broadest mix of customers, since some customers (e.g., with sensitive production

[7] Currently, differences in nominations are allowed across seasons, but not within seasons.

loads) will always prefer manual participation. However, facilitating automation for more customers (e.g., through financing, technology incentives for enablement, etc.) can help firm the resource and also allow certain customer segments to participate by curtailing remotely, as opposed to paying employees overtime to curtail after business hours. As an example, three of the seven non-participants with manual curtailment and four non-participants expressed possible interest in financing options from PGE for upgrading or installing a building management system (BMS) to enable automated curtailment.

6. **Revisit the baseline methodology used for some customers to avoid under- or over-estimating the baseline demand of customers with highly variable load.** PGE's current baseline method takes the highest 5 of 10 prior business days, with day-of adjustment except for winter mornings. For some customers with load that is highly variable (apart from weather-related variability), this can lead to a disconnect between demand reduction estimates and the actual DR actions. As an example, a customer with a large irregular industrial process load that was operating on the 5 highest of the 10 past business days, but not on the day of the DR event, would have a baseline that vastly over-estimates their true baseline demand the day of the event. This scenario can lead to challenges with program impact evaluation, less predictable program performance, and decreased participant satisfaction in the program outcomes. To account for this while still allowing customers with highly variable load to participate in a meaningful, more predictable way, PGE may consider offering certain customers one of the following options:
    a. Allow a customized baseline for customers with additional operational information that can help design a baseline methodology tailored to their specific operating characteristics. This is consistent with the evaluation findings of the Energy Partner program that a regression baseline could perform better for some customers.
    b. Allow certain participants to provide their own day-ahead baseline every day before the standard notification time, with penalties for large departures from the participant's "scheduled" load on non-event days.
    c. Require that these participants achieve a firm service level, rather than curtailing a certain amount (i.e., a "down-to" commitment as opposed to a "down by" commitment). PGE could do this through the existing Schedule 77 tariff or by providing a customer with a choice of baseline via the Energy Partner program. However, this approach provides PGE with less visibility into the probability that the load will be available for curtailment than the other options discussed above.[8]

3.3 Program Delivery

The following section discusses recommendations for changes to the program related to the program delivery, including marketing and outreach strategies.

1. **Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.** Table 1 below shows recommended roles and responsibilities for the implementation vendor and PGE's existing DRMS vendor, relative to PGE. The agreement with the implementation vendor should consider the following:
    a. **Overall structure:** If PGE wants to manage the marketing and recruitment but needs more help on the technical side and back-end support, it can find the right type of vendor to provide such functions. More than likely, PGE should explore arrangements outside of a pay-for-performance structure to facilitate more program flexibility and

[8] *Measurement and Verification for Demand Response*, Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group, February 2013, https://eaei.lbl.gov/sites/all/files/napdr-measurement-and-verification.pdf.

ownership of the customer relationship. It is important to be clear about which party owns each function and which is in a supporting role to avoid competing efforts amongst parties.

b. **Agreement with the customer:** In the absence of a pay-for-performance structure with the vendor, then PGE can own the agreement with the customer, as opposed to the implementation vendor owning the agreement. To the extent possible, PGE should create a standard payment structure for all customers and the vendor to eliminate individual negotiations between the vendor and each customer.

c. **Marketing and recruitment:** If PGE has staff available that can open up prospective participants, the vendor could provide technical support to make prospects comfortable with participation in the program and help close the deal. In this scenario, a vendor would provide technical sales support, rather than pure customer sales resources, with PGE leading the marketing and recruitment. This would provide opportunities for PGE to have more contact with the customer and have more control over program-related branding.

d. **Technology and enablement expertise:**

   i. A primary responsibility of the vendor would be to provide technical implementation support. The vendor would install and enable the equipment at the customer site, help the customer develop a curtailment strategy, and provide ongoing technical support to troubleshoot under-performance, refine the curtailment strategy, and potentially provide ongoing customer support via a call center (if desired by PGE).

   ii. Vendors should be asked for solutions that can be implemented using customers' existing interval meters to reduce program costs. PGE should then carefully weigh the reduced costs proposed by the vendor against the reduction in the value of the data to the customer.

   iii. Assuming PGE can use its existing DRMS for dispatch, there is no need to use an implementation vendor's DRMS.

e. **Exit strategy:** Ensure that expectations are clearly laid out for who owns the DR equipment at the end of the contract term, with a buyout clause specified, if the vendor owns the equipment over the course of the program.

Table 1. Roles and Responsibilities for C&I DR Program

Business Function	Responsible Party		
	PGE	Implementation Vendor	DRMS Vendor
a. Define Program Parameters	P, A	-	-
b. Marketing, Customer Recruitment and Outreach	P, A	p	-
c. Contract with Customer	P, A	-	-
d. Provision of Metering	P, A	-	-
e. Provision of Technology Products and Services	-	P, A	-
f. Technology Installation and Enablement	p	P, A	-
g. Initiate Load Control Events	P, A	-	p
h. Data Support and Performance Analysis	p	P, A	p
i. Billing and Settlement	A	P	p
j. EM&V[9]	P, A	-	p
k. Customer Service and Satisfaction	p, A	P	-
l. Coordination with Energy Trust, KCMs, and Other PGE Programs	P, A	p	-

Level of Responsibility:
A = Accountable (answerable for the correct and thorough completion of the deliverable or task, and often the one who delegates the work to the performer)
P = Perform (carries out the activity)
p = Performs with a lower level of responsibility than P
Blanks indicate that the party is neither accountable nor responsible.

2. **Focus the program marketing and delivery around the benefits to the customers:**
   a. **Highlight the corporate social responsibility benefits of participating in program marketing.** PGE should also investigate channels for externally showcasing current participants, such as through case studies or co-advertising with one of the customers to feature that customer through the program promotion.
   b. **Revisit the financial incentives that can be cost-effectively provided to customers**, including the level of financial support or financing that can be offered for automation. Demand response participation requires indirect costs on the part of the customer, including transaction costs and the value of service lost. To a customer considering participating in the program, the value provided by the program must

[9] Note that PGE is responsible/accountable for hiring an independent third-party to perform the EM&V.

outweigh these costs. While financial incentives are not the only benefit that customers consider, they generally must compensate for all or most of the indirect costs of participation (e.g., curtailing production, paying overtime for after-hours curtailment, installing new systems, etc.). Several non-participants indicated that the current program value does not perceptibly meet that threshold for their business.

c. **Enhance the real-time energy information system and promote its value to customers.** Customers are most interested in using the real-time energy information system to understand how they performed during events and to identify non-essential uses of energy within their facility. PGE could enhance the value to the customer by including case studies or workshops to show how customers can use the granular data for diagnostics.

   Current participants use the energy information system to varying degrees, with one of the key barriers to using more frequently is having limited time available to review the information. To the extent practicable, PGE should work with the vendor to ensure the system provides streamlined access to energy data and ease of use. Two customers also expressed interest in having “more real-time feedback on financial benefits” by seeing the incentives from events sooner after the event through the program portal.

d. **Package DR marketing and participation with other EE incentives**, including the SEM, Energy Tracker, and Energy Expert programs. This provides customers with more up-side to offset the effort and hassle factor of participating.

3. **Enhance education for both participants and non-participants:**

   e. **Non-participants:** PGE should emphasize clear, upfront communications to non-participants about the benefits of the program and the perceived costs, particularly in terms of how the program might affect their operations. Several non-participants expressed concern about impacts to occupancy comfort, which in many cases is something that can be overcome through customer education and an appropriate curtailment strategy. When current participants were asked what PGE might do to reduce barriers to participation for non-participants, several participants thought that information from current participants explaining how participation has impacted their business would help encourage more customers to participate. PGE could highlight the existing customer case studies on the Energy Partner website in initial discussions with non-participants and potentially identify current participants who can champion the program to other customers.

   f. **Participants:** One customer suggested organizing a forum for ongoing participants to interact and discuss ideas for curtailment strategies and lessons learned. Alternatively, PGE could host periodic webinars where customers could share best practices and lessons learned. A couple of customers also expressed interest in receiving help educating stakeholders within their organization about the benefits of the program and explaining why comfort or production might be temporarily impacted.

4. **Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust’s day-to-day processes with minimal overhead:**

   g. **Streamlined processes:** Given competing priorities for Energy Trust staff’s limited time, PGE should strive to streamline the efforts required by Energy Trust program managers and contractors for cross-marketing.

   h. **Coordinated customer touchpoints:** This program needs to be sensitive to customer fatigue by coordinating touchpoints to the extent possible, since some customers may have already been contacted about the Energy Partner program by EnerNOC or their KCM, in addition to the Energy Trust contractor, who does the cross-marketing to the customer.

   i. **Consistent contractor touchpoints:** Energy Trust contractors are currently blending in discussion of the Energy Partner program, where appropriate, and if customers have questions. PGE should build in consistent touchpoints (e.g., quarterly) to ensure that cross-marketing the Energy Partner program continues to be a priority for the Energy Trust's contractors.

j. **Training curriculum:** The Energy Trust suggested incorporating DR into the SEM curriculum, with an emphasis on "what is DR," what makes good DR opportunities, and how it relates to demand management. This approach would help promote DR, but would also help enhance the value proposition to the customer for participation in SEM. While this approach would market more broadly than the targeted approach PGE has used previously, it shifts the focus away from providing customers a particular "product," while opening the door for conversations about Energy Partner and serving as a foundation for expanding the program reach beyond customer segments historically targeted.

k. **Technical alignment:** At a high level, there is overlap in the use of energy information and interval metering between the Energy Partner and SEM programs. However, EnerNOC required a separate energy information management system and meter that did not match the needs of the SEM program, particularly for industrial customers with unique production data. While it may ultimately be infeasible to find a system in the near-term that serves the needs of both programs and is supported by DR providers, PGE should explore this as an option with vendors during the procurement process.

l. **Formal agreement:** Explore options for codifying the terms of collaboration with the Energy Trust in a formal agreement that clearly defines expectations for the arrangement, including opportunities for PGE to cross-market the SEM program. PGE should also clearly state expectations with DR vendors upfront for coordination with the SEM program as part of the procurement process.

5. **Increase marketing to medium-size customers (200 kW to 1+ MW peak load).** Partner with a vendor that is geared toward smaller C&I customers, particularly in the commercial sector.

6. **Evaluate options for using existing interval meters to lower program equipment costs.** If metering is part of a vendor's proposed solution, PGE should ask the vendor for program cost estimates with and without the use of additional meters, as well as any technical limitations or interoperability issues that the vendor might anticipate with using PGE's interval meters. PGE should then evaluate the cost savings against the tradeoffs in more detail.

7. **To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.** By setting initial load curtailment targets low, the customer can start to understand how DR will affect their operations and will start off successful in the program. PGE used this approach with a current participant and saw positive results. The implementation vendor should also discuss different possible operations scenarios in depth with the customer while developing the curtailment strategy to ensure customers can provide accurate estimates of curtailment across varying operational conditions.

8. **Leverage existing and new channels for broader and more continuous customer engagement:**

   a. **KCMs:** PGE should continue to use and grow the role of KCM's as one of the channels for marketing and customer enrollment. If PGE decides to lead marketing and recruitment in-house, the role of KCMs will be particularly important. Opportunities include more clearly defining the expectations for KCM contributions to enrollment in relation to the implementation vendor and providing more training for KCMs specific to the program. Collaboration with account managers in other jurisdictions tends to be most successful when the utility ties program-specific metrics to performance scores, if that option is available to PGE.

   b. **Local technical expertise:** Several participants said that they would have benefited from more upfront implementation assistance with deep technical knowledge of certain end uses. Customers also expressed a desire for ongoing technical assistance throughout their participation for identifying new ways to curtail more. PGE may consider partnering with a local energy engineering firm, such as Cascade Engineering, to provide strategic technical expertise for some customers.

c. **Alternative marketing channels:** Exploration of new marketing channels will be particularly crucial if PGE markets the program in-house. Examples could include offering referral bonuses to building controls trade ally channels for large commercial (i.e., similar to Hawaiian Electric Company), cross-marketing with the vendor who provides PGE's storage solutions, or working through local industry associations and chambers of commerce.

3.4 Procurement

Given PGE's unique market and operating environment, rather than offer a traditional RFP solicitation, Navigant recommends that PGE define the situation and the problem, and invite solutions in a very short response format (e.g., with only proposed structures, drivers of pricing, caveats, and indicative pricing). Based on the vendor's responses, PGE would then invite a few firms for a brainstorming discussion that helps PGE think through the issues constructively. Following this working session, PGE would select one of the firms to help modify the program and to deliver it in a new way that addresses the challenges identified.

Section IV Summary

PGE has faced challenges building C&I DR capacity within its service area, due to issues like limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. However, there are changes PGE can make to increase participation and capacity by refocusing the program as a customer-centric resource comprised of more diverse C&I customers in terms of size and industry type, with an emphasis on education and strategic partnerships for customer outreach. As part of this, PGE should also revisit and prioritize the operational requirements for the C&I DR resource to facilitate flexibility for the customer where possible, while also meeting PGE's operational needs. This new DR philosophy emphasizes flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within the customers' and PGE's operations requirements.

UM 1514

Attachment F

Notice of Application for Reauthorization
Of Deferral of Incremental Costs Associated with
Non-Residential Demand Response

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1514

In the Matter of the Application of Portland General Electric Company for an Order Approving the Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response	**Notice of Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response**

On September 21, 2017, Portland General Electric Company (PGE) filed an application with the Oregon Public Utility Commission (Commission) for an Order reauthorizing the deferral of incremental costs associated with the Non-Residential Demand Response Pilots with the Commission.

Approval of PGE's reauthorization application will continue to support the use of an automatic adjustment clause rate schedule, which will provide for changes in rates reflecting incremental costs associated with the pilot.

Persons who wish to obtain a copy of PGE's application will be able to access it on the OPUC website.

Any person who wishes to submit written comments to the Commission on PGE's application must do so no later than October 20, 2017.

Dated September 21, 2017.

Stefan Brown
Manager, Regulatory Affairs
Portland General Electric Company
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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **Notice of Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response Pilots** to be served to those parties whose e-mail addresses appear on the attached service lists for OPUC Docket Nos. UE 319 and UM 1514.

Dated at Portland, Oregon, on September 21, 2017.

Stefan Brown
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