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November 13, 2020

Via Electronic Filing

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

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

Dear Filing Center:

Enclosed for filing is Portland General Electric Company's ("PGE's") application for reauthorization to defer incremental costs associated with Non-Residential Demand Response ("DR") Pilot (PGE Rate Schedule 26) and Non-Residential Direct Load Control ("DLC") Pilot (PGE Rate Schedule 25), collectively known as Energy Partner, with an effective date of January 1, 2021. PGE received the most recent reauthorization pursuant to Public Utility Commission of Oregon ("Commission" or "OPUC") Order No. 20-259.

PGE indicated in PGE Advice No. 20-27 (Updating Schedule 25, Non-Residential Direct Load Control Pilot Term Extension) that the deferral reauthorization application for future cost recovery would include a memo of planned pilot activities, pilot-to-program progress, and opportunities and challenges, which has been enclosed as Attachment B (Pilot Extension for Non-Residential Direct Load Control ("DLC") Pilot).

PGE also indicated in PGE Advice No. 20-26 (Schedule 26, Non-Residential Demand Response Program Update) that Schedule 26 has met the pilot-to-program criteria and PGE will subsequently file a pilot-to-program transition plan in 2021. PGE acknowledges this commitment and is seeking an extension of the Pilot to prepare a transition plan that is aligned with concurrent, initiatives. Specifically, once the Flexible Load Plan is accepted by the Commission, PGE will file a Multi-year Plan and Budget which will include cost recovery and program treatment for the Nonresidential DR Program. Pilot to Program Progress for the Non-Residential DR Pilot has been enclosed as Attachment C.

PGE originally received permission for deferral of incremental costs associated with Energy Partner through Commission Order No. 11-182. A Notice of Application regarding the filing of this application has been served by electronic mail to OPUC Docket Nos. UE 335 and UM 1514 service lists.

Thank you for your assistance in this matter. If you have any questions or require further information, please call Alina Nestjorkina at (503) 464-2144.

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

Sincerely,

/s/ *Jaki Ferchland*
Jaki Ferchland
Manager, Revenue Requirement

JF/np

Enclosure
cc: Service Lists: UE 335 and 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 Pilot and Non-Residential Direct Load Control Pilot**

Pursuant to Oregon Revised Statute ("ORS") 757.259, Oregon Administrative Rule ("OAR") 860-027-0300, and the Public Utility Commission of Oregon ("Commission" or "OPUC") Order Nos. 19-151 and 20-259, Portland General Electric Company ("PGE") hereby requests approval for the continuance of the deferral that is associated with the Non-Residential Demand Response ("Non-Res DR") Pilot and Non-Residential Direct Load Control ("Non-Res DLC") Pilot, collectively known as Energy Partner. Energy Partner is subject to the automatic adjustment clause tariff, Schedule 135 and operational tariffs Schedule 25 and Schedule 26, respectively. PGE requests this reauthorization be effective January 1, 2021 through May 31, 2021. As discussed with Staff in November 2020, PGE will coordinate the Demand Response ("DR") related deferral periods and tariff term dates to align on June 1[1]. This would allow PGE to better plan and propose product design changes in deferral applications and file tariff updates that reflect these changes,[2]. It will also allow the OPUC Staff to review all the filings associated with the Energy Partner at the same time rather than separately and on disparate schedules.

[1] For most DR offerings, June 1 represents the beginning of the summer event season.

[2] Tariff updates would be filed with an effective date of June 1 but ahead of time to allow for adequate Staff review

I. **Deferral History**

In alignment with the State of Oregon and Commission policies and requirements, PGE has developed Energy Partner to help address decarbonization goals, assist customers in managing their energy consumption and total energy costs, and enhance operational performance and efficiency. Energy Partner continues to comply with Oregon's policy direction, as recently outlined in Executive Order 20-04, and supports PGE's decarbonization strategy to reduce our greenhouse gas ("GHG") emissions by more than 80% by 2050 and performance imperatives to provide clean, safe and reliable power to our customers.

PGE filed the initial application for deferral of incremental costs associated with Energy Partner, which at the time was named Automated DR ("ADR"), on December 29, 2010 and cost recovery via Schedule 135 was approved by Commission Order No. 11-182 on June 1, 2011[3].

Proposed Modification:

- PGE's most recent deferral period spanned from January 1, 2020 to December 31, 2020.
- PGE is proposing to alter the deferral period with this application to only include the period from January 1, 2021 to May 31, 2021. As discussed above, this is to align PGE's deferral and tariff filings associated with Energy Partner. Prior to June 1, 2021, PGE will submit its next request for UM 1514 deferral reauthorization and that will be for the twelve-month period of June 1, 2021 through May 31, 2022.

As discussed in PGE's report submitted April 28, 2016, with the second ADR evaluation, the pilot in its then-current form had fallen short of its nomination goal of 25 MW with only

[3] PGE Advice No. 10-29

10.6 MW nominated for the summer of 2017[4]. In addition, PGE's third-party provider, EnerNOC, informed PGE that, as of September 30, 2017, they would be terminating their contract to provide the aggregator demand response services under the ADR pilot. In response, PGE reviewed the ADR pilot, along with Schedule 77,[5] and revised them to create two separate Non-Res DR and Non-Res DLC pilots that make up Energy Partner, targeted to meet PGE's goal of 27 MW of peak load reduction by 2021 across all nonresidential segments and products. Commission Order No. 17-429 approved PGE's rebranded "ADR" as "Energy Partner" which created interchangeable components for various solution providers that include a third-party implementer for customer engagement (CLEAResult), third-party evaluator for quality assurance (Guidehouse), asset management solution provider (EDM Software) and Demand Response Management System ("DRMS") provider (Enbala). In alignment with the 2016 and 2019 Integrated Resource Plans ("IRPs"), PGE tracks Energy Partner's peak load reduction for winter and summer seasons individually instead of an aMW target. As a result, the targeted 27 aMW has been adjusted to 23.4 MW in the winter season and 30.7 MW in the summer season to provide visibility into seasonality of DR.

PGE submitted the first of two evaluations on September 27, 2019, after the first three operating seasons under the current structure were completed to allow for adequate time and number of events to provide meaningful results. This evaluation was in support of the Non-Res DR Pilot and excluded the Non-Res DLC Pilot because thermostats were not yet installed during the evaluation period. Specifically, the evaluation reported that the Non-Res DR Pilot is in transition as: 1) new system integration took longer than expected because of the complexity of

[4] See Attachment C

[5] Firm Load Reduction Program, which had only one customer.

the systems; and 2) the current effort strives to achieve scale and maturity by meeting 23.4 MW in the winter season and 30.7 MW in the summer season goal by 2021. For the Non-Res DR pilot, customer interviews determined that participants were generally very satisfied. Specifically, customers were pleased with incentives, flexibility and options for participation. The evaluation also highlighted that the coordination between PGE's Key Customer Managers and the third-party implementer was working well. Additionally, PGE held a workshop on November 2, 2019 with Staff and stakeholders to discuss the findings of the Non-Res DR pilot evaluation and review the key considerations for transitioning the pilot into a full program. Attachment C (Pilot to Program Progress for Non-Residential Demand Response Pilot) highlights the progress towards transitioning the Pilot to Program.

PGE has 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, 2021 through May 31, 2021 and asks that the Pilots continue as currently included in Schedules 25, 26, and 135.

Table 1
UM 1514 Authorizations

Filing Date	Deferral Period	Order No.	Approval Date
12/29/2010	1/01/2011 – 12/31/2011	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
09-21-2017	1/01/2018 – 12/31/2018	17-429	10-24-2017
12-20-2018	1/01/2019 – 12/31/2019	19-151	04-23-2019
12-26-2019	1/01/2020 – 12/31/2020	20-259	8-11-2020
11-13-2020	01/01/2021 – 05/31/2021		

II. Approved Current Program

PGE proposes to continue the Non-Res DR and Non-Res DLC Pilots and associated operational tariffs: Schedule 25 and Schedule 26, respectively. These pilots will continue to be administered directly by PGE with its customers, with support from third-party vendors. PGE took this approach primarily to manage the customer's experience, allowing PGE the flexibility to offer a variety of products and potentially adjust those products in the future.

Schedule 25 (Non-Res DLC Pilot)

The Non-Res DLC Pilot provides nonresidential customers with a turnkey, direct load control program, similar to Schedule 5 (Residential DLC pilot) for our residential customers. This provides 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 Non-Res DLC Pilot offers incentives to allow PGE to control up to 3,800[6] qualified thermostats during direct load control events while providing for customer override. Eligible customers must be on a qualified rate schedule and have a PGE network meter, a qualified thermostat connected to the customer's internet, and a qualifying heating or cooling system. To be eligible for the winter event season, customers must have a ducted heat pump or electric forced air heating. To be eligible for the summer event season, the customers must have central air conditioning or a ducted heat pump.

Schedule 26 (Non-Res DR Pilot)

The Non-Res DR Pilot provides diversity of participation levels, allowing customers to select differing availability periods, notification times, and maximum event hours. This pilot also allows customers with multiple Service Points the ability to self-aggregate them. Customers participate in summer, winter, or both seasons. This pilot makes several firm load reduction options available to customers including maximum event hours per season, notification periods,

[6] See Attachment B.

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 to participate in each event window (i.e. time period for an event) per season.

Evaluations

In accordance with Commission Order No. 20-259, PGE filed evaluations for winter 2018-19 and summer 2019 on November 5, 2020[7]. The Non-Res DR Pilot evaluation reported the following:

- Impact evaluations for the Non-Res DR Pilot indicated PGE achieved up to 13.8 MW of demand reduction per event from Customer Baseline Load ("CBL") customers in the 2019 summer season and 8.5 MW demand reduction in the 2018-19 winter during the only event called with CBL customers.
- Forty-two of fifty CBL customers consistently delivered reductions over the course of the 2019 summer season, with a maximum event realization rate of 91%. Note that the winter 2017-18 event, summer 2018, and winter 2018-19 events had maximum realization rates of 66.5%, 159%, and 68%, respectively.
- In the 2018-19 winter season, 11 out of 61 customers had performance discrepancies between -62% and 100%. However, only one customer's incentive level is affected—specifically, a customer reached over 70% of their nomination (whereas CLEAResult calculated that they reached 0%) and should have received an incentive payment. Based on this discrepancy this customer was provided an incentive payment.

[7] https://edocs.puc.state.or.us/efdocs/HAH/um1514hah155829.pdf

- In the 2019 summer season, Guidehouse identified 14 customers that had a CBL discrepancy between Guidehouse and CLEAResult's calculated impacts differed by 5% or greater and the discrepancy was greater than 5% of the customer's nomination. For each event, the demand reduction discrepancies between Guidehouse and CLEAResult's ranged from -2.5% to 3.7%. Of the 14 customers, only one customer's incentive payment is affected by the discrepancies. In contrast to CLEAResult, Guidehouse's calculated impact for customer reached 100% of their nomination and, thus, this customer was provided an incentive payment.

The Non-Res DLC Pilot evaluation reported the following:

- Impact evaluation for the Non-Res DLC Pilot indicated PGE achieved peak of the season 139 kW of total demand reduction from customers with a relative precision of 30%. The average impact across all events was 92 kW with relative precision of 92%. Due to the relatively small sample size, results lacked statistical significance.
- The best performing event (July 22, 2019) delivered 139 kW. This event included the greatest number of participating thermostats (120), but also corresponded with the lowest temperature day (83 degrees) of the season.
- The event with the greatest per thermostat impact (August 28, 2019) delivered 3.74 kW per thermostat. The event corresponded to the highest temperature day (96 degrees) of the season and the lowest participation rate (16%) of the season. However, it also had the highest average event standard error and relative

precision at 90% confidence interval. This means that the estimated impact for August 28 may vary as much as 73% from the actual performance.

PGE will submit the summer 2020 evaluation in the second quarter of 2021 for both Non-Res Pilots. Seasonal evaluations for each Pilot will be submitted within six months of the seasons' end.

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 Energy Partner. 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 Energy Partner through Schedule 135.

Prior Commission decisions in UM 1514 approved PGE's applications for deferral of incremental costs associated with Energy Partner. Consequently, PGE requests that the deferral be renewed beginning January 1, 2021 through May 31, 2021 and continue to 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 Energy Partner. 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, 2020. PGE is filing this reauthorization application for the period January 1, 2021 through May 31, 2021.

c. Proposed Accounting

PGE proposes to record the deferral as a regulatory asset in FERC Account 182.3 (Other Regulatory Assets) and credit the appropriate FERC expense accounts. When specific identification of the particular source of the regulatory asset cannot be reasonably made, then FERC account 407.4 (Regulatory Credits) will be credited. In the absence of a deferred accounting order, the costs would be debited to the appropriate cost accounts.

d. Estimate of Amounts

PGE estimates the amounts to be deferred for Energy Partner from January 1, 2021 through May 31, 2021 to be approximately $2.1 million.

e. Notice

A copy of the notice of application for reauthorization of the deferred accounting treatment is attached to the application as Attachment A. In compliance with the provisions of OAR 860-027-0300(6), PGE is serving the Notice of Application on the UM 1514 Service List and the UE 335 Service List, PGE's last general rate case.

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

a. Description of deferred account entries

Please see Section II (a) and (c) above.

b. The reason for continuing deferred accounting

Please see Section II (b) above. PGE is seeking reauthorization to continue deferred accounting treatment for incremental Energy Partner costs between January 1, 2021 and May 31, 2021.

IV. PGE Contacts

Communications regarding this reauthorization application should be addressed to:

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V. Summary of Filing Conditions

a. Earnings Review

Cost recovery for Energy Partner will be subject to an automatic adjustment clause rate schedule and would not be subject to an earnings review under ORS 757.259.

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

Under deferred accounting, all prudently incurred costs are to be recoverable by PGE with no sharing mechanism.

d. Rate Spread/Rate Design

Per Commission Order No. 11-517, 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 amortization of the pilots' deferred costs will be subject to the three percent test in accordance with ORS 757.259(6) and (8), which limits aggregated deferral amortizations during a twelve-month period to no more than three percent of the utility's gross revenues for the preceding year.

VI. Conclusion

For the reasons stated above, PGE requests permission to continue to defer for later rate-making treatment incremental costs associated with Energy Partner effective January 1, 2021 through May 31, 2021.

Dated this November 13, 2020.

Respectfully Submitted,

/s/ *Jaki Ferchland*
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UM 1514
Attachment A

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

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 Pilots**

On November 13, 2020, Portland General Electric Company ("PGE") filed an application with the Public Utility Commission of Oregon ("Commission" or "OPUC") for an Order reauthorizing the deferral of incremental costs associated with the Non-Residential Demand Response Pilots.

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 December 13, 2020.

Dated November 13, 2020.

/s/ *Jaki Ferchland*

Jaki Ferchland
Manager, Revenue Requirement
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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 335 and UM 1514.

Dated at Portland, Oregon, on November 13, 2020.

/s/ *Jaki Ferchland*

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UM 1514
Attachment B

Pilot Extension for
Non-Residential Direct Load Control ("DLC") Pilot

Attachment B: Pilot Extension for Non-Residential Direct Load Control ("DLC") Pilot

The Non-Residential DLC Pilot (Schedule 25), in compliance with Order No. 17-429[8], went into effect on December 1, 2017. The DLC Pilot is designed to address both the needs of PGE's nonresidential customers while helping to grow a resilient and flexible demand response portfolio to create a program able to meet PGE's goals of greater than 77 MW of winter peak load reduction and 69 MW of summer peak load reduction by 2021; Energy Partner's goal is to meet 23.4 MW of nonresidential peak load reduction[9] in winter and 30.7 MW in summer. The Pilot's key objective is to enable a demand response ("DR") offering for small to medium-sized businesses through smart thermostat technologies by shifting business customers' loads during peak times. PGE will leverage pilot learnings to continual improve the Pilot in preparation of transitioning the pilot-to-program.

Figure 1: Number of Thermostats installed by Brand

	Winter	Summer	Total
Pelican	101	402	402
Ecobee	177	747	739*
Total	**278**	**1149**	**1141**

*Total thermostats takes into account 8 thermostats that are winter only

Figure 2: Demand (MW) by Brand

	Winter	Summer
Pelican	0.129	0.212
ecobee	0.274	0.385
Total	**0.403**	**0.597**

While the tariff was created three years ago, the Pilot is still new to the market and early in its maturity. The first Pelican thermostat (*model TS200*) was enabled prior to the summer 2019 Event Season and Ecobee thermostat (*model EMS Si*) was launched in the fourth quarter of 2019. As of October 14, 2020, PGE has installed 1,141 cumulative thermostats (Figure 1) representing 410 customers across 1,187 sites and is anticipating up to 1400 installations by year-end. Based on estimated demand, the existing fleet will facilitate 0.4 MW in the winter and 0.6 MW in the summer (Figure 2) and will reach 0.5 MW in winter and 0.7 MW in summer.

This attachment is intended to provide details regarding Planned Activities during Pilot Extension, Pilot-to-Program progress, and opportunities and challenges until the next scheduled advice filing.

<u>Planned Activities During DLC Pilot Extension (in order of priority)</u>

1. **Alignment of the tariff's term and thermostat cap**
    a. <u>Current State</u>: Currently, the term and the thermostat installation cap are misaligned in the Fourth Revision of Sheet No.25-4. The term of the Pilot is set to expire prior to reaching the installation cap.
    b. <u>Recommendation</u>: PGE is seeking a 17-month extension by changing the term from December 31, 2020 to May 31, 2022 and reducing the installation cap from 10,000 to 3,800 thermostats to reflect the installation pace of the Pilot. PGE will file an advice filing accompanied by a Tariff update (with an effective date of June 1, 2021) by April 15, 2021. The purpose of the advice filing will restate Pilot objectives, identify anticipated learnings through a research plan, describe benefits to ratepayers, show how this Pilot fits into the demand response portfolio, and facilitate key delivery and regulatory milestones.

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[8] See OPUC Docket No. ADV 646, Advice No. 17-23, approved at the November 21, 2017 public meeting. https://edocs.puc.state.or.us/efdocs/UBH/adv646ubh145442.pdf

[9] See OPUC Docket No. UM 1514, PGE's Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response filed on September 21, 2017, page 2. https://edocs.puc.state.or.us/efdocs/HAQ/um1514haq142830.pdf

c. Justification: A 17-month extension will be used to reset expectations to ensure that Pilot will be able to meet targeted outcomes by specified timelines while meeting its budgetary commitments. PGE would like to establish the Nonresidential DLC Pilot independent from the Nonresidential Demand Response Pilot. Despite the separation of the Pilots, PGE will continue to market to customers as Energy Partner.

d. Benefits: Clear and concise term and caps for Pilots will provide administrative efficiency between the tariff and the deferral reauthorization cycle.

2. **Collaborate with Energy Trust**

   a. Current State: PGE and Energy Trust have a memorandum of understanding ("MOU") to cost share the installment of the commercial thermostats, which is set to expire on December 31, 2020. The current cap for the MOU has been set for 2,500 units and provides parameters on what configurations are eligible for Energy Trust incentives and how data is shared

   b. Recommendation: To extend the MOU one year and adjust cap to align with PGE's 2021 forecast.

   c. Justification: This cost sharing model assists with providing visibility into the energy efficiency and demand response benefits of commercial thermostats. This collaboration is intended to quantify annual energy savings (kWh) and demand (kW) shifted during events in order to inform pilot learnings and pilot design.

   d. Benefits: This collaboration benefits the customer by quantifying the value proposition of commercial thermostats.

3. **Leverage customer insights**

   a. Current State: A process evaluation for the Pilot has not yet been performed; preliminary process evaluation results for the summer 2020 will be available in January 2021. The process evaluation assesses how well the Pilot is operating and identifies beneficial modifications in terms of program rules, implementation and administration. Interviews with PGE staff, the contracted program implementation team, existing participants, and non-participants will be performed to inform the process evaluation findings.

   b. Recommendation: PGE leverages the results from the summer 2020 evaluation for incremental improvements prior to making structural changes to the tariff that would impact the commitment between PGE and the customer.

   c. Justification: Customer feedback from evaluations, in concert with third party recommendations, are critical to making informed decisions about enhancing the Pilot to meet customer needs and creating a stable program design

   d. Benefits: Customer programs that are designed to meet the customers' needs lead to enhanced customer engagement, increased customer satisfaction, and delivers demand response capacity.

4. **Investigate incentive structures**

   a. Current State: Customers with eligible HVAC equipment receive $60 per thermostat per season for participating in 50% or greater event hours. Customers whose heating system provides greater demand reduction receive the same incentive as a customer whose potential is less.

   b. Recommendation: To pursue a new incentive structure that is still easy for customers to understand and continues to reward customers based on the seasons in which they are participating in, while also integrating how much demand response (kW) can be delivered during an event. Customer insights from the process evaluation will be considered in the pilot design change in order to ensure that the incentives are meeting customer needs. Participating customers will be notified within 30 days of change and updated tariff will be effective June 1, 2021. Through the duration of the Pilot, PGE will assess if the incentive structure meets customer expectations and if seasonal incentives are necessary to achieve the desired load reductions during an event.

c. Justification: The design of the current incentive structure does not account for the wide range of equipment sizes (tonnage) in the commercial setting. Typical commercial grade equipment ranges from 5 to 25 tons whereas residential grade equipment ranges from 3 to 5 tons. Larger equipment can facilitate 5 times more demand response value in comparison to residential equipment.

d. Benefits: PGE will have the ability to compensate based on demand, which will assist with targeting customers with greater demand response potential. In turn, this will improve the average demand reduction per thermostat and will have positive impacts to the cost-effectiveness of the Pilot.

5. **Leverage performance results**

a. Current State: Summer 2019 marked the first season where smart thermostats were enrolled in Schedule 25 and four events were called during the season. The evaluation for summer 2019 indicated that the approach for impact evaluations will continue to evolve as more customers become enrolled in the program and more observations of response are available. PGE anticipates that the summer 2020 impact evaluation will yield an adequate sample size and better represent thermostat performance. The evaluation for winter 2019/20 season represents one thermostat event due to the mild weather conditions. Altogether, only 39 thermostats were eligible for a winter incentive payment. Due to a low sample size and the number events called an impact evaluation was not performed. The winter 2020-21 Season will be the first season to receive an impact evaluation.

b. Recommendation: Closely monitor impact evaluation results to ensure that thermostats are performing as intended. Where applicable, PGE will compare Advanced Metering Infrastructure ("AMI") data to kW estimates using telemetry run-time data and nameplate power ratings in order to determine the best approach to validating thermostat performance. The impact evaluation outcomes will directly inform potential program design changes as means to offset the differential between how thermostats are performing in the field and what is achievable. PGE anticipates that the summer 2020 will provide valuable insight required to make program design decisions. No structural program design changes will occur until evaluation results are available.

c. Justification: Performance results from evaluations are critical to making informed decisions about designing a program that meets customers' needs.

d. Benefits: PGE will gain valuable insights into the performance of thermostats prior to dispatch integration with Power Operations. This will inform the predictability of hourly load and the potential of flexible services.

6. **Demand response planning value refinement**

a. Current State: PGE is no longer tracking demand reduction assumptions through the .3kW per thermostat deemed value and has adopted CLEAResult's Regional Technical Forum ("RTF") approved engineering-based approach which uses efficiency ratings, system tonnage, Heating, Ventilation & Air Conditioning ("HVAC") type and set points as mean to calculate the demand of each thermostat. This approach leveraged three different building models for one small office prototype. PGE believes that the initial deemed value was underestimating demand and did not account for the wide range of equipment sizes within the commercial setting.

b. Recommendation: The summer 2020 impact evaluation will assist with validating the RTF approved engineering approach. An analysis will be performed to determine if there are demand variations between small office and other building uses such as restaurants, retail and convenience stores. Building types with higher demand response potential would assist with targeting specific business customers.

c. Justification: The ability to forecast demand response potential by thermostat is critical to maintaining the Pilot's operations, pathway to cost effectiveness and load predictability during an event.
d. Benefits: Understanding the relationship of demand response potential and equipment size will assist with prioritizing and targeting customers.

Pilot-to-program progress

PGE has identified five key interrelated considerations for the transition from Pilot-to-Program, which are Customer Experience, Infrastructure Stability, Grid Performance, Financial Performance and Dispatch Integration. Figure 3 below, depicts PGE's progress in meeting the acceptance criteria. At this time only Financial Performance has met the acceptance criteria

Figure 3. Pilot-to-Program Considerations

	Consideration[3]	Progress	Acceptance Criteria
☐	**Customer Experience** • Customer onboarding • Event communication • Participant satisfaction	PGE does not have evaluations to support the onboarding, event communication or participant satisfaction of the Pilot, however, early indicators have been positive. PGE's energy efficiency outreach team, who are assisting with lead generation, have indicated that customers are highly satisfied with the offering. To date, all program attrition has been related to systems issues, not customer satisfaction.	• Consecutive process evaluations indicate customers are highly satisfied. • Customer Satisfaction is 80% or greater (as reported in the third-party process evaluation).
☐	**Infrastructure Stability** • Mature and scalable technologies • Optimal communication platform • Billing and IT enablement	Evaluation results and larger sample sizes are required to adequately assess infrastructure stability. There are no known communication issues with reaching assets in the field during an event or customer's ability to log into cloud-based portal. Through implementation, Operations has encountered several HVAC system incompatibility issues, which has led to service issues that were resolved by a HVAC professional. The defect rate remains below the tolerable threshold. Customers are receiving seasonal incentive through physical checks.	• Defect rate is less than 5% or less (i.e. incompatible systems or defective equipment) • Customers receive seasonal incentives on-bill instead of physical check
☐	**Grid Performance**		• Hourly loads are predictable and validated

	• Hourly load predictability • Flexible load predictability	Evaluation results and larger sample sizes are required to adequately assess grid performance.	through consecutive seasonal evaluations • Predictability of loads during weather-based events • (TBD) MW in summer and (TBD) MW in winter
✓	**Financial Performance** • Cost effectiveness	The combined Total Resource Cost ("TRC") Test for the Nonresidential DR and Nonresidential DLC Pilots is 1.2	• TRC > 1
☐	**Dispatch Integration** • Shared dispatch protocols • Dispatched by Power Ops • Dispatching entity • Dispatched by distribution • Balancing Authority grid benefits	The Ecobee integration was completed and successfully tested during the 2020 summer season. As a result, both thermostat models are now being called through Enbala's Concerto platform by Program Operations. Prior to the integration Ecobee thermostats were called through the Ecobee utility portal and Pelican thermostats were called through Concerto. Shared dispatch protocols have not been developed and Power Ops are not driving the decision to call events.	• Event-calling procedures and protocols are fully tested and achieve favorable results • Use-cases to call commercial thermostats are defined

<u>Pilot Extension</u>

There is still more to learn about commercial thermostats before the Pilot is ready to transition to program.
The greatest opportunity to evolve the Pilot is to refine Pilot objectives and research questions to ensure that desired outcomes will be delivered within anticipated timelines. The initial phase of the Pilot has been extremely insightful into understanding the market potential, barriers to participation, program design strategy, and the infrastructure required to leverage these assets. These learning will be essential to growing and evolving the Pilot and transitioning into a Program.

Like any Pilot, there have been challenges. The most notable challenge has been identifying and targeting gatekeepers and decision makers within small to medium sized businesses. It is evident that who the Pilot should be targeting varies greatly from business to business and getting their attention can be challenging because they may be facilitating multiple roles within their organization. PGE's Customer Care and Billing ("CC&B") system has been successful in assisting with targeting business, but the contact who is paying the bill may not always be best suited for discussing the value propositions of commercial thermostats. Additionally, contact identification through CC&B is further challenged due role changes and attrition within the customer's organization. Currently lead generation and the resources required to perform field installations are balanced, however, as the Pilot progresses PGE will be investigating cost-effective ways to better reach the customer.

During the 17-month pilot extension the next significant regulatory milestone will be an advice filing accompanied by a tariff updated by April 15, 2021. The purpose of the advice filing will be to provide greater visibility into the Pilot through a Pilot Research Plan. PGE would like to establish the Nonresidential DLC Pilot as standalone Pilot that is independent from the Nonresidential Demand Response Pilot.

Specifically, the research plan will:

- Provide a timeline of programmatic and regulatory activities with built-in milestones in order to address scope changes and/or early retirement
- Facilitate a supplemental budget independent of the Nonresidential Demand Response Pilot
- Define learning objectives that inform the research questions and how these objectives will be achieved
- Highlight relevant and similar utility studies pertaining to the demand response potential of commercial thermostats
- Address Pilot participation regarding who or what will this pilot target
- Outlines potential benefits to ratepayers
- Identify the potential scale and facilitate insights into product adoption and market barriers.
- Define the total number of participants required to evaluate Pilot and provide statistical rationale, while taking into consideration evaluation result timelines
- Outline the Pilot's evaluation strategy and indicators that the market is ready for broader adoption
- Address reporting cadence and the metrics that define the Pilot's status

UM 1514

Attachment C

Pilot to Program Progress for

Non-Residential Demand Response (“DR”) Pilot

Attachment C: Pilot-to-Program -Progress for Non-Residential Demand Response ("DR") -Pilot

This attachment is intended to facilitate the progress of transitioning the Nonresidential DR Pilot into a Program by outlining the current state of the Program through five interrelated considerations; and highlighting activities that are forthcoming and how PGE will successfully navigate these activities. At this time PGE has proposing a 9-month extension to file the Nonresidential DR Pilot Transition Plan in order to synchronize guidance on Pilot-to-Program Transition criteria with the Commission Staff. As PGE transitions to multiyear planning and budgeting, it will propose program treatment of Schedule 26 as part of its forthcoming Strategic Plan and Budget. The Schedule 26 transition to Program is a minor transformation and PGE anticipates that there will not be major changes to the Tariff or program design. Throughout the Pilot phase, many customer-facing enhancements have been gradual and were in direct response to feedback obtained through seasonal evaluations. During this time, PGE built out the infrastructure required to support demand response events, manage behind the meter assets, and implemented processes and protocols to integrate resources with PGE's operations.

Through the pilot phase of Schedule 26, PGE tested implementation, customer engagement, and marketing approaches, measured customer satisfaction and acceptance, provided final validation of the business case, and demonstrated cost effectiveness. As a result of the pilot's achievements, activities are cost-effective, performance is stable and reliable, and the budgets are forecastable within an acceptable tolerance. The pilot-to-program criteria outlined below were gained through numerous learnings in the context of an accelerated resource build with a high degree of risk. Consequently, Schedule 26 will be the first PGE pilot to transition into a program and many of the Company's flexible load or demand response customer offerings will remain in the pilot phase. While these criteria alone do not constitute a pilot's readiness to transition to a Program, PGE sees five key interrelated considerations for the transition from pilot-to-program offering:

- Customer Experience
- Infrastructure Stability
- Grid Performance
- Financial Performance
- Dispatch Integration

<u>Background:</u>

In compliance with Order No. 17-429, the Non-Residential Demand Response Program (Schedule 26) went into effect on December 1, 2017.[4] The Program replaced both PGE's Schedule 77 Firm Load Reduction Program and the Automated Demand Response Pilot. The Program is designed to address both the needs of PGE's nonresidential customers while helping to grow a resilient and flexible demand response portfolio to create a program able to meet PGE's goals of greater than 77 MW of nonresidential peak load reduction by 2021; Energy Partner's goal is to meet 27 MW of nonresidential peak load.[5]

As of October 2020, the actual MW nomination for Schedule 26 is 20.1 MW (summer) and 15.4 MW (winter) representing 71 customers across 146 sites. By year end 2020, the Program is expected to grow by 0.5 MW in the summer and 0.4 MW in the winter to a total of 20.7 MW (summer) and 15.8 MW (winter). In 2020, the Program saw little to no aggregated demand (MW) growth. Stakeholder interviews performed in 2019 (from the winter 2018-19 season) indicated that the Program was on track to meet its 2019 goal; however, stakeholders acknowledged that it will be challenging to reach its 2020 goal without creative and strategic approaches to marketing and enrolling harder-to-reach customer segments. One creative market tactic that was deployed in 2020 was for prospective customers, in which gift-baskets were created from existing participant's products. Due to the anticipated length of the sales cycle, it is likely that the program will not benefit from the tactic until 2021. Despite best efforts to reach the 2020 MW target, unforeseen economic and environmental considerations hampered PGE's ability to meet growth targets. To combat the impact of the COVID pandemic, efforts shifted from aggressively growing load to minimizing reduced nominations from existing participants, while bringing on new load from new customers into the Program. In some cases, the nomination drops were quite significant. For example, educational institutions which are now practicing distance learning no longer have load to curtail.

Customer Experience:

Current State:

According to the last process evaluation (conducted for 2018-19 summer and winter seasons), existing participants are generally very satisfied with the current program. Interviewees responded with an average score of 9 to the question: "Based on your experience over the past year, how satisfied are you with the Energy Partner program using a 0 to 10 scale, where a 0 means you are extremely dissatisfied and a 10 means you are extremely satisfied?" Specifically, the existing participants expressed a high degree of satisfaction with the new options for participation (e.g., choices of event hour windows) and third-party implementer's performance, including their responsiveness, willingness to troubleshoot, and frequency of touch points. All participants identified financial benefits (i.e., incentives and/or reduced energy costs) as one of the primary reasons for participating in the program, with many of these customers citing financial benefits as the most important driver for participation. A significant number of participants also identified "doing good for the community" as another primary reason for participating. The program options that customers noted as the most beneficial or important include the ability to change nominations each month, more flexibility in the event-hour windows, the ability to optout of events, and weekly notifications of possible events from the third-party implementer. To date, PGE has had a successful retention rate from existing participants and exited customers have been attributed to economic reasons outside the control of PGE. Overall, the customer experience was a critical to transitioning Schedule 26; from the initial pilot design to customer onboarding to how the program operates internally.

From the start, this DR Program was designed with the customer in mind. In the design process, PGE carefully considered varying participation structures and applied lessons learned from early iterations of PGE's demand response Pilots. One notable change was that the curtailment nomination was contracted between PGE and the customer instead of the customer and a third-party aggregator. This way, the customer would always know with who they had contracted, and they would always have transparency about the value of their nominated load.

Due to the nature of the program, customers are carefully targeted, and are guided throughout the turnkey solution from prospecting customers to equipment testing through enablement. The onboarding process is customer-centric and begins with educating the customer on what demand response is, what participation looks like for their peers, how it intersects with regional climate goals, and how similar customers have benefited from the Program. The value proposition of the Program includes monthly financial incentives, upfront capital to enable automation, visibility into telemetry data through the customer portal, and assists with meeting the customer's sustainability goals.

> *"We had a brief meeting and plant tour, worked together to set a kW goal, and successfully tested the process before we started."*
>
> \- Henningsen Cold Storage

As a next step, PGE's third-party implementer conducts a site review and the customer releases their historical consumption data. In turn, the third-party implementer works closely with the customer's facility management team to determine curtailment potential and which loads can be shifted. Ultimately, customers select their nominations, which loads can be curtailed during an event, and how the load will be controlled. The control strategy varies widely and considers the customer's industry as well as the type of control systems in place.

> *"The voluntary aspect of this program was key to our involvement. It's realistic and supports our ability to service our customers."*
>
> - Hardwood Industries

Customers appreciate the simplicity, optionality and flexibility in which they can participate. Customers decide on how loads are controlled as well as the elections that determine their incentive rate. Control strategies are either automated, semi-automated or manual. Customers with an automated strategy are directly controlled through PGE's Demand Response Management System ("DRMS"), whereas semi-automated and manual strategies are implemented on the customer-side when an event notification is received. The difference between semi-automated and manual strategies is that semi-automated loads are controlled through a proprietary system that is not integrated with PGE's DRMS and manual loads are implemented by turning down or off electric equipment. For example, one of our predominant food storage customers uses automation to curtail designated refrigeration equipment and manually disables the forklift battery charging station, unplugs unused equipment and sets back the HVAC. Commercial and industrial customers also predetermine the number of hours (20, 40 or 80 hours) that can be curtailed during a season, the amount of notice (18 hours, 4 hours or 10 minutes) before an event begins, as well as the times of day (election windows) during an event season. Seasonal incentive rates are based on the customer's flexibility, therefore, a customer who can commit to 80 hours, 10-minute notification period and more election windows will receive a higher incentive during an event. Additional incentives may be available if building control upgrades are needed to participate. Once contracted, seasonal nomination plans are revisited prior to the beginning of each season to ensure that the plan still makes sense and to identify opportunities for automation or additional loads. While seasonal planning is an opportunity for increasing commitments there are times when nominations are lowered. Lowered nominations are often a result of operational changes at the facility and in some cases are directly tied to economic drivers.

Enhancements under consideration:

Evaluations have indicated that the primary reasons for participation include the financial benefits and helping the community, with customers identifying financial benefits as the more important driver for participation. As a result, PGE plans to investigate into the following:

- **How upfront financial incentives drive customer value.** Many existing customers have commented that the Program's automation control strategy is a compelling program feature. In some cases, upgrading controls can be covered through program delivery, however, work required to enhance or install controls can be costly and may not fit within the constraints of the Program. Upfront incentives might encourage customers to leverage capital expenditure dollars that would enable additional nominations and procure additional equipment that could be curtailed.

- **How flexible service use-cases could provide year-round value to Schedule 26 customers.** Evaluations have indicated that some customers would like to receive energy payments during shoulder months, months outside of the summer and winter seasons. While non-seasonal incentives do not pencil out due to how capacity is valued, Schedule 26 customers may benefit from flexible load value streams beyond capacity. Demand that can be curtailed because of frequency regulation or due to distribution constraints might be eligible for additional incentives. In turn, year-round value might assist with the procurement of customer owned storage devices.

Approach for program design change:

PGE's Product Lifecyle Management ("PLM") process is the channel through which potential ideas and products must travel on the way to program status. Once the product or concept has achieved Program status, new product design features will undergo a modified PLM process to ensure that the feature has been sized accordingly, meets the customer's needs, is financially sound and determines requirements to launch. PLM provides the key questions to answer, the deliverables, decision-making criteria, timelines for evaluation, and other protocols necessary to manage the rollout of a full-scale offering. By creating a channel that enables PGE to test more ideas, products, and technology, promising projects are able to mature and reach full-scale deployment, while poor concepts are discarded early with less wasted effort and resources. This deliberate process for product advancement allows PGE to create compelling and cost-effective solutions for customers that align with our goals of serving load, reducing carbon, and maintaining reliability.

Infrastructure Stability:

Current State:

As indicated in the Customer Experience section above, the Program was designed to allow interchangeability of programmatic components. This design feature was developed with the customer in mind, but it also enables Infrastructure Stability. As part of the revamped Non-Residential Demand Response Program (Energy Partner 2.0) PGE has direct contracts and relationships with different functions of the customer solution in order to plug and play different components as needed. As a result, PGE could replace an aspect of the Program without an abrupt disruption to customer participation. Instead of one solution provider PGE has created three distinct functions; a third-party implementer (CLEAResult), DRMS provider (Enbala) and asset management provider (EDM Software). The third-party implementer acts as the customer-facing arm of the Program and is an intermediary between the DRMS and asset management providers. The DRMS provider is the system in which events are called and the asset management provider is the engine behind the customer-facing portal and serves as an integration point for data and systems.

Currently all DRMS integrations are complete and processes have been developed to streamline future integration work. The Program is transitioning between the DRMS provider's first-generation platform (Symphony) and the provider's enhanced and reskinned platform (Concerto). The first-generation platform met PGE's needs during the Pilot, however, the enhanced version enables additional functionality (e.g. ease of use, telemetry data feeds, ability to group and dissect customers) that is supportive of Schedule 26's future needs.

The customer facing portal has been operational since 2018 and allows customers to view performance data in near real-time. PGE recognizes that an area for program improvement includes enhancements to customer data availability and the web portal. Some participants would like the ability to view their electricity usage, understand their incentive calculations, and change nominations in the portal or through a mobile app. PGE's third-party evaluator reported that one of the greatest opportunities for enhancing customer satisfaction is related to the availability of data about energy consumption/curtailment and the functionality of the web portal.

To ensure that the customer nominations and associated incentives are calculated correctly, PGE uses their third-party evaluator (Guidehouse) as a quality assurance agent. Guidehouse's seasonal impact evaluations validate the estimates of load curtailment provided by CLEAResult for customers enrolled in Schedule 26. Specifically, Guidehouse replicates and validates the impact calculations for settlement payment performed by CLEAResult through formal data requests.

Enhancements under consideration:

PGE does not intend to make significant investments into enhancing Schedule 26's backend infrastructure without considering PGE's Integrated Resource Roadmap as outlined in the draft Flexible Load Plan. Minor enhancements that either maintain or sustain systems will be prioritized and evaluated on a case by case basis. Currently there no activities planned to improve customer or backend platform functionality. Potential Application Programming Interface ("API") integrations will likely include electric vehicle charging stations and storage devices.

PGE views Flexible Load as a system resource, a tool with which to help decarbonize our system and integrate variable renewable resources at least cost while maintaining reliability. We commissioned our Decarb Study[10] to understand if a decarbonized energy future is attainable while serving the growing electric and energy needs of our customers. The findings of the study show a decarbonized future is attainable with today's technology, but to enable the kind of future suggested by the study, major changes are required in the way our society produces, delivers, and uses all forms of energy. This includes driving down greenhouse gas emissions in our own resource portfolio while creating a modernized, smart grid to help efficiently integrate clean, renewable resources and enable electrification. Flexible loads are key components of this modernized grid and the study found – in the High Electrification Pathway – that more than 900MW of flexible load could be needed by 2050. To achieve this success, PGE must build, monitor and utilize flexible load in real-time. Enabling the full capabilities of flexible load requires PGE to make investments today not only to build the flexible load resource but also to capture the greatest benefit through reliable, secure real-time control that is fully integrated with PGE's operations.

For flexible load to support decarbonization in the way envisioned by PGE's Decarb Study, flexible load must be aggregated into Virtual Power Plants as described in Chapter 1. These Virtual Power Plants must then be optimized in real time across the range of services that they can provide. For example, if the Virtual Power Plant is providing distribution deferral, the limitations of the distribution equipment must be respected for the flexible load to also provide flexibility reserves or other grid services. To optimize flexible load across multiple value streams, PGE must be able to integrate it into PGE real time dispatch and monitoring systems. This integration is what enables flexible load to operate on par with generation resources.

PGE is committed to the investments necessary to support the utilization and optimization of flexible load. These investments include: an ADMS, distribution automation; and Distributed Energy Resource Management Systems ("DERMS"). These are the tools and the integrated operating platforms that will enable PGE's customers to realize the greatest overall value from flexible load. PGE's Smart Grid Report outlines this vision[7].

Approach towards infrastructure improvements:

Minor enhancements that maintain or sustain the Infrastructure Stability will be reflected in aggregate in PGE's UM 1514 request for deferral reauthorization and recovered through Schedule 135.

<u>Grid Performance</u>:

Current State:

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[10] Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory, April 24, 2018, available at https://investors.portlandgeneral.com/static-files/6e630aff-fcff-44e2-9ddb82232f24bcd4.

Since program revisions in 2017, Energy Partner has seen steady demand (MW) growth and has demonstrated load drop stability through average realization rates. Overall performance of the resource has remained within a tolerable range (15 – 20%) of nominated capacity for the summer seasons. While winter has not achieved this desired threshold, the realization rates by year are consistent and stable. Tables 1 and 2 below, provide a comparison of each season by depicting how many events were called, how many customers participated in the season, as well as what was nominated versus what was realized.

Table 1. Performance Summary for Summer Seasons

Summer Seasons	# of events	# of participants	Average Nominated Load	Average Demand Reduction (MW)	Max Demand (MW)	Max Realization Rate	Average Realization Rate
2017*	4	48	9.73	11.1	11.5	119%	114%
2018	6	38	8.54	11.2	11.8	159%	131%
2019	3	41	15.2	12.5	13.8	91%	82%
2020**	5	62	16.9	14.5	15	91%	86%

*Events were called during third-party implementation vendor transition; events were called through predecessor's platform
**Represents preliminary results that have not been validated by third-party evaluator

Table 2. Performance Summary for Summer Seasons

Winter Seasons	# of events	# of participants	Average Nominated Load	Average Demand Reduction (MW)	Max Demand (MW)	Max Realization Rate	Average Realization Rate
2017-2018	1	36	5.1	2.7	2.7	66.5%	66.5%
2018-2019	1	43	9.7	6.6	6.6	68%	68%
2019-2020	1	53	11.4	8.5	8.5	73%	73%
2020-2021	NA	NA	TBD (June 2021)				

Enhancements under consideration:

Investigate hourly load predictability of nominations by customer throughout the event in order to determine trends within industries and by load type.

Approach for evaluation enhancements:

Augmentations to the third-party evaluator's scope will be addressed through PGE's internal change order process. Fiscal impacts to the scope will be reflected in aggregate in PGE's UM 1514 request for deferral reauthorization and recovered through Schedule 135.

<u>Financial Performance</u>:

Current State:

As indicated in Table 3 below the cost effectiveness is 1.23.

Table 3. Cost Effectiveness: Non-Residential Demand Response Program

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$8.21		$8.21		$8.21			
Avoided costs of supplying electricity		$17.79		$17.79		$17.79		
Bill reductions								$0.22
Capital costs to the utility	$0.00		$0.00		$0.00			
Environmental benefits		$0.01						
Incentives paid			$12.55		$12.55			$12.55
Revenue loss from reduced sales					$0.22			
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$6.28						$6.28	
Sum of costs and benefits	$14.48	$17.81	$20.76	$17.79	$20.98	$17.79	$6.28	$12.77
Benefit Cost Ratio		1.23		0.86		0.85		2.04

Enhancements under consideration:

A comprehensive approach towards calculating cost effectiveness will be addressed in the Distributed Resource Plan ("DRP") as well as the Flexible Load Strategy and Budget Plan, which are expected to be filed in 2021.

Approach towards addressing Financial Performance:

Cost effectiveness calculations will be revised annually using actual and forecasted expenditures. Revised calculations will occur when proposed program design changes have a financial impact to the Program's operations. Design changes that result in a TRC less than 1 will not be sought.

Dispatch Integration:

Current State:

Event calling was transitioned from Program Operations to PGE Power Operations (Power Ops) in the summer 2020 season so that the resource could be economically dispatched. Previously, events were primarily called due to weather-related reasons, but there were instances when Power Ops made the event-calling recommendation. To ensure the customer experience remained intact through the transition these departments worked closely together to establish three guiding principles to reduce the risks of lowered nominations, decreased event performance and customer defection:

1. **Manage customers' seasonal expectations of why events are called to maximize retention**
2. **Manage customer fatigue from consecutive event calling**
3. **Manage the customer experience by creating internal caps on participation thresholds**

As a result of these recommendations it was determined that the operational change only impacted customer nominations by -0.375 MW and the Program retained all participating customers who had load to curtail. Altogether Power Ops called 5 events, did not exceed 20 hours of events and called 2 events during the same week once during the season.

Enhancements under consideration:

During the Winter Season Power Ops has requested that:

- **More events are called during the Season**. Like summer 2020, Power Ops will dispatch events and the customer experience will be maintained by informing customers that events will be called more often and internal caps on participation thresholds will be created. For the past three years there has only been one event per season due weather conditions.
- **Consecutive event-calling should be tested.** The PGE service territory has been observing higher incidences of heat waves and cold spells that last for several consecutive days. Coincidentally these tend to be the days when prices are at their highest. Given the public's response to California's rolling blackouts and the recent PSPS due to wildfires, the public's opinion regarding curtailing energy during inclement weather event may be more forgiving than it previously was.
- **10 minute and 4-hour notifications should be tested.** During the Pilot phase only the 18-hour event calling procedure was tested to ensure that there was an adequate sample size for evaluation purposes. Testing will show which loads are able to respond within the notification period. It will be recommended that 10-minute customers with manual or semi-automated control strategies are migrated to four hours or invest in infrastructure to automate the load from the DRMS.

Approach towards testing dispatch procedures:

PGE will implement standard testing procedures in order to test consecutive event-calling and 10 minute and 4-hour notification periods. During test events, customers are made aware of testing, event communications are sent, and customers follow through with nomination plans as if it was a regular event. However, the performance from the test event does not impact their monthly incentive payment. Performance from test events will be validated through the evaluation process.