BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY
OF THE
OREGON CITIZENS' UTILITY BOARD

June 4, 2020

CUB
EST. 1984

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. In my testimony, I respond to various arguments raised by PacifiCorp (PAC or the Company) in its initial filing and attendant testimony in this proceeding. In this Opening Testimony, CUB discusses various proposals centered on ratemaking for various investments, policy proposals made by the Company, and rate design issues raised by PacifiCorp.

Q. How is CUB's Opening Testimony organized?

A. CUB's testimony includes the following:

- Exhibit 100, which discusses CUB's proposals related to:

    1. Aligning the general rate case (GRC) and the concurrent Transition Adjustment Mechanism (TAM);

    2. The transition away from coal, including capital investments at Jim Bridger, the proposed treatment for Cholla 4, Exit Dates for coal plants, and decommissioning cost allocation for the Company's coal-fired resources;

    3. The Company's proposal to eliminate the Power Cost Adjustment Mechanism (PCAM), which, if approved, would shift significant power cost risk from Berkshire Hathaway to PacifiCorp customers; and

    4. The Company's proposal regarding its Pryor Mountain Wind Project.

- Exhibit 200, sponsored by Economists Sudeshna Pal and William Gehrke, discusses CUB's proposals relating to:

    1. The Company's proposed rate design for residential customers; and

    2. The Company's proposed time-of-use rate for residential customers.

II. ALIGNMENT WITH THE TAM

Q. What is CUB's proposal regarding aligning the GRC with the TAM?

A. In the TAM, CUB proposed moving wheeling revenues from the GRC to the TAM and moving legacy Deer Creek pension costs from the TAM to the GRC.

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1. Wheeling Revenues

Q. Why is CUB proposing moving wheeling revenue to the TAM?

A. CUB discussed this issue in its TAM testimony last month.[1] PacifiCorp is a major wholesale transmission purchaser and seller in the West. When PacifiCorp purchases wholesale transmission, it incurs costs known as the wheeling costs. The Company's expected wheeling costs are updated each year in the Company's annual TAM forecast. When PacifiCorp sells transmission to third parties, the Company earns wheeling revenue. Unlike wheeling costs, which are updated annually in the TAM, wheeling revenue is credited to customers in the GRC. However, since 2013, an annual deferral has been in place to track the difference between the GRC forecasted wheeling revenues and actual wheeling revenues. Recognizing that annual deferrals are not a preferred way to establish rates, CUB is proposing that wheeling revenues be added to the TAM. This can be accomplished by adding wheeling revenues (FERC Account 565) to the list of accounts that is updated annually in the TAM Guidelines. CUB believes this improves ratemaking for several reasons:

- These are variable revenues associated with dispatching the utility's resources to meet load. The use of transmission is a function of energy demand, the performance of generation assets, and wholesale power prices. These factors are influenced by season, temperature, time of day, fuel prices, and economic conditions. Transmission costs and revenues

[1] UE 375 – CUB/100/Jenks/4-9 *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue375htb165320.pdf.

are like NPC in that they are caused by the dispatch of power by a utility to meet load.

- FERC regulates PacifiCorp's transmission rates. FERC has approved formula rates for PacifiCorp, which includes updating rates based on an annual revenue requirement.[2] The forecast of transmission revenues in the GRC test year is based on the formula rates that PacifiCorp expects in 2021.[3] But the transmission revenue requirement will be reset and rates in 2022 will be different, which will require a new deferral to track the difference between the wheeling revenues forecast in the rate case and the wheeling revenues expected from new rates.
- CUB's proposal would parallel wheeling costs. Wheeling costs are included in the TAM and updated through the case. Because the rates charged to PacifiCorp by other transmission providers also change each year, the updates allow PacifiCorp to make sure rates always reflect the most up-to-date rates that it will be charged for wheeling. Under the Company's current methodology, in 2022, customers are paying 2022 rates for wheeling costs and receiving 2021 rates for wheeling revenues. Correcting this will require a deferral. CUB's proposal would eliminate this mismatch.
- Setting up ratemaking so annual deferrals are needed makes little sense. As the Oregon Public Utility Commission (Commission) notes, "deferrals

[2] UE 374 – PAC/1000/Vail/12.
[3] Because transmission rates are set on a June 1—May 31 basis, the 2021 forecast is actually a combination of the June, 2020—May 2021 transmission rate and the June 2021 – May 2022 transmission rate.

should be used sparingly" and the Commission "will consider whether there are other more appropriate regulatory tools to address recovery of the identified costs or revenues."[4] Rather than relying on it, it makes more sense to forecast transmission revenues in the TAM.

- Deferred accounting creates a timing mismatch between costs and revenues. In 2022, customers would be paying rates that reflect 2022 wheeling costs at 2022 FERC-approved wheeling rates, but the transmission credits would still reflect 2021 wheeling revenues at 2021 FERC-approved wheeling rates. The difference would be deferred, but those deferrals would flow back to customers at some later date.
- Deferring transmission revenues can also lead to large deferral balances. Having pots of money that the Company owes to customers can be useful in solving problems, but CUB does not believe that it is transparent ratemaking. For example, in 2016, the transmission revenue deferral was \$18.5 million and the Commission decided to amortize it over 4 years to customers, but to first subtract the Multi-State Process (MSP) equalization adjustment.[5] The equalization adjustment was an agreement between the MSP parties to add a surcharge to state's revenue requirement to recognize that the MSP agreement in place at the time did not allow PacifiCorp to fully recover its costs. Oregon's annual surcharge was \$2.6 million.[6] PacifiCorp customers paid \$2.6 million per year to PacifiCorp as part of

[4] *In re Public Utility Commission of Oregon, Investigation into the Scope of the Commission's Authority to Defer Capital Costs*, OPUC Docket No. UM 1909, Order No. 20-147 at 13 (Apr. 30, 2020).
[5] OPUC Order No 16-491.
[6] OPUC Order No 16-491.

this agreed upon MSP equalization adjustment, but it showed up on bills as reduced wheeling revenue. Earlier this year, the wheeling revenue deferral balance was used to offset the remaining rate base associated with investment that was being removed from PacifiCorp's wind plants as part of its wind repowering.[7] While CUB supported these actions, we recognize that these actions do not represent ideal, transparent ratemaking.

- Utah includes wheeling revenues as an offset to NPC in its annual power cost tracker. The Utah Commission:

> determined that while not modeled through the Generation and Regulation Initiative Decision Tool (GRID), wheeling revenues have a relationship with NPC in that they form an offset to wheeling expenses.[8]

  CUB finds the logic of the Utah Commission compelling on this issue.

- As the Western United States continues to explore new regional approaches, the treatment of wheeling costs and revenues could change. For example, a new extended day-ahead market (EDAM) might include wheeling costs and revenues. Placing both wheeling costs and wheeling revenues in the TAM would create more regulatory flexibility and enhance Oregon's ability to accommodate new regional markets outside a GRC.

For these reasons, CUB believes that wheeling revenue should be forecast annual in the TAM and subject to regular updates in the TAM.

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[7] UM 374 – PAC/1300/McCoy/33.
[8] Utah PSC, Order in DOCKET NO. 09-035-15, page 8.

2. Deer Creek Mine Pension Costs

Q. Why is CUB proposing to move legacy Deer Creek pension costs from the TAM to the GRC?

A. CUB also discussed this in the TAM.[9] In 2015, the Commission found that closing PAC's Deer Creek mine produced a "substantial net benefit" to customers.[10] Much of this benefit derived from changes in future pension liability. The Deer Creek mine closure allowed PacifiCorp to withdraw from the 1974 Pension Trust associated with the mine. The Pension Trust was a multi-employee pension plan that was very under-funded. Keeping the mine open and staying in the 1974 Pension trust would result in incurring substantial future liability. Withdrawing from the pension trust required PacifiCorp to incur a penalty, which could be paid with a lump sum payment or a $3 million annual payment "in perpetuity."[11] The Commission found that withdrawing from the trust and agreeing to pay this $3 million penalty would provide "significant net benefits to customers."[12] There are several reasons CUB believes this legacy pension cost should be moved from the TAM to base rates:

- This cost is fixed, not variable, and has no relationship to the current cost of fueling coal plants. If all coal plants closed this cost would continue.
- It is a legacy pension cost and should be included in pension expense in the same manner as legacy pension costs associated with PacifiCorp employees

[9] UE 375 – CUB/100/Jenks/9-12 *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue375htb165320.pdf.
[10] OPUC Order No 15-161, page 5.
[11] OPUC Order No. 15-161, page 5.
[12] OPUC Order No. 15-161, page 9.

who once worked at the coal plants. CUB does not see a reason to treat legacy pension costs for coal miners differently than legacy pension costs for coal plant operators.

- SB 1547 directs PGE and PacifiCorp to eliminate the costs and benefits of coal fire resources by 2030. Continuing to label these legacy pension costs as part of the cost of fueling coal plants identifies these costs as current costs of coal fire resources. This identification will lead to these costs being unrecoverable after January 1, 2030. Removing these costs from net power costs and placing them in pension expense will help make clear that these are not costs associated with coal resources used to provide electricity to retail customers – by 2030 there will not be coal resources providing electricity to Oregon retail customers of PacifiCorp. I was CUB's representative in the negotiations that led to SB 1547 and lobbied in support of the bill. The bill was not intended to create barriers to PacifiCorp's recovery of legacy pension expenses associated with coal mining, or operating coal expenses. Its intent was to eliminate coal from the fuel mix of Oregon utilities by 2030.

For these reasons, CUB believes that Deer Creek legacy pension costs should be recovered annually as part of pension expense.

Q. In its Opening Testimony in UE 375, the Alliance of Western Energy Consumers (AWEC) witness Brad Mullins stated that his "understanding of the TAM Guidelines and orders that adopted those guidelines is that any

recommended changes to the TAM Guidelines should be proposed in a concurrently filed general rate case."[13] Do you agree with Mr. Mullins?

A. Yes. While CUB raised issues related to changing the TAM Guidelines in our TAM Opening Testimony, we intend to address any substantive issues related to altering the TAM Guidelines in this proceeding. This includes the proposal to include wheeling revenues in the TAM referenced above and CUB's reaction to the Company's proposal to alter and conflate the TAM and the PCAM, which I will address later in testimony.

III. TRANSITION AWAY FROM COAL

Q. What is CUB proposing related to PacifiCorp's transition away from coal?

A. There are several elements in this case that deal with the transition away from coal and CUB proposes several adjustments:

- Jim Bridger SCRs. CUB believes that the SCRs installed on Jim Bridger Units 3 and 4 were not prudent. They were never acknowledged in the Commission's Integrated Resource Plan (IRP) process. The Company should have avoided these costs by committing to close the units at a future date.
- Cholla Unit 4 regulatory asset. While I am not an attorney, my understanding is that Oregon law and precedent preclude receiving a profit on a power plant that is retired from service in the public interest.[14] CUB

[13] UE 375 – AWEC/100/Mullins/20, lines 5-7 citing Docket No. UE 207, Order No. 09-432, App. A at 5:9-16 (Oct. 30, 2009) ("The Parties agree that the TAM Guidelines do not limit the ability of the Company or other Parties to propose changes to the TAM Guidelines…in future rate general rate cases.").
[14] *See* OPUC Order No. 08-487.

proposes to adjust the carrying charge for the regulatory asset to remove the Company's profit component.

- Exit Orders. CUB supports establishing exit orders for PacifiCorp's coal fleet to help guide Oregon's transition away from coal. Doing so will also create certainty around Oregon's position in the Company's ongoing MSP negotiations.
- Decommissioning costs. CUB will wait until after the Independent Evaluator's report to address level of additional decommissioning that should be placed into Oregon rates. However, CUB is proposing that any incremental increase in decommissioning charges should be recovered through a non-bypassable charge that includes direct access customers.

CUB's testimony will address each of these issues in turn.

1. Jim Bridger SCR

Q. What is CUB's concern regarding PacifiCorp installing SCRs at Jim Bridger Units 3 and 4?

A. PacifiCorp installed the SCRs at Bridger in response to the Regional Haze requirements of the Federal Clean Air Act to reduce NO_x and SO_2 emissions that contribute to regional haze. CUB believes PacifiCorp's analysis of the investment was seriously flawed. It failed to recognize the flexibility that is allowed under Regional Haze Rules, it failed to consider the least cost alternatives to the SCRs, it failed to analyze the investment in an IRP prior to committing to the investment which would have allowed the Commission (and Oregon parties) to weigh in on the analysis needed to support the investment, and it failed to consider the Oregon useful life of the plant. Essentially, PacifiCorp was bullish on the future of coal, did not take seriously that coal plants would discontinue operation, and failed to seriously investigate alternatives to the indefinite future operation of its coal fleet. Additionally, as CUB demonstrated in our recent testimony in Commission Docket No. UE 375, the Company had ample warning from the Oregon Commission that it should be considering coal plant retirements.[15]

Q. What is the purpose of the Regional Haze Rule?

A. The Regional Haze Rule is a requirement of the Federal Clean Air Act. Regional Haze refers to air pollution that causes a visibility impairment at national parks and wilderness areas (Class 1 areas). In 1999, the EPA issued the Regional Haze Rule which requires states to identify Class 1 areas and develop and implement plans to ensure that reasonable progress is being made to reduce haze so that, by 2064, regional haze is reduced to background levels. CUB Exhibit 102 contains a series of fact sheets from the Oregon Department of Environmental Quality (DEQ) that provide background on the Regional Haze Rule. It is important to realize that the program does not have a specific, mandated pollution limit, or specific, mandated pollution controls. It is based on analysis of the Class 1 areas impacted by a point source, how much pollution from a plant (or set of plants) affects visibility in that Class 1 area, what pollution controls are available (Best Available Control Technology or BART), how cost effective are those pollution controls in terms of dollars/ton of pollution removed, and the life of the plant.

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[15] UE 375 – CUB/100/Jenks/13-20.

Q. Please describe the flexibility under the rule.

A. The purpose of the rule is to ensure meaningful progress toward reducing haze from emission sources. By making large capital investment in plant retrofits (SCRs) to comply with the rule, the strategy PacifiCorp was applying is only one option. However, a plant owner can also reduce the plant's useful life which reduces the cost effectiveness of pollution control. Closing a plant early is another means of complying with the Regional Haze Rule.

Q. How does the useful life of a resource affect its cost effectiveness?

A. A default evaluation of 20 years is used in the regional haze cost effectiveness calculation. An SCR might be found to be cost effective at reducing pollution at a cost of $3000/ton over 20 years. If the useful life of that was cut in half to 10 years, then the amount of pollution removed would also be cut in half, raising the cost effectiveness well above $3000/ton. This could render the SCR no longer cost effective.

This is what Portland General Electric (PGE) did with Boardman in 2009/2010. Oregon DEQ was looking to require a capital investment of more than $500 million as part of an environmental retrofit. PGE proposed reducing Boardman's useful life to 2020, which made the capital investment no longer cost effective – PGE had to reduce pollution through a chemical process (Dry Sorbent Injection or DSI), but no large capital investment was required.

In 2013, PacifiCorp finally recognized the role that the useful life of a coal plant played in its Regional Haze requirements and applied it to Naughton Units 1 and 2 and Dave Johnston Unit 3, but did not go back and seriously apply this approach to Jim Bridger 3 and 4:

> PacifiCorp further emphasizes that in the environmental compliance realm, EPA does utilize a 20-year assessment period for retrofit emissions control equipment cost effectiveness calculations unless the affected resource has firmly committed to an earlier retirement date. In fact, in the Company's recent public comments submitted in EPA's Wyoming Regional Haze FIP docket, the Company specifically addresses this issue as it pertains to EPA's pending decision-making on Naughton 1 and 2 and Dave Johnston 3. In its comments, PacifiCorp specifically advises EPA that the remaining depreciable lives for those units are less than 20 years and that EPA's assessment of cost effectiveness of available retrofit controls must consider those shorter lives.[16]

Q. What do you mean when you say they did not "seriously" apply this approach (reducing the useful life to less than 20 years)?

A. In testimony defending the SCR investment, PacifiCorp states that it used the same analysis in the Wyoming CPCN filing that it did in the 2013 Oregon IRP.[17] This is misleading. PacifiCorp decided after the Wyoming CPCN decision that it would proceed with the SCR at Bridger. That was in May 2013.[18] The Company's Reply Comments in the IRP quoted above were in November 2013. The analysis that was presented in Wyoming was presented in Oregon, but not everything presented in Oregon was presented in Wyoming. Specifically, PacifiCorp did not include analysis in Wyoming that adjusted the useful life of

[16] LC 57 –PacifiCorp Reply Comments, page 57.
[17] UE 374 – PAC/700/Link/88.
[18] CUB Exhibit 103.

Bridger to change the required pollution controls. The Company did that in Oregon specifically "to respond to previous requests from CUB to include this type of analysis in the Company's IRP filings."[19] The Company did not seriously consider this because it did not include it in Wyoming where the issue was decided. That analysis was presented in Oregon, after the decision to install the SCR had already been made. In addition, that analysis relating to the life of the plant was flawed.

Q. What about the analysis was flawed?

A. While there were several flaws, the most important one was that PacifiCorp limited the benefit of reducing the plant life by choosing end-of-life dates that were too soon therefore limiting the benefit of reducing the useful life of the plant.

Q. How did the earlier dates effect the analysis?

A. The coal plants were economic at the time, but CUB's concern was that adding the cost of the pollution control (SCR) and future carbon regulation would make the plants uneconomic. Therefore, the longer the plants operated without an SCR, the longer they would remain economic and the more benefits would be produced. To comply with the Regional Haze Rule, SCRs were required in 2015 and 2016. As an alternative, PacifiCorp modeled phasing out the plants and closing them in 2020 and 2021. Instead of PacifiCorp's dates, CUB had proposed that the dates should be 2023 and 2024.[20] CUB's IRP comments cited to Dave Johnston 3

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[19] LC 57 – PacifiCorp Reply Comments, page 57.
[20] LC 57 – PacifiCorp Reply Comments, page 58.

where the Company was in discussions with EPA about shutting the plant down at the end of its useful life of 2027. If the EPA would accept 2027 for Dave Johnston 3 then it should accept 2023 and 2024 for Bridger 3 and 4. But it is important to remember that this discussion was in the Oregon IRP, when the decision to retrofit the plant was made based on the analysis in the Wyoming CPCN case.

Q. Please describe the Wyoming analysis.

A. In their Opening Testimony in this case PacifiCorp describes the analysis that led it to invest in the SCR.[21] They considered two options. First, early retirement with replacement resources (a new gas plant, firm market purchases, demand-side management, or wind) in January 2016 and January 2017 or conversion to natural gas in March 2016 and March 2017. This analysis showed that installing the SCR was the least cost option, followed by converting it to natural gas and that retiring and replacing the plant had the highest cost.

Q. What was wrong with the analysis?

A. The primary problem with the analysis was that it did not consider the actual least cost alternatives to the SCR. Retiring the plants in 2015 and 2016 and replacing them was not the least cost retirement scenario. Converting the plants to natural gas in March 2016, and March 2017 was not the least cost gas conversion scenario. The Company should have looked at avoiding the SCR investment by ending their useful life in 2023 and 2024, or, at converting the plants to natural gas in 2024 and 2025, respectively.

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[21] UE 374 – PAC/700/Link/ 86-110.

At this point, it has been demonstrated that adjusting the useful life was an alternative compliance methodology that could save money. It was found to be true with Boardman. The Company was beginning to consider it with Naughton 1 and 2, while realizing that it could use this theory to delay the Naughton 3 conversion to gas and was in discussions with the EPA about applying this to Dave Johnston unit 3. There was no good reason not to apply this analysis to Jim Bridger.

Q. Are there other concerns with PacifiCorp's analysis?

A. Yes. By the time that PacifiCorp was contemplating these SCRs, the Commission had offered several warnings to the Company regarding its flawed assumptions that environmental retrofits are reasonable and coal plants will not close.[22] PacifiCorp chose not to heed those warnings, which included the Commission rejecting a stipulation between Commission Staff and PacifiCorp revising depreciation rates and extending the life of coal plants. The Commission rejected extending the depreciable life of the four Jim Bridger units from 2025 to 2037. The Commission's Order sent a clear warning to the Company:

> Pacific Power assumes that coal-fired generating plants will continue to be an economic source of power "well into the foreseeable future" and will stay in service as long as the plants are operational. Pacific Power also assumes that any increased capital expenditures resulting from environmental regulations will be recoverable in rates because the expenditures will be "for the benefit of customers.[23]

and

> In other words, continued operation of a coal-fired generating plant could become uneconomic, leading to early retirement of the facility. Pacific Power ignores this possibility by assuming both

[22] UE 375 – CUB/100/Jenks/16-17.
[23] OPUC Order No. 08-327.

> that coal-fired generating plants will remain economic and that all capital expenditures associated with these plants will be recoverable in rates.[24]

In its analysis of the Jim Bridger SCRs, the Company used the 2037 useful life[25], which had been rejected by the Oregon PUC, not the Oregon depreciable lives. If the Company had used the Oregon depreciable life, it is likely the SCR would not have been cost effective, and even more importantly, as discussed above, the SCR would not have been required.

Q. What is CUB's recommendation with regards to the SCRs at Jim Bridger Units 3 and 4?

A. CUB urges the Commission to find the investment in the SCRs imprudent, deny the company cost recovery, and continue to adjust the TAM to remove the net power cost impact of the SCRs.

2. Cholla Unit 4

Q. What is CUB's concern about Cholla Unit 4?

A. CUB supports the Company's proposal to close Cholla Unit 4 due to its unfavorable economics. Because this plant is being closed to reduce costs to customers, CUB recommends the Commission find that the property is being retired in the public interest. The two most recent IRPs support closing it in 2020 and the Company's analysis demonstrates that this is a cost-effective decision for customers. However, CUB believes that the regulatory asset PacifiCorp proposed to recover remaining Cholla 4 costs is inconsistent with the legal framework

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[24] OPUC Order No. 08-327.
[25] UE 374 – PAC/700/Link/87

established through the litigation over the retired Trojan nuclear plant.[26] CUB believes that the interest rate used in that mechanism that is applied to a retired plant must be changed to be consistent with the Trojan decision.

Q. Can you explain the implications of the Trojan litigation?

A. I am not an attorney, so the legal basis for the Trojan decision will be discussed in briefs. However, I was the Executive Director of CUB when we challenged the Commission's decision on Trojan, when the Court of Appeals first decided the case, when voters approved a referendum upholding the decision, and when CUB and PGE settled our part of the legal battle. While the court challenges continued without CUB with multiple legal proceedings and at least two remands to the Commission after we settled our case with PGE, I continued to follow the issue. Finally, I have participated in dockets such as the Deer Creek Mine closure in which the principles and precedent from the Trojan case were applied.

At issue in the Trojan cases (the case CUB was involved in and the other non-CUB case) was whether PGE could continue to charge customers for a return <u>of</u> its unrecovered capital investment in Trojan and a return <u>on</u> its investment. Capital investments that are not presently used to serve customers are prohibited from utility rates in Oregon.[27] However, if the Commission finds that the property was retired in the public interest, it can allow recovery of the remaining, unrecovered capital investment, but a return on that investment is not allowed.

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[26] *See* OPUC Order No. 08-487.
[27] ORS 757.355.

CUB settled our lawsuit with PGE in 2000 consistent with the following principles that CUB has continued to apply in cases like this:

- Retired or abandoned plant is generally not eligible for recovery from customers because it is not presently used to serve customers.
- When the Commission finds the plant was retired in the public interest, it can allow the Company to recover its investment in that plant.
- A utility is not allowed to earn a return on (profit) the unrecovered property.
- The Commission can allow an interest rate on retired property that is recovered over several years that reflects the time-value of money.

Q. Is it fair to allow a utility to recover a cost over a multi-year period without a full return on the investment?

A. Yes. By providing the utility with the time value of money, the utility is made whole. It essentially gets to cash out its remaining investment. What it loses is the return that is above the time value of money. This return represents the profit to shareholders. There is a longstanding ratemaking principle that utility costs should be recovered from the customers who are benefiting from the property associated with that cost. Allowing utilities to recover costs related property that is no longer serving customers violated that principle and is retroactive ratemaking. However, there can be circumstances where the public interest is served by retiring utility plant before the end of its useful life. For example, in the1990s, Oregon was dealing with the need to get phone companies to replace old analog switches with new digital switches, but the analog switches had long useful lives. The Commission found that replacing these with analog switches was in the public interest. So, while Oregon generally discourages allowing retroactive recovery of retired plant, it does make an exception.

This exception can be applied in a fair manner by making a utility whole, while disallowing additional profits. When a utility retires a plant, it normally is replacing it with a new investment. The new investment becomes the source of new profits. The utility is still profiting from the service, but profit comes from the new productive investment, not the old, unproductive investment. Customers are paying the utility a profit for providing the service, but the profit is sized to represent the useful investment.

I believe it is a policy that is balanced and treats customers and shareholders fairly. Again, while I am not an attorney, my understanding is that allowing a utility to earn a profit stream on a capital investment that is no longer presently used and useful would run counter to ORS 757.355. The Commission's longstanding approach avoids that concern and treats all parties fairly.

Q. Has this policy been applied in additional cases?

A. Yes. It has applied to several cases. The closest example to the issue here is probably the Deer Creek Mine closure. There, PacifiCorp believed closing the Deer Creek Mine provided significant benefit to customers. CUB's review of the filing concluded that PacifiCorp's proposal indeed provided significant benefits. That case was a little unusual in that PacifiCorp and CUB came to an agreement and filed a stipulation without other parties. CUB strongly felt that, while the rate adjustment was a single-issue ratemaking, the Company was proposing an action that provided significant benefit to customers and should be supported. At that time, PacifiCorp had $21 million in unrecovered investment in the mine.[28] CUB and PacifiCorp proposed that the Commission find that the mine closure was in the public interest and the remaining $21 million in capital investment be recovered over 2 years at an interest rate of 3.31%, a figure we believed represented the time value of money.[29]

While the Commission rejected the stipulation that was proposed by CUB and the Company, the Commission clearly evaluated the proposal consistent with the Trojan litigation:[30]

- The Commission found that "closure of the mine and sale of the mining assets is in the public interest."
- The Commission adopted a four-year amortization, rather than the two-year amortization proposed by CUB and PacifiCorp, "with interest accruing at 3.31 percent. We find that this interest rate reasonably reflects the time value of money, and does not represent a return on the undepreciated investment."[31] This last statement came with a footnote identifying the Trojan litigation: *Gearhart v. Pub. Util. Comm'n of Oregon,* 356 Or 216, 250-51 (2014).

Q. What ratemaking treatment does CUB propose for Cholla costs?

A. PacifiCorp is seeking recovery of two different costs associated with Cholla 4. It is seeking its remaining uncollected rate base and then it is seeking recovery of

[28] OPUC Order No. 15-161.
[29] *Id*.
[30] *Id*.
[31] *Id*.

additional decommissioning costs, which will be updated later in this docket. PacifiCorp is proposing collecting these costs over four years and estimates the cost at $17.3 million per year.[32]

In the Trojan case, the unrecovered capital investment relating to the retired plant was treated separately from the decommissioning costs and it was the unrecovered plant that was subject to litigation. CUB believes the same approach is appropriate here. The remaining capital investment needs to be identified separately from the decommissioning costs and only be recovered with an interest rate reflecting the time value of money. CUB used the interest rate from five-year treasury bonds as a proxy for the time value of money.

Capital Structure			
Equity	50%	**0.35%**	0.18%
Debt	50%	4.77%	2.39%
Weighted Average			2.56%

Reflecting current financing costs and assuming a 50/50 capital structure that the appropriate interest rate is 2.56%:

The Company is proposing amortizing these amounts over 4 years. CUB believes that is reasonable, but the remaining investment and the decommissioning costs should have two different interest rates. CUB is not agreeing to the amount proposed for decommissioning and will want to review the decommissioning update.

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[32] UE 374 – PAC/200/Lockey/3.

Q. Is there anything else you would like to add?

A. We think this is a fair solution. The Company may feel that having to give up additional profits on Cholla is punitive, but we disagree. The Company is made whole, recovers its capital expenditures, and can earn a profit on the new generating plant it is adding as coal plants are being retired. But it is important to note that this could have been avoided. CUB believes that retiring coal plants reduces economic risks to customers and should be supported. CUB worked with PGE to close Boardman and has worked with Idaho Power on North Valmy. In those cases, we were able to accelerate recovery of the plant's capital investment and close the plant without having to continue to charge customers for the plant after it closed. Here, PacifiCorp had ample warning, from two previous IRPs, that Cholla was not an economic plant. The Company should have begun working with parties to accelerate Cholla's depreciation and avoid having to deal with retired, undepreciated plant.

Oregon has benefitted from the fact that the Commission rejected extending the life of PacifiCorp coal fleet in 2008. The remaining plant balances are manageable compared to other Pacific Power states. CUB urges the Company to put more effort into advanced planning around coal plant closures and is willing to work with utilities to manage these closures in a way that is fair to customers and shareholders.

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3. Exit Orders.

Q. What is an Exit Order?

A. The 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol[33] (MSP Agreement) establishes coal plant Exit Orders as a way for a state to provide notice to the system of the date at which a state intends to stop utilizing a coal plant. Exit Orders in the MSP are important for several reasons:

- It establishes a date at which a state will no longer receive any benefit from the coal plant and will not be subject to new costs associated with that plant.
- It establishes a limited decommissioning cost obligation on the departing state – the exiting state has no additional responsibility if decommissioning costs increase after the Exit Date.
- It kicks off a process that allows for reassignment to other states of the coal capacity created by the exiting state. Other states can also join the state issuing an Exit Order and choose to exit the plant at that time or close the plant entirely.
- It creates the plan that allows Oregon to implement SB 1547, the coal to clean legislation that requires that by 2030 utilities stop using coal to serve Oregon load.

Q. Does an Exit Order mean that a coal plant will be shut down?

A. No. In some cases, the exit date is aligned with the expected closure date. In other cases, the coal plant is expected to keep operating past the exit date,

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[33] *See* OPUC Docket No. UM 1050.

assuming other states are willing to accept the reassignment of the coal resource. Finally, there will likely be cases where coal plants become uneconomic and shut down before the exit dates established in Exit Orders.

Q. What is PacifiCorp's proposal relative to Exit Orders?

A. PacifiCorp is asking the Commission to use this docket to establish Exit Orders for 23 of its 24 coal plants. The exception is Hayden Units 1 and 2. PacifiCorp does not operate Hayden and will make a recommendation to the Oregon Commission by February 1, 2021 as to its future operation. The exit dates proposed by the Company are consistent with the MSP agreement and remove coal plants from Oregon beginning with Cholla 4 this year:[34]

Coal-Fired Resource	Recommended Oregon Exit Date
Cholla 4	December 31, 2020
Jim Bridger 1	December 31, 2023
Craig 1	December 31, 2025
Jim Bridger 2	December 31, 2025
Jim Bridger 3	December 31, 2025
Jim Bridger 4	December 31, 2025
Naughton 1	December 31, 2025
Naughton 2	December 31, 2025
Craig 2	December 31, 2026

[34] UE 374 – PAC/200/Lockey/15.

Colstrip 3	December 31, 2027
Colstrip 4	December 31, 2027
Dave Johnston 1	December 31, 2027
Dave Johnston 2	December 31, 2027
Dave Johnston 3	December 31, 2027
Dave Johnston 4	December 31, 2027
Hunter 1	December 31, 2029
Hunter 2	December 31, 2029
Hunter 3	December 31, 2029
Huntington 1	December 31, 2029
Huntington 2	December 31, 2029
Wyodak	December 31, 2029

Q. What is CUB's recommendation regarding Exit Orders?

A. CUB recommends that the Commission adopt these dates as Exit Orders for the coal plants listed above. This will allow a planned, phase-out of coal from PacifiCorp's Oregon system, consistent with SB 1547. CUB believes that this transition away from coal will benefit customers by eliminating a very large economic risk.

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4. Coal Plant Incremental Decommissioning Costs Should be Non-Bypassable

Q. What are incremental decommission costs?

A. After a coal plant closes, a significant investment must be made to clean up the site where the coal plant operated. Some of PacifiCorp's coal plants also have coal mines that will require closure and remediation costs. The costs to deconstruct a coal plant and clean up the site are called decommissioning costs or negative salvage costs. Because the costs associated with a plant should fall on the customers who benefit from the plant, these costs are normally collected over the life of the plant. PacifiCorp has been collecting funds for decommissioning as part of its depreciation expense. As PacifiCorp begins to reconsider the economics of its coal fleet and Oregon is beginning to transition away from PacifiCorp's use of coal, the Company is undertaking a review of its expected decommissioning costs associated with it coal plants. The review will reveal to what extent, PacifiCorp has been over or under collecting decommissioning costs. Those costs will be reviewed later in this proceeding. After that review, there will likely be two sets of coal plant decommissioning costs. The base amount reflects the current coal decommissioning costs which reflects the share of decommissioning that should be properly be allocated to current usage. The incremental addition reflects the historic under payment or historic over payment of decommissioning costs that will be determined by the current coal decommissioning studies.

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Q. **What are non-bypassable charges?**

A. Non-bypassable charges are charges that apply to all customers, including customers who have stopped purchasing energy from the utility through direct access (i.e. these customers are unable to bypass these costs). The 3% Public Purpose Charge is an example of a charge that is non-bypassable.

Q. Why are you proposing that incremental decommission costs be non-bypassable?

A. These costs are related to historic coal usage, not current usage which is collected in the base decommissioning charges. CUB anticipates that the decommissioning studies will show either that historically we have been over-collecting decommissioning, in which case the customers who overpaid should receive a credit, or we have been under-collecting decommissioning costs, in which case the customers who underpaid should pay a surcharge.

Consider two customers. A residential customer who moves into PacifiCorp's system in 2021 and a large direct access customers who took power from PacifiCorp for 25 years before going on direct access 5 years ago. It makes no sense to require the new customer who has not under-paid into the decommissioning fund to pay some of the incremental decommissioning costs, but not the large direct access customer who used that coal plant for 25 years. If there was an over-payment, it makes no sense to reward the customer who did not overpay.

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Q. Have other states made decommissioning costs non-bypassable?

A. Yes. The direct access investigation has revealed that two of Oregon's neighboring states, California and Nevada require decommissioning to be non-bypassable. California IOU's divested of most non-nuclear generation when it tried deregulation in the late 1990s, so California does not have a legacy coal decommissioning issue. It does, however, have a legacy nuclear decommissioning problem. California decommissioning charges are non-bypassable and customers who have gone to direct access pay these charges.[35] Nevada does have a legacy coal decommissioning problem and requires direct access customers to pay for coal decommissioning.[36]

Q. How could the Commission establish non-bypassable charges for decommissioning?

A. The Commission would first have to divide the costs between the current liability and the historic under- or over-collection. This over- or under-collection would then become the non-bypassable charges or credits related to coal decommissioning. The Commission could then attach these costs or credits to the distribution system, making them non-bypassable. While these costs would be collected through distribution charges, the costs would continue to be allocated based on the allocation of generation plant.

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[35] UM 2024, OPUC Staff Opening Comments, page 8.
[36] UM 2024, AWEC Opening Comments, page 16.

IV. POWER COST RATEMAKING PROPOSALS

1. PacifiCorp's Proposal.

Q. What is PacifiCorp's proposal to eliminate the Power Cost Adjustment Mechanism (PCAM)?

A. PacifiCorp is proposing to eliminate the current version of the TAM and PCAM and replace it with an Annual Power Cost Adjustment (APCA). Essentially, the Company is proposing that net power costs be charged on a retroactive rather than prospective basis, a drastic change in Oregon's long-standing ratemaking process. Oregon's method for power cost ratemaking provides PacifiCorp, PGE and Idaho Power an incentive to control and manage costs since rates are set based upon a forecast that may or may not be subject to later true-up. PacifiCorp's proposal represents a significant shift in risk from shareholders to customers that is completely unwarranted under current economic circumstances. It is unnecessary – the regulation of the Commission already provides PacifiCorp the opportunity to recovery its prudently incurred cost and earn a reasonable return for its shareholders.

Q. How would PacifiCorp's APCA function?

A. It would function in a manner similar to the TAM and the PCAM, except it would eliminate the PCAM deadband, sharing and earnings test. Rather than forecast costs in the TAM in April, the APCA would forecast them in May. More importantly, in May the Company has completed its books for the prior year, so the May APCA can retroactively true up the previous year's power costs and add those retroactive charges to bills. There are three critical elements to the APCA:

- The APCA filing would be in May rather than April:
- It combines the TAM and the PCAM into a single mechanism; and
- The true up would no longer be subject to a deadband, earnings test or sharing.

I believe that the last point is the real goal of PacifiCorp's proposal. The Company seeks to minimize risks to shareholders and, instead, shift these risks onto customers.

Q. Why do you dismiss the value of the first two elements?

A. They are not meaningful.

PacifiCorp claims that by starting the APCA on May 15th rather than April it can bring in six more months of data.[37] The TAM is filed on April 1st and updated regularly through October. The forecast part of the APCA would be filed on May 15th and updated regularly through October. There is no information available between May and October that is not also available between April and October.

Likewise, there is little value in combining these two cases into a single case. Because Oregon has direct access and the forecasting part of the APCA will be used to set transition charges, this part of the proceeding will still be examined closely and will be contested. Transition costs, which are a payment to some customers and a credit to other customers, will still need to be as accurate as

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[37] UE 374 – PAC/500 Wilding/11.

possible. Even if PAC changes are adopted, CUB anticipates that this part of the case will still be contentious. Because it starts six weeks later, parties will have less time to review the modeling involved and the case will likely be more difficult.

This leaves the elimination of the deadbands, sharing, and earnings test as the real goal of PacifiCorp.

2. The Current Regulatory System is Fair

Q. PacifiCorp argues that elimination of deadbands, sharing and an earnings test is necessary to ensure that they have a reasonable opportunity to recover their prudently incurred costs. Do you agree?

A. I do not agree. The Company is provided an opportunity to recover its prudently incurred costs and earn a reasonable return on its invested capital and the Company has been successful. The Company uses data from 2014 to 2018 to claim that it is not recovering its prudently incurred costs, but that is not true. The following table shows PacifiCorp earnings during that period (and 2019):[38]

Year	Unadjusted	With Normalizing Adjustments	authorized
2014	10.19%	9.45%	9.8%
2015	9.48%	9.90%	9.8%
2016	10.43%	9.72%	9.8%
2017	12.23%	9.82%	9.8%
2018	9.59%	9.31%	9.8%
2019	10.00%	9.35%	9.8%
average	10.32%	9.59%	

[38] These numbers come from the Company's Oregon Results of Operation from 2014-2019. *See* OPUC Docket No. RE 56.

Unadjusted earnings represent the earning before normalizing adjustments. From 2014 to 2019 the Company's unadjusted Oregon earnings were above its authorized earnings four times by as much as 240 basis points. Unadjusted earnings were below authorized twice and were never more than 40 basis points below authorized. On average unadjusted earnings were more than 50 basis points above authorized. Normalized earnings were above authorized twice, and below authorized four times. On average, normalized earnings averaged 21 basis points below authorized. Generally, Oregon has considered that earnings that are within 100 basis points of authorized earnings reasonable. This data shows me that the Company has had the opportunity to earn its prudently incurred costs and earn a reasonable return on both an unadjusted and a normalized basis. The only place earnings are outside of the reasonable range was in 2017, its unadjusted earnings were greater than what Oregon would traditionally consider reasonable.

Q. You are referring to overall earnings, not just net power costs, and you are including unadjusted earnings, why are these relevant to the consideration of how power costs are recovered.

A. We will address the legal standard for ratemaking in briefs, but the primary evaluation of whether rates are fair, just, and reasonable to both customers and shareholders is based on whether on a comprehensive basis the rates allow the utility to recover its costs and earn a reasonable return. The rates may have some elements that favor customers and some that favor shareholders, but overall, are the authorized rates, after recovery of costs, producing reasonable earnings? The answer in PacifiCorp's case is yes, they are producing reasonable earnings. It is also the case that customers are not billed separately for power costs, so looking at total earnings is important.

This also gets to the issue of why unadjusted earnings is a useful data point. Consider the example provide by PacifiCorp witness Mr. Graves:[39]

> If the net load variance is positive for a particular year, the system experiences higher-than-expected net load, resulting in PacifiCorp having to secure more power from dispatchable resources and market purchases than anticipated for that year. As I explained above, power in these instances would have to come from the Company's more expensive generation sources, or from additional purchases.
>
> As seen in Confidential Figure 4, net load variance was positive in 2014, 2015, and 2018, meaning the actual volume exceeded the forecast. Because of the economic dynamics that I explain above, NPC under-recovery was also among the highest for these three years. Vice versa, a negative net load variance indicates that PacifiCorp relied less on its marginal units and market purchases, leading to a lower NPC under-recovery as was the case in 2016 and 2017. In absolute terms, the net load variance is largest in 2016, when forecast net load exceeded the actual by 1.7 million MWh. As a result, 2016 was the only year that PacifiCorp experienced NPC over-recovery.

I generally agree with this statement. If net loads are higher during a year, this will lead the Company to rely on power supply with a higher marginal cost and this will raise net power costs. But what PacifiCorp does not discuss is what happens outside of net power costs. The fixed costs of the system (distribution, customer service, generation ratebase …) are recovered through variable charges. When loads are normal, the utility will recover its fixed costs. When loads are higher during the year, the utility will over-recover its fixed costs. For residential

[39] UE 374 – PAC/600/Graves/20.

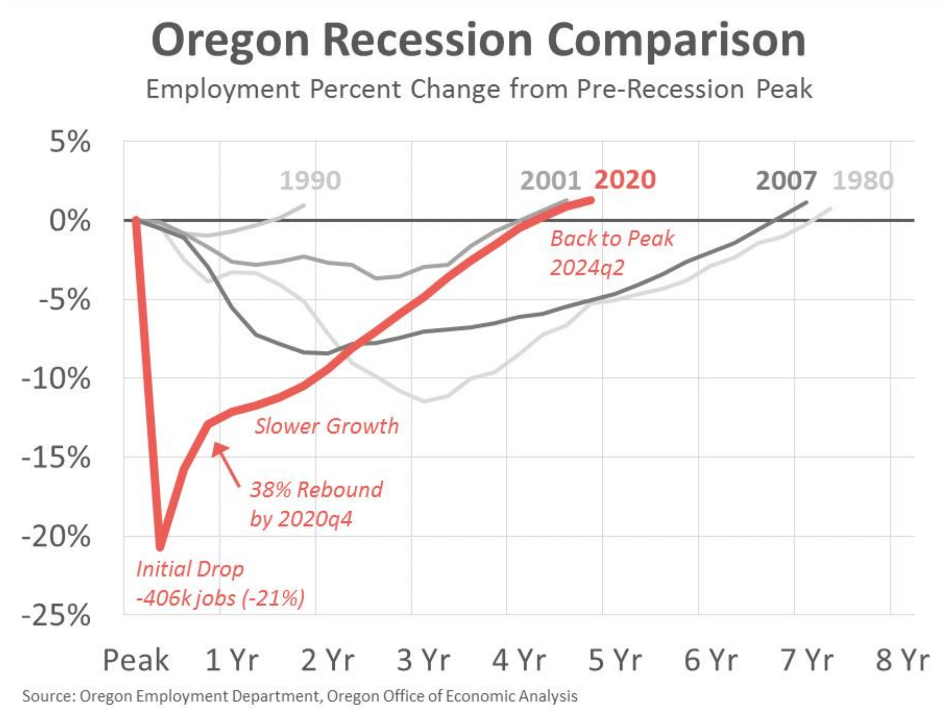
customers, net power costs make up less than 30% of the bill. When loads are greater than normal, residential customers are paying about 10 cents/kWh ($100 MWh) more for the additional load with the bulk of this representing overpayment of fixed cost. This is a good example of why an examination of whether current rates are just and reasonable rates must focus comprehensively on total costs and earnings and not narrowly at a subset of costs like net power costs.

This is also why CUB tracks unadjusted earnings. We normalize load forecasts to average weather when we forecast rates. When a utility reports earnings, they also normalize those, so we can compare what earnings would have been under normal weather. But PacifiCorp wants to true up net power costs and explicitly bring in higher incremental power costs caused by load exceeding the forecast, but some of the effect of this higher load (the overpayment of fixed costs, for example) shows up in the unadjusted earnings. As we can see from the chart above, unadjusted earnings never fall below a reasonable level. The deviations from normalized ratemaking – deviations in load from what is forecast – are not harming the utility.

3. Shifting Risk in Today's Economy

Q. Can you explain why this is unwarranted under current economic circumstances?

A. The economy has changed significantly since PacifiCorp filed this case due to COVID-19 and the economic effects of the virus. The Company's proposals need to be evaluated based on current conditions and the conditions that are likely to be in place in 2021, not the conditions that were in place when the Company filed its case. CUB Exhibit 104 is the most recent economic forecast for the state of Oregon. It forecasts that unemployment will reach 21% and will stay above 10% for two years:



The unemployment rate has only exceeded 10% once since the Great Depression, but today it is twice that amount. Parts of PacifiCorp's service territory are particularly hard hit and will have a difficult time with recovery:

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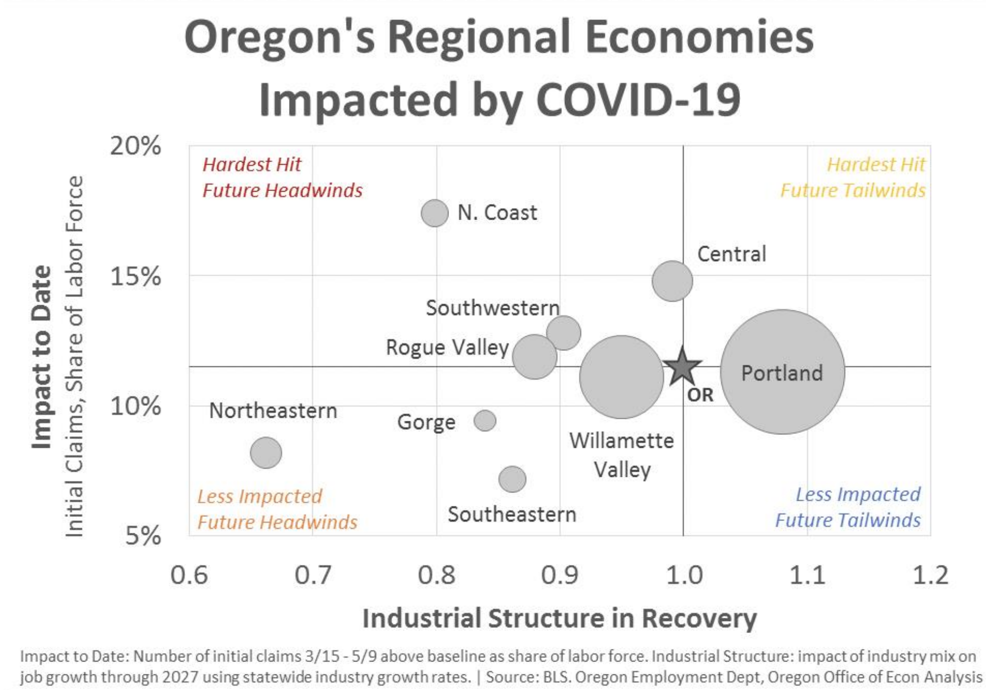

PacifiCorp residential, commercial and, industrial customers are all dealing with unprecedented hardships. This is not the time to shift economic risk from shareholders to customers – particularly for PacifiCorp. PacifiCorp is fully owned by Berkshire Hathaway (through its subsidiary, Berkshire Hathaway Energy). A single Class A share of stock in Berkshire Hathaway was priced at $339,188 as of January 8, 2020, more than five times the annual median income for an Oregon household.[40] The CEO of Berkshire Hathaway is Warren Buffett, the 4th wealthiest person in the world. In this case, PacifiCorp is proposing to shift the economic risk associated with variations in net power costs from the very wealthy shareholders of Berkshire Hathaway to the very vulnerable, suffering families and businesses of Oregon. While CUB believes that PacifiCorp's

[40] Oregon 2018 median household income was $63,426. Source: https://www.deptofnumbers.com/income/oregon/

proposal is poor policy, unneeded and should be rejected, if such a change was going to be considered, it should at the very least be proposed when there are better economic conditions.

Consider PacifiCorp's 2019 PCAM. According to the Company's filing, PacifiCorp's unrecovered power costs for 2019 is $45.1 million. This is greater than the deadband, making some of it eligible for recovery. However, the earnings test shows that PacifiCorp's earnings were considered reasonable, so there is no basis to provide the Company with the additional revenue. PacifiCorp's 2019 unadjusted earnings were 10.005% and their normalized earnings were 9.35%. Normalized earnings are used for the PCAM earnings test and PacifiCorp were within 50 basis points of its authorized earnings. This is well within the reasonable earnings range. However, if PacifiCorp's APCA was in place, there would be no deadband and no earnings test. This $45.1 million would be added to customers' 2021 rates. Customers in 2021 would pay shareholders an additional $45.1 million to retroactively true up 2019 net power cost, even though shareholders already earned a reasonable return in 2019, and customers will be financially struggling in 2021.

4. Drastic Change in Oregon's Regulatory Approach

Q. Can you explain why this is a drastic change in Oregon's long-standing ratemaking process?

A. Yes. Let's begin with CUB's view of the regulatory system. The Commission's primary responsibility is to establish fair, just, and reasonable rates which allow a utility to recover its costs and earn a reasonable return.[41] This is done on a prospective, not retroactive basis. While we recognize a specific, forecasted target ROE is used to set rates, a reasonable return is generally considered as a range. In this case, PacifiCorp is proposing a reasonable range of 9.75 percent to 10.25 percent.[42] Once rates are established, the utility is expected to manage its operations and expenses to the rate. This last part is important because it forms the core of Oregon's approach to utility incentives. With rates set on a forward-looking basis, the utility has an incentive to manage costs. If the utility can keep the costs below the forecast, it raises earnings, if the utility is unable to keep the costs under the forecast then it reduces its earnings. As we have shown above, PacifiCorp has fared well under this circumstance. In addition, Oregon's regulatory approach recognizes the benefits of providing good price signals to customers. Under PacifiCorp's proposal customers, would not actually know the cost of heating their home in the winters, cooling it in the summer or the cost of charging an EV because some of these costs will not show up on customer bills until two years later.

This incentive approach to regulation is one of the reasons Oregon has recognized a general prohibition against retroactive ratemaking. Where the Commission has allowed retroactive ratemaking it usually includes mechanisms to retain some of the cost-control incentive. For example, Oregon's LDC utilities have a Purchased

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[41] https://www.oregon.gov/puc/about-us/Pages/default.aspx#:~:text=Our%20Mission,of%20the%20regulated%20public%20utilities.

[42] UE 374 – PAC/400 Bulkley/86.

Gas Adjustment mechanism[43] requires sharing of higher and lower costs and deferrals are subject to earnings tests. Power cost true-ups are a clear example of retroactive ratemaking and the Commission has identified a set of principles that it applies to PCAMs to prevent them from simply becoming a retroactive adjustment.

Q. Can you describe these principles?

A. Yes. The current PCAM structure was first established for PGE. In 2012, PacifiCorp requested that the Commission establish a PacifiCorp PCAM that was nearly identical to what it is asking for here. Net power costs would be forecast in the TAM, with a PCAM added to "collect or credit the differences between actual net power costs and the forecasted net power costs approved in the TAM."[44]

The Commission resolved the issue by first reiterating the principles that it had established to review such mechanisms.[45] These principles were applied in a series of dockets over the years, including UE 180, UE 181 and UE 184:

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[43] The purchased gas adjustments apply to gas utilities. Gas is a pass through cost. So the gas companies don't earn a profit on the commodity. This is the reason that there is not a deadband in the PGA.

[44] OPUC Order No. 12-493, page 8

Commission Principles for Power Cost Adjustments

1. **any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility;**
2. **there should be no adjustments if the utility's overall earnings are reasonable;**
3. **the PCAM's application should result in revenue neutrality;**
4. **the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer;**
5. **the PCAM should provide an incentive to the utility to manage its costs effectively.**

Q. Does PacifiCorp's proposal meet each of these principles?

A. No. It does not meet any of these principles.

Principle 1. PacifiCorp's proposal contains no elements that limit it to unusual circumstances. In fact, it is designed to be triggered every year that net power cost is not forecast completely accurately. We forecast costs based on normal weather, and weather is a normal business risk for an electric utility. Fuel costs and plant operations are forecast and are considered traditional risks for utilities. The size, as opposed to the nature of a risk, however, could fall outside of the normal business risk, which is why there is a deadband. The use of a power cost deadband to identify the normal business risk preceded the PCAM, when deferrals were utilized for power costs when unusual circumstances happened. For example, in UM 995, PacifiCorp filed for a net power cost deferral and the Commission imposed a 250 basis points deadband, with 50/50 sharing of cost exceeding this deadband and 75(customer)/25(company) sharing for costs that exceed 400 basis points.[46] This was a much wider deadband than is applied today and required the Company to take a larger share of the costs outside of the deadband. The principle that utilities' absorb normal business risk related to power costs is long established in Oregon.

Principle 2. PacifiCorp's proposal would adjust rates regardless of earnings, so it contains no elements that would prevent adjustment when earnings are reasonable. When utilities' earnings are reasonable, there is no basis for adding a surcharge to bills because the utility has recovered its costs and earned a reasonable return.

Principle 3. PacifiCorp's proposal contains no elements that are designed to ensure revenue neutrality. The idea of revenue neutrality was that the Commission was not trying to change the allocation of risk, but instead was trying to put in place an on-going mechanism to deal with power costs that fell outside normal business risk. The risks of variations in power costs were not equal. For example, poor hydro conditions would cause a greater increase in power prices than good hydro conditions would reduce prices. Revenue neutrality is the reason for the asymmetrical deadband. With the asymmetrical deadband, the

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[46] OPUC Order No. 01-420.

Commission believed that over time credits flowing to customers would generally be about the same as charges flowing to the Company.

Principle 4. Because it was only supposed to cause adjustments in unusual circumstance, and unusual circumstances occur infrequently, the Commission wanted it to be in place for a long period of time. Unusual circumstances were more likely to occur over a long period of time, creating credits and charges that would balance out. Rather than leave it in place for a long time period, PacifiCorp has made multiple attempts to change the PCAM. This case is simply the latest.

Principle 5. By giving the Company dollar-for-dollar recovery, the Company loses all incentive to control cost. Under today's PCAM, the Company does not know if it will be in the deadband or whether its earnings will be reasonable, so it has a large incentive to control costs. If it can reduce costs, its earnings will generally improve. This incentivizes the Company to manage its generating assets and work to improve performance. It incentivizes the Company to be thoughtful when deciding how much generation to sell into bilateral markets versus save for the EIM. It incentivizes the Company to accurately forecast wind capacity factors. It incentivizes the Company to have a well-designed strategy for hedging. These incentives to control cost will be lost under PacifiCorp's proposal.

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Q. Do you believe the mechanism is working as intended?

A. Yes. Very much so. PacifiCorp did not want a PCAM that was tied to unusual circumstances and they still do not want one tied to unusual circumstances. The fact that the PCAM does not require regular adjustments is both a function of its design and that the magnitude of risk associated with net power costs is relatively low. Natural gas prices have fallen considerably since the days when unusual power cost events were triggering deferrals. Power prices have fallen. The UM 995 deferral was triggered by a catastrophic outage at the Hunter coal plant, combined with high power prices in the wholesale market and very poor hydro conditions. While hydro conditions continue to vary, it has been quite a few years since the Pacific Northwest had very poor hydro conditions.[47] With more renewables on the grid, market prices have fallen a great deal and are stable. Natural gas prices no longer have the volatility that existed a decade ago. Today, we economically shut down coal plants on a regular basis, therefore, an extended outage at a coal plant is unlikely to trigger significant net power costs. While the net power cost forecasts associated with the TAM are contentious, net power costs themselves are much more stable than they used to be. Under current conditions, it is not surprising that there are not a lot of adjustments under the PCAM. Without unusual events, there should not be PCAM adjustments.

Q. What is CUB's recommendation regarding the PCAM and APCA?

A. PacifiCorp's proposal should be rejected. The Company already has the opportunity to recover its costs and earn a reasonable return. Current economic circumstances make this a terrible time to shift economic risk from shareholders

[47] OPUC Order No. 01-420.

to customers. The Commission has established a set of principles for evaluating power cost adjustment mechanisms. Because PacifiCorp's proposal violates those principles, the Company simply ignores the principles.

V. PRYOR MOUNTAIN WIND PROJECT

Q. Please summarize your concerns regarding the Pryor Mountain Wind Project.

A. CUB is concerned that the modeled benefits PacifiCorp used to justify the Pryor Mountain Wind Project (Pryor Mountain) may not materialize. Vitesse, LLC (Vitesse) (a wholly-owned subsidiary of Facebook, Inc.) will purchase all of the renewable energy credits (RECs) generated by Pryor Mountain over a 25-year period under PacifiCorp's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option.[48] While Vitesse is guaranteed the RECs—helping a single large customer meet its renewable energy desires—the benefits promised to other customers are not guaranteed. First, Pryor Mountain will only qualify for 100% of federal production tax credits (PTCs) if it is operational by the end of 2020. While the Company maintains that the project is on schedule to be in service by December 31, 2020,[49] unanticipated delays—especially due to the COVID-19 pandemic—may affect the on-line date. Second, CUB is concerned that the RECs sold to Vitesse and the contract term do not maximize the value for other customers. Third, a substantial portion of the modeled revenue requirement benefits to PAC's customers do not appear until the final year of the project, 2050.[50] CUB is concerned that PAC is relying too heavily on Pryor Mountain's speculative terminal

[48] UE 374 – PAC/700/Link/68, lines 10-14.
[49] UE 374 – PAC/700/Link/71, lines 8-10.
[50] UE 374 – PAC/700/Link/76, Figure 8.

value in order to justify its investment. Finally, CUB is concerned that Pryor Mountain may not be the best resource to meet all customers' needs. This testimony addresses each issue in turn.

Q. Please provide a background for the Company's decision to pursue Pryor Mountain.

A. PAC filed a Notice of Exception to justify a deviation from the Commission's standard request for proposals (RFP) process for resource procurement on September 27, 2019 in Docket No. LC 70, its 2019 Integrated Resource Plan (IRP).[51] The impetus for this resource acquisition was a series of negotiations between the Company and Vitesse, which resulted in an agreement executed on June 27, 2019 for the purchase of all RECs generated by Pryor Mountain over a 25-year period.[52] Under the terms of this Schedule 272 Agreement, PacifiCorp will retire all RECs on behalf of Vitesse.[53] PacifiCorp contends that the Pryor Mountain is a time-limited opportunity that provides unique value to its customers, and, as such, argue it was eligible for an exception to the Commission's standard RFP process for new resources.[54]

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[51] *In re PacifiCorp, dba Pacific Power's 2019 Integrated Resource Plan,* OPUC Docket No. LC 70, PacifiCorp's Notice of Exception under OAR 860-089-0100 (Sep. 27, 2019) (hereafter "Notice of Exception").
[52] Notice of Exception at 1.
[53] Notice of Exception at 1, fn. 6.
[54] *See* Notice of Exception.

Q. What benefits does PacifiCorp believe its customers will realize from this project?

A. From the Company's filing, the principal benefits Pryor Mountain provides to customers (other than Vitesse/Facebook) are the result of federal PTCs, the offset of project costs by selling RECs to Vitesse, and the terminal value associated with the site in the project's final year.

Q. Are these benefits guaranteed?

A. No. The Company admits that the broad balance of these benefits are subject to variation.[55] Regardless of any variation in the benefits provided to PAC's customers, Vitesse is guaranteed to receive the full output of RECs from the facility for the contract term. While the RECs Vitesse will receive from the project will also fluctuate with Pryor Mountain's production, their desire to apply the environmental attributes of renewable energy generation towards part of their overall load will be met.[56] Meanwhile, other customers are exposed to a variety of risks.

1. Construction Risk

Q. Please explain the construction risk PacifiCorp's customers face.

A. CUB understands that on May 27th, because of the COVID-19 pandemic, the US Treasury issued guidance granting wind projects that met the Safe Harbor requirements an additional year to be placed into service and still be able to capture

[55] Notice of Exception at 2, fn. 9 ("Unlike a power purchase agreement where a price per MW is contractually set, here there will be some variation in the cost to customers based on performance of the project (*i.e.*, based on actual wind conditions).").
[56] UE 374 – PAC/700/Link/72, lines 11-13.

PTC benefits.[57] This is helpful, because the was a looming deadline of December 31, 2020 to capture 100% of federal PTCs associated with new wind generation. This guidance was issued one week ago as a Notice. Notices may be used to relate what regulations will say in situations where regulations may not be published in the immediate future.[58] However, because this was issued one week ago, and CUB is not an expert on IRS tax guidance, CUB still has some concern that a construction delay could lead to PacifiCorp receiving less than 100% PTCs. CUB notes that the current administration is not a strong supporter of wind energy.

Q. Why is CUB concerned that there may be construction delays?

A. According to PacifiCorp, Pryor Mountain is "on schedule to be in service by December 31, 2020."[59] However, the country is in the middle of an unprecedented pandemic that is having profound impacts on both public health and the economy. The social distancing requirements in effect across the country have grinded many non-essential business operations to a halt. Therefore, it may be difficult for construction crews to work together to complete Pryor Mountain on its anticipated timeline. Further, according to the American Wind Energy Association (AWEA), planned US wind power projects totaling 25 gigawatts are in danger of being delayed, scaled back, or scrapped altogether due to the COVID-19 economic slowdown.[60]

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[57] www.irs.gov/pub/irs-drop/n-20-41.pdf
[58] www.irs.gov/newsroom/understanding-irs-guidance-a-brief-primer
[59] UE 374 – PAC/700/Link/71, lines 8-9.
[60] *US 2020 wind projects at risk due to COVID-19 delays*, Chris Barnett, JOC.COM, (Apr. 20, 2020), *available at* https://www.joc.com/breakbulk/energy-and-renewables-project-logistics/us-2020-wind-projects-risk-due-covid-19-delays_20200420.html.

Q. Does the information in PacifiCorp's filing assuage CUB's concerns?

A. No. The Company provides very little evidence or information regarding Pryor Mountain's construction other than reiterating that it remains on time. The anticipated commercial operation date leaves very little leeway for any unexpected delays. CUB is concerned that unanticipated delays, potentially due to the COVID-19 pandemic, may shift the commercial operation date and render PacifiCorp's customers unable to realize the full PTC benefits that were modeled in the Company's justification for this project.

Q. What is CUB's recommendation?

A. The Company should put additional evidence on the record in its Reply Testimony to justify its position that Pryor Mountain will be operational by December 31, 2020 and address whether the recent IRS Notice provides assurance of an extra year to capture PTC benefits. Given that Pryor Mountain was pursued in order to capture economic benefits to customers, CUB recommends that customers be held harmless if 100% of PTC benefits are not captured due to construction delays.

2. Term Risk

Q. Please explain the risk that PacifiCorp's customers face due to the length of the contract between PAC and Vitesse.

A. According to the Company, the present-value cost reduction to Pryor Mountain resulting from Vitesse's purchase of all RECs "will mitigate risks under the various price-policy assumptions."[61] The Company's best estimate of this benefit is [redacted]

[61] UE 374 – PAC/700/Link/72, lines 1-4.

[redacted].[62] Meanwhile, Pryor Mountain's capital costs total [redacted][63] By locking in a contract for the sale of RECs to one party for a period of 25 years, PacifiCorp is placing risk on its customers. A lot can happen in 25 years. Facebook, itself has only existed for 16 years and the digital age has several examples of industry leaders who could not maintain most of their business (Wang Computers, AOL, Yahoo). A 25-year contract with a 16-year old company carries a risk. In addition, REC prices will undoubtedly fluctuate, and it is unclear whether the anticipated benefit from the sale of RECs to Vitesse will be greater than the benefit PacifiCorp could have received for customers absent the contract. There is a potential that PacifiCorp could sell these RECs in the future for a greater value than they are selling them to Vitesse for. Utilities have an obligation to optimize their assets to create the best value for customers. It is unclear that PacifiCorp is doing so here.

Q. What do you recommend ameliorating the term risk CUB sees in the contract?

A. Again, there is little evidence on the record that PacifiCorp's contract to sell all RECs to Vitesse for 25 years is the best deal for its non-Facebook customers. CUB would like to see evidence that supports the REC sales as optimizing value for the rest of the system.

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3. Terminal Value Risk

[62] UE 374 – PAC/700/Link/72, line 3.
[63] UE 374 – PAC/820/Teply/1.

Q. What is terminal value?

A. A terminal value benefit recognizes that there may be a benefit to customers at the end of a resource's life. This can be due to the facilities supporting the resources, such as transmission facilities that have longer useful lives than the resource in question.[64] In the case of wind projects, there is inherent value in the site itself.[65] There are a limited number of specific geographic locations suitable for wind development which also have access to transmission networks, and this scarcity can result in a high terminal value for sites that are known to have a high capacity factor. The terminal value of a wind site can create a benefit at the end of the resource's useful life due to the value of the land and attendant facilities. Conversely, a coal-fired power plant has a negative salvage value since the land must be remediated at the end of the resource's useful life, which leads to high decommissioning costs.

Q. Did Pryor Mountain's terminal value play a role in the Company's analysis in concluding to move forward with the resource?

A. Yes. There is a dramatic increase in the project's expected benefits in the last year of its useful life.[66]

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Q. Has this issue been addressed?

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[64] UE 374 – PAC/700/Link/70, lines 6-7.
[65] UE 374 – PAC/700/Link/70, lines 7-9.
[66] UE 374 – PAC/700/Link/76, Figure 8.

A. Yes, in its response to the Company's notice of exception filed in LC 70, Staff expressed concern that "this portion of the expected benefit could be the result of an un-realistic end-effect in PacifiCorp's modeling."[67]

Q. What was Staff's finding in that proceeding?

A. Staff did not find that an exception to the competitive bidding rules was warranted based upon PacifiCorp's filing.[68] Staff found that the large portion of benefits forecasted in 2050 may be skewing the analysis.[69]

Q. How did the Company respond?

A. In its pre-filed testimony in this proceeding, PAC claims that its analysis does not rely heavily on 2050 results to demonstrate a positive net benefit.[70] PAC claims that even if the terminal value were completely eliminated, project customer net benefits would range between $57 and $70 million.[71]

Q. How does CUB respond?

A. Despite the Company's arguments, CUB is concerned that a large portion of projected customer benefits will not be apparent until 2050. According to the Company's analysis, the project will result in a net cost to customers in nine of the first seventeen years the project is in service.[72] Further, as discussed, the projected net benefits that the Company argues will exist even without the terminal value benefit are not guaranteed and will fluctuate with production and various future

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[67] *In re PacifiCorp's 2019 Integrated Resource Plan,* OPUC Docket No. LC 70, Staff's Comments on PacifiCorp's September 27, 2019 Notice of Exception to the Competitive Bidding Rules at 3 (Oct. 25, 2019).
[68] *Id*. at 5.
[69] *Id*.
[70] UE 374 – PAC/700/Link/70, lines 18-19.
[71] UE 374 – PAC/700/Link/70-71.
[72] UE 374 – PAC/700/Link/76, Figure 8.

scenarios. What is guaranteed is that, if Pryor Mountain is found to be prudent, customers will be paying a rate of return on the capital investment for each of the thirty years the resource is in service.

Q. Does CUB have additional concerns about the terminal value of the site?

A. Yes. The Company's anticipated terminal value adds greatly to the project's overall benefits and is speculative. It is very difficult to forecast what the value of a parcel of land and its attendant facilities will be thirty years in the future. The Company assumes that a willing buyer will be looking to pay top dollar for a wind site, but it is uncertain whether wind generation will even be valuable at that point in the future. The Company's best estimate now is that the terminal value for the site will be [redacted][73] [redacted][74] CUB is concerned that the majority of Pryor Mountain's benefits arise from a future terminal value whose actual amount is unknown. Meanwhile, customers realize net costs for a significant part of the project's early life.

4. A Brown Resource with a Green Production Shape

Q. Do you believe Pryor Mountain is the best, least cost, least risk resource to serve customers at this time?

A. Quite possibly not. By selling the RECs associated with Pryor Mountain's output to Vitesse, other cost-of-service customers are essentially procuring a brown resource with a variable load shape. Since all of the environmental attributes will be stripped away from the energy that flows from Pryor Mountain, the project will

[73] CUB Exhibit 105.
[74] UE 374 – PAC/700/Link/70-71.

be ineligible for RPS compliance purposes. Further, as a wind plant, it has a very limited contribution to capacity. This is troubling as we are entering a period of capacity need in the region. We are also in a period in which various clean energy policies are being implemented in western states, including in Oregon. Oregon considered a carbon cap-and-invest program during the prior legislative session, and it is likely that some form of clean energy legislation will be passed soon. Whether that is cap-and-invest or a 100% clean mandate, the energy from Pryor Mountain will not add any environmental attributes to Oregon's electricity mix.

Q. Will PacifiCorp's customers realize any environmental attributes from this wind project?

A. Yes, but their benefits will not be realized until far into the future, at which point they will be limited and speculative. Vitesse is purchasing all RECs from Pryor Mountain for 25 years. Pryor Mountain has a 30-year depreciable life. Customers will receive bundled renewable energy from the facility for its last five years. However, it is unclear what market there will be for RECs—if any—at that time. After paying a rate of return for 25 years, customers will receive the RECs from a facility that is likely heavily degraded at a time in which there may be no actual value from REC production. The resource may also require repowering at some point during its depreciable life, which means customers will be paying even more than they initially anticipated.

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Q. What is CUB's recommendation with regards to Pryor Mountain?

A. CUB believes that the evidence in this case shows that this investment is a good deal for Vitesse/Facebook which gets 25 years of RECs and it a good deal for PacifiCorp which gets 30 years of return on investment. The remaining customers, however, take the risk associated with the plant. At this point, with the evidence on the record, CUB does not recommend the Commission approve the Company's request on this issue. This project was negotiated by PacifiCorp and Facebook in the absence of the Commission or any stakeholders, and it now seeks approval based upon a sparse evidentiary record. CUB would like to see the Company address the following risks, and discuss whether there are ways to mitigate these risks on behalf of customers:

- Construction Risk. What is the real likelihood that the project's in-service date could be delayed beyond this year? What level of PTC assurance is granted by the IRS Notice?
- Term Risk. What evidence is there to demonstrate that the 25-year contract to sell RECs to Vitesse maximizes the value of the resource? What protections exist if Vitesse/Facebook does not continue to purchase the RECs?
- Terminal Value Risk. What protections are there if in 30 years there is little terminal value?

Finally, we would like more analysis showing this is a least cost/least risk resource. This resource was not selected in the IRP to meet the resource needs of the Company. It does not include any RECs for the system for 25 years. The

Company needs to show that this resource provides real value to the system and is least cost/least risk.

VI. Conclusion

Q. Can you summarize your recommendations.

A. Yes. I am making the following recommendations:

1. *Wheeling Revenue.* Rather than forecasting wheeling revenue in general rate cases, wheeling revenue should be annually adjusted in the TAM. The TAM guidelines should be amended to include FERC Account 565.

2. *Deer Creek Mine Legacy Pension Costs.* The legacy pension costs associated with the Deer Creek Mine no longer represent net power costs and should instead be moved to Pension Expense and be recovered through general rate cases.

3. *Jim Bridger 3 and 4 SCRs.* PacifiCorp was imprudent when it decided to install SCRs on its two Bridger plants. The cost of the SCRs should not be allowed to be added to rate base. In addition, operation of the Bridger units in the TAM should reflect prudent operation without any SCRs.

4. *Cholla Unit 4 regulatory asset.* The Commission should find that Cholla 4 retirement is in the public interest. The interest rate on the portion of the

regulatory asset related to retired plant should be reduced to 2.56% to reflect the time value of money and remove the profit component.

5. *Coal Plant Exit Orders.* The Commission should approve the proposed Exit Orders for PacifiCorp's coal fleet.

6. *Coal Plant Incremental Decommissioning.* The portion of coal plant decommissioning that relates to historic over or under collection of decommissioning should be collected from or credited to customers through a non-bypassable charge.

7. *Power Cost Ratemaking.* PacifiCorp's proposal to replace the current TAM and PCAM with its proposed APCA should be rejected because it fails to meet any of the principles established by the Commission for power cost recovery.

8. *Pryor Mountain Wind Project.* At this time, CUB does not recommend approval of this project. CUB believes the Company has failed to address the risks that this project places on most of its customers.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

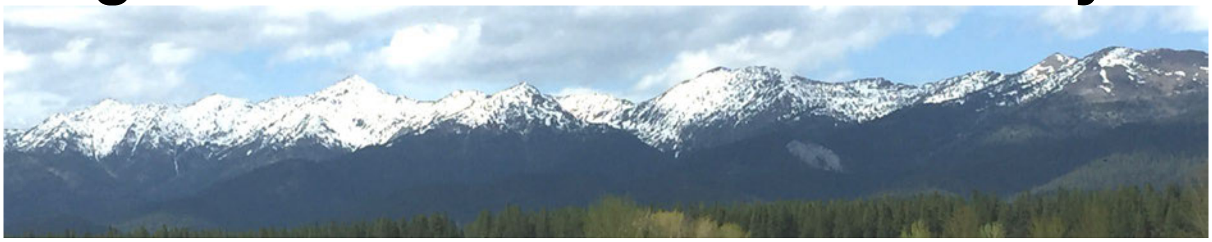
EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

Fact Sheet

Regional Haze: Four Factor Analysis



Hells Canyon Wilderness.

State of Oregon Department of Environmental Quality

Air Quality Planning
700 NE Multnomah St., Suite 600
Portland, OR 97232
Phone: 503-229-5269
800-452-4011
Fax: 503-229-6124
Contact: D Pei Wu, PhD

www.oregon.gov/DEQ

DEQ is a leader in restoring, maintaining and enhancing the quality of Oregon's air, land and water.

Why did I receive a letter from DEQ requiring that my facility conduct a four factor analysis?
The Oregon Department of Environmental Quality is developing a State Implementation Plan for the second implementation period of the federal Regional Haze program (40 CFR 51.308). This implementation period focuses on making reasonable progress toward national visibility goals by analyzing progress-to-date from the 2000-2004 baseline and considering whether additional emission reductions are necessary to continue a reasonable rate of progress.

What is a four factor analysis?
The four factor analysis involves assessing potential emission controls technologies against four statutory factors:

(1) The cost of control,
(2) Time necessary to install controls,
(3) Energy and non-air quality impacts, and
(4) Remaining useful life.

How do I prepare a four factor analysis?
DEQ will rely on the following three resources to review facility four factor analyses to ensure accuracy and consistency. All information prepared as part of the reasonable progress analysis should be prepared using the guidance provided in these documents.

1. EPA Guidance on Regional Haze SIPs for the Second Implementation Period. ("Guidance")[1]
2. EPA Air Pollution Control Cost Manual ("Control Cost Manual")[2]
3. EPA Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze ("Modeling Guidance")[3]

For the four factor analysis, a 20-year planning horizon should be assumed. The only exception to this horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired. Additionally, the generally accepted accuracy in the Control Cost Manual is within plus or minus 30%. Facilities using technical experts and consultants may have more accurate projections due to their previous hands-on experience. Please explain any deviations from the 20-year planning horizon or the presumed 30% accuracy in your estimates.

The latest guidance from EPA points to the interest rate that is most appropriate for your facility based on previous project engineering experience at your facility. This most likely will result in the selection of an interest rate between 3% and 7%. In the absence of a more specific interest rate, EPA recommends that you use the current bank prime rate, which is 4.75% as of the date of this letter, as a default.[4]

[1] Environmental Protection Agency, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 2019, EPA-457/B-19-003. https:\\www.epa.gov\visibility\guidance-regional-haze-state-implementation-plans-second-implementation-period
[2] EPA, "EPA Air Pollution Control Cost Manual." https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. Please refer to the most current finalized version of the relevant chapters.
[3] EPA, "Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze," November 2018, EPA-454/R-18-009. https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance
[4] The current bank prime rate can be found on the Federal Reserve website: https://www.federalreserve.gov/releases/h15/

Capital and annual costs should be estimated as if the project will be constructed at the time the cost estimate is prepared. The annualized cost of the project should be presented by annualizing the capital cost and adding that to the annual operating costs. Calculate the cost in dollars per ton of emission reduction for each evaluated control alternative by dividing the uniform annual cost by the tons of annual emission reduction anticipated.

Alternative formats

DEQ can provide documents in an alternate format or in a language other than English upon request. Call DEQ at 800-452-4011 or email deqinfo@deq.state.or.us.

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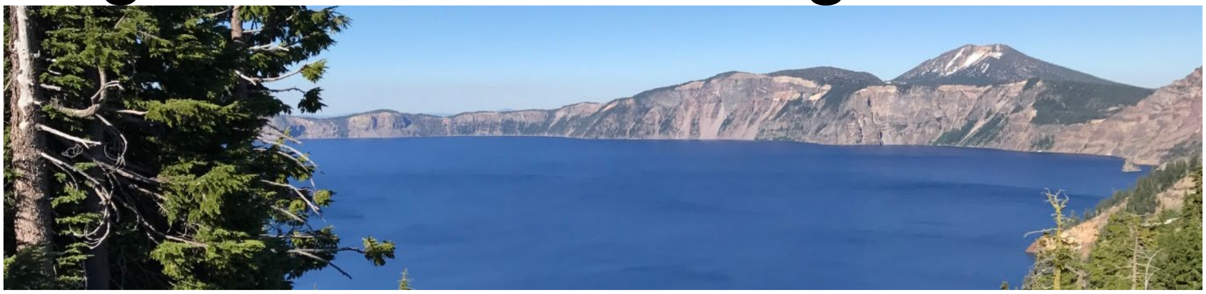
Fact Sheet

Regional Haze Planning



Crater Lake National Park.

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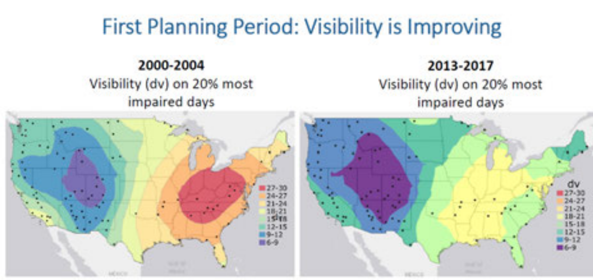
History of Regional Haze Program

In 1977, pollution and decreased visibility of scenic views at national parks and wilderness areas prompted Congress to require the U.S. Environmental Protection Agency to take action. EPA identified specific facilities whose emissions clearly caused regional haze in these nationally treasured places. This initial work led to the 1999 Regional Haze Rule.

This rule mandates gradual progress toward restoring natural visibility conditions by the year 2064 at designated national parks, wilderness areas, monuments, forests, seashores, and wildlife refuges, collectively referred to as Class I areas. The rule was revised in 2017 to strengthen visibility protection, emphasizing that states reduce man-made emissions of air pollutants that impair visibility at these special places held in the public trust.

The good news is that visibility has improved significantly in nearly all areas of the U.S. from 2000 to 2017, as seen in the two maps below.



Two color coded maps showing visibility improving from the baseline period (2000-2004) to the most current 5-year period (2013-2017) in all areas of the United States. Source: 9/10/19 EPA Webinar Overview of [Guidance on Regional Haze SIPs for the Second Implementation Period](#).

The Planning Process Required by the Regional Haze Rule

The Regional Haze Rule sets up a multi-step process to improve visibility. The rule divides the process into ten-year planning periods. During each period, states undertake a series of steps to achieve gradual improvement in visibility.

The current planning period is an exception to the ten-year rule. It begins in 2021 and ends in 2028. EPA anticipates that later planning periods will resume the normal ten-year interval. By the time the final planning period ends, in 2064, EPA's goal is for visibility to be restored to what state and federal planners agree is natural for each Class I area.

This requires estimating emissions from natural sources, emissions from anthropogenic (human-related) sources, and amounts of pollution which are beyond the control of states (such as international emissions, and some transportation-related emissions).

Before each ten-year planning period begins, every state must complete a series of steps:

1. States review the data in the IMPROVE monitoring network, which measures the visibility-impairing pollutant concentrations at a given Class I area;
2. States calculate the amount of air pollutants known to contribute to poor visibility that is emitted within their boundaries from different sources;
3. States analyze this data on visibility and pollutants to identify

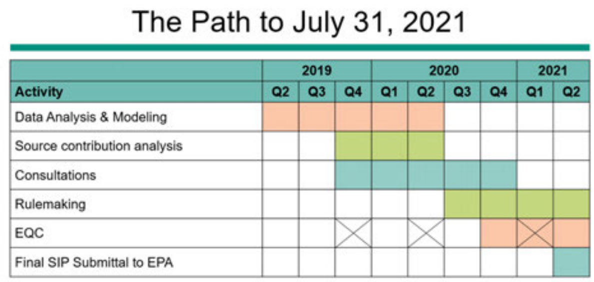
pollution sources likely contributing to visibility problems at particular areas, both inside their own borders and in other states;

4. Each state identifies reasonable pollution control methods that will reduce emissions to improve visibility;
5. Regional technical experts use computer modeling to project how much the identified pollution control measures are expected to improve visibility at each Class I area over ten years;
6. Throughout the plan development, states consult with the Federal Land Managers of the Class I areas that states' regulatory actions are intended to benefit, and then ask the Federal Land Managers for a formal review of the plan before it is released to the public for final review.
7. States adopt plans to implement the identified pollution control methods, make them legally binding, and work to achieve the projected ten-year visibility improvement at each area; and
8. States report to the public and to EPA regarding what the visibility trends have been and the improvements to visibility that are expected due to the adopted pollution control techniques.

Timeline of Activities

DEQ works with the Western Regional Air Partnership Regional Haze Program Working Group to perform the analyses and coordinate activities among western states. Data analysis and modeling runs are expected to be completed by the end of the second quarter of 2020. Source contribution analysis is happening concurrently during that period.

Consultations are starting in late 2019 and should happen throughout the process through to the end, in July 2021. DEQ expects rulemaking to begin in mid to late 2020, with public comment taking place in late 2020 and/or early 2021. The final State Implementation Plan is due to EPA on or before July 31, 2021.



Alternative formats

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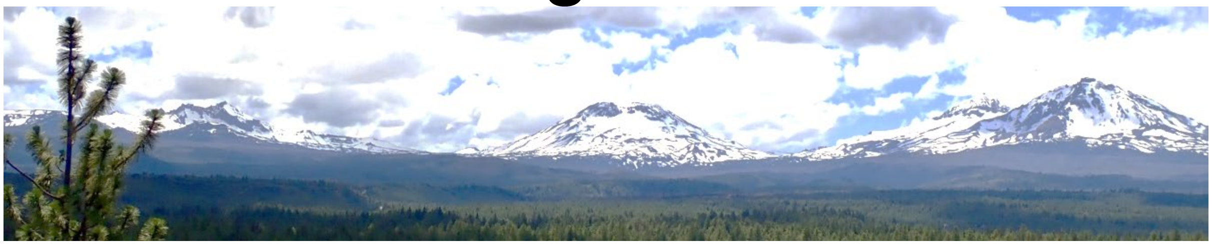
Fact Sheet

Overview of Regional Haze



Three Sisters Wilderness.

State of Oregon Department of Environmental Quality

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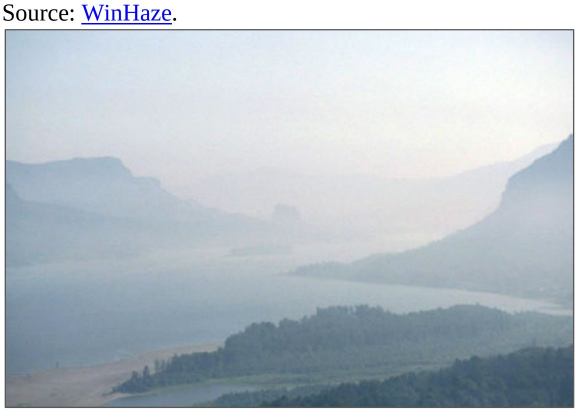
What is regional haze?

Regional haze is a term that EPA uses to refer to visibility impairment at designated national parks and wilderness areas caused by air pollution from different sources over a wide geographic area. EPA defines regional haze as different from visibility impairment caused by a single source at a single park or wilderness area.

Visibility in the regional haze program is measured using deciviews, which is a measure of the loss of light. The lower the number of deciviews, the clearer the day.

Looking east from Vista House, Columbia River Gorge, good visibility (9 deciview impairment, over 100 miles visibility). Source: [WinHaze].

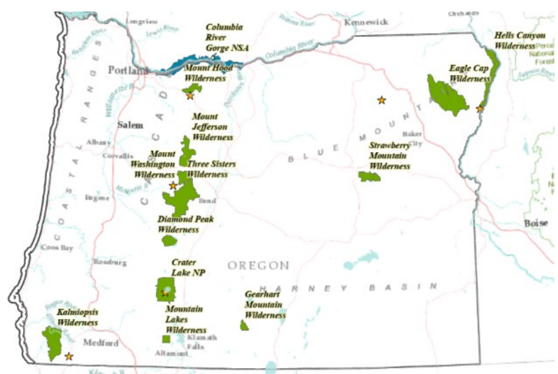


Looking east from Vista House, Columbia River Gorge, poor visibility (23 deciview impairment, less than 25 miles visibility). Source: WinHaze

What are the designated parks and wilderness areas where visibility is impaired by regional haze?

EPA refers to these designated parks and wilderness areas as "Mandatory Federal Class 1 Areas," which are referred to as Class 1 Areas. There are 156 Class I Areas listed in federal regulations. You can see the list at https://www.epa.gov/visibility/list-areas-protected-regional-haze-program.

Oregon has 12 Class I Areas. We also include the Columbia River Gorge National Scenic Area in our Regional Haze planning processes.



Map of Oregon's 12 Class I Areas (green) and the Columbia River Gorge National Scenic Area.

What causes regional haze?

Regional haze is caused by air pollution made up of particles that scatter sunlight, blurring visibility over distances visible to the human eye. The particles that cause this effect are from both particles and gasses emitted by human activity and natural events.

In Oregon, stationary sources, motor vehicles, agriculture and dairies, prescribed burning, agricultural field burning, and wintertime wood smoke are all significant sources of haze-forming pollutants. Natural events, such as wildfires, volcanic activity, and high winds can put particles into the atmosphere that also decrease visibility.

What does the federal government do to try to alleviate regional haze?

The federal Clean Air Act mandates that EPA issue regulations to improve visibility in Class 1 Areas, and in 1999, EPA issued the Regional Haze Rule. These regulations require states to submit plans to EPA, which must do three things:

- The plans must show which Class 1 Areas have visibility that's affected by the air pollutant emissions from that state, whether those Areas are in the state or beyond its borders.
- The plans must show reasonable pollution control measures the state will put in place to reduce the state's emissions from human activity that affects visibility at Class 1 Areas. The plans do not address emissions from natural events beyond human control.
- The plans must show how much visibility improvement is expected to result from the pollution control measures. The federal regulations on Regional Haze require that states evaluate progress in improving visibility conditions in Class 1 Areas relative to the rate of progress needed to achieve "natural conditions" by the 2064 benchmark.

How do we know how much visibility impairment exists at a Class 1 Area?

Air quality monitors are positioned in or near each Class 1 Area. These monitors measure the amount of visibility impairing particles in the air – that is, how much pollution is in the air that keeps people from seeing natural vistas clearly. This nationwide network of monitors is called the IMPROVE (**I**nteragency **M**onitoring of **PRO**tected **V**isual **E**nvironments) network. IMPROVE is managed and operated by a committee of federal agencies, including EPA and the various land management agencies, as well as organizations that represent state regulatory agencies. More information on IMPROVE is available at http://vista.cira.colostate.edu/Improve/.

How do we find the source of visibility impairing pollutants?

Federal and state air quality planners, working with federal land managers, perform highly technical analyses to answer that question. In part, they do this by identifying air pollutant emission sources in the region around a Class 1 Area. For each source, planners and land managers measure the amount of air pollutants emitted that are known to contribute to visibility impairment. They use state of the art computer models to identify where these pollutants are traveling, taking into account things like:

- the type of emission source (for example, a power plant versus a wildfire);
- the kind of pollutant;
- wind and temperature conditions;
- how different pollutants interact with each other in the atmosphere;
- how pollution travels across state boundaries; and
- how pollution is transported into the United States from outside U.S. borders.

Alternative formats

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.1

Sierra Club Data Request 1.1

Refer to the Direct Testimony of Rick Link, page 86 at 26 through page 87 at 2. "PacifiCorp conducted its economic analysis as part of its 2013 IRP. PacifiCorp decided in May 2013 to move forward with SCR emissions control systems for Jim Bridger Units 3 and 4 based on this analysis."

(a) State the date on which the Company decided that the 2013 IRP provided sufficient information for the Company to decide to "move forward" with SCRs at Jim Bridger 3 and 4.

(b) Provide all correspondence, memos, orders, decision documents, directives, or the like by PacifiCorp management during or around May 2013 documenting PacifiCorp's decision "to move forward" with SCR emissions control systems.

(c) Confirm or deny: the May 2013 directive "to move forward" with the SCR systems included signing a Limited Notice to Proceed (LNTP) with the contractors of the SCR systems. If denied, identify and produce the directive the Company relied on to make the decision to "move forward."

(d) Provide all correspondence, orders, memos, decision documents, directives, or the like by PacifiCorp management during or around May 2013 documenting the fact that the decision to proceed with the SCR projects was based on PacifiCorp's 2013 IRP.

(e) Confirm or deny: PacifiCorp filed a request for Certificate of Public Convenience and Necessity (CPCN) for the SCRs at Jim Bridger in Wyoming Public Service Commission (Wyoming PSC) Docket No. 20000-418-EA-12.

(f) Confirm or deny: the May 2013 directive "to move forward" with the SCR systems followed approval of the CPCN by the Wyoming PSC.

(g) Provide the unredacted direct and rebuttal testimonies of Mr. Rick Link and Mr. Chad Teply in Wyoming Docket No. 20000-418-EA-12 with respect to the Bridger SCRs.

(h) Confirm or deny: the CPCN application in Wyoming Docket No. 20000-418-EA-12 was based on an Official Forward Price Curve (OFPC) dated December 2011.

Response to Sierra Club Data Request 1.1

UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.1

(a) The decision to move forward with the installation of selective catalytic reduction (SCR) emissions control systems was finalized with the approval of an appropriation approval request (APR) on May 30, 2013.

(b) Please refer to Confidential Attachment SC 1.1-1 which provides the following key PacifiCorp decision documents:

1. Confidential Project Proposal – APR 10003396, Jim Bridger Unit 3 SCR System Implementation Phase, May 20, 2013.

2. Confidential Project Proposal – APR 10003398, Jim Bridger Unit 4 SCR System Implementation Phase, May 20, 2013.

3. Confidential Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR Systems Approval Request, May 22, 2013.

4. Confidential Letter to Idaho Power Company, June 5, 2013.

(c) Confirmed. A limited notice to proceed concept was included in its engineer, procure, and construct contract for the Jim Bridger Unit 3 and Jim Bridger 4 SCR projects.

(d) Please refer to the company’s response to subpart (b) above. In addition, please refer to the company’s response to Sierra Club Data Request 1.2 subpart (b).

(e) Confirmed. PacifiCorp filed a request for a certificate of public convenience and necessity (CPCN) for the SCRs at Jim Bridger Unit 3 and Jim Bridger Unit 4 with the Wyoming Public Service Commission (WPSC) in Docket 20000-418-EA-12.

(f) Confirmed. The May 2013 directive “to move forward” with the SCR systems followed the approval of the CPCN by the WPSC in Docket 20000-418-EA-12. Please refer to Attachment Sierra Club 1.1-2 which provides a copy of the WPSC’s order dated May 29, 2013.

(g) PacifiCorp objects to this data request on the grounds that it is unduly burdensome for it to provide the requested documents given that the company is informed and believes that the information sought in the data request may already be in the possession of Sierra Club due to their participation in the out of state proceeding. If Sierra Club seeks to introduce confidential material from an out of state proceeding in this case, PacifiCorp urges Sierra Club to meet and confer with it to discuss the intended use of such documents. PacifiCorp expressly reserves all its rights to object to the introduction of such confidential material from out of state proceedings on all appropriate grounds.

(h) Yes, the CPCN application in Wyoming (Docket 20000-418-EA-12) used the December 2011 official forward price curve for the base case. Please refer to the direct testimony Rick T. Link, specifically Confidential Exhibit PAC/708. There were eight other price curves of the same vintage (low gas $16 carbon dioxide ($CO_2$,) high gas $16 CO_2, base gas $0 CO_2, base gas $34 CO_2, low gas $34 CO_2, high gas $0 CO_2) were used in the Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR analysis to provide a range of results.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

June 2020 Economic and Revenue Forecast

May 20th, 2020

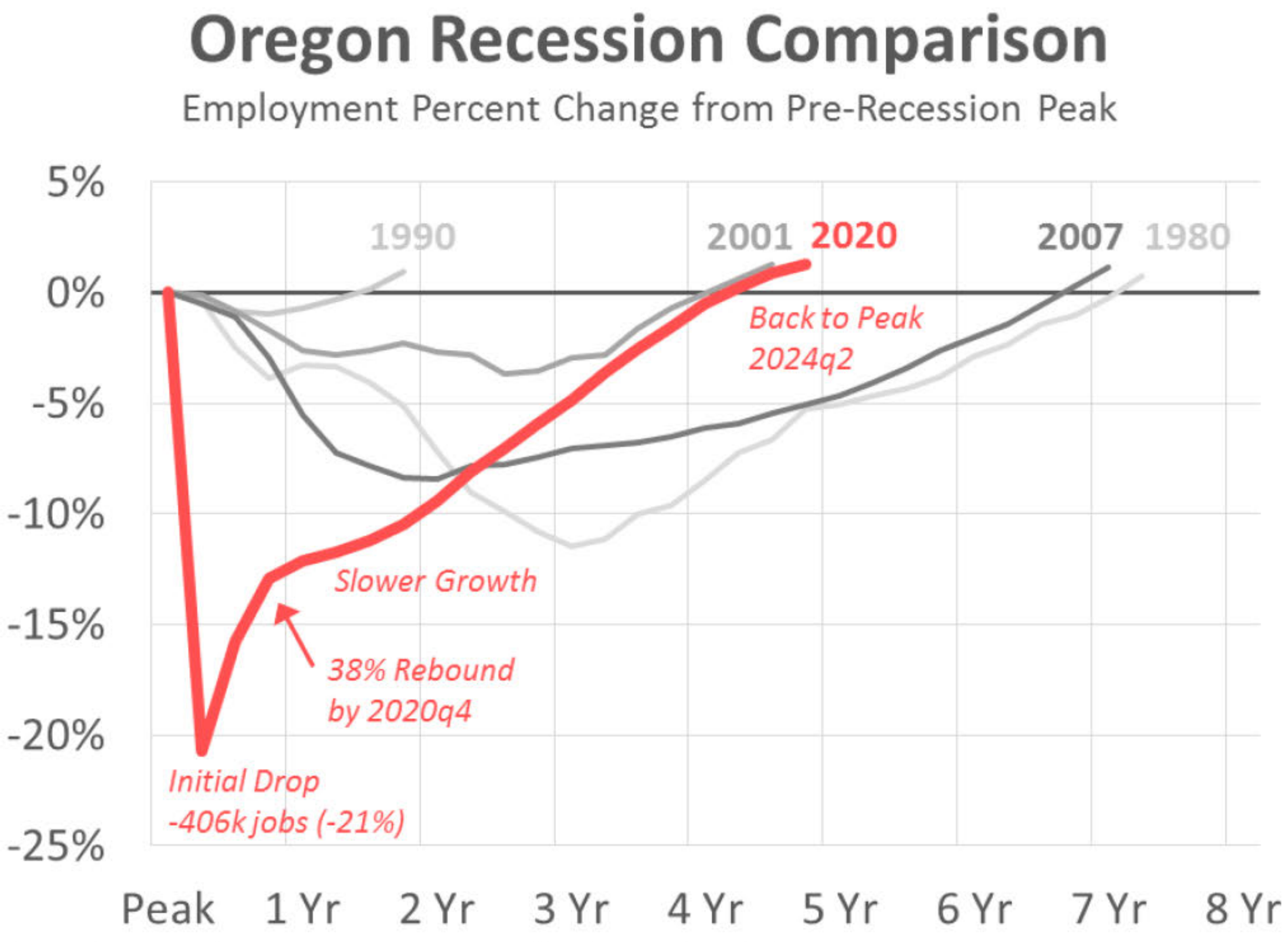
Oregon Office of Economic Analysis
Mark McMullen
Josh Lehner

Economic Outlook

Health Assumptions

- Uncertainty abounds. Our office is translating a public health crisis into an economic and revenue forecast. Two key health assumptions in the baseline:
  - Social distancing policies begin lifting this summer. Phase 1 reopening is just a first step.
  - Health crisis wanes by end of 2021 due to some available treatment or vaccine

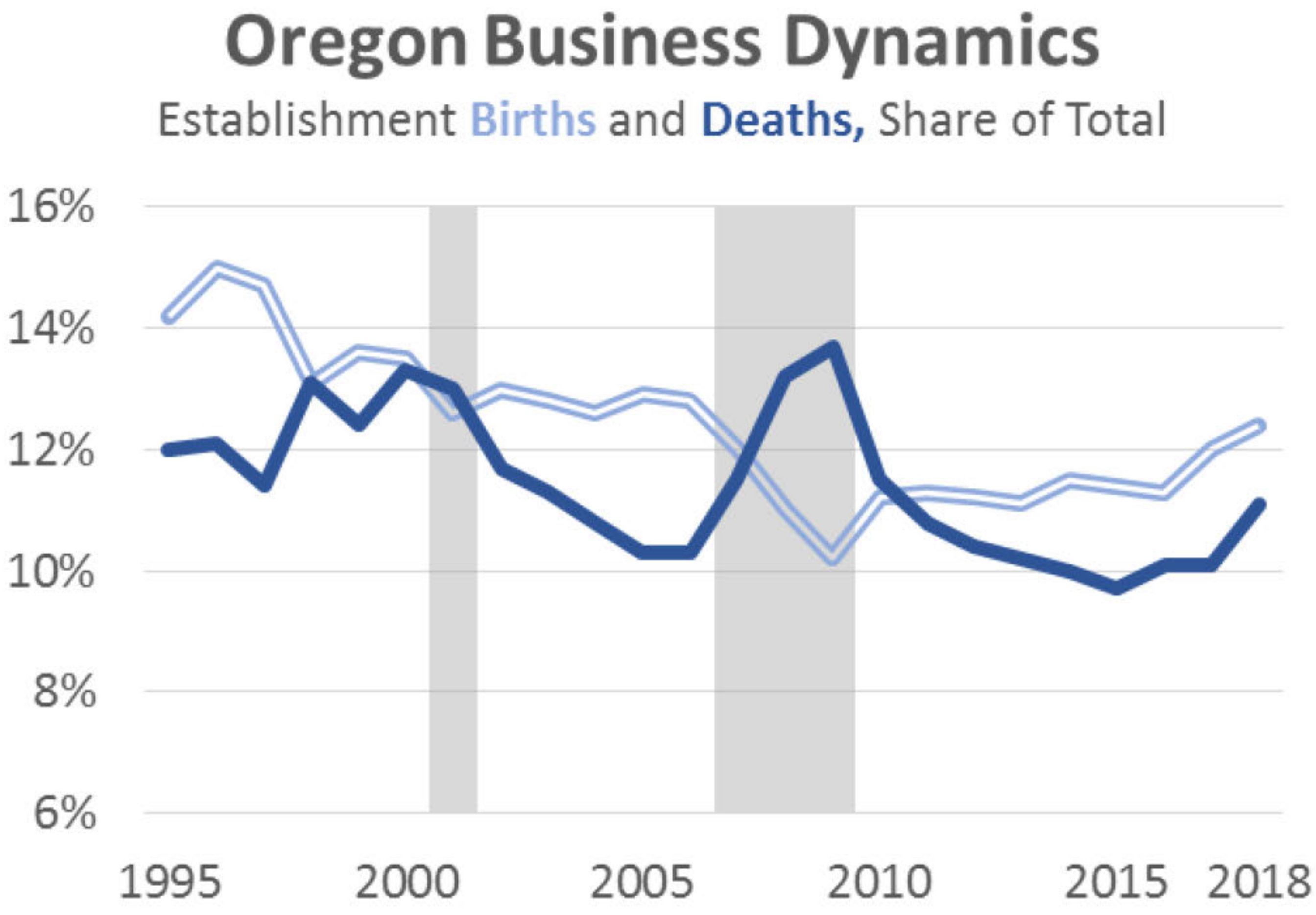
It Takes Years to Recover from Severe Recessions



Source: Oregon Employment Department, Oregon Office of Economic Analysis

- When restrictions lift, strong initial rebound, but incomplete
- Slower growth next year due to uncertainty over virus and income losses
- Once medical treatment widely available, stronger recovery expected
- Economy returns to health by mid-decade

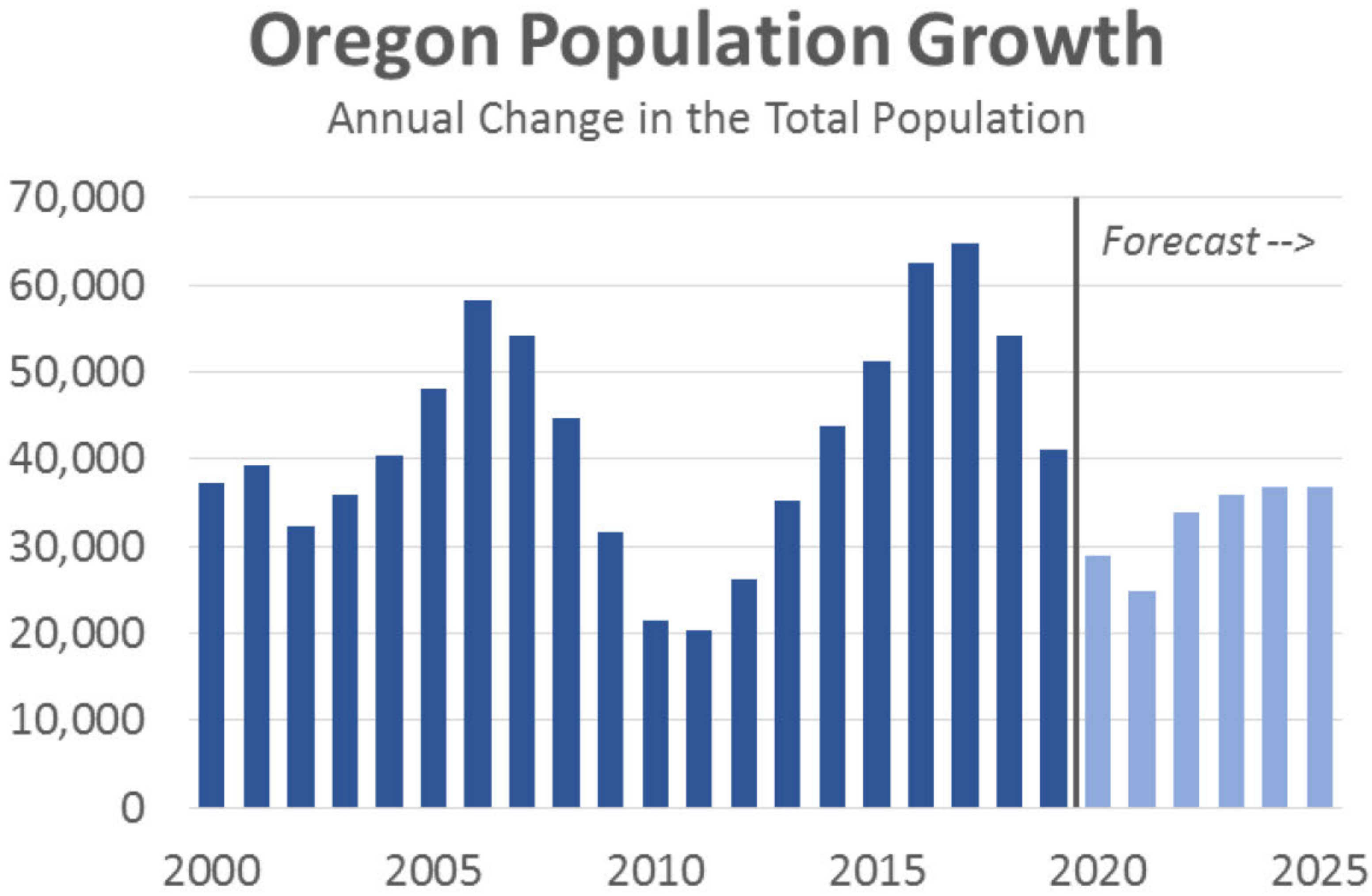
Permanent Damage & Federal Policy



Latest Data: 2018 | Source: BLS, Oregon Office of Economic Analysis

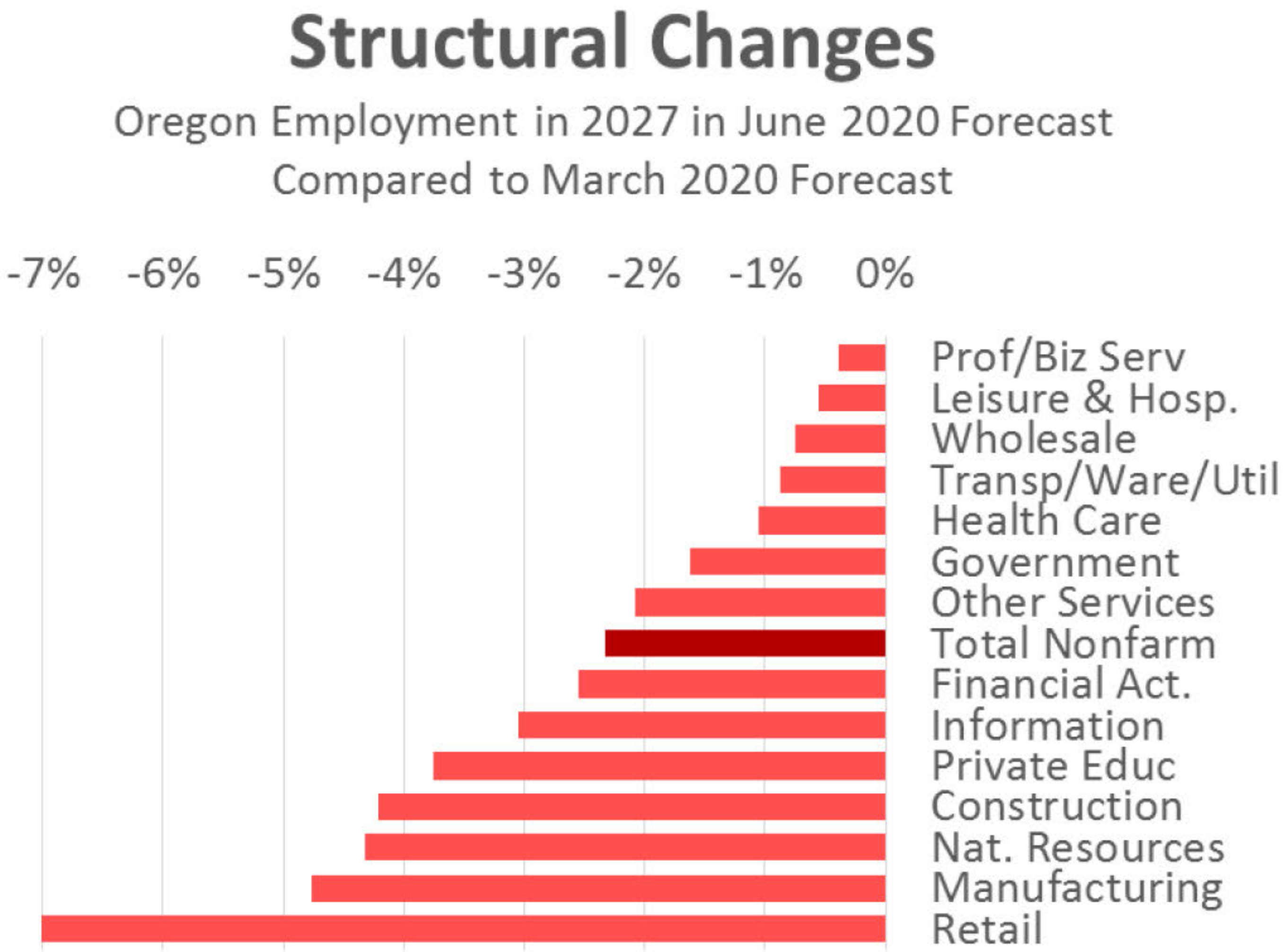
- Recovery Rebates
  - Nearly $4b to Oregon households
- Unemployment Insurance
  - Nearly $7b total given recession and expanded program
- Paycheck Protection Program (PPP)
  - 49,900 small Oregon businesses have been approved for $6.83b in loans through 5/1/2020

Migration is Pro-cyclical



- Near Term: no one is moving during the pandemic
- Medium Term: migration reduced due to recession
- Long Term: Oregon's ability to attract and retain working-age households is expected to remain intact

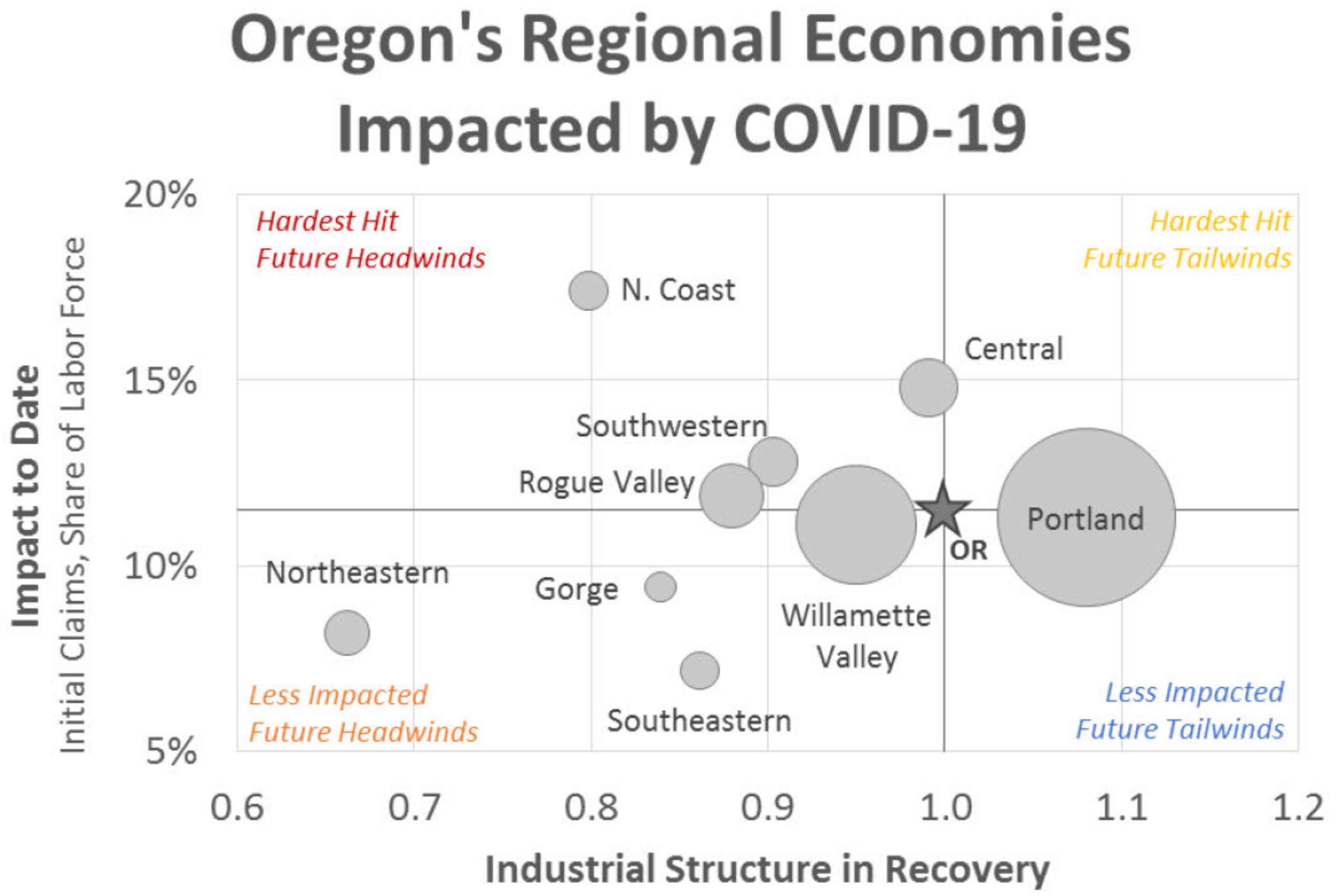
Industrial Structure Likely to Change



Source: Oregon Office of Economic Analysis

- Oregon's long-run trajectory is lower due to the recession
  - Fewer jobs, less income, smaller population
- Largest relative changes expected in goods-producing industries plus retail

Regional Outlook: Recession Severity and Future Growth

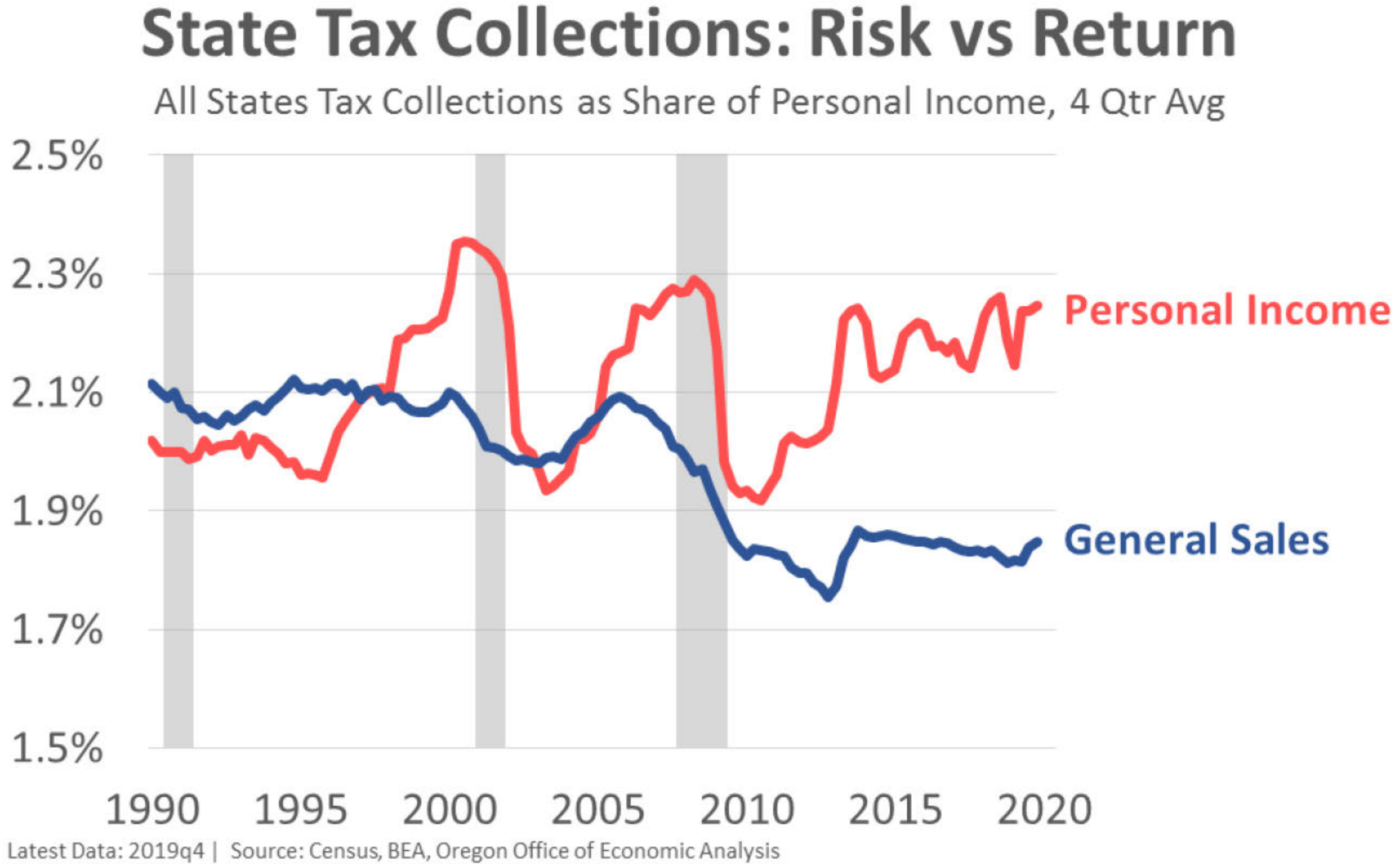


- Initial impacts largest in tourism-reliant regions
- Future headwinds based on larger reliance on goods-producers, and fewer office-based jobs that are concentrated in metro areas

Impact to Date: Number of initial claims 3/15 - 5/9 above baseline as share of labor force. Industrial Structure: impact of industry mix on job growth through 2027 using statewide industry growth rates. | Source: BLS. Oregon Employment Dept, Oregon Office of Econ Analysis

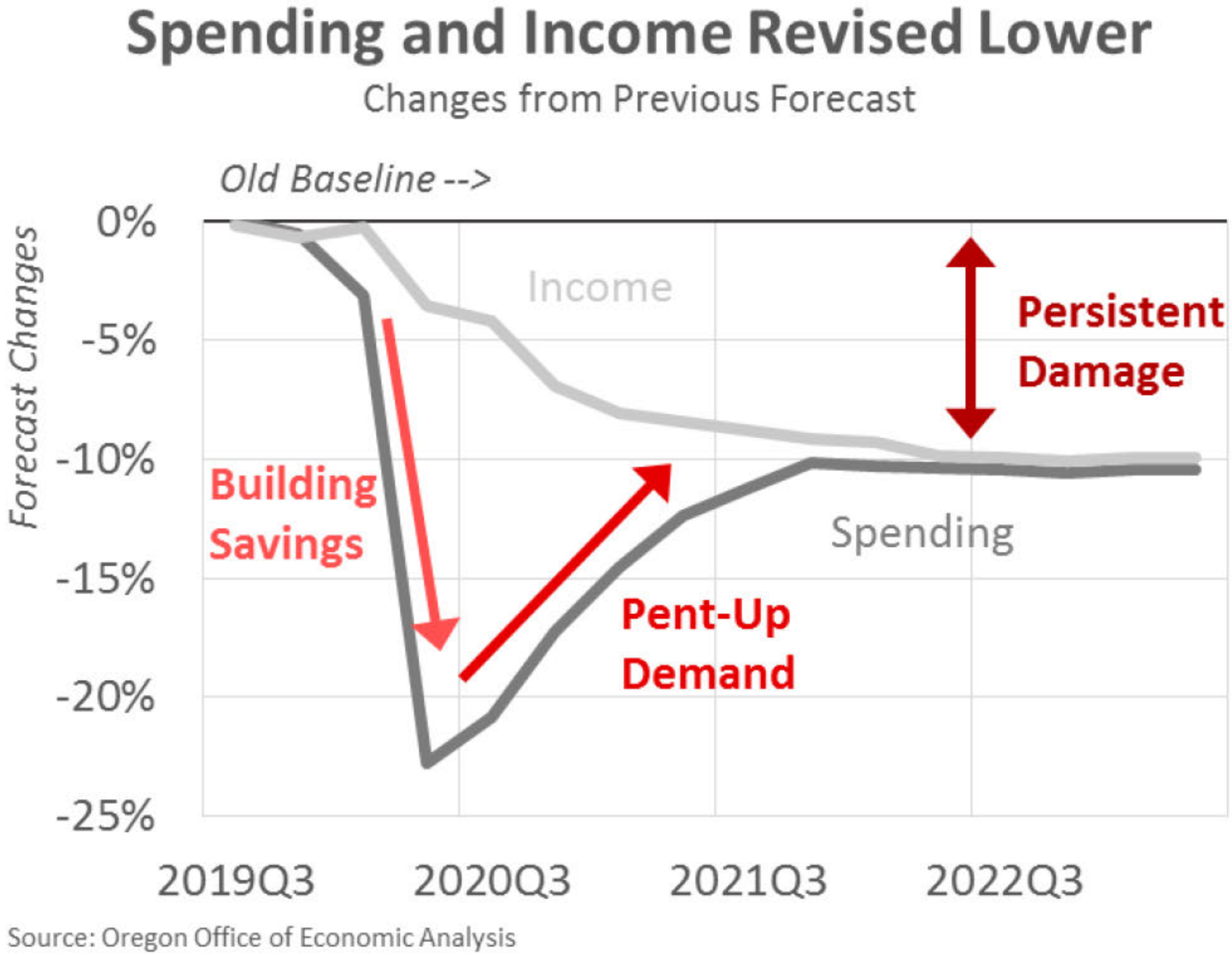
Revenue Outlook

Mix of Tax Instruments Matters



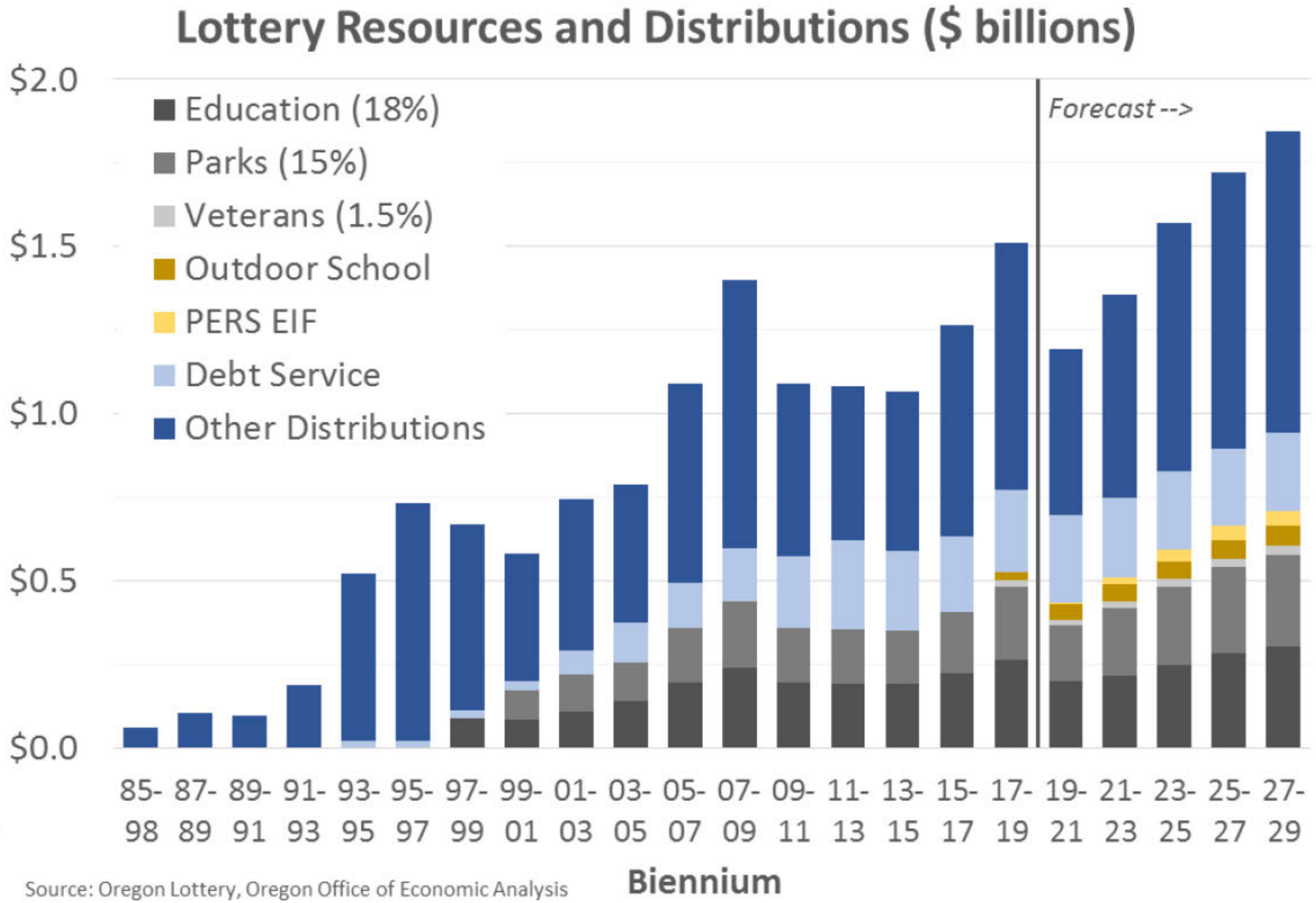
- Oregon's reliance on personal and corporate income taxes has made its revenues more volatile than in most states
- This recession may be different given the oversized impact on spending
- Oregon's revenue system has become far more dependent on sales in recent years: (CAT, lodging, gasoline, vehicle privilege, video lottery, marijuana)

Oregon revenues have never been more exposed to consumer spending, Part 1



	Corporate Activity Tax Revenue Changes ($ million)
2019-21	-$414.1
2021-23	-$599.0
2023-25	-$489.1

Oregon revenues have never been more exposed to consumer spending, Part 2



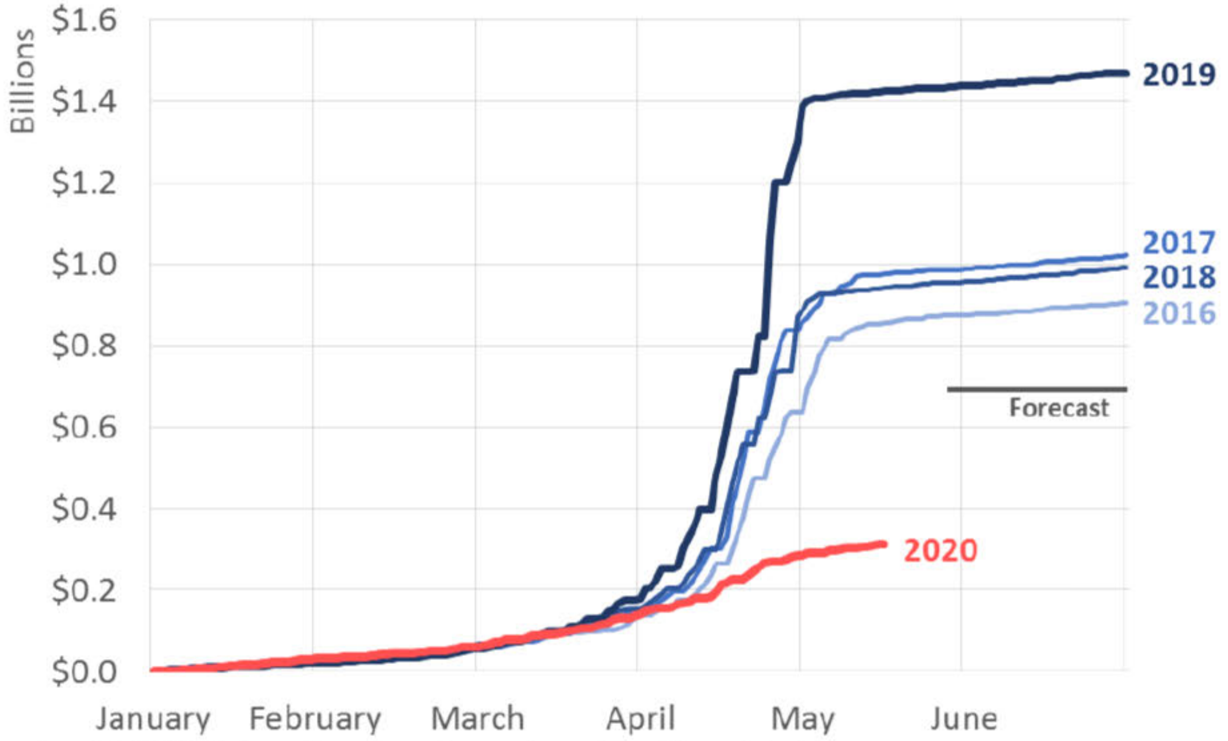
Source: Oregon Lottery, Oregon Office of Economic Analysis

- Lower revenues today due to social distancing
- There is pent-up demand for gaming
- Long-run growth lowered due to smaller economy and less personal income

COVID-19 Messes with Tax Season

Year-End Payments Delayed

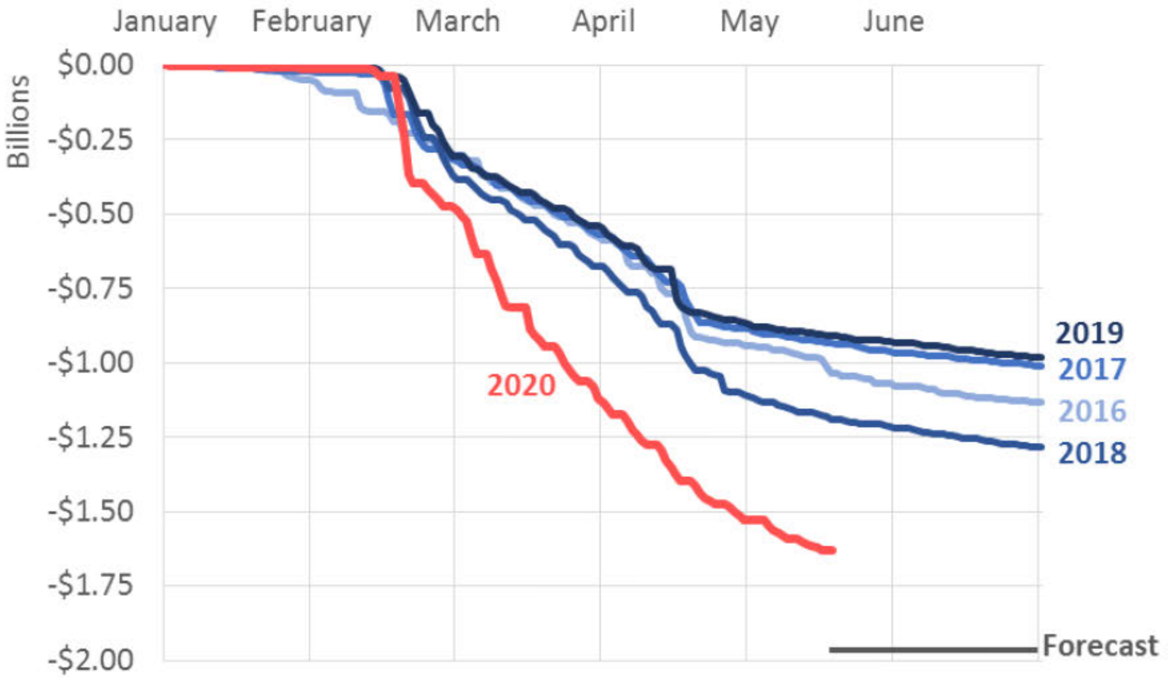
Oregon Cumulative Personal Income Tax Payments



Latest Data: May 15, 2020 | Source: Oregon Dept of Revenue, Oregon Office of Economic Analysis

Refunds Probably Still on Track

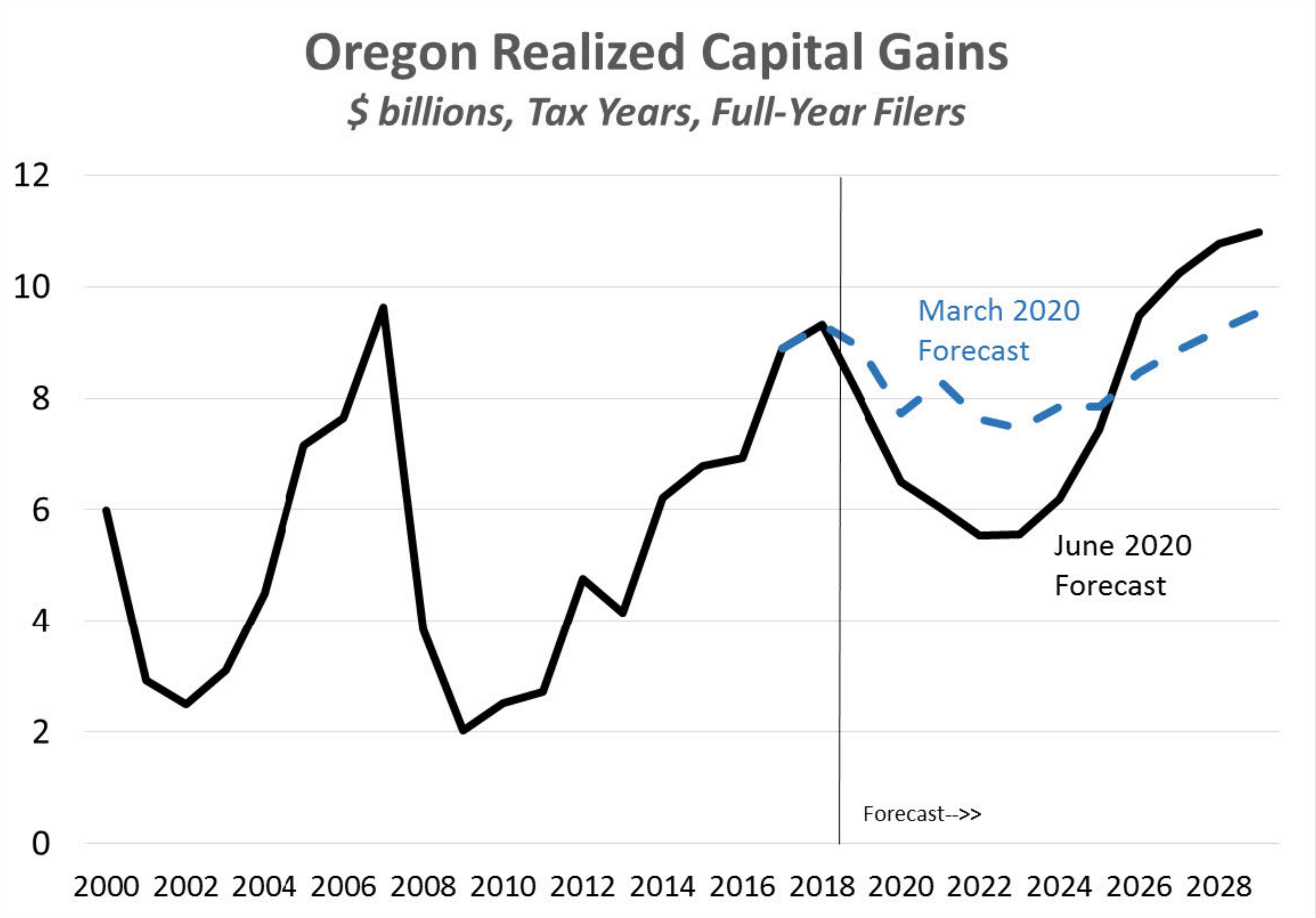
Personal Income Tax Refunds, Cumulative



Latest Data: May 15, 2020 | Source: Oregon Dept of Revenue, Oregon Office of Economic Analysis

Oregon Office of
Economic Analysis

Volatile Income Steams



- Income Tax Volatility is led by large swings in business and investment income
- Some weakening of capital gains was expected prior to the market correction
- IHS vendor forecast incorporates fast recoveries for profits and equity markets
- Stock market correction is expected to be less than half as deep and less than half as long as in 2007

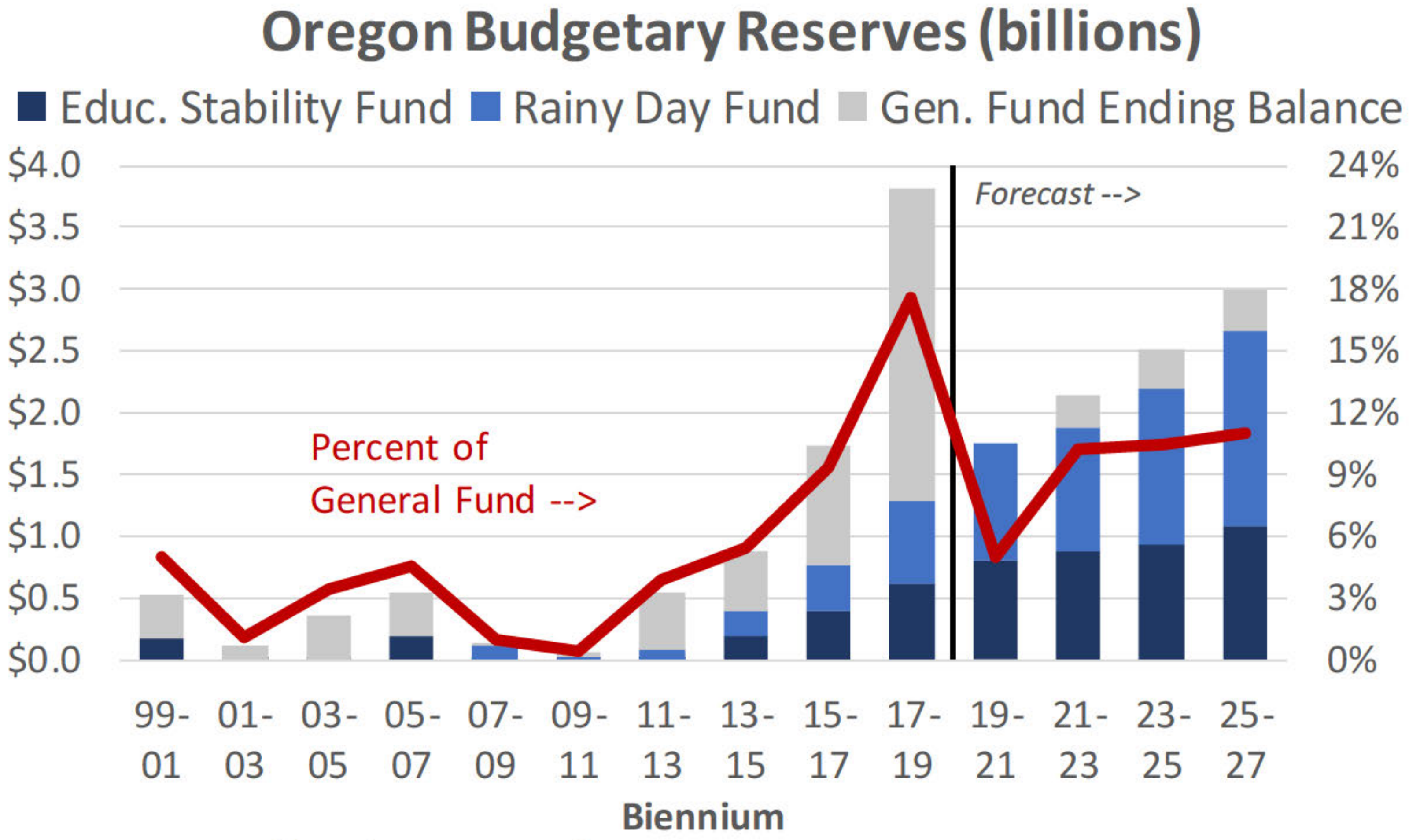
Revenue bottom line

General Fund Revenues	Biennium ($ Million)		
	2019-21	2021-23	2023-25
Personal Income Taxes	-1,588	-3,231	-2,429
Corporate Income Taxes	-233	-137	-118
Other	-108	-152	-140
Total	**-1,929**	**-3,520**	**-2,687**

Other Revenues	Biennium ($ Million)		
	2019-21	2021-23	2023-25
Lottery	-364	-260	-187
Corporate Activity Tax	-414	-599	-489
Marijuana Tax	9	-5	-18
Total	**-769**	**-864**	**-694**

	Biennium ($ Million)		
	2019-21	2021-23	2023-25
Total Sum	**-2,698**	**-4,384**	**-3,381**

Sizable Reserves Will Help Some



Source: Oregon Office of Economic Analysis

Effective Reserves ($ millions)

	April 2020	*End 2019-21*
ESF	$708	$800
RDF	$878	$949
Reserves	$1,586	$1,750
% of GF	8.1%	9.0%

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UE 374/PacifiCorp
June 1, 2020
OPUC Data Request 558

OPUC Data Request 558

Regarding Pryor Mountain's 2050 terminal value discussed at Exhibit PAC/700 Link/70-71, please provide the dollar amount of the 2050 terminal value associated with the retained site.

Confidential Response to OPUC Data Request 558

Terminal value (nominal) 2050 after removal cost = **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

Terminal value discounted to 2019 after removal cost = **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

OPENING TESTIMONY OF THE

OREGON CITIZENS' UTILITY BOARD

RESIDENTIAL RATE DESIGN AND TIME OF USE PILOT

EXHIBIT 200

I. INTRODUCTION AND SUMMARY

Q. Please state your names, occupations, and business addresses.

A. My name is Sudeshna Pal. I am an Economist employed by the Oregon Citizens' Utility Board (CUB). My name is William Gehrke. I am an Economist employed by CUB. Our business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. Sudeshna Pal's witness qualification statement is found in exhibit CUB/201. William Gehrke's witness qualification statement is found in exhibit CUB/202.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to evaluate the residential rate design changes and residential Time of Use Pilot (TOU) program which PacifiCorp is proposing in this general rate case (GRC) proceeding.

Q. Please summarize your testimony.

A. The first part of our testimony examines the proposed increase in basic charges from the current $9.50 per month to $12 per month for single family homes and the concurrent Company plan to flatten its current tiered rate structure. CUB finds the proposed rate structure unduly burdensome on low usage single family residential customers. CUB recommends the Commission reject the Company's proposal of raising the basic charge for customers who reside in single family houses.

The second part of our testimony examines the proposed TOU Pilot for residential customers. CUB has some issues with the rate design proposed in the pilot along with the design of the pilot itself that could adversely affect the learning outcomes from the pilot. In response to the proposed schedule 6 program, CUB recommended an alternative time of use program, with a shorter peak period for residential customers.

II. RESIDENTIAL RATE DESIGN

Q. What changes is the Company proposing in its current residential rate structure?

A. The Company has proposed to increase the Oregon residential basic charge from the existing $9.50 to $12 for single-family residential customers and decrease the existing basic charge to $7 for multi-family residential customers. The Company also proposed to decrease the differential between its two inclining tier charges for residential customers by 50%.[1]

Q. What factors are driving PacifiCorp's proposed changes to the residential basic charge?

A. The basic charge is designed to cover the monthly fixed costs of serving a single residential customer. PacifiCorp states that the new charge more closely reflects the true value of billing and commitment costs including meters, service drops, line transformers, poles and conductors.[2] The Company also explains that distance between customers and the distribution substation serving these customers is a key

[1] UE 374 – PAC/1400/Meredith/28, lines 11-17.
[2] UE 374 – PAC/1400/Meredith/30, lines 3-21.

driver behind the marginal commitment costs of poles and conductors.[3] The Company argues that this cost is inadvertently high for single-family home customers who tend to be located further away from the substation as opposed to multi-family dwellers, most of whom are located closer to substations.[4] Based on this, the Company proposed the changes in its basic charge.

Q. Why does the Company want to reduce the rate differential between the two tiers in its existing inclining block prices, or, in other words, flatten the tiered rate structure?

A. The Company points out several reasons for this. First, PAC argues that tiered rates have the potential to create incentives to switch to natural gas, and discourage customers from buying electric vehicles.[5] Second, the Company posits tiered rates can be unfair as these unduly penalize customers who are more likely to use electric heat and benefit customers that use natural gas or wood stove for heating. Third, the Company found that most of its customers did not understand the tiered rates and their electricity usage was unaffected by the rate differential. Finally, it is the timing of energy usage rather than the total overall usage that affects the utility's cost of providing service, making less economic sense to have the tiers in place.

Q. Does CUB's have a response to any of the Company's arguments around tiered rate structure?

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[3] *Id.*
[4] *Id.*
[5] UE 374 – PAC/1400/Meredith/36, lines 7-21.

A. Yes. The Company argues that tiered rates have the potential to incentivize fuel switching. Fuel switching has been driven by decreased natural gas commodity costs. CUB Exhibit 203 shows that, since 2009, natural gas prices at the Henry Hub has decreased. Henry Hub is a general accepted national price benchmark for the North American natural gas market. Similar trends are visible in the price at major natural gas supply basins in the Pacific Northwest such as AECO and Sumas. CUB Exhibit 204 also calculates a heating operating cost comparison for electric heat versus natural gas heating. The evidence indicates that natural gas is cheaper to operate for heating than electric heat, which is driving fuel switching. PacifiCorp is at a competitive disadvantage compared to LDCs due to low gas commodity costs.

The Company also argues that tiered rates discourage electric vehicle adoption. The fuel cost of electric vehicles at Pacific Power's highest tier for residential customer is still lower than the fuel cost of an internal combustion engine.[6] CUB does not agree with the Company that tiered rates make residential transportation electrification significantly less attractive.

Q. What is CUB's position on the proposed changes in PacifiCorp's residential structure including the changes in basic or customer charge and reducing the rate differential between the tiers?

A. CUB supports the Company's proposal to reduce the basic or customer charge for multi-family home dwellers based on the difference between the unit marginal cost

[6] CUB Exhibit 205.

of transformers for single family and multifamily customers. However, CUB does not support the increase in customer charge for single-family home customers.

Q. Since CUB is not recommending an increase to the single-family customer charge, how should that revenue be collected from residential customers?

A. CUB recommends the revenue that would be collected from an increase in customer charge for single-family home residential customers be collected from all residential customers in the form of an increased volumetric distribution charge under Schedule 4.

Q. Explain why CUB does not support the increase in basic charges for single family home customers.

A. There are several reasons why CUB is not supportive of the proposed increase in basic charges.

First, a higher basic charge for single family home customers coupled with a flatter tiered block would significantly increase a low usage single family customer's total bill. CUB Exhibit 206 is a chart comparing impact of the Company's rate proposal on single family home residential customers' bills. CUB Exhibit 207 is a chart comparing impact of the Company's rate proposal on single family home residential customers' bills. CUB's proposal to maintain the single-family customer charge would provide a gradual increase across usage levels to single family home residential customers rates.

Additionally, PacifiCorp is a six-state utility. Increasing the basic charge in Oregon would be inconsistent with the Company's treatment of customers in other states. Table 1 in CUB Exhibit 208 shows basic charges in all six PacifiCorp states. The median basic charge across those states is $7.48. This shows Oregon customers are already on the higher end of the spectrum within the Company's system. CUB Exhibit 209 shows a survey of residential customer chargers for major utilities in the Pacific Northwest. The Company's proposal would give Pacific Power Oregon single family customers the highest customer charge among major utilities in the region.

Also, at a more fundamental level, CUB believes that customer charge for residential customers should include the cost of the ratepayer-funded investments required to serve a single residential customer. These costs are related service drop, the portion of the meter directly related to billing for usage, and the costs of billing and collection.

Q. Does CUB support the Company's proposal to flattening its tiered rate structure?

A. CUB supports flattening the cost to customers between tiered rates, but only if it is not done in conjunction with an increased basic charge. If the Company agrees to maintain the existing basic charge for residential customers, CUB would support the tiered rate structure proposal. A combination of a high basic charge and a low differential between the tiers could discourage energy conservation efforts on the customer side and significantly increase the monthly bill of low usage single-family home residential customers.

CUB also finds that evidence from the Company's 2017 survey and testimony supports the flattening of the tiered rate structure. Only 48 percent of customer were aware of the tiered rate structure. Of the 48 percent who were aware of the structure, 44 said that it did not impact electricity usage decisions.[7] Since a relatively low number of customers even know that a tiered rate structure exists, altering that structure would have a relatively low impact on customer behavior.

Q. Would CUB like to comment on customer bills in general?

A. Yes. In the future, CUB is interested in asking the Commission to open an investigation into electric utility customer bill design. CUB Exhibit 210 provides a sample residential bill from Pacific Power. For the average customer, Pacific Power's bills are difficult to follow and contain a laundry list of charges. CUB recognizes that there are various requirements imposed on Pacific Power regarding customer bill information, including the requirements imposed by SB 1149. However, CUB would like to see customer bills that are less dense that would enable residential customers to more easily distinguish and identify their volumetric rate and basic charge.

Q. What is CUB's recommendation regarding the proposed rate structure?

A. CUB recommends that the Commission reject the proposal to raise the basic charge for single-family home customers. CUB also recommends that the

[7] UE 374 – PAC/1400/Meredith/38, lines 13-15.

Commission approve the Company's proposal to flatten the tiers provided it is not accompanied by an increased basic charge.

II. RESIDENTIAL TIME OF USE PILOT

Q. What rates has PacifiCorp's proposed in its residential TOU Rate Pilot?

A. PacifiCorp has proposed creation of a new residential Time of Use (TOU) pilot, Schedule 6. The proposed Schedule 6 rates are presented below:

Table 1: PacifiCorp TOU Pilot Proposal[8]

Summer (July – September)	
On-Peak: 3pm-9pm	*Off-Peak: All Other Times*
17.917 cents per kWh	6.633 cents per kWh
Non-Summer/ Winter (October – June)	
On-Peak: 6am-8am, 5pm – 11pm	*Off Peak: All Other Times*
17.917 cents per kWh	6.633 cents per kWh

PacifiCorp plans to offer these rates to 5,000 residential customers on a first come, first served basis.

Q. What are some advantages and disadvantages of TOU rates?

Some of the advantages of having a TOU rate include shifting load away from peak hours to off peak hours saving the utility and customers on electricity costs. TOU rates are usually easy to understand due their simple design. These rates have the potential to encourage good electric vehicle charging behavior and allow

[8] UE 374 – PAC/1400/Meredith/41, lines 6-12.

utilities to manage load. Customers have incentives to charge their vehicle during off-peak hours.

TOU rates are, however, not dynamic. This means these rates or prices cannot be instantaneously established to reflect actual wholesale market prices or in reliability related conditions. Therefore, these rates might be less useful in addressing special events. Studies also show that TOU rates are not as effective as dynamic rate designs in shaving the energy consumption peaks.[9]

Q. What issues does CUB have regarding PacifiCorp's Proposed Schedule 6 TOU Pilot?

A. CUB addresses two main issues related to the proposed pilot. First, CUB discusses the rate design aspect of the proposed pilot. Second, CUB discusses the pilot design issues including setting clear pilot goals and participation selection. CUB believes that PacifiCorp could use lessons learned from similar pilots implemented by other electric companies, for instance, Portland General Electric (PGE) and others, to design an improved pilot that would yield results for the Company. CUB supports of TOU rates to the extent that these are customer friendly, easily understandable, and effective in reducing peak usage.

Q. Explain CUB's concerns with the proposed Schedule 6 Rate design?

[9] For a more detailed explanation of advantages and disadvantages of TOU rates, please refer to: Faruqui et. al, *Time-varying and Dynamic Rate Design,* Figure 3 (2012) *available at* https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

A. Schedule 6 characterizes a span of 6 hours a day (3pm-9pm) as Summer Peak and a span of 8 hours (6am-8am; 5pm-11pm) as Non-Summer or Winter peak. There are no allowances for weekends or holidays. Summer TOU rates are made effective for 3 months in a year while the winter rates apply to the remaining 9 months.

CUB would prefer to have TOU rates that have short peak periods and strong price signals. In the future, CUB would like to see pairing TOU rates implemented with access to enabling technologies such as smart thermostats and managed charging. CUB expands on each of these issues below.

Peak Period Duration: Longer peak periods impose an additional and unmeasured cost on customers defined as "hassle factor."[10] This refers to the inconvenience that customers must endure as they shift their energy usage from high cost to low cost periods. For example, a customer may have to wait several hours to run a dryer or dishwasher in order to avoid on-peak charges. Longer the high-cost or peak period, higher is the hassle factor. Customers are less likely to respond to these programs if the program hassle factor is too high, thereby rendering it ineffective.

[10] Faruqui et. al, *Time-varying and Dynamic Rate Design* (2012) *available at* https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

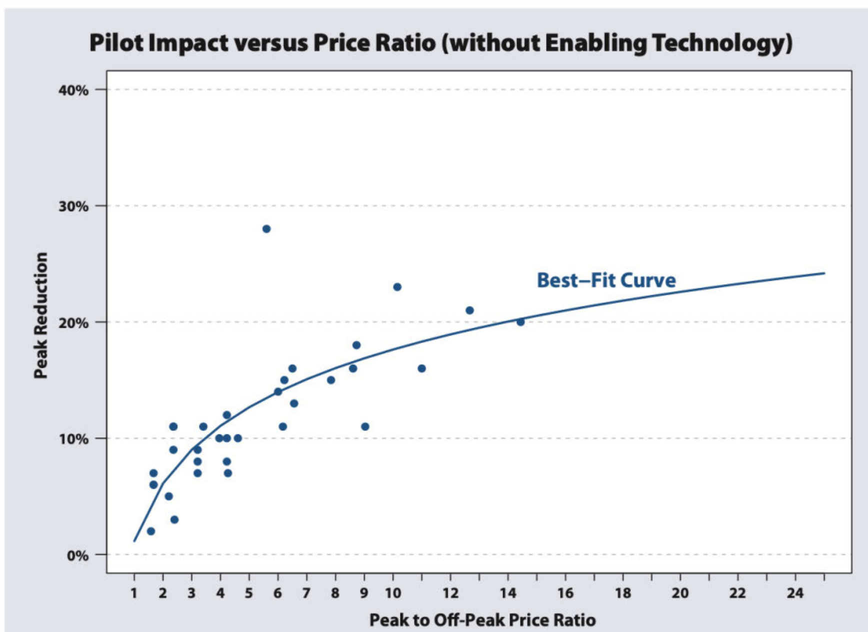
Additionally, having a morning peak (6am-8am) during winter months is especially burdensome for customers who use electric heating. In a typical winter, temperature drops in the nighttime. In order to maintain a livable temperature, customers must run electric heating in the morning during on-peak times. This issue is especially apparent in the more rural areas of PacifiCorp's Oregon service territory in which many customers live in poorly weatherized manufactured homes that are heated with electricity and subject to extreme climate variations. While CUB acknowledges that this is a voluntary TOU pilot program, CUB would prefer to have TOU program without a morning peak in the interest of higher customer satisfaction.

Importantly, PGE's TOU pilot evaluation outcomes provide valuable lessons for other electric companies including PacifiCorp. The PGE pilot evaluation shows that TOU rates with shorter peak periods (3pm – 8pm) during summer yielded grater savings than the rate schedule with a longer peak period, as well as higher customer satisfaction. PGE's customers also expressed much lower satisfaction for winter programs; winter TOU rates failed to produce statistically significant reductions in or shifts in peak-period loads. TOU rates that had both morning and evening peaks in winter adversely affected customer response and satisfaction levels.[11] CUB recommends a peak period of no longer than four hours.

[11] CUB Exhibit 204. See p. 7 of Evaluation Report, PGE's Flex Pricing and Behavioral Demand Response Pilot Program.

Strong Price Signal: A strong price signal results from a higher on-peak to off-peak price ratio. Studies show a positive correlation between peak to off-peak price ratios and energy savings. The following Figure 2 is from a Regulatory Assistance Project (RAP) study on a survey of 24 residential pricing pilots that were conducted by utilities in North America, Europe, and Australia between 1997-2011. The study shows that for pilots without enabling technology, customer response increases with an increase in the price-ratio, but at a decreasing rate.[12]

Figure 2



The above graph could be used to locate an optimum price ratio (provided it is economically meaningful). PacifiCorp is using a 2.7 ratio, which is on the lower end of the spectrum. It is possible that other higher and economically feasible price

[12] Faruqui et. al, *Time-varying and Dynamic Rate Design,* Figure 3 (2012) *available at* https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf.

ratios exist that would result in greater peak reduction for the Company. It is not clear to CUB how the Company arrived at the 2.7 ratio, other than knowing that this number is also used in the Company's Idaho TOU Schedule 36.[13]

Q. Explain CUB's concerns with the proposed residential TOU Pilot design?

A. A survey of TOU pilots from across the country and internationally shows that successful pilots have, among other things, well-defined goals and a good representation of its broader customer base among program participants.

It is not clear what specific purpose will be served by PacifiCorp's proposed residential TOU pilot. For instance, is PacifiCorp looking to save energy today or is this an experiment which, if successful, will be expanded to include all residential customers in Oregon? CUB would appreciate the Company providing clarity on this issue in subsequent testimony.

Q. What is CUB Schedule 6 pilot proposal?

A. CUB has an alternative to PAC's proposal that is more fully detailed on Table 2 on the following page. CUB has the following recommendations:

i. CUB's TOU pilot proposal would shorten the peak periods for both summer and non-winter seasons to the top four hours.[14] CUB's proposal would remove the morning peak periods from the non-summer season. CUB would like to see a short four-hour peak period, in order to reduce the hassle factor associated with a time of

[13] UE 374 – PAC/1400/Meredith/44, lines 1-4.
[14] UE 374 – PAC/1412/Meredith.

use program.[15] CUB would like the pilot program to have a higher peak to off peak price ratio, which is greater than 3. CUB's proposal would meet that goal.

ii. CUB's calculation of the proposed rate includes a decreased customer charge multi-family customers and $9.5 customer charge for single-family residential customers.

iii. CUB's proposal does not include tiered energy charges and does not make the weekends or holiday's off-peak.

iv. CUB wanted to propose a simple TOU pilot program. The peak for this program is four hours throughout the year and the peak is consistently in the evening during the day.

Details of CUB's TOU proposal can be found in the following Table 2.

Table 2: CUB TOU Pilot Proposal[16]

Summer (July – September)	
On-Peak: 4pm – 8pm	*Off-Peak: All Other Times*
23.552 cents per kWh	7.735 cents per kWh
Non-Summer/ Winter (October – June)	
On-Peak: 5pm – 9pm	*Off Peak: All Other Times*
23.552 cents per kWh	7.735 cents per kWh

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[15] CUB Exhibit 211.
[16] CUB Exhibit 212.

Q. Is CUB open to suggested changes around its alternative TOU proposal?

A. Yes. CUB's goal is to provide a successful pilot TOU program for residential customers. CUB is looking forward to engaging in conversations on TOU programs in settlement discussions.

Q. Besides its alternative proposal, what are CUB's recommendations for the proposed rate design in the Schedule 6 pilot?

A. CUB has the following recommendations:

i. PacifiCorp should shorten the peak periods for both summer and winter seasons, and, remove the morning peak periods from its winter rates.

ii. PacifiCorp should use lessons learned in similar pilots by other electric utilities serving similar residential customers, for example, PGE.

iii. PacifiCorp should evaluate a variety multiple peak to off-peak price ratios and pick the one that maximizes peak reduction while being economically meaningful.

iv. PacifiCorp should consider a hybrid TOU rate in which TOU rates are combined with Peak Time Rebates (PTR). CUB Exhibit 213 shows hourly residential on-peak energy consumption for summer and winter months. The graphs reveal that there is a considerable amount of variability in terms of hourly energy usage and several peak time events in which energy consumption exceeded 1,000,000 kWh on certain on-peak hours on certain days of the month. TOU rates would not address the special events. Therefore, CUB believes that a TOU-PTR combination will be more effective for this kind of a load profile. PGE's TOU pilot evaluation also finds that pairing TOU rates with a PTR could raise customer satisfaction and Flex event savings.[17]

Q. What is CUB's recommendation for the proposed Residential TOU Pilot?

A. CUB recommends that the Commission accept CUB's proposed TOU pilot program, or modify Pacific Power's program to have shorter peak pricing periods.

Q. Does this conclude your testimony?

A. Yes.

---

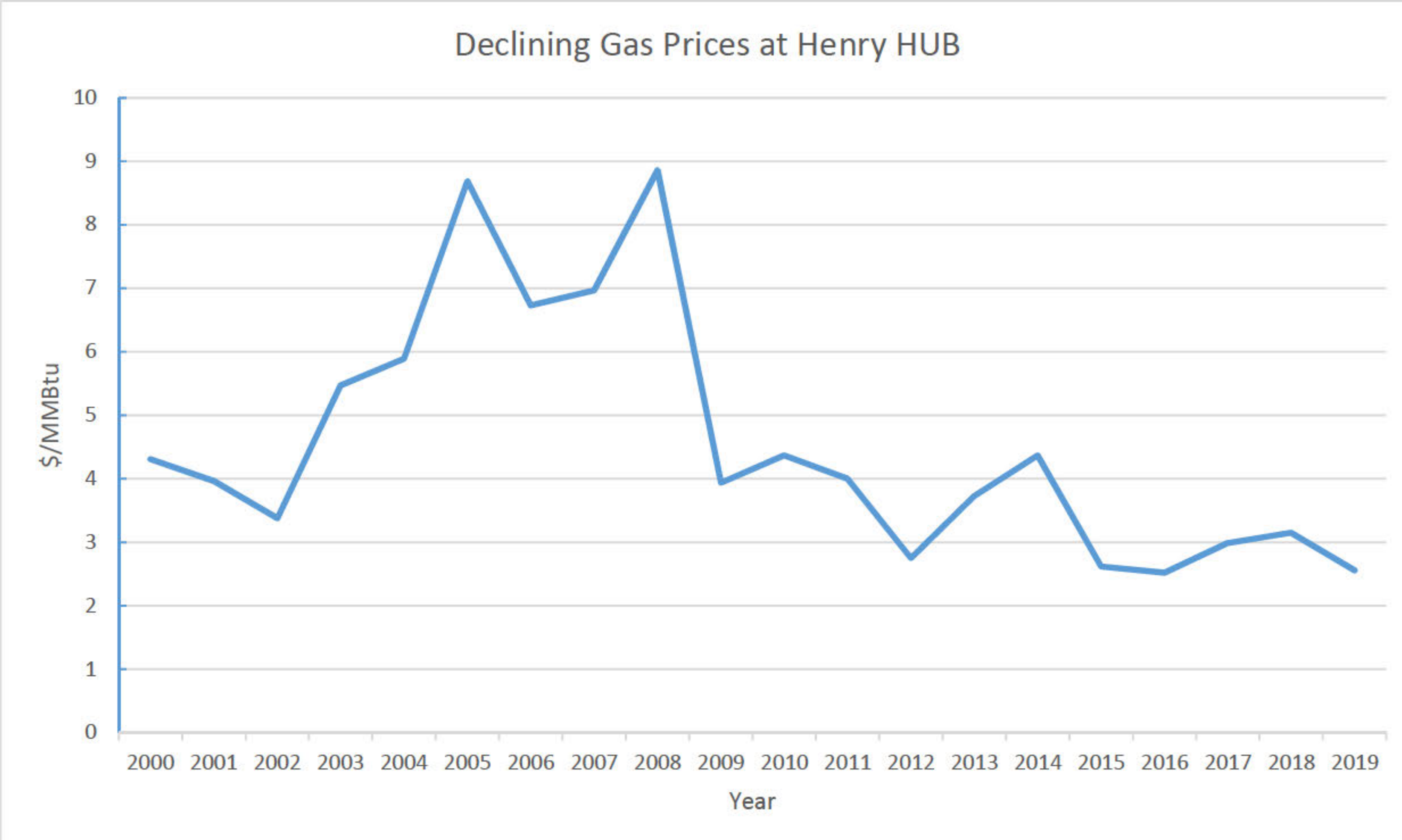
[17] CUB Exhibit 214. See p. 11 of Evaluation Report, PGE's Flex Pricing and Behavioral Demand Response Pilot Program.
Note: Flex is the name of PGE's Residential Pilot Programs.

WITNESS QUALIFICATION STATEMENT

NAME:	Sudeshna Pal
EMPLOYER:	Oregon Citizens' Utility Board
TITLE:	Economist
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	Ph.D., Economics West Virginia University, Morgantown, WV MA, Economics Jawaharlal Nehru University, New Delhi, India
EXPERIENCE:	Provided comments in several Oregon Commission dockets including LC 73, LC 70, LC 74. Written testimony in UG 388. Worked as Assistant Professor of Economics at Georgia College and State University (2003 - 2008). Employed part-time as Adjunct Faculty in the Department of Economics at Portland State University (2014 – present).

WITNESS QUALIFICATION STATEMENT

NAME:	William Gehrke
EMPLOYER:	Oregon Citizens' Utility Board
TITLE:	Economist
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	MS, Applied Economics Florida State University, Tallahassee, FL BS, Economics Florida State University, Tallahassee, FL
EXPERIENCE:	Provided testimony or comments in several Oregon Commission dockets. Worked as an Economist for the Florida Department of Revenue. Worked as Utility Analyst at the Florida Public Service Commission, providing advice on rate cases and load forecasting. Attended the Institute of Public Utilities Annual Regulatory Studies program in 2018.


Declining Gas Prices at Henry HUB
10
9
8
7
6
5
4
3
2
1
0
$/MMBtu
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019
Year

Fuel Heating Cost Comparison (Oregon)
January 1st, 2020

	Fuel Type	Heat Value/Therms/Unit		Unit Cost		Unit Cost Per Therm	Appliance Type	Appliance Efficency	(%, COP, or AFUE)	Cost Per Therm
Tier 1	Electric (Pacific Power)	0.0341	/kWh	0.10012	/kWh	2.93352	Baseboard	100	%	$ 2.93
Tier 2	Electric (Pacific Power)	0.0341	/kWh	0.11985	/kWh	3.51161	Baseboard	100	%	$ 3.51
Tier 1	Electric (Pacific Power)	0.1024	/kWh	0.10012	/kWh	2.93352	Air-Air Heat Pump	3	C.O.P	$ 0.98
Tier 2	Electric (Pacific Power)	0.3072	/kWh	0.11985	/kWh	3.51161	Air-Air Heat Pump	3	C.O.P	$ 1.17
Tier 1	Natural Gas (NW Natural)	1	/Therm	0.86564	/Therm	0.86564	Furnace	90%	AFUE	$ 0.96
Tier 1	Natural Gas (NW Natural)	1	/Therm	0.86564	/Therm	0.86564	Furnace	96%	AFUE	$ 0.90

Fuel price of Electric Vehicle versus Gas Vehicle

eGallon
eGallon formula ($/gal) = FE * EC * EP

where

FE = the average comparable passenger car adjusted combined fuel economy, miles/gallon

Sedan/Wagon	30.8	MPG
Source:	2019 EPA Automative Trends Report	

EC = the average electricity consumption (kWh/mi) of the top selling PEVs in the U.S.

Top Five Selling Plug-In Electric Vehicles (2019)

1	Tesla Model 3	0.26	kWh/1 mi
2	Tesla Model S	0.31	kWh/1 mi
3	Chevrolet Volt	0.31	kWh/1 mi
4	Nissan LEAF	0.3	kWh/1 mi
5	Toyota Prius Prime	0.25	kWh/1 mi
	Average	0.286	kWh/1 mi

Source: Fueleconomy.gov

EP = electricity price

Schedule 4 - < 1001 KWh	0.10012	$
Schedule 4 - >= 1001 kWh	0.11985	$

	(A) FE	(B) EC	(C) EP	(A)*(B)*(C)=(D) eGallon
eGallon at Pacific Power's Schedule 4 < 1001 kWh	30.8	0.286	0.10012	$0.88
eGallon at Pacific Power's Schedule 4 > 1001 kWh	30.8	0.286	0.11985	$1.06

U.S. Regular Gasoline Prices

West Coast (PADD5)	$2.58

Source: EIA Gasoline and Diesel Fuel Update

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost Based Supply Service
Residential Service - Single Family

kWh	Present Price	PAC Proposed Price		CUB Proposed Price	
		#	% Δ		% Δ
100	$20.22	$23.36	15.53%	$21.01	3.91%
200	$29.90	$33.61	12.41%	$31.49	5.32%
300	$39.59	$43.87	10.81%	$41.98	6.04%
400	$49.27	$54.12	9.84%	$52.46	6.47%
500	$58.97	$64.37	9.16%	$62.96	6.77%
600	$68.67	$74.63	8.68%	$73.45	6.96%
700	$78.35	$84.88	8.33%	$83.93	7.12%
800	$88.04	$95.14	8.06%	$94.43	7.26%
900	$97.72	$105.39	7.85%	$104.90	7.35%
1000	**$107.42**	**$115.65**	**7.66%**	**$115.40**	**7.43%**
1100	$120.08	$128.29	6.84%	$128.27	6.82%
1200	$132.74	$140.91	6.15%	$141.13	6.32%
1300	$145.41	$153.55	5.60%	$154.00	5.91%
1400	$158.07	$166.17	5.12%	$166.87	5.57%
1500	$170.74	$178.81	4.73%	$179.73	5.27%
1600	$183.41	$191.45	4.38%	$192.61	5.02%
2000	$234.06	$241.97	3.38%	$244.06	4.27%
3000	$360.71	$368.30	2.10%	$372.73	3.33%
4000	$487.36	$494.63	1.49%	$501.39	2.88%
5000	$614.00	$620.95	1.13%	$630.06	2.62%

* Net Rate including Schedules 91, 98, 290 and 297.
#PAC's proposed price is based on the Company's pricing model.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost Based Supply Service
Residential Service - Multi-Family

kWh	Present Price	PAC Proposed Price		CUB Proposed Price	
		#	% Δ		% Δ
100	$20.22	$18.19	-10.04%	$18.43	-8.85%
200	$29.90	$28.44	-4.88%	$28.90	-3.34%
300	$39.59	$38.70	-2.25%	$39.40	-0.48%
400	$49.27	$48.94	-0.67%	$49.88	1.24%
500	$58.97	$59.20	0.39%	$60.37	2.37%
600	**$68.67**	**$69.46**	**1.15%**	**$70.87**	**3.20%**
700	$78.35	$79.71	1.74%	$81.35	3.83%
800	$88.04	$89.97	2.19%	$91.84	4.32%
900	$97.72	$100.22	2.56%	$102.32	4.71%
1000	$107.42	$110.48	2.85%	$112.81	5.02%
1100	$120.08	$123.11	2.52%	$125.69	4.67%
1200	$132.74	$135.74	2.26%	$138.54	4.37%
1300	$145.41	$148.38	2.04%	$151.42	4.13%
1400	$158.07	$161.00	1.85%	$164.28	3.93%
1500	$170.74	$173.64	1.70%	$177.15	3.75%
1600	$183.41	$186.28	1.56%	$190.02	3.60%
2000	$234.06	$236.80	1.17%	$241.48	3.17%
3000	$360.71	$363.13	0.67%	$370.14	2.61%
4000	$487.36	$489.45	0.43%	$498.80	2.35%
5000	$614.00	$615.78	0.29%	$627.48	2.20%

* Net Rate including Schedules 91, 98, 290 and 297.
#PAC's proposed price is based on the Company's pricing model.

Six State Comparison

Utility	Residential Customer Charge
Pacific Power Oregon	$9.50
Pacific Power California	$7.20
Pacific Power Washington	$7.75
Rocky Mountain Power Utah	$6.00
Rocky Mountain Power Wyoming	$20.00
Rocky Mountain Power Idaho	$5.00
Median	**$7.48**

Data Source: OPUC Staff DR 229.

Residential Customer Charge Survey (Pacific Northwest)

Utility	State	Charge
Puget Sound Energy	WA	$ 7.49
Avista	WA	$ 9.00
Portland General Electric	OR	$ 11.00
Avista	ID	$ 6.00
Idaho Power	ID	$ 5.00
Idaho Power	OR	$ 8.00
BC Hydro *	BC	$ 4.42
Pacific Power	WA	$ 7.75
Pacific Power	CA	$ 7.20

Pacific Power's Proposed OR Single Family Rate	**$ 12.00**

* BC Hydro is a Canadian Company. Therefore, BC Hydro's RES tariff is priced in CAD. An exchange rate of 1 CAD to 0.74 USD is used.

[redacted]

FIRST-CLASS MAIL PRESORTED U.S.POSTAGE PAID PACIFICORP

Questions: Call
1-888-221-7070
24 hours a day,
7 days a week
pacificpower.net

PACIFIC POWER

BILLING DATE:	**Jan 22, 2020**
ACCOUNT NUMBER:	[redacted]
DUE DATE:	**Feb 7, 2020**
AMOUNT DUE:	**$75.80**

Your Balance With Us

Previous Account Balance	88.39
Payments/Credits	-88.39
New Charges	+75.80
Current Account Balance	**$75.80**

Payments Received

DATE	DESCRIPTION	AMOUNT
[redacted]	[redacted]	88.39
Total Payments		**$88.39**

Detailed Account Activity

ITEM 1 - ELECTRIC SERVICE

[redacted]
Residential Schedule 4

METER NUMBER	SERVICE PERIOD From	To	ELAPSED DAYS	METER READINGS Previous	Current	METER MULTIPLIER	AMOUNT USED THIS MONTH
[redacted]	Dec 19, 2019	Jan 21, 2020	33	5701	6396	1.0	695 kwh

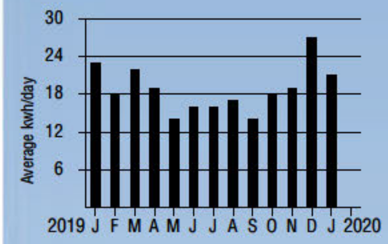
Next scheduled read date: 02-19. Date may vary due to scheduling or weather.

NEW CHARGES 01/20	UNITS	COST PER UNIT	CHARGE
Basic Charge - Single Phase			9.50
Delivery Charge			
for 21 day(s)	442 kwh	0.0442600	19.56
for 12 day(s)	253 kwh	0.0438800	11.10
Supply Energy Charge Block 1			
for 21 day(s)	442 kwh	0.0551200	24.36
for 12 day(s)	253 kwh	0.0564200	14.27
Federal Tax Act Adjustment	695 kwh	-0.0044500	-3.09
Public Purpose		0.0300000	2.27
Energy Conservation Charge	695 kwh	0.0034600	2.40
Low Income Assistance			0.69
B P A Columbia River Benefits for 33 day(s)	695 kwh	-0.0093400	-6.49
Portland City Tax		0.0150000	1.07
Multnomah County Fee		0.0023000	0.16
Total New Charges			**75.80**

Effective January 1, 2020, the Oregon Public Utility Commission approved to cancel a credit to Oregon customers from the

See reverse

Historical Data - *ITEM 1*



Your Average Daily kwh Usage by Month

PERIOD ENDING	Jan 2020	Jan 2019
Avg. Daily Temp.	[redacted]	43
Total kwh	[redacted]	751
Avg. kwh per Day	[redacted]	23
Cost per Day	[redacted]	$2.59

To better serve you, we updated our bill alert emails. The new emails give you easy access to your bill, your energy usage graph and more. Go paperless at pacificpower.net/paperless.

Looking for other ways to pay?

Visit pacificpower.net/pay for all your options. You can choose to pay on your device using our mobile app, on our website, at a pay station in your community, or pay over the phone by calling 1-888-221-7070.

Late Payment Charge for Oregon
A late payment charge of 2.0% may be charged on any balance not paid in full each month.

Write account number on check & mail to: Pacific Power, PO Box 26000, Portland, OR 97256-0001

RETAIN THIS PORTION FOR YOUR RECORDS.
RETURN THIS PORTION WITH YOUR PAYMENT.

INSERT THIS EDGE FIRST

PACIFIC POWER
PO BOX 400
PORTLAND OR 97207

Change of Mailing Address or Phone?
Check here & provide information on back.

Account Number:	[redacted]
Date Due:	**Feb 7, 2020**

[redacted]

Bank Payment - Do Not Pay

Please enter the amount enclosed.

[redacted]

PACIFIC POWER
PO BOX 26000
PORTLAND OR 97256-0001

Automatic Withdrawal for Total Amount Due to occur on the payment due date

PACIFIC POWER

Questions about your bill: Call toll free **1-888-221-7070** pacificpower.net

BILLING DATE: **Jan 22, 2020** ACCOUNT NUMBER: [redacted] DUE DATE: **Feb 7, 2020** AMOUNT DUE: **$75.80**

Open Access Transmission Tariff (OATT) revenue deferral. This change is included in the energy delivery charges shown on your statement. Your statement may show charges at the old and new rate.

Effective January 1, 2020, the Oregon Public Utility Commission approved several changes to the energy supply charges on your bill. These changes result in a net decrease and include wind power upgrades, solar incentive program costs, and lower net power costs. Your statement may show charges at the old and new rate.

When you provide a check as payment, you authorize us to use the information from your check either to make a one-time electronic fund transfer from your account or to process the payment as a check transaction. When we use information from your check to make an electronic fund transfer, funds may be withdrawn from your account as soon as we receive your payment and you will not receive your check back from your financial institution. If you would like to opt out of this program and continue processing your payment as a check transaction, please call 1-800-895-0561. If you have opted out previously, please disregard this message.

New Mailing Address or Phone?

Please print your new information below and check the box on the reverse side of this Payment Stub. Thank you.

ACCOUNT NUMBER: [redacted]

LAST FIRST M.I.

NEW STREET ADDRESS

CITY

ST ZIP TELEPHONE NUMBER

Pacific Power
State of Oregon
Residential Time of Use Pilot - Proposed Schedule 6 - Pacific Time
Proposed Time of Use Period Justification - Oregon CUB

All Days

Month \ **HE**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	17.85	16.94	16.78	17.39	18.05	20.68	23.69	25.98	21.15	19.47	18.26	16.32	14.95	14.68	15.34	17.46	22.43	28.12	25.81	24.37	24.98	23.73	19.84	18.08
2	17.45	15.60	15.62	16.20	18.20	22.71	29.40	27.17	19.29	16.06	13.30	11.23	10.36	10.49	9.19	12.12	18.25	32.35	36.67	29.55	24.63	21.66	19.75	17.15
3	15.29	14.43	14.04	14.82	15.77	20.73	24.49	26.15	19.25	16.91	12.20	9.89	10.50	7.68	7.57	8.04	10.30	17.16	24.70	30.98	26.89	22.19	20.27	16.77
4	13.03	11.57	10.48	10.56	12.09	19.04	20.13	18.38	15.10	11.59	9.09	8.12	8.33	7.90	8.21	9.55	9.09	12.19	21.31	32.90	31.28	19.09	18.13	14.33
5	14.78	10.57	8.76	8.62	10.70	14.46	14.14	13.66	11.41	10.95	10.70	9.57	9.57	10.84	10.71	12.54	13.93	13.48	18.18	22.23	24.30	21.04	21.41	18.64
6	13.43	11.87	10.67	9.58	10.74	11.96	8.38	11.31	12.44	11.98	13.18	13.77	14.29	18.94	15.65	16.51	16.40	16.80	17.59	17.78	16.92	16.56	16.90	14.57
7	26.97	24.98	24.11	23.26	24.12	24.71	20.60	22.78	24.02	25.50	28.13	29.20	29.56	31.92	34.48	37.23	37.43	34.58	36.66	37.29	34.37	32.42	31.74	27.82
8	27.12	25.16	23.75	22.85	23.46	25.76	22.64	23.94	23.80	25.44	27.71	29.28	30.44	33.57	37.00	40.12	46.06	51.91	61.70	53.00	41.46	35.47	33.02	28.87
9	27.51	26.01	25.13	24.79	25.64	28.91	28.14	29.47	27.11	26.81	27.38	27.99	28.68	30.71	32.57	33.62	33.62	35.68	42.24	44.89	37.02	33.01	32.80	29.00
10	15.26	14.28	14.37	13.98	14.88	17.96	20.27	25.67	17.12	14.46	13.38	13.04	13.34	13.81	13.95	14.72	16.92	29.72	37.38	27.16	21.32	19.56	19.10	15.97
11	15.73	14.66	14.33	14.94	15.86	19.23	21.02	23.47	17.31	14.94	13.81	13.41	12.70	12.46	14.11	17.98	25.36	26.31	22.63	20.80	20.31	19.79	19.25	17.50
12	17.87	17.29	16.72	17.07	18.00	20.09	22.10	26.62	25.01	19.26	18.01	15.78	14.70	14.48	15.52	18.33	23.62	25.82	24.29	23.13	22.83	21.76	20.47	18.18

Summer (July-Sept) Average Prices **Top 4 hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	27.20	25.38	24.33	23.63	24.40	26.46	23.79	25.39	24.98	25.91	27.74	28.82	29.56	32.07	34.68	36.99	39.03	40.72	46.87	45.06	37.61	33.63	32.52	28.56
Rank	15	19	22	24	21	16	23	18	20	17	14	12	11	10	7	6	4	3	1	2	5	8	9	13
																	17	18	19	20				

On-Peak = 4pm - 8pm

Winter (Oct-Jun) Average Prices **Top 4 hours**

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$/MWh	15.63	14.13	13.53	13.68	14.92	18.54	20.40	22.05	17.56	15.07	13.55	12.35	12.08	12.37	12.25	14.14	17.37	22.44	25.40	25.43	23.72	20.60	19.46	16.80
Rank	13	17	20	18	15	9	7	5	10	14	19	22	24	21	23	16	11	4	2	1	3	6	8	12
																		18	19	20	21			

On-Peak = 5pm to 9pm

PACIFIC POWER
State of Oregon
CUB Proposed Residential Time-of-use Pilot Program

Schedule	Forecast 1/21 - 12/21 Units		Proposed Schedule 4 Price		Proposed Schedule 4 Dollars	CUB Proposed Schedule 6 Price		CUB Proposed Schedule 6 Dollars
Schedule No. 6								
Residential Service								
Transmission & Ancillary Services Charge								
per KWh	5,521,126,670	kWh	0.820	¢	$ 45,273,239	0.820	¢	$ 45,273,239
System Usage Charge								
Sch 200 related, per kWh	5,521,126,670	kWh	0.084	¢	$ 4,637,746	0.084	¢	$ 4,637,746
T & A and Schedule 201 related, per kWh	5,521,126,670	kWh	0.077	¢	$ 4,251,268	0.077	¢	$ 4,251,268
Distribution Charge								
Basic Charge Single Family, per Month	4,984,041	bill	12.00	$	$ 59,808,492	9.5	$	$ 47,348,390
Basic Charge Multi Family, per Month	1,228,844	bill	7.00	$	$ 8,601,905	7	$	$ 8,601,905
Total Bills	6,212,885	bill						
Three Phase Demand Charge, per KW demand	15,565	kW	2.20	$	$ 34,244	2.20	$	$ 34,244
Three Phase Minimum Demand Charge, per month	1,443	bill	3.80	$	$ 5,482	3.80	$	$ 5,482
Distribution Energy Charge per kWh	5,521,126,670	kWh	3.822	¢	$ 211,017,461	4.048	¢	$ 223,501,281
Energy Charge Schedule 200								
First Block kWh (0-1000)	4,171,965,406	kWh	3.279	¢	$ 136,798,746	0.000	¢	$ -
Second Block kWh (>1000)	1,349,161,264	kWh	3.779	¢	$ 50,984,804	0.000	¢	$ -
All kWh	5,521,126,670					3.401	¢	$ 187,783,550
Subtotal	5,521,126,670	kWh			$ 521,413,387			$ 521,437,105
Schedule 201								
First Block kWh (0-1000)	4,171,965,406	kWh	2.444	¢	$ 101,962,835	0.000	¢	$ -
Second Block kWh (>1000)	1,349,161,264	kWh	3.340	¢	$ 45,061,986	0.000	¢	$ -
All kWh	5,521,126,670					2.663	¢	$ 147,024,821
On-Peak Adder (CUB Proposal)	1,172,258,731					12.459	¢	$ 146,050,161
Off-Peak Adder (CUB Proposal)	4,348,867,939					(3.358)	¢	$ (146,050,161)
Total	5,521,126,670	kWh			$ 668,438,208			$ 668,461,926

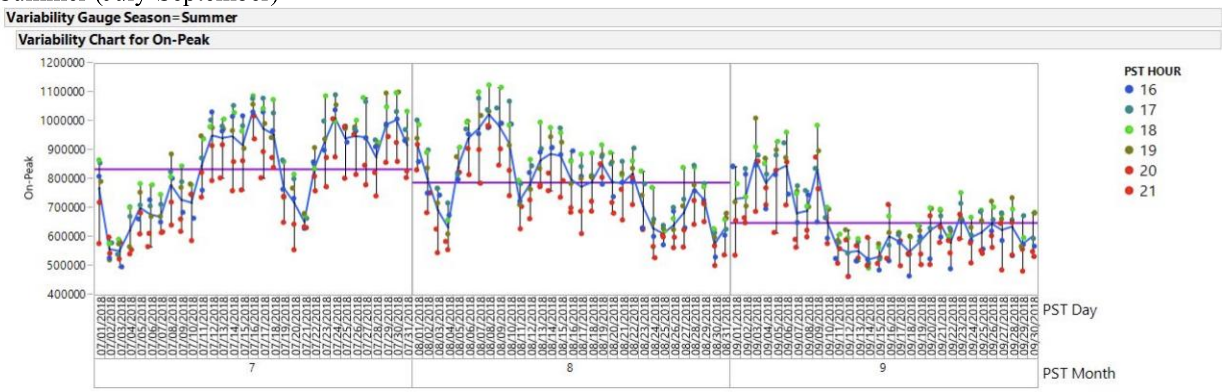
On-Peak kWh	23.552	¢
Off-Peak kWh	7.735	¢
On/Off Diff	3.045	
On/off Cents per kWh Difference	15.82	¢

Schedule 6 TOU definition

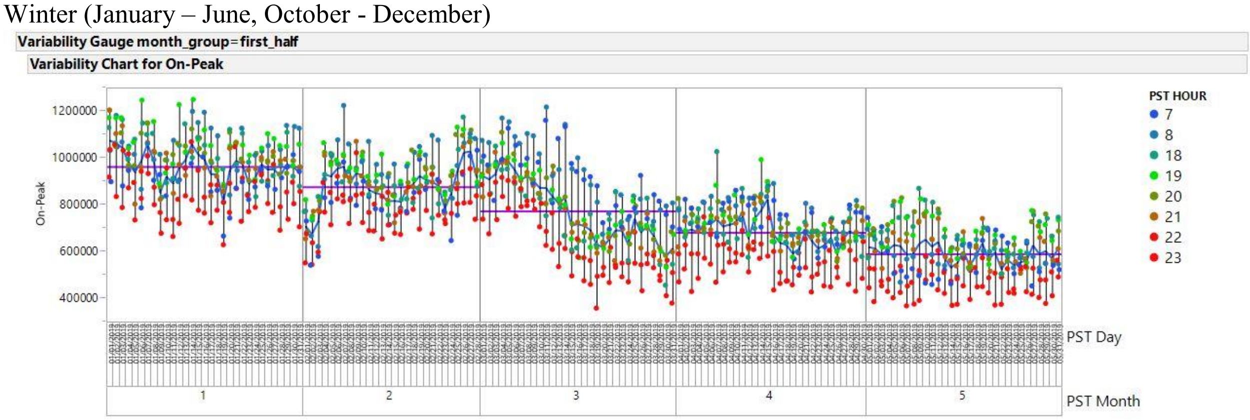
Summer (July - September) On-Peak: All Days 4 - 8PM
Non-Summer (Ju - October) On-Peak: All Days 5-9PM
Off-Peak: All Other Hours

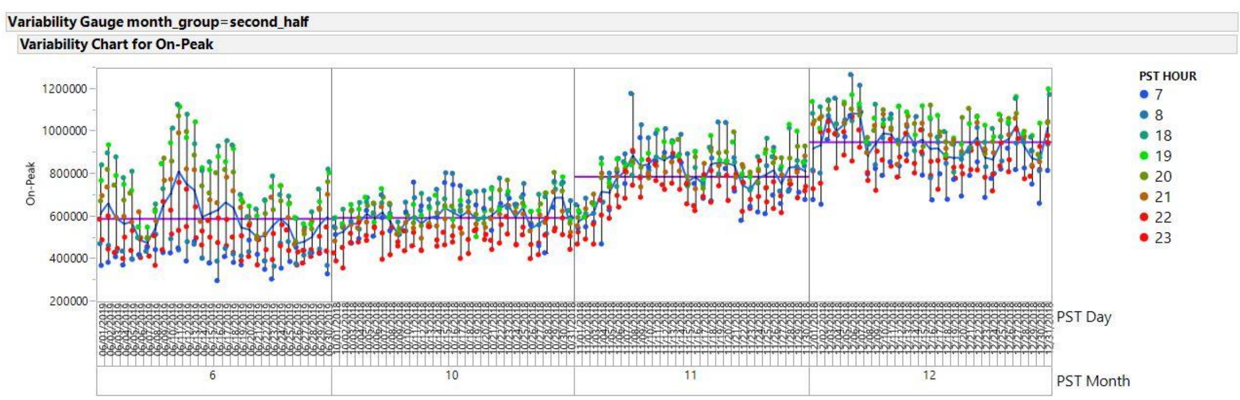
Figure 1: Residential Hourly Energy Use (kWh) During On-Peak Hours

Summer (July-September)



Winter (January – June, October - December)





Notes: Graphs generated by CUB from OPUC DR 232 Attachment.

Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204
PortlandGeneral.com

July 10, 2018

Email
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High Street, S.E., Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Attn: Commission Filing Center

Re: UM 1708 Cadmus Evaluation of PGE's Residential Pricing Pilot

Enclosed is Cadmus' evaluation of the Cadmus evaluation of our Residential Pricing Pilot (also known as Flex). PGE contracted with Cadmus to evaluate the load impacts and customer satisfaction associated with different pricing and behavioral demand response program designs for Flex. Flex is intended to test the load impacts and residential customer acceptance of various demand response approaches. The Cadmus evaluation reviewed two winter seasons (2016/2017 and 2017/2018) and two summer seasons (2016 and 2017) and involved analysis of randomized control trials for twelve demand response (DR) treatments including peak-time rebates (PTR), time-of-use (TOU) pricing, behavioral demand response (BDR), and combinations of these treatments. Cadmus performed the research design, peak demand impact analysis, program staff interviews, and customer surveys. Cadmus' evaluation report is provided as Attachment A.

The Cadmus evaluation confirms that PGE can obtain customer demand savings through pricing and behavior-based DR programs to manage its system peak demand while delivering a positive customer experience. Based on the Cadmus findings and recommendations for increasing demand savings and customer satisfaction, PGE will propose a combination of offerings that achieved high customer satisfaction and will support PGE's goal of at least 77 megawatts of DR by end-of-year 2020. The offerings will likely include the following:

- Opt-in PTR – Customers receive notifications asking them to shift energy use during peak-time events (16-20 events per year). As a reward, they receive an on-bill credit based on actual versus expected usage if they had not shifted.

- Opt-in TOU and PTR Hybrid – Customers can save on their daily energy costs by shifting usage to off-peak times when rates are lower. They also receive notifications asking them to shift energy use during peak-time events (16- 20 events per year). As a reward, they receive an on-bill credit based on actual versus expected usage if they had not shifted.

- BDR Public Alert Strategy – Residential customers learn of *critical* PTR events via public alerts (e.g., radio, television, web) and are encouraged to shift energy use during critical peak events (one or two times per year). Customers will be informed of, and encouraged to enroll in, the higher-frequency PTR program to support ongoing DR goals.

Opt-in PTR

Of the twelve scenarios tested, Opt-in PTR produced the second highest demand savings during events and had the highest customer satisfaction rating. Opt-in PTR customers also had the lowest un-enrollment rates of the opt-in scenarios which is promising for customer retention moving forward.

PGE tested three incentive "tiers" for Opt-in PTR customers:

- PTR1 $0.80C/kWh;
- PTR2 $1.55/kWh; and
- PTR3 $2.25 kWh.

PGE's proposal for the Pricing Program will likely include Opt-in PTR as one of the core offerings with a change to the tested incentive tiers.

Opt-in TOU/PTR Hybrid

Hybrid treatments, which combined TOU pricing with PTR incentives, resulted in the highest demand savings of those scenarios tested. Satisfaction was also high for those customers who saved on the hybrid plan. TOU/PTR hybrid customers had lower satisfaction in winter, as demand saving or shifting proved challenging for them in this season and they voiced concern about winter bill increases. Satisfaction was lowest and opt-out was highest for those customers who faced a negative financial impact. PGE is currently conducting detailed analysis of the TOU structures to see where changes could potentially be made to mitigate issues in winter while maintaining resource value.

Using the Cadmus findings and recommendations, to inform our target participants, PGE is conducting further segmentation to profile those customers who could benefit most from the rate plan, those with a neutral impact, and those who could be negatively impacted. For its next program proposal, PGE's marketing efforts would target those customers who are most likely to benefit from the program.

Opt-Out Behavioral Demand Response (BDR)

Pilot participants in this group received a subset of PTR event notifications but were not incented for their participation. Opt-out BDR achieved the lowest demand shift and satisfaction ratings of the scenarios tested. Many participants did not understand DR program goals or the value of their participation. However, the size of this potential population (400,000 to over 700,000) provides opportunity for limited engagement that could yield significant load shift. For its next program proposal, PGE is weighing benefit/risk of implementing a low-touch, BDR communication strategy during absolute critical peak periods (e.g., grid emergencies).

Demand Response Education

As Cadmus reported, PGE's opt-in rates were significantly lower than those achieved by other utilities such as Sacramento Municipal Utility District (SMUD). It's likely that PGE customers are less familiar with the concept of DR and time varying rates, and customer feedback from the pilot supports that theory. For its next program proposal, PGE considering providing a DR awareness campaign to help educate customers about DR objectives and participation advantages and enhance program engagement. Ongoing communication efforts would encourage retention and continued customer satisfaction post enrollment.

If you have any questions or require further information, please call me at (503) 464-7805 or Kalia Savage at (503) 464-7432.

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

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

Encls

cc: UM 1708 Service List

Flex Pricing and Behavioral Demand Response Pilot Program

EVALUATION REPORT

June 25, 2018

Prepared for:

Portland General Electric

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Acknowledgements

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Acronyms, Terms, and Definitions

Acronym/Term	Definition
AMI	Advanced Metering Infrastructure
BDR	Behavioral Demand Response
CI	Confidence Interval
Conversion rate	Measures a given marketing channel's effectiveness in spurring enrollment, calculated by taking the number of customers who enrolled from a given channel and dividing this by the total number of customers that the channel reached.
CDH	Cooling Degree Hours
Flex	Pricing and Behavioral Demand Response Pilot Program
HDH	Heating Degree Hours
OLS	Ordinary Least Squares
OO	Opt-Out – Opt-out customers are automatically enrolled in the pilot and given the opportunity to opt out of the pilot; an alternative to opt-in program design format.
Opt-in rate	The ratio of the number of customers who enrolled in a treatment to the total number of customers invited to participate.
Opt-out rate	The ratio of the number of enrolled customers who opted out of treatment to the total number enrolled.
PGE	Portland General Electric
PTR	Peak-Time Rebate
QC	Quality Control
RCT	Randomized Control Trial
TOU	Time-of-Use

Abstract

Through its residential Pricing and Behavioral Demand Response Pilot program (Flex), Portland General Electric (PGE) sought to assess the load impacts from and customer satisfaction with different pricing and behavior-based demand response treatments. Findings from the pilot would be used to inform offerings for a future, large-scale rollout of a PGE demand response program.

In 2015, PGE contracted with Cadmus to evaluate Flex. The evaluation covered two winter seasons (2016/2017 and 2017/2018) and two summer seasons (2016 and 2017) and involved analysis of randomized control trials (RCT) for 12 demand response treatments including peak time rebates (PTR), time-of-use (TOU) pricing, behavioral demand response (BDR), and combinations of these treatments. Cadmus performed the research design, peak demand impact analysis, program staff interviews, and customer surveys.

Opt-in PTR produced demand savings during Flex events ranging from 17%–21% in summer and 7%–12% in winter. Opt-out PTR and BDR yielded event demand savings of 7% and 2% in summer, and 5% and 1% in winter, respectively. Two of three TOU rates delivered demand savings during peak periods of 5%–8% in summer. In winter, none of the TOU rates produced statistically significant savings. Hybrid treatments combining TOU and either PTR or BDR achieved peak period demand savings of 8%–23% in summer and 1%–5% in winter. During summer and winter Flex events, TOUxPTR treatments tended to produce less demand savings than opt-in PTR-only customers. For many treatments, the estimated load impacts equaled or surpassed PGE planning estimates.

In general, Flex customers were satisfied with the pilot. Opt-in PTR customers consistently had the highest satisfaction (79%–92%). TOU and opt-out customer automatically enrolled in the pilot tended to have lower satisfaction (51%–82%). TOU and TOU-hybrid customers had lower satisfaction in winter, as demand saving or shifting proved challenging for them in this season.

These findings demonstrate that PGE can deploy pricing and behavior-based demand response to manage its system peak demand while delivering a positive customer experience. This report makes recommendations for increasing Flex demand savings and improving the customer experience.

Executive Summary

In 2016, Portland General Electric (PGE) launched Flex, a pricing and behavioral demand response pilot program. PGE launched the program to test the load impacts and customer acceptance of various demand response strategies. The program enrolled 14,000 customers and tested 12 pricing and behavior-based program design options (referred to as “treatments” in this report) aimed at reducing residential peak demand during summer and winter months. The treatments featured three time-of-use (TOU) rates, three peak-time rebates (PTR), behavioral demand response (BDR), four hybrid demand response treatments (TOU pricing in combination with PTR or BDR), and opt-out (OO) BDR and PTR demand response that automatically enrolled customers.

PGE called upon customers enrolled in PTR or BDR treatments to reduce loads during a limited number of Flex events in summer and winter. PGE paid rebates of $0.80/kWh, $1.55/kWh, or $2.25/kWh to PTR customers for reducing consumption during Flex events below individual-customer baselines, and PGE provided encouragement to BDR customers to save during Flex events, but did not compensate them for saving or shifting their demand. In contrast to event-based PTR and BDR, TOU pricing always was in effect. PGE moved participating customers on a standard flat rate to rate schedules that varied the cost of electricity as a function of the day of the week and hour of the day. Table 1 shows the three rate schedules (TOU1, TOU2, and TOU3) that PGE tested for the Flex pilot.

Table 1. Flex Pilot Summer and Winter TOU Rate Schedules

Summer	TOU1	TOU2	TOU3
Off Peak	7.5₵/kWh	8.3₵/kWh	6.9₵/kWh
	10:00 pm–6:00 am	8:00 pm–3:00 pm	10:00 pm–11:00 am
Mid Peak			11.9₵/kWh
			11:00 am–3:00 pm 8:00 pm–10:00 pm
On Peak	13.6₵/kWh	17.6₵/kWh	18.0₵/kWh
	6:00 am–10:00 pm	3:00 pm–8:00 pm	3:00 pm–8:00 pm
Winter	**TOU1**	**TOU2**	**TOU3**
Off Peak	8.0₵/kWh	8.8₵/kWh	7.4₵/kWh
	10:00 pm–6:00 am	8:00 pm–7:00 am; 11:00 am–3:00 pm	10:00 pm–7:00 am
Mid Peak			12.4₵/kWh
			11:00 am–3:00 pm; 8:00 pm–10:00 pm
On Peak	14.1₵/kWh	18.1₵/kWh	18.5₵/kWh
	6:00 am–10:00 pm	7:00 am–11:00 am; 3:00 pm–8:00 pm	7:00 am–11:00 am; 3:00 pm–8:00 pm

*TOU rates in effect as of August 1, 2016.

TOU customers paid a higher unit price to consume electricity during peak periods (e.g., weekday afternoon hours) when electricity was most costly to supply and a lower unit price during off-peak periods (weekday morning, weekend, and evening hours). The TOU3 rate also included a mid-peak period, when the retail electricity price was about midway between the off-peak and on-peak prices.

Evaluation Context

As presented in its 2016 Integrated Resource Plan, in the next several years, PGE expects to face a shortfall in generating capacity from the planned closure of its Boardman facility in 2020 and the expiration of wholesale power contracts.[1] At the same time, PGE plans to increase its production of electricity from intermittent renewable energy resources to comply with the requirements of Oregon Senate Bill 1547. In consideration of these developments, PGE's Integrated Resource Plan (2016) calls for the use demand response to help manage system peak loads and to assist with integration of

1 PGE's integrated resource plan for 2016 is available at https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp

renewable energy resources. The IRP sets a goal of adding demand response capacity of 77 MW in winter and 69 MW in summer.

An important source of future demand response capacity for PGE will come from residential customers. These customers contribute to PGE's system peak demand through weather-driven increases in demand for air conditioning in summer and demand for space heating in winter. By deploying demand response programs to residential customers, PGE can manage its peak system loads and reduce its costs of electricity supply. Between 2010 and 2013, PGE ran a critical peak pricing (CPP) pilot and obtained demand savings between 10%–12%. To lay the groundwork for a full-scale launch of residential pricing and behavior-based demand response offerings, PGE implemented the Flex pilot and hired Cadmus to conduct an evaluation. The evaluation sought to assess a range of program design options, including different peak rebates, time-of-use rate schedules, behavioral demand response, and customer opt-in and opt-out designs.

This evaluation report presents findings addressing the Flex pilot's design and delivery, load impacts, and customer experience, and provides recommendations to help PGE optimize its future demand response program offerings. Cadmus evaluated four seasons of the Flex pilot (Summer 2016, Winter 2016/2017, Summer 2017, and Winter 2017/2018), but this report focuses on Summer 2017 and Winter 2017/2018 as PGE did not reach its customer recruitment targets until summer 2017, and PGE changed some aspects of the program's delivery during the first two seasons.

Key Findings

Table 2 presents findings from the Flex pilot evaluation regarding peak demand savings, customer satisfaction, and customer opt-out rates across treatments for Summer 2017 and Winter 2017/2018. The table shows demand savings during Flex events for all treatments and on-peak period demand savings for all TOU and Hybrid treatments. Although PGE did not notify TOU-only customers of Flex events, Cadmus estimated Flex event savings for these customers to assess the peak capacity impacts of TOU pricing.

The most significant findings follow:

- Opt-in PTR treatments produced demand savings during Flex events ranging from 17%–21% in summer and 7%–12% in winter.
- Opt-out PTR and BDR treatments reduced loads during Flex events by 7% and 2% in summer and 5% and 1% in winter, respectively.
- The TOU1 rate, which defined on-peak periods as weekday hours between 6:00 a.m. and 10:00 p.m., did not result in shifting of loads from on-peak periods to off-peak periods or demand savings during Flex events. The TOU1 load impacts were not statistically different from zero.
- In summer, the TOU2 and TOU3 rates, which defined a shorter on-peak period on weekdays from 3:00 p.m. to 8:00 p.m., resulted in demand savings from 5%–8% during on-peak periods and Flex event hours. In winter, neither TOU2 nor TOU3 resulted in statistically significant Flex event demand savings or shifting of loads from peak to off-peak hours.

- During on-peak TOU periods, Hybrid treatments, which combined PTR or BDR with TOU pricing, resulted in demand savings from 8%–23% in summer and 1%–5% in winter. During summer Flex events, Hybrid treatments saved 10%–20% of peak demand. During winter Flex events, TOU2 and TOU3 hybrid treatments saved about 13%.
- None of the TOU-only or Hybrid treatments led to changes in total energy consumption. Estimates of changes in total energy consumption were close to zero and not statistically significant.
- Opt-in PTR customers were those most satisfied with the pilot. In summer and winter, 80% or more of PTR customers reported a satisfaction rating of 6 or higher on a 10-point scale.
- TOU-only customers and opt-out customers were the least satisfied with Flex. Among TOU-only customers, 76% were satisfied with Flex in summer and 61% were satisfied in winter. For opt-out customers, 56% were satisfied in summer and 61% were satisfied in winter. Some TOU customers reported less-than-expected bill savings, and some opt-out customers were not interested in participating.
- TOU customer satisfaction with the pilot depended on perceived bill savings. Satisfied customers (those giving 6–10 ratings on a 10-point scale) most often noted that the program delivered bill savings. Unsatisfied customers (those giving 0–5 ratings a 10-point scale) most often noted seeing little to no difference in their bills.
- Customers opting into the pilot exhibited high engagement with Flex events. Depending on the season, 93% to 96% of opt-in PTR-only respondents and 94% to 97% of opt-in Hybrid respondents remembered receiving event notifications. Also, 76% to 86% of opt-in respondents reported conserving electricity during events in both seasons.
- Opt-out customers automatically enrolled in the pilot exhibited lower awareness of Flex events compared to opt-in customers. Depending on the season, 77% to 89% of opt-out respondents remembered receiving event notifications, and 48% to 63% reported conserving electricity during events in both seasons.
- TOU customers did not have strong awareness of their rate schedules. Only about one-half of TOU and Hybrid respondents (52%) correctly identified their rate schedules from a list of three rate schedule images, a result only slightly better than customers guessing at random.
- During the first season, PGE experienced challenges in providing accurate and timely feedback to participants about savings during Flex events. However, with improvements in the baseline calculation methodology and data QC procedures, PGE increased the feedback's accuracy and shortened the time required to send customers feedback to less than 24 to 48 hours after the event.
- Around one-half of customers (48%) did not know they could change their event notification channel preferences on the Flex website. PGE received complaints from BDR-OO customers that they received too many event notifications.

- TOU and Hybrid customers, who faced financial risks from participating in the pilot, opted out of the pilot at higher rates (8%–11%) than opt-in PTR, opt-out PTR, and BDR customers (2%–6%), who did not face such risks.
- PGE experimented with three marketing channels (email, postcard, and business letter) and three messaging themes (economics, control, and community) to determine which marketing strategies converted to higher customer enrollment. The two paper-based channels (business letter 4.5% and postcard 2.5%) had a higher conversion rate than email (1.5%).
- PGE found that financial-focused messaging resonated more with customers as PGE enrolled a higher percentage of customers when it emphasized the opportunity to earn bill credits or savings. In surveys, customers reported that saving money on electric bills was the top reason for enrollment (78%).

Table 2. Flex Evaluation Findings by Treatment and Season*

Category	Treatment		Summer				Winter					Program Opt-Out Rate****
			Savings**		Satisfaction***		Savings**			Satisfaction***		
			Planning	Evaluation	Satisfied (6-10)	Delighted (9-10)	Planning	Evaluation		Satisfied (6-10)	Delighted (9-10)	
								AM	PM			
PTR-Only	PTR1		13%	18%	79%	46%	14%	13%	7%	80%	44%	4%
	PTR2			22%	92%	42%		0%	8%	89%	55%	6%
	PTR3			17%	84%	52%		3%	12%	89%	58%	5%
Opt-Out	PTR2-OO		6%	7%	73%	40%	7%	0%	6%	79%	35%	2%
	BDR-OO		3%	2.3%	51%	23%	3%	-0.7%	1%	57%	25%	3%
TOU-Only	TOU1	On-Peak	5%	2%	57%	23%	6%	-1%		54%	23%	8%
		Flex Event		-1%				2%	0%			
	TOU2	On-Peak		8%	82%	45%		3%		62%	23%	9%
		Flex Event		5%				2%	2%			
	TOU3	On-Peak		5%	82%	42%		0%		68%	23%	9%
		Flex Event		6%				3%	-1%			
Hybrids	TOU1xPTR2	On-Peak	5.2% TOU; 12.9% PTR	3%	72%	34%	5.8% TOU; 14.2% PTR	1%		69%	38%	11%
		Flex Event		10%				10%	5%			
	TOU2xPTR2	On-Peak	5.2% TOU; 12.9% PTR	24%	70%	27%	5.8% TOU; 14.2% PTR	5%		73%	18%	10%
		Flex Event		20%				12%	13%			
	TOU2xBDR	On-Peak	5.2% TOU; 3.0% BDR	8%	81%	37%	5.8% TOU; 3.3% BDR	1%		71%	36%	8%
		Flex Event		11%				-1%	1%			
	TOU3xPTR2	On-Peak	5.2% TOU; 12.9% PTR	9%	88%	50%	5.8% TOU; 14.2% PTR	4%		72%	46%	10%
		Flex Event		8%				4%	13%			

* Seasonal results presented only for Summer 2017 and Winter 2017/2018.

**Impact values reflect percentage demand reduction during Flex peak-time events (and on-peak periods for TOU rates); green font indicates significance at 90%.

*** Satisfaction values represent participant survey respondents' satisfaction with Flex on a 0-10 rating scale.

**** Opt-out rates show the percentage of customers enrolled in a specific treatment who have unenrolled through February 2018.

Conclusions and Recommendations

Key takeaways from the Flex pilot evaluation include the following:

Peak-Time Rebates

Larger rebates did not yield more Flex event savings.
Opt-In PTR customers saved about 20% of consumption during summer Flex events and between 7% and 12% of consumption during winter Flex events. No statistically significant differences in savings appeared by rebate amount. In summer, customers receiving a $0.80/kWh rebate achieved the same savings as customers receiving a $2.25/kWh rebate.

Of 12 treatments, Opt-In PTR-only customers were most satisfied with the Flex pilot.
In both seasons, Opt-In PTR-only respondents had the highest satisfaction rates with Flex (83% reported a program satisfaction score of 6 or higher on a 10-point scale in winter; 86% in summer) compared to Hybrids (71% in winter; 79% in summer) and TOU-only (61% in winter; 76% in summer).[2] Opt-In PTR2 treatment achieved the highest satisfaction rate of 92% in the summer survey. Opt-In PTR2 (89%) and PTR3 (89%) treatments also achieved high satisfaction rates in the winter survey. PTR customers may have been most satisfied as they faced no financial risk from participation. Customers could earn rebates for saving energy during Flex events, but were not penalized if their consumption increased.

Larger rebates (greater than $1.55/kWh) increased customer satisfaction with the Flex pilot.
PTR1 customers, who received the smallest rebate ($0.80/kWh), had lower satisfaction with Flex for both winter and summer seasons than PTR2 ($1.55/kWh) or PTR3 ($2.25/kWh) customers. In summer, 79% of PTR1 customers expressed satisfaction with the program, while 92% of PTR2 customers and 84% of PTR3 customers expressed satisfaction. In winter, PTR1 had a satisfaction rate of 80%, about 10 percentage points lower than that of PTR2 (89%) and PTR3 (89%).

Flex event savings from peak-time rebates did not depend on outside temperatures.
A statistical relationship was not found between PTR savings and outside temperatures during Flex events in winter or summer. Outside temperatures during Flex events ranged between 82°F and 96°F in summer and 28°F and 45°F in winter.

PTR Recommendation

- When setting rebates for future PTR programs, PGE should consider the tradeoff arising from offering a higher rebate: over the lower range of rebates tested ($0.80/kWh to $1.55/kWh), there were positive effects on customer satisfaction but no impacts on Flex event savings

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[2] Respondents rated their overall satisfaction with the program on a 0–10 scale, where 0 meant *extremely dissatisfied* and 10 meant *extremely satisfied*. PGE defined a 6–10 rating as *satisfied*.

from increasing the rebate. This suggests that larger rebates may raise customer satisfaction, but lower program cost-effectiveness.

TOU Rates

Customers under the TOU1 rate schedule encountered difficulties in shifting consumption from peak to off-peak hours.

The TOU1 rate used "day/night" off-peak and on-peak period definitions. As the on-peak period was set from 6:00 a.m. to 10:00 p.m., many customers were awake only during peak hours and asleep during off-peak hours, making load shifting inconvenient or difficult. Shifting loads would require many customers to adjust their sleep schedules or to have appliances programmed to run at night. Among TOU customers, those on the TOU1 rate had the lowest program satisfaction rates (57% in summer and 54% in winter) and did not achieve peak savings in either season. TOU1 respondents dissatisfied with Flex most often mentioned the rate schedule being difficult for their households; these respondents said it was not convenient or worth changing one's sleep time to do chores during off-peak periods.

TOU rate schedules with short peak-period definitions yielded peak savings and high satisfaction in summer.

In summer, TOU2 and TOU3 customers achieved significant savings during peak periods (8% and5%, respectively). They also saved 5%–6% during Flex event hours, which Cadmus used as a proxy for the peak capacity impact of TOU, even though TOU customers did not receive Flex event notifications or incentives. In summer, the TOU2 and TOU3 schedules had relatively short peak periods, from 3:00 p.m. to 8:00 p.m., which coincided with PGE's summer system peak and enabled customers to shift loads to off-peak periods. In summer, TOU2 and TOU3 customers had relatively high customer satisfaction ratings of 82%.

The simpler TOU rate schedule achieved the same peak period savings and satisfaction as the more complex one.

In summer, the TOU3 rate, with peak (3:00 p.m.–8:00 p.m.), mid-peak (11:00 a.m.–3:00 p.m.), and off-peak periods, reduced loads by 5% during the mid-peak period. However, no differences emerged in peak period savings between the simpler TOU2 rate, which only had peak (3:00 p.m.–8:00 p.m.) and off-peak periods, and the more complex TOU3 rate. TOU2 and TOU3 showed statistically similar program satisfaction rates in summer (TOU2 82%; TOU3 82%) and winter (TOU2 62%; TOU3 68%).

In winter, TOU customers experienced difficulties in shifting loads from peak to off-peak periods and achieving bill savings.

During winter, none of the TOU-only treatments produced statistically significant reductions in or shifts in peak-period loads. Either TOU did not affect customer loads, or the load impacts were too small to detect with the existing sample sizes. TOU customers also reported relatively low satisfaction with Flex (54%–68%) because of adverse bill impacts and the rate schedule being difficult for their households. TOU schedules had morning *and* evening peak periods. Notably in the survey's open-ended comments, TOU-only and Hybrid customers mentioned the program was more difficult to participate in during winter than summer. Moreover, TOU-only and Hybrid treatments showed significantly lower program satisfaction rates in winter (61%–71%) than in summer (76%–79%).[3] This seasonal pattern in program satisfaction for TOU-only and Hybrid treatments suggests that the TOU aspect may be more challenging for customers in winter than in summer.

TOU Recommendations

- Unless an economic case justifies shifting customer loads from mid-peak to off-peak hours, PGE should implement the TOU2 rate schedule, which is simpler for customers to understand.
- PGE should consider redesigning the winter TOU rate schedules by removing the morning peak period. This would minimize the potential for adverse customer bill impacts and simplify the customer experience.
- PGE should redesign the TOU1 rate schedule or offer TOU1 customers enabling technology to facilitate load shifting from peak to off-peak periods.
- PGE did not test the impacts of pairing enabling technology with TOU pricing, but studies of other TOU pricing programs suggest that enabling technology such as price-responsive smart thermostats can increase load shifting. PGE should consider testing the load impacts of enabling technology in the future.
- PGE should consider enhancing customer screening during the enrollment process to determine whether a customer is a good fit for a TOU rate.
- Given TOU customers' challenges in achieving winter bill savings, PGE should offer them more education about how to save energy or shift loads from peak to off-peak periods.

Opt-Out Behavioral Demand Response

Behavior-based treatments caused PGE customers to save energy during Flex events.
BDR-OO customers saved an average of 2.3% of consumption in summer and 1.2% of consumption in winter. PGE sent opt-out BDR customers Flex event alerts, encouragement to reduce consumption, and individualized post-event feedback but did not charge them higher electricity prices or provide them with rebates during Flex events, demonstrating that residential customers responded to non-price interventions.

Opt-out BDR program design yielded capacity benefits, but resulted in relatively low customer satisfaction.
PGE automatically enrolled over 12,000 residential customers in the BDR-OO treatment. While average savings per treated customer were small (only 1%–2% of consumption), total program demand savings were large due to the size of the treated population. In the future, PGE can deploy the BDR program to help manage system peaks, but at the potential cost of lower customer satisfaction: only 51% of BDR-OO customers in winter and 57% in summer rated the program a 6 or higher on a 10-point scale.

[3] Significant difference with 90% confidence (p≤.10).

Satisfaction ratings were likely low due to the opt-out program design and the unfamiliarity of many customers with behavioral demand response and the costs of supplying energy during utility system peaks. The program sent event notifications to many customers who had little interest in receiving them or participating in a BDR program. PGE also mentioned in the interviews that it received feedback from some BDR customers that it dispatched too many events and that these customers had not been aware that they could change their event notification settings.

BDR Recommendations

- PGE should consider using opt-out BDR for achieving capacity savings targets, given its success with BDR in reducing loads during this pilot; but it should consider possible changes to program design to increase customer satisfaction, such as:
  - Limiting the frequency of future BDR events, which would also limit the number of event notifications customers received.
  - Shortening the duration of future BDR events to lessen the burden on customers.
  - Spacing out future BDR events to avoid calling back-to-back events or multiple events in the same week.
  - Sending BDR customers a handy reminder magnet or sticker about BDR events and how to save, akin to the clock sticker PGE sent to TOU customers.
- PGE should clearly inform opt-out BDR customers that they can opt out of treatment, and should make it relatively easy for customers to opt out if they do not want to participate.

Opt-Out Peak-Time Rebates

The opt-out participation program design significantly increased program participation.
PGE attained a much higher participation by presenting customers with a choice to opt out of the program rather than opt in. PGE automatically enrolled approximately 1,600 customers in the PTR2-OO program. By the end of the Winter 2017/2018 season, only 2.3% of customers had opted out. In comparison, at the end of the recruitment period for opt-in PTR treatments, less than 7% of PGE customers accepted offers to participate in a PTR1 (4.3%), PTR2 (2.8%), or PTR3 (6.2%) treatment.[4] Of customers opting in to PTR treatment, between 4.5% and 6.3% subsequently opted out. The opt-out design took advantage of customers who were expected to be "complacent": they would neither opt in nor opt out of a demand response program, if given the choice. Cadmus estimated that 92% of opt-out customers were complacent customers. By making participation the default choice, PGE obtained program participation and peak capacity that it would not have achieved otherwise.

[4] PGE experimented with different marketing strategies during the first two waves and obtained higher rates of acceptance during the third wave after improving its approach. Also, PGE stopped recruiting for the opt-in PTR2 treatment after the second wave.

The design of the pilot participation choice (opt-in vs. opt-out) presents a tradeoff between savings per customer and number of participants.

Depending on the rebate amount, opt-in PTR customers saved 17% to 21% of consumption during summer Flex events and from 7% to 12% of consumption during winter Flex events. Customers automatically enrolled in PTR2 saved an average of 7% during summer Flex events and 5% during winter Flex events.[5] Cadmus estimated that in Summer 2017, "complacent customers"—who would neither opt in nor opt out of a PTR program if given the choice—saved 6% during Flex events. While opt-in PTR customers saved more, the opt-out design enrolled many more customers. As noted above, fewer than 6% of PGE customers took up offers to participate in the PTR program. In contrast, more than 97% of customers defaulted onto PTR2-OO remained in treatment through the end of the Winter 2017/2018 season.

Adding a peak-time rebate to behavior-based demand response increased Flex event demand savings and customer satisfaction.

The opt-out BDR treatment and the opt-out PTR treatment only differed in the rebate paid to customers for saving energy during Flex events. PTR customers received the same notifications, tips for saving energy, and individualized feedback about savings as BDR-OO customers. Opt-out PTR customers, however, saved significantly more during Flex events than BDR-OO customers (5% in winter and 7% in summer vs. 1% and 2%, respectively), demonstrating that the rebate lifted savings and complemented the behavior-based treatment. The rebate also increased customer satisfaction. PTR2-OO customers reported 73% program satisfaction in summer and 79% in winter—high customer satisfaction rates for customers automatically enrolled in a program. In contrast, BDR-OO customers only reported program satisfaction rates of 51% in summer and 57% in winter.

Opt-Out PTR Recommendation

- Given the tradeoff between savings per customer and numbers of participants, PGE should analyze whether the opt-in or opt-out PTR design proved more cost-effective, and whether each design will generate the desired aggregate demand response capacity.

Hybrid Treatments

TOU pricing did not enhance (and possibly diminished) savings from PTR during Flex events and customer satisfaction (TOUxPTR vs. PTR).

[5] The surveys also found that a higher percentage of opt-in (75% in summer, 89% in winter) than opt-out (37% in summer, 75% in winter) PTR2 customers reported participating in Flex events.

During Summer Flex events, opt-in PTR customers saved 17% to 21% of consumption, but TOUxPTR customers only saved 9% to 19%[6]. During Winter Flex events, opt-in PTR customers saved 7% to 12%, but TOUxPTR customers only saved 4% to 12%. TOU pricing may cause PTR customers to become inattentive to Flex event alerts, or TOUxPTR customers may have less incentive to save energy during Flex events because their consumption baseline used for calculating rebates is lower. In summer and winter, satisfaction with Flex was 10 to 20 percentage points lower for TOUxPTR customers than for PTR-only customers.

Adding peak-time rebates to TOU pricing increased customer satisfaction and Flex event savings (TOUxPTR and TOUxBDR vs. TOU-Only).
Peak-time rebates had positive impacts on customer satisfaction for TOU customers. Depending on the TOU rate, TOU-only customers reported program satisfaction ranging from 57% to 82% in summer and 54% to 68% in winter. In contrast, TOUxPTR customers reported satisfaction levels ranging from 70% to 88% in summer and from 69% to 73% in winter, suggesting that the PTR enhanced customer satisfaction with the program.

During Flex events (i.e., hours used in this report to approximate system capacity conditions), TOUxPTR customers also saved more than TOU-only customers. In summer, TOUxPTR or TOUxBDR customers saved from 8% to 19% of Flex event demand, while TOU-only customers saved from 2% to 8%. During Winter events, TOU2xPTR2 and TOU3xPTR2 customers saved 12% of consumption, while TOU-only customers did not save any demand.

Hybrid Treatment Recommendations

- If PGE's primary objective is to save demand during system peaks, it should consider enrolling more customers in PTR-only treatments than hybrid TOUxPTR treatments to maximize the impact on system peak.
- If PGE deploys TOU rates on a wide scale, it should consider pairing TOU rates with a peak-time rebate to raise customer satisfaction and Flex event savings.

Customer Experience

TOU and Hybrid customers reported higher satisfaction with the Flex pilot in summer than winter, primarily due to greater summer bill savings.

[6] The Flex event savings estimate for Hybrid customers indicates the combined effects of TOU and PTR during Flex events. The savings are estimated relative to customers who are treated with neither PTR nor TOU pricing.

Overall, participant respondents were more satisfied with the Flex pilot in Summer 2017 (74% *satisfied*) than Winter 2017/2018 (69% *satisfied*).[7] The seasonal satisfaction differences, however, were greatest for treatments involving TOU pricing, which typically produced annual bill savings, with most or all savings occurring in summer. For TOU-only and Hybrid treatments, respondents reported significantly higher program satisfaction in summer (76%–79% *satisfied*) than in the winter (61%–71% *satisfied*).[8] Summer and winter respondents giving the program satisfied ratings most often noted that the program delivered bill savings. Respondents giving a less-than-satisfied rating most often noted seeing little to no difference in their bill savings. In summer, 16% of TOU survey respondents said they saved on their electric bills, compared to 9% of TOU survey respondents in winter. These program satisfaction results align with demand savings estimates showing participants achieved higher peak-period load reductions in summer than winter.

Although PGE automatically enrolled them, opt-out PTR and BDR customers showed high event awareness and engagement with the pilot.

As expected, customers opting into the pilot exhibited high awareness of and engagement with Flex events. Depending on the season, 93% to 96% of opt-in PTR-only respondents and 94% to 97% of opt-in Hybrid respondents remembered receiving event notifications. Also, 76% to 86% of opt-in respondents reported conserving electricity during events in both seasons. These awareness and engagement levels were higher than for BDR-OO and PTR2-OO customers automatically enrolled in the pilots. and 89% of opt-out respondents remembered receiving event notifications. Also, 48% of opt-out respondents in summer and 63% of respondents in winter reported conserving energy during these events. This suggests that PGE can engage customers in achieving demand savings who are automatically enrolled in demand response programs.

PGE has an opportunity to increase peak period and Flex event demand savings from TOU rates through additional education with existing TOU customers.

TOU2 and TOU3-only and Hybrid treatments saved 5% to 8% of demand during peak periods and 8% to 20% of demand during Flex events, indicating that TOU treatments proved effective. TOU customers, however, did not have strong awareness of their rate schedules. Only about one-half of TOU and Hybrid respondents (52%) correctly identified their rate schedules from a list of three rate schedule images. That was only slightly better than results one would expect (33%) if all customers guessed at random. This suggests TOU customers could save more if they knew of their rate schedules. PGE might be able to increase TOU customer demand savings through doing additional education and outreach.

PGE identified several pilot implementation issues that negatively affected customer experiences and either corrected the issues or will correct them in future Flex deployments.

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7 Respondents rated their overall satisfaction with the program on a 0–10 scale, where a zero meant *extremely dissatisfied* and a 10 meant *extremely satisfied*. PGE defined a 6–10 rating as *satisfied*.

8 Significant differences at the 90% level (p≤.10).

In interviews with Cadmus, PGE managers and implementation contractors described several program implementation issues:

- PTR and BDR customers received inaccurate and delayed feedback regarding their demand savings during Flex events. The inaccurate feedback may have discouraged some customers from saving, and the delay in providing feedback prevented PGE from calling additional events until these issues resolved. By the start of Winter 2016/2017, PGE had resolved the savings calculation issues and managed to deliver feedback to participants within 24 to 48 hours of events.
- Another issue concerned communication about event notification settings. Some customers complained that they received too many notifications or that the notifications did not arrive through their preferred delivery channels. Many customers reported being unaware that they could change their notification settings. In the future, PGE plans to communicate more proactively with participants about options for program communications and will simplify the process for changing the settings.

Pairing technology with Flex treatments may improve customer's ability to achieve load reduction. While the Flex pilot did not test the impacts of pairing enabling technologies, such as smart thermostats, advanced water heaters, or in-home displays, with the pricing or behavior-based treatments, other studies have found the pairing of these technologies enhances peak demand savings. The experience of TOU1 customers illustrates the potential benefits of enabling technology. TOU1 customers reported challenges in shifting loads from daytime on-peak periods to nighttime off-peak periods; programmable or price-responsive enabling technologies may facilitate shifting of loads and increase TOU1 on-peak demand savings.

Customer Experience Recommendations

- PGE should consider modifying the TOU design and delivery for the winter season to help customers save or shift more electricity consumption. This would improve customer satisfaction and increase load impacts. Modifications could include eliminating the morning on-peak period, shortening the length of the on-peak periods, or automatically enrolling TOU customers in the PTR program. A conjoint analysis of the TOU program offering could examine tradeoffs between different rate schedule designs, customer satisfaction, and load impacts.
- PGE should provide TOU customers with additional education about their rate schedules. This information should be simple and easy to understand. One idea is delivering educational information through alternative media, such as online video.
- PGE should consider opt-out demand response programs as a component of its demand response portfolio. The Flex pilot demonstrated that opt-out programs can reach large numbers of customers and that 50% or more of customers automatically enrolled in PTR or BDR remained engaged, as measured by self-reported rates of Flex event awareness and conservation.

- PGE should conduct test events before the start of each season to assess readiness of its customer communications and data analytics platforms. Testing will allow PGE to correct issues before the season starts, refamiliarize customers with the program, and give customers a chance to change their communications preferences.

- PGE should consider conducting pilots to test the impacts of pairing enabling technologies such as smart thermostats or advanced water heaters with time-based rates or behavior-based treatments if PGE expects the technologies would be cost effective.

Marketing

Paper-based marketing and bill-savings messaging resonated most with customers.
PGE experimented with email, postcard, and business letter marketing, and found business letters achieved the highest customer marketing conversion rate (4.5%), followed by postcards (2.5%), and then email (1.5%).[9]

Business letters emphasized financial messaging (i.e., rate comparison information and a bill savings pitch). PGE initially used economic, control, and community messaging in the emails and post cards, but those approaches proved unsuccessful in enrolling customers. The recruitment survey also found a large majority of participants enrolled to save money on their electric bills (78%); far fewer respondents indicated enrolling to save energy (46%) or help the environment (28%).

Marketing Recommendation

- PGE should consider employing business letter marketing approach for future demand response programs to increase the cost-effectiveness of its marketing. This approach would include leading with bill savings and rate comparisons rather than energy savings or community as primary messages in postcards, emails, or other marketing channels.

[9] A conversion rate measures a given marketing channel's effectiveness in spurring enrollment, calculated by taking the number of customers who enrolled from a channel and dividing this by the total number of customers that the channel reached.

Introduction

In the next several years, PGE will face a shortfall in generating capacity from the planned closure of its Boardman facility in 2020 and the expected expiration of wholesale power contracts. At the same time, PGE plans to increase its production of electricity from intermittent renewable energy resources to comply with the requirements of Oregon Senate Bill 1547. In consideration of these developments, PGE's Integrated Resource Plan (2016) calls for the use of dispatchable resources including demand response to help manage system peak loads and to assist with the integration of renewable energy resources. The IRP sets a goal of adding demand response capacity of 77 MW in winter and 69 MW in summer.

Residential customers participating in demand response programs will provide an important source of Portland General Electric's (PGE) future demand response capacity. These programs use price signals, direct load control, behavior-based treatments, or combinations of these to encourage customers to reduce demand during periods when it is costly for the utility to supply or distribute electricity.

Demand response represents a fundamental shift in the utility's relationship with its customers. Customers participating in demand response programs do not simply just consume utility-supplied electricity; they also provide peak capacity to utilities. To take full advantage of this evolving "prosumer" role, PGE will need to offer its customers new retail electricity rates or other incentives as well as compelling education, marketing, and program experience to encourage customers to participate.

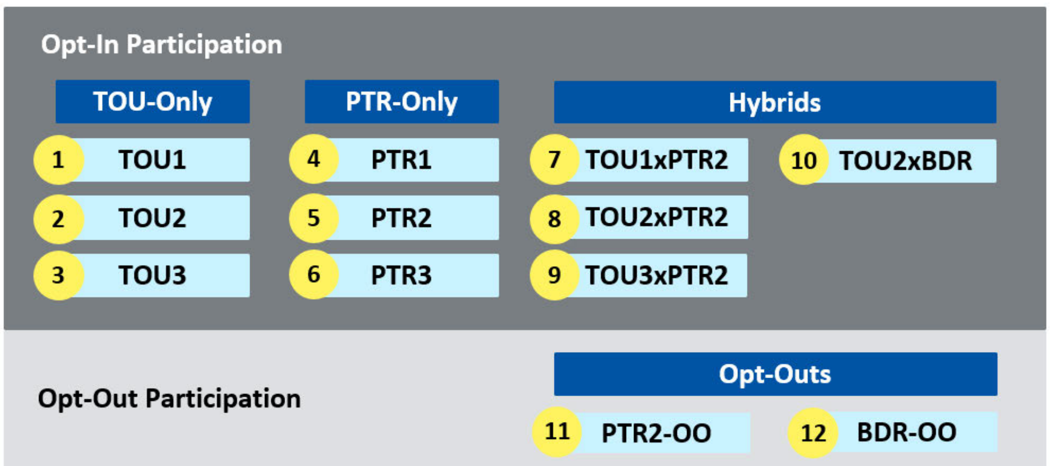
In 2015, PGE launched the Flex pilot program to test the effectiveness and customer acceptance of different demand response program offerings, including time-of-use (TOU) pricing, peak-time rebates (PTR), and behavioral demand response (BDR). By assessing a range of program treatment designs involving different incentive levels, rate structures, and recruitment approaches, PGE sought to understand its options and to lay the groundwork for a future where most of its residential customers participate in demand response programs.

This evaluation report assesses the design and delivery, load impacts, and customer experiences of 12 demand response treatments. PGE tested the demand response treatments as randomized control trials (RCTs), providing highly credible evidence about the treatment effects. The evaluation provides PGE with feedback about the pilot's performance in these areas, and presents insights that can be used to optimize PGE's future demand response program offerings.

Pilot Program Description

In 2016, PGE launched the Pricing and Behavioral Demand Response Pilot Program. The pilot enrolled approximately 14,000 residential customers and tested 12 pricing and behavior-based program design options (treatments), aimed at reducing residential peak demand during summer and winter months. The treatments featured TOU pricing, peak-time rebates (PTR), behavioral demand response (BDR), hybrid demand response (TOU in combination with PTR or BDR), and opt-out demand response (OO) that automatically enrolled customers. PGE offered the 12 treatments as the Flex Pilot Program. Figure 1 shows a diagram of the Flex Pilot Program's multi-treatment program design.

Figure 1. Twelve Treatments Tested in the Flex Pilot Program



PGE outlined the following Flex Pilot Program objectives:

- Implement the program over four seasons (e.g., Summer 2016, Winter 2016/2017, Summer 2017, and Winter 2017/2018), with six to 10 peak demand events per season
- Identify treatment(s) that could be cost-effective at scale, with 10% of customers participating
- Help customers achieve lower or cost-neutral rates
- Achieve positive customer experiences

To facilitate evaluation and planning for a future, full-scale rollout of Flex, PGE established planning estimates for expected demand reduction during Flex events (shown in Table 3). PGE developed the planning estimates based on load impacts reported by utilities operating similar demand response programs.

Table 3. Flex Pilot Program Demand Reduction Planning Estimates

Treatment	Summer	Winter
TOU-Only: TOU1, TOU2, TOU3	5.2%	5.8%
PTR-Only: PTR1, PTR2, PTR3	12.9%	14.2%
Hybrids (PTR): TOU1xPTR2, TOU2xPTR2, TOU3xPTR2	5.2%–12.9%	5.8%–14.2%
Hybrids (BDR): TOU2xBDR	3.0%–5.2%	3.3%–5.8%
PTR2-OO	6.4%	7.1%
BDR-OO	3.0%	3.3%

Note: Table shows PGE planning estimate of percentage demand savings during Flex events.

PGE also set total enrollment goals of approximately 3,850 customers for the 10 opt-in treatments and 13,610 customers for the two opt-out treatments. These enrollment goals ensured sufficient statistical power for testing the various treatments.

PGE designed and implemented the pilot program with assistance from CLEAResult and AutoGrid as the implementation contractors. CLEAResult co-managed day-to-day program implementation and executed program marketing, while subcontracting with AutoGrid to provide the program's technology platform software and data services. PGE selected Cadmus as the program evaluator, assisting PGE with research design, savings analyses, and customer surveys.

Treatments Tested

The Flex Pilot Program tested 12 treatments, consisting of TOU, PTR, BDR, Hybrids, and Opt-Out program designs. This section summarizes these five program designs and the 12 different treatments.

Time-of-Use Rates

Customers enrolled in a TOU treatment paid a different unit price for electricity depending on when the electricity was consumed. TOU rates encourage customers to shift electricity consumption from periods when the utility's cost of supplying electricity is high to periods when the cost is low.

PGE tested three TOU rate schedules: TOU1, TOU2, and TOU3. Table 4 shows TOU rate schedules for summer and winter seasons under Flex.[10] TOU1 and TOU2 only had off-peak and on-peak periods, with TOU1 charging lower on- and off-peak rates, but having a longer on-peak period than TOU2. TOU3 had off-peak, mid-peak, and on-peak periods, with the off-peak rate below and the on-peak rate above those of TOU1 and TOU2. The TOU rate schedules also varied by season. During winter, each TOU rate included morning and afternoon peak periods, while, during summer, the TOU rates only included an afternoon peak period.

[10] Summer TOU rates are in effect from May 1 to October 31. Winter TOU rates are in effect from November 1 to April 30. This evaluation estimated TOU pricing impacts in summer between June 1 and September 30 and in winter between December 1 and February 28.

In summer, the peak-to-off-peak price ratio equaled 1.8 for TOU1, 2.1 for TOU2, and 2.6 for TOU3. In winter, the peak-to-off-peak price ratios were essentially unchanged, equaling 1.8 for TOU1, 2.1 for TOU2, and 2.5 for TOU3. A higher peak-to-off-peak price ratio should encourage greater load shifting, all else equal.

During the first year of participation, TOU customers could request refund if their annual electricity bills exceeded what they would have paid under the standard PGE residential rate. After the first year of participation, the bill protection lapsed and customers could not request a refund.

Table 4. Flex Schedule: TOU Summer and Winter Rates*

Summer	TOU1	TOU2	TOU3
Off Peak	7.5₵/kWh	8.3₵/kWh	6.9₵/kWh
	10:00 pm–6:00 am	8:00 pm–3:00 pm	10:00 pm–11:00 am
Mid Peak			11.9₵/kWh
			11:00 am–3:00 pm 8:00 pm–10:00 pm
On Peak	13.6₵/kWh	17.6₵/kWh	18.0₵/kWh
	6:00 am–10:00 pm	3:00 pm–8:00 pm	3:00 pm–8:00 pm
Winter	**TOU1**	**TOU2**	**TOU3**
Off Peak	8.0₵/kWh	8.8₵/kWh	7.4₵/kWh
	10:00 pm–6:00 am	8:00 pm–7:00 am; 11:00 am–3:00 pm	10:00 pm–7:00 am
Mid Peak			12.4₵/kWh
			11:00 am–3:00 pm; 8:00 pm–10:00 pm
On Peak	14.1₵/kWh	18.1₵/kWh	18.5₵/kWh
	6:00 am–10:00 pm	7:00 am–11:00 am; 3:00 pm–8:00 pm	7:00 am–11:00 am; 3:00 pm–8:00 pm

* TOU rates in effect as of August 1, 2016.

TOU customers received a rate schedule (the Flex schedule), depicting these various costs and times. Each month during summer and winter seasons, PGE sent TOU customers a report on how much money they saved under the TOU rate, with comparisons to the previous month, and tips on how to conserve or shift energy. For the first year, PGE provided bill protection to customers on TOU rates. This insured that TOU customers would not pay more than they would have if they remained on the standard flat rate. Bill protection was applied to a customer's annual—not monthly—consumption.

Peak-Time Rebate

Customers enrolled in a PTR treatment received cash rebates for reducing electricity consumption during Flex time events. PGE tested three rebate amounts[11]:

- PTR1 customers received $0.80 per kWh of savings
- PTR2 customers received $1.55 per kWh
- PTR3 customers received $2.25 per kWh

A customer's PTR savings were calculated relative to his or her baseline consumption, which was an estimate of what normal consumption would have been during the event hours.

One day in advance, PGE dispatched event notifications via email, text, and voice mail to customers, with another notification on the day of the event. These event notifications came with tips on conserving or shifting energy.

Within two days after an event, PGE provided PTR customers with feedback regarding their performance, showed them how much electricity they saved and incentives earned. Within two weeks after the season's end, PGE mailed a report (along with a rebate check) to customers, addressing the total amount of electricity they saved during the season's events. The end-of-season report also showed energy savings for the customer and all Flex Program participants.

Behavioral Demand Response

The BDR treatment used behavior-based strategies to encourage customers to reduce electricity consumption during Flex events. PGE sent BDR customers event notifications, similar to those for PTR treatment, asking them to reduce electricity during specific hours of high demand. BDR customers, however, did not receive rebates or other financial incentives for reducing consumption during events. Rather, PGE provided BDR customers with social-normative peer comparisons and appeals to participate in collective actions to reduce electricity demand during peak periods. BDR customers received an end-of-season report similar to that provided for the PTR treatment, but they did not receive a rebate check.

Hybrids

Customers in Hybrid treatment received a combination of TOU and PTR treatments or a combination of TOU and BDR treatments:

- **TOUxPTR**: PGE tested three TOU rate treatments paired with the PTR2 treatment: TOU1xPTR2, TOU2xPTR2, and TOU3xPTR2. Customers in this Hybrid treatment paid different unit prices for electricity, depending on the day of week and time of day, *and* became eligible to receive a rebate for reducing consumption below baseline levels during Flex events.

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11 PTR incentives reflect pricing as of August 1, 2016.

- **TOU2xBDR**: PGE tested TOU2 paired with BDR. Customers in this Hybrid treatment paid the TOU2 rate *and* were asked to reduce consumption during Flex events, without financial incentive.

Opt-Out Participation

PGE tested BDR as an opt-out treatment, automatically enrolling customers but allowing them to opt out at any time. PGE also tested PTR2 as an opt-out and opt-in treatment to determine how the framing of the participation choice affected enrollments, demand savings, and customer satisfaction. PGE administered the PTR2 treatments identically to opt-out and opt-in customers.

Research Design and Program Set-Up

PGE implemented a large, randomized field experiment to test the Flex Pilot Program, using recruit-and-deny randomized controlled trials (RCT) to test the 10 opt-in treatments and a standard RCT to test the two opt-out treatments. Randomized field experiments serve as the gold standard for demand-side management program evaluation and are expected to produce unbiased estimates of treatment effects.

Customer Eligibility Requirements

PGE identified 246,000 residential customers eligible to participate in the pilot. To receive an invitation to participate or to be automatically enrolled in the pilot, customers had to meet the following criteria:

- Receive electricity service from PGE and the current service address for at least the previous 12 months
- Not be a solar energy customer (i.e., did not have solar panels installed on the premises and on a net metering rate)
- Not be a participant in the Rush Hour Rewards thermostat control demand response program
- Provide PGE with a valid email address
- Have a functioning interval consumption meter that records and communicates energy consumption to PGE

PGE did not impose eligibility requirements regarding minimum or maximum energy consumption or peak demand levels, allowing customers with low or high consumption levels to participate. However, PGE screened all eligible customers for expected bill savings from TOU treatments. Only customers expected to reduce their annual electricity bill payments with TOU pricing were given the opportunity to participate.[12]

[12] Only customers with positive bill savings under the assumption that they shifted 7% of load from peak period to off-peak period were invited to participate in a TOU or Hybrid treatment.

Random Assignment to Treatment

PGE randomly assigned eligible customers to a pricing treatment (e.g., TOU2 or PTR1) and to a test or control group, and then invited them to participate in the pilot. Customers who opted into the pilot and had been randomly assigned to a test group were placed into treatment, while customers who opted in and had been assigned to the control group were not enrolled. Customers assigned to an opt-out treatment test group were automatically enrolled and received the assigned treatment unless they opted out. Customers assigned to the control group of an opt-out pricing treatment did not receive that treatment or any program-related communications. None of the customers assigned to a control group could participate in the Flex pilot.

Marketing and Recruitment

Customer recruitment for 10 opt-in treatments began in mid-February 2016 and continued through Spring 2017. PGE recruited customers to the pilot in three waves: Spring 2016; Summer/Fall 2016; and Spring 2017.

PGE and CLEAResult developed marketing materials and messaging for the pilot. This messaging focused on economics (personal gains, including bill savings), control (taking charge of your consumption), and community (the greater good). For customers invited to participate in a TOU treatment, the marketing presented expected bill savings under the assumptions of 7% and 15% shifts in consumption from the peak to off-peak period. For TOUxPTR hybrid customers, the marketing also presented bill savings with expected PTR-earnings.

In marketing the program to customers, PGE employed the following communication channels:

- **Email.** PGE sent multiple emails to customers with valid email addresses.
- **Direct mail.** PGE first sent postcards and then later sent business letters.
- **Flex website:** PGE established a customer engagement web portal, where customers could enroll in the program, review their current pricing plan, view information on ways to save, and obtain information about their household’s electricity consumption.

Opt-In Treatment Recruitment and Enrollment Process

As discussed, PGE and Cadmus randomly preassigned eligible customers to one of 10 opt-in treatments and to either a test group or a control group. All eligible customers received an email and postcard invitation to enroll in Flex. The email and postcard included rate comparison information pertaining to the customer’s assigned pricing option. The email and postcard provided customers with an activation code to sign up through the Flex website. Customers received a reminder email to enroll a week after the initial email and were given up to 45 days to enroll.

After logging into the Flex website, a customer completed enrollment by accepting the assigned pricing treatment. Test group customers who accepted their assigned pricing treatment became program participants. Control customers who accepted their pricing treatment were not placed into treatment, but rather received a message saying they did not qualify to enroll currently, but may be able to do so in the future.

PGE initially offered test and control customers a reward for enrolling during the early 2016 recruitment period. Enrolled customers could choose between an Amazon gift card and a pair of zoo tickets. After seeing very little enrollment impact, however, PGE eliminated the enrollment reward.

Test group customers participating in the 10 opt-in pricing treatments could opt out at any time by contacting the pilot's call center.

Opt-Out Treatment Enrollment Process

PGE automatically enrolled randomly-chosen customers into one of two opt-out treatments: a peak-time rebate (PTR2-OO); or a behavioral demand response (BDR-OO). Customers randomly assigned to an opt-out treatment test group received a welcome email and postcard in mid-June 2016. The email and postcard included a link to access the Flex website.

Test-group customers participating in an opt-out treatment could opt out of the program in two ways: unsubscribing to the emails; or contacting the program's call center.

Recruitment Targets and Actual Enrollments

Table 5 shows PGE's enrollment targets, the number of customers enrolled in each Flex test group at the beginning of each season, and historical maximum enrollment as a percentage of the target. The enrollment targets were determined through statistical power analysis, with the objective of enrolling enough customers to detect the expected load impacts through statistical analysis. At first, recruitment proceeded slower than expected. In Summer 2016, only 50% of the targeted customers had enrolled, but, by Summer 2017, the program exceeded its targets, with many treatments reaching 150% or more of the sample size targets.[13] All treatments except for BDR-OO met their enrollment targets.

[13] Because PTR2 had recruitment priority to achieve a sample size large enough to support analysis for the Summer 2016 season, PGE stopped recruiting for PTR2 after Spring 2016.

Table 5. Flex Customer Recruitment Targets and Enrollments

Treatment	Number of Customers (N)				Target (N)	Percent of Target Achieved (Maximum)
	Summer 2016	Winter 2016/2017	Summer 2017	Winter 2017/2018		
PTR1	112	144	368	344	220	167%
PTR2	243	227	225	206	220	110%
PTR3	165	219	456	414	220	207%
TOU1	136	152	413	386	390	106%
TOU1xPTR2	132	146	346	329	220	157%
TOU2	480	564	1013	946	875	116%
TOU2xBDR	184	217	898	833	875	103%
TOU2xPTR2	251	234	220	202	220	114%
TOU3	130	158	432	401	390	111%
TOU3xPTR2	126	147	321	292	220	146%
PTR2_OO	375	703	631	564	430	163%
BDR_OO	6,233	11,215	10,089	9,095	13,180	85%
Total Opt-In	**1,959**	**2,208**	**4,692**	**4,353**	**3,850**	**122%**
Total Opt-Out	**6,608**	**11,918**	**10,720**	**9,659**	**13,610**	**88%**

Table 6 shows target and enrolled numbers of control group customers by treatment and season for the Flex pilot study. The control group sizes for individual treatments largely mirror those for the test groups. All treatments except BDR-OO achieved their targets by Summer 2017.

Table 6. Flex Control Group Sizes

Treatment	Number of Customers (N)				Target (N)	Percent of Target Achieved (Maximum)
	Summer 2016	Winter 2016/2017	Summer 2017	Winter 2017/2018		
PTR1	121	155	363	343	220	165%
PTR2	212	199	191	181	220	96%
PTR3	160	218	453	422	220	206%
TOU1	114	128	454	417	390	116%
TOU1xPTR2	118	123	326	302	220	148%
TOU2	388	453	554	513	390	142%
TOU2xPTR2	230	208	189	171	220	105%
TOU3	108	136	460	422	390	118%
TOU3xPTR2	126	159	309	287	220	140%
PTR2_OO	405	730	662	605	430	170%
BDR_OO	6,186	11,178	10,087	9,081	13,180	85%
Total Opt-In	**1,577**	**1,779**	**3,299**	**3,058**	**2,490**	**132%**
Total Opt-Out	**6,591**	**11,908**	**10,749**	**9,686**	**13,610**	**87%**

Event and Data Management

CLEAResult subcontracted with AutoGrid to operate the Flex Pilot Program's technology platform and to provide PGE with program management software and data management services. AutoGrid built and configured an online system to handle data from three different program designs (TOU, PTR, and BDR), employing a two-part system to manage the program's demand response events and data:

- The engagement portal (Flex website), which houses and tracks customer-facing program data and information
- The demand response management system, designed to schedule events and measure consumption at short time intervals

AutoGrid's system communicated with PGE's customer information system to gather up-to-date customer account information and, through PGE's advanced metering infrastructure (AMI), to gather customer interval consumption data at the meter level. PGE scheduled and dispatched events via the AutoGrid system, which sent event notifications to customers on the day before the scheduled event. On the day after the event, the AutoGrid system received and analyzed interval consumption data and estimated the load impacts. After reviewing the event performance results, PGE released them to customers, usually within 24-48 hours.

Table 7 shows Flex events that PGE called over the two summer and winter seasons.

Table 7. Flex Time Events by Season

Season	Date	Event Period	Notes
Summer 2016	7/27/2016	4:00 p.m.–7:00 p.m.	
	7/29/2016	4:00 p.m.–7:00 p.m.	
	8/11/2016	4:00 p.m.–7:00 p.m.	
	8/12/2016	4:00 p.m.–7:00 p.m.	
	8/18/2016	4:00 p.m.–7:00 p.m.	
	8/25/2016	4:00 p.m.–7:00 p.m.	
Winter 2016/2017	12/6/2016	4:00 p.m.–7:00 p.m.	
	12/8/2016 (snow day)	4:00 p.m.–7:00 p.m.	
	12/15/2016 (snow day)	4:00 p.m.–7:00 p.m.	BDR-OO not dispatched.
	1/3/2017	4:00 p.m.–7:00 p.m.	
	1/4/2017	4:00 p.m.–7:00 p.m.	
	1/11/2017	5:00 a.m.–8:00 a.m.	
	2/1/2017	7:00 a.m.–10:00 a.m.	
	2/3/2017 (snow day)	7:00 a.m.–10:00 a.m.	TOU2xBDR and BDR-OO not dispatched.
Summer 2017	7/25/2017	4:00 p.m.–7:00 p.m.	
	8/1/2017	5:00 p.m.–8:00 p.m.	
	8/3/2017	4:00 p.m.–8:00 p.m.	
	8/7/2017	4:00 p.m.–7:00 p.m.	TOU2xBDR and BDR-OO not dispatched.
	8/9/2017	3:00 p.m.–6:00 p.m.	
	8/28/2017	4:00 p.m.–8:00 p.m.	
	9/5/2017 (fire day)	4:30 p.m.–7:30 p.m.	Air quality issue from Eagle Creek fire.
Winter 2017/2018	1/3/2018	5:00 p.m.–8:00 p.m.	
	1/9/2018	5:00 p.m.–7:00 p.m.	TOU2xBDR and BDR-OO not dispatched.
	1/18/2018	5:00 p.m.–8:00 p.m.	
	1/25/2018	5:00 p.m.–8:00 p.m.	TOU2xBDR and BDR-OO not dispatched.
	1/31/2018	5:00 p.m.–8:00 p.m.	TOU2xBDR and BDR-OO not dispatched.
	2/20/2018	5:00 p.m.–8:00 p.m.	
	2/23/2018	7:00 a.m.–10:00 a.m.	

Evaluation Objectives

PGE specified the following evaluation objectives for the Flex pilot:

- Estimate the load impacts for each treatment and compare the estimated treatment effects.
- Assess customer enrollments in and satisfaction with the different treatments, including opt-in and opt-out treatments.
- Assess whether customer opt-in rates, satisfaction, and estimated load reductions depend on the PTR incentive amount or TOU pricing schedule.
- Determine whether behavior-based treatments result in significant and sustained reductions in customer demand.
- Assess whether Hybrid treatments result in larger peak demand reductions than single treatments.
- Identify implementation challenges, improvement opportunities, and potential for expanding the pilot.
- Assess program successes, challenges, and areas for improvement and scalability.

PGE's research objectives did not include cost-effectiveness analysis, as PGE planned to conduct the cost-effectiveness analysis using the study's results as inputs.

Evaluation Activities

Evaluation Background

In October 2015, PGE hired Cadmus to evaluate the Flex pilot. At the beginning, Cadmus assisted with the research design for the evaluation, which involved selecting demand response treatments, designing the randomized field experiments, and determining minimum sample sizes. After selecting the 12 treatments for testing, PGE began implementing the pilot. Cadmus assisted by randomly assigning eligible customers to one of the 12 treatments and to a test or control group. In March 2016, PGE began recruiting customers for enrollment; this was the first of three recruitment waves, with subsequent waves launching in summer/fall 2016 and spring 2017.

This Flex evaluation covers two summers and two winters, beginning in June 2016 and ending in February 2018. While Cadmus evaluated the pilot during all four seasons, this report focuses on Summer 2017 and Winter 2017/2018 seasons because the pilot did not reach its customer recruitment targets until summer 2017 and PGE changed some aspects of the program's delivery during the first two seasons.

To assess program delivery, design, and the customer experience, Cadmus performed a series of participant surveys (for treatment and control groups), including just after recruitment, during seasons after a peak-saving events, and at the end of a season, after all events had been completed. Cadmus also conducted multiple interviews with program and implementation staff at various points across the evaluation cycle.

Cadmus estimated pilot load impacts by analyzing hourly AMI customer consumption data. This involved performing separate regressions by season and treatment to assess differences in loads between test and control customers.

Table 8 summarizes the Flex pilot evaluation activities and how each relates to PGE's evaluation objectives. Below, we discuss each of these evaluation activities in greater detail, except for the research design, which was discussed already.

Table 8. Flex Pilot Evaluation Activities

Activity	Description	Outcomes	Relevance to Study Research Objectives
Research design	Designed recruit-and-deny RCT for opt-in treatments and RCT for opt-out treatments. Determined sample sizes for each treatment required to detect expected savings.	Randomized field experiment design and required sample sizes to obtain accurate and precise estimates of treatment effects.	1, 2, 3, 4, 5
Data collection and preparation	Collecting and preparing analysis of individual-customer AMI meter interval consumption data.	Final analysis sample for estimation of load impacts.	1
Load impact analysis	Regression analysis of individual-customer AMI meter interval consumption data.	Estimates of Flex event savings for 12 treatments and for peak and off-peak load impacts for TOU pricing.	1, 3, 4, 5, 6
PGE manager and implementation contractor interviews	Interviewed managers and contractors regarding program design, implementation, successes, and challenges.	Documentation of pilot implementation and lessons learned.	1, 6, 7
Customer surveys	Recruitment, event, and customer experience surveys.	Findings about customer satisfaction with the program and PGE, customer engagement, and event awareness.	2, 3, 6, 7

Data Collection and Preparation

Cadmus collected and prepared the following data for analysis:

- Individual-customer AMI meter electricity consumption data for all test and control group customers
- Weather data for each customer from the NOAA weather station closest to each customer's residence.
- Pilot enrollment, program participation, and account closure data for customers who received an invitation to participate in Flex, were automatically enrolled in the pilot (opt-out BDR or PTR), or assigned to the opt-out BDR control group or PTR control group.
- Dates and times of all Flex events and rate schedules for all Flex TOU pricing treatments

The AMI meter data recorded a customer's electricity consumption at 15 or 60-minute intervals and covered 12 months before the customer first received treatment (i.e., the customer's TOU rate became active) and all post-treatment months while the customer's account remained active. Cadmus aggregated all 15-minute interval consumption data to the customer-hour level. We performed standard data-cleaning steps to address duplicate observations, extreme outliers, and missing values. These data cleaning steps are discussed in Appendix A.

The weather data were high-frequency, asynchronous temperature and humidity readings from seven NOAA weather stations across PGE's service area. Cadmus aggregated the weather data to the hourly level and merged them with the hourly interval consumption data.

The pilot enrollment and program participation data included the following fields for each customer:

- Assignment to treatment (e.g., BDR, TOU1, etc.), assignment to test or control group, and indicator for recruiting wave (Wave 1, Wave 2, or Wave 3)
- For opt-in customers an indicator for whether the customer opted into the pilot and the date when the customer opted in.
- The official enrollment date if the customer opted into the pilot and had been assigned to the test group
- For customers assigned to receive an opt-out treatment, the date when the customer was automatically enrolled in the pilot.
- The account closure date if the customer's account closed during the pilot.
- The date the customer unenrolled from the pilot if the customer opted out of treatment.

Cadmus used the pilot enrollment and program participation data to identify customers in the test and control groups for each treatment, to define different variables for the load impact analysis, such as treatment and test-group indicator variables, to develop survey sample frames, and to calculate treatment opt-out rates.

In cleaning and preparing the AMI meter data, Cadmus encountered several issues that had to be addressed before the data could be analyzed. These issues included:

- Some AMI datasets were recorded on Coordinated Universal Time (UTC) instead of Pacific Time (UTC -8 or UTC -7).
- During the pre-treatment period, some customers' AMI meter data were recorded as integer kWh instead of as watt-hours.
- PGE did not provide pretreatment data for the same 12 months for all pilot customers

Appendix A discusses Cadmus' solutions to these issues. Robustness checks of the Flex treatment savings estimates indicate that the estimates were not sensitive to the specific solutions Cadmus developed.

Analysis Samples

Table 9 shows the initial and final analysis samples for each treatment in Summer 2017 and Winter 2017/2018 seasons. The initial analysis sample includes all customers who were randomly assigned to a test or control group and whose billing account remained active at the beginning of the Flex season.

Customers who opted out of treatment were included in both total enrollment and final analysis customer counts. Customers who moved or discontinued electricity service before the season began were excluded from samples.

Table 9. Flex Pilot Final Analysis Sample Sizes

Treatment	Summer 2017			Winter 2017/2018		
	Initial Analysis Sample (N)	Final Analysis Sample (N)	Analysis Sample Percentage	Initial Analysis Sample (N)	Final Analysis Sample (N)	Analysis Sample Percentage
PTR1	731	722	99%	687	678	99%
PTR2	416	408	98%	387	380	98%
PTR3	909	889	98%	836	823	98%
PTR2-OO	1,293	1,256	97%	1,169	1,149	98%
BDR-OO	20,176	19,587	97%	18,176	17,889	98%
TOU1	867	827	95%	803	787	98%
TOU2	1,567	1,510	96%	1,459	1,406	96%
TOU3	892	849	95%	823	805	98%
TOU1xPTR2	672	638	95%	631	612	97%
TOU2xPTR2	409	385	94%	373	354	95%
TOU2xBDR	1,452	1,398	96%	1,346	1,317	98%
TOU3xPTR2	630	598	95%	579	559	97%

The final analysis sample includes customers used in the impact estimation. The analysis sample excluded only a small number of test and control group customers in each treatment. For most treatments, the analysis included more than 97% of enrolled customers in the analysis. The main drivers of customer attrition from the analysis sample included lack of pre- or post-period AMI data.

Cadmus verified that there were not statistically significant differences in pre-treatment consumption between test and control group customers in the final analysis sample. For almost all treatments, the test and control groups were well balanced. Appendix C provides detailed balance test results.

Savings Estimation Approach

Cadmus estimated savings for each Flex treatment by collecting individual-customer AMI interval consumption data from before and after the customer enrolled in the Flex pilot and by comparing the peak demand of customers in the randomized test and control groups. This evaluation reports the following impacts:

- Flex event demand savings for all treatments, including TOU rates
- Peak period and off-peak period load impacts for TOU-based treatments, including TOU-only and hybrid treatments

We provide an overview of the estimation approach but a more detailed description is found in Appendix B.

Event-Based Treatments

Cadmus estimated the demand savings from event-based treatments (e.g., PTR1, opt-out BDR) by comparing demand during Flex events of customers in the randomized test and control groups. Using data for event hours during each winter or summer season, Cadmus estimated a multivariate panel regression of customer hourly energy demand on control variables for pretreatment hourly average demand, hour-of-sample fixed effects, and assignment to treatment. We estimated a separate model for each treatment.

The pretreatment demand variables controlled for average differences in electricity demand between customers during Flex event hours. Cadmus calculated separate mean pretreatment demand for morning and evening hours for each season, using AMI interval data for days before the beginning of the Flex season. Cadmus did not calculate mean pre-treatment demand using non-event days during the demand response season in consideration of evidence from other studies showing that event-based treatment can produce savings on non-event days. The hour-of-sample fixed effects controlled for weather and other unobserved factors specific to each event hour.

Cadmus estimated the models by ordinary least squares (OLS) and clustered the standard errors on customers to account for correlation over time in customer demand. Given the random assignment of customers to test and control groups, the regression was expected to produce an unbiased estimate of the treatment effect. Cadmus estimated alternative model specifications to test the estimates' robustness to specification changes, and found the results were very robust. Cadmus tested specifications that included indicator variables for a customer's recruitment wave (i.e., Wave 1, Wave 2, or Wave 3) as standalone variables and interacted with other explanatory variables and that dropped the pre-treatment consumption variables from the regression.

Time of Use Rate and Hybrid Treatments

Cadmus estimated treatment effects for TOU rate and hybrid-TOU rate treatments by comparing demand of customers in each treatment's randomized test and control groups. Using interval data on customer demand for each winter or summer season, Cadmus estimated a multivariate panel regression of customer hourly energy demand on control variables for pretreatment demand, peak and off-peak hours, day-of-the-week, weather, and assignment to treatment. We estimated treatment effects for Summer 2017 using data from June 1, 2017 to September 30, 2017 and for Winter 2017/2018 using data from December 1, 2017 to February 28, 2018. We estimated a separate model for each treatment.

Cadmus estimated the TOU and Hybrid models by OLS and clustered the standard errors on customers. Again, because of random assignment of customers to test and control groups, the regression was expected to produce unbiased savings estimates. Cadmus also estimated alternative model specifications to test the robustness of estimates to specification changes. For example, Cadmus tested specifications that included indicator variables for a customer's recruitment wave (i.e., Wave 1, Wave 2, or Wave 3) as standalone variables and interacted with other explanatory variables. The results proved robust to this and other specification changes. To estimate the treatment effect for the TOU3 rate, which included a mid-peak period, Cadmus added an indicator variable for the mid-peak period to the specification.

To estimate treatment effects for the Hybrid treatments such as TOU1xPTR2 or TOU2xBDR, Cadmus specified a model that allowed the effect of peak period hours to depend on whether the hour was a Flex event hour.

Adjusting the Treatment Effects for Customer Opt-Outs

Estimation of the average treatment effect using data for all customers who were randomly assigned to the test or control groups and whose account remained active provides an estimate of the intent-to-treat (ITT) effect. However, not all customers assigned to treatment received treatment or treatment for the duration of the study. Over the randomized field experiment's course, some customers opted out of the pilot, ending their participation. Including these opt-outs in the analysis yields a savings estimate across customers who remained in treatment and those who opted out.

To estimate the average treatment effects for customers randomly assigned to and remaining in treatment, Cadmus scaled the intent-to-treat (ITT) savings estimates by dividing them by one minus the percentage of customers assigned to treatment who opted out before or during the season.[14] This produces an estimate of savings for treated customers. Since, in general, the opt-out rates for individual treatments were small, scaling of the ITT savings estimates had little effect.

Staff Interviews

Over the course of two summer and winter Flex seasons, Cadmus conducted five interviews with PGE and CLEAResult managers of the Flex pilot. The first interview occurred prior to Summer 2016 and focused on documenting and understanding the program design, recruitment, marketing, and delivery plan for the individual treatments. After each subsequent summer and winter season, Cadmus conducted additional interviews, focused on implementation changes and new perspectives on program successes, challenges, and learnings. Cadmus also used information from the interviews to design and refine the customer surveys for each season.

[14] This scaling produces an unbiased estimate of the treatment's effect for treated customers (i.e., those not opting out) if customers who opt out do not continue to save demand. If opt-out customers continue to save, the treatment effect estimate will be biased upward. Although customers did not receive event notifications after opting out, they could continue to save demand if they had programmed thermostats or other household appliances to run during off-peak periods and do not adjust the settings after opting out.

Customer Surveys

Cadmus designed and administered the following six customer surveys online:

- Recruitment survey (fielded in May 2016)
- Summer 2016 event survey (fielded in August 2016)
- Summer 2016 experience survey (fielded in November/December 2016)
- Winter 2016/2017 experience survey (fielded in April 2017)
- Summer 2017 experience survey (fielded in January 2018)[15]
- Winter 2017/2018 experience survey (fielded in April 2018)

The recruitment survey asked test group customers in the 10 opt-in treatments about how they heard about Flex, their awareness of TOU pricing and Flex events, about their satisfaction with PGE, and questions designed to establish demographics.

The event surveys asked test group customers in PTR and BDR treatments about event notifications and participation, load-shifting and conservation behaviors, and satisfaction with Flex and PGE. Control group customers were surveyed at the same time to collect comparative data on satisfaction with PGE.

The experience surveys asked test group customers in all 12 treatments about program awareness and participation, load-shifting and conservation behaviors, satisfaction with Flex and PGE, and demographics. Control group customers were surveyed at the same time to collect comparative data on satisfaction with PGE and demographics.

Each survey took respondents, on average, five minutes to complete and were fielded for a two-week period. Respondents did not receive an incentive or reward for completing a survey. For more details on the customer survey design, see Appendix E.

Survey Sampling and Response Rates

The number of test and control customers available at the time of survey fielding in each of the 12 treatments determined the sampling method for customer surveys. For all treatments except BDR-OO, Cadmus surveyed the census of active customers. For BDR-OO, however, Cadmus surveyed a random sample of 3,333 customers due to the very large number of customers in this treatment. Table 10 shows the number of test group customers contacted for each survey and the response rates by opt-in and opt-out treatment type. Table 11 shows the number of control group customers contacted and the response rate by opt-in and opt-out treatment types. For sampling and response rate details on each of the 12 treatments, see Appendix E.

[15] Cadmus fielded the Summer 2017 experience survey late compared to the previous summer experience survey due to survey instrument revisions and coordination with PGE on customer contact approval.

Table 10. Customer Survey Samples and Response Rates: Test Group

	Recruitment Survey 2016	Summer 2016 Event Survey	Summer 2016 Experience Survey	Winter 2016/2017 Experience Survey	Summer 2017 Experience Survey	Winter 2017/2018 Experience Survey
Opt-In Treatments						
Number of Contacted	865	969	1,467	1,659	3,828	3,635
Number of Completes	458	348	319	328	817	833
Response Rate	53%	36%	22%	20%	21%	23%
Opt-Out Treatments						
Number of Contacted	–	3,610	3,551	3,679	3,895	3,840
Number of Completes	–	329	119	160	202	277
Response Rate	–	9%	3%	4%	5%	7%
Total (Opt-In and Opt-Out Treatments Combined)						
Number of Contacted	865	4,579	5,018	5,338	7,723	7,475
Number of Completes	458	677	438	488	1,019	1,110
Response Rate	53%	15%	9%	9%	13%	15%

Table 11. Customer Survey Samples and Response Rates: Control Group

	Summer 2016 Event Survey	Winter 2016/2017 Experience Survey	Winter 2017/2018 Experience Survey
Opt-In Treatments			
Number of Contacted	–	–	2,647
Number of Completes	–	–	599
Response Rate	–	–	23%
Opt-Out Treatments			
Number of Contacted	3,602	3,729	3,926
Number of Completes	389	345	362
Response Rate	11%	9%	9%
Total (Opt-In and Opt-Out Treatments Combined)			
Number of Contacted	3,602	3,729	6,573
Number of Completes	389	345	961
Response Rate	11%	9%	15%

Survey Data Analysis

Cadmus compiled frequency outputs, coded open-end survey responses, and ran statistical tests to determine whether survey responses differed significantly between treatments and groups. Cadmus also compared survey responses between seasons.

Detailed Findings

Customer Enrollment and Retention

Opt-In Rates

Table 12 provides the cumulative opt-in rates for each opt-in treatment through the Summer 2017 season when PGE stopped recruiting customers for Flex. These rates indicate the number of customer who opted into the pilot compared to the total number of customers invited to participate. Cadmus calculated opt-in rates across all three waves of recruitment that received enrollment offers via mail or email and included opt-in rates for customers who were assigned to the control group. Note that in Table 12 the TOU2 and TOU2xBDR treatments are combined, since PGE randomly assigned some customers who opted into the TOU2 treatment to receive the BDR treatment. Note also that the opt-in rates are identical in Winter 2017/2018 as they were for Summer 2017 because there were no new enrollments.

Table 12. Opt-In Rates by Treatment*

Treatment	Through Summer 2017	
	Invited Customers Who Opted In (%)	Count of Customers Who Opted In (N)
PTR Only		
PTR1	4.3%	790
PTR2	2.8%	481
PTR3	6.2%	986
TOU Only		
TOU1	3.5%	932
TOU2 and TOU2xBDR**	3.4%	2,656
TOU3	3.7%	937
Hybrids		
TOU1xPTR2	4.5%	720
TOU2xPTR2	2.4%	489
TOU3xPTR2	4.5%	675

* Results presented here include both test and control participants

** TOU2 and TOU2xBDR are presented together because PGE randomly assigned TOU2 customers to receive the BDR treatment.

The opt-in rates reflect customer enrollments over three waves of recruitment. These rates varied over time, as PGE experimented and experienced different degrees of success with various marketing and messaging strategies. In general, PGE experienced greatest success in recruiting in Wave 3, as it incorporated important marketing lessons learned during Waves 1 and 2. These lessons are discussed below in the *Implementation Challenges and Lessons Learned* section. Also, PGE prioritized recruiting of

certain treatments and stopped recruiting for some treatments before others. This meant that PGE did not recruit customers to some treatments during Wave 3.

The opt-in rates ranged between 2.4% and 6.2%. Overall, opt-in rates were higher for treatments that included peak-time rebates. The highest opt-in rate was for PTR3, which offered the most generous rebate of $2.25 per kWh of savings. The PTR2 and TOU2xPTR2 treatments experienced the lowest opt-in rates because PGE had stopped recruiting for these treatments after completing Wave 2. PGE customer opt-in rates were lower than those achieved by SMUD, which obtained opt-in rates ranging between 16% and 19% for a TOU and CPP program.[16] A likely explanation for the difference is that PGE customers are less familiar with the concepts of demand response and time varying rates than SMUD customers. As PGE educates its residential customer population more about peak demand and its demand response program offerings, it is expected that a higher percentage of PGE customers will opt into future pricing programs.

Opt-Out Rates

Table 13 provides the cumulative opt-out rates by treatment and season. These rates pertain to enrolled customers who opted-out of each treatment between June 1, 2016 and the last day of the summer or winter season (September 30, 2017 and February 28, 2018, respectively). Customers could opt out of the program by contacting PGE customer service and asking to be un-enrolled. Customers who moved residences were removed from the program but were not counted as opt-outs.[17]

Table 13. Cumulative Opt-Out Rates by Treatment and Season

Treatment	Summer 2017		Winter 2017/2018	
	%	Count of Customers	%	Count of Customers
PTR Only				
PTR1	4.2%	15	4.5%	16
PTR2	4.6%	11	6.3%	15
PTR3	5.1%	21	5.4%	22
Opt-Outs				
PTR2-OO	1.7%	13	2.3%	18
BDR-OO	1.9%	241	3.2%	398
TOU Only				
TOU1	7.0%	28	8.0%	32

16 Potter, Jennifer, Stephen George, and Lupe R. Jimenez. 2014. *SmartPricing Options Final Evaluation, Sacramento Municipal Utility District*, p. 106. Available at https://www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf

17 Due to limitations in the availability of accurate opt-out dates across the entire evaluation period, these rates constitute an upper bound on the true opt-out rate. The true opt-out rates may be lower.

Treatment	Summer 2017		Winter 2017/2018	
	%	Count of Customers	%	Count of Customers
TOU2	7.3%	68	8.6%	80
TOU3	8.1%	33	8.6%	35
Hybrids				
TOU1xPTR2	9.9%	32	10.6%	34
TOU2xPTR2	9.4%	22	9.9%	23
TOU2xBDR	7.2%	63	8.3%	72
TOU3xPTR2	8.7%	26	9.7%	29

Cumulative opt-out rates through Winter 2017/2018 ranged between 2.3% and 10.6%. The most important differences in opt-out rates were between treatments of different types: opt-in vs. opt-out treatments and PTR vs. TOU or Hybrid treatments. In general, only small differences existed between treatments of a given type. For example, opt-rates ranged between 7.0% and 8.1% for TOU-only customers and 4.6% and 5.1% for PTR-only customers. Most differences in opt-out rates between treatments of a given type were random and not statistically significant.

Opt-out rates for opt-in treatments were higher than those for opt-out treatments. For opt-in treatments, opt-out rates through the end of W2017/2018 season ranged from 4.5% (PTR1) to 10.6% (TOU1xPTR2). For the opt-out PTR2 and BDR treatments, opt-out rates were 2% and 3%, respectively. The opt-out rates were lower for opt-out treatments than opt-in treatments because many customers automatically enrolled in the program are complacent: they will neither opt in nor opt out of a program if given the opportunity. Also, opt-out customers may be less likely to know how to opt-out of treatment.

Among opt-in treatments, opt-out rates were higher for TOU and Hybrid treatments than for PTR treatments. The opt-rates for TOU and Hybrid treatments ranged between 8% and 11% through W17/18, almost twice as high as those for PTR customers. The higher opt-out rates for TOU and Hybrid customers aligns with the lower rates of customer satisfaction with these treatments as documented below in the *Customer* Experience section.

Load Impacts

The following section provides load impact estimates by Flex treatment for the Summer 2017 and Winter 2017/2018 events seasons. Table 14 summarizes the average load reductions during Flex events and on-peak TOU periods. Reporting is focused on the most current Flex event seasons due to two factors:

- The final wave of Flex recruitment occurred in March 2017. PGE did not achieve its recruitment targets until summer 2017, and previous seasons had participation levels significantly below the targets.
- During the first two pilot seasons, PGE implemented major improvements in the program delivery (e.g., in deploying events, messaging customers, and providing participants with feedback); by summer 2017, PGE had these refinements in place, and the pilot better reflected how a full-scale program will be implemented.

Load impacts from two initial Flex seasons are provided in the Appendix D. PGE plans additional research to estimate load impacts as a function of customer demographic and housing characteristics. PGE will use research about the relationships between demand savings and customer characteristics will inform future demand response program design, marketing, and delivery.

Prior to the Flex pilot, PGE ran a critical peak pricing (CPP) pilot between 2011 and 2013, which achieved demand savings during summer and winter afternoon events of 10% and 12%, respectively. In comparison to the Flex PTR-only treatments, the CPP pilot achieved lower savings in summer, but higher savings in winter.

Table 14. Flex Demand Savings by Treatment and Season*

Category	Treatment		Summer Demand Savings**				Winter Demand Savings**						
			Planning (%)	Evaluation (%)	Abs. Precision at 90% Conf.	Evaluation (kW)	Planning (%)	Evaluation (%)		Abs. Precision at 90% Conf.		Evaluation (kW)	
								AM	PM	AM	PM	AM	PM
PTR-Only	PTR1		13%	18%	±4%	0.41	14%	13%	7%	±7%	±4%	0.23	0.13
	PTR2			22%	±6%	0.48		0%	8%	±8%	±5%	-0.01	0.14
	PTR3			17%	±4%	0.39		3%	12%	±7%	±3%	0.05	0.22
Opt-Out	PTR2-OO		6%	7%	±3%	0.16	7%	0%	6%	±5%	±3%	0.00	0.10
	BDR-OO		3%	2.30%	±1%	0.05	3%	-0.7%	1%	±1%	±1%	-0.01	0.02
TOU-Only	TOU1	On-Peak	5%	2%	±3%	0.02	6%	-1%		±4%		-0.02	
		Flex Event		-1%	±6%	-0.02		2%	0%	±7%	±5%	0.03	0.00
	TOU2	On-Peak		8%	±3%	0.12		3%		±3%		0.04	
		Flex Event		5%	±5%	0.10		2%	2%	±6%	±4%	0.04	0.04
	TOU3	On-Peak		5%	±4%	0.07		0%		±3%		0.00	
		Flex Event		6%	±6%	0.13		3%	-1%	±9%	±5%	0.05	-0.01
Hybrids	TOU1xPTR2	On-Peak	5.2% TOU; 12.9% PTR	3%	±4%	0.04	5.8% TOU; 14.2% PTR	1%		±5%		0.01	
		Flex Event		10%	±7%	0.21		10%	5%	±11%	±6%	0.17	0.08
	TOU2xPTR2	On-Peak	5.2% TOU; 12.9% PTR	24%	±5%	0.33	5.8% TOU; 14.2% PTR	5%		±5%		0.08	
		Flex Event		20%	±8%	0.43		12%	13%	±13%	±6%	0.22	0.25
	TOU2xBDR	On-Peak	5.2% TOU; 3.0% BDR	8%	±3%	0.12	5.8% TOU; 3.3% BDR	1%		±4%		0.02	
		Flex Event		11%	±5%	0.23		-1%	1%	±7%	±5%	-0.02	0.02
	TOU3xPTR2	On-Peak	5.2% TOU; 12.9% PTR	9%	±5%	0.12	5.8% TOU; 14.2% PTR	4%		±4%		0.06	
		Flex Event		8%	±7%	0.17		4%	13%	±10%	±6%	0.08	0.25

* Seasonal results presented only for Summer 2017 and Winter 2017/2018. Percentage demand savings estimated as kW demand savings estimate divided by average control customer demand.

**Impact estimates are percentage demand savings during Flex peak-time events and on-peak savings for TOU rates; green indicates significance at 90%.

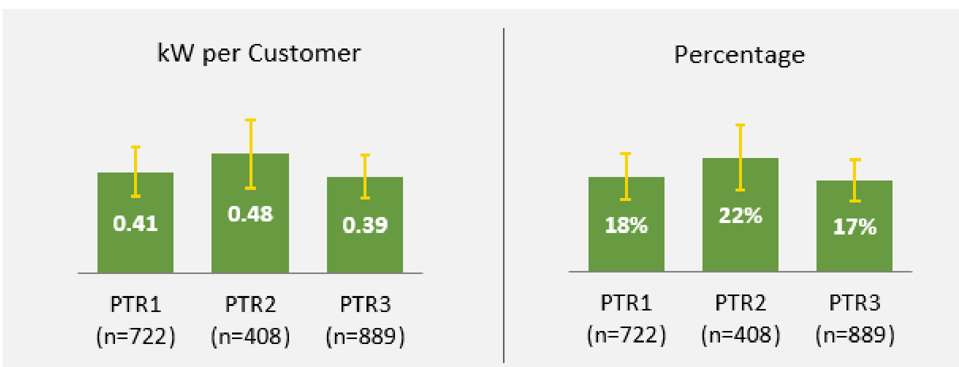
Peak-Time Rebates—Summer

Figure 2 shows the kW and percentage demand savings during Flex events for opt-in PTR treatments during summer 2017. PGE tested the load impacts of three peak rebates ($0.80/kWh, $1.55/kWh, and $2.25/kWh) during seven Flex events. The PTR treatments saved between an average of 0.39 kW per customer and an average of 0.48 kW per customer, or about 20% of demand. All PTR load impacts surpassed PGE's planning estimate of 13% for summer seasons.

Despite large differences in rebate levels, significant differences did not emerge between PTR treatments in the estimated demand savings. The $0.80/kWh and the $2.25/kWh rebates produced approximately the same demand savings. This demonstrates that PGE customers reduced consumption in response to the higher opportunity cost of consuming electricity during Flex events, but the rebate amount did not determine the magnitude of the response. In a recent study of a California critical peak-pricing program, Gillan (2017) made a similar finding, showing that customers were not sensitive to marginal changes in critical peak prices.[18]

Although the rebate did not influence the estimated demand savings, it affected customer satisfaction, as discussed demonstrate in the Customer Satisfaction with Flex section.

Figure 2. PTR-Only Demand Savings During Flex Events—Summer 2017



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during Flex events. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

Figure 3 shows estimated PTR demand savings and ambient outdoor temperature in °F for each of seven events during summer 2017. Peak-time rebates produced similar average demand savings per customer across events, between 0.3 kW and 0.5 kW. No correlation occurred between outdoor temperatures and demand savings during events.

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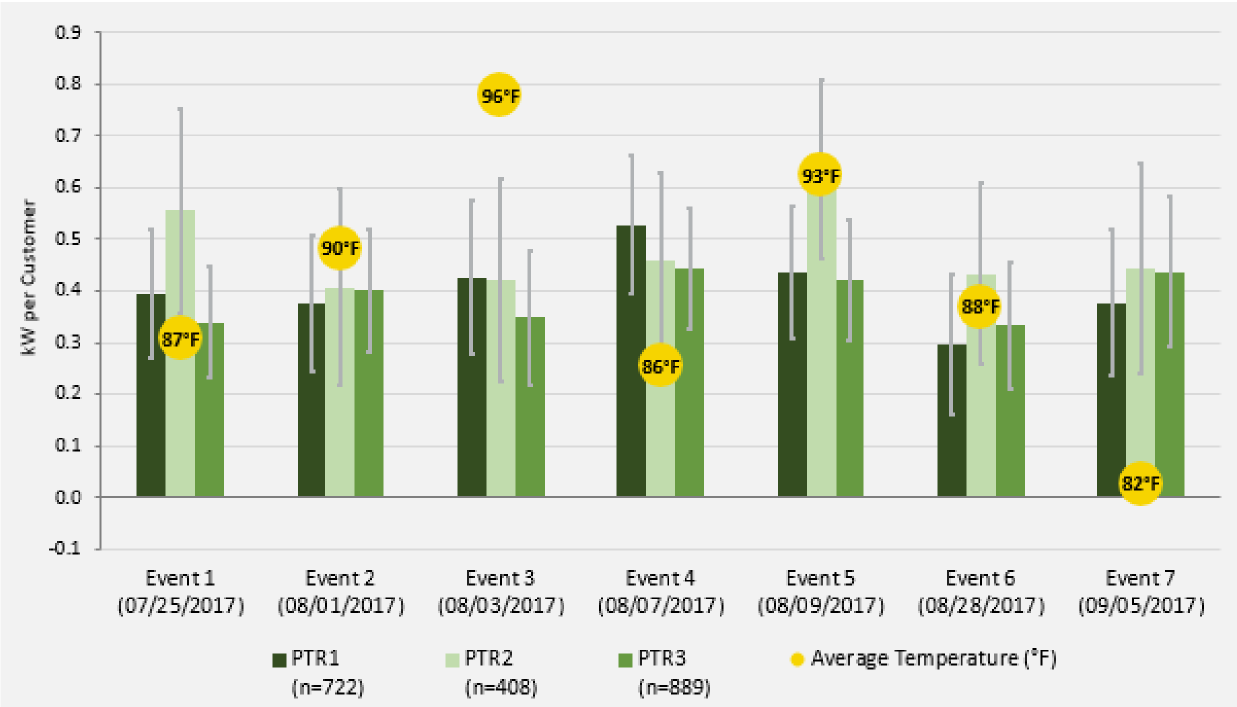
[18] Gillan, James, 2017. Dynamic Pricing, Attention, and Automation: Evidence from a Field Experiment in Electricity Consumption. Energy Institute at Haas Working Paper 284. Available at: https://ei.haas.berkeley.edu/research/papers/WP%20284.pdf

Figure 3. PTR-Only Demand Savings by Flex Event—Summer 2017



Notes: Figure shows by Flex event the average outdoor temperature during event hours and estimates of average kW savings per customer. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

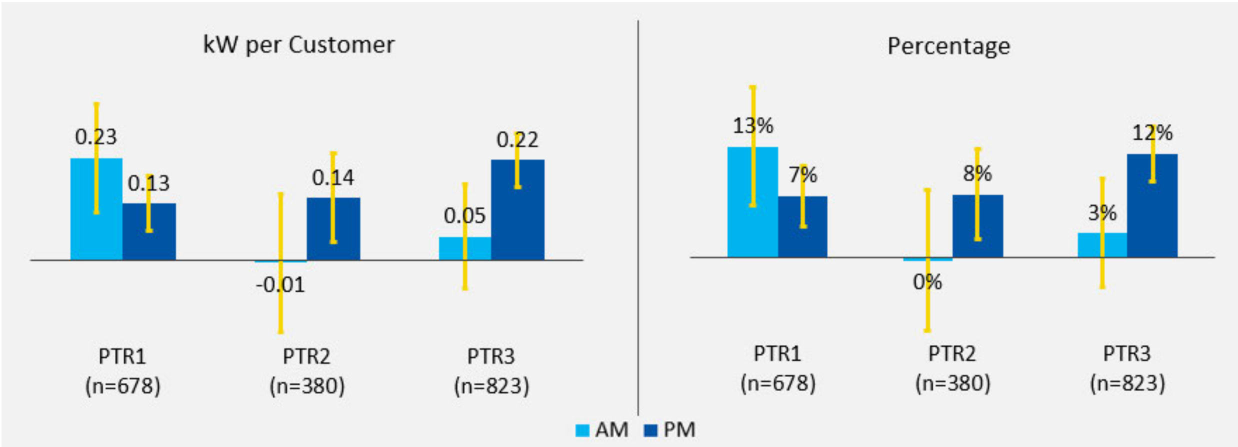
Peak-Time Rebates—Winter

Figure 4 shows demand savings during Winter 2017/2018 Flex events for the opt-in PTR treatments. Six afternoon PTR events and one morning event occurred. The figure presents separate savings estimates for the morning (AM) and afternoon (PM) events. Unlike the summer season, all PTR treatments during the winter season produced point estimates of savings lower than PGE's planning estimates (14%). The PTR savings estimates may have been lower than PGE expected because the Winter 2017/2018 season was milder than normal.[19]

During the morning event, opt-in PTR customers saved between 0% (PTR2) and 13% (PTR1) of demand. During the six afternoon events, opt-in PTR customers saved between 7% (PTR1) and 12% (PTR3). As in summer, no relationship between savings and the rebate amount became evident. While PTR3 customers, who received the largest rebate, saved the most during evening events, PTR1 customers, who received the smallest rebate, saved the most during the morning event.

19 See *Mean Temperature Departures from Average* in NOAA National Climate Report for December 2017, January 2018, and February 2018. Available at: https://www.ncdc.noaa.gov/sotc/national/.

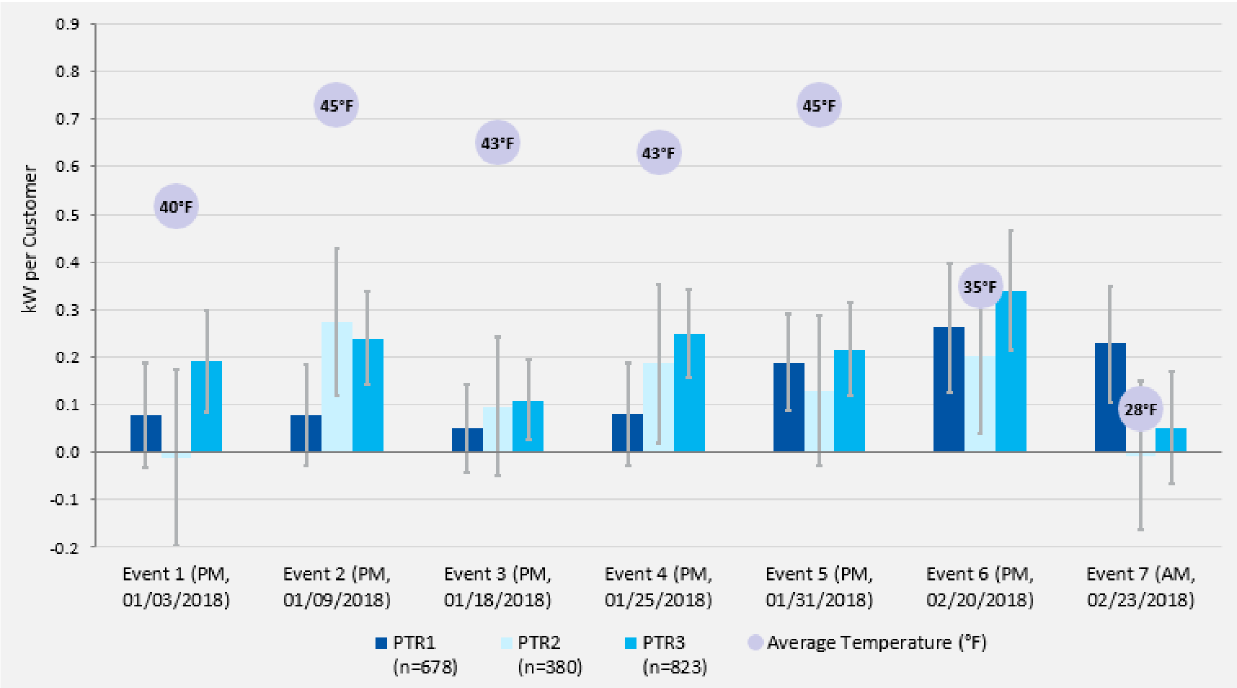
Figure 4. PTR-Only Demand Savings During Flex Events—Winter 2017/2018



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during Flex events. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

Figure 5 shows demand savings for opt-in PTR customers and outdoor ambient temperatures (°F) during each of the seven events in winter 2017/2018. There was more variation in average demand savings per customer between PTR treatments and across events in winter than summer. PTR3 customers tended to save the most and PTR1 customers the least, but this relationship did not hold for all events. As in summer, no relationship emerged between outdoor temperature and demand savings.

Figure 5. PTR-Only Demand Savings by Flex Event—Winter 2017/2018



Notes: Figure shows by Flex event the average outdoor temperature during event hours and estimates of average kW savings per customer during Flex events. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

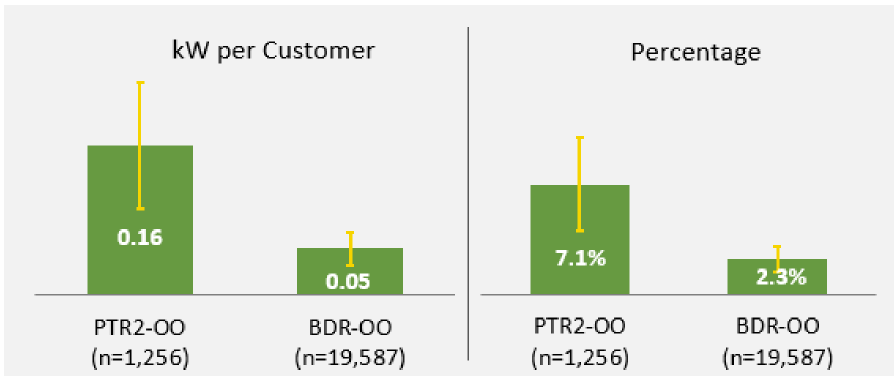
Opt-Out Treatments—Summer

PGE also tested opt-out BDR and PTR2 treatments. PGE automatically enrolled customers in these treatments but gave them opportunity to opt-out, which less than 3% of customers did. Though not all PTR-OO customers who remained in the pilot attempted to save during PTR events, as discussed below, many customers did save, including those who would not have enrolled if given the choice. Except for the rebate, the BDR and PTR treatments were similar: opt-out customers received event notifications, encouragement to reduce demand, and personalized feedback about their savings. By comparing the BDR and PTR treatments, Cadmus could isolate the incremental effect of providing a rebate on peak demand savings.

Figure 6 shows the estimated demand savings for opt-out treatments during summer 2017 Flex events. Opt-out PTR2 customers saved an average of 0.16 kW per customer (or 7% of demand); and BDR saved an average of 0.05 kW per customer (or 2% of demand). While load impacts for PTR2-OO slightly surpassed PGE's 6% planning estimate, the load impacts for BDR-OO savings fell short of PGE's planning estimate (3%).The rebate's incremental effect was about 0.12 kW per customer or 5% of demand. In addition to increasing Flex event demand savings, the rebate increased customer satisfaction with the Flex pilot. As shown in Figure 20 below, PTR2-OO participants reported being more satisfied (6 to 10 ratings) and delighted (9 to 10 ratings) than BDR-OO participants by significant margins.

Opt-out PTR2 customers saved substantially less during Flex events than opt-in PTR2 customers, who, as Figure 2 shows, saved about 20% of demand; however, the group of treated opt-out customers included a large percentage of customers who would not have opted into treatment if given the choice. These customers included *complacent* customers, who stayed in treatment after PGE automatically enrolled them, and *never-takers*, who opted out after enrollment. A back-of-the envelope calculation suggests that the average *complacent* PTR customer saved about 6% of demand during Flex events.[20]

Figure 6. Opt-Out Treatments Demand Savings During Flex Events—Summer 2017

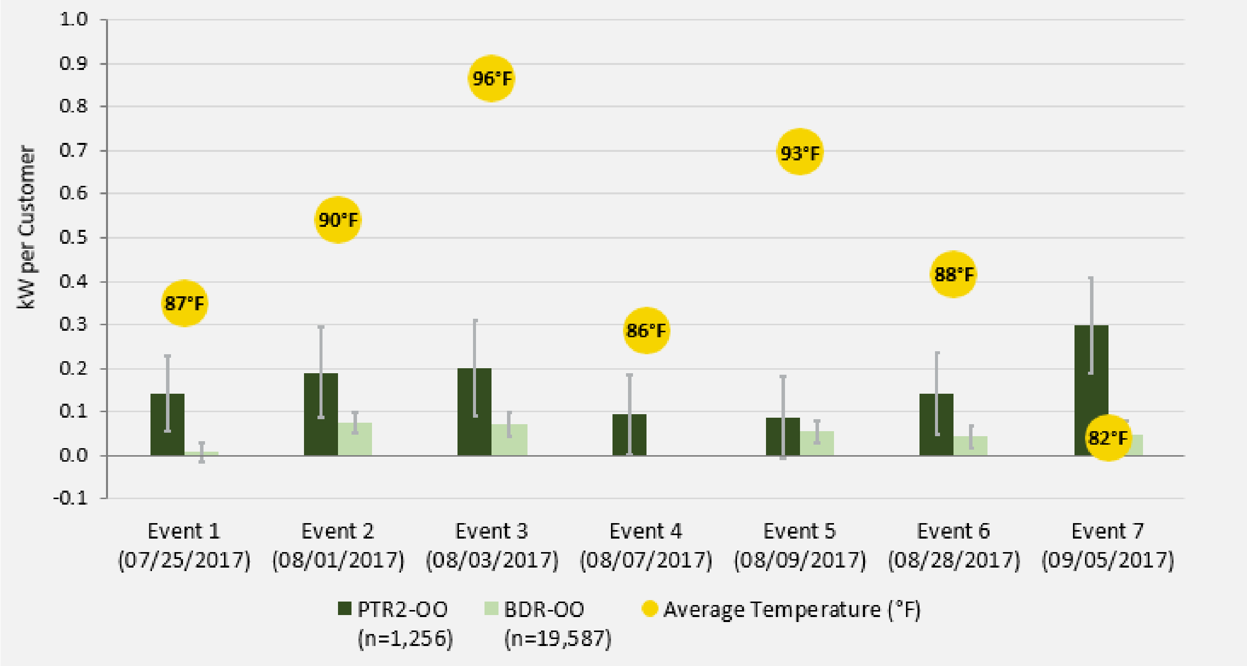


Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during Flex events. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

Figure 7 shows PTR2-OO and BDR-OO demand savings and ambient outdoor temperatures during Flex events for each of the seven events during summer 2017. PGE did not dispatch BDR-OO for Event 4 (August 7, 2017). Across the events, PTR2-OO produced average demand savings per treated customer between 0.1 kW per customer and 0.3 kW per customer; BDR-OO produced savings between 0.01 kW per customer and 0.08 per customer. No relationships between outdoor temperatures and savings became evident in the event impact estimates.

[20] The 7% savings estimate for the opt-out PTR2 treatment represented an average of savings across the following customer types: (1) *always-takers*—customers who would opt into the pilot if given the opportunity; (2) *complacents*—customers who would neither opt-in nor opt-out of treatment if given the choice, but who nevertheless might save when enrolled; and (3) *never-takers*—customers who would never enroll and always opted out given the choice. Our estimate assumed never-takers would not save and the 22% savings estimate for opt-in PTR2 customers was a reasonable estimate of PTR2 savings for always-takers. Additionally, from Table 11 and Table 12, *always-takers* constituted about 5% of the population (i.e., average opt-in rates for PTR1, PTR2, and PTR3 treatments), and *never-takers* constituted about 3% of the population (i.e., opt-out rate for opt-out PTR2). This implies that *complacent* customers constituted 92% of the customers defaulted into PTR2 treatment; and that *complacent* customers saved an average of 6.4% of demand.

Figure 7. Opt-Out Treatments Demand Savings by Flex Event—Summer 2017



Notes: Figure shows estimates of average kW savings per customer. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. During event 4, PGE did not dispatch BDR-OO customers.

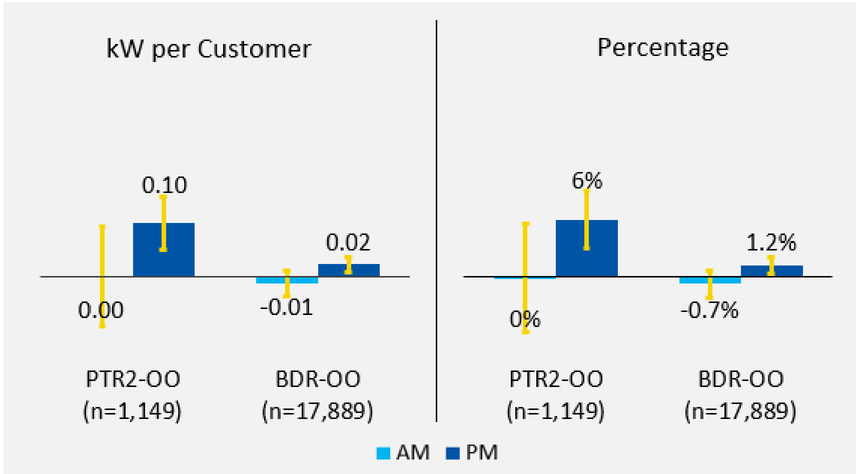
Opt-Out Treatments—Winter

Figure 8 shows demand savings estimates during winter 2017/2018 Flex events, which included six afternoon events and one morning event, for PTR2-OO and BDR-OO treatments.

During morning events, neither opt-out treatment achieved demand savings. The savings point estimates were small and statistically indistinguishable from zero. During evening events, PTR2-OO customers saved 6% of demand and BDR-OO customers saved 1% of demand, with both estimates statistically significant. For both opt-out treatments, demand savings were slightly less than PGE planning estimates for winter (7% for PTR-OO and 3% for BDR-OO). Based on a comparison of PTR2-OO and BDR-OO impacts, the rebate increased Flex events savings by about 4%. As in summer, the rebate enhanced customer satisfaction with Flex, lifting the percentage of satisfied customers by about 10%.

The opt-out PTR and BDR treatments saved less in winter than summer. One hypothesis explaining the smaller winter savings is that PGE customers had a lower tolerance for cold than heat and therefore were less willing to adjust their thermostat settings in winter. Another hypothesis holds that PGE customers had fewer opportunities to save. Many PGE customers heat with natural gas, eliminating the potential for demand savings from the largest home energy end use.

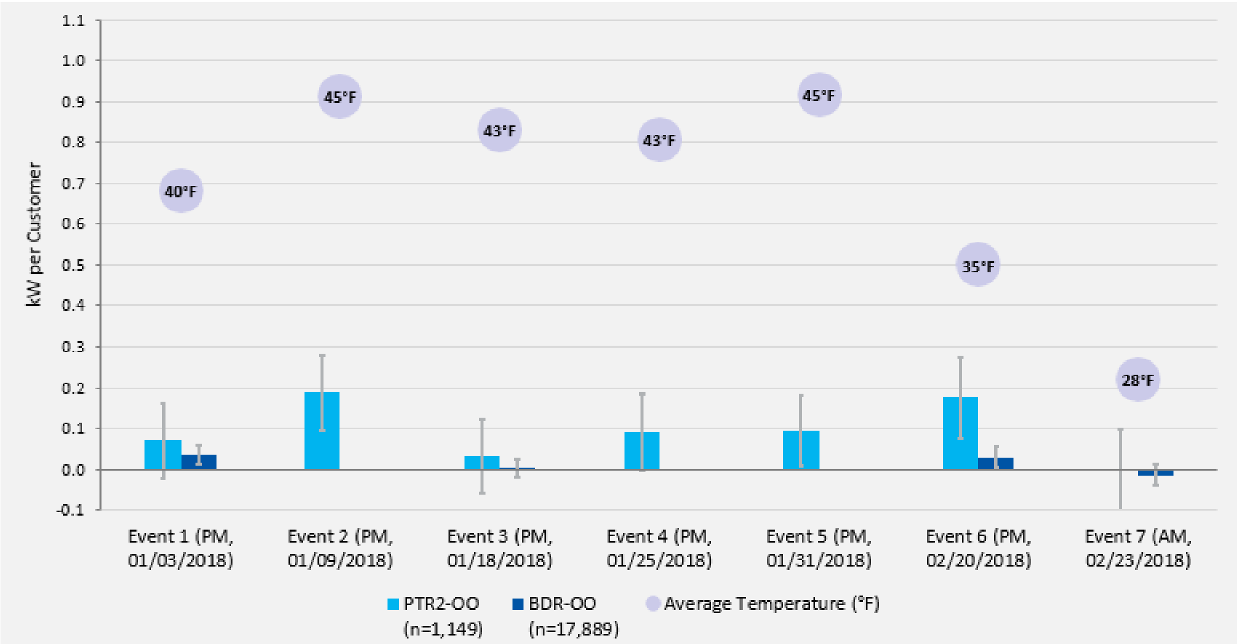
Figure 8. Opt-Out Treatments Demand Savings During Flex Event—Winter 2017/2018



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during Flex events. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers.

Figure 9 shows PTR2-OO and BDR-OO demand savings and ambient outdoor temperatures for each winter 2017–2018 event. PGE did not dispatch BDR-OO for events 2, 4, and 5 (January 1, 2018, January 25, 2018, and January 31, 2018). PTR2-OO demand savings ranged from zero kW per customer (Event 7) to 0.2 kW per customer (Event 2). As with opt-in PTR, no relationship emerged between outdoor temperatures and demand savings.

Figure 9. Opt-Out Treatments Demand Savings by Flex Event—Winter 2017/2018



Notes: Figure shows estimates by event of average kW savings per customer. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. During events 2, 4, and 5, PGE did not dispatch BDR-OO customers.

PGE Payments for Savings Caused by Peak Time Rebates

PTR customers earned rebates for saving energy relative to a customer-specific baseline but were not penalized for exceeding the baseline.[21] PGE paid customers for savings whether the savings were caused by the rebate, naturally-occurring, or from random variation in the customer's consumption. Since PGE pays for some savings that are not caused by the rebate and there is no corresponding financial penalty for increasing consumption above the baseline, PGE will overpay for savings at the program level.

As Table 15 reports, in Summer 2017, PGE paid an average of between $10 and $30 in rebates per PTR customer, depending on the rebate amount. In Winter 2017/2018, PGE paid an average of $6 and $20 in rebates per PTR customer. To estimate how much of the savings that PGE paid for represented savings caused by the program, Cadmus compared the evaluation's estimate of PTR savings per customer with PGE's estimate of average PTR savings per customer from its performance calculations.

Table 15 compares the savings estimates from PGE's performance calculation and the evaluation. For PTR-only treatments, the ratio of evaluated average PTR savings per customer to performance-calculated average savings per customer ranged between 67% and 83% in summer and 25% and 44% in

21 The PTR is an asymmetric incentive. Customers face a higher effective marginal price for electricity equal to the sum of the rebate and the standard rate when their consumption is below the baseline and a lower effective marginal price for electricity equal to the standard rate when consumption is above the baseline.

winter. For the PTR hybrid treatments, the ratio ranged from 37% to 108% in summer and from 27% to 74% in winter.

Table 15. Evaluated Demand Savings vs. PGE Performance-Calculated Savings – Opt-In PTR

Treatment	Summer 2017			Winter 2017/2018		
	Performance-Calculated (kWh)	Evaluated Savings (kWh)	Ratio	Performance-Calculated (kWh)	Evaluated Savings (kWh)	Ratio
PTR1	12.59	9.38	75%	7.97	2.82	35%
PTR2	13.36	11.04	83%	9.20	2.33	25%
PTR3	13.27	8.91	67%	8.98	3.95	44%
TOU1xPTR2	10.20	4.73	46%	7.11	1.95	27%
TOU2xPTR2	9.27	9.96	108%	6.69	4.95	74%
TOU3xPTR2	10.33	3.85	37%	7.15	4.47	63%

Notes: Performance-calculated savings are average savings per customer per season verified by PGE for calculating customer rebates. Evaluated savings are the average savings per customer per season estimated by Cadmus.

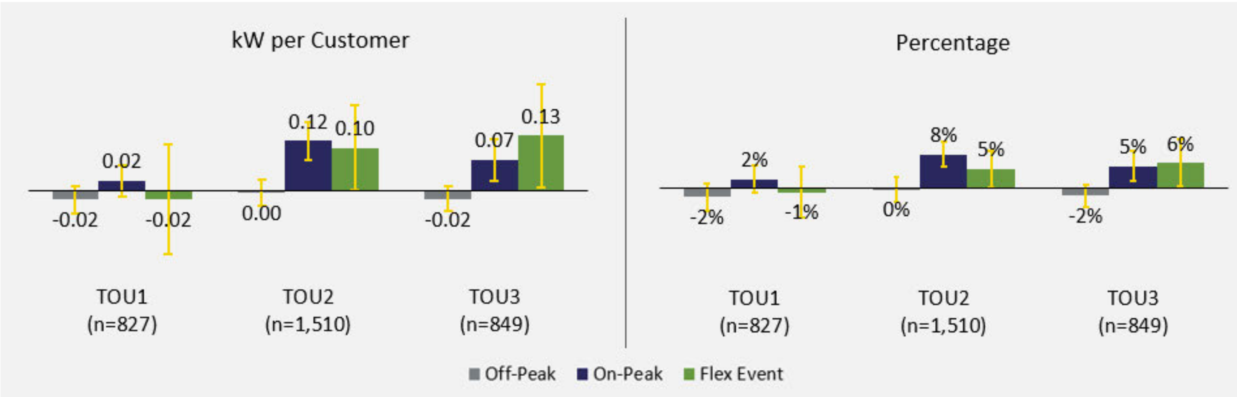
These results confirm that at least some savings for which PGE paid customers were naturally occurring and not caused by the rebates. For PTR-only customers, between one-third and one-fifth of performance-calculated savings in summer and one-half and three-quarters of performance-calculated savings in winter were not attributable to the program. Note, these overestimates of savings apply only to the performance-calculated figures used to pay customers, not to the evaluated savings shown in this report.

PGE may have overpaid for savings more in winter than summer for two reasons. First, as comparison of Figure 2 and Figure 4 show, PTR customers tended to save less in winter than summer, suggesting that a higher percentage of customers who PGE estimated to have saved did not in fact save. Second, customer demand during Flex events tended to be more variable in winter than summer, which could also increase PGE's payments for savings not caused by the pilot.

TOU-Only Treatments—Summer

Figure 10 shows kW and percentage load impacts for TOU-only treatments in summer 2017. The figures show estimated average load impacts per treated customer during off-peak hours, on-peak hours, and Flex event hours. Although TOU-only customers did not receive notification of Flex events, Cadmus measured load impacts during Flex hours to estimate impacts of TOU pricing on reducing system peak demand. The figures show reductions in demand or savings as positive impacts, and show load increases as negative impacts.

Figure 10. TOU-Only Demand Savings—Summer 2017



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during TOU off-peak, TOU on-peak, and Flex event hours (i.e., a proxy for system-peak demand hours). Reductions in demand (savings) are shown as positive values and increases in demand are shown as negative values. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. The TOU3 rate also had a mid-peak period. During the mid-peak period, TOU3 customers demanded 0.05 kW or 5% less on average, with a 90% confidence interval of [0.01 kW, 0.09 kW] or [1%, 8%].

Estimated load impacts for TOU1 customers were small and not statistically significant. In summer 2017, TOU1 customers reduced their consumption during on-peak hours by 2% and increased their consumption by 2% during off peak hours, but neither impact proved statistically significant, as shown by the 90% confidence intervals (CI), which were tightly estimated and included zero. TOU1 customers also did not save demand during Flex events, which proxy for hours of PGE system-peak demand.

The TOU1 rate schedule's design likely explained the small estimated impacts. The on-peak period occurred on non-holiday weekdays, from 6:00 a.m. to 10:00 p.m., covering waking hours for many customers, and making it difficult for them to shift loads from on-peak to off-peak periods. Many customers would need to adjust their routines to accommodate the TOU1 schedule or to schedule their household appliances (e.g., dishwashers, washing machines) to run at night. It remains unclear, however, how many Flex customers could schedule when their appliances would operate. In surveys, many TOU1 customers reported dissatisfaction with Flex due to the rate schedule being difficult for their households to adopt; these customers said it was not convenient or worth changing sleep schedules to do chores during off-peak periods.

While TOU1 did not yield the desired load shifting, the TOU2 and TOU3 rates, having shorter on-peak periods, did so. Both rates defined on-peak periods as hours during non-holiday weekdays, from 3:00 p.m. to 8:00 p.m. In addition, the TOU3 rate defined the mid-peak period as non-holiday weekday hours from 11:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. During the mid-peak period, customers faced a lower retail rate for electricity than the on-peak period rate, but had a rate higher than the off-peak period rate.

The TOU2 and TOU3 rates produced similar off-peak and on-peak load impacts. During on-peak hours, TOU2 customers reduced demand by about 0.12 kW per customer (or 8%), and TOU3 customers reduced demand by about 0.07 kW per customer (or 5%). The difference in these estimates was not statistically significant. Only weak evidence emerged of load shifting. TOU2 customers increased off-peak consumption by less than 0.5%, and TOU3 customers increased consumption by about 2%, but neither estimate proved statistically different from zero. This suggests customers tended to reduce demand during peak periods by, for example, adjusting their thermostat settings or turning off lights, rather than shifting consumption from peak to off-peak periods by, say, delaying dishwashing and laundry. As Figure 18 shows, approximately 50% of TOU participants reported having turned off lights or adjusted thermostat settings during peak periods.

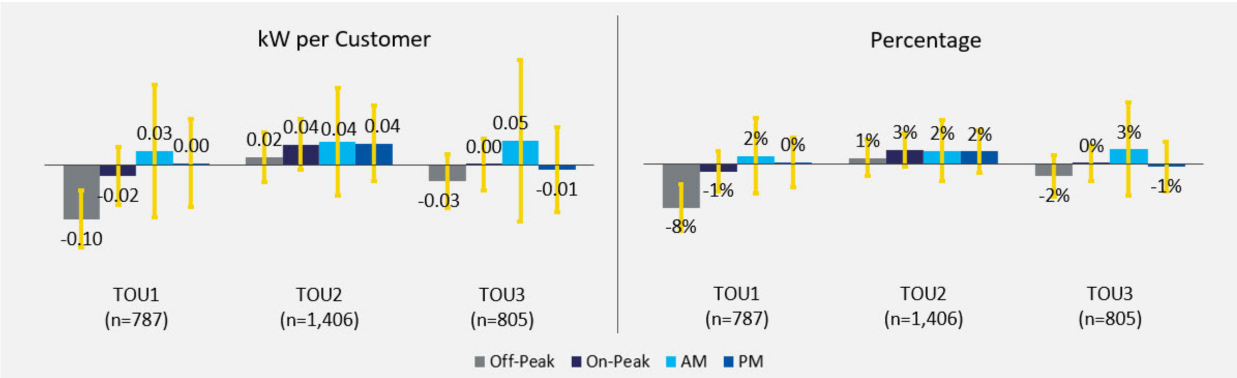
Estimated load impacts during Flex event hours (i.e., a proxy for system-peak demand hours) were about the same as those during on-peak hours. TOU2 and TOU3 customers saved about 5% and 6% of demand. Again, PGE did not notify TOU-only customers of Flex events; so it was expected that demand savings during event hours would not be significantly greater. For TOU2 and TOU3, load impacts for on-peak and Flex event periods met or surpassed the 5% PGE planning estimate.

TOU-Only Treatments—Winter

Figure 11 shows load impacts during peak, off-peak, and Flex event hours (again, a proxy for system-peak demand hours) for TOU1, TOU2, and TOU3 treatments. In winter, PGE scheduled morning and afternoon on-peak periods. Although TOU-only customers were not notified of Flex events, Cadmus estimated the average TOU savings per customer during seven Flex events to assess the impacts of TOU pricing during periods approximating system peak demand.

TOU pricing produced smaller reductions in demand in winter than summer. Except for TOU1 during off-peak hours, none of the TOU-only treatments reduced loads during on-peak hours or shifted loads to off-peak hours. In general, impact estimates were small, and confidence intervals for all estimated impacts included zero. None of the TOU-only treatments saved demand during Flex events, or the savings were too small to detect with the available sample sizes. The savings estimates were small and statistically insignificant. Peak period and Flex event saving for all TOU treatments were lower than PGE's planning estimate of 6% reduction for winter. Based on the estimated confidence intervals, it is possible to reject the hypothesis that demand savings during on-peak and Flex hours were greater than or equal to 6% for each TOU rate.

Figure 11. TOU-Only Demand Savings—Winter 2017/2018



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during TOU off-peak, TOU on-peak, and a.m. and p.m. Flex event hours. Reductions in demand (savings) are shown as positive values and increases in demand are shown as negative values. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. The TOU3 rate also had a mid-peak period. During the mid-peak period, TOU3 customers demanded 0.03 kW or 2% less on average, with a 90% confidence interval of [-0.02 kW, 0.07 kW] or [-2%, 5%].

Why did TOU2 and TOU3 customers reduce demand during peak hours and Flex events in summer but not winter? Two explanations seem possible. First, according to surveys completed with TOU customers, a significant source of peak savings comes through adjustments to thermostat settings. In winter, savings could have been achieved by setting thermostats at a lower temperature during peak periods. PGE customers, however, may have had less tolerance for cold than for heat, and therefore been less willing to make such adjustments. Second, many TOU customers heated their homes with gas (approximately 60% of TOU-only and 53% of Hybrid customers, per the Winter 2017/2018 survey), eliminating a large, potential source of savings from home heating.

TOU Conservation Impacts

TOU pricing encourages customers to shift demand from on-peak, high-price periods to off-peak, low-price periods. However, the expected effect of TOU pricing on total energy consumption is ambiguous. Depending on the customer's elasticity of demand and the changes in relative and absolute prices, total energy consumption could increase, decrease, or stay the same. In Summer 2017, the TOU2 and TOU3 treatments reduced demand during on-peak periods, but there were not statistically significant demand increases during the off-peak periods. This suggests that TOU pricing may have led to a small decrease in overall electricity consumption for the average customer.

Table 16 presents estimates of the total electricity consumptions impacts of TOU pricing in summer and winter. Cadmus estimated the impacts by regressing customer daily electricity consumption on an indicator for assignment to the test group, day-of-sample fixed effects, recruitment-wave fixed effects, customer pre-treatment average daily consumption, and daily cooling degrees. We tested the sensitivity of the estimates to different model specifications and found that the estimates were robust. The impacts shown in the table are adjusted for opt-outs.

Table 16. TOU-Only Energy Conservation Impacts

Treatment	Daily Energy Savings, Summer 2017		Daily Energy Savings, Winter 2017-2018	
	kWh	Abs. Precision at 90% Conf.	kWh	Abs. Precision at 90% Conf.
TOU1	0.08	±0.82	-1.27	±1.35
TOU2	0.02	±0.83	0.38	±1.21
TOU3	0.37	±0.86	-0.39	±1.14

Notes: The table reports the average daily energy savings per treated customer. Positive values indicate energy savings. The precision was estimated based on standard errors clustered on customers.

TOU pricing did not result in statistically significant changes in energy consumption. In summer, the impacts for TOU1 and TOU2 were small and not statistically significant, as the estimated confidence intervals included zero. TOU3 customers saved an average of 0.37 kWh per customer per day, but, as with the other TOU-only treatments, the estimate was not statistically significant. In winter, none of the energy savings estimated was statistically different from zero. The point estimates show that relative to control group customers, TOU1 and TOU3 customers increased energy consumption, while TOU2 customers reduced their consumption.

When Cadmus calculated the average daily energy savings per TOU customer using the on-peak period and off-peak period demand impact estimates in Figure 10 and Figure 11, we also obtained small and statistically insignificant savings.

Hybrid Treatments—Summer

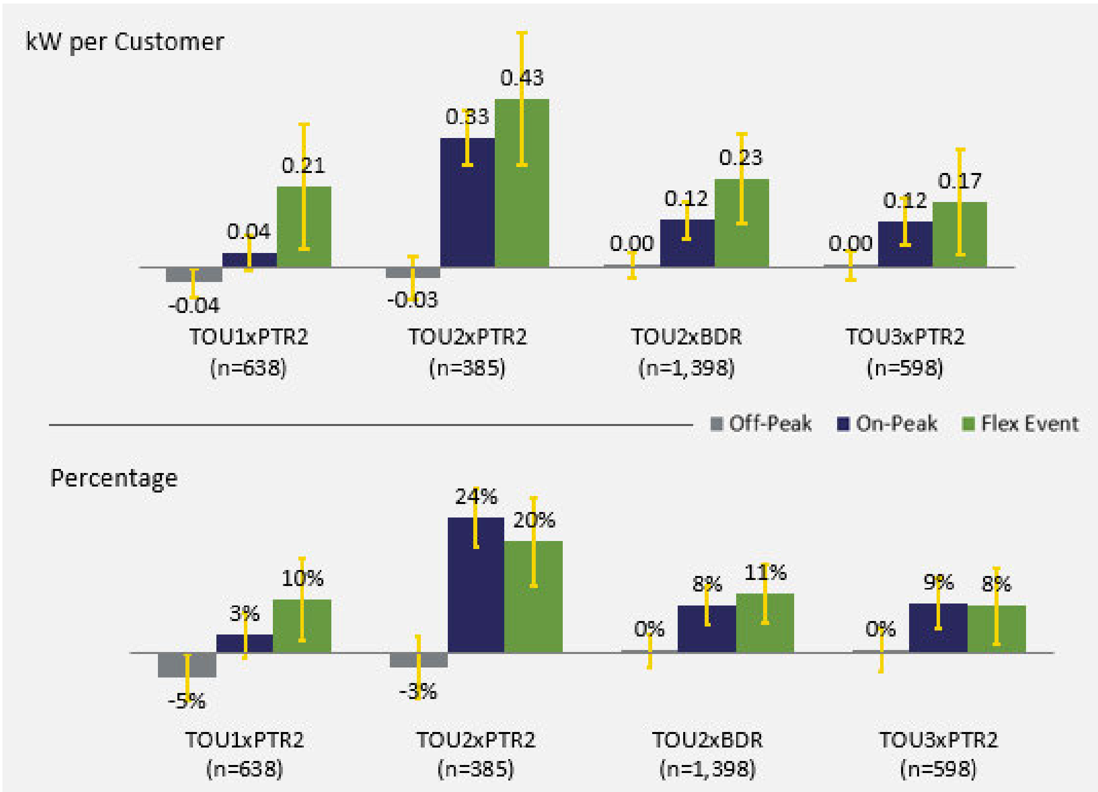
Figure 12 shows load impacts for Hybrid treatments in summer 2017, including TOU pricing with PTR and TOU pricing with BDR.

In general, the Hybrid treatments produced load reductions during on-peak periods similar to those for TOU-only treatments. The TOU1xPTR2 treatment did not produce statistically significant peak savings. Customers on TOU2xPTR2, TOU2xBDR, and TOU3xPTR2 saved, respectively, 0.33 kW per customer (24%), 0.12 kW per customer (8%), and 0.12 kW per customer (9%). The TOU2xBDR and TOU3xPTR2 impacts during on-peak hours were similar to those for TOU2 and TOU3 treatments. Customers on TOU2xPTR2, however, saved more than TOU2 (8%) customers. These peak savings estimates exceeded PGE's planning estimate of 5% for TOU rates in summer. None of the Hybrid treatments produced statistically significant load shifting from peak to off-peak hours. The load impact estimates for off-peak hours were close to zero and statistically insignificant. While generating approximately the same peak-period demand savings as the TOU-only treatments, the TOUxPTR2 treatments tended to produce higher customer satisfaction Table 34.

During Flex events, the Hybrid treatments produced savings between 8% and 20% of demand. TOU1xPTR2, TOU2xBDR, and TOU3xPTR3 yielded Flex event savings of approximately 10%, results close to and not statistically different from demand savings estimates during on-peak periods. TOU2xPTR2 saved about 20% of demand—about twice as large as Flex event savings estimates for other Hybrid treatments and four times as large as the Flex event savings for TOU2-only treatment. Except for

TOU2xPTR2, the Hybrid PTR treatments did not exceed PGE's planning estimate of 13% savings for opt-in PTR treatments in summer.

Figure 12. Hybrid Demand Savings—Summer 2017



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during TOU off-peak, TOU on-peak, and a.m. and p.m. Flex event hours. Reductions in demand (savings) are shown as positive values and increases in demand are shown as negative values. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. The TOU3 rate also had a mid-peak period. During the mid-peak period, TOU3xPTR2 customers demanded 0.10 kW or 9% less on average, with a 90% confidence interval of [0.05, 0.15 kW] or [4%, 13%].

In comparison to PTR2-only treatment, TOU-PTR hybrid treatments tended to generate smaller savings during Flex events (i.e., a proxy for system-peak demand hours). TOU2xPTR2 yielded approximately the same Flex event savings (20%) as PTR2 (22%), but TOU1xPTR2 and TOU3xPTR2 treatments produced much smaller savings than PTR2 only (10% and 8% vs. 22%). TOU1xPTR2 and TOU3xPTR2 treatments also produced smaller Flex event savings than PTR1 (18%), which offered customers a smaller rebate per kWh of savings than PTR2.

Hybrid treatments may have produced smaller Flex event savings than PTR-only for two reasons:

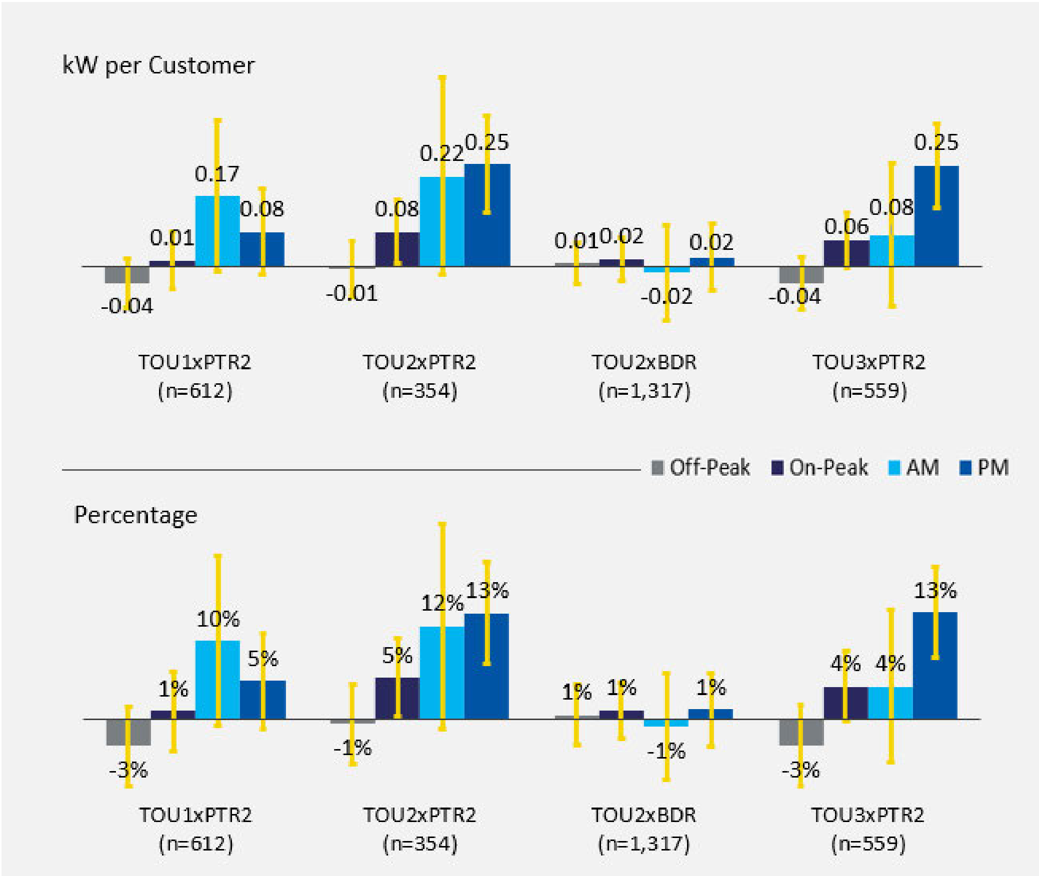
- Hybrid customers who reduced peak period consumption or shifted consumption to off-peak periods would have had lower baselines than PTR-only customers for calculating PTR savings, decreasing rebate payments and reducing the incentives for saving during Flex events. PGE used non-event days during Summer 2017 to establish the consumption baseline for calculating a customer's PTR savings, which would tend to result in lower baselines for TOU customers who saved during peak periods.

- Hybrid customers may have become inattentive to Flex events, having formed energy consumption habits (e.g., programming thermostats) to save demand during TOU on-peak periods that would have been costly from a time, effort, or psychic perspective to change during Flex events. For example, customers may have adjusted their thermostat settings to save during TOU on-peak periods, and it may have been easier for TOU customers simply to ignore event notifications than to make further adjustments to their settings. As discussed below, many TOUxPTR customers' surveys reported that they already conserved regularly and did not feel they needed to do more during events.

Hybrid Treatments—Winter

Figure 13 shows load impacts for TOU Hybrid treatments in Winter 2017/2018. In many ways, the results mirrored those for summer 2017, though load impacts tended to be smaller. As with TOU1-only treatment, TOU1xPTR2 treatment proved difficult for PGE customers; TOU1xPTR2 treatment did not result in peak savings or load shifting from peak to off-peak periods in winter. As discussed below, however, TOU1xPTR2 customers experienced higher satisfaction than TOU1-only customers, suggesting PTR lifted customer satisfaction. TOU2xPTR2 and TOU3xPTR2 customers reduced demand during peak periods by 0.08 kW per customer (5%) and 0.06 kW per customer (4%), but TOU2xBDR treatment did not produce statistically significant demand savings. TOU2xBDR was the only hybrid treatment that did not provide rebates to customers for reducing demand during Flex events, and it produced demand savings during on-peak periods and Flex events very similar to the savings from TOU2-only. None of the Hybrid treatments resulted in statistically significant increases in demand during off-peak hours.

Figure 13**. Hybrid Demand Savings—Winter 2017/2018**



Notes: Figure shows estimates of average kW savings per customer and percentage kW savings relative to control group customer demand during TOU off-peak, TOU on-peak, and a.m. and p.m. Flex event hours. Reductions in demand (savings) are shown as positive values and increases in demand are shown as negative values. Numbers (n) indicate the total number of test and control group customers used in the impact estimation. Errors bars show 90% confidence intervals estimated with standard errors clustered on customers. The TOU3 rate also had a mid-peak period. During the mid-peak period, TOU3xPTR2 customers demanded 0.05 kW or 2% less on average, with a 90% confidence interval [-0.02, 0.12 kW] or [-1%, 8%].

During Flex events, all Hybrid treatments except TOU2xBDR produced significant demand savings. During the morning Flex event, TOU1xPTR2 saved an average of 0.17 kW per customer (10%), TOU2xPTR2 saved an average of 0.22 kW per customer (12%), and TOU3xPTR2 saved an average of 0.08 (4%), though only the savings estimates for TOU2xPTR2 and TOU3xPTR2 were close to being statistically significant at the 10% level. During afternoon Flex events, TOU1xPTR2 treatment saved 0.08 kW per customer (5%) and TOU2xPTR2 and TOU3xPTR2 treatments saved 0.25 kW per customer (13%). These estimated impacts were close to those for PTR-only treatments in winter.

Hybrid Conservation Impacts

Table 17 presents estimates of the energy conservation impacts in Summer 2017 and Winter 2017/2018 for the Hybrid treatments.

Table 17. Hybrid Treatment Energy Conservation Impacts

Treatment	Daily Energy Savings, Summer 2017		Daily Energy Savings, Winter 2017-2018	
	kWh	Abs. Precision at 90% Conf.	kWh	Abs. Precision at 90% Conf.
TOU1xPTR2	0.14	±1.14	0.22	±1.67
TOU2xPTR2	0.35	±1.47	0.75	±1.82
TOU2xBDR	0.36	±0.87	0.20	±1.29
TOU3xPTR2	0.70	±1.06	0.57	±1.62

Notes: The table reports the average daily energy savings per treated customer. Positive values indicate energy savings. The precision was estimated based on standard errors clustered on customers.

The point estimates suggest that in summer and winter Hybrid treatments may have reduced energy consumption by less than an average of 0.7 kWh per customer day, but none of the estimates were statistically significant. For example, it was estimated TOU2xPTR2 treatment reduced consumption by an average of 0.35 kWh per customer per day, but the estimated confidence interval [-1.12, 1.82] is wide and includes zero. The confidence intervals for the other treatments are similarly wide and include zero.

When Cadmus calculated the average daily energy savings per TOU customer using the on-peak period and off-peak period demand impact estimates in Figure 12 and Figure 13 and, we also obtained small and statistically insignificant savings.

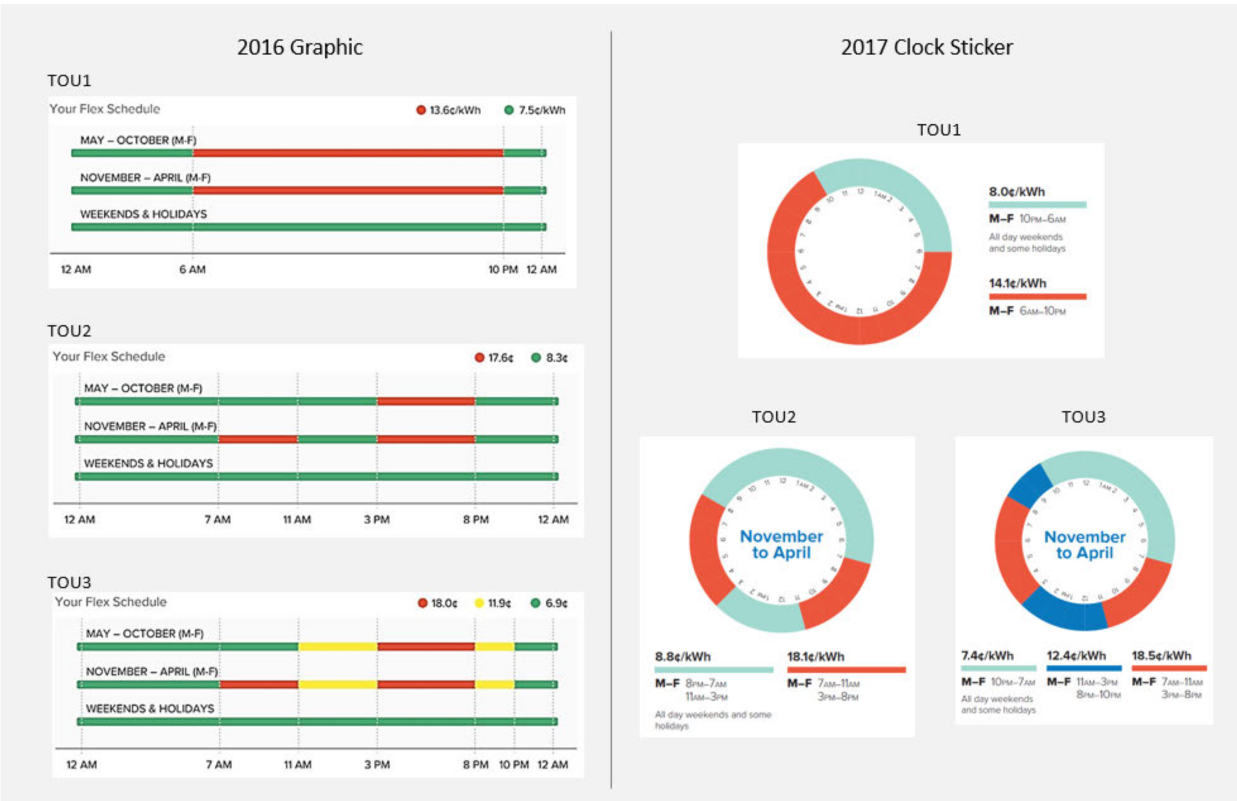
Customer Experience

The summer and winter experience surveys asked Flex customers about their awareness of rates and event notifications, efforts to reduce or shift loads, participation challenges, satisfaction with Flex, and satisfaction with PGE. Respondents rated their satisfaction on a 0–10 scale, where zero meant *extremely dissatisfied* and 10 meant *extremely satisfied*. PGE defined a 6-10 rating as *satisfied* and a 9-10 rating as *delighted*. The following section describes the major findings from the surveys.

Pricing Awareness

TOU customers could manage electricity costs by either: (1) reducing consumption during high-cost periods; or (2) shifting consumption from high-cost periods to lower-cost periods. Therefore, educating TOU customers about the Flex schedule (i.e., the rates and times) would prove crucial for program success. PGE educated TOU customers in two ways. First, PGE posted rate schedules online, allowing customers to review them on the Flex website. Also, in 2016, PGE distributed a rate schedule diagram to customers and, in 2017, a rate schedule clock sticker (see Figure 14).

Figure 14. Flex Schedule Educational Materials Distributed to TOU Customers

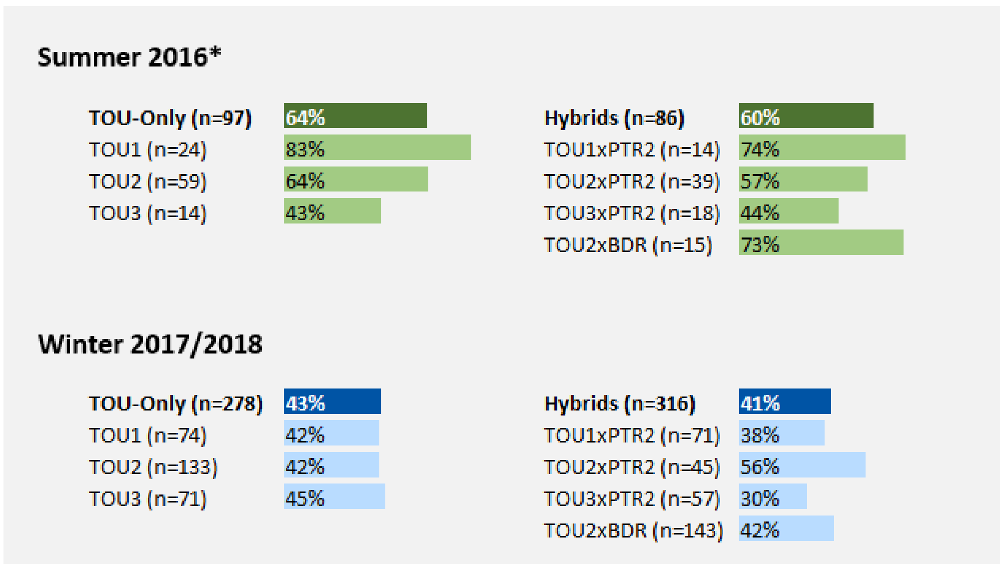


The summer and winter experience surveys asked customers in TOU-only and Hybrid treatments to identify their rate schedule from a list of three schedule images (i.e., the 2016 graphic shown in Figure 14). The surveys, administered online, displayed the 2016 rate schedule images and did not use the 2017 clock sticker images.

Figure 15 shows the percentage of respondents who correctly identified their rate schedules by season and TOU treatment. Due to the small number of respondents per treatment in the summer survey, caution should be exercised in making comparisons between treatments and seasons.

Across treatments and seasons, only 52% of respondents correctly identified their rate schedules. The relatively low rate of correct identification suggests that PGE could do more to educate customers about their TOU rates.

Figure 15. Percentage of Correct Rate Schedule Identification



Survey Question: Which image describes the rates you pay for electricity on the Flex Program?
*The Summer 2017 experience survey did not ask the rate schedule identification question. Results from the Summer 2016 experience survey are reported here instead. Appendix F contains the survey results for Winter 2016/2017.

No significant differences emerged between TOU-only and Hybrid respondents, but in general survey respondents more successfully identified their rate schedule correctly in summer than winter: average correct identification rates were 64% for TOU-only and 60% for Hybrids in summer, while 43% for TOU-only and 41% for Hybrids in winter. Across TOU treatments (except TOU3), a significantly higher percentage of summer respondents correctly identified their rate schedules than winter respondents.[22] The summer and winter surveys used the same rate schedule images from 2016. The rate schedule clock sticker that PGE distributed to customers in 2017 did not look like the images found in the survey and may have confused respondents who were used to seeing a clock graphic.

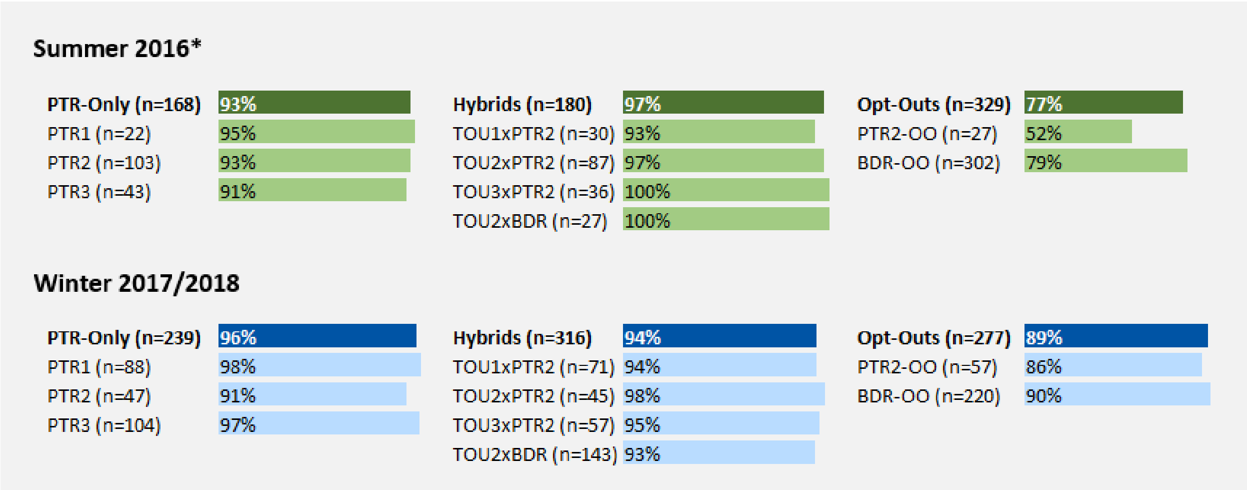
Flex Event Notifications

PGE called approximately seven Flex events per season (see Table 7 for further details). PTR, Hybrid, and BDR customers received an event notification on the day before and day of the event through their

[22] Significant difference with 90% confidence (p≤.10).

preferred communication channels (i.e., email, text, or voice message). The surveys asked customers in PTR and BDR treatments whether they remembered receiving event notifications. Figure 16 shows the percentage of respondents who recalled receiving event notifications by season and treatment.

Figure 16. Percentage of Event Notification Recall



Survey Question: Do you remember being notified of Flex Time events prior to their occurrence?
*As the Summer 2017 experience survey did not ask the event notification question, results from the Summer 2016 event survey are reported here instead.

Most respondents, especially PTR-only and Hybrids, remembered being notified of events. Recall was close to 100% for Hybrid (94%–97%) and PTR-only (93%–96%) respondents, but was significantly less (though still high) for Opt-Out respondents (77%–89%), suggesting those voluntarily enrolling in the program were more likely to look for notifications.[23]

The winter survey asked respondents to rate their satisfaction with their chosen event notification channels (email, text message, and/or voice mail) on a 0–10 scale, where zero meant *extremely dissatisfied* and 10 meant *extremely satisfied*. The survey question before this rating question asked respondents how they received notifications about Flex events; the response to this question determined which notification channels respondents rated on. As shown in Table 18, respondents were most satisfied with text message notifications, followed by email notifications, and voice mail notifications.

[23] The difference in recall rates between PTR or Hybrid respondents and Opt-Out respondents was significant, with 90% confidence (p≤.10).

Table 18. Satisfaction with Flex Event Notifications by Channel Type

Notification Channel	Satisfied (6-10 rating)	Delighted (9-10 rating)	n
Text Message	95%	77%	253
Email	88%	62%	685
Voice Mail	64%	48%	103

Survey Question: How satisfied were you with Flex Time event notifications? Please use a 0 to 10 scale where 0 means "extremely dissatisfied" and 10 means "extremely satisfied." A) Satisfaction with email notification, B) Satisfaction with text notification, C) Satisfaction with voice notification.

In open-ended comments about customer satisfaction with the Flex Program, several recurring themes pertaining to event notifications emerged in the summer and winter surveys:

- ***Awareness of Changing Notification Preferences***: Several respondents did not know they could change their notification channel preferences on the Flex website and suggested that PGE allow customers to select their preferred channels. The Summer 2016 event survey also found that 48% (n= 822) of respondents did not know they could change their notification preferences on the Flex website.
- ***Notification Reminders***: Several respondents wanted more notification reminders and/or earlier notifications, varying from a few days' notice to a few weeks' notice.
- ***Accidental Changes to Notification Settings***: Twenty-four respondents said they received notifications in summer but not in winter, or their notification preference settings changed without their knowledge. PGE confirmed that it reset Wave 3 customers' notification settings after realizing it set Wave 3 customers to receive all three types of notifications (e.g., email, text, and voice); PGE reset settings to email notifications for these customers.

Efforts to Reduce or Shift Loads

PTR or BDR customers were asked to reduce loads during Flex events, while TOU customers were encouraged to reduce loads and/or shift loads from peak to off-peak hours. To facilitate these efforts, PGE provided PTR and BDR customers with energy conservation one-liner tips in event email notifications as well as event performance results addressing how their household performed; tips focused on cooling, heating, and hot water – the high energy-consuming end-uses for the residential sector. PGE provided TOU customers with load-shifting and energy conservation tips, and provided household consumption performance in monthly reports.

Flex Event Participation and Behaviors

The Summer 2016 and Winter 2017/2018 experience surveys asked PTR, Hybrid, and BDR customers whether their household did anything to conserve energy during Flex events. Overall, the majority of respondents said "yes" to participating in Flex event conservation in both seasons (68% summer, 81% winter). A significantly higher percentage of winter respondents (78%, n=832) participated in Flex event conservation than summer respondents (63%, n=677).[24] The higher participation rate in winter can be explained by the surveys used to draw the comparison and customer habituation to the program. Cadmus did not ask the Flex event participation question in the Summer 2017 experience survey and used the Summer 2016 survey data instead. This created a one-and-a-half year gap between the Summer 2016 and Winter 2017/2018 surveys in which customers from Summer 2016 had fewer event feedback, tips, encouragement, and time to act on the tips compared to customers from Winter 2017/2018.

These self-reported Flex event participation results contradict the demand savings results whereby customers saved more during summer events than winter events. Although customers reported taking more actions in winter, it may be that customers took more of the low-saving actions and less of the high-saving actions struggling to manage the high-saving actions. In open-ended comments from the Summer 2017 and Winter 2017/2018 experience surveys, 40 respondents (a mix of PTR-Only, Hybrids, and Opt-Outs) mentioned that the Flex events were more difficult to participate in during winter than summer. The following quotes from these respondents demonstrate customers' difficulty in winter compared to summer:

- "It is much harder to reduce use during winter Flex hours. Unless we dine out, there is no way to reduce during Flex time because I routinely aim for lower demand hours for laundry, dishwasher, etc. Driving to a restaurant or fast food place would negate the energy reduction at the house and, unlike during summer, we don't want a cold dinner."
- "Works for me in the summer. Managing AC is doable. Managing heat and light in the winter is not as workable. I think my bills are higher in the winter due to Flex."
- "We are very conscientious about shifting our energy use, and our warm weather savings reflect that. However, a household member is disabled, home most of the day, and needs the thermostat kept at 68 degrees. During the winter, that heating requirement just kills our savings."

A significantly higher percentage of Opt-In respondents (76%) than Opt-Out respondents (48%) participated in summer events and winter events (89% Opt-In, 63% Opt-Out).[25] The Opt-In customers' participation rate was higher than that of Opt-Out customers because opt-in programs typically attract the most engaged customers.

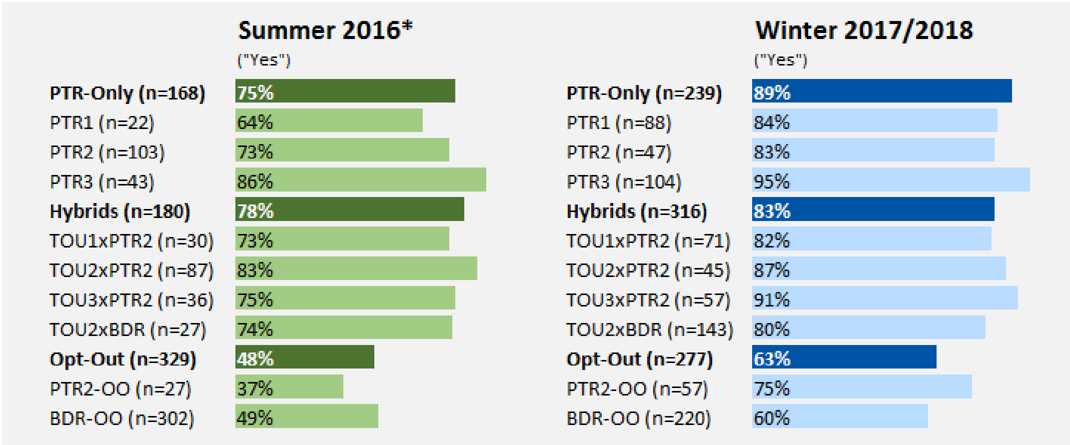
As shown in Figure 17, PTR-only respondents (75%) did not differ from Hybrid respondents (78%) in summer, but significantly differed in winter, when more PTR-only respondents (89%) than Hybrid respondents (83%) reported conserving during events.[26] In both seasons, PTR3 respondents showed the highest event participation rates.

[24] Significant difference with 90% confidence ($p \leq .10$).

[25] Significant difference with 90% confidence ($p \leq .10$).

[26] Significant difference with 90% confidence ($p \leq .10$).

Figure 17. Flex Event Energy Conservation Participation Rates



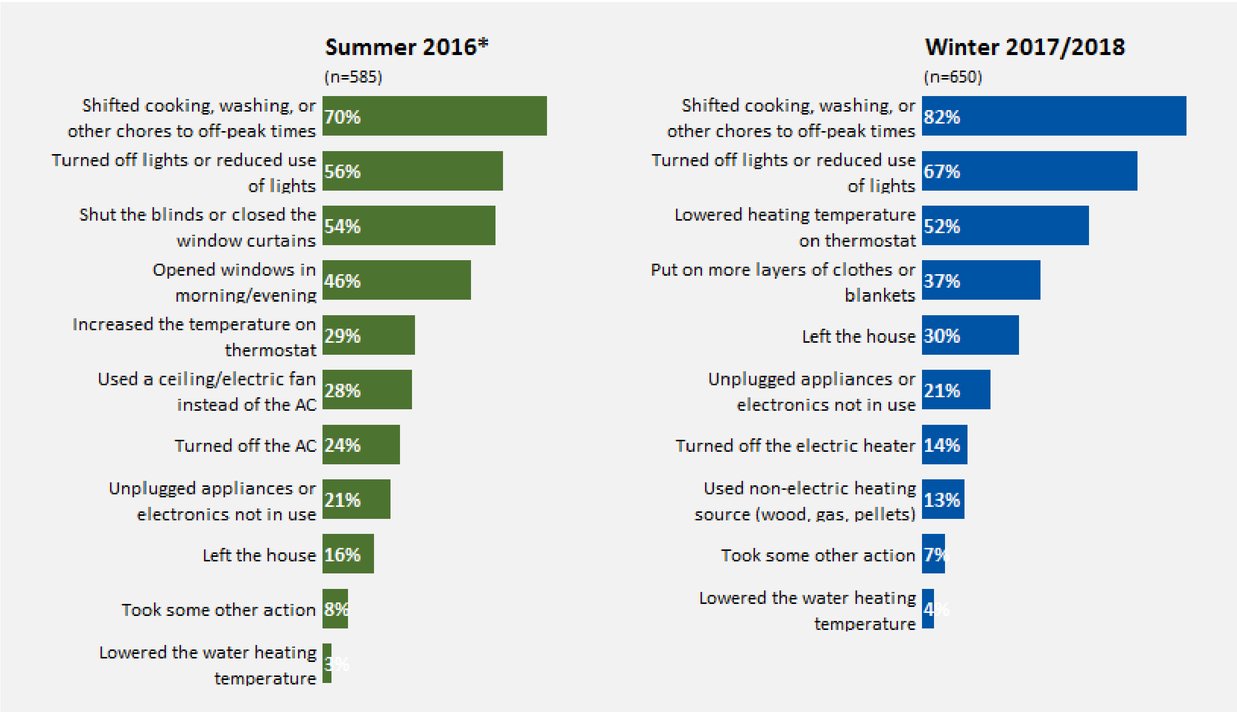
Survey Question: Did you and your household do anything to conserve energy during the Flex Time event?
* The Summer 2017 experience survey did not ask the event participation question. Results from the Summer 2016 event survey are reported here instead. Appendix F contains the survey results for Winter 2016/2017.

The surveys also asked respondents answering "yes" to participating in event energy conservation how their household conserved. Figure 18 shows self-reported customer conservation actions by season.

In both seasons, respondents most frequently reported using one of two strategies: shifting chores to off-peak times; or turning off or reducing use of lights. In summer, 70% of respondents reported shifting their chores to off-peak times, and 56% reported reducing lighting. In winter, 82% of respondents reported shifting their chores to off-peak times, and 67% reported reducing lighting. In both seasons, large percentages of respondents reported reducing use of lighting, even though savings from such behaviors will be low due to the prevalence of efficient CFLs and LEDs in residential customer homes. This presents PGE with an opportunity to educate customers about strategies for producing larger demand savings or shifting such as managing space conditioning and water heating loads. The differences between summer and winter in proportions of respondents employing these strategies were statistically significant.[27] Higher activity rates in winter aligned with findings in Figure 17, indicating event participation was higher in winter than summer. Other actions tended to differ by season, such as adjusting a thermostat's temperature up or down.

[27] Significant difference with 90% confidence ($p \leq .10$).

Figure 18. How Customers Conserved During Events



Survey Question: How did you and your household conserve energy during Flex Time events? (Select all that apply)
*The Summer 2017 experience survey did not ask the event participation question. Results from the Summer 2016 event survey are reported here instead. Appendix F contains the survey results for Winter 2016/2017.
Note: This survey question was asked to customers in the event-based treatments (PTR-only, Hybrids, and Opt-Outs).

In summer, respondents saying they did not conserve during events (n=134) most often cited the following three reasons:

1. Did not know there was an event. (36%)
2. It was too hot or feeling cool was of high priority. (29%)
3. Forgot there was an event. (18%)

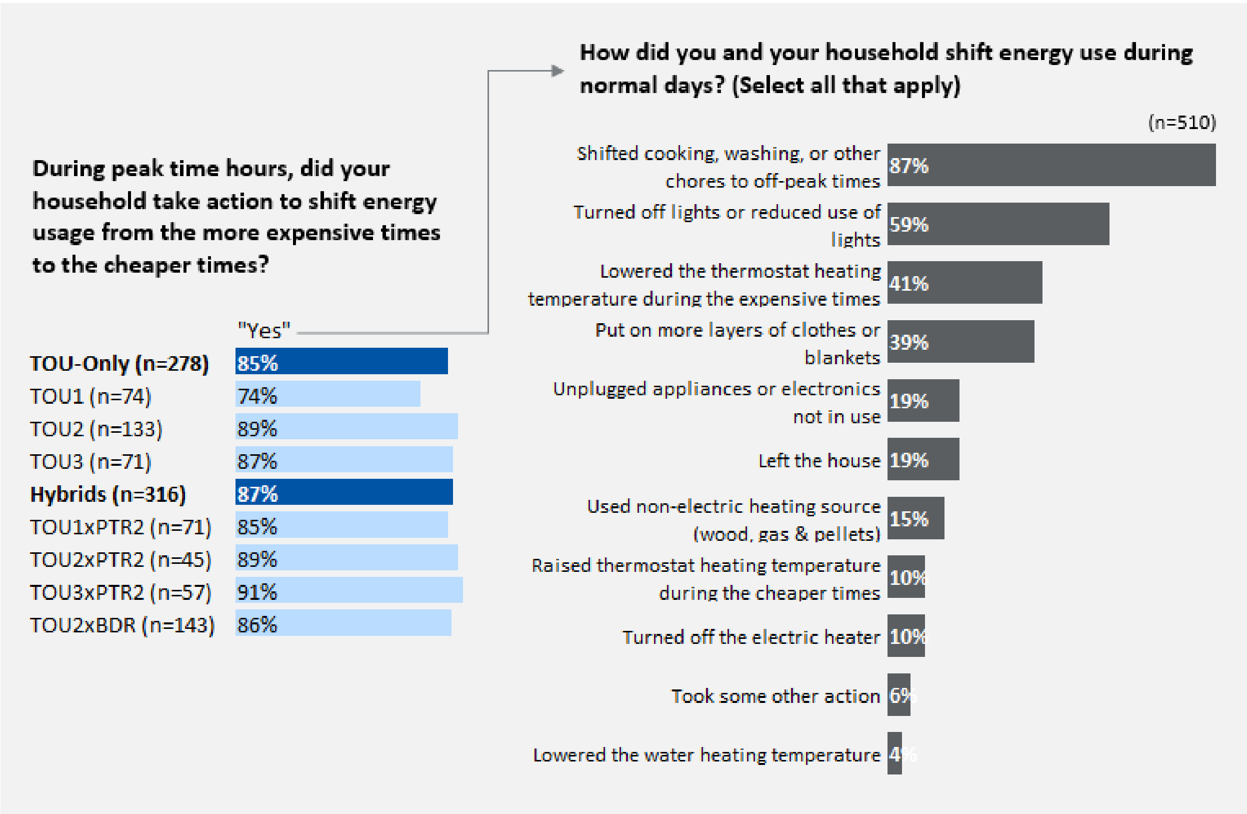
In winter, respondents saying they did not conserve during events (n=86) most often cited the following three reasons:

1. The event timing did not work for them. (26%)
2. Already conserving on a regular basis, so did not feel the need to do more on event days. (24%)
3. Forgot there was an event. (17%)

Time of Use Participation and Behaviors

The Winter 2017/2018 experience survey asked TOU customers whether their households took actions to shift energy consumption from more expensive to less expensive times. This question was not asked in the summer surveys. As shown in Figure 19, a similarly high percentage of TOU-only respondents (85%) and Hybrid respondents (87%) reported shifting their energy consumption. For TOU-only and Hybrid treatments, TOU2 and TOU3 respondents showed a significantly higher percentage of shifting energy consumption than TOU1 respondents.[28] The relatively low percentage of TOU1 customers who reported shifting consumption might reflect the TOU1 rate's day/night schedule, which made load shifting challenging for customers. Among Hybrid treatments, participation rates for shifting energy consumption (87%) were not significantly different from winter event participation rates (83%).

Figure 19. Customer Efforts to Reduce Load During Normal Days – Winter 2017/2018



Note: A comparison to summer is not available. The Summer 2016 and 2017 experience surveys did not ask the two load-shifting questions; these two questions were added to the winter 2017/2018 experience survey.

The winter survey also asked respondents who said "yes" to shifting energy consumption how their households took action. As shown in Figure 19, respondents most frequently shifted their chores to off-peak times and turned off or reduced use of lights—the same top two actions for events. TOU respondents showed one notable behavioral difference from event-based respondents: a significantly lower percentage of TOU respondents reported leaving the house (19% vs. 30%).[29] The TOU program design encourages customers to shift or reduce energy consumption on a regular basis, making leaving the home an impractical strategy. In contrast, PTR and BDR program designs asked customers to shift or reduce demand on event days only, making it easier for them to leave during periods of high demand.

[28] Significant difference with 90% confidence ($p \leq .10$).

[29] Significant difference with 90% confidence ($p \leq .10$).

In winter, respondents saying they did not participate in shifting energy consumption (n=65) most often cited the following three reasons:

1. Particular members in my household make it difficult to shift energy use. (20%)
2. Feeling comfortably warm is a high priority. (14%)
3. Inconvenient/hard to remember to do every day. (14%)

Customer Satisfaction with Flex

The summer and winter experience surveys asked Flex customers to rate their overall satisfaction with the program on a 0–10 scale, where zero meant *extremely dissatisfied* and 10 meant *extremely satisfied*. Figure 20 shows the percentage of satisfied (6–10 rating) and delighted (9 –10 rating) participants across treatments for Summer 2017 and Winter 2017/2018. Appendix F contains survey results for Summer 2016 and Winter 2016/2017.

In assessing Flex satisfaction, the results from PGE's CPP pilot (2011-2013) are a useful point of reference. Using a similar 0–10 rating scale as the Flex evaluation, PGE reported that 68% of customers were satisfied (6–10 rating) and 40% of customers were delighted (9 –10 rating) with CPP. As evident below, overall, PGE customers gave the Flex pilot higher satisfaction ratings. Perhaps because of risk of or actual energy bill increases from CPP and the absence of such risk for PTR, satisfaction proved significantly lower for CPP.

Over 50% of respondents in each Flex treatment expressed satisfaction, with the highest program satisfaction observed for PTR-only (83%–86%),[30] followed by Hybrids (71%–79%), TOU-only (61%–76%), and Opt-Outs (56%–61%). Opt-In PTR2 treatment achieved the highest program satisfaction rate at 92% in the summer survey. Opt-In PTR2 (89%) and PTR3 (89%) treatments also achieved high program satisfaction rates in the winter survey. On the other hand, BDR-OO and TOU1 treatments showed the lowest satisfaction rates in the summer survey (BDR-OO 51%; TOU1 57%) and in the winter survey (TOU1 54%; BDR-OO 57%). The higher program satisfaction rates among PTR-only treatments suggest that providing financial incentives without risk of penalty boosts customer satisfaction with the program.

Opt-In treatments showed significantly higher program satisfaction rates than Opt-Out treatments. In the summer survey, a significantly higher percentage of Opt-In treatment respondents (79%) than Opt-Out treatment (56%) respondents expressed satisfaction. [31] In the winter survey also, a significantly higher percentage of Opt-In treatment respondents (72%) than Opt-Out treatment respondents (61%) expressed satisfaction. [32] Opt-In treatments showing higher satisfaction with the program was expected

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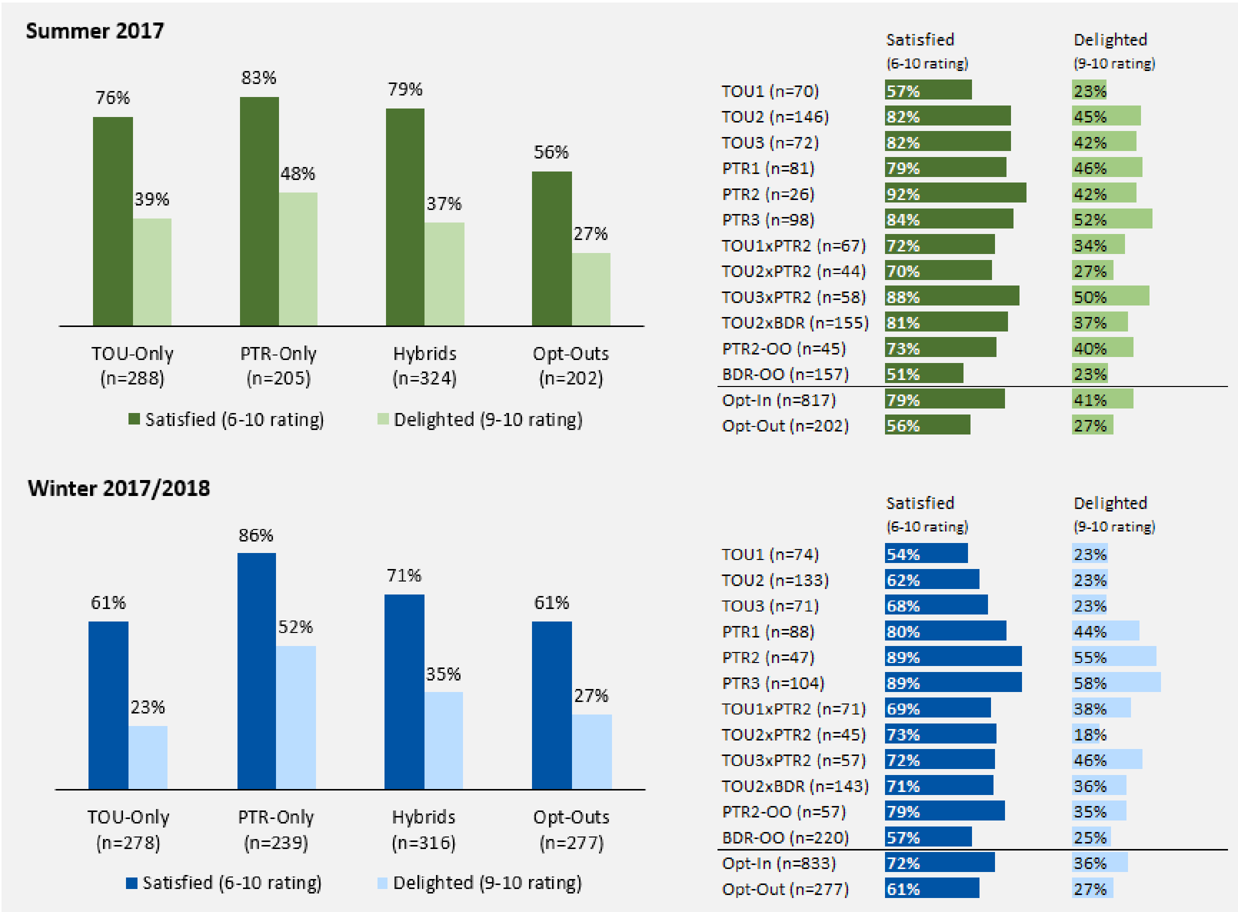
[30] In comparison to the 2013-2015 PGE CPP pilot, PGE reported that 68% of customers were satisfied (6–10 rating) and 40% of customers were delighted (9 –10 rating) with CPP

[31] Significant difference with 90% confidence (p≤.10).

[32] Significant difference with 90% confidence (p≤.10).

as customers who opt in to a program are more engaged than customers who are automatically enrolled in a program (opt-out program design).

Figure 20. Overall Satisfaction with Flex



Survey Question: Please rate your overall satisfaction with the Flex Program using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Program satisfaction tended to be higher in summer than in winter. As shown in Figure 20, seven of the 12 treatments exhibited higher satisfaction rates in summer than winter. In particular, TOU-only and Hybrid treatments showed significantly higher satisfaction rates in summer (76%–79%) than in winter (61%–71%).[33] This seasonal pattern for TOU-only and Hybrid treatments suggests that the TOU pricing may have been more challenging for customers in winter than in summer.

Additionally, the summer and winter experience surveys asked respondents to explain their program satisfaction ratings. Satisfied respondents most often said the program delivered bill savings, helped their household manage energy use, brought education and awareness about energy conservation, and helped the environment. Respondents not satisfied most often said they saw little to no difference in

[33] Significant difference with 90% confidence (p≤.10).

their bill savings, and found the Flex schedule or events difficult for their households. In particular, BDR-OO respondents most often mentioned the Flex events being difficult and TOU-only respondents (especially TOU1) most often mentioned the Flex schedule being difficult for their households.

Notably, respondents found the program more difficult to participate in during winter than summer, especially TOU-only and Hybrid respondents: 16% of respondents in the summer survey said the program helped them save on their electric bills, compared to 9% of respondents in the winter survey. Specifically, respondents said winter on-peak hours and event times occurred when household members were often home and needed to heat the home to stay warm. No respondents found the program more difficult in summer than in winter. PGE could lessen customer concerns about the seasonality of bill savings by encouraging them to enroll in *Equal Pay*, a payment option that allows customers to smooth their payments over months of the year. Another strategy, which PGE has already implemented, is to present cumulative, rather than monthly, bill savings to customers. Even if customers do not reduce their bills in winter, most do so over 12 months.

Among open-ended responses to the satisfaction rating question, 6% of respondents from the summer survey and 5% of respondents from the winter survey offered the following suggestions to improve the program:

- Provide a bill credit for savings instead of sending a check
- Provide more advanced Flex time event notifications
- Adjust the Flex schedule hours and/or Flex event times
- Provide more personalized information on tips and consumption data

Customer Satisfaction with PGE

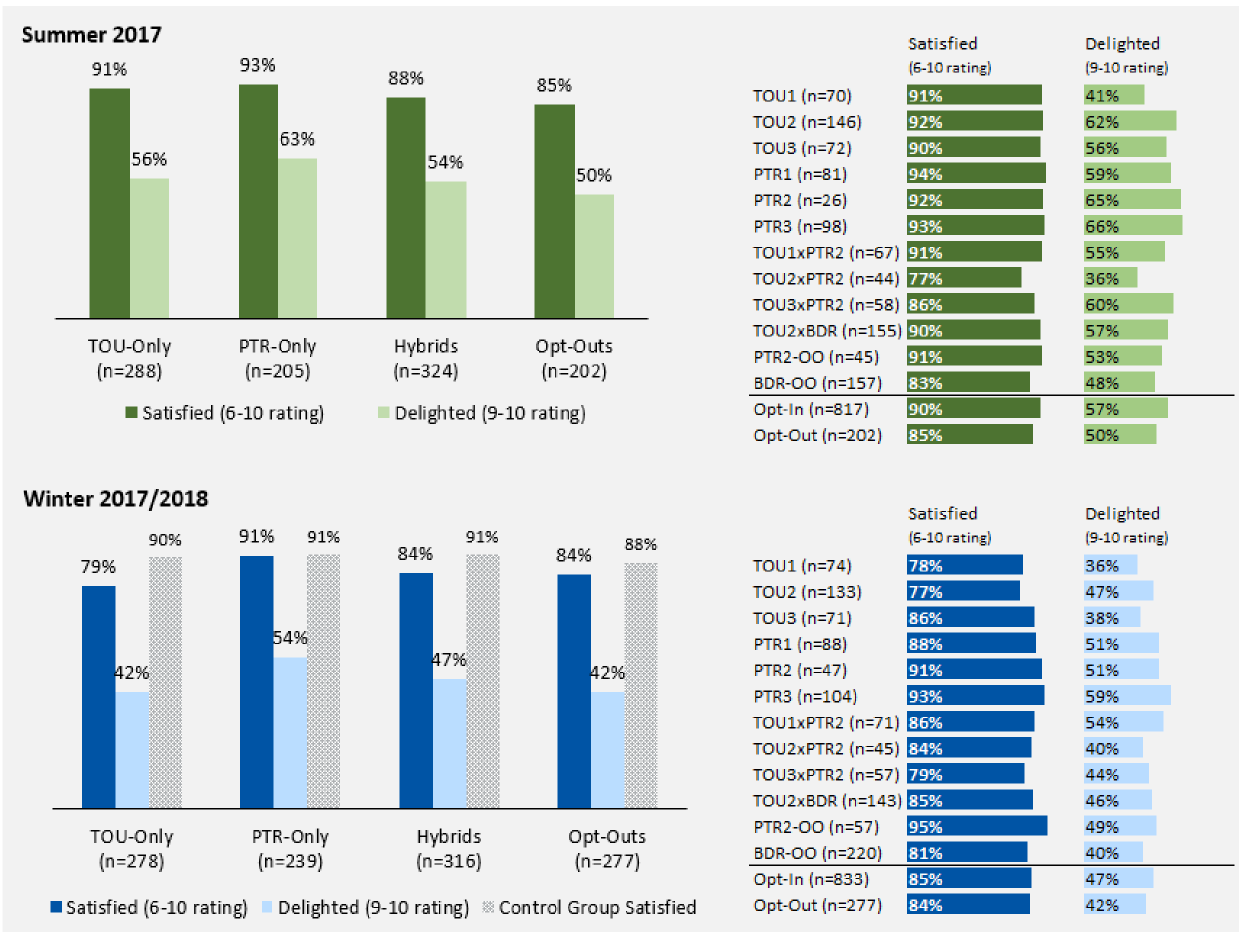
The surveys asked test and control group customers to rate their overall satisfaction with PGE on a 0–10 scale, where zero meant *extremely dissatisfied* and 10 meant *extremely satisfied*. Figure 21 shows the percentage of *satisfied* (6–10 rating) and *delighted* (9–10 rating) customers across treatments and groups for Summer 2017 and Winter 2017/2018. Appendix F contains survey results for Summer 2016 and Winter 2016/2017.

Among test group treatments, PTR-only had the highest PGE satisfaction rates. As shown in Figure 21, PTR-only had a PGE satisfaction rate of 93% in summer and 91% in winter. Opt-Outs had the lowest PGE satisfaction rates (85% in summer and 84% in winter). PGE satisfaction rates significantly differed between PTR-only and Opt-Outs in both seasons.[34] However, when combined, Opt-In customers showed no significant differences from Opt-Out customers in PGE satisfaction rates. In summer, Opt-Ins had a satisfaction rate of 90% and Opt-Outs had a satisfaction rate of 85%. In winter, Opt-Ins had a satisfaction rate of 85% and Opt-Outs had a satisfaction rate of 84%.

[34] Significant difference with 90% confidence ($p \leq .10$).

Customer satisfaction with PGE was lower in winter than summer. Most treatments showed a decrease in PGE satisfaction in winter, with TOU-only showing a significant decrease. TOU-only respondents significantly rated their satisfaction with PGE as lower in winter (79%) than in summer (91%).[35] Hybrid respondents also rated their satisfaction with PGE as lower in winter (84%) than in summer (88%), though this was not a statistically significant difference. The lower PGE satisfaction ratings in winter possibly reflected challenges in saving energy during winter. As discussed in the previous section, TOU-only and Hybrid customers reported the program as more difficult to participate in during winter than summer.

Figure 21. Overall Satisfaction with PGE



Survey Question: Please rate your overall satisfaction with PGE using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

*Note: Cadmus did not survey the control group customers in the Summer 2017 experience survey. Appendix F contains the satisfaction results for Summer 2016 and Winter 2016/2017 as well as the control group's Winter 2017/2018 satisfaction results for all 12 treatments.

35 Significant difference with 90% confidence (p≤.10).

PGE satisfaction ratings are compared between test and control groups only for winter (see the gray, hatched bars); control customers were not included in the summer survey. As shown in Figure 21, PTR-only had no impact on customer satisfaction with PGE, but other treatments had a negative impact on customer satisfaction with PGE. PTR-only test group and control group both had a PGE satisfaction rate of 91%. TOU-only test group had a significantly lower PGE satisfaction rate (79%) than control group (90%).[36] Hybrid test group also showed a significantly lower PGE satisfaction rate (84%) than control group (91%).[37] Opt-Out test group showed a lower PGE satisfaction rate (84%) than control group (88%), though not a statistically significant difference.

Implementation Challenges and Lessons Learned

PGE enrolled approximately 14,000 residential customers in the Flex pilot, which involved a complex RCT design using multiple treatments. Never having implemented a pilot of this scale or complexity, PGE encountered several implementation challenges, including marketing and providing feedback about demand savings to customers after events. This section documents these challenges and lessons learned, as communicated by PGE and implementation contractor program staff in interviews.

Marketing

Recruitment proceeded more slowly than expected, but still met its overall enrollment target by Summer 2017 (see Marketing and Recruitment and Table 5 for marketing and enrollment details). PGE and CLEAResult struggled at first with finding a marketing and messaging approach that resonated with customers. PGE experimented with marketing through emails, gift card rewards, postcards, and business letters as well as with messaging that emphasized economics (personal gains, including bill savings), control (taking charge of your consumption), and community (the greater good).

PGE reported the following customer conversion rates for Flex marketing channels over the course of the pilot:[38]

- 1.5% enrolled from email
- 2.5% enrolled from postcard
- 4.5% enrolled from business letter

Over the course of the pilot, PGE improved the effectiveness of its marketing through experimentation. PGE learned the types of messaging that resonated most with customers and the most effective marketing channels. It also found that offering a gift card as a reward did not increase the likelihood of

36 Significant difference with 90% confidence (p≤.10).

37 Significant difference with 90% confidence (p≤.10).

38 A conversion rate measures a given marketing channel's effectiveness in spurring enrollment, calculated by taking the number of customers who enrolled from a channel and dividing this by the total number of customers that the channel reached.

enrollment. PGE reported that during the third and final recruitment wave it had enrolled 4.5% of customers receiving one well-designed email or business letter who had not received a previous Flex solicitation. According to PGE, it enrolled a high percentage of customers in the pilot after “a single touch” because of critical lessons about marketing it had learned during the previous two recruitment waves.

PGE’s experiments with marketing approaches revealed two critical lessons:

1. **Customers respond to paper (even after many emails).** Business letters and postcards enrolled customers more effectively than emails. Initially, PGE recruited customers with valid email addresses and only later opened recruitment to customers without email. Recruiting both customer sets helped the pilot program meet its enrollment targets. PGE also reported that it switched to business letters after having emailed customers as much as nine times; notably, when customers not responding by email received the business letter, they responded as if they had seen the program marketing for the first time.
2. **Customers respond to messaging about bill savings.** Business letters more successfully enrolled customers due to comparisons of standard flat rates vs. TOU rates and financial messaging about bill savings. Initially, PGE used control and community messaging in emails and postcards, which proved unsuccessful in converting customers. PGE realized that financial-focused messaging resonated more with customers as the primary participation benefit arose from the opportunity to earn bill credits or savings. Recruitment survey results (n=458) further supported this contention, indicating that saving money on electric bills was the top reason for enrollment (78%), followed by saving energy (46%), and helping the environment (28%).

Event Management

PGE encountered challenges in providing accurate and timely feedback to customers about their success in reducing or shifting loads during Flex events and in dispatching the appropriate number of events. A summary of challenges follows, along with PGE’s efforts to address them:

- **PGE delivered inaccurate event savings feedback to some customers during the initial part of the Summer 2016 season.** To provide individualized feedback on event savings to participants, AutoGrid’s data management platform performed consumption baseline calculations for each participating customer. During the initial Summer 2016 events, some customers received inaccurate or no feedback about their savings due to misaligned baseline calculation inputs. Inaccurate feedback or absence of feedback may have discouraged some customers from participating in future Flex events. To address these data errors, PGE and AutoGrid worked to refine the baseline calculation methodology and developed a quality control (QC) process to review event data before delivering them to customers. They began implementing the QC process in late Summer 2016.
- **PGE did not deliver event savings feedback to customers within the ideal 24-hour time frame.** PGE intended to send customers their event savings feedback within 24-hours of events, believing that each passing day could diminish the value customers gained from the feedback. PGE reported that, for the first few Summer 2016 events, it took a few days to a week to provide

feedback due to the baseline calculation difficulties and inaccuracies described previously. The delay in feedback also prevented PGE from calling additional events until these issues were resolved. However, by the end of Winter 2016/2017, PGE refined its process flow and managed to achieve 48-hour delivery. Though data management and QC processes made it difficult for PGE to achieve a shorter timeframe, PGE continued to improve its processes for delivering feedback and achieved close to a 24-hour turnaround in Summer 2017.

- **PGE dispatched too many BDR events.** PGE received feedback from some BDR customers that it dispatched too many events. As PGE does not compensate BDR customers, it is mindful of not calling upon them to reduce demand too often. As a result, while BDR saved 1%–2% of demand for thousands of customers, PGE used BDR less frequently over the pilot's course and plans to use it even less frequently in the future. In contrast, PGE is considering dispatching more PTR events in future winter seasons because it is popular with customers and effective at reducing peak demand. Moreover, PGE reported that it could have communicated better with BDR customers about their options for receiving event notifications after receiving feedback that some customers had not been aware that they could change their event notification settings.

Conclusions and Recommendations

Peak-Time Rebates

Larger rebates did not yield more Flex event savings.
Opt-In PTR customers saved about 20% of consumption during summer Flex events and between 7% and 12% of consumption during winter Flex events. No statistically significant differences in savings appeared by rebate amount. In summer, customers receiving a $0.80/kWh rebate achieved the same savings as customers receiving a $2.25/kWh rebate.

Of 12 treatments, Opt-In PTR-only customers were most satisfied with the Flex pilot.
In both seasons, Opt-In PTR-only respondents had the highest satisfaction rates with Flex (83% reported a program satisfaction score of 6 or higher on a 10-point scale in winter; 86% in summer) compared to Hybrids (71% in winter; 79% in summer) and TOU-only (61% in winter; 76% in summer).[39] Opt-In PTR2 treatment achieved the highest satisfaction rate of 92% in the summer survey. Opt-In PTR2 (89%) and PTR3 (89%) treatments also achieved high satisfaction rates in the winter survey. PTR customers may have been most satisfied as they faced no financial risk from participation. Customers could earn rebates for saving energy during Flex events, but were not penalized if their consumption increased.

Larger rebates (greater than $1.55/kWh) increased customer satisfaction with the Flex pilot.
PTR1 customers, who received the smallest rebate ($0.80/kWh), had lower satisfaction with Flex for both winter and summer seasons than PTR2 ($1.55/kWh) or PTR3 ($2.25/kWh) customers. In summer, 79% of PTR1 customers expressed satisfaction with the program, while 92% of PTR2 customers and 84% of PTR3 customers expressed satisfaction. In winter, PTR1 had a satisfaction rate of 80%, about 10 percentage points lower than that of PTR2 (89%) and PTR3 (89%).

Flex event savings from peak-time rebates did not depend on outside temperatures.
A statistical relationship was not found between PTR savings and outside temperatures during Flex events in winter or summer. Outside temperatures during Flex events ranged between 82°F and 96°F in summer and 28°F and 45°F in winter.

PTR Recommendation

- When setting rebates for future PTR programs, PGE should consider the tradeoff arising from offering a higher rebate: over the lower range of rebates tested ($0.80/kWh to $1.55/kWh), there were positive effects on customer satisfaction but no impacts on Flex event savings from increasing the rebate. This suggests that larger rebates may raise customer satisfaction, but lower program cost-effectiveness.

[39] Respondents rated their overall satisfaction with the program on a 0–10 scale, where 0 meant *extremely dissatisfied* and 10 meant *extremely satisfied*. PGE defined a 6–10 rating as *satisfied*.

TOU Rates

Customers under the TOU1 rate schedule encountered difficulties in shifting consumption from peak to off-peak hours.

The TOU1 rate used “day/night” off-peak and on-peak period definitions. As the on-peak period was set from 6:00 a.m. to 10:00 p.m., many customers were awake only during peak hours and asleep during off-peak hours, making load shifting inconvenient or difficult. Shifting loads would require many customers to adjust their sleep schedules or to have appliances programmed to run at night. Among TOU customers, those on the TOU1 rate had the lowest program satisfaction rates (57% in summer and 54% in winter) and did not achieve peak savings in either season. TOU1 respondents dissatisfied with Flex most often mentioned the rate schedule being difficult for their households; these respondents said it was not convenient or worth changing one’s sleep time to do chores during off-peak periods.

TOU rate schedules with short peak-period definitions yielded peak savings and high satisfaction in summer.

In summer, TOU2 and TOU3 customers achieved significant savings during peak periods (8% and5%, respectively). They also saved 5%–6% during Flex event hours, which Cadmus used as a proxy for the peak capacity impact of TOU, even though TOU customers did not receive Flex event notifications or incentives. In summer, the TOU2 and TOU3 schedules had relatively short peak periods, from 3:00 p.m. to 8:00 p.m., which coincided with PGE’s summer system peak and enabled customers to shift loads to off-peak periods. In summer, TOU2 and TOU3 customers had relatively high customer satisfaction ratings of 82%.

The simpler TOU rate schedule achieved the same peak period savings and satisfaction as the more complex one.

In summer, the TOU3 rate, with peak (3:00 p.m.–8:00 p.m.), mid-peak (11:00 a.m.–3:00 p.m.), and off-peak periods, reduced loads by 5% during the mid-peak period. However, no differences emerged in peak period savings between the simpler TOU2 rate, which only had peak (3:00 p.m.–8:00 p.m.) and off-peak periods, and the more complex TOU3 rate. TOU2 and TOU3 showed statistically similar program satisfaction rates in summer (TOU2 82%; TOU3 82%) and winter (TOU2 62%; TOU3 68%).

In winter, TOU customers experienced difficulties in shifting loads from peak to off-peak periods and achieving bill savings.

During winter, none of the TOU-only treatments produced statistically significant reductions in or shifts in peak-period loads. Either TOU did not affect customer loads, or the load impacts were too small to detect with the existing sample sizes. TOU customers also reported relatively low satisfaction with Flex (54%–68%) because of adverse bill impacts and the rate schedule being difficult for their households. TOU schedules had morning *and* evening peak periods. Notably in the survey’s open-ended comments, TOU-only and Hybrid customers mentioned the program was more difficult to participate in during winter than summer. Moreover, TOU-only and Hybrid treatments showed significantly lower program satisfaction rates in winter (61%–71%) than in summer (76%–79%).[40] This seasonal pattern in program satisfaction for TOU-only and Hybrid treatments suggests that the TOU aspect may be more challenging for customers in winter than in summer.

TOU Recommendations

- Unless an economic case justifies shifting customer loads from mid-peak to off-peak hours, PGE should implement the TOU2 rate schedule, which is simpler for customers to understand.
- PGE should consider redesigning the winter TOU rate schedules by removing the morning peak period. This would minimize the potential for adverse customer bill impacts and simplify the customer experience.
- PGE should redesign the TOU1 rate schedule or offer TOU1 customers enabling technology to facilitate load shifting from peak to off-peak periods.
- PGE did not test the impacts of pairing enabling technology with TOU pricing, but studies of other TOU pricing programs suggest that enabling technology such as price-responsive smart thermostats can increase load shifting. PGE should consider testing the load impacts of enabling technology in the future.
- PGE should consider enhancing customer screening during the enrollment process to determine whether a customer is a good fit for a TOU rate.
- Given TOU customers' challenges in achieving winter bill savings, PGE should offer them more education about how to save energy or shift loads from peak to off-peak periods.

Opt-Out Behavioral Demand Response

Behavior-based treatments caused PGE customers to save energy during Flex events.
BDR-OO customers saved an average of 2.3% of consumption in summer and 1.2% of consumption in winter. PGE sent opt-out BDR customers Flex event alerts, encouragement to reduce consumption, and individualized post-event feedback but did not charge them higher electricity prices or provide them with rebates during Flex events, demonstrating that residential customers responded to non-price interventions.

Opt-out BDR program design yielded capacity benefits, but resulted in relatively low customer satisfaction.
PGE automatically enrolled over 12,000 residential customers in the BDR-OO treatment. While average savings per treated customer were small (only 1%–2% of consumption), total program demand savings were large due to the size of the treated population. In the future, PGE can deploy the BDR program to help manage system peaks, but at the potential cost of lower customer satisfaction: only 51% of BDR-OO customers in winter and 57% in summer rated the program a 6 or higher on a 10-point scale.

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40 Significant difference with 90% confidence (p≤.10).

Satisfaction ratings were likely low due to the opt-out program design and the unfamiliarity of many customers with behavioral demand response and the costs of supplying energy during utility system peaks. The program sent event notifications to many customers who had little interest in receiving them or participating in a BDR program. PGE also mentioned in the interviews that it received feedback from some BDR customers that it dispatched too many events and that these customers had not been aware that they could change their event notification settings.

BDR Recommendations

- PGE should consider using opt-out BDR for achieving capacity savings targets, given its success with BDR in reducing loads during this pilot; but it should consider possible changes to program design to increase customer satisfaction, such as:
    - Limiting the frequency of future BDR events, which would also limit the number of event notifications customers received.
    - Shortening the duration of future BDR events to lessen the burden on customers.
    - Spacing out future BDR events to avoid calling back-to-back events or multiple events in the same week.
    - Sending BDR customers a handy reminder magnet or sticker about BDR events and how to save, akin to the clock sticker PGE sent to TOU customers.
- PGE should clearly inform opt-out BDR customers that they can opt out of treatment, and should make it relatively easy for customers to opt out if they do not want to participate.

Opt-Out Peak-Time Rebates

The opt-out participation program design significantly increased program participation.
PGE attained a much higher participation by presenting customers with a choice to opt out of the program rather than opt in. PGE automatically enrolled approximately 1,600 customers in the PTR2-OO program. By the end of the Winter 2017/2018 season, only 2.3% of customers had opted out. In comparison, at the end of the recruitment period for opt-in PTR treatments, less than 7% of PGE customers accepted offers to participate in a PTR1 (4.3%), PTR2 (2.8%), or PTR3 (6.2%) treatment.[41] Of customers opting in to PTR treatment, between 4.5% and 6.3% subsequently opted out. The opt-out design took advantage of customers who were expected to be "complacent": they would neither opt in nor opt out of a demand response program, if given the choice. Cadmus estimated that 92% of opt-out customers were complacent customers. By making participation the default choice, PGE obtained program participation and peak capacity that it would not have achieved otherwise.

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41 PGE experimented with different marketing strategies during the first two waves and obtained higher rates of acceptance during the third wave after improving its approach. Also, PGE stopped recruiting for the opt-in PTR2 treatment after the second wave.

The design of the pilot participation choice (opt-in vs. opt-out) presents a tradeoff between savings per customer and number of participants.

Depending on the rebate amount, opt-in PTR customers saved 17% to 21% of consumption during summer Flex events and from 7% to 12% of consumption during winter Flex events. Customers automatically enrolled in PTR2 saved an average of 7% during summer Flex events and 5% during winter Flex events.[42] Cadmus estimated that in Summer 2017, "complacent customers"—who would neither opt in nor opt out of a PTR program if given the choice—saved 6% during Flex events. While opt-in PTR customers saved more, the opt-out design enrolled many more customers. As noted above, fewer than 6% of PGE customers took up offers to participate in the PTR program. In contrast, more than 97% of customers defaulted onto PTR2-OO remained in treatment through the end of the Winter 2017/2018 season.

Adding a peak-time rebate to behavior-based demand response increased Flex event demand savings and customer satisfaction.

The opt-out BDR treatment and the opt-out PTR treatment only differed in the rebate paid to customers for saving energy during Flex events. PTR customers received the same notifications, tips for saving energy, and individualized feedback about savings as BDR-OO customers. Opt-out PTR customers, however, saved significantly more during Flex events than BDR-OO customers (5% in winter and 7% in summer vs. 1% and 2%, respectively), demonstrating that the rebate lifted savings and complemented the behavior-based treatment. The rebate also increased customer satisfaction. PTR2-OO customers reported 73% program satisfaction in summer and 79% in winter—high customer satisfaction rates for customers automatically enrolled in a program. In contrast, BDR-OO customers only reported program satisfaction rates of 51% in summer and 57% in winter.

Opt-Out PTR Recommendation

- Given the tradeoff between savings per customer and numbers of participants, PGE should analyze whether the opt-in or opt-out PTR design proved more cost-effective, and whether each design will generate the desired aggregate demand response capacity.

Hybrid Treatments

TOU pricing did not enhance (and possibly diminished) savings from PTR during Flex events and customer satisfaction (TOUxPTR vs. PTR).

[42] The surveys also found that a higher percentage of opt-in (75% in summer, 89% in winter) than opt-out (37% in summer, 75% in winter) PTR2 customers reported participating in Flex events.

During Summer Flex events, opt-in PTR customers saved 17% to 21% of consumption, but TOUxPTR customers only saved 9% to 19%[43]. During Winter Flex events, opt-in PTR customers saved 7% to 12%, but TOUxPTR customers only saved 4% to 12%. TOU pricing may cause PTR customers to become inattentive to Flex event alerts, or TOUxPTR customers may have less incentive to save energy during Flex events because their consumption baseline used for calculating rebates is lower. In summer and winter, satisfaction with Flex was 10 to 20 percentage points lower for TOUxPTR customers than for PTR-only customers.

Adding peak-time rebates to TOU pricing increased customer satisfaction and Flex event savings (TOUxPTR and TOUxBDR vs. TOU-Only).
Peak-time rebates had positive impacts on customer satisfaction for TOU customers. Depending on the TOU rate, TOU-only customers reported program satisfaction ranging from 57% to 82% in summer and 54% to 68% in winter. In contrast, TOUxPTR customers reported satisfaction levels ranging from 70% to 88% in summer and from 69% to 73% in winter, suggesting that the PTR enhanced customer satisfaction with the program.

During Flex events (i.e., hours used in this report to approximate system capacity conditions), TOUxPTR customers also saved more than TOU-only customers. In summer, TOUxPTR or TOUxBDR customers saved from 8% to 19% of Flex event demand, while TOU-only customers saved from 2% to 8%. During Winter events, TOU2xPTR2 and TOU3xPTR2 customers saved 12% of consumption, while TOU-only customers did not save any demand.

Hybrid Treatment Recommendations

- If PGE's primary objective is to save demand during system peaks, it should consider enrolling more customers in PTR-only treatments than hybrid TOUxPTR treatments to maximize the impact on system peak.
- If PGE deploys TOU rates on a wide scale, it should consider pairing TOU rates with a peak-time rebate to raise customer satisfaction and Flex event savings.

Customer Experience

TOU and Hybrid customers reported higher satisfaction with the Flex pilot in summer than winter, primarily due to greater summer bill savings.

[43] The Flex event savings estimate for Hybrid customers indicates the combined effects of TOU and PTR during Flex events. The savings are estimated relative to customers who are treated with neither PTR nor TOU pricing.

Overall, participant respondents were more satisfied with the Flex pilot in Summer 2017 (74% *satisfied*) than Winter 2017/2018 (69% *satisfied*).[44] The seasonal satisfaction differences, however, were greatest for treatments involving TOU pricing, which typically produced annual bill savings, with most or all savings occurring in summer. For TOU-only and Hybrid treatments, respondents reported significantly higher program satisfaction in summer (76%–79% *satisfied*) than in the winter (61%–71% *satisfied*).[45] Summer and winter respondents giving the program satisfied ratings most often noted that the program delivered bill savings. Respondents giving a less-than-satisfied rating most often noted seeing little to no difference in their bill savings. In summer, 16% of TOU survey respondents said they saved on their electric bills, compared to 9% of TOU survey respondents in winter. These program satisfaction results align with demand savings estimates showing participants achieved higher peak-period load reductions in summer than winter.

Although PGE automatically enrolled them, opt-out PTR and BDR customers showed high event awareness and engagement with the pilot.

As expected, customers opting into the pilot exhibited high awareness of and engagement with Flex events. Depending on the season, 93% to 96% of opt-in PTR-only respondents and 94% to 97% of opt-in Hybrid respondents remembered receiving event notifications. Also, 76% to 86% of opt-in respondents reported conserving electricity during events in both seasons. These awareness and engagement levels were higher than for BDR-OO and PTR2-OO customers automatically enrolled in the pilots. and 89% of opt-out respondents remembered receiving event notifications. Also, 48% of opt-out respondents in summer and 63% of respondents in winter reported conserving energy during these events. This suggests that PGE can engage customers in achieving demand savings who are automatically enrolled in demand response programs.

PGE has an opportunity to increase peak period and Flex event demand savings from TOU rates through additional education with existing TOU customers.

TOU2 and TOU3-only and Hybrid treatments saved 5% to 8% of demand during peak periods and 8% to 20% of demand during Flex events, indicating that TOU treatments proved effective. TOU customers, however, did not have strong awareness of their rate schedules. Only about one-half of TOU and Hybrid respondents (52%) correctly identified their rate schedules from a list of three rate schedule images. That was only slightly better than results one would expect (33%) if all customers guessed at random. This suggests TOU customers could save more if they knew of their rate schedules. PGE might be able to increase TOU customer demand savings through doing additional education and outreach.

PGE identified several pilot implementation issues that negatively affected customer experiences and either corrected the issues or will correct them in future Flex deployments.

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[44] Respondents rated their overall satisfaction with the program on a 0–10 scale, where a zero meant *extremely dissatisfied* and a 10 meant *extremely satisfied*. PGE defined a 6–10 rating as *satisfied*.

[45] Significant differences at the 90% level (p≤.10).

In interviews with Cadmus, PGE managers and implementation contractors described several program implementation issues:

- PTR and BDR customers received inaccurate and delayed feedback regarding their demand savings during Flex events. The inaccurate feedback may have discouraged some customers from saving, and the delay in providing feedback prevented PGE from calling additional events until these issues resolved. By the start of Winter 2016/2017, PGE had resolved the savings calculation issues and managed to deliver feedback to participants within 24 to 48 hours of events.
- Another issue concerned communication about event notification settings. Some customers complained that they received too many notifications or that the notifications did not arrive through their preferred delivery channels. Many customers reported being unaware that they could change their notification settings. In the future, PGE plans to communicate more proactively with participants about options for program communications and will simplify the process for changing the settings.

Pairing technology with Flex treatments may improve customer's ability to achieve load reduction. While the Flex pilot did not test the impacts of pairing enabling technologies, such as smart thermostats, advanced water heaters, or in-home displays, with the pricing or behavior-based treatments, other studies have found the pairing of these technologies enhances peak demand savings. The experience of TOU1 customers illustrates the potential benefits of enabling technology. TOU1 customers reported challenges in shifting loads from daytime on-peak periods to nighttime off-peak periods; programmable or price-responsive enabling technologies may facilitate shifting of loads and increase TOU1 on-peak demand savings.

Customer Experience Recommendations

- PGE should consider modifying the TOU design and delivery for the winter season to help customers save or shift more electricity consumption. This would improve customer satisfaction and increase load impacts. Modifications could include eliminating the morning on-peak period, shortening the length of the on-peak periods, or automatically enrolling TOU customers in the PTR program. A conjoint analysis of the TOU program offering could examine tradeoffs between different rate schedule designs, customer satisfaction, and load impacts.
- PGE should provide TOU customers with additional education about their rate schedules. This information should be simple and easy to understand. One idea is delivering educational information through alternative media, such as online video.
- PGE should consider opt-out demand response programs as a component of its demand response portfolio. The Flex pilot demonstrated that opt-out programs can reach large numbers of customers and that 50% or more of customers automatically enrolled in PTR or BDR remained engaged, as measured by self-reported rates of Flex event awareness and conservation.

- PGE should conduct test events before the start of each season to assess readiness of its customer communications and data analytics platforms. Testing will allow PGE to correct issues before the season starts, refamiliarize customers with the program, and give customers a chance to change their communications preferences.

- PGE should consider conducting pilots to test the impacts of pairing enabling technologies such as smart thermostats or advanced water heaters with time-based rates or behavior-based treatments if PGE expects the technologies would be cost effective.

Marketing

Paper-based marketing and bill-savings messaging resonated most with customers.
PGE experimented with email, postcard, and business letter marketing, and found business letters achieved the highest customer marketing conversion rate (4.5%), followed by postcards (2.5%), and then email (1.5%).[46]

Business letters emphasized financial messaging (i.e., rate comparison information and a bill savings pitch). PGE initially used economic, control, and community messaging in the emails and post cards, but those approaches proved unsuccessful in enrolling customers. The recruitment survey also found a large majority of participants enrolled to save money on their electric bills (78%); far fewer respondents indicated enrolling to save energy (46%) or help the environment (28%).

Marketing Recommendation

- PGE should consider employing business letter marketing approach for future demand response programs to increase the cost-effectiveness of its marketing. This approach would include leading with bill savings and rate comparisons rather than energy savings or community as primary messages in postcards, emails, or other marketing channels.

[46] A conversion rate measures a given marketing channel's effectiveness in spurring enrollment, calculated by taking the number of customers who enrolled from a channel and dividing this by the total number of customers that the channel reached.

Appendix A. Data Preparation

AMI Meter Data

The AMI data included a mix of 15- and 60-minute interval readings. Cadmus removed a small number of duplicate interval readings from the data. After summing 15-minute interval consumption data to obtain hourly interval consumption, Cadmus dropped a small number of outliers and hourly observations with one or more missing 15-minute interval readings. Specifically, we removed hourly consumption readings greater than 24 kWh from the analysis sample.[47] Also, Cadmus dropped customers with high average monthly consumption, who were unlikely to have been residential customers. We dropped a small number of customers consuming an average of 300 or more kWh per day from the analysis sample.[48]

Cadmus encountered other issues with the AMI meter data and developed solutions to address them. First, the timestamps on the AMI meter datasets were set to different time zones. Some were recorded on Coordinated Universal Time (UTC) instead of Pacific Time (UTC -8 or UTC -7) and required adjustment. In these cases, Cadmus shifted the timestamps to the correct time zone and adjusted for daylight savings time. Cadmus performed a review of the raw, average daily load shapes in each dataset before and after each adjustment to verify the timestamp adjustments.

Second, during the pretreatment period, some customers' AMI interval data were reported in integer kWh instead of in watt-hours. PGE did not switch meters of many participants to record watt-hours until the customer enrolled in the pilot. Cadmus determined these data were not truncated or rounded to the nearest kilowatt hour, but instead represented the change in kilowatt hours between intervals.[49] Since the pretreatment consumption data were measured with error, Cadmus wanted to avoid having pretreatment period hourly consumption directly enter the regression models used to estimate savings. We selected a regression approach that did not require using pretreatment period hourly consumption as a dependent or independent variable. However, to explain variation between customers in hourly consumption during the treatment period, it would be important to control for pre-treatment consumption. We determined that averaging the integer kWh over hours and making an adjustment for expected small errors produced an accurate estimate of a customer's pretreatment mean kWh per hour.

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47 Twenty-four kWh represented the maximum possible hourly energy consumption of a home with a 100-amp service. Such observations were extremely rare, and more likely reflected bad data (or commercial/industrial activity) rather than true residential consumption. This filter removed any hours with incomplete data or multiple observations for the same period. The hour in fall when DST ended was the exception to this filter, resulting in two 1:00 a.m.–2:00 a.m. periods on the same day.

48 Customers consuming over 300 kWh per day on average unlikely lived in single-family residential homes. The 300 kWh/day bound is standard practice for evaluation of residential behavioral programs.

49 For example, if a customer consumed 0.4 kWh per hour for each hour over a three-hour period, the meter data would show 0, 0, and 1 in the kWh field.

Using AMI meter data for customers with consumption reported in watt-hours, we tested the accuracy of our methodology and found that it produced accurate estimates of mean consumption. As noted above, Cadmus included customer pretreatment mean consumption as an independent variable in the regressions to explain variation between customers in energy consumption during the treatment period.

Third, PGE did not provide pretreatment data for the same 12 months for all pilot customers as recruitment lasted longer than one year and PGE only retained interval meter data for the previous 13 months. The date range for the available pretreatment consumption data depended on the customer's recruitment wave. For example, for TOU customers opting into the pilot in spring 2016, PGE provided Cadmus with AMI meter interval data for calendar year 2015, but, for TOU customers opting into the pilot in spring 2017, PGE provided Cadmus with AMI meter interval data for the second half of 2015 and the first half of 2016. This complicated the calculation of each customer's pretreatment mean consumption, which would be included as a control variable.

To obtain comparable estimates of pretreatment consumption for customers from different recruitment waves, Cadmus built a regression model for each customer to predict the customer's pretreatment demand under a standard set of conditions. The standard set of conditions was defined by the specific hours and weather for which Cadmus was attempting to estimate demand savings during the treatment period. For example, to estimate TOU2 demand savings during the on-peak period in Summer 2017 analysis, Cadmus used pretreatment data to predict pretreatment consumption for each customer in the TOU2 test or control group during on-peak hours (between 3:00 p.m. and 8:00 p.m. on non-holiday weekdays) when the outside temperature equaled average outdoor temperatures during on-peak hours in 2017.

Specifically, using available pretreatment consumption data for summer or winter, Cadmus estimated individual customer regressions of hourly energy consumption on a constant and cooling or heating degree hours:

Equation 1

$$kWh_{it} = \alpha_i + \beta_i HD_{it} + \varepsilon_{it}$$

Where:

kWh_{it}	=	Electricity consumption of customer i during on-peak hour t of the summer or winter pre-treatment period.
α_i	=	Intercept for customer i indicating average consumption per hour during on-peak or off-peak hours.
β_i	=	Coefficient for customer i indicating average effect of cooling (heating) degree hours during summer (winter) on electricity consumption.
HD_{it}	=	Heating (cooling) degrees for customer i during peak or off-peak hour t using base temperature of 65°F in winter and 75°F in summer.
ε_{it}	=	Error term for consumption of customer i during peak or off-peak hour t.

Cadmus estimated the customer models by OLS and then predicted each customer's consumption for typical weather during on-peak and off-peak hours as follows:

Equation 2

$$\widehat{kWh_{ip}} = a_{ip} + b_i\overline{HD}_{ip}$$

where:

kWh_{ip} =		Predicted mean electricity consumption for customer i during on-peak or off-peak hours during the pre-treatment period.
a_i	=	Estimated intercept for customer i indicating average consumption per hour during on-peak or off-peak hours.
b_i	=	Coefficient for customer i indicating average effect of cooling (heating) degree hours during summer (winter) on electricity consumption during on-peak or off-peak hours.2.
$\overline{HD}_{ip}$	=	Mean cooling (heating) degree hours during on-peak or off-peak hours of the treatment period.

Cadmus included the predicted pre-treatment consumption as an explanatory variable in Equation 2.

Ineligible Customers and Account Closures

A small number of customers opting into the pilot or automatically enrolled in opt-out treatments were determined ineligible for participation. Cadmus removed any customer from the analysis sample if PGE determined they were ineligible (e.g., customers with solar arrays or participants in the Rush Hour Rewards program). Cadmus applied these sample selection criteria identically to customers in the randomized test and control groups.

Also, some customers opting in or automatically enrolled in the pilot moved residences. When a customer moved, their participation in the pilot ceased, and Cadmus removed all AMI data for the period after the customer's move-out date.

Appendix B. Model Specifications

Event-Based Treatments

Cadmus estimated the demand savings from event-based treatments (PTR1-PTR3, opt-out BDR, and Opt-out PTR2) by comparing the hourly consumption of customers in each treatment's randomized test and control groups. Using data for event hours during each winter or summer season, Cadmus estimated a panel regression of customer hourly energy consumption on control variables for pretreatment consumption, hour-of-sample fixed effects, and assignment to treatment. Letting i, i=1, 2, …, N, denote customer, and t, t=1, 2, …, T, denote the Flex hour, the model took the following form:

Equation 3

$$kWh_{it} = \beta_1 Test_i + \mathbf{kWh}^{Pre}_{it}{}'\boldsymbol{\gamma} + \tau_t + \varepsilon_{it}$$

Where:

kWh_{it}	=	Electricity consumption of customer i during Flex event hour t.
β_1	=	A coefficient indicating average treatment effect (in kWh) per customer per hour.
$Test_i$	=	An indicator variable for whether customer i was assigned to receive the treatment. This variable equals one if the customer was assigned to the treatment group and zero otherwise.
$\mathbf{kWh}^{Pre}_{it}$	=	A vector of variables characterizing mean consumption during the pretreatment period for customer i.
$\boldsymbol{\gamma}$	=	A vector of coefficients indicating average effect of pretreatment consumption on consumption of customer i during Flex events.
τ_t	=	Error term for Flex hour t of the analysis period. Cadmus captured these effects with hour-of-the-sample fixed effects (i.e., a separate dummy variable for each Flex event hour).
ε_{it}	=	Error term for consumption of customer i and hour t.

The pretreatment consumption variables account for differences between customers in average consumption during Flex event hours. Cadmus calculated separate morning and evening pretreatment consumption means using data for hours when events typically occur (e.g., 4:00 p.m. to 7:00 p.m.) on non-holiday weekdays before the Flex season began or before the first PTR or BDR event occurred.[50] Cadmus attempted to use days that had low (winter) or high (summer) temperatures to temperatures experienced during Flex events.[51] Cadmus did not calculate mean consumption using non-event days

[50] For Summer 2017, Cadmus selected days between April 1, 2017, and July 23, 2017. For Winter 2017–2018, Cadmus selected days between November 1, 2017, and December 31, 2017. In each case, the last day of the period was the last non-holiday weekday before the first event of the season.

[51] Only days where the mean temperature fell no lower than 10 degrees below the event day mean temperature.

during the demand response season because of evidence from other studies showing that event-based treatment can produce savings on non-event days. The hour-of-sample fixed effects control for weather and other unobserved factors specific to each event hour.

Cadmus estimated a separate model for each treatment by OLS and clustered the standard errors on customers to account for correlation of consumption for individual customers, and estimated alternative model specifications to test the robustness of the estimates to specification changes. These alternative specifications included the following:

- Substituting day-of-the week and hour-of-the-day variables for the hour-of-the-sample fixed effects.
- Adding weather variables such as cooling degree hours (CDH) or heating degree hours (HDH) to the regression.
- Omitting pretreatment mean consumption from the regression equation.
- Adding indicator variables for a customer's recruitment wave (Wave 1, Wave 2, or Wave 3) as standalone variables and interacted with other variables.

These specification changes affected the estimated standard error, but not the point estimates of savings.

Time of Use Rate-Based Treatments

Cadmus estimated treatment effects for TOU rate and hybrid-TOU rate treatments by comparing consumption of customers in each treatment's randomized test and control groups. Using data on customer consumption for event and non-event hours during each winter or summer season, Cadmus estimated a panel regression of customer hourly energy consumption on control variables for pretreatment consumption, peak and off-peak hours, day-of-the-week, weather, and assignment to treatment. Again, letting i, i=1, 2, …, N, denote customer, and t, t=1, 2, …, T, denote the Flex hour, the TOU and TOU-hybrid treatment models took the following form:

Equation 4

$$kWh_{it} = \alpha + \gamma_1\, OffPeak_t + \gamma_2 Peak_t + \beta_1 Test_i{*}OffPeak_t + \beta_2 Test_i{*}Peak_t + \beta_3 Treatment_i{*}OffPeak_t{*}Wkend_t + \mathbf{kWh}^{Pre}{}_{it}'\boldsymbol{\gamma} + \varepsilon_{it}$$

Where:

$(kWh/hour)_{it}$	=	Electricity consumption of customer i during hour t of the summer or winter treatment period.
α	=	Intercept indicating baseline average consumption (kWh) per customer per TOU weekend (off-peak) hour.
γ_1 `	=	Coefficient on $OffPeak_t$ indicating baseline average consumption (kWh) per customer per TOU off-peak period hour.

$Offpeak_t$ = An indicator variable for whether the hour is a TOU off-peak period weekday hour. This variable equals one if the hour was not a peak period hour or weekend hour and zero otherwise.

γ_2 = Coefficient on $Peak_t$ indicating baseline average consumption per customer (kWh) per TOU peak period hour.

$Peak_t$ = An indicator variable for whether the hour is a TOU peak period hour. This variable equals one if the hour was a peak period hour and zero otherwise.

$Test_i$ = An indicator variable for whether customer i was assigned to receive the treatment. This variable equals one if the customer was assigned to the treatment group and zero otherwise.

β_1 = Coefficient on $Treatment_i$*$OffPeak_t$ indicating average TOU treatment effect per customer during off-peak period hours in kWh per hour.

β_2 = Coefficient on $Treatment_i$*$Peak_t$ indicating average TOU treatment effect per customer during peak period hours in kWh per hour.

β_3 = Coefficient on $Treatment_i$*$OffPeak_t$*$Wkend_t$ indicating average TOU treatment effect per customer during period weekend hours in kWh per hour.

$Wkend_t$ = An indicator variable for whether the hour is a weekend (TOU off-peak) hour. This variable equals one if the hour was a weekend period hour and zero otherwise.

$\mathbf{kWh}^{Pre}_{it}$ = A vector of variables characterizing mean consumption during the pretreatment period for customer i. This vector included mean off-peak period mean hourly consumption interacted with *Offpeak*$_t$, on-peak period mean hourly consumption interacted with *Peak$_t$*, and weekend (non-peak period) mean hourly consumption interacted with *Wkend$_t$*.

$\boldsymbol{\gamma}$ = A vector of coefficients indicating average effect of pretreatment kWh on consumption of customer i.

ε_{it} = Error term for consumption of customer i and hour t.

In the regression equation, the omitted variable is the indicator for the weekend (off-peak) period. The main coefficients of interest are β_1, β_2, and β_3, which indicate, respectively, TOU treatment effects during off-peak, peak, and weekend hours.

Cadmus estimated a separate model for each TOU treatment by OLS and clustered the standard errors on customers. To estimate the treatment effect for the TOU3 rate, which included a mid-peak period, Cadmus added an indicator variable for the mid-peak period to the specification. Again, because of the random assignment of customers to test and control groups, the regression was expected to produce an unbiased estimate of the treatment effect.

Cadmus estimated the following alternative model specifications to test the robustness of the TOU treatment effect estimates to specification changes:

- Substituting hour-of-sample fixed effects for the peak hour and off-peak hour variables.
- Adding weather variables such as cooling degree hours (CDH) or heating degree hours (HDH) to the regression.

- Omitting pretreatment mean consumption from the regression equation.
- Adding indicator variables for a customer's recruitment wave (Wave 1, Wave 2, or Wave 3) as standalone variables and interacted with other variables.

The point estimates of savings proved robust to these specification changes. The main effect was to increase or decrease the estimated standard errors.

Hybrid TOU Treatments

To estimate treatment effects for the hybrid treatments such as TOU1xPTR2 or TOU2xBDR, in Equation 2, Cadmus substituted *Peak***Event* and *Peak**(1-*Event*) *indicator* variables for the *Peak* variable, thereby allowing the effects of *Peak* and *Peak***Test* to depend on whether the hour was a Flex event hour. The *Event* variable equals 1 if the hour is a Flex event hour and equals zero otherwise.

Appendix C. Equivalency Checks and Analysis

Sample Summary Statistics

Table 19 presents results from tests of differences in pre-treatment consumption between the randomized test and control groups for each treatment. Cadmus regressed customer mean pre-treatment consumption on an indicator variable for assignment to the test group and separate indicator variables for the different recruitment waves. For the PTR-only, opt-in PTR, and BDR treatments, Cadmus presents balance tests of demand in hours that would have qualified as Flex events during the pretreatment period. For the TOU-based treatments, Cadmus presents separate balance tests of demand in on-peak period and off-peak period hours during the pre-treatment period.

Table 19. Balance Tests for Flex Pilot Randomized Test and Control Groups

	Summer 2017					Winter 2017/2018				
Treatment	N	Control Group kW	ΔkW (T-C)	Std. Error	T-stat	N	Control Group kW	ΔkW (T-C)	Std. Error	T-stat
PTR1	722	1.543	0.127	0.086	1.48	678	0.828	0.020	0.058	0.34
PTR2	408	1.528	0.167	0.116	1.44	380	0.892	0.062	0.092	0.68
PTR3	889	1.608	-0.061	0.076	0.80	823	0.871	-0.047	0.055	0.85
PTR-OO	1,256	1.588	0.057	0.068	0.84	1,149	0.876	0.032	0.050	0.65
BDR	19,587	1.644	-0.006	0.017	0.35	17,889	0.891	-0.006	0.013	0.44
TOU1										
Peak	827	0.932	0.036	0.033	1.09	787	1.459	-0.007	0.052	0.14
Off-Peak	827	0.799	0.037	0.029	1.28	787	1.326	-0.001	0.048	0.01
TOU2										
Peak	1,510	1.209	0.023	0.033	0.70	1,406	1.481	-0.004	0.040	0.09
Off-Peak	1,510	0.951	-0.023	0.025	0.93	1,406	1.320	-0.011	0.037	0.30
TOU3										
Peak	849	1.059	0.002	0.027	0.07	805	1.499	-0.010	0.037	0.27
Off-Peak	849	0.889	-0.020	0.022	0.90	805	1.372	-0.010	0.035	0.29
TOU1xPTR2										
Peak	638	0.981	0.025	0.044	0.57	612	1.451	0.018	0.059	0.30
Off-Peak	638	0.784	0.012	0.037	0.33	612	1.264	0.033	0.055	0.60
TOU2xPTR2										
Peak	385	1.051	0.181	0.064	2.83	354	1.551	-0.073	0.076	0.96
Off-Peak	385	0.899	-0.015	0.042	0.36	354	1.302	-0.074	0.064	1.16
TOU2xBDR										
Peak	1,398	1.209	-0.018	0.071	0.25	1,317	1.481	0.000	0.082	0.00
Off-Peak	1,398	0.951	-0.015	0.056	0.27	1,317	1.320	0.038	0.079	0.48
TOU3xPTR2										
Peak	598	1.076	0.027	0.034	0.80	559	1.501	-0.009	0.045	0.20
Off-Peak	598.0	0.802	-0.009	0.022	0.41	559	1.300	-0.017	0.038	0.45

Notes: N is number of test and control group customers. For PTR, PTR-OO, and BDR treatments, pre-treatment demand was average kW during event hours on 10 warmest (summer) or coldest (winter) non-holiday weekdays during 60 days preceding start of treatment. For TOU and Hybrid treatments, pre-treatment demand was predicted average demand during on-peak (off-peak) hours and was estimated with a separate regression for each customer of hourly demand during peak (off-peak) period hours for summer (winter) in the year before start of treatment. Difference between test and control group demand estimated with regression of customer mean pre-treatment demand on an indicator variable for assignment to the test group and separate indicator variables for the different recruitment waves.

The results of the balance tests show the test and control groups for almost all treatments and periods were well balanced on mean pre-treatment consumption, as expected from the random assignment to treatment. The only statistically significant difference was for the TOU2xPTR2 treatment.

Table 20 presents the sample mean and standard deviation of electricity demand during Summer 2017 and Winter 2017/2018 Flex events for test and control group customers in the PTR-only, opt-in PTR, and opt-in BDR treatments.

Table 20. Analysis Sample Summary Statistics for PTR and BDR Treatments

	Summer 2017				Winter 2017/2018		
Treatment		**N**	**Mean**	**Std. Dev.**	**N**	**Mean**	**Std. Dev.**
PTR1							
	Control	8,577	2.273	1.756	6,780	1.719	1.526
	Test	8,541	2.039	1.823	6,780	1.625	1.551
PTR2							
	Control	4,446	2.222	1.898	3,500	1.826	1.792
	Test	5,178	1.939	1.781	4,100	1.802	1.727
PTR3							
	Control	10,472	2.248	1.838	8,260	1.774	1.639
	Test	10,584	1.818	1.727	8,200	1.505	1.484
PTR-OO							
	Control	15,098	2.287	1.896	11,880	1.841	1.656
	Test	14,508	2.196	1.846	11,094	1.819	1.724
BDR							
	Control	230,912	2.243	1.860	107,210	1.915	1.791
	Test	231,371	2.193	1.840	107,373	1.891	1.803

Notes: Table shows sample means and standard deviations of demand during Flex event hours for event-based treatments. N is the number of observations of hourly demand for customers.

Table 21 presents sample means and standard deviations of electricity demand during Summer 2017 and Winter 2017/2018 on-peak and off-peak hours for test and control group customers in the TOU and Hybrid treatments.

Table 21. Analysis Sample Summary Statistics for TOU and Hybrid Treatments

		Off-peak			On-Peak		
Summer 2017							
Treatment		N	Mean	Std. Dev.	N	Mean	Std. Dev.
TOU1							
	Control	625,512	0.954	1.036	559,632	1.101	1.158
	Treatment	604,901	1.038	1.180	541,227	1.155	1.216
TOU2							
	Control	1,270,420	1.042	1.203	219,965	1.417	1.447
	Treatment	4,463,949	0.990	1.077	772,815	1.306	1.365
TOU3							
	Control	1,008,796	1.019	1.125	174,680	1.352	1.365
	Treatment	1,033,528	0.972	1.099	178,925	1.281	1.297
TOU1xPTR2							
	Control	448,735	0.916	1.014	401,584	1.114	1.193
	Treatment	509,200	0.955	1.100	455,600	1.122	1.234
TOU2xPTR2							
	Control	407,496	0.988	1.088	70,560	1.370	1.376
	Treatment	510,935	0.989	1.050	88,465	1.389	1.345
TOU2xBDR							
	Control	1,270,420	1.042	1.203	219,965	1.417	1.447
	Treatment	2,092,450	0.978	1.072	362,270	1.264	1.339
TOU3xPTR2							
	Control	686,774	0.957	1.030	118,895	1.335	1.318
	Treatment	755,520	0.935	1.041	130,800	1.292	1.388
Winter 2017/2018							
Treatment		N	Mean	Std. Dev.	N	Mean	Std. Dev.
TOU1							
	Control	438,002	1.237	1.321	372,556	1.422	1.467
	Treatment	397,696	1.309	1.347	338,224	1.428	1.377
TOU2							
	Control	720,000	1.344	1.452	251,054	1.520	1.478
	Treatment	2,543,971	1.292	1.381	887,119	1.433	1.450
TOU3							
	Control	606,091	1.314	1.384	211,341	1.466	1.420
	Treatment	569,966	1.309	1.469	198,737	1.439	1.508
TOU1xPTR2							
	Control	306,386	1.221	1.366	260,568	1.450	1.515
	Treatment	344,911	1.272	1.394	293,392	1.466	1.501
TOU2xPTR2							
	Control	239,910	1.363	1.453	83,639	1.607	1.621
	Treatment	277,087	1.213	1.250	96,624	1.402	1.310
TOU2xBDR							
	Control	720,000	1.344	1.452	251,054	1.520	1.478
	Treatment	2,543,971	1.292	1.381	887,119	1.433	1.450
TOU3xPTR2							
	Control	398,239	1.294	1.392	138,865	1.526	1.535
	Treatment	419,036	1.242	1.371	146,113	1.442	1.475

Notes: Table shows sample means and standard deviations of demand during TOU on-peak and off-peak periods for TOU and Hybrid treatments. N is the number of observations of hourly demand for customers.

Appendix D. Load Impact Estimates for Summer 2016 and Winter 2016/2017

Table 22 presents savings estimates for Flex treatments during summer 2016, which was the pilot's first season. At the beginning of summer 2016, PGE had not completed customer recruitment, and many of the treatments were not fully enrolled. As a result, the sample sizes were small and the savings estimates were not precise and not statistically different from zero for many treatments. In particular, almost all TOU impact estimates were statistically insignificant.

Table 22. Flex Evaluation Findings by Treatment – Summer 2016

Category	Treatment		Summer 2016				
			N of customers	PGE Planning Savings Estimate	Evaluation		
					Savings (%)	Abs. Precision at 90% Conf.	Savings (kW)
PTR-Only	PTR1		131	13%	34%	±11%	0.65
	PTR2		447		29%	±7%	0.53
	PTR3		198		33%	±10%	0.65
Opt-Out	PTR2-OO		737	6%	17%	±5%	0.37
	BDR-OO		11,618	3%	1.3%	±1.2%	0.03
TOU-Only	TOU1	On-Peak	241	5%	3%	±6%	0.03
		Flex Event			4%	±15%	0.08
	TOU2	On-Peak	847		1%	±4%	0.01
		Flex Event			2%	±8%	0.03
	TOU3	On-Peak	232		-7%	±10%	-0.08
		Flex Event			-21%	±17%	-0.33
Hybrids	TOU1xPTR2	On-Peak	242	12.9% PTR; 5.2% TOU	6%	±8%	0.05
		Flex Event			3%	±18%	0.05
	TOU2xPTR2	On-Peak	468	12.9% PTR; 5.2% TOU	-2%	±4%	-0.02
		Flex Event			5%	±9%	0.09
	TOU2xBDR	On-Peak	561	3.0% BDR; 5.2% TOU	1%	±4%	0.01
		Flex Event			0%	±10%	0.00
	TOU3xPTR2	On-Peak	245	12.9% PTR; 5.2% TOU	1%	±7%	0.01
		Flex Event			0%	±15%	0.00

Notes: n is the number of customers included in the impact analysis. All estimates were obtained through OLS regression analysis, with standard errors clustered on customers. Green denotes the estimate was statistically significant at the 10% level.

Table 23 presents savings estimates for Flex treatments during winter 2016/2017, which was the pilot's first winter season. At the beginning of this season, PGE had still not completed customer recruitment, and many of the treatments had not met their enrollment targets. As a result, the sample sizes were small and the savings estimates were not precise and not statistically different from zero for many treatments.

Table 23. Flex Evaluation Findings by Treatment—Winter 2016/2017

Category	Treatment		Winter 2016/2017							
			N of customers	PGE Planning Savings Estimate	Evaluation					
					AM			PM		
					Savings (%)	Abs. Precision at 90% Conf.	Savings (kW)	Savings (%)	Abs. Precision at 90% Conf.	Savings (kW)
PTR-Only	PTR1		289	14%	6%	±10%	0.09	6%	±7%	0.13
	PTR2		408		-2%	±9%	-0.03	3%	±7%	0.07
	PTR3		420		1%	±8%	0.01	14%	±7%	0.31
Opt-Out	PTR2-OO		680	7%	-3%	±6%	-0.05	-4%	±5%	-0.09
	BDR-OO		10,665	3%	0.5%	±2%	0.01	0%	±1%	0.01
TOU-Only	TOU1	On-Peak	256	6%	1%	±5%	0.01	1%	±5%	0.01
		Flex Event			-4%	±9%	-0.07	3%	±8%	0.08
	TOU2	On-Peak	919		4%	4%	0.06	4%	±4%	0.06
		Flex Event			2%	±6%	0.04	2%	±5%	0.05
	TOU3	On-Peak	268		-8%	6%	-0.14	-8%	±6%	-0.14
		Flex Event			-17%	13%	-0.30	-14%	±11%	-0.30
Hybrids	TOU1xPTR2	On-Peak	236	14.2% PTR;	13%	9%	0.21	13%	±9%	0.21
		Flex Event		5.8% TOU	17%	14%	0.30	9%	±10%	0.19
	TOU2xPTR2	On-Peak	408	14.2% PTR;	7%	±5%	0.13	7%	±5%	0.13
		Flex Event		5.8% TOU	11%	9%	0.20	7%	±7%	0.15
	TOU2xBDR	On-Peak	615	3.3% BDR;	0%	±5%	0.00	0%	±5%	0.00
		Flex Event		5.8% TOU	-8%	±9%	-0.14	0%	±7%	0.00
	TOU3xPTR2	On-Peak	278	14.2% PTR;	2%	±5%	0.04	2%	±5%	0.04
		Flex Event		5.8% TOU	-2%	±11%	-0.03	8%	±8%	0.17

Notes: n is the number of customers included in the impact analysis. All estimates were obtained through OLS regression analysis, with standard errors clustered on customers. Green denotes the estimate was statistically significant at the 10% level.

Appendix E. Survey Design and Samples

This appendix describes the six customer surveys and samples that Cadmus designed and administered.

Recruitment Survey

Because opt-in control customers were denied enrollment, Cadmus fielded the recruitment survey only to treatment customers in the 10 opt-in treatments. Test group customers in the two opt-out treatments did not receive the recruitment survey as these customers were automatically enrolled rather than recruited. The recruitment survey asked questions about how customers heard about Flex, their familiarity with TOU pricing, reasons for enrolling, and their satisfaction with PGE. Table 24 shows the number of test group customers contacted for the recruitment survey and the response rate.

Table 24. Recruitment Survey Sample and Response Rate

Treatment	Test Group		
	Number of Contacted	Number of Completes	Response Rate
TOU1	62	35	56%
TOU2	158	77	49%
TOU3	49	23	47%
PTR1	38	23	61%
PTR2	144	76	53%
PTR3	65	35	54%
TOU1xPTR2	53	30	57%
TOU2xPTR2	164	80	49%
TOU3xPTR2	58	36	62%
TOU2xBDR	74	43	58%
Total	**865**	**458**	**53%**

Summer 2016 Event Survey

Cadmus fielded the event survey with test customers in the nine treatments with an event component. PGE and Cadmus also decided to field the event survey with control customers in the PTR2-OO and BDR-OO treatments to obtain a baseline metric for satisfaction with PGE. The event survey asked test customers about event notifications, whether they did anything to reduce consumption during the events, and their satisfaction with Flex and PGE. The event survey asked control customers about their familiarity with peak demand, whether they did anything to reduce consumption during days associated with peak demand, and their satisfaction with PGE. Table 25 shows the number of customers contacted for the event survey and the response rate.

Table 25. Event Survey Sample and Response Rate – Summer 2016

Treatment	Test Group			Control Group		
	Number of Contacted	Number of Completes	Response Rate	Number of Contacted	Number of Completes	Response Rate
PTR1	68	22	32%	–	–	–
PTR2	246	103	42%	–	–	–
PTR3	105	43	41%	–	–	–
TOU1xPTR2	90	30	33%	–	–	–
TOU2xPTR2	255	87	34%	–	–	–
TOU3xPTR2	94	36	38%	–	–	–
TOU2xBDR	111	27	24%	–	–	–
PTR2-OO	277	27	10%	269	36	13%
BDR-OO	3,333	302	9%	3,333	353	11%
Total	**4,579**	**677**	**15%**	**3,602**	**389**	**11%**

Summer and Winter Experience Surveys

After the end of each season, Cadmus fielded the experience survey with test customers in all 12 treatments. The experience survey asked questions about events, pricing awareness, load-reducing behaviors, participation barriers, satisfaction with the program, satisfaction with PGE, and suggestions for program improvements. Control customers were also surveyed during the winter seasons to supply comparative data for satisfaction with PGE. Table 26, Table 27, Table 28, and Table 29 show survey samples and response rates for each of the four seasonal experience surveys.

Table 26. Experience Survey Sample and Response Rate – Summer 2016

Treatment	Test Group		
	Number of Contacted	Number of Completes	Response Rate
TOU1	65	13	20%
TOU2	242	57	24%
TOU3	100	32	32%
PTR1	96	24	25%
PTR2	335	59	18%
PTR3	95	14	15%
TOU1xPTR2	88	19	22%
TOU2xPTR2	243	68	28%
TOU3xPTR2	93	18	19%
TOU2xBDR	110	15	14%
PTR2-OO	218	11	5%
BDR-OO	3,333	108	3%
Total	**5,018**	**438**	**9%**

Table 27. Experience Survey Sample and Response Rate – Winter 2016/2017

Treatment	Test Group			Control Group		
	Number of Contacted	Number of Completes	Response Rate	Number of Contacted	Number of Completes	Response Rate
TOU1	110	18	16%	–	–	–
TOU2	402	66	16%	–	–	–
TOU3	115	19	17%	–	–	–
PTR1	103	24	23%	–	–	–
PTR2	206	61	30%	–	–	–
PTR3	157	40	25%	–	–	–
TOU1xPTR2	94	17	18%	–	–	–
TOU2xPTR2	203	39	19%	–	–	–
TOU3xPTR2	110	26	24%	–	–	–
TOU2xBDR	159	18	11%	–	–	–
PTR2-OO	346	28	8%	396	42	11%
BDR-OO	3,333	132	4%	3,333	303	9%
Total	**5,338**	**488**	**9%**	**3,729**	**345**	**9%**

Table 28. Experience Survey Sample and Response Rate – Summer 2017

Treatment	Test Group		
	Number of Contacted	Number of Completes	Response Rate
TOU1	342	70	20%
TOU2	781	146	19%
TOU3	365	72	20%
PTR1	306	81	26%
PTR2	188	26	14%
PTR3	358	98	27%
TOU1xPTR2	285	67	24%
TOU2xPTR2	177	44	25%
TOU3xPTR2	260	58	22%
TOU2xBDR	766	155	20%
PTR2-OO	562	45	8%
BDR-OO	3,333	157	5%
Total	**7,723**	**1,019**	**13%**

Table 29. Experience Survey Sample and Response Rate – Winter 2017/2018

Treatment	Test Group			Control Group		
	Number of Contacted	Number of Completes	Response Rate	Number of Contacted	Number of Completes	Response Rate
TOU1	318	74	23%	389	83	21%
TOU2	746	133	18%	388	79	20%
TOU3	338	71	21%	389	88	23%
PTR1	289	88	30%	295	77	26%
PTR2	181	47	26%	169	43	25%
PTR3	339	104	31%	351	83	24%
TOU1xPTR2	275	71	26%	265	53	20%
TOU2xPTR2	172	45	26%	153	41	27%
TOU3xPTR2	251	57	23%	248	52	21%
TOU2xBDR	726	143	20%	–	–	–
PTR2-OO	507	57	11%	593	53	9%
BDR-OO	3,333	220	7%	3,333	309	9%
Total	**7,475**	**1,110**	**15%**	**6,573**	**961**	**15%**

Appendix F. Additional Survey Results

Table 30, Table 31, Table 32, Table 33, Table 34, Table 35, Table 36, Table 37, Table 38, Table 39, and Table 40 provide additional survey results, which the report's main body does not include.

Table 30. Percentage of Correct Rate Schedule Identification – Winter 2016/2017

Treatment	% Who Correctly Identified Their Rate Schedule	n
TOU-Only	**63%**	**103**
TOU1	78%	18
TOU2	58%	66
TOU3	53%	19
Hybrids	**65%**	**100**
TOU1xPTR2	76%	17
TOU2xPTR2	79%	39
TOU3xPTR2	50%	26
TOU2xBDR	56%	18
All	**64%**	**203**

Survey Question: Which image describes the rates you pay for electricity on the Flex Program?

Table 31. Flex Event Energy Conservation Participation Rates – Winter 2016/2017

Treatment	% Who Responded "Yes" to Conserving During Events	n
PTR-Only	**79%**	**125**
PTR1	79%	24
PTR2	75%	61
PTR3	85%	40
Hybrids	**81%**	**100**
TOU1xPTR2	94%	17
TOU2xPTR2	82%	39
TOU3xPTR2	92%	26
TOU2xBDR	50%	18
Opt-Outs	**64%**	**160**
BDR-OO	64%	132
PTR2-OO	61%	28
All	**73%**	**385**

Survey Question: Did you and your household do anything to conserve energy during "Flex Time" events?

Table 32. How Participants Conserved During Flex Events – Winter 2016/2017

Action Taken	% (n=313)
Shifted cooking, washing, or other chores to off-peak times	77%
Turned off lights or reduced use of lights	70%
Adjusted the heating thermostat settings by lowering the temperature	53%
Put on more layers of clothes or blankets	43%
Left the house	28%
Unplugged appliances or electronics not in use	25%
Used non-electric heating source such as wood, gas, and pellets	17%
Turned off the electric heater	15%
Lowered the water heating temperature	7%
Took some other action	7%

Survey Question: How did you and your household conserve energy during "Flex Time" events? (Select all that apply)

Table 33. Overall Satisfaction with Flex – Summer 2016

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**7.0**	**31%**	**68%**	**97**
TOU1	5.4	17%	38%	24
TOU2	7.3	34%	76%	59
TOU3	8.1	43%	86%	14
PTR-Only	**7.5**	**41%**	**78%**	**102**
PTR1	7.5	46%	85%	13
PTR2	7.0	33%	72%	57
PTR3	8.3	53%	88%	32
Hybrids	**7.1**	**32%**	**73%**	**120**
TOU1xPTR2	6.3	32%	63%	19
TOU2xPTR2	7.5	38%	79%	68
TOU3xPTR2	6.6	17%	56%	18
TOU2xBDR	6.7	20%	73%	15
Opt-Outs	**6.4**	**18%**	**53%**	**119**
BDR-OO	6.4	17%	54%	108
PTR2-OO	6.4	27%	45%	11
All	**7.0**	**30%**	**68%**	**438**

Survey Question: Please rate your overall satisfaction with the Flex Program using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 34. Overall Satisfaction with Flex – Winter 2016/2017

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**4.4**	**17%**	**33%**	**103**
TOU1	2.8	6%	28%	18
TOU2	4.4	15%	27%	66
TOU3	6.0	32%	58%	19
PTR-Only	**7.3**	**41%**	**78%**	**125**
PTR1	5.8	17%	63%	24
PTR2	7.3	36%	77%	61
PTR3	8.3	63%	90%	40
Hybrids	**5.9**	**20%**	**58%**	**100**
TOU1xPTR2	6.5	24%	71%	17
TOU2xPTR2	5.7	13%	54%	39
TOU3xPTR2	7.0	38%	69%	26
TOU2xBDR	4.3	6%	39%	18
Opt-Outs	**6.4**	**26%**	**63%**	**160**
BDR-OO	6.3	22%	64%	132
PTR2-OO	6.7	43%	57%	28
All	**6.1**	**26%**	**59%**	**488**

Survey Question: Please rate your overall satisfaction with the Flex Program using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 35. Overall Satisfaction with Flex – Summer 2017

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**7.4**	**39%**	**76%**	**288**
TOU1	6.5	23%	57%	70
TOU2	7.7	45%	82%	146
TOU3	7.8	42%	82%	72
PTR-Only	**8.1**	**48%**	**83%**	**205**
PTR1	7.9	46%	79%	81
PTR2	8.0	42%	92%	26
PTR3	8.2	52%	84%	98
Hybrids	**7.5**	**37%**	**79%**	**324**
TOU1xPTR2	7.2	34%	72%	67
TOU2xPTR2	6.9	27%	70%	44
TOU3xPTR2	8.0	50%	88%	58
TOU2xBDR	7.6	37%	81%	155
Opt-Outs	**6.4**	**27%**	**56%**	**202**
BDR-OO	6.1	23%	51%	157
PTR2-OO	7.8	40%	73%	45
All	**7.4**	**38%**	**74%**	**1,019**

Survey Question: Please rate your overall satisfaction with the Flex Program using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 36. Overall Satisfaction with Flex – Winter 2017/2018

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**6.3**	**23%**	**61%**	**278**
TOU1	5.9	23%	54%	74
TOU2	6.5	23%	62%	133
TOU3	6.2	23%	68%	71
PTR-Only	**8.1**	**52%**	**86%**	**239**
PTR1	7.7	44%	80%	88
PTR2	8.2	55%	89%	47
PTR3	8.3	58%	89%	104
Hybrids	**6.9**	**35%**	**71%**	**316**
TOU1xPTR2	6.9	38%	69%	71
TOU2xPTR2	6.7	18%	73%	45
TOU3xPTR2	7.1	46%	72%	57
TOU2xBDR	7.0	36%	71%	143
Opt-Outs	**6.4**	**27%**	**61%**	**277**
BDR-OO	6.2	25%	57%	220
PTR2-OO	7.3	35%	79%	57
All	**6.9**	**34%**	**69%**	**1,110**

Survey Question: Please rate your overall satisfaction with the Flex Program using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 37. Overall Satisfaction with PGE – Summer 2016

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**8.2**	**43%**	**93%**	**97**
TOU1	8.2	33%	92%	24
TOU2	8.2	44%	93%	59
TOU3	8.6	57%	93%	14
PTR-Only	**8.1**	**44%**	**89%**	**102**
PTR1	8.4	46%	92%	13
PTR2	7.8	37%	88%	57
PTR3	8.5	56%	91%	32
Hybrids	**7.9**	**40%**	**88%**	**120**
TOU1xPTR2	7.9	47%	84%	19
TOU2xPTR2	8.1	43%	88%	68
TOU3xPTR2	7.5	39%	89%	18
TOU2xBDR	7.6	20%	93%	15
Opt-Outs	**7.6**	**45%**	**80%**	**119**
BDR-OO	7.6	45%	80%	108
PTR2-OO	7.5	36%	82%	11
All	**7.9**	**43%**	**87%**	**438**

Survey Question: Please rate your overall satisfaction with PGE using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 38. Overall Satisfaction with PGE – Winter 2016/2017

Treatment	Test Group				Control Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**7.1**	**28%**	**78%**	**103**	**–**	**–**	**–**	**–**
TOU1	6.4	17%	72%	18	–	–	–	–
TOU2	7.3	30%	79%	66	–	–	–	–
TOU3	7.4	32%	79%	19	–	–	–	–
PTR-Only	**8.0**	**46%**	**87%**	**125**	**–**	**–**	**–**	**–**
PTR1	7.8	42%	88%	24	–	–	–	–
PTR2	7.9	46%	85%	61	–	–	–	–
PTR3	8.3	50%	90%	40	–	–	–	–
Hybrids	**7.5**	**35%**	**82%**	**100**	**–**	**–**	**–**	**–**
TOU1xPTR2	7.7	47%	88%	17	–	–	–	–
TOU2xPTR2	7.2	28%	79%	39	–	–	–	–
TOU3xPTR2	8.2	50%	88%	26	–	–	–	–
TOU2xBDR	6.8	17%	72%	18	–	–	–	–
Opt-Outs	**7.6**	**39%**	**83%**	**160**	**8.2**	**47%**	**90%**	**345**
BDR-OO	7.7	39%	83%	132	8.2	46%	91%	303
PTR2-OO	7.4	39%	79%	28	8.1	55%	88%	42
All	**7.6**	**38%**	**83%**	**488**	**8.2**	**47%**	**90%**	**345**

Survey Question: Please rate your overall satisfaction with PGE using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 39. Overall Satisfaction with PGE – Summer 2017

Treatment	Test Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**8.4**	**56%**	**91%**	**288**
TOU1	8.0	41%	91%	70
TOU2	8.5	62%	92%	146
TOU3	8.5	56%	90%	72
PTR-Only	**8.7**	**63%**	**93%**	**205**
PTR1	8.5	59%	94%	81
PTR2	8.7	65%	92%	26
PTR3	8.8	66%	93%	98
Hybrids	**8.3**	**54%**	**88%**	**324**
TOU1xPTR2	8.6	55%	91%	67
TOU2xPTR2	7.4	36%	77%	44
TOU3xPTR2	8.3	60%	86%	58
TOU2xBDR	8.5	57%	90%	155
Opt-Outs	**8.1**	**50%**	**85%**	**202**
BDR-OO	8.0	48%	83%	157
PTR2-OO	8.3	53%	91%	45
All	**8.4**	**56%**	**89%**	**1,019**

Survey Question: Please rate your overall satisfaction with PGE using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."

Table 40. Overall Satisfaction with PGE – Winter 2017/2018

Treatment	Test Group				Control Group			
	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n	Mean Rating	% Delighted (9–10 Rating)	% Satisfied (6–10 Rating)	n
TOU-Only	**7.7**	**42%**	**79%**	**278**	**8.4**	**55%**	**90%**	**250**
TOU1	7.3	36%	78%	74	8.2	52%	87%	83
TOU2	7.8	47%	77%	133	8.8	65%	96%	79
TOU3	7.8	38%	86%	71	8.2	50%	86%	88
PTR-Only	**8.5**	**54%**	**91%**	**239**	**8.4**	**53%**	**91%**	**203**
PTR1	8.4	51%	88%	88	8.3	47%	91%	77
PTR2	8.3	51%	91%	47	8.2	49%	88%	43
PTR3	8.7	59%	93%	104	8.5	61%	93%	83
Hybrids	**7.9**	**47%**	**84%**	**316**	**8.2**	**51%**	**91%**	**146**
TOU1xPTR2	8.2	54%	86%	71	7.9	51%	89%	53
TOU2xPTR2	7.7	40%	84%	45	8.4	54%	95%	41
TOU3xPTR2	7.7	44%	79%	57	8.4	50%	90%	52
TOU2xBDR	7.9	46%	85%	143	–	–	–	–
Opt-Outs	**7.8**	**42%**	**84%**	**277**	**8.2**	**49%**	**88%**	**362**
BDR-OO	7.7	40%	81%	220	8.2	50%	89%	309
PTR2-OO	8.3	49%	95%	57	7.7	42%	81%	53
All	**8.0**	**46%**	**84%**	**1,110**	**8.3**	**52%**	**89%**	**961**

Survey Question: Please rate your overall satisfaction with PGE using a 0 to 10 scale where a zero means you are "extremely dissatisfied" and a 10 means you are "extremely satisfied."