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April 28, 2016

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Public Utility Commission of Oregon
Attn: OPUC Filing Center
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Salem, OR 97308-1088

Re: **UM 1708 – PGE's Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots**

As a follow up to Commission Order No. 15-203 and the workshop on February 9th, enclosed is a white paper describing PGE's cost-effectiveness methodology for demand response.

If you have any questions or require further information, please call me at (503) 464-7623. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Alex Tooman

Alex Tooman
Project Manager, Regulatory Affairs

AT:kr

cc: Jason Salmi Klotz, OPUC
Rebecca Brown
Josh Keeling

A Proposed Cost-Effectiveness Approach for Demand Response

Presented to:

Portland General Electric

Portland General Electric
121 SW Salmon St,
Portland, OR 97204
April 29, 2016

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Executive Summary

Portland General Electric (PGE) commissioned this white paper to inform the Oregon demand response (DR) cost-effectiveness discussion with best practices from other areas of the country. Prepared by Navigant, this white paper outlines a proposed cost effectiveness methodology for DR. It is intended to be the starting point of an iterative process to arrive at a cost-effectiveness methodology that satisfies the needs of PGE, the Commission, and stakeholders.

The cost-effectiveness framework presented in this white paper is based on California protocols[1] and other industry best practices established around the country, then adapted for PGE's purposes based on stakeholder feedback. This framework also draws from current efforts underway at the Energy Trust of Oregon and previous work Navigant conducted to develop a regional business case for grid modernization investments for Bonneville Power Administration.[2] This framework achieves the following:

- Defines four cost-effectiveness tests with DR-specific benefit and cost streams.
- Describes the treatment of typical DR-related costs in these tests, including administrative costs, capital costs to the utility and the participant, incentives, and other participant costs, with a suggested approach for incorporating the uncertainty associated with DR program participant costs as a sensitivity within the analysis.
- Proposes potential methods for accounting for differences in usage and availability between a demand resource versus a traditional generating resource in the application of avoided costs.
- Assesses the difficulties associated with quantifying certain cost and benefit streams, due to lack of DR program performance data, lack of generally accepted quantification methodologies, or insufficient historical performance data for DR programs.
- Presents other methodological considerations beyond the scope of traditional cost-effectiveness tests, including regionally unique factors, such as the overlap with regional energy efficiency programs and how to accommodate dual-peaking benefits and costs.
- Proposes an approach for extending this methodology to other grid modernization investments.

This white paper provides the foundation for determining the cost-effectiveness of DR programs within PGE's jurisdiction, with an initial application planned for PGE's Energy Partner program. This work also provides a starting point for quantifying the costs and benefits of deploying other grid modernization initiatives, beyond DR.

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[1] California Public Utilities Commission, Attachment 1: *2010 Demand Response Cost Effectiveness Protocols*
[2] Bonneville Power Administration, *Smart Grid Regional Business Case White Paper*, Prepared by Navigant Consulting, Inc., September 2015

NAVIGANT

A Proposed Cost-Effectiveness Approach for Demand Response

Section I Introduction

Portland General Electric (PGE) commissioned this white paper to inform the Oregon demand response (DR) cost-effectiveness discussion with best practices from other areas of the country. Prepared by Navigant, this white paper outlines a proposed cost effectiveness methodology for DR. It is intended to be the starting point of an iterative process to arrive at a cost-effectiveness methodology that satisfies the needs of PGE, the Commission, and stakeholders.

The remainder of this section provides context for the white paper and an overview of the methodology proposed within.

1.1 Background

As of March 2016, PGE is running multiple pilots of new DR programs, the cost-effectiveness of which is a necessary metric to help PGE, the Public Utilities Commission, and stakeholders make decisions about the programs. However, Oregon has not yet adopted an authoritative DR cost-effectiveness methodology, which led the Commission, in docket No. UM 1708, to call for development of cost effectiveness best practices. That order pointed out that "the utility and stakeholders will need to explore the development of a cost effectiveness methodology for DR programs." PGE held a workshop on DR cost effectiveness in February 2016 and intends this white paper to advance the discussion started at that time.

This white paper presents an approach for determining the cost-effectiveness of DR programs within PGE's jurisdiction. PGE will initially apply the framework discussed within this white paper to PGE's Energy Partner program, which is a third-party administered, day-of load curtailment program targeted at commercial and industrial customers. The framework will subsequently inform the cost-effectiveness analyses of PGE's other DR programs.

PGE also sees this work as a starting point for quantifying costs and benefits of other grid modernization initiatives. For this reason, PGE asked Navigant to include a high-level discussion of how those metrics are treated in other regions.

1.2 Methodology Overview

DR is becoming a widely-used and trusted resource across the country for reducing capacity expansion and upgrade costs. Nevertheless, as a distributed energy resource, DR is a technically and logistically more complex source of capacity than typical generation-side combustion turbines. The primary benefit of DR (avoided capacity costs) can only be realized to the extent that system planners are able to trust the capacity provided by DR as "firm", and adjust future supply-side investment plans accordingly.

The cost-effectiveness framework presented in the following sections is based on California protocols[3] and other industry best practices established around the country, then adapted for

[3] California Public Utilities Commission, *2010 Demand Response Cost Effectiveness Protocols, October 2010.*

PGE's purposes based on stakeholder feedback. This framework also draws from current efforts underway at the Energy Trust of Oregon and previous work Navigant conducted to develop a regional business case for grid modernization investments for the Bonneville Power Administration.[4] As DR programs move from pilot phases to full deployment in Oregon, DR will continue to establish itself as a trusted, and therefore more beneficial, resource. The methodology in this whitepaper accommodates this development—the avoided cost adjustments provide analysts with a means for quantifying and tracking the firmness of DR capacity.

It is important to note that not all costs and benefits will be able to be quantified in dollar terms (i.e., due to a lack of available data, market mechanisms, etc.). Cost-effectiveness analyses of DR programs seek to quantify in dollar terms as many of the costs and benefit streams as possible, to allow for a basis of comparison between different programs and different stakeholder perspectives on a net present dollar value basis. However, the complex nature of most DR programs makes it difficult or impossible to quantify all benefits and costs with currently available information. These benefits and costs still warrant qualitative consideration and are presented in this white paper, as they may represent real value to certain stakeholders and may be effectively quantified in the future as programs mature and new data becomes available.

The remainder of this white paper includes the following sections:

- Section II introduces the different cost-effectiveness tests and their inputs.
- Section III describes the various benefit streams considered for inclusion in DR cost-effectiveness analyses.
- Section IV describes the various cost streams considered for inclusion in DR cost-effectiveness analyses.
- Section V discusses other methodological considerations for DR programs and grid modernization investments, including considerations beyond the cost-effectiveness test framework.

Section II Overview of the Relevant Cost-Effectiveness Tests

A cost-effectiveness test measures whether a program or investment's benefits exceeds its costs. It allows regulators and program implementers to make well-informed decisions on programs and projects that require significant financial investments. These decisions include but are not limited to program planning, budgeting and implementation. In general, a cost-effectiveness test employs cash flow analysis and the net present value (NPV) of benefit and cost streams over the lifetime of the investment or program. The primary benefit stream typically associated with a DR program is the avoided cost of additional capacity, while the primary costs streams are equipment purchase costs, program implementation costs, and incentive payments. The result of a cost-effectiveness test can be presented as a net benefit value or a benefit-cost ratio.

[4] Bonneville Power Administration, *Smart Grid Regional Business Case White Paper*, Prepared by Navigant Consulting, Inc., September 2015

The benefit and cost streams included in a particular cost-effectiveness test depend on the perspective of the party or stakeholder in question. For example, a program that is cost-effective to the utility may not be cost-effectiveness to a customer. This section discusses four different tests typically employed by utilities:

- **Total Resource Cost (TRC) test:** Assesses cost-effectiveness from the perspective of all stakeholders involved. The TRC is the most widely used test for energy efficiency, with 35 states using it,[5] and also very commonly used for DR.
- **Program Administrator Cost (PAC) test:** Assesses cost-effectiveness from the perspective of the program implementer. This is typically the utility.
- **Ratepayer Impact Measure (RIM) test:** Assesses cost-effectiveness from the perspective of ratepayers. It is considered to be the most restrictive test.[6]
- **Participant Cost (PCT) test:** Assesses cost-effectiveness from the perspective of program participants, who are typically customers.

2.1 Total Resource Cost (TRC) Test

The TRC measures net benefits of a program for all stakeholders involved. The cost streams included in the TRC test are overhead costs and incentive payments incurred by the program implementer, as well as incremental costs of purchasing and installing equipment incurred by customers. The benefit streams used in this test are avoided costs of energy and capacity, tax credits (if applicable), and other non-energy benefits. From the customer perspective, these non-energy benefits could include the perception of contributing to community electric reliability and avoidance of environmental harm associated with peak power production. From the utility perspective, non-energy benefits could include increased customer satisfaction and credibility. Bill savings and incentive payments are not included in the TRC as they offset each other. Reduced bill savings is a benefit to customers, while it is a cost incurred by the utility due to lost revenue. Similarly, incentive payments are a benefit to customers, but a cost to the utility. Therefore the TRC ends up being more restrictive than the PAC test as it includes the full capital costs to participants and not just incentives paid to participants. PGE intends to use the TRC as the primary metric for ranking importance of DR programs, as it considers the impact of such programs on all stakeholders involved. Secondary or tertiary consideration will be given to the other tests to ensure that each stakeholder's interests are considered.

2.2 Program Administrator Cost (PAC) Test

The PAC test measures the net benefits of a program from the perspective of the program implementer. This is typically a utility, government agency, or other third party. The cost streams included in the PAC test are overhead costs and incentive payments. The benefit

[5] Martin Kushler, Ph.D. *Benefit-Cost Tests for Energy Efficiency: National Survey Results, And Some Related Concerns*. Presentation to the NEEP Regional EM&V Forum, Annual Public Meeting October 12, 2011
[6] US Environmental Protection Agency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers.* November 2008.

stream used in this test is the avoided cost of supplying electricity to customers. This is typically valued for DR programs through reduced wholesale purchases, generation costs, capacity expansions, system operating costs, and ancillary services, as applicable. The PAC test is valuable in helping PGE decide if a program or investment is worth pursuing.

2.3 Rate Impact Measure (RIM) Test

The RIM test measures the net benefits of a program from the perspective of ratepayers. It is used to especially protect the interests of customers who are not program participants. It is considered one of the more restrictive tests.[7] Since programs are typically funded by ratepayers, the cost streams included in the RIM test are overhead costs and incentive payments. Also included is lost revenue from reduced energy sales, which is the cost stream that puts upward pressure on retail rates (note that this cost is small or negligible in the case of DR, but important to consider when assessing other demand side management and grid modernization investments). The benefit streams used in this test are energy and capacity related costs avoided by the utility, as applicable.

2.4 Participant Cost Test (PCT)

The PCT test measures the net benefits of a program from the perspective of customers installing equipment required for DR programs. PGE uses this test to screen a program or investment for net positive participant benefits. These customers can range from homeowners to business owners. The cost streams included in the PCT test are the incremental costs of purchasing and installing equipment. The benefit streams used in this test are incentive payments provided by the program implementer to offset purchase and installation costs, tax credits, and reduced energy bills, as applicable. Reduced energy bills are typically valued using the net present value of energy savings over the lifetime of the equipment.

Table 1 summarizes the various cost and benefit streams that are included in the different cost-effectiveness tests used by utilities. The paragraphs that follow address each of these cost and benefits streams in more detail.

[7] US Environmental Protection Agency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers.* November 2008.

Table 1: Summary of Cost-Effectiveness Tests and Proposed Value Streams for DR Programs[8]

Cost/Benefit Category	Total Resource Cost (TRC) Test	Program Administ-rator Cost (PAC)Test	Rate Impact Measure (RIM) Test	Participant Cost Test (PCT)
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
Capital costs to utility	COST	COST	COST	
Capital costs to participant	COST			COST
Environmental benefits	BENEFIT			
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Market participation revenue	BENEFIT	BENEFIT	BENEFIT	
Non-energy/monetary benefits	BENEFIT			BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax credits	BENEFIT			BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

Section III Benefits

This section discusses the cost/benefit categories identified as possible benefit streams under most tests in Table 1 above, namely:

1. Avoided costs of supplying electricity
2. Bill reductions and increases

[8] Based on Navigant analysis and California Public Utilities Commission, Attachment 1: *2010 Demand Response Cost Effectiveness Protocols*

3. Environmental benefits
4. Market benefits
5. Ancillary service market participation revenue
6. Non-energy and non-monetary benefits
7. Tax credits

3.1 Avoided Costs of Supplying Electricity

The primary benefits of a DR program are often the avoided costs of supplying electricity to customers, avoided or deferred generation capacity expansions, and avoided or deferred transmission and distribution (T&D) upgrades. Some of these streams yield more value than others depending on the DR investment in question. The following metrics can be used to value these avoided costs:

- Energy purchase costs
- Generation capacity and resource adequacy costs
- T&D capacity costs
- Ancillary and specialty service costs incurred to meet fluctuating demand within short time periods
- Air pollution permitting costs
- Renewable energy compliance costs

In most DR programs, the avoided cost of deferred generation capacity expansion is the most valuable benefit stream. PGE develops sufficient generation capacity to serve peak load within a specified reserve margin. As peak load increases, PGE must build more generation capacity to maintain a reserve margin. Increases in electric rates fund the costs of generation capacity expansion. It is these costs of new construction of generation capacity that DR programs often seek to avoid by curtailing peak load.

Directly using the avoided cost value in a cost-benefit calculation assumes that the DR program can be optimized to realize the full, unconstrained benefits from event calls. However, usage and availability constraints on customer loads can limit the ability of a demand resource to respond in the same manner as a traditional generator. Therefore, the avoided cost of capacity value is adjusted downwards in some cases to reflect these different constraints for DR resources. Where applicable, the avoided costs of energy and T&D may also be adjusted downwards as appropriate. PGE identified two potential methods for accounting for this downward adjustment.

- **Effective Load Carrying Capability (ELCC):** The first available method is to discount the capacity benefits of DR based on the ELCC of DR. ELCC is a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or outage events (considering availability and use limitations). It is calculated via probabilistic reliability modeling, and yields a single percentage value. ELCC can be thought of as a derating factor that can be applied to the maximum capacity savings of DR to account for the fact that DR is not always available during capacity constrained hours.

  Calculation of ELCC requires hourly Loss of Load Probability (LOLP), hourly impacts of each DR program, and information regarding the availability of event calls (e.g., daily, but not more than two consecutive days). Currently, PGE maintains LOLP as a normalized value aggregated by week and month, not a specific value for each hour of the year.

- **Avoided cost adjustment factors:** The California's Public Utilities Commission (CPUC) outlines a second method for discounting the capacity benefits of DR. This framework adjusts applicable avoided cost streams using the following five adjustment factors: [9]

    1. Availability (A Factor)
    2. Notification Time (B Factor)
    3. Trigger (C Factor)
    4. Distribution (D Factor)
    5. Energy Price (E Factor)

Due to the limitations with calculating the ELCC discussed above, the avoided cost adjustment factors and possible approaches for quantifying these factors are discussed more in the subsections below.

3.1.1 Availability (A Factor)

A DR program is usually constrained by the frequency and duration of event calls permitted. For example, if the utility needs to call an event during a certain hour of the year during which the DR program is unavailable, the value of the resource is reduced in comparison to traditional available generating capacity. This factor reflects those availability constraints. The *A factor* should be estimated as the percent of time the DR resource is likely to be available when the system-level Loss of Load Probability (LOLP) is above a certain threshold value (corresponding to the need for DR, as determined by PGE).

Some utilities, such as the California investor-owned utilities (IOUs), calculate the A factor using Loss of Load Expectation (LOLE) or LOLP models, whereby the overlap between forecasted periods of highest load loss and program availability windows is assessed. The CPUC provides the California IOUs with the flexibility to base the LOLE or LOLP on system outage levels instead of generator-specific outage levels. Other utilities calculate the A factor based on top load hours.

There can be significant uncertainty and variance in assessing the A factor. For example, Pacific Gas & Electric (PG&E) presents two different ways of calculating the A factor for each of their programs. In the PeakChoice program, which has a similar number of hours of availability as PGE's Energy Partner program, PG&E estimates A factors of 41 and 82 percent, depending on the assumption made about what to use for the historical load hours.[10] This range highlights the uncertainty possible for a given program. There can also be significant variance across the portfolio. Southern California Edison (SCE) calculated annual A factors for various programs in its portfolio based on overlap of the program's availability with the top 250 load hours averaged from 2006 through 2009.[11] The A factors

[9] California Public Utilities Commission, Attachment 1: *2010 Demand Response Cost Effectiveness Protocols.*
[10] PG&E Demand Response July 26, 2011 Cost-Effectiveness spreadsheets. Found on California Public Utilities Commission website. < http://www.cpuc.ca.gov/General.aspx?id=7023>.
[11] Southern California Edison Company. *Demand Response Measurement and Evaluation, Program*

ranged from 26 to 83 percent.

A factors for PGE's DR programs may be similarly calculated using historical load data. PGE may also reference publicly available values, such as those from the SCE filing, where appropriate.

3.1.2 Notification Time (B Factor)

Some DR events are called a day in advance of the actual event period. As such, differences in weather and demand forecasting can result in different curtailment impacts on the day of the event. Differences in day-ahead and real-time energy prices (in the CAISO market, in the case of California) also affects the true avoided cost associated with the event call. Thus, the *B factor* captures the uncertainty in value for DR resources called with longer notification times. The CPUC currently only distinguishes this adjustment factor between day-ahead and day-of programs.

Day-of programs, like PGE's Energy Partner program, will be assigned a B factor value of 100%, while day-ahead programs will be assigned a value less than 100%.[12] Longer notification times yield smaller B factors.

3.1.3 Trigger (C Factor)

The C factor represents how flexible the event call trigger is. Examples of triggers are day-ahead market prices, which are dependent on certain conditions.[13] The CPUC recommends that programs with flexible triggers should have a higher avoided cost of capacity value than programs with more specific trigger conditions. The CPUC suggests two methods for calculating the C factor. The first of these involves examining past events to determine how different trigger conditions would have resulted in different decisions on event calls. Alternatively, the C factor can be calculated from the ratio of the number of events actually called to the maximum number of events allowed for each program.

Determining the trigger factor involves a complex analysis of how different trigger conditions may have impacted DR event calls. A C factor of 100% indicates the trigger conditions were flexible enough to call events during all applicable system peak periods. If there was a system peak that should have triggered an event in retrospect, but did not trigger available DR capacity, the C factor will be less than 100%.

Calculation of the C factor for PGE's DR programs relies on having a strict definition of trigger conditions, combined with sufficient data on the operational history of the program.

Enrollment and Load Impacts, Cost-Effectiveness, and Ratemaking Proposal. Application No. A.11-03-003. March 2011. SCE developed their A factor values for various DR programs based on overlap between program availability and the top 250 historical load hours, weighted by the highest load hours.

[12] Energy Division's "Guidance on cost-effectiveness" (Guidance.doc), distributed to the 07-01-041 service list on January 21, 2011. Cited by Southern California Edison (SCE) in an amended testimony for its *Demand Response Measurement and Evaluation, Program Enrollment and Load Impacts, Cost-Effectiveness, and Ratemaking Proposal* to the CPUC on May 20, 2011.

[13] San Diego Gas & Electric Company. *Data Response of San Diego Gas and Electric Company (U 902 M) Requiring Additional Cost-Effectiveness Information.* February 23, 2009.

3.1.4 Distribution (D Factor)

The D factor is specific to the avoided T&D cost stream. It is associated with locational benefits of DR programs, which is discussed in further detail in Section V. The premise for the D factor is that program implementation in areas where T&D capacity expansions would be considerably and reliably deferred adds more value to the avoided T&D cost. The CPUC assumes that all programs will have a default value of 0% unless IOUs can prove that T&D upgrades will be deferred for a fixed period of time.

The D factor would be considered in the cost-benefit analysis for PGE's DR programs that have demonstrated or are anticipated to demonstrate impacts on T&D upgrades.

3.1.5 Energy Price (E Factor)

The E factor, is associated with the relationship between electricity prices and event call times. It is used to adjust the avoided cost of energy benefit stream to more accurately reflect the actual avoided cost that is realized during times when event calls are most likely to happen given program availability constraints and trigger conditions.

The E factor would be considered in the cost-benefit analysis for PGE's DR programs that have demonstrated or are anticipated to demonstrate energy savings.

3.2 Bill Reductions and Increases

The PCT considers bill reductions and increases for customers participating in DR programs. Bill reductions are a benefit to participants, while bill increases are considered a cost. These bill impacts are typically driven by a change in the volumetric energy use charges for customers (kWh). For instance, bill increases might be driven by an increase in the total energy consumption of a facility as a result of snapback from a DR event.14

These benefits and costs will only be quantified for DR programs where estimates of energy impacts are available and they demonstrate significant energy savings. Future analyses may consider these benefits and costs, if they are able to be quantified in DR program evaluations. However, in general, energy impacts (in terms of savings or consumption) from DR programs are typically negligible.15

DR programs can also affect customer bills by lowering demand charges, provided that the DR event is coincident with the facility peak demand for the interval over which the demand charge is levied. Future analyses can consider customer demand charges.

[14] Snapback is the increase in energy or demand consumption in the hours following a DR event, to compensate for the loss of energy service occurring during the event.
[15] Typically, load is shifted during a DR event, and most of the energy that would have been consumed during the event is instead consumed before or after the event. Even in the case that a DR event results in load reduction that is not shifted to another hour of the day, the energy savings are relatively small. For example, for the Energy Partner program in 2014, the average hourly impact per event was 2,616 kW. There were 6 events in the year, which lasted an average of 3 hours each. Even making the very optimistic assumption that none of the reduced load was shifted to other hours of the day (e.g.,. no snapback), this yields 4.7 MWh of savings for the year, which is the equivalent of lifetime savings from installation of approximately 250 compact fluorescent lightbulbs (CFLs) under the most optimistic of assumptions.

3.3 Environmental Benefits

Environmental benefits are only included in the TRC test. These benefits include reduced emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, and particulate matter. Emission reductions are typically derived from energy savings and the emissions intensity of a utilities' generation mix. Additionally, DR programs may also reduce emissions through the provision of ancillary services. For example, in the ERCOT, PJM, and MISO markets, the potential for annual emissions reduction from DR, based on the Clean Power Plan (CPP) targets for 2030, is on the order of 0.05 percent to 0.35 percent of the target, with the variance caused by the number of MWh of DR that are called within the year.[16]

Environmental benefits from energy savings will be quantified for DR programs with quantified energy impacts or ancillary service benefits; otherwise, these benefits will be discussed qualitatively.

Furthermore, there is currently no method for PGE to quantify the value of carbon reductions in the Pacific Northwest. Depending on the progress of the Environmental Protection Agency's CPP, Oregon may adopt a mass-based system of carbon valuation similar to California, in which case prices in Oregon would likely be aligned with the California price on a $/ton of emissions basis.[17]

3.4 Market Benefits

This category of benefits includes increased market efficiency improvement in overall system load factors and improved market performance (e.g., decreasing price volatility). This benefit is often quantified as the price elasticity of demand market price effect, also known as demand reduction induced price effect (DRIPE).

In competitive electricity markets, lower demand for capacity yields lower overall prices. Therefore, a significant load reduction can have the effect of suppressing market capacity prices for all parties participating in the market. This price suppression is a benefit to all market participants, separate and additional to the avoided cost of capacity for a particular utility administering the DR program.

A competitive capacity market is a prerequisite to realizing any DRIPE benefits from DR, as well as a having a critical mass of DR resources in the market. DRIPE benefits have not yet been demonstrated in the Pacific Northwest power markets, therefore this benefit will not be measured or quantified for current analyses.

3.5 Ancillary Service Market Participation Revenue

The TRC, PAC, and RIM tests all consider ancillary service market participation revenue as a benefit. Utilities can earn revenue from DR by selling ancillary services that help to balance the transmission system. In certain jurisdictions, ancillary services are compensated in a

[16] Advanced Energy Management Alliance. "Carbon Dioxide Reductions from Demand Response: Impacts in Three Markets." Prepared by Navigant Consulting Inc. November 25, 2014.

[17] The latest price from the California carbon credit auction is $12.73 per ton. http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf

dynamic energy market.[18]

This benefit would only be quantified for DR programs that provide ancillary services. However, the value of ancillary services is difficult to quantify in the Pacific Northwest at this time in the absence of an organized market for ancillary services. The Bonneville Power Administration has developed values for regional non-spinning reserves, based on the current cost of resource purchases that can be used as a placeholder value in future analyses.[19]

As the region becomes more integrated with the California Independent System Operator (CAISO) through the Energy Imbalance Market (EIM), a market for ancillary services may emerge. CAISO currently accepts ancillary service bids for four types of services: Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve. PGE cannot currently bid to provide these services, but future valuation of ancillary services in the Pacific Northwest should consider CAISO market valuation.[20]

3.6 Non-Energy and Non-Monetary Benefits

This category of benefits includes participants' perception of decreased impact on the environment, being good citizens by helping to prevent outages, improving their ability to manage their energy usage, having a better public image (for commercial enterprises), improving working conditions, etc. These benefits are difficult to quantify for DR programs without an in-depth participant analysis.

However, these benefits may help offset participant transaction costs and the value of service lost for participants. A participant may discount these costs if participation yields one or more of the non-energy benefits described above (such as improving their ability to manage their energy usage). Currently, there is no information to quantify such an offset for PGE's DR programs, yet future analyses may explore this issue with participant interviews or surveys, and consider including non-energy and non-monetary benefits as either an explicit benefit, or an implicit discount to the participant costs.

3.7 Tax Credits

Tax credits are not currently available for DR programs in the Pacific Northwest. If they do become available in the future, they are considered a benefit in the TRC and PCT.

Section IV Costs

This section discusses the cost/benefit categories identified as cost streams under most

[18] For example, PJM operates several markets for ancillary services: the Synchronized Reserve Market, the Non-Synchronized Reserve Market, the Day-Ahead Scheduling Reserve Market and the Regulation Market. http://www.pjm.com/markets-and-operations/ancillary-services.aspx

[19] The values for INC and DEC ancillary services developed by the Bonneville Power Administration were used to estimate the benefits of using demand response for ancillary services in their Smart Grid Regional Business Case White Paper (found here:https://www.bpa.gov/projects/initiatives/smartgrid/pages/default.aspx).

[20]CAISO Business Practice Manual for Market Instruments https://bpmcm.caiso.com/Lists/PRR%20Details/Attachments/656/Market%20Instruments%20BPM%20PFPReg%20PRR.pdf

tests in Table 1, namely:

1. Administrative Costs
2. Capital Costs to Utility
3. Capital Costs to Participant
4. Incentives Paid
5. Increased Supply Costs
6. Revenue Loss/Gain from Reduced/Increased Sales
7. Transaction Costs to Participant and Value of Service Lost

4.1 Administrative Costs

Program administrative costs, or overhead costs, typically cover marketing and outreach efforts, rebate processing costs, research and development associated with program design, and evaluation costs. Utilities often contract third party implementers for DR programs, and this contracting cost, which is typically an annual dollar value, is included in the administrative cost stream.

These costs will be quantified and valued in dollar terms in the analysis, based on costs provided by PGE for each DR program.

4.2 Capital Costs to Utility

Since the cost of purchasing and installing equipment is often incurred by customers, capital costs incurred by the utility may only include any additional equipment installations or infrastructure required on the program implementer's end to effectively manage the program. This may especially be applicable to load curtailment DR programs or direct load control programs that require communications and control infrastructure on the utility side.

These costs will be quantified and valued in dollar terms in the analysis, based on costs provided by PGE for each DR program.

4.3 Capital Costs to Participant

Capital costs incurred by customers from participation in energy efficiency utility programs are typically captured as an incremental cost, whereby customers are replacing an existing piece of equipment with a more efficient one. However, in the context of DR programs, this cost is typically the full cost of procuring and installing equipment required to curtail load.

These costs will be quantified and valued in dollar terms in the analysis, based on costs provided by PGE for each DR program.

4.4 Incentives Paid

Incentives are a transfer under the TRC, a cost under the PAC and RIM, and a benefit under the PCT. For the PCT test, capital costs, such as equipment procurement and installation costs incurred by customers would be net of incentive payments. Incentives are typically paid per unit energy or capacity saved. The rebate is typically also contingent on specific criteria the utility has set for the equipment being purchased.

Incentives will be included in the analysis, based on costs provided by PGE for each DR program.

4.5 Increased Supply Costs

Increased supply costs are any costs incurred by the utility in providing additional electricity to ratepayers as the result of a DR program. These costs would normally be close to zero, as DR generally has a negligible effect on overall electricity consumption.[21] When DR does have an effect on electricity consumption (however small) the effect is typically a reduction in consumption. This cost is included here because, on rare occasions, overall electricity consumption may increase from a DR program. Quantification of this cost relies on significant estimates of an increase in overall electricity consumption from a DR program.

4.6 Revenue Loss/Gain from Reduced/Increased Sales

The RIM test considers revenue gain from increased sales, and revenue loss from reduced sales as a benefit and a cost respectively. Most DR programs will result only in revenue loss, rather than revenue gain, but there may be programs in which electricity consumption might increase, especially during certain time periods due to load shifting activities.

The same considerations for quantifying bill reduction and increases apply to quantification of these costs and benefits (see Section 3.2 above). These costs and benefits will only be quantified for DR programs where estimates of energy impacts are available and there is sufficient data to warrant a comprehensive analysis of demand charge impacts.

4.8 Transaction Costs to Participant and Value of Service Lost

Transaction costs incurred by the participant represent opportunity costs associated with education, equipment installation, program application processing, audits, evaluations, program planning, and program operation. These may overlap with capital costs and program administrative costs.

The value of services lost is a cost stream that represents any productivity losses and comfort costs associated with a utility program. In the context of a DR program for example, an event that shuts off space heating during a cold day could cause some discomfort to customers.

It is widely recognized that these metrics are difficult to quantify.[22] Typically, the combined transaction cost and value of service lost are valued at 50-100% percent of the incentive payment made to the customer.[23] The theory is that a customer assigns some intrinsic value

[21] Some technologies, such as learning thermostats, may provide significant energy savings, but this capability is considered as an energy efficiency mechanism, separate from the DR mechanisms of the technology.
[22] US Environmental Protection Agency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* November 2008.
[23] In a recent DR potential study for PGE, the Brattle Group valued transaction costs and value of service lost at 50% of the incentive value (see https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning). In other jurisdictions such as Pennsylvania,

to service lost and transaction costs, but this value must be capped at 100% of the incentive costs, as the incentives must be sufficient to cover these losses otherwise there would be no program participants. Many participants likely value these costs somewhere below 100% of the incentive value, assuming there is some surplus value they are capturing from participation in the program, such as non-energy benefits that could include the perception of contributing to electric service reliability and reduced environmental harm (see 4.6 Non-Energy and Non-Monetary Benefits for more discussion of this topic).

It is important to note that these costs may also vary by DR program type. For instance, programs that utilize smarter, automated technologies may require less deliberate action by the customer, resulting in lower transaction costs. Additionally, these automated technologies may be capable of optimizing their performance to provide greater customer comfort during events. Programs that require more deliberate manual action on the part of participants will logically have higher transaction costs. Future analyses can consider establishing two or more tiers of transaction costs, reflecting the difference in hassle-factor between automatic DR and manual DR.

Given the uncertainty of this value, a sensitivity analysis will be performed on this parameter in the cost-effectiveness analyses for PGE’s DR program. This parameter may also vary based on program type, where appropriate. For certain program types (e.g., a peak-time rebate program where incentives drive the majority of program costs), it is anticipated that the uncertainty in this parameter will have a greater effect on the program’s overall cost-effectiveness than on other program types.

Section V Other Methodological Considerations

The following section addresses other methodological considerations beyond the scope of traditional cost-effectiveness tests, including regionally unique factors such as the overlap with regional energy efficiency programs, how to accommodate dual-peaking benefits and costs, and how this framework might apply to other types of grid modernization investments.

5.1 Special Considerations for Dual Peaking Utilities

PGE has both a summer and winter peak, which introduces special considerations for valuing the avoided cost of capacity benefits of DR in terms of the potential for:

1) Differential capacity savings per participant by season, and;
2) 2) Differential avoided costs of capacity by season.

Future differentiation of seasonal avoided capacity costs can be driven by evolving demand preferences or a change in market characteristics on the supply supply-side.

PGE system-level avoided costs are based on new construction of capacity, and are expressed as a single price throughout the year. However, a resource that only provides capacity in one season is roughly half as valuable for PGE’s system as a resource that is capable of providing capacity in both seasons. PGE has DR programs that are administered in both the summer and winter, yet depending on the load characteristics of participating customers, the program may not be able to provide an equal amount of capacity in each season. For example, customers may be more willing to forgo cooling in the summer than

these costs are valued at 75% (Pennsylvania Public Utility Commission Public Meeting held June 11,2015).

heating in the winter, resulting in higher nominated loads per customer in the summer. In these cases, the cost-effectiveness analysis should allow an option for participant load reductions to vary by season. The ability to seasonally differentiate load reduction in the analysis is dependent on data availability; for instance, the Energy Partner program, which is still in the pilot phase, currently has limited data available for seasonal differentiation of load reduction. Future analyses can consider a study of participant end use loads, and characterize participants' potential for load reduction by season based on their specific load types and willingness to curtail these loads.

At the moment, system-level avoided costs of capacity for PGE are roughly equivalent between the summer and winter seasons, yet these values may change as customer preferences and end use loads change (e.g., increased prevalence of air conditioning in homes in the PGE service territory may increase the value of DR events called during the summer peak).

Furthermore, specific seasonal considerations on the supply side, such as the availability of load serving resources in the broader market, may influence the avoided cost calculation. As the Pacific Northwest becomes increasingly connected to the California energy markets, the summer peak may be more supply constrained than the winter peak, due to high summer peak demand from California utilities. As such, the cost-effectiveness analyses for PGE's DR programs should allow the option for avoided capacity costs to vary by season.

5.2 Overlapping Benefits and Costs with Energy Efficiency Programs

The Energy Trust of Oregon (Energy Trust) is responsible for administering all energy efficiency programs on behalf of Oregon utilities. Consequently, the Energy Trust has strong relationships with PGE customers, and could potentially serve as a conduit for introducing DR-enabled technology into the market. However, the Energy Trust's mandate does not cover DR programs, so costs, benefits, and incentives for programs administered by Energy Trust that promote DR-enabled technology would need to be allocated and shared between Energy Trust and PGE.

Currently, the Energy Trust has several program offerings that could be offered as "standard" efficient appliances, or more advanced DR enabled appliances[24]. Assuming that PGE will leverage DR-enabled technology installed through Energy Trust programs[25], there are two potential methods for sharing costs and benefits of these program offerings between DR (PGE) and energy efficiency (Energy Trust) depending on the nature of the energy efficiency and DR technology.

1. In the first method, costs could be allocated based on the relative monetary benefits of DR (value of avoided capacity costs) and energy efficiency (value of avoided energy costs). If the capacity savings from DR equal 30% of the total value of the DR-enabled appliance, then 30% of the costs of the appliance would be allocated to PGE. This has the advantage of maintaining consistent benefit-cost ratios across programs.
2. The second method entails assessing the incremental increase in cost necessary to

[24] These program offerings include heat pump water heaters, smart thermostats, commercial lighting, and commercial/industrial energy management systems.
[25] If PGE is only seeking to develop a DR program offering on 2020 that leverages appliances installed in 2016, costs for those units installed between 2016 and 2020 may fall entirely on ETO, or be retroactively accounted for by PGE once the DR program is initiated.

make the efficient appliance DR-enabled. In this case, the incremental cost of the DR functionality would be borne by PGE, while the costs of the more efficient appliance only (with or without DR) would be borne by Energy Trust. This method fairly allocates costs to the two parties, however, it may be difficult to quantify the incremental cost of DR functionality for certain measures like smart thermostats or strategic energy management systems.

The choice of methods should be informed by the specific characteristics of the measures being offered through the programs and the sequencing of investments. For example, certain measures are not conducive to separately pricing the DR functionality. The choice of methods also depends on PGE's DR program intentions. If PGE does not intend to implement DR for a particular end use load in the near-term, costs of DR-enabled appliances cannot be shared with Energy Trust, which provides Energy Trust less of an incentive to install DR-enabled technology upfront. In this case, Energy Trust may desire to quantify the costs of the DR functionality separately from the costs of the higher efficiency appliance.

5.3 Geographically Targeted DR for Asset Deferral

Specific geographic targeting of DR events can greatly enhance the program's value and cost effectiveness. Geographically targeted DR events can be used for grid distribution asset investment deferral by addressing local distribution capacity needs. Effective deployment of DR in this manner requires both locational transparency into grid congestion areas and assurance that the DR can be credibly relied upon for local needs and not just system-wide needs.

Locational valuation of DR will require both establishing granular load-growth expectations to identify specific opportunity zones for DR, and enrolling specific customers and end use loads in each opportunity zone. Once those capabilities are established, DR program administrators must build a track record of successful and reliable events so that DR can be credibly integrated as a resource into load forecasting and grid asset develop plans.

The CPUC Cost Effectiveness protocols include a Distribution (D Factor) to account for the *"right time", "right place", "right certainty" and "right availability"* benefits of DR (see Section 3.1.4 above). [26] For Energy Partner and other programs that do not consider specific customer location when recruiting or approving participants, the D Factor is 0%.[27] Although perfect locational targeting of DR is far from reality today, it could be possible that locationally targeted DR is more valuable than incremental development of generation assets, in which case the D Factor could theoretically exceed 100%.

Though there is currently limited precedent for locationally targeted DR in the industry, projects that seek to lengthen the life of grid assets and defer specific T&D upgrades consistently emphasize locational targeting of distributed energy resources (DER), such as DR, load control, and behind the meter generation.[28] In the Pacific Northwest, the

[26] California Public Utilities Commission Demand Response Cost Effectiveness Protocols. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7024
[27] Southern California Edison (SCE) established a precedent for assigning a D factor of 0% to DR programs with no locational dispatch capability. For SCE, a DR program can achieve a D factor of greater than 0% if it can be dispatched on specific constrained circuits. See: http://www3.sce.com/sscc/law/dis/dbattach10.nsf/0/7CCF9C52D6E52E6488257896007B844A/$FILE/A1103003++DR+-+SCE-01+Vol.4+Amended+Testimony.pdf
[28] A strong example of this concept is Con Edison's Brooklyn Queens Demand Management Program, which seeks to avoid costly reconstruction of constrained distribution capacity through

emergence of Bonneville Power Administration's non-wires initiative[29] exemplifies this shift in emphasis toward locational DER as an alternative to the "business as usual" investment in physical T&D upgrades.

5.4 Grid Modernization Cost-Effectiveness beyond Demand Response

Though cost-effectiveness analysis of DR investments is the focus of this white paper, the benefits, costs, and cost-effectiveness tests presented in this white paper form the foundation for looking at a broader set of investments. As such, the general principles of the cost-effectiveness methodology outlined herein can apply to many other types of grid modernization investments with various benefit streams and business cases.

The methodology within this white paper is consistent methodologically with the framework Navigant developed for the Bonneville Power Administration's (BPA) Smart Grid Regional Business Case.[30] The BPA grid modernization framework draws from the industry standard approach published by the Electric Power Research Institute (EPRI) in January 2010.[31] Navigant and Summit Blue Consulting (now also Navigant) contributed to the development of the EPRI framework. In 2012, the European Commission adopted a benefit-cost framework largely based on the EPRI framework.[32]

The methodology within this white paper can be extended to assess the cost-effectiveness of grid modernization investments, including DR and other investments that demonstrate a myriad of benefits to the modern grid, by layering on elements from the grid modernization framework developed for BPA. The BPA framework uses a methodology that acknowledges the complex nature of grid modernization investments. This framework incorporates over 30 unique benefit streams (as shown in Appendix B) in the following categories:

- Improved reliability
- Reduced grid O&M expenses
- Reduced energy use
- Reduced capacity expansion
- Reduced emissions
- Accommodation of higher penetrations of DER

The deployment of a particular grid modernization investment links to costs through assets, such as hardware and software, and also incorporates operations and maintenance costs. Similarly, the deployment of investment is linked to benefits through grid impacts such as reduced demand, reduced consumption, or improvements in grid reliability. Ultimately, the benefits and costs attributed to each grid modernization investment determine the cost-

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deployment of locationally-targeted DER. For more information on this project, see http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800

[29] https://www.bpa.gov/Projects/Initiatives/Pages/Non-Wires.aspx

[30] Bonneville Power Administration, *Smart Grid Regional Business Case White Paper*, Prepared by Navigant Consulting, Inc., September 2015 (found here: https://www.bpa.gov/projects/initiatives/smartgrid/pages/default.aspx).

[31] Electric Power Research Institute. January 2010. *"Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects."*

[32] European Commission. 2012. *"Guidelines for conducting a cost-benefit analysis of Smart Grid projects."*

effectiveness of the overall investment portfolio.

A unique deployment curve characterizes each grid modernization investment. The overall shape of this deployment curve determines the rate of accrual of benefits and costs, which are, in turn, determined from the number and type of assets required and the investment's impacts. The framework also reflects asset replacement cycles, impact persistence, and recurring operations and maintenance costs.

Examination of grid modernization investment plans is necessary to accurately reflect and characterize each grid modernization investment, the equipment (or assets) required to achieve a desired capability, the rate of deployment and cost-accrual of those assets, the expected impact on the electricity grid, and the corresponding benefits to customers and PGE.

Appendix A. Energy Partner Program Availability

The Energy Partner program aims to provide a total of 25 MW of peaking capacity to the PGE system by July 1, 2017 by enabling participants to receive payments for reducing electricity consumption during peak usage periods. Program events may be called at PGE's discretion and typically coincide with peak demand on the electric grid (e.g., hot summer or cold winter days).

The program runs for a three-month period from July 1 through September 30 ("summer period") and for a three-month period from December 1 through the last day of February ("winter period") starting in Summer 2013. During the summer and winter periods, program events may be called: 1) during non-holiday weekdays from 12 p.m. to 10 p.m. Pacific Time for the summer period and 2) during non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. Pacific Time for the winter period.

The program is designed to curtail load on the system during peak periods within 10 minutes of notification. Events are dispatched in one-hour blocks lasting between one and five hours. PGE may dispatch an event to begin at any minute within the available dispatch window. No more than one event may be called in any single day. PGE may not dispatch events for more than two consecutive days or more than 10 days per month during any summer period or winter period. PGE may not dispatch more than 40 hours of events during any summer period of winter period.

Appendix B. Benefits and Benefit Categories in Bonneville Power Administration's Smart Grid Regional Business Case[33]

Benefit Categories	Benefits
Reduced Energy Use	Reduced End Use Consumption
	Reduced T&D Line Losses
	Reduced T&D No Load Losses
	Energy Conversion Losses Associated with Storage (Negative Impact)
	Reduced Congestion Redispatch Cost
Reduced Capacity Expansion	Reduced End Use Peak Load
	Reduced T&D Line Loss Load Coincident with Peak
	Increased T&D Capacity Utilization
	Reduced Reserve Margin
Reduced Ancillary Service Costs	Reduced Regulation Cost
	Reduced Non-Spinning Balancing Reserve Cost (INC)
	Reduced Spinning Reserve Cost
	Reduced Non-Spinning Balancing Reserve Cost (DEC)
	Reduced Multiple Hour Ramping Cost
Improved Renewables Integration	Reduced Renewable Integration Cost
	Increased Renewable Capacity Factor
	Increased Distributed Renewables (Energy)
	Reduced Cost of Oversupply Mitigation
Improved Reliability	Reduced Frequency of Widespread Outages on Transmission Grid
	Reduced Frequency of Momentary Outages on Distribution Grid
	Reduced Frequency and Duration of Sustained Outages on Distribution Grid
	Reduced Customers Affected by Major Outages on Distribution Grid
Extended Equipment Life	Extended Life of Existing Grid Assets
	Extended Life of Existing End Use Assets
Improved Utility O&M	Reduced Costs of Service Restoration
	Reduced Costs of Manual Distribution Switching
	Reduced On-Site Meter Reads
	Reduced Electricity Theft
	Reduced Program Administration Cost
Reduced Emissions	Reduced CO2 Emissions
	Reduced Pollutant Emissions

[33] Bonneville Power Administration, *Smart Grid Regional Business Case White Paper*, Prepared by Navigant Consulting, Inc., September 2015 (found here: https://www.bpa.gov/projects/initiatives/smartgrid/pages/default.aspx).

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