STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

Application of Delmarva Power	**)**	
Company For Adjustments to its Retail	**)**	**Case No. 9424**
Rates for the Distribution of Electric	**)**	
Energy	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLES COUNSEL

RESOURCE INSIGHT, INC.

SEPTEMBER 28, 2016

PUBLIC VERSION

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil-engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-four states and six Canadian provinces, and two US Federal agencies. This testimony has included many reviews of utility avoided costs, marginal costs, rate design, and related issues.

Q: Have you testified previously before the Commission?

A: Yes. I have testified approximately 17 times before the Commission, from 1990 through 2015, as follows:

- Case No. 8278, on the adequacy of the integrated resource plan of Baltimore Gas & Electric (BGE);
- Case No. 8241, Phase II of BGE's Application for CPCN for the Perryman Project;
- Case No. 8473, Review of the Power Sales Agreement of BGE with AES Northside;
- Case No. 8487, BGE 1993 Electric Rate Case, on cost allocation and rate design;
- Case No. 8179, Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run;
- Case No. 8697, BGE 1995 gas rate proceeding, on cost allocation and rate design;
- Case No. 8720, Washington Gas Light (WGL), on DSM avoided costs and least-cost planning;

- Case No. 8725, the proposed merger of BGE and Potomac Electric Power Company (Pepco), on allocation of merger benefits and rate reductions;
- Case No. 8774, the proposed Allegheny Power-Duquesne merger;
- Case Nos. 8794 and 8804, BGE restructuring;
- Case No. 8795, Delmarva Power & Light (DPL) restructuring;
- Case No. 8797, Potomac Edison restructuring;
- Case No. 9036, BGE's 2005 rate proceeding;
- Case No. 9159, Columbia Gas's 2009 rate proceeding; and
- Case No. 9230, BGE's 2010 rate proceeding.
- Case No. 9361, the proposed merger of Exelon and Pepco Holdings.
- Case Nos. 9153, et al., the 2015 review of the EmPOWER Maryland programs.
- Case No. 9406, on the benefits of the BGE smart-grid programs.
- Case No. 9418, on the benefits of the PEPCo smart-grid programs.

I testified on behalf of the OPC in each of these proceedings, other than Case No. 9361, in which I testified on behalf of the Sierra Club and Chesapeake Climate Action Network.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Maryland Office of Peoples Counsel.

Q: What is the scope of your testimony?

A: I review some of the benefits that Delmarva ("DPL") asserts are provided by residential programs supported by the advanced meters of DPL's recent advanced-metering infrastructure (AMI) investment:

- The Dynamic Pricing (DP) demand-response program, which provides a Peak Energy Savings Credit (PESC) to customers who reduce usage on designated hours on Energy Savings Days (ESDs).
- The Energy Manager Tools (EMT) energy-efficiency program.
- Conservation Voltage Reduction (CVR) enhancements from AMI data.
- Incremental savings from the pre-existing Energy Wise Rewards (EWR) residential air conditioner cycling direct load-control program.[1]

Q: What aspects of DPL's benefit estimates do you review?

A: My review focuses primarily on the following five categories of annual program savings, in terms of the value of reductions in $/kWh and $/MW-day:[2]

Table 1: DPL claimed AMI Benefit Categories

Type	Driver	Programs	DPL ID
DPL revenues	Energy sales to PJM	DP	OPR 18
	Cleared PJM Capacity	DP, EWR	OPR 17
Avoided costs from load reductions	Energy consumption	DP, CVR, EMT	DSM 04, 09, 14
	Capacity obligation	All	DSM 03, 08, 13
Price mitigation by added supply & reduced demand	Energy price	DP, CVR, EMT	DSM 02, 07, 12
	Capacity price		DSM 01, 06, 11
Transmission investment	Load reductions	DP, CVR, EMT	OPR 19, 21, 23
Distribution investment	Load reductions		OPR 20, 22, 24

In DPL's terminology, the benefits related to the generation market are demand-side (DSM) benefits, while the T&D savings are a portion of the operational (OPR) benefits (which also include various operating costs). I will

[1] DPL includes the EWR savings and benefit as part of the DP/PESC program. (Lefkowitz Direct at 49-50, OPC DR 13-1)

[2] DPL also includes about $0.8 million in avoided environmental costs, based on the $2/MWh value used in prior claimed AMI avoided environmental costs in Case Nos. 9418 and 9406. This value is too small to warrant much attention, other than reducing the environmental benefits in proportion to any adjustments to the estimate of program energy savings.

refer to all the generation-market benefits and the avoided T&D as program benefits, since DPL attributes all those benefits to the operation of its programs.

The system benefits claimed by DPL are described at a high level of generality in the testimony of DPL witnesses Karen Lefkowitz and Mario Giovannini, and documented primarily in the spreadsheets provided as attachments to OPC DR 1-3, particularly Attachment KRL-C.[3]

In Exhibit PLC-2, I attach the non-confidential data requests that I cite, excluding only the bulky spreadsheets, such as the attachments to OPC DR 1-3. Exhibit PLC-3 contains the confidential data requests that I cite.

I am aware of the Commission's recent decision in Case No. 9406 on BGE's AMI investment; I understand that matter to be subject to additional proceedings. I have analyzed the benefits of DPL's AMI programs on their own merits, without reference to the proceedings in Case No. 9406.

Q: Did you review any other matters?

A: In addition to reviewing and as appropriate re-estimating these unit-price values per kilowatt-hour and per megawatt-day, I reviewed some related issues, such as the extent to which the types of peak reduction achieved by the various programs would affect the capacity costs borne by DPL ratepayers and other Maryland ratepayers. I also offer some comments on the treatment of the payments to PESC participants and the magnitude of PESC savings.

Q: What do you mean by "types of peak reduction"?

A: The term "peak" has a range of meanings, in a variety of applications. "Peak load" may refer to PJM's maximum load on a single annual hour, on several monthly maximum hours, or many high-load hours. Other types of peak may be defined as

[3] For brevity, I refer to this spreadsheet as "Attachment C." My testimony is based on the update that DPL provided on August 8, 2016.

the maximum load (or a number of high loads) for DPL, SWMAAC, MAAC, a particular DPL rate class, a transmission line, a substation, or a feeder. Each demand-related cost category is driven by its own type of peak, which may be different from that driving other costs.

Q: Are the categories of program benefits that DPL claims from the AMI programs all costs that can be avoided by some types of load reductions?

A: Yes. These categories of benefits are real. The questions I address are whether DPL has properly estimated the benefits, including whether the nature of the programs will provide those benefits.

Q: Will you present conclusions about the cost-effectiveness of DPL's smart-grid investment?

A: No. The testimony of Max Chang, on behalf of OPC, combines my unit-price results and other results with corrected estimates of program energy and capacity savings, and of operational benefits, to determine the overall cost-effectiveness of the investment.

Q: How important are the various portions of the benefits that you review?

A: Table 2 disaggregates the program benefits among the three programs and the various components that DPL includes, based on Ms. Lefkowitz's Table F, Mr. Giovannini's Table 1, and OPC DR 1-3 Attachment KRL-C.

Table 2: Breakdown of DPL Claimed System Benefits, $M in 2015 PV

Benefit Category	CVR	DP & EWR	EMT	Total
Capacity Price Mitigation	$0.3	$20.4	$1.1	$21.7
Energy Price Mitigation	—	—	$0.1	$0.2
Capacity Revenue	—	$9.1	—	$9.1
Energy Revenue	—	$0.5	—	$0.5
Avoided Capacity	$0.4	$10.2	$2.2	$12.8
Avoided Energy	$5.5	—	$20.3	$25.9
Reduction in Air Emissions	$0.2	—	$.6	$0.8
Avoided Transmission Capacity	$0.4	$13.7	$12.5	$16.6
Avoided Distribution Capacity	$0.1	$3.9	$0.7	$4.7
Total	$6.8	$57.8	$27.6	$92.2

The claimed system benefits are dominated by the capacity benefits (capacity revenue, price mitigation, avoided capacity and T&D) of the DP program, which account for63% of the total.

Table 3 provides a program-level summary of my corrections to DPL's claimed system benefits. Each adjustment in Table 3 includes multiple corrections of DPL's inputs, assumptions and calculations.

Table 3: Corrections of DPL Benefit Estimates (PV $M)

	EMT	DP	CVR	Total
DPL Claimed Benefits	$27.6	$57.8	$6.8	$92.2
Adjustments	–$5.5	–$36.9	–$1.2	–$43.6
Adjusted Benefits	$22.0	$20.9	$5.7	$48.6

These results have been included in Mr. Chang's testimony.

Q: Please summarize your conclusions.

A: The benefits claimed by DPL are overstated due to over a dozen distinct errors (in addition to any overstatement of savings discussed in the testimony of OPC witness Max Chang), the most important of which are as follows:

- The DP and EWR load reductions, given their rarity and timing, are unlikely to affect transmission or distribution investment.
- For similar reasons, the capacity obligation for DPL customers and capacity price for all Maryland customers will not be significantly reduced by the DP and EWR load reductions.

- Reductions in contribution to PJM peak load have less effect on capacity prices than DPL assumes.
- DPL's estimate of energy price mitigation is significantly overstated, because DPL has incorrectly assumed that energy prices for each of the Maryland zones is driven by Maryland load. In reality, the DPL energy price is driven by loads over a large area (probably most of PJM, and possibly adjacent regions), as are the energy prices for Pepco, Baltimore Gas and Electric, and Potomac Edison. A change in DPL load appears to reduce energy prices by roughly half of DPL's estimate.
- Program savings claimed from the CVR are speculative and should be rejected.

All of these errors and the lower–impact errors are discussed in Sections III through VII and summarized in Section VIII.

In the course of correcting DPL's errors, I found several situations in which DPL did not claim a particular benefit for some years for which I believe benefits would accrue. In these cases, I increased DPL's claimed benefits.

III. Treatment of the Dynamic-Pricing Rebate

Q: How should the Commission treat the rebates in the DP program?

A: The rebates represent how much participants insist on being paid in exchange for bearing the burden of the program and should thus be treated as a cost. The DP program pays $1.25/kWh customers to suffer discomfort and inconvenience, to tolerate higher indoor temperature and humidity on the most unpleasant summer days, and to rearrange their household schedules.

Q: How does DPL treat the rebates?

A: Mr. Giovannini says that "The costs of customer bill credits are treated as a transfer payment and not included in the cost-effectiveness analysis as is customary in Maryland." (OPC DR 13-26).

Q: What is a "transfer payment"?

A: A typical definition of a transfer payment in economics would be "A payment that does not form part of an exchange of services but rather represents a gift without anything being received or required in return" or "One-way payment for which no money, good, or service is received in exchange."

Q: How is the concept of a transfer payment relevant to evaluating the cost-effectiveness of DSM programs?

A: This concept arises in the discussion of two aspects of valuation of energy-efficiency programs. First, reduced recovery of fixed costs from participants in any particular program shifts cost recovery to other customers in the same class and/or other classes. These shifts are treated as transfers among customers and are excluded from the Total Resource Cost ("TRC") tests.

Second, the incentives paid by the utility to the participants, vendors, and other trade allies are treated as part of the program costs. The total cost of the measure is included in the TRC, regardless of the share of the costs absorbed by the participants, paid by participants and reimbursed by the utility, or paid directly by the utility. Payments by the utility to vendors, and other trade allies are normally part of measure costs, as is the total cost paid by participants, regardless of whether they are reimbursed by the utility.

Q: How do these concepts apply to the DP program?

A: The first concept—that shifts in fixed-cost recovery do not affect cost-effectiveness—means that the reduction in normal residential rates recovered from some customers is not treated as a cost or benefit. The second concept—that all costs of the program to participants or DPL are included as costs in the TRC—means that all the costs borne by the participants must be treated as costs.

Q: What are the costs of the DP program to participants?

A: There are two categories of such costs: cash costs and the costs of lost service quality, discomfort and inconvenience.

The cash category includes purchasing internet-based remote controls or timers to change thermostat settings and turn off appliances in the PESC hours; buying take-out food to avoid cooking and reduce air-conditioning load from 1 PM to 7 PM; or using the gas oven rather than the microwave. The service-degradation costs include running around unplugging appliances at 1:30 and plugging them back in (and resetting all the clocks) at 6 PM; turning the thermostat up to 80° on a humid summer day; running laundry and washing dishes before 2 PM or after 6 PM; putting off showers and children's baths until after 6 PM; and resetting and rescheduling other appliances.

If DPL could determine the dollar value of these costs of the DP program, the TRC test for the DP program would be straightforward. Unfortunately, DPL does not know what customers are doing to shift energy usage out of the PESC hours, how much cash they are spending, or how much they value the disruption and discomfort of changing schedules and higher temperatures. So the cost of the DP measures must be estimated.

Q: Do other regulators include as TRC costs the payments to customers to reduce loads in demand-response programs?

A: Yes. A review of cost-effectiveness testing for demand-response programs for the Pennsylvania Public Utility Commission found that:

> there is consistency between states with published TRC test methods in regard to the treatment of DR program incentive payments. In California, New York and Pennsylvania, incentive payments made by EDCs to program participants are included in the TRC test as a proxy for participant costs. The rationale is that a participant's actual transaction costs cannot be readily or easily determined, but an end-user would not participate unless the incentives received are at least equal to the participant's costs to curtail usage during peak demand periods.[4]

The study also found that Illinois treat incentive payments as a cost, but not explicitly as a proxy for participant costs. The Pennsylvania PUC affirmed its treatment of incentive costs in Case M-2015-2468992, June 11, 2015.

Q: Do energy-efficiency programs have participant costs similar to those in the DP program?

A: No. Energy-efficiency ("EE") programs are designed to reduce the barriers to adoption of efficient technologies that provide the participant with equal or higher service quality than the existing or standard technology. The program design strives to align the incentives of trade allies (retailers, wholesalers, contractors, builders, plumbers) with customer interests, to reduce first-cost barriers (and hence programs with financing, decision-making and regret) and hassle (such as selecting contractors, and reviewing savings claims). The EE incentives do not pay the participants to accept a lower quality electricity service and bear the

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[4]Gogte, S, et al.; Act 129 Demand Response Study, Final Report; GDS Associates, Nexant, and Mondre Energy; May 13, 2013, at 16. The Statewide Evaluator (SWE) "included 100% of customer incentives as cost, in following with the 2013 TRC Test" (PA PUC Order in Docket No. M 2012 2289411, February 20, 2014, at 33). The SWE Team included "75% of the incentive amount as a proxy for the participant cost when examining the cost-effectiveness of DR" (Demand Response Potential Pennsylvania, February 25, 2015, prepared for the Pennsylvania PUC, at 21).

resulting burdens. The EE programs are designed to eliminate the customer's incremental costs.[5]

In contrast, the bill credit in the DP program does not eliminate any market barriers; the explicit purpose of the credit is to pay customers to accept a lower quality electricity service and endure discomfort and inconvenience that they would not accept without the credit. Unlike the EE analysis, DPL's DP analysis does not include any out-of-pocket costs to customers: the cost of timers, remote controllers, or any other expenses the DP participants incur. In terms of direct expenditures, energy-efficiency programs generally offset or reduce the costs of identifiable measures that are explicitly identified and included in the cost-benefit analysis. In contrast, the DP program pays customers for unidentified expenses and does not eliminate any market barriers.

Q: Has the Commission taken a position on whether program evaluation should reflect participant costs?

A: Yes. In Order 87082, the Commission directed the use of both the Total Resource Cost (TRC) test and the Societal Cost Test (SCT) (at 6) and found that "the TRC test includes all participant costs" (at 15).[6] The Commission explicitly ordered the inclusion of non-monetary comfort benefits "in the TRC test and the SCT." (ibid) Given the Commission's requirement that costs and benefits be symmetrical, including a comfort benefit for EE programs that increase comfort would require

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[5] Some skeptics of EE programs assume that these costs cannot be eliminated and that EE incentives are payments to induce customers to accept burdens and reduced quality of life. That assumption does not describe well-designed EE programs, but does describe the DP program design.

[6] While the Commission did not explicitly require that "all participant costs" be included in the SCT, that test usually includes a broader group of costs and benefits than the TRC, not a narrower group.

inclusion of a discomfort costs for the DP program, which decreases customer comfort.

The only measure that we have of the monetary and non-monetary costs of participating in the DP program is the bill credit that DPL has determined it must pay customers to bear those costs.

Q: Have any of DPL's witnesses argued that demand-response rebates should be treated as customer costs?

A: Yes. In a January 2015 report prepared for Enernoc, Dr. Faruqui said that incentives should be included in demand-response program evaluation:

> In any valuation of a DR resource, the benefits should be weighed against the cost of the program. Examples of program costs would include equipment, marketing and customer outreach, participation incentive payments, and general program administration. (Hledik, R., and Faruqui, A., Valuing Demand Response: International Best Practices, Case Studies, and Applications, January 2015, attached as Exhibit PLC-4, at 3)

The category of "participation incentive payments" would include the DP bill credits.

A year later, Dr. Faruqui and his Brattle colleagues explained this point in more detail in a report for Portland General Electric:

> Treatment of participant incentives as a cost was given close consideration in the study. There is not a standard approach for treating incentives when assessing the cost-effectiveness of DR programs. In some states, incentive payments are simply considered a transfer payment from utilities (or other program administrators) to participants, and therefore are not counted as a cost from a societal perspective. Others suggest the incentive payment is a rough approximation of the "hassle factor" experienced by participants in the program (e.g., reduced control over their thermostat during DR events), and should be included as a cost.

> While there is some merit to the latter argument–that customers may experience a degree of inconvenience or other transaction costs when participating in DR programs–the cost of that inconvenience is overstated if it is assumed to equal the full value of the incentive payment. If that were the case, then no customer would be better off by participating in the DR program. For example, it would be unrealistic to assume that an industrial facility would participate in a curtailable tariff program if the cost of reducing operations during DR events (e.g., reduction in output) exactly equaled the incentive payment for participating. In reality, customers participate in DR programs because they derive some incremental value from that participation. Further, in some DR programs customers experience very little inconvenience. Some A/C DLC programs, for instance, can pre-cool the home and manage the thermostat in a way that few customers report even being aware that a DR event had occurred, let alone a loss of comfort.
>
> Given the uncertainty around this assumption, this study counts half of the incentive payment as a cost in the cost-effectiveness analysis.[7] (Hledik, R., and Faruqui, A., Bressan, L., Demand Response Market Research: Portland General Electric, 2016 to 2035, January 2016, attached as Exhibit PLC-5, at 12)

Q: Based on Dr. Faruqui's report to PGE, what proportion of the DP program bill credits should he have treated as a cost in this proceeding?

A: Dr. Faruqui should have urged DPL to include more than half the rebate as a cost. In the PGE report, Dr. Faruqui and his team treat half of the incentive payment as a cost for all demand-response programs, both direct load control (such as DPL's EWR), in which they believe "customers experience very little inconvenience" and "AMI-enabled rate options" including the "Peak Time Rebate (PTR) [programs] being offered by BGE and Pepco to residential customers in Maryland" (Exhibit PLC-5 at 4–5). The DP program would fall in their high-inconvenience category; if half the incentive payment is a reasonable estimate of participant costs averaged over a variety of programs, the participant costs for the DP program would be more than half the bill credit and probably much more.

[7] The Brattle team also evaluated programs with "sensitivities" in which 100% and 0% of the incentives were treated as costs.

IV. DPL's Estimates of Load Reductions

Q: What types of load reductions does DPL claim for its programs?

A: For the CVR and EMT programs, DPL claims equal percentage load reductions in all hours. For DP and EWR, DPL encourages or implements load reductions in a small number of hours—for DP, typically four contiguous hours on up to four summer days per year.

Q: Do the DP and EWR programs reduce demand at most of the hours that determine the total PJM capacity obligation and the portion of the capacity obligation that PJM allocates to the DPL zone?

A: No. Each year, some 120 daily summer peaks contribute to the summer peak-load forecasts. The DP and EWR programs reduce loads on only a few days in each summer. DPL called Energy Savings Days on two days in 2014, three days in 2015 and two in 2016. Table 4 lists all Energy Saving Days that DPL selected in 2014 and 2015; all PESC periods were from 2 PM to 6 PM (Staff 6-24).There were no PJM events called in 2014 or 2015 and the number of participants in 2014 was "available to a limited number of customers as part of the phase-in introduction." (OPC DR 13-22b).[8] That limited number was 4,471 eligible residential customers (Quarterly Report, May 16, 2016, Case No. 9207 at 11) out of DPL's estimated 176,477 residential customers in 2015 (OPC DR 1-3 Attachment KRL-C, Tab "Global Assumptions").

[8] PJM test events were called on 9/18/2014 and 9/25/2015 for 1 hour each.

Table 4: PESC Energy Saving Days

Event date
8/28/2014
9/2/2014
7/30/2015
8/3/2015
9/9/2015

Q: How did DPL estimate the load reductions due to the DP program?

A: DPL uses the concept of an "engaged participant," defined as a customer who received a rebate on a given event day, using a customer baseline (CBL) method (OPC DR 4-10h). The customer's usage in the PESC hours was compared to the average of its usage in the same period in its three highest–load days in the last 30 non–holiday weekdays (OPC DR 13-4 Attachment D).DPL estimated the total DP energy savings as the sum of its estimate of the reductions over all of the so-called participants, completely excluding the customers who increased usage.[9] DPL estimated the peak reduction as the average of the load reductions at hour-ending 17 (5 PM) in 2014 and **BEGIN CONFIDENTIAL** [redacted] [redacted] [redacted] **END CONFIDENTIAL** in 2015, adjusted to a weighted temperature-humidity index (WTHI) of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. There are at least four major problems with this approach:

- DPL counts all below-average loads on ESDs, but ignores the large number of customers with above-average loads.
- DPL ignores entirely the results of ESDs for which even its biased analysis indicates that load increased.
- DPL selects an unrepresentative peak hour within the ESDs to overstate peak savings.

[9] For 2014, Brattle conducted a regression analysis to estimate customer weather–normalized usage in the event hours, based on loads in the entire summer. For 2015, DPL says that a regression was conducted, but does not say who conducted the analysis.

- DPL assumes that load reductions on a handful of summer days will reduce future capacity obligations and prices.

I discuss the first two problems in the next section and the third in Section B, which also discusses the effect of load reductions from other programs on PJM load forecasts, capacity obligations and prices.

A. Including All Customers in the Dynamic Pricing Computation

Q: What problems did DPL introduce in its selection of customers for its estimates of peak reductions from the DP program?

A: DPL biases the analysis of DP saving and overstates the load reductions by including only a subset of customers.

1. Including Only a Subset of Customers

Q: How did including only a subset of customers overestimate the load reductions due to the DP program?

A: Brattle estimated the DP savings as the sum of its estimate of the reductions over all of the so-called participants, completely excluding the customers who increased usage compared to the DPL baseline and received no rebate.[10] As a result, DPL's estimate of the DP savings includes reductions due to customers actually reacting to the $1.25/kWh incentive and also customers who just

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[10] Brattle conducted a regression analysis for each year, to estimate normal customer usage in the event days, given usage on other days and the weather. Hence, the Brattle study may have found that some of the rebated customers did not save any energy, while other customers saved more than DPL credited them. But Brattle was working only with the biased group of rebated customers.

happened to have lower consumption that day for other reasons, but does not net out the customers who just happened to have higher consumption.[11]

Q: Why is this a problem?

A: There is no evidence that the "engaged" customers were all engaged, or that the reduction in load from the baseline days to the PESC day was all due to the DP program. All customers were automatically enrolled in the DP program. Customer responses to the existence of the program will vary in different ways, including the following:

- Some of them intended to decrease usage in the PESC hours, experienced no complications, and succeeded, resulting in benefits below the baseline.
- Others probably intended to decrease usage in the PESC hours, but experienced usage above the baseline.
- Other customers did not intend to decrease usage in the PESC hours, and had usage similar to the baseline.
- Others did not intend to decrease usage in the PESC hours, but reduced load for other reasons and had usage below the baseline.

All customers were subject to the same incentives, and the relevant measure of savings is the average or total response of all eligible customers.

Q: What factors might cause usage to vary from the baseline to the event day?

A: Aside from weather and reaction to the DP incentive, the usage of any one customer may be lower on the event day than would otherwise be expected (based

[11] The latter group might be called "free riders," since they get benefits from the program without actually responding to the program. The DP free riders do not intentionally shift loads; in energy-efficiency programs, free riders are participants who intentionally install efficiency measures, and thus provide benefits, but would have done so without the program incentives.

on either the limited baseline used to assign rebates or the Brattle regression), including:

- The people who would normally be home during the day in the summer (e.g., children, supervising parents, at-home workers, retirees) being out of town on the event day.
- The people who would normally be home during the day in the summer being out shopping, at the movies, etc., in the incentive hours.
- Shift workers (e.g., medical staff, retail clerks) who happen to be working the afternoon shift on the event day.
- An air conditioner or other appliance failing, decreasing load.

Similar events can operate in the opposite direction, increasing load on the PESC day: customers who are usually out of the house may be home on the PESC day or host a party, or equipment may operate in a way that increases load.

Q: Is DPL's decision to ignore customers who increased their usage on the ESDs consistent with industry standards?

A: No. The Brattle report on DPL's 2014 program says that:

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DPL has not presented any analysis of the response of all eligible customers.[12]

[12] Brattle's justification for selectively omitting data is inconsistent with DPL's use of the analysis, which treats the results as representing all the effects of the DP program, not a maximum potential.

Q: Would DPL's approach of counting only the customers who reduced use, and not those that increased use, be tolerated in reporting of results in other applications?

A: No. Imagine a casino that claimed that it made its players $100 million richer, counting only the "engaged" winners and ignoring the losses by the many players who won nothing. Regulators would not tolerate that type of misrepresentation, and neither should the Commission.

Q: Does DPL accept the reality that some of the customers who receive DP rebates were not responding to the program?

A: Yes. DPL agrees "it is likely the [that] some of the DPL DP customers who receive PESC rebates were not responding to the program" (OPC DR 13-34).

Q: Does DPL accept that this is a problem?

A: Not really. DPL believes that the panel regression evaluation methodology used to estimate the level of demand reductions "will tend to understate the reductions" (OPC DR 13-34). Ms. Lefkowitz claims as follows:

> It is also likely that there are other customers who take energy reduction actions, but do not earn a bill credit because of the manner that Customer Baseline Load shapes are used to indicate participation. Delmarva Power relies on panel regression modeling to indicate the level of reductions achieved, but this will tend to understate the reductions achieved by the program due to the exclusion of EWR participants and the exclusion of customers who do not appear to have reduced load, but actually did so. (OPC 13 DR-34)

Q: Is Ms. Lefkowitz correct in this regard?

A: No. The CBLs compare the customer's consumption in the customer's highest three usage days in the past thirty days, so customer usage would need to be suppressed for most of that thirty-day period to miss a customer who really made an effort to reduce their usage on the energy-saving day. This is particularly true for DPL's data (which all comes from 2015). As shown in Figure 2, there were several hotter days in the thirty days preceding the ESDs on 7/30 and 8/3, and several hot days in the thirty days preceding the 9/9 ESD, so it would not be difficult to use less energy on the ESD than in the highest days in the CBL.[13]

If DPL had included all customers in its analysis, the customers who tried to reduce usage on the ESD but failed might offset the customers who did nothing to reduce usage by happened to have lower usage on the ESD. Unfortunately, the DPL analysis breaks that symmetry. DPL excludes the effect of the first group, but claims credit for the random usage reduction of the second group.

Q: Can random variability contribute significantly to overstating the apparent savings from the DP program?

A: Yes. In Case No. 9406, Brattle provided the results of its analysis using all customers, from which I was able to compute that the inclusion of the "non-participants" in BGE's DP-like program would reduce estimated savings by 30%–50%. In Case No. 9418, I used Pepco's data on the random variation of EWR customers whose control system were not working, and found that the average customer saved only 28% as much as the Pepco/DPL method would indicate. I also determined that the PEPCo/DPL method would have estimated that about half of PEPCo's customers would have been erroneously identified as participants on summer days on which no PESC event was announced, saving about 2.6 kWh each, or about 28% of PEPCo's estimated savings.

I have looked at data DPL provided on the hourly loads of individual customers. In Figure 1, I plot the energy use of 7,682 residential customers in the PESC hours on two non-PESC days, July 21and July 29, 2015. I selected those

[13] DPL excluded the EWR customers from the DP analysis, because the two programs operate at the same time and DPL could not demonstrate that the DP program had generated any incremental savings.

dates due to their similarly high WTHI weather variables over the PESC event hours on two non-event days (77.85° and 77.92°, respectively).

Figure 1: Random Variation in Customer Consumption

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Each data point represents a single customer's load on July 21 (vertical axis) and July 29 (horizontal axis). Customers below the red line used more energy on July 29, those above used more energy of July 21.

In this sample, 5,409 customers used more on July 29, 2015, averaging an additional 2.8 kWh apiece than on July 21, while 2,273 customers used more on July 21, averaging 0.72 kWh more than on July 29. If DPL had decided that July

29 would be a PESC day, but forgot to tell the public (and thus gave no signal for customers to respond to), and July 21 were used as a baseline, DPL would have thrown out the 5,430 customers who used more on July 29 as non-participants, concluded that the 2,273 engaged participants in the DP program responded by reducing usage 0.72 kWh apiece, and would have claimed 1.6 MWh of savings without any actual customer response. DPL credits energy and demand savings to the PESC program and the AMI meters that actually result from random variation in customer circumstances.

The averaging of loads over the baseline would reduce this effect somewhat, but temperature adjustment would have almost no effect in this example and in some cases would increase DPL's estimate of customer response.

Much of the demand and energy reductions estimated by DPL are artifacts of these random variations in customer usage, which DPL's analysis does not identify or remove from its estimates of load reductions. My review of this data confirms that DPL's estimates of DP load reductions are overstated and must be substantially reduced.

2. *The Effect of the Regression Analyses*

Q: How does DPL's regression analysis correct for differences in accounting for individual customer variations in load use patterns?

A: DPL runs a panel regression on "engaged participants" to compare customers event day usage to their non-event day usage after adjusting for weather.[14] The Brattle Group was responsible for developing the regression model and running

[14] DPL's defines both "engaged" and "participant" as "a customer who used less energy on the PESC event day than in the baseline day."

the original analysis in 2014, but DPL performed the regression analysis in 2015 (OPC DR 13- 20d).

Q: Would the regression analysis correct the bias in DPL's selection of customers to include as DP "participants"?

A: No. The Brattle analysis does not exclude customers who randomly happened to have lower load on the ESD. To the extent that a customer's load was lower on an ESD because of mild weather, the Brattle analysis would correct for that weather effect, reducing the savings. That weather correction is the likely explanation for the conclusion that the "participants" that DPL identified for the 8/3/2015 ESD **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** their usage by **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** (OPC DR 13-4 Attachment E Confidential, Table 3).

B. Effect of Load Reductions on Capacity Responsibility

Q: How long does DPL assume it takes for a reduction in peak retail load to affect the capacity obligation for customers in the DPL zone?

A: For the DP program, DPL assumes zero or negative delay, so a megawatt load reduction in the summer of 2020 reduces the capacity obligation by 1 MW starting June 1, 2020, before the load reduction occurs. For the other programs, DPL assumes a four-year delay, so a megawatt load reduction in 2014 reduces the capacity obligation starting June 2018.

Q: How are the capacity obligations of PJM zones determined?

A: For clarity, I will describe the process in terms of a particular capacity delivery year, starting in June of 2019. The PJM Resource Adequacy Planning Department conducts a series of regression analyses, for each load zone, in which the dependent variable is the daily peak load for the load zone, or its load coincident with the RTO load, or for other intermediate delivery areas, such as MAAC (the mid-Atlantic region, or roughly the pre-2002 PJM territory). The independent variables in the regressions are

- various binary (or dummy) variables for the month, day of the week, and holidays, and
- various combinations of weather measures (e.g., cooling degree days and a temperature-humidity index or THI), an economic index, and equipment efficiency measures, with many variables being the product of two or more of these parameters (e.g., CDD × economy × cooling efficiency). The effect of THI (either by itself or times the cooling-efficiency index) is split into four ranges (or splines), which for DPL are up to 65°, 65°–74°, 74°–82°, and over 82°.[15]

The daily data cover the period from 1998 through the summer four years before the start of the delivery year, or August 2015 in our example. Those 6,400 observations are used to develop a regression equation for predicting (among other loads):

- PJM daily peak hour for various dates and weather conditions, given projected economic and efficiency trends.
- DPL load in the PJM daily peak hour.

[15] Load Forecasting Model Whitepaper, Resource Adequacy Planning Department, PJM Interconnection, April 27, 2016, Table IV-1. The PESC days that DPL called in 2015 had WTHI values in the range of 78.1° to 81.3°. Since the DP program reduced load at the low end of the third spline, it may have increased the slope of that spline, and increased the model's sensitivity to temperature. The normal peak temperature for the DPL zone is about 84° (Weather Normalization of Peak Load, Load Analysis Subcommittee, September 2, 2015, slide 14).

For the 2016 Load Forecast Report, PJM computed the RTO daily maximum loads for 273 variations of historical weather patterns, and identifies the peak load for each variant, and identifies the median peak for the delivery year (e.g., the summer of 2019). The forecast is used to determine the required reserve margin, and hence the total capacity obligation. The DPL zonal capacity obligation is determined by the forecast of its contribution to the PJM peak load, plus the reserve margin resulting from the intersection of the VRR and the supply curve. Thus, the critical question is the extent to which reducing DPL load in particular hours reduces PJM's forecast of DPL load at future peaks.

Mr. Giovannini agrees that "the DP, CVR and EMT programs reduce capacity prices only to the extent that they reduce PJM's forecast of peak load" (OPC DR 13-13).

Q: Once the DPL zone's capacity obligation for a delivery year has been determined, do reductions in customer loads affect the total obligation in the DPL zone?

A: No. The Peak Load Contribution for each customer is determined by allocating the zonal obligation in proportion to the customer's contribution to PJM's highest-load hour in each of the five highest-load days in the previous summer (e.g., 2018 for the 2019/20 delivery year). But anything that a DPL customer does to reduce its Peak Load Contribution simply shifts capacity obligation to other customers in the DPL zone.

Q: Did DPL activate the DP program on the days that determine customer Peak Load Contributions?

A: No. Table 5 lists the five highest-load days from 2014 and 2015, and the peak hour for each such day. DPL did not call a PESC day on any of these ten days.[16]

Table 5: Days Determining Peak Load Contribution Allocation for Following Delivery Year

Year	Date	Hour
2014	17-Jun	6 PM
	18-Jun	5 PM
	1-Jul	6 PM
	22-Jul	6 PM
	5-Sep	4 PM
2015	20-Jul	5 PM
	28-Jul	5 PM
	29-Jul	5 PM
	17-Aug	3 PM
	3-Sep	5 PM

Q: What reductions in post-2013 loads would affect the forecasts of PJM's peak load, the reserve requirement, and DPL's share of the capacity obligation?

A: That is a complicated issue.

Load reductions in the majority of the 365 observations for each recent year would tend to reduce the coefficients of variables that have been higher in the recent years than in previously years, such as the composite variables that include the rising quarterly economic index, partially offset by the declining indices for energy intensity. Those changes might tend to reduce the load forecast, since PJM expects the past trend in the indices to continue.[17]

[16] In addition, while DPL assumes that the peak hour is always 5 PM, that was the peak hour in only about half these days, with the other days peaking at 3, 4, and 6 PM.

[17] The variable that includes the economic index and the index for cooling-equipment efficiency also includes the daily cooling degree days, further complicating predictions about the effect of DR load reductions in mild weather.

Reductions in most of the days in a month will tend to reduce the binary variable for that month, and hence forecasts for peaks in that month. Since each month has over 500 observations in the data base, reductions phasing in with a tiny change in 2014 (and reflected in the BRA forecasts for the capacity years starting in 2017) would have only a modest effect in forecasts until long after 2020.

Similarly, reductions in most of the occurrences of a particular weekday will tend to reduce the binary variable for that weekday, and hence forecasts for peaks for that weekday. Since each weekday has over 900 observations in the data base, reductions phasing in starting in 2013 would have only a modest effect in forecasts for 2020.

Reductions that primarily occur in the worst weather conditions will tend to reduce the coefficient on the weather variables. Since there are so many hot summer days in the historical data, many years of load reductions would be needed to change the projections.[18] To further complicate the situation, if a load reduction occurs at the lower end of a THI spline, it will tend to increase the coefficient for that THI range; if the load reduction occurs on a day at the high end of a range, it will tend to decrease the THI coefficient.

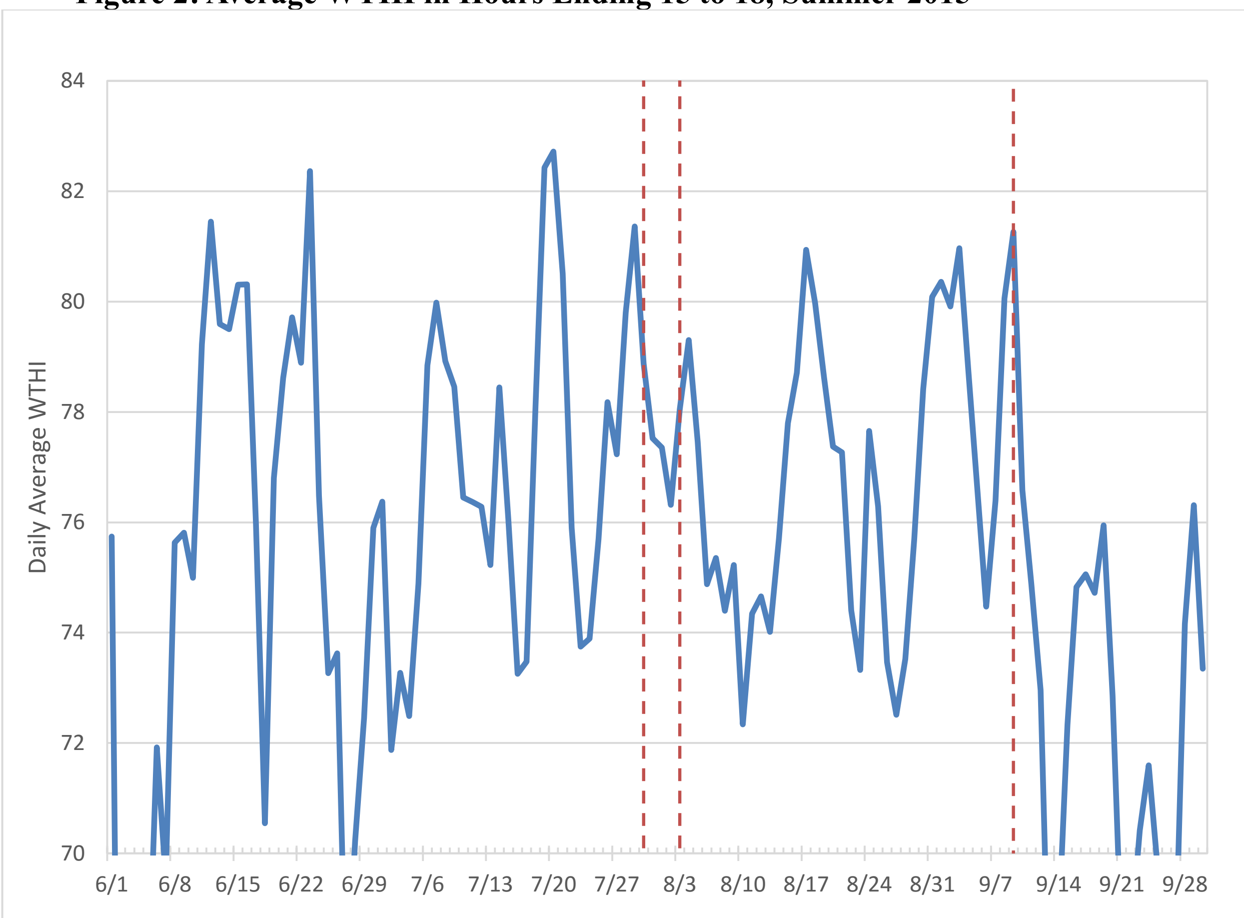
As I discuss in Section V.B.1, PJM's own computations indicate that the scattered load reductions from the DP program will have miniscule effect on its peak load forecasts, and even the more consistent load reductions that DPL claims for the EMT and CVR programs would phase in much more slowly than DPL assumes.

[18] This dilution effect is similar to the effects for the month and weekday binary variables, but more difficult to characterize, due to the multiplicity of weather measures and the range of values for each.

Q: Were the PESC days that DPL called for the DP program the days with the worst summer weather?

A: No. Figure 2 shows DPL's estimate of the daily WTHI for each day of the summer of 2015.[19] These figures also show the days on which DPL declared DP events. In each year, DPL missed the hottest day and declared a DP event on a modestly warm event.

Figure 2: Average WTHI in Hours Ending 15 to 18, Summer 2015



Q: Did DPL call PESC events on the PJM peak days?

A: No. In the summer of 2014, DPL began phasing in the PESC program to 5,000 residential customers over the summer of 2014 (Lefkowitz, Direct at 48), DPL

[19] Created from WTHI data provided in OPC DR 13-28, Attachment D.

called two event days, neither of which was on PJM peak day. DPL's ESDs in 2014 were the second-, ninth- and eleventh-highest PJM loads.[20] The 2015 ESDs were the sixteenth-, 23rd-, and 30th-highest days. The PJM peak day load was 10,413 MW higher than the peak on the average ESD in 2015.[21]

In addition to missing the extreme weather conditions, DPL has been missing the highest PJM peak loads, which would have the highest effect on the PJM regression-based forecasts. The actual peak hours are listed in Table 5, above.

Q: Does DPL acknowledge that the DP load reductions have missed the peak hours and worst-weather hours in all three years?

A: No. Bizarrely enough, Mr. Giovannini asserts that "One kwh of savings for one hour is equivalent to 1 kw of demand savings during that hour." (OPC DR 13-41g), which is patently untrue. The DP program has never reduced DPL's contribution to PJM peak loads, or to the DPL peak loads.

V. Claimed Generation Capacity Benefits

A. Capacity Revenue

Q: Have you identified any problems in DPL's estimates of capacity revenue?

A: No. DPL's analysis assumes that its DP program will receive capacity revenue for demand reductions through 2019/20. I have not reviewed the claimed level of capacity revenue in detail, but the values appear reasonable.

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[20] In addition, several of the highest-load days were in January and February 2014, when the DP program does not operate.

[21] PJM did not call any emergency load-management events in the summers of 2014 and 2015 (Staff DR 6-26).

B. Avoided Capacity Cost

Q: How does DPL estimate avoided capacity costs?

A: DPL's analysis can be broken down into three steps. First, DPL estimates a measure of peak load reduction, from each program, for the summers of 2014 through 2024, as follows:

CVR: 1.1% of residential contribution to peak load plus 0.9% of non-residential contribution to peak load.

EMT: 1.55% of DPL Maryland residential contribution to peak loads.

DP: An average of 52 MW for 2020 through 2024.[22]

EWR: Savings from EWR customers have been netted to reflect only those savings that are in excess of EWR savings and eligible for PESC savings.

Second, DPL assumes that each megawatt of DP load reductions in a particular year, other than capacity bid into the PJM auction, results in a megawatt reduction in the zonal capability responsibility for that capacity delivery year, through the rest of the analysis period. DPL assumes these instantaneous benefits occur from 2020 onward. For the other two programs, DPL lags the capacity benefit by 4 years.

Third, DPL multiplies the assumed DP and EWR reductions by the DPL zonal performance capacity price for 2020/21, escalated by 2.1% annually thereafter, through 2024. For EMT and CVR, DPL multiples the assumed forecast reductions by the following prices:

- for each delivery year through 2019/20, the weighted average capacity prices in the DPL zone for that year.

[22] The load reductions prior to 2020 are treated as providing capacity revenue, rather than avoiding retail capacity charges.

- For 2020/21, the average of the cleared performance capacity price for delivery years 2016/17 through 2019/20, plus a large amount of escalation, and
- For 2021/22–2023/2024, the 2020/21 value escalated at 2.1% annually.

Q: How do you address the problems in this analysis?

A: Mr. Chang will address issues in the first step (estimation of load reductions for each program) in his testimony. In Section IV.B, I discussed DPL's error in imputing reductions in the DPL zonal peak forecast and the DPL capacity obligation to the DP and EWR programs. My testimony in this section concentrates on the timing of DP effects in the second step and DPL's double counting of demand reductions participating as both avoided capacity and capacity revenue.

1. Timing of Avoided Capacity Benefit

Q: How long does DPL assume it takes for a reduction in peak retail load to affect the capacity obligation for customers in the DPL zone?

A: For the DP program, DPL assumes zero or negative delay, so a megawatt load reduction in the summer of 2020 reduces the capacity obligation by 1 MW starting June 1, 2020, before the load reduction occurs. For the other three programs, DPL assumes a four-year delay, so a megawatt load reduction in 2015 reduces the capacity obligation starting June 2019.

Q: Is either of these assumptions realistic?

A: No. Capacity obligations are driven by PJM's forecast of zonal load for the delivery year, based on a load forecast developed three years earlier (prior to the BRA), based on load data from 1998 through the summer four years before the delivery year. Hence, the four-year delay assumed for the non-DP programs is a minimum lag in the effect. As discussed in Section IV.B, the few days of DP and EWR load reductions have almost no effect on the DPL forecast or capacity obligation, so these benefits are essentially zero.

In connection with Case No. 9418, OPC asked PJM to model the load reductions that PEPCo estimated for its dynamic-pricing program. PJM ran its forecasting model with adjustments for increasing load on the PESC days by Pepco's estimate of the DP savings, and projected that the 2016 forecast for 2019 (when PEPCo's model would have predicted a 300 MW reduction in load) would show a reduction in PEPCo's peak load of only about 3 MW.

The CVR and EMT programs (if DPL's savings assumptions are realistic) would start to reduce capacity obligations four years after the load reduction occurs, but the effect for the next several years would be much smaller than DPL assumes. In connection with Case No. 9406, OPC also asked PJM to model the effect on the PJM peak forecasts of a reduction in BGE's load by 1% in each hour in 2013, 1.4% in 2014, and 1.5% in 2015. PJM found that this adjustment reduced the 2016 forecast for BGE 2019 peak by about 0.45%, while the DPL method for CVR and EMT assumes that the reduction would be 1.5%, which is more than three times the reduction that PJM would actually recognize.

For Case No. 9418, OPC also asked PJM to model the effect on the PJM peak forecasts of a reduction in PEPCo's load by .83% in each hour in 2013, 2014, and 2015. PJM found that this adjustment reduced the 2016 forecast for PEPCo 2019 peak by about 0.22%, while the DPL method for CVR and EMT assumes that the reduction would be 0.83%, which is about four times the reduction that PJM would recognize.

Q: What would be a realistic assumption regarding the effect of load reductions on capacity price mitigation?

A: DPL's estimates of avoided capacity obligations from the EWR and DP programs should be reduced by about 99% (or just set to zero) and reduced 70% for the CVR and EMT programs, pending PJM's response to OPC's request for a DPL specific recomputation.[23]

These adjustments are in addition to the reductions in the price of capacity, discusses in the next section.

2. Avoided Capacity Costs

Q: What does DPL assume will be the price of the generation capacity obligation avoided by load reductions?

A: For reductions in obligations in 2016/17 through 2019/20, DPL uses a weighted average of prices for multiple types of capacity.[24] These values are broadly appropriate for capacity obligations in those years.

For 2020/21, DPL estimated the avoided price as $173/MW-day, which is 10% higher than the average of the capacity-performance prices for the preceding four years and 32% higher than the last actual value, which was $120/MW-day in 2019/20.[25] Since new generation units totaling 5,374 MW (in UCAP terms)

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[23] Interestingly, DPL has not asked PJM to perform similar modeling of the effects of load reductions on the load forecasts that determine DPL capacity obligation and PJM's resource requirement (and hence, capacity prices). (OPC DR 13–18)

[24] These prices are applied only for EMT and CVR, since DP and EWR capacity benefits are treated as revenues through 2019/20. And due to the delay from load reduction to the first delivery year for which the BRA would reflect that reduction, values prior to 2018/19 do not matter for EMT and values prior to 2019/20 do not matter for CVR.

[25] DPL inflated the prices in 2016/17 through 2020/21 as though they were in 2016 dollars. DPL also erroneously assumed that the price in the seven months of 2020/21 that are part of 2021 would be even more expensive that the first five months of 2020/21, even though PJM sets the price for the entire delivery year.

cleared at the $120 MW-day price, including 32.6 MW in EMAAC, even in a period with low expected energy revenues, that price appears sufficient to support building new generation. DPL does not justify the use of prices above $120/MW-day.

Q: What is DPL's position regarding the avoided capacity value of the DP program after 2019/20?

A: DPL assumes that the DP program will avoid $158/MW-day, even though, as I have shown in Section IV.B above, the DP program will not reduce DPL capacity obligations. DPL acknowledges that the DP program will receive no capacity payments, but expresses its hope that it can convince Maryland stakeholders to support paying for the DP program.

> Delmarva Power's DP resource…will be unable to earn PJM capacity revenue after May 31, 2020. However, Delmarva Power will seek additional DP capacity market revenue in future years to the extent that evolving PJM capacity market rules permit it to do so. Additionally, Delmarva Power will continue to work with Maryland stakeholders to determine the best method of funding the customer incentives for DP and deriving Maryland electricity customer value. For cost effectiveness modeling, Delmarva Power has assumed that no PJM capacity market revenue will be available to fund DP after May 31, 2020, which is the end date of PJM Delivery Year 2019/20. (Giovannini Direct at 8–9)

Q: If "Delmarva Power has assumed that no PJM capacity market revenue will be available to fund DP after May 31, 2020," what does the $158/MW-day value represent?

A: Mr. Giovannini (Direct at 9) suggests that the DP program could be subsidized in one of three ways:

1. establishing a demand response portfolio standard, requiring wholesale electric suppliers to fund DP,
2. collecting funding through the EmPOWER surcharge on electric distribution bills,

3. converting the existing DP Program from a rebate program to a critical peak pricing program.

He elaborates on these options in OPC DR 13-7.

Q: Would these options represent real benefits that should be included in cost-effectiveness screening?

A: No. Options 1 and 2 simply propose ways to force consumers to pay for the DP program, without establishing that it actually creates any value. Option 3 is not a substantial change from the current program design, and would not create any new benefits. DPL has not been able to time the DP hours to capture high-priced energy, reduce loads at the PJM peaks, or reduce peak transmission loads, and Mr. Giovannini does not explain how DPL would improve its performance. Indeed, reducing the capacity obligation significantly would require many PESC days each summer, which would probably seriously erode customer response.

C. Capacity Price Mitigation

Q: How does DPL estimate the effect of the programs on the capacity prices paid by consumers.

A: DPL includes the following capacity-price effects:

- DP for 2016 through 2022, assuming that the price effect is experienced in the year that the resource cleared in the BRA and lasts four years or through May 2022, whichever is earlier.[26]
- EMT for 2018 through 2022, assuming that the price effect is lagged by four years from the date of incremental load reductions (i.e., from the load reductions in 2014 to a price effect in 2018).

[26] DPL left out any capacity price mitigation from the DP program in delivery years 2013/14 through 2015/16. I have corrected this in my computations,

- CVR for 2019 through 2023, using the timing assumptions for EMT.[27] adjusted for a PJM-mandated reserve margin.[28]

DPL multiplies these assumed reductions in peak loads by an annual coefficient that is the product of the following two factors:

- The zonal capacity obligation in each BRA of Maryland load (BGE, SMECo and the Maryland portions of Potomac Edison, PEPCo and Delmarva,[29] and
- A coefficient that DPL presents as representing the change in the BRA clearing price for premium capacity in $/MW-day per megawatt of low-cost capacity added to the supply curve in the BRA or per megawatt of load reduction.

Q: What problems have you identified in DPL's estimate of capacity price mitigation?

A: I have identified four errors in DPL's analysis. First, DPL assumes for the CPM computations that it will continue to clear DP capacity in 2020/21 and 2021/22, even though PJM has no capacity product for which the DP program would be eligible. DPL does not assume any DP capacity revenue in those years, and it is not clear why DPL would include any price-mitigation effects in that period.

[27] DPL estimates that the CVR load reductions start a year later than the EMT reductions, and that the CVR reductions increase through 2019, pushing the price effects through 2023, while the EMT reductions plateau in 2017, so the price effects end in 2022. The CVR capacity price mitigation estimates appear to reflect some computational errors, so I am not sure exactly what DPL was trying to do.

[28] The durability of the price effect is difficult to directly observe or estimate and DPL's four-year estimate falls in the range I have seen elsewhere.

[29] DPL omits the Potomac Edison load in 2016/17, when MAAC cleared at higher prices than AP, and includes only Delmarva load in 2018/19 and 2019/20, when EMAAC separated from the rest of the system.

Second, the DP load reductions after May 2020 (when the DP program will no longer be counted as a capacity resource) will not substantially affect the amount of capacity that PJM acquires, so those reductions will have no effect on capacity prices. PJM's modeling of an load reduction similar to those claimed by DPL for the EMT and CVR programs also indicates that those will affect the PJM capacity requirement and the price of capacity much less and much more slowly than DPL assumes.

Third, DPL assumes that prices for all of the capacity products (annual, limited, demand response, base, and capacity performance) are always affected by cleared DP capacity, even though the DP resource has usually cleared at a lower price than most of the capacity obligation. As a result, the reduction in capacity prices paid by customers due to the addition of demand resources to the capacity auctions is usually much less than the reduction from adding generation or other premium resources.

Fourth, the coefficients that DPL uses to convert load reductions and cleared resources to price reductions are significantly overstated.

I explained the first error in Section IV.B. I discuss the last two errors in the next two sections.

1. Effects of CVR and EMT Load Reductions on Capacity Prices

Q: How are capacity prices for the Maryland zones affected by changes in DPL load and resources?

A: That varies from auction to auction, depending on supply and demand conditions in the zones. The EMAAC LDA, including Delmarva, has separated from SWMAAC (which includes Pepco and BGE) in four of the last eight BRAs, including the two most recent auctions (2018/19 and 2019/20), and separated from the rest of the RTO (which includes AP) in every year. DPL excludes capacity price benefits for the other Maryland utilities 2018/19 and 2019/20, since it is not clear that reductions in DPL load would have reduced capacity prices outside EMAAC. DPL also excludes any benefits from reducing AP prices in 2016/17, when AP prices would not have declined in response to lower forecast DPL load.

Q: How did DPL estimate the capacity-price mitigation coefficient?

A: DPL assumes that the reduction in price in $/MW-day per megawatt of load reduction or cleared capacity will be 50% of the slope of the steeper portion of the Variable Resource Requirement (VRR) curve. DPL presents no evidence to support this value, and has conducted no supporting analysis (OPC DR 28-4 and OPC DR 28-5).

Q: What is the origin of this approach?

A: The MEA invented it in the EmPOWER consultation process, also without any analytical support, other than the fact that it is half-way between zero and the slope of the VRR.

Q: How should the capacity-price mitigation coefficient be estimated?

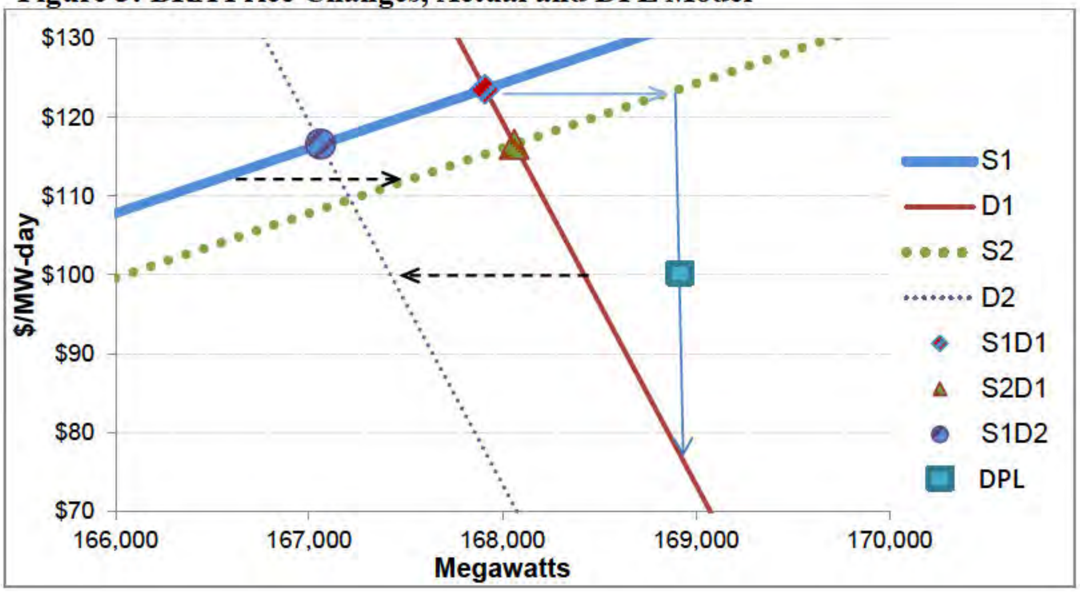
A: The $/MW-day/MW coefficient should reflect the operation of the PJM capacity auction. Figure 3 illustrates the operation of the RPM market, or any other simple matching of supply and demand.[30] This illustration could be right out of an introductory economics text.

Figure 3 illustrates the effect of adding 1,000 MW of peak reduction to the RTO market as an increase of supply (shifting the S_1 supply curve to the S_2 supply

[30] For ease of presentation, this example ignores the multiple types of capacity acquired at different prices in some PJM auctions, as well as the multiple pricing zones. As I discuss below, the capacity product that DPL has bid into some of the auctions has little or no effect on the price paid for most of Maryland's capacity obligation.

curve) or a decrease in demand (shifting the D_1 VRR curve to the D_2 VRR curve). The dashed lines show a 1,000 MW shift in the supply curve to the right, or the demand curve to the left.

Figure 3: BRA Price Changes, Actual and DPL Model



In addition to the actual clearing price (point S_1D_1), Figure 3 shows the effect of shifting the supply curve 1,000 MW to the right (point S_2D_1, reflecting addition of 1,000 MW of low-price premium capacity into the auction) and the effect of shifting the demand curve 1,000 MW to the left (point S_1D_2, reflecting 1,000 MW reduction in the demand curve from reflecting the same amount of reduction in the forecast driving the demand curve). In each case, the 1,000 MW shift reduces the market-clearing price by about $7/MW-day.

The DPL method, on the other hand, would estimate a $23 reduction in price, also shown in Figure 3. The DPL method is uniformly biased upward.

Q: How should this coefficient be estimated?

A: One approach is to use the available data on the VRR and the supply curve to find the new market-clearing prices following a load change. Since PJM released only graphic representations of the supply curves by zone and (where relevant) resource type for the 2014/15, 2015/16, and 2016/17 BRAs, this method requires some approximation and it is limited to those three years.

An alternative approach that I have employed for BGE and Pepco uses the sensitivity analyses performed by PJM following the 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19 BRAs. Since PJM has all the price bids and all the rules it uses in setting the market-clearing price in each zone, these results should be very accurate. Unfortunately, the PJM did not perform sensitivity studies in these years for changes in EMAAC demand resources.

Q: Has the first method been implemented?

A: Yes. As discussed in the MEA's EmPOWER 2015–2017 Cost Effectiveness Framework and demonstrated in the VRR Curve Capacity DRIPE table, MEA estimated the slope of the Variable Resource Requirement (VRR) curve (the administrative equivalent of a demand curve) from PJM filings of Planning Period Parameters documents, and the supply curve from graphics that PJM has provided for three BRAs.[31] Table 6 compares DPL's estimated coefficients for those years with the coefficient that results from determining the new equilibrium price.

Table 6: Comparison of DPL and Equilibrium Price Response to Load Reductions ($/MW-Day/MW)

	2014/15	2015/16	2016/17	Average
MAAC (DPL, BGE, Pepco)				
DPL Method	$0.0387	$0.0431	$0.0443	
New Equilibrium	$0.0338	$0.0266	$0.0167	
Ratio	87%	62%	38%	62%
Rest of RTO (AP)				
DPL Method	$0.0266	$0.0228	$0.0230	
New Equilibrium	$0.0163	$0.0129	$0.0070	
Ratio	61%	57%	30%	49%

[31] 2014/2015 Base Residual Auction Report Addendum, 2015/2016 Base Residual Auction Supply Curves, and 2016/2017 Base Residual Auction Supply Curves, all available at www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/.

A realistic assessment of the change in prices, using only the VRR and supply-curve data that PJM has released, would result in price reductions about 40% less than DPL assumed for MAAC and 50% less than DPL assumed for AP.I have used this assessment to compute the adjustments I have made to DPL's analysis.

2. *Effects of the Cleared DP Resources on Consumer Capacity Costs*

Q: Are all capacity resources paid the same price in the PJM auctions?

A: No. Prior to the BRA for the 2018/19 delivery year, PJM used three categories of resources: Annual, Extended Summer, and Limited. DPL's bid its DP program as a Limited resource into the 2015/16 and 2016/17 auctions, and as an Extended resource for 2017/18. In 2018/19 and 2019/20, PJM used Capacity Performance, Base Generation, and Base Demand Resource categories; the DP resource cleared as Base Demand Resources in both years.

Q: How do those categories affect the capacity price mitigation that results from cleared demand resources?

A: The manner in which PJM clears the different categories of resources is illustrated in Figure 4, for prices in MAAC in the 2014/15 BRA, and Figure 5, for MAAC prices in the 2015/16 BRA.[32] PJM limited the amount of Limited Resources that could clear in each auction. In most years, there were effectively two separate auctions, one for Limited Resources and one for Annual and Extended Resources.

[32] DPL and the rest of EMAAC cleared with the remainder of the MAAC zone in 2014/15 through 2017/18. PJM has provided these graphs for only some years and some zones.

Figure 4: Separation of Limited Supply Price, 2014/15 MAAC Supply Curve

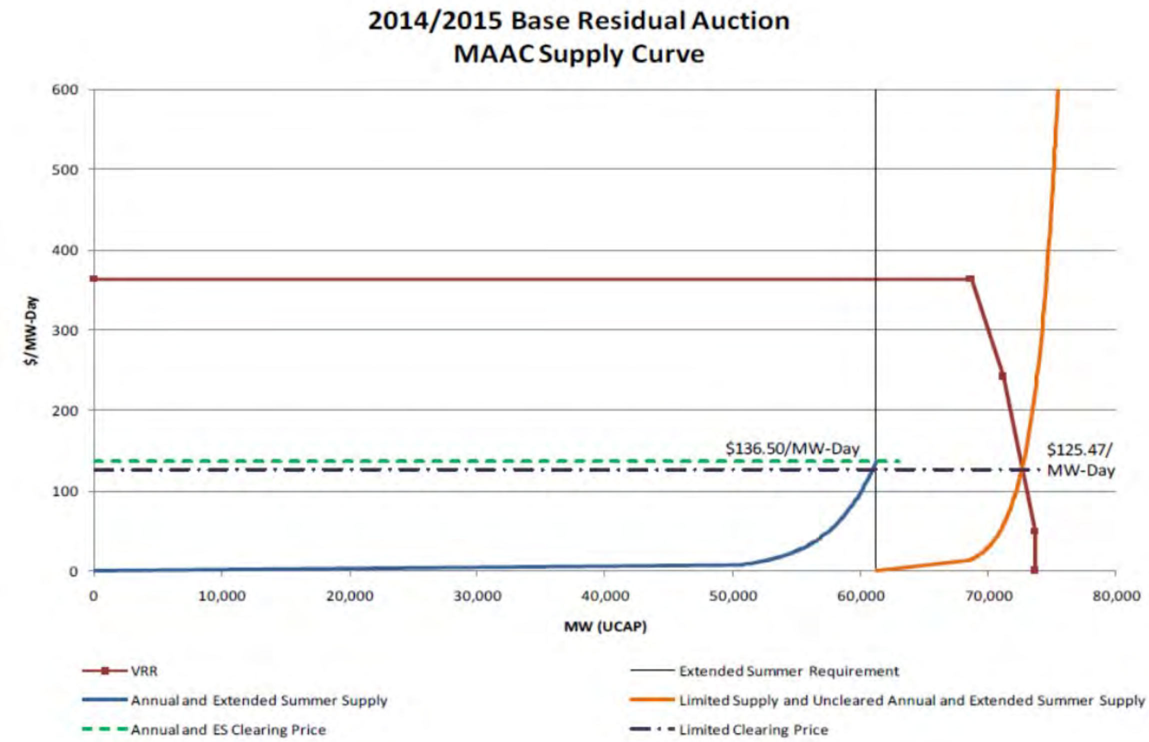
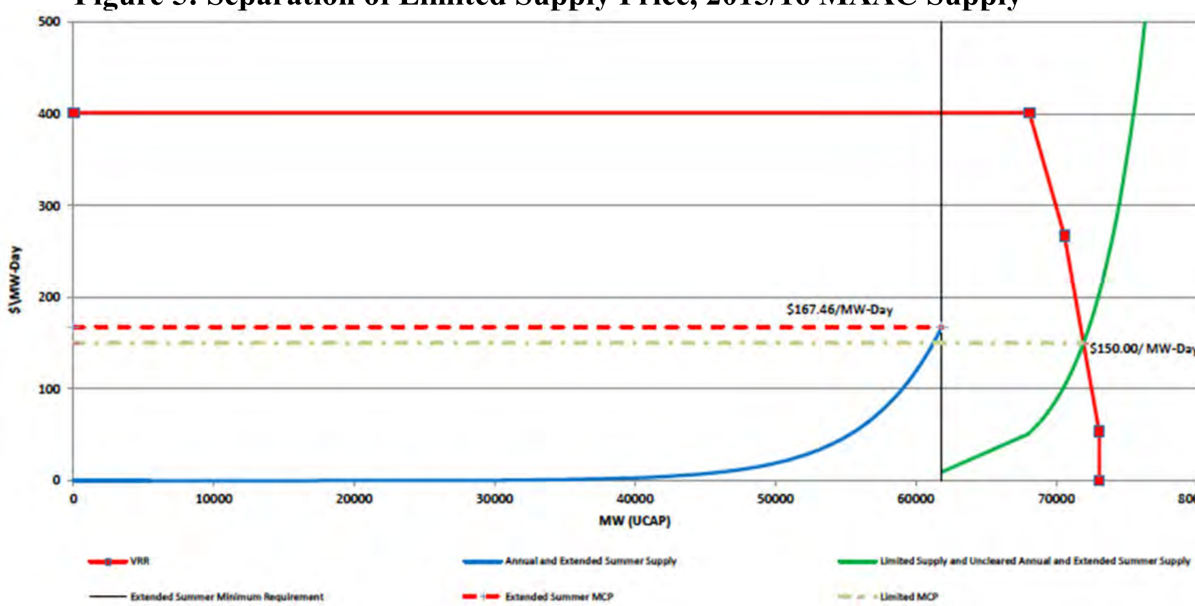


Figure 5: Separation of Limited Supply Price, 2015/16 MAAC Supply



Reducing the amount of low-price limited capacity (if, for example, DPL had not bid the DP capacity into the auction) would have shifted the green line, which includes the Limited Resources, to the left, raising the market-clearing price for the Limited Resources. But unless several hundred or thousands of Limited Resources were removed, the price of the Annual and Extended Resources would not change.

The effect would have been similar in 2018/19 and 2019/20, when the DP program was a Base resource, clearing below the price of performance capacity.

Only in 2016/17, when all resources cleared at the same price, and 2017/18, when the DP program cleared as an Extended resource at the same price as Annual resources, would the cleared DP capacity have reduced the price for the dominant class of capacity resources.

Q: What type of resource did PJM allow DPL's DP program to clear as?

A: The DP resource cleared as an Extended summer resource in 2015/16 through 2017/18, a Base resource in 2018/19, and a Base Demand resource in 2019/20. (OPC DR 13-3c).[33] The Extended resources in 2015/16 to 2017/18 received the same price as the Annual resources that represented a majority of PJM's capacity.[34]

Q: How does DPL reflect the fact that the DP resources were not Capacity Performance resources in 2018/19 and 2019/20?

A: Ignoring the difference in types of resources and the operation of the PJM capacity markets, DPL has assumed that all cleared supply-side resources will have the same effect on all wholesale capacity market prices.

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[33] DPL claims that some DP capacity cleared in 2014/15, but does not specify what resource product that capacity cleared as. I assume that it cleared as a Limited resource.

[34] For some reason, DPL did not take credit for any capacity price mitigation for its DP capacity that cleared in the 2014/15 and 2015/16 BRAs. I added those benefits into my estimate. Since Limited Resources cleared separately from Annual and Extended Resources in 2014/15, the benefits of the cleared DP capacity were small.

Q: How much would a dollar/MW-day change in the Base Resource price in the 2018/19 and 2019/20 auctions have changed the capacity price paid by consumers?

A: Since most of the resources procured for those years was performance capacity, whose price was not affected by the change in the Base Resource price, the effect on standard-offer service prices and contracts from competitive suppliers would be small. For each dollar that the DP program reduced the Base Resource price, the price to load would fall only about $0.16 in either 2018/19 or 2019/20.

Q: Is the change in price the only effect of changing the amount of demand resources that DPL sells into the capacity market?

A: No. PJM developed the VRR to increase the amount of capacity procured as price falls and decrease the amount procured as price rises. If DPL had not bid the DP program into the capacity market, some prices would have been higher, but the amount of capacity procured and hence the capacity obligation would have been lower. DPL has not taken this effect into account.

3. Summary of Capacity Price Mitigation Effects

Q: Please summarize your review of the effect of the AMI programs on capacity prices.

A: DPL's estimates of the capacity-price effects should be adjusting the three ways. First, all of the estimated capacity-price effects should be reduced about 45%, reflecting the correction to DPL's assumed relationship between cleared capacity or load reductions and price declines, as shown in Table 6. Second, the effects of the DP program in 2018/19 and 2019/20 should be reduced 84%, to reflect the fact that the program affected the pricing of only a small amount of Base Resources. Third, the DP program will not clear in the PJM capacity market after May 2020 and will have no resource-related capacity-price effect after that date. Since the very limited load reductions from the DP program will have little effect on the capacity acquired for the DPL zone or PJM as a whole, the program is unlikely to produce any meaningful capacity-price benefits. Fourth, any AMI-related load reductions from the EMT and CVR programs may produce some price benefits, but these will be about 70% lower than DPL projects, because of the lower effect of load reductions on the forecast, in addition to the correction of DPL's overstated estimate of the price reduction per megawatt of forecast load reduction. Combining these corrections reduces DPL's claimed capacity price mitigation benefit for the DP program by about $10.2 million and from the CVR and EMT programs by about $1.8 million, all in present value.

VI. Claimed Transmission and Distribution Benefits

Q: What problems have you identified that regarding DPL's estimates of transmission and distribution benefits?

A: I have identified three such problems. First, DPL developed a carrying charge that is levelized in nominal dollars, but escalates it over time. Second, no T&D projects were avoided in the years in which DPL claims large avoided capital costs. Third, the DP program does not reduce loads at the times of peak loads on the lines that DPL uses in estimating avoided transmission costs, and hence cannot reduce transmission peak loads or avoid transmission costs.

Q: Please explain DPL's error in the development of the T&D carrying charge.

A: In OPC DR 1-3 KRL Attachment J, DPL derives a 9.2 % levelized carrying charge for T&D. This is a nominally–levelized rate, computed from the observation that $9,173 annually over 44 years, discounted at DPL's 7.23% nominal rate of return, would have the same present value ($120,988) as the revenue requirements (return, taxes, depreciation and insurance) of a $100,000 investment. DPL takes the $9,173 annual cost (which would be the right value if held constant over 44 years) and escalates it at 2.1% annual inflation.

Q: If DPL had wanted to properly use escalating avoided T&D costs, how should it have computed the carrying charge?

A: The economic, or real-levelized, carrying charge for DPL's inputs and a $100,000 investment, would be $6,895 (6.9%) in year one, not $9,174 (9.2%), increasing by 2.1% inflation to $7,039 in year two and $16,479 in year 44. That real-levelized, inflating cash flow would also have the same present value of $120,988 over 44 years as the revenue requirement or the nominally-levelized avoided cost.

The real-levelized avoided cost is generally more flexible and easier to use properly than the nominally-levelized avoided cost, and produces more accurate results for periods shorter than the life of the equipment. But regardless of which approach DPL might choose, it cannot combine the higher initial carrying charge the nominal carrying charge and the inflation of the real-levelized carrying charge.

Q: Can you give a numerical example illustrating the problem in DPL's treatment of annual T&D costs?

A: As I understand DPL's approach to annualizing avoided T&D costs, the underlying assumption must be that a load reduction would avoid a new, more-expensive project in each year. That implicit model would be something like the following, for a reduction that starts in 2015 and stays constant through the analysis period:

- Project A would have been required in 2015, but is not needed in that year due to the load reduction.
- In 2016, Project A is built, but a similar Project B is deferred, saving the 2015 cost plus another year's inflation.

- In 2017, Project B is needed, but Project C is deferred, with yet more inflation.
- This pattern repeats through at least 2023.

This interpretation of avoided T&D costs is illustrated in Table 7.[35] The total savings are 9.2% of the cost of the first avoided project, rising at the 2.1% inflation rate.

Table 7: DPL Annualization of Avoided T&D Cost

	Project	2015	2016	2017	2018
Avoided investment	Project A	$600	($600)		
Annual savings			$55.2	$0.0	$0.0
Avoided investment	Project B		$612.6	($612.6)	
Annual savings				$56.4	$0.0
Avoided investment	Project C			$625.5	($625.5)
Annual savings					$57.5
Total Savings	A+B+C		$55.2	$56.4	$57.5

Q: Is DPL's approach realistic?

A: No. DPL ignores the inflation in the cost of deferred projects, when they are eventually built. Table 8 corrects this error, adding the inflation rate to the deferred cost and recognizing that the carrying cost of the deferred, inflated project will be higher than the carrying cost of the original project. Table 8 shows that this effect offsets the inflation in the new projects deferred in later years.

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35 For convenience, I assumed that each deferral lasts one year and that the deferred projects all have the same cost in constant dollars. Deferred T&D costs are lumpy and uneven, but this example puts DPL's assumptions in the best possible light.

Table 8: Realistic Treatment of Avoided T&D

	Project	2015	2016	2017	2018
Avoided investment	Project A	$600	($612.0)		
Annual savings			$55.2	($1.2)	($1.2)
Avoided investment	Project B		$612.6	($625.5)	
Annual savings				$56.4	($1.2)
Avoided investment	Project C			$625.5	($638.6)
Annual savings					$57.5
Total Savings	A+B+C		$55.2	$55.2	$55.2
DPL Overstatement			$0.0	$1.2	$2.3

In this example, the error starts at $1.2 million in the first year, rises to $2.3 million in the second year, and would continue to rise, to $10.9 million in 2023, totaling over $55 million.

Q: Are there any other problems with DPL's approach?

A: Yes. DPL ignores the effect of the end of the T&D deferrals in 2024, when the capacity avoided through 2023 would need to be built. In the example in Table 7 and Table 8, the replacement equipment would cost $723 million in 2024.

These errors result from DPL using the nominally-levelized avoided costs, rather than the real-levelized avoided costs that are standard practice in valuing deferral of investments.

Q: How should the avoided T&D costs be adjusted to correct the error in DPL's computation of the carrying charge?

A: The avoided T&D costs should be reduced by 24% to correct this overstatement.

Q: For what years does DPL claim that the AMI programs have avoided T&D investments?

A: DPL claims that the AMI programs reduced T&D costs by about $2.4 million annually by 2015. Since these saving are estimated using a 9.2% carrying charge, DPL must be claiming that it avoided $26 million in T&D projects by 2015. DPL assumes that even more expensive projects are avoided in each future year.

Q: How long a delay does DPL assume between a reduction in load due to the AMI programs and the avoidance of T&D investments?

A: DPL assumes that these programs avoid T&D costs in the year that they reduce loads.

Q: When would DPL have needed to forecast the AMI load reductions in order to avoid T&D investments in 2015?

A: For the pool transmission facilities, PJM would have needed to anticipate the 2015 load reduction as early as the RTEP analysis in 2010. As explained in PJM's response to Staff DR 1-1, the RTEP loads are reduced by the average of "Committed DR for each of the most recent three delivery years." Assuming that means the three future delivery years for which the BRA has been completed, those years would have included the summers of 2011, 2012 and 2013, before DPL's DP program had cleared any capacity. Hence, the RTEP conducted in 2014 for the summer of 2019 would not have recognized any DP-related load reductions. Since the DP program will not produce any committed DR after 2019, it is unlikely that the DP program will affect PJM's transmission planning.

The load effects of the CVR and EMT programs would not affect the PJM forecast until 2015, and then only modestly, since DPL's claimed savings for 2014 are very small and the effects of load reductions affect the PJM forecasts only rather gradually, as I discuss in Section IV.B. That 2015 forecast was used in the 2015 RTEP for 2020, and may have reduced the 2020 peak forecast by a megawatt or so, assuming that DPL's estimate of the EMT load reduction is correct. The EMT and CVR load reductions in 2015–2017 might reduce the forecasts for the 2021–2023 RTEPs by a few megawatts. DPL claims avoided transmission costs starting in 2014, about six years too early.

For any radial transmission facilities developed by DPL with minimal PJM involvement, as well as DPL distribution facilities, a load reduction in 2012 or 2013 might avoid a project that would have been charged to customers in 2015. The AMI programs were not in place at that time, and DPL has not demonstrated that it reduced its load forecast to reflect future AMI programs.[36] The first of the claimed EMT load reductions in 2014 might affect distribution additions as early as 2016 or 2017, depending on the project lead time and the extent to which DPL's distribution planners are willing to trust the continuation of a small load reduction in a single year. At best, the savings assumed by DPL would be delayed two or three years, to reflect construction lead time.

The DP load reductions (as opposed to DP capacity committed in the capacity market) have almost no effect on the PJM load forecasts for transmission, and the sporadic load reductions are unlikely to affect the peak loads affecting many distribution substations.

Q: What is your basis for saying that DPL cannot identify any projects avoided in the years in which DPL claims large avoided capital costs?

A: DPL acknowledged that it has not fully eliminated any projects from either the distribution or transmission capital budgets because of AMI (OPC DR 5-17 and OPC 5-18). DPL identified two distribution substations "experienced deferrals based on a reduction in the load forecast" (OPC DR 5-17) and admitted that "Delmarva Power has not delayed or cancelled any projects from the transmission capital budget because of AMI."

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[36] Even where DPL identifies projects that have been delayed by lower load growth, it cannot identify any forecasted effect of the AMI programs on the need for those projects. (Staff DR 6-31 and Staff DR 6-32 and OPC DR 13-43)

According to Staff DR 3-28 Attachment B, both of the distribution substations deferred due to reduced load forecasts (McCleans and Crest) were originally conceived in 2007 and "have been deferred until their new respective in-service dates when the projects will be completed for reliability reasons." McCleans was initially scheduled to be completed before the summer of 2012 and has been deferred to the winter of 2019. Crest was initially scheduled to be completed before the summer of 2013 and has been deferred to the summer of 2018.

Q: Is it possible that the delay in either substation was attributable to the AMI programs?

A: That is unlikely. DPL broke ground on Crest in February 2016, implying a construction time of about 2¼ years. In order to defer construction of McClean, assuming that lead time, DPL would have needed to make the deferral decision in the winter of 2010; for Crest, the decision would have been needed in the winter of 2011. Both of those decisions must have been made long before DPL's loads would have reflected the results of the AMI programs. DPL does not attribute any specific portion of the load reduction or deferral to the AMI programs, or even specify the timing and magnitude of the reduction in the load forecast.

Importantly, the drivers for adding the Crest and McClean substations were the peak loads on the Cecil substation and Feeder MD2245 from the Chestertown substation, respectively. None of the DP PESC hours have coincided with the peak hours on the Cecil nor Chestertown substations (or any other DPL substation), so the DP program (which contributes most of DPL's claimed demand reductions) could not have deferred them.[37]

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[37] I reviewed the 2014 and 2015 loads on each DPL substation, provided in OPC DR 5-11. None of the substations peaked in a PESC hour, and for those substations DPL provided data for, 78% of

Q: What can you conclude about the T&D benefit of DPL's claimed AMI load reductions?

A: My conclusions are as follows:

- No DPL high-voltage transmission investments have been deferred since the start of the AMI programs, so no transmission costs have been avoided.
- The DP program cannot defer any future transmission investments, since it will have provided no committed resources beyond 2019/20.
- The EMT and CVR programs could defer some transmission costs at the end of the analysis period in 2023, at the earliest.
- The DP program cannot defer any distribution substation investments, since it does not reduce peak loads on distribution substations.
- The EMT and CVR programs could defer some distribution costs after about 2017, but DPL has not demonstrated that it has decided to delay any substations since the beginning of EMT and CVR load reductions.

Correcting DPL's analysis to correct the error in the carrying charge and eliminate the claimed benefits of the DP program, the avoided transmission costs claimed for the EMT and CVR programs through 2022 and the avoided distribution costs claimed for the EMT and CVR programs through 2017 results in a present value of avoided T&D of about $.24 million, 99% of DPL's claim.

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the substations were operating at less than 65% of their annual peak load duringthe PESC hours. Indeed, since the DP program shifts loads to other hours, it may have increased loads on some substations.

VII. Claimed Energy Benefits

A. Energy Revenue

Q: How has DPL calculated energy revenues from the AMI programs?

A: DPL includes energy revenue from the DP program as an operating benefit (OPR 19) for years 2016–2024, although it sometimes refers to the energy revenue as part of avoided energy costs, as in the DP tab of Attachment C. DPL assumes that the energy revenue will be $200/MWh in 2016, rising at 2.1% annually.

Q: Is that price for energy revenues reasonable?

A: No. DPL has not received any revenues for its DP program in either 2014 or 2015 (OPC DR 5-22e and OPC DR 5-22f), so the benefits to customers would be due to reduced energy purchases (through standard service or otherwise). The avoided energy cost used in DPL's analysis of the EMT and CVR programs is $69/MWh about a third of DPL's estimate, rising with inflation. This value would be more reasonable for the DP program, as well.

B. Avoided Energy Costs

Q: How has DPL calculated avoided energy benefits achieved from the PESC event days?

A: DPL computes EMT and CVR energy benefits as the product of the estimated energy reduction multiplied by estimates of the energy portion of supplier generation charges. The approach for these programs is straightforward and appears reasonable.

C. Energy Price Mitigation

Q. How does DPL estimate the energy–price mitigation resulting from reductions in energy consumption?

A: DPL estimates the energy–price mitigation by regressing the percentage change in hourly real–time prices as a function of the percentage change in Maryland load, using data from 2013 through early 2015. The price variable was computed from a load–weighted average of the hourly zonal energy prices in the four load zones that cover parts of Maryland. The load variable was computed from the sum of hourly load in the Maryland portion of each of the four zones. The load–weighting calculations were performed for each of four time periods (peak and off–peak, summer and winter). These Maryland loads and load–weighted prices were then normalized (apparently so that the average normalized load and price in each of the four periods were each 1.0). The resulting regression coefficients and the goodness–of–fit measures are shown in Table 9. The coefficients represent DPL's estimate of the percentage change in weighted price per 1% change in Maryland load.[38]

Table 9: DPL Regression Results for Energy Price Mitigation (%Δ price per %Δ load)

	Coefficient	R^2	Adjusted R^2
Summer peak	1.667	0.069	0.069
Summer off–peak	1.613	0.102	0.102
Non–Summer peak	4.579	0.125	0.125
Non–Summer off–peak	3.130	0.138	0.138

[38] Since DPL is about 31% of Maryland load, the equivalent price change for a 1% change in DPL Maryland load would be about 0.5% in the summer periods, 1.4% in the non-summer peak, and 1.0% in the non-summer off-peak. Averaged over the year, the effect of a 1% reduction in Maryland DPL load would be about 1% on peak and 0.7% off-peak.

Since the load of the DPL zone is about 29% of Maryland's load, these values expressed in terms of percent changes in DPL load would be as shown in Table 10.

Table 10: DPL Regression Results for Energy Price Mitigation, Restated in Terms of DPL Zonal Load

	%Δ price per %Δ MD load	%Δ price per %Δ DPL zonal load
Summer peak	1.667	0.483
Summer off-peak	1.613	0.468
Non-Summer peak	4.579	1.328
Non-Summer off-peak	3.130	0.908
Annual average		0.846

DPL then converts these coefficients into a reduction in Maryland energy bills per megawatt–hour of load reduction. That computation should involve multiplying the coefficient times the average energy price, dividing by Maryland load, and multiplying by Maryland energy purchases from the market.[39] DPL appears to have done something along those lines, although there is no indication that DPL recognized the energy that Maryland customers obtain from contracts. In OPC DR 1-3 KRL Attachment L, DPL's estimate of the energy–price mitigation effect is approximately $1.42 per MWh of savings. DPL seems to have computed this value for one year but applies it for the entire benefit analysis, with most of the benefits in 2016 through 2024.

Q: What problems have you identified in DPL's analysis of energy price mitigation?

A: I have identified several problems with DPL's estimation of energy price mitigation, other than the unnecessary complex and contradictory documentation.

[39] Not all Maryland energy is purchased at short-term market prices, so the price reductions would not affect all usage, especially in the short term.

- DPL assumed that observed changes in prices were driven exclusively by Maryland loads.
- DPL assumed that the effect of load in any part of Maryland had the same effect on prices in all parts of Maryland.
- DPL failed to reflect changing energy prices in estimating the effect of a percentage change in price.

Q: How did DPL determine the effect of DPL load on the price in each zone?

A: DPL's evidence on this point is ambiguous. According to the work process flow provided in OPC DR 1-3 Attachment L, a regression was run for each period and each utility zone. The regression results provided in OPC DR 28-1 Attachment K, indicate regressions were run for each period only for the weighted prices. The documentation in OPC DR 1-3 Attachment L, also indicates that only one set of regressions was run for each time period. It does not appear that DPL determined the effect of reducing DPL load on the price in each zone.

Q: Is there any justification for DPL's assumption that only Maryland load affects Maryland prices?

A: No. At the simplest level, DPL's exclusion of load in the other parts of the DPL, PEPCo and AP zones strains credulity. There is only one Delmarva zone, and Delaware load affects the Delmarva zonal energy price as much as load in Delmarva's Maryland territory does. Yet DPL ignores Delaware load. There is only one Pepco zone, and load in DC affects the Pepco zonal energy price as much as Pepco's Maryland load does. Yet DPL ignores DC load. There is only one Allegheny zone, and load in Pennsylvania, Virginia, or West Virginia affects the AP zonal energy price as much as load in AP's Maryland territory does. Yet DPL ignores AP's Pennsylvania, Virginia, and West Virginia loads.

At a broader level, DPL's assumption that other zones do not affect prices in the load zones that cover portions of Maryland is also implausible. The Allegheny zone appears to be at least as well connected to PJM's Ohio and Pennsylvania utilities as to the other Maryland utilities, while Delmarva and AP are connected only through western MAAC utilities. Since most transmission connections between Delmarva and SWMAAC (BGE and Pepco) run through WMAAC (especially PPL and MetEd), it seems obvious that load in WMAAC would be important in determining Delmarva prices.

Q: Is there any justification for assuming that load in any part of Maryland has the same effect on energy prices in each of the Maryland zones?

A: No.

Q: Have you conducted any additional analysis of the effects of DPL load on energy prices in the four Maryland zones?

A: Yes. I have run a number of other regressions, using various combinations of PJM, MAAC, WMAAC, and local zones. The best fits I found, which are summarized in Table 9, are more realistic than the method employed by DPL because they reflect loads other than DPL MD, and recognize the effect of wider areas. The statistical tests for the equations in Table 11 are generally better than the complicated and questionable results provided by DPL's aggregation of loads, regression of load weighted pricing periods, and averaging of residual sales. The coefficients make much more sense, and the equations fit the data much better.

Table 11 shows these results, and computes the effect of a 1% change in DPL's load on the price of energy in each of the other zones.

Table 11: Improved Regressions for Maryland Load Zones

	% Change in Zonal Price per % Change in Area Load						
Price Zone	**BGE+ PEPCo +DPL**	**AP**	**WMAAC +AP**	**PJM - ComEd**	**R^2**	**DPL as % of Variable**	**% price Δ per DPL % load Δ**
On-peak							
BGE	**1.46**	1.58			0.48	22.7%	0.332
PEPCo	**1.46**	1.60			0.48	22.7%	0.332
DPL	**1.10**		2.10		0.51	22.7%	0.250
AP				**2.81**	0.42	2.3%	0.064
Off-peak							
BGE	**1.08**	1.00			0.48	22.5%	0.246
PEPCo	**1.11**	0.96			0.48	22.5%	0.252
DPL	**1.37**		0.53		0.48	22.5%	0.311
AP				**1.67**	0.40	2.3%	0.038

Averaged over the four load zones, weighted by the energy load in each zone, these coefficients are 0.29 on peak and 0.25 off-peak, about 30% of DPL's estimates.

Q: What are the implications of these results for DPL's estimates of energy price mitigation?

A: This improvement would reduce the energy price mitigation by 70% or $100,000.

VIII. Summary of Corrections

Q: Please list the errors you have found in DPLs analysis of system benefits from the load reductions that DPL attributes to smart-meter-enabled programs.

A: In Sections III through VII, I identified the following errors:

- Avoided Capacity Cost
  - The capacity obligation for DPL customers will not be significantly reduced by the DP load reductions, because they affect very few of the thousands of summer days used in the PJM peak forecasts, and the affected days are not well chosen to change PJM's load forecasts.

- DPL overstates the DP load reductions, by ignoring customers whose load increased on ESDs and hence not offsetting reductions that would have occurred without the program with increases that occurred even with the program.
- The load reductions from CVR and EMT would tend to affect capacity obligation much more slowly than DPL assumes, with only about 30% of the 2013–2015 reductions affecting the 2016 forecasts that will determine DPL's 2019/20 obligations.

- Capacity Price Mitigation
  - While capacity bid into the BRA from the DP program has and will tend to reduce capacity prices through 2020/21, it will also increase capacity obligations.
  - Load reductions from the DP program that are not bid into the BRA have negligible effects on market price, due to their rarity and timing.
  - DPL overstates the DP load reductions, by ignoring the customers who increase load and the customers who would have decreased load even without the program.
  - The load reductions from EMT would reduce capacity prices much less than DPL assumes.
  - DPL's estimate of the effect of load reductions on capacity prices is grossly overstated.
  - Historical experience suggests that capacity prices in the Delmarva service territory will often be unaffected by supply and demand in the DPL zone.
  - DPL incorrectly assumes that its demand response resources have always reduced prices for premium resources.
- Transmission and Distribution Benefits

- DPL improperly combines a nominally levelized T&D carrying charge (which includes the effect of inflation over 44 years) and inflation of the resulting annualized costs.
- None of the transmission investment modeled by DPL has been deferred through the present time, and there is little prospect for such deferral in the AMI analysis period.
- The DP load reductions, given their rarity and timing, are unlikely to affect distribution investment, given the variability in the timing of peaks on distribution equipment. The peak loads on the distribution substations have not fallen on the PESC hours. DPL has not demonstrated that the AMI programs contributed to any part of the deferral of either of the two substations that DPL has deferred since 2010.

- Energy Revenue
  - DPL overstates the price of energy during its PESC hours.
- Energy Savings
  - DPL overstates the DP benefits, by including randomly-occurring load reductions.
  - DPL failed to reflect the cost of buying energy savings through the PESC rebates.
- Energy Price Mitigation
  - DPL incorrectly assumed that energy prices for each of the Maryland zones is driven solely by Maryland load, ignoring the influence of the rest of the PEPCo, DPL and AP zones, and other parts of PJM, and thus overstating the effect of DPL load.
  - DPL overstates DP savings (and hence the effect on prices) by including random load reductions (but not random load increases) in the PESC hours.

Q: Please summarize the system benefits with your adjustments.

A: Table 12 updates Table 2 to reflect the adjustments I made above.[40]

Table 12: Adjusted System Benefits, $M of 2015 PV

Benefit Category	CVR	DP & EWR	EMT	Total
Capacity Price Mitigation	$0.1	$11.8	$0.2	$11.9
Energy Price Mitigation	$0.0	—	$0.1	$0.1
Capacity Revenue	—	$9.0	—	$9.0
Energy Revenue	—	$0.2	—	$0.2
Avoided Capacity	$0.1	—	$0.6	$0.7
Avoided Energy	$5.5	—	$20.3	$25.9
Reduction in Air Emissions	$0.2	—	$0.6	$0.8
Avoided Transmission Capital Recovery	–$0.1	—	$0.1	–$0.2
Avoided Distribution Capital Recovery	–$0.1	—	$0.1	$0.1
Total	**$5.7**	**$20.9**	**$22.0**	**$48.6**

For the purposes of this summary, I have accepted DPL's assumptions about the percentage reduction in energy and peak loads attributable to the effect of the smart meters on the EMT and CVR programs. If these savings are not realistic or could have been achieved without the smart meters, the EMT and CVR column should be reduced or eliminated. Mr. Chang adjusts the these savings in his testimony and also reflects the DP rebates, which are appropriately treated as a program cost.

Q: Does this conclude your direct testimony?

A: Yes. DPL has recently filed supplementary evidence from Ms. Lefkowitz, and additional data may become available from DPL and PJM, to which I may respond in supplemental or rebuttal testimony.

[40] The negative values for the CVR T&D benefits result from the CVR implementation costs, which DPL chose to include as a reduction in benefits, rather than a cost.

Professional Qualifications of Paul Chernick

Exhibit PLC-1

PAUL L. CHERNICK

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Price Effects as a Benefit of Energy-Efficiency Programs" (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

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"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

"Determining the Marginal Value of Greenhouse Gas Emissions" (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

"Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs" (with Emily Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

"Accounting for Externalities" (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

"Methods of Valuing Environmental Externalities" (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

"The Valuation of Environmental Externalities in Energy Conservation Planning" (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

"The Valuation of Environmental Externalities in Utility Regulation" (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

"Externalities and Your Electric Bill," *The Electricity Journal*, October 1990, p. 64.

"Monetizing Externalities in Utility Regulations: The Role of Control Costs" (with Emily Caverhill) *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

"Monetizing Environmental Externalities in Utility Planning" (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment,” (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

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“Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?” in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

“Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities,” in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

“The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal” (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

“Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels,” in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

“Capital Minimization: Salvation or Suicide?,” in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

“The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions,” in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

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“Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System” (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

“Forensic Economics and Statistics: An Introduction to the Current State of the Art” (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

“Power Plant Performance Standards: Some Introductory Principles,” *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

“Opening the Utility Market to Conservation: A Competitive Approach,” *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

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"Implications of the Proposed Clean Power Plan for Arkansas: Review of Stakeholder Concerns and Assessment of Feasibility." 2014. Report to Arkansas Audubon, Arkansas Public Policy Panel, and Arkansas Sierra Club.

"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." 2013. Filed by the Nova Scotia Small Business Advocate in N.S. UARB Matter No. 05355.

"Avoided Energy Supply Costs in New England: 2013 Report" (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

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"Audubon Arkansas Comments on Entergy's 2012 IRP." 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

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"Comments for The Alliance for Affordable Energy on Staff's 'Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana.'" 2011. Filed by the Alliance for Affordable Energy in Louisiana PSC Docket R-30021.

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"State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings" (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ont. Energy Board EB 2007-0707.

"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Jonathan Wallach, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

"Avoided Energy Supply Costs in New England: 2007 Final Report" (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Integrated Portfolio Management in a Restructured Supply Market" (with Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"Natural Gas Efficiency Resource Development Potential in New York" (with Phillip Mosenthal, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak). 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Natural Gas Efficiency Resource Development Potential in Con Edison Service Territory" (with Phillip Mosenthal, Jonathan Kleinman, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

“Evaluation and Cost Effectiveness” (principal author), Ch. 14 of “California Evaluation Framework” Prepared for California utilities as required by the California Public Utilities Commission. 2004.

“Energy Plan for the City of New York” (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

“Updated Avoided Energy Supply Costs for Demand-Side Screening in New England” (with Susan Geller, Bruce Biewald, and David White). 2001. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc.” (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Avoided Energy Supply Costs for Demand-Side Management in Massachusetts” (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Performance-based Regulation in a Restructured Utility Industry” (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

“Distributed Integrated-Resource-Planning Guidelines.” 1997. Appendix 4 of “The Power to Save: A Plan to Transform Vermont’s Energy-Efficiency Markets,” submitted to the Vt. PSB in Docket No. 5854. Montpelier: Vermont DPS.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People’s Counsel.

“Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire’s Electric-Utility Industry” (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

“Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities” (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

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“Analysis Findings, Conclusions, and Recommendations,” vol. 1 of “Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro” (with Plunkett, John, and Jonathan Wallach), December 1992.

"Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro," December 1992.

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.), February 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with Emily Caverhill), January 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities," (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"Rethinking Utility Rate Design—Retail Demand and Energy Charges," Solar Power PV Conference, Boston MA, February 24, 2016.

"Residential Demand Charges - Load Effects, Fairness & Rate Design Implications." Web seminar sponsored by the NixTheFix Forum. September 2015.

"The Value of Demand Reduction Induced Price Effects." With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant." With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

“Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling” (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

“Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making.” Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

“Cost Recovery and Decoupling” and “The Clean Air Act and Externalities in Utility Resource Planning” panels (session leader), DSM Advocacy Workshop. April 15 1992.

“Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs,” Energy Planning Workshops; Columbia, S.C. October 21 1991.

“Least Cost Planning and Gas Utilities.” Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

“Least-Cost Planning in a Multi-Fuel Context.” NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

“Accounting for Externalities: Why, Which and How?” Understanding Massachusetts’ New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

New England Gas Association Gas Utility Managers’ Conference. Woodstock, Vermont, September 10 1990.

“Quantifying and Valuing Environmental Externalities.” Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy’s Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

“Conservation in the Future of Natural Gas Local Distribution Companies.” District of Columbia Natural Gas Seminar; Washington, D.C. May 23 1989.

“Conservation and Load Management for Natural Gas Utilities,” Massachusetts Natural Gas Council; Newton, Massachusetts. April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop. Portsmouth, New Hampshire, January 22–23 1989.

“Assessment and Valuation of External Environmental Damages.” New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; “Lessons from Massachusetts on Long Term Rates for QFs”.

“Reviewing Utility Supply Plans.” Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

“Power Plant Performance.,” National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

Austin City Council, Austin Energy Rates, March to June 2012.

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass. DPU** 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298, Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass. EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass. DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass. DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass. EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass. DPU** 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass. DPU** 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **D.C. PSC** FC785, Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H. PSC** DE1-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich. PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass. DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass. DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich. PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Public Advocate. November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113, Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **Mass. DPU** 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vt. PSB** 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **Mass. DPU** 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985 and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **Mass. DPU** 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M. PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn. PUC** R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass. DPU** 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn. PUC** R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M. PSC** 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 7 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. CC** 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.

    Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass.** DPU 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass.** DPU 88-123, petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988 and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass.** DPU 88-67, Boston Gas Company; Boston Housing Authority. June 17 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I.** PUC 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt.** PSB 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100, Boston Edison rate case; Massachusetts Energy Office. June 30 1989.

    Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass. DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass.** **DPU** 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt.** **PSB** 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **Mass.** **DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California** **PUC,** incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill.** **CC** 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md.** **PSC** 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. Ind. URC, integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. Mass. DPU 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. Mass. EFSC 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. Maine PUC 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Va. SCC PUE900070, Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Mass. DPU 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Private arbitration, Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt.** **PSB** 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C.** **PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md.** **PSC** 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board,** AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **Mass.** **DPU** 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla.** **PSC** 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla.** **PSC** 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn. PUC** I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 10 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C. PSC** 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass. DPU** 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C. PSC** 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md. PSC** 8179, Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich. PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich. PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt. PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla. PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. UC** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. UC** E-2 Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona CC** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass. DPU** 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md. PSC** 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H. PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York PSC** 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. Vt. PSB 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. Mass. DPU 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. Vt. PSB 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. Mass. DPU 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. Mass. DTE 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. N.H. PUC Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. Md. PSC 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.

154. Vt. PSB 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine** PUC 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass.** DTE 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt.** PSB 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass.** DTE 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md.** PSC 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md.** PSC 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md.** PSC 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn.** DPUC 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Conn. DPUC** 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Wash. UTC** UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Conn. DPUC** 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Conn. DPUC** 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Va. PSC** 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ont. Energy Board** RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Conn. DPUC** 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass. EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn. DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn. DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass. DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn. DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt. PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J. BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J. BPU** GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Conn. DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **N.Y. PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **Mass. DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J. BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt. PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt. PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn. DPUC** 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn. DPUC** 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J. BPU** ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn. DPUC** 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn. DPUC** 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt. PSB** 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn.** **DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn.** **DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y.** **PSC** Case No. 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn.** **DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio** **PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y.** **PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb.** **EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC** 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** 01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** 0496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass.** **DPU** 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah** **PSC** 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah** **PSC** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn.** **PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C.** **UC** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark.** **PSC** 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark.** **PSC** 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark.** **PSC** 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** 02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** 03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** NSPI-P-892, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB** 03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** 04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** 04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla.** CC PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada** PUC 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La.** PSC R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. **Okla.** CC PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky.** PSC 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S.** UARB M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. **Kansas** CC 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S.** UARB M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah** PSC 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

289. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.

293. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

296. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Ky. PSC** 2014-00371, Kentucky Utilities Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky. PSC** 2014-00372, Louisville Gas and Electric Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

302. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **PUC Ohio** Case No. 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S. UARB** Matter No. M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. **N.S. UARB** Matter No. M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. **Md. PSC** Case No. 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. **City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. **Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. **Md. PSC** Case No. 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load shifting and load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

Cited Responses to Data Requests

Exhibit PLC-2

Cited Responses to Data Requests

Exhibit PLC-2

Discovery Request	Attachment #	Attachment Attached?	Attachment Spreadsheet?
OPC DR 1-3	C	Yes	
OPC DR 1-3	J	No	Yes
OPC DR 1-3	K	Yes	
OPC DR 1-3	L	No	Yes
Staff DR 3-28	B	Yes	
OPC DR 4-10			
OPC DR 5-11	All	No	Yes
OPC DR 5-17			
OPC DR 5-18			
OPC DR 5-22			
Staff DR 6-24			
Staff DR 6-26			
OPC DR 6-31			
OPC DR 6-32			
OPC DR 13-1			
OPC DR 13-3			
OPC DR 13-4			
OPC DR 13-7			
OPC DR 13-8			
OPC DR 13-13			
OPC DR 13-18			
OPC DR 13-20			
OPC DR 13-22			
OPC DR 13-26			
OPC DR 13-28	D	No	Yes
OPC DR 13-34			
OPC DR 13-41			
OPC DR 13-43			
OPC DR 28-1	K	No	Yes
OPC DR 28-4			
OPC DR 28-5			

MD-PSC – Case No 9424 – Delmarva Power

Staff Data Request No. 1 to PJM Interconnection

1-1. Does PJM take into consideration the following Delmarva's programs in the PJM transmission expansion planning and analysis process:

a. Dynamic pricing (DP)?

b. Conservation Voltage Reduction (CVR)?

c. Energy Management Tools (EMT's)?

If PJM does take any of these Delmarva programs into consideration, please explain in detail how it does.

PJM RESPONSE

(a) PJM's RTEP process considers Delmarva's DP program to the extent it is submitted to PJM as part of a Delmarva Demand Resource (DR) Program sell offer plan and reflected in PJM's forward capacity auction results.

(b) and (c) Delmarva's Conservation Voltage Reduction Program and Energy Management Tools Program are demand side resources acting outside of the PJM forward capacity auctions. The impact of these programs is recognized in the PJM load forecast over time, as they lower the historical loads used in developing the load forecast.

In addition to the above, PJM offers the following summary of how Demand Response programs are accounted for in its RTEP process.

Load Forecast Development

PJM's RTEP process begins with development of power flow cases on which it conducts established power flow tests to ensure compliance with NERC and regional reliability criteria. Power flow study models incorporate the effect of many system expansion factors including the latest zonal load forecasts, generating resources, transmission topology, demand resources, and power transfer levels with adjoining systems. PJM Manual 14B, Attachment H, provides more specific detail regarding the power system modeling data used to create RTEP base cases:
http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

As part of load forecast development, PJM uses the results of its forward capacity auctions to adjust the base forecast, which is on an unrestricted basis, to account for demand resources. From a markets perspective, limited demand resource, extended summer demand resource and annual demand resource products comprise one or both contractually interruptible program types: Firm Service Level and Guaranteed Load Drop, as described in PJM Manual M19, "Load Forecasting and Analysis" accessible from PJM's website via the following link: http://pjm.com/~/media/documents/manuals/m19.ashx.

PJM uses these program types in load forecasting terms to comply with NERC load management reporting requirements. Note that any programs that are not bid into the PJM capacity markets but reduce loads, such as Delmarva's CVR and EMT programs, have the effect of reducing future PJM load forecasts over time and as such are inputs into the requirements for transmission in the RTEP planning process by virtue of being reflected in the load forecast.

PJM recently changed the methodology to forecast demand resources. For demand resources that participate in the capacity market, forecasted values for each zone are computed based on the following procedure. Specifically, the forecast is based on the PJM final summer season committed demand resource amount, where the committed demand resource means all demand resources that have committed through the RPM Base Residual Auction and all incremental auctions, or a fixed resource requirement plan.

1. Compute the final amount of Committed DR for each of the most recent three delivery years. Express the committed demand resource amount as a percentage of the zone's 50/50 forecast summer peak from the January Load Forecast Report immediately preceding the respective delivery year.

2. Compute the most recent three year average committed demand resource percentage for each zone.

3. The demand resource forecast for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the result from Step 2.

Further details can be found in PJM Manual M19, "Load Forecasting and Analysis" accessible from PJM's website via the following link:
http://pjm.com/~/media/documents/manuals/m19.ashx.

RTEP Process Studies

In order to develop a power flow base case model, PJM assigns zonal load from its January forecast to individual zonal buses according to ratios of each bus load to total zonal load; ratios are supplied by each transmission owner. These power flow models become the basis on which PJM conducts Load Deliverability and other system reliability tests.

As part of the Load Deliverability test, the area evaluated is assumed to be experiencing a capacity deficiency due to a combination of higher-than-expected load demand – a "90/10" load forecast – and greater-than-expected generator unavailability. The 90/10 load forecast level is modeled by using the value of the 90/10 load contained in the latest PJM Load Forecast. The forecast 90/10 MW load for the area under test is reduced by the available demand response, both in megawatts. Testing methods are described in more detail in PJM Manual 14B, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx

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1-2. What is the MW peak demand load reduction for the Delmarva Transmission Zone that PJM has determined due to each of the following Delmarva programs:

a. Dynamic pricing (DP)?

b. Conservation Voltage Reduction (CVR)?

c. Energy Management Tools (EMT's)?

d. Total peak demand reduction for these programs?

PJM RESPONSE

PJM does not have Delmarva Transmission Zone peak demand load reduction data for Delmarva CVR and EMT programs.

Delmarva DP programs may be included in Delmarva Demand Resource (DR) Programs submitted to PJM as part of forward capacity auctions as noted in PJM's response to Question 1-1. However, those DR programs contain commercially-sensitive information that PJM is obligated to maintain as confidential. DP data – as well as CVR and EMT data – should be requested directly from PHI.

Notwithstanding, PJM's annual load forecast, Table B-7 includes load management placed under PJM coordination. That load management includes Limited DR, Extended Summer DR, Annual DR, Base DR and Capacity Performance DR, as discussed in PJM's response to No. 1-1. PJM annual load forecast reports are accessible on PJM's web site: http://www.pjm.com/documents/reports.aspx#load.

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1-3. What is the % peak demand load reduction for the Delmarva Transmission Zone that PJM has determined due each of the following Delmarva programs:

a. Dynamic pricing (DP)?

b. Conservation Voltage Reduction (CVR)?

c. Energy Management Tools (EMT's)?

d. **Total peak demand reduction for these programs?**

PJM RESPONSE

See PJM response to No. 1-2.

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1-4. If Delmarva's Dynamic Pricing (DP) days do not coincide with the PJM energy reductions days, would it affect transmission expansion planning? If yes, how? Please explain in detail.

PJM RESPONSE

PJM's RTEP process assumes that Delmarva DP programs, to the extent they are a part of Delmarva Demand Resource Programs submitted to PJM as discussed in Response to Question 1-1, will be available during the peak hour of the summer given that they have cleared a forward capacity auction and are contractually based. In actual operations, DR Programs that are not available during actual peak load periods are subject to RPM enforcement penalties.

Notwithstanding, DP days that do not coincide with PJM energy reduction days can influence historical loads. Subsequently, that data, through PJM's load modeling process, becomes accounted for in future load forecasts.

SPONSOR: Paul McGlynn

1-5. PJM RTO transmission expansion projects.

a. **Where there any transmission expansion projects in the PJM RTO during the last 8 years (2008 to 2016) that were planned and then withdrew or deferred due to Delmarva's DP, CVR, or EMT's Programs?**

b. **If there were, please provide a list of the projects including: name of the project, a brief description of the project, date project was originally approved by PJM in the RTEP Process, the original required in service date, the original driver/justification for the project, the date that the project was deferred or cancelled, whether the project was deferred or cancelled, the new required in service date, and the estimated cost for the project.**

PJM RESPONSE

Many assumptions are used in the development of the RTEP. PJM does not try to determine which of those assumptions may be driving the need for a project or conversely, which of those assumptions may be obviating the need for an RTEP project.

SPONSOR: Paul McGlynn

1-6. Delmarva transmission projects.

a. Where there any Delmarva transmission projects during the last 8 years (2008 to 2016) that were planned and then withdrew or deferred due to Delmarva's deployment of DP, CVR, or EMT's Programs?

b. If there were, please provide a list of the projects including: name of the project, a brief description of the project, date project was originally approved by PJM in the RTEP Process, the original required in service date, the original driver/justification for the project, the date that the project was deferred or cancelled, whether the project was deferred or cancelled, the new required in service date, and the estimated cost for the project.

PJM RESPONSE

See PJM response to 1-5.

SPONSOR: Paul McGlynn

1-7. PJM RTO transmission expansion projects and Delmarva Power AMI.

a. Where there any transmission expansion projects in the PJM RTO during the last 8 years (2008 to 2016) that were planned and then withdrew or deferred due to Delmarva's deployment of AMI Meters?

b. If there were, please provide a list of the projects including: name of the project, a brief description of the project, date project was originally approved by PJM in the RTEP Process, the original required in service date, the original driver/justification for the project, the date that the project was deferred or cancelled, whether the project was deferred or cancelled, the new required in service date, and the estimated cost for the project.

PJM RESPONSE

See PJM response to 1-5.

SPONSOR: Paul McGlynn

1-8. Delmarva transmission projects and AMI.

a. **Where there any Delmarva transmission projects during the last 8 years (2008 to 2016) that were planned and then withdrew or deferred due to Delmarva's deployment of AMI Meters?**

b. **If there were, please provide a list of the projects including: name of the project, a brief description of the project, date project was originally approved by PJM in the RTEP Process, the original required in service date, the original driver/justification for the project, the date that the project was deferred or cancelled, whether the project was deferred or cancelled, the new required in service date, and the estimated cost for the project.**

PJM RESPONSE

See PJM response to 1-5.

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DPL MD Electric
Levelized Annual Carrying Charge Rate Calculations
(Avoided T&D assets)

Inputs

1	Capital Investment	$100,000
2	Book Life (years)	44
3	MACRS Tax Life (years)	20
4	Cost of Equity	10.60%
5	Equity Capitalization %	49.10%
8	Cost of Debt	3.99%
9	Debt Capitalization Ratio, B	50.90%
10	Composite Income Tax Rate	40.36%
11	Gross Receipt Tax	2.22%
12	Insurance (% of replacement value)	0.03%
13	State Tax Rate	8.25%
14	Federal Tax Rate	35.00%
15	Insurance Replace Value escalator	2%

Reciprocal of average depreciation rate (2.3%). Rounded up to the nearest whole number

CARRYING CHARGE RATE : Discounting @ Before Tax WACC

LEVELIZED ANNUAL CARRYING CHARGE RATE **9.17259%**

Rounded **9.20%**

Energy Price Mitigation Working Papers

Delmarva Power and Light (DPL conducted a regression analysis of PJM Maryland zonal hourly Location Marginal Pricing (LMP) of energy to the corresponding hourly load in Maryland for each Maryland utility zone (Potomac Edison, BGE, Pepco (including SMECO) and Delmarva Power). The selected time period for the regression analysis was for pricing and load data starting on January 1 2013 and ending August 31 2015. Four time-of-use time periods were selected and a load weighted average price was determined for each time period. The hourly load data was then used to determine an average load for each time period for each zone. A load weighted[1] price of energy was than calculated for each of the four zones in Maryland, and the four time periods for each zone. A regression model was run for each zone to determine the change in price resulting from a one percent change in load. The electricity cost impact was then determined by multiplying the price change times the residual load.

Step by Step Work Process Flow

First Work Process: Compile hourly load data for all four Zones by time period in Maryland.

1. Developed and allocate the data across the four time periods, based on PJM definitions:
   - Summer On Peak, Summer Off Peak, Non-summer On Peak, Non-Summer Off Peak
   - The hourly loads were split into on and off-peak periods as defined by NERC. On-peak is hour ending (HE) 8 through HE 23, Monday – Friday excluding holidays. Off-peak is HE 1 through 7 and HE 24, Monday – Friday, all day Saturday, all day Sunday and all day on NERC holidays.

   - The NERC holidays are:

	2013	2014	2015
New Year's Day	01/01/2013	01/01/2014	01/01/2015
Memorial Day	05/27/2013	05/26/2014	05/25/2015
Independence Day	07/04/2013	07/04/2014	07/04/2013
Labor Day	09/02/2013	09/01/2014	09/07/2015
Thanksgiving	11/28/2013	11/27/2014	11/26/2015
Christmas	12/25/2013	12/25/2014	12/25/2015

2. Apply the Maryland utility share of each of the four PJM Zones in Maryland. APS 17%, BGE 100%, Pepco 61.9% (includes SMECO), DPL 31%.

3. Determine the hourly load by the residual Maryland share of zone load

[1] Load was assigned to the portion the Maryland portion of the PJM utility zones based upon the most recently available PJM BRA 2018/2019 Load Pricing Results.

4. Calculate the average of the loads by the four time periods.

5. Calculate the indexed load for the four periods.

   The indexed load is defined as the actual hourly load divided by the average load over each of the four periods (same formula applies to the indexed prices).

Second Work Process: Read in hourly price data for all four Zones and periods in Maryland.

1. Read in the hourly prices by zone

2. Compile the data into the four time periods.

3. Apply the load weights (calculated outside the SAS program) to the hourly prices by zone.

4. Sum prices across the four zones by the four time periods.

5. Calculate the average of the prices by four periods

6. Calculate the indexed price (load for hour/avg. load for four periods.

Third Work Process: Merge the indexed loads and indexed prices by four periods.

1. The indexed price for each bin was calculated and merged with the indexed loads by the four time periods.

2. Calculate the Maryland load weighted average, based on the load and price in each of the resulting sixteen specific Maryland time periods (four zones x four time periods).

Fourth Work Process: Perform the regressions.

A regression model was run to determine the relationship between price and load for each period and each utility zone. Index prices were estimated on an hourly basis.

Regression formula:

$IP_t = \beta_0 + \beta_1 * IL_t$

Where, IP_t is the Indexed Price for time *t* and IL_t is the Indexed load for time *t*. *(Indexed prices were estimated on an hourly basis).*

Maryland Aggregated Load Weighted Regression Results:

For each 1% reduction in load, prices decrease by the following amount: (Note: these are from the All Sourced Zones, not individual Zones as represented in the dollars figures further below).

- Summer On Peak: 1.6672%
- Summer Off Peak: 1.6128%
- Non-Summer On Peak: 4.5792%
  Non-Summer Off Peak: 3.1338%

Fifth Work Process: The calculation to derive the estimated energy capacity price mitigation of $1.42 per MWh of AMI savings.

The 1% load reduction parameter estimate has been further adjusted to reflect the proportion of PDPL AMI savings to all Maryland load. The adjusted parameter estimates were then applied to residual average energy load and average price for each time period to yield the estimates savings in a given year. This total amount of annual savings in energy mitigation across Maryland is then divided by the total DPL annual AMI MWhs of savings in a specific year to determine the avoided energy price mitigation value per MWh of AMI savings each year. This value is approximately $1.42 per AMI reported MWh of savings.

The formula is: $1.42/ MWh of AMI Savings = (DPL AMI Savings/Residual Maryland Sales) x (Parameter Estimate) x (Price) x Residual Maryland Sales) / DPL AMI Savings

WBS Element	Project Title	Family	Project Conceived Date	Driver of Project	% Overload	Faciltiy	Ratings Normal	Emergency	Projected Load after Completion	Original Service Date	Revised Project Service Date	Rational for Deferrment	Expected Completion Date
UDLBLM7C1	Chesapeake College - Distribution Lines Upgrades (UDLBLM7C1)	Chesapeake College Upgrades	May-16	Pilot project to develop advanced control and lower cost secure communications to DERs (Distributed Energy Resources)	-	Wye Mills Sub. Feeder MD2248	18.0	18.0	13.0	3/31/2017	-	-	03/31/17
UDSBLM77A	Chesapeake College - Substation (UDSBLM77A)									3/31/2017	-	-	03/31/17
UDLBLM7S3	Convert Muskrattown Road to 25kV (UDLBLM7S3)	Convert Muskrattown Road to 25kV	May-16	Voltage Deficiency	Bishop Sub. MD2295 Voltage Drop = 7.6%	Bishop Sub. Feeder MD2295	22.5	22.5	11.5	6/1/2016	-	-	06/01/16
UDSNLFC2	Crest Substation - Establish 230-34kv Substation (UDSNLFC2)	Crest New Substation	May-07	Substation Overload	Cecil Sub. Overload = 3%	Cecil Sub.	-	119.5	97.8	5/31/2013	05/31/19	Loads in the area lower than predicted	05/31/18
UDLNLFC1	Crest: Extend 4 New Feeders (UDLNLFC1)												
UDSBLBR2	Establish 69-12KV Lakeside(Barber road)Substation (UDSBLBR2)	Lakeside New Substation	May-07	Substation Overload	Trappe Sub. Overload = 3%	Trappe Sub.	-	29.0	19.4	10/31/2010	10/31/20	Loads in the area lower than predicted	10/31/20
UDLBLBR1	Lakeside: Construct 2 New Feeders (UDLBLBR1)												
UDSBLMC2	McCleans - Establish 69/25kV Substation (UDSBLMC2)	McCleans New Substation	May-07	Feeder Overload	Chestertown Sub. MD2245 Overload = 2%	Chestertown Sub. Feeder MD2245	22.5	22.5	10.5	5/31/2012	12/31/19	Loads in the area lower than predicted	12/31/19
UDLBLMC1	McCleans: Construct 2 New Feeders (UDLBLMC1)												

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 10

WITH REFERENCE TO THE DIRECT TESTIMONY OF KAREN LEFKOWITZ ON PAGE 48, LINES 3-10:

A. PLEASE QUANTIFY THE BENEFITS AND COSTS ATTRIBUTABLE TO THE COMPANY'S PEAK ENERGY SAVINGS PROGRAM;
B. PLEASE PROVIDE SUPPORTING DOCUMENTATION AND CALCULATIONS IN ELECTRONIC FORMAT WITH ALL FORMULAE INTACT USED BY THE COMPANY TO QUANTIFY THE BENEFITS AND COSTS ATTRIBUTABLE TO ITS DYNAMIC PRICING PROGRAM;
C. PLEASE INDICATE THE DATES OF ALL PESC EVENTS SINCE THE SUMMER OF 2012;
D. PLEASE STATE THE ANNUAL NUMBER OF ANTICIPATED PESC EVENTS USED IN THE COMPANY'S DETERMINATION OF PESC EVENTS;
E. PLEASE PROVIDE THE ANNUAL AMOUNT OF BILL CREDITS PAID BY THE COMPANY FOR PESC EVENTS;
F. PLEASE PROVIDE THE PROJECTED ANNUAL AMOUNT OF BILL CREDITS TO BE PAID BY THE COMPANY FOR FUTURE PESC EVENTS;
G. PLEASE STATE THE NUMBER OF PARTICIPANTS FOR EACH PESC EVENT;
H. PLEASE DEFINE WITH REASONABLE SPECIFICITY PARTICIPANTS AND NON-PARTICIPANTS FOR THE PEAK ENERGY SAVINGS PROGRAM; AND,
I. PLEASE STATE WHETHER THE COMPANY ADJUSTS FOR FREE-RIDERSHIP IN ITS PESC EVENTS. IF SO, PLEASE EXPLAIN AND QUANTIFY. IF NOT, PLEASE EXPLAIN WHY THE COMPANY DOES NOT ADJUST FOR FREE-RIDERSHIP IN ITS PESC EVENTS.

RESPONSE:

A. Please see OPC DR 1-3 Attachment KRL-C.

B. Please see OPC DR 1-3 Attachment KRL-C.

C. Please refer to the Delmarva Power AMI quarterly metrics filings in Case No. 9207.

D. For cost-effectiveness modeling purposes, the Company has assumed that four PESC events will be called each summer beginning in 2016. These calls would be initiated by either PJM or by Delmarva Power.

E. 2014 -- $34,401
2015 -- $2,513,869 (includes $4,015 paid during early 2016)

2016 – Not yet available

F. The Company has forecast that $4,050,000 of PESC billing credits will be paid during 2016. Delmarva Power has not forecast PESC billing credit amounts for the period of 2017 through 2024.

G. Please refer to the Delmarva Power AMI quarterly metrics filing in Case No. 9207.

H. Participants are defined as those customers who have earned a bill credit by reducing their electricity use during a PESC event below their established Customer Baseline Load level as described in Delmarva Power's PESC Commission approved rate tariff, Rider DP. A non-participant is defined as a customer who did not earn a bill credit during a PESC event.

I The Company performs panel regression modeling to further examine PESC Program performance. It is difficult to determine what constitutes a "free rider" -- presumably the definition would be a customer who takes no action, but earns a bill credit. However, such a definition would not appropriately cover a customer who intentionally took a vacation during a hot weather event and as a result raised the temperature setting for their air conditioner. Note that there are likely to be many other customers who are "underpaid riders" – customers who do not earn a bill credit, but have taken steps to reduce their load during an event. This is caused by the use of a Customer Baseline Load to determine what energy use would have occurred in absence of an event.

SPONSOR: Karen R. Lefkowitz

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. 17

PLEASE IDENTIFY ANY DPL MARYLAND PLANNED DISTRIBUTION SUBSTATION PROJECTS THAT WERE CANCELED OR DELAYED DUE TO THE AMI INVESTMENT, AND DOCUMENT THAT THE AMI LOAD REDUCTIONS WERE CRITICAL IN THE CANCELATION OR DELAY.

RESPONSE:

Reduction in the load forecast that results in cancelled or delayed Delmarva Power planned distribution substation projects has many causes, including AMI-related load reductions. Two substations, McCleans Substation (an in-service date of 2019) and Crest Substation (an in-service date of 2018), experienced deferrals based on a reduction in the load forecast. These two substations are moving forward based on the added reliability benefit customers would realize.

SPONSOR: Bryan L. Clark

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. 18

PLEASE IDENTIFY ANY DPL TRANSMISSION PROJECTS THAT WERE CANCELED OR DELAYED DUE TO THE AMI INVESTMENT, AND DOCUMENT THAT THE AMI LOAD REDUCTIONS WERE CRITICAL IN THE CANCELATION OR DELAY.

RESPONSE:

Delmarva Power has not delayed or cancelled any projects from the transmission capital budget because of AMI. Transmission projects are determined by PJM and they identify the need for new facilities based on he projected load. Since the projected loads have been reducing over the past few years PJM has not identified any new projects needed for reliability reasons to serve new load. This reduction in load directly results in deferral of the need for new projects. Reduced loads are a result of many reasons including reductions resulting from AMI, dynamic pricing, CVR and other energy efficiency initiatives.

SPONSOR: Bryan L. Clark

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. 22

FOR EACH DPL MARYLAND AMI-ENABLED DR PROGRAM, PLEASE PROVIDE THE FOLLOWING DATA FOR DELIVERY YEAR 2012/13 THROUGH 2015/16:

A. CLEARED CAPACITY FOR THE PROGRAM, IN THE BRA AND ANY OTHER AUCTIONS OR TRANSACTIONS IN WHICH DPL CHANGED ITS CAPACITY OBLIGATION.
B. THE ACTUAL CAPACITY THAT PJM FOUND DPL HAD DELIVERED.
C. ACTUAL CAPACITY PAYMENTS THAT DPL HAS RECEIVED FROM PJM OR ANY OTHER COUNTERPARTY.
D. ACTUAL PAYMENTS FROM DPL TO PJM OR ANY OTHER COUNTERPARTY TO REDUCE ITS DELIVERY OBLIGATIONS OR COMPENSATE FOR FAILURE TO DELIVER CAPACITY AS CONTRACTED.
E. THE MWHS OF ECONOMIC AND EMERGENCY ENERGY DELIVERED TO PJM,.
F. ACTUAL ENERGY PAYMENTS THAT DPL HAS RECEIVED FROM PJM OR ANY OTHER COUNTERPARTY.

RESPONSE:

A. For the referenced time period, the PESC Program participated in the first incremental auction for the 2015/2016 Delivery Year and cleared at 10.4 MW of unforced capacity.
B. Delmarva Power delivered the 10.4 MW commitment.
C. Delmarva Power received $422,510 in capacity revenue.
D. Delmarva Power made no payments to PJM or any other counterparty.
E. Zero.
F. Zero.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 5

QUESTION NO. 25

REFERRING TO DPL'S USE OF THI IN ESTIMATING THE EFFECTS OF AMI-ENABLED PROGRAMS (E.G., IN CVR, FARUQI, P.13), PLEASE PROVIDE THE FOLLOWING:

A. THE FORMULA USED TO CALCULATE THE THI;
B. ALL INPUT DATA USED IN THE CALCULATION OF HOURLY THI; AND,
C. HOURLY THI FROM JUNE 1 FOR SEPTEMBER 30 FOR 2014 AND 2015, AND FOR ANY DATA AVAILABLE FOR 2016.

RESPONSE:

A. THI = (0.55 * Temperature) + (0.2 * Dewpoint) + 17.5.
B. Please refer to OPC DR 5-25 Attachment A (electronic only).
C. Please refer to OPC DR 5-25 Attachment B (electronic only). THI have not been calculated for any days in 2016.

SPONSOR: Ahmad Faruqi

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO STAFF DATA REQUEST NO. 6

QUESTION NO. 24

From 2014 to 2015, please provide a listing of the days that DPL called for Dynamic Pricing (DP).

RESPONSE:

Please refer to the table below:

Date	Time
8/27/2014	2- 6 PM
9/2/2014	2- 6 PM
7/30/2105	2- 6 PM
8/3/2015	2- 6 PM
9/9/2015	2- 6 PM

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO STAFF DATA REQUEST NO. 6

QUESTION NO. 26

From 2014 to 2015, please provide a listing of the DPL DP days when PJM called for load reduction.

RESPONSE:

PJM did not call for any load reductions during 2014 and 2015.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO STAFF DATA REQUEST NO. 6

QUESTION NO. 31

Were there any transmission or distribution expansion projects in the last 8 years (2008 to 2016) that were planned and then withdrew or deferred due to DPL's DP?

RESPONSE:

Please see the table below, which includes distribution expansion projects in the last eight years that were planned and then withdrew or deferred due to reduction in the load forecast. Reduction in the load forecast that results in cancelled or delayed Delmarva Power planned distribution substation projects has many causes, including AMI-related load reductions. Please also refer to the response provided to OPC DR 27-4. There were no identified PJM baseline projects at 230 kV or above for the Delmarva Power Maryland service territory driven by load level requirements that went into service between 2008 and 2016. Please refer to the response to OPC DR 27-7 for additional transmission information.

Planned Date	Substation	Capacity (MVA)	Voltage (kV)	Asset Expanded	Driver	Status	Date Deferred
1/22/2013	Crest	112	34	Substation	Load Relief	Deferred	12/31/2018
05/31/2013	McCleans	37	25	Substation	Load Relief	Deferred	12/31/2019
5/31/2014	Queenstown	28	25	Substation	Load Relief	Cancelled	N/A
12/31/2016	Lakeside	28	12	Substation	Load Relief	Deferred	12/31/2025

SPONSOR: Bryan L. Clark

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO STAFF DATA REQUEST NO. 6

QUESTION NO. 32

If yes, please provide a detailed list of projects (including the original project service date, the date the decision was made to defer or cancel the project, the new service date for the project, the original project cost estimate, the current project cost estimate, and a detailed explanation for the project deferral.

RESPONSE:

Please see the table below for the information requested.

Project	**Need Date**	**Need Date Current**	**Original Cost Estimate* (millions $)**	**Current Cost Estimate* (millions $)**	**Comments**
McCleans Substation	5/31/2013	12/31/2019	6.4	11.1	Deferred due to reduced load forecast
Queenstown Area Substation	5/31/2014	Cancelled	5.7	N/A	Cancelled in 2014 due to reduced load forecast
Lakeside Area Substation	10/31/2011	12/31/2025	6.1	5.6	Deferred due to reduced load forecast
Crest Substation	1/22/2013	12/31/2018	19.6	18.25	Deferred due to reduced load forecast

*Cost estimates are reflective of substation costs only

SPONSOR: Bryan L. Clark

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 1

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 6, EWR: PLEASE EXPLAIN HOW SAVINGS FROM THE EWR PROGRAM WERE EXCLUDED FROM SAVINGS COUNTED FOR PESC EVENTS. AND, PLEASE DISCUSS HOW DPL INCLUDES EWR SAVINGS THAT ARE ELIGIBLE FOR PESC PARTICIPATION.

I. THE HOURS FOR WHICH THE INCENTIVE WAS COMPUTED,
II. THE LEAD TIME FOR NOTIFICATION OF CUSTOMERS OF THE PEAK SAVINGS DAY.

RESPONSE:

The stated Testimony reference page appears to be incorrect. Dynamic pricing incentives that are in excess of EWR credits are paid to EWR customers. The Company's regression modeling impact of dynamic pricing excludes EWR participants to provide a conservative estimate of performance.

I. Incentive payments for dynamic pricing customers are calculated for the specific dynamic pricing event hours. Table 3 of Witness Giovannini provides the dynamic pricing event hours.
II. The Company attempts to notify all eligible customers about a dynamic pricing event the evening before the event takes place. The minimum required notification time is 2 hours.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 3

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 7:

A. PLEASE PROVIDE A BREAKDOWN OF DPL'S CLEARED DR CAPACITY AND EE CAPACITY IN EACH DELIVERY YEAR 2014/15 TO 2019/20, IDENTIFYING THE CLEARED CAPACITY (MW) FROM EACH DPL AMI ENABLED DR PROGRAM BY CONTRIBUTING CUSTOMER CLASS.
B. PLEASE PROVIDE THE PJM ANNUAL CAPACITY REVENUE FOR EACH DPL AMI ENABLED DR PROGRAM BY RESIDENTIAL AND NON-RESIDENTIAL CONTRIBUTIONS.
C. FOR EACH DPL DR PROGRAM, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS AN ANNUAL, LIMITED OR EXTENDED SUMMER RESOURCE, FOR EACH YEAR THROUGH DY 2017/18.
D. FOR EACH DPL AMI ENABLED DR PROGRAM CLEARED FOR DY 2016/17 OR DY 2017/18, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS CAPACITY PERFORMANCE IN THE SUBSEQUENT TRANSITION INCREMENTAL AUCTION.
E. FOR EACH DPL DR PROGRAM (EWR, DP, EMT) CLEARED IN BRAS FOR DY 2018/19 OR 2019/20, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS CAPACITY PERFORMANCE, BASE CAPACITY OR BASE CAPACITY GENERATION.
F. PLEASE PROVIDE THE AMOUNT OF ANNUAL CAPACITY (MW) BID INTO THE PJM BRAS FOR EACH OF DPL'S DR (EWR, DP, EMT) PROGRAMS FOR DY 2015/16 – DY 2019/20.
G. PLEASE PROVIDE THE AMOUNT OF ANNUAL CAPACITY (MW) CLEARED IN THE PJM BRAS FOR EACH OF DPL'S DR PROGRAMS (EWR, DP, EMT) FOR DY 2015/16 – DY 2019/20.

RESPONSE:

A. Dynamic Pricing (DP) is the only one of Delmarva Power's demand response programs that is both AMI-enabled and has cleared in the PJM capacity market. All participants in Delmarva Power's DP program are residential customers. Delmarva Power's cleared capacity from DR and EE resources, by delivery year is:

Delivery Year	EWR	DP	EE
2014/2015	39.9		8.1
2015/2016	29.3	10.4	12.1
2016/2017	39.4	47.4	15.7
2017/2018	26.4	47.5	27.8
2018/2019	28.2	50.9	9.6
2019/2020	27.0	48.0	8.2

B. Please refer to the response provided to OPC DR 13-2. All participants in the DP Program are residential customers.

C. Delmarva Power's EWR and DP programs cleared as extended summer resources in the DY 2015/2016 through DY 2017/18. In DY 2014/2015, EWR capacity from participants who chose the 100% cycled option cleared as a limited resource and EWR capacity from participants who chose the 50% or 75% cycled options cleared as an extended summer resource.

D. Delmarva Power's DP program did not clear as a capacity performance resource in either transition incremental auction.

E. The EMT program has never been offered into the capacity market. EWR and DP cleared as base capacity in the DY 2018/2019 and DY 2019/2020 capacity auctions.

F. The annual capacity (MW) offered into the PJM BRAs in DY 2015/2016 through DY 2019/2020 for Delmarva Power's EWR and DP programs is:

Delivery Year	EWR	DP
2015/2016	55.3	
2016/2017	39.4	47.4
2017/2018	26.4	47.5
2018/2019	28.2	50.9
2019/2020	27.0	48.0

G. Please refer to the table provided in response to part (f). All of the capacity offered into the PJM BRAs in DY 2015/2016 through DY 2019/2020 for Delmarva Power's EWR and DP programs cleared the auctions.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 4

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P.7. DYNAMIC PRICING PROGRAM. PLEASE PROVIDE:

A. THE "VALUE OF ESTABLISHED BID POSITIONS" FOR THE DP PROGRAM BY DELIVERY YEAR.
B. ALL CALCULATIONS AND WORKSHEETS THAT WERE USED TO ESTIMATE ACTUAL LOAD REDUCTIONS THROUGH DYNAMIC PRICING.
C. THE MEASUREMENT ALGORITHM THAT PJM HAS APPROVED FOR DPL'S DP PROGRAM.
D. ALL SUBMISSIONS AND FILINGS IN WHICH PJM HAS DOCUMENTED AND/OR CLAIMED LOAD REDUCTIONS FOR THE DP PROGRAM.
E. ALL STUDIES USED TO ASSESS DPL CONSUMERS' RESPONSIVENESS TO DYNAMIC PRICING.
F. A LIST OF ALL PESC EVENT DATES AND TIMES.

RESPONSE:

A. Please refer to the table provided in the response to OPC DR 13-2 for the value of established bid positions for the DP program.
B. Please refer to the response provided to OPC DR 13-28.
C. The measurement of performance in the PJM capacity market is Firm Service Level.
D. The available PJM documents are attached. Please refer to OPC DR 13-4 Attachment A (confidential), Attachment B (confidential), and Attachment C (confidential).
E. Pepco conducted panel regression modeling on the dynamic pricing results for the summers of 2014 and 2015. Please see OPC DR 13-4 Attachment D (confidential) and Attachment E (confidential).
F. Please refer to the Delmarva Power AMI metrics filing in Case No. 9207.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 7

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 9. PLEASE EXPLAIN HOW DPL IMAGINES EACH OF THESE POTENTIAL PROGRAMS OPERATING, AND FOR EACH PROGRAM:

A. EXPLAIN HOW THE EVENT DAYS (OR PEAK SAVINGS DAYS) AND HOURS WOULD BE DETERMINED.

B. EXPLAIN HOW THE PROGRAM WOULD BE JUSTIFIED IF IT DID NOT RECEIVE ANY PJM CAPACITY CREDIT.

RESPONSE:

Delmarva Power has identified the following options for discussion purposes, however these options or others should be considered through a Maryland stakeholder process. Note that the future PJM market structure and associated rules are also likely to be modified over time and these changes will influence the manner that demand response programs should be designed and operate in Maryland.

Option 1 – Demand Response Portfolio Standard – All electricity suppliers would be required to match a percentage of their peak electric load sales in Maryland with Maryland sourced demand response resources. The price of the Maryland sourced demand resources could be established through a competitive bid process or via a Commission established pricing schedule.

Option 2 – Funding via the EmPOWER Surcharge – The dynamic pricing credit funding could be provided through the existing EmPOWER Surcharge.

Option 3 – Delmarva Power's existing dynamic pricing could be modified from a bill rebate program to a critical peak pricing program, whereby prices would be higher during peak event hours and lower during other hours.

A. The selection of peak event days would be based upon one or more of the following factors: 1) PJM day ahead energy prices, 2) forecast regional electricity loads, 3) PJM and distribution system emergency conditions, and 4) temperature and humidity conditions.

B. The program would be justified by avoided capacity and energy costs, capacity and energy price mitigation, air emissions reductions, deferring/avoiding additional transmission and distribution projects, helping to ensure the continuing reliability of electricity supply during high load periods, achieving Maryland demand reduction goals, and motivating Delmarva Power Maryland customers to lower their electricity use and their resulting electric bills.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 8

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P 11 :

A. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE DP PROGRAM BEGINNING JUNE 1, 2020.

B. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE DP PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL FOR RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS..

C. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE DP REDUCTION IN PEAK LOADS IN THE SUMMER OF 2020 WOULD AFFECT CAPACITY OBLIGATIONS IN THE DPL ZONE IN EACH YEAR FROM 2020 TO 2024.

D. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE CVR PROGRAM.

E. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE CVR PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL.

F. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE CVR REDUCTION IN PEAK LOADS IN THE SUMMER OF 2014 WOULD AFFECT CAPACITY OBLIGATIONS IN THE DPL ZONE IN EACH YEAR FROM 2014 TO 2024.

G. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE EMT PROGRAM.

H. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE EMT PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL.

I. PLEASE EXPLAIN HOW DPL ESTIMATED THE EXTENT TO WHICH THE EMT REDUCTION IN PEAK LOADS IN THE SUMMER OF 2017 WOULD AFFECT CAPACITY OBLIGATIONS IN THE DPL ZONE IN EACH YEAR FROM 2018 TO 2024.

RESPONSE:

A. Please refer to the response provided to OPC DR 13-28 (a).

B. Delmarva Power's dynamic pricing only affects the Company's residential loads. During the time that the dynamic pricing program participates in the PJM capacity market, for PJM capacity market purposes, an unrestricted load forecast is developed that excludes the impacts of dynamic pricing. Beginning with PJM Delivery Year 2020/21 it is assumed that demand reductions achievable by dynamic pricing will result in an adjustment in the PJM load forecast for the Delmarva Power Zone. PJM is aware of the specific aspects of the Company's dynamic pricing program.

C. The assumed peak impact of the dynamic pricing program was estimated through reliance on the most recently established PJM capacity market positions for the program.

D. Please refer to Company Witness Faruqui's Direct Testimony and Schedule (AF)-3.

E. Delmarva Power has assumed that there will be a four year lag in the recognition of achieved capacity reductions for the program. Refer to OPC DR 1-3, Attachment KRL-C, Tab CVR Benefits for the specific assumptions.

F. Refer to OPC DR 1-3, Attachment KRL-C, Tab CVR Benefits.

G. Please refer to Company Witness Faruqui's Direct Testimony and Schedule (AF)-2.

H. Delmarva Power has assumed that there will be a four year lag in the recognition of achieved capacity reductions for the program. Refer to OPC DR 1-3, Attachment KRL-C, Tab EMT Benefits for the specific assumptions.

I. Refer to OPC DR 1-3, Attachment KRL-C, Tab EMT Benefits.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 13

DOES MR. GIOVANNINI AGREE THAT THE DP, CVR AND EMT PROGRAMS REDUCE CAPACITY OBLIGATIONS IN THE DPL ZONE ONLY TO THE EXTENT THAT THEY REDUCE PJM'S FORECAST OF ZONAL PEAK LOAD?

A. IF NOT, PLEASE EXPLAIN WHY, AND HOW ELSE MR. GIOVANNINI BELIEVES THE PROGRAMS AFFECT CAPACITY OBLIGATIONS IN THE DPL ZONE.

RESPONSE:

Yes, the CVR and EMT Programs do so. During the years that the DP Program is accepted into the PJM capacity market a supply side resource, it affects the supply side of the market rather than the demand side of the market. During the years that DP operates on the demand side, the statement is accurate.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
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RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 18

HAS DPL REQUESTED THAT PJM ESTIMATE THE EFFECT OF THE DP, CVR AND EMT LOAD REDUCTIONS ON CAPACITY PRICES BY ZONE?

A. IS MR. GIOVANNINI FAMILIAR WITH THE PJM SENSITIVITY SCENARIOS FOR THE RPM AUCTIONS?

B. PLEASE EXPLAIN WHETHER DPL'S CAPACITY PRICE MITIGATION ASSUMPTIONS ARE CONSISTENT WITH PJM'S ESTIMATES OF THE EFFECTS OF CHANGING SUPPLY OR DEMAND, AS INDICATED BY THE SENSITIVITY SCENARIOS.

C. IF PJM'S ESTIMATE OF THE EFFECT OF CHANGING DEMAND ON CAPACITY PRICES IS DIFFERENT FROM DPL'S ESTIMATE BASED ON THE METHODOLOGY DPL USED IN CASE NO. 9155, WOULD MR. GIOVANNINI AGREE THE PJM ESTIMATES ARE MORE RELIABLE?

RESPONSE:

No.

A. Yes.

B. Delmarva Power has not studied PJM's calculations to determine their consistency with the Maryland Commission established mitigation methodology.

C. No, Witness Giovannini is not familiar with all of the modeling assumptions made by PJM.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 20

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 17 AT 7-10:

A. PLEASE PROVIDE ALL REGRESSION MODELING AND DATA USED TO COMPARE HOURLY ENERGY LOAD TO REAL TIME PJM LMPS FOR EACH MARYLAND ZONE BETWEEN JANUARY 1, 2013 AND AUGUST 31, 2015.

B. EXPLAIN WHY REAL-TIME PJM LMPS WERE USED AND NOT DAY-AHEAD.

C. PROVIDE ANY REGRESSION MODELING UTILIZING PJM DAY AHEAD LMPS IN COMPUTER-READABLE FORMAT (EXCEL OR EQUIVALENT).

D. PLEASE CONFIRM WHETHER DR. FARUQUI WAS INVOLVED IN THE PANEL REGRESSION ANALYSIS PERFORMED BY THE BRATTLE GROUP THAT WAS CONDUCTED TO ASSESS CUSTOMER REDUCTIONS ATTRIBUTED TO THE DP PROGRAM PERFORMED BY THE BRATTLE GROUP, AND IF SO, PLEASE DESCRIBE HIS ROLE.

E. PLEASE PROVIDE THE PANEL REGRESSION RESULTS INCLUDING ALL STATISTICAL OUTPUTS.

RESPONSE:

A. Please see the attached files used for the regression modelling and data used.
Attachment A: APS-BGE-Hourly LMP (electronic only)
Attachment B: DPL-Pepco- Hourly LMP (electronic only)
Attachment C: APS by SEA TOU w Revised MD Share of Zone
Attachment D: BGE by SEA TOU w Revised MD Share of Zone
Attachment E: DPL by SEA TOU w Revised MD Share of Zone
Attachment F: Pepco by SEA TOU w Revised MD Share of Zone
Attachment G: Zones Combined by SEA TOU w Revised MD Share of Zone
Attachment H: Pepco and DPL Maryland Load corresponding to LMP (electronic only)
Attachment I: BGE and APS Maryland Load corresponding to LMP (electronic only)

B. Real-time PJM LMPs represent the actual prices in the PJM wholesale market given the load and supply conditions. Day-Ahead PJM LMPs provide a forecast of day-ahead electric loads and supply conditions. Delmarva Power relied on actual load and actual energy prices for its analysis.

C. The Company did not perform this modeling.

D. Yes, the Brattle Group performed the summer 2014 modeling and Delmarva Power performed the summer 2015 modeling. The Brattle Group reviewed and confirmed the 2015 modeling results. Witness Faruqui oversaw the Group analysts who performed this work.

E. Please refer to the response to OPC DR 13-28, Part A.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 22

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 20, TABLE 3: PESC EVENT DAYS:

A. PLEASE INDICATE FOR EACH EVENT DATE IF IT WAS A PJM-CALLED EVENT, AND IF SO, THE TYPE OF PJM EVENT.

B. PLEASE UPDATE THE PESC PROGRAM EVENT DPL SETTLEMENT INFORMATION PROVIDED IN TABLE 3 TO INCLUDE THE SAME INFORMATION FOR EACH EVENT OCCURRING IN 2014 AND 2016. PLEASE CLARIFY WHETHER THE PESC PROGRAM EVENTS (DAYS AND HOURS) ARE THE SAME AS THE PEAK SAVINGS DAYS (GIOVANNINI, P. 7), AND IF NOT, HOW THOSE EVENTS DIFFER.

C. PLEASE PROVIDE FOR EACH EVENT DATE INDICATED, HOURLY AMI INFORMATION FOR A FULL 48 HOURS STARTING 24 HOURS PRIOR TO THE EVENT DATE.

D. PLEASE CONFIRM, FOR EACH EVENT, THE NUMBER OF PESC CUSTOMERS PARTICIPATING IN OTHER DPL DEMAND SIDE MANAGEMENT PROGRAMS? PLEASE IDENTIFY THOSE CUSTOMERS FOR EACH HOUR FOR EACH PESC EVENT INDICATING THE OTHER DPL DSM PROGRAMS THEY ARE PARTICIPATING IN AND THE AVERAGE HOURLY SAVINGS ASSUMED FROM EACH OF THOSE OTHER PROGRAMS.

RESPONSE:

A. There were no PJM-called events during 2015.

B. During the summer of 2014, Delmarva Power's Dynamic Pricing Program was available to a limited number of customers as part of the phase-in introduction. The requested information is provided in Delmarva Power's AMI Metrics Report in Case 9207. There have been two Delmarva Power Dynamic Pricing events during the summer of 2016 through August 16^{th}. Those event dates were: July 8, 2016 during the hours of 1 pm to 5 pm and on July 14, 2016 during the hours of 2 pm to 6 pm. Additional details related to those operational dates are not yet available.

C. Please refer to the Company's response to OPC DR 5-24. Only a small group of Delmarva Power customers participated in the Program during the summer of 2014, therefore a similar data set for this period is not meaningful.

D. The types and participation levels of customers in other demand side management programs can be found in Delmarva Power's EmPOWER reports, which are available on the Commission website in Case No. 9156. EWR participants were excluded from the panel regression modeling for PESC and therefore are exclude from the results.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 26

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 20: PLEASE EXPLAIN HOW THE COSTS OF THE REBATES PAID TO INDUCE CUSTOMERS TO PARTICIPATE IN THE DP PROGRAM ARE ACCOUNTED FOR IN THE COST BENEFIT ANALYSIS.

RESPONSE:

The cost of bill credits are treated as a transfer payment and not included in the cost-effectiveness analysis as is customary in Maryland. This is consistent with the treatment of transfer costs for cost-effectiveness in the EmPOWER Maryland proceeding under the Total Resource Cost Test (Case No. 9156), the treatment of direct load control program incentives (Case Nos. 9156 and 9155), and the treatment of transfer costs in the smart grid proceeding (Case No. 9207). The Commission recently affirmed this cost-effectiveness treatment in its BGE rate case Order No. 87591, p. 64.

SPONSOR: Karen Lefkowitz/Ahmad Faruqui

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 28

WITH REFERENCE TO GIOVANNINI DIRECT TESTIMONY, P. 20 AT 13-15:

A. PLEASE PROVIDE THE REGRESSION MODEL AND ALL DATA, IN ELECTRONIC FORMAT, WHICH DPL UTILIZED IN THE MODELING OF THE DP EVENTS DURING THE SUMMERS 2014-2016

B. IF DPL SUBCONTRACTED THE EVALUATION OF THE PESC PROGRAM DEMAND REDUCTION CAPABILITY, PLEASE INDICATE THE FIRM OR INDIVIDUAL RESPONSIBLE FOR THE ANALYSIS AND THE PRIMARY AUTHOR.

C. PLEASE EXPLAIN HOW THE ENERGY CONSUMPTION RESULTS FROM THE DP PANEL REGRESSION HAVE BEEN APPLIED IN DPL'S AMI COST EFFECTIVENESS ANALYSIS, SPECIFICALLY, PLEASE IDENTIFY EACH BENEFIT IDENTIFIER (GIOVANNINI, TABLE 1 P.5) WHERE THE DP PANEL REGRESSION RESULTS ARE USED AS AN INPUT.

RESPONSE:

A. Attachment A, B and C contain the interval data for the customers, Attachment D contains the weather data and Attachment E contains customer information. Below are the formats for the three files.

MD 9424 OPC DR 13-28 Attachment A Confidential.csv (electronic only)
MD 9424 OPC DR 13-28 Attachment B Confidential.csv (electronic only)
MD 9424 OPC DR 13-28 Attachment C Confidential.csv (electronic only)

Variables:	**Description**
ServicePointID	Customer ID
Operatingdate	Date (**MM/DD/YYYY**)
H1-H24	Hourly kwh

MD 9424 OPC DR 13-28 Attachment D.csv (electronic only)

Variables:	**Description**
Operatingdate	Date (**MM/DD/YYYY**)
Hour	Hour
WTHI	Weighted Temperature Humidity Index

MD 9424 OPC DR 13-28 Attachment E Confidential.csv (electronic only)

Variables:	**Description**
ServicePointID	Customer ID

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 34

PLEASE CONFIRM WHETHER IT IS LIKELY THE SOME OF THE DPL DP CUSTOMERS WHO RECEIVE PESC REBATES WERE NOT RESPONDING TO THE PROGRAM AND EXPLAIN HOW DPL ACCOUNTS FOR SUCH POTENTIAL FREE-RIDERSHIP IN LOAD REDUCTION CALCULATIONS ASSOCIATED WITH THE DP PROGRAM.

RESPONSE:

Yes. It is also likely that there are other customers who take energy reduction actions, but do not earn a bill credit because of the manner that Customer Baseline Loadshapes are used to indicate participation. Delmarva Power relies on panel regression modeling to indicate the level of reductions achieved, but this will tend to understate the reductions achieved by the program due to the exclusion of EWR participants and the exclusion of customers who do not appear to have reduced load, but actually did so.

SPONSOR: Karen R. Lefkowitz.

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 41

WITH REFERENCE TO LEFKOWITZ DIRECT TESTIMONY, P. 48: REFERRING TO THE PESC PROGRAM, PLEASE PROVIDE THE FOLLOWING:

A. PLEASE PROVIDE ALL SUPPORTING WORKSHEETS AND CALCULATIONS USED TO ESTABLISH THE PESC BILL CREDIT AMOUNT OF $1.25 PER KWH.
B. PLEASE EXPLAIN WHETHER THE $1.25 CREDIT WAS INTENDED TO REFLECT THE PROJECTED PJM CAPACITY MARKET REVENUES AND WHETHER OR NOT THIS RATE WAS DEVELOPED AS A REVENUE-NEUTRAL RATE.
C. PLEASE PROVIDE AN EXAMPLE CALCULATION AND THE PROPOSED TARIFF LANGUAGE USED TO CALCULATE THE CUSTOMER BASE LINE (CBL).
D. PLEASE EXPLAIN HOW DPL DETERMINED THE DAYS IDENTIFIED AS PESC EVENT DAYS AND INCLUDE ANY ESTABLISHED GUIDELINES OR CRITERIA DPL USED TO MAKE SUCH DETERMINATIONS. IF SUCH FORMAL PROCESS EXISTS, PLEASE PROVIDE.
E. PLEASE PROVIDE THE MONTHLY NUMBER OF CUSTOMERS ELIGIBLE TO PARTICIPATE IN THE PESC PROGRAM SINCE 2014 AND PLEASE CONFIRM WHETHER THE PESC PROGRAM IS LIMITED TO ONLY RESIDENTIAL CUSTOMERS.
F. PLEASE DISCUSS THE CUSTOMER BASELINE CALCULATION METHODOLOGY AND PROVIDE AN EXAMPLE OF AN ELIGIBLE PARTICIPANT BUT NON-PARTICIPATING AND AN EXAMPLE FOR AN ELIGIBLE AND PARTICIPATING CUSTOMER.
G. PLEASE PROVIDE AN EXAMPLE CALCULATION FOR DETERMINING THE DEMAND SAVINGS FOR EACH HOUR OF A PESC EVENT.

RESPONSE:

A. Please refer to the response to OPC DR 13-6.
B. No, the rate was not intended to reflect PJM capacity revenues and it was not designed to be necessarily revenue neutral. The rate was guided by generation NET CONE.
C. Please refer to the response to OPC DR 13-29 for the DP tariff.
D. Please refer to the response to OPC DR 13-25.
E. Please refer to the Delmarva Power AMI Metrics filings in Case No. 9207. The PESC Program is available to residential distribution customers.
F. Please refer to OPC DR 13-41 Attachment for the example calculation of bill credits. To simplify the example, the duration of the event is set at 3 hours rather than the typical 4 hours. A description of the Baseline methodology is provided in the DP tariff. Please refer to OPC DR 13-29 for a copy of that tariff.
G. One kwh of savings for one hour is the equivalent of 1 kw of demand savings during that hour. PJM compares the Peak Load Contribution assigned to each customer to the actual hourly load to verify that the committed reductions have been achieved. The Company

statistically estimates the achieved reductions through panel regression modeling. The retail CBL calculation provides another estimate of the reductions achieved.

SPONSOR: Karen Lefkowitz

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 43

WITH REFERENCE TO LEFKOWITZ DIRECT TESTIMONY, P. 72: PLEASE EXPLAIN HOW SAVINGS FROM AMI ENABLED DR PROGRAMS ARE INCORPORATED INTO DPL'S LOAD GROWTH FORECASTS. WHAT DATE DID DPL START INCORPORATING LOAD REDUCTIONS INTO ITS FORECASTING MODELS AND HOW HAS THIS INFORMATION AFFECTED DPLS FORECASTED ENERGY SALES AND LOAD GROWTH FORECASTS?

RESPONSE:

Energy reductions that are sourced from the PESC Program are netted from the Company's energy load forecast. Delmarva Power relies on the PJM determined demand forecast and the Company does not net out DR program reduction capability from those figures. The Company has confirmed that it has adjusted its energy forecasts since the Commission approved the implementation of the Delmarva Power PESC Program.

SPONSOR: Karen Lefkowitz

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 28

QUESTION NO. 1

The following questions refer to Attachment KRL – L, Energy Price Mitigation:
Provide all supporting worksheets and documents used in each step of the work process flow in determining the energy price mitigation of a 1% change in load.

a. Please provide all supporting worksheets, calculations and data used in determining the Maryland utility shares of each for the four PJM zones.
b. Please provide the regression model and regression output results used to determine the energy price mitigation impact of $1.42/Mwh.
c. Please explain how weatherization normalization was achieved in the energy price mitigation regressions.
d. Please explain the methodology used to index prices on an hourly basis.
e. Please provide hourly WTHI for January 1, 2013 through most current available.
f. Please identify supporting worksheets or provide the annual DPL AMI savings from the DP, CVR, and EMT programs used to calculate the energy price mitigation impact.

RESPONSE:

a. Please refer to OPC DR 28-1 Attachment K (electronic only), Tab "Maryland Carve Out" which is the last tab in the workbook. The Company determined the following Maryland utility shares for each of the four PJM zones. Data used are based upon 2014-2015 sales.
   - Pepco Maryland is 61.9% of PJM Pepco zone, this incorporated SMECO within the Pepco Maryland zone.
   - Delmarva Maryland is 31% of the PJM Delmarva zone. This includes the Maryland Delmarva municipal loads in Maryland. Delmarva Power Maryland (including municipal cooperatives in Maryland) was based on 2014-2015 sales.
   - Potomac Edison (PE) Maryland is 17% of the PJM APS zone, based on load settlement from PE,
   - BGE Maryland is 100% of BGE zone

b. Please refer to OPC DR 28-1 Attachment K (electronic only). This file takes the load weighted average parameter estimates and calculates the energy price mitigation benefits that accrues to Maryland customers.

c. WTHI was not included in the analysis. OPC DR 28-1 Attachment J (electronic only) contains the requested WTHI data. WTHI in this data set are calculated using the following formula: WTHI = ((12 * THIt) + (3 * THIt-24) + (2 * THIt-48))/17 Where THI = (0.4 * Hourly Dry Bulb Temperature) + (0.4 * Hourly Wet Bulb Temperature) + 15.
   Note that this differs from the PJM WTHI calculation method.

d. Please refer to OPC DR 28-1 Attachments A-K. For the first and second work process as detailed in MD 9424 OPC DR 1-3 KRL Attachment L, refer to Attachments A and B for hourly prices. For the loads refer to Attachments H and I. In the Third work process, refer to the SAS files in Attachments C through G.

e. Please refer to OPC DR 28-1 Attachment J (electronic only).

f. At the time of filing of energy price mitigation, the savings estimates were used as depicted in OPC DR 28-1 Attachment L (electronic only).

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 28

QUESTION NO. 4

The following questions refer to Attachment KRL – K, Capacity Price Mitigation:
Please provide any information available to DPL regarding the actual slope of the capacity supply curve.

RESPONSE:

Delmarva Power does not have this information.

SPONSOR: Mario Giovannini

DELMARVA POWER & LIGHT COMPANY
MARYLAND CASE NO. 9424
RESPONSE TO OPC DATA REQUEST NO. 28

QUESTION NO. 5

The following questions refer to Attachment KRL – K, Capacity Price Mitigation:
Please explain the basis and provide any analysis supporting the stated assumptions, "Assumed 100% of slope b-c for AMI Metrics, and 50% for the AMI Rate Case." ('Capacity Mitigation Overview' tab).

RESPONSE:

Delmarva Power adjusted the mitigation calculation for this proceeding to be consistent with Commission Order No. 87082 in the EmPOWER Maryland proceeding. The basis for the 50% assumption is that the point at which the supply curve crosses the demand curve is unknown and the slope of the line is unknown. The 50% assumption provides a more conservative estimate of price mitigation effects than the 100% assumption relied on for the AMI metrics. This recommendation originated from the EmPOWER Maryland planning group established by the Maryland Energy Administration.

SPONSOR: Mario Giovannini

Cited Responses to Confidential Data Requests
Exhibit PLC-3 OMITTED

Valuing Demand Response
Ryan Hledik and Ahmad Faruqui
January 2015

Prepared for Enernoc

Exhibit PLC-4

Valuing Demand Response:

International Best Practices, Case Studies, and Applications

PREPARED FOR

EnerNOC

PREPARED BY

Ryan Hledik, M.S.
Ahmad Faruqui, Ph.D.

January 2015

THE Brattle GROUP

This report was prepared for EnerNOC. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone. The examples, facts, and requirements summarized in this report represent our interpretations. Nothing herein is intended to provide a legal opinion.

The authors would like to thank Phil Martin and Aaron Breidenbaugh of EnerNOC for insightful input and feedback throughout the development of this report. They would also like to thank Vince Faherty of EnerNOC and Bruce Tsuchida and Wade Davis of Brattle for valuable insights and research assistance.

Table of Contents

1. Introduction

1.1. Background and Purpose

Demand response (DR) programs have been utilized around the globe for decades as a cost-effective resource for maintaining a reliable electrical grid. By reducing load during a limited number of hours per year, DR can defer the need for new peaking capacity, reduce peak period energy costs, and lessen transmission and distribution (T&D) infrastructure investment needs, among other benefits.

In the United States, for example, a five percent reduction in peak demand through DR programs could lead to $35 billion in savings over a 20 year period.[1] If anything, this is a conservative estimate. A 2009 study commissioned by the Federal Energy Regulatory Commission (FERC) found that, under certain market conditions, peak demand in the U.S. could be reduced by two to four times this amount, effectively eliminating the need for the equivalent of between 1,000 and 2,500 peaking units.[2]

The benefits of DR are not just limited to U.S. markets – they are applicable internationally. In Europe, the financial benefits of smart grid-enabled DR have been estimated at over 50 billion Euros over a 20 year period.[3] In the Middle East, an assessment of demand-side management potential in Saudi Arabia revealed that DR could significantly reduce the country's dramatically growing capacity needs at a benefit of nearly $2 billion over 10 years.[4] A study of the National Electricity Market in Australia found that reductions in peak demand could provide between $4.3 and $11.8 billion in benefits over the next decade.[5] In the United Kingdom, a recent study found that the financial benefits of DR could amount to over $160 million annually.[6] Globally, it is estimated that annual spending on DR will be over $5.5 billion by 2020, with more than 20 million customers participating in a DR program worldwide.[7]

Policymakers, regulators, and utilities that are considering introducing or expanding their portfolio of DR resources face an essential question: Will the benefits of the new DR program outweigh its costs? An accurate and defensible estimate of the value of DR must be developed in order to provide an answer. At the most basic level, the principles for estimating the value of DR programs are the same regardless of geographical region, regulatory structure, or market design. However, the nuances of the valuation approach will depend on these factors.[8] The purpose of this paper is to discuss best practices for establishing the value of DR while accounting for nuanced differences across a range of market and regulatory structures.

While there are many types of DR benefits, this paper focuses on quantifying the financial benefits that are derived from avoided costs. Our primary focus is on avoided generation capacity costs, as this benefit has driven the majority of the business case for most recent DR programs. That is discussed in Section 2. Section 3 addresses other avoided costs such as reduced peak energy costs, avoided investment in new T&D capacity, and ancillary services benefits. Harder-to-quantify benefits are discussed briefly in Section 4.

The focus of this paper is specifically on quantifying the benefits of DR. In any valuation of a DR resource, the benefits should be weighed against the cost of the program. Examples of program costs would include equipment, marketing and customer outreach, participation incentive payments, and general program administration.[9]

1.2. Defining DR

For the purposes of this paper, we define DR to refer to customer actions that are taken to reduce their metered electricity demand in response to an "event," e.g., a dispatch signal, whether in response to the high price of electricity, the reliability of the grid, or any other request for reduction from a grid operator, utility, or load aggregator. This definition of DR implies the following:

- DR must be "dispatchable." DR is event-based and we do not consider a program to qualify as DR if it entails a permanent (i.e., daily or seasonal) load reduction. This is an obvious distinction between DR and energy efficiency (EE), the latter of which involves technological or behavioral change that is static in nature. This also means that a time-of-use (TOU) rate - in which the retail electricity price is higher during peak hours than during off peak hours on every weekday – is not considered DR because the peak period price does not change dynamically in response to system conditions.

- DR can include behind-the-meter generation. As long as it is dispatchable, our definition of DR includes the use of behind-the-meter generation. One example would be a standby diesel generator or a cogeneration unit at an industrial facility that can also be used to reduce the facility's demand for electricity from the grid during DR activations. Non-dispatchable forms of self-generation, such as rooftop solar panels, however, do not fall within our definition of DR.

- DR can be price-based or reliability based. Our definition of DR includes programs and markets in which activations can stem both from energy prices and system reliability. Pricing programs, such as critical peak pricing (CPP) or real-time pricing (RTP) charge prices that are higher during hours when it is more expensive to generate and deliver electricity, and lower when it is less expensive to do so. Reliability-based programs, including DR participation in wholesale capacity markets, typically provide an incentive payment for automated or behavior-based load reductions – these programs clearly also fall under this definition of DR.

1.3. Recent Examples of DR Performance

To put the specifics of DR valuation into context, consider a few recent cases where DR has provided significant tangible benefits under a range of system conditions.

In most parts of the world, DR is typically utilized during months when temperatures lead to a rise in use of electricity. If temperatures are very high, particularly for several consecutive days, there is a risk that demand for electricity will exceed supply. This was recently observed during the summer of 2013, when a heat wave caused record demand for electricity in parts of the Northeastern U.S. such as the New York and the PJM Interconnection markets (comprising much of the Mid-Atlantic U.S.). In these markets, where DR had already been procured through a centralized wholesale capacity market, the resource provided significant load reductions. Peak demand in New York was reduced by over 1,000 MW in response to reliability concerns. In PJM, the market operator utilized around 1,600 MW of the over 9,000 MW of DR at its disposal.[10] The DR programs that were utilized spanned a range of customer groups, including residential, commercial, and industrial customers.

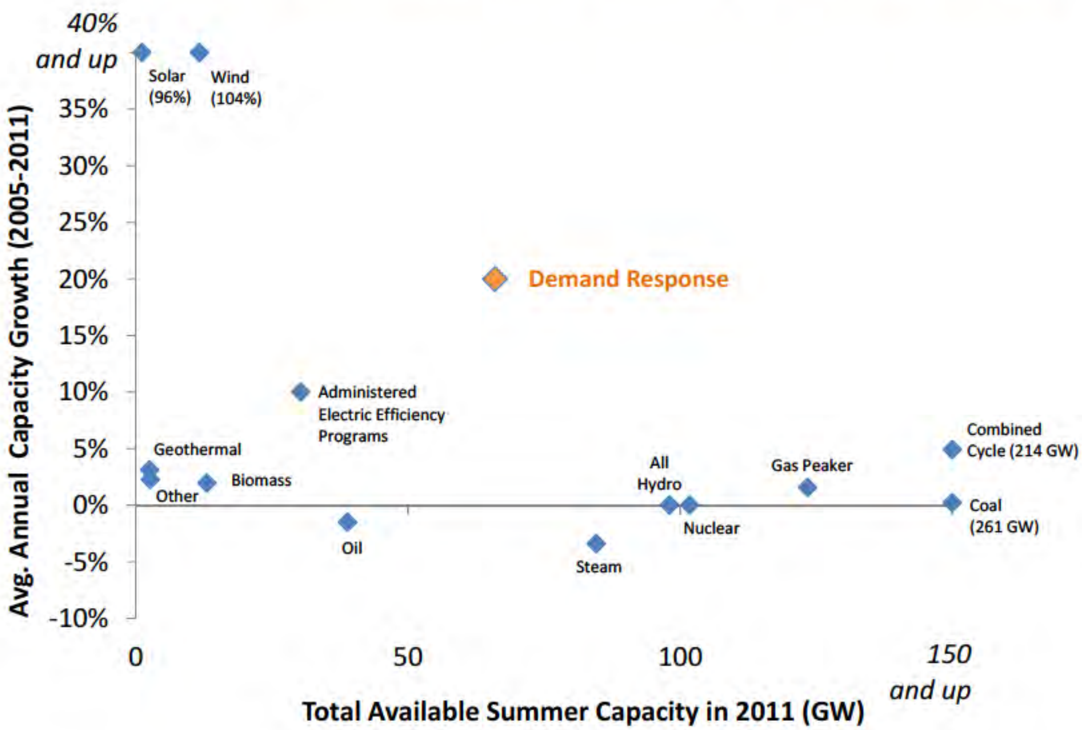
The value of DR is not just limited to hot summer months. The winter of 2013/2014 was one of the coldest in recent memory in parts of North America. Referred to as the "polar vortex," an Arctic cold front dropped temperatures to record lows in the Eastern and Southern U.S. This resulted in a sustained increased need for space heating, driving natural gas and electricity prices through the roof and raising serious concerns about maintaining grid reliability. This was particularly a concern in Texas, where the severe weather not only lead to a spike in demand but also caused outages at two major power plants. In response to these conditions, ERCOT (the grid operator) called on more than 600 MW of DR.[11] Within 45 minutes, the DR resources had reduced load to acceptable levels and the supply and demand balance had been stabilized, avoiding potential rolling brownouts.

Unexpected extreme weather conditions are not the only driver of DR utilization, or local reliability concerns. In 2012, Southern California Edison (SCE) was forced to take its San Onofre Nuclear Generating Station (SONGS) offline due to equipment reliability concerns. This led to the retirement of more than 2,200 MW of generation in a part of the Southern California electricity grid that was significantly transmission constrained. In response to a potential capacity shortage in the region, SCE has ramped up its efforts to procure DR capacity. SCE has announced that of the 2,200 MW that were lost after the retirement, 1,300 MW could be replaced with DR.[12] This highlights not only DR's value as a local resource, but also its potential to provide new capacity on shorter notice than would be required to install a new power plant or build new transmission capacity to the region.

While the three previous examples illustrate the use of DR in response to emergency conditions, it is a low cost resource that also provides economic benefits. In the 2017/2018 PJM capacity auction, for example, it was estimated that bids from DR and energy efficiency reduced total expenditure on capacity by $9.3 billion in the market for that year alone.[13] There has been a trend recently toward greater utilization of DR for reducing energy costs. Many energy markets in the U.S. and Europe have been revised to facilitate competition between DR and traditional supply-side resources. While participation has not been as high as in capacity markets, some U.S. regions like PJM, California, and the southern Midwest have seen up to approximately two percent of peak period energy participation coming from DR resources. Some ancillary services markets have also experienced a substantial amount of DR participation. In PJM, where DR is able to participate in the synchronized reserve market, DR has often come up against the current administratively-set cap of 25 percent of the total requirement, which is now being increased due to the levels of DR successfully participating in the market.[14] ERCOT also has a significant amount of participation in its ancillary services markets through its Load Resources program.[15]

Given the demonstrated value of DR in these examples, it is no surprise that DR has been growing quickly as a resource in the U.S. over the past several years. Next to wind and solar generation, which have been heavily subsidized at the federal and state levels, DR is the fastest growing resource in the country in terms of average growth rate. Between 2005 and 2011, DR has grown by 20 percent per year. Figure 1 summarizes the size and growth of DR relative to other resources.

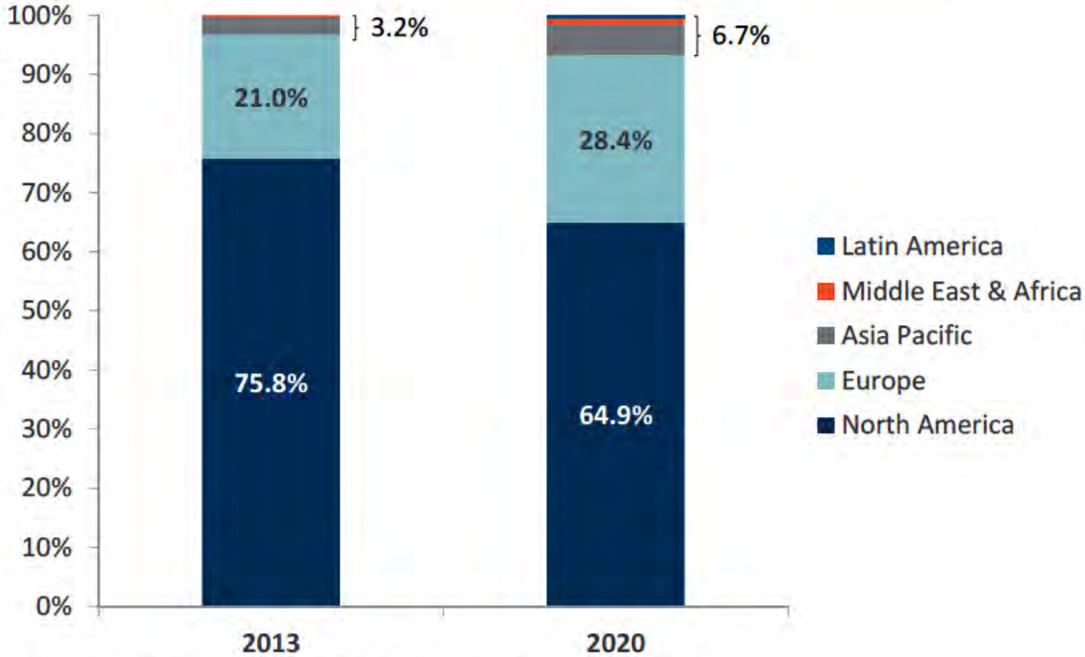
Figure 1: U.S. Available Capacity Resources and Growth in Resources



Notes:
Figure reproduced from Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporate Demand Response in Long Term Resource Planning," *Utilities Policy*, March 2014.
Source of generation capacity data is Ventyx Energy Velocity Database
Demand response data from FERC 2013 Assessment of Advanced Metering and Demand Response
Energy efficiency data based on actual peak reduction estimates from EIA-861
Summer capacity is total for generating units classified as "operating" with commercial online date before January 2012
Assumes 50% peak coincidence for solar and 25% peak coincidence for wind; all other types assume 100% availability for simplicity

This rapid growth in DR in North America is expected to be accompanied by even faster growth in DR in the rest of the world. Whereas North America represents around 75 percent of the worldwide DR market currently, this share is projected by Navigant Research to drop to approximately 65 percent by 2020.[16] Much of the international growth activity is expected to be in the commercial and industrial (C&I) sector, with the Asia Pacific region accounting for nearly 40 percent of all C&I DR participation by 2020. The projected growth in DR adoption outside of North America is illustrated in Figure 2.

Figure 2: Worldwide Share of DR Participation, 2013 and 2020



Source: Navigant Research, "Market Data: Demand Response," 2Q 2013.

2. Avoided Generation Capacity Cost

Avoiding or deferring the need for new generating capacity has long been the single largest source of value provided by DR. Often, this can comprise 80 to 90 percent of the value of a DR resource.[17] Since any electrical grid must have enough capacity available to serve load during the instantaneous time of highest demand (i.e., the coincident system peak), DR resources that are utilized to reduce the system peak lessen the need to invest in new generation capacity.

This basic calculation of the avoided generation capacity value of DR applies regardless of market structure, that is, whether in a traditionally regulated market or a restructured market. The computation requires determining the marginal cost of new capacity (i.e. the cost of serving a one kilowatt increase in system peak demand). In most regions, this is typically an open-cycle combustion turbine (OCCT), also referred to as a peaking unit. Relative to other sources of generation, peaking units have low capital costs and high operating costs, meaning they are cheap to build but expensive to run. For this reason, the units typically sit idle for most hours of the year and are only utilized during top peak load hours. Peaking units are typically the type of capacity avoided by DR because of their similar operational profile.[18]

Modifications to that installed cost of new capacity are then made to account for the energy and ancillary services value that the new generating unit would provide to the grid, as well as considerations for the availability and performance characteristics of the DR program. It is in these modifications that there are nuanced differences in the value calculation between restructured markets and regulated markets.

2.1. In Regulated Markets

In traditionally regulated markets where utilities own generation, transmission, and distribution and serve retail customers, all within a given territory, the utilities are responsible for planning to have enough capacity available to meet system peak demand. This is typically done through a resource planning process that is reviewed and commented upon by the regulator and stakeholders. Resource planning typically involves projecting peak demand over a multi-year period and then running sophisticated optimization models to determine the economically optimal timing and location of new generating capacity that would be needed to meet that peak demand.

While the economic valuation of DR would ideally be integrated into this process, most utilities assess its value outside of their resource planning modeling.[19] This is a two-stage process. They first determine the amount and cost of new generating capacity additions that would be needed to meet peak demand. Then, they use this result to assess the value of a reduction in peak demand attributable to demand response. In detail, this valuation process consists of the following six steps.

Step 1: Identify the marginal cost of capacity. The cost of new capacity will typically be based on quotes or bids from manufacturers. There are also often public sources of cost estimates that can be used as a proxy for a more region-specific estimate. Recently in the U.S., where gas-fired combustion turbines are often the marginal unit, the overnight cost of a conventional CT has ranged anywhere from around $700 to over $1,400 per kilowatt of installed capacity, depending on location and the type of technology.[20]

Step 2: Levelize the installation cost as an annual value. To properly account for differences in the useful life of a DR program relative to a generator, it is necessary to levelize the installation cost of the power plant. This will require establishing a lifetime of the unit (typically 20 to 30 years) and an appropriate discount rate. At a useful life of 20 years and a hypothetical utility's weighted average cost of capital (WACC) of seven percent, the annual value of a $900/kW peaking unit would be approximately $85/kW-year. Fixed operations and maintenance (O&M) costs should be added to this estimate. For a combustion turbine, those could be approximately between $5 and $10/kW-year.[21] Adding a fixed O&M cost of $5/kW-year to the levelized installation cost brings the total cost of the hypothetical marginal unit to $90/kW-year.

Step 3: Subtract the energy and ancillary services profit margin of the marginal unit. In the absence of DR, the peaking unit would be installed and it would generate electricity during hours when its variable costs (fuel and variable O&M) are less than the marginal cost of energy (i.e. it would run when doing so is profitable). The difference between the marginal cost of energy and the unit's variable costs are its "energy margin." Similarly, the unit could provide ancillary services and further increase its profit margin. This profit margin represents the incremental energy and ancillary services value that the unit would have provided to the grid. When estimating the net avoided cost of DR, this profit margin should be subtracted from the capacity cost (in other words, it is a benefit that is avoided by DR).[22]

Energy and ancillary services margins will depend heavily on the economics of the system that is being analyzed. For instance, in a region with tight reserve margins and a high dependency on fuels with volatile prices, there is a greater likelihood of energy price spikes and a new peaking unit would have a better opportunity to earn high energy margins than in a region with a large amount of excess capacity. For illustrative purposes, assume the peaking unit in our example has energy margins of $20/kW-year.[23] Subtracting this from the levelized cost of the unit gives a net avoided cost of $70/kW-year.

Step 4: Derate the resulting net avoided cost to account for DR availability and performance. Unlike the around-the-clock availability of a combustion turbine unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

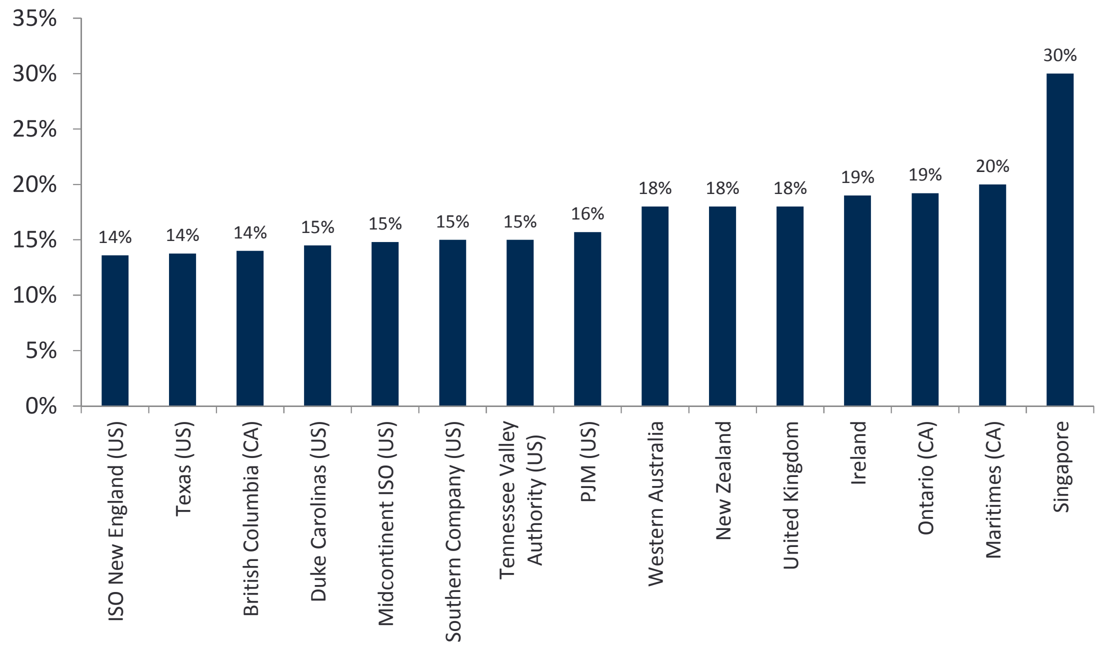
Some utilities account for this through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero percent to roughly 50 percent of the capacity value of the programs.[24] The derate is program- and utility-specific. In California, programs with short response time and dispatch flexibility are derated by less than programs that do not have those characteristics. Historically in California, day-ahead programs with voluntary load reductions have been derated by as much as 60 percent whereas technology-enabled air-conditioning load control programs and aggregator-managed C&I programs with short response time could be derated by less than 20 percent.[25] In Colorado, Xcel Energy estimated that the capacity value of DR programs with a four hour dispatch limit per day and a 40 hour dispatch limit per year should be derated by around 30 percent, while unconstrained DR programs that could be dispatched up to 160 hours per year (a large number of hours for a DR program) should only be derated by five percent.[26] Very rough estimates by Portland General Electric (PGE) include derate factors of between five and 30 percent for direct load control programs and 50 to 60 percent for programs in which the load reductions are not automated. Many other utilities do not include any derate mechanism whatsoever, similar to DR valuations in wholesale capacity markets. While there is not a "typical" derate across markets due to the program-specific and system-specific nature of the adjustment, we find that 25 percent is a reasonable midpoint estimate to use as a representative value. Derating the $70/kW-year net avoided cost estimate in our example by 25 percent produces an adjusted avoided cost estimate of $53/kW-year.

Of course, the relative availability of peaking units should also be taken into account when establishing these derate factors. If rarely-used peaking units are found not to be reliable when needed during times of system emergencies, then the relative disadvantage of DR is not as significant as it may initially appear. For example, a recent analysis found that of 750 MW of peaking units in the San Diego area of Southern California, roughly 60 percent were available when called due to startup issues.[27] While DR resources have some dispatch limits, their availability and reliability during periods of system need could match or possibly exceed that of generation in some instances, enabling them to be comparably valued to a peaking resource by comparison in these instances.. ISO New England (ISO-NE) dispatched DR resources on July 19, 2013 for system reliability purposes and 95 percent of dispatched DR resources responded.[28] This also highlights the very system-specific nature of the derate calculation. It must be developed on a case-by-case basis with careful consideration for factors like the system load profile, DR program characteristics, and generating unit performance.

Step 5: Increase the avoided cost estimate to account for line losses and reserve margin. Demand response produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of eight percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise. Therefore, when estimating the avoided cost of DR, the avoided cost should be grossed up to account for this factor.

Similarly, most utilities incorporate a planning reserve margin into their capacity investment decisions. Reliability standards can be incorporated into planning decisions in a variety of ways (e.g., establishing a maximum target number of allowable reliability "emergencies" per year, or establishing a minimum amount of installed capacity in excess of peak load during a high load year due to unexpected weather). Figure 3 illustrates the range of reserve margins that are implied in the reliability standards of various markets around the globe.[29]

Figure 3: Implied Reserve Margin Requirement in Markets with Reliability Standard



Source: Sam Newell and Kathleen Spees, "Resource Adequacy in Western Australia: Alternatives to the Reserve Capacityi Mechanism," prepared for EnerNOC, August 2014.

A common target reserve margin is 15 percent, meaning the utility will plan to have enough capacity available to meet its projected peak demand plus 15 percent of that value.[30] In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.15 kW of capacity. Combining the adjustments for both 8% line losses and a 15% reserve margin in our hypothetical example increases the avoided capacity cost from $53/kW-year to $66/kW-year.[31]

<u>Step 6: Calculate the present value of avoided capacity over the lifetime of the DR program.</u> The final step in quantifying the avoided capacity cost of a DR program is to account for the expected life of the program and the extent to which this aligns with new capacity needs. The life of a DR program will vary by program type and will be determined by the life of equipment that is being used (e.g., a switch on the compressor of an air-conditioner) and expectations about the amount of time that participants will choose to stay enrolled in the program. In our hypothetical example, assume that the utility's resource plan has determined that new capacity will first be needed three years from now due to a short-run capacity surplus. In valuing a DR program that would be offered today, the avoided capacity cost in years one and two would be near zero.[32] Assuming our hypothetical DR program has a 10 year life, it would have capacity value of $66/kW-year for the remaining eight years of its life.

Table 1 summarizes the six steps in determining the capacity value of DR for a vertically integrated utility in a regulated market.

Table 1: Steps to Calculate Avoided Generation Capacity Cost for Vertically Integrated Utility

Step	Description	Value	Calculation
[1]	Identify the marginal cost of capacity	$900/kW	Assumption
[2]	Levelize the installation cost (including O&M)	$90/kW-yr	(7% x [1]) / (1 - (1 + 7%)^-20) + $5/kW-yr
[3]	Subtract energy & ancillary services margins	$70/kW-yr	[2] - $20/kW-yr
[4]	Derate to account for DR availability and performance	$53/kW-yr	[3] x (1 - 25%)
[5]	Gross up for line losses and reserve margin	$66/kW-yr	[4] x (1 + 8%) x (1 + 15%)
[6]	Calculate present value over life of DR program	$344/kW	Present value over 10 years with avoided cost starting in year 3

Notes:
[1] Based on overnight cost of gas-fired combustion turbine
[2] Assumes discount rate of 7%, useful life of unit of 20 years, and fixed O&M cost of $5/kW-year
[3] Assumes energy & ancillary services margin of $20/kW-year
[4] Assumes derate factor of 25%
[5] Assumes line losses of 8% and reserve margin of 15%
[6] Assumes 7% WACC, 10 year life, and new capacity need in year 3

2.2. In Restructured Markets with Capacity Mechanisms

In restructured markets with centralized capacity mechanisms, there is a wholesale market that is designed to encourage investment in an economically optimal amount of capacity to meet the expected peak demand (plus a reserve margin). Capacity markets produce an annual marginal price of capacity that is paid to sellers in the market (i.e., generators and DR aggregators). This capacity price is the cost that is avoided if DR is procured in the market. Therefore, in a sense, it is simpler to assess the value of a new DR program in the context of a centralized capacity market – the price is published and does not require the multi-step computations that it would when valuing DR for a vertically integrated utility.

Capacity prices can be set in different ways depending on the specific mechanics of the capacity market, although most capacity markets share a basic set of common elements. First, the market operators will determine the gross cost of new entry (CONE).[33] Gross CONE is the marginal cost of new capacity, the same basic starting point that was discussed in Section 2.1 for vertically integrated utilities. Gross CONE is typically determined as a bottom-up engineering estimate or through a survey of recent power plant additions, and ultimately vetted through a public stakeholder process.[34]

Second, the market operators will subtract energy and ancillary services margins to produce Net CONE. Similar to the discussion in Section 2.1, and for the same reasons discussed in that section, an estimate of the likely profit margin that would be earned by the marginal generating unit is subtracted from Gross CONE to produce an estimate of Net CONE. In a state of perfect market equilibrium, Net CONE would be the marginal price of capacity.

Third, the market operators will establish a process through which to adjust the capacity price to balance the supply of and demand for new capacity. Due to the cyclical nature of power generation development, markets typically fluctuate between conditions of excess capacity and of tightened reserve margins. The pricing mechanism is designed to reflect these conditions. The price rises as the need for new capacity rises, and vice versa. The specific mechanism through which this happens is very specific to the market design. While a comprehensive detailed review of the nuances of the price setting process is beyond the scope of this paper, the following are examples of how it is done in a few existing markets.[35]

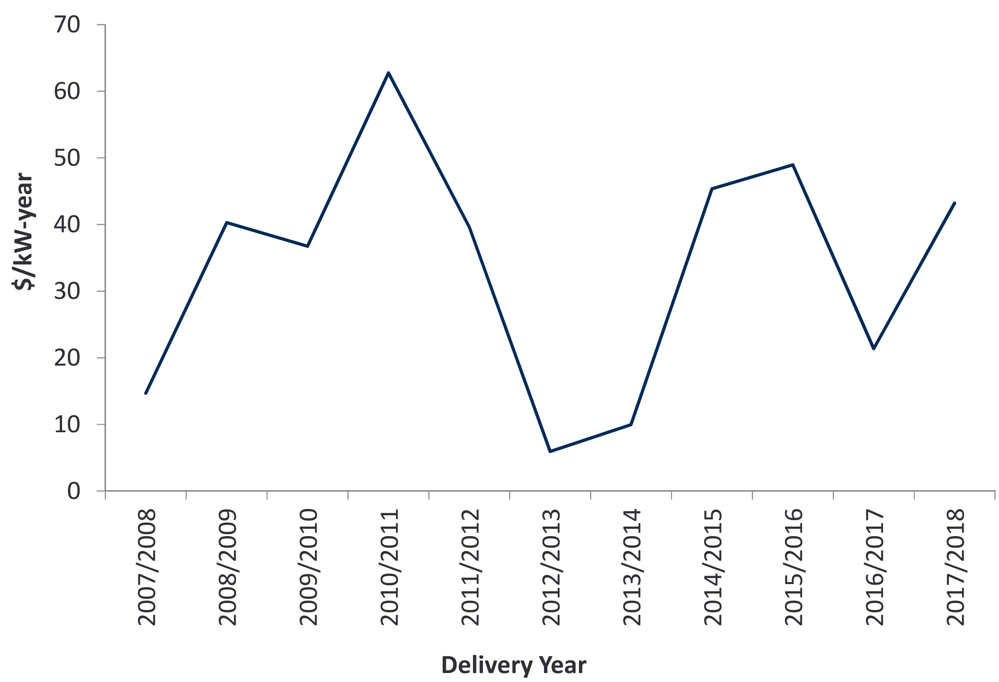
- **PJM:** A downward sloping "demand curve" is established to represent the price that will be paid for capacity at various reserve margin levels. When the reserve margin is low, supply is short and a high price would be paid for new capacity. The price progressively decreases for increasing amounts of capacity. The curve is anchored on a price that is equivalent to the Net CONE value, which would be paid for capacity that produces the target reserve margin level. PJM then conducts an auction into which participants bid their capacity. This creates a supply curve of capacity, and the intersection of the supply and demand curves determines the capacity price that is paid to all accepted bids. PJM conducts their auction annually on a three-year forward looking basis, meaning bids in the current year's auction are a commitment to provide capacity three years out.[36]

- **Western Australia:** As in PJM, Western Australia' Wholesale Electricity Market (WEM) starts with an estimate of net CONE and establishes this as a payment level that is associated with a target level of capacity procurement. Unlike in PJM, however, the capacity price is not ultimately set through an auction process. Rather, retailers and generators establish bilateral contracts for capacity, or sell to the market operator directly. If the amount of capacity procured through these bilateral transactions meets the target amount of capacity that is needed in the market, then the entities that are selling capacity are awarded a payment that is close to Net CONE. If the amount of capacity traded is higher than the target amount, then the payment level is progressively reduced from this price. Alternatively, if an insufficient amount of capacity has been procured, then the market operator would hold a supplemental capacity auction to procure enough capacity to meet the target. In Western Australia, procurement happens two years in advance of the delivery date.

- **Ireland:** In Ireland's Single Electricity Market (SEM), there is no auction process. Rather, pre-established capacity prices are paid to market participants for each half hour period of the year, depending on the participant's availability to provide capacity in each half hour interval. Depending on projected reliability conditions during each time interval, the capacity price can vary widely. In periods when supply and demand conditions are expected to be tight, the price is set higher. This allows the participants flexibility in the timing and duration of their commitment to provide capacity over the course of the year. All prices are derived from a common starting point, which is Net CONE. Unlike both the PJM and WEM markets, there is no forward procurement mechanism in the SEM.

These examples illustrate that there is likely to be fluctuation in the capacity price over time. In PJM, for example, prices have varied significantly over the decade that the capacity market has been in place (as well as across its various geographic zones). This annual volatility is illustrated in Figure 4.

Figure 4: PJM Capacity Prices[37]



Regardless of the specific price setting mechanics of the capacity market, the basic methodology for calculating the avoided capacity cost attributable to DR follows the same three steps:

<u>Step 1: Identify the capacity price for all relevant years.</u> The market price for capacity should be used for all years available. For instance, since PJM is a three-year forward auction, there would be three years of capacity prices that would be used as the short-run avoided cost of capacity.[38]

Step 2: Establish Net CONE as the long-run equilibrium capacity price. Analysis of DR benefits in organized wholesale markets is sometimes short-sighted in the sense that it limits the evaluation to prices based on recent market results.[39] In the long-run, however, prices are likely to evolve and eventually would be expected to reach an equilibrium state. Economic theory suggests that, in the long run, supply and demand will equilibrate and the marginal cost of capacity will eventually stabilize at Net CONE. Thus, for the outer years of the forecast, Net CONE is used as the avoided capacity cost.

Step 3: Interpolate in intermediate years to create a smooth transition from market prices to the long-run equilibrium price. To account for a multi-year transition from the market price to the long-run equilibrium price, it is common practice to interpolate between the two prices over a three to five year period. Linear interpolation is sufficient.

Illustrative results of this three step process are summarized in Figure 5 using PJM capacity prices. In PJM, various economic factors and fluctuations in the market design have kept the capacity price from reaching Net CONE (for the 2017/18 auction, Net CONE was around $127/kW-year). In this specific case, if there is a belief among the evaluators of the DR program that these factors would continue to depress the capacity price, then the long run equilibrium price could be set below Net CONE. Some judgment is necessary when projecting capacity prices.

Figure 5: Capacity Price Forecast for PJM

Unlike in the previous discussion of DR valuation in regulated markets, no derating mechanism is used to account for operational constraints of the DR programs. Rather, these constraints are accounted for by the market rules that specify how a DR product must perform in order to be accepted as a resource in the market. For example, a market rule might specify a minimum number of hours for which the DR resource must available, a maximum lead time for notification, or specific technologies that must be used for communications and settlement purposes. Therefore, the market design includes a "screening" process that ensures that accepted DR bids will provide the same value to the market as a generating unit. As a result, in all of these wholesale capacity market constructs, DR receives the same remuneration for capacity as a traditional supply-side resource.

2.3. In Restructured Energy-Only Markets

Some restructured markets do not have a centralized mechanism for procuring capacity. These are commonly referred to as "energy-only" markets. The theory in these markets is that, as reserve margins tighten, energy prices will rise to a point that economically supports a sufficient amount of new entry of capacity into the market.[40] The Electric Reliability Council of Texas (ERCOT), the Ontario Power Authority (OPA) in Canada, and Australia's National Electricity Market (NEM) market are three examples of energy-only markets.

In these markets, since energy prices are intended to represent the cost of energy as well as capacity, there is no specific capacity price per se that is used to specifically evaluate the generation capacity value of DR. However, the operators of these markets will often create specific "products" that are designed to encourage DR resources to be available for capacity purposes. Payments are made to DR providers to be available for curtailment when needed and/or on a pay-for-performance basis. In this sense, the capacity value of DR programs in these markets is determined by the payment that is made to the DR providers.

These DR products exist in several energy-only markets. For example, in ERCOT's Emergency Response Service (ERS) program, customers are paid for providing load reductions on 10 or 30 minutes notice. Load reductions are procured for different time periods (varying by season and time of day). In the 30-minute ERS program (a pilot program at this point), prices are set through an auction process. Prices in the ERS program have cleared between \$60 and \$200/kW-year and are continuing to fluctuate as the product definition evolves.[41] In Canada, the Ontario Power Authority (OPA) has a mandatory, capacity-based DR program called "DR3".[42] Prices vary across the three programs and across locations on the OPA's grid. In Toronto, payments in the DR3 program, have been in the range of \$100/kW-year to \$170/kW-year.

To determine the capacity value of DR in these types of programs, the first step is to determine whether the DR program being evaluated meets the specific performance requirements of the market product (or, if multiple products are offered, as in the examples described above, determine which product, if any, is the best fit in this regard for the DR program being considered). The performance requirements are typically publicly available documents published on the market operator's website. Then, determine how much of a load reduction will be provided by the DR program. This load reduction is then multiplied into the published payment schedule to determine the overall monetizable value of the DR program.

3. Other Avoided Costs

While avoided generation capacity costs have driven the bulk of DR benefits historically, there are other avoided costs that can also be attributed to DR. This section discusses other avoided costs, including T&D capacity costs, energy costs, and ancillary services costs.

3.1. Avoided Transmission and Distribution Capacity

Reductions in peak demand lessen the need to expand the T&D system. A portion of T&D investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Geographic expansion of the system requires T&D investment, and that is often correlated to growth in peak demand. By reducing peak demand, DR reduces the need for new T&D capacity. In 2012, for example, the U.S. market of PJM cancelled plans for a new transmission line (the "PATH" line) that would improve import capability in its transmission-constrained eastern portion of the power grid, citing an increase in DR in the east as a reason for canceling the project.[43]

There are also aspects of T&D system expansion that are not driven by growth in peak demand. For example, some reliability-driven projects are built to ensure that enough capacity is available to address congestion during mid-peak and off-peak periods. Other projects are driven to integrate new generation additions which may be built as baseload resources rather than peaking generation. As a result, when calculating avoided costs for valuing DR programs, utilities will often calculate the total amount of expected T&D infrastructure investment and then derate it to account for the share of that investment that is driven by peak demand.

Utility estimates of avoided T&D costs vary significantly and are very system specific. In a review of utility DR filings and marginal cost studies, and interviews with utility engineers, avoided T&D costs typically ranged from $0 to $75/kW-yr. Table 2 summarizes avoided T&D cost estimates from recent DR studies. While the range is broad, we find that avoided costs of $20 to $30/kW-year are the most commonly accepted assumption in regulatory settings as well as in several unpublished studies for utilities.

Table 2: DR Avoided T&D Costs

Entity		State(s)	Avoided Cost ($/kW-year)
[1]	Pepco Holdings, Inc	DE, DC, MD, NJ	$0.00
[2]	Portland General Electric	OR	$18.00
[3]	Pennsylvania Statewide Evaluator	PA	$25.00
[4]	Connecticut Light & Power	CT	$29.20
[5]	Xcel Energy	CO, MN	$30.00
[6]	Southern California Edison	CA	$54.60
[7]	San Diego Gas & Electric	CA	$74.80
[8]	Pacific Gas & Electric	CA	$76.60

Note: Where multiple avoided cost scenarios were considered, the base case value was used
Sources: Utility DR potential studies, state regulatory decisions

In addition to avoiding system peak-driven T&D investment, DR can be deployed selectively in specific geographic locations to address local congestion issues on the transmission or distribution system.[44] For example, some utilities have used DR to manage loads at specific substations and transformers that were at or near capacity. Reflecting this location-specific value, Con Edison, a distribution utility in the U.S. state of New York, has developed its Distribution Load Relief Program (DLRP) which offers customers in congested parts of the grid incentive payments that are twice as high as those of customers in uncongested parts of the grid.[45]

Wholesale energy and capacity markets do not specifically address T&D system expansion needs. In both regulated and restructured markets, this is done through a centralized planning process. Therefore, there are not significant differences in the way T&D capacity benefits are estimated for DR in restructured and regulated markets. There are a few options for establishing the avoided cost of T&D:

<u>Option 1: Rely on estimates from a recent marginal cost study.</u> Many utilities will conduct marginal cost studies, primarily for the purpose of designing their retail rates. Among many calculations, these studies will include estimates of the portion of T&D costs that are driven by growth in the system peak. This estimate can be used as the basis for the avoided T&D cost of DR that is dispatched to reduce the system peak.

<u>Option 2: Use an estimate from a review of assumptions in other utility filings.</u> In the absence of marginal T&D cost estimates that are specific to the region or service territory being analyzed, an estimate of avoided T&D costs can be established based on a review of estimates in other regions, such as those summarized in Table 2 above. The results can be tailored to the service territory in

question by restricting the survey to similarly situated utilities (e.g. similar geographic region, urban versus rural utility, etc.).

Option 3: Develop a bottom-up engineering estimate of the avoided cost of T&D. In instances where the utility is considering establishing a new DR program in a congested part of the grid in order to avoid or defer the expansion of the T&D system to that part of the grid, the specific cost of the T&D project in question should be taken into consideration. This will be a very project-specific estimate that most likely cannot be derived from other studies.

3.2. Avoided Energy Costs

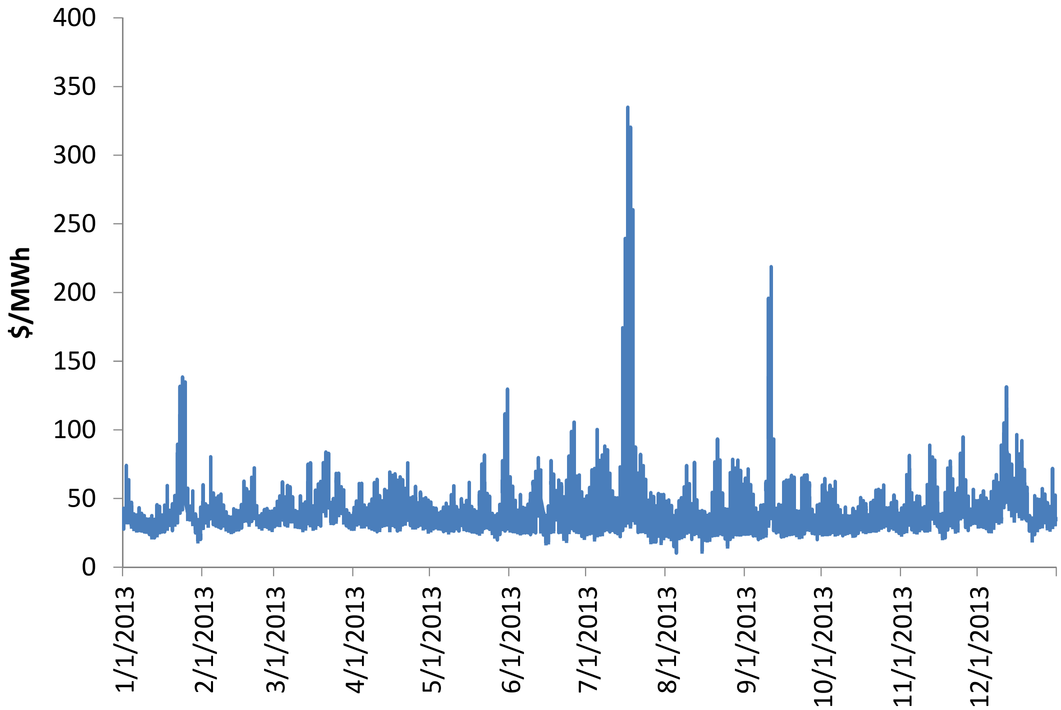
Reductions in consumption will avoid the marginal cost of generating electricity (primarily fuel costs, as well as variable O&M). This is typically a primary benefit of energy efficiency programs, which derive most of their value from overall reductions in consumption. For DR programs, avoided energy costs have historically made a relatively minor contribution to the total benefit, since consumption reductions are concentrated in a small number of hours in the year. However, when these reductions occur during hours of very high electricity prices – particularly in restructured energy-only markets – the benefit can be significant. There is a growing trend toward incorporating DR into wholesale energy markets in order to provide comparable opportunities to those of generating units, and to facilitate broader market participation and competition.

Avoided energy costs are a time-dependent source of value. Reductions during peak times avoid a higher marginal cost, because less efficient generating units are on the margin during these times. These costs also vary by season for the same reason – in the summer, when demand is often higher due to air-conditioning load, energy prices also tend to be higher.

The methodology for determining energy benefits is generally the same in restructured and regulated markets, with the only difference being the source of data for the marginal cost of energy. Steps for estimating the avoided cost are summarized below:

Step 1: Establish an hourly projection of marginal energy costs. In a restructured market, hourly energy prices – often referred to as the locational marginal prices (LMPs) - are established in the energy market. For a vertically integrated utility, marginal energy costs are simulated using a production cost model and represented by something referred to as a "system lambda." In either case, recent historical hourly marginal energy costs for a year with normal weather are typically used as the basis for estimating avoided costs. Figure 6 illustrates the hourly day ahead LMP in the Eastern Hub of PJM for each hour of the year 2013. The energy price exceeded $100/MWh in 89 hours in 2013.

Figure 6: Eastern PJM Hourly Energy Price (2013)



Step 2: Define the period when DR is likely to be utilized. The DR program will only be dispatched during a limited number of hours per year. A key question is whether the DR program is being dispatched for reliability purposes or economic purposes (or both). If it is being dispatched for reliability purposes, the demand reductions will likely coincide with the highest system load hours of the year. If it is being dispatched for economic purposes, the demand reductions will often coincide with the highest priced hours of the year.[46] In both cases, the top hours should be identified and restricted to the likely total number of hours that the program will be dispatched (typically 50 to 100 hours per year, primarily focused on the season of the system peak, which in the U.S. is typically the summer season). To illustrate, consider an economically-dispatched DR program that can be utilized up to 10 days per summer between the hours of 2 pm to 7 pm. In 2013, this program would have been dispatched during 10 days between the months of May and September in PJM (with the exception of one day in December during the Polar Vortex), as these were days with the highest average peak period prices. Table 3 identifies the top 10 days and the average day ahead LMP during the 2 pm to 7 pm window on those days.

Table 3: 10 Highest Priced Days in Eastern PJM, 2013

Date	Average Peak Period Price ($/MWh)
7/17/2013	297.30
7/18/2013	267.80
7/19/2013	214.04
7/16/2013	209.65
9/11/2013	185.11
7/15/2013	152.91
9/10/2013	148.64
5/31/2013	106.12
12/12/2013	101.37
5/30/2013	94.65
Average	**177.76**

Step 3: Calculate the average energy price during the hours when the DR program is utilized. The average marginal energy cost during the hours of dispatch represents the energy value of the DR program. In the example above, the average energy price during the 50 hours of dispatch was approximately $178/MWh.[47] This value would be multiplied by the total amount of energy reduced during that period to determine the total annual energy value of the DR program. Converted to a dollars-per-kilowatt-year estimate for comparability to the avoided capacity cost estimates discussed previously, this equates to approximately $9/kW-year. Thus, in this example, the avoided energy cost is a fraction of the range of avoided capacity cost estimates that have been discussed, but it is still a material financial benefit to be considered.

3.3. Avoided Ancillary Services Costs

The use of DR to provide ancillary services is becoming a topic of increasing interest in the industry due to growing concerns regarding the ability to reliability integrate large amounts of intermittent resources into the grid. Regardless of whether a utility is regulated or in a restructured market, DR could provide value by acting as a fast-response resource that would decrease or even increase load in response to unpredictable fluctuations in power generation. Specifically, there are four reliability-related problems that must be addressed when variable generation is adopted at high levels:[48]

- Increased intra-hour variability in supply

- Large magnitude of overall ramping requirements
- Over-generation concerns
- Near-instantaneous production ramps.

Newly emerging technologies and DR initiatives could eventually help to address some of these barriers. "Smart" appliances, home energy management systems (HEMS) and automated DR systems for the C&I sector are being developed and are becoming commercially available. These technologies can be programmed to respond to fluctuations in the real-time price of electricity. Initiatives are underway to open the market for these devices.

To be valuable in this new environment, ancillary services DR will likely need to be used in new and innovative ways. Specifically, it is likely that DR will need to be able to respond not just during peak hours, but during many of the 8,760 hours of the year. Additionally, there will be value not only in load reductions but also in the ability to *increase* load to maintain balance on the grid. The valuation techniques that have been discussed in this whitepaper are generally applicable in estimating the value of this type of "flexible" DR. For instance, to the extent that DR can be utilized in this environment to provide services that are comparable to those of an OCCT, then the same basic approach to estimating avoided capacity cost would be used. But if the operational characteristics of DR make it a unique resource that is not directly comparable to a generating resource in this environment, then a more sophisticated valuation approach may be needed. This could require a multi-step process, including:

1. Identify the customer segments and end-use loads that are the best candidates for participation in a "flexible DR" program, meaning those end uses that can be controlled with automating technology and used to both increase and decrease load (e.g., residential water heating);

2. Determine the total potential load increase/decrease in those end-uses and the cost associated with enrolling them in a DR program;[49]

3. Characterize the operational constraints of the portfolio of DR participants, such as the number of hours of allowable interruption per year and per day, and the response time;

4. Include this DR portfolio in a resource planning model with a level of granularity that accurately accounts for the volatility in electricity production from intermittent resources of generation;

5. Use the model simulations to determine the extent to which the inclusion of the DR portfolio reduces overall system costs.[50]

4. Other Benefits

It is important to consider additional benefits that are difficult to quantify but which certainly add to the overall attractiveness of DR programs. Qualitative factors such as these should be taken into consideration when conducting a detailed assessment of the benefits and costs of moving forward with a new portfolio of DR offerings.

4.1. Wholesale market price mitigation

When DR bids are accepted in a market, they displace bids from higher cost resources that otherwise would have been accepted. This serves to reduce the market price (a result that one would expect from increased competition in any market). This reduction in market prices can significantly benefit buyers in the market. As described earlier, DR and energy efficiency are estimated to reduce capacity expenditures by billions of dollars per year annually in the PJM capacity market.[51] In the energy market, a study found that a three percent reduction in peak demand through new DR programs could reduce energy prices by between five and eight percent, varying by geographic zone.[52]

However, whether wholesale price mitigation should be considered a benefit depends on one's perspective. While buyers in the market benefit from reduced prices, this represents a loss to suppliers. In this sense, wholesale price mitigation is simply a wealth transfer without a significant net benefit at the societal level. Additionally, the impact of wholesale price mitigation may only persist in the short run. In the long run, reduced prices could lessen the incentive for new market entry, and the market could return to equilibrium at prices similar to those prior to the introduction of DR. Finally, there is a tradeoff to consider between energy and capacity markets. The introduction of new DR will replace relatively efficient new generating capacity that would otherwise have entered the market. This will reduce capacity prices, but could put upward pressure on energy prices over time.

4.2. Possible environmental benefits

To the extent that a DR program results in a net reduction in energy consumption, there could be environmental benefits in the form of reduced greenhouse gas (GHG) emissions. Even in the absence of overall conservation, load shifting may lead to a small reduction in emissions, although this will depend on the emissions rates of marginal units during peak and off-peak hours.[53] For example, if DR causes load to be shifted from hours when an inefficient oil- or natural gas-fired unit is on the margin to hours when a more efficient gas-fired combined cycle unit is on the margin, one could expect a net decrease in GHG emissions. However, in a different service territory, there might be a gas-fired unit on the margin during peak hours and a coal unit on the margin during off-peak hours. In this situation, an increase in GHG emissions could arise.

Peak period load reductions could also reduce other types of generator emissions such as criteria and hazardous air pollutants. In the U.S., for instance, these reductions would be particularly valuable in designated "non-attainment areas" where pre-determined emissions levels cannot be exceeded.

To the extent that peak demand reductions result in avoided investment in new generation capacity or T&D capacity, the result would be a smaller geographical footprint of the grid. This would reduce the impact to wildlife habitat and sensitive ecosystems.

Finally, if DR is offered in the form of time-varying retail rates, this could facilitate the adoption of renewable sources of energy. For example, a strong time-of-use rate could improve the economics of rooftop solar by aligning the higher priced peak pricing period with the time of highest output from the system. To the extent that time-varying rates encourage adoption of technologies that automate load changes in response to prices, this could be valuable for integrating variable renewable energy resources (as discussed previously).

4.3. Option value

Assessment of DR value often relies on point estimates of factors like the peak demand forecast and generating unit availability. By limiting the analysis to a few discrete scenarios, the full spectrum of extreme events that could occur on a system is often underrepresented. In fact, it is in response to uncertain and extreme events that DR has been found to provide the most value; this is described as the "option value" of DR.[54] Studies have shown that being able to avoid blackouts in extreme reliability situations through the use of DR programs could justify investment in the programs even if they happen only once every five or ten years.[55]

4.5. Improved post-outage power restoration

After an outage, it is necessary to control the rate at which power is restored to the grid in order to avoid over-stressing the system. Some load control technologies have a feature which brings the controlled end-uses online in a staggered fashion in order to "spread out" the ramping of load over time.

4.6. More equitable retail rates

Demand response can be offered in the form of retail prices that are higher during peak periods and lower during off-peak periods (i.e., time-varying rates). By providing a price signal that more accurately reflects the cost of supplying electricity over the course of a day, time-varying rates are more equitable than a flat rate and reduces the cross-subsidization that currently exists between customers with “peaky” or “flat” load shapes.

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[7] Navigant Research, "Market Data: Demand Response," 2Q, 2013. http://www.navigantresearch.com/research/market-data-demand-response

[8] For instance, the specific mechanics of evaluating the capacity value of DR in a region with a centralized wholesale capacity market will be inherently different than those of valuing DR for a vertically integrated utility, despite the fact that the value is derived in both cases from the avoided or deferred cost of a new peaking unit.

[9] For further examples of DR costs, see EPRI, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Projects," January 2010.

[10] Midwestern Energy News: http://www.midwestenergynews.com/2013/07/25/heat-waves-provide-critical-test-for-demand-response/

[11] Environmental Defense Fund blog: http://blogs.edf.org/energyexchange/2014/04/10/update-demand-response-helped-texas-avoid-rolling-blackouts-in-the-face-of-polar-vortex-2/

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[15] See the ERCOT website for more information: http://www.ercot.com/services/programs/load/laar/

[16] Navigant Research, "Market Data: Demand Response," 2Q, 2013. http://www.navigantresearch.com/research/market-data-demand-response

[17] Ahmad Faruqui, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, "The Power of Five Percent," *The Electricity Journal*, October 2007.

[18] Depending on the specific economic conditions of the system, such as load shape and mix of existing generation resources, a different type of generating unit, such as a combined cycle (CCCT), could be the marginal unit. For simplicity, we use a combustion turbine as a proxy for marginal generation capacity cost throughout this report. System-specific modeling will reveal which technology makes the most sense, but generally the most "pure" form of generation capacity (lowest capital and highest operating costs) will be an open-cycle combustion turbine.

[19] Ideally, a supply curve of DR resources would be developed and incorporated into the modeling such that they are competing against conventional generation resources. For further discussion, see Andy Satchwell and Ryan Hledik, "Analytical Frameworks to Incorporating Demand Response in Long-Term Resource Planning," Utilities Policy, March 2014.

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[21] Ibid.

[22] Of course, DR would also potentially provide energy and ancillary services value that would offset some or all of this "avoided" benefit. The energy and ancillary services value of DR is discussed in Section 3.

[23] For instance, consider a new peaking unit with an average variable cost of $60/MWh. If the plant ran for 500 hours of the year and the average marginal price of electricity during these hours was $100/MWh, the energy margin would be ($100/MWh - $60/MWh) x 500 hours = $20,000/MW-year or $20/kW-year.

[24] For further detail on the derate factor, see the CPUC website. http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

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[27] SNL Financial, "Cal-ISO: Huntington plant revival crucial for summer if San Onofre outage continues," by Jeff Stanfield, April 12, 2013.

[28] NE-ISO presentation to Demand Resource Working Group, *July 19th 2013 OP4 Action 2 Initial Real Time Demand Resource Performance*, July 31, 2013.

[29] Derived from Sam Newell and Kathleen Spees, "Resource Adequacy in Western Australia: Alternatives to the Reserve Capacity Mechanism," prepared for EnerNOC, August 2014. http://www.brattle.com/system/publications/pdfs/000/005/070/original/WA_Resource_Adequacy_Spees_Newell.pdf?1408985223

[30] If the system peak is projected to be 1,000 MW, the utility would have 1,150 MW of available capacity.

[31] $53/kW-year x (1 + 8%) x (1 + 15%) = $66/kW-year.

[32] It is possible that some old, inefficient, excess peaking capacity would be retired if DR is added to the system, in which case the fixed O&M associated with that capacity would be an avoided cost attributable to DR.

[33] CONE is commonly accepted industry terminology, although various markets will use alternative terms for the same concept.

[34] For an example of Gross CONE estimation, see Samuel A. Newell et al, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," prepared for PJM Interconnection, May 15, 2014. http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx

[35] For more detailed discussion, see EnerNOC, "Best Practices of Demand Response in Capacity-Based Markets and Programs," June 2014.

[36] PJM also runs annual interim auctions.

[37] RTO clearing prices for the Base Residual Auction. Other zones have cleared at higher prices to due transmission constraints. See PJM Website: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

[38] Note that PJM pays variations of the market clearing price for DR products with different performance characteristics. Similar to the derate that is applied in some regulated markets to account for the availability and flexibility of a DR program, PJM provides higher payments for more reliable and flexible DR products and lower payments for less flexible products. This type of price variation should be accounted for if it is a feature of the specific market being analyzed.

[39] U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," February 2006. http://energy.gov/oe/downloads/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report

[40] These market constructs typically have a "scarcity pricing" mechanism through which energy prices are administratively increased during emergency conditions in order to encourage new entry into the market.

[41] See Constellation website:
http://www.constellation.com/documents/government%20case%20studies/ercot%20load%20response%20snapshot.pdf

[42] IESO, "OPA Demand Response Programs," January 17, 2011. http://www.ieso.ca/Documents/icms/tp/2012/01/IESOTP_256_7b_OPA_Demand_Response_Programs.pdf. See also the Save ON Energy website: https://saveonenergy.ca/Business/Program-Overviews/Demand-Response.aspx

[43] PJM letter to Transmission Expansion Advisory Committee, August 28, 2012 http://www.pjm.com/~/media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx

[44] At the distribution level, this may be a particularly valuable aspect of DR in the future if there is significant growth in electric vehicle adoption; direct control of charging could help to manage potential reliability issues on the distribution system.

[45] ConEd website. Tier II customers receive payments of $6/kW-month and Tier I customers receive payments of $3/kW-month. Due to its very densely populated urban service territory in New York, ConEd is an

example of a utility with potentially very high peak-driven T&D costs. One study found that these costs could grow in excess of $200/kW-year over time. Josh Bode, Stephen George, and Aimee Savage, "Cost-Effectiveness of CECONY Demand Response Programs," November 2013. http://documents.dps ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBE9E7304-DA3C-4C06-B18B-ADD0D4568E3F%7D

46 This may not always be the case, as unplanned unit outages can lead to reliability concerns during mid-peak or even off-peak hours of the day.

47 This is a weighted average, with the weights being the amount of energy reduced in each hour attributable to the DR program. In our example, we assume the same load reduction in each hour.

48 Kiliccote, Sila et al, "Integrating Renewable Resources in California and the Role of Automated Demand Response," Lawrence Berkeley National Laboratory, November 2010. http://poet.lbl.gov/drrc/pubs/lbnl-4189e.pdf

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Demand Response Market Research:
Portland General Electric, 2016 to 2035

Ryan Hledik, Ahmad Faruqui and Lukas Bressan

January 2016

Exhibit PLC-5

Demand Response Market Research:

Portland General Electric, 2016 to 2035

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Table of Contents

I. Introduction

Interest in demand response (DR) in the Pacific Northwest has grown considerably since Portland General Electric's (PGE's) first DR potential study was conducted in 2009 and subsequently updated in 2012.[1] A need to integrate growing amounts of intermittent resources (e.g., wind and solar) into the grid, increasingly stringent constraints on the operation of regional hydro generation, growth in summer peak demand, and an expectation of a capacity shortfall in the next five years have all driven interest in DR.

As a result of this growing interest from stakeholders, several new studies have explored the potential for DR to address these issues. For instance, in 2014 the Northwest Power and Conservation Council (NPCC) completed a study to assess the market for various flexible load resources.[2] In that same year, PacifiCorp completed a detailed DSM potential study spanning all of its jurisdictions, with considerable attention being paid to DR programs.[3] That study was noted for the considerable role that demand-side resources will play in future resource planning efforts. Several demonstration projects and pilot studies are now also underway in the region, including the involvement of the Bonneville Power Administration (BPA), Pacific Northwest National Laboratory (PNNL), and many regional utilities including PGE.

To better inform its own DR initiatives and to establish inputs to its integrated resource planning (IRP) process, PGE contracted with The Brattle Group to develop an updated DR potential study ("the 2015 study"). The purpose of this study is to estimate the maximum system peak demand reduction capability that could be realistically achieved through the deployment of specific DR programs in PGE's service territory under reasonable expectations about future market conditions. The study also assesses the likely cost-effectiveness of these programs.

The 2015 study includes several improvements over the prior studies commissioned by PGE, both in terms of the quality of the data being relied upon and the breadth of issues which it addresses. Specific improvements in the 2015 study include the following:

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1 The Brattle Group and Global Energy Partners, "Assessment of Demand Response Potential for PGE," prepared for PGE, March 16, 2009. Also, Ahmad Faruqui and Ryan Hledik, "An Assessment of Portland General Electric's Demand Response Potential," prepared by The Brattle Group for Portland General Electric, November 28, 2012.

2 Navigant, "Assessing Demand Response Program Potential for the Seventh Power Plan: Updated Final Report," prepared for the Northwest Power and Conservation Council, January 19, 2015.

3 Applied Energy Group and The Brattle Group, "PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034," prepared for PacifiCorp, January 30, 2015.

- Market data was updated to account for changes in forecasts of the number of customers by segment, seasonal peak demand, the expected timing and cost of new capacity additions, and other key assumptions that drive estimates of DR potential and its cost-effectiveness.

- Assumptions about DR participation and impacts were updated to reflect emerging DR program experience in the Pacific Northwest. Ten regional studies conducted in the past five years in the region informed these updates.

- The findings of 24 new dynamic pricing pilots, conducted both in the U.S. and internationally, were incorporated to refine potential estimates for pricing programs. This allowed several important aspects of pricing potential to be accounted for, including seasonal impacts and differences in price response when programs are offered on an opt-in versus opt-out basis.

- A survey of market research studies and full-scale time-varying pricing deployments was utilized to improve assumptions around participation in dynamic pricing programs.

- The methodology for estimating the cost-effectiveness of the DR programs, while conceptually consistent with the prior PGE potential studies, was improved to address comments from the Oregon PUC regarding the derating of avoided costs to account for operational constraints of the DR programs. Accounting for incentive payments on the cost-side of the analysis was also refined.

- The menu of program options analyzed was significantly expanded to include several newly emerging options that have recently begun to generate interest among utilities around the country, such as smart water heating load control, behavioral DR, electric vehicle charging load control, and "bring-your-own-thermostat" programs.

A few key points should be kept in mind while reading this report:

1. The load reduction potential and cost-effectiveness of each DR option are evaluated in isolation from each of the other options; they do not account for potential overlap in participation that may occur if several DR options were simultaneously offered to a single customer segment. Therefore, the potential estimates of the individual DR options are not additive and the economics of the programs may change when the DR options are offered as part of a portfolio.

2. The analysis is based on typical program designs with illustrative yet realistic incentive payments. Rather than being the final word on the cost-effectiveness of these programs, findings should be used as a starting point for further exploring how different program designs would change the economics of the programs.

3. Unless otherwise noted, peak reduction potential estimates are reported for the year 2021. This was chosen as the reporting year of interest, because it is the first year in which PGE is projected to need new capacity.

4. Any options requiring a change to the rate structure could not be offered until 2018 or 2019 due to constraints with the current billing system.

5. In all cases, the cost of advanced metering infrastructure (AMI) is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

6. As is discussed in the Methodology section of this report, the estimates of potential are not projections of what is likely to occur. Rather, they represent an estimated upper-bound on what is achievable under current expectations of future system conditions and reflect utility experience with successful DR programs around the country. Achieving this potential will require a significant customer outreach and education effort and will likely take time, given the relative lack of experience with DR in the Pacific Northwest relative to other parts of the country. Like energy efficiency, successful DR programs require active customer participation. DR in the Pacific NW is in a similar place to where energy efficiency was in the region in the late 1970s or early 1980s. The region – and PGE – has the potential to achieve a significant amount of DR, but there is an upfront investment in awareness and program design that will be required to meet this potential. Ultimately, PGE's ability to achieve significant impacts through DR programs will depend on customer understanding and acceptance of the programs.

The remainder of this report is organized as follows. Section 2 describes the various DR options that were analyzed. Section 3 summarizes highlights of the methodology for estimating potential and evaluating cost-effectiveness. Section 4 presents the key findings of the study. Section 5 concludes with a discussion of considerations for PGE's ongoing and future DR initiatives. The report is intended to be a concise summary of the highlights of the study; the appendices contain significantly more detail on methodology and assumptions.

II. The DR Options

Thirteen different types of DR programs were analyzed in this study. Eligibility for the programs varies in part by customer segment. PGE's customer base was divided into five customer classes. Customer class definitions were determined based on both applicability of DR programs and data availability.

- Residential: All residential accounts
- Small Commercial & Industrial (C&I): Less than 30 kW of demand
- Medium C&I: 30 kW to 200 kW of demand
- Large C&I: More than 200 kW of demand
- Agricultural: All agriculture accounts

Non-metered customers, such as street lighting, were excluded from the analysis, as were customers who have chosen direct access.

Accounting for the number of DR programs offered to each customer segment, a total of 28 different options were analyzed. For organizational purposes, the DR programs can be assigned to three categories: (1) Pricing options, (2) conventional non-pricing options, and (3) newly emerging DR options.

Pricing Options

AMI-enabled rate options include prices that vary by time of day. The potential in each pricing option was modeled both with and without the adoption of enabling technology. For residential and small C&I customers, the enabling technology is assumed to be a programmable communicating thermostat (PCT), also known as a smart thermostat, which would allow the customer to automate reductions in heating or cooling load during times when the price in the retail rate is high. For medium and large C&I customers, the enabling technology is Auto-DR, which can be integrated with a building's energy management system to facilitate a range of automated load reduction strategies.

<u>Time-of-use (TOU) rate:</u> A TOU rate divides the day into time periods and provides a schedule of rates for each period. For example, a peak period might be defined as the period from 3 pm to 8 pm on weekdays and Saturdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the average variation in the cost of supply (including marginal capacity costs). In some cases, TOU rates may have a shoulder (or mid-peak) period, or particularly in the winter season, two peak periods (such as a morning peak from 6 am to 10 am, and an afternoon peak from 3 pm to 8 pm). Additionally, the prices and period definitions might vary by season. With a TOU rate, there is certainty as to what the prices will be and when they will occur.

<u>Critical peak pricing (CPP):</u> Under a CPP rate, participating customers pay higher prices during the few days when wholesale prices are the highest or when the power grid is severely stressed (i.e., typically up to 15 days per year during the season(s) of the system peak). This higher peak

price reflects both energy and capacity costs. In return, the participants receive a discount on the standard tariff price during the other hours of the season or year to keep the utility's total annual revenue constant. Customers are typically notified of an upcoming "critical peak event" one day in advance.

Peak Time Rebate (PTR): Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply pay the existing rate. There is no rate discount during non-event hours. Customers stay on the standard rate at all hours. The program is analogous to the pay-for-curtailment programs that have been offered to large commercial and industrial customers in restructured markets for many years. Opt-out deployments of PTR are being offered by BGE and Pepco to residential customers in Maryland. These relatively new programs will provide more information in the next few years as their impact evaluations become available.

CONVENTIONAL NON-PRICING PROGRAMS

There is a long history of experience with conventional non-pricing programs in the U.S. These programs provide customers with incentive payments or bill credits in return for relatively dependable load reductions and do not require AMI.

Direct load control (DLC) for heating and cooling: With heating/cooling DLC the utility controls a customer's electric heating or central air-conditioning equipment on short notice. In exchange for participating, the customer receives an incentive payment or bill credit. Recent DLC programs have involved the installation of smart thermostats for customers, which allow remote adjustment of temperature settings, so the utility can remotely adjust the temperature to reduce demand from central air-conditioning (CAC) and central space heating units. After an event, load control is released, allowing the thermostat control to revert back to the customer's original settings.

Water heating DLC: Like DLC for heating and cooling, water heating DLC allows the utility to control the load of electric resistance water heaters. The water heating element is turned off during times when load reductions are needed, and turned back on before the average water temperature in the tank drops below a minimum threshold. In some applications, the water is superheated during nighttime hours to allow for longer periods of load curtailment during the day. One difference between water heating DLC and space heating/cooling DLC is that water heaters are used, on average, year-round and during all hours of the day, and can be interrupted without any detectable impact by the customer.

Curtailable tariff. This is similar to PGE's Firm Load Reduction program (Schedule 77).[4] Under a curtailable tariff, eligible customers agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year) and are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment varies with the load commitment level and the amount of notice required (e.g., number of hour or minutes). In addition to the fixed capacity payment, participants typically receive a payment for energy reduction. Since load reductions must be of firm resource quality, curtailment is often mandatory and penalties can be assessed for under-performance or non-performance.

Third-party C&I DLC: This is similar to PGE's Energy Partner program. With Third Party DLC, an "aggregator" (also known as a "curtailment services provider") works with customers to establish protocols to automate load reductions at times when they are needed from PGE. PGE purchases the aggregated load reduction from the aggregator, who shares the revenues with the customers who participate in the program. With the Third Party DLC program, customer recruitment and certain operational aspects of the program are handled by the aggregator rather than the utility.

EMERGING DR OPTIONS

Several new DR options were analyzed in this study. These are DR options with which there is relatively limited experience to-date. However, the programs have garnered significant interest from utilities around the U.S. recently and are beginning to be tested through pilot programs and some full-scale rollouts.

Bring-your-own-thermostat (BYOT): In a BYOT program, customers who already own a smart thermostat are paid to participate in a DLC program. An advantage of this program over a traditional heating/cooling DLC program are that the customer already has the necessary equipment, so there are no equipment or installation costs associated with the program. Additionally, given that the customer has made the decision to invest in a smart thermostat, it is likely that participants are already more engaged in their energy usage than the typical customer. In PGE's service territory, the market penetration of central A/C is growing rapidly and the Energy Trust of Oregon (ETO) is promoting the adoption of smart thermostats for energy efficiency benefits, suggesting that the eligible customer base for such a program will grow considerably in the coming years. Even the low-end of the range of national studies on likely smart thermostat adoption suggests that 25 percent of households will be equipped with a smart

[4] Whereas PGE's Schedule 77 program has a specific design and incentive structure developed by PGE, our assessment of the Curtailable Tariff program in this study is based on average participation across a range of curtailable tariff program designs in the U.S. In this sense, our analysis is for a more generic design that is a hybrid of these programs.

thermostat by 2020.[5] Several utilities, such as Austin Energy, Southern California Edison, ConEd, and Hydro One have recently introduced BYOT programs. PGE is currently exploring this program option through a pilot program with Nest Labs.

Behavioral DR (BDR): In a BDR program customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. BDR can be thought of as a PTR without the rebate payment. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Customer response is driven by new information that they didn't previously have. BDR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, BGE, and four Minnesota cooperatives.

Smart water heating DLC: In contrast to the conventional water heating DLC program described above, smart water heating DLC accounts for an emerging trend toward the availability and adoption of "DR-ready" water heaters. These water heaters come pre-equipped with the communications capability necessary to participate in a DR program and have the potential to offer improved flexibility and functionality in the control of the heating element in the water heater. Rather than simply turning the element on or off, the thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. This has the potential for facilitating the integration of intermittent sources of generation. Smart water heating DLC was modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters in the Pacific Northwest and are the most attractive candidates for a range of advanced load control strategies.[6]

EV charging load control: EVs represent a potentially flexible source of nighttime load, and adoption of EVs is projected to grow in the future. This study focuses only on the potential to control home charging of personal EVs. It does not include, for example, load control at public charging stations or for commercial fleets.

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[5] Berg Insight, "Smart Homes and Home Automation," January 2015.

[6] It may also be possible to control the load of heat pump water heaters, though there is more uncertainty around the technical and economic effectiveness of this option.

III. Methodology

This study focuses on estimating "maximum achievable potential." This is founded in the assumption that enrollment rates in the DR programs reach the levels attained in successful DR programs being offered around the country. Therefore, while the assumed enrollment levels have been demonstrated to be achievable by other utilities, they represent an approximate upper-bound based on recent DR experience. In other words they represent some of the highest enrollment levels observed in DR programs to-date.

A few factors suggest that PGE may be able to attain levels of enrollment approaching what the very top programs have achieved nationally:

1. There has been a long history of success with energy efficiency programs in PGE's service territory, suggesting that customers are open to participating in energy management programs.
2. PGE has an environmentally conscious customer base.
3. There has been a trend toward the rising adoption of new energy management products, such as smart thermostats, in the region.
4. Growth in summer peak demand means that DR programs that were previously not applicable to PGE's service territory can now be productively offered to customers.

At the same time, it is important to note that it will likely take time for PGE to approach these levels of enrollment. PGE, like much of the rest of the Pacific Northwest, is starting from a point of limited experience with DR programs and low energy prices relative to utilities in other regions of the U.S., and customers will need to be educated about the benefits of the programs before having the confidence to enroll. To some extent, this appears to have been the experience thus far with the Energy Partner program. Nationally, the most successful DR programs often required years of promotion and experimentation by utilities and aggregators before achieving the high enrollment levels that are observed today.

DR potential is estimated using empirically-based assumptions about the eligible customer base, participation, and per-customer impacts. The fundamental equation for calculating the potential system impact of a given DR option is shown in Figure 1 below. Market characteristics (e.g. system peak demand forecast, customer load profiles, number of customers in each class, appliance saturations) were provided by PGE.

Figure 1: The DR Potential Estimation Framework

Potential DR Impact	**=**	**Total Demand of Customer Base**	**X**	**% of Base Eligible to Participate**	**X**	**% of Eligible Customers Participating**	**X**	**% Reduction in demand per participant**

PARTICIPATION

Two variations of maximum achievable potential were estimated for the pricing options (TOU, CPP, PTR), based on different assumptions about the manner in which these programs would be offered to customers. Opt-in deployment assumes that customers would remain on the currently existing rate and would need to proactively make an effort to enroll in the dynamic rate. Default deployment (also known as opt-out deployment) assumes that customers are automatically enrolled in a dynamic rate with the option to revert back to the otherwise applicable tariff if they choose. Default rate offerings are typically expected to result in significantly higher enrollment than when offered on an opt-in basis. Default deployment of dynamic pricing for residential customers is currently uncommon, although TOU rates have been rolled out on an opt-out basis across the province of Ontario, Canada and throughout Italy. PTR has been offered on an opt-out basis by Southern California Edison, Baltimore Gas & Electric (BGE), and Pepco Holdings in Maryland and Washington, D.C.

Participation in the pricing programs was based on a review of market research studies and full-scale deployments of time-varying rates. The market research studies used a survey-based approach to gauge customer interest in the various pricing options, while the full-scale deployments reflect actual experience in the field. Opt-in participation rates range from 13 to 28 percent, which varies by pricing option and customer segment. When offered on an opt-out basis, the participation assumptions range from 63 to 92 percent.

Participation in the conventional non-pricing programs is based on a review of DR program data collected by the Federal Energy Regulatory Commission (FERC).[7] FERC surveyed U.S. utilities to gather information on the types of DR programs they offer, the number of customers enrolled, the peak demand reduction capability of the programs, and several other variables. To establish a reasonable upper-bound on participation for this study, the 75th percentile of the distribution of participation rates in each program in the FERC database was used as the basis for enrollment. The resulting participation rates generally range from 15 percent to 25 percent, although they are higher in a few instances where significant enrollment has been observed (e.g., large C&I curtailable tariff enrollment of 40%).

Enrollment in emerging DR options (BYOT, behavioral DR, smart water heating DLC) was based largely on the experience of pilot programs, because by nature there is limited full-scale experience with the emerging options at this point. In instances where the programs have not been piloted, expert judgment was used to develop plausible enrollment estimates that were intuitively consistent with participation assumptions for other programs in the study.

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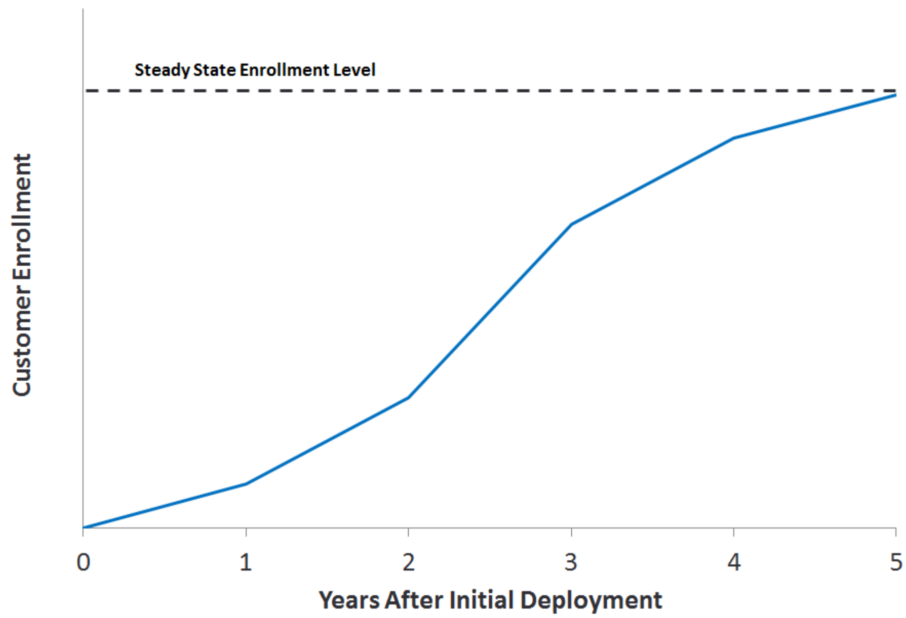
7 FERC, "Assessment of Demand Response and Advanced Metering," December 2012. Supporting database: http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

Changes in participation are assumed to happen over a five-year timeframe once the new programs are offered. The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the five-year period, and then slows over the second half (see Figure 2). A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options. This reflects an aggressive ramp-up in participation for a utility with relatively limited DR experience like PGE. See Appendix A for more detail on the development of the participation assumptions.

Figure 2: Illustration of S-shaped diffusion curve



Per-participant Impacts

Per-participant impacts for the pricing options were based on the results of 225 different pricing tests that have been conducted across 42 residential pricing pilots over roughly the past 12 years.[8] These pilots have almost universally found that customers do respond to time-varying rates, and that the amount of price responsiveness increases as the peak-to-off-peak price ratio in the rate increases. The simulated impacts that were simulated for PGE in this study account for this non-linear relationship between a customer's price responsiveness and the peak-to-off-peak price ratio. The impacts also account for differences by season, across rate designs, and whether the rates are assumed to be offered on an opt-in or default basis. The study has assumed a price ratio of two-to-one in the TOU rate, four-to-one in the CPP rate, and eight-to-one in the PTR rate.

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8 Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

These price ratios were provided by PGE based on rate designs that they would consider offering in the future.

Impacts for conventional non-pricing programs remained relatively stable relative to PGE's 2012 DR potential study, given the long history of experience with these programs in the U.S. In this updated study for PGE, those impact assumptions were refreshed based on a review of ten DR pilot programs that have been conducted in the Pacific Northwest. For the emerging DR options, impacts were based on the findings of pilots where available and otherwise calibrated to the impacts of other DR programs in the study to ensure reasonable relative impacts across the programs. While estimates of impacts associated with all of the programs have some degree of uncertainty, there is less uncertainty in the impacts of the conventional and pricing programs due to significant experience with these programs through both a full-scale rollouts and scientifically rigorous pilots. There is a higher degree of uncertainty in the impacts of the emerging DR programs as, by nature, they are newer and less tested. See Appendix B for more detail on the development of the per-participant impact assumptions.

COST-EFFECTIVENESS

The cost-effectiveness of each DR option was assessed using the total resource cost (TRC) test. The TRC test measures the total benefits and costs of a program, including those of both the utility and the participant. The TRC test is the cost-effectiveness framework that is commonly used by the Oregon PUC to assess the economics of demand-side programs. The present value of the benefits is divided by the present value of the costs to arrive at a benefit-cost ratio. Programs with a benefit-cost ratio greater than 1.0 are considered to be cost-effective. [9]

Benefits in the cost-effectiveness analysis include:[10]

- Net avoided generation capacity cost ($145/kW-yr)[11]
- Avoided peak-driven T&D cost ($31/kW-yr)
- Avoided peak energy cost ($32/MWh, growing over time)

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9 For further information on cost-effectiveness analysis of DR programs, see Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

10 Avoided cost estimates were provided by PGE and reviewed by The Brattle Group for reasonableness.

11 The total cost of a peaking unit is reduced by an estimate of the unit's expected energy margins to arrive at a net avoided cost that would be roughly equivalent to the net cost of new entry (CONE) in an organized capacity market.

Costs in the cost-effectiveness analysis vary by program type and include:[12]

- Program development
- Administrative
- Equipment and installation
- Operations and maintenance
- Marketing and recruitment
- Incentive payments to participants

Treatment of participant incentives as a cost was given close consideration in the study. There is not a standard approach for treating incentives when assessing the cost-effectiveness of DR programs. In some states, incentive payments are simply considered a transfer payment from utilities (or other program administrators) to participants, and therefore are not counted as a cost from a societal perspective. Others suggest the incentive payment is a rough approximation of the "hassle factor" experienced by participants in the program (e.g., reduced control over their thermostat during DR events), and should be included as a cost.

While there is some merit to the latter argument – that customers may experience a degree of inconvenience or other transaction costs when participating in DR programs – the cost of that inconvenience is overstated if it is assumed to equal the full value of the incentive payment. If that were the case, then no customer would be better off by participating in the DR program. For example, it would be unrealistic to assume that an industrial facility would participate in a curtailable tariff program if the cost of reducing operations during DR events (e.g., reduction in output) exactly equaled the incentive payment for participating. In reality, customers participate in DR programs because they derive some incremental value from that participation. Further, in some DR programs customers experience very little inconvenience. Some A/C DLC programs, for instance, can pre-cool the home and manage the thermostat in a way that few customers report even being aware that a DR event had occurred, let alone a loss of comfort.

Given the uncertainty around this assumption, this study counts half of the incentive payment as a cost in the cost-effectiveness analysis. Two sensitivity cases were also analyzed, exploring how the findings change when the full incentive is counted as a cost as well as when it is entirely excluded from the calculation.[13] This is similar to the approach adopted by the California Public

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12 Costs of the programs were typically annualized over a 15-year life in this study. Fifteen years is an illustrative but plausible assumption. While the life of individual appliances and technologies will vary around this number, the impact of that variance is well within the magnitude of other uncertainties in the analysis such as projections of marginal costs and load growth. In future research, sensitivity analysis could be conducted around uncertain variables such as these to develop a better understanding of the key drivers of the findings.

13 See Appendix C for the results of the sensitivity cases. Relative to the case where half of the incentive is included as a cost, when none of the incentive is included as a cost, water heating load control for

Continued on next page

Utilities Commission, which considers a range of treatments of the incentive payment when evaluating DR cost-effectiveness.

Another important consideration in the cost-effectiveness analysis is how to derate avoided capacity costs to account for operational constraints of the DR programs. Unlike the around-the-clock availability of a peaking unit, DR programs are typically constrained by the number of load curtailment events that can be called during the course of a year. Further, there are often pre-defined limitations on the window of hours of the day during which the events can be called, and sometimes even on the number of days in a row that an event may be called. It is also often the case that hour-ahead or day-ahead notification must be given to participants before calling an event. All of these constraints can potentially limit the capacity value of a DR program.

Some utilities account for these constraints of DR programs through a derate factor that is applied to the avoided capacity costs that are estimated for any given DR program. The derate factor is program-specific and is estimated through an assessment of the relative availability of DR during hours with the highest loss of load probability. Historically, depending on program characteristics and utility operating conditions, some derate factors have ranged from zero to roughly 50 percent of the capacity value of the programs. The derate factor is program- and utility-specific.

In California, a methodology for establishing these derates has been codified by the CPUC in its DR Cost-Effectiveness Protocols.[14] There are effectively three factors that are used to adjust the avoided costs attributable to DR programs:

1. The "A Factor" represents the "portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted." In other words, it accounts for limitations on the availability of the DR program, when DR events can occur, and how often.

Continued from previous page

small C&I, agricultural pumping load control, and technology-enabled PTR for residential and small C&I become moderately cost-effective. When the full incentive is counted as a cost, several DLC programs for residential and small C&I customers become slightly uneconomic. Across these cases, through the changes in the economics are relatively modest, with benefit-cost ratios that remain close to 1.0.

14 California Public Utilities Commission, "2010 Demand Response Cost-Effectiveness Protocols," December 16, 2010. http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC. An Energy Division Staff Proposal to update the protocols, dated June 2015, includes additional information on the derate factors and changes that are being considered: http://docs.cpuc.gov/SearchRes.aspx?DocFormat=ALL&DocID=94268875

2. The "B Factor" accounts for notification time. Programs requiring day-ahead notification are less likely than programs with hour-ahead or real-time notification to coincide with system peak or reliability conditions due to forecasting uncertainty.

3. The "C Factor" accounts for limitations on any triggers or conditions that would permit the utility to call a DR event. For example, a DR tariff might only allow an event to be called if the outdoor air temperature exceeds some predetermined threshold.
4. Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE. The CPUC is currently examining the possible modification and expansion of these factors.

To develop derate factors for PGE, the derate factors applied by the California investor-owned utilities (IOUs) to their extensive portfolio of DR programs were compiled.[15] Based on a review of these derate factors, the values were calibrated to capture the appropriate relative relationships across the programs evaluated for PGE. Expert judgement was used to develop estimates for those programs for which there is not a clear example in the California data. This approach – starting with approved utility estimates from a nearby jurisdiction and modifying them to better reflect the programs that could be offered by PGE – ensures that the estimates are based on actual DR program experience and reasonably well tailored to PGE's system conditions. As a result, the avoided capacity costs were derated anywhere between 19 and 47 percent. A summary of the portion of avoided capacity cost attributed to each DR program is presented in Table 1.

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[15] See the links for the utility programs at the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

Table 1: Share of Total Avoided Cost Attributed to DR Program

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

Notes: A-factor estimates for dynamic pricing (PTR and CPP), residential DLC, and curtailable tariffs are derived from values estimated by the California utilities. A-factor estimates for other programs are based on intuitive relationships to those programs. B-factor estimates follow a general assumption observed in California that day-ahead programs have an 88% value and day-of programs have a 100% value. C-factor estimates in California tend to assume 100% for all programs except DLC, for which the assumption is 95%.

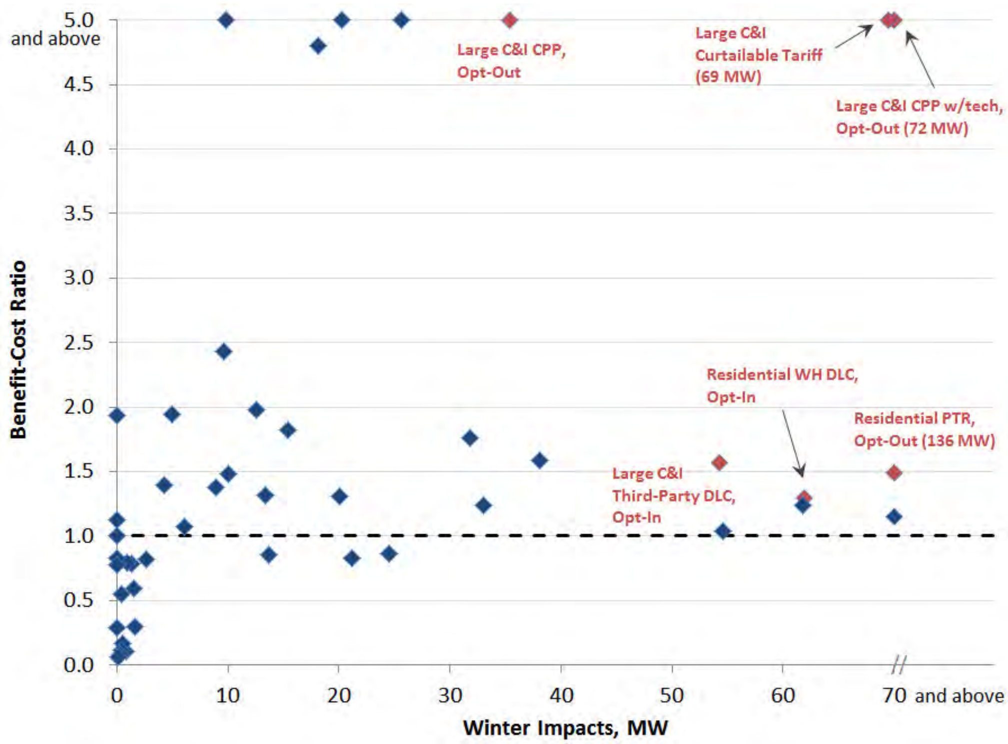
IV. Findings

The result of the analysis is an estimate of the maximum achievable peak reduction capability of each DR program for each year from 2016 through 2035, as well as a benefit-cost ratio for each program. These annual results are provided in Appendix D as a Microsoft Excel File. The results can be organized around 10 key findings:

1. The largest and most cost-effective DR opportunities are in the residential and large C&I customer segments
2. Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment
3. The incremental benefits of coupling enabling technology with pricing options are modest from a maximum achievable potential perspective and perhaps best realized through a BYOT program
4. BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term
5. Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits
6. EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand
7. Small C&I DLC has a small amount of cost-effective potential
8. DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a number of programs
9. Agricultural DR programs are small and uneconomic
10. The economics of some programs improve when accounting for their ability to provide ancillary services

Finding #1: The most cost-effective DR opportunities are in the residential and large C&I customer segments. In fact, nine of the ten programs with the largest potential are in the residential and large C&I sectors. Those also tend to be the sectors with the most cost-effective programs. Figure 3 below illustrates each program's cost effectiveness relative to its peak reduction potential. Those programs in the top-right portion of the chart provide the biggest "bang for the buck" whereas those in the bottom-left corner are small and uneconomic. The largest and most cost-effective programs tend to be pricing programs for residential and large C&I customers.

Figure 3: Winter Potential vs. B-C Ratio by Measure



Finding #2: Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment. If offered on an opt-out basis, residential PTR and CPP programs could potentially provide over 100 MW of peak reduction capability.[16] Offered on an opt-in basis, the potential is smaller but still in excess of 40 MW for both of these options. Impacts from TOU rates are smaller than those of PTR and CPP due to the lower peak period price in the TOU. However, the TOU impacts would represent a permanent shift in the daily system load profile due to the daily price signal embodied in the rate's design.[17] Based on the experience of recent pilot programs an opt-out BDR program could lead to peak demand reductions of close to 60 MW. However, given limited experience with BDR programs on a large scale, there is uncertainty around the extent to which the impacts would persist across multiple

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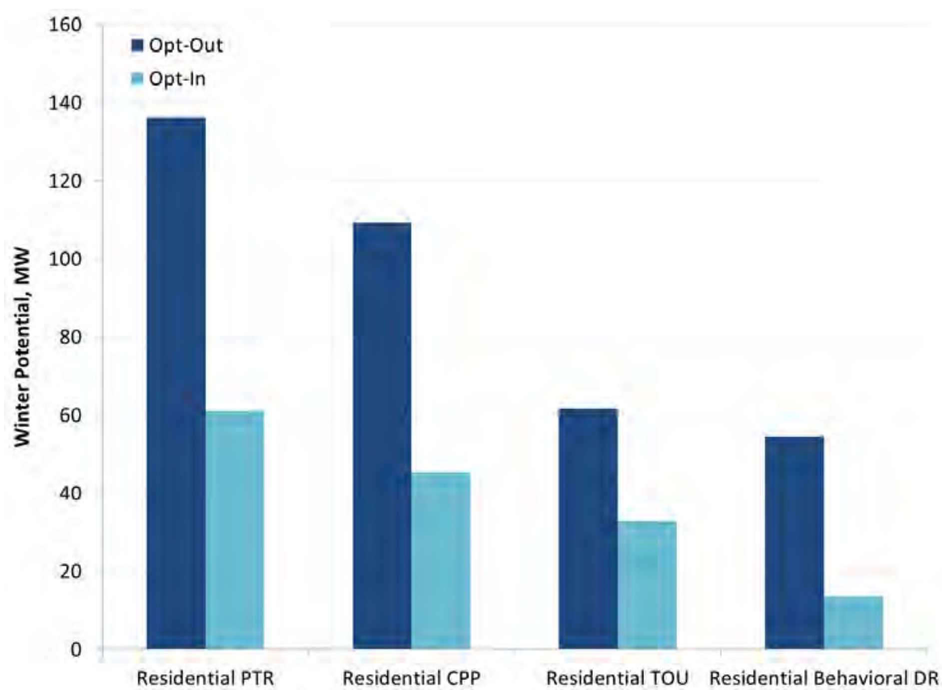
16 In this analysis, the higher potential in PTR relative to CPP is driven by the assumption that the PTR would have a significantly higher price ratio, and therefore produce larger per-participant load impacts. If the PTR and CPP were assumed to have the same price ratio, there would be more potential in a CPP rate offering.

17 It is also important to note that a TOU design could be coupled with a CPP or PTR rate. The TOU rate would apply most days of the year, with the CPP or PTR peak price (or rebate) applying on a limited number of days. This would provide both the daily load shifting benefits of the TOU rate and the advantages of a dynamic CPP or PTR price signal that can be dispatched in response to changing system conditions.

events and when deployed to all customers in PGE's service territory. There is significantly more certainty and reliability in the impacts of the pricing programs.

Figure 4 summarizes the potential estimates of residential pricing programs. All of these impacts are in the absence of enabling technology – they are purely based on behavioral response to the new prices and information. Additionally, it should be noted that the pricing options likely could not begin to be rolled out to customers on a full-scale basis until 2018 or 2019 due to constraints with the current billing system. While this would still leave time to reach significant enrollment levels by 2021, it means that the pricing options will not be available to address immediate needs for load reductions.

Figure 4: Winter Peak Reduction Potential for Residential Pricing and BDR



The programs are cost-effective in all cases except opt-in BDR.[18] For conventional pricing programs the opt-in offering has a slightly higher benefit-cost ratio than the opt-out offering due to marketing and education costs that are lower on a dollars-per-kW basis. However, opt-out offerings provide greater net benefits in absolute dollar terms. In all cases, the cost of AMI is not accounted for in the cost-effectiveness analysis as the infrastructure is already in place regardless of whether or not a decision is made to the offer pricing programs.

[18] It is unlikely that BDR would be offered on an opt-in basis in any case. These programs are typically based on mass appeals to customers to reduce load, and customers could elect to opt out of the notifications if they desired.

Finding #3: The incremental benefits of coupling enabling technology with residential pricing options are modest and perhaps best realized through a BYOT program. The provision of enabling technology such as smart thermostats only modestly increases the potential of pricing options in the aggregate. On its surface, this appears counterintuitive because recent studies have found that enabling technology provides a 90 percent boost over the impact of price alone for a given customer, almost doubling their price responsiveness. The reason for the low incremental potential is that the eligible market for the technology is limited. We have assumed that only customers with both electric heat and central A/C would be eligible for pricing with enabling technology, as these are the only segment for which it is likely to be cost-effective given PGE's dual peaking nature and the need for load reductions in both the summer and winter seasons. Less than 10 percent of residential customers have both electric heat and central A/C. As a result, in the aggregate, potential increases only by about 5 MW for opt-in offerings and 10 MW for opt-out offerings.

Further, the provision of enabling technology by PGE does not appear to be incrementally cost-effective. Assuming there is already a plan to roll out dynamic pricing to customers, the incremental load reduction capability provided by enabling technology, above and beyond the impact that would be achieved in the absence of the technology, is not enough to justify the cost. This is a different outcome from some other jurisdictions, where a summer peak and significant air-conditioning market penetration can help to justify the investment.

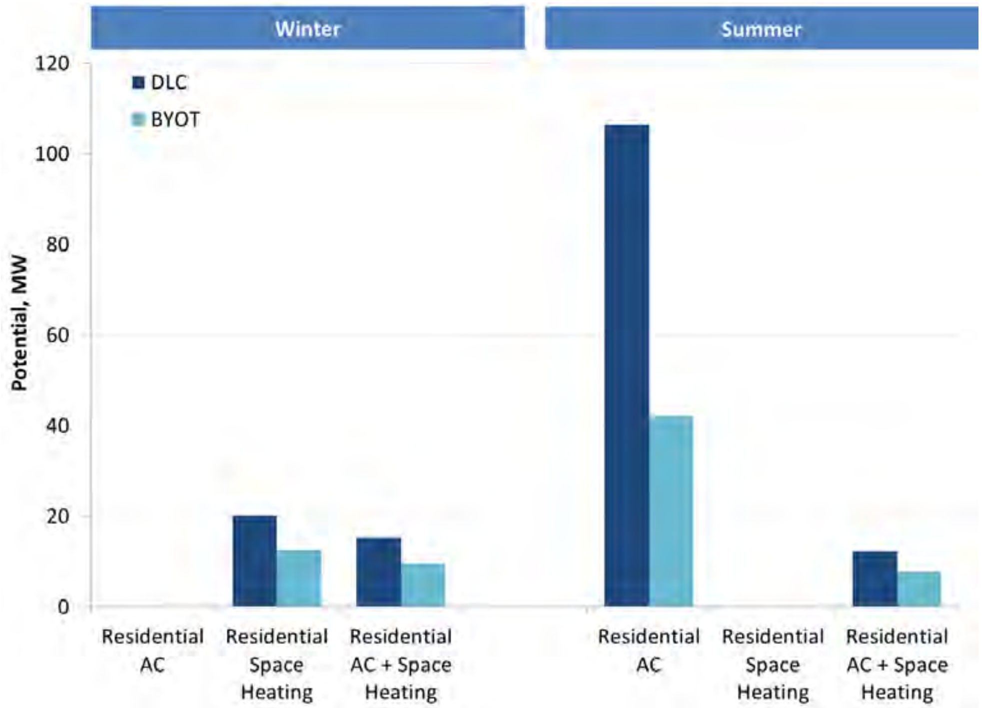
This conclusion changes when customers already own a smart thermostat; a BYOT program coupled with a dynamic pricing program could be highly cost-effective. In the future there may also be additional value in a "prices-to-devices" concept with real-time pricing and end-uses that provide automated response to changes in the price with short notification, as these programs could provide significant energy and even ancillary services benefits, in addition to avoided capacity costs. Additionally, the provision of enabling technology has the potential to improve customer satisfaction and participation in the programs by automating load reductions and allowing customers to "set it and forget it."

Finding #4: BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term. As is illustrated in Figure 5, A/C load control is a particularly large summer resource, representing over 100 MW of peak reduction capability. Potential is significant but smaller in the BYOT program, because it will take time for adoption of smart thermostats to materialize in the market. However, BYOT programs offer better cost savings than conventional DLC because there is no associated equipment cost. Whereas the benefit-cost ratio of conventional A/C DLC is around 1.1, the benefit-cost ratio of a BYOT A/C program is close to 2.0.[19] A program design consideration, therefore, will be whether to pursue the larger potential in the conventional DLC program versus the most cost-effective potential in

[19] Note that A/C load control in either form will become increasingly cost-effective as summer capacity needs escalate in PGE's service territory.

the BYOT program. The potential for differences in customer satisfaction with the programs is also an important consideration – this could be tested further through primary market research.

Figure 5: Seasonal Peak Reduction Potential for Residential DLC

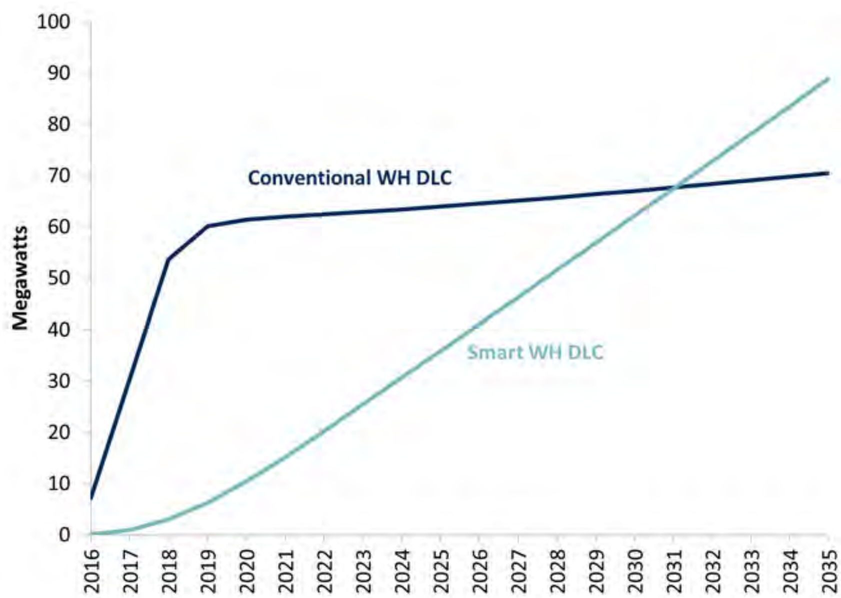


DLC programs are typically offered as part of a bundled package targeting multiple end-uses. Customers could receive different incentive payments based on the number of end-uses (A/C, space heating, electric water heating) they enroll in the program. Both the conventional DLC approach and the BYOT approach are cost-effective as bundled packages, with the conventional approach having a benefit-cost ratio of 1.3 and the BYOT approach having a ratio of 2.0. Additionally, for customers with an electric vehicle, EV charging load control could be added to the portfolio. In this case, the conventional approach would still be cost-effective, with a ratio of 1.2.

Finding #5: Residential water heating load control is a cost-effective opportunity with a broad range of potential benefits. As described in Section 3, two types of water heating load control programs were modeled. The first is conventional water heating DLC. With this type of program, it is assumed that the control technology is a retrofit on existing or new water heaters. The typical equipment and installation costs would amount to approximately $300 per participant.[20] The second type of program is "smart" water heating DLC. This assumes that DR-ready water heaters continue to gain market share. In this scenario, costs are lower, with roughly $40 for equipment and installation (a communications module) and an incremental manufacturing cost to build in the DR capability of $25 per water heater.

Smart water heating DLC potential is low in early years of the forecast horizon due to limited market penetration of "DR-ready" water heaters. However, if these water heaters gain market share, potential in the program will increase. Eventually, due to likely higher participation rates among customers who invest in DR-ready water heaters, the potential could exceed that of a conventional DLC program. Figure 6 illustrates the annual winter peak reduction potential estimate based on one plausible trajectory of smart water heating market penetration.[21]

Figure 6: Winter Peak Reduction Potential for Water Heating Load Control



Both program options are cost-effective, although the smart water heating DLC program has a considerably higher benefit-cost ratio of 2.2, compared to 1.3 in the conventional program. This is because DR-ready water heaters offer a number of cost saving opportunities relative to conventional DLC, primarily in the form of reduced equipment and installation costs. Smart water heaters could also incorporate more sophisticated load control algorithms that provide

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20 Cost assumptions for the water heating DLC analysis were derived from EPRI, "Economic and Cost-Benefit Analysis for Deployment of CEA-2045-Based DR-Ready Appliances," December 2014. Some costs were modified to be consistent with assumptions for other DR programs in this study.

21 Assumes 6% annual replacement of the existing stock of electric resistance water heaters, the assumed annual share of new water heaters that are DR-ready reaching 60% by 2022, and 25% of those customers participating in a water heating DLC program.

harder-to-quantify benefits. These algorithms could facilitate larger load reductions than a conventional on/off switch in the long run by anticipating the water heating needs of the owner and responding accordingly. This technology could also reduce the risk of insufficient hot water supply following a DR event relative to the conventional technology.

Ultimately, with water heating load control programs, benefits will vary depending on the load control strategy and the characteristics of the electric water heater. For example, if equipped with the appropriate control technology, electric resistance water heaters can provide significant increases and decreases in average load with very little notification, making them an ideal candidate to offer ancillary services.[22] Alternatively, or possibly in conjunction with this strategy, water heaters could be used as a form of thermal energy storage. Large tanks equipped with a mixing valve can super-heat the water at night and then require little to no additional heating during the day. This would be beneficial in a situation where the marginal cost of generating electricity is low or even negative at night (e.g., large amounts of nighttime wind generation coupled with inflexible baseload capacity) or when energy prices are high during the day; it provides an energy price arbitrage opportunity. The potential to provide this type of energy price arbitrage is highly dependent on the size of the water heater and the number of hours over which the load shifting is occurring.

Finding #6: EV charging load control is relatively uneconomic as a standalone program due to low peak-coincident demand. Most residential charging occurs during off peak hours. Figure 7 illustrates the average EV charging load profile across many EV owners. While any individual owner's charging load would likely be concentrated in a smaller number of hours, the average load profile is the relevant profile to use in this study, because it represents the load shape that would be associated with a number of DR program participants with naturally diverse charging patterns across the service territory. As shown in the figure, the average amount of peak-coincident load available to curtail on a per-participant basis is less than 0.2 kW. As a result, even if most or all of the charging load can be shifted away from the peak hours, the low peak reduction potential translates into small benefits relative to the cost of the charging control equipment and the program is not cost-effective on a standalone basis. Total load reduction capability in the program is less than 2 MW by 2021 and less than 8 MW by 2035.[23]

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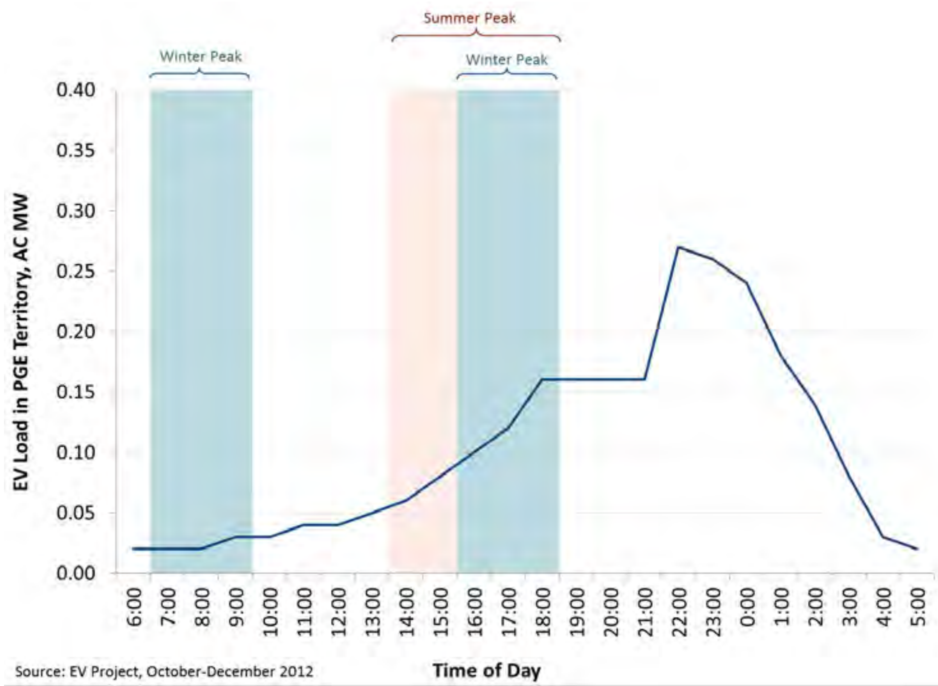
22 The technology that would facilitate this type of operation is in development and has been proven through a number of demonstration projects. It would include a potentially significant additional incremental cost beyond the costs modeled in this study.

23 Assumes roughly 140,000 personal EVs in PGE's service territory by 2025.

Figure 7: Average Hourly Home Charging Profile of EV Owner



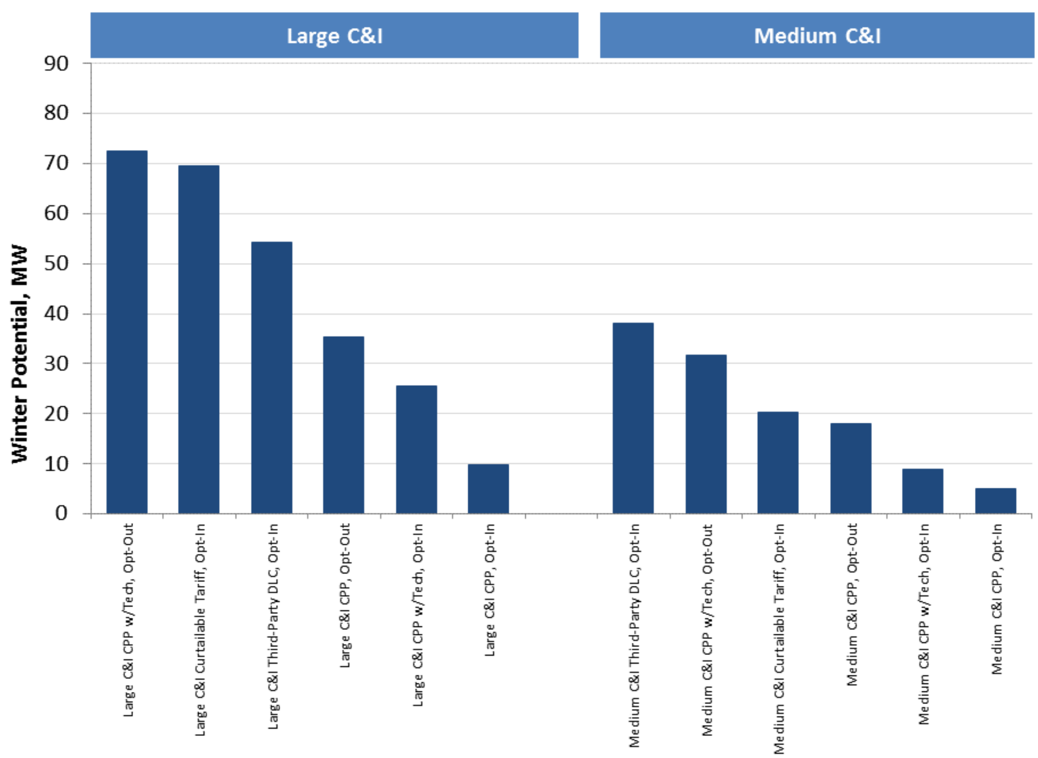
There are several important considerations to be aware of when interpreting these results, however. DR potential would be higher if targeting the late evening period with the most charging load; his time period could in fact eventually be the target of future DR programs that are designed to address distribution feeder-level constraints that are peaking at that time. The potential could also be higher in the future if EV owners adopt high-speed chargers that concentrate a larger amount of load in a smaller number of hours. It is also possible that there is more potential in programs focused on charging load outside the home. For example, the economics of load control at public charging stations might be more cost-effective. Control of commercial vehicle charging could also be cost-effective as part of a broader load control strategy, perhaps integrated with an Auto-DR program. Finally, as noted earlier in this section of the report, when EV charging load control is included as part of a broader DLC program, the package as a whole is cost effective.

Finding #7: Small C&I DLC has a small amount of cost-effective potential. Space heating DLC is the only cost-effective measure identified for the small C&I segment and its potential is small (around 6 MW in the winter). This is partly because small C&I customers tend to be unresponsive to time-varying rates unless equipped with enabling technology. Generally, electricity costs are a small share of the operating budget for these customers and they lack the sophisticated energy management systems of larger C&I customers. Further, while there is some potential in technology-enabled options, these customers have historically tended to be less likely to enroll in a DR program and generally represent a small share of the total system load.

Finding #8: DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a variety of programs. All of the analyzed DR programs are cost-effective for medium and large C&I customers. Customer acquisition costs tend to be lower on a dollars-per-kilowatt basis for these segments, leading to improved economics for DR. The large C&I segment accounts for the majority of the DR market in other regions of the U.S. for this reason.

In addition to being highly cost-effective, several large/medium C&I programs have large peak reduction potential. Figure 8 summarizes the potential in each DR option. There is significant potential in a curtailable tariff and a third-party DLC program. A CPP rate would provide similarly large impacts. In general, these programs could be considered the "low hanging fruit" of the available DR options.

Figure 8: Winter Potential for Medium and Large C&I DR Programs



Finding #9: Agricultural DR programs are small and uneconomic in PGE's service territory. There are large irrigation load control programs in the Pacific Northwest, such as Idaho Power's Irrigation Peak Rewards program. However, PGE has little irrigation pumping load. Relative to other options, programs focused on agricultural customers are small and not cost-effective in PGE's service territory. While pumping load control could become slightly cost-effective if PGE were to become a more heavily summer peaking utility, it is still too small to be considered a top priority given the other DR opportunities that exist.

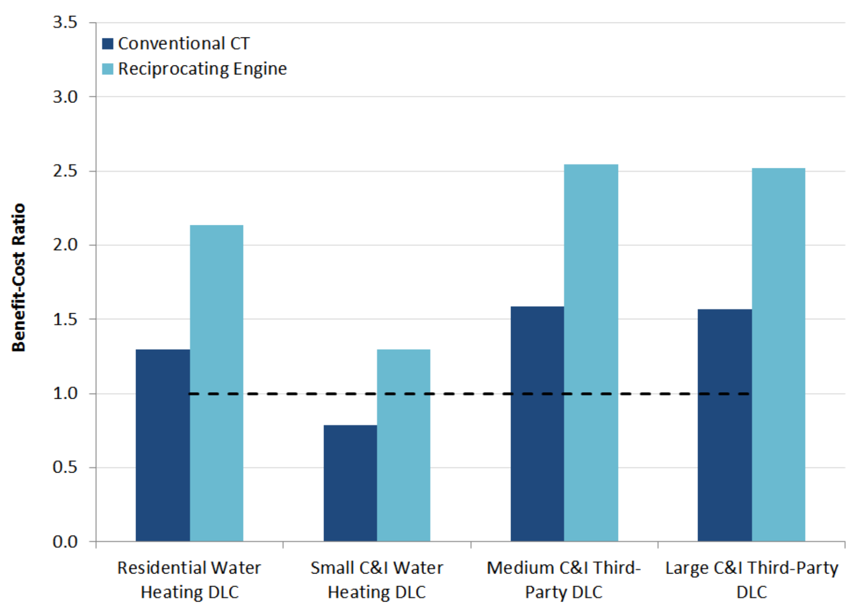
Finding #10: The economics of some programs improve when accounting for their ability to provide ancillary services. There is emerging interest in the Pacific Northwest in DR programs that can provide load reductions on very short notice in response to fluctuations in supply from intermittent generation resources like wind and solar. DR options that can provide both load decreases and increases provide even more value to the grid as ancillary services.

Since there is not currently an ancillary services market in the Pacific Northwest, the avoided cost of a reciprocating engine was used as a proxy for the value associated with these "fast" DR options. Reciprocating engines are more expensive than a conventional combustion turbine, but also have more operational flexibility and are better suited to address some of the reliability challenges posed by intermittent sources of generation.

Benefit-cost ratios were recalculated for those options capable of providing fast response (i.e., only DR options relying on automating technology). While the reciprocating engine is a good first-order approximation of this additional value, there are limitations to this approach and more granular analysis of the ancillary services value of the DR options would be informative in future research activities. Further, it should be noted that this cost-effectiveness analysis is based on the full coincident peak reduction capability of the programs; in practice, they would not be able to provide a reduction of that magnitude at regular intervals as an ancillary service, and the economics could change accordingly.

With a reciprocating engine as the basis for avoided costs, the economics improve for all programs and small C&I water heating DLC becomes cost-effective. Mass market water heating load control and medium and large C&I load control could provide fast ramping capability in the form of load increases and decreases, and would be particularly valuable as sources of ancillary services. Figure 9 illustrates the cost-effectiveness of these DR programs.

Figure 9: Cost-effectiveness for measures with "fast" load decrease and increase capability



V. Considerations for Future DR Offerings

This study utilized a detailed bottom-up approach to estimating PGE's peak demand reduction potential through DR programs. These estimates were carefully tailored to PGE's system conditions through research on likely adoption rates, per-customer impacts that are consistent with the experience of utilities around the country including the Pacific Northwest, and market conditions that are consistent with PGE's projections. The market potential for a variety of DR options and the economics of these options were assessed under a range of assumptions. The findings of the study suggest several considerations for future DR offerings by PGE.

Run a new dynamic pricing and behavioral DR pilot. A new pilot could provide insight about relatively untested issues such as the impact of a PTR in PGE's service territory, persistence in behavioral DR impacts, the relative difference in seasonal impacts of these programs, and even the difference in impacts when the rates are offered on an opt-in versus default basis. A pilot could also be designed to test a "prices-to-devices" concept involving real-time prices and automated response from specific end-uses, to address fluctuations in supply from renewable generation.

Develop a water heating load control program. There is a clear economic case for water heating load control and the potential benefits are diverse. Piloting or even a larger scale program would help to identify optimal load control strategies and further test the technical feasibility.

Continue to pursue opportunities in the large and medium C&I sectors. DR potential in the large C&I sector can be cost-effectively achieved through curtailable tariffs, third-party programs, and pricing options. Which of these programs to pursue is largely a strategic question, as each have their advantages and disadvantages. To maximize the participation from this customer segment, it may be beneficial to eventually pursue all of the program options through a portfolio-based approach.

Establish well-defined cost-effectiveness protocols. There does not appear to be a well-established approach to analyzing the cost-effectiveness of DR programs in Oregon. For example, the appropriate treatment of incentives as costs and the methodology for establishing derate factors to account for operational limitations of DR programs are two areas in need of further discussion. Reviewing the approaches being used in other states and tailoring these to the specific needs of the Oregon utilities would be a productive starting point. Well-defined protocols should be established while developing utility DR portfolios and strategies.

Develop a long-term rates strategy enabled by PGE's AMI investment. The strategy should address important considerations such as whether to offer new rates on an opt-in or default basis, the advantages and disadvantages of CPP versus PTR, whether a demand charge or increased customer charge is needed to address emerging inequities in cost recovery due to growing market penetration of distributed energy resources, how to transition customers to the new rate options, and other such considerations.

Explore the distribution system value of DR. Recent initiatives in other states have highlighted that the distribution-level value of DR may be understated in current practices. Additional analysis of distribution system constraints and the potential to deploy DR locally to address these constraints would be a useful research activity.

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Appendix A:
Participation Assumptions

Estimating Maximum Achievable Enrollment in DR Programs for PGE

PRESENTED TO

Portland General Electric

PRESENTED BY

The Brattle Group
Applied Energy Group

THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind estimates of enrollment in potential new DR programs in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Participation rates shown in this presentation are "steady state" enrollment rates once full achievable participation has been reached; they are expressed as a % of eligible customers

Pricing Programs

We developed enrollment estimates based on an extensive review of pricing participation studies

The enrollment estimates are derived from a review of 6 primary market research studies and 14 full scale deployments:

Primary market research studies

- A survey-based approach designed to gauge customer interest
- Adjustments were made to account for natural tendency of respondents to overstate interest in survey responses
- Respondents were randomly selected from utility customer base and confirmed to be representative of entire class
- Samples were large enough to ensure statistical validity of findings

Full-scale deployments

- Based on enrollment levels reported by utilities and competitive retail suppliers to FERC and other sources
- Restricted to programs with significant enrollment
- Focus on well marketed deployments

The market research studies and full-scale rate deployments span many regions of the U.S.

Additionally, our analysis includes the Ontario, Canada TOU rollout and three non-public market research studies in the Upper Midwest, Central Midwest, and Asia

Full-scale rate offerings have mostly been for residential and large C&I customers

Utility/Market	State/Region	Applicable class	Rates	Offering type	Approx. years offered
Arizona Public Service (APS)	Arizona	Residential	TOU	Opt-in	30+
Ontario Power Authority (OPA)	Ontario, CA	Residential	TOU	Opt-out	2
Salt River Project (SRP)	Arizona	Residential	TOU	Opt-in	30+
Gulf Power	Florida	Residential	CPP	Opt-in	14
Oklahoma Gas & Electric (OGE)	Oklahoma	Residential	CPP	Opt-in	2
Pacific Gas & Electric (PG&E)	California	Residential	CPP	Opt-in	3
Oklahoma Gas & Electric (OGE)	Oklahoma	Large C&I	TOU	Opt-in	?
Pacific Gas & Electric (PG&E)	California	Large C&I	CPP	Opt-out	3
San Diego Gas & Electric (SDG&E)	California	Large C&I	CPP	Opt-out	3
Southern California Edison (SCE)	California	Large C&I	CPP	Opt-out	3
Los Angeles DWP (LADWP)	California	All C&I	TOU	Opt-in	?
Progress Energy Carolinas	North/South Carolina	All C&I	TOU	Opt-in	15+

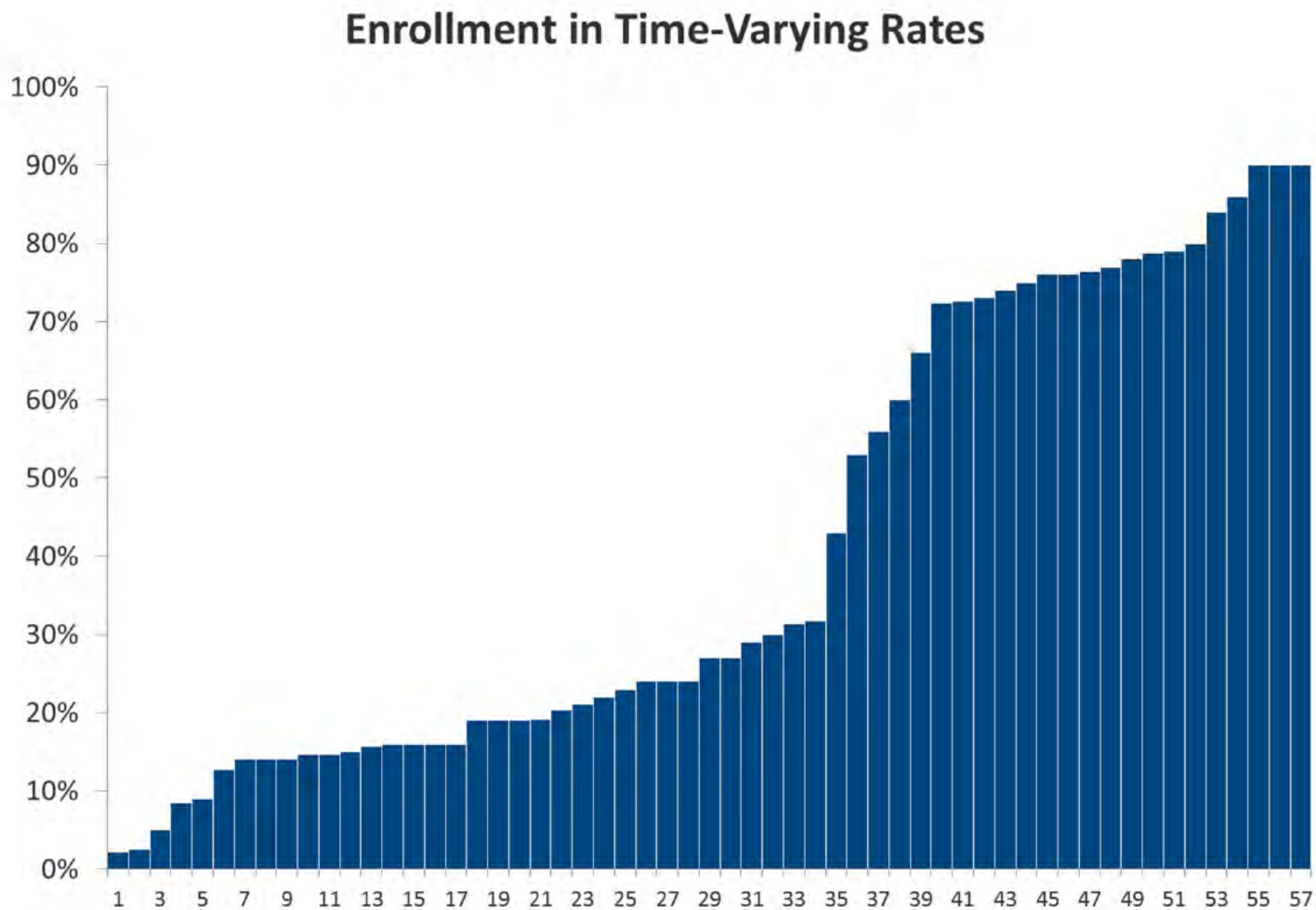
Notes:
BGE, Pepco, SDG&E and SCE have rolled out default PTR to their residential customers, but enrollment data is not available. Results are forthcoming.
The OPA TOU deployment is considered opt-out rather than mandatory because customers can switch to a competitive retail supplier.

The six market research studies primarily surveyed residential and small/medium C&I customers

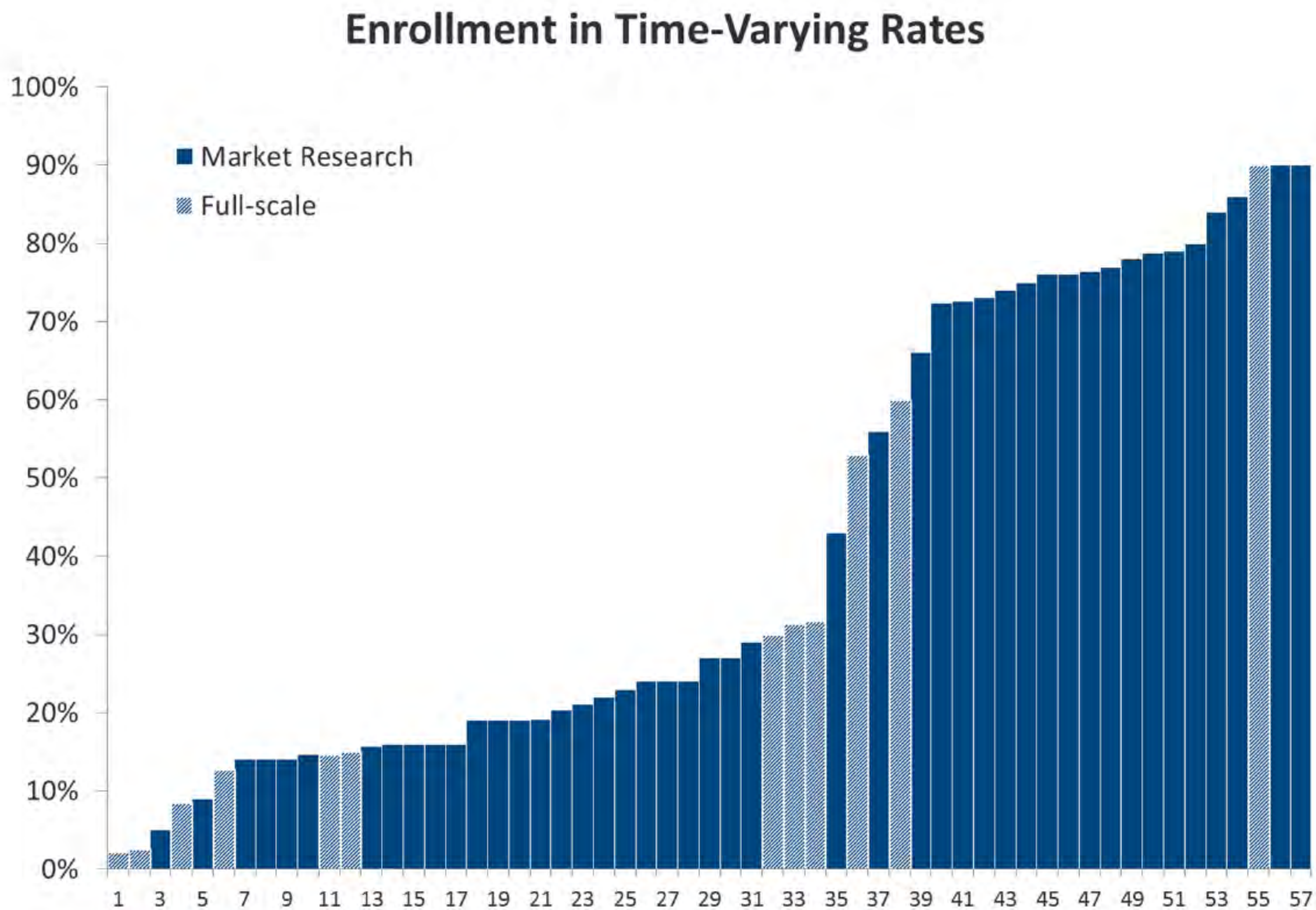
Utility/Market	Year of Study	Applicable classes			Rates	Deployment type	
		Res.	Small/Med	Large C&I		Opt-in	Opt-out
California IOUs	2003	X	X		TOU, CPP	X	X
ISO New England	2010	X	X		TOU, CPP, PTR, RTP	X	
Asian Utility	2013	X			TOU, PTR	X	
Large Midwestern IOU	2013	X	X	X	TOU, CPP	X	X
Mid-sized Midwestern Utility	2013	X	X		TOU, CPP	X	
Xcel Energy (Colorado)	2013	X	X	X	TOU, CPP, PTR	X	X

- These market research studies were conducted in order to form the basis for utility AMI business cases or DSM potential studies
- They were led by Dr. David Lineweber and a team of market researchers who are now with Applied Energy Group (AEG)

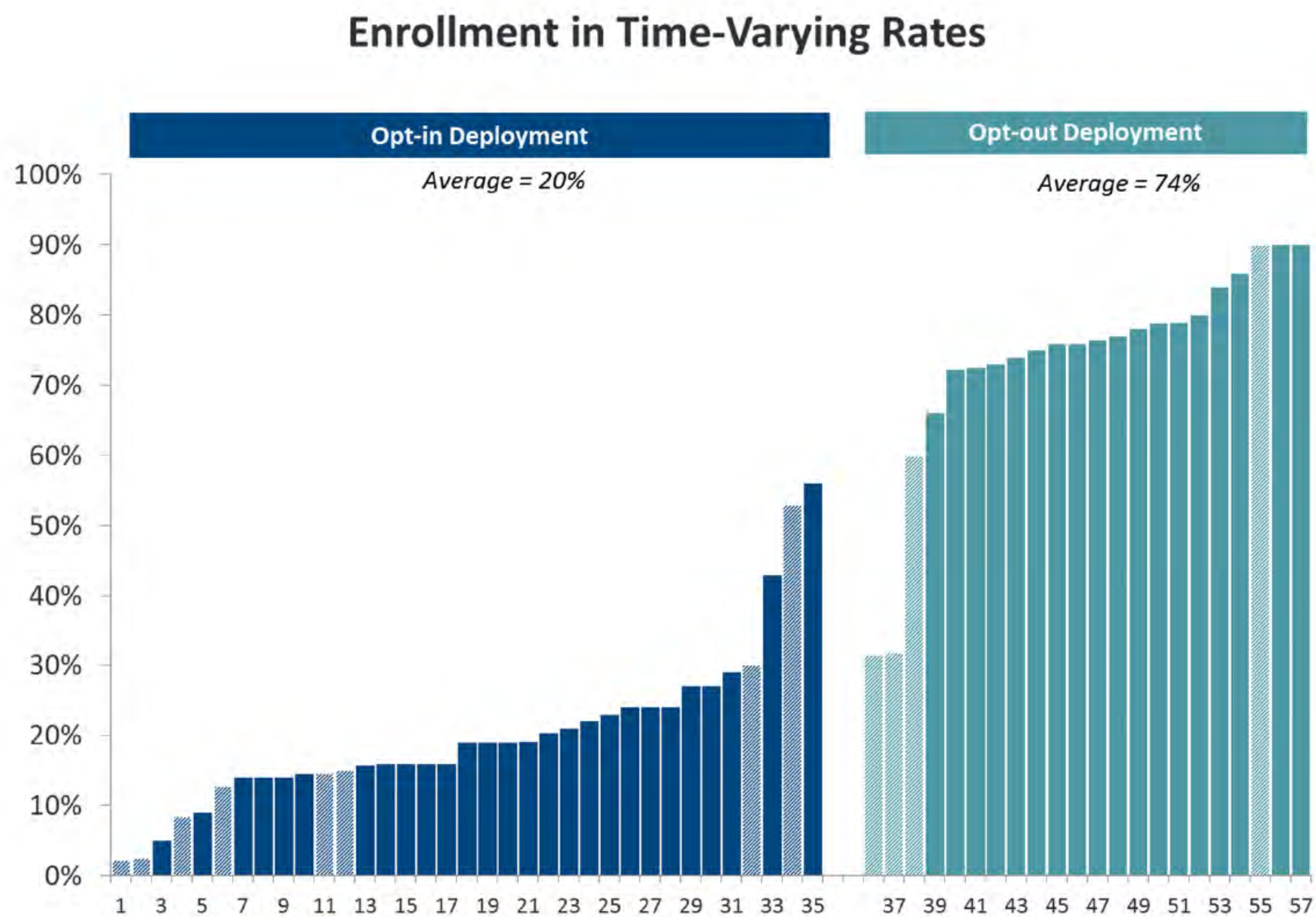
There are 57 enrollment observations across all of the studies (sorted low to high)



There is no obvious bias in market research results relative to full-scale deployments



Opt-out offerings result in significantly higher enrollment on average



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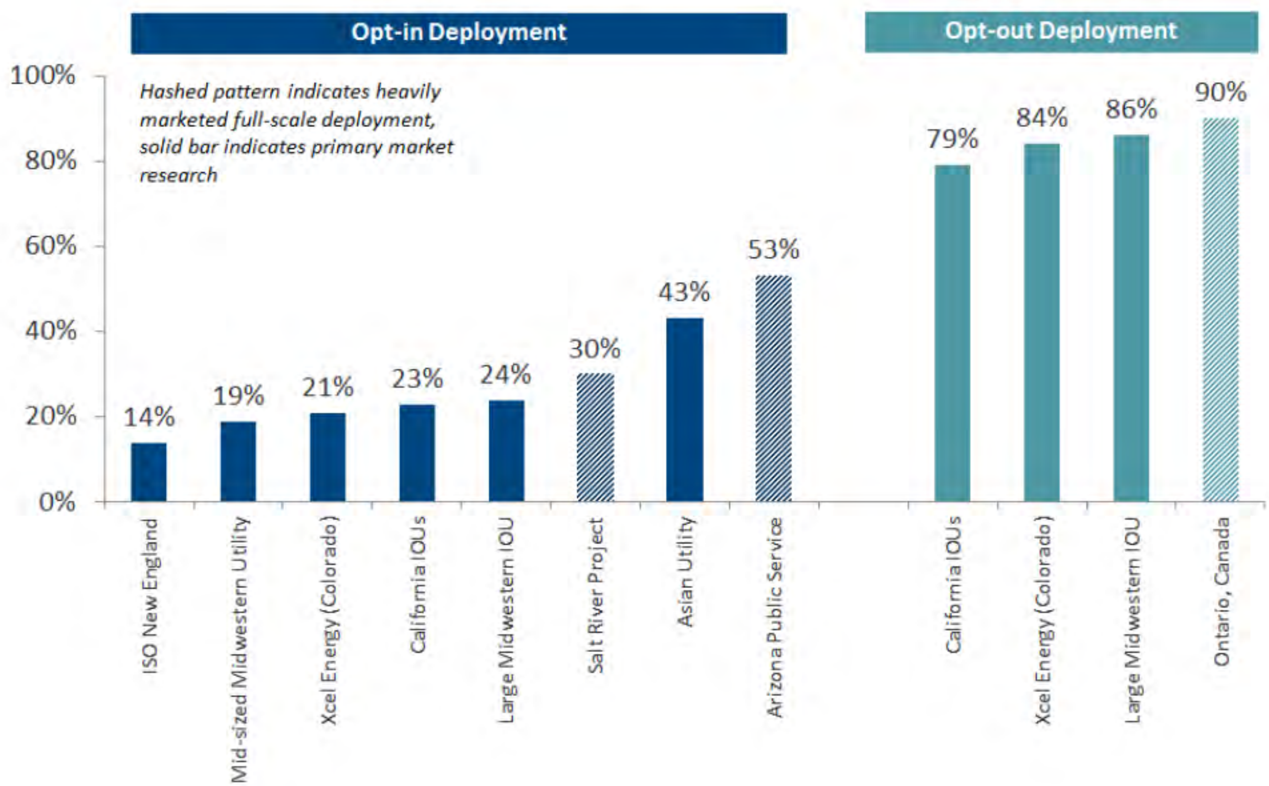
The enrollment data can be further organized with additional granularity

We have organized the data across the following elements

- Customer class (residential vs non-residential)
- Rate (TOU, CPP)
- Offering (opt-in vs opt-out)

We summarize the key findings of this comparison in the slides that follow

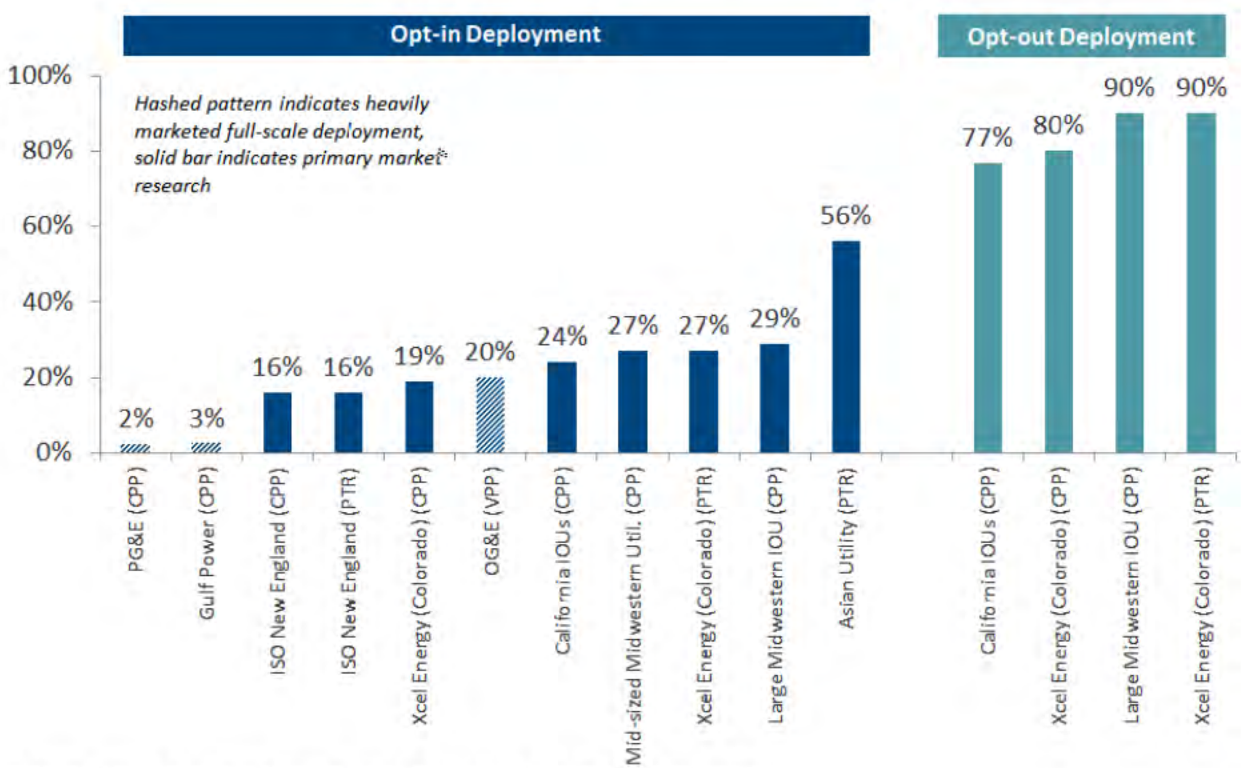
The results of our residential TOU analysis are summarized below



Comments

- Opt-in average = 28%
- Opt-out average = 85%
- Opt-out rate offerings are likely to lead to enrollments that are 3x to 5x higher than opt-in offerings
- Arizona's high opt-in TOU participation is attributable to heavy marketing as well as large users' ability to avoid higher priced tiers of the inclining block rate
- In Ontario, the 10% opt-out rate includes some customers who switched to a competitive retail provider even before the TOU rate was deployed

Residential dynamic pricing enrollment observations are similar to those of TOU



Note: Pepco and BGE have deployed a default residential PTR. Results forthcoming.

Comments

- Dynamic pricing options considered include CPP, variable peak pricing (VPP), and peak time rebates (PTR)
- PTR enrollment is roughly 20% higher than CPP enrollment
- OG&E's VPP rate was rolled out on a full scale basis in 2012 and has reached its target enrollment rate of 20% a year ahead of schedule
- Availability of Gulf Power's CPP rate is limited
- Additionally, Pepco, BGE, SCE, and SDG&E have deployed a default residential PTR; results are forthcoming

Why are the full scale residential dynamic pricing enrollment levels slightly lower than the market research results?

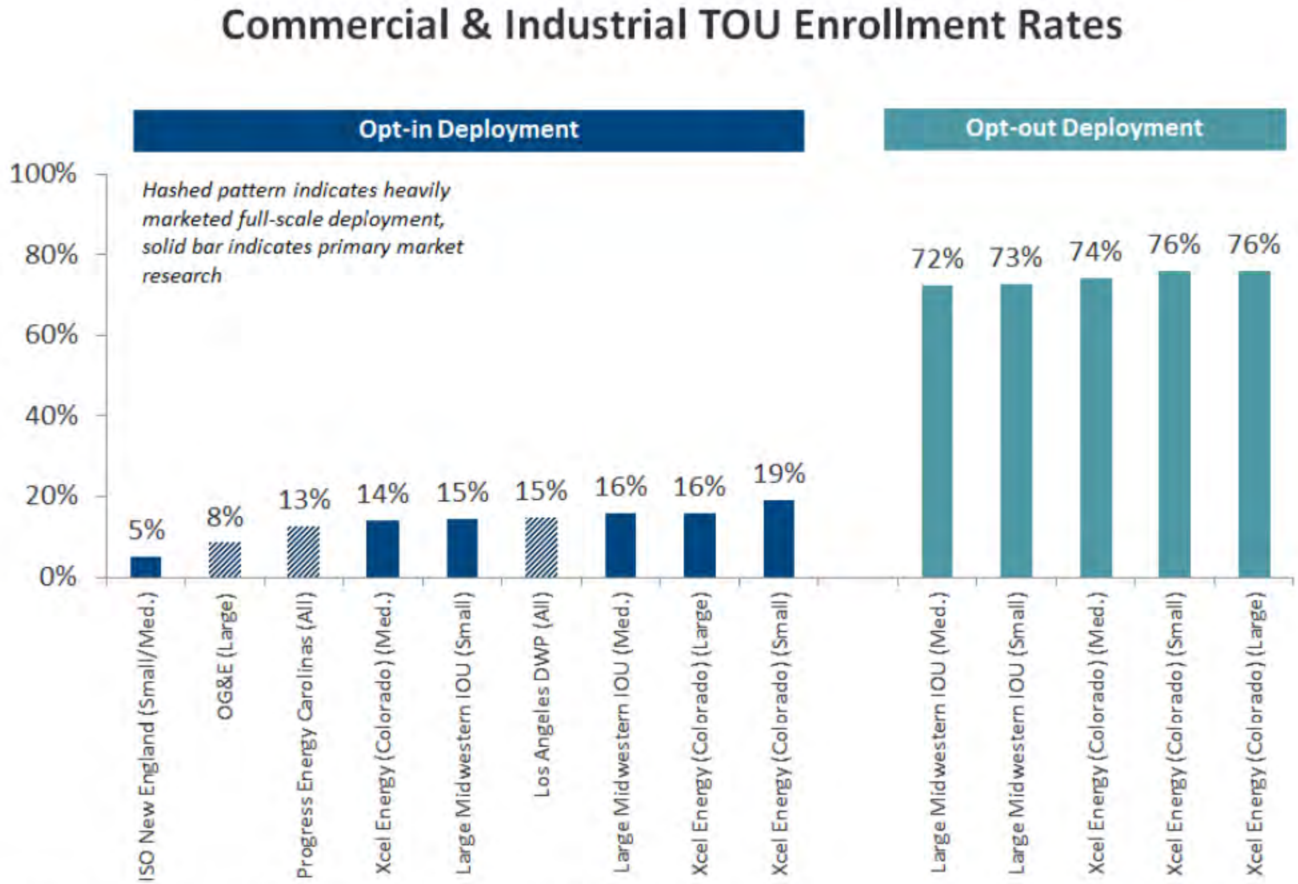
- The primary market research identifies all “likely participants” in the dynamic pricing rate, some of whom are very proactive and eager to sign up, while others would sign up but require more education, clear explanation, and additional outreach

- Most utility marketing budgets for dynamic pricing programs have been relatively low and are not designed to provide the type of outreach necessary to enroll customers falling in the latter category

- These customers represent untapped potential in the program and could likely be signed up with a more intensive marketing effort

- For example, heavily marketed utility energy efficiency programs with similar bill savings opportunities reach enrollment rates of 60%

C&I TOU enrollment levels are slightly lower than those of the residential class



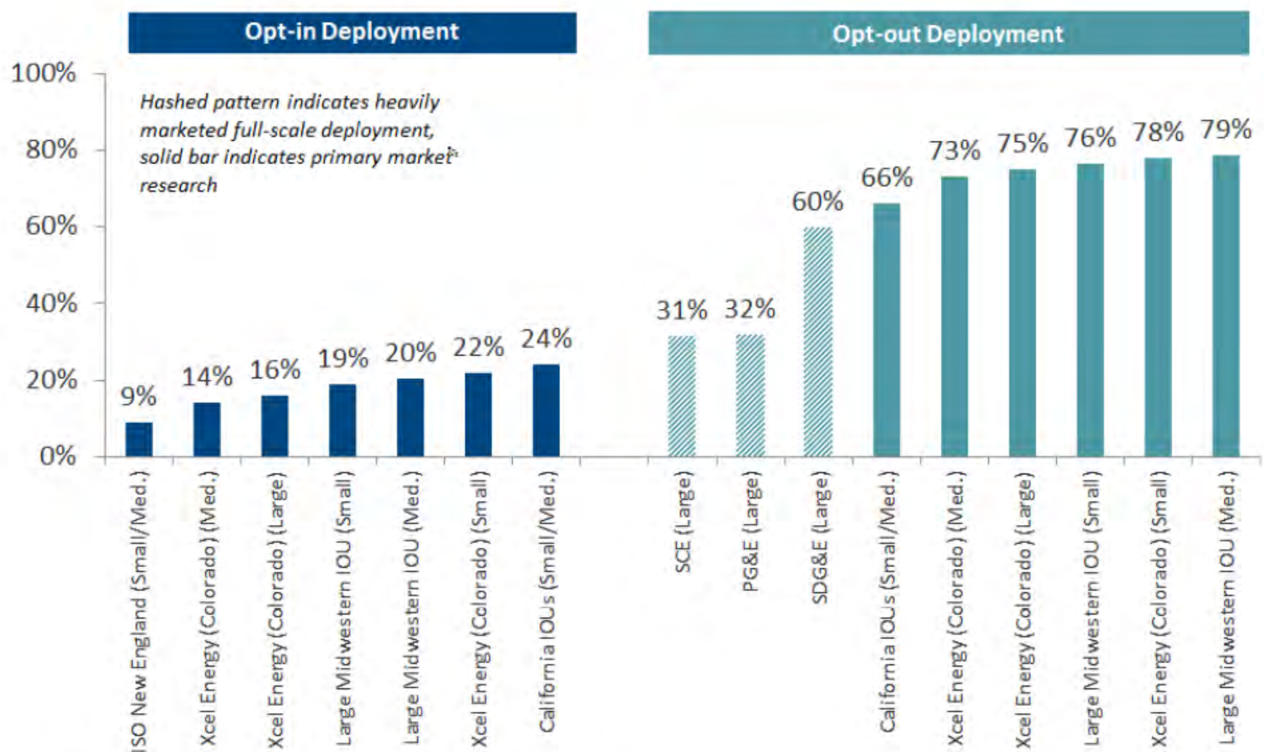
Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 13%
- Opt-out average = 74%
- Estimates are reported separately for Small, Medium, and Large C&I customers (as designated by the utility) where possible
- Full-scale opt-in deployment estimates were derived from FERC data, with a focus on the highest enrolled programs
- TOU rates are often offered on a mandatory basis to Large C&I customers; these are excluded from our assessment

There is limited full-scale CPP deployment experience for C&I customers

Commercial & Industrial CPP Enrollment Rates



Note: Size of applicable C&I customer segment indicated in parentheses.

Comments

- Opt-in average = 18%
- Opt-out average = 63%
- C&I preferences for CPP rates tend to be slightly higher than for TOU rates – the opposite of the relationship observed among residential customers
- The California IOU default CPP offering began in 2011 and has experienced significant opt-outs - it may not have been effectively marketed. The rate is being deployed to smaller customers and further results are forthcoming

Preliminary conclusions can be drawn from our assessment, although further research and experience are needed

- Opt-out rate offerings produce enrollment levels that are between 3x and 5x higher than opt-in rate offerings

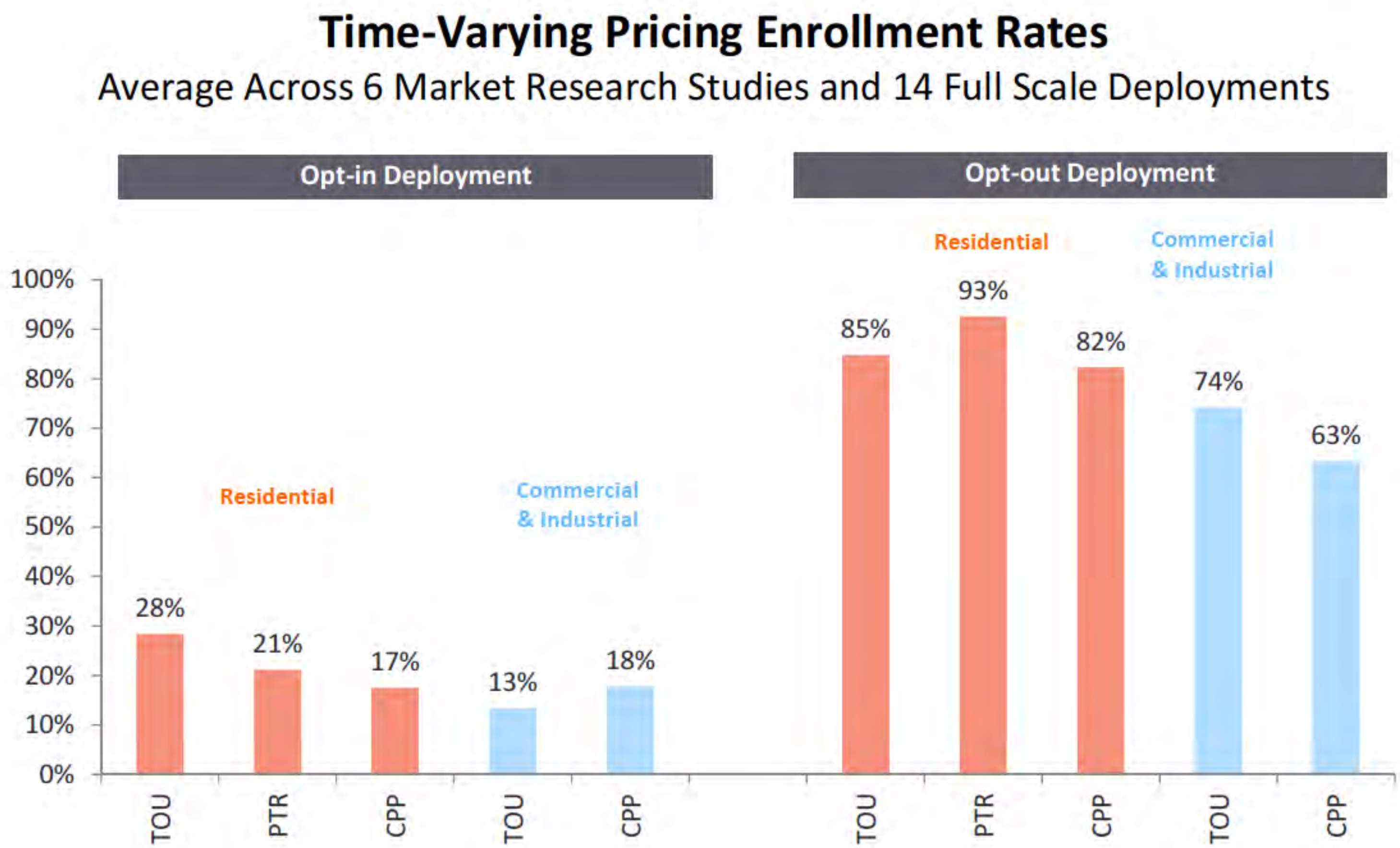
- Residential customers express a slightly higher likelihood to enroll in time-varying rates than small/medium C&I customers, both through market research and in full-scale deployments

- When offered in isolation, residential customers appear to have a slight preference for TOU over CPP; when offered as two competing rate options, more customers choose CPP

- Customers appear more likely to enroll in PTR than CPP

- Market research and full scale deployment results generally align well; in cases where full deployments produces lower enrollment estimates, it is likely that additional enrollment could be achieved through more focused marketing efforts

The results of our assessment can be averaged across the studies for each customer class and rate option



Offering enabling technology is likely to slightly increase participation among eligible customers

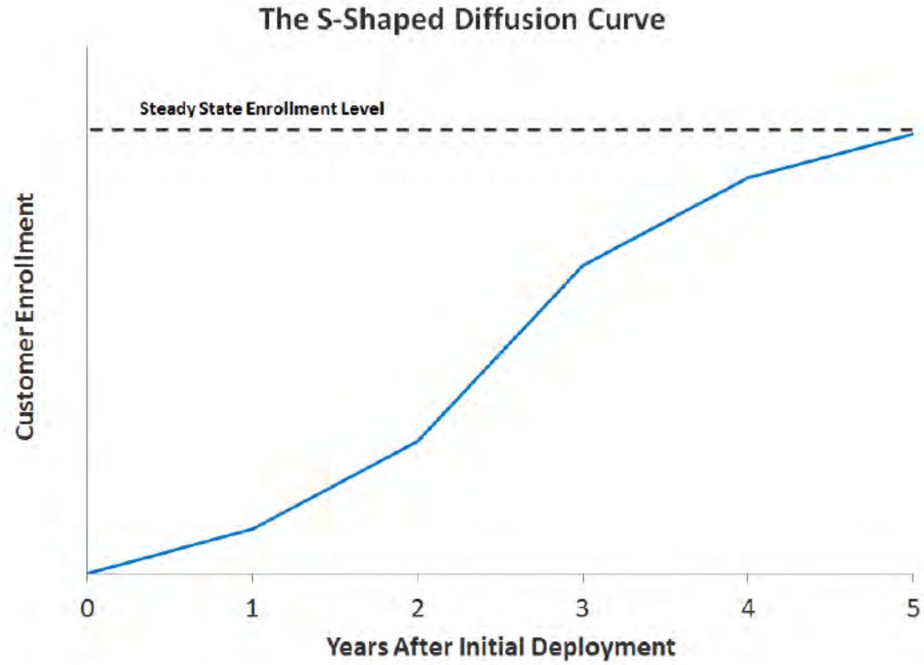
- For residential and small C&I customers, programmable communicating thermostats (PCTs) would automate reductions in air-conditioning load during critical peak periods
- For medium and large C&I customers, Auto-DR technology could be integrated with a facility's energy management system to automate load reductions during high priced periods of the CPP rates
- Market researchers have estimated that enrollment among tech-eligible customers will increase if they are also offered these technologies as part of the rate deployment
- **Opt-in enrollment among eligible customers is likely to increase by around 25% if offered enabling technology** (i.e., an enrollment rate of 20% would become 25% among tech-eligible customers)
- **For an opt-out rate offering, enrollment would likely increase by roughly 10%** (i.e. an enrollment rate of 80% would become 88% among tech-eligible customers)
- Large C&I customers are assumed to have more interest in Auto-DR than medium C&I customers due to a higher degree of sophistication in energy management capability

The proposed "steady state" enrollment rates

Class	Option	Opt-in	Opt-out
Residential	TOU - No Tech	28%	85%
Residential	CPP - No Tech	17%	82%
Residential	CPP - With Tech	22%	91%
Residential	PTR - No Tech	21%	93%
Residential	PTR - With Tech	26%	95%
Small C&I	TOU - No Tech	13%	74%
Small C&I	CPP - No Tech	18%	63%
Small C&I	CPP - With Tech	20%	69%
Small C&I	PTR - No Tech	22%	71%
Small C&I	PTR - With Tech	27%	78%
Medium C&I	CPP - No Tech	18%	63%
Medium C&I	CPP - With Tech	20%	69%
Large C&I	CPP - No Tech	18%	63%
Large C&I	CPP - With Tech	25%	69%

We account for a multi-year transition to the steady state enrollment levels

- Changes in participation are assumed to happen over a 5-year timeframe once the new rates are offered
- The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half
- A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options



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- Lineweber, David, "Understanding Business Customer Opinions of Time-Based Pricing Options in New England," prepared for ISO New England, May 2010
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003
- Momentum Market Intelligence, "A Market Assessment of Time-Differentiated Rates Among Small/Medium Commercial & Industrial Customers in California," July 2004
- PG&E, "PG&E's SmartRate Program Tops 100,000 Participants," PG&E Currents, May 28, 2013
- Various utility tariff sheets, as of January 2014

Non-Pricing Programs
Included in Prior PGE Studies

Participation in non-pricing programs was updated using the most recent FERC data

FERC conducts a bi-annual survey of utility DR programs, including information on program impacts and enrollment

The 2012 PGE DR potential study enrollment estimates were based on data in the 2010 FERC survey, which was the most current information available at the time

FERC has since released the 2012 survey results and has discontinued the survey; information is now collected through EIA form 861, but with much less granularity

We have updated the enrollment estimates using the 2012 FERC survey

The 75th percentile of achieved enrollment is used as a "best practices" estimate

The FERC data provides a national distribution of actual enrollment in DR programs

To establish a "best practices" estimate of what could eventually be achieved through a new program, we use the 75th percentile of the distribution for each program type

The recent PacifiCorp DR potential study used the 50th percentile

However, since the purpose of our study is to estimate maximum achievable potential rather than the average participation rate, we recommend using the 75th percentile

We will acknowledge throughout the final report that the figures presented are estimates of maximum achievable potential rather than what is necessarily likely to occur, particularly in the short run given the relatively limited experience with DR in the Pacific Northwest

Updated estimates are fairly similar to those of the 2012 PGE potential study

Class	Option	PGE (2012)	PacifiCorp (2014)	PGE (2015)
Residential	DLC - Central A/C	20%	15%	**20%**
Residential	DLC - Space Heat	20%	15%	**20%**
Residential	DLC - Water Heating			**25%**
Small C&I	DLC - Central A/C	20%	3%	**14%**
Small C&I	DLC - Space Heat	20%	3%	**14%**
Small C&I	DLC - Water Heating			**2%**
Medium C&I	DLC - AutoDR	18%		**15%**
Medium C&I	Curtailable Tariff		24%	**20%**
Large C&I	DLC - AutoDR	18%		**25%**
Large C&I	Curtailable Tariff	17%	24%	**40%**

Note:
An average curtailable tariff participation rate of 30% for C&I customers was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's ISOC program)

In a couple of instances, we deviated from the 75^{th} percentile assumption

Space heating DLC participation is assumed to be the same as air-conditioning DLC due to lack of better data

The 75^{th} percentile participation rate of 30% for C&I customers in a curtailable tariff was adjusted upward for large customers and downward for medium customers, based on an observation that large customers are more likely to participate (e.g., Xcel Energy's highly subscribed "ISOC" program)

There is limited data available on Auto-DR adoption rates when deployed at scale; we have assumed that adoption would be similar to that of technology-enabled CPP for C&I customers, since it offers a similar financial incentive to manage load

New Non-Pricing Programs Not Included in Prior PGE Studies

We estimated participation rates for three new programs; two more are in development

Draft participation rates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Participation rates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- All assumptions for these two programs are being developed in parallel and in coordination with PGE staff

Enrollment in BYOD programs will be driven partly by the market penetration of smart thermostats

We have based our estimates of the eligible population for BYOD programs on projections of market deployment for communication-enabled thermostats

Research by Berg Insight projects that over 25% of homes in North America will be equipped with a ‘smart system’ by 2020, relative to 6% currently

CMO, and Adobe Company, reports that smart thermostats are expected to have over 40% adoption by 2020

Acquity Group’s 2014 Internet of Things (IoT) survey reports that approximately 30% of consumers will adopt smart thermostats in the next 5 years

To be conservative, we use an assumption at the low end of this range

Source	Year	Market Penetration (%)
Berg Insight – N. America	2020	25%
CMO	2020	40%
Acquity Group – N. America	2020	30%

- We assume that smart thermostat market penetration in PGE's service territory will reach 25% of all homes by 2020
- The Energy Trust's interest in promoting smart thermostats could drive this estimate upward
- Additionally, rapid growth in central air-conditioning adoption in the Pacific Northwest relative to other parts of the country could lead to a future scenario that exceeds this estimate, as new A/C systems are installed with smart thermostats
- Note: Estimate could be refined further upon receiving the Navigant Research report on smart thermostats

Participation among eligible customers is likely similar to participation in conventional DLC programs

The BYOD program is assumed to be offered on an opt-in basis only

With a similar participation incentive as in the conventional DLC program, we assume that participation in the BYOD program would be similar to but slightly higher than that of the conventional DLC program

The intuitive reasoning for this is that customers who purchase a smart thermostat are more likely to be conscious about their energy usage and keen on using the features of their new device

To capture this, we estimate that participation in BYOD programs to be 25%, which is 5% higher than in DLC programs

We have modeled Behavioral DR both on an opt-in and an opt-out basis, similar to pricing programs

Behavioral Demand Response is essentially a peak time rebate (PTR) program without the accompanying financial incentive to reduce consumption during event hours

The no-incentive, no-risk nature of BDR programs could make customers slightly less likely to opt-in and slightly more likely to opt-out

To establish the BDR participation rates, we start with the PTR participation rates discussed previously in this presentation, and make adjustments to the share of customers that opt-in and opt-out

Three sources suggest that BDR participation could resemble that of a PTR program

OPower estimates that customer adoption of their opt-out BDR programs is upwards of 90%

Green Mountain Power (2012-2013)

- Recruitment strategies used a combination of mail, web and phone
- Participation in the opt-in, notification-only program achieved a 34% participation rate

MyMeter Program (four electric co-ops in Minnesota)

- Opt-in participation rates range from 9% to 16% per co-op, with more weight toward the high end of the range

Research supports a 20% opt-in and a 80% opt-out participation rate

Utility/Program	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
OPower BDR program adoption rate		90%
Green Mountain Power	34%	
MN electric co-ops (MyMeter Program)	9-16%	

- In both the opt-in and opt-out deployment scenarios, we choose fairly conservative participation rates relative to the data that is available on BDR enrollment
- This is in recognition of the long-term uncertainty in enrollment in these programs and the fairly small scale at which the existing pilots were conducted

Irrigation Load Control Programs typically target large irrigation & drainage pumping systems

Many utilities, such as SCE, Entergy Arkansas, and Idaho Power focus on large customers

The 2014 PacifiCorp potential study sets the eligibility threshold at customers with pumps 25 HP and higher, representing 78% of total agricultural load

We propose that the eligible population be limited to customers on Schedule 49

- Comprises Irrigation & Drainage Pumping customers with loads >30 kW
- These customers represents about 75% of total Irrigation and Drainage load (based on PGE’s February 2015 Rate Case Filing)

There are a few data points upon which to base PGE's irrigation DLC participation estimate

EnerNOC's 2013 Irrigation Load Control Report provides enrollment estimates for Rocky Mountain Power

- The Utah service territory had a participation rate of about 20% of eligible load, whereas the Idaho service territory had participation of 48% of eligible load
- All irrigation customers were eligible to participate
- Customers with loads <50 kW required to pay an enablement fee

Idaho Power has achieved significant enrollment

- Conversations with Idaho Power staff indicate that roughly 10% of irrigation customers are enrolled
- These participants are significantly larger than average, representing peak reduction capability of 39% of system peak coincident irrigation load

The recent PacifiCorp DSM potential study suggested a lower participation rate for Oregon

- Participation in California, Oregon, Washington, and Wyoming assumed to be 15% of eligible load, based on PacifiCorp program experience
- Assumed participation rates for Idaho and Utah were significantly higher, likely reflecting the different nature of the crops in those two states, leading farmers to be more likely to allow more regular curtailments to their irrigation cycle

There is support for a 15% participation rate assumption for Irrigation Load Control programs

Utility/Program	Opt-In Participation Rate (% eligible load)
PacifiCorp 2015 (CA, OR, WA, WY)	15%
RMP 2013 (Utah)	20%
Idaho Power	39%
RMP 2013 (Idaho)	48%

- The range of participation rates observed in existing programs is wide
- We have chosen an estimate on the low end of the range to avoid overstating participation that may be associated with hotter, drier climates like those of Idaho and Utah
- This assumption has the added benefit of being consistent with the Oregon assumption in the PacifiCorp potential study

Summary of Participation Assumptions for New Non-Pricing programs

Program	Eligible Population in 2020 (%)	Opt-In Participation Rate (%)	Opt-Out Participation Rate (%)
BYOD	25% of Residential Customers	25%	N/A
Behavioral DR	100%	20%	80%
Irrigation Load Control	75% of Irrigation Customers	15%	N/A

Sources for new non-pricing participation assumptions

- Acquity Group, The Internet of Things: The Future of Consumer Adoption, 2014.
- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015.
- Berg Insight, Smart Homes and Home Automation, January 2015.
- CMO, 15 Mind-Blowing stats about the Internet of Things, April 17, 2015.
- Edison Institute, Innovations Across the Grid, Volume II, December 2014.
- EnerNOC, 2013 PacifiCorp Irrigation Load Control Program Report, March 3, 2014.
- Honeywell, Structuring a Residential Demand Response Program for the Future, June 2011.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- R. Kiselewich, The Future of Residential Demand Response: BGE's Integration of Demand Response and Behavioral, E Source Forum 2014, September 29 - October 2, 2014.
- S. Blumsack and P. Hines, Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013, March 5, 2015.

Appendix B:

Per-Participant Load Impact Assumptions

Estimating Per-Participant DR Impacts for PGE

PRESENTED TO

PGE

PRESENTED BY

Ahmad Faruqui
Ryan Hledik
Lucas Bressan

THE Brattle GROUP

In this presentation

This presentation summarizes the methodology and assumptions behind our estimates of per-participant peak demand reductions for DR programs that could be offered in PGE's service territory

The presentation is divided into three sections

- Pricing programs
- Non-pricing programs included in prior PGE studies
- Non-pricing programs that are new to this study

Note that the impacts in this presentation are per average participant; they are not multiplied into participation rates to arrive at estimates of system-level impacts

Pricing Programs

Pricing impact estimates have undergone a significant overhaul relative to the 2012 study

Incorporated new findings of 24 pilots and full-scale rollouts that have occurred since the 2012 study, including the DOE-funded consumer behavior studies

Modified the impact estimation methodology to take advantage of the greater number of data points that are now available

- Differentiation in price responsiveness between TOU, CPP, and PTR rates
- Accounting for difference in average response under opt-in versus opt-out deployment
- Improved differentiation between winter and summer impacts

The following slides provide a step-by-step description of our approach

First, we established a reasonable peak-to-off-peak price ratio for each rate option

The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates

A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result

Price ratios are based on rate designs that have recently been offered by PGE or are currently under consideration

- TOU: 2-to-1
- CPP: 4-to-1*
- PTR: 8-to-1*

* Rate designs were provided by PGE. It would alternatively be useful to explore CPP and PTR rates with consistent price ratios.

Impacts of time-varying rates were then simulated based on a comprehensive review of recent pilot results

PGE has recently conducted a CPP pilot and previously conducted a TOU pilot; the results are incorporated into our analysis, but have been supplemented with findings from dynamic pricing pilots across the globe to develop more robust estimates of price response

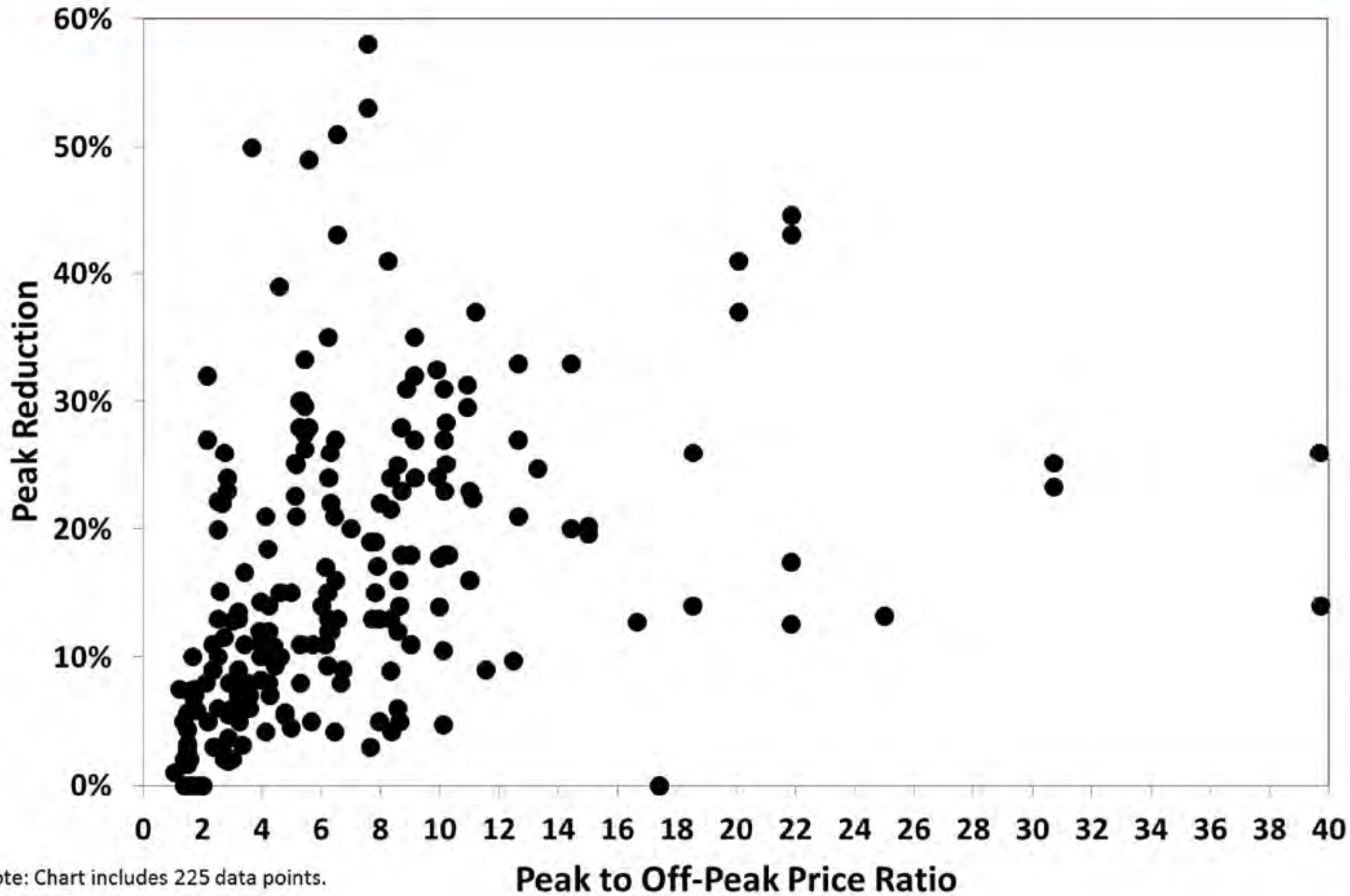
For residential customers, we rely on results from 225 pricing tests that have been conducted in a total of 42 pilots in the U.S. and internationally over roughly the past decade

Small and Medium C&I impacts are based on results of a dynamic pricing pilot in California

Large C&I impacts are based on experience with full-scale programs in the Northeastern U.S.

To estimate residential impacts, we begin with a survey of impacts from recent pilots

Results of All Residential Time-Varying Pricing Tests



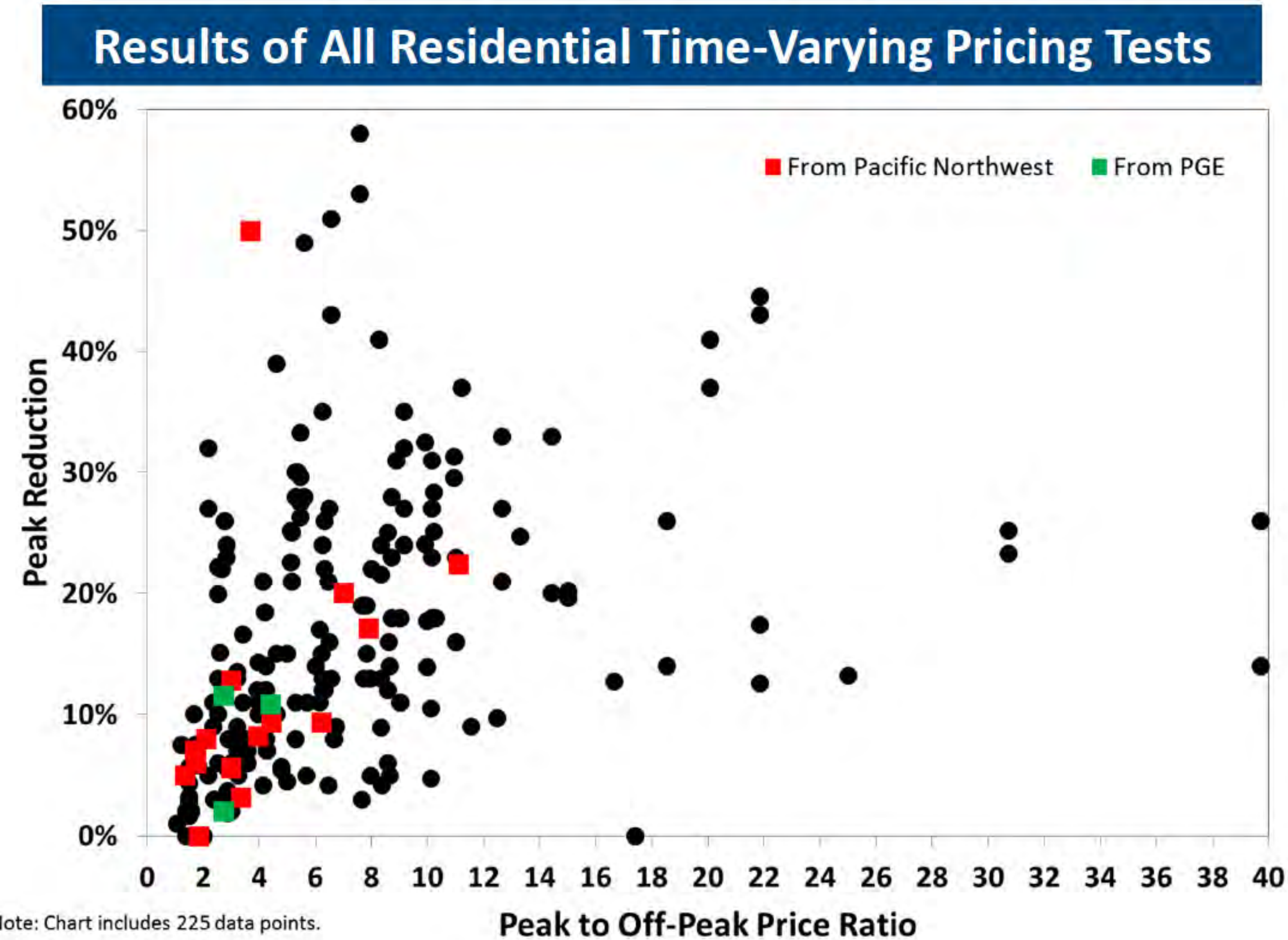
Note: Chart includes 225 data points.

Our database of dynamic pricing pilots includes seven that have been conducted in the Pacific Northwest

Utility/Organization	State/Province	Name of Pilot	Year(s)	Rates Tested	Range of Price Ratios	Range of Peak Prices	Range of Impacts	Number of Pilot Participants	Season of System Peak
BC Hydro	British Columbia	Residential TOU/CPP Pilot	2007-2008	TOU CPP	TOU: 3.0-6.2 CPP: 7.9-11.1	TOU: 19-28¢ CPP: 50¢	TOU: 3-13%, CPP: 17-22%	TOU: 1,031 CPP: 273	Winter
Idaho Power	Idaho	Energy Watch (EW) and Time-of-Day (TOD) Pilot Programs	2005-2006	TOU CPP	TOU: 1.8 CPP: 3.7	TOU: 8¢ CPP: 20¢	TOU: 0% CPP: 50%	TOU: 85 CPP: 68	Summer
PacifiCorp	Oregon	TOU Rate Option	2002-2005	TOU	Summer: 1.7-2.1 Winter: 1.7	Summer: 11-14¢ Winter: 11¢	Summer: 6-8% Winter: 7%	~1200	Summer Winter
Portland General Electric (PGE)	Oregon	Residential TOU Option	2002-2003	TOU	2.7	8¢	8%	1,900	Winter
Portland General Electric (PGE)	Oregon	Critical Peak Pricing Pilot	2011-2013	CPP	4.4	44¢	11%	996	Winter
Puget Sound Energy	Washington	TOU Program	2001	TOU	1.4	See notes	5%	300,000	Winter
US DOE, PNNL, BPA, PacifiCorp, Portland General Electric, Public Utility District #1 of Clallam County, and City of Port Angeles	Washington/ Oregon	Olympic Peninsula Project	2006-2007	CPP	7.0	35¢	20%	112	Winter

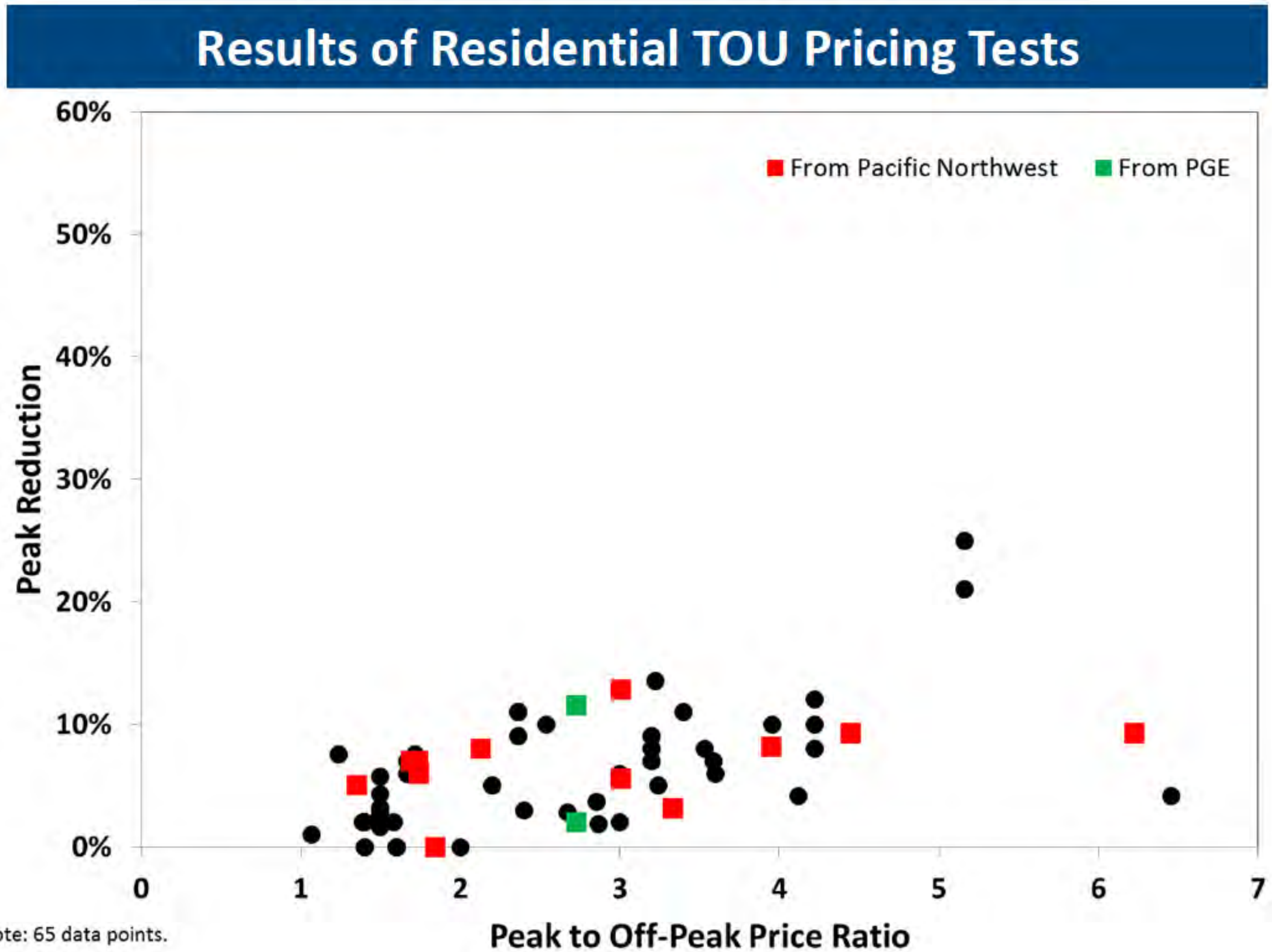
Notes:
Could not find published estimates of TOU prices for Puget Sound Energy; only the price differential was available.
Price ratios are presented on an all-in basis.

The Pacific Northwest price ratios and impacts are generally consistent with those of other pilots



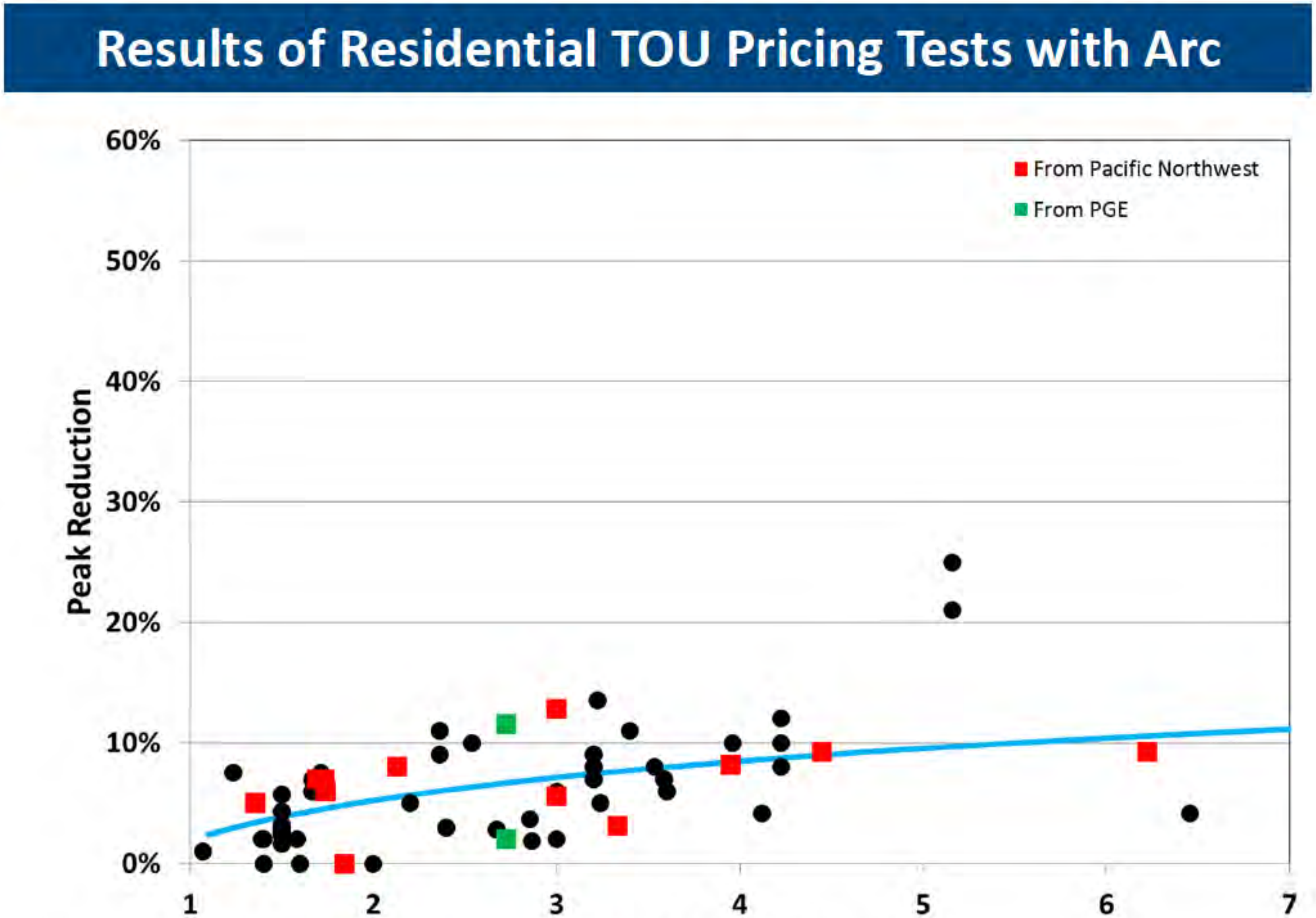
Note: Chart includes 225 data points.

To estimate TOU impacts, we focus only on those pilots which tested TOU rates



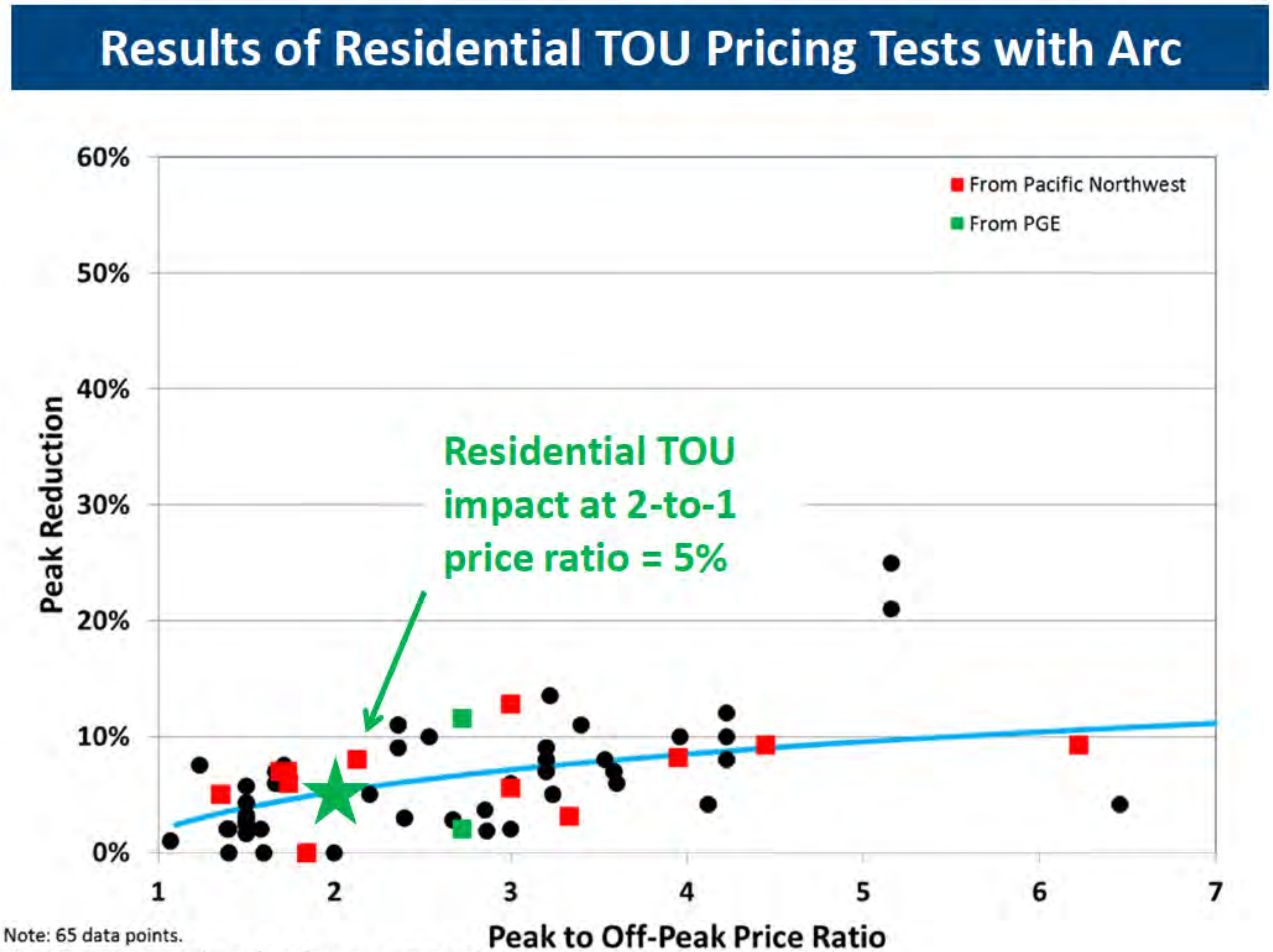
Note: 65 data points.

We then fit a curve to the summer data to capture the relationship between price ratio and impacts



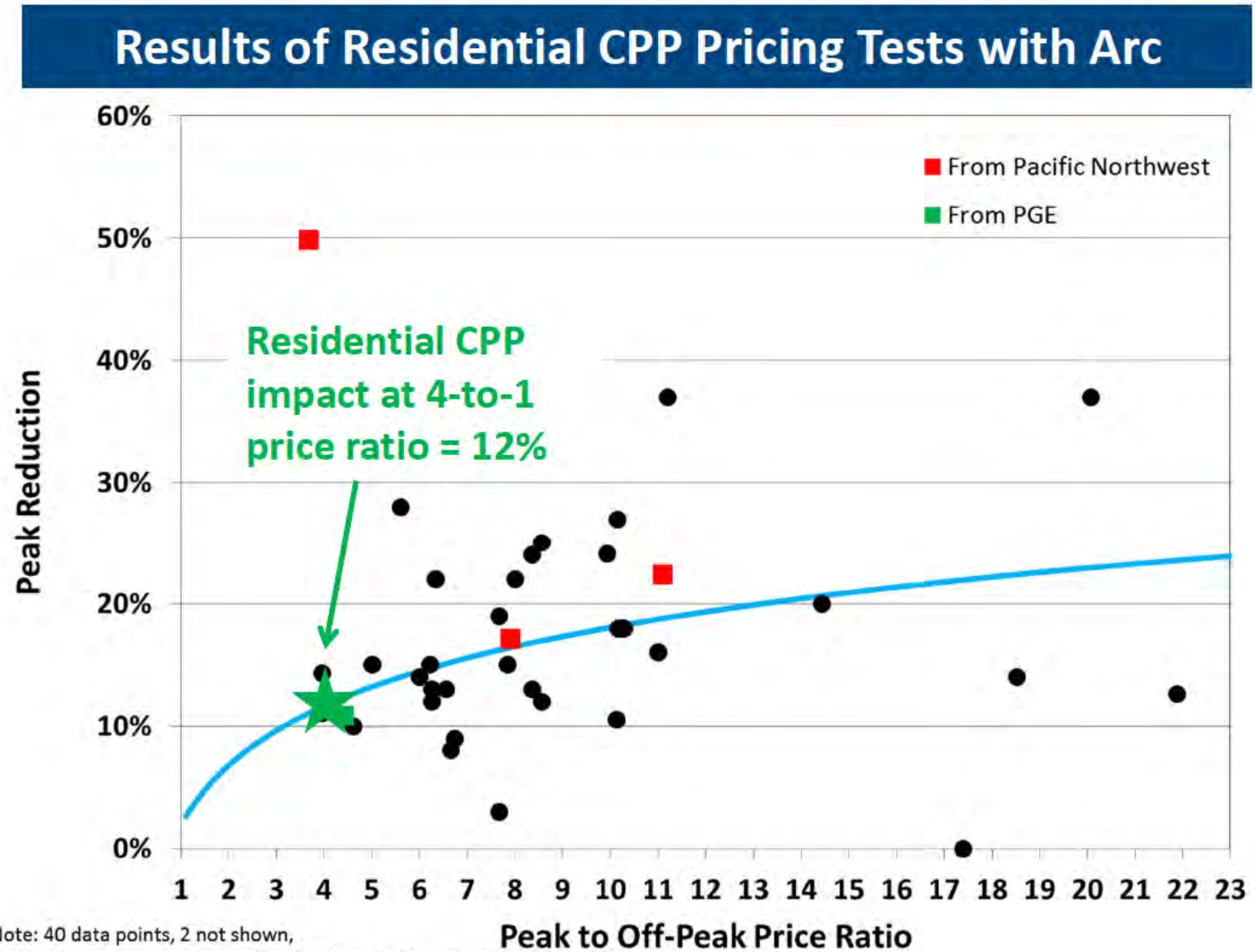
Note: 65 data points.
20 winter impacts are shown for reference purposes only.

We use the arc to simulate the impact of the residential TOU rate for our study



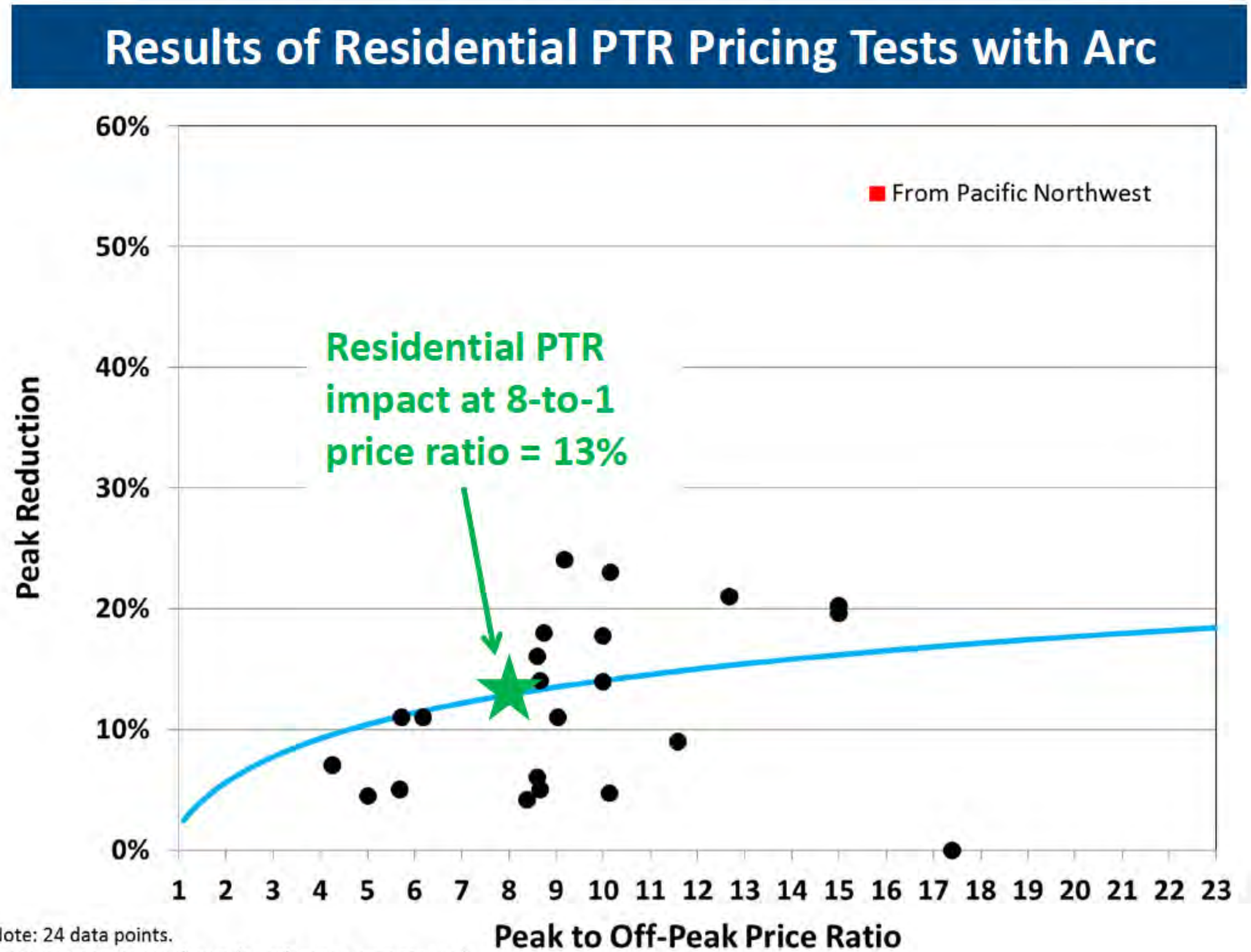
Note: 65 data points.
20 winter impacts are shown for reference purposes only.

The same approach was used to estimate CPP impacts



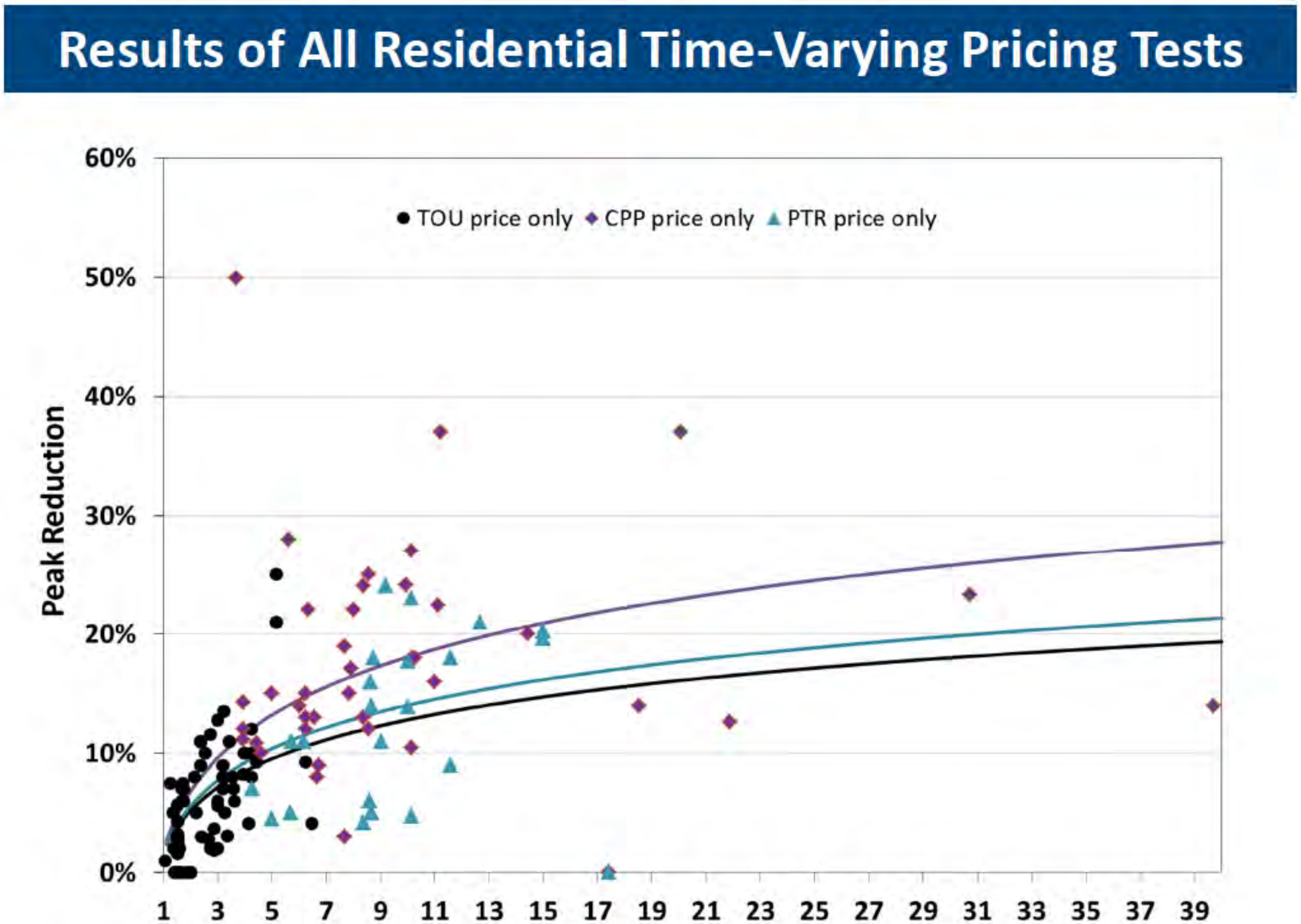
Note: 40 data points, 2 not shown, 1 dropped as outlier in regression. 5 winter impacts are shown for reference purposes only.

PTR impacts were also estimated using the same approach



Note: 24 data points.
2 winter impacts are shown for reference purposes only.

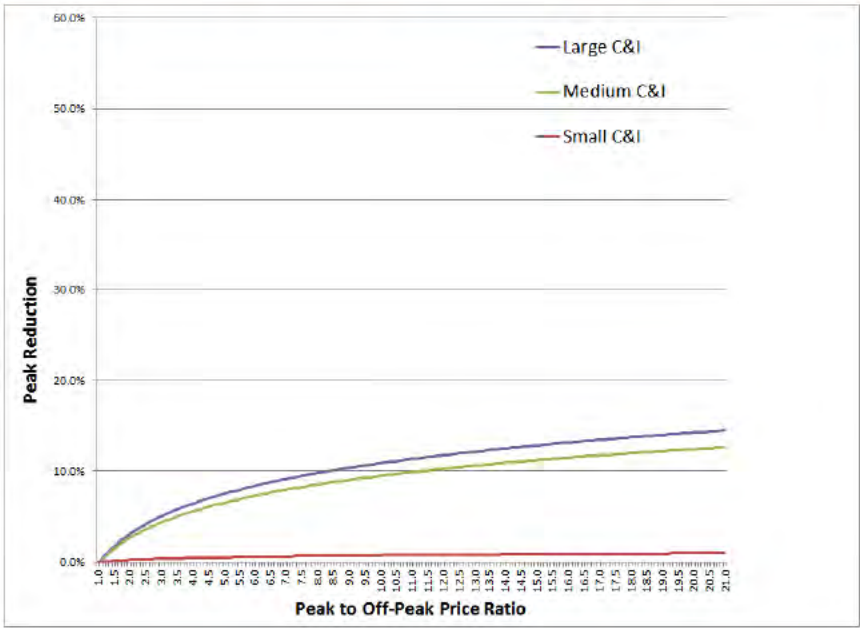
Price elasticity appears to be higher for CPP rates than PTR or TOU



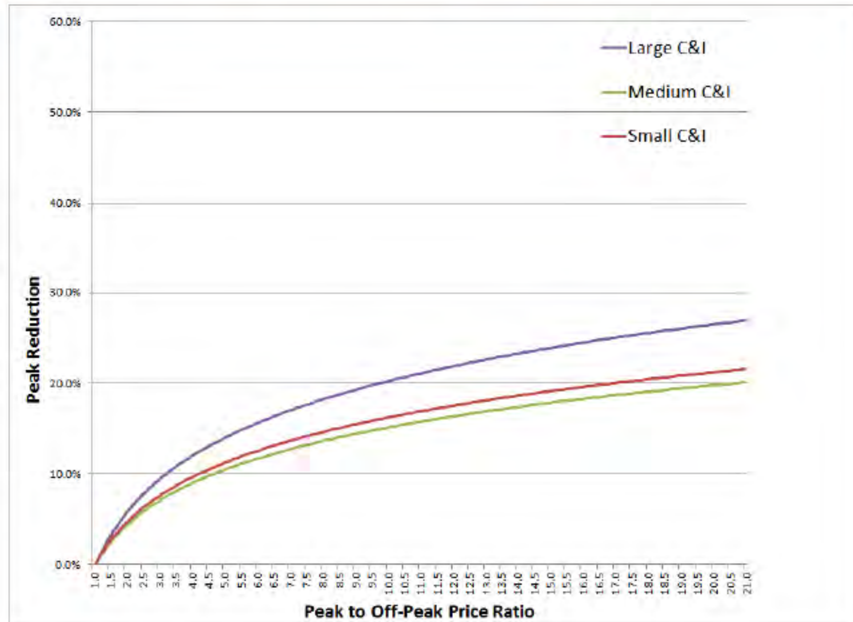
Note: 129 data points,
1 dropped as outlier in regression. 26 winter impacts are shown for reference purposes only.

C&I impacts were estimated using a similar approach, but fewer pilots have been conducted for these customers

C&I Arcs without Tech



C&I Arcs with Tech



Seasonal variation is based on the relationship observed in a limited number of pilots

To develop winter impact estimates, we created a scaling factor based on the relationship observed in pilots that tested both rates

The challenge is that there is not a consistent seasonal relationship across these pilots (see table)

Recognizing this uncertainty, but remaining consistent with the directional relationship in the PGE studies, we assumed a slightly higher degree of price responsiveness (10%) in the winter than in the summer

New primary research (e.g., the upcoming PTR pilot) is needed to refine this assumption

Pilot	Winter impact relative to summer
PGE TOU	Much larger (6x)
PGE CPP	Slightly larger*
PacifiCorp	Similar
Ontario TOU	Slightly smaller
Australian TOU	Much smaller (0.4x)
Xcel	Relationship varies

* Based on very limited summer data

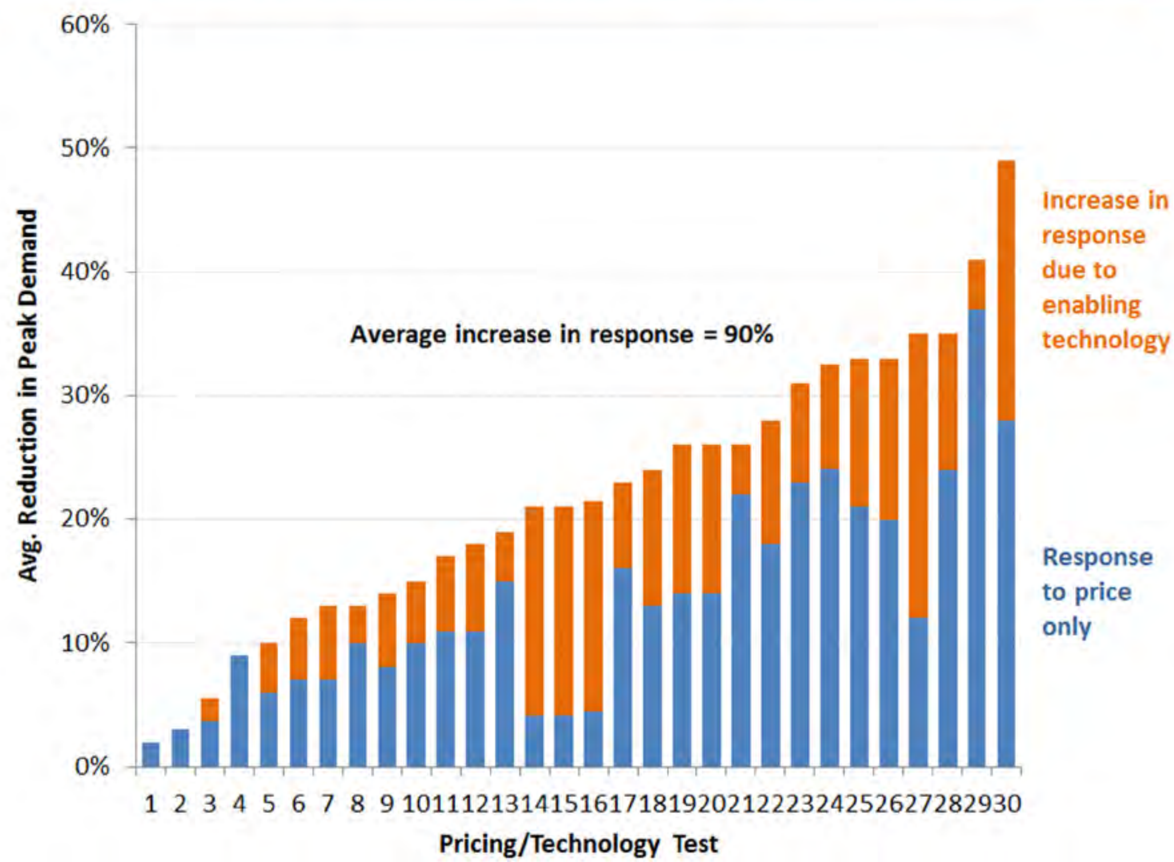
Impacts are scaled to account for enabling technology

Based on the relationship observed in other pilots, we assume a 90% increase in response attributable to technology (largely smart thermostats)

Winter technology impacts are assumed to be 80% of summer technology impacts based on the relationship observed in direct load control programs

TOU is not coupled with enabling technology because it does not have a dispatchable price signal

Price Response with and without Tech



Per-customer pricing impacts are scaled down in the opt-out deployment scenario

A new dynamic pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment

This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario; note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger

Per-customer TOU impacts were 40% lower when offered on an opt-out basis

Per-customer CPP impacts were roughly 50% lower

We have accounted for this relationship in our modeling of the residential impacts

We also simulated the impact of a TOU rate for irrigation customers

A 2001/2002 irrigation TOU pilot in Idaho found that customers produced, on average, a 9% reduction in peak for a TOU with a 3.5-to-1 price ratio

We used the Arc of Price Responsiveness to scale these impacts to the TOU price ratio we're analyzing in this study

The resulting peak reduction estimate is 4.7% for a TOU rate

Summary of draft results

		Without Tech			With Tech		
		TOU	CPP	PTR	TOU	CPP	PTR
Opt-in Deployment							
Residential	Summer	5.2%	11.7%	12.9%	N/A	31.0%	34.2%
	Winter	5.8%	12.8%	14.2%	N/A	24.8%	27.4%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A
Opt-out Deployment							
Residential	Summer	3.1%	5.8%	6.4%	N/A	15.5%	17.1%
	Winter	3.5%	6.4%	7.1%	N/A	12.4%	13.7%
Small C&I	Summer	0.2%	0.4%	0.7%	N/A	9.6%	14.6%
	Winter	0.2%	0.5%	0.7%	N/A	7.7%	11.7%
Medium C&I	Summer	2.6%	5.6%	N/A	N/A	9.0%	N/A
	Winter	2.6%	5.6%	N/A	N/A	9.0%	N/A
Large C&I	Summer	3.1%	6.4%	N/A	N/A	12.0%	N/A
	Winter	3.1%	6.4%	N/A	N/A	12.0%	N/A
Agricultural	Summer	4.7%	N/A	N/A	N/A	N/A	N/A
	Winter	4.7%	N/A	N/A	N/A	N/A	N/A

Notes:

Impacts are average per eligible participant – individual participants could produce larger or smaller impacts

For ease of comparison, tech impacts are expressed as a % of the average customer even though they would only apply to customers with electric A/C or space heat, who have higher peak demand

Non-Pricing Programs
Included in Prior PGE Studies

We estimate per-participant impacts for the following non-pricing programs from prior studies

	Residential	Small C&I	Medium C&I	Large C&I
DLC - A/C	X	X		
DLC - Space heat	X	X		
DLC - Water heating	X	X		
DLC - Auto-DR			X	X
Curtailable tariff			X	X

Updates to assumptions for conventional non-pricing programs were fairly minor

Impact assumptions remain stable for the conventional non-pricing programs analyzed in prior studies for PGE, since these programs are well established with a long history of performance

Where applicable, we revised the estimates to be more consistent with findings of studies in the Pacific Northwest

We also compared the 2012 assumptions to those of the more recent PacifiCorp potential study and resolved any discrepancies to ensure consistency

We relied on the following Pacific Northwest DR studies to refine our impact estimates

- Avista, "Idaho Load Management Pilot," 2010
- Cadmus Group, "Kootenai DR Pilot Evaluation: Full Pilot Results," 2011
- Cadmus Group, "OPALCO DR Pilot Evaluation", 2013
- Itron, "Draft Phase I Report Portland General Electric Energy Partner Program Evaluation," 2015
- Lawrence Berkeley National Lab, "Northwest Open Automated Demand Response Technology Demonstration Project," 2009
- Michaels Energy, "Demand Response and Snapback Impact Study", 2013
- Navigant and EMI, "2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program," 2012
- Navigant, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", 2014
- Nexant, "SmartPricing Options Final Evaluation - The Final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study", 2014
- Rocky Mountain Power, "Utah Energy Efficiency and Peak Reduction annual Report", 2014

The following assumptions were updated for this study

Residential air-conditioning DLC

- Reduced slightly from 1.0 kW to 0.8 kW to reflect lower-than-average impacts observed in Pacific Northwest studies

Residential space heat DLC

- Increased from 0.6 kW to 1.0 kW
- Even higher impacts are observed in Pacific Northwest studies, but a 2004 PGE study found impacts in the 0.7 kW range
- Note that the relationship between space heat and air-conditioning has been reversed based on this revision

Assumption updates (cont'd)

Small C&I air-conditioning and space heat

- Scaled to be consistent with residential assumption (1.5x residential load reduction capability)

Medium and Large C&I Auto-DR

- Increased from 15-20% of peak load to 30% of peak load to establish appropriate relationship between curtailable tariff impacts and Auto-DR impacts
- Assumed to be offered in conjunction with curtailable tariff type of program and provides 50% incremental increase in load reduction relative to impact with no technology
- There is a significant range of uncertainty around this assumption; to be discussed further with PGE relative to the findings of its Auto-DR pilot, which referenced a fairly broad range of impacts

Summary of assumptions for non-pricing impacts from prior studies

Class	Program	Season	2012 Assumption	Updated 2015 Assumption
Residential	DLC - Central A/C	Summer	1.0 kW	0.8 kW
Residential	DLC - Space Heat	Winter	0.6 kW	1.0 kW
Residential	DLC - Water Heating	Summer	0.4 kW	0.4 kW
Residential	DLC - Water Heating	Winter	0.8 kW	0.8 kW
Small C&I	DLC - Central A/C	Summer	2.0 kW	1.2 kW
Small C&I	DLC - Space Heat	Winter	1.2 kW	1.5 kW
Small C&I	DLC - Water Heating	Summer	1.2 kW	1.2 kW
Small C&I	DLC - Water Heating	Winter	0.6 kW	0.6 kW
Medium C&I	DLC - Auto-DR	Year-round	15%	30%
Medium C&I	Curtailable tariff	Year-round	N/A	20%
Large C&I	DLC - Auto-DR	Year-round	20%	30%
Large C&I	Curtailable tariff	Year-round	20%	20%

New Non-Pricing Programs Not Included in Prior PGE Studies

We estimated per-participant peak demand impacts for three new programs; two more are in development

Draft impact estimates have been developed for:

- Bring-your-own-device (BYOD) load control (residential)
- Behavioral DR (residential)
- Irrigation load control (agricultural)

Impact estimates are in development for:

- Smart water heating load control (residential)
- Electric vehicle charging load control (residential)
- Developing assumptions for these programs requires ongoing interaction with PGE staff, which is already underway

We relied on the following data sources to develop our impact estimates for new non-pricing programs

- Applied Energy Group, PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034 Volume 5: Class 1 and 3 DSM Analysis Appendix, January 30, 2015
- Austin Energy, PowerSaver Program website, Accessed May 1, 2015
- Con Ed of NY, Rider L – Direct Load Control Program filing, Case C14-E-0121, April 3, 2014
- Edison Foundation, Innovations Across the Grid, December 2013 and December 2014
- Hydro One website, Accessed May 1, 2015.
- Illume, MyMeter Multi-Utility Impact Findings, March 2014.
- J. Bumgarner, The Cadmus Group, Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program, March 24, 2011.
- Nest Inc., White Paper: Rush Hour Rewards, Results from Summer 2013, May 2014.
- Opower, Using Behavioral Demand Response as a MISO Capacity Resource, June 4, 2014.
- Rocky Mountain Power, Utah Energy Efficiency and Peak Reduction Annual Report, June 26, 2013 and May 16, 2014.
- S. Blumsack and P. Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013", March 5, 2015.
- Southern California Edison website, Accessed May 1, 2015.

We have identified key elements of "Bring Your Own Device" Type Programs

Bring Your Own Device/Thermostat ("BYOD" or "BYOT") programs provide an alternative to utility direct-install programs, reducing equipment and installation costs

The incentive structure for participating in BYOD programs is diverse

- One-time rebate/refund, with or without a minimum time commitment
- Fixed annual/monthly participation incentive in addition to a one-time rebate
- Variable monthly incentive based on kWh savings

Programs also include monetary incentives to thermostat vendors and annual compensation for portal/interface maintenance

Customers can opt out of individual events without penalty

Our assumptions are based on research of five different BYOD programs

We have identified five primary programs

- Hydro One
- Austin Energy
- Con Edison of NY
- Southern California Edison
- "Rush Hour Rewards (RHR)" program by Nest Inc.

These programs have been able to successfully sign up new customers

- As of December 2014, Austin Energy had enrolled 7,000 thermostats (out of ~383,000 residential customers), with a planned expansion to 70,000 thermostats
- Con Edison enrolled 2,000 customers in its first year and believes that it can achieve 5,000 new sign-ups each year
  - Low enrollment may be explained by a relatively small number of eligible thermostats currently installed (~30,000)
- In 2013 Nest's Rush Hour Rewards program included over 2,000 customers from Austin Energy, Reliant, and Southern California Edison. Nest is currently expanding this program, and enrollment has likely increased since then

Our BYOD program impact estimates are similar to those of other Residential A/C DLC programs

Austin Energy's *Power Partner Thermostat* program has achieved a per device load shed of up to 33% during a peak event

Con Edison expects 1.0 kW of peak load reduction per thermostat based on its experience with other Residential DLC participants

Nest's "RHR" program studied the peak load impacts across three different utilities (Austin Energy, Reliant, and Southern California Edison)

- A total of 19 events were studied across the three utilities
- Each event reduced load by an average of 1.18 kW per device
- Only 14.5% of customers reduced their temperature during an event

Research suggests a per-customer peak reduction of around 1 kW

Utility/Program	Number of Participants	Customer Incentive	Peak Demand Impact (%/customer)	Peak Demand Impact (kW/customer)
Austin Energy	7,000	$85/one-time	33%	N/A
SCE	N/A	$1.25/kWh reduced	N/A	N/A
Con Ed of NY	2,000	$85/one-time; $25 annual for additional participation	N/A	1.0
Hydro One	2,000	$100-125/one-time	N/A	N/A
Nest Inc.'s "RHR"	2,000	N/A	55%	1.18

The available data suggests that per-customer impacts are similar to that of a utility-administered DLC program; we therefore assume the same summer and winter impacts that are being modeled in the conventional programs

Impacts of Behavioral DR programs were based primarily on programs conducted by OPower

Behavioral Demand Response aims to increase customer engagement

Achieved via a software-centered approach based on targeted and customized email, mobile, and interactive voice response (IVR) communications

Customers are notified of DR events ahead of time and receive post-event feedback on performance

Easy to deploy and scale relative to other DR programs that require hardware installations

No financial incentives are offered for load reductions

OPower reports significant summer peak savings from BDR programs

Deployed to 150k customers in Consumers Energy (MI), Green Mountain Power (VT), and Glendale Water & Power (CA)

- Achieved peak load reductions of 3% on average (max 5%)

BGE launched BDR in combination with a Peak Time Rebate Program

- 5% average reduction at peak across homes without a device (~0.2kW/home)

Added benefit of customer engagement and increased satisfaction, although it is possible that customers could find the notifications to be intrusive

Others are also exploring the potential of Behavioral DR

In Minnesota, four electric co-ops used MyMeter – a program that gives utility customers more detailed info about their energy use

- In 2013, demand reduction ranged between 1.8 – 2.8% per customer
- This program is different from those offered by Opower, as information is driven through an in-home display

In the fall of 2012 and summer of 2013, Green Mountain Power study tested a behavioral DR-like program

- GMP ran fourteen peak event tests for seven treatment groups with varying rate structures and informational treatments
- Customers who stayed on a flat rate, but were notified of peak events, reduced by peak demand by 3.4% and 8.2% in 2012 and 2013, respectively (0.030 - 0.073 kW)

We have heard that Silver Spring Networks may be developing BDR capability. However, we have not yet found any evidence and further research is needed

Research suggests a 3% reduction impact for Behavioral DR programs would be reasonable

Utility/Program	Summer Peak Demand Impact (%)
Consumers Energy, Green Mountain Power, and Glendale Water & Power	3.0%
BGE	5.0%
MN electric co-ops (MyMeter Program)	1.8-2.8%
Green Mountain Power	3.4-8.2%

- Since little is known about the persistence of BDR impacts over the long-term, we assume an impact from the lower end of this range, of 3%
- To establish a winter impact, we use the same assumption that is used in our dynamic pricing analysis, that winter impacts are 10% higher than summer impacts; this is because BDR similarly relies on behavioral response from customers rather than targeting a specific end-use

There is support for high per-customer impacts from Irrigation Load Control programs

Irrigation Load Control consists of scheduling or shutting off irrigation pumps above a certain size

The programs researched are available only during the summer and typically provide a fixed (per event) incentive payment

Customers can opt out of a maximum number of events per year

In the Pacific Northwest, PacifiCorp has experience with such programs in Idaho and Utah; Idaho Power and a number of electric cooperatives also offer irrigation load control programs

Southern California Edison and Entergy also offer irrigation load control programs, as do coops in other parts of the US

Estimates of irrigation peak load reductions are fairly large on a per-participant basis

Rocky Mountain Power (part of PacifiCorp) ran its irrigation load control program in 2009 and 2010 with customers in Idaho

- About 2,000 customers were enrolled between 2009 and 2010
- Aggregate reductions in 2009 was 206 MW out of 260 MW of irrigation load
- In 2010, reductions amounted to 156 MW out of 283 MW of load

RMP also ran a program in Utah that achieved reductions in the 62-73% range

FERC's DR Study reports peak demand reductions of about 60% for electric cooperatives

Southern California Edison and Entergy report impacts of 82% and 49%, respectively

In its 2014 DR potential study, PacifiCorp's assumed that 100% of agricultural irrigation load could be curtailed during an event

Our research suggests peak reductions in the 65%-75% range for Irrigation Load Control programs

Utility/Program	Peak Demand Impact (MW)	Baseline Demand (MW)	Peak Demand Impact (%)
PacifiCorp DR potential study	N/A	N/A	100%
Southern California Edison			89%
RMP 2009	205	260	79%
RMP 2010	156	283	55%
RMP 2012	35	48	73%
RMP 2013	16	26	62%
Various Coops (FERC 2013 Study)	N/A	N/A	60% (mean)
Entergy (Arkansas)			49%

Notes: Peak demand impact % calculated for RMP 2009-2012 as (peak demand impact) / (baseline demand).
RMP 2009-10 from The Cadmus Group, *Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program,* March 24, 2011, pp. 1-2.
RMP 2012 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* Revised June 26, 2013, p. 19.
RMP 2013 from Rocky Mountain Power, *Utah Energy Efficiency and Peak Reduction Annual Report,* May 16, 2014, p. 19.

Summary of Impact Assumptions for New Non-Pricing programs

Program	Winter Peak Demand Impact (kW)	Winter Peak Demand Impact (%)	Summer Peak Demand Impact (kW)	Summer Peak Demand Impact (%)
BYOD	1.0 kW		0.8 kW	
Behavioral DR		3.3%		3%
Irrigation Load Control		N/A		70%

Appendix C:

Cost-Effectiveness Adjustments

Should the incentive payment be included as a cost in the TRC cost-effectiveness test?

If every participant valued their loss of comfort at an amount equal to the incentive payment (assume $90/year), then it would be correct to include the full incentive amount as a cost in the TRC test

However, every participant is unique and will therefore value the loss of comfort differently; consider four prototypical customers in a DLC program:

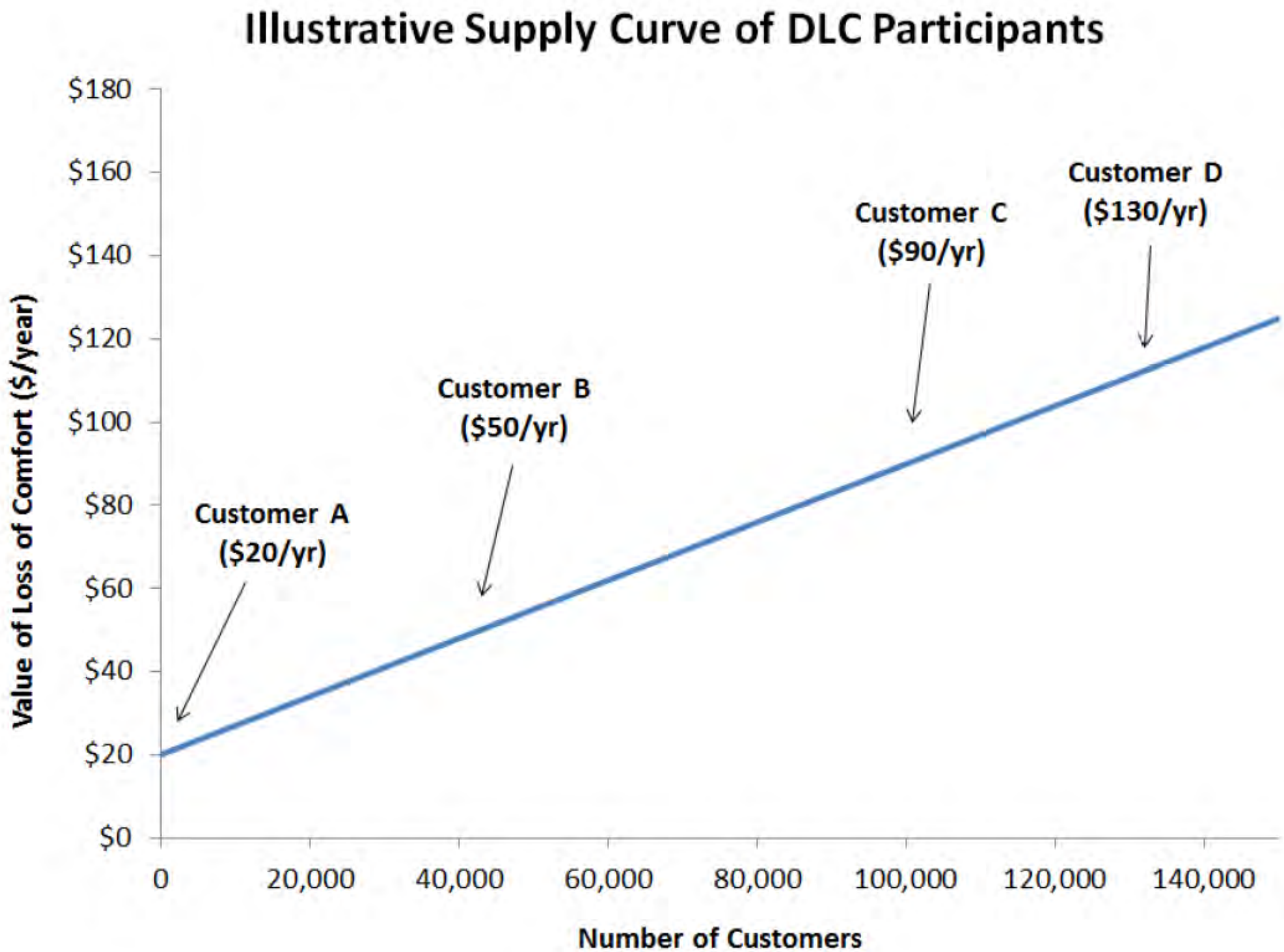
Customer A, for example, is rarely home and therefore only values his loss of comfort from participating in the DLC program at $20/year – his "profit" from participating in the program would be $70/year

Customer B is home more often, but does not particularly mind relinquishing control of his air-conditioner occasionally; he values the loss of comfort at $50/kW year

Customer C places higher value on comfort, and the cost of participating is roughly the same to him as the incentive payment that he receives; this is the "marginal" customer

Customer D is more temperature-sensitive and does not like the idea of curtailing use of his air-conditioner; his value of lost comfort is $130/year, or $40 more than the incentive payment that is being offered

The prototypical customers represent a “supply curve” of participants in the DLC program



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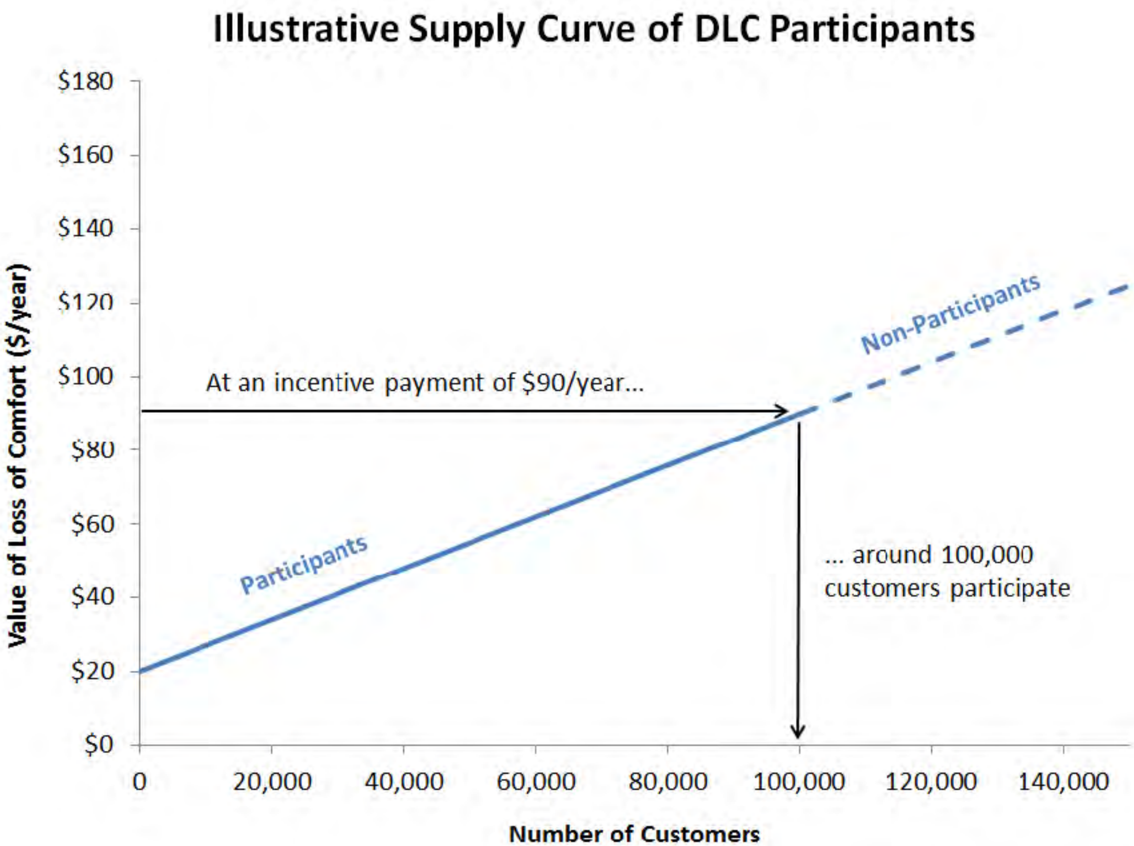
The cost associated with "loss of comfort" should be the average across all participants



- Customers will only participate if their loss of comfort is less than the incentive payment
- In this purely illustrative example, the average loss of comfort among participants is $50 per year, which is 55% of the incentive payment
- The remaining 45% is simply a transfer payment and should not be considered a cost in the TRC test (which is consistent with treatment of energy efficiency programs)
- While that estimate would change depending on the slope of the supply curve, it is more realistic than assuming all customers incur a cost of $90/year
- We count 50% of the incentive as a cost in the base case of our analysis for this reason

We tested the sensitivity of our findings to the amount of incentive counted as a cost

Class	Program	Opt-in: Base Case (50%)	Opt-in: 0%	Opt-in: 100%
Residential	AC DLC	1.12	1.57	0.87
Residential	Space Heating DLC	1.31	1.78	1.03
Residential	Water Heating DLC	1.30	2.09	0.94
Residential	AC/Space Heating DLC	1.82	3.10	1.29
Residential	TOU	1.24	1.24	1.24
Residential	PTR	1.75	4.49	1.24
Residential	PTR w/Tech	1.32	2.26	0.98
Residential	CPP	1.62	1.62	1.62
Residential	CPP w/Tech	1.49	1.49	1.49
Residential	Behavioral DR	0.85	0.80	0.80
Residential	BYOT - AC	1.94	3.55	1.27
Residential	BYOT - Space Heating	1.98	3.30	1.41
Residential	BYOT - AC/Space Heating	2.43	5.39	1.57
Small C&I	AC DLC	1.00	1.51	0.75
Small C&I	Space Heating DLC	1.07	1.52	0.83
Small C&I	Water Heating DLC	0.79	1.14	0.60
Small C&I	AC/Space Heating DLC	1.40	2.41	0.98
Small C&I	TOU	0.06	0.06	0.06
Small C&I	PTR	0.17	0.18	0.16
Small C&I	PTR w/Tech	0.79	1.03	0.64
Small C&I	CPP	0.08	0.08	0.08
Small C&I	CPP w/Tech	0.55	0.55	0.55
Medium C&I	Third-Party DLC	1.59	2.09	1.23
Medium C&I	Curtailable Tariff	5.37	28.26	2.96
Medium C&I	CPP	1.94	1.94	1.94
Medium C&I	CPP w/Tech	1.38	1.38	1.38
Large C&I	Third-Party DLC	1.57	2.06	1.22
Large C&I	Curtailable Tariff	6.30	168.36	3.21
Large C&I	CPP	14.42	14.42	14.42
Large C&I	CPP w/Tech	6.70	6.70	6.70
Agricultural	Pumping Load Control	0.78	1.02	0.63
Agricultural	TOU	0.29	0.29	0.29

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The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-in** program deployment

Cost-effectiveness sensitivity case results (cont'd)

Class	Program	Opt-out Base Case (50%)	Opt-out 0%	Opt-out 100%
Residential	AC DLC	N/A	N/A	N/A
Residential	Space Heating DLC	N/A	N/A	N/A
Residential	Water Heating DLC	N/A	N/A	N/A
Residential	AC/Space Heating DLC	N/A	N/A	N/A
Residential	TOU	1.24	1.05	1.05
Residential	PTR	1.49	2.76	1.06
Residential	PTR w/Tech	0.86	1.16	0.69
Residential	CPP	1.15	1.04	1.04
Residential	CPP w/Tech	0.83	0.80	0.80
Residential	Behavioral DR	1.04	0.97	0.97
Residential	BYOT - AC	N/A	N/A	N/A
Residential	BYOT - Space Heating	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	N/A	N/A	N/A
Small C&I	AC DLC	N/A	N/A	N/A
Small C&I	Space Heating DLC	N/A	N/A	N/A
Small C&I	Water Heating DLC	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	N/A	N/A	N/A
Small C&I	TOU	0.11	0.09	0.09
Small C&I	PTR	0.30	0.30	0.26
Small C&I	PTR w/Tech	0.82	1.07	0.66
Small C&I	CPP	0.11	0.10	0.10
Small C&I	CPP w/Tech	0.60	0.58	0.58
Medium C&I	Third-Party DLC	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	N/A	N/A	N/A
Medium C&I	CPP	4.80	3.56	3.56
Medium C&I	CPP w/Tech	1.76	1.63	1.63
Large C&I	Third-Party DLC	N/A	N/A	N/A
Large C&I	Curtailable Tariff	N/A	N/A	N/A
Large C&I	CPP	42.10	34.79	34.79
Large C&I	CPP w/Tech	7.15	7.02	7.02
Agricultural	Pumping Load Control	N/A	N/A	N/A
Agricultural	TOU	0.83	0.63	0.63

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The table at left shows benefit-cost ratios assuming that 50%, 100%, and 0% of the incentive payment is counted as a cost in the TRC cost-effectiveness test, for **opt-out** program deployment

Avoided costs derates are derived from the California cost-effectiveness protocols

The California PUC currently defines three factors that are used to adjust avoided capacity costs to better reflect the value of demand response:

(A) **Availability:** "The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted."

(B) **Notification time:** "The B factor calculation should be done by examination of past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls… By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program."

(C) **Trigger:** "The C factor should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions.

Additionally, the CPUC defines two factors used to adjust T&D costs and energy cost, but those are specific to avoided assumptions in California and not directly applicable to this analysis for PGE

For more information, see the 2010 California DR Cost Effectiveness Protocols report:
http://www.cpuc.ca.gov/NR/rdonlyres/7D2FEDB9-4FD6-4CCB-B88F-DC190DFE9AFA/0/Protocolsfinal.DOC

The CPUC is currently examining the possible modification and expansion of these factors

Avoided cost derates used in the PGE analysis

Class	Program	A) Availability	B) Notification	C) Trigger	Combined
Residential	TOU - No Tech	65%	100%	100%	65%
Residential	CPP - No Tech	60%	88%	100%	53%
Residential	CPP - With Tech	60%	88%	100%	53%
Residential	PTR - No Tech	60%	88%	100%	53%
Residential	PTR - With Tech	60%	88%	100%	53%
Residential	DLC - Central A/C	70%	100%	95%	67%
Residential	DLC - Space Heat	70%	100%	95%	67%
Residential	DLC - Water Heating	85%	100%	95%	81%
Residential	DLC - BYOT	70%	100%	95%	67%
Residential	Behavioral DR	70%	88%	100%	62%
Small C&I	TOU - No Tech	65%	100%	100%	65%
Small C&I	CPP - No Tech	60%	88%	100%	53%
Small C&I	CPP - With Tech	60%	88%	100%	53%
Small C&I	PTR - No Tech	60%	88%	100%	53%
Small C&I	PTR - With Tech	60%	88%	100%	53%
Small C&I	DLC - Central A/C	70%	100%	95%	67%
Small C&I	DLC - Space Heat	70%	100%	95%	67%
Small C&I	DLC - Water Heating	85%	100%	95%	81%
Medium C&I	CPP - No Tech	60%	88%	100%	53%
Medium C&I	CPP - With Tech	60%	88%	100%	53%
Medium C&I	DLC - AutoDR	75%	100%	95%	71%
Medium C&I	Curtailable Tariff	75%	88%	100%	66%
Large C&I	CPP - No Tech	60%	88%	100%	53%
Large C&I	CPP - With Tech	60%	88%	100%	53%
Large C&I	DLC - AutoDR	75%	100%	95%	71%
Large C&I	Curtailable Tariff	75%	88%	100%	66%
Agriculture	DLC - Pumping	75%	100%	95%	71%

- Values at left represent the percent of the avoided cost that is attributed to the DR program
- Estimates are based on a survey of values developed by the California IOUs across a wide variety of DR programs
- Values are calibrated to capture appropriate relative relationships across the programs evaluated for PGE and intuitive estimates were developed for those programs for which there is not a clear example in the California data

Appendix D:

Annual Potential Estimates and Benefit-Cost Ratios

See the accompanying MS Excel file titled “PGE DR Potential Results - Annual Tables.xlsx”.

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0	42.0	43.2	44.6	45.7
Residential	PTR	Summer	0.0	94.3	97.2	100.3	102.9
Residential	PTR w/Tech	Summer	0.0	23.5	24.3	25.0	25.7
Residential	CPP	Summer	0.0	76.2	78.3	80.8	82 9
Residential	CPP w/Tech	Summer	0.0	20.4	21.0	21.6	22 2
Residential	Behavioral DR	Summer	45.2	38.1	39.3	40.6	41.7
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0	0 5	0.6	0.6	0.6
Small C&I	PTR	Summer	0.0	1.7	1.8	2.0	2.1
Small C&I	PTR w/Tech	Summer	0.0	3.7	4.0	4.3	4.6
Small C&I	CPP	Summer	0.0	0 9	1.0	1.0	1.1
Small C&I	CPP w/Tech	Summer	0.0	2 2	2.3	2.5	2.6
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0	21 9	23.3	25.2	26.8
Medium C&I	CPP w/Tech	Summer	0.0	38 5	41.1	44.4	47.3
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0	40 9	44.3	48.4	52.1
Large C&I	CPP w/Tech	Summer	0.0	83 9	90.9	99.4	106.9
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0	1.7	1.6	1.4	1.3

Measure-level Peak Reduction Potential: Summer (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	11.0	106 5	120.9	134.2	144.3
Residential	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Residential	Water Heating DLC	Summer	3.6	31 0	32.3	33.8	35.2
Residential	AC/Space Heating DLC	Summer	1.4	12 3	13.0	13.7	14.3
Residential	TOU	Summer	0.0	22.7	23.9	24.6	25.3
Residential	PTR	Summer	0.0	42.6	44.7	46.1	47.3
Residential	PTR w/Tech	Summer	0.0	12.9	13.5	13.9	14.3
Residential	CPP	Summer	0.0	31.9	33.5	34.6	35.5
Residential	CPP w/Tech	Summer	0.0	9.6	10.1	10.4	10.7
Residential	Behavioral DR	Summer	1.1	9.5	9.8	10.2	10.4
Residential	BYOT - AC	Summer	1.9	42.1	44.5	46.9	49 0
Residential	BYOT - Space Heating	Summer	0.0	0.0	0.0	0.0	0 0
Residential	BYOT - AC/Space Heating	Summer	0.9	7.7	8.1	8.6	8 9
Residential	Smart Water Heater DLC	Summer	0.1	7.6	20.5	33.7	44.5
Residential	Electric Vehicle DLC	Summer	0.4	1.3	2.7	4.9	6 9
Small C&I	AC DLC	Summer	1.5	12 8	13.8	14.9	15.9
Small C&I	Space Heating DLC	Summer	0.0	0.0	0.0	0.0	0.0
Small C&I	Water Heating DLC	Summer	0.1	0.7	0.7	0.8	0 8
Small C&I	AC/Space Heating DLC	Summer	0.4	3.4	3.7	4.0	4.2
Small C&I	TOU	Summer	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Summer	0.0	0 5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Summer	0.0	1 2	1.4	1.5	1.6
Small C&I	CPP	Summer	0.0	0 2	0.3	0.3	0.3
Small C&I	CPP w/Tech	Summer	0.0	0.6	0.7	0.7	0.8
Medium C&I	Third-Party DLC	Summer	5.2	46.1	49.6	53.6	57.1
Medium C&I	Curtailable Tariff	Summer	23.3	24.6	26.5	28.6	30.4
Medium C&I	CPP	Summer	0.0	6.1	6.7	7.2	7.7
Medium C&I	CPP w/Tech	Summer	0.0	10 9	11.9	12.9	13.7
Large C&I	Third-Party DLC	Summer	7.0	62 8	68.6	75.1	80.7
Large C&I	Curtailable Tariff	Summer	75.5	80.4	87.8	96.1	103.3
Large C&I	CPP	Summer	0.0	11.4	12.6	13.8	14.9
Large C&I	CPP w/Tech	Summer	0.0	29.6	32.9	36.0	38.7
Agricultural	Pumping Load Control	Summer	0.5	3.8	3.5	3.2	2.9
Agricultural	TOU	Summer	0.0	0 3	0.3	0.2	0.2

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Summer	0.0%	1.2%	1.1%	1.1%	1.1%
Residential	PTR	Summer	0.0%	2.6%	2.6%	2 5%	2.5%
Residential	PTR w/Tech	Summer	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Summer	0.0%	2.1%	2.1%	2 0%	2.0%
Residential	CPP w/Tech	Summer	0.0%	0.6%	0.6%	0 5%	0.5%
Residential	Behavioral DR	Summer	1.3%	1.1%	1.0%	1 0%	1.0%
Residential	BYOT - AC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Summer	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Summer	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP w/Tech	Summer	0.0%	1.1%	1.1%	1.1%	1.1%
Large C&I	Third-Party DLC	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Summer	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Summer	0.0%	1.1%	1.2%	1 2%	1.2%
Large C&I	CPP w/Tech	Summer	0.0%	2.3%	2.4%	2 5%	2.5%
Agricultural	Pumping Load Control	Summer	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0 0%	0.0%

Measure-level Peak Reduction Potential: Summer (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Summer	0.3%	3.0%	3.2%	3 3%	3.4%
Residential	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Residential	Water Heating DLC	Summer	0.1%	0.9%	0.9%	0 8%	0.8%
Residential	AC/Space Heating DLC	Summer	0.0%	0.3%	0.3%	0 3%	0.3%
Residential	TOU	Summer	0.0%	0.6%	0.6%	0.6%	0.6%
Residential	PTR	Summer	0.0%	1.2%	1.2%	1 2%	1.1%
Residential	PTR w/Tech	Summer	0.0%	0.4%	0.4%	0 3%	0.3%
Residential	CPP	Summer	0.0%	0.9%	0.9%	0 9%	0.8%
Residential	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0 3%	0.3%
Residential	Behavioral DR	Summer	0.0%	0.3%	0.3%	0 3%	0.2%
Residential	BYOT - AC	Summer	0.1%	1.2%	1.2%	1 2%	1.2%
Residential	BYOT - Space Heating	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Residential	BYOT - AC/Space Heating	Summer	0.0%	0.2%	0.2%	0 2%	0.2%
Residential	Smart Water Heater DLC	Summer	0.0%	0.2%	0.5%	0 8%	1.1%
Residential	Electric Vehicle DLC	Summer	0.0%	0.0%	0.1%	0.1%	0.2%
Small C&I	AC DLC	Summer	0.0%	0.4%	0.4%	0.4%	0.4%
Small C&I	Space Heating DLC	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	Water Heating DLC	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	AC/Space Heating DLC	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR w/Tech	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	CPP	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	CPP w/Tech	Summer	0.0%	0.0%	0.0%	0 0%	0.0%
Medium C&I	Third-Party DLC	Summer	0.1%	1.3%	1.3%	1 3%	1.4%
Medium C&I	Curtailable Tariff	Summer	0.7%	0.7%	0.7%	0.7%	0.7%
Medium C&I	CPP	Summer	0.0%	0.2%	0.2%	0 2%	0.2%
Medium C&I	CPP w/Tech	Summer	0.0%	0.3%	0.3%	0 3%	0.3%
Large C&I	Third-Party DLC	Summer	0.2%	1.7%	1.8%	1 9%	1.9%
Large C&I	Curtailable Tariff	Summer	2.1%	2.2%	2.3%	2.4%	2.5%
Large C&I	CPP	Summer	0.0%	0.3%	0.3%	0 3%	0.4%
Large C&I	CPP w/Tech	Summer	0.0%	0.8%	0.9%	0 9%	0.9%
Agricultural	Pumping Load Control	Summer	0.0%	0.1%	0.1%	0.1%	0.1%
Agricultural	TOU	Summer	0.0%	0.0%	0.0%	0 0%	0.0%

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0	61.7	62.8	64.1	65.2
Residential	PTR	Winter	0.0	136.2	138.9	141.8	144.1
Residential	PTR w/Tech	Winter	0.0	24.6	25.0	25.6	26.0
Residential	CPP	Winter	0.0	109.4	111.3	113.6	115.5
Residential	CPP w/Tech	Winter	0.0	21.2	21.6	22.1	22.4
Residential	Behavioral DR	Winter	65.6	54.6	55.7	56.9	57.9
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0	0.5	0.5	0.5	0.6
Small C&I	PTR	Winter	0.0	1.7	1.8	1.9	2.0
Small C&I	PTR w/Tech	Winter	0.0	2.7	2.9	3.1	3.3
Small C&I	CPP	Winter	0.0	0.8	0.9	0.9	1.0
Small C&I	CPP w/Tech	Winter	0.0	1.6	1.7	1.8	1.9
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0	18.1	19.2	20.7	22.0
Medium C&I	CPP w/Tech	Winter	0.0	31.8	33.9	36.5	38.8
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0	35.4	38.2	41.6	44.7
Large C&I	CPP w/Tech	Winter	0.0	72.5	78.4	85.5	91.7
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0	0.0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (MW, grossed up for line losses)

Maximum Achievable Potential Opt-In Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	Space Heating DLC	Winter	2.3	20.1	21.2	22.4	23.3
Residential	Water Heating DLC	Winter	7.2	61 9	64.5	67.6	70.4
Residential	AC/Space Heating DLC	Winter	1.7	15.4	16.2	17.1	17.9
Residential	TOU	Winter	0.0	33 0	34.3	35.0	35.6
Residential	PTR	Winter	0.0	61 0	63.4	64.7	65.8
Residential	PTR w/Tech	Winter	0.0	13.4	13.9	14.2	14.5
Residential	CPP	Winter	0.0	45.4	47.2	48.2	49.0
Residential	CPP w/Tech	Winter	0.0	10 0	10.4	10.6	10.8
Residential	Behavioral DR	Winter	1.6	13.6	13.9	14.2	14.5
Residential	BYOT - AC	Winter	0.0	0.0	0.0	0.0	0.0
Residential	BYOT - Space Heating	Winter	1.4	12.6	13.2	14.0	14.6
Residential	BYOT - AC/Space Heating	Winter	1.1	9.6	10.1	10.7	11.2
Residential	Smart Water Heater DLC	Winter	0.2	15.1	41.1	67.5	88.9
Residential	Electric Vehicle DLC	Winter	0.3	0 9	2.0	3.5	5.0
Small C&I	AC DLC	Winter	0.0	0.0	0.0	0.0	0.0
Small C&I	Space Heating DLC	Winter	0.7	6 0	6.5	7.1	7.5
Small C&I	Water Heating DLC	Winter	0.2	1 3	1.4	1.5	1.6
Small C&I	AC/Space Heating DLC	Winter	0.5	4 3	4.6	5.0	5.3
Small C&I	TOU	Winter	0.0	0.1	0.1	0.1	0.1
Small C&I	PTR	Winter	0.0	0 5	0.5	0.6	0.6
Small C&I	PTR w/Tech	Winter	0.0	0 9	1.0	1.1	1.1
Small C&I	CPP	Winter	0.0	0 3	0.3	0.3	0.4
Small C&I	CPP w/Tech	Winter	0.0	0.4	0.5	0.5	0.6
Medium C&I	Third-Party DLC	Winter	4.2	38.1	40.9	44.1	46.8
Medium C&I	Curtailable Tariff	Winter	19.0	20 3	21.8	23.5	25.0
Medium C&I	CPP	Winter	0.0	5 0	5.5	5.9	6.3
Medium C&I	CPP w/Tech	Winter	0.0	9 0	9.8	10.6	11.2
Large C&I	Third-Party DLC	Winter	6.0	54 3	59.2	64.5	69.2
Large C&I	Curtailable Tariff	Winter	64.3	69 5	75.7	82.6	88.6
Large C&I	CPP	Winter	0.0	9 8	10.9	11.9	12.8
Large C&I	CPP w/Tech	Winter	0.0	25.6	28.4	31.0	33.2
Agricultural	Pumping Load Control	Winter	0.0	0 0	0.0	0.0	0.0
Agricultural	TOU	Winter	0.0	0 0	0.0	0.0	0.0

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-Out Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	TOU	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR	Winter	0.0%	3.7%	3.6%	3 5%	3.4%
Residential	PTR w/Tech	Winter	0.0%	0.7%	0.6%	0.6%	0.6%
Residential	CPP	Winter	0.0%	3.0%	2.9%	2 8%	2.7%
Residential	CPP w/Tech	Winter	0.0%	0.6%	0.6%	0 5%	0.5%
Residential	Behavioral DR	Winter	1 8%	1.5%	1.4%	1.4%	1.4%
Residential	BYOT - AC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	BYOT - AC/Space Heating	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Smart Water Heater DLC	Winter	N/A	N/A	N/A	N/A	N/A
Residential	Electric Vehicle DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	Water Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	AC/Space Heating DLC	Winter	N/A	N/A	N/A	N/A	N/A
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0 0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0 0%	0.0%
Medium C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Medium C&I	CPP	Winter	0.0%	0.5%	0.5%	0 5%	0.5%
Medium C&I	CPP w/Tech	Winter	0.0%	0.9%	0.9%	0 9%	0.9%
Large C&I	Third-Party DLC	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	Curtailable Tariff	Winter	N/A	N/A	N/A	N/A	N/A
Large C&I	CPP	Winter	0.0%	1.0%	1.0%	1 0%	1.1%
Large C&I	CPP w/Tech	Winter	0.0%	2.0%	2.0%	2.1%	2.2%
Agricultural	Pumping Load Control	Winter	N/A	N/A	N/A	N/A	N/A
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0 0%	0.0%

Measure-level Peak Reduction Potential: Winter (% of System Peak, grossed up for line losses)

Maximum Achievable Potential Opt-in Scenario

Class	Program	Season	2016	2021	2026	2031	2035
Residential	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	Space Heating DLC	Winter	0.1%	0.5%	0.5%	0.6%	0.6%
Residential	Water Heating DLC	Winter	0.2%	1.7%	1.7%	1.7%	1.7%
Residential	AC/Space Heating DLC	Winter	0.0%	0.4%	0.4%	0.4%	0.4%
Residential	TOU	Winter	0.0%	0.9%	0.9%	0.9%	0.8%
Residential	PTR	Winter	0.0%	1.7%	1.6%	1.6%	1.6%
Residential	PTR w/Tech	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	CPP	Winter	0.0%	1.2%	1.2%	1.2%	1.2%
Residential	CPP w/Tech	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Behavioral DR	Winter	0.0%	0.4%	0.4%	0.4%	0.3%
Residential	BYOT - AC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Residential	BYOT - Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	BYOT - AC/Space Heating	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Residential	Smart Water Heater DLC	Winter	0.0%	0.4%	1.1%	1.7%	2.1%
Residential	Electric Vehicle DLC	Winter	0.0%	0.0%	0.1%	0.1%	0.1%
Small C&I	AC DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	Space Heating DLC	Winter	0.0%	0.2%	0.2%	0.2%	0.2%
Small C&I	Water Heating DLC	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	AC/Space Heating DLC	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Small C&I	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	PTR w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Small C&I	CPP w/Tech	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Medium C&I	Third-Party DLC	Winter	0.1%	1.0%	1.1%	1.1%	1.1%
Medium C&I	Curtailable Tariff	Winter	0.5%	0.6%	0.6%	0.6%	0.6%
Medium C&I	CPP	Winter	0.0%	0.1%	0.1%	0.1%	0.1%
Medium C&I	CPP w/Tech	Winter	0.0%	0.2%	0.3%	0.3%	0.3%
Large C&I	Third-Party DLC	Winter	0.2%	1.5%	1.5%	1.6%	1.6%
Large C&I	Curtailable Tariff	Winter	1.8%	1.9%	2.0%	2.0%	2.1%
Large C&I	CPP	Winter	0.0%	0.3%	0.3%	0.3%	0.3%
Large C&I	CPP w/Tech	Winter	0.0%	0.7%	0.7%	0.8%	0.8%
Agricultural	Pumping Load Control	Winter	0.0%	0.0%	0.0%	0.0%	0.0%
Agricultural	TOU	Winter	0.0%	0.0%	0.0%	0.0%	0.0%

Benefit-Cost Ratios

Opt-out Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	N/A
Residential	Space Heating DLC	N/A
Residential	Water Heating DLC	N/A
Residential	AC/Space Heating DLC	N/A
Residential	TOU	1.24
Residential	PTR	1.49
Residential	PTR w/Tech	0.86
Residential	CPP	1.15
Residential	CPP w/Tech	0.83
Residential	Behavioral DR	1.04
Residential	BYOT - AC	N/A
Residential	BYOT - Space Heating	N/A
Residential	BYOT - AC/Space Heating	N/A
Residential	Smart Water Heater DLC	N/A
Residential	Electric Vehicle DLC	N/A
Small C&I	AC DLC	N/A
Small C&I	Space Heating DLC	N/A
Small C&I	Water Heating DLC	N/A
Small C&I	AC/Space Heating DLC	N/A
Small C&I	TOU	0.11
Small C&I	PTR	0.30
Small C&I	PTR w/Tech	0.82
Small C&I	CPP	0.11
Small C&I	CPP w/Tech	0.60
Medium C&I	Third-Party DLC	N/A
Medium C&I	Curtailable Tariff	N/A
Medium C&I	CPP	4.80
Medium C&I	CPP w/Tech	1.76
Large C&I	Third-Party DLC	N/A
Large C&I	Curtailable Tariff	N/A
Large C&I	CPP	42.10
Large C&I	CPP w/Tech	7.15
Agricultural	Pumping Load Control	N/A
Agricultural	TOU	0.83

Benefit-Cost Ratios

Opt-in Scenario (Red text indicates ratio is less than 1.0)

Class	Program	Ratio
Residential	AC DLC	1.12
Residential	Space Heating DLC	1.31
Residential	Water Heating DLC	1.30
Residential	AC/Space Heating DLC	1.82
Residential	TOU	1.24
Residential	PTR	1.75
Residential	PTR w/Tech	1.32
Residential	CPP	1.62
Residential	CPP w/Tech	1.49
Residential	Behavioral DR	0.85
Residential	BYOT - AC	1.94
Residential	BYOT - Space Heating	1.98
Residential	BYOT - AC/Space Heating	2.43
Residential	Smart Water Heater DLC	2.22
Residential	Electric Vehicle DLC	0.14
Small C&I	AC DLC	1.00
Small C&I	Space Heating DLC	1.07
Small C&I	Water Heating DLC	0.79
Small C&I	AC/Space Heating DLC	1.40
Small C&I	TOU	0.06
Small C&I	PTR	0.17
Small C&I	PTR w/Tech	0.79
Small C&I	CPP	0.08
Small C&I	CPP w/Tech	0.55
Medium C&I	Third-Party DLC	1.59
Medium C&I	Curtailable Tariff	5.37
Medium C&I	CPP	1.94
Medium C&I	CPP w/Tech	1.38
Large C&I	Third-Party DLC	1.57
Large C&I	Curtailable Tariff	6.30
Large C&I	CPP	14.42
Large C&I	CPP w/Tech	6.70
Agricultural	Pumping Load Control	0.78
Agricultural	TOU	0.29