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August 13, 2014

Via Electronic Mail and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: PORTLAND GENERAL ELECTRIC
Request for a General Rate Revision
Docket No. UE 283

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the Rebuttal Testimony and Exhibits of Michael P. Gorman, Ali Al-Jabir, and Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities.

Thank you for your assistance. If you have any questions, please do not hesitate to contact our office.

Sincerely,

Jesse O. Gorsuch

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Rebuttal Testimony and Exhibits of Michael P. Gorman, Bradley G. Mullins, and Ali Al-Jabir on behalf of ICNU** upon all parties in this proceeding by causing a copy to be sent via electronic mail to the following parties at the following addresses.

Dated this 13th day of August, 2014.

Sincerely,

Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision	)
	)

REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 13, 2014

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Exhibit ICNU/304—Energy Trust of Oregon, "Funding Limitations for Large Energy Users" (April 16, 2014)

Exhibit ICNU/305—Pinnacle Economics, Economic Impacts from Energy Trust of Oregon 2013 Program Activities, Final Report (May 5, 2014)

Exhibit ICNU/306—State & Local Energy Efficiency Action Network. (2014). Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector. Prepared by A. Goldberg, R.P. Taylor, and B. Hedman, Institute for Industrial Productivity (excerpt)

Exhibit ICNU/307—Corrected Calculation of Production Tax Credits Carry-forwards

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. ARE YOU THE SAME BRADLEY G. MULLINS THAT PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I originally filed testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU") addressing several revenue requirement and policy issues in the initial filing of Portland General Electric Company ("PGE" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Parties in this proceeding have reached a settlement in principle on all issues with the exception of four: 1) the energy efficiency proposal made by the Citizens' Utility Board ("CUB"); 2) my proposal to recalculate the level of production tax credit ("PTC") carry-forwards included in rate base; 3) the Company's proposed Renewable Portfolio Standards ("RPS") carve-out mechanism; and, 4) the Company's return on equity ("ROE"). My testimony will address the first three of these remaining issues.

Q. ARE ANY OTHER WITNESSES PROVIDING REBUTTAL TESTIMONY ON BEHALF OF ICNU IN THIS PROCEEDING?

A. Yes. ICNU witness Mr. Ali Al-Jabir will also address, and present additional information regarding, CUB's energy efficiency proposal in the context of marginal cost pricing. ICNU witness Mr. Michael P. Gorman will address the Company's ROE.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony is summarized and organized as follows:

1. **CUB Energy Efficiency Proposal**. The Commission should reject the proposal made by CUB regarding energy efficiency. The proposal is a violation of energy efficiency funding limitations mandated by Oregon law and is not reasonable in light of the substantial investments being made by industrial customers in energy efficiency in this state.
2. **Direct Benefit Cap**. I recommend that the limitation CUB identified on Senate Bill ("SB") 1149 incentive funding for large customers be lifted, while still retaining the requirement that large customers receive no incentive funding out of SB 838 funds.
3. **Production Tax Credit Carry-Forwards**. I continue to recommend that the level of PTC carry-forwards included in rate base should be calculated based on the level of taxes that ratepayers pay, not the level of tax that the Company pays, which is often materially less than the amounts included in rates. Additionally, errors in the Company's calculation of the PTC carry-forward balance should be corrected if the Commission does not adopts my proposal.
4. **Renewable Portfolio Standards Carve-Out**. I continue to recommend that the Company's proposed RPS carve-out mechanism be rejected. Not only would this proposal require the Commission to set-aside the policies established in Docket No. UE 165, it is based on unsound technical principles, which the Company did not adequately address in its rebuttal filing.

II. CUB ENERGY EFFICIENCY PROPOSAL

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RESPONSE TO CUB'S ENERGY EFFICIENCY PROPOSAL.

A. While CUB has framed its proposal as a technical matter of incorporating energy efficiency into the Company's marginal cost of energy,[1/] the substance of what it has proposed is to reallocate costs to industrial customer classes. On its face, the proposal—which, as the Company recognized in its reply testimony, would result in double-digit

1/ CUB/100 at 20:4-43:4.

rate increases for industrial customers[2/]—is unreasonable. Not only does it violate energy efficiency funding limitations established by Oregon law, this proposal would work contrary to the Commission's long-standing policy to encourage conservation, at a time when the need for support from industrial customers to perform energy efficiency is increasing.

Q. WHAT WAS CUB TRYING TO ACCOMPLISH WITH ITS ENERGY EFFICIENCY PROPOSAL?

A. The energy efficiency proposal made by CUB was premised on solving three general problems. The first is that the Company's marginal cost of energy is misstated because energy efficiency, "as the go-to energy resource," is not included.[3/] The second is that the Energy Trust of Oregon ("ETO") is in danger of not being able to acquire all cost-effective energy efficiency from the Company's largest customers in the coming years. The third is that residential customers have been paying a disproportionate amount for energy efficiency.

Q. HOW DID CUB PROPOSE TO SOLVE THESE PROBLEMS?

A. CUB proposed a new cost of service methodology, ultimately reflected in the marginal cost of energy, that would reallocate costs to industrial rate classes. The proposal would increase the amount of costs allocated to Schedules 89 and 90 by 14.22% ($10.8 million) and 17.93% ($15.1 million), respectively—a material shift in costs between rate classes.[4/]

2/ PGE/1600 at 26:22-27:1.

3/ CUB/100 at 20:19.

4/ Id. at 36:1, Table 9.

Q. DOES THE CUB PROPOSAL SOLVE ANY OF THESE PROBLEMS?

A. No. As Mr. Al-Jabir points out, despite its detailed discussion explaining why energy efficiency should be accounted for as a marginal energy resource, CUB does not, in fact, include energy efficiency as a resource in the marginal cost of energy. Additionally, the CUB proposal has no impact on the ability of the ETO to acquire additional energy efficiency, nor does it properly account for the substantial investments that industrial customers are making with their own funds to perform conservation.

Q. WILL THE CUB PROPOSAL ENABLE THE ETO TO ACQUIRE ADDITIONAL COST-EFFECTIVE CONSERVATION FROM LARGE INDUSTRIAL CUSTOMERS?

A. No. The statutory limitations placed on the amount of incentives that the ETO can provide to customers with loads in excess of one average megawatt ("aMW") cannot be bypassed as a result of a new cost of service methodology. Only action by the Oregon Legislature can have the effect of changing the law limiting the incentive funding provided to those customers. Therefore, the CUB proposal will have no impact on its stated objective. On the contrary, it is my view that the CUB proposal, if adopted, will send a message to large industrial customers that their efforts to pursue conservation are now being penalized, discouraging those customers, whose participation in energy efficiency is vital to the long-term policy objectives of this state,[5/] from performing energy efficiency in the future.

[5/] This is particularly true as a result of the Environmental Protection Agency's proposed 111(d) regulations (42 U.S.C. § 7411), which will require Oregon to meet a large portion of its carbon reduction targets from energy efficiency measures.

Q. HOW DOES OREGON LAW LIMIT WHAT THE COMPANY IS PERMITTED TO COLLECT FROM CUSTOMERS TO FUND ENERGY EFFICIENCY?

A. The Company collects money from customers in rates to fund energy efficiency pursuant to SB 1149 and SB 838. SB 1149, the 1999 Oregon law that gave rise to the ETO, established a 3 percent public purpose charge that applies to the unbundled rate elements of all rate schedules, including costs paid by a direct access customer to an energy service supplier.[6/] Of the total public purpose charge, 63% is earmarked for "new cost-effective conservation …."[7/] SB 838, passed by the Oregon Legislature in 2007, allowed electric companies to collect additional amounts in rates to fund energy conservation measures, but prohibited the Company from collecting these additional amounts from customers with loads over one aMW.[8/] The customers with loads over one aMW, however, were also prohibited from receiving any "direct benefit" from the funds collected pursuant to SB 838.[9/]

Q. WOULD THE CUB PROPOSAL LIKELY VIOLATE THE FUNDING LIMITATIONS ESTABLISHED BY SB 838 AND SB 1149?

A. Yes. My understanding is that SB 838 not only limits the direct benefit to large customers from SB 838 funds, it also prohibits them from paying in rates an amount above the three percent SB 1149 public purpose charge to fund energy efficiency. Thus, the substance of the CUB proposal, in requiring industrial customers to pay additional amounts for energy efficiency, violates these funding limitations.

6/ ORS § 757.612.
7/ Id. § 757.612(3)(b)(A).
8/ ORS § 757.689.
9/ Id. § 757.689(2)(b).

Table 1, below, outlines the maximum amount of energy efficiency funding that the Company is authorized to collect by rate class pursuant to limits established in SB 1149 and SB 838. Note that the funds collected from large industrial customers on Schedules 89 and 90 are limited to the 3 percent public purpose charge established under SB 1149.[10/]

TABLE 1
MAXIMUM ENERGY EFFICIENCY FUNDING PERMITTED UNDER SB 1149 AND SB 838 IN THE TEST PERIOD
($000)

	(a) = Note 1	(b) = (a) * 3%	(c) = Note 2	(d) = (b) + (c)	(e) = (d) / (a)
	Rev. Req.	SB 1149	SB 838	Total	% of Rev. Req.
Schedule 7	$ 879,952	$ 26,399	$ 27,612	$ 54,011	6.1%
Schedule 15	3,751	113	96	208	5.6%
Schedule 32	168,185	5,046	5,323	10,368	6.2%
Schedule 38	5,715	171	173	345	6.0%
Schedule 47	5,046	151	82	233	4.6%
Schedule 49	15,835	475	219	694	4.4%
Schedule 83	235,923	7,078	7,609	14,687	6.2%
Schedule 85	238,833	7,165	7,249	14,414	6.0%
Schedule 89	75,906	2,277	-	2,277	3.0%
Schedule 90	84,247	2,527	-	2,527	3.0%
Schedule 91/95	17,260	518	527	1,045	6.1%
Schedule 92	247	7	9	16	6.4%

Note 1: Initial Filing
Note 2: Company's response to CUB Data Request 37A

Q WHAT AMOUNT WOULD BE COLLECTED FROM EACH CUSTOMER CLASS TO FUND ENERGY EFFICIENCY IF THE CUB PROPOSAL IS ADOPTED?

A. Table 2, below, details the total amount each customer class would pay in rates for energy efficiency if the CUB proposal is adopted. The table demonstrates that the funds

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10/ This table does not account for customers who self-direct conservation projects. In addition, the energy efficiency funds collected from certain customers on Schedule 85 with loads in excess of one aMW is also limited to the 3 percent public purpose charge.

collected from customers on Schedules 89 and 90 with loads in excess of one aMW would exceed the 3 percent limit established under SB 1149. In addition, several other customer classes will pay amounts less than the public purpose charge—with some rate classes, such as street lighting Schedules 91 and 95, effectively receiving a rebate for energy efficiency.

TABLE 2
ENERGY EFFICIENCY FUNDING UNDER
CUB PROPOSAL IN THE TEST PERIOD
($000)

	(a) = Note 1	(b) = (a) * 3%	(c) = Note 2	(d) = Note 3	(e) = (b) + (c) + (d)	(f) = (e) / (a)
	Rev. Req.	SB 1149	SB 838 (c)	**CUB Allocation**	Total w/ CUB Alloc.	% of Rev. Req.
Schedule 7	$ 879,952	$ 26,399	$ 27,612	**$ (26,683)**	$ 27,328	3.1%
Schedule 15	3,751	113	96	**(304)**	(96)	-2.6%
Schedule 32	168,185	5,046	5,323	**(4,200)**	6,168	3.7%
Schedule 38	5,715	171	173	**(240)**	105	1.8%
Schedule 47	5,046	151	82	**(179)**	54	1.1%
Schedule 49	15,835	475	219	**(191)**	503	3.2%
Schedule 83	235,923	7,078	7,609	**1,163**	15,850	6.7%
Schedule 85	238,833	7,165	7,249	**6,136**	20,551	8.6%
Schedule 89	75,906	2,277	-	**10,794**	13,071	17.2%
Schedule 90	84,247	2,527	-	**15,104**	17,631	20.9%
Schedule 91/95	17,260	518	527	**(1,405)**	(360)	-2.1%
Schedule 92	247	7	9	**4**	20	8.1%

Note 1: Initial Filing
Note 2: Company's response to CUB Data Request 37A
Note 3: CUB/100 at 36:1, Table 9 (column 4 minus column 5)

A comparison of Table 1 and Table 2 demonstrates the absurdity of CUB's proposal. Rates for Schedule 89 and 90 customers would be nearly nine percent (or more) higher than the next highest rate schedule to compensate for the fact that these customers pay, at most, 3.4 percent less to the ETO than other rate schedules.

Moreover, as Table 2 shows, while the form of the CUB proposal is framed within the context of cost of service, the economic substance of the proposal is to change the amount that each rate class pays to fund energy efficiency. The concept behind the CUB proposal is to reallocate costs between rate classes based on the level of ETO funding that each rate class contributes. Because the cost shifts resulting from CUB's proposal are directly attributable to energy efficiency acquired, as calculated by CUB, these increases are amounts "included in rates" to fund energy efficiency, in violation of the limits established in SB 1149 and SB 838.

Q. IS CUB'S PROPOSAL JUSTIFIED BASED ON FAIRNESS ARGUMENTS?

A. No. Even if it did not violate Oregon law, the fairness arguments made by CUB do not justify its proposal. CUB alleges that "residential customers buy half of all efficiency: without reflection of this fact in the marginal cost of service study, residential customers are effectively buying system resources."[11/] Accordingly, CUB proposed to "give[] credit where credit is due"[12/] by adjusting the loads used to allocate the marginal cost of energy, allegedly to give residential and small commercial customers credit for the energy efficiency they are funding.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH CUB'S FAIRNESS ARGUMENTS?

A. CUB's marginal cost model does not equitably reallocate costs based on a realistic level of energy efficiency funding. As discussed in Mr. Al-Jabir's testimony, CUB's model assumes an amount of energy efficiency in the test year—800 aMWs—that is many times greater than what the ETO is likely to acquire. The ETO's most recent draft strategic

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11/ CUB/100 at 28:11-13.

12/ Id. at 34:3.

plan sets a goal of acquiring 240 aMWs between 2015 and 2019, in total.[13/] This is less than one-third of the amount CUB's model assumes will be acquired in 2015 alone. And the ETO admits its goal is "ambitious."[14/] Thus, even if CUB's equity arguments were valid and its method for reflecting energy efficiency in the marginal cost study was an appropriate way of addressing those arguments, CUB's model assumes an unreasonable amount of conservation, resulting in an unfair shift in costs to industrial customers.

Q. NOTWITHSTANDING, DO YOU AGREE WITH CUB THAT RESIDENTIAL CUSTOMERS ARE PAYING AN UNFAIR SHARE OF ENERGY EFFICIENCY?

A. No. The CUB proposal only reflects energy efficiency funding submitted directly to the ETO and ignores the fact that industrial customers are paying substantial amounts of their own money in order to perform conservation measures. For industrial customers, the incentives received from the ETO often represent only a fraction of the actual capital required to complete a large industrial energy efficiency project. The incentives provided by the ETO for large capital projects, for example, are based on annual energy savings, at a rate of $0.25 per kilowatt-hour saved, up to 50 percent of eligible project cost.[15/]

Q. CAN YOU PROVIDE SOME EXAMPLES OF THE INDEPENDENT INVESTMENTS THAT INDUSTRIAL CUSTOMERS ARE MAKING TO FUND ENERGY EFFICIENCY?

A. Yes. Pacific Natural Foods, a Tualatin-based producer of natural and organic food products, recently completed a number of projects in order to produce 1,757,132

13/ Energy Trust of Oregon, Draft 2015-2019 Strategic Plan at 5 (July 25, 2014), available at: http://energytrust.org/library/forms/Draft_Strategic_Plan_July-25-2014_for_public_comment.pdf.

14/ Id.

15/ Available at http://energytrust.org/industrial-and-ag/industry/

kilowatt-hour savings annually.[16/] These energy efficiency projects cost a total of $520,909, of which Pacific Natural Foods contributed $347,081 and the ETO contributed $173,891 in incentives.[17/]

Another example, Maxim Integrated Products, a Beaverton-based integrated circuit manufacturer, recently invested $75 million in order to upgrade its fabrication facility and improve its overall efficiency.[18/] As a part of this project, Maxim Integrated Products installed a highly-efficient "fan-wall" composed of six small fans with variable frequency drives, producing 3,725,224 in kilowatt-hour savings annually.[19/] This fan-wall, alone, cost approximately $1.5 million, of which Maxim Integrated Products contributed approximately $1.0 million of its own capital and the ETO contributed $533,760 in incentives.[20/]

These are just two examples done in conjunction with the ETO. Not only are there many more examples, many efficiency measures performed by industrial customers are self-funded, with customers receiving no incentives from the ETO at all.

16/ See Pacific Natural Foods Cooks up a Recipe for Savings, Energy Trust of Oregon at 1. A copy of this report can be found online at http://energytrust.org/library/case-studies/PacificFoods_CS_PE_1201.pdf.

17/ Id.

18/ See Area Development Online News Desk (June 29, 2012), available at http://areadevelopment.com/newsItems/6-29-2012/maxim-beaverton-oregon-fabrication-facility-expansion-251816556.shtml; see also Chip Fabricator Crystallizes Commitment to Energy Efficiency, Energy Trust of Oregon at 1, available at http://energytrust.org/library/case-studies/PE_MaximIntegrated_CS.pdf.

19/ Chip Fabricator Crystallizes Commitment to Energy Efficiency, Energy Trust of Oregon at 1, available at http://energytrust.org/library/case-studies/PE_MaximIntegrated_CS.pdf.

20/ Id.; Green Smart, Sustainable Building in the Northwest at 30 (Feb-Mar 2010) (estimating an ETO contribution of only about 30 percent of installation costs), available at http://www.oregonairreps.com/downloads/files/GreenSmart_March_2010.pdf.

Q. IF THESE CUSTOMER FUNDS WERE REFLECTED IN CUB'S MODEL, WOULD IT GENERATE THE SAME DEGREE OF COST SHIFTING?

A. No. If these customer funds were reflected in the CUB analysis, the results would likely be different.

Q. ARE THERE OTHER BENEFITS RESULTING FROM INDUSTRIAL CONSERVATION THAT CUB DID NOT ADDRESS?

A. Yes. CUB's equity arguments are limited in scope. Industrial projects reduce costs to the system. Thus, as the ETO reports, "Although a larger proportion of funding goes to large energy users than the portion of 1149 revenues contributed by that group, the cost of savings acquired is much lower than other projects and therefore the savings per ratepayer dollar invested are much higher. *All ratepayers are benefiting from the higher savings*."[21]

Further, there are benefits of large customer conservation projects that go beyond mere energy savings and are not present to the same degree with residential conservation. These projects improve product quality, lower emissions, enhance productivity, and improve worker health and safety.[22/] By reducing costs, large customer projects make Oregon's most significant employers more competitive in a global marketplace.[23/] They also allow businesses to retain and hire more workers. A report for the ETO prepared by Pinnacle Economics estimates that the net economic benefits from ETO programs in 2013 included $175.1 million in increased economic output, $60.4 million in increased

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21/ ICNU/301 at 22 (emphasis added).

22/ ICNU/306 at 26-28, 46-47, 74-75 (State & Local Energy Efficiency Action Network. (Mar. 2014). Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector at 6-8, 26-27, 54-55. Prepared by A. Goldberg, R.P. Taylor, and B. Hedman, Institute for Industrial Productivity (excerpt). The full report is available at: http://energy.gov/sites/prod/files/2014/03/f13/industrial_energy_efficiency.pdf.

23/ Id. at 26-27.

wages, and 1,091 new jobs.[24/] These benefits impact the economy as a whole, and thus provide significant indirect benefits to residential customers.

Q. WHAT IS THE LIKELY IMPACT ON LARGE PROJECTS IF THE CUB PROPOSAL IS ADOPTED?

A. The theory behind CUB's approach is that the rate class performing an energy efficiency project should not receive the benefits of its project.[25/] Rather, the benefits should be reallocated based on the amount of funds that each rate class contributes to the ETO (disregarding the substantial investments being made by industrial customers to achieve these benefits).[26/] Accordingly, CUB's proposal is likely to disincentivize industrial customers, knowing that the benefits of their projects are being reallocated to another rate class, from investing in new conservation.

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD REJECT THE CUB ENERGY EFFICIENCY PROPOSAL.

A. Energy efficiency is a joint effort on behalf of the ETO and the utility customer, and imposing what amounts to little more than a penalty on large industrial customers, at a time when those customers are working aggressively to achieve Oregon's energy efficiency goals, is not good policy. Despite claiming that energy efficiency belongs in the marginal cost study, CUB's proposal does not model energy efficiency as a marginal resource. Despite claiming that smaller customers are unfairly subsidizing larger customer conservation projects, CUB's proposal shifts a material amount of costs to larger customers without any legitimate factual basis for doing so. And, despite claiming

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24/ ICNU/305 at 12 (Pinnacle Economics, Economic Impacts from Energy Trust of Oregon 2013 Program Activities, Final Report at 7 (May 5, 2014)).

25/ CUB/100 at 33:2-13.

26/ Id.

that funding limitations will soon inhibit the ETO's ability to acquire all cost-effective energy efficiency from industrial customers, CUB's proposal has no impact on these funding limitations and, as I understand, violates Oregon law. Accordingly, I recommend that the Commission reject the CUB proposal.

III. DIRECT BENEFIT CAP

Q. PLEASE RESTATE CUB'S CONCERN OVER THE ETO'S ABILITY TO ACHIEVE ALL COST-EFFECTIVE ENERGY EFFICIENCY.

A. As a justification for its energy efficiency proposal, CUB has testified that "under the current legal interpretation, PGE's industrial customers will very soon be restricted from receiving additional industrial EE programs because of the 'direct benefit' cap in SB 838."[27/] CUB argues that its marginal cost proposal, coupled with its unique interpretation of the phrase "direct benefits" in SB 838 discussed above, will solve this problem.

Q. HOW DO YOU PROPOSE TO RESOLVE CUB'S CONCERN?

A. While I recommend adherence to, and accounting for, the law prohibiting large industrial customers from receiving incentives out of SB 838 funds, I propose that the "direct benefit cap" referred to by CUB be lifted, enabling the ETO to utilize the entire amount of SB 1149 funds in the manner it believes to be in the public interest.

27/ CUB/100 at 38:8-10.

Q. EARLIER YOU PROVIDED AN OVERVIEW OF THE DIRECT BENEFIT CAP IN SB 838. IS THIS CAP PREVENTING THE ETO FROM ACQUIRING ALL COST-EFFECTIVE ENERGY EFFICIENCY IN THE COMPANY'S SERVICE TERRITORY?

A. No. To date, the ETO has been able to acquire all cost-effective energy efficiency from customers over 1 aMW and projects that it will be able to do so in 2014.[28/] More importantly, to the extent the ETO is in danger of not being able to acquire cost-effective energy efficiency from these customers, this is not because of the SB 838 direct benefit cap, it is because of the "current legal interpretation" of this cap.[29/]

Q. WHAT IS THE "CURRENT LEGAL INTERPRETATION" OF THE SB 838 DIRECT BENEFIT CAP?

A. CUB states that the "current interpretation of [SB 838] is to maintain industrial programs at the same percentage of funding as they were before [the passage of SB 838]."[30/] Thus, under this interpretation, customers over one aMW are only allowed to receive a certain percentage of SB 1149 conservation incentives from the public purpose charge.

Q. WHAT IS THE PERCENTAGE CAP OF SB 1149 INCENTIVES THE ETO STATES IT CAN PROVIDE TO CUSTOMERS OVER ONE aMW?

A. It is 18.4 percent.[31/] This percentage represents the average amount of incentives paid to large customers between 2005 and 2007 relative to total energy efficiency funding in that period.[32/] If the ETO exceeds the 18.4 percent industrial cap, it has two years to bring

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28/ Energy Trust of Oregon, Conservation Advisory Council Meeting Notes at 2 (July 23, 2014), available at: http://energytrust.org/library/meetings/cac/CAC_Notes_140723.pdf; see also, ICNU/303 at 7 (PGE Resp. to ICNU DR 145); PGE Advice No. 14-08, Staff Report at 1 (June 17, 2014) (noting that PGE requested $4 million reduction to SB 838 funding and despite this reduction, "Energy Trust estimates it can still achieve its forecasted energy savings goals … for the years 2014-2016").

29/ CUB/100 at 38:8-10.

30/ Id. at 27:15-16.

31/ ICNU/304 at 2 (Energy Trust of Oregon, "Funding Limitations for Large Energy Users" (Apr. 16, 2014)).

32/ Id.

incentives back below the cap amount.[33/] The percentage cap for PacifiCorp is 27 percent.[34/]

Q. HOW WERE THESE PERCENTAGES ESTABLISHED?

A. ETO reports that they are the outcome of a "2008 informal multiparty agreement."[35/]

Q. IS THE ETO IN DANGER OF EXCEEDING THE INFORMAL 18.4 PERCENT INDUSTRIAL CAP FOR PGE?

A. Both the ETO and the Company indicate so. In an October 31, 2013 briefing paper, the ETO noted that, if "in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M), we would exceed the current spending limit in 2015."[36/] Additionally, in response to a CUB data request, the Company stated that the 18.4 percent industrial cap could prevent the acquisition of all cost-effective energy efficiency in the next five years.[37/]

Q. DOES THIS CONCERN ICNU?

A. Yes. Like CUB, ICNU wants the ETO to be able to acquire all cost-effective energy efficiency. As discussed above, industrial energy efficiency programs reduce system-wide costs and provide broad economic and welfare benefits, for the good of all customers.[38/] And, as CUB recognizes, industrial energy efficiency is often the cheapest to acquire.[39/] The ETO reports that "large site projects are 2.5 times more cost effective

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33/ Id.
34/ Id.
35/ Id. at 1.
36/ ICNU/301 at 7.
37/ ICNU/303 at 1 (PGE Resp. to CUB DR 27).
38/ Supra at 11-12.
39/ CUB/100 at 38:1.

than [smaller] site projects."[40/] Thus, ICNU agrees that something should be done to ensure the ETO can fund the most economic projects.

Q. WHAT DO YOU PROPOSE?

A. I propose that the Commission remove the 18.4 percent industrial cap on SB 1149 funding.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The 18.4 percent cap is not a statutory requirement. It is nowhere to be found in SB 838 or SB 1149. As CUB states, it is an "artificial cap placed on industrial programs by the current interpretation of the law."[41/] Furthermore, the 2008 informal multiparty agreement that established this "artificial cap" has no basis in the regulatory record. The ETO notes that, with respect to this agreement, the "details of the discussions and resulting methodology were not created within the formal regulatory docket process, [thus] the history is sparse and largely undocumented."[42/] While various ETO briefing papers refer to the 18.4 percent cap, they do not provide or refer to any document that established this cap.[43/] The closest ICNU has come to locating this agreement is a straw man proposal the ETO sent to various stakeholders in 2007 that outlines the process the ETO planned to establish following passage of SB 838.[44/] No final agreement appears to exist. Thus, the ETO has stated that its process "is meant to reflect our best

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40/ ICNU/301 at 16.

41/ CUB/100 at 30:14-15.

42/ ICNU/301 at 21.

43/ See ICNU/301 at 7, 15, 21; ICNU/304 at 2.

44/ ICNU/302 at 5-8 (attachment to CUB Resp. to ICNU DR 11 (note that this attachment was originally part of a PGE response to a CUB data request in Advice No. 07-25 and is labeled accordingly)).

understanding of the intent at the time" of the informal agreement.[45/] In sum, the cap was not adopted in a regulatory proceeding and is not binding.

Q. ARE THERE ANY OTHER REASONS TO REMOVE THE 18.4 PERCENT CAP?

A. Yes. This cap is arbitrary. As proof of this, just look at PacifiCorp. It is subject to the same laws, yet the funding cap the ETO applies to PacifiCorp is 27 percent.[46/] This is because the industrial cap is entirely dependent on the amount of funding PGE and PacifiCorp provided to large customers between 2004 and 2007.[47/] Because PacifiCorp had more industrial conservation activity during this period, its cap is higher and it is not currently in danger of exceeding it.[48/] This makes no sense, particularly given the changed circumstances of the Company's industrial load. When the informal cap was implemented, "PGE activity was largely limited to one large paper mill. [Today, a] larger proportion of PGE's large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until recently."[49/] Thus, if the Company's service territory in 2005-2007 had an industrial profile similar to what it has today, its informal cap would almost certainly be higher and the ETO would have no problem acquiring all cost-effective conservation from large customers.

45/ ICNU/301 at 21.

46/ Id. at 4.

47/ Id. at 7. As further evidence of the arbitrariness of this cap, the baseline period is different for the Company than it is for PacifiCorp. For PGE it is 2005-2007, while it is 2004-2007 for PacifiCorp.

48/ Id. at 15.

49/ Id. at 21.

Q. HAS THE COMMISSION QUESTIONED WHETHER IT REMAINS GOOD POLICY TO MAINTAIN THE 18.4 PERCENT INFORMAL CAP?

A I am unaware of any formal statement the Commission has issued. However, various ETO papers indicate that the Commission "is aware of these issues and is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy."[50/]

Q. WOULD YOUR PROPOSAL RESULT IN THE ETO SPENDING ALL SB 1149 DOLLARS ON INDUSTRIAL CUSTOMERS?

A. No. I am not suggesting that the ETO should spend all SB 1149 energy efficiency dollars on industrial customers, just that it should have the freedom to pursue the most cost-effective options. Currently, the ETO is acquiring all cost-effective conservation from large customers even with the artificial 18.4 percent cap in place; thus, there is no reason to think that removing the cap would materially increase incentives to these customers. According to an October 2013 ETO briefing paper, "[i]f we assume the average incentive demand for the past three years in PGE ($5.8M) increases by 25% ($7.25M) and is sustained for the next three years, the cumulative % of incentives to total revenues from PGE large customers would increase from 17% to 20%."[51/] Thus, even a significant and unanticipated increase in incentive demand from industrial customers is not likely to result in a material shift of dollars to this customer group.

Q. HOW WOULD YOUR PROPOSAL COMPLY WITH SB 838?

A. I propose that the ETO be required to develop separate fund accounting for SB 1149 and SB 838 receipts in order prevent any funds received pursuant to SB 838 from being used

50/ Id. at 7.
51/ Id. at 9.

to provide incentives to large customers. Under this proposal, large customers exceeding one aMW could receive incentives out of the SB 1149 fund, with no limitation. They would be prohibited, however, from receiving any incentive from the SB 838 fund, in compliance with that law's direct benefit limitation.[52/]

Q. PLEASE SUMMARIZE HOW YOU PROPOSE TO ADDRESS THE ISSUE RELATED TO THE DIRECT BENEFITS CAP.

A. To the extent the ETO is currently in danger of not being able to acquire all cost-effective energy efficiency, the use of an 18.4 percent cap on SB 1149 funding, which is not part of any formal agreement and has no basis in Oregon law, should be re-evaluated. I propose that the cap be eliminated and that the ETO be required to develop fund accounting in order to ensure that large industrial customers receive no incentives from SB 838 funds.

IV. PRODUCTION TAX CREDIT CARRY-FORWARDS

Q. DO YOU HAVE ANY GENERAL COMMENTS REGARDING THE COMPANY'S TAX CALCULATIONS BEFORE DISCUSSING PTC CARRY-FORWARDS?

A. Reviewing the Company's tax calculations in this proceeding has been difficult. Throughout the course of this proceeding, numerous errors and inconsistencies have been identified, the extent of which make it nearly impossible to have a clear understanding of the appropriate level of tax expense and accumulated deferred income taxes ("ADIT") to assume in rates. On May 12th, for example, the Company identified a $32.7 million error in its accumulated deferred income tax balance, which resulted in revenue

52/ ORS § 757.689(2)(b).

requirement being overstated by $3.8 million.[53/] On August 8th (only four business days prior to the filing of this testimony), the Company identified another error that would change the amount of deferred taxes associated with Tucannon River by approximately $85 million.[54/] The Company claims that this material change in deferred tax expense has no impact on revenue requirement, but there has not been adequate time to verify the Company's assertion or its calculations. Therefore, the following discussion regarding PTC carry-forwards is premised on the Company's tax calculations as of August 13, 2014, which have not been thoroughly reviewed at the time of this filing.

Q. REGARDING PTC CARRY-FORWARDS, PLEASE RESTATE THE FUNDAMENTAL ISSUE IDENTIFIED IN YOUR OPENING TESTIMONY.

A. While there is no argument over whether PTCs generated in the test period should be reflected in income tax expense, the issue is the appropriate level of PTC carry-forwards to include as a deferred tax asset in rate base, upon which the Company earns a return.

Q. HOW DID YOU PROPOSE TO REFLECT PTC CARRY-FORWARDS IN RATE BASE?

A. In my opening testimony I argued that the level of normalized income tax expense included in revenue requirement, rather than the tax actually paid by the Company, should be used to calculate the level of PTC carry-forwards included in rates. Because normalized income tax expense was sufficient to utilize all PTCs generated in the period, I recommended that $75.6 million in PTC carry-forwards be removed from rate base, resulting in an $8.3 million reduction to revenue requirement.

53/ PGE/1801 at 3.

54/ Exhibit ICNU/303 at 10 (PGE Resp. to ICNU DR 169 (stating "The 'Deferred Ms' for Tucannon in PGE Exhibit 1701 were inadvertently included as $71.7 million rather than $156.2 million")).

Q. HAVE YOU UPDATED YOUR RECOMMENDATION AS A RESULT OF THE COMPANY'S RESPONSE?

A. Yes. While the Company has not provided an explanation of the difference, it claims that only $53.1 million of PTC carry-forwards were included in rate base,[55/] rather than the $75.6 million included in my opening testimony.[56/] Thus, I have updated my recommendation to reflect this value, modifying my adjustment to a $53.127 million reduction in rate base and a $6.069 million reduction to revenue requirement. In addition, in reviewing the Company's testimony, I have discovered several errors in the Company's calculation of PTC carry-forwards, which should be corrected if the Commission disagrees with my proposal. Correcting for these errors result in a reduction to rate base of $28.952 million and a reduction revenue requirement of $3.307 million.

Q. PLEASE SUMMARIZE WHY YOU PROPOSED TO CALCULATE PTC CARRY-FORWARDS BASED ON NORMALIZED TAX EXPENSE, RATHER THAN CURRENT TAX.

A. In light of the substantial tax savings that the Company will receive when it files its tax return, I have proposed that PTC carry-forwards be calculated in revenue requirement based on the level of normalized income tax expense paid by customers, not the level of current income taxes paid by the Company. The reason for this treatment is that the amount of taxes customers must pay in revenue requirement far exceeds the amount that the Company will actually pay. For example, in the test period customers are paying an additional $69.2 million to compensate the Company for taxes, which will not ultimately be paid when the Company files its tax return. This amount exceeds the entire revenue

55/ PGE/1900 at 4, Table 2.
56/ ICNU/100 at 14:15-17.

requirement increase requested for Tucannon River. In recognition of these of cash benefits, my proposal is that the Company should be responsible for the PTC carry-forwards that arise as a result of the difference between the amount of taxes paid by ratepayers and the amount of taxes that it pays.

Q. CAN YOU DEMONSTRATE HOW YOUR PROPOSAL IS DIFFERENT FROM THE METHODOLOGY PRESENTED BY THE COMPANY IN ITS REBUTTAL FILING?

A. Yes. The amount of taxes that customers pay includes both current and deferred taxes. As discussed in my opening testimony, much of the deferred taxes included in rates arise as a result of the normalization requirements in IRC § 168(f)(2), which prohibit including the benefits of accelerated depreciation in income tax expense for ratemaking purposes. My proposal is to calculate PTC carry-forwards included in rates based on the amount of tax that ratepayers are paying, including both current and deferred taxes. In contrast, the Company's methodology calculates the level of PTC carry-forwards in rates based on the level of tax it pays, limiting the calculation only to current income tax. Table 3, below, demonstrates the difference between these two methodologies.

TABLE 3
COMPARISON OF PTC METHODOLOGIES
PROPOSED VERSUS COMPANY
($000)

	Description	Reference	Proposed	Company
(a)	Current Taxes	PGE/1701*, PGE/1900	53,810	34,315
(b)	Deferred Taxes	PGE/1701*	41,657	
(c)	Income Tax Before Credits	∑ (a), (b)	95,467	34,315
(d)	Tax Payable In Excess of $25,000	(d) - $25k	95,442	34,290
(e)	25 % of Tax Payable in Excess of $25,000	(e) * 25%	23,861	8,573
(f)	PTC Credit Utilization Limit (I.R.C. § 45(c)(1)(B))	(c) - (e)	71,607	25,743
(g)	2014 Carry Forward	PGE/1701*†	-	30,327
(h)	Tucannon PTC	PGE/1701*	19,757	19,757
(i)	Biglow PTC	PGE/1701*	28,929	28,785
(j)	Total 2015 PTC	∑ (g):(i)	48,686	78,869
(k)	Normalized Credit Utilized	Min (f), (j)	48,686	25,743
(l)	2015 YE Credit Carry-forward	(j) - (k)	-	53,126

* Based on corrected revenue requirement table provided informally in response to Data Request ICNU 169
† 2014 tax credit carry forwards are excluded from the proposed calculation because the Company's income tax expense included in UE 262 would have also been sufficient to utilize all tax credits generated, and carried-forward into 2014.

Q. PLEASE PROVIDE AN OVERVIEW OF TABLE 3.

A. As can be seen from the table, the key difference between my proposal and the calculation detailed in the Company's rebuttal filing is line (c), the level of taxes before credits. My calculation includes deferred taxes in the calculation, while the Company's calculation excludes them. My calculation also assumes that no 2014 production tax credit carry-forwards should be included in the current year calculation. This assumption was made because, in reviewing the Company's 2014 revenue requirement calculations in its previous rate case, UE 262, it appears that the level of income tax expense included in rates in 2014 would have been sufficient to utilize all PTCs from 2014, using the same methodology detailed above.

This table also demonstrates a material error in the Company's calculation, which will be discussed further below: the level of current taxes included on line (a) by the Company is inconsistent with the level of current tax that it has included in revenue requirement.

Q. HOW DID THE COMPANY RESPOND TO YOUR PROPOSAL?

A. The Company's response was brief, reiterating that PTC carry-forwards "are based upon the cash expended for federal income tax; they are not based on the total of current and deferred tax expense as suggested by the ICNU model."[57/]

Q. DO YOU AGREE WITH THE COMPANY?

A. Yes. The issue is not how PTC carry-forwards are generated on the Company's tax return. The issue is the level of PTC carry-forwards that should be included in rates. I agree that deferred taxes are not taken into account when the Company files its tax return. The disagreement is that customers should only be responsible to pay for PTC carry-forwards to the extent that those carry-forwards would have been generated based on normalized income tax expense, the amount customers are paying in rates.

Q. WHAT EVIDENCE DID THE COMPANY PROVIDE TO SUGGEST THAT PTC CARRY-FORWARDS SHOULD NOT BE BASED ON NORMALIZED INCOME TAX EXPENSE?

A. Its primary argument seems to be that the rate base reduction associated with ADIT justifies the Company's inclusion of PTC carry-forwards in rate base based on the level

57/ PGE/1900 at 10:5-8.

of current income tax.[58/] Because the Company is the beneficiary of the cash collected through revenue requirement as a result of deferred taxes, however, it should be solely responsible for any tax attributes, including PTC carry-forwards, that arise from the deferred tax portion of income tax expense. Deferred taxes are essentially a loan to the utility from its customers, and if, as a result of receiving that loan, the Company is unable to utilize the full amount of tax credits generated in a period, it should bear the financial burden of the ensuing credit carry-forward.

Q. DO YOU AGREE THAT PTC CARRY-FORWARDS ARE ANALOGOUS TO ADIT?

A No. ADIT must be viewed separately from these particular PTC carry-forward tax attributes. In contrast to ADIT, which arises as a result of temporary differences between financial and tax accounting methods (for instance, straight-line versus accelerated depreciation), a PTC carry-forward arises at a single point in time as a result of the level of taxes included on the Company's tax return. Unlike ADIT, PTCs have no bearing on the level of taxable income that a company will report on its tax return, nor the level of pre-tax income that will result on its books. They are simply an intangible right (or "attribute"), established under the construct of the tax code, to reduce future taxes that an entity must pay. Thus, the question becomes, why must ratepayers compensate the Company for this intangible right, if their rates reflect a level of tax that would not have established such a right in the first place?

58/ PGE/1900 at 7:10-16 & n.7.

Q. ARE THERE OTHER PROBLEMS WITH INCLUDING PTC CARRY-FORWARDS IN RATES BASED ON CURRENT TAXES?

A. Yes. As a result of the cumulative nature of these attributes, the inclusion of PTC carry-forwards calculated based on non-normalized income tax expense also becomes increasingly complicated over time. Unlike ADIT, which can be calculated by comparing depreciation schedules and accounting methods, PTC utilization is entirely dependent on the level of income taxes paid on a tax return, which can vary substantially year to year. Because the credit carry-forwards accumulate, the level of income taxes paid by the Company in prior years impacts the level of carry-forwards in later years. For example, the level of income tax paid in 2013 had an impact on the level of PTC carry-forwards included in 2014, which, in turn, impacts the level of PTC carry-forwards that the Company has proposed to include in rates in this proceeding. Thus, the unique hydro and market conditions from 2013 are implicitly reflected in the Company's calculation of PTC carry-forwards proposed in the test period. Similarly, if the Company's financial position in 2014 results in it being able to utilize more PTCs than it had previously forecast, it will result in overstating the level of PTC carry-forwards included in rates, a financial windfall to the Company. Not only does the cumulative nature of PTCs call into question issues of retroactive ratemaking and deferred accounting, the consequence of including PTC carry-forwards in rates based on non-normalized taxes is that ratepayers are required to pay for amounts that are uncertain and do not rise to the level of "known and measurable."

Q. DO YOU AGREE WITH MR. GREENE THAT YOU HAVE MISINTERPRETED AND MISAPPLIED IRC § 168(f)(2)?[59/]

A. No. Under 26 CFR § 1.167(l)-1(a)(1), the normalization requirements of IRC § 168(f)(2)[60/] only apply to depreciation expenses, and not to other tax items, such as PTCs, as follows:

> The normalization requirements of section 167(l) with respect to public utility property defined in section 167(l)(3)(A) pertain only to the deferral of Federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. Regulations under section 167(l) do not pertain to other book-tax timing differences with respect to State income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

It follows that the application of the IRC § 168(f)(2) normalization requirements are not the issue. The issue is the level of PTC carry-forwards that should be included in rate base, and unlike depreciation expense, IRC § 168(f)(2) does not restrict the Commission's ability to exclude PTC carry-forwards from rate base.

Q. HAS THE IRS ISSUED ANY PRIVATE LETTER RULINGS TO CONFIRM THE ABILITY OF THE COMMISSION TO EXCLUDE PTC CARRY-FORWARDS FROM RATE BASE?

A. Yes. Private Letter Ruling ("PLR") 201418024 discusses the requirements of IRC § 168(f)(2) with respect to the inclusion of alternative minimum tax ("AMT") credit carry-forwards from rate base,[61/] an issue that is substantively similar to the PTC issue in this case. The utility discussed in that ruling had accrued AMT credit carry-forwards related

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[59/] PGE/1900 at 2:3-4.

[60/] 26 U.S.C. § 168.

[61/] PLR 201418024 can be found online at http://irs.gov/pub/irs-wd/1418024.pdf.

to the cash tax payment of alternative minimum tax included on its tax return but which was not reflected in the utility's normalized income tax expense—a situation very similar to what is being discussed with regards to PTC carry-forwards. Despite proposing to include AMT credit carry-forwards in rate base, the utility's regulator rejected the utility's proposal. The IRS determined that the commission, in declining to include the AMT credit carry-forwards in rate base, did not violate the requirements of IRC § 168(f)(2).[62/]

Q. DO YOU AGREE WITH THE COMPANY'S TESTIMONY REGARDING HOW IT WOULD "NORMALIZE" PTCs IN RATES?

A. No. The Company has suggested that normalizing PTCs would result in only $1.5 million in benefits to customers.[63/] It appears that the Company has applied the same, or similar, methodology that the Commission has used in the past to normalize investment tax credits. Unlike investment tax credits, however, PTCs accrue when energy is generated, not as a result of the level of investment in qualified property. Thus, the proposal to amortize PTCs over a resource's life, in a manner similar to investment tax credits, is inconsistent with when and how the benefits of PTCs are accrued.

Q. NOTWITHSTANDING YOUR PROPOSAL, PLEASE BRIEFLY DESCRIBE THE ERRORS YOU IDENTIFIED IN THE COMPANY'S CALCULATIONS.

A. In reviewing the Company's rebuttal filing, I identified two corrections to the Company's methodology for calculating PTC carry-forwards in rate base. First, as noted above, the Company's calculations are based on a level of current taxes that is inconsistent with the amount included in its most recent revenue requirement calculations. Second, the

62/ Id. at 6.
63/ PGE/1900 at 9:21-10:2.

Company calculated the PTC carry-forwards based on the December 31, 2015 year-end balance, rather than an average balance.

Q. WHAT LEVEL OF CURRENT TAXES IS THE COMPANY FORECASTING IN THE TEST PERIOD?

A. It is not clear. The Company's latest filed revenue requirement calculations, an errata correcting multiple numerical errors from the Company's rebuttal filing, includes current taxes of $81.1 million.[64/] In response to a data request provided four business days prior to this filing, however, the Company indicated that the amount included in its errata filing was wrong,[65/] and informally provided a document suggesting that current taxes should be $53.8 million. The Rebuttal Testimony of Mr. Greene, on the other hand, suggests an entirely different number, indicating that a level of current taxes actually used to calculate the production tax credit carry-forwards was $34.3 million.[66/]

Q. WHICH OF THESE CURRENT TAX CALCULATIONS SHOULD BE USED TO CALCULATE PRODUCTION TAX CREDIT CARRY-FORWARDS IN RATE BASE?

A. If my recommendation regarding the use of normalized income tax expense is not adopted, I recommend that $81.1 million in current taxes be used. This value is the amount included in the Company's most recent revenue requirement table filed with the Commission.

64/ PGE/Errata 1701 at 2:65 (July 31, 2014).
65/ Exhibit ICNU/303 at 10 (PGE Resp. to ICNU DR 169).
66/ PGE/Exhibit 1900 at 4, Table 3.

Q. WHY DO YOU BELIEVE THE PTC CARRY-FORWARDS INCLUDED IN RATE BASE SHOULD BE CALCULATED AS AN AVERAGE BALANCE?

A. The Company's ADIT calculations for Tucannon River and Port Westward II appear to have been based on an average, in contrast to a year-end, balance. Thus, for consistency purposes the Company's calculations should be corrected to reflect the average balance for PTC carry-forwards, as well.

Q. WHAT IS THE COMBINED IMPACT OF CORRECTING THESE ERRORS?

A. Exhibit ICNU/307 details the impact of these corrections. As detailed in the exhibit, correcting for the level of current taxes included in the PGE/1701 errata filing and adjusting to the average balance results in a $29.0 million reduction to rate base and a $3.3 million reduction to revenue requirement. In addition, under the headings "Alternative Correction #1" and "Alternative Correction #2", I have detailed the rate base and revenue requirement impact of using the differing current tax values detailed in the Company's response to ICNU Data Request 169 and in the Company's rebuttal filing at PGE/1900, respectively.

Q. PLEASE SUMMARIZE YOUR RESPONSE REGARDING PTC CARRY-FORWARDS.

A. I continue to recommend that the level of PTC carry-forwards included in rate base should be calculated based on the level of taxes that ratepayers pay, not the level of tax that the Company pays, which is often materially less than the amounts included in rates. Thus, I propose that normalized income tax expense, rather than current taxes, be used to calculate the PTC carry-forwards included in revenue requirement in this proceeding, resulting in the adjustment detailed above. Notwithstanding this issue, I have identified several errors in the Company's tax calculations that should be corrected if the Commission decides to use the Company's methodology.

V. RENEWABLE PORTFOLIO STANDARDS CARVE-OUT

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE COMPANY'S REBUTTAL TESTIMONY ON THE RPS CARVE-OUT.

A. In May of 2004, the Company initiated Docket No. UE 165 to develop a mechanism to recover the power costs and benefits of variations in hydro generation.[67/] The result of that proceeding was a comprehensive policy framework, through which the criteria for designing power cost adjustment mechanisms ("PCAMs") in this state was established.[68/] These criteria are: (1) the PCAM must be limited to unusual events; (2) no adjustments if overall earnings are reasonable; (3) revenue neutrality; and (4) long-term operation.[69/] Now, the Company requests that the Commission disregard its long-standing PCAM design criteria, which were recently affirmed in Docket No. UE 246,[70/] and approve a mechanism that attempts to isolate the power cost variation related to RPS resources and recover the associated costs through a dollar-for-dollar true-up mechanism that is not subject to dead bands, sharing bands, or an earnings test. The Company's rebuttal testimony provides no compelling evidence to demonstrate why the Commission should set-aside the principles established in UE 165, and, accordingly, I continue to recommend that the Company's proposal be rejected.

67/ In Re PGE, Docket Nos. UE 165/UM 1187, Order No. 05-1261 at 1 (Dec. 21, 2005).

68/ Id. at 8-13.

69/ Id. at 8.

70/ See In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket UE 246, Order No. 12-493 at 13-15 (Dec. 20, 2012).

Q. DO YOU AGREE WITH THE COMPANY THAT THE COMMISSION'S DECISION IN UE 246 DOES NOT APPLY TO ITS PROPOSED RPS CARVE-OUT?

A. No. The Company claims that the Commission's order in Docket No. UE 246, which established PacifiCorp's PCAM, has no bearing on its proposed RPS Carve-out mechanism.[71/] The Company argues that the Commission's order in that docket applied to the totality of power costs, not PacifiCorp's attempt to isolate the impact of RPS resources.[72/] I disagree with the Company's interpretation. PacifiCorp's Post-Hearing Brief well summarized the issue decided in that proceeding as follows:

> Staff, ICNU, and CUB argue that SB 838 does not require dollar-for-dollar recovery of all NPC. The statute's plain language, however, allows the Company to recover "all prudently incurred costs associated with compliance" with the law, including integrating, firming, and shaping renewable energy sources.[73/]

Thus, when the Commission rejected PacifiCorp's request for dollar-for-dollar recovery of its power costs and found that "the most prudent way to accomplish proper recovery is through a well-designed PCAM that complies with the principles [outlined in UE 165],"[74/] it implicitly determined that the PCAM satisfies the recovery standard for RPS resources established in SB 838, and that SB 838 does not mandate dollar-for-dollar recovery of power costs associated with RPS resources.

71/ PGE/1600 at 14.
72/ Id.
73/ Docket No. UE 246, PacifiCorp's Post-Hearing Brief at 36 (Nov. 7, 2012).
74/ Docket No. UE 246, Order No. 12-493 at 14.

Q. PLEASE SUMMARIZE THE TECHNICAL ISSUES RAISED IN YOUR OPENING TESTIMONY.

A. In addition to the policy issues associated with a potential RPS carve-out mechanism, I questioned three general aspects of the Company's proposal—first, the influence of market prices on the Company's proposed mechanism; second, the portfolio diversification benefits of renewable resources; and, third, the ability of the Company to accurately calculate the costs and benefits associated with system re-dispatch in actual operations.

Q. DID THE COMPANY ADEQUATELY RESPOND TO YOUR CONCERN REGARDING THE INFLUENCE OF MARKET PRICES IN ITS RPS PROPOSAL?

A. No. My concern with market price had to do with the fact that changes in market prices are unrelated to RPS compliance under SB 838, and accordingly have no place in a deferral mechanism that is premised on achieving dollar-for-dollar power cost recovery from SB 838 resources. I disagree with the Company that I have a misunderstanding of how it operates its system,[75/] as the issue is not how the Company operates its system, but, rather, whether SB 838 requires the Commission to provide dollar-for-dollar recovery of market price variances. I have not identified any language in SB 838 discussing the recovery of market price variance, and, accordingly, I do not believe that market price variance should be reflected in any mechanism premised on the recovery standard outlined SB 838.

75/ PGE/1600 at 12:10-13.

Q. DOES THE COMPANY'S PROPOSED REMEDY ADEQUATELY RESOLVE THE MARKET PRICE VARIANCE ISSUE?

A. No. The Company has proposed to modify its mechanism to exclude the impact of market price variance when the actual hourly generation from the renewable resource is exactly the same as generation forecast in rates.[76/] As the Company testifies, however, the actual hourly generation from its wind resources is the same as the forecast hourly generation in only 0.2 percent of hours—practically never.[77/] Thus, this proposed remedy has no practical impact on the level of market price variance reflected in the Company's RPS carve-out proposal.

Q. WHY IS IT CRITICAL THAT MARKET PRICE VARIANCE BE EXCLUDED FROM THE PROPOSAL?

A. To the extent market prices vary in actual operations relative to the forecast, it will result in broader power cost implications than just those related to renewable resources, impacting the dispatch, and associated cost, of the Company's entire system. In addition, the risks associated with market price variance are already captured in the Company's hedging policy. Thus, if the Company collects a deferral as a result of market price variance, it will effectively be compensated twice—once through the RPS carve-out and again through its hedging position.

76/ Id. at 13:4-13.

77/ Id. at 13:7-8.

Q. HOW DID THE COMPANY RESPOND TO YOUR CONCERNS REGARDING THE DIVERSIFICATION IMPACTS OF RPS RESOURCES ON ITS RESOURCE PORTFOLIO?

A. The Company simply alleged that the stock portfolio analogy I used to illustrate this issue was a "strained comparison."[78/] I disagree. Portfolio diversification is one of the fundamental principles relied on by utilities in order to develop a least-cost, least-risk resource portfolio. This was acknowledged by the Company in its Integrated Resource Plan as follows:

> One of the most common forms of hedging with respect to portfolio construction and management is asset diversification. From the stand-point of an electric utility, this can be accomplished by increasing the number and type of resources (both technology and fuel types) used to serve customer demand. *By diversifying its* portfolio *of energy and capacity resources, a utility is less likely to experience large, adverse changes in the cost to produce and deliver electricity to its customers over time.*[79/]

Accordingly, the Company has no basis to claim that diversification benefits of RPS resources are irrelevant to its proposal.

Q. HOW DID THE COMPANY RESPOND TO YOUR CONCERNS REGARDING ITS ABILITY TO ACCOUNT FOR THE SYSTEM RE-DISPATCH ASSOCIATED WITH ISOLATING THE POWER COST VARIANCE OF RPS RESOURCES?

A. The Company devotes one paragraph to this issue, claiming no evidence exists to support the argument that system re-dispatch cost cannot be accurately measured in actual operations.[80/]

78/ Id. at 14:1.

79/ 2013 Integrated Resource Plan, Portland General Electric, at 100 (Mar. 2014) (emphasis added).

80/ PGE/1600 at 13:14-19.

Q. WAS THIS ISSUE REGARDING SYSTEM RE-DISPATCH A KEY FACTOR IN THE DESIGN OF THE CURRENT PCAM?

A. Yes. In Docket No. UE 165, the Company originally requested a power cost mechanism that would only track variances in hydro output, ignoring changes to other power cost variables. Staff member, Maury Galbraith, testified that it was inappropriate to limit an adjustment mechanism solely to a single resource type, noting as follows:

> PGE operates its hydro resources as an integrated part of it overall supply portfolio. The company manages its resource portfolio to be in approximate load-resource balance on an expected hydro basis. If hydro output is less than expected PGE rebalances its overall position by increasing thermal resource output and/or making market purchases. If hydro output is greater than expected PGE rebalances its overall position by decreasing thermal resource output and/or making market sales. PGE manages its overall supply portfolio to minimize power costs. It is important to capture the complex, often offsetting interaction of resources within the supply portfolio when setting supplemental adjustment rates. Ignoring thermal plant optionality in the design of a hydro-only adjustment mechanism produces an economic windfall to the utility. The best way to address this issue is to use a PCA mechanism that tracks all the components of NVPC.[81/]

Q. DOES THIS PASSAGE FROM MR. GALBRAITH'S TESTIMONY IN UE 165 APPLY EQUALLY TO RPS RESOURCES?

A. Yes. The PCAM in place today is the type Mr. Galbraith recommended then, and it should not be changed to "carve out" RPS costs for the same reasons. In fact, PacifiCorp appears to agree. As part of its argument in Docket No. UE 246 that dollar-for-dollar recovery of all of its power costs was warranted, PacifiCorp stated: "*The Company has shown that it is impossible to isolate, quantify, and accurately forecast the NPC impacts*

81/ In re Portland General Electric Application for a Hydro Generation Power Cost Adjustment Mechanism, Docket No. UE 165, Staff/100 at 16:9-20 (Feb. 14, 2005).

of SB 838-eligible resources …."[82/] If PacifiCorp thinks it is impossible to carve out RPS costs from its resource portfolio, it is unclear why the Company thinks it can do so.

Q. WILL SYSTEM RE-DISPATCH COSTS BECOME EVEN MORE DIFFICULT TO QUANTIFY WHEN THE COMPANY BEGINS TO SELF-INTEGRATE WIND?

A. Yes. As discussed by CUB, the Company's proposed mechanism will not adequately track the re-dispatch associated with integration resources, such as Port Westward II and Carty, if the Company chooses to self-integrate.[83/] The Company's only response to CUB's observation was that it was not yet self-integrating and that it is "open to input regarding how the mechanism should function when PGE self-integrates in whole or in part."[84/] Needless to say, this is not a substantive response to this problem, as the Company assumes it will self-integrate by the fourth quarter of the test year.

Q. DID STAFF IDENTIFY ANY PROBLEMS WITH THE COMPANY'S RPS CARVE-OUT PROPOSAL?

A. Yes. Staff's witness, Ryan Bracken, provided a comprehensive evaluation of the Company's RPS carve-out proposal. One of the issues Mr. Bracken identified was the effect of the Company's proposal on its PCAM. In Confidential Table 2 on page 13 of his testimony, Mr. Bracken shows that the Company's proposal can lead to a situation where it over-recovers total power costs, yet under-recovers RPS costs. This is a major flaw in the Company's proposal and its occurrence is not a speculative or remote possibility. In 2012, if the Company's RPS carve-out mechanism had been in place, it would have refunded none of its over-collection to customers due to the dead bands,

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82/ Docket No. UE 246, PacifiCorp's Post-Hearing Brief at 36 (emphasis added).
83/ CUB/100 at 17:8-23.
84/ PGE/1600 at 11:16-17.

sharing bands, and earnings test in the PCAM, yet it would have collected a significant amount of additional power costs associated with its RPS resources from customers. Based on the Company's response to ICNU DR 150, the same thing would have happened in 2010. Thus, in two of the last four years, the Company would have over-collected power costs, refunded none to customers, and nevertheless collected additional RPS-related power costs. This is simply not just and reasonable.

Q. DID STAFF PROPOSE ALTERNATIVES TO THE COMPANY'S RPS CARVE-OUT PROPOSAL?

A. Yes. Mr. Bracken presented four alternatives that he argued were superior to the Company's proposal.[85/]

Q. SHOULD THE COMMISSION ADOPT ONE OF STAFF'S ALTERNATIVES?

A. No. In fact, it is important to note that Staff doesn't think the Commission should adopt them either. Mr. Bracken made clear that, while he felt his alternatives were superior to the Company's proposal, none of them were superior to the status quo.[86/] Moreover, none of them fix the problem Staff identified with the Company's PCAM if an RPS carve-out is adopted.[87/] While Staff stated that it felt changes to the PCAM should be "reserved for after an RPS carve-out mechanism is identified because recommendations for changes would be dependent upon the design of the RPS carve-out mechanism,"[88/] I do not believe the Commission should authorize a mechanism that creates the real

85/ Staff/1100 at 28-38.
86/ ICNU/301 at 24 (Staff Resp. to ICNU DR 5).
87/ Staff/1100 at 38, Table 11.
88/ ICNU/301 at 26 (Staff Resp. to ICNU DR 7c).

possibility for the Company to double-recover a portion of its power costs, even if it is only temporary.

Q. IS A SEPARATE REQUEST FOR INVESTIGATION RELATED TO RECOVERY OF RPS COSTS OUTSIDE OF THE PCAM PENDING BEFORE THE COMMISSION?

A. Yes. On March 21, 2014, the Company and PacifiCorp filed a joint supplemental application in Docket No. UM 1662 asking the Commission to open an investigation to consider whether RPS resource costs should be recovered outside of those utilities' respective PCAMs. Given that, as discussed above, the Commission's policy on this matter is well established, that the Company is requesting such a mechanism in this case, and that PacifiCorp has already stated that its requested relief is "impossible," I recommend that the Commission decline to open an investigation to address this issue in UM 1662.

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD REJECT THE COMPANY'S RPS CARVE-OUT PROPOSAL AND DECLINE TO INVESTIGATE THIS MATTER FURTHER IN DOCKET NO. UM 1662.

A. Notwithstanding the fundamental technical flaws in its proposal, the Company has not satisfied its burden to demonstrate that the Commission should set-aside its long-established policy on power cost adjustment mechanisms. Accordingly, the Company's proposal should be rejected and the Commission should decline to open an investigation to review this issue in a separate proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

EXHIBI ICNU/301

STAFF RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

ICNU 3rd Data Request DR 008
Staff Response to ICNU DR 008
Page 1

Date: August 4, 2014

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FROM: Judy Johnson
Senior Economist
Rates, Finance & Audit

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 283 – ICNU Data Request Set 3 (008)

Data Request ICNU 008:

008. Please provide all documents in Staff's possession that refer to the 18.4% cap on the Energy Trust of Oregon's ability to provide industrial energy efficiency funding in PGE's service territory, referenced in CUB/100 at 27.

Staff Response to ICNU 008:

008. See Attachment A.

From: Fred Gordon [mailto:Fred.Gordon@energytrust.org]
Sent: Thursday, June 06, 2013 2:30 PM
To: JOHNSON Juliet
Cc: Steve Lacey; Peter West; Elaine Prause; Margie Harris; Debbie Goldberg Menashe
Subject: >1 aMW

Juliet, we convened after our meeting with PUC and weren't 100% clear regarding what the PUC was asking for.
We came up with two versions of what the PUC staff is considering. Below, I describe both. It would be good to clarify what you want before we start doing more analysis.

WE'RE PRETTY SURE ABOUT THIS PART

The 2008 informal multiparty agreement locks in a percentage of 1149 funding that should go to customer over 1 aMw. PUC is questioning whether that is the best PUC policy. There may be a level of funding for customers >1 aMW that is the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes, gets all cost-effective measures.

WE'RE NOT SO SURE ABOUT THIS PART.

There seem to be two ways to gauge equity that were discussed, sometimes in rapid succession. They may be alternatives of complimentary perspectives. One is easy to do, one isn't.

1. **Assess whether large customer loads, as a share of all customer loads, grew.** This would be an indicator of whether perhaps funding from this class of customers grew, so it is reasonable to increase funding to them beyond the percentage from the pre-838 period. We think we have the data to look at this and will do so. This would inform analysis in any event. This analysis would not factor in rate differentials or the influence of self-direct on revenues, as we'd simply be looking at load trends.

2. **Assess what percent of *revenue* to Energy Trust comes from large customers.** PUC does not consider this a "dollar in/dollar out = 1" criteria, but will consider the level of revenue in vs. out from the large customers to assess the "right" level of funding for larger customers.

We can readily do #1, have explored how to do #2. If the PUC wants this information to proceed, we suggest that the PUC request data from the utilities regarding how much of the revenue to the Energy Trust came from customers over vs. under 1 aMW. We don't think we have the information in hand, and the task will require an understanding of rates which we'd need to build from scratch. In addition to rates, we don't have data in hand to gauge the impact of self-direct, and we know that it has changed significantly over time, as fewer customers are self-directing. It may have a sizeable influence on the trend. So we'd like to factor that in. For this analysis, we suggest a three year historical period would be enough to see whether there were trends that are meaningful or bumps to smooth out.

In either case, we're hearing that the PUC staff might want to:

- The amount of resource available from >1 aMw vs all customers.

- The amount of that which might be impacted by a cap (this will be highly speculative).
- How levelized cost for large customer projects compare to costs for other customers. If you agree that this is important, we'll do the added analysis, which will be imprecise, but meaningful.

So- Is the PUC staff currently thinking about the first option above, or the second, or both, considering that the second will require added work by the utilities, or less ideally and less accurately, by Energy Trust?
And, do we have it right that you also want us to take a cut at the three bullets below?

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EnergyTrust of Oregon

Large Energy User Funding Analysis

September 6, 2013

Background

Through SB838, electric utility customer sites with usage less than or equal to 1aMW can be charged an additional rate that is used to fund electric efficiency beyond the established public purpose charge from SB 1149 to meet efficiency resource needs identified in utility integrated resource planning. Because not all customers are paying in to the 838 fund, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are calculated as either 2004-2007 total >1aMW incentives divided by 2004-2007 total 1149 efficiency funds directed to Energy Trust. For PacifiCorp this value is **27%** and for PGE it is **18%**. Compliance with this spending limit is calculated on a cumulative basis from 2008 forward, as an average of the % of 1149 incentives for >1aMW over that years 1149 total energy efficiency revenue to Energy Trust. 2008-2012 for PacifiCorp is 22% and PGE is 17% (1% below the limit of 18%).

Today the OPUC is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue and make decisions.

Scope

To help inform the process to review the spending limit methodology, information that can provide the ability the gauge the balance between funder equity and best benefit for all ratepayers is needed.

Questions to be addressed:

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?
2. How much is currently being spent on them?
3. How much savings is acquired with current cap?
4. How levelized cost for large customer projects compare to costs for other customers.
5. How does self-direct factor into the whole issue?
6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?
7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.
8. Estimate how much savings we could end up foregoing with the current cap to spending
9. Looking at how limiting spending on > 1 aMW might affect levelized cost

Analysis

To help answer these questions, both utilities provided historical annual load and revenue data separated by 838 exempt (>1aMW sites) and non-exempt (<=1aMW sites) customer categories. The exempt group was further separated according to those that actively self-directing energy efficiency as well. Those sites don't contribute to 838 but also don't contribute to Energy Trust revenue.

This utility data was combined with Energy Trust's historical database of savings and incentives paid, also separated by those >1aMW and those <=1aMW. Below are brief responses to each question by utility, starting with PGE, based on the work attached in an excel file.

PGE

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?

Since 2005, they have contributed between $1.8 and $2.7million per year, equating to 6.5%-12% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2005-2007 averages 10.3%, 2008-2012 average is 8.1%.

	2005	2006	2007	2008	2009	2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
% of total ETO EE 1149 $ reported	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%

2. How much is currently being spent on them?

Our current metric for limiting spending is measured by incentives spent on sites >1aMW as a percentage of total 1149 efficiency funds received. For PGE this limit is the average of this annual calculation for years 2005-2007, 18%. The cumulative average for 2008-2012 is 17% with specific years ranging from 9% to 27% in 2012. Actual incentives per year range from $1.3M to a high of $9.7M. 2012 incentives totaled $7.5M.

To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency program, where most of the projects are seen, which is 64%. From this perspective, >1aMW sites have received 25% of total funds.

3. How much savings is acquired with current cap?

Annual savings have ranged from 1.6aMW to 14.4aMW, with 7.1aMW in 2012 and total of 47.4aMW from 2005-2012. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load growth) and maintaining a cumulative average of 18% incentives vs. total collected, $5-$5.5M per year can be directed in incentives to >1aMW sites. Assuming an average acquisition rate of 11.3 cents per kWh, escalating by 2% per year, about 5aMW can be acquired per year at the current cap.

Due to the uncertainty in each of the assumptions behind this estimate, there's likely a range around that estimate of at least 25%.

4. How levelized cost for large customer projects compare to costs for other customers.

Levelized incentive costs for these projects have averaged just under 1cent/kWh since 2005,with 2012 being 1.2 cents/kWh and seeing much year to year variability, no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.3cents/kWh.

5. How does self-direct factor into the whole issue?

Revenues to PGE from sites self-directing efficiency have increased over time from $16M in 2005 to $41M in 2012. Although a small proportion of >1aMW revenues, the efficiency public purpose charge they are self-directing is equal to 25% of the >1aMW efficiency revenues received by Energy Trust. Although the energy use and utility revenues for efficiency self-directors has increased the number of sites has declined. One large partial requirements self-director is mainly responsible for the large increase in load seen in 2010.

6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?

The ratio of revenues received compared to spending has trended down over time reaching 35% of incentive dollars in 2012.

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW revenues to ETO	$ 2,483,367	$ 2,735,959	$ 1,824,171	$ 1,755,651	$ 1,762,977	$ 2,443,411	$ 2,578,003	$ 2,615,79
>1aMW incentive spending	$ 9,742,145	$ 1,282,158	$ 1,762,765	$ 2,421,817	$ 2,778,261	$ 4,189,900	$ 5,950,881	$ 7,508,72
>1aMW total spending	$ 15,222,102	$ 2,003,372	$ 2,754,320	$ 3,784,089	$ 4,341,033	$ 6,546,719	$ 9,298,252	$ 11,732,38
Revs/incentives	25%	213%	103%	72%	63%	58%	43%	35
Revs/total $	16%	137%	66%	46%	41%	37%	28%	22

7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.

The ratio of energy use has remained very consistent over time, hovering around 19% of total load.

8. Estimate how much savings we could end up foregoing with the current cap to spending

Based on a high level estimate of ~ 5aMW acquired per year maintaining the cap of 18% incentives budget to total 1149 revenues, over the next five years, we anticipate 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. We may be able to "roll" projects forward in time and if funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements, and might not be available if funding is not provided at the right time.

From our current resource assessment, about 20% of the 20 year achievable potential is estimated to be from industrial (~15%) and commercial (~5%) sites >1aMW.

9. Looking at how limiting spending on > 1 aMW might affect levelized cost

By limiting spending the ratio of lower levelized cost project spending would be maintained at roughly 30%. Using 2012 spending as an indicator of demand needing 40% of spending, the weighted average levelized cost would increase approximately 6%.

EnergyTrust of Oregon

Large Energy User Funding Analysis

October 31, 2013

Background

Through SB838, electric utilities can add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are based on large customer funding prior to SB 838 implementation. They are calculated as the total *incentives* paid to >1aMW sites divided by total 1149 efficiency *revenues* directed to Energy Trust over a base pre-838 timeframe. For PacifiCorp the base period is 2004-2007 and for PGE, the base period is 2005-2007. For PacifiCorp this value is **27%** and for PGE it is **18%**.

Compliance with this spending limit is evaluated by comparing post-838 funding to these limits. The post-838 percentage for comparison to the numbers described above is calculated on a cumulative basis starting in 2008. It is the sum of incentives for >1aMW over the sum of total 1149 energy efficiency revenues to Energy Trust. 2008-2012 for PacifiCorp is 22% (five points beneath the limit of 27%) and for PGE is 17% (1% point below the limit of 18%).

There are two types of issues to be addressed: 1) Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M), we would exceed the current spending limit in 2015. The cap may cause us to redirect funds above the cap to higher cost projects from smaller, 838 eligible sites. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings.

2) Implementation of the spending limit is extremely challenging. A) Energy Trust still does not have access to knowing which meters and sites are paying 838 and which are not- the estimates cited above are based on the best available data. B) This is further complicated by the fact that the definition of a self-direct eligible site and an 838 exempt site differs. Meters that are <1aMW yet are included with a self-direct site definition totaling >1aMW pay 838 charges. Since they are meters within a self-direct site (total meter load >1aMW) the programs are only reasonably able to treat them as an exempt, 1149 only site. It's impossible to know which projects are on which meters and which ones are paying 838 or not paying 838. We run the risk of limiting program participation to sites which do have some meters paying 838.

Today the OPUC is aware of these issues and is questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. To determine this we need to look at the problem differently. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue and make decisions and offers some recommendations to address both categories of issues.

Scope

To help inform the review of the spending limit methodology, information is needed that can help policymakers gauge the balance between funder equity and best benefit for all ratepayers.

Questions to be addressed:

1. How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?
2. How much is currently being spent on them?
3. How much savings is acquired with current cap?
4. How levelized cost for large customer projects compare to costs for other customers.
5. How does self-direct factor into the whole issue?
6. How has the ratio of revenues received from <1aMW customer to spending for <1aMW has changed over time?
7. Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.
8. Estimate how much savings we could end up foregoing with the current cap to spending
9. Looking at how limiting spending on > 1 aMW might affect levelized cost

Analysis

To answer these questions, both utilities provided historical annual load and revenue data separated by 838 exempt (>1aMW sites) and non-exempt (<=1aMW sites) customer categories. The exempt group was further separated into those that are versus are not actively self-directing energy efficiency. Those sites don't contribute to 838 but also don't contribute to Energy Trust revenue.

This utility data was combined with Energy Trust's historical database of savings and incentives paid (created by a third party contractor to date), also separated by those >1aMW and those <=1aMW. Below is a brief summary of key takeaways, followed by responses to each question for each utility.

Summary of key findings

- Dollars provided to Energy Trust by sites with loads greater than 1aMW have remained relatively steady over all years while non-exempt sites are contributing 36%--66% more per kWh in 1149 funds than in 2004/2005. This reflects 838 charge increases plus other rate increases over the years for the non-exempt meters.

- Demand for efficiency program spending from >1aMW sites has varied year to year but is expected to maintain recent levels or increase over the next 5 years, just how much of an increase is unknown.

- In recent years, >1aMW sites contribute 9% and 13% of total 1149 revenues (PGE/PAC) and receive 18% and 24% of 1149 incentives.

- The utility cost of savings from >1aMW sites is less than half the cost of non-exempt site projects

- Savings potential from >1aMW sites is estimated to be 20% of our current 20 year potential assessment.
- The risk of the current spending cap hindering acquisition is high in PGE territory but low for PAC.
- Although Energy Trust has historically spent more on large sites than the revenue collected from those sites, the value of the large site energy savings to the system has been significant and benefits all ratepayers.

Options

Option 1. Consider removing the exemption for >1aMW sites contributing to the 838 funds. This would require a legislative act.

- Large sites have received significantly more incentive benefit per dollar contributed compared to non-exempt sites as well as more savings per dollar received. However, the lower-cost savings benefit both large users directly and nonexempt sites through a lower cost energy system.
- If the large customer exemption were removed, the impact of removing the exemption would be an overall increase in Energy Trust funding from large customers from an average of 0.09 cents/kWh to 0.31 cents/kWh.

Option 2. Align implementation of 838 charges to self-direct site definitions.

Individual meters within a self-directing site may be <1aMW and therefore charged 838 rates. Administration of spending caps within a site is overly complex. For example, project eligibility would need to be tied to an 838 eligible meter. That level of precision is not reasonable to assume is possible in implementing a program. The risk to Energy Trust is that we would be limiting program participation for sites that are paying 838 at some meters. By aligning definitions, meters within a self-direct eligible site would not be charged 838, regardless of load and the risk of unnecessarily limited participation at some meters would be minimized.

Option 3. Revise the method for compliance with 838 from the current spending cap to some less restrictive cap.

The cap will result in a resource acquisition constraint in PGE territory but is not estimated to have an impact on acquisition in PAC. Removing the constraint ensures that all least cost resource can be acquired and reactive program design methods intended to comply with the cap don't result in damaging participant interest/relationships for future projects.

Removing or adjusting the cap results in small incremental risk to equity. Large site demand varies significantly by year. If we assume the average incentive demand for the past three years in PGE ($5.8M) increases by 25% ($7.25M) and is sustained for the next three years, the cumulative % of incentives to total revenues from PGE large customers would increase from 17% to 20%. This is still below the current PAC spending cap. It would allow PGE's >1aMW customer to spend about twice the revenue collected from them. That is roughly the limit for PacifiCorp.

There are several possible ways to set a different cap. The new cap for PGE might be set at a particular ratio of revenue from and to larger customers or it might be set at the same level as PacifiCorp. There might be a different way to assure compliance than the cap, but we do not recommend running separate programs for the same customer with 838 and 1149 funds as was suggested after SB 838 was passed. From a customer relationships and program effectiveness strategy, this is not feasible.

Option 4: Apply the limit across both utilities as a single limit.

This would provide some additional headroom, but might not provide a permanent solution.

Option 5. Maintain current policy. Based on our current projections (which depend greatly on what customers choose to do) this is likely to result in the need to limit funding to projects at >1aMW sites for PGE in 2015. A review of options for limiting program activity was provided as part of the board retreat packed for the June, 2012 retreat. All of the options would reduce acquisition of cost-effective savings. There would also be some disruption of customer relationships and the ability to pursue additional savings. The preferred options from that review might minimize this disruption.

DETAILED ANALYSIS OF UTILITY DATA

1. **How much are > 1aMW sites paying in to Energy Trust efficiency funding? How has this changed over time?**

PGE

Since 2005, they have contributed between $1.8 and $2.7million per year, equating to 6.5%-12% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2005-2007 averages 10.3%, 2008-2012 average is 8.1%.

	2005	2006	2007	2008	2009	2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
% of total ETO EE 1149 $ reported	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%

The downward trend may be attributed to a few factors. Although load as a % of total load is not decreasing, rates for non-exempt sites have increased more than for exempt sites. Although the calculation of efficiency funds to Energy Trust from SB 1149 has not changed (56.7% of 3% of rates), the underlying $/kWh for non-exempt sites has increased due to SB 838 charges and other general rate case increases allocated to these customer segments that are not impacting the >1aMW sites.

PAC[1]

Since 2004, they have contributed between $1.9 and $2.9million per year, equating to 11%-22% of the total 1149 energy efficiency revenues to Energy Trust with a trend towards a decreased percentage in more recent years. 2004-2007 averages 18.5%, 2010-2012 average is 12.8%.

	2004	2005	2006	2007		2010	2011	2012
$M- revenues to ETO EE >1aMW	$2.9	$2.9	$2.7	$1.9		$2.3	$2.1	$2.7
% of total ETO EE 1149 $ reported	22%	21%	19%	12%		14%	11%	14%

Similar to PGE, 838 exempt revenues have not changed much over time but the revenues from non-exempt have increased due to 838 charges and other larger rate increases over the years than large customers have seen. These factors are leading to their revenues being a lower % of the total 1149 funds received.

2. **How much is currently being spent on them?**

PGE

Our current metric for limiting spending is measured by incentives spent on sites >1aMW as a percentage of total 1149 efficiency funds received. For PGE this limit is the average of this annual calculation for years 2005-2007, **18%**. The cumulative average for 2008-2012 is **17%** with specific years ranging from 9% to 27% in 2012. Actual incentives per year range from $1.3M to a high of $9.7M. 2012 incentives totaled $7.5M.

To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency program, where most of the projects are seen, which is 64%. From this perspective, >1aMW sites have received 25% of total funds. Although more is being spent on these sites, significantly more savings are being acquired per kWh of load, and per dollar spent via these sites when viewed as a group than through smaller sites as a group.

PAC

For PAC our spending limit is the average of this annual calculation for years 2004-2007, **27%**. The cumulative average for 2008-2012 is **22%** with most recent years at 20 and 22%. Actual incentives per year range from $1.5M to a high of $9.2M. 2012 incentives totaled $3.8M, up from $3.6M in 2011.

[1] Our data analysis approach for PacifiCorp is slightly modified to work with the data provided by the utility which differs from what PGE was able to provide. PAC provided 2004-2007 and 2010-2012. Load and revenue detail for efficiency self -directors was not possible to distinguish from renewables only self-directors which make up the majority of PAC self-directors. The one exception is for efficiency specific revenue data from 2011 and 2012 which was available through monthly revenue reports provided outside of the data request for this study.

3. **How much savings is acquired with current cap?**

PGE

Annual savings from <1aMW PGE customers have ranged from 1.6aMW to 14.4aMW, with 7.1aMW in 2012 and total of 47.4aMW from 2005-2012. On average, the 20% of Energy Trust efficiency spending dedicated to this group is acquiring 34% of the savings. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load and rate growth) and maintaining a cumulative average of 18% incentives vs. total 1149 PGE revenue collected, $5-$5.5M per year can be directed in incentives to >1aMW sites. Assuming an average acquisition cost of 11.3 cents per annual kWh saved, escalating by 2% per year, about 5aMW can be acquired per year at the current cap.

Due to the uncertainty in each of the assumptions behind this estimate, there's likely a range around that estimate of at least 25%.

PAC

Annual savings have ranged from 1.7aMW to 8.8aMW, with 4.9aMW in 2011 and 6.9aMW in 2012 for a total of 42 aMW from 2004-2012, averaging 4.7 aMW/yr. Energy Trust spending in PAC territory (>1aMW incentives / total revenues) has not yet reached the cumulative cap of 27%. Going forward, assuming a 1% annual increase in total 1149 efficiency funds collected (to represent load growth), to reach the 27% spending cap in 2016, annual spending on PacifiCorp sites >1aMW would need to increase by 40% to $6.5M per year (For reference the average of the past three years of spending has been $4.6M.) This implies that there's room within the PAC methodology to meet a 40% growth in demands from >1aMW sites for the next 4 years. Assuming an average acquisition cost rate of 8 cents per annual kWh (based on the last 3 years of project acquisition and escalating by 2% per year) about 9aMW can be acquired per year within the current cap.

Again, there is much uncertainty in each of the assumptions behind these estimates, there's likely a range around that estimate of at least 25%.

4. **How does levelized cost for large customer projects compare to costs for other customers?**

PGE

Levelized ***incentive*** costs for these projects have averaged just under 1cent/kWh since 2005, with 2012 being 1.2 cents/kWh. There is much year to year variability, and no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.3cents/kWh.

PAC

Levelized incentive costs for PAC projects have also averaged under 1 cent/kWh since 2005, with 2012 being just 0.6 cents/kWh . There is much year to year variability with no real trend in cost up or down through time. This compares with levelized incentive costs for <=1aMW sites averaging 2.5 cents/kWh.

5. **How does self-direct factor into the whole issue?**

PGE

Revenues to PGE from sites self-directing efficiency have increased over time from $16M in 2005 to $41M in 2012. Although a small proportion of >1aMW revenues, the efficiency public purpose charge they are self-directing is equal to 25% of the >1aMW efficiency revenues received by Energy Trust. Although the energy use and utility revenues for efficiency self-directors has increased the number of sites has declined. One large partial requirements self-director is mainly responsible for the large increase in load seen in 2010.

PAC

PacifiCorp could not provide revenue, load and site data for efficiency self-directing sites. For 2011 and 2012, revenues but not loads from these sites were available. We do know that there are very few sites self-directing efficiency (yet several are self-directing their renewable portion of the PPC) and that in 2012, >1aMW revenues to Energy Trust would have been just 5% greater had these customers not self-directed. With current levels of self-direction, it really doesn't factor into the issue other than noting that over time the trend away from self-direct has helped maintain >1aMW revenue contributions to Energy Trust at a sustained annual level.

6. **How has the ratio of revenues received from >1aMW customer to spending for >1aMW changed over time?**

PGE

The ratio of 1149 revenues received compared to incentive spending has trended down over time reaching 35% of incentive dollars in 2012. When considered on a total 1149 spending basis (includes estimates for program management and administration costs), the ratio is now 22%.

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW revenues to ETO	$ 2,483,367	$ 2,735,959	$ 1,824,171	$ 1,755,651	$ 1,762,977	$ 2,443,411	$ 2,578,003	$ 2,615,79
>1aMW incentive spending	$ 9,742,145	$ 1,282,158	$ 1,762,765	$ 2,421,817	$ 2,778,261	$ 4,189,900	$ 5,950,881	$ 7,508,72
>1aMW total spending	$ 15,222,102	$ 2,003,372	$ 2,754,320	$ 3,784,089	$ 4,341,033	$ 6,546,719	$ 9,298,252	$ 11,732,38
Revs/incentives	25%	213%	103%	72%	63%	58%	43%	35
Revs/total $	16%	137%	66%	46%	41%	37%	28%	22

PAC

The ratio of revenues received compared to spending has bounced up and down over time from a low of 36% to a high of 125%. In 2012, revenues were 68% of incentive $s spent on >1aMW.

7. **Whether the ratio of energy usage by > 1 aMW to other customers has grown or shrunk since base period.**

PGE - The ratio of energy use has remained very consistent over time, hovering around 19% of total load.

PAC - The ratio of energy use has also remained very consistent over time, averaging around 19% of total load. Since we were unable to pull out load from sites self-directing efficiency over the years, this was calculation was done without adjusting load to reflect only those contributing to Energy Trust. We know that the number of sites self-directing efficiency has declined but can't confidently reflect that trend in load comparisons.

8. **Estimate how much savings we could end up foregoing with the current cap to spending**

PGE

Based on a high level estimate of ~ 5aMW acquired per year maintaining the cap of 18% incentives budget to total 1149 revenues, over the next five years, we anticipate 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. We may be able to "roll" projects forward in time if there are years with fewer large projects, but that would not address the cumulative decrease. If funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements, and might not be available if funding is not provided at the right time.

From our current resource assessment, sites <1aMW provide about 20% of the 20 year achievable potential. Three quarters of that is from industrial sites, and one quarter from commercial and institutional sites.

PAC

In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

9. **Looking at how limiting spending on > 1 aMW might affect levelized cost**

PGE

By limiting spending the ratio of lower levelized cost project spending would be maintained at roughly 30%. Using 2012 spending as an indicator of demand (40% of spending) and assuming that smaller projects could be found to make up the different, 10% of spending would shift from sites >1aMW to projects at smaller sites due to the current spending cap. This results in the weighted average levelized cost increasing approximately 6%.

PAC

Any >1aMWw incentives dollars that are shifted to non-exempt projects result in fewer savings acquired. (62% of what could have been acquired for >1aMW projects) The impact to levelized cost would depend on how much of the dollars intended to meet >1aMW demand was shift to non-exempt projects. Since we don't anticipate enough large site demand to cause us to reach the spending cap we don't foresee and impact to levelized cost for PAC.

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Large Energy User Funding Analysis

January 31, 2014

Background

Through SB838, electric utilities can add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>> (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

The limits, established separately for each utility, are based on large customer funding prior to SB 838 implementation. They are calculated as the total *incentives* paid to >1aMW sites divided by total 1149 efficiency *revenues* directed to Energy Trust over a base pre-838 timeframe. For PacifiCorp the base period is 2004-2007 and for PGE, the base period is 2005-2007. For PacifiCorp this value is **27%** and for PGE it is **18%**. The large difference in limits between utilities reflects differences in size and volume of large customer projects during the base period years and is out of alignment with current utility specific large site activity. PGE activity for the past two years averaged 25%, incentives divided by total 1149 revenues.

Conformance with this spending limit is evaluated by comparing post-838 funding to these limits. The post-838 percentage for comparison to the numbers described above is calculated on a cumulative basis starting in 2008. It is the sum of incentives for >1aMW over the sum of total 1149 energy efficiency revenues to Energy Trust. For the years 2008-2012 for PacifiCorp this is 22% (five points beneath the limit of 27%) and for PGE is 17% (1% point below the limit of 18%).

Issue

Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

To maintain compliance with the cap for PGE will cause us to limit annual spending on customers > 1 aMW. To reach goals we will need to redirect funds above the cap to higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in less savings at higher cost. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust savings comes through such events.

Today the OPUC is aware of this issue and is questioning whether the current methodology used to set Energy Trust's spending limit for >1aMW sites is an optimal approach. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. The solution should leave sufficient revenue for other customer classes while not limiting the acquisition of all cost-effective savings. This paper summarizes an analysis of key questions to help frame the issue

Scope

To help inform the review of the spending limit methodology, information was gathered to help policymakers gauge the balance between funder equity and best benefit for all ratepayers.

Summary of key findings

- In recent years (2010-2012), >1aMW sites contributed about 9% and 13% of total 1149 revenues (PGE/PAC) and receive project incentives 20% and 25% of 1149 total spending.

- Dollars provided to Energy Trust by sites with loads greater than 1aMW have remained relatively steady over all years while non-exempt sites are contributing 2.5 times more per kWh in 1149 and 838 funds combined than they paid through 1149 only in 2004/2005 (prior to SB838). This reflects 838 charge increases plus other rate increases over the years for the non-838-exempt meters.

- Demand for efficiency program spending from >1aMW sites has varied year to year but is expected to maintain recent levels or increase over the next 5 years. The size and likelihood of an increase is unknown. Possible increases may come from deeper engagement with the semiconductor industry, possible increases in combined heat and power, accelerated capital investment by larger commercial and industrial businesses, or other drivers.

- On average, the cost to the utility system since 2010 for savings from >1aMW sites is 60% of the cost of non-exempt site projects. In other words, large site projects provide 1.3-2.5 times the savings per incentive of non-exempt sites on average.
- Savings potential from >1aMW sites is estimated to be 20% of our current 20 year potential assessment.
- The risk of the current spending cap hindering acquisition is high in PGE territory but low for PAC.
- Although Energy Trust has historically spent more on large sites than the revenue collected from those sites, the value of the large site energy savings to the system has been significant and benefits all ratepayers.

PGE Annual Statistics

	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW EE 1149 revenues to ETO ($M)	$2.48	$2.74	$1.82	$1.76	$1.76	$2.44	$2.58	$2.62
Total EE 1149 revenues to ETO ($M)	$21.07	$22.72	$25.67	$26.89	$26.67	$27.07	$28.51	$28.12
>1aMW revenues as % of total ETO EE 1149	11.8%	12.0%	7.1%	6.5%	6.6%	9.0%	9.0%	9.3%
Total Incentive spending for >1aMW ($M)	$9.74	$1.28	$1.76	$2.42	$2.78	$4.19	$ 5.95	$7.51
>1aMW Incentives as % of total 1149 revenues to ETO [1]	18% = cap			17%				
Total EE 1149 spending for >1aMW ($M)[2]	$15.2	$2.0	$2.8	$3.8	$4.3	$6.5	$9.3	$11.7
Total EE 1149 spending ($M)	$27.8	$19.2	$21.9	$26.4	$26.7	$31.7	$30.2	$27.8
>1aMW EE 1149 spending as % of total	55%	10%	13%	14%	16%	21%	31%	42%
Total Savings from >1aMW (aMW)	14.4	1.6	7.8	2.4	3.0	5.7	5.3	7.1
Levelized cost of savings from >1aMW sites ($/kWh)	0.008	0.009	0.003	0.011	0.010	0.008	0.012	0.012

[1] This is our current metric for compliance with funding limitations
[2] Although Energy Trust can track the incentive dollars that are paid to >1aMW sites knowing that only 1149 funds are spent, all programs are delivered with the mix of 838 and 1149 funds, making the total 1149 dollars spent for >1aMW sites a reasonable estimation only. To estimate total 1149 dollars spent on these sites, we applied the current ratio of incentives to total budget for the Production Efficiency programs, where most of the large site projects are seen, which is 64%.

Levelized cost of savings from <=1aMW sites ($/kWh)	0.012	0.010	0.015	0.012	0.017	0.016	0.016	0.016
Cost/kWh of >1aMW sites as % of <=1aMW site projects	64%	87%	16%	91%	60%	52%	76%	75%

2010-2012 averages:

- >1aMW EE 1149 revenues as % of total EE 1149 revenues = **9.1%**
- >1aMW EE 1149 annual incentive spending as % of total annual EE 1149 revenues = **20%** (funding limit is set at cumulative incentives from customers >1aMW not exceeding 18% of cumulative revenue, actual cumulative spending 2008-2012 = 17%)
- >1aMW EE 1149 total spending as % of total EE 1149 spending= **31%**
- Incentive cost/kWh of >1aMW site projects as % of <=1aMW site projects = **68%**

PAC Annual Statistics

	2004	2005	2006	2007	2008	2009	2010	2011	2012
>1aMW EE 1149 revenues to ETO ($M)	$2.95	$2.90	$ 2.72	$ 1.86			$2.31	$2.07	$2.71
Total EE 1149 revenues to ETO ($M)	$ 13.35	$13.58	$ 14.6	$ 15.5	$ 16.1	$ 16.4	$ 16.25	$ 18.77	$ 19.6
>1aMW revenues as % of total ETO EE 1149	22.1%	21.4%	18.6%	12.0%			14.2%	11.0%	13.8%
Total Incentive spending for >1aMW ($M)	$ 8.11	$ 3.40	$ 2.19	$1.87	$2.5	$2.4	$ 5.60	$ 4.22	$ 3.99
>1aMW incentives as % of total 1149 revenues to ETO	27% = cap				2008-2012=22%				
Total EE 1149 spending for >1aMW ($M)	$12.67	$ 5.31	$3.43	$ 2.92	$ 3.9	$ 3.8	$ 8.74	$6.60	$ 6.24
Total EE 1149 spending ($M)	$21.48	$17.13	$ 16.66	$ 14.50	$ 14.8	$ 16.4	$ 20	$18.06	$ 18.7
>1aMW EE 1149 spending as % of total	59%	31%	21%	20%	27%	23%	44%	37%	33%
Total Savings from >1aMW (aMW)	7.3	4.2	1.7	3.1	3.3	2.4	8.4	4.9	6.9
Levelized cost of savings from >1aMW sites ($/kWh)	0.012	0.009	0.014	0.007	0.009	0.012	0.007	0.010	0.006

Levelized cost of savings from <=1aMW sites ($/kWh)	0.015	0.013	0.010	0.007	0.010	0.017	0.014	0.016	0.016
Cost/kWh of >1aMW sites as % of <=1aMW site projects	80%	70%	143%	89%	86%	67%	52%	62%	39%

2010-2012 averages:

- >1aMW EE 1149 revenues as % of total EE 1149 revenues = **13%**
- >1aMW EE 1149 annual incentive spending as % of total annual EE 1149 revenues = **26%** (funding limit is set at cumulative incentives from customers >1aMW not exceeding 27% of cumulative revenue, actual cumulative spending 2008-2012 = 22%)
- >1aMW EE 1149 total spending as % of total EE 1149 spending= **38%**
- Incentive cost/kWh of >1aMW site projects as % of <=1aMW site projects = **51%**

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Large Energy User Funding Limit

History of the Methodology Used in Determining the Limit and Current Status

March 12, 2014

Issue Summary

The 1999 Oregon law that gave rise to Energy Trust, SB 1149, required the electric utilities to devote three percent of their revenues to electric efficiency programs. The three-percent charge is collected from all electric customers regardless of the amount of energy they use. A 2007 state law, SB 838, authorized utilities, with OPUC approval, to collect additional electric efficiency funds from customers using less than one average megawatt (aMW) or more per year. Large customers (those using more than 1 aMW) were excluded from paying additional funding, and so are not supposed to receive direct benefit from SB 838 funding. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning. Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>> (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

Due to success of the programs serving them, savings from large customers and incentives going to them have been increasing. Without a change, before 2015 Energy Trust will likely need to cap spending in PGE's service territory for these customers. In the fairly near term and in the long run, the limitation in SB 838 funding means that Energy Trust will not be able to pursue all cost-effective efficiency from these customers. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand but PAC customers will be impacted by program designs instituted to manage funding for PGE.

Today the OPUC and stakeholders are questioning whether the methodology used to set Energy Trust's spending limit for >1aMW sites is the best policy. There may be a more appropriate level of funding for customers >1 aMW that brings the proper balance between getting all cost-effective measures and reasonable equity for funders. This paper documents the creation of the existing spending limit methodology and documents current discussions by stakeholders related to next steps.

Methodology

One of the first steps in implementing 838 efficiency funding was to set up processes for ensuring that large energy users were not charged and did not receive direct benefit from funds collected. Energy Trust, OPUC staff and utilities met informally to work through details. Since the details of the discussions and resulting methodology were not created within the formal regulatory docket process, the history is sparse and largely undocumented. The following description documents the practice that Energy Trust has followed since those discussions took place and is meant to reflect our best understanding of the intent at the time.

- Exempting large energy users from contributing towards 838 was, with PUC knowledge, addressed within specific customer billing systems at each utility, informed by site use and self-direct certification status. Utilities worked through their process with OPUC staff to ensure large energy users were not charged 838.

- The next step was to ensure that those that are not contributing are not directly benefiting. The group interpreted the need to show no direct benefits are received as meaning that the current spending practices should not be exceeded going forward. This could be shown by tracking what proportion (%) of public purpose charge funding (SB1149 only) went, collectively, to large energy users prior to the new 838 funding and limiting future spending (post 838) to not exceed that pre 838 baseline spending.

- Tracking <u>project incentives paid</u> to large energy users <u>compared to total efficiency 1149 revenues</u> to Energy Trust was the agreed upon metric to characterize spending. Incentive spending was thought to be a reasonable, but not perfect, indicator of spending to a specific customer class that was relatively easy to separate from other program data. Funding spent on delivery and program management is more challenging to separate between types of customers.

- To best represent current (pre-838) spending, Energy Trust elected to look at <u>utility specific</u> spending, not a combined look.

- There are slight differences in the baseline years selected by Energy Trust for comparison between utilities, 2005-2007 PGE and 2004-2007 for PAC. PGE had one very large ("megaproject") year and two small years in their baseline and PAC had four consistently high activity years. The PGE range was likely limited to three years because there was not much of an operational industrial program in 2004, and a significant proportion of large customer activity is from industrial customers.

- The resulting methodology sets the baseline funding limit as the sum of incentives in base years, divided by the sum of 1149 efficiency revenue to Energy Trust. This value is set as the funding cap, not to be exceeded.
  - The funding caps differ significantly by utility, PAC = 27%, PGE 18%
  - The difference is representative of specific project activity that occurred during the base period; PAC territory saw many forest products projects move forward while PGE activity was largely limited to one large paper mill. A larger proportion of PGE's large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until recently.

- Determining "compliance" against this funding limit was agreed to be calculated as a rolling, cumulative look. Because large projects can have lumpy impacts on program incentive spending with year by year variability, measuring compliance on a year to year basis did not seem appropriate. The resulting methodology takes a broader perspective. The sum of all large energy user post 838 incentives are divided by total 1149 revenues across the same time period. For example, to determine compliance with funding limits at the close of 2012, by utility, all large user incentives from 2008-2012 were summed and divided by the total 1149 efficiency revenues for each utility. PAC was 22% and PGE was 17%.

- The final step is to compare the "post 838" percentage to the baseline funding limit. Through 2012 activity, PAC is 5 percentage points below the limit and PGE is 1 percentage below their limit.
- If cumulative spending reached or exceeded baseline spending, parties agreed that time would be needed for "correction" to be able to adjust program spending below the limit within 2 years.

This development of a process to limit benefits was never a question of setting a dollar in (revenues from large customers) to dollar out (expenditures on large customers) measure but rather to find a way to set a reasonable level of spending for large users that made sure there was enough funding left for those who were contributing to 838.

Current Situation

In anticipation of reaching the funding limit in PGE territory before 2015, Energy Trust staff raised the topic of possible impacts on the program at the June 2013 board retreat. Program staff outlined possible program tactics that could be employed if we were to reach the limit and need to take actions to adjust program spending downward.

Due to possible limitations to acquire cost effective savings that could result from Energy Trust managing to the existing funding caps, OPUC staff asked Energy Trust to provide more information on the topic. Because Energy Trust did not have complete data describing r how much of the 1149 revenue received is from large energy users, OPUC staff issued a data request to utilities to provide that information. As a result, the full picture of costs and benefits to large energy users and all ratepayers could be compared. Although a larger portion of funding goes to large energy users than the portion of 1149 revenues contributed by that group, the cost of savings acquired is much lower than other projects and therefore the savings per ratepayer dollar invested are much higher. All ratepayers are benefiting from the higher savings.

Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust's ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. In PAC territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand. Annual demand for funding for customers>1 aMW would need to increase 40% and hold steady for the next 4 years to hit the spending cap.

To maintain compliance with the cap for PGE will cause us to limit annual spending on customers > 1 aMW. To reach goals we will need to redirect funds above the cap to higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in less savings at higher cost. It is also possible that as a consequence Energy Trust does not meet IRP goals in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust large customer savings comes through such events.

Outreach Efforts

Energy Trust convened a meeting of stakeholders January 31, 2014 to discuss the issue and current situation. In attendance were representatives from utilities, OPUC staff, CUB, ICNU, NWFPA, NWEC, NEEC, ODOE, and Energy Trust staff. A variety of views were heard. Stakeholders offered a range of ideas to address the funding limitations including;

- Expand 838 charges to large energy users (would require legislative action)
- Revisit the methodology so that it's more reflective of current large energy user potential activity and available cost effective resource
- Change the methodology to allow more funding to large users under the condition that those paying to 838 see direct rate benefit from the low cost efficiency in which they are investing (would require rate re-design)

No consensus was reached among attendees but Energy Trust did agree to keep the group fully informed of the situation going forward.

Next Steps

Energy Trust plans to provide results of the 2013 analysis in April 2014. If we have met or exceeded the funding limit in PGE territory, we plan to begin to take programmatic actions to lower funding and come back into compliance over a two year period. These actions will be worked through with our Conservation Advisory Council.

Date: July 18, 2014

TO: S.Bradley Van Cleve
Tyler C. Pepple
Bradley G. Mullins
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Michael P. Gorman
Brubaker & Associates, Inc.
P.O. Box 412000
St. Louis, MO 63141-2000
mgorman@consultbai.com

FROM: Ryan Bracken
Senior Economist
Energy Resources and Planning

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 283 – ICNU Data Request Set 1 (001-006)

Data Request ICNU 005:

005. Reference Staff/1100 at 28:4-5 where witness Bracken states that "a perfect methodology to carve out RPS attributed variance is not possible." Does Staff consider any of its four alternative methodologies to be superior to the status quo in which PGE recovers its RPS resource costs through the Annual Update Tariff and Power Cost Adjustment Mechanism? If so, please explain in detail which alternative is preferable and why.

Staff Response to ICNU 005:

005. Staff does not consider any of its four alternative methodologies to be superior to the status quo. The four alternative methodologies are developed for commission consideration in the event the Commission decides to adopt an RPS carve out, as is described at Staff/1100, 1:21: "if the Commission decides to adopt an RPS carve out, a suitable calculation methodology is required. PGE's proposed calculation methodology has major flaws and Staff recommends that an alternate methodology be used *in the event the Commission adopts an RPS carve out*. Staff proposes four alternative calculation methodologies that improve upon PGE's methodology and recommends its preferred method." (emphasis added)

Date: July 22, 2014

TO: S.Bradley Van Cleve
Tyler C. Pepple
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FROM: Ryan Bracken
Senior Economist
Energy Resources and Planning

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 283 – ICNU Data Request Set 2 (007)

Data Request ICNU 007:

007. Reference Staff/1100 at 19:18-19, where witness Bracken indicates that it "may be necessary to revisit the PCAM mechanism if an RPS carve out mechanism were to be adopted."

a) Does Staff have, or anticipate it will have, any proposals for how to modify PGE's PCAM in this case?

b) If your answer to a) is "yes", please provide a detailed description of such proposals along with all associated documents, data, and workpapers.

c) If your answer to a) is "no", does Staff believe that, if the Commission were to create an RPS carve-out mechanism for PGE, it should do so before it addresses the structural problems with the PCAM that Staff, at Staff/1100 at 19-20, identified could occur as a consequence? Please explain your answer in detail.

Staff Response to ICNU 007:

007. a) No

b) N/A

c) Any needed changes to the PCAM are best reserved for after an RPS carve-out mechanism is identified because recommendations for changes would be dependent upon the design of the RPS carve-out mechanism.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)

EXHIBIT ICNU/302

CUB RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

Citizens' Utility Board of Oregon

610 SW Broadway, Suite 400
Portland, OR 97205
(503) 227-1984 ▪ fax (503) 274-2956 ▪ cub@oregoncub.org ▪ www.oregoncub.org

August 4, 2014

Bradley Van Cleve
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Bradley Mullins
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333 SW Taylor Ste 400
Portland Or 97204

Michael P. Gorman
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Suite 140
Chesterfield, MO 63017

RE: UE 283 CUB's August 4, 2014 Data Responses to ICNU's July 24, 2014 Data Requests

Dear Brad, Brad and Michael:

The following are CUB's Data Responses to ICNU's Data Requests dated July 24, 2014.

I. <u>DATA REQUESTS</u>

0011 Please provide all documents in CUB's possession that memorialize or in any way refer to the 18.4% industrial cap on energy efficiency funding.

Response 0011: CUB has reviewed our archives and found the following documents: PGE Advice Filing 07-25, dated October 26, 2007, and also one attachment to a Data Response related to the Advice Filing. In the Advice Filing, PGE references the requirement that there would be "no shift in the allocation of Public Purpose Funding", and in the attachment provides the methodology used to prevent the shift in the allocation of the Public Purpose Funding.

0012 Please provide all documents in CUB's possession that demonstrate that ICNU agreed to the 18.4% industrial cap on energy efficiency funding.

Response 0012: CUB has no documents that demonstrate that ICNU agreed to the 18.4 % cap beyond PGE's Reply Testimony the UE 283 docket. ICNU opposed SB 838 which included the prohibition on industrial customers receiving a direct benefit from SB 838 energy efficiency programs.

PGE's Reply testimony in the UE 283 docket states that:

"To ensure that customers with loads less than one average megawatt were not subsidizing customers with over one average megawatt, PGE, PacifiCorp, the ETO, Staff, CUB and ICNU reached an informal agreement that the ETO would not exceed a historical amount of energy efficiency funding for the larger customers' energy efficiency projects. PGE's cap of 18% was an historical average of the ETO energy efficiency payments (under SB 1149) to PGE's customers over one average megawatt, for the three years preceding the passage of SB 838."

0013 In order to achieve all cost-effective energy efficiency, would CUB agree to removing the 18.4% industrial cap on energy efficiency funding and limiting such funding to customers over 1 aMW to the total energy efficiency funding derived from SB 1149 funds? If not, please explain in detail why not.

Response 0013: Yes. Our proposal in the UE 283 rate case would remove the 18.4% cap on industrial energy efficiency programs by recognizing that the direct benefits of SB 838 energy efficiency programs are lower costs for the utility system. Energy efficiency is a system resource, just like a natural gas plant or a wind farm. CUB would support increasing energy efficiency programs targeted at large customers as long as it is done in a manner that does not require a significant subsidy from customers with smaller loads. Our proposal accomplishes this because it flows the benefits of energy efficiency back to the classes of customers who fund that energy efficiency so the direct benefit from energy efficiency programs is directed at the classes of customers who pay for those programs.

0014 Please provide all data, documents, and other evidence relied on by CUB for its statement that "EE is a cumulative resource." CUB/100 at 21:7.

Response 0014: PGE[1] and The Energy Trust of Oregon[2] consider EE a cumulative resource. In addition, logistically, once a conservation measure has been adopted, and meets load for a particular structure, or appliance, that measure continues to serve in its capacity for its useful life. Data abounds online testifying to the useful life of conservation measures. The ETO provides analysis on conservation measures.[3]

In CUB's experience ratemaking has for at least 15 years treated energy efficiency as an expense in the year the expenditure is made, but the benefits of energy efficiency flow over the life of the measure. This means that in any particular year, customers are benefiting from energy efficiency measures that have been procured in previous years.

0015 Reference CUB's response to ICNU Data Request 3. Please provide all support for CUB's assertion that PGE "is unable to acquire all cost-effective energy efficiency in its forecasted test year."

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[1] LC 56 page 56 figure 4-2.
[2] http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf, page 20, figure 16
[3] http://energytrust.org/library/reports/resource_assesment/etoresourceassessfinal.pdf

Response 0015:

A. On January 31, 2014, CUB attended a meeting of stakeholders at the ETO where this issue was discussed.

B. In its UE 283 Response testimony, PGE stated that "spending will need to be curtailed in 2015 or sooner."[4] 2015 is the current test year.

C. In its LC 56 IRP Reply Comments, PGE suggests that "ETO is likely to reach it funding limit for industrial customers this year" and that ETO has estimated that 1.5 to 2 MWa of industrial EE measure will be missed annually.[5]

"With respect to the funding cap on industrial customers, CUB is correct; the ETO's forecast presumes that the funding limitation on industrial energy efficiency measures is removed or similarly resolved to allow unfettered ongoing large customer EE funding. Should the funding limitation not be resolved, the ETO has estimated that 1.5-2 MWa of incremental industrial EE measures will be missed annually. The ETO is likely to reach its funding limit for PGE's industrial customers this year.

PGE is advocating in its General Rate Case testimony for a resolution that addresses the current large customer EE funding constraint. Losing cost effective energy efficiency opportunities would ultimately require acquisition of more expensive resource alternatives to meet long term energy and capacity needs".

D. The Energy Trust forecasts Conservation losses without a resolution to this issue.

"If incentive funding for sites in PGE territory is capped over the next five years, 8-12 aMW of savings could be lost, or 32-48 aMW over a 20-year period. Energy Trust may be able to influence changes in project timing, although if funding continues to be limited, the issue will remain. Furthermore, many large efficiency projects are scheduled as part of other planned capital improvements and might not be available if funding is not provided at the right time".[6]

0016 Reference CUB's response to ICNU Data Request 3. Is it CUB's position that the 18.4% cap on industrial energy efficiency in PGE's service territory is the same as the "direct benefit" cap established in SB 838?

[4] UE 283 PGE 1600 pg 25.
[5] LC 56 -PGE's Reply Comments at page 20.
[6] http://energytrust.org/library/reports/Brief-Energy_Efficiency_Programs.pdf, page 27-28

Response 0016: No. SB 838 requires the Commission to ensure that a large customer does "not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section." This is not a cap on direct benefits – this is a prohibition on large industrial customers from receiving a direct benefit from SB 838 energy efficiency programs.

When the energy efficiency section was added to SB 838, CUB was assured that it would not lead to greater subsidies from small customers to industrial customers for energy efficiency programs because the direct benefit prohibition would prevent the shifting of established public purpose funded programs to industrial customers. The 18.4 % cap on industrial efficiency was believed to be adequate to prevent an expansion of the subsidies from small customers to large industrial customers for energy efficiency programs. As CUB's testimony shows, the 18.4 % cap on industrial efficiency is no longer adequate to prevent residential and small commercial customers from significantly subsidizing large industrial customers to support the system resource of energy efficiency.

In this sense, the 18.4% cap on industrial efficiency was the tool or the methodology that was selected to ensure that subsidies were not increased and industrial customers did not receive a direct benefit from SB 838 energy efficiency programs. But that methodology has not been successful at preventing the subsidy from growing to a point that it is significant. Industrial customers are clearly receiving a direct benefit from the lower cost resources that are being acquired through SB 838 energy efficiency programs, even though SB 838 prohibits such a direct benefit.

Sincerely,

Jaime McGovern, Ph.D.
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Advice 07-25
PGE Response to CUB Request No. 001
Attachment 001-C

From: "Fred Gordon" <fred@energytrust.org>
To: "KOHO Lori G." <Lori.Koho@state.or.us>, "Jones JR, Don (DSM)" <Don.Jones_JR@PacifiCorp.com>, "Joe Barra" <Joe.Barra@pgn.com>, "Laura Rooke" <Laura.Rooke@pgn.com>, "Julie Brandis" <julie@aoi.org>, "Michael B. Early " <mearly@icnu.org>, "Steve Lacey" <steve@energytrust.org>
Date: Tuesday, August 14, 2007 6:46 PM
Subject: Proposal for tracking expenditures for efficiency above and below 1 AMW/customer
CC: "Margie Harris" <margie@energytrust.org>, "John Volkman" <John.Volkman@energytrust.org>, "Linda Rudawitz" <Linda.Rudawitz@energytrust.org>, "Jill Steiner" <jill.steiner@energytrust.org>, "Matt Braman" <matt.braman@energytrust.org>

Pursuant to our last working group meeting at the PUC, I have met with PGE and Pacificorp to develop a proposal for how Energy Trust will assure that new efficiency funds under SB838 will go to the customers, as a group, who provide the funds. The attached proposal was developed with the active participation of PGE and Pacificorp. Due to time limitations and my illness, they have not seen the modest revisions in this draft. I hope and believe that the revisions are consistent with their preferences as stated in our meeting last Thursday. I will take responsibility for any needed corrections.

This document presents the proposal in three levels of detail- first in concept, then a summary of tasks to make it happen, then a detailed nuts-and-bolts description of what ET and the utilities would need to do under each task. I hope the detailed description can be taken as approximate, as the details will likely evolve slightly as we try to execute them. The details were developed to test the feasibility of the task set, to show that the method is reasonable and fair and as precise as practical, and to clarify likely assignments for utilities, ET planning staff and ET program operations.

If this proposal has the principles about right, I would be happy to take any further comments as needed to finalize it as soon as possible, as this agreement is the first step on a critical path to developing a filing. Agreement on these principles will define analytic work needed at the utilities and Energy Trust. I look forward to your comments.

If you think it necessary to meet individually or collectively to fully understand or to finalize this, let me know and I will work with the PUC staff to arrange it as quickly as possible.

Fred Gordon
Energy Trust of Oregon, Inc.
Director of Planning and Evaluation
phone: 503-445-7602
fax: 503.546.6862

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Portland, OR 97204
www.energytrust.org

STRAW MAN PROPOSAL FOR ADDRESSING REQUIREMENTS IN SB838 NOT TO INCREASE EFFICIENCY EXPENDITURES ON CUSTOMERS > 1 AMW

Summary: This is a draft proposal for an administrative system that assures that SB838 efficiency funding does not result in additional funding for customers who are not providing the funding. Specifically it assures that the Energy Trust (ET) will not, on a cumulative basis, spend a larger percentage of SB1149 money on incentives for all customers over 1 AMW than it expected to spend prior to the passage of SB838, This will not be more than it has spent on these customers historically. Additionally, SB838 money will not go directly to equipment over 1 AMW. Compliance is assured through the following system:

- A control percentage of spending > 1 AMW is established by reviewing the data for the past three years and reviewing forecasts of spending.
- If ET incentive spending for customers > 1AMW exceeds this percentage over a cumulative period (from the beginning of SB838 efficiency funding for that utility to the end of the last calendar year) then ET would be required to reduce spending on larger projects in the ensuing two calendar years to bring the cumulative total back into balance with the control percentage. This assures fairly while minimizing accounting costs. This system also provides the flexibility for the Energy Trust to pursue large, low cost projects by making balancing adjustments in later years.
- Cumulative compliance with the historic average is analyzed annually at the time of the annual report, and is also forecast each year as part of the budget process.

PUC performance metrics would be based on the combined funding from SB1149 and SB838. However, as needed, ET would describe cost and savings under each bill.

Basic Tasks. Steps to achieve these tasks are introduced in this section and detailed in the next section

1. **Define Boundary.** "1 AMW Per meter, totalized meter, or site or what?" We propose that to start the "customer" be defined as the meter so that the process can begin, but customers can propose "sites" consistent with the self-direct definition and utilities will certify and use these. Sites currently certified sites for self-direct are defined as "customers" from the beginning. An approach to estimation for new buildings is also developed in the detailed discussion below.

2. **Utilities will Project Load & Resource Potential from Customers Smaller than 1 AMW.** As requested ET can help utilities with the analysis. ET will need load data provided by utilities once the boundary definition is set, to analyze efficiency resources..

3. **Describe Historic ET Spending Patterns.** ET will develop an analysis of historic ET incentive funding by <1 and > 1 AMW, with data from utilities as needed.

4. **ET Develops Control Percentage.** This is the maximum percent of SB1149 funding to go to meters > 1 AMW. Two options for doing this are presented in the next section.

5. **ET will develop and Implement a Management Approach.** ET will develop systems to assure that over a multi-year period overall funding for customers >1 AMW does not exceed these trend forecasts, and to correct for temporary overages.

6. **Reporting.** ET will report on how it will stay within these bounds in two ways:

    a. As part of our budget process, we will forecast spending by program above and below 1 AMW.
    b. As part of our annual report process, we will report on how it went for the prior year and cumulatively from 2008 forward.
    c. If required by the legislature we will also report on spending and savings separately for SB838 funds and SB1149 funds. However the separation will be approximate, and will require agreement on assumptions.

Detailed Tasks:

1. ***Define Boundary.*** We propose that to start the "customer" be defined as the meter so that the process can begin, but customers can propose "sites" consistent with the self-direct definition and utilities will certify and use these. Customer with currently certified sites for self-direct would be defined in their entirety as "customers" from the beginning. This approach is proposed because
   - It is consistent with the self-direct program and thus will minimize customer confusion.
   - It also prevents utilities from needing to perform all the analyses to certify sites prior to the proposal for new funding, which would cause significant delay.
   - It also avoids the confusion which would occur if an analysis would require splitting efficiency measures between meters. Some measures save energy on multiple meters, and some customers do not know what loads are on which meter.

   Another issue is what to do with new buildings. The utilities have to figure this out to classify the buildings for rates- so we assume that ET will follow their lead. Options include:
   a. *Treat them all as <1 AMW since their historic load is zero* (convenient but not equitable; they would reap the benefits and not pay)
   b. *Use the projected connected load/meter that they provide to the utility x a standard load factor.* We could brainstorm with the utilities what the standard load factors are for various building types. Utilities need to classify by connected load anyway, the only new part is the load factor.

   Energy Trust may contract with some facilities for efficiency years before there's a utility capacity estimate or rate classification. We sometimes may need to rough out a pre-guess at the classification for purposes of forecasting spending in the two groups. Mistakes are not that big a deal as long as we can correct later.

2. **Utilities will Project Load &Resource Potential Below 1 AMW.**
   a. Utilities will provide total load by class of customer and utility < 1AMW and > 1 AMW for 2006.
   b. Utilities will apply this data to define the load in the rate class or other rate discriminator for the new charge..

   Utilities will also use this to update their their resource assessment to develop potential savings for each group by utility. This will influence the size of funding (depends on timing) Energy Trust will assist as requested.

3. **Describe Historic ET Spending Patterns.** Identify the % of ET incentive dollars in past three years which are >1 AMW per customer.. If the proposal above is accepted and customers will eventually be defined as sites consistent with the self-direction definition, ET will use functional sites as the basis for analysis, ET will
   a. Provide utilities with a list of participating customers, all of whom have signed releases allowing access to energy use information.
   b. Ask utilities to identify the subset with meters that fit the "large" definition".
   c. To provide energy use data consistent with the existing data-sharing agreement for all meters.
   d. For sites with a "large" meter, Energy Trust will assume that the entire site will eventually be certified as "large" and will allocate the entire incentive expenditure for site to the "large" category.

   ET will summarize the percent of SB1149 efficiency expenditures by year and for the total three year period which went to customers >1 AMW, both in total and by program. The total three-year all-program percentage would be used as the "control percentage". Data by program or year would be used only to help in forecasting and program planning.

4. **ET Develops Control Percentage**.
    a. ***Adjust for Forecast***. In early 2007, ET forecasted trends in spending by sector through 2012. The historic percentage could be adjusted for these trends. This would modestly decrease the amount of spending allowable for customers > 1 AMW. This would make the control percentage consistent with prior intent.
    b. Forecast only runs through Feb, 2012. After that point, the control percentage would be frozen.

5. **ET will develop and Implement a Management Approach.**
    a. Track % of ET incentive $ in each year which is going to customers > 1AMW.
        i. ET Develops a field in Fast Track database for utility rate class, which should track MW status. This field should be set up to record successive annual reclassifications provided by utilities.
        ii. Develop crystal report or other reporting tool which analyzes $ of incentives going to > 1 AMW by program. Report should work for both forecasting and reporting after the fact..
    b. Train PDCs and/or ATACs (ET contractors who work with the site) to identify when a project may be on a meter>1 AMW, and then identify the meter and have ET check the rate. ET must then directly acquire the load data, which is now done by the Program Management Contractor.
        i. This will involve some back-and-fill for projects where the project or study is already approved, but the project will be completed in 2008 or beyond.
        ii. This will need to become a key element of quality control and acceptance procedures for projects.
    c. Pro Rate Site Incentives to have the correct amount in < 1AMW and > 1AMW categories in the tracking system. . For customers who have projects covering multiple meters but have not certified a site. (We hope this is rare) We will need to train contractors to define a site consistently with the utility definition, and identify all meters. The contractor will work with ET personnel to come up with a pro-rate between large and small meters for the site. This will not impact how ET treats the site, but will influence allocation of costs from that site to large vs. small.
    d. ***Alternative to c: Identify Projects by Meter.*** For sites with large and small meters, require consumers and contractors to identify new potential projects by meter, as best they can.
        i. Where a measure serves more than one meter, the audit contractor and customer should estimate savings by meter the best they can, and use that to pro-rate costs. This will be problematic as a policy and not recommended because customers may not know what equipment is on which meter.

6. **Reporting**
    a. ***Savings reporting*** by SB838 versus SB1149 would be based on the same data and methods describe above. Once we track and pro rate we can report
    b. For ***cost reporting***, there are two options:
        i. *Option 1*. Assume that average cost/kwh is the same for both piles of money. For overall reporting, assign costs in proportion to savings by program. This is simple, but would result in reports of increased cost/kWh for SB1149, and probably understate costs for SB838. This is not recommended.
        ii. *Option 2*. Assume that cost/kwh for SB 1149 would remain same as 2007. Allocate costs above (SB1149 new kwh x 2007 costs) this level to SB838. This is recommended.
            1. Detail issue: use 07 forecasts or 06 annual report? Maybe 06 to prevent dust-up when 07 is not exactly as predicted.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

EXHIBIT ICNU/303

COMPANY RESPONSES TO ICNU DATA REQUESTS

August 13, 2014

March 20, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 027
Dated March 6, 2014

Request:

Does PGE see any barriers over the next 5 years to achieving all cost effective energy efficiency contained in the IRP?

Response:

Yes, PGE does foresee potential barriers within the next five years to achieving all cost-effective energy efficiency (EE) in the IRP. To highlight one such barrier and as discussed in PGE's Response to CUB Data Request No. 026, large-user funding limitations could become a barrier to achieving all cost-effective EE savings in that business sector. Project interest for this customer group has been much higher in the past three years than the years against which the funding cap is measured. We expect this trend of interest to remain steady or increase, largely in the semiconductor industry, hospitals, and colleges and universities with a range of cost-effective projects.

May 6, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 037
Dated April 23, 2014

Request:

Does the Company have predictions for the SB 1149 and SB 838 funds in 2015. If so, please provide them (a) SB 1149 funds broken down by customer class and (b) SB 838 funds broken down by customer class.

Response:

Attachment 037-A contains 2015 projections of both SB 1149 (Schedule 108) and SB 838 (Schedule 109) collections by rate schedule. For the SB 1149 projections, PGE presumed a January 1, 2015 on-line date for both Port Westward 2 and Tucannon River.

Rate Schedule	2015 SB 1149 Amount
Schedule 7	$26,423,221
Schedule 15	$109,524
Schedule 32	$5,239,857
Schedule 38	$180,309
Schedule 47	$98,694
Schedule 49	$259,070
Schedule 83	$7,581,648
Schedule 85	$7,523,811
Schedule 89	$1,584,333
Schedule 90	$1,724,197
Schedule 91/95	$540,061
Schedule 92	$8,026
Schedule 485	$403,213
Schedule 489	$256,089
Total	$51,932,052

July 30, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 142
Dated July 22, 2014

Request:

For each of the last ten years, please identify the total amount (in terms of dollars) of revenue PGE provided to the Energy Trust of Oregon to fund energy efficiency measures (please exclude funding earmarked for other ETO projects). Please separately identify the amount that represents SB 1149 dollars and the amount that represents SB 838 dollars.

Response:

Please reference Attachment 142-A for SB 838 amounts and Attachment 142-B for the SB 1149 amounts.

Energy Efficiency Funding - SCHEDULE 109

2008	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected						424,709.05	1,075,654.80	1,099,514.57	1,093,167.55	1,011,464.74	1,037,816.20	1,218,270.30	6,960,597.21
Uncollectible						(1,704.36)	(4,316.60)	(4,412.35)	(4,848.20)	(4,485.85)	(4,602.71)	(5,805.06)	(30,175.13)
Remittance	-	-	-	-	-	423,004.69	1,071,338.20	1,095,102.22	1,088,319.35	1,006,978.89	1,033,213.49	1,212,465.24	6,930,422.08
2009	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	1,506,202.89	1,290,742.48	1,264,145.82	1,130,646.20	997,876.60	1,010,406.28	1,023,179.50	1,174,138.73	1,062,515.39	992,677.15	1,052,393.05	1,330,470.08	13,835,394.17
Uncollectible	(7,177.06)	(6,150.39)	(6,180.41)	(5,527.73)	(4,878.62)	(4,939.88)	(5,359.41)	(6,150.14)	(5,226.51)	(4,882.98)	(5,176.72)	(6,830.63)	(68,480.48)
Remittance	1,499,025.83	1,284,592.09	1,257,965.41	1,125,118.47	992,997.98	1,005,466.40	1,017,820.09	1,167,988.59	1,057,288.88	987,794.17	1,047,216.33	1,323,639.45	13,766,913.69
2010	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	1,681,912.96	1,831,048.42	1,713,662.74	1,612,118.88	1,503,813.46	1,750,803.66	2,093,777.13	2,256,416.50	2,150,790.75	2,017,673.98	2,195,915.74	2,698,722.96	23,506,657.18
Uncollectible	(8,634.94)	(9,400.60)	(8,520.33)	(8,015.46)	(7,476.96)	(7,936.39)	(9,491.09)	(10,228.34)	(9,297.87)	(8,722.40)	(9,492.94)	(11,518.15)	(108,735.47)
Remittance	1,673,278.02	1,821,647.82	1,705,142.41	1,604,103.42	1,496,336.50	1,742,867.27	2,084,286.04	2,246,188.16	2,141,492.88	2,008,951.58	2,186,422.80	2,687,204.81	23,397,921.71
2011	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	2,884,237.22	2,591,139.62	2,624,890.14	2,286,873.17	2,105,726.10	2,036,665.78	2,014,948.89	2,162,966.11	2,221,738.35	2,023,787.90	2,228,587.06	2,716,953.89	27,898,514.23
Uncollectible	(12,309.92)	(11,058.98)	(11,854.00)	(10,327.52)	(9,509.46)	(8,594.73)	(8,503.08)	(9,127.72)	(10,344.41)	(9,422.76)	(10,376.30)	(12,022.52)	(123,451.40)
Remittance	2,871,927.30	2,580,080.64	2,613,036.14	2,276,545.65	2,096,216.64	2,028,071.05	2,006,445.81	2,153,838.39	2,211,393.94	2,014,365.14	2,218,210.76	2,704,931.37	27,775,062.83
2012	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	3,670,661.55	4,026,225.40	3,831,062.40	3,384,201.38	3,072,178.68	3,021,766.72	3,164,515.38	3,298,800.93	3,283,816.08	3,033,402.78	3,275,381.90	3,922,185.15	40,984,198.35
Uncollectible	(16,242.68)	(17,816.05)	(16,055.98)	(14,183.19)	(12,875.50)	(13,724.86)	(14,373.23)	(14,983.15)	(17,975.61)	(16,604.85)	(17,929.44)	(16,261.38)	(189,025.92)
Remittance	3,654,418.87	4,008,409.35	3,815,006.42	3,370,018.19	3,059,303.18	3,008,041.86	3,150,142.15	3,283,817.78	3,265,840.47	3,016,797.93	3,257,452.46	3,905,923.77	40,795,172.43
2013	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	4,844,489.23	4,650,345.50	4,226,700.25	3,857,869.62	3,668,170.73	3,649,967.92	3,928,210.80	4,041,299.86	4,041,561.52	3,644,599.95	3,817,118.31	5,222,503.16	49,592,836.85
Uncollectible	(20,085.25)	(19,280.33)	(17,278.75)	(15,770.97)	(14,995.48)	(14,077.93)	(15,151.11)	(15,587.29)	(14,052.51)	(12,672.27)	(13,272.12)	(17,683.40)	(189,907.41)
Remittance	4,824,403.98	4,631,065.17	4,209,421.50	3,842,098.65	3,653,175.25	3,635,889.99	3,913,059.69	4,025,712.57	4,027,509.01	3,631,927.68	3,803,846.19	5,204,819.76	49,402,929.44
2014	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	5,189,572.46	4,794,270.27	4,300,282.66	3,857,900.54	3,693,624.43	3,618,435.02							25,454,085.38
Uncollectible	(17,571.89)	(16,233.40)	(14,612.36)	(13,109.15)	(12,550.94)	(12,928.67)							(87,006.41)
Remittance	5,172,000.57	4,778,036.87	4,285,670.30	3,844,791.39	3,681,073.49	3,605,506.35	-	-	-	-	-	-	25,367,078.97
TOTAL June 2008 - YTD 2014	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Amount billed/collected	19,777,076.31	19,183,771.69	17,960,744.01	16,129,609.79	15,041,390.00	15,512,754.43	13,300,286.50	14,033,136.70	13,853,589.64	12,723,606.50	13,607,212.26	17,109,105.54	162,778,197.99
Uncollectible	(82,021.74)	(79,939.75)	(74,501.83)	(66,934.02)	(62,286.96)	(63,906.82)	(57,194.52)	(60,488.99)	(61,745.11)	(56,791.11)	(60,850.23)	(70,121.14)	(709,775.81)
Remittance	19,695,054.57	19,103,831.94	17,886,242.18	16,062,675.77	14,979,103.04	15,448,847.61	13,243,091.98	13,972,647.71	13,791,844.53	12,666,815.39	13,546,362.03	17,038,984.40	162,068,422.18

Note: Billing for program was initiated mid June 2008.

Energy Trust of Oregon - Conservation													
MONTH / YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YEAR-TO-DATE
2004	2,015,295.24	1,939,185.58	1,719,732.35	1,605,169.50	1,513,468.13	1,584,377.54	1,664,738.10	1,716,022.63	1,765,416.90	1,563,599.16	1,618,741.27	1,899,135.99	20,604,882.39
2005	2,097,525.58	1,886,136.99	1,778,874.54	1,736,003.64	1,624,344.71	1,632,069.82	1,617,230.33	1,783,809.95	1,752,086.50	1,652,082.05	1,606,512.61	2,103,365.56	21,270,042.27
2006	2,152,327.66	2,130,305.30	2,025,543.15	1,810,953.37	1,697,874.65	1,700,094.25	1,831,253.32	1,865,045.72	1,837,591.54	1,783,207.06	1,735,576.43	2,104,439.89	22,721,457.99
2007	2,460,334.41	2,288,903.57	2,093,926.82	1,915,104.39	1,806,263.47	1,899,976.14	2,122,985.42	2,154,028.52	2,070,427.37	2,023,704.91	2,183,865.70	2,447,920.13	25,467,440.86
2008	2,728,280.31	2,462,725.80	2,389,316.35	2,232,226.09	2,079,582.92	2,004,530.58	2,098,175.93	2,120,618.90	2,056,567.78	1,974,984.45	2,003,193.86	2,236,844.41	26,387,047.38
2009	2,778,935.67	2,572,090.40	2,404,169.27	2,205,095.50	1,964,631.38	1,945,723.21	2,038,859.22	2,311,188.16	2,114,281.82	2,002,015.66	2,095,786.63	2,536,021.87	26,968,798.79
2010	2,802,172.52	2,360,497.67	2,374,622.54	2,201,903.57	2,058,839.59	2,056,007.75	2,089,969.83	2,233,522.96	2,146,644.99	2,026,083.21	2,179,477.26	2,538,307.98	27,068,049.87
2011	2,776,973.21	2,606,150.77	2,605,180.72	2,341,970.21	2,195,423.94	2,134,608.35	2,243,263.40	2,253,490.84	2,348,904.28	2,178,641.51	2,287,854.69	2,725,666.56	28,698,128.48
2012	2,892,839.65	2,620,307.73	2,502,217.46	2,309,531.22	2,092,155.39	2,063,923.52	2,166,265.39	2,182,204.45	2,209,036.89	2,130,405.84	2,225,104.17	2,577,833.28	27,971,824.99
2013	2,782,804.74	2,360,709.07	2,235,951.47	2,072,721.54	2,047,128.50	1,974,726.35	2,091,302.29	2,065,387.97	2,184,065.56	1,998,758.98	2,093,016.01	2,741,384.40	26,647,956.88

July 30, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 145
Dated July 22, 2014

Request:

Please reconcile PGE's testimony that the 18% industrial energy efficiency cap will be reached in 2014 (PGE/1600 at 25:2) with its May 21, 2014 filing (Advice No. 14-08), which reduced Schedule 109 energy efficiency funding by $4 million and claimed that "[d]espite this level of reduction in annual funding, the ETO estimates that it can still achieve its forecasted energy efficiency savings goals of 37.6, 34.0, and 30.6 average megawatts for the years 2014-2016 respectively."

Response:

PGE objects to this request on the basis of ambiguity and relevance. Without waiving its objection, PGE responds as follows:

The ETO informed PGE that the industrial EE cap might be reached in 2014. Subsequent communications with the ETO now indicate that the cap may be reached in 2015 rather than 2014. Please reference PGE's Response to ICNU Data Request No. 147 for more information.

Regarding PGE Advice 14-08, PGE relied on the statements made by the ETO regarding the level of funding needed to achieve their energy efficiency goals. As stated in the transmittal letter to this filing, one reason for the reduction in Schedule 109 funding was to reduce the amount of funds that were carried over from prior periods.

August 1, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 147
Dated July 22, 2014

Request:

Please provide copies of all documents prepared by PGE in the last 5 years that refer or relate to: a) energy efficiency funding provided by customers over 1 aMW, b) energy savings due to energy efficiency measures implemented by customers over 1 aMW, c) the cap on investment in energy efficiency resulting SB 838, or d) the potential energy efficiency projects and energy savings available by rate class or rate schedule.

Response:

PGE objects to this request as overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

PGE requested information from employees from the following departments: Rates & Regulatory Affairs, Integrated Resource Plan, and Customer Mass Programs. Attachment 147-A contains the material related to this request.

The documents included in Attachment 147-A include the notes from various ETO Conservation Advisory Council meetings, a summary of some of those meetings, and early 2013 results for PGE from the ETO that contain an estimate of the potential lost conservation opportunities due to the one average megawatt cap.

Further information may be found at the Energy Trust of Oregon's website:
http://energytrust.org/About/public-meetings/CACMeetings.aspx
http://energytrust.org/About/public-meetings/BDMeetings.aspx

August 1, 2014

TO: Bradley Van Cleve
Bradley Mullins
Ali Al-Jabir
Michael Gorman

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 148
Dated July 25, 2014

Request:

Please provide all documents in PGE's possession that memorialize or in any way refer to the 18.4% industrial cap on energy efficiency funding.

Response:

PGE objects to this request on the basis of ambiguity. PGE is uncertain what is meant by "memorialize." Without waiving its objection, PGE responds as follows:

Please reference PGE's Response to ICNU Data Request No. 147.

August 7, 2014

TO: Bradley Van Cleve
Bradley Mullins
Michael Gorman

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 169
Dated July 29, 2014

Request:

Reference PGE/1900, Greene/9: Please provide an explanation of why Table 3, Column "Tucannon + Base", Row "a" contains total current taxes (before tax credits) for the 2015 test year of $34.3 million, yet PGE Exhibit 1701 contains total current taxes (before tax credits, including Tucannon River and Port Westward II) of $81.1 million

Response:

Attachment 169-A contains a reconciliation between the $34.3 million in Table 2 of PGE Exhibit 1900 and the $81.1 million in PGE Exhibit 1701. The 'Deferred Ms' for Tucannon in PGE Exhibit 1701 were inadvertently included as $71.7 million rather than $156.2 million. The amount of accumulated deferred income taxes corresponding to the $156.2 million was already included as a reduction to PGE's rate base in this filing and as such this change has no bearing on revenue requirement, but does reduce the $81.1 million in this comparison to $53.8 million. We then remove Port Westward 2 which is not included in PGE Exhibit 1900, Table 2. Finally, we adjust pre-tax book income for deductions not included in PGE's revenue requirement.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
	)

EXHIBIT ICNU/304

ENERGY TRUST OF OREGON, "FUNDING LIMITATIONS FOR LARGE ENERGY USERS" (APRIL 16, 2014)

August 13, 2014

Funding Limitations for Large Energy Users

History of the Methodology Used in Determining the Limit and Current Status

April 16, 2014

Background

The 1999 Oregon law that gave rise to Energy Trust, SB 1149, required the electric utilities to devote three percent of their revenues to electric efficiency programs. The three-percent charge is collected from all electric customers regardless of the amount of energy they use. A 2007 state law, SB 838, authorized electric utilities to add an additional amount to the bills of all customer sites with usage less than or equal to 1aMW. The resulting funds are to be used to fund electric efficiency beyond the established public purpose charge from SB 1149, to meet efficiency resource needs identified in utility integrated resource planning.

Because larger customers are not paying in to the 838 fund, they are ineligible for efficiency program funding from 838. Language describing this efficiency funding mechanism in legislation reads as follows;

> SECTION 46.
> (1) In addition to the public purpose charge established by ORS 757.612, the Public Utility Commission may authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures implemented on or after the effective date of this 2007 Act. The costs may include amounts for weatherization programs that conserve energy.
> (2) The commission shall ensure that a retail electricity consumer with a load greater than one average megawatt:
>> (a) Is not required to pay an amount that is more than three percent of the consumers' total cost of electricity service for the public purpose charge under ORS 757.612 and any amounts included in rates under this section; and
>> (b) Does not receive any direct benefit from energy conservation measures if the costs of the measures are included in rates under this section.

Large energy users are both commercial and industrial customers that span the mix of market segments from hospitals, higher education campuses and commercial real estate to food processing, cold storage facilities, metals, forest products, semiconductors and other manufacturing.

As a way of assuring that large customers are not benefitting from this added funding, a 2008 informal multiparty agreement set a limit to the percentage of 1149 incentive funding that Energy Trust can allocate to customers over 1 aMW.

Funding Limit Methodology

One of the first steps in implementing 838 efficiency funding was to set up processes for ensuring that large energy users were not charged and did not receive direct benefit from funds collected. This development of a process to limit benefits was never a question of setting a dollar in (revenues from large customers) to dollar out (expenditures on large customers) measure but rather to find a way to set a reasonable level of spending for large users that made sure they were not benefiting from 838 funding.

1. Defining the baseline "pre-838"

To ensure that those that are not contributing are not directly benefiting was interpreted as meaning that the “pre-838” spending practices should not be exceeded going forward. The baseline spending was defined as project incentives paid to >1aMW sites compared to total 1149 efficiency revenues and are calculated on a utility specific basis. For PacifiCorp the baseline period is 2005-2007 with incentives being 27% of total 1149 revenues. For PGE, the baseline period covers 2004-2007 with incentives being 18.4% of total 1149 revenues.

The difference is representative of specific project activity that occurred during the base period; PAC territory saw many forest products projects move forward while PGE activity was largely limited to one large paper mill. A larger and growing proportion of PGE’s large customer loads are from the semiconductor industry. Energy Trust programs were not as active in that industry until “post 838”.

2. Defining the current spending, “post 838”

Determining current spending was agreed to be calculated as a rolling, cumulative look. Because large projects can have lumpy impacts on program incentive spending with year by year variability, measuring compliance on a year to year basis did not seem appropriate. The resulting methodology takes a broader perspective by summing all large energy user post 838 incentives are divided by total 1149 revenues across the same time period.

For example, to determine spending through 2012, by utility, all large user incentives from 2008-2012 are summed and divided by the total 1149 efficiency revenues by utility. PacifiCorp was 22% and PGE was 17%.

3. Determining compliance to limits

The final step is to compare the “post 838” percentage to the baseline funding limit. Through 2012 activity, PAC is 5 percentage points below the limit and PGE is 1 percentage below their limit. 2013 results are currently in draft and expected to be finalized by May 2014.

If cumulative spending reached or exceeded baseline spending, parties agreed that time would be needed for “correction” to be able to adjust program spending below the limit within 2 years.

Results to Date

Due to success of the programs serving them, savings from large customers and incentives going to them have been increasing. Strong program interest from large sites is expected to continue, leading to the potential for the current funding cap methodology to limit Energy Trust’s ability to acquire all cost effective resources. If in PGE territory we were to continue >1aMW incentive spending at a rate equal to the average of the past 3 years (2010-2012, $5.9M/yr. in incentives), we would exceed the current spending limit in 2015. Figure 1 shows year by year incentive dollars to >1aMW participants as a percent of total 1149 efficiency revenue to Energy Trust for PGE. 2008 – 2012, program demand has been consistently increasing.

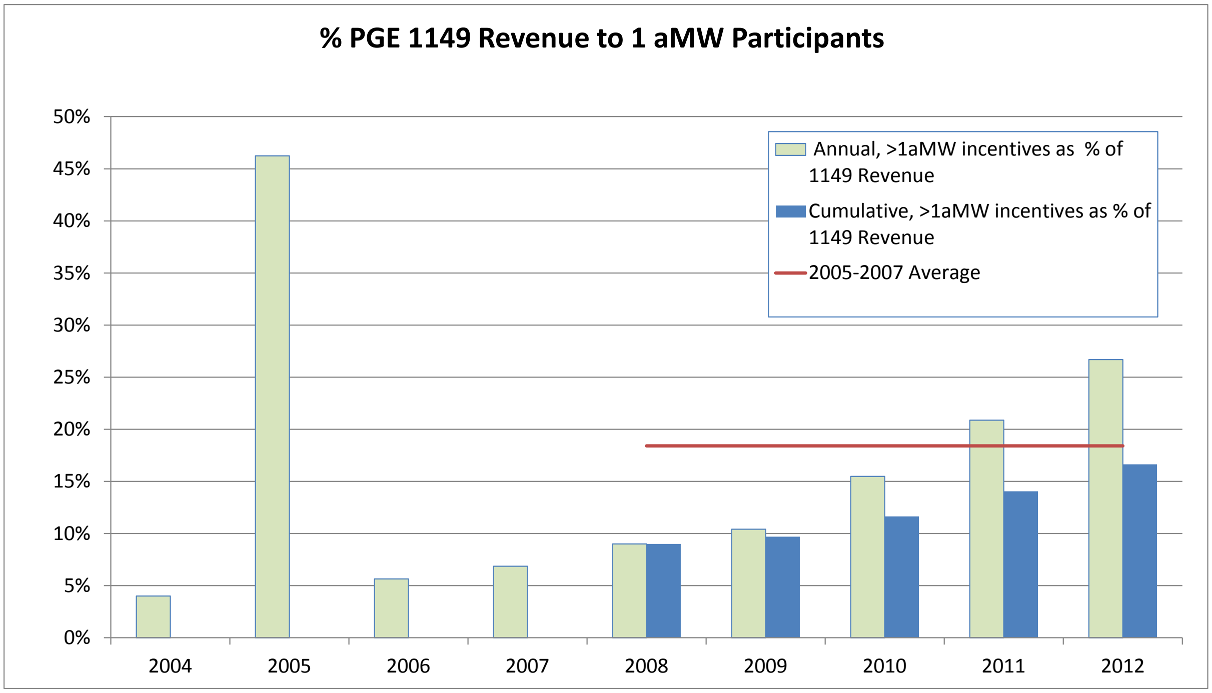

Figure 1

In PacifiCorp territory, we don't foresee a short-term risk of needing to forego resource acquisition with the current methodology and demand but PAC customers could be impacted by program designs or other changes instituted to manage funding for PGE. Figure 2 shows year by incentive dollars to >1aMW participants as a percent of total 1149 efficiency revenue to Energy Trust for PacifiCorp.

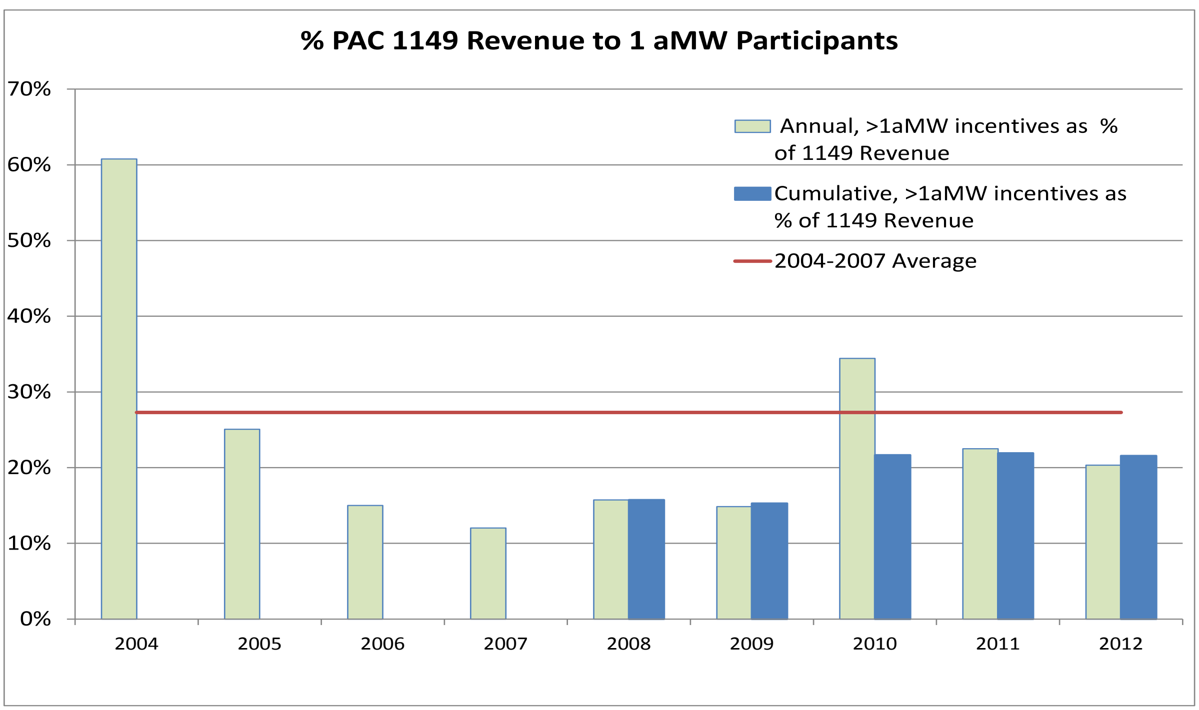

Figure 2

Possible Impacts

To reach goals we will need to redirect funds above the cap to smaller, higher cost projects from 838 eligible sites. On average, large site projects are 2.5 times more cost effective than 838 eligible site projects. Therefore directing funding away from large site projects would result in fewer savings at higher cost. It is also possible that as a consequence Energy Trust cannot acquire all cost effective resource in some years. The result may mean lost opportunity of low cost resource, unmet demand and unrealized savings. In the long run, some savings from larger sites will not be captured. This is a particular threat for "lost opportunity" savings that must be acquired during specific events, such as a major capital investment in a process line upgrade or redesign or a building renovation. A significant share of Energy Trust large customer savings comes through such events.

Outreach Efforts

In anticipation of reaching the funding limit in PGE territory before 2015, Energy Trust staff raised the topic of possible impacts on the program at the June 2013 board retreat. Program staff outlined program tactics that could be employed if we were to reach the limit and need to take actions to adjust program spending downward.
(http://energytrust.org/library/meetings/board/120607_Board_strategic_Planning_Workshop.pdf)

Energy Trust convened a meeting of stakeholders January 31, 2014 to discuss the issue and current situation. In attendance were representatives from utilities, OPUC staff, CUB, ICNU, NWFPA, NWEC, NEEC, ODOE, and Energy Trust staff. A variety of views were heard. Stakeholders offered a range of ideas to address the funding limitations including;

- Expand 838 charges to large energy users (would require legislative action)
- Revisit the methodology so that it's more reflective of current large energy user potential activity and available cost effective resource
- Change the methodology to allow more funding to large users under the condition that those paying to 838 see direct rate benefit from the low cost efficiency in which they are investing (would require rate re-design)

No consensus was reached among attendees but Energy Trust did agree to keep the group fully informed of the situation going forward.

Next Steps

Energy Trust plans to have final results of the 2013 analysis in April/May 2014. If we have met or exceeded the funding limit in PGE territory, we plan to begin to take programmatic actions to lower funding and come back into compliance over a two year period. These actions will be worked through with our Conservation Advisory Council.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

EXHIBIT ICNU/305

PINNACLE ECONOMICS, ECONOMIC IMPACTS FROM ENERGY TRUST OF OREGON 2013 PROGRAM ACTIVITIES, FINAL REPORT (MAY 5, 2014)

August 13, 2014

Economic Impacts From Energy Trust of Oregon 2013 Program Activities

Final Report

pinnacle economics

3030 NW 12th Avenue
Camas, WA 98607
(503) 816-0295

May 5, 2014

Acknowledgements

This report was prepared by Pinnacle Economics for the Energy Trust of Oregon. Alec Josephson, senior economist, was the lead economist and author of this report. Mr. Josephson has directed and/or conducted all of the previous economic impact analyses of Energy Trust programs, as well as similar analyses for the Bonneville Power Administration, Consumers Energy of Michigan, the Hawaii Public Utility Commission, the U.S. Department of Energy, and the American Council for an Energy-Efficient Economy ("ACEEE").

Table of Contents

1. Introduction and Summary

Pinnacle Economics ("Pinnacle") was retained by Energy Trust of Oregon ("Energy Trust") to estimate the economic impacts of its energy efficiency and renewable energy programs in 2013 on the Oregon economy.[1] These impacts include changes in output, wages, business income, and employment in Oregon that resulted from 2013 program spending and activities. Each year, Energy Trust programs generate energy efficiency gains (i.e., energy savings) and renewable energy generation that continue into the future. As a result, Pinnacle also analyzed the economic impacts from the current program year that accumulate in following years.

For this analysis, *gross impacts* are calculated and then compared against a Base Case spending scenario, which assumes that funds that were paid to Energy Trust are returned and spent by Oregon ratepayers in the Oregon service territories of Portland General Electric (PGE), Pacific Power, Northwest Natural, and Cascade Natural Gas. The difference in economic impacts between the gross economic impacts attributed to Energy Trust program spending and the Base Case scenario is referred to as *net impacts*.[2]

In 2013, Energy Trust spending totaled $130.3 million. This spending was primarily focused on program implementation, with $118.1 million for energy efficiency programs and $7.9 million for renewable energy programs. In addition, the Energy Trust incurred $4.3 million in administrative and program support costs during the 2013 program year. On an annual basis, Energy Trust achieved energy efficiency savings and renewable energy generation during the 2013 program year totaling 60.7 average megawatts (aMW) of electricity (531,500 MWh) and 5.3 million therms of natural gas.

The gross and net economic impacts for Energy Trust 2013 program activities are shown in Table ES1. The changes in spending and energy savings/generation associated with these programs had the following <u>net</u> economic impacts on the Oregon economy in 2013:

- An increase of $175.1 million in output;
- An increase of $60.4 million in wages and $14.7 million in income to small business owners; and
- 1,091 full- and part-time jobs.

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[1] Some of these projects also received financial and/or technical assistance through state and federal tax credit programs. Based on evaluations, Energy Trust believes their participation to be critical to these projects.

[2] An analysis of the *net economic impacts* requires that only economic stimuli that are new or additive to the economy be counted, i.e., net impacts consider both the positive economic impacts from investment in energy efficiency and the negative economic impacts of foregone spending associated with program funding. By making adjustments for program funding, net economic impacts provide a more reliable measure of job and income creation. For example, if an impact of five net new jobs is reported, this means that spending on Energy Trust programs resulted in five more jobs relative to what would have occurred had the money been returned and spent by Oregon ratepayers in the utility service territories.

Table ES1: Gross and Net Economic Impacts, 2013

Impact Measure	Gross Impacts	Net Impacts
Output	$325,550,000	$175,089,000
Wages	$106,771,000	$60,448,000
Business Income	$21,654,000	$14,705,000
Jobs	2,312	1,091

Table ES2 reports the net economic impacts for every million dollars in Energy Trust spending.[3] For the 2013 program year, every million dollars in Energy Trust spending is associated with approximately $1.3 million in new economic activity in Oregon, including $463,800 in wages, $112,800 in business income, and 8.4 jobs.

Table ES2: Net Economic Impacts Per $1 Million in Energy Trust Spending, 2013

Impact Measure	Net Impacts Per $1 Million in Spending
Output	$1,343,500
Wages	$463,800
Business Income	$112,800
Jobs	8.4

The remainder of this report documents the analysis that was completed to develop these economic impact estimates.

[3] These are "fully loaded costs" that include Energy Trust program and administrative costs, as well as incentives paid to program participants.

2. ENERGY TRUST 2013 PROGRAM ACTIVITIES

2.A. 2013 EXPENDITURES

For this analysis, budget information provided by Energy Trust was aggregated into several general categories to facilitate economic impact modeling for similar areas of spending. Table 1 shows the general areas of spending for Energy Trust and reflects actual expenditures for 2013.[4] As shown at the bottom of the table, total spending by Energy Trust in 2013 was $130.3 million.

As a general rule, spending on program incentives goes directly to equipment purchases and labor for installation. Common measures that receive incentives include high efficiency lighting, high efficiency HVAC systems, appliances, industrial process efficiency improvements, and home and commercial weatherization. Energy Trust also incurs non-incentive expenses for program delivery. In 2013, program expenditures[5] for energy efficiency measures totaled $118.1 million (a decrease of $10.2 million or -7.9 percent from previous year). Program expenditures for renewable energy resources totaled $7.9 million (a decrease of $13.9 million or -63.7 percent from 2012).

Table 1: Energy Trust Program Spending ($ millions), 2013

Spending Category	Total Program Expenses	Total Support Costs	Total
Energy Efficiency Programs	$118.1		$118.1
Renewable Energy Programs	$7.9		$7.9
Other Admin & Program Support		$4.3	$4.3
Total	**$126.1**	**$4.0**	**$130.3**

Source: Energy Trust of Oregon, "Statement of Functional Expenses"
Note: Energy Trust program spending includes $1.2 million in spending on projects in Clark County, Washington.

2.B. 2013 ENERGY SAVINGS AND GENERATION

Table 2 shows the total net energy saved and generated by Energy Trust programs in 2013. On an annualized basis, a total of 60.7 average megawatts were saved or generated as a direct result of Energy Trust program activities in 2013. This includes energy savings for both residential and commercial-industrial energy efficiency programs, as well as energy generated through Energy Trust's renewable energy program. It also includes the net energy savings attributed to market transformation effects by the Northwest Energy Efficiency Alliance (NEEA).

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[4] Energy Trust did not commission a full economic impact study for the 2012 program year. As a result, direct measures of program activity (spending and energy savings) for that year were provided by Energy Trust to provide additional context for this analysis. In addition, the economic impacts for 2012 were estimated by Energy Trust using economic impact results from the 2011 study and the level of program spending in 2012.

[5] Program expenditures are based on incentives and allocated support costs.

Table 2: Annualized Net Energy Savings and Generation, 2013

Program Sector	Annual kWh	Average MW (aMW)	Annual Therms
Residential Energy Efficiency	139,823,822	16.0	2,079,520
Commercial/Industrial Energy Efficiency	366,543,982	41.8	3,230,030
Energy Efficiency Subtotal	**506,367,804**	**57.8**	**5,309,550**
Renewable Energy	25,132,210	2.9	0
Total Energy Saved or Generated	**531,500,014**	**60.7**	**5,309,550**

Source: Energy Trust of Oregon
Notes: 1) Energy savings are reported on a net basis and have been adjusted by the Energy Trust for free-ridership, i.e., program participants who would have adopted energy efficient measures or renewable energy projects even in the absence of Energy Trust programs. 2) Net energy savings include energy savings attributed to market transformation effects by NEEA.

Electric energy savings form the bulk of net energy savings. In total, on an annualized basis, 506,368 MWh of electricity were saved as a result of energy efficiency programs in 2013. This is approximately 0.3 percent more than in 2012, when Energy Trust energy efficiency programs saved 504,602 MWh of electricity. The mix of electric energy savings across programs was approximately the same as in previous years. In 2013, commercial and industrial energy efficiency programs account for 72.4 percent of total electric energy savings (compared to 70.4 percent in 2012). Residential energy efficiency programs account for 27.6 percent of total electric energy savings in 2013 (compared to 29.6 percent in 2012).

Similar to previous years, the amount of energy generated by the renewable energy program in 2013 is relatively small compared to the energy savings attributed to the efficiency programs. In 2013, renewable energy projects generated approximately 25,132 MWh of electricity. This represents a decline of 41.1 percent from the previous program year.

The efficiency gains shown in Table 2 result in a loss of revenue to Oregon utilities due to lost power sales, and this loss of revenue is included in the gross economic impacts measured in this analysis.[6] If the utility sector had similar economic impact multipliers as other sectors in Oregon's economy, then the energy cost savings in other sectors would roughly cancel out the loss of revenue in the utility sector. For Oregon utilities, much of the spending impact flows outside the state, as Pacific Power is owned by an out-of-state company, and both Pacific Power and PGE have shareholders that are widely distributed throughout the country. Consequently, some of the revenue losses for utilities (and the resulting losses in employment and economic activity) accrue to businesses and households outside of Oregon.

[6] For this analysis, it was assumed that utilities did not sell saved power on the spot market, as estimates of the amount of power sold due to energy efficiency are generally unavailable. If utilities can sell conserved power on the market due to the efficiency programs, then there is an additional benefit in the form of increased revenues to the utility sector. As this was not included in this analysis, the results discussed here represent a lower bound for potential utility sector benefits.

There is an additional long-term benefit from the efficiency gains, as they delay the need for building new power generation. Power generated from new sources will almost certainly be more expensive than existing power resources due to increased costs of capital and issues associated with siting new power plants. In this sense, efficiency gains can be viewed as a means for prolonging the use of lower-cost resources and delaying the need for switching to higher cost power supplied by new generation. By enabling the efficient use of lower cost resources, these programs help the entire Oregon economy run more efficiently. This benefit was not explicitly modeled for this analysis because it is directly addressed in the Energy Trust's benefit/cost analysis. It is nevertheless an important issue and is one of the primary tenets underlying conservation and demand-side management programs.

3. ANALYSIS METHODS

Estimating the economic impacts attributable to Energy Trust programs is a complex process, as spending by Energy Trust—and subsequent changes in spending by program participants—unfold over a lengthy period of time. From this perspective, therefore, the most appropriate analytical framework for estimating the economic impacts is to classify them into the following categories:

- *Short-term* economic impacts associated with changes in business activity as a direct result of changes in spending by Energy Trust programs and participants.

- *Long-term* economic impacts associated with the subsequent changes in factor costs and optimal use of resources.

This analysis estimates the short-term economic impacts of Energy Trust program activities during the 2013 program year. The short-term economic impacts are those attributed to additional dollars accruing to Oregon businesses and households as a result of these programs. The economic modeling framework that best measures these short-term economic impacts is called input-output modeling. Input-output models provide an empirical representation of the economy and its inter-sectoral relationships, enabling the user to trace the effects (economic impacts) of a change in the demand for commodities (goods and services).

Because input-output models generally are not available for state and regional economies, special data techniques have been developed to estimate the necessary empirical relationships from a combination of national technological relationships and county-level measures of economic activity. This modeling framework, called IMPLAN (for IMpact Analysis for PLANning), is the technique that Pinnacle Economics has applied to the estimation of impacts.[7]

[7] IMPLAN was developed by the Forest Service of the US Department of Agriculture in cooperation with the Federal Emergency Management Agency and the Bureau of Land Management of the US Department of the Interior to assist federal agencies in their land and resource management planning. Staff at Pinnacle Economics used IMPLAN and the same modeling framework for all of our previous impact analyses for Energy Trust, as well as similar analyses conducted for the Bonneville Power Administration, Consumers Energy of Michigan, the Hawaii Public Utility Commission, the U.S. Department of Energy, and the American Council for an Energy-Efficient Economy ("ACEEE").

This analysis relies on 2012 IMPLAN data for the Oregon economy—the most current data available.

Input-output analysis employs specific terminology to identify the different types of economic impacts that result from economic activities. Expenditures made through Energy Trust programs affect the Oregon economy *directly*, through the purchases of goods and services in this state, and *indirectly*, as those purchases, in turn, generate purchases of intermediate goods and services from other, related sectors of the economy. In addition, the direct and indirect increases in employment and income enhance overall economy purchasing power, thereby *inducing* further consumption- and investment- driven stimulus. This cycle continues until the spending eventually leaks out of the local economy as a result of taxes, savings, or purchases of non-locally produced goods and services or "imports."

The IMPLAN model reports the following economic impact measures:

- *Total Industrial Output (Output)* is the value of production by industries for a specified period of time. Output can be also thought of as the value of sales including reductions or increases in business inventories.
- *Employee Compensation (Wages)* includes workers' wages and salaries, as well as other benefits such as health and life insurance, and retirement payments, and non-cash compensation.
- *Proprietary Income (Business Income)* represents the payments received by small-business owners or self-employed workers. Business income would include, for example, income received by private business owners, doctors, accountants, lawyers, etc.
- *Job* impacts include both full and part time employment. Over time, job impacts are referred to as person-years of employment.

All of the economic impacts measured in this analysis are transitory and depend on program spending and energy savings in each year. That is, economic impacts for each program year are generated by changes in final demand (spending) that can be directly or subsequently linked back to Energy Trust programs. The mix and level of program spending may change from year to year, or could end in any given year. This means that the economic impacts will also vary from year to year, or could end in any given year. This is particularly important when discussing employment impacts. Although employment impacts are reported as a mix of full- and part-time jobs, they are jobs that occur as spending occurs and should be considered person-years of employment. In addition, it is highly likely that some of the employment benefits accrue to the same individuals over time.

Within this modeling framework, the following terms are used to classify impacts:[8]

- *Gross Impacts* reflect the economic impacts with no adjustment made for impacts that might have occurred in the Base Case scenario. Gross impacts include:
    - *Program operations spending* as Energy Trust purchases labor and materials to carry out its energy efficiency and renewable energy programs.
    - *Incremental measure spending* by participants in Energy Trust programs.
    - *Reductions in energy consumption* and the associated lower operating costs to businesses and increases in household disposable income.[9]
    - *Reductions in utility revenues* as households and businesses consume less electricity and natural gas.

- *Net Impacts* are the effects of Energy Trust program activities that have been adjusted to reflect the Base Case scenario. That is, net impacts are those impacts over and above what would have occurred in the Base Case scenario. Net impacts are based on:
    - *Gross* Energy Trust program impacts (discussed above).
    - *Less foregone household spending* as a result of the public purpose charges that are collected from ratepayers and used by Energy Trust to cover program management and administrative costs, and as incentives in their energy efficiency and renewable energy programs.

4. Gross Economic Impacts

The gross economic impacts attributed to Energy Trust programs are based on the program costs (including administration costs), and the net incremental measure spending and net energy savings of program participants. Incremental measure spending by program participants consists of expenditures on energy efficiency equipment such as appliances and furnaces/boilers, heating, ventilation and air conditioning (HVAC) systems, lighting modifications, etc., and spending on renewable energy projects. In both cases, incremental measure spending includes spending on measure installation. This is important because expenditures on measure installation benefit local, Oregon contractors while spending on the measures themselves generally benefit non-local manufacturers.[10] As a result, spending on installation (labor) and equipment will produce substantially different economic impacts for the Oregon economy. Pinnacle received detailed

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[8] Both incremental measure spending and energy savings are included on a net basis, i.e., both have been adjusted to account for potential free riders. In energy efficiency programs, free riders are participants who would have adopted the energy efficiency measure or renewable energy project even in the absence of the program.

[9] Energy savings include the net energy savings associated with market transformation efforts conducted by NEEA. These effects cannot be measured on a project-by-project basis. Thus, Pinnacle Economics allocated NEEA's commercial and industrial net energy savings on a *pro rata* basis using the distribution of net energy savings, across industry sectors, for the Energy Trust's commercial and industrial programs.

[10] For some measures, the use of "margining" on equipment sales generates economic benefits (albeit modest impacts) for Oregon retailers, wholesalers, and transporters.

incremental measure spending data from Energy Trust, and mapped this spending to over 30 different IMPLAN sectors.

Energy Trust also supplied detailed energy savings estimates, broken out by fuel type (electricity, natural gas) for program participants. For residences, lower energy costs will increase Oregon households' disposable income. Therefore, the estimated energy cost savings for residential customers were input into a modified consumption function representing the spending pattern of a middle-income household in Oregon, which mapped the spending to over 400 IMPLAN sectors.[11]

Energy savings for commercial-industrial program participants were first mapped to industry sector using North American Industrial Classification System ("NAICS") codes, and then cross-referenced to 237 different business sectors in the IMPLAN model.[12] From an input-output perspective, energy savings will affect Oregon businesses by lowering their production costs. To estimate the economic impacts associated with these lower energy costs, Pinnacle used an elasticity-based approach to estimate the change in output. That is, this approach assumes that lower energy costs increase the competitiveness of Oregon businesses, allowing them to decrease price, and increase output.[13]

Lastly, the energy savings for households and businesses translate into lower revenues to electric and natural gas utilities. Pinnacle used estimated energy savings, by fuel type, to reduce revenues to utilities. The gross economic impacts of Energy Trust programs for 2013 are shown in Table 3.

Table 3: Gross Economic Impacts, 2013

Impact Measure	Gross Impacts
Output	$325,550,000
Wages	$106,771,000
Business Income	$21,654,000
Jobs (person-years)	2,312

Sources: Pinnacle Economics using detailed Energy Trust program data and IMPLAN.

In 2013, spending and energy savings attributed to Energy Trust programs increased economic output in Oregon by $325.6 million, including increases of $106.8 million in wages and

[11] This consumption function was modified to exclude spending on electricity and natural gas.

[12] Over time, Energy Trust's commercial and industrial energy efficiency programs have expanded to more industry sectors. In 2006, energy savings were allocated to 100 industry sectors in the IMPLAN model. In this analysis, energy savings for commercial and industrial program participants are mapped to 237 industry sectors. This is modestly less than in 2010, when energy savings were mapped to 267 different business sectors, but still represents a 137 percent increase since 2006.

[13] Because we do not have elasticity coefficients for each of the 237 business sectors (and their commodities) that benefited from reduced energy costs, Pinnacle uses unitary elasticity, i.e., a 1 percent decrease in costs translates into a 1 percent increase in output.

$21.7 million in business income. This activity also supported 2,312 jobs in Oregon. Table 3, however, reports gross impacts that do not take into consideration alternative uses of Energy Trust and participant spending related to these programs. These net impacts are addressed in the next section.

5. NET ECONOMIC IMPACTS

All of the economic impacts reported in this section of the report are *net impacts* and reflect economic benefits over and above what would have occurred had Energy Trust programs not existed. To calculate net impacts, the economic impacts of the Base Case scenario are estimated first, which assumes that the money that is currently spent on Energy Trust programs is instead reallocated to, and spent by, utility ratepayers. The economic impacts resulting from the Base Case scenario are then subtracted from the gross impacts discussed in the previous section to determine net impacts.

Table 4 shows the net economic impacts attributed to Energy Trust programs in 2013. The net economic impacts are positive and (by design) significantly less than the gross economic impacts reported previously. The gross economic impacts include the assumption that revenues to utilities and other providers of energy services decline as a result of the energy savings by households and businesses. To this, we have now included the Base Case spending scenario that assumes that all Energy Trust funds are instead spent by ratepayers of the utilities according to the spending patterns of a typical Oregon household.

For 2013, Energy Trust programs had a net effect of increasing Oregon's economic output by $175.1 million relative to the Base Case scenario. This includes an increase of $60.4 million in wages and $14.7 million in business income within Oregon. Energy Trust programs also had a positive net impact on employment in Oregon, with 1,091 jobs sustained by Energy Trust program activities in 2013. This reflects jobs over and above what would have been created in the Base Case scenario, i.e., in the absence of Energy Trust's energy efficiency and renewable energy programs.

Table 4: Net Economic Impacts, 2013

Impact Measure	Net Impacts
Output	$175,089,000
Wages	$60,448,000
Business Income	$14,705,000
Jobs (person-years)	1,091

Sources: Pinnacle Economics using detailed Energy Trust program data and IMPLAN.

6. ECONOMIC IMPACTS ACROSS ALL PROGRAM YEARS, 2002 THROUGH 2013

An important dimension of energy efficiency programs is that energy savings and the associated economic impacts continue to benefit the economy after the first program year, when spending and installations occur, as most measures have estimated useful lives of eight to 20 years, or more.

The cost savings from these measures for homes and businesses also extend into future years (with some degradation as equipment ages and some increase in savings as rates increase) after the initial purchase. These cost savings continue to benefit the economy, as households spend less on electricity and natural gas and more on other consumer products, and businesses are able to produce goods and services more efficiently. As a consequence, the net effects from the first year when the equipment and program spending occur only capture a fraction of the overall benefit of these programs.

Table 5 shows the annualized economic impacts due to energy cost savings from energy efficiency measures installed in 2013. These estimates were calculated using the input-output model to estimate the economic impacts of reduced energy costs while setting all other costs (i.e., equipment purchases and program implementation costs) equal to zero. To truly isolate the impact of the energy cost savings, we also assumed that there are no lost utility revenues resulting from the measures installed and that utilities would be able to sell the unused power to other customers. This provides an estimate of energy efficiency benefits based solely on the reduced energy costs to the economy and excludes any additional benefits due to the spending on these programs and measures.

Table 5: Annualized Economic Impacts Due to Energy Savings Alone, 2013

Impact Measure	Impact Due to 2013 Energy Savings
Output	$66,694,000
Wages	$20,570,000
Business Income	$2,410,000
Jobs	538

Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Notes: 1) Energy savings impacts are based on both electric and natural gas savings, and include the net energy savings attributed to NEEA's market transformation efforts. 2) Energy savings impacts do not include energy generation attributed to Energy Trust's renewable energy program.

To be consistent with previous impact reports, the energy savings impacts shown in Table 5 are reported on an annualized basis, i.e., they describe the economic impacts from energy savings for energy efficiency measures that were installed in 2013 and operated for an entire year. In the first program year, energy savings develop as energy efficiency measures are installed, and installation occurs over the course of the year. Pinnacle does not have data on when each individual installation was completed. Thus, we have assumed that installations occur evenly throughout the year and have used a 50 percent implementation adjustment factor for energy savings in the first program year. (The economic impacts shown earlier in this report are based on energy savings that have been adjusted using this implementation adjustment factor.)

Energy Trust first introduced its energy efficiency and renewable energy programs in Oregon in 2002. Thus, the 2013 program year represents the 12th year of program activity in this state. This section of the report looks at the net energy savings and net economic impacts over this 12-year period.

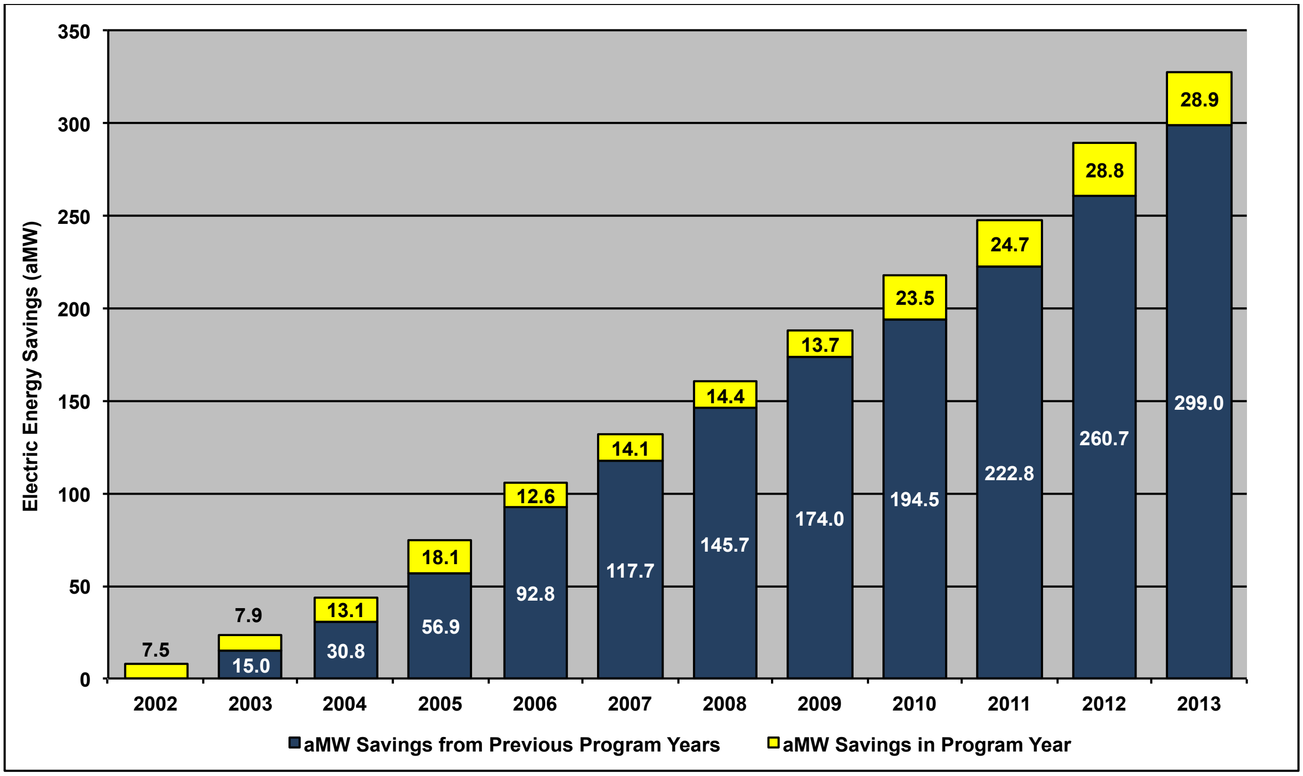
Program year impacts include the net economic impacts associated with net energy savings adjusted for measure implementation (i.e., 50 percent of the annualized net energy savings), and program and participant spending. **Future out-year impacts** are based on the annualized net energy savings installed in each program year with adjustments for the following:

- **Measure Estimated Useful Life (EUL).** To account for the Estimated Useful Life of installed measures, Energy Trust supplied a matrix of electric and natural gas "die-off" rates for each program year. These die-off rates allow net energy savings in future out-years to be adjusted for the percent of measures still in place. For example, Energy Trust estimates that 44 percent of the electric measures installed in the 2002 program year will be in operation in 2013. As a result, the electric energy savings associated with the 2002 program year are adjusted downward from 15.0 aMW in 2002 (annualized) to 6.7 aMW in 2013.
- **Program True Up.** Each year, the Energy Trust adjusts previously reported energy savings and renewable generation through a True Up process that includes corrections for transaction errors, new data, anticipated evaluation results, and actual evaluation results. Once completed, this True Up process results in the most accurate reporting of energy savings (both electric and natural gas savings) and renewable generation.[14]

To illustrate, Figure 1 reports the net electric energy savings (aMW) for energy efficiency measures installed as part of Energy Trust's energy efficiency programs between 2002 and 2013.

[14] The True Up process results in increases or decreases in reported energy savings for each program year. Although this has changed the distribution of reported energy savings over time, the overall effect on total energy savings attributed to Energy Trust energy efficiency programs is quite small. Between 2002 and 2012, Trued Up electric energy savings represent 98.2 percent of reported electric energy savings. Similarly, Trued Up natural gas savings represent 98.3 percent of reported natural gas savings between 2002 and 2012. True Up reports that provide detailed information about the adjustments made to energy savings in each annual True Up process are available on Energy Trust's website, energytrust.org.

Figure 1: Net Electric Energy Savings for Energy Trust Energy Efficiency Programs, 2002—2013

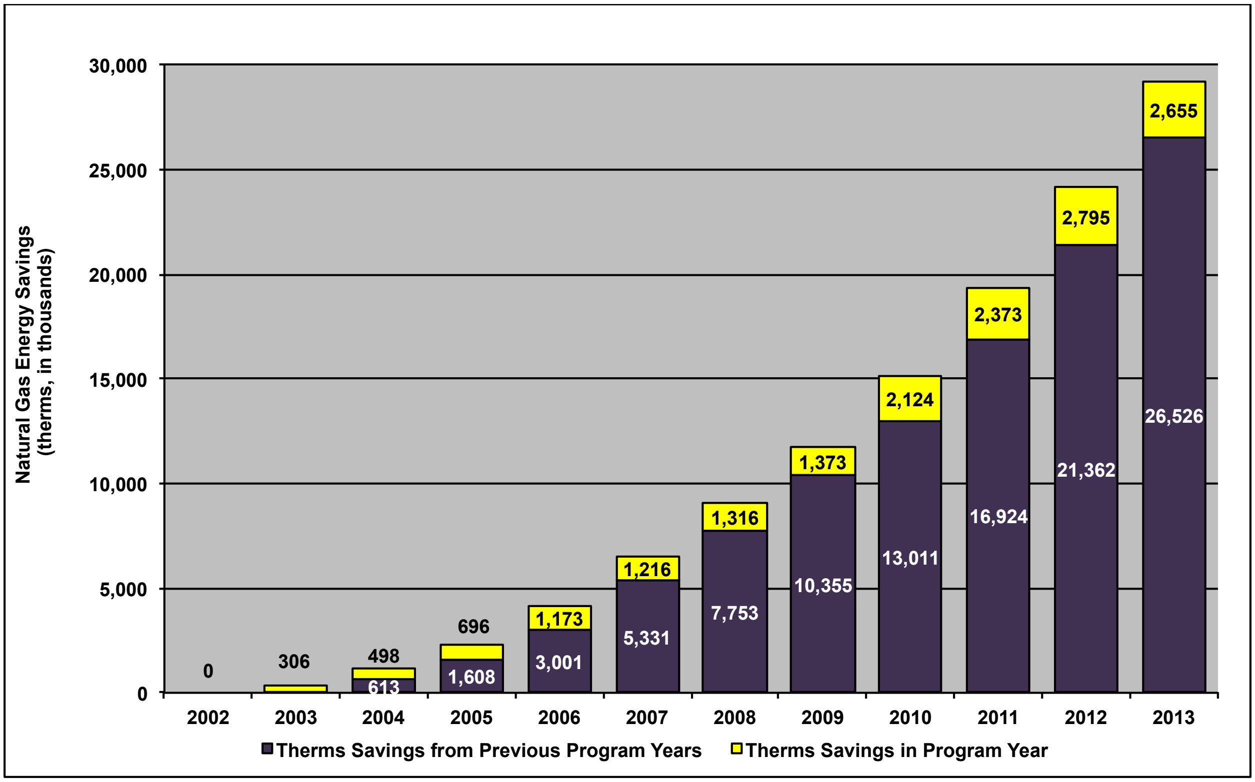


Sources: Calculations by Pinnacle Economics using detailed Energy Trust Program data
Notes: 1) Net electric energy savings have been adjusted for Energy Trust True Up. 2) Net electric energy savings include NEEA electric energy savings.

In 2013, Energy Trust's program activities included installation of energy efficiency measures that would yield an estimated 57.8 aMW of electric energy savings annually. As shown in Figure 1, these energy savings have been adjusted in the first program year to account for actual implementation throughout the year using the 50 percent implementation adjustment factor assumption referenced previously.

Figure 2 reports the net natural gas savings (in thousands of therms) for energy efficiency measures installed as part of the Energy Trust's energy efficiency programs between 2002 and 2013.

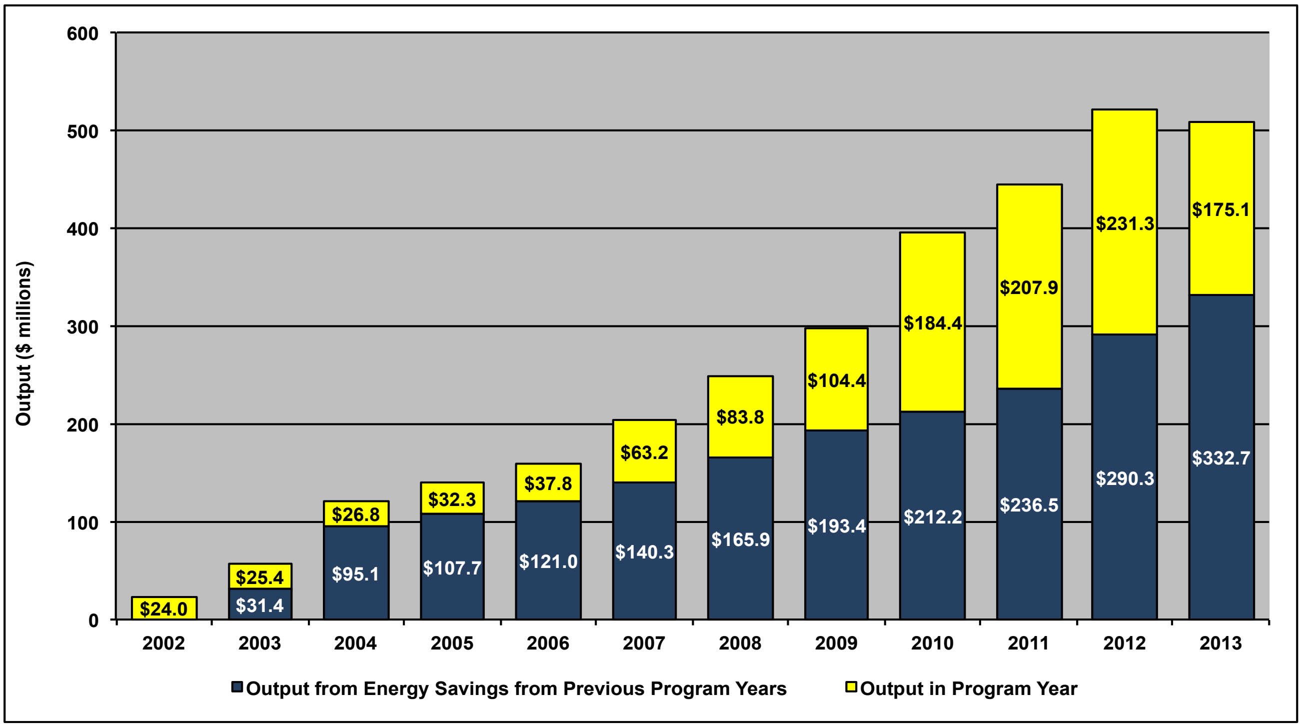
Figure 1: Net Natural Gas Energy Savings for Energy Trust Energy Efficiency Programs, 2002—2013



Sources: Calculations by Pinnacle Economics using detailed Energy Trust Program data
Notes: 1) Net natural gas energy savings have been adjusted for Energy Trust True Up. 2) Net natural gas energy savings include NEEA natural gas energy savings.

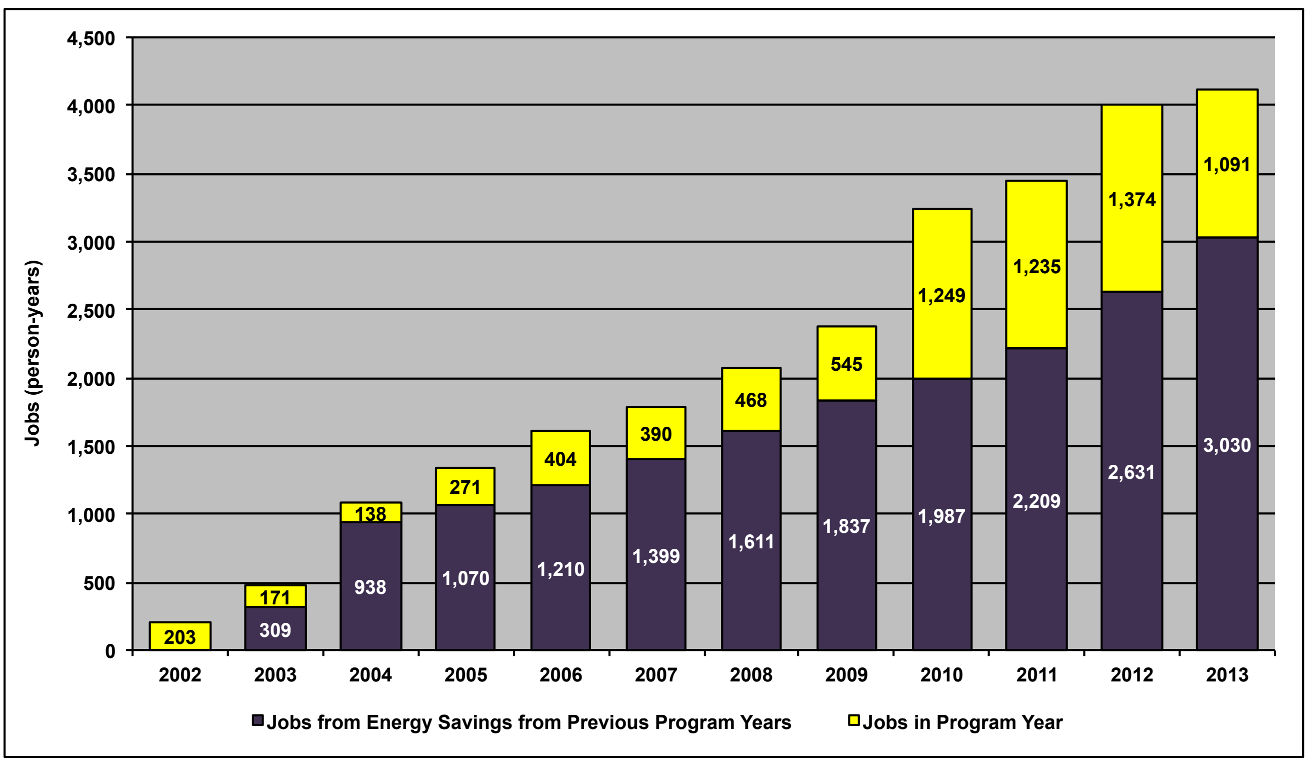
A similar effect occurs for the net economic impacts attributed to each program year. For businesses, energy savings lower production costs and enable businesses to increase output. Similarly, less residential spending on energy allows households to spend more on everything else. This contributes to increased employment as spending shifts to other goods and services in sectors that have a greater impact on the Oregon economy. Figures 3 and 4 show the annual output and job impacts, respectively, associated with Energy Trust program activities between 2002 and 2013.

Figure 3: Net Output Impacts Of Energy Trust Programs, 2002—2013



Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Note: Energy savings impacts based on both electric and natural gas energy savings.

Figure 4: Net Employment Impacts Of Energy Trust Programs, 2002—2013



Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.
Note: Energy savings impacts based on both electric and natural gas energy savings.

Table 7 reports the net economic impacts associated with Energy Trust' energy efficiency programs in Oregon between 2002 and 2013. The net economic impacts are based on spending and actual energy savings in each program year, as well as the annualized energy savings for energy efficiency measures in future out-years.

Table 7: Summary of Cumulative Net Impacts From Energy Trust Program Activities Between 2002 and 2013 (in millions of nominal dollars)

Economic Impact Measure	Cumulative Net Impacts During Program Years 2002-2013	Annualized Impacts in Future Years
Output	$3,123.0	$399.4
Wages	$928.7	$120.7
Business Income	$180.8	$17.1
Jobs (person-years)	25,770	3,567

Sources: Pinnacle Economics using detailed Energy Trust Program data and IMPLAN.

As is shown in Table 7, the spending and energy savings associated with Energy Trust program activities in Oregon between 2002 and 2013:

- Sustained, on a net basis, $3,123.0 million in output, including $928.7 million in wages, $180.8 million in business income and 25,770 person-years of employment over the twelve-year period.
- Will continue to generate additional energy savings that is linked to $399.4 million in output, including $120.7 million in wages, $17.1 million in business income, and 3,567 person-years of employment annually, albeit at diminishing levels, in the short run.

The cumulative net impacts reported in Table 7 are derived from previous analyses conducted by Pinnacle Economics that rely on a consistent methodology across program years. This methodology measures 1) **gross impacts** based on program spending, net incremental measure spending and energy savings, and foregone utility revenues, and 2) **net impacts** based on gross impacts less foregone household spending as a result of ratepayer charges used to fund Energy Trust program activities and incentives. Energy savings beyond each program year do not include energy savings from the renewable energy projects, and have been adjusted (reduced) to reflect the EUL of measures installed in each program year.

There are, however, other economic factors that could cause the economic impacts to decline over time in which case the economic impacts reported above would be overstated. Given the static nature of input-output modeling, in general, and the IMPLAN model used in this analysis, cumulative impacts do not take into account changes in production and business processes that Oregon businesses make in anticipation of future higher energy prices and/or increased market pressure from international competition to increase production efficiency. To the extent that Oregon businesses are already adjusting in anticipation of higher costs and/or tougher competition, then cumulative impacts presented here are overstated, as the overall market would become more efficient due to factors outside Energy Trust influence. However, Energy Trust savings estimates do not include the energy savings that program evaluations indicate would have happened, either immediately or in the very near future, without Energy Trust programs. This possible overstatement, therefore, only pertains to additional, future market-driven increases in efficiency. Furthermore, in a period of moderating forecasts of energy costs, this is less of a concern.

The cumulative numbers also rely on the critical assumption that each dollar saved will translate into a dollar of increased economic output for those businesses adopting conservation measures. This assumption is a simplifying assumption made in absence of better information specific to Oregon's economy. This assumption is reasonable in the short run, but in the long run it is likely that a dollar of energy savings will translate to less than a dollar of increased economic output (as reflected in the current economic variables for Oregon used in IMPLAN) if the overall market adopts more efficient production practices in anticipation of increased competition and higher energy costs. Consequently, the cumulative impacts shown here represent an upper bound. Despite these caveats, the ongoing and cumulative effect of conservation due to Energy Trust activities is nevertheless a significant net benefit to Oregon’s economy.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
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EXHIBIT ICNU/306

STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK. (2014). INDUSTRIAL ENERGY EFFICIENCY: DESIGNING EFFECTIVE STATE PROGRAMS FOR THE INDUSTRIAL SECTOR. PREPARED BY A. GOLDBERG, R.P. TAYLOR, AND B. HEDMAN, INSTITUTE FOR INDUSTRIAL PRODUCTIVITY (EXCERPT)

August 13, 2014

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STATE & LOCAL ENERGY EFFICIENCY ACTION NETWORK

Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector

Industrial Energy Efficiency and Combined Heat and Power Working Group

March 2014

The State and Local Energy Efficiency Action Network is a state and local effort facilitated by the federal government that helps states, utilities, and other local stakeholders take energy efficiency to scale and achieve all cost-effective energy efficiency by 2020.

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Acronyms

BPA	Bonneville Power Administration
Btu	British thermal units
CEE	Consortium for Energy Efficiency
CEPS	clean energy portfolio standard(s)
CFA	Consolidated Funding Application
CHP	combined heat and power
C&I	commercial and industrial
DOE	U.S. Department of Energy
DSM	demand-side management
EERS	energy efficiency resource standard(s)
EPA	U.S. Environmental Protection Agency
EPI	energy performance indicator
EnMS	energy management system
ETO	Energy Trust of Oregon
EWEB	Eugene [Oregon] Water and Electric Board
FTE	full-time equivalent employee
GWh	gigawatt-hour
IEE	Industrial energy efficiency
IOF-WV	Industries of the Future West Virginia
IPE	NYSERDA's Industrial Process Efficiency program
IPMVP	International Performance Measurement and Verification Protocol
IRP	integrated resource planning
HVAC	heating, ventilating, and air conditioning
HPEM	High Performance Energy Management (BPA program)
kW	kilowatt
kWh	kilowatt hour
M&V	measurement and verification
MMBtu	million British thermal units
MW	megawatt
MW_{avg}	average megawatts
MWh	megawatt-hour
NAICS	North American Industry Classification System
NEEA	Northwest Energy Efficiency Alliance
NEB	non-energy benefit
NWFPA	Northwest Food Processors' Association
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
PAC	program administrator cost test
PDC	program delivery contractor
RMP	Rocky Mountain Power
SEM	strategic energy management
SEO	state energy office
SEP	U.S. Department of Energy Superior Energy Performance program
SME	small- and medium-sized enterprise
SWEEP	Southwest Energy Efficiency Project
Therm	100,000 Btu
TRC	total resource cost
UMP	Uniform Methods Project
WFE	Wisconsin Focus on Energy

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Executive Summary

Industry[1] is a key energy-using sector in the United States and accounted for about one-third of the nation's total primary energy consumption in 2012. In addition, the potential cost-effective energy savings in U.S industry is large—amounting to approximately 6,420 trillion British thermal units of primary energy (including combined heat and power), according to a comprehensive 2009 analysis by McKinsey & Company. In the United States, efforts to capture more of the potential energy savings in industry at the state level have grown in recent years as energy efficiency programs that capture cost-effective savings continue to be created and expand.

This report provides state regulators, utilities, and other program administrators an overview of the spectrum of U.S. industrial energy efficiency (IEE) programs[2] delivered by a variety of entities including utilities and program administrators. The report also assesses some of the key features of programs that have helped lead to success in generating increased energy savings and identifies new emerging directions in programs that might benefit from additional research and cross-discussion to promote adoption.

Why Do States Undertake Industrial Energy Efficiency Programs?

Many states have instituted energy efficiency programs funded by the public or ratepayers to achieve a variety of benefits. A core, compelling reason for this is because energy efficiency represents a least-cost option for supplying energy services compared to other prevailing options, providing both consumers and society with cost savings. Additional benefits can include environmental gains (including carbon or water use reduction), improved security against energy supply disruption or rapid price increases, and enhanced economic competitiveness. Most state governments have determined that it is necessary to include programs that cover all customers as part of their overall energy efficiency efforts, with industrial customers often a critical component. Experience has shown that the industrial sector historically saves more energy per program dollar than other customer classes: at the national level, IEE programs had an average cost of saved energy of $0.030 per kilowatt hour (kWh) in 2012—nearly one cent lower than the aggregate average energy efficiency program cost of $0.038/kWh.[3] Many of the well-established ratepayer-funded IEE programs in North America, such as those of Bonneville Power Authority, BC Hydro, Energy Trust of Oregon, or Wisconsin's Focus on Energy, continue to realize reliable energy savings from industry at or below the average costs they face for their programs overall. To realize these low-cost energy savings, however, requires a concerted effort developed specifically for the industrial sector and long-term, focused efforts addressing specific industrial needs and circumstances.

States have found that a larger amount of energy savings potential in industry can be gained from energy efficiency programs than can likely be achieved if industrial energy users pursue energy efficiency individually, with limited program assistance. Industrial companies are often aware of energy savings projects in their facilities and many companies have a solid record of developing these projects to save money; however, energy efficiency often cannot compete with other capital demands, even with similar or better paybacks. Moreover, industrial staff members often report that it is difficult to effectively navigate corporate project decision-making systems to get management endorsement for even quick payback energy efficiency projects. In addition, small- or medium-sized energy savings projects often do not compete well with other projects in garnering management attention and

[1] As defined by the Energy Information Administration (EIA), industry consists of the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, fishing, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23). This report principally focuses on the manufacturing subsector.

[2] The best practices information presented in this report is based on a review of publically available literature on state energy efficiency programs and materials and presentations from related workshops and discussions with industrial energy efficiency experts and program administrators, including: the ACEEE Summer Study on Industry (July 2013, Niagara Falls), the ACEEE Resource Acquisition Conference (September 2013, Nashville), the Industrial Energy Efficiency and CHP Regional Dialogue Meetings (held in 2011, 2012 and 2013), the Midwestern Governor's Association Industrial Energy Productivity Meeting (November 2013, Chicago).

[3] Source: Aden et al. 2013 based on EIA 2012 demand-side management, energy efficiency, and load management programs data for more than 1,000 utilities. Note: To ensure consistency and comparability, these values only include the 182 organizations that reported residential, commercial, and industrial savings and expenditure data; transport sector energy efficiency program data are not included except as a component of the aggregate average.

enthusiasm. Finally, limitations on staff resources and knowhow can further hinder implementation of cost-effective energy efficiency measures.[4]

In states where ratepayer-funded energy efficiency programs are in place, industrial programs can make a significant difference, not only by fostering higher implementation of quick payback projects, but also by providing financial incentives that improve the economics of what would have been longer-term payback projects (3–6 years) that are well outside the typical interest scope of industrial managers. Program incentives to help industrial customers capture the potential for large, additional energy savings can strengthen the alignment of company incentives with the broader interests of energy users statewide in developing low-cost resources for energy service supply. In addition, other intensive but highly cost-effective initiatives of key medium-term interest can be fostered through multi-year programming, such as development of new strategic energy management (SEM) systems in industrial companies.

Even relatively simple programs providing technical assistance, fostering peer exchange, and disseminating practical information can make a difference by supporting facility or company energy management staff in their work and drawing company management attention to energy cost saving possibilities. Increasing awareness of the non-energy benefits (NEBs) that often accompany energy saving projects can help tip the scale in favor of project implementation.

The Wide Spectrum of Ongoing and Useful State Programs

There is wide variation in the types of IEE programs pursued by states, utilities, and energy efficiency program administrators. The dynamics of local economies, existing regulatory frameworks, political interest, and characteristics of local industrial sectors help define what different states feel are the most appropriate approaches for IEE programs. Within this wide spectrum of successful—if diverse—experience, all states can certainly launch new programs, or adapt existing programs, providing cost-saving benefits to industry and the state at large. Moreover, because of the diversity of programs and experience, each state can learn from others about new ideas and lessons learned in program design and implementation.

This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities. Broadly speaking, there are two main types of IEE programs in the United States:

- Ratepayer-funded energy efficiency programs which are funded through electric and gas customer rates
- Non-ratepayer-funded programs, which are funded by other means (e.g., federal resources, state operating budgets) and are often run by out-of-state energy offices and universities.

This report principally focuses on ratepayer-funded programs, although non-ratepayer-funded programs are also touched upon. Many states also mix a variety of different offerings and funding streams. The National Association of State Energy Officials (NASEO) reports that at least 35 state energy offices operate some type of IEE program separate from, or in support of, ratepayer-funded programs. Forty-one states have ratepayer-funded energy efficiency programs, and just over one-half of states operate ratepayer-funded programs with clean energy portfolio standards/energy efficiency resource standards or utility energy efficiency targets. Some states have chosen to include a self-direct or opt-out option to industrial programs. Self-direct programs are defined in this report as programs that allow qualifying industrial customers to "self-direct" fees that would normally be charged for a ratepayer-funded program directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funds collected through a public benefits charge for energy efficiency programs. Not to be confused with "opting out," where the industrial company does not have to participate in the program, self-directed industrial customers are still obligated to spend money and deliver energy savings, either on a project-by-project basis, or over a certain amount of time.

[4] These IEE program challenges were identified through SEE Action Industrial Energy Efficiency and Combined Heat and Power Regional Dialogue Meetings held across the country in 2011, 2012, and 2013 (www1.eere.energy.gov/seeaction/ieechp_dialogues.html).

APPROACH	DESCRIPTION	PROGRAM EXAMPLES
KNOWLEDGE SHARING	• Low-cost or no-cost technical assistance • Workshops and other outreach • Peer exchange opportunities between industrial clusters or groups of companies • Success story dissemination	• West Virginia Industries of the Future • Southwest Energy Efficiency Project
PRESCRIPTIVE INCENTIVES	• Explicit incentives or rebates for certain specific eligible technologies (e.g., lighting, motors, drives, compressed air, process heating equipment)	• Rocky Mountain Power • Efficiency Vermont
CUSTOM INCENTIVES	• Specific energy efficiency projects tailored to individual customers or specific industrial facilities • May be a mix of technologies • Incentives or rebates often based on entire electricity or natural gas savings	• Xcel Energy • NYSERDA
MARKET TRANSFORMATION	• Streamlined path for introduction of new energy efficiency products to the market • Address structural barriers to energy efficiency (e.g., outdated building codes or lack of vendors offering an emerging technology)	• Northwest Energy Efficiency Alliance
ENERGY MANAGEMENT	• Operational, organizational, and behavioral changes through strategic energy management • Continuous energy improvement (e.g., embedded energy manager to provide leadership and organiza-tional continuity for implementing change)	• Wisconsin Focus on Energy • Energy Trust of Oregon
SELF-DIRECT	• Customer fees directed into energy efficiency investments in their own facilities instead of a broader aggregated pool of funds • Eligibility for customer participation often based on threshold amount of energy use or energy use capacity • Verified energy savings	• Puget Sound Energy • Michigan Self-Direct Energy Optimization

Source: Categorization adapted from Bradbury et al. (2013)

Figure ES-1. Spectrum of IEE state program approaches with program examples

Financial incentives and technical assistance are often provided to energy users to implement sufficient energy efficiency measures to meet specific statewide energy savings goals or pursue all cost-effective energy efficiency opportunities. The main types of offerings, shown in Figure ES-1, are the following:

- **Technical Assistance and Knowledge-Sharing Programs.** These programs typically offer no-cost or low-cost expertise and advice to industrial companies on new technologies and practices, share analytical tools, disseminate success stories and case studies, and offer networking opportunities.
- **Prescriptive Programs.** Standardized prescriptive program offerings provide explicit incentives for adoption of specified higher-efficiency technologies in applications that are common among a variety of commercial and industrial energy users.
- **Custom Programs.** These program offerings provide financial and technical support, usually for customized, often process-specific, project implementation designed to meet the explicit needs of specific industrial customers. They can unlock substantial energy savings beyond what is possible when targeting only individual pieces of equipment and are usually quite cost-effective.

- **Market Transformation Programs.** These programs aim to streamline the path from market introduction of new energy efficiency products or practices to their promotion and consumer acceptance. Adoption of the new products can be supported through increasingly stringent energy efficiency codes and standards, technical assistance, and/or financial incentives.
- **Strategic Energy Management and Energy Manager Support Programs.** Rather than focusing on technology and equipment, these programs seek to promote operational, organizational, and behavioral changes resulting in energy efficiency gains on a continuing basis. SEM involves the operation of internal cross-organization management systems for companies that need to identify and implement many energy efficiency measures year after year.

Experience from Designing and Delivering Programs

A central finding of this report is that achieving success in IEE programs requires significant upfront investment and steady commitment over a number of years. In practice, the experience of strong IEE programs shows that the dedicated effort required is worth it in terms of generating robust and low-cost energy savings. This is especially true in the industrial sector where energy improvement decisions may be linked to operational or capital cycles.

The industrial sector is heterogeneous; different plants have different needs, all of which takes time and skill to grasp. Industrial plant staff members are generally more sophisticated concerning energy matters compared to residential and many commercial energy users. However, internal decision-making processes in industrial companies concerning energy efficiency investments or energy use behavioral change can be complex. Plant operational cycles must be understood and typically define project scheduling. Often, non-energy benefits, including increased productivity, may provide a key tipping point benefit in favor of pursuing a given line of projects, but such benefits may not be immediately obvious. As detailed further in Chapter 4, the barriers and challenges of the industrial sector must be addressed if IEE programs are to create real value for their customers.

To overcome existing barriers and provide high value to industrial customers, programs require quality market assessments, steady and close interaction with customers, a critical mass of knowledgeable staff and strategically engaged consultants, and operational stability. This requires upfront investment and a multi-year focus.

There are 10 IEE program features highlighted by analysts and practitioners that consistently add value to industrial customers and contribute to program success. These program features are:

1. **Clearly demonstrating the value proposition of IEE projects to companies.**
   There are many direct and indirect benefits from IEE projects. A key point in making the value proposition case to industrial company managers is to lay out in simple and concise terms the operating cost savings and other benefits—including profits—that are being left on the table by not addressing cost-effective energy efficiency improvement opportunities.
2. **Developing long-term relationships with industrial customers that include continual joint efforts to identify IEE projects.** Maintaining relationships with key industrial customers is important in pure technical assistance programs as well as energy efficiency resource acquisition programs. It takes time and a steady relationship for program personnel to understand company circumstances and needs, and for company personnel to understand what a program can offer them. Projects tend to be identified over time, as circumstances change and opportunities arise.

   Maintaining quality long-term relationships is people-dependent. Most programs have found that it is necessary to have a consistent and savvy contact person for industrial customers to interact with, such as an account manager. Satisfaction of industrial customers with program delivery and results often hinges on the level of trust established in relationships with program staff or experts.

   Due to the importance of long-term relationships, substantial program investments in staffing or contracted expert capacity are necessary over a number of years to generate the best results. Contracting for program delivery capacity based on only short-term goals, with frequent changes in contractors, is not likely to succeed. Time and effort is needed to set up effective institutional systems.

3. **Ensuring program administrators have industrial sector credibility and offer quality technical expertise.** Effective IEE programs also develop credibility with the industrial customer by employing staff and/or contracted experts that understand the customer's industrial segment and have the technical expertise to provide quality technical advice and support on energy efficiency options and implementation issues specific to that industry and customer. Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context that it operates within. Effective IEE programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and their investment decision-making processes allows IEE program administrators to generate trust with their industrial customers, boosting IEE implementation rates while making better use of limited resources.
4. **Offering a combination of prescriptive and custom options to best support diverse customer needs.** A combination of both prescriptive offerings for common cross-cutting technologies and customized project offerings for more unique projects can best meet diverse customer needs and provide flexible choices to industries.
5. **Accommodating scheduling concerns.** Program flexibility to meet industry project scheduling requirements is important to meet industrial customer needs. Typically, scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation and capital investment cycles and decision-making processes. Programs with multi-year operational planning can best accommodate company scheduling requirements and the ebb and flow of company project implementation progress.
6. **Streamlining and expediting application processes.** Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome. Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.
7. **Conducting continual and targeted program outreach.** Even where industrial programs are well established, various industrial customers may remain unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands. Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation. Effective long-term relationships with industrial customers create better information flow and can assist in program outreach efforts.
8. **Leveraging partnerships.** Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities. Partnerships can help programs by providing technical expertise, program design and implementation guidance, and expanding program outreach and implementation channels.
9. **Setting medium- to long-term goals as an investment signal for industrial customers.** Most state IEE programs have found that establishing and reporting on energy savings goals in three-year cycles is effective. Medium- and longer-term goals and coordinated funding cycles set a framework for long-term programming and can signal increased certainty to the market and program administrators.
10. **Undertaking proper project measurement and verification and completing program evaluations.** Effective measurement and verification (M&V) of project energy savings is critical to program administrators and regulators to assess the actual results of program activities and measure the contribution of projects and aggregate programs for achieving their goals. Manufacturers also can obtain clear views of the results of investment. Planning for M&V during the program design phase as well as periodic evaluation and adjustment in M&V approaches is important. If NEBs can be included in project assessments, they can further improve understanding of these often important benefits in conveying the value proposition for future energy efficiency projects. Finally, it is useful for programs to undertake periodic process and/or operational strategy evaluations of their full range of activities to assess where program efficiency and results can be further improved.

Self-Direct Programs

This report's review of self-directed IEE programs found a wide range in program structures. Some programs leave obligations of self-directed industries only vaguely defined, include little reporting, and little or no monitoring of energy-saving actions. Such programs ultimately may be little different in terms of results from provisions allowing industry to opt out of energy efficiency programs entirely. At the other end of the spectrum, some programs require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived. Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.

Emerging Industrial Program Directions

Most states with active IEE programs continue to devote much effort to expanding and improving their programs. There are four key areas of particular interest for further program evolution.

- **Expanding and strengthening strategic energy management programs in industry.** Efforts to support implementation of SEM systems in industry (and also commercial and institutional) are gaining momentum in state programs and internationally. Successful implementation of SEM in many industries could have a dramatic impact on capturing more unrealized energy efficiency potential. The benefits of supporting internal company platforms for continual identification and implementation of energy savings measures include more comprehensive identification and prioritization of energy savings investments (including across organizations), high-impact and low-cost behavioral changes, and operational and maintenance improvements, all contributing to the company bottom line. For example, use of greater submetering as part of an SEM initiative may allow previously unclear issues and solutions to come to light, or enable a new energy intensity program to be put in place.

  SEM implementation can be effectively supported through technical assistance and recognition programs or through energy efficiency resource acquisition programs. One key common challenge is how to easily convey options for introducing SEM into different corporate environments and the value proposition of these management systems. Experience has shown that company senior management support for SEM initiatives is necessary for success and strategies are needed to garner such support.

- **Providing energy efficiency incentives for whole-facility performance.** Program expansion to assess energy savings from SEM implementation could provide directions for taking energy efficiency programs that encompass process- or plant-wide opportunities (e.g., providing incentives and assessing savings credits for whole industrial facility performance) as opposed to performance of individual investments or measures. Efforts are underway to determine baselines and performance metrics that can provide sufficiently robust measurements of facility savings so that regulators and the public are confident that funds have produced real and new energy efficiency savings.

- **Valuing and expanding quantification and recognition of project NEBs.** Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects. Awareness of the importance of quantifying or otherwise highlighting key and large co-benefits is growing. Even so, quantification of these benefits tends to occur mainly after project commissioning as part of project evaluation efforts. Some co-benefits, such as water savings, are relatively easy to quantify, while others, such as safety improvements, are more complex to assess. If programs employed systematic ways to assess some of the NEBs for key projects earlier in the project cycle, the clarity added to both the resulting total returns and shorter project payback could tip the scale on a variety of projects from "wait and see" to implementation.

- **Continuing efforts to expand industrial natural gas efficiency programs.** Although natural gas efficiency programs have been implemented in various states for years, effective coverage of the industrial sector is much less common than for electricity efficiency programs, even though industry accounts for about 26%

of total end-use natural gas consumption in the United States. A key challenge is that most large industrial customers purchase their gas through third-party suppliers, rather than their distribution companies. Another challenge is the recent decrease in natural gas prices (even though many gas saving projects are still cost-effective at current prices). Nevertheless, a number of states and Canadian provinces continue to serve as promising examples in delivery of industrial natural gas efficiency programs, which other states may profit from reviewing. In addition, innovative concepts are under consideration to increase the effectiveness and the reach of gas efficiency programs. One such concept proposes to pool gas and electric efficiency funds to allow participating manufacturers to implement larger and more holistic programs with the flexibility to deliver both electricity and gas savings.

The Importance of Cross Exchange

As this report will show, the experience gained by various states in developing and implementing IEE programs is both diverse and rich. Often, however, valuable details of different programs—and the successes, failures, and lessons learned—are not well known or are poorly understood out-of-state, even though other state practitioners could benefit from these experiences. In addition, early ideas on new programs or improvements to existing ones are common among various practitioners. Opportunities for peer exchange on design and operational specifics could further programs' progress. Finally, there are benefits from greater mutual understanding that can be gained from increased cross-state exchange among different types of stakeholders in the IEE program practice, including regulatory agencies, program administrators, and involved industrial energy users in different states, as well as associated experts.

Various formal and informal networking mechanisms exist for further information exchange. In addition, the State and Local Energy Efficiency Action Network (SEE Action) can play a role in organizational and implementation specific activities on program design and implementation topics of greatest interest. Regional IEE organizations also are well-placed to help foster the increased cross-exchange needed to further ramp up the promising results in IEE programs in the states.

Conclusion

Many opportunities remain to incorporate cost-effective, energy-efficient technologies, processes, and practices into U.S. manufacturing. IEE remains a large untapped potential for states and utilities looking to improve energy efficiency, reduce emissions, and promote economic development. Successful IEE programs vary substantially in operational mode, scope, and financial capacity, but also exhibit common threads and challenges.

Gaining industry support for IEE programs is key; one of the best means to gain increased industry support is by demonstrating the high value of efficiency programs to industrial customers. Experience highlighted in this report will show that IEE programs can effectively deliver value to industries in terms of lower costs, reduced environmental impact, and improved competitiveness, and can help alleviate common resistance by industry to pay into ratepayer programs.

The development and operation of a highly valued IEE program requires a close understanding of the special needs of industrial customers, flexibility in program offerings, and sustained engagement. In practical terms, this means helping industry achieve concrete energy cost reduction benefits, improved competitive position, and additional NEBs such as enhanced productivity and product quality well above the costs of paying into the program. Flexibility in addressing project scheduling and investment cycles, provision of high-quality technical expertise, and comprehensive offerings that include both prescriptive and custom incentives are features of successful programs.

In addition to responding to the needs of industrial customers, IEE programs that leverage strategic partnerships, have robust M&V and evaluation methodologies, and seek to introduce more holistic program approaches, such as SEM and pooled gas and electric programs, will ultimately help program administrators operate more effective programs and deliver significant additional energy savings. As this report will show, states' experience in developing and implementing IEE programs is both diverse and rich. There are benefits from greater mutual understanding that can be gained from increased cross-state exchange among regulatory agencies, program administrators, industrial energy users, and associated experts.

Table ES-1 summarizes the key issues and considerations for regulators and program administrators in designing and implementing effective energy efficiency programs for industry, as well as programs that address that issue. They do not cover all decisions or issues that regulators and program administrators may need to consider because there will undoubtedly be jurisdiction- and case-specific topics that are not anticipated here. However, these considerations provide a starting point for addressing many of the issues that typically arise.

Table ES-1. Summary of Key Issues and Considerations for Regulators and Program Administrators

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
The value of energy efficiency projects	Energy efficiency projects may compete with core business investments and decision-making is often split across business units.	• Clearly demonstrate the value proposition of energy efficiency projects to companies • Relay the operating cost savings and other benefits—including profits—lost if energy efficiency improvement opportunities are not addressed.	• Bonneville Power Administration • New York State Energy Research and Development Authority • West Virginia Industries of the Future
Relationships with industrial customers	It takes a long-term relationship for programs to understand industrial operation and needs, and for industrial companies to understand what a program can offer them.	• Long-term relationships with industrial companies enable joint identification of energy efficiency opportunities • Stability in program support and personnel over a number of years is critical.	• Energy Trust of Oregon
Industrial sector credibility and technical expertise	Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context the plant operates within.	Effective IEE programs develop credibility with industrial companies by employing staff/contractor experts that understand the industrial segment and have the technical expertise to provide quality technical advice and support issues specific to that industry and customer.	• Efficiency Vermont • Wisconsin Focus on Energy • Xcel Energy (Colorado and Minnesota)
Diverse industrial customer needs	Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption. Focusing on simple common technology fixes alone will miss many of the opportunities.	A combination of both prescriptive offerings for common crosscutting technology and customized project offerings for larger, more unique projects can best meet diverse customer needs and provide flexible choices to industries.	• Rocky Mountain Power • CenterPoint Energy • Xcel Energy
Project scheduling	Scheduling of energy efficiency investments can be heavily dependent on a plant's operational and capital cycle, as proposed equipment changes must be guided through rigorous, competitive, and time-consuming approval processes.	Programs with multi-year operational planning can best accommodate company scheduling requirements, as scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation as well as capital investment cycles and decision-making processes.	• NYSERDA

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Application processes	Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome.	Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.	• BPA • NYSERDA
Program outreach	Various industrial customers may be unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands.	Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation.	• AlabamaSAVES • NYSERDA
Leveraging partnerships	A range of federal, national, regional, and state initiatives and resources are relevant to state IEE programs, including those provided by the U.S. Department of Energy, the U.S. Environmental Protection Agency ENERGY STAR® program, state energy offices, and the Manufacturing Extension Partnership.	Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities.	• AlabamaSAVES • Northwest Energy Efficiency Alliance, Northwest Food Processors Association and BPA
Medium- and long-term goals	Industrial companies and program administrators seek market certainty and reduced risk in ramping up the implementation of cost-effective energy efficiency measures.	Regulators and program administrators can set energy savings goals or targets for the medium- to long-term, coordinated with funding cycles (e.g., in three-year cycles).	• Michigan Self-Direct Energy Optimization Program • Southwest Energy Efficiency Project
Measurement, verification, and evaluation	Effective M&V is critical for program administrators to assess results and measure progress, and is also useful for industrial companies to verify results of their investments.	• Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted • Periodic impact and process evaluations help identify where IEE program efficiency and results can be further improved • Non-energy benefits (NEBs) can be a key element of both project M&V and program evaluation.	• DOE's Uniform Methods Project • International Performance Measurement and Verification Protocol • ETO process evaluations • NYSERDA, Mass-achusetts, and BPA valuation of NEBs
Self-direct programs	There is a wide range in structures of self-direct programs: from those that are only vaguely defined, and include little M&V of energy saving actions, to those that require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived.	Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.	• Michigan Self-Direct Energy Optimization Program • Puget Sound Energy • Xcel Energy

Emerging Industrial Program Directions			
Topic	**Issue**	**Considerations for Regulators and Program Administrators**	**Program Examples**
Expanding and strengthening strategic energy management programs	Efforts to support implementation of SEM in industry are gaining momentum in state programs.	The challenge of crediting SEM (how to quantify and credit energy savings specifically achieved through SEM), as well as other SEM-related topics, is worthy of further research and cross-exchange.	• AEP Ohio • BPA • BC Hydro • ETO • WFE • Xcel Energy
Program approaches for whole-facility performance	Significant challenges exist in determining baselines and performance metrics that can provide sufficiently robust measurements of facility savings while maintaining practical and easy-to-implement methodologies.	Work on crediting energy savings from SEM could facilitate the provision of incentives and assessing savings credits for whole industrial facility performance, as opposed to performance of individual investments or measures.	• European experience
Capturing non-energy benefits at the project level	Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects.	If programs employed systematic ways to assess NEBs earlier in the project cycle, the resulting total returns and shorter payback could tip the scale on a variety of projects from "wait and see" to implementation.	• Energy Trust of Oregon
Expanding natural gas programs	• There is less coverage of the industrial sector in natural gas efficiency programs than in electricity efficiency programs. • Most large industrial customers purchase their gas through third-party suppliers rather than their distribution companies. • Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings in both gas and electric energy use.	• Gas and electric efficiency measures—when delivered together as part of the same project or a combined program—can result in larger, more effective programs that capture more of the technically and economically viable energy efficiency potential. • Innovative concepts are under consideration to increase the effectiveness and the reach of natural gas efficiency programs.	• Efficiency Vermont • ETO • NYSERDA • PG&E • WFE

1. Introduction

The purpose of this report is to inform state regulators, utilities, and other program administrators about the significant benefits that states in the United States have experienced with industrial energy efficiency (IEE) programs, and to assist these stakeholders in successfully developing and implementing IEE programs in their service territories. This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities.

This report recognizes that states have their own circumstances, industrial market characteristics, and regulatory structures, and therefore will respond with their own IEE program approaches. These approaches range from ratepayer-funded energy programs—often required under mandatory energy efficiency resource standards (EERS)[5] or other clean energy portfolio standard (CEPS)[6] or through demand-side management (DSM) programs—to knowledge sharing and technical assistance outreach programs without a regulatory incentive structure. The report does not attempt to make specific recommendations that could potentially conflict or be incompatible with individual state regulatory environments. Instead, it explores the practical, proven approaches states have taken. This information can be used by state policymakers and program administrators who wish to further develop their existing IEE programs or start new programs to achieve greater energy savings from industrial customers.

The best practices information presented in this report is based on a review of publically available literature on state energy efficiency programs and materials and presentations from related workshops,[7] and discussions with industrial efficiency experts and program administrators.

The report first provides an overview of why states support strong efforts to promote energy efficiency in the industrial sector and summarizes the current status of IEE programs in the United States. It then illustrates the breadth of existing approaches and program offerings and describes how programs have matured as administrators gain knowledge and experience of customer needs and ramp up energy efficiency improvements.

This is followed by a characterization of IEE program design features intended to respond to industrial customer needs, and highlights of proven practices from states with longstanding experience that have overcome challenges to engaging industrial customers and ensuring broad program uptake. The report focuses on the industrial manufacturing sector—as opposed to industry[8] more broadly defined (which typically includes agriculture, mining, and construction)—but recognizes that many state programs target broader industrial subsectors, combine offerings for industrial and commercial customers, or tend to structure offerings based on customers' energy consumption. In exploring how programs respond to manufacturers' needs, the report identifies programs that target specific industrial process improvements, as well as crosscutting support systems such as motor systems.

Finally, the report discusses two additional topics:

- **Self-direct programs** that allow some customers to "self-direct" their program fees directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funding. Concepts that can be used to ensure these programs are achieving energy savings are discussed.
- **Next-generation IEE programs** that expand IEE savings options and industrial participation through strategic energy management (SEM) programs, facility-level programs, better integration of non-energy benefits (NEBs) and fuel sources, and other innovative approaches.

[5] EERS policies aim for quantifiable energy savings by recognizing that energy efficiency is a utility system resource and should be considered by the utility at the same time that supply resources are evaluated.

[6] Clean energy portfolio standards include renewable energy portfolio standards (RPS), EERS, and alternative energy portfolio standards (APS).

[7] Including: the ACEEE Summer Study on Industry (July 2013, Niagara Falls), the ACEEE Resource Acquisition Conference (September 2013, Nashville), the Industrial Energy Efficiency and CHP Regional Dialogue Meetings (held in 2011, 2012 and 2013), the Midwestern Governor's Association Industrial Energy Productivity Meeting (November 2013, Chicago).

[8] As defined by the Energy Information Administration, industry consists of the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, fishing, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23). This report principally focuses on the manufacturing subsector.

The focus of the report is primarily on ratepayer-funded programs (funded by energy utility customers) due to their relative size in spending terms.[9] Programs that are funded from other sources such as state energy offices are also noted. Numerous examples, case studies, and program descriptions are provided throughout the report. The program examples highlighted here have been successful, not only because they have been able to respond to manufacturers' needs and achieve significant energy savings, but also because they demonstrate cost-effectiveness (according to the relevant cost test the state requires), have good rates of participation, or show they have some longevity and a track record of successful projects. Because this report does not attempt to profile all programs, this by no means suggests that other programs have not been successful.

Although not the focus of this report, the policy contexts for establishing IEE programs are important. These topics include[10]:

- Types of policy mechanisms, such as the decision process for setting CEPS and establishing ratepayer-funded energy efficiency programs
- Institutional guidance for including energy efficiency in integrated resource planning (IRP) processes
- Aligning utility and customer interests in increasing energy efficiency
- Funding sustainability and sources
- Standard criteria for evaluating and screening programs for cost-effectiveness (cost-effectiveness tests)
- Types of data and metrics derived by evaluators for use in impact evaluation of IEE programs
- Choice of program administrator.

[9] In a study of electric IEE program spending in 2010, the bulk of the spending (84%) came from ratepayer-funded utility program budgets, with the remainder of the funding coming from state and federal budgets, universities, nonprofit organizations, and other groups (Chittum and Nowak 2012).

[10] Key resources include Chittum 2012, DOE 2007, EPA 2006, Hayes et al. 2011, Nowak et al. 2011, Sedano 2011, SEE Action Network 2011a, 2011b, and 2012c, Taylor et al. 2012, and Woolf et al. 2012.

2. The Importance of Industrial Energy Efficiency Programs

Effectively managing and reducing energy use in the U.S. industrial sector through increased efficiencies is a key federal, state, and local policy priority as well as a good business decision. The industrial sector is a significant consumer of energy, accounting for about one-third of total U.S. energy consumption (EIA 2013). Implementation of cost-effective industrial energy efficiency (IEE) measures can help defer the need to build more power generation, transmission, and distribution capacity while also enhancing energy security and mitigating risk considerations. Beyond the local and national policy benefits of improved energy efficiency, it is also a key tool in helping U.S. manufacturers reduce their costs and increase competitiveness. To help meet state energy efficiency goals, energy efficiency program administrators are looking to tap the large and cost-effective resource potential the manufacturing sector holds.

2.1. Manufacturing is an Important Sector

The industrial sector accounts for around one-third of all end-use energy in the United States and remains the largest energy user in the U.S. economy (Figure 1). Although IEE has increased dramatically and manufacturing energy intensity has fallen since 1990, industry is projected to consume 34.8 quads of primary energy in 2020 (EIA 2013a). Estimates of the potential to reduce industrial energy consumption through efficiency measures by 2020 are as high as 18% (McKinsey 2009).[11] The energy intensity of production in industrial subsectors varies widely, from 52.3 end-use Btu per dollar of value added in cement production, to 0.4 Btu per dollar in computer assembly. Opportunities for subsector-specific processes make up 67% of the IEE potential, while opportunities in crosscutting energy support systems, such as steam systems and motor systems, comprise the remaining 33%. Sixty-one percent of the total opportunity resides in energy-intensive sectors such as iron and steel, cement, and chemicals, with the remaining 39% in non-energy-intensive sectors (McKinsey 2009).

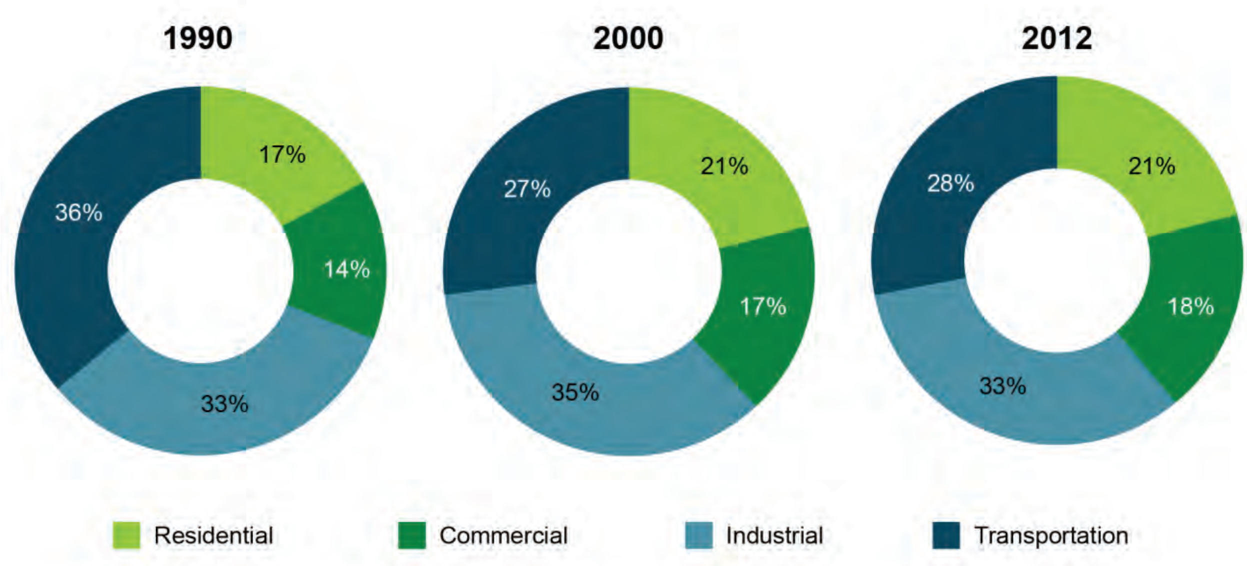


Figure 1. Energy consumption in the United States (1990, 2002, and 2012)

[11] Other estimates are similar; the National Academy of Sciences (NAS) concluded in 2010 in *Real Prospects for Energy Efficiency in the United States* that 14%–22% of industrial energy use could be saved through cost-effective energy efficiency improvements (those with an internal rate of return of at least 10% or that exceed a company's cost of capital by a risk premium). These innovations would save 4.9–7.7 quads annually by 2020.

Figure 2 shows the 2020 IEE potential in various subsectors and cross-sectorial systems, referred to as clusters. The energy savings potential is shown in both direct reductions in end-use energy and in primary energy terms that includes all of the upstream energy consumed in the delivery of energy to the industrial consumer. The potential in primary energy terms reflects the full fuel cycle basis and the avoided electricity losses possible through IEE.

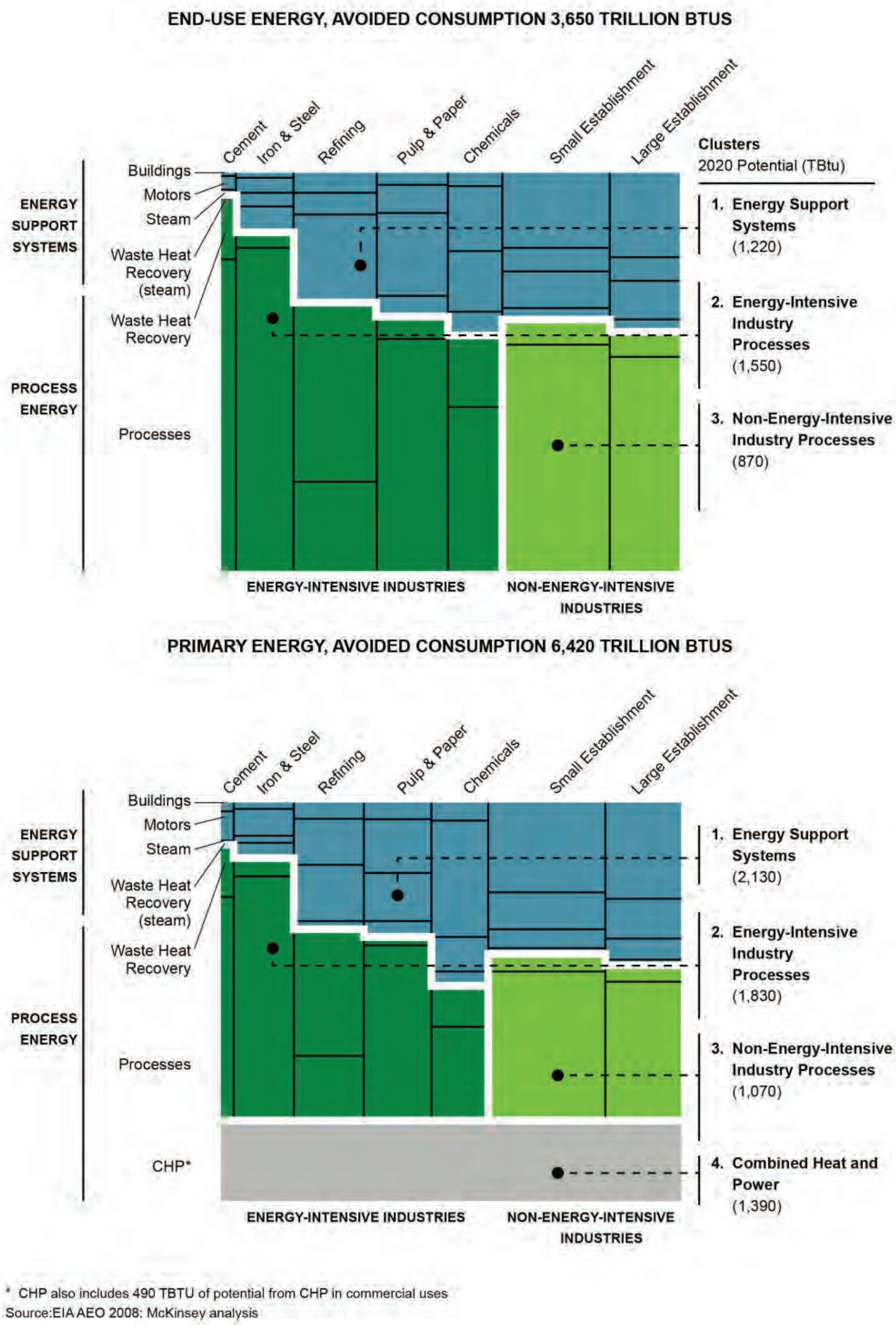


Figure 2. Clusters of end-use energy efficiency potential in the industrial sector

2.2. Industrial Energy Efficiency Resources Are Cost-Effective

Delivery of electricity efficiency resources generally costs much less than delivery of new electricity supply resources in most regions of the country. In most electric power systems, delivery of reliable energy efficiency resources to meet electrical energy consumption (kilowatt-hours [kWh]) costs somewhere between 15%–50% of the cost of power from new central station generation (Lazard 2011). A study examining evaluation results across 14 states found that energy efficiency programs on average cost the sponsoring utility or program administrator about $0.025 per kWh saved and about $3.40 per million Btu of natural gas saved over the life of energy efficiency measures. When costs paid directly by participants are also included, the average cost of efficiency savings is about $0.046 per kWh and $6.80 per million Btu. This is far less than the cost of power from new central station generating plants, which can range from $0.07 to more than $0.30 per kWh (ACEEE 2009, Lazard 2009, SEE Action Network 2011a).

Energy efficiency resources offer cost advantages for meeting new power capacity (kilowatts [kW]) needs as well. Similarly, the costs of improvements in the efficient use of natural gas also are generally substantially lower than acquiring new natural gas supply resources over the medium term, although gas industry structure and economics are different from those of the power sector (Trombley and Taylor 2013).[12] As an example of the economic attractiveness of energy efficiency, Figure 3 highlights the levelized costs[13] of different energy resources in Tucson Electric Power's service area.

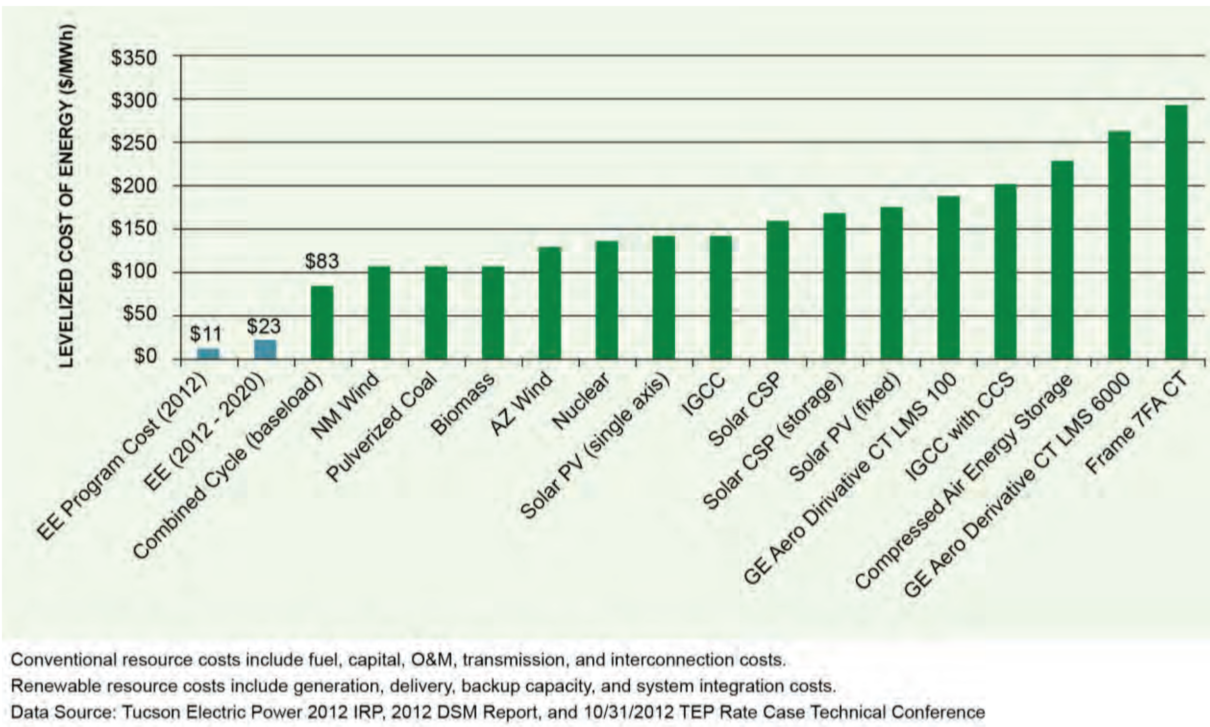


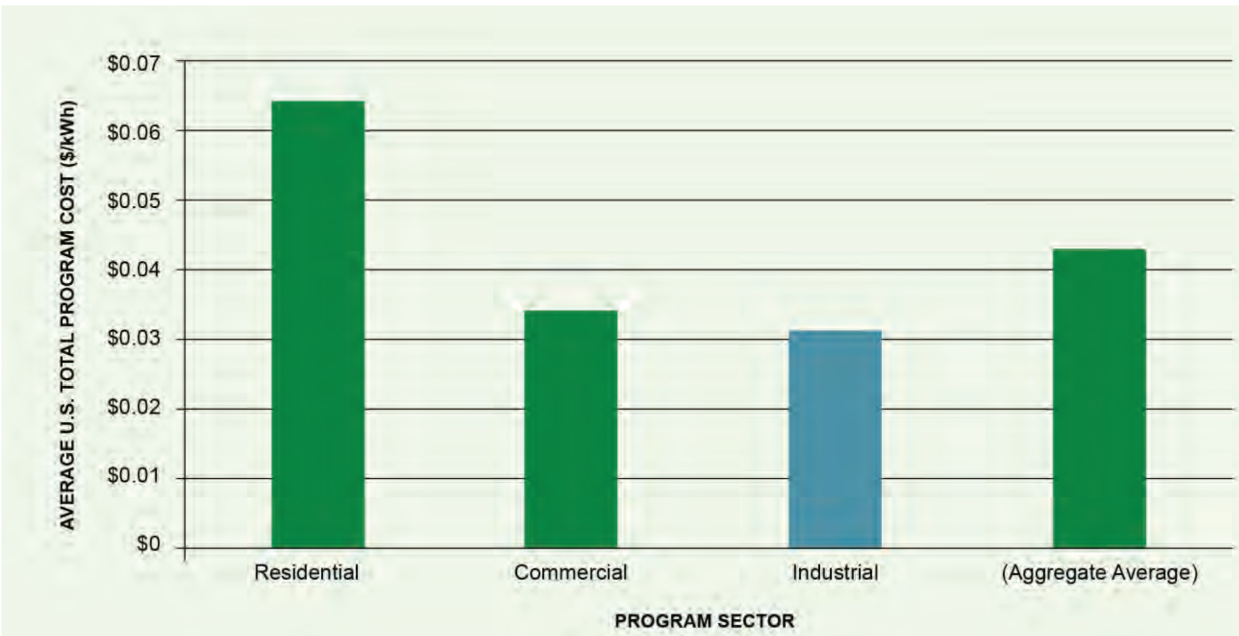
Figure 3. Levelized costs of energy resources in Tucson Electric Power's service area

[12] Although natural gas prices were at an all-time low in 2012, prices have already rebounded to around $4 per MMBtu and current forecasts estimate that prices will remain steady or slightly increase at $4 to $6 per MMBtu for the foreseeable future. Natural gas energy efficiency programs remain cost-effective when gas prices reach around $4 per MMBtu (using the Total Resource Cost test), so under the more likely natural gas price paths, these programs will continue to remain cost-effective. The program design implications of providing incentives for natural gas savings are discussed in Chapter 6.

[13] Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kWh cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle, expressed in terms of real dollars to remove the impact of inflation, and often converted to equal annual payments. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.

Not only is energy efficiency, in general, a more cost-effective option than new supply resources, recent studies suggest that IEE is often among the lower cost, if not the lowest cost, energy efficiency resource (Bradbury et al. 2013, Chittum 2011). Accordingly, many energy efficiency program administrators are not only looking to the industrial sector as a large potential source for energy efficiency resources, but also as a relatively low-cost energy savings acquisition option.

Figure 4 illustrates that the industrial sector has the lowest cost of saved energy on a national level, although it is important to note that cost structures vary by program and sector at the state level (Aden et al. 2013). In British Columbia, for example, the well-established industrial program under the electric utility's Power Smart Program is expected to provide energy savings at a cost to the utility of $0.015 Canadian per kWh during FY 2012–14, compared to utility costs of $0.031 Canadian per kWh for the residential program (Taylor et al. 2012). Additional examples are discussed in Appendix A, including programs in Wisconsin, Rhode Island, Oregon, and the Northwest. These show that industrial programs can often be twice as cost-effective as programs targeting the residential sector.



Source: Aden et al. 2013 based on EIA 2012 DSM, energy efficiency and load management programs data for more than 1,000 utilities www.eia.gov/electricity/data/eia861.

Note: To ensure consistency and comparability, this figure only includes the 182 organizations that reported residential, commercial, and industrial savings and expenditure data; transport sector energy efficiency program data are not included in this figure except as a component of the aggregate average.

Figure 4. Average costs of energy efficiency programs by sector (2012)

2.3. Industrial Energy Efficiency Creates Value for Companies and Society

IEE provides numerous benefits to industrial customers, to utilities, to all ratepayers, and to society as a whole.

Industrial Companies

Energy efficiency reduces costs and increases manufacturers' operational efficiency and productivity. It also often results in a number of co-benefits such as reduced material loss, improved product quality, and lower emissions. In addition, investors increasingly value corporate commitment to energy efficiency and sustainability as an indicator of sound governance and business acumen. Research consistently suggests that NEBs from efficiency measures in the industrial sector are substantial (Hall and Roth 2003, Worrell et al. 2003, Lung et al. 2005, Chittum 2012, Lazar and Colburn 2013). Facilities that take advantage of IEE program offerings provide a valuable hedge against energy supply disruptions or shortages, energy price volatility, and price spikes. For example, Darigold, a dairy and food processing company with 1,400 employees in the Northwest, adopted an energy reduction strategy in 2001. Due to SEM practices and energy-efficient capital improvements implemented since 2001, the company's energy intensity decreased by 21% in 2012. In addition, its productivity grew, the reliability and safety of its equipment increased, the risk of work-related injuries associated with operating machinery decreased, and the company experienced less workforce turnover (IIP 2012a). An analysis of NEBs in Wisconsin found that in calendar year 2010, participants in Focus on Energy business programs enjoyed $8.9 million in NEBs above and beyond the estimated $56 million in annual energy savings for the same year's business customers (Chittum 2012). Productivity and NEBs enjoyed by industrial customers are further discussed in Chapter 6.

System-Wide Benefits

States have found that specific IEE programs can help deliver a larger slice of the energy savings potential in industry than can likely be achieved if industrial energy users pursue energy efficiency on their own with no program assistance of any kind. Company staff are often aware of profitable energy saving opportunities, and many companies have a solid record of developing these projects to save money. However, focus is often on projects that can pay off in one or two years. Other projects that have substantial potential long-term benefits, but that have higher initial costs and longer payback periods, are left on the table. IEE programs can make a key difference, not only by fostering greater adoption of short payback projects, but additionally providing financial incentives that improve the payback of projects outside industrial managers' typical interest scope (less than two years). Program incentives to help industrial customers capture significant additional cost-effective energy savings potential can improve the alignment of company business practices with the broader interest of energy users statewide in developing lowest-cost energy supply resources.

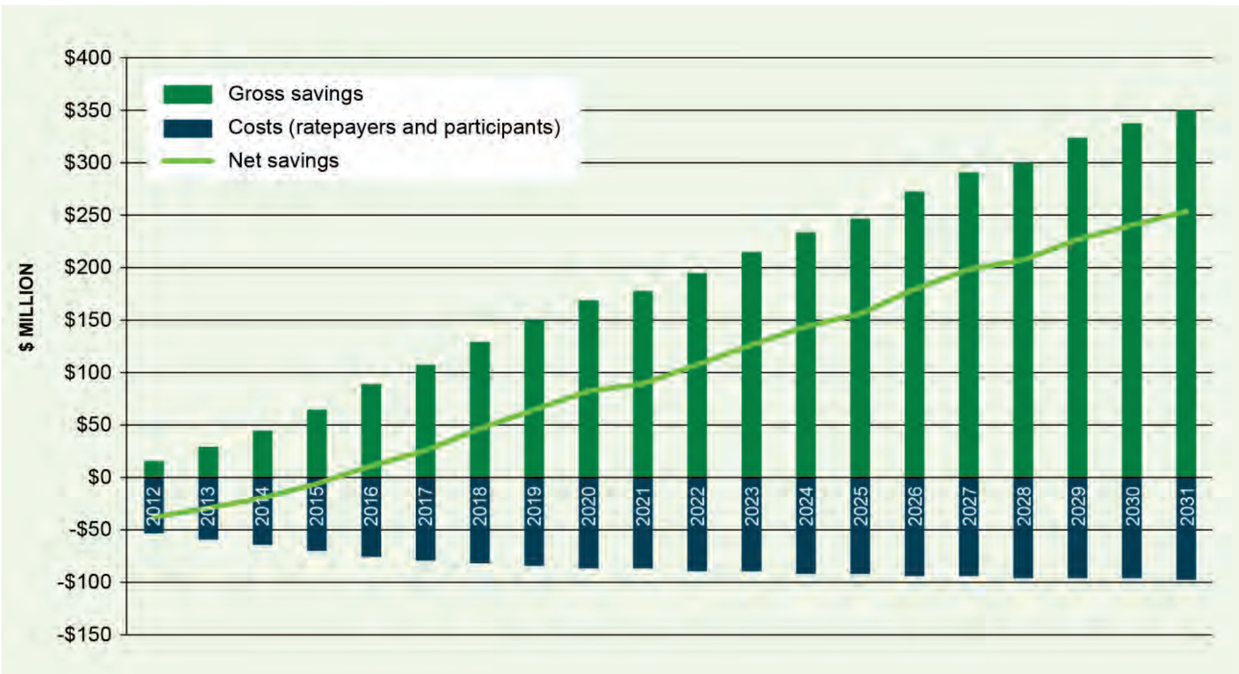
Implementation of cost-effective energy efficiency measures, if made within the context of ratepayer-funded energy efficiency programs, ultimately reduces the energy bills of all consumers. This is because energy efficiency can eliminate or delay the need to build more power generation, transmission, and distribution capacity. As a result, efficiency investments tend to lower electricity prices over the medium-to-long term due to the avoidance of utility rate increases otherwise necessary to develop more expensive new supply and transmission resources. How fast rates may decline relative to the no-energy efficiency base case, and by how much, depends primarily on how fast electricity demand is growing and the differences between the marginal costs for new supply and the marginal costs of energy efficiency resources. Generally speaking, however, a small rate increase in the near term (for energy efficiency program costs) will result in lower level rates in the long term compared to a no-energy efficiency base case (Taylor et al. 2012). This is especially true in regions where energy demand is growing and when other NEBs such as the environmental and public health externalities associated with the extraction of fuels and the extension of power transmission and distribution capacity are accounted for.

However, in order to achieve decreases in rates over time, it will be necessary to provide efficiency services to the vast majority of customers, including industrial customers, which represent a large share of potential savings. If this goal is achieved, then most customers will eventually be program participants and will enjoy the benefits of the efficiency programs, mitigating the issue of differential treatment. Therefore, pursuing the goal of achieving all cost-effective energy efficiency could lead to a reduction, not an increase, in rate impact concerns, as the vast majority of customers experience reduced bills over time. As participation levels increase, thoughtful program designs can ensure that all customers have a fair opportunity to participate (SEE Action Network 2011c).

As an example of the impact of energy efficiency programs on system costs, ACEEE recently modeled the benefits of Ohio's EERS, estimating it could save customers a total of almost $5.6 billion in avoided energy expenditures by 2020 and result in reduced wholesale energy and capacity prices, with wholesale energy price mitigation savings of $880 million (in 2012 dollars) and wholesale capacity price mitigation of $1,320 million (Neubauer et al. 2013).

In another example in the Pacific Northwest, acquisition of efficiency resources to meet additional electricity demand is far cheaper than developing new generation and can help moderate increases in consumer prices. The cost for additional supply of electricity from new sources is substantially higher than current average prices. The Sixth Northwest Conservation and Power Plan, issued in 2010, estimates the long-run averaged levelized cost of new electricity from natural gas-fired combined-cycle power plants to be about $0.092 per kWh, and the cost of Columbia Basin wind power to be about $0.104 per kWh. Compared to this, the average levelized cost of securing the Plan's aggressive portfolio of energy efficiency resources over 2010–2029 is $0.036 per kWh, including consumer costs (Taylor et al. 2012). The Plan also shows that energy efficiency reduced expected electricity loads by approximately 4,000 average MW since 1980 through the end of 2009, helping to level out demand.

Figure 5, from the Vermont Department of Public Service, illustrates how efficiency programs are expected to deliver long-term system savings relative to costs over 20 years.



Source: Vermont Department of Public Service (2011)

Figure 5. Efficiency Vermont costs and savings, high-efficiency case 2012–31 (current $)

Society as a Whole

IEE not only benefits individual companies at which the efficiency improvements are installed as well as all other utility ratepayers, but it also creates broader societal value. In addition to delivering cost-effective energy resources, energy efficiency reduces environmental impacts from energy production and use, and enhances energy supply security. Reductions in energy use, in addition to reducing greenhouse gas emissions, lead to lowering the burden of local air pollution, improving water use and efficiency, minimizing waste, and protecting the health and safety of workers. A recent U.S. Environmental Protection Agency (EPA) report calculated that each ton of reduced emissions from power plants (which might be displaced through IEE) has the following public health cost savings benefits: $130,000 to $290,000 for particle emissions ($PM_{2.5}$), $35,000 to $78,000 for sulfur dioxide (SO_2), and $5,200 to $12,000 for nitrogen oxides (NO_X) (EPA 2013a, Lazar and Colburn 2013).

Large quantities of water are also used in many industrial applications, mostly in process cooling. Energy efficiency measures often reduce water consumption and heat rejection control strategies can impact both process efficiency and water use. For example, significant opportunities exist to upgrade cooling towers to improve thermal capability, increasing energy efficiency and reducing water use. In water-constrained regions with significant industrial activity such as Texas, water- and energy-saving technologies can help to alleviate water scarcity and increase access for other users (Texas IOF 2013).

2.4. The Role of Energy Efficiency in an Expanding Manufacturing Base

Several trends suggest that the United States is beginning a major expansion of manufacturing capacity in a number of sectors (*The Economist* 2013). The U.S. government is tracking billions of dollars in planned manufacturing investments, including in fertilizers, chemicals, steel, cement, and assembly industries. Ample, low-cost natural gas supplies coupled with favorable foreign exchange rates and increasing labor productivity trends are attracting new investment in the U.S. manufacturing sector. For example, nearly 100 chemical industry investments valued at $71.7 billion had been announced through the end of March 2013 (American Chemical Council, May 2013). Companies such as Dow Chemical and Vallourec (steel tube producer) have announced new investments to take advantage of low gas prices and to supply extraction equipment.

The expansion of U.S. manufacturing has brought new awareness of the potential for energy efficiency to support the wider goal of increasing industrial competitiveness, productivity, and innovation. The installation of the most efficient processes and equipment (both in retrofitting existing systems and as new capacity is developed) serves as a hedge to maintain competitiveness for the future when energy supply and price conditions may once again change. Energy efficiency remains a profitable investment opportunity even in a low natural gas price environment and provides the added value of using this valuable domestic resource wisely and efficiently.

Lower American energy prices could result in up to one million additional manufacturing jobs (*The Economist* 2013). Manufacturing is often the key economic engine for local economies, so to the extent that energy efficiency investments help these facilities survive and grow, they support job retention and job growth within the local area. For example, Whirlpool attributes its ability to maintain the majority of its workforce at its Clyde, Ohio, plant, to industrial efficiency and production upgrades made at the facility, in addition to its production of a highly efficient line of front-load washing machines (NRDC 2012, Selko 2013).

2.5. The Current Status of State Industrial Energy Efficiency Programs

This report defines a state IEE program in broad terms as a program that provides information, services, and/or financial support to interested industrial facilities within the state for energy efficiency activities. IEE programs may have multiple goals but almost always have a public interest objective in mind—whether it is least-cost resource development, environmental benefits, consumer benefits, or economic development. State IEE programs can be administered by utilities, program administrators, or state energy offices. The most common are ratepayer-funded energy efficiency programs administrated by utilities and program administrators.[14]

IEE programs in the United States vary widely from state to state, as well as within states in both form and function. Some states have passed legislation mandating that a certain level of energy efficiency resources should be acquired or that all cost-effective energy efficiency opportunities should be pursued. Some programs may focus on electricity only, gas only, both of these energy sources, or all energy sources. State utility regulators, utilities, and energy efficiency program administrators often play pivotal roles in approving and delivering IEE programs. State energy offices are also important drivers of programs. Program funding may come from electric and natural gas ratepayers, funds from the state operating budget, federal and other sources, or a combination of sources. Program offerings are diverse, ranging from prescriptive incentives, custom/process efficiency, market transformation, strategic energy management, and self-direct program types (as described in Chapter 3).

In practice, because many states have chosen to include the manufacturing sector in energy efficiency programs funded by energy utility customers, ratepayer-funded programs are the focus of this report. These programs are predominantly funded by customers of electric and gas utilities. This is done either implicitly or explicitly, as charges added to electric and gas utility bills either as a cost of service and embedded in the total costs customers pay or as a separate line item to bills. These funds are often channeled into a public benefits fund or demand-side management (DSM) fund and programs are administered by utilities and/or energy efficiency program administrators.

[14] In a study of electric IEE program spending in 2010, the bulk of the spending (84%) came from ratepayer-funded utility program budgets; the remainder of the funding came from state federal budgets, universities, nonprofit organizations, and other groups (Chittum and Nowak 2012).

As of January 2014, 28 states have policies in place that establish specific energy savings targets, either through EERS, CEPS, or specific utility goals (ACEEE 2013a and ACEEE 2013b). Many states without energy efficiency targets still have ratepayer-funded programs.[15] In total, 41 states now require utility customers to contribute to supporting energy efficiency programs (Chittum in Uhlenhuth 2013). At least 35 state energy offices (SEOs) administer energy programs for manufacturers and the industrial sector (NASEO 2012). Appendix A provides a more detailed landscape of the scope and breadth of state IEE programs and the policy mechanisms that IEE programs currently operate under, including CEPS, energy savings targets for individual utilities, requirements to pursue all cost-effective energy efficiency opportunities, DSM mandates, or voluntary SEO-run programs.

Under these ratepayer-funded energy efficiency programs, utilities remain primarily responsible for administering and implementing programs with regulatory oversight. However, third-party energy efficiency program administrators also offer energy efficiency programs (ACEEE 2012). Although it is more common for each utility to develop and administer its own program, some states, such as Oregon, through the Energy Trust of Oregon (ETO), have unique programs set up to coordinate activities across the state and retain experts on staff to run the program. Others, like DTE Energy in Michigan, contract the work out to third parties while managing program savings targets (Taylor et al. 2012). Whatever the type of program administrator, each administrator operates under guidance and rules from the state utility regulator.[16]

Industrial Customer Class Coverage

Ratepayer-funded energy efficiency programs are typically designed to include all customer classes—residential, commercial, and industrial. In some states, however, industrial customers have been able to "opt out"[17] from programs altogether, or "self-direct" the funds—that they would have otherwise paid to the fund or utility—to their own direct energy efficiency actions.

Although there are many ratepayer-funded programs that include the industrial sector, there also are many states where development of programs has met with resistance by some manufacturers. In some cases, industrial customers may feel that they can design and implement energy efficiency efforts by themselves and do not want to provide funds through their utility bills for a separate entity to provide design and implementation assistance. In addition, industrial companies often are concerned that they fund a higher share of the program costs and receive less practical benefit compared with other ratepayer classes.

To address these concerns, some states allow industrials to opt out entirely as a "special customer class" from paying energy efficiency system benefit charges and not participate in programs at all. States with legislative opt-out clauses for large customers include Arkansas, Indiana, Kentucky, Maine, Michigan, Texas, and North Carolina (ACEEE 2013, Lewin 2013, Paradis 2013). States that are currently considering opt-out provisions include Oklahoma, Illinois, Louisiana, and Ohio (Ballard 2013, Elliott 2013, Ohio Township Association 2013).

Other states allow manufacturers (usually energy-intensive) to self-direct program funds toward their own energy efficiency activities. Examples include Massachusetts, Minnesota, Ohio, Oregon, Vermont, Washington, and Wisconsin. Note that regulatory oversight, use of program funds, and verification of savings will vary between states and program administrators. Self-direct programs, as opposed to full opt-out provisions, can be an attractive option if properly designed and monitored. Best practices in self-direct program design are further discussed in Chapter 5.

However, opt-out and loosely defined and monitored self-direct programs can be viewed as unfair to other customer classes who are required to pay program costs for energy efficiency resource acquisition that benefits all ratepayers, including manufacturers. Other system resources, such as new generation assets, are generally paid for

[15] Examples of states without EERS/energy efficiency targets but with ratepayer-funded energy efficiency programs include Idaho (Idaho Power), Wyoming (Rocky Mountain Power), and Utah (Rocky Mountain Power).

[16] For a discussion on choice of program administrator, see Sedano (2011).

[17] Opt-out programs allow large customers to fully opt out of paying their energy efficiency charges with no corresponding obligation to make energy efficiency investments on their own (ACEEE 2012b).

by all customers (Chittum 2011). The logic of energy efficiency programs is to procure least-cost energy efficiency resources, as opposed to only energy supply resources, for an entire utility system, ultimately reducing bills for all customers. Capturing cost-effective energy efficiency resources from all customer classes is an important element of an overall least-cost energy strategy for a utility, state, and region.

Many states have focused their energy efficiency program activities on the commercial and residential sectors due to the lower complexity of deploying common solutions throughout these markets. However, as regulators and program managers seek to meet increasing CEPS targets, they have begun to look at the industrial sector for greater energy savings. In addition, federal efficiency appliance standards are raising the baseline efficiency levels for many common residential and commercial measures such as lighting and home appliances, which further reduces the savings potential for these measures.

As a result, energy efficiency program administrators are increasingly turning to the industrial sector to help meet efficiency goals and are rethinking IEE program design and delivery to better meet industrial customers' evolving needs. Custom and tailored approaches are important for engaging industrial customers and responding to their specific needs.

Whatever framework they operate under, IEE programs can provide a variety of offerings and many programs offer a combination of services. For example, financial incentives for investments may be coupled with direct technical assistance. The major types of IEE program offerings generally in use in state IEE programs are discussed in Chapter 3.

3. How States Successfully Promote Industrial Energy Efficiency

Every industrial energy efficiency (IEE) program administrator can learn from its own experience and from the successes of others. This chapter summarizes the lessons and experiences of IEE program administrators, describes ways in which some states have been able to provide attractive offerings to manufacturers in a cost-effective manner, and explores how programs have matured and adapted through time to match evolving manufacturers' needs while simultaneously meeting statewide goals. Many states have effective IEE programs that have active participation from manufacturers and are producing verifiable energy savings.

As shown in Figure 6, these successful IEE programs represent a "spectrum of approaches," ranging from efforts by some states to promote IEE generally through knowledge sharing and technical assistance, to direct financial support of the implementation of strategic energy management and continuous improvement practices. Each offering can be effective in its own way and be an appropriate choice for individual states, depending on their regulatory contexts and circumstances. However, a more comprehensive set of program offerings—including combinations of the approaches on the spectrum (Figure 6)—is likely to deliver greater overall energy savings.

The spectrum highlights the range of program offerings that states can leverage as experience accrues and relationships develop with industrial customers. Effective IEE programs typically evolve over time with program administrators refining the program in cycles to increase its effectiveness.

Many mature IEE programs offer a suite of services to address diverse needs according to manufacturing sector, regional cluster, and each company's knowledge of and experience with IEE. These programs also provide companies with access to different offerings as they progress through an energy management pathway and look to implement more sophisticated improvement measures over time.

EXAMPLE 1: THE COLORADO INDUSTRIAL ENERGY CHALLENGE

The Colorado Industrial Energy Challenge (CIEC) is a voluntary program designed to help industrial facilities improve energy performance. The CIEC program challenges companies to set a five-year energy efficiency goal, and provides assistance in the form of free energy assessments, networking and training opportunities, and public recognition from the governor's office. The program is open to industrial facilities in Colorado with more than $300,000 in annual energy costs. The Southwest Energy Efficiency Project leads and coordinates the program with funding from the Colorado Governor's Energy Office and the U.S. Department of Energy (DOE). To join the program, companies sign a commitment letter agreeing to set a five-year goal for reducing total energy use or energy intensity and report energy information, energy efficiency project implementation, and progress toward the goal. As of 2013, the program has participation from around thirty facilities, and many have undertaken innovative projects to save energy and money. For example, Avago, a manufacturer of semiconductor devices, set a goal as part of CEIC to reduce energy intensity by 40% from 2008 levels by 2013. Avago implemented a project to use waste heat from a chiller condenser that would have otherwise been sent to cooling towers to preheat ultra-pure water needed in the manufacturing process. A heat exchanger now intercepts the rejected heat and pre-heats the cold water needed as feedstock for the process. The project cost $14,000, with a payback of only one month. It generates yearly savings of nearly $200,000, saves 28,000 decatherms of natural gas per year, reduces water use (through evaporation), and reduces CO_2 emissions by 1,600 tons per year.

Source: SWEEP 2013b

The spectrum of program approaches is discussed below and includes examples of successful state programs in each category. Detailed information on successful programs is provided in Appendix B.

APPROACH	DESCRIPTION	PROGRAM EXAMPLES
KNOWLEDGE SHARING	• Low-cost or no-cost technical assistance • Workshops and other outreach • Peer exchange opportunities between industrial clusters or groups of companies • Success story dissemination	• West Virginia Industries of the Future • Southwest Energy Efficiency Project
PRESCRIPTIVE INCENTIVES	• Explicit incentives or rebates for certain specific eligible technologies (e.g., lighting, motors, drives, compressed air, process heating equipment)	• Rocky Mountain Power • Efficiency Vermont
CUSTOM INCENTIVES	• Specific energy efficiency projects tailored to individual customers or specific industrial facilities • May be a mix of technologies • Incentives or rebates often based on entire electricity or natural gas savings	• Xcel Energy • NYSERDA
MARKET TRANSFORMATION	• Streamlined path for introduction of new energy efficiency products to the market • Address structural barriers to energy efficiency (e.g., outdated building codes or lack of vendors offering an emerging technology)	• Northwest Energy Efficiency Alliance
ENERGY MANAGEMENT	• Operational, organizational, and behavioral changes through strategic energy management • Continuous energy improvement (e.g., embedded energy manager to provide leadership and organizational continuity for implementing change)	• Wisconsin Focus on Energy • Energy Trust of Oregon
SELF-DIRECT	• Customer fees directed into energy efficiency investments in their own facilities instead of a broader aggregated pool of funds • Eligibility for customer participation often based on threshold amount of energy use or energy use capacity • Verified energy savings	• Puget Sound Energy • Michigan Self-Direct Energy Optimization

Figure 6. Spectrum of IEE state program approaches with program examples

3.1. Technical Assistance and Knowledge Sharing

Technical assistance and knowledge sharing programs are those that provide low-cost or no-cost expertise on energy-efficient technologies and practices, create networking opportunities between industrial clusters or groups of companies, and capture success stories and disseminate case studies. Some programs may also link companies with energy efficiency equipment and solution providers, leverage federal and other government resources so that industries may take advantage of equipment rebates, or direct customers to low- or no-cost industrial assessments funded through or by other programs.

Technical assistance and knowledge sharing programs are often initiated by program administrators voluntarily (i.e., without regulatory proceedings mandating ratepayer-funded programs and collection of a public benefits charge). Peer learning often provides a powerful driver for companies to implement energy efficiency measures and reap the productivity or competitive advantages their peers have enjoyed from similar investments. In those states that do not currently have ratepayer-funded programs, technical assistance and knowledge sharing programs can still generate significant energy savings to both manufacturers and society.

Examples of effective programs in this category include:

- The Colorado Industrial Energy Challenge (Example 1), which has been effective in its public recognition of IEE performance and providing companies with an opportunity to showcase their energy efficiency achievements
- The Industrial Energy Efficiency Network in the Southeast (Example 2), which hosts an effective peer exchange forum that provides a strong driver to share lessons learned
- The West Virginia Industries of the Future (WV-IOF) (Example 3), which has effectively leveraged partnerships with academic institutions and the U.S. Department of Energy (DOE) to provide training, technical assistance, and energy assessments to industrial staff.

EXAMPLE 2. THE SOUTHEAST INDUSTRIAL ENERGY EFFICIENCY NETWORK

The Industrial Energy Efficiency Network in the Southeast[18] is a regionally focused collaborative effort that unites cross-sector industrials in a peer-to-peer manufacturing network. As a platform for collaboration and education rather than providing technical assistance from a central program administrator to individual companies, the Network elevates energy efficiency best practices and project implementation, links manufacturers to financial and technical resources, and promotes strategic energy management practices.

Elevation of project ideas leads to implementation successes, with companies meeting regularly to share project experiences from initial conception through to measurable savings and other benefits. The exchange of qualified vendor references between peer energy managers is designed to shorten the time to project initiation. The Network offers a venue for activity at individual companies to be validated and celebrated by energy management peers.

The Network received an initial seed grant from DOE and is financed by public benefactors. Attendance at the peer-to-peer meetings continues to grow, with the average attendance around 80; manufacturers in the group have been actively making referrals to other firms in order to deepen the pool for collaboration. Firms are learning new tactics to manage energy at both the corporate and plant levels.

Sources: Marsh 2011, Marsh and Glatt 2011

3.2. Prescriptive and Custom Efficiency Offerings

Prescriptive and customized project offerings provide manufacturers with a financial incentive, often paired with technical assistance, for energy-efficient equipment and projects. Incentives for prescriptive and customized efficiency offerings are usually provided through ratepayer-funded programs. However, some non-ratepayer programs have designed IEE revolving funds in order to provide financial incentives (and technical support) on a self-sustaining basis.[19]

Prescriptive Offerings

Many energy efficiency programs have traditionally engaged the industrial sector through prescriptive incentives for lighting, motors, mechanical drives, compressed air, process heating equipment, and other energy support systems and equipment (Harris 2012). Prescriptive or standardized offerings provide explicit incentive or rebate amounts for certain specific eligible technologies. They can be useful for targeting those crosscutting pieces of equipment that are applicable across diverse commercial and industrial (C&I) sectors, and at both large facilities as well as small and medium enterprises (SME), such as variable speed drives for motor systems.

Prescriptive incentives for cross-cutting technologies can play an important role in helping to deploy high efficiency equipment across a broad base of industrial customers in different sectors and size classes. IEE programs have historically found it challenging to address the needs of SMEs as they have less staff capacity to address energy

[18] The program was previously administered by the Southeast Energy Efficiency Alliance (SEEA).

[19] Non-ratepayer-funded programs include AlabamaSAVES and the Tennessee Energy Efficiency Loan program administered by Pathway Lending. Pathway Lending received seed funding from the Tennessee State Energy Office, Tennessee Valley Authority, and DOE, but financing is leveraged principally through private community development banks. Low interest loans are available for businesses to invest in energy upgrades and the energy savings form a primary component of the principle repayment plan. These programs are profiled in Appendix B.

efficiency and generally have implemented fewer energy efficiency projects than larger companies. Taking advantage of less labor-intensive program offerings, such as prescriptive offerings—as long as eligible technologies are relevant to their situation—is a successful way to engage SMEs that may still have "low hanging" efficiency opportunities involving common technologies.

Prescriptive incentives are widespread throughout many states and are most often included as part of joint C&I rebate programs.[20] Although these measures may apply to manufacturing facilities, they do not address the majority of industrial energy-consuming equipment and processes. Some utilities have prescriptive measures for compressed air equipment, but in general a much larger percentage of energy savings projects specific to key industrial processes are categorized as custom measures (Seryak and Schreier 2013).

Custom Offerings

Instead of focusing on specific equipment upgrades, process or custom efficiency programs emphasize achieving savings from the manufacturing process itself, where the potential for energy savings is greatest (Harris 2012). Custom programs allow individual customers to develop specific energy efficiency projects that may be a mix of technologies and practices and qualify for incentives as long as they meet a required cost/benefit hurdle. Custom efficiency programs usually offer incentives based on a facility's entire electricity (kWh) or natural gas (therm) savings. Custom programs that use a per-unit-of-production calculation method shift the emphasis from traditional equipment upgrades (e.g., drives, motors) to improving a firm's ratio of energy use to physical output (Harris 2012). This allows program administrators to credit savings acquired via the implementation of a wide variety of technologies or plant and process modifications (Bradbury et al. 2013) rather than by choosing specific eligible technologies as in prescriptive rebate programs.

EXAMPLE 3. WEST VIRGINIA INDUSTRIES OF THE FUTURE

Industries of the Future West Virginia (IOF-WV), West Virginia's IEE program, was the nation's first state-level program (IOF-WV 2013) and helps manufacturers create financial savings through energy efficiency. IOF-WV teams work with individual companies to assess high priority research needs and develop projects that improve energy efficiency and environmental performance. IOF-WV grew out of a collaboration between West Virginia University, the West Virginia Development Office and DOE. The program provides technical assistance, conducts energy assessments, and runs best practice workshops on system-wide and component-specific topics to teach employees how to operate plants more efficiently. For example, the IOF-WV team conducted a plant-wide energy assessment at the Pechiney (now Alcan) facility in Ravenswood, West Virginia, from March 2002 to November 2003. The team identified $2.5 million in annual energy savings with average payback of less than 8 months. The assessment identified numerous areas for energy savings:

- Turning off comfort heating furnaces in summer months and in places where they are ineffective ($1,014,000 per year)
- Burner tuning and maintenance ($692,000 per year)
- Repair of compressed air leaks ($112,000 per year)
- Turning off idle equipment ($16,000 per year)
- Improving annealing furnace operating practice and modifying nitrogen plant control strategies to prevent waste of nitrogen ($75,000 per year).

The program is funded by a mix of state energy program funds, DOE funds, private sector leveraged funds, and cost-share.

Source: IOF-WV 2013, NASEO 2012

[20] The Database of State Incentives for Renewables and Efficiency (DSIRE) contains comprehensive information on rebates for specific technologies. See www.dsireusa.org.

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Custom programs generally require specialized resources to administer and support and may require greater program budgets than prescriptive offerings (Chittum et al. 2009). However, because they tend to deliver much larger savings and offer attractive paybacks per project, unit administration cost per kWh is often lower than prescriptive projects. Custom programs can be very cost-effective because they can unlock significant savings not possible through targeting individual pieces of equipment (Bradbury et al. 2013). CenterPoint Energy (see Example 4) has a successful custom program that was designed to address a gap in CenterPoint Energy's program coverage by reaching out to energy-intensive industrial customers who cannot avail themselves of standardized energy savings measures.

EXAMPLE 4. CENTERPOINT ENERGY CUSTOM PROCESS REBATE PROGRAM

CenterPoint Energy is an electric and gas utility based in Minneapolis, Minnesota, and has operated its rebate programs since the late 1990s. CenterPoint Energy provides financial incentives to customers who improve energy efficiency through innovative, customized energy-saving projects.

The Custom Process Rebate Program provides assistance and financial support to energy efficiency projects that do not qualify under prescriptive programs. Rebates primarily go to large-volume and dual-fuel customers that use throughput for process rather than heating purposes. Financial incentives are awarded to customers to assist with the first cost of the energy efficiency upgrade. The program has promoted such projects as bio-methane energy recovery, waste-heat energy recovery, boiler flue-gas condensers, thermal oxidizers, integral quench furnaces, heat-treat ovens, control packages, window replacement, stack economizers, and enthalpy wheels.

Each prospective project is compared to a base case to calculate efficiencies gained by installing the new technology. Once a project passes all requirements, an appropriate financial incentive is awarded to assist with the first cost of the energy efficiency upgrade(s). In some instances, C&I customers reach out to CenterPoint, seeking more effective energy efficiency processes. CenterPoint also works with customers to develop customized systems and solutions, and offers to buy down the new equipment, paying up to 50% of incremental cost.

In 2011, the program processed 148 custom projects that achieved a savings of 374,000 decatherms. The Custom Process Rebate Program addressed a gap in CenterPoint Energy's program coverage by reaching out to energy-intensive industrial customers who cannot avail themselves of standardized energy savings measures.

Source: Heffner et al. 2013

3.3. Market Transformation Programs

Market transformation programs work to streamline the path from the introduction and promotion of new energy efficiency products into the market to the establishment of customer acceptance. Market transformation programs require a long-term focus and are intended to address structural barriers to energy efficiency such as outdated building codes or lack of vendors offering an emerging technology. Their goal is to change marketplace behavior to increase acceptance of energy efficiency technologies and practices, but effecting this change can take time (often 5 to 15 years) (Taylor et al. 2012). Energy savings from these programs typically grow slowly in the early years, but are more likely to be persistent without relying on continued direct policy intervention once market acceptance is achieved (Taylor et al. 2012). An example of a successful market transformation program is the Northwest Energy Efficiency Alliance (NEEA) (Example 5). The initial phases of the process involve significant investments of time and effort to identify promising technologies and ideas and develop and test operational approaches to promote them. This type of effort is difficult for energy efficiency program administrators to justify because the costs are high for initial savings return. However, when an idea takes off, savings can materialize quickly, especially because program administrators in the Northwest (e.g., Energy Trust of Oregon and BPA) provide program support and leverage NEEA's market transformation solutions, pushing up market penetration rates and energy savings (Taylor et al. 2012).

EXAMPLE 5. NEEA'S MARKET TRANSFORMATION PROGRAM

The Northwest Energy Efficiency Alliance is a regional nonprofit alliance of more than 100 Northwest utilities and energy efficiency organizations working on behalf of more than 12 million energy consumers. It operates in Oregon, Washington, Idaho, and Montana. Formed in 1996, NEEA was tasked to undertake energy efficiency market transformation initiatives throughout the region in support of both regional utility energy efficiency programs and the energy efficiency agenda overall. NEEA works across residential, commercial, and industrial sectors; helps accelerate the innovation and adoption of energy-efficient products; and identifies, develops, and advances emerging technologies to fill the energy efficiency pipeline with new products. NEEA's costs are paid by the Bonneville Power Administration, the Energy Trust of Oregon, and distribution utilities.

NEEA's market transformation initiatives involve identifying promising technologies and developing and implementing programs that allow them to be effectively picked up in the marketplace on a sustainable basis. NEEA tracks the energy savings resulting from its various initiatives, which include both savings from ratepayer programs of the utilities or ETO that build directly from NEEA's innovations, as well as savings directly from overall market penetration. Since 1996, the region has cost-effectively delivered, on average, over 900 MW of energy efficiency per year through market transformation.

Sources: Taylor et al. (2012), NEAA (2013).

3.4. Strategic Energy Management and Energy Manager/Staffing Programs

Traditionally, IEE programs have generally focused on promoting energy efficiency technology and supporting the installation of new, more efficient equipment or processes. In contrast, continuous energy improvement,[21] strategic energy management (SEM), or energy manager programs seek to promote operational, organizational, and behavioral changes that result in greater efficiency gains on a continuing basis. Although technology-based programs typically involve energy assessments to identify specific efficiency opportunities, organizational issues often prevent cost-effective measures from being implemented. SEM and energy manager programs focus on establishing the framework and internal processes for managing energy use, as well as on implementing capital projects.

Strategic Energy Management Programs

SEM programs help support the deployment of holistic energy management strategies and seek to encourage energy savings generated from changes in corporate culture, behavior, and operations and maintenance (O&M) practices. SEM programs, which in this report also include the adoption of energy management systems (EnMS), usually involve establishing a team representing personnel from across the organization (rather than just one energy manager) and require corporate management support to raise energy efficiency as a priority within the firm. SEM programs support the development of baselines, energy performance indicators, and metering capabilities. Although implementation of capital projects is still guided by energy management processes to identify and prioritize energy efficiency opportunities, SEM programs also encourage best practices in O&M independent of new investments.

SEM programs can be an effective tool for companies that want to extend their efforts to systematically identify and prioritize capital projects beyond the isolated technical improvements they may have already made at their facilities. At the same time, SEM can also provide a framework for saving energy at little or no cost through changes in operational efficiency. For example, J.R. Simplot's corporate energy manager noted that by simply

[21] While the term "continuous energy improvement" was common in the past, the term "strategic energy management" has gained currency in today's programs.

applying behavioral changes, one plant was able to realize a 3% reduction in energy consumption in one year alone, with no capital expenditures (Sturtevant 2013). Energy management practices can be an especially attractive option for companies that do not have the capacity at that time to make significant investments, or are in the middle of operational cycles that limit plant modifications.

Examples of SEM programs include the BPA, the Energy Trust of Oregon (ETO), Wisconsin Focus on Energy (WFE), Xcel Energy Process Efficiency Program, BC Hydro, and AEP Ohio. An overview of the programs is provided in Table 1. Note that these programs' SEM offerings are often integrated into prescriptive or custom/process incentive programs but incentives for SEM can be different from custom or prescriptive incentives. Federal programs such as ENERGY STAR® offer resources that can be used and incorporated into an SEM offering.

BPA and ETO's SEM programs involve training "cohorts," or groups of non-competing companies, on SEM approaches. Companies typically meet monthly, with homework and coaching provided between meetings. These programs measure total energy savings achieved through the SEM training process, including savings from O&M changes, and provide incentives per unit of energy savings. BPA also offers a "track and tune" program to help companies find and implement low- and no-cost energy saving opportunities, and provides assistance with developing more sophisticated systems for monitoring energy consumption and measuring savings (Kolwey 2013).

Energy Manager Programs

A knowledgeable and dedicated energy manager is often the key to successfully implementing SEM within a company. An energy manager who works within and for the company for a period of time can provide leadership and organizational continuity for implementing change. Energy managers help guide energy efficiency capital expenditures through the company's approval process and provide the leadership and communication skills needed to inspire collaboration and minimize resistance to change within the organization. However, given the competitive pressures imposed on manufacturers today, many organizations are not able to obtain or reassign staff with the skill set to be a fulltime energy manager. Many organizations may lack awareness of the costs and benefits of hiring a fulltime staff member relative to other business investment opportunities and may also not anticipate the scope of the responsibilities. BPA's Energy Project Manager program (Example 6) has been successful in promoting the value of energy managers, as indicated by the fact that several facilities have gone on to hire their own energy managers after receiving BPA support.

To overcome these challenges, some IEE programs specifically support the placement of on-site energy managers in industrial facilities or with the corporate office. The energy manager can either be sourced as an existing staff member from within the company or brought in as an external expert (Russell 2013b). In some cases, programs provide support for on-site energy managers for a period of one year or longer. Program-sponsored energy manager initiatives promote the development of a cadre of experts needed to support SEM and achieve continuous energy efficiency gains over time (Russell 2013b).

For example, WFE provides a staffing grant to facilities that have already documented their major energy improvement needs. Reimbursements are paid upon implementation of energy efficiency projects. Twenty-eight facilities have been served to date. In 2010, 35 projects facilitated by the staffing grant in seven facilities generated energy savings of 278,872 MMBtu, or an average of 54,823 MMBtu per recipient). Staffing grant savings averaged $0.91 per MMBtu. Note that the energy savings totals include some projects that were not eligible for additional investment incentives (Russell 2013b).

BPA and Puget Sound Energy also have energy manager co-funding programs. Puget Sound Energy, BPA, and WFE programs provide partial financial support for the energy manager position assigned from existing personnel within the facility. The advantage of assigning an existing employee is that the person has already garnered trust of his/her colleagues and is familiar with the operational and technical processes of the workplace.

Roving energy project managers that assist multiple companies (as opposed to embedded energy managers for a single facility as described above) can also be an effective option, particularly for SMEs. SMEs often lack technical expertise and can thus benefit from external personnel who can share their technical and implementation experience from working with companies in similar applications. A roving energy manager can assist five to six companies at once by providing energy project management support and implementing energy efficiency opportunities identified through an energy audit (Weir 2013). For example, from 2010 to 2012, the Minnesota Energy Resources Corporation provided an energy management team coordinator to help the internal energy management teams of five industrial customers identify and implement energy conservation improvements (i.e., the coordinator dedicated 20% of total work time to each customer).

Table 1. Selected Energy Management and Energy Manager/Staffing Programs

Energy Management Offering	SEM Incentives	Customer Size
BONNEVILLE POWER ADMINISTRATION—ENERGY SMART INDUSTRIAL PROGRAM		
- **High Performance Energy Management (HPEM):** Provides training and individual assistance to 8–15 companies for one year. Measurement and incentive funding is available for 3–5 years. - **Track and Tune**: Low/no-cost operations O&M with incentive funding over 3–5 years and tools for interval data acquisition and performance tracking. - **Energy Project Manager (EPM) Program**: Funding of energy efficiency staff to support project identification and implementation (see Example 6).	$0.025/kWh for 3 or 5 years, for O&M savings	18,000 MWh/yr (guideline)
ENERGY TRUST OF OREGON—PRODUCTION EFFICIENCY PROGRAM		
- **Industrial Energy Improvement (IEI)**: Year-long engagement provides cohorts of manufacturing companies trainings on SEM principles, tools, and practices designed to help companies manage their energy strategically. - **Corporate SEM (CSEM):** Focuses on corporate sites, instead of the cohort model, CSEM provides training and on-site activities on SEM principles and practices (9–12 months). - **SEM-Maintenance:** Helps former SEM participants maintain, deepen, and continue the integration of SEM into their business' operations. - **CORE Improvement**: Offering similar to IEI in focus and structure but services and instructions are tailored to small to medium manufacturers. - **ISO 5001 pilot implementation** (see Chapter 6).	$0.02/kWh, $0.20/therm for 1 year of savings. SEM-Maintenance: $0.01/kWh, $0.10/therm	IEI/CSEM: More than 8,000,000 kWh/yr, or if eligible for gas, 500,000 therms/yr usage. CORE: Spending $50,000–$500,000 on total energy costs (electricity and gas combined)
WISCONSIN FOCUS ON ENERGY—INDUSTRIAL PROGRAM		
- **Practical Energy Management**: Provides best practice training events and applies its industry-specific Energy Best Practice Guidebooks to key cluster industries. - **Staffing grants:** Allow companies to hire an FTE.	Grants for energy staff	Customers with more than $60,000 in monthly bills
XCEL ENERGY—PROCESS EFFICIENCY PROGRAM (CO & MN)		
Provides individual assistance in developing a 3–5 year energy management plan using the Envinta One-2-Five Energy Methodology that evaluates energy intensive processes, benchmarks energy management practices, and provides an assessment prioritizing opportunities.	For capital projects only	> 2,000 MWh/yr of savings potential
BC HYDRO—POWER SMART		
- **Industrial Energy Manager:** Offers funding for large customers to hire an on-site energy manager and a structured support group of local companies that share best practices. - **Energy Management Assessment:** Free assessment of opportunities, customized SEM action plan, and rating against the Energy Management Scorecard. - **Various free energy management tools and training**, employee awareness kits, and customer recognition through public media.	Co-funding of energy manager	> 20 GWh annually
AEP OHIO—CONTINUOUS ENERGY IMPROVEMENT PROGRAM		
- **Coaching assistance, tools, and templates** to help meet plant and corporate cost saving targets. - **Custom statistical models** to help measure and manage energy intensity. - An **Energy Coach** to help identify and implement opportunities.	$0.06 /kWh (or $0.02/kWh over 3 years)	> 10 GWh annually

Sources: Batmale and Gilless 2013, IIP 2013, Kolwey 2013, Russell 2013, Nowak et al. 2012, BC Hydro 2013, AEP Ohio 2013, Xcel Energy 2010

EXAMPLE 6. BPA'S ENERGY PROJECT MANAGER PROGRAM

BPA has introduced an Energy Project Manager (EPM) program that funds a position for an engineer at an industrial facility. This individual can be an existing staff engineer or someone specifically hired for the position. One of the primary requirements is that the facility has the potential for, and commits to, annual energy savings of 1 million kWh through efficiency projects.

Initially, BPA and the customer estimate achievable energy savings. The energy manager is then required to develop a plan with updates every three to six months. The savings are tabulated according to the upfront feasibility studies for specific projects and revised according to final measurement and verification of achieved savings. Once the EPM is assigned and the estimated savings have been agreed, an initial $25,000 funding payment is made to the facility. The program also reimburses a fixed rate per kWh saved ($0.025 per KWh saved) subject to a funding cap of $250,000 maximum annual amount. Additional incentives are available for capital and O&M projects.

From 2009 through March 2013, 28 energy managers had been placed in a variety of industries and capacity savings averaging 16.6 MW had been implemented. More than half of program participants apply for term renewals. Some facilities are currently in years 2–3 of their participation. BPA has found that several facilities have gone on to hire their own energy managers after receiving this type of funding support for several years.

Sources: BPA 2012a, DOE 2010, Kolwey 2013, Russell 2013b

4. Program Features that Respond to Manufacturers' Needs

The spectrum of program approaches discussed in Chapter 3 demonstrates that there are a range of program offerings designed to help manufacturers improve their energy efficiency. These can range from providing technical assistance to offering financial incentives for common technologies to sponsoring an energy manager to guide a facility toward behavioral changes that result in more energy-efficient operations and maintenance. These approaches can be customized to meet a variety of conditions, and fundamental success factors can be worked into a wide variety of program designs and policy environments.

Effective industrial energy efficiency (IEE) programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and the investment decision-making processes allows state IEE program administrators to boost implementation rates while making better use of limited resources.

This chapter first discusses the special needs and characteristics of industrial companies as energy users and provides basic information that may help program administrators recognize and navigate prevailing capital investment practices and corporate culture perspectives on energy. The reader should keep in mind these are generalizations, and may not be applicable to any specific industrial customer. It then discusses reasons why manufacturers may resist participating in state IEE programs. Finally, building on approaches that are currently operating in a variety of state contexts, it explores specific features that can respond to manufacturers' needs.

For the most part, these features are engagement strategies that have been proven to provide value to industrial customers. With greater industrial engagement and participation, state goals such as providing utility customers with low-cost energy resources and environmental benefits can be met more quickly and cost-effectively. The program examples highlighted here have been successful, not only because they have been able to respond to manufacturers' needs and achieve significant energy savings, but also because they often demonstrate cost-effectiveness (according to whatever cost tests a state may require for the program), have had good rates of participation, or show they have some longevity and a track record of successful projects.

4.1. Special Needs and Characteristics of Manufacturers as Energy Users

Manufacturing is Complex and Sophisticated

Understanding energy use patterns in manufacturing plants can be far more complex than in other end-user sectors. Manufacturing uses energy in various common technologies such as boilers, air compressors, or motors, as well as in processes that are specific to each industry.

Although the technical choices and energy use characteristics for various common technologies may at times be straightforward, the economics of adopting energy savings measures in these cases can still be complicated, as they are heavily related to production patterns that typically change with the ups and downs of market demands. Energy use tied to specific manufacturing processes, then, is highly plant-specific and typically requires a level of specialized knowledge that often is found only among subsector technical experts.

Industrial companies are also generally more knowledgeable about energy issues than other customer categories, especially in factories where the cost of energy is a substantial proportion of overall costs. For example, in the steel industry, energy accounts for about 15% of total manufacturing costs, and in the glass industry, energy costs are 8%–12% of production cost (DOE 2013a). Even in applications where energy is not a large proportion of costs, some industrial managers view energy as a cost that can be controlled more easily than labor or feedstock inputs—at least in the near term.

Manufacturing is Heterogeneous

The industrial sector is very diverse, comprising a wide variety of different industry subsectors with different production processes and energy use characteristics. Even within subsector processes, product mix output and energy use patterns vary substantially. In the chemical industry, for example, it is typical for individual plants to continually adjust their product outputs as market conditions change and new opportunities arise. Such changes often require adjustments in process flows and the equipment and energy use patterns of different parts of a facility.

The industrial sector includes a broad spectrum of company size and technical sophistication ranging from very large companies with internal engineering staff to small and medium enterprises (SMEs) with limited technical capabilities.

The heterogeneity of the manufacturing sector can make it difficult for IEE programs to meet the specific needs of individual companies. To some extent, fairly simple programs designed to assist companies to save energy in common technology applications can be designed to be relevant to a wide range of manufacturing plants, providing some value. However, focus on simple common technology fixes alone will tend to put programs on only the periphery of manufacturing energy use and savings concerns. Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption in addition to heating, ventilating, and air conditioning (HVAC) and lighting loads. Although it varies depending on manufacturing subsector, HVAC and lighting typically make up around 20% of total energy consumption (Kolwey 2012).

Although manufacturing as a sector is usually heterogeneous, industries may cluster in certain service areas for a variety of reasons. This creates opportunities for program administrators to concentrate energy efficiency process expertise in such places. Wisconsin's cluster approach is discussed in Section 4.7.

Energy Efficiency is Often Not Integrated into a Company's Decision-Making Process

Because energy can be a significant percentage of total manufacturing costs, lowering energy costs through increased efficiency can improve a company's bottom line and overall competitiveness. However, the decision-making processes of industrial companies involve a variety of participants, concerns, and procedures. There is a range of reasons why internal decision-making processes may not result in implementation of highly cost-effective energy efficiency opportunities, including:

- Energy efficiency projects may compete with core business investments that dominate attention, as well as investments for safety, environmental, and other regulatory requirements
- Decision-making is often split across business units
- The skills required to identify and pursue energy efficiency opportunities are not always present.

Projects focusing on operating cost savings may not compete well internally with projects focusing on expansion or new market development, despite very attractive financial returns. The profit benefits of investments leading to operating cost reductions may be difficult to clearly identify or communicate. Sometimes, other major investments may be seen as more core to the business, attracting higher priority. At other times, access to financing for operating cost saving projects also may be a barrier. Projects may be difficult to finance with outside loan capital if they are relatively small, due to lukewarm interest among financiers and high transaction costs.

Large companies often split responsibility for plant operations, energy bills, and investment decisions across different organizational units. A plant manager may be interested in energy efficiency, but does not see the actual energy bills or get credit for reducing them. A procurement manager may be motivated to minimize first costs instead of life-cycle costs, even if efficient choices save operating costs at the plant level. These "principal-agent" or "split-incentive" barriers can keep cost-effective improvements from happening.

In addition, in some cases manufacturers concerned about controlling energy costs may focus on efforts to gain more favorable energy pricing and contractual arrangements with energy suppliers and not necessarily on improving the efficiency of energy use in operations.

Finally, the skills required to identify and implement IEE opportunities are not always present in existing staff or staff are tasked with addressing other priorities. Companies often lack in-house staff capacity and specialized expertise in energy management and technology skill sets. This prevents cost-effective measures from being identified, and also prevents known options from being advanced to the implementation stage.

Operational Cycles Influence When Energy Efficiency Investments Can Be Made

Energy efficiency investments are heavily dependent on the industrial customer's operational cycle, which can span four to seven years on average (Chittum 2009). Maintaining stable production is critical in industry. Project implementation can require temporary downtime for equipment installation and testing, impacting plant operations and production. Flexible scheduling to best match production requirements—for example, delaying implementation to times when many projects can be done at once or to planned shutdowns—will minimize plant interruptions and reduce management concerns.

In addition, IEE projects can often be significantly larger than projects in other sectors, requiring completion of comprehensive project approval processes and careful consideration by various personnel across a number of corporate divisions. Time horizons for project approval may be long. Moreover, implementation scheduling may require linkages to a variety of other project implementation measures at the same time.

Co-Benefits Are Often Not Included in the Cost-Benefit Analysis for Energy Efficiency Projects

Although additional co-benefits or non-energy benefits (NEBs) from energy efficiency projects may be substantial for the industrial customer, they are generally not included in the cost-benefit analysis for energy efficiency projects. This is despite extensive evidence that NEBs can be a key part of project benefits and can reduce payback times for new investments. Co-benefits may even exceed the value of energy savings. A 2003 study of commercial and IEE programs in Wisconsin valued these benefits at approximately 2.5 times the projected energy savings of the installed technologies (Hall and Roth 2003). In a recent survey of 30 energy managers, engineers, sustainability managers, plant managers, presidents, and vice presidents from a diverse pool of companies nationwide, 90% of energy projects were found to also have a broader productivity impact (Russell 2013a). For one company surveyed, energy improvements provided a fourfold return in the form of production improvements and some companies claimed that NEBs "dominated" the returns from energy projects. NEBs are further discussed in Chapter 6.

4.2. Industrial Participation in Energy Efficiency Programs

Historically, energy efficiency program administrators have struggled to create programs that overcome concerns from manufacturers about perceived or real costs, potential risk for production disruptions, or lack of flexibility in prescriptive incentive programs. When new ratepayer energy efficiency programs are being contemplated, large industries may resist paying systems benefits charges. In cases where some types of industrial programs have already been put in place as part of resource acquisition efforts, some industries remain lukewarm about participating. Several common reasons for this include:

- Saving energy is already claimed to be a business imperative and many industrial customers feel they can best manage their own energy needs, so they may think there is no added value in participating in IEE programs.
- Manufacturers are not aware of the IEE program offerings that may be most useful for their operations.
- IEE program offerings may not be flexible enough to meet the most pressing energy efficiency investment priorities of manufacturers and may be considered administratively complex and burdensome.
- Available IEE programs are perceived as being unresponsive to core energy issues in plants that are subsector- and site-specific.
- IEE program administrators may be perceived to have insufficient expertise in manufacturing and/or are not knowledgeable about key customer concerns and needs.
- There is a mismatch between industrial planning and project cycles and IEE program terms. Equipment replacement or refurbishment or plant retrofits can often only occur at the end of appointed times in operational cycles.

- Industrial firms can be sensitive about releasing confidential information and may be concerned that programs end up sharing information on what they consider to be their competitive advantage.

All of these observations help explain why manufacturers may not always respond quickly or positively to IEE program offerings. Program designers who are aware of the issues and concerns that can limit industrial participation can be better equipped to design programs that address these concerns and better meet the specific needs of their industrial market (Section 4.7 discusses how program administrators have been able to provide significant value to their industrial customers).

As described in further detail below, successful IEE programs that provide value both to individual industrial energy users and to society at large:

- Clearly demonstrate the value proposition of energy efficiency projects and IEE programs
- Develop long-term relationships with industrial customers, with continual efforts to identify effective projects
- Accommodate project scheduling issues
- Provide both common technology and customized project development options
- Ensure that program administrators have industrial sector credibility and can offer high quality technical expertise targeted to specific subsectors
- Streamline and accelerate application processes
- Leverage strategic partnerships
- Conduct active and continuing program outreach
- Set medium- and long-term energy efficiency goals as an investment signal for industrial customers
- Ensure robust evaluation, monitoring, and verification.

EXAMPLE 7. NORPAC'S WASHINGTON MILL BENEFITS FROM CUSTOM EFFICIENCY OFFERING

NORPAC, a large paper mill in Washington State, is the largest newsprint and specialty paper mill in North America. The 33-year-old mill produces 750,000 tons of paper a year and is the largest industrial consumer of electricity in the state, requiring about 200 MW_{avg} of power. It takes a lot of energy, water, and wood to make paper and the process begins with wood chips. Refining wood chips is a mechanical process that requires large amounts of energy.

Bonneville Power Administration (BPA) and the Cowlitz County Public Utility District (PUD) funded the installation of new screening equipment between refiners that reduces the electricity and chemicals used to refine wood chips and reduces the amount of pulp needed for the process. The equipment is estimated to save NORPAC 100 million kilowatt-hours of electricity per year, equivalent to cutting its power requirements by about 12%, and is enough energy to power 8,000 Northwest homes.

The improved refining processes have also allowed NORPAC to expand its product line. The mill can now produce a brighter and whiter paper that is made from fewer wood chips than a similar grade from its competitors.

NORPAC employs 415 full-time employees and about 30 contractors and the construction phase of the project created 64 full-time family-wage jobs.

BPA has funded about $21 million for three custom projects at NORPAC, and Cowlitz PUD will contribute up to an additional $3.9 million. NORPAC is funding the remaining $35 million of the $60 million project.

Source: Taylor et al. (2012); BPA (2012b)

4.3. Clearly Demonstrate the Energy Efficiency Project Value Proposition to Companies

Energy efficiency measures, which generally lower the cost of production or increase output per input costs, have repeatedly demonstrated their effectiveness in improving a facility's bottom line and in increasing company competitiveness and productivity. Benefits can include strong life-cycle cost savings with sometimes minimal capital investment, a variety of non-energy co-benefits, and even reputational advantages. It is not uncommon for manufacturing facilities to realize energy efficiency improvements as high as 10%, with corresponding cost savings and financial paybacks of two years or less when they implement basic operational and maintenance improvements. For example, as part of the U.S. Department of Energy's (DOE's) Superior Energy Performance (SEP) program, 14 pilot plants have implemented the global energy management standard, ISO 50001, and achieved SEP certification. Nine of these plants have shown an average energy performance improvement of 10% in the first 18 months of SEP implementation, with an average payback of 1.7 years (DOE 2013c). Energy Trust of Oregon (ETO) and AEP Ohio also estimate that their industrial customers can typically achieve 5%–15% savings through energy management with little or no capital investment (ETO 2013, AEP Ohio 2013). And Efficiency Vermont estimates its Continuous Energy Improvement program can help companies cut energy consumption by 10%–15% within the first three years and 25%–35% within six years (Efficiency Vermont 2013).

Many companies that have participated in IEE programs have experienced strong cost savings benefits, and successful IEE programs document how program offerings have helped their industrial customers' bottom lines. For example, the Bonneville Power Administration (BPA) extensively documents results from its Energy Smart Industrial Program. Success stories include:

- The NORPAC pulp and paper mill in Washington State, which cut its power requirements by 12% per year through upgrades financed by BPA (Example 7)
- J.R. Simplot, which identified energy savings of $715,000 per year with a three-year payback (Example 8)
- Irving Tissue, which, through participation in the New York State Energy Research and Development Authority's (NYSERDA's) industrial FlexTech and Industrial Process Efficiency (IPE) programs, was able to save 14,800,000 kWh per year (Example 9).

EXAMPLE 8. SIMPLOT AND CASCADE ENGINEERING IDENTIFY $1,000,000 IN ELECTRICAL SAVINGS

J.R. Simplot Company is one of the largest privately-held corporations in the United States, consisting of AgriBusiness, Land and Livestock, and Food Group divisions. The company was successful in developing and integrating a company-wide energy management program and worked with Cascade Energy within local utility energy programs to obtain energy study co-funding and implementation incentives. Simplot is also a U.S. Department of Energy Better Plants Challenge Partner and a U.S. Environmental Protection Agency (EPA) ENERGY STAR® partner.

Simplot and Cascade Energy have joined forces on 14 detailed energy studies at nine facilities over the past 10 years. Cascade provided facility scoping, energy analysis, project costing, design assistance, commissioning, and final inspection services on these projects. Cascade evaluated refrigeration, compressed air, hydraulics, pumping systems, processes, and controls at both existing and new facilities. Simplot implemented seven of the largest projects to date, capturing well over half the identified energy savings.

Energy Savings: $715,000 per year or 21,000,000 kWh per year ($1,000,000 or 36,000,000 kWh per year identified)

Investment: $950,000 to date ($2,000,000 identified)

Financial Return: Three-year simple payback on implemented projects

Source: EPA 2013b

PacifiCorp, an investor-owned utility operating in five northwestern states, offers extensive ratepayer-funded energy efficiency programs throughout their territory. For those customers participating in IEE programs, PacifiCorp has found that a one-dollar investment can yield $4.10 to $5.60 in long-term savings. The utility has documented that these energy savings are predictable over time, measurable, and long-lasting (WGA 2013).

A key point in making the value proposition case to industrial company managers is to lay out in simple and concise terms the operating cost savings and other benefits—including profits—that are being left on the table by not addressing cost-effective energy efficiency improvement opportunities. The case can then move on to the simple steps required to capture the most prominent savings opportunities. Cost-saving examples and success stories from similar companies in similar situations can also greatly help to further buttress the case. Discussion and exchange with peers can also be a strong driver for energy efficiency with individuals and companies. Many successful programs offer a venue for peer exchange.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Document results from successful IEE projects.
- Include non-energy benefits of energy efficiency measures in the value proposition.
- Develop case studies and examples for different industrial sectors.

4.4. Develop Long-Term Relationships with Industrial Customers and Continue to Refine Project Offerings

Maintaining multi-year and steady relationships with individual industrial customers is a key factor for achieving success in state IEE programs. All the energy efficiency programs that have been successful with industry have this element in common.

The reasons why long-term, steady relationships with individual customers are so important stem in large part from the particular characteristics and needs of the industrial sector described previously. Key reasons include:

- Strong understanding of industrial customer circumstances and needs. To add real value to existing energy efficiency efforts at a customer facility, program staff need to understand the specific circumstances of the plant as well as their plans and issues.
- Develop projects on a flexible timeframe. IEE projects tend to be identified over time, as plant circumstances change and opportunities arise. In addition, project implementation scheduling must accommodate a host of industrial client concerns (see Section 4.5). Successful program staff consistently report that the best results are maintained through steady dialogue and contact, responding to the opportunities when they arise.
- Build synergies between program offerings. Proven results with industrial customers often involve a variety of program offerings and services. Typically, these are delivered at different times, as opportunities and customer needs develop, but they are also often interrelated and build on each other. For example, assistance in completing an audit may often lead to identification of a project for program support or an energy management improvement opportunity. Joint work on completion of a customized project may lead to identification of a number of simple prescriptive project options that a company was not aware of. Advice on how to access a key process expert may lead to a new project.

EXAMPLE 9. IRVING TISSUE BENEFITS FROM NYSERDA'S INDUSTRIAL OFFERINGS

The New York State Energy Research and Development Authority's (NYSERDA's) longstanding technical assistance program—known as FlexTech—and its Industrial Process Efficiency grant programs have assisted Irving Tissue, a tissue, paper towel, and napkin manufacturer located in Fort Edward, New York, with increasing its new plants' efficiency. The company was considering a major plant expansion to improve productivity and competitiveness. To ensure that the new operation was cost competitive, Irving Tissue worked with manufacturers, suppliers, and NYSERDA to build energy efficiency into the new paper-making systems. A proposed upgrade for a more efficient vacuum system would create significant energy and cost savings while delivering a higher quality product. However, the cost of the system was too great for the company to self-finance. The Industrial Process Efficiency program was not only able to provide grant funding for the vacuum, but also was able to recommend the installation of premium efficiency motors and variable-speed drives. NYSERDA was able to finance $1.8 million of the full incremental cost of $4.3 million for the efficiency upgrades. The new papermaking machine is saving 14,800,000 kWh per year compared with a standard paper machine.

Source: NASEO 2012

The importance of building long-term relationships is bolstered by a stable and skilled IEE program contact for industrial customer interaction. Satisfaction of industrial customers with program delivery and results often hinge on the degree of success achieved in establishing a strong relationship with program staff. Within IEE programs, the industrial program account management system provides a structure for steady engagement with industrial customers. Individual account managers may be staff, long-term contractors, or a blend of these (see Section 4.7). Successful programs have a cadre of skilled staff and experts to develop, build, and maintain the long-term relationships with individual customers needed for industrial program success.

Many programs become steadily stronger because of long-lasting industrial customer relationships. IEE program administrators that have developed long-term relationships with industrial customers can track the status of the firm's energy efficiency efforts and investments made over time. This enables them to provide continued relevant solutions to the company.

In their efforts to maintain steady, regular dialogue with industrial customers, successful IEE programs engage at the customer's corporate level as well as the plant level. Note that this can be a challenging task for a regional program, especially when corporate headquarters is located outside the region. Identifying an internal energy champion within the industrial company and connecting with several additional staff so relationships can continue despite staff changes also helps foster long-lasting relationships.

EXAMPLE 10. XCEL ENERGY INCENTIVES AND TECHNICAL SUPPORT

Xcel Energy operates in eight states. Their incentives portfolio has been lauded by industrial customers for offering simple incentive applications for providing a full suite of programs—custom, self-direct, and process energy efficiency incentives. Xcel representatives noted that they see the most manufacturing participation where there is flexibility and incentive stability.

Xcel's Process Efficiency (PE) program in Colorado integrates its technical assistance, energy management support, and incentive programs. The PE program is available to industrial customers with energy conservation potential of at least 2 GWh, which usually translates to total annual electricity consumption of at least 20 GWh. The program offers a free scoping assessment and provides support for strategic energy management. A second more detailed assessment is then undertaken, for which the customers pays 25% of the cost, up to $7,500. After the detailed assessment is completed, Xcel Energy and the customer sign an agreement that specifies which projects will be implemented, the timeframe for implementation, and the incentive amount based on the rate of $400 per kilowatt of peak demand reduction. Xcel Energy encourages the customer to agree to complete projects within a year, but allows longer timeframes if needed.

Source: Kolwey 2012, WGA 2012

In ETO's Production Efficiency program (see Example 11), additional customer support has encouraged more cost-effective savings. The ETO program focuses on long-term relationships using a business-like approach to customer relations to help customers achieve significant ongoing savings. Increased program delivery expenditures have delivered higher savings and lower resource acquisition costs than increased incentive levels. Customers recognize the value of program assistance in customer satisfaction surveys (Nowak et al. 2012).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Understand the industrial customer's circumstances, needs, and operational cycles.
- Build synergies between program offerings.
- Develop stable, long-lasting relationships for maximum results.

EXAMPLE 11. ENERGY TRUST OF OREGON PRODUCTION EFFICIENCY PROGRAM

Recognizing that large manufacturers can realize deep energy savings with low-cost changes, the Energy Trust of Oregon (ETO) offers the Industrial and Agricultural Production Efficiency program, a custom and prescriptive rebate program, to help achieve these savings. Portland General Electric, Pacific Power, NW Natural, and Cascade Natural Gas customers, who pay into the state public benefit fund, qualify.

The program promotes innovative IEE technological and behavioral approaches and provides technical expertise, training, and project funding to help companies plan, manage, and improve their energy efficiency. All industrial size classes are eligible, but the program focuses on measures that will yield more significant energy savings: custom projects for industrial process improvements, strategies for large energy users, and projects with certain low-cost changes that can yield significant energy savings. The program also offers prescriptive incentives available for projects such as lighting and heat pumps.

ETO provides free technical services, typically valued at $20,000 to $50,000, to complete a study of energy efficiency opportunities. Custom incentives are calculated on a case-by-case basis. Incentives of $0.08 per kWh and $0.04 per therm are also available for operations and maintenance improvements (up to 50% of eligible project costs or up to 90% if completed within 90 days), energy management practices ($0.02 per kWh saved or $0.20 per therm saved), and custom process or production equipment projects (up to 50% of project costs).

ETO contracts with energy efficiency account managers throughout Oregon, termed program delivery contractors, and with energy efficiency process engineers termed allied technical assistance contractors, who provide detailed technical and scoping studies to determine the most cost-effective energy upgrades.

ETO's 2013 energy savings from industrial customers reached 16.9 MW_{avg} of electricity and 2.2 million therms of natural gas. The Production Efficiency program completes nearly a thousand projects per year.

Sources: ETO 2012, ETO 2013b, Nowak et al. 2013

4.5. Ensure Program Administrators Have Industrial Sector Credibility and Offer High Quality Technical Expertise

As discussed in the previous section, development of long-term relationships between industrial customers, program administrators, and experts is important for IEE program success. Effective IEE programs also develop credibility with the industrial customer by employing staff and/or contracted experts that understand the customer's industrial segment, and have the technical expertise to provide quality technical advice and support on energy efficiency options and implementation issues specific to that industry and that customer.

Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context that the plant operates within. Effective IEE programs will adopt the language, engagement strategies, and metrics that are meaningful to the corporate managers who drive capital investment decisions. Understanding customer needs and their investment decision-making processes allows IEE program administrators to generate trust with their industrial customers, boosting IEE implementation rates while making better use of limited resources.

Access to specific subsector technical expertise for specific short-term assignment is almost always necessary. Engagement of technical experts can address customers' specific technical needs such as completing diagnostics, developing new internal metering programs, assessing technology options for new projects, and developing project-specific measurement and verification (M&V) plans.

There are different approaches to ensure that this key program contact function is effective. Some program administrators rely heavily on in-house staff for this function. For example, Efficiency Vermont maintains six account managers in charge of all day-to-day relations with industrial customers. On the other side of the spectrum, some program administrators rely heavily on contractors to undertake day-to-day account-manager type functions for their industry programs. One example includes Wisconsin's long-standing Focus on Energy program, which one contractor has operated successfully for almost 14 years, providing steady service to large industrial customers under the Focus on Energy brand (Taylor et al. 2012). Others rely heavily on contractors to undertake day-to-day account-manager type functions.

A mixed approach can also be adopted, using both in-house and contractor staff to maintain day-to-day dialogue. In Oregon, for example, nine of ETO's 80–85 internal staff are responsible for delivery of the industry and agriculture Production Efficiency program. These staff work together with six outsourced Program Delivery Contractor (PDC) teams. The PDC teams include six to seven people each, working on day-to-day delivery of the program. There are currently 30–35 PDC full-time equivalent employees (FTEs), and approximately 10–20 FTEs that provide technical assistance and energy management advice that, in 2012, served 800 discrete facilities with 1,000 projects covering a mix of types and sizes of industrial and agricultural customers (Crossman 2013).[22] ETO places emphasis on maintenance of close individual client contact by its in-house staff as well as by its PDCs (Taylor et al. 2012).

Wisconsin's Focus on Energy program has used a "cluster" approach to organize program delivery with greater subsector and industrial process expertise for specific industrial groups, such as food processors, pulp and paper manufacturers, or plastics companies. Including workshops with cluster members and relevant trade associations, this approach also has fostered cross-peer exchange and learning (Taylor et al. 2012, Chittum 2009). In 2012, its program for large energy users generated savings of 61,344,005 kWh and 3,119,919 therms (see Appendix B-7).

Xcel found that one of the biggest challenges in implementing IEE projects is that technical needs vary from industry to industry and company to company with no standard template for implementation. To address this, Xcel's team of account managers works closely with industrial customers to understand their production processes and operational needs, and provides both initial energy audits and continued support throughout project construction (WGA 2013). Similar to many other programs, Xcel's efforts to provide project development support expertise extends beyond basic diagnostic service to help move projects through the implementation stage, helping decision makers to make a go/no go decision based on accurate, complete, and customized project information. In Colorado, Xcel's custom and process efficiency programs generated average savings of 10,838,108 kWh per year from 2010–2012 (see Appendix B-8).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Invest in knowledgeable, skilled technical staff.
- Use high quality technical assistance to enhance prescriptive and custom program success.
- Recognize that technical needs vary from industry to industry and company to company.

4.6. Offer a Combination of Prescriptive and Custom Offerings to Best Support Diverse Customer Needs

A combination of both prescriptive offerings for common cross-cutting technology and customized project offerings for larger, complex projects in IEE programs can best meet diverse customer needs and provide flexible choices to industries. Prescriptive offerings—typically involving rebates for a portion of the cost of common technology equipment upgrades or certain other clearly defined actions—can be relatively simple for both customers and administrators. However, their value to large customers may not be significant. Custom approaches are needed for the larger, complex, or process-specific projects. If both types of offerings are included, IEE incentive program offerings can be tailored to accommodate both large manufacturers and SMEs, depending on the state's industrial base.

[22] For ETO's Production Efficiency program, incentives are budgeted at 63%, delivery at 26%, and internal costs are 11% (Crossman 2013).

Xcel's programs (Example 10) have been lauded by industrial customers for offering simple incentive applications for providing a full suite of programs—custom, self-direct, and process energy efficiency incentives. ETO (Example 11) has been successful in its ability to help its Oregon industrial customers realize deep energy savings through low-cost changes as well as complex custom approaches. Rocky Mountain Power (Example 12) couples its custom Energy FinAnswer program with the complementary Energy FinAnswer Express program offering prescriptive rebates to target deep savings as well as quick wins. Efficiency Vermont, NYSERDA, and PG&E, among others, also provide both prescriptive technology and customized project development options.

Including customized project offerings requires administrator investment in program capacity and development of mechanisms to access specific technical expertise (see Section 4.7). However, the energy savings can be well worth the investment. In Vermont, six industrial account managers are actively engaged full-time in Efficiency Vermont industrial programs, centering primarily on customized project identification, development, delivery, and savings measurement and verification. Their work yields nearly 90% of Efficiency Vermont's annual industrial program energy savings delivery (Taylor et al. 2012).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Prescriptive offerings support common cross-cutting technologies or practices.
- Custom offerings support larger, complex, or process-specific energy efficiency measures.
- Offering prescriptive and custom offerings allows programs to accommodate large industrials and SMEs.

4.7. Accommodate Industrial Project Scheduling Needs

Scheduling energy efficiency investments can be heavily dependent on a plant's operational cycle. Equipment is normally renewed or refurbished at the end of an operational cycle. The timing of a major investment window can be difficult to predict, particularly by someone not engaged in the plant's day-to-day activities (Chittum et al. 2009).

Operational cycles and investment windows can be few and far between, and proposed equipment changes must be guided through rigorous, competitive, and time-consuming capital expenditure approval processes. Firms often have long timeframes between identifying an opportunity and project implementation, especially when large companies consider large dollar proposals.

IEE program cycles may not match industrial company timing for allocating capital for projects. Manufacturers, particularly large organizations, need time to secure capital and plan for potential plant shutdown to accommodate energy efficiency assessments and project implementation. This often leads to a "phased approach" to energy efficiency implementation.

Programs with flexible timelines that can accommodate an industrial client's investment cycle will help to maximize energy efficiency implementation. Programs that are not limited to one-year timeframes but instead accommodate multi-year projects and application periods—or have multi-year planning and operation as their standard operating procedure—allow companies the flexibility to consider and implement program offerings on a schedule that matches their decision and investment cycle. This, in turn, can promote higher program participation levels. To the extent possible, program managers should also be mindful of industrial operational and investment cycles and time recruitment and outreach accordingly (Russell 2013b). In addition, by examining current and projected economic trends in the industrial sector, an efficiency program can anticipate when the next large cycle of construction, infrastructure, and capital investment is likely to occur (Harris 2012) and therefore help to encourage energy efficiency, either from new production equipment or a new facility (Seryak and Schreier 2013).

For example, evaluations of NYSERDA's IPE program suggested that program managers should target specific industrial subsectors based on an understanding of a firm's hours of operation, capital plans, level of interest in energy efficiency and sustainability initiatives, and capacity utilization.[23] The IPE Program is positioned to take advantage of potential capacity investments by developing lists that classify industrial customers using North American Industry Classification System (NAICS) codes to include evidence of plant capacity constraints, using capacity utilization data published by the U.S. Federal Reserve System. Companies with a high capacity utilization rate relative to their historical averages are prioritized for targeted outreach concerning large infrastructure investments. Firms reporting mid- or low-capacity utilization rates are targeted to increase the productive capacity of existing facilities, implement and/or adopt a strategic approach to energy management, and/or implement low- and no-cost operational improvements (Harris 2012). NYSERDA estimates that its IPE program will save 200,000 megawatt-hours per year and 735,000 million Btu (MMBtu) per year from 2012 through 2015 (see Appendix B-5).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Accommodate multi-year projects and application periods or have multi-year planning and operation as their standard operating procedure.
- Understand the operational cycle and capital approval process cycle of individual industrials.
- Monitor economic and investment trends of industries in your region to plan for expansion and new plant opportunities industrials and SMEs.

EXAMPLE 12. ROCKY MOUNTAIN POWER'S ENERGY FINANSWER AND FINANSWER EXPRESS PROGRAMS

Rocky Mountain Power's (RMP's) Energy FinAnswer program in Idaho offers engineering services, technical expertise, and cash incentives to help industrial and commercial customers upgrade to the most energy-efficient systems, tailored to the needs of retrofit or new construction projects. The Energy FinAnswer program is a long-standing program that has been in place in some form since the 1990s. It has continued to evolve to accommodate changing market and company resource positions.

RMP is involved from the very beginning of projects and starts by reviewing facility plans and identifying possible efficiency opportunities. The next step involves the utility preparing a free energy analysis report to provide specific recommendations and estimates of what each efficiency measure will cost and how much the customer will save. RMP also includes an incentive offer and any commissioning requirements. The incentive amount available is typically $0.12 per kWh of annual energy savings plus an additional $50 per kW for average monthly on-peak demand savings. Prior to July 2013, incentives were capped at 50% of the project cost and at least one-year payback (if the payback is less than one year, the incentive is reduced so that the payback equals one year). Program revisions in July 2013 increased the incentive cap to 70% of project cost. The two parties sign an incentive agreement form before the company proceeds with any purchase orders for the equipment. RMP allows two years for customers to implement the projects.

The program provides a number of resources, including case studies of past projects, to help those interested in the program determine their own project plans, and provides a list of engineering firms under contract to provide program services. Energy FinAnswer has a complementary program, Energy FinAnswer Express, which offers simple, prescriptive incentives for lighting, HVAC, and other common efficiency upgrades. Customers typically receive the incentive payment within 45 days of completing a post-installation report. These two programs complement each other in the market, providing a broad platform of services and incentives for a wide variety of energy efficiency projects.

In 2012, RMP generated electrical gross savings of 4,473,114 kWh per year across 81 measures under its FinAnswer Express program and 318,915 kWh per year across seven measures under its Energy FinAnswer program.

Source: Rocky Mountain Power 2013a, Rocky Mountain Power 2013b, Kolwey 2012

[23] The capacity utilization rate describes the extent to which the industrial sector's production capabilities are actually being used to produce the current level of output. In general, a high rate of capacity utilization is a positive indicator of economic health.

4.8. Streamline and Expedite Application Processes

Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome. Achieving the right balance between meeting key program administration needs for information and streamlining the application process is helpful.

As an example, BPA began using a third party to evaluate and then help streamline procedures to address industrial concerns about the application process. A third party also helps individual companies navigate application procedures.

NYSERDA also provides upfront assistance to help companies navigate the application process, and uses a Consolidated Funding Application (CFA) developed as part of a statewide plan to streamline and expedite the grant application process. Because the CFA is commonly used across a range of programs, this simplifies the application process and applicants may already have experience with this documentation.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Streamlined application procedures encourage participation.
- Assistance in navigating the application process is helpful to industrials.
- Balancing program administrative needs for information with keeping procedures simple and efficient may require continual evaluation and improvement.

4.9. Conduct Continual and Targeted Program Outreach

Manufacturers are sometimes unaware of the industrial program offerings that may be most applicable or useful for them. Significant outreach and development of information, such as examples of successful past projects, is often necessary to encourage participation. As an example, Wisconsin’s Focus on Energy program provides program engineers who reach out to industrial firms via numerous training classes, webinar series, and outreach to industrial associations. The AlabamaSAVES loan program formed partnerships with Bank of America, Philips Lighting, Metrus Energy, and Efficiency Finance, not only to provide private sector leveraging of funds, but also to conduct marketing and outreach for the program itself. Using their existing sales and marketing channels and networks with Alabama industries and contractors, these private partners are driving program uptake and demand in the market (NASEO 2012). As of April 2013, more than 20 loans have closed and nearly $17 million in funding has been put toward the installation of energy efficiency projects. The initial $60 million in funding will continue to cycle through loans and has the potential to finance up to $121 million in projects over the next 20 years (see Appendix B-1).

NYSERDA’s IPE program demonstrates an awareness of industrial customers’ decision-making processes when it markets its offerings to potential program participants. When marketing IPE incentives for non-process equipment upgrades (motors, lighting, etc.), NYSERDA targets facility directors and executives. In contrast, when working to secure process-efficiency projects, NYSERDA conducts targeted outreach to industrial staff in charge of production lines and revenue-generating projects, as well as members of continuous improvement teams and executives, who consider the costs and benefits of energy efficiency projects that affect production capability. This approach reflects research findings that show facility maintenance and process engineers play a critical role in the decision-making processes within their companies (Harris and Gonzales 2013).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Continual and targeted outreach is needed to make sure industrials are aware of applicable program offerings.

4.10. Leverage Strategic Partnerships

Successful IEE programs often partner with a variety of federal, state, and regional organizations to share technical expertise, program design, and implementation guidance, and leverage access to customers for outreach and implementation. For example, the collection of assessment and recommendation data in DOE's Industrial Assessment Center Database is commonly used by program staff and support contractors to inform thousands of investments in state and utility IEE programs.[24] The database includes information on the type of facility assessed (size, industry, energy usage, etc.) and details of resulting recommendations (type, energy and cost savings, etc.). In addition, DOE's Combined Heat and Power (CHP) Technical Assistance Partnerships (formerly called the Clean Energy Application Centers) promote and assist in transforming the market for CHP, waste heat to power, and district energy technologies and concepts throughout the United States. And the EPA ENERGY STAR for Industry program provides guidance, tools, and recognition to help industrial companies improve their energy performance.

Efforts by SEOs complement and support ratepayer-funded programs. States can provide resources or programs, such as tax incentives, that utilities often cannot. States are not constrained by regulatory cost-effectiveness tests that may limit what programs are offered. Therefore, states can often support IEE activities such as training, certification, and recognition awards. SEOs use their established partnerships with other relevant stakeholders and program administrators, such as utilities, regional energy efficiency groups, and the National Institute of Standards and Technology's Manufacturing Extension Partnership (MEP), to coordinate and expand programs with existing resources available to manufacturers. SEO energy assessment and audit programs typically include utility cost-share. Training workshops organized or supported by SEOs are often offered in conjunction with universities and MEP, and typically leverage DOE efforts (NASEO 2012). For example, Washington State has an IEE award program that is hosted by the governor, who recognizes leaders in IEE.

In another example, the Alabama SEO brought together key state partners including the Alabama Industrial Assessment Center, University of Alabama in Huntsville, and the Alabama Technology Network to implement AlabamaSAVES, a revolving fund loan program, and Alabama E3.[25] Over time, the SEO will coordinate both programs so they can grow together and companies who take advantage of E3 assessments can finance energy efficiency upgrades through AlabamaSAVES (NASEO 2012) (profiled in Appendix B).

BPA partnered with the Northwest Energy Efficiency Alliance (NEEA) to consolidate costs and expand program resources in an effort to reach more customers and initiate more projects. As a regional organization, NEEA was able to support replication of the BPA approach across a variety of local distribution utilities in the BPA service area. Similar regional energy efficiency organizations exist in most regions of the United States, and can be engaged in similar ways.

In 2008, NEEA partnered with the Northwest Food Processors' Association (NWFPA), the largest industrial trade organization in the region, representing more than 100 food processing enterprises, to convene food processing industry leadership around common energy reduction goals and strategic energy management practices. Aggregating energy saving efforts through NWFPA allows the industry to apply resources toward a unified energy reduction goal—sharing the risk, efficiency, and energy savings potential. The partnership was able to secure buy-in and establish trust when reaching out to potential customers and leveraged funding from the State Technologies Advancement Collaborative and DOE's technical assistance resources to establish a customized program dedicated to the unique needs of the northwest region's food processing industry (IIP 2012, Chittum et al. 2009).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

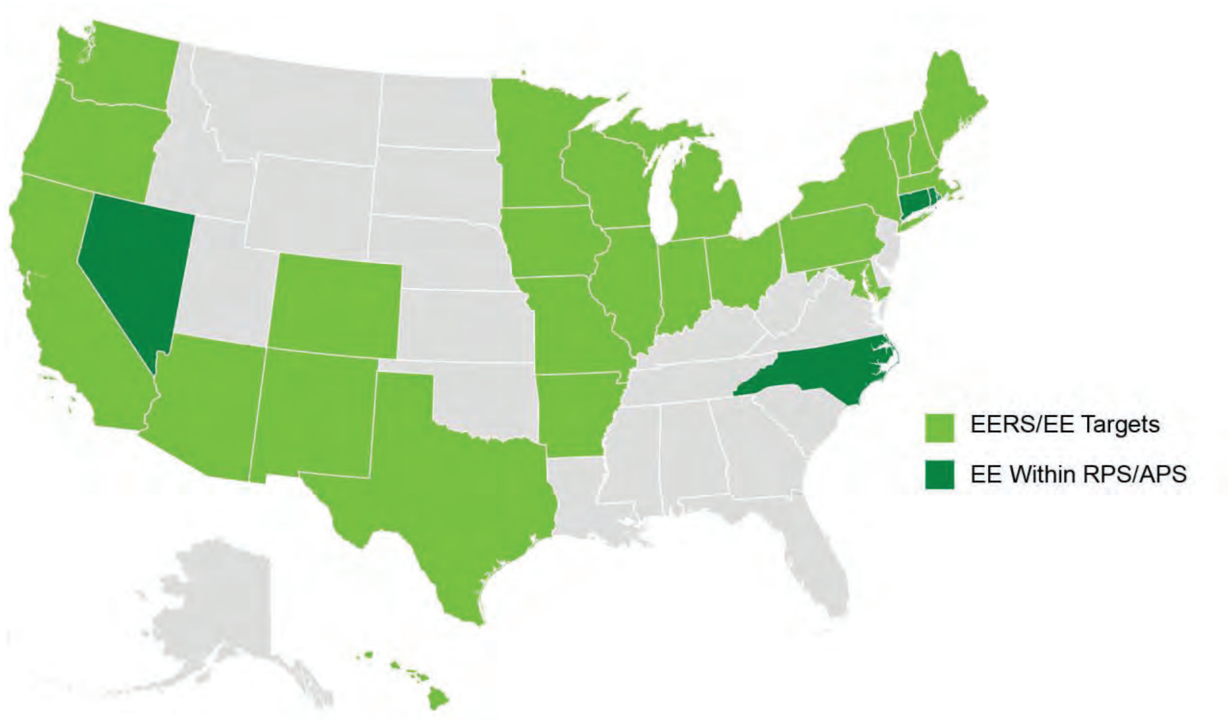
- Partner with federal, state, and regional organizations to leverage their expertise, access to customers, and program implementation support capacities.
- Partnerships can help programs by providing technical expertise, program design, and implementation guidance as well as expanding program outreach and implementation channels.

[24] http://iac.rutgers.edu/database
[25] E3—Economy, Energy, and Environment—is a coordinated federal and local technical assistance initiative that helps communities work with their manufacturing base to adapt and thrive in a new business era focused on sustainability for SME manufacturing companies.

4.11. Set Medium- and Long-Term Energy Efficiency Goals as an Investment Signal for Manufacturers

To provide signals of certainty to the market, regulators and program administrators can set energy savings goals or targets for the medium- to long-term to reduce risk in ramping energy efficiency measures implementation. Specific targets and extended program lengths (minimum three years) can give both program administrators and manufacturers the confidence to invest over sufficiently long program timeframes.

CEPS are an important tool states use to set goals and targets. A CEPS sets electricity and/or natural gas energy savings targets, usually expressed in energy savings delivered per year (including cumulative delivery over a period) or a percentage of utility sales. CEPS have gained popularity in the United States, and 28 states now have some sort of high-level energy savings target (see Figure 7). The longer-term goals associated with CEPS send a clear signal to market players about the importance of energy efficiency in utility planning and create a level of certainty to encourage large-scale investment in energy efficiency technology and services. Longer-term goals also help build customer engagement and develop an energy efficiency workforce and market infrastructure (ACEEE 2012, SEE Action Network 2011a).



Sources: ACEEE 2013a and 2013b

Figure 7. Energy efficiency resource standards and targets

CEPS are often designed and integrated into the integrated resource planning (IRP) processes to ensure that acquired energy efficiency resources are cost-effective compared with supply resources. An IRP can be a powerful impetus for promoting energy efficiency and other demand management alternatives to new supply. Although the amount of available cost-effective energy efficiency will vary based on local circumstances, some quantity will likely always be available at a lower levelized cost per megawatt-hour than supply side alternatives. Thus, any planning process that requires utilities to consider demand-side resources as part of an integrated strategy to meet customer demand is likely to promote energy efficiency. This is especially true where IRP processes are mandatory and overseen by a utility regulatory commission, because the IRP requirement may require utilities to consider demand-side programs that benefit ratepayers even if the programs do not benefit shareholders. In some circumstances, cost-effective energy efficiency measures may even be available in sufficient quantities to satisfy all of the projected load growth within the planning timeframe (SEE Action Network 2011b).

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Longer-term goals provide increased certainty to the market and to program administrators.
- Higher annual savings targets require a more comprehensive set of program offerings and will drive programs to IEE.

4.12 Ensure Robust Measurement, Verification, and Evaluation

M&V of project energy savings is critical to program administrators and regulators to assess the actual results of program activities and to measure the contribution of projects and aggregate programs for achieving their goals. Robust M&V programs also allow customers to obtain clear views of the results of their efficiency investments. In addition, effective M&V enables program administrators to undertake periodic process and operational strategy evaluations to assess where program efficiency and results can be further improved.

Require Robust Measurement and Verification

Measurement and verification requirements

Planning for M&V during the design phase of a program is key to ensuring that energy savings can be tracked and program success can be systematically assessed. M&V is required at some level in all programs, and M&V plans and requirements are a condition of funding in most programs. For example, NYSERDA has stringent technical analysis and M&V requirements for its programs, and performance-based incentive payments are only provided on a verified kWh or MMBtu energy-saved basis (Taylor et al. 2012).

Clear, concise guidelines for M&V requirements benefit both project and program evaluations. Planning for M&V during the program design phase and periodic evaluation and adjustment in M&V guidelines are both important. In most custom projects, M&V plans are an integrated part of the process. Some program administrators will help design project M&V plans and may assist in arranging financing of meter installation to execute the plan.

Submetering can further strengthen M&V programs, because measuring energy use at the project or equipment level provides the discrete data needed to demonstrate the savings from a specific project or plant improvement (which is typically not the case when this type of data is not collected). Submetering can be a necessity for proper M&V of many projects, and is best applied both before and after project implementation.

Broadening the scope of project M&V to include benefits beyond energy savings can be used in the cost-effectiveness analysis of projects and programs, further quantifying the full economic and societal benefits of energy efficiency investments, and improving overall cost-effectiveness of energy efficiency measures. If these are to be included, M&V plans need to extend requirements and guidelines to non-energy benefits.

Consistent methodologies in measurement and verification protocols

Current M&V practices in the United States use multiple methods for calculating verifiable energy savings. These methods were initially developed to meet the needs of individual energy efficiency program administrators and regulators. Although the methods serve their original objectives well, they have resulted in differing and incomparable savings results—even for identical measures. These differences can be significant, and inconsistent results have limited the acceptance of reported energy savings beyond specific program applications.

Increasing the consistency and transparency of how energy savings are determined through consistent and clear M&V protocols strengthens the credibility of energy efficiency programs. Examples of existing protocols include the International Performance Measurement and Verification (IPMVP) protocol, which is used in Xcel's self-direct programs, and the Superior Energy Performance (SEP) M&V protocol, which will play an important role in DOE's Industrial Strategic Energy Management Accelerator[26] initiative.

Another opportunity for common methodologies is DOE's Uniform Methods Project (UMP). Through UMP, DOE aims to establish easy-to-follow protocols based on commonly accepted engineering and statistical methods for determining gross savings for a core set of commonly deployed energy efficiency measures. The protocols provide guidance on energy savings determinations, which will be available as a reference to improve M&V practices. The addition of industrial measures in UMP provides a potential opportunity to create consistent protocols for IEE programs that would make it easier and less costly for efficiency programs to quickly establish good M&V practices because they no longer have to develop protocols from scratch (DOE 2013b).

Use Evaluations to Support Continual Program Improvement

Periodic process evaluations identify ways to improve program design and delivery

Robust M&V plans enable program administrators to conduct periodic process evaluations that identify successes and weaknesses in program implementation and point to ways to improve program design and delivery. Process evaluations can be initiated during the first year of operation to identify lessons learned from implementation as soon as possible and to apply them to subsequent program cycles. They can also be helpful in adjusting programs to match manufacturers' needs on a continuing basis. ETO regularly commissions process and impact evaluations, which have identified specific areas for improvement in its Industrial Production Efficiency program. These areas include:

- To maximize the effectiveness of program marketing, program staff can improve their understanding and augment the marketing skills of contractors to increase uptake of programs.
- To add credibility to program reporting and enhance marketing efforts, staff improved specific and consistent definitions of data entry categories and date variables to report program activity by year, thereby improving data collection, tracking, and processing.
- To simplify the program review and oversight function, and to enhance quality control of technical studies, program staff promulgated and implemented uniform procedures and standards or guidelines for both the technical studies and the review of those studies (ETO 2006).

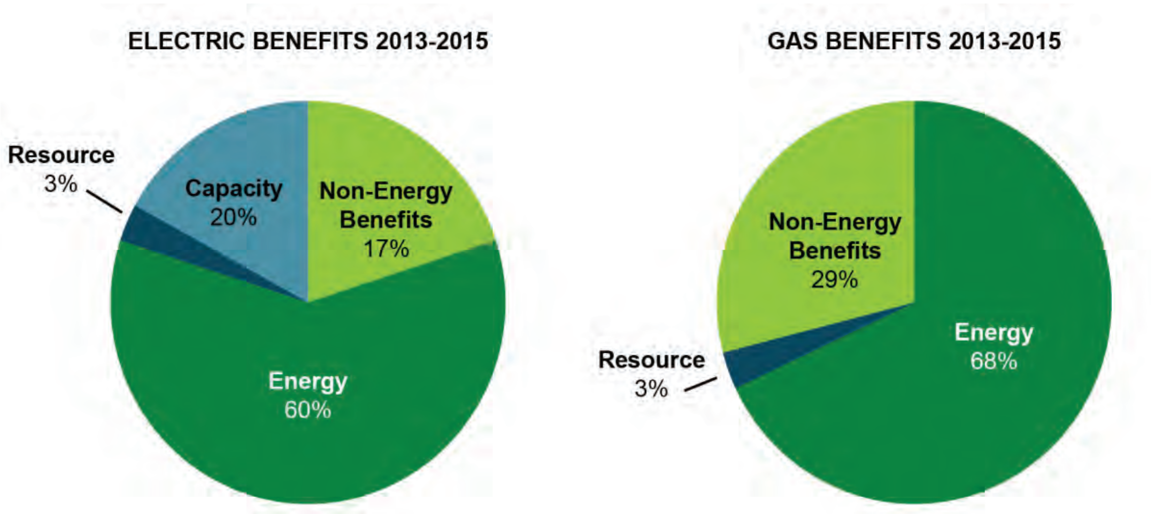
Include non-energy benefits in program evaluations

In addition to M&V methods, NEBs can be included in program evaluation to prove the improved cost-effectiveness resulting from NEBs additional to energy saving benefits in both projects and programs (for a discussion of NEBs at the industrial customer level, see Chapter 6). Many studies suggest that the NEBs of IEE measures can be quite large, often far greater than any energy savings (Chittum 2012). Including NEB elements in program cost-effectiveness evaluations could significantly increase the benefit-to-cost ratios of IEE programs.

Because valuing NEBs can be difficult and has sometimes proven controversial, most states that currently account for NEBs typically do so only for benefits that are readily quantifiable, mostly confined to water and other fuel savings (Kushler et al. 2012). Some regulators and stakeholders resist including benefits such as improved participant/public health, comfort, and property values because they are "externalities" outside the usual realm of utility regulation, and if benefits occur outside the system, it could create an implication that other stakeholders might be expected to contribute to energy efficiency funding to the extent that they receive benefits. Estimating the value of some NEBs can also be complicated, leading many administrators to resist attempts at monetizing all of them (Lazar and Colburn 2013). Thus, it may be most practical to focus on only the key NEBs most amenable to quantification. Examples of programs that incorporate a relatively large range of NEBs include NYSERDA, Massachusetts, and BPA.

[26] The Industrial Strategic Energy Management Accelerator is designed to demonstrate SEP as a practical and cost-effective energy efficiency program offering. Signatories to this Accelerator are utilities and energy efficiency program administrators that agree to deploy SEP to a set of industrial customers across their service territories. This Accelerator was launched in December 2013.

Over the last decade, Massachusetts has integrated NEBs when estimating the value of its energy efficiency program offerings to the whole utility system (using the Total Resource Cost Test). Figure 8 shows that NEBs represent approximately a quarter of total benefits that accrue to the system. Note that many benefits, such as productivity gains or environmental benefits are not included, meaning that if these positive environmental and social externalities were included, NEBs would in fact be much greater.[27]



Source: Halfpenny 2013

Figure 8. The value of non-energy benefits in Massachusetts' energy efficiency programs

Acknowledge free ridership and positive spillover effects

Free ridership is a situation in which a program incentivizes a company to implement an energy project that they would have conducted on their own without the program's financial and/or technical assistance. Program administrators want to get the most from the incentives they offer by encouraging projects that would not have otherwise been implemented. However, identifying and preventing free ridership is complicated, and estimating the impact can be costly. Based on surveys that ask people to relate why they made energy conservation investments, it is difficult to make accurate estimates.

Although the number of "free riders" can be high for certain programs, other end users may see substantial energy cost-saving advantages from some of the investments or concepts being promoted in an energy efficiency program and decide to undertake measures themselves without receiving any program incentives or being otherwise involved with the program. This "spillover effect" can work to mitigate or neutralize the level of free ridership. For example, NYSERDA has found that for most (though not all) IEE delivery programs, "spillover" equals or exceeds "free riders" (Taylor et al. 2012).

Programs in Vermont, British Columbia, New York, and Oregon attempt to estimate free riders and report net savings against targets for at least some of their specific IEE programs (Taylor et al. 2012). Regulators and program administrators can expect some level of free ridership, and may wish to accept moderate levels, as long as the programs remain cost-effective overall.

As with other key elements of project M&V, it is important that any needs to consider free ridership or spillover effects in assessing how energy savings from specific project and programs will be credited to users and administrators be clearly stated and agreed to by all parties prior to project and program implementation efforts.

[27] **Approved NEBs**: 1) C&I new construction and retrofit: operations and maintenance costs, administrative costs, material handling; 2) Low income: utility savings, rate discounts, bad debt write off, terminations and reconnections, collections and notices; 3) Residential new construction and retrofit: customer perceived savings, thermal comfort health benefits, noise reduction rental marketability, property value increase, reduced tenant complaints, lighting quality, home durability, equipment maintenance. **Not approved**: national security, economic development, reduced waste.

This includes clarification of both what specific types of projects must consider free ridership and spillover, and details on the quantification methodologies to be used. Ambiguity about how reported savings may be discounted in after-the-fact evaluations may lead to contentious arguments or inhibit project implementation.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Effective M&V is critical for program administrators to assess results and measure progress, and useful for industrials to verify results of their investments.
- Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted.
- Periodic impact and process evaluations help identity where IEE program efficiency and results can be further improved.
- NEBs can be a key element of both project M&V and program evaluation.
- Any needs to make allowances for free ridership and spillover effects should be clearly stated and agreed by all parties prior to project or program implementation.

5. Designing Effective Self-Direct Programs

Effectively capturing energy efficiency opportunities within the industrial sector adds substantially to total state program energy savings and often helps lower total unit costs of saved energy. As discussed in Chapter 3, maximizing industrial energy efficiency (IEE) typically brings down overall system costs over the medium term, which is in the interest of all utility customers.

There is a strong public policy case for including the industrial sector in ratepayer-funded energy efficiency programs. A large portion of the overall available energy efficiency potential resides in this sector, and the unit costs of energy savings in industrial projects is typically lower than in most other sectors targeted for resource acquisition (see Chapter 3). In addition, many advocates point out an issue of fairness—why are certain customers exempted from paying into ratepayer-funded programs even though they ultimately benefit from lower total system costs?

However, industrial customers often raise legitimate concerns about the extent to which ratepayer-funded energy efficiency programs will be able to meet their specific needs. Especially when programs are first being contemplated, industries may be skeptical about whether the programs will be administered with enough flexibility to meet their priorities. They may be skeptical about the IEE capability of program administrators compared with their own capabilities, and they may have concerns about administratively complex and burdensome participation requirements. In essence, many industries—especially larger ones—may raise concerns that the benefits that they might receive from a ratepayer energy efficiency program will not be commensurate with the costs of paying into the program and dealing with administrative requirements.

As of January 2014, 16 states offer "self-direct" programs. To achieve energy savings, these programs must be designed and implemented to meet both the public policy objective of the programs and the industrial customers' desire for greater flexibility and control of energy efficiency efforts in their own companies. Self-direct programs should not be confused with "opt-out" program clauses. "Opt out" means that a class of consumers is allowed to not participate in a ratepayer-funded energy efficiency program—these customers do not pay into the system, do not have an obligation to deliver energy savings, and do not directly benefit from participation in the programs. Under self-direct programs, qualifying consumers implement their own energy savings programs, often without design and implementation assistance from a program administrator. However, they are still obligated to spend money and deliver energy savings, either on a project-by-project basis or over a certain amount of time. A self-direct option keeps large customers in the energy savings portfolio but allows them the flexibility to take advantage of cost-effective energy efficiency opportunities. There is wide variability in terms of the industrial savings requirements and measurement and verification (M&V) rigor across existing self-direct programs. As such, those that employ high levels of M&V rigor and achieve robust industrial savings can serve as the best examples for delivering successful self-direct programs.

Some self-direct programs have proven to be effective tools to both deliver low-cost energy savings for system-wide benefits and to help industrial customers achieve substantial cost savings and bottom-line benefits through energy efficiency improvements. This chapter describes the types of self-direct programs common among the states, outlines program features that help achieve both public policy goals and increased flexibility for industrial customers, and provides examples of successful self-direct programs currently in operation. Readers should note that the program design features discussed in Chapter 4, such as demonstrating the value proposition of energy efficiency to customers, also apply to self-direct programs.

5.1. What are Self-Direct Programs?

In this report, self-direct programs are defined as programs that allow some customers, usually large industrial ones, to "self-direct" fees directly into energy efficiency investments in their own facilities instead of into a broader aggregated pool of funds collected through a public benefits charge for energy efficiency programs. This is in contrast to opt-out provisions, which allow large customers to fully opt out of paying their energy efficiency charge with no corresponding obligation to make energy efficiency investments on their own (ACEEE 2012b).[28]

Self-direct programs usually define eligibility for customer participation in terms of a threshold amount of energy use or energy use capacity (e.g., megawatt-hour [MWh] or megawatt [MW]), with the view that, generally speaking, only larger customers are likely to have the capacity to undertake serious energy efficiency programs themselves and attempting self-direction among small consumers is inefficient.

Self-direct programs may be administered by a utility, state regulatory authority, or state agency. In Oregon, for example, the state's self-direct program is overseen by the state energy office (although the customized administrator-managed industrial offering—the Production Efficiency program—is implemented by the Energy Trust of Oregon). In Vermont, self-direct customers report their programs to the state utility regulator, although there is currently only one customer that uses the large self-direct program and two customers that use the smaller self-direct program.[29] In Michigan and Washington, self-direct customers report their plans to their utilities, and validation of plans falls to the state utility regulatory commission.

Table 2 illustrates the continuum of self-direct programs existing in the states, showing differences in the rigor with which the programs are structured to ensure achievement of public policy energy savings delivery goals. As programs move down the continuum from the least to the most structured programs, they vary in two key ways: 1) accounting with respect to energy efficiency payments that would be required without self-direction and with respect to use of funds, and 2) extent of M&V of energy savings and follow-up by utility regulatory commissions or program administrators.

Table 2. Structure of Self-Direct Programs

Public Benefit Maximization

Program Type	Energy Efficiency Payment	Measurement and Verification of Savings	Use of Funds	Follow-Up	Examples
Less structured self-direct	None	Minimal; self-reported	Company uses retained cash for energy efficiency	None to minimal	MN, OH
More structured, lower oversight self-direct	Fully or partially paid on bill	Minimal; self-reported	Rate credit or project rebate	Minimal	MT, OR
More structured, higher oversight self-direct	Fully or partially paid on bill	Robust; similar to ratepayer-funded programs	Personal escrow, rate credit, or project rebate	Minimal to substantial	WA, CO

Source: Adapted from Chittum in Elliott 2013

In the less structured cases, programs may exempt a customer entirely from paying energy efficiency charges, and require them to simply channel the funds directly into their own energy efficiency projects. To be considered self-direct programs as defined above, however, there should be some level of formal reporting on funds spent and the projects implemented. In more structured cases, there are reporting mechanisms that aim to ensure that self-

[28] It should be noted that some states have "self-direct" terminology in legislation that provides energy-intensive customers to be fully exempted from energy efficiency charges to direct towards energy efficiency measures, but there is minimal to no oversight or requirements to report on implementation of measures. This is in reality equivalent to opt-out provisions (Chittum 2011).

[29] See http://aceee.org/sector/state-policy/vermont for more information that distinguishes both programs.

direct customers spend at least as much on energy efficiency projects as they would have on energy efficiency charges. Customers may be exempted from paying energy efficiency charges for a certain time if they undertake a reported project or set of projects as planned. More commonly, customers are required to pay most or all energy efficiency charges and then receive project rebates or rate credits against their qualified expenditures on self-direct projects. Ongoing accounts of energy efficiency payment requirements against qualified energy efficiency project expenditures also may be used.

Programs also vary substantially as to the extent of program follow-up on project execution and on energy savings M&V. Some less-structured programs require some documentation stating the customer has invested in energy efficiency in the past or plans to do so in the future, but the customer is not required to provide detailed information on its investment. More structured programs require that purchase receipts or other evidence of investments be submitted, but energy savings reporting may be minimal or the reported savings may not be verified. Finally, the most structured programs with high levels of administrative oversight are subject to M&V protocols in the same way as administrator-managed IEE programs. In some cases, a small portion of energy efficiency charges may be retained by program administrators rather than fully rebated to customers to help cover oversight costs (Chittum 2011).

Figure 9 provides a snapshot of the prevalence of self-direct programs among the states as of January 2014. At least 16 states have some type of self-direct program, and six states have opt-out provisions. Figure 9 also provides a sense of the prevalence of less structured and more structured programs by state. However, it should be noted that definition into these categories is not a perfect science and characterization of individual state programs requires customized review.

Source: Elliott (2013)

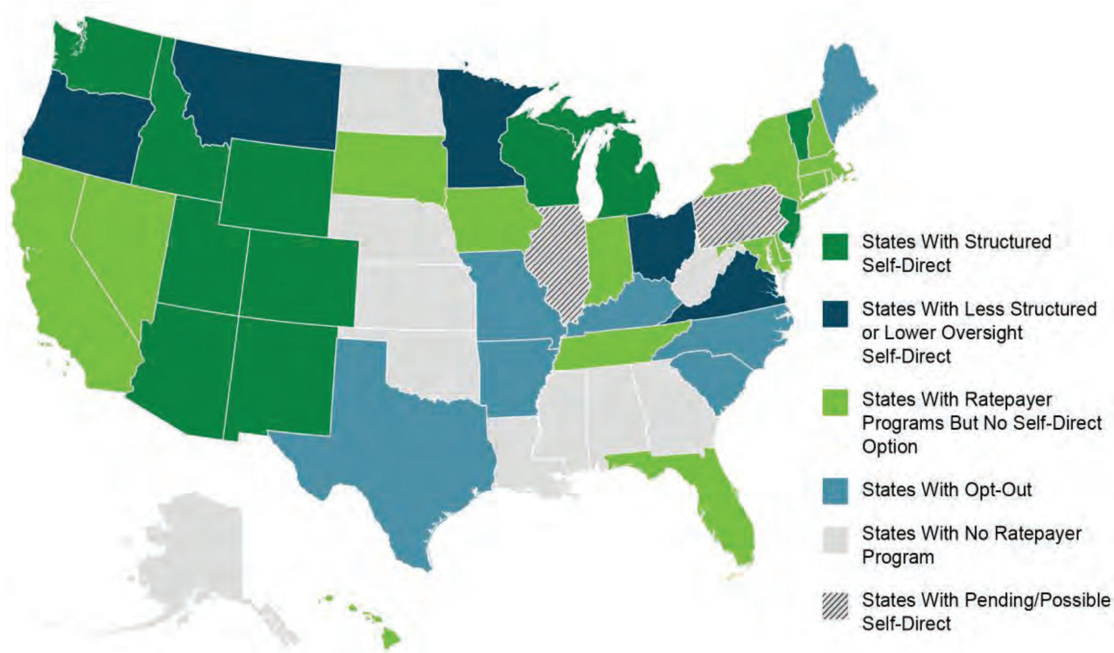


Figure 9. Current snapshot of self-direct programs (subject to review)

5.2. Ensuring Achievement of Public Policy Goals

To meet basic energy efficiency public policy goals, it is necessary to ensure that self-direct programs are producing cost-effective energy savings equal to or greater than what would have been realized in a traditional, administrator-directed program. Based on the experience of the most successful programs, one path to achieving this is to operate self-direct programs as one option within the overall energy efficiency program. Rather than designing a self-direct program as a means of avoiding participating in the state's resource acquisition effort altogether, the program can be designed as a program choice for industry's participation in the state's overall resource acquisition effort. Industries can choose to direct their own efforts or to have staff and consulting experts from the program administrator work with them as part of an administrator-directed program. Minimum expenditures (e.g., energy efficiency charges or equivalent amounts) are expected to be the same for either choice.

From the public policy perspective, it is important to ensure that self-direct customers meet their energy savings requirement with the funds they would otherwise pay into the ratepayer-funded program for the benefit of all.

There are competing viewpoints about whether one type of program can achieve greater savings or leverage greater benefits for the industrial customers as well as all system users, and states have had differing experience with the value of self-direct programs compared with core programs managed by a utility or program administrator. This report does not compare the effectiveness of these two types of programs. Instead, for states that are choosing to introduce or allow self-direct programs as an option, it highlights how self-direct programs in some states have been able to provide an attractive alternative to large customers while meeting public policy goals.

Set Goals to Achieve at Least Equivalent Performance

Where self-direct programs are offered as part of overall energy efficiency programs, large consumers are asked to report on their actual programmed energy efficiency investments. If the investments are assessed by program administrators as meeting program criteria, the customers receive rebates or credits against ongoing energy efficiency payments or they receive energy efficiency payment exceptions related to the size of the investment. The assumption is that customers participating in the self-direct program must pay the energy efficiency contributions, similar to all other customers, unless they are excused from payment based on evidence of comparable investments they have programmed themselves.

Some self-direct programs simply ask that customers spend a certain amount of money on energy efficiency. However, solely focusing on spending fails to take account of the quantity of energy savings delivered. Developing concrete savings goals can help improve the working relationship between the customer and the self-direct program administration. Instead of focusing on dollars, these goals keep the conversation focused on energy. When customers buy into the idea of energy savings goals, they may squeeze more energy savings out of every dollar spent (Chittum 2011).

For example, in Michigan's self-direct program, large customers must develop energy optimization plans that set annual energy savings targets based on the previous year's energy consumption, factoring out changes in business activity, energy required for pollution control equipment, or, if relevant, weather normalization (see Example 13).

Another example is the Eugene [Oregon] Water and Electric Board (EWEB) self-direct program. EWEB's individual self-directing customers develop energy savings goals in collaboration with utility staff. Goals are based primarily on the percent of load a customer represents. EWEB notes that they are acquiring more efficiency from their two self-directing customers than they had in the past when the customers were using EWEB's standard program offerings (Chittum 2011).

Energy Savings Measurement and Verification

Some form of energy savings M&V is needed to ensure that self-direct programs are achieving expected energy savings. Data collection to track the amount of funds directed toward energy efficiency projects—and the savings achieved from those projects—is necessary to determine whether a self-direct program is performing as effectively as a traditional program might (Chittum 2011).

Most self-direct programs do not penalize customers for failure to demonstrate verified energy savings or meet goals. Although such structures may not be always necessary, some self-direct program administrators have found that requiring companies to pay back energy efficiency charges if no or insufficient action is taken can encourage customers to meet energy savings goals or use up all of their allotted energy efficiency funds. If a company earns rate credits or rebates in advance of project implementation, customers may have to pay back a portion of the rate credit or rebate if a planned project does not come to fruition. Michigan's self-direct program (see Example 13) asks customers to meet set energy savings targets. If a customer fails to meet its targets, it must repay energy efficiency charges in proportion to the shortfall. Puget Sound Energy's self-direct customers simply lose their allotted energy efficiency fund credits if they do not dedicate all resources toward implementation of energy efficiency measures (Example 14).

Self-Direct Options as Complementary to Core Industrial Offerings

In states that may be starting out and do not have mature industrial offerings that provide quality technical assistance or if manufacturers may be seeking opt-out provisions, self-direct programs can be viewed as attractive options to ensure the industrial sector remains in the program portfolio. If IEE potential is substantial and capacities can be developed, the most complete service package can include both strong administrator-directed industrial programs and strong self-direct programs. Ultimately, both administrator and self-direct programs have their comparative advantages.

As experience accumulates, states may wish to offer self-direct options as complementary to, rather than instead of, core program offerings for companies interested in going beyond those offerings (Elliott 2013). For instance, Xcel Energy (Example 15) in Colorado provides a self-direct program alongside a range of other prescriptive and custom program offerings. With the potential for wide variability in participation, not all industrial customers can be expected to self-direct funds effectively toward all cost-effective opportunities. They also may be interested in the specialized technical support that a statewide program can potentially provide. Comprehensive and mature industrial offerings as part of administrator-directed core programs have many times demonstrated added value to manufacturers. At least three self-direct programs—in Oregon, Michigan, and Wisconsin—reported that customers who had been self-directing or had considered self-directing chose to return to paying the energy efficiency charge and using core ratepayer programs because these programs yielded substantial benefits. The ratepayer-funded industrial offerings in these states are robust and have evolved to meet customer needs over time (Chittum 2011).

It is interesting to note that Rocky Mountain Power allowed industrial customers above a certain size threshold to opt out of paying 50% of the ratepayer surcharge if they could show—through third-party audit—that there are no more energy efficiency opportunities below a certain payback period. During the 10-year period that the credit was in place, no companies took up the credit, which implies that participants either could not prove that all energy efficiency opportunities had been implemented or valued the energy efficiency program offerings more than the exemption.

SUCCESSFUL DESIGN AND IMPLEMENTATION APPROACHES

- Structure self-direct programs as part of a larger portfolio of robust IEE programs that are responsive to industrial and other large customers' needs.
- Develop self-direct programs with active engagement with industrial customers to ensure the programs meet user needs.
- Allow flexibility in eligible technologies and timelines.
- Require verified energy savings equivalent to what would be achieved with core program offerings, with routine progress reporting and robust approaches for measurement and verification.
- Consider escrow-like accounts to structure a "use it-or-lose-it" fund base that encourages greater participation.

EXAMPLE 13. MICHIGAN'S SELF-DIRECT ENERGY OPTIMIZATION PROGRAM

Under Michigan's 2008 Public Act 295 (PA 295), certain customers may create and implement—or self-direct—a customized energy optimization (i.e., energy efficiency) plan and thus be exempt from paying the full energy optimization (EO) surcharge to its utility provider. The EO plan is consistent with the energy savings goals required of electric utilities as part of the state's energy efficiency resource standards. The plan identifies targets, planned projects, and verification process for approval by their utility, and the utility approves the plan and reports aggregated program data to the Public Service Commission.

Self-direct customers do not pay fully into the energy efficiency fund in exchange for the execution of their energy savings plan. They do pay a portion of their assigned charges to cover administration of the self-direct program and a portion of the public benefit charge that funds programs for low-income consumers.

In the first years of PA 295 implementation (2009 and 2010), the self-direct option was made available only to large customers with at least 2 MW of peak demand (or 10 MW peak demand for aggregate sites). For 2011 and 2012, PA 295 allows customers with at least 1 MW annual peak demand in the preceding year or 5 MW aggregate at all of the customer's sites within a service provider's territory to participate. The number of customers enrolled to self-direct their own EO program has dropped from 79 in 2010 to 47 in 2011 to 32 in 2012. This reflects the perceived value of the flexibility and comprehensive program options that are being offered under utility programs. Electric reductions from self-direct programs reached 53,593 MWh across customers from all providers (DTE Electric, Consumers Energy, Efficiency United, and cooperative and municipal utilities).

PA 295 specifies that all but the largest self-direct customers must hire an energy efficiency service company to develop an EO plan, which sets annual energy savings targets based on the previous year's energy consumption, factoring out changes in business activity, energy required for pollution control equipment, and weather normalization. As an alternation to normalizing for weather, the self-directing company can choose to base savings off of a three-year average annual demand for all retail customers in the state. Very large customers (more than 2 MW per site or 10 MW in aggregate) are not required to hire an energy efficiency services company.

Every year, the self-direct customer must submit a report detailing the energy savings projects and estimated energy savings. The third-party energy efficiency service company hired by the company is responsible for notifying the utility if the targets are not being met. If the targets are not met, the self-direct customer must pay the utility a portion of the avoided public benefit charge proportional to the percentage by which it missed the target. If the company exceeds their goal, excess savings may be applied to the following year's goal.

For 2009 and 2010, 26 customers of DTE Energy took advantage of the self-direct option, although DTE has reported that several customers may opt back in to DTE Energy's efficiency program due to the low surcharge.

Source: Taylor et al. 2012, Chittum 2011, Michigan Public Service Commission 2013

EXAMPLE 14. PUGET SOUND LARGE POWER USER SELF-DIRECTED ELECTRICITY CONSERVATION PROGRAM

Program Overview

One of Puget Sound Energy's (PSE) four commercial and industrial programs is the Large Power User Self-Directed Electricity Conservation Program, which started in its current form in 2006 (a pilot program was initiated in 1999). The self-direct program provides funding for customers that contribute to a conservation fund. Self-direct customers have access to 82.5% of the fund. Although participants in other PSE commercial and industrial programs are limited to maximum incentives of 70% of the measure cost, self-direct customers may fund up to 100% of measure cost. PSE keeps 7.5% of the conservation fund for program administration and 10% for Northwest Energy Efficiency Alliance market transformation programs activities. Customers are eligible under the self-direct program when they take three-phase service at greater than 50,000 volts.

PSE requests customers to calculate electric energy savings using standard engineering practices and to document data, assumptions, and calculations for PSE review. PSE reviews savings calculations and reserves the right to modify energy savings estimates. After receipt of project final cost documentation, a PSE Energy Management Engineer conducts a post-installation site inspection to review installed equipment and confirm implementation of the M&V plan. Actual savings may be trued-up based on post-installation energy use monitoring.

PSE works with self-direct customers to track energy efficiency contributions for future use and allows them to earn an incentive against their tracked contributions whenever an approved project is completed. The program focuses on large customers that often have in-house engineering resources, which can help reduce overall program costs and guarantee successful implementation of efficiency measures funded. PSE relies on trade allies such as energy service companies to help self-direct customers identify and implement projects.

Participation Process

PSE's program is creatively structured in that it combines grants with a competitive bid process. The program begins with a non-competitive phase during which customers are guaranteed access to their portion of energy efficiency fees and are responsible for proposing cost-effective projects to use their allocation. At the end of the non-competitive phase, customers not proposing projects to fully use their allocation forfeit their remaining balance to a competitive bid phase. Funds are aggregated together and disbursed via a competitive bid process among all self-direct customers, encouraging highly cost-effective projects. The projects funded as a result of this competitive bid process are generally more cost-effective than those funded during the first two years, as customers compete against each other to make a case for their projects. The program saw a very large volume of competitive projects proposed during the competitive bid process. For example, in 2009, self-direct customers proposed cost-effective energy efficiency investments of more than four times the amount of funding actually available in the aggregated fund.

All projects must meet PSE's avoided cost requirements. Although the customer submits its own proposal and M&V plan, PSE reviews the proposal and plan. Upon approval, PSE enters into a funding allocation agreement with the company and conducts a post-installation inspection after the measure is implemented.

Program Performance

PSE reports its self-direct program is acquiring energy efficiency at a cost equal to its other programs and that the program is acquiring more efficiency resources than would have otherwise been the case. Participation rates are also higher in the self-direct program among eligible customer classes than in other programs.

Each year, more customers qualify for the self-direct program; for the 2010–2013 program period, 54 customers were eligible. PSE has awarded more than $12 million in project incentives and projects 42,000 MWh per year in annual savings. As the program matures, PSE is seeing a shift toward longer payback projects, in part because more commercial customers have begun to participate in the self-direct program.

Sources: Puget Sound Energy 2012, Chittum 2011

EXAMPLE 15. XCEL ENERGY'S COLORADO SELF-DIRECT PROGRAM

Program Overview

Xcel Energy launched the Colorado Self-Directed Custom Efficiency Product in 2009. The program provides rebates to large commercial and industrial electricity customers who engineer, implement, and commission qualifying projects at their facilities. Self-direct customers perform the design, engineering, measurement, verification, and reporting of energy efficiency projects approved by Xcel Energy. The intent of the offering is to allow customers with the internal expertise, or access to expertise (through a third party), to drive their own energy efficiency projects while providing utility incentives to help them overcome financial barriers to implementation. Customers must have access to appropriate resources to properly identify, quantify, scope, and implement a project—without the assistance of Xcel Energy.

Due to this increased reporting and validation burden placed on the customer, Xcel Energy is able to provide a larger rebate than those offered through other incentive programs in exchange for the in-house engineering analysis required of a self-direct customer. Self-direct customers continue to pay their assigned energy efficiency charge, and self-direct projects are reimbursed through a rebate. Customers may earn rebates of up to 50% of the incremental project costs, either $525 per kilowatt (kW) or $0.10 per kilowatt-hour (kWh). Eligible business customers must have aggregate peak demand at all meters of at least 2 megawatts (MW) in any single month and have an aggregate annual usage of at least 10,000,000 kWh.

Participation Process

Participation is a multi-step process:

- Customers receive a rebate application from their Xcel Energy account manager, who ensures that all eligibility requirements are met. Pre-qualified customers then identify energy efficiency opportunities in their building and submit a detailed energy efficiency improvement plan to Xcel Energy.
- Xcel Energy reviews the project and provides a total resource cost (TRC) calculator for the customer to analyze the cost/benefit relationship of the project. To qualify for a rebate, the TRC must be greater than 1.0 and payback periods must be greater than one year and less than the lifetime of the equipment.
- Upon review and pre-approval of the improvement plan, customers are notified of project approval and potential rebate amount. At this stage, a monitoring plan is finalized to verify the project's results.
- Upon project completion, the customer submits a completion report including measurement and verification of the energy savings if savings are anticipated to be greater than 250,000 kWh. Once Xcel Energy approves the completion report, the rebate, based on measurement and verification savings, is issued to the customer.

Program Performance

Since its inception, the program has seen considerable customer interest and has achieved early success. Participating customers report high satisfaction with the program and vendors are optimistic about the future of performance contracting due to increasing customer prioritization in addressing energy costs.

- Since the 2009 launch, the self-direct program has achieved more than 26 gigawatt-hours (GWh) and 3,531 kW of savings and paid rebates in excess of $3.4 million (average savings per participant is 1.7 GWh with TRCs of more than 2.0).
- 2010 had 10 projects and achieved savings of 8.97 GWh against a goal of 4.4.
- 2011 had two participants and achieved 7.67 GWh against a goal of 5.6 GWh.
- 2013 has a pipeline of more than 8 GWh.

In 2012, TRC was 1.79, Utility Cost Test was 4.67; and lifetime cost of conserved energy was $0.01 per kWh.

Source: Nowak et al. 2013

6. Emerging Industrial Program Directions

Well-designed self-direct programs such as those discussed in the previous chapter are likely to play an important role in states that have clean energy portfolio standards (CEPS) but do not have mature industrial program offerings, or where manufacturers may be seeking opt-out provisions. However, in other circumstances, other types of programs may be more relevant. For example, states with long-standing industrial programs may want to ramp up efforts or, at the other end of the spectrum, there may be no regulatory driver to acquire energy efficiency resources. This chapter discusses promising opportunities for the next level programs that can further address some of the traditional barriers to industrial participation and expand the development of energy efficiency potential present in manufacturing facilities.

This chapter focuses on new program opportunities rather than providing detailed pathways for immediate implementation because further research, regulatory guidance, and implementation experience is needed. Some approaches, such as next-level strategic energy management (SEM) programs, are based on proven practices that states have implemented for years, while others are in the development stage and may not be market-ready.

The approaches discussed below could result in increased industry participation, develop deeper or harder-to-find savings, enhance the value of certain energy efficiency projects to manufacturers, and expand the fuel options for IEE programs. Initial discussions on these innovative or emerging approaches include:

- Further expanding the use of SEM programs and overcoming current challenges with crediting savings from SEM improvements
- Compensating customers beyond individual energy management or equipment installation and for performance at the whole-facility level
- Integrating non-energy benefits (NEBs) more effectively at the industrial customer level
- Developing new mechanisms that allow natural gas saving projects to receive incentives.

6.1. Next-Level Energy Management Programs

As discussed in Section 3.4, SEM and energy manager/staffing programs seek to promote operational, organizational, and behavioral changes that result in greater efficiency gains on a continuing basis. SEM programs seek to move beyond incentives for equipment and technologies toward a systems focus that rewards operational efficiency, maintenance improvements, “lean” techniques, and ongoing implementation strategies. SEM programs, although diverse in nature, usually offer incentives for operations and maintenance (O&M) improvements, provide energy management training and workshops, and offer support to establish energy tracking systems. Energy manager/energy staffing placement programs provide financing for an energy manager or dedicated personnel to provide leadership and technical expertise beyond discrete projects to identify opportunities and bring them through to implementation on a continuous basis. In practice, several program administrators have tended to offer both SEM and energy manager/energy staffing programs. Incentives are often provided for operational efficiency measures, energy tracking systems, and staff time (see Chapter 3).

The success of these programs has been noted by long-standing administrators, such as Wisconsin Focus on Energy, which has been offering SEM for 1 years, and there is growing interest in applying this approach in new service territories. Administrators that have traditionally offered prescriptive and custom programs are now piloting energy management programs. Recent programs have been introduced by DTE Energy, the Energy Trust of Oregon (ETO), Southern California Edison, Vectren (Indiana), Rocky Mountain Power (PacifiCorp) in Utah and Wyoming (the latter as an energy manager pilot), and Minnesota Energy Resources Corporation (see Table 3).

Table 3. Recent Energy Management Programs, Pilots, and Initiatives

Activities	Incentives (Where Applicable)
Energy Trust of Oregon CORE Improvement	
The CORE Improvement offering is designed to implement strategic energy management (SEM) for highly motivated small and medium industrial cohorts. Through a 12–15 month engagement, plants participate in four peer-to-peer cohort workshops, and SEM coaches meet with participants individually. These meetings leverage tools and resources to ensure that assignments are applicable to the site and effective for each facility.	Technical services in the form of the SEM coaches, which cost around $25,000–$40,000 per facility over the 15 month engagement.
Energy Trust of Oregon ISO 50001 Pilot	
In 2012, the Energy Trust of Oregon (ETO) initiated a pilot offering under the Production Efficiency program to deploy energy management practices to the ISO 50001 level to establish a system that could be externally certified.	Financial incentives for achieving certification within six months of completing the statistical energy savings model (as well as incentives already available from existing ETO programs)
Minnesota Energy Resources Corporation Energy Management Team Coordinator Pilot	
Minnesota Energy Resources Corporation (MERC) undertook a pilot program from August 2010 to June 2012 to help industrial customers identify and implement energy conservation improvements. The pilot provided an Energy Management Team Coordinator to assist the internal Energy Management Teams of five MERC customers (i.e., the coordinator dedicated 20% of work time to each customer). Customers were recruited as part of MERC's Commercial & Industrial Turn-Key Efficiency program, requiring minimum annual gas usage of 500,000 therms. During the two-year pilot, the coordinator worked with each participating customer to implement an energy management system similar to ISO 50001 and based on U.S. Environmental Protection Agency's ENERGY STAR program publication, Teaming Up to Save Energy. The results of the pilot were positive. Participants outperformed the comparison group by implementing an average of nearly twice the number of energy savings projects, achieving higher annual energy savings, and attaining a conversion ratio of three times the achieved therms savings compared with identified potential therms savings.	
Northwest SEM Collaborative	
The Northwest Energy Efficiency Alliance (NEEA), Bonneville Power Authority (BPA), Energy Trust of Oregon (ETO), BC Hydro, and a number of Northwest utilities are taking a collaborative approach to industrial SEM to share best practices in SEM research, design, implementation, and evaluation. The Collaborative aims to help energy efficiency program administrators accelerate the adoption of SEM in the industrial sector by focusing on: • Strategic planning: Provide long-term direction for the Northwest SEM community • Solution improvement: Enhance the efficiency and effectiveness of Northwest SEM offerings • Program innovation: Increase the reach of industrial Northwest SEM programs • Knowledge transfer: Broaden and deepen the extended SEM community's capabilities and skill sets.	
NEEA SEM Cohorts (Montana)	
NEEA and Northwestern Energy are partnering to work with SEM cohorts, groups of Montana companies that share both their experiences launching energy-saving programs and their vision of a more competitive Montana business community. Representatives from each organization champion energy management goals and regularly share results. Northwestern Energy and NEEA provide training and support on developing SEM plans, and participating companies meet regularly and share their experiences and progress throughout the nine-month program (NEEA 2013b).	
Rocky Mountain Power (PacifiCorp) Schedule 24 Revisions (Utah)	
Effective July 2013, Rocky Mountain Power (PacifiCorp) revised its programs through Schedule 140, which introduces incentives for operations and maintenance (O&M) savings and copayment for an internal energy project manager over 12–18 months.	$0.02/kWh for annual O&M savings; and $0.025/kWh annual savings for energy project manager co-funding with minimum savings of 1,000,000 kWh for 12–18 months

Source: Carl 2012, Batmale and Gilless 2013, ETO 2013a, Franklin Energy 2013, Rocky Mountain Power 2013

Despite the interest in expanding SEM programs in other service territories, these efforts are challenging to implement because of the following issues, which include the lack of common policy guidance and regulatory rules:

- Crediting savings from improvements from SEM
- Determining appropriate baselines
- Justifying incentives for energy management hardware such as submetering and for support of energy managers, which do not directly save energy
- Evaluating SEM typically requires both quantitative information (demonstrated energy savings) as well as qualitative information (energy management practices).

An initial discussion of design considerations that would support more and better energy management programs—i.e., "next generation energy management programs"—is provided below. It is important to note that early adopters have been leading the way in overcoming these challenges and some of their experience is touched on here. For example, the Northwest SEM Collaborative is leading a work program that would drive greater understanding and consensus on SEM research, design, implementation, and evaluation. In-depth coverage of these issues, however, is not provided in this chapter.

Incentives for Submetering

Attention to improving facility metering can generate more accurate knowledge of where energy is being used. This is often the first step to create a continuous energy savings program. Constant monitoring allows the facility to gauge the ongoing effectiveness of its portfolio of energy savings investments and measures. Utility incentives that include submeters and other energy monitoring equipment would allow companies to fine tune operational performance, identify new opportunities for projects, and inform where to focus resources, and track progress.

However, many program administrators face challenges in providing incentives for submetering or other energy management hardware. Although meters do not directly save energy, accurate metering is a critical element of effective benchmarking and verifiable measurement and verification (M&V). Effective strategies that could be used by energy efficiency program administrators include rolling meter costs into the overall measure cost or treating submetering as a persistence strategy for certain energy efficiency measure types, especially O&M measures.

Energy Management Maturity

Energy management approaches are diverse and can range from a set of principles with top-level commitment based on the "Plan Do Check Act" framework, focused O&M improvements, implementing energy management system (EnMS) standards (ISO 50001), lean manufacturing techniques, or use of energy management software tools such as energy management information systems. In addition, the energy management approach employed by an individual company will mature as experience accrues—implementing new technologies, replacing outdated technology with newer, more energy-efficient systems, and investing in energy management assets throughout the organization. The SEM approach itself becomes more sophisticated and energy savings persist.

As well as focusing on the quantitative aspects of M&V from SEM (i.e., energy savings—see next section), program administrators and industrial customers need to be able to assess industrial customer energy management practices and maturity. Energy management assessments are used as a diagnostic tool to determine baseline practices at the beginning of a customer's participation in SEM and are also useful to assess progress and evaluate programs. In addition, maturity models can help to integrate SEM within other business improvement and productivity models (IIP and MSS 2013).

Several successful programs that already assess energy management maturity include:

- The Northwest Energy Efficiency Alliance (NEEA) and the Northwest Food Processors' Association's (NWFPA's) Industrial Energy Roadmap outlines an "Energy Efficiency Self-Assessment" to help enterprises gauge their current level of energy efficiency efforts and understand how energy is viewed within the organization. The self-assessment helps both enterprise and evaluator establish a level of energy management sophistication, creating a roadmap on SEM implementation improvement.

- BC Hydro's Energy Management Scorecard serves to rate companies' energy management in multiple areas, identifying critical areas for improvement and outlining ways to excel in those areas.
- Xcel Energy helps companies benchmark their energy management practices.
- The U.S. Department of Energy's (DOE's) Superior Energy Performance (SEP) program has developed an industrial facility Best Practice Scorecard, which enables companies with mature EnMS to earn credits by implementing energy management best practices as well as improving energy performance. The best practices are activities, processes, or procedures that are above and beyond what is required by ISO 50001 and encourage "best in class" companies to continually improve their EnMS, which will lead to improved performance and sustained energy savings (SEP 2012).
- EPA's ENERGY STAR® program has several assessment matrices that gauge the amount of energy management implementation presently in place for an industrial company or facility. Matrices address energy management programs, plant programs, and small or medium sized plants.

Baselines, Energy Models, and Measurement and Verification

Traditionally, prescriptive approaches use deemed savings for common equipment or verify the savings from replacing a piece of equipment, where estimating the before and after energy consumption is relatively straightforward. With industrial custom projects, M&V analysis is done for each project at the measure level because of the high specificity of the industrial process and application. Using either method, utilities can be relatively confident in the amount of energy savings resulting from replacing existing equipment with more efficient equipment.

SEM programs move away from the equipment focus to continuous improvement across all factors that affect energy use—equipment, systems optimization, O&M, and behavior. In this way, SEM programs unlock the potential of persistent O&M and behavioral savings, which have rarely been included as eligible measures in traditional programs. However, SEM programs that focus on "how,"—for example using a piece of equipment less or using it more optimally—often suffer from an inability to confidently quantify savings or demonstrate persistence over time (Milward et al. 2013).

Attributing savings to projects identified through SEM programs is challenging, but tracking success will be increasingly important as SEM programs become more widespread and their effectiveness is put under regulatory scrutiny. SEM M&V can also be a valuable tool for industrial managers, by making energy performance visible, meaningful, and actionable. SEM M&V requires the development of a robust baseline (typically for a period of one year or more) and an energy model against which actual performance is measured. The general approach is described in Example 16.

Although SEM is broader than just O&M or operational efficiency, the approach as described in Example 16 that subtracts out the savings from capital projects is currently the most common M&V approach to credit financial incentives for SEM. Current programs deploying this approach apply traditional incentives for custom retrofit measures, where retrofit measure savings are subtracted from facility-wide savings, and then a lower incentive is paid on the difference (Gilless 2013). Programs that estimate and incentivize SEM program savings in this way include NEEA, ETO, the Bonneville Power Administration (BPA), and Rocky Mountain Power (PacifiCorp).

In contrast, in addition to crediting operational efficiency, BPA also tracks the increased number of equipment retrofits due to SEM and includes this information in its program results. Companies participating in BPA's High Performance Energy Manager Program (HPEM) show that companies tend to significantly increase the number of capital projects after enrolling in the program: new capital projects submitted after HPEM adoption rose to 23 projects compared with 10 projects beforehand (Wallner 2011). Energy management programs that estimate program results solely in terms of increased numbers of equipment retrofit projects (i.e., they do not count operational, behavioral, or non-equipment savings) include BC Hydro and Xcel Energy (Wallner 2012).

Experience from energy management programs in Europe also supports this observation. Participants in Ireland's Energy Agreements Programme were surveyed to understand how the Irish energy management standard, primarily driven by impending carbon limits, had contributed to their energy efficiency efforts. Surveys report that 67% of the projects to save energy were derived or driven by the EnMS process, and since the introduction of EnMS in Ireland in 2005, the pace of energy savings has increased (Reinaud et al. 2012).

Engaging Supply Chains

Utility or third-party energy management programs may wish to encourage these leading companies with mature SEM experience to collaborate with their supply chains to improve supplier energy management performance. For example, the NEEA-NWFPA Energy Efficiency Assessment recognizes "Industry Collaborators" as companies that actively work outside their own facilities to collaborate with suppliers, utilities, organizations, competitors, consortiums, and associations. Similar program initiatives also exist abroad. In the Netherlands' Long Term Agreements, companies meet one third of their reduction target outside the plant boundaries by engaging their value chains. In Japan's benchmarking policy, companies that demonstrate that they are already at global best practice can collaborate with other companies in their supply chain instead of searching for additional savings within their own operations (Goldberg et al. 2012).

EXAMPLE 16. BASELINES AND ENERGY MODELS

To isolate the effect of strategic energy management (SEM) versus capital projects and other variables, program administrators and customers typically develop an energy use baseline and an energy (regression) model for the entire facility. Payments are made based on actual savings once equipment changes and other variables have been subtracted. Robust models require reliable sources of facility and production data to establish the facility baseline and any savings. For example, the Energy Trust of Oregon and the Bonneville Power Administration model a facility's energy consumption as a function of production and other variables such as weather to determine a baseline level. Using meter-level analysis, they then track actual performance against projected usage—the difference is the potential savings. Actions and measures taken to reduce energy use and the dates of those actions are also tracked in order to be able to tie changes in energy use in the model to actual energy efficiency actions taken. To calculate the annual SEM incentive for the customer, savings from all capital projects are subtracted out (because capital projects receive their own incentives) so that only operations and maintenance savings are included in the cost-effectiveness evaluations of SEM programs (Kolwey 2013, Crossman 2013).

The Consortium for Energy Efficiency and the Northwest SEM Collaborative are actively working to develop a greater common understanding of these issues and to provide guidance to regulators and program administrators to promote more widespread deployment of SEM programs.

At the implementation level, new developments in intelligent technology are emerging as promising tools to ease the burden of determining baselines and using energy models. Companies with longstanding experience with SEM approaches perhaps started out looking at their energy use once a week or month and might have updated their energy models once a year. However, recent developments in information technology systems such as for submeters, energy management information systems, and Intelligent Efficiency, are paving the way toward giving manufacturers the ability to track and measure their energy use and savings performance data in real time across their entire operation. Self-diagnostic, comparative, and anticipatory analytical capabilities of smart devices are enabling a new level of process energy management and systems optimization within companies and can help prevent the degradation of energy savings. With this information, companies can prioritize different operations, tune up systems and integrate demand response, and support less costly measurement and verification.

6.2. Whole-Facility Energy Intensity Programs

The building up of energy baseline and consumption models that were developed to allow customers to receive incentives for SEM implementation provides possible new directions: customers could be compensated beyond individual energy management or operational efficiency and be paid for performance at the whole-facility level—i.e., incentives are not separated by project or equipment installation.

Under this new program model, utilities or program administrators could work with customers to agree on an energy baseline for a certain period (e.g., a year) and provide incentives based on improvements in energy intensity below the baseline. These types of pay-for-performance programs resemble power-purchasing agreements for renewables or white certificates schemes in Europe. They could also be closely integrated into national initiatives and provide greater applicability for a single company with industrial facilities in multiple service territories.

However, the outlook for these programs is likely longer-term because of a range of technical and policy questions such as:

- Accepted methods for setting baselines. There already are existing methods, such as the International Performance Measurement and Verification Protocol (IPMVP) Option D and those used by the New York State Energy Research and Development Authority (NYSERDA), Connecticut Light & Power, and outlined in BPA's Energy Efficiency Implementation Manual (2013) (Seryak and Schreier 2013). The Consortium for Energy Efficiency (CEE) and the Northwest SEM Collaborative are working to gain a common understanding of these issues.
- Whether incentives for improvements in energy intensity can become a commonly accepted policy approach for regulators and legislators across different states—there can be regulatory concerns and restrictions to base analysis of savings on intensity reduction (Crossman 2013).
- The inability of many industrial customers to quickly and effectively analyze their energy consumption information provided by utilities.

EXAMPLE 17. EPA ENERGY STAR PROGRAM

EPA's ENERGY STAR program for industry has developed a number of whole-plant energy benchmarks known as ENERGY STAR plant energy performance indicators (EPIs). These tools provide an energy performance score for plants based on the energy performance of the plant type nationally. To learn more about which industrial sectors have an EPI, visit www.energystar.gov/epis.

6.3. Enhancing the Value of Industrial Energy Efficiency Projects through Non-Energy Benefits

Energy efficiency measures often result in a number of non-energy benefits (NEBs) such as increased productivity, reduced material loss, improved product quality, and lower emissions. In addition, investors increasingly value corporate commitment to energy efficiency and sustainability as an indicator of sound governance and business acumen. Several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects (Kushler et al. 2012, Chittum 2012, Lazar and Colburn 2013). Full quantification of NEBs for use by implementers and industrial customers at the project or measure level is not commonplace.

NEBs can play an important role in persuading industrial customers to participate in programs. A 2003 study of commercial and industrial (C&I) energy efficiency programs in Wisconsin valued these benefits at approximately 2.5 times the projected energy savings of the installed technologies (Hall and Roth 2003). Worrell et al. (2003) analyzed the NEBs that accrued to industrial customers from 52 energy efficiency projects, where 55% of the cost savings came from productivity improvements as summarized in Table 4. Lung et al. (2005) undertook a similar study with 81 projects (Table 5), showing that 31% of the savings were attributable to NEBs.

Table 4. Energy Cost Savings and Non-Energy Cost Savings from 52 IEE Projects

Total project investment	$54.2 million
Total annual energy savings	$12.9 million (45% of total savings)
Total annual productivity savings	$15.7 million (55% of total savings)
Combined total savings	$28.6 million
Average energy payback	4.2 years
Average payback including energy and non-energy benefits	1.9 years

Source: Worrell et al. 2003

Table 5. Energy and Non-Energy Cost Benefits from 81 IEE Projects

Total project costs	$68.2 million
Total annual energy savings	$47.7 million (69% of total savings)
Total annual non-energy savings	$21.1 million (31% of total savings)
Total annual savings	$68.7 million
Simple payback of energy savings	1.43 years
Simple payback of non-energy benefits	0.99 years

Source: Lung et al. 2005

In a recent survey of 30 energy managers, engineers, sustainability managers, plant managers, presidents, and vice presidents from a diverse pool of companies nationwide, 90% of energy projects were found to also have a broader productivity impact (Russell 2013a). For one company surveyed, energy improvements provided a four-fold return in the form of production improvements and some companies claimed that NEBs "dominated" the returns from energy projects.

However, at the industrial customer level, NEBs are often not quantified prior to making an investment. Some assessment of NEBs may be undertaken post-implementation for evaluation or recognition purposes, but this is for measures that already pass the cost-effectiveness test on energy cost considerations alone. ETO tries to address NEBs upfront and will help industrial customers to quantify NEBs to support the investment decision for projects that are of interest to the industrial customer but do not quite satisfy the cost-effectiveness test. For ETO, water savings is a common NEB to be quantified and is relatively straightforward to quantify relative to other NEBs, such as improved safety and employee morale (Crossman 2013).

Valuing NEBs at the project level prior to an investment could significantly broaden the number and types of projects eligible for program support and incentivize additional efforts for the industrial customer. Although this may require additional engineering resources, collaborative opportunities with water utilities could be pursued to bring additional incentives for water and energy efficiency measures (e.g., steam leaks, steam traps).

As well as focusing on water benefits, using lean approaches can provide benefits in the "non-energy wastes." For example, an hour shaved off of a two-hour line start-up saves energy, scrap material (from sub-optimal line speed), and an hour of staff labor (Gilless 2013).

6.4. Natural Gas Industrial Efficiency Programs

Energy efficiency programs designed to help natural gas customers reduce energy use and costs have existed for more than 30 years in a number of states (ACEEE 2012c). The first customer energy efficiency programs were primarily targeted at residential customers and typically focused on increasing home insulation, reducing air leaks, and installing high-efficiency furnaces. Also, many of these early programs targeted the needs of low-income customers who had difficulty keeping up with rising winter heating costs at a time when natural gas prices were increasing rapidly. Making energy affordable was a primary objective of many of these early gas programs and still is one of the goals of most programs today.

Although the roots of natural gas efficiency programs lie within residential markets, there are a growing number of programs that now serve a broad range of gas customers, from homeowners to, increasingly, large industries. However, although opportunities for natural gas savings in the industrial sector are significant, most of the current IEE program activity at the state level focuses on electricity. In 2011, $6.8 billion was budgeted for overall electric programs (residential, commercial, and industrial); C&I program budgets were approximately $2.6 billion. In contrast, $1.2 billion was budgeted for overall gas programs in 2011, with approximately $350 million for natural gas C&I programs (CEE 2012). Total C&I natural gas program expenditures were approximately $225 million in 2011, with $50 million specific to industrial programs (AGA 2013).[30] Further, estimates show that C&I customers accounted for more than 50% of gas efficiency program savings in 2011 (approximately 71.8 trillion Btu out of a total savings of 125.2 trillion Btu), with industrial programs accounting for 30 trillion Btu on their own (AGA 2013).

Natural gas utilities recover energy efficiency costs in a number of ways, one of which is to apply a surcharge to the delivery charge (other methods include special energy efficiency tariffs or riders or cost recovery via base rates). Nearly 40% of U.S. industrial customers have separate purchasing agreements with wholesale gas suppliers or third-party marketers for the commodity. However, 88% of the natural gas volumes delivered by U.S. utilities to industrial customers were purchased from a third party, which implies that large industrials predominantly acquire their natural gas supply from a source other than the utility. Thus gas utilities serve those large industrial customers mainly with transportation services, so typically they would not include large-volume industrial customers in their gas efficiency programs. With the industrial sector being the second largest end-use consumer of natural gas (after electric generators)—accounting for 26% of total U.S. end-use gas consumption (EIA 2013)[31]—this represents an enormous opportunity in gas savings by targeting industrial customers.

In addition to this challenge, recent low gas prices have made energy efficiency challenging from a cost-effectiveness perspective. Gas utilities are continuing to deliver energy efficiency programs in this low price environment and most gas efficiency programs still continue to pass cost-effectiveness tests. Where engaged, industrial customers tend to be one of the most cost-effective options in the portfolio of efficiency program offerings. Although natural gas prices were at an all-time low in 2012, prices have already rebounded to around $4 per million Btu (MMBtu) and current forecasts estimate that prices will remain in the range of $4 to $6 per MMBtu for the foreseeable future (EIA 2013).[32] In addition, the attractive price outlook for natural gas has created an opportunity for industrial customers to invest in new technologies, processes, and systems. Industrial gas efficiency programs can help ensure that these investments are based on the latest, most efficient practices and technologies, ensuring continued benefits for customers and the state. A particular efficiency opportunity driven by the positive long-term outlook for natural gas supply and price in the United States is combined heat and power (CHP). CHP can play a unique role in IEE programs because it is not only a highly efficient use of the natural gas resource, but reduces load requirements on electric utilities similarly to straight electric efficiency measures. By providing both electricity and useful thermal energy at the industrial facility in one energy-efficient step, CHP delivers overall energy savings both from its own high efficiency and from avoiding transmission and distribution line losses that normally occur in delivering power from the central station generator to the customer.

The organization of utility service provision often impacts the way in which energy efficiency program services are delivered and their cost-effectiveness evaluated. Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings from end uses that reduce both gas and electric energy use. Delivered together as part of the same project or program, gas and electric efficiency measures may very well pass cost-effectiveness tests even if the gas measures on their own do not. Delivering gas and electric efficiency programs together has the benefit of avoiding the loss of technically and economically viable energy efficiency potential. Energy efficiency technical potential comes from individual end uses and the interaction of those measures with one another and the facility itself in which they are implemented. Ignoring the benefits of energy savings from “other fuels” may lead regulators and administrators of gas efficiency programs to

[30] Overall gas efficiency program budgets for 2012 were $1.4 billion (AGA 2013).
[31] The power generation sector is the largest consumer of natural gas, using an estimated 32.5% of total gas consumption in 2013 (EIA Annual Energy Outlook 2013).
[32] Natural gas energy efficiency programs remain cost-effective when gas prices reach around $4 per MMBtu (using the total resource cost test).

undervalue investment in packages of measures that deliver savings across fuels. The resulting customer under-investment may foreclose on energy efficiency savings opportunities because long-lived equipment is installed that is oversized or because certain improvements can only be technically or economically installed in conjunction with a broader package of measures (Hoffman et al. 2013).

Some states have been able to overcome the cost-effectiveness challenges and can serve as promising examples for other states that wish to further increase gas savings and meet CEPS targets through industrial gas efficiency programs and/or combined electric and gas efficiency programs. For example, PG&E's gas efficiency program in California achieves 60% of its savings through industrial customers, in contrast to 20% of its electricity savings from industrial programs (Sethuraman 2013).

Programs that offer incentives for industrial gas savings as well as electric savings include NYSERDA, ETO, Wisconsin Focus on Energy, Efficiency Vermont, NSTAR, and CenterPoint Energy (Example 4). Another example of a holistic approach to energy savings is an innovative mechanism being proposed by the Utah Association of Energy Users. The proposal suggests that gas utilities offer large industrial customers the opportunity to voluntarily "opt in" to a demand-side management fund, through a self-assessed contribution of 1%–3% of their gas expenses, and to pool these funds with contributions already made to electric public benefits funds. Participating manufacturers could then self-direct these funds to cover both electric and gas energy efficiency opportunities, thereby implementing larger and more effective programs with the flexibility to deliver both electricity and gas savings (Weir 2013).

In summary, industrial customers provide a large savings potential for natural gas utilities and regulators that aim to reduce energy consumption and costs, infrastructure costs, and greenhouse gas emissions through efficiency programs. To achieve this, it is important to align policy goals with implementation rules and evaluation methodologies. Clear and streamlined guidance can help utilities to work with their industrial customers to implement building and process efficiency measures and optimize energy use, while being able to track and credit energy savings to the efficiency program, rather than to new, more stringent energy codes.

7. Conclusion

Building on the improvements in energy efficiency in the U.S. industrial sector that have occurred over the past decades in response to volatile energy prices, fuel shortages, and technological advances is essential to maintaining U.S. industry's viability in an increasingly competitive world. The fact is that many opportunities remain to incorporate cost-effective, energy-efficient technologies, processes, and practices into U.S. manufacturing. Industrial energy efficiency (IEE) remains a large untapped potential for states and utilities that want to improve energy efficiency, reduce emissions, and promote economic development. Successful IEE programs vary substantially in operational mode, scope, and financial capacity, but also exhibit common threads and challenges.

As this report shows, the states' experience gained in developing and implementing IEE programs is both diverse and rich. In Table 6, specific issues discussed in each of the preceding chapters are summarized for regulators and program administrators to consider when designing and implementing effective energy efficiency programs for industry. They do not cover all decisions or issues that regulators and program administrators may need to consider because there will undoubtedly be jurisdiction- and case-specific topics that are not anticipated here. However, these considerations provide a starting point for addressing many of the issues that typically arise.

Table 6. Summary of Key Issues and Considerations for Regulators

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
The value of energy efficiency projects	Energy efficiency projects may compete with core business investments and decision-making is often split across business units.	• Clearly demonstrate the value proposition of energy efficiency projects to companies • Relay the operating cost savings and other benefits—including profits—lost if energy efficiency improvement opportunities are not addressed.	• Bonneville Power Administration • New York State Energy Research and Develop-ment Authority • West Virginia Industries of the Future
Relationships with industrial customers	It takes a long-term relationship for programs to understand industrial operation and needs, and for industrial companies to understand what a program can offer them.	• Long-term relationships with industrial companies enable joint identification of energy efficiency opportunities • Stability in program support and personnel over a number of years is critical.	• Energy Trust of Oregon
Industrial sector credibility and technical expertise	Addressing industrial companies' core needs requires understanding a plant's production processes, operating issues, and the market context the plant operates within.	Effective IEE programs develop credibility with industrials by emp-loying staff/contractor experts that understand the industrial segment and have the technical expertise to provide quality technical advice and support issues specific to that industry and customer.	• Efficiency Vermont • Wisconsin Focus on Energy • Xcel Energy (Colorado and Minnesota)
Diverse industrial customer needs	Manufacturers use energy differently than the commercial sector, typically having significant process-related consumption. Focusing on simple common technology fixes alone will miss many of the opportunities.	A combination of both prescriptive offerings for common crosscutting technology and customized project offerings for larger, more unique projects can best meet diverse customer needs and provide flexible choices to industries.	• Rocky Mountain Power • CenterPoint Energy • Xcel Energy

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Project scheduling	Scheduling of energy efficiency investments can be heavily dependent on a plant's operational and capital cycle, as proposed equipment changes must be guided through rigorous, competitive, and time-consuming approval processes.	Programs with multi-year operational planning can best accommodate company scheduling requirements, as scheduling of capital project implementation must consider both operational schedules that dictate when production lines may be taken out of operation as well as capital investment cycles and decision-making processes.	• NYSERDA
Application processes	Industrial customers may perceive the application and implementation procedures for IEE programs to be administratively complex and burdensome.	Achieving the right balance between meeting key program administration needs for information and keeping program procedures simple and efficient may often require a continual process of evaluation and improvement.	• BPA • NYSERDA
Program outreach	Various industrial customers may be unaware of the industrial program offerings that may be most applicable or useful for them due to staff turnover and internal demands.	Steady and continual outreach and dissemination of information, such as examples of successful past projects, is important to encourage participation.	• AlabamaSAVES • NYSERDA
Leveraging partnerships	A range of federal, national, regional, and state initiatives and resources are relevant to state IEE programs, including those provided by the U.S. Department of Energy, the U.S. Environmental Protection Agency ENERGY STAR® program, state energy offices, and the Manufacturing Extension Partnership.	Successful IEE programs often partner with federal, state, and regional agencies and organizations to leverage their expertise, access to customers, and program implementation support capacities.	• AlabamaSAVES • Northwest Energy Efficiency Alliance, Northwest Food Processors Association and BPA
Medium- and long-term goals	Industrial companies and program administrators seek market certainty and reduced risk in ramping up the implementation of cost-effective energy efficiency measures.	Regulators and program administrators can set energy savings goals or targets for the medium- to long-term, coordinated with funding cycles (e.g., in three-year cycles).	• Michigan Self-Direct Energy Optimization Program • Southwest Energy Efficiency Project
Measurement, verification, and evaluation	Effective M&V is critical for program administrators to assess results and measure progress, and is also useful for industrial to verify results of their investments.	• Guidelines for M&V need to be clearly defined and periodically reviewed and adjusted • Periodic impact and process evaluations help identify where IEE program efficiency and results can be further improved • Non-energy benefits (NEBs) can be a key element of both project M&V and program evaluation.	• DOE's Uniform Methods Project • International Performance Measurement and Verification Protocol • ETO process evaluations • NYSERDA, Mass-achusetts, and BPA valuation of NEBs

Topic	Issue	Considerations for Regulators and Program Administrators	Program Examples
Self-direct programs	There is a wide range in structures of self-direct programs: from those that are only vaguely defined, and include little M&V of energy saving actions, to those that require verified self-directed customer investment and energy savings to be achieved in order for payment into the programs to be waived.	Clarity in self-directed customer obligations and M&V of results are necessary if the policy goal is to ensure that self-directed industrial customers contribute to overall efforts to ensure least-cost electricity or gas service at a level on par with the contributions of other customers.	• Michigan Self-Direct Energy Optimization Program • Puget Sound Energy • Xcel Energy
Emerging Industrial Program Directions			
Expanding and strengthening strategic energy management programs	Efforts to support implementation of SEM in industry are gaining momentum in state programs.	The challenge of crediting SEM (how to quantify and credit energy savings specifically achieved through SEM), as well as other SEM-related topics, is worthy of further research and cross-exchange.	• AEP Ohio • BPA • BC Hydro • ETO • WFE • Xcel Energy
Program approaches for whole-facility performance	Significant challenges exist in determining baselines and performance metrics that can provide sufficiently robust measurements of facility savings while maintaining practical and easy-to-implement methodologies.	Work on crediting energy savings from SEM could facilitate the provision of incentives and assessing savings credits for whole industrial facility performance, as opposed to performance of individual investments or measures.	• European experience
Capturing non-energy benefits at the project level	Although there is wide variation between projects, several studies have shown that NEBs from IEE projects, such as broader productivity or quality gains, can be as high as or even higher than the energy cost saving benefits achieved by the projects.	If programs employed systematic ways to assess NEBs earlier in the project cycle, the resulting total returns and shorter payback could tip the scale on a variety of projects from "wait and see" to implementation.	• Energy Trust of Oregon
Expanding natural gas programs	• There is less coverage of the industrial sector in natural gas efficiency programs than in electricity efficiency programs. • Most large industrial customers purchase their gas through third-party suppliers rather than their distribution companies. • Most single-fuel utilities administer energy efficiency programs on their own. However, energy efficiency opportunities typically lead to savings in both gas and electric energy use.	• Gas and electric efficiency measures—when delivered together as part of the same project or a combined program—can result in larger, more effective programs that capture more of the technically and economically viable energy efficiency potential. • Innovative concepts are under consideration to increase the effectiveness and the reach of natural gas efficiency programs.	• Efficiency Vermont • ETO • NYSERDA • PG&E • WFE

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT ICNU/307

CORRECTED CALCULATION OF PRODUCTION TAX CREDITS CARRY-FORWARDS

August 13, 2014

Correction of Production Tax Credit Carry-forward Balances
Using Company's Various Currrent Tax Calculations
($000)

		(a) 2014 PTC End Balance	(b) 2015 PTC Generation	(c) 2015 PTC Utilization	(d) = ∑ (a), (b), (c) 2015 PTC End Balance	(e) = (a) + ((b) +(c)) / 2 2015 PTC Average Balance	(f) = [(d),(9)] - (e) Rate Base Delta From PGE	(g) [RR Model] Rev. Req. Adj.
	Proposed Correction:							
	Current Tax From PGE/1700 Eratta							
(1)	Biglow	29,579	28,785	(60,848)	(2,484)	13,548		
(2)	Tucannon River	748	19,757		20,505	10,627		
(3)	Total	30,327	48,542	(60,848)	18,021	24,174	**(28,952)**	**(3,307)**
	Alternative Correction #1							
	Current Tax From ICNU DR 169							
(4)	Biglow	29,579	28,785	(40,364)	18,000	23,789		
(5)	Tucannon River	748	19,757		20,505	10,627		
(6)	Total	30,327	48,542	(40,364)	38,505	34,416	**(18,711)**	**(2,137)**
	Alternative Correct Balance #2							
	Current Tax from PGE/1900							
(7)	Biglow	29,579	28,785	(25,743)	32,622	31,100		
(8)	Tucannon River	748	19,757		20,505	10,627		
(9)	Total	30,327	48,542	(25,743)	53,127	41,727	**(11,400)**	**(3,307)**

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REBUTTAL TESTIMONY OF ALI AL-JABIR

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 13, 2014

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REBUTTAL TESTIMONY OF ALI AL-JABIR

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ali Al-Jabir and my business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411. I am an energy advisor and a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc ("BAI"). My qualifications are provided in Exhibit ICNU/401.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony will respond to the Citizens' Utility Board of Oregon's ("CUB") proposal to adjust the class cost allocation factors for energy-related production costs in Portland General Electric Company's ("Company") generation marginal cost study to reflect differences in funding levels for energy efficiency ("EE") costs, as set forth by CUB in Section IV of its opening testimony in this proceeding.[1/]

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/401 through ICNU/404.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. CUB's proposal represents an unprecedented and inappropriate departure from traditional marginal cost theory. EE is not a proper marginal resource because it does not reflect a utility's costs to meet incremental load, and therefore, does not send proper price signals

[1/] CUB/100 at 20-37.

to customers. CUB's methodology, which allocates EE to customer classes based on customer payments to the Energy Trust of Oregon ("ETO"), arbitrarily distorts the marginal cost study and overemphasizes EE's impact on customer costs. The result is a marginal cost study that does not send proper price signals to customers and improperly shifts enormous costs from smaller customers to larger customers.

III. DESCRIPTION OF CUB'S ALLOCATION PROPOSAL

Q. CAN YOU PROVIDE A BRIEF DESCRIPTION OF ENERGY EFFICIENCY PROGRAMS?

A. EE involves reducing or modifying customer power and energy requirements using a variety of techniques, such as more efficient appliances, control of appliance operating times, and more efficient lighting and motors. EE measures can be undertaken directly and unilaterally by the customer, or can be facilitated by the intervention of the utility, or a third party like the ETO. It is important to recognize that many customers have already undertaken substantial EE and demand management measures in their plant operations or homes at their own expense and initiative in order to remain competitive or to conserve energy.

Q. DO INDUSTRIAL CUSTOMERS PURSUE EE EFFORTS USING INTERNAL FUNDING, OUTSIDE THE SCOPE OF COMPANY-FUNDED EE PROGRAMS?

A. Yes. Industrial customers operate in competitive global markets and therefore have a strong economic incentive to pursue independent EE efforts to reduce their operating costs. Moreover, these customers are sophisticated users of electricity who have a thorough understanding of their electricity requirements. These customers have both the means and the incentive to readily access the competitive EE services market to procure the equipment, advice and expertise needed to cost-effectively reduce their energy consumption, without intervention or funding by others. Furthermore, even when industrial customers receive incentive funding from organizations like the ETO, this only covers a portion of the costs of a conservation project. The rest are borne by the customer.

Q. PLEASE COMPARE THE COST ALLOCATION METHODOLOGY PROPOSED BY CUB IN THIS PROCEEDING WITH THE METHODOLOGY PROPOSED BY THE COMPANY.

A. Currently, the Company models its marginal production costs in its marginal cost of service study from a mix of traditional resources (simple cycle and combined cycle combustion turbines). The Company incorporates the impact of EE by modeling rate schedule loads based on their actual usage. This approach essentially internalizes the load reductions produced by EE efforts for each rate schedule.

By contrast, CUB uses EE to shift the costs of production resources in the Company's marginal cost of service study between rate classes. Specifically, CUB creates a resource mix for the Company which assumes that EE resources constitute 20.05% of the Company's theoretical resource needs. Importantly, CUB also develops a special allocation for the portion of the theoretical resource mix that it attributes to EE by giving each rate schedule credit for EE based on the level of ETO payments provided by that schedule, as calculated by CUB. CUB then subtracts these allocated EE-related amounts from the total system megawatts served by its theoretical resource mix. The resulting allocation of system megawatts to the rate schedules (net of EE) forms the basis for the modified production energy cost allocator developed by CUB that it then applies to the total production energy-related costs found in the Company's marginal cost study.[2/]

[2/] CUB/100 at 31 – 36.

Q. DOES CUB'S PROPOSAL HAVE A SIGNIFICANT IMPACT ON THE ALLOCATION OF COSTS TO THE RATE SCHEDULES?

A. Yes. Exhibit ICNU/402 compares the production energy cost allocation factors proposed by PGE to the modified allocation factors developed by CUB. As can be seen in Columns 1 and 2 of the Exhibit, CUB's proposal increases the production energy cost allocators for Schedules 89 and 90 relative to PGE's proposal, while reducing these allocation factors for residential and small commercial customers. Column 5 of the Exhibit shows the magnitude of the resulting changes in the allocation of production energy costs by rate schedule. The Exhibit shows that, on a combined basis, CUB's proposal would increase the allocation of such costs to Schedules 89 and 90 by almost $26 million relative to PGE's proposal, while reducing the cost allocation to Schedule 7 by $26.7 million. It should be noted that these figures are based on the Company's as-filed revenue requirement.

Exhibit ICNU/403 summarizes the change in overall cost allocation that results from CUB's proposal, relative to the cost allocation proposed by PGE. This Exhibit reinforces the fact that CUB's proposal would generate a massive cost shift that favors smaller customers on PGE's system at the expense of industrial customers. As shown in Column 6 of Exhibit ICNU/403, CUB's proposal would increase rates under Schedule 89 by 14.22% and under Schedule 90 by 17.93% relative to the Company's proposed allocation. By contrast, CUB's approach would reduce Schedule 7 rates by 3.03% and would also reduce Schedule 15 rates by 8.11%.[3/] Again, these figures are based on the Company's as-filed revenue requirement.

[3/] CUB/100 at 36, Table 9.

IV. RESPONSE TO CUB'S ALLOCATION PROPOSAL

Q. WHAT IS YOUR CONCERN WITH CUB'S PROPOSAL?

A. CUB's proposal ignores the fact that the purpose of a class cost of service study is to allocate a utility's cost of service rather than to allocate system benefits. These utility costs should be allocated consistent with sound principles of cost causation. When EE is included in the marginal cost study in the manner proposed by CUB, this causes a distortion of the price signals to customers by arbitrarily shifting the allocation of costs among the rate schedules.

Moreover, CUB does not propose to simply include EE in the marginal cost study. Rather, CUB allocates EE's benefits to different customer classes based on highly dubious assumptions, as explained further below. This raises significant questions about the value of CUB's marginal cost study. The drivers for a utility's incurrence of costs are primarily actual (or projected) customer demands and energy consumption. Therefore, it is appropriate to allocate energy-related generation costs based on actual forecasted test year usage, as proposed by the Company. Once one begins to distort the production energy cost allocation factor through arbitrary adjustments in an effort to capture the value of vaguely defined system benefits, as proposed by the CUB, one quickly deviates from the cost causation principles that define the development of a proper class cost of service study.

Q. WHY HAS CUB PROPOSED TO MODIFY PGE'S GENERATION MARGINAL COST STUDY?

A. CUB argues that EE is "the primary resource added to meet load growth," and therefore, "a model of energy marginal costs that excludes EE would be both inaccurate and misleading."[4/] CUB also alleges that residential customers are unfairly subsidizing large customer conservation projects and that, due to an informal funding cap developed after the passage of Senate Bill ("SB") 838, the ETO may not be able to acquire all cost-effective energy efficiency from large customers in PGE's service territory in the near future.[5/] CUB represents that its marginal cost proposal will remedy these issues.[6/]

Q. GIVEN CUB'S CLAIM THAT A MARGINAL COST STUDY THAT EXCLUDES EE WOULD BE MISLEADING, ARE YOU AWARE OF ANY PRECEDENT IN OREGON OR IN OTHER JURISDICTIONS FOR ADJUSTING PRODUCTION COST ALLOCATORS TO REFLECT EE SYSTEM BENEFITS IN THE MANNER PROPOSED BY CUB?

A. No, I am not aware of any jurisdiction that has attempted to adjust cost allocators in a class cost of service study in an effort to capture system benefits derived from EE programs. In fact, I am not familiar with any jurisdiction that models EE as a marginal resource. Moreover, in response to discovery, neither the Company nor CUB could cite to any precedent supporting CUB's approach. In fact, CUB acknowledged that its proposal does not follow standard practice or precedent.[7/]

Q. HAS THE COMPANY EXPRESSED CONCERNS WITH CUB'S PROPOSAL?

A. Yes. In its reply testimony in this proceeding, the Company pointed out that CUB's proposal goes beyond traditional marginal cost analysis. The Company also stated that EE in not a traditional capacity or energy resource.[8/]

4/ CUB/100 at 20:17-21:1.

5/ The rebuttal testimony of Bradley G. Mullins (ICNU/300) provides additional response to these issues.

6/ CUB/100 at 28.

7/ Exhibit ICNU/404 (PGE's Response to ICNU Data Request No. 138 and CUB's Response to ICNU Data Request No. 10a).

8/ PGE/1600 at 26.

Q. DO YOU AGREE WITH THE COMPANY'S TESTIMONY?

A. Yes. Under traditional economic theory, the definition of the marginal cost of generation is based on the cost associated with the next increment of demand or energy use on a utility's system. The increased demand or energy requirements could be met by owned or purchased generation resources. By contrast, EE resources are not used to meet increased demand or energy needs on the system. Rather, EE is designed to reduce demand or energy usage relative to current (or forecasted) levels. While CUB argues that the Company's marginal cost should be the resources the Company projects it will actually use to meet long-term demand in its Integrated Resource Plan ("IRP"),[9/] the marginal cost study is not designed necessarily to reflect a utility's actual resource mix. The study uses a *theoretical* resource mix to capture the costs necessary to make the utility financially whole for meeting the increased increment of demand.

Q. WHAT ARE THE BENEFITS OF SETTING PRICES AT MARGINAL COST?

A. According to theory, pricing services at marginal cost sends accurate price signals to customers that encourage them to conserve energy. The Commission has previously recognized these principles: "Oregon's general rate design approach is to set rates that reflect costs. This approach has the effect of emphasizing the appropriate economic incentives for energy conservation …. Oregon's general rate design approach of basing rate design on marginal cost considerations, rather than embedded cost or historic cost, has the effect of emphasizing the economic incentive for energy conservation."[10/]

9/ CUB/100 at 31:9-32:4.

10/ Docket No. UM 1409, Order No. 09-501 (Dec. 18, 2009); see also, Docket No. UM 827, Order No. 98-374, 1998 Ore. PUC LEXIS 246 at *6-*7 (Sept. 11, 1998) ("Proper calculation of marginal costs provides proper price signals to customers, which, in turn, can lead to more efficient consumption").

Q. HOW DOES INCLUDING EE AS A MARGINAL RESOURCE DIMINISH THESE BENEFITS?

A. Under CUB's analysis, incorporating EE in the marginal cost study is used as a means to shift the allocation of production costs among the rate schedules in a manner that deviates from a cost allocation that is based on customer usage characteristics. Including EE in the marginal cost study in this manner would distort the proper, cost-based price signals for customers. Consequently, it is conceptually flawed to devise a marginal cost study with a "theoretical" resource mix that includes EE resources on an equal par with traditional physical generation resources.

Q. ARE THERE OTHER REASONS WHY EE SHOULD NOT BE CONSIDERED A MARGINAL RESOURCE?

A. Yes. It is problematic to include EE in the marginal cost study as a resource on par with supply-side resources. This is because EE cannot be relied upon to meet long-run load requirements in the same manner as incremental supply side resources. EE measures are subject to a rebound effect, under which a portion of the energy savings associated with the implementation of EE programs is often eroded over time. This erosion occurs because the reduced end-use customer power costs resulting from EE programs stimulate an increase in the customer's energy consumption that partially offsets the initial EE program savings. Thus, one aMW of conservation does not necessarily result in one aMW of reduced load. While there is no consensus on the magnitude of the rebound effect among researchers, few dispute its existence.[11/]

[11/] See, e.g., Sheetal Gavankar & Roland Geyer, The Rebound Effect: State of the Debate and Implications for Energy Efficiency Research, University of California Santa Barbara Bren School of Environmental Science and Management (June 26, 2010) (finding approximate 30% impact); Kenneth Gillingham, et al., The Rebound Effect and Energy Efficiency Policy, Yale University School of Forestry & Environmental Studies (2013) (arguing that the rebound effect is overemphasized, yet still finding a 10%-30% impact on electric efficiency).

Furthermore, in some cases, investments in new technology may also degrade the energy savings associated with EE over time. For example, a customer may attain reduced energy usage due to an EE program but may subsequently invest in facility upgrades that consume greater amounts of electricity in total, thereby eroding some of the savings associated with the initial program implementation at that location. The Environmental Protection Agency has recognized these issues in technical documents released as part of its "111(d)" rulemaking, noting that EE programs "represent a diverse portfolio of programs, that range in measure lives from as little as a few years … to as long as fifteen or twenty years …."[12/]

Note that my testimony should not be interpreted to suggest that pursuing all cost-effective EE is not worthwhile or beneficial. Rather, it is simply to point out that the potential degradation of EE savings over time, as well as the diverse measure lives of various EE technologies raises doubts regarding the validity of using EE as a long-run resource in the marginal cost study, on an equal footing with supply-side resources.

Q. IF ONE WERE TO NEVERTHELESS EXPLICITLY MODEL EE RESOURCES IN THE MARGINAL COST STUDY DESPITE THE CONCERNS RAISED ABOVE, WOULD YOU EXPECT THIS TO INCREASE COSTS FOR SOME RATE SCHEDULES WHILE REDUCING COSTS FOR OTHER RATE SCHEDULES, AS REFLECTED IN THE CUB MODEL?

A. No. If the Commission believes that EE should be explicitly accounted for in the marginal cost study despite the concerns raised in my testimony, it should be noted that inclusion of EE in the cost study would not be expected to result in higher costs for some rate schedules and lower costs for others. If EE is a low-cost resource, as CUB alleges,

12/ Environmental Protection Agency, GHG Abatement Measures, (Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants), Docket ID No. EPA-HQ-OAR-2013-0602 at 5-35 (June 10, 2014), available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

adding EE to the marginal cost study as an explicit resource should displace some of the more expensive supply-side resources that the Company included in its cost study, resulting in lower total marginal production energy costs at the system level. If these lower production energy costs were appropriately allocated to the rate schedules based on forecasted usage as proposed by the Company, this should result in a lower marginal cost of production for all rate schedules in the marginal cost study.

By contrast, CUB's effort to arbitrarily revise the allocation of energy-related production costs distorts the marginal cost pricing signals that the Company's cost study is intended to provide to customers, which is why it vastly increases costs for some customers while lowering costs for others.

Q. PLEASE EXPAND ON WHY CUB'S METHODOLOGY OF INCLUDING EE IN THE MARGINAL COST STUDY INCREASES COSTS FOR SOME CUSTOMERS WHILE REDUCING COSTS FOR OTHERS.

A. This occurs because CUB does not, strictly speaking, include EE as a resource in the marginal cost of energy, despite its claims otherwise.[13/] This is evident from Table 8 on page 35 of CUB's testimony, reproduced in part in Table 1, below:

TABLE 1
MARGINAL COST OF ENERGY
COMPANY FILING VERSUS CUB PROPOSAL

	Company Filing	CUB Proposal	
Marginal Cost of Energy	$975,598,466	$975,598,466	(a)

(a) See CUB 35:1, Table 8.

Here, it can be seen that CUB's and the Company's total marginal energy costs are identical. Thus, CUB's inclusion of EE in the marginal cost study does not actually

13/ CUB/100 at 31-36.

change the Company's marginal costs; it simply shifts marginal production costs between customer classes based on questionable assumptions about EE funding and acquisition.

Q. WHY ARE CUB'S ASSUMPTIONS QUESTIONABLE?

A. CUB's EE assumptions in its marginal cost study are based on the Company's IRP, which projects that it will meet approximately 20% of long-term load growth through energy efficiency measures.[14/] CUB then takes this 20% figure and applies it to the Company's 2015 load projections.[15/] This generates an assumption that the Company will achieve 800 aMW of EE in the test year.[16/] This can be seen in Table 2, below:

TABLE 2
CUB PROPOSAL TO REALLOCATE MARGINAL COST OF ENERGY IN COMPANY'S INITIAL FILING

	Company		CUB				
	Load (aMW)	MCE* %	Load (aMW)	**EE aMW**	Net Load (aMW)	MCE* %	Load Delta
Schedule 7	1,717	43.0%	1,717	**(431)**	1,285	40.3%	-25%
Schedule 15	3	0.1%	3	**(2)**	2	0.0%	-51%
Schedule 32	352	8.8%	352	**(84)**	268	8.4%	-24%
Schedule 38	10	0.3%	10	**(3)**	7	0.2%	-28%
Schedule 47	4	0.1%	4	**(1)**	3	0.1%	-34%
Schedule 49	16	0.4%	16	**(4)**	12	0.4%	-24%
Schedule 83	624	15.6%	624	**(121)**	503	15.8%	-19%
Schedule 85	688	17.3%	688	**(118)**	571	17.9%	-17%
Schedule 89	239	6.0%	239	**(13)**	227	7.1%	-5%
Schedule 90	315	7.9%	315	**(14)**	301	9.4%	-4%
Schedule 91/95	20	0.5%	20	**(9)**	11	0.3%	-44%
Schedule 92	1	0.0%	1	**(0)**	1	0.0%	-18%
Total	3,990	100%	3,990	**(800)**	3,190	100%	-20%

*"Marginal Cost of Energy"

Moreover, because CUB allocates these aMWs to rate classes based on ETO funding levels, CUB assumes that all of this EE will be achieved through the ETO.

14/ CUB/100 at 32.
15/ CUB/103.
16/ CUB/100 at 34, Table 7.

Q. WHAT IS WRONG WITH CUB'S METHODOLOGY?

A. The fallacy in CUB's methodology is readily apparent from the fact that the 800 aMWs assumed in the study exceeds the total EE the ETO acquired in PGE's service territory in 2013 by a factor of almost 23.[17/] In fact, it far exceeds the total EE the ETO has acquired since its inception, as represented in CUB's testimony.[18/] Furthermore, CUB's methodology assumes that all EE acquired in PGE's service territory is funded entirely by ETO dollars. This is demonstrably wrong. As I discussed earlier in my testimony, large industrial customers operate in competitive global markets and therefore have every incentive to implement EE initiatives using their own funds in an effort to reduce their operating costs. Furthermore, even when industrial customers receive ETO incentive funding, such funding covers, at most, 50% of the costs of the project.[19/] The remaining costs are borne by the customer. These self-implemented EE efforts are ignored under CUB's proposal.

Thus, the amount of EE CUB includes in its marginal cost study is both over-inclusive and under-inclusive. It is over-inclusive because it vastly overstates the amount of EE the ETO is likely to acquire in 2015, and it is under-inclusive because it does not account for EE measures that are customer-funded.

Q. WHY DOES THIS MATTER?

A. Because CUB's methodology results in an arbitrary shifting of production resource costs between customer classes, which distorts the marginal cost study. As discussed above,

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17/ ETO 2013 Annual Report at 25. The ETO reports that it achieved 35.62 aMWs of EE in 2013.

18/ CUB/100 at 23, Figure 1 (assuming 327.9 aMWs in total EE acquired by the ETO, less than half the amount assumed in CUB's marginal cost model).

19/ http://energytrust.org/industrial-and-ag/industry/; the Rebuttal Testimony of Bradley G. Mullins provides specific examples of the resources industrial customers provide on their own to implement conservation measures.

rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions (i.e., how much energy to consume, at what rate, and when) they tend to take actions which not only minimize their own costs, but those of the utility as well, thereby benefitting all customers. If the production cost allocation factors by rate schedule are arbitrarily and artificially increased or reduced in the marginal cost study, as CUB's methodology does, then prices these customers pay do not accurately reflect the costs of increased consumption.

CUB's approach comes close to one the Commission has previously rejected in the context of capacity and energy resources, and which CUB itself argued against. In addressing the cost allocation methodology to apply to PGE's automated demand response pilot program, the Commission adopted CUB's (as well as PGE's and Staff's) recommendation and rejected ICNU's proposal to apply the costs of this pilot program as a capacity charge.[20/] The Commission found that "we cannot look at an allocation scheme for a given resource in isolation. If we adopted ICNU's proposed methodology without altering the cost allocation scheme for all other resources, it would result in a less fair allocation of costs in the aggregate."[21/] CUB's proposal in this case demonstrates the Commission's point.

Q. DOES THE COMPANY'S MARGINAL COST OF SERVICE STUDY ALREADY CAPTURE THE EFFECTS OF EE?

A. Yes. As CUB recognizes, under PGE's cost study, "the Company models Schedule loads from actual usage, indirectly internalizing EE applied to each rate schedule. This means

[20/] Docket No. UE 234, Order No. 11-517 (Dec. 21, 2011).
[21/] Id. at 5.

that each customer class is affected by the energy efficiency programs that reduce the load from its class."[22/] The Company's allocation of energy-related generation costs in its cost study is based on projected electricity consumption by rate schedule for the test year, using actual historical data as a starting point for the projections. These consumption projections internalize the impact of EE funded by each rate schedule through reductions in the test year energy usage used to develop the allocation factors for each schedule. The benefit of this approach is that it accurately reflects the impact of EE in the marginal cost study, unlike CUB's methodology. Load reductions that are actually achieved through EE measures are included in the model. This maintains the necessary relationship between pricing signals and cost-causation.

Q. WHAT ARE THE LIKELY CONSEQUENCES TO THE COMPANY'S SYSTEM FROM CUB'S PROPOSAL?

A. As the Company pointed out in its reply testimony, CUB's proposal could incent large industrial customers to opt for long-term direct access.[23/] Because direct access customers do not pay the Company's energy charge, large customers currently on PGE's system could choose direct access as a means of avoiding the large, uneconomic production cost increases that would result from the proposal. If this were to transpire, PGE could be left with a significantly smaller customer base purchasing regulated generation service across which it could spread its production costs, to the detriment of all customers on the Company's system. Although transition charges would offset this difference for a period of time, under the Company's long-term opt-out program, transition charges cease after five years.

22/ CUB/100 at 33:6-9.
23/ PGE/1600 at 26-27.

Q. BASED ON THE FOREGOING CONSIDERATIONS, WHAT DO YOU CONCLUDE WITH RESPECT TO CUB'S PROPOSAL?

A. CUB's proposal represents an unwarranted and unprecedented deviation from generally accepted class cost allocation principles. By departing from such principles, CUB's proposal would result in rates that deviate dramatically from the Company's actual cost to serve the customer classes on its system, as determined by actual customer usage characteristics. Moreover, CUB's proposal would distort the marginal cost of service study results to achieve the goal of arbitrarily and dramatically shifting the allocation of the Company's production costs towards large industrial customers. For these reasons, the Commission should reject CUB's proposal.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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EXHIBIT ICNU/401

QUALIFICATIONS OF ALI AL-JABIR

August 13, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ali Al-Jabir. My business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of the University of Texas at Austin ("UT-Austin"). I hold the degrees of Bachelor of Arts and Master of Arts in Economics, both from UT-Austin. I have also completed course work at Harvard University. I received my B.A. degree with highest honors, and I am a member of the Phi Beta Kappa Honor Society.

Q. PLEASE STATE YOUR EXPERIENCE.

A. I joined BAI in January 1997. My work consists of preparing economic studies and economic policy analysis related to investor-owned, cooperative, and municipal utilities. Prior to joining BAI, I was employed at the Public Utility Commission of Texas ("Texas Commission") since 1991, where I held various positions including Policy Advisor to the Chairman. As Policy Advisor, I advised the Chairman on policy decisions in numerous rate and rulemaking proceedings. In 1995, I advised the Texas Legislature on the development of the statutory framework for wholesale competition in the Electric Reliability Council of Texas ("ERCOT"), and I was involved in subsequent rulemakings at the Texas Commission to implement wholesale open access transmission service in the region.

During my tenure at the Texas Commission and in my present capacity, I have reviewed and analyzed several electric utility base rate and fuel filings in Texas. I have also worked on utility rate, fuel, and merger proceedings and rulemakings in Louisiana, Virginia, Missouri, Colorado, Indiana, Pennsylvania, North Carolina, South Carolina, Michigan, Rhode Island, Alberta and Nova Scotia. In addition to my work on such proceedings, I have drafted policy papers and comments regarding electric industry restructuring and competitive policy issues in Texas, Alabama, Louisiana, Georgia, and Delaware, as well as before the Federal Energy Regulatory Commission. I have been an invited speaker at several electric utility industry conferences, and I have presented seminars on utility regulation and industry restructuring.

BAI and its predecessor firms have been active in utility rate and economic consulting since 1937. The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some competitive retail power providers and utilities and, on occasion, state regulatory agencies. In addition, we have prepared depreciation and feasibility studies relating to utility service. We assist in the negotiation of contracts and the solicitation and procurement of competitive energy supplies for large energy users, provide economic policy analysis on industry restructuring issues, and present seminars on utility regulation. In general, we are engaged in regulatory consulting, economic analysis, energy procurement, and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas and Phoenix, Arizona.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN CONTESTED UTILITY PROCEEDINGS?

A. Yes, I have filed written testimony in the following dockets:

1. Texas Docket No. 10035 – Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors;

2. Texas Docket No. 10200 – Application of the Texas - New Mexico Power Company for Authority to Change Rates;

3. Texas Docket No. 10325 – Application of the Central Texas Electric Cooperative, Inc. for Authority to Change Rates;

4. Texas Docket No. 10600 – Application of the Brazos River Authority for Approval of Rates;

5. Texas Docket No. 10881 – Application of the New Era Electric Cooperative, Inc. for Authority to Change Rates;

6. Texas Docket No. 11244 – Petition of the Medina Electric Cooperative, Inc. to Reduce its Fixed Fuel Factor and the Application of the South Texas Electric Cooperative, Inc. for Authority to Refund an Over-Recovery of Fuel Cost Revenues and to Reduce its Fixed Fuel Factor;

7. Texas Docket No. 11271 – Application of Bowie-Cass Electric Cooperative, Inc. for Authority to Change Rates;

8. Texas Docket No. 11567 – Application of Kaufman County Electric Cooperative, Inc. for Authority to Change Rates;

9. Texas Docket No. 18607 – Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs;

10. Texas Docket No. 20290 – Application of Central Power & Light Company for Authority to Reconcile Fuel Costs;

11. Virginia Case No. PUE980814 – In the matter of considering an electricity retail access pilot program: American Electric Power – Virginia;

12. Texas Docket No. 21111 – Application of Entergy Gulf States Inc. for Authority to Reconcile Fuel Costs and to Recover a Surcharge for Under-Recovered Fuel Costs;

13. Virginia Case No. PUE990717 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Virginia Code Section 56-249.6;

14. Texas Docket No. 22344 – Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule § 25.344;

15. Texas Docket No. 22350 – Application of TXU Electric Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Phase III);

16. Texas Docket No. 22352 – Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

17. Texas Docket No. 22353 – Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

18. Texas Docket No. 22354 – Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

19. Texas Docket No. 22356 – Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344;

20. Texas Docket No. 22349 – Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

21. Virginia Case No. PUE000584 – Application of Virginia Electric and Power Company for Approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act;

22. Texas Docket No. 24468 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool;

23. Texas Docket No. 24469 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council;

24. Virginia Case No. PUE-2002-00377 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Section 56-249.6 of the Code of Virginia;

25. Texas Docket No. 27035 – Application of Central Power and Light Company for Authority to Reconcile Fuel Costs;

26. Texas Docket No. 28818 – Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas;

27. Virginia Case No. PUE-2000-00550 -- Appalachian Power Company d/b/a American Electric Power: Regional Transmission Entities;

28. Texas Docket No. 29408 – Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs;

29. Texas Docket No. 29801 – Application of Southwestern Public Service Company for: (1) Reconciliation of its Fuel Costs for 2002 and 2003; (2) A Finding of Special Circumstances; and (3) Related Relief;

30. Texas Docket No. 30143 -- Petition of El Paso Electric Company to Reconcile Fuel Costs;

31. Texas Docket No. 31540 – Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Substantive Rule 25.501;

32. Texas Docket No. 32795 – Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA Section 39.253(f);

33. Texas Docket No. 33309 – Application of AEP Texas Central Company for Authority to Change Rates;

34. Texas Docket No. 33310 – Application of AEP Texas North Company for Authority to Change Rates;

35. Michigan Case No. U-15245 – In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Rate Relief;

36. Texas Docket No. 34800 – Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs;

37. Texas Docket No. 35717 – Application of Oncor Electric Delivery Company LLC for Authority to Change Rates;

38. RIPUC Docket No. 4065 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11; and

39. RIPUC Docket No. 4323 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-1-3-11.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision.	)
____	)

EXHIBIT ICNU/402

CHANGE IN COST ALLOCATION BASED ON
PGE AND CUB GENERATION ENERGY ALLOCATION FACTORS

August 13, 2014

Change in Cost Allocation Based on
PGE and CUB Generation Energy Allocation Factors
(000)

Line	Schedule	PGE Generation Energy Allocation Factor (1)	CUB Generation Energy Allocation Factor (2)	CUB Power Supply Costs (3)	PGE Power Supply Costs (4)	Difference (5) = (3) - (4)	Percent Difference (6) = (5) / (4)
1	7	43.03%	40.30%	$393,157	$419,841	($26,683)	-6.4%
2	15	0.08%	0.05%	$484	$788	($304)	-38.6%
3	32	8.83%	8.40%	$81,920	$86,120	($4,200)	-4.9%
4	38	0.25%	0.23%	$2,247	$2,487	($240)	-9.6%
5	47	0.11%	0.09%	$863	$1,042	($179)	-17.2%
6	49	0.40%	0.38%	$3,706	$3,897	($191)	-4.9%
7	83	15.64%	15.76%	$153,751	$152,588	$1,164	0.8%
8	85	17.26%	17.89%	$174,492	$168,356	$6,137	3.6%
9	89	5.99%	7.10%	$69,277	$58,483	$10,794	18.5%
10	90	7.90%	9.44%	$92,137	$77,033	$15,104	19.6%
11	91&95	0.49%	0.35%	$3,382	$4,788	($1,406)	-29.4%
12	92	0.02%	0.02%	$181	$177	$4	2.2%
13	Total	100.00%	100.00%	$975,598	$975,598	($0)	0.0%

Data Source:

CUB Exhibit 103

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT ICNU/403

IMPACT OF CUB'S ALLOCATION PROPOSAL

August 13, 2014

Impact of CUB's Allocation Proposal
(000)

Line	Schedule	PGE Power Supply (1)	CUB Power Supply (2)	CUB Cost Allocation (3)	PGE Allocation (4)	Difference (5) = (3) - (4)	Schedule Change from PGE 2015 (6) = (5) / (4)
1	7	$ 419,841	$ 393,157	$ 853,269	$ 879,952	$ (26,683)	-3.03%
2	15	$ 788	$ 484	$ 3,447	$ 3,751	$ (304)	-8.11%
3	32	$ 86,120	$ 81,920	$ 163,985	$ 168,185	$ (4,200)	-2.50%
4	38	$ 2,487	$ 2,247	$ 5,475	$ 5,715	$ (240)	-4.20%
5	47	$ 1,042	$ 863	$ 4,867	$ 5,046	$ (179)	-3.54%
6	49	$ 3,897	$ 3,706	$ 15,644	$ 15,835	$ (191)	-1.21%
7	83	$ 152,588	$ 153,751	$ 237,086	$ 235,923	$ 1,163	0.49%
8	85	$ 168,356	$ 174,492	$ 244,969	$ 238,833	$ 6,136	2.57%
9	89	$ 58,483	$ 69,277	$ 86,700	$ 75,906	$ 10,794	14.22%
10	90	$ 77,033	$ 92,137	$ 99,351	$ 84,247	$ 15,104	17.93%
11	91&95	$ 4,788	$ 3,382	$ 15,855	$ 17,260	$ (1,405)	-8.14%
12	92	$ 177	$ 181	$ 251	$ 247	$ 4	1.68%
13	Total	$ 975,598	$ 975,598	$ 1,730,900	$ 1,730,900	$ (0)	0.00%

Data Source:

CUB Exhibit 103

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 283

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision.	)
	)

REBUTTAL TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 13, 2014

**TABLE OF CONTENTS TO THE
REBUTTAL TESTIMONY OF MICHAEL P. GORMAN**

Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND EMPLOYER.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri.

Q. ARE YOU THE SAME MICHAEL P. GORMAN WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. On June 11, 2014, I submitted Opening Testimony and exhibits on behalf of the Industrial Customers of Northwest Utilities ("ICNU") regarding Portland General Electric Company's ("PGE" or the "Company") overall rate of return including return on equity, embedded debt cost and capital structure.

Q. WHAT IS THE SUBJECT MATTER OF THIS TESTIMONY?

A. My rebuttal testimony will respond to PGE witness Dr. Bente Villadsen.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/501 and ICNU/502.

Summary

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations can be summarized as follows:

1. For the reasons outlined in my Opening Testimony, Dr. Zepp's return on equity for PGE is overstated and unreasonable. Dr. Villadsen has not provided justification or a demonstration that the excessive return on equity is reasonable.

2. Dr. Villadsen's argument that PGE has greater investment risk than the proxy group is without merit, and is not based on competent evidence.

3. Dr. Villadsen's criticisms of my DCF study contain contradictory assertions, and are based on an inaccurate assessment of my studies.

4. Dr. Villadsen's criticisms of my CAPM return estimates are based on unreasonable estimates of the market risk premium, and should be disregarded.

5. Dr. Villadsen's assessment of my risk premium study is based on an erroneous interpretation of the risk premium data, and her adjustments overstate a fair return on equity for PGE.

6. Because Dr. Villadsen's criticisms of my DCF, CAPM and risk premium studies are based on inaccurate assessments of my studies, and incomplete review of the study data, her conclusion that my return on equity estimate is understated is without merit and erroneous.

Q. PLEASE SUMMARIZE THE REPLY TESTIMONY OF DR. VILLADSEN.

A. In her testimony, Dr. Villadsen takes the following positions:

1. She concludes that Dr. Zepp's return on equity finding for the proxy group of 9.9% to 10.6% is reasonable.

2. She agrees with Dr. Zepp that PGE has greater risk than the proxy group and therefore a fair authorized return on equity for PGE should be toward the high-end of the estimated proxy group range. She concludes that a 10.5% return on equity for PGE is reasonable.

3. She concludes that Staff's authorized return on equity recommendation for PGE does not reflect PGE's investment risk. She states that, because Staff failed to make a return on equity adder to reflect her belief that PGE's risk is greater than that of the proxy group, that there is a downward bias in Staff's recommended return on equity for PGE.

4. She claims that there are technical problems with my recommended return on equity studies. She also asserts that I failed to recognize PGE's greater investment risk, and therefore my recommended return on equity for PGE is downward biased.

5. She reviews industry authorized returns on equity for electric utility companies and integrated electric utility companies. Based on this review, she believes that her adoption of Dr. Zepp's proposed return on equity of 10.5% for PGE is reasonable.

<u>Dr. Zepp's Return on Equity Recommendation</u>

Q. HAVE YOU ALREADY RESPONDED TO THE ACCURACY AND REASONABLENESS OF DR. ZEPP'S RETURN ON EQUITY STUDY?

A. Yes. As outlined in my Opening Testimony at pages 35-50, Dr. Zepp's methodologies and data inputs substantially overstate a fair and reasonable return on equity for PGE in this case. Dr. Zepp's finding on his DCF estimate was unreasonable because:

1. He excluded low-end outliers, without also eliminating high-end outliers; and
2. His growth rate included in his constant growth DCF analysis overstated a reasonable estimate of long-term sustainable growth.
3. Dr. Zepp's small company size equity risk premium adjustment for PGE is flawed. Dr. Zepp ignores risk comparability in recommending this return on equity adder for PGE based on its market capitalization size.

For these reasons, Dr. Zepp's recommended return on equity for PGE is overstated and not reasonable.

<u>PGE Investment Risk</u>

Q. WHY DOES DR. VILLADSEN BELIEVE THAT PGE'S INVESTMENT RISK IS GREATER THAN THAT OF THE PROXY GROUP?

A. She believes that PGE has greater risk based on the following factors. Based on data outlined on her Exhibit PGE/2002, Dr. Villadsen believes that PGE has greater risk than the proxy group due to: (1) construction risk, (2) purchased power agreement ("PPA") financial obligations, and (3) market capitalization size.

Q. HAS DR. VILLADSEN SUPPORTED HER NOTION THAT PGE HAS GREATER INVESTMENT RISK BASED ON THESE FACTORS?

A. No. Dr. Villadsen is focusing on single elements of PGE's total investment risk. While PGE could have greater components of total risk than the proxy group, it may have other components of risk that are lower than that of the proxy group. As such, in assessing a fair return on equity, it is important to focus on <u>total investment risk</u>, not single risk factors that are included in total investment risk, as proposed by Dr. Villadsen.

All of the risk factors observed by Dr. Villadsen are recognized by credit rating agencies in assigning a credit rating to PGE and each of the companies in the proxy group. However, credit rating agencies will also consider <u>all other relevant risks</u> in assessing each company's credit rating. Importantly, a credit rating is based on a complete and thorough investigation of total investment risk. In significant contrast, Dr. Villadsen focused on only certain risk factors, and she ignored other relevant risk factors.

Q. DOES PGE HAVE GREATER RISK THAN THE PROXY GROUP BASED ON CREDIT RATING?

A. No. As shown on Dr. Zepp's risk comparison schedule on his Exhibit PGE/1201, Zepp/1, PGE has Standard & Poor's ("S&P") and Moody's bond ratings that are higher than the proxy group average and most of the companies in his proxy group. A comparison of PGE's bond rating proves that it does not have greater risk than the proxy group, but rather has comparable risk, if not slightly less risk, to that of the proxy group.

Q. DO YOU BELIEVE DR. VILLADSEN'S ASSERTION THAT PGE HAS GREATER CAPITALIZATION RISK THAN THE PROXY GROUP IS ACCURATE?

A. No. Dr. Villadsen's study is based on a specific point in time, rather than a review of capital investment risk over time. Further, just examining the level of capital investment does not give an indication of the utility's ability to fund the capital program, and the regulatory mechanisms in place to support the utility's ability to make capital investments.

Q. DID S&P CONSIDER CONSTRUCTION PLANS IN ITS BOND RATING FOR PGE?

A. Yes. Contrary to Dr. Villadsen's testimony, S&P specifically considered PGE's construction risk in assigning its bond rating. S&P does the same for the other proxy group companies. In its report dated May 8, 2014, S&P noted its assumptions in reviewing PGE's current credit rating. In those assumptions, S&P stated that it assumed that PGE would have $1 billion of capital expenditures in 2014, and $500 million in 2015. With those assumptions, S&P projected that PGE's credit metrics would actually strengthen in 2014 and 2015 compared to 2013 actual. S&P made the following projections on credit metrics for PGE:

Key Metrics

	2013A	**2014E**	**2015E**
FFO to debt (%)	16.8	17.5-18.6	18.6-20.1
Debt to EBITDA (x)	4.3	3.9-4.4	3.4-3.9
Cash flow from operations to debt (%)	21.8	15.1-16.3	16.0-17.0

Note: Standard & Poor's adjusted figures. A--Actual. E--Estimate. FFO--Funds from operations.[1/]

Based on the table above, PGE's construction program build-up in 2014 will negatively impact, on a temporary basis, its credit metrics in 2014 relative to 2013. However, as its construction program winds down in 2015, its credit metrics again strengthen, and, in

[1/] *Standard & Poor's RatingsDirect*: "Summary: Portland General Electric Co.," May 8, 2014 at 3.

fact, mostly improve relative to those metrics actually incurred in 2013. As such, PGE's construction program does not create a sustained level of financial stress on the Company, and actually is moderated quite quickly as its construction program decreases over time.

Q. IS THERE OTHER INFORMATION THAT HELPS TO GAUGE PGE'S CONSTRUCTION RISK COMPARED TO THAT OF THE PROXY GROUP?

A. Yes. A comparison of PGE's internal funds available to fund capital programs, in relationship to its actual capital expenditure budget, helps gauge the financial risk of funding the capital programs. A company that is able to fund its capital program predominantly with internal funds has less exposure to external capital markets to fully fund its capital program. Therefore, the capital program has less funding risk and is more affordable. PGE's internal funding relative to its capital program illustrates less funding risk, and less construction risk than that of the proxy group. I base this conclusion on projections made by *The Value Line Investment Survey* ("*Value Line*").

Value Line provides data for PGE and all the proxy group companies to help illustrate how much of their capital programs can be funded with internal funds, and how much can be funded from external capital sources.

This is illustrated on my Exhibit ICNU/501. On this exhibit, I have provided *Value Line*'s projections for cash flow available for capital expenditures, compared to the capital expenditures in 2014, 2015, and the three- to five-year projection. Similar to S&P's projections described above, PGE's capital program is large in 2014, and decreases in 2015 through 2018. Based on *Value Line*'s three- to five-year projections, PGE's construction program will be very manageable and likely not require PGE to go to external capital markets to support its construction budgets.

My Exhibit ICNU/501 illustrates that PGE's ability to internally finance its construction program improves significantly in 2015. As shown on page 1 of this exhibit, in 2014, *Value Line* projects that PGE's internal cash flow will support only about 36% of its construction activity. This will require it to go to the capital markets to fund approximately 64% of its construction budget. In contrast, the proxy group will fund approximately 54% of its construction activity in 2014 with internal funds, and will need to go to the market for around 46% of this construction budget. While PGE's risk is slightly greater than that of the proxy group in 2014, it is not materially different than the proxy group.

In 2015, *Value Line* projects that PGE will fund approximately 79% of its construction program with internally generated funds. This is a stronger internal funding of budgeted capital programs for PGE than that of the proxy group average in 2015. *Value Line* projects that the proxy group will fund approximately 64% of its construction program from internal funds in 2015. Hence, PGE's ability to fund its capital program with internal funds strengthens from slightly more risk than the proxy group in 2014 to less risky than the proxy group by 2015, which is the test year in this proceeding.

This strengthening of PGE's internal cash generation in relationship to its construction budget further increases in *Value Line*'s three- to five-year projections. As shown on page 3 of Exhibit ICNU/501, *Value Line*'s projections show that PGE will have significantly more internal cash generation than it has budgeted capital spending in the next three to five years. This is in significant contrast to the proxy group, which will continue to have a need to go to the external market to fund its capital program over the three- to five-year projection. At this point, PGE's ability to fund its construction program is significantly stronger and much less risky than that of the proxy group.

Based on this funding and construction budget comparison, PGE is better able to fund its construction program from internally generated funds through most of the next five years. This is an indication that PGE's construction risk is not greater than the proxy group, but is actually less than that of the proxy group, contrary to Dr. Villadsen's assertion.

Q. IS DR. VILLADSEN'S CRITIQUE, THAT PGE'S FINANCIAL RISK IS GREATER THAN THE PROXY GROUP BECAUSE OF ITS PPA OBLIGATIONS, ACCURATE?

A. No. Dr. Villadsen's conclusion that PGE's financial risk is greater than that of the proxy group because of PPA debt obligations is not supported. However, she did seem to agree with my S&P credit metric review of PGE reflecting its PPA obligations. PPA obligations increase PGE's debt ratio from 50%, excluding the PPAs, up to 53.4% including the PPAs. A 53% debt ratio is well within the range of total debt ratios of the proxy group shown on my Exhibit ICNU/203, Gorman/1.

On this exhibit, I show the *Value Line* long-term equity ratio. The debt ratio would be 1 less than this. Hence, all companies that have a common equity ratio of less than 47% would have a comparable long-term debt ratio to PGE with my PPA debt equivalent. As shown on this exhibit, approximately half the companies have debt ratios of less than 50%, and around a quarter of the companies have debt ratios of under 48%.

Hence, PGE's financial risk including PPAs is comparable to the other proxy group companies even excluding the adjustments needed to reflect the proxy group companies' PPA debt equivalents. As such, recognizing Dr. Villadsen provided no evidence of a comparison of financial risk including PPAs for all the companies in the proxy group, and recognizing that PGE's debt ratio adjusted for PPAs is still reasonably consistent with the proxy group companies, I conclude that Dr. Villadsen's finding that PGE's financial risk is greater than the proxy group because of its PPAs to be erroneous and without merit.

Q. IS THERE ANY MERIT TO DR. VILLADSEN'S ARGUMENT THAT PGE'S RISK IS GREATER BECAUSE OF ITS SMALL SIZE?

A. No. I addressed this in my Opening Testimony at pages 48-50. There, I show all the risk factors considered by credit rating agencies which reflect the Company's ability to operate its system successfully, attract qualified management, and secure regulatory mechanisms that allow it to fully recover its reasonable and prudent cost of service. S&P reviews the risk of all utility companies, large and small, and their ability to operate their systems as a means to fully meeting their financial obligations. As such, small utility company risk is a component of business risk and is reflected in the bond rating of PGE. PGE's bond rating suggests that it is comparable in risk to the proxy group, if not slightly less risky than the proxy group. As such, Dr. Villadsen's argument, that return on equity premiums should be added because of PGE's small size risk, is without merit and should be disregarded.

<u>Response to Dr. Villadsen's Critique of My Recommended Return</u>

Q. DR. VILLADSEN ASSERTS THAT YOUR METHODOLOGY INCLUDED CERTAIN ERRORS AND MISGUIDED ASSUMPTIONS. DID SHE OUTLINE WHAT THOSE ARE?

A. Yes. Her claim that I made errors and/or used misguided assumptions is based on the following conclusions:

1. I relied on a geometric mean methodology to develop a long-term GDP growth rate for my DCF model (Exhibit PGE/2000, Villadsen/20);

2. She asserts it is inappropriate to use historical data to form forward-looking outlooks of expected growth in DCF studies (Exhibit PGE/2000, Villadsen/21, lines 1-4.); and

3. I should have used historical data to derive a long-term GDP growth outlook for use in my multi-stage DCF model (Exhibit PGE/2000, Villadsen/21, lines 11-13 and Table 5).

Q. PLEASE RESPOND TO THESE ALLEGED ERRORS AND/OR MISGUIDED ASSUMPTIONS.

A. Dr. Villadsen simply has not accurately described or does not understand my testimony and analyses.

For example, at page 20, her statement that I relied on a geometric series comparison of U.S. GDP growth compared to the stock market to derive my long-term sustainable growth outlook is simply not accurate. In my DCF studies, I used consensus long-term GDP growth projections as a third-stage growth long-term sustainable growth rate for my multi-stage DCF model, and consensus analysts' growth rate projections in my constant growth DCF model. I did not use a geometric series growth rate anywhere in my DCF studies, as Dr. Villadsen falsely asserts. Dr. Villadsen's discussions at page 20, lines 11-21, are simply an inaccurate characterization of my testimony.

Second, she seems to completely contradict herself with respect to the reliability of historical data for use in forming an expectation of future growth. Specifically, she states at page 21, lines 1-4 that, for purposes of determining cost of equity over the next period, a forward-looking measure is required. She advocates for the use of forward-looking measures to estimate the expected growth over many years, not the performance over the last several decades. I agree with her to the extent that there are forward-looking projections available.

That is precisely why I used forward-looking long-term projections published by independent economists in forming expectations of future GDP growth. But, importantly, Dr. Villadsen then completely contradicts her testimony in her proposal to use a historical derived GDP growth rate of 5.63%. By doing this, at page 21 of her testimony and in Table 5, she reruns my multi-stage DCF analysis and produces a DCF estimate of 9.35%, rather than 8.67% based on GDP growth from only historical data.

However, Dr. Villadsen's proposed growth rate reflects historical growth and not forward-looking expected growth that investors rely on to value current market stock prices. Therefore, it is not a reasonable estimate of the market's expected GDP growth, and does not produce a reliable estimate of PGE's current market cost of equity.

Dr. Villadsen's testimony is simply contradictory, inaccurate, and should be rejected.

Q. DR. VILLADSEN ALSO IS CRITICAL OF YOUR SUSTAINABLE GROWTH RATE DCF ANALYSIS. PLEASE SUMMARIZE HER CRITICISM.

A. Dr. Villadsen is critical of the sustainable growth rate methodology because it is based on earnings retention rate, and can be impacted by shares sold or repurchased by the Company. She states that shares being repurchased could impact the sustainable growth rate, and therefore this model is not reasonable. I disagree.

The sustainable growth rate analysis considers the amount of equity build-up in the company through retained earnings, and share purchases or sales. To the extent a company sells stock above book value, there is a positive accretion effect on the growth outlook for existing shareholders. Conversely, if the company repurchases stock at a price above book value, there is an erosion in the growth outlook for the company. Either way, it is an actual consideration for a long-term sustainable growth outlook for the company.

In reality, companies do sell and repurchase their stock. Those stock sales and repurchase transactions impact long-term sustainable growth. Simply because Dr. Villadsen chooses to ignore this real market effect on long-term sustainable growth does not make her argument concerning the sustainable growth DCF model real or valid.

For these reasons, Dr. Villadsen's arguments at page 22 of her testimony, lines 1-14, are simply erroneous and should be rejected.

Q. DID DR. VILLADSEN HAVE ANY CRITICISMS OF YOUR CAPITAL ASSET PRICING MODEL ("CAPM")?

A. Yes. At page 23 of her testimony, Dr. Villadsen states that I should have relied on a 7% market risk premium, which is Morningstar's highest market risk premium estimate, rather than the 6.2% I use in my CAPM study.[2] She states correctly that this is consistent with Morningstar's recommendation to use the total return on the Company stock, less the income return on Treasury bonds. However, Dr. Villadsen's proposal is imbalanced and unreasonable for several reasons.

First, Morningstar's recommendation does not reflect the true differential in investment risk for making a stock investment versus a Treasury bond investment. If an investor makes a Treasury bond investment, they will receive the income return, but will also receive the monthly change in capital gain, or loss on the bond price. So a true comparison of the actual difference in investment return for a stock investment versus a Treasury bond investment is based on the difference in the total investment return for both securities. From that perspective, Morningstar's data supports a market risk premium of 6.2%.

2/ It should be noted that Dr. Villadsen, at page 20 of her testimony, incorrectly states that I use a market risk premium of 6.1%, rather than 6.2%.

Further, Morningstar estimates two market risk premiums based on a stock market total return, and the income return on the Treasury bond. One is based on the unadjusted S&P 500 Index. This produces a market risk premium of 7.0%. However, Morningstar also recognizes that the market risk premium can depend on the market index used. Therefore, it also estimates a long-run market risk premium based on certain companies followed by the New York Stock Exchange ("NYSE"). In this study, using the total return on stocks less income return on Treasury bonds, it estimates a market risk premium of 6.8%. Further, if the two decile NYSE companies are used as an index for reasons discussed in my Opening Testimony, the market risk premium is 6.2%. (Gorman Opening Testimony at 30).

Therefore, using Morningstar's recommended methodology, the market risk premium is within the range of 6.2% to 7.0%. There is simply no justification for Dr. Villadsen to only recognize a 7.0% market risk premium estimate from Morningstar. As such, Dr. Villadsen's proposed modification of my CAPM results is not balanced and does not produce a reasonable result.

Q. DID DR. VILLADSEN RESPOND TO YOUR RISK PREMIUM STUDY?

A. Yes. Dr. Villadsen attempted to manipulate my risk premium study to support what she believes to be a more appropriate risk premium result of 10%. As shown at page 24 of her rebuttal testimony, she relies on various risk premium estimates taken from my testimony. She shows that over the entire study period of 1986-2014, the lowest risk premium measure would be 9.82%. She then considers various time periods within that total study period to measure risk premiums over 10, 15 and 20-year periods. She finds that the highest risk premium estimate occurred over the last 10 years at 10.67%.

When she applies 30% weight to the group average risk premium of 8.91%, and 70% weight to the highest 10-year-period risk premium estimate of 10.67%, she claims that return on equity of 10.1% is produced.

Q. IS DR. VILLADSEN'S RISK PREMIUM RESULT BASED ON YOUR RISK PREMIUM STUDY REASONABLE?

A. No. In my testimony, I recommend giving 30% weight to a <u>low-end result</u> and 70% weight to a <u>high-end result</u>. Dr. Villadsen, however, did not make an assessment to determine a low-end risk premium. Rather, she substituted the risk premium based on the average over the study period as a substitute for the low-end risk premium estimate during the study period. This is not balanced.

Q. CAN YOU MODIFY YOUR RISK PREMIUM STUDY TO ACCOUNT FOR A 10-YEAR ROLLING AVERAGE MARKET RISK PREMIUM TO CORRECT DR. VILLADSEN'S ERRONEOUS INTERPRETATION OF YOUR RISK PREMIUM RESULTS?

A. Yes. As shown on my Exhibit ICNU/502, I recreate my risk premium study using the 10-year rolling average equity risk premium estimates, as Dr. Villadsen proposes.

As shown for the Treasury bond yields, the rolling 10-year average equity risk premiums range from a low of 4.38% to a high of 6.08% during this time period. Applying a 30% weight to the lowest equity risk premium, and 70% weight to the highest equity risk premium, produces an equity risk premium of 5.57%.[3/] Applying this risk premium to my projected 4.4% Treasury bond yield produces a risk premium estimate of 9.97%.

Performing this same 10-year rolling average for my utility bond risk premium studies, produces a risk premium in the range of 3.20% (low-end) to 4.79% (high-end). Applying 30% weight to the low-end risk premium estimate, and 70% weight to the high-

3/ (30% x 4.38%) + (70% x 6.08%).

end risk premium estimate produces a risk premium of 4.31%.[4/] Using a 4.31% risk premium and the current "Baa" utility bond yield of 4.87%, shown in my Opening Testimony and Exhibit ICNU/215, produces a return on equity estimate of 9.18%.

This modified risk premium study based on rolling 10-year averages of historical risk premium estimates, indicates a risk premium in the range of 9.18% to 9.97% with a midpoint of 9.58%. This estimate using Dr. Villadsen's proposed 10-year rolling average period produces approximately the same result, although slightly lower, than the midpoint of 9.70% I estimated in my Opening Testimony at page 26.

As such, Dr. Villadsen's modification of my risk premium study is simply biased because she does not consider low-end results in producing her estimated risk premium estimate for PGE. Rather, she skews the risk premium estimate using a period average risk premium, in place of a low-end risk premium, thus increasing her risk premium estimate for PGE.

Q. BASED ON DR. VILLADSEN'S TESTIMONY, HAS YOUR RECOMMENDED RETURN ON EQUITY FOR PGE CHANGED FROM YOUR ORIGINAL FILING?

A. No. I continue to recommend a return on equity for PGE in this case of 9.4%. This return on equity is a reasonable compensation for PGE's total investment risk, will support its investment grade rating, and will support its access to capital to support its ability to make necessary investments in utility plant and equipment to maintain a high quality reliable utility. For all these reasons, I continue to support my recommended return on equity for PGE.

[4/] (30% x 3.20%) + (70% x 4.79%).

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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	)
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EXHIBIT ICNU/501

INTERNALLY GENERATED FUNDS

August 13, 2014

Portland General Electric Company
Internally Generated Funds
2014 Projections

Line	Company	Cash Flow Per Share (1)	Dividends Per Share (2)	Free Cash Flow (3)=(1)-(2)	Capital Spending Per Share (4)	Free Cash Flow to Capital Spending (5)=(3)/(4)
1	ALLETE, Inc.	5.40	1.96	3.44	14.05	24%
2	Alliant Energy Corporation	6.60	2.04	4.56	7.50	61%
3	Avista Corporation	4.35	1.27	3.08	5.65	55%
4	Black Hills Corporation	6.25	1.56	4.69	10.05	47%
5	Cleco Corporation	5.35	1.53	3.82	3.55	108%
6	CMS Energy Corporation	4.30	1.08	3.22	6.10	53%
7	Great Plains Energy Inc.	4.25	0.94	3.31	4.95	67%
8	Hawaiian Electric Industries, Inc.	3.30	1.24	2.06	3.50	59%
9	IDACORP, Inc.	6.20	1.72	4.48	5.70	79%
10	MGE Energy, Inc.	3.45	1.10	2.35	3.43	69%
11	NorthWestern Corporation	5.70	1.60	4.10	6.90	59%
12	OGE Energy Corp.	3.40	0.93	2.47	3.00	82%
13	Pinnacle West Capital Corporation	8.40	2.32	6.08	9.10	67%
14	PNM Resources, Inc.	3.65	0.74	2.91	4.25	68%
15	Portland General Electric Company	5.95	1.12	4.83	13.30	36%
16	SCANA Corporation	6.85	2.10	4.75	11.35	42%
17	TECO Energy, Inc.	2.60	0.88	1.72	3.40	51%
18	UNS Energy Corporation	7.35	1.85	5.50	9.45	58%
19	Westar Energy, Inc.	4.45	1.40	3.05	6.50	47%
20	Wisconsin Energy Corporation	4.60	1.56	3.04	3.35	91%
21	**Average**	**5.12**	**1.45**	**3.67**	**6.75**	**54%**

Source: *The Value Line Investment Survey,* May 23, June 20, and August 1, 2014.

Portland General Electric Company
Internally Generated Funds
2015 Projections

Line	Company	Cash Flow Per Share (1)	Dividends Per Share (2)	Free Cash Flow (3)=(1)-(2)	Capital Spending Per Share (4)	Free Cash Flow to Capital Spending (5)=(3)/(4)
1	ALLETE, Inc.	5.90	2.04	3.86	6.95	56%
2	Alliant Energy Corporation	6.85	2.20	4.65	9.45	49%
3	Avista Corporation	4.60	1.32	3.28	5.95	55%
4	Black Hills Corporation	6.55	1.64	4.91	8.70	56%
5	Cleco Corporation	6.05	1.63	4.42	2.25	196%
6	CMS Energy Corporation	4.50	1.14	3.36	5.45	62%
7	Great Plains Energy Inc.	4.55	1.02	3.53	4.50	78%
8	Hawaiian Electric Industries, Inc.	3.40	1.24	2.16	3.45	63%
9	IDACORP, Inc.	6.35	1.80	4.55	6.45	71%
10	MGE Energy, Inc.	3.95	1.14	2.81	4.00	70%
11	NorthWestern Corporation	6.10	1.68	4.42	7.05	63%
12	OGE Energy Corp.	3.50	1.03	2.47	2.00	124%
13	Pinnacle West Capital Corporation	8.80	2.41	6.39	9.55	67%
14	PNM Resources, Inc.	3.70	0.80	2.90	4.75	61%
15	Portland General Electric Company	5.75	1.14	4.61	5.85	79%
16	SCANA Corporation	7.05	2.16	4.89	11.20	44%
17	TECO Energy, Inc.	2.75	0.88	1.87	3.20	58%
18	UNS Energy Corporation	7.60	1.95	5.65	8.05	70%
19	Westar Energy, Inc.	4.60	1.44	3.16	7.00	45%
20	Wisconsin Energy Corporation	4.85	1.68	3.17	3.70	86%
21	**Average**	**5.37**	**1.52**	**3.85**	**5.98**	**64%**

Source: *The Value Line Investment Survey,* May 23, June 20, and August 1, 2014.

Portland General Electric Company
Internally Generated Funds
Three to Five Year Projections

Line	Company	Cash Flow Per Share (1)	Dividends Per Share (2)	Free Cash Flow (3)=(1)-(2)	Capital Spending Per Share (4)	Free Cash Flow to Capital Spending (5)=(3)/(4)
1	ALLETE, Inc.	7.00	2.30	4.70	5.75	82%
2	Alliant Energy Corporation	7.75	2.40	5.35	6.80	79%
3	Avista Corporation	5.50	1.50	4.00	6.00	67%
4	Black Hills Corporation	7.50	1.90	5.60	8.25	68%
5	Cleco Corporation	7.25	2.00	5.25	2.25	233%
6	CMS Energy Corporation	5.25	1.35	3.90	5.25	74%
7	Great Plains Energy Inc.	5.75	1.30	4.45	3.75	119%
8	Hawaiian Electric Industries, Inc.	4.00	1.30	2.70	4.50	60%
9	IDACORP, Inc.	6.75	2.00	4.75	12.70	37%
10	MGE Energy, Inc.	4.70	1.30	3.40	5.30	64%
11	NorthWestern Corporation	6.75	1.90	4.85	3.75	129%
12	OGE Energy Corp.	4.25	1.35	2.90	1.75	166%
13	Pinnacle West Capital Corporation	9.50	2.75	6.75	9.25	73%
14	PNM Resources, Inc.	4.60	1.15	3.45	4.15	83%
15	Portland General Electric Company	6.50	1.40	5.10	2.75	185%
16	SCANA Corporation	8.00	2.35	5.65	9.00	63%
17	TECO Energy, Inc.	3.50	0.95	2.55	2.00	128%
18	UNS Energy Corporation	8.00	2.28	5.72	7.85	73%
19	Westar Energy, Inc.	5.10	1.56	3.54	8.15	43%
20	Wisconsin Energy Corporation	5.75	2.10	3.65	4.00	91%
21	**Average**	**6.17**	**1.76**	**4.41**	**5.66**	**78%**

Source: *The Value Line Investment Survey,* May 23, June 20, and August 1, 2014.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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	)
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EXHIBIT ICNU/502

EQUITY RISK PREMIUM – TREASURY BOND AND EQUITY RISK PREMIUM – UTILITY BOND

August 13, 2014

Portland General Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 10-year Average
1	1986	13.93%	7.80%	6.13%	
2	1987	12.99%	8.58%	4.41%	
3	1988	12.79%	8.96%	3.83%	
4	1989	12.97%	8.45%	4.52%	
5	1990	12.70%	8.61%	4.09%	
6	1991	12.55%	8.14%	4.41%	
7	1992	12.09%	7.67%	4.42%	
8	1993	11.41%	6.60%	4.81%	
9	1994	11.34%	7.37%	3.97%	
10	1995	11.55%	6.88%	4.67%	4.53%
11	1996	11.39%	6.70%	4.69%	4.38%
12	1997	11.40%	6.61%	4.79%	4.42%
13	1998	11.66%	5.58%	6.08%	4.65%
14	1999	10.77%	5.87%	4.90%	4.68%
15	2000	11.43%	5.94%	5.49%	4.82%
16	2001	11.09%	5.49%	5.60%	4.94%
17	2002	11.16%	5.43%	5.73%	5.07%
18	2003	10.97%	4.96%	6.01%	5.19%
19	2004	10.75%	5.05%	5.70%	5.37%
20	2005	10.54%	4.65%	5.89%	5.49%
21	2006	10.36%	4.99%	5.37%	5.56%
22	2007	10.36%	4.83%	5.53%	5.63%
23	2008	10.46%	4.28%	6.18%	5.64%
24	2009	10.48%	4.07%	6.41%	5.79%
25	2010	10.24%	4.25%	5.99%	5.84%
26	2011	10.07%	3.91%	6.16%	5.90%
27	2012	10.01%	2.92%	7.09%	6.03%
28	2013	9.79%	3.45%	6.34%	6.07%
29	2014 [3]	9.57%	3.68%	5.89%	6.08%
30	**Average**	**11.27%**	**5.92%**	**5.35%**	**5.30%**
31	**Min**				**4.38%**
32	**Max**				**6.08%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 1985 - Dec. 1996, and April 9, 2014, excluding the VA cases, which are subject to an adjustment for certain generation assets up to 200 basis points.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[3] The data includes the period Jan - Mar 2014.

Portland General Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 10-year Average
1	1986	13.93%	9.58%	4.35%	
2	1987	12.99%	10.10%	2.89%	
3	1988	12.79%	10.49%	2.30%	
4	1989	12.97%	9.77%	3.20%	
5	1990	12.70%	9.86%	2.84%	
6	1991	12.55%	9.36%	3.19%	
7	1992	12.09%	8.69%	3.40%	
8	1993	11.41%	7.59%	3.82%	
9	1994	11.34%	8.31%	3.03%	
10	1995	11.55%	7.89%	3.66%	3.27%
11	1996	11.39%	7.75%	3.64%	3.20%
12	1997	11.40%	7.60%	3.80%	3.29%
13	1998	11.66%	7.04%	4.62%	3.52%
14	1999	10.77%	7.62%	3.15%	3.52%
15	2000	11.43%	8.24%	3.19%	3.55%
16	2001	11.09%	7.76%	3.33%	3.56%
17	2002	11.16%	7.37%	3.79%	3.60%
18	2003	10.97%	6.58%	4.39%	3.66%
19	2004	10.75%	6.16%	4.59%	3.81%
20	2005	10.54%	5.65%	4.89%	3.94%
21	2006	10.36%	6.07%	4.29%	4.00%
22	2007	10.36%	6.07%	4.29%	4.05%
23	2008	10.46%	6.53%	3.93%	3.98%
24	2009	10.48%	6.04%	4.44%	4.11%
25	2010	10.24%	5.46%	4.78%	4.27%
26	2011	10.07%	5.04%	5.03%	4.44%
27	2012	10.01%	4.13%	5.88%	4.65%
28	2013	9.79%	4.48%	5.31%	4.74%
29	2014 [3]	9.57%	4.56%	5.01%	4.79%
30	**Average**	**11.27%**	**7.30%**	**3.97%**	**3.90%**
31	**Min**				**3.20%**
32	**Max**				**4.79%**

Sources:

[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and April 9, 2014, excluding the VA cases, which are subject to an adjustment for certain generation assets up to 200 basis points.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2013 were obtained from http://credittrends.moodys.com/.

[3] The data includes the period Jan - Mar 2014.