Examining the History of Texas Energy Efficiency Programs

Utility Load Management Programs

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About the South-central Partnership for Energy Efficiency as a Resource (SPEER)

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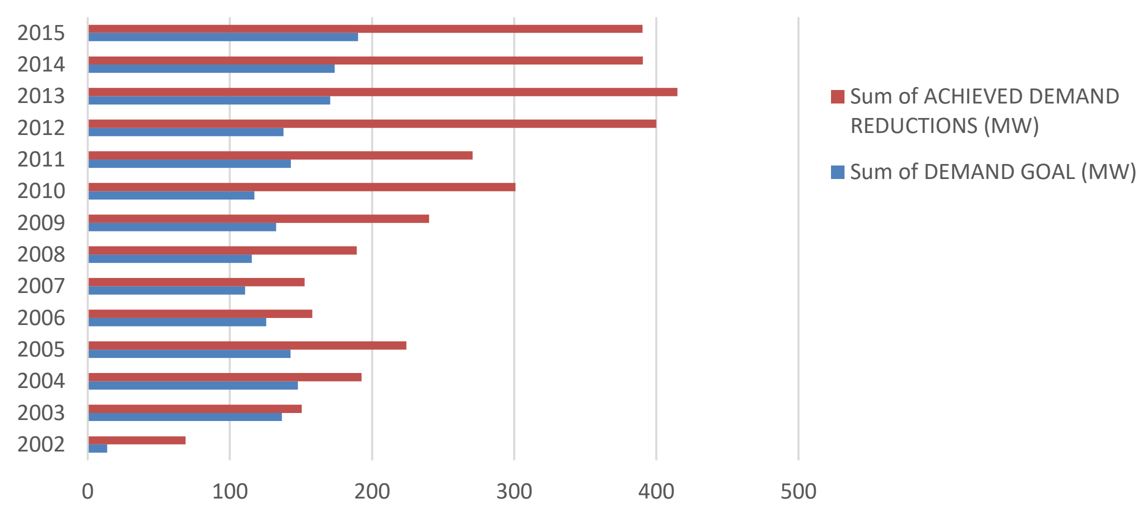
I. INTRODUCTION

This is the fourth in a series of brief reports, looking back at the history of the Investor Owned Utilities (IOUs) programs.[1] The ten IOU's in Texas have spent about $125 million annually on energy efficiency programs[2] in the past 5 years to encourage customers to use less energy and reduce peak demand. A Texas energy efficiency resource standard (EERS) requires these utilities to meet goals, which, in 2015, amounted to about 200 MW in peak demand reduction, and about 350,000 MWh in reduced consumption. Collectively, the utility efforts produce an attractive payback for all Texans, yielding future energy-related savings worth three to four times the costs[3]. These costs include the direct utility costs of administering their programs, and the direct benefits of energy and capacity saved (or capacity reserved in the case of demand response). This paper looks at the role of load management programs, a component of the broader utility energy efficiency programs portfolio.

Peak load management, or demand response, refers to the capacity of customers, alone or with the help of technology and/or third party service providers, to reduce or modify their energy use in response to some form of market signal. Load management can help to avoid rolling blackouts during grid emergencies and is an important reliability tool in the ERCOT market. It can also put downward pressure on the price of energy supply if employed in response to high prices. Further, because the electric grid must be sized to meet peak demand, load management also has the potential to defer or avoid infrastructure upgrades such as substation expansions, if it is used to relieve local congestion during the grid equivalent of rush hour.

Chart 1: Total Annual MW Goals vs. Achieved MW for all Texas Investor-Owned Utilities 2002 - 2015



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[1] https://eepartnership.org/program-areas/policy/history-of-energy-efficiency-programs/
[2] Average total spending from 2011 to 2015 was $124 million and from 2003 to 2015 was $99 million.
[3] https://eepartnership.org/wp-content/uploads/2017/06/EE-History-series-Cost-Benefits.pdf

For the most part, Texas utility load management programs have been used to provide added insurance against emergency outages, although they were briefly encouraged to help avoid or defer transmission and distribution costs in 2006-2007.

Load management programs have been available as Commercial Standard Offer programs within the utilities' energy efficiency portfolios since 2003, with expanding participation. Residential demand response programs piloted in 2012, have recently been gaining traction as the population of connected home devices multiplies, but currently represent only about 1% of the utility's' total demand savings. In 2015, the IOUs spent an average of only 5% of their total program expenditures on load management programs, which achieved enough savings to entirely meet their combined demand reduction goal, which makes this the most cost effective demand reduction measure.[4]

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The original EERS or goal for energy efficiency was adopted in Senate Bill 7 in 1999, to help customers "…reduce energy consumption and reduce energy costs…"[5] and called for an annual reduction of the growth in demand. Utilities are now provided an annual cost recovery process, and the opportunity for a performance bonus for cost-effectively exceeding their goals. Changes in the energy efficiency program rules over time have been responsible for demand response contributing an increasing share of the utilities' demand reductions and have helped them minimize spending and optimize their performance bonuses. However, from another perspective, the expansion of load management programs has prevented the significant increases in the state's EERS from actually leading to significantly more energy savings.

II. What Load Management Contributes

The Public Utility Commission of Texas (PUCT) defines the EERS to include both a reduction in demand and energy. Demand is defined as "*the rate at which electric energy is used at a given instant, or averaged over a designated period, usually expressed in kW or megawatt (MW).*" Demand savings then, avoids the need for additional power plant capacity to be built to serve this instantaneous requirement. Energy Savings is defined as "*a quantifiable reduction in a customer's consumption of energy that is attributable to energy efficiency measures, usually expressed in kWh or MWh*." Load Management is defined as "*Load control activities that result in a reduction of peak demand, or a shifting of energy usage from a peak to*

[4] PUCT project 45675, 2016 energy efficiency plans and reports pursuant to 16 tac §25.181(n)
[5] SB 7. Section 39.905(a)(2). http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007F.htm

an off-peak period or from high-priced periods to lower-priced periods."[6] Although efficiency generally and load management specifically can also help avoid transmission and distribution costs of the administering utilities themselves, the PUCT has never evaluated this impact or potential, or credited utilities with these savings, except to credit reduction of line losses in delivery of power.

Load management requires a response by the customer when called upon, either automated or manual, that provides a temporary reduction, or shift in energy demand, but does not provide the kind of sustained, cumulative, energy savings that result from the installation of equipment that improves heating, cooling or lighting efficiency over several years or even decades. By and large, load management programs involve promises by customers to respond if called, on an as-needed basis – once they demonstrate their ability to curtail or shift demand upon request.

Load management, or load control measures that reduce or shift peak demand, have increasingly contributed towards meeting or exceeding the overall utility demand reduction goals. For example, in 2005, the utilities reported that load management contributed a combined total of 13 MW of load management, towards a combined demand goal of 143 MW, or 9% (see Table 1 for individual utility data). Load management peaked in 2012 at 272 MW, or nearly 200% of the combined demand goal of 138 MW.

The early programs required the customer to have an interval data recorder (IDR) meter, which limited participation to larger businesses with a minimum of 700 kW demand or more. The installation of smart meters since then has allowed the participation of much smaller businesses (down to 50 kW demand), and opened the door to a much broader commercial customer base for load management program participation. Smart meters and controls have also allowed the expansion to include residential customer aggregations in the past few years.

Table 1. Peak demand reductions achieved with Commercial Load Management Programs (MW)[7]

Year	AEP-TCC	AEP-TNC	CNP	El Paso	Entergy	Oncor	Sharyland	SPS	SWEPCO	TNMP	Combined LM Total	Combined Demand Goal
2003						13.13					13.13	136.49
2004						15.11					15.11	147.83
2005					0.23	12.90					13.13	142.77
2006	1.09					23.75					24.84	125.62
2007	0.28					21.51					21.79	119.42
2008	2.09		15.79		0.50	20.19			2.44		41.02	115.50
2009	7.47	0.74	33.08	1.38	1.81	26.71			5.58		76.77	132.63
2010	9.45	1.40	81.52	4.55	2.74	39.31			9.30	0.21	148.48	117.31
2011	7.00	1.47	71.22	7.21	6.60	21.50			8.67	0.26	123.93	142.92
2012*	17.43	3.71	140.54	7.04	5.50	84.85		1.90	8.24	2.92	272.13	137.75
2013	17.73	3.54	153.04	9.03	5.90	55.00	2.32	2.29	7.70	3.70	260.25	170.56
2014	23.00	4.65	113.30	8.28	6.02	59.25	0.00	1.79	8.30	3.99	228.58	186.72
2015	27.42	1.74	106.04	6.71	7.32	54.90	0.00	4.25	5.88	3.74	218.01	190.12

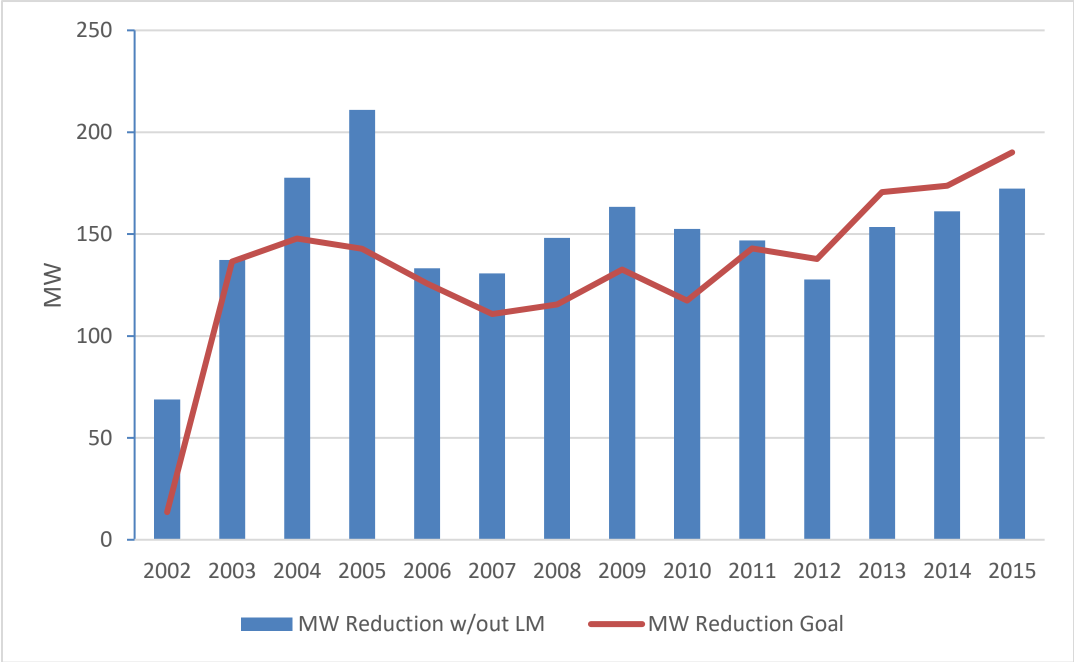
[6] PUCT substantive rule, §25.181 Energy Efficiency Goal, the definition of "energy efficiency" in section (c)(12)
[7] Data compiled by SPEER from annual utility filings of Energy Efficiency Plans and Reports.

*In 2012, the PUCT made a special request to the utilities for increased load management due to resource adequacy concerns. In direct response, in addition to amounts already planned for, CenterPoint added 100 MW, Oncor added 50 MW and AEP added $666,666 in incentives to its commercial load management programs for 2012.[8]

With the deployment of advanced meter infrastructure (AMI, or smart meters) and the emergence of a growing variety of connected homes products, particularly communicating thermostats, the cost to manage the loads of thousands of homes was suddenly quite realistic. This resource began to really take off only when third-party energy management companies focused on this technology began to enter the market. CenterPoint funded the very first residential load management pilot in 2012, enabled by the AMI network. In the 2015 program year, CenterPoint and Oncor each had a residential load management market transformation program with a total of 12,600 customers and reported verified available reductions of 20.3 MW of summer peak demand.[9] AEP had also launched a residential load management pilot program.

In Chart 2, below you can see that from the inception of the EERS, utilities achieved their demand reduction goals without the help of load management. Since 2011, however, persistent demand reductions achieved through efficiency incentives have been insufficient to meet the growing EERS goals.

Chart 2. Total combined utility demand goal compared to the total combined utility achieved demand reductions without load management



[8] See PUCT projects 39363 (CenterPoint), 40123 (Oncor) and 39360 (AEP).
[9] Utility Energy Efficiency Plans and Reports filed with the PUCT in docket 45675.

III. TIMELINE OF POLICY CHANGES

2000: In the original version of PUCT Substantive Rule §25.181, Energy Efficiency Goal, adopted in 2000, load management programs were constrained in two ways. Incentives for load management programs were capped at 15 percent of the avoided costs[10] as determined by the PUCT. In addition, savings achieved by load management programs were not permitted to contribute more than 15 percent towards a utility's total demand reduction goal. These limitations were in response to concerns of consumer advocates that load management provided no lasting value to consumers, little if any energy conservation, and no persistent reduction in peak demand. The statute did not provide any specific guidance regarding load management, but the inclusion was allowed by the PUCT in response to interest from the private sector load management providers and utilities. At the time, large commercial and industrial customers were eligible for the utility energy efficiency programs and many of these customers were accustomed to utility contracts for attractive interruptible rates enjoyed prior to restructuring.[11] These customers were looking for a way to monetize the value of their flexibility in the newly restructured electric market.

The utilities initially established their incentives for all efficiency measures based on a minimum measure life of ten years. Under the load management programs, this required customers to enter into ten-year contracts in order to receive incentive payments. This limited utility interest because the cost for a MW of load management over a decade was not significantly cheaper than incentivizing a MW of load reduction from installation of more efficient air conditioning or extra attic insulation. Oncor was the only utility that had significant participation before 2008 (Table 1).

2005-2006: Senate Bill 712 included language that clarified that load management was a clearly permitted efficiency measure, because the revised law now required utilities to offer options for customers "…to reduce energy consumption, peak demand, or energy costs…".[12] In the follow-up rulemaking, the PUCT stated in the final order;

> *"In the recently-concluded regular session of the Texas Legislature, §39.905 was amended in a way that removes any legal argument that load-management programs are not permitted under the statute because they do not result in energy savings."*[13]

In updating Substantive Rule §25.181, Energy Efficiency Goal, in 2006, the PUCT actually placed an increased emphasis on load management, citing concerns about resource adequacy and keeping the lights on in Texas. The maximum incentive level for load management programs was increased from 15 to 25

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[10] Avoided capacity cost represents the estimated cost of a new gas turbine, which was $78.50 per kW when the Energy Efficiency rule was initially adopted in 2000 and remained at that level until 2010 when it was increased to $80.00 per kW, where it has remained ever since.

[11] Nucor asserted in comments filed in project 30331 that prior to restructuring incentives for interruptible rates were generally set close to or at full avoided costs.

[12] SB 712, page 1. https://texashistory.unt.edu/ark:/67531/metapth157868/m1/1/

[13] PUCT Project 30331, Amendments to Energy Efficiency Rules and Templates. Final order, page 9.

percent of the avoided cost and a provision was added to allow for even higher incentives for load management programs that were targeted at constrained areas of the electric grid. At this time, the rule went so far as to require ERCOT to annually identify areas of the grid where transmission system enhancements could potentially be avoided or deferred, and allowed utilities to identify areas where distribution system costs could be avoided or deferred through load management. Incentives offered by utilities in these areas could be as high as 55 percent of the avoided costs for residential and small commercial customers and 35 percent for large commercial and industrial customers.

… A provision was added to allow for even higher incentives for load management programs that were targeted at constrained areas of the electric grid.

In addition, the cap limiting the contribution of load management towards a utility's overall annual demand reduction goal was doubled to 30 percent, due to growing concerns about generation adequacy after ERCOT forecasted the capacity reserve margin to be dropping below acceptable levels.[14]

2007-2008: House Bill 3693 was passed by the Texas Legislature in 2007 and doubled the minimum energy efficiency goal, to at least 20% of the annual growth in demand. In addition, partly in recognition that effective efficiency programs would reduce utility sales and therefore revenues, the legislature also authorized the commission to establish a performance bonus for utilities, to offset those loses. The new language limited the energy efficiency goal to "residential and commercial customers," however, carving out industrial customers, at their request, from either paying into the utility administered effort, or participating in it. Combined with the economic downturn, which slowed the rate of growth in demand, this had the effect of limiting the actual increase in achieved savings required of, and achieved by the utilities, as shown in Chart 1.

The PUCT revisions to rule §25.181 in response to H.B. 3693, in 2008, included five important changes made in response to ERCOT's concerns about capacity reserves that had a significant impact on load management.

1) The maximum incentive payment for load management programs was increased from 25 to 100 percent of avoided costs for each customer class.
2) The 30 percent cap on the amount of load management used to meet the demand goal was eliminated.
3) A performance bonus was established to provide the utilities one percent of the net benefits generated by the programs for every 2 percent each utility exceeded its demand reduction goal, capped at 20 percent of the utility's total program spending.
4) A "ratchet" or backstop was adopted to prevent a utility's demand reduction goal from ever falling below the prior year's goal, which provided some stability to both utility administrators and private sector efficiency services providers, despite a volatile economy.

[14] PUCT Project 30331, Amendments to Energy Efficiency Rules and Templates. Final order, pages 1 and 7

5) The minimum measure life of 10 years for efficiency acquired by the programs was relaxed to allow variable measure life, so long as compensation was varied appropriately as well.

This last change addressing measure life grew indirectly from a specific legislative direction in 2005, to allow utilities to adopt certain market transformation programs, including air conditioning tune ups. These had never qualified for incentives because they could not meet a 10-year measure life, and forcing the commission to accept a wider range of measures required acceptance of a wider range of measure lives as well. The preamble to the commission's decision addressed using variable measure life which allowed for program changes to be adopted.[15] The rule addressed the issue in the list of requirements of standard offer programs in section (l)(2)(E);

> *"shall be limited to projects that result in consistent or predictable energy or peak demand savings over an appropriate period of time based on the life of the measure"*

Given the combination of changes being adopted, some stakeholders were reasonably concerned that the utilities would only need to use load management to achieve the statewide goal. And the law, while broadened to specifically include a goal of peak reduction, still called for programs to enable customers save energy and reduce costs. In response to this the commission created an energy savings goal, so the utilities would have to meet the dual goal of energy use reduction annually. The goal set was equal to the demand reduction goal over 20% of the hours of the year.[16]

2009-2012: Although no significant legislation was adopted impacting the EERS in the 2009 session of the legislature, in 2010, the PUCT on its own motion adopted an increase in the utility efficiency goals. The legislative language had always set a floor for the EERS, directing that the programs should achieve at least 10, and later 20 percent of the annual growth in demand. In part because the rate of growth in demand had been nearly flat during the recession years leading up to this period, the PUCT increased the minimum goal to at least 30 percent of the annual growth in demand. As part of the 2010 rulemaking, the PUCT also added a requirement that utilities exceed their energy savings goal (in addition to their demand savings goal) in order to be eligible to earn a performance bonus. Lastly, the PUCT adopted cost caps for the first time on the monthly fees to customers that fund the efficiency programs.

Then in 2011, Senate Bill 1125 was adopted codifying the increased goals the PUCT had previously adopted, from at least 20 to at least 30 percent of peak demand growth by 2013, as well as the "ratchet" which had been adopted in rule to help stabilize the program budgets. The bill also established that once 30 percent of the rate of growth in demand for a covered utility was equal to at least 0.4% of the utility's total summer peak demand, the utility goal was to become, and be capped at 0.4% of total summer peak demand. The state was coming out of the recession and, fearing this recovery might signal a return to load growth, utilities wished to limit their obligations under the state's efficiency goal.

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[15] PUCT docket 33487, final order, p.100.

[16] So a 1 MW demand reduction goal would lead to an energy goal of 8760 hrs *.20* 1MW = 1,752 MWh.

In response to these legislative changes, the PUCT again opened a docket to update their efficiency rules in 2012. Three significant policy revisions were adopted that impacted load management. First, utility load management programs would be required to be integrated with ERCOT markets, to the extent feasible (discussed further below). "Measure life" was clearly defined for the first time in the energy efficiency rule as "estimated useful life".[17] And, the basis for each utility earning a performance bonus was modified: utilities could earn up to 10% of net program benefits (avoided energy and capacity costs), instead of up to 20% of program costs.

IV. Impacts of These Changes

The Increase in EERS Goal

As it turned out, rapid load growth never materialized in the state, thanks at least in part to energy efficiency, including load management and other distributed resource adoption. Market changes seem to have decoupled the rate of growth in electric demand from that of the economy in Texas much like it had in many other states, if to a lesser degree. Under the new goal established in 2011 by SB 1125, CenterPoint, AEP-Central, AEP-North and Texas-New Mexico utilities have hit the trigger of 30 percent of annual growth in demand, shifting to a ceiling of 0.4% of total summer peak demand. Nevertheless, the change from 20 to 30 percent of annual growth in demand in 2012 has supported a modest growth in the combined utility demand goal - from 138 MW in 2012, to 190 MW in 2015.

Utility Load Management Achievement

With the various regulatory and legislative changes noted above, the load management programs have grown significantly since 2008, as seen in Charts 3 and 4.

[17] The following definition of Estimated Useful Life was added to §25.181(c)(19) in 2012 in docket 39674; "*The number of years until 50% of installed measures are still operable and providing savings, and is used interchangeably with the term "measure life". The EUL determines the period of time over which the benefits of the energy efficiency measure are expected to accrue."* The chart is correct. Values are small but not zero.

Chart 3. Load Management Growth in Oncor, CenterPoint, and AEP-Central: 2003 - 2015

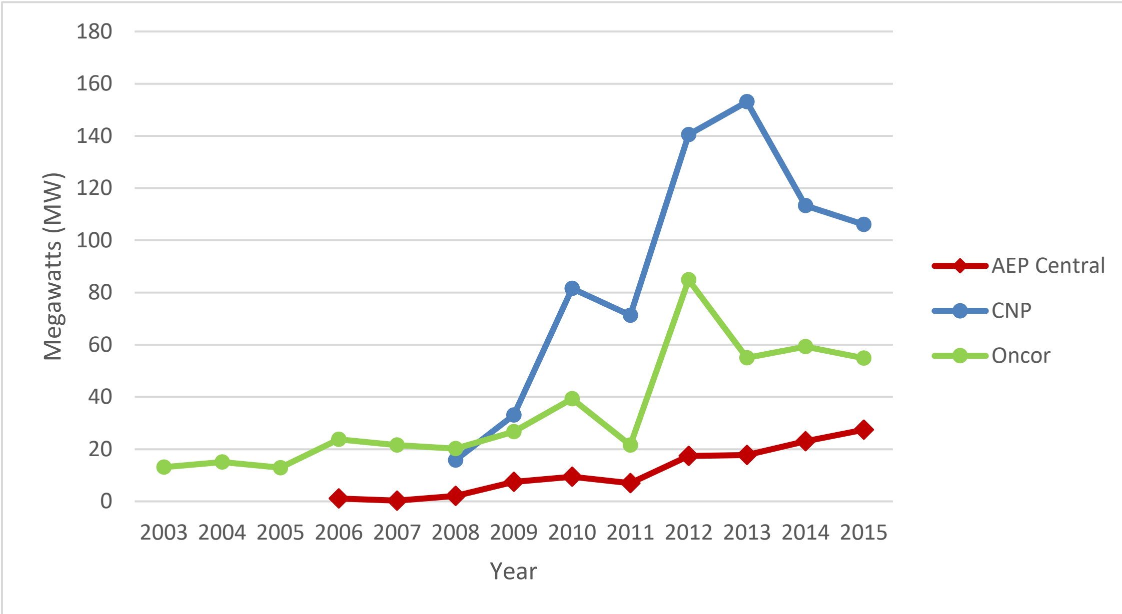
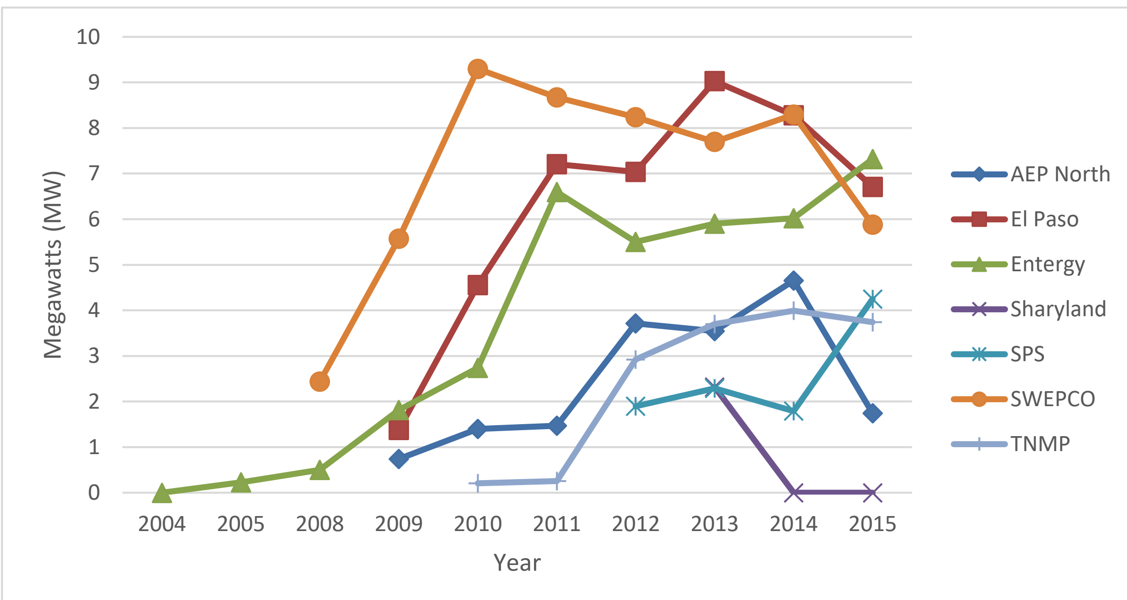


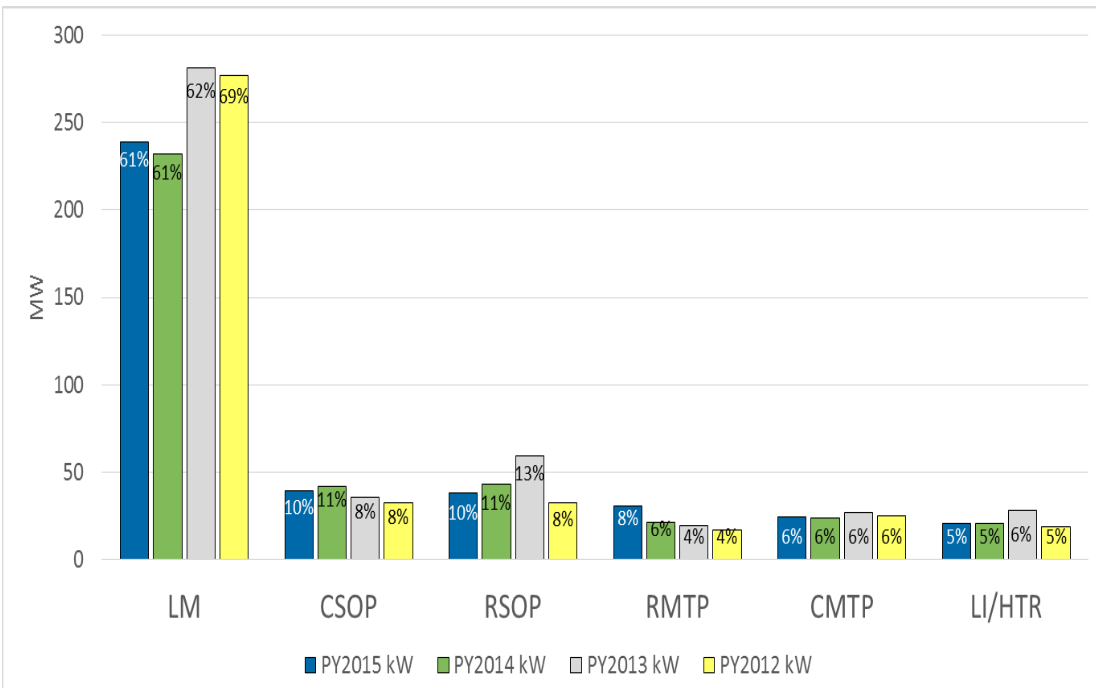
Chart 4. Load Management Growth in Smaller Utilities: 2003 - 2015



Prior to 2008, Oncor (then TXU Electric Delivery) was the only utility offering a significant Emergency Load Management program for large commercial and industrial customers. Initially, it acquired around 20 MW of controllable load annually. This Oncor program grew to nearly 85 MW of total cumulative load under control in 2012, in spite of the industrial exclusion, which took effect by the end of 2008. This was both because the program was able to expand to accept smaller businesses, and the grandfathering of some large customer contracts.[18]

Between 2012 and 2015, over 60 percent of the annual demand reductions the utilities achieved, came through their load management programs (Chart 5). At the same time, these programs contributed very little to energy savings (Chart 6).The cost of programs was very low, particularly because the reduced measure life assigned required a proportionately reduced incentive. One year load management programs could be expected to cost one-tenth of ten-year programs, and significantly less than incentives for more persistent capacity reductions like ceiling insulation. Still the one year load management achieves the same load reduction credit toward the current year's EERS as the more persistent, more costly measure. In 2015, the load management program amounted to 69% of their total capacity savings (over 100% of the statewide demand goal), while the utilities spent less than 10 percent of their overall efficiency budget on load management.

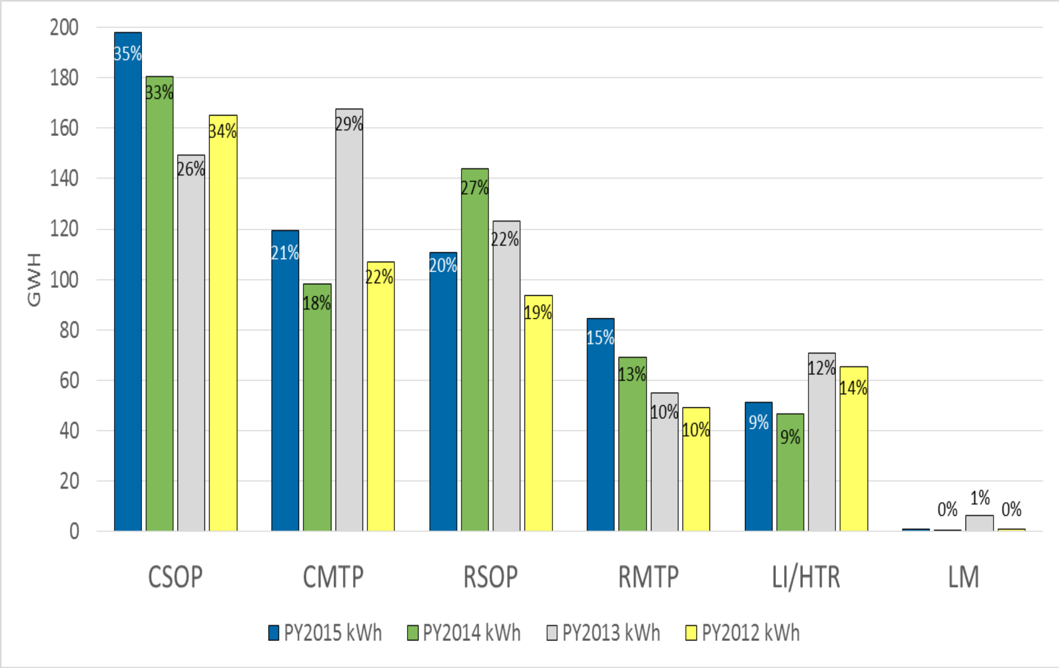
Chart 5. Achieved Demand Savings by Program 2012 – 2015



Note: Program categories are (from left to right) load management, commercial and residential standard offer, commercial and residential market transformation, and low-income/hard-to-reach. Slide courtesy of Frontier Associates.

[18] Section 39.905 of PURA, paragraph (a) (6) reads in part "electric utilities shall continue to make available, at 2007 funding and participation levels, any load management standard offer programs developed for industrial customers and implemented prior to May 1, 2007."

Chart 6. Achieved Energy Savings by Program 2012 - 2015



Note: Program categories are (from left to right) load management, commercial and residential standard offer, commercial and residential market transformation, and low-income/hard-to-reach. Slide courtesy of Frontier Associates.

Influence of the Performance Bonus Construct

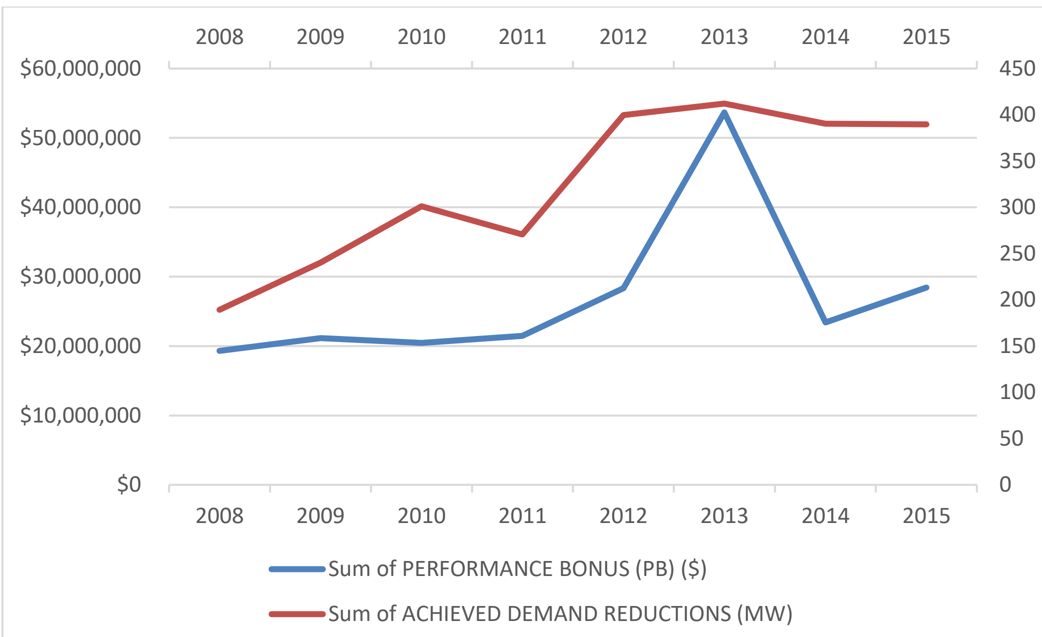
Partly in recognition of the fact that energy savings reduce revenues to utilities, the legislature agreed to provide the utilities the opportunity to earn an offsetting performance bonus. The PUCT subsequently determined that the bonus should be given only for exceeding the minimum goal. The initial bonus established allowed the utilities one percent of the net benefits generated by the programs for every 2 percent each utility exceeded its demand reduction goal, capped at 20 percent of the utility's total program spending. Later, in an effort to focus the utilities on net benefits rather than total spending, the cap was changed to 10% of net benefits generated by the programs.

In order to receive the maximum allowable portion (10%) of total program net benefits as their bonus, utilities must exceed their demand goal by at least 20% (because the performance bonus is capped at 10% of total program net benefits). As noted throughout this report, the least cost means to reach a maximum bonus is through load management programs. For that reason, the role of load management has increased in importance for the utilities.

Energy savings, however, must still be achieved for two reasons. First, the commission had the foresight to set an energy savings goal in addition to a peak demand reduction goal.[19] Secondly, the other limitation on the utility performance bonus is the actual size of the net benefits. If net benefits are relatively low, then even achieving the maximum 10% of net benefits could be underwhelming. Energy savings create the majority of net benefits.

Some utilities and other parties opposed the change to a net-benefits based cap[20] as they were concerned that net benefits might decrease in the future as building codes and advances in technology make incremental efficiency gains more costly to achieve. Consumer groups generally praised the change, as a way to tie bonuses to overall customer benefits, but many expressed concerns that bonuses could vary widely and recommended they choose a lower percentage of net benefits than 10 percent. OPUC[21] asserted that the utilities were using their load management programs to inflate their bonuses and that the bonus calculation should be more closely tied to energy savings, rather than demand savings. [22]

Chart 7: Total Amount of Performance Bonuses Awarded vs. Achieved Demand Reduction



Note: The peak of performance bonuses awarded in 2013 was driven by a spike in the avoided cost of energy due to the sustained heat wave in 2011 and 2012, as described below.

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[19] A case could be made that the legislature in originally setting a goal of at least 10% of the rate of growth in demand, were only thinking of "demand" as opposed to "supply," as a general concept, and did not mean to indicate by the use of that term, "peak demand." Nevertheless, the rules adopted initially set only a peak demand reduction goal.
[20] PUCT docket 39674, final order, p. 147.
[21] PUCT Project 30331, Amendments to Energy Efficiency Rules and Templates. Final order, p. 8; *"OPUC and Texas ROSE also argued that load-management programs do not conserve energy or provide societal benefits and are, therefore, not appropriate under the energy efficiency program."*
[22] PUCT docket 39674, final order, p.150

The PUCT rule changes in 2010 also modified the methodology used to calculated the avoided cost of energy from a one-year lookback at summer peak wholesale prices, to a two-year lookback at both summer *and* winter peak wholesale prices. This change, combined with historically high energy prices in 2011, caused the avoided cost of energy to go from $0.06 per kWh in 2012, to $0.10 in 2013, and back down to $0.05 per kWh in 2014. The high avoided cost of energy drove up *total* net benefits, leading to the elevated bonuses seen in 2013. Since 2013, bonus amounts have been remained about 30 percent above the levels prior to the 2011 rule change in the performance bonus cap.

While the legislature and the PUCT has tripled the goal for energy efficiency over time, overall spending, read demand and energy savings, have changed much less than might have been expected, in part due to the slowing rate of growth in demand and industrial opt-out provisions, but also because of the utilities' ability to meet and exceed their demand reduction goals with one-year emergency load reduction commitments.

The Relative Roles of Integration of Load Management and the Wholesale Market

While the large industrial consumers were lobbying to be relieved of participation in the state IOU efficiency programs, they were also working to replace their previous interruptible rate benefits through the wholesale market. ERCOT did evolve market rules during this same period that permitted large load resources (able to drop at least 1 MW of load for an extended period) to provide Responsive Reserve Service. In 2007, the PUCT directed ERCOT to create an additional Emergency Interruptible Load Service (EILS, now Emergency Response Service, or ERS), and specified that ERCOT procure between 500 and 1000 MW of demand response capacity at a cost of no more than $50 million dollars annually. Together these programs allow nearly 2500 MW of load resources to be compensated by the market annually

The law and PUCT rules over the years have not maintained a clear policy with respect to either the role of distribution level load management programs for the utilities themselves, or the role of these retail programs relative to demand response resources of the wholesale Market.

In 2005, the commission recognized the ability of load management to avoid or defer transmission or distribution system investments and to reduce costs associated with congestion management. The PUCT required ERCOT to help identify trouble spots in the transmission system and allowed utilities to offer higher incentive payments for load management targeted to these areas.[23] However, in 2008, when the PUCT increased the maximum incentive payment for all programs to 100% of avoided costs, it effectively eliminated the additional incentive for targeted load

In 2008, when the PUCT increased the maximum incentive payment for all programs to 100% of avoided costs, it effectively eliminated the additional incentive for targeted load management and the requirement for ERCOT to identify opportunities to avoid or defer distribution costs was removed.

[23] PUCT project 30331. Final order, page 23, rule §25.181(e)(3)(D). This section was subsequently removed.

management and the requirement for ERCOT to identify opportunities to avoid or defer distribution costs was removed.

Later, in the wake of grid outages in 2011, the legislature added language to the Goal for Energy Efficiency[24]:

> "(b) The commission shall provide oversight and adopt rules and procedures to ensure that the utilities can achieve the goal of this section, including:
>
> > ……………………
> >
> > 7) ensuring that an independent organization certified under Section 39.151 allows load participation in all energy markets for residential, commercial, and industrial customer classes, either directly or through aggregators of retail customers, to the extent that load participation by each of those customer classes complies with reasonable requirements adopted by the organization relating to the reliability and adequacy of the regional electric network and in a manner that will increase market efficiency, competition, and customer benefits.[25]

This language is actually somewhat confusing because utilities programs and the market at ERCOT (the independent organization) are quite separate. Utilities have nothing to do with their administration. Perhaps as a result of this misplacement of the language, it was never clearly acted upon, although some new opportunities for load resources have been created at ERCOT, and the PUCT has insisted that the retail programs respond to system-wide ERCOT emergencies.

In 2012, it considered transitioning the utility load management programs to ERCOT entirely given they are really a reliability measure.[26] The feedback the PUCT received in public comments was that many of the customers participating in the utilities' simpler load management programs would be unable or unwilling to participate in ERCOT's ERS program, which required a 10-minute response time and offered less certain financial compensation. In addition, utilities were reluctant to let go of load management programs that so cost-effectively helped them meet and exceed their demand reduction goals and earn substantial financial bonuses. Thus, the commission decided that the utility load management programs provided a unique and valuable reliability safeguard that could be used by ERCOT for system-wide emergencies, or by utilities to address local distribution network issues:

> "Utilities offering load management programs shall work with ERCOT and energy efficiency service providers to identify eligible loads and shall integrate such loads into the ERCOT markets to the extent feasible. Such integration shall not preclude the continued operation of utility load

[24] PURA Section 39.905, Paragraph (b)(7).
[25] PURA Section 39.151.
[26] PUCT project 39674. Final order, pages 13 to 21.

> management programs that cannot be feasibly integrated into the ERCOT markets or that continue to provide separate and distinct benefits.[27]

Integration has apparently been interpreted such that Utilities only curtail the load in these programs upon ERCOT's declaration or anticipation of an ERCOT Energy Emergency Alert Level 2 during the summer season. However, ERCOT confirmed that the most recent summer curtailment to which retail programs could contribute was in August 2011.

Finally, the commission did take one other step to "integrate" IOU programs with wholesale markets. Responding to concerns that loads not be allowed to inappropriately "double-dip," by participating in both ERCOT markets and IOU load management programs, the current rules read:

> "A load-control standard-offer program shall not permit an energy efficiency service provider to receive incentives under the program for the same demand reduction benefit for which it is compensated under a capacity-based demand response program conducted by an independent organization, independent system operator, or regional transmission operator. The qualified scheduling entity representing an energy efficiency service provider is not prohibited from receiving revenues from energy sold in ERCOT markets in addition to any incentive for demand reduction offered under a utility load-control standard offer program."[28]

Still, while this clarifies what is not allowed, it falls short of drawing the most benefit from the resources being acquired by the utilities. As noted earlier in this paper, the load management programs are judged based on the benefits they generate, largely reduction of capacity (in an emergency). The PUCT rule recognizes the cost of emergency capacity such load resources provide, but they no longer address or recognize the potential savings to the business of the IOUs themselves, the avoided transmission or distribution costs that might be earned.

V. CONCLUSIONS AND QUESTIONS

Load management within the state IOU-administered efficiency programs has evolved from a carefully restricted resource, to the utilities' primary vehicle for acquiring demand reductions. In the first years of the programs no load management was acquired, and its inclusion was at first carefully circumscribed. Recently commercial load management programs are maintained near 200 MW, more than 100 percent of each years' demand reduction goal. Load management has now become an inexpensive way for utilities to meet their demand reduction goals, and exceed those goals to help maximize their bonus.

While the legislature and the PUCT tripled the goal for energy efficiency, spending on efficiency has changed much less dramatically. This outcome is at least due in part to the greater reliance on annual emergency load management agreements, which in turn is an outgrowth of incentives embedded in the

[27] PUCT Rule §25.181. Energy Efficiency Goal. Section (m)(6).
[28] PUCT Rule §25.181. Energy Efficiency Goal. Section (m)(5)

PUC rules. Perhaps it is time to reconsider whether the bonus structure is encouraging the optimum results? Should it be based more on actual energy savings or persistent reductions in demand?

In addition, if the utilities will continue to acquire load management agreements in addition to the demand response resources acquired by ERCOT should each be addressing different needs? Or is it enough that the utilities attract additional load resources that might not be able to participate in ERCOT programs? Utility load resources can certainly continue to be deployed to backup ERCOT when there is a system-wide or regional emergency, but there hasn't been a summer season emergency call for load management since 2011. Couldn't these resources also be used by the utilities to avoid or defer traditional infrastructure investments. Should load management funded with efficiency funds do more than provide emergency reserves? Could the PUCT provide guidance to the utilities to clarify that they should strive to reap the maximum benefit from their load management resource? And, if a given load resource were used to provide separate local infrastructure support, in addition to system-wide emergency services, is compensation for both appropriate?

Finally, this raises another related issue. Today the PUCT rules define the benefits of all efficiency measures, including load management, in terms of the avoided energy and capacity costs. Shouldn't the PUCT credit utilities for avoiding transmission and distribution costs through their energy efficiency programs? Why not encourage utilities to reduce their own internal costs through efficiency and load management?[29]

SPEER is establishing a collaborative process for stakeholders to help digest this and the other briefs we have published on the history of energy efficiency programs in Texas, to encourage market participants to openly discuss these issues, and consider the changes that may be needed to update state goals and programs.[30]

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[29] See also: SPEER Commission on Energy Efficiency Policy, 2017. The Commission reached a consensus over 2016-2017 that utilities should be recognized and even rewarded for reducing their own costs through efficiency. https://eepartnership.org/wp-content/uploads/2017/06/SPEER-Commission-Final-Report-6.20.17-1.pdf

[30] The entire set of EE Briefs can be found at: https://eepartnership.org/program-areas/policy/history-of-energy-efficiency-programs/