PROJECT NO. 39674

RULEMAKING PROCEEDING TO AMEND ENERGY EFFICIENCY RULES	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §25.181
AS APPROVED AT THE SEPTEMBER 28, 2012 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to §25.181, relating to Energy Efficiency Goal, with changes to the proposed text as published in the April 27, 2012 issue of the *Texas Register* (37 TexReg 2936). The purpose of these amendments is to incorporate the changes from the 82nd Legislative Session, resulting from the passage of Senate Bills (SB) 1125, 1150, 1434, and 1910. The addition of an evaluation, measurement, and verification (EM&V) framework as directed by SB 1125 will result in the commission hiring an outside consultant(s) to develop a process that ensures accurate estimation of energy and demand impacts and will provide feedback to the commission, utilities, and stakeholders on program performance. The amendments also make several revisions to the energy efficiency cost recovery factor (EECRF) proceedings, including revising the procedural schedule and scope of the EECRFs and allowing an annual consumer price index (CPI) adjustment to the cost caps beginning in 2014; requiring costs to be directly assigned on a rate class basis and calculating EECRFs to provide for energy charges for residential and commercial customers billed for base rates on an energy basis and as an energy or demand charge for each commercial rate class billed on a demand basis for base rates; and replacing the three-year reconciliation proceeding with an expanded annual EECRF proceeding that includes the issue of the extent to which the costs recovered through the EECRF complied with PURA §39.905 and this section, and the extent to which the costs recovered were reasonable and necessary to reduce demand and energy growth, except for the 2013 proceedings that will allow a review of expenses for program years prior to 2012.

Other amendments include updating the avoided cost calculations to account for the transition to a nodal market design in the Electric Reliability Council of Texas (ERCOT); increasing the demand reduction goals to 30% of annual growth in demand beginning in 2013 and moving to four-tenths of summer-weather adjusted peak in subsequent years; setting the bonus at a maximum of 10% of total net benefits; adding provisions for utility self-delivered programs; revising load management programs by requiring more coordination with ERCOT; increasing the set-aside for targeted low-income programs to 10% of the utility's budget; formalizing the energy efficiency implementation project (EEIP) process; revising the customer protection standards and applicable definitions to allow behavioral programs; and adding an opt-out provision for industrial customers taking service at distribution voltage. The amendments constitute a competition rule subject to judicial review as specified in Public Utility Regulatory Act (PURA) §39.001(e). Project Number 39674 is assigned to this proceeding.

The commission received comments on the proposed amendments from Beneficial Results, LLC, CenterPoint Energy Houston Electric, LLC (CenterPoint), the City of El Paso, CLEAResult Consulting, Comverge, Earth Networks, Inc., EnergyConnect, Inc. (ECI), EnerNOC, Inc., Environmental Defense Fund, Inc. (EDF), the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (collectively Entergy

Cities), the Electric Reliability Council of Texas (ERCOT), Oncor Electric Delivery Company, LLC (Oncor), CenterPoint, AEP Texas North Company (AEP TNC), AEP Texas Central Company (TCC), Southwestern Electric Power Company (SWEPCO), Entergy Texas, Inc. (ETI), Xcel/Southwestern Public Service Company (SPS), El Paso Electric Company (EPE), Texas-New Mexico Power Company (TNMP), and Sharyland Utilities, L.P. (Sharyland) (collectively Joint Utilities), North American Power Partners (NAPP), Opower, Inc., Office of Public Utility Counsel (OPUC), Pepco Energy Services (Pepco), Public Citizen and Sustainable Energy and Economic Development Coalition (Public Citizen and SEED Coalition), the Responsible Energy Codes Alliance (RECA), the Retail Electric Provider Coalition (REP Coalition), Sierra Club, Lone Star Chapter, SPS, Steering Committee of Cities Served by Oncor (Cities), TAS Energy (TAS) and Natgun, Texas Association of Community Action Agencies, Inc. (TACAA), Texas Citizens in Response to a Sierra Club Action Alert, which included the names of 1,526 citizens (Texas Citizens), Texas Combined Heat and Power Initiative (TX CHPI), Texas Industrial Electric Consumers (TIEC), Texas Ratepayers' Organization to Save Energy (TX ROSE) and Texas Legal Services Center (TLSC), Texas Renewable Energy Industries Association (TREIA), TNMP, and Wal-Mart Stores Texas, LLC and Sam's East, Inc. (Walmart).

The REP Coalition was composed of the Alliance for Retail Markets (ARM); CPL Retail Energy, LP; Reliant Energy Retail Services, LLC; WTU Retail Energy, LP; TXU Energy Retail Company LLC; the Alliance for Retail Markets (ARM); and Texas Energy Association for Marketers (TEAM). The participating members of ARM with respect to the REP Coalition comments were: Champion Energy Services, LLC; Direct Energy, LP; Gexa Energy, LP; and

Green Mountain Energy Company. The participating members of TEAM with respect to the REP Coalition comments were: Accent Energy; Amigo Energy; Bounce Energy; Cirro Energy; Energy Plus Holdings; Green Mountain Energy Company; Just Energy; Hudson Energy Services; StarTex Power; Stream Energy; Tara Energy; Texas Power; and TriEagle Energy.

In addition to comments on the proposed amendments, the commission also received comments in response to the following preamble questions:

(1) Should the commission require utilities to transition their load management programs to ERCOT once loads are able to participate in the ERCOT energy market? What changes would need to occur to phase-out existing programs and over what time period?

(2) Should the commission develop performance standards for the loads that are similar to the Emergency Response Services (ERS) standards outlined in §25.507? Should the utilities offer incentives to loads for equipment that would enable their participation in the ERCOT market? If so, should the utilities be allowed to count the demand and energy savings associated with the installed equipment toward meeting their goals? How should these savings be calculated?

Preamble question one:

OPUC, Public Citizen, SEED Coalition, REP Coalition, TX ROSE, and TLSC generally supported the transition of the utilities' load management programs to ERCOT. OPUC commented that its overarching interest is that the utility programs be used to achieve the greatest benefit to the grid, and that program costs are market-based, competitive, and allocated in a way that reflects the benefits of the programs. It stated that ERCOT is in the best position to utilize the programs with the most benefit to the grid, and responsive reserve program costs are more appropriately allocated than the energy efficiency program costs. It stated that it believed ERCOT is in the best position to provide the most market-neutral, equitable and unbiased guidance to the commission on the load management issue.

TX ROSE and TLSC stated that the load management programs should be moved to ERCOT in their entirety and that any incentive for load management or demand response programs should be market-based and passed on to consumers by REPs. They commented that it is not necessary to support load management through the regulated utilities, and instead, the commission should steer the utilities towards making program investments that offer the highest long-term value to the customer. They commented further that load management does not result in energy savings or provide savings that will persist over time as they would with traditional energy efficiency investments. Load management is an appropriate measure for managing system reliability and as such should be supported by the market. They stated that energy efficiency measures have a higher value than load management since they operate on-peak and off-peak, making a lasting contribution to the system as well as producing long-term bill reductions for customers. Load management changes the timing of energy use rather than the amount.

REP Coalition commented that active participation of economically-dispatchable load in the ERCOT wholesale market will expand the role of load in the context of resource adequacy in both the short- and long-term. Load resources will be permitted to submit price offers at ERCOT to set the market-clearing price for energy in competition with generation resources, providing more accurate price signals during periods when available generation is scarce. The resulting prices will reflect customers' outage costs or the value of lost load. It stated that the utilities' programs do not send an affirmative price signal to the competitive market and the value of the load curtailed is not communicated within a dynamic framework of resources competing on the basis of price. Instead, the curtailment under the utility programs actually dampens or reverses pricing signals in the competitive energy market and ultimately disserves ERCOT's energy-only market. It also stated that economically-dispatchable load will facilitate more robust demand response in ERCOT, including allowing REPs to offer products and services featuring dynamic pricing. It stated that §25.243(c) limits a utility's provision of competitive energy services to the *administration* of energy efficiency programs and opposed any expansion of the utilities' role in load management when the competitive market is capable of providing services and products to meet customers' needs. It commented that the load management programs might have compromised the opportunity for REPs to offer similar products outside the utilities' energy efficiency portfolios, which are funded through regulated rates. It also commented that contrary to opposing parties' arguments, the proposed transition is not premature. It stated that such commission directive ensures the intent of PURA §39.905(b)(7), which allows all loads to participate in ERCOT's energy markets subject to certain qualitative prerequisites.

Public Citizen and SEED Coalition commented that many load management programs can be transitioned into the ERCOT market through the "Loads in SCED" project. They noted that some participants in the load management program may, for technical reasons, not be able to participate in the ERCOT market, and the utility load management programs should be maintained for those participants.

NAPP and TIEC commented on the need to separate any program with utility benefits from programs providing services in the competitive market. NAPP commented that the utility programs should be used to continue to develop as long as they are designed to serve a separate and unique purpose such as transmission and distribution cost deferral or local congestion relief. It maintained that utility programs that duplicate functions of ERCOT programs should be transitioned to ERCOT, as they demonstrate potential for adoption at the ISO. It stated that allowing demand response participation is a necessary component of the energy-only market and will allow more stable, predictable pricing patterns to emerge. It commented that an efficient market should provide a balance between generation and demand so that an appropriate market price is reached. Curtailed load would be added to the bid stack when it is actually curtailed.

TIEC stated it has long supported demand response in the competitive energy and ancillary services markets, but does not take a position at this time on the continuation of utility load management programs that are not market-based or price-driven. They stated that a load should not be able to participate in both a utility program and the competitive market at the same time, and that while the rule prohibits load participating in the utility program from offering ancillary services, the rule should also be applied to loads participating in the competitive energy market. They stated that any load participation in the ERCOT market must be entirely competitive and cost-based, and not subsidized by utility ratepayers. To transition a load currently in a utility program to the ERCOT energy market that load would need to be removed from the regulated utilities' programs. They proposed language in subsection (m)(6) clarifying their proposed amendments.

Cities, CLEAResult, Comverge, ECI, EnerNOC, Joint Utilities, and Sierra Club generally opposed requiring the utilities' load management programs to be transitioned to ERCOT. ECI stated that it does not support removing the programs from the utilities' portfolios without an overall strategic effort to enhance demand response in the ERCOT market. It noted that the utilities' programs and the ERCOT real-time energy market serve fundamentally different purposes and many customers may be unwilling or unable to participate in the ERCOT market. It believed that utility and ERCOT programs are complementary and should both be offered to provide different options for customers. It stated that it was unclear why the commission would even be considering sunsetting the utility programs since they are helping to ensure resource adequacy and have recently been increased by the commission to ensure sufficient resources are available. Cities and Sierra Club commented that the utility programs might actually facilitate participation in load management activities, as the programs appeal to less sophisticated, smaller-sized commercial customers without the expertise to participate in the ERCOT market. They stated that the continuation of the utility programs is reasonable as long as participating customers do not receive incentives from multiple sources for the same interruption events. Comverge noted that there are risks associated with the assumption that the utility programs can smoothly transition into the ERCOT market, as it is not clear if market protocols or pricing arrangements would be sufficiently attractive for them. It stated that for customers who are able to participate in both the utility programs and current ERCOT ancillary services markets, it may be appropriate for the utilities to facilitate the transition once economic dispatch is available. It stated that instead of bringing uncertainty to customers currently participating in the utility programs, especially those unable to participate in the ERCOT market, the rule should direct the utilities to develop demand response that accommodates customers not able to participate in the utilities' programs today and expand demand response. CLEAResult stated that the capacity shortage in Texas requires any and all methods to reduce peak demand be employed. It, therefore, opposed eliminating the utility load management programs and supported greater coordination with ERCOT.

EnerNOC commented that load management types of demand response programs remain a tool for utilities to meet system needs in their local areas in a more focused manner than can be achieved by ERCOT-wide programs. It noted that the Loads in SCED project will have a fundamentally different focus, and therefore value to the grid, than the current utility programs. Particularly, as an economically-based program, participants will provide reductions in response to price signals at their own discretion rather than when called to provide dispatchable capacity for reliability, emergency, or peak demand management purposes at the utility's discretion. Further, it commented that Loads in SCED is only working towards allowing loads with a single point of connection to participate rather than aggregated load like those that participated in the utility programs. It stated that many load management participants would also not be suited to participate in ERS at ERCOT. It commented that a phase-out would negatively affect the maintenance and growth of the utilities' programs in the interim, as the providers will know that the time over which they may able to recoup their investment will be limited. With the capacity concerns in ERCOT, it stated that now is not the time to reduce load management programs. It stated that it is important to recognize the differences in load management and other resources in the ERCOT market, mainly that the underlying providers of the service are retail customers whose primary focus is their normal day-to-day business operations. These customers are not likely to consider enrolling in a demand response program based on uncertain estimates of potential compensation or as little as 10 minutes' notice before their business operations are interrupted. It noted that no market that compensates demand response participants based solely on an energy-only market structure has more than a modicum of participation and a shift to such in ERCOT is unlikely to incent the same level of participation as the current utility programs.

Joint Utilities agreed with the support provided by parties in favor of continuing the energy efficiency load management programs and provided numerous reasons to support their position, including load management programs are essential components of the utilities' energy efficiency programs and have been since PURA §39.905 was adopted in 1999. The programs are vital components of the energy efficiency portfolio, and provide high net benefits as well as reliability benefits. The programs are supported by PURA and commission precedent. Since the original §25.181 was adopted, the commission has found that load management programs were an allowable type of energy efficiency. The commission later expanded the role of load management to facilitate increased participation and ensure adequate capacity is available to meet demand. Utility support for the increased energy efficiency goals was based upon the belief that load management would continue to be an available program option.

According to Joint Utilities, the programs are an integral piece of the utilities' energy efficiency portfolios and a phase-out would require a complete structural change to the program mix of the portfolio. There remains a critical need for many types of demand-side programs due to reliability challenges, and a variety of program options with different features and requirements enables greater participation. The utility programs play a different role than ERCOT-administered load management programs. Specifically, the utility programs can target an individual utility's transmission and distribution system. The programs complement ERCOT's efforts to preserve reliability. Considering projected reserve margins and national policy changes, the programs will continue to be a valuable near-term resource and help balance demand in system emergencies. The commission has acknowledged this recently when approving a significant expansion of the programs for the summer of 2012.

Further, Joint Utilities added, many program participants are not likely to be candidates for participation in the ERCOT market due to the performance and load forecasting requirements, yet will remain candidates for the load management programs. ERCOT has acknowledged the uncertainty that all loads currently participating in the utility programs would migrate to ERCOT-operated markets once economic dispatch is enabled. The necessary technical requirements, qualification criteria, and differences in payment structures established at ERCOT could limit participation. Providing customers a multitude of program options would tend to increase the resources available to the system during an emergency. Additionally, any ERCOT-administered program would be an economic program, which would require participants to curtail usage whenever wholesale prices were at or above their offer price. High prices do not necessarily correspond with the type of reliability event for which curtailments are triggered under the utility programs.

Joint Utilities argued that the Loads in SCED project has an uncertain status and is undergoing substantial redesign at ERCOT's Market Enhancement Task Force. Loads in SCED is likely to have strict standards regarding the predictability of load levels, a minimum curtailment amount of 100 kW at a specific node, communications telemetry, strict noncompliance penalties, and fast response times. Further, a phase-out would seemingly not apply to non-ERCOT utilities, thus creating different program opportunities for different utilities, which would be at odds with the commission's goal of ensuring statewide consistency among the utilities in their program offerings. Certain non-ERCOT customers may have access to programs that their ERCOT equivalents do not.

Joint Utilities stated that, for these reasons, the commission should take further steps to increase, not phase-out, demand reduction opportunities made available through the utility load management programs.

In replies, Joint Utilities maintained that they are committed to working with ERCOT to ensure both ERS and the load management programs are successful in addressing the needs of the market. They clarified that ERCOT is already able to request that the utility programs within its region be dispatched within the program's constraints on the number and duration of curtailments based on the implementation of a memorandum of understanding (MOU) signed by all of the utilities in ERCOT. Therefore, they stated OPUC's key concerns have been addressed for the utilities in ERCOT, and are irrelevant for those outside the ERCOT region. Further, they stated that TX ROSE and TLSC's comments were at odds with nearly all other parties on the issue, and if there truly was such little value in the programs, they would not have been expanded this year with regards to resource adequacy. They appreciated ERCOT's support and its increasing reliance upon the load management programs.

Joint Utilities also provided a response to concerns regarding the load management programs' impact on price signals in the wholesale market. Specifically, they responded that the concerns regarding the program's distortive impact on energy prices seems to be more properly directed to the ERS program, which would presumably have similar, though larger impacts. They noted that the commission recently affirmed its support of ERS and did not order ERS to be transitioned to the Loads in SCED initiative.

C***ommission response***

The commission appreciates the comments provided by all parties regarding this very important issue and the potential impact of greater load participation in ERCOT. The commission will continue to look at ways the role of load can be expanded in the context of resource adequacy as both an energy and capacity resource.

In response to the specific question posed regarding the possible transition of utility load management programs to ERCOT, the commission agrees with Cities, CLEAResult, Comverge, ECI, EnerNOC, Joint Utilities, and Sierra Club that a mandatory transition is not appropriate at this time. While the commission supports and prefers market-based economic dispatch of resources, such a mechanism is not available at this time in the ERCOT market. The commission, therefore, does not disagree with OPUC, NAPP, Public Citizen, SEED Coalition, REP Coalition, TIEC, TX ROSE, and TLSC's preference for

market-based dispatch, but contends that this discussion is premature. The commission agrees with EnerNOC that adopting a phase-out of the programs at this time would make it more difficult to attract energy efficiency service providers to the utility programs in the interim. The commission does not wish to limit potential demand response in the face of potential capacity shortfalls in the next few years.

Further, the commission agrees with ECI, EnerNOC, Joint Utilities, Public Citizen, and SEED Coalition that some loads may not be able to participate in the ERCOT market due to technical requirements. The commission also agrees with Cities and Sierra Club that load management programs appeal to smaller, less sophisticated customers. These customers might never have the expertise needed to be able to participate in the ERCOT market and load management provides them an opportunity to participate in demand response activities. Many load management service providers aggregate multiple customers rather than focus on a single customer, which is similar to the activities of ERS providers; the commission agrees with EnerNOC that this aggregation may further limit the ability of customers in the load management programs from transitioning to market-based programs. The commission also agrees with EnerNOC, Joint Utilities, NAPP, and TIEC that load management programs serve a separate purpose and are able to provide benefits such as targeted congestion relief to individual utility systems. Also, the commission agrees with EnerNOC that the load management programs' focus on reliability and peak shaving is fundamentally different than Loads in SCED's focus on economic dispatch. The commission does not believe that additional functionality provided by the utility programs should necessarily be tied to economic dispatch.

The commission recognizes REP Coalition's concerns that load curtailment programs, including the load management programs, can dampen or reverse pricing signals. Similar concerns were raised during the adoption of the new ERS rule under Project Number 39948, *Rulemaking to Amend Substantive Rule §25.507, Relating to Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS)*. The commission continues to believe that while there may be some impact on energy prices due to the deployment of curtailment programs, it is inappropriate to adopt a specific mechanism to mitigate such pricing impacts in the rule. ERCOT stakeholder groups, including the Reliability Deployments Task Force, continue to discuss an approach to mitigating the pricing impacts of all reliability measures taken by ERCOT. The Retail Markets Subcommittee has also discussed pricing mechanisms in relation to retail customers and demand response. The commission believes that such stakeholder groups are the correct forum to address pricing impacts rather than this rule.

The commission believes that many loads will voluntarily migrate to ERCOT programs such as ERS and Loads in SCED when it is launched due to more attractive pricing in those markets for load. For instance, load management incentives average $40 per kW, while ERS (formally EILS) averaged over $47 per kW in 2010. The commission anticipates that the market-clearing price for energy and potential earnings for loads bidding into SCED will also be greater than the load management incentive payments considering the commission recently raised the system-wide offer cap to $4500 MWh. Load participating in ERS is already prohibited from participating in the utility programs during the same

interval periods. The commission appreciates similar comments regarding load participation in various programs filed by Cities and Sierra Club. The commission further discusses load participation in utility programs and at ERCOT in response to comments filed in regards to subsection (m)(6).

The commission agrees with Joint Utilities that the load management programs are an integral piece of the utilities' energy efficiency portfolios. PURA §39.905(d)(6) supports the inclusion of customer energy management and demand response programs and subsection (a)(6) requires the utilities to make available load management standard offer programs to industrial customers at the 2007 participation levels. Requiring the utility programs to transition would require a complete structural change to program portfolios. Further, market-based programs are not uniformly available to utilities across Texas. Transitioning the load management programs of the ERCOT utilities would potentially create different opportunities for loads depending on the system operator in their territory and would limit the ability of some utilities to offer programs based on its inclusion in a certain independent system operator or regional transmission organization. The commission agrees with Joint Utilities that this is at odds with the goal of consistency among the utilities in their program offerings and creates an inequality for customers. Therefore, for these reasons and those discussed in further detail below, the commission declines to require the utilities to transition their load management programs at this time. The commission will continue to encourage both economic incentives for loads and the development of security constrained economic dispatch and other mechanisms in the ERCOT market that will attract competitive load participation at ERCOT. The commission agrees with CLEAResult that

greater coordination between utilities, their service providers and ERCOT is needed to ensure the grid receives the full benefit of the utility programs in the interim.

Cities, CLEAResult, ECI, EnerNOC, and Joint Utilities noted that load management programs are among the most cost-effective of the energy efficiency programs and serve as the foundation for utilities to meet their goals while minimizing overall program costs. EnerNOC commented that utilities should have the flexibility to continue cost-effective programs. Similarly, Cities stated that as a ratepayer-funded program, energy efficiency should be achieved in the most cost-effective manner. They commented that if load management programs are transitioned to ERCOT, it may become difficult for utilities to reach their energy efficiency goals. CLEAResult commented that load management is a cost-effective, quickly deployable product that should be expanded in light of capacity shortages. It commented that if the commission decided to eliminate the load management programs, the cost caps should be raised to reflect the higher costs per kW of traditional programs and incentives.

Joint Utilities stated that any phase-out of the load management programs would significantly increase the cost of meeting the utilities' goals and drive total program costs above the EECRF cost caps. If load management is completely removed from the program portfolio, the average portfolio cost per kW would increase approximately 50% to $630/kW. This, combined with the mandatory increased funding for targeted low-income customers, would further hamstring utilities under the current cost caps.

Separately, Cities stated that it would support a strict cost cap per kW for load management in the utility programs.

C*ommission response*

The commission agrees with Cities, CLEAResult, ECI, EnerNOC, and Joint Utilities that the load management programs have historically proven to be the most cost-effective programs in the utilities' energy efficiency portfolios and that eliminating the programs would make it difficult for utilities to meet their goals under the current cost caps. The commission disagrees with Cities that a separate cost cap is needed for load management programs. All program incentives are capped by the avoided costs set by the commission, currently at $80 per kW. Utility incentives for the load management programs have traditionally been set at half the avoided cost, or $40 per kW. The commission does not believe the incentive payment for load management to be inappropriately high given the benefit the programs provide both utility systems and the grid as a whole, especially given the fact that the payment is substantially below the avoided cost of capacity.

Comverge, Earth Networks, EnerNOC, ERCOT, Joint Utilities, OPUC, Public Citizen, SEED Coalition, and REP Coalition commented on the timelines associated with load management in the interim period prior to the economic dispatch of load in the ERCOT market.

Earth Networks stated that while it may be appropriate to transition the load management products to the ERCOT programs, the utility programs serve an important role in providing a flexible platform for programs to be designed and technologies tested. Once programs are established and achieve a critical mass of participation, they could then be moved to ERCOT. It commented that the current ERS program is structurally not designed with peak load programs in mind.

EnerNOC stated that eliminating the utility programs will strand the load management assets until a later stage of the Loads in SCED project works towards allowing aggregations, which is at least three to four years away. Public Citizen and SEED Coalition stated that a transition to ERCOT through Loads in SCED would take several years, and the utility load management programs should continue until full implementation of the project.

Comverge stated that it believes the load management transition to ERCOT should be based on a vibrant DR environment and a working economic dispatch system capable of accommodating load resources in all segments of the market, including residential customers. Adopting a rule at this point would be based on the supposition that transitioning the programs to the ERCOT markets will work, when the demand response energy market is dominated by large commercial and industrial demand response, with economic dispatch several years from being realized.

Joint Utilities agreed with parties who recognized that there will be some ongoing need for utility load management programs even after Loads in SCED is launched by ERCOT and that the proposed transition may be premature.

OPUC stated that the utilities should be required to transition their load management programs to ERCOT once the logistics of participation in the ERCOT markets have been finalized. Similarly, REP Coalition provided modifications under proposed subsection (m)(6) that would facilitate the continued operation of utility load management programs during the period preceding the transition and integration of its participating load within the framework of

ERCOT's competitive energy markets. It stated that many of the arguments in opposition to transitioning the load management programs to ERCOT's competitive energy markets lack merit in view of the purpose of the transition requirement and the current estimated timetable for triggering it. It commented that several comments indicate confusion about the trigger that transitions the load management programs participation in the competitive energy market. It noted that the trigger allows for the continued operation of utility programs that cannot be "feasibly" integrated to participate at ERCOT and the Loads in SCED project will not necessarily cause the feasibility component to be met. Feasibility may vary according to customer class or subclass, which will determine if and/or when the load transitions.

ERCOT did not take a position on the transition of the utility programs, but commented that any integration should not depend on the Loads in SCED project. If in the future loads and demand response can ultimately offer into SCED, it stated that it is unlikely that all load management participants will be able to participate and some loads may be better served by participating in ERS. It commented that a 30-minute ERS pilot has been recently proposed, but at this time, it does not have sufficient information to determine whether a 30-minute product will provide operational benefits, justifying full integration into the Protocols, or even if a 60-minute product would be valuable. The utility programs accommodate 30-minute and 60-minute response times, so it is unclear whether and to what extent the current participants would be able to participate in ERS should the programs be phased-out. It noted that some load management growth appears to have come at the expense of ERS, which traditionally has a 10-minute response time. It commented that possible reasons for the migration of loads to the utility programs include less restrictive performance requirements and higher payments.

C*ommission response*

As discussed above, the commission agrees with Comverge, EnerNOC, and Joint Utilities and believes that economic dispatch is several years away from realization and any transition of load management programs to the ERCOT energy markets is premature. The commission appreciates REP Coalition's comments regarding transition timelines and the feasibility of integration. Specifically, the commission agrees that feasibility may vary according to customer class or subclass. The commission agrees with EnerNOC, Public Citizen, and SEED Coalition that the development of Loads in SCED will take several years. The commission agrees with ERCOT and determines that it is not appropriate to tie any utility integration to the Loads in SCED initiative. Current load management service providers need the ability to bid in aggregated loads prior to even considering participation in the ERCOT market. This capability is not in development for the initial launch of economic dispatch for loads. The commission agrees with ERCOT that it is unlikely all utility program participants will be able to participate at ERCOT and that even new ERS pilot programs may not appeal to current program participants. Further, the commission agrees with Earth Networks that utility programs remain an important, flexible platform for program development and technology testing in both residential demand response and load management. The commission maintains that when economic and feasible, loads will voluntarily transition to ERCOT programs and the utility programs will remain an option for load management participants unable to transition and for separate utility purposes.

REP Coalition stated that given that transition and integration of all utility programs might not be feasible, the commission should ensure that deployment of load by a program retained by a utility should occur at the same time that ERS is deployed pursuant to the ERCOT Nodal Protocols. Joint Utilities stated that REP Coalition comments fail to allow for programs to meet local utility system needs through load management.

C*ommission response*

The commission recognizes the need for utilities to be able to deploy load management resources for their own local reliability and system concerns. While the commission appreciates REP Coalition's recommendation, ERS and the utility programs serve different purposes and requiring them to be deployed at the same time would not allow ERCOT or the utilities any latitude in utilizing the programs outside of an energy emergency. The commission believes that ERCOT and Joint Utilities should continue to be provided flexibility in the manner in which they coordinate the dispatch of load management resources.

Until load management can be moved to a market-based mechanism, TX ROSE and TLSC recommended that load management and demand response be limited to 15% of the demand reduction goal, as it has in the past. They also requested that a cap be placed on the incentive level for such programs. In replies, EnerNOC asked the commission to reject TX ROSE and TLSC's suggestion to limit the amount of load management and demand response in the program. It noted that this was in direct contrast to recommendations in the Brattle Group Report, citing the need for more demand response in the energy-only market to support

ERCOT's current reliability targets. Joint Utilities also requested that the commission reject TX ROSE and TLSC's request. They agreed with EnerNOC that, in light of ERCOT's resource adequacy situation, more load management is needed. They commented that they had moved to increase the programs as recently as five months ago to address summer 2012 resource adequacy concerns.

C*ommission response*

The commission disagrees with TX ROSE and TLSC's recommendation to reinstall a limit on the amount of load management and demand response allowable under the energy efficiency program. While the order adopting the original §25.181 established a cap of 15% of the overall demand savings for the load management programs, the commission has worked to expand the program in subsequent proceedings. *See Project Number 21074, Energy Efficiency Programs*. Specifically, the commission cited resource adequacy concerns when raising the incentive levels and amount of permissible load management to 30% of overall demand savings when amendments to the rule were approved in 2005 in *Project Number 30331, Amendments to Energy Efficiency Rules and Templates*. The commission removed the restriction completely when further amendments were adopted in 2008 in *Project Number 33487, Amendments to Energy Efficiency Rules and Templates*. As noted by EnerNOC and Joint Utilities, the state is facing a similar capacity shortage to that cited in the 2005 order. While the commission has worked with ERCOT since 2005 to create ancillary service programs such as ERS to create additional opportunities for load to provide capacity in the ERCOT region, resource adequacy concerns necessitate ERCOT having access to as many load curtailment options as possible. The commission believes

that imposing a strict limit on the size of load management programs is inappropriate at this time.

ECI and Comverge requested a broader review of load management in light of possible economic dispatch in the ERCOT markets. ECI stated that it recommends the commission sever the questions posed in the preamble regarding the utility load management programs from this docket and open a new docket to address these issues. It commented that the issues posed are only a subset of the issues that the commission should be addressing in order to facilitate load management programs, and an overall strategy for demand response in the ERCOT market should be undertaken. Comverge stated that the commission should consider a broader review after the market demonstrates that the economic dispatch of loads is a success and of economic dispatch will be sufficient to address reliability needs or there is still a needed reliability backstop.

C***ommission response***

The commission appreciates the comments of Comverge and ECI regarding the need for a broader review of load management. The commission has several projects currently devoted to reviewing demand response in the context of resource adequacy and changes in the market. Specifically, the commission is reviewing the broad topic of resource adequacy in Project Number 40000, ***Commission Proceeding to Ensure Resource Adequacy in Texas*****. The project will allow commission discussions to continue regarding recommendations made in the Brattle Group's report on ERCOT investment incentives and resource adequacy, including any particular recommendations or comments made in the report**

referenced by parties in comments on the proposed rule. The commission also continues to explore technologies enabling advanced metering-related demand response in Project Number 34610, *Implementation Project Relating to Advanced Metering*. Commission staff continuously monitors ERCOT stakeholder processes, protocol revision requests, and initiatives, including Loads in SCED. The commission will open projects as needed when activities at ERCOT necessitate specific commission action. The specific utility programs will continue, at this point, to be discussed through the EEIP process. Economic dispatch, resource adequacy, and demand response technologies will be discussed in their respective projects and through the ERCOT stakeholder processes.

Preamble question two:

Earth Networks, EnerNOC, Joint Utilities, NAPP and Sierra Club stated that there is no need to formalize performance standards in the rule.

Earth Networks and NAPP commented that the utilities should retain the ability to develop new programs and establish the performance standards as needed for each program. NAPP noted that a one size fits all standard is not appropriate and for loads participating in the ERCOT market, ERCOT should be able to impose appropriate standards. Joint Utilities stated that the performance standards established by the utilities are already adequately documented in their program manuals. EnerNOC commented that performance standards similar to ERS are not needed and moreover, to the extent a utility desires to adopt performance standards similar to the ERS standards, they already have that flexibility. Sierra Club stated that ERS and other ERCOT programs are regulated programs intended for emergencies. It noted that the utility programs under the proposed rule have mechanisms, such as the proposed EM&V provisions and EECRF proceedings, which would give concerned interests the ability to question any of the programs.

ECI, ERCOT, Public Citizen, SEED Coalition, and TIEC commented that load management programs should not necessarily require the *same level* of performance standards as the ERS program. While ERCOT maintained a neutral position on whether load management programs should be transitioned to ERCOT control in the future, it commented that if the programs are to be completely integrated into ERCOT's administration, more standardization is required. It noted that it is already working with the utilities on the coordination and deployment of the load resources in the program by ERCOT during declared Energy Emergency Alert (EEA) events. In replies, EnerNOC commented that the required standardizations noted by ERCOT should the utilities' programs come under its control limit the very aspects of the utility programs that enable a broader scope or participations.

Public Citizen and SEED Coalition stated that while the same level of standards required by ERS are not necessary, some standardization would insure equal treatment and participation amongst program participants. TIEC stated that if the utilities continue to operate load management programs, performance requirements may be appropriate, but any transitioned load should be held to the same testing, qualification and performance requirements that apply to all other ERCOT market participants. They maintained that transitioned loads must be treated like any other market participants and should not be subsidized or afforded any other special treatments that are not available to competitors.

ECI stated that the commission should not develop performance standards for the utility programs that are similar to ERS. It stated that it believes the ERS performance standards remain a major barrier for customer participation in ERS. Further, the current compliance and enforcement policies ERCOT utilizes for ERS are the strictest in the nation and results in providers de-rating their capacity in the program to avoid suspension for noncompliance. It recommended, at a minimum, the commission wait until ERCOT evaluates the alternative compliance mechanisms proposed in ERCOT's 30-minute pilot prior to determining a basic set of performance standards.

Comverge, OPUC, and REP Coalition stated that availability and performance standards like those developed for ERS are appropriate for utility programs and supported uniform standards among the utilities. Comverge recommended the utilities be given sufficient time to develop and file standards rather than the commission adopting such standards immediately. OPUC commented that the commission should develop performance standards similar to ERS, but maintained that the programs should be transitioned to ERCOT rather than remain in the energy efficiency program.

REP Coalition stated that given potential overlap of load participants between utility programs and ERS, it supports the development of performance standards for the utility programs that are comparable to the ERS standards in §25.507. REP Coalition commented that this would ensure that the utility programs would not compete with or undermine ERS by offering incentives to loads without subjecting them to a corresponding level of performance standards for their obligations. During replies, REP Coalition stated that it does not view Joint Utilities' response with much comfort, as it is clear the performance standards adopted by the utilities for the curtailment and load management programs are not comparable to the current ERS standards. Further, it stated that ERCOT's response was extremely telling of the purpose of the performance standards issue. It specifically noted that failure to perform under the utility programs merely results in a reduced payment, while non-performance is subject to an administrative penalty under the ERCOT administered ERS program. It maintained that a reasonable equivalency between programs should exist between the standards of performance for participating loads and the manner in which those standards are applied.

EnerNOC disagreed with OPUC and REP Coalition, stating that the commission should reject REP Coalition and OPUC's request for uniform performance standards, as preferences demonstrated by participants in these programs should be viewed as an opportunity for ERCOT or the utilities to learn what standards help the success of their programs compared to other programs.

C***ommission response***

The commission would like to clarify that the question posed by the commission along with the proposed rule refers to potentially developing performance standards for the load management programs administered by the utilities and not any future load management that might be transitioned to ERCOT. The commission agrees with ERCOT and TIEC that once loads transition away from the utilities' programs and begin participating in the ERCOT market, they should be held to the same compliance standards as other market

participants and all applicable protocols. Any transitioned load would also be subject to the same penalties as any other load participating in the competitive market.

The commission also notes that if a utility is deploying load in response to an ERCOT directive per the MOU, then failure to perform could have an impact on system reliability. The commission, however, agrees with Earth Networks, EnerNOC, Joint Utilities, NAPP, and Sierra Club that there is no need to formalize performance standards in the rule. The utilities have worked with ERCOT in the last year to coordinate deployment of utility load management programs in accordance with the MOU. This process will ensure some level of standardization, as requested by Public Citizen and SEED Coalition. The commission believes that precedent has shown that it is appropriate for utilities to continue to have the latitude to develop performance standards and penalties should any program participant fail to meet their obligations. Currently, non-compliance results in the utilities either reducing incentive payments or excluding certain loads from participation in the future. The commission believes these penalties are appropriate given the nature of the utilities' programs. Statute necessitates that utilities in areas open to competition must rely on energy efficiency service providers to find and contract load to participate in the programs, except in limited circumstances for rural areas. It is in the best interest of the provider to meet the minimum requirements of the utility to ensure continued inclusion in the program.

As stated above, the commission agrees that allowing the utilities to develop their own performance standards and coordinate the load management programs with ERCOT

continues to be the best course of action at this time. The commission disagrees with ECI that the standards similar to ERS should specifically not be used for the load management programs. If the utility finds such standards to be effective for their program, they should have the flexibility to adopt similar requirements. The commission also disagrees with OPUC and REP Coalition that one-size-fits-all standards are the best course of action at this time. Each utility has a unique service territory with varying climate, customer mix, dominant type of air conditioning, housing stock, and commercial operations. One-size-fits-all standards could hinder the ability of a utility to design standard offer load management programs that are able to best serve the customers in its service territory. The commission appreciates Comverge's comments and agrees that if standards are developed in the future, the utilities should be given sufficient time to develop and file the standards rather than the commission adopt the standards by rule.

Public Citizen and SEED Coalition stated that they recommend any participants using back-up generation to meet their obligations be required to register with Texas Commission on Environmental Quality (TCEQ) and follow the appropriate standards.

C***ommission response***

The commission recognizes the need for generation resources to meet all applicable emissions and standards requirements. The commission believes, however, that it is up to the operators of distributed generation units to be aware of all applicable rules and regulations pertaining to their operation. As discussed in the order adopting Project Number 39948, distributed generation operators are responsible for all regulations and if

they are not able to participate in a manner consistent with regulations imposed by other agencies, the commission would expect them to refrain from participating in the program.

Comverge, Earth Networks, ECI, EnerNOC, NAPP, Public Citizen, SEED Coalition, and Sierra Club did not oppose allowing the utilities to offer incentives for equipment and installation to enable customer participation in load management programs, including those participating in the ERCOT markets. NAPP stated that it supports utilities offering incentives to load for equipment, as well as allowing the utilities to count one or two years of demand and energy savings towards meeting the goals. It commented that the cost of equipment is still a barrier to demand response participation. In replies, NAPP maintained support for utilities offering incentives for load control equipment to facilitate participation in the ERCOT market, especially to help overcome the initial costs of implementation for applications such as pool pumps and residential demand response. It stated that some commenters seemed to misunderstand that the utility would not actually own the equipment, but rather the incentive payment would be used by the provider to offset the customer's purchase of the enabling equipment in exchange for an agreement with respect to the use of the equipment. Further, it commented that this would be an appropriate market transformation program to take full advantage of the new advanced meter infrastructure and savings associated with the equipment should be counted towards the utilities' goals.

Earth Networks stated that allowing the incentive funds would help overcome the high implementation costs and add a level of assurance to new participants who might be less familiar with grid reliability and demand issues. Removing this financial barrier would accelerate adoption. It commented that utilities should be able to claim the resulting energy savings for at least the first year. ECI commented that utilities should be allowed to offer incentives for the purchase of equipment for customer participation in the ERCOT market. It commented that while ERCOT has high smart meter deployment numbers, it lacks premise-based curtailment equipment and pricing programs to fully appreciate demand response in the market. It commented that equipment should be marketed through service providers able to offer subsidized equipment to customers. Savings should be counted to the utilities' goals, but how any savings would be calculated need further exploration.

Public Citizen and SEED Coalition recommended that if equipment is paid for with program dollars, it should be compatible with the guidelines setup in the AMIT process and be configured and controlled by authorized entities. They stated that if these conditions are followed, savings should be allowed to be counted towards the utilities' goals. Sierra Club stated that if the utility incentivizes equipment needed to participate in the ERCOT market, it should only be able to claim savings for the program year the incentive was paid. EnerNOC commented that utilities should continue to have authority to develop programs that suit their particular needs and modify their programs without petitioning the commission for a good cause exception. Comverge stated that simply providing customers control equipment in the current environment will not result in a significant increase in customer participation in the ERCOT markets since the equipment needs to be connected to a service provider that sends signals to initiate load reductions and financial incentive to install the equipment.

While ERCOT and Joint Utilities took no position on whether equipment incentives should be offered by the utilities, each provided additional input should the commission decide to allow such equipment in the program. Specifically, Joint Utilities noted that some justification would be required for spending energy efficiency funds for such a purpose. They stated that if a utility did incentivize the equipment, then the resulting demand reduction should be credited to the utility's goal to properly justify the cost. Further, the savings calculations should be left to ERCOT and its stakeholder process, and the resulting demand reduction and energy savings calculated by ERCOT should then be adopted by the utilities. ERCOT commented that the right incentives and equipment could foster greater participation in all demand response programs, especially for residential customers who account for 50% of peak load.

EnerNOC, OPUC, the REP Coalition, TIEC, TX ROSE, and TLSC commented that utilities should not offer incentives for load control equipment to enable participation in the ERCOT market. TIEC commented that all ERCOT market participants are responsible for the costs of any necessary equipment required to participate in the market and utilities should not subsidize equipment for loads through their programs. They believed that such a program would give those loads a competitive advantage over current market participants, which is discriminatory and violates PURA §39.001(c). They stated that utility load management programs that receive ratepayer-funded incentive payments must remain separate from the ERCOT markets, including any program in which a utility installs equipment to enable participation in the ERCOT market. Similarly, EnerNOC noted that currently customers or providers bear the cost of such equipment and based on the number of companies in the market, there is no indication that there is a failure in the competitive market due to the cost of this equipment. Further, the cost of the equipment should be a cost of doing business for the customer or provider and not reduce the already limited funds available through the energy efficiency programs. In replies, EnerNOC stated that while it appreciates the difficulties mentioned by ERCOT associated with tapping the region's potential demand response capabilities, significant competition among companies seeking to aggregate commercial load and provide demand response services shows that there does not appear to be a significant need for incentives for equipment to enable participation in the market. If incentives are made available, it recommends that the commission limit such incentives to residential customers.

TX ROSE and TLSC also stated its belief that the ERCOT and utility programs should be separate; utility incentives should not be used to subsidize participation in the ERCOT market, and any savings should not be counted towards to utility's goal. They commented that the commission should require instead for all customers to be financially compensated for interruption of their load, rather than allow the incentive to be kept by the provider to help cover the cost of load control equipment. REP Coalition did not support allowing utilities to purchase equipment or offer incentives relating to such load-enabling equipment for the purpose of enabling participating in the ERCOT market, particularly if the utility is allowed to own the equipment. It stated that any legacy utility load management program should continue to allow the energy efficiency service provider to determine how to use the incentive payment, which may include purchasing equipment to be owned by the customer or provider. OPUC stated that the utilities should not offer incentives for load curtailment equipment, nor should savings from such equipment be counted towards their goals.

C*ommission response*

The commission would like to clarify that utilities currently have the ability to offer demand response programs that provide incentives to customers for the installation of equipment to facilitate their participation in the utilities' programs. For example, CenterPoint is running a REP standard offer pilot program that provides incentives towards the costs of installing direct load control equipment, smart thermostats, and in-home devices. The savings claimed from demand response resulting from the CenterPoint program are allowed in accordance with this section. After the customer has honored the contract signed with the energy efficiency service provider, the equipment is their own and may be used by the load to further participate in a utility program. Once ERCOT allows the aggregation of loads, the customer could use their equipment to participate in the ERCOT market. The question posed by the commission along with the proposed rule instead refers to allowing energy efficiency incentives for the purchase of equipment for the direct purpose of participating in the ERCOT markets.

That said, the commission agrees with EnerNOC, OPUC, REP Coalition, TIEC, TX ROSE, and TLSC that utilities should not offer incentives for the singular purpose of allowing loads to participate in the ERCOT market. The commission appreciates EnerNOC's comments that there is already significant competition amongst companies seeking to aggregate commercial load and provide demand response services; competitive forces may encourage competitors to offer equipment to loads as an incentive for them to sign up with a particular aggregator. The commission agrees that REPs, aggregators, and loads that wish to participate in the ERCOT markets need to weigh the costs of installing any

required equipment against the expected compensation from the market and make their own economic decision.

Section 25.181; Energy Efficiency Goal

Subsection (a); Purpose

No comments.

Subsection (b); Application

No comments.

Subsection (c); Definitions

Subsection (c)(2); Baseline

TX ROSE and TLSC opined that utilities should claim and pay for only those incentives that occur as a result of their energy efficiency program and agreed in principle with the use of a baseline. They suggested that the commission replace the proposed definition for baseline with one based on standards used by the California Public Utilities Commission that states that a baseline should be established based on applicable state and/or federal efficiency standards for appliance or building energy efficiency, the efficiency of equipment being sold in the market for common replacement, or current design practices as defined by the program evaluated.

Commission response

The commission agrees with TX ROSE and TLSC that utilities should only claim and pay for incentives that occur as a result of their energy efficiency program. The commission

notes that the proposed definition of baseline is broad enough to count savings from the standard to the newly installed higher efficiency measure and to take into account early replacement programs where a consumer has a working piece of equipment or system and the energy efficiency program convinces the consumer to replace the measure early. In this case, the baseline would not be based on the standard but on the existing measure because the consumer would not have replaced it without the program. Savings would be based on the difference between the efficient measure and the existing measure until the end of the existing measure's estimated life and then reduced to the difference between the efficient measure and the standard at that time. This is standard practice for early replacement programs and the commission's definition is consistent with standard practice, including requests for new or amended deemed savings for equipment retrofits. The purpose of the baseline is discussed below in more detail in the discussion related to subsection (q)(8). Therefore, the commission declines to adopt changes suggested by TX ROSE and TLSC to the proposed definition.

Subsection (c)(6); Conservation load factor

Sierra Club suggested that the definition of conservation load factor be revised to remove the reference to the goals and simply state that the load factor is the ratio of energy savings to peak demand. It justified this request by stating that the load factor should be applied to all peak demand achieved, not just the peak demand goal.

EDF stated that the current definition of conservation load factor captures all kWh achieved by a program but only the kW goal and therefore leaves the true capacity factor of programs undetermined. It noted that utilities have historically exceeded their goals. It also suggested that the conservation load factor be tied to peak demand achieved rather than the peak demand goal. It opined that the concept of capacity factor is to measure kWh achievement relative to kW demand achievement.

Commission response

The commission notes that a utility is required to administer a portfolio of energy efficiency programs designed to achieve the minimum demand and energy savings goals, as defined in subsection (e). The conservation load factor is used to determine a utility's energy savings goal for the year. To calculate the utility's energy savings goal, a utility's demand goal (kW) is first multiplied by the number of hours in the year and then multiplied by the conservation load factor. Should a utility exceed its goal at a cost that does not exceed the cost caps, it will be awarded a performance bonus. The proposed definition correctly captures the purpose of the conservation load factor in the context of this section. The commission, therefore, declines to adopt the revisions requested by Sierra Club and EDF.

Subsection (c)(7); Deemed savings calculation

OPUC suggested that the deemed savings calculation should be an industry-wide standard rather than an agreed upon standard as proposed in the rule. It recommended that the proposed definition of deemed savings calculation be modified to reflect this change.

Commission response

In order to ensure that calculations of deemed savings are reasonable and consistent, the commission agrees with OPUC that the deemed savings calculation should be consistent with the industry-wide accepted standard and therefore adopts the modification provided to the proposed definition.

Subsection (c)(11); Eligible customers

OPUC proposed that the definition of eligible customers be revised to include all customers in all classes. It stated that the proposed definition limits the participation of industrial classes solely to load management standard offer programs in place prior to May 1, 2007. It commented that there is, however, no provision in PURA that prevents or prohibits an industrial customer from participating in any of the utilities' programs. It noted that PURA §39.905(a)(2) sets out a goal that all customers in all classes have access to energy efficiency programs; PURA §39.905(a)(3) requires utilities to provide standard offer or market transformation programs to residential and commercial customers; and PURA §39.905(a)(6) requires utilities to provide grandfathered load management programs to the industrial class. It suggested that a proper reading of PURA results in the conclusion that a utility may offer an industrial customer an energy efficiency program and the industrial customer may participate in the program.

OPUC stressed that it in order to be compliant with PURA §39.905(a)(2), it is incumbent upon utilities to provide programs for the industrial class. Load management programs are the minimum that the utilities should offer to the industrial class. It commented that legislative history surrounding the above-referenced sections leads to the conclusion that the Legislature was not limiting industrial class participation in energy efficiency programs to grandfathered load management programs but was trying to ensure that those programs would be continued amid concerns surrounding declining reserve margins.

Public Citizen and SEED Coalition agreed with all of OPUC's comments and added that the industrial class has the largest potential savings when compared to the residential and commercial class and noted a study by the Department of Energy (DOE) Oak Ridge Labs prepared for ERCOT that proves this point. Public Citizen and SEED Coalition proposed that the commission add a self-directed or other suitable program for the industrial class.

TIEC disagreed with OPUC's claim that there is no exclusion in PURA from the energy efficiency mandate for industrial customers, as detailed in their comments pertaining to the definition for industrial customer (subsection (c)(30)).

Commission response

In House Bill (HB) 3693 of the 80th Legislature, Regular Session in 2007, the Legislature added language to PURA §39.905(a) and (b) to clarify that the energy efficiency goals and programs under the statute were to be oriented to residential and commercial customers, and that it is these customers receiving services under the programs that are to bear the cost of the programs. PURA §39.905(a)(3) now specifically limits a utility's energy efficiency programs to residential and commercial customers. As the commission stated at page 22 of the order adopting a new version of this rule in Project Number 33487, "The clear import of the amendments in HB 3693 was to curtail industrial programs, except to

the extent that they are grandfathered under PURA §39.905(a)(6)." In SB 1125 of the 82nd Legislature, Regular Session, in 2011, the Legislature further emphasized this principle of cost responsibility by amending PURA §39.905(b)(4) to clarify that the performance bonus should also be borne by the customer classes receiving services. The commission believes that these policy decisions have already been made by the Legislature, and it is now the function of the commission to effectuate those decisions.

The commission declines to adopt OPUC's recommended changes. As discussed above, the commission stated in Project Number 33487, and maintains, that the purpose of the amendments in HB 3693 was to curtail industrial programs, except to the extent such programs were grandfathered under PURA §39.905(a)(6). It would be contrary to the Legislative intent to broaden the definition of "eligible customers" to increase the ability of industrial customers to participate in, and to increase the requirement that such customers pay for, the energy efficiency programs established pursuant to the statute and rule.

Subsection (c)(12); Energy efficiency

TX CHPI proposed modifying the language in the definition of energy efficiency in order to include actions taken by a customer that lowers the demand of energy delivered to the customer.

Commission response

The commission appreciates the comments of TX CHPI and recognizes the importance of actions taken by a customer to lower the demand for energy delivered to the customer. Because the definition of energy efficiency as proposed does not exclude actions taken by a

customer to lower the demand for energy delivered to a customer, but rather is broad enough to incorporate it, the commission declines to adopt the requested amendment.

Subsection (c)(13); Energy Efficiency Cost Recovery Factor (EECRF)

TNMP suggested that the definition of Energy Efficiency Cost Recovery Factor (EECRF) be revised to include all the expenditures listed in subsection (f)(2), including the requirement that it must satisfy the goal of PURA §39.905.

Commission response

In response to TNMP's suggestions, the commission notes that listing the expenditures included in subsection (f)(2) (now subsection (f)(1)) is not necessary since compliance with subsection (f) is referenced in the definition. However, the commission appreciates the suggestion to expand the definition to include the fact that the EECRF must satisfy the goal of PURA §39.905 and therefore amends adopted subsection (c)(13) accordingly.

Subsection (c)(14); Energy efficiency measures

TX CHPI recommended changing the definition of energy efficiency measures to clarify that the measures are implemented on the customer's side of the meter and result in a reduction in consumption or peak demand measured on the customer's side of the meter. They suggested expanding the list of measures to include all varieties of active and passive demand side management, distributed renewable energy systems, and combined heat and power systems. They suggested that energy efficiency measures should not include any approach that simply lowers the level of service to customers.

TAS and Natgun requested that the proposed rule be amended to allow chilling plants at generation facilities to be eligible as potential participants in the energy efficiency program.

Commission response

The commission agrees in part with TX CHPI. In response to the first part of TX CHPI's suggestion, the commission agrees to clarify the proposed definition to state that energy efficiency measures are implemented on the customer's side of the meter. However, since measuring reduction in consumption or peak demand at the customer's site is part of a utility's verification process, the commission declines to make the suggested amendments to the definition regarding the measurement of consumption or peak demand at the customer's meter. Furthermore, the commission notes that the proposed definition is broad enough to include all varieties of active and passive demand-side management, distributed renewable energy systems, and combined heat and power systems. Rather than add a list that might exclude a measure, the commission maintains the inclusive definition. With regard to TX CHPI's recommendation to include a statement in the proposed definition that energy efficiency measures do not include any approach that simply lowers the level of service to a customer, the commission points out that the definition of energy efficiency already precludes this possibility. Therefore, the commission declines TX CHPI's further amendments to the proposed definition.

The commission declines to adopt the amendment requested by TAS and Natgun. As discussed previously, PURA §39.905(a)(3) specifically limits a utility's energy efficiency

programs to residential and commercial customers. A generation facility is not a residential or commercial customer as those terms are used in PURA §39.905 and is therefore not eligible for energy efficiency programs under PURA §39.905. Furthermore, providing an energy efficiency program that is available only to generation facilities with chilling units would raise concerns under PURA §39.905(a)(1), which requires that the energy efficiency programs be administered in a market-neutral manner.

Subsection (c)(17); Energy efficiency service provider

TX ROSE and TLSC initially suggested that the commission revise the proposed definition of energy efficiency service provider to acknowledge that an energy efficiency service provider can be either a person or entity that installs energy efficiency measures or performs other energy efficiency services under this section. They also suggested striking the last sentence of the definition which states that an energy efficiency provider may be a governmental entity.

Cities opposed TX ROSE and TLSC's request to strike the last sentence in the proposed definition, stating that the energy efficiency of governmental facilities is in the public interest. They commented that governmental entities should be able to apply energy efficiency services to governmental facilities in the most cost efficient manner, which may include acting as the energy efficiency service provider.

TX ROSE and TLSC responded by clarifying that their intent was to ensure that non-profit entities could also qualify as energy service providers and therefore modified their request and suggested that the last sentence of the definition instead be expanded by adding that an energy service provider may be a governmental entity or a non-profit corporation.

Commission response

The commission agrees that an energy efficiency service provider may be a governmental entity or a non-profit organization and therefore agrees that it is appropriate to amend the definition of energy efficiency service provider, as requested by TX ROSE and TLSC. The commission has also amended the definition to clarify that the term is not intended to include an electric utility.

The commission appreciates Cities' comments and agrees that a governmental entity should be able to provide energy efficiency services in a cost-effective manner and that an energy efficiency service provider may be a governmental entity.

Subsection (c)(19); Estimated useful life (EUL)

For the definition of estimated useful life (EUL), TX ROSE and TLSC recommended that the statement that the EUL is the number of years until 50% of installed measures are still operable and providing savings be replaced with language that states the EUL is an estimate of the median number of years that the measures installed under a program are still in place and operable.

Commission response

The proposed definition of estimated useful life (EUL) was included in the final order of Docket Number 36779, *Joint Petition of Electric Utility Marketing Managers of Texas to*

Revise Existing Estimated Useful Life Values**, at Finding of Fact 33, which states: "EUL is commonly defined as 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 commission declines TX ROSE and TLSC's requested change, because they provided no justification for not using the common definition of EUL as stated in Docket Number 36779.**

Subsection (c)(30); Industrial customer

TIEC supported the commission's proposed definition of industrial customer and stated that it is compliant with PURA §39.905(a)(3), which they stated provides that only residential and commercial customers are eligible to receive services through utility sponsored programs. They commented that the commission's initial approach of excluding transmission-level customers did not give full effect to PURA §39.905 since industrial customers that were not in a transmission-level rate class had to pay energy efficiency costs despite their statutory exclusion.

Cities, EDF, EnerNOC, and CLEAResult suggested that the proposed definition of industrial customer be deleted. The Joint Utilities, with the exception of CenterPoint Energy, also opposed the proposed definition of industrial customer. Pepco remarked that they felt the proposed language for industrial customer is too broad. OPUC, Sierra Club, Public Citizen, and SEED Coalition opposed the proposed definition of industrial customer and suggested that the definition be narrowed to only include a for-profit entity engaged in an industrial process taking electric service at a transmission voltage.

With regard to SB 1125, EnerNOC commented that there is nothing in SB 1125 or any other enacted statute that requires the commission to adopt the proposed broader definition of industrial customer. Similarly, EDF opined that there is no indication that it was ever the legislative intent of SB 1125 that commercial operations connected to certain industrial processes be exempt from energy efficiency programs. EnerNOC noted that TIEC argued that a revised definition is necessary to give full effect to PURA §39.905. EnerNOC commented that the Legislature could have adopted clarifying amendments to PURA §39.905 as part of its consideration of SB 1125, but it did not.

Although CLEAResult acknowledged that the statute exempts industrial customers taking service at 69kV and above from participation in energy efficiency programs, it, Joint Utilities, and Sierra Club stated that there is no statutory direction to extend an "opt-out" provision for customers served at distribution voltage. The Joint Utilities added that, to the contrary, the Legislature's goal of ensuring that all customers in all classes have a choice of and access to energy efficiency alternatives suggest that an opt-out should not be permitted. They noted that where the Legislature intended to exclude a group of customers from an analogous requirement, it has explicitly done so as evidenced by PURA §39.904(m-l), *Goal for Renewable Energy*.

Cities noted that PURA does not exempt individual customers from paying for energy efficiency programs and contended that the definition in the proposed rule contradicts PURA §39.905(b)(4) by exempting customers from paying for energy efficiency programs in whatever customer class they are grouped. They further noted that any exemption extends only to a customer class that does not receive energy efficiency services from utility programs. They stated that TIEC and Walmart err in their interpretation of PURA.

TIEC commented that Cities mistakenly conflates customer class with rate class by their contention that industrial customers cannot be exempt from energy efficiency mandates. They noted that customer class designations are based on how a customer uses the electricity it consumes. They purported that a customer engaging in an industrial process is a member of the industrial class and exempt from the energy efficiency mandates regardless of the rate class it is assigned to by a utility.

Both Cities and OPUC opined that the proposed rule violates PURA §36.003. Cities stated that the definition would establish discriminatory rates within a customer class by exempting certain customers from paying EECRF charges while other members of the class would not be exempt. OPUC stated that the proposed rule violates PURA §36.003 by discriminating within a customer class by allowing certain customers to opt-out of the energy efficiency program based on the type of business taking place at the premise.

TIEC disagreed with OPUC and asserted that the opt-out for distribution-level industrial customers does not violate PURA §36.003 because the Legislature applied the exemption from energy efficiency mandates to the entire industrial class.

Cities, Public Citizen, and SEED Coalition objected to the fact that the proposed definition of industrial customer is tied to those for-profit entities that are tax exempt under Texas Tax Code

§151.317. Cities commented that under this statutory provision, entities may be tax exempt if they take electric service at distribution voltage for the purpose of powering equipment under Tax Code §151.318. Cities concluded that the definition of industrial customer would be difficult, if not impossible, to implement due to the legal uncertainty surrounding the interpretation of Tax Code §151.318 currently underway. Additionally, Cities, Joint Utilities, and EnerNOC recalled that the commission previously declined TIEC's proposal to define an industrial customer using Tax Code §151.317 in their final order in Project Number 33487.

TIEC refuted Cities comments and stated that the legal uncertainty surrounding Tax Code §151.318, which has to do with sales tax treatment of equipment used in oil and gas recovery, has no impact on the eligibility of industrial customers for the electricity tax exemption under §151.317.

EnerNOC warned that the proposed definition could result in a potentially large group of non-residential customers being classified as industrial customers and noted that the proposed rule does not provide a definition of what constitutes an "industrial process" for purposes of the definition. It remarked that the broad definition of industrial customer is inconsistent with the commission's other definitions in §25.311 and §25.431. Pepco warned that Tax Code §151.317 appears to encompass makers of any product regardless of size, market served, or strategic importance. Joint Utilities remarked that they were unclear how electric accounts, which have no manufacturing or industrial activities but are affiliated with an industrial account, should be handled.

TIEC responded to EnerNOC's comments that the definition of industrial customer is too broad by proposing additional language to the rule that refines it by clarifying that an industrial customer does not purchase electricity under a utility's residential rate schedule but rather purchases electricity under a utility's rate schedule that is based on metered demand.

Cities claimed that the definition as proposed would effectively double the amount of the EECRF charge for commercial customers who could not opt-out of the energy efficiency program since the applicable size of the commercial class would be cut in half. CLEAResult, Public Citizen, and SEED Coalition opined that extension of the opt-out provision to certain distribution customers unfairly burdens other customers who cannot opt-out.

Similarly, Joint Utilities commented that energy efficiency goals are based on a five- year average of load growth measured at the utilities annual system peak and have been historically calculated using load figures that included customers who would be eligible to opt-out. Joint Utilities and Cities warned that without adequate adjustment to these goals, costs would shift to remaining customers resulting in an increase in EECRF charges and more frequent requests for good cause exceptions to EECRF caps and demand and energy goals. Cities noted that costs could rise for the residential class as well if the utility is forced to compensate for the decrease of participants in the program by including additional expensive residential programs to meet its goals. Sierra Club opined that allowing entities to opt-out will decrease funds available for energy efficiency programs and decrease the opportunities for utilities to achieve their goals.

TIEC disagreed with Cities' claim that allowing industrial customers to opt-out would reduce the applicable size of the commercial class in half and noted that Cities' provided no support for this contention. They explained that proposed subsection (w) addresses these concerns by providing that the utility's demand goal be adjusted to remove load that is lost as a result of an opt-out. Joint Utilities acknowledged that there is considerable confusion surrounding how many customers could eventually opt-out of the program. They expect, however, that the policy will diminish the opportunities available to utilities to achieve energy efficiency savings and is, therefore, at odds with an objective to maximize the potential for energy efficiency savings across the state.

EDF and Joint Utilities opined that allowing certain customers to opt-out of the program shifts the cost of producing net benefits to other customers. EDF, Joint Utilities, and CLEAResult agreed that the net benefits achieved through the utility programs benefits all customers. Joint Utilities noted that many of the facilities that would be eligible to opt-out have historically participated in energy efficiency programs and if allowed to leave would enjoy the benefit of the incentive received without contributing to the on-going costs of the program. Pepco added that since it appears that exemption could be requested at any time, this would allow a company to receive a utility incentive for its own retrofit one year and then apply for an exemption from the program the next year. EnerNOC remarked that customers should not be given the opportunity to opt-out of a program from which they also benefit from and doing so would be detrimental to all customers that depend on receiving reliable electric service. Pepco opined that the exemption should require a showing from the customer that there is a competitive impact outside the U.S. market, minimum scale, and no history of receiving benefits from an energy efficiency program.

Furthermore, EnerNOC noted that in its final order in Project Number 37623, *Rulemaking Proceeding to Amend Energy Efficiency Rules,* the commission previously rejected a proposal that would have allowed certain customers to opt-out of energy efficiency programs.

Commission response

As explained by the commission in response to comments related to subsection (c)(11), PURA §39.905(a)(3) now specifically limits a utility's energy efficiency programs to residential and commercial customers. Although some rate classes may include only a particular type of customer, a particular rate class may include both industrial and commercial customers. The primary impact of the changes currently proposed by the commission under this project is to include a means of identifying industrial customers that are in rate classes that also include commercial customers. The commission proposes to now exclude those industrial customers taking service at distribution voltage, if certain requirements are met and the customers actively opt-out.

Cities and OPUC also argue that the proposed rule violates PURA §36.003 by establishing discriminatory rates. PURA §36.003 prohibits unreasonably discriminatory rates. Not applying the EECRF to industrial customers in a particular class is not unreasonably discriminatory, because this approach carries out PURA §39.905 and because industrial customers that are not subject to the EECRF are not eligible for the energy efficiency programs that the EECRF funds.

Several parties noted the difficulty of interpreting eligibility for exemption under the provisions of the Tax Code. The commission believes that the current proposal is much more effective in this respect than similar provisions proposed by TIEC during Project Number 33487. Under the current definition of eligible customer adopted in subsection (c)(30) and the identification notice provision in subsection (w), it is now the industrial customer's burden to determine exemption eligibility and submit relevant opt-out information to the utility, including a description of its industrial processes and a copy of the customer's Texas Sales and Use Tax Exemption Certificate. The commission believes that placing the burden on industrial customers in this manner will also have the effect of reducing the total number of industrial customers that opt-out and minimize any resulting cost-shifting to the remaining customers. Further, an industrial customer will not be able to participate in the energy efficiency programs for a three-year period once a utility accepts the identification notice.

During the comment period for Project Number 33487, TIEC recommended amendments to this rule to implement HB 3693 using Tax Code exemptions to define industrial customers and exempt such customers from non-applicable provisions of the rule. They proposed exemptions found in Tax Code §151.317, which exempts gas and electricity from sales tax when the gas and electricity is sold for use in certain specified industrial processes. However, the commission did not adopt TIEC's recommendations. The commission instead determined that relying on voltage level provided a simpler means of identifying industrial customers. Limiting the definition of "commercial customer" to non-residential

customers taking service at distribution voltage therefore represented a simple but rough cut at the issue by excluding those entities taking service at transmission voltage.

In this project, TIEC has again proposed a finer cut at the issue that attempts to accomplish the objective of excluding all industrial customers while minimizing the practical problems associated with identifying industrial customers. The commission believes that TIEC's current recommendation can accomplish the intent of the statute without prohibitive administrative costs. The commission therefore adopts the amendments as proposed by TIEC, and will continue to monitor the implementation of this change to the rule to ensure that associated administrative costs do not outweigh the benefits of the exclusion.

The adopted amendments include the following actions: (1) retaining the definition of "commercial customer" in subsection (c)(4) to include non-residential customers taking service at distribution voltage; (2) retaining the definition of "eligible customers" in subsection (c)(11) to include residential and commercial customers, and industrial customers only to the extent they are grandfathered under certain load management program; (3) defining "industrial customer" in subsection (c)(30) as a for-profit entity engaged in an industrial process taking service at transmission voltage, or taking service at distribution voltage if it qualifies for a tax exemption under Tax Code §151.317 and has submitted an identification notice under subsection (w); (4) defining "rate class" in subsection (c)(49) to exclude non-eligible customers; (5) limiting the allocation of the

performance bonus in subsection (h)(6) to eligible customers; and (6) providing a process for industrial customers to submit the identification notice in subsection (w).

Subsection (c)(33); International performance measurement and verification protocol (IPMVP)

In the definition of international performance measurement and verification protocol, Sierra Club suggested removing the word "four" before M&V to reflect the fact that more than four approaches may be developed in the future.

Commission response

The commission acknowledges that more than four M&V approaches may be developed by the Efficiency Valuation Organization in the future and therefore agrees to remove the word four before M&V in the definition of International Performance Measurement and Verification Protocol (IPMVP), as requested by Sierra Club.

Subsection (c)(34); Lifetime energy (demand) savings

TX ROSE and TLSC suggested narrowing the definition of lifetime energy (demand) savings by replacing energy (demand) savings with net energy (demand) savings, the term lifetime with effective useful life, and deleting the last sentence that states the lifetime energy (demand) savings can be gross or net savings.

Commission response

The commission appreciates TX ROSE and TLSC's comments. The commission clarifies that the definition for lifetime energy (demand) savings was left intentionally broad to

allow the EM&V contractor flexibility when evaluating specific energy efficiency projects or programs. Therefore, the commission declines to adopt TX ROSE and TLSC's requested revisions to the definition.

Subsection (c)(39); Net savings

In the definition of net savings, TX ROSE and TLSC recommended that the definition of net savings be revised to require that the total change in load that is attributable to an energy efficiency program be adjusted to account for the effects of free riders, energy efficiency standards, changes in the level of energy service, and other causes of changes in energy consumption or demand by replacing the language "may consider" with "shall be adjusted to account for." Similarly, Cities suggested the commission revise the definition of net savings to give it a clearer distinction from the related definition of gross savings. In addition, Sierra Club suggested adding the words "spillover effect" to the list of issues that may be considered when determining the net savings.

Commission response

In response to TX ROSE and TLSC's suggestion, the commission has clarified that the definition so that net savings shall include consideration of appropriate factors. The commission agrees, as suggested by Sierra Club, that it is appropriate to add "spillover effect" to the list of factors that may be considered when determining net savings. The commission also agrees with Cities' suggestion that the definition be given a clearer distinction from the definition of gross savings.

Subsection (c)(45); Peak demand reduction

CLEAResult supported the definition of peak demand reduction stating that it incorporates winter peak, as intended in SB 1125.

TNMP suggested that since the definition of peak demand reduction was revised to include winter peak periods and the definition of peak period was revised to include times during the winter months of December, January, and February, the commission should affirm that utilities can use any programs, summer or winter peak demand programs, to achieve demand and energy savings that meet the utilities' total demand and energy savings goal. It opined that this is the intent of SB 1125 and the rule should be implemented to encourage the development of new energy efficiency programs that include winter programs.

Commission response

The commission agrees with CLEAResult that the definition of peak demand incorporates winter peak, as intended by SB 1125. The commission agrees with TNMP and affirms that a utility may use winter peak demand programs as well summer peak demand programs to achieve demand and energy savings towards its total demand and energy savings goals. Therefore, a utility may offer a program or measure that reduces either winter or summer demand and count that reduction towards its demand goal.

Subsection (c)(46); Peak period

In the definition of peak period, Sierra Club suggested extending the summer peak period by one hour to eight p.m. to better reflect actual peak use in the summer period.

Commission response

The commission notes that the peak period reflects the time of highest peak demand on the utility's system. According to ERCOT, the highest use period during the hottest days of summer occurs between the hours of 3 and 7 p.m. The commission, therefore, believes that the definition as proposed is appropriate and declines to adopt the suggested amendment.

Subsection (c)(48); Projected savings

Cities suggested that the definition of projected savings be revised to remove any reference to gross savings. They stated that net savings give a more accurate picture of projected savings since factors unrelated to energy efficiency programs would be removed. In addition, they stated that ratepayers should not be required to pay a performance bonus attributable to demand savings achieved from free riders or pay for programs that appear to be effective only due to the use of a gross measure.

Commission response

The commission notes that a utility's performance bonus is not based on projected savings, but rather on exceeding verified demand and energy savings goals. Projected savings are typically used by the utility for program and/or portfolio planning purposes, while the performance bonus is based on the utility's actual energy efficiency achievements for the previous program year. Prior to awarding a performance bonus, the utility's budget is trued up and reported savings are verified. Because projected savings are used for

planning purposes rather than in the true-up process, the commission declines to revise the proposed definition to remove any reference to gross savings.

However, the addition of subsection (q), Evaluation, measurement, and verification (EM&V), necessitates several minor clarifications in this subsection. The commission clarifies the first sentence to note that projected savings are values reported by an electric utility prior to the time the energy efficiency activities are implemented. The second sentence is clarified to state that projected savings are typically estimates of savings prepared for program and/or portfolio design or planning purposes.

Subsection (c)(49); Rate class

Cities approved of the proposed definition of rate class because defining rate class based on classes approved in the utility's most recent base-rate proceeding ensures uniformity across transmission and distribution utility (TDU) service territories. TNMP also supported the proposed definition of rate class but noted that some portions of the rule refer to rate class and some to customer class. Since no definitions for customer class or residential customer are included in the proposed rule, TNMP proposed adding definitions of those terms. Cities noted that TNMP does not propose removing the provision that rate classes be used to allocate EECRF, they opposed the two proposed definitions made by TNMP, arguing that they add too much confusion given the rule's mandate that costs should be allocated by rate classes, and recommended that the commission reject the additional definitions.

Commission response

The commission declines to include definitions of customer class and residential class in the rule, and notes that customer class and residential customer are defined in §25.5. Although the terms "rate class" and "customer class" have had different meanings in different contexts in the industry, the commission's use of rate class versus customer class in this rule is intentional. In the rule as adopted, "rate class" is defined because it has a specific meaning and is used for cost recovery purposes in subsections (f) and (h). In contrast, "customer class" is used in the rule for program administration purposes and has a more fluid meaning.

Subsection (c)(57); Technical reference manual (TRM)

Opower suggested that the definition be revised to include a provision for protocols for the ex-post verification of energy efficiency program savings. It opined that this will allow the commission to more closely follow the efforts of other states in developing a TRM and make clear that protocols are critical tools for measurement that will be included in the TRM.

TX ROSE and TLSC commented that the definition of TRM be revised to state the TRM is a document compiled by an EM&V contractor.

Commission response

The commission appreciates the comments of Opower and acknowledges that protocols can be critical tools for measurement. The commission agrees to make a broad inclusion for protocols in the TRM, rather than the requested provision for "protocols for the ex-post

verification of energy efficiency program savings," in order to recognize that other types of protocols may also be used.

The development of a statewide TRM shall be accomplished by the commission's EM&V contractor. Therefore, the commission agrees to amend the proposed definition to acknowledge that the TRM is a document compiled by the commission's EM&V contractor.

Subsection (c)(58); Verification

TX ROSE and TLSC requested that the definition of verification be revised to add that it is an independent assessment conducted by the EM&V contractor.

Commission response

The commission notes that in addition to the activities of the EM&V contractor, verification may also be conducted by a utility or third party. Therefore, the commission declines to adopt the proposed definition as requested by TX ROSE and TLSC.

Subsection (d); Cost-effectiveness standard

Joint Utilities requested that the commission modify subsection (d) to state that while a utility's overall program portfolio must be cost-effective, individual programs do not need to comply with the cost-effectiveness standard. They stated that there is no need for all individual programs to be cost-effective and that a requirement that all programs be cost-effective will discourage the experimentation required to develop long-term, overall successful energy efficiency programs.

Commission response

The commission concludes that all programs, with the exception of the low-income program, must meet the cost-effectiveness standard in subsection (d). To assure best use of ratepayer funds, a program that does not meet the cost-effectiveness standard in the rule may need to be modified to reduce program costs or increase savings, or be discontinued. The commission, however, points to subsection (k) that provides market transformation programs some flexibility in meeting the cost-effectiveness standard during their first year of implementation. This allows utilities the flexibility to experiment with programs in order to develop more successful energy efficiency programs. In addition, the low-income programs are not required to meet the cost-effectiveness standard in the rule, but must meet standards required by the Savings-to-Investment ratio (SIR) methodology. The commission, therefore, declines to amend the rule, as suggested by Joint Utilities, to exempt individual energy efficiency programs from meeting the cost-effectiveness standard in the rule.

Subsection (d)(1)

REP Coalition and OPUC objected to the exclusion of EM&V costs allocated to a utility pursuant to the proposed subsection (q)(12)(B) (now (q)(10)(B)) from the calculation of the total cost of an energy efficiency program for the purpose of assessing a program's cost-effectiveness and requested that subsection (d)(1) be revised to include these costs. They opined that EM&V costs constitute measurement and verification costs that are specified for inclusion in the program cost calculation pursuant to subsection (d)(1). They also suggested that the exclusion of

EM&V costs in the program cost calculation could result in the selective application of measurement and verification expenses under the cost-effectiveness standard in subsection (d). They opined that there is no valid reason to discriminate in the treatment of such costs, as long as the work performed by the utility, EM&V contractor, or third party legitimately constitutes measurement and verification activities. Finally, they stated that exclusion of EM&V costs from the programs cost-effectiveness calculation could increase the probability that a program would be deemed cost-effective when it is cost-effective in name only, contrary to the legislative goal in PURA §39.905(a)(3).

OPUC recommended that if the commission permits the utilities to recover rate case expenses, this cost should be listed along with other costs in the cost-effectiveness standard in subsection (d)(1). It agreed with the commission that the performance bonus be included in the cost of the program.

Joint Utilities disagreed with the REP Coalition's proposal to include EM&V costs and OPUC's suggestion to include rate case expenses in program costs when determining the cost-effectiveness of a program. Joint Utilities did not understand how these costs would be included since these would be historical costs. They stated that these costs are of a different nature than typical program costs and should not be included in the cost-effectiveness calculation.

Commission response

The commission agrees with REP coalition and OPUC that EM&V costs constitute measurement and verification costs that are specified for inclusion in the program cost

calculation pursuant to subsection (d)(1). In addition, the commission also agrees that exclusion of these costs from the program cost calculation could cause a program to appear to be cost-effective when in fact it is not. The commission does not agree with Joint Utilities that EM&V costs are historical costs that should be excluded from a program's cost calculation. The commission notes that utilities can allocate projected EM&V expenses to each program in order to determine the cost-effectiveness of a program. The commission, therefore, agrees to include EM&V costs along with other costs in the cost-effectiveness standard in subsection (d)(1).

The commission notes that because rate case expenses do not directly contribute to a reduction in demand and energy growth, these expenses are more appropriately allocated to individual rate classes rather than being allocated to specific energy efficiency programs. Therefore, the commission disagrees with OPUC that these expenses should be included in the cost-effectiveness standard in subsection (d)(1) and declines to adopt the requested change.

Subsection (d)(2)(A)

Sierra Club commented that the proposed calculation of the avoided cost of capacity is reasonable and in keeping with long-standing commitments.

Cities supported the language added to the proposed provisions for calculating the avoided cost of capacity because it references conventional combustion turbine technology as well as advanced combustion turbine technology as identified by the Energy Information Administration

(EIA) and requires that the lower of the two avoided benchmarks be utilized. They claimed this was a more accurate method to determine the avoided cost of capacity since new generation developers would be expected to select the least costly technology.

Commission response

The commission appreciates the comments of Cities and Sierra Club and agrees that the proposed calculation of the avoided cost of capacity is reasonable and provides a more accurate method to determine the avoided cost of capacity by taking into account that new generation developers may select the lowest cost technology.

Subsection (d)(3)(A)

Public Citizen, SEED Coalition, and Sierra Club disagreed with the proposed method of determining the avoided cost of energy. They stated that calculating the avoided cost of energy (for the ERCOT region) by determining the load-weighted average of the competitive load zone settlement prices for the peak periods for two years is too short of a timeframe and could cause the program to vary considerably. Sierra Club justified their statement by explaining that if the previous two years happened to experience low prices, it would be difficult for utilities to justify programs as cost effective and alternately if prices were high for the previous two years, it would be too easy to justify more costly programs. Sierra Club, Public Citizen, and SEED Coalition instead suggested that the commission base the avoided cost of energy on a five-year time period to account for yearly swings in prices. They opined that a five-year weighted average would provide a more consistent calculation for utilities to base their program on as well as additional certainty in program design.

Similarly, CLEAResult opined that the proposed calculation of the avoided cost of energy will introduce additional uncertainty for energy efficiency and demand side management planning. It stated that programs offered on a multi-year basis may be subject to an annual cost-effectiveness calculation that is not produced by ERCOT until November 1st of each year, which may cause a timing issue for programs expected to be launched the following year. It recommended that the cost figure be published by October 1st of each year, and that utilities retain the option to use the avoided cost figure in existence at the time of their approved EECRFs.

EDF proposed that utilities be allowed an adjustment mechanism to the avoided cost of energy that takes into account future energy prices. It also showed concern with using the previous two years of energy prices to determine the cost-effectiveness of an energy efficiency program. It opined that the benefits of energy efficiency programs are based on savings gained versus the price of energy in the future and that using the previous two years energy prices with historically low natural gas prices could undercut the ability of utilities to offer cost-effective programs. Sierra Club recommended adding up to 10% to the avoided costs if it is anticipated that they will significantly increase in the coming year.

Public Citizen and SEED Coalition stated that since consumers are paying a retail rate, the commission should consider using an average based on the average retail cost. They opined that doing so would provide a direct comparison for determining customer impact and savings. Sierra Club also suggested that the price be based instead on an average ERCOT region retail rate to recognize the fact that energy is saved not only at the peak and that residential and commercial customers generally pay a retail rate.

Cities recommended that the commission reject comments made by Public Citizen, SEED Coalition, and Sierra Club that suggest that the commission use retail rates to determine the avoided cost of energy. Cities stated that using retail rates would result in an inaccurate calculation of the avoided cost of energy, which is determined by the actual energy (wholesale) price. Cities explained that the retail price includes transmission and distribution charges along with profit and/or billing cost incurred by the retail electric provider (REP). Using retail rates would result in bill savings, a different concept than avoided costs which is the accurate method for determining the benefits of an energy efficiency program. Cities recalled that in Project Number 33487, the commission rejected the use of transmission and distribution costs in avoided costs. They contended that the commission recognized that the primary economic benefit of energy efficiency programs is caused by reducing the demand for generation services, which appropriately includes incremental capacity and energy costs. Furthermore, they explained that using retail rates would include costs that are not part of the energy efficiency program. This, in turn, would artificially inflate program benefits and erroneously increase a utility's performance bonus.

Commission response

The commission amended the avoided cost of energy calculations in the proposed rule to take into account the transition to a nodal market in the ERCOT region. The avoided cost of energy shall now be calculated by determining the load-zone weighted average of the

competitive load zone settlement point prices for the peak periods covering the two previous winter and summer peaks. The commission believes that this method will give an accurate determination of the actual wholesale cost of energy and that using two years' worth of data will account for any abnormalities such as changes in wholesale prices and weather. The commission, therefore, does not agree with Public Citizen, SEED Coalition, and Sierra Club that use of more than two years' worth of data is warranted and declines their request to base the cost of energy on a five-year time period.

With regard to CLEAResult's recommendation that the cost of energy figure be posted by October 1st of each year rather than November 1st as proposed by the commission, the commission notes that the use of load zone settlement point prices at summer and winter peaks is integral to the calculation of the cost of energy. Because the summer peak period runs through the end of September each year, it is not practical that ERCOT calculate the avoided cost of energy by October 1st. With regard to CLEAResult's suggestion that utilities retain the option to use the avoided cost figure in existence at the time of their approved EECRFs, the commission notes that the proposed rule gives the utilities time to make the needed adjustments to their energy efficiency program manuals before the new program year begins. Therefore, the commission declines to adopt CLEAResult's suggested changes.

The commission appreciates the comments of EDF that suggest that utilities should be allowed an adjustment mechanism to the avoided cost of energy that takes into account future energy prices. However, due to the numerous assumptions needed to go into a

projection of future prices as well as the variety of different price projection models that could be utilized, the commission concludes that an unacceptable amount of subjectivity would be introduced into the calculation of the avoided cost of energy, and therefore declines to make EDF's proposed amendments.

In addition, the commission declines Sierra Club's request to add up to 10% to prices if it is anticipated that they will significantly increase in the coming year because, like EDF's proposal, such an addition would be too subjective.

The commission agrees with Cities and declines the request made by Public Citizen, SEED Coalition, and Sierra Club to use a cost based on the average retail rate. The commission notes that using the avoided cost of energy is appropriate because the primary economic benefit of energy efficiency programs is the reduction in demand for generation services, which include incremental capacity and energy costs. The avoided cost materializes in the wholesale generation market and is based on the sum of incremental capacity cost and wholesale energy prices. Using retail rates rather than wholesale energy prices would therefore not reflect the intent of the program to reduce demand for generation services. Retail rates include additional utility and service provider costs that are not avoided as a result of energy efficiency programs. As pointed out by Cities, basing avoided costs on retail rates would inflate program benefits and erroneously increase a utility's program bonus.

Subsection (e); Annual energy efficiency goals

Pepco expressed concern that language allowing crediting of behavioral change toward the savings goals is too sweeping and broad. It recommended language that requires that the behavioral change be the result of some enabling investment in on-premise energy monitoring or energy management system capacity. At a minimum, it suggested that savings credited to a utility for behavioral changes be limited to no more than 10% of the utility's program goal.

Opower disagreed with Pepco's comments that questioned whether a call for conservation through a behavioral program is creditable and their request for a cap on the amount of behavioral energy efficiency that can be included in a utility's portfolio. It noted that although caution is understandable, measurable and verifiable savings have been attributed to behavioral programs at scale in several states. It also noted that the statute requires that utilities be allowed to implement behavioral energy efficiency programs.

Likewise, the Joint Utilities argued that PURA §39.905(d)(16) does not require savings associated with behavioral programs to be tied to "physical improvements" or that the programs be limited to 10% of the utility's goal, as Pepco asserted.

Commission response

Pepco expressed concern that language that allows crediting of behavioral change towards the savings goals is too broad and they recommended that the language be amended to require the behavioral change to be the result of an actual investment being made. In response, the commission points out that behavioral programs differ from most energy

efficiency programs, which require that an investment be made in order to determine savings. Behavioral programs are geared towards educating and motivating customers in such a way that they modify when and how much energy they consume. These programs are implemented over time through a series of interactions with customers to reinforce and encourage energy-saving behavior. The commission notes that although a recommendation may be made to replace or install energy efficient devices, the focus of the program is to encourage long-lasting energy saving behavior that may or may not involve installation of a particular energy efficiency measure. For this reason, the commission does not agree with Pepco that the proposed language be amended to require that behavioral change credited to a utility's savings goals be the result of some enabling investment in on-premises energy monitoring or energy management system capacity.

The commission also disagrees with Pepco's recommendation that a limit be placed on behavioral programs. The commission notes that SB 1125, which instructed the commission to allow utilities to implement "energy use programs with measurable and verifiable results that reduce energy consumption through behavioral changes that lead to efficient use patterns and practices," did not call for a limit on these programs. The commission, therefore, declines to adopt Pepco's suggested change.

Subsection (e)(1)

TX CHPI recommended adding language that would require a utility to administer a portfolio of energy efficiency programs in a market-neutral, non-discriminatory manner.

Commission response

The commission notes that subsection (a)(1) requires that utilities administer energy efficiency incentive programs in a market-neutral, non-discriminatory manner. Because the language recommended by TX CHPI already exists in the rule, the commission determines that no further action is necessary.

Subsection (e)(1)(D)

OPUC agreed that language required by SB 1125 to shift the metric of energy efficiency goals from growth in demand to peak demand savings better reflects a valuable purpose for energy efficiency programs, to reduce the need for peaking generation deployment.

Commission response

The commission appreciates OPUC's comment and agrees that the demand savings goal shift to a percentage of the utility's summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year appropriately reflects the intent of SB 1125.

Subsection (e)(1)(E)

OPUC commented that if the commission permits certain customers to opt-out of the commercial class, then goals should be revised to take into account actual participation so that participants do not have a larger load to carry.

Sierra Club requested that the portion of subsection (e)(1)(E) that refers to subsection (w) be deleted as a result of their request to delete subsection (w).

Commission response

The commission makes no change in response to OPUC's comment, because subsection (w) allows a utility to revise its demand reduction goal to remove any load that is lost should an industrial customer taking service at a distribution voltage submit an identification notice that allows it to opt-out of participation in a utility's energy efficiency program.

Further, the commission declines to delete subsection (w) for the reasons specified in subsections (c)(11), (c)(30), and (w), and therefore rejects Sierra Club's request to delete subsection (e)(1)(E).

Subsection (e)(2)

OPUC, Cities, and Sierra Club stated that if a utility receives a good cause exception for any reason under subsection (e)(2), then the utility should not be eligible for a performance bonus under subsection (h) of this section. OPUC and Cities opined that a performance bonus is to promote exceptional achievement in administering energy efficiency programs and should not be given to utilities that receive exceptions to cost caps or goals. They suggested that subsection (e)(2) be modified to reflect this goal.

TX ROSE and TLSC recommended, and OPUC agreed, that clarification needs to be provided for establishing what constitutes a good cause exception to the minimum standards for goals and cost caps proposed in the rule and suggested the commission replace the proposed rule language for subsection (e)(2) with language that requires a utility to show that it cannot reasonably meet the established goals and demonstrate that its load growth, system load factor, or other exceptional factors significantly hinder the utility's ability to meet these goals. In addition, TX ROSE and TLSC requested that a utility, including a utility with self-delivered programs, be required to provide the commission with exceptional factors that prevent the utility's expenditures from remaining under cost or rate caps.

Joint Utilities are opposed to the proposal by OPUC, Cities, and Sierra Club that states that if a utility receives a good cause exception they should not be eligible for a performance bonus. Joint Utilities stated that good cause exceptions are generally granted by the commission because circumstances outside the utility's control prevent them from achieving the goal. They noted that a study commissioned by the commission in 2008, *Assessment of the Feasible and Achievable Levels of Electricity Savings from Investor Owned Utilities in Texas: 2009-2018,* found that the goals that could be realistically met by the state's utilities varied greatly depending on climate, customer mix, housing stock, and dominant type of air conditioning. They stated that to deprive a utility from the opportunity to earn a bonus under these conditions removes the incentive to implement successful energy efficiency programs and was not the Legislature's intent when adopting PURA §39.905. They opined that the directive of PURA §39.905(b)(2) was that an incentive be given to a utility that exceeds their energy efficiency goals. Finally, they stated that the best time to make a determination of whether a utility deserves a bonus is at the time the good cause exception is requested or in the EECRF proceeding where the bonus is requested.

Commission response

The commission does not agree with OPUC, Cities, and Sierra Club that if a utility receives a good-cause exception under subsection (e)(2), it should not be eligible to receive a performance bonus under subsection (h) of this section. The commission notes that performance bonuses are awarded on a case-by-case basis for utilities that have received good-cause exceptions. The purpose of a performance bonus is to reward exceptional achievement in administering energy efficiency programs and to provide an incentive to a utility to achieve successful energy efficiency programs. However, the commission also notes, as mentioned by Joint Utilities, that a good-cause exception is generally granted by the commission when circumstances outside the utility's control prevent it from meeting the requirements of the rule. Therefore, the commission will continue to award performance bonuses on a case-by-case basis for utilities that receive good-cause exceptions, and declines to make OPUC, Cities, and Sierra Club's requested change.

Further, the commission's decision to exclude OPUC, Cities, and Sierra Club's requested limitation is consistent with the commission's final order in Docket Number 39361, *Application of AEP Texas North Company to Adjust Energy Efficiency Cost Recovery Factor and Related Relief*, in which the commission adopted the portion of the proposal for decision (PFD) that awarded a performance bonus to the utility despite its request for a good-cause exception to its 2010 goal calculation pursuant to subsection (e)(3)(C), which allows a utility to request an alternative method for calculating its demand goal. *See* Docket Number 39361, Order (Dec. 15, 2011) at Finding of Fact 38. In that docket, the

administrative law judge (ALJ) concluded that "[b]ecause TNC's performance met the reduction goals calculated using the alternative method approved by the commission and because TNC properly calculated its performance bonus in conformance with that method, the ALJ recommends that its proposed bonus be approved." ***See*** **Docket Number 39361, Proposal for Decision (Nov. 3, 2011) at 20.**

The commission does not wish to narrowly define the requirements for a utility, including a utility that offers self-delivered programs, to be granted a good-cause exception because a utility's reasons for the request may be specific to that particular utility. These reasons as well as limitations experienced by a utility will be taken into account during the commission's review of the utility's request for a good-cause exception. Therefore, the commission declines to adopt the requested amendments to subsection (e)(2).

The commission further discusses the performance bonus in relation to a good-cause exception in response to comments filed regarding subsection (h).

Subsection (e)(3)(C) and (D)

Sierra Club recommended that the commission clarify the alternative method to calculate demand growth. It suggested adding language to require that a utility experiencing negative growth either meet the previous year's demand reduction goal with an additional 50% requirement or 0.4% of peak demand, whichever is higher.

Commission response

For cases where a utility is experiencing negative growth, the commission notes that the rule states that a utility's demand goal shall not be lower than its goal for a previous year unless the commission establishes a goal pursuant to subsection (e)(2). The commission believes that no further clarification is needed regarding alternative demand goal calculations. The commission also notes that if a utility is experiencing negative growth, the additional requirement suggested by Sierra Club may not be possible for the utility to achieve. Therefore, the commission declines to adopt Sierra Club's suggested changes.

Subsection (e)(3)(E)

Joint Utilities opposed the proposed rule language that would prohibit a utility from claiming savings from energy efficiency measures from settlement orders or federal grant programs. They urged that subsection (e)(3)(E) be modified to allow a utility to claim savings from energy efficiency measures unless explicitly prohibited by a commission order or settlement agreement. They claimed that the proposed language is a disincentive for utilities to engage in settlement negotiations relating to energy efficiency programs or to seek federal grant funds to fund energy efficiency programs. They also opined that the proposed language contradicts the commission's historical encouragement of parties to seek settlement of contested issues and programs that reduce costs to end-use customers. They commented that certain regulatory settlements have been entered into with the expectation that energy efficiency savings could be counted towards a utility's goals. They remained uncertain how the proposed language would affect collaborations between utilities and federal, state, and municipal agencies receiving federal grants. They noted that savings associated with measures sponsored by federal funds and utility funds are tracked separately. They suggested that if the proposed language is an attempt to prevent consumers from taking advantage of both utility programs and federal grants for particular energy efficiency projects, it is not possible for the utilities to comply with this requirement unless they are provided data pertaining to recipients of federal grant programs.

OPUC recommended that subsection (e)(3)(E) be clarified to make it clear that energy and demand savings from settlement programs and grants are not included in either meeting a utility's goals or in the performance bonus.

Commission response

The prohibition in subsection (e)(3)(E) is similar to that in subsection (h) that "[t]he bonus calculation shall not include demand or energy savings that result from programs other than programs implemented under this section." The concept behind both prohibitions is that the energy efficiency rule should provide a cohesive scheme of goals, programs, cost recovery, and performance bonuses. To the extent possible, this scheme should be kept separate from energy efficiency activities undertaken by utilities with funding from settlements, grants, or other similar sources. Depending on the specific nature of each grant, settlement, or other source, it may be very difficult to tell how such items should be allocated or should count toward the utility's goals, bonus, or indeed toward its actual recovery of costs.

The bonus issue was decided in Docket Number 36952, *Application of CenterPoint Energy Houston Electric, LLC to Defer Energy Efficiency Cost Recovery and for Approval of an*

***Energy Efficiency Cost Recovery Factor*, in which the commission upheld an administrative law judge's decision to disallow bonus amounts requested by CenterPoint based on expenditures made pursuant to a settlement agreement. Contrary to the representations made by Joint Utilities, the commission does not find support in either the proposal for decision or the order in Docket Number 36952 for Joint Utilities' proposition that "the commission has found in the last two CenterPoint EECRF proceedings that its settlement programs were appropriately considered for purposes of meeting the statutory goals."**

The commission does not intend for this rule provision to discourage settlement or the utilities from seeking grant-funding for energy efficiency activities. The commission would encourage parties settling cases to consider this provision in crafting settlement agreements that may relate to energy efficiency programs, and to the extent that particular grant funds or activities can be appropriately incorporated within the energy efficiency scheme, the affected utility may request a good-cause exception to the rule for purposes of including the grant funds and activities.

Subsection (e)(3)(F)

TX ROSE and TLSC commented that the requirement that savings achieved through programs for hard-to-reach customers be no less than 5.0% of a utility's total demand reduction goal is insufficient because one third of the population of Texas have incomes below 200% of federal poverty guidelines. They recommended, as they have previously, that the goal be raised to 40% of the utility's total demand goal for all customers.

Joint Utilities recommend that TX ROSE and TLSC's proposal that the goal for hard-to-reach be increased should be rejected. They noted that some utilities are already at or above their EECRF cost caps for the residential class. An increase in the cost of residential programs would generate more requests for good cause exceptions unless EECRF cost caps are raised.

Commission response

The commission agrees with Joint Utilities that some utilities are already at or above the EECRF cost caps for their residential customer classes. An increase in the cost of residential programs resulting from increasing the percentage of more expensive hard-to-reach programs would generate more requests for good-cause exceptions unless EECRF cost caps are raised. In addition, the commission believes that increasing the required percentage of hard-to-reach programs could serve as a disincentive for utilities to grow programs that achieve high demand and energy savings at costs much lower than for the more costly hard-to-reach programs. Therefore, the commission declines to adopt TX ROSE and TLSC's requested amendments.

Subsection (e)(3), new subparagraph (G)

CLEAResult recommended that the commission add subsection (e)(3)(G) to clarify that utilities may claim peak savings on a per project basis towards summer or winter peak, but not both. Savings towards a utility's peak goal would be the sum of summer and winter peak reduction.

Commission response

The commission agrees with CLEAResult and adopts subsection (e)(3)(G) to clarify that a utility may claim peak savings on a per project basis towards summer or winter peak, but not both, and that savings towards a utility's peak goal is the sum of summer and winter peak reduction.

Subsection (e)(4)

Public Citizen and SEED Coalition opined that the proposed conservation load factor of 20% is set too low and suggested that utilities be required to use at least a 25% and preferably a 30% load factor that applies to the entire program and not just the minimum peak demand. They stated that this will save real energy not just peak demand and will bring overall savings to customers. They observed that as load management programs migrate over to economic programs, the utilities should find this goal easier to achieve.

Sierra Club opined that utilities should design their programs to meet a conservation load factor of 25% or 30%. It stated that the required energy savings goal only applies to the minimum peak demand and not programs once the goal is met. It suggested that the conservation load factor be applied to all energy demand reduced not just the goal in order to encourage utilities to invest in programs that reduce peak demand and lead to energy and water savings.

EDF suggested that the capacity factor be tied to peak demand achieved rather than the peak demand goal. It opined that the concept of capacity factor is to measure kWh achievement relative to kW demand achievement.

Commission response

The commission notes that a utility is required to administer a portfolio of energy efficiency programs designed to acquire at least the minimum demand and energy savings goals as defined in subsection (e). In the context of this section, the conservation load factor is used to determine a utility's energy savings goal for the year. The energy savings goal establishes the minimum energy savings a utility must acquire. Should a utility exceed its goal at a cost that does not exceed the cost caps, it will be awarded a performance bonus. The prospect of a performance bonus gives a utility the incentive to exceed its minimum goals. Further, it would be difficult to change the energy goal throughout the program year to track the utility's actual demand reduction.

The commission also notes that it previously rejected proposals to increase the conservation load factor in Project Number 37623. The commission maintains the belief that increasing the load factor would increase the cost of the programs and believes that the proposed rule balances the benefits of energy savings with the costs of the programs. The commission, therefore, declines to adopt the amendments to the proposed conservation load factor as requested by Public Citizen, SEED Coalition, Sierra Club, and EDF.

Subsection (e)(5)(C)

RECA and Joint Utilities agreed with the commission's proposed language in subsection (e)(5)(C). RECA explained that the benefit of this language is that it ensures that standard offer, market transformation, and self-delivered programs aimed at promoting early adoption, implementation, and enforcement of building codes are not categorically deemed ineligible simply because the energy codes may be mandatory by law.

OPUC commented that it was not clear whether this proposed provision would allow a utility to pay an incentive to a builder to enable the builder to comply with new building codes or whether the utilities would pay a local government to enforce a new building code. It found both scenarios objectionable. OPUC and Cities stated that builders should not be paid for complying with the law and that the utilities should not use ratepayer money to fund local government to enforce new codes. Cities opined that using ratepayer funds for these types of measures contributes to the free ridership problem. Although Cities acknowledged that the proposed language is tailored only to the degree energy codes do not achieve full compliance rates, Cities feared that it may be impossible to determine whether codes achieve full compliance. OPUC recommended that subsection (e)(5)(C) be struck in its entirety.

Joint Utilities disagreed with OPUC and asserted that subsection (e)(5)(C) should be adopted. They believed that energy savings may be achieved by encouraging compliance with building energy codes. They found it appropriate that an EM&V contractor would have the latitude to consider code enforcement when developing the TRM and when estimating savings achieved through a program.

RECA disagreed with the concerns of OPUC and Cities. It stated that it is widely known that compliance rates for mandatory energy codes fall well below 100% and when full compliance is not achieved, substantial energy and peak savings are lost. It commented that the proposed rule will allow for the development, review, and possible implementation of programs proposed by utilities. It suggested that efforts to improve compliance and enforcement of energy codes could take many forms, including the use of third-party enforcement solutions such as using home energy raters to check compliance.

RECA remarked that the proposed language in subsection (e)(5)(E) could help bridge the multi-year gap between the publication of new energy codes and statewide adoption and enforcement of these codes by promoting early adoption and jump-starting compliance. It noted that the 2009 International Energy Conservation Code (IECC) did not become effective in Texas for single-family homes until April 1, 2011 and the International Residential Code (IRC) did not become effective until January 1, 2012. It explained that during these “gap” years, hundreds of thousands of new homes are built according to an older version of the code and thus forfeit substantial energy and demand savings over the life of the homes. A study by the Energy Systems Lab at Texas A&M University found that energy savings as a result of the 2009 IECC ranged from 8.3 to 14.6%, as compared to the previous version of the code. The 2012 IECC and IRC have been available since early 2012 but Texas is only in the preliminary stages of considering the codes for adoption. Texas A&M found that the energy savings resulting from these codes range from 14 to 25% for residential construction on top of savings already achieved in the 2009 codes. Peak demand savings of 14 to 26% are estimated for the summer months and 29 to 40% savings in winter months. RECA noted that these savings will not be fully realized until the state first adopts the code and the building industry and jurisdictions receive the training and education necessary to implement, comply with, and enforce the codes. It noted that the timetable for this process varies and could take up to several years.

RECA commented that the rule should permit a baseline for early adoption that gives credit for jurisdictions that either adopt the statewide energy code earlier than required or adopt a future edition of the national model energy code before the state has completed the code adoption process. In addition, RECA and Joint Utilities requested that the baseline for incentives and market transformation programs that target new buildings consider the actual compliance rate of code implementation and enforcement statewide and that programs be measured against actual or estimated compliance levels with existing building codes, not against an assumed 100% compliance.

Commission response

The commission agrees with RECA's comments that subsection (e)(5)(C) provides that standard offer, market transformation, and self-delivered programs aimed at promoting early adoption and increased adoption, implementation, and enforcement of building codes, to the extent that such enforcement does achieve full compliance rates, are not categorically deemed ineligible because the energy codes are required by law, or in the case of early adoption, may soon be required by law. The commission also agrees with Joint Utilities that the EM&V contractor should have the latitude to consider code enforcement when developing the TRM and when estimating savings achieved by a particular program. As noted by RECA, energy code compliance rates fall well below 100%. Therefore, the commission does not agree with Cities that encouraging compliance contributes to the free ridership problem or share their concerns that it may be impossible to determine whether codes achieve full compliance. To the extent that compliance typically falls below 100%,

savings that result from promoting greater compliance contributes appropriately to the demand and energy goals of a utility. The commission agrees with RECA that when full compliance is not achieved, substantial demand and energy savings are lost. RECA also provided evidence that a multi-year gap exists between publication of new energy codes and statewide adoption and enforcement of codes. Likewise, the commission agrees that encouraging early adoption can result in substantial demand and energy savings.

In response to Cities and OPUC's concern that builders should not be paid to comply with energy codes and ratepayer money should not be used to fund enforcement of new codes, the commission agrees with RECA that efforts to improve compliance and enforcement of energy codes can take a variety of forms, including the use of third-party enforcement solutions. With regard to RECA and Joint Utilities' request regarding baselines, the commission notes that the proposed definition of baseline is consistent with their request.

Thus, the commission does not agree with OPUC that subsection (e)(5)(C) should be struck from the rule and therefore declines to make the change.

Subsection (e)(5)(E)

Sierra Club supported permitting utilities to provide a self-delivered program in rural areas but suggested that they be allowed to do so without a contested case hearing. It suggested that the utilities be required only to demonstrate that their goal could not be met without the provision unless a contested case hearing was requested by either energy service providers or retail electric providers.

Commission response

The commission notes that PURA §39.905(i) specifically requires a contested case hearing in order for a utility to demonstrate that the requirements of PURA §39.905(a) cannot be met in a rural area through retail electric providers or energy service providers but can be met by providing a self-delivered program. Therefore, the commission declines to adopt Sierra Club's requested change.

Subsection (f); Cost recovery

Proposed Subsection (f)(1); adopted subsection (f)(2)

OPUC stated that PURA §39.905 is based on customer classes and does not mention rate classes, and therefore believes that utilities should not be precluded from assigning costs based on customer class. It recommended deleting subsection (f)(1).

Cities disagreed with parties such as OPUC who recommended changes to remove the EECRF cost assignment by rate class established in the applicable utility's last base rate case. They stated that, in designing the EECRF tariff, the foremost principles should be the utilization of the rate classes approved in the utility's most recent base rate proceeding. They noted that, during the process of setting unbundled TDU rates, the commission established generic rate classes as a policy of promoting uniformity. Any modification of rate classes as part of an EECRF, they stated should only be an exception based on unusual circumstances, because proposals to merge or create new classes for EECRF proceedings can be used to circumvent the cost caps set out in the proposed rule.

Commission response

The commission declines to adopt OPUC's recommendation and agrees with the comments of Cities. In the commission's Order in Docket Number 39359, *Application of Southwestern Electric Power Company to Adjust Energy Efficiency Cost Recovery Factor and Related Relief*, the commission found that "a customer class can be defined as an EECRF rate class." Further, the commission believes that direct assignment of costs to rate classes ensures adherence to PURA §39.905(b)(4), while alternative allocations may not. This language is also consistent with the commission's decision in Docket Numbers 39359, 39360, and 39361, which were the respective applications of SWEPCO, AEP TCC, and AEP TNC to adjust their 2012 EECRFs.

The term "customer class" does not have a well-established meaning. For example, Order No. 40 at page 4 issued in Docket Number 22344, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission SUBST. R. 25.344*, established "six customer classes" as Residential, Secondary less than 10 kW or kVa (less than 5 kW for TNMP and EGSI), Secondary greater than 10 kW or kVa (greater than 5 kW for TNMP and EGSI), Primary, Transmission, and Lighting. The commission agreed that cost causation was a "significant factor in developing a uniform customer class configuration" and adopted these six "customer classes." However, those classes have been more commonly referred to as rate classes rather than customer classes in recent discussions of energy efficiency programs. As

discussed in relation to subsection (c)(49), the commission has defined "rate class" for purposes of this rule to be clear about what the commission intends when using this term.

Public Citizen and SEED Coalition commented that a utility should choose how to categorize its customers, noting that some classes may only contain one or two customers, in which one customer may have already participated, leaving the other customer to provide its own incentive and a portion of the utility's overhead. Similarly, Joint Utilities argued that, in a rate class with a small number of customers, the customers would be forced out of participating in energy efficiency programs. They stated that inequity issues are created when there are few customers in a rate class and recommended spreading the cost amongst a larger number of customers to mitigate that impact and correct the inequity. They recommended, if the commission believes that assigning costs at the rate class level is appropriate, modifying subsection (f)(1) to permit a utility to combine a rate class with a small number of customers with another similar rate class for the purpose of assigning costs and designing an EECRF.

City of El Paso commented that Joint Utilities' argument would charge customers in some rate classes for the benefits received by customers in other rate classes. It asserted that, even in the example of a rate class with one customer, there must have been a valid reason for the establishment of a rate class with a single customer. It observed that, while a "customer class" allocation mitigates the cost to the single customer, it spreads that cost to other rate classes, though it benefited that customer, and does not track the costs with the benefits received.

Commission response

The commission wishes to clarify that the relevant language in the proposed rule does not directly assign costs to those customers who benefit, but to those *rate classes* that have customers that receive services under the program. In the example given by Public Citizen and SEED Coalition, the commission expects that the energy efficiency measures provided to the customer by the utility, per PURA §39.905(a)(3)'s requirement that utilities provide "cost-effective energy efficiency," will produce benefits in terms of dollar savings greater than the costs; therefore, even though some utilities have some rate classes with few customers, this should not discourage participation, as participating customers will receive savings in excess of the cost. Further, as a practical matter, the issue of rate classes with few customers by definition affects a small number of customers, who are the exception rather than the norm.

In response to the comments made by Joint Utilities, the commission notes that direct assignment of costs to rate classes in no way "forces" customers in small rate classes out of participating in programs; such customers remain free to participate in programs. However, to address Joint Utilities' concerns about EECRFs charged to rate classes with a small number of customers, the commission modifies adopted subsection (f)(2) to permit a utility to request a good cause exception allowing for the combination of one or more rate classes that contain fewer than 20 customers with a similar rate class that receives services under the same programs. The commission appreciates the comments of City of El Paso, but modifies and adopts Joint Utilities' proposal. The commission believes that allowing the utilities to apply for a good cause to combine small rate classes receiving services under

the same energy efficiency programs should mitigate any inequities that arise from subsidization of one rate class by another. In addition, parties participating in an EECRF proceeding will be able to review and respond to such requests for good cause exceptions.

Joint Utilities asserted that energy efficiency is a resource that provides benefits to all customer classes; therefore, the utilities should be allowed to recover the costs of those resources from all customer classes. They stated that the principles of cost causation do not apply to energy efficiency due to the system-wide benefits of the programs, which was the basis of the Legislature's goal to offer energy efficiency to all customers in all customer classes. They stated that if there are system-wide benefits created by the programs, at least some of the costs should be equitably shared by all end-use customers, consistent with generally-accepted ratemaking principles. Similarly, Public Citizen and SEED Coalition stated that utilities may upgrade a substation or add additional transmission that will benefit a small group of customers yet all customers are charged accordingly.

EDF commented that there was no legislative direction provided to make this change, and that such change does not exist in the relevant statue. It asserted that PURA uses "customer class" because it benefits all customers while benefiting participants more, and that a "rate class" allocation risks stranding funds and is less efficient for utilities running programs.

Cities supported the definition of rate class as proposed in the rule. They stated that they oppose the creation of new EECRF classes, suggesting this would circumvent the commission's goal to promote rate uniformity through establishment of generic rate classes.

Commission response

Because the rule establishes a cost cap on the *aggregate* commercial class, no funds will be "stranded" in a rate class, as EDF argues; a utility may allocate program funds to customers participating in an energy efficiency program regardless of how much of the funds are allocated to customers in a particular rate class. The commission agrees with Cities' suggestion that adhering to the generic TDU utility rate classes for the purposes of calculating an EECRF promotes rate class uniformity, which benefits the competitive retail market by allowing REPs to more easily price and market their offerings throughout the various TDU service areas.

In response to comments by Joint Utilities that energy efficiency provides system-wide benefits, the commission generally directly assigns and allocates costs based on cost causation, not receipt of benefits. As in the example provided by Public Citizen and SEED Coalition, substations and transmission lines are network elements, and typically serve customers in multiple classes. While directly assigning costs is generally preferred, because it is frequently impossible to directly assign the cost of a substation upgrade or transmission investment, those costs are typically allocated to classes based on cost causation principles, not based on the benefits that a particular class receives from the upgrade or investment. Furthermore, PURA §39.905(b)(4) prohibits recovery of energy efficiency costs from non-participating classes, which would prohibit a true benefits-based allocation of costs. Direct assignment of actual energy efficiency expenditures to the classes that received the incentives associated with those expenditures is consistent with the

principle of cost causation. As with the example above concerning allocating substation and transmission lines to classes based on cost causation principles, not all energy efficiency costs can be directly assigned. The commission has therefore clarified adopted subsection (f)(2) to state that EECRF costs shall be directly assigned to each rate class that receives services under the programs to the maximum extent reasonably possible.

The commission believes that, as a matter of policy, direct assignment of actual energy efficiency expenditures to the rate classes established in the utility's most recent base rate proceeding is appropriate, because a broader allocation methodology would result in some rate classes subsidizing programs for other rate classes. Those rate classes providing subsidies to other rate classes would be allocated a larger share of the utility's cost of service in the next base rate proceeding, because the load and energy usage of the subsidized classes would decline or grow at a lesser rate as a result of the energy efficiency programs. As a result, the customers in the rate classes with fewer suitable programs would be doubly harmed, because they would subsidize the other rate classes for the cost of the energy efficiency programs and would receive a greater portion of the utility's cost of service in the next base rate proceeding.

Joint Utilities stated that rate class assignment will result in volatile EECRF rates, depending upon participation in the previous year.

Commission response

The commission believes that the goal of assigning costs based on cost causation generally outweighs any concern over EECRF rate volatility. However, as discussed previously, the commission revises subsection (f)(2) to permit a utility to request a good cause exception, allowing for the combination of one or more rate classes, each containing fewer than 20 customers, with a similar rate class that receives services under the same energy efficiency programs. This revision addresses concerns regarding rate volatility for classes with a small number of customers while mitigating the impact of inter-class subsidization.

Joint Utilities recommended granting utilities the latitude to assign costs and set EECRFs on a customer class basis, a rate class basis, or some combination of the two, depending on each utility's circumstance. Sierra Club similarly commented that it recommends removing references to rate class. CLEAResult and Sierra Club also recommended at least permitting, but not requiring, utilities to collect fees, and track and report program costs by either customer or rate class. Sierra Club stated that some utilities prefer to charge rate classes separately; other utilities would like the flexibility to spread the costs amongst rate classes and collect by customer class.

CLEAResult, EDF, Public Citizen, SEED Coalition, Sierra Club, and Texas Citizens commented that tracking and applying EECRFs to rate classes rather than customer classes is a significant administrative burden that will divert costs away from energy-saving projects to administrative functions.

Commission response

For the reasons stated previously, the commission has concluded that energy efficiency costs should be directly assigned to rate classes. Based on the experience of utilities that have already directly assigned energy efficiency costs to rate classes, the commission concludes that the administrative costs of doing so are relatively small.

EnerNOC stated that the smaller the subset of customers from which the commission requires utilities to charge and collect energy efficiency fees, the smaller the subset of customers that may participate in the utility energy efficiency program based on the available funds allocated to them. It asserted that it is possible that a smaller subset of customers may eliminate the potential for well-qualified customers to participate in a utility's load management program, because the funds available for that subset of customers may already be exhausted. It agreed with EDF, Joint Utilities, and Sierra Club's recommendation that the commission continue to allow utilities the flexibility to charge and collect energy efficiency fees by customer class or rate class.

Public Citizen and SEED Coalition commented that the rule states that the program must be cost-effective and show that all customers derive benefits, not just those that participate in a particular program within the program year.

EDF stated that when utilities evaluate programs based on rate class instead of customer class, their budgets and savings achieved decreased. It recommended that utilities be given the flexibility to decide whether to charge and collect by rate or customer class, but should the commission retain the proposed language, it suggested that the cost caps apply to the entire customer class and not to an individual rate class.

Commission response

The commission notes that it is not instituting a rate class cap for each commercial rate class, and that the utility has the flexibility, in the course of a program year, to shift funds among commercial rate classes as those rate classes receive services from those programs, provided that, *on the aggregate* for commercial rate classes, the resulting rates are not designed to recover more than the overall commercial cost cap. Then, in the subsequent true-up year, the classes that actually received incentives will be directly assigned the costs of those incentives. The commission emphasizes the importance of rate classes paying for programs from which they actually received services, and that this does not restrict the ability of utilities to provide funds to any appropriate rate classes in the course of a program year. The proposed rule already clarifies this at subsection (f)(7)(c), stating that the rates for the commercial rate classes must be set such that the resulting total commercial revenue recovery is below the cap amount calculated by multiplying the cap rate by the aggregate of all eligible commercial customers' kWh consumption.

For clarification, the language previously included under subsection (f)(2) has been moved to subsection (f)(1) and subsequent paragraphs have been renumbered.

Proposed subsection (f)(2); adopted subsection (f)(1)

TX ROSE and TLSC recommended that "may" be used instead of "shall" in subsection (f)(2) to more accurately reflect ratemaking under PURA. They also proposed language to clarify that the EECRF proceeding costs are "rate case expenses". They also proposed language to ensure that only actual costs determined by commission to be reasonable and necessary to reduce demand and energy growth were prudently incurred are included in the EECRF. They commented that in subsection (f)(2)(A) the term "actual" as a modifier to costs in the calculation of the under- or over-recovery of the EECRF costs is vague, and that the costs used in the calculation should be consistent with ratemaking principles, which are costs that were reasonable and necessary to reduce demand and energy growth and were prudently incurred. TX ROSE and TLSC provided language that would amend the proposed subsection to this effect. They also recommended deleting subsection (f)(4) as it appears to be duplicative to previous subsection (f)(2).

Commission response

The commission declines to adopt TX ROSE and TLSC's recommendations to change "shall" to "may;" in adopted subsection (f), once energy efficiency costs are removed from base rates, the EECRF is intended to be the exclusive means for recovering energy efficiency costs, and the use of "shall" reflects this intention. Subsection (f)(12) addresses the standards for cost recovery, and the commission therefore declines to adopt TX ROSE and TLSC's proposed language in that regard. The use of "actual" in subsection (f)(2)(A) indicates that the costs referred to are actual costs instead of forecasted costs. EECRF proceedings are ratemaking proceedings, and the proposed rule allows recovery of utility and municipal costs for those proceedings. Use of "rate case expenses" in the rule

provisions addressing EECRF proceedings is unnecessary and would be awkward. To provide clarification, the commission has reorganized subsection (f) so that proposed subsection (f)(2) is clarified and made to be adopted subsection (f)(1). The commission deletes proposed subsections (f)(2), (f)(4), and portions of subsection (f)(6) and (7) as this language, now inclusive of OPUC's modified load growth language (discussed below), is reflected in adopted subsection (f)(1).

Subsection (f)(2)(A)

OPUC recommended clarifying language to ensure that load growth is accounted for when setting the EECRF rates for utilities that collect energy efficiency costs in base rates. It stated that if load growth is not accounted for, the utility may over-earn if more kWhs were sold than when base rates were set. It proposed language to this effect under subsection (f)(2)(A).

Commission response

The commission agrees with the comments provided by OPUC and adopts language in subsection (f)(2), with modifications, to state that the EECRF will recover costs in excess of "the amount of energy efficiency costs expressly included in base rates, adjusted to account for changes in billing determinants from the test year billing determinants used to set rates in the last base rate proceeding." The amount of energy efficiency costs expressly included in the calculation of base rates will be adjusted to account for changes in billing determinants from those used to set base rates to the actual billing determinants used to collect revenues. This adjustment will account for changes stemming from sources such as

energy sales, load, and weather to determine the actual energy efficiency revenues recovered by the utility in its base rates.

The commission now accounts for load growth in the Distribution Cost Recovery Factor (DCRF) rule, and PURA §39.905(b-1) states that the EECRF may not result in any over-recovery of costs but may be adjusted each year to change rates to enable utilities to match revenues against energy efficiency costs and any incentives to which they are granted. Therefore, load growth adjustment language in the rule is appropriate until all utilities collect energy efficiency costs solely through the EECRF.

Proposed subsection (f)(2)(B); adopted subsection (f)(3)

Cities recommended edits to proposed subsection (f)(2)(B). They asserted that the proposed rule would require municipalities to wait until the subsequent EECRF case to support their expenses. They stated that the timing of the reimbursement of the municipalities' expenses is unclear, as the rule envisions utilities quantifying rate case expenses for the last case for which it has yet to reimburse cities. They stated that they are not regulated utilities, but rather regulatory authorities under PURA and are authorized to recover rate case expenses incurred from participating in ratemaking proceedings. They suggested that the commission consider permitting for the recovery of estimated rate case expenses, as the utility is permitted to seek projected energy efficiency costs in the course of an EECRF proceeding. Should the commission not wish to revisit its prior decision regarding estimated rate case expenses, Cities urged the commission to allow municipalities to quantify their rate case expenses in their direct case, provide an update at some later point prior to the decision in the case, and be able to prove the reasonableness of any remaining expenses in the utility's next EECRF case. They provided language modifying subsection (f)(2)(B) to this effect, which they asserted was consistent with commission precedent finding that EECRF proceedings are ratemaking proceedings and that municipal rate case expenses from EECRF proceedings are reimbursable.

Commission response

The commission has added rule language to expressly state that a proceeding conducted pursuant to subsection (f) is a ratemaking proceeding for purposes of PURA §33.023. PURA §33.023(b) does not expressly contemplate payment of estimated rate case expenses. Furthermore, EECRF proceedings are conducted annually and therefore should be streamlined to the extent possible. Considering all municipal expenses for an EECRF proceeding in the subsequent proceeding is an administratively efficient means of addressing those expenses. Proposed subsection (f)(2)(B) is subsection (f)(3) in the adopted rule.

Proposed subsection (f)(5); adopted subsection (f)(8)

Cities supported subsection (f)(5), which establishes EECRFs as ratemaking proceedings for the purposes of PURA §33.023, asserting that the EECRFs clearly fall within the definition of "rate" in PURA §11.003(16)(A), making them ratemaking proceedings subject to municipal intervention and reimbursement.

Commission response

The commission appreciates Cities' comments and retains the proposed language. The commission also re-designates subsection (f)(5) as subsection (f)(8) to provide information on the effective date of the EECRFs prior to the discussion of the procedural schedule.

Proposed subsection (f)(7); adopted subsection (f)(6)

Some of the parties, including City of El Paso, Joint Utilities, OPUC, Public Citizen, SEED Coalition, Sierra Club, and Texas Citizens, stated that the utilities should retain the flexibility to assess the EECRF on an energy or customer charge basis. Public Citizen and SEED Coalition asserted that this subsection is too restrictive and that the utility should determine the method that best fits its existing systems. They stated further that this change could require extensive modifications to the utilities' billing systems and add excess costs without any benefit. Joint Utilities, Sierra Club, and Texas Citizens agreed that the utilities needed flexibility to recover costs on either basis, though Joint Utilities and Sierra Club argued that an appropriate approach can be determined in the utility's EECRF proceeding. Joint Utilities stated that permitting utilities the option of either rate design approach will minimize disruptions. City of El Paso agreed with Joint Utilities that the option to charge residential customers on energy usage should be available.

City of El Paso argued that cost recovery for residential customers should not be limited to a customer charge, as there is no theoretical difference in the nature of cost recovery of energy efficiency expenditures, and that the cost effect could be staggering on residential customers with low usage. It recommended that the commission allow recovery of the EECRF for residential customers through either a customer or energy charge.

OPUC opposed requiring TDUs to use a monthly customer charge. It argued that a customer charge is regressive, runs contrary to the goal of encouraging reduced energy consumption, and that it would negate some inducement for customer participation in these programs. It proposed language permitting utilities to charge either an energy or customer charge and to clarify that load growth will be accounted for in the EECRFs.

In reply comments, TNMP joined with City of El Paso, Joint Utilities, OPUC, and Sierra Club that utilities should have the option of recovering program costs from commercial customers through either an energy or customer charge. TNMP disagreed with Cities' proposal that only energy or volumetric charges be used to recover program costs from consumers. It stated that the intent of the statute is to reduce peak demand growth and utilities are required to administer energy efficiency programs designed to achieve a reduction in demand during the peak period; the EECRF is designed to satisfy the goals prescribed. It stated that, while utilities are required to implement energy efficiency programs so that all customers are eligible to participate, not every customer can because of limited utility funds; therefore, all customers should be equally responsible for these costs by amortizing the costs across the entire class.

In reply comments, Joint Utilities noted that comments in support of both energy charges and customer charges have merit, and that utilities should continue to have the latitude to recover these costs using either method for both residential and commercial customers. Similarly, CLEAResult recommended in reply comments that utilities have the flexibility to recover costs on a per-customer or per-kWh basis.

Cities, TX ROSE, and TLSC supported the assessment of an energy charge. Cities recommended that the EECRF be collected as an energy charge for both commercial and residential customers. They asserted that an energy charge is appropriate for residential customers as well as commercial customers, as it encourages energy efficiency and discourages cost shifting to low usage customers within the residential class. They argued that higher than average consumers can achieve greater potential bill savings because they use more power than other consumers, who may have little ability to effectively participate in the energy efficiency programs.

Cities further asserted that an energy charge facilitates a rate class cap, based on a kWh usage to produce a uniform and equitable rate cap in the state, since the same per kWh cap is applicable to end users. They noted that a fixed cap per customer does not recognize the variation in annual usage among utilities.

TX ROSE and TLSC supported an energy charge for residential customers, arguing that a fixed customer charge discourages energy conservation, and an energy charge more fairly distributes the costs within the residential customer class with those residential customers using the most energy paying their fair share of the energy efficiency costs. They further asserted that low-use customers are disproportionately impacted by a fixed charge.

TIEC, TNMP, and Walmart recommended that the commission maintain a customer charge. TNMP stated that a utility should be permitted the option of recovering program costs from commercial customers through a customer charge. It noted that, in its own example, some customers' bills would increase to nearly $135 per month. It stated that, since not all commercial customers can participate because of limited program budgets and because rates are not developed to pass the cost of energy efficiency to those customers that actually benefit from TNMP programs, the commission should allow a per-customer charge, so that customers are only paying their fair share of the costs of the programs.

Cities asserted that TNMP's interpretation of the commission rules presents another reason why the commission should reject the use of a customer charge. They observed that TNMP is the only utility that asserts that the rule does not impose a cap on commercial EECRF charges if the EECRF is charged on a per-customer basis. They recommended that the commission reject a customer charge to avoid TNMP's interpretation.

Walmart stated that setting an energy charge for commercial customers should be rejected. It commented that the proposed rule provides for a hard cost cap on the total EECRF that may be assessed on residential customers per month, but not commercial customers, asserting that the result is effectively no cap on a volumetric charge for commercial customers. It stated that the proposed rule disproportionately impacts larger customers as the change would result in an exponential increase in EECRF charges to certain customers, regardless of the commercial customer facility's level of energy efficiency relative to smaller customers whose EECRF assessment is less.

In reply comments, Walmart agreed with commenters that, at the very least, no change should be made to the existing language allowing the EECRF to be charged on either an energy or customer charge basis. It reasserted that requiring an energy charge for commercial and a customer charge for residential is inequitable, and that commercial customers should be optimally charged on a per-customer basis, though at the least, the commission should not modify the existing rule without exploring the collection of the EECRF on a demand basis.

TIEC urged the commission to reject proposals from Cities and OPUC to impose all EECRF charges on an energy basis. They argued that the Legislature did not adopt an energy efficiency mandate to be a tax on energy to discourage consumption, and that the cost of energy alone is sufficient to encourage customers to limit their consumption to the extent that they are able. They stated that the Legislature adopted a mandate for utilities to offer energy efficiency programs to eligible customers in order to provide programs that help customers achieve additional demand reductions. They reiterated their argument that the costs of these programs are derived from the cost of making a particular program available to customers, and are therefore determined by the number of customers to whom the program is offered. They noted that program costs have nothing to do with how much energy a particular customer uses, offering as an example, the costs of providing weather-stripping to a customer, which are not related to the amount of energy that customer consumes. They stated that cost causation dictates that the EECRF charges should be imposed on a customer basis, just as those costs are incurred. They asserted that disproportionately burdening high-load-factor customers, who already have the greatest incentive to reduce their energy usage, with EECRF costs is unjustified. Additionally, they stated that a per-customer charge is simpler and more accurate, and easier for utilities to administer. They further added that PURA §39.905(a) provides that energy efficiency programs should be designed to achieve a reduction in growth in demand, and therefore, costs should not be collected on an energy basis when the savings are measured on a demand basis.

In reply comments to TIEC, Cities noted that a customer cost cap would be impossible to implement. They noted that rate caps on a per kWh basis are designed to uniformly impose a cost cap for commercial customers, despite the diversity in customer size and class. They challenged TIEC's argument that cost causation is the number of customers seeking access to the programs. They asserted that a utility's energy efficiency costs are caused by the costs of implementing programs designed to achieve specific goals, based on the reduction of both energy use and demand use; therefore, energy usage, by rule, is an explicit cost causative factor. They noted that a fixed customer charge is not sensitive to either energy or demand usage. They stated that the development and design of the energy efficiency program is affected by energy usage; high energy use is associated with higher program costs. They noted that the budget available for a program may be a more significant limiting factor than the number of customers seeking access to the program, and that the available budget will be indirectly affected by participants' energy use. They stated that cost causation does not dictate the use of a customer charge, and that an energy charge is preferable.

Cities also recommended rejecting the approach asserted by commenters such as Sierra Club, TIEC, TNMP, and Walmart that the EECRF be collected as a customer charge, because customer charges do not send appropriate price signals for customers to conserve energy. Cities asserted that energy charges encourage energy conservation because the customer pays more as their electric use rises.

City of El Paso disagreed with TIEC's reference to PURA §39.905(a), arguing that paragraph (a)(2) references the opportunity to achieve savings in energy consumption as well as winter and summer peak demand. It disagreed that there was any valid basis in the statute to only permit the EECRF on a customer basis.

If the commission rejects proposals to assess an energy charge, TIEC and Walmart recommended the examination of a demand charge, in lieu of an energy charge. Walmart stated that charging customers on an energy charge basis is inconsistent as the goals are stated in terms of reductions in demand, not energy. Should the commission refuse to adopt a per-customer EECRF charge for commercial customers, it recommended that the commission explore assessing a demand-based EECRF charge on commercial customers billed on demand.

In reply comments, TIEC asserted that a demand charge is more appropriate than an energy charge if the commission does not allow a customer charge to be used. They stated that if the commission seeks to use the EECRF charge as a usage deterrent that will compel customers to meet energy efficiency goals, the charge would need to be imposed on a demand basis in order to track statutory requirements. They noted that an energy-based charge does not track either cost causation or the statutory energy efficiency goals and should be rejected. They recommended the adoption of a customer charge for all customer classes or alternatively a demand charge; at a minimum, they stated that utilities should retain the discretion to impose the EECRF charges and caps on a customer or demand basis, as requested in initial comments. If the commission were to determine that energy efficiency costs should not be collected on a per-customer basis, they asserted instead that costs should be collected on a demand basis for those non-residential customers currently billed on a demand basis. They commented that this would be more appropriate, as energy efficiency goals are reductions to peak demand, and costs were historically allocated on a demand basis when they were collected in base rates.

In reply comments, Cities asserted that a demand charge is impractical, as it can only be imposed on customers that have demand meters. They noted that customers in the less than 10 kW class are not required to have demand meters and are billed on a per-kWh basis and some customers in the greater than 10 kW are exempted from demand charges. Cities noted that Walmart did not state whether the EECRF demand charge would be subject to a ratchet like other distribution demand charges, but if it is, such a proposal adds another layer of inequity and customer confusion. They argued that a ratchet creates unfair situations for certain types of users such as churches, schools, ball parks, and other extreme seasonal or off-peak demand users. They noted that the Legislature has responded to the complaints of small business customers to exempt low load factor customers from ratchets. To the extent that the commission does implement a demand charge for the EECRF, they advised that a ratchet not be used for these reasons.

Commission response

The commission appreciates the comments of Cities, City of El Paso, Joint Utilities, OPUC, Public Citizen, SEED Coalition, Sierra Club, Texas Citizens, TIEC, TNMP, and Walmart. As noted by Cities, TX ROSE, and TLSC, a customer charge fails to provide a rate

incentive that aligns with the policy goal of encouraging energy efficiency, and therefore an energy (volumetric) charge is appropriate for the EECRF.

The commission agrees with Cities, OPUC, TX ROSE, and TLSC that the rule should mitigate the rate impact of the EECRF on low-income and low-usage residential customers whose ability and incentive to participate in programs may be somewhat limited compared to high-usage residential customers. The commission therefore permits utilities to charge residential customers only on an energy basis.

With respect to a demand charge for commercial customers, the commission agrees with TIEC and Walmart that the statute does address demand goals, and that savings are based upon the avoided cost of capacity. The commission agrees with Cities that ratchets should not be applied to an EECRF charged on a demand basis, and that charging the EECRF based on actual monthly peak demand will reduce customer confusion. As energy efficiency costs are of a different nature than those costs that are typically recovered using a demand ratchet mechanism, a demand ratchet is not appropriate for EECRF billing purposes. In addition, applying the EECRF to the commercial customer's actual monthly peak demand, for commercial customers typically billed on a demand basis, will provide a more immediate incentive for those types of customers to reduce their peak demand. Therefore, the commission adopts the requirement that the EECRF be billed as an energy charge for commercial rate classes whose base rates do not provide for a demand charge, and the commission permits either an energy or a non-ratcheted demand charge for those commercial rate classes whose base rates provide for a demand charge. Having both an

energy charge and a demand charge for the EECRF for a rate class would add unnecessary complexity. Therefore, the commission has precluded this option in the adopted rule. For rate classes that are billed on a demand basis, whether to design the EECRF to provide for an energy or demand charge will be determined in the EECRF proceedings based on the particular relevant facts. Proposed subsection (f)(7) is adopted subsection (f)(6), and the provision has been changed to clarify that a utility will have more than one EECRF.

Proposed subsection (f)(8); adopted subsection (f)(7)

Beneficial Results, CLEAResult, Joint Utilities, Public Citizen, and SEED Coalition suggested eliminating the cost caps. Joint Utilities recommended removing the EECRF cost caps from the rule entirely and instead considering the costs within the EECRF proceedings.

However, REP Coalition stressed the importance of the cost caps, as well as their uniform application to all utilities, and asserted that PURA §39.905 authorizes energy efficiency programs, but makes the programs subject to cost ceilings established by the commission. It stated that the commission adopted the current cost ceilings to control the program cost impacts that are borne by residential customers. Prior to the current EECRF caps, the programs were subject to budget-based caps on program expenditures, which provided less certainty to REPs and their customers about the level of recoverable program costs. With respect to the commercial customers, it asserted that the commission adopted cost ceilings for commercial customers based on the level of energy consumption due to the impracticality of adopting uniform rate caps for all classes of commercial customers. REP Coalition said that the adoption of the current cost ceilings provided REPs with critical information needed regarding future adjustments to the EECRF.

TX ROSE and TLSC agreed with REP Coalition that cost caps provide transparency, cost control, and rate certainty. They recommended that the cost caps be maintained until the programs and costs have been reviewed by the EM&V contractor. In the meantime, they recommended that the commission avail itself of the good cause exception for utilities that are unable to meet their goal without an increase to the rate cap.

Commission response

The commission agrees with REP Coalition that the intent of the commission in adopting the cost cap on a per-customer basis for residential customers was to control the rate impact on residential customers as much as possible. The overall commercial cap allows the utilities more flexibility due to the varying characteristics of the commercial customer classes, while still limiting the total impact on commercial customers. Further, the good cause exception provision provides a mechanism to address concerns about utilities achieving the goals. As a result, the commission disagrees with the comments provided by Beneficial Results, CLEAResult, EDF, Joint Utilities, and Sierra Club, and retains the EECRF cost caps.

The commission has revised the residential cost cap to be based on a per kWh cap in order to be consistent with the revisions in adopted subsection (f)(6) (proposed subsection (f)(7)) regarding the design of the EECRF. In addition, the commission strikes portions of this

subsection that discuss the calculation of the EECRF, as this is addressed in adopted subsection (f)(1).

CLEAResult, EDF, Public Citizen, SEED Coalition, and Sierra Club highlighted the resource adequacy issue within the ERCOT region. Public Citizen and SEED Coalition asserted that, given risk of increased consumer electric prices due to the potential increase in the system-wide offer cap in ERCOT, it would be in the consumer's best interest to substantially increase the cost caps on energy efficiency programs and reduce predicted load growth. Sierra Club acknowledged the commission's decision to raise the scarcity pricing mechanisms such as the system-wide offer cap and mentioned the potential for more proposed rules in 2013 and 2014, but expressed skepticism at whether these proposals would result in more generation. It stated that ERCOT has done a preliminary "Back Casting" scenario of various stakeholder proposals and found that these proposals, if implemented in 2011, would have raised the overall price of energy between $3.00 per MWh, if no additional changes are made, to as much as $40 per MWh, if all potential changes to the power balancing curve, cap, and peaker net margin were adopted. It asserted that the cost of energy efficiency programs would be much less than the anticipated cost increases related to the proposed resource adequacy related rules since energy efficiency programs in Texas largely targeted peak demand.

Based upon its review of benchmarked program costs throughout the U.S., CLEAResult recommended that a thorough analysis be undertaken to set the cost caps, considering that the current cost caps are set at one-third of typical energy efficiency riders. It, too, stated that energy efficiency could be used as a means of reducing capacity strains. It also stated that the current cost caps were artificially low, and until a thorough review of the current cost caps is completed, the commission should double the cost caps for rural utilities and those in areas in which customer choice is not offered.

TIEC recommended that the commission reject EDF, Public Citizen, SEED Coalition, and Sierra Club's proposals to raise the cost caps on the justification that increasing the budgets for energy efficiency programs will help with the current resource adequacy concerns. They asserted that EDF, Public Citizen, SEED Coalition, and Sierra Club's reasoning is incorrect and conflicts with the Brattle Report. They observed that the Brattle Report emphasizes that in order for demand response to play a pivotal role in the wholesale market, it must be market-based and play a role in price setting. They noted that utility-run energy efficiency programs meet neither criterion. They commented that in the report, the Brattle Group discouraged market intervention as a means to increase demand response through out-of-market payments with respect to the Emergency Response Program (ERS); those principles apply equally to focusing efforts to increase demand response on regulated utility programs. They stated that the commission should facilitate any additional demand response in the ERCOT market through the market, not ratepayer-funded, subsidized, regulated utility energy efficiency programs.

Commission response

The commission agrees with TIEC that resource adequacy concerns in the ERCOT region are best addressed through market-based solutions. While energy efficiency reduces load growth, it is not appropriate to conflate the commission's and ERCOT's market design efforts meant to ensure sufficient generation margins with utility energy efficiency

programs. Therefore, the commission will not consider resource adequacy issues in setting the energy efficiency cost caps.

Beneficial Results, EDF, Joint Utilities, Public Citizen, and SEED Coalition expressed concern that the proposed cost caps would limit the ability of the utilities to achieve their goals. Public Citizen and SEED Coalition stated that under the existing caps it will be difficult for utilities to achieve the statutory requirements, especially if energy consumption continues to rise per ERCOT's predictions. EDF asserted that the level of the cost caps are too low to enable utilities to meet the goals in the statute, explaining that approximately half of the utilities would have difficulty meeting the 2013 goal at the current cost caps. Joint Utilities stated that the cost caps fail to keep pace with the increase in goals, and that the increased low-income requirements along with the possible removal of load management programs will strain utilities' ability to meet their goals under the proposed cost caps. Beneficial Results asserted that the cost caps limit the benefits available through these programs, and urged the commission to increase the cost caps to enable greater savings.

OPUC noted that most utilities met their goals and earned a bonus in 2011, and stated that there seemed to be no justification for raising the cost caps if utilities are meeting or exceeding their goals. It stated that it was unaware of any case in which a utility was denied recovery or even a bonus due to the fact that it was unable to meet its goals within the cost caps. It commented that utilities that are unable to meet their goals within the spending caps should request a good cause exception in their EECRF case. If necessary, the cost caps should be revisited in a later revision of this section.

Sierra Club engaged Green Energy Economics Group (GEEG) to estimate how much Texas utilities would need to spend on energy-saving demand-side management (DSM) to achieve the minimum goals. In its findings, GEEG noted that economies of scale and diminishing returns on efficiency resource acquisition costs were evident as utilities increase the depth of electricity savings achieved; efficiency investment costs increase as efficiency portfolios mature; non-residential efficiency investment tends to cost less per annual kWh than residential; and that locations matter in that efficiency portfolios in California and New England tend to be more expensive than elsewhere. Sierra Club provided a study of GEEG's findings in its comments. It recommended that the commission increase the cap and allow an annual adjustment based upon a maximum of 10% per year, which assumes that incentives will need to increase to maintain and expand the goals in the future. It, along with Texas Citizens, stated that cost caps should be at least 50% greater than previous cost caps, to the equivalent of $2 a month for residential and $0.0001 per kWh for commercial customers. It stated that the clear legislative intent is to allow utilities to move beyond the minimum goals where possible under reasonable cost caps.

TREIA agreed with the positions of Beneficial Results, CLEAResult, EDF, Joint Utilities, Public Citizen, SEED Coalition, and Sierra Club that the cost caps prescribed in the rule are too low. TREIA responded that renewable DSM programs have made progress in transforming the market by consistently and predictably lowering offered incentive levels. It asserted that the solar PV programs are on a trajectory to be cost-effective within the next several years, but the proposed cost caps would likely derail the progress by forcing incentive levels too low, too quickly, or by forcing utilities to eliminate such offerings altogether. It stated that higher cost caps provide utilities with additional flexibility to include some higher-cost programs for diversity, experience, and market transformation.

Commission response

The commission appreciates the comments of the parties regarding the ability of utilities to achieve the statutory demand reduction goals. The commission understands that the goal for 2013 and beyond represents an increase to 30% of the utility's growth in demand of residential and commercial customers pursuant to PURA §39.905(a)(3). However, the commission agrees with OPUC that utilities have not been denied a recovery amount or a bonus as a result of non-attainment of the goal, and that a majority of utilities appear to be meeting and exceeding the goal, which results in the achievement of performance bonuses. In addition, in the future, EM&V should provide for a process that considers how programs can be designed for maximum cost-effectiveness and attainment of the goal. As the EM&V process has not yet been implemented, the commission has not had an opportunity to study available avenues to assist the utilities in achieving their goals under the current cost caps. The commission declines to adopt a higher cost cap on the basis of assisting utilities in achieving their goals, as a majority of utilities are exceeding the goals, and the proposed rule provides for a good cause exception to the cost cap that will assist utilities that are unable to meet their goals under the cost cap.

In response to arguments raised by TREIA, the commission notes that PURA §39.905(e) provides for research and development funds to be capped at 10% of the commission-approved expenditures for energy efficiency in the previous year. Therefore, the

commission concludes that it is not appropriate to raise the cost cap to support research and development and experience in the marketplace when an avenue has already been made available through a capped research and development program.

CLEAResult recommended that the cost caps be doubled for smaller, less metropolitan and/or non-ERCOT utilities. Sierra Club stated that the proposed cost caps prevent utilities from meeting the energy efficiency goals in SB 1125. It noted that in this year's EECRF filings, Sharyland, TNMP, and EPE, stated that they would be unable to meet the 30% growth in demand goal unless they substantially exceeded the proposed cap on spending. It further noted that to stay within the cap, each utility asked for a good cause exception and much lower goals. It asserted that to realize the maximum potential of the energy efficiency resource and to fully implement the Legislature's intent the commission should implement a program in which all utilities can meet the statutory goals. It asserted that if the commission raises the cap, these three utilities would be able to raise their proposed goals, giving customers in these areas more access to energy efficiency programs.

Sierra Club supported allowing vertically-integrated utilities to have a higher cap than those in the competitive market, stating that vertically-integrated utilities tend to be rural and have higher costs than more urban competitive utilities. These utilities assume all costs for serving their customers, thereby justifying a higher cost for energy efficiency programs because the programs lower overall system requirements. CLEAResult stated that the cost caps create a greater burden for smaller and more rural utilities.

In reply comments, Cities urged the commission to reject calls from parties such as CLEAResult and Sierra Club for higher or non-existent cost caps. They noted that in the immediately previous rulemaking on this section the commission rejected such recommendations because it sought to strike a balance between promoting energy efficiency and cost-effectiveness of the programs. They noted that the desired balance appeared to have been successful; despite utilities' allegations that increases in the cost caps have not kept pace with the increase in the utility goals for energy efficiency, the applications to set 2013 EECRF rates by the utilities all claim to achieve compliance with the cost caps. They noted that while some utilities have requested good cause exceptions, these appear to be exceptions rather than the general rule. They stated that the good cause exception was created to accommodate utilities faced with unusual circumstances, and that these have only been applied sparingly. They asserted that the retail market needs predictability regarding their exposure to the EECRF. Cities stated that significantly increasing the caps will upset the balance sought by the commission in the current rule and will place greater pressure on the rates paid by the general body of ratepayers, most of whom cannot, or do not, participate in the energy efficiency programs.

Commission response

The commission notes that the good cause exception provision should provide parties advocating for a higher cost cap on the justification of greater savings a mechanism by which to advocate for higher rates in an EECRF proceeding. The commission wishes to ensure that the utilities have exhausted all the low-cost, high-benefit energy efficiency options before migrating to a higher cost cap. The addition of EM&V and expanded

annual proceedings will allow the commission the opportunity to better ascertain whether all the low-cost, high-benefit options have been exhausted.

With respect to utilities operating in an area in which customer choice is not offered, the commission notes that PURA §39.905(h) allows those utilities to provide rebate or incentive funds directly to customers, which may reduce administrative costs and provide for more incentive funds under the cost caps. With respect to rural areas, PURA §39.905(i) allows a utility operating in an area in which customer choice is offered to provide incentive and rebate funds directly to customers after a demonstration in a contested case hearing that they cannot meet their goals through retail electric providers or energy efficiency service providers, which may also assist in reducing the program and administrative costs spent by the utility. As PURA already provides this assistance in both rural areas in which customer choice is offered and in areas in which customer choice is not offered, these avenues should be considered before raising the cost caps for the reasons discussed by the parties above.

CLEAResult and Sierra Club stated that the cost caps are low relative to other states. Sierra Club noted that Austin Energy has proposed a rate of three times the limit prescribed in this rule to funds its energy efficiency programs, and that CPS Energy spends nearly $5 per month per customer. CLEAResult asserted that the caps are arbitrarily low, resulting in some utilities either filing exceptions to the goal or reducing the savings that could be achieved beyond the minimum goal. It recommended that cost caps be set at or above the median rates for utilities with state-wide energy efficiency goals.

Commission response

The commission is not persuaded that the cost caps relative to other states or areas are relevant to the standards set by this commission. While it provides a useful comparison, the individual characteristics of the state such as the competitive market, extreme summers, and the legislatively-mandated goals differentiate Texas from many other large states such as California. The commission notes that both examples cited by Sierra Club are municipally-owned utilities, which have energy efficiency programs governed by the policy goals of their municipal governments as opposed to the policy goals of the legislature.

Cities, City of El Paso, CLEAResult, EDF, Joint Utilities, REP Coalition, Sierra Club, TX ROSE, and TLSC opposed the proposed rule's CPI adjustment for a wide variety of reasons. CLEAResult, EDF, REP Coalition, and Sierra Club commented that cost pressures for energy efficiency are unrelated to the CPI. Joint Utilities asserted that energy efficiency costs are likely to grow at a rate higher than an inflation adjustment.

Sierra Club opposed the CPI adjustment, supporting instead either a 10% surcharge per year on cost caps with a petition from utilities, or language similar to that proposed by CLEAResult which would allow a group of utilities to petition the commission for higher cost caps due to escalating costs.

TX ROSE and TLSC agreed that CPI is not an appropriate index to adjust the cost caps and encouraged the commission to delete the proposed language. Additionally, they recommended that the cost cap for 2013 include all subsequent years until the commission by rule amends the cost caps, asserting that some programs such as behavioral and self-delivered programs have costs that are likely to decrease and accompanying incentive costs of the utility can also decrease.

REP Coalition stated that the Legislature could have incorporated the CPI in a manner similar to the use of the index to annually update universal service support amounts pursuant to PURA §56.032(d)(2). It recommended deleting the entire subsection, and urged the commission to continue to consider and approve multiple cost ceilings with future effective dates, rather than adopt an index to adjust annually. Joint Utilities concurred with REP Coalition that inflation is not the best indicator of changing program costs, but asserted that the CPI adjustment recognized the increasing costs and offers some relief to utilities unable to meet their energy efficiency goals.

REP Coalition recommended amending subsection (f)(8)(B) and (D) to indicate that the cost caps for residential and commercial customers in program year 2013 will continue to apply in subsequent years, unless otherwise adjusted by the commission. Joint Utilities argued that if the commission eliminated the CPI adjustment, they agreed with REP Coalition's proposal to specify multiple cost ceilings for different years, so long as the caps are set at levels high enough to enable the utilities to meet their statutory goals.

City of El Paso commented that the provision allows the charges to customers to be increased without regard to any other costs in the utility's cost structure. It stated that the CPI adjustment does not contemplate that cost by which items could decrease on a per-unit basis due to growth in customers or sales, or that costs related to programs could decrease without regard to the CPI. It further stated that PURA §36.201 prohibits an automatic pass through of changes in costs, and that the effect of the CPI adjustment would be to build in an automatic increase in customer rates each year that the CPI changes, violating the principles of ratemaking. It noted that the exceptions in PURA §36.204 still address the issue of the reasonable costs and changes in those costs. It recommended that the commission substitute "may" for "shall" at a minimum, if it does not delete subsection (f)(8)(E).

In reply comments, Cities noted that utilities acknowledged that the proposed rule already includes a CPI adjustment. While Cities opposed the CPI adjustment, they recommended that should the commission include the adjustment, there is no justification to increase or eliminate cost caps. They agreed with City of El Paso's opposition to a CPI adjustment. They disagreed with the automatic CPI adjustment, stating that CPI only measures the *prices* of goods and services purchased by customers. They commented that changes in cost involve both changes in price and changes in the quantity of labor and materials used, which are driven by productivity. They stated that CPI does not reflect the extent that customers reduce their costs by replacing the purchase of higher-priced products with lower-priced subsidies, and is therefore not an appropriate measure of the need for higher cost caps.

CLEAResult recommended that the CPI adjustment be eliminated unless a more thorough and germane index, which accounts for baseline changes and regulatory requirements, is referenced.

Commission response

In response to arguments raised by the City of El Paso with respect to PURA §36.201, this section prohibits an automatic *rate* adjustment, not an automatic *cap* adjustment. As a utility must file an application to adjust its EECRF, the EECRF cannot be automatically adjusted.

In response to the claims that energy efficiency cost pressures are unrelated to a CPI increase, the commission would note that, with respect to residential customers, it is primarily concerned with the customer impact of EECRF rates. If the EECRF cap is raised at an amount higher than inflation, the EECRF charges would become an ever-larger share of a typical customer's cost of living. Therefore, the commission concludes that a CPI-South adjustment is a reasonable means of increasing the cap while protecting customers from excessive EECRF increases. A CPI-South adjustment will appropriately adjust the EECRF cap for inflation.

Joint Utilities stated that EM&V costs are outside of the utility's control and were not envisioned when the current cost caps were set. They argued that if they are now included within categories of costs that are capped the caps must be increased accordingly.

CLEAResult recommended that EM&V, rate case, and incremental low-income costs not be subject to cost caps unless the cost caps are raised to reflect adding EM&V and rate case expenses.

In contrast, OPUC stated that the costs of the EECRF proceedings should be included in the cost caps, and must be reviewed prior to being granted, in order to control costs and ensure that the cases do not become even more contentious. It proposed striking the exemption language for rate case expenses in subsection (f)(8).

REP Coalition opposed both exemptions to the cost ceilings in subsection (f)(8)(A)-(D), asserting that the statutory provision in PURA §39.905(b)(1) envisioned the energy efficiency programs offered by the utilities as "subject to cost ceilings established by the commission." It stated that the EECRF rates should be set to recover the exempted costs. With exemptions, the cost caps in subsection (f)(8) are not true cost caps. It asserted that cost ceilings provide cost transparency, cost control, and rate certainty, as well as more informed pricing of retail products and services to retail customers; without "true" cost caps, those benefits are lost. It asserted further that adoption of exemptions is unnecessary given the availability of good cause exceptions under the proposed amendments to the rule in subsection (e)(2). While REP Coalition admitted that a good cause exception also results in a loss of the benefits described above, it asserted that the good cause exception must be requested by the utility, may be contested in an EECRF proceeding, must show good cause, and, if granted, is only applicable to that proceeding. It believed that the availability of a good cause exception to the cost ceilings further justifies the rejection of the two proposals to codify exemptions by rule. It recommended deleting the exemptions.

In reply comments to REP Coalition, Cities noted that the commission permitted municipalities to recover expenses for participating in Oncor's 2012 EECRF proceeding. They recommended that the commission reject the suggestions of REP Coalition and OPUC to subject rate case expenses to either the overall cost cap or the administrative cost caps. They responded to arguments about transparency and cost control with the assertion that the staff reviews municipal rate case expenses to ensure that such expenses are reasonable. Additionally, they asserted that they review their own municipal rate case expenses prior to submitting such expenses for reimbursement for duplications or unreasonable charges. They noted that these expenses are filed in the docket for which reimbursement is sought as a part of Cities' direct case, obviating REP Coalition's concerns about transparency.

In reply to the comments of the REP Coalition regarding rate certainty, Cities stated that EECRFs change rates every year, and it is impossible for REPs to know in advance the true amount a utility will request in any given year's EECRF proceeding, nor can it anticipate good cause exceptions or many factors which may alter the EECRF amounts a utility not only requests but the amount ultimately granted by the commission. They asserted that EECRFs themselves create rate uncertainty for the REPs, and that placing municipal rate case expenses within utility administrative cost caps cannot change that. They noted that applications begin in May, are generally resolved in September or October, and the rates do not go into effect until January, giving REPs plenty of time to make necessary billing changes.

Joint Utilities stated that the utilities have no control over municipal rate case expenses, and that the inclusion of rate case expenses could cause utilities with smaller program budgets to exceed either the administrative or overall cap where an EECRF case is contested or requires extensive discovery. They noted that the proposed rule also allows OPUC, REP Coalition, TX ROSE, and TLSC to inquire into the reasonableness of the costs during the EECRF process, and that the comments of OPUC, REP Coalition, TX ROSE, and TLSC expressing concern relating to cost control should be rejected. TX ROSE and TLSC disagreed with Joint Utilities that a utility's rate case expenses should not be subject to the cap.

Joint Utilities requested clarification that rate case expenses are exempt from the overall cost cap in the same manner as EM&V costs. They stated that it is consistent with commission practice and precedent to treat rate case expenses separately from energy efficiency program expenses and exclude them from the overall cap. They noted that if rate case expenses were not excluded from the overall cost cap, utilities may have to either reduce program funding to remain below the limit or request a good cause exception or both.

City of El Paso disagreed with Joint Utilities, stating that no special cause exists to treat rate case expenses as apart from the cost of the program and create a further burden on ratepayers. It responded to Joint Utilities' argument that utilities have no control over rate case expenses by replying that the commission will decide the reasonable amount of rate case expenses. It noted that many utilities are at or near the cost cap without including rate case expenses, and that the purpose of a cap is to limit the exposure of ratepayers to the cost of these programs and encourage the utility to operate efficient programs. It said that if the final rule allows the utility to make charges in addition to the cap it defeats the incentive for efficient utility operation.

In reply comments, Joint Utilities stated that while it does not oppose the collection of municipal rate case expenses, updating them in a rate case is unnecessary. They commented that the EECRF proceedings must already be processed within a short period of time, and that the filing of updated information may slow this process. They said that the actual rate case expenses reimbursement is consistent with commission precedent, and contrary to Cities' claim, does not result in risk of non-reimbursement. They stated that if municipal rate case expenses incurred in recent EECRF proceedings are any indication, the risk of sizeable unreimbursed legal fees appears small. They supported staff's proposal that both the utility and municipalities wait for reimbursement to encourage efficiency and cost control and recommended that staff's proposal be adopted.

Commission response

The commission agrees with Cities that municipal EECRF proceeding expenses should be excluded from the cost caps, as these expenses are beyond the control of the utilities. However, the commission believes that it is appropriate to include the EECRF proceeding expenses of the utilities as subject to cost caps. Therefore, the commission modifies the language in the proposed rule to include utility EECRF proceeding expenses within the caps. This change is consistent with the commission's order in Docket Number 40356.

With respect to the inclusion of EM&V costs in the cost caps, the EM&V contractor will be hired by the commission, and therefore, the costs of the evaluation are outside of the utilities' control. The commission will make every effort to select the best-qualified contractor with a competitively-priced bid. However, the commission finds that, like the municipal EECRF proceeding expenses, the EM&V expenses are appropriately excluded from the cost caps because they are outside of a utility's control.

Walmart noted that economies of scale might be realized with respect to lower costs of administering the programs. It requested that the commission reconsider whether 15% remains an appropriate cap for administrative costs in light of market development.

CLEAResult asserted that the new 10% budget set aside for expensive low-income programs will place greater cost pressure on the utility's residential portfolios, and that other residential customers who do not qualify for low-income programs may not have access to programs because residential program funds will be exhausted. It additionally recommended that residential low-income programs should not be subject to the cost cap.

TX ROSE and TLSC disputed CLEAResult's assertion, stating that a set-aside for low-income programs has always been statutorily required. They provided legislative history regarding SB 712 of the 79th Legislature, Regular Session, in 2005, which set spending for low-income programs at 2003 levels. They noted that utilities have rapidly increased their energy efficiency program budgets but have not maintained a similar increase for targeted weatherization programs; SB 1434 provided an adjustment for the targeted weatherization funds in recognition of the ever-increasing energy efficiency programs. They asserted that it was unfair to label the low-income weatherization program as expensive without further study and review.

In reply comments, Cities stated that the utilities' premise for needing changes to the caps is based on the assumption that load management programs will be transferred to ERCOT, which they rejected in their initial comments.

Commission response

The commission appreciates the comments of Walmart. However, given several changes in the proposed rule including the expanded annual proceedings, the upcoming EM&V evaluation, the direct assignment of costs to rate classes and tracking of those costs, and the increasing goals, the commission believes it may be premature to reduce the administrative cost cap at this time. The commission declines to adopt the suggestion of Walmart and retains the 15% administrative cap.

With respect to the low-income residential programs, the commission agrees with the comments of TX ROSE and TLSC that the cost caps should not be raised until further study by the EM&V contractor is conducted and recommendations are made regarding these programs.

REP Coalition acknowledged that three new categories of energy efficiency program costs will be recoverable through the EECRF (EM&V, increased costs to low-income energy efficiency program attributable to the 10% floor in PURA §39.905(f), and the costs reimbursed to the governing body of a municipality pursuant to PURA §33.023(b) relating to the municipality's participation in a utility's EECRF proceeding). Due to these changes, it recommended a modest adjustment to the existing cost ceilings in program year 2014 to accommodate all of these costs.

TX ROSE and TLSC recommended retaining the current cost caps for the purposes of transparency and cost control. They noted that the new statutory goals were the same goals established in the 2010 rulemaking, and there is no need to change them at this time. They stated that utilities establish budgets in excess of the statutory goals, citing Oncor and CenterPoint's 2011 EEPRs filed under Project Number 40194, *Calendar Year 2011 Energy Efficiency Reports Pursuant to SUBST. R. §25.181(m)*. They acknowledged that a generic cost cap may not be appropriate given the diversity of Texas' utilities, but that there has been no reconciliation proceeding or EM&V implementation to review the costs. They asserted that the current caps should not be modified until the utilities' energy efficiency programs and their costs have been reviewed through a reconciliation proceeding and reviewed in EM&V. Similarly, OPUC recommended reassessing the cost caps after the initial EM&V is complete, arguing that the evaluation should provide insight as to whether the utilities need to spend more to meet their goals and how much more they need to spend.

City of El Paso stated that the cost caps should not be removed or raised in order to encourage efficient utility operation and provide protection for ratepayers. It noted that the burden for showing grounds for a change in a cap should be an extraordinary remedy granted only under certain circumstances.

Commission response

The commission rejects the proposed amendments of REP Coalition, and as discussed in subsections (i) and (q), the municipal EECRF proceeding expenses and EM&V costs are excluded from the cost caps, because these costs are beyond the control of the utilities. In response to TX ROSE, TLSC, and City of El Paso's proposed amendment, the commission believes that the CPI-South adjustment is an appropriate adjustment to the cost caps beginning in 2014, as it will go into effect after the initiation of the EM&V process, concurrent with the expanded annual proceedings, and is a reasonable compromise among parties seeking to retain the current cost cap and to raise or eliminate it altogether.

In addition, for clarity, the commission re-designates subsection (f)(8) as subsection (f)(7) and strikes portions of what has become adopted subsection (f)(6) that describe the recovery of the EECRF, as this is addressed in adopted subsection (f)(1).

Subsection (f)(9)

REP Coalition asserted that the procedural timelines in subsection (f)(9)(B) and (C) should target March 1 as the effective date of any new or adjusted EECRF approved by the commission, and should ensure at least a 45-day notice of any new or adjusted EECRF from the date the utility files its compliance tariff reflecting the commission-approved date. It noted that a target date of March 1 coincides with the semi-annual TCRF update, and a 45-day notice period is consistent with those proceedings as well. It commented that while it understood the need for flexibility in the proceedings, it recommended that the 45-day notice requirement be left intact and not subject to any good cause exception and proposed language to that effect.

Commission response

The proposed rule does not provide for a good cause exception to the time period between the filing of the compliance tariff and the effective date of the tariff: "In no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF." Inter-related with this 45-day period is the requirement in the proposed rule that the utility serve notice on REPs of the approved rates and the effective date of the approved rates by the working day after the utility files the compliance tariff. In response to REP Coalition's comments, the commission has modified subsection (f)(9)(B) and (C) to reinforce its intention that neither the 45-day period nor the one working day deadline are subject to good cause exceptions.

Subsection (f)(10)

TX ROSE and TLSC proposed new language requiring the utility to provide the results of the utility's EM&V activities, to be submitted in the EECRF proceeding, along with a report of proposed corrections or corrections to deficiencies identified in the EM&V study. They stated that the results of the EM&V study should be used to adjust the amount collected by the EECRF. They asserted that the utility should be required to describe the process for procuring the EM&V contractor and how that process ensures the contractor's independence, and that the EM&V contractor should also be assigned to review the EEPR and support the EECRF application. They also proposed language to require EM&V reports filed by the EM&V contractor appointed by the commission that relate to energy efficiency programs for previous years and for the time new EECRF rates will be in effect.

Cities supported the requirement in the published rule that a utility requesting an EECRF file explanations of administrative costs in its application. They suggested that utilities be required to file information regarding any affiliate costs for which the utilities request recovery from consumers, which would allow intervenors to verify that the utility has met the standard under PURA §36.058 for affiliate costs.

Cities opposed the removal of the requirement that a utility file billing determinants of the most recent year and for the year in which the EECRF is expected to be in effect in its EECRF filing. They stated that a review of the billing determinant forecast is necessary to ensure that the utility has attempted to minimize over- and under-recoveries. They stated that removal of this requirement would result in a greater discovery burden and decreased transparency. They recommended that the language requiring the utility to file in its EECRF "billing determinants for the most recent year and for the year in which the EECRF is expected to be in effect" be retained in the current rule at subsection (f)(9)(B).

In response to the suggestion by Cities, TX ROSE, and TLSC, Joint Utilities stated that it did not support the suggestion to add "reconciliation" to the proposed rule in subsection (f)(10)(D). They commented that the EM&V contractor will examine the utilities' programs on an annual basis. The contractor may conduct discovery throughout the process and will issue a report with recommendations that parties will be able to address in the context of future EECRF proceedings. They stated that Cities, TX ROSE, and TLSC failed to state why this process will not address their concerns, and that this suggestion should be rejected.

OPUC stated that the EECRF must account for actual energy efficiency base rate revenues, and that the language in subsection (f)(10)(B) should make clear that it is the amount of money that the utility collected through base rates rather than what the utility's final order allows it to collect through base rates. It stated that it was not clear as to the meaning of subsection (f)(10)(F), and opposed any suggestion that the utilities be allowed to spend beyond their approved budget and up to the cost caps. It stated that the EECRF proceedings are designed to evaluate the proposed budget and are approved as a reasonable estimate. It stated that if the intent of the subsection is that the utilities' budgets do not need to be followed, then the projected budget approval process should be discarded as redundant.

OPUC stated it believed the recipients of incentive payments and the number of incentives the recipient has received should be included in this application to help monitor the fostering of competition among energy service providers. Additionally, it proposed language in subsection (f)(10)(I) requiring that the utility provide rate case expense costs and an explanation of those costs.

TX ROSE and TLSC proposed language to add additional requirements and offered clarifications to the new expanded annual proceeding for the previous year's expenditures. Additionally, they proposed to add language so that the reasonableness of the utility's forecasted energy efficiency costs sought to be recovered are considered. In addition, they provided some clarification language for subsection (f)(10)(J) to clarify that the over- and under-recovery be the "actual revenues attributable to the EECRF by rate class for any period for which the utility calculates an under- or over-recovery of EECRF costs." They also recommended language reflecting the utilities' requirement to determine whether the previous year's revenues were sufficient in recovering its reasonable and necessary expenses. They proposed modifications to subsection (f)(10)(K) that would require a utility to show a competitive bidding and engagement process, including those contractors paid with funds collected through the EECRF. They proposed deleting the requirements that any contracts must be treated as confidential, stating that such is unsupported in law and works contrary to public interest in a transparent, competitive market. Sierra Club supported TX ROSE and TLSC's comments, stating that the public should have access to basic information about the programs and insight into which contractors are being paid ratepayer incentives. TX ROSE and TLSC noted that utilities are required to use competitive methods to select contractors.

Commission response

In response to TX ROSE and TLSC's concerns with respect to the EM&V contractor, the commission notes that one EM&V contractor will be retained by the commission, so concerns about a competitive bidding process by the utilities for the EM&V contractor are not warranted.

The commission adopts the proposed language of Cities to require a utility to file explanations of its administrative costs in the application, as well as any information on affiliate transactions to ensure compliance with PURA. In addition, the commission retains

the language currently in subsection (f)(9)(B) of the existing rule and modifies proposed subsection (f)(10)(E) to retain the current language, as Cities suggested.

The commission amends subsection (f)(10)(B) as OPUC suggested to clarify that actual base rate energy efficiency revenues are accounted for in the EECRF calculations by requiring a consideration of changes in load when calculating base rate recovery of energy efficiency costs, and adopts OPUC's suggested language for subsection (f)(10)(I) to include supporting information for EECRF proceeding expenses. The commission rejects the modifications proposed by OPUC for subsection (f)(10)(F), because while a utility plans a budget for projected expenditures, it is allowed to make reasonable deviations from that budget in the course of the program year. However, the commission retains full discretion to approve or disallow those historical costs. This allows the utilities some degree of flexibility in the program year while also continuing to ensure that those costs are reasonable. The commission adopts the proposal of OPUC to modify subsection (f)(10)(H) regarding incentive payments and requires a utility who provides more than 5% of its overall incentive payments to any administrator or energy efficiency service provider to provide a copy of the applicable contracts in the utility's EECRF filing. The commission notes that one of the goals of the energy efficiency programs is to foster the growth of the number of energy efficiency service providers and REPs providing competitive services. The information proposed by OPUC will allow the commission and intervenors to determine compliance with subsection (i)(2), which states that a utility should limit the number of projects or level of incentives that a single service provider and its affiliates are eligible to receive.

The commission believes that the information requested by TX ROSE and TLSC for subsection (f)(10)(J) and (K) is reasonable, but maintains that any competitively-sensitive information should be treated as confidential when it is filed with the commission.

In addition to the changes in response to comments, the commission has modified subsection (f)(10) to require utilities to submit all schedules in their applications in Excel format by retail rate class. This will assist the commission and intervenors in reviewing the applications and calculating proposed rates.

Subsection (f)(11)

Cities opposed the language proposed in subsection (f)(11)(B), stating that it shifts too much discretion away from the commission and places it instead with the EM&V contractor. They asserted that the language as currently proposed indicates that if the EM&V contractor found no material deficiencies in the utility's administration of its portfolio of energy efficiency programs, this would preclude any examination of the reasonableness of the utility's programs. They stated that PURA §39.905(b)(1) provides that the commission is ultimately responsible for determining the reasonableness of the utility's requested EECRF recovery. They asserted that while the EM&V contractor's review of a utility's program portfolio may be helpful evidence for the commission's consideration, the EM&V contractor's review should not be determinative and proposed language to this effect.

TX ROSE and TLSC made several suggested revisions to this subsection. They proposed language in subsection (f)(11) that would be a more direct statement concerning relevant factors that should be considered by the commission. They proposed language to amend subsection (f)(11)(B) to determine "whether the EM&V contractor has found any material deficiencies in the utility's administration of its portfolio of energy efficiency programs and whether the program portfolio was implemented in accordance with the recommendations made by the commission's EM&V contractor and approved by the commission." In addition, they proposed language for subsection (f)(11)(C) to clarify that the low-income expenditures must be no less than 10% of the utility's energy efficiency budget for that year, and for subsection (f)(11)(D) to clarify whether market conditions in the utility's service territory affected the ability to implement one or more of the energy efficiency programs or was a factor in its costs. They proposed language for subsection (f)(11)(E) to place the use of the utility's previous energy efficiency program costs and achievement into context. They proposed language for subsection (f)(11)(F) – (H) for clarification whether circumstances, the number of energy efficiency service providers, and customer participation have affected the ability of the utility to implement its programs or affects its costs. They proposed language for subsection (f)(11)(I) clarifying whether the utility's energy efficiency costs for the previous year or estimated for the year the requested EECRF will be in effect are comparable to costs in other markets with similar conditions. They recommended that the current subsection (f)(11)(J) be deleted as it is unnecessary with their proposed revisions, which cover the "et. al." phrase, and recommended new language which clarifies whether the utility set its incentive payments to maximize its energy and savings goal at the lowest reasonable cost per program. They proposed language for subsection (f)(11)(K), recommending a new factor which clarifies whether the utility's expenditures could have been leveraged with existing public or non-public energy efficiency programs to decrease operating costs. They noted that if energy efficiency costs can be decreased because of leveraging these relationships, consumers and utilities benefit, as utilities obtain energy savings at a more efficient cost, thereby increasing their opportunity for a bonus and lowering the overall EECRF rate.

Commission response

The commission declines to adopt TX ROSE and TLSC's proposed language for subsections (f)(11) and (f)(11)(A), because the determination of whether a utility's expenses were reasonable will be determined during the true-up/reconciliation portion of EECRF proceedings as outlined under subsection (f)(12). The factors outlined in subsection (f)(11) pertain to the setting of the utility's budget for the upcoming year. The commission believes that TX ROSE and TLSC's proposal for a new subsection (f)(11)(B) is not necessary. The commission prefers to retain the proposed language for subsection (f)(11)(C) to incorporate the statute by reference and avoid the need for the commission to reopen the rule in the case that the Legislature revises the targeted low-income set-aside. The commission adopts the language proposed by TX ROSE and TLSC for subsection (f)(11)(D)-(J) to expand and clarify the items that must be addressed in a utility's EECRF to support the recovery of program costs. As the performance bonus has been revised to encourage utilities to maximize net benefits, the commission does not believe it is necessary to add TX ROSE and TLSC's proposed language to subsection (f)(11)(K), as utilities will already have an incentive to seek such opportunities.

The commission is persuaded by the comments of Cities and adopts language for subsection (f)(11)(B) similar to the language proposed by Cities, but does wish to clarify that this subsection applies to the reasonableness of expenses not the reasonableness of each of the programs. As stated below under subsection (s), parties that participate in the EEIP process will be afforded several opportunities to weigh in on proposed program design issues.

Subsection (f)(12)

Cities opposed the proposed language in subsection (f)(12), claiming it would severely limit the scope of EECRF proceedings. They stated that the published language would preclude any party from challenging the reasonableness of a utility's energy efficiency portfolio design and would nullify the commission's discretion and authority under PURA, which provides that the commission has the ultimate authority to determine the reasonableness and necessity of a utility's energy efficiency program offerings. They asserted that a determination of prudence is critical to determining the reasonableness of the costs. They proposed language which would expand the scope of the proceeding to include the utility's compliance with PURA §39.905 and the rule, an examination of the whether the costs were reasonable and necessary, and language prohibiting the recovery of affiliate expenses.

TX ROSE and TLSC also asserted that the EECRF proceedings will be the only opportunity for parties to determine that the programs were approved in compliance with the EEIP process. They proposed adding to the list of findings of fact required in the EECRF to include whether the proposed EECRF rates complied with the requirements of PURA §39.905(f).

Joint Utilities opposed Cities, TX ROSE, and TLSC's proposal to include program design issues in the scope of the EECRF proceedings. They believed that stakeholders have the opportunity to provide input on changes in program designs when the energy efficiency plans and reports (EEPRs) are filed and during the EEIP process. This ensures that the potential arguments over program design issues take place before the programs costs are incurred.

Commission response

The commission declines to make the changes proposed by Cities, TX ROSE, and TLSC. As stated in subsection (f)(12): "The scope of an EECRF proceeding includes the extent to which the costs recovered through the EECRF complied with PURA §39.905 and this section, and the extent to which the costs recovered were reasonable and necessary to reduce demand and energy growth. The proceeding shall not include a review of program design to the extent that the programs complied with the energy efficiency implementation project (EEIP) process defined in subsection (s) of this section." Contrary to the Cities' position, the commission has not proposed to preclude any party from challenging the reasonableness of the programs offered by the utilities. Rather, the commission has expanded the existing EEIP process to include a more robust discussion and opportunity for comment on proposed programs and program design changes. There are two additional items added to subsection (s) that the commission would like to highlight. First, a utility offering new programs or making significant changes to an existing program would be required to file a petition with the commission in a separate proceeding. Second, any party that is not satisfied with the outcome of an EEIP project can file a petition with

the commission. The commission believes these additional protections are sufficient to allow the bifurcation of program expenses and program design between the EECRF proceedings and the EEIP process.

Adopted subsection (f)(13)

TX ROSE and TLSC proposed adding the state agency that administers the federal weatherization program, currently the Texas Department of Housing and Community Affairs (TDHCA), to the list of parties that receive notice in an EECRF proceeding. They maintained that since TDHCA is statutorily obligated to participate in the proceedings, it should be afforded notice to facilitate its participation.

Commission response

The commission agrees with TX ROSE and TLSC that providing notice to the state agency that administers the federal weatherization program is appropriate and has amended the language accordingly.

Existing subsection (f)(13)

Entergy Cities raised concerns that utilities were relying on the changes proposed in this rulemaking, which includes an annual true-up proceeding in lieu of a three-year reconciliation proceeding, to avoid filing a reconciliation of the EECRF expenses pursuant to this subsection in the current rule. They noted that the proposed rule replaces the triennial reconciliation proceeding with a provision that permits the review of the reasonableness and necessity of energy efficiency costs annually as part of the EECRF filing. They noted that they have attempted to address concerns regarding the expenses incurred in past program years during previous proceedings. However, testimony filed in the prior proceeding became subject to motions to strike and they were denied discovery regarding past program year EECRF expenses based upon the premise that the reasonableness and necessity of the EECRF costs would be addressed in a future reconciliation. They filed documentation from a previous EECRF proceeding in support of this claim. They stated that the obligation to seek a determination of the reasonableness and necessity of EECRF costs incurred in prior years should not be waived. They recommended that, as a remedy, the commission require the first annual filing pursuant to the revised energy efficiency rule include in its scope a determination of the reasonableness and necessity of past EECRF program years, for programs that have not been determined reasonable or necessary. Alternatively, they proposed that the each utility could be required to file for a first and final reconciliation of past program year EECRF expenses.

Cities opposed the proposed rule change to remove the current rule's requirement for utilities to reconcile their energy efficiency costs and revenues every three years. They noted that the commission has yet to undertake a reconciliation proceeding. They stated that EECRFs are to be processed in only 120 days if a hearing is requested, pursuant to subsection (f)(10)(B), and asserted that this is not enough time to complete a full review. They stated that a separate reconciliation proceeding would better facilitate a full review of the reasonableness of the costs. They asserted that the purpose of the EM&V process is to help utilities create portfolios consisting of programs that capture the most peak demand reductions at the lowest possible price, and is not designed to replace the reconciliation proceeding. They recommended that the final rule retain the language requiring a three-year reconciliation proceeding.

Commission response

Adopted subsection (f)(12) provides that the scope of an EECRF proceeding includes the extent to which the costs recovered through the EECRF complied with PURA §39.905 and this section, and the extent to which the costs recovered were reasonable and necessary to reduce demand and energy growth. This expansion of the scope of an EECRF to address what is referred to in the existing rule as a reconciliation is accommodated in subsection (f)(9) through a longer timeline for completing an EECRF proceeding. Subsection (f)(1) provides that the EECRF shall be calculated to recover the preceding year's over- or under-recovery. The commission clarifies that it intends that the adopted rule to be interpreted as follows: A utility has over-recovered costs in the preceding year to the extent that it has recovered costs through the EECRF, in the preceding year or any other prior year, that do not comply with subsection (f). For the 2013 EECRF proceeding initiated by a utility, the reasonableness of incurred expenses for all years prior to 2013 shall be an issue to be addressed because those expenses have not been reconciled. After the 2013 EECRF proceeding, the reconciliation in an EECRF proceeding will be limited to the costs recovered in the preceding year because parties will have had an opportunity in prior EECRF proceedings to challenge the appropriateness of the expenses recovered in years prior to the preceding year and the commission will have determined in those prior EECRF proceedings whether those expenses complied with subsection (f)(12).

In the proposed rule, the commission included in the scope of the EM&V contractor's responsibilities under subsection (q)(4)(C) an evaluation of the programs offered during

the program years that would have been subject to the reconciliation proceeding contemplated under the existing rule. Given that a reconciliation proceeding is set to occur in 2013 for all prior years, the EM&V contractor will not be involved in this proceeding, because the EM&V contractor would not have time to review the prior year's programs. Further, the commission intends for the EM&V contractor to focus on evaluating programs in order to improve them on a prospective basis, rather than evaluating them in order to review the appropriateness of program expenses already incurred. Therefore, the requirement for the EM&V contractor to review the programs in operation prior to 2012, as stated in subsection (q)(4)(C), has been removed.

Subsection (g); Incentive payments

TX ROSE and TLSC stated that a major problem with the current rule is its failure to ensure that customers participating in the program benefit from the incentives paid by the utilities for energy efficiency programs. They commented that since there is no requirement to pass on the incentive payment to the ultimate customer, no information is available as to what extent customers benefit from the program. They recommended amending proposed subsection (g) to require all contractors paid incentives by the utility for energy and demand savings to pass the full amount of the incentive through to the customer.

Joint Utilities requested that the commission reject TX ROSE and TLSC's proposed modifications. They stated that in some cases, a portion of the incentive provided to a contractor must be used for marketing, energy assessments, and related tasks. If all incentives were passed through to the customer, there would be little or no benefit for contractors or project sponsors to participate in the program. They also noted that providing the incentive directly to a customer in a lease property or multi-family home would not be appropriate if the cost incurred was borne by a landlord.

C***ommission response***

The commission agrees with Joint Utilities that it is not always appropriate for the customer to receive the full incentive provided by the utility to the energy efficiency provider. TX ROSE and TLSC's recommendation does not consider that utilities are restricted by PURA §39.905(a)(1) from administering competitive services under the energy efficiency programs, and therefore, additional costs will be incurred by project sponsors and contractors that might be accounted for in the incentive payment. The commission rejects TX ROSE and TLSC's recommendation and adopts subsection (g) as proposed.

Subsection (h); Energy efficiency performance bonus

TX CHPI recommended that the commission modify the bonus calculation in subsection (h) to include incentives awarded to long-range efficiency projects not yet completed or commissioned in order to account for project timetables associated with combined-heat and power projects.

OPUC stated that a bonus should only be awarded to a utility for exemplary behavior and not to a utility that does not achieve its goals or exceeds the costs caps; TX ROSE and TLSC agreed. OPUC recommended modifying subsection (h) so that a utility *may* be awarded a performance bonus. Joint Utilities disagreed and stated that the bonus is not for exceptional achievement, but rather a mechanism to incentivize greater implementation of energy efficiency programming and to partially offset lost revenue. The revisions proposed here, and under proposed subsection (h)(4), serve to de-incentivize utilities and would re-open the subject of a lost revenue recovery mechanism to provide reasonable opportunity to meet and surpass energy efficiency goals without unreasonable risk of loss. In its reply, TNMP commented that the bonus provided for under the rule allows the utility to share in a small fraction of the benefits delivered by the programs and is subject to a cap. It stated that the bonus provides a utility a partial offset of lost revenues where the programs reduce load and energy sales from the level on which base rates may have been set.

Commission response

The commission disagrees with TX CHPI that bonuses should be awarded for energy efficiency projects not yet completed or commissioned. Bonuses should be based on actual savings achieved rather than incomplete projects that may never provide savings.

The commission disagrees with OPUC. PURA §39.905(b)(2) requires the commission to establish an incentive to reward utilities administering energy efficiency programs who exceed the minimum goals established by the statute. The commission agrees with Joint Utilities that they are authorized to receive a bonus for exceeding the goals, not for an arbitrary definition of exemplary behavior. The rule already implicitly disallows a bonus for a utility that does not achieve its established goal or exceeds the cost caps from receiving a bonus. However, as explained below with respect to subsection (h)(4), the

commission will consider a good cause exception to the statutory goals, the administrative cost caps, and the overall cost caps when determining the appropriate performance bonus.

Subsection (h)(3)

CLEAResult, OPUC, and Sierra Club supported the proposal to change the basis of the bonus calculation from program costs to net benefits. Public Citizen and SEED Coalition stated that utilities should be encouraged to achieve as much energy efficiency as possible and that the bonus is an effective incentive to achieve this goal.

EDF and Cities opposed the proposed changes to subsection (h)(3). EDF stated that changes give utilities less of an incentive to try to control costs while exceeding their goals. Cities requested that the commission reject the changes, suggesting that the proposed language has the potential to greatly increase the bonuses awarded for utilities, especially large utilities with high reported net benefits. They stated that the proposed changes will provide an added windfall to large utilities without any additional actions or improvements to their programs. Further, they commented that net benefits are based on speculative numbers and a net benefits-based bonus could incentivize utilities to make changes to avoided costs forecast assumptions. Joint Utilities stated that the analysis performed by Cities does not accurately present the bonus achievable by utilities under the proposed calculation. They stated that the intent of the proposal is to base the performance incentive on net benefits as a means to tie the incentive to overall customer benefits. They commented that they are concerned net benefits will decrease in the future as a result of technology changes and revised building codes, and have already been decreased by the requirements to increase spending on the low-income programs, which are the least cost-effective programs. Further, if lost revenues were taken into account, the performance incentive ceases to be an incentive at all. They stated that staff's proposal properly recognizes that net benefits will be less in the future and attempts to maintain the status quo. That said, given the comments by OPUC and Cities, Joint Utilities requested that the current method of calculating the bonus stays in place, as there is no need to modify the current rule.

Cites recommended that if the commission decides to base the bonus calculation on net benefits, the maximum bonus be set at 6% of net benefits. OPUC also disagreed with capping the maximum bonus at 10% of net benefits. It proposed that the cap be set at 2% of net benefits to prevent utilities from receiving outrageous bonuses. TX ROSE and TLSC agreed with OPUC in its reply. Joint Utilities and Sierra Club disagreed with capping the bonus at 2%. Public Citizen, SEED Coalition, and Sierra Club recommended that the maximum bonus be restored to 20% as long as the utilities achieve both their demand and energy goals. Sierra Club commented that the bonus is an important mechanism for utilities to recoup losses in sales due to energy efficiency programs given the lack of decoupling or a lost revenue recovery mechanism for the programs. It stated that extra costs associated with the higher bonus are justified by additional savings generated by the incentive. It was supported in its concerns that the proposed changes result in less incentive for utilities to exceed their goals by Texas Citizens. In reply comments, Sierra Club stated that it now believed 10% of net benefits to be a sufficient bonus and that there is no need to increase the bonus level.

CLEAResult believed that it is inappropriate to apply rate case costs to the net benefit calculations. Sierra Club disagreed, stating that the bonus must be limited by the cost caps.

OPUC recommended the bonus calculation be based on energy savings captured through the programs rather than demand savings, as customers are billed on an energy basis and energy savings more directly correlate with bill savings. It noted that the change would end the incentive for utilities to focus on load management as a way of inflating their bonuses since the programs do not produce energy savings. Sierra Club recommended the bonus calculation include both demand and energy savings achieved beyond the goal. It commented that such a change should encourage utilities to exceed their goals in a cost effective manner.

Commission response

The commission appreciates the comments of CLEAResult, OPUC, Public Citizen, SEED Coalition, and Sierra Club regarding the transition of the bonus calculation from program costs to net benefits. The commission disagrees with EDF and Cities that the change de-incentivizes or provides an undue windfall to utilities. As stated by Joint Utilities, the intent of the change is to tie the incentive to overall customer benefits rather than program costs. The commission, therefore, also disagrees with Cities, OPUC, Public Citizen, and SEED Coalition that 10% is an inappropriate cap for the performance incentive. The commission believes that 10%, given that the bonus must also be achieved under the costs caps, is an appropriate attempt to maintain the bonus potential for utilities under the rule.

Regarding CLEAResult's request to remove rate case expenses from the net benefit calculation, the commission disagrees. All applicable expenses should be included in the calculations for an accurate representation of the net benefits of the program. The

commission also rejects OPUC's and Sierra Club's recommendations to include energy savings in the bonus calculation. The performance incentive allowed by PURA §39.905(b)(2) is based on a utility exceeding its goals. The goals for energy efficiency outlined in PURA §39.905(a)(3) are based solely on a utility's growth in demand. The commission has adopted a conservation load factor to establish an energy goal in order to encourage the utilities to develop programs with a variety of both energy and demand savings. While the commission has established that a utility must meet the energy goal prior to being eligible to receive a bonus, it believes that the demand goal is the appropriate basis for the bonus calculation. The commission has modified the rule language to clarify that the new bonus calculation method first applies to the 2012 program year.

Subsection (h)(4)

Cities, OPUC, Public Citizen, SEED Coalition, Sierra Club, TX ROSE, and TLSC commented that any utility who fails to meet their goals should not be eligible for a bonus and requests the commission eliminate the potential for such a bonus to be awarded. Cities and OPUC proposed language modifying subsection (h)(4) to reflect the requirements that a utility exceeded both its demand and energy reduction goals, and remain under the costs caps in order to achieve a bonus. TX ROSE and TLSC requested the utilities be required to meet the goal of spending 10% of its energy efficiency budget on targeted low-income programs prior to being eligible to receive a bonus. They maintained that performance bonuses should be reserved for outstanding performance and never be permitted for substandard accomplishments, including failing to meet the low-income goal.

Further, Cities, OPUC, Public Citizen, TX ROSE, and TLSC commented that utilities that apply for and are granted a good cause exemption and who do not achieve their original program goals should not be granted a performance bonus. Joint Utilities, and separately TNMP, opposed the notion that a utility who requests a good cause exception from either the goal or the costs cap should be denied a bonus. Joint Utilities stated that a good cause exception is granted based on situations beyond a utility's control that prevent it from meeting a goal. They cited the study prepared by Itron for the commission that linked the ability for a utility to meet its goal with other factors such as climate, customer mix, housing stock, and dominant type of air conditioning. All of these factors vary across service territories. TNMP commented that the suggestion that the bonus is not applicable in such a case appears to penalize a utility for requesting and demonstrating facts that support a good cause exception, which is based on commission determination that achieving either the goal or cost cap is not reasonably possible. Once the commission determines what is reasonably possible for the utility, it should be entitled to its full performance bonus based on the calculation provided for in the rule, the same as a utility operating against the statutory standard. It stated that to allow a utility to request a good cause exception, find the exception warranted, but then disqualify the utility equal opportunity to earn a bonus under the new goal is incongruous and unwarranted.

Joint Utilities recommended that rather than making a blanket determination of whether a utility is deserving of a bonus in the rule, the commission consider the availability of a bonus when the good cause exception is requested, or in the EECRF proceeding where the bonus is requested. This would allow the commission to look at the factors promoting the need to establish a lower goal.

Commission response

A good cause exception granted under subsection (e)(2) should not automatically disqualify a utility from receiving a bonus. The commission agrees instead with Joint Utilities and TNMP that a good cause exception is granted based on situations beyond a utility's control that prevent it from meeting its goal. In such cases, the bonus should be decided on a case-by-case basis, taking into consideration the factors that led to the exception being granted. As stated in response to the comments on subsection (e)(2), the commission previously approved the award of a performance bonus despite AEP TNC's request for a good cause exception to the goal calculation in Docket Number 39361. The commission rejects the language provided by OPUC and Cities and instead amends subsection (h)(4) to allow that the commission may reduce the bonus otherwise permitted under this section for a utility with a lower goal, higher administrative spending cap, or higher EECRF cost cap established by the commission, as specified in subsection (e)(2).

While the targeted low-income program is now tied to a percentage of the utilities' budgets, the commission disagrees with TX ROSE and TLSC that the utilities should be required to meet the goal of spending 10% of its energy efficiency budget on targeted low-income programs prior to being eligible to receive a bonus. As further discussed in response to comments regarding subsection (r), the commission believes it is appropriate that targeted low-income funds that remain uncommitted by July of a program year may be made available for use in the hard-to-reach program in order to further fund energy efficiency for low-income customers. Therefore, the commission rejects TX ROSE and TLSC's

recommendation to require the utility to meet the limited 10% goal prior to being eligible for a bonus.

TX CHPI recommended language that would allow the commission to award a bonus if the energy and demand savings are not met, but the project portfolio contains measures not completed or with implementation times longer than one program year, such as for combined heat and power or thermal energy storage systems. Cities opposed TX CHPI and stated that cost-based utility ratemaking is premised on the "used and useful" principle. A utility is not permitted to earn a profit on facilities that are not used and useful in providing utility service. They commented that TX CHPI's proposal would provide a profit on facilities that are not held to this standard, which is contrary to PURA.

Commission response

The commission agrees with Cities and rejects TX CHPI's recommendation to allow a bonus if energy and demand savings are not met, but projects are still pending. As discussed in response to TX CHPI's comments on subsection (h), any performance incentive awarded is calculated based on the actual savings achieved during the prior program year. The commission declines to include forecasted savings for projects that will not generate savings during the program year for consideration in the applicable EECRF proceeding.

Subsection (h)(5)

Cities stated that it would support the proposed change to subsection (h)(5) should the commission choose to adopt a bonus calculation based on net benefits. They commented that the careful consolidation of how net benefits are calculated will help ensure that ratepayers will not have to shoulder artificially inflated performance bonuses.

Commission response

The commission appreciates Cities' comments. The commission has adopted the proposed bonus calculation based on net benefits proposed in subsection (h)(3) and therefore adopts subsection (h)(5) as proposed.

Subsection (i); Utility administration

OPUC stated that customer protections are needed when providing rate case expenses to the utilities and cities. It recommended including such expenses in the administrative cap calculations and provided conforming changes to subsection (i)(1)(F) and (G).

Commission response

The commission agrees with OPUC, in part, regarding the inclusion of rate case expenses in the cost caps. As previously stated in the discussion of proposed subsection (f)(8) (adopted subsection (f)(7)), the commission believes that rate case expenses incurred by the utility should be included within the administrative cost caps and amends subsection (i)(1)(F) accordingly. However, the commission disagrees with OPUC that municipal rate

case expenses are within the utilities' control. The commission therefore rejects OPUC's recommendation and adopts subsection (i)(1)(G) as proposed.

Subsection (j); Standard offer programs

No comments.

Subsection (k); Market transformation programs

Cities and OPUC expressed concern regarding amendments to the proposed rule that would expand program eligibility to market transformation programs aimed at energy code adoption, implementation and compliance. Cities stated that energy codes are mandatory and ratepayer funds should not be used to meet objectives that must be met pursuant to law. Expending funds for such programs would contribute to free ridership problems and they expressed fear that it may be impossible to figure out whether codes achieve full compliance rates. RECA disagreed, stating that any actual programs proposed by utilities can be vetted by stakeholders after they are developed, and that the current proposed rule simply allows for the development, review and possible implementation of such programs if deemed effective.

OPUC commented that the energy efficiency program should not be providing incentives for complying with new codes as builders must already comply with applicable codes because it is the law. It stated that contractors should not be given an incentive from ratepayers to comply and modified proposed subsection (k) accordingly. RECA disagreed, stating that the proposed rule ensures that market transformation, and self-delivered programs that aim to promote early adoption or effective implementation and enforcement of energy codes are not categorically deemed ineligible simply because these energy codes may be mandatory in the legal sense. As with similar comments provided under subsection (e)(5)(C), it noted that it is widely known that compliance rates for mandatory energy codes are well below 100% even after being in place for years, and that in many locals, compliance and enforcement efforts might not exist. Further, statewide energy code updates in Texas typically lag the latest national model codes by several years, such as the two to three year gap between the availability of the 2009 IECC codes and the statewide effective date of the code. During the gap year, new homes were required to meet an older version of the code, potentially forfeiting substantial energy and peak demand savings over the useful lifetimes of the homes.

While Sierra Club stated that it supported proposed subsection (k), it recommended additional language requiring the utility programs to actually lead to better enforcement, compliance and installment of energy efficient buildings. It stated that an expression of support as stated in the proposed rule is not enough to count towards savings and peak demand reductions.

Commission response

The commission agrees with RECA and disagrees with Cities and OPUC regarding market transformation programs aimed at achieving compliance with energy and building codes. As discussed previously in response to comments regarding subsection (e)(5)(C), energy code compliance rates fall well below 100%. Therefore, the commission does not agree with Cities that encouraging compliance contributes to the free ridership problem or share their concerns that it may be impossible to determine whether full compliance with codes is achieved. Likewise, the commission agrees that encouraging early adoption can result in

substantial demand and energy savings. The commission disagrees with OPUC that the language in subsection (k) should be struck from the rule and therefore declines to make the change. The commission also disagrees with Sierra Club that additional language is required for actual energy and demand savings to be achieved. Market transformation programs that are designed to express support for the most recent versions of energy conservation codes must still meet all the other requirements of this section, including providing measurable and verified savings. The commission adopts subsection (k) as proposed.

Cities cited concern that any savings claimed from behavioral modification type programs would be highly speculative and unreliable as no good method exists for deemed savings resulting from such programs. They stated that ratepayers need some certainty that what they are paying for is creating real energy efficiency savings and therefore suggested removing all sections of the rule that would allow behavioral modifications measures from being eligible for funding. Joint Utilities responded that Cities' recommendation was in direct contrast to PURA §39.905(d)(16), which provides that an energy efficiency program may include "energy use programs with measurable and verifiable results that reduce energy consumption through behavioral changes that lead to efficient use patterns and practices." They stated that the requirement for behavioral programs to have measurable and verifiable results is a safeguard that should address Cities' concerns. Further, the EM&V process should provide additional review of any savings claimed through behavioral programs. They requested that the commission reject Cities' recommendation to remove behavioral modifications from the measures eligible for funding under the rule.

Commission response

The commission understands the concerns regarding savings claimed from behavioral modification based programs, but rejects Cities' recommendation to remove all allowances for such programs from the rule. The commission agrees with Joint Utilities that PURA §39.905(d)(16) allows the commission to authorize utilities to offer programs with measurable and verifiable results that reduce energy consumption through behavioral changes that lead to efficient use patterns. Measurement and verification will be used by utilities to estimate savings for behavioral programs absent the availability of deemed savings. As stated in response to Pepco with respect to subsection (e)(3), behavioral programs are geared towards educating and motivating the customer in such a way that they modify when and how much energy they consume.

Pepco stated that the proposed rule missed the opportunity to address more permanent peak shifting through thermal storage. It noted that with unbundling, the benefits of thermal storage were split between generators, retailers, utilities and customers, and that the customer benefit alone is insufficient to drive customers to invest in thermal storage. It recommended that the commission direct utilities, through the rule itself or through additional guidance, to develop a statewide market transformation program promoting on-site thermal energy storage. It commented that thousands of MWs could permanently and quickly be shifted off peak, reducing the need for new peak capacity.

Commission response

As discussed in response to comments filed regarding subsection (c)(14), the commission believes that providing incentive payments under the energy efficiency program to promote thermal solution at generation facilities is beyond the scope of the rule. The commission maintains, with support from the statute, that the goal of the energy efficiency program is to reduce demand, not to increase the efficiency of generation plants. To the extent that thermal storage could be installed at an eligible customer's premise and be classified as captured waste heat, steam, or cold from cogeneration technologies, then the project could fall under the classification of a combined heat and power project, which is currently eligible for inclusion in energy efficiency programs, as outlined in subsection (m)(1)(E).

Subsection (l); Self-delivered programs

TX ROSE and TLSC stated that the proposed rule fails to define the term "self-delivered program" or determine when a self-delivered program is allowed and how the commission would make that determination. They recommended language amending proposed subsection (l) to clarify that a self-delivered program is a program made directly available to customers by a bundled utility instead of through an energy efficiency service provider, and a utility may offer a self-delivered program upon a finding by the commission that the self-delivered program does not violate §25.343 and is necessary to provide energy efficiency service to customers in the service area.

Joint Utilities requested that the language proposed by TX ROSE and TLSC be rejected. They stated that the language offered by TX ROSE and TLSC fails to distinguish between utilities in an area in which customer choice is offered and those in an area in which customer choice is not offered. The utilities in an area in which customer choice is not offered have lower regulatory requirements when offering self-directed programs under SB 1125.

Commission response

The commission agrees with Joint Utilities and rejects the language proposed by TX ROSE and TLSC regarding self-delivered programs. PURA §39.905(h)(1) allows utilities in areas not open to competition to offer self-delivered programs and subsection (h)(2), pursuant to PURA §39.905(h)(2), allows such utilities to develop new programs other than standard offer or market transformation programs with commission approval. PURA §39.905(i) requires a utility in an area open to competition to petition the commission for approval after a contested case hearing in order to offer a self-delivered program, and the self-delivered program may be offered only in a rural area. With this direction, the commission has modified the rule throughout to incorporate self-delivered programs, including a definition of such programs in subsection (c)(52).

Subsection (m); Requirements for standard offer, market transformation, and self-delivered programs

TX ROSE and TLSC commented that the intent of the original energy efficiency rule was to design programs that would operate in the competitive market and gradually phase out utility involvement in energy efficiency. Yet, they stated changes to the rule are having the opposite effect as utilities are being required to broaden the scope of their programs to include incentive payments for behavioral measures, energy audits, and program advertisement. They commented that the addition of self-delivered programs seems to further return to the model of utility owned and operated energy efficiency that was previously rejected.

Commission response

PURA §39.905 specifically allows such incentives under subsections (a)(5), (d)(16) and (j), regarding educational materials, behavioral programs, and energy audit programs, respectively. Further, as discussed above, PURA §39.905(h) and (i) allow the utilities to offer self-delivered programs directly to customers in certain circumstances. Thus, these programs are expressly contemplated by PURA §39.905.

Subsection (m)(1)

TX ROSE and TLSC recommended that subsection (m)(1) of the proposed rule should include a provision requiring the contractor to pass utility incentives through to the customer in all cases where residential customers are investing their own money for an eligible energy efficiency measure. They noted that the customer has no choice but to pay the costs of the programs through rates and therefore should receive the incentive and provided language accordingly.

Commission response

As explained with respect to subsection (g), the commission does not believe that a contractor should be required to pass the full utility incentive through to a customer. The commission, therefore, rejects TX ROSE and TLSC's proposed changes to subsection (m)(1).

TX ROSE and TLSC stated that the hard-to-reach (HTR) program was initially designed to provide customers with incomes up to 200% of the federal poverty guidelines with a comprehensive energy efficiency program at no charge or a very low cost. It came to their attention that HTR contractors are charging customers and that the utilities have no limits on how much a contractor can charge HTR customers for the services. They recommended an additional provision to proposed subsection (m)(1), asserting that all programs serving low-income customers, including the HTR program, shall be provided to the customer at no cost.

Commission response

HTR programs have different requirements and purposes than the targeted low-income programs, which must comply with the same requirements as federal weatherization assistance programs. The HTR programs are provided to customers who meet the same income guidelines as for targeted low-income programs. The customer is informed of certain measures that would improve the efficiency of the customer's home. In some cases, a measure such as attic insulation may be provided at no cost to the homeowner, depending on the amount of insulation currently installed in the customer's home. In other instances, the customer is informed that there is an incremental cost that will be borne by the customer, and the customer is given the option of proceeding with the installation or rejecting the project. This program installs measures that are included under the utilities' residential standard offer programs, but there are energy efficiency service providers who focus on customers that may qualify for the HTR programs. This program design results in the utilities operating HTR programs that are much less expensive on a cost per kW

basis than targeted low-income programs, and therefore allows utilities to provide a greater number of incentives for energy efficiency measures compared to the targeted low-income programs.

The targeted low-income programs are markedly different from the HTR programs. Energy efficiency service providers first conduct an energy audit to determine which measures would improve the efficiency of a home. Each measure on the list is ranked in terms of the Savings-to-Investment Ratio (SIR). All measures with an SIR of 1.0 or greater qualifies for installation, up to a total of $6,500 per home. While this relieves the homeowner of any financial obligation, it results in fewer homes being served and a much greater cost per kW.

Therefore, the commission does not feel it is good policy to require the utilities to administer the HTR programs under the same standards as the targeted low-income programs, as the HTR programs must meet the cost-effectiveness standard under subsection (d) while targeted low-income programs are subject to the SIR defined in subsection (r).

Subsection (m)(1)(E)

TX CHPI proposed modifying the rule to allow incentives paid for distributed generation, geothermal, heat pump, solar water heater and combined heat and power technologies to be paid for the first two megawatts of the installed system.

Commission response

Subsection (m)(1)(E) already allows for utility programs to incentivize the use of distributed renewable generation, geothermal, heat pump, solar water heater, and combined heat and power projects up to ten megawatts. Therefore, the commission believes TX CHPI's proposed change is unnecessary.

Subsection (m)(1)(F)

Pepco, Sierra Club, TX ROSE, and TLSC expressed concern with allowing the baseline to be dropped to reflect actual or typical efficiency savings. TX ROSE and TLSC stated that allowing a baseline to be established using typical or actual current features is inconsistent with other provisions in the rule regarding baselines and measurement and evaluation processes. Pepco stated that while it would benefit from receiving credit for the actual savings if the incentives offered were also based on actual savings and thereby increased; allowing the baseline to be dropped to reflect actual or typical efficiency could more than double the credit for any given project. Pepco and Sierra Club commented that by allowing a utility to take credit for the actual improvement of a measure rather than the marginal improvement achieved over the current code baseline, utilities could reduce by half what must be acquired to meet their energy efficiency goals, which does not seem necessary given the current levels of the goals. Sierra Club stated that the changes made to proposed subsection (m)(1)(F) need clarification. Pepco, TX ROSE, and TLSC recommended that the baseline calculations in proposed subsection (m)(1)(F) be rejected.

Commission response

The commission agrees with the comments of TX ROSE and TLSC that this subsection may be read to be inconsistent with the definition of baseline in subsection (c)(2) and the calculation of the baseline in subsection (q)(8). In contrast to the comments of Pepco and Sierra Club, the commission believes that there may be instances when the baseline cannot be determined based on a current code, so it is necessary to provide further delineation of the baseline, as stated in subsection (q)(8).

As stated in subsection (q), TX ROSE and TLSC state that changes to proposed subsection (m)(1)(F) may result in potential conflicts with language proposed in subsection (q)(8). Subsection (q)(8) more clearly defines the calculation of the baseline, and therefore, the commission deletes subsection (m)(1)(F) and re-designates subsequent subparagraphs accordingly.

Subsection (m)(1)(G)

Given the discussion under proposed subsection (m)(1)(F), OPUC, TX ROSE, and TLSC recommended that proposed subsection (m)(1)(G) be deleted as well.

Commission response

While the commission believes that subsection (m)(1)(F) should be deleted in favor of the more prescriptive language proposed in subsection (q)(8), the commission disagrees with OPUC, TX ROSE, and TLSC that subsection (m)(1)(G) should be deleted as well. As previously discussed in response to comments regarding proposed changes to subsection

(k), the commission believes that utilities should be allowed to offer market transformation programs designed to promote compliance with building and energy codes. Subsection (m)(1)(G) provides conforming changes to the amendments adopted under subsection (k), and therefore the commission adopts the provision as proposed.

Subsection (m)(1)(H)

TX ROSE and TLSC stated that the information listed in proposed subsection (m)(1)(H) should be mandatory rather than an optional utility requirement. They commented that there is no excuse for a contractor to not provide this information to the customer.

Commission response

The commission disagrees with TX ROSE and TLSC's assertion that the information proposed under subsection (m)(1)(H) should be mandatory and declines to make the proposed changes. The information that may be required under the provision would be provided at the utility's request to the utility, not the customer. Each utility should be given some latitude in defining the requirements for their service providers and contractors.

Subsection (m)(2)(F)

TX ROSE and TLSC stated that a utility that finds poor performance in a contractor's work should be required to limit or disqualify the contractor from participating in a program until satisfactory changes and practices are adopted by the contractor.

Commission response

The commission disagrees with TX ROSE and TLSC that a utility should be, at any point, required to limit or disqualify a contractor. Utilities should continue to have the discretion to disqualify contractors on a case-by-case basis, according to their own specific procedures.

Subsection (m)(5)

Cities, ERCOT, and TIEC expressed concern with proposed subsection (m)(5). NAPP supported the language as proposed.

ERCOT expressed concern that subsection (m)(5) could be read to establish an obligation on ERCOT's part to compensate providers for energy supplied or demand response supplied to the grid. It commented that its protocols do not allow for such compensation and recommended the rule be clarified to remove any unnecessary confusion. It provided language modifying the rule to state that the qualified scheduling entity (QSE) representing a provider is not prohibited from receiving revenues from energy sold in ERCOT energy markets in addition to any incentive for demand reduction offered under a utility load-control standard offer program. REP Coalition agreed with ERCOT that proposed subsection (m)(5) should be modified to clarify that payments will be made to a QSE for any revenues settled in the ERCOT market. EnerNOC also agreed, commenting that the ERCOT language makes clear that just because a provider receives an incentive for a demand reduction call it does not prohibit the provider's QSE from also offering energy for sale in the ERCOT market.

TIEC stated that any utility load management program that would emulate or would constitute subsidized participation in the ERCOT energy or ancillary services markets should be removed from the programs. They stated that in no event should the same load be counted toward a utility program and be simultaneously allowed to participate in the ERCOT market. EnerNOC agreed with TIEC that the language should not be interpreted as allowing a provider to receive compensation from both a utility and ERCOT for the same demand reduction.

NAPP agreed that a provider should not receive incentives for both programs when the programs are intended for the same purpose or provide the same benefit. It stated that utility programs duplicate the reliability purpose of the ERS program, and ultimately, ERCOT should manage all of the reliability resources. It noted that ERCOT could learn from the utility programs' recent ability to attract participation. Further, it commented that the utilities should always be able to initiate load management programs that allow them to accomplish other goals appropriate to their missions, such as deferring transmission and distribution costs or relieving local congestion. Such programs provide direct benefit to the utility, and therefore, they should be financed out of their own rate revenues rather than receive guaranteed rate recovery form the efficiency programs. If the programs are continued, it stated that the commission could view the programs as a potential tool for piloting demand response programs for new customer classes or end-use applications. Even with ERCOT's new ability to conduct pilots, it commented that the utilities may have more flexibility to test new concepts or experiment with approaches prior to the programs being picked up by ERCOT and adopted as a full program. At that time, a utility should cease to offer the same program.

Commission response

The commission appreciates the comments of ERCOT, REP Coalition, and EnerNOC regarding a QSE's ability to sell energy into the ERCOT market and receive an incentive for demand reduction from a utility and adopts ERCOT's suggested changes to this subsection. The commission also agrees with ERCOT, TIEC, EnerNOC, and NAPP that a provider should not receive payments from both ERCOT and a utility if its demand reduction provides the same benefits or serves the same purpose for both programs. As discussed in response to comments filed in regards to the first preamble question, the commission believes the utility load management programs provide a continued value. PURA §39.905(d) grants the commission the authority to consider the ability of a program to reduce costs to customers through several factors, including the relief of congestion and subsection (d)(6) specifically mentions energy management and demand response programs. Approved energy efficiency programs are subject to rate recovery through the EECRF. The commission agrees with NAPP that the utility programs are an important and useful tool for offering demand response pilot programs and testing new end-use applications. CenterPoint has already begun offering a REP pilot standard offer program this year that provides incentives towards the cost of installing direct load control equipment, smart thermostats, and in-home devices.

TIEC stated that the last sentence in proposed subsection (m)(5) is unclear and unneeded. They noted that any ERCOT market participant that owns or has previously contracted for an energy supply may already sell that energy into the wholesale market if it is not being used. They expressed concern that including the specific language in the rule may inadvertently create issues for any contractual agreements that do not allow a provider to retain revenues from energy sold into the wholesale market, such as if the provider were obligated to pass revenues through to a third party. They also stated that they opposed any implication that the language somehow supports double-payment for demand response, as the issues have already been discussed at ERCOT as part of the discussion on Loads in SCED.

Cities proposed language clarifying that an energy efficiency service provider is allowed to receive payment for demand reduction offered under both utility and ERCOT programs only to the extent that the payments do not involve the same interruption event. EnerNOC requested that the commission reject Cities' proposed modifications. It stated that it does not support duplicative compensation, but Cities' language would prohibit a provider from participating in a load management program as well as serve distributed generation customers who are allowed to sell energy at ERCOT under the ERS program.

NAPP and REP Coalition disagreed with Cities and TIEC that the last sentence of proposed subsection (m)(5) should be amended or deleted. REP Coalition stated that it does not endorse any double-dipping of payments for demand response, but that it reads proposed subsection (m)(5) to refer to the ability of a provider to receive an incentive from the utility, which acts as a capacity payment for load available for interruption, and to receive revenue from demand response economically dispatched through ERCOT, which acts as an energy payment based on a providers' price to interrupt. It stated that this allows for two separate revenue streams that are legitimately available to the provider with each type of payment serving a distinguishable purpose rather than a double payment for the same demand response. NAPP stated that while an energy payment in the energy-only market may implicitly include some capacity value, an exact amount or method of calculating the energy payment can be developed in the ERCOT stakeholder process. It commented that this would allow smaller customers to participate in demand response in much the same way as many industrial customers currently do.

Further, NAPP believed that loads providing benefits in addition to reliability benefits should be able to receive compensation from both ERCOT and the utility. The purpose of the utility program would be distinct from the ISO program and if the load is called from both programs and curtails as promised, the load would be considered in compliance with both programs. It provided language in proposed subsection (m)(5) that would accommodate such a concept.

Commission response

The commission appreciates the comments of Cities, EnerNOC, NAPP, REP Coalition, and TIEC regarding potential double-dipping of payments for demand reduction. The commission clarifies that the last sentence in subsection (m)(5) allows a load management provider to receive an incentive for capacity provided under the utility program and payment for any energy sold on their behalf in an ERCOT market.

The commission amends subsection (m)(5) to state that a service provider is not permitted to receive incentives for the same demand reduction benefit for which it is compensated (through a capacity payment) by an independent organization, independent system operator, or regional transmission operator. The commission further amends the last sentence of the subsection to clarify that qualified scheduling entities are not prohibited

from receiving revenues (through an energy payment) from energy sold in the ERCOT markets. The commission declines at this time to adopt language regarding specific demand response, energy, ancillary service, or capacity programs. The commission believes that a global approach to assuring that resources do not receive duplicative compensation for the same curtailment should be undertaken through the ERCOT stakeholder process. The commission encourages the utilities and ERCOT staff to explore instances when a load participating in the load management program can provide a distinct and separate benefit through the ERCOT market during a contract period. The rule as adopted gives ERCOT the flexibility to adopt protocol and market guide amendments through the ERCOT process rather than the commission developing a requirement through this rule for ERCOT to undertake such an effort.

The commission appreciates the comments of TIEC. The commission has addressed its concerns about the last sentence of the rule subsection by clarifying that a QSE is not prohibited from receiving revenues from energy sold in the ERCOT markets, rather than the energy efficiency service provider being allowed to receive revenues as was originally proposed.

Subsection (m)(6)

REP Coalition and Walmart supported proposed subsection (m)(6). CenterPoint, EDF, EnerNOC, and Sierra Club encouraged the continuation of utility-administered load management programs. TIEC did not oppose programs with a separate and valid utility purpose from continuing as utility-based programs.

REP Coalition commented that proposed subsection (m)(6) is structured similarly to PURA §39.905(b)(7), as both impose a requirement promoting the full participation of load resources in ERCOT's competitive energy markets, conditional on certain qualitative prerequisites. Neither provision is an all-or-nothing proposition.

Walmart stated that the proposed rule is appropriate in shifting costs from ratepayer-funded demand response to market-based options as they become available. Walmart commented that the proposal is flexible enough to ensure customers seeking to participate in load management programs will continue to have options equivalent, or where ERCOT offerings do not replicate those of the utility, the same as those options currently enjoyed. REP Coalition agreed, in part, providing language to address the scenario in which a utility's load management program does not transition to the ERCOT wholesale market, such as if one or more programs cannot be feasibly integrated within the framework of the competitive energy market in the short-term. It specifically acknowledged obstacles residential and small commercial load might face with transitioning to ERCOT markets, but stated that any exclusion should not be permanent.

REP Coalition noted that the Brattle Report indicates the efficient integration of price-responsive load in the ERCOT market is unlikely feasible in the short-term and loads in ERCOT are not presently capable of expressing price-sensitive offers in SCED. The report also noted that feasible integration of load will entail something more than the completion of the Loads in SCED initiative. It stated that it views the feasible integration of loads envisioned by proposed subsection (m)(6) as a long-term objective and that the Brattle Report should alleviate many of the concerns expressed by parties in opposition of proposed subsection (m)(6). It maintained that the continued operation of the programs is not threatened in the short-term and may remain unaffected for a significant period or longer. It stated that the integration of loads proposed in subsection (m)(6) remains an important objective to promote more robust and comprehensive demand response, which is critical to the long-term success of the ERCOT wholesale market.

TIEC maintained that any utility program that is being administered and deployed like an ERCOT ancillary service, or in a way that mimics market participation, should be discontinued and the load management activity provided exclusively through the market. They stated that regulated utilities should not be in the business of offering subsidized “shadow” programs that mimic market participation without the strict requirements of actual ERCOT market participation. They noted that many utility programs are deployed during ERCOT Energy Emergency Alert (EEA) 2, which is the same trigger as ERS, and are in some cases, according to ERCOT comments, competing with ERS for load participation. They commented that PURA §39.001(c) explicitly prohibits utilities from participating in the competitive market.

Sierra Club stated that while the language proposed in subsection (m)(6) is satisfactory, it cautions against the assumption that market-based programs alone will serve to reduce peak demand to the full potential. EDF stated that it believes utility programs and the ERCOT market-based programs are complimentary rather than mutually exclusive, and the potential for load management programs to provide ERCOT with a substantial amount of reliable resources far exceeds both current programs’ participation rates. It commented that given concerns regarding resource adequacy it seems shortsighted to plan a phase-out of one type of program in favor of another, especially given the current low level of load management within ERCOT.

CenterPoint stated that load management programs are a vital component within its overall energy efficiency portfolio, producing approximately 100 MW of savings in 2010 and 2011. It stated that with an increase in load management efforts in light of resource adequacy concerns, its 2012 program have been designed to achieve approximately 200 MW of savings. The programs are the most cost-effective programs in CenterPoint's portfolio, and if phased out, it would need to increase energy efficiency spending beyond the costs caps by 2015 in order to continue meeting its goals. It stated that without the load management program, overall portfolio costs per kW would increase approximately 150% to nearly $650 per kW.

REP Coalition also commented that load management programs grandfathered under PURA §39.905(a)(6) may be exempt from the transition and integration requirements proposed as a matter of legal infeasibility and that their continued deployment could considerably benefit the market during emergency conditions, as long as it does not dampen or reverse price signals in the competitive market.

EnerNOC commented that it supports allowing utilities the flexibility to continue to provide load management programs even after loads are able to participate in the ERCOT energy market. While it understood that proposed subsection (m)(5) and (6) intend to provide that flexibility, it is concerned with the use of the terms "feasible" and "feasibility," as they could be interpreted as more prescriptive. It recommended that the commission replace the terms to reflect that the programs will "voluntarily" integrate to the ERCOT market.

REP Coalition disagreed with the language proposed by EnerNOC and stated that something more than voluntary integration of loads is required to meet the objective of price-setting demand response. It stated that proposed subsection (m)(6) does not require ERCOT to administer these utility load management programs, rather that the loads participating in a utility program will transition upon their feasible integration into the competitive energy market. Any participation in the competitive energy market is voluntary, and to the extent that a utility facilitates the loads' voluntary integration through the load management programs, the programs will reside at the utility rather than ERCOT.

REP Coalition stated that any remaining utility programs should be deployed concurrent with ERCOT's deployment of load resources obligated to provide ERS. It also noted a need for ERCOT to implement a mechanism ensuring that deployment pursuant to a retained load management program does not cause a price reversal or otherwise negatively impact wholesale market prices during the deployment period. The mechanism should cover the full duration of the deployment. It cited discussion of such a mechanism at ERCOT in the "0 to LSL" issue. It stated that ultimately loads that transition need to be dispatched based on price, rather than the same criteria as ERS, but performance standards for non-transitioning load management should be comparable to ERS and provided modifications to proposed subsection (m)(6) to clarify this intent.

EnerNOC stated that REP Coalition's proposed modifications requiring utility programs to be deployed when ERCOT deploys ERS are unnecessary. It stated that ERCOT already has an MOU regarding coordination with the utility programs and it is concerned that REP Coalition's proposal would undermine additional operational benefits the programs provide independent of ERCOT operations.

TIEC proposed modifying subsection (m)(6) to assert that loads that participate in the ERCOT energy or ancillary services markets may not participate in utility load management programs. They commented that this change is consistent with their comments under the second preamble question.

REP Coalition stated that TIEC's amendments concerning double payments should be rejected. It maintained that the incentive payment for participating in the load management program and the payment received for energy sold through the ERCOT real-time market is separate and distinguishable.

Commission response

The commission appreciates REP Coalition and Walmart's support of the market-based competitive energy programs and economic dispatch. As discussed at length in response to comments filed regarding the first preamble question, the commission believes that many loads will voluntarily migrate to ERCOT programs such as ERS and Loads in SCED when it is launched due to more attractive pricing in those markets for load. The commission continues to support and prefer market-based economic dispatch of resources. However,

the commission disagrees with REP Coalition, TIEC, and Walmart that the commission should require a transition tied to a specific trigger. The commission agrees with comments filed by ERCOT regarding the first preamble question that the Loads in SCED initiative would not be an appropriate trigger for a transition. Furthermore, some loads may not be able to participate in ERCOT markets due to technical requirements. Customers should choose the appropriate demand response, energy, ancillary service, or capacity program for their load. The customer should consider whether any integration of its load into the ERCOT markets is feasible. The commission encourages the utilities to work with ERCOT, energy efficiency service providers, and customers to determine if load management participants can be best served by programs in the ERCOT markets. The commission amends subsection (m)(6) to state that utilities offering load management programs shall work with ERCOT and energy efficiency service providers to identify eligible customers and shall integrate such loads into the ERCOT markets to the extent feasible.

The commission agrees with CenterPoint, EDF, EnerNOC, Sierra Club, and TIEC that the utility load management programs should continue for small, less sophisticated customers and should continue to the extent they serve a separate purpose or are able to provide benefits such as targeted congestion relief to individual utility systems. Small, less sophisticated load, such as residential and small commercial customers, may not have access to a feasible means of participating in the ERCOT market for several years. The commission further amends subsection (m)(6) to state that integration shall not preclude the continued operation of utility load management programs that cannot be feasibly

integrated into the ERCOT markets or that continue to provide separate and distinct benefits.

The commission has addressed TIEC's concerns regarding potential double payment in response to comments filed regarding subsection (m)(5). The commission has also addressed REP Coalition's concerns regarding the utility programs' deployment concurrent with ERS and reverse pricing signals in response to comments filed regarding the first preamble question. The commission, therefore, rejects the language proposed by REP Coalition.

TX ROSE and TLSC recommended the rule include a reporting requirement for the utilities and ERCOT to report to the commission every six months on the progress of allowing loads to participate in the energy market and a timeline for transitioning the load management programs to ERCOT. They stated that the transition could be accomplished by December 31, 2014. REP Coalition disagreed, stating that the high-level directive provided by subsection (m)(6) is sufficient and that the rule need not specify the process or schedule for transitioning load management programs to ERCOT's SCED system. It commented that the provision provides the utilities, ERCOT, and interested market participants the flexibility to work on the details of the transition and integration and is consistent with the general approach taken by the commission in other rules addressing ERCOT's administration of similar services, such as ERS.

Commission response

The commission agrees with REP Coalition that TX ROSE and TLSC's recommendation to include specific reporting requirements regarding the transition of load management programs is unnecessary. The Loads in SCED initiative is in the beginning development stages and significant stakeholder input will be required before any such mechanism is available in the ERCOT market. Adopting a specific timeline for the transition is unrealistic at this point. Commission staff has been involved in the discussions at ERCOT involving Loads in SCED and will continue to participate and follow developments in the project as they occur.

Subsection (n); Energy efficiency plans and reports (EEPR)

Subsection (n)(2)(I)

TX ROSE and TLSC commented that information needed to evaluate programs, especially low-income programs, is not provided by the utilities and their contractors. They recommended amendments to proposed subsection (n)(2)(I), requiring the utility budget information reported in the EEPR to include a break-out for targeted low-income energy efficiency customers.

TX ROSE and TLSC also recommended a new provision to proposed subsection (n)(2), which would require the EEPR to contain a table illustrating how incentives are to be passed through to customers under each energy efficiency program, except those for targeted low-income customers. They noted that the HTR program information should instead show any amount that was charged to the customer over and above the incentive paid to the contractor by the utility.

Commission response

The commission disagrees with TX ROSE and TLSC that additional reporting information for low-income programs is needed in the EEPR. The EEPRs filed by the utility are already required by subsection (n)(2)(I) to break-out programs by customer class, including HTR customers and any other set-asides. The utilities, therefore, are already providing a break-out for low-income programs in the EEPR. Based on the response provided under subsection (g), the commission rejects TX ROSE and TLSC's recommendation to require the utility to illustrate how incentives are to be passed through to customers.

Subsection (o); Review of programs

TX ROSE and TLSC stated that they anticipate that the EECRF process will afford intervenors the opportunity to evaluate a utility's programs and recommended that this subsection be modified to expressly state that the EECRF is the proper forum.

Commission response

As discussed with respect to subsection (s), the commission is modifying the role of the Energy Efficiency Implementation Project (EEIP) to allow a more complete review of new programs and significant changes to existing programs prior to implementation. This allows commission staff and stakeholders to focus on the reasonableness of expenses incurred for administering the programs during the EECRF proceedings. Therefore, the commission declines to adopt TX ROSE and TLSC's suggested change.

Subsection (p); Inspection, measurement and verification

TX ROSE and TLSC believed that every program should be required to follow the same protocol. Therefore, they recommended that the phrase "or a protocol approved by the commission" be deleted. They also stated that the new provisions added to address behavioral programs should be modified so that measures installed under these programs are verified before payment is made. Likewise, they suggested that subsection (p)(3), which requires a customer's signature verifying the measures were installed, provide an alternative standard for behavioral programs.

Opower opposed TX ROSE and TLSC's comments that behavioral programs should be evaluated using approved industry standards for installed rather than behavioral measures. It stated that these programs are fundamentally different and require different approaches. It asserted that behavioral programs continue to be implemented over time and messages and interventions must be delivered consistently to encourage behavior that reduces consumption. It believed behavioral programs should be treated according to industry best practice and offered examples such as the DOE consensus report, which recommends the use of random controlled trials, ex-post measurement, and the panel data method analysis for evaluation of energy savings. *See Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations*, the State and Local Energy Efficiency Action Network (May 2012). It added that this approach is endorsed by all parties to the document and urged the commission to adopt this best practice for the evaluation of behavioral programs.

Opower also cautioned that TX ROSE and TLSC's comments regarding the creation of a single protocol, passing through all incentives, and treating behavioral program service providers the same as all other service providers would be counter to the goal of maximum energy efficiency at the least cost. It stated that while on the surface their suggestions may appear to bring uniformity to all programs doing so could prevent implementation of new programs that do not emulate the existing programs. To support its position, Opower countered TX ROSE and TLSC's comments that behavioral program service providers should be reimbursed once work is completed. It pointed out that the proposed rule would allow a utility to reimburse a behavioral service provider on an incremental basis, which is consistent with industry best practices; however, the utilities would still need to verify that the work is completed.

Commission response

While there are currently no behavioral programs being offered in the areas open to competition, there are potential service providers interested in offering these programs. Some programs are set up in such a manner that customers in the participant group would receive monthly mailings that suggest ways a customer could reduce their usage, ranging from changes with very little cost to installation of new appliances. In other programs, usage for a group of consumers with similar-sized homes and usage patterns is continually compared to the participant's monthly consumption to try to promote changes in consumption. The reduction in consumption is measured by comparing the baseline electricity usage, provided by a control group, with the participant group's consumption. One of the first academic journal articles evaluating the effectiveness of the behavioral programs demonstrated that the average program reduces energy consumption by 2.0%.

See **Allcott, H.,** ***Social Norms and Energy Conservation, Journal of Public Economics (2011).*** **Utilities offering a behavioral program would claim similar savings and count those towards their energy and demand reduction goals. In addition, Sharyland plans to offer a behavioral pilot program in 2013 to its customers in the areas not open to competition and expects savings ranging between 1.5 and 3%.**

The commission agrees with Opower that the behavioral programs vastly differ from the traditional programs currently offered by the utilities. The commission also believes that it may be appropriate to consider other protocols and best practices beyond the IPMVP and the DOE consensus report for behavioral programs and would like to retain the flexibility to consider other sources. Therefore, the commission declines to make the changes suggested by Opower, TX ROSE, and TLSC.

Further, due to the unique relationship between energy efficiency service providers offering behavioral programs and customers participating in these programs, it may be difficult to ascertain which measures were installed based on the mailings received by the customer. However, through bill analyses it can be determined that the customer's overall usage has declined. The utility would be responsible for conducting an inspection at some future date, and the verified savings can be captured by the utility to meet its demand or energy goal. Therefore, the commission agrees with Opower that behavioral program service providers may receive incentives on an incremental basis.

Subsection (q); Evaluation, measurement and verification (EM&V)

Public Citizen and SEED Coalition supported the addition of an EM&V process and added that it is likely to result in significant improvements and an increased level of transparency, including uniformity among the various utilities' programs. OPUC stated that it is a proponent of the framework proposed in this subsection. Likewise, Pepco supported evaluation of the programs, but urged the commission to use the reports to improve the programs on a prospective basis, rather than penalizing the utilities.

Commission response

Concerning Pepco's comments, the results of the EM&V process will be used to make improvements to programs for future program years, but may also be used in evaluating the reasonableness of a utility's expenses recovered through its EECRF.

Joint Utilities believed that the addition of this section increased the complexity of the rule and included some additional details that may be best included in the TRM or the commission's request for proposal (RFP) and contract with the EM&V contractor. They were specifically concerned that references to certain external documents and possible approaches can not only become outdated, but it would be more difficult to make changes to the rule in response to frequent EM&V changes. Moving appropriate sections of subsection (q) to other documents allows the commission the flexibility to make changes in a more efficient manner as the situation warrants. CLEAResult, Public Citizen, and SEED Coalition offered their support for Joint Utilities' suggestion to simplify the EM&V program requirements outlined in the rule to maintain flexibility in conducting the evaluations. OPUC agreed with the Joint Utilities, but went a step further to add that the sections removed from the rule could be moved to the TRM that is approved by the EEIP, which ensures that the stakeholders can participate in the approval process.

Commission response

The commission agrees that details of the EM&V activities should be removed from the rule to allow for more flexibility as circumstances change. Specifically, the commission has responded to the comments by deleting language that describes the principles that guide the EM&V activities (previously included in subsection (q)(2)), outlines plans (previously included in subsection (q)(4)), including the requirement to review programs from prior years and reports (previously included in subsection (q)(7)) to be provided by the EM&V contractor, the associated schedule (previously included in subsection (q)(9)), and specific impact evaluation activities (previously included in subsection (q)(5)). The commission believes this information is more appropriately included in the scope of work included in the RFP and contract documents or the TRM. The commission has also made clarifications throughout this subsection.

Joint Utilities commented that subsection (q) does not clearly state whether the burden falls on the utilities to continually update deemed savings values and installation standards, or if the EM&V contractor will now be responsible for making these updates. Alternatively, the utilities could be required to make the necessary updates and the EM&V contractor would review any petitions filed by the utilities. They requested clarification on this issue.

Commission response

With regard to Joint Utilities' request for clarification, utilities would still be responsible for filing petitions to revise or establish new deemed savings pursuant to subsection (i)(4). The approved deemed savings will be included in future updates to the TRM. The responsibilities of the EM&V contractor in subsection (q)(4)(C) indicates that the TRM is to be prepared by the EM&V contractor and subsection (q)(6)(B) indicates that the EM&V contractor will review the TRM at least annually to determine if an update is required. In addition, subsection (q)(6)(B) indicates that the utilities and other stakeholders can request changes to the TRM at any time for review by the EM&V contractor (as directed by commission staff). The commission expects that the utilities will be providing TRM updates for consideration, as they feel appropriate.

CLEAResult remained concerned that utilities could be penalized for offering new programs and measures. It believed that the regulatory process should include a feedback loop designed to improve programs and provided a diagram for the EM&V process that starts with the EEIP process and TRM, which then feeds into program and measure implementation. The evaluation process would include a review of program designs and analysis of savings per measure and program. The EM&V contractor would use this information to make recommendations for improving the programs and any necessary changes to the deemed savings.

Commission response

With respect to the feedback loop indicated by CLEAResult, the stated EM&V objectives of subsection (q) already include providing feedback and input into the planning process; therefore, the commission believes that further guidance is not required.

ERCOT requested two minor revisions to this subsection. First, ERCOT stated that it does not have authority over planning or siting of proposed generation resources and suggested that subsection (q)(1)(c) be modified to accurately reflect ERCOT's role by removing the term "energy resource". However, it did not object to the EM&V contractor providing input into its planning activities. Second, it proposed to supplant the term "demand response" found in subsection (q)(1)(A) with the term "load management," which is used throughout the rule.

Commission response

The commission appreciates ERCOT's suggestions and has made the requested changes in subsection (q)(1).

REP Coalition expressed concern about protecting customer data from disclosure during an EECRF proceeding. It stated that if the additional services to be provided by the EM&V contractor included providing experts for hearings under subsection (q)(4)(G), all documents reviewed or possessed by the EM&V contractor could be subject to discovery if the contractor serves as the testifying expert in an EECRF. It added that the commission could try to protect some of the proprietary information from disclosure, but there is no guarantee that this information would ultimately be protected.

Commission response

The commission considers the privacy of customer information to be a serious issue, and has crafted subsection (q)(11) accordingly. However, the commission and parties engaged in litigated matters before the commission frequently encounter situations in which confidential and highly sensitive information is included in discovery and even within the evidentiary record. The commission believes that the standard procedures, including protective orders, that are typically employed to protect such information will continue to be sufficient to protect information that may be reviewed or used by the EM&V contractor. Therefore, the commission declines to adopt the language offered by REP Coalition to limit the EM&V contractor's release of data.

TX ROSE and TLSC questioned whether the impact evaluation activities outlined in subsection (q)(5) are consistent or should be consistent with the IPMVP. With regard to the TRM discussed in subsection (q)(6), they felt that the current wording of subparagraph (A) may make it difficult for an EM&V contractor to recommend changes to the information used to develop the TRM. They also argued that staff cannot be delegated the authority to approve the TRM and to set baselines, as contemplated in subsection (q)(6) and (10). While they agreed that staff could make recommendations, the commission should adopt any substantive procedures relating to EM&V. They also disagreed with the proposal to apply the changes in an updated TRM prospectively, and argued that it may be appropriate to adjust demand and energy savings for prior years. They further suggested that the commission should determine whether or not historical adjustments are appropriate. With regard to the definition of baseline in subsection (q)(10), they suggested that the baseline should refer to what measures are installed in the absence of a program not the equipment that is being replaced. They also proposed modifications to subsection (q)(11) that would require the commission to issue an order directing the utilities to implement certain recommendations from the EM&V contractor's report.

Joint Utilities disagreed with TX ROSE and TLSC's assertion that changes to the TRM may need to be applied retrospectively. Rather, they agreed with staff that changes should only be applied prospectively and added that the TRM aides in the implementation of current programs and in the planning of future programs. They believed that TX ROSE and TLSC's suggested re-evaluation of the methodologies previously applied is not appropriate for the TRM. Further, they pointed out that the revised EEIP section of the rule (subsection (s)) affords TX ROSE and TLSC the opportunity to present comments and information to the commission and stakeholders regarding historical savings.

Commission response

The commission believes that the provisions in this subsection are consistent with the IPMVP and the baseline definitions are consistent with industry standard practice. Similarly, applying the changes in an updated TRM prospectively is consistent with industry and regulatory practice in other states. Furthermore, and most importantly, this policy provides certainty and thus encouragement for development and implementation of energy efficiency actions using best available, and with the TRM, approved, savings values, without the potentially chilling effect of retroactive changes due to information beyond the control of program participants or efficiency providers. With regard to TX ROSE and

TLSC's concerns about commission staff approving the TRM, the commission points out that the items to be included in the TRM such as the deemed savings and the procedures for creating and updating the TRM as outlined in subsection (q)(6) have been reviewed and approved by the commission either in a proceeding pursuant to subsection (i)(4) or in this rulemaking proceeding. Therefore, the commission does not see the need for the commission to further approve a manual that is the compilation of items previously approved by the commission. As the level of detail in the EM&V sections is being reduced, the commission believes that some of the concerns expressed by TX ROSE and TLSC are no longer relevant.

In their reply comments, TX ROSE and TLSC stated that there are provisions in the rule that undermine the EM&V effort. They cited subsection (m)(1)(F), pertaining to the setting of a baseline, as an example of where the EM&V contractor may not have the flexibility to raise the baseline for certain programs. Therefore, they suggested that any language that would hinder the EM&V contractor's efforts should be deleted from the rule.

Commission response

In response to TX ROSE and TLSC's comments regarding baselines, the commission has deleted subsection (m)(1)(F) to avoid any potential conflict with the language in this subsection. General requirements for baselines, outlined under subsection (q)(8), provide an indication to the utilities, EM&V contractor, and other stakeholders as to the basis for which savings are to be determined. These requirements follow industry standard practice.

REP Coalition warned that while subsection (q)(13)(B) would require the EM&V contractor to aggregate the data that is included in its report or filing, it again suggested the EM&V contractor may be compelled to offer the underlying data in response to a discovery request. In response to these concerns, REP Coalition would prefer for the utilities to limit the documents and information provided to the EM&V contractor by aggregating the data to mask any proprietary information relating to a specific REP or customer. EnerNOC also urged the commission to require an EM&V contractor to protect any proprietary information of any energy service provider and suggested that this subsection be modified to include service providers. OPUC encouraged the commission to safeguard customer information and urged the commission to adopt the language proposed by the REP Coalition.

In contrast, Cities urged the commission to reject the request to only provide aggregated data to the EM&V contractor. They stated that REP Coalition has not adequately explained why the use of a standard protective order would be inadequate and that customer-specific data is often examined in rate cases.

Commission response

As stated above, the commission treats the protection of customer information seriously. However, the commission agrees with Cities that, in addition to the language added to subsection (q)(11), the commission's standard procedures for protecting confidential and sensitive information in the course of litigated proceedings will be sufficient in this context as well. In response to EnerNOC's suggestion, the commission has modified subsection (q)(11)(B) to include REPs and energy efficiency service providers.

REP Coalition opposed the exclusion of the EM&V costs from the overall program cost caps, as outlined in subsection (q)(12)(B). It believed that excluding these costs will allow the costs to implement subsection (q) to increase dramatically. Therefore, the commission should examine the cost-effectiveness of the EM&V process, because ultimately the retail customers will bear the costs of retaining an EM&V contractor.

Commission response

The commission appreciates the comments from REP Coalition regarding the exclusion of EM&V costs from the cost caps. The commission will work diligently to review competitive bids when selecting an EM&V contractor. Since the commission will be responsible for hiring and maintaining a contractor, the costs associated with the EM&V will be outside of the control of the utilities. Similar to the rationale applied in the discussion of the municipalities' rate case expenses, the commission believes it is appropriate to exclude these expenses from the list of expenses that must remain under the cost caps.

Opower offered an addition to the list of documents included in the TRM, as outlined in subsection (q)(6)(A). It believed that an additional reference to protocols should be made to acknowledge their importance to the TRM.

Commission response

In response to Opower's suggestion, the commission agrees to add "protocols" to the list of resources that can be used in developing a TRM. The commission also agrees that the TRM may include standardized EM&V protocols; however, whether such protocols would be applied in a mandatory or voluntary manner is left to the process through which the commission staff approves the initial TRM and adopts any further amendments to future TRMs.

In addition to the changes adopted in response to comments, the commission has also added language that clarifies that the EM&V expenses incurred and expected to be incurred in 2013 and 2014 shall be recovered in utilities' 2013 EECRFs. The commission expects the EM&V contractor to begin work in early 2013 and it is imperative that utilities have the resources available to pay the invoices submitted by the EM&V contractor for its evaluation of the programs and development of the TRM.

The addition of subsection (q), Evaluation, measurement, and verification (EM&V), necessitates several clarifications throughout this subsection. In the definition of claimed savings (in subsection (c)(3)), the commission makes a change to the first sentence to clarify that claimed savings are values reported by an electric utility after the energy efficiency activities have been completed, but prior to an independent, third party evaluation of the savings is performed. The commission also clarifies that evaluated savings (in subsection (c)(20)) are savings estimates that may also include adjustments to claimed savings. The

commission adopts clarifying changes to subsection (p) to reflect the addition of the new EM&V process.

Subsection (r); Targeted low income energy efficiency program

First, TX ROSE and TLSC stated that the low-income program is the only program statutorily required and that the Legislature intended for low-income customers to have access to programs. They believed that the 10% set aside of a utility's budget is conservative, considering the percent of low-income customers across the state. They offered language that would ensure that the utilities spend at least 10% of their budget on low-income programs and stated that any funds allocated above and beyond 10% could be used for hard-to-reach programs if these funds are unused by July of the program year. They also argued that a utility should not be allowed to spend less than the statutorily-required amount. Second, they also provided language for a new subsection that would require the utilities to offer programs that complied with the federal weatherization requirements. Finally, they requested that language from PURA §39.905(f) be added that would require the TDHCA to provide reports to the commission regarding current energy and demand savings achieved by each utility.

Similarly, TACAA provided a recommendation that would establish appropriate benchmarks to be used by utilities to determine whether the amount of funding to a particular service provider should be reduced because of the inability to meet the benchmarks. Any funds re-allocated as a result of this failure should be specifically earmarked for programs serving low-income customers, including making these funds available to another service provider who has met the benchmarks. It proposed language that would allow a utility to reduce the contracted amount after six or nine months of implementation of the program in proportion to the difference between the original contracted amount and the total funds obligated.

Joint Utilities replied to TX ROSE and TLSC's comments by stating that utilities need the flexibility to move funds from under-performing programs to those with higher participation in order to meet their goals. They are in agreement with TACAA that subsection (r)(3) could be revised to change the phrase "unspent funds" to "funds that are not obligated."

Commission response

In response to TX ROSE and TLSC's first suggestion, the commission agrees with the response of Joint Utilities that if funds are unable to be spent on the targeted low-income programs, those funds should be reallocated to the hard-to-reach program, which also serves customers at or below 200% of the federal poverty guidelines. In SB 1434 (82nd Regular, 2011), the Legislature amended PURA §39.905(f) to update the measure of funding for low-income programs from the level of funding in hard-to-reach programs in 2003 to a percentage of the utility's energy efficiency budget. SB 1434 provides that within the utility's budget for the program year, 10% of the budgeted funds should be designated for targeted low-income programs. However, the bill left unchanged another provision of the statute which provides that "[t]he commission shall determine the appropriate level of funding to be allocated to both targeted and standard offer low-income energy efficiency programs in each unbundled transmission and distribution utility service area." Reading these two provisions together, the commission believes it to be within the language and the policy intent of the revised statute that at least 10% of the utility's energy efficiency budget

should be designated for targeted low-income programs, but if the required amount of targeted low-income program funds are not obligated after July of a program year, such funds may be reallocated to hard-to-reach programs in order to ensure that those funds will still be spent for the purpose of providing low-income customers with access to energy efficiency.

The commission appreciates TACAA's recognition of the distinction between unspent and unobligated funds, considering that service providers submit proposals for providing services in advance of determining the number of customers that will actually participate in the low-income programs. The commission agrees with TACAA and Joint Utilities that the modification to subsection (r)(3) should be made and has amended the language accordingly.

With regard to TX ROSE and TLSC's second suggestion, this subsection was modified to recognize that the DOE currently requires agencies receiving assistance for the Weatherization Assistance Program (WAP) to use the SIR methodology to determine cost-effectiveness of individual measures and an overall program. As a result, agencies receiving funding from the DOE such as TDHCA also use the ratio when it conducts an energy audit of a customer's home to determine which measures meet the cost-effectiveness test and are eligible to be installed, up to a $6,500 maximum. The commission recognized this policy and approved the use of the SIR by utilities in areas open to competition in Docket Number 32103, *Commission Staff's Application for Approval of Plan to Implement Targeted Low-Income Energy Efficiency Programs*. Therefore, the current language

conforms to the statutory requirements outlined in PURA §39.905(f), and TX ROSE and TLSC's proposed modifications are unnecessary.

SPS recommended that the rule allow utilities in areas not open to competition to also use the SIR to measure the cost-effectiveness of their low-income programs rather than the cost-effectiveness standard required in subsection (d). Through its low-income program, SPS offers funding to non-profit community action agencies and governmental agencies that provide weatherization services to residential customers that meet the DOE income eligibility guidelines. Since 1995, it has offered a low-income program that is patterned after the DOE's WAP, which is the model for programs administered under PURA §39.905(f). It added that it would be extremely difficult for a utility to demonstrate that its low-income program is cost-effective under subsection (d), which could potentially call into question the continuation of this vital program. It also felt it was important to note that the low-income programs offer additional installation and repair costs that: 1) do not offer any additional savings; and 2) would not be provided under any other program. All of this works to decrease the cost-effectiveness of the overall program and would reduce the number of measures installed if the utility had to demonstrate compliance with subsection (d). Therefore, it asked that it be allowed to continue to utilize the SIR method, as provided for utilities in areas open to competition and offered language that would permit utilities in areas not open to competition to use the same methodology used by the other utilities.

TX ROSE and TLSC supported SPS' requested language, stating that using the same methodology to calculate energy and demand savings for all low-income programs will provide for more efficient and effective review of these programs. Further, they recognized that the SIR method is used to determine the cost-effectiveness of measures installed under the federal weatherization programs and complies with PURA §39.905(f). While not specifically stated in written comments, they take exception to parties' suggestions that the low-income programs are the most expensive programs. They argued that the costs of these programs have not been subject to review by an EM&V contractor, which means that the net-to-gross ratio has not been applied nor were the savings adjusted for free ridership, which they argued is not applicable to these programs because the measures would not be installed absent incentives from the utilities.

Joint Utilities offered an additional change to SPS's proposed modifications to clarify that the overall program should be evaluated using the SIR methodology. The use of the SIR has been questioned in recent EECRFs and Joint Utilities wanted to clarify that this method is used not only to determine which measures should be installed in an individual household but also to determine the overall cost-effectiveness of a low-income program under the DOE guidelines established for the WAP. They believed that staff was interpreting the audit requirement in PURA §39.905(f) to include the application of the SIR to low-income programs, and it should be applied at the program and measure level to be in compliance with the DOE requirements. This change would highlight the distinction between the cost-effectiveness of low-income programs and all other programs that must comply with the cost-effectiveness standard outlined in subsection (d). They argued that the low-income programs may have a positive SIR but would not meet the cost-effectiveness standard that is based on avoided costs.

Commission response

The commission recognizes the importance of uniformity in administering low-income programs across the state. While the statute does not require utilities in areas not open to competition to provide low-income programs, those that choose to administer these programs should afford their customers the same benefits as those in areas open to competition. This includes allowing program administrators in areas not open to competition to use the SIR methodology when serving low-income customers. The commission believes that if a utility in an area not open to competition is subject to the SIR methodology, rather than the cost-effectiveness standard set forth in subsection (d), this ensures that customers in these service territories qualify for the same types of measures installed in areas open to competition up to the $6500 household maximum. The commission appreciates SPS's comments and TX ROSE and TLSC's support of those comments and has included its proposed language in this subsection. The commission also adopts Joint Utilities' proposed modification to subsection (r)(2) to clarify that the SIR applies to the cost-effectiveness of measures eligible to be installed and the overall program.

As to TX ROSE and TLSC's recommendation regarding the request of reports from TDHCA, the commission currently receives plans and reports from utilities every April that outlines the measured and verified savings for the previous five years and the planned savings for the current and following year. Therefore, the commission declines to adopt TX ROSE and TLSC's suggested language.

Subsection (s); Energy Efficiency Implementation Project – EEIP

TX ROSE and TLSC commented that the EEIP should not be allowed to approve programs or program changes. The utility should be required to submit information on a new program or program amendment in an EECRF proceeding. They also disagreed with the provision that would allow utilities to update program changes in its EEPR without coming to the EEIP. They stated that reviewing the EEPRs is a time consuming task and many parties lack the resources to review them. They suggested that the utilities be required to notify the EEIP when a new program is developed or a change is made to an existing program.

Joint Utilities stated that the phrase "substantially different" added to subsection (s)(3) should be defined. They believed that deciding whether or not a program is substantially different requires the use of considerable judgment.

In replies, Joint Utilities opposed TX ROSE and TLSC's proposal to litigate program design issues during the EECRF proceedings. They stated that the utilities implement programs that have been approved by the commission. They agreed with the proposed rule, which sets forth a process where program design issues are discussed at EEIP meetings. Additionally, comments could be filed or raised at an EEIP meeting in response to annual EEPR filings. Participation in the EEIP would be much more efficient than the proposals advanced by TX ROSE and TLSC, which takes place after the utilities have already initiated programs and incurred expenses. Joint Utilities also opposed TX ROSE and TLSC's proposal to require the utilities to file a new program template each time a program differs "in any way" from an existing program. They stated that there will always be slight variations in the implementation of the same program by each utility, and requiring multiple filings places an unnecessary burden on the commission.

Opower suggested clarification on the role of the EEIP with regards to the introduction of new programs or program redesigns, as outlined in subsection (s)(5). It recommended a process where the EEIP is notified about the new program and is offered 21 days to provide comments. The utility could then petition the commission and the commission would have the flexibility to act on the petition or allow the program to go into effect after 45 days.

Commission response

In response to Joint Utilities' comment regarding the term substantially different, the commission believes that it is necessary to leave subsection (s)(3) general, because attempting to specifically define what constitutes a substantially different program would be difficult and could produce unintended results. As provided for under subsection (s)(6), if a party files a petition with the commission to consider changes to programs, the utility may be asked to provide a program template and additional information regarding the changes to the program in this proceeding.

As previously stated in response to comments in subsection (f), the commission is modifying the role of the EEIP to allow stakeholders to provide feedback on programs or potential programs at the beginning of the process. This allows stakeholders and commission staff to provide input that could be used to modify existing or planned programs. If the utility is offering a new program or making programmatic changes that coincide with the filing of

its EEPR, those would be outlined in the report and could be discussed at an EEIP prior to the utility's EECRF filing. Further, the rule also requires utilities to use standard forms, procedures, deemed savings estimates, and program templates, as outlined in subsection (i)(4). A utility offering a new program during a program year would be required to make a filing with the commission using the program template approved in Docket Number 31965, *Application of PUC Legal for Approval of Energy Efficiency Program Template*. Part of this requirement also includes distribution of the filing to the EEIP listserv. Stakeholders are encouraged to file comments supporting or making recommendations for modifications to the proposed program. The current process allows utilities to begin offering new programs in an efficient manner, usually within 30 days of filing the template with the commission and providing notice to the EEIP. This process is consistent with Opower's suggested changes to subsection (s)(5); the commission believes that no additional changes are warranted.

The rule as adopted provides that cost recovery is addressed in the EECRF proceedings. Subsection (f)(12) specifically states that "the proceeding shall not include a review of program design to the extent the programs complied with the energy efficiency implementation project (EEIP) process defined in subsection (s) of this section." The commission appreciates the comments of Joint Utilities and would like to move forward with this delineation between the role of the EEIP and the scope of the EECRF proceedings. Therefore, the commission declines to make additional changes to this subsection.

Subsection (t); Retail providers

No comments.

Subsection (u); Customer protection

No comments.

Subsection (v); Grandfathered programs

No comments.

Subsection (w); Identification notice

Two parties filed comments in support of an opt-out provision for an industrial customer taking electric service at distribution voltage. TIEC, who originally proposed the new provision, bolstered their position by citing PURA §39.905(a)(3), which they argued states that only residential and commercial customers are eligible to participate in energy efficiency programs. PURA §39.905(b)(4) goes on to state that the costs associated with the programs shall be borne by the customer classes that receive services. They asserted that the Legislature acknowledged that industrial customers are large consumers that are incented to reduce their energy usage through adopting energy efficiency measures absent any incentives from utilities. Furthermore, industrial customers are able to participate in market-based demand response programs such as those offered by ERCOT and do not rely on receiving an incentive through a utility’s load management program. They noted that residential and commercial customers do not pay for demand response or energy efficiency measures self-implemented by industrial customers. Likewise, industrial customers should not be required to pay for programs provided to other customer classes. In Project Number 33487, the commission excluded transmission-level industrial customers from the definition of eligible customers, except to the extent they were participating in utility load management programs that were implemented prior to May 1, 2007. TIEC argued that the exclusion of only transmission-level customers did not go far enough because distribution-level industrial customers continue to pay for energy efficiency costs. Their proposed solution, developed in conjunction with CenterPoint, is the addition of subsection (w), which allows distribution-level industrial customers to identify themselves by submitting an identification notice, including a copy of the customer's Texas Sales and Use Tax Exemption Certification. This provision would allow those customers that provide the requisite information to "opt-out" of the energy efficiency programs, and TIEC believed this is a reasonable compromise that carries out the legislative intent to exclude industrial customers.

Walmart also supported the opt out provision for an industrial customer taking electric service at distribution voltage and requested that the opt-out provision be expanded to include commercial customers who make investments in energy efficiency and demand-side management without the use of utility incentives. It provided rule language that would allow any customer with consumption of one million kWh that implements its own energy efficiency programs to opt-out. It added that these customers are already looking for ways to stay competitive and have the ability to tailor programs to meet their specific needs. It argued that there is no difference between the rationale applied to the industrial opt-out and an expanded opt-out for commercial customers. It further stated that since some of the industrial customers that would be included under this provision are in the same rate classes as the large commercial customers, it would not be more difficult to track these additional customers that would be excluded from the programs.

It further noted that commercial customers who reduce their consumption apart from utility incentives provide a direct benefit to the grid, as they reduce the total demand on the system. If commercial customers were allowed to opt-out, Walmart added that such customers would have more funds available to invest in their own programs while they themselves assume all the risks of their investments.

Joint Utilities supported the comments of Public Citizen and the SEED Coalition, Sierra Club, EDF, CLEAResult, OPUC, EnerNOC, and Cities and replied that Walmart's proposal illustrates how an opt-out provision for manufacturing facilities served at distribution voltage could lead to a slippery slope, whereby customers continually propose to establish their own programs. This could lead to smaller energy efficiency programs, increased administrative complexity in determining eligibility, and increased administrative costs.

Walmart defended its position by responding to the concerns expressed by EDF, Joint Utilities, and Sierra Club. Specifically, it countered comments that suggested that the opt-out provision would decrease the funds available for energy efficiency programs and that the customers that might opt-out have historically participated in the programs. It believed that its proposed commercial opt-out already addresses these concerns. Walmart reiterated that its proposal is limited to customers with consumption of one million kWh or greater who can demonstrate that they have installed or plan to install energy efficiency measures to reduce their overall consumption by the amounts specified in PURA §39.905. Those customers that have participated in one of a utility's programs would not be eligible to opt-out for a period of five years. In response to concerns voiced by the Joint Utilities about the ability to meet their goals absent distribution-level industrial customers, it proposed a modification to the commercial opt-out through the use of self-directed rebates for customized programs that meet the specific needs of the commercial customers.

CLEAResult, EnerNOC, Joint Utilities (with the exception of CenterPoint who supported the opt-out language), Public Citizen, SEED Coalition, and Sierra Club opposed the proposed new subsection. Joint Utilities stated that other than the comments filed by TIEC in Project Number 33487 in 2007, there is no legislative or regulatory history to suggest that industrial customers taking service at distribution voltage should be excluded from the rule. To support their position, they cited PURA §39.904(m-1), relating to the Goal for Renewable Energy, as an example of specific exclusions provided by the Legislature for industrial customers choosing not to participate in the REC program. PURA §39.904(m-1) states, in relevant part that "the commission shall reduce the requirement under Subsection (c)(1) for a retail electric provider, municipally owned utility, or electric cooperative that is subject to a renewable energy requirement under this section that serves *a customer receiving electric service at transmission-level voltage* if, before any year for which the commission calculates renewable energy requirements under Subsection (c)(1), the customer notifies the commission in writing that the customer chooses not to support the goal for renewable energy under this section for that year" (emphasis added). The commission established Project Number 35113, *Industrial Customers Notification Under PURA Section 39.904(m-1) Relating to Non-Support of Renewable Energy Requirements*, which provides transmission-level industrial customers the ability to opt-out of the REC requirement so long as this request is renewed every two years. They concluded that if the Legislature had intended to exclude a group of customers from the energy efficiency programs, it could have done so in PURA §39.905.

TIEC countered Joint Utilities comments regarding PURA §39.904(m-1) by arguing that this section creates a voltage-level distinction among the industrial class, whereas PURA §39.905 excluded all industrial customers, regardless of voltage level. They further stated that if the Legislature had intended to exclude only transmission-level customers from the energy efficiency requirements, it would have included language to that effect in PURA §39.905.

Joint Utilities strongly opposed the imposition of any opt-out provisions for manufacturing facilities taking service at distribution voltage due to the following reasons: 1) excluding certain customers from the energy efficiency programs is at odds with the commission's objective to maximize demand and energy savings across the state; 2) if energy efficiency programs benefit all customers then it is unfair to allow certain customers to receive the benefits without also incurring a portion of the costs; 3) the commission previously rejected TIEC's request to define industrial customers based on Tax Code exemptions in Project Number 33487, but instead relied on voltage level and exempted transmission-level customers and nothing has changed since 2008 that would challenge the commission's original position; 4) nothing in PURA specifically allows distribution-level customers to opt-out and this proposal is at odds with PURA §39.905(a)(2), which states that "all customers, in all customer classes, will have a choice of and access to energy efficiency alternatives;" 5) some of the customers that would be allowed to opt-out have previously participated in utility programs and would be allowed to enjoy the benefits of the installed measures without continuing to contribute to the costs of the programs; 6) the billing systems developed by utilities cannot readily identify customers with a manufacturing tax exemption, which would increase the costs of all utilities by an estimated $500,000 to implement necessary system changes; 7) the number of customers that could potentially opt-out is unknown; 8) it would reduce the ability of utilities to achieve required goals; 9) exemptions of certain customers would require the recalculation of the “floor” for a goal set each year, meaning that the provision that prevents a utility from achieving a lower goal than the previous year would need to be revisited; 10) absent an adjustment of the floors, significant costs could be shifted to the remaining customers; and 11) it is unclear how the industrial accounts that do not have a manufacturing or industrial component should be handled.

TIEC argued, in response to Joint Utilities’ comment that the number of accounts affected is unknown, that all industrial customers are entitled to the exemption and the number of accounts does not have an impact on this exemption. They believed the provision as proposed would result in fewer distribution-level industrial customers being excluded from the programs since the burden is on the customers to provide the requisite information to the utilities. They also disagreed with Joint Utilities’ statement that this provision would result in administrative difficulties such as the above mentioned changes to the utilities’ billing systems. They believed that the language takes administrative complexity into account and is designed to be easy for the utilities to administer. They noted that Oncor and CenterPoint have already segregated the transmission-level rate classes, so segregation at the distribution level should also be feasible.

Similar to the comments advanced by Joint Utilities, EnerNOC argued that there is nothing in SB 1125, enacted laws, or commission rules that would allow an industrial customer taking service at distribution voltage to exclude itself from the utility's programs. PURA §39.905 already exempts industrial customers from the programs, with the exception of those that continue to participate in a utility's load management programs. EnerNOC cited an article that demonstrates that not all industrial customers have achieved their energy efficiency potential. *See Money Well Spent: Industrial Energy Efficiency Program Spending in 2010*, American Council for an Energy Efficient Economy (April 5, 2012). It also stated that there is no reason the commission should limit access to customers who could potentially provide significant additional efficiency opportunities to the grid and benefit from the utilities' programs. It further commented that this provision adds uncertainty to the programs, including a utility's determination of its demand goal. It believed the utilities would be required to verify that each commercial customer is eligible to participate because of the potentially broad impact of subsection (w) resulting from the broad definition of industrial customer in subsection (c)(30). It concluded by stating that all customers benefit from the energy efficiency by reducing usage and demand on the grid and that removing certain customers from the program is detrimental to all customers who expect reliable service.

In response, TIEC stated that the provision allows industrial customers, which EnerNOC acknowledged are exempt under PURA §39.905, taking service at distribution voltage to opt-out. This would not extend to commercial facilities owned by customers that also have industrial facilities. They went on to note that many industrial customers are served at distribution voltage, and the voltage level does not factor into whether a customer is a commercial or industrial customer. They stated that customers engaging in industrial processes should be exempt from the energy efficiency requirements. They added that the manufacturing tax exemption included in the proposed rule does not apply to accounts that are not engaged in an industrial process, so commercial accounts would not be eligible. Further, the office buildings of a company whose primary business is an industrial process would not qualify for the exemption. They also added that the verification issues raised by EnerNOC will be addressed by the development of a standardized form.

In response to EnerNOC's summary of the *Money Well Spent* report, TIEC stated that the report only looked at public monies spent and did not examine additional expenditures by industrial customers in the private sector. TIEC also cited the report prepared for ERCOT by the Brattle Report to contend that requiring distribution-level industrial customers to continue to participate in the utilities' programs is counter to encouraging demand response programs in the ERCOT market. TIEC believed that providing these customers an opt-out would allow them to use their resources to develop self-funded energy efficiency programs and to efficiently participate in the market.

Public Citizen, SEED Coalition, and Sierra Club offered comments similar to others opposing the opt-out provision by stating that the commission does not have the statutory authority to exclude certain commercial facilities from the programs. They are also concerned that this exclusion would reduce the amount of funding available for utilities' programs, which would in turn reduce their ability to meet their goals. Therefore, they believed, as did CLEAResult, that this subsection should be deleted from the rule. In replies, CLEAResult reiterated its opposition to the new subsection and added that this provision will place a greater financial burden on customers still participating in the programs.

TREIA supported the comments filed by Cities, CLEAResult, EDF, EnerNOC, Joint Utilities, OPUC, Public Citizen, SEED Coalition, and Sierra Club. It stated that all customers benefit from energy efficiency regardless of participation and allowing certain customers to opt-out reduces funding for the programs and undermines public support for the programs by shifting costs to the remaining customers.

Commission response

As discussed above in response to comments regarding proposed subsection (c)(11) and (30), the larger policy of excluding industrial customers has been established by the Legislature, and the commission is now required to implement that policy. As previously noted, in HB 3693 of the 80th Legislature, Regular Session in 2007, the Legislature added language to PURA §39.905(a) and (b) to clarify that the energy efficiency goals and programs under the statute were to be oriented to residential and commercial customers, and that it is these customers receiving services under the programs that are to bear the cost of the programs. PURA §39.905(a)(3) now specifically limits a utility's energy efficiency programs to residential and commercial customers. The commission acknowledges, as pointed out by the Joint Utilities, that the commission previously rejected TIEC's request to define industrial customers based on tax code exemptions but instead opted to rely on voltage level as a more practical and simpler method to identify an industrial customer. However, the commission believes that the particular approach proposed in the current rulemaking by TIEC and CenterPoint is more effective than what was proposed by TIEC in Project Number 33487 and will allow industrial customers

engaged in an industrial process taking service at distribution voltage to opt-out in a manner that minimizes burdens on utilities and remaining commercial customers, and yet complies with the language and policy of the statute.

In reply to the Joint Utilities' fear that the proposed opt-out provision would reduce the ability of a utility to achieve their required goals, the commission notes that subsection (w) provides that a utility's demand reduction goal shall be adjusted to remove any load lost as a result of a customer exercising its right to opt-out. In response to similar concerns regarding the provision that prevents a utility from achieving a lower goal than the previous year, the commission notes that subsection (e)(1)(E) provides an exception for a utility in accordance with subsection (w). Furthermore, since a customer must submit a notice by the date specified in subsection (w) in order to be eligible to opt-out in the next program year, the commission believes the utility will have sufficient time to adjust its goals and programs costs to reflect the customer base its programs will serve.

The commission disagrees with Walmart that large commercial customers should also be permitted to opt-out. The Legislature has not written such an exclusion into the law and Walmart's proposal may be difficult to administer and may have adverse effects on customers who are not able to opt-out.

Therefore, for the reasons stated above, the commission declines to adopt changes to subsection (w).

Subsection (x); Administrative penalty

Sierra Club suggested that the commission restore subsection (x)(4) and (5) from the current rule, because they believed the provisions are important in determining whether to assess an administrative penalty on a utility for failure to meet its energy efficiency goal.

Commission response

The commission deleted these two provisions, which relate to the utility's actions to correct any deficiencies and the utility's effectiveness in administering its programs, in the proposed rule because PURA §15.023, relating to Administrative Penalty, Disgorgement Order, or Mitigation, contains similar provisions that shall be considered in the case of a potential violation. For example, PURA §15.023(c)(5) requires the commission to consider efforts to correct the violation when assessing an administrative penalty. As a result, the commission has deleted the language in the rule, because it is unnecessary given the Legislative directive on administrative penalties codified in PURA.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes changes for the purpose of clarifying its intent, including changes throughout this section to conform to the new subsection (q) provisions.

The amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §§14.001, 14.002, 36.204, and 39.905 (West 2007 and Supplement 2011) (PURA). Section 14.001 provides the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; §14.002 provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; §36.204 authorizes the commission to establish rates for an electric utility that allow timely recovery of the reasonable costs for conservation and load management, which includes additional incentives for conservation and load management; §39.905 requires the commission to provide oversight of energy efficiency programs of electric utilities subject to that section and adopt rules and procedures to ensure that electric utilities subject to that section can achieve their energy efficiency goals, including rules providing for EECRFs and an incentive for electric utilities that meet the energy efficiency goals; SB 1125, which amends PURA §39.905 (a), (b), and (d) and adds subsections (h) and (k), and which increases the energy efficiency goals, defines demand-side renewable systems, expands the list of eligible programs to include behavioral measures, requires the development of an evaluation, measurement, and verification (EM&V) framework, allows non-ERCOT utilities to develop self-directed programs and ERCOT utilities to offer these programs after a contested case proceeding and adds PURA §39.9054, which requires the utilities to submit an annual plan and report; SB 1434, which amends PURA §39.905(f), which requires at least 10% of a utility's budget to be set aside for low-income programs; SB 1150, which amends PURA §39.402(a), which requires Southwestern Public Service Company to establish an EECRF; and SB 1910, which adds PURA §39.555, which allows El Paso Electric Company to market an energy efficiency program directly to a retail electric customer.

Cross Reference to Statutes: PURA §§14.001, 14.002, 36.204, 39.905, SB 1125 (codified as PURA §39.905(a), (b), (d), (h), and (k)), SB 1434 (codified as PURA §39.905(f)), SB 1150 (codified as PURA §39.402(a)), and SB 1910 (codified as PURA §39.555).

§25.181. Energy Efficiency Goal.

(a) **Purpose**. The purpose of this section is to ensure that:

(1) electric utilities administer energy efficiency incentive programs in a market-neutral, nondiscriminatory manner and do not offer competitive services, except as permitted in §25.343 of this title (relating to Competitive Energy Services) or this section;

(2) all customers, in all eligible customer classes and all areas of an electric utility's service area, have a choice of and access to the utility's portfolio of energy efficiency programs that allow each customer to reduce energy consumption, summer and winter peak demand, or energy costs; and

(3) each electric utility annually provides, through market-based standard offer programs, targeted market-transformation programs, or utility self-delivered programs, incentives sufficient for residential and commercial customers, retail electric providers, and energy efficiency service providers to acquire additional cost-effective energy efficiency, subject to EECRF caps established in subsection (f)(7) of this section, for the utility to achieve the goals in subsection (e) of this section.

(b) **Application**. This section applies to electric utilities.

(c) **Definitions**. The following terms, when used in this section, shall have the following meanings unless the context indicates otherwise:

(1) **Affiliate --**

(A) A person who directly or indirectly owns or holds at least 5.0% of the voting securities of an energy efficiency service provider;

(B) A person in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider;

(C) A corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by an energy efficiency service provider;

(D) A corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:

(i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of an energy efficiency service provider; or

(ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider; or

(E) A person who is an officer or director of an energy efficiency service provider or of a corporation in a chain of successive ownership of at least 5.0% of the voting securities of an energy efficiency service provider;

(F) A person who actually exercises substantial influence or control over the policies and actions of an energy efficiency service provider;

(G) A person over which the energy efficiency service provider exercises the control described in subparagraph (F) of this paragraph;

(H) A person who exercises common control over an energy efficiency service provider, where “exercising common control over an energy efficiency service provider” means having the power, either directly or indirectly, to direct or cause the direction of the management or policies of an energy efficiency service provider, without regard to whether that power is established through ownership or voting of securities or any other direct or indirect means; or

(I) A person who, together with one or more persons with whom the person is related by ownership, marriage or blood relationship, or by action in concert, actually exercises substantial influence over the policies and actions of an energy efficiency service provider even though neither person may qualify as an affiliate individually.

(2) **Baseline --** A relevant condition that would have existed in the absence of the energy efficiency project or program being implemented, including energy consumption that would have occurred. Baselines are used to calculate program-related demand and energy savings. Baselines can be defined as either project-specific baselines or performance standard baselines (*e.g.*, building codes).

(3) **Claimed savings --** Values reported by an electric utility after the energy efficiency activities have been completed, but prior to the time an independent, third-party evaluation of the savings is performed. As with projected savings estimates, these values may utilize results of prior evaluations and/or values in technical reference manuals. However, they are adjusted from projected savings estimates by correcting for any known data errors and actual installation rates and may also be adjusted with revised values for factors such as per-unit savings values, operating hours, and savings persistence rates. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(4) **Commercial customer --** A non-residential customer taking service at a metered point of delivery at a distribution voltage under an electric utility's tariff during the prior program year or a non-profit customer or government entity, including an educational institution. For purposes of this section, each metered point of delivery shall be considered a separate customer.

(5) **Competitive energy efficiency services --** Energy efficiency services that are defined as competitive under §25.341 of this title (relating to Definitions).

(6) **Conservation load factor --** The ratio of the annual energy savings goal, in kilowatt hours (kWh), to the peak demand goal for the year, measured in kilowatts (kW) and multiplied by the number of hours in the year.

(7) **Deemed savings calculation --** An industry-wide engineering algorithm used to calculate energy and/or demand savings of the installed energy efficiency measure that has been developed from common practice that is widely considered acceptable for the measure and purpose, and is applicable to the situation being evaluated. May include stipulated assumptions for one or more parameters in the algorithm, but typically requires some data associated with actual installed measure. An electric utility may use the calculation with documented measure-specific assumptions, instead of energy and peak demand savings determined through measurement and verification activities or the use of deemed savings.

(8) **Deemed savings value --** An estimate of energy or demand savings for a single unit of an installed energy efficiency measure that has been developed from data sources and analytical methods that are widely considered acceptable for the measure and purpose, and is applicable to the situation being evaluated. An

electric utility may use deemed savings values instead of energy and peak demand savings determined through measurement and verification activities.

(9) **Demand --** The rate at which electric energy is used at a given instant, or averaged over a designated period, usually expressed in kW or megawatts (MW).

(10) **Demand savings --** A quantifiable reduction in demand.

(11) **Eligible customers --** Residential and commercial customers. In addition, to the extent that they meet the criteria for participation in load management standard offer programs developed for industrial customers and implemented prior to May 1, 2007, industrial customers are eligible customers solely for the purpose of participating in such programs.

(12) **Energy efficiency --** Improvements in the use of electricity that are achieved through customer facility or customer equipment improvements, devices, processes, or behavioral or operational changes that produce reductions in demand or energy consumption with the same or higher level of end-use service and that do not materially degrade existing levels of comfort, convenience, and productivity.

(13) **Energy Efficiency Cost Recovery Factor (EECRF) --** An electric tariff provision, compliant with subsection (f) of this section, ensuring timely and reasonable cost recovery for utility expenditures made to satisfy the goal of PURA §39.905 that provide for a cost-effective portfolio of energy efficiency programs pursuant to this section.

(14) **Energy efficiency measures --** Equipment, materials, and practices, including practices that result in behavioral or operational changes, implemented at a

customer's site on the customer's side of the meter that result in a reduction at the customer level and/or on the utility's system in electric energy consumption, measured in kWh, or peak demand, measured in kW, or both. These measures may include thermal energy storage and removal of an inefficient appliance so long as the customer need satisfied by the appliance is still met.

(15) **Energy efficiency program --** The aggregate of the energy efficiency activities carried out by an electric utility under this section or a set of energy efficiency projects carried out by an electric utility under the same name and operating rules.

(16) **Energy efficiency project --** An energy efficiency measure or combination of measures undertaken in accordance with a standard offer, market transformation program, or self-delivered program.

(17) **Energy efficiency service provider --** A person or other entity that installs energy efficiency measures or performs other energy efficiency services under this section. An energy efficiency service provider may be a retail electric provider or commercial customer, provided that the commercial customer has a peak load equal to or greater than 50 kW. An energy efficiency service provider may also be a governmental entity or a non-profit organization, but may not be an electric utility.

(18) **Energy savings --** A quantifiable reduction in a customer's consumption of energy that is attributable to energy efficiency measures, usually expressed in kWh or MWh.

(19) **Estimated useful life (EUL) --** 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.

(20) **Evaluated savings --** Savings estimates reported by the EM&V contractor after the energy efficiency activities and an impact evaluation have been completed. Differs from claimed savings in that the EM&V contractor has conducted some of the evaluation and/or verification activities. These values may rely on claimed savings for factors such as installation rates and the Technical Reference Manual for values such as per unit savings values and operating hours. These savings estimates may also include adjustments to claimed savings for data errors, per unit savings values, operating hours, installation rates, savings persistence rates, or other considerations. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(21) **Evaluation --** The conduct of any of a wide range of assessment studies and other activities aimed at determining the effects of a program; or aimed at understanding or documenting program performance, program or program-related markets and market operations, program-induced changes in energy efficiency markets, levels of demand or energy savings, or program cost-effectiveness. Market assessment, monitoring, and evaluation, and measurement and verification (M&V) are aspects of evaluation.

(22) **Evaluation, measurement, and verification (EM&V) contractor --** One or more independent, third-party contractors selected and retained by the

commission to plan, conduct, and report on energy efficiency evaluation activities, including verification.

(23) **Free driver --** Customers who do not directly participate in an energy efficiency program, but who undertake energy efficiency actions in response to program activity.

(24) **Free rider --** A program participant who would have implemented the program measure or practice in the absence of the program. Free riders can be total, in which the participant's activity would have completely replicated the program measure; partial, in which the participant's activity would have partially replicated the program measure; or deferred, in which the participant's activity would have completely replicated the program measure, but at a time after the time the program measure was implemented.

(25) **Growth in demand --** The annual increase in demand in the Texas portion of an electric utility's service area at time of peak demand, as measured in accordance with this section.

(26) **Gross savings --** The change in energy consumption and/or demand that results directly from program-related actions taken by participants in an efficiency program, regardless of why they participated.

(27) **Hard-to-reach customers --** Residential customers with an annual household income at or below 200% of the federal poverty guidelines.

(28) **Impact evaluation --** An evaluation of the program-specific, directly induced changes (e.g., energy and/or demand reduction) attributable to an energy efficiency program.

(29) **Incentive payment --** Payment made by a utility to an energy efficiency service provider, an end-use customer, or third-party contractor to implement and/or attract customers to energy efficiency programs, including standard offer, market transformation and self-delivered programs.

(30) **Industrial customer --** A for-profit entity engaged in an industrial process taking electric service at transmission voltage, or a for-profit entity engaged in an industrial process taking electric service at distribution voltage that qualifies for a tax exemption under Tax Code §151.317 and has submitted an identification notice pursuant to subsection (w) of this section.

(31) **Inspection --** Examination of a project to verify that an energy efficiency measure has been installed, is capable of performing its intended function, and is producing an energy savings or demand reduction equivalent to the energy savings or demand reduction reported towards meeting the energy efficiency goals of this section.

(32) **Installation rate --** The percentage of measures that receive incentives under an energy efficiency program that are actually installed in a defined period of time. The installation rate is calculated by dividing the number of measures installed by the number of measures that receive incentives under an efficiency program in a defined period of time.

(33) **International performance measurement and verification protocol (IPMVP) --** A guidance document issued by the Efficiency Valuation Organization with a framework and definitions describing the M&V approaches.

(34) **Lifetime energy (demand) savings --** The energy (demand) savings over the lifetime of an installed measure(s), project(s), or program(s). May include consideration of measure estimated useful life, technical degradation, and other factors. Can be gross or net savings.

(35) **Load control --** Activities that place the operation of electricity-consuming equipment under the control or dispatch of an energy efficiency service provider, an independent system operator, or other transmission organization or that are controlled by the customer, with the objective of producing energy or demand savings.

(36) **Load management --** Load control activities that result in a reduction in peak demand, or a shifting of energy usage from a peak to an off-peak period or from high-price periods to lower price periods.

(37) **Market transformation program --** Strategic programs intended to induce lasting structural or behavioral changes in the market that result in increased adoption of energy efficient technologies, services, and practices, as described in this section.

(38) **Measurement and verification --** A subset of program impact evaluation that is associated with the documentation of energy or demand savings at individual sites or projects using one or more methods that can involve measurements, engineering calculations, statistical analyses, and/or computer simulation modeling. M&V approaches are defined in the IPMVP.

(39) **Net savings --** The total change in load that is attributable to an energy efficiency program. This change in energy and/or demand use shall include, implicitly or

explicitly, consideration of appropriate factors. These factors may include free ridership, participant and non-participant spillover, induced market effects, changes in the level of energy service, and/or other non-program causes of changes in energy use and/or demand.

(40) **Net-to-gross --** A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program impacts. The factor may be made up of a variety of factors that create differences between gross and net savings, commonly considering the effects of free riders and spillover.

(41) **Non-participant spillover --** Energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence.

(42) **Off-peak period --** Period during which the demand on an electric utility system is not at or near its maximum. For the purpose of this section, the off-peak period includes all hours that are not in the peak period.

(43) **Participant spillover --** The additional energy savings that occur when a program participant independently installs incremental energy efficiency measures or applies energy savings practices after having participated in the efficiency program as a result of the program's influence.

(44) **Peak demand --** Electrical demand at the times of highest annual demand on the utility's system. Peak demand refers to Texas retail peak demand and, therefore, does not include demand of retail customers in other states or wholesale customers.

(45) **Peak demand reduction --** Reduction in demand on the utility's system at the times of the utility's summer peak period or winter peak period.

(46) **Peak period --** For the purpose of this section, the peak period consists of the hours from one p.m. to seven p.m., during the months of June, July, August, and September, and the hours of 6 to 10 a.m. and 6 to 10 p.m., during the months of December, January, and February, excluding weekends and Federal holidays.

(47) **Program year --** A year in which an energy efficiency incentive program is implemented, beginning January 1 and ending December 31.

(48) **Projected savings --** Values reported by an electric utility prior to the time the energy efficiency activities are implemented. Are typically estimates of savings prepared for program and/or portfolio design or planning purposes. These values are based on pre-program or portfolio estimates of factors such as per-unit savings values, operating hours, installation rates, and savings persistence rates. These values may utilize results of prior evaluations and/or values in the Technical Reference Manual. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

(49) **Rate class --** For the purpose of calculating EECRF rates, a utility's rate classes are those retail rate classes approved in the utility's most recent base-rate proceeding, excluding non-eligible customers.

(50) **Renewable demand side management (DSM) technologies --** Equipment that uses a renewable energy resource (renewable resource), as defined in §25.173(c) of this title (relating to Goal for Renewable Energy), a geothermal heat pump, a

solar water heater, or another natural mechanism of the environment, that when installed at a customer site, reduces the customer's net purchases of energy, demand, or both.

(51) **Savings-to-Investment Ratio (SIR) --** The ratio of the present value of a customer's estimated lifetime electricity cost savings from energy efficiency measures to the present value of the installation costs, inclusive of any incidental repairs, of those energy efficiency measures.

(52) **Self-delivered program --** A program developed by a utility in an area in which customer choice is not offered that provides incentives directly to customers. The utility may use internal or external resources to design and administer the program.

(53) **Spillover --** Reductions in energy consumption and/or demand caused by the presence of an energy efficiency program, beyond the program-related gross savings of the participants and without financial or technical assistance from the program. There can be participant and/or non-participant spillover.

(54) **Spillover rate --** Estimate of energy savings attributable to spillover expressed as a percent of savings installed by participants through an energy efficiency program.

(55) **Standard offer contract --** A contract between an energy efficiency service provider and a participating utility or between a participating utility and a commercial customer specifying standard payments based upon the amount of energy and peak demand savings achieved through energy efficiency measures,

the measurement and verification protocols, and other terms and conditions, consistent with this section.

(56) **Standard offer program --** A program under which a utility administers standard offer contracts between the utility and energy efficiency service providers.

(57) **Technical reference manual (TRM) --** A resource document compiled by the commission's EM&V contractor that includes information used in program planning and reporting of energy efficiency programs. It can include savings values for measures, engineering algorithms to calculate savings, impact factors to be applied to calculated savings (e.g., net-to-gross values), protocols, source documentation, specified assumptions, and other relevant material to support the calculation of measure and program savings.

(58) **Verification --** An independent assessment that a program has been implemented in accordance with the program design. The objectives of measure installation verification are to confirm the installation rate, that the installation meets reasonable quality standards, and that the measures are operating correctly and have the potential to generate the predicted savings. Verification activities are generally conducted during on-site surveys of a sample of projects. Project site inspections, participant phone and mail surveys and/or implementer and participant documentation review are typical activities associated with verification. Verification is also a subset of evaluation.

(d) **Cost-effectiveness standard**. An energy efficiency program is deemed to be cost-effective if the cost of the program to the utility is less than or equal to the benefits of the program. Utilities are encouraged to achieve demand reduction and energy savings through a portfolio of cost-effective programs that exceed each utility's energy efficiency goals while staying within the cost caps established in subsection (f)(7) of this section.

(1) The cost of a program includes the cost of incentives, measurement and verification, any shareholder bonus awarded to the utility, and actual or allocated research and development and administrative costs. The benefits of the program consist of the value of the demand reductions and energy savings, measured in accordance with the avoided costs prescribed in this subsection. The present value of the program benefits shall be calculated over the projected life of the measures installed or implemented under the program.

(2) The avoided cost of capacity is $80 per kW-year for all electric utilities through program year 2012, unless the commission establishes a different avoided cost of capacity in accordance with this paragraph. The avoided cost of capacity shall be revised beginning with program year 2013, in accordance with this paragraph.

(A) By November 15 of each year, commission staff shall post a notice of a revised avoided cost of capacity on the commission's website, on a webpage designated for this purpose, effective for the next program year. If the avoided cost of capacity has not changed, staff shall post a notice that the avoided cost of capacity remains the same.

(i) Staff shall calculate the avoided cost of capacity from the base overnight cost using the lower of a new conventional combustion turbine or a new advanced combustion turbine, as reported by the United States Department of Energy's Energy Information Administration's (EIA) Cost and Performance Characteristics of

New Central Station Electricity Generating Technologies associated with EIA's Annual Energy Outlook. If EIA cost data that reflects current conditions in the industry does not exist, staff may establish an avoided cost of capacity using another data source.

(ii) If the EIA base overnight cost of a new conventional or an advanced combustion turbine, whichever is lower, is less than $700 per kW, the avoided cost of capacity shall be $80 per kW. If the base overnight cost of a new conventional or advanced combustion turbine, whichever is lower, is at or between $700 and $1,000 per kW, the avoided cost of capacity shall be $100 per kW. If the base overnight cost of a new conventional or advanced combustion turbine, whichever is lower, is greater than $1,000 per kW, the avoided cost of capacity shall be $120 per kW.

(iii) The avoided cost of capacity calculated by staff may be challenged only by the filing of a petition within 45 days of the date the avoided cost of capacity is posted on the commission's website on a webpage designated for that purpose.

(B) A utility in an area in which customer choice is not offered may petition the commission for authorization to use an avoided cost of capacity different from the avoided cost determined according to subparagraph (A) of this paragraph by filing a petition no later than 45 days after the date the avoided cost of capacity calculated by staff is posted on the commission's website on a webpage designated for that purpose. The avoided cost of capacity proposed by the utility shall be based on a generating resource or purchase in the utility's resource acquisition plan and the terms of the purchase or the cost of the resource shall be disclosed in the filing.

(3) The avoided cost of energy is $0.064 per kWh for all electric utilities through program year 2012, unless the commission establishes a different avoided cost of energy in accordance with this paragraph. The avoided cost of energy shall be revised beginning with program year 2013, in accordance with this paragraph.

(A) Commission staff shall post a notice of a revised avoided cost of energy by November 15 of each year on the commission's website, on a webpage designated for this purpose, effective for the next program year. If the cost of energy has not changed, staff shall post a notice that the cost of energy remains the same. By November 1 of each year, ERCOT shall calculate the avoided cost of energy for the ERCOT region, as defined in §25.5(48) of this title (relating to Definitions), by determining the load-weighted average of the competitive load zone settlement point prices for the peak periods covering the two previous winter and summer peaks.

(B) A utility in an area in which customer choice is not offered may petition the commission for authorization to use an avoided cost of energy other than that otherwise determined according to this paragraph. The avoided cost of energy may be based on peak period energy prices in an energy market operated by a regional transmission organization if the utility participates in that market and the prices are reported publicly. If the utility does not participate in such a market, the avoided cost of energy may be based on the expected heat rate of the gas-turbine generating technology specified in this subsection, multiplied by a publicly reported cost of natural gas.

(e) **Annual energy efficiency goals**.

(1) An electric utility shall administer a portfolio of energy efficiency programs to acquire, at a minimum, the following:

(A) The utility shall acquire no less than a 25% reduction of the electric utility's annual growth in demand of residential and commercial customers for the 2012 program year.

(B) Beginning with the 2013 program year, until the trigger described in subparagraph (C) of this paragraph is reached, the utility shall acquire a 30% reduction of its annual growth in demand of residential and commercial customers.

(C) If the demand reduction goal to be acquired by a utility under subparagraph (B) of this paragraph is equivalent to at least four-tenths of 1 % its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year, the utility shall meet the energy efficiency goal described in subparagraph (D) of this paragraph for each subsequent program year.

(D) Once the trigger described in subparagraph (C) of this paragraph is reached, the utility shall acquire four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year.

(E) Except as adjusted in accordance with subsection (w) of this section, a utility's demand reduction goal in any year shall not be lower than its goal for the prior year, unless the commission establishes a goal for a utility pursuant to paragraph (2) of this subsection.

(2) The commission may establish for a utility a lower goal than the goal specified in paragraph (1) of this subsection, a higher administrative spending cap than the cap specified under subsection (i) of this section, or an EECRF greater than the cap specified in subsection (f)(7) of this section if the utility demonstrates that compliance with that goal, administrative spending cap, or EECRF cost cap is not reasonably possible and that good cause supports the lower goal, higher administrative spending cap, or higher EECRF cost cap. To be eligible for a lower goal, higher administrative spending cap, or a higher EECRF cost cap, the utility must request a good cause exception as part of its EECRF application. If approved, the good cause exception is limited to the program year associated with the EECRF application.

(3) Each utility's demand-reduction goal shall be calculated as follows:

(A) Each year's historical demand for residential and commercial customers shall be adjusted for weather fluctuations, using weather data for the most recent ten years. The utility's growth in residential and commercial demand is based on the average growth in retail load in the Texas portion of the utility's service area, measured at the utility's annual system peak. The utility shall calculate the average growth rate for the prior five years.

(B) The demand goal for energy-efficiency savings for a year pursuant to paragraphs (1)(A) or (B) of this subsection is calculated by applying the percentage goal to the average growth in demand, calculated in accordance with subparagraph (A) of this paragraph. The annual demand goal for energy efficiency savings pursuant to paragraph (1)(D) of this subsection is calculated by applying the percentage goal to the utility's summer weather-adjusted five-year average peak demand for the combined residential and commercial customers.

(C) A utility may submit for commission approval an alternative method to calculate its growth in demand, for good cause.

(D) If a utility's prior five-year average load growth, calculated pursuant to subparagraph (A) of this paragraph, is negative, the utility shall use the demand reduction goal calculated using the alternative method approved by the commission beginning with the 2013 program year or, if the commission has not approved an alternative method, the utility shall use the previous year's demand reduction goal.

(E) A utility shall not claim savings obtained from energy efficiency measures funded through settlement orders or count towards the bonus calculation any savings obtained from grant incentives that have been awarded directly to the utility for energy efficiency programs.

(F) Savings achieved through programs for hard-to-reach customers shall be no less than 5.0% of the utility's total demand reduction goal.

(G) Utilities may apply peak savings on a per project basis to summer or winter peak, but not to both summer and winter peaks.

(4) An electric utility shall administer a portfolio of energy efficiency programs designed to meet an energy savings goal calculated from its demand savings goal, using a 20% conservation load factor.

(5) Electric utilities shall administer a portfolio of energy efficiency programs to effectively and efficiently achieve the goals set out in this section.

(A) Incentive payments may be made under standard offer contracts, market transformation contracts, or as part of a self-delivered program for energy savings and demand reductions. Each electric utility shall establish standard incentive payments to achieve the objectives of this section.

(B) Projects or measures under a standard offer, market transformation, or self-delivered program are not eligible for incentive payments or compensation if:

(i) A project would achieve demand or energy reduction by eliminating an existing function, shutting down a facility or operation, or would result in building vacancies or the re-location of existing operations to a location outside of the area served by the utility conducting the program, except for an appliance recycling program consistent with this section.

(ii) A measure would be adopted even in the absence of the energy efficiency service provider's proposed energy efficiency project, except in special cases, such as hard-to-reach and weatherization programs, or where free riders are accounted for using a net to gross adjustment of the avoided costs, or another method that achieves the same result. A project results in negative environmental or health effects, including effects that result from improper disposal of equipment and materials.

(C) Ineligibility pursuant to subparagraph (B) of this paragraph does not apply to standard offer, market transformation, and self-delivered programs aimed at energy code adoption, implementation, compliance, and enforcement under subsection (m) of this section, nor does it preclude standard offer, market transformation, or self-delivered programs promoting energy efficiency measures also required by energy codes to the degree such codes do not achieve full compliance rates.

(D) A utility in an area in which customer choice is not offered may achieve the goals of paragraphs (1) and (2) of this subsection by:

(i) providing rebate or incentive funds directly to eligible residential and commercial customers for programs implemented under this section; or

(ii) developing, subject to commission approval, new programs other than standard offer programs and market transformation programs, to the extent that the new programs satisfy the same cost-effectiveness standard as standard offer programs and market transformation programs using the process outlined in subsection (s) of this section.

(E) For a utility in an area in which customer choice is offered, the utility may achieve the goal of this section in rural areas by providing rebate or incentive funds directly to customers after demonstrating to the commission in a contested case hearing that the goal requirement cannot be met through the implementation of programs by retail electric providers or energy efficiency service providers in the rural areas.

(f) **Cost recovery**. A utility shall establish an energy efficiency cost recovery factor (EECRF) that complies with this subsection to timely recover the reasonable costs of providing a portfolio of cost-effective energy efficiency programs pursuant to this section.

(1) The EECRF shall be calculated to recover:

(A) For a utility that does not collect any amount of energy efficiency costs in its base rates, the utility's forecasted annual energy efficiency program expenditures, the preceding year's over- or under-recovery that includes municipal and utility EECRF proceeding expenses, any performance bonus earned under subsection (h) of this section, and EM&V costs allocated to the utility by the commission.

(B) For a utility that collects any amount of energy efficiency in its base rates, the utility's forecasted annual energy efficiency program expenditures in excess of the actual energy efficiency revenues collected from base rates as described in paragraph (2) of this subsection, the preceding year's over- or under-recovery that includes municipal and utility EECRF proceeding expenses, any performance bonus earned under subsection (h) of this section, and EM&V costs allocated to the utility by the commission.

(2) The commission may approve an EECRF for each eligible rate class. The costs shall be directly assigned to each rate class that receives services under the programs to the maximum extent reasonably possible. In its EECRF proceeding, a utility may request a good cause exception to combine one or more rate classes, each containing fewer than 20 customers, with a similar rate class that receives services under the same energy efficiency programs. For each rate class, the under- or over-recovery of the energy efficiency costs shall be the difference between actual EECRF revenues and actual costs for that class that comply with paragraph (12) of this subsection. Where a utility collects energy efficiency costs in its base rates, actual energy efficiency revenues collected from base rates consist of the amount of energy efficiency costs expressly included in base rates, adjusted to account for changes in billing determinants from the test year billing determinants used to set rates in the last base rate proceeding.

(3) A proceeding conducted pursuant to this subsection is a ratemaking proceeding for purposes of PURA §33.023. EECRF proceeding expenses shall be included in the EECRF calculated pursuant to paragraph (1) of this subsection as follows:

(A) For a utility's EECRF proceeding expenses, the utility may include only its expenses for the immediately previous EECRF proceeding conducted under this subsection .

(B) For municipalities' EECRF proceeding expenses, the utility may include only expenses paid or owed for the immediately previous EECRF proceeding conducted under this subsection for services reimbursable under PURA §33.023(b).

(4) Base rates shall not be set to recover energy efficiency costs.

(5) If a utility recovers energy efficiency costs through base rates, the EECRF may be changed in a general rate proceeding. If a utility is not recovering energy efficiency costs through base rates, the EECRF may be adjusted only in an EECRF proceeding pursuant to this subsection.

(6) For residential customers and for commercial rate classes whose base rates do not provide for demand charges, the EECRF rates shall be designed to provide only for energy charges. For commercial rate classes whose base rates provide for demand charges, the EECRF rates shall provide for energy charges or demand charges but not both. Any EECRF demand charge shall not be billed using a demand ratchet mechanism.

(7) The total EECRF costs outlined in paragraph (1) of this subsection, excluding EM&V costs and municipal EECRF proceeding expenses shall not exceed the amounts prescribed in this paragraph unless a good cause exception filed pursuant to subsection (e)(2) of this section is granted.

(A) For residential customers for program year 2012, $0.001 per kWh; and

(B) For residential customers for program year 2013, $0.0012 per kWh;

(C) For commercial customers for program year 2012, rates designed to recover revenues equal to $0.0005 per kWh times the aggregate of all eligible commercial customers' kWh consumption; and

(D) For commercial customers for program year 2013, rates designed to recover revenues equal to $0.00075 per kWh times the aggregate of all eligible commercial customers' kWh consumption.

(E) For the 2014 program year and thereafter, the residential and commercial cost caps shall be calculated to be the prior period’s cost caps increased by a rate equal to the most recently available calendar year’s percentage change in the South urban consumer price index (CPI), as determined by the Federal Bureau of Labor Statistics.

(8) Not later than May 1 of each year, a utility in an area in which customer choice is not offered shall apply to adjust its EECRF effective January 1 of the following year. Not later than June 1 of each year, a utility in an area in which customer choice is offered shall apply to adjust its EECRF effective March 1 of the following year. If a utility is in an area in which customer choice is offered in some but not all parts of its service area and files one energy efficiency plan and report covering all of its service area, the utility shall apply to adjust the EECRF not later than May 1 of each year, with the EECRF effective January 1 in the parts of its service area in which customer choice is not offered and March 1 in the parts of its service area in which customer choice is offered.

(9) Upon a utility’s filing of an application to establish a new EECRF or adjust an EECRF, the presiding officer shall set a procedural schedule that will enable the

commission to issue a final order in the proceeding required by subparagraphs (A), (B), and (C) of this paragraph as follows:

(A) For a utility in an area in which customer choice is not offered, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding prior to the January 1 effective date of the new or adjusted EECRF, except where good cause supports a different procedural schedule.

(B) For a utility in an area in which customer choice is offered, the effective date of a new or adjusted EECRF shall be March 1. The presiding officer shall set a procedural schedule that will enable the utility to file an EECRF compliance tariff consistent with the final order within 10 days of the date of the final order. The procedural schedule shall also provide that the compliance filing date will be at least 45 days before the effective date of March 1. In no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF. The utility shall service notice of the approved rates and the effective date of the approved rates by the working day after the utility files a compliance tariff consistent with the final order approving the new or adjusted EECRF to retail electric providers that are authorized by the registration agent to provide service in the utility's service area. Notice under this subparagraph may be served by email. The procedural schedule may be extended for good cause, but in no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF, and in no event shall the utility serve notice of the approved rates and the effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the utility's service area more than one working day after the utility files the compliance tariff.

(C) For a utility in an area in which customer choice is offered in some but not all parts of its service area and that files one energy efficiency plan and report covering all of its service area, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding prior to the January 1 effective date of the new or adjusted EECRF for the areas in which customer choice is not offered, except where good cause supports a different schedule. For areas in which customer choice is offered, the effective date of the new or adjusted EECRF shall be March 1. The presiding officer shall set a procedural schedule that will enable the utility to file an EECRF compliance tariff consistent with the final order within 10 days of the date of the final order. The procedural schedule shall also provide that the compliance filing date will be at least 45 days before the effective date of March 1. In no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF. The utility shall serve notice of the approved rates and the effective date of the approved rates by the working day after the utility files a compliance tariff consistent with the final order approving the new or adjusted EECRF to retail electric providers that are authorized by the registration agent to provide service in the utility's service area. Notice under this subparagraph of this paragraph may be served by email. The procedural schedule may be extended for good cause, but in no event shall the effective date of any new or adjusted EECRF occur less than 45 days after the utility files a compliance tariff consistent with a final order approving the new or adjusted EECRF, and in no event shall the utility serve notice of the approved rates and the effective date of the approved rates to retail electric providers that are authorized by the registration agent to provide service in the utility's service area more than one working day after the utility files the compliance tariff.

(D) If no hearing is requested within 30 days of the filing of the application, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within 90 days after a sufficient application was filed; or

(E) If a hearing is requested within 30 days of the filing of the application, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within 180 days after a sufficient application was filed. If a hearing is requested, the hearing will be held no earlier than the first working day after the 45th day after a sufficient application is filed.

(10) A utility's application to establish or adjust an EECRF shall include testimony and schedules, in Excel format with formulas intact, showing the following, by retail rate class, for the prior program year and the program year for which the proposed EECRF will be collected as appropriate:

(A) the utility's forecasted energy efficiency costs;

(B) the actual base rate recovery of energy efficiency costs, adjusted for load changes in load subsequent to the last base rate proceeding, with supporting calculations;

(C) the energy efficiency performance bonus amount that it calculates to have earned for the prior year;

(D) any adjustment for past over- or under-recovery of energy efficiency revenues;

(E) information concerning the calculation of billing determinants for the most recent year and for the year in which the EECRF is expected to be in effect;

(F) the direct assignment and allocation of energy efficiency costs to the utility’s eligible rate classes, including any portion of energy efficiency costs included in base rates, provided that the utility's actual EECRF expenditures by rate class may deviate from the projected expenditures by rate class, to the extent doing so does not exceed the cost caps in paragraph (7) of this subsection;

(G) information concerning calculations related to the requirements of paragraph (7) of this subsection;

(H) the incentive payments by the utility, by program, including a list of each energy efficiency administrator and/or service provider receiving more than 5% of the utility’s overall incentive payments and the percentage of the utility’s incentives received by those providers. Such information may be treated as confidential;

(I) the utility's administrative costs, including any affiliate costs and EECRF proceeding expenses and an explanation of both;

(J) the actual EECRF revenues by rate class for any period for which the utility calculates an under- or over-recovery of EECRF costs;

(K) the utility’s bidding and engagement process for contracting with energy efficiency service providers, including a list of all energy efficiency service providers that participated in the utility programs and contractors paid with funds collected through the EECRF. Such information may be treated as confidential;

(L) the estimated useful life used for each measure in each program, or a link to the information if publicly available; and

(M) any other information that supports the determination of the EECRF.

(11) The following factors must be included in the application, as applicable, to support the recovery of energy efficiency costs under this subsection.

(A) the costs are less than or equal to the benefits of the programs, as calculated in subsection (d) of this section;

(B) the program portfolio was implemented in accordance with recommendations made by the commission's EM&V contractor and approved by the commission and the EM&V contractor has found no material deficiencies in the utility's administration of its portfolio of energy efficiency programs. This subparagraph does not preclude parties from examining and challenging the reasonableness of a utility's energy efficiency program expenses nor does it limit the commission's ability to address the reasonableness of a utility's energy efficiency program expenses;

(C) if a utility is in an area in which customer choice is offered and is subject to the requirements of PURA §39.905(f), the utility met its targeted low-income energy efficiency requirements;

(D) existing market conditions in the utility's service territory affected its ability to implement one or more of its energy efficiency programs or affected its costs;

(E) the utility's costs incurred and achievements accomplished in the previous year or estimated for the year the requested EECRF will be in effect are consistent with the utility's energy efficiency program costs and achievements in previous years notwithstanding any recommendations or comments by the EM&V contractor;

(F) changed circumstances in the utility's service area since the commission approved the utility's budget for the implementation year that affect the ability of the utility to implement any of its energy efficiency programs or its energy efficiency costs;

(G) the number of energy efficiency service providers operating in the utility's service territory affects the ability of the utility to implement any of its energy efficiency programs or its energy efficiency costs;

(H) customer participation in the utility's prior years' energy efficiency programs affects customer participation in the utility's energy efficiency programs in previous years or its proposed programs underlying its EECRF request and the extent to which program costs were expended to generate more participation or transform the market for the utility's programs;

(I) the utility's energy efficiency costs for the previous year or estimated for the year the requested EECRF will be in effect are comparable to costs in other markets with similar conditions; or

(J) the utility has set its incentive payments with the objective of achieving its energy and demand goals at the lowest reasonable cost per program.

(12) The scope of an EECRF proceeding includes the extent to which the costs recovered through the EECRF complied with PURA §39.905 and this section, and the extent to which the costs recovered were reasonable and necessary to reduce demand and energy growth. The proceeding shall not include a review of program design to the extent that the programs complied with the energy efficiency implementation project (EEIP) process defined in subsection (s) of this section. The commission shall not allow recovery of expenses that are designated

as non-recoverable under §25.231(b)(2) of this title (relating to Cost of Service). In addition, the order shall contain findings of fact regarding the following:

(A) the costs to be recovered through the EECRF are reasonable estimates of the costs necessary to provide energy efficiency programs and to meet the utility's goals under this section;

(B) calculations of any under- or over-recovery of EECRF costs is consistent with this section;

(C) any energy efficiency performance bonus for which recovery is being sought is consistent with this section;

(D) the costs assigned or allocated to rate classes are reasonable and consistent with this section;

(E) the estimate of billing determinants for the period for which the EECRF is to be in effect is reasonable;

(F) any calculations or estimates of system losses and line losses used in calculating the charges are reasonable;

(G) whether the proposed EECRF rates comply with the requirements of paragraph (7) of this subsection; and

(H) whether the proposed EECRF rates comply with the requirements of subsection (r) of this section, if the utility is in an area in which customer choice is offered.

(13) Notice of a utility's filing of an EECRF application is reasonable if the utility provides in writing a general description of the application and the docket number assigned to the application within 7 days of the application filing date to:

(A) All parties in the utility's most recent completed EECRF docket;

(B) All retail electric providers that are authorized by the registration agent to provide service in the utility's service area at the time the EECRF application is filed;

(C) All parties in the utility's most recent completed base-rate proceeding; and

(D) The state agency that administers the federal weatherization program.

(14) The utility shall file an affidavit attesting to the completion of notice within 14 days after the application is filed.

(g) **Incentive payments**. The incentive payments for each customer class shall not exceed 100% of avoided cost, as determined in accordance with this section. The incentive payments shall be set by each utility with the objective of achieving its energy and demand savings goals at the lowest reasonable cost per program. Different incentive levels may be established for areas that have historically been underserved by the utility's energy efficiency programs or for other appropriate reasons. Utilities may adjust incentive payments during the program year, but such adjustments must be clearly publicized in the materials used by the utility to set out the program rules and describe the programs to participating energy efficiency service providers.

(h) **Energy efficiency performance bonus**. A utility that exceeds its demand and energy reduction goals established in this section at a cost that does not exceed the cost caps established in subsection (f)(7) of this section shall be awarded a performance bonus calculated in accordance with this subsection. The performance bonus shall be based on the utility's energy efficiency achievements for the previous program year. The bonus calculation shall not include demand or energy savings that result from programs other than programs implemented under this section.

(1) The performance bonus shall entitle the utility to receive a share of the net benefits realized in meeting its demand reduction goal established in this section.

(2) Net benefits shall be calculated as the sum of total avoided cost associated with the eligible programs administered by the utility minus the sum of all program costs. Total avoided costs and program costs shall be calculated in accordance with this section.

(3) Beginning with the 2012 program year, a utility that exceeds 100% of its demand and energy reduction goals shall receive a bonus equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, with a maximum of 10% of the utility's total net benefits.

(4) The commission may reduce the bonus otherwise permitted under this subsection for a utility with a lower goal, higher administrative spending cap, or higher EECRF cost cap established by the commission pursuant to subsection (e)(2) of this section. The bonus shall be considered in the EECRF proceeding in which the bonus is requested.

(5) In calculating net benefits to determine a performance bonus, a discount rate equal to the utility's weighted average cost of capital of the utility and an escalation rate of 2 % shall be used. The utility shall provide documentation for the net benefits calculation, including, but not limited to, the weighted average cost of capital, useful life of equipment or measure, and quantity of each measure implemented.

(6) The bonus shall be allocated in proportion to the program costs associated with meeting the demand and energy goals and allocated to eligible customers on a rate class basis.

(7) A bonus earned under this section shall not be included in the utility's revenues or net income for the purpose of establishing a utility's rates or commission assessment of its earnings.

(i) **Utility administration**. The cost of administration shall not exceed 15% of a utility's total program costs. The cost of research and development shall not exceed 10% of a utility's total program costs for the previous program year. The cumulative cost of administration and research and development shall not exceed 20% of a utility's total program costs, unless a good cause exception filed pursuant to subsection (e)(2) of this section is granted. Any portion of these costs which are not directly assignable to a specific program shall be allocated among the programs in proportion to the program incentive costs. Any bonus awarded by the commission shall not be included in program costs for the purpose of applying these limits.

(1) Administrative costs include all reasonable and necessary costs incurred by a utility in carrying out its responsibilities under this section, including:

(A) conducting informational activities designed to explain the standard offer programs and market transformation programs to energy efficiency service providers, retail electric providers, and vendors;

(B) for a utility offering self-delivered programs, internal utility costs to conduct outreach activities to customers and energy efficiency service providers will be considered administration;

(C) providing informational programs to improve customer awareness of energy efficiency programs and measures;

(D) reviewing and selecting energy efficiency programs in accordance with this section;

(E) providing regular and special reports to the commission, including reports of energy and demand savings;

(F) a utility’s costs for an EECRF proceeding conducted pursuant to subsection (f) of this section;

(G) the costs paid by a utility pursuant to PURA §33.023(b) for an EECRF proceeding conducted pursuant to subsection (f) of this section; however, these costs are not included in the administrative caps applied in this paragraph; and

(H) any other activities that are necessary and appropriate for successful program implementation.

(2) A utility shall adopt measures to foster competition among energy efficiency service providers for standard offer, market transformation, and self-delivered programs, such as limiting the number of projects or level of incentives that a single energy efficiency service provider and its affiliates is eligible for and establishing funding set-asides for small projects.

(3) A utility may establish funding set-asides or other program rules to foster participation in energy efficiency programs by municipalities and other governmental entities.

(4) Electric utilities offering standard offer, market transformation, and self-delivered programs shall use standardized forms, procedures, deemed savings estimates and program templates. The electric utility shall file any standardized materials, or any change to it, with the commission at least 60 days prior to its use. In filing such materials, the utility shall provide an explanation of changes from the version of the materials that was previously used. For standard offer, market transformation, and self-delivered programs, the utility shall provide relevant documents to REPs and EESPs and work collaboratively with them when it changes program documents, to the extent that such changes are not considered in the energy efficiency implementation project described in subsection (s) of this section.

(5) Each electric utility in an area in which customer choice is offered shall conduct programs to encourage and facilitate the participation of retail electric providers and energy efficiency service providers in the delivery of efficiency and demand response programs, including:

(A) Coordinating program rules, contracts, and incentives to facilitate the statewide marketing and delivery of the same or similar programs by retail electric providers;

(B) Setting aside amounts for programs to be delivered to customers by retail electric providers and establishing program rules and schedules that will give retail electric providers sufficient time to plan, advertise, and conduct energy efficiency programs, while preserving the utility's ability to meet the goals in this section; and

(C) Working with retail electric providers and energy efficiency service providers to evaluate the demand reductions and energy savings resulting from time-of-use prices, home-area network devices, such as in home displays, and other programs facilitated by advanced meters to determine the demand and energy savings from such programs.

(j) **Standard offer programs**. A utility's standard offer program shall be implemented through program rules and standard offer contracts that are consistent with this section. Standard offer contracts will be available to any energy efficiency service provider that satisfies the contract requirements prescribed by the utility under this section and demonstrates that it is capable of managing energy efficiency projects under an electric utility's energy efficiency program.

(k) **Market transformation programs**. Market transformation programs are strategic efforts, including, but not limited to, incentives and education designed to reduce market barriers for energy efficient technologies and practices. Market transformation programs may be designed to obtain energy savings or peak demand reductions beyond savings that are reasonably expected to be achieved as a result of current compliance levels with existing building codes applicable to new buildings and equipment efficiency standards or standard offer programs. Market transformation programs may also be specifically designed to express support for early adoption, implementation, and enforcement of the most recent version of the International Energy Conservation Code for residential or commercial buildings by local jurisdictions, express support for more effective implementation and enforcement of the state energy code and compliance with the state energy code, and encourage utilization of the types of building components, products, and services required to comply with such energy codes. The existence of federal, state, or local governmental funding for, or encouragement to utilize, the types of building components, products, and services required to comply with such energy codes does not prevent utilities from offering programs to supplement governmental spending and encouragement. Utilities should cooperate with the REPs, and, where possible, leverage existing industry-recognized programs that have the potential to reduce demand and energy consumption in Texas and consider statewide administration where appropriate. Market transformation programs may operate over a period of more than one year and may demonstrate cost-effectiveness over a period longer than one year.

(l) **Self-delivered programs**. A utility may use internal or external resources to design, administer, and deliver self-delivered programs. The programs shall be tailored to the unique characteristics of the utility's service area in order to attract customer and energy efficiency service provider participation. The programs shall meet the same cost effectiveness requirements as standard offer and market transformation programs.

(m) **Requirements for standard offer, market transformation, and self-delivered programs**. A utility's standard offer, market transformation, and self-delivered programs shall meet the requirements of this subsection. A utility may conduct information and advertising campaigns to foster participation in standard offer, market transformation, and self-delivered programs.

(1) Standard offer, market transformation, and self-delivered programs:

(A) shall describe the eligible customer classes and allocate funding among the classes on an equitable basis;

(B) may offer standard incentive payments and specify a schedule of payments that are sufficient to meet the goals of the program, which shall be consistent with this section, or any revised payment formula adopted by the commission. The incentive payments may include both payments for energy and demand savings, as appropriate;

(C) shall not permit the provision of any product, service, pricing benefit, or alternative terms or conditions to be conditioned upon the purchase of any other good or service from the utility, except that only customers taking transmission and distribution services from a utility can participate in its energy efficiency programs;

(D) shall provide for a complaint process that allows:

(i) an energy efficiency service provider to file a complaint with the commission against a utility; and

(ii) a customer to file a complaint with the utility against an energy efficiency service provider;

(E) may permit the use of distributed renewable generation, geothermal, heat pump, solar water heater and combined heat and power technologies, involving installations of ten megawatts or less;

(F) may factor in the estimated level of enforcement and compliance with existing energy codes in determining energy and peak demand savings; and

(G) may require energy efficiency service providers to provide the following:

(i) a description of how the value of any incentive will be passed on to customers;

(ii) evidence of experience and good credit rating;

(iii) a list of references;

(iv) all applicable licenses required under state law and local building codes;

(v) evidence of all building permits required by governing jurisdictions; and

(vi) evidence of all necessary insurance.

(2) Standard offer and self-delivered programs:

(A) shall require energy efficiency service providers to identify peak demand and energy savings for each project in the proposals they submit to the utility;

(B) shall be neutral with respect to specific technologies, equipment, or fuels. Energy efficiency projects may lead to switching from electricity to another energy source, provided that the energy efficiency project results in overall lower energy costs, lower energy consumption, and the installation of high efficiency equipment. Utilities may not pay incentives for a customer to switch from gas appliances to electric appliances except in connection with the installation of high efficiency combined heating and air conditioning systems;

(C) shall require that all projects result in a reduction in purchased energy consumption, or peak demand, or a reduction in energy costs for the end-use customer;

(D) shall encourage comprehensive projects incorporating more than one energy efficiency measure;

(E) shall be limited to projects that result in consistent and predictable energy or peak demand savings over an appropriate period of time based on the life of the measure; and

(F) may permit a utility to use poor performance, including customer complaints, as a criterion to limit or disqualify an energy efficiency service provider or its affiliate from participating in a program.

(3) A market transformation program shall identify:

(A) program goals;

(B) market barriers the program is designed to overcome;

(C) key intervention strategies for overcoming those barriers;

(D) estimated costs and projected energy and capacity savings;

(E) a baseline study that is appropriate in time and geographic region. In establishing a baseline, the study shall consider the level of regional implementation and enforcement of any applicable energy code;

(F) program implementation timeline and milestones;

(G) a description of how the program will achieve the transition from extensive market intervention activities toward a largely self-sustaining market;

(H) a method for measuring and verifying savings; and

(I) the period over which savings shall be considered to accrue, including a projected date by which the market will be sufficiently transformed so that the program should be discontinued.

(4) A market transformation program shall be designed to achieve energy or peak demand savings, or both, and lasting changes in the way energy efficient goods or services are distributed, purchased, installed, or used over a defined period of time. A utility shall use fair competitive procedures to select EESPs to conduct a market transformation program, and shall include in its annual report the justification for the selection of an EESP to conduct a market transformation program on a sole-source basis.

(5) 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.

(6) 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 management programs that cannot be feasibly integrated into the ERCOT markets or that continue to provide separate and distinct benefits.

(n) **Energy efficiency plans and reports (EEPR)**. Each electric utility shall file by April 1 of each year an energy efficiency plan and report in a project annually designated for this purpose, as described in this subsection. The plan and report shall be filed as a searchable pdf document.

(1) Each electric utility's energy efficiency plan and report shall describe how the utility intends to achieve the goals set forth in this section and comply with the other requirements of this section. The plan and report shall be based on program years. The plan and report shall propose an annual budget sufficient to reach the goals specified in this section.

(2) Each electric utility's plan and report shall include:

(A) the utility's total actual and weather-adjusted peak demand and actual and weather- adjusted peak demand for residential and commercial customers for the previous five years;

(B) the demand goal calculated in accordance with this section for the current year and the following year, including documentation of the demand, weather adjustments, and the calculation of the goal;

(C) the utility's customers' total actual and weather-adjusted energy consumption and actual and weather-adjusted energy consumption for residential and commercial customers for the previous five years;

(D) the energy goal calculated in accordance with this section, including documentation of the energy consumption, weather adjustments, and the calculation of the goal;

(E) a description of existing energy efficiency programs and an explanation of the extent to which these programs will be used to meet the utility's energy efficiency goals;

(F) a description of each of the utility's energy efficiency programs that were not included in the previous year's plan, including measurement and verification plans if appropriate, and any baseline studies and research reports or analyses supporting the value of the new programs;

(G) an estimate of the energy and peak demand savings to be obtained through each separate energy efficiency program;

(H) a description of the customer classes targeted by the utility's energy efficiency programs, specifying the size of the hard-to-reach, residential, and commercial classes, and the methodology used for estimating the size of each customer class;

(I) the proposed annual budget required to implement the utility's energy efficiency programs, broken out by program for each customer class, including hard-to-reach customers, and any set-asides or budget restrictions adopted or proposed in accordance with this section. The proposed budget shall detail the incentive payments and utility administrative costs, including specific items for research and information and outreach to energy efficiency service providers, and other major administrative costs, and the basis for estimating the proposed expenditures;

(J) a discussion of the types of informational activities the utility plans to use to encourage participation by customers, energy efficiency service providers, and retail electric providers to participate in energy efficiency programs, including the manner in which the utility will provide notice of energy efficiency programs, and any other facts that may be considered when evaluating a program;

(K) the utility's performance in achieving its energy goal and demand goal for the prior five years, as reported in annual energy efficiency reports filed in accordance with this section;

(L) a comparison of projected savings (energy and demand), reported savings, and verified savings for each of the utility's energy efficiency programs for the prior two years;

(M) a description of the results of any market transformation program, including a comparison of the baseline and actual results and any adjustments to the milestones for a market transformation program;

(N) a description of self-delivered programs;

(O) expenditures for the prior five years for energy and demand incentive payments and program administration, by program and customer class;

(P) funds that were committed but not spent during the prior year, by program;

(Q) a comparison of actual and budgeted program costs, including an explanation of any increase or decreases of more than 10% in the cost of a program;

(R) information relating to energy and demand savings achieved and the number of customers served by each program by customer class;

(S) the utility's most recent EECRF, the revenue collected through the EECRF, the utility's forecasted annual energy efficiency program expenditures in excess of the actual energy efficiency revenues collected from base rates as described in subsection (f)(2) of this section, and the control number under which the most recent EECRF was established;

(T) the amount of any over- or under-recovery energy efficiency program costs whether collected through base rates or the EECRF;

(U) a list of any counties that in the prior year were under-served by the energy efficiency program;

(V) a calculation showing whether the utility qualifies for a performance bonus and the amount of any bonus;

(W) a description of new or discontinued programs, including pilot programs that are planned to be continued as full programs. For programs that are to be introduced or pilot programs that are to be continued as full programs, the description shall include the budget and projected demand and energy savings; and

(X) a link to the program manuals for the current program year.

(o) **Review of programs**. Commission staff may initiate a proceeding to review a utility's energy efficiency programs. In addition, an interested entity may request that the commission initiate a proceeding to review a utility's energy efficiency programs.

(p) **Inspection, measurement and verification**. Each standard offer, market transformation, and self-delivered program shall include use of an industry - accepted evaluation and/or measurement and verification protocol, such as the International Performance Measurement and Verification Protocol (IPMVP) or a protocol approved by the commission, to document and verify energy and peak demand savings to ensure that the goals of this section are achieved. A utility shall not provide an energy efficiency service provider final compensation until the provider establishes that the work is complete and evaluation and/or measurement and verification in accordance with the protocol verifies that the savings will be achieved. However, a utility may provide an energy efficiency service provider that offers behavioral programs incremental compensation as work is performed. If inspection of one or more measures is a part of the protocol, a utility shall not provide an energy efficiency service provider final compensation until the utility has conducted its inspection on at least a sample of measures and the inspections confirm that the work has been done. A utility shall provide inspection reports to commission staff within 20 days of staff's request.

(1) The energy efficiency service provider, or for self-delivered programs the utility is responsible for the determination and documentation of energy and peak demand savings using the approved evaluation and/or measurement and verification protocol, and may utilize the services of an independent third party for such purposes.

(2) Commission-approved deemed energy and peak demand savings may be used in lieu of the energy efficiency service provider's measurement and verification, where applicable. The deemed savings approved by the commission before December 31, 2007 are continued in effect, unless superseded by commission action.

(3) Where installed measures are employed, an energy efficiency service provider shall verify that the measures contracted for were installed before final payment is made to the energy efficiency service provider, by obtaining the customer's signature certifying that the measures were installed, or by other reasonably reliable means approved by the utility.

(4) For projects involving over 30 installations, a statistically significant sample of installations will be subject to on-site inspection in accordance with the protocol for the project to verify that measures are installed and capable of performing their intended function. Inspection shall occur within 30 days of notification of measure installation.

(5) Projects of less than 30 installations may be aggregated and a statistically significant sample of the aggregate installations will be subject to on-site inspection in accordance with the protocol for the projects to ensure that measures are installed and capable of performing their intended function. Inspection shall occur within 30 days of notification of measure installation.

(6) Where installed measures are employed, the sample size for on-site inspections may be adjusted for an energy efficiency service provider under a particular contract, based on the results of prior inspections.

(q) **Evaluation, measurement, and verification (EM&V)**. The following defines the evaluation, measurement, and verification (EM&V) framework to be implemented starting in program year 2013. The goal of this framework is to ensure that the programs are evaluated, measured, and verified using a consistent process that allows for accurate estimation of energy and demand impacts.

(1) EM&V objectives include:

(A) Documenting the impacts of the utilities' individual energy efficiency and load management portfolios, comparing their performance with established goals, and determining cost-effectiveness;

(B) Providing feedback for the commission, commission staff, utilities, and other stakeholders on program portfolio performance; and

(C) Providing input into the utilities' and ERCOT's planning activities.

(2) The principles that guide the EM&V activities in meeting the primary EM&V objectives are:

(A) Evaluators follow ethical guidelines.

(B) Important and relevant assumptions used by program planners and administrators are reviewed as part of the EM&V efforts.

(C) All important and relevant EM&V assumptions and calculations are documented and the reliability of results is indicated in evaluation reports.

(D) The majority of evaluation expenditures and efforts are in areas of greatest importance or uncertainty.

(3) The commission shall select an entity to act as the commission's EM&V contractor and conduct evaluation activities. The EM&V contractor shall operate

under the commission's supervision and oversight, and the EM&V contractor shall offer independent analysis to the commission in order to assist in making decisions in the public interest.

(A) Under the oversight of the commission staff and with the assistance of utilities and other parties, the EM&V contractor will evaluate specific programs and the portfolio of programs for each utility.

(B) The EM&V contractor shall have the authority to request data it considers necessary to fulfill its evaluation, measurements, and verification responsibilities from the utilities. A utility shall make good faith efforts to provide complete, accurate, and timely responses to all EM&V contractor requests for documents, data, information and other materials. The commission may on its own volition or upon recommendation by staff require that a utility provide the EM&V contractor with specific information.

(4) Evaluation activities will be conducted by the EM&V contractor, starting with activities associated with program year 2012, to meet the evaluation objectives defined in this section. Activities shall include, but are not limited to:

(A) Providing appropriate planning documents.

(B) Impact evaluations to determine and document appropriate metrics for each utility's individual evaluated programs and portfolio of all programs, annual portfolio evaluation reports, and additional reports and services as defined by commission staff to meet the EM&V objectives.

(C) Preparation of a statewide technical reference manual (TRM), including updates to such manual as defined in this subsection.

(5) The impact evaluation activities may include the use of one or more evaluation approaches. Evaluation activities may also include, or just include, verification activities on a census or sample of projects implemented by the utilities. Evaluations may also include the use of due-diligence on utility-provided documentation as well as surveys of program participants, non-participants, contractors, vendors, and other market actors.

(6) The following apply to the development of a statewide TRM by the EM&V contractor.

(A) The EM&V contractor shall use existing Texas, or other state, deemed savings manual(s), protocols, and the work papers used to develop the values in the manual(s), as a foundation for developing the TRM. The TRM shall include applicability requirements for each deemed savings value or deemed savings calculation. The TRM may also include standardized EM&V protocols for determining and/or verifying energy and demand savings for particular measures or programs. Utilities may apply TRM deemed savings values or deemed savings calculations to a measure or program if the applicability criteria are met.

(B) The TRM shall be reviewed by the EM&V contractor at least annually, pursuant to a schedule determined by commission staff, with the intention of preparing an updated TRM, if needed. In addition, any utility or other stakeholder may request additions to or modifications to the TRM at any time with the provision of documentation for the basis of such an addition or modification. At the discretion of commission staff, the EM&V contractor may review such documentation to prepare a recommendation with respect to the addition or modification.

(C) Commission staff shall approve the initial TRM and any updated TRMs. The approval process for any TRM additions or modifications, not made during the regular review schedule determined by commission staff, shall include a review by commission staff to determine if an addition or modification is appropriate before an annual update.

(D) Any changes to the TRM shall be applied prospectively to programs offered in the appropriate program year.

(E) The TRM shall be publicly available.

(F) Utilities may use their existing deemed savings values in their 2013 program year energy efficiency plan and report, submitted in 2012, if the TRM is not available. Starting with their 2014 program year energy efficiency plan and report, submitted in 2013, utilities shall utilize the values contained in the TRM, unless the commission indicates otherwise.

(7) The utilities shall prepare projected savings estimates and claimed savings estimates. The utilities shall conduct their own EM&V activities for purposes such as confirming any incentive payments to customers or contractors and preparing documentation for internal and external reporting, including providing documentation to the EM&V contractor. The EM&V contractor shall prepare evaluated savings for preparation of its evaluation reports and a realization rate

comparing evaluated savings with projected savings estimates and/or claimed savings estimates.

(8) Baselines for preparation of TRM deemed savings values or deemed savings calculations or for other evaluation activities shall be defined by the EM&V contractor and commission staff shall review and approve them. When common practice baselines are defined for determining gross energy and/or demand savings for a measure or program, common practice may be documented by market studies. Baselines shall be defined by measure category as follows (deviations from these specifications may be made with justification and approval of commission staff):

(A) Baseline is existing conditions for the estimated remaining lifetime of existing equipment for early replacement of functional equipment still within its current useful life. Baseline is applicable code, standard or common practice for remaining lifetime of the measure past the estimated remaining lifetime of existing equipment;

(B) Baseline is applicable code, standard or common practice for replacement of functional equipment beyond its current useful life;

(C) Baseline is applicable code, standard or common practice for unplanned replacements of failed equipment; and

(D) Baseline is applicable code, standard or common practice for new construction or major tenant improvements.

(9) Relevant recommendations of the EM&V contractor related to program design and reporting should be addressed in the Energy Efficiency Implementation

Project (EEIP) and considered for implementation in future program years. The commission may require a utility to implement the EM&V contractor's recommendations in a future program year.

(10) The utilities shall be assigned the EM&V costs in proportion to their annual program costs and shall pay the invoices approved by the commission. The 2013 and 2014 EM&V expenses outlined in the EM&V contractor's budget shall be recovered through the EECRFs approved by the commission in the EECRF proceedings initiated by the utilities in 2013. The commission shall at least biennially review the EM&V contractor's costs and establish a budget for its services sufficient to pay for those services that it determines are economic and beneficial to be performed.

(A) The funding of the EM&V contractor shall be sufficient to ensure the selection of an EM&V contractor in accordance with the scope of EM&V activities outlined in this subsection.

(B) EM&V costs shall be itemized in the utilities' annual reports to the commission as a separate line item. The EM&V costs shall not count against the utility's cost caps or administration spending caps.

(11) For the purpose of analysis, the utility shall grant the EM&V contractor access to data maintained in the utilities' data tracking systems, including, but not limited to, the following proprietary customer information: customer identifying information, individual customer contracts, and load and usage data in accordance with §25.272(g)(1)(A) of this title (relating to Code of Conduct for Electric

Utilities and Their Affiliates). Such information shall be treated as confidential information.

(A) The utility shall maintain records for three (3) years that include the date, time, and nature of proprietary customer information released to the EM&V contractor.

(B) The EM&V contractor shall aggregate data in such a way as to protect customer, retail electric provider, and energy efficiency service provider proprietary information in any non-confidential reports or filings the EM&V contractor prepares.

(C) The EM&V contractor shall not utilize data provided or received under commission authority for any purposes outside the authorized scope of work the EM&V contractor performs for the commission.

(D) The EM&V contractor providing services under this section shall not release any information it receives related to the work performed unless directed to do so by the commission.

(12) For evaluation of 2012 and 2013 program years' programs and portfolios, the EM&V contractor may implement a reduced level of EM&V activities as the EM&V contractor will not be retained by the commission until after the start of the 2012 program year. Should the EM&V contractor determine that deemed savings values utilized by the utilities for program years 2012 and/or 2013 are different than values the EM&V contractor develops for the TRM, the EM&V contractor shall report two sets of impacts - one with the TRM values and one with the utilities' values for 2012 and/or 2013 program years.

(r) **Targeted low income energy efficiency program**. Unless funding is provided under PURA §39.903, each unbundled transmission and distribution utility shall include in its energy efficiency plan a targeted low-income energy efficiency program as described by PURA §39.903(f)(2). A utility in an area in which customer choice is not offered may include in its energy efficiency plan a targeted low-income energy efficiency program that utilizes the cost-effectiveness methodology provided in paragraph (2) of this subsection. Savings achieved by the program shall count toward the utility's energy efficiency goal.

(1) Each utility shall ensure that annual expenditures for the targeted low-income energy efficiency program are not less than 10% of the utility's energy efficiency budget for the program year.

(2) The utility's targeted low-income program shall incorporate a whole-house assessment that will evaluate all applicable energy efficiency measures for which there are commission-approved deemed savings. The cost-effectiveness of measures eligible to be installed and the overall program shall be evaluated using the Savings-to-Investment (SIR) ratio.

(3) Any funds that are not obligated after July of a program year may be made available for use in the hard-to-reach program.

(s) **Energy Efficiency Implementation Project - EEIP**. The commission shall use the EEIP to develop best practices in standard offer market transformation, self-directed, pilot, or other programs, modifications to programs, standardized forms and procedures, protocols, deemed savings estimates, program templates, and the overall direction of the energy efficiency program established by this section. Utilities shall provide timely responses to questions posed by other participants relevant to the tasks of the EEIP. Any recommendations from the EEIP process shall relate to future years as described in this subsection.

(1) The following functions may also be undertaken in the EEIP:

(A) development, discussion, and review of new statewide standard offer programs;

(B) identification, discussion, design, and review of new market transformation programs;

(C) determination of measures for which deemed savings are appropriate and participation in the development of deemed savings estimates for those measures;

(D) review of and recommendations on the commission EM&V contractor's reports;

(E) review of and recommendations on incentive payment levels and their adequacy to induce the desired level of participation by energy efficiency service providers and customers;

(F) review of and recommendations on a utility annual energy efficiency plans and reports;

(G) utility program portfolios and proposed energy efficiency spending levels for future program years;

(H) periodic reviews of the cost-effectiveness methodology; and

(I) other activities as identified by commission staff.

(2) The EEIP projects shall be conducted by commission staff. The commission's EM&V contractor's reports shall be filed in the project at a date determined by commission staff.

(3) A utility that intends to launch a program that is substantially different from other programs previously implemented by any utility affected by this section shall file a program template and shall provide notice of such to EEIP participants. Notice to EEIP participants need not be provided if a program description or program template for the new program is provided through the utility's annual energy efficiency report. Following the first year in which a program was implemented, the utility shall include the program results in the utility's annual energy efficiency report.

(4) Participants in the EEIP may submit comments and reply comments in the EEIP on dates established by commission staff.

(5) Any new programs or program redesigns shall be submitted to the commission in a petition in a separate proceeding. The approved changes shall be available for use in the utilities' next EEPR and EECRF filings. If the changes are not approved by the commission by November 1 in a particular year, the first time that the changes shall be available for use is the second EEPR and EECRF filings made after commission approval.

(6) Any interested entity that participates in the EEIP may file a petition to the commission for consideration regarding changes to programs.

(t) **Retail providers**. Each utility in an area in which customer choice is offered shall conduct outreach and information programs and otherwise use its best efforts to encourage and facilitate the involvement of retail electric providers as energy efficiency service companies in the delivery of efficiency and demand response programs.

(u) **Customer protection**. Each energy efficiency service provider that provides energy efficiency services to end-use customers under this section shall provide the disclosures and include the contractual provisions required by this subsection, except for commercial customers with a peak load exceeding 50 kW. Paragraph (1) of this subsection does not apply to behavioral energy efficiency programs that do not require a contract with a customer.

(1) Clear disclosure to the customer shall be made of the following:

(A) the customer's right to a cooling-off period of three business days, in which the contract may be canceled, if applicable under law;

(B) the name, telephone number, and street address of the energy efficiency services provider and any subcontractor that will be performing services at the customer's home or business;

(C) the fact that incentives are made available to the energy efficiency services provider through a program funded by utility customers, manufacturers or other entities and the amount of any incentives provided by the utility;

(D) the amount of any incentives that will be provided to the customer;

(E) notice of provisions that will be included in the customer's contract, including warranties;

(F) the fact that the energy efficiency service provider must measure and report to the utility the energy and peak demand savings from installed energy efficiency measures;

(G) the liability insurance to cover property damage carried by the energy efficiency service provider and any subcontractor;

(H) the financial arrangement between the energy efficiency service provider and customer, including an explanation of the total customer payments, the total expected interest charged, all possible penalties for non-payment, and whether the customer's installment sales agreement may be sold;

(I) the fact that the energy efficiency service provider is not part of or endorsed by the commission or the utility; and

(J) a description of the complaint procedure established by the utility under this section, and toll free numbers for the Office of Customer Protection of the Public Utility Commission of Texas, and the Office of Attorney General's Consumer Protection Hotline.

(2) The energy efficiency service provider's contract with the customer, where such a contract is employed, shall include:

(A) work activities, completion dates, and the terms and conditions that protect residential customers in the event of non-performance by the energy efficiency service provider;

(B) provisions prohibiting the waiver of consumer protection statutes, performance warranties, false claims of energy savings and reductions in energy costs;

(C) a disclosure notifying the customer that consumption data may be disclosed to the EM&V contractor for evaluation purposes; and

(D) a complaint procedure to address performance issues by the energy efficiency service provider or a subcontractor.

(3) When an energy efficiency service provider completes the installation of measures for a customer, it shall provide the customer an "All Bills Paid" affidavit to protect against claims of subcontractors.

(v) **Grandfathered programs**. An electric utility that offered a load management standard offer program for industrial customers prior to May 1, 2007 shall continue to make the program available, at 2007 funding and participation levels, and may include additional customers in the program to maintain these funding and participation levels.

(w) **Identification notice.** An industrial customer taking electric service at distribution voltage may submit a notice identifying the distribution accounts for which it qualifies under subsection (c)(30) of this section. The identification notice shall be submitted directly to the customer's utility. An identification notice submitted under this section must be renewed every three years. Each identification notice must include the name of the industrial customer, a copy of the customer's Texas Sales and Use Tax Exemption Certification (pursuant to Tax Code §151.317), a description of the industrial process taking place at the consuming facilities, and the customer's applicable account number(s) or ESID number(s). The identification notice is limited solely to the metered point of delivery of the industrial process taking place at the consuming facilities. The account number(s) or ESID number(s) identified by the industrial customer under this section shall not be charged for any costs associated with programs provided under this section, including any shareholder bonus awarded; nor shall the identified facilities be eligible to participate in utility-administered energy efficiency programs during the term. Beginning with the 2013 program year, notices shall be submitted not later than February 1 to be effective for the following program year. A utility's demand reduction goal shall be adjusted to remove any load that is lost as a result of this subsection.

(x) **Administrative penalty**. The commission may impose an administrative penalty or other sanction if the utility fails to meet a goal for energy efficiency under this section. Factors, to the extent they are outside of the utility's control, that may be considered in determining whether to impose a sanction for the utility's failure to meet the goal include:

(1) the level of demand by retail electric providers and energy efficiency service providers for program incentive funds made available by the utility through its programs;

(2) changes in building energy codes; and

(3) changes in government-imposed appliance or equipment efficiency standards.

(y) **Effective date**. The effective date of this section is January 1, 2013.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.181, relating to Energy Efficiency Goal is hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS on the 11th day of OCTOBER 2012.

PUBLIC UTILITY COMMISSION OF TEXAS

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DONNA L. NELSON, CHAIRMAN

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KENNETH W. ANDERSON, JR., COMMISSIONER

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ROLANDO PABLOS, COMMISSIONER

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