PROJECT NO. 39917

RULEMAKING ON ENERGY STORAGE ISSUES	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

**ORDER ADOPTING AMENDMENTS TO §25.192 AND §25.501
AS APPROVED AT THE MARCH 7, 2012 OPEN MEETING**

The Public Utility Commission of Texas (commission) adopts amendments to §25.192, relating to Transmission Service Rates, and §25.501, relating to Wholesale Market Design for the Electric Reliability Council of Texas, with changes to the proposed text as published in the December 23, 2011 issue of the *Texas Register* (36 TexReg 8693). The amendments provide that energy storage equipment or facilities will be settled at the node when charging, and that such transactions will be considered wholesale transactions and will generally not be subject to ancillary costs. The amendments are competition rules subject to judicial review as specified in Public Utility Regulatory Act (PURA) §39.001(e). The amendments are adopted under Project Number 39917.

The commission received initial comments from the Lone Star Chapter of the Sierra Club (Sierra Club), South Texas Electric Cooperative, Inc. (STEC), Luminant Energy Company LLC and Luminant Generation Company LLC (Luminant), CenterPoint Energy Houston Electric, LLC (CenterPoint), Oncor Electric Delivery Company LLC (Oncor), Chamisa CAES at Tulia LLC (Chamisa), Texas Industrial Energy Consumers (TIEC), Apex Compressed Air Energy Storage LLC (Apex), Texas Electric Cooperatives, Inc. (TEC), ConocoPhillips Company, Austin Energy and CPS Energy (Cities), Xtreme Power, Texas Energy Storage Alliance (TESA), NRG Energy, Inc. (NRG), Denton Municipal Electric (DME), and the Electric Reliability Council of Texas

(ERCOT). Reply comments were filed by TESA, Apex, TIEC, NRG, Oncor, Chamisa, ConocoPhillips, Xtreme Power, STEC, and TEC.

The commission requested comments on the following questions:

1. How should the amendments address the situation where there is retail load or other generation facilities behind the transmission system point of delivery at which energy storage equipment or facilities are located?
2. Does the proposed rule strike the appropriate balance between removing barriers to storage technologies and ensuring that storage technologies pay their share of ancillary services costs?
3. Should the rule require storage facilities to pay additional ancillary services costs? If so, which ancillary services costs should they be required to pay?
4. Should the rule allow ERCOT to establish pilot projects for storage facilities and other new technologies? If so, what safeguards should the rule include to ensure that pilot projects do not impose undue costs on other market participants?

Question 1: ***How should the amendments address the situation where there is retail load or other generation facilities behind the transmission system point of delivery at which energy storage equipment or facilities are located?***

Sierra Club, STEC, CenterPoint, Oncor, Chamisa, APEX, TEC, Conoco Phillips, Cities, Xtreme Power, TESA, TEC, and DME all commented that storage should be metered separately from retail load and "station power" (the electricity needed for general facility operations and generation processes of a generation facility) behind the same transmission point of delivery. TIEC was in agreement with these other commenters that separately metering storage units from retail load and other generation would be appropriate when storage is coupled with retail load and generation resources behind one transmission system point of delivery and that the rule's treatment for stored energy should not apply to any non-storage loads at the site. TIEC stated that when storage is acting as a load, it should be treated as such, and when storage is discharging, it should be treated as generation. NRG commented that no special treatment is needed when storage coexists with retail load or generation behind the transmission point of delivery, and NRG further stated that generation and load could be netted in instances in which they are behind one system point of delivery. NRG also addressed the issue of distributed generation and how net metering instead of separate metering would be appropriate. Oncor noted that conventional generation and station load are currently netted if they occur simultaneously within a 15-minute interval behind a transmission system point of delivery. Outside of 15 minutes, the inflows and outflows are not netted. The inflows are settled through a retail electric provider (REP), cooperative, or municipal utility. The interconnecting utility installs a two-channel interval demand recorder (IDR) meter at the transmission system point of delivery to measure such inflows and outflows for large conventional generation facilities. TEC stated that energy stored for wholesale should be served by a dedicated meter. DME expressed concerns that the rule may allow load to install an energy storage device between itself and the distribution system to avoid retail charges. Sierra Club, DME, and TIEC commented that separate metering in situations such as those described in Question 1, would prevent abuse of ERCOT settlement processes by ensuring retail load situated behind a single transmission point of delivery would not receive the nodal price. CenterPoint argued for separate meters for each load and generation behind the point of delivery. TESA disagreed with the supposition that separate meters are needed to measure the inflow and outflow from the storage facility, and requested that only retail load at the facility be separately metered.

ConocoPhillips and TESA wanted more clarity in the rule and provided their own clarifying language for instances in which storage is coupled with renewable energy sources such as wind and solar and how those pairings should not necessitate the metering of the energy inflow from such renewable sources to their coupled storage units. These parties also expressed the need for commission clarity that such renewable resource and storage configurations would be considered as one storage resource for ERCOT wholesale generation dispatch purposes and not subject to the limitations and requirements imposed on intermittent resources. On this issue, ConocoPhillips stated that their CAES equipment will receive electricity primarily from co-located generation and that charging would not interfere with grid reliability. ConocoPhillips also noted that “station power” to operate and control office equipment would be treated as a retail transaction. ConocoPhillips further specified that they would withdraw from the grid when needed by ERCOT as an ancillary service. ConocoPhillips, reemphasized, however, that their CAES facilities will be behind the transmission point of delivery with other generation and will receive electricity primarily from the co-located resources instead of the ERCOT grid. ESA recommended that the separate metering should be used for telemetry and settlement purposes, and not treated as a measure of a separate transaction because it occurs entirely behind the point of interconnection and not over the ERCOT network.

Cities stated that the proposed language makes no reference to interconnection to the transmission system, and assumed that the rule applied equally to facilities interconnected at distribution voltages. Cities also stated that all station power or load ancillary to the storage device should be treated as retail load.

Commenters differed on whether the phrase “separately metered” would imply the need for metering both the inflow of electricity from the grid to the storage unit as well as the outflow of electricity from the same storage unit to the ERCOT grid. Oncor, STEC, and DME all expressed the view that each storage device should have a two-channel IDR meter that would measure both the inflow and outflow of electricity associated with any one storage device. STEC further commented that any discrepancy from such inflow when charging and outflow when providing energy to the grid should be measured by IDR metering in a pilot project and ERCOT could then decide how to treat such differences.

DME expressed the view that any amount withdrawn that is ultimately not returned to the grid, such as energy lost in the storage process, would classify the storage facility as a retail customer under the definition in PURA § 31.002, and these amounts not returned to the grid should be settled as retail purchases and billed accordingly by the REP or NOIE retail seller. In addition, DME stated that only the net energy that is re-released to the grid should receive wholesale settlements and the commission rule should ensure the appropriate metering configurations to measure such net energy released to the grid. TIEC stated that if the commission allows the separate treatment for energy that is stored, any energy lost in the storage process should be treated as retail load. DME commented that electricity purchased by the storage owner that is lost in the storage process and not returned to the grid should be considered end-use consumption, and therefore should be billed accordingly by the REP or non-opt-in entity (NOIE) as retail load. On this topic, DME suggested the commission apply a customer-specific reduction factor to monitor how storage purchase amounts compare to the grid injection amounts (or the predicted grid injection amounts) and the difference would be the retail purchase amount that would be subject to retail and transmission charges. DME admitted this proposed measurement process might not be ideal because energy storage owners do not necessarily purchase and re-sell energy simultaneously. DME therefore proposed another process that would meter and measure accumulated storage sales and purchases over a specific period of time, such as an entire month, and apply retail charges at an average monthly rate for settlement and billing purposes. TIEC agreed with DME that only energy stored and released should be given special treatment if the commission exempts energy withdrawals from certain charges. TIEC argued that energy lost in the storage process or used to serve retail load should be measured. TIEC also argued that a storage facility could effectively act as a direct-current (DC) tie by taking power from ERCOT, paying no delivery or ancillary service charges, and discharging to another power pool.

Taking the alternative view, TESA, Chamisa, and Xtreme Power all commented that two-channel metering for any given storage unit would not be necessary and would entail added costs. Chamisa suggested that a single meter could be used to measure when a CAES facility is simultaneously withdrawing electricity from the grid and injecting regenerated electricity back onto the grid. Chamisa also sought to ensure that charges will be based on the net of energy withdrawn and generated during an interval. APEX explained in their comments that thermodynamic losses occur between the storage charging phase and the storage discharging phase, and the requirement of meters to measure those net losses with exact precision would not be possible. TIEC responded to Chamisa's proposal for independently metered withdrawal and generation functions by arguing that the "facility" should be treated as a single resource for purposes of participating in the energy and ancillary service markets and should be net metered to determine the net impact of that facility on the grid. TIEC asserted that PURA §35.152(a) requires that a storage facility be interconnected and net metered as a "generation asset," not as a separate load and generator. TIEC also remarked that an industrial site that consists of an internal generator and load must be connected to the grid at a common metering point, abide by strict ERCOT protocols, and be equipped with a meter that measures the site's net impact to the grid. TIEC stated that the requirement to meter the entire storage facility as a single resource using a net meter is distinguishable from the related need to meter the storage facility separately from other retail loads.

ConocoPhillips, Apex, and TESA offered clarifying language to the proposed "separately metered" language to specify that storage owners would be entitled to wholesale treatment for purchases if storage units are metered "separate from other retail load or generation station load." Apex's proposed language went even further to ensure losses inherent in the storage conversion process itself would still be entitled to wholesale settlement treatment. Chamisa agreed with the substance of Apex's position on this issue, but did not see the need for new rule language, as the wholesale nature of the transaction should not change solely because there are energy losses during the storage process. Apex also noted that the "separately metered" language should not refer to a single meter for the entire resource. Rather, separate and possibly multiple meters could be installed for the wholesale load.

TESA pointed out that the current commission rules are not overly prescriptive in terms of metering generation arrangements behind one given point of interconnection; therefore, ERCOT has the ability to develop the modeling and metering practices for storage, generation, and load configurations behind single points of interconnection on the system. TESA and Chamisa commented that such ERCOT autonomy in modeling various metering configurations should also apply to instances in which storage co-exists with other generation and station load behind one transmission point of delivery.

ERCOT commented that they take no policy position on the issue; however, they noted that the change could result in ERCOT system changes in terms of metering for settlement purposes. ERCOT explained that it could use an ERCOT-Polled Settlement (EPS) meter that could, for settlement purposes, measure energy flows associated with withdrawals and injections. Settlements for electricity flows would be calculated at the EPS meter point for generation and charging by the energy storage equipment or facility. For configurations noted in the first question, ERCOT commented that there could be one or more EPS meters behind the point of interconnection from energy storage equipment or a facility for settlement. ERCOT requested clarity in regards to the exact electricity flows they will be required to measure for storage, other generation, retail load, and ancillary load situated behind the transmission point of delivery. ERCOT also commented that they were still examining settlement parameters for fossil fuel for generation that is used in conjunction with CAES in order to properly understand the settlement implications of energy flows for this prototype technology. ERCOT commented that they would also like clarity on how they are to measure nonconventional energy flows for settlement purposes. Apex responded to ERCOT's concern, and stated that if generation and station power were only located in ERCOT, there would be no issue, as it would be settled consistent with ERCOT practice.

TESA opposed TIEC's and DME's claim that only storage energy that is released to the grid should be allowed wholesale settlement treatment, whereas the energy that is lost in the normal storage processes should receive retail settlement treatment. TESA also opposed NRG's position that storage resources should be treated no differently than a retail customer when charging, noting that while storage may remove power from the grid, the storage facility is not the ultimate consumer. TESA further addressed TIEC's concern that storage resources could be used to serve load behind the meter by reiterating TESA's position supporting separate metering of any retail load behind a single transmission point of delivery. Oncor also reiterated its original point that the commission and staff vet carefully and in detail the practical aspects of metering and settlement before determining the final rule. TESA opposed TIEC's proposed language that would only allow storage energy re-released to the grid to receive wholesale settlement treatment. TESA did support Apex's proposed language that specifically states that the energy lost in the storage process should receive wholesale settlement prices. TESA offered support for Chamisa's clarifying language in terms of "separately metered." Chamisa emphasized in their own reply comments that their clarifying language regarding "separately metered" would ensure the rule language does not prohibit a single meter for both storage purchases and re-sales.

ConocoPhillips noted that most of the comments on the treatment of "retail load" assumed the storage unit would obtain electricity from the ERCOT grid. ConocoPhillips repeated its assertion that its CAES facility would be coupled with wind or solar generation and would occur "behind the meter" where there would be no retail transaction, no requirement of transmission service, and no impact to the ERCOT market. This would clearly be a wholesale transaction and should be treated as proposed. When ConocoPhillips would use the grid to charge its storage facility, it urged the commission to consider the benefits created by the use of this electricity when determining how to account for the use of generation from the grid.

TESA disagreed with commenters supporting the position that two-channel meters are needed on any given storage unit to separately measure the inflow of electricity with the outflow of electricity to the grid. In their reply comments, TESA made the request that only retail load be separately metered in situations where retail load and storage co-exist behind one transmission system point of delivery, which would address TIEC's concerns regarding the storage resources being used to serve load.

Apex and Chamisa replied to DME's and TIEC's claim that losses associated with purchased electricity for storage not resold to the grid should be treated as retail load. Apex, TESA, and Chamisa noted that thermodynamic losses cannot be metered. Apex rebutted DME's claim that storage losses should be considered retail purchases by arguing that losses associated with storage processes are not consumed by an end use customer. Apex commented that those losses should not be separately metered and they are not retail transactions. TESA and Chamisa also supported this position. Chamisa also noted the implementation issues to determine losses, especially for CAES, which produces more energy than withdrawn. Apex and other storage developers noted that DC tie sales are not subject to any retail load tariffs associated with such thermodynamic losses, and DC ties receive wholesales settlement for both inflows and outflows of electricity. Apex also argued that a wholesale transaction does not become part wholesale and part retail simply because losses occur during the process of delivering the power. On the topic of DC ties, TIEC raised concerns in their reply comments that a storage facility connected with both ERCOT and another power pool could act as a DC tie if the energy withdrawn from the ERCOT grid for a storage unit is not metered and compared with the energy supplied back to the ERCOT grid.

Apex noted that all parties are in agreement that station power should not be considered as a wholesale charging transaction. Apex claimed their proposed language would make this point clear because their language would change the phrase “separately metered” to “metered separately from any retail load.” In response to other commenters’ proposed language changes, Apex suggested that the revision it proposed provides more clarity in terms of the separate metering arrangements behind a transmission point of delivery and the Apex language is preferable in terms of specifically addressing losses. Apex also supported the same treatment for storage station power as is received by all other generators in ERCOT, where station load is a retail transaction only if it is separately metered or is a net load in an interval for a meter that measures both generation output and station power load.

STEC suggested in its reply comments that the commission rule be explicit in identifying exactly what should be metered and then allow ERCOT to determine how to accomplish such metering.

STEC also proposed that all energy taken from the grid be treated as load, which would align the market incentive for the storage device such that recharging would occur when energy and ancillary charges would be the most financially beneficial to the storage device and the market. Apex in their reply comments also agreed that ERCOT should decide how to implement the technical aspects of the metering prescribed by the commission.

TIEC reiterated their position that any energy that is withdrawn for charging and is not re-released to the grid should be assessed retail delivery charges, and the only way to quantify such lost energy would be to meter the specific inflow and outflow of electricity for any given storage unit and facility. In their reply comments, TIEC also expounded on potential market gaming abuses if the net impact of the entire storage facility on the grid is not metered. TIEC gave an account of a possible scenario in which a storage facility would have two separate interconnecting points for injection and withdrawal yet no aggregate metering device for the facility. Such a facility, TIEC posed, might be able to game the settlement system by acting as a Load acting as Resource (LaaR) and a battery resource at the same time even though the battery would just be a conduit for circular energy flows. Under such a scenario, the net energy being provided to the grid would be zero even though the storage facility could potentially receive LaaR settlements as well as wholesale generation settlements.

Commission Response

PURA §35.152 provides that a storage facility is entitled to be treated like other generation facilities in the *sale* of energy and ancillary services at wholesale. A key issue for the commission to resolve is how to treat a storage facility when it is *acquiring* energy. As

explained below, the commission determines that the electricity withdrawn to charge a storage facility is a wholesale transaction. There are a number of possible scenarios where this issue arises, including the following: (1) only a storage facility and its auxiliary facilities (station power); (2) a storage facility, auxiliary facilities, and other consuming facilities, all under common ownership; (3) a storage facility, auxiliary facilities, other consuming facilities, and a non-storage generation facility, all under common ownership; and (4) a storage facility, auxiliary facilities, other consuming facilities, and a non-storage generation facility, with different ownership.

In the first scenario, where there is only a storage facility and its auxiliary facilities, the storage facility purchases electricity from the ERCOT system to charge. This purchase of electricity is a wholesale transaction because the stored energy will subsequently be injected into the ERCOT system for a wholesale sale. Energy losses resulting from the energy conversion process and during storage are in the chain between the wholesale purchase and wholesale sale by the storage facility and therefore remain wholesale, like energy losses that occur in delivering energy from a generation facility through the ERCOT system to an end-use customer. However, the electricity purchased from the ERCOT system for the auxiliary facilities is consumed by those facilities and should be treated as a retail sale, like electricity purchased off the ERCOT system for a non-storage generation facility and its auxiliary facilities are net consumers of energy from the ERCOT system.

In the second scenario, where there is a storage facility, auxiliary facilities, and other consuming facilities, all under common ownership, the other consuming facilities' use of electricity should be treated as a retail sale, like for consuming facilities that do not share interconnection points with generation facilities. Otherwise, the owner could use the storage facility to make wholesale energy purchases from the ERCOT system for the end-use consumption of the energy at the consuming facilities.

In the third scenario, where there is a storage facility, auxiliary facilities, other consuming facilities, and a non-storage generation facility, all under common ownership, the energy produced by the non-storage generation facility to charge the storage facility is self-use energy and should therefore not be treated as a retail sale, like energy generated by a non-storage generation facility and used for its auxiliary facilities.

In the fourth scenario, where there is a storage facility, auxiliary facilities, other consuming facilities, and a non-storage generation facility, with different ownership, the energy produced by the non-storage generation facility to charge the storage facility should be treated as a wholesale sale, like in the first arrangement where the storage facility purchases electricity from the ERCOT system to charge.

These four scenarios produce a number of possible metering arrangements, including the following: scenario one – one meter at the interconnection point and one meter to measure the load of the storage facility (with the difference being the auxiliary load); scenario two - one meter at the interconnection point and one meter to measure the load of the storage

facility (with the difference being the auxiliary load and the load from the other consuming facilities); scenario three - one meter at the interconnection point, one meter to measure the load of the storage facility, and one meter to measure the energy production (or consumption) of the non-storage generation facility; and scenario four – same as scenario three. For any of these scenarios, the storage facility could choose not to separately meter the storage facility and treat all energy purchased from the ERCOT system as retail sales.

ConocoPhillips and TESA requested that storage coupled with renewable energy sources be treated as one storage resource for ERCOT wholesale generation dispatch purposes and not be subject to the limitations and requirements imposed on intermittent resources. This issue is an operational and reliability issue and is outside the scope of this rulemaking. Because it is an operational and reliability issue, it should be addressed by ERCOT.

TIEC raised concerns that a storage facility connected with both ERCOT and another power pool could act as a DC tie if the energy withdrawn from the ERCOT grid for a storage facility is not metered and compared with the energy supplied back to the ERCOT grid. This situation is like the situation where an entity makes a wholesale purchase of energy in ERCOT and exports the energy over a DC tie. Any storage facility that attempts to interconnect ERCOT with another power region must obtain a declaratory order from FERC providing that the facility would not affect FERC jurisdiction over ERCOT.

TIEC described a scenario in which a storage facility has an interconnection point for injection and a separate one for withdrawal. TIEC was concerned that such a facility

might be able to game the settlement system by acting as a Load acting as Resource (LaaR) and a generation resource at the same time, even though the storage would just be a conduit for circular energy flows. Such conduct would be a violation of §25.503(g), which prohibits any act or practice of a market participant that materially and adversely affects the reliability of the regional electric network or the proper accounting for the production and delivery of electricity among market participants. To avoid this conduct and properly account for the impact of a storage facility on the ERCOT system, the commission has changed the rule to provide that, for a storage facility that has more than one delivery point, ERCOT shall net the impact of those delivery points on the ERCOT system for settlement purposes. However, the rule should not be construed to preclude a storage facility from delivering ancillary services simultaneously as a load resource and as a generation resource when done in accordance with appropriate measurement and testing procedures. The commission notes that current ERCOT Nodal Protocols requires that for any facility with more than one interconnection point, that the points are no more than 400 yards apart. The commission directs ERCOT to amend this Protocol to remove this requirement for storage facilities that may have more than one interconnection point.

Question 2: ***Does the proposed rule strike the appropriate balance between removing barriers to storage technologies and ensuring that storage technologies pay their share of ancillary services costs?***

Question 3: ***Should the rule require storage facilities to pay additional ancillary services costs? If so, which ancillary services costs should they be required to pay?***

Sierra Club believes that not charging ancillary service obligations, except under a system emergency, is the appropriate balance.

Oncor stated that the commission is charged with determination of allocation of ancillary costs; therefore, it is within the commission's jurisdiction to determine whether the proposed treatment of electric energy storage is appropriate. However, Oncor noted that the proposed language treats electric energy storage differently from other power generation companies.

NRG, STEC, and TIEC commented that storage facilities should be treated as any other purchaser or seller; when storage is consuming energy it should be treated as load and when it is putting power onto the grid it should be treated as a generation resource. These parties agreed that storage devices should pay ancillary services under the same terms as all other entities that take power from the grid. TIEC argued that a storage facility will contribute to ancillary service requirements when it is a net load regardless of what may occur when it releases stored energy at a later time. TIEC pointed out that a storage facility co-located with generation behind a common metering point will not pay ancillary service costs under current rules, but this situation should not be the basis for exempting other storage facilities that will take power from the grid from paying ancillary service costs that they cause. DME stated that energy purchased and not ultimately returned to the grid should be treated as "end use consumption," and subject to all applicable retail charges, including ancillary service charges. Conversely, the proportion of energy purchases made available for resale should be exempt from these charges.

NRG stated that when storage co-exists with retail load or generation behind the transmission point of delivery, no special treatment is needed as whatever load and generation behind the point of interconnection can be netted. However, storage should be required to pay its “fair share” of ancillary service costs; paying for load services when operating as a load on the system and not being exempt from charges other loads are required to pay. NRG’s responded that proposals that energy storage facilities be exempted from retail charges, including ancillary costs, would be inconsistent with cost causation principles. NRG stated that there is nothing that distinguished storage load from ordinary load, and that ancillary services relate to the operation of the wholesale market. NRG rejected arguments that charging storage for load-related costs is “double charging” by pointing out that a bilateral transaction involving a wholesale supplier is not serving load, which is different from a charging battery that is connected to the transmission system. TIEC pointed out that an industrial site that has both load and generation resources can be either net load or net generation to the grid, just like storage, and would compete with storage facilities to provide energy and ancillary services. The different settlement treatment for two similarly situated entities appears to be discriminatory. NRG also agreed with TIEC’s argument that the different treatment of energy storage from other loads that put energy back on the grid may result in inappropriate discrimination. TIEC agreed with NRG that the legally sound course of action would be to treat storage facilities like any other net load when they withdraw power. TEC agreed that to the extent that power generation companies use electric energy provided by a retail electric provider or NOIE, the retail energy is subject to standard retail charges.

TIEC stated that ancillary service costs are dependent not just on the quantity of power that is ultimately consumed, but also on the time at which that power is consumed. Storage devices will contribute to regulation service deployments, as any withdrawal or injection impacts grid frequency. TIEC also argued that unless storage devices are prohibited from withdrawing power from the grid during emergency periods, and this is monitored and enforced in real time, then it is inappropriate for storage devices to be exempt from paying for responsive reserve service and other emergency ancillary services.

Chamisa stated that there are three functions or transaction types that the energy storage facility is engaging in: purchasing electricity for onsite consumption (station power), purchasing electricity to convert and store it for re-generation and resale, or regenerating and reselling the stored energy. Chamisa stated that there should be no question that, when generating for resale the facility should pay all applicable charges assigned to generation resources in ERCOT. Chamisa stated that as a serious, prospective new entrant into the ERCOT market with plans to invest over $200,000,000, it recognizes that energy storage facilities should and must pay their fair share of costs. Similarly, Chamisa continued, there should be no question about the facility's purchase of electricity for station power (lights, heating, air conditioning, computers, etc.). That purchase is clearly a retail purchase and all applicable retail load charges should apply just as they do to other retail customers when a qualified scheduling entity (QSE) purchases electricity on behalf of load-serving entities that serve those customers. Chamisa stated that all of the above concerns are currently treated in the protocols and no rule amendment is needed.

Chamisa commented that the rule is needed to address the purchase of electricity not for consumption, but for storage. Chamisa argued that the purchase of electricity for this purpose does not represent retail load but is a wholesale transaction and to append retail charges to a wholesale purchase of energy would impose a double charge on the same megawatt hour. The risk of double charge arises because ERCOT systems do not recognize "storage resources." The ERCOT energy management system recognizes only "generation resources" and "loads," and the ERCOT network model recognizes only "generation resources," "transmission elements," and "loads." Constrained to use its "load" and "generation" boxes, the ERCOT systems will see energy storages wholesale purchase of energy for storage as load and energy storages regeneration for resale as generation. Chamisa believed that the changes made in this rule will prevent the double counting from occurring and suggested language to further clarify this. TESA did not believe that storage should pay for additional ancillary services. TESA disagreed with TIEC's position, noting that energy used to charge the storage facility is not consumed, and could be used to provide a necessary reliability service.

TESA stated that energy withdrawn by an energy storage resource is neither load nor generation, but due to ERCOT's operational paradigm it must be characterized as one or the other. TESA stated that all ancillary service costs are currently borne by load based on the energy it consumes. It would be inequitable to single out storage resources and require them to pay such costs based on energy withdrawn from the grid as storage is a service and does not actually purchase energy for consumption.

Apex pointed out that there appears to be a discrepancy between "ancillary services" as defined in the substantive rules and "ancillary service obligation" as defined in the ERCOT Nodal Protocols. ERCOT ancillary service obligations are established in the day-ahead market and only pertain to responsive reserves, non-spinning reserves, and up and down regulation reserves.

They do not include black start, volt-ampere reactive (VAR), reliability unit commitment (RUC), reliability must-run (RMR), and many other charges assessed by ERCOT that are ancillary services under the definition in the commission’s rules. Since the proposed rule is a commission rule, Apex concluded the commission’s definition should be used. Apex also stated that the rationale behind not subjecting storage load to ancillary service obligations is that power for storage will not be purchased during periods of scarcity under the rule and thus it should not incur the costs associated with avoiding such conditions. Furthermore, since storage will to a great extent be providing ancillary services, it makes little sense to assign it an ancillary service obligation. Austin Energy and CPS Energy believe the commission should not only consider ancillary services but also should determine whether RUC charges should be borne by storage facilities.

Luminant stated that it supports the exception of storage devices from the requirement to pay ancillary service costs, so long as the rule applies to true storage devices and not to load resources. Luminant stated that it would not support a proposal to include load resources within the proposed storage provisions as such resources do not provide the same types of benefits as storage or otherwise face the same barriers to participation in the market. Luminant also suggested changes to the rule language to prohibit storage facility owners from purchasing energy for the purpose of storage during an ERCOT declared emergency unless directed to do so by ERCOT or unless the facility is a limited duration storage facility that can be used to provide needed ancillary services. TESA supported Luminant’s position on this issue.

ERCOT did not take a position on this issue, but noted that any decision would have an ERCOT system impact. Implementation costs would be less if the storage load were excluded from Adjusted Meter Load (AML), which is used in numerous settlement charge types. If some ancillary service costs were charged, but not others, then implementation costs would increase.

Cities stated that the Commission should determine whether RUC costs should be borne by storage facilities.

ConocoPhillips stated that storage coupled with generation does not create the need for additional ancillary services, and should not be charged for these costs. ConocoPhillips disagreed with comments that the proposed rules are discriminatory. It noted that the rules are intended to address the characteristics of storage resources, which do not fit within the existing ERCOT protocols. The modification of commission rules and ERCOT protocols to allow storage to "fit" in the ERCOT market does not make the proposed rules discriminatory. ConocoPhillips stated that a storage resource should be able to provide ancillary service, provided it can meet the ERCOT testing requirements for qualifying to provide such service. ConocoPhillips also addressed alleged discrimination against load resources, and stated that load resources can participate as storage resources if they can provide the same services. However, ConocoPhillips noted that storage resources can increase the total supply of electricity available to the grid, while load resources merely shifted electricity from one user to another without actually increasing the total supply of electricity.

Commission Response:

As stated in the response to question 1, the commission determines that energy used to charge a storage facility is a wholesale transaction. Certain ancillary services are for the benefit of retail load and their costs are allocated to entities serving retail load on a load-ratio-share or per megawatt-hour basis. Because the withdrawal of electricity by a storage facility is a wholesale transaction, a storage facility should not be allocated those costs.

Question Four: ***Should the rule allow ERCOT to establish pilot projects for storage facilities and other new technologies? If so, what safeguards should the rule include to ensure that pilot projects do not impose undue costs on other market participants?***

Chamisa, ConocoPhillips, DME, ERCOT, Luminant, NRG, TESA, Sierra Club, STEC, and Xtreme Power generally favored granting ERCOT the authority to conduct pilot projects.

TESA stated that pilot projects would be critical to the storage industry and could address issues associated with integrating storage to the grid. This process would be complex and time consuming if taken up through the ERCOT stakeholder process without the actual operational experience a pilot project would provide. Allowing pilot projects would potentially attract commercially viable storage projects to Texas when ERCOT needs additional resources and would take less time to develop than conventional generation. Luminant commented that the ERCOT stakeholder process should be used instead to develop the specific parameters of pilot projects and ensure impacts are adequately monitored and mitigated. Sierra Club commented that it supports allowing ERCOT to establish pilot projects for storage facilities if the programs are limited in scope, duration, and subject to a public request for proposal (RFP) process so as to not unduly favor a particular vendor or technology. DME similarly commented that a pilot project would only be viable if storage presented technological issues that could be resolved in actual experience, and then should have a defined capacity and future review date. Apex stated that if a pilot is established, it should be based on competitive rules, be short-term and technology neutral, and require any property rights and payments to cease at the pilot's expiration date. Oncor commented that the pilot project would benefit from commission guidance with regard to scope, size, and applicability of ERCOT protocols, and that the pilot project scope should be limited to storage as a generation resource, as storage for the purpose of transmission or distribution reliability is not at issue. Chamisa stated that a pilot project would be useful for battery or flywheel technologies, but is not needed for CAES. Imposing a pilot project requirement for CAES would be counterproductive.

ConocoPhillips stated that pilot projects may allow ERCOT to determine if new technologies can meet existing reliability requirements or are in need of special provisions in order to interconnect. Luminant stated that a storage-specific pilot was only needed for limited duration storage devices with characteristics that do not fit into the current market design. Limited duration storage technologies do not have the characteristics required for the current ancillary services market and a shorter-term product would need to be developed and tested prior to such devices being introduced into the market on a broader scale. Long-term energy storage devices act more like conventional generation and will be able to provide traditional ancillary and energy services once the commission clarifies the issues surrounding storage-related retail and wholesale transactions. Apex, Luminant, Chamisa, and ConocoPhillips stated that CAES fits into the existing ERCOT services and protocols, and a pilot project of the technology is not needed. ConocoPhillips commented that participation in any pilot should be voluntary and not be held as an interconnection prerequisite, and requested that any rule regarding a possible energy storage pilot specifically recognize that there is no requirement for CAES or other technologies able to meet current ERCOT testing requirements to participate in the pilot prior to entering the market. Apex and NRG agreed with this position.

Chamisa stated that while CAES does not need a pilot project, such a pilot is necessary for battery and flywheel projects to be considered in ERCOT. Xtreme Power commented that without authority to pilot certain limited-duration storage technologies, ERCOT will forego near-term additional capacity resources, as many implementation issues cannot be worked through without actual operational experience. Xtreme Power suggested language that would allow ERCOT in the near term to pilot up to 100 megawatts (MW) of storage using existing market mechanisms to the extent feasible, while granting waivers to participants as necessary to effectuate the purpose of the pilot. Xtreme Power suggested that such a pilot would allow ERCOT to work through a myriad of issues and evaluate any system changes necessary to implement lessons learned in the future.

ERCOT and NRG approved of the language provided to the commission by ERCOT at the October 6, 2011 workshop on energy storage and filed under Project Number 39764 giving the commission the authority to conduct pilots and grant temporary exemptions from protocols. Both parties commented on the operational and data benefits of a storage pilot and the ability of a pilot to highlight needed substantive rule and protocol changes. The proposed language included requirements for the ERCOT board to approve the scope and purpose of any pilot, which would be appealable to the commission and could serve as a starting point for a pilot rule. STEC, ERCOT, and NRG noted that ERCOT board approval allowed for parties to appeal the board's decision to the commission, which they believe is the only safeguard requirement needed to ensure undue costs are not imposed on ratepayers across ERCOT. STEC also supported the granting of temporary waivers from ERCOT protocols.

DME stated that the commission is rightly concerned regarding the undue imposition of costs on other market participants, and an unneeded pilot could distort the market and result in an uneconomic allocation of facilities on the grid. STEC commented that a pilot is an economical way to address storage implementation in the ERCOT market and that utilizing established generation interconnection practices would make the pilot cost effective. Sierra Club commented that pilot costs should be borne by ratepayers through the ERCOT administrative fee as all consumers and market participants will ultimately benefit. TIEC stated that any pilot should be paid for by the project's participants rather than the grid as a whole. Apex commented that TIEC's proposal for participants to fund the pilot should be further discussed in the subsequent pilot rulemaking. Xtreme Power stated that issues regarding who would bear the costs of a pilot project are premature and that it took no position at this time as it envisions program costs to be minimal. Cities stated that while it had no comment at this time regarding the establishment of pilot projects, it appreciated the commission's acknowledgement that such pilots could foist costs if not carefully designed and implemented.

Oncor stated that while it takes no advocacy position on the pilot issue, it felt that commission guidance would benefit such a pilot and cited the guidance provided during the 2001 retail pilot project.

TIEC stated that it is neither necessary nor appropriate for ERCOT to establish any pilot project. The ability of storage to participate in ERCOT should be determined by whether these technologies can meet applicable performance standards, and a pilot project should not make it "easier" for certain technologies to compete. TIEC stated that it opposes authorizing pilots in this rulemaking, as such projects could impose unknown costs on ERCOT customers without real benefits to the grid, and an ERCOT pilot is neither necessary nor appropriate. TIEC also commented that ERCOT can gain experience with any new technology once it is viable and enters the market at no additional cost to consumers, and with no special treatment given to new technologies. ERCOT should establish general, uniform standards and compensation schemes without providing favorable treatment, subsidies, or reliability exemptions to allow certain entities to compete in the market. TIEC noted that the ERCOT grid already has a number of interconnected storage facilities, as do other markets and the Federal Energy Regulatory Commission (FERC) recently rejected similar calls for pilot programs, and there are no operational unknowns or impediments to storage participating in the ERCOT market today. If the commission does move forward, TIEC recommended that any pilot should be based on the general characteristics of a service that ERCOT is seeking to procure and open to any resources that can meet the technology-neutral, appropriate standards. TIEC further commented that a pilot that did not allow other capable technologies to compete would be anti-competitive as well as discriminatory. Such a pilot would be in violation of PURA §39.001(c) and §39.151(a)(4).

TIEC provided recommended language regarding a technologically and competitively neutral pilot should the commission proceed.

TESA and Xtreme Power disagreed with TIEC's blanket dismissal in regards to the proposed energy storage pilot. Xtreme Power rejected TIEC's statement that there is no need for a pilot project. Xtreme Power pointed to a presentation by ERCOT in Project Number 39764 that identified 16 specific areas where more experience with storage is needed. Xtreme Power also asserted that TIEC mischaracterized the nature of pilot projects with the argument that a pilot would "make it easier for certain technologies to compete." A pilot project would allow ERCOT to investigate promising technologies to meet reliability challenges. Xtreme Power stated that imposing concepts, as suggested by TIEC, that a pilot must be designed on a service that ERCOT is seeking to procure and that all costs should be paid by the entities participating in the pilot are premature and ill-considered. Xtreme Power also expressed concern that STEC intends that energy storage technologies be limited to certain defined pilot project activities for some undefined period of time – even if such a technology could otherwise qualify to participate in the ERCOT market. Xtreme argued that such an approach would be destabilizing for certain technologies such as CAES, and potentially limiting for other storage technologies. Xtreme stated that this would prolong, rather than resolve, fundamental issues and hamper ERCOT's ability to successfully integrate technologies.

Xtreme Power commented that TIEC members have participated in both of the official pilot projects managed by ERCOT since restructuring began in 1999, and that despite TIEC's assertion that there is no need to study how storage technologies interact with ERCOT market rules and systems, ERCOT identified 16 specific areas where more experience with storage is needed in its presentation at workshop on storage issues in Project No. 39764. Xtreme Power stated that TIEC mischaracterized the nature of pilot projects by implying that a storage pilot would make it easier for certain technologies to compete; rather, the pilot would determine how to scientifically and efficiently investigate how emerging technologies could meet reliability and resource adequacy challenges. TESA stated in response to TIEC that the current market rules were designed for conventional generation prior to storage emerging as a resource and tool available to the grid. TESA commented that it agrees with TIEC's request for uniform standards and compensation schemes to meet the market's needs, but that creation of a new service does not create a break from these standards and cited emergency interruptible load service (EILS) as an example. TESA also argued that TIEC misses the objective of a pilot project, which is to provide operational experience needed by stakeholders and ERCOT to make informed recommendations on changes that will allow ERCOT to benefit from the unique characteristics that storage offers.

Apex, Chamisa, ConocoPhillips, TESA, and TIEC supported a separate rulemaking to consider granting ERCOT the ability to conduct new technology pilot projects, since specific language was not included in the rule currently proposed; therefore, stakeholders were not provided the opportunity to offer specific comments.

TIEC stated that since the proposed rule does not contain language regarding pilot projects, commenters are prevented from providing meaningful input, and the rule should either be republished with specific language or a separate rulemaking should be conducted. Chamisa recommended that the commission defer consideration of an energy storage pilot to a subsequent rulemaking in order to comply with section 2001.024 of the Administrative Procedures Act. Apex commented that a pilot proposal could delay decision on the threshold issues contained in the proposed rule and prevent storage projects from moving forward expeditiously.

NRG responded that it does not believe that the pilot project should necessarily be severed into a separate project, as the commission sufficiently noticed parties that it was granting ERCOT the ability to conduct pilot projects by publishing the question in the preamble of the proposed rule. Xtreme Power similarly stated that the commission can address piloting in stages by proposing rule language in this or another project that would allow ERCOT to conduct a limited duration storage pilot. Xtreme Power commented that a pilot project could be authorized without addressing the issue of granting ERCOT broader pilot program authority. In reply comments, Xtreme Power proposed that the commission incorporate any proposed amendments it is inclined to accept into the rule and republish the proposal for a final round of comments. Xtreme Power recommended that the commission incorporate language authorizing a storage pilot project to be conducted within the year. The broader issue of granting ERCOT general pilot authority should be reserved for a separate, dedicated proceeding.

Commission Response

The commission appreciates the parties' comments on the issue of allowing ERCOT to establish pilot projects. The commission has created Project Number 40150 to consider this issue further.

Section 25.192

TESA commented that the proposed amendment to §25.192(b) would be an effective way to dis-incent large, longer-duration storage facilities from charging during system peak intervals. TESA, however, commented that enabling the transmission service providers (TSPs) to assess transmission charges to storage owners based on their charging behavior during four coincident peak (4CP) intervals would be unfair to short-duration storage facilities that could be charging in order to provide frequency response and regulation up and down services, even when the system may be at peak demand. In these cases, TESA argued that such storage units are still providing a needed frequency control service at peak times when the grid needs stability, yet they would be penalized for providing this service. TESA suggested that short-duration storage owners should be exempt from transmission charge assessments when they are charging as directed by ERCOT, or providing ancillary services, even though the charging might occur at the same time as the 4CP intervals. TESA also recommended that the commission make it clear that charging energy from a co-located generator, and not drawing from the transmission system, is not subject to TSP charges.

Chamisa and Apex stated that assessing transmission charges to storage facilities based on their charging during 4CP intervals is justified. These parties noted, however, that if they are assessed transmission charges based on their share of load during 4CP intervals, as other load entities are currently assessed such charges, then storage facilities should be entitled to revenues from the congestion revenue right (CRR) auctions just as other load is entitled to revenues from the CRR auctions on a load-ratio share basis. TESA stated that they agreed storage should be entitled to their share of CRR revenues from CRR auctions.

Cities, TEC, Oncor, and ConocoPhillips expressed concern regarding the proposed amendment language providing that TSPs shall charge storage owners for transmission service in the same manner as a distribution service provider (DSP). ConocoPhillips stated that the proposed language could be interpreted to require TSPs to subject storage resources to other standards applicable to DSPs. ConocoPhillips noted that some TSPs do not have separate rates for DSPs, and stated its belief that the rule was not intended to address specific rates and tariff provisions, but only to address payment under the transmission cost matrix. TEC stated that treating energy storage facilities in the same manner as DSPs should also be further examined, and Oncor noted that the full implication of linking the treatment of energy storage facilities to the DSP designation nay not have been fleshed out.

NRG offered modifying language to the proposed amendment to §25.192(b) by suggesting that the last sentence of the proposed amendment read: "For an owner or operator of electric storage equipment or facilities described by §25.501(m) of this title, the monthly transmission charge to be paid shall be calculated in the same manner as the monthly transmission charge to be paid by each DSP." ConocoPhillips offered similar clarifying language indicating the transmission charge calculation method used for storage owners would be similar to the calculation methods that TSPs use to assess transmission charges to DSPs. In their reply comments, Chamisa supported ConocoPhillips' clarifying language.

Cities included language that would address how municipal utilities and electric cooperatives that have not opted into customer choice could assess transmission charges to owners of storage at distribution level voltages using similar tariff calculation methods based on demand during 4CP intervals, pursuant to §25.191(d)(2).

Oncor and CenterPoint both raised concerns regarding the application of charges to storage providers. CenterPoint noted that it has not developed tariffs for wholesale transmission services provided at the distribution level. CenterPoint noted that the commission should require energy storage facilities to have meters to record energy purchases and energy exports, because the TSP will need to have the amount of load used by the energy storage facility to charge the transmission rate. CenterPoint also pointed out that TSPs charge DSPs through the wholesale transmission matrix, and asked whether energy storage facilities should be added to the matrix or whether the TSPs will charge the energy storage facility under another tariff. Apex suggested that development of a new tariff should not be an undue burden, since the initial number of storage devices will be small, or the commission could develop a pro forma tariff to apply to all TSPs and the changes would be the same. Oncor noted that storage facilities would incur no charges if the storage facilities avoided charging during 4CP intervals. Oncor also noted that an energy storage facility would incur no non-bypassable charges when it uses electricity, an outcome different from use by other transmission level power generation companies. Oncor also stated that it has a tariff for providing access at distribution voltage, although other TSPs may not. In its reply comments, Oncor clarified the difference between its tariffs in that wholesale load served at transmission voltage is based on demand measured at the 4CP, while transmission service at distribution voltage is based on the maximum demand delivered to the point of delivery regardless of what time of day the load was demanded. TESA and Apex addressed this concern in reply comments by arguing that storage facilities have no way of knowing beforehand when the 4CP intervals will occur, and storage facility would make its charging decisions based on economics. Apex also noted that non-bypassable charges related to wholesale load would be paid by storage facilities.

Commission Response

In its discussion of question 1, the commission decided that storage load may be treated as wholesale load. In response to questions 2 and 3, the commission decided that certain ancillary service costs that are currently allocated to retail load should not be allocated to wholesale storage load. The commission also decided that transmission service charges, currently determined by the load-ratio share of DSPs during the 4CP, as a charge that is allocated based on retail load, shall also not be allocated to purchases of electricity by storage facilities. The commission amends the rules on transmission service rates to exclude wholesale storage load from the ERCOT 4CP calculation and the allocation of transmission service charges to DSPs. The exclusion of wholesale storage from the 4CP calculation that TSPs use to bill wholesale transmission costs to DSPs should ensure that TSPs do not undercollect their transmission costs of service. Wholesale load that is interconnected to a TSP's or DSP's system at distribution voltage receives "wholesale transmission service at distribution level voltage" pursuant to §25.191(d)(2), in which a TSP or DSP assesses a separate charge for that service. Wholesale storage load would be subject to any applicable tariffs or charges if it connects and receives service at the distribution level. TSPs and DSPs may need to amend their tariffs to address wholesale transmission service to storage facilities, and below the commission has set a deadline for compliance tariff filings.

In its discussion of questions 2 and 3, the commission decided that ancillary service costs allocated to load on a load-ratio-share or per megawatt-hour basis should not be allocated to a storage facility when the storage facility is withdrawing energy from the ERCOT system. Because storage facilities are generally not allocated ancillary service charges, storage facilities should not be allocated any CRR auction revenues based on load.

Section 25.501(m)

Apex stated that a commission decision to allow energy for storage to be a wholesale transaction follows the *Norton* decision at FERC and Texas law, as the energy purchased is not consumed, as noted in the definition of "retail customer" in PURA. Apex noted that energy used as part of the storage process, including losses, should be considered as part of the wholesale transaction. Apex responded to NRG's position that the electricity purchased by storage be subject to all retail fees ignores the statutory definition of retail customer, traditional definitions of wholesale transactions, and analogous decision by FERC and other independent system operators. Apex maintained that a purchase for later resale is by definition not a retail load.

Oncor sought clarification on whether the rule envisions a conventional metering design or something different. Oncor also analogized the power used by a storage facility to the "fuel" used by other generation resources, and as with other sources of fuel, asked which costs are properly borne by the energy resource and which costs are borne by the market. Oncor also requested an explanation of how relieving storage of obligations for certain charges can be reconciled with PURA §35.004(b) and (c).

Chamisa and TESA stated that they support the settlement at the nodal price for both charging and discharging, and that it is appropriate that these transactions be considered wholesale transactions and not be subject to charges assessed in conjunction with the retail purchase of electricity or with ancillary service obligations that are paid by load. Chamisa also noted that FERC supported the wholesale distinction for energy used to charge storage facilities. Chamisa declared that this decision is crucial for storage to operate, and no investor would finance a CAES facility if the facility was compelled to pay retail charges in order to resell at wholesale. Chamisa also noted that assigning the nodal price to charging eliminated uncertainty regarding the settlement at the load zone price. Apex agreed that energy withdrawn should be settled nodally at the same point where it is returned. Apex provided language to clarify this position.

Cities urged the commission to be clear that ERCOT have a wholesale settlement process in place that allows energy storage equipment or facilities to be settled in a manner that allows a non-opt in entity to shadow settle its wholesale statement without any impact from the energy storage facility's wholesale transaction.

ERCOT noted the "if" in the first sentence of the proposed §25.501(m) appears to give the owner or operator of the energy storage equipment or facility the permissive right to choose the settlement treatment and requests clarification from the commission on this point.

Apex, Chamisa, ConocoPhillips, Sierra Club, and TESA stated that they believe not charging ancillary service obligations except under a system emergency in appropriate. Chamisa stated that §25.501(m) correctly confirms that wholesale purchases for storage purposes are not subject to retail related charges in the ERCOT region. TESA stated that exempting storage from charges associated with load, including ancillary service obligations, is necessary to remove barriers to entry and ensure the wholesale nature of storage resources. Further, Chamisa commented that charges normally assigned to retail load should not be charged at the wholesale level, and charging storage entities a share of ancillary services obligations, as borne by metered retail load, would result in an improper double-charge of these obligations for MWs ultimately consumed by a retail customer. Chamisa provided amendments, which TESA supported, to the proposed language expanding the exemption from ancillary service obligations to include all other load ratio share or per megawatt-hour (MWh) based charges and allocations. NRG stated that the "double charging" argument is flawed as that type of transaction is typically preformed as a bilateral trade outside the ERCOT sponsored market.

Apex stated that the proposed rule needs clarification with regards to "ancillary services," as there are discrepancies between the definition of the term in §25.5(9) and the ancillary service obligations defined in Section 2 of ERCOT's Nodal Protocols. Apex stated that the rationale for removing storage load from ancillary service costs can be expanded to remove storage load from being subject to RUC costs, RMR costs, emergency power increase charges, and EILS charges, since storage will not be contributing to the events that cause such services to be needed. If storage will be providing ancillary services, it makes little sense to assign it an ancillary service obligation charge. Apex commented that since this is a commission rule, the commission's definition should be used and the only charges that storage load might be accountable for therefore are the ERCOT Administration fee and revenue neutrality adjustments. Apex provided language clarifying that storage load would be exempt from other load-ratio share or MWh-based charges and allocations.

DME stated that it is concerned about the potential for energy not being returned to the market to avoid retail tariff rate charges and for new loads to hide behind storage facilities in order to avoid retail charges. DME provided amendments to proposed subsection (m) clarifying that only transmission level purchases that are ultimately made available for sale in the wholesale market for resale would not be subject to ancillary service obligations.

NRG stated that, consistent with cost causation principles, it does not support fully exempting certain energy purchases by storage entities from ancillary service obligations. NRG agreed that it is appropriate to settle purchases for storage at the nodal price. However, NRG did not agree that electricity purchased for later regeneration and resale should be treated differently from other purchased electricity. Storage draws energy from the grid and therefore imposes the same costs on the grid as any other load. NRG commented that these costs could be considered fuel costs since unlike other, more traditional generators, storage devices derive fuel from the grid, which has its own inherent costs. NRG commented that while the commission may lower the fuel costs for storage through the ancillary service obligation exemption, it does not mean the market would be best served by lowering the cost of one technology versus another. NRG stated that costs associated with various services such RUC, black start services, and EILS all help ERCOT protect the grid and are related to wholesale market operations, and there is no reason not to charge storage load for this protection. NRG proposed deleting the last two sentences of proposed subsection (m), which provides the exemption for storage load from paying charges associated with retail load and ancillary services. NRG also noted that the FERC decision on to energy storage loads does apply load-related charges.

TESA disagreed with NRG's assertions that storage should pay retail and ancillary costs associated with load, as the energy stored is for later re-use rather than traditional load. These charges would diminish the value of the wholesale transaction nature of energy storage and would create a barrier to entry. Chamisa stated that NRG's request for a "light regulatory touch" would in fact set a heavy regulatory obstacle that would block wholesale energy storage's entry into the competitive market. Chamisa disputed NRG's assertions, arguing that an energy storage facility does not consume the stored energy, and that energy storage facilities do not purchase electricity like consumers, but can provide and reduce the need for ancillary services.

STEC and TIEC stated that a major concern with the rule is the failure to require storage to pay a fair share of ancillary services. These obligations are ordinarily incurred by other market participants. Oncor commented that this must be reconciled with statutory requirements in PURA §39.004(b) and (c) regarding nondiscriminatory access to wholesale transmission service and cost recovery. Apex agreed. STEC stated that in any instance where the use of energy is considered load, ancillary service obligation and related ERCOT charges should apply.

TIEC stated that while it continued to oppose providing special treatment to storage entities, if the commission proceeds in this direction it should impose ancillary service charges since a subsequent delivery to a retail customer does not negate the withdrawal from the grid impacting ancillary service procurement and deployments. Ancillary service deployments are a function of overall grid conditions at the time energy is withdrawn for the grid and storage will contribute to these conditions when it is net load regardless of whether energy is returned at a later point in time. When it is returned, the retail load in that interval will be responsible for its ancillary service obligations. TIEC stated that this is not double charging, but rather reflective of the cost causation of ancillary service obligations at each transaction. TIEC recommended removing the entire last sentence in proposed subsection (m). NRG stated that TIEC made valid arguments that granting different treatment to storage versus other loads that put energy back on the grid may result in discrimination among market participants.

Chamisa stated that contrary to TIEC's position, potential discrimination is only at issue when similarly situated parties are treated differently without a reasonable basis, and there are reasonable differences between wholesale energy storage and retail load resources. Chamisa stated that TIEC's members purchase energy and use that energy in their manufacturing and other processes, which is clearly a retail purchase by the end consumer. As load resources, these customers have the option to drop their load, but it does not change the nature of the purchases. Chamisa commented that TIEC failed to recognize that purchasing energy during peak periods is uneconomic for storage entities and that the proposed rule expressly states that a storage facility will be responsible for ancillary service charges if they make purchases during a declared system emergency without ERCOT direction. Chamisa supported Apex's and Luminant's suggested changes relating to the purchase of energy for storage during system emergencies. This would address TIEC's concerns that storage would pay for ancillary services if it occurred during a system emergency and the purchase was not directed by ERCOT. Additionally, Chamisa noted that TIEC's cost causation argument has a faulty premise, because most ancillary service costs are not allocated on a cost causation basis, but are allocated on a load ratio share basis, regardless of whether a particular load causes or alleviates the need for ancillary services. STEC also disagreed with TIEC's argument that the storage rules are potentially discriminatory. STEC noted that load resources already have a mechanism to participate as a resource, do not face the same type of barriers as storage resources to participate in the ERCOT market, and do not provide the same benefits as storage resources.

TEC stated that while Senate Bill (SB) 943 gave impetus for the proposed amendments, there is no indication that the legislature intended for energy storage facilities to be exempt from ancillary service charges. Chamisa disagreed; SB 943 does not affect the commission's authority to determine regulatory treatment of energy purchases for the purpose of storage. Chamisa cited PURA §35.004(e), which grants the Commission authority to ensure that ancillary services are available at reasonable prices with terms and conditions that are not preferential, discriminatory, or anticompetitive. Apex also noted that SB 943 did not change anything in PURA with regard to whether purchases by storage facilities are wholesale, and reserved the issue for the commission.

ERCOT stated that exempting storage entities from ancillary service fees except in the cases of declared system emergencies would create an ERCOT system impact by requiring ERCOT to track the quantity of MWs charged by storage facilities during an emergency situation and adjust for such during settlement.

Luminant suggested that the rule should be clarified so that storage devices are prohibited from charging during an ERCOT declared emergency unless specifically requested by ERCOT. Luminant also commented that limited-duration storage technologies capable of providing ancillary services during the event should be exempt from this provision. Luminant provided suggested rule language regarding these changes and suggested that the amendments would be more straightforward and easier to implement than as originally proposed. TESA supported the language provided by Luminant allowing limited-duration storage resources to continue providing ancillary services during an emergency event.

Apex commented that the proposed rule should be amended to allow a scheduled ancillary service to continue unless ERCOT directs the entity otherwise, as decisions should be made on economics rather than command and control. Apex stated that it strongly believes that CAES should be treated the same as other similar resources and therefore not be specifically prohibited from operating during certain periods. Apex commented that since CAES co-fires with natural gas, it could actually provide more capacity in an emergency if it is allowed to purchase for storage purposes and regenerate for resale. Apex also disputed Luminant's and TESA's claims that only duration-limited storage is capable of providing needed ancillary services during an emergency.

Chamisa commented that an energy storage facility can actually provide ancillary services as a controllable load or contribute as a generation resource. Chamisa stated that it supports combining the approaches proposed by Luminant and Apex. Chamisa therefore recommended that the proposed language in subsection (m) be amended to state that purchases shall not be subject to charges associated with ancillary service obligations and the owner or operator of energy storage facilities shall not make purchases during a declared system emergency if ERCOT has directed that such purchases cease. Chamisa commented that this would leave violations subject to enforcement actions rather than settlement adjustments.

Xtreme Power suggested that the commission incorporate the suggested changes in the proposed rule and re-publish the rule for a final round of comments.

Commission Response

In its discussion of question 1, the commission decided that storage load may be treated as wholesale load. In its discussion of questions 2 and 3, the commission addressed the allocation of ancillary service costs and CRR auction revenues to storage facilities. The commission also agrees that the purchase of electricity by a storage facility should be settled at the nodal price if the facility is connected at the transmission level. If a storage facility is connected at distribution level voltage, the price assigned to any purchase should be the nodal price at the nearest electrical bus that connects to the transmission system. The commission also agrees that energy storage facilities should not purchase electricity during system emergencies, unless directed to do so by ERCOT. Any such purchases would also be exempt from ancillary service charges, and the rule language is modified accordingly. Concerning Cities' comment about the wholesale settlement process, the settlement of storage load at wholesale should not be allowed to affect the settlement of a utility's other wholesale load. Xtreme Power's suggested that the commission incorporate

changes to the rule and re-publish the rule for a final round of comments. The commission declines to do so, because it has received sufficient comment on the issues.

Compliance Tariff Filings

If necessary, a TSP or DSP shall, within 30 days of the effective date of the rule amendments, apply to amend its tariff for wholesale transmission service to address the provision of service to storage facilities. Such applications shall be filed in a separate tariff proceeding for each TSP and DSP.

All comments, including any not specifically referenced herein, were fully considered by the commission. The commission has changed the proposed amendments consistent with the discussion above and for the purpose of clarifying its intent.

The amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (West 2007 and Supp. 2011) (PURA), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §§35.001-35.008, which grants the commission authority over wholesale transmission service and rates; and PURA §39.151, which grants the commission oversight and review authority over independent organizations such as ERCOT.

Cross Reference to Statutes: PURA §§14.002, 35.001-35.008, and 39.151.

§25.192. Transmission Service Rates.

(a) **Tariffs.** Each transmission service provider (TSP) shall file a tariff for transmission service to establish its rates and other terms and conditions and shall apply its tariffs and rates on a non-discriminatory basis. The tariff shall apply to all distribution service providers (DSPs) and any entity scheduling the export of power from the Electric Reliability Council of Texas (ERCOT) region. The tariff shall not apply to any entity engaging in wholesale storage as described by §25.501(m) of this title (relating to Wholesale Market Design for the Electric Reliability Council of Texas) (storage entity).

(b) **Charges for transmission service delivered within ERCOT**. DSPs, excluding storage entities, shall incur transmission service charges pursuant to the tariffs of the TSP.

(1) A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load. A TSP's transmission rate shall remain in effect until the commission approves a new rate. The TSP's annual rate shall be converted to a monthly rate. The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

(2) Payments for transmission services shall be consistent with commission orders, approved tariffs, and §25.202 of this title (relating to Commercial Terms for Transmission Service).

(c) **Transmission cost of service.** The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 (or accounts with similar contents or amounts functionalized to the transmission function) plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function), less accumulated depreciation and accumulated deferred federal income taxes, as applicable.

(1) The following facilities are deemed to be transmission facilities:

(A) power lines, substations, reactive devices, and associated facilities, operated at 60 kilovolts or above, including radial lines operated at or above 60 kilovolts, except the step-up transformers and a protective device associated with the interconnection from a generating station to the transmission network;

(B) substation facilities on the high side of the transformer, in a substation where power is transformed from a voltage higher than 60 kilovolts to a voltage lower than 60 kilovolts;

(C) the portion of the direct-current interconnections with areas outside of the ERCOT region (DC ties) that are owned by a TSP in the ERCOT region, including those portions of the DC tie that operate at a voltage lower than 60 kilovolts; and

(D) capacitors and other reactive devices that are operated at a voltage below 60 kilovolts, if they are located in a distribution substation, the load at the substation has a power factor in excess of 0.95 as measured or calculated at the distribution voltage level without the reactive devices, and the reactive devices are controlled by an operator or automatically switched in response to transmission voltage.

(E) As used in subparagraphs (A) - (D) of this paragraph, reactive devices do not include generating facilities.

(2) For municipal utilities, river authorities, and electric cooperatives, the commission may permit the use of the cash flow method or other reasonable alternative methods of determining the annual transmission revenue requirement, including the return element of the revenue requirement, consistent with the rate actions of the rate-setting authority for a municipal utility.

(3) For municipal utilities, river authorities, and electric cooperatives, the return may be determined based on the TSP's actual debt service and a reasonable coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the TSP's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the TSP.

(4) The commission may adopt rate-filing requirements that provide additional details concerning the costs that may be included in the transmission costs and how such costs should be reported in a proceeding to establish transmission rates.

(d) **Billing units**. No later than December 1 of each year, ERCOT shall determine and file with the commission the current year's average 4CP demand for each DSP, or the DSP's agent for transmission service billing purposes, as appropriate, excluding the portion of coincident peak demand attributable to wholesale storage load. This demand shall be used to bill transmission service for the next year. The ERCOT average 4CP demand shall be the sum of the coincident peak of all of the ERCOT DSPs, excluding the portion of coincident peak demand attributable to wholesale storage load, for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, divided by four. As used in this section, a DSP's average 4CP demand is determined from the total demand, coincident with the ERCOT 4CP, of all customers connected to a DSP, including load served at transmission voltage, but excluding the load of wholesale storage entities. The measurement of the coincident peak shall be in accordance with commission-approved ERCOT protocols.

(e) **Transmission rates for exports from ERCOT.** Transmission service charges for exports of power from ERCOT will be assessed to transmission service customers for transmission service within the boundaries of the ERCOT region, in accordance with this section and the ERCOT protocols.

(1) A transmission service customer shall be assessed a transmission service charge for the use of the ERCOT transmission system in exporting power from ERCOT based on the megawatts that are actually exported, the duration of the transaction

and the rates established under subsections (c) and (d) of this section. Billing intervals shall consist of a year, month, week, day, or hour.

(2) The monthly on-peak transmission rate will be one-fourth the TSP's annual rate, and the monthly off-peak transmission rate will be one-twelfth its annual rate. The peak period used to determine the applicable transmission rate for such transactions shall be the months of June, July, August, and September.

(3) The DSP or an entity scheduling the export of power over a DC tie is solely responsible to the TSP for payment of transmission service charges under this subsection.

(4) A transmission service customer's charges for use of the ERCOT transmission system for export purposes on a monthly basis shall not exceed the annual transmission charge for the transaction.

(f) **Transmission revenue.** Revenue from the transmission of electric energy out of the ERCOT region over the DC ties that is recovered under subsection (e) of this section shall be credited to all transmission service customers as a reduction in the transmission cost of service for TSPs that receive the revenue.

(g) **Revision of transmission rates.** Each TSP in the ERCOT region shall periodically revise its transmission service rates to reflect changes in the cost of providing such services. Any request for a change in transmission rates shall comply with the filing requirements established by the commission under this section.

(h) **Interim Update of Transmission rates.**

(1) **Frequency.** Each TSP in the ERCOT region may apply to update its transmission rates on an interim basis not more than once per calendar year to reflect changes in its invested capital. Upon the effective date of an amendment to §25.193 pursuant to an order in Project Number 37909, *Rulemaking Proceeding to Amend P.U.C. Subst. R. 25.193, Relating to Distribution Service Provider Transmission Cost Recovery factors (TCRF)*, that allows a distribution service provider to recover, through its transmission cost recovery factor, all transmission costs charged to the distribution service provider by TSPs, each TSP in the ERCOT region may apply to update its transmission rates on an interim basis not more than twice per calendar year to reflect changes in its invested capital. If the TSP elects to update its transmission rates, the new rates shall reflect the addition and retirement of transmission facilities and include appropriate depreciation, federal income tax and other associated taxes, and the commission-authorized rate of return on such facilities as well as changes in loads. If the TSP does not have a commission-authorized rate of return, an appropriate rate of return shall be used.

(2) **Reconciliation.** An update of transmission rates under paragraph (1) of this subsection shall be subject to reconciliation at the next complete review of the TSP's transmission cost of service, at which time the commission shall review the costs of the interim transmission plant additions to determine if they were reasonable and necessary. Any amounts resulting from an update that are found to have been unreasonable or unnecessary, plus the corresponding return and taxes, shall be refunded with carrying costs determined as follows: for the time

period beginning with the date on which over-recovery is determined to have begun to the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the same rate of return that was applied to the transmission investments included in the update. For the time period beginning with the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the TSP's rate of return authorized in that complete review.

(3) **Future consideration of effect on TSP's financial risk and rate of return.** For a TSP that has increased its rates pursuant to paragraph (1) of this subsection, the commission may, in setting rates in the next complete review of the TSP's transmission cost of service, expressly consider the effects of reduced regulatory lag resulting from the interim updates to the TSP's rates and the concomitant impact on the TSP's financial risk and rate of return.

(4) **Commission processing of application**. The commission shall process an application filed pursuant to paragraph (1) of this subsection in the following manner.

(A) **Notice and intervention deadline.** The applicant shall provide notice of its application to all parties in the applicant's last complete review of the applicant's transmission cost of service and all of the distribution service providers listed in the last docket in which the commission set the annual transmission service charges for the Electric Reliability Council of Texas.

The intervention deadline shall be 21 days from the date service of notice is completed.

(B) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 21 days after an application is filed. The motion shall be served on the applicant by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the applicant or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The applicant's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not filed a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.

(C) **Review of application.** A proceeding initiated pursuant to paragraph (1) of this subsection is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition). If the requirements of §22.35 of this title are met, the presiding officer shall issue a notice of approval within 60 days of the date a materially sufficient application is filed unless good cause exists to extend this deadline or the presiding officer determines that the proceeding should be considered by the commission.

(5) **Filing Schedule.** The commission may prescribe a schedule for providers of transmission services to file proceedings to revise the rates for such services.

(6) **DSP's right to pass through changes in wholesale rates.** A DSP may expeditiously pass through to its customers changes in wholesale transmission rates approved by the commission, pursuant to §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)).

(7) **Reporting requirements.** TSPs shall file reports that will permit the commission to monitor their transmission costs and revenues, in accordance with any filing requirements and schedules prescribed by the commission.

§25.501. Wholesale Market Design for the Electric Reliability Council of Texas.

(a) General. The protocols and other rules and requirements of the Electric Reliability Council of Texas (ERCOT) that implement this section shall be developed with consideration of microeconomic principles and shall promote economic efficiency in the production and consumption of electricity; support wholesale and retail competition; support the reliability of electric service; and reflect the physical realities of the ERCOT electric system. Except as otherwise directed by the commission, ERCOT shall determine the market clearing prices of energy and other ancillary services that it procures through auctions and the congestion rents that it charges or credits, using economic concepts and principles such as: shadow price of a constraint, marginal cost pricing, and maximizing the sum of consumer and producer surplus.

(b) Bilateral markets and default provision of energy and ancillary capacity services. ERCOT shall permit market participants to self-arrange (self-schedule or bilaterally contract for) energy and ancillary capacity services, except to the extent that doing so would adversely impact ERCOT's ability to maintain reliability. To the extent that a market participant does not self-arrange the energy and ancillary capacity services necessary to meet its obligations or to the extent that ERCOT determines that the market participant's self-arranged ancillary services will not be delivered, ERCOT shall procure energy and ancillary capacity services on behalf of the market participant to cover the shortfall and charge the market participant for the services provided.

(c) Day-ahead energy market. ERCOT shall operate a voluntary day-ahead energy market, either directly or through contract.

(d) Adequacy of operational information. ERCOT shall require resource-specific bid curves for energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, and ERCOT shall use these bid curves or ex-ante mitigated bid curves to address market failure, as appropriate, in its operational decisions and financial settlements.

(e) Congestion pricing.

(1) ERCOT shall directly assign all congestion rents to those resources that caused the congestion.

(2) ERCOT shall be considered to have complied with paragraph (1) of this subsection if it complies with this paragraph. ERCOT shall settle each resource imbalance at its nodal locational marginal price (LMP) calculated pursuant to subsection (f) of this section; each load imbalance at its zonal price calculated pursuant to subsection (h) of this section; and congestion rents on each scheduled transaction for a resource and load pair at the difference between the nodal LMP at the resource injection location calculated pursuant to subsection (f) of this section and the zonal price at the load withdrawal location calculated pursuant to subsection (h) of this section.

(f) Nodal energy prices for resources. ERCOT shall use nodal energy prices for resources. Nodal energy prices for resources shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch.

(g) Energy trading hubs. ERCOT shall provide information for energy trading hubs by aggregating nodes and calculating an average price for each aggregation, for each financial settlement interval.

(h) Zonal energy prices for loads. ERCOT shall use zonal energy prices for loads that consist of an aggregation of either the individual load node energy prices within each zone or the individual resource node energy prices within each zone. Individual load node or resource node energy prices shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch. ERCOT shall maintain stable zones and shall notify market participants in advance of zonal boundary changes in order that the market participants will have an appropriate amount of time to adjust to the changes.

(i) Congestion rights. ERCOT shall provide congestion revenue rights (CRRs), but shall not provide physical transmission rights. ERCOT shall auction all CRRs, using a simultaneous combinatorial auction, except as otherwise ordered by the commission for any preassigned CRRs approved by the commission. CRRs shall not be subject to "use-it-or-lose-it" or "schedule-it-or-lose-it" restrictions and shall be tradable.

(j) Pricing safeguards. ERCOT shall apply pricing safeguards to protect against market failure, including market power abuse, consistent with direction provided by the commission.

(k) Simultaneous optimization of ancillary capacity services. For ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall use simultaneous optimization and shall set prices for each service to the corresponding shadow price.

(l) Multi-settlement system for procuring energy and ancillary capacity services. For any energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall set a separate market clearing price for each procurement of a particular service.

(m) **Energy Storage**.

(1) For a storage facility that has more than one delivery point, ERCOT shall net the impact of those delivery points on the ERCOT system for settlement purposes.

(2) Wholesale storage occurs when electricity is used to charge a storage facility; the storage facility is separately metered from all other facilities including auxiliary facilities; and energy from the electricity is stored in the storage facility and subsequently re-generated and sold at wholesale as energy or ancillary services. Wholesale storage is wholesale load and ERCOT shall settle it accordingly, except that ERCOT shall settle wholesale storage using the nodal energy price at

the electrical bus that connects the storage facility to the transmission system, or if the storage facility is connected at distribution voltage, the nodal price of the nearest electrical bus that connects to the transmission system. Wholesale storage is not subject to retail tariffs, rates, and charges or fees assessed in conjunction with the retail purchase of electricity. Wholesale storage shall not be subject to ERCOT charges and credits associated with ancillary service obligations, or other load ratio share or per megawatt-hour based charges and allocations. The owner or operator of electric storage equipment or facilities shall not make purchases of electricity for storage during a system emergency declared by ERCOT unless ERCOT directs that such purchases occur.

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 §25.192, relating to Transmission Service Rates, and §25.501, relating to Wholesale Market Design for the Electric Reliability Council of Texas, are hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 29th DAY OF MARCH 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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