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Regulatory Highlights – The Year 2016 In Review and Implications for 2017

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The Public Utility Commission of Texas ("PUCT" or "Commission") started out last year much the same way that it is starting out this year—the key item on its agenda will be the sale of Oncor Electric Delivery, LLC out of the EFH bankruptcy—however this sale will be to NextEra Energy Resources, LLC instead of two entities spearheaded by the Hunt family. Many of the other key issues initiated in 2016 have carried over into 2017, including the implications of Reliability Must Run, the determination of a standard for reliability, and the use and deployment of both distributed generation and emergency response service, and possible transitions of Lubbock Power & Light ("LP&L") and Rayburn Country Electric Cooperative ("Rayburn") load into the Electric Reliability Council of Texas ("ERCOT"). A review and discussion of these issues demonstrates that the market design, which continues to evolve around many of the same key issues and in particular renewable development, is influenced by legislative changes, agency guidance and changes to rules.

Extension of Production Tax Credits for Wind Generation

On December 18, 2015 President Obama signed the *Consolidated Appropriations Act, 2016* (the "Appropriations Act") amending Section 45 of the U.S. Internal Revenue Code and extending the Production Tax Credit ("PTC") available to wind generators until 2020 with a phase-out provision. Prior to the passage of the legislation, the PTC was available for wind facilities that had begun construction before January 1, 2015. The passage of this legislation permits wind facilities in development during 2015 and any time through 2020 to be eligible for PTCs. However, the legislation also contemplates a reduction in the value of the PTC for those projects for which construction begins after 2016. If construction begins in 2017, the value of the PTC will be reduced by 20% per MWh, a 40% reduction will apply to facilities that begin construction in 2018 and a 60% reduction applies to facilities beginning construction in 2019. The PTCs are slated to be phased out by the beginning of 2020. It is important to note that beginning construction is a subjective standard and can include spending money committed for construction, such as entering into a turbine supply agreement, so it is likely that developers will have projects front-loaded to maximize the available PTCs, even for projects that will not truly begin development until 2020. The current level of the PTC for wind is $23/MWh and that amount is adjusted upward each year for inflation, though now it will also be reduced in accordance with the statutory scheme. The effect in ERCOT over the last year has been to delay certain projects that were rushing to meet the prior deadlines, but now have more time, and to increase the overall number of projects planned for the ERCOT market.

Extension of the Investment Tax Credit for Wind and Solar Energy Production

The Appropriations Act also amended Section 48 of the U.S. Internal Revenue Code that includes the Investment Tax Credit ("ITC"). The ITC is based on the percentage of each energy property brought into service during a taxable year and is available to a qualified wind or solar development. The current ITC is a 30% tax credit. The ITC available to wind facilities is reduced and eventually phased out during 2017, 2018, and 2019 in the same manner as the PTC, and is not available in 2020. The ITC was set to be reduced to 10% at the end of 2016 for utility scale solar and no longer be available in any amount for residential solar. However the ITC has

now been extended through 2021 for solar, a five year extension, though if construction begins in 2020 the ITC will be 26%; if construction begins in 2021 the ITC will be 22%; and if construction begins after 2021, the ITC will be 10%. Similar to the impact of the extension of the PTCs for wind, solar development is anticipated to increase in ERCOT in time to take advantage of the earlier, higher percentage ITCs.

IRS Guidance on Tax Credits

The IRS issued Notice 2016-31 on May 5, 2016 providing guidance as to how wind, solar, biomass, hydropower and other qualified facilities can meet the "safe harbor" provision to obtain production tax credits ("PTC") following the passage of the PTC extension by Congress in December of 2015. The IRS notice essentially extends the construction period by stating that if a facility is placed in service *no more than four years after the calendar year in which construction of the facility began*, then it satisfies the Continuity Requirement of Section 45 of the Internal Revenue Code. In essence so long as 5% or more of the total cost of the project is paid, the project can be considered safe-harbored for purposes of obtaining PTCs for its generation for more than four years after the date the 5% was paid (*e.g*. some proportion of wind turbines were procured) from the time the PTCs expire, which following the extension in 2015 means the beginning of 2020. The extension of the PTC provided for a reduction in the value of the ITC by 20% in 2017, 40% in 2018 and 60% in 2019. However, this new guidance means that if turbines were procured in 2016, a project could be constructed in 2020 and still considered safe-harbored for the entire 100%. For ERCOT, this means that the PTC revenues that incentivize the siting of new wind generation in ERCOT will be around well after the PTCs would otherwise have expired by statute.

Distributed Generation Rulemaking

The Commission initiated Project No. 45078, *Rulemaking Related to Distributed Generation Interconnection Agreements*, to consider amendments to the standard agreement required by P.U.C. Subst. R. 25.211(p), relating to interconnection agreements for distributed generation. The primary issue throughout the rulemaking was which entity would be authorized to sign a distributed generation interconnection agreement—the end-use customer of the Transmission and Distribution Service Provider ("TDSP") as had been the case previously, or the distributed generation developer. As part of the proceeding, the Commissioners discussed their limited jurisdiction over developers of distributed generation ("DG") and requested briefing from the parties concerning the Commission's jurisdiction over a DG owner that develop DG but that are not a customer of the utility, and are not subject to the TDSP tariff in taking transmission and distribution service as a load. Although the Commissioners agreed that they would not have jurisdiction to penalize a DG owner for the failure to comply with Commission rules, both Commissioners Anderson and Marquez voted to allow the DG owner to sign the interconnection agreement with the TDSP *if* the end-use customer agreed that the DG owner had authorization to sign the interconnection agreement. Chairman Nelson dissented because of the likely public expectation that a non-performing DG owner signing an interconnection agreement should be under the jurisdiction of the PUCT and subject to its enforcement authority. The Order adopting this amendment was approved at the December 16, 2016 Open Meeting.

EFH Bankruptcy Sale of Oncor—Part 1

The *Joint Report and Application of Oncor Electric Delivery Company, LLC, Ovation Acquisition I, LLC, Ovation Acquisition II, LLC, and Shary Holdings, LLC for Regulatory Approvals Pursuant to PURA*[1] *§14.101, 37.154, 39.262(i)-(m), and 39.915* was filed in P.U.C. Docket No. 45188. The proposed transaction would have taken Oncor out of bankruptcy in 2016, however all parties, including Oncor Electric Delivery Company ("OEDC") were opposed to the structure of the sale as represented in the Application at the time of the hearing and the docket never reached a settlement. The primary issues in contention were (i) the use of the Real Estate Investment Trust ("REIT") structure; (ii) the lack of arm's length transactions between OEDC and the Asset Company ("AssetCo") where the Hunt owners would be on both sides of the transaction; (iii) the question of whether two utilities are permitted to hold the same Certificate of Convenience and Necessity ("CCN") for the same facilities; (iv) the lack of Commission oversight into the lease agreement between AssetCo and OEDC; and (v) the removal of key ring-fencing protections for OEDC and exposure of OEDC to direct debt at the parent level. The Creditors Committee in the bankruptcy proceeding attempted to intervene in the PUCT proceeding but the Administrative Law Judge ("ALJ") did not permit the intervention following objections by PUCT Staff and intervenors. Litigation over the sale of the minority interest in Oncor held by Texas Transmission, Inc. ("TTI") took place simultaneously as EFH attempted to force TTI to sell at the pre-arranged price at which TTI was obligated to sell its interests if Oncor was no longer a private entity.

The hearing on the merits concluded on January 14, 2016 and the Commission set an expedited briefing schedule. Two additional briefing issues added by the Commissioners were purely legal issues and were briefed separately from the post-hearing briefs. These issues were: (i) whether PURA allows the Commission to treat two separate companies as one utility for ratemaking purposes and the authority under PURA that permits the Commission to do so; and (ii) how the lease proposed by the applicants (between the asset company and the operating company) that constitutes a tariff would be reviewed. Despite the Commissioners having encouraged settlement among the parties throughout the proceeding and keeping additional hearing dates open for January 19th and 20th in the event that a settlement was reached before that time and evidence to support the settlement needed to be entered into the record, no settlement was ever reached.

The Commission approved the Application at the March 25, 2016 Open Meeting with significant conditions creating uncertainties that called into question whether the transaction would be able to close as a result of the order. These included that each company (the Operating Company or "OpCo") and the Asset Company ("AssetCo"), would be required to have CCNs to operate and own, respectively, the wires and other facilities. The lease between the two entities would be considered an affiliate transaction under PURA subject to Commission oversight. The lease between OEDC and AssetCo was also determined to be a tariff that must be approved by the PUCT in a separate proceeding. That proceeding was initiated on April 6, 2016 in Docket 45815, *Application of Ovation Acquisition I, L.L.C., Ovation Acquisition II, L.L.C. and Shary Holdings L.L.C. OEDC for Approval of Initial Leases and Rates of Oncor AssetCo L.L.C*. The

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2007 & Supp. 2015)("PURA").

Hunts and Ovation, which would have owned AssetCo, had sought to have the leases be treated as contracts, that would not be subject to review by the PUCT. As a compromise in the proceeding, they further sought to have the leases be treated similar to an interconnection agreement, where the general terms would be established, but AssetCo and OEDC could agree on the costs/rates without PUCT oversight. The final order held that the leases were to be reviewed, including all associated rates, costs and charges, as a tariff.

The Commissioners disagreed on the tax issue. A REIT does not itself pay tax but can collect it if allowed by the Commission. Chairman Nelson did not want to treat the REIT differently than other utilities such as Oncor under EFH that was not subject to tax because of the offsetting losses at the parent level, despite taxes being collected. Commissioner Marquez stated that there should be no recovery of the $150 Million in taxes annually, and Commissioner Anderson thought there should be a sharing of any taxes collected between customers and the REIT. There were implications also for other utilities that were considering converting to the REIT structure because of the tax recovery. The rulemaking the Commissioners sought to initiate following the approval of the transaction that would have reviewed tax structures for utilities made the recovery of taxes by Oncor uncertain for purposes of the transaction. It will also likely dampen the enthusiasm other electric utilities had expressed concerning converting to a REIT structure in order to recover taxes in rates that will not be required to be paid.

At a hearing in the bankruptcy court at the end of April, the creditors committee withdrew its support for the sale of Oncor to the Hunts. Those creditors were the joint applicants that would have owned AssetCo, in the application filed with the Hunts to acquire OEDC and transfer OEDC's assets to AssetCo. Prior to the May 4, 2016 Open Meeting, Ovation made a filing withdrawing its application. Several intervenors stated that consideration of the Application at this time, after Ovation had withdrawn as the co-applicant, would be tantamount to issuing an advisory opinion since the transaction as filed could no longer be implemented without Ovation's participation. Motions for Rehearing were filed by the Hunts and other intervenors and were denied. Despite the fact that the transaction did not close, the matter has been appealed, likely largely due to the implications for the Sharyland service territory which is operated through a REIT structure and impacted by the holdings in the final order.

EFH Bankruptcy Sale of Oncor—Part 2

NextEra Energy Inc. entered into an agreement in the EFH bankruptcy proceeding to purchase OEDC. The $18.4 Billion transaction was approved by the bankruptcy court and the application was filed with the PUCT seeking approval of the transaction on October 31, 2016 in P.U.C. Docket No. 46238, *Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy, Inc. for Regulatory Approvals Pursuant to PURA §§14.101, 39.262 and 39.915*. The hearing on the merits of the proposal is scheduled before the Commissioners on February 21-24, 2017. The jurisdictional deadline for consideration of the application is April 29, 2017.

LP&L Proposed Transfer Into ERCOT

At the end of 2015, Lubbock Power & Light ("LP&L") began taking steps to integrate into the ERCOT system. This is the first time that a large load has sought to transfer into

ERCOT and is a case of first impression for the PUCT. At the PUCT's direction, ERCOT began working with the Regional Planning Group ("RPG") to develop study parameters for the potential integration of LP&L. ERCOT discussed the scope of the LP&L Integration Study at its RPG meeting on December 15, 2015 and stated that LP&L anticipates interconnecting with the ERCOT system as early as 2019. LP&L performed its own studies and developed preferred options, however ERCOT was instructed to study the integration of LP&L into the ERCOT grid and work on its own plan to identify the transmission facilities necessary to integrate LP&L load while satisfying both ERCOT and North American Electric Reliability Corporation ("NERC") transmission planning reliability standards. The ERCOT LP&L load integration study is required to take into account the ERCOT N-1-1 contingency standard and other N-1 maintenance outage conditions. ERCOT stated that its study would be informed by, but not limited to, the preferred options identified in LP&L's study. Initially, ERCOT stated that it would perform both an economic analysis, for short-listed options based on project capital cost and production costs, and a sensitivity analysis to test future load growth/integration. As part of the sensitivity analysis, ERCOT was to perform a cost-benefit analysis for the recommended options, accounting for any avoided costs for future upgrades deemed not required by virtue of the LP&L integration. All of the above essentially would have reviewed the transmission costs and benefits but could not take into account all relevant costs and benefits as would a public interest analysis.

The PUCT opened P.U.C. Project No. 45633 on March 3, 2016 to investigate the potential impacts of the integration of the Lubbock Power & Light ("LP&L") system into ERCOT including the impacts to both ERCOT customers and Southwest Power Pool ("SPP") customers in Texas. The questions on which the Commission initially sought comments related primarily to the costs and reliability impacts associated with LP&L integration into ERCOT, both with respect to costs and transmission changes required in the SPP and in ERCOT. Substantive comments were filed by SPP and ERCOT with respect to technical issues under study and without taking a position on whether such integration would be in the public interest. Some commenters stated that an expansion of the grid would increase reliability and support wind generation while others were concerned with the costs and reliability impacts to both SPP and ERCOT. Many parties agreed that the Commission should adopt standards for entities that want to join the ERCOT market both from the perspective of reliability and cost, and in determining whether such a change was in the public interest.

A workshop was held on May 3, 2016 to discuss issues associated with LP&L integration. The discussion centered on the process for evaluating LP&L's proposal to join ERCOT. There parties discussed the need for a public interest filing, and Commission approval of such a filing, before LP&L could be permitted to join ERCOT, much like Cap Rock filed when it joined the ERCOT market. LP&L has proposed that the PUCT leave any cost/benefit analysis to the "need" issues in the CCN process with respect to its integration into ERCOT. However LP&L may not be the party filing the CCN, and in the CCN process the cost/benefit analysis would already assume integration of LP&L and then evaluate whether a given CCN was needed to provide integration. As a result, absent a separate cost/benefit study relating to the integration of LP&L into ERCOT or a public interest determination by the PUCT, there would not otherwise have been an opportunity to evaluate the proposal on its merits.

The Commissioners asked both ERCOT and SPP to perform studies using a similar scope. Both ERCOT and SPP said they would be willing to perform any studies requested by the

PUCT and developed compatible work scopes for their respective studies. The studies performed by LP&L had preferred integration option cost estimates ranging between $269 Million and $336 Million, and its next best options costing between $315 Million and $383 Million. On September 25, 2016, ERCOT and SPP filed a letter with the Commission stating that the required study will be concluded before the end of the second quarter of 2017.

Municipally-Owned Utility and Large DC Tie CCN Rulemaking

Commission Staff filed its Proposal for Publication in Project No. 45124, *Rulemaking Regarding Certificates of Convenience and Necessity for DC Ties, Municipally-Owned Utilities, and Non-ERCOT Utilities Pursuant to SB 776, SB 933, and HB 1535 of the 85th Legislature (R.S.)* on February 4, 2015 for consideration by the Commissioners at the February 11, 2016 Open Meeting. The rulemaking is intended to require a person to (i) first obtain a Certificate of Convenience and Necessity ("CCN") from the PUCT before connecting a tie line into the ERCOT transmission grid as required by SB933; (ii) require a municipally-owned utility ("MOU") or municipal power agency ("MPA") to obtain a CCN for any construction, installation or extension of a transmission facility outside of the boundaries of the MOU or MPA and to allow the MOU to recover payments made in lieu of ad valorem taxes on such transmission facilities as required by SB 776; (iii) to require a non-ERCOT utility to file a request for a certificate to purchase an existing electric generating facility within 181 days, and a new generating facility within 366 days, of the request being filed as required by HB 1535; (iv) to rule that the Commission no longer has authority to utilize the PURA §39.904(g) provision that established the Competitive Renewable Energy Zones ("CREZ") to authorize new transmission projects other than for a second circuit on the Panhandle Alibates-AJ Swope-Windmill-Ogallala-Tule Canyon transmission line; and (v) to require an application for a DC tie to include a study by the ERCOT independent system operator. The Commissioners adopted the rule in June 15, 2016. The rulemaking was a continuation of the PUCT policy not to allow interconnections that could subject ERCOT to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). It does raise the question of what rights the PUCT may have to block interstate transmission that may have already been approved by the FERC and whether such action rises to the level of interstate commerce. Importantly, although the PUCT cannot bind a future Commission, it is clear that the Commission will not utilize any CREZ process under its existing rules in the future other than to approve the last remaining CREZ double circuit contemplated in the earlier CREZ proceedings.

Emergency Response Service Rulemaking

The Emergency Response Service ("ERS") rulemaking was initiated following a discussion at the April 14, 2016 Open Meeting in a Notice of Violation proceeding relating to an entity's failure to meet the ERS testing criteria. Commissioner Anderson stated that ERS may need to be re-examined to make sure that only parties that are complying with the requirements are getting paid for the service and that the PUCT would have fewer violations if ERS was made a Day-Ahead service and settled in the Day-Ahead Market in the same manner as Non-Spin Day Ahead service is settled. As a result, the *Rulemaking Regarding Emergency Response Service* ("ERS") in Project No. 45927 was initiated.

Commission Staff issued a Request for comments on July 15, 2016, which questioned the value of ERS, and whether the service should be brought into the competitive market. One party proposed a pilot to determine whether changes to ERS would improve the service, noting that bringing the service into the Day Ahead Market would create efficiencies and may reduce concerns with the failure of ERS resources to perform, if participation did not decline. Comments filed by the parties in large part stated that ERS was a valued service that should be continued. One party argued that ERS costs too much at $50 million for a service that is infrequently used, and that it should be discontinued in favor of procuring more Non-Spinning Reserve Service ("NSRS").

On July 29, 2016, the Independent Market Monitor ("IMM") and ERCOT filed comments on the questions posed by the Commission Staff. Although the IMM questioned the value of ERS in its current form, it deferred to ERCOT and the Commission for a determination of whether the service was necessary or valuable. The IMM opined that the service could be improved by making it more competitively priced and by encouraging greater load participation. If it is continued, the IMM suggested that its scope should be expanded to allow it to be used to address shortages caused by local transmission issues and not just for system-wide shortages. ERCOT presented a summary of ERS deployments and opined that it has value, although it is not essential because ERCOT can resort to firm load shed. ERCOT noted that it would be difficult to determine in advance whether a change to the Day-Ahead procurement of ERS would increase or decrease participation in ERS.

The Commission Staff filed a Memorandum prior to the October 7, 2016 Open Meeting that included modifications to the draft ERS Rule concerning the deployment of ERS based on discussion in Open Meetings concerning using ERS as a substitute for Reliability Must Run ("RMR") agreements. Those comments related to the limited use of ERS only for system-wide emergencies, despite the capacity having been reserved at all times. As a result, the proposed rule changes reflected a modification to ERS service such that ERS could be deployed to forestall firm load shed in instances of local congestion, and could be used as a Must Run Alternative for RMR units. As a result, it is likely that ERS, should these provisions be adopted in the final Rule, would be used more frequently, and potentially on a less predictable basis, given that local constraints are more difficult to gauge than an overall diminution in reserves ERCOT-wide, and that RMR is intended to be used for longer periods of time. The proposed amendment was published by the Texas Register on October 21, 2016. According to the initial schedule in the project, a proposal for adoption of the amendment will be presented to the Commissioners in May, 2017.

<u>CFTC Litigation and Private Rights of Action Proposed Amendment to RTO/ISO Orders</u>

In *Aspire Commodities, L.P., et al v. GDF SUEZ Energy*, No. 15-20125 (5th Cir. 2016), the plaintiffs, Aspire Commodities ("Aspire") and Raiden Commodities ("Raiden"), sought a private cause of action under the Commodity Exchange Act for market manipulation against GDF Suez Energy North America, Inc. ("GDF Suez") and its affiliated generation project companies. The Fifth Circuit upheld the dismissal by the District Court, maintaining the protection ERCOT "small fish" market participants have against private rights of action pursuant to the Commodity Exchange Act. Following the dismissal of their appeal to the Fifth Circuit,

Aspire and Raiden filed a motion for rehearing, which was denied. These entities were successful, however in garnering the attention of the Commodity Futures Trading Commission ("CFTC") which announced a proposed amendment to make "private rights of action" available to litigants against parties conducting business through the Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") markets. This was precisely what the Aspire Commodities and Raiden Commodities action attempted to do with respect to GDF Suez in the ERCOT market since GDF Suez was bidding as a "small fish." The proposed change in the rules would have been significant for ERCOT in particular because only the "small fish" can bid freely in the market and push the energy-only market price up in times of scarcity. Without a scarcity mechanism, the energy-only market has no way of sending price signals to incentivize new generation. The other market participants that are not "small fish" are typically subject to market mitigation plans with the PUCT that preclude them from bidding higher during certain scarcity situations. The Chairman of the CFTC however, after proposing and supporting the amendment, withdrew his support and the amendment was not adopted.

Reliability Must Run

ERCOT executed a Reliability Must Run ("RMR") agreement with NRG Texas Power to keep the 371 MW Greens Bayou Unit 5 available to ERCOT for all hours during the months of July 2016 through September 2016, June 2017 through September 2017 and June of 2018. The RMR Agreement commenced on June 1, 2016 and will stay in effect through June 30, 2018, a 25-month contract with a standby payment of $3,185 per hour during peak hours. It was approved by the ERCOT Board of Directors. This is the first RMR agreement that ERCOT has entered into since 2011.

During the Open Meeting discussion in September the Commissioners stated that they wanted to revisit the Reliability Must Run ("RMR") criteria, largely with respect to the new Greens Bayou Unit No. 5 that did not run during the highest peaks set in August, despite ERCOT having committed a standby payment of $60 Million in its RMR agreement to have the resource available. Chairman Nelson proposed that Commission Staff be directed to open a narrowly focused rulemaking project on an expedited schedule to revise ERCOT's RMR process. The scope has been expanded to address concerns with the current 90-day period provided for in Commission Rule 25.502(e) for RMRs to be evaluated by ERCOT. As a result, the Commission opened Project No. 46369, *Rulemaking Relating to Reliability Must Run Service.* Following the opening of the rulemaking project, the Commission Staff filed an initial Strawman Proposal on October 10, 2016, and requested comments on the Strawman. Comments are due to be filed October 31, 2016, with Reply Comments due on November 14, 2016. Both ERCOT and the Independent Market Monitor ("IMM") are to file Reply Comments after the other parties, on November 28, 2016.

The Staff's Strawman Proposal asks four questions. The first question is whether RMR capacity should be included in the installed capacity calculation under P.U.C. Subst. R. 25.401, which is used to determine market power for purposes of the 20% cap on generation in ERCOT established in PURA §39.154. The second question relates to the type of resources that can be considered for RMR—whether non-dispatchable resources (such as wind generation units), units that are part of a private use network, or cogeneration units—should be included. Specifically

this second question raises PURA §39.151(l), which prohibits ERCOT from making any rule or requirement that would adversely affect or impede any manufacturing or other internal process operation associated with a generating facility connected to the ERCOT system, "except to the minimum extent necessary to assure reliability of the transmission network." The third question relates to the authority to approve an RMR agreement. That approval currently rests with ERCOT Staff. The ERCOT Board of Directors does not have to approve an RMR agreement. The Staff Strawman asks whether either or both of the ERCOT Board of Directors or the PUCT should have to approve an RMR agreement. Lastly, the Strawman asks whether, "assuming there is a reliability need" ERCOT should have the discretion *not* to enter into an RMR agreement, or select a Must Run Alternative, either because of cost or because the likelihood of the reliability event occurring is so remote.

The questions in the Strawman reflect developments relating to RMR at ERCOT. ERCOT has been receiving push back on its designation of the Greens Bayou Unit No. 5 as an RMR unit. Following the determination by ERCOT that the Greens Bayou Unit No. 5 was required to be an RMR, Calpine notified ERCOT that its Clear Lake cogeneration facility would terminate service. ERCOT's initial determination was that the Calpine unit would be needed for RMR, even though the unit itself contributed only 3.62% to resolving the planning model issues ERCOT had identified. A unit cannot be considered for RMR under the ERCOT Protocols if its impact on a constraint is less than 3%. At the same time, NPRR 788 proposed by Lower Colorado River Authority was proceeding through the ERCOT process to change the percentage level that an RMR unit must contribute to the resolution of a transmission constraint from 3% to 5%, in addition to making other changes to RMR determinations by ERCOT. NPRR 788 was approved by the ERCOT Board on October 11th, and as a result the Calpine Clear Lake cogeneration unit can be shut down on its chosen schedule.

<u>Rulemaking on Transmission Service Rates</u>

The Commission Staff filed a draft of proposed language to modify the transmission cost of service ("TCOS") rule in P.U.C. Project No. 46393, *Rulemaking Proceeding to Amend 16 TAC §25.192, Relating to Transmission Service Rates.* Commission Staff is seeking to amend P.U.C. Subst. R. 25.192, and significantly modify the provisions associated with transmission rate setting in both full TCOS and interim TCOS update ("TCOS Updates") proceedings. The impetus for the Commission Staff's proposed language as expressed by Commission Staff at a workshop held in the proceeding is that some utilities have not been in for full rate cases in several years and could be over-earning. However, the Commission requires the submission of Earnings Monitoring Reports in the Commission-prescribed format to determine if a utility is over-earning and uses that, or additional information requests, as the basis to determine whether a utility should be subjected to a rate case. Instead of using the process as designed in current rules and under PURA, the proposal floated by Commission Staff, would require that all electric cooperatives, municipally-owned utilities and river authorities should be brought in for a full rate case. In some cases the cost of the rate case may exceed any benefit to consumers and may result in a rate increase. Additionally, the proposal would eliminate the use of cash basis ratemaking, which has traditionally been relied upon by some non-IOU transmission providers in establishing their rates and used by the Commission in reviewing such rates. There are a number of other proposed changes to the rule that are problematic, including considering nonrecurring

revenue in TCOS updates—neither non-recurring revenue nor non-recurring costs are considered under ratemaking principles because of the transitory nature of these revenues and costs. Similarly, the changes to the interim TCOS process would require a utility to come in for an interim TCOS update within four years of its most recent full rate case, would not allow an interim TCOS filing if the PUCT determines that the utility may be over-earning under as yet to be defined requirements, and would change the return of the utility based on the total revenues of the utility, some of which may include generation over which the PUCT has no jurisdiction. Such a result may create uncertainty for transmission service providers ("TSPs") in the recovery of transmission costs for new transmission additions. To the extent recovery of these costs is questionable that may create uncertainty for generators that rely on transmission to plan and interconnect power projects and may also increase the perceived risk to investors, resulting in increased risk premiums for financing transmission additions.

Market participants have been very engaged in this proceeding and it is as yet unclear how the Commission will take up these issues. The ERCOT market has been successful serving increases in load by ensuring that generation can reach load centers. The market participants in ERCOT will continue to monitor this project very closely.

Conclusion

In summary, with the Legislature in session and a number of key items on the Commission's Agenda, the 2017 year could greatly impact generation and transmission, with repercussions in availability of supply and pricing for loads.