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PROJECT NO. 47199

PROJECT TO ASSESS PRICE-FORMATION RULES IN ERCOT'S ENERGY-ONLY MARKET	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

NRG'S REPLY COMMENTS

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<u>NRG's Reply Comments</u>

TO THE HONORABLE CHAIRMAN AND COMMISSIONERS OF THE PUBLIC UTILITY COMMISSION OF TEXAS:

NRG Texas Power LLC, NRG Power Marketing LLC, Reliant Energy Retail Services LLC, Green Mountain Energy Company, US Retailers LLC, and NRG Curtailment Solutions LLC – all wholly owned subsidiaries of NRG Energy, Inc. (collectively "NRG") appreciate the opportunity to reply to comments submitted to the Commission on December 1, 2017 in PUCT Project 47199, *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market.*

I. General Comments

As pointed out in initial comments, filed on December 1, 2017, NRG seeks to improve the Electric Reliability Council of Texas (ERCOT) energy-only market design. NRG has committed significant investment in the state and is the largest load-serving entity and second largest generation owner within ERCOT. The health and proper functioning of the competitive wholesale and retail markets in ERCOT is NRG's top priority. Lingering price formation deficiencies and the influence of policies external to market design affect the performance of the wholesale market and hinder market outcomes. These lingering concerns were the primary motivations for NRG's co-sponsorship of the *Priorities for the Evolution of an Energy-Only Electric Market Design in ERCOT* Report, prepared by Dr. William Hogan and Dr. Susan Pope of FTI Consulting and filed in this project on May 22, 2017 (Hogan Pope Report).[1] The Hogan Pope Report recommends a number of market design adjustments to bolster price formation and improve the sustainability of the ERCOT energy-only market. Calpine Corporation's (Calpine's) concerns over price formation in the Lower Rio Grande Valley spurred their co-sponsorship of the Hogan Pope Report. As Calpine explained in its initial comments in this project, over the

[1] William W. Hogan and Susan L. Pope, Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT at i (May 9, 2017) (Hogan Pope Report).

last few years, scheduling and performing maintenance at their units in the Lower Rio Grande Valley has been extremely difficult because ERCOT has required Calpine to defer the maintenance outages to stay online and ensure reliability in the Lower Rio Grande Valley yet wholesale market pricing outcomes did not reflect that reliability need – a clear failure of market prices.[2] NRG has experienced similar situations in the Houston area particularly during Reliability Unit Commitment (RUC) deployments used by ERCOT to address perceived grid reliability threats.[3]

The Commission has remained committed to the energy-only market design and that commitment cannot apply only in times of low prices. With the recent retirement announcements, now is the time for the Commission to act to ensure price formation in the ERCOT energy-only market drives the right choices by market participants – to invest in generation resources, repowering, equipment maintenance, demand response, and innovative retail products for example – in the right locations and in a timely fashion. It is essential for the Commission to ensure the key principles of market design are not ignored as market conditions evolve. Given the varied financial interests of market participants and the divisive nature of wholesale market design and energy price formation policy, it is necessary for the Commission to give clear direction to stakeholders to drive market design improvements to completion to support a sustainable market structure.

A. The Need for Market Pricing Improvements

In initial comments filed in this project, a small group of commenters argued that no changes to the ERCOT market structure are needed. NRG believes the extensive analysis in the Hogan Pope Report and the support of the ERCOT Independent Market Monitor (IMM)[4] clearly justify market design changes to improve energy price formation. However for further justification, ERCOT provided their latest reserve margin projections in the December 2017 Capacity, Demand, and Reserves (CDR) report released on December 18th, 2017. Reserve

[2] *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Calpine Corporation's Comments at 1-2 (Dec. 1, 2017) (Calpine Comments).

[3] *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, NRG Response to Request for Comment at 16 (Dec. 1, 2017) (NRG Comments).

[4] *See generally, Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Comments of Potomac Economics (Sept. 15, 2017) (IMM Comments).

margins for the summer of 2018 dropped from 18.9% in the May report to 9.3% in the December report due to the significant retirement of dispatchable capacity announced this year. In addition, NRG also points out that nearly every major competitive supplier of electricity in the ERCOT market has either filed for bankruptcy, was acquired while in financial distress, or restructured operations due to historically low equity valuations. Examples include market participants with sizable investment in ERCOT such as Vistra Energy,[5] NRG,[6] Calpine,[7] Exelon,[8] Panda Power Funds,[9] GDF-Suez,[10] and Dynegy.[11] Together these entities represent well over half of the dispatchable generation capacity in ERCOT. NRG is unaware of any market currently in operation where this level of financial distress is accepted as normal and healthy. While it's not clear to what extent the existing deficiencies in the ERCOT energy-only market design contributed to this market distress, they certainly played a part. Proceeding with improvements to the energy market structure will help ensure pricing deficiencies do not contribute to unnecessary retirements in the future and such action will demonstrate that the Commission is committed to a well-designed energy market. Enhancements to the ORDC as detailed in NRG's initial comments[12] are quick fixes that will improve scarcity pricing immediately. The remaining

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[5] Peg Brickley, TXU Energy, Luminant Cleared to Exit Bankruptcy – Court Confirms Plan of Energy Future Units, Wall Street J., Aug. 26, 2016, https://www.wsj.com/articles/txu-energy-luminant-cleared-to-exit-bankruptcy-1472233708.

[6] Press Release, NRG, NRG Energy Launches Transformation Plan (Jul. 12, 2017) (http://investors.nrg.com/phoenix.zhtml?c=121544&p=irol-presentations).

[7] Press Release, Calpine Corporation, Calpine Agrees to be Acquired by Investor Consortium Led by Energy Capital Partners (Aug. 18, 2017) (http://investor.calpine.com/news/press-release-details/2017/Calpine-Agrees-to-be-Acquired-by-Investor-Consortium-Led-by-Energy-Capital-Partners/default.aspx).

[8] Reuters, Exelon's Power Unit Files for Chapter 11 Bankruptcy, Wall Street J., Nov. 7, 2017, https://www.reuters.com/article/us-exelon-exgen-restructuring/exelons-power-unit-files-for-chapter-11-bankruptcy-idUSKBN1D7277.

[9] Jonathan Randles, Panda Power Funds' Power Plant Files for Chapter 11 – Company Blames Bankruptcy on Electric Reliability Council of Texas and its Energy-Price Projections, https://www.wsj.com/articles/panda-power-funds-power-plant-files-for-chapter-11-1492551224.

[10] Geraldine Amiel, GDF Suez Plans Sale of Assets, Wall Street J., Jul 1, 2011, https://www.wsj.com/articles/SB10001424052702303763404576417932264311302..

[11] Press Release, Vistra Energy, Vistra Energy and Dynegy to Combine to Create Leading Integrated Power Company (Oct. 30, 2017) (https://investor.vistraenergy.com/investor-relations/news/press-release-details/2017/Vistra-Energy-And-Dynegy-To-Combine-To-Create-Leading-Integrated-Power-Company/default.aspx).

[12] *See generally* NRG Comments.

recommendations are important reforms to ensure the ERCOT energy-only market operates efficiently from an economic perspective and provides fair and accurate pricing outcomes consistent with the Commission's rules.

B. Inaccurate Criticism Regarding Motivation

The recommendations supported by NRG, many of which are outlined in the Hogan Pope Report, seek to obtain fair pricing outcomes consistent with well-established economic principles and best practices implemented in other markets. Notably, the IMM is supportive of many of same recommendations including improved RUC pricing, marginal losses, and locational reserves.[13] In initial comments of TIEC and Vistra Energy, both NRG and Calpine were criticized for their motivations behind sponsorship of the Hogan Pope Report. It is important for the Commission to recognize that the criticism comes from entities that benefit from deficiencies in the current market design. The market design improvements recommended in the Hogan Pope Report and supported by NRG are focused on getting the prices right and properly compensating resources for the value they provide the ERCOT grid, which is vital to the success of an energy-only market. The current treatment of transmission losses and the pricing of RUC commitments for congestion undervalue certain resources in areas with higher loads. In addition, the current design of the Operating Reserve Demand Curve (ORDC) understates scarcity pricing outcomes. Competitive markets should rely on competitive forces driven by the incentives created by prices that reflect the true economics and fundamentals of the electric system. The Commission should consider the recommendations in this project as solutions necessary to correct current market deficiencies that will benefit consumers through more efficient market performance and improved reliability over the long-term.

C. Mischaracterization of Important Locational Price Formation Reforms

It has been alleged that the locational pricing reforms recommended in the Hogan Pope Report are attempts to "balkanize" the ERCOT grid.[14] This description is not only a gross

[13] IMM Comments at 2.

[14] *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Texas Industrial Energy Consumers' Initial Comments at 3 (Dec. 1, 2017) ("[i]n no event should the Commission pursue market changes that seek to reward generators in one portion of the state at the expense of balkanizing the grid and impairing ERCOT's operation as a single integrated market") (TIEC Comments).

mischaracterization, it also fundamentally conflicts with the intent of the Commission's rules. The expression of locational price differences in a locational marginal pricing market is a critically important design feature. Describing the need for the ERCOT market to price energy using locational differences as somehow hostilely dividing the market is nonsensical and should be patently rejected by the Commission. Market design reforms to more accurately price the use of RUC to protect reliability, the cost of transmission losses, and the value of scarce locational reserves all improve locational price formation and enhance the market's performance. The mischaracterization that these reforms would balkanize the ERCOT grid fundamentally conflicts with the basic operation of a market that includes locational economics. This also runs counter to the Commission's policy objective as expressed in the order issued in Project No. 26376 (Nodal Order) that established the current nodal market.[15] The Nodal Order expressly states the benefits to adopting a locational marginal pricing market design. Specifically, the Nodal Order clearly finds that the transition to a nodal market will

> yield important benefits, such as... ***increased locational price transparency*** for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a ***reduction*** in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market.[16] (emphasis added)

When adopting the nodal market design, the Commission found a significant benefit in providing locational price signals which are the same signals that will be improved with the implementation of marginal loss pricing for example. Importantly, in no instance were the locational pricing features implemented in the nodal market ever deemed to be a balkanization of the grid by the Commission.[17] The significant benefits realized by implementing the nodal market would not have been possible if the Commission viewed those market changes so narrowly and unfavorably.

The Commission is now considering similar market structure improvements compared to those adopted in Project No. 26376. In that project, the Commission determined that the zonal market structure at that time was "inefficient, produce[d] unnecessary costs, and fail[ed] to send

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[15] *Rulemaking Proceeding on Wholesale Market Design Issues in ERCOT*, Project No. 26376, Order Adopting New § 25.501 at 103 (Sept. 23, 2003) (Nodal Order).

[16] *Id.* at 1.

[17] *See generally Id.*

adequate locational price signals for the siting of resources."[18] In this current Project 47199, market design reforms have been identified to address similar deficiencies. Some entities, such as TIEC and Vistra Energy, are currently opposing locational price formation enhancements such as marginal losses but they supported the transition to the nodal market.[19] In particular, TIEC should recall their recommendations in Project No. 26376. In that project, TIEC recommended that a nodal market model should be designed to achieve the goal of "provid[ing] transparent and accurate price signals that would encourage appropriate siting of new generation and transmission facilities."[20] TIEC also "strongly support[ed] direct assignment of congestion costs to the resources that cause the congestion."[21] As an economic principle, the direct assignment of congestion costs to resources that cause the congestion is no different from the direct assignment of transmission losses to the resources that cause the losses. Therefore, it is unclear how the proposal to directly assign transmission losses "rewards generators" yet the direct assignment of congestion costs provides a "transparent and accurate price signal that would encourage appropriate siting of new generation."[22] In reality, the concepts overlap and provide similar benefits and market signals. Including marginal losses in energy prices in ERCOT keeps with the principles and policies the Commission adopted in the nodal market to improve locational price formation. Pricing differences in electricity costs based on location is a crucial design element of ERCOT's nodal-based energy-only market and drives long-term benefits through more efficient siting decisions.

D. *Claims of Harm and a Property Right on Inefficient Market Design*

Many opponents of marginal losses have argued that its implementation will cause collateral damage to customers and certain thermal generators. Not only is this assertion

[18] *Id.* at 15.

[19] TXU Energy was the predecessor of Vistra Energy. *Rulemaking Proceeding on Wholesale Market Design Issues in ERCOT*, Project No. 26376, Initial Comments of TXU Energy at 1 (June 23, 2003) ("TXU Energy generally supports the direction of proposed 25.501").

[20] *Rulemaking Proceeding on Wholesale Market Design Issues in ERCOT*, Project No. 26376, Response of Texas Industrial Energy Consumers to Questions Filed by the Market Oversight Division at 5 (Jan. 31, 2003).

[21] *Rulemaking Proceeding on Wholesale Market Design Issues in ERCOT*, Project No. 26376, Comments of Texas Industrial Energy Consumers at 1 (Aug. 13, 2003).

[22] Response of Texas Industrial Energy Consumers to Questions Filed by the Market Oversight Division at 5.

hyperbolic, but it also suggests that no market reforms should be implemented to correct serious inefficiencies within the market if it will harm those entities that have historically benefitted from the inefficiency. This would be tantamount to creating a property right in an inefficient market design feature or policy. Since marginal losses will result in more efficient utilization of existing resources and incentivize more efficient resource siting decisions, it will reduce costs for consumers as a whole and will benefit the entire market. The Brattle Group *Analysis of Marginal Losses Proposal* (Brattle Analysis), sponsored by First Solar Inc., Vistra Energy, and the Wind Coalition, found that implementing marginal losses will save ERCOT consumers $8.6 million per year in production costs presumably under a worst case scenario.[23] More specific to consumers, the Brattle Analysis states that "marginal loss implementation would increase annual average load LMPs [Locational Marginal Prices] by 2% ($0.50/MWH on average across ERCOT)."[24] However, this is not a complete picture. The implementation of marginal losses will accrue surplus revenue similar to the accrual of congestion rent in the existing market structure. That surplus revenue should be distributed to consumers and will lower their costs of transmission losses. This is akin to the disbursement of congestion rent to consumers which lowers the costs of congestion for them today. The Brattle Analysis estimated the marginal loss surplus for the study year to be $205 million. If the marginal loss surplus of $205 million is distributed to consumers based on a system-wide load-ratio share for example (using the modeled 364 TWh of ERCOT load in the Brattle Analysis) as is the practice in PJM, consumers would receive a credit of $0.56/MWh,[25] which would more than offset the estimated price increase. Therefore, it is not clear how a policy that lowers system production costs and reduces the all-in cost of losses for consumers could be considered damaging or detrimental to them.

Regarding impacts to existing generators, NRG agrees that the implementation of marginal losses will change the existing pricing dynamic in the ERCOT market. Any change in the existing pricing dynamic, even to correct long standing inefficiencies in the market, will

[23] *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Analysis of Marginal Losses Proposal at 1 and Attachment at 3 (Oct. 12, 2017) (Brattle Analysis).

[24] *Id.*, Attachment at 15.

[25] *Id.*, Attachment at 13 (even if the marginal loss surplus was allocated on a system wide basis assuming no self-serve load (402 TWh) in the Brattle Analysis, it would still result in a credit to consumers of $0.51/MWh that exceeds the average price increase).

affect existing generators in different ways. However under the current treatment of transmission losses, existing resources that *increase* the cost of transmission losses in the ERCOT grid currently benefit by having others pay for the costs they cause. Existing resources that are closer to load centers and *decrease* the cost of transmission losses in ERCOT are disadvantaged by being undercompensated for the value they provide to consumers and the ERCOT grid. Implementing marginal losses to correct this pricing deficiency will end the over-compensation and under-compensation of resources from a transmission loss perspective. Additionally, this modification is consistent with the rationale underlying the transition to the nodal-based pricing market design many years ago.

Since the implementation of marginal loss pricing will result in the cost of transmission losses being accurately reflected in price, it should not surprise the Commission that existing resources and market participants that benefit from the current treatment of losses do not favor a more accurate and causation driven approach. In terms of magnitude, the Brattle Analysis estimated that marginal losses will decrease total (gross) generator revenues by $248 million in their study case. For comparison, a reduction of total generator revenues by $248 million equates to a $0.10/MMBtu decrease in the price of natural gas on an annual basis.[26] Between 2014 and 2016, the average price of natural gas decreased by $1.87/MMBtu from $4.32/MMBtu to $2.45/MMBtu.[27] This $1.87/MMBtu reduction in the price of natural gas equates to a reduction of total generator revenues of approximately $4.6 billon.[28]

NRG provides this comparison to put these claims of harm into perspective. While NRG agrees it is important for the Commission to weigh potential harm from policy changes, sufficient evidence has not been presented that would warrant ignoring the clear economic principles supporting the implementation of marginal losses. Parties opposing marginal losses are attempting to preserve inefficient market design that benefits them without merit. The Commission has asked ERCOT to perform an independent study of marginal losses to quantify

[26] *Id.*, Attachment at 6 (this conservatively assumes that a 7MMBtu/MWh market heat rate is marginal on an annual basis and uses 364TWh of annual energy from the analysis found in the Brattle Analysis).

[27] *See* Potomac Economics, 2014 State of the Market Report for the ERCOT Electricity Markets at i (Jul. 2015) and Potomac Economics, 2016 State of the Market Report for the ERCOT Electricity Markets at i (May 2017).

[28] This assumes a conservative 7MMBut/MWh market heat rate and 351.5TWh of energy for 2016 from ERCOT's 2016 Demand and Energy Report.

the benefits and NRG is confident that the results will demonstrate that the implementation of marginal losses will be cost effective and beneficial to consumers.

II. Responses to Comments Regarding Specific Questions Presented

1. What market design reforms, if any, are necessary to support efficient investment and retirement decisions in the Electric Reliability Council of Texas (ERCOT) region?

NRG was motivated to sponsor the Hogan Pope Report due to concerns over inaccuracies in price formation and the influences of out-of-market policies. With the recent generation retirement announcements, NRG is increasingly convinced that market refinements are necessary now in order to encourage resources to be built in the proper locations, and to prevent a further decrease in reserves (premature retirement), potentially resulting in unnecessary grid reliability threats. The foundation of the ERCOT energy-only market should be based on sound economic principles whereby the true costs of the generation and delivery of electricity are reflected in prices at all times especially when electricity is scarce. Because price signals are of the utmost importance in an energy-only market, NRG continues to urge the Commission to adopt the price formation reforms detailed in NRG's initial comments filed on December 1, 2017 in this project.[29] Enhancements to the ORDC, marginal loss pricing, improvements to the RUC process and RUC pricing, and locational reserves will all strengthen the energy-only market and help to ensure it will incentivize adequate resources or demand response in the right locations.

A. The Commission has Not Thoroughly Evaluated Marginal Losses

NRG disagrees with those who claim the Commission has already thoroughly evaluated the implementation of marginal losses; the Commission has never made a policy decision regarding the implementation of marginal loss pricing. In fact, in the Nodal Order, the Commission found that pricing losses was an issue that could be addressed by ERCOT.[30] City Public Service of San Antonio (CPS) filed comments in Project 26376 to request that the Commission adopt marginal losses as part of locational marginal prices in ERCOT's nodal

[29] *See generally*, NRG Comments.

[30] Nodal Order at 103.

market to ensure consistency with "established economic principles."[31] In their comments, CPS stated that "...San Antonio has recommended that transmission losses be accounted for on a marginal basis. To do otherwise would not be consistent with established economic principles, in our opinion."[32] CPS argued further that "several definitions will be required in this rule, and [CPS] has initially added a proposed definition for 'locational marginal price.'"[33] The definition supported by CPS included energy, transmission loss, and congestion components.[34]

When adopting the Nodal Order, the Commission was clearly focused on addressing transmission congestion and dedicated numerous pages of the Nodal Order to explain the rationale for improving price formation by including transmission congestion costs into energy prices. When addressing the recommendation to include transmission losses into prices, the Commission felt addressing transmission congestion was the priority and the topic of pricing losses was important and could be addressed later by ERCOT. The Commission stated that "the [C]ommission's goal in enacting this rule is to prescribe fundamental market design elements that it believes are essential, while leaving ERCOT the flexibility to address many other important design elements, such as the precise definition of nodal energy price."[35]

Therefore, when ordering the adoption of the nodal market, the Commission did not conclusively make a policy decision on marginal losses. Rather, the Commission acknowledged and affirmed the economic principles that support marginal losses but was rightly more focused on implementing transmission congestion pricing to address the large inefficiencies observed in the zonal market related to congestion. In addition, at the time, there was not a large presence of remote generation like there is today. This proliferation of remote generation has changed the dispatch pattern in ERCOT and exposed the inefficiency of socializing transmission losses rather than accurately expressing these costs in energy prices to drive more efficient dispatch and investment siting decisions. Ultimately, the Nodal Order directed ERCOT to address important design elements of the nodal market, such as whether marginal losses should be implemented.

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[31] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376, Comments of City Public Service of San Antonio at 5 (Apr. 21, 2003) (CPS Comments).

[32] *Id.* at 15.

[33] *Id.*

[34] *Id.*

[35] Nodal Order at 103.

Given the sufficient experience with the nodal market and the evidence of increased inefficiency with the treatment of transmission losses, it is now appropriate for the Commission to adopt the incorporation of marginal losses in energy prices.

B. Out-of-Market Actions and Mitigation Procedures Interfere with Locational Price Formation

NRG agrees with TIEC and Vistra Energy that the current market mitigation process described in ERCOT's Constraint Competitiveness Test (CCT)[36] is important to prevent the abuse of local market power when the presence of a transmission constraint gives a resource the ability to set prices unilaterally. However, in an energy-only market, it is equally important to send locational scarcity price signals when grid reliability is threatened. The IMM, who is responsible for monitoring market manipulation, agrees with this conclusion.[37] When ERCOT takes out-of-market reliability actions such as the deployment of RUC and RMR resources, energy prices must reflect the fact that supply is scarce in that location. The mitigation techniques in the CCT can undermine this objective. NRG supports many of the proposals offered to address the issue of local price mitigation during out-of-market reliability actions. Solutions to address RUC and Reliability Must Run (RMR) pricing include adjustment of the mitigated offer caps (for RUC and RMR resources only), price adjustments to reflect the reliability contribution of the RUC or RMR resource, and the Extended Locational Marginal Pricing (ELMP) mechanism. NRG would also be open to reexamining the input parameters to the CCT as suggested by TIEC.[38]

C. Price Signals Will Attract Investment in the Right Locations

In initial comments, TIEC argued that no new investment will occur in supply constrained areas in response to prices. This perspective is troubling and calls into question the structure of the existing competitive wholesale market in ERCOT. TIEC proffers that the looming threat of more transmission development or overbuild of supply would make any

[36] ERCOT Nodal Protocols § 3.19.

[37] IMM Comments at 4.

[38] TIEC Comments at 10.

response to price futile since the price signal would be fleeting.[39] Correcting locational price formation deficiencies in this project and ensuring policies balance competitive market response rather than favoring transmission development will help address these concerns expressed by TIEC. In addition, the Commission clearly it expressed its intention in the Nodal Order for energy prices to improve "locational price transparency for resources" and improve "siting of new resources." Therefore, TIEC's assertions do not reconcile with the basic foundation of the nodal market structure.

TIEC's assertion that new development will not occur in supply constrained regions because additional supply will cause the price signal to disappear is counter to the economic theory that nearly all markets are based upon. As explained by Dr. Patton at the August 10th workshop, suppliers are incentivized to build an economically efficient amount of supply in response to price signals.[40] TIEC is correct that if suppliers overbuild in response to price, then the expected prices will not materialize to support the investment. However, this is true of every market including ERCOT's energy-only market. It is also true from a system-wide perspective in ERCOT, not just for "load pockets" as claimed by TIEC. For example, consider the structure of the ORDC which provides system-wide scarcity pricing signals. 3,000MW of additional supply (reserves) can cause the scarcity price determined by the ORDC to drop from approximately $9,000/MWh to under $50/MWh. 2,000MW of additional supply can cause the price to drop from over $2,000/MWh to under $50/MWh.[41] Thus, investors have the incentive to develop an economically rational amount of new capacity that meets the supply deficiency but does not oversupply the market. This fundamental economic principle applies to supply constrained regions in ERCOT as well as to system-wide capacity insufficiency.

TIEC's perspective also appears to be outdated and backward looking. The days of constructing large coal or gas plants that add thousands of MWs of capacity appear to be numbered, if not over. The future of electric generation technology is more nimble and incremental such as distributed generation, demand response, residential and community solar, and battery storage. Smaller, more incremental resources are easier to site and remove the

[39] *Id.* at 5.

[40] *Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, Workshop (Aug. 10, 2017).

[41] Hogan Pope Report at 15 (ORDC chart).

"chunkiness" observed in the past that TIEC is referring to when the addition of large power plants extinguished price signals. Therefore, market design that includes effective locational price signals is necessary to attract these investments in the right locations. For those reasons, NRG urges the Commission to direct ERCOT to proceed with changes to RUC and RMR pricing, implement marginal losses, and incorporate locational reserves into real-time co-optimization.

D. The Remedy for Market Pricing Inefficiencies is Not More Transmission

Market resources such as generation and load resources respond to supply and demand fundamentals in specific locations driven by economics (i.e. price signals). These market resources are funded by private investment and not by captive ratepayers. Open and effective competitive markets require robust private investment. TIEC argues that the solution to market pricing deficiencies is to build more regulated transmission infrastructure.[42] Besides contradicting the intent of the Commission's wholesale market design rules,[43] this suggestion will suffocate the competitive retail market with high transmission costs and prevent the competitive wholesale market from addressing supply and demand deficiencies more economically through private investment. NRG outlined the increasing costs of transmission construction in ERCOT in initial comments.[44] As an additional data point, consider the Transmission Cost of Service (TCOS) annual revenue requirements in ERCOT that are allocated to consumers. TCOS represents the total costs necessary to support construction, maintenance, and operation of the transmission system in ERCOT per year. TCOS has increased from $1.21 billion in 2007[45] to $3.45 billion in 2017.[46] This increase includes costs associated with CREZ

[42] TIEC Comments at 6.

[43] *See* Nodal Order at 1 ("[t]he rule is expected to yield important benefits, such as a reduction in local congestion costs; reduced opportunities for gaming and manipulation in the wholesale electricity market; increased price transparency and liquidity in the wholesale electricity day-ahead energy market; increased locational price transparency for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a reduction in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market").

[44] NRG Comments at 9-10.

[45] *See Commission Staff's Application to Set 2007 Wholesale Transmission Service Charges for Electric Reliability Council of Texas*, Docket No. 3550, Final Order at 5 (March 30, 2007).

[46] *See Commission Staff's Application to Set 2017 Wholesale Transmission Service Charges for Electric Reliability Council of Texas*, Docket No. 46604, Final Order at 11 (March 30, 2017).

which were reflected in TCOS by 2014.[47] However, TCOS for 2014 was $2.66[48] billion which means annual transmission system costs have increased by over $800 million since CREZ was completed. Moreover, the latest ERCOT Transmission Planning and Information Tracking report shows there are $6.9 billion of future transmission projects currently in engineering, routing, licensing, and construction which are not reflected in TCOS yet (not all projects will proceed however).[49] These transmission costs are locked in for an extended period of time, some up to 40 years, and they are funded by captive ratepayers. As regulated transmission charges become a larger proportion of the average consumer's bill, retail customers become less interested in competitive retail products and services offered by Retail Electric Providers that can reduce the energy component of their bill.

TIEC's argument to increase transmission development rather than allow prices to form fails to consider more economic solutions driven by private investment in market resources. Investors bear the costs and risks of these investments, not consumers. The direction proposed by TIEC to emphasize transmission over market-based solutions creates a cycle where price signals fail to form properly in supply deficient areas preventing the necessary generation or load resources from responding. This downward spiral leads to a need for more and more transmission to compensate for the lack of supply or demand response in the area and ever increasing transmission costs. As explained by Dr. Patton of Potomac Economics at the ERCOT Board meeting on June 14, 2016, this reliance on transmission is not an economic outcome for the market or consumers.

> You can either just keep building transmission and building transmission to make sure you never have areas like that [supply constrained areas]...and the reality is that transmission is not always the cheapest answer. In fact, it's often not the cheapest answer.[50]

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[47] *See* Competitive Renewable Energy Zone Program Oversight CREZ Progress Report No. 17 at 9 (November 2014) ("[b]ased upon information provided by TSPs at the time of this report all projects have been energized").

[48] *See Commission Staff's Application to Set 2014 Wholesale Transmission Service Charges for Electric Reliability Council of Texas*, Docket No. 46604, Final Order at 7 (March 28, 2014).

[49] *See* ERCOT October 2017 Transmission Project and Information Tracking Report (http://www.ercot.com/content/wcm/key_documents_lists/89026/ERCOT_October_TPIT_No_Cost_100117.xlsx).

[50] ERCOT Board of Directors Meeting, Tuesday June 14, 2016, Agenda Item 7, Tr. at 81-82 (IMM Report).

There must be balance between transmission and market solutions. Improving locational price formation through the recommendations supported by NRG in this project will support market forces and allow generation and load resources to respond in supply deficient areas.

The Commission should question any recommendation to rely on more transmission infrastructure as a remedy for market pricing ailments when transmission costs for consumers are already at a historic high of $3.45 billion per year. As currently designed, the 4CP transmission cost allocation mechanism allows larger and more sophisticated consumers of electricity to reduce their portion of transmission costs. This shifts a larger proportion of transmission costs to the other consumer classes who cannot reduce their portion of transmission costs through the 4CP mechanism (such as residential and small business consumers). NRG looks forward to discussing the issues related to 4CP transmission cost allocation in a separate project.

2. Do wholesale electricity prices in ERCOT fully reflect the value of supply during normal conditions? During shortage conditions? If not, what changes should be made.

It has been established in the Hogan Pope Report and in initial comments that ERCOT's wholesale electric prices do not fully reflect the value of supply during normal and scarcity conditions. Most commenters have agreed on this point. NRG's initial comments explain how the current design of the ORDC understates scarcity prices by undervaluing reserve volatility and failing to adjust for RUC and RMR out-of-market actions. TIEC argues that the ORDC overstates scarcity pricing outcomes due to the selection of the Minimum Contingency Level (MCL, also referred to as the value of X) which is set to 2,000MW. The Commission initially chose this value in recognition that the ERCOT ISO begins to take out-of-market actions well before firm load shed in an attempt to prevent it from happening. Load shed typically occurs when reserves diminish to levels around 1,000MW. TIEC fails to consider that while setting MCL at 2,000MW was an attempt to reflect ERCOT's out-of-market actions, it is still too low. ERCOT begins to take reliability actions when reserves drop below 3,000MW by issuing advisories. When reserves reach 2,500MW, ERCOT begins to "use quick-start capacity and non-spinning reserves (available within 30 minutes)."[51] ERCOT stakeholders examined the

[51] ERCOT, ERCOT Energy Emergency Alert Communications (Oct. 27, 2017), http://www.ercot.com/content/wcm/lists/114742/Energy_Emergency_Alert_Communications_Matrix_2017-Oct2017_FINAL.pdf.

reliability actions taken by ERCOT and whether energy prices properly reflected these out-of-market actions. In a list of fifteen potential reliability actions, only five are included in the Reliability Deployment Price Adder (the RDPA is designed to offset the impact of ERCOT's reliability actions on pricing outcomes).[52] None of the fifteen are included at all in the ORDC to offset the pricing impact.[53] ERCOT stakeholders approved Nodal Protocol Revision Request (NPRR) 768 to address one aspect of this problem, incorporation of emergency DC Tie imports and Block Load transfers in the RDPA, but ERCOT has not implemented it yet.[54] NPRR768 does not include adjustments to address the other out-of-market reliability actions described above.

The current configuration of the ORDC should also be evaluated against other market impacts. During the peak load hour in 2017 (July 28th at Hour Ending 17:00),[55] for example, the total wind output in the ERCOT grid was 3,081MW.[56] During the peak load hour in 2016 (August 11th at Hour Ending 17:00)[57], the total wind output in the ERCOT grid was 4,784MW.[58] The Hogan Pope Report and NRG's initial comments explained how the ORDC understates the scarcity pricing risk of reserve volatility related to renewable output. In addition, ERCOT recently reported that 4CP response has increased to approximately 1,200MW even without including Non-Opt In Entity (NOIE) participation.[59] Including NOIE participation, 4CP response is likely in the 1,800MW to 2,000MW range. 4CP response occurs in reaction to transmission costs and not in reaction to electricity prices. Finally, as mentioned in NRG's

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[52] ERCOT, Consideration of Reliability Actions in Pricing OMWG Update (2017), http://www.ercot.com/content/wcm/key_documents_lists/113936/Consideration_of_Reliability_Actions_in_Pricing_QMWG_Update.xlsx (showing pricing impacts of out-of-market actions).

[53] *Id.*

[54] ERCOT, NPRR No. 768, Revisions to Real-Time On-Line Reliability Deployment Price Adder Categories (Oct. 17, 2017), http://www.ercot.com/content/wcm/key_documents_lists/96080/768NPRR-19_Board_Report_101717.doc.

[55] ERCOT, 2017 Report on Demand and Energy (Dec. 7, 2017), http://www.ercot.com/content/wcm/lists/114740/DemandandEnergy2017.xlsx.

[56] ERCOT, Hourly Aggregated Wind Output (2017), http://www.ercot.com/gridinfo/generation.

[57] ERCOT, Electric Reliability Council of Texas Demand for 2016 (Feb 7, 2017), http://www.ercot.com/content/wcm/lists/89476/ERCOT2016D_E.xlsx

[58] ERCOT, Hourly Aggregated Wind Output Report (2017) http://www.ercot.com/gridinfo/generation.

[59] *See* Sarah Moore & Calvin Opheim, 2018 Long-Term Load Forecast at 25-36 (Dec. 8, 2017), http://www.ercot.com/content/wcm/key_documents_lists/131805/2018_LTLF_-_SAWG_12-08-2017_-_Final.pptx.

initial comments, ERCOT will deploy RUC for capacity when they anticipate less than the full amount of ancillary service procurement which is typically over 3,500MWs in the summer months.

NRG provides this information to make it very clear to the Commission that the ORDC will not "overvalue" supply as claimed by TIEC. It is very difficult to assign an accurate economic value to each reliability action taken by ERCOT or even to identify an accurate amount of capacity that each discreet out-of-market action provided. In addition, as stated in the Hogan Pope Report, it is not the purpose of good market design to attempt to reverse the fundamentals of what is already done. Attempting to adjust energy prices to compensate for price suppression caused by renewable subsidies or 4CP response would likely be inaccurate and cause other price distortion effects. But it is prudent to ensure the ORDC is conservatively designed to reflect scarcity events. This is why NRG supports the reasonable adjustments to the ORDC to properly price the risk of reserve variability (LOLP shift) and reflect the impacts of out-of-market RUC and RMR deployments. From a locational perspective, improving locational price formation mechanisms will help fulfill the goals of the adoption of the nodal market and will help establish more of a balance between market investment and regulated transmission development, something that is clearly missing from the current market design.

3. Are the reliability contributions of units subject to operator-initiated commitment being undervalued due to mitigation or for any other reason? Are the current pricing rules sufficient to control for the locational effect of reliability deployments? If the current pricing rules are not sufficient, what changes should be made.

Energy prices currently set by ERCOT are inadequate because they undervalue the reliability contributions of units subject to operator-initiated RUC and RMR commitment. Improving locational price formation during RUC and RMR commitments is consistent with the goals for adopting the nodal market and will help establish more of a balance between market investment and regulated transmission development, something that is currently missing in ERCOT. NRG has already refuted TIEC's argument that building more transmission is a better solution for locational price formation deficiencies. However, TIEC further argues that once congestion costs are sufficiently high, it will be in the interest of consumers to build transmission to reduce those costs and, in turn, reduce the likelihood of a significant load pocket that might cause reliability issues later.[60] TIEC argues that this aggressive type of transmission planning is the best approach to minimize RMR and RUC and believes the Commission should restore the "consumer benefit test" transmission planning policy, which it argues provides "substantial benefits" to ERCOT customers by facilitating "cost-effective" transmission to avoid congestion.[61] If the Commission restored the consumer benefit test, it would lower the bar for ERCOT transmission planning criteria and would make it easier to justify additional transmission construction based on future predictions of congestion pricing.[62] The Commission has previously rejected this construct and should continue to reject it.

TIEC asserts that NRG and Calpine's "efforts" were responsible for causing certain transmission planning criteria to be "eliminated" in order to block transmission projects.[63] TIEC is referencing the elimination of the consumer benefit test planning method. However, TIEC incorrectly characterizes the "efforts" made by NRG and Calpine. In fact, it was the Commission that amended its rules to eliminate what was called the "consumer impact/generator revenue reduction (GRR) test" in Project No. 39537. It was after a robust rulemaking that the Commission eliminated the GRR test because

> the test is very sensitive to [forecasted] input assumptions; a transmission project that passes the test can result in a substantial number of customers paying higher prices; and the use of the test may result in generation resources not being built, thereby harming resource adequacy.[64]

Ultimately, the Commission found that the GRR test requires the use of predicted future market prices based on assumptions that are inherently speculative, such as long-term prediction of gas prices, assumptions about generator bidding behavior, and other market dynamics.[65] The

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[60] TIEC Comments at 10.

[61] *Id.*

[62] *Id.*

[63] *Id.*

[64] *Rulemaking Proceeding to Implement HB 971, Relating to Economic Criteria for a Certificate of Convenience and Necessity for an Electric Transmission Project*, Project No. 39537, Order Adopting Amendment at 15 (March 21, 2012) (Order Adopting Amendment).

[65] *See Id.* at 16-17.

Commission determined that the projection of these factors is unreliable over the long-term and therefore not appropriate to justify costly 40-year capital assets.[66]

In contrast, the Commission chose to utilize the "societal impact/production cost savings (PCS) test as the economic project standard, because it is a more sound and reliable test that looks to the actual power production cost reduction of a proposed transmission project as compared to the cost of the project to consumers in their utility rates."[67] The Commission made the appropriate choice when adopting the PCS test because it utilizes more accurate and reliable criteria and helps avoid costly, unneeded transmission projects. With transmission costs already a significant burden, unnecessary transmission threatens effective locational price signals and discourages resources to locate where supply is most needed.[68] This compounds a cycle of inefficiency and cost in the ERCOT system (described above). The illusory short-term savings of the GRR are speculative and not sustainable in the long run because the GRR cannot accurately predict the long-term market dynamics of attracting sufficient generation in a competitive market to serve the long-term growing demand.

Therefore, TIEC is incorrect in its assessment that the solution to RMR and RUC is to restore the GRR test. The best solution to RMR and RUC is to more closely align locational scarcity pricing with reliability actions taken by ERCOT or locational reserve deficiencies. NRG's initial comments and the comments of many others support improvements to RUC and RMR pricing such as adjustments to RUC and RMR mitigated offer caps, implementation of pricing adjustments to reflect the reliability value of the RUC or RMR resource, or implementation of an Extended LMP construct. NRG believes the details of this market design change could be handled in the ERCOT stakeholder process if direction is provided by the Commission. NRG also recommends that the Commission direct ERCOT to include locational criteria in their ancillary services studies to determine future locational reserve needs.

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[66] *See Id.* at 15-18.

[67] *See Id.* at 15-16 ("[t]he PCS test compares the estimated levelized annual savings in system production costs resulting from the project to the estimated first-year revenue requirement form the project. If the system production cost savings is equal to or greater than the first-year revenue requirement of the project, the project passes the test"). *See also* ERCOT Protocols § 3.11.2(5).

[68] *See* Project No. 39537, Order Adopting Amendment at 18.

4. Are out-of-market payments for renewable generation interfering with competitive outcomes in ERCOT's wholesale electricity market? If so, please describe this effect and provide any relevant analysis. How should any interference be corrected, if at all?

Most commenters recognize the impacts of renewable subsidies, in particular the Production Tax Credit (PTC), on energy price formation. NRG also recognizes the comments by many renewable interests that nearly all resources in the market receive some type of subsidy. NRG made the same point in initial comments but also distinguished between subsidies that have a more substantial impact on energy price formation such as the PTC. Importantly, the Hogan Pope Report and NRG do not propose or support market design changes that attempt to unwind those subsidies or discriminate against specific technologies that receive those subsidies. While the evaluation is informed by the presence of these out-of-market impacts, the focus is on principled market design changes that bolster the competitive energy-only market in ERCOT.

5. Given recent retirement announcements, should the commission defer certain changes to the market design to observe market dynamics over summer 2018 or longer?

As stated above, NRG believes the extensive analysis in the Hogan Pope Report and the support of the IMM clearly justify proceeding with market design changes to improve energy price formation. Also, the fact that ERCOT has had to take an increasing number of out-of-market RUC actions in recent years is evidence of flaws in the energy market that should be addressed.

In initial comments, NRG offered a proposed work plan for the Commission to consider that recommends a prioritization of the energy market design improvements. ORDC enhancements should be implemented immediately. These are incremental adjustments to improve scarcity prices when scarcity conditions are present. Nearly every entity owning a generation resource (thermal or renewable) that filed comments agreed changes to the ORDC methodology are necessary. The market is currently faced with declining reserves making the ORDC more important than it has ever been in its existence. The proposed ORDC reforms will improve the incentives for existing generation and demand resources to be available, will help prevent the premature retirement of capacity currently in the market, and will encourage new resources to develop in response to lower reserves.

Market design changes to more accurately price out-of-market actions by ERCOT such as RUC and RMR should also proceed as soon as possible. The IMM supported changes to improve locational price formation along with many other commenters. There are many options on the table for the Commission to consider that vary in complexity. NRG supports the Commission's direction to review a benefits study for both marginal losses and real-time co-optimization given the effort involved by ERCOT. NRG proposed in initial comments that the Commission direct ERCOT to collaborate with stakeholders to draft implementation details in an NPRR for marginal losses and real-time co-optimization. This suggestion will allow ERCOT and stakeholders to think through the design details and more thoroughly understand the mechanics. NRG fully recognizes the Commission may need a rulemaking to pursue either of those market constructs. Upon review of the Commission's rules, it appears such a rule change would be straightforward however.

6. Please comment on the appropriate allocation of the excess revenues collected under marginal loss pricing. How should this surplus be distributed and why?

The Commission should first make the decision to proceed with the implementation of marginal loss pricing. After that policy decision is clearly made, the appropriate allocation mechanism for surplus revenues should be considered. NRG continues to support the proposal to allocate surplus marginal loss revenues to consumers. This will help offset the significant transmission cost burden in utility rates. NRG remains generally neutral regarding whether the Commission adopts a system-wide or zonal based approach to distribute marginal loss surplus revenues.

7. Please provide any other comment regarding the merits of the specific proposals set forth in the FTI Consulting Report or in the written comments filed by the Independent Market Monitor or other parties in this project.

NRG strongly supports the adoption of marginal loss pricing in ERCOT as it not only represents a "best practice"[69] in power market design, but it also strengthens locational price formation and establishes the right incentives for siting of new investments. The market should encourage resources to site close to load, where it is most useful and efficient. NRG is strongly

[69] IMM Comments at 2.

opposed to arguments made by Vistra Energy in opposition to the implementation of marginal losses. Vistra Energy argues that Senate Bill 7's (SB 7) requirement for wholesale transmission services to use a postage stamp method of pricing prohibits the Commission from instituting marginal losses.[70] This interpretation of SB 7 is fundamentally flawed – the postage stamp method does not apply to transmission losses in the same way that it does not apply to transmission congestion. Notably in PURA, "postage stamp pricing" is limited to transmission-owning utilities annual costs to support utility transmission investment ("transmission service") and does not include transmission losses or congestion.[71]

If the Legislature had intended for transmission losses to be included in a postage stamp rate, it would have included those costs in the price of wholesale transmission service as described in SB 7. One must only look at both the introduced and engrossed (final) version of the bill to see that SB 7 intended to narrowly limit the price of transmission service to a utility's annual cost of transmission divided by the total demand placed on the combined transmission systems of all such transmission owning utilities within a power region.[72] Additionally, the Legislature did not define "transmission service" to include transmission losses.[73] Instead, PURA defines transmission service to include

> construction or enlargement of facilities, transmission over distribution facilities, control area services, scheduling resources, regulation services, reactive power support, voltage control, provision of operating reserves, and any other associate electrical service the commission determines appropriate, except that, on and after the implementation of customer choice, control area services, scheduling resources, regulation services, provision of operating reserves, and reactive power support, voltage control, and other services provided by generation resources are not 'transmission service.'[74]

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[70] *Project to Assess Price Formation Rules in ERCOT's Energy-Only Market*, Project 47199, Vistra Energy's Comments and Alternative Proposals at 15 (Dec. 1, 2017) (Vistra Comments).

[71] Public Utility Regulatory Act, Tex. Util. Code § 35.004(d) (West 2007 & Supp. 2014) (PURA).

[72] *Id. See also* 76th Tex. Leg., R.S., SB 7, ch. 405 § 17 (Sept. 7, 1999).

[73] PURA § 31.002(20).

[74] *Id.*

It is clear PURA and Commission rules do not consider transmission losses to be a utility annual cost, and since the electric industry restructured in 2002, transmission losses have not been included in the annual Transmission Cost of Service calculation.[75]

Vistra Energy also grossly mischaracterizes the 1999 Scope of Competition Report[76] and omits relevant discussion regarding the purpose of open transmission access and postage stamp pricing in order to fit their narrative. Vistra Energy uses the 1999 Scope of Competition Report to suggest that socializing transmission losses "puts wholesale providers across the state on level competitive footing, by removing any competitive advantage based on location on the grid."[77] However, this assertion does not reflect a complete reading of the 1999 Scope of Competition Report. The Commission's discussion of transmission pricing and the examples provided in the 1999 Scope of Competition Report suggests location and siting choices are a key component of wholesale competition. As described in the 1999 Scope of Competition Report, the "postage stamp methodology" was intended to solve the issue of differing wholesale transmission rates across multiple utility service territories. The Commission explained that the Federal Electric Regulatory Commission (FERC) had "permitted transmission rates to be developed on a utility-by-utility basis" which impeded the development of competitive markets because of a complicated tariff system and disparate interests amongst parties in establishing transmission pricing.[78] The Commission noted that having a system-wide Transmission Cost of Service rate simplifies access to the transmission system and permits robust competition amongst generators.[79]

The Commission further separated transmission losses from the postage stamp rate by stating that "[a] user of the transmission system pays the fixed costs of the transmission network up front [in the form of postage stamp rates], and the cost of using the network on a day-to-day basis is limited to the cost of transmission losses, that is the 'fuel cost' of moving power from

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[75] 16 Tex. Admin. Code § 25.192(h) (TAC).

[76] Public Utility Commission of Texas, *Report to the 76th Texas Legislature: The Scope of Competition in the Electric Industry in Texas* (Jan. 1999) (1999 Scope of Competition Report).

[77] Vistra Comments at 15 (citing the 1999 Scope of Competition Report at 36-38).

[78] 1999 Scope of Competition Report at 36.

[79] *Id.* at 37.

one point to another."[80] The Commission explained that "[w]hen electricity is transmitted over a conductor, part of it is converted to heat and does not reach the appliance that is powered by the electricity. The lost energy is referred to as transmission losses, and additional fuel must be consumed in the generator to make up for the losses."[81] The Commission illustrated the differences in the ERCOT transmission rates and the typical FERC-approved rates by using an analogy to a road system – "[t]he ERCOT transmission pricing system works like the tax assessments that cover the cost of the road network, where the fixed costs of the transportation network are not included in the daily and hourly fees for using the system."[82]

Using the analogy more illustratively, the Commission gave the highway and truck example: "tomatoes can be delivered to Dallas from California, South Texas, or Florida <u>for the cost of the fuel used in the truck that delivers them</u>, so there is competition among producers that benefits Dallas customers."[83] (emphasis added) This analogy demonstrates that the postage stamp rate was narrowly designed to allow free access to the highway while allowing generators to compete on the cost to produce ***and deliver*** the product; the "drive" from California would obviously cost more than a "drive" across Dallas. The location of the starting point matters in the analogy when considering transmission losses and transmission congestion. The location of generation and siting decisions are extremely important because it impacts the amount of transmission losses and congestion incurred by the ERCOT system, which are ultimately borne by consumers. Generation resources are not prohibited from siting in certain locations but they are incentivized, through prices, to site in certain areas that lower system costs. Including transmission losses in energy prices is appropriate and consistent with the stated goals of vigorous competition between producers on the basis of the price of power supply and delivery. Marginal losses appropriately assigns the delivery cost of transmission losses to resources based on their location and contribution to transmission losses. This will more accurately reflect the cost of producing and delivering electricity in the ERCOT market.

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[80] *Id.* at 36.

[81] *Id.* at n.38.

[82] *Id.* at 37.

[83] *Id.*

III. Conclusion

NRG appreciates the consideration of the Commission and the opportunity the Commission has provided to reply to comments submitted by other parties regarding the above questions. Matters of wholesale market design have great significance to the investment and operational decisions of the generation and load resources in the ERCOT region. The Commission's leadership and clear direction is needed to strengthen the performance of the ERCOT market through improved price formation. NRG looks forward to working with the Commission in this project to evaluate the recommendations and provide further information as requested. As the Commission provides its guidance, and as other parties provide their positions and suggestions, NRG reserves the right to refine and modify its positions herein and to take positions on other issues not addressed in these comments.

Respectfully submitted,

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