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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 RESPONSE TO REQUEST FOR COMMENT

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 comment on important wholesale market design improvements in this project and hereby file this Response to the Commission's Request for Comments filed on October 27, 2017.

I. Introduction

In the ERCOT energy-only market, the integrity of energy price formation is the foundation of the competitive market's success. Energy prices are the primary source of financial incentive and they drive behavior by generation and load resources and consumers. Energy prices also provide important investment and siting signals. As with all other important market design changes implemented in ERCOT, such as the transition to a nodal-based pricing market design (i.e. a nodal market utilizing locational marginal prices) in 2010[1], the Commission has provided the leadership necessary to ensure that iterative improvements are made to the wholesale market and to ensure disagreement among stakeholders does not impede such improvements. While ERCOT stakeholders will undoubtedly be impacted by market design changes in different ways (as they always are), it is important for the Commission to evaluate proposed market design improvements using well-established economic principles and best practices. Ensuring accurate price formation is critical to support a sustainable market structure that can withstand the economic and investment cycles of the industry.

The Commission has remained committed to the energy-only market design and NRG has been supportive of the Commission's deliberations and direction as the ERCOT market

[1] *ERCOT Accounting of the Amount and Timing of the Collection of the Nodal Surcharge*, Docket No. 42122. http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/42122_2_776935.PDF. This market reform represented a $500 million in systems investment by ERCOT that paid for itself in market efficiency savings in just a few years, *see, e.g., Update on the ERCOT Nodal Market Cost-Benefit Analysis*, CRA International for the Public Utility Commission of Texas, December 18, 2008. http://www.puc.texas.gov/industry/electric/reports/31600/puct_cba_report_final.pdf

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evolves. Lingering price formation deficiencies and the influence of policies external to market design have affected the performance of the wholesale market and hindered market outcomes. If left unaddressed, market inefficiencies will compound and result in uneconomic decisions that ultimately prove costly for consumers, such as excessive and premature retirement of generation resources in the wrong locations resulting in unnecessary Reliability Must Run (RMR) service and transmission infrastructure costs. It is imperative that the Commission ensures that the wholesale market structure adheres to the guiding principles established in the PUCT substantive rules. This includes making the needed modifications to the market in response to the issues that hinder price formation. As explained in these comments, market design improvements must be made to ensure that price formation in the ERCOT energy-only market drives the right choices by market participants – to invest in generation, repowering, equipment maintenance, demand response, and innovative retail products – in the right locations. NRG urges the Commission to set forth a clear path for needed market design adjustments, prioritizing those than can be achieved in a timely and cost-effective manner.

II. Discussion

A. Direction from the Commission is required to decide meaningful wholesale market design policy

Wholesale market design is among the most important and impactful policies under the Commission's oversight. A core tenant of wholesale market design is the integrity of energy price formation. The Commission plays an essential role in establishing and maintaining rules regarding wholesale market design and price formation in ERCOT. While the details of implementing market rules are rightly left to the ERCOT stakeholder process, the Commission ensures that the key principles of market design are not ignored nor abandoned as the ERCOT market evolves. The topics of wholesale market design and energy price formation are often divisive amongst ERCOT stakeholders given the varied financial interests of market participants. Therefore, it is critical for the Commission to provide clear direction to ERCOT and stakeholders on these important matters.

B. Review of Commission rules and the basis for adopting those rules

The PUCT substantive rules establish the principles that the wholesale market design and price formation rules must follow in ERCOT. The Commission's rules in Subchapter S, 16 TAC §25.501, "Wholesale Market Design for the Electric Reliability Council of Texas" ("Wholesale Market Design Rule") paragraph (a) state:

> The protocols and other rules and requirements of the Electric Reliability Council of Texas (ERCOT) that implement this section shall be developed with consideration of ***microeconomic principles*** and shall ***promote economic efficiency in the production and consumption of electricity***; support wholesale and retail competition; support the reliability of electric service; and ***reflect the physical realities of the ERCOT electric system***. (emphasis added)

The section continues with more specific requirements for price formation by directing ERCOT to determine the market clearing prices for energy:

> . . . ERCOT shall determine market clearing prices . . . using economic concepts and principles such as: shadow price of a constraint, ***marginal cost pricing***, and maximizing the sum of consumer and producer surplus. (emphasis added)

The preamble of the Commission's order implementing the nodal market ("Nodal Order") and adopting the Wholesale Market Design Rule frames the motivation and intention for establishing these principles:

> The 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. (emphasis added)[2]

The Nodal Order further emphasizes the importance of accurate energy price formation based on the principles in the Wholesale Market Design Rule. The order states:

> These benefits will provide participants in the wholesale and retail markets with more accurate wholesale prices, which will facilitate better-informed price responses by customers in those markets.[3]

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[2] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376, Final Order, (September 23, 2003) at 1.
[3] *Id.* at 1.

The direction provided by the Wholesale Market Design Rule and the Nodal Order are important to consider when evaluating the current performance of the ERCOT market and the recommendations provided in these comments and in this project.

C. The importance of evaluation and evolution of wholesale market design

Electricity markets are complex given the unique nature of electricity as a commodity and service. The economics involved and the physical characteristics of supplying, delivering, and consuming electricity all contribute to the complexity. Implementing the details of market design to accommodate a complex industry is difficult to get right on the first, second, or even third attempt. Consider further the fact that supply fundamentals and the technology of producing and using electricity constantly change. In addition, influential policies external to market design are frequently adopted at both the federal and state level. Therefore, it should not be a surprise that inefficient market design features exist or negative impacts to price formation develop over time. These dynamics create a need to frequently evaluate wholesale market design and implement adjustments to ensure efficient market principles continue to prevail. While market stability and regulatory certainty are important factors to consider as part of this review, they should not be used as an excuse to ignore or delay needed improvements to market design that clearly align with the mandates of the Wholesale Market Design Rule and increase the ability of the ERCOT wholesale market to deliver the benefits anticipated in the Nodal Order.

Indeed, since the implementation of competitive markets in ERCOT in 2002, the Commission and ERCOT stakeholders have regularly modified the wholesale market design to improve price formation in the energy-only market. Examples include:

- The System-Wide Offer Cap (SWOC) was increased gradually over the course of many years. The SWOC was initially under $1,500/MWh at the beginning of the zonal market and increased to the following values between 2007 and 2015: $1,500/MWh, $2,250/MWh, $3,000/MWh, $5,000, $7,000/MWh, and $9,000/MWh.[4]
- The nodal market was implemented in December of 2010 which transitioned from a zonal-based pricing market and made significant changes to nearly all aspects of the wholesale market design.[5]

[4] 16 TAC 505(g).
[5] 16 TAC 501.

- Ancillary Service offer floors were established in 2012 to improve price formation during scarcity events (when Ancillary Services were deployed) and prevent energy price reversals.[6]
- The Operating Reserve Demand Curve (ORDC) was implemented in the summer of 2014 to establish discipline and improve scarcity price formation.[7]
- The Reliability Deployment Price Adder (RDPA) was implemented in 2015 to partially offset the price distortions caused by ERCOT's reliability actions.[8]

These changes were all adopted to provide continuous improvement to the ERCOT market design. And for perspective, the implementation of the nodal market was far more impactful to market participants than any recommendation under discussion in this project. While there are more examples, this history demonstrates the importance of continuing to evaluate the wholesale market design and to improve the accuracy of price formation. The Commission has not hesitated in the past to support needed market design improvements and it should not ignore them now. Competitive markets should decide winners and losers based on sound economic principles; in an energy-only market that means accurate price formation that reflects the physical realities and costs of the ERCOT system.

D. Objective: Improve energy price integrity in ERCOT's energy-only market

The report by Dr. Hogan and Dr. Pope filed in this project ("Hogan Pope Report"),[9] contributes to the long history of evaluating improvements to the ERCOT market design. From NRG's perspective, the motivation for the report was spurred by lingering concerns over inaccuracies in price formation and influences by out-of-market policies. This led to a comprehensive review of factors that impact price formation in ERCOT and a discussion of what improvements could be made to the market design guided by the economic principles established in the Wholesale Market Design Rule. Importantly, the Hogan Pope Report stresses the

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[6] ERCOT Nodal Protocols Revision Request ("NPRR") 428, *Energy Offer Curve Requirements for Generation Resources Assigned Non-Spin Responsibility* (implemented January 5, 2012). http://www.ercot.com/mktrules/issues/NPRR428#keydocs; Commissioner Anderson Memo in Project 40000 (July 24th, 2012) http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_64_732236.PDF.
[7] ERCOT NPRR 568, *Real-Time Reserve Price Adder on Operatin Reserve Demand Curve* (implemented June 1, 2014). http://www.ercot.com/mktrules/issues/NPRR568 .
[8] ERCOT NPRR 626, Reliability Deploykment Price Adder (formerly "ORDC Price Reversal Mitigation Enhancemenets") (full implementation June 25, 2015). http://www.ercot.com/mktrules/issues/NPRR626.
[9] William W. Hogan & Susan L. Pope (FTI Consulting, Inc.), *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT* (May 9, 2017) (hereafter "Hogan Pope Report").

importance of recognizing changing market fundamentals and dynamics for the purposes of context, but remains disciplined in what recommendations are considered:

> Lower natural gas prices and the proliferation of renewables in ERCOT have changed market fundamentals and transformed the balance sheets of electricity generation owners in the region. These changes in fundamentals cannot be reversed, ***nor is it the purpose of good market design to attempt to reverse the fundamentals or unwind what is already done***. But, just as one would be concerned about high prices, persistent pressure on pricing outcomes ***motivates an examination of whether the market design and price formation rules in ERCOT could be improved in support of greater efficiency and sustainable electricity markets***. (emphasis added)
>
> Retirement of existing facilities, even early retirement, could be consistent with efficient market operations. In ERCOT, the pressure is on dispatchable generation capacity due to falling natural gas prices, increasing wind production spurred by out-of-market payments, and other factors external to the energy market under the direct control of the PUCT. The low level of region-wide energy prices and ORDC adders are sending a message for dispatchable resources to exit the market, and there is a need to evaluate the consequences of increasing reliance on intermittent sources of energy. ***In particular, these external factors and shifting market conditions highlight the importance of improving price formation to ensure that it is fundamentals, and not avoidable market influences or defects that drive decisions about retirement, entry or plant maintenance***. (emphasis added)

In other words, wholesale electric market design should focus on well-established economic principles and best practices rather than an attempt to offset the impacts of market distortions with other distortions. The key is accurate energy price formation. The energy-only market relies on the integrity of price formation and the need for prices to accurately reflect supply and demand fundamentals including reliability actions of the ERCOT Independent System Operator (ISO) and to accurately reflect the costs of the physical properties of the ERCOT system such as transmission losses. Accuracy in energy price formation applies to system-wide scarcity prices and locational price formation that reflects the costs of delivering electricity to consumers. The objective of this project should be to maintain and evolve the market features to be as consistent as possible with the economic and market design principles set forth in the Commission's rules as well as to apply best practices implemented in other markets. Since energy prices create the single most important incentive for operational, consumption, and investment decisions, the Commission should be motivated to have the most well-designed energy market possible.

III. Responses to the Commission's Questions

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?*

a. Scarcity pricing reforms to support investment and retirement decisions

The wholesale market design in ERCOT should be improved in many ways to support efficient investment and retirement decisions. First, a critical market design feature in ERCOT's energy-only market that signals a need for investment is the scarcity pricing mechanism. The ORDC acts as the primary scarcity pricing mechanism. Past reliance on offering behavior by market participants and ancillary service offer floors for scarcity price formation proved ineffective, as evidenced by various analyses including the June 2012 "Brattle Report."[10] In response, the Commission directed the implementation of the ORDC in June of 2014 to establish a mechanism to more accurately reflect the value of electricity during scarcity conditions. The ORDC estimates the probability of electric system load shed (Loss of Load Probability – "LOLP") and assigns an economic value to that outcome to determine scarcity prices.

As described in the Hogan Pope Report, the current design of the ORDC tends to understate scarcity pricing outcomes due to its historical perspective of reserve error (reserve error is a key input in determining LOLP).[11] In an energy-only market, there is a strong argument that the ORDC should be designed to be more conservative (not less) and include a risk premium in its evaluation of scarcity events given the increased variability of reserves driven by the increase of installed capacity of renewables. ERCOT has recently adopted changes to how it procures ancillary services in a similar way to incorporate the impact of increased renewable installed capacity.[12] In addition, ERCOT uses out-of-market reliability actions through the Reliability Unit Commitment ("RUC") process to ensure there is enough online

[10] The Brattle Group, *ERCOT Investment Incentives and Resource Adequacy (June 1, 2012)* ("Brattle Report") pp. 14 – 28. Ancillary service offer price floors, implemented for a time beginning in 2012 through part of 2014, provided marginal improvement but introduced other disruptive issues such as price reversals.
[11] ERCOT Report *Methodology for Implementing ORDC to Calculate Real-Time Reserve Price Adder,* Version_1.4 (June 28, 2017).http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Implementing_ORDC_to_Calculate_Real-Time_Reserve_Price_Adder.zip .
[12] *ERCOT Methodologies for Determining Minimum Ancillary Service Requirements for 2018* (draft November 30, 2017). http://www.ercot.com/content/wcm/key_documents_lists/107888/10._ERCOT_Reports.zip.

capacity to maintain ancillary service quantities which is much more conservative than the design of the ORDC. The design of the scarcity pricing mechanism (ORDC) should be consistent with the reliability processes employed by ERCOT.

As recommended in the Hogan Pope Report, a simple adjustment to the ORDC to more closely align scarcity pricing with reliability actions taken by ERCOT includes removing RUC and Reliability Must Run ("RMR") capacity from the calculation of reserves used to determine scarcity prices. Under the current Protocols, when ERCOT commits resources through the RUC process, the capacity from the RUC resources inflates online reserves in the ORDC calculation and the scarcity prices produced by the ORDC will be suppressed. Action taken by ERCOT to manage the system for reliability should not interfere with accurate scarcity pricing. Removing RUC and RMR capacity from the ORDC will offset that impact.[13]

In addition, to ensure that the ORDC does not understate scarcity risk and prices, the LOLP should also be modified through a simple conservative adjustment of the statistical method used to estimate reserve error, as described in the Hogan Pope Paper on page 39. The reserve error represents the historical variability in the amount of remaining electricity reserves needed to prevent electric system load shed or rolling outages. The standard deviation of historical reserve error helps quantify the risk of load shed or LOLP. By using a historical perspective when determining the reserve error and LOLP, the variability in reserves caused by the growth of renewables is determined through a backward looking approach and is understated. A simple conservative adjustment to the LOLP by shifting or increasing the standard deviation would help ensure scarcity prices better reflect the risk of higher reserve variability.

In addition, a lingering issue with the current design of the ORDC is the step change increase in ORDC prices when reserve levels approach the minimum contingency level (also called "the value of X"). ORDC prices increase by approximately $4,500/MWh with a 1 MW change in the amount of remaining reserves at the value of X. This outcome creates substantial and unnecessary volatility, changing too quickly to allow the market to respond rationally; this pricing would be handled more efficiently through a continuous price increase. The adjustment to the LOLP as recommended above would help address this step change increase in ORDC prices by smoothing the shape of the ORDC at the value of X. Other recommendations have

[13] RMR capacity is committed through the RUC process. Therefore, removing RUC capacity from the ORDC could also accommodate RMR capacity.

been made by other parties to accomplish similar objectives and NRG would be supportive of the direction of these changes, but the mechanisms recommended in these comments offer a simple and presumably low cost approach that can be implemented in a timely fashion.

b. Locational pricing reforms to support investment and retirement decisions

A second pressing need for improvement in price formation to support investment and retirement decisions in ERCOT is locational price formation. Locational price formation refers to the determination of energy prices in sub-regions and at each element of the ERCOT transmission system. In other words, the price of electricity for consumers in Houston should be different than the price for consumers in Abilene assuming the costs to deliver electricity to both locations is different. The local market power mitigation process,[14] RUC process and pricing,[15] design of the Reliability Deployment Price Adder,[16] and the treatment of transmission losses[17] all negatively impact locational price formation. When describing the expected benefits of moving to the nodal market, the Nodal Order clearly articulated the importance for the wholesale market to rely on locational price signals for investment siting and operational decisions:

> The rule is expected to 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. [18]

By expecting benefits of improved siting decisions and a *reduction* in the amount of new transmission facilities to support reliability and competition, the Commission very clearly intended for the wholesale market to incentivize generation and load resources to respond to locational price signals and site in the right locations in a manner that would reduce the need for future transmission projects. That expected reduction has not materialized. The costs of ERCOT transmission system construction prior to the nodal market averaged $760MM per year for the

[14] ERCOT Protocols Section 3.19.
[15] ERCOT Protocols Section 5.
[16] ERCOT Protocols Section 6.5.7.3.1.
[17] ERCOT Protocols Section 11.4.5 and 13.
[18] *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, Project No. 26376, Final Order, (September 23, 2003) at 1.

years 2006 through 2010, excluding CREZ costs.[19,20] After the nodal market was implemented at the end of 2010, those costs averaged $1.1B for the years 2011 through 2017, excluding CREZ.[21,22] The costs of planned ERCOT transmission system construction for the years 2018 through 2020 average $1.2B per year.[23] The failure of locational energy prices to incentivize sufficient response and appropriate siting decisions is likely a contributing factor to the increased transmission cost. Improving locational price formation mechanisms will help establish more of a balance between market investment and regulated transmission development. This is clearly missing in the current market design.

The Commission has many recommendations to consider when addressing the deficiency in locational price formation. One group of recommendations is related to accurate locational pricing when the ERCOT ISO takes out-of-market reliability actions such as RUC and RMR unit commitments.[24] This is when the ISO takes command and control action to commit and deploy units in response to perceived reliability issues. Discussion of out-of-market impacts to pricing will focus on RUC in these comments since RUC activity dominates the out-of-market actions taken by ERCOT. However, the same arguments regarding RUC apply to the deployment of RMR resources. It should be noted that stakeholders are discussing price formation improvements for RMR dispatch in the ERCOT stakeholder process but it is not clear as of this filing whether there is support to approve them. Regarding RUC, the first step to address RUC is to reduce the need for it by reviewing the current unduly conservative assumptions used in the RUC process and ensuring RUC is only used for true reliability emergencies. Addressing the pricing outcomes after ERCOT commits RUC units is equally important. Since operator-initiated commitments such as RUC are the subject of Question 3 below, discussion and recommendations regarding the RUC process and pricing will be reserved for the response to that question. Accurate locational pricing during out-of-market actions is a clear deficiency in price formation in the current ERCOT market design and should be addressed in this project.

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[19] ERCOT Constraints and Needs Report, 2008.
http://www.ercot.com/content/news/presentations/2008/2008_Constraints_and_Needs_Report_30DEC2008.pdf
[20] ERCOT Constraints and Needs Report, 2016.
http://www.ercot.com/content/wcm/lists/89476/2016_Constraints_and_Needs_Report.pdf
[21] *Id.*
[22] ERCOT Transmission Project and Information Tracking (TPIT) report, October 13th 2017.
http://www.ercot.com/content/wcm/key_documents_lists/89026/ERCOT_October_TPIT_No_Cost_100117.xlsx
[23] *Id.*
[24] See response to question 3.

c. The importance of implementing marginal losses in energy pricing on future investment decisions in ERCOT

Incorporating the cost of transmission losses into energy prices in ERCOT is among the most straightforward and beneficial price formation improvements the Commission could adopt as part of this project to support efficient investment and siting decisions over the long term. As background, the movement of electricity on each transmission element (i.e. transmission lines and transformers) will incur losses such that the amount of electricity injected on one end of the element will always be greater than the amount withdrawn on the other end. The current design of the ERCOT market calculates transmission losses based on a system-wide average and allocates those losses to every load-serving entity (LSE) without incorporating those costs into prices. Therefore, generation resources that increase transmission losses have no economic incentive to behave differently and developers or demand response providers have no economic incentive to site new resources in locations that lower the costs of losses for consumers. In stark contrast, the market design concept of marginal losses directly assigns the cost of transmission losses to each transmission element and therefore accurately expresses the cost of losses in each locational energy price providing more accurate siting and dispatch signals avoiding the highly inefficient average loss allocation mechanism currently in place in ERCOT.

Since every other competitive power market in the United States and Mexico has already implemented marginal losses as part of energy price formation, the literature on marginal losses as an economic principle and best practice in power market design is extensive. In the foundational textbook on competitive wholesale power market design titled "Power System Economics" (2002), Dr. Steven Stoft includes a chapter on "Pricing Losses on Lines" and "Pricing Losses on Nodes." Explaining the theory of marginal losses using long-established competitive principles, Stoft states:

> If transmission were provided by many small competing line owners, each with an unconstrained line, the price of transmission would equal the marginal cost of losses. This price would minimize the total cost of power.[25]

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[25] Steven Stoft, *Power System Economics* (2002) at 417.

> That the competitive price equals marginal cost is neither coincidental nor surprising but is, once again, the standard result of competitive economics. Those who argue against marginal-cost pricing of losses are arguing against competitive pricing. When they argue in favor of average-cost pricing…, they argue in favor of old-fashioned regulatory pricing.[26]

In the section titled "Inefficiency of Average-Cost Loss Pricing," Stoft derives the dispatch and cost of both average-cost loss pricing and marginal-cost loss pricing. The result proves mathematically that "average-cost loss pricing raises the cost of production" compared to marginal-cost loss pricing.[27] To further elaborate on the economic principle of marginal losses, in a FERC technical report on loss estimation titled "Marginal Loss Calculations for the DC Optimal Power Flow" (2017), the authors explain:

> The marginal cost pricing approach is economically efficient in a competitive market because the price signal to each node reflects the increase in system cost required to serve the next unit of demand. Marginal loss prices are a component of marginal pricing and reflect the portion of the change in cost that is due to a change in system line losses.[28]

Dr. David Patton of Potomac Economics submitted testimony to the New York Public Service Commission in 2003 to explain the importance that marginal losses has on investment decisions:

> Removing marginal losses from the locational prices in New York will result in inefficiencies in both the short-run and the long-run as inaccurate price signals lead to inefficient production, consumption, and investment decisions.[29]

Dr. Patton explained further that socializing transmission losses by not including marginal losses in LMPs (like ERCOT does today) would disturb the price signals sent to generators and loads and provide inefficient incentives for remote generation to produce additional output even though it increased system costs. More concerning and impactful considering the future of the ERCOT market, Patton concludes that not including marginal losses "would also reduce incentives to invest in generation in locations close to load and result in higher costs to

[26] *Id* at 421.
[27] *Id* at 423
[28] Brent Eldridge, Richard O'Neill, and Anya Castillo, *Marginal Loss Calculations for the DCOPF,* Federal Energy Regulatory Commission Technical Report on Loss Estimation (January 24, 2017) at 3.
[29] *Motion of the New York Independent System Operator, Inc. and the New York Transmission Owners for Leave to Supplement the Record,* FERC Dockets ER97-1523-068, OA97-470-000, ER97-4234-000, at 14.

consumers in the State."[30] Indeed this is the case in ERCOT. By currently ignoring transmission losses in pricing, ERCOT prices create no economic incentive to site new resources in locations that reduce the cost of transmission losses for consumers.

In comments filed in this project on September 15th, 2017, the Independent Market Monitor (IMM) for the ERCOT region characterized marginal losses as a "best practice" in wholesale market design.[31] And in their most recent annual "State of the Market Report," the IMM included marginal losses as a recommended market design change in the section titled "Improving Price Formation in the ERCOT Market".[32] The IMM explains the justification behind including marginal losses as a recommendation:

> The ERCOT market is unique in its treatment of transmission losses. Marginal losses are not included in ERCOT real-time energy prices and the costs of losses are collected from loads on an average basis. This approach may have been reasonable at the time ERCOT was implementing its initial real-time energy markets because generators were relatively close to load centers. However, as open access transmission expansion policies and other factors have led to a wider dispersion of the generation fleet, the failure to recognize marginal losses in the real-time dispatch and pricing has led to larger dispatch inefficiencies and price distortions. Therefore, we are now recommending that the ERCOT real-time market be upgraded to recognize marginal losses in its dispatch and prices.[33]

The IMM further states that their recommendation to include marginal losses will "produce sizable benefits" by "improving long-term investment and retirement decisions by improving ERCOT's price signals."

On October 12th, 2017, First Solar, Vistra Energy Corp, and The Wind Coalition filed analysis by the Brattle Group (Brattle) titled "Impacts of Marginal Loss Implementation in ERCOT" in this project presumably to make a case why marginal losses should not be implemented in ERCOT.[34] However, one of the sources for their analysis is a report titled "The Importance of Marginal Loss Pricing in an RTO Environment" which states:

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[30] *Id* at 15.
[31] Potomac Economics Comments in 47199 (September 15th, 2017) at 2. http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47199_19_955004.PDF
[32] *ERCOT 2016 State of Market Report*, Potomac Economics (June 2017). https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf.
[33] *Id.* at at xxvii
[34] Metin Clebi, Bruce Tsuchida, Rebecca Carroll, Colin McIntyre, and Ariel Kaluzhny (Brattle), *Impacts of Marginal Loss Implementation in ERCOT, 2018 Reference Scenario Results* (October 11, 2017) filed in Project 47199 on October 12, 2017.

> With the formation of large RTOs and the move toward elimination of pancaked transmission rates, transmission prices need to reflect the increase in transmission losses as power moves across large geographical distances. In order for generators and consumers to receive correct short- and long-term signals with regard to transmission, the loss component should be accurately priced using marginal cost methods.[35]

It should be noted that this Brattle analysis concluded that implementing marginal losses in ERCOT would decrease lost electricity by 1,000,000 KWh per year and save consumers $8.6 million annually.[36] ERCOT has estimated the cost to modify its processes to implement marginal losses in energy pricing to be a one-time cost of $10 million.[37] Therefore, implementing marginal losses in energy pricing would pay for itself in less than two years under worst case assumptions and represent an attractive return on investment that would exceed the vast majority of market rule changes adopted in the ERCOT stakeholder process.

In March of 2017, Brattle published a study to estimate the net benefits that the Canadian Province of Ontario could realize by reforming the wholesale electricity markets operated by the Independent Electricity System Operator (IESO). The study concluded that the IESO market could realize substantial benefits ranging from $2.2 billion to $5.2 billion primarily caused by more efficient dispatch and investment driven by more competitive pricing. Importantly, Brattle assumed that "nodal prices would likely reflect three components: the marginal cost of energy, the marginal cost of congestion on the transmission system, and the marginal cost of transmission losses at any given location."[38] Brattle explains the importance of designing energy prices in this manner:

> By accounting for locational differences in marginal costs, nodal prices more accurately incentivize production (or load reductions) where it is most valuable to the system. This provides improved incentives for both short-term dispatch and long-term investment purposes.[39]

The electric power industry is at a turning point as older coal and gas plants reach the end of their economic life. Over 18,000MW of dispatchable generation capacity in ERCOT will be

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[35] Leslie Liu and Assef Zobian, *The Importance of Marginal Loss Pricing in an RTO Environment*, The Electricity Journal (October 2002) https://www.sciencedirect.com/science/article/pii/S1040619002003706.
[36] Brattle at 3.
[37] ERCOT's Comments in Project 47199 (September 29th, 2017) at 4. http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47199_22_956447.PDF.
[38] The Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project* (March 3rd, 2017), prepared for the IESO, at page 24.
[39] *Id* at 24.

40 years of age or older by the year 2020.[40] The ERCOT market must include marginal losses to send accurate investment siting signals for the next generation of electric production technology such as battery storage, distributed generation, residential solar, and others. PUCT substantive rules section §25.501 requires that the ERCOT wholesale market design *reflect the physical realities of the ERCOT electric system* and determine energy prices using *marginal cost pricing.* Transmission losses are very much a physical reality of the ERCOT electric system and similar to transmission congestion, should be included in locational marginal prices. The continued failure to include marginal losses in energy prices will contribute to a compounding of inefficient decisions over time. For example, ignoring transmission losses in prices could eventually lead to the need for transmission infrastructure in particular areas that might not be needed if ERCOT's pricing included losses and created the incentive to site resources in locations closer to load centers. Incorporating marginal losses into energy prices in ERCOT fulfills the Commission rules, benefits consumers by lowering the costs of production, and provides the correct investment and siting decisions for the next generation of technology in the decades to come.

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?*

No. Wholesale electricity prices do not fully reflect the value of supply during normal or shortage (scarcity) conditions. During times when there is no scarcity present, supply is valued at the marginal cost of providing the last increment of electricity to meet demand. As explained in the Hogan Pope Report and summarized in the response to Question 4, the presence of renewable subsidies (mainly the federal Production Tax Credit for wind generators – "PTC") distort the marginal cost of energy by artificially lowering the cost of supply. The same impact exists during scarcity conditions. The value of supply during scarcity conditions should represent the economic value of avoiding firm load shed. The ORDC attempts to estimate this economic value and incorporate it in the energy price. However, the inputs to the current ORDC are distorted by numerous factors as explained in NRG's response to Question 1. The recommended adjustments to the LOLP input to the ORDC and the removal of RUC and RMR capacity will help ensure scarcity prices are properly valued.

[40] May 2017 ERCOT CDR. http://www.ercot.com/content/wcm/lists/114798/CapacityDemandandReserveReport-May2017.pdf.

The other major impact to electricity prices during shortage conditions is the Four Coincident Peak ("4CP") transmission cost allocation mechanism used in rate design for the transmission utilities in ERCOT.[41] There are numerous market and policy concerns related to 4CP transmission cost allocation and NRG supports the Commission direction to open a separate project to evaluate all aspects of the mechanism. While there are certainly benefits related to 4CP that must be weighed during this evaluation, there is no doubt that 4CP has a major impact on price formation in ERCOT's energy-only market and NRG looks forward to discussing it in a separate project.

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?*

Inaccurate locational pricing during out-of-market actions by the ISO is a clear deficiency in price formation in the current ERCOT market design. The reliability contributions of units subject to ISO-initiated commitments are being undervalued and locational prices do not reflect the reliability actions taken. For example, ERCOT issued 136 RUC commitments in the summer of 2016 and 43 RUC commitments in the summer of 2017.[42] A RUC commitment is when ERCOT directs a generation unit to start when that unit wasn't planning to on its own and is an out-of-market, operator-initiated directive. ERCOT issues RUC dispatch instructions to address perceived reliability needs. The average price of electricity during those RUC hours was $44.40/MWh in 2016 and $37.40/MWh in 2017.[43] These average prices were computed using the Houston hub prices since most of these commitments were during times when the RUC process detected a "reliability problem" in Houston. These prices do not reflect a reliability condition or grid emergency. If there was a true reliability need, high locational scarcity prices would be observed in the areas subject to the RUC commitment. The discrepancy between the need for reliability actions by the ISO and the resulting low prices during those actions demonstrates the clear deficiency in locational price formation. The pricing outcomes during RUC commitments do not properly reflect grid reliability emergencies for the following reasons:

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[41] The Hogan Pope Report at 76.
[42] ERCOT Market Information System, "Hourly RUC Committed or Decommitted Resources" report.
[43] ERCOT Market Information System, "Settlement Point Prices at Resource Nodes, Hubs and Load Zones" report.

- The RUC process is configured to be overly conservative and therefore can commit capacity when it is not truly needed for reliability.
- Price adjustments do occur through the Reliability Deployment Price Adder in an attempt to offset the impacts of some reliability actions including RUC but these price adjustments are calculated and applied system-wide and therefore they do not offset price suppression imposed on locational prices.
- Offers of resources committed by the ISO through the RUC process are required by the ERCOT Protocols to be submitted at or above a $1,500/MWh offer floor to indicate scarcity. However, when RUC is committed for transmission congestion (which is the majority of the RUC instructions), the offers of RUC resources are often mitigated to values well below the $1,500/MWh offer floor due to the local market power mitigation process.[44]

a. RUC process

The first step in addressing pricing issues related to RUC is to ensure that the RUC process is not configured in a way that is overly conservative and results in unnecessary RUC commitments. There are many layers of conservative assumptions included in the design of the RUC process that should be reviewed such as the selection of a load forecast among numerous vendors, assumptions around available quick start capacity, costs of predicted constraint violations, and the objective to procure out-of-market capacity to maintain the full quantity of ancillary services. For comparison, the ORDC does not price system scarcity until the ERCOT grid typically observes relatively low reserve levels (Physical Responsive Capability below 3,000MW). In contrast, the RUC process will detect a system capacity "reliability problem" if the full amount of all ancillary services is compromised and ERCOT typically procures more than 3,500MW of ancillary services during the summer months.[45] While pricing adjustments and settlement rules have been implemented to try to offset the negative impacts of RUC on the market and on resources trying to earn market revenues, one approach is to reduce the need for

[44] ERCOT Protocols Section 3.19, Constraint Competitiveness Tests.

[45] ERCOT Methodologies for Determining Minimum Ancillary Service Requirements for 2018 (draft November 30, 2017). http://www.ercot.com/content/wcm/key_documents_lists/107888/10._ERCOT_Reports.zip.

RUC commitments by reviewing the current conservative assumptions used in the RUC process and ensure RUC is only used for true grid reliability emergencies.

b. Locational reserves

Most of the recommendations in this project that address pricing of out-of-market actions involve determining how to set prices ***after*** a local reliability problem has already occurred. Only one recommendation establishes a market solution to address the local reliability need before there is a problem and that is the concept of locational reserves. The current design of the ORDC does not have a locational component and therefore it is not effective at assisting locational price formation. Locational reserves, however, would provide a market for additional capacity in specific locations in the ERCOT region and send price signals for that capacity if there were deficiencies compared to a pre-determined requirement.

ERCOT explained in their memo filed in this project on September 29th, 2017, that:

> As a key part of ensuring reliable operations in the real-time market, ERCOT procures various ancillary service products based on an Ancillary Service Plan ("ASP") that is developed based on system studies and in consideration of applicable reliability requirements.
>
> * * *
>
> The ASP has always produced system-wide requirements for the ERCOT ancillary service products. [46]

Therefore, ERCOT's conclusion that their system studies associated with the ASP "have not identified a reliability need that has resulted in a requirement for a minimum quantity of any of the ancillary service products in a particular location within the ERCOT system" is logical because ERCOT's ASP studies do not include locational criteria or look for locational reliability needs. As mentioned by the IMM in their comments filed in this project on September 15th, 2017:

> It is common in other markets to plan and operate the system to be able to maintain reliability in a local area even after the two largest contingencies occur (transmission or generation outages). This is one of the most common reasons that a unit may be deemed needed for reliability and given an RMR contract, but such an action should be seen as a failure of the wholesale market to provide sufficient revenues to support the continued operation of the resource. [47]

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[46] ERCOT's Comments in Project 47199 (September 29th, 2017) at 2.
[47] Potomac Economics Comments in 47199 (September 15th, 2017) at 8.

NRG agrees with this assessment and recommends that the Commission direct ERCOT to incorporate locational criteria into their ASP studies. The IMM suggested a method for doing so in their comments.[48] Rather than repeat the details of those comments, NRG highlights this recommendation as an approach for consideration and supports that direction. Including locational criteria in ERCOT's ASP will allow ERCOT and market participants to monitor any potential needs for locational reserves. NRG supports the implementation of real-time co-optimization due to the improvement it provides to price formation. However, locational reserves should be part of an implementation of real-time co-optimization to directly address many of the deficiencies observed with locational price formation in the ERCOT market and reduce the need for RUC and RMR.

c. Pricing out-of-market actions by the ISO

Many recommendations have been made in this project regarding how to improve the pricing of ISO out-of-market actions mostly related to pricing during RUC commitments. The recommendations can generally be organized into three groups:

- Increase the mitigated offer caps for RUC (and RMR) resources to be more reflective of the reliability action;
- Adjust prices to reflect the reliability contribution or economic value of the commitment relative to unloading the constraint; and
- Set prices based on the full cost of commitment and dispatch of either the RUC unit or quick start resources (i.e., Extended Locational Marginal Pricing - "ELMP" – which allows these units to set price when they wouldn't under the current pricing regime).[49,50]

NRG is supportive of any approach that improves locational price formation when out-of-market action is taken and believes that all options are viable. The Hogan Pope Report attempted to balance simplicity with effectiveness. In that regard, establishing a mechanism to modestly increase the mitigated offer caps for RUC resources would be the simplest and lowest

[48] Potomac Economics Comments in 47199 (September 15th, 2017) at 8-10.
[49] Potomac Economics Comments in 47199 (September 15th, 2017) at 6.
[50] Shell Energy North America Comments in 47199 (September 29th, 2017) at 2. http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47199_26_956507.PDF.

cost approach by far. Mitigated offer caps for RMR resources should be set higher than RUC resources due to the severity of the reliability need. An ex-post price adjustment or a more sophisticated approach to allow price setting based on an ELMP style mechanism would also be effective at addressing the current locational price formation deficiency if designed properly. Given the additional complexity involved with an ELMP style mechanism, NRG suggests that the Commission direct the ERCOT stakeholder process to explore this alternative in more detail if that is the preferred approach.

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?*

Yes. The Hogan Pope Report provides an in-depth explanation of how renewable subsidies, in particular the Production Tax Credit (PTC), result in out-of-market payments that interfere with energy price formation.[51] The vast majority of wind capacity built in ERCOT (total of 19,947MW as of October 31, 2017[52]) has done so primarily due to the additional revenue stream provided by the PTC. The Hogan Pope Report explains why the PTC is such a powerful financial incentive and disruptive force in energy price formation:

> When a PTC is paid, the payment is triggered by actual production, in effect changing the marginal cost intended to incent suppliers to produce electricity. The current PTC for qualifying renewable systems is $23 per MWh, meaning that a qualifying supplier would want to produce as much as possible whenever the locational price at its location was greater than -$23 per MWh, because at any price just above -$23 per MWh, its total payment, including the PTC, would be positive.[53] In effect, from the perspective of the generator, the marginal cost for wind has been reduced from approximately zero to -$23 per MWh.[54]

Subsidies exist for nearly all types of generation resources including the Investment Tax Credit, severance and property tax breaks, turbine vendor cost sharing, and environmental offset credits. However, these other subsidies pale in comparison and magnitude to the PTC regarding impact to energy prices and the ERCOT market. In an energy-only market design that relies primarily

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[51] The Hogan Pope Report at 21-31.
[52] ERCOT Generation Interconnection Report, October 2017. http://www.ercot.com/content/wcm/lists/114799/GIS_REPORT__October_2017.xlsx.
[53] Energy.gov. "Renewable Electricity Production Tax Credit (PTC)." https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.
[54] Hogan Pope Report at 24.

on energy price signals, the presence of this type of subsidy is devastating to the integrity of energy price formation that dispatchable resources rely on so heavily.

It is tempting to attempt to offset with impact of the PTC with price adjustment mechanisms such as instituting an energy price floor of $0/MWh. However, such blunt mechanisms often equate to another subsidy that likely distort energy prices in different ways and lead to other inefficient behavior. Eliminating or altering the PTC is beyond the purview of the Commission. Within the scope of this project is price formation, and NRG urges the Commission to adjust the LOLP component of the ORDC to properly reflect the impact of renewable variability on scarcity price formation. In addition, the Commission should recognize that the presence of the PTC and the amount of renewable capacity that this policy has attracted may contribute to a resource adequacy issue in the future due to the uneconomic displacement of dispatchable generation resources.

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

No. The recent announcement of capacity retirements has been anticipated for years and is based on rational economic evaluation of the costs to operate those resources compared to expected revenues. All owners of generation resources conduct the same analysis and will continue to do so. Importantly, the retirement of generation capacity does not address any of the price formation issues examined by the Hogan Pope Report or discussed in this project. On the contrary, the exit of uneconomic capacity increases the chances of scarcity prices and makes the proposed reforms even more important, by providing the incentive for existing resources to ensure they are available and encouraging new resources that can come to market quickly such as demand response to do so. When system-wide and locational energy price signals are distorted and chronically suppressed, existing resources won't respond when they should, new resources will be discouraged from entering the market, and premature retirement of capacity will occur in the wrong locations in the ERCOT system compounding the issues. This will lead to inefficient costs borne by consumers such as RMR service and investment in unnecessary transmission infrastructure. As stated in the Nodal Order discussed above, the benefits of implementing a Locational Marginal Pricing market design include "*more efficient and transparent dispatch of resources in real-time*" and "*a reduction in the amount of new* *transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market."* This will only occur if prices are allowed to form properly. The Commission should not delay in adopting improvements to price formation in this project.

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

Similar to transmission congestion, the implementation of marginal losses will result in the accrual of surplus revenue by ERCOT. Because consumers pay for the costs of building and maintaining the transmission system, it was decided that transmission congestion revenue (i.e., congestion rent) should be distributed to consumers. The same should be done in the case of marginal losses surplus. Allocating surplus marginal loss revenues to consumers will help offset the significant transmission cost burden in utility rates. PJM allocates marginal loss surplus to consumers based on a simple system-wide load ratio share.[55] In ERCOT, transmission congestion revenue (through Congestion Revenue Rights – "CRR" – auction revenue) is distributed to consumers based on a mechanism that separates inter-zonal and intra-zonal congestion.[56] Inter-zonal congestion revenue is allocated based on system-wide load-ratio share. Intra-zonal congestion revenue is allocated to consumers only in that particular zone based on intra-zonal load-ratio share. NRG is generally neutral regarding whether the Commission adopts a system-wide or zonal based approach to distribute marginal loss surplus revenues. As a matter of fairness, a zonal based approach will distribute a proportionally larger amount of loss revenue to consumers that pay more for losses. However, a system-wide distribution would be a simpler approach and would still result in meaningful cost savings that will benefit consumers.

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.*

While not related to price formation, NRG notes other proposals filed in this project that the Commission should direct ERCOT and stakeholders to pursue. The first was raised in the

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[55] *PJM Quarterly State of the Market Report for 2017,* Potomac Economics (January 2017) at 489. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017.shtml.
[56] ERCOT Protocols Section 7.

comments of Texas Industrial Energy Customers ("TIEC") who suggested that intermittent generation bear a portion of the costs they impose on the ERCOT system, such as ancillary services.[57] ERCOT has continued to modify their ancillary services procurement methodology to be more dependent on installed wind capacity and the influence of wind generation on the fluctuations in net load.[58] NRG supports discussion of this proposal in the ERCOT stakeholder process.

In addition, both Vistra and TIEC suggest evaluation of a policy to allocate interconnection costs to generators. Due to the escalation of transmission costs for consumers, any policy change that helps relieve this burden would be beneficial. Thus, NRG supports discussion of this topic in a separate project.

IV. Proposed Work Plan for the Commission's Consideration

NRG proposes the following work plan for the Commission to consider when addressing the issues and recommendations in this project.

1. Direct ERCOT to improve price formation during scarcity events by filing an NPRR to shift the LOLP by one standard deviation and remove RUC and RMR capacity from online reserves in the ORDC calculation with a firm target for implementation by June of 2018.
2. Direct ERCOT to review and report back on the conservative assumptions used in the RUC process, provide recommendations on options to adjust those assumptions to minimize the use of RUC, and collaborate with stakeholders to propose modifications by NPRR; set a goal to implement changes by June of 2018.
3. Direct ERCOT to improve locational price formation by working with stakeholders to develop out-of-market pricing solutions based on higher mitigated offer caps for RUC and RMR resources, pricing adjustments, or full cost of dispatch price setting mechanisms and collaborate with stakeholders to propose modifications by NPRR. Implementation costs can be compared between the various approaches to determine a cost-effective solution.

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[57] TIEC Comments (September 29th, 2017) at 5.

[58] ERCOT Methodologies for Determining Minimum Ancillary Service Requirements for 2018 (draft November 30, 2017). http://www.ercot.com/content/wcm/key_documents_lists/107888/10._ERCOT_Reports.zip.

4. Review the benefit study for marginal losses and consider the additional benefits that implementation of marginal losses will have on future investment and siting decisions. Direct ERCOT to collaborate with stakeholders to draft the necessary implementation details through an NPRR. Since ERCOT estimates that marginal losses will take two years to implement, there should be sufficient notice to market participants if adopted. However, to be sure, set a goal to implement on a specific date such as 1/1/2020 to provide market participants certainty.
5. Direct ERCOT to incorporate locational criteria in their ancillary services procurement studies to detect a future need and collaborate with stakeholders to propose ASP study modifications by NPRR or Other Binding Document; set a firm target to implement the criteria when evaluating 2019 ancillary service needs.
6. Review the benefit study for real-time co-optimization. Direct ERCOT to collaborate with stakeholders to draft the necessary implementation details through an NPRR that includes the software necessary to enable locational reserves if a future need is determined. Since ERCOT estimates that real-time co-optimization will take five years to implement, there would be sufficient notice to market participants if adopted.

IV. Conclusion

NRG appreciates the opportunity to provide these comments and the consideration of the Commission on these important market design improvements. The Commission's leadership and clear direction is needed to set forth a path forward for market design enhancements to strengthen the performance of the ERCOT market through improved price formation – the foundation of the ERCOT energy-only market design. Recent retirements of generation resources bolster the need for 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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