PROJECT NO. 47199

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

PUBLIC UTILITY COMMISSION FILING CLERK

VISTRA ENERGY'S COMMENTS AND ALTERNATIVE PROPOSALS

Vistra Energy submits the following responses to the request for additional analysis and alternative proposals issued by the Public Utility Commission of Texas (Commission).[1]

I. INTRODUCTION

Vistra Energy appreciates the opportunity to respond to the Staff's questions regarding the NRG/Calpine-commissioned whitepaper by Drs. Hogan and Pope (NRG/Calpine Whitepaper). The ERCOT market is functioning reasonably well, and there is no need to implement significant market design changes such as marginal loss pricing, a locational reserve requirement, or a local Operating Reserve Demand Curve (ORDC). A large part of the success of ERCOT's energy only market design comes from the fact that investors and market participants expect and benefit from a consistent and steady regulatory environment. Many of the reforms proposed in the NRG/Calpine Whitepaper would alter that dyamic and are significantly detrimental to generators and other market participants throughout the state. Many customers would see price increases, without any demonstrable benefits, and other parts of the state could see a loss of jobs and reduced tax revenue due to potential premature retirements of generation units that would stand to lose significant net revenues from the marginal loss proposal in particular. Vistra Energy does, however, support thoughtful refinements to the current market design to support accurate system-wide price formation during both normal and scarcity conditions and to ensure that compensation to other resources is not unfairly impacted by the dispatch of zero and negative offers by subsidized renewable resources. With these overarching considerations in mind, Vistra Energy responds to each of the Commission's questions in detail below.

[1] Project No. 47199, Public Utility Commisson of Texas Request for Comment (Oct. 27, 2017).

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II. QUESTIONS

Question 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?

Sweeping market design reforms that are intended to divide ERCOT into higher priced load pockets—such as the marginal loss proposal and locational market design reforms proposed in the NRG/Calpine Whitepaper—are neither needed nor beneficial to support efficient investment and retirement decisions in ERCOT. It is important, however, to ensure that the market is designed to deliver prices that accurately reflect system conditions, both to attract new resources to ERCOT when needed, and to allow existing resource owners to make efficient investment and retirement decisions. The current market design does not adequately correct for the price distortion caused by federal subsidies for renewable generation in the ERCOT market. To that end, Vistra Energy has proposed two alternative reforms, both of which were presented in comments filed on September 29, 2017 and are re-urged here—(1) a pricing mechanism to address the current failure of Locational Marginal Prices (LMPs) to recognize the costs of traditional dispatchable resources when renewable resources are the marginal unit; and (2) a requirement for new generation to self-fund some or all of the cost of interconnecting to the transmission grid. The second proposal relates to a topic that the Commission has indicated will be taken up in a separate project,[2] and therefore, these comments do not elaborate on that proposal.

The first proposal (i.e., the pricing mechanism) is intended to address the occurrence of negative and depressed prices when renewable resources are the marginal unit, even though traditional resources are needed at the same time to serve load. This occurs because thermal units by design must operate at minimum levels and therefore cannot be dispatched below their low sustained limit (LSL). The amount of energy produced at the LSL of those units, because they cannot be dispatched lower, is considered "price-taking" and does not contribute to price formation. Therefore, in instances where online thermal units are all operating at their LSL, the LMPs are set by the offer of a renewable resource. Renewable resources' offers are often negatively priced, because renewable resource owners are able to reflect the value of federal subsidies as "negative costs," and as a result, the LMPs set by the renewable resource

[2] *See* Project No. 47199, Commission Staff Request for Comment (Oct. 27, 2017) ("As discussed at the October 26, 2017 open meeting, transmission cost allocation and rate design, the assignment of interconnection costs, and the 'loads in SCED' proposal should not be referenced in comments. These issues will be considered in separate projects.")

offers are lower than the costs of the thermal units that are operating at their minimum output levels as price-takers.

The goal of marginal pricing is for the LMPs to reflect the cost to serve <u>the next</u> MW of load,[3] which, theoretically, should be higher than the cost to serve the last MW of load (i.e., because offer curves increase monotonically for price and quantity[4]). But because ERCOT's Security-Constrained Economic Disptach (SCED) ignores the cost of the energy between zero and LSL, those megawatts are not contributing to price formation even when the thermal units are needed to serve load and have a higher cost than the unit that SCED is treating as marginal. In other words, even though the megawatts up to a thermal unit's LSL may be more expensive than the marginal resource, the marginal resource is the one that sets the LMPs. When that marginal resource's offer is lower than the cost of the energy between zero and LSL for online thermal resources, the resulting LMPs do not reflect the true cost of serving load. This gap becomes meaningful and distortive when the marginal resource is a renewable resource offering at $0 or negative prices, particularly when those prices are supported by federal subsidies exogenous to the wholesale market. As noted in earlier comments and illustrated below under Question 4, ERCOT is experiencing greater numbers of intervals with $0 and negative prices, and those prices are not the result of market fundamentals.[5]

To address this issue, Vistra Energy recommends a price adder on the real-time price during intervals where dispatchable thermal resources are needed to serve load, but are not price-setting. The proposed adder would be calculated based on the highest cost traditional resource whose minimum output is needed to serve load in any affected interval. Creating a price adder would allow the LMPs to reflect those costs to serve load that today are masked by the SCED optimization that treats all LSL energy as price taking. Such an adder should be paid only to those thermal resources whose LSL is needed to serve load, both to minimize the cost of the adder to loads and to avoid creating an incentive for unnecessary flexible thermal generation to stay online when it is not cost effective. The adder should

[3] *See* ERCOT Protocols § 2 (defining "Locational Marginal Price" as "[t]he offer and/or bid-based marginal cost of serving the next increment of Load at an Electrical Bus, which marginal cost is produced by the [Day-Ahead Market (DAM)] process or by the SCED process").

[4] *See* ERCOT Protocols § 4.4.9.3.1(1)(c) (requiring a monotonically increasing offer curve for both price (in $/MWh) and quantity (in MW)).

[5] In 2016, the Houston, South, and North Hubs each experienced almost 600 settlement intervals of negative prices while the West Hub had almost 1,200 settlement intervals of negative prices during that same time, an enormous increase compared to 2015. *See* NRG/Calpine Whitepaper at 31 (Bates); *see also* ERCOT Historical RTM Load Zone and Hub Prices, *available at*: <u>http://www.ercot.com/mktinfo/prices</u>.

not be paid to renewable resources because they are already compensated in the form of their federal subsidies, and paying the adder would exacerbate, rather than address and resolve, the price distortions caused by their negative offers.[6]

As noted by an NRG representative at the October 13, 2017 workshop,[7] this proposal is conceptually similar to a proposal currently under consideration in PJM,[8] in the sense that both proposals are aimed at addressing a failure of the market design to appropriately value the energy up to the LSL of thermal units. However, Vistra Energy's proposal is tailored specifically for the ERCOT market, in that it would take the form of a price adder, paid to the specific thermal resources whose LSL is needed to serve load, rather than a modification to SCED to allow such resources to actually set the LMP.

Question 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?

As discussed above, while extensive reforms are not needed in the ERCOT market, wholesale electricity prices in ERCOT do not fully reflect the value of supply during normal (i.e., non-scarcity) conditions, based on the failure of SCED to recognize the value of the energy up to the LSLs of thermal units. For these reasons and those discussed above, the Commission should direct ERCOT to adopt Vistra Energy's proposed price adder to value the energy up to the LSLs of thermal resources needed to serve load.

With respect to shortage conditions, some improvements could be made to the system-wide ORDC, for example, to address the current dampening effect of including Reliability Unit Commitment (RUC) capacity in the calculation of available reserves.[9] When the Commission was evaluating the initial version of the ORDC in Project No. 40000, Vistra Energy's subsidiary filed comments

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6 For an example calculation showing Vistra Energy's proposed adder, see Vistra Energy's September 29, 2017 comments.

7 *See, e.g.*, Tr. at 146 (comments by Bill Barnes) (Oct. 13, 2017).

8 *See* PJM, Energy Price Formation and Valuing Flexibility (Jun. 15, 2017) (explaining the pricing reform proposal related to LSL), *available at*: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

9 Project No. 47199, NRG/Calpine Whitepaper at 60 (Bates) (May 22, 2017); *see also* ERCOT Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder, Version 1.4 (Jun. 28, 2017) (including RUC in the reserve calculation), *available at*: http://www.ercot.com/mktrules/obd/obdlist.

recommending that the Commission address potential price depressing effects that could be caused by including RUC capacity in the calculation of available reserves for purposes of the ORDC.[10] Those modifications are still warranted.

The ORDC is intended to properly value reserves and energy during scarcity conditions. In an energy-only market, which is significantly dependent upon scarcity prices to provide demand response and investment signals, out-of-market services should not interfere with the scarcity pricing mechanism. As noted in the NRG/Calpine Whitepaper:

> The ORDC provides a principled basis for pricing region-wide scarcity, but when a RUC occurs . . . , the measurement of the Real-Time On-Line Reserve Capacity used to calculate the ORDC scarcity price is distorted by the inclusion of the RUC capacity. The ORDC price adder should rise when there is increased scarcity, but if a RUC reduces this scarcity by increasing the quantity of available reserves as measured by Real-Time On-Line Reserve Capacity, the ORDC price adder will fall (or stay the same), rather than rise. ERCOT supply will increase by the amount of the minimum load of the RUC . . . committed unit. . . . When ERCOT initiates a RUC prior to the development of scarcity, it thus may forestall the development of a price signal to induce market-based solutions to such scarcity.[11]

To avoid this detrimental impact, RUC units' high sustained limits (HSLs) should be excluded from the calculation of reserves for the ORDC.

In addition, other improvements to the system-wide ORDC may be warranted, such as modifying the value of "X" (i.e., the minimum contingency level), the Value of Lost Load (VOLL), and/or the slope of the ORDC. In 2016, Vistra Energy's subsidiary participated with a coalition of stakeholders to develop proposed revisions to the ORDC parameters (summarized in comments filed in Project No.

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[10] *Commission Proceeding to Ensure Resource Adequacy in Texas*, Project No. 40000, Luminant's Response to Request for Comments Regarding Adjustments to the Value of Lost Load (Nov. 4, 2013).

[11] Project No. 47199, NRG/Calpine Whitepaper at 60–61 (Bates) (May 22, 2017).

45572[12]). Those proposals bear further consideration, as do other suggested improvements to the system-wide ORDC, such as those proposed by Dynegy Inc. in the current project.[13]

With that said, there is no need to address any local shortages by adopting the proposals in the NRG/Calpine Whitepaper (such as a local reserve requirement or a local ORDC). Local shortages are an entirely different issue than system-wide scarcity and tend to be caused by conditions that are transient in nature, such as transmission or generation outages. Notably, ERCOT recently commented in this project that it has not identified a reliability need for a local reserve requirement.[14] In so doing, ERCOT acknowledged that while other markets (such as the New York Independent System Operator and ISO New England Inc.) have such requirements, there are key differences between ERCOT and those markets—for example, the construction of new transmission infrastructure is much more limited, and congestion into large load centers is much more chronic as compared to ERCOT.[15]

Rather than create a local reserve requirement or local ORDC, a better solution to address high congestion costs and provide customers in existing load pockets with access to cheaper generation across the system would be to build new transmission when the costs of a project will be more than offset by the reduction in congestion costs for consumers.[16] In fact, the Houston Import Project, slated to come online by summer of 2018, is anticipated by ERCOT to largely relieve the existing constraints into the Houston area, which should alleviate much of the "localized scarcity" in that area. As explained by ERCOT in its most recent *Report on Existing and Potential Electric System Constraints and Needs*:

> The long-term solution for relieving the constraints for the [Houston] area is the Houston Import Project, which includes the construction of a new 345 kV import path from the

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[12] *See Review of the Parameters of the Operating Reserve Demand Curve*, Project No. 45572, Luminant's Comments Regarding Changes to the ORDC (Mar. 11, 2016) (recommending that: (1) ERCOT purchase at least 2,750 MW of Responsive Reserve Service (RRS) in each hour to cover the near-simultaneous loss of the two largest resources in ERCOT; (2) the value of "X" for the ORDC be set equal to the sum of RRS and Up Regulation Service; (3) the VOLL be increased to $18,000 (with an effective cap of $9,000) in order to produce a smoother curve for the ORDC; and (4) the ORDC be added to the ERCOT Day Ahead Market to function as a reserve demand curve to promote convergence with the Real-Time Market ORDC).

[13] Project No. 47199, Comments of Dynegy, Inc. (Sept. 29, 2017) (suggesting adding standard deviations to the ORDC to shift the slope of the curve to make it a more gradual change between reserve levels).

[14] Project No. 47199, Electric Reliability Council of Texas, Inc.'s Second Report in Response to Commission Staff's Request (Sept. 29, 2017).

[15] *Id.* at 2.

[16] Project No. 47199, Texas Industrial Energy Consumers Comments (Sept. 29, 2017); Tr. at 150–51 (Oct. 13, 2017) (comments by Katie Coleman for TIEC).

> north. This project was endorsed by the ERCOT Board of Directors in 2014 and is expected to be inservice by the summer of 2018.[17]

In sum, there are improvements that could be made to address system-wide price formation during both normal and scarcity conditions, but there is no need for a local reserve requirement or local ORDC to address localized "scarcity" or pricing issues.

Question 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?

Reliability contributions of units subject to operator-initiated commitment are undervalued, but not due to over-mitigation. As discussed below, Vistra Energy supports the current constraint competitiveness test (CCT) that operates to mitigate certain offers in the event ERCOT identifies a constraint as non-competitive, because the CCT is an important protection for load and offers should be mitigated in those instances. However, when RUC units are dispatched at their LSL, they can be undervalued due to the failure of the SCED engine to value the energy from 0 MW to LSL. To address this issue, the Enhanced or Extended LMP (ELMP)[18] model proposed by the Independent Market Monitor (IMM) bears further consideration to promote more efficient pricing for units subject to operator-initiated commitment.

Specifically, under the ELMP model (a version of which has been adopted by the Midwest Independent System Operator (MISO)), there would be a separate pricing run from the SCED run that determines dispatch in which, for purposes of setting price, the offers for offline units would be considered from 0 MW to HSL, rather than only from LSL to HSL. As explained by the IMM:

> The pricing dispatch relaxes the minimum dispatch level for the peaking resources, allowing them to be dispatched at any level between zero and the high operating limit for the resource. If they are dispatched to zero, they will not set prices (nor will they distort prices because they will not be producing output in the pricing dispatch). However, if

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[17] ERCOT, Report on Existing Potential Electric System Constraints and Needs at ii (Dec. 2016).

[18] The IMM's comments use the term "Enhanced LMP," but the IMM cites the model used by the Midwest Independent System Operator, which is called "Extended LMP."

they are economic, including their startup and no-load costs, they will be dispatched at a non-zero output level and will contribute to setting prices.[19]

The ELMP model effectively would "recognize[] the full cost of a unit that is committed or RUC'd to solve a problem and allow[] the market, or at least the pricing algorithm, to recognize the full cost of that unit."[20] It is important to note that this proposal could have additional benefits, beyond more efficiently pricing RUC units. A well-designed ELMP model could price other offline units more effectively as well, such as quick start generation units, and could have other benefits, such as those outlined by MISO, including minimizing uplift charges and eliminating spikes in LMPs.[21] Importantly, Vistra Energy does not agree with the IMM that the ELMP should be adopted as an alternative to removing RUC capacity from the available reserves calculation for the ORDC; the latter should be done regardless of whether the ELMP proposal is implemented for the reasons outlined above in response to Question 2.

While a more efficient pricing model like ELMP for RUC and possibly other units bears consideration, RUC units in constrained areas are not being over-mitigated due to the operation of the CCT, and there should not be a penalty price applied to RUC units that are dispatched for local congestion.[22] The purpose of the CCT is to identify whether a constraint is competitive "by evaluating each Market Participant's ability to exercise market power by physical or economic withholding"[23] and, if the constraint is not competitive, to mitigate the offers of the relevant resources. More specifically, the CCT "evaluates whether there is sufficient competition to resolve the constraint on the import side by calculating the Element Competitiveness Index (ECI) on the import side of the constraint and by determining whether a single Entity is needed to resolve the constraint."[24] In the event ERCOT determines a constraint is non-competitive, generators that are either identified as a "pivotal player" for the constraint or have a certain ECI Effective Capacity score are subject to price mitigation in step 2 of

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19 Project No. 47199, Comments of Potomac Economics at 7 (Sept. 15, 2017).

20 *Id.* at 6.

21 *See* MISO, Extended Locational Marginal Pricing (Jun. 2010), *available at*: https://www.ferc.gov/CalendarFiles/20100530130229-Gribik,%20Zhang,%20Midwest%20ISO%20-%20Extended%20LMP.pdf.

22 *See* NRG/Calpine Whitepaper at 57–59, 67–68 (Bates) (May 22, 2017) (arguing that RUC units dispatched for local congestion are being over mitigated and that the mitigated offer cap for RUC'd units should be increased).

23 ERCOT Protocols § 3.19.1(1).

24 *Id.*

the SCED run.[25] That result is appropriate to ensure that prices are not inflated due to the exercise of local market power and is an important protection for customers. Moreover, the CCT was thoroughly debated and ultimately recommended for approval without opposition by the ERCOT Technical Advisory Committee and adopted unanimously by the ERCOT Board.[26]

The dispatch of RUC for system-wide capacity shortages is different—and should be priced differently—than the dispatch of RUC for local congestion in circumstances where the RUC committed unit is a pivotal supplier behind a non-competitive constraint. While it is important to ensure that the price fully captures the reliability value of the unit, RUC pricing rules should not override the structural protections of the CCT in the instance where a unit with market power is RUC committed to address local transmission reliability issues.

Question 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?

Federal subsidies for renewable generation are interfering with competitive outcomes in ERCOT's wholesale electricity market. Since the implementation of the nodal market in 2011, ~21,000 MW of new generation has come online including ~11,000 MW of renewable resources, of which ~10,000 MW is wind. In the ERCOT IMM's 2016 State of the Market Report, the IMM estimates that the "cost of new entry," which represents the revenues needed to break even on the construction of a new natural gas combustion turbine in ERCOT, range from \$80 to \$95 per kW-year.[27] The IMM points out that the *actual* net revenue for a new gas turbine in ERCOT in 2016 "was calculated to be approximately \$20 to \$33 per kW-year."[28] In fact, the IMM has determined in every year since 2012 that

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25 *Id.* § 3.19.4(7).

26 NPRR520, "Real-Time Mitigatino Rules and Creation of a Real-Time Constraint Competitiveness Test," ERCOT Board Minutes, March 19, 2013 http://www.ercot.com/content/meetings/board/keydocs/2013/0319/March_19,_2013_Board_General_Session_Meeting_Minutes.pdf. ERCOT TAC Recommendation, http://www.ercot.com/content/mktrules/issues/nprr/501-525/520/keydocs/520NPRR-07_TAC_Report_030713.doc.

27 Potomac Economics, 2016 State of the Market Report for the ERCOT Electricity Markets at 100 (May, 2017), *available at*: http://www.puc.texas.gov/industry/electric/reports/ERCOT_annual_reports/2016annualreport.pdf.

28 *Id.*

net revenues were insufficient to justify new natural gas build.[29] The investor community has also expressed concern with the deep financial challenges of the ERCOT market caused by low natural gas prices and an abundance of renewable resources. Investors have noted that the addition of more than 10 GW of renewable resources in ERCOT (primarily wind) over the past five years has had "severe consequences for its competitors in the fossil fuel space."[30] S&P Global estimates that more than 11.5 GW of ERCOT capacity (both coal and natural gas) is at risk for retirement due in part to "mild summer weather" and "surges in renewable energy generation," which has resulted in negative earnings forecasts for multiple power plants in ERCOT.[31]

The impact of subsidized renewable resources is aptly illustrated in the graphs below, which show a sharp increase in the occurrence of zero and negative pricing intervals over the past few years. Up until 2013, negative pricing predominantly occurred in the West zone, where the bulk of wind resources were located and effectively trapped due to insufficient transmission capacity. Once construction of the competitive renewable energy zone (CREZ) transmission was completed in 2013, the renewable resources in West Texas were able to reach the rest of the state, and the impact on pricing is clear. Between 2013 and 2016, the number of 15-minute pricing intervals with $0 or negative pricing increased from the twenties and thirties to nearly 700 in the Houston, North, and South zones and increased from approximately 750 to over 1,300 in the West zone.

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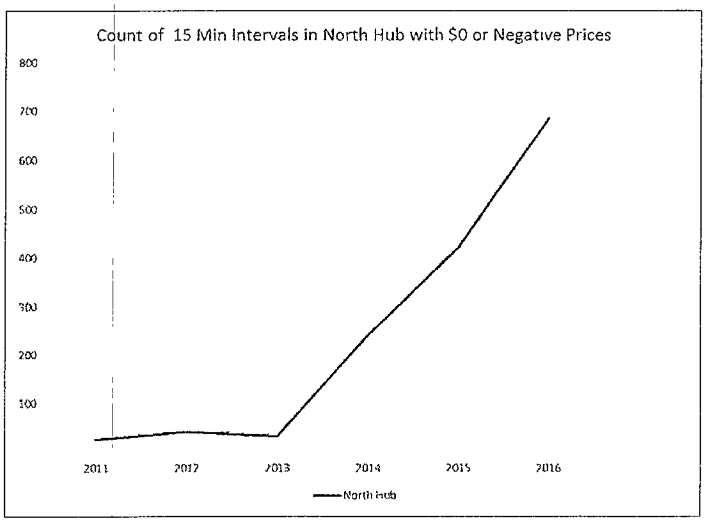
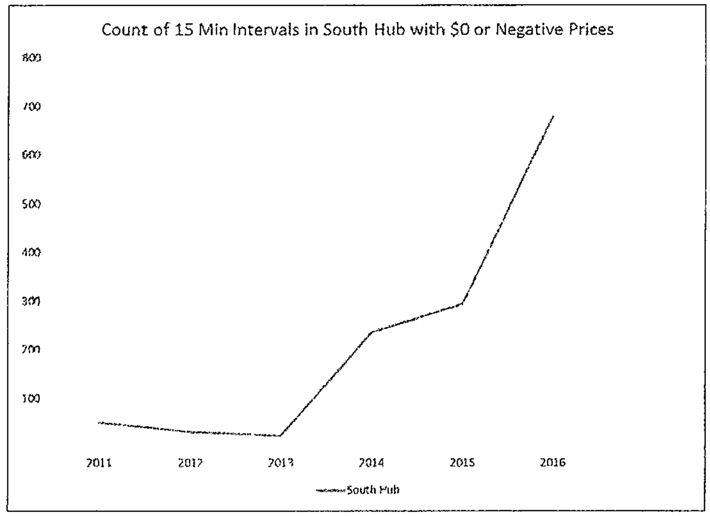
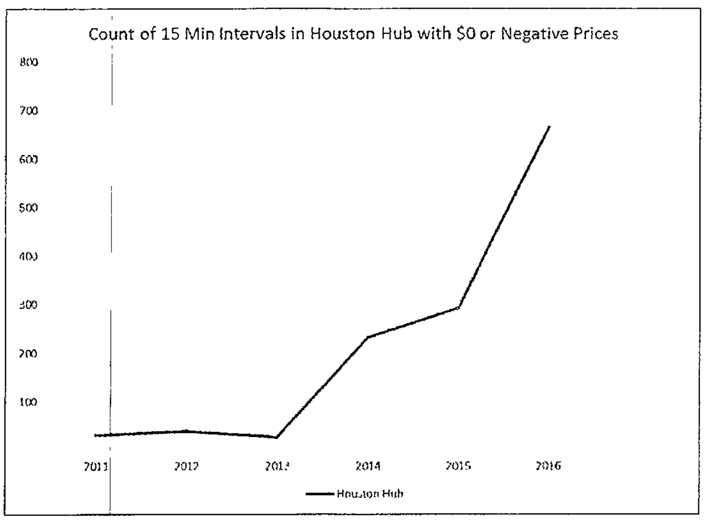
[29] *Compare* Potomac Economics, 2011 State of the Market Report for the ERCOT Wholesale Electricity Markets at ii (Jul. 2012), *with* Potomac Economics, 2012 State of the Market Report for the ERCOT Wholesale Electricity Markets at ii (Jun. 2013); Potomac Economics, 2013 State of the Market Report for the ERCOT Wholesale Electricity Markets at ii (Sept. 2014); Potomac Economics, 2014 State of the Market Report for the ERCOT Wholesale Electricity Markets at ii (Jul. 2015); Potomac Economics, 2015 State of the Market Report for the ERCOT Wholesale Electricity Markets at i (Jun. 2016); Potomac Economics, 2016 State of the Market Report for the ERCOT Electricity Markets at i (May 2017). All State of the Market Reports are available here: http://www.puc.texas.gov/industry/electric/reports/ERCOT_annual_reports/Default.aspx.

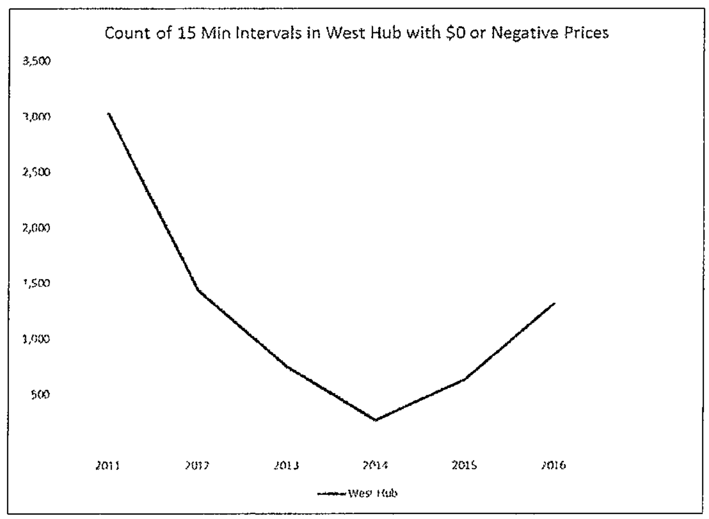
[30] S&P Global Ratings, Low-Voltage Prices Are Dimming The Future At ERCOT (Mar. 13, 2017).

[31] S&P Global Market Intelligence, More than 11.5 GW of ERCOT capacity at risk for retirement (Mar. 23, 2017).









To be clear, Vistra Energy is not taking a position on the policy decisions made by lawmakers to provide subsidies for renewable resources and is not suggesting that such resources do not provide benefits to the state. Rather, Vistra Energy is simply noting the fact that such resources, due to their low operational costs and their access to subsidies, have had a distorting effect on power prices in the state, as evidenced by the sharp increase in $0 and negative pricing since their proliferation. With that said, a straightforward and simple way to correct for some of this impact would be to implement a price adder like the one described in response to Question 1.

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

If the Commission is motivated to address the detrimental impacts of subsidized renewable resources on system-wide price formation, the Commission should not delay until the summer of 2018 or longer based on recent retirement announcements. The LSL issue discussed in response to Question 1 is a flaw in the pricing mechanism that should be fixed, regardless of whether the upcoming retirements have any impact on "market dynamics." If the market design is flawed, those flaws will not correct themselves just because uneconomic generation exits the market.

In contrast, the high costs of congestion in the Houston area *will be* resolved largely by the Houston Import Project, which will commence operation in summer 2018. As noted above, ERCOT has expressed its view that this project is the long-term solution to high congestion costs in the Houston area. Likewise, ERCOT has approved transmission projects to address other locally constrained areas in ERCOT, such as the Lower Rio Grande Valley.[32] Therefore, it absolutely would be prudent for the Commission to hold off on considering any significant locational market design changes (such as implementing a local reserve requirement or local ORDC) until there is evidence that ERCOT's transmission planning process is not sufficiently addressing these issues.

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

As discussed further in response to Question 7, Vistra Energy strongly opposes implementation of marginal loss pricing and therefore does not have a proposal regarding the appropriate allocation of excess revenue collected under marginal loss pricing. However, the likely contentious nature of this issue is one more reason (in addition to those detailed below) that the Commission should not pursue marginal loss pricing.

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[32] *See* General Session Minutes of the Board of Directors Meeting of the Electric Reliability Council of Texas, Inc. at 6 (Jun. 14, 2016) (noting that the Board approved the Valley Import project), *available at*: http://www.ercot.com/content/wcm/key_documents_lists/76336/June_14__2016_Board_General_Session_Meeting_Minutes.pdf.

Determining the appropriate allocation of excess revenues would be a necessary decision before marginal loss pricing could be implemented in ERCOT, and it would almost certainly be a controversial determination that could delay implementation of marginal loss pricing beyond the two to three year timeline estimated by ERCOT.[33] The Federal Energy Regulatory Commission (FERC) has yet to endorse a specific methodology for allocating marginal loss excess revenues,[34] and FERC precedent reveals that the determination of how to allocate those revenues by various independent system operators (ISOs) has been contentious. For example, market participants in PJM filed a complaint in 2006 related to the allocation of marginal loss excess revenues in which one of the primary complaints was that PJM had unreasonably delayed implementing marginal losses due to stakeholder disputes regarding the appropriate allocation methodology.[35]

ERCOT preliminarily has estimated that a marginal loss pricing mechanism would double the payments associated with line losses as compared to the average loss mechanism used today,[36] and the

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33 Project No. 47199, Electric Reliability Council of Texas, Inc.'s Report in Response to Commission Staff's Request at 7 (Sept. 29, ,2017) (estimating 18 to 24 months to implement systems changes for marginal loss pricing and another 6 to 12 months to adopt necessary Protocol changes).

34 *See, e.g., Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,042 (2008) (noting that there is more than one fair and reasonable methodology for allocating marginal loss excess revenues: "In the May 1, 2006 Order, the Commission provided PJM's stakeholders with an opportunity to consider a methodology for crediting the surplus, but the stakeholders were unable to reach consensus on an approach. In the November 1, 2006 Order, the Commission considered three proposals for allocating the excess revenue collected: a majority proposal to credit the surplus to those paying for network service in proportion to each customer's ratio shares of the total megawatt-hours (MWh) of energy delivered to load; a minority proposal to credit the surplus 40 percent to network service users in proportion to load ratio share, 40 percent to generation providers, and 20 percent to fund Financial Transmission Rights (FTR) deficiencies; and a proposal by PJM to use the surplus to cover FTR shortfalls with any surplus credited to load. The Commission determined that all three proposals met its principal criterion of not allocating the surplus to customers in proportion to the amount of each customer's payment of marginal losses. The Commission chose the majority proposal under which excess amounts are allocated to load. The Commission found that 'it is fair to distribute surpluses back to load customers since they pay for the fixed costs of the grid.'"). There is a lengthy subsequent history for this case, but it is cited simply as a reference for the FERC's determination that there could be more than one reasonable allocation methodology, which the FERC did not change in any of the subsequent history (which primarily related to whether the complainants were owed refunds). *See Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,262 (2009) (Compliance Order), *reh'ing*, 131 FERC ¶ 61,024 (2009), *reh'ing*, 136 FERC ¶ 61,040 (2011), *reh'ing*, 139 FERC ¶ 61,111 (2012); *Black Oak Energy, L.L.C. v. FERC*, 725 F.3d 230 (D.C. Cir. 2013); *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,231 (2015) (Order on Remand), *reh'ing*, 155 FERC ¶ 61,013 (2016).

35 *Atlantic City Electric Company v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132 (2006), *reh'ing*, 117 FERC ¶ 61,169 (2006); *see also Black Oak Energy, L.L.C.*, 125 FERC ¶ 61,042 (2008) (summarizing the *Atlantic City* complaint by stating that the complainants' argument was that "PJM was unreasonably delaying implementation of the marginal loss method because of stakeholder disputes on how to allocate the overcollected surplus that necessarily would result" and noting that "most other parties urged that PJM retain the average loss method of recovering transmission losses, or that implementation of the marginal loss method be delayed until June 1, 2007").

36 Project No. 47199, Electric Reliability Council of Texas, Inc.'s Report in Response to Commission Staff's Request at 6 (Sept. 29, ,2017).

Brattle Group (in a report jointly commissioned by Vistra Energy, First Solar, Inc., and the Wind Coalition) estimated $205 million per year of over-collection from a marginal loss methodology.[37] In other words, there would be significant excess revenues over which stakeholders would fight—both in determining the initial allocation methodology and in perpetuity through proposed changes to that methodology.

In addition, FERC has assessed significant fines against traders for allegedly engaging in fraudulent trades to gain excess marginal loss revenue allocation payments.[38] While Vistra Energy takes no position on whether those particular fines were justified,[39] these enforcement actions reveal that there is the potential for gaming with respect to the allocation of marginal loss excess revenues, which is another issue that stakeholders would have to debate in any implementation process for marginal losses. Further, the incremental costs associated with monitoring and litigation that the Commission, the IMM, ERCOT, and market participants would bear from the implementation of marginal loss pricing would not be immaterial.

In short, the likely complexity, contentiousness, and costs of addressing the allocation of marginal loss excess revenues and implementing appropriate protections against gaming are important factors Commissioners should carefully consider as they continue to review the potential implementation of marginal losses.

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37 Project No. 47199, Analysis of Marginal Losses Proposal (Oct. 12, 2017).

38 *In Re Houlian Chen et al.*, 151 FERC ¶ 61,179 (2015) (assessing civil penalties against various traders and entities in amounts ranging from $1 million to $16.8 million); *In re City Power Marketing, LLC et al.*, 152 FERC ¶ 61,012 (2015) (assessing civil penalties against traders ranging from $1 million to $14 million).

39 Dr. Hogan has argued that the fine against Powhatan reveals that the marginal loss allocation methodology in PJM is "flawed." Dr. Hogan's arguments further underscore the contentiousness of the marginal loss allocation issue. *See* Dr. William Hogan, *Electricity Market Design Flaws and Market Manipulation* at 2 (Feb. 3, 2014) ("Both PJM and the Commission have considered different means for the loss surplus allocation. A full discussion of alternative means of allocation would go beyond the scope of the present comments. Suffice it to say that the original method of allocation by actual load-ratio share for network customers was a better method than the one that was eventually applied by PJM and endorsed by the Commission in 2009. ***That rule followed after a lengthy discussion within the unhappy frame of esoteric distinctions about who was and who was not paying for the transmission grid.***") (emphasis added), *available at*: https://sites.hks.harvard.edu/fs/whogan/Hogan_MDFMM_02_03_14.pdf.

Question 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.

The marginal loss pricing proposal in the NRG/Calpine Whitepaper should not be adopted in ERCOT. The push to move from the current methodology of averaging transmission losses and uplifting those costs to load on a load ratio share basis to a marginal loss methodology, whereby losses would be incorporated into pricing and dispatch, elevates economic theory over both sound public policy and practical considerations in the ERCOT market.

As an intial matter, the current average loss methodology is rooted in the policy call made by the Legislature at the outset of deregulation regarding the pricing of transmission services in ERCOT. In Senate Bill 7, the Legislature required that the Commission "**shall price** wholesale transmission services within ERCOT based on the postage stamp method of pricing."[40] Notably, the adopted version of the bill differed from the introduced version, which would have made postage stamp pricing optional.[41] The decision to make postage stamp pricing mandatory reflects a policy decision by the Legislature that all users of the transmission system should pay the same for transmission, regardless of location. In its Scope of Competition Report to the Legislature just before the adoption of Senate Bill 7, the Commission described the purpose of open access and postage stamp pricing (which was partially implemented in ERCOT at that time) as follows:

> The ERCOT pricing method was adopted in the expectation that it would lead to ***vigorous competition*** between producers on the basis of the price of power, and ultimately to lower prices for customers in Texas.[42]

In other words, this pricing methodology puts wholesale providers across the state on level competitive footing, by removing any competitive advantage based on location on the grid. The current methodology for pricing transmission losses is based on the idea that all users of the transmission system pay the same

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40 76th Tex. Leg., R.S., SB 7, ch. 405, § 17 (Sept. 1, 1999) (emphasis added).

41 *Compare id. with* 76th Tex. Leg., R.S., SB 7, § 7 (introduced version) (Jan. 20, 1999).

42 *See* Public Utility Commission of Texas, Report to the 76th Texas Legislature, The Scope of Competition in the Electric Industry in Texas at 36–38 (Jan. 1999) (note that this report pre-dated Senate Bill 7 and the Commission did not have a full-blown postage stamp pricing methodology in place at the time this report was written; however, the Commission's statement was made in the context of comparing ERCOT's pricing system, which at the time was largely based on the postage stamp method, with FERC's system, which the Commission compared to a toll road system where users paid significantly more the further they had to travel), *available at*: http://www.puc.texas.gov/industry/electric/reports/scope/1999/1999scope_elec.pdf.

for losses, rather than saddling and essentially retroactively punishing some users with a larger proportion of those costs based on where they happen to have sited their generation resources or loads—in some cases, decades ago before marginal losses were ever a consideration.

The NRG/Calpine Whitepaper's assertion that marginal loss pricing would incentivize "more efficient retirement decisions and more efficient siting of future generation"[43] also ignores reality on a number of levels. For one thing, Texas is a large state with population centers throughout the state—many existing generators have located near the load they primarily serve, which may not be near the arbitrary "center" of load, which Vistra Energy's analysis indicates is near the Houston area. For example, one of the predecessors to Vistra Energy (Dallas Power & Light) sited its power plants near the Dallas area, where its load was located. Electric cooperatives similarly have located their power plants near the loads they serve.[44]

There are numerous other considerations that go into the siting of generation besides the location of load. For instance, the availability of land, the quality of natural resources such as wind and sun in different areas of the state, and access to coal or natural gas supply can drive siting decisions. Weather conditions and risk of natural disaster also might impact siting decisions and weigh against locating in a particular area of the state (such as in a flood zone).

Another significant driver of siting decisions is environmental regulation. There are substantial environmental hurdles to siting a power plant in or around Houston, which would seriously dissuade any future plants from siting there, without regard to the methodology by which transmission losses are calculated. The Houston-Galveston-Brazoria area (HGB) is currently classified as an "ozone nonattainment" area, and the area is not on track to achieve attainment by its current deadline of July 20, 2018.[45] What this means for new generators wishing to site in that area, or for existing generators wishing to make major modifications, is that they would have to satisfy significantly more onerous (and therefore more costly) environmental standards than a generator in an area that has achieved ozone

[43] Project No. 47199, NRG/Calpine Whitepaper at 50 (Bates) (May 22, 2017).

[44] In its initial comments in this project, South Texas Electric Cooperative (STEC) pointed out that STEC is strategically located near its load, which is not near the Houston area. Project No. 47199, Comments of South Texas Electric Cooperative, Inc. at 6 (Sept. 29, 2017). Vistra Energy does not agree with STEC's proposed solution to this issue, though, which would calculate multiple centers of load for purposes of calculating losses, as that proposal is not practically workable.

[45] For information regarding HGB's non-attainment status and deadline for attainment, see: https://www.tceq.texas.gov/airquality/sip/hgb/hgb-status.

attainment status. For example, rather than using "best available" controls for emissions (which includes a consideration of the cost of such controls), such generators would have to use the lowest emission rate controls, regardless of cost.[46] Further, emission increases must be "offset" with the purchase and retirement of emission reduction credits in tons per year (tpy), and the generator must obtain an emissions "stream of allowances"[47] or purchase allowances annually in the Mass Emissions Cap and Trade program to operate. The cost for offsets and allowances can be significant. For example, three recent (2017) trades of Nitrogen Oxide emissions in HGB cost $80,000 to $85,000 per tpy with the quantity of trades ranging from 2 to 43 tpy;[48] recent trades (2016 - 2017) for stream allowances include trades of $42,500 per tpy for 12.1 tons, $65,000 per tpy for 43 tons, and $70,000 per tpy for 17.6 tons.[49] In other words, environmental restrictions result in significant additional costs to siting a new generation resource in the Houston area (or even making major modifications to an existing generation resource), and it therefore ignores reality to suggest that shifting the methodology for calculating transmission losses from an average to marginal basis would cause new generators to site their plants in the Houston area.

Though marginal losses are unlikely to have any material impact on future siting decisions (i.e., the one purported benefit of this methodology), marginal losses would be likely to cause significant detriment to the bulk of generators in the state. Vistra Energy, along with First Solar, Inc. and the Wind Coalition, filed an analysis by the Brattle Group in this project, which projects that the marginal loss methodology would reduce generator net revenues by $239 million per year, while producing only $8.6 million in production cost savings in ERCOT[50] (i.e., a 0.13% reduction, and a very small number compared to the $100 million production cost savings figure cited in the NRG/Calpine Whitepaper, which was taken from the PJM market[51]). In fact, according to the Brattle Group's analysis, generator revenues would decrease by several million dollars per year in every zone (ranging from $14 million to

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46 For information regarding requirements for new resources/major modifications in a non-attainment zone, see: https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/factsheet-psd-na-6241.pdf.

47 A stream of allowances is an allocation that continues in perpetuity. Alternatively, an emission source without an allowance stream would have to purchase allowances on the market every year, the cost of which would be subject to availability.

48 See: https://www.tceq.texas.gov/assets/public/implementation/air/banking/reports/ectradereport.pdf.

49 See: https://www.tceq.texas.gov/assets/public/implementation/air/banking/reports/mecttradereport.pdf.

50 Project No. 47199, Analysis of Marginal Losses Proposal (Oct. 12, 2017). Note that these estimates do not account for behavioral changes that would occur in response to the change in policy.

51 Project No. 47199, NRG/Calpine Whitepaper at 47 (Bates) (May 22, 2017).

nearly $60 million in losses), except in the Coastal zone where annual revenues would increase by over $8 million.[52]

To illustrate the potential impact of this proposal, at the October 13, 2017 workshop, a representative for Invenergy (which owns both thermal and wind resources in Texas) stated that they have projected a loss of revenues between $9 and $11 million **per year** for their West Texas portfolio if the marginal loss proposal is adopted.[53] The Invenergy representative further noted that Invenergy paid over $34 million in taxes, land payments, and salaries in 2016.[54] Invenergy's projections of lost revenue are consistent with Brattle's analysis, which estimated roughly $40 million of net revenue reductions in each of the West and Far West Texas zones from the marginal loss proposal. Losses in those ranges could ultimately result in premature generation retirements and the unnecessary loss of jobs and tax revenues for the areas of the state negatively impacted by the marginal loss proposal.

Finally, ERCOT has estimated that implementing marginal losses would be a major project, requiring multiple systems changes, that would take between two and three years to implement and cost approximately $10 million.[55] Importantly, those timing estimates assume a minimum of 6 to 12 months for the Commission to make its policy decisions and applicable Protocol changes to be approved by the ERCOT Board, which, as noted above in response to Question 6, may be an underestimate due to the likely contentious nature of determinining how to allocate excess revenues and address potential gaming concerns.

The market rules in every competitive electric market, as in ERCOT, must balance economic efficiencies with national, state, and local public policy. For this reason and those discussed above, it makes no sense to overturn long-standing policy in Texas regarding the pricing of transmission losses to implement a costly new methodology for pricing those losses, which would benefit one group of generators to the detriment of all others that have made prudent investments based on fair assumptions about the relative stability of market rules. The Commission should reject the proposal to move from average to marginal loss pricing.

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52 Project No. 47199, Analysis of Marginal Losses Proposal at 17 (Bates) (Oct. 12, 2017).

53 Tr. at 61–62 (Oct. 13, 2017).

54 *Id.* at 62.

55 Project No. 47199, Electric Reliability Council of Texas, Inc.'s Second Report in Response to Commission Staff's Request at 6–7 (Sept. 29, 2017).

III. CONCLUSION

Vistra Energy appreciates the Commission's thoughtful approach to this Project and its consideration of these comments. We look forward to engaging with others to discuss Vistra Energy's proposals and other potential refinements to the ERCOT wholesale market in the near future.

Respectfully submitted,

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