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Item Number: 29

Addendum StartPage: 0

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PROJECT NO. 48539

REVIEW OF THE INCLUSION OF MARGINAL LOSSES IN SECURITY-CONSTRAINED ECONOMIC DISPATCH	§ § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

VISTRA ENERGY'S COMMENTS

Vistra Energy Corp. (Vistra Energy) submits the following comments in response to the request approved for publication by the Public Utility Commission of Texas (Commission) at its August 9, 2018 open meeting[1] and published in the *Texas Register* on August 24, 2018.[2]

I. INTRODUCTION

Vistra Energy appreciates the opportunity to respond to the Commission's request for comments. As it did in its comments filed in 2017 in Project No. 47199, Vistra Energy continues to oppose marginal transmission loss pricing as a fundamental shift in the way that transmission losses have been priced in ERCOT for nearly two decades, to the significant detriment of most generators, other market participants, and communities throughout the state. Marginal transmission losses offer little to no net benefits to the ERCOT market or consumers and would serve only to drive a substantial wealth transfer to Houston-area generators primarily at the expense of thermal generators in the North and West Zones, putting further pressure on ERCOT long-term resource adequacy. Adopting marginal transmission losses would be squarely at odds with the Commission's efforts in Project No. 48551 to evaluate improvements to ERCOT's scarcity pricing mechanism, following lackluster wholesale power prices during the summer of 2018 despite reserve margins in the single digits.

II. RESPONSE TO QUESTIONS

A. Overview

Marginal transmission loss pricing is fundamentally inconsistent with almost twenty years of Texas policy and would change the rules in the middle of the game for both generators and retail customers, picking winners and losers based upon factors that cannot be responded to, and undermining

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1 Public Notice of Request for Comments (Aug. 9, 2018). Citations without a project number listed are to Project No. 48539.

2 43 Tex. Reg. 5443, 5602-03 (Aug. 24, 2018).

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confidence in the relative regulatory stability of the ERCOT market. It would be a significant market design change that would be substantially detrimental to the majority of the market, while benefiting only a few. Marginal transmission loss pricing is not likely to materially affect future siting decisions, so its sole market impact would be to penalize existing generators based on siting decisions they made years (and sometimes decades) ago. Siting decisions are based on numerous and varied reasons, including the location of a generator's specific load or historical control area (as compared to the theoretic and amorphous center of load near Houston), the availability of land, access to natural resources, and environmental restrictions. Simply shifting the method of accounting for transmission losses from an average basis to a marginal basis will not change any of those considerations.

A marginal loss basis for pricing transmission losses would come at significant cost for generators throughout the state in a power market that is already experiencing sustained low power prices, at an estimated range from $375 to $605 million of estimated annual reductions in net revenues for the North and West zones, of which $256 to $469 million would come from thermal generators.[3] Those reductions are significant enough that they could drive some generators to make premature retirement decisions, resulting in a loss of salaries and revenue for the relevant communities, and a loss to the ERCOT market of needed generating capacity during a time of tightening reserve margins and concerns about ensuring sufficient resource to meet growing peak load demands. Load Serving Entities would also be negatively impacted, as their long-term supply contracts, which take into account the current mechanism for pricing transmission losses, would no longer reflect their underlying cost and risk structures, with no options available to hedge loss pricing risk and an erosion in the ability of congestion revenue rights to hedge congestion risk. In addition, the implementation of marginal losses would cost ERCOT a minimum of $10 million.[4] This estimate is undoubtedly understated, however, given the controversy and costs expected to result from the debate regarding the appropriate allocation of excess revenues if marginal losses are implemented as well as individual market participant costs to adjust to an implementation of a marginal transmission loss allocation methodology.

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[3] *Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*, Project No. 47199, ERCOT's Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch at 15 (Bates) (Jun. 29, 2018) (hereafter, ERCOT ML Benefits Study); *Questions on ERCOT ML Study 09052018a*, posted to http://www.ercot.com/mktinfo/rtm/marginallosses.

[4] 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).

Though it is certain to result in substantial costs to the market, the marginal loss mechanism would not significantly improve market efficiency. First, even ERCOT's most "optimistic" low gas price projection of $13.4 million in annual production cost savings[5] is *de minimis*, a mere 0.175 percent projected savings, which is highly sensitive to assumptions about the price of natural gas and fully reverses to a production cost *increase* in the high gas price scenario. Second, the failure of that estimate to consider the impact over more than one year and the possibility of unit retirement responses is short-sighted. Vistra Energy's own proprietary modeling, which closely mirrors ERCOT's outputs, determined that a generic 1 percent thermal capacity reduction across the North and West Zones—i.e., a conservative estimate of the thermal retirements that might occur if marginal losses are implemented, given the magnitude of ERCOT's projected annual revenue reductions for North and West Zone generators—would likewise result in an *increase* of annual system-wide production costs. In other words, the total costs—considering not only the costs for ERCOT to implement marginal loss pricing, but also the significant costs to generators, other market participants, and communities throughout the state—are not worth the comparatively insignificant and tenuous incremental improvements in market efficiency.

Additionally, a marginal loss basis for pricing transmission losses would upend a policy decision made by the Texas Legislature nearly twenty years ago. The decision to socialize the costs of transmission and thereby to put all wholesale market participants on a level playing field was one that the Legislature made when it directed the move to competition. 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."[6] Notably, the adopted version of the bill differed from the introduced version, which would have made postage stamp pricing optional.[7] 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:

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5 Project No. 47199, ERCOT ML Benefits Study at 14 (Bates) (Jun. 29, 2018) (based on ERCOT's "base case" estimate of marginal loss impacts, using an estimated gas price of $3.55 per MMBtu).

6 76th Tex. Leg., R.S., SB 7, ch. 405, § 17 (Sept. 1, 1999) (emphasis added).

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

> 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.[8]

In other words, this pricing methodology puts wholesale providers across the state on level footing, by removing competitive advantages 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 for losses, rather than saddling (and essentially retroactively and arbitrarily punishing) some users with the internalization of those costs based solely on where they happen to have sited their generation resources or loads—decisions that, in some cases, were made decades before the competitive ERCOT market, let alone marginal losses, were ever a consideration.

Some proponents of marginal transmission losses have argued that this is the norm in the rest of the country, but that is irrelevant to whether that methodology is appropriate for ERCOT. The rest of the country is subject to the plenary jurisdiction of the Federal Energy Regulatory Commission (FERC), and FERC-jurisdictional markets are significantly different than in Texas. For one relevant example, in FERC areas transmission costs are allocated based on a beneficiary pays model, whereas in ERCOT the decision was made at the outset of the competitive market to socialize transmission costs. For another example, capacity markets are the norm in FERC-jurisdictional markets, whereas in ERCOT generators rely solely on energy prices for revenue. Changing the rules in the middle of the game for ERCOT generators and loads will unfairly penalize those that cannot change their siting decisions (i.e., the vast majority of them), will negatively impact communities throughout the state (particularly in rural areas of North, East, and West Texas), and will potentially chill future investment in the state by signaling both an unstable regulatory environment and an overall reduction in anticipated wholesale market revenues available to support new build.

In sum, implementing marginal losses would be a fundamental, unnecessary, and significantly detrimental design change for the ERCOT market, and the Commission should not adopt marginal

8 *See* Public Utility Commission of Texas, Report to the 76th Texas Legislature, The Scope of Competition in the Electric Industry in Texas at 36 (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.

losses. Within this overarching framework, Vistra Energy responds to the Commission's specific questions below.

B. Response to Specific Questions

Question 1: What are the benefits of implementing the use of marginal transmission losses rather than average transmission losses in the Electric Reliability Council of Texas' (ERCOT) Security-Constrained Economic Dispatch (SCED) over the long term?

Question 2: Are the benefits identified in response to Question 1 sufficient to justify the near term costs to the market as a whole? Please consider individual stakeholder implementation costs as well as the costs to ERCOT identified in its study.

Vistra Energy responds to Question Nos. 1 and 2 together. In short, there would be no meaningful or reliable benefits to implementing marginal transmission losses in ERCOT, and, in consideration of the much more meaningful costs and other negative market impacts, marginal transmission losses would be detrimental over the long-term.

Vistra Energy's own proprietary modeling, which closely mirrors ERCOT's modeled outputs, considered as a test case the impact of a generic 1 percent thermal capacity reduction across the North and West Zones, a modest capacity reduction of ~310 MW evenly spread across those areas, and found that annual system-wide production costs would *increase* with marginal transmission losses.

1. Projected Short-Term Quantitative Benefits—Highly Variable and Potentially Detrimental Over the Medium-to-Long-Term

In its *Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch* filed in Project No. 47199,[9] ERCOT projected the benefits of marginal losses by simulating expected system conditions in the year 2020 and provided a base case and two sensitivity cases that varied based on the price of natural gas—(1) the base case assumed a natural gas price of $3.55/MMBtu; (2) the low gas price case assumed a natural gas price of $2.55/MMBtu; and (3) the high gas price case assumed a natural gas price of $3.96/MMBtu. Under these assumed scenarios, ERCOT estimated projected changes in terms of both (a) production cost impacts (i.e., the changes in costs

[9] *See supra* note 3.

incurred by generators to produce electricity);[10] and (b) total consumer costs. Both of these measures varied significantly depending on the assumed natural gas price (and, in the case of consumer costs, also on the load zone):

- For production cost savings, ERCOT's projections varied from a \$0.9 million increase in *costs* (i.e., 0.009 percent) in the high gas price case to \$13.4 million in savings (i.e., 0.175 percent) in the low gas price case (with a base case projection of \$11.4 million, or 0.117 percent, savings).
- For consumer costs, ERCOT's projections ranged from a \$21.9 million *increase* in annual customer costs in the Houston Zone (under the low gas price case) to an \$81.3 million decrease in annual customer costs in the North Zone (under the high gas price case), with base case estimates ranging from annual decreases of \$18.5 million in the South Zone to \$73.6 million in the North Zone.

In other words, the estimated benefits to customers, whether measured as production cost savings or consumer costs, are clearly variable, depending on the inputs and assumptions underlying that estimate.

Further, the estimated benefits are limited in the sense that they are based on one modeled future year (2020) and thus do not capture the likely long-term effect of implementing marginal losses, which presumably would impact future entry and exit decisions by generators, as implementing marginal losses is projected to result in significant annual decreases in generator revenue in the North and West Zones (in the range of \$375 to \$605 million). Vistra Energy's own proprietary modeling, which closely mirrors ERCOT's modeled outputs, considered as a test case the impact of a generic 1% thermal capacity reduction across the North and West Zones, a modest capacity reduction of ~310 MW evenly spread across those areas, and found that annual system-wide production costs would *increase* with marginal transmission losses. In addition, a consultant engaged by Invenergy LLC (PA Consulting Group Inc.) conducted a study earlier this year, which evaluated the impacts of marginal losses over a longer term—2018 to 2037—and found that the production cost savings over that long-term period would be significantly negative, in the range of \$5 billion, based on the detrimental impact that marginal losses

10 ERCOT noted production cost reductions are indicative of increased system efficiency but do not necessarily represent immediate savings to consumers.

would have on future generation investment.[11] While it is difficult to predict with certainty the exact long-term impact of marginal transmission losses, it is certain to harm future generation investment if, as predicted by ERCOT, Brattle,[12] and Vistra Energy, it causes generators in the North and West Zones to lose hundreds of millions of dollars in revenue a year, in a wholesale market with already depressed power prices. In other words, evaluating benefits such as production cost savings over a one-year period does not take into account how implementing marginal losses might negatively affect the market over time, which could erode—or even substantially reverse—any value (such as production cost savings) over the long-term.

2. Potential Qualitative Benefits (i.e., Future Siting Decisions) Unlikely to Materialize and Not Optimal for Grid Resiliency and Stability

Another supposed qualitative benefit of marginal losses is that it would incentivize more efficient generation resource retirement and siting decisions in the future. This 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 ERCOT-wide load, which is estimated to be typically 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 and municipally-owned utilities similarly have located their power plants within or near their service territories, which inherently encompass the loads they serve.[13]

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 hurricane or flood zone).

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11 Project No. 47199, Informational Filing by Invenergy LLC, Report: The Long-Term Impacts of Marginal Losses on Texas Electric Retail Customers at 5 (Apr. 20, 2018) (hereafter, PA Consulting ML Impacts Report).

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

13 In comments filed in Project No. 47199, 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.

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—the area did not attain the 2008 ozone standard of 0.075 parts per million (ppm) by its attainment deadline of July 20, 2018 and also has not yet attained the 2015 ozone standard of 0.070 ppm, which has a deadline of August 3, 2021.[14] 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 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 achievable emission rate controls, regardless of cost.[15] 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"[16] 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, recent trades (2018) of Nitrogen Oxide emissions credits in HGB include trades of $40,000 per tpy for 13.6 tons, $80,000 per tpy for 6.8 tons, and $130,000 per tpy for 3.5 tons;[17] recent trades (2018) for stream allowances include trades of $57,500 per tpy for 50.9 tons, $45,000 per tpy for 0.8 tons, $78,125 per tpy for 64 tons, and $59,830 per tpy for 48 tons.[18] 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 near the typical center of ERCOT load in the Houston area.

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

15 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.

16 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.

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

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

In addition, assuming for a moment that marginal losses would create sufficient incentives for generators to site future resources near the theoretical center of load near Houston and that environmental obstacles could be overcome, that would still not be a desirable outcome for the resiliency of the ERCOT grid. Resilience refers to the ability of the grid to withstand idiosyncratic shocks to the supply system.[19] In the event of a major storm, cyber attack, or other potentially disruptive event, it is desirable to have generation resources (such as black-start resources[20]) located throughout the state that can start up independently of the grid to restore the grid to a stable condition, rather than having all or most generation resources concentrated in one area (such as near the theoretical center of load outside Houston).[21]

Similarly, if implementing marginal losses incentivizes more thermal resources to retire (without significant new build near the theoretical center of load due to the limitations just discussed), that could be deleterious to the stability and system inertia of the ERCOT grid, especially in light of the ever increasing penetration of non-synchronous, intermittent resources (like wind and solar) in ERCOT. As noted by ERCOT in a recent report on system inertia, "[c]ontinuous growth of non-synchronous generation [(i.e., wind and solar)] as well as retirements of traditional thermal generation resources bring

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19 For example, the National Infrastructure Advisory Council has defined "resilience" as follows: "Infrastructure resilience is the ability to reduce the magnitude, impact, or duration of a disruption. Resilience is the ability to absorb, adapt to, and/or rapidly recover from a potentially disruptive event." *See* Department of Homeland Security, National Infrastructure Advisory Council, *Critical Infrastructure Resilience: Final Report and Recommendations* (Sept. 8, 2009), *available at*: https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf.

20 ERCOT Nodal Protocols § 2 (defining Black Start Service as "An Ancillary Service provided by a Resource able to start without support of the ERCOT Transmission Grid"); *id.* § 6.5.9.6 ("ERCOT may Dispatch [Black Start Service] pursuant to an emergency restoration plan to begin restoration of the ERCOT System to a secure operating state after a Blackout."); *id.* § 2 (defining "Blackout" as "A condition in which frequency for the entire ERCOT System has dropped to zero and Generation Resources are no longer serving Load" and "Partial Blackout" as "A condition in which an uncontrolled separation of a portion of the ERCOT System occurs and frequency for that portion has dropped to zero and Generation Resources within that portion are no longer serving Load and restoration is dependent on either internal Black Start Plans or assistance for restoration is needed from neighboring transmission operator(s) within the ERCOT System which requires ERCOT coordination."). North American Electric Reliability Corporation (NERC) Reliability Standards require that each Transmission Operator have a restoration plan that allows for restoring the Transmission Operator's System following a disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of black start resources is required to restore the shut down area to service. *See* NERC Reliability Standard, EOP-05-002, R1.

21 *See* U.S. Department of Energy, *Final Report: Energy Resilience Solutions for the Puerto Rico Grid* (Jun. 2018) ("To better enable system recovery and/or black start restoration, there might be operational benefits for segmenting the transmission system into smaller portions. While this would be done out of necessity following a large-scale event, there could be some advantages to pre-selecting which segments are likely able to survive a future event, and proactively plan for segmenting the transmission system accordingly. These portions of the system would be identified to include a mix of generating assets, including black-start capable units, along with appropriately sized load, so that when the distribution system is undergoing restoration activities, and enough load would be present to constitute minimum generation capabilities, stable portions of the system could be energized and maintained prior to the longer transmission lines being repaired and energized. These portions of the system could then be re-energized with each other later in the restoration process."), *available at*: https://www.energy.gov/sites/prod/files/2018/06/f53/DOE%20Report_Energy%20Resilience%20Solutions%20for%20the%20PR%20Grid%20Final%20June%202018.pdf.

more uncertainties to grid operations and a greater need to monitor system inertia in real-time."[22] ERCOT also recently published a report detailing potential stability issues associated with the increasing penetration of intermittent resources in north, west, and far west Texas.[23] In a time of already depressed wholesale power prices, implementing a loss allocation mechanism that would cause thermal generators in the North and West Zones to lose an estimated $256 to $469 million in revenue per year[24] could incentivize additional retirement of the resources needed to promote system inertia and grid stability.

3. Implementation Costs – ERCOT-Wide and Individual Market Participant

While the projected benefits are miniscule in relative terms, highly dependent upon input assumptions, and unlikely to materialize (or just as likely to fully reverse) over the long-term, there would be immediate costs to implement marginal transmission losses, both on an ERCOT-wide and individual market participant basis. ERCOT has indicated 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.[25] 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 is likely an underestimate due to the almost certainly contentious nature of determining how to reallocate the annual excess marginal loss revenues collected from loads. Those excess revenues are certain to occur, because, by nature, marginal losses always result in an overcollection as compared to average losses. As the FERC has explained:

> It is a characteristic of the electric grid that marginal losses increase as the number of megawatts of power moved on the grid increases. It is a principle of mathematics that whenever any variable is continuously increasing, the marginal value of the last unit exceeds the average of all the units. As a result, marginal losses will always exceed average losses.[26]

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22 ERCOT, *Inertia: Basic Concepts and Impacts on the ERCOT Grid*, at 5, 12 (Apr. 4, 2018), *available at*: http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf

23 ERCOT, *Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT Grid* (Apr. 19, 2018), *available at*: http://www.ercot.com/content/wcm/lists/144927/Dynamic_Stability_Assessment_of_High_Penetration_of_Renewable_Generation_in_the_ERCOT_Grid.pdf

24 *Questions on ERCOT ML Study 09052018a*, posted to http://www.ercot.com/mktinfo/rtm/marginallosses.

25 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).

26 *Atlantic City Electric Company v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132, at P5 (2006), *reh'ing denied*, 117 FERC ¶ 61,169 (2006).

The FERC has yet to endorse a specific methodology for allocating marginal loss excess revenues (requiring only that the methodology not result in direct refunds in proportion to the amount paid for marginal losses),[27] and FERC precedent reveals that the determination of how to allocate those revenues by various ISOs has been contentious and time consuming. For example, market participants in the PJM Interconnection, L.L.C. (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.[28] Subsequently, in 2007, a group of virtual traders in PJM filed a complaint that they should either not have to pay marginal losses (because they did not engage in physical trades) or should receive a share of the reallocation—that case resulted in numerous orders on rehearing and appeals to the D.C. Circuit Court of Appeals (with parties arguing over $37 million in overcollection allocations that the FERC initially ordered be provided retroactively to the complainants and then, reversing course, ordered be recouped from the complainants), and it is still pending today at FERC following a remand from the court.[29] Disputes over the implementation of marginal losses and the appropriate mechanism for reallocating marginal loss surpluses have arisen in every other non-ERCOT ISO as well and have spanned multiple years.[30]

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27 *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, so long as the allocation is not a direct refund in proportion to the payment for marginal losses in the first instance). This case has significant subsequent history, cited *infra* in note 29.

28 *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").

29 *Black Oak Energy, LLC v. PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,208 (2008), *reh'ing*, 125 FERC ¶ 61,042 (2008), *clarified by*, 126 FERC ¶ 61,114 (2009), *compliance order*, 128 FERC ¶ 61,262 (2009), *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), *on remand*, 153 FERC ¶ 61,231 (2015), *reh'ing*, 155 FERC ¶ 61,013 (2016). The 2015 and 2016 orders were appealed to the D.C. Circuit Court of Appeals, which then remanded the case back to FERC upon an unopposed motion for remand. See D.C. Circuit Court of Appeals, Docket No. 16-1172, Clerk's Order (Nov. 9, 2016). According to PJM's Q2 2018 Quarterly Financial Report filed with FERC on August 24, 2018, the *Black Oak* case is still pending before FERC. PJM's report is available here: https://www.pjm.com/-/media/committees-groups/committees/fc/20180822/20180822-pjm-quarterly-unaudited-financial-statements-as-of-june-30-2018.ashx?la=en.

30 California Independent System Operator Corporation (CAISO): *E.g., In re California Independent System Operator Corporation*, 105 FERC ¶ 61,140 (2003) (FERC approved conceptual design for marginal losses and surplus credit mechanism but sought more information), *reh'ing*, 105 FERC ¶ 61,278 (2003); *In re California Independent System Operator Corporation*, 107 FERC ¶ 61,274 (2004) (FERC upheld surplus credit mechanism upon receiving further information from CAISO), *reh'ing*, 108 FERC ¶ 61,254 (2004), *reh'ing*, 110 FERC ¶ 61,041 (2005), *reh'ing*, 110 FERC ¶ 61,381 (2005), *clarified by*, 111 FERC ¶ 61,138 (2005); *In re California Independent System Operator Corporation*, 116 FERC ¶ 61,274 (2006) (FERC approved revised allocation mechanism but sought more information on the details), *reh'ing*, 119 FERC ¶ 61,076 (2007), *reh'ing*, 120 FERC ¶ 61,271 (2007); *In re California Independent System*

Operator Corporation, 120 FERC ¶ 61,023(2007) (FERC denied one party's motion to implement a marginal loss hedging mechanism, noting that no ISO had been able to develop one yet), *reh'ing*, 124 FERC ¶ 61,094 (2008).

Midwest Independent Transmission System Operator, Inc. (MISO): *E.g.*, *In re Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 (2003) (initial marginal loss proposal), *clarified*, 102 FERC ¶ 61,338 (2003), *reh'ing*, 103 FERC ¶ 61,210 (2003); *In re Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶ 61,145 (2003) (FERC accepted MISO's motion to withdraw its Jul. 25, 2003 proposed tariff filing to allow MISO more time to address additional issues, including the marginal loss credit mechanism), *reh'g*, 105 FERC ¶ 61,272 (2003); *In re Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 (2004) (FERC sought more information on MISO's proposed treatment of grandfathered agreements), *reh'g*, 111 FERC ¶ 61,042 (2005), *reh'g*, 112 FERC ¶ 61,311 (2005); *In re Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (2004) (FERC approved marginal loss method and credit mechanism, including 5-year transition period), *reh'g*, 109 FERC ¶ 61,157 (2004), *clarified by*, 111 FERC ¶ 61,367 (2005); *In re Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,290 (2005), *reh'ing*, 111 FERC ¶ 61,053 (2005) (FERC sought more information on surplus credit mechanism), *reh'ing*, 112 FERC ¶ 61,086 (2005); *In re Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,285 (2004) (FERC sought more information on surplus credit mechanism); *In re Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,142 (2006) (FERC accepted MISO's compliance filing including marginal losses but ordered MISO to analyze surplus allocations for certain protestors and provide more information), *reh'ing*, 119 FERC ¶ 61,207, *reh'ing*, 121 FERC ¶ 61,208 (2007), *pet. denied, Integrys Energy Group, Inc. v. FERC*, No. 08-1032, 314 Fed. Appx. 324 (D.C. Cir. Feb. 4, 2009); *Wisconsin Public Power, Inc. v. F.E.R.C.*, 493 F.3d 239 (D.C. Cir. 2007) (court affirmed FERC's approval of MISO's tariff with marginal loss provision and credit mechanism); *In re Midwest Independent Transmission System Operator, Inc.*, 121 FERC ¶ 61,166 (2007) (FERC accepted MISO proposal on grandfathered agreements); *In re Midwest Independent Transmission System Operator, Inc.*, 131 FERC ¶ 61,185 (2010) (FERC approved permanent methodology for marginal losses following transition period); *Midwest Independent Transmission System Operator, Inc.*, 152 FERC ¶ 61,084 (2015) (FERC rejected MISO's proposal to apply same marginal loss provisions to grandfathered agreements that applied to non-grandfathered agreements). Much of the litigation in MISO focused on the treatment of grandfathered agreements, as well as the implementation of a transition period for moving from average to marginal losses.

New England Power Pool / ISO New England, Inc.: *E.g.*, *In re New England Power Pool*, 100 FERC ¶ 61,287 (2002) (FERC approved initial marginal loss and surplus credit mechanism - subsequent history not relevant to marginal loss issue); *Northeast Utilities Service Co. v. ISO New England Inc.*, 105 FERC ¶ 61,122 (2003) (complaint relating to marginal loss allocation), *reh'ing*, 109 FERC ¶ 61,204 (2004).

New York ISO (NYISO): *E.g.*, *Central Hudson Gas & Elec. Corp. et al.*, 86 FERC ¶ 61,062 (1999) (FERC accepted NY ISO's proposal for marginal loss pricing and its proposed allocation of excess revenues but denied request of NYISO members to generically modify existing transmission agreements to incorporate various provisions of NYISO's open access transmission tariff, including marginal losses), *reh'ing*, 88 FERC ¶ 61,138 (1999), *reh'ing*, 90 FERC ¶ 61,045(2000), *reh'ing*, 95 FERC ¶ 61,008 (2001); *Central Hudson Gas & Elec. Corp. et al.*, 88 FERC ¶ 61,306 (1999) (FERC accepted revised transmission agreements filed by certain NYISO members), *reh'ing*, 89 FERC ¶ 61,241 (1999), *reh'ing*, 90 FERC ¶ 61,042 (2000); *Central Hudson Gas & Elec. Corp. et al.*, 90 FERC ¶ 61,011 (2000) (same); *Central Hudson Gas & Elec. Corp. et al.*, 94 FERC ¶ 63,007 (2001) (FERC Administrative Law Judge (ALJ) certified for FERC's consideration a stipulation among certain NYISO members and municipal customers regarding payment of marginal losses); *Central Hudson Gas & Electric Corp. et al.*, 95 FERC ¶ 63,013 (2001) (FERC ALJ determined that marginal loss methodology not reasonable as applied to particular grandfathered customers and ordered surplus revenue allocation payments to those customers), *aff'd*, 100 FERC ¶ 61,023 (2002), *reh'ing*, 103 FERC ¶ 61,143 (2003); *Sithe/Independence Power Partners, L.P. v. Federal Energy Regulatory Commission*, 285 F.3d 1 (D.C. Cir. 2002) (court determined FERC had not adequately addressed complaint of a particular grandfathered customer and remanded to FERC), *on remand*, *Central Hudson Gas & Elec. Corp. et al.*, 103 FERC ¶ 61,142 (2003) (FERC determined the issue had become moot based on decision in a different case ordering surplus revenue allocation payments to the grandfathered customer); *Central Hudson Gas & Elec. Corp. et al.*, 103 FERC ¶ 61,144 (2003) (FERC accepted NYISO member's filing in response to particular grandfathered customer, but ordered some changes to allocation calculation), *reh'ing*, 104 FERC ¶ 61,225 (2003); *Central Hudson Gas & Elec. Corp. et al.*, 105 FERC ¶ 61,198 (2003) (FERC sustained grandfathered customer's objection to NYISO member's filing concerning calculation of allocation payments).

Southwest Power Pool (SPP): *In re Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) (FERC determined proposed marginal loss surplus revenue allocation mechanism did not comport with FERC guiding principles because it would result in direct refund in proportion to payments), *reh'ing*, 142 FERC ¶ 61,205 (2013); *In re Southwest Power Pool, Inc.*, 144 FERC ¶ 61,224 (2013) (FERC continued to reject proposed allocation mechanism, following SPP submission of expert testimony in support); *In re Southwest Power Pool, Inc.*, 146 FERC ¶ 61,050 (2014) (FERC accepted SPP's alternative allocation proposal modeled after MISO); *In re Southwest Power Pool, Inc.*, 150 FERC ¶ 61,242 (2015) (FERC conditionally accepted SPP's proposed revisions related to marginal loss surplus revenue allocation mechanism, but ordered correction of formula); *In re Southwest Power Pool, Inc.*, 160 FERC ¶ 61,115 (2017), *reh'ing*, 163 FERC ¶ 61,063 (2018) (case involving grandfathered customers and marginal losses).

Further, FERC has assessed significant fines against traders for allegedly engaging in fraudulent trades to gain excess marginal loss revenue allocation payments.[31] While Vistra Energy takes no position on whether those particular fines were justified,[32] 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. The incremental costs associated with monitoring and litigation that the Commission, the Independent Market Monitor (IMM), ERCOT, and market participants would bear from the implementation of marginal loss pricing would not be immaterial.

In addition, ERCOT's cost estimate does not take into account the costs to individual market participants to implement marginal losses or the potential additional costs of updates to the Congestion Revenue Rights (CRR) and Day-Ahead Markets (DAM) software to utilize the estimated center of ERCOT load as the reference bus (as discussed in response to Question Nos. 3, 18, and 19). With respect to individual market participant costs, as discussed further below under Question Nos. 5, 6, and 7, Vistra Energy initially has estimated that it will cost six to seven figures for us to implement marginal transmission losses internally, and it would require significant time and employee resources, at the expense of deferring other potentially beneficial upgrades and projects. If litigation over the allocation of surplus marginal loss revenues ensues (as it likely would), that litigation presumably would impose additional costs on individual market participants, likely including Vistra Energy.

4. Summary

In sum, the potential benefits of marginal losses are both minimal and highly speculative, while the costs are conservative but certain and the negative impacts of marginal losses are consistently indicated across multiple analyses. In addition to the implementation costs, ERCOT has projected that

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[31] *E.g.*, *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).

[32] 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.

generators in the North and West Zones stand to lose $375 to $605 million in revenue a year,[33] mostly at the expense of thermal generators in those areas,[34] in a wholesale power market that is already struggling to produce sufficient pricing signals to incentivize generators to remain in the market or to build new resources.[35] Marginal losses are also starkly at odds with the Legislature's policy decision, at the outset of competition, to socialize transmission costs and enable full and open competition among generators. Reversing course now—two decades later and after significant investment in the market has already been made on the presumption of the current mechanism for calculating losses—would undermine confidence in the regulatory certainty of the Texas competitive market, further threaten grid reliability and resiliency, and hamper competition—simply put, it would be bad for the market and bad for the State of Texas. The Commission should not adopt or endorse marginal losses.

<u>Question 3</u>: What are the effects on retail customers and the retail market from the implementation of marginal transmission losses?

As an initial matter, retail customers and the retail market would be charged approximately twice as much for losses under a marginal loss mechanism than they are today under an average loss system, due to the inherent nature of marginal transmission losses to overcollect the estimated cost of losses in locational marginal prices (LMPs) as compared to the existing average transmission loss recovery methodology (as noted above, The Brattle Group has estimated the over-collection would amount to more than $200 million a year). As discussed above, other ISOs have spent years litigating how to reallocate this money and which entities are entitled to be in the reallocation pool. It is uncertain if or how that controversy would be settled in ERCOT and how long it would take, but in the meantime, retail customers (depending on their current contractual arrangements) would potentially pay a significantly higher amount for losses through their energy prices than they do today.

It is also inevitable that any allocation methodology will pick winners and losers amongst consumers, power marketers, retail electric providers (REPs), and qualified scheduling entities (QSEs)

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33 Project No. 47199, ERCOT ML Benefits Study at 15 (Bates) (Jun. 29, 2018) (projecting annual losses between $222 and $415.3 million for the North Zone and between $153 and $190.2 million for the West Zone, depending on the price of natural gas, as compared to annual gains for the Houston Zone between $172 and $257.6 million and for the South Zone between $38.3 and $125.9 million, again depending on the price for natural gas).

34 *Questions on ERCOT ML Study 09052018a*, posted to http://www.ercot.com/mktinfo/rtm/marginallosses; Project No. 47199, Analysis of Marginal Losses Proposal (October 12, 2017).

35 This issue is discussed at length in Vistra Energy's comments that were filed on September 14, 2018 in Project No. 48551.

because some entities would inevitably receive a greater or lesser allocation of surplus revenues relative to the loss components embedded in the energy transacted and consumed. Considering that ERCOT's primary interaction in the market is with the QSE and not the REP or the end-use customer, it is likely that any ERCOT allocation methodology would end at the QSE, and that individual QSEs would then apportion their surplus revenue share amongst the REPs that they represent in accordance with their contracts, and the contracts between REPs and individual consumers would in turn have to account for how those surplus revenue allocations would be reflected in rates.

From a settlements standpoint, it is also notable that marginal transmission losses would only complicate the process by adding an administrative surplus revenue allocation without removing the need to adjust metered load to account for losses and unaccounted-for-energy (UFE) altogether. Because marginal losses only account for losses on the transmission system, distribution system losses would still be present and require metered load to be adjusted upward for settlement. Similarly, because losses (be they transmission or distribution, average or marginal) are only estimates of the losses incurred in the transmission and distribution of energy, there will still be a need for UFE in settlements (as well as to socialize the cost of any unmetered or under-metered activity such as substation power consumption and electricity theft).

Load Serving Entities, such as REPs, electric co-operatives, and municipally-owned utilities, would also be negatively impacted, as their long-term supply contracts, which take into account the current mechanism for pricing transmission losses, would no longer reflect their underlying cost and risk structures. In addition, there is currently no mechanism by which to hedge the risk of marginal losses in ERCOT, and we are not aware of any other ISO having developed one, despite having attempted to do so for several years. As the FERC noted in one case:

> As for hedging marginal losses, it is much more difficult to design a marginal loss hedge than a congestion hedge, in part due to the variables that influence marginal losses, such as ever-shifting line loading. While theoretically possible, to date, as noted in the marginal loss section above, no one has been able to design a workable hedge, and no ISO offers a marginal loss hedge. Indeed, none of the parties in this case have offered such a hedge.[36]

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[36] *In re California Independent System Operator Corporation*, 119 FERC ¶ 61,076 (2007).

Because of the difficulty of designing an adequate hedge against the risk of marginal losses, it will be difficult for retail customers and the retail market to hedge against that risk. Furthermore, marginal loss transmission pricing in LMPs erodes the value of CRRs in managing power flow risks from the forward markets into real-time. Under the current average loss paradigm, losses are not included in the LMP, and the LMP consists solely of the energy price and the congestion component; thus, the basis risk for the LMP (meaning the risk associated with difference in the price you buy/sell power on a forward basis and the actual price in real-time due to the impact of congestion in real-time) can be fully hedged through CRRs. Under a marginal loss paradigm, the LMP would have three components—the energy price, congestion, and the loss component—and the loss component could not be included in the CRR auctions, because ERCOT has not designed the CRR engine to take into account the effect that marginal loss transmission pricing would have on unit dispatch. Further, the ERCOT CRR and DAM auctions both utilize fixed reference buses, compared to the use of the calculated ERCOT center of load as the reference bus for marginal transmission losses, which would create further basis risk for market participants. Notably, ERCOT did not take alignment of the CRR, DAM, and real-time reference buses into account in its cost estimate for marginal loss implementation. To the extent that the loss component of the LMP grows, the ability of a CRR to fully account for basis risk diminishes because it would increasingly fail to hedge the price differential between a source and sink node.

At a broader qualitative level, retail customers benefit from having generation resources located all over the state rather than in the middle of cities (for obvious reasons, such as environmental impacts and aesthetics, in addition to the resiliency reason discussed above). As a result of the Texas Legislature's policy decision to socialize the costs of transmission and thereby facilitate open competition, retail customers have already paid, through the transmission and distribution utility rates assessed to their REPs, for the transmission facilities needed to deliver power from generation resources located all over the state to load centers (which, again, are also located throughout the state and not at an abstract singular point outside of Houston). Switching to a marginal loss mechanism now would effectively be to charge those retail customers again—particularly those in the Houston area—that would be paying higher energy prices ostensibly to incentivize generation to site closer to them when they have already paid for the transmission needed to deliver power from across the state to them.

Further, a move from average to marginal transmission losses would be counter to the Legislature's policy decision to socialize transmission costs to promote equal access to the ERCOT grid and encourage healthy competition from resources across the state. To be consistent with that policy, the costs of losses, like the costs to build and operate transmission facilities, should be shared by all customers equally on a load-ratio share basis, as they are today through the average loss mechanism.

Question 4: The ERCOT study of using marginal transmission losses instead of average transmission losses in SCED simulated one year. How would cumulative, multi-year impacts of using marginal transmission losses be different, if at all?

The cumulative, multi-year impact of using marginal transmission losses is likely to be detrimental to the ERCOT market. As noted above, ERCOT has projected that annual generator revenues in the North and West Zones would decrease in the range of hundreds of millions of dollars per year (by as much as $605 million total in the North and West Zones, depending on the price of natural gas).[37] An annual decrease in generator revenues of that magnitude is certain to have some negative impact on future investment in generation resources in ERCOT, especially given that the ERCOT market is already not producing wholesale price signals sufficient to incentivize continued operation or new entry for natural gas-fired generation and has rarely ever produced such price signals since 2002.[38]

While it is difficult to predict with certainty the exact long-term impact of marginal transmission losses, it is certain to harm future generation investment if, as predicted by ERCOT, Brattle,[39] and Vistra Energy, it causes generators in the North and West Zones to lose an estimated $375 to $605 million in revenue a year,[40] mostly at the expense of thermal generators in those areas,[41] in a wholesale market with already depressed power prices. Given the comparative unattractiveness of the Houston area from a

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37 *Supra* note 33.

38 The Independent Market Monitor (IMM) has determined net revenues were or might be sufficient to support new build of gas-fired plants only three times since 2002, and most of those circumstances were based on anomalies rather than market design fundamentals supporting new investment. *See* Potomac Economic's 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets at 51-52 (July 2006) (finding that net revenue "might" be sufficient to incentivize new entry for gas-fired plants); Potomac Economic's 2008 State of the Market Report for the ERCOT Wholesale Electricity Markets at xix August 2009) (finding that net revenue was sufficient to support new entry for gas-fired units, but largely due to anomalous market design related inefficiencies rather than market fundamentals); Potomac Economic's 2011 State of the Market Report for the ERCOT Wholesale Electricity Markets at 79 (Jul. 2012) (finding that extremely inefficient transmission congestion management and pricing mechanisms led to sufficient revenues). The State of the Market Reports are available here up through 2016: http://www.puc.texas.gov/industry/electric/reports/ERCOT_annual_reports/Default.aspx and here for 2017: https://www.potomaceconomics.com/wp-content/uploads/2018/05/2017-State-of-the-Market-Report.pdf.

39 Project No. 47199, Analysis of Marginal Losses Proposal (October 12, 2017).

40 Project No. 47199, ERCOT ML Benefits Study at 15 (Bates) (Jun. 29, 2018) (projecting annual losses between $222 and $415.3 million for the North Zone and between $153 and $190.2 million for the West Zone, depending on the price of natural gas, as compared to annual gains for the Houston Zone between $172 and $257.6 million and for the South Zone between $38.3 and $125.9 million, again depending on the price for natural gas).

41 *Questions on ERCOT ML Study 09052018a*, posted to http://www.ercot.com/mktinfo/rtm/marginallosses; Project No. 47199, Analysis of Marginal Losses Proposal (October 12, 2017).

renewables siting standpoint and the previously-discussed difficulty that new thermal generators would have siting there because of stringent emissions constraints, it is highly doubtful that any new generating capacity would be able to respond to the wholesale wealth transfer toward Houston generators, leaving the ERCOT generation fleet smaller than it would otherwise be, all things equal. Such an outcome would both increase system-wide production costs on net and be squarely at odds with the Commission's apparent objectives in Project No. 48551 to improve the scarcity pricing mechanism in ERCOT and thereby improve the long-term outlook for resource adequacy.

> <u>Question 5</u>: What costs would be incurred by market participants if marginal losses were implemented in the ERCOT market? Please provide an estimate of the costs that would be incurred by your company or companies or customers represented by your organization. Please describe the elements of those costs.

> <u>Question 6</u>: How would a decision to use marginal transmission losses affect your company's market systems?

> <u>Question 7</u>: How would a decision to use marginal transmission losses affect your company's internal operations?

Vistra Energy responds to Question Nos. 5, 6, and 7 together. As indicated above, Vistra Energy initially has estimated that it will cost six to seven figures for it to implement marginal transmission losses and will take a significant amount of design time, testing time, debugging time, further testing, adjustments and revisions, and more tests and trials to implement the internal changes needed to shift from average to marginal transmission losses, which would impact both the LMPs and unit deployment. Vistra Energy would have to rebuild its shadow settlement system (i.e., shadowing how we think the market will settle) to account for the impact of marginal losses on both LMPs and unit deployment. This would be a substantial project and require us to devote significant employee resources, at the expense of deferring other potentially beneficial upgrades and projects. If litigation over the allocation of surplus marginal loss revenues ensues (as it likely would), that litigation presumably would impose additional costs on individual market participants, likely including Vistra Energy.

> <u>Question 8</u>: What are the effects on reliability on the ERCOT grid of using marginal transmission losses instead of average transmission losses in SCED?

In the short term, marginal transmission losses are unlikely to affect real-time operational reliability during normal system conditions; however, implementing a major design shift that would challenge the economic viability of thermal generators in the North and West Zones,[42] in an already depressed wholesale power price environment, would likely impact long-term resource adequacy, which is a component of reliability.[43] The IMM has repeatedly determined that net revenues in ERCOT were insufficient to incentivize new entry for natural gas-fired resources.[44] Assuming ERCOT's estimate is reasonable that implementing marginal transmission losses would cause generators in the North and West Zones to lose $375 to $605 million per year in revenues (depending on natural gas prices),[45] then implementing marginal transmission losses would almost certainly have a negative impact on long-term resource adequacy, especially in the North and West Zones. In a market with reserve margins in the single digits going into (and actualized during) summer 2018 and only slightly improved for next summer (in the 11 percent range),[46] it would seem unwise to pursue a market design change that would encourage additional resource retirements. Moreover, thermal generation is needed locationally for voltage and stability support of the grid, and to provide adequate system inertia. Implementing a policy shift designed to incentivize retirement of remote generation and development of centralized generation could, in the long-term, require additional ancillary services or operational tools to support the physical reliability of the ERCOT grid.

Question 9: What effects, if any, would marginal transmission losses have on grid hardening and resilience?

As noted above, "resilience" refers to the ERCOT grid's ability to withstand idiosyncratic shocks, such as those caused by a severe storm or cyber attack. If marginal transmission losses were

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42 *Questions on ERCOT ML Study 09052018a*, posted to http://www.ercot.com/mktinfo/rtm/marginallosses; Project No. 47199, Analysis of Marginal Losses Proposal (October 12, 2017).

43 *See, e.g.*, *In re Reliability and Resilience Pricing*, Federal Energy Regulatory Commission (FERC) Docket No. RM18-1-000, Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking (Oct. 23, 2017) ("Reliability is a function of resource adequacy and operating reliability. Resource adequacy reflects the ability of the system to supply electricity to meet consumer demand. Operating reliability includes resilience and is the ability of the system to withstand sudden disturbances to system stability or unanticipated loss of components. A balanced portfolio of generation resources and transmission infrastructure ensures that the system has adequate capacity to meet consumer needs and is ready to respond to unexpected outages or extreme weather events."), *available at*: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Comments%20of%20NERC%20re%20Proposed%20Grid%20Reliability%20and%20Resilience%20Pricing.pdf.

44 *Supra* note 38.

45 *Supra* note 33.

46 In the December 2017 Report on the Capacity, Demand and Reserves in the ERCOT Region (CDR), ERCOT projected a 9.3 percent planning reserve margin for summer 2018. ERCOT CDR, 2018-2027 (Dec. 18, 2017), *available at*: http://www.ercot.com/content/wcm/lists/143977/CapacityDemandandReserveReport-Dec2017.pdf. Going into summer 2018, ERCOT projected a planning reserve margin at approximately 7.5 percent based on projected reserves of 5,428 megawatts (MW) and projected adjusted peak demand of 72,756 MW. ERCOT, Seasonal Assessment of Resource Adequacy for the ERCOT Region, Summer 2018 – Final (Apr. 30, 2018). At the same time, ERCOT projected only a slight improvement in the outlook for summer 2019 at approximately an 11 percent reserve margin. ERCOT CDR, 2019-2028 (Apr. 30, 2018), *available at:* http://www.ercot.com/content/wcm/lists/143977/CapacityDemandandReserveReport-May2018.pdf.

implemented and somehow did overcome the obstacles outlined previously in these comments to cause future generation investment to occur primarily near the theoretical center of load outside Houston (as intended), that result would be detrimental to grid hardening and resilience.[47] For example, if a major hurricane hit the Houston area and disabled numerous generation resources in that area (e.g., as occurred with Hurricane Harvey in 2017, with the Energy Information Administration indicating that ERCOT experienced 10,000 MW of forced outages of generating capacity during peak demand[48]), then it is paramount to have generation resources located in other parts of the State that are not affected by the storm to be available to generate power to serve load. In a severe event where the ERCOT grid experienced a partial or complete blackout, it would be critical to have black-start resources (meaning resources that can start independently of the power on the grid and begin generating power to return the grid to a stable condition) located near load pockets throughout the state, rather than having them all located near the theoretical center of load outside Houston. Having black-start resources spread out in that fashion would create redundancies across the grid and enable small islands of the grid to start-up and restore the grid to a stable condition.

In short, it would be detrimental to the resiliency of the grid to have all generation resources located near Houston, in the event a severe storm or other unexpected disturbance occurred and disabled a significant amount of resources in Houston (as has happened in the past and likely will occur in the future given the location of that city in a flood zone). It is far preferable to have generation resources located throughout the state to withstand unexpected shocks to the system and to have black-start resources spread out across the grid to return the grid to a stable condition in the event of a partial or complete blackout.

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[47] For example, the National Infrastructure Advisory Council has defined "resilience" as follows: "Infrastructure resilience is the ability to reduce the magnitude, impact, or duration of a disruption. Resilience is the ability to absorb, adapt to, and/or rapidly recover from a potentially disruptive event." *See* Department of Homeland Security, National Infrastructure Advisory Council, *Critical Infrastructure Resilience: Final Report and Recommendations* (Sept. 8, 2009), *available at*: https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf.

[48] The Energy Information Administration (EIA) found: "Hurricane Harvey caused substantial electricity outages, as power plants and transmission infrastructure—particularly in south Texas and along the Gulf Coast—were affected by high winds and significant flooding. At its peak, more than 10,000 megawatts (MW) of electricity generating capacity in the Electric Reliability Council of Texas (ERCOT) grid and a substantial number of transmission and distribution lines experienced forced outages." See EIA, *Hurricane Harvey caused electric system outages and affected wind generation in Texas* (Sept. 13, 2017), *available at*: https://www.eia.gov/todayinenergy/detail.php?id=32892.

Question 10: What effects would the use of marginal transmission losses in SCED have on grid reliability in regions of the ERCOT grid where non-synchronous generation is more prevalent?

As indicated above, ERCOT has recently studied the need to address both system inertia and stability as the penetration of non-synchronous renewable generation (like wind and solar) on the ERCOT grid increases significantly.[49] That generation is primarily located in the north and west parts of the state. Implementing a design change that is likely to incentivize additional retirements of thermal, synchronous resources in the North and West Zones would almost certainly make things worse.

Question 11: How would a decision to implement marginal transmission losses affect investment in new generation resources in ERCOT over the next five years, the next 10 years, and in the years beyond 10 years?

As Vistra Energy has noted throughout these comments, ERCOT's estimated outcome of implementing marginal transmission losses is an annual loss of revenues for generators in the North and West Zones in the range of $375 to $605 million, and it would primarily impact thermal generators in those areas, to the tune of $256 to $469 million. While admittedly an oversimplification, multiplying those figures out over 5 years for demonstrative purposes yields a staggering $1.875 to $3.025 billion reduction in the North and West Zones, $1.28 to $2.345 billion of which would come at the expense of thermal generators in those zones. Given that the IMM has stated that energy prices in ERCOT have been too low to support new generation investment for the past 6 years,[50] it is inescapable that implementing marginal transmission losses would detrimentally affect generation investment in ERCOT (especially in the North and West Zones). In a wholesale power market that is dependent on energy pricing signals to incentivize new entry and that is consistently producing pricing signals that are insufficient to support that entry, and with low planning reserve margins projected over the next several years,[51] embarking on a market design change that would further diminish generator revenues in two of the four load zones in ERCOT seems unwise and inconsistent with a litany of other valid policy goals that have already been set out or are under current consideration.

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49 *Supra* notes 22 and 23.

50 *Supra* note 38.

51 ERCOT CDR, 2019-2028 (Apr. 30, 2018) (showing projected planning reserve margins of 11.0 percent for summer 2019, 12.3 percent for summer 2020, 12.0 percent for summer 2021, and 10.9 percent for summer 2022), *available at:* http://www.ercot.com/content/wcm/lists/143977/CapacityDemandandReserveReport-May2018.pdf.

Question 12: How would the implementation of marginal transmission losses affect the composition of the generation fleet in ERCOT?

As indicated under Question Nos. 1 and 2, environmental restrictions make it unlikely that implementing marginal transmission losses would cause significant new investment of thermal resources in the Houston area, even though, in theory, the wholesale wealth transfer into that area that marginal transmission losses would cause should incentivize new entry. As discussed throughout these comments, it is highly unlikely that any material new generation would be able to build into the Houston area. Wind build-out could be stifled, though that may happen in any event following the expiration of the current federal production tax credit and given that the Competitive Renewable Energy Zone (CREZ) transmission is already fully subscribed. Implementing marginal losses hoping to stop the otherwise economic development of wind and solar resources would be short-sighted in that it would squander the vast and valuable land and resources in west Texas. The largest impact of implementing marginal transmission losses likely would be to accelerate the retirement of existing thermal resources in the North and West Zones, which are consistently modeled to take the brunt of the generator revenue reductions.

Question 13: Assuming the Commission decided to go forward with implementation of marginal transmission losses, what are the key issues related to determining the appropriate treatment and allocation of the marginal transmission loss surplus revenues?

As indicated under Question Nos. 1 and 2, the subject of allocating marginal transmission loss surplus revenues has been hotly contested in other ISOs and continues to be litigated in PJM,[52] and Vistra Energy anticipates that ERCOT would be no different in that regard.

As an example of the source of controversy, the issue in PJM has revolved around whether virtual traders (i.e., that do not engage in physical sales or purchases of power) should have to pay marginal transmission losses in the first place and, if so, should be entitled to a portion of the surplus reallocation. In that particular litigation, the FERC initially found that the traders did have to pay marginal transmission losses and were not entitled to the surplus reallocation, but the FERC later changed course and decided they were entitled to a surplus allocation in proportion to their contribution to paying for the transmission system (which amounted to roughly $37 million); FERC then changed

[52] For the response to this question generally, the relevant citations are set forth, *supra*, in notes 29 through 32.

course again and decided it could not retroactively order those surplus reallocation payments to be made and thus directed PJM to recoup the money, which led to several entities going out of business and which is still in litigation today.[53] In other ISOs, there have been significant disputes about whether transmission customers subject to a grandfathered agreement with the incumbent utility should have to pay marginal losses and, if not, how they should be refunded the difference between what they were erroneously charged for losses under the marginal loss mechanism and what they should have been charged under the average loss mechanism.[54]

The FERC has not endorsed a particular methodology for allocating the surplus, but has provided, as a general guiding principle, that whatever mechanism is adopted, it should not result in a direct refund in proportion to the payment for the losses in the first instance, because, in FERC's view, that would erode the intended price signal in a marginal loss paradigm.[55] In the ISOs subject to FERC jurisdiction, the marginal loss surplus allocation is generally allocated back to the payers of the transmission system in some fashion, but the particular mechanisms differ and in some ISOs (like the Midwest Independent Transmission System Operator, Inc. and Southwest Power Pool, Inc.) involve multiple loss pools and appear exceedingly complex.[56]

The FERC analogy is useful in the sense that it demonstrates that with hundreds of millions of dollars of over-collection per year at stake (estimated at more than $200 million by the Brattle Group), there is likely to be significant controversy over who is entitled to the surplus. And, in the meantime, retail customers will be exposed to loss payments nearly twice as high as what they pay under the current system. In addition, as discussed in Question No. 3, the nature of the retail market structure in ERCOT would create additional complexities for any surplus allocation methodology in ERCOT.

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53 *Supra* note 29.

54 This has been an issue in MISO, NYISO, and SPP. *Supra* note 30.

55 *E.g.*, *In re Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) (FERC determined proposed marginal loss surplus revenue allocation mechanism did not comport with FERC guiding principles because it would result in direct refund in proportion to payments), *reh'ing*, 142 FERC ¶ 61,205 (2013).

56 *Supra* note 30.

Question 14: Does the ERCOT analysis of the benefits of including marginal transmission losses in SCED accurately measure such benefits? Are potential costs to the market or to market participants adequately accounted for?

As discussed throughout Vistra Energy's responses, the ERCOT analysis of marginal transmission losses is largely consistent with the analysis provided by Brattle and Vistra Energy's own proprietary analysis. They have all found that traditional benefits metrics such as production cost savings are *de minimis* at best and negative (i.e., increased cost) at worst, and that the net negative impacts to the wholesale market as a whole, and wealth transfers from generators in the North and West Zones to Houston-area generators in particular, are substantial. Vistra Energy refers back to its response to Question Nos. 1 and 2 for a detailed analysis of why, on the whole, implementing marginal transmission losses would be significantly detrimental for ERCOT.

Question 15: What ERCOT operational changes would need to be made that are not considered in ERCOT's studies?

Vistra Energy defers to ERCOT to comment on what specific additional operational changes it might need to make beyond what is listed in its studies, but based on past experiences such as nodal, we assume that ERCOT's studies are just a starting point and that the actual implementation process would be more involved. In addition to resolving the surplus revenue allocation issue and implementing the agreed upon mechanism (as discussed above), presumably, ERCOT would have to develop and implement new training materials regarding marginal transmission losses. ERCOT also might need to update its load forecast methodology if, for example, the implementation of marginal transmission losses incentivized any changes in the future location of load. Marginal transmission losses also might impact the deployment of Reliability Unit Commitment (RUC) (as with all other resources), in the sense that ERCOT would have to determine which units to deploy for RUC based not only on shift factor (as they do today) but also on marginal transmission losses (which would be a factor in deployment of all resources going forward).

Question 16: Would the use of marginal transmission losses in SCED change the ERCOT transmission planning process and transmission build-out?

While it is difficult to predict at this stage exactly how implementation of marginal transmission losses would impact the transmission planning process and transmission build-out, marginal transmission losses would be certain to have some impact on transmission planning and build-out if, as designed, they are effective at incentivizing changes in future generation siting decisions (and, possibly, also in the future location of load). Although there are a number of hurdles to siting generation resources near the theoretical center of ERCOT load in Houston, if the implementation of marginal transmission losses even had some impact on the location of generation and load across the grid, that logically would affect the process for planning and building new transmission.

Question 17: Assuming that the implementation of marginal transmission losses results in the location of generation closer to load, what advantages and disadvantages would there be during an emergency event or a market restart to having generation located closer to load?

As indicated above under Question Nos. 1, 2, and 9, it would be disadvantageous during an emergency event or a market restart to have generation resources concentrated at the theoretical center of load near Houston. Importantly, marginal transmission losses would not have the effect of generally encouraging generation resources to locate closer to load throughout the state, because the losses would be measured in reference to a theoretical center of load, outside Houston. Even if it were possible (given environmental, zoning, and other siting restrictions) for generation resources to all locate near the Houston area, that would be detrimental to the ability of the ERCOT grid to recover from an emergency event like a hurricane or cyber attack or to restart from a partial or complete black-out. In those sorts of circumstances, as discussed above, it is not only advantageous but critical to have generation resources that can start independently of the power of the grid (i.e., black-start resources) located throughout the state so that there are redundancies in the grid and those resources can start up in small islands to restore the grid to a stable condition. Even in the absence of a partial or complete black-out, in the event of a hurricane (or even high temperatures that cause derates of generation resources and transmission in Houston), it would be important and advantageous to have diversification in the location of supply across the grid.

Question 18: What effects, if any, would the implementation of marginal transmission losses have on the Congestion Revenue Rights (CRR) market?

Question 19: How should the Commission direct ERCOT to implement marginal transmission losses in a way that mitigates any deleterious effects on the CRR market?

Vistra Energy responds to Question Nos. 18 and 19 together. The implementation of marginal transmission losses would change the underlying value of CRRs because it would add a new component to the energy price that is not captured in the CRR model. Vistra Energy's proprietary modeling did show that some changes in the congestion component of prices would be expected, and the spreads in prices among load zones would increase. Moreover, as compared to an average loss system (where the loss component of LMP is the same for all LMPs and has no impact on unit deployment), the use of marginal transmission losses would impact unit deployment and thereby impact the location of congestion on the grid. The result would be that the value of the associated CRRs would change.

Furthermore, marginal loss transmission pricing in LMPs erodes the value of CRRs in managing power flow risks from the forward markets into real-time. As noted above, under the current average loss paradigm, losses are not included in the LMP, and because the LMP consists solely of the energy price and the congestion component, the basis risk for the LMP can be fully hedged through CRRs. Under a marginal loss paradigm, a loss component would be added to the LMP, and the loss component could not be included in the CRR auctions, because ERCOT has not designed the CRR engine to take into account the effect that marginal loss transmission pricing would have on unit dispatch. Further, the ERCOT CRR and DAM auctions both utilize fixed reference buses, compared to the use of the calculated ERCOT center of load as the reference bus for marginal transmission losses, which would create further basis risk for market participants. Notably, ERCOT did not take alignment of the CRR, DAM, and real-time reference buses into account in its cost estimate for marginal loss implementation. To the extent that the loss component of the LMP grows, the ability of a CRR to fully account for basis risk diminishes because it would increasingly fail to hedge the price differential between a source and sink node.

It is not clear to Vistra Energy how the Commission could implement marginal transmission losses in a way that mitigates any deleterious effects on the CRR market. As discussed above in the response to Question No. 3, despite attempting to develop a hedging mechanism for marginal losses for a number of years, no other ISO (to Vistra Energy's knowledge) has yet been successful in doing so. One apparent issue has been that the somewhat unpredictable nature of losses due to variables such as ever-increasing line loading has made it difficult to develop an effective hedging mechanism.[57]

[57] *E.g.*, *In re California Independent System Operator Corporation*, 119 FERC ¶ 61,076 (2007).

Question 20: Does your assessment of the incorporation of marginal transmission losses change based on the timeline of implementation?

No. Vistra Energy opposes marginal transmission losses, regardless of the implementation timeline, for all the reasons discussed at length throughout these comments.

Question 21: What are the effects of implementing both Real Time Co-optimization (RTC) and marginal transmission losses on reliability and price formation?

Question 22: Are there any synergies that may result from contemporaneous adoption of both RTC and marginal transmission losses?

Question 23: What are the effects on retail customers and the retail market from the implementation of both RTC and marginal transmission losses?

Vistra Energy responds to Question Nos. 21 through 23 together. RTC and marginal transmission losses are each likely to have a materially negative impact on the ERCOT wholesale market on an individual basis and thus likely would have an even worse impact if adopted simultaneously.[58] RTC was backcasted by the IMM to have reduced 2017 wholesale power prices by $4 per megawatt-hour and virtually eliminated scarcity pricing.[59] Marginal transmission losses are projected by ERCOT to reduce annual generator revenues in the North and West Zones in the range of $375 to $605 million.[60] Both of these efforts are also likely to be costly and time-consuming to implement and do not offer any obvious synergies in terms of implementation—while both would affect unit dispatch in some way, the mechanisms by which they would affect that dispatch are very different. RTC relates to the dispatch of resources for energy versus ancillary services, while marginal transmission losses relates to changing the way the loss component of LMP is calculated (which, in turn, would necessarily affect unit dispatch). Given that adopting one or the other of these mechanisms, individually, would be detrimental to the ERCOT market, then adopting both of them simultaneously seemingly would be exponentially more detrimental in a wholesale market that already has depressed power prices and is failing to incentivize new entry.

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58 Vistra Energy discusses the likely negative impacts of RTC in comments filed today in Project No. 48540.

59 Project No. 47199, Potomac Economics, Simulation of Real-Time Co-Optimization of Energy and Ancillary Services For Operating Year 2017 at 1, 5 (June 29, 2018).

60 *Supra* note 33.

III. CONCLUSION

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

Respectfully submitted,

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