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

FILING CLERK

COMMENTS OF NEXTERA ENERGY RESOURCES, LLC

NextEra Energy Resources, LLC ("NextEra") appreciates the opportunity to respond to the Request for Comments as approved by the Public Utility Commission of Texas ("Commission") during the August 9, 2018 Open Meeting and published in the *Texas Register* on August 24, 2018. NextEra submits the following reply comments to the Commission's questions regarding Project No. 48539, *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch.* In this filing, NextEra does not provide a question-by-question response to every question posed by the Commission, but rather NextEra responds where applicable. The absence of an answer to a particular question should not be construed as support for the inclusion of marginal transmission losses in ERCOT's security-constrained economic dispatch ("SCED").

I. Introduction

NextEra has broad interests in the Texas electric markets, including investments of over $10 billion in wholesale generation, transmission, and the retail electric market. NextEra is committed to supporting the ongoing success of the Texas electric market and believes the proposal to include marginal transmission losses in SCED leads to outcomes that are bad for consumers in Texas and bad for the majority of ERCOT market participants.

Although some proponents of including marginal transmission losses in SCED are advertising the change as a significant benefit for consumers, contradictory study results and significant differences in the quantification of key value measures should raise doubts in the Commission's mind about the certainty of any consumer benefit. NextEra opposes the implementation of marginal transmission losses and believes the Commission should carefully consider the risk of unforeseen outcomes, especially in a finely balanced market with tight reserve margins, before

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moving forward with a material market change that is designed to realize a relatively modest economic benefit for Texas consumers.

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?

Answer:

The very near-term benefits of implementing marginal transmission losses in SCED are fairly well established: Including marginal transmission losses in SCED is intended to provide more accurate price signals to generators, thereby creating a more efficient economic dispatch of generation that reduces the total energy required to serve load, and potentially provides production-cost savings and lower costs for consumers.

Over time, the short-term benefits of including marginal transmission losses in SCED are supposed to lead to additional long-term benefits. Potential long-term benefits from adopting marginal transmission losses include optimal siting of new generation, lower congestion costs, and lower transmission investment, yet these potential benefits could fail to materialize for any number of reasons. For example, higher Locational Marginal Prices ("LMPs") associated with the adoption of marginal transmission losses might send an economic signal that improves incentives for generation investment in Houston; however, regional environmental permitting challenges, community opposition, unfavorable project economics, or many other unforeseeable factors could still arise and preclude siting and development of new generation near Houston, despite higher LMPs.

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.

Answer:

ERCOT and The Brattle Group have each published studies on the impact of marginal transmission losses, and the results of both studies have shown almost no change in production costs, only relatively modest decreases in costs to consumers, and equally modest reductions in overall system transmission losses.[1] NextEra believes the financial benefit to consumers that results from marginal transmission losses implementation is too small and too uncertain to justify moving forward with a market change that may lead to further erosion in ERCOT reserve margins as additional generation retires in response to the impact of marginal transmission losses.

3. What are the effects on retail customers and the retail market from the implementation of marginal transmission losses?

Answer:

ERCOT's evaluation of the annual change in total consumer costs attributable to the implementation of marginal transmission losses predicts benefits ranging from $76 million to $170 million annually.[2] However, conclusions on the broader impact of marginal transmission losses on customers and the retail market should not be drawn from ERCOT's single-year analysis because the analysis does not address other second-order effects and costs that may arise from marginal transmission losses implementation and have significant adverse impacts on customers and the retail market.

If marginal transmission losses are approved, other key elements of the current ERCOT market design will also need to be modified to accommodate the change. Before the effect of marginal transmission losses on customers can be evaluated in a meaningful way, ERCOT and market stakeholders need to inventory which elements of the market will be modified and come to agreement on how those modifications will be implemented. Until the broader market redesign that is necessary as a result of the adoption of marginal transmission losses is understood, any

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1 *See, Project to Access Price-Formation Rules in ERCOT's Energy-Only Market,* Project No. 47199, ERCOT Studies on Benefits of Real-Time Co-Optimization and Marginal Losses at 14 (June 29, 2018) (ERCOT Studies) and Analysis of Marginal Losses Proposal at 7 (Oct. 12, 2017) (Brattle Study).

2 ERCOT Studies at 16.

attempt to determine the effect on customers will be incomplete and potentially lead the Commission to wrong conclusions about the overall effect on retail customers and the retail market.

A partial list of issues that are currently unknown but will affect retail customers includes:

1) Revenue over collection and allocation of excess revenue.
2) Treatment of losses in Congestion Revenue Right (CRR) settlements.
3) Additional unhedgeable risk from CRR redesign.
4) Changes to CRR values, CRR auction revenues, and revenue distribution to load.
5) Impact of lower generator revenues on generator retirements, reserve margins, reliability, and prices.

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?

<u>Answer:</u>

While a static one-year analysis of the impact of introducing marginal transmission losses in SCED may accurately calculate certain market efficiency measures, such as generator revenues and total system energy, a single-year analysis will obviously not reflect the cumulative, multi-year impact that occurs as market participants respond to the effects of marginal transmission losses. Any suggestion that the initial benefit observed from marginal transmission losses will be sustained over an extended period of time implies that generation owners will not respond to marginal transmission losses price signals and will simply participate in a marginal transmission losses "groundhog day" existence for extended periods of time.

In light of continuing generator retirements and the ERCOT system's low reserve margins, NextEra believes that the small reductions in generator production costs and lower generator revenues that were observed in ERCOT's one-year study will ultimately be overshadowed by the accumulated economic and reliability impacts of additional generator retirements that occur in response to the large, ongoing redistribution of revenue from generation owners in the North and

West zones to Houston and South zone generation owners. The cost of these retirements and the cost of mitigating the reliability impacts that new retirements create will not be captured in a study that simulates just one year.

5. 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.

Answer:

Although NextEra has not performed a detailed analysis of the costs required to upgrade databases, risk management, shadow settlement, accounting, and retail pricing and billing systems, NextEra has experience with similarly impactful IT projects and believes the cost of implementing marginal transmission losses across all impacted systems will be between $1 million and $2 million.

6. How would a decision to use marginal transmission losses affect your company's market systems?

Answer:

NextEra has not performed a market systems impact scoping study; however, based on NextEra's current understanding the way in which marginal transmission losses would likely be implemented, NextEra believes risk management, shadow settlement, accounting, and retail pricing and billing systems would all need to be modified to accommodate the addition of a marginal transmission losses component to the LMP.

7. How would a decision to use marginal transmission losses affect your company's internal operations?

Answer:

NextEra does not expect the adoption of marginal transmission losses to cause material operational impacts. Functions such as generation dispatch and scheduling should be relatively unimpacted by changes in the underlying mechanics of LMP formation associated with marginal transmission losses.

8. What are the effects on reliability on the ERCOT grid of using marginal transmission losses instead of average transmission losses in SCED?

Answer:

ERCOT's modelling of the impact of marginal transmission losses on generator revenues should raise significant concerns that the implementation of marginal transmission losses will have severely negative effects on ERCOT reserve margins and on reliability.

The North Zone currently contains approximately 9,000 MW of operational coal and nuclear generation. Coal and nuclear generation in ERCOT is widely known to be at risk of retirement due to the ongoing impact of low power prices. ERCOT's marginal transmission losses study concluded that North Zone generator revenues declined by over $330 million in a single year as a result of marginal transmission losses implementation.[3]

The massive reduction in North Zone generator revenues that results from marginal transmission losses implementation in the ERCOT study exacerbates an already tenuous situation. Although lower generator revenue is characterized by proponents of marginal transmission losses as a key benefit, the reality is that redistributing and reducing North Zone generator revenues only serves to further impair the viability of already challenged generators and accelerate retirements at a time when reserve margins are already well below the ERCOT minimum target level.

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

[3] ERCOT Studies at 15.

Answer:

NextEra is unaware of any impact marginal transmission losses will have on grid hardening, however, NextEra believes marginal transmission losses could adversely affect grid resilience by reducing generator fuel diversity and, as stated previously, by driving additional generation retirements within ERCOT.

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?

Answer:

NextEra believes the use of marginal transmission losses will negatively impact reliability throughout the entire ERCOT region by frustrating development of generation in locations that are farther from load centers. Non-synchronous generation tends to be sited further from load centers in order to benefit from lower development costs and superior wind and solar production profiles. Adopting marginal transmission losses reduces the likelihood that new generation will be built in remote locations by offsetting the economic advantages of low-cost, remotely located generation sites with lower LMPs. Therefore, marginal transmission losses negatively impacts reliability by reducing the amount of new generation that is added to the market.

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?

Answer:

A decision to implement marginal transmission losses would affect investment in new generation across each of the Commission's time frames by reducing generator revenues in areas of Texas in which development is currently most active, thereby causing marginal planned-future generation investments in those areas to become uneconomic and not occur. Given the fact that investment in solar generation currently requires a higher levelized cost of electricity (LCOE) than investment in wind generation, NextEra believes investments in remotely located solar generation will be disproportionately impacted by the implementation of marginal transmission losses.

Due to a combination of factors, including higher development costs, lower wind and solar production profiles, and in some cases, environmental siting challenges, less investment in generation is currently occurring in areas near Houston, where generator revenues will likely increase after marginal transmission losses are adopted. NextEra believes that simply shifting generator revenues by raising LMPs near the Houston load center will not bridge the economic gap that currently limits investment there. Therefore, NextEra believes the overall impact of marginal transmission losses on investment in generation resources in Texas is likely to be negative because generation investment near Houston is unlikely to offset the loss of generation investment in other areas of Texas.

This question and other related questions were also investigated and answered in the PA Consulting Group study of the long-term impact of marginal transmission losses that was filed with the Commission in Project No. 47199 and attached for inclusion in this project.[4]

Noteworthy conclusions from PA Consulting's study of the impact of marginal transmission losses on investment in generation between 2018 and 2037 include the following:

1) Marginal transmission losses implementation produces no additional combined cycle capacity.
2) Marginal transmission losses implementation suppresses investment in both wind and solar generation.
3) Marginal transmission losses implementation suppresses development of West Zone solar generation by 800 MW.
4) Marginal transmission losses implementation raises production costs by $5.1 billion and eliminates nearly $4.6 billion in production cost savings.
5) Marginal transmission losses implementation reduces installed capacity by almost 2 GW.

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[4] *See,* Report: The Long-Term Impact of Marginal Losses on Texas Electric Retail Customers by PA Consulting Group (Apr. 20, 2018) (PA Study) Attached.

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

Answer:

NextEra believes the implementation of marginal transmission losses would affect the composition of the generation fleet in different ways over time. In the near term, the implementation of marginal transmission losses and the associated reduction in generator revenues in the North and West zones will further threaten the viability of remaining coal and nuclear generation in those areas, potentially driving additional retirements and reductions in fuel diversity. In the longer term, modeling of the impact of marginal transmission losses shows modest additions of gas peaking units, but these additions are more than offset by significant decreases in renewables.[5] These changes create additional costs to consumers in the form of additional emissions from greater dispatch of gas fired resources and significantly higher overall energy prices.[6]

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?

Answer:

NextEra believes some of the key issues related to the appropriate treatment and allocation of marginal transmission losses surplus revenues are:

1) Which market participants are the appropriate recipients of the surplus revenues?
2) If surplus revenues are allocated to transmission customers, on what basis should allocations be determined (demand, volume, or total charges)?
3) Which market periods (day ahead, real time, or some combination) should be used when determining allocations?
4) What is the appropriate time interval (hourly, daily, monthly, or annual) upon which allocations should be based?

5 PA Study at 19-20.

6 PA Study at 21-22.

5) What is the appropriate treatment of DC-tie exports?

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?

Answer:

No response provided.

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

Answer:

No response provided.

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

Answer:

The implementation of marginal transmission losses will change power flows, generation locations, and the generation resource mix. These changes will likely require additional transmission build-out to support reliable operations. The impact of implementing marginal transmission losses on ERCOT's planning process in not clear.

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?

Answer:

While it is possible that the addition of generation resources near load centers could potentially enhance reliability during extreme and unforeseeable situations, NextEra believes that siting additional generation closer to load provides little if any benefit during an emergency or black start event that is not already provided by existing local generation.

NextEra is also unaware of any potential disadvantages that generation sited close to load would create during an emergency or black start event.

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

Answer:

The exact impact of marginal transmission losses on the CRR market will depend on implementation details that have not been addressed to date, however the adoption of marginal transmission losses in other markets provides examples of negative impacts on the CRR market that the Commission should consider when evaluating the overall benefits of marginal transmission losses implementation.

In other markets that have adopted marginal transmission losses, the change has typically forced CRR owners to accept additional unhedgeable risks because marginal transmission losses are included in the LMP, but excluded from the CRR settlement calculation. The inability to hedge the marginal transmission losses component of the LMP has broad, unfavorable risk management implications for all market participants who rely on CRRs to manage basis exposure and will likely raise prices to consumers because the additional risk will ultimately drive market participants to include new risk premiums in both wholesale and retail energy transactions.

In addition, total CRR auction revenues are likely to decrease and, therefore, so will the subsequent distribution of CRR auction revenue to load.

Finally, depending on when marginal transmission losses are implemented, the change in the treatment of losses in CRR settlements could adversely affect market participants who have

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purchased CRRs for periods that extend beyond the marginal transmission losses implementation date.

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

Answer:

To mitigate deleterious effects of marginal transmission losses on the CRR market the Commission should direct ERCOT to implement marginal transmission losses in the following ways:

1) The Commission should instruct ERCOT to present a range of CRR market redesign plans for evaluation and approval by the Commission through a formal rulemaking process.
2) If CRRs will ultimately exclude the impact of marginal transmission losses, marginal transmission losses should be implemented after any CRRs sold through CRR auctions have settled and ERCOT should clearly announce a date after which CRRs sold through subsequent auctions will no longer include marginal transmission losses, thereby providing notice to market participants to incorporate the change into their bids.
3) The Commission should direct ERCOT to bring forward a range of proposed CRR market modifications, including potential designs that continue to include marginal transmission losses in the CRR settlement so the Commission can evaluate the relative tradeoffs and make an informed decision.
4) The Commission should instruct ERCOT to begin publishing marginal transmission losses data in parallel to the current LMP price for a full year before CRRs that exclude losses are auctioned so market participants can evaluate the impact of marginal transmission losses on CRR vales during each season.

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

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Answer:

No.

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

Answer:

No response provided.

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

Answer:

Although NextEra opposes the implementation of marginal transmission losses in ERCOT, NextEra believes that integrating multiple major market changes into a single set of modifications that are designed and executed together as a suite of changes is more efficient and will achieve a better overall outcome for the market. NextEra believes this approach reduces the number of market disruptions and reduces the cost of system redesign for ERCOT and for market participants.

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

Answer:

No response provided.

RESPECTFULLY SUBMITTED,

John Ritch by with permission

John Ritch
Senior Director, Regulatory Affairs and Strategy
NextEra Energy Resources, LLC
(713) 401-5738 (telephone)
john.ritch@nee.com

ercot

June 29, 2018

Public Utility Commission of Texas
Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin
1701 N. Congress Ave.
Austin, Texas 78701

Re: *PUC Project No. 47199 – Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market*

Dear Chairman and Commissioners:

As requested by the Commission at its October 27, 2017 open meeting, Electric Reliability Council of Texas, Inc. (ERCOT) hereby submits its *Study of the Operational Improvements and Other Benefits Associated with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services* (Attachment A) and its *Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch* (Attachment B). ERCOT also notes that the Independent Market Monitor (IMM) for the ERCOT region, Potomac Economics, is today filing its assessment of the benefits of co-optimization with respect to Security Constraint Economic Dispatch in the ERCOT market.

ERCOT appreciates the opportunity to provide this information to the Commission and would be pleased to provide any additional information or analysis the Commission may request.

Respectfully,

Nathan Bigbee
Assistant General Counsel
(512) 225-7093
nathan.bigbee@ercot.com

Attachment A

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Study of the Operational Improvements and Other Benefits Associated with the Implementation of Real-Time Co-optimization of Energy and Ancillary Services

June 29, 2018

1. [illegible]

Electric Reliability Council of Texas, Inc. (ERCOT) provides this report in response to the October 27, 2017, Open Meeting discussion directing ERCOT and the Independent Market Monitor of Texas to study the expected benefits of the potential implementation of Real-Time Co-optimization (RTC) of energy and Ancillary Services (AS). This report addresses the implications of RTC on the actions of ERCOT's operators to manage system reliability and provides a quantitative analysis of the effects of RTC on historical Reliability Unit Commitment (RUC) and Supplemental Ancillary Service Market (SASM) activity. ERCOT has also provided support to the Independent Market Monitor (IMM) in its historical analysis of the impact of RTC on Security-Constrained Economic Dispatch (SCED), which is being submitted separately.

ERCOT's analysis has yielded several key findings. First, ERCOT anticipates significant operational benefits from the implementation of RTC, including more timely procurement of additional AS when necessary, more effective congestion management, a reduction in manual actions by operators, and an improved management of Resource-specific capabilities in assigning and deploying AS. Regarding RUC activity, a study of 165 historical RUC cases from 2016 indicates that co-optimization would have eliminated Resource commitments in at least 9 of the cases. Finally, ERCOT has executed 391 SASMs covering more than 2,200 operating hours since the beginning of the nodal market at clearing prices averaging approximately $100/MWh more than the corresponding Day-Ahead Market (DAM) price for the same operating day, hour, and AS product. The number of MW procured in these SASMs, when priced at the $100/MW premium, is a cost difference of approximately $11 million. RTC would eliminate the need for these SASMs. Also related to SASMs, the ability of Market Participants to buy back their AS in Real-Time under RTC and reduce their risk of a Day-Ahead AS obligation due to a SASM would likely increase the liquidity of the Day-Ahead AS market.

2. Operational Benefits of Co-optimization

Under the current market design, ERCOT procures required quantities of AS in the DAM to ensure grid reliability in Real-Time. AS procured in the DAM acts as insurance for system events ranging from forecast error to unit trips. ERCOT operators rely on SASMs to replace AS responsibilities that are declared infeasible due to congestion or that the responsible Qualified Scheduling Entity (QSE) fails to provide. The approximate two-hour period required to announce a SASM, allow Market Participants to update their offers, execute the SASM, post the results, and allow Market Participants to update their Current Operating Plans (COPs) reflecting awards, effectively prevents ERCOT from replacing the AS responsibility within the two hours following identification of the insufficiency, potentially extending AS shortages during that period. ERCOT operators have, in fact, experienced these shortages while awaiting procurement. By contrast, under RTC, SCED would dynamically assign AS responsibilities during its next execution and replace that responsibility. RTC thus resolves the reliability concerns associated with the delay in procuring infeasible or insufficient AS.

RTC would also improve ERCOT's ability to manage changing AS needs associated with the evolving Resource mix in the ERCOT region. As ERCOT's Resource mix continues to change, identifying risks associated with forecasted demand, wind, and solar will be key to ensuring reliable grid operations. ERCOT expects these changes will also result in more efficient and nimble unit commitments by Market Participants. The excess headroom capacity that the grid has enjoyed in Real-Time has often covered the historical risk associated with infeasible and insufficient AS and AS that QSEs fail to provide; but a decrease in this capacity could result in lower margins of error in both identifying AS requirements as well as replacing AS responsibilities. RTC would allow ERCOT to dynamically adjust AS quantities in Real-Time as uncertainties associated with demand, wind power, and solar power change. Without RTC, the changes to ERCOT's Resource mix would require ERCOT to be more conservative in estimating the needed AS quantities to ensure reliability, which may add costs to the market.[1]

The implementation of RTC would also allow ERCOT to more efficiently resolve congestion on the transmission system. RTC would enable SCED to recognize and act on the preference for having energy, as opposed to AS, at a given location on the transmission system, including during periods of non-scarcity. While locational pricing will indicate this preference under the current design, individual Market Participants cannot always respond to this preference in the near-term, especially those with small Resource portfolios. Additionally, the ability to act on this preference automatically and immediately will reduce the volatility of dispatch of Resources across the system.

Implementing RTC would also allow ERCOT operators to focus on other reliability issues. Significant operator attention is currently allocated to various activities associated with monitoring and addressing system AS needs. These activities include (1) identifying the conditions that will trigger the need to deploy AS and release additional capacity for economic dispatch, (2) tracking the ability of individual Resources to meet scheduled AS responsibilities, and (3) detecting cases in which the provision of AS is infeasible due to congestion on the transmission system. These manual activities would be automatically performed with the implementation of RTC and would be done without adversely impacting market pricing, which is a risk when using manual processes. Automating these activities through RTC would allow ERCOT operators to refocus their attention on various other concerns arising on the grid during Real-Time operations. RTC would also result in more consistent, predictable outcomes for Market Participants, due to the replacing current manual reliability actions with a market solution, and would allow Market Participants to better prepare for and respond to conditions on the grid.

Finally, the implementation of RTC would result in improved management of Resource-specific capabilities in assigning and deploying AS through continuous Real-Time adjustments of individual AS responsibilities. Today, the scenarios in which this does not occur can lead to degradation of the services. For example, in transitioning from one operating hour to another, Resources may take multiple SCED intervals to adjust to their updated AS responsibilities, which means the full amount of AS they are obligated to provide may not necessarily be available for deployment during this transition period. Similar concerns arise with the deployment of Regulation Service at the portfolio level where the system is not designed to consider individual Resource capabilities and the total

[1] The quantities of AS that are procured in the DAM are typically determined between 1 month and 13 months ahead of the operating period during which they will be in effect. With these values being determined far in advance, the amount of AS procured may not necessarily truly reflect the needs in Real-Time. The methodology for determining the minimum amount of AS can be found at http://www.ercot.com/content/wcm/key_documents_lists/89135/ERCOT_Methodologies_for_Determining_Minimum_Ancillary_Service_Requirements.zip.

expected output of the Resource cannot be fully attained. The continuous adjustments enabled through RTC would increase the likelihood that procured AS would be fully provided.

In a related manner, implementation of RTC would allow ERCOT to better utilize limited-duration Resources such as batteries and Controllable Load Resources. RTC would allow ERCOT to use system-wide information updated every five minutes to identify the optimal AS responsibility quantities for each Resource while considering and respecting the Resource's limits and status. This will remove unnecessary barriers to participation in the AS markets.

[illegible]

3.1. Impact of RTC on the Need for RUC Commitments

If RTC were to be implemented in the ERCOT market, ERCOT presumes that the optimization engine for the RUC process would also be modified to co-optimize energy and AS. As a result, the RUC engine would have improved capability to resolve projected congestion on the transmission system with Resources that are already committed by their Qualified Scheduling Entity (QSE) to be on-line. Co-optimization would allow all on-line capacity from Resources, including capacity that is currently reserved by Market Participants to provide AS, to be used in the most effective way to meet all of the constraints of the system: balancing power needs, meeting AS requirements, and managing transmission constraints. This would lead to an overall reduction in the need for ERCOT to instruct additional Resources on-line.

Currently, each QSE decides which of its Resources will be responsible for satisfying the QSE's AS obligation in Real-Time. These obligations can result from DAM awards, SASM awards, self-schedules of AS, or trades with other Market Participants. The decisions are communicated to ERCOT through Resource COPs, and the COPs are used as inputs to the RUC optimization engine. The RUC optimization engine is unable to modify the AS assignments of Resources, even if the reserved capacity could help resolve transmission congestion and avoid out-of-market Resource commitments. Incorporating the co-optimization of energy and AS in the RUC process would provide the RUC optimization engine the flexibility to determine the most efficient way to make use of the Resources projected to be on-line and available.

Two conditions need to be met in order for co-optimization to reduce the need for RUC instructions by ERCOT. First, at least one Resource with an AS responsibility must be located at a point in the system where it could help manage transmission congestion that cannot be resolved through the re-dispatch of other on-line Resources. Second, there must be other Resources elsewhere in the system that are both qualified to provide the service and not currently needed to help resolve other constraints on the system. In cases where these conditions are not met, co-optimization will not affect the need for RUC instructions. In cases where these conditions are met, the magnitude of the benefit will depend on the amount of capacity being reserved on the Resource to provide AS, the sensitivity of the Resource in helping to resolve the transmission congestion, and the magnitude of the projected overloading of the transmission equipment prior to rearranging the AS responsibilities.

3.2. Impact of RTC on Historical RUC Activity

ERCOT performed an analysis to quantify the effect of co-optimization on historical RUC cases. In this analysis, 165 historical RUC cases from 2016, during which a RUC instruction occurred, were executed with the inputs modified to determine whether there was a reduction in commitment recommendations from the RUC engine if it were able to co-optimize energy and AS. These 165 cases account for all cases in 2016 where the RUC engine recommended the commitment of the Resource that was instructed on-line by ERCOT. In the cases where a RUC instruction was not recommended by the RUC engine (e.g., a Verbal Dispatch Instruction (VDI) or a manual selection by the operator), a change to the commitment recommendation from the RUC engine would not clearly indicate a change in the decision to commit the Resource. It should also be noted that not all recommendations from the RUC engine are accepted and issued as instructions by ERCOT. For example, a recommendation is typically deferred if there is ample time to commit the Resource during a later RUC study.

To simulate the effects of co-optimization for this study, ERCOT modified the RUC cases to remove all AS responsibilities from on-line Generation Resources in order to provide the optimization engine flexibility to resolve transmission constraints with all on-line capacity. After executing the RUC optimization with these modified cases, the results were analyzed to determine whether there was still sufficient qualified on-line capacity available to which the AS responsibility could be reallocated. If sufficient capacity was identified in the solution, the analysis concluded that a RUC engine with co-optimization would have reached that solution while still honoring on-line AS requirements.[2] This approach is conservative and will not identify all cases in which co-optimization would have reduced the need for a RUC instruction. Even in a case where the solution did not have sufficient on-line capacity to meet the AS requirements, it is possible that a co-optimized solution could have found an alternative solution meeting both transmission and AS requirements by shifting dispatch from AS-qualified capacity elsewhere in the system to unused capacity on Resources not qualified to provide AS.

[2] RUC with co-optimization would not ensure that there is a specific amount of on-line capacity providing Non-Spinning Reserve but would instead ensure that there is a sufficient combination of on-line and off-line capacity available. For this reason, this analysis did not require that the Non-Spinning Reserve be provided by on-line Resources.

The results from this analysis can be found in the following table:

Result	Expected Co-optimization Impact	Number of Cases
All originally committed Resources would still be recommended.	The RUC-committed Resource would still have been committed.	109
At least one originally committed Resource was no longer recommended, and the decision to commit one or more of the Resources in the new set of recommendations could not be deferred.	A different Resource would have been committed instead of the RUC-committed Resource.	20
At least one originally committed Resource was no longer recommended, and the decision to commit all Resources in the new set of recommendations could be deferred.	The RUC-committed Resource would not have been committed, and the decision to commit an alternative Resource would have been deferred. No Resources would have been RUC-committed in some of these cases.	27
The committed Resources were no longer recommended, and no alternative Resources were recommended. There was sufficient remaining capacity for AS.	No Resource would have been RUC-committed.	9
Total		165

Table 1. 2016 RUC re-run results comparing recommended resources

These results show that, in 109 of the 165 cases, removing AS responsibilities did not change the Resource commitment recommendations, suggesting that RTC would not likely have impacted the decision to commit the Resource. There are two likely reasons that the commitment recommendations did not change in these cases: either the case had few or no Resources that were carrying AS and that also had the ability to reduce flow on the constrained element, or the initial constraint violations were so large that the capacity reserved for AS would be insufficient to resolve the constraint.

In 47 of the 165 cases, the analysis recommended commitment of a new Resource in place of one or more originally recommended Resources. In 20 of these 47 cases, the recommendation could not be deferred due to Resources' startup times. In these cases it is likely that co-optimization would not have impacted the decision to commit a Resource. However, in 27 of the 47 cases, the decision to commit all of the recommended Resources could be deferred for at least one hour, indicating that the operator could wait until closer to Real-Time to see if system conditions changed or there were self-commitments that obviated the need for a RUC instruction. It is likely that in some of these 27 cases, co-optimization would have eliminated the need for the RUC instruction.

In the 9 remaining cases, removing the AS responsibilities from the RUC cases resulted in the elimination of all RUC recommendations. In each of these cases, there was sufficient qualified capacity remaining to fulfill AS requirements, indicating that co-optimization would have eliminated the need for the RUC instruction. Thus, in total, ERCOT's analysis suggests that RTC would have eliminated the need for RUC instructions in at least 9 of the 165 cases studied; but, as noted above, it might also have eliminated the need for RUC instructions in some of the 27 cases in which the decision to commit could be deferred.

As part of this analysis, ERCOT also considered the impact of RTC on the total amount of capacity recommended for commitment by the RUC engine. For example, if co-optimization allowed a 50 MW HSL Resource needed for one hour to replace a 100 MW Resource needed for two hours, the out-of-market capacity would decrease from 200 MW-hours to 50 MW-hours (i.e., a reduction of 150 MW-hours).

The results from this additional analysis are shown in the following two tables:

Result	Number of Cases
Cases with fewer recommended HSL MW-hours	103
Cases with equal recommended HSL MW-hours	32
Cases with more recommended HSL MW-hours	30
Total	165

Table 2. 2016 RUC re-run results comparing recommended HSL MW-hours

Result	Number of Cases
Cases with fewer recommended LSL MW-hours	103
Cases with equal recommended LSL MW-hours	33
Cases with more recommended LSL MW-hours	29
Total	165

Table 3. 2016 RUC re-run results comparing recommended LSL MW-hours

The above tables illustrate that, out of 165 RUC cases studied, 103 of the cases (62%) recommended fewer HSL MW-hours in total after releasing AS responsibilities, 32 of the cases (19%) recommended the same number of HSL MW-hours, indicating that co-optimization had no effect on the need to issue RUC commitments, and 30 of the cases (18%) had more HSL MW-hours recommended. The impact to LSL MW-hour recommendations is nearly the same. In the cases where RUC recommended more HSL or LSL MW-hours, the RUC engine was able to resolve more transmission violations with the individual Resource AS responsibilities relaxed. While resulting in more MW-hours, this result illustrates that co-optimization would increase the reliability of the system by providing the dispatch engine more options to resolve transmission constraints. In total, the analysis reduced the total HSL MW-hours recommended in the 165 cases from approximately 712 GW-hours to 577 GW-hours, a reduction of 19%, and reduced the total LSL MW-hours from approximately 207 GW-hours to 164 GW-hours, a reduction of 21%.

An example illustrates how co-optimization can eliminate the need for a RUC commitment. On May 31, 2016, ERCOT issued a RUC instruction to commit Capitol Cogen, a Combined-Cycle Generation Resource in the Houston area, for three hours to relieve congestion on the Singleton-Zenith lines that carry power into Houston. In this particular case, co-optimization would have allowed RUC to access approximately 1,500 MW of capacity that could have helped relieve the constraint, but was reserved for AS. The Resources with this capacity had varying sensitivities to the projected congestion, but in aggregate could have provided up to 136 MW of relief on the congested transmission line and removed the need to commit Capitol Cogen. In fact, there was one on-line Resource alone that had 120 MW of capacity reserved for AS that could have otherwise resolved the transmission constraint on its own, without needing to reassign AS from any of the other Resources in the system.

This analysis only studied the RUC commitments that occurred in 2016, and the number and impact of RUC instructions can vary and are hard to predict. While this analysis is only an indication of the impact of co-optimization on future RUC instructions, the results show that co-optimization would have reduced the need for RUC instructions by at least 9 of the 165 cases studied. To the extent that changes in market conditions or system complexity and uncertainty increase the need for ERCOT to issue RUC instructions, co-optimization would likely further mitigate the impact of those commitments.

[illegible]

SASMs are one mechanism ERCOT uses to reassign AS obligations when one or more QSEs are unable to provide their AS obligation in Real-Time. SASMs are often less liquid than the DAM, resulting in clearing prices that are significantly higher than DAM and not reflective of either the DAM or RTM conditions. With RTC, the RUC process would ensure that sufficient AS-qualified capacity is available and AS responsibilities would be dynamically assigned to the optimal set of on-line qualified Resources in Real-Time by RTC. As a result, the liquidity for reassigning AS responsibility would be increased in Real-Time. ERCOT expects that SASM would not be necessary with RTC, particularly for the cases in which a SASM is being used to reassign AS for a QSE that is unable to meet its AS obligations.

Clearing prices are higher in SASMs than in the DAM for several reasons. First, SASMs typically have much less liquidity than the DAM, which is primarily attributable to the infrequent and unpredictable nature of SASMs. Market Participants do not set aside capacity from DAM to offer into a SASM, and capacity that was cleared in the DAM is also no longer available in a SASM. Liquidity is also limited because Market Participants may not have the fuel arrangements necessary to provide AS. The second reason SASM clearing prices are higher is that offer prices are higher. SASM offers are generally higher than DAM offers because the more economic AS capacity already cleared in the DAM and because there is no make-whole guarantee, so QSEs have to include any applicable startup and minimum generation costs in their SASM offer without knowing what volume of AS they will be awarded. All these factors tend to result in higher clearing prices, potentially significantly higher, in a SASM, relative to the DAM.

These higher prices can result in disproportionate impacts on QSEs with fewer Resources in their portfolios. If a QSE fails to meet its AS obligation, it is required to pay a financial penalty, which may be based on the SASM clearing price. A QSE with a larger fleet is more insulated from the risk of paying this penalty as it is more likely to be able to shift the AS responsibility to another Resource within its portfolio. This asymmetry in risk for Market Participants is present in both energy and AS products, but is of greater significance in the AS market because the financial penalties are often higher for AS than for energy. RTC would reduce this asymmetry and would create an opportunity for increased participation in the DAM AS market.

To quantify the risk of high penalties due to failing to meet an AS obligation, ERCOT studied historical SASM and DAM AS prices from Nodal Go-Live through January 2018 to determine the price spread between the two markets. During this period, ERCOT executed 391 SASMs to replace approximately 130,000 MWh of AS covering more than 2,200 operating hours. Table 4 below contains statistics for the differences between each SASM clearing price and the DAM clearing price for the same operating day, delivery hour, and AS product. The average difference is $99.78/MWh, which is a substantial risk for products that normally clear between $1/MWh and $20/MWh in the DAM. The total difference in cost of these SASMs was approximately $11 million. RTC would eliminate SASMs and their associated risk and would also likely increase the liquidity of the DAM AS market as a consequence.

Statistic	SASM Price Minus the DAM Price for the Same Hour and AS Type
Min	-$491.14
10%	-$8.40
25%	-$2.23
Median	$2.05
75%	$15.90
90%	$253.45
Max	$6,969.49
Mean	$99.78

Table 4. Statistics on differences between SASM prices vs. corresponding DAM prices (Dec. 2010 - Jan. 2018). Positive values indicate SASM price cleared higher than the corresponding DAM price for the same operating day, hour, and AS product.

Conclusions

ERCOT's analysis of the impacts of RTC on operations and on RUC and SASM procurement identified a number of potential benefits.

The study of historical RUC cases suggests that co-optimization would have reduced the need for a RUC instruction in at least 9 of the 165 cases studied, due to the optimization engine having the flexibility to use all of the on-line capacity to meet the energy and AS requirements of the system.

ERCOT's analysis of 391 historical SASMs found that SASM clearing prices averaged nearly $100/MW higher than the corresponding DAM price for the same operating day, hour, and AS product. The number of MW procured in the 391 historical SASMs priced at the approximate $100/MW premium is a cost difference of approximately $11 million. RTC would eliminate the need for these SASMs and the associated risk. This, combined with the ability of Market Participants to buy back their AS obligation in Real-Time through the clearing of AS awards under RTC, will increase the liquidity of the DAM AS market.

ERCOT believes that implementation of RTC would provide significant operational and reliability benefits as the complexities of managing a changing resource mix continue to grow through more timely procurement of AS when additional AS is required or Resources are unable to provide those services, more effective congestion management, and a reduction in manual actions by operators.

Finally, RTC will also provide a framework that will provide a mechanism for improved management of Resource-specific capabilities in assigning and deploying AS.

Attachment B

ercot

Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch

June 29, 2018

I. Introduction

At the request of the Public Utility Commission of Texas (PUCT), ERCOT has conducted an analysis of the expected benefits from incorporating marginal losses into the Security-Constrained Economic Dispatch (SCED) process. When electricity is produced in one location and consumed at another location within the power grid, the electricity flows through the transmission and distribution system and some of it is lost. The losses vary depending on the distance the electricity is traveling and the voltage of the circuits. In ERCOT's current market design, these losses are not reflected in Locational Marginal Prices (LMPs) and are compensated for on a system-wide average basis. Incorporating marginal losses into the SCED process results in transmission losses being considered during the dispatch of resources and reflected in the dispatch outcomes and the resulting LMPs.

This benefit analysis was conducted using the same methodology that is used to conduct the economic analysis of transmission projects for the Regional Transmission Plan and for Regional Planning Group independent reviews (see Appendix A of the Regional Transmission Plan report for complete details[1]). The Uplan Network Power Model version 10.4, a production cost model that includes a security-constrained unit commitment and economic dispatch algorithm, was used to simulate expected system conditions in the year 2020 for this analysis.

This benefit analysis used the same data input assumptions that were used in the 2017 Regional Transmission Plan, with the following exceptions: The natural gas price forecast for the base case of this analysis was updated to be consistent with the natural gas price forecast currently being used in the development of the 2018 Regional Transmission Plan (an annual average cost of $3.55/MMBTU). This natural gas price forecast is based on the High Oil and Gas Resource and Technology forecast in the 2018 Energy Information Agency (EIA) Annual Energy Outlook (AEO). In addition, two other gas prices were used to show the sensitivity of the model results to this input assumption: one sensitivity case used a lower gas price ($1/MMBTU lower or $2.55/MMBTU); the second sensitivity case used a higher gas price ($3.96/MMBTU, based on the natural gas price forecast from the Reference Case in the 2018 EIA AEO). All generating units that met the criteria described in Planning Guide Section 6.9 as of February 1, 2018, were included in the study, and the recently retired generating units were removed from the model database.

For each of the three sets of analyses (the base case and the two natural gas price sensitivities), two model runs were conducted. The first run was conducted consistent with the current system dispatch. In the second run, the system dispatch included consideration of marginal losses. The differences between the outputs of these runs, as described in this summary, indicate the expected benefits from the proposed switch to incorporating marginal losses in system dispatch.

[1] http://www.ercot.com/content/wcm/lists/114740/2017_RTP_PublicVersion.zip

This analysis quantifies the benefits resulting from implementing marginal losses in three different ways: changes in total system production costs; changes in the portion of consumer costs that are paid to generators (i.e., generator revenues); and changes in total consumer costs.

2.1. Production Costs

Production costs are the costs incurred by generators to produce electricity—specifically fuel costs, variable operations and maintenance costs, and unit start-up costs. Production cost savings are indicative of increased system efficiency. Production cost savings do not necessarily represent immediate savings to consumers, as these savings can flow to generators, consumers, or both. The table below shows the annual production costs from the three scenarios evaluated in this study.

Annual Production Costs

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	7,651.5	9,723.0	10,477.9
Marginal Losses ($M)	7,638.0	9,711.6	10,478.8
Savings ($M)	13.4	11.4	-0.9

These production cost savings derive primarily from reductions in the amount of energy required to serve the equivalent amount of customer demand, as incorporating marginal losses into economic dispatch reduces power flows on the transmission system and thus reduces transmission system losses. The lack of production cost savings in the high gas price case is likely due in part to the increased competitiveness of coal-fired units, which are more distant from urban load centers, as gas prices increase. In the three cases studied, including marginal losses in energy dispatch reduced the total generation by approximately 800-1,200 GWh per year, as shown in the following table.

Total Annual Generation

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses (GWh)	431,027	431,279	431,270
Marginal Losses (GWh)	430,200	430,200	430,018

2.2. Consumer Costs

One way to assess changes in consumer costs is to evaluate changes in generator revenues. Money paid to generators is a major component of the overall costs to consumers, and changes in generator revenues can be expected to directly affect consumers. Before the PUCT amended its rules in 2012, ERCOT considered the change in generator revenues as one criterion for justifying economic transmission projects.

The following table shows the annual generator revenues for the three scenarios evaluated in the study. While generators have multiple revenue streams, these revenues are based on energy sales only and do not take into account generator revenues due to providing ancillary services.

Annual Generator Revenues

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	9,666.4	12,136.3	13,076.5
Marginal Losses ($M)	9,498.7	11,923.8	12,852.0
Revenue Change ($M)	-167.7	-212.5	-224.5

Breaking down the generator revenue results by Load Zone indicates a significant transfer of revenues within the generation fleet—specifically from generators in the West and North Load Zones to generators in the Houston zone.

Annual Generator Revenue Changes by Load Zone

	Low Gas Price Case	Base Case	High Gas Price Case
Houston Zone ($M)	172.0	216.4	257.6
North Zone ($M)	-222.0	-331.9	-415.3
South Zone ($M)	38.3	86.8	125.9
West Zone ($M)	-153.0	-180.7	-190.2

Again, this table provides the marginal loss result minus the average loss result, so a negative number indicates a reduction in generator revenues. The positive numbers for the Houston and South zones indicate that generators in these zones in aggregate would be expected to have higher revenues if marginal losses were implemented.

The model output also indicates that wind generation units in West Texas do not show a reduction in energy production due to including marginal losses in the system dispatch, just a reduction in the price they are paid for the energy they produce. However, the reductions in generator revenues for thermal generation units in the West and North Load Zones reflect both reduced production and lower prices for the energy they produce.

The analysis of changes in generator revenues described above indicates cost-savings for consumers across the system. However, these results do not indicate any expected differential impacts to consumers in different parts of the grid.[2] Evaluating changes to LMPs alone is also not informative because 1) LMPs in systems with average losses do not include a cost component for losses, whereas systems with marginal losses do include the cost of losses in the LMPs; and 2) in systems with average losses, the energy losses are accounted for in the energy usage charged to each customer rather than in the cost of the electricity. As a result, the LMPs in the two runs are not directly comparable.

When evaluating the consumer impacts resulting from switching from average losses to marginal losses by zone, one must evaluate the combined impact of changes to both the amount of energy charged to consumers as well as the cost of that energy. The following table provides these results, but it should be noted that the net costs to consumers may differ based on the specific arrangements between customers and their Load Serving Entities (LSEs). The congestion cost components of the payments in the table below are capable of being hedged through the Congestion Revenue Rights (CRR) market, which may result in additional payments or charges to consumers in Real-Time. In addition, any excess revenues derived from the loss components of the consumer payments in the marginal loss scenarios would presumably be redistributed, although the manner in which this would be done has not yet been determined.

Annual Changes in Total Consumer Costs by Load Zone

	Low Gas Price Case	Base Case	High Gas Price Case
Houston Zone ($M)	21.9	-21.8	-58.5
North Zone ($M)	-62.2	-73.6	-81.3
South Zone ($M)	-13.8	-18.5	-12.1
West Zone ($M)	-22.0	-21.1	-18.4
Total ($M)	-76.1	-135.0	-170.4

[2] The preceding table showing impacts to generator revenues in each Load Zone does not necessarily reflect the impact to consumers in the corresponding Load Zones.

These results are calculated by subtracting the average loss result from the marginal loss result, so negative numbers indicate savings to consumers. The one positive number, for the Houston zone in the low gas price case, indicates that consumer costs would be expected to rise in the Houston zone following implementation of marginal losses if gas prices are low.

2.3. Unit Revenue Shortfalls

In addition to the results indicating reductions in system production costs and system-wide consumer costs, the Uplan model results also indicate that unit revenue shortfalls would be expected to increase if marginal losses were implemented. These results are provided in the following table.

Annual Unit Revenue Shortfalls

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	98.9	152.7	203.9
Marginal Losses ($M)	120.4	196.4	269.8

The Uplan simulation model does not simulate the ERCOT Day-Ahead Market (DAM) or the ERCOT Reliability Unit Commitment (RUC) process, both of which provide the opportunity for units to receive make-whole payments if they do not make adequate revenue through real-time energy prices to cover their operating costs. However, the Uplan model does track the difference between the operating costs of units committed to maintain local grid reliability and their daily energy revenue. (The model refers to these revenue shortfalls as "No Load and Start-up Revenue.")

The increased revenue shortfalls in the table above could indicate that implementing marginal losses would result in an increase in units being committed out of merit order so as to maintain local reliability and an increase in unit make-whole payments. It should also be noted that these revenue shortfalls are included in the generator revenue changes described in the previous section. So, even with these increased costs for running units out of merit, the model is still showing significant reductions in generator revenues.

One possible reason for an increase in unit revenue shortfalls may be a corresponding increase in unit startup costs. These results are provided in the following table.

Unit Startup Costs

	Low Gas Price Case	Base Case	High Gas Price Case
Average Losses ($M)	69.3	72.6	73.5
Marginal Losses ($M)	82.5	107.7	127.0

It is not clear from the model results why the start-up costs increase in the marginal losses runs or why the difference grows as the gas price increases. Start-up costs in these simulations are not tied to gas prices in the model input, so the increased costs reflect an increase in the number of unit starts and/or an increase in the number of starts of units with higher start-up costs.

The ERCOT market design does not necessarily ensure system-wide optimization of start-up decisions. These commitment decisions are made independently by resource owners based on their expectations of future on-peak and off-peak market prices. The Uplan model incorporates a simplistic representation of this start-up process, and while the Uplan algorithm cannot predict changes in startup decisions by resource owners, it does suggest a potential change in system costs. As these increased start-up costs would not necessarily be reflected in LMPs, they could be part of the reason that the model shows unit revenue shortfalls increasing in the marginal loss simulations.

[illegible]

In summary, this analysis indicates that both production cost savings and reductions in consumer costs are likely results of incorporating marginal losses in system dispatch decisions. The model results also project increases in unit make-whole payments and unit startup costs, which could indicate possible additional costs if marginal losses are implemented.

PROJECT NO. 47199

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

ANALYSIS OF MARGINAL LOSSES PROPOSAL

COME NOW First Solar Inc., Vistra Energy Corp., and the Wind Coalition (collectively, "Commenters"), and file a copy of *Impacts of Marginal Loss Implementation in ERCOT* by the Brattle Group. Commenters hired the Brattle Group to perform an independent analysis of the potential impacts of implementing a marginal loss methodology for pricing and dispatching generation in ERCOT, as proposed by NRG and Calpine in the current Project.

The Brattle Group performed a production cost study using Power System Optimizer software to simulate current ERCOT market dispatch as compared with the expected ERCOT market dispatch and pricing using a marginal loss component. The modeling analyzed a 2018 study case on an hourly basis for the full year. While the paper submitted by NRG and Calpine referenced an expected $100 million in annual savings in PJM,[1] what the Brattle Group's modeling shows is only $8.6 million in production cost savings could be realized in ERCOT – a savings of only 0.13%. The Brattle Group's modeling also shows that that savings would come in the form of a $239 million reduction in generator net revenues, which, in the Commenters view, would introduce a significant new challenge to the financial viability of existing generation in West and North Texas. Moreover, the modeling shows that the absolute reduction of generation is twice as much as the production cost savings, because adding a marginal loss component would cause less efficient thermal generation in and around Houston to generate in place of more efficient generation that is sited further from the center of load.

In short, given the magnitude of disruption to certain generators when compared to the very small production cost savings, Commenters are convinced that the implementation of a marginal loss component would not be beneficial in ERCOT, and plan to elaborate further on the associated policy issues in subsequent comments.

[1] William W. Hogan & Susan L. Pope (FTI Consulting, Inc.), *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, p. 42 (May 9, 2017).

Commenters appreciate the Commission's deliberate approach to analyzing the proposed changes to ERCOT's market design, and look forward to discussing these and other policy issues in future comments.

Respectfully submitted,

Colin Meehan
First Solar
Director, Regulatory and Public Affairs
11757 Katy Freeway, Suite 400
Houston, TX 77079
512-537-2169 (phone)

Amanda Frazier

Amanda Frazier
Vistra Energy
Vice President, Regulatory Policy
1005 Congress Ave, Suite 725
Austin, TX 78701
512-364-3275 (phone)

Jeff Clark
The Wind Coalition
President
3571 Far West Boulevard, #230
Austin, Texas 78731
512-651-0291

Impacts of Marginal Loss Implementation in ERCOT

PREPARED BY

Metin Celebi
Bruce Tsuchida
Rebecca Carroll
Colin McIntyre
Ariel Kaluzhny

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THE Brattle GROUP

Disclaimer

This report was prepared for Ad Hoc Group that includes Vistra Energy, The Wind Coalition, and First Solar. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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Overview of Analysis
Executive Summary

- Implementing marginal losses reduces system production costs, transmission losses, and generator net revenues.
  - Would reduce system production cost by **0.13% per year ($8.6 million out of $6,784 million**).
  - Would reduce system-wide load inclusive of losses by **0.27% per year (1.06 TWh out of 402 TWh**).
  - Would decrease generator net revenues by **7.54% per year ($239 million out of $3,166 million** before potential allocation of over-collected ML payments).
    - $248 million reduction in revenues, offset by $8.6 million reduction in variable costs.
- Marginal loss implementation changes load LMPs and payments:
  - Annual average LMP (ERCOT-wide) increases by 2.06% ($0.50/MWh increase from $24.33/MWh).
  - LMP payments by load decrease by **$38 million** (before potential allocation of over-collected ML payments).
    - Lower payments in North ($52 million) and West ($47 million) load zones.
    - Higher payments in Houston ($53 million) and South ($8 million) load zones.
- Over-collection of marginal loss payments would be **$205 million**—allocation of these revenues would be subject to a separate policy decision.
- Generation resources closer to the center of load are dispatched more than remote resources.
  - Increased dispatch of higher cost generation resources near center of load offsets the production cost savings coming from the reduction in losses.
  - Generation in Coast, South, and South Central zones increases by 14.2 TWh, offset by a decrease of 15.3 TWh in other weather zones.

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Study Objective and Method

Assess the impact of marginal loss (ML) implementation in the ERCOT Market on system production costs, LMPs, and shift in payments/revenues among market participants.

- Modeled the ERCOT Day-Ahead Market under a Reference Scenario (most likely future world in 2018, given what we know today) to quantify impacts.
  - Compared the Base Case (without Marginal Losses) and Marginal Loss Case
  - Assumed mandatory participation of all market players.
  - Base Case calibrated to historical data without the Houston Import Project ("HIP"), then added HIP in mid-year 2018.
  - Marginal Loss Case was run using Base Case assumptions but with marginal losses implemented. All else is equal.

This study does <u>not</u> account for:

- Impacts of changing locational price signals on economics of entry/exit decisions (including environmental constraints on siting new generation);
- Dynamic impacts of potential changes in entry/exit decisions on market prices and system costs; and
- Implementation costs of marginal loss.

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Overview of Analysis

Model Calibration

We calibrated the model (without ML implementation) against market outcomes in recent years.

- The Reference Scenario modeled 2018 without HIP and showed model results on zonal congestion patterns, implied market heat rates and generation capacity factors are either similar to actuals during 2014-16 or can be explained by the changes in market fundamentals.
  - Total modeled 2018 congestion cost of $341 million, compared to $497 million actual congestion cost in 2016 and $352 million in 2015.
    - 2016 congestion was higher than other recent years due to system upgrade related outages. 2018 congestion is highest in the Panhandle constraint, consistent with ERCOT's expectations[1]
  - Modeled capacity factors are consistent with recent years by unit type and zone. Except for:
    - Low modeled capacity factors for Gas Turbine/Internal Combustion Engine generators, as expected when modeling DA conditions. High modeled capacity factors for the Combined Cycle generators in the West, due to higher gas price differential than recent years.
- The 2014 Test Case (with load, installed wind capacity, and natural gas basis differentials consistent with 2014 levels) had modeled transmission losses of 7.1 TWh similar to the 6.2 TWh of actual losses in 2014.

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Source 1: December 2016 ERCOT Report on Existing and Potential Constraints and Needs

Overview of Analysis

Key Modeling Assumptions

System Load (w/o ML implementation)

- Total annual energy of 402 TWh. This includes 364 TWh from ERCOT Load and T&D losses, and an additional 38 TWh of Private Use Network (PUN) load.
- Total peak load of 78.3 GW. This includes 74 GW from ERCOT load and T&D losses, and an additional 4.3 GW from PUN load.
- PUN load is modeled as flat hourly load throughout the year.

Generation

- The total modeled generation capacity (as of January 1, 2018) is 102 GW (21 GW of Wind):
  - This includes 3 GW (2.2 GW of Wind) that comes online in 2017 and excludes 0.6 GW that retired in 2016.
  - An additional 3 GW (2.6 GW of Wind) of generation is added and 0.8 GW is retired during 2018.
- PUN generation is dispatched similarly to other generation (modeled separately from PUN load), but committed at minimum operating limit.
- 600 Planned and forced generation outages are modeled based on information from NERC.

Key Modeling Assumptions (cont'd)

Transmission

- Houston Import Project coming online on June 1, 2018.
- No transmission outages, forced or planned, were accounted for in the simulation.
- No modeled transactions over DC-ties.

Reference Bus

- Distributed reference bus that represents the center of ERCOT load ("center of load").
- Note: The selection of a reference bus impacts the loss and congestion components of LMPs, thus impacting payments to CRRs and loss payments/refunds.

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Marginal Loss Methodology

This study implements marginal losses with full marginal loss pricing, consistent with the current marginal loss implementations in the U.S. RTOs. Traditionally, there have been two methods:

- **Marginal Loss Pricing:** Under this method, transmission losses are priced according to their marginal loss factor. This results in over collection of loss revenues, by a factor of 2. These revenues will be refunded by the market operator.
- **Scaled Marginal Loss Pricing:** Under scaled marginal loss pricing the marginal loss factor of LMP is reduced to prevent the over collection of loss revenues. This reduction can be done in different ways, and may distort the incentives to generators for least-cost dispatch.

Sources:

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Change in Losses

Implementing marginal losses reduces system transmission losses by 0.27% of the 393 TWh of total energy served (or a reduction of 1.06 TWh) in 2018.

- Losses are approximately 9.51 TWh in the Base Case and 8.45 TWh in the Marginal Loss Case.

Change in Losses – Reference Scenario

Case	Effective Load (TWh) [1]	Transmission Losses (TWh) [2]	Transmission Losses (% of Effective Load) [3]	Change in Losses (TWh) [4]
Base Case	393	9.51	2.42%	
Marginal Loss Case	393	8.45	2.15%	-1.06

[1]: Load Served
[2]: Transmission Losses
[3]: [2]/[1]
[4]: Marginal Loss Case Transmission Losses - Base Case Transmission Losses

- In the peak hour (August 1 HE 16), transmission losses are only reduced by 30 MW (0.04% from 1.67% to 1.63%).
  - Transmission losses (as a % of load) under Base Case are lower during the peak load hour (1.67%) than the annual average since there is more generation from peaking units close to the center of load during this hour.
  - This dispatch pattern means that ML implementation has a lower impact on losses (0.04% reduction) since most generation near the center of load is already running in the Base Case.

013

Change in Production Costs

Implementing marginal losses reduces system production costs by 0.13% from the Base Case ($8.6 million reduction from $6,784 million).

- Marginal losses increase generation from resources closer to the center of load.
- Marginal cost of generation ($/MWh) is higher in zones near the center of load (i.e., less efficient generators are dispatched in the Marginal Loss Case).
- Therefore, implementing marginal losses reduces production cost by only half as much (0.13%) as it reduces total load plus losses (0.27%).

Production Costs ($ million)

Case	Total Production Costs	Production Cost Savings
Base Case	$6,784	-
Marginal Loss Case	$6,775	$8.6

Base Case Average Marginal Costs ($/MWh)

	Combined Cycle	Coal
Coast	24.8	17.4
South	22.9	17.2
S. Central	21.2	19.4
East	20.7	14.3
N. Central	20.9	16.9
North	21.3	21.7
West	20.3	0.0
Far West	19.0	0.0

014

High Level Review of 2018 Reference Scenario Results

Change in Generation

ML implementation shifts generation closer to the center of load (shaded rows).

Change in Generation (TWh)

		Total	CC	Coal	GT	STOG	Nuclear	Biomass	IC	Hydro	Wind	Solar	Storage
Base Case	Coast	**95**	54	14	6	2	20	0	0	0	0	0	0
	South	**38**	14	7	0	0	0	0	0	0	17	0	0
	S. Central	**43**	14	28	0	1	0	0	0	0	0	0	0
	East	**61**	8	53	0	0	0	0	0	0	0	0	0
	N. Central	**77**	30	21	0	0	20	0	0	0	6	0	0
	North	**38**	12	2	0	0	0	0	0	0	24	0	0
	West	**24**	4	0	0	0	0	0	0	0	19	1	0
	Far West	**26**	10	0	0	0	0	0	0	0	14	1	0
	Total	**402**	145	124	7	3	40	0	0	0	80	3	0
Marginal Loss Case	Coast	**105**	62	16	6	2	20	0	0	0	0	0	0
	South	**39**	15	7	0	0	0	0	0	0	17	0	0
	S. Central	**45**	16	29	0	0	0	0	0	0	0	0	0
	East	**54**	6	48	0	0	0	0	0	0	0	0	0
	N. Central	**74**	27	20	0	0	20	0	0	0	6	0	0
	North	**33**	8	2	0	0	0	0	0	0	24	0	0
	West	**24**	4	0	0	0	0	0	0	0	19	1	0
	Far West	**26**	10	0	0	0	0	0	0	0	14	1	0
	Total	**401**	146	122	7	3	40	0	0	0	80	3	0
Delta (Marginal Loss - Base)	Coast	**10**	8	2	0	0	0	0	0	0	0	0	0
	South	**1**	1	0	0	0	0	0	0	0	0	0	0
	S. Central	**3**	2	1	0	0	0	0	0	0	0	0	0
	East	**-7**	-2	-4	0	0	0	0	0	0	0	0	0
	N. Central	**-4**	-3	0	0	0	0	0	0	0	0	0	0
	North	**-5**	-5	0	0	0	0	0	0	0	0	0	0
	West	**0**	0	0	0	0	0	0	0	0	0	0	0
	Far West	**0**	0	0	0	0	0	0	0	0	0	0	0
	Total	**-1**	1	-2	0	0	0	0	0	0	0	0	0

Increase

Decrease

No Significant Change

015

Change in Average Generator LMPs

Marginal loss implementation impacts on Generator LMPs:

- LMPs increase near the center of load (Houston Load Zone).
- LMPs decrease based on distance from the center of load.
  - North and South Load Zone both decrease.
  - West Load Zone decreases significantly.

Annual Average Generator LMPs by Load Zone ($/MWh, Generation-weighted average)

	Houston	North	South	West	ERCOT
Base Case	$25.11	$24.62	$24.56	$19.62	$23.78
Marginal Loss Case	$25.30	$24.30	$24.23	$17.62	$23.26
Delta	$0.19	-$0.32	-$0.33	-$2.00	-$0.51

016

Change in Generator Net Revenues

- Marginal loss implementation lowers the net revenues paid out to generators overall, driven by decreasing gen LMPs in remote zones and total generation decrease.
  - Net revenues increase for some classes of thermal generators near center of load.
- Total net revenues across all generation units decline by 7.54% per year ($239 million out of $3,166 million).
  - Total revenues decrease by $248 million.
    - $233 million decrease in energy revenues, $15 million decrease in ancillary service revenues and uplift payments.
  - Revenue decrease is offset by $8.6 million decrease in variable costs.

Generator Net Revenue Change Between Base and ML Cases ($k)

	CC	Coal	GT	STOG	Nuclear	Biomass	IC	Hydro	Wind	Panhandle Wind	Solar	Storage	Total
Coast	$6,963	$4,842	-$864	-$514	-$2,150	$0	$3	$0	$70	$0	$1	$0	**$8,352**
South	-$1,260	$899	-$81	$7	$0	$7	-$67	-$38	-$24,673	$0	$0	$0	**-$25,205**
S. Central	-$1,662	-$11,922	-$17	-$115	$0	$0	-$84	-$280	$0	$0	$2	$0	**-$14,078**
East	-$4,436	-$26,568	-$0	-$46	$0	-$311	$0	$0	$0	$0	-$0	$0	**-$31,362**
N. Central	-$10,899	-$6,789	-$1	$22	-$7,134	$0	$57	-$69	-$8,393	$0	$1	$0	**-$33,205**
North	-$7,945	-$894	-$15	$0	$0	$0	-$91	-$56	-$20,552	-$28,549	-$1,729	-$63	**-$59,895**
West	-$1,695	$0	-$2	$0	$0	$0	$1	-$51	-$40,334	$0	-$664	$0	**-$42,744**
Far West	-$8,332	$0	-$17	$0	$0	$0	-$4	$0	-$28,985	$0	-$3,340	-$78	**-$40,756**
Total	**-$29,266**	**-$40,431**	**-$996**	**-$646**	**-$9,284**	**-$304**	**-$185**	**-$494**	**-$122,866**	**-$28,549**	**-$5,729**	**-$141**	**-$238,891**

High Level Review of 2018 Reference Scenario Results

Change in Average Load LMPs

Marginal loss implementation would increase annual average load LMPs by 2% ($0.50/MWh on average across ERCOT).

- Implementation of losses increases cost of marginal generator—raising average prices in ERCOT.
- Offset in the West zone (distant from center of load) by highly negative MLC, and exacerbated in areas near center of load by positive MLC.

Annual Average Load Zone LMP ($/MWh, Load-weighted average)

	Houston	North	South	West	ERCOT
Base Case	$24.28	$24.43	$24.46	$23.73	$24.33
Marginal Loss Case	$24.99	$24.79	$25.13	$23.34	$24.83
Delta	$0.71	$0.37	$0.67	-$0.38	$0.50

Annual Average Load Zone LMP Components ($/MWh, Load-weighted average)

		Houston	North	South	West
Marginal Energy Component	Base Case	24.20	24.49	24.38	23.97
	Marginal Loss Case	24.63	24.97	24.84	24.47
Marginal Congestion Component	Base Case	0.08	-0.06	0.07	-0.25
	Marginal Loss Case	0.01	0.00	0.04	-0.15
Marginal Loss Component	Base Case	0	0	0	0
	Marginal Loss Case	0.35	-0.17	0.25	-0.98

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Change in Load Payments

Marginal loss implementation would reduce the total load payments in ERCOT by $38 million (before loss refunds), driven by 9.6 TWh decrease in volume subject to LMP payment (but offset by the increase in the average load LMP).

- Under ML settlement, load pays for marginal losses as part of the MLC of LMPs. Therefore, load is charged the LMPs for the metered load (not grossed up for average losses) to avoid paying for losses both in the LMPs and in the volume.
- Load payments in the North and West zones decrease since the impact of the reduction in load volume is larger than the impact of the increase in load LMPs.
- The reverse effects applies to the Houston and South zones (small reduction in load volume, and large increase in LMPs).

Over-collection of ML payments would be $205 million.

- Allocating over-collected ML payments among loads and generators would be subject to a separate policy decision.
- Loss refund calculated as (Nodal Load * MLC) – (Nodal Gen * MLC) – (System Losses * MEC).

Total Annual Load (TWh)

	Houston	North	South	West	ERCOT	
Base Case	121.7	136.0	111.3	33.1	402.2	Including Tx Losses
Marginal Loss Case	120.4	131.9	108.7	31.7	392.6	Excluding Tx Losses
Delta	-1.4	-4.1	-2.7	-1.5	-9.6	

Annual Load Zone LMP Payments ($ Millions, before loss refunds)

	Houston	North	South	West	ERCOT
Base Case	$2,956	$3,323	$2,722	$786	$9,786
Marginal Loss Case	$3,009	$3,271	$2,730	$739	$9,748
Delta	$53	-$52	$8	-$47	-$38

019

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PROJECT NO. 47199

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

INFORMATIONAL FILING BY INVENERGY LLC
REPORT: THE LONG-TERM IMPACTS OF MARGINAL LOSSES ON TEXAS ELECTRIC RETAIL CUSTOMERS

Invenergy LLC ("Invenergy") respectfully submits the attached report: "*The Long-term Impacts of Marginal Losses on Texas Electric Retail Customers*" ("Report") prepared by PA Consulting Group, Inc. ("PA Consulting"). The Commission opened Project No. 47199 to assess various proposals to change price formation outlined in the whitepaper, "*Priorities for the Evolution of the Energy Only Market*," sponsored by Calpine and NRG (the "Calpine-NRG Whitepaper").[1] This informational filing is in response to the Calpine-NRG Whitepaper proposal to incorporate marginal line losses into dispatch and pricing.

In Invenergy's Reply Comments filed on December 27, 2017, Invenergy noted that it had engaged PA Consulting to conduct a "historical and forward-looking analyses related to the economic impacts associated with incorporating marginal losses."[2] Invenergy sponsored the Report due to the lack information surrounding the marginal losses proposal which resulted in a collective uncertainty among stakeholders.[3] Thus, the Report is meant to compliment and build upon other recent studies on marginal losses, including one filed jointly by stakeholders in the Project[4] and the anticipated ERCOT analysis.[5]

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[1] Competitive Markets, Memorandum, Docket No. 47199 (May 31, 2017).

[2] Invenergy's Reply Comments at 1-2, Docket No. 47199 (Dec. 27, 2017) (citing PA Consulting Group, Inc., *ERCOT CREZ and Marginal Loss Impact Analysis Memorandum*).

[3] For example, in Lower Colorado River Authority's (LRCA) initial comments, it noted: "LCRA and many other market participants have participated in discussions with ERCOT regarding the implementation of marginal loss pricing. It is still unclear to LCRA what assumptions are being used to evaluate marginal loss pricing." LRCA's Comments at 4 (Dec. 1, 2017).

[4] "*Impacts of Marginal Loss Implementation in ERCOT: 2018 Reference Scenario Results*," authored by the Brattle Group and jointly filed by First Solar, Inc., Vistra Energy Corp., and the Wind Coalition, Docket No. 47199, (Oct. 12, 2017).

[5] ERCOT was directed by the Commission to initiate an analysis of expected economic benefits of implementing marginal losses. The report is anticipated to be complete in June 2018.

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Since the competitive market's inception, the Commission has dependably taken measured responses to evolve the ERCOT wholesale market design. As such, the continued success of the competitive power market hinges on implementing policies that are thoroughly studied and narrowly tailored to address specific and persistent, system-wide issues. Such policies should deliver measurable benefits, and have low foreseeable risks to market participants and end-use customers. By sponsoring the report, it is Invenergy's intention to provide useful information so that the Commission, ERCOT, and stakeholders may meaningfully evaluate the marginal losses proposal.

Respectfully submitted,

STAHL, BERNAL, DAVIES, SEWELL & CHAVARRIA, LLP

Brittany May Dadón

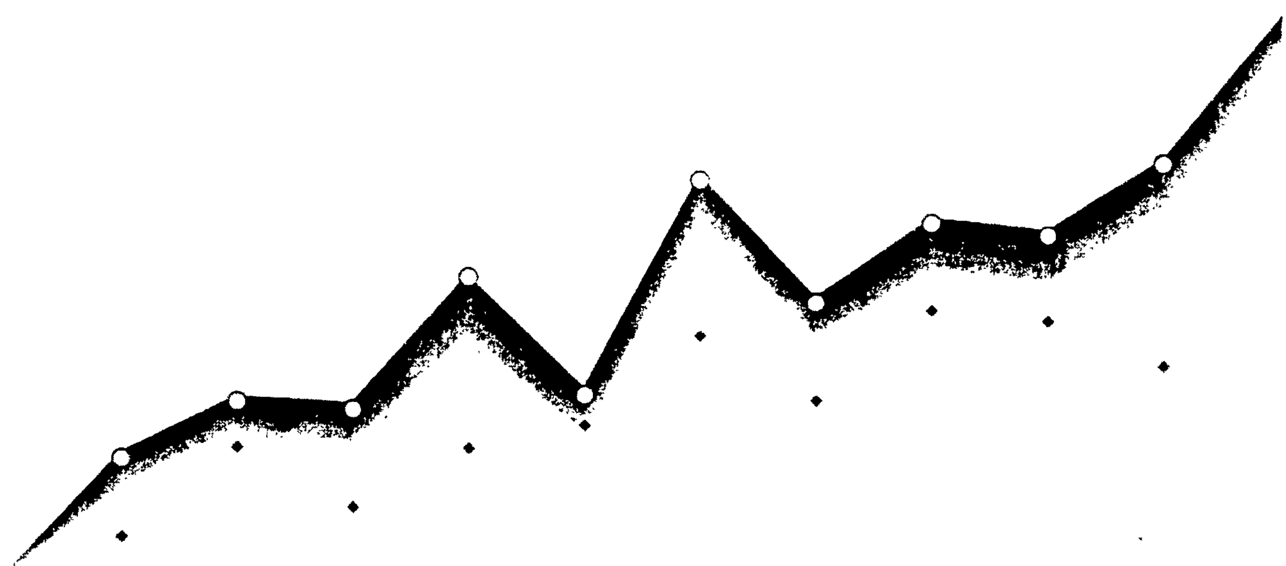
Brittany May Dadón
State Bar No. 24097888
7320 N. MoPac, Suite 211
Austin, Texas 78731
(512) 346-5558
(512) 652-2948

Lisa Chavarria
State Bar No. 24006987
7320 N. MoPac, Suite 211
Austin, Texas 78731
(512) 346-5558
(512) 652-2947

ATTORNEYS FOR INVENERGY LLC

THE LONG-TERM IMPACT OF MARGINAL LOSSES ON TEXAS ELECTRIC RETAIL CUSTOMERS

April 2018



PA Regional Office:
PA Consulting Group
1700 Lincoln Street
Suite 3550
Denver, CO 80203
USA
Tel: +1 720 566 9920
Fax: +1 720 566 9680
www.paconsulting.com

Prepared by: PA Consulting Group

DISCLOSURES AND DISCLAIMERS

The methodology, analysis, and findings expressed in this report are current as of April 2018 and, where applicable, incorporate underlying market data as of November 30, 2017. They were prepared by PA Consulting Group, Inc. ("PA") at the request of Invenergy LLC and Pattern Development. PA is not responsible for any loss or damage to any third party as a result of their use or reliance (direct or otherwise) on PA's analysis and this report.

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EXECUTIVE SUMMARY

Historically, power generation owners within the Electric Reliability Council of Texas ("ERCOT") power market have made investment decisions based on the expectation of energy price formation that excludes marginal losses. However, recently, some power generation owners have voiced concerns that the ERCOT market is not providing high enough power pricing to justify past and future investment decisions.[1] These generation owners have advocated for several proposed market design changes, including the addition of marginal losses to locational marginal price ("LMP") formation.

To help better understand how the inclusion of marginal losses in LMP formation will impact electricity customers within the State of Texas, Invenergy LLC and Pattern Development engaged PA Consulting Group, Inc. ("PA") to conduct an independent long-term economic study. Specifically, PA's study is designed to answer the following question:[2]

> ***How will the inclusion of marginal losses in ERCOT's market structure impact electricity customers in the State of Texas over the long-term?***

To evaluate this question, PA conducted a forward-looking, long-term analysis (years 2018-2037) that assessed the economic and environmental impacts of integrating marginal losses into LMP formation. For this analysis, PA modeled the ERCOT market under two Cases: (i) a "Base Case" that reflects the current market structure and (ii) a "Forward Marginal Losses Case" that includes marginal losses in LMP formation.

PA's results demonstrate that **customers in Texas would be much better off under the current market structure without the integration of marginal losses**. Table 1 summarizes the results of PA's analysis.

Table 1: Benefits of Current Market Structure versus Integration of Marginal Losses[3]

Timeframe 2018-2037	*Foregone Benefits to Texas if Marginal Losses are Implemented*
Economic Output in Texas	$7.1 Billion
Energy Cost Savings	$4.6 Billion
Production Cost Savings	$5.1 Billion
Additional Jobs in Texas	29,500 FTEs
CO_2 Emissions Savings	66.5 Million Tons
NOx Emissions Savings	13.8 Thousand Tons
SO_2 Emissions Savings	54.9 Thousand Tons

From a theoretical perspective, marginal losses are intended to improve the economic efficiency of a wholesale power market by increasing the dispatch of generators located closer to load centers, which improves the physical efficiency of the system by reducing transmission line losses. This is essentially achieved by financially penalizing electricity based on how far away from load centers it is produced. In a traditional power system based exclusively on thermal generation resources, this improvement in *physical* efficiency can improve *economic* efficiency by reducing the overall system cost to produce electricity, since less electricity needs to be produced to meet demand. However, PA's findings demonstrate that in a unique

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[1] Hogan, William and Pope, Susan. "Priorities for the Evolution of an Energy-Only Market in ERCOT." PUCT Project Nos. 40000, 41837, 45572. Informational Filing by Calpine Corporation and NRG Energy Inc. 10 May 2017. <http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_669_939373.PDF>.

[2] PA's modeling process is described in detail in Section 3, titled "Methodological Overview."

[3] Unless otherwise stated, all financial figures are in nominal dollars assuming a 2.2 percent per annum average inflation rate; FTE: Full Time Equivalent; all emissions are quoted in short tons.

market like ERCOT, focusing on optimizing physical efficiency of system dispatch misses the forest for the trees, as **optimizing physical efficiency does not necessarily optimize economic efficiency for Texas customers in the long-run**.

The ERCOT market is unique—among several reasons—in that the best renewable generation potential is located within the western and northern portions of the State, whereas the majority of electricity demand is concentrated in regions farther east and south. Wind and solar resources are different from thermal generation in that the marginal cost of producing electricity from wind and solar is close to zero, whereas the marginal costs of thermal resources are much higher due to fuel and other operating costs.

PA finds that the implementation of marginal losses would alter future power generation investment decisions. Since implementation of marginal losses would financially penalize resources farther from load, it would decrease the development and, in turn, overall electricity production of zero marginal cost renewable resources on the system. In turn, higher levels of thermal generation would be needed on the system, which have higher marginal costs than renewable generation, thus increasing system production and energy costs in a system with marginal losses implemented. This indicates a less optimal economic outcome for consumers.

The decision not to implement marginal losses is just one example of how of market structure decisions that take into account ERCOT's unique system attributes can drive significant long-term benefits to the customer. To further demonstrate this dynamic, PA also evaluated the economic and environmental impacts of the generation development enabled by construction of the Competitive Renewable Energy Zones ("CREZ") transmission projects, which facilitated renewable energy development in ERCOT by removing transmission constraints between wind- and solar-rich regions and load centers.

PA conducted a historical analysis (years 2010-2017) and forward looking analysis (years 2018-2037) that evaluated the economic impacts of CREZ and associated renewable energy development. For these analyses, PA modeled the ERCOT power market under two Cases: (i) a "Base Case" that reflects the current market structure and (ii) an "Elimination of CREZ Case" that assumes the CREZ projects did not enter service, which leads to less renewable generation being constructed in ERCOT. PA's analysis demonstrates that **customers in Texas have been (and will be) materially better off with CREZ and associated renewable development**. The results of this analysis are shown in Table 2:

Table 2: Benefits of Current Market Structure versus the Exclusion of CREZ

	Historical benefits to Texas driven by CREZ (2010-2017)	*Future benefits* to Texas driven by CREZ (2018-2037)	*Total benefits* to Texas driven by CREZ (2010-2037)
Economic Output in Texas	**$8.0 Billion**	**$56.8 Billion**	**$64.8 Billion**
Energy Cost Savings	$2.8 Billion	$33.9 Billion	$36.7 Billion
Production Cost Savings	**$3.0 Billion**	**$44.5 Billion**	**$47.5 Billion**
Additional Jobs in Texas	46,400 FTEs	238,600 FTEs	285,000 FTEs
CO_2 Emissions Savings	**79.8 Million Tons**	**584.9 Million Tons**	**664.7 Million Tons**
NOx Emissions Savings	42.2 Thousand Tons	175.4 Thousand Tons	217.8 Thousand Tons
SO_2 Emissions Savings	**89.4 Thousand Tons**	**245.0 Thousand Tons**	**334.4 Thousand Tons**

ERCOT's unique energy-only market design is intended to allow competitive market forces to drive power generation investment in a manner that is most efficient for the consumer. This intent is reflected in historical approaches to transmission pricing and cost allocation within the State of Texas and ERCOT, which represent deliberate efforts by legislators and regulators to ensure that the power system provides cost-effective service to, and in turn maximizes economic benefits for, electric retail customers across the State. PA's analysis demonstrates that the current ERCOT market structure has facilitated these goals, and will continue to facilitate these goals, with the exclusion of marginal losses from LMP formation.

INTRODUCTION

Historically, power generation owners within the ERCOT power market have made investment decisions based on the expectation of energy price formation that excludes marginal losses. However, some power generation owners have recently voiced concerns that the ERCOT market is not providing high enough power pricing to justify past and future investment decisions. These generation owners have advocated for several proposed market design changes, including the integration of marginal losses in LMP formation.

To help better understand how the inclusion of marginal losses in LMP formation would impact electricity customers within the State of Texas, Invenergy LLC and Pattern Development engaged PA Consulting Group, Inc. to conduct an independent long-term economic study. Specifically, PA's study is designed to answer the following question:[4]

> ***How will the inclusion of marginal losses in ERCOT's market structure impact electricity customers in the State of Texas over the long-term?***

PA's analysis finds that the current ERCOT market structure is highly beneficial and cost-effective for customers within the State of Texas compared with the implementation of marginal losses. Specifically, PA's analysis demonstrates that the current market structure provides greater economic output for the State of Texas, provides customers with material energy cost savings, increases the number of jobs in Texas, has lower production costs, and provides material emissions savings.

Background

The ERCOT power market is unique among North American electric regions in that it relies on an energy-only market design to ensure reliability. In an energy-only market, a generator must seek to recover fixed costs when energy prices rise above that generator's short-run marginal costs. This is in contrast to most other competitive wholesale markets in North America, in which generators are able to recover fixed costs through capacity markets or bilateral capacity contracts with incumbent utilities. The intent of an energy-only market design is to allow competitive market forces to drive power generation investment in a manner that is most efficient for the consumer.

The ERCOT market is also unique in that the best renewable generation potential is located within the western and northern portions of the State (see Figure 1 and Figure 2 below), whereas the majority of electricity demand is concentrated in regions farther east and south. In other words, within Texas, renewable capacity cannot simply be sited closer to load and achieve the same generation outcome, so the economic case for renewable capacity sited closer to load is worse, all else equal.[5] Wind and solar resources are different from thermal generation in that the marginal cost of producing electricity from wind and solar is essentially zero, whereas the marginal costs of thermal resources are much higher due to fuel and other operating costs.

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[4] PA's modeling process is described in detail in Section 3, titled "Methodological Overview."

[5] In addition, land acquisition costs closer to load centers are likely materially higher than locations in the West and North Zones of ERCOT. Furthermore, sufficient land may be physically unavailable closer to load centers given the required land parcel size to site cost-effective, large-scale renewable resources.

Figure 1: Texas 80-Meter Wind Speed Map[6]

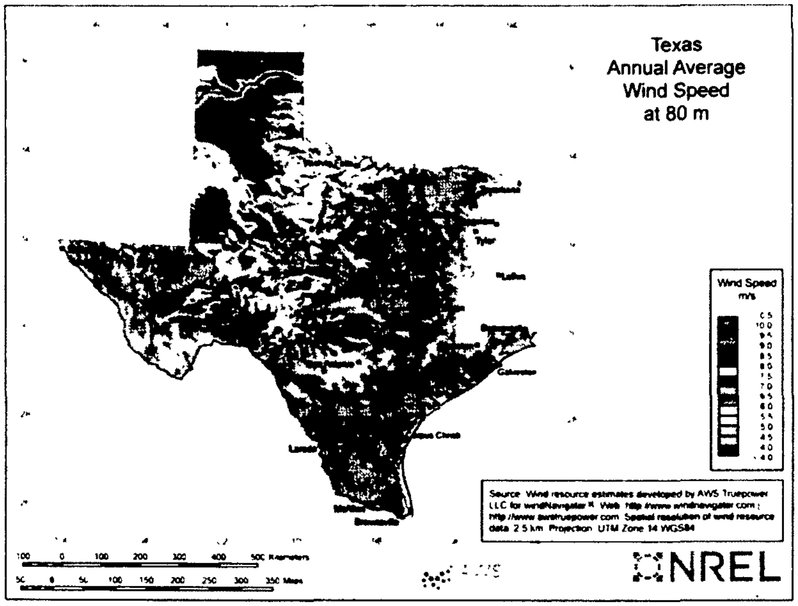
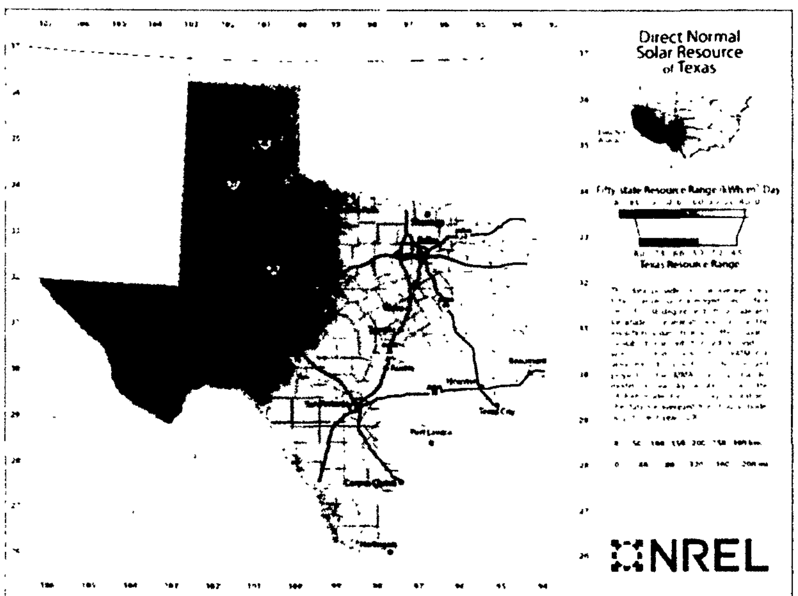


Figure 2: Texas Solar Resource Map[7]



[6] Source: AWS Truepower, LLC, NREL.

[7] Source: NREL.

Consistent with this purpose, Texas' historical approach to transmission planning and cost allocation within ERCOT represents a deliberate effort to ensure that generation resources compete on a level playing field to provide cost-effective service to retail customers. In its 1999 Report to the 76th Texas Legislature, "*The Scope of Competition in the Electric Industry of Texas*", the Public Utility Commission of Texas ("PUCT" or "Commission") stated that it "*adopted a uniform transmission pricing system for ERCOT*" to promote "*vigorous competition between producers on the basis of the price of power, and ultimately to lower prices for customers in Texas.*"[8] A uniform transmission pricing system is one that excludes marginal losses from LMP formation. In other words, the Commission has historically viewed the transmission system as a vehicle to promote competition among generators across the State so that the electricity system provides low-cost electric service to customers, in turn creating economic benefits across the state.

With this view of the transmission system in mind, in 2005, the 79th Texas Legislature amended PURA §39.904 to direct the Commission to develop "*a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the competitive renewable energy zones.*"[9] In October 2008, the Commission released its first major Order regarding CREZ, which determined the most beneficial and cost-effective level of transmission capacity for the CREZ projects. Between 2009 and 2014, the majority of CREZ-related transmission projects were built and energized, allowing for greater transfer capability of new renewable generation in the West and North Zones to load farther to the east within Texas.

For many years, power generation owners within the ERCOT power market have made investment decisions based on this expectation of uniform transmission pricing (i.e., no marginal losses) and the inclusion of the CREZ transmission projects. These investment decisions—especially those related to renewable generation—were incentivized via these deliberate market design choices by the State of Texas and occurred through the competitive forces unleashed by these market design choices.

However, some owners of generation resources have recently voiced concerns that the ERCOT market is not providing high enough power pricing to justify past and future investment decisions; these generators have argued that market design components such as the lack of marginal losses within LMP formation are negatively impacting the ERCOT power market via inefficient pricing signals.

On May 10, 2017, Calpine Corporation and NRG Energy, Inc. filed a paper titled "*Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*" under three separate PUCT Project Dockets (Nos. 40000, 45572, and 41837).[10] At the direction of the Commission, PUCT Staff opened a new Project on May 22, 2017, called the "*Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market,*" under Project No. 47199. In this Project, Staff requested comment on the paper's "*price-formation concerns and proposed solutions.*"[11]

Seeking to add rigor to the assessment of potential impacts of some of these proposed market design changes within ERCOT, on October 12, 2017, a group comprised of First Solar, Inc., Vistra Energy Corp., and the Wind Coalition jointly filed an independent study titled "*Impacts of Marginal Loss Implementation in*

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[8] Page 36.

[9] Within its first major order approving CREZ, the PUCT found within its finding of fact that "the intent of the Legislature in passing the amendments to PURA §§ 36.053, 39.203, and 39.904 in 2005 was to further encourage the development of renewable-energy resources by establishing a process to provide reliable and economical transmission resources ahead of renewable generation." (PUC Order, Project No. 33672, 7 October 2008, Page 46)."

[10] Ibid.

[11] PUCT, "Memorandum Re: Project No. 47199 – Project to Assess Price-Formation Rules in ERCOT's Energy-Only Market – Agenda Item No. 9."

ERCOT: 2018 Reference Scenario Results."[12] This study found that production cost savings from the incorporation of marginal losses would be immaterial, while reductions to generator net revenues would be substantial. Further, on December 7, 2017, ERCOT and the Independent Market Monitor ("IMM") announced a plan to "*assess the benefits of the potential implementation of Real-Time Co-optimization ("RTC") and/or Marginal Losses in the ERCOT wholesale electricity market.*"[13]

PA's study complements these two quantitative studies by examining the comparative long-term economic and environmental benefits and costs associated with the current ERCOT market structure versus the implementation of marginal losses. PA's findings indicate that the long-term economic and environmental benefits are materially higher under the current market structure versus with the implementation of marginal losses.

The decision not to implement marginal losses is just one example of how market structure decisions that appropriately take into about ERCOT's unique physical realities can drive significant long-term benefits to the customer through competitive market forces. To further demonstrate this dynamic, PA also evaluated the economic and environmental impacts of the generation development enabled by the CREZ transmission projects, which facilitated renewable energy development in ERCOT by removing transmission constraints between wind- and solar-rich regions (i.e., western and northern Texas) and load centers in eastern and southern Texas. Specifically, PA sought to answer the following questions:

- ***How have the CREZ transmission projects and associated generation development enabled by CREZ impacted electricity customers in the State of Texas to date?***
- ***How will the CREZ transmission projects and associated generation development enabled by CREZ impact electricity customers in the State of Texas over the long-term on a going forward basis?***

While PA shows that the historical benefits resulting from the generation development enabled by the CREZ transmission projects are already significant, this development is projected to provide materially greater economic output for the State of Texas over the long-term, provide customers with significant energy cost savings, increase the number of jobs in Texas, lower production costs, and provide material emissions savings.

The remainder of this white paper is divided into three primary sections that describe (i) PA's methodology; (ii) the results of the study; and (iii) a discussion of the results.

[12] Performed by The Brattle Group.

[13] ERCOT, "Proposed Plan for Conducting Benefits Analyses," Project No. 47199. 7 December 2017, Page 1.

METHODOLOGICAL OVERVIEW

To evaluate the long-term benefits and cost-effectiveness of the current market structure versus proposed alternatives, PA used its proprietary electricity market modeling process. The core of PA's modeling process uses an industry standard chronological dispatch simulation model (AURORAxmp) to simulate the hourly operations of ERCOT.[14] The AURORAxmp model is widely used by electric utilities, power market regulators, independent system operators, and other market consultants. This model enables PA to project hourly power prices, energy flows, the development of new power plants, and the operating profiles of the power plants and transmission lines within a given system; in this case ERCOT.

To forecast the long-term wholesale natural gas prices that are used in AURORAxmp, PA uses the GPCM® Natural Gas Market Forecasting System™ ("GPCM"). GPCM models natural gas production, existing pipeline flows and constraints, new pipeline construction, and natural gas demand from the power sector and residential, commercial, and industrial sectors for the entire United States. PA used GPCM to develop a long-term forecast of both Henry Hub natural gas prices and the prices of regional natural gas pricing hubs applicable to the ERCOT region. GPCM is used across the energy industry, including by government agencies such as the U.S. Federal Energy Regulatory Commission ("FERC") and Canadian National Energy Board ("NEB"), as well as independent system operators such as the Midcontinent Independent System Operator ("MISO").

To estimate economic impacts, PA employed two widely utilized tools for Input-Output ("I-O") analysis: the Impact Analysis for Planning ("IMPLAN") model and the Jobs and Economic Development Impact ("JEDI") model. IMPLAN and JEDI both use data from multiple U.S. government sources and employ estimation methods based on industry accounts to project how changes in demand for specific types of goods and services are likely to affect a specific geographic region. Both models estimate economic impacts by relating projected expenditures specified by the user (e.g., the various costs of constructing a large industrial structure) with economic multipliers specific to Texas provided to PA by IMPLAN.[15]

PA modeled the ERCOT market under three primary Cases. These Cases include a Base Case that represents ERCOT's current market structure, as well as two other Cases to compare against the Base Case.

Aside from the assumption differences noted below, PA has kept assumptions consistent across the Cases (e.g., natural gas prices, new build construction costs, etc.) to facilitate comparisons. Importantly, PA's analysis does not alter construction costs for resources (thermal and renewable) built closer to load centers, although these costs (such as land acquisition) could be higher closer to load centers. PA's analysis also does not limit the amount of renewables that can be sited closer to load centers, even though acquiring the necessary land to site renewables near load centers could prove more difficult.[16] In addition, PA's analysis does not account for potential changes in transmission feeder and/or ancillary costs between the Cases, but PA notes that these costs are expected to be immaterial relative to the other analyzed impacts.

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[14] AURORAxmp is a product of EPIS, LLC.

[15] PA acquired the necessary data concerning inter-industry accounts for Texas from IMPLAN.

[16] PA allowed for the economic build out of renewable generation (both wind and solar) subject to the current backbone transmission system and did not assume any new backbone transmission projects.

Base Case (2010-2037):

The Base Case represents the status quo environment within ERCOT. Marginal losses *are not* incorporated into LMP formation, and the CREZ transmission projects and associated generation projects built because of CREZ (e.g., western ERCOT wind projects) enter service at their historical and projected commercial online dates. Note that in projecting the development of new renewable energy plants, PA limited development according to the expected transmission limitations of the CREZ transmission upgrades – in other words, projected renewable additions do not require any new large-scale transmission development (and associated costs) in the state.[17] Future investment decisions in ERCOT are impacted by the presence of CREZ and the exclusion of marginal losses from LMP formation.

Forward Marginal Losses Case (2018-2037):

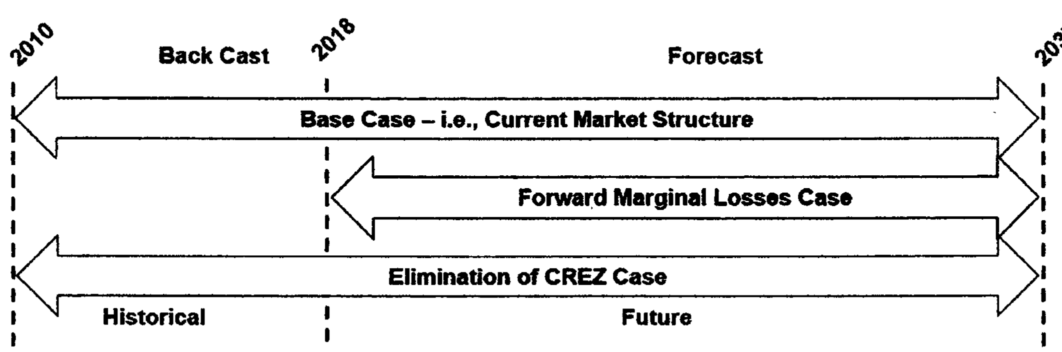
This Case is designed to determine the long-term economic impacts associated with the integration of marginal losses in LMP formation. The Forward Marginal Losses Case represents the Base Case world, but marginal losses *are* incorporated into LMP formation on a go-forward basis starting in 2018. Comparing this Case against the Base Case provides a basis for understanding whether the inclusion of marginal losses in LMP formation in ERCOT would be beneficial and cost-effective for customers in the State of Texas.

Elimination of CREZ Case (2010-2017):

This Case is designed to determine the economic impacts associated with the elimination of the CREZ transmission projects and associated renewable energy development made possible by the increased transmission capability due to CREZ. Comparing this Case against the Base Case provides an assessment of long-term economic and environmental impacts. Specifically, comparing this Case against the Base Case provides a basis for understanding whether CREZ was beneficial and cost-effective for customers in the State of Texas.

PA references this case using two names: (i) **Historical Elimination of CREZ Case** (2010-2017), and (ii) **Forward Elimination of CREZ Case** (2018-2037). The purpose in making this distinction is to separate historic from future benefits.

Figure 3: Overview of Modeled Cases



[17] Similarly, the Forward Marginal Losses Case incorporates these same limitations.

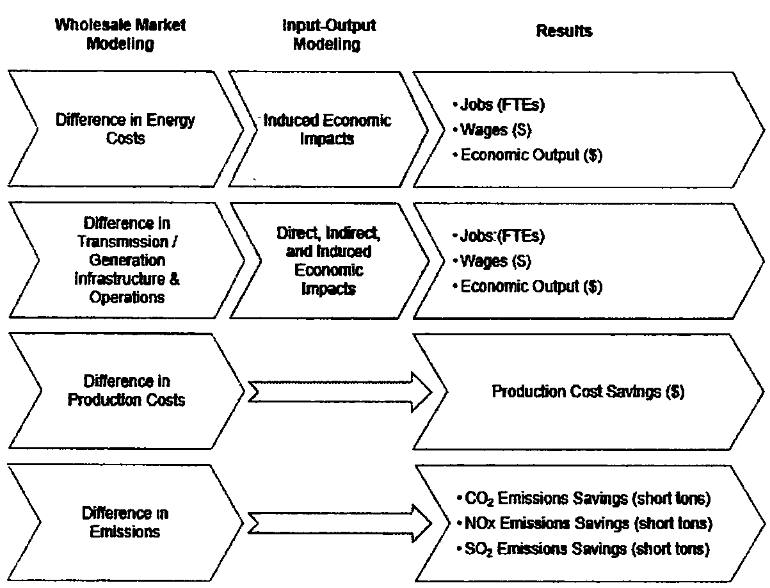
RESULTS

PA's analysis demonstrates that the current market structure in ERCOT has been, and will continue to be, highly beneficial and cost-effective for electricity customers in the State of Texas.

The results of PA's analysis can be divided into two categories: (i) the results of the wholesale market analysis; and (ii) the results of the I-O analysis. The wholesale market results include differences in production costs, energy costs, generator investment decisions (e.g., differences in installed wind, solar, and natural gas-fired generation builds), and generator operations across the different Cases.

The I-O analysis results include direct, indirect, and induced economic benefits driven by the construction and operation of transmission and power generation infrastructure, as well as induced economic benefits due to energy cost savings.[18]

Figure 4: Overview of Modeling Process and Results



While reported within this results section of the study, we note that generator investment decisions (i.e., capacity built and generation by fuel type) are not considered benefits in and of themselves. Rather, these investment decisions contribute to differences in construction, operation, production, and energy costs that drive differences in economic impacts for the State of Texas, and understanding these differing investment decisions between the Cases is crucial to understanding the economic and emissions results.

[18] Energy cost savings only provide induced economic benefits and do not provide direct or indirect economic benefits.

Similarly, historical and projected production and energy cost savings are driven by a multitude of factors, some of which are unrelated to ERCOT's market structure. For example, renewable energy investment decisions and related changes to production and energy costs depend partly on federal subsidies for renewable generation (specifically the Production Tax Credit for wind and the Investment Tax Credit for solar). It is important to note that these subsidies will step down or expire completely in the near future. Additionally, low natural gas prices have contributed and will continue to contribute to lower production and energy costs since natural gas-fired generation is the predominant generation source on the ERCOT system and sets the price of power in a majority of hours. However, by keeping these external factors constant across Cases (as we have done in our analyses), it is possible to assess the incremental impacts of proposed changes to ERCOT's market structure to the economic benefits experienced by Texas electric retail customers.

Forward Marginal Losses Results

To answer the question, "***How will the inclusion of marginal losses in ERCOT's market structure impact electricity customers in the State of Texas over the long-term?***", PA compared the results of the Base Case with the Forward Marginal Losses Case. The Forward Marginal Losses Case represents the Base Case world, but where marginal losses <u>are</u> incorporated into LMP formation on a go-forward basis starting in 2018.

The results of this comparison demonstrate that the current market structure provides significantly greater benefits to customers going forward compared to including marginal losses in LMP formation.

Over the 2018-2037 timeframe:

- Total economic output would be $7.1 billion higher under the current market structure, with $5.8 billion of the additional economic output attributable to energy cost savings and $1.3 billion attributable to higher construction and operations expenditures.
- Under the current market structure, the ERCOT system would experience $5.1 billion of total future production cost savings and nearly $4.6 billion of total future energy cost savings over the next 20 years due to higher levels of low variable cost power generation.
- Under the current market structure, total future jobs in Texas over the next 20 years would higher by over 29,500 FTEs, with a 26,600 FTE increase attributable to energy cost savings and a 3,000 FTE increase attributable to higher construction and operations expenditures.[19]
- Under the current market structure, total future CO_2 emissions over the next 20 years would be lower by 66.8 million tons, NOx emissions would be lower by 13,800 tons, and SO_2 emissions would be lower by 53,900 tons.

Wholesale Market Impacts

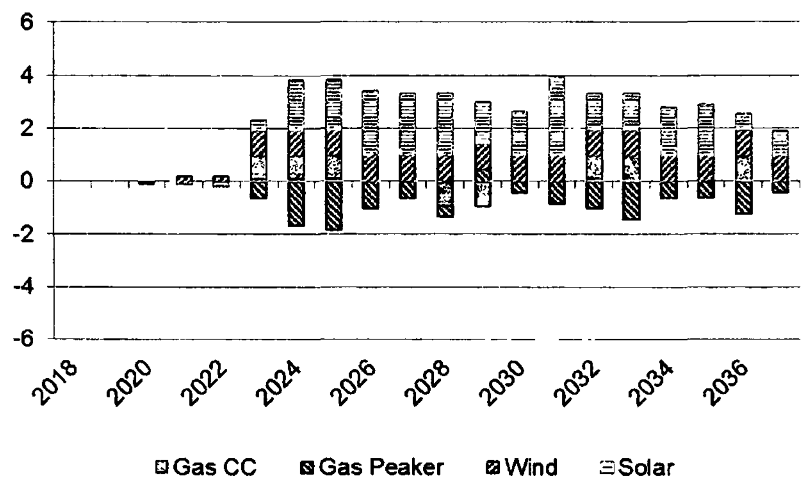
<u>Comparison of Capacity Built by Fuel Type</u>

PA's analysis demonstrates that the integration of marginal losses into LMP formation would lead to material changes in future power generation investment. In particular, PA's analysis projects a meaningful impact on the amount of new wind and solar development in ERCOT compared with continuing the current market structure. Across the study period, the current market structure will lead to higher levels of installed wind and solar capacity on the ERCOT system as compared with a market where marginal losses are included in LMP formation. See Figure 5. By 2037, under the current market structure, installed wind and solar

[19] When we refer to FTEs throughout this report, we are referring to full time equivalent jobs over a 12 month time frame. So, two FTEs can be thought of a two jobs for one year or one job for two years. Additionally, numbers may not sum perfectly due to rounding.

capacity in ERCOT would be 3 percent and 4 percent higher, respectively, than under a market where marginal losses are incorporated into LMP formation, although gas peaker capacity would be 2 percent lower under the current market structure. There is no projected difference in combined cycle ("CC") development.

Figure 5: Difference in Installed Capacity – Base Case vs. Forward Marginal Losses Case (GW)



The majority of the difference in wind capacity additions under the current market structure takes place in the West Zone, with more wind capacity installed in the West Zone under the current market structure. Similarly, the differences in installed solar capacity by zone reflect the economic favorability of solar development in the West Zone under the current market structure. Conversely, including marginal losses in LMP formation results in reduced solar development in the West Zone by roughly 800 MW by 2037 compared to the current market structure.

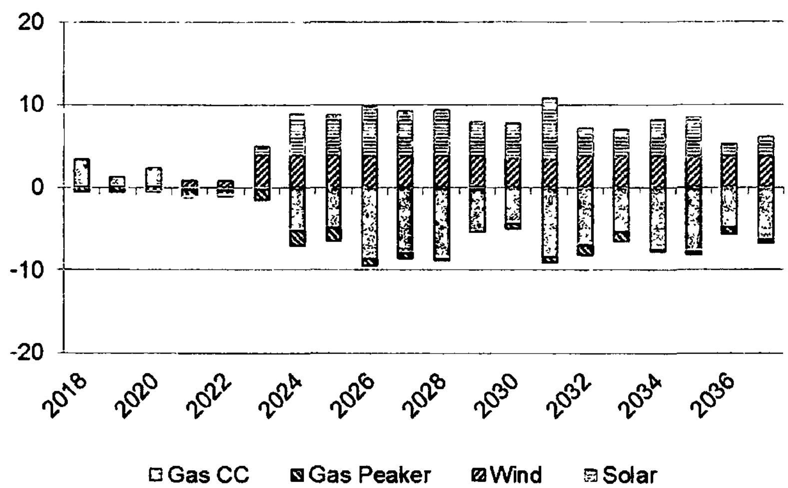
The higher levels of wind and solar capacity under the current market structure are partially offset by slightly lower levels of natural gas-fired peaking capacity than would otherwise be expected with marginal losses included in LMP formation. The locations of combined cycle and peaking capacity additions are also different under the current market structure compared to a market where marginal losses are included in LMP formation. Specifically, with marginal losses included in LMP formation, more capacity is built in the Houston and South Zones near population centers, reflecting increased power pricing closer to load in those Zones.

It is important to note that by the end of the study period, there is less than a ~2 GW difference in total installed capacity between the two cases. While PA's analysis does not incorporate interconnection costs from the point of interconnect to the current transmission system (as such costs are highly site specific), the limited difference in installed capacity between the two cases suggest that any such feeder costs would be similar between the two cases. However, as described in the next section, while there are minimal differences in overall capacity, the amount of generation by fuel type varies materially between the two cases on a MWh basis.

<u>*Comparison of Generation by Fuel Type*</u>

Reflecting projected impacts on installed capacity by fuel type (see previous section), PA's analysis also projects a meaningful impact on the amount of solar and wind generation in ERCOT if marginal losses are incorporated into LMP formation. Figure 6 illustrates the differences in generation by fuel type between the Base Case and the Forward Marginal Losses Case.

Figure 6: Difference in Generation – Base Case vs. Forward Marginal Losses Case (TWh)

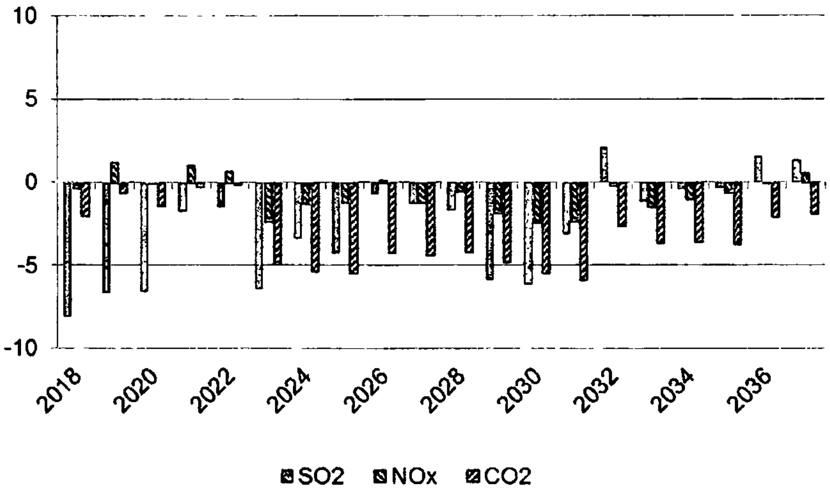


Specifically, under the current market structure, by 2037, wind and solar generation would be 3 percent and 4 percent higher, respectively, compared to a market where marginal losses are incorporated into LMP formation. Meanwhile, natural gas combined cycle and peaker generation, by 2037, would each be approximately 3 percent lower, respectively. These higher levels of lower marginal cost generation under the current market structure (driven by more wind and solar development in the West Zone of ERCOT across the study period) lead to lower overall production and energy costs.

Comparison of Emissions

Incorporating marginal losses in LMP formation leads to higher levels of thermal generation dispatch, with a corresponding decrease in the amount of emission-free wind and solar generation. PA's analysis projects that CO_2, SO_2, and NOx emissions will be higher with marginal losses included in LMP formation than under the existing market structure. Figure 7 illustrates the differences in power sector emissions between the Base Case and the Forward Marginal Losses Case.

Figure 7: Difference in Emissions – Base Case vs. Forward Marginal Losses Case (Million tons for CO_2 and thousand tons for SO_2 and NOx)



Although annual emissions impacts vary across the study period, with some years seeing higher emissions of certain gases under the current market structure compared with a market where marginal losses are included in LMP formation, PA's analysis projects that by 2037, total SO_2, NOx, and CO_2 emissions will each be approximately 1 percent lower, respectively, under the current market structure. While appearing small on a percentage basis, these differences in emissions are noteworthy on an absolute basis. For example, total CO_2 emissions over the study period are nearly 67 million tons lower under the current market structure than a market where marginal losses are included in LMP formation. This equates to taking over 450,000 passenger vehicles off the road each year over the study period.[20]

Comparison of Production Costs and Energy Costs

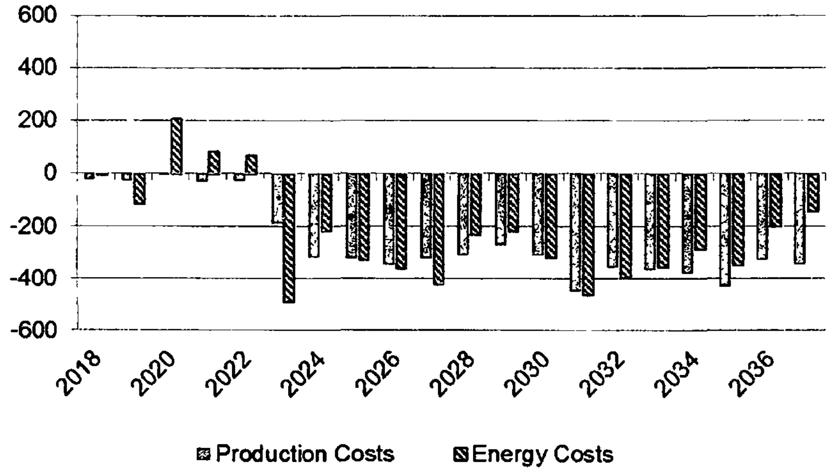
The higher levels of low-cost renewable generation under the current market structure compared to a market where marginal losses are included in LMP formation reduce ERCOT's reliance on more expensive thermal generators in most years of the study period. This decreased reliance on thermal generation significantly decreases total system production costs, which include the cost of fuel and variable operations and maintenance ("O&M") of generators on the ERCOT system.

This same dynamic also leads to lower all-hours power prices in ERCOT under the current market structure, which leads to lower total energy costs in ERCOT. Energy costs represent the total cost of electricity consumed on the ERCOT system, inclusive of transmission losses. Energy costs differ from production costs because energy prices are based on the cost of the marginal generator at that time rather than the summation of the individual production costs of all resources that are generating at that time.

Under the current market structure, PA's analysis projects $5.1 billion lower production costs and $4.6 billion in energy cost savings over the study period compared with the inclusion of marginal losses in LMP formation. Figure 8 illustrates the differences in production costs and energy costs between the Base Case and the Forward Marginal Losses Case.

[20] Source: U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator. One passenger vehicle emits 4.67 metric tons, or 5.15 short tons, per year, on average.

Figure 8: Difference in Production and Energy Costs – Base Case vs. Forward Marginal Losses Case ($ Millions)



Economic Impacts

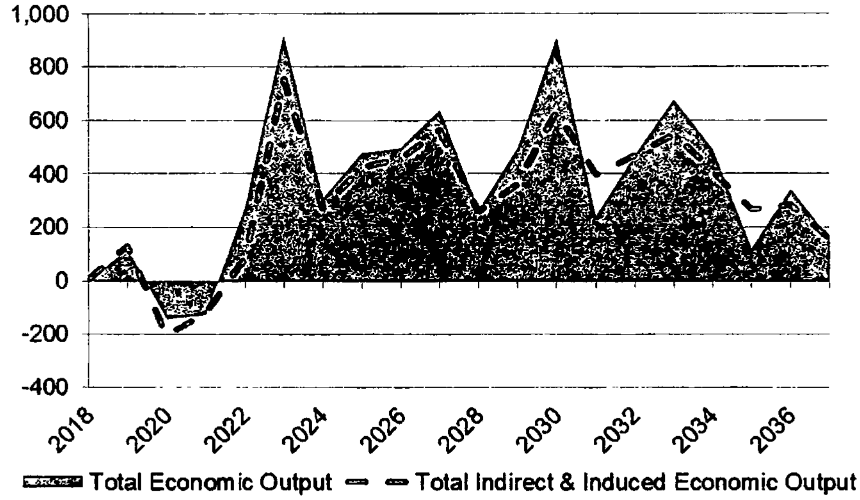
Total Economic Impacts

Across the study period, the current market structure leads to significant benefits for the Texas economy compared to a market where marginal losses are included in LMP formation, with total economic output across the study period projected to be over $7.1 billion higher under the current market structure. This difference is driven by direct, indirect, and induced contributions from construction and operation jobs and wages that would otherwise not have materialized, as well as from the induced jobs and wages spurred by energy cost savings experienced by Texas' electric retail customers.

Over the study period, indirect and induced economic output provides approximately 86 percent of the total incremental economic output created under the current market structure compared to a market where marginal losses are incorporated in LMP formation. This figure accounts for the value provided throughout the Texas economy resulting from the indirect benefits of the direct spending as well as the increased household spending spurred by direct and indirect wages as well as the energy cost savings.

Although total economic output is projected to be higher in some years with incorporation of marginal losses into LMP formation when compared to the current market structure, as shown by the slightly negative values in Figure 9 (largely driven by differences in the timing of generator additions), the benefits of the current market structure are clear over the study period. If marginal losses are incorporated into LMP formation on a go-forward basis, PA's analysis expects direct economic output to be materially lower over the course of the study period.

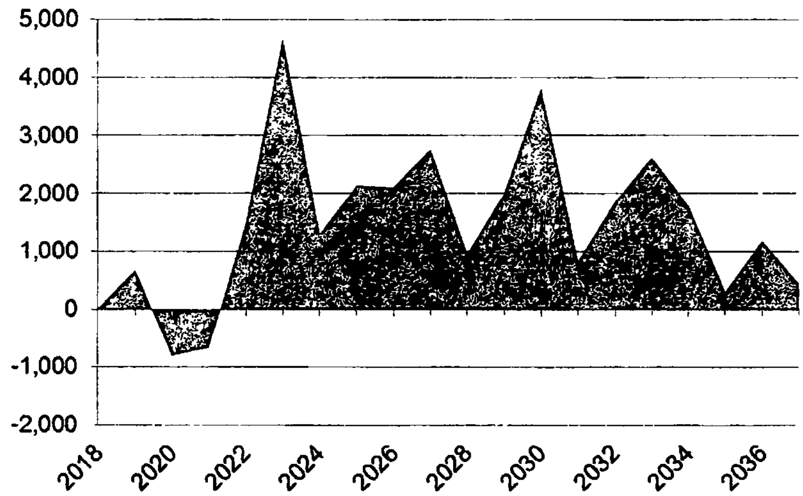
Figure 9: Difference in Total Economic Output – Base Case vs. Forward Marginal Losses Case ($ Millions)



Total Jobs Created

PA's analysis expects 29,500 higher FTEs, or approximately 1,500 higher FTEs per year on average, under the current market structure compared with a market where marginal losses are incorporated in LMP formation. This includes direct, indirect, and induced jobs. Projected job creation impacts follow similar patterns to those observed in total economic impacts. Figure 10 illustrates the differences in total jobs created between the Base Case and the Forward Marginal Losses Case.

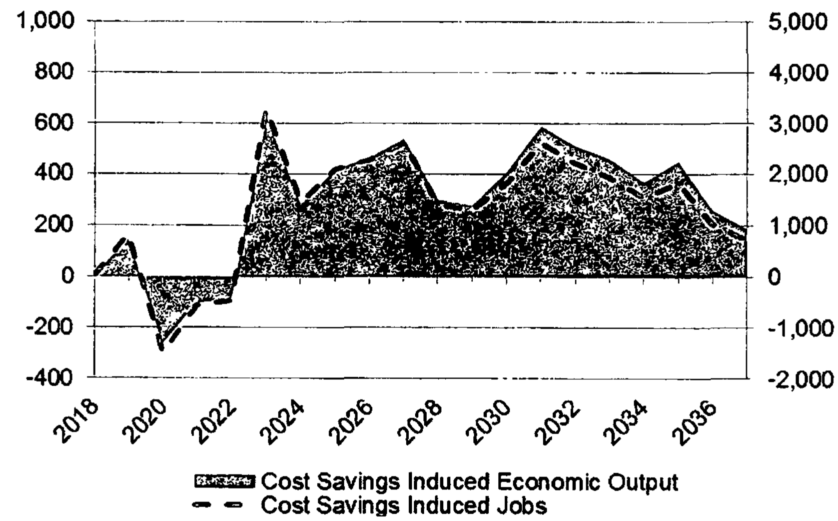
Figure 10: Difference in Total Jobs – Base Case vs. Forward Marginal Losses Case (FTE)



Induced Economic Impacts from Retail Customer Cost Savings

Induced economic output and the number of induced jobs attributable to energy cost savings would be higher under the current market structure than under a market where marginal losses are included in LMP formation. The economic benefits spurred by energy cost savings are expected to drive the majority of additional economic benefits over the study period. Nearly 26,600 additional FTEs and an additional $5.8 billion in economic output would be generated by induced economic activity under the current market structure compared with a market where marginal losses are included in LMP formation. Figure 11 illustrates the differences in economic output and job creation driven by energy cost savings between the Base Case and the Forward Marginal Losses Case.

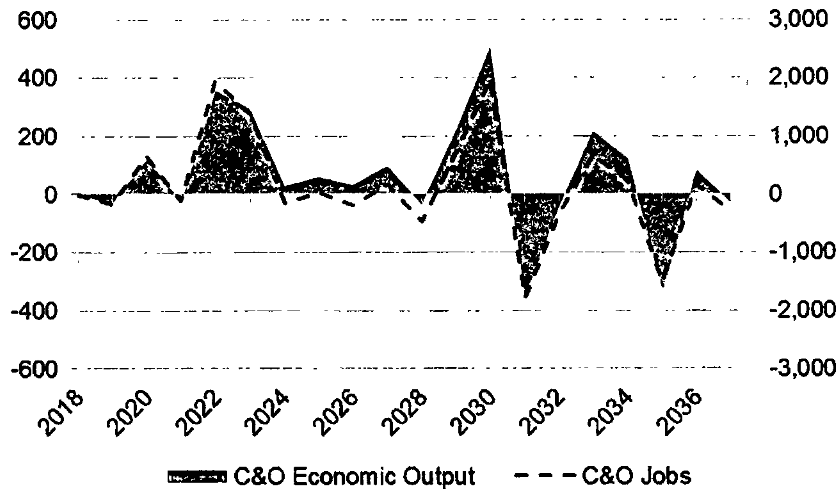
Figure 11: Difference in Cost Savings-Induced Economic Output ($ Millions, left) and Jobs (FTE, right) Base Case vs. Forward Marginal Losses Case



Construction & Operations Economic Output

While the majority of economic impact differences between the two Cases would be driven by differences in energy costs, the economic impacts stemming from construction and operation of generation infrastructure are still material. Under the current market structure, increased construction and operations activity would result in an additional 3,000 FTEs and nearly $1.3 billion in incremental economic output over the study period compared with a market where marginal losses are included in LMP formation. Figure 12 illustrates the differences in economic output and job creation driven by construction and operations between the Base Case and the Forward Marginal Losses Case.

Figure 12: Difference in Construction & Operations Economic Output ($ Millions, left) and Jobs (FTE, right) Base Case vs. Forward Marginal Losses Case



Historical Elimination of CREZ Results

To answer the question, ***"How have the CREZ transmission projects and associated generation development enabled by CREZ impacted electricity customers in the State of Texas to date?"***, PA compared the results of the Base Case with the Historical Elimination of CREZ Case. The Historical Elimination of CREZ Case represents a world where the CREZ transmission system was not built. Comparing this Case against the Base Case provides a basis for understanding whether the generation development enabled by the CREZ transmission projects has been beneficial and cost-effective for customers in the State of Texas.

The results of this comparison demonstrate that the current market structure has provided significantly greater benefits to customers than eliminating CREZ and its associated renewable energy development.

Over the 2010-2017 timeframe:

- Total economic output was $8.0 billion higher under the current market structure, with $3.6 billion of the additional economic output attributable to energy cost savings and $4.4 billion attributable to higher construction and operations expenditures.
  - This $8.0 billion in additional economic output is already higher than the $6.9 billion published cost of CREZ,[21] which indicates that the CREZ projects will be of material benefit to customers over the long-term.
- Under the current market structure, the ERCOT system has experienced $3.0 billion in past production cost savings and nearly $2.8 billion in past energy cost savings due to higher levels of low variable cost power generation.

[21] Public Utility Commission of Texas. "Comments by the Public Utility Commission of Texas Regarding the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Emissions from Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule; EPA Docket ID No. EPA-HQ-OAR-2013-0602." June 18, 2014, <http://www.puc.texas.gov/agency/topic_files/PUCT_Comments.pdf>

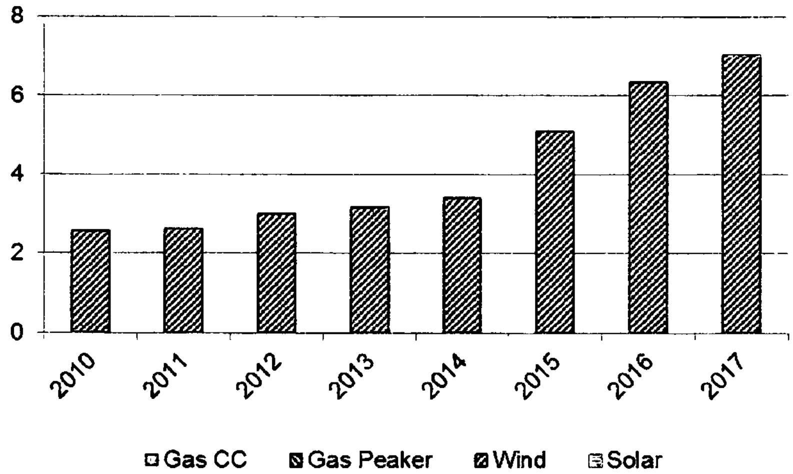
- Under the current market structure, total jobs over the 8-year study period were higher by 46,400 FTEs, with a 22,700 FTE increase attributable to energy cost savings and a 23,700 FTE increase attributable to increased construction and operations expenditures.
- Under the current market structure, total CO_2 emissions over 8 years were lower by nearly 79.8 million tons, NOx emissions were lower by 42,200 tons, and SO_2 emissions were lower by 89,400 tons.

Wholesale Market Impacts

Comparison of Capacity Built by Fuel Type

PA's analysis estimates that the CREZ transmission projects had a significant impact on the amount of wind development in ERCOT compared with a market where CREZ was excluded. Nearly all of the difference in wind capacity additions under the current market structure takes place in the West Zone, with significantly more wind capacity installed in the West Zone under the current market structure. However, the exclusion of CREZ had no impact on the overall levels of installed natural gas-fired generation. These results indicate that the current market structure has indeed helped encourage renewable development within the CREZ regions, which was the explicit goal of the Texas Legislature when it originally promoted CREZ. Figure 13 illustrates the differences in installed capacity by fuel type between the Base Case and the Historical Elimination of CREZ Case.

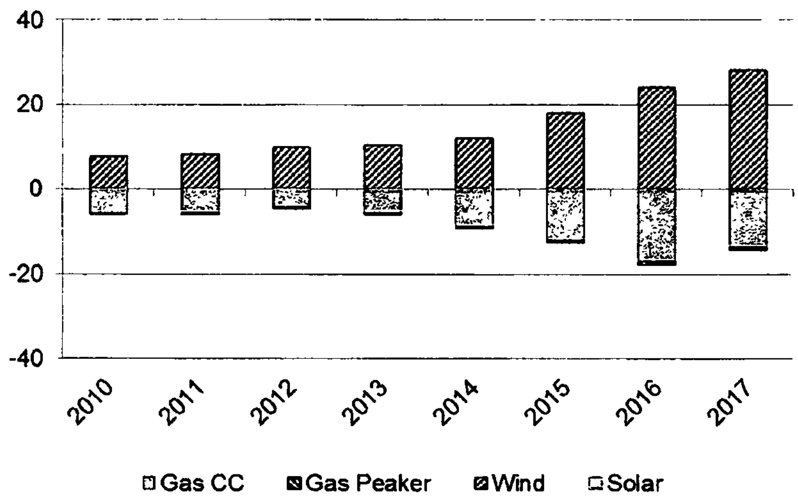
Figure 13: Difference in Installed Capacity – Base Case vs. Historical Elimination of CREZ Case (GW)



Comparison of Generation by Fuel Type

PA's analysis also projects that the CREZ transmission projects had a meaningful impact on the amount of wind and natural gas-fired generation in ERCOT. The increase in wind capacity compared to excluding CREZ materially increases total expected wind generation in ERCOT, with commensurate decreases in thermal generation. With CREZ included, wind generation was 63 percent higher compared to a market where CREZ was not built. Meanwhile, natural gas combined cycle and peaker generation were 6 percent and 4 percent lower, respectively, with CREZ included. Figure 14 illustrates the differences in generation by fuel type between the Base Case and the Historical Elimination of CREZ Case.

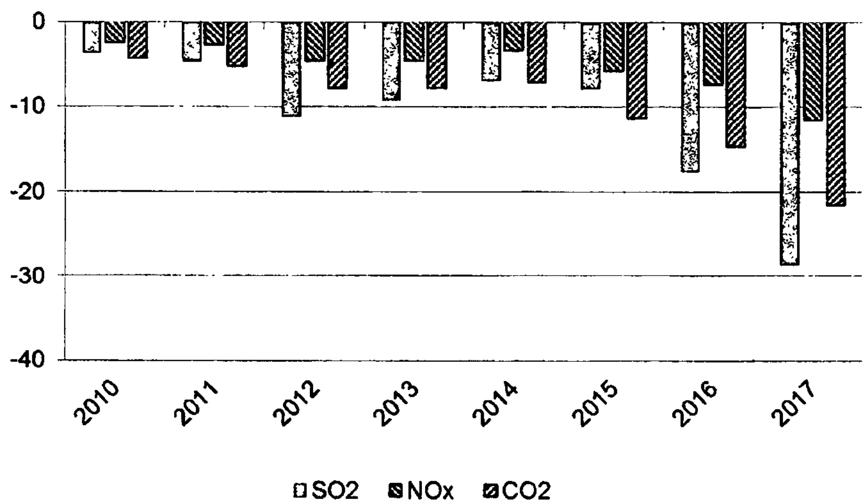
Figure 14: Difference in Generation – Base Case vs. Historical Elimination of CREZ Case (TWh)



Comparison of Emissions

Including the CREZ transmission projects increased the amount of emission-free wind generation in ERCOT, with a corresponding decrease in the amount of emitting thermal generation. PA's analysis projects that CO_2, SO_2, and NOx emissions were substantially lower with CREZ than under a market where CREZ was excluded. Figure 15 illustrates the differences in power sector emissions between the Base Case and the Historical Elimination of CREZ Case.

Figure 15: Difference in Emissions – Base Case vs. Historical Elimination of CREZ Case (Million tons for CO_2, thousand tons for SO_2 and NOx)



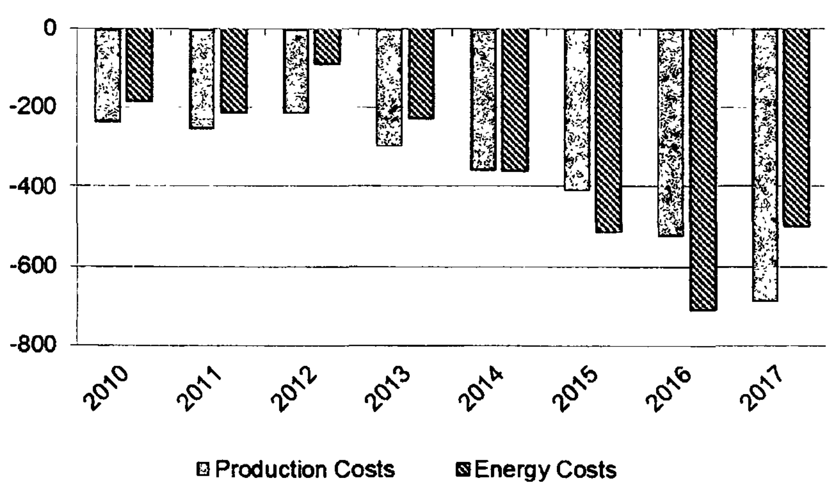
PA's analysis projects that from 2010 to 2017, CO_2, SO_2, and NOx emissions were approximately 5 to 6 percent lower under the current market structure than they would have been without CREZ. In absolute terms, SO_2 emissions were 89,000 tons lower, NOx emissions were 42,000 tons lower, and CO_2 emissions were 80 million tons lower under the current market structure. The reduction in CO_2 emissions equates to having taken over 1.9 million passenger vehicles off the road each year.

Comparison of Production Costs and Energy Costs

Increased reliance on wind generation and decreased reliance on more expensive thermal generators under the current market structure significantly decreased total system production costs in ERCOT compared to a market where the CREZ transmission projects were not built. Similarly, increased reliance on wind generation decreased all-hours power prices in ERCOT, which decreased the total energy costs paid by customers in ERCOT.

PA's analysis projects that the construction of CREZ led to production costs that were $370 million lower per year, on average, from 2010-2017 compared to a market where CREZ was not built. PA's analysis also projects that energy costs would have been $350 million lower per year, on average, over the same timeframe compared to a market where CREZ was not built. Figure 16 illustrates the differences in production costs and energy costs between the Base Case and the Historical Elimination of CREZ Case.

Figure 16: Difference in Production and Energy Costs – Base Case vs. Historical Elimination of CREZ Case ($ Millions)



Economic Impacts

Total Economic Impacts

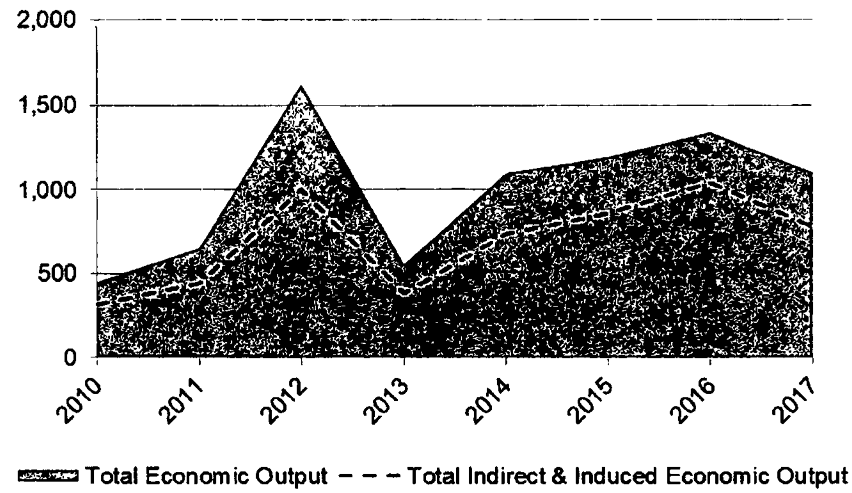
Across the study period, the current market structure led to significant benefits for the Texas economy compared to a market where CREZ and associated renewable energy capacity was not built, with total economic output across the study period projected to be over $8.0 billion higher under the current market structure due to the integration of CREZ. This difference is driven by direct, indirect, and induced contributions from construction and operation jobs and wages that would have otherwise not materialized, as well as from the induced jobs and wages spurred by energy cost savings experienced by Texas' electric retail customers.

Over the study period, indirect and induced economic output provided approximately 69 percent of the total incremental economic value created under the current market structure compared to a system without

CREZ. This figure accounts for the value provided throughout the Texas economy resulting from the indirect benefits of the direct spending as well as the increased household spending spurred by the direct and indirect wages as well as the energy cost savings.

Total economic output is calculated to have been higher in all years under the current market structure than would have occurred without CREZ. See Figure 17.

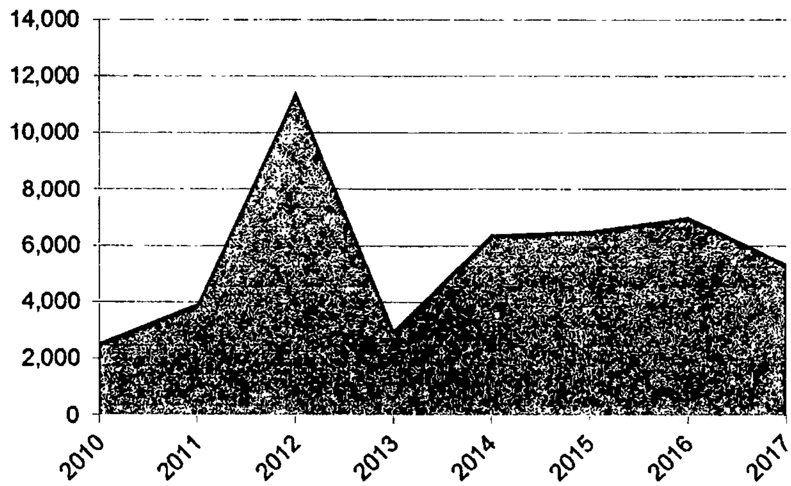
Figure 17: Difference in Total Economic Output – Base Case vs. Historical Elimination of CREZ Case ($ Millions)



Total Jobs Created

PA's analysis estimates that 46,400 total incremental FTEs, or approximately 5,800 incremental FTEs per year on average, were created throughout the Texas economy under the current market structure compared with a market where CREZ and its associated renewable energy development were excluded. This includes direct, indirect, and induced jobs. Job creation impacts follow similar patterns to those observed in total economic impacts. Figure 18 illustrates the differences in total jobs created between the Base Case and the Historical Elimination of CREZ Case.

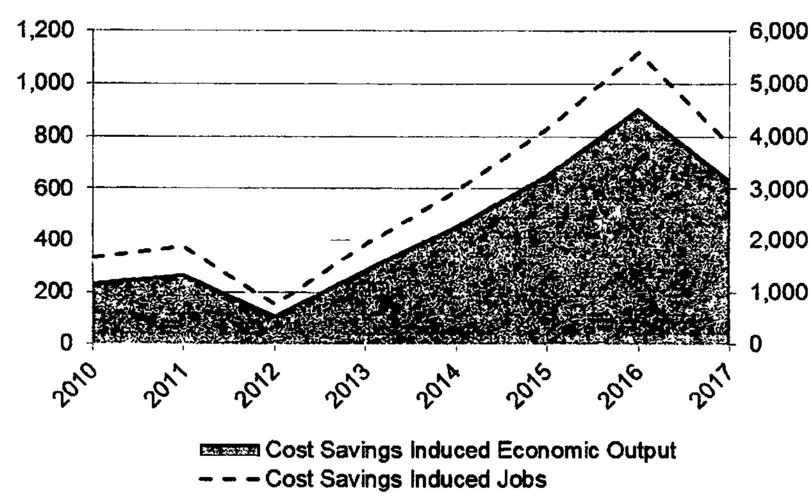
Figure 18: Difference in Total Jobs – Base Case vs. Historical Elimination of CREZ Case (FTE)



Induced Economic Impacts from Retail Customer Cost Savings

Induced economic output and the number of induced jobs attributable to energy cost savings are higher under the current market structure than under a market where CREZ and its associated renewable energy development was not built. The economic benefits spurred by energy cost savings drove a substantial share of additional economic benefits over the study period. The buildout following CREZ generated 22,700 FTEs and $3.6 billion of induced economic activity that would not have been realized otherwise. Figure 19 illustrates the differences in induced economic output and job creation driven by energy cost savings between the Base Case and the Historical Elimination of CREZ Case.

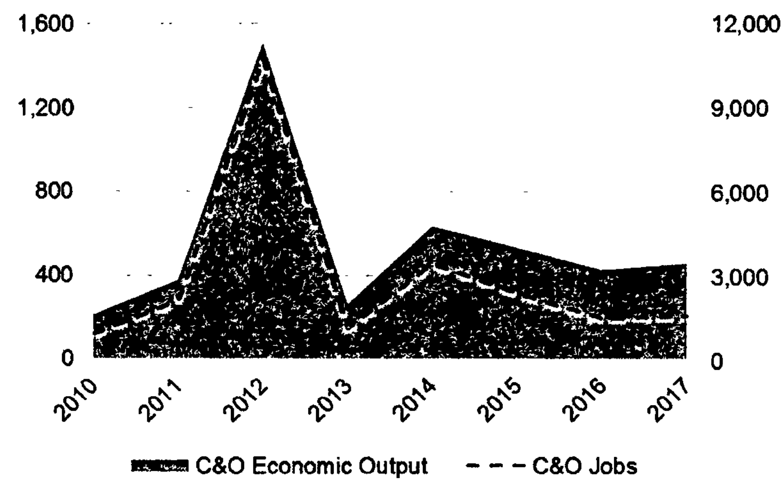
Figure 19: Difference in Cost Savings-Induced Economic Output ($ Millions, left) and Jobs (FTE, right) Base Case vs. Historical Elimination of CREZ Case



Construction & Operations Economic Output

The economic impacts stemming from construction and operations are materially higher under the current market structure than under a market where CREZ and its associated renewable energy development was not built. The increased construction and operations activity associated with the CREZ projects and associated renewable development resulted in an additional 23,700 FTEs and nearly $4.4 billion in incremental economic output from 2010-2017. Figure 20 illustrates the differences in economic output and job creation driven by construction and operations between the Base Case and the Historical Elimination of CREZ Case.

Figure 20: Difference in Construction & Operations Economic Output ($ Millions, left) and Jobs (FTE, right) Base Case vs. Historical Elimination of CREZ Case



Future Elimination of CREZ Results

To answer the question, *"**How will the CREZ transmission projects and associated generation development enabled by CREZ impact electricity customers in the State of Texas over the long-term on a going forward basis?**"*, PA compared the results of the Base Case with the Future Elimination of CREZ Case. This Case relies on the same assumptions as the Historical Elimination of CREZ Case, but considers impacts from these assumptions on a go-forward basis starting in 2018.

The results of this comparison demonstrate that the current market structure will provide significantly greater benefits to customers than the absence of CREZ and its associated renewable energy development.

Over the 2018-2037 timeframe:

- Total economic output is projected to be nearly $56.8 billion higher under the current market structure, with $43.4 billion of the economic output attributable to energy cost savings and $13.3 billion attributable to higher construction and operations expenditures.
  - This nearly $57 billion of additional economic output, plus the $8.0 billion in economic output already achieved (as described in Section 4.2), is significantly higher than the $6.9 billion published cost of CREZ.

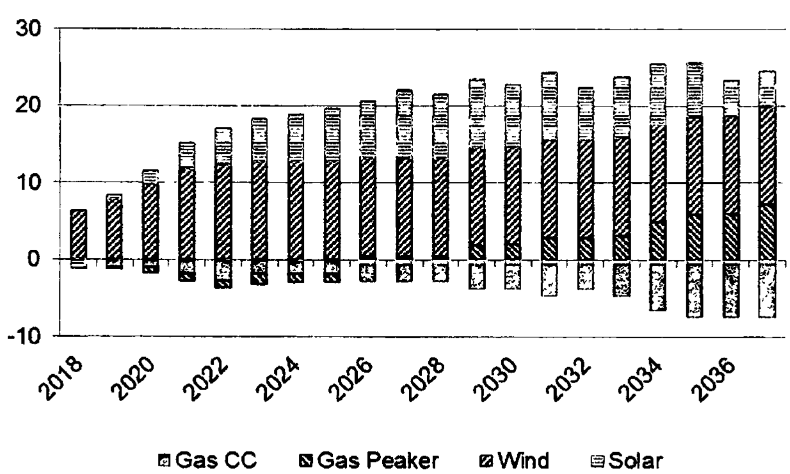
- Under the current market structure, the ERCOT system is projected to experience \$44.5 billion of total future production cost savings and \$33.9 billion of total future energy cost savings over the next 20 years due to higher levels of low variable cost power generation.
- Under the current market structure, total future jobs over the next 20 years are projected to be higher by 238,600 FTEs, with a 214,800 FTE increase attributable to energy cost savings and a 23,800 FTE increase attributable to higher construction and operations expenditures.
- Under the current market structure, total future CO_2 emissions over the next 20 years are projected to be lower by 585 million tons, NOx emissions lower by 175,000 tons, and SO_2 emissions lower by 245,000 tons.

Wholesale Market Impacts

Comparison of Capacity Built by Fuel Type

PA's analysis demonstrates that the absence of CREZ would result in material changes in future power generation investment on a going-forward basis. In particular, PA projects higher levels of wind and solar capacity under the current market structure, mostly located in the West Zone, partially offset by slightly lower levels of natural gas-fired combined cycle capacity than would otherwise be expected without CREZ. By 2037, the current market structure yields 12 percent less combined cycle capacity compared to a market where CREZ is absent. Conversely, gas-fired peaking capacity is ultimately 41 percent higher under the current market structure. Figure 21 illustrates the differences in installed capacity by fuel type between the Base Case and the Future Elimination of CREZ Case.

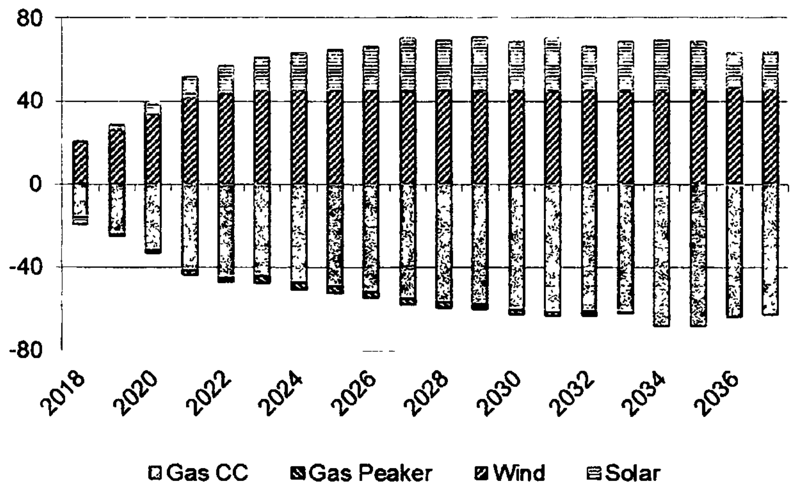
Figure 21: Difference in Installed Capacity – Base Case vs. Future Elimination of CREZ Case (GW)



Comparison of Generation by Fuel Type

Reflecting projected impacts on installed capacity by fuel type (see previous section), PA's analysis also projects a meaningful impact on the amount of solar and wind generation between the two Cases. Figure 22 illustrates the differences in generation by fuel type between the Base Case and the Future Elimination of CREZ Case.

Figure 22: Difference in Generation – Base Case vs. Future Elimination of CREZ Case (TWh)

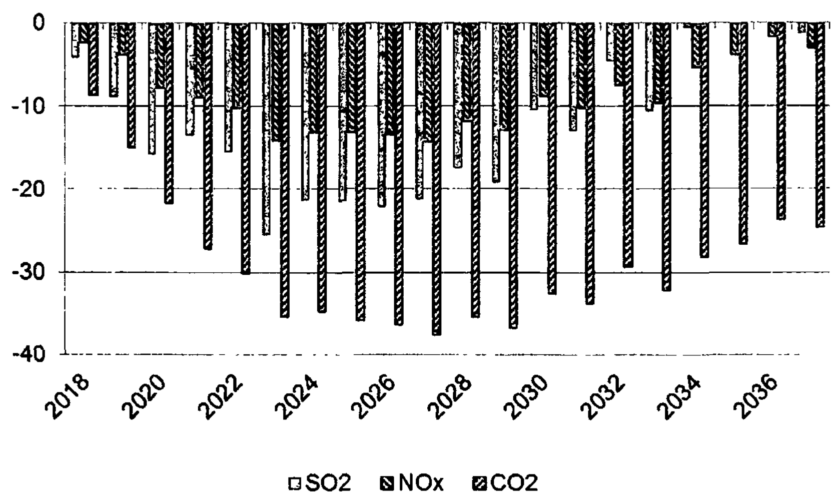


Specifically, under the current market structure, total wind and solar generation are 59 percent higher and 82 percent higher, respectively, over the course of the study period compared to a market where CREZ is excluded. Meanwhile, natural gas combined cycle and peaker generation are projected to be 23 percent lower and 12 percent lower, respectively, under the current market structure.

Comparison of Emissions

Driven by higher levels of emission-free wind and solar generation, with a corresponding decrease in the amount of thermal generation dispatch, PA's analysis projects that CO_2, SO_2, and NOx emissions will be lower under the current market structure compared to a market where CREZ is excluded. Figure 23 illustrates the differences in power sector emissions between the Base Case and the Future Elimination of CREZ Case.

Figure 23: Difference in Emissions - Base Case vs. Future Elimination of CREZ Case (Million tons for CO_2, thousand tons for SO_2 and NOx)



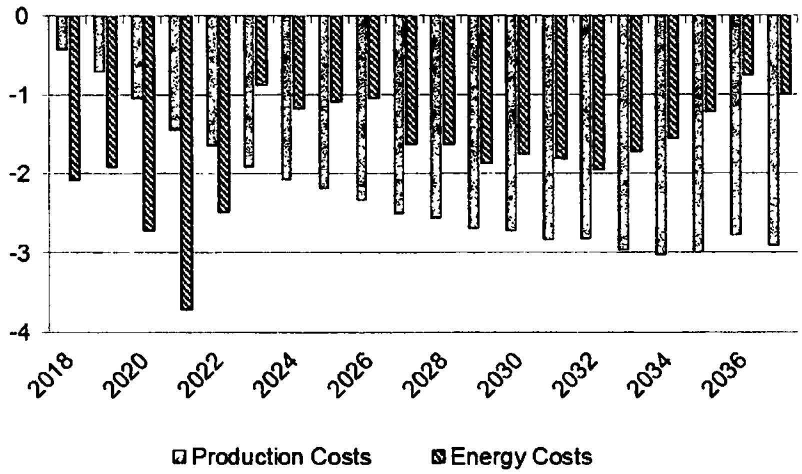
PA's analysis projects that over the 2018-2037 study period, SO_2, NOx, and CO_2 emissions are projected to be 10 percent lower, 12 percent lower, and 14 percent lower, respectively, under the current market structure. In absolute terms, this means that the presence of CREZ and its associated renewable energy development will avoid 245,000 tons of SO_2 emissions, 175,000 tons of NOx emissions, and 585 million tons of CO_2 emissions over the study period. To put these CO_2 emissions reductions in context, avoiding 585 million tons of CO_2 emissions is the rough equivalent of taking 5.7 million passenger vehicles off the road each year over the study period.

Comparison of Production Costs and Energy Costs

The higher levels of low variable cost renewable generation under the current market structure compared to a market where CREZ is excluded reduces ERCOT's reliance on more expensive thermal generators in most years of the study period. This decreased reliance on thermal generators significantly decreases both total system production costs and total energy costs.

Under the current market structure, PA's analysis projects \$44.5 billion lower production costs and \$33.9 billion in energy cost savings over the study period compared with a market where CREZ and its associated renewable development are excluded. Figure 24 illustrates the differences in production costs and energy costs between the Base Case and the Future Elimination of CREZ Case.

Figure 24: Difference in Production and Energy Costs - Base Case vs. Future Elimination of CREZ Case ($ Billions)



Economic Impacts

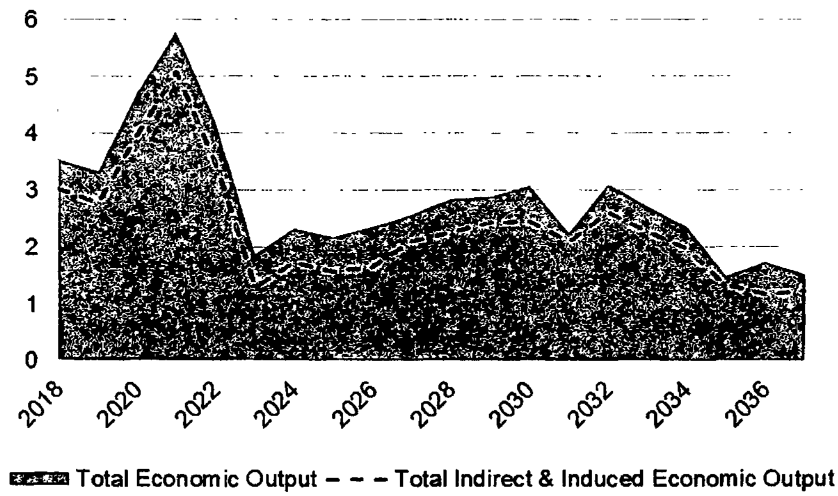
Total Economic Impacts

Across the study period, the current market structure leads to significant benefits for the Texas economy compared to a market where CREZ and its associated renewable energy development are excluded, with total economic output across the study period projected to be $56.8 billion higher under the current market structure. This difference is driven by direct, indirect, and induced contributions from construction and operation jobs and wages that would have otherwise not materialized, as well as from the induced jobs and wages spurred by energy cost savings delivered to Texas' electric retail customers.

Over the study period, indirect and induced economic output provides approximately 82 percent of the total incremental economic value created under the current market structure compared to a market where CREZ and its associated renewable energy development are excluded. This figure accounts for the value provided throughout the Texas economy resulting from the indirect benefits of the direct spending as well as the increased household spending spurred by the direct and indirect wages as well as the energy cost savings.

Total economic output is projected to be higher in all years under the current market structure compared to the Future Elimination of CREZ Case, as shown in Figure 25.

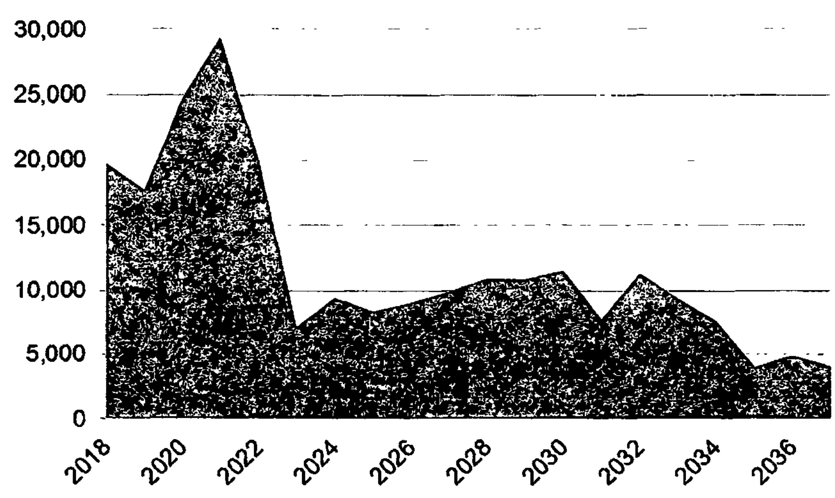
Figure 25: Difference in Total Economic Output - Base Case vs. Future Elimination of CREZ Case ($ Billions)



Total Jobs Created

PA's analysis expects 238,600 more FTEs, or approximately 11,900 more FTEs per year on average, under the current market structure compared with a market where CREZ and its associated renewable energy development are excluded. This includes direct, indirect, and induced jobs. Projected job creation impacts follow similar patterns to those observed in total economic impacts. Figure 26 illustrates the differences in total jobs created between the Base Case and the Future Elimination of CREZ Case.

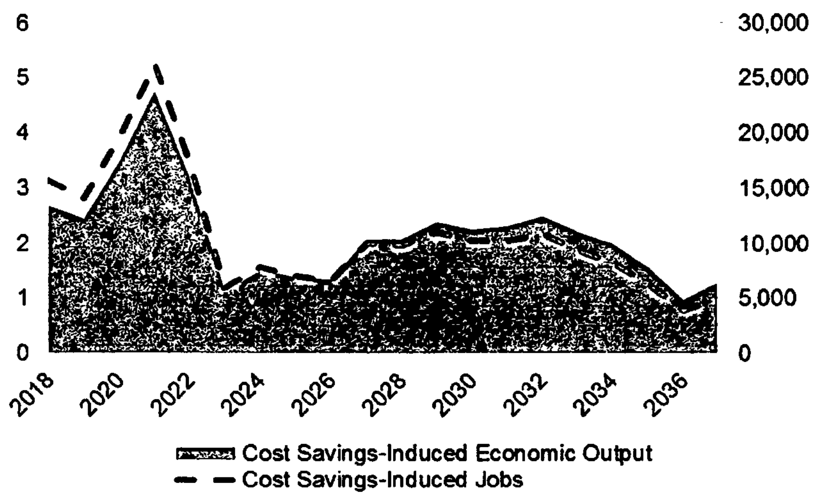
Figure 26: Difference in Total Jobs - Base Case vs. Future Elimination of CREZ Case (FTE)



Induced Economic Impacts from Retail Customer Cost Savings

Induced economic output and the number of induced jobs attributable to energy cost savings would be higher under the current market structure than under a market where CREZ and its associated renewable energy development are excluded. The economic benefits spurred by energy cost savings are expected to drive the majority of additional economic benefits over the study period. Energy cost savings under the current market structure compared to the alternative would create an incremental 214,800 FTEs and generate an additional $43.4 billion in economic output. Figure 27 illustrates the differences in economic output and job creation driven by energy cost savings between the Base Case and the Future Elimination of CREZ Case.

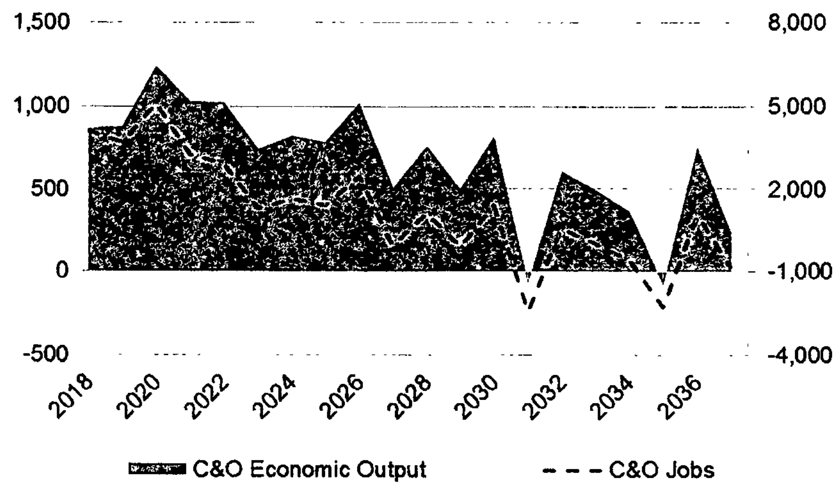
Figure 27: Difference in Cost Savings-Induced Economic Output ($ Billions, left) and Jobs (FTE, right) Base Case vs. Future Elimination of CREZ Case



Construction & Operations Economic Output

While the majority of differences in economic impacts between the current market structure and the alternative would be driven by energy cost savings, the economic impacts stemming from the operation of CREZ and construction and operation of generation infrastructure are still material. Under the current market structure, increases in construction and operations activity are projected to result in an incremental 23,800 FTEs and $13.3 billion in additional economic output over the course of the study period. Figure 28 illustrates the differences in economic output and job creation driven by construction and operations between the Base Case and the Future Elimination of CREZ Case.

Figure 28: Difference in Construction & Operations Economic Output ($ Millions, left) and Jobs (FTE, right) Base Case vs. Future Elimination of CREZ Case



DISCUSSION

ERCOT's unique energy-only market design is intended to allow competitive market forces to drive power generation investment in a manner that is most efficient for the consumer. This intent is reflected in historical approaches to transmission pricing and cost allocation within the State of Texas and ERCOT, which represent deliberate efforts by legislators and regulators to ensure that the power system provides cost-effective service to, and in turn maximizes economic benefits for, electric retail customers across the State. As PA's analysis shows, two specific features of the current ERCOT market that have facilitated these goals are the exclusion of marginal losses from LMP formation and the addition of the CREZ transmission upgrades.

In recent months, some power generation owners have voiced concerns that the ERCOT market is not providing high enough power pricing to justify past and future investment decisions. These generation owners have advocated for several proposed market design changes, including the addition of marginal losses to LMP formation. It is certainly true that excluding marginal losses from LMP formation alters system dispatch patterns. Furthermore, incorporating marginal losses into LMP formation may increase the physical efficiency of ERCOT system dispatch by increasing the dispatch of generators located closer to load centers, ultimately reducing transmission line losses on the system.

However, the singular focus on optimizing the physical efficiency of system dispatch misses the forest for the trees, as optimizing physical efficiency is not projected to be economically beneficial for Texas electricity customers in the long-run. Rather than a narrow focus on physical efficiency, the Commission is tasked with ensuring the availability of safe, reliable, high quality services that meet the needs of all Texans at just and reasonable rates. Rates are made more reasonable for consumers by creating a market structure within ERCOT that achieves long-term production and energy cost savings by maintaining the current competitive market environment.

PA's study shows that the implementation of marginal losses would alter future power generation investment decisions, decreasing the development and, in turn, overall electricity production of zero marginal cost renewable resources on the system. These changes to long-term investment in new power generation facilities and associated lower levels of zero marginal cost generation would ultimately lead to higher electricity costs for customers, less economic output for the State of Texas, higher production costs, and increased emissions. In other words, incorporating marginal losses in LMP formation would forego billions of dollars in production cost savings and economic output, create fewer jobs in Texas, and lead to higher air pollution, all to the detriment of Texas residents.

PA's study also shows the impacts of the absence of CREZ, providing an additional example of how market structure decisions that take into account ERCOT's unique physical attributes can have significant long-term economic and environmental impacts in Texas. The absence of CREZ would have led to even more substantial foregone benefits than the implementation of marginal losses, both historically and into the future.

These examples demonstrate that any analysis of potential changes to the current market structure should carefully consider the ramifications of such changes to the competitive market forces in the unique ERCOT system that have created, and will continue to create, sizeable benefits for Texas electricity customers. Furthermore, this study demonstrates the critical importance of considering the impacts to benefits of market structure changes over the long-term.

GLOSSARY

Locations and Organizations

- **Electric Reliability Council of Texas ("ERCOT")**: Transmission operator that coordinates the movement of wholesale electricity generation and transmission of power throughout most of Texas.
- **Houston Zone**: A distinct ERCOT electric market zone covering the Houston area in Southeastern Texas.
- **North Zone**: A distinct ERCOT electric market zone covering the majority of Northeastern and North-central Texas.
- **South Zone**: A distinct ERCOT electric market zone covering southern Texas.
- **West Zone**: A distinct ERCOT electric market zone covering much of western Texas.

Market Features

- **Bilateral capacity contract**: Allows a buyer and seller to exchange rights to generating capacity under mutually agreeable terms for a specified amount of time.
- **Capacity**: The physical amount of power the electric system has available to serve load in megawatts (MW); it represents generators' potential to generate electricity.
- **Capacity market**: A competitive market that is designed to ensure that a power system has the adequate resources to meet current and future demand for electricity by providing monetary rewards to power suppliers for their generating capacity.
- **Combined cycle ("CC")**: A power plant that uses both a gas and a steam turbine to produce electricity.
- **Carbon dioxide ("CO_2")**: The primary greenhouse gas emitted through burning fossil fuels (such as coal and natural gas) to generate electricity.
- **Competitive Renewable Energy Zones ("CREZ")**: Identified geographic areas located in West Texas and the Texas panhandle with favorable (i.e., wind- and solar-rich) conditions for wind and solar generation development.
- **Construction and operations expenditures**: The cost incurred by a business or firm for the construction and operating of a project.
- **Direct economic impact**: A measure of the total amount of additional expenditure within a defined geographical region that is directly attributed to an event.
- **Economic output**: The value of all goods and services (output) produced by an economy.
- **Energy cost**: The marginal cost of electricity multiplied by energy demand in any given hour.
- **Energy-only market**: A market where electric generators are compensated only for the physical power that they supply to the grid, as compared to capacity markets where electric generators are paid for the capability to generate a certain amount of power when needed to maintain electric system reliability.
- **Fixed cost**: A cost that does not change over time and is independent of the number of goods or services (such as electricity) produced.

- **Full time equivalent ("FTE")**: When used in this report, FTEs refer to full time equivalent jobs over a 12 month time frame. For example, two FTEs can be thought of a two jobs for one year or one job for two years.
- **Indirect economic impact**: A measure of the secondary effects resulting from a direct economic stimulus, such as the number of FTEs created or eliminated.
- **Induced economic impact**: A measure of the results of increased personal income due to the direct and indirect economic impacts.
- **Locational marginal price ("LMP")**: LMP, measured in $/MWh, gives market participants a signal of the price of energy at every location on the electric system. LMP represents the cost of serving the next MW of load at a specific location on the transmission system at a certain point in time. LMP in ERCOT reflects the costs of both energy and transmission congestion.
- **Nitrous oxide ("NOx")**: Nitrous oxide, an air pollutant emitted through burning fossil fuels such as coal and natural gas to generate power.
- **Peaker**: Power plants that generally run only when there is a high demand for electricity. Peakers are typically simple-cycle gas turbines.
- **Production cost**: The cost of generating electricity for each electric generator, which includes the cost of fuel as well as variables operations and maintenance expenditures.
- **Regional Transmission Organization:** An independent, non-profit organization of members responsible for managing bulk power flows over a designated transmission system via wholesale electricity markets and ensuring electric system reliability.
- **Short-run marginal cost**: The variable cost incurred by a supplier to produce one unit of electricity. Short-run marginal cost includes the cost of fuel and variable operations and maintenance.
- **Sulfur dioxide ("SO_2")**: An air pollutant emitted through the combustion of sulfur in fuel (primarily coal) used by electric generators and industrial facilities.
- **Variable cost**: A cost that varies with the amount of goods and services (e.g., electricity) produced.

Methodology

- **AURORA^{xmp}**: Computer-based chronological dispatch simulation model used to project wholesale power prices.
- **Chronological dispatch simulation model**: A computerized model that simulates the dispatch of power generation units in (a) given market(s) while minimizing total system cost, taking into account both fixed and future capital costs required to meet electric demand and ensure system reliability.
- **GPCM (Natural Gas Market Forecasting System)**: Computer-based natural gas price forecasting system that models natural gas production, existing pipeline flows and constraints, new pipeline construction, and natural gas demand from the power sector and residential, commercial, and industrial sectors for the entire United States.
- **Impact Analysis for Planning ("IMPLAN")**: Computer-based software used in Input-Output ("I-O" analysis) to project how changes in demand for specific types of goods and services are likely to affect a specific geographic region.
- **Input-Output ("I-O") analysis**: A form of economic analysis that models the interdependencies between economic sectors or industries.

- **Jobs and Economic Development Impact ("JEDI")**: Computer-based model used in Input-Output ("I-O" analysis) to estimate the economic impacts of constructing and operating power generation and biofuel plants at the local and state levels.

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Corporate headquarters
10 Bressenden Place,
London SW1E 5DN
United Kingdom
+44 20 7730 9000

United States headquarters
45th Floor, Chrysler Building
405 Lexington Avenue
New York, NY 10174
USA
+1 212 973 5900

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