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REVIEW OF MARKET REFORM	**§**	
ASSESSMENT PRODUCED BY	**§**	**PUBLIC UTILITY COMMISSION OF**
ENERGY AND	**§**	**TEXAS**
ENVIRONMENTAL ECONOMICS,	**§**	
INC. (E3)		

RESPONSES OF CITY OF GEORGETOWN TO COMMISSION QUESTIONS

City of Georgetown (Georgetown) submits the following comments in response to the Public Utility Commission of Texas (PUCT or Commission) Staff's request for comment on the Performance Credit Mechanism (PCM) as described in the Energy and Environmental Economics, Inc. (E3) Report entitled "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" dated November 2022.

I. INTRODUCTION

Georgetown appreciates the opportunity to comment on E3's report. However, Georgetown is concerned that the report has inaccuracies in its analysis that make the report's findings and recommendations unreliable. The most significant of these inaccuracies is the failure to appropriately adjust the Operating Reserve Demand Curve (ORDC) that may significantly impact the reports' findings regarding the Energy-Only market design outcomes – as pointed out by the Independent Market Monitor (IMM). The second is that, while the Report recognizes that ERCOT's current Energy-Only market is expected to far exceed the LOLE reliability standard in 2026, the Report does not account for the fact that the ERCOT market already has a mechanism – notably the Reliability Must Run (RMR) process – to address the concerns raised by the Report that this high level of supply will lead to some resource retirements thereby reducing Loss of Load Expectation just below the 0.1 day/year standard.

While the primary goal of this Project is the review of market reform assessment produced by the E3 Report, Georgetown submits the following conclusions based on the Report but which may not be obvious due to the scope of the Report.

1. **ERCOT's Energy-Only market already meets or exceeds the LOLE reliability standard and thus the added consumer costs and market disruption with capacity markets is not justified**: The E3 Report finds that "the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common industry benchmark of 0.1 days per year" and "[T]his study shows that the "pre-equilibrium" 2026 system has a surplus of resources that need to be retained to achieve target reliability as opposed to incenting new dispatchable resources into the system." The E3 Report expresses the concern that some resources may retire due to the lower market prices with the addition of significant amounts of capacity currently being built. Their Base Case scenario for 2026 does not account for the actual low cost of retention for existing resources and thus should be considered an extreme scenario – thus, their "Low Cost of Retention" scenario is a more realistic scenario and this scenario assumes retirements will result in LOLE increasing to 0.47 days/year. However, as pointed out by the Independent Market Monitor in the Senate Business and Commerce Committee meeting on 11/17/22, E3's analysis does not take into account the self-correcting mechanism built into the Operating Reserve Demand Curve (ORDC) mechanism that increases the ORDC, and thus market prices, with increasing LOLE. This impact of the ORDC would likely provide enough price support to negate some of the retirements forecasted by the Report. It's important to note that no resource has notified ERCOT of their intent to retire in the latest ERCOT Capacity, Demand, and Reserve Report. Thus, the ERCOT market does not currently nor is forecasted to have a reliability issue in terms of annual LOLE and all proposed market design changes being evaluated by the PUCT are focused on ensuring an LOLE standard that ERCOT grid is forecasted to far exceed. If there is any concern with resources retiring due to possible low market prices, ERCOT's current Reliability Must Run (RMR) mechanism can be used to ensure LOLE is maintained at 0.1 day/year level or better. Resources intending to retire are currently required to notify ERCOT of its intent and ERCOT can deem the resource critical to system reliability and require the resource to keep operating while guaranteeing cost recovery for the resource through the RMR contract until an alternate solution (such as new dispatchable resource addition) is implemented. This may be considered the most cost-effective implementation of the Backstop Reserve Service (BRS) being considered by the PUCT. Since RMR resources

are offered into the market at System-Wide Offer Cap (SWOC), it has the same impact on increasing market prices as if the resource had actually retired except that the resource's energy is still used to reliably serve load during scarcity situations. Thus, ERCOT's current Energy-Only market design with possible enhancement of the RMR mechanism is the most cost-effective way to meet or exceed the LOLE-based reliability standard – negating the need for abandoning the current market design in favor of a very expensive (to implement and increased costs to load), highly disruptive and regulated capacity market whether LSERO, FCM, or PCM. Even the IMM with experience monitoring other markets with regulated capacity requirements does not seem to favor such capacity markets for ERCOT.

2. **Prolonged winter storm remains a serious threat to the ERCOT system**: However, the only reliability threat to the ERCOT system is a prolonged winter storm as pointed out by the following recent studies:

    a. NERC 2022-2023 Winter Reliability Assessment which has a -21.4% projected reserve margin with electricity demand, generation outages, and energy derates under extreme conditions and
    b. ERCOT Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) for Winter 2022/23 which shows a 10,234 MW capacity deficit under High Peak Load/Extreme Unplanned Outages /Extreme Low Wind Output scenario.

These analyses take into account the Phase I weatherization and other changes that have been implemented. Additional changes are still in the works that will help further in reducing the market's exposure to firm load shed. However, until additional natural gas storage and firm transportation from that storage to generators are built, there will be some level of natural gas supply interruption and increased thermal and intermittent resource outages during winter storms. Simple math from the SARA shows that load during a winter storm can be 77,375 MW with total thermal resource capacity of 73,104 MW less outage of 14,780 MW or available thermal capacity of 58,324 MW which, even with some generation from IRRs and batteries, is insufficient. Thus, if the Commission is willing to accept about 10,000 MW of rolling firm load shed during a prolonged winter storm (changes being implemented are likely to ensure better rotation of such load shed), then there is no significant change necessary beyond the use of RMR to ensure LOLE standards are met or exceeded. However, if the Commission would like to address the winter storm scenario, then Georgetown would like to suggest the following changes that specifically address this scenario. The suggested changes will likely be costly for load including Georgetown; however, such changes will actually protect consumers from the devastating impacts of prolonged winter storms – an actual benefit for the added cost whereas the capacity market proposals have added consumer costs with no reliability benefits. If the winter storm threat is resolved, that will result in a super reliable grid during all other times including extreme summer scenarios.

Summary of Georgetown's suggested market design changes to address exposure to winter storms:

1. **Greatly expand FFSS but make FFSS cost-based weatherization requirement**: Firm Fuel Supply Service (FFSS) should try to achieve the reliability objectives of PURA § 39.159(c)(2) based on experience from Winter Storm Uri while minimizing the costs to load. Uri clearly demonstrated the critical need for weatherization of the fuel supply and electric infrastructure and the added protection of a reliability product like FFSS. Even with power plant weatherization, another Uri could result in fuel supply (particularly production) disruptions and significantly reduced renewable generation. Consequently, it is prudent to further augment the weatherization requirements by requiring all existing and new thermal resources to provide FFSS. This obligation should be limited to those resources that can provide firm fuel capability at a reasonable cost (PUCT-specified) for a minimum of 48 hours or 72 hours sustained duration.

   Because FFSS is an essential reliability service, FFSS should be structured to minimize the total cost for this service. Procurement of FFSS should be treated similar to Reliability Must Run (RMR) service – i.e., a cost-based service over a 10-year or remaining life of asset period with clawback of a specified percentage (e.g. 85-100%) of profits when FFSS is deployed. The clawback will serve to offset the cost to load and give an incentive to certain resources to provide FFSS without requiring an FFSS contractual payment. In addition, the cost of providing FFSS can be minimized by amortizing the capital cost over a 10-year period or the remaining life of the asset.

The cost of providing FFSS varies greatly between thermal resources and based on sustained duration requirement. For example, a nuclear plant always has more than 72 hours of onsite fuel available when operating and thus would incur no cost to provide FFSS whereas a gas plant not having onsite fuel storage or firm transportation to storage would incur significant capital cost to install such capability. It would be unacceptably expensive to pay all FFSS capacity the same single clearing price of the most expensive resource providing that service. The first FFSS auction has clearly shown that such auction-based procurement of FFSS is very costly for consumers ($52 million for only about 3,000 MW of FFSS capacity – which implies about $1 billion for 60,000 MW of FFSS capacity). Therefore, resources should be paid for the FFSS reliability service based on verified costs. Under this construct, like RMR, resources capable of providing FFSS at little to no additional cost may decide to provide FFSS without the need to enter into an FFSS contract in order to avoid any clawback of profits when FFSS is deployed. This incentive to self-provide should reduce the cost that loads have to pay for the service.

Such a design for the FFSS is likely to facilitate the development of additional natural gas storage and pipelines from such storage to power plants. If not, the Commission may want to explore additional means to facilitate development of new natural gas storage and pipelines.

2. **Keep existing long duration dispatchable resources from retiring using RMR if needed for winter storm scenario**: This is the most cost-effective way to maintaining reliability during a winter storm when there is a need for such retiring resources (effective alternative to implementing a Backstop Reserve Service (BRS)).

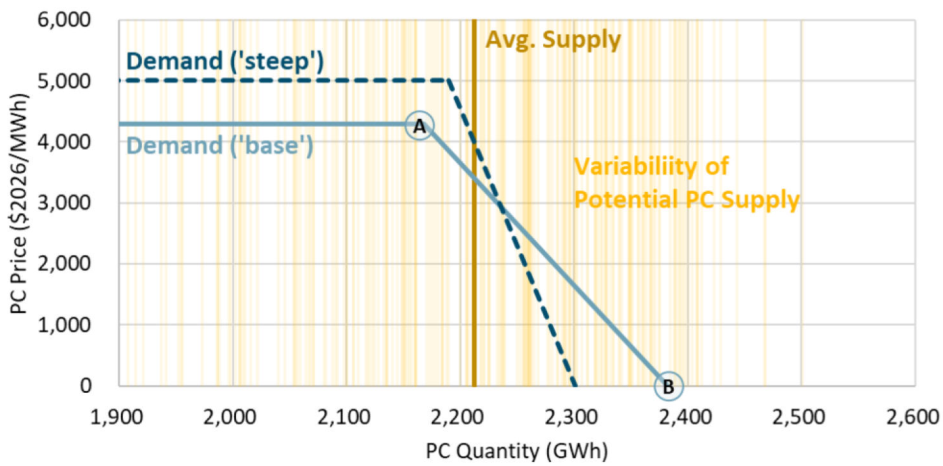
3. **Directly procure new long duration dispatchable resources sufficient to meet winter storm scenario**: Instead of LOLE or other theoretical reliability measures, ERCOT would use their winter SARA extreme scenario to determine the deficit in FFSS-capable long duration dispatchable resource capacity (e.g. 10,000 MW for 2022-20223 winter) and procure the required amounts of such resources through a 3-year forward auction. Currently investors in any thermal resource require increased certainty of return in the form of higher returns or faster depreciation to account for exposure to future environmental regulations. Thus, the lowest cost option may be for ERCOT to contract the awarded resources for a term of 10 years to minimize capital costs. The unavailability penalties and allocation of costs to load for these resources can be use the same method proposed in the Performance Credit Mechanism (PCM) proposal. These resources would be allowed to fully participate in the ERCOT energy and ancillary service markets as any other resource. However, to offset the price suppressing impact of this added capacity, market prices would be adjusted to account for any price suppression caused by the dispatch of these resources using the existing ERCOT Reliability Deployment Price Adder (RDPA) mechanism and such resource capacity would not be considered as contributing to "operating reserves" in the Operating Reserve Demand Curve (ORDC). This makes other resources in the market indifferent to the addition of these resources from an energy price perspective while ensuring the most efficient dispatch of the system. However, the addition of these dispatchable resources will reduce the prices of Non-Spinning and ECRS Ancillary Services. The IMM states in the 2021 State of Market Report that "we estimate that the combined cost increase of the higher procurement is in the range of $300-400 million for the period of July 12 to December 31, 2021." ECRS is also a new cost that consumers will pay with about the same price tag. Based on the E3 Report estimate of CT net CONE of $82.5/kW-year, the cost of procuring 10,000 MW of CT under this proposal would be about $825,000,000 /year. However, much of this cost to consumers will be offset by the reduction in the about $1 billion increased Non-Spin and ECRS costs to consumers. Also, any profits made by these resources from selling energy and/or ancillary services would be clawed back to offset the contracted capacity payments to these resources. This proposal may be considered a combination of targeted PCM, DEC, and BRS in that it pays only new dispatchable resources like DEC, uses the

PCM mechanism to reward performance and allocate cost, and reverses the energy price impact of these resources similar to BRS.

Although Georgetown does not believe there is a need to abandon ERCOT's Energy-Only market design in favor of a capacity market, Georgetown would like to express our grave concerns about the E3's proposed Performance Credit Mechanism (PCM). These shortcomings would negate any possible new dispatchable resource addition benefits intended by PCM due to the uncertainty of Performance Credit revenue streams for investors. The major shortcomings of E3's proposed PCM are as follows:

1. **Use of 30 hours in the year with the lowest incremental available operating reserves to award PCs to resources and allocate costs to Load**. Such hours could occur in a single winter event or fall/spring outage season when any particular resource may have scheduled its planned maintenance outage. This would imply that the resource would earn no PCs for the year due to its unlucky choice of days to take required planning maintenance outage. This possible outcome also makes selling PCs forward very risky and thus ensures very high prices for PCs offered in forward markets. The revenue stream for resources would be highly unpredictable for investment purposes and Loads would find it difficult to lower PCM costs by reducing consumption during such hours.
2. **The PCM design will result in highly uncertain PC values from year to year which is likely to not result in the desired investment in new generation**. Since PC prices are determined by the PC Demand Curve based on ERCOT's forecast of total PC generation for the next year that is used to value actual PC generation, this will result in highly unpredictable and almost random PC prices that are not tied to the ERCOT system meeting the reliability standard set by the Commission. PC prices could be $0 even when the system does not meet the reliability standard and PC prices could be at the cap when the system far exceeds the reliability standard. The graph in page 106 of the E3 report illustrates this uncertainty in PC prices based on variability of PC supply:

Figure 43. Potential PCM Supply and Demand ('Base' and 'Steep') Curves



This uncertainty and randomness of PC prices from year to year will not incentivize new dispatchable resource investment.

II. RESPONSES TO COMMISSION QUESTIONS

1. The E3's report observes that the PCM has no prior precedent for implementation. Does this fact present a significant obstacle to its operation for the ERCOT market?

Georgetown believes that this lack of precedent introduces significant risks for the ERCOT market. We have described above some of the shortcomings we were able to identify – however, their may be other unintended consequences of the PCM design that have yet to be identified.

2. Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?

The PCM design as described in the E3 report will **not** incentivize generation performance, retention, and market entry consistent with the Legislature's and the Commission's goal to meet demand during times of net peak load and extreme power consumption conditions. First of all, the PCM design does not even address extreme power consumption conditions like a prolonged winter storm. Second, due to the very high uncertainty in PC revenues described above, PCM is unlikely to incentivize new dispatchable resources.

3. What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

LOLE is not be a good measure of system reliability. For example, relatively minor amount of unserved energy over say 10 days would result in LOLE of 10 days/year whereas a more significant amount of unserved energy in 1 day would result in LOLE of 1 day/year. Thus, LOLE by itself does not provide a good measure of a system's reliability. Since ERCOT's reliability concerns have little to do with expected outcomes as measured by all standard reliability measure, none of those measures can appropriately applied to the ERCOT system. Since having sufficient resources to meet the extreme winter SARA scenario is the only reliability challenge facing the ERCOT system, the only reliability standard needed for ERCOT is to have 0 MW shortfall in the extreme winter SARA scenario. If the ERCOT system has sufficient resources to meet this standard, it will be reliable in the winter and super reliable throughout the rest of the year.

4. The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?

E3 proposes using 30 hours in the year with the lowest incremental available operating reserves to award PCs and allocate PCM costs to Load. As described above, this makes selling PCs forward very risky and makes it very difficult for Loads to adjust consumption or predict its exposure to PCM costs.

5. Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?

A more predictable period to determine highest reliability risk would be a month so that PC revenue stream for resources is more predictable for investment purposes and hours for Loads to reduce consumption during each month.

6. Would a voluntary forward market for generation offers and a mandatory residual settlement process for LSE procurement provide additional generation revenue sufficient to incentivize resource availability in a way that improves reliability?

A voluntary forward market for PCs provides an opportunity for resources and Loads to hedge some of their PC exposure. However, given the uncertainty risks described above, the forward market price of PCs are likely to be close to the cap and thus of little use to Loads.

7. Does a centrally cleared market through ERCOT sufficiently mitigate the risk of market power abuse? Should additional tools be considered?

Awarding PCs based on monthly peak net load (so as to avoid manipulation through outage scheduling) along with a centrally cleared market mitigate much of the risk of market power abuse.

8. If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service (BRS), to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?

Regardless of whether PCM is implemented (we have not seen a good justification to implement PCM) and even after PCM implementation if that should occur, there is a need to implement the following to ensure ERCOT system reliability (described in greater detail in the Introduction section):

1. Greatly expand FFSS but make FFSS cost-based weatherization requirement.
2. Keep existing long duration dispatchable resources from retiring using RMR if needed for winter storm scenario: This is the most cost-effective way to maintaining reliability during a winter storm when there is a need for such retiring resources (effective alternative to implementing a Backstop Reserve Service (BRS)).

9. If implementing a short-term design as a “bridge” delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the l-in-10 LOLE reliability standard?

The measures proposed above as well as a long-term commitment to buy the additional 5,630 MW of Ancillary Services can be immediately implemented.

Commission should give time for market outcomes to be realized from these changes prior to implementing any capacity market. These changes may be more than sufficient to meet the reliability standards set by the Commission.

10. What is the impact of the PCM on consumer costs?

PCM, as other capacity market constructs, will greatly impact consumer costs as determined by ICF and Brattle Group analyses already submitted to the Commission.

11. What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.

Please refer to answers to questions 8 and 9.

12. In what ways could the Dispatchable Energy Credit (DEC) design be modified through quantity and resource eligibility requirements, e.g. new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

A modified DEC, that combines elements of PCM and BRS, should be considered by the Commission to address extreme weather resiliency. The concerns with DEC as proposed in E3 report are the price suppressing energy offer incentives and market price suppression caused by DEC resource dispatch. To address both these concerns, DEC needs to be modified as follows:

i. DECs are awarded for being available and offering into energy and/or Ancillary Services during the same monthly high risk hours as PCM and the cost of DECs would be allocated to Load on Load Ratio Share during those same peak net load hours of the month.
ii. For DEC resource energy dispatch to not suppress market prices, any potential price suppression from DEC resource energy deployment by SCED should be reversed by applying the Reliability Deployment Price Adder and such resource capacity would not be considered as contributing to "operating reserves" in the ORDC. This will make the energy

market prices indifferent to the addition of new subsidized DEC resources. This is an efficient adaptation of the BRS proposal.

This modified DEC proposal is an efficient and least cost method of directly procuring new long duration dispatchable resources sufficient to meet the winter storm scenario while ensuring that the DEC-eligible resources do not distort the energy market. However, these resources will likely participate in the Non-Spin and ECRS markets thereby significantly reducing the clearing price for those products. Thus, much of this cost to consumers of this modified DEC proposal will be offset by the reduction in the increased Non-Spin and ECRS costs to consumers since July 2021. Georgetown would gladly provide details of this proposal if so desired by the Commission.

Respectfully submitted,

City of Georgetown

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EXECUTIVE SUMMARY OF GEORGETOWN'S RESPONSE TO COMMISSION QUESTIONS ON E3 REPORT

An Executive Summary of Georgetown's responses to Commission Staff's request for comment on the Performance Credit Mechanism (PCM) as described in the Energy and Environmental Economics, Inc. (E3) report entitled "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" dated November 2022 is given below.

Georgetown submits the following conclusions based on the Report but which may not be obvious due to the scope of the Report.

1. **ERCOT's Energy-Only market already meets or exceeds the LOLE reliability standard and thus the added consumer costs and market disruption with capacity markets is not justified**: The E3 Report finds that "the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common industry benchmark of 0.1 days per year" and "[T]his study shows that the "pre-equilibrium" 2026 system has a surplus of resources that need to be retained to achieve target reliability as opposed to incenting new dispatchable resources into the system." The E3 Report expresses the concern that some resources may retire due to the lower market prices with the addition of significant amounts of capacity currently being built. ERCOT's current Reliability Must Run (RMR) mechanism can be used to ensure LOLE is maintained at 0.1 day/year level or better. Thus, ERCOT's current Energy-Only market design with possible enhancement of the RMR mechanism is the most cost-effective way to meet or exceed the LOLE-based reliability standard – negating the need for abandoning the

current market design in favor of a very expensive (to implement and increased costs to load), highly disruptive and regulated capacity market whether LSERO, FCM, or PCM.

2. **Prolonged winter storm remains a serious threat to the ERCOT system**: However, the only reliability threat to the ERCOT system is a prolonged winter storm as pointed out by the following recent studies:

   a. NERC 2022-2023 Winter Reliability Assessment which has a -21.4% projected reserve margin with electricity demand, generation outages, and energy derates under extreme conditions and
   b. ERCOT Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) for Winter 2022/23 which shows a 10,234 MW capacity deficit under High Peak Load/Extreme Unplanned Outages /Extreme Low Wind Output scenario.

If the Commission wants to address the winter storm scenario, then Georgetown would like to suggest the following changes that specifically address this scenario:

1. **Greatly expand FFSS but make FFSS cost-based weatherization requirement**: Firm Fuel Supply Service (FFSS) should try to achieve the reliability objectives of PURA § 39.159(c)(2) based on experience from Winter Storm Uri while minimizing the costs to load. Because FFSS is an essential reliability service, FFSS should be structured to minimize the total cost for this service. Procurement of FFSS should be treated similar to Reliability Must Run (RMR) service – i.e., a cost-based service over a 10-year or remaining life of asset period with clawback of a specified percentage (e.g. 85-100%) of profits when FFSS is deployed. The clawback will serve to offset the cost to load and give an incentive to certain resources to provide FFSS without requiring an FFSS contractual payment. In addition, the cost of providing FFSS can be minimized by amortizing the capital cost over a 10-year period or the remaining life of the asset. Such a design for the FFSS is likely to facilitate the development of additional natural gas storage and pipelines from such storage to power plants. If not, the Commission may

want to explore additional means to facilitate development of new natural gas storage and pipelines.

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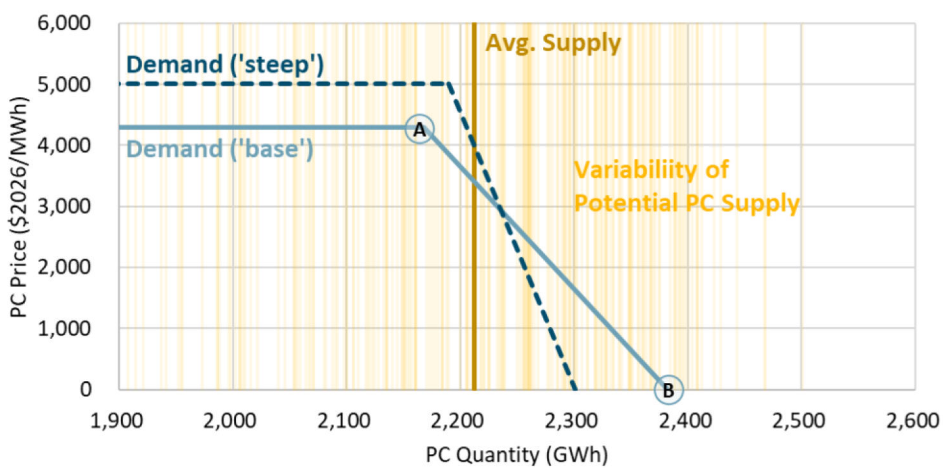
The major shortcomings of E3's proposed PCM are as follows:

1. **Use of 30 hours in the year with the lowest incremental available operating reserves to award PCs to resources and allocate costs to Load**. Under this design, the revenue

stream for resources would be highly unpredictable for investment purposes and Loads would find it difficult to lower PCM costs by reducing consumption during such hours.

2. **The PCM design will result in highly uncertain PC values from year to year which is likely to not result in the desired investment in new generation**. Since PC prices are determined by the PC Demand Curve based on ERCOT's forecast of total PC generation for the next year that is used to value actual PC generation, this will result in highly unpredictable and almost random PC prices that are not tied to the ERCOT system meeting the reliability standard set by the Commission. The graph in page 106 of the E3 report illustrates this uncertainty in PC prices based on variability of PC supply:

Figure 43. Potential PCM Supply and Demand ('Base' and 'Steep') Curves



This uncertainty and randomness of PC prices from year to year will not incentivize new dispatchable resource investment.