# Filing Receipt

**Received - 2022-12-15 09:15:53 AM**
**Control Number - 54335**
**ItemNumber - 59**

PROJECT NO. 54335

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

## JOINT COMMENTS OF TEXAS SOLAR POWER ASSOCIATION AND SOLAR ENERGY INDUSTRIES ASSOCIATION

COMES NOW the Texas Solar Power Association (TSPA) and Solar Energy Industries Association (SEIA) and file these joint comments regarding the report Energy + Environmental Economics (E3) filed in Project No. 52373, *Review of Wholesale Electric Market Design,* on November 10, 2022. On November 15, 2022, the Commission requested comments regarding the Report and questions asked by the Commission be filed by noon on December 15, 2022.[1] TSPA and SEIA are not affiliates, but we (the Solar Associations) have combined our comments for this filing to assist the Commission.

## INTRODUCTION

The TSPA is a statewide industry trade association that promotes the development of solar electric generation. Our member companies invest in the development of solar photovoltaic products and projects in Texas, serving customers in both wholesale and retail markets, with products ranging from utility-scale generation, community solar and customer-sited solar and storage solutions.

SEIA is a national trade association of the solar energy industry. Through advocacy and education, SEIA and its members are building a strong solar industry to power America. As the voice of the industry, SEIA works to make solar a mainstream and significant energy source by

[1] 47 Tex. Reg. 7991 (Nov. 25, 2022).

expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA represents solar companies across a variety of solar energy technologies, including photovoltaic ("PV"), solar water heating, and concentrating solar power ("CSP"). Additionally, SEIA represents diverse solar companies providing utility-scale generation community solar, and customer-sited solar and storage solutions.

The Solar Associations are concerned that the proposed Performance Credit Mechanism (PCM) undermines the wholesale and retail markets, creates unnecessary credit and operational risk, and fails to achieve increased reliability in a cost-disciplined manner. At its base, the proposal transfers money from some generators to others without producing any public benefit and does not address the specific operational concerns experienced by ERCOT over the past several years. For these reasons, the Solar Associations recommend that the Commission focus on the technology neutral "Uncertainty Product" proposed by the Independent Market Monitor (IMM) and supported by a wide variety of stakeholders. In the event a near-term "bridge" is required, the Solar Associations recommend the Commission increase ERCOT's procurement of ECRS above what it currently forecasts to procure upon implementation and, potentially, increase procurement of non-spin reserve service.

If the Commission chooses to implement the PCM, it should adopt several changes to improve the PCM's effectiveness and minimize impacts to the existing energy-only market, which generally works well in procuring power for Texans at affordable prices. First, generators should be able to receive a PC even if they do not run in real time or provide ancillary services – if they appropriately offered into the DAM and are not on outage. Second, customers should not have to turn offline to avoid PCM charges – just because the 25$^{th}$ worst hour of the year qualifies for performance credits doesn't mean that there is an operational reliability reason to encourage customers to stop consuming electricity. It would lead to curtailments for accounting instead of curtailments for actual operational concerns. Given that the purpose of a power grid is to serve customer demand, creating artificial reasons to curtail customers is bad policy. An alternative would be to create a robust demand response program where customers voluntarily agree to be curtailed by ERCOT instead of being made to guess which hours to self-curtail in a PCM structure. Third, the Operating Reserve Demand Curve (ORDC) should be designed to deliver the Commission's desired reserve margin on its own, so that revenue from the PCM is narrowly crafted in a way to guarantee that the desired reserve margin is met while not overpaying generators unnecessarily at the expense of customers; e.g., the PCM should be designed to make up no more than 10% of the combined energy and PCM markets.

In addition to the market design issues raised by the E3 report, the Commission should continue to focus on resolving transmission constraints and reducing congestion costs. Effective and forward-looking transmission planning processes and implementation plans are needed for a reliable and resilient grid in order to move generation to load cost effectively.

The Solar Associations respond to the Commission's questions below.

**1. The E3's report observes that the Performance Credit Mechanism (PCM) has no prior precedent for implementation, does this fact present a significant obstacle to its operation for the ERCOT market?**

Yes. Several major issues are immediately apparent and significantly more transparent and robust analysis is required for the Commission and stakeholders to understand the impact of these and additional issues. For example, the E3 report failed to consider the credit impacts on ERCOT market participants. ERCOT requires collateral in the form of cash or letters of credit from market participants to cover the risk of future unpaid invoices. ERCOT bases this collateral requirement on recent market activity. Under the PCM as proposed, approximately 25% of the annual cost of energy, according to E3, would be collected once a year in a lookback settlement. In today's market design, smaller amounts of collateral are needed because invoices are paid on a daily basis. In the proposed PCM, ERCOT would require enormous amounts of collateral to be posted for most of the year in anticipation of this future PCM invoice. This could increase credit requirements by billions of dollars for both generators and customers that have PCM obligations. A $5 billion PCM market could require $6 or $7 billion in collateral to cover the risk of generator non-performance and load non-payment, because collateral will be required from both generators that may not earn performance credits they sold in advance and from customers that may not pay their invoices.

The requirement for significantly more credit will have its own consequences. ERCOT limits banks to a maximum $750 million in letter of credit exposure with ERCOT, resulting in a total letter of credit limit for all banking relationships with ERCOT, at present, to just over $13 billion. Under the PCM design, a high-cost energy market coupled with PCM obligations in the same year could easily max out ERCOT's total credit limits with banking counterparties. ERCOT could minimize this risk by billing customers for estimated PCM impacts on a more frequent basis, such as monthly, but this would result in large sums of money moving back and forth between ERCOT and its counterparties because the proposed 30 PCM hours are not allocated to a particular month in advance. While a monthly PCM would still have large credit costs, those costs will be at a lower scale – hundreds of millions of dollars of risk from unearned performance credits or unpaid load invoices would accrue each month.

An additional issue is that the E3 report fails to consider how the PCM would cause large swings in generation and consumption in response to the start of an expected performance credit hour. During performance credit hours, generators and load share the same incentive. Generators that are out of the money on an energy cost basis have an incentive to continue to run at a loss in the hopes of earning performance credits. Similarly, interruptible loads have an incentive to reduce consumption or shut off – similar to how large loads respond to transmission cost of service (4CP) today. Unlike 4CP, however, incentives for generators and loads will compound under PCM, so that the 30 hours of performance credit hours could result in 90 or more hours of behavioral changes, because performance credit hours are not known in advance, will not be confirmed until the following year (or shorter compliance term), and may occur at any time due to a variety of factors. These behavioral changes in non-performance credit hours will go uncompensated, yet generators that started up in hopes of earning performance credits would incur completely unnecessary wear-and-tear on their equipment while loads that responded would reduce economic activity and profits for no private or public benefit. Initial reviews of hours in 2022 with the lowest operating reserves have indicated that the performance credit hours can occur at any time as a result of multiple factors. If further analysis of historical ERCOT data confirms this initial analysis, then market volatility may become even more extreme as generators and loads try to capture or avoid performance credits. From an operational perspective, the ERCOT control room will have to manage enormous changes in participation during some hours. If thousands of megawatts of load shuts down and thousands of megawatts of generation start up, ERCOT could have trouble balancing the system – potentially for no system reliability benefit at all.

A third issue that E3 did not consider was the impact the PCM would have on Texas' retail market. Under the PCM, Retail Electric Providers (REPs) would have to hedge against an unknown quantity of performance credits at an unknown price while still offering fixed price products. At a minimum, the definition of what constitutes a fixed price product would need to be changed to include retrospectively adjusting prices to reflect the cost of performance credit procurement caused by customer consumption during a performance credit hour, as well as including performance credit costs in the fixed price. In addition, REPs that are not affiliated with generators will have too little certainty around their hedging risk exposure, which would be further exacerbated if the REP has significant customer churn throughout the year. This hedging risk uncertainty would be even worse for retailers with demand response products or distributed energy resources (DERs), and would create new barriers to DER deployment. If retailers respond to PCM risk by curtailing load or discharging batteries too often because the REP is trying to guess when the PCM hours will occur, that will create customer concerns, especially if the REP is forced to explain that it curtailed a customer or used their battery for no compensation because the current hour turned out to not be a performance credit hour. Even if it were a performance credit hour, there would be no way to know until the end of the year, creating a substantial timing disconnect between action and compensation, making it very difficult if not impossible to know how to compensate customers for demand response on retail products, much less charge to and collect from customers who consumed energy during a performance credit hour the additional cost that customer caused during that hour. While shorter compliance periods could reduce the maximum length of a lookback period for customer billing, shorter compliance periods would not reduce the amount of customer inconvenience and frustration associated with uncertain demand response and DER utilization discussed above. Thus, even though the PCM is intended to promote demand response, the randomness of the 30 PCM hours would make it very challenging if not impossible to deliver demand response as a practical matter.

Additionally, E3 did not address potential perverse incentives that the PCM would create for battery storage. Under normal conditions, daily energy price volatility creates arbitrage opportunities for energy storage that also benefits the reliability of the ERCOT system by helping to smooth net load. However, the PCM would distort these price signals by creating a new opportunity cost for storage associated with missing out on PCM hours. In other words, batteries would refrain from discharging during tight margin hours even when energy prices were high in anticipation of a potential PCM hour later in the day. This problem would be exacerbated when the tightest day of the year has several consecutive performance credit hours or multiple blocks of compliance hours. For example, if a particular afternoon had hours ending 14, 15, and 16 that could qualify as performance credit hours, a one-hour duration storage resource would have an incentive to not offer their energy during hours 14 and 15 to avoid being discharged by the market in order to retain its state of charge for hour 16. While this behavior could look like withholding, it would in fact be a storage resource reflecting its opportunity costs in its energy offers under PCM incentives. This incentive results in extremely inefficient dispatch and use of batteries. If hour 16 turned out not to be a performance credit hour, the battery will have missed its opportunity to earn a credit, and the grid will have lost the opportunity for more reliable operations if the battery had been available. This perverse incentive benefits no one and is just an artifact of a flawed market design.

Finally, it's not clear that the performance credit mechanism could actually result in new generation being financed by parties that are unwilling to take on risk from energy markets, due to their own risk tolerance. While thousands of megawatts of new capacity already have been built and more are expected to be online in the next two years because of the energy-only market,[2] some investors are apparently on the sidelines because of the performance requirements of the existing energy market and uncertainty around the forward curve. Those same investors probably would remain on the sidelines due to the performance requirements of the PCM – particularly the need to guess performance credit hours. The performance credit scoring method creates risks that are difficult to resolve because of the incentives around certain hours. This "gamification" of a capacity market to make it appear more like an energy market creates additional complexities that creates additional costs compared to traditional capacity markets, but without the primary benefit of a capacity market: revenue certainty. Even if more generation is built, capacity payments from

2 *See* Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2023-2032, November 29, 2022, Worksheet labeled "Changes" (available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.xlsx). For example, ERCOT expects more than 1,500 MW of new gas-fired generation to be online by Summer 2024.

the PCM likely will accrue only to existing generators. Incumbents like NRG, Vistra, Calpine, and others will reap billions of dollars in extra revenue in exchange for continuing to do the same things they are already doing and without any requirement to invest in new generation resources.

**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?**

Unlikely. The unpredictability inherent to the PCM market design would make performance in the short-term difficult to predict, and financing new generation difficult to guarantee in the long-term. The PCM does not guarantee that it will produce enough revenue to attract new generators. Investors need certainty and the risk of non-performance may prevent the very investment the PCM is trying to attract. In addition to the risk of non-performance, the hours during which performance credits may be awarded is unknown until after the fact and can occur almost randomly, creating an incentive for generators to run when they are not needed and loads to curtail when they should not have to in an attempt to chase the performance credit hour. These are economically inefficient outcomes.

Loads should not have to guess what hours to curtail to avoid PCM costs. If a customer were to sign up to be willing to curtail based on ERCOT instructions (similar to ERS, but with more advanced notice, such as four or eight hours in advance), then ERCOT could count on them being offline if necessary without other load voluntarily curtailing for what may or may not be a PCM hour. This unnecessary curtailment would cause both customer confusion and lost economic activity. Customers that agreed to a voluntary curtailment program could have their PCM obligation reduced and also reduce the total number of performance credits that ERCOT would need overall to meet a target reserve margin – reducing both their share of performance credits and the total cost for the whole system. To have the PCM meet a reserve margin and avoid cross-subsidization, customers that sign up for the voluntary program would still have some allocation of performance credits – the amount of capacity necessary in excess of energy demand to meet a reserve margin. For example, if the target capacity and reserve margin was 115% of total demand, the customer in the voluntary program would still have to pay for the 15% that represents the reserve margin so that other customers not in the voluntary program would not be charged in excess.

**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)?**

A one-in-ten year standard is an outdated metric from the vertically integrated utility regulation model of the 20th century. Moreover, any reliability standard that exists solely to establish a market for extra capacity will be fought over by consultants and lawyers. If the Commission intends to adopt a reliability standard that is the basis for a capacity market, ERCOT should develop multiple metrics with robust and transparent analyses for each of them to give policy makers a better view of the health of the energy-only market, such as unserved energy or economically optimal reserve margins. However, any proposed standard will be overly simplistic. Almost all standards fail to appreciate the wide spectrum of values of lost load, fail to integrate energy efficiency opportunities, make poor assumptions around market behavior, and fail to account for large, abnormal events like Winter Storm Uri. Reliance on a particular standard as an indicator of reliability is misplaced. For example, prior to Winter Storm Uri, ERCOT expected a reserve margin of 16.2%, but instead suffered a reserve margin of -21.1% on February 15, 2021.[3] What appeared to be a healthy reserve margin clearly did not equate to grid reliability.

Even marginally more accurate methodologies such as an economically optimal reserve margin that have made an attempt to determine the actual spectrum of values of lost load in the

---

[3] Patrick Milligin, "Winter Storms Wreak Havoc on ERCOT Grid," ICF Insights / Energy, Feb. 23, 2021 (available at https://www.icf.com/insights/energy/winter-storms-ercot-grid).

Texas economy would have its own flaws around the spectrum of costs of value of lost load, and modeling assumptions about what capacity will get built in a vacuum from reality and the diversity of investment that is already occurring and helping to serve load.

The purpose of a mandatory planning reserve margin is to administratively determine that there is a capacity shortage that must be resolved through side payments to generators. ERCOT has an operational problem of unit commitment, not a long-term capacity shortage. In its report, even E3 recognizes that ERCOT does not have a capacity shortage today – E3 estimates ERCOT's current installed capacity results in an LOLE of 0.03, or more than three times better reliability than E3 seeks to achieve with any of its market design proposals.[4] Moreover, E3 also estimates that ERCOT's reliability will improve over the next four years to a LOLE of 0.02 – more than five times better that E3 is trying to achieve with any of its market design proposals – even if no changes are made to the current market design.[5] Capacity reports like the ERCOT CDR report show excess capacity for years into the future. Thus, "solving" ERCOT's problems by creating a capacity market, whether the PCM or any other construct, is not addressing the actual operational issues faced by ERCOT but simply creating new capacity revenues for incumbent generators.

**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?**

Any measure like this creates problems and is an inherent flaw in the PCM proposal. Any number of performance credit hours that is picked will necessarily be arbitrary and will not address the operational problem that a market design is supposed to solve. Instead, it will just spread extra revenue across the chosen number of hours, regardless of whether those hours have operational concerns. In addition to the number of hours used for the PCM, the length of the period over which performance credits are awarded directly impacts the uncertainty inherent in this market

---

4 E3 Report at 126.
5 E3 Report at 46.

design. For example, it is more unpredictable to guess which hour in a year may be a performance credit hour than it is to guess which hour in a week or a day may be a performance credit hour. Both the number of hours used as well as the compliance period during which performance credits are awarded impacts the randomness of the hours. The incentives created by those hours, as explained above, can hurt the performance of the real time market and may not be related to operational concerns that should actually be addressed.

**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?**

Please see response to Question 4 above. In addition, since the determination of the highest reliability risk hours is an arbitrary cost allocation decision, it also should be considered in coordination with the credit concerns raised above. The longer the timeframe the hours are spread across, the longer it will take to invoice the costs of those hours, so the more credit will have the be kept on the sidelines for a future invoice. For example, a monthly market will require credit sized for monthly invoices, and an annual market will require credit sized for an annual invoice. While a monthly PCM could resolve some of the issues caused by annual uncertainty of which hours are performance credit hours, this ignores the fact that ERCOT does not have a capacity problem. As a result, designing a program to pay for excess capacity on a monthly basis does not help address the operational needs of the system. This would simply increase costs to customers while providing no reliability value.

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

No. In fact, there is a significant potential that this proposed market design would reduce system reliability because it would create new operational risks that could lead to early retirements. Generators that sold forward would **have** to be available in PCM hours, leading them to run in any hour that **might be** a PCM hour. This increased incentive to run, even if the energy price is below their short-term marginal costs, will lead to, essentially, uncompensated reliability unit commitments (RUCs) for the potential near-PCM hours. While the revenue from PCM hours might make up for these uncompensated hours, it would still increase the wear and tear on the resources for no real public or private benefit which could cause generation units not to be available to operate in times of actual system need.

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

No. If anything, the PCM approach will concentrate market power into the largest existing generators, because it reduces the capability of some types of generation to earn credits. The definition of market power will need to be modified to consider the forward auction concentration, and voluntary mitigation plans will need to be updated for both forward market participation as well as behavioral incentives to run (or not run) to impact PCM hours and PC revenue.

**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?**

No. The Commission should adopt an uncertainty ancillary service that addresses the so-called "blue sky days" and addresses the actual operational needs of ERCOT while the Commission takes time to consider long term market design options more thoroughly. This approach does not require a short-term bridge product or service as it can be quickly implemented. An ancillary service approach could be implemented immediately and refined over time (e.g. changes to ramping criteria, start time, duration or other performance characteristics as determined by future market needs and market design criteria), and then potentially be reduced in the future if a future market design warrants it. If the Commission determines that a bridge is needed, an increase of existing or soon to be implemented ancillary services, such as ECRS and non-spin, could be quickly implemented,

**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 1-in-10 LOLE reliability standard?**

Increasing the amount of ECRS and even non-spin immediately, then adding an uncertainty product as soon as possible that had parameters such as a two-hour notice and four-hour duration would directly address the current operational concerns of ERCOT and increase pressure on the forward market to further encourage new construction. The Commission should also consider changes to reduce the current duration requirements or other performance characteristics for non-spin and ECRS if it directs ERCOT to buy the new four-hour duration uncertainty service.

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

As acknowledged by E3, all consumers will have increased costs, but the Solar Associations would like to focus on two sets of consumers that we believe will be especially adversely impacted. First, consumers that prefer to buy renewable power will have significant costs from the PCM as they will need to contract with new resources for capacity, even if they currently receive all of the energy they need from their existing retail products. Customers on 100% solar products still get 100% of their kilowatt hours purchased by their REP in the real-time market based on their actual demand – there is not any shortcut. If solar underperforms, in today's market design, the customer that buys solar still needs power and so must buy it from the market. In a PCM construct, the customer would have to buy both the megawatt hour of power from the energy market and buy the PCM as well, forcing them to "double pay" for capacity and energy. In other words, customers already pay for potential solar underperformance by using the energy market to firm their supply needs.

Secondly, we encourage the Commission to consider the example of a retail electric provider with an Aggregated Distributed Energy Resource (ADER) offering. To minimize costs, a DER aggregation will be incentivized to discharge to reduce load during PCM hours. Because PCM hours won't be known until the next year (or next month, if a monthly PCM, or next week, if a weekly PCM, etc.), the retailer **and the customer** will have no way of knowing whether the discharge actually saved money or not. This would significantly complicate the retail billing arrangement for this product and lead to customer confusion about why their battery was being discharged. This arrangement could hurt the adoption of DERs.

**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.**

ERCOT could immediately buy more ECRS and even non-spin as a bridge to an uncertainty product that could be developed in the next six to twelve months, leveraging the existing work already done for ECRS. The NPRR and OBDRR necessary to implement a new uncertainty product would mirror almost exactly the ECRS language, but would have different duration and notice times. Notifying the market immediately of the anticipated quantity of ancillary services would have immediate upward pressure on the forward price of power, especially if it was made clear that an offer floor would be in place. In addition, as described above, the Commission could quickly expand the purpose of the ORDC, and redraw it to target a specific reserve margin. The sooner the Commission begins work on this new curve, the better, in order to have regulatory certainty and sufficient notice.

ERCOT could also immediately issue an RFP for a Backstop Reserve Service after writing new Protocols to support it. The Backstop Reserve Service, if modeled as originally suggested by Commissioner Cobos, and not as a capacity market the way E3 proposed, could focus on procuring enough additional capacity to provide a higher level of ancillary services or headroom for unexpected demand, and even potentially fund the construction of new generators. If new capacity is funded through this mechanism, it should continue to be a load related charge, the way RMR costs are assigned and the Commission's policy blueprint suggested.[6] New capacity that provides BRS and is held "out of the market" to avoid price suppression should have its capital costs repaid to load on a depreciated basis if the owner wants to operate the facility in the future without restrictions on offer prices and market participation, similar to how capacity contributions are considered and repaid in the Protocols today.

**12. In what ways could the Dispatchable Energy Credit 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?**

The Dispatchable Energy Credit proposal as originally proposed by Commissioner McAdams is very different from the one proposed and modeled by E3. The original proposal should be reevaluated without the need for it to provide a target reserve margin the way capacity markets do. Instead, it could be modeled to cover a portion of new load growth or, as an alternative, the volume of DECs to be procured could be based on incenting the development of a specified amount of DEC-compliant resources, similar to the goals provided in Utilities Code §39.904(a). If structured as a percentage of new load growth, it is unlikely to cause generator retirements because it is helping to meet new demand and not taking away revenues from existing generators. The DEC proposal also could be modified to have more new resources be DEC-compliant to earn credits. For example, at the most extreme, the DEC program could allow all new dispatchable generation resources in ERCOT to be eligible, allowing the competitive market to determine which resources would be the most economical to build. This approach would allow new technology such as small modular nuclear reactors to be eligible for this incentive as well. The DEC proposal deserves

6 Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT, Project No. 52373, Review of Wholesale Electric Market Design (Jan. 13, 2022) (Item 336).

additional consideration as an alternative to forward capacity markets that were proposed by E3. E3's work that modified both the BRS and DEC as capacity markets failed to fulfill the objectives of the report, which was to model the proposals on the table that had been extensively commented on by stakeholders.

## CONCLUSION

SEIA and TSPA appreciate the opportunity to provide these Comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

Tonya Miller

Tonya Miller
Executive Director
Texas Solar Power Association
www.txsolarpower.com
State Bar No. 24026771
tonya@txsolarpower.org
(512) 560-9735

*/s/ Marcus Pitchford*

Markus Pitchford
Central US Regional Manager
Solar Energy Industries Association
www.seia.org
mpitchford@seia.org
(630) 730-2533

PROJECT NO. 54335

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

## JOINT COMMENTS OF TEXAS SOLAR POWER ASSOCIATION AND SOLAR ENERGY INDUSTRIES ASSOCIATION

## EXECUTIVE SUMMARY

- The Solar Associations are concerned that the proposed Performance Credit Mechanism (PCM) undermines the wholesale and retail markets, creates unnecessary credit and operational risk, and fails to achieve increased reliability in a cost-disciplined manner. If adopted, the PCM should be modified as follows:
    - Generators should be able to receive a credit even if they do not run in real time or provide ancillary services as long as they appropriately offered into the DAM and are not on outage.
    - Customers should not have to turn offline to avoid PCM charges, as it would lead to curtailments for accounting instead of curtailments for actual operational concerns. ERCOT could develop a robust demand response program where customers agree to be curtailed by ERCOT instead of being made to guess which hours to self-curtail in a PCM structure.
    - The Operating Reserve Demand Curve (ORDC) should be designed to deliver the Commission's desired reserve margin on its own, so that revenue from the PCM is narrowly crafted in a way to guarantee that the desired reserve margin is met while not overpaying generators unnecessarily at the expense of customers; e.g., the PCM should be designed to make up no more than 10% of the combined energy and PCM markets.
- The Solar Associations recommend that a better solution than PCM would be for the Commission focus on the technology neutral "Uncertainty Product" proposed by the Independent Market Monitor (IMM) and supported by a wide variety of stakeholders.
- As a "bridge," the Commission could increase ERCOT's procurement of ECRS and increase procurement of non-spin reserve service.
- The Commission should also continue to focus on resolving transmission constraints and reducing congestion costs.