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

December 15, 2022

COMMENTS OF THE INSTITUTE FOR POLICY INTEGRITY AT NEW YORK UNIVERSITY SCHOOL OF LAW

The Institute for Policy Integrity at New York University School of Law (Policy Integrity) respectfully submits the following comments in response to the Public Utility Commission of Texas's (PUCT) request for comments on E3's *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System* (the E3 Report). Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and public policy.[1] Policy Integrity's past work on electricity policy includes academic papers and policy reports on optimal wholesale market design and resilience threats to the grid.[2]

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[1] These comments do not purport to represent the views, if any, of New York University School of Law.

[2] *E.g.*, SYLWIA BIALEK ET AL., INSTITUTE FOR POLICY INTEGRITY, RESOURCE ADEQUACY IN A DECARBONIZED FUTURE: WHOLESALE MARKET DESIGN OPTIONS AND CONSIDERATIONS 33 (2021), https://policyintegrity.org/files/publications/Resource_Adequacy_in_a_Decarbonized_Future.pdf (last visited Dec. 14, 2022); Sylwia Bialek & Burçin Ünel, *Will You Be There for Me the Whole Time? On the Importance of Obligation Periods in Design of Capacity Markets*, 32(2) ELEC. J. 21 (2019); BURÇIN ÜNEL & AVI ZEVIN, INSTITUTE FOR POLICY INTEGRITY, TOWARD RESILIENCE: DEFINING, MEASURING, AND MONETIZING RESILIENCE IN THE ELECTRICITY SYSTEM 12 (2018), https://policyintegrity.org/files/publications/Toward_Resilience.pdf (last visited Dec. 14, 2022).

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I. Introduction

After Winter Storm Uri, S.B. 3 charged the PUCT with ensuring that the Electric Reliability Council of Texas (ERCOT) "establishes requirements to meet the reliability needs of the power region."[3] In addition, S.B. 3 directed PUCT to make sure that ERCOT "determines the quantity and characteristics of ancillary or reliability services necessary to ensure appropriate reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production in the power region," and "procures ancillary or reliability

[3] Tex. Util. Code Ann. § 39.159(b)(1) (West 2022); 2021 Tex. Sess. Law. Serv. Ch. 426 (West) (text of S.B. 3).

services on a competitive basis to ensure appropriate reliability."[4] The E3 Report assesses five market mechanisms intended to satisfy these directives.[5] The PUCT has invited comments on the E3 Report, especially on the Performance Credit Mechanism (PCM) described therein, which is the leading candidate among the proposals.[6]

Our comments make the following recommendations to the PUCT:

1. The PUCT should do additional analysis on the reliability needs of ERCOT, as it is currently unclear whether the PUCT needs to create a new mechanism to ensure reliability.
2. If a new mechanism is necessary, it should be technology-neutral to ensure just and reasonable rates for consumers. A technology-neutral mechanism would compensate all resources for their reliability value, rather than favoring particular generation methods.
3. Non-performance penalties should reflect the societal value of generation, including reliability, to incentivize generators to be available when generation would be most valuable to society.

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[4] Tex. Util. Code Ann. § 39.159(b)(2)–(3).

[5] ZACH MING ET AL., E3, ASSESSMENT OF MARKET REFORM OPTIONS TO ENHANCE RELIABILITY OF THE ERCOT SYSTEM 1, 7–10, 13 [hereinafter E3 REPORT].

[6] In brief, the PCM would impose an obligation on Load-Serving Entities to procure performance credits proportionate to their share of demand during the highest-risk hours for the grid. Those hours would be assessed retrospectively at the end of each compliance period. Performance credits would be distributed to generators that offered into the energy or ancillary services market during those same hours. The value of credits would be determined based on the amount of generation that was made available (offered) during those hours and an administratively set demand curve, with a relatively higher value assigned to performance credits when relatively little generation was made available. In advance of each compliance period, a forward market would exist to allow generators and Load-Serving Entities to make offers to buy and sell performance credit obligations, respectively, using ERCOT as a clearing house. In addition, there would be a penalty for offering to sell credits in the forward market and then failing to create those credits during the highest-risk hours.

4. Any reliability mechanism should reduce risk premia, and hence costs, by mitigating uncertainty around market revenues for investors and payments made by Load Serving Entities (LSEs).
5. Any reliability mechanism should address the potential for generation resource operators to exercise market power.

Our comments also analyze the PCM, offering both critiques of the PCM and proposals for how to improve its design.

II. It Is Unclear Whether a Second Reliability Mechanism Is Necessary

S.B. 3 directs the PUCT to establish a reliability standard and then to determine the quantity and characteristics of ancillary or reliability services to achieve it.[7] Only after the PUCT has accomplished these steps should the PUCT execute its subsequent duty: ensuring that ancillary or reliability services are procured to satisfy the reliability standard.[8] Thus, before the PUCT rushes to implement a new mechanism to procure additional services, it should first assess whether existing mechanisms are insufficient to meet the reliability standards PUCT will set under S.B. 3.

The mechanisms in the E3 report primarily address a specific type of reliability problem—resource adequacy—before properly diagnosing ERCOT's true needs. In reality, the reforms PUCT already implemented since Uri may have been enough to achieve the forthcoming reliability standard. For this reason, we agree with the Senators who advised the PUCT to "first take action to define the reliability goals for the ERCOT region prior to moving forward with any significant market redesign."[9]

A. The Role of Markets in Achieving Reliability

To understand whether there is a need for a new reliability mechanism in ERCOT, it is important to review some preliminaries about how markets efficiently achieve reliability and the current functioning of ERCOT's wholesale market. Investment in generation capacity is efficient

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[7] Tex. Util. Code Ann. § 39.159(b)(1)–(2).

[8] *Id.* § 39.159(b)(3); *accord Hearing on Assessing the Elec. Market in Tex. Before the S. Comm. on Bus. & Com.* 2022 Leg., 87th Sess. at 20:05 (statement of Chairman Schwertner that the relevant portion of S.B. 3 "starts with setting a reliability standard" and then "obtaining reliability, ancillary services, or a product or changes in the market that would incent the market to adjust to that reliability standard," and that this is a "stepwise . . . blueprint for the PUC to have followed").

[9] Letter from Sen. Charles Schwertner, Chairman, Sen. Comm. on Bus. & Com., et al., to Peter Lake, Chairman, Pub. Util. Comm., et al. (Dec. 1, 2022).

when the marginal societal benefits from an additional unit of generation capacity equals the marginal societal cost of providing that capacity.[10] When considering the societal benefits of new generation capacity, one should consider not only the value of the energy that the resource can generate, but also other sources of value, such as reliability. In well-designed markets, investors have the incentive to add new capacity to the system until the societal costs of the additional capacity begins to outweigh its societal benefits, including reliability.

Reliability has two dimensions: (1) resource adequacy—having enough resources to meet demand, taking into account scheduled and reasonably expected outages; and (2) security—operational ability to withstand sudden disturbances.[11] Wholesale electricity markets (day-ahead, real-time, and ancillary-service markets) are intended to efficiently achieve both dimensions of reliability.[12] When wholesale electricity prices are allowed to fluctuate according to the value that energy provides to the electricity system, the resulting revenue incentivizes the efficient level of generation capacity, ensuring resource adequacy.[13] Energy prices increase when there is scarcity, signaling the societal value of additional investment. In these situations, high prices create sufficient revenue opportunities for investors to recover the costs of investing in capacity,

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[10] *See* ROBERT S. PINDYCK & DANIEL L. RUBINFELD, MICROECONOMICS 691 (8th ed. 2013).
[11] *Frequently Asked Questions*, NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, 1 (2013), https://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf (last visited Dec. 14, 2022); ÜNEL & ZEVIN, *supra* note 2, at 12.
[12] *See, e.g.*, Peter Cramton, *Electricity Market Design,* 33(4) OXFORD REV. ECON. POL'Y 589, 591 (2017).
[13] William W. Hogan, *Electricity Scarcity Pricing Through Operating Reserves,* 2(2) ECONS. OF ENERGY & ENV'T POL'Y 65, 66 (2013) ("In principle, efficient electricity prices provide good incentives for both short-run operations and long-run investments. In the short run, prices reward generators who make their plants available when needed and in response to the changing dispatch conditions. The same prices provide incentives for loads to moderate demand during the most expensive hours and manage load to shift requirements to lower priced hours. In the long run, the expected value of future short-run payments for energy and ancillary services provides revenue for investment in new generating facilities or energy conservation.").

even if the prices occur for only a few hours each year. Both price-setting generators and price-taking generators rely on these few hours to recover their investment costs.[14]

However, binding price caps and a variety of other factors prevent electricity prices from reflecting the full societal value of electricity during scarcity.[15] In turn, prices typically do not reach levels high enough to allow generation resources to recover their investment costs, discouraging adequate investment in generation capacity.[16] This problem is called the "missing money" problem, because investors are missing some of the money they would need to recoup their investments.[17] The missing money problem prevents investment in generation capacity from reaching the efficient level, where marginal societal benefits equal marginal societal costs. Thus, some additional reliability mechanism is needed to overcome the missing money problem and ensure resource adequacy.

In ERCOT, the ORDC is such a reliability mechanism. Under this policy, a scarcity price kicks in when operating reserves are low. This high price reflects the value of energy produced during scarcity periods, compensating generators according to the value they provide to the system. The level of scarcity price, and thus strength of the investment incentive, is determined by how low the operating reserves are and where that value falls on the ORDC. Thus, if the ORDC, which is set administratively, is not well calibrated, the resulting scarcity prices may not suffice to solve the missing money problem caused by ERCOT's price cap. In such a case, a

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[14] Paul W. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16(3) UTILS. POL'Y 159, 160 (2008).
[15] *Id.* at 160 (noting the following factors that suppress market prices: insufficient quantities of demand response available to clear the market and maintain reliability; market prices often do not reflect the societal cost of using operating reserves to supply energy; use of out-of-market actions by system operators to prevent prices from rising; administrative price caps; and use of emergency reliability protocols).
[16] Hogan, *supra* note 13, at 66.
[17] Joskow, *supra* note 14, at 160–61.

second reliability mechanism may be necessary to further incentivize the investment needed to achieve a reliable system. If the ORDC *is* well calibrated, however, a second reliability mechanism is not needed.

B. Whether ERCOT Needs a New Reliability Mechanism

ERCOT made significant changes after Winter Storm Uri. Among other changes,[18] ERCOT lowered the maximum ORDC price from $9,000 MWh to $5,000 MWh while also increasing a parameter known as the minimum contingency level (which affects when scarcity prices are triggered) from 2,000 MW to 3,000 MW.[19] While the first change exacerbates the missing money problem, the second change ameliorates it. According to ERCOT, the net effect of these changes has been "higher price signals during periods of lower reserves" relative to previous ORDC policies.[20]

If the new ORDC better addresses the missing money problem, ERCOT may not have a resource adequacy problem moving forward. If so, there would be no need for a second reliability mechanism (in addition to the ORDC) to address resource adequacy. But if the recent changes on net do not sufficiently solve the missing money problem, then an additional reliability mechanism may be justified.

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[18] ERCOT's approved "Phase I" changes also included allowing earlier deployment of emergency response services, facilitating demand response, and enhancing services in its ancillary services market (introducing a firm fuel product, expanding its non-spinning reserve service, introducing a new fast frequency response service, developing a voltage support compensation product, and introducing a new contingency reserves service product). Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT, *Review of Wholesale Electric Market Design*, Project No. 52373 (Jan. 13, 2022).

[19] ERCOT, *2022 Biennial ERCOT Report on the Operating Reserve Demand Curve* 10 (2022), https://www.ercot.com/files/docs/2022/10/31/2022%20Biennial%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf (last visited Dec. 14, 2022).

[20] *Id.* at 1; *accord* ICF RESOURCES, LLC, ASSESSMENT OF ERCOT MARKET STRUCTURAL CHANGES 1, 24 (2022) ("[M]ore generation generally receive lower scarcity prices in a few hours of the year but higher scarcity prices in many more hours of the year (and on net, more dollars overall on average in all modeled years).").

But the existing record does not sufficiently show that ERCOT has a resource adequacy problem. The E3 Report sought in part to address the resource adequacy question by modeling the exit and entrance of generation resources in light of the recent changes to the ORDC and other reforms.[21] It concluded that ERCOT would have a resource adequacy problem in 2026.[22] However, the E3 Report's analysis of this issue is not sufficiently comprehensive to support any structural reforms.

For example, E3's modeling fails to take into account the full universe of generation technologies that could be added to the system to meet reliability standards. Instead, E3's modeling approach assumes that a single technology, combustion turbines, is added to the system until reliability is achieved.[23] In addition, the E3 Report focuses on the single "snapshot" year of 2026.[24] Investors in generation resources plan over decades-long time horizons, and the incentives put into place by a market design would therefore have implications for how the electricity system would evolve well beyond 2026. E3 recognizes that the market designs it analyzes may not even be implemented until 2026,[25] thus, an assessment of reliability pertaining only to that year tells the PUCT little about the long-term need for—and consequences of—a new reliability mechanism. Other parties who have submitted comments in this proceeding have

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[21] E3 REPORT, *supra* note 5, at 2–3.
[22] *Id.* at 5.
[23] *Id.* at 31 ("Based on calculations from the SERVM model, this study determined that a natural gas combustion turbine (CT) was the marginal capacity resource. If CT margins exceed CONE, new gas CT units are added. If CT margins are lower than CONE, coal and gas steam turbine units are removed from the system.").
[24] *Id.* at 3 ("The analysis in this study focuses on the snapshot year of 2026, a near-term year that was intentionally selected by the Consulting Team as 1) near-term enough that there is relative certainty about expected loads and resources but 2) long-term enough that any potential market design reform could be implemented.").
[25] *Id.* at 81–82 (estimating that the BRS "would take approximately one to three years to fully implement"; the Dispatchable Energy Credits would take one to four years; and the Forward Reliability Market, Load Serving Entity Reliability Obligation, and PCM would take two to four years).

identified further methodological issues associated with the E3 Report, and the PUCT should consider them carefully.[26]

The need for further analysis is especially acute because the PCM, the leading candidate among the proposed reliability mechanisms, primarily aims to address resource adequacy and would do little to address the conceptually distinct issue of resilience.[27] (The same is true of the proposed Backstop Reliability Services and the Dispatchable Energy Credits.[28]) S.B. 3 partially reflects Legislature's concern with resilience in the directive that the PUCT procure services to ensure continued operations during "extreme heat and cold weather."[29] Resilience refers to "the ability of a system to resist, absorb and adapt, and recover after an external high-impact, low-probability shock," such as Winter Storm Uri.[30] Yet, while resource adequacy and resilience are related, one does not guarantee the other.[31] Thus, it may be that ERCOT does not have a resource adequacy problem but still has a resilience problem that leaves ERCOT vulnerable during extreme weather events.

Furthermore, many of the reforms already implemented since Uri—such as winterization and winter firm fuel service—already improve both reliability and resilience. Thus, in light of the recent changes to the ORDC and the PUCT's other Phase I market reforms, more analysis is necessary before it can be determined that ERCOT has the type of resource adequacy problem that would be addressed by the proposals in the E3 Report.

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[26] *See, e.g.*, Comments of Alison Silverstein Consulting, *Review Of Market Reform Assessment Produced By Energy And Environmental Economics, Inc. (E3)*, Project No. 54335 (Dec. 9, 2022).
[27] E3 REPORT, *supra* note 5, 86–87; *Hearing on Proposed Changes to ERCOT Market Design Before the H. Comm. On State Affs.*, 2022 Leg., 87th Sess. at 1:01:27 (statement of PUCT Chairman Lake describing the PCM as "really directed at" at addressing periods of low non-dispatchable power, rather than Uri-like conditions).
[28] E3 REPORT, *supra* note 5, at 86–87.
[29] Tex. Util. Code Ann. § 39.159(b)(3).
[30] ÜNEL & ZEVIN, *supra* note 2, at 4.
[31] *See id.* at 11.

It may be that ERCOT has a different type of reliability problem (i.e., an operational security problem), or that ERCOT's challenge is primarily resilience. Rushing into implementing an unproven market design without understanding the true nature of any reliability or resilience problems that remain after the recent reforms would be unnecessarily costly and would unnecessarily interfere with the relatively efficient price signals of ERCOT's existing market.

III. Any New Reliability Mechanism Should Reflect Fundamental Economic Principles

The PUCT should adopt a new reliability mechanism beyond the ORDC only after it has sufficiently evaluated the reliability needs of ERCOT and only if doing so is necessary to achieve the forthcoming reliability standard. If the PUCT does move forward with a new reliability mechanism, the mechanism should, like other components of ERCOT's market, be designed with economic efficiency in mind. Specifically, the reliability mechanism should: (1) compensate all generation resources—both dispatchable and non-dispatchable—according to their reliability values; (2) include a penalty that reflects the value of lost reliability to society; (3) mitigate uncertainty to lower the cost of investment; and (4) avoid design flaws that will allow market participants to exploit the mechanism through anticompetitive behavior.

This approach would benefit consumers and investors by ensuring the cost effectiveness of any reliability standard the PUCT adopts and, in turn, would fulfill the PUCT's mandate to "ensure . . . just and reasonable" rates.[32] Adherence to our recommendations would also be consistent with the PUCT's obligations to "ensure[s] appropriate reliability" and procure reliability services "on a competitive basis."[33]

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[32] Tex. Util. Code Ann. § 36.003(a) (West 2022).
[33] *Id.* § 39.159(b)(3).

A. A Reliability Mechanism Should Compensate All Resources According to Their Reliability Value

Any reliability standard would cost more if non-dispatchable resources were excluded from reliability payments. Thus, implementing the PCM (or any other reliability mechanism) in a manner that excludes non-dispatchable resources would force consumers to overpay for reliability. But some design proposals discussed in the E3 Report and propounded by Commissioners preclude non-dispatchable resources from being compensated for the reliability they provide and thus ignore these economic fundamentals. But it is possible to appropriately account for the reliability value of non-dispatchable resources in many of the mechanisms that are considered in the E3 report. And, because compensating non-dispatchable resources in accordance with their reliability value would allow the PUCT to achieve a reliability standard at the least cost, adopting this recommendation would accord with the PUCT's responsibility to ensure just and reasonable rates.[34]

1. Both Dispatchable and Non-Dispatchable Technologies Contribute to Reliability and Should Be Compensated Accordingly

[34] *Id.* § 36.003(a).

Even though the amount of power they provide to the system cannot be adjusted at will, non-dispatchable resources can contribute to reliability by providing energy during the highest-risk hours for the grid.[35] ERCOT already recognizes that non-dispatchable resources have reliability value: The ORDC compensates both dispatchable and non-dispatchable resources during scarcity, and in proportion to the reliability value that they provide.[36] It is also well established that an efficient generation mix—one which meets reliability criteria at least cost—typically includes a variety of dispatchable and non-dispatchable technologies.[37]

The most economically efficient way to achieve reliability is for all generation types to be eligible for compensation for the reliability that they contribute to the system. This result, demonstrated consistently in the economics literature, follows from the general notion that efficiency is achieved when the marginal cost of adding reliability is equal to its marginal benefit, regardless of its technology type.[38] A market design that ignores certain types of resources despite their ability to provide reliability would result in excessive costs, which are ultimately borne by consumers.

From an investment standpoint, a narrowly focused reliability mechanism results in higher costs to consumers for two main reasons. First, if a cheaper resource is restricted from participating in the market, a more expensive resource will be procured, increasing the unit price

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[35] For example, solar resources delivered greater generation than expected during Uri. Joshua W. Busby, et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas,* 77 ENERGY RSCH. & SOC. SCI. 1, 4 (2021).
[36] ERCOT, *supra* note 19, at 10.
[37] *See, e.g.,* SYLWIA BIALEK & BURÇIN ÜNEL, INSTITUTE FOR POLICY INTEGRITY, CAPACITY MARKETS AND EXTERNALITIES AVOIDING UNNECESSARY AND PROBLEMATIC REFORMS 13 (2018), https://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf (last visited Dec. 14, 2022).
[38] For example, Joskow and Tirole demonstrate that, in the presence of price caps that reduce investors' revenue from the energy market, payments for offering generation capacity can restore an optimal investment outcome as long as all generation types are eligible. Paul Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets,* 38 RAND JOURNAL OF ECONS. 60, 83 (2007).

paid for reliability. Second, ignoring a portion of existing resources could also lead to over-procurement—procuring more resources than are needed to satisfy reliability standards. These consequences have been observed in other restructured electricity markets.[39]

From a short-run operational standpoint, an inefficient resource mix can result in excessively high energy prices. Failing to appropriately compensate renewable generators, for example, would lead to a generation mix that is disproportionately composed of thermal units that have relatively high marginal costs. Dispatching these units more frequently would lead to higher aggregate energy costs. Indeed, the E3 Report acknowledges as much, warning that "in the long-run," reduced compensation for non-dispatchable resources "could result in smaller wind and solar buildout (relative to the counterfactual), which would have the effect of increasing energy prices."[40]

2. The PUCT Should Ensure that Non-Dispatchable Resources Are Eligible for Payments Under Any New Reliability Mechanism

Contrary to fundamental economic principles, some Commissioners have expressed interest in a reliability mechanism that is narrowly focused on dispatchable technologies. For example, in public testimony, PUCT Chairman Lake indicated his support for restricting the PCM to dispatchable resources.[41] The E3 Report accordingly includes analysis of scenarios in which the PCM, the Load Serving Entity Reliability Obligation, and the Forward Reliability Market compensate only dispatchable generation technologies.[42] Additionally, the Dispatchable

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[39] *E.g., N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102, at P 36 (2022) (finding that NYISO's minimum offer price rules for capacity resources had "considerable cost," including "over-procure[ment] [of] capacity").
[40] E3 REPORT, *supra* note 5, at 74.
[41] *E.g.*, *Hearing on Proposed Changes to ERCOT Market Design Before the H. Comm. On State Affs.*, 2022 Leg., 87th Sess. at 1:30:04 (statement of Chairman Lake).
[42] E3 REPORT, *supra* note 5, at 74–75.

Energy Credit proposal would involve compensating an even narrower subset of generation technologies through strict eligibility criteria.[43]

A reliability mechanism that excludes non-dispatchable resources would be economically inefficient for the reasons discussed above. An economically inefficient design would mean that consumers would be overpaying for reliability, as they could have achieved the same level of reliability for less if non-dispatchable resources were also compensated for the real reliability value that they contribute.

3. The PUCT Should Facilitate Technology Neutrality If a Reliability Mechanism Is Adopted

As we discuss in Section II, it remains unclear whether any of the reliability mechanisms assessed in the E3 Report are necessary, given the ORDC and other changes that have already been implemented following Winter Storm Uri. But if an additional reliability mechanism is deemed necessary, many of the design proposals could be adopted in a way that is technology-neutral and therefore grounded in fundamental economic principles.

Any mechanism that determines reliability in an ex post manner—that is, by compensating generation technologies based on a retrospective assessment of performance—should cover both dispatchable and non-dispatchable technologies. In other words, any resource that has performed should get paid. Similarly, any mechanism that determines reliability in an ex ante manner—compensating generation technologies based on an expectation of performance—should do so for all technologies according to their reliability value as set through an accreditation process.

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[43] *Id.* at 27.

Ideally, this ex ante accreditation would be precise, taking into account all sources of uncertainty that could affect a generator's capability to perform, including uncertainty as to which hours will pose the highest reliability risk throughout the year. Wind generation resources tend to contribute more to reliability in the winter and at night; solar resources in the summer and during the day.[44] Demand tends to peak in either winter or summer. Reliability depends on which resources are going to be available when they are most needed due to demand patterns; this availability cannot be precisely assessed without taking into account such temporal patterns.

Indeed, if an ex ante mechanism were chosen, implementing a reliability mechanism that reflects seasonal variations in the performance of resources would accord with S.B. 3. The law instructs the PUCT to ensure that the reliability services procured "meet continuous operating requirements for the season in which the service is procured" and satisfy certain enumerated qualifications for the summer and winter.[45]

The E3 Report suggests "that either a properly implemented annual construct that accounts for risks across all seasons or a full seasonal construct would . . . yield similar economic outcomes,"[46] and that costs from a seasonal reliability mechanism would sum to the same cost as an annual mechanism.[47] However, this characterization assumes the most important point of accounting for seasonality: Ensuring that accreditation "accounts for risks across all seasons" is critical for effectively valuing reliability.[48] That is, without perfect aggregation of seasonal generation capabilities, the outcomes under different seasonal constructs would differ.

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[44] BIALEK & ÜNEL, *supra* note 2, at 22.
[45] Tex. Util. Code Ann. § 39.159(c).
[46] E3 REPORT, *supra* note 5, at 101.
[47] *Id.* at 102 ("Even under a seasonal implementation approach, prices would be expected to clear in a manner that generators earn the same total annual revenues through the LSERO or FRM construct as illustrated in Figure 41.").
[48] Bialek & Ünel, *supra* note 2, at 24.

If an ex ante mechanism were chosen, the accreditation should also reflect spatial supply and demand patterns. Supply patterns vary geographically within Texas based on weather fluctuations, variation in wind patterns and solar radiation, and transmission constraints. Demand patterns are also spatially heterogeneous. Regional market clearing of reliability mechanisms is a common feature of reliability mechanisms in other restructured markets including ISO-NE, MISO, NYISO, and PJM.[49]

B. Penalties for Non-Performance Should Reflect the Value of Lost Reliability

Without an appropriate level of non-performance penalty, no mechanism can ensure sufficient incentives for generators to invest in necessary measures that would guarantee their availability under stressed conditions. By imposing a penalty that reflects the value of lost reliability, the PUCT would better disincentivize non-performance during the highest-risk hours and thus fulfill S.B.'s requirement that any reliability mechanism "ensure" reliability.[50] It is difficult to evaluate the PCM's penalty against these principles because the E3 Report omits key details on how this penalty would work.

1. Efficient Penalties Under a Reliability Mechanism Should Reflect the Value of the Missing Generation Capacity

When units that have committed to providing reliability fail to perform, society incurs a cost from lost reliability. This cost fluctuates depending on system conditions. If conditions are strained, there is a higher probability that one additional MW of generation capacity will prevent a blackout event, implying greater reliability value for that capacity. When conditions are not

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[49] Conleigh Byers et al., *Capacity Market Design and Renewable Energy: Performance Incentives, Qualifying Capacity, and Demand Curves,* 31(1) ELEC. J. 65, 66 (2018).
[50] Tex. Util. Code Ann. § 39.159(b)(3).

strained, one MW of additional capacity may not have any effect on the stability of operations, meaning the additional capacity would have little reliability value.

In an energy-only market with no price caps, explicit penalties for non-performance are not necessary because each generator faces the opportunity cost equal to the energy market price per MWh if they do not perform. In other words, the generators face what amounts to a penalty in the form of forgone revenue. Because, without a price cap, the market price for electricity includes its reliability value, this implicit penalty for non-performance efficiently fluctuates with the changing value of reliability. An ideal penalty for non-performance for any new reliability mechanism should provide a similar incentive.[51]

This type of penalty mechanism is partly embodied in the ORDC: Any unit that does not produce energy during scarcity hours misses out on significant revenue. But the ORDC design includes a cap on energy prices during scarcity hours, which prevents energy prices from reflecting the value of reliability when that value becomes very high. Indeed, the ORDC price cap implies that the forgone revenue from non-performance is at most $5,000, which is less than typical estimates of the societal cost that is imposed by non-performance during scarcity hours.[52] This difference between the societal cost of non-performance and the incentive to generate power during scarcity hours implies that some additional penalty would be needed as part of the

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[51] *See* SYLWIA BIALEK ET AL., *supra* note 2, at 33 ("[A] non-performance penalty should approximate the revenue loss that the resource would experience for failing to perform in an energy-only market.").

[52] The administratively set price cap of $5,000, implemented in January 2022, is significantly less than the previous cap of $9,000. These caps are referred to as the "value of lost load," which refers to consumers' "willingness to pay for electricity service (or avoid curtailment)." LONDON ECONOMICS, LLC, ESTIMATING THE VALUE OF LOST LOAD, ERCOT BRIEFING PAPER 6 (2013), https://www.ercot.com/files/docs/2013/06/19/ercot_valueoflostload_literaturereviewandmacroeconomic.pdf (last visited Dec. 14, 2022). In practice, the administratively set value of lost load is likely to differ from its true value. Although determining the true value of lost load is notoriously difficult, estimates tend to be significantly higher than the administratively determined value, often ranging from $30,000 to $40,000. *Id.* at 53.

design of any additional reliability mechanism intended to address the missing money problem. Otherwise, the design would not be guaranteed to ensure reliability as S.B. 3 directs.

2. The PCM's Proposed Penalty Structure Requires Clarification

Despite the importance of non-performance penalties for ensuring reliability, it is not clear from the E3 Report how these penalties are going to be implemented with respect to the PCM[53] E3 proposes that, when a generator sells performance credits in the forward market and then fails to offer availability during the highest-risk hours, the generator will need to "procur[e] [performance credits] in the retrospective settlement process."[54]

This proposal is ambiguous. In the proposed ex post settlement of performance credits, the supply of credits is determined by the amount of resources that actually end up performing during the highest-risk hours, the clearing price is determined by the administratively set demand curve, and costs are allocated to LSEs according to their share of consumption.[55] If all performance credits, the number of which is determined after the market settlement process, have been claimed by LSEs then it is not apparent how a generator that fails to perform will "procure [performance credits] in the retrospective settlement process," as there will be no remaining performance credits for non-performing generators to procure.

One possible interpretation of E3's proposal is that failing to be available after selling performance credits would result in a purely financial penalty set at the settlement price of the performance credits, without actually requiring the purchase of any credits. As described above, such a penalty would be sensible only to the extent that the PCM results in a settlement price that

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[53] The E3 Report gives only a brief qualitative assessment of how penalties might be implemented for the PCM. *See* E3 REPORT, *supra* note 5, at 84–85.
[54] *Id.* at 85.
[55] *Id.* at 23.

reflects the value of reliability lost from failing to be available to deliver energy. But, as described throughout Part III, it is not clear the performance credit price under the PCM would reflect this value. For example, if the PCM does not compensate all resources according to their reliability value, the mechanism will be inefficient as discussed in Section III.A, resulting in a performance credit price that does not accurately reflect the value of reliability. If market power exercise (discussed in Section III.D) is left unchecked, the resulting performance credit price may be artificially elevated.

C. The Reliability Mechanism Should Mitigate Uncertainty

Fluctuations in electricity supply and demand imply significant risk and uncertainty for parties involved in wholesale electricity market transactions. This risk and uncertainty can translate to risk premia, which are likely to be passed through to consumers as additional costs. However, reliability mechanisms can be designed to mitigate this risk. The PCM design is inherently more risky, and therefore potentially costlier, than other market designs assessed by E3. Thus, relative to other proposals, the PCM is inconsistent with the PUCT's mission to ensure just and reasonable rates.[56]

1. Uncertainty and Risk Lead to Greater Investment Costs

[56] *See* Tex. Util. Code Ann. § 36.003(a).

Investors make capacity-investment decisions based on expectations about future market outcomes. And they can be risk averse.[57] Imagine that an investment has a 50% chance of earning $200 and a 50% chance of earning $0. Although the expected value of that investment would be $100, a risk-averse investor might value the investment at only $90 because of the high probability that it would lose all value. In that case, the risk premium—i.e., the difference between the expected return and the investor's willingness to pay—would be $10.[58] The same logic applies to investments in generation resources and the uncertainty caused by new reliability mechanism.

Because the price of electricity fluctuates with high frequency, electricity markets are inherently risky, for both consumers and investors. A reliability mechanism that includes certain types of forward-contracting can mitigate this risk, thus reducing financing costs by reducing the risk premia for investment in new generation.[59] But not every reliability mechanism reduces risk. If a new mechanism introduces additional uncertainty in the expected returns from investing in a generation resource, the cost of acquiring financing would include a higher risk premium. Higher financing costs would ultimately lead to increased costs for consumers.

2. The PCM Introduces Significant Uncertainty and Would Increase Costs to Consumers

The PCM, as proposed by E3, has more uncertainty than the other designs. Specifically, the PCM would inject uncertainty surrounding the revenue from investing in generation

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[57] PINDYCK & RUBINFELD, *supra* note 10, at 165. It is commonly assumed that large investors are risk neutral. However, in ERCOT there are also smaller investors whose risk attitude may be different than those of large market participants.
[58] *Id.*
[59] *See, e.g.*, Lawrence M. Ausubel & Peter Cramton, *Using Forward Markets to Improve Electricity Market Design*, 18 UTILS. POL'Y 195, 196 (2010).

resources because of the unpredictability of which hours will be the highest-risk and the price of performance credits. This uncertainty would likely to lead to high risk premia for new investments in generation resources, which would be passed on to consumers in their electricity bills.

Consider a hypothetical combined-cycle natural gas plant under the PCM and proposed Forward Reliability Market. This unit would receive compensation under the PCM only if it delivered power during the compliance period's high-risk hours, currently defined as "the hours of lowest incremental available operating reserves," which will be unknown until the ex post settlement process.[60] This approach implies that generators and LSEs will face a moving target when predicting which hours will be high risk. Given the time necessary to ramp the hypothetical combined cycle plant to its full generation output, an investor would not have certainty about the plant's level of generation during the highest-risk hours. A surge in net load could arise suddenly, giving the generation unit insufficient time to respond and produce energy. This uncertainty may cause a risk-averse investor to demand a risk premium. In contrast, under the Forward Reliability Market, generators would receive reliability credits according to the assigned effective load carrying capacity of their resources, regardless of performance in any specific hours.[61] The investors would therefore know with certainty the quantity of credits to be produced by the gas plant. Such an arrangement would entail relatively less risk for the investor, hence a relatively smaller risk premium, and a relatively lower cost to consumers.

Under the PCM, in addition to the uncertainty about whether generators will earn credits at all, there would be uncertainty as to the settlement price of the credits. E3 explains that the

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[60] E3 REPORT, *supra* note 5, at 22.
[61] *Id.* at 19.

settlement price is set according to where the demand curve (set administratively, ex ante) intersects a vertical supply curve during the compliance period's highest-risk hours.[62] The vertical supply curves in each of the high-risk hours are determined based on "weather conditions, plant outages, and other factors," [63] thus creating uncertainty around price. This additional uncertainty would likely raise investment costs and cause consumers to pay more.

Although the PCM would include a voluntary forward market, prices settled in the forward market would also reflect the risk aversion of LSEs and generators. More risk in the market settlement price implies greater risk premia, as described above, and higher costs to consumers. In contrast, proposals such as the Forward Reliability Market and Load Serving Entity Reliability Obligation would alleviate price risk by allowing LSEs and generators to lock in prices and quantities without potential exposure to a volatile ex post settlement process.[64]

D. The PUCT Should Address Potential Market-Power Concerns Related to Any New Reliability Mechanism

Market power is a perennial concern in electricity markets, and, if unchecked, will lead to higher settlement prices, which will ultimately be borne by consumers.[65] The exercise of market power implicates not only the PUCT's obligation to ensure just and reasonable rates,[66] but also S.B. 3's instruction that any reliability service be procured "on a competitive basis."[67]

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[62] *Id.* at 58–59.
[63] *Id.* at 58.
[64] The E3 Report compares system cost variability under the analyzed market designs. *Id.* at 49 fig. 25. E3 notes that "[v]oluntary hedging by LSEs can mitigate exposure to volatility." *Id.* at 63 n.1. Without further clarification of the market designs (and the PCM design in particular) it is unclear the extent to which hedging will mitigate risk.
[65] *See, e.g.*, Severin Borenstein et al., *Market Power in Electricity Markets: Beyond Concentration Measures*, 20(4) ENERGY J. 65 (1999).
[66] Tex. Util. Code Ann. § 36.003(a).
[67] *Id.* § 39.159(b)(3).

In a typical energy market, a supplier with market power can elevate settlement prices by strategically withholding supply. ERCOT, like any other U.S. wholesale electricity market, monitors and automatically mitigates energy-offer prices if suppliers are deemed to have locational market power. In addition, forward contracts can reduce the risk of supplier-side market power in the spot market.[68]

Introducing a new market creates new market-power concerns. The E3 Report relies on a qualitative assessment of potential market-power concerns related to the proposed reliability mechanisms and claims that existing tools to contain market power are likely to be sufficient under most design proposals.[69] But a closer examination of market power is warranted, especially before launching a never-before-tested reliability mechanism like the PCM.

Under the PCM, a supplier would not only be rewarded for the quantity of energy generated in real time, but also for the total available quantity that it has offered into energy and ancillary services markets during the compliance period's high-risk hours. This additional reward may amplify a supplier's incentive to withhold some supply during high-risk hours to induce both a higher energy-clearing price and a higher performance-credit settlement price. Although the PCM includes a voluntary forward market, which could potentially mitigate market-power

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[68] Blaise Allaz & Jean-Luc Vila, *Cournot Competition, Forward Markets and Efficiency*, 59(1) J. ECON. THEORY 1, 2 (1993). An expected profit-maximizing supplier with the ability to exercise unilateral market power with a fixed-price forward contract obligation has an incentive to minimize the cost of supplying the quantity of energy sold in the forward contract. Frank A. Wolak, *Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables*, 3 ENVT'L & ENERGY POL'Y & ECON. 155, 198 (2022). Consider a supplier owning 150 MW of generation capacity that has sold 100 MWh in a fixed-forward contract at a price of $25/MWh for a certain hour of the day. *Id.* This supplier has two options for fulfilling this forward contract: (1) produce the 100 MWh energy from its own units at their marginal cost of $20/MWh or (2) buy this energy from the short-term market at the prevailing market-clearing price. *Id.* The supplier will receive $2,500 from the buyer of the contract for the 100 MWh sold, regardless of how it is supplied. *Id.* This means that the supplier maximizes the profits it earns from this fixed-price forward contract sale by minimizing the cost of supplying the 100 MWh of energy. *Id.*

[69] E3 REPORT, *supra* note 5, at 77–78.

exercise, it remains unclear whether a voluntary market would sufficiently incentivize generators to participate in a manner that mitigates market-power concerns. While the number of generators that participate in the forward market may be high, the participants are not necessarily incentivized to offer meaningful levels of capacity in the forward market.[70] As such, there might be significant market power in the ex post settlement market.

While ERCOT's existing market-power-mitigation tools can help with mitigating the price impact of locational market power in the energy market, they may not be sufficient to solve these new concerns that the PCM would create. The benefit of ERCOT's existing mitigation tools is that they operate right before the energy market is cleared and therefore can prevent locational market power instantaneously. However, these procedures are aimed at limiting offer prices and cannot compel units to operate, which means they are insufficient to eliminate market power, particularly during periods of near scarcity.[71] Accordingly, the PUCT should conduct additional analysis of market power, and implement any new tools needed to mitigate such power, before adopting a design as novel as the PCM.

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[70] The PCM requires generators to participate in the forward market to be eligible to receive performance credits, but it remains unclear whether generators will be incentivized to make economically meaningful offers in the forward market to maintain their eligibility. *See id.* at 22 ("While the forward market is voluntary, participation in the forward market is a prerequisite for generators to be eligible to produce PCs; however, actual quantities of PCs produced may differ from forward offers – thus it is not expected that this mandatory forward offer requirement would have any impact on the ultimate quantity of PCs that are awarded or on the settlement price.").
[71] *See* JAMES BUSHNELL ET AL., CAPACITY MARKETS AT A CROSSROAD 15, 15 (2017), https://www.haas.berkeley.edu/wp-content/uploads/WP278Updated.pdf (last visited Dec. 14, 2022); *see generally* MATT WOERMAN, MARKET SIZE AND MARKET POWER: EVIDENCE FROM THE TEXAS ELECTRICITY MARKET (2019), https://haas.berkeley.edu/wp-content/uploads/WP298.pdf (last visited Dec. 14, 2022).

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Executive Summary of the Comments of
the Institute for Policy Integrity at New York University School of Law

- S.B. 3 tasked the PUCT with procuring reliability services only after (1) establishing a reliability standard and (2) determining the quantity and characteristics of the reliability services needed to meet that standard. At this point, it is unclear whether ERCOT has a reliability problem that would justify the creation of a new reliability mechanism.
    - ERCOT already possesses a reliability mechanism in the form of the ORDC. The ORDC was recently altered in a way that may have improved its ability to promote reliability. Until the effects of these and other changes, such as the introduction of new products in the ancillary services market, have been more carefully studied, it would be premature to launch a potentially costly new reliability mechanism. The existing mechanism may be sufficient.
    - Whether ERCOT has a reliability problem that would justify a new reliability mechanism is a separate question from whether ERCOT has a resilience problem that leaves it vulnerable to Uri-like conditions.
    - The PUCT should not adopt a new reliability product until the reliability needs of ERCOT have been better studied.
- If the PUCT does move forward with a new reliability mechanism, the PUCT can best implement its mandate to ensure just and reasonable rates by choosing a design that accords with economic principles.
    - Any reliability mechanism should compensate both dispatchable and non-dispatchable generation resources for their reliability value. If the reliability mechanism excludes non-dispatchable resources, the PUCT would force Texas consumers to overpay for reliability, because non-dispatchable resources do provide some reliability value.
    - The penalty for failing to provide promised reliability should be set in proportion to the value of reliability that a generator fails to deliver. But, as described in the E3 Report, it is unclear how the penalty in the PCM would function.
    - A new reliability mechanism has the potential to increase electricity costs by creating uncertainty about the revenue from investing in generation resources. The risk premia that investors may demand in light of this added uncertainty would be passed on to consumers. Relative to the other proposed designs, the PCM would increase uncertainty more and thus increase costs to consumers more.
    - The PCM would create new opportunities for the exercise of market power. Because the PCM is a never-before-tried market design, and because this market-power issue has been understudied thus far, the PCM should not be implemented until the possibility of including additional market-power mitigation measures has been analyzed.