BATES WHITE
ECONOMIC CONSULTING

Assessment of ERCOT Market Reform Alternatives

Initial Results

February 22, 2023

In the preparation of this report, Bates White, LLC has relied on data provided by S&P Global Market Intelligence. Under the terms of its contract, S&P Global requires that we include the following Disclaimer:

Contents

I. Introduction

Bates White Economic Consulting ("Bates White") was engaged[1] to evaluate proposed modifications to the ERCOT markets intended to support reliability of the system, with specific reference to the results of the market reforms assessment conducted by Energy and Environmental Economics, Inc. ("E3 Report"). As part of that evaluation, Bates White has reviewed E3's evaluation of the ERCOT market reform options, including the Performance Credits Mechanism ("PCM") proposal, and has also performed preliminary analysis of two modifications to the ERCOT markets that would support system reliability while also retaining the essential features of the energy-only construct. These are: (1) a Dispatchable Reliability Reserve Service ("DRRS"), a new ancillary reliability service similar to the uncertainty product recommended by ERCOT's Independent Market Monitor ("IMM"), and (2) a Direct Procurement mechanism that could be implemented as a last resort if a shortfall of dispatchable resources is identified in the future.

II. Summary Findings

- There is ***no current or imminent capacity shortage*** in ERCOT.
  - The existing energy and ancillary services markets have successfully supported the addition of dispatchable capacity, and have done so at least as well as other RTOs with capacity markets. We believe the current ERCOT system will continue to support investment in sufficient generation to reliably serve customers.
  - ERCOT's immediate reliability challenge is to ensure operational flexibility to accommodate expected large additions of intermittent renewable generation.
  - The energy and ancillary services markets are the appropriate focus for ensuring flexible and cost-effective operations, and would be enhanced in this function with the addition of a DRRS product to efficiently manage operational uncertainty.
  - By enhancing the revenues available to dispatchable resources, DRRS will further incentivize the continued investment in dispatchable generation to meet ERCOT's reliability needs.

[1] Our work has been funded by the Texas Association of Manufacturers, the Texas Oil & Gas Association, the Texas Chemical Council, and the Texas Industrial Energy Consumers.

- The modeling performed by E3 is not a forecast of capacity need, and ***flawed modeling assumptions exaggerate the potential for retirements while radically underestimating the incremental cost of capacity market proposals such as PCM***.
  - The E3 methodology creates an equilibrium scenario in 2026 that selectively retires a large quantity of existing thermal dispatchable capacity (approximately 11,260 MW) based on a flawed and simplistic modeling analysis in order to eliminate "excess" capacity under ERCOT's current forecast. This assumption is made to drive up the market clearing price so that the modeled energy and ancillary services revenues for a new combustion turbine to meet the annual cost of new entry ("CONE").
  - Neither the year 2026 nor the 11,260 MW removed in their analysis represents a forecast, but rather these are methodological choices that are at odds with actual circumstances, and therefore highly misleading.
  - The "equilibrium" reference case created by E3 to represent continuation of the energy-only market construct is extreme and is contradicted by actual behavior of market participants.
- The proposed ***PCM capacity mandate would entail billions in costs for customers without a meaningful improvement in reliability.***
  - The E3 Report estimates annual costs of PCM of **$5.7 billion**, which would be largely or fully additive to current market costs. E3's much lower estimated incremental cost is an artifact of the flawed analysis of the likelihood of near-term unit retirements that in turn substantially exaggerate the costs of maintaining an energy-only market construct and the operational reliability benefits afforded by the PCM.
  - Based on actual performance of the ERCOT market, PCM is not needed as an additional incentive to retain and induce new capacity. Further, PCM would not guarantee the addition of any new capacity, but would with certainty impose substantial new costs.
  - PCM could also create counter-productive incentives for resources – including demand response – to chase anticipated reliability credit hours, when they are not actually needed. This is a particular concern if the reliability credit hours are arbitrarily assigned to months or seasons, rather than correlating with the absolute hours of highest risk throughout the year. This will cause inefficient behavioral response from market participants when it is not needed.
  - PCM would be a novel and untested alteration to the ERCOT market that would be complicated to implement and administer. It would require a number of complex tasks, including defining the periods during which performance credits ("PCs") would be awarded, establishing the quantity of PCs needed to meet a reliability standard and developing a process for market clearing.
- ***Implementing an uncertainty product*** such as DRRS ***would provide a targeted procurement*** of dispatchable resources specifically suited to addressing intermittent resource forecast uncertainty,

and ***<u>would guide revenue to such dispatchable resources</u>*** corresponding to the reliability value they contribute.

- By providing targeted compensation, DRRS would reduce the potential for valuable flexible resources to retire prematurely, target payments to flexible resource, and reduce the excess cost from ERCOT's current conservative operations;
- We estimate that DRRS would provide annual revenue of approximately **$1.7 billion** directed to the dispatchable resources that help address forecast uncertainty.
- The cost to customers of DRRS would be offset by cost savings from reducing ERCOT's current practice of procuring excessive Non-Spinning reserve service ("Non-Spin") and using Reliability Unit Commitment ("RUC") to commit generators to manage operational uncertainty. DRRS would address this issue more efficiently using longer-notice resources. As a result, we estimate the net annual cost of DRRS to be approximately **$923 million.**

- If the need should arise, ***<u>direct procurement of backup capacity</u>*** to support grid reliability offers a ***<u>straightforward and much less costly failsafe mechanism as compared to the PCM</u>*** or any other capacity market construct.
  - Data on existing plant going-forward costs indicate that actual capacity at risk of retirement for economic reasons is on the order of 2,000 MW. The E3 modeling results indicate ERCOT could have more than 5,000 MW of capacity retire and still exceed a "one day in ten years" reliability standard, meaning that no additional capacity is needed for reliability.
  - If replacement of retired capacity were in fact required (contrary to the E3 analysis), procurement of 2,000 MW of new gas-fired combustion turbine generation would entail an annual cost of approximately **$187 million**, a small fraction of the $5.7 billion annual cost for the capacity procurement mechanisms that E3 evaluated.

III. ERCOT Capacity Balance

As an initial matter, ERCOT has more than sufficient capacity to meet reliability needs now, and there is no imminent risk of a capacity deficiency looking forward. The implied capacity shortfall in E3's 2026 equilibrium case is an outgrowth of E3's modeling approach and flawed assumptions. It is particularly important to recognize that the year 2026 is simply assumed by E3 for the purposes of creating a market "equilibrium" scenario; it is not an output of the modeling exercise, and importantly is not a prediction or forecast of when ERCOT will be short of capacity.

E3 constructs an equilibrium model case in 2026 by adding significant amounts of new wind and solar resources based on the ERCOT interconnection queue, and then by removing (i.e., permanently retiring) sufficient thermal resources to achieve a market price that provides annual net revenue in the energy and ancillary services markets of $93.50/kW. Neither of these two changes is likely to occur, and certainly not by 2026. E3 removes 11,259 MW of thermal resources on this basis, more than 18% of existing natural gas and coal-fired capacity in ERCOT.

The $93.50/kW-year benchmark is E3's assumed cost-of-new-entry ("CONE") for a new simple-cycle combustion turbine ("CT"). E3 assumes substantial retirements of dispatchable generation as a modeling approach to create a supposed "equilibrium" state; this is not a forecast of actual resource retirements between now and 2026 or any point in the future, and is not based on any known facts about these resources. In fact, existing resources would not use CONE – notionally the annual market revenue required to support investment in a newly constructed CT – as a threshold for a retirement decision, but rather each would consider its annual going forward cost, which varies by unit but is significantly lower than CONE.

In stark contrast, the actual historical context is that the only major generation resource type in ERCOT to contract over the past decade has been coal-fired power plants, and nearly all of this net change was represented by three Luminant facilities taken offline in 2018.[2]

Following implementation of ERCOT's Operating Reserve Demand Curve ("ORDC") in 2014, the energy-only market construct has successfully induced net additions of nearly 4,300 MW of gas-fired capacity, as shown in Figure 1. Looking forward, there are more than 2,300 MW of gas-fired capacity with signed interconnection agreements that are currently scheduled to come on line from 2023 to 2026.[3]

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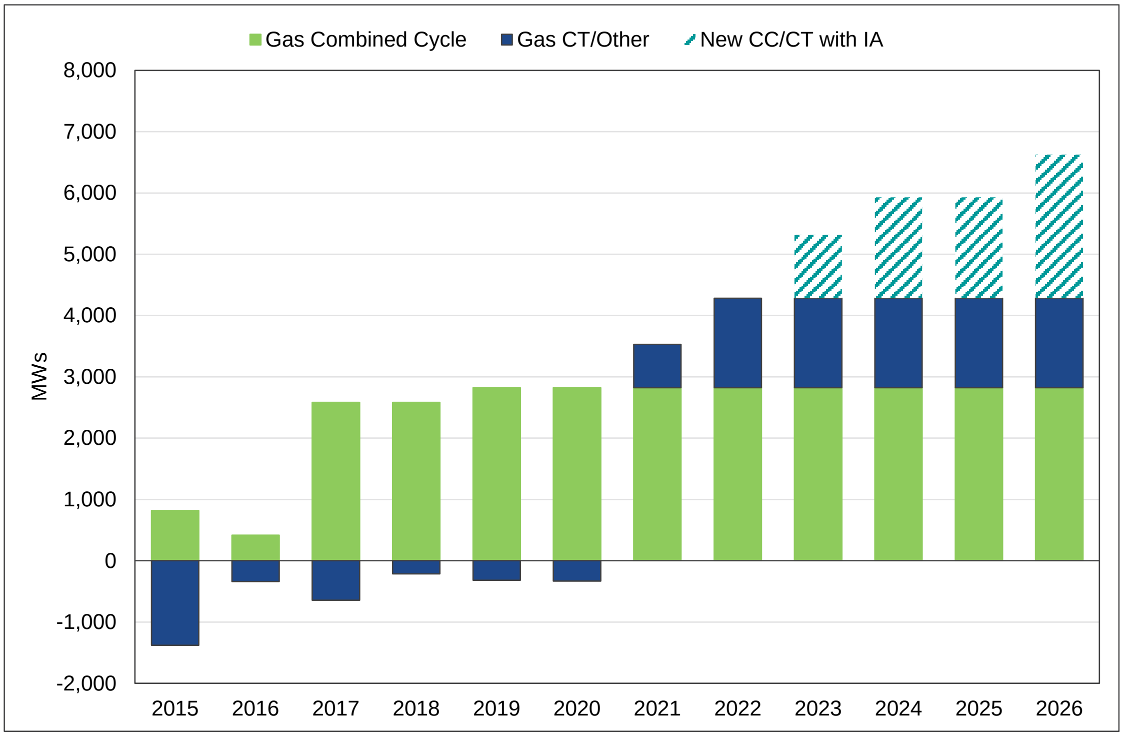
[2] The 2012 to 2022 net change in ERCOT coal-fired capacity was -4,378 MW; the combined capacity of Luminant's retired Big Brown, Sandow and Monticello units was 4,267 MW, more than 97% of the total net change (S&P data). These retirements were likely caused by regulatory capacity ownership limits in addition to the economic return and operating cost of the units.

[3] ERCOT capacity data: https://www.ercot.com/files/docs/2023/01/05/Capacity_Changes_by_Fuel_Type_Charts_December_2022.xlsx.

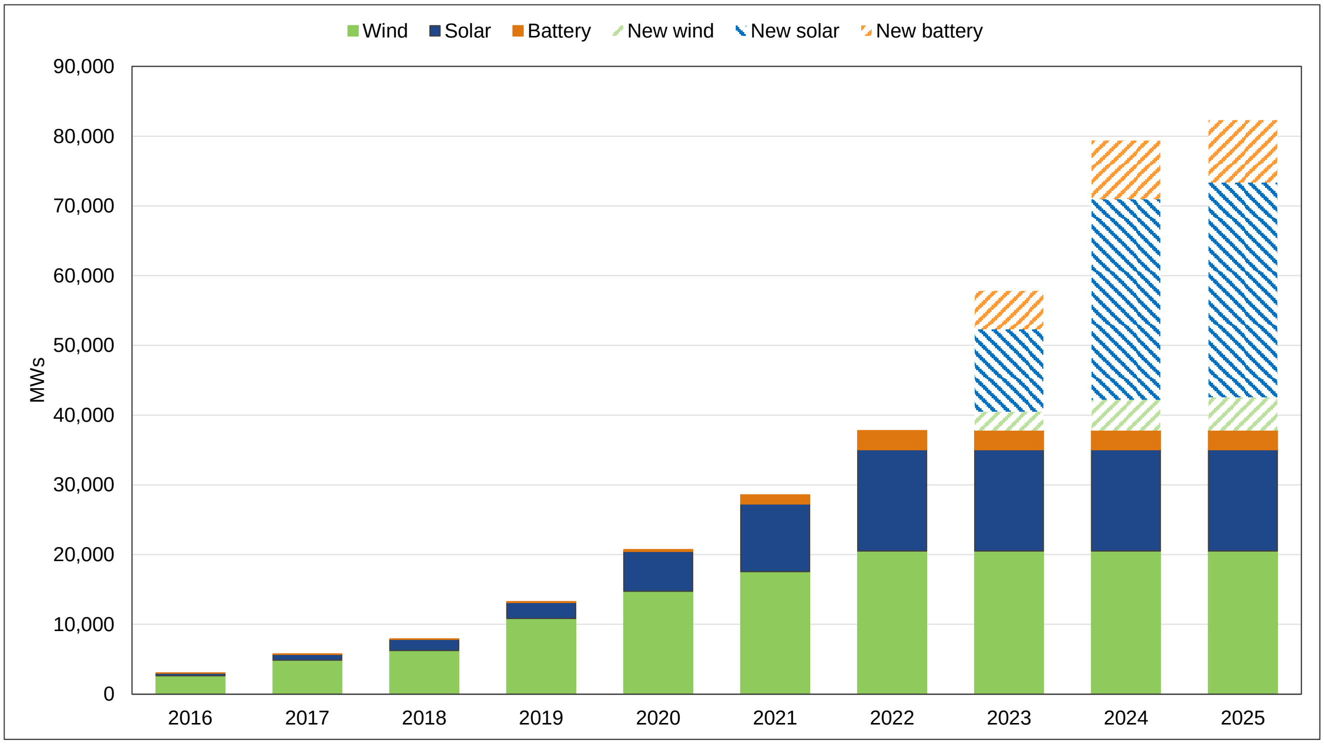
Figure 1: Cumulative net change in ERCOT gas-fired capacity 2014-2022, and new CC/CT with signed interconnection agreement, MW[4]



Of course, there have also been very substantial additions of wind, solar, and increasingly battery storage capacity in ERCOT, with significantly more in the interconnection queue, as shown in Figure 2 below.

[4] *Id.*

Figure 2: Renewable and battery additions, 2016-2022, and with signed Interconnection Agreements through 2025[5]

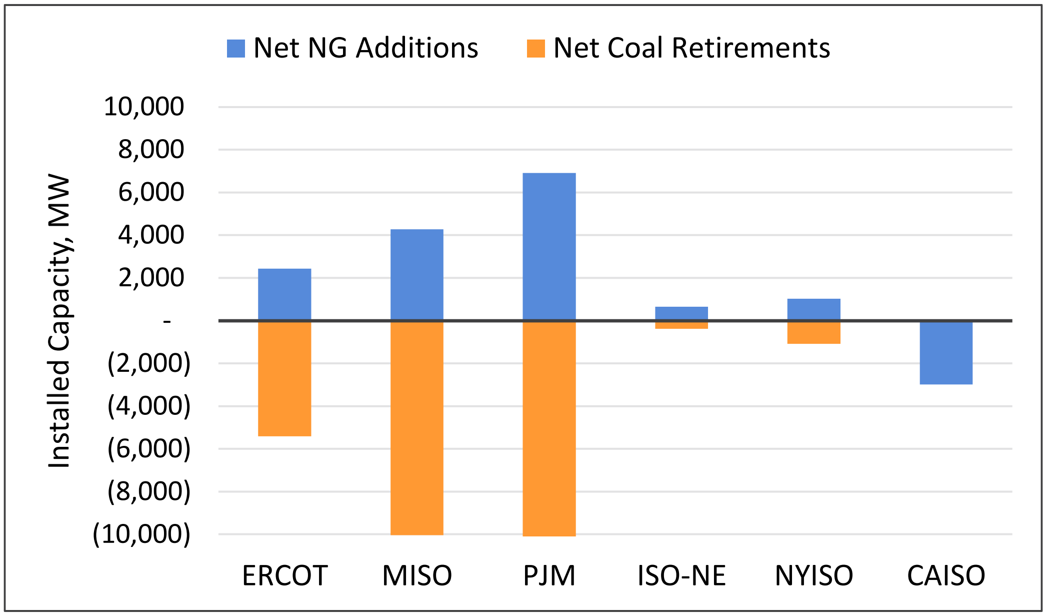


A. Net Thermal Capacity Additions in ERCOT and other RTOs

ERCOT's energy-only market construct has successfully incentivized the addition of new thermal capacity as older coal and gas resources have retired, and has done so at least as well as other RTOs with capacity markets. Figure 3 summarizes net additions of gas-fired capacity and net retirements of coal-fired capacity from 2018 to 2022 by RTO. PJM and ISO-New England have fully elaborated forward capacity markets, while the New York ISO and Midcontinent ISO have variations on a "prompt" capacity market, and the California ISO has a mandatory resource adequacy requirement that must be met by load-serving entities (a decentralized/bilateral capacity market).

[5] *Id.*

Figure 3: Net thermal capacity changes by RTO, 2018-2022[6]



From 2018 to 2022, net natural gas additions in ERCOT were approximately 2,400 MW, with coal retirements exceeding that by approximately 3,000 MW, and the overall installed capacity reserve margin standing at 24% in summer 2022.[7] Net thermal retirements in PJM over the same period totaled more than 3,200 MW, while the summer 2022 capacity reserve stood at approximately 29%.[8] MISO experienced a net thermal capacity contraction of approximately 5,800 MW, and its 2022 summer capacity reserve margin was approximately 18%.[9] Net thermal capacity additions have been much smaller in the other RTOs, with CAISO being significantly negative.

There are two important implications of the historical (and projected) capacity changes summarized in the figures above:

1) The ERCOT market is currently providing sufficient revenue to support new capacity investment.

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[6] Data via S&P Global Market Intelligence.

[7] Reserve margin from: ERCOT Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2022-2031, (December 2021); https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx.

[8] Reserve margin from: PJM; https://www.pjm.com/-/media/planning/res-adeq/20220119-forecasted-reserve-margin-graph.ashx.

[9] Reserve margin from: MISO Planning Year 2022-2023 Loss of Load Expectation Study Report, (November 2021); https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

2) Additional revenue provided by capacity market mechanisms in other RTOs has not prompted greater net additions of new thermal generation on an apples-to-apples basis.

ERCOT's experience demonstrates that capacity markets and/or reserve margin mandates are not needed for the market to provide reliability. Moreover, capacity markets do not protect against reliability challenges that are operational in nature, as demonstrated during Winter Storm Elliott in December 2022. These operational challenges cause the vast majority of reliability risks in ERCOT today. For example, in PJM, neither the system's long capacity position nor its capacity non-performance penalties (which are estimated to be $2 billion over two days) prevented the system from entering emergency conditions as up to 57 GW of expected capacity was unavailable on December 24.[10]

B. The Primary Concern for ERCOT is Operational Flexibility

ERCOT does not currently have a shortage of capacity, and data available today does not indicate there will be such a shortage in the near future. The "equilibrium" case presented in the E3 Report, before the 11,000 MW of capacity are removed from the model, has a reported LOLE of 0.02 days per year (or 1 day in 50 years).[11] This demonstrates that resources required to maintain reliability already exist, and is also fully consistent with the fact that the reliability issues seen during 2021 and 2011 were not a consequence of insufficient installed capacity. ERCOT's latest reports indicate installed capacity reserve margins rising to 40% for summer 2024, and 36% for winter 2024/25. In addition, winter reliability will be bolstered by new emergency preparedness standards implemented by the PUCT in October 2022; these standards will require generators to complete winter weather preparedness measures by December 1, 2023.[12]

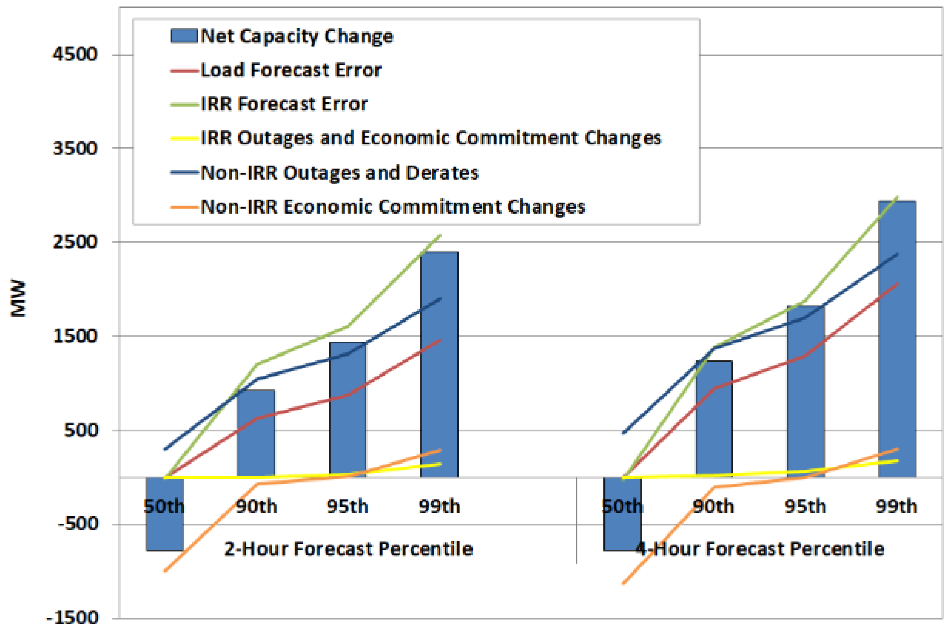
The main challenge facing the ERCOT market is to ensure sufficient operational flexibility to address increasing forecast uncertainty associated with growing quantities of wind and solar generation on the system. The IMM has presented estimates of 4-hour forecast uncertainty for the ERCOT system based on 2021 data, as shown in Figure 4.

[10] PJM Winter Storm Elliott Overview; https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

[11] E3 Report at 46.

[12] Weather Emergency Preparedness rule (16 TAC § 25.55); see, https://www.ercot.com/files/docs/2022/10/28/Weatherization-FAQs-2022-12-19.pdf.

Figure 4: Forecast Error and Net Capacity Change (2021 State of the Market) [13]



Errors in forecasting the output of Intermittent renewable resources (IRRs, i.e. wind and solar) is a substantial driver of operational uncertainty as shown in the green line. This uncertainty is currently being inefficiently managed by ERCOT through the commitment of additional resources outside of market mechanisms. This forecast uncertainty is expected to grow in proportion to additions of IRR capacity in coming years, exacerbating the inefficiencies and costs associated with relying on out-of-market actions to support operational flexibility. An ancillary service that is tailored to address forecast uncertainty will reduce actual reliability risk on the system and will also reduce inefficient market costs from the current "conservative operations" in ERCOT.

For the foreseeable future, the goal of any market modifications aimed at supporting system reliability in ERCOT should be on incentivizing flexible resources already in operation to remain in service and – equally important – to perform when needed. In doing so, market revenues for resources with the desired operating profiles will increase, further supporting new entry. To date, ERCOT's energy-only construct has successfully provided such incentives and, as discussed below, can be readily enhanced to meet future system needs economically.

[13] Potomac Economics, *2021 State of the Market Report* (May 2022), page 3. https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf

Longer term, it is simply unknowable at this time whether the current market will move to an equilibrium state in which there are insufficient dispatchable resources necessary to meet an appropriate reliability standard. New technologies are currently being connected to the ERCOT grid and other technologies are emerging that may radically alter the availability and even the need for dispatchable resources in future years. These technology changes indicate that there should be no rush to provide guaranteed future revenues to existing capacity, or attempt to induce capacity solutions based on today's more limited set of options.

IV. The DRRS Product Would Provide Revenue to Resources Based on Their Ability to Address Forecast Uncertainty

DRRS (Dispatchable Reliability Reserve Service) has been proposed as an additional market product corresponding approximately to the uncertainty product recommended by the IMM.[14, 15] This day-ahead reserve product would be an additional ancillary service that would be deployed by ERCOT when uncertainty associated with IRR output and load increases. Importantly, DRRS is an ancillary service, as it procures a discrete number of MWs per day in the market to address a specific operational need. DRRS does not create a mandated revenue stream from consumers to generators to support a reserve margin mandate, which is the hallmark feature of a capacity market.

DRRS would be valuable for deploying dispatchable resources more efficiently, and in ensuring that associated revenue accrues to resources that are well-suited to addressing the reliability impacts of uncertainty. Resources would compete to provide the service economically, and cleared resources would access a new source of revenue.

To evaluate the impact of a DRRS product, we estimated the associated annual revenue going to dispatchable resources, using as a starting point the IMM's assessment of 4-hour forecast uncertainty associated with IRRs in 2021, shown in Figure 4. To establish a scenario which covers almost all of the renewable resource forecast uncertainty, we assumed that the annual average hourly quantity of the DRRS uncertainty product would correspond to the 99th percentile of the 4-hour forecast uncertainty for IRRs in the IMM's assessment. For 2021, this value is approximately 2,800 MW.

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[14] The IMM addresses the proposed uncertainty product in the 2021 State of the Market Report (see footnote 13), and also in comments filed in PUCT Project No. 52373, https://interchange.puc.texas.gov/Documents/52373_178_1160003.PDF.

[15] DRRS has been described in some detail in comments by the Coalition for Dispatchable Reliability Reserve Services filed in PUCT Project No. 52373, https://interchange.puc.texas.gov/Documents/52373_384_1258736.PDF.

We assumed that DRRS would be deployed based on estimated uncertainty six hours ahead, and translated the 4-hour DRRS uncertainty quantity to a 6-hour uncertainty value by applying a standard statistical adjustment based on volatility scaling used in commodity and financial markets.[16, 17] Time scaling of volatility using a square root of time rule is applied such that the N-period volatility is equal to the one period volatility multiplied by the square root of N. In this case, the 6-hour uncertainty (N-period) equals the 4-hour forecast uncertainty (one period) multiplied by the square root of 6/4 (1.5), reflecting the fact that six hours is 1.5 times four hours (i.e. there are 1.5 4-hour periods in six hours). The result is 2,800 MW x $\sqrt{(\frac{6}{4})}$ = 3,429 MW, the assumed annual average hourly quantity of day-ahead DRRS that would be applicable for 2021.

Adjustment for added IRR capacity

To capture the expected increase in forecast uncertainty from additional IRR capacity on the system, we relied on data from ERCOT's Report on Capacity Demand and Reserves ("CDR") as well as findings from a December 2022 study that estimated the effective capacity of renewable resources by year based on an assessment of their Effective Load-Carrying Capability ("ELCC").[18] Based on the November 2022 CDR, approximately 48.5 GW of wind and solar installed capacity could be added in ERCOT from 2021 to 2024, resulting in a total of 77.4 GW of installed capacity in 2024[19]. However, according to the results of the ELCC study, this 2024 total would represent a total capacity contribution for reliability purposes of only 24.4 GW, based on average ELCC for the identified categories of wind and solar generation.

To evaluate the effect of IRR additions and changes in ELCC on forecast uncertainty and DRRS need in 2024, we looked at the change in the excess of installed capacity over ELCC capacity between 2021 and 2024. We calculated that the excess would grow by approximately 177%. We then assumed that forecast

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[16] See for example: Linda Allen, Jacob Boudoukh and Anthony Saunders, *Understanding Market, Credit and Operational Risk: The Value at Risk Approach*, (New York: Wiley-Blackwell, 2004).

[17] This square root of time volatility scaling over multiple time periods has been observed in wind power forecasting. See, e.g., NREL, *Wind Power Forecasting Error Distributions over Multiple Timescales*, (2011). See also, NREL, *Wind Power Forecasting Error Distributions: An International Comparison*, (2012).

[18] Astrapé Consulting, *Effective Load Carrying Capability Final Report*, (December 7, 2022), https://www.ercot.com/files/docs/2022/12/09/2022-ERCOT-ELCC-Study-Final-Report-12-9-2022.pdf

[19] These numbers do not represent a forecast, but rather are the schedules provided by resource developers for all resources that have signed interconnection agreements in the ERCOT interconnection queue. Historical analysis indicates that a large percentage of units in the ERCOT interconnection queue are delayed or even cancelled. For more information, see: https://www.ercot.com/files/docs/2022/12/12/2__SAWG_Planned_Project_Success_Factor_Analysis_12-13-2022_.pptx

uncertainty and the need for DRRS would grow by the same proportion, such that the average 2024 need would equal 9,491 MW = 3,429 MW x 2.768.

Annual DRRS revenue

The annual revenue provided by DRRS to dispatchable resources is determined based on the volume derived above multiplied by a price calculated as a 10% discount to the average hourly price of Non-Spinning reserves in 2022. The rough discount is based on the expectation that DRRS should be less costly on a unit basis than Non-Spin, which must be available on a 30-minute basis (i.e., the operational requirements for DRRS resources are less restrictive than for Non-Spin resources, and consequently a larger pool of resources would have access to offering and providing DRRS). Estimated annual DRRS revenue for 2024 is: 9,491 MW x 8,760 hours x $20.24/MWh /100000 = **$1,683 million**.

Net annual cost of DRRS to customers

In terms of the cost impact to customers, the DRRS revenue for dispatchable resources would be offset to some extent because an uncertainty product such as DRRS should allow ERCOT to reduce Non-Spin procurement and RUC to prior levels, before it initiated "conservative operations" in July 2021.[20] This offset allows an estimate of the net cost to customers of DRRS. Another way to consider this change is that the DRRS would allow ERCOT to procure operational reliability through a targeted, market-based mechanism, reducing the need to rely on Non-Spin and RUC , while maintaining reliability and targeting revenue to units that can cost-effectively address the problem.

Under ERCOT's conservative operations, the minimum hourly quantity of Non-Spin and RUC was increased by 2,900 MW, from 3,600 MW to 6,500 MW. We assume, per the IMM, that 2,900 MW of the DRRS need would represent a displacement of Non-Spin and RUC. In the absence of detailed information on hourly RUC costs, we assume that the avoided cost of all 2,900 MW per hour would be at the 2022 average hourly Non-Spin cost of $22.49/MWh.[21]

We assume a further displacement by DRRS of the higher quantity of Non-Spin in 2024 that is expected as a result of added IRRs. We quantify the incremental Non-Spin needs resulting from solar and wind capacity additions based on ERCOT estimates provided in its "2023 Minimum Ancillary Services

[20] IMM comments in PUCT Project No. 52372 (see footnote 14), pages 6-7.

[21] The costs of excess RUC commitment are both direct, in the form of payments to RUC'ed resources, and indirect through distortions of the rest of the market. In addition, increased use of RUC typically targets less flexible, older resources with long startup times. Greater use of RUC may reduce the remaining economic life of existing units.

Quantities and Methodology."[22] The document provides estimated incremental Non-Spin quantities for 1,000 MW increments of installed wind and solar capacity. This calculation results in an additional 957 MW per hour of Non-Spin in 2024 that is assumed to be displaced by DRRS, and the avoided cost is again calculated based on the 2022 average Non-Spin cost. The annual avoided cost is estimated to be $760 million, and the resulting annual net cost to customers of DRRS is: $1,683 million - $760 million = **$923 million.**

This estimate of avoided cost, which is netted from the estimate of gross DRRS cost, does not include avoided inefficiency costs associated with ERCOT's current high level of RUC commitments. The IMM has estimated added annual system costs from ERCOT's conservative operations implemented in July 2021, including both excess Non-Spin and RUC, to be $800 million - $1 billion for the period August 1, 2021 through July 31, 2022.[23] If these values are applied as the avoided cost from implementing DRRS, the annual net cost to customers would be lower, in the range **$683 million - $883 million**.

The estimated savings from reinstating ERCOT's prior operational stance and using DRRS to manage operational uncertainty instead are conservative to the extent that the actual increase in Non-Spin by 2024 – in the absence of DRRS – would likely be greater than we estimated. Indeed, it is likely that the impact on Non-Spin in the absence of DRRS would be greater if non-linear effects, including reduced ELCCs of IRR capacity, were fully evaluated.

The calculation of DRRS annual net cost is summarized in Table 1 below.

[22] ERCOT, 2023 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements, Attachment A, pages 12-13 (December 2022). Available at https://www.ercot.com/files/docs/2021/12/02/18_2022_ERCOT_Methodologies_for_Determining_Minimum_AS_Requirements.pdf

[23] Potomac Economics estimate provided to the Texas Senate, Business and Commerce Committee December, 2022.

Table 1: Estimated annual cost of DRRS uncertainty product, 2024 reference

Quantity of DRRS need				
2021 4-hr IRR forecast uncertainty	(a)	IMM estimate	2,800	MW
2021 Day-ahead uncertainty	(b)	Adjusted for 6-hours ahead	3,429	MW
2024 Day-ahead uncertainty	(c)	Adjusted for new wind and solar	9,491	MW
Annual revenue impact of DRRS				
2024 average DRRS cost, $/MWh	(d)	90% of 2022 Non-Spin cost	$20.24	$/MWh
Annual DRRS revenue	(e)	= (c) x (d) x 8760 / 1000000	$1,683	$MM
Displaced Non-Spin and RUC cost				
Conservative ops, increased min. Non-Spin and RUC	(f)	ERCOT protocol	2,900	MW/hr
2024 increase in Non-Spin for added wind and solar	(g)	Calculated from ERCOT data	957	MW/hr
Total Non-Spin and RUC displaced by DRRS	(h)	= (f) + (g)	3,857	MW/hr
Annual cost savings from displacement	(i)	Cost at 2022 Non-Spin rate	$760	$MM
Net annual cost of DRRS	**(j)**	**= (e) - (i)**	**$923**	**$MM**

V. PCM Would Entail Large Costs for Customers and Doubtful Benefits

The proposed PCM would be a mandatory capacity credit mechanism under which resources would generate PCs – which load serving entities ("LSEs") would be required to purchase, and which will be passed through to customers – based on resource performance during retrospectively determined hours of reliability risk. The volume of required PCs would be administratively determined according to a reserve margin mandate, similar to other proposed capacity market mechanisms such as the Forward Reliability Market ("FRM"), and the LSE Reliability Obligation ("LSERO"). Our initial assessment has identified several significant concerns with the PCM proposal.

Under E3's "equilibrium" case analysis, PCM (as well as FRM and LSERO) would entail $5.7 billion in annual payments from ERCOT customers to generators. E3 presents an estimate that the annual *incremental* cost of PCM would be only $460 million, based on a comparison of an overly optimistic PCM implementation compared to an extremely pessimistic energy-only market reference constructed by E3. As discussed above, E3's energy-only reference case is created based on exaggerated and unrealistic assumptions regarding the market revenue that existing and new resources require in order to continue operation or enter the ERCOT market. By creating an extreme "but for" reference case that is forced by design to produce very high market pricing, E3's model shows $5.1 billion in savings in the energy and ancillary services markets from implementing PCM to offset the $5.7 billion in cost of the PCM capacity mandate.

In reality, PCM would not be implemented in an ERCOT market context remotely like the case that E3 manufactured. Instead, PCM would be attached to a market that is already long on capacity and would therefore provide little or no offsetting benefit from reduced energy and ancillary services costs relative to the status quo. The incremental cost of PCM is consequently likely to be much closer to the gross cost of $5.7 billion, and could even be significantly more, depending on how the program were implemented and the resulting price of PCs. As discussed above, the ERCOT energy and ancillary services markets have successfully supported reliability, capacity retention and new investment, so PCM is not needed as an additional incentive. There is no need to spend an $5.7 billion to induce what the existing market can already provide. Further, the proposed PCM cannot guarantee that new dispatchable capacity is built at all. The PCM approach would impose penalties on LSEs that fail to procure a proportional share of PCs necessary to offset customer usage during arbitrarily determined PC hours. But PCM cannot *require* that sufficient capacity be built. In a sense this is analogous to the circumstances during Winter Storm Uri, when energy and ancillary services prices rose to the $9000/MWh price cap, but ultimately could not make generators available that were forced out by cold weather.

A claimed benefit from implementing PCM is that it would provide more revenue certainty to existing and prospective generators. Like other capacity market constructs, this is achieved by shifting financial risk away from competitive market participants and onto retail customers through mandated payments that are designed to achieve a pre-determined level of available revenues for eligible generators However, it is not apparent that this revenue stream will meaningfully improve revenue certainty compared to today. The E3 Report focuses on modeling revenue available to generators from the volatile energy and ancillary services markets, but the reality is that generators in ERCOT typically do not rely on those markets to any significant extent, but rather sell capacity forward for both energy and ancillary services under bilateral contracts that may extend out multiple years. For example, in its recent 10-Q SEC filing for Q3 2022, Vistra describes the extent of its forward hedging: "As of September 30, 2022, we have hedged approximately 70% of our expected generation volumes on average for the three-year period 2023 to 2025 (with approximately 90% hedged for 2023)."[24] Similarly, NRG states that that it fully hedges its

[24] Vistra Corp., Form 10-Q For the Quarterly Period Ended September 30, 2022, at 56; https://filecache.investorroom.com/mr5ir_vistracorp_ir/294/VST%20%28Vistra%20Corp.%29%20%20%2810-Q%29%202022-11-04.pdf

commitments for its fixed-price customers and partially hedges expected yet to be priced customer commitments through time, which means that it tries to avoid transacting in the real-time markets.[25] The average term for a new customer is now two years.[26] Rather than simply making a revenue stream more certain for generators, what PCM really does is make the revenue stream billions of dollars higher.

PCM could also create counter-productive incentives for resources – including demand response – to chase anticipated performance credit hours, even when these hours do not align with grid reliability needs. Such behavior would be an expected response to the proposed credit mechanism, and could serve to undermine the efficiency of price signals in the energy and ancillary services markets. There is significant potential that the specification of performance credit hours will be arbitrary, for instance if a certain number of performance credit hours are established by set time-frames (such as by month) regardless of whether system conditions are truly tight. This is not a hypothetical concern, but is one that is currently being debated in MISO, which is developing a seasonal capacity market construct in which the accreditation of capacity values for most non-renewable resources is determined based on 65 Resource Adequacy ("RA") hours per season. These 65 RA hours would be the 3% of tightest hours of each season, which may not be tight by objective measures. Both load response and generation are typically time limited over the course of a season or year – load by contractual, business and/or process need, and generation by maintenance need. Providing financial rewards in hours when the actual system need is not high may reduce the availability of load response and generation in hours when the need is critical. In this way, PCM could actually reduce reliability.

The operational efficiency of ERCOT's energy and ancillary services markets, and by extension the reliability of the system, depends on the markets producing clearing prices that accurately signal the need for resources and for demand response. We find that PCM would likely impose substantial additional costs, with little or no incremental reliability benefit, and could actually diminish operational reliability. PCM has the potential to affect the ERCOT market in other negative ways, including suppressing and distorting price signals that guide decisions by ERCOT operators and market participants.

Finally, PCM would be a novel and untested alteration to the ERCOT market that would be significantly more complex to implement than the DRRS uncertainty product described above. The complexity of PCM is acknowledged in the E3 Report, which notes that "[i]mplementing a PCM requires a number of

[25] NRG 4Q Earnings Call Presentation at 18. https://investors.nrg.com/static-files/37ea983f-f16f-4bda-a239-c1dddffa1805.

[26] NRG 4Q Earnings Call Transcript at https://seekingalpha.com/article/4579114-nrg-energy-inc-nrg-q4-2022-earnings-call-transcript.

analytically complex tasks….," including determining the target reliability standard, the quantity of performance credits needed to meet such a standard, development of an auction process for market clearing, and establishing methods and procedures for allocating costs to LSEs.[27] E3 further notes that PCM would not avoid the complexity of resource accreditation that would apply for the LSERO and FRM proposals, because the same modeling effort would be required to determine performance credit need under PCM.[28]

In contrast, DRRS would be much simpler to implement, as it would fit easily into the existing structure of co-optimized energy and ancillary services procurement. As argued by the IMM, an uncertainty product would be more efficient at meeting system needs than the current excessive procurement of Non-Spin ancillary service capacity; it would allow co-optimized prices to better reflect the value of managing uncertainty; and it would reduce the need for and costs of out-of-market actions.[29]

VI. Estimated Cost of Direct Procurement

Direct Procurement as a reliability backstop could be deployed on short notice if system circumstances indicated a need for dispatchable capacity in order to ensure reliability. In contrast to the proposed Backstop Reliability Service ("BRS") evaluated by E3, Direct Procurement would secure only newly built, dispatchable resources with assured fuel on a one-time basis. The mechanism would be specifically designed to be isolated from existing energy and ancillary services markets, to prevent distortion of incentives for existing resources and new competitive entry. Direct Procurement resources would only be deployed under foreseeable emergency reserve shortage conditions.

As noted above, the methodology applied in the E3 Report, in which existing capacity is assumed to retire if it does not achieve revenue equivalent to CT-based CONE, is not economically justified, and vastly exaggerates the likelihood that retirement of dispatchable capacity will threaten system reliability. Existing resources will remain in operation as long as they can expect to cover their annual fixed costs of operation, which is demonstrated by what has actually occurred in the market. The E3 Report includes a Low Cost of Retention sensitivity that ostensibly is more consistent with the reality of market behavior, but even that case substantially overstates the amount of capacity at risk of retirement for economic

[27] E3 Report at 83.

[28] *Id.*

[29] 2021 State of the Market Report, at 23.

reasons. The Low Cost of Retention case assumes that resources will retire if they fail to achieve $50/kW-year in net revenue, rather than the CT CONE rate of $93.50 applied in the E3's base equilibrium scenario. In E3's model this causes 2,072 MW of gas-fired capacity to be retained compared to the base equilibrium case, but more than 9,000 MW of capacity would still be assumed to retire, requiring additional new capacity to achieve a 1-event-in-10-years level of reliability. E3 does not directly report the additional required capacity, but we estimate from other reported data that it is approximately 3,700 MW.

Available data on the fixed operations and maintenance ("O&M") costs of existing coal and gas-fired resources in ERCOT indicate that far less capacity would retire at the $50/kW-year net revenue threshold. We estimate that little or no existing capacity would be expected to retire for economic reasons if the market were providing that level of net revenue. We estimate that only about 2,000 MW of capacity would be at risk of retirement even at a significantly lower threshold of $30/kW-year. Based on the E3 model results, the system would continue to achieve reliability better than the 1-event-in-10-years level with that level of retirement, and under E3's assumptions, no new capacity would be needed to support reliability.

For reference, if replacement of retired capacity were in fact required (contrary to the E3 analysis), procurement of 2,000 MW of new gas-fired combustion turbine generation would entail an annual cost of approximately $187 million (2,000 MW x $93.50/kW-year, applying the E3 CT CONE assumption). This would be a small fraction of the $5.7 billion in effectively assured annual cost for the capacity procurement mechanisms that E3 evaluated. To put this comparison differently, instead of paying $5.7 billion *annually* to existing generators under PCM, for a one-time payment of $5.7 billion, ERCOT could procure over 8,500 MW of back-up combustion turbine capacity have them available to support grid reliability for thirty years. Direct procurement of new generation is far less expensive than paying all generators additional revenue, and it would provide the same reliability.