Assessment of ERCOT Market Reform Alternatives

Bates White Economic Consulting

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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 two recent reports assessing the modifications – one produced by Energy and Environmental Economics, Inc. ("E3 Report")[2], and one produced by ICF ("ICF Report")[3]. 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 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 ***<u>no current or imminent capacity shortage</u>*** 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.

[2] Energy and Environmental Economics, "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" (November 2022).

[3] ICF, "Assessment of ERCOT Market Structural Changes" (October 26, 2022).

- Proposed capacity mandates would fundamentally alter the ERCOT market construct and would impose substantial costs with uncertain resulting effects on reliability.
  - The common feature of all the market reform proposals is to require consumers to pay for additional revenue streams for generation capacity distinct from the compensation for hourly or daily provision of services in the market.
  - We do not see evidence of a current or imminent market failure that would justify such a change in course. It remains to be seen to what extent the anticipated wave of investment in solar and battery storage may alter that picture, but in any case there are less costly alternatives that would preserve the operational incentives of the current market construct.
- The E3 and ICF reports disagree about the current reliability of the ERCOT system.
  - The E3 Report characterizes ERCOT's current reliability as "close to the 0.1 days/yr benchmark."
  - The ICF Report presents a very different assessment of current ERCOT reliability, estimating it at 0.5 days/yr LOLE.
  - Previous ERCOT-sponsored analysis has indicated that the energy-only market construct is expected to produce reliability in market equilibrium that exceeds the economically optimal reliability level based on the value of lost load.
- The E3 and ICF reports present contrasting findings on the costs and impacts of several proposed capacity support alternatives, differences that result partly from different methodological perspectives, but also from extreme sensitivity of the results to key assumptions.
  - E3's methodology of creating an equilibrium market state in 2026 with which to compare alternatives causes its incremental cost estimates for all the alternatives to be extremely, and unrealistically, low.
  - The E3 methodology obscures the challenges and costs of implementing the various proposals.
  - ICF estimates a peak annual cost of the LSEO proposal of $8.5 billion, which under different shortage penalties would be as high as $30 billion. Though ICF did not explicitly model the FRM and PCM proposals, these would likely entail similar peak year costs.
  - E3 and ICF reach very different conclusions about the cost of DEC, with E3 estimating it as the most costly proposal, and ICF estimating that it would produce net savings, though with limited benefit to reliability. The contrasting results reflect different assumptions about market dynamics, highlighting the high degree of uncertainty associated with such analyses.
- 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 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 ***would guide revenue to such dispatchable resources*** 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 resources, 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**, which is, equivalently, the net incremental revenue to generation resources provided by DRRS.
- Incremental net revenue from DRRS would support the addition or retention of about **9,900 MW** of incremental capacity on the ERCOT system, if the cost per MW is at CONE, and potentially much more if capacity is retained at a lower going forward cost.

- If the need should arise, ***direct procurement of backup capacity*** to support grid reliability offers a ***straightforward and much less costly failsafe mechanism as compared to the PCM*** 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. Proposed Capacity Mandates Would Substantially Alter the ERCOT Market Construct

In January 2022, the Public Utility Commission of Texas ("PUCT") approved a blueprint for modifying the design of the wholesale electric market that included options for a "load-side reliability mechanism" intended to ensure a sufficient supply of dispatchable generation to serve ERCOT load reliably.[4] This blueprint has guided the high level development of several alternative capacity mandates:

[4] PUCT, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT, Project No. 52373, January 13, 2022; https://interchange.puc.texas.gov/Documents/52373_336_1180125.PDF.

- Forward Reliability Market ("FRM")

  A mandatory capacity credit market, centrally administered by ERCOT, with a sloped demand curve; similar to existing capacity markets in eastern regional transmission organizations ("RTOs").

- Performance Credit Mechanism ("PCM")

  A novel capacity market construct in which resources would receive performance credits ("PCs") based on retrospective availability during hours of high reliability risk, and LSEs would be assigned responsibility for acquiring PCs in a quantity proportional to load.

- Load Serving Entity Reliability Obligation ("LSERO") or Load Serving Entity Obligation ("LSEO")

  LSEs required to procure capacity credits from generators based on a forecast of peak load and system capacity need.

- Dispatchable Energy Credits ("DEC")

  LSEs required to procure DECs based on a proportion of annual energy; only resources with specified performance characteristics (fast-start, flexible) are eligible to generate DECs.

- Backstop Reliability Service ("BRS")

  ERCOT would procure BRS from resources that would otherwise retire based on going-forward costs. Cost assigned to LSEs based on load during high reliability risk hours. BRS resources would operate only during emergency conditions.

These alternatives would all be distinct and separate from ERCOT's existing energy-only market construct, in which energy, reserves and other ancillary services are procured from supply and demand resources on an hourly or daily basis consistent with system requirements. The need for such add-ons rests on the presumption that the existing market construct is incapable – under current circumstances, or in the near future – to provide economic incentives to generators and load sufficient to maintain system reliability. As discussed in this report, we do not find this presumption to be well-supported, though there are significant uncertainties from anticipated changes in supply in demand looking forward.

All of the alternatives would create additional revenue streams for generating resources separate from compensation for services provided to meet immediate operational needs. FRM, PCM and LSERO would each entail the specification of an explicit forward reliability standard, and an obligation on LSEs to bear a proportional share of the cost of meeting that standard through the respective mechanisms. While the general reliability objective can be stated succinctly, the details – and uncertainties – associated with the specification, implementation and evaluation of reliability mechanisms are substantial. The reliability of the system based on loss of load expectation ("LOLE") or related metrics is not readily observed, but must be estimated using complex models that try to capture a wide range of potential circumstances for load, generator outages, weather, transmission system conditions, fuel availability, etc.

Different modeling methods result in different calculations of reliability, and any given reliability standard is substantially a function of the underlying model and associated assumptions. Even more challenging is to determine the quantity of reliability contributed by each resource, which is necessary both to determining aggregate system reliability relative to the specified standard and to compensating each resource consistently. Moreover, the reliability contribution of each resource is dynamic and dependent on the quantity and mix of other resources on the system over time.

Recent evaluations of the capacity mandate proposals, discussed in the next section, have focused on the relative costs and effects of each. At a more fundamental level, there is the challenge of determining the appropriate standard or target for electric system reliability. Pursuing higher reliability through greater resource retention and new generation investment necessarily entails higher cost to consumers. Unlike most other RTOs, ERCOT has not mandated a particular capacity reserve quantity for the system, but has relied on energy and ancillary services market mechanisms to provide signals from, and to, supply and demand to produce economically efficient operational outcomes. The result over time in terms of system reliability is a joint function of administrative components of the market construct (e.g., the specification of the Operating Reserve Demand Curve ("ORDC") and price caps) and the behavior of market participants on the supply and demand sides. In the energy-only construct, reliability is an output of the markets, not an *ex ante* requirement imposed on the market.

Beyond the complexities and uncertainties of measuring system reliability and the contributions of individual resources, establishing a reliability mandate should be informed by an assessment of the trade-offs of the cost and value of reliability. Additional increments of reliability may have value, but may come at a cost that exceeds that value. As discussed in the following section, there are analytical approaches to estimating an optimal level of reliability, but it is important to appreciate that imposing a forward reliability mandate on the ERCOT market would be a substantial departure from the function of the current market design, and would make reliability and the associated cost paid by consumers an administrative determination rather than dynamic result of the competitive market.

In section VII, below, we assess the reliability value of enhancing the ERCOT operational markets with the Dispatchable Reliability Reserve Service ("DRRS"), a day-ahead reserve product targeted at addressing uncertainty in load and the output of wind and solar resources. Such an enhancement has the potential to improve reliability while maintaining the particular strengths of the current energy-only market design, and avoiding the need for a new mandated revenue stream from consumers to generators.

IV. Recent Reports on ERCOT's Reliability and Proposed Market Reforms Present Contrasting Findings

Two reports completed at the end of 2022 have addressed ERCOT's reliability and capacity balance and have evaluated the cost and effects of alterations to the ERCOT market that have been proposed as ways to ensure reliability of the electric system. One report, by ICF on behalf of the Consumer Fund of Texas, was released in October. The other report, by E3 on behalf of the PUCT, was released in November. While the assessments apply similar types of analytical tools, they take different methodological perspectives, which partly explains the differences in reported results. Bates White was asked to assess and compare the analyses presented in the two reports. While each report provides general descriptions of their respective methods, and some specifics regarding data sources and assumptions, Bates White did not have access to the models or to the detailed inputs or outputs that would be required to perform a comprehensive assessment. Nonetheless, the available information is sufficient to identify several important features of studies, and to highlight ways in which they agree or differ in the evaluation of the proposed market alterations.

In broad terms, the ICF Report assesses the annual effects over time of the various proposals, estimating costs and reliability effects in 2023, 2024, 2025, 2027 and 2029. The ICF results show different patterns of costs and effects over time. In contrast, the E3 Report compares the costs and effects of the proposals based on a single equilibrium year (chosen as 2026, simply by assumption), created as a common frame with which to evaluate the presumed long-term characteristics of the different capacity support mechanisms.

A. E3 and ICF identify very different current levels of reliability

Despite relying to a large extent on common load and resource data for the ERCOT system, and applying similar modeling tools, it is notable that the reports present quite different conclusions about ERCOT's current reliability state in the absence of proposed capacity mandates. (Reliability is typically assessed in terms of the industry standard reference of 1-day-in-10-years LOLE, equivalent to 0.1 days/year, which is the metric used in both reports).[5]

[5] The 1-day-in-10-years terminology is not intended to correspond to a full day of system-wide blackout, but to a day with any forced load-shedding *events*, of any duration.

The E3 Report characterizes ERCOT's current reliability as "close to the 0.1 days/yr benchmark,"[6] and finds that existing resources plus planned additional capacity would achieve reliability of 0.02 days/yr LOLE (i.e., significantly more reliable than the benchmark) for expected load levels in 2026. As discussed below, E3 makes aggressive resource retirement assumptions to create an "equilibrium" scenario in 2026 with which to evaluate each of the capacity mandate proposals.

The ICF Report presents a very different assessment of current ERCOT reliability, estimating it at 0.5 days/yr LOLE. The respective reports do not contain sufficient information to assess the cause of this stark difference in estimated current reliability. While E3 does not explicitly report model cases for 2023, as ICF does, E3's "pre-equilibrium" result of very high reliability in 2026 builds on, and is consistent with, the current state of the system. The respective reports do not provide sufficient information to explain the different conclusions regarding ERCOT's current reliability. Ultimately, the results are driven by the myriad assumptions required to model a complex, dynamic and uncertain system. For instance, ICF's higher expected LOLE is likely driven by a very wide distribution of expected demand, much wider than assumed by E3.[7]

Regarding its estimate of ERCOT's current LOLE at 0.5 days/yr, ICF points to similar results in a study by Astrapé Consulting.[8] Astrapé performed a study for ERCOT published in 2021 examining 'market equilibrium' and 'economically optimal' capacity reserve margins for 2024, based on the then-applicable market design parameters.[9] The study found that market equilibrium in 2024 would produce a capacity reserve margin of 12.25%, with projected reliability of 0.5 LOLE. However, this reliability result is a modeled output for a hypothetical future market equilibrium state. The Astrapé study does not present LOLE estimates for any existing state of the system, and cannot be calibrated to current conditions, so it is not possible to construe the Astrapé LOLE estimates as validation of the ICF estimates.

The Astrapé study does provide interesting information regarding the economically optimal level of system reliability. Astrapé models the total costs for the system for different capacity reserve margins, with the costs including firm load shed at the value of lost load ("VOLL") and assumed full recovery of marginal combustion turbine ("CT") fixed costs as well as other production and ancillary services costs. This

[6] E3 Report, p. 7.

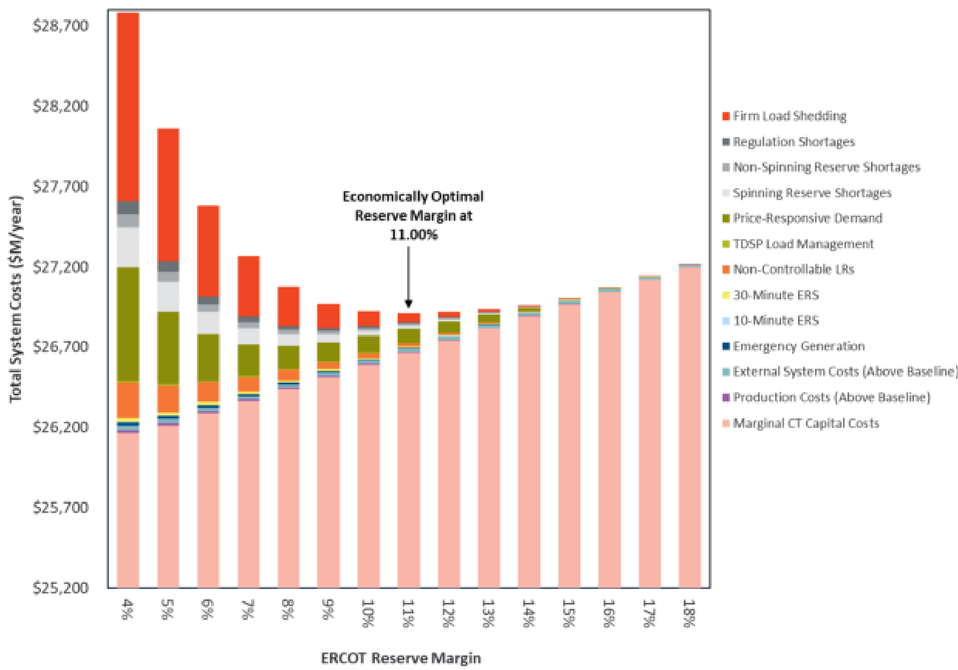
[7] Compare Figure 35 of the ICF Report to Table 7 of the E3 Report. The summer 1-in-100 value assumed by ICF is ~15% above the median value, while E3 assumes it is only 8% above the median value. ICF's distribution of expected winter loads is also extremely broad; ICF has approximately a 5% chance of ERCOT exceeding a winter peak of 80 GW. This assumption will drive a large probability of outage in the winter.

[8] ICF Report, p. 20.

[9] Astrapé Consulting, Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (January 15, 2021) ("Astrapé Study").

provides a useful view of the tradeoff between the value of reliability (reduced costs associated with firm load shed) and the costs of achieving that reliability through additional CT capacity (assuming that the CTs fully recover fixed costs). Figure 1 reproduces a figure from the Astrapé Study showing the tradeoff, and the result that the economically optimal reserve margin would be at 11.00%, 1.25 percentage points less than the equilibrium result of 12.25% produced by operation of the competitive energy-only markets. This result implies that the energy-only market is expected to produce *greater* reliability than would result from balancing the incremental costs of additional capacity against the incremental value of increased reliability.

Figure 1: Astrapé Study results – total system costs across planning reserve margins[10]



The Astrapé results are sensitive to assumptions and subject to substantial uncertainty, as with all such complex analyses. Nonetheless, they highlight several important points. One, the energy-only market construct produces reliability as a function of various design parameters (as modeled in the study). Two, there is an intuitive tradeoff between the value reliability, which increases as firm load shed (the top, red bar in the figure) falls, and the cost of fully paying for excess capacity (the bottom, pink bar in the figure). Three, the energy-only market can produce reliability in excess of the economically optimal level where the cost of extra capacity just balances the incremental reliability value it provides. And four, that

[10] Astrapé Study, Figure ES-10, page 14.

administratively mandating a particular level of reliability, above the level produced by the energy-only market, is likely to be sub-optimal – i.e., the extra cost that LSEs would have to pay to generators would exceed the value of the resulting additional reliability.

B. Comparison of E3 and ICF Results

As noted above, the E3 and ICF reports rely on similar modeling tools and data, but apply different methodological perspectives. E3 creates a market equilibrium case, and also evaluates the cost of the capacity mandate options assuming that a 0.1 days/yr LOLE level is achieved in its model. ICF examines costs and reliability results for several individual years based on particular specifications of the alternatives; the reported reliability level is an output of the modeling, not a constraint as in the E3 analysis. Neither approach is necessarily superior; each provides a different, though incomplete and uncertain, view. The reality is that the reliability values can be compared within models but not across models, due to the different assumptions and techniques used in each approach.

Table 1: Comparison of E3 and ICF Results

	E3 Report		ICF Report		
	2026 Incremental Cost ($b)	**2026 LOLE (days/yr)**	**2025 Incremental Cost ($b)**	**2030 Incremental Cost ($b)**	**2030 LOLE (days/yr)**
Energy-Only (before retirement assumption)		0.02			
Energy-Only (equilibrium)	-	1.25	-	-	0.64
LSERO/LSEO	$0.46	0.10	$8.52	$0.68	0.45
FRM	$0.46	0.10			
PCM	$0.46	0.10			
BRS	$0.36	0.10	$0.14	$0.85	0.17
DEC	$0.49	2.03	$0.35	($1.99)	0.44
DEC/BRS	$0.92	0.10			

The following discussion addresses key issues with respect to the ICF and E3 modeling, and the differences in results as summarized in Table 1.

The E3 Report applies the 0.1 days/yr LOLE as a constraint

The 0.1 days/yr LOLE value for each of the capacity mandate alternatives (excluding DEC) is not an output of the modeling, but rather is a constraint, intended to provide a common basis for evaluating the relative cost of each alternative. This methodology achieves a common basis, but obscures the challenges and costs of transitioning from the current construct. The ICF methodology provides a more detailed view of the potential pattern of costs over time, though as discussed below, these are highly sensitive to a range of assumptions.

The E3 incremental cost estimates are very low

As described above, the E3 methodology creates an equilibrium reference case in 2026 that establishes a common basis for comparison of the incremental costs of the evaluated capacity support alternatives. To create this case, a large quantity of new renewable generation is added to the modeled system, and more than 11,000 MW of existing thermal generation is removed, such that energy and ancillary services prices are high enough to cover a CT CONE of $93.50 per kW-year. This is not a realistic scenario, which we discuss further below, and its function is primarily to create the common reference basis. However, this methodological approach also results in the incremental cost estimates for all the alternatives to be extremely, and unrealistically, low. As constructed, the equilibrium reference case entails very high market pricing (and very low reliability). The evaluation of the capacity support alternatives relative to this case effectively assigns offsetting benefits to the alternatives of lowering energy and ancillary services market prices based on the capacity added in order to achieve the 0.1 days/yr LOLE.

The E3 cost results for LSERO, FRM and PCM are identical

The E3 Report concludes that the incremental costs of LSERO, FRM and PCM are identical. This result follows from the fact that all three alternatives are modeled to have the same volume, type and cost of new resources added to the reference case in 2026. This can be interpreted as a long-term equilibrium state, which again may provide a common reference frame for the alternatives, but suffers from obscuring important details about how the options would be implemented over time. It is important to understand that E3 is not asserting that each alternative could achieve 0.1 days/yr LOLE by 2026, and that the substantial costs of pursuing any of the three are obscured by the methodology, both in the pattern of imposed costs over time and, as noted above, in the overall level of incremental cost.

The cost results are highly sensitive to assumed implementation details

A notable contrast in the Table 1 comparison is between the very high ICF cost estimate for LSEO in 2025 – $8.5 billion – and the much lower incremental cost results from E3 – $0.46 billion. This is largely a function of the methodological differences already discussed, but it also reflects the extreme sensitivity of the estimates to assumed implementation details. ICF notes this sensitivity as it relates to key LSEO parameters, which are uncertain – for example, the applicable forward period, the method used to determine resource capacity accreditation, and applicable shortage penalties.[11] ICF notes that a shortage penalty cap set at 3xCONE could increase the 2025 cost to more than $30 billion. In the ICF analysis, this particular sensitivity is driven by modeled supply constraints. ICF's estimated annual cost of LSEO drops significantly over time as supply constraints are eased, though the 2030 estimate of $0.68 billion is still nearly 50% higher than the E3 incremental cost estimate.

ICF did not evaluate the FRM and PCM alternatives, but these would involve similar complexities and challenges, likely with comparable patterns of very high initial costs that fall somewhat over time. As detailed in section VIII with respect to the PCM proposal, capacity procurement mandates in ERCOT are likely to impose substantial incremental costs with little or no incremental reliability benefits.

E3 and ICF reach very different conclusions about the cost of DEC

There is a stark difference between the E3 and ICF estimates of DEC cost, despite the fact that DEC is one of the more well-defined of the proposals. In particular, the ostensible long-term equilibrium cost estimated by E3 is greater than that of any of the standalone proposals, at $0.49 billion, while the ICF analysis shows the costs of DEC falling sharply and becoming *negative* $1.99 billion by 2030 – i.e., providing a net cost reduction to the system, albeit with very little reliability benefit. These strikingly different results reflect fundamentally different modeling of the market dynamics from implementing DEC.

E3's modeling of DEC assumes that new, high-efficiency aeroderivative CTs would be the primary source of DECs, displacing frame CTs from the market, with the additional assumption that the aeroderivative CTs would bid into the energy markets at below their short-run marginal costs (because DECs provide production revenue additional to that from existing markets).[12] This causes energy prices to fall, which in turn pushes more frame CT capacity to retire. DEC is consequently a relatively costly method of enhancing reliability, because new aeroderivative CTs receive extra compensation not available to frame CTs. Effectively, new aeroderivative capacity is added in excess, and potentially useful, but under-compensated frame CTs are pushed to exit the market.

ICF's modeling is partly consistent with this picture. It also finds that DEC would reduce energy prices. However, ICF's modeling shows 2-hour batteries filling much of the DEC need, and forecasts that supply competition will push DEC prices down over time. In ICF's modeling, the reduction in energy prices across the system more than offsets the cost of DEC, resulting in an overall reduction in system cost, though again, the reliability impacts of DEC are modest. Perhaps the biggest driver of this result is ICF's assumption that

[11] ICF Report, page 31.

[12] See: E3 Report footnote 31, page 50.

all new thermal generation projected to enter the market in the continued energy-only market would be qualified to provide DECs.[13] In ICF's scenario, the 2-hour batteries required to fill additional DEC needs push DEC prices down, with the implication that DEC-qualified thermal resources are forced to accept lower returns. ICF acknowledges that impacts could be different, for example if low energy prices cause retirements to exceed additions of new DEC-qualified capacity, and consequently that "the DEC program would have to be carefully balanced…."

The E3 and ICF Reports describe the respective modeling of DEC in reasonable terms, but the dramatically different results point to two important issues. One is that it is difficult to assess dueling models in the absence of the models themselves or a great deal of detail that is impractical to present in summary reports. More important, the contrasting results demonstrate that modeling market dynamics is complex and highly sensitive to assumptions that may seem reasonable but rest on a cascade of interrelated factors that may make the outputs both uncertain and unreliable.

C. The E3 2026 equilibrium case is not realistic

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 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.

It is important to recognize that the year 2026, and the large capacity shortfall in the derived equilibrium case are assumptions applied by E3 in creating its market "equilibrium" scenario. Neither the year nor the quantity of capacity retirement are outputs of the modeling exercise, and importantly do not constitute a prediction or forecast of when ERCOT will be short of capacity.

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

[13] ICF Report, page 36.

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.

V. ERCOT's Current and Historical Capacity Balance

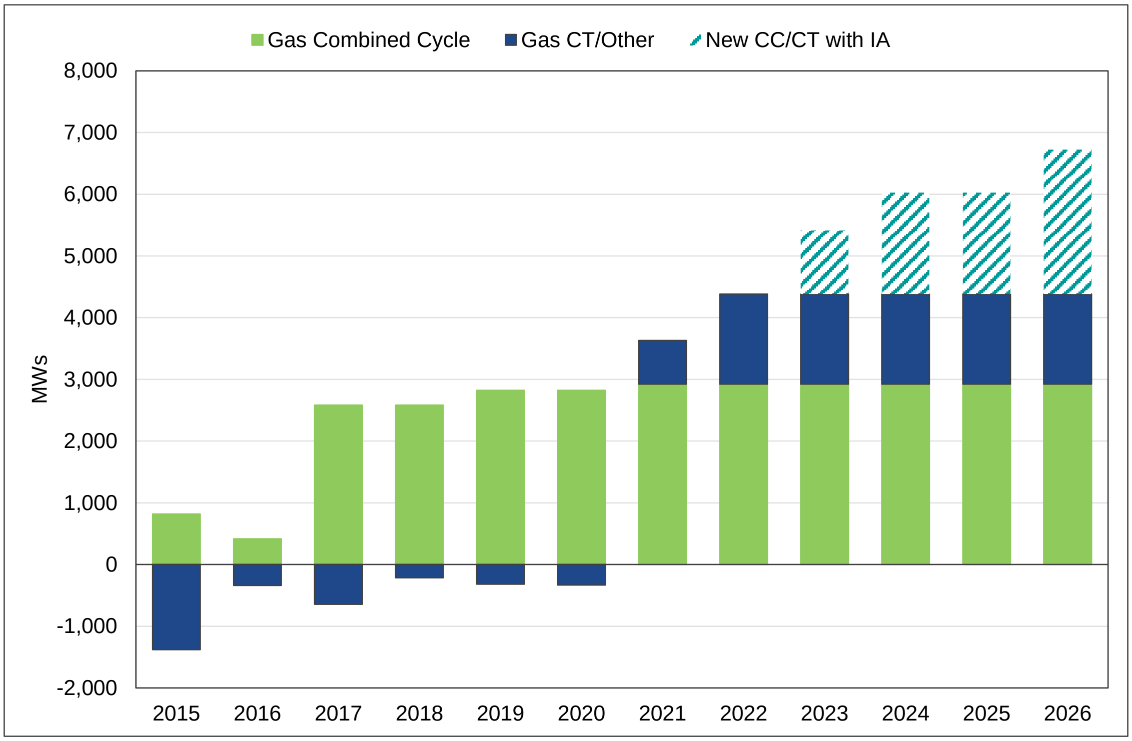
As an initial matter, ERCOT has more than sufficient capacity to meet reliability needs now, and there is no imminent risk of a capacity deficiency looking forward. In stark contrast to the aggressive retirement assumptions required to produce E3's 2026 market equilibrium scenario, the actual historical 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.[14]

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 2. 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.[15]

[14] 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.

[15] ERCOT capacity data: https://www.ercot.com/files/docs/2023/04/07/Capacity-Changes-by-Fuel-Type-Charts-March-2023.xlsx.

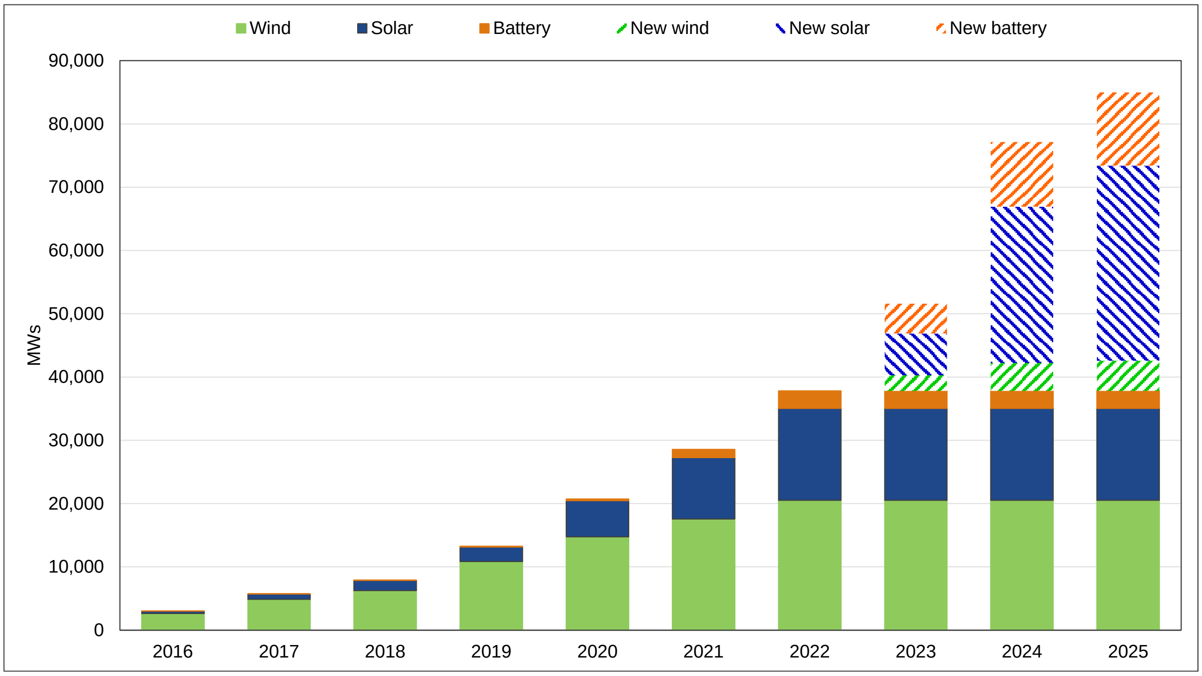
Figure 2: Cumulative net change in ERCOT gas-fired capacity 2014-2022, and new CC/CT with signed interconnection agreement, MW[16]



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. Figure 2, below, shows historical additions of renewable and battery storage capacity from 2016 through 2022, and planned resources through 2025 that currently have signed interconnection agreements.

[16] *Id.*

Figure 3: Renewable and battery additions, 2016-2022, and with signed Interconnection Agreements through 2025[17]

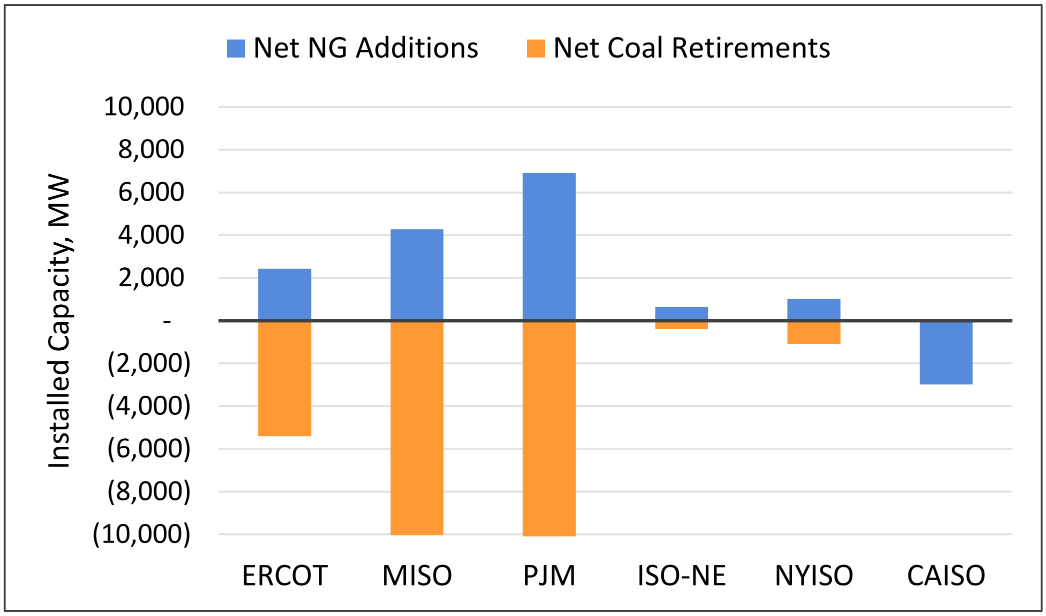


A. Net Thermal Capacity Additions in ERCOT and other RTOs

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 4 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).

[17] *Id.*

Figure 4: Net thermal capacity changes by RTO, 2018-2022[18]



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.[19] 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%.[20] MISO experienced a net thermal capacity contraction of approximately 5,800 MW, and its 2022 summer capacity reserve margin was approximately 18%.[21] 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:

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

[19] 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.

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

[21] 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.

1) The ERCOT market is currently providing sufficient revenue to support new capacity investment.
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.[22]

VI. 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).[23] 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.[24]

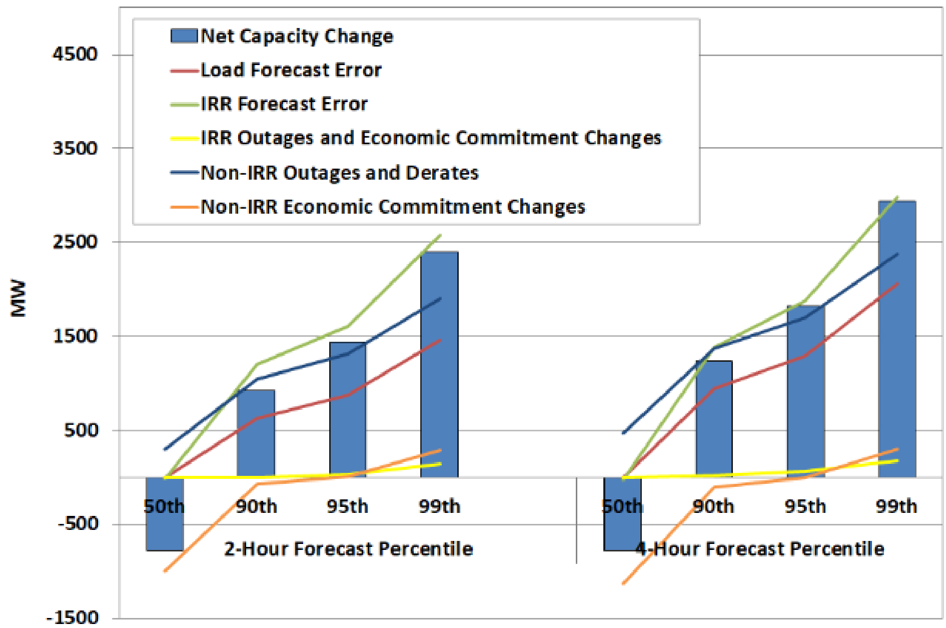
The main challenge facing the ERCOT market is to ensure sufficient operational flexibility to address increasing forecast uncertainty associated with growing quantities of wind and solar generation on the system. The IMM has presented estimates of 4-hour forecast uncertainty for the ERCOT system based on 2021 data, as shown in Figure 5.

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

[23] E3 Report at 46.

[24] 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 5: Forecast Error and Net Capacity Change (2021 State of the Market) [25]



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.

[25] 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.

VII. Enhancing the ERCOT Energy-Only Market with the Dispatchable Reliability Reserve Service

DRRS (Dispatchable Reliability Reserve Service) has been proposed as an additional market product corresponding approximately to the uncertainty product that has been recommended by the IMM.[26, 27] 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, and so is readily incorporated within ERCOT's existing market mechanisms for energy and ancillary services. Unlike the proposed market alterations addressed above, DRRS would not create a mandated revenue stream from consumers to generators to support an administrative reserve margin requirement, which is the hallmark feature of a capacity market.

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

DRRS would be valuable for deploying dispatchable resources more efficiently, and for 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 revenues.

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

[26] The IMM addresses the proposed uncertainty product in the 2021 State of the Market Report (see footnote 25), and also in comments filed in PUCT Project No. 52373, https://interchange.puc.texas.gov/Documents/52373_178_1160003.PDF.

[27] 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.

associated with IRRs in 2021, shown in Figure 5. 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.

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.[28, 29] 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.

1. 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").[30] 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[31]. 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.

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[28] 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).

[29] 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).

[30] 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

[31] 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

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 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.

2. 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 /1,000,000 = **$1,683 million**.

3. 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.[32] 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.[33]

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[32] IMM comments in PUCT Project No. 52372 (see footnote 26), pages 6-7.

[33] 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.

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 Quantities and Methodology."[34] 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 is, equivalently, the net incremental revenue to generation resources from DRRS.

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.[35] 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 revenue/cost is summarized in Table 1 below.

[34] 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

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

Table 2: Estimated annual revenue/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 revenue/cost of DRRS	**(j)**	**= (e) - (i)**	**$923**	**$MM**

B. DRRS Impacts on ERCOT Capacity Balance

DRRS would procure a new reserve service important to managing growing IRR and net load uncertainty on the ERCOT system. As estimated above, it would provide annual gross revenue to generation resources of approximately $1.7 billion, and annual incremental revenue relative to the existing market construct, of approximately $923 million. This revenue will be allocated through competitive procurement to resources best suited to provide DRRS economically. Some resources that would otherwise have retired will remain in the market specifically because they are well-suited to provide DRRS, but are otherwise uneconomic. By providing improved management of IRR and load forecast uncertainty, DRRS will reduce the need for out-of-market actions that tend to reduce market clearing prices, thereby providing more revenue to other resources on an economic basis. The net revenue impacts of DRRS would consequently be distributed across a range of capacity resources, including new resources entering the market.

The net impact on ERCOT capacity of DRRS-supported incremental revenue will be a function of the costs and operating characteristics of the existing resource mix, and related market dynamics. If the impact of DRRS is primarily to retain existing resources, then the net capacity effect will depend on the supported going-forward costs of such resources. If the going forward costs of such resources average $50/kW-yr, that would imply a net capacity increase relative to the status quo of **+18,460 MW** (=$923MM ÷ $50/kWyr × 1000). If the net capacity effect is predominantly channeled by the market to new resources, then the capacity increase would be determined by CONE, and would be approximately **+9,872 MW** (=923MM ÷ $93.50/kWyr × 1000).

As previously addressed, cost data indicate that ERCOT capacity at risk of retirement for economic reasons is on the order of 2,000 MW, while E3's modeling results indicate ERCOT could still exceed a 0.1 days/yr reliability level with retirements in excess of 5,000 MW. Thus, the incremental capacity that could be supported by DRRS through retention or new addition would be available to support system reliability as increasing volumes of solar and wind generation are added.

VIII. 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 the costs of 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)."[36] Similarly, NRG states that that it fully hedges its 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.[37] The average term for a new customer is now two years.[38] 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

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[36] 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

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

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

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 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.[39] 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.[40]

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

[39] E3 Report at 83.

[40] *Id.*

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.[41]

IX. 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 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,

[41] 2021 State of the Market Report, at 23.

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.