Phase II Market Design Bridging Options Comment Form

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Comments

Executive Summary

The Commission directed ERCOT to consider bridging options until the PCM can be fully implemented.[1] However, the Commission has also indicated that it will wait until after the legislative session before it moves forward with any significant market redesign. As such, Texas Industrial Consumers (TIEC) believes that ERCOT should focus on "no regrets" strategies designed to reduce the use of reliability unit commitment (RUC), which could expedite the retirement of existing generation units.

To satisfy ERCOT's current preferred reliability margin of 6,500 MW, ERCOT is now routinely RUC'ing resources, and the IMM predicts RUCs will substantially increase in the coming years with more renewable generation connecting to the grid.[2] Accordingly, a bridge solution should mitigate ERCOT's use of RUCs because increased RUCs may expedite the retirement of dispatchable resources. As Commissioner Cobos clarified at the Reliability and Markets Committee meeting on February 27, 2023, "The focus of the bridge was to, yes, maintain existing generation, but also to take that physical operational pressure off those units that are being RUC'ed. And the solution would be to help reduce RUC, so that we don't end up with these older plants that end up with an expedited retirement date and a gap in reliability."[3] Therefore, it's important that any bridging solution reduce ERCOT's use of RUCs.

- **Manual Performance Credit Mechanism (PCM)**
    - A net-cone-based charge on consumers that is designed to provide revenue

[1] *Wholesale Electric Market Design Implementation*, Project No. 53298, Order, Attached Commissioner Memorandum at 4 of 4 (Jan. 19, 2023).

[2] Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Markets* at xviii (May 2022) (*available at:* https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf).

[3] Reliability and Markets Committee, February 27, 2023 Meeting at 16:54 (*available at:* https://ercot.new.swagit.com/videos/209044).

sufficiency to generators, like a manual PCM, runs counter to the Commission's instructions to wait until after direction from the legislature.

- Importantly, none of the parameters of PCM have been set, so ERCOT and stakeholders would be acting in a vacuum without policy guidance or explicit authority.
- ERCOT indicated that the manual PCM would pay ***all*** resources, including renewable resources, which is contrary to the Commission and the Legislature's intent to focus market solutions on dispatchability.
- As was discussed at the most recent workshop, a manual PCM would be allocated on a load ratio share to load serving entities, creating an unexpected financial burden on these entities with very little notice and no ability to hedge.
- ERCOT contemplates an annual or seasonal settlement, which could create a massive PCM charge to LSEs (or loads) during mild years when the market does not reach peaker net margin. ERCOT should provide modeling of 2018 and 2020 to allow market participants to understand what the PCM charge(s) could look like.
- Even if the Load Serving Entities (LSEs) could pass these unexpected costs onto customers, customers will be in the same position—facing potentially massive costs that cannot be hedged that were completely unexpected. This is not a reasonable outcome.

- **Additional Ancillary Services**
  - ERCOT Staff has indicated that an ancillary service product to address forecast uncertainty, like the Dispatchable Reliability Reserve Service (DRRS), would reduce RUC'ing. Additionally, DRRS would increase annual revenues for dispatchable resources by approximately $1.7 billion. By enhancing the revenues available to dispatchable resources, DRRS will further incentivize the continued investment in dispatchable generation, meeting the Commission's goals of retaining existing assets and incentivizing new generation.
  - TIEC believes that ERCOT lacks the authority and direction needed to implement bridge options that are not grounded in existing market systems, such as ancillary services. This makes DRRS an attractive option because it is based on existing authority and market design, which will minimize potential legal issues.
- **Enhance the Operating Reserve Demand Curve (ORDC)**
  - TIEC notes that the Commission previously adjusted the ORDC in January 2022 with the stated intent of encouraging self-commitment to reduce reliance on RUC, but ERCOT has continued to RUC units out in front of real-time operations. This tool has not proven to address the market distortions being caused by conservative operations and TIEC does not believe an additional adjustment will provide a different result.
  - Further, artificially inflating the ORDC yet again will indiscriminately pay all resources, including renewable resources, which will not change investment patterns. This has been repeatedly proven in the past. As a result, this proposal is contrary to the legislature's intent with SB3 and the Commission's directive to focus additional revenues on dispatchable generation.

- The ORDC changes would be based on achieving a pre-determined revenue level for new generators, which will create excessive returns for some existing generators and an electricity tax on consumers. Incumbent generators have made clear by their actions since the last ORDC change in 2019 that they will use these revenues to supercharge returns for shareholders or invest in ESG-favored generation out of state.[4] There is no reason to believe the additional revenue will be used to build in-state dispatchable generation.

- **Backstop Reserve Service (BRS) and Contracts for Capacity**
  - The parameters for these bridging solutions are still unclear, so it's difficult to provide constructive input. It appears that BRS will cost less than enhancing the ORDC or implementing a manual PCM. It will also result in quantifiable retention of capacity.
  - TIEC views this as the second most preferable option after implementing DRRS.
- **Publish Indicative PCM Values**
  - Many of the key features of the PCM have not been determined by the Commission, so PCM values may not be indicative of the impact PCM would have on the market. Further, it is still unclear whether PCM will be the Phase II market design solution because the legislature is still evaluating options.

The non-DRRS solutions also preempt the Commission and the legislature because there is no established reliability standard, so any solution that is premised on a reserve margin mandate or revenue sufficiency for generators is premature.

Option 1: Implement a Basic settlement component of PCM manually

The parameters of the PCM have not been set, so ERCOT and the stakeholders would be acting in a vacuum with little guidance or authority from the Legislature or the Commission. The Commission's order adopting the PCM included a number of issues that ERCOT, the Commission, the IMM, or some combination thereof must analyze and decide on before a functional PCM could go into effect. However, this proposal ignores those critical decision points. Importantly, without a clear framework for the PCM, it's impossible to determine whether

[4] *See e.g.*, See Vistra, Vistra Reports Second Quarter 2022 Results; Authorizes $1.25 Billion for Share Repurchases (Aug. 5,2022) (*available at:* https://investor.vistracorp.com/2022-08-05-Vistra-Reports-Second-Quarter-2022Results-Authorizes-Additional-1-25-Billion-for-Share-Repurchases) ("[T]he board has authorized a cumulative $3.25 billion in share repurchases since Vistra announced its capital allocation plan in Nov. 2021.") (Aug. 5, 2022); *see also* NRG Energy, Inc., NRG Closes 4.8 GW Asset Sale and Announces $1 Billion Share Repurchase Program *ec. 6, 2021) (*available at:* https://www.nrg.com/about/newsroom/2021/40856.html) ("[T]he NRG Board of Directors has authorized $1 billion for share repurchases, effective immediately. The program is expected to begin in 2021 and will continue throughout 2022.") (Dec. 6, 2021); *see also* NRG Energy, Inc., NRG, Inc. to Acquire Vivint Smart Home, Inc. (Dec. 6, 2022) (*available at*: https://www.nrg.com/about/newsroom/2022/41771.html?utm_source=newsletter-hubwire&utm_medium=email&utm_campaign=pe-hub-wire-subscriber&utm_content=06-12-2022) ("NRG Energy, Inc. (NYSE: NRG) and Vivint Smart Home, Inc. (NYSE: V-VNT) today announced they have entered into a definitive agreement under which NRG will acquire Vivint for $12 per share or $2.8 billion in an all-cash transaction.") (Dec. 6, 2022).

this bridging solution will actually retain resources or incentivize new generation. Notably, during Vistra's earnings call on March 1, 2023, Vistra's CEO stated that the current PCM discussion is too vague to result in new investment. Further, there is no indication a manual PCM would address the Commission's goal of decreasing RUC'ing, and it would unreasonably shift risk onto customers because the associated costs cannot be hedged without a forward market.

As previewed during the workshop on March 3rd, a manual PCM will cause substantial disruption for consumers and the ERCOT market without providing any real investment signal. A Manual PCM would be allocated on a load ratio share to load servicing entities, creating an unexpected financial burden on these entities with very little notice and very little ability to adjust. LSEs with fixed contract cycles will need time to be able to renegotiate contract terms or be subject to financial stress, and LSEs with fixed contracts cannot pass through PCM costs without the Commission expressly designating the charge as beyond the LSE's control for a customer's existing contract under 16 TAC 25.475(b). Further, in mild years if the market does not reach peaker net margin, PCM charges could become a massive one time or seasonal payment from all LSEs and/or loads. At a minimum, ERCOT should provide modeling on this to see what the payment should have looked like in 2018 or 2020 to gauge the significance of this potential issue.

Even if LSEs can pass these unexpected costs to customers, this just shifts the unexpected financial burden to end-users. Because the parameters of the PCM are unclear, customers have had no notice of what the manual PCM will entail, and there is little to no transparency in determining the value of PCs, the hours they can be earned, what resources qualify, etc. Accordingly, customers cannot incorporate these new costs into their business plans or their budgets. Importantly, a manual PCM cannot be hedged as it just an administrative charge, so there is no way for customers or LSEs to protect themselves through prudent contracting.

Additionally, the manual PCM proposal lacks many of the principles the PUC adopted in its memorandum from January 19, 2023.

- There is no defined reliability standard, so ERCOT's demand curve would be arbitrary. This means it will not be sized accurately and it will not be self-correcting.
- There are no market power mitigations, so affiliated retailers will have an advantage because they can use their affiliated generation resources to offset the unknown costs of a manual PCM. Importantly, the manual PCM does not include any central exchange or prohibition on bilateral trades, which the Commission specifically discussed because it was concerned about market power abuse.
- The manual PCM only permits eligible resources to participate on the demand side, even though the Commission's goal was to define eligible resources on both generation and load side.
- ERCOT indicated that the manual PCM would allow any resource to participate. However, the Commission and Legislature were clear that the market design solutions should benefit dispatchable resources.

A manual PCM will be very disruptive for customers and businesses of all sizes across ERCOT. Therefore, a manual PCM as bridging solution should be rejected. Because any increase in generation revenue will be borne by customers, ERCOT and the Commission should only adopt a bridging solution that is carefully tailored to avoid excessive costs to customers without a corresponding increase in reliability.

Option 2: Procure Additional Ancillary Services

ERCOT's ancillary service bridging solution seems to involve procuring more non-spin, rather than creating a new service. However, relying on Non-Spin is inconsistent with ERCOT's stated goals and the Commission's discussion on January 26th. Increasing non-spin (without accounting for those resources) will increase the need to RUC because non-spin is illiquid, as ERCOT recognizes.

Instead, ERCOT should move forward with a service consistent with DRRS. ERCOT staff has acknowledged that a service consistent with DRRS would help address the RUC issue letting the markets perform. Importantly, by providing targeted compensation, DRRS would reduce the potential for dispatchable resources to retire prematurely. DRRS would provide an estimated $1.7 billion of annual revenues directed to dispatchable resources. By enhancing revenues available to dispatchable resources, DRRS will incentivize the continued investment in dispatchable generation and help maintain existing resources.

Option 3: Enhance the Operating Reserve Demand Curve (ORDC)

Enhancing the ORDC will not address the Commission's objectives. As proposed, the ORDC changes seeks to boost the headroom calculation for offline and partially unloaded resources. This will indiscriminately pay ***all resources***, contrary to SB 3, which was limited to dispatchable resources. Not only will enhancing the ORDC compensate renewable resources, it will only increase revenues by approximately $150 million, which is not enough to attract new generation. Additionally, nuclear resources already have a floor far in excess of operating costs.

ERCOT's proposed ORDC changes may actually expedite retirements. ORDC adjustments will not address the RUC'ing issues, and if investment patterns continue, there will be substantially more renewable resources on the ERCOT system. Accordingly, ERCOT will need to RUC more often, which will further strain dispatchable resources. This is what has happened with previous adjustments to the ORDC, including those in January 2022 that were designed to encourage self-commitment and reduce RUC. This has proven to be a costly and ineffective solution unless ERCOT is willing to forego RUC at some level and wait for market units to self-commit.

Changes to the ORDC curve will not shift investment away from renewable resources. The ORDC was shifted twice in 2019, and the two changes increased wholesale market prices by 40% relative to 2019, adding $1.4-$1.6 billion in market revenues. However, there was no material change in investment patterns. There is no reason an additional change in the ORDC curve would lead to more dispatchable generation when the largest existing generators have made clear by their actions since the ORDC changes in 2019 that they will use these revenues to supercharge returns for shareholders or invest in ESG-favored generation outside of Texas.

Additionally, enhancing the ORDC will increase payments to intermittent resources. The most recent changes to the ORDC intentionally avoided paying resources when there were more than 3,000 MW of reserves because it would increase payments to non-dispatchable resources. If ERCOT enhanced the ORDC, the ORDC becomes an energy tax that would increase revenues for both dispatchable *and* ***non-dispatchable resources.*** As with the PCM, this bridging solution is inconsistent with the authority from the Legislature or the direction from the Commission to focus market solutions on dispatchability.

Because enhancing the ORDC will distort market signals for generator performance, reduce customers' ability to hedge, and fail to increase investments in dispatchable resources, it should be rejected.

Option 4: Backstop Reserve Service (BRS)

The parameters of BRS as a bridging solution are still unclear, so it is difficult to provide constructive input. However, many of the cons ERCOT provided in its introduction presentation are illogical.

- None of the solutions seek to replace ERCOT's energy-only market, so BRS does not rely on scarcity conditions more than any of the other bridging solutions.
- Only paying a subset of resources serving the grid is actually a benefit of BRS. Depending on how resources can qualify to provide BRS, the Commission should ensure that only dispatchable resources receive the increased revenues. Unlike the manual PCM or the ORDC adjustment, this would be consistent with the SB 3 and the Commission's directive.
- While BRS may create a regulated group of resources that receive a capacity payment, it is unclear how this is unique to BRS. A manual PCM or ORDC enhancement would similarly only benefit a specific group of resources that were available during a specific time period. However, BRS is more targeted and efficient because it would only compensate dispatchable resources.
- Similar to all of the solutions, additional revenues provide an advantage for resources that can participate in the solution.

Additionally, there are certain parameters could help make BRS more effective:

- If BRS is procured closer to real time, it would give market participants flexibility to manage their positions. This would essentially allow BRS to function like a longer-lead time ancillary service.
- If BRS resources are deployed at a price lower than the HCAP, but behind other market participants, it would provide pricing signals and minimize market inefficiencies.

Option 5: Contracts for Capacity
This construct currently exists with RMR, so it is not clear what changes are needed for this bridging solution. More information is needed to fully consider this option.

Option 6: Publish Indicative PCM Values
As noted above, many of the key features of the PCM have not been determined by the Commission, which forces ERCOT to make a number of premature judgment calls on the reliability standard, the demand curve, the potential resources that would qualify, etc. Accordingly, any numbers published could be wholly disconnected from what the PCM may look like and would provide little value to market participants or investors. As Vistra indicated during its recent earnings call, PCM is still too vague, so it is doubtful published numbers based on ERCOT's arbitrary assumptions would incentivize investors. Additionally, the PCM may not be the Phase II solution, so publishing indicative PCM values would waste ERCOT staff's valuable time. However, this option has a number of benefits as compared to Option 1 because it would not disrupt the existing market.

Conclusion/Additional Comments

When the Commission directed ERCOT to consider bridging options, the Commission indicated that it would wait until after the legislative session before moving forward with market redesign. Accordingly, ERCOT should avoid preempting the legislature. Instead, ERCOT should focus on strategies designed to reduce the use of out of market actions such as RUC. Notably, the Commission intended for ERCOT to consider bridge solutions specifically to address RUC'ing because ERCOT's use of RUC could expedite the retirement of dispatchable resources.

- Commissioner Cobos initiated the discussion of bridge options at the January 12th Open Meeting by noting that RUC'ing is putting pressure on older units and may expedite retirement.[5]
- On January 26th, Commissioner McAdams stated, "It is very important to have [stakeholder] input on how we can begin to withdraw ERCOT out of that command and control posture and let that market start to work again."[6] Commissioner Cobos also discussed how it would be important to see the impact RUC'ing had on various resources during 2021-2022.[7]
- At the RMS meeting on February 27, 2023, Commissioner Cobos clarified, "The focus of the bridge was to, yes, maintain existing generation ,but also to take that physical operational pressure off those units that are being RUC'ed. And the solution would be

[5] Open Meeting, January 12, 2023 at 2:49:35 (*available at:* https://www.adminmonitor.com/tx/puct/open_meeting/20230112/).
[6] Open Meeting, January 26, 2023 at 1:23:57 (*available at:* https://www.adminmonitor.com/tx/puct/open_meeting/20230126/).
[7] *Id.* at 1:24:30

> to help reduce RUC, so that we don't end up with these older plants that end up with an expedited retirement date and a gap in reliability."[8]

Bridging solutions that do not minimize RUCs may actually cause more resources to retire. As the IMM predicts, ERCOT will increase its RUCs in the coming years with additional renewable generation on the system. This may cause older plants to retire more quickly because they cannot sustain the frequent RUC'ing.

ERCOT should move forward with an ancillary service similar to DRRS because ERCOT Staff has indicated that additional ancillary services through a new service similar to DRRS would address RUC'ing and it is not clear the other options would similarly cause ERCOT to reduce its use of RUC. Further, DSSR relies on ERCOT's existing tools, so customers and other stakeholders understand how ancillary services are procured. Customers could easily adapt their business plans, which avoids disrupting the ERCOT market.

Conversely, many of the other bridging solutions like the manual PCM or ORDC changes preempt the Commission and the legislature because the Commission has not set a reliability standard, and the Legislature has not provided any input. Accordingly, any solution that is premised on creating a net-CONE-based tax on consumers is premature. Importantly, ERCOT lacks the policy guidance or explicit authority needed for any options that establish a reserve margin mandate or create a pre-determined revenue stream for generators.

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[8] Reliability and Markets Committee, February 27, 2023 Meeting at 16:54 (*available at:* https://ercot.new.swagit.com/videos/209044).