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PROJECT NO. 54335

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

COMMENTS OF OCTOPUS ENERGY

Octopus Energy, REP License #10262, files these Comments on the report Energy + Environmental Economics (E3) filed in Project No. 52373, *Review of Wholesale Electric Market Design* (hereinafter E3 Report), on November 10, 2022. On November 15, 2022, the Commission requested comments regarding the E3 Report and questions asked by the Commission be filed by noon on December 15, 2022.[1] Accordingly, these comments are timely filed.

INTRODUCTION

Octopus Energy started as a Retail Electric Provider (REP) in ERCOT in 2019 as Evolve Energy. In 2020, Octopus Energy, based in the United Kingdom, purchased Evolve Energy. Octopus Energy's US offices are in Houston, Texas. Globally, Octopus Energy provides retail energy service in the US, UK, Germany, France, Italy, Japan, New Zealand, and Spain. Octopus Energy serves over three million customers across these countries and is significantly expanding its operations in ERCOT. Octopus Energy has projects around the world to increase grid flexibility, leading to lower overall costs and stronger energy markets.

Based on the questions posed in the Request for Comment and public comments made by the Commission Chair in recent legislative hearings, it appears that the Commission is leaning toward adoption of some form of the Performance Credit

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

Mechanism (PCM) discussed in the E3 Report. From Octopus Energy's perspective as a REP unaffiliated with any thermal power generation companies in Texas, the PCM as proposed is unworkable. The PCM would create a level of uncertainty and risk that REPs – at least those unaffiliated with generators – cannot adequately hedge. In responding to the questions put forth by the Commission, Octopus Energy discusses in greater detail these areas of concern.

Additionally, while it would create new subsidies for specific generators in the ERCOT market and increase costs to consumers and businesses who purchase electricity, the PCM would fail to address the most pressing operational issues that ERCOT faces, such as the need for additional fast and flexible ramping resources. For these reasons, as articulated in more detail below, Octopus Energy does not support adoption of the PCM. The existing energy-only market is not fundamentally flawed but could be improved by addressing certain operational risks through the procurement of ancillary services. Nevertheless, if the Commission moves to adopt some form of the PCM, Octopus Energy offers several suggestions to reduce the harm that would be imposed on independent (i.e., unaffiliated with generation) REPs.

COMMENTS ON QUESTIONS POSED BY THE COMMISSION

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

The novelty of the PCM does not, in and of itself, present a significant obstacle. The challenge arises from failing to state with clarity what the problem is that the proposed public policy is intended to solve and to then allow a full vetting of the issues associated with any proposals that are put forth to solve the stated problem. Especially in the case of the PCM, there has been a total lack of analysis from E3 regarding how the PCM would have worked using recent ERCOT data, including examination of which hours would have been the hours for which the proposed credits would have been awarded. Allowing only one round of comments on a new market design concept that no one has seen before, especially given the lack of critical analysis about how the concept would have worked using actual historical data, and then adopting that market design at the scheduled January 12, 2023, Open Meeting, does not provide for adequate public and stakeholder vetting of the proposal.

2. Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?

All of the proposals in the E3 report, including the PCM, would, in theory, create additional subsidy revenues for certain generators to make them less expensive than they would be otherwise, and therefore would distort the existing energy market without clearly providing reliability benefits. This distortion is what E3 relies on to claim that the PCM would cost customers only an additional $460 million rather than its estimated total cost of $5.7 billion.[2] The legislative direction in SB 3 was to ensure that ERCOT procures adequate ancillary or reliability services on a competitive basis to meet extreme hot and cold weather conditions and periods of low non-dispatchable power production.[3] As proposed, the PCM fails to meet the Legislature's directive, as it would establish capacity payments for 30 hours across the year that represent the highest reliability risk hours – those hours with the lowest incremental available operating reserves – which may or may

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2 E3 Report at 60.

3 Utilities Code §39.159(b)(3) (SB 3, §18).

not be during extreme weather or peak net load hours.[4] The highest risk hours would include hours when thermal generation resources have forced outages, which are impossible to predict by market participants not affiliated with the generator. Therefore, the PCM is based on a concept that rewards generators that can be available in those 30 random hours throughout the year. It appears highly unlikely that investors would choose to invest in a new generation resource based on its potential to be rewarded for availability during 30 random hours. While shorter compliance periods could reduce the degree of randomness of the PCM as proposed by E3, those hours still will remain random and exceedingly difficult, if not impossible, to predict. For example, no matter how short the compliance period, no one would have expected significant forced outages of thermal resources on May 13, 2022, which resulted in several hours of that day to be among the hours with lowest operating reserves in ERCOT thus far this year.

3. What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

The Commission has "put the cart before the horse" by developing proposed market design changes and then, after the fact, asking stakeholders what the reliability standard should be. To the extent that the Commission deems a 1-in-10 LOLE standard to be appropriate as a target, then it is notable that the existing market design already meets and exceeds that goal. According to E3: "The results showed that the current system achieves a loss of load expectation (LOLE) of 0.03 days/year, exceeding the

[4] E3 Report at 25. An analysis of the hours in 2022 with the lowest incremental available operating reserves demonstrates that, in the vast majority of instances, there is no necessary correlation to the high peak net load.

common industry benchmark of 0.1 days/year or 'one day in ten years'."[5] Moreover, E3 observes that this reliability is expected to increase over the next few years: "Without further adjustments to the resource mix beyond CDR additions and retirements, the "per-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common benchmark of 0.1 days per year."[6] These statements beg the question as to why the Commission is racing toward adoption of the PCM at its January 12, 2023, Open Meeting.

It may be that the Commission intends to adopt a reliability standard as a basis to justify adoption of a capacity construct to meet that reliability standard. However, whether through the PCM or some other capacity market such as a traditional forward capacity market (FCM) or the load serving entity obligation (LSEO),[7] mandating a capacity market structure is not necessary to address ERCOT's operational issues, nor was it directed by the legislature. The legislative language contemplates adopting adequate ancillary and reliability services to meet extremely tight operating conditions – not a radical redesign of the wholesale market. Further, as the ERCOT independent market monitor has noted on several occasions, the operational issues that ERCOT is facing relate to difficulties in forecasting changes in load, changes in the weather, and forced thermal generation outages.[8] Focusing on these operational issues does not require adoption of a single reliability standard such as 1-in-10 LOLE, nor would adopting a single reliability standard

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5 E3 Report at 126.

6 E3 Report at 46.

7 Octopus Energy previously filed comments on November 1,2021, expressing its concerns about the LSEO in Project No. 52373, *Review of Wholesale Electric Market Design.* (See Item 233.)

8 *See* Potomac Economics, 2021 State of the Market Report for the ERCOT Electricity Markets (May 2022) at 3 (available at https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf).

drive towards a solution to these issues. Moreover, a focus on a reliability standard, and the resulting reserve margin it would indicate ERCOT should achieve, ignores the fact that meeting a reserve margin does not equate to system reliability. For example, prior to Winter Storm Uri, ERCOT forecast that it had a reserve margin of 16.2%. Instead, it suffered a reserve margin of -21.1% on February 15, 2021.[9] The solutions to ERCOT's problems should focus on ensuring that ERCOT has the operational tools it needs to improve intraday flexibility with more services provided by fast ramping, flexible resources which could come from either the supply side or the demand side.

4. The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?

The choice of 30 hours is random and lacks policy justification. The reliance on payments to generators during these potential high-risk hours – in whatever quantity, 30 hours or otherwise – is a fundamental flaw of the PCM. As proposed, ERCOT would predict "X" potential hours one year in advance and estimate the expected load to be served during those hours to develop the pricing curve, and then after the operational year, the market would learn when the PCM hours actually happened and how much load actually needed to be served during those hours. This mechanism takes a capacity market construct – which does not address the problem at hand – and then adds a "crap shoot" element to it, by requiring both generators and REPs to guess when the 30 hours might occur. As noted previously, the market would be better served by focusing on reducing the uncertainty risks that ERCOT faces by improving intraday flexibility with

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

more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side.

5. Over what period should the hours of highest reliability risk be determined? A year, a season, a month, or some other interval? At what point in time should that determination be made?

This question, like others in this Request for Comments, presupposes that the Commission will adopt the PCM. While Octopus Energy does not support the PCM, if the Commission adopts it, then the PCM interval should be changed from annual to daily, with a clear articulation of what will be the precipitating factor(s) to determine the hour during which credits will be awarded to generation resources. While the Commission could choose to focus on the hour with the lowest operating reserves, based on an analysis of the hours in 2022 with the lowest incremental available operating reserves, this hour often is highly correlated to thermal generator outages. This correlation affords an entity with a large fleet of dispatchable generation resources the ability to cause a specific hour to have the lowest operating reserves and harvest credits on demand to the detriment of its competitors and the market as a whole. If the Commission wants to target when dispatchable generators are most needed to serve load on any day, that would be the hour of highest peak net load[10] – the hour when the most dispatchable generation resources are required to serve demand on the grid. This hour will occur every day regardless of potential intervention by any generation resource.

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10 In its report, E3 defines "Peak Net Load" as "The maximum total electricity demand in a system during a specified time period (usually a year), net of wind, solar, and storage generation." E3's inclusion of storage generation in this definition should be rejected since storage generation is inherently dispatchable with an "On/Off" switch – a concept that the Commission has indicated is key to its perception of what is "dispatchable" generation.

The proposed annual interval creates an insurmountable challenge for a REP (and by extension, its customers) to discern when it would need to take action to reduce consumption to avoid the assignment of PCM costs. As noted previously, many of the hours of highest risk will be those hours when thermal generators break down and must take unplanned outages, and those times cannot be predicted as they may happen during any hour of the year, unrelated to extreme weather or peak net load. As a practical matter, this means that a REP will be asking customers to reduce consumption at times that will make no intuitive sense to the customer. Additionally, it would be the following year/month/week/etc. when the REP would know whether the requested load reductions coincided with the actual 30 hours of highest risk. It would be almost impossible for the REP to properly charge or credit customers for their consumption behavior related to those 30 hours based on retroactive settlements. This lack of proper alignment of incentives to induce customer behavior with the times when it is most beneficial to the grid is a major flaw to the PCM market design and creates significant new barriers to demand response and other distributed energy resources (DERs). A daily implementation of the PCM at least would reduce the adverse impacts of this timing disconnect and afford better alignment of behavioral incentives and compensation for customers.

In a daily implementation of the PCM, the Commission could administratively predetermine a value of the PCs at the beginning of the year, which would provide transparency and certainty for the value of the credits. For example, the Commission could determine the gross value of compensation it wants to distribute through this methodology and divide by 365 to determine the daily compensation to be made available. Then, credits could be awarded to generators who perform that day (by providing energy or ancillary services) during the designated hour of concern for the operating day. This also would make it more possible for REPs to have the ability to buy adequate credits to meet their obligations during those hours, manage their load to reduce their exposure to the cost of credits during those hours, and even incorporate the expected cost of credits into retail pricing to which would allow the REP to continue to offer fixed price contracts to customers.

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

As noted above, a fatal flaw with the PCM as proposed in the E3 report is the timing disconnect between when credits are awarded, when generators and REPs find out the hours for which credits were awarded, and charging customers for costs incurred by their consumption during those hours. If the Commission were to implement a daily PCM, rather than following an annual approach, then the PCM could be included in the day ahead and real time markets like other services in ERCOT.

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

As proposed, the annual PCM severely disadvantages REPs who are unaffiliated with generation. Simply using a centrally cleared market does not mitigate the potential for market abuse. When an affiliated REP buys from its affiliated generator, that is essentially just moving money "from one pocket to another pocket," but unaffiliated REPs would have to buy PCs from a handful of generators with oligopoly power. As with monopolies, oligopolies are characterized as having the ability to strongly influence prices. Similarly, those handful of generators have affiliated REPs that wield oligopsony power, i.e., they are a handful of major buyers in the market that control the purchasing of PCs. It's not difficult to imagine a situation where an oligopoly generator may be able to share information with its affiliate REP so that the REP is better able to respond through customer demand response measures to meet some of the 30 hours of highest risk, and then the REP can resell its excess PCs to an unaffiliated REP for a profit, meaning that the PC is sold twice by the same family of companies. Moving to a daily market would also reduce these risks, especially if the price for each credit to be earned is known ahead of time through a set price established by ERCOT administratively.

8. If the commission adopts a market design with a multi-year implementation timeline, is there a need for a short-term "bridge" product or service, like the Backstop Reliability Service (BRS), to maintain system reliability equivalent to a 1-in-10 LOLE or another reliability standard? If so, what product or service should be considered?

As noted previously, Octopus Energy does not support adopting a market design that will require a multi-year implementation, as it is unnecessary, would distort the existing energy-only market, and is inconsistent with legislative direction in SB3, which called for ensuring adequate ancillary and reliability services. Adopting the PCM would not solve the actual reliability problems faced by ERCOT right now, regardless of whether it produces new subsidy revenues to specific generators. Texans would be better served if the Commission were to focus its efforts on reducing the intraday uncertainty risks that ERCOT faces by improving operational flexibility with more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side.

See also our response to Question No. 12.

9. If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution

that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?

The operational issues that ERCOT is facing primarily relate to difficulties in forecasting changes in load, forecasting changes in the weather, and forced thermal generation outages. Addressing these reliability issues does not require adoption of a new wholesale market design, nor would adopting a new wholesale market design solve these problems. What the market requires for reliability is to have more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side through services such as ECRS. Procurement of additional fast ramping reserves is not only an immediate bridge solution, but it is also the best long-term solution. Nevertheless, if the Commission chooses to implement the PCM, focusing on having ERCOT procure more fast-ramping ancillary services would also be the best bridge solution. The Commission has already taken several actions to enhance reliability through weatherization and modifications to wholesale market design, such as changing the energy offer caps, and modifying the ORDC. More time should be allowed to evaluate the market impacts and costs of these Phase 1 measures before embarking on a costly, multi-year implementation that does not address the actual problems at hand.

See also our response to Question No. 12.

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

The PCM is intended to increase revenues to generators, so by design will result in higher consumer costs. E3 estimates that the net increased cost to consumers will be less than $500 million annually, but this assumes that wholesale energy prices will be reduced by more than $5 billion.[11] It is unlikely that this assumption would turn out to be correct, though, given the unpredictable nature of the PCM as proposed. Regardless, as noted previously, the PCM does nothing to address current operational reliability shortcomings in the market today. According to the E3 Report, a subset of Commissioners would prefer to discriminate among technologies by awarding PCs only to non-renewable generators. As is well-established, and as E3 itself acknowledged, renewables currently deliver substantial savings to customers in the ERCOT market.[12] The PCM is guaranteed to increase revenues to specific generators, which means it will increase costs to customers while ensuring neither new generation nor reliable operations in ERCOT. E3 acknowledges this cost increase in their report:

> One such [discriminatory] implementation of interest to a subset of PUCT Commissioners would exclude the participation of wind and solar resources. In the short-run, implementing such a policy would decrease system costs by the quantity of reliability credit payments that would have gone to wind and solar resources. However, **in the long-run, this reduction in compensation could result in smaller wind and solar buildout (relative to the counterfactual), which would have the effect of increasing energy prices.**
> [emphasis added][13]

Octopus Energy opposes the government picking technology winners and losers, as free markets are best at determining competitive outcomes. Texans benefit from the savings that solar and wind bring to the system, and it would be unfortunate if the Commission were to make a policy choice to prefer a specific technology at the expense of customers who have to pay the bill for that choice.

11. What is the fastest and most efficient manner to build a "bridge" product or service, such as the BRS, in order to start sending market signals for

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11 E3 Report at 60.

12 E3 Report at 67-68.

13 E3 Report at 74.

investment in new and dispatchable generation, while a multi-year market design is implemented by ERCOT? Please provide specific steps.

See our responses to Questions No. 9 and 12.

12. In what ways could the Dispatchable Energy Credit design be modified through quantity and resource eligibility requirements, e.g., new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

Although Octopus Energy disagrees that a change in wholesale market design is warranted by either SB 3 or the actual operational issues that ERCOT is facing, the DEC proposal as initially proposed by Commissioner McAdams[14] – not as outlined in the E3 report – would be our preferred market design "add-on" should the Commission determine that procuring ancillary services is not enough. Because the DEC design (as it was initially proposed) would be structured on a well-known construct akin to the long-standing renewable portfolio standard, it would be simple and fast to implement. The DEC market would reward whichever resources are included in the definition of "dispatchable," so this market can be easily designed to incentivize exactly the resources needed. If opened to include all new dispatchable generation resources, the DEC could incent new technology such as small modular nuclear reactors. As discussed throughout these comments, the PCM – and the DEC program as it has morphed into a 48-hour capability, which can be met only by thermal generation resources – does not address the operational issues that the market is actually facing. What the market requires for reliability is to have more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side, and the DEC market could be designed to reward these kinds of resources. Adding a DEC market to the existing energy-only market would be the

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[14] Commissioner McAdams Memorandum filed on Nov. 17, 2021, in Project No. 52373, *Review of Wholesale Electric Market Design,* Item No. 250.

least disruptive mechanism after Octopus Energy's preferred solution, which is to address operational concerns through ancillary services.

To the extent that the Commission were to determine an additional "bridge" solution would be needed above and beyond DECs to explicitly retain existing dispatchable generation that would otherwise retire due to unfavorable economics, then Octopus Energy would recommend implementing the backstop reliability service (BRS) – as initially proposed by Commissioner Cobos,[15] not as described in the E3 report – to increase revenues to certain generators that would otherwise retire their old and inefficient plants. As proposed initially, the BRS was intended more as an "insurance policy" to retain generation for reliability, and would have imposed firm fuel and winterization requirements, and seasonal certification testing. In contrast, the E3 report ignores the need for firm fuel and would treat BRS as a forward capacity market construct to meet a 1-in-10 LOLE standard.

CONCLUSION

Octopus Energy appreciates the opportunity to provide these Comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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15 Commissioner Cobos Memorandum filed on November 18, 2021, in Project No. 52373. (Item 253).

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COMMENTS OF OCTOPUS ENERGY

EXECUTIVE SUMMARY

- From Octopus Energy's perspective as a REP unaffiliated with any thermal power generation companies in Texas, the PCM as proposed is unworkable. The PCM would create a level of uncertainty and risk that REPs – at least those unaffiliated with generators – cannot adequately hedge.
- Octopus Energy does not support adoption of the PCM. While it would create new subsidies for specific generators in the ERCOT market and increase costs to consumers and businesses who purchase electricity, the PCM would fail to address the most pressing operational issues that ERCOT faces, such as the need for additional fast and flexible ramping resources.
- The existing energy-only market is not fundamentally flawed but could be improved by addressing certain operational risks through the procurement of ancillary services.

Summary of responses to specific questions:

1. The key issue is not novelty, but rather not being clear about the problem to be solved, and a lack of analysis from E3 regarding how the PCM would have worked using recent ERCOT data, including examination of which hours would have been the hours for which the proposed credits would have been awarded.
2. As proposed, the PCM fails to meet the Legislature's directive, as it would establish capacity payments for 30 hours across the year that represent the highest reliability risk hours, including hours when thermal generation resources have forced outages, which are impossible to predict by market participants not affiliated with the generator. It appears highly unlikely that investors would choose to invest in a new generation resource based on its potential to be rewarded for availability during 30 random hours.
3. The operational issues that ERCOT is facing relate to difficulties in forecasting changes in load, changes in the weather, and forced thermal generation outages. Focusing on these operational issues does not require adoption of a single reliability standard such as 1-in-10 LOLE, nor would adopting a single reliability standard drive towards a solution to these issues.

4. The choice of 30 hours is random and lacks policy justification. The reliance on payments to generators during these potential high-risk hours – in whatever quantity, 30 hours or otherwise – is a fundamental flaw of the PCM. The market would be better served by focusing on reducing the uncertainty risks that ERCOT faces by improving intraday flexibility with more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side.
5. Octopus Energy does not support the PCM, but if adopted, the PCM interval should be changed from annual to daily. With a daily implementation, the Commission could determine the gross value of compensation it wants to distribute annually through this methodology and divide by 365 to determine the daily compensation to be made available. Then, credits could be awarded to generators who perform that day (by providing energy or ancillary services) during the designated hour of concern for the operating day. This also would make it more possible for REPs to have the ability to buy adequate credits to meet their obligations during those hours, manage their load to reduce their exposure to the cost of credits during those hours, and incorporate the expected cost of credits into retail pricing, which would allow the REP to continue to offer fixed price contracts to customers.
6. A fatal flaw with the PCM as proposed in the E3 report is the timing disconnect between when credits are awarded, when generators and REPs find out the hours for which credits were awarded, and when customers are charged for costs incurred by their consumption during those hours. If the Commission were to implement a daily PCM instead, the PCM could be included in the day ahead and real time markets like other services in ERCOT.
7. An annual PCM would severely disadvantage REPs who are unaffiliated with generators (who, in turn, would wield oligopoly power), but moving to a daily PCM would reduce these risks.
8. Octopus Energy does not support adopting a market design that will require a multi-year implementation, as it is unnecessary, would distort the existing energy-only market, and is inconsistent with legislative direction in SB3, which called for ensuring adequate ancillary and reliability services.
9. What the market requires for reliability is to have more services provided by fast ramping, flexible resources, which could come from either the supply side or the demand side through services such as ECRS. Procurement of additional fast ramping reserves is not only an immediate bridge solution, but it is also the best long-term solution.
10. The PCM is intended to increase revenues to generators, so by design will result in higher consumer costs, while failing to address the operational issues in ERCOT that exist today. Regarding the intent of a subset of Commissioners to disallow all technologies from earning credits under PCM, Octopus Energy opposes the government picking technology winners and losers, as free markets are best at

determining competitive outcomes. Texans benefit from the savings that solar and wind bring to the system, and it would be unfortunate if the Commission were to make a policy choice to prefer a specific technology at the expense of customers who have to pay the bill for that choice.

11. See Questions 9 and 12.
12. Although Octopus Energy disagrees that wholesale market design changes are warranted, the DEC proposal as initially proposed by Commissioner McAdams would be our preferred market design “add-on” should the Commission determine that procuring ancillary services is not enough. The DEC market would reward whichever resources are included in the definition of “dispatchable,” so this market can be easily designed to incentivize exactly the resources needed, and would be least disruptive to the current market design. BRS as originally proposed by Commissioner Cobos could be included as a bridge solution to retain existing dispatchable generation in the interim.