Filing Receipt

Filing Date - 2024-06-05 12:41:38 PM

Control Number - 56693

Item Number - 14

DOCKET NO. 56693

APPLICATION OF ENTERGY TEXAS,	§	
INC. TO AMEND ITS CERTIFICATE	§	PUBLIC UTILITY COMMISSION
OF CONVENIENCE AND NECESSITY	§	
TO CONSTRUCT A PORTFOLIO OF	§	OF TEXAS
DISPATCHABLE GENERATION	§	
RESOURCES	§	

DIRECT TESTIMONY

OF

NICHOLAS W. OWENS

ON BEHALF OF

ENTERGY TEXAS, INC.

JUNE 2024

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF NICHOLAS W. OWENS
DOCKET NO. 56693

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Nicholas W. Owens. My business address is 30 Monument Square, Suite 105, Concord, Massachusetts 01742. I am a Partner at The NorthBridge Group ("NorthBridge").

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am submitting this Direct Testimony to the Public Utility Commission of Texas ("Commission") on behalf of Entergy Texas, Inc. ("ETI" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Colby College in 2004 with a B.A. in economics and government. I spent two years as an Analyst with FTI Consulting before joining NorthBridge in 2007. I became a Partner at NorthBridge in 2019. NorthBridge is an economic and strategic consulting firm serving the electricity and natural gas sectors. My practice includes generation planning and operations within regional transmission organization markets.

Q4. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. I provided testimony to the Public Utility Commission of Texas in Docket

No. 52487,[1] the Arkansas Public Service Commission in Docket No. 20-049-U, the Louisiana Public Service Commission in Docket Nos. U-32148 and U-33592, and the City Council of New Orleans in Docket No. UD-11-01.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Company in support of its application seeking an amendment to its certificate of convenience and necessity ("CCN") to construct, own, and operate the Legend Power Station ("Legend"), a proposed combined-cycle combustion turbine ("CCCT") facility to be built in Jefferson County, Texas, and the Lone Star Power Station[2] ("Lone Star"), a proposed combustion turbine ("CT") facility to be built in Liberty County, Texas (collectively, the "Dispatchable Portfolio"). Specifically, my testimony: 1) explains why it was reasonable for ETI to value the resources within the Dispatchable Portfolio by comparing their costs to the costs of alternative sources of physical capacity rather than a projection of the cost to purchase capacity credits in the Midcontinent Independent System Operator, Inc. ("MISO") Planning Resource Auction ("PRA"); 2) describes certain changes to the PRA and how ETI has accounted for those changes to estimate its need for capacity; and 3) addresses the possibility of a future transition to retail competition in ETI's service area and explains why that possibility should not prevent the Commission from approving ETI's application.

[1] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Power Station,* PUCT Docket No. 52487, Order on Rehearing, (Jan 12, 2023).

[2] Lone Star Power Station is also referred to in some materials as Western CT, which was the name of the resource utilized during the planning phase.

Q6. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. First, ETI has reasonably chosen to value the Dispatchable Portfolio by comparing the cost to serve customers using that portfolio to the cost to serve customers using a portfolio that includes an alternative source of physical capacity. This valuation approach makes sense because if ETI was not planning to construct the Dispatchable Portfolio, it would be planning to procure alternative sources of physical capacity through ownership or long-term bilateral contracts. In contrast, it would not make sense to compare the cost of the Dispatchable Portfolio to a projection of the cost to purchase capacity credits in the PRA because PRA purchases do not represent an alternative to the Dispatchable Portfolio. Further, such a comparison would not make sense because PRA purchases are not comparable to physical capacity; in particular, unlike physical capacity, PRA purchases do not contribute to local reliability or hedge exposure to wholesale spot prices for energy and capacity.

Second, MISO has recently restructured the PRA to establish seasonal delivery periods and an availability-based system of accrediting capacity. ETI has accounted for these changes when estimating its future capacity needs by using an approach that makes use of the new seasonal reserve margins published by MISO and the new MISO accreditation system. This approach establishes an estimated need for capacity that is demonstrably reasonable and that exceeds the amount of capacity provided by the Dispatchable Portfolio.

Third, the possibility of a future transition to retail competition in ETI's service area should not prevent the Commission from approving ETI's application.

In 2009, the Texas Legislature amended the Public Utility Regulatory Act ("PURA")[3] to include a provision directing ETI to cease all activities related to the transition to retail competition while simultaneously granting the Commission authority to initiate proceedings to implement an eventual transition. Since 2009, the Commission has not initiated any such proceedings, and I am not aware of any plans to do so. While there remains a possibility of a future transition to retail competition in ETI's service area, the amendment of ETI's CCN to include the Dispatchable Portfolio should not affect the process or plan to transition to competition in any meaningful way and certainly would not affect it in any way that is sufficient to outweigh ETI's pressing need for the additional capacity that the Dispatchable Portfolio would provide.

II. CAPACITY ALTERNATIVES AND ETI'S VALUATION APPROACH

Q7. HOW DID ETI VALUE THE DISPATCHABLE PORTFOLIO?

A. ETI valued the Dispatchable Portfolio by estimating its costs to serve customers using the Dispatchable Portfolio and comparing that to an estimate of its costs to serve customers using a portfolio that includes an alternative source of physical capacity. Notably, ETI did not value the Dispatchable Portfolio by comparison to a portfolio that relies on PRA purchases instead of physical capacity. This makes sense because if ETI was not planning to construct the Dispatchable Portfolio, it would be planning to procure alternative sources of physical capacity through ownership or long-term bilateral contracts, not planning to purchase additional capacity credits in the PRA.

[3] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016.

Q8. WHAT IS THE PRA?

A. As described in more detail below, the PRA is a capacity auction that is administered by MISO. Demand in the auction is determined by MISO and represents the amount needed to achieve "resource adequacy" in the upcoming delivery year. This amount is determined through statistical simulations that account for uncertainty in generator availability (due to outages or derates) and demand (due to weather and other factors) and is calculated such that there is a 10% probability that firm demand will need to be curtailed in the upcoming year. A 10% chance of having to curtail firm demand in each year translates to an expectation that curtailment will occur once every ten years. This "1-in-10" standard is commonly used to quantify the amount of capacity that would be adequate to serve customer needs.

Supply in the auction is represented by offers from generators to provide capacity, which entails an obligation to submit an offer in the energy market on each day of the delivery period that the generator is not on an outage. MISO has detailed protocols to "accredit" generators – *i.e.*, to quantify the amount of capacity that each generator may provide based on the size of the generator and its historical availability.

The auction "clears" at the price at which there is enough supply to meet demand. Generators that clear are paid the clearing price and Load Serving Entities ("LSEs") are charged the clearing price for their proportional share of the total cleared amount. An LSE is considered to be "short" and to "purchase" capacity in the PRA when the megawatt ("MW") amount it is charged for (its proportional share of cleared demand) exceeds the MW amount it is paid for (its cleared supply).

Q9. WHEN ETI CONDUCTS LONG-TERM RESOURCE PLANNING, DOES ETI PLAN TO PURCHASE CAPACITY CREDITS IN THE PRA?

A. No. When ETI conducts long-term resource planning, ETI plans enough capacity to meet its share of the amount necessary for resource adequacy using owned and contracted resources and therefore does not plan on a long-term basis to be "short" in the PRA. However, ETI does use the PRA to purchase or sell capacity credits to address near-term imbalances that arise for various reasons, such as unanticipated load growth or changes in unit ratings.

Q10. IS ETI'S APPROACH IN PLANNING ENOUGH CAPACITY TO MEET ITS NEEDS, RATHER THAN PLANNING TO RELY ON THE PRA, REASONABLE?

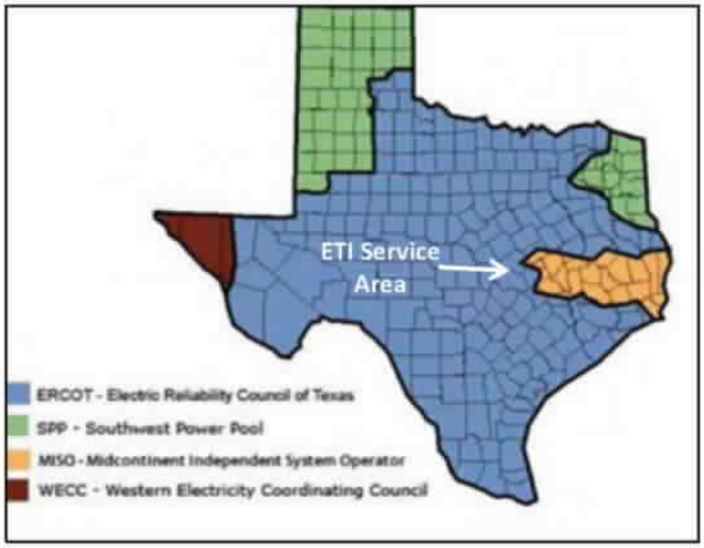
A. Yes, ETI's approach to planning is reasonable and consistent with the interests of its customers for several reasons.

First, there is a cost associated with purchasing capacity credits in the PRA. In the past, this cost has been low because PRA prices have been low. However, as discussed further below, MISO has proposed reforms to the PRA that will increase prices. With these reforms, the capacity market will be designed to yield prices that, on average over time, provide an attractive return on investment in new capacity when the market has just enough capacity to meet the 1-in-10 reliability target (*i.e.*, when the market is in equilibrium). Such equilibrium prices are much higher than have been observed historically and will continue to be volatile. Thus, if ETI were planning to rely on the PRA, it would be exposed to capacity prices that are expected to be much higher than they have been, to reflect the cost of a new resource on average over time, and to be volatile.

Second, PRA purchases do not provide the local reliability benefit of actual, physical generation. This is particularly important because ETI's service territory is located entirely within the West-of-the-Atchafalaya ("WOTAB") load pocket, which is not supported by electricity flows from the west because of the asynchronous border with Electric Reliability Council of Texas ("ERCOT") or from the south because of the Gulf of Mexico. ETI relies on local generation and a finite amount of transmission from the east to serve its customers, as shown in Figure 1. In the recent past, during Hurricane Laura (2020) and Winter Storm Uri (2021), ETI was forced to curtail firm service to its customers because the amount of available transmission and local generation serving the area was insufficient to serve customer demand in the area. And during the summer of 2023, ETI's Western Region, which is a more acutely stressed load pocket within the WOTAB load pocket, operated in an Entergy Load Risk Alert Level ("ELRAL") 1 condition for three months and an ELRAL 2 condition for four days, indicating an elevated risk of curtailment as described by ETI witness Daniel Kline. These recent instances in which load was curtailed or at elevated risk of curtailment demonstrate the real and meaningful local reliability benefit of having actual physical generation. If ETI were planning to rely on the PRA, it would not obtain the local reliability benefit of new physical capacity, which is particularly important because of the location of ETI's service area within a load pocket.

Figure 1

ETI Relies on Local Generation and Finite Transmission Capacity from the East



Third, unlike physical capacity, PRA purchases do not convey a right to obtain energy at the cost of production. ETI purchases 100% of its energy needs at the Locational Marginal Price ("LMP"), but the cost of these purchases is offset by revenue derived from the sale of owned and contracted generation at LMP. In this way, owned and contracted generation "hedges" the cost of purchasing energy at LMPs, which are volatile. If ETI were planning to rely on the PRA, it would not be offsetting or hedging its exposure to the volatile cost of purchasing energy at LMPs.

Q11. GIVEN THE NATURE OF ETI'S NEEDS TO SERVE ITS CUSTOMERS, ARE PRA PURCHASES A VIABLE ALTERNATIVE TO THE DISPATCHABLE PORTFOLIO?

A. No. As addressed in further detail by ETI witness Daniel Kline, ETI must address specific and pressing locational needs within its service area. The resources included in the Dispatchable Portfolio would contribute to addressing these needs. In contrast, PRA purchases would not address these needs and are thus non-viable alternatives to the Dispatchable Portfolio.

Q12. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE REASONABLENESS OF ETI'S VALUATION APPROACH.

A. In summary, ETI's valuation approach is reasonable because it compares the Dispatchable Portfolio to physical alternatives that it would otherwise consider given its prudent approach to planning enough capacity to meet its needs with physical resources, rather than planning to rely on PRA purchases. ETI's approach to planning physical capacity, rather than planning to rely on PRA purchases, is reasonable in general and the only viable alternative for ETI at this time because of its pressing need for new capacity in specific locations within its service area.

Q13. HAS THIS ISSUE BEEN ADDRESSED BEFORE?

A. Yes, this issue was disputed in a recent proceeding to address an application by ETI for certification of a different dispatchable generator, the Orange County Advanced Power Station ("OCAPS"). In their proposal for decision in that docket, the Administrative Law Judges found that it was reasonable for ETI to value OCAPS by comparison to a physical alternative and that the evidence "conclusively" showed that the PRA is not a long-term planning solution.[4]

III. CHANGES TO THE PRA AND ETI'S APPROACH TO ESTIMATING ITS NEED FOR CAPACITY

Q14. PLEASE DESCRIBE HOW THE PRA HAS BEEN RESTRUCTURED TO INCORPORATE SEASONAL DELIVERY PERIODS AND AVAILABILITY-BASED ACCREDITATION.

A. First, beginning with the capacity auction that took place in early 2023, the PRA changed from having one annual delivery period to having four separate seasonal delivery periods. Demand in the auction is now set for each seasonal delivery period by applying a seasonal reserve margin to the seasonal coincident peak load forecast for the upcoming year. The reserve margins are recalculated each year by MISO. For the auction that took place in early 2023, the seasonal reserve margins were 7.4%, 14.9%, 25.5%, and 24.5% in summer, fall, winter, and spring, respectively. Second, to coincide with the transition from one annual delivery period to four seasonal delivery periods, the accreditation system changed from one in which generators were given annual ratings based on their historical forced outage rates throughout the year (Annual Unforced Capacity, or "UCAP") to one in which generators are given

[4] "The ALJs find that it was reasonable for ETI to value OCAPS by comparing its cost to an alternative long-term source of physical capacity, *i.e.*, the levelized cost of CTs. The evidence conclusively shows that PRAs are not a long-term planning solution… Because the PRA is only a short-term solution to meet resource adequacy requirements, it is not an equivalent alternative to the capacity provided by a long-term resource, in the early years or otherwise. Therefore, PRA prices are not an appropriate proxy for the value of OCAPS' capacity." Proposal for Decision at 133-134, PUCT Docket No. 52487 (Sep. 26, 2022). This portion of the Proposal for Decision was adopted by the Commission without modification. Order on Rehearing, PUCT Docket No. 52487 (Jan. 12, 2023).

seasonal ratings based on their historical availability during the relevant season (Seasonal Availability Capacity, or "SAC"). These changes are summarized in Figure 2 below.

Figure 2

Recent Changes to the PRA

	Prior to 2023 Auction	Current
Demand	Annual Coincident Peak x Annual Reserve Margin	Seasonal Coincident Peak x Seasonal Reserve Margin
Supply	Annual UCAP	Seasonal SAC

Q15. DOES ETI'S APPROACH TO ESTIMATING ITS NEED FOR CAPACITY ACCOUNT FOR THESE CHANGES TO THE PRA?

A. Yes. ETI has accounted for these changes when estimating its future capacity needs by using an approach that makes use of the new seasonal reserve margins published by MISO and the new MISO accreditation system. Specifically, ETI estimated its gross need for capacity in each season by multiplying its seasonal coincident peak load forecasts by the seasonal reserve margins. Then, to estimate its unmet need for capacity in each season, ETI subtracted its existing and approved capacity – rated in Seasonal SAC – from its gross need. This unmet need represents the amount of additional capacity that ETI must add to meet its proportional share of the amount MISO has determined is necessary to maintain resource adequacy, which is an LSE responsibility.[5] By planning to address this unmet need, ETI is not only fulfilling its responsibility as an LSE, but also mitigating its exposure to PRA prices.

Q16. ARE ETI'S ESTIMATES OF ITS UNMET NEED FOR CAPACITY REASONABLE?

A. Yes. Using this new approach, ETI estimated an unmet need for capacity in 2028 of 1,485 MW in the summer and 1,635 MW in the winter. These estimates are reasonable by comparison to an estimate of ETI's unmet need using a former approach that the Commission and Administrative Law Judges found reasonable in the OCAPS proceeding.[6] That former approach, which applies a 12.69% annual reserve margin to the annual peak load and then subtracts the annual UCAP ratings of ETI's existing and planned capacity, results in an unmet need in 2028 of 1,662 MW. As seen in Figure 3 below, whether using ETI's new approach or its former approach, ETI has a clear need for capacity that exceeds the amount of capacity provided by the Dispatchable Portfolio.[7]

---

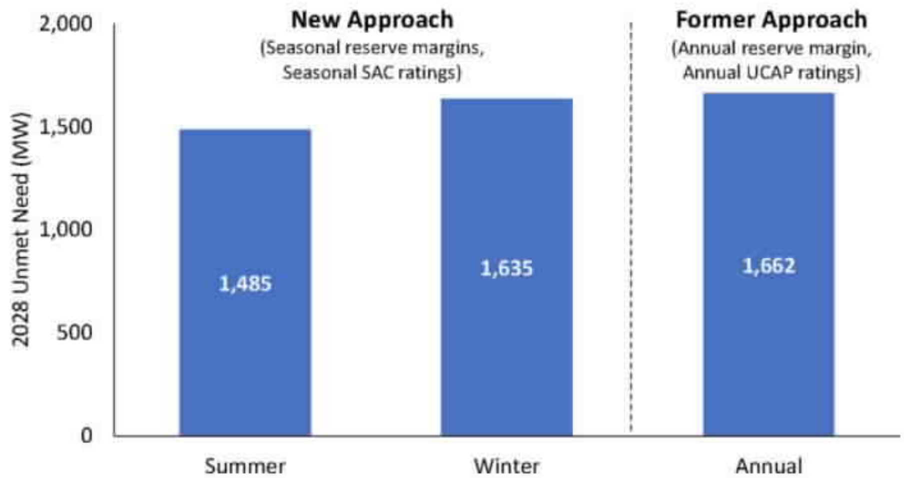
[5] "In the MISO Region, the responsibility for achieving Resource Adequacy rests primarily with Load Serving Entities ("LSEs") overseen by states and Relevant Retail Electric Regulatory Authorities ("RERRAs")." MISO Transmittal Letter for Reliability Based Demand Curve Filing at 2, FERC Docket No. ER23-2977 (filed Sep. 29, 2023).

[6] "Finally, the ALJs find ETI's reserve margin reasonable. ETI's four-year planning horizon reasonably accounts for long-term uncertainty by accounting for the approximate time to bring a new resource to operation." Proposal for Decision at 34, PUCT Docket No. 52487 (Sep. 26, 2022). "Entergy's long-term planning reserve margin of 12.69% appropriately and reasonably reflects the amount of capacity that must be planned, during the approximately four years required to plan, develop, and construct new capacity, to ensure that firm load would be curtailed only once every ten years." Order on Rehearing at Finding of Fact 76, PUCT Docket No. 52487 (Jan. 12, 2023).

[7] The estimated Seasonal SAC ratings of the Dispatchable Portfolio are 1,079 and 1,124 MW for summer and winter, respectively. The estimated Annual UCAP rating of the Dispatchable Portfolio is 1,068 MW.

Figure 3

Comparison of Approaches to Estimating Unmet Capacity Needs



Q17. DOES MISO PLAN TO IMPLEMENT FURTHER CHANGES TO THE PRA?

A. Yes. As discussed above, MISO has recently implemented changes to the PRA to establish seasonal delivery periods, seasonal capacity requirements, and an availability-based system for seasonal capacity accreditation. MISO plans to implement several further changes, including the use of sloped demand curves at the regional and subregional level, further restructuring of the availability-based accreditation system, and the use of a new method to allocate the aggregate capacity requirement among individual LSEs. ETI is evaluating its long-term planning reserve margin targets in light of these changes. None of these changes – to the MISO PRA or to ETI's long-term planning reserve margin – would obviate the need for the Dispatchable Portfolio, which is clearly necessary to address ETI's very substantial need for additional capacity, including its need for additional capacity within specific locations of its service area.

Q18. PLEASE DESCRIBE MISO'S PLAN TO USE SLOPED DEMAND CURVES AT THE REGIONAL LEVEL.

A. MISO has proposed to change the representation of demand in the PRA.[8] Beginning in 2025, MISO will no longer represent demand as a fixed requirement ("vertical demand curve") and will instead begin representing demand using a variable requirement ("sloped demand curve") that is intended to represent the marginal value of reliability.

In the past with the vertical demand curve, prices were either very low during periods of surplus or set at the price cap during periods of scarcity.[9] This means that the average price over time would be less than the cost of a new resource, even if the market had just enough capacity to meet the 1-in-10 reliability target over time.[10] Going forward with sloped seasonal demand curves, surpluses will yield prices that are higher than they would be with a vertical demand curve and deficits will yield prices that approach or reach the cap.[11] Unlike the vertical demand curves, the sloped demand curves are designed to yield prices that, on average over time, provide an attractive return on investment in new capacity when the market has just enough

---

[8] MISO's Reliability-Based Demand Curve, FERC Docket No. ER23-2977 (filed Sep. 29, 2023).

[9] "MISO's historical application of a vertical demand curve in the PRA has contributed to low auction clearing prices as a result of setting the Auction Clearing Price close to zero when the market has even a small surplus of capacity and inversely setting an artificially high Auction Clearing Price at or near the Cost of New Entry ("CONE") if there is any shortfall of capacity." MISO Transmittal Letter for Reliability Based Demand Curve Filing at 3, FERC Docket No. ER23-2977 (filed Sep. 29, 2023).

[10] This is so because the price cap was set at the levelized cost of a new resource. If there was enough capacity to meet the 1-in-10 reliability target over time, then prices would oscillate between the cost of a new resource (during periods with scarcity) and approximately zero (during periods with surplus) and thus average less than the cost of a new resource over time.

[11] The price cap in each season is now equal to the annual levelized cost of a new resource. This means it is now possible for the sum of prices across the seasons to exceed – indeed, to be a multiple of – the annual levelized cost of a new resource.

capacity to meet the 1-in-10 reliability target.[12] Such prices are much higher than have been observed historically and will continue to be volatile.

Q19. PLEASE DESCRIBE MISO'S PLAN TO USE SLOPED DEMAND CURVES AT THE SUBREGIONAL LEVEL.

A. MISO's plan to use sloped demand curves beginning in 2025 includes the use of subregional sloped demand curves for MISO South and MISO North that reflect the additional reliability value of capacity in a subregion due to import limits into the subregion. While MISO has effectively used vertical subregional demand curves in past auctions that are conceptually similar to the subregional demand curves that MISO will use going forward, the way in which the subregional demand curves are calculated is meaningfully different and is expected to increase the amount of capacity that MISO deems necessary to achieve the 1-in-10 reliability target within a subregion.[13]

---

[12] "The key features of a Net CONE-based demand curve are a sloping shape that is drawn with an "anchor point" at the 0.1 [loss of load expectation] reliability target and Net CONE. The underlying concept is to set up a design with [reliability based demand curves] that, over time, allow prices in a long-run equilibrium state to reach Net CONE." MISO Transmittal Letter for Reliability Based Demand Curve Filing at 15, FERC Docket No. ER23-2977 (filed Sep. 29, 2023).

[13] In the past, MISO effectively established vertical subregional demand curves that were equal to a proportional share of the overall MISO target, which was determined using statistical simulations of load and generation throughout MISO and without any consideration of the subregional import limits. Going forward, MISO will establish sloped subregional demand curves using statistical simulations that incorporate the subregional import limits. The inclusion of these constraints, which have not previously been modeled in the statistical simulations, is expected to increase the amount of capacity MISO deems necessary to achieve the 1-in-10 reliability target within a subregion.

Q20. PLEASE SUMMARIZE THE EXPECTED IMPACT OF MISO'S PLAN TO USE SLOPED DEMAND CURVES.

A. MISO's plan to use sloped demand curves is expected to increase the level of capacity MISO deems necessary to achieve the 1-in-10 reliability target and is expected to increase the capacity prices at which that target is met. Such prices are much higher than have been observed historically and will continue to be volatile.

Q21. PLEASE DESCRIBE MISO'S PLAN TO FURTHER RESTRUCTURE THE AVAILABILITY-BASED ACCREDITATION SYSTEM.

A. MISO recently filed a proposal at the Federal Energy Regulatory Commission ("FERC") to further restructure its accreditation system beginning in 2028.[14] The new methodology is referred to as "Direct Loss of Load," or "DLOL," and it involves two basic steps. The first step is to determine – through statistical simulation – the expected aggregate availability level in each season of resource classes (*e.g.*, coal, combined - cycle, solar, wind) during hours when the simulation identifies scarcity. The next step is to allocate the expected aggregate level of availability for each resource class in each season among individual resources within the class based on their historical availability during hours within the season in which there was actual scarcity. In summary, the first step is to estimate the expected availability of resource classes using a model and the second step is to allocate that capacity amount among individual resources within a class based on historical availability.

[14] Filing to Reform MISO Accreditation Requirements, FERC Docket No. ER24-1638 (filed Mar. 28, 2024).

Because this change will affect unit ratings, it will also affect the amount of capacity that MISO quotes as being necessary to achieve resource adequacy. For example, if MISO today determines that 130 gigawatts ("GW") of SAC-rated resources are sufficient to meet the 1-in-10 standard, and those same resources are rated at 120 GW using the DLOL methodology, the new capacity target will be 10 GW lower when quoted in DLOL.

Unlike the planned use of sloped demand curves, which is expected to increase the amount of capacity deemed necessary to meet the 1-in-10 standard by incorporating fundamentals that have previously been excluded from the modeling, the proposed change to the accreditation system will not affect the amount of capacity deemed necessary; rather, it will just change the way that the amount deemed necessary is counted and quoted.

Q22. PLEASE DESCRIBE MISO'S PLAN TO USE A NEW METHOD TO ALLOCATE RESPONSIBILITY FOR THE AGGREGATE CAPACITY REQUIREMENT AMONG INDIVIDUAL LSEs.

A. MISO currently allocates responsibility for the amount of capacity purchased in the PRA among LSEs in proportion to their coincident peak load. This means, for example, that if an individual LSE's coincident peak load was 10% of the MISO coincident peak load, then that LSE would be charged for 10% of the aggregate amount purchased in the PRA at the clearing price. MISO has proposed, but not yet filed, to change the way that this responsibility is allocated among LSEs.[15] The proposal is not yet final, but MISO has indicated that the new methodology will allocate responsibility among LSEs in proportion to their load during hours when there is scarcity.

Q23. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING CHANGES TO THE PRA AND ETI'S APPROACH TO ESTIMATING ITS NEED FOR CAPACITY.

A. ETI used an approach to estimate its unmet need for capacity that accounts for recent changes to the PRA with respect to seasonal delivery periods, seasonal reserve margins, and seasonal capacity ratings. This approach and the resulting estimates are reasonable as evidenced by comparison to the results of a former approach recently found to be reasonable. Under either approach, ETI has a clear need for capacity that exceeds the amount of capacity provided by the Dispatchable Portfolio.

MISO plans to implement three additional changes to the PRA related to sloped demand curves, DLOL accreditation, and allocation of purchase capacity responsibility. The use of sloped demand curves is expected to increase the amount of capacity deemed necessary to meet the 1-in-10 reliability target by incorporating fundamentals that have previously been excluded from the modeling. The DLOL accreditation system will change the way that capacity is counted and capacity targets are quoted, but it will not fundamentally change the amount of capacity needed to

---

[15] *Market Redefinition: Accreditation Reform*, a presentation by MISO to the Resource Adequacy Subcommittee at 5 (Jan. 17, 2024). https://www.misoenergy.org/events/2024/resource-adequacy-subcommittee-rasc---january-17-2024/

meet the 1-in-10 reliability target. The use of a new ratio to allocate responsibility for the aggregate amount of capacity purchased in the auction will not affect the amount of capacity deemed necessary to meet the 1-in-10 reliability target, although it could affect ETI's proportional share of this amount. In light of these changes, ETI is evaluating its long-term planning targets.

IV. POTENTIAL FUTURE TRANSITION TO RETAIL COMPETITION

Q24. WHY ARE YOU ADDRESSING THE EFFECT OF A CCN FOR THE DISPATCHABLE PORTFOLIO ON THE POTENTIAL FUTURE TRANSITION TO RETAIL COMPETITION IN ETI'S SERVICE AREA?

A. The Commission identified this as an issue to be addressed in Docket No. 52487, the proceeding to evaluate ETI's application for certification of OCAPS. In particular, the Commission identified market power as an issue to be addressed in that proceeding.

> What effect, if any, would approval of the CCN amendment have on the implementation of customer choice in Entergy's service territory, particularly on how Entergy would mitigate market power and achieve full customer choice, including specific alternatives for constructing additional transmission facilities, auctioning rights to generation capacity, divesting generating capacity, or any other measure that is consistent with the public interest? PURA § 39.452.[16]

[16] Preliminary Order at 6, PUCT Docket No. 52487 (Dec. 16, 2021).

Q25. PLEASE PROVIDE BACKGROUND ON THE IMPLEMENTATION OF RETAIL COMPETITION IN ETI'S SERVICE AREA.

A. In 2006, ETI made a filing at the Commission to transition to competition. While that proposal was pending, the Texas Legislature in 2009 modified section 39.452 of PURA to direct ETI to cease all activities related to the transition to competition but granted the Commission authority to initiate a process that could eventually lead to competition. Since 2009, the Commission has not initiated such a process, and I am not aware of any plans to do so.

Q26. WHAT DOES THAT PROCESS ENTAIL?

A. The process includes a proceeding to determine whether ETI's power region meets certain statutory criteria. The process also includes the filing of a transition to competition plan that the Commission could approve no earlier than four years after certifying the power region. The four-year waiting period would provide the Texas Legislature with an opportunity to address whether and how to implement retail competition in ETI's service area if it chose to do so. Following any order approving the transition plan, additional time would be required to implement it.

Q27. WOULD APPROVAL OF ETI'S INSTANT APPLICATION AFFECT THIS PROCESS?

A. No. As PURA is written, there would be a proceeding to certify ETI's power region, a proceeding to evaluate a transition plan filed by ETI, a four-year waiting period before the Commission could approve a plan, and implementation activities following that. Commission approval of ETI's application to amend its CCN to construct, own, and operate the Dispatchable Portfolio would not affect this process.

Q28. WOULD APPROVAL OF ETI'S INSTANT APPLICATION AFFECT MARKET POWER ISSUES TO BE ADDRESSED IN ANY POTENTIAL TRANSITION PLAN?

A. No, not in any meaningful way. In the Preliminary Order in the OCAPS CCN proceeding, the Commission used the same text as is included in section 39.452(g)(1) of PURA, which identifies issues to be addressed in a transition to competition plan. These issues concern market power and certain options to address it, including the construction of additional transmission facilities, auctioning of generation rights, and divestiture of generation facilities.[17]

These issues would have to be addressed in any plan, regardless of whether the Commission approves ETI's CCN application for the Dispatchable Portfolio. The extent of actions taken to address them could be affected by virtue of ETI having additional generating capacity, but ETI needs additional capacity to serve its customers, and when it conducts long-term planning, it plans to meet its needs using physical capacity, not PRA capacity credits. Thus, the addition of the Dispatchable Portfolio should not affect the way in which market power is addressed or the extent of actions taken to address it in any potential future transition plan in any meaningful

[17] A transition to competition plan must "identify how the electric utility intends to mitigate market power and to achieve full customer choice, including specific alternatives for constructing additional transmission facilities, auctioning rights to generation capacity, divesting generation capacity, or any other measure that is consistent with the public interest." PURA § 39.452(g)(1).

way because if ETI was not planning the Dispatchable Portfolio, it would be planning another portfolio of physical resources to meet its needs.

Even if one were to take the view that there is an alternative to the Dispatchable Portfolio that does not involve a comparable amount of capacity such that the Dispatchable Portfolio represents incremental capacity, and even if that incremental capacity were deemed to create incremental market power concerns, the Commission could address those concerns using its existing authority or any new authority that may be granted to it by the Texas Legislature during the four-year waiting period.

Q29. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE EFFECT OF APPROVING ETI'S INSTANT APPLICATION ON MARKET POWER CONCERNS ASSOCIATED WITH A POTENTIAL FUTURE TRANSITION TO RETAIL COMPETITION.

A. Commission approval of ETI's application to add the Dispatchable Portfolio to its CCN would not affect the process to transition to retail competition, nor would it create any incremental market power concerns. To my knowledge, there are no plans at this time to initiate a transition to retail competition in ETI's service area, and if a transition were to occur, it would not be for many years. Meanwhile, ETI has proposed to add the Dispatchable Portfolio to address a pressing need for additional capacity to serve customers within its service area. Any concerns that the Dispatchable Portfolio would create incremental market power concerns could be addressed by the Commission using its existing authority and/or new authority granted to it by the Texas Legislature and should not prevent the Commission from approving ETI's CCN application.

Q30. WOULD APPROVAL OF ETI'S INSTANT APPLICATION AFFECT ITS ABILITY TO RECOVER STRANDED COSTS IF IT WERE TO TRANSITION TO RETAIL COMPETITION?

A. No. A utility's stranded cost represents the difference between the book value and the market value of its generating assets.[18] If ETI were to transition to competition, it would be eligible to recover its stranded costs.[19] ETI's stranded costs could be affected by the addition of Legend and Lone Star, but the direction (*i.e.*, positive or negative) and extent of the effect would depend on the difference between the future book and market values of these assets and how that compares to the difference between the future book and market values of physical alternatives that ETI would otherwise pursue. The future is uncertain, so we do not know – standing here today – what these future values would be if there is a transition to competition in ETI's service area. With that said, Legend and Lone Star will be among the most efficient resources of their kind in the market when they are placed in service.

---

[18] "[']Stranded cost['] means the positive excess of the net book value of generating assets over the market value of the assets...." PURA § 39.251(7).

[19] "An electric utility is eligible to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric service." PURA § 39.252(a).

Q31. HAS THIS ISSUE – THE EFFECT OF A CCN ON A POTENTIAL FUTURE TRANSITION TO RETAIL COMPETITION – BEEN ADDRESSED BEFORE?

A. Yes, this issue was addressed in the proceeding to evaluate an application by ETI for certification of the OCAPS facility. In their proposal for a decision in that docket, the Administrative Law Judges concluded "that the addition of necessary dispatchable power and related regional reliability outweigh any potential effects on customer choice."[20] There is no basis for a different conclusion with regard to ETI's current application.

Q32. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

[20] "The ALJs conclude that although OCAPS may have an effect on the implementation of customer choice in ETI's service territory, a meaningful evaluation of the exact effect is tenuous at this point. No initiation of customer choice has occurred. And, although it is foreseeable that some increase in ETI's market share may occur (despite deactivation plans), the ALJs further conclude that the addition of necessary dispatchable power and related regional reliability benefits outweigh any potential effects on customer choice." Proposal for Decision at 141, PUCT Docket No. 52487 (Sep. 26, 2022). This portion of the Proposal for Decision was adopted by the Commission without modification. Order on Rehearing, PUCT Docket No. 52487 (Jan. 12, 2023).

ATTESTATION

STATE OF Massachusetts

COUNTY OF Middlesex

Nicholas W. Owens states that the attached is his sworn testimony and that the statements contained therein are true and correct to the best of his knowledge, information, and belief.

Nicholas W. Owens

SWORN AND SUBSCRIBED BEFORE ME

This 28 day of May 2024

Notary Public

My Commission Expires: September 19, 2025