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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF SOUTHERN POWER COMPANY

I. INTRODUCTION AND EXECUTIVE SUMMARY

Southern Power Company ("SPC") appreciates the opportunity to respond to the request for comments issued by the Public Utility Commission of Texas ("Commission") on August 3, 2021 in Project No. 52373. SPC, a subsidiary of Southern Company, is a leading wholesale energy provider meeting the electricity needs of municipalities, electric cooperatives, investor-owned utilities, and commercial and industrial customers. SPC and its subsidiaries own 54 facilities nationally – including natural gas (61.1% of generating capacity), wind (17.5%), solar (19.8%), battery storage and fuel cells (1.5%) – operating or under construction in 14 states with more than 12,498 megawatts ("MW") of generating capacity. SPC owns four wind and three solar generation facilities totaling approximately 1,100 MW of generating capacity in the Electric Reliability Council of Texas ("ERCOT") region. SPC has a unique perspective as a competitive generation company owning and operating a diverse fleet of generating facilities in multiple power markets across the country and as an affiliate of three retail electric operating companies in the Southeast.[1]

In response to the Commission's questions, SPC offers the following recommendations:

- Change the shape of the Operating Reserve Demand Curve ("ORDC") by lowering the overall price cap and lengthening the tail.
- Provide ORDC payments to all resources who provide energy and reserves in the real-time market.
- Do not require day-ahead market participation as a condition to receive ORDC payments or participate in the energy market.
- Evaluate new ancillary services to provide needed reliability services and ensure costs of new and existing ancillary services are allocated on a nondiscriminatory basis, to adhere to Senate Bill 3's ("SB3") directive.
- Increase participation of Distributed Energy Resources ("DERs").

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[1] Alabama Power, Georgia Power, and Mississippi Power are vertically integrated electric utilities regulated by their respective state utility commissions tasked with ensuring reliable, clean, and cost-effective electric service for their citizens. Southern Company has a combined 42,000 MW of generating capacity, including natural gas, coal, nuclear, hydroelectric, wind, solar, battery storage, and fuel cells. Southern Company's 2020 total energy mix was: 51% gas, 17% coal, 17% nuclear, and 15% renewables and other.

- Allow time for ERCOT and stakeholders to work through recently filed Nodal Protocol Revision Requests ("NPRRs") related to Emergency Response Service ("ERS").

SPC strongly supports efforts to address issues that contributed to the disaster caused by Winter Storm Uri and to improve the overall reliability and resiliency of the Texas electric grid. To achieve these goals, SPC encourages the Commission to prioritize ERCOT market design changes that (1) promote long-term bilateral contracting between electric market participants, (2) incentivize a diverse portfolio of supply-side and demand-side technologies, (3) utilize technology-neutral rules that apply based on technical capabilities, rather than specific technology types and (4) maintain regulatory and financial certainty. Such actions will be critical to attract and retain investment in supply and demand resources necessary to ensure reliable, clean, and cost-effective electric service for Texans. In addition to the responses to the Commission's questions below, SPC is forming more comprehensive and detailed comments recommending specific market design improvements and plans to file those comments at a future time in Project No. 52373.

II. RESPONSE TO QUESTIONS

1. **What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC - based dispatchability be adjusted to specific seasonal reliability needs?**

SPC recommends three primary policies related to ORDC: (1) change the shape of the ORDC by lowering the overall price cap and lengthening the tail, (2) provide ORDC payments to all resources who provide energy and reserves in the real-time market, and (3) do not mandate day-ahead market participation as a condition to receive ORDC payments.

First, ERCOT's energy-only market is predicated on the law of supply and demand incentivizing actions to increase electricity supply or reduce electricity usage. The energy-only construct pays generators only for the power produced and delivered to the transmission grid, with the price of that power varying based on the marginal cost of producing electricity, congestion impacts from transmission constraints, and the incremental value provided during grid scarcity conditions. Good market design assigns increasing value to energy and reserves provided during scarcity conditions when the probability of load shed increases. ERCOT achieves this through the ORDC, which represents the value of reserves at different reserve levels based on the value of lost load and the loss of load probability. Multiple factors are contributing to lower electricity prices and a decreasing number of scarcity events. SPC believes that the existing ORDC construct promotes "boom or bust" outcomes, with generation resources increasingly relying on a smaller number of scarcity events to recover their costs plus necessary returns. To mitigate this effect, SPC recommends that the Commission change the shape of the ORDC by lowering the price cap and lengthening the tail. The result would be to lower the maximum reserve value during high reserve shortage conditions (i.e., reducing the high system wide offer cap) and to increase the value of reserves during more numerous, less-stressed time periods, thereby incentivizing new generation and better supporting existing generation (particularly dispatchable resources). This would lead to more predictable energy revenues, thus encouraging generation resources to be available and decreasing the impact of operational availability during any single scarcity event. SPC believes that long-term certainty is preferable to short-term upside when evaluating significant investments, like new generation, intended to be recovered over 30 to 50 years.

Second, ERCOT should continue to provide ORDC payments to all resources who provide energy and reserves in the real-time market. Changing ORDC payment eligibility to include only dispatchable resources would result in discriminatory treatment of certain technologies, create regulatory uncertainty, discourage future investment, and threaten the financial viability of more than $70 billion of capital investment by renewable projects located in Texas based on the existing regulatory compact. Tying ORDC payment eligibility to technology type would be discriminatory and counter to the Public Utility Regulatory Act's ("PURA") requirement that ERCOT operate in a nondiscriminatory fashion,[2] as energy and reserves provide the same value of serving load and reducing involuntary load shed risk regardless of their generation type or fuel source. To the extent that changes to the ORDC significantly reduce revenue, rural Texas communities with renewable generation resources likely will be harmed as lower project revenues can reduce property tax values for such facilities and reduce landowner payments. Additionally, existing renewable power

[2] See PURA § 31.002(9) ("Independent System operator means an entity supervising the collective transmission facilities of a power region that is charged with nondiscriminatory coordination of market transactions, systemwide transmission planning, and network reliability.").

purchase agreements would become liabilities due to disruption to contract settlements,[3] and while it may be possible to amend existing contracts, significantly changing these contract terms will inevitably lead to varied interpretations, disputes, additional costs, uncertainty and, many times, an inability to modify contract terms. SPC is also concerned that ineligibility to receive ORDC, whether because of technology type or day-ahead market participation, would actually counteract reliability by discouraging certain resources from providing energy or reserves in the real-time market.

Finally, day-ahead market participation should not be a condition to receive ORDC payments. The day-ahead market is a financial market used by ERCOT to plan for next-day operations and by market participants to hedge risks; it does not require physical schedules. Required day-ahead market participation would significantly harm existing renewable resources who have made significant investments based on existing market design, discourage future investment, upset market participants' risk and optimization decisions, harm reliability, and disrupt existing contracts. Resource owners take on risk by offering into the day-ahead market, because varying factors (e.g., forced outages or inaccurate generation or load forecast) can cause shortage conditions and high prices in the real-time market, which would negatively impact a resource's financial position (i.e., by buying back its short position at a high real-time price). Resource owners are best equipped to evaluate risk and reward tolerance and determine market participation decisions. A blanket day-ahead must-offer requirement would increase risk for all resources, but particularly renewables, under a current market design that only compensates resources for energy. Additionally, required day-ahead market participation would upset or violate existing tax equity financing and power purchase agreements.[4] SPC believes that a more effective method of achieving improved reliability is to promote longer-term revenue certainty via bilateral contracting between market participants, rather than a day-ahead must-offer requirement that would create regulatory and financial uncertainty.

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[3] Many renewable power purchase agreements have settlement terms known as "contracts for differences", where a renewable facility is paid a fixed price in exchange for a defined real-time electricity price, many times a "Hub", which is a collection of different pricing nodes in a given area. If renewables were ineligible to receive ORDC, then they would only receive their nodal Locational Marginal Price that excludes ORDC, and then would pay a higher Hub price that would include dispatchable resource nodes and at times ORDC values.

[4] Many renewable energy resources enter into tax equity financing agreements, which can either limit losses from day-ahead market participation compared to a real-time benchmark or outright prohibit it.

2. **Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?**

No, ERCOT should not require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market. Please see more detail in response to question one above.

a. **If so, how should that minimum commitment be determined?** No comment

b. **How should that commitment be enforced?** No comment

3. **What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.**

Ancillary services are defined in the ERCOT Protocols as a "service necessary to support the transmission of energy to Loads while maintaining reliable operation of the Transmission Service Provider's transmission system using Good Utility Practice."[5] Currently ERCOT procures Regulation Service, Responsive Reserve Service ("RRS"), and Non-Spinning Reserve Service ("Non-Spin") that each serves a specific purpose in support of reliable grid operations. SB3 requires the Commission to "evaluate whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation."[6] SPC supports the Commission's review of potential new services, which should incentivize development and maintenance of resources with certain desired technical capabilities. For example, a new fuel reliability service could pay resources to weatherize equipment, add dual fuel capabilities to generation facilities, procure firm gas transportation, or maintain onsite fuel storage. The Commission should also evaluate ramp and uncertainty products, which pay resources to hold dispatchable capability in reserve to respond to unexpected net load variations.

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[5] Ancillary services definition under ERCOT Protocols Section 2.

[6] PURA § 35.004(g)(2). "Dispatchability" is a desired technical characteristic rather than a generation technology type. Any new ancillary services should be technology-neutral and open to all resources who can satisfy technical requirements. This could include storage resources or hybrid resources (i.e., a renewable resource paired with a storage resource) depending on the technical requirements.

Additionally, SB3 requires the Commission to require ERCOT to "modify the design, procurement, and cost allocation of ancillary services for the region in a manner consistent with cost-causation principles and on a nondiscriminatory basis".[7] To a certain extent, all loads and generation resources benefit from the provision of ancillary services and contribute to their need. Load benefits from ancillary services facilitating the reliable delivery of electricity. Generation of all types benefits from the system reliability provided through ancillary services as they sell electric power on the ERCOT grid. Load and generation also create the need for ancillary services to respond to uncertainties – such as load forecast error, load and generation forced outages, intermittency of renewable generation, and the need to plan for the forced outage of the largest resource on the system – and thus also cause the costs incurred. While renewables' intermittency is one factor that impacts net load variations and must be managed, there is not strong evidence that renewables significantly impact the need for ancillary services. From 2011 to 2020, wind and solar installed generation capacities in ERCOT increased from 9,603 MW to 25,121 MW and 15 MW to 3,974 MW respectively, while ancillary service procurement remained flat or even slightly decreased.[8]

Any shift in the assignment of costs for ancillary services will necessarily require that such changes be supported by sufficient data and stakeholder consideration. Historic ERCOT data and prior ERCOT stakeholder consideration of the issue did not support the assignment of ancillary services charges to generation resources. To the extent the Commission desires to revisit this issue, SPC believes that the Commission would need to initiate a robust stakeholder process to

[7] PURA § 35.004(h). ERCOT and the Commission has a long history of analyzing this issue and, to date, has not identified or adopted an ancillary services charge to non-dispatchable generation. For example, in 2009-10, ERCOT established the Wind Cost Allocation Task Force ("WCATF") to address the issue and no such ancillary services product attributable to non-dispatchable generation could be reached. In around 2014, ERCOT stakeholders developed the "Future Ancillary Services Team" or "FAST", which similarly did not lead to an ancillary services product charged to non-dispatchable generation. Also, in the context of transmission costs associated with renewables in ERCOT, in Commission Project No. 42647, Luminant Energy Company contended that "The integration of significant quantities of renewable capacity will also result in the need for additional ancillary services, thereby increasing ancillary services costs. ERCOT should take into account these incremental costs when assessing proposed transmission projects under the economic planning criteria (i.e., the production cost savings test), but the costs should be allocated to customers like all other ancillary services costs (rather than, for example, allocating the costs to the renewable resource owner)." No ancillary service or cost allocation to non-dispatchable generation resulted from that Project either.

[8] Please see installed capacity information in the ERCOT Resource Capacity Trend Charts reports found at http://www.ercot.com/gridinfo/resource; and hourly average ancillary service capacity information in Independent Market Monitor reports found at https://www.potomaceconomics.com/markets-monitored/ercot/.

understand whether any intervening changes improve reliability and warrant a change in the allocation of ancillary services costs.

SPC urges the Commission to adhere to SB3's directive, ensuring that the costs of new and existing ancillary services should be paid and borne on a "nondiscriminatory basis". The ultimate standard of reliability is how well an ancillary service, new or existing, fulfills its role reliably serving load. SPC views ancillary service products strictly as a set of operational tools to ensure short term reliability, and not as the appropriate mechanism to incent long term investments, ensure resource adequacy, or penalize resources with different technical capabilities.

4. Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

While SPC does not participate in residential demand response programs, it offers the following comments in support of sound, comprehensive market design principles.[9]

A significant increase in electric demand and inability to deliver electric output from generation resources exacerbated Winter Storm Uri's impact on Texans. DERs[10] can provide significant benefits by generating electricity, providing ancillary services, reducing electricity consumption, increasing resiliency, and avoiding necessary system upgrades. Additionally, DERs provide ERCOT flexibility to operate the system, respond to contingencies, and maintain system health to avoid involuntary load shed. Good, comprehensive market design should aim to increase DER participation to capture these benefits. The Commission should evaluate expansion of Transmission and/or Distribution Service Provider load management programs and Retail Electric Provider price-responsive programs, considering time-of-use rate options and upfront enrollment incentives, as well as electric energy efficiency goals and programs targeting reduction in both energy use and peak loads.

At the wholesale level, DERs should be allowed to provide services that they are technically capable of performing, while at the same time complying with ERCOT's registration,

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[9] The comments provided here represent SPC's position on these issues. However, it should be noted that SPC has an affiliate company, PowerSecure, that provides distributed energy solutions.

[10] DERs can be thought broadly as any resource located on the distribution system or behind a customer meter and include (but are not limited to) electric storage resources, distributed generation, demand response, energy efficiency, and electric vehicles.

modeling, telemetry, and operational requirements. ERCOT has approved multiple revisions requests,[11] which are expected to be implemented sometime in 2022, that more clearly define registration, planning processes, modeling, and pricing for DERs. The Commission should direct ERCOT to continue refining DER rules with lessons learned over time and respond as the adaptation of advanced electric technologies increases.

5. How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?

While SPC does not participate in the ERS program, it offers the following comments related to ERS. ERCOT recently filed NPRR1087, Prohibit Participation of Critical Loads and Generation Resource Support Loads as Load Resources or ERS Resources and NPRR1090, ERS Winter Storm Uri Lessons Learned Changes and Other ERS Items. NPRR1087 defines "Critical Load" and "Generation Resource Support Load" and prohibits the registration and participation of such Load Resources or ERS Resources. SPC supports efforts to strengthen reliability through improved ERS participation rules but is concerned that an overly broad prohibition may inadvertently decrease the ERS program's reliability benefits and harm critical loads that have invested significant dollars in onsite generation or storage solutions with the expectation of supporting grid reliability. Critical loads should be eligible to participate as Load Resources or ERS Resources if they are able to serve their critical loads while also meeting obligations as a Load Resource or ERS Resource without compromising their ability to achieve both. This could be managed through onsite generation or storage solutions or a curtailment plan targeting non-critical loads. More time is needed for ERCOT and stakeholders to form a narrowly tailored approach that reduces risk of disrupting electricity supply to critical loads, while also not overly prohibiting resources who can provide reliability benefits while continuing to serve critical loads.

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[11] See NPRR917, Nodal Pricing for Settlement Only Distribution Generators and Settlement Only Transmission Generators; NPRR1016, Clarify Requirements for Distribution Generation Resources and Distribution Energy Storage Resources; and Planning Guide Revision Request ("PGRR") 082, Revise Section 5 and Establish Small Generation Interconnection Process.

6. **How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?**

SPC supports the Commission's review of potential new services to manage inertia, voltage support, and frequency. Such review should comport with SB3's framework described in more detail in response to question three above.

Power system inertia is defined as the ability of a power system to oppose changes in system frequency due to resistance provided by rotating masses, meaning that higher system inertia will slow down the rate of frequency change resulting from sudden supply and demand imbalances. An inertia product could compensate a synchronous generation resource for contribution to system inertia, which would make the electric grid more resistant to frequency deviations caused by generation and load forced outages. Alternatively, ERCOT could evaluate procurement and rules for RRS and Fast Frequency Response Service ("FFRS"), which are frequency response products intended to provide necessary response to significant frequency deviations and could play a bigger role as system inertia decreases.

In other power markets in the United States, generation resources are paid for reactive power support as long as they meet certain technical requirements, such as operating in automatic voltage control mode, meeting certain reactive power range requirements, and responding to voltage setpoint instructions. Currently ERCOT requires generation resources to provide reactive power in order to maintain voltage at their point of interconnection within a defined tolerance band, but resources receive no compensation for providing this service. A major indicator of the need for additional reactive power on certain parts of the grid is ERCOT's increasing use of Generic Transmission Constraints ("GTCs").[12] ERCOT uses GTCs to manage non-thermal constraints, such as voltage instability caused by a lack of reactive power, by limiting electricity that can flow on a defined set of transmission lines at any given time. A voltage support market product could enhance reliability in an economically efficient way by competitively procuring needed reactive power capability, in addition to providing economic benefits by releasing low-cost renewable energy trapped behind GTCs. SPC encourages further discussion amongst the Commission, ERCOT, and stakeholders on reactive power compensation.

[12] As of August 16, 2021, ERCOT has 16 effective GTCs. Please see the August 21, 2020 ERCOT "Transmission Issues Related to Generation Constraints Workshop" for more details about GTCs. The Workshop page is located at http://www.ercot.com/calendar/2020/8/21/209816.

ERCOT's frequency response performance continues to be healthy and has actually improved over the past five years.[13] All of ERCOT's ancillary services play a role in maintaining system frequency within a desired tolerance. Regulation Service balances net load variations over five-minute intervals and brings frequency closer to 60 Hertz ("Hz"), RRS arrests frequency decay within the first few seconds of a significant frequency deviation, and Non-Spin can be deployed as needed to provide energy and help restore frequency. ERCOT also has approved a to-be-implemented ancillary service product called ERCOT Contingency Reserve Service that will help restore frequency to 60 Hz within ten minutes of a significant frequency deviation. Additionally, all generation and load resources are required to provide frequency responsive capabilities and thus a significant portion of resources provide this service for free. While a new product to compensate all frequency-responsive capability is an option, SPC believes that the Commission should instead (1) prioritize more impactful market design changes that incentivize long-term bilateral contracting between market participants and (2) direct ERCOT to continue evaluating rules to procure necessary frequency-responsive services in light of lessons learned from Winter Storm Uri.

III. CONCLUSION

SPC appreciates the opportunity to provide comments for the Commission's consideration in its review of wholesale electric market design and looks forward to working with the Commission and other stakeholders on this important project.

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Respectfully submitted,

John L. Pemberton,
Senior Vice President, General Counsel &
Chief Compliance Officer
Southern Power Company
30 Ivan Allen Blvd, NW
Atlanta, GA 30308

[13] See Performance Disturbance Compliance Working Group report presented at the August 5, 2021 Reliability and Operations Subcommittee meeting.