UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interregional Transfer Capability Study	))))))	**Docket No. AD25-4-000**

COMMENTS OF NRG ENERGY, INC.

Pursuant to the Notice of Request for Comments issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") on November 25, 2024, NRG Energy, Inc. ("NRG") hereby submits these comments on the Interregional Transfer Capability Study ("ITC Study") that the North American Electric Reliability Corporation ("NERC") submitted to FERC on November 19, 2024.

I. Introduction

NRG appreciates NERC's work developing the ITC Study and the opportunity to comment on this process. As the Commission is aware, this study was required by Congress amidst a spirited debate on whether a universal minimum transfer capability requirement should be mandated by federal law. NRG strongly believes such a mandate would be costly and, given the differences between adjoining electricity markets, harmful to reliability. NRG agrees with the ITC Study's bottom line, which is that "a one-size-fits-all requirement for a minimum amount of transfer capability may be inefficient and potentially ineffective."[1]

Beyond this bottom-line conclusion, the ITC Study has significant shortcomings—some of which the report itself acknowledges.[2] The ITC Study consciously excluded the economic costs involved with the construction and maintenance of new interregional transmission facilities. While the study proposes resource additions that it deems "technically prudent,"

[1] Interregional Transfer Capability Study Final Report (ITCS) at xvii, available at: ITCS Final Report.
[2] *Id.,* "How to Use this Report" at xix-xx.

decisions that are prudent naturally arise from a consideration of economic tradeoffs. As a result of its professed limitations, the ITC Study cannot be considered a cost-benefit analysis. NRG urges the Commission to resist accepting the ITC Study's recommendations as prudent on their face.

More specifically, NRG identifies a handful of flaws about both the operations of interregional transfer capability and its feedback loop on the viability of power-generation business models that are neither modeled nor given any meaningful qualitative consideration in the ITC Study:

- New interregional transfer capabilities would lead to more resource retirements and fewer resource additions in certain markets that have no capacity mechanism, particularly the Electric Reliability Council of Texas ("ERCOT"), which would ironically undermine reliability in the state during critical times when the imports on which ERCOT became increasingly reliant were unavailable;
- In restructured markets that do have a capacity function, the capacity market would become an ever-greater share of revenue and a more essential feature of retaining endogenous generation that was uneconomic on an energy-production basis, increasing the dependency on capacity market design as an administratively determined stop-gap;
- Empirical evidence of actual energy interchange between regions does not support the ITC Study's implicit assumptions about hurdle-less and economic flows between regions to which interregional transfer capability is added; and
- Finally, the ITC Study does not accurately model probable resource additions in ERCOT in light of the state's latest public policies.

For both the Commission and Congress, which should evaluate electricity policy from the power plant to the substation, and through the lens of reliability, affordability, and abundance, the ITC Study provides analysis around only a single dimension of a single segment of the bulk power system.

II. Comments

A. Chapter 1: The Reliability Value of Transfer Capability

The ITC Study states that extreme weather events continually underscore the need for interregional energy transmission to ensure reliability, stating that "transfer capability, or the lack thereof, had a direct impact on the magnitude and duration of firm load shed" during extreme winter storms in 2021 and 2022, and the heatwave experienced by western states in 2020.[3]

However, simply building additional interregional transmission interconnections will not alone minimize reliability impacts. Both the economics of power generation and the operational interface of adjoining markets largely dictate if and how generation capacity is available in the first instance, and whether that capacity's energy production can be transferred between regions, regardless of the availability of transmission capacity. The Commission must pragmatically assess the proposed transmission additions and consider documented limitations, such as those described below, of using interregional transmission as a solution to reliability problems.

First, from an operational perspective, the timing of transactions can complicate how one region helps another during transient shortage conditions. It is not obvious that market-to-market interchange practices would actually lead additional interregional transmission, were it to exist, to deliver excess power to regions with power shortages. Empirical data supports this proposition. For example in 2021, PJM Interconnection, L.L.C.'s ("PJM") market monitor reported that transactions between the Midcontinent Independent System Operator ("MISO") and PJM moved in the economically efficient direction—i.e., from the region with the lower price to the market with the higher priced—only about 60% of the time, and the direction of hourly flows was inconsistent with price differentials 40.1% of the hours.[4] Similarly, transactions between New York Independent System Operator ("NYISO") and PJM moved in the economically

[3] ITCS at 1.
[4] Excerpts from Monitoring Analytics, LLC, State of the Market Report for PJM, 2021 at 459 (Mar. 10, 2022) (Attachment A).* Myriad factors can drive these observed inefficiencies, from interregional schedules under long-term contracts that are not sensitive to real-time price, inefficient market structures or seams and real-time dispatch decisions driven by existing interregional coordination protocols. Simply increasing interregional transfer capability, while important, should not be considered a panacea for unaddressed market seams and obstacles that also need to be addressed to improve interregional market efficiencies.
*All attachments referenced in footnotes 4-7, and 10 are references to the attachments in: Post-Workshop Comments of Vistra Corp. And NRG Energy, Inc., Docket No. AD23-3-000 (May 15, 2023).

efficient direction only about 57% of the time.[5] The following year, the PJM market monitor found similar patterns—48% of the flows were in the economically inefficient direction in 2022 at the PJM-MISO interface,[6] and 39.5% were in an economically inefficient direction in 2022 at the PJM-NYISO interface.[7]

Moreover, price benefits are typically relatively small even when the flows are moving consistent with the price differential. In 2022, the price differential in hours with economically efficient flows was less than $20 in 85% of the hours at the PJM-MISO interface, and less than $20 in 78% of the hours at the PJM-NYISO interface.[8] But even at high price differentials, the flows are not more likely to follow price differentials. For instance, when the price differential was above $50 at the PJM-NYISO interface, there were as many hours (360) with power flowing inconsistent with the price differential as consistent with it.[9] Thus, the mere existence of interregional transmission infrastructure does not automatically create the conditions necessary for power to flow from one region to another during times of relative abundance and scarcity between the two. Any policy evaluation of interregional transmission must also include an analysis of the market conditions necessary to produce the desired dispatch of power during scarcity events. It may be the case that adjacent markets running separated security-constrained economic dispatch are unlikely to produce a co-optimized result, in which case a more profound question of balancing area consolidation (or something that practically achieves the same result, through a jointly dispatched market) would necessarily be entailed by any reform that hopes to achieve the hoped-for reliability benefits of great interregional transfer capability.

Some of these trading dislocations, beyond operational challenges across a market-to-market interface, suggest conscious differences in market design to energy price formation and scheduling practices, which in the policy framework of allowing Commission-jurisdictional RTOs to adopt non-standard market design is an inevitability. For example, differing approaches to scarcity pricing between markets can lead to delays between when scarcity appears in one

[5] Excerpts from Monitoring Analytics, LLC, State of the Market Report for PJM, 2021 at 460-61 (Attachment B).
[6] Excerpts from Monitoring Analytics, LLC, State of the Market Report for PJM, 2022 at 501 (Mar. 9, 2023) (Attachment C).
[7] Excerpts from Monitoring Analytics, LLC, State of the Market Report for PJM, 2022 at 503 (Attachment D).
[8] *Id.* at 502 (Table 9-27), 504 (Table 9-29).
[9] *Id.* at 504 (Table 9-29).

market and imports start to arrive from neighboring regions.[10] In a 2014 report, Commission Staff found that "[b]ecause of the lag between price signals and import and export scheduling, it is difficult for market participants to efficiently schedule exports and imports to respond to shortage conditions, sometimes leading to inefficient behavior."[11] To the degree that adjoining markets do not have a common, flow-based dispatch, some interregional ties have long-term firm point to point reservations that reduce the Available Transmission Capacity values for the intertie through the scheduling window in the day-ahead market, with unused capacity released or redispatched in real-time with such short windows that real-time scheduling of that unused capacity is difficult. Again, any evaluation of the use of interregional transmission to alleviate reliability issues must also address the market signals necessary if interregional transmission is to provide increased reliability value.

Experience with external direct current ("DC") ties during shortage events in ERCOT provides additional support for considering the complicating aspects of market pricing in the analysis of how apparent interregional transfer capability could actually be utilized. The external DC ties between ERCOT and the Southwest Power Pool ("SPP") are based on the anticipated value of hourly energy arbitrage in day-ahead trading, though they also have superseding emergency protocols that affect their operation. Therefore, interregional transfers may be of limited use during transient shortage events because market signals would not operate quickly enough to signal a shortage to another region. Thus, obtaining efficient interregional transfer capability is not a problem that can be analyzed solely in light of interregional transmission facility additions; it requires coordination and joint dispatch between markets. The ITC Study, in understandably seeking a simplified model to study the question at hand, simply does not grapple with these transaction costs and trade barriers. But without the requisite pricing and operational mechanisms, the reliability value of interregional transmission may never be realized.

Finally, even assuming a common underlying philosophy of energy-market design and a joint dispatch, the reality is that even joining together adjacent markets would not create a grid big enough to diversify supply in the face of large severe weather systems. The ITC Study

[10] Staff Analysis of Shortage Pricing in RTO and ISO Markets at 21-23, Docket No. AD14-14-000 (issued Oct. 21, 2014) (Attachment F).
[11] *Id.* at 39.

specifically mentions Winter Storm Uri as a scenario in which increased DC ties likely would have prevented the worst outages.[12] The DC ties linking ERCOT to SPP did not import to ERCOT at full capacity during the storm, and were substantially or entirely curtailed during the daytime hours of February 16 and 17, 2021.[13] Even assuming a perfect dispatch between the adjacent markets, increased DC capacity between ERCOT and SPP would have done little to obviate the conditions on the ERCOT grid during those times, as SPP was enduring the same winter storm as ERCOT, and needed as much of its own capacity as possible. Indeed, the geographic breadth of Winter Storm Uri spanned all three interconnections. During the entirety of the extremely cold weather, from February 14 to 18, 2021, there were more than 3,300 daily temperature records broken at North Oceanic and Atmospheric Administration and National Climatic Data Center weather stations spanning from the Texas-Mexico border to central Washington to Michigan's Upper Peninsula.[14]

B. Chapter 2: Overview of ITC Study Scope and Terminology

1. ITC Study Scope

While the ITC Study was understandably limited to the evaluation of increased interregional transfer to mitigate energy deficiency, and provides helpful information on this topic, NRG agrees with NERC that any careful policy evaluation must nevertheless consider all other pertinent issues. Namely, a policy evaluation must consider alternative approaches to meeting energy requirements, such as increased generation or demand response, and must consider market structures and the economics of building additional transmission infrastructure, as described above.

[12] ITCS at 1.
[13] ERCOT, "DC Tie Flows During Winter Storm Uri." Available at: https://www.ercot.com/files/docs/2022/02/14/DCTieFlows_February2021.pdf.
[14] NRG analysis of weather data sampled through a third-party vendor from NCDC/NOAA (https://www.ncdc.noaa.gov/cdo-web/datatools/records)

2. Stakeholder Participation

3. General Comments on the ITC Study Scope and Terminology

C. Transfer Capability Analysis (Part 1)

1. Chapter 3: Transfer Capability (Part 1) Study Process

ERCOT's energy-only market presents particular challenges to integration via interregional transmission. The ITC Study provided limited information regarding the methodology used to calculate ERCOT's current interregional transfer capabilities. It does not contain a base case for ERCOT because ERCOT is only connected to other interconnections via DC ties. Base cases were created for the Eastern and Western Interconnections which included new generation, planned retirements, facility ratings, and load forecasts. A thorough interregional transmission capabilities study would model a reasonable feedback loop, forecasting additions and retirements of generation as a result of the additional transfer capabilities that would allow the import and export of energy to and from ERCOT's energy-only market. It would also properly model operational constraints to the scheduling and dispatch of DC ties to and from ERCOT as hurdles to the real-time optimization of energy flows.

ERCOT has three back-to-back high voltage DC converter stations that tie ERCOT to other grids, and one transmission facility that is configured to act as a DC Tie. The bulk of capacity is oriented north and east to the Eastern Interconnection through SPP, with two other, smaller and less frequently used facilities, connecting ERCOT to Mexico's National Center for Energy Control. Two additional long-distance DC lines have been proposed in the past decade, Southern Cross and Pecos West. If either project became operational, it would more than double existing transfer capability into and out of ERCOT, which currently is limited to approximately 1,220 megawatts.

Energy flows across DC ties in ERCOT depend on scheduling and transmission reservation practices on both sides of the tie border.[15] At a high level, trading occurs bilaterally on hourly schedules in the day-ahead market, subject to an adjustment period where schedules

[15] ERCOT, "ERCOT DC Tie Operations," Version 3.0, Rev. 13 (July 2020), available for download at: https://www.ercot.com/files/docs/2020/07/30/ERCOT_DC_Tie_Operations_Document.docx.

may be changed until the hour that precedes the operating hour in ERCOT. The ties are not dispatched in real time. NRG observes trading on these ties closely, and nearly all trading appears to be premised on the expected value of energy arbitrage between the markets. The ties also have detailed protocols associated with their use in emergency conditions. Given that the ties are not dispatched in real time, it is unclear if they would provide reliability benefits during short term scarcity events. Additionally, any analysis of additional interregional transmission construction must consider the market mechanisms that would dictate, and possibly restrain, energy flows across the newly created transmission.

2. Chapter 4: Transfer Capability (Part 1) Study Results

3. Other Comments on the Transfer Capability Analysis (Part 1)

D. Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)

1. Chapter 5: Prudent Additions (Part 2) Inputs

NRG notes that it is the public policy of Texas to provide low-interest financing through the Texas Energy Fund of up to 10 GWs of dispatchable natural gas resources. At the same time, ERCOT has on recent occasions retained for reliability dispatchable fossil-fueled electric generating units when they have been proposed by their owners for retirement. At odds with this, the ITC Study includes in its model only 1,190MW of additional natural gas generation capacity to be installed in ERCOT by 2033.[16] As such, in NRG's view, the ITC Study's growth projections, which show fewer than 1.2 GWs of thermal generation in net additions between 2023 and 2033, significantly understate the likely growth in gas-fired power generation and the possibility of retaining power generation that is modeled to retire.[17]

[16] ITCS at 151-152.
[17] *Id.* at 118.

2. Chapter 6: Prudent Additions (Part 2) Process, Including Energy Margin Analysis Results

3. Chapter 7: Prudent Additions (Part 2) Recommendations

The prudence analysis in the ITC Study recommends that ERCOT construct an additional 14,100 MW of interregional transmission facilities, connected to MISO, SPP, and the Front Range, to maintain reliability.[18] The extremely high Additional Transfer Capability value for ERCOT is in part derived from the fact that the "ERCOT system, on average, reaches lower margin levels on a more regular basis than other TPRs. This vulnerability is partly attributable to ERCOT's limited transfer capability, which restricts its ability to import energy from neighboring TPRs during periods of high demand or supply shortages."[19] This conclusion is not especially revelatory, and to a large extent reflects conscious policy and regulatory decisions by the legislature and Public Utility Commission of Texas. Indeed, it is only as ERCOT approaches what the ITC Study terms "minimum margin levels" that ERCOT's energy-only market triggers its operating reserves demand curve ("ORDC") pricing function, which is intended to remit to generators producing energy during those tight hours a scarcity price that simulates a capacity payment. This pricing mechanism is intended to increase energy supply in advance of actual systemic reliability issues related to power generation and, while imperfect, it would not work at all if up to 14,100 MWs in energy transfers into ERCOT occurred whenever the ERCOT system reached "tight margin levels." And as noted above, the ITC Study does not take into consideration increased dispatchable generation being deployed in ERCOT.

The ITC Study acknowledges the "crucial relationship between generation and transmission."[20] The study states that if neighboring regions both lack generation, then no amount of interregional transmission can address the attendant reliability problems.[21] This is exactly the scenario that likely would ensue from the interconnection of the ERCOT region with neighboring regions. ERCOT and its neighbors lack a common market design for resource adequacy. ERCOT's market depends on energy scarcity pricing to recover capacity costs—

[18] *Id.* at 98.
[19] *Id.* at 94.
[20] *Id.* at 102.
[21] *Id.*

unlike literally every other market in the United States, where capacity costs are paid for through a separate market or through regulated-utility side payments. The periods of tight supply-and-demand balance in the ERCOT market are a feature, and not a bug, to incent the operation and construction of necessary dispatchable generation, while disciplining investments that are unnecessary. This scarcity-pricing mechanism is not intended to run to deficit before producing adequate price signals. Higher real-time energy prices, produced through the ORDC during the hours when operating reserves are at their lowest, propagate higher forward energy prices than otherwise would exist. In turn, those forward energy prices produce resource investments that help maintain the reliability of the ERCOT system. Indeed, many dispatchable generators rely on these periods of scarcity and the attendant high prices to support their entire operating year. Just as in the Commission-jurisdictional capacity markets, these ORDC-influenced energy payments are the "missing money" to compensate marginal units that deliver necessary energy for their otherwise unrecoverable capacity costs.

Ironically, the ITC Study used the principles behind the ORDC as the basis for its scarcity weighting factor.[22] In ERCOT, the ORDC increases wholesale energy prices once system reserves fall below a certain level. In the ITC Study, a mechanism similar to the ORDC was used to develop the scarcity weighting factor, which is not a price, but rather a numerical quantity, for comparison of the hourly energy margin in each region. While the ORDC increases prices when system reserves are low, the scarcity weighting factor artificially inflates scarcity itself when reserves are low. The ITC Study thereby divorces the ORDC mechanism from the concept of pricing, thereby creating a scenario in which scarcity begets greater scarcity which can only be alleviated by increased interregional transmission.

The interregional energy imports recommended by the ITC Study would erode the incentive for construction of additional generation resources, and the ERCOT system would become dependent on imports to endure scarcity conditions. Such a dependence would be disastrous during a crisis like Winter Storm Uri, where two adjoining markets faced similarly significant emergency conditions. It cannot reasonably be expected that a market like SPP, adjacent to ERCOT, would continue exporting; like any other market, it would cordon its

[22] *Id.* at 164.

capacity for usage within its footprint in emergency conditions. This would lead to a predictable and unfortunate situation where external resources would be needed to serve their local market and would be committed pursuant to their market's resource adequacy policy, making imports unavailable to ERCOT. ERCOT would thus have the worst of both worlds: Imports would depress prices during normal scarcity events, thereby reducing system reliability by disincentivizing generation development, while imports would also not be available to mitigate a cross-regional crisis.

While imports generally benefit consumers with respect to energy pricing and reliability, in a market that depends on energy scarcity pricing for resource adequacy, such as ERCOT, imports ironically would have a negative effect on long-term reliability. Put simply, without additional resource adequacy reforms in ERCOT, which NRG has long supported, increased interregional transfer capability could harm reliability in ERCOT. NRG does not oppose imports, but believes that the business model of interregional transmission should exist along the same basis as that of the merchant generation within ERCOT, as opposed to investments in interregional transmission that are undertaken for supply adequacy but deployed through a regulatory planning model that Texas has consciously rejected for its competitive market in energy.

In its comments on the ITC Study, the Department of Energy ("DOE") purports to fill in the analytical gaps left by the ITC Study's failure to take into consideration cost, as well as other factors, and states that when cost is included in the analysis, policy makers should view the 35GW of new interregional transmission capacity recommended by the ITC Study as the minimum necessary for reliability and customer cost reduction.[23] The DOE states that its studies on the interregional transmission address customer cost, least cost solutions, reliability, and various policy objectives, and that the results of these studies mirror those of the ITC Study, namely that more interregional transmission is essential for grid reliability.[24] However, the DOE studies also fail to take into consideration the operational and market realities of the ERCOT

[23] Comments of the United States Department of Energy at 2-3, Docket No. AD25-4-000 (Jan. 17, 2025).
[24] *Id.* at 13 and 24.

system, and fail to acknowledge that an increase in interregional transfer would negatively affect reliability in the ERCOT system.

Further, the DOE studies found that "ERCOT has access to diverse, low-cost generation within its footprint, so there is little cost-optimization benefit to connect ERCOT to other regions with low-cost generation," thereby negating any additions the DOE studies could make to the TCL Study in terms of analytical scope.[25] The DOE merely parrots the ITC Study's finding that increased interregional transmission is necessary to support ERCOT reliability during extreme weather events.[26] The DOE also notes that the scope of the ITC Study was intentionally limited by Congress' instruction to only address reliability benefits of increased transmission, and that "interactions between generation, energy markets, and transmission/transfer capability are nuanced and require co-optimized planning", acknowledging the necessarily myopic methodology of the ITC Study.[27] The DOE claims to have addressed these additional criteria in its studies.[28] However, as noted above, the DOE analysis of the ERCOT region focused solely on reliability during extreme weather events, and therefore would not have analyzed generation, energy markets, or costs, which will be extremely consequential for ERCOT, given its uses cost and market mechanisms to incent reliability. Therefore, while the DOE comments attempt to bridge the cost analysis gap left by the ITC Study, they admittedly fail to do so for findings pertaining to the ERCOT region.

While the issues NRG raises concerning differences between adjoining markets are most acute for ERCOT's energy-only market and its neighbors, they are not exclusive to ERCOT's interregional pairings. When considering the benefit of interregional transmission to address extreme events, the Commission should remember that a neighboring region is only available to help to the extent that it has excess resources during the event. This was recently borne out, in New England, during Winter Storm Elliott and Winter Storm Maura. During Winter Storm Elliott, conditions in neighboring regions resulted in a 1,100 MW reduction in imports.[29] To

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[25] *Id.* at 15.
[26] *Id.*
[27] *Id.* at 20.
[28] *Id.*
[29] *See* ISO New England, January 2023 Participants Committee Meeting Composite Materials, December 24, 2022 OP-4 Event and Capacity Shortage Condition, available at https://www.iso-ne.com/staticassets/documents/2023/01/npc-2023-01-05-composite4.pdf ("December 24, 2022 OP-4 Event Report"); ISO New England, March 2023 Participants Committee Meeting Composite Materials, March 2, 2023

manage load, ISO New England Inc. ("ISO-NE") ordered curtailment to adjust to the non-delivery of energy and adjust its forecasting to reflect system conditions in Quebec disallowing full utilization of ISO-NE/Hydro Quebec interface capabilities. During Winter Storm Maura, ISO-NE was again faced with significant real-time deviations from day-ahead interchange schedules driven by cold weather conditions in Quebec. Both storms rendered otherwise available interregional transmission capacity effectively unavailable to ISO-NE in extreme events, which is precisely the type of reliability event the ITC Study claims such interregional transmission will help alleviate. These examples further underscore the need for appropriate market structures and economic considerations when evaluating the potential reliability benefits of interregional transmission.

One readily foreseeable effect of additional interregional transmission capability for restructured markets that do have a capacity retention function, or for vertically integrated utilities that conduct insular integrated resource planning, would be a renewed emphasis on these mechanisms to retain or add generation that is apparently out-of-market on an energy-cost basis in order to provide a safety blanket of capacity that is endogenous to the region, on the basis that market rules and operational practices would not allow imports to be actually available in emergency conditions. Put another way, adding interregional transfer capability based on "technically prudent" guesswork, paid for as is typical of transmission by all ratepayers in affected regions, would beg further administrative guesswork and attendant reliance on capacity side payments for endogenous capacity still deemed necessary to avoid over-reliance on imports for reliability.

4. Chapter 8: Prudent Additions (Part 2) Sensitivity Analysis

5. Chapter 9: Prudent Additions (Part 2) Transmission Planning Region-Specific Results

As described in NRG's comment related to Chapter 5, the study appears to underestimate the expansion of natural gas fired generation in ERCOT.

COO Report at 4748- 4750 and Summary of Operations, Feb. 3 and 4, at slides 22-24, available at https://www.iso-ne.com/staticassets/documents/2023/03/npc-2023-03-02-composite3.pdf ("February 3-4 Event Report").

6. Chapter 10: Meeting and Maintaining Transfer Capability (Part 3)

The ITC Study methodology states that the study does not take cost allocation or economic considerations into account. At the same time, the ITC Study states that increased interregional transmission capabilities are necessary to maintain reliability and recommends the construction of new transmission facilities to achieve this goal. However, any recommendation to construct interregional transmission ties cannot be analyzed in an economic vacuum. Allocating responsibility for the significant costs of interregional transmission investments will be difficult. Any cost allocation method based on the distribution of projected benefits during infrequent extreme weather events or unusual market conditions will be particularly speculative and unlikely to meet the fundamental requirement for allocation of costs that are roughly commensurate with derived benefits.

7. Other Comments on Prudent Additions (Part 2)

Despite the ITC Study's frequent use of the term "prudent," it is impossible to determine on the basis of the ITC Study alone that the additional transfer capabilities the report recommends are "prudent additions." That term's long usage in utility regulatory practice means an evaluation in the context of the whole. Our comments observe a number of missing elements that would belong in any such analysis.

The ITC Study acknowledges that there are multiple ways to mitigate identified energy adequacy risks. As the Commission considers whether and how it should establish policies on resource adequacy, and how interregional transmission capability should factor into such a policy, the Commission should be fully cognizant of the impacts of potential transmission development requirements on the market environment for other competing investments and strategies in the power-generation, demand-response, and battery-storage industries. It would be counterproductive for regulatory policies that require investment in cost-of-service interregional transmission to squeeze out more economically efficient market-based alternatives.

8. Other Comments on Meeting and Maintaining Transfer Capability (Part 3)

E. E. Chapter 11: Future Work

The ITC Study recommends evaluation of inter-interregional transmission transfers, for example between ERCOT and California, stating that such transfer capability could reduce grid vulnerability and increase reliability. However, the chain of interregional transfers through multiple systems presents inherent risk to the receiving region, particularly with respect to tariff requirements of the intermediary regions. For example, in 2021, California Independent System Operator, Inc. ("CAISO") instituted wheel-through rules that placed interregional transfers from the Pacific Northwest to Arizona at significant risk of curtailment.[30] In that case, Arizona utilities had relied on existing interregional transfer capability in planning for, and executing, long-term firm contracts with external renewable resources with delivery using known, existing available interregional transfer capability. The disruption of expectations through new curtailment procedures underscores a practical reality. Establishing transfer capabilities between non-neighboring regions will be followed by an expectation of availability. If, in practice, existing or newly adopted operational practices hinder that utilization, the effectiveness of such interregional transfer requirements will be diminished.

An additional area for future work to address issues that were not explored in the ITC Study analysis is funding methods for interregional transmission. To address this issue in the future, the Commission may look to pipelines for inspiration. To be certificated, a natural gas pipeline developer must demonstrate that a project is needed. To demonstrate need, developers often submit agreements with prospective customers for long-term firm service. A similar approach could be taken with interregional transfer capabilities; shippers should be allowed to participate in solicitation offered by the line's developer to bilaterally negotiate for capacity on that line. This has the benefit of right-sizing a line's capacity and also assuring that market participants who can use the resulting capacity to substitute for generation, storage, distributed energy resources, or other technologies can take long-term positions in the project and choose

[30] *See Cal. Indep. Sys. Operator Corp.*, 175 FERC ¶ 61,245 (2021), *order on arguments raised on reh'g*, 178 FERC ¶ 61,180 (2022).

between technologies on an equitable basis. NRG believes a variety of market participants would be interested in purchasing such capacity if holding it conferred a property right that would not be eroded by government-backed approaches that cause rival interregional transmission to be constructed and paid for in a more cost-socialized manner.

Similar to gas pipeline markets, the Commission and local regulators could adopt rules regulating solicitations, capacity releases, and other features that ensure a liquid market and efficient use of transmission capacity, while also ensuring that payments for its use redound to investors in long-term capacity. The Commission has already formulated a policy on merchant electric transmission, which allows transmission developers to allocate a specific amount of capacity to "anchor tenants," after which an open season process allocates the remaining capacity. Under the existing policy, the Commission has oversight over solicitations, open seasons, and ultimately, allocations. The Commission policy statement also blesses a participant-funded cost-of-service approach that allows greater Commission supervision over costs, but continues to allocate costs and capacity in the project to a set of identified off-takers. In any future work on this issue, NRG recommends that the Commission or policy makers look to the example of natural gas pipelines as an example for how to fund future interregional transmission and how to allocate capacity.

F. F. ITC Study Appendices (A – J)

G. G. Additional Comments Outside the Specific Report Sections

H. Appendix A: Interregional Transfer Capability Study 2024

[continued on next page]

I. <u>Conclusion</u>

NRG appreciates the opportunity to comment on the ITC Study and urges the Commission to incorporate into its transmittal to Congress a clear message about the policymaking limitations of the ITC Study. In view of the unique nature of the ERCOT market design, elaborated upon at length in these comments, the Commission should draw particular attention and skepticism to the ITC Study's extraordinary recommendations about the size of transfer capability that it deems "prudent" into and out of ERCOT.

February 20, 2025

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