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Filing Date - 2024-11-19 03:12:39 PM

Control Number - 56022

Item Number - 9

North American Electric Reliability Corporation

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ____________**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INTERREGIONAL TRANSFER CAPABILITY STUDY AS DIRECTED IN THE FISCAL RESPONSIBILITY ACT OF 2023

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November 19, 2024

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INTERREGIONAL TRANSFER CAPABILITY STUDY AS DIRECTED IN THE FISCAL RESPONSIBILITY ACT OF 2023

The North American Electric Reliability Corporation ("NERC") respectfully submits the Interregional Transfer Capability Study ("ITCS" or "Study") directed by the United States ("U.S.") Congress in the Fiscal Responsibility Act of 2023 ("Fiscal Responsibility Act") for Federal Energy Regulatory Commission consideration.[1] The ITCS was prepared by NERC as the Electric Reliability Organization ("ERO")[2] in consultation with NERC's six Regional Entities (together with NERC, the "ERO Enterprise")[3] and transmitting utilities.

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[1] Fiscal Responsibility Act , H.R. 3746 (2023) [hereinafter Fiscal Responsibility Act]. *See* Section 322 of the Fiscal Responsibility Act (providing, "The Electric Reliability Organization …in consultation with each regional entity… and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:

(1) Current total transfer capability, between each pair of neighboring transmission planning regions.
(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.
(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.").

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672]. NERC was certified by the Commission as the ERO, pursuant to § 215(c) of the Federal Power Act ("FPA"), by Commission order issued July 20, 2006. *Order Certifying the North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) [hereinafter NERC ERO Certification Order].

[3] The Regional Entities are (i) Midwest Reliability Organization ("MRO"); (ii) Northeast Power Coordinating Council, Inc. ("NPCC"); (iii) ReliabilityFirst Corporation ("ReliabilityFirst"); (iv) SERC Reliability Corporation ("SERC"); (v) Texas Reliability Entity, Inc. ("Texas RE"); and (vi) Western Electricity Coordinating Council ("WECC"). Please note, unless otherwise defined herein, all capitalized terms should be assigned the meanings reflected in the NERC Glossary posted on NERC's website.

Over the past 15 months, NERC has developed the attached ITCS (**Appendix A**) in consultation with stakeholders to provide:

(i) Current total transfer capability ("TTC" or "transfer capability") between each pair of neighboring transmission planning regions in the U.S.;[4]

(ii) Recommendations for technically prudent additions to TTC between pairs of neighboring transmission planning regions where these additions would demonstrably strengthen reliability;[5]

(iii) Recommendations on how to meet and maintain TTC now and as enhanced in response to the ITCS findings.

As stated herein and detailed in the attached materials, the ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions.[6] Transmission assessments, like the ITCS, are crucial to mitigating future risks to Bulk Power System ("BPS") reliability, although other approaches beyond transmission (such as local generation or demand-side solutions) can also mitigate future energy risks. The ITCS focuses on transfer capability in accordance with the congressional directive, while acknowledging that other processes and pending projects may help support a reliable future grid. The ITCS is not designed to be a transmission plan or blueprint.

The ITCS demonstrates that sufficient transfer capability and resources exist at present to maintain energy adequacy under most scenarios. As discussed below and in the attached ITCS, however, when calculating current transfer capability and projected future conditions,[7] the ITCS

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[4] In addition, results that include transfer capabilities between the U.S. to Canada and between Canadian provinces is planned for the first quarter of 2025. While evaluating Canada is outside the specific congressional mandate, the interconnectedness of the North American BPS warrants analysis of Canada.

[5] Prudence means whether the recommendations are the type that a reasonable entity would make in good faith under the same circumstances, and at the relevant point in time. *See infra* Section II.b. The ITCS is not an evaluation of economics, siting, or environmental impacts.

[6] Transfer capability or "TTC" is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas under specified system conditions. 18 C.F.R. § 37.6(b)(1)(vi).

[7] Via an energy margin analysis that uses a ten-year forward-looking case that accounts for extreme weather, resources, and demand growth as described below and detailed in Appendix A.

identifies potential energy inadequacy across several transmission planning regions in the event of extreme weather. This finding confirms congressional and electric industry concerns that North American transmission infrastructure may become insufficient to maintain energy adequacy when considering the changing resource mix, extreme weather events, and increasing demand. Therefore, using the assumptions underlying the analysis, the ITCS recommends an increase of 35 GW of transfer capability across different regions as technically prudent additions to demonstrably strengthen reliability. The ITCS bases its analysis of prudence and the extent to which recommendations would demonstrably strengthen reliability according to the anticipated impact of the recommendations on BPS reliability in terms of energy adequacy. Further, the ITCS recommends region-specific enhancements to transfer capability, because a one-size-fits all approach across the U.S. may be inefficient and ineffective.

The ITCS is an essential element of the continuing transmission discussion in North America. The ITCS demonstrates a significant opportunity to improve the use of surplus resources when they are available during extreme weather events and shows how interregional transmission can maximize the use of local resources, including storage and demand response. Further, it highlights the continuing importance of integrated transmission and resource planning, as increasing transfer capability without surplus available energy would be inefficient. NERC looks forward to the Commission's proceeding to examine the ITCS, opportunities identified therein, and stakeholder comments in anticipation of the Commission's report to U.S. Congress.

I. EXECUTIVE SUMMARY

The Bulk Power System is a complex grid that has evolved over the past several decades to include an integrated network of generation, transmission, and distribution across vast geographic areas. NERC is focused on assuring the reliability of the BPS throughout the ongoing North American energy transformation. As the grid modernizes, governmental authorities and the electric industry are rising to the challenge to ensure that continued reliability accompanies that growth.

On June 3, 2023, the President signed into law the Fiscal Responsibility Act in which Congress (as part of measures associated with the debt ceiling) required NERC to conduct an assessment by December 2, 2024 of the total transfer capability between transmission planning regions.[8] The resulting ITCS analyzes the amount of energy that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. This transfer capability is a measure of the system's ability to address energy deficiencies by relying on resources in neighboring regions and is a key component of a reliable and resilient BPS. Recent and continuing resource mix changes require greater access and deliverability of resources between neighboring systems to maintain reliability, particularly during widespread, extreme weather conditions.

Ensuring a transmission system with sufficient transfer capability between transmission planning regions is important to support energy adequacy. In the interest of public health, safety, and security, the electric industry must continue advancing improved planning to support reliable energy supplies under an evolving grid with more frequent extreme weather conditions. As a result of the changing resource mix and extreme weather, interregional energy transfers play an

8 *Supra* note 1.

increasingly pivotal role.[9] NERC assessments and experiences during recent events, such as the Western Interconnection Heatwaves of 2020 and 2022, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022, demonstrate that action is warranted to support energy adequacy going forward. More transfer capability and a carefully planned resource mix are desirable to address these identified challenges (such as extreme weather, existing resource retirements,[10] and natural gas reliance), as well as the ongoing electrification of the economy with its growing transportation sector, industrial loads, and data centers. The ITCS is an integral part of that discourse by providing an independent, reliability-focused assessment of the extent of transfer capability across the transmission system and opportunities to harness that potential as we collectively prepare for the future.

In the first part of the ITCS, NERC calculates current transfer capability in a manner that combines base transfer levels together with first contingency incremental transfer capability for each of the winter and summer seasons, (*see infra* Section II.a.). Based on these calculations, NERC determines that transfer capability varies widely across North America with import capability anywhere between 1% to 92% of the associated peak loads. The ITCS shows that transfer capability varies seasonally, regionally, and under different system conditions. The ITCS also generally finds lower transfer capability in the Mountain States, Great Plains, Southwest, and Northeast, with greater capability in the West Coast, Great Lakes, and Mid-Atlantic areas. The magnitude of transfer capability is not itself a measure of energy adequacy, however, these findings informed the second part of the ITCS.

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9 An explanation of the grid can be found on the U.S. Energy Information Administration website. U.S. Energy Information Administration, *Electricity Explained* (Mar. 26, 2024), https://www.eia.gov/energyexplained/electricity/ (including detailed subtopics under "Also in Electricity Explained").

10 *See* Appendix A, ITCS at p. 1 and Chapter 11 (summarizing ITCS limitations and potential further considerations).

The second part of the ITCS contains an energy margin analysis that enabled NERC to identify whether a particular transmission planning region would be at risk for energy inadequacy considering the calculated TTCs and extreme weather events. The ITCS characterizes this risk for energy inadequacy as a "deficiency." In each scenario where the ITCS identifies a deficiency in a transmission planning region, NERC further applied a six-step process to examine the extent to which additional transfer capability could mitigate that deficiency and thereby demonstrably strengthen reliability.[11] The Part 1 TTC calculation (which includes simultaneous import capability analysis) together with the Part 2 prudent additions analysis (which includes energy margin analysis of past weather events applied to the projected resource mix and demand) ensure the reasonableness and therefore prudence of ITCS recommended additions to transfer capability. The last part of the ITCS provides recommendations to meet and maintain transfer capability. The resulting recommendations identify directional (rather than prescriptive) guidance for policymakers and industry. The ITCS provides a roadmap for understanding where it may be beneficial to enhance transmission to support a reliable future grid, without mandating specific projects or a minimum level of transfer capability.

The ITCS is a unique assessment centered on reliability. Transmission planners, regional transmission organizations/independent system operators ("RTOs/ISOs"), and policymakers might consider other factors such as economics, environmental effects, and broader policy objectives when deciding which solutions to implement to address reliability issues. Different markets, RTOs/ISOs, or regions of the U.S. may have different approaches to evaluate transfer capability and prudent additions thereto. The ITCS, for example, in some instances subdivided RTO/ISO and Commission Order No. 1000 areas to avoid masking issues between neighboring

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[11] The energy margin analysis (which identified the deficiencies) constitutes steps 1 and 2 of the 6-step process.

transmitting utilities within the scope of the Congressional directive. The ERO Enterprise approach was specifically designed to evaluate TTC and potential prudent additions to transfer capability that would demonstrably strengthen reliability without regard to specific market structures, economic considerations, or policy matters in the expectation that the Commission, U.S. Congress, States, and industry will use NERC's ITCS as part of this broader evaluation.

Based on the analysis in Part 2 of the ITCS, NERC identifies that in the present year, there are relatively few deficiencies across transmission planning regions. As a result, the ITCS suggests that existing infrastructure is generally sufficient at this time to maintain energy adequacy under most scenarios (barring severe conditions such as limitations on gas generation performance during cold weather and natural gas production and transportation challenges for electric generators). This conclusion also establishes 2024 as a useful reference point for future comparisons.

Nevertheless, when examining the ten-year forward-looking case that accounts for the future resource mix and forecasted load, energy inadequacy was identified across almost half of the studied transmission planning regions.[12] This confirms congressional and electric industry concern that, given the changing resource mix, extreme weather, and anticipated demand, transmission infrastructure may place a strain on energy adequacy in the future. As a result, based on calculated deficiencies and the broader six-step approach to identify prudent additions to demonstrably strengthen reliability, the ITCS recommends 35 GW of additional transfer capability across different areas of the U.S. As discussed in Section II.b. below, transmission planning regions across North America would benefit from increased transfer capability. Since the needed import capability, as analyzed, varied significantly across the U.S., a one-size fits all requirement

12 Specifically, 11 out of 23 transmission planning regions.

or approach to additional transfer capability is expected to be inefficient and ineffective. The increased transfer capability recommended in the ITCS, in addition to other measures outside of its scope, such as resource adequacy and fuel assurance, would demonstrably improve energy adequacy under reasonably anticipated extreme conditions.[13]

Part 3 of the ITCS also provides recommendations how to meet and maintain transfer capability. *See infra* Section II.c. These recommendations should be taken, together with remainder of the ITCS, as foundational insights for further discussions and decisions on regulatory and legislative solutions. Planners, for example, should consider conditions impacting their systems and those of neighboring transmitting utilities while also considering resource adequacy.[14] The ITCS also does not evaluate particular projects. Rather, under a holistic approach, the Study recommends how much additional transfer capability at each interface would strengthen the grid.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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13 NERC highlights that transmission and TTC are part of a more expansive equation underlying energy adequacy in a modern grid, which includes matters such as available generation. The ITCS relies, for example, on future resource assumptions. If these change it could impact the energy margin analysis underlying the Part 2 analysis.

14 Please see the ITCS for discussion of additional factors that stakeholders may analyze.

I. INTRODUCTION TO NERC AND THE ERO ENTERPRISE

Electricity is a key component of the fabric of modern society. NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. The vision of the ERO Enterprise is a highly reliable and secure North American BPS. The Regional Entities help NERC support reliability across various interconnections with differing needs and characteristics.[15]

When Congress enacted the Energy Policy Act of 2005[16] and section 215 of the Federal Power Act, it entrusted the Commission with: (i) approving and enforcing rules to ensure the reliability of the BPS; and (ii) certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval, and with assessing reliability and adequacy of the BPS in North America.[17] Section 215 and Commission regulation reflect certification of an ERO subject to Commission oversight.[18] In 2006, the Commission certified NERC as the ERO.[19]

Consistent with NERC's responsibility to "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America"[20] such as NERC's Long-Term

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15 NERC's relationship with the Regional Entities is governed by Regional Delegation Agreements or "RDAs" filed with the Commission every five years. 18 C.F.R. § 39.8. A delegation agreement shall not be effective until it is approved by the Commission. *See also*, *N. Am. Elec. Reliability Corp.*, 133 FERC ¶ 61,061 (2010), *order denying reh'g*, 134 FERC ¶ 61,179 (2011), *order on compliance filing*, 137 FERC ¶ 61,028 (2011). *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61,135 (2015) (approving pro forma and individual RDAs, subject to compliance filing) and *N. Am. Elec. Reliability Corp.*, Docket No. RR15-12-001 (Mar. 23, 2016) (delegated letter order) (accepting final pro forma and individual RDAs) (collectively "2015 RDA Order"); and Order Conditionally Approving Revised *Pro Forma* Delegation Agreement and Revised Delegation Agreements with Regional Entities, 173 FERC ¶ 61,277 (2020).

16 Pub. L. 109–58, title XII, § 1211(b), Aug. 8, 2005, 119 Stat. 946.

17 16 U.S.C. § 824o(a)(2). *See also* § 824o(c) (providing the ERO certification criteria). *See also* Pub. L. 109–58, title XII, §1211(b), Aug. 8, 2005, 119 Stat. 946 (clarifying, "[t]he Electric Reliability Organization… and any regional entity delegated enforcement authority… are not departments, agencies, or instrumentalities of the United States Government.").

18 Order No. 672 at PP 183-191.

19 *See* NERC ERO Certification Order.

20 16 U.S.C. § 824o(g).

Reliability Assessment ("LTRA"), Summer Assessment, Winter Assessment, and special assessments, the Fiscal Responsibility Act tasked NERC with preparing the ITCS in consultation with the Regional Entities and transmitting utilities.

II. OVERVIEW OF THE INTERREGIONAL TRANFER CAPABILITY STUDY

The Fiscal Responsibility Act requires the ERO, in consultation with the Regional Entities and transmitting utilities with facilities neighboring another in a neighboring transmission planning region (referred to generally as "neighboring transmitting utilities"), to conduct a study of total transfer capability (also known as "TTC") between transmission planning regions that contains:

(1) Current total transfer capability between each pair of neighboring transmission planning regions.

(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.

(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.[21]

Consistent with NERC's collaborative process and congressional directive, the ITCS was prepared over a 15-month period with significant stakeholder engagement, as discussed in Section III below and reflected in Appendices B through D. The ITCS examined current TTC as Part 1 of the analysis. Part 2 of the Study completed an energy margin analysis that compared TTC against 12 weather years (including extreme weather) to identify transmission planning region energy deficiencies that warrant prudent additions to TTC to demonstrably strengthen reliability.[22] As Part 3 of the ITCS, the ITCS recommended methods to meet and maintain current TTC and

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21 *Supra* note 1.

22 The 12 weather years to ensure the ITCS examined extreme weather were selected from 2007-2023 and are non-contiguous.

enhanced TTC. These recommendations interpreted the ITCS as part of the broader discourse between the Commission, U.S. Congress, States, other policymakers, and the electric industry to leverage the ITCS findings along with more specific regional, policy, market, economic, and environmental considerations. Finally, the ERO Enterprise plans to continue regular assessments of transfer capability that will consider the latest developments in resource mixes, transmission infrastructure, new load projections, and changing weather and climate patterns.

a. Calculating Current Total Transfer Capability

In accordance with the Fiscal Responsibility Act, the fundamental question of the ITCS is the ability of the BPS to support transfers of energy between transmission planning regions when needed to ensure adequate energy to meet demand. The first required component of the ITCS is calculating current transfer capability, or TTC, between pairs of neighboring transmission planning regions.[23]

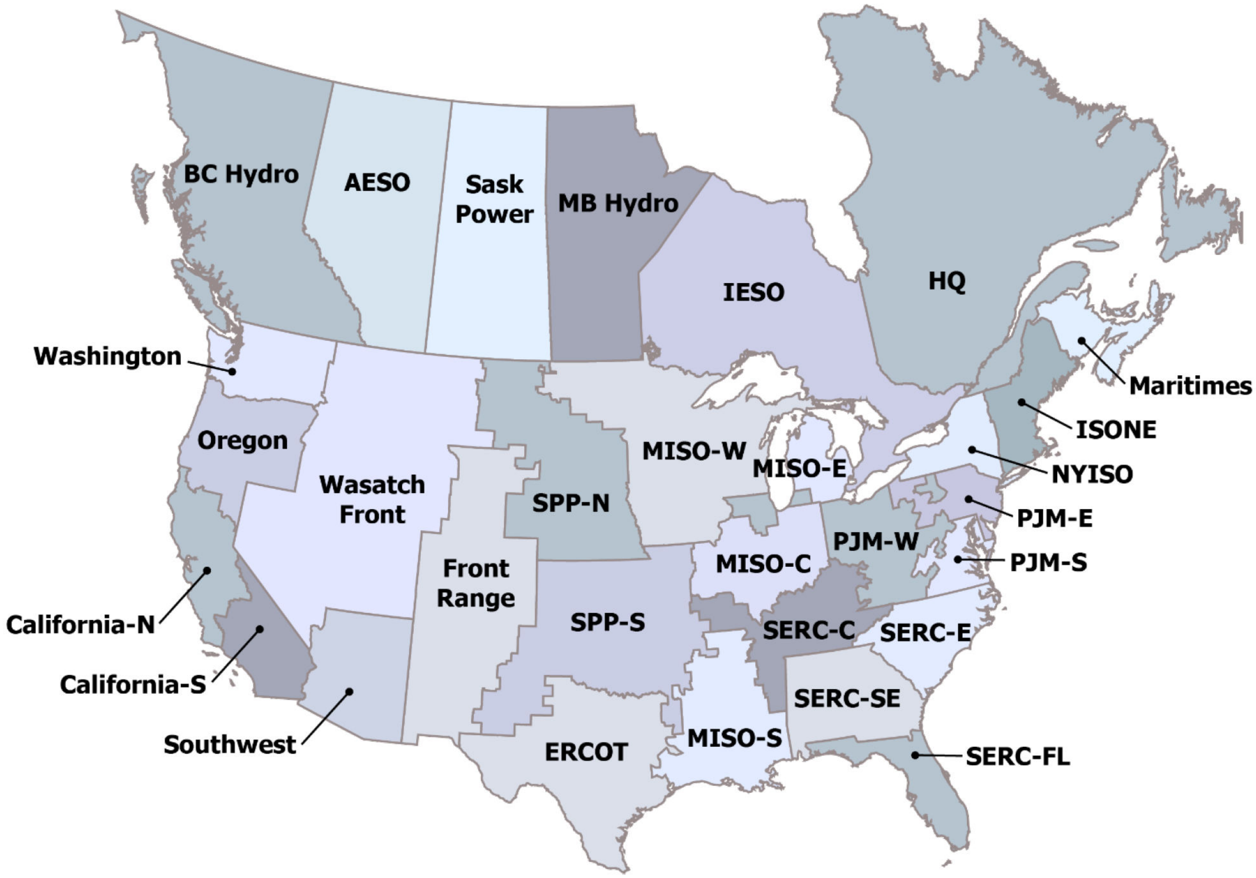
To calculate TTC, the ITCS study team, comprised of ERO Enterprise staff and consultants, first determined appropriate transmission planning regions for purposes of the Study after coordinating with the ITCS Advisory Group. To establish transmission planning regions for purposes of the Study, NERC, working with the Regional Entities, selected a set of interfaces that included all pairs of neighboring transmission planning regions to enable the ITCS performance of transfer analysis from source (exporting) region to sink (importing), and vice versa. Only electrically connected neighboring systems were evaluated to identify the transmission planning regions for purposes of Part 1 of the ITCS.[24] The ITCS regions were smaller than the Commission's Order No. 1000 regions and those that RTOs/ISOs might use to provide a more

[23] *Supra* note 1.

[24] Some geographic neighbors that were not electrically connected were evaluated as potential new connections in Part 2 of the ITCS as NERC evaluated potential recommendations to enhance transfer capability.

granular analysis of potential TTC limitations and to enable the ITCS to identify key constraints to interregional TTC.

As reflected in NERC's August 2024 posted materials, the transmission planning regions were established as follows:



After the identification of transmission planning regions, the ITCS calculated TTC according to the following steps:[25]

i) Select base cases using relevant Eastern Interconnection and Western Interconnection base cases created through Reliability Standard MOD-032-1 processes;[26]

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[25] *See* ITCS Appendix A (providing detailed explanation on the Study and its design).

[26] Base cases are computer models that simulate the behavior of the electrical system under various conditions as a snapshot in time. Base cases were not required for ERCOT and Québec Interconnections for purposes of the ITCS as they were only tied with the Eastern Interconnection via dc ties. Also, small ERCOT dc ties to Mexico were omitted from evaluation and the ERCOT-Mexico interface was outside the scope of the document.

ii) Calculate TTC using Area Interchange method as the sum of base transfer levels together with first contingency incremental transfer capability;[27]

iii) Adjust for facility monitoring criteria and thresholds to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements to avoid the appearance of artificially constrained TTC;

iv) Ensure special interface considerations (such as pertinent remedial action schemes) are understood and properly reflected in study results; and

v) Analyze total import capabilities of each transmission planning region (although not required under the Fiscal Responsibility Act) as technically requisite to appropriately model system capability for purposes of the Part 2 analysis of any prudent enhancements to TTC.

This analysis identified current TTC as illustrated in the maps discussed in more detail in the ITCS at Appendix A. These TTC results are highly dependent on the base cases and modeling assumptions described in the ITCS. The ITCS did not attempt to optimize dispatch or topology to maximize TTC, just as it also was designed to avoid underestimating TTC. The ITCS used the steps highlighted above to avoid the appearance of artificially constrained TTC.[28]

The ITCS found that transfer capability varies seasonally and under different system conditions that limit transmission loading so that it cannot be represented by a single number. Transfer capability also varies widely across North America, with total import capability between 1% and 92% of peak load. Transfer capabilities were observed as generally higher in the West Coast, Great Lakes, and mid-Atlantic areas, while relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. In addition, the ITCS found limited transfer capability between Interconnections (Western Interconnection, Eastern Interconnection, ERCOT Interconnection ("ERCOT"), and Québec). As NERC discussed these Part 1 results with industry during the Summer of 2024, it explained that the findings suggested that Part 2 analysis would

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[27] Contingencies were based on NERC Reliability Standard TPL-001-5.1 category P1 contingencies (100 kV and above).

[28] As this is a study, observed TTC may differ from the conclusions in the ITCS based on operational conditions.

probably identify prudent additions to TTC to strengthen reliability. NERC underscored that the magnitude of transfer capability is not itself a measure of energy adequacy. Rather, the identified TTC provides the foundation for subsequent energy margin analysis in Part 2 of the ITCS.

b. <u>Identifying Prudent Additions to Transfer Capability to Demonstrably Strengthen Reliability</u>

The Fiscal Responsibility Act requires NERC to consider and recommend prudent additions to TTC "between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions."[29] For the purposes of determining a "prudent addition," NERC looked to the standard used in Commission precedent in electric utility ratemaking proceedings, which provides that "prudence" means a determination of whether (1) a reasonable entity (2) would have made the same decision, (3) in good faith, (4) under the same circumstances, and (5) at the relevant point in time.

Determining exactly how much additional transfer capability is "prudent" can depend on the totality of factors and circumstances. For example, as part of examining the totality of circumstances, the Commission has considered matters such as whether activities have enhanced the ability to restore service, achieved significant efficiencies, reduced costs or time delays, and/or made efficient use of resources to ensure reliability.[30] As discussed immediately below, NERC applied a six-step process to ensure that the ITCS's tailored recommendations for prudent additions to transfer capability for certain pairs of neighboring transmission planning regions are those that a reasonable entity would have made in good faith under the same circumstances and at the same point in time considering reliability of the system as the driving factor.

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29 *Supra* note 1.

30 *See, e.g.*, *New England Power Co.*, 31 FERC ¶ 61,047 at 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC*, 140 FERC ¶ 61,229 at P 82 (Sept. 20, 2012).

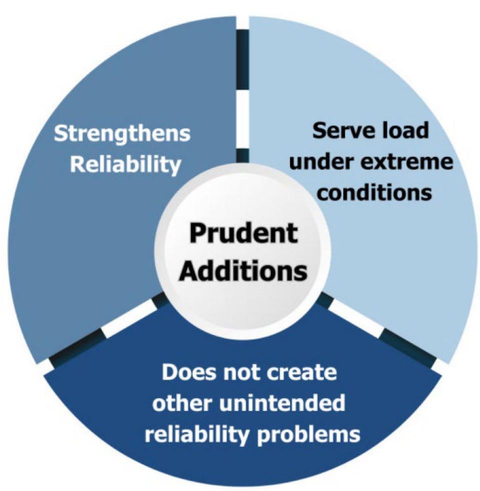
NERC underscores that nothing in the ITCS should be used as justification for a particular project and that no part of the ITCS is intended as evidence regarding prudence in any ratemaking proceeding. The ITCS does not include economic assessments, project-specific recommendations, transmission expansion analysis, operational mitigation or capacity expansion planning. A holistic view of the BPS and a thorough understanding of its behavior will be essential when calculating or increasing transfer capability.

The ITCS particularly examined the extent to which recommended enhancements would be reasonably expected to demonstrably strengthen reliability of the BPS. To do so, the ITCS examined whether the potential recommendation would strengthen reliability, serve load under extreme conditions, and avoid creating unintended reliability concerns as follows:

(1) **Strengthen Reliability:** Provides a potential solution that enables more flexibility between transmission planning regions and access to resources that may be available during local energy deficits.

(2) **Serve Load Under Extreme Conditions:** Provides a solution that serves future demand during extreme conditions, which is a more restrictive design basis than current resource adequacy constructs.

(3) **Does Not Create Unintended Reliability Concerns:** Recommendations for larger connections between transmission planning regions will require detailed system studies to assure system stability.



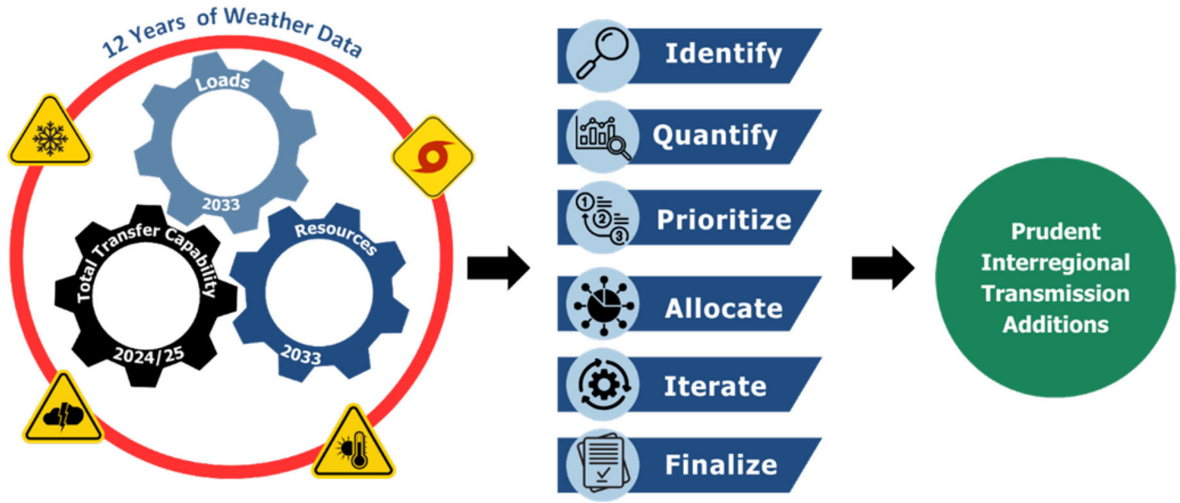
Under Part 2 of the ITCS, the ITCS conducted energy margin analysis of resource availability and interregional transfers across 12-years of meteorological conditions and extreme weather data to examine whether the transfer capability calculated for a pair of neighboring transmission planning regions would be unable to meet energy needs under times of stress, being thus "deficient" and reflecting a risk of energy inadequacy for those regions.

As a result, where the ITCS energy margin analysis found a deficiency and corresponding risk, NERC led a further layer of study that applied several considerations and criteria under a six-step process to evaluate whether, and how much, additional transfer capability would mitigate the potential risk of energy inadequacy created by the deficiency.

The six-step process entails the following and is discussed in detail in Chapter 6 of the ITCS at Appendix A:

i. Identify hours of resource deficiency
ii. Quantify the maximum resource deficiency
iii. Prioritize constrained interfaces
iv. Allocate additional transfer capability
v. Iterate until resource deficiencies are mitigated
vi. Finalize prudent level of transfer capability

A diagram of the analysis will help explain further:



The ITCS recommended prudent additions to transfer capability to the extent that results reflected that enhanced transfer capability would assuage the risk of energy inadequacy (as reflected by the deficiencies shown after energy margin analysis).

In total, across various regions of the U.S., the ITCS recommends 35 GW of additional transfer capability to demonstrably strengthen reliability. These recommendations are detailed in the ITCS at Appendix A and break down according to the following table **Table ES.1**:[31]

[31] In two cases, it was not possible to eliminate all energy deficiencies, even by increasing transfer capability, due to wide-area resource shortages. In ERCOT and California North, resource deficiencies remained even after increasing transfer capability by 14 GW and 1 GW, respectively.

Table ES.1: Recommended Prudent Additions Detail					
Transmission Planning Region	**Weather Years (WY) / Events**	**Resource Deficiency Hours**	**Maximum Deficiency (MW)**	**Additional Transfer Capability (MW)**	**Interface Additions (MW)**
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				**35,000**	

Increasing Energy Deficiency Hours

In making these recommendations, NERC acknowledges that transfer capability is only one part of the overall equation and that other elements such as generation resource availability, new load projections, additional weather information, and demand response should also be taken into account.[32] Moreover, these recommendations do not account for economic, environmental, permitting or policy considerations that the Commission, U.S. Congress, other policymakers, and the electric industry may apply following the ITCS.

[32] Please see NERC's website for more information regarding these issues. *See also*, ITCS, Appendix A, Chapter 11 (providing further considerations). NERC has focused the ITCS on transfer capability in accordance with Congressional directive.

c. Recommendations to Meet and Maintain Sufficient Transfer Capability

The final requirement of the Fiscal Responsibility Act of 2023 is to develop recommendations to meet and maintain transfer capability together with recommended prudent additions.[33] The ITCS provided recommendations to support transfer capability in the future without specifying a particular set of projects or approach. This recognizes that increased transfer capability is one of many options for addressing the identified energy deficiencies. Such options at a high level include:

- Increase transfer capability to neighbors with surplus resources
- Construct local generation
- Increase demand response resources
- Accept the identified risks during extreme events (assuming other reliability thresholds are met).

Timing for these approaches may vary, so further studies are needed for implementation. Grid operators must also be prepared to maintain BPS reliability through emergency measures (including rotating outages if necessary) meanwhile.

If planners elect to increase transfer capability to meet the recommendations listed in the ITCS, options to consider include:

- **Upgraded transmission infrastructure**: Such as building new lines and reconductoring existing lines or raising existing tower structures where feasible.
- **Remedial action schemes ("RAS")**: Increasing transfer capability via adjustments to RAS may be helpful in the short-term while other solutions are implemented. RAS are not advised as a long-term solution as these schemes introduce higher operational complexity.
- **Dynamic line ratings ("DLR")**: DLR could use real-time and forecasted weather conditions to continuously calculate the thermal capacity of transmission lines and

[33] *Supra* note 1.

may at times facilitate increased transfer capability during favorable weather conditions. However, DLR may not be suitable in all situations.

- **Power flow control devices**: Power flow control devices with newer digital control technology that allows for faster responses to system needs may help support transfer capability and enhance the transmission planning process.

With regard to maintaining transfer capability, the ITCS explained that actual transfer capability available during real-time operations may be different from that calculated due to system conditions during actual operations. A certain level of transfer capability cannot always be maintained due to those changing system conditions and, therefore, the ITCS focused on what can be accomplished during the planning horizon. These recommendations to maintain transfer capability include:

- **Coordination Agreements**: Strong coordination procedures and agreements can maximize available support during stress conditions (such as extreme weather events). This coordination could include rigorous maintenance activities and coordinated maintenance to avoid overlapping with periods of increased stress.

- **Future Studies**:

    - **ERO Enterprise Studies**: The ERO Enterprise, working with industry, is planning to conduct regular assessments rolled into future Long-Term Reliability Assessment reports that will consider developments in this area. NERC is also considering the issues as part of its Energy Assessment Strategy.

    - **Planning / Maintenance**: Planners can evaluate changes in transfer capability as part of regular processes.

- **Regulatory and Policy Mechanisms**:

    - The ITCS noted that a uniform minimum transfer capability requirement may not be an effective or efficient approach to ensure energy adequacy.

    - The ITCS recommended that policy makers consider mechanisms to address existing challenges associated with siting/permit approvals, cost-allocation, and multi-party operating and maintenance agreements.

- **Reliability Standards**:

- The ITCS clarified that it is not NERC's intent to develop Reliability Standard modifications to require entities to meet and maintain a certain transfer capability, without prejudice to NERC's consideration of modifications in the future of matters such as assessments associated with planned transfer capability.
- NERC has two standard development projects (Project 2022-03 Energy Assurance with Energy-Constrained Resources and 2024-02 Planning Energy Assurance) related to energy assurance and the assessment of energy adequacy.

System studies are urged to ensure careful deployment of ITCS recommendations. To give these recommendations meaning, transmission planners and planning coordinators will need detailed studies to select projects or actions that take advantage of the opportunity identified in the ITCS without inadvertent consequences. The ITCS explained limitations on its scope as well as steps that stakeholders could take to further build on the opportunities identified therein.[34] As highlighted throughout the ITCS and this filing, the ITCS is intended as a launch-pad to further North America's efforts to plan infrastructure and coordination that supports a modern grid.

NERC urges policymakers and industry to carefully consider how to leverage the recommended additions to transfer capability outlined in the ITCS. As mentioned above, the recommendations identify directional, rather than prescriptive, guidance. The ITCS provides a roadmap for understanding where transmission may benefit from enhancement, without mandating specific projects or a minimum level of transfer capability. While the ITCS recommends increased transfer capability on particular interfaces, NERC does not endorse projects or particular approaches. This is intentional because planners must evaluate potential downstream impacts of increased transfer capability. For example, while greater transfer capability can improve energy adequacy, there can be situations where a large transfer of energy has consequences for other

[34] Without limitation on future analysis or action, NERC does not recommend any Reliability Standards changes at this time as a result of the ITCS.

aspects of reliable system operations such as system stability, voltage control, and measures to minimize the potential for cascading outages. Transmission planning regions must coordinate system enhancements to support rational and effective implementation of the ITCS findings. Further, planners might consider other options not within the scope of the ITCS. While the ITCS focuses on transfer capability per congressional directive, regions might construct additional resources or increase demand response resources. Further, the ITCS acknowledges that existing or planned projects may also be responsive to the opportunities and recommendations identified in the ITCS. As stated above, the ITCS findings should be considered foundational insights for further discussions and decisions.

III. CONSULTATION WITH REGIONAL ENTITIES AND TRANSMITTING UTILITIES

The Fiscal Responsibility Act requires that NERC conduct the ITCS in consultation with the six Regional Entities and neighboring transmitting utilities.[35] Consultation is understood as a meaningful exchange of information prior to final decision-making.[36] Consistent with Congressional directive and NERC's regular collaborative process as the ERO Enterprise coordinating with stakeholders to ensure reliability, NERC frequently consulted with the Regional Entities and transmitting utilities throughout the design and execution of the ITCS.

As illustrated below, the stakeholder engagement process included 14 Advisory Group meetings, three letters to transmitting utilities seeking input and feedback, presentations at NERC Board of Trustee ("Board") meetings and over 100 industry and trade group meetings. In addition,

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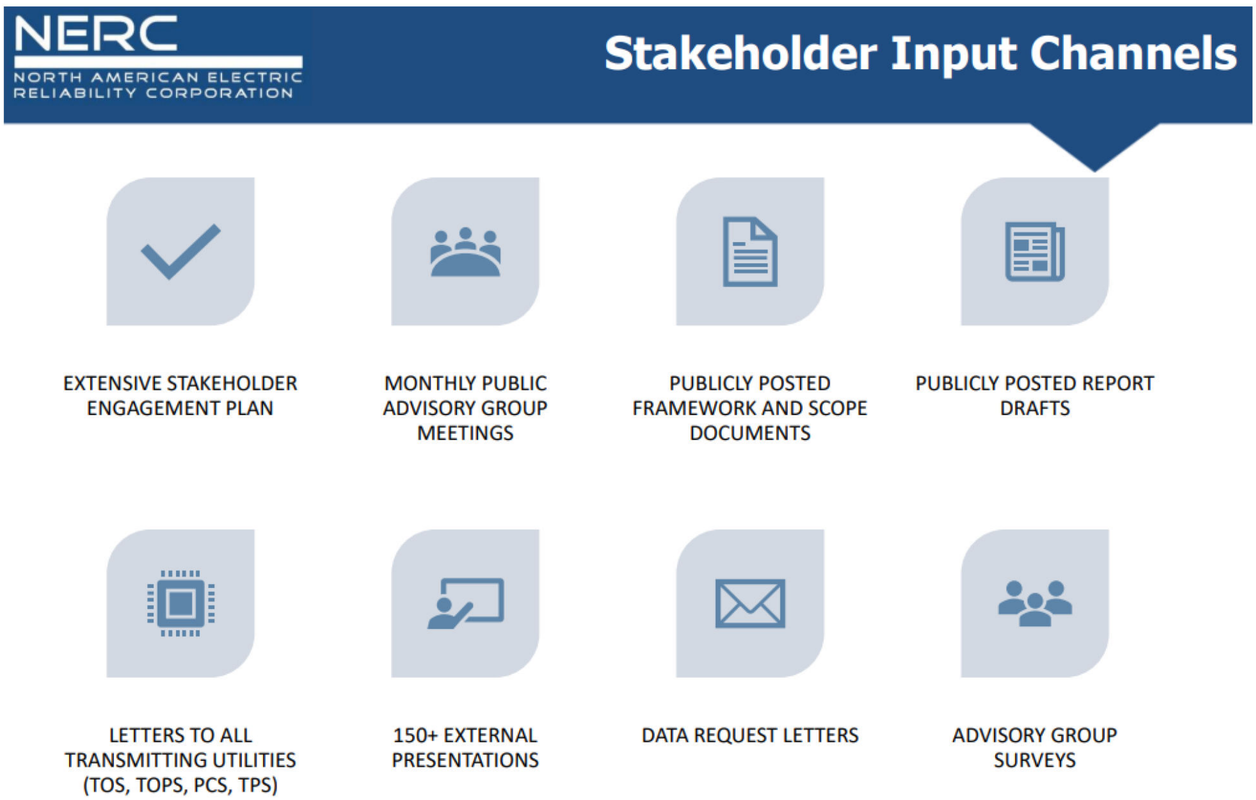
35 *Supra* note 1.

36 *See, e.g.*, *Envtl. Def. Ctr., Inc. v. U.S. Envtl. Protection Agency*, 344 F.3d 832 (9th Cir. 2003) (highlighting that consultation was reflected by activities such as circulating a draft report to stakeholders, establishing an advisory committee, holding several meetings as part of that advisory committee, and obtaining input from State and municipal representatives on drafts); and *South Carolina v. United States*, 329 F. Supp. 3d 214 (2018) (finding that the Department of Energy engaged in a meaningful exchange of information and views with governor prior to the decision); *cf. Cal. Wilderness Coalition v. U.S. Dep't of Energy*, 631 F.3d 1072, 1087, 1080, 1085) (2011) (explaining that consultation entails a meaningful exchange and more than public comment).

to facilitate these conversations and ongoing exchange of perspectives as NERC led the ITCS, NERC publicly published scoping documents and quarterly updates associated with the ITCS on NERC's ITCS webpage. Further, NERC published the parts of the ITCS via a series of three reports (an introductory Overview report, transfer capability analysis Part 1 report, and prudent recommended additions to transfer capability Part 2 and 3 report) prior to finalizing and consolidating these portions into the attached ITCS (**Appendix A**).



This consultation process is consistent with the ITCS Framework that NERC published in the summer of 2023. That Framework established NERC's plan to engage with its executive leadership, Regional Entities across different levels of leadership and technical expertise, and industry. This plan included the ERO Enterprise's coordination with an ITCS Advisory Group comprised of diverse industry experts (including, for example, those from the Department of Energy ("DOE"), the Commission, and transmission planners from across the BPS), as well as additional outreach to transmitting utilities. *See*, **Appendix B** (list of stakeholder engagement activities), **Appendix C** (letters to transmitting utilities for feedback); and **Appendix D** (Advisory Group and ITCS Study Team Rosters and List of Public Meetings).

In accordance with the Framework illustrated above, NERC involved Regional Entities in the ITCS on a weekly basis to design and execute the ITCS and has met with the Advisory Group approximately every month to obtain input on ITCS design, execution, and findings. These groups were also asked to provide feedback on draft materials, such as the initial draft Framework, subsequent scope documents for different parts of the ITCS, and the portions of the ITCS that were rolled out in phases and culminated in the ITCS attached at **Appendix A**. All Advisory Group meeting presentations were publicly posted on NERC's ITCS webpage. Comments from Advisory Group members on various parts of the ITCS were also posted on NERC's ITCS webpage along with NERC's consideration and responses. The process ensured that NERC received input during each stage of the ITCS from its initial framing to more detailed scoping and throughout the ITCS while the ERO Enterprise study team examined the issues and finalized decisions.[37]

To maximize the opportunity for stakeholder consultation, NERC published draft portions of the ITCS on its webpage (after seeking Advisory Group feedback) in stages. First, NERC published an Overview report introducing the ITCS and its approach in June 2024. Second, NERC published its calculated total transfer capability in August 2024. Third, in November 2024, NERC published its proposed recommended prudent additions to total transfer capability in certain regions of the U.S. and recommended means to meet and maintain transfer capability today and as enhanced after consideration of the ITCS recommendations. (Part 2 & 3 Report). These three parts were consolidated after final revisions into the attached ITCS (**Appendix A**). NERC plans to issue a fourth report in 2025 studying transfer capabilities from the U.S. to Canada and between Canadian provinces.[38]

In addition, NERC sent three sets of letters to all transmitting utilities in 2024 to obtain feedback on the ITCS.[39] The first letter was sent in January of 2024 seeking input generally on the ITCS, posted framework, and scope documents. The second letter was sent in September of 2024 to solicit input from transmitting utilities on the ITCS Overview report, total transfer capability report (Part 1), and Advisory Group materials (which included material on considerations and criteria to determine any recommended prudent additions to transfer capability). NERC's third letter to transmitting utilities was issued November 4, 2024, after the

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37 Examples included the decision to study simultaneous import capability and use 2024/2025 system conditions (or "base cases") to calculate current total transfer capability.

38 While this part is outside the specific congressional mandate, the interconnectedness of the North American BPS warrants analysis of Canada.

39 The Fiscal Responsibility Act required NERC to consult with neighboring transmitting utilities, however, to facilitate the broadest opportunity for consultation NERC sent these letters to all transmitting utilities.

final in-person Advisory Group meeting, to solicit input on NERC's proposed recommended prudent additions and recommendations on how to meet and maintain current total transfer capability and transfer capability as enhanced by any additions (the Part 2 & 3 report). NERC's preliminary recommendations for prudent additions were also shared with the Advisory Group in September 2024 with publicly posted materials available on the ITCS webpage to provide ample opportunity for comments before the Part 2 and 3 publication and before finalizing a final report.

NERC takes this opportunity to thank all those stakeholders and members of the ERO Enterprise who participated in the ITCS. This feedback has been instrumental in developing a nuanced study that is unique in terms of its geographic magnitude and overall approach to assessing energy adequacy under extreme conditions.

IV. CONCLUSION

Therefore, for the reasons set forth above, NERC hereby submits this ITCS to the Commission as directed by the U.S. Congress in the Fiscal Responsibility Act. The ITCS finds that while current total transfer capability is largely sufficient to support energy adequacy at present, when calculating energy margin analysis and extreme weather over a forward-looking ten-year outlook, there may likely be insufficient transfer capability. Based on the identified deficiencies that reveal certain transmission planning regions at risk for energy inadequacy, the ITCS recommends 35 GW of additional total transfer capability as a prudent measure to demonstrably strengthen reliability subject to coordination between governmental authorities, policy makers, and industry. NERC also plans to continue evaluating transfer capability as a regular part of its assessments going forward such as the LTRA. NERC on behalf of itself and the full ERO Enterprise, looks forward to continuing to participate in this discourse and preparing North America to meet the needs of the modern grid.

Respectfully submitted,

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Date: November 19, 2024

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Appendix A

Interregional Transfer Capability Study 2024

NERC
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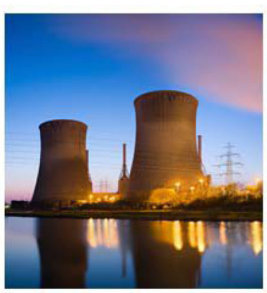
Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Final Report

RELIABILITY | RESILIENCE | SECURITY

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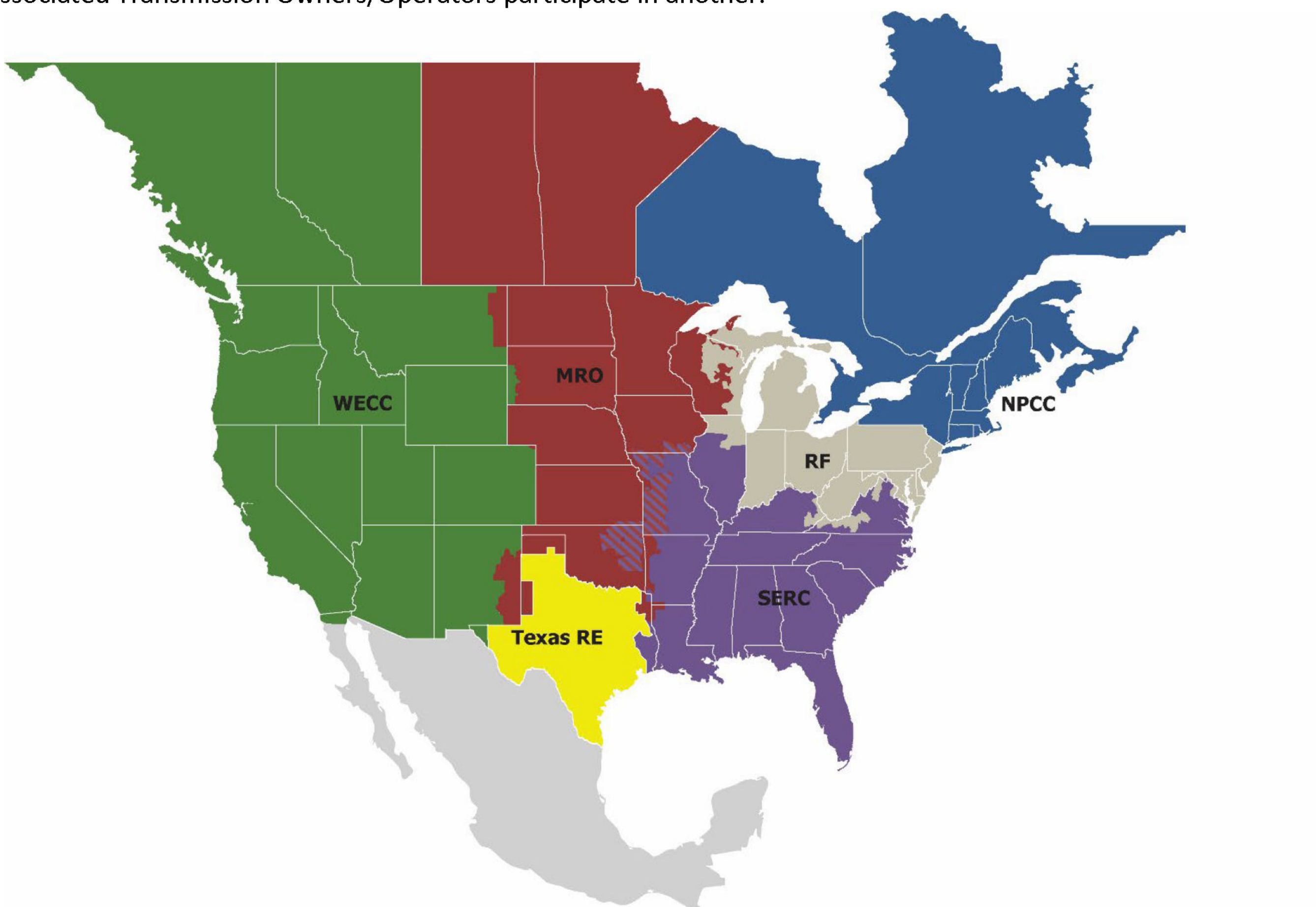
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American Bulk Power System (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Statement of Purpose

In June 2023, Congress enacted legislation – the Fiscal Responsibility Act of 2023[1] – that mandated NERC, as the ERO, to conduct the Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission transfer capability to enhance reliability:

> *The Electric Reliability Organization…in consultation with each regional entity…and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:*
>
> *(1) Current total transfer capability, between each pair of neighboring transmission planning regions.*
> *(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.*
> *(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.*

This congressional directive falls within the scope of NERC's obligation under section 215 of the Federal Power Act,[2] to "conduct periodic assessments of the reliability and adequacy of the bulk power system in North America."[3] NERC and the six Regional Entities,[4] collectively called the ERO Enterprise, developed and executed the ITCS in collaboration with industry to address the congressional directive. This report details the inputs, processes, key findings, and recommendations of the ITCS.

[1] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[2] 16 U.S.C. § 824o [hereafter section 215]

[3] Section 215(g). Such reliability assessments include the Long-Term Reliability Assessment (LTRA), Summer Assessment, Winter Assessment, and special assessments.

[4] NERC's work with the Regional Entities is governed by Regional Delegation Agreements (RDA) on file with FERC and posted on NERC's website. See also section 215(e)(4).

Executive Summary

The North American grid is a complex machine that has evolved over many decades and integrates a network of generation, transmission, and distribution systems across vast geographic areas.[5] As a result of the changing resource mix[6] and extreme weather, interregional energy transfers play an increasingly pivotal role. More than ever, a strong, flexible, and resilient transmission system is essential for grid reliability. NERC, as the Electric Reliability Organization (ERO), remains focused on assuring reliability throughout this energy transformation. As evidenced during recent operational events,[7] more needs to be done to support energy adequacy[8] to be able to continuously meet customer demand. This is the reliability risk that the Interregional Transfer Capability Study (ITCS) seeks to identify and mitigate through additions to transfer capability[9] as directed in the Fiscal Responsibility Act of 2023.[10]

THE ITCS

In Scope

- ✓ A common modeling approach to study the North American grid independently and transparently
- ✓ Evaluation of the impact of extreme weather events on hourly energy adequacy using the calculated current transfer capability and 10-year resource and load futures
- ✓ Recommendations for additional transfer capability between neighboring regions to address energy deficits when surplus is available
- ✓ Extensive consultation and collaboration with industry
- ✓ Reliability improvement as the sole factor in determining prudence

Out of Scope

- ✗ Economic, siting, political, or environmental impacts
- ✗ Alternative modeling approaches – ITCS results may differ from other analyses
- ✗ Quantified impacts of planned projects
- ✗ Recommendations for specific projects, as additional planning by industry would be necessary to determine project feasibility
- ✗ Recent changes to load forecasts, renewable targets, or retirement announcements

A Critical Study

Previous NERC assessments[11] identified the need for more transmission transfer capability, as well as a strategically planned resource mix,[12] to address these changes and support the ongoing electrification of the economy including the growing transportation sector, industrial loads, and data centers. More frequent extreme weather events further compound the challenge. While always important, the need for a reliable energy supply – in the interest of public health, safety, and security – becomes most pronounced under these extreme conditions. These factors emphasize the criticality of adequate and informed planning at a broader interregional level that will support future grid reliability. For this reason, developing a common approach and consistent assumptions, with model development, validation, and results coordinated with industry, was key to the study's design. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions but is not a transmission plan or blueprint. Transmission assessments, like the

---

[5] An explanation of the grid can be found at *Electricity Explained – U.S. Energy Information Administration* (*April 2024*).

[6] This phrase relates to the replacement of traditional dispatchable resources with a higher percentage of intermittent resources with non-stored fuel sources, such as wind and solar resources.

[7] The ITCS Overview of Study Need and Approach includes examples of the role of transfer capability during the Western Interconnection Heatwave (2020), Winter Storm Uri (2021), and Winter Storm Elliott (2022).

[8] While there are many facets to reliability, the ITCS focuses on energy adequacy, the ability of the bulk power system (BPS) to meet customer demand at all times.

[9] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[10] H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[11] NERC's assessments can be found at nerc.com.

[12] The terms "resource mix" and "resources" broadly include generators, storage, and demand response.

ITCS, are crucial to mitigating future risks; however, alternative approaches other than transmission can also mitigate future energy risks, such as local generation, or demand-side solutions.

The study specifically does not include:

- **Economic Assessments:** Economic analysis, cost-benefit evaluation, or financial modeling were not factors in determining prudent recommendations. The focus was strictly on improving energy adequacy.
- **Project-Specific Recommendations:** This report highlights areas where new capacity is desirable to improve reliability but does not endorse individual transmission projects.
- **Transmission Expansion Analysis:** The ITCS is not a replacement for existing or future transmission expansion planning efforts or interconnection studies nor does it represent a comprehensive transmission plan. Economic and project viability assessments are needed to fully understand cost implications, market impacts, siting and permitting challenges, and further technical considerations.
- **Operational Mitigation:** The ITCS used existing interconnection planning models developed annually by NERC and the Regional Entities. The analysis did not evaluate operational mitigations through re-dispatch or other actions.
- **Capacity Expansion Planning:** Transmission needs are heavily influenced by future resource assumptions. Significant changes to the underlying assumptions could impact the energy margin analysis and, consequently, the identified prudent additions. Due to gaps in firm resource plans for 2033 in many areas, the ITCS established a future resource mix assumption based on available plans, ranging from certain to speculative resources.[13]

The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and action in response to the opportunities identified. Therefore, the ITCS:

- **Acknowledges Anticipated Benefits of Projects Already in Progress:** NERC acknowledges that transmission projects in planning, permitting, or construction phases may reduce some needs identified in the ITCS. The existence of these projects supports the ITCS findings by highlighting their relevance to improving reliability. By underscoring these projects' critical roles, the study affirms the need for timely completion of these or similar efforts supporting overall grid resilience.
- **Leaves Implementation to Policymakers and Industry:** The ITCS does not prescribe "how" prudent additions to transfer capability should be achieved, rather provides information on what would be desirable to improve energy adequacy. While prudent additions are one approach to reducing vulnerability during extreme conditions, these needs can be addressed in various ways. The study's findings underscore the urgency of targeted, strategic actions but remain flexible in implementation. The directional guidance provided by the ITCS is foundational to ongoing planning, regulatory, and legislative efforts aimed at securing a resilient and reliable grid.

The ITCS demonstrates a significant opportunity to optimize reserve use during extreme weather events and shows how transmission can maximize the use of local resources, including storage and demand response. Further, the ITCS highlights the continuing importance of resource planning, as increasing transfer capability without surplus energy would be inefficient.

[13] The future resource mix assumptions are based on the 2023 Long-Term Reliability Assessment (LTRA), which projects new resources in three tier levels. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion, and Tier 3 resources are even less certain.

Study Progression: Enhancing Reliability

As shown in **Figure ES.1**, the ITCS project consists of four parts.

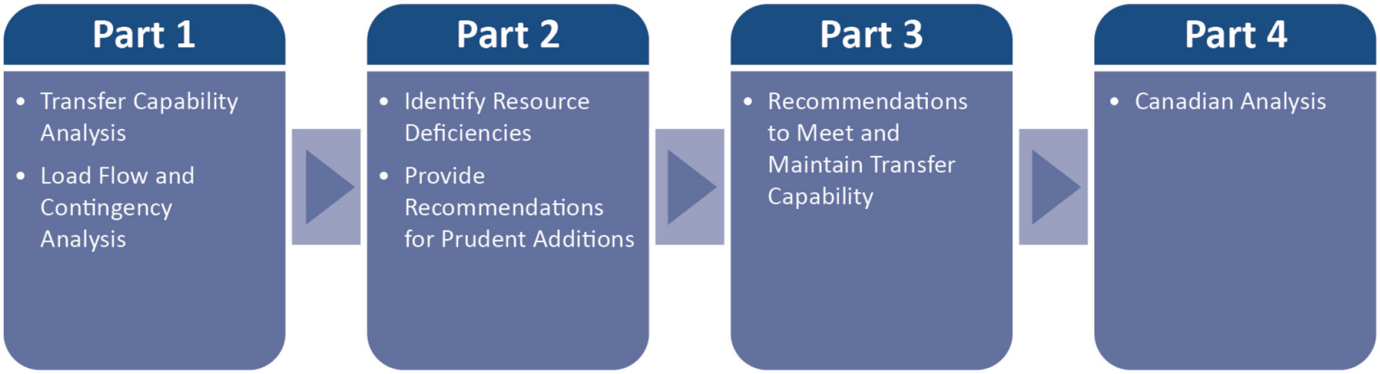


Figure ES.1: Study Parts

Overview of Study Need and Approach

The first ITCS document – *Overview of Study Need and Approach*[14] – was released in June 2024. It provides background and context on the study, including a brief discussion of recent operational events. It also includes details of transfer capability calculations and the approach for recommending additions to transfer capability, laying the foundation for the ITCS.

Transfer Capability Analysis (Part 1)

The second ITCS document – *Transfer Capability Analysis (Part 1)*[15] – was released in August 2024 and addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring Transmission Planning Regions (TPR).[16] Transfer capability is the amount of power that can be reliably transported over a given interface under specific conditions. The Part 1 study report provided the calculation and limitations of current total transfer capability (TTC)[17] and informed Part 2 of the study.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

The third ITCS document – *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)*[18] – was released in November 2024. It contained an energy margin analysis and resulting recommendations for prudent[19] additions[20] to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.

[14] The ITCS Overview of Study Need and Approach further explains transfer capability, calculation method, study assumptions, and other study information.

[15] The ITCS Transfer Capability Analysis (Part 1) report was published in August 2024.

[16] This is not a defined term in the NERC Glossary of Terms, but for the ITCS, this term refers to the study regions that are described in the ITCS Overview, the ITCS Transfer Capability Analysis (Part 1) report, and in **Chapter 1** of this report.

[17] The TTC method was used for consistency across the study area, and these values are distinct from the path limits used by some entities.

[18] The ITCS Parts 2 and 3 Report was published in November 2024.

[19] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., *New England Power Co*., 31 FERC ¶61,047 at p. 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC,* 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).

[20] A discussion of the interpretation of technically prudent additions to transfer capability can be found in the ITCS Overview of Study Need and Approach. Hereafter, this is typically referred to interchangeably as "recommended additions" or "prudent additions."

Canadian Analysis

Due to the interconnected nature of the bulk power system (BPS),[21] NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[22] The Canadian analysis will be published in the first quarter of 2025.

Stakeholder Engagement During the ITCS

To ensure a comprehensive and inclusive study, an ITCS Advisory Group of stakeholders was formed including regulators, industry trade groups, and transmitting utilities across North America. Throughout the process, NERC and the Regional Entities undertook a comprehensive outreach program to keep industry and stakeholders informed through regular updates and to provide opportunities for input. The ITCS Advisory Group meetings, which are public, are posted on the ITCS web page, along with other project materials and supporting information. The involvement of these stakeholders is critical toward making the ITCS as effective as possible.

The ITCS is the beginning of an extensive process involving the evaluation of the recommended additions made in this report. NERC encourages all stakeholders to continue the constructive engagement and collaboration shown in this process to address the challenges facing our grid. NERC is committed to doing its part by integrating transmission adequacy into future Long-Term Reliability Assessments (LTRA) and continuing to highlight risks in its reliability assessments.

ANALYSIS: Transfer Capability (Part 1)

Part 1 (beginning in **Chapter 3**) addressed the first part of the congressional directive that mandated an analysis of the current transfer capability between each pair of neighboring TPRs. The results of the Part 1 analysis informed Part 2 of the study.

Key Findings – Part 1

- Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas, but relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. There is limited transfer capability between Interconnections.

The Part 1 current transfer capability analysis between each pair of neighboring TPRs focused on two different base cases[23] representing 2024 Summer and 2024/25 Winter, with results shown in **Figure ES.2** and **Figure ES.3**, respectively. A complete listing of the current TTC results can be found in **Chapter 4**.

[21] The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

[22] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

[23] Base cases are computer models that simulate the behavior of the electrical system under various conditions. The cases chosen were from readily available seasonal peak load models and updated by industry to reflect future conditions.

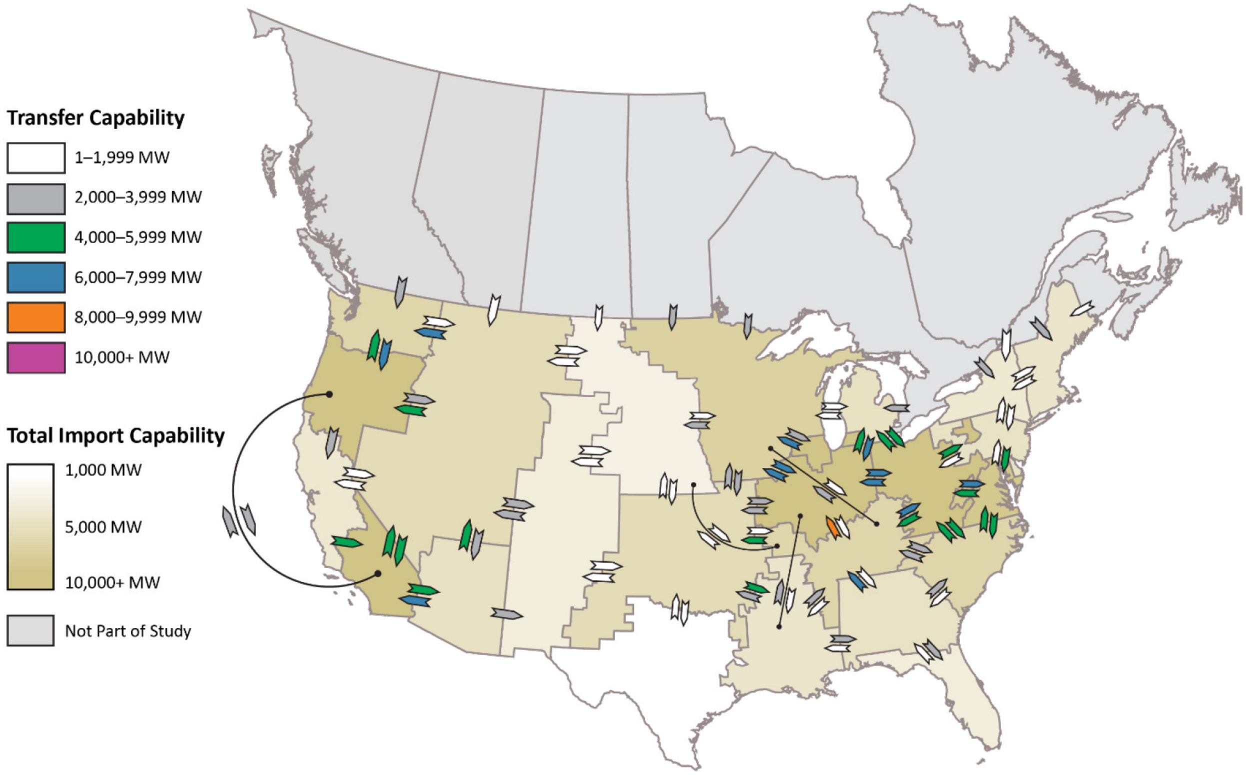


Figure ES.2: Transfer Capabilities (Summer)

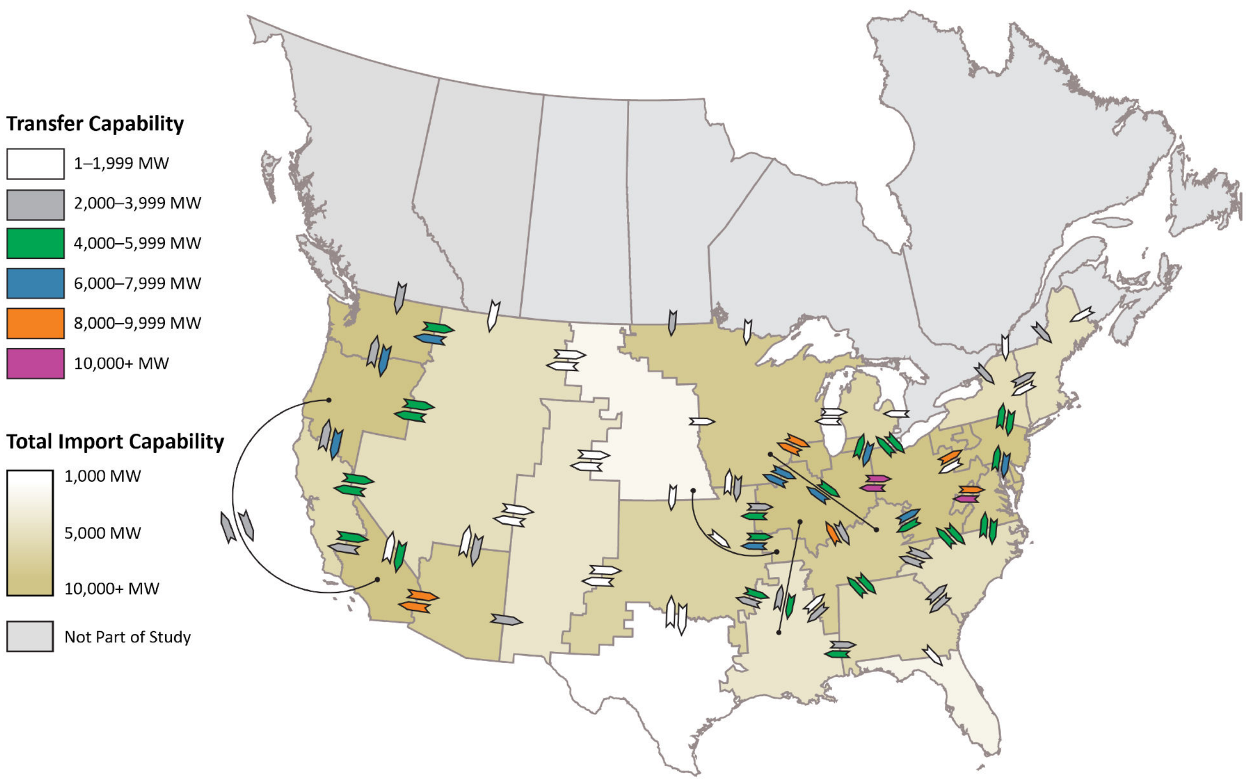


Figure ES.3: Transfer Capabilities (Winter)

The transfer capability results in this report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, both of which can vary significantly between seasons. For the same reasons, transfer capability can be different during non-peak periods than the peak conditions studied. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR, but over many routes, some of which may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

RECOMMENDATIONS: Prudent Additions to Transfer Capability (Part 2)

Part 2 (beginning in Chapter 5) addressed the second part of the congressional directive, which mandated a set of recommendations for prudent additions to transfer capability that would strengthen reliability.

Key Findings – Part 2 and 3

- The North American system is vulnerable to extreme weather. Transmission limitations, and the potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing specific transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional conditions. The import capability needed during extreme conditions varied significantly across the country, indicating that a one-size-fits-all requirement may be ineffective. An additional 35 GW of transfer capability is recommended across the United States as a vehicle to strengthen energy adequacy under extreme conditions:
  - ERCOT faces large energy deficits under various summer and winter conditions, including Winter Storm Uri in 2021.
  - California North faces energy adequacy challenges during large-scale heat events in the Western Interconnection, such as the one that occurred in 2020.
  - Energy shortages in New York were observed during multiple events.
  - MISO-E, PJM-S, SERC-E, SERC-Florida, and SPP-S each have significant vulnerability to extreme weather (>1,000 MW).
  - Enhancing interfaces between Interconnections (Western, ERCOT, Eastern, and Québec) could provide considerable reliability benefits.
  - The inclusion of Canada highlights interdependence and opportunities to increase transfer capability.
- Interregional transmission could mitigate certain extreme conditions by distributing resources more effectively, underscoring the value of transmission as an important risk mitigation tool, if there is sufficient available generation in neighboring systems at the times of need. However, there are numerous barriers to realizing these benefits in a timely fashion.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher than expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability needed than recommended in this study (if surplus energy is available from neighbors).
- The ITCS provides foundational insights for further study, discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions. A diverse and flexible approach allows solutions tailored to each TPR's vulnerabilities, risk tolerance, economics, and policies.

Defining Prudent Additions in Context of Reliability

Prudent additions mitigate identified instances of energy deficiency without regard to economic considerations.

This study defined "prudent additions" as potential transmission enhancements identified to mitigate grid reliability risks under especially challenging conditions. The ITCS mandate requires NERC to develop these recommendations that *"demonstrably strengthen reliability;"* therefore recommendations are made that are beyond the existing reliability requirements and transmission needs supporting reliability and economic planning. Notably, the ITCS does not consider economic feasibility. The analysis excludes cost-benefit assessments, meaning no economic or financial modeling was used in determining prudent recommendations. Prudent additions are recommendations based on reducing energy deficits by transferring available excess energy from neighboring TPRs and have three primary objectives:

- **Strengthen Reliability:** Provides a potential solution that enables more flexibility between TPRs and access to resources that may be available during local energy deficits.
- **Serve Load Under Extreme Conditions:** Provides a solution that serves future demand during extreme conditions, which is a more restrictive design basis than current resource adequacy constructs.
- **Does Not Create Unintended Reliability Concerns:** Recommendations for larger connections between TPRs will require detailed system studies to assure system stability.

These recommendations are built upon rigorous modeling of extreme conditions where the BPS experiences stress due to factors such as elevated demand levels, limited generation availability (e.g., from weather-dependent renewables), and transmission limitations or contingencies impacting energy delivery. Across all TPRs evaluated, the estimated unserved load – the hours during which demand outstrips supply – varies from 0 to 135 hours, directly reflecting different levels of reliability risk. Recommended additions seek to reduce these potential load-shedding risks. In some cases, policymakers may choose to accept some risk as the likelihood of load loss is small, and other mitigation may be more acceptable.

The prudent additions to transfer capability represent directional guidance for strengthening reliability under extreme conditions and should not be misconstrued as mandatory construction directives but rather as directional insights for supporting system resilience.

Evaluating Prudent Additions to Transfer Capability

Part 2 of the ITCS evaluated the future energy adequacy of the BPS based on past weather conditions occurring again in 2033. Specifically, the study applied 12 past weather years to the 2033 load and resource mix using the current transfer capabilities as calculated in Part 1.[24] This future year (2033) was selected because interregional transmission projects typically require at least 10 years to plan and build but forecasting demand and resources beyond that timeframe becomes increasingly speculative and uncertain.

The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby improving energy adequacy. The six-step process (see **Figure ES.4**) used in this evaluation is described in **Chapter 6**, culminating in a list of recommended additions. While there are several factors that transmission planners consider – including reliability, economics, and policy objectives – given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[24] Part 1 calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Prudent additions do not account for any changes to the transmission network that are planned after winter 2024/25.

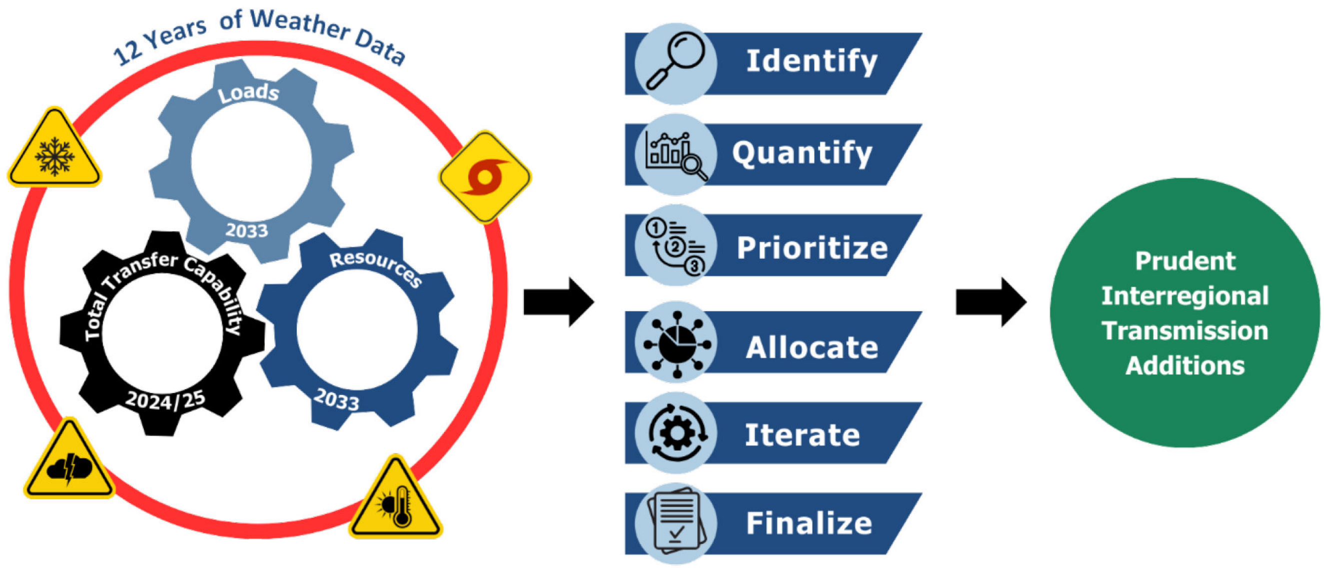


Figure ES.4: Part 2 Process Overview

Potential for energy deficiency[25] was identified in all 12 weather years evaluated and in 11 different TPRs, with a maximum resource deficiency of almost 19 gigawatts (GW) in ERCOT. Results from the energy margin analysis can be found in **Chapter 7**.

Potential for energy deficiency was identified in all 12 weather years evaluated.

These results were used to develop a list of recommended additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. As a result, 35 GW of additional transfer capability is recommended to improve energy adequacy under the studied extreme conditions throughout the United States.[26] **Figure ES.5** shows the existing and potential[27] new interfaces where additional transfer capability is recommended, and **Table ES.1** provides further detail. These additions are discussed in detail in **Chapter 7**.

35 GW of additional transfer capability is recommended to improve energy adequacy under extreme conditions.

[25] The terms "resource deficiency" and "energy deficiency" are used interchangeably throughout this report to describe instances in the study where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level, described further in **Chapter 6**.

[26] The ITCS recommendations result from NERC working with the Regional Entities and in collaboration with the ITCS Advisory Group.

[27] The full list of potential new interfaces evaluated is shown in **Chapter 2**.

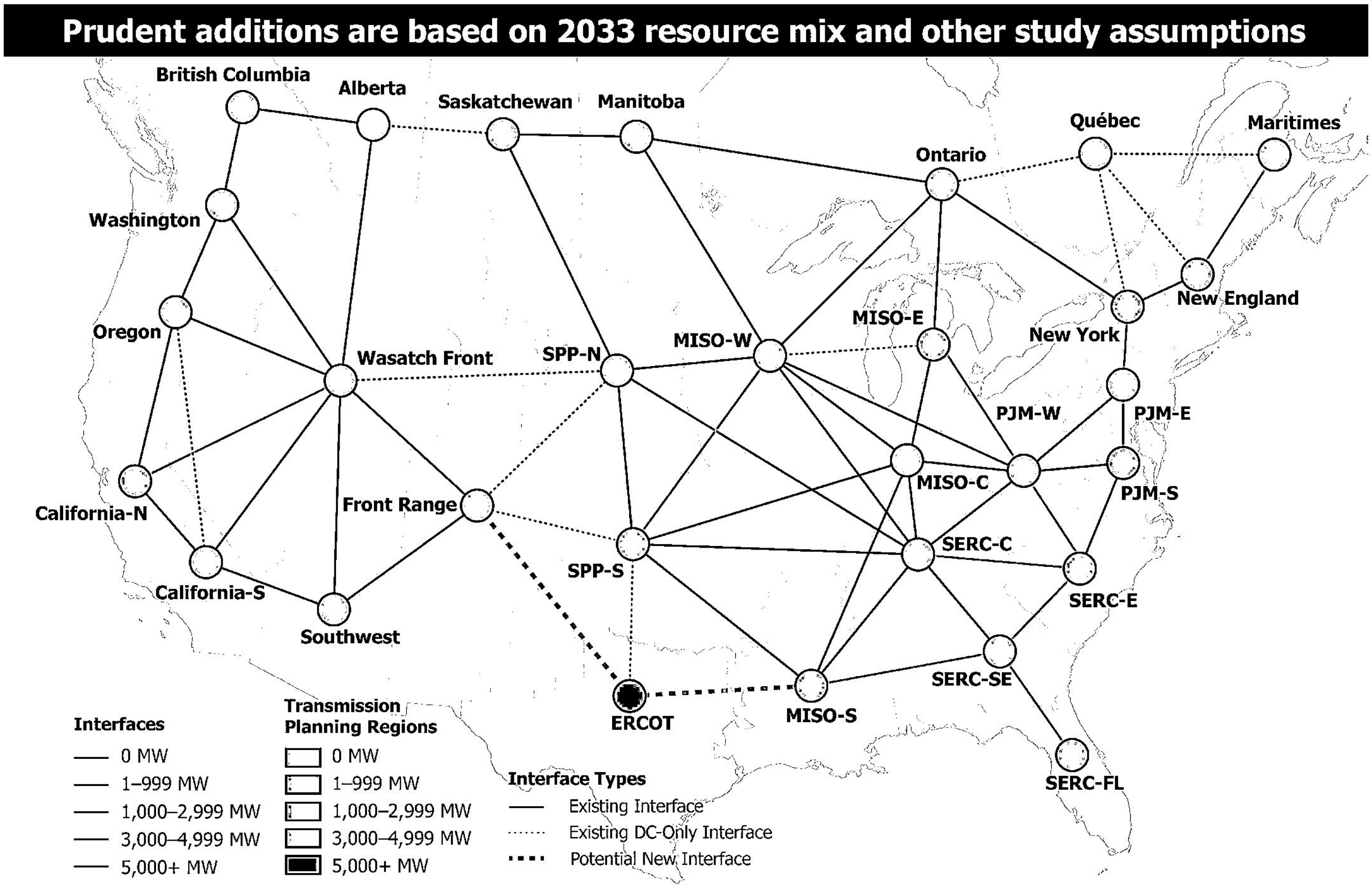


Figure ES.5: Prudent Additions to Transfer Capability

Increasing Energy Deficiency Hours

Table ES.1: Recommended Prudent Additions Detail					
Transmission Planning Region	**Weather Years (WY) / Events**	**Resource Deficiency Hours**	**Maximum Deficiency (MW)**	**Additional Transfer Capability (MW)**	**Interface Additions (MW)**
ERCOT	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)
TOTAL				**35,000**	

In two cases, it was not possible to eliminate all energy deficiencies, even by increasing transfer capability, due to wide-area resource shortages. In ERCOT and California North, resource deficiencies remained even after increasing transfer capability by 14 GW and 1 GW, respectively.

The amount of transfer capability required to reliably serve customers during extreme conditions varied significantly, demonstrating that a one-size-fits-all requirement may be inefficient and ineffective.

The amount of transfer capability needed to mitigate energy adequacy risk varied significantly across the country. Specifically, some TPRs with relatively low transfer capability did not show resource deficiencies, such as SERC-SE and SERC-C with transfer capabilities of 11%-18% of peak load.[28] In contrast, other TPRs with relatively high transfer capability did show resource deficiencies. Examples include MISO-E and PJM-S, with transfer capabilities of 25%-44% of peak load. This is a direct result of the unique challenges that face each TPR, such as energy availability resulting from its resource mix, each neighbor's resource mix, and probable weather impacts. **Based on these findings, the ITCS concludes that a one-size-fits-all requirement for a minimum amount of transfer capability may be inefficient and potentially ineffective.**

[28] These TPRs did not show resource deficiency even in the higher margin sensitivity analysis, underscoring the importance of holistic transmission and resource planning.

The ERCOT system had the most significant energy deficiency and the greatest volume of recommendations for increased transfer capability. Recommendations for prudent increases to transfer capability total approximately 14 GW between the ERCOT-Front Range, ERCOT-SPP South, and ERCOT-MISO South interfaces. These additions address, in part, energy deficits across 135 total hours in the 2033 case, the most severe of which was a shortfall of 19 GW during extreme cold weather. The identified prudent additions also support and provide mutual benefits to resolve energy deficits in the SPP South and MISO South areas. While significant advancements have been made at the state-level and through new NERC winterization standards, better performance should be observed to gain confidence in the performance of natural gas generation during extreme cold weather.

Again, future resource assumptions are pivotal in ascertaining the amount of prudent additions needed. If fewer resources are assumed, many TPRs would exhibit energy deficiencies, as shown in the "Tier 1 Only Resource Mix" sensitivity in **Chapter 8**. This could limit the ability to support neighboring TPRs during extreme weather events. Conversely, if more resources are assumed, the need for prudent increases to transfer capability is reduced. The 2033 "Replace Retirements" case, which is derived from 2023 LTRA data, strikes a balance to appropriately assess energy adequacy risks and inform recommended additions. The specific resource assumptions can be found in **Appendix E**. Resource projections may shift over time with new technologies, market conditions, or policy directives. These dynamics, as well as changes to load growth forecasts, highlight the need for this type of analysis to be repeated in future LTRAs.

Various Options to Address Prudent Addition Recommendations

When it comes to addressing the identified risks, entities have various tools at their disposal. While the ITCS identifies prudent additions as one means of addressing extreme condition vulnerabilities, these needs can be addressed in a variety of ways:

Planners have multiple options to mitigate identified energy deficiencies and should consider the impacts of each option.

- **Internal Resource Development**: Adding internal resources, such as generation or storage, can reduce the need to rely on the transfer of energy from external resources. Importantly, these resources should not be subject to the same common-mode failures as extreme conditions may impact multiple parts of the system simultaneously. For example, adding solar resources may not reveal significant reliability benefits if energy deficits are expected in the early morning or evening hours of a wide-area cold weather event.
- **Transmission Enhancements to Neighboring TPRs**: Building new transmission lines or increasing transfer capability with, for example, grid enhancing technologies can provide critical access to external energy resources that may not be simultaneously impacted by the extreme conditions; however, this approach necessitates:
  - **Resource Evaluations**: Each neighboring TPR must be assessed to verify that sufficient, reliable generation resources are available to support the needed energy transfers during the critical periods. Building transfer capability between systems that are simultaneously resource-deficient will not improve energy adequacy during those extreme conditions.
  - **Permitting and Siting Requirements**: Transmission projects require extensive regulatory processes including permitting, siting, and often complex cross-jurisdictional agreements.
  - **Cost-Allocation Mechanisms**: Since transmission projects serve multiple stakeholders, clear and fair cost-allocation structures are essential to advance these projects efficiently.
- **Demand-Side Management and Resilience Initiatives**: In some cases, the need for additional transmission transfer capability can be mitigated by strategic demand-side solutions. Examples include:

- **Demand Shifting**: Encouraging shifts in demand to non-peak periods through rate structures or operational adjustments.
- **Energy Efficiency**: Achieving reduction in demand through implementation of new technologies.
- **Targeted Demand Response**: Designing programs specifically for extreme conditions, where demand reduction can alleviate stress on the grid.
- **Enhanced Storage Deployment**: Providing backup capacity in the form of storage that can release energy to the grid during peak demand, reducing reliance on external transmission sources.

Planners should consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an overreliance on one or the other.

How to Use this Report

This report is a tool for envisioning and planning the future of a more resilient and reliable grid. While the ITCS offers critical insights, its findings should be considered as foundational insights for further study, discussion, and decisions on regulatory and legislative solutions. While the study highlights specific needs to improve resilience under extreme conditions, NERC encourages flexibility in meeting these needs through various approaches, including enhanced collaboration with regional planning entities, careful alignment with FERC and state policies, and consistent stakeholder engagement to effectively assess, refine, and execute strategies.

The ITCS is designed to explore reliability under extreme conditions, such as severe weather or peak demand. It is not a general assessment of routine operations or a prescription for addressing routine grid concerns. The study's conclusions are, therefore, relevant for identifying high-stress scenarios and should be used accordingly. Below is guidance for policymakers, planners, and stakeholders on how to best use this study's recommendations.

Like all reliability studies, understanding the study scope and future resource and transmission assumptions is critical.

Understand how best to interpret the recommendations for prudent additions. Before pursuing new transmission projects, system planners and stakeholders should first identify existing projects in the planning, permitting, or construction phases that could address some or all the transmission needs outlined in the ITCS. Once completed, these in-progress projects may reduce or eliminate the need for additional transmission capability in certain areas, reinforcing the value of these projects as part of the broader solution.

The findings identify directional, not prescriptive, guidance. The ITCS provides a roadmap for understanding where transmission may need enhancement but does not mandate specific projects or a minimum level of transfer capability. Instead, the findings are directional, helping stakeholders identify where improvements could be most impactful without imposing specific requirements. This flexibility enables industry stakeholders and policymakers to consider the best solutions for their unique needs and resources.

This study's recommendations should be considered as a starting point, prioritizing those areas where the study suggests significant reliability improvements. Policymakers should look at these areas with an open perspective toward potential solutions — whether that involves building additional resources, increasing transmission, or managing demand — to create a resilient approach that aligns with regional conditions and economic viability.

Policymakers should consider the barriers to achieving the prudent additions identified in the ITCS. Policy, regulations, and coordination considerations can create significant challenges in the development of transmission. The study reinforces the value of interregional transmission for managing extreme conditions and supporting an evolving energy mix. However, realizing these benefits requires coordinated policy support. Policymakers, in consultation with Planning Coordinators, should consider potential enhancements to current frameworks, such as establishing a process or forum for addressing large, multi-regional transmission projects. Such a forum would enable collaboration on cost-sharing, permitting, and regulatory hurdles, among other issues. Given the cost-intensive nature of transmission projects, policymakers should prioritize those solutions with the broadest benefits. Wide-area transmission planning could support a more equitable approach to cost allocation and decision-making, ensuring that investments are balanced with the collective resilience needs. Better valuation of the reliability benefits to all impacted parties can help identify the most impactful projects. Regulations including siting and permitting also need to be addressed. Finally, operational tie agreements need to be reviewed and considered by Transmission Planners and Transmission Operators. Market-to-market and seams issues must be resolved to enable flows at required critical times. Different regulatory environments can make achieving some of the recommendations difficult, but some TPRs are exposed to risks that require solutions.

A one-size-fits-all approach may not be effective in achieving the needed transfer capability. When considering a minimum transfer capability requirement, the study's findings do not support a universal minimum transfer capability. A blanket requirement could lead to inefficient investments in areas where transmission needs are already met or could fail to address the identified energy deficiency risks. For example:

- Some TPRs with high levels of transfer capability may require further enhancements due to high demand or significant renewable integration.
- Other TPRs with lower transfer capability may already have adequate resources to meet reliability needs, even under extreme conditions.
- Other TPRs may need additional energy, but transfer capability could be ineffective because neighboring TPRs do not have sufficient surplus energy during the times of need.

Each TPR's unique footprint should drive decision-making. The study's flexibility allows TPRs to identify and address specific vulnerabilities, ensuring that investments are efficient, targeted, and effective in achieving the desired level of reliability.

Use of the ITCS can foster collaboration between utilities, regional planning organizations, and state regulators and develop forward-thinking solutions for resource mix vulnerabilities. The study underscores that reliability challenges cannot be solved with a single approach. Rather, a combination of strategies — adapted to meet the needs of each TPR — will create a more resilient, adaptable grid for the future. Reliability planning is an ongoing process. As technology advances, transmission plans unfold, and the resource mix evolves, this study should be revisited, with findings used to refine and adapt future transmission and resilience strategies. Updates will be incorporated into future LTRAs.

The ITCS offers critical insights to help stakeholders understand and prepare for extreme scenarios. The findings emphasize a balanced, flexible approach to resilience, where transmission is an important but not exclusive solution. By considering these recommendations thoughtfully and holistically, stakeholders can make decisions that meet today's challenges and build a foundation for a reliable, adaptable energy system for the future.

Study Lessons

Increasing Need to Conduct Wide-Area Energy Assessment and Scenario Development

- ✓ Ensuring energy deliverability requires more than transfer capability and transmission tie-lines; resources must be readily available to provide surplus energy.
- ✓ Adding scenarios and probabilistic energy analysis can provide more robust results, introducing different sets of resource and demand assumptions. Assessing the results of various scenarios can provide a range of options and highlight areas of greatest need.
- ✓ A consistent approach to transfer capability studies and calculations advances industry's ability to study the wide-area impacts induced by wide-area weather events. Most importantly, this consistency ensures that one area is not counting on excess generation from their neighbors when the neighbors are also experiencing the same weather impacts and are unable to share.

Increasing Need to Fully Incorporate Weather Impacts in Assessments

- ✓ Risks due to weather are becoming more significant. Weather impacts several TPRs simultaneously, so planning entities must collaborate to study the wide-area impacts on the system and plan accordingly.
- ✓ With an increasing wind, solar, and storage fleet, weather events may present greater impacts to resource availability unless solutions are put in place.

Changes in System Planning Evaluation

- ✓ In some instances, adding transfer capability was insufficient due to resource limitations. It is essential to plan transmission and resources together to prevent over-dependence on one versus the other.
- ✓ Wide-area system studies are essential to increase transfer capability without compromising reliability. Detailed studies must be conducted to identify reinforcements needed to meet reliability criteria before selecting solutions.

Barriers to Transmission Development Present Risk to Timely Solutions

- ✓ Appropriate projects and solutions must be included while considering all factors including reliability, cost, and policy objectives.
- ✓ Siting, permitting, and cost allocation and recovery present significant barriers to interregional transmission. Addressing these challenges will enable planning entities to implement effective solutions.
- ✓ Policy and planning processes need to be more adaptive. The ITCS underscores the importance of a more coordinated approach to regional and interregional planning, particularly as the resource mix changes and the grid faces increasing stress from extreme weather. While there are several examples of planned projects and emerging interregional planning efforts, existing planning structures may be insufficient for addressing broader transmission needs. Establishing a wide-area planning forum could facilitate more collaboration among stakeholders.

Common Data Sets, Case Development, and Consistent Metrics Are Essential Components of Future Assessment Strategy

- ✓ More data will be needed to assess system risks in the future.
- ✓ Future resource projections are highly uncertain and as underlying assumptions change, so do the results; therefore, it is essential to establish a cadence to study the system periodically and identify risks.
- ✓ The impact of Canadian systems is crucial for assessing the reliability of U.S. systems and vice versa.

Chapter 1: The Reliability Value of Transfer Capability

Recent Extreme Weather Events Show Reliance on Neighbors

Analyses of extreme weather events, such as Winter Storms Uri and Elliott and the heatwave experienced in the Western Interconnection in 2020, as summarized below, have reinforced the critical need for neighboring systems to exchange energy with one another when needed to minimize reliability impacts. During these events, transfer capability, or the lack thereof, had a direct impact on the magnitude and duration of firm load shed. These recent extreme weather events have highlighted the importance of the interregional transmission network in improving reliability by transferring surplus energy between TPRs to mitigate shortfalls. In short, these events underscore the types of challenging scenarios that system operators must be equipped to overcome:

- The **Western Interconnection Heatwave**, from August 14–19, 2020, affected much of the Western Interconnection as noted in the associated report.[29] Several Balancing Authorities declared energy emergencies and the California Independent System Operator (CAISO) shed more than 1,000 MW of firm load. In addition to the primary cause of extreme and widespread heat, this report notes two secondary causes related to interregional transfer capability limitations.
- **Winter Storm Uri** impacted the BPS in the Electric Reliability Council of Texas (ERCOT) and Eastern Interconnections during February 8–20, 2021. As noted in the associated report,[30] extreme cold temperatures, freezing precipitation, and generator outages led the ERCOT operators to order firm load shed for nearly three consecutive days, peaking at 20,000 MW on February 15.[31] The Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) also declared transmission emergencies and shed firm load in lower quantities and for shorter durations. Firm load shed during this event was directly related to the transfer capability from TPRs with surplus energy into the TPRs with energy shortfalls, as the eastern portion of the continent was not experiencing extreme conditions and had surplus energy to provide.
- **Winter Storm Elliott** impacted the BPS in the Eastern Interconnection from December 21–26, 2022. As noted in the associated report,[32] several Balancing Authorities in the Southeast United States shed firm load during the event to maintain reliability. This firm load shed in total (at different points in time) exceeded 5,400 MW, the largest controlled firm load shed recorded in the history of the Eastern Interconnection. Even though interregional transfers were limited by availability of resources in neighboring TPRs, energy transfers from Florida, New York, and the Midwest into the most heavily affected TPRs almost certainly reduced the amount and duration of firm load shed that would otherwise have been required.

Setting the Stage for Transfer Capability Analysis

Recognizing the transforming grid and the reliability impacts of the extreme events summarized above, the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have examined transfer capability, each considering a variety of factors. The DOE released the *National Transmission Needs Study* (October 2023)[33] as part of its State of the Grid report, which is required by Congress at least every three years to assess national electric transmission constraints and congestion. This DOE study assessed current and near-term transmission needs through 2040 across 13 geographic regions.

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[29] August 2020 Heatwave Event Report.pdf (wecc.org)

[30] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[31] Ibid.

[32] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission (ferc.gov)

[33] https://www.energy.gov/gdo/national-transmission-needs-study

In 2022, FERC initiated a proceeding regarding interregional transfer capability transmission planning and cost allocation and hosted a staff-led workshop on December 5–6, 2022.[34] The workshop considered whether a minimum requirement for interregional transfer capability should be established and, if so, how to identify the right levels of transfer capability. Some panelists spoke in favor of a minimum interregional transfer capability requirement for each planning region, such as a percentage of peak load, noting benefits of new transmission beyond pure reliability benefits. Other panelists encouraged a more deliberate approach that would study the needs of each area rather than a one-size-fits-all requirement. The ITCS team took this latter approach to ensure reasonableness of any recommendations, recognizing that a simple percentage requirement may not produce desired outcomes across all TPRs. For instance, some of the considerations lost in the former approach include ignoring dynamic transmission use patterns, varying resource mixes, regional network topology, size of the largest contingency, and periods of stress that do not always correlate to peak demand.

Recently, FERC issued Order No. 1920 “Building for the Future Through Electric Regional Transmission Planning and Cost Allocation” to revise the *pro forma* Open Access Transmission Tariff.[35] In particular, FERC revised tariff requirements pertaining to regional and local transmission planning and cost allocation, including requiring long-term regional transmission planning as well as other reforms to improve the coordination of regional transmission planning and generator interconnection processes. NERC filed comments supporting FERC’s examination of transmission planning under the changing resource mix and stated, “Transmission will be the key to support the resource transformation enabling delivery of energy from areas that have surplus energy to areas which are deficient. The frequency of such occurrences is increasing as extreme weather conditions resulting from climate change impact the fuel sources for variable energy resources. Regional transmission planning can ensure that sufficient amounts of transmission capacity will be needed to address these more frequent extreme weather conditions.”[36]

Transfer capability is the amount of power that can be reliably transported over a given interface under specific conditions. Planning engineers model elements on the system and simulate how power flow will impact the transmission system under a series of reliability tests. These studies provide assurance that the system is stable and within predefined ranges. As stated in NERC’s 2013 Adequate Level of Reliability (ALR)[37] filing, “[a] target to achieve adequate transmission transfer capability and resource capability to meet forecast demand is an inherent, fundamental objective for planning, designing, and operating the BES [Bulk Electric System].”[38]

Each Interconnection consists of a network of transmission lines for redundancy, avoiding reliance on a single path. Electricity transfers flow over parallel paths, introducing a variety of operating constraints. Consequently, planning studies must be performed to ensure that these transfers will not jeopardize the reliability of an Interconnection. Additional details regarding the ITCS evaluation of transfer capability can be found in **Chapter 2**.

The Part 2 recommendations to increase transfer capability are prudent to strengthen reliability but may go beyond what is required to meet current Reliability Standards. Additional transmission studies will be needed once specific projects or other actions are identified to address these recommended increases to transfer capability.

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[34] Staff-Led Workshop Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Docket No. AD23-3-000 (December 5-6, 2022)

[35] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920, 187 FERC ¶ 61,068 (2024), at https://ferc.gov/media/e1-rm21-17-000.

[36] NERC Comments, Docket No. RM21-17-000; also Order No. 1920, at page 94 (discussing comments such as NERC’s pertaining to transmission under the changing resource mix); and ibid., at page 586 (referencing NERC comments on potential studies pertaining to transmission)

[37] For more information regarding ALR, see the informational filing on the Definition of “Adequate Level of Reliability” (filed May 10, 2013), at https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf.

[38] Ibid. at Exhibit A, page 3

Chapter 2: Overview of ITCS Scope and Terminology

The purpose of this study is to perform a U.S.- and Canada-wide assessment of the reliable transfer capability of electricity between neighboring Transmission Planning Regions. While the congressional mandate[39] applies to the United States, any analysis would be incomplete without a thorough understanding of the Canadian limits and available resources. The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

The ITCS is the first comprehensive study of transfer capabilities between adjacent TPRs, including neighboring Interconnections, making it unique. Further, to perform the future-looking energy assessment to determine potential deficiencies, the study used 12 years of data to capture a wide variety of operating conditions and account for historical weather events. It is also unprecedented in scope, as it used internally consistent assumptions and modeling approaches for all neighboring interfaces and TPRs across interconnected North America. This broad view is key when evaluating the support that may be available to assist in meeting energy adequacy while considering transfer capability limitations. Ultimately, the goal is to incorporate this analysis into future LTRAs to provide a more comprehensive picture of each TPR's reliability risks.

Within this strategic context, the key objectives of the ITCS are the following:

- Conduct a comprehensive, repeatable study of existing interregional transfer capability across the contiguous United States and Canada between each TPR to assess currently available transfer capability (Part 1) and the future need for additional transfer capability (Part 2) to ensure reliability under various system conditions, including extreme weather.
- Provide analysis-driven recommendations for additions to the amount of energy that can be transferred between neighboring TPRs (Part 2).
- Recommend approaches to achieve and maintain an adequate level of transfer capability (Part 3).
- Actively engage stakeholders and gather inputs, assumptions, and conditions from Regional Entities, industry, and the Advisory Group to ensure a comprehensive and inclusive study.
- Identify expectations for next steps and continuing analysis of transfer capability to reinforce future NERC assessments, including trends.

Study Scope

Part 1 consists of transfer capability analysis for forecasted 2024 summer and 2024/25 winter conditions. This transfer capability analysis produced a set of transfer capability limits between neighboring TPRs. More information can be found in the Part 1 scoping document.[40]

As shown in **Figure 2.1**, the Part 1 results were vital inputs to Part 2, which identified TPRs that are deficient under the study scenarios, including extreme weather events. TPRs with an energy deficiency were first evaluated to determine if there is sufficient transfer capability to cover the deficiency, then prudent additions to transfer capability were recommended. Part 3 identified various actions that could be taken by policy makers, industry leaders, and the ERO Enterprise to meet and maintain transfer capability.

[39] H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[40] ITCS Transfer Study Scope Part 1 (nerc.com)

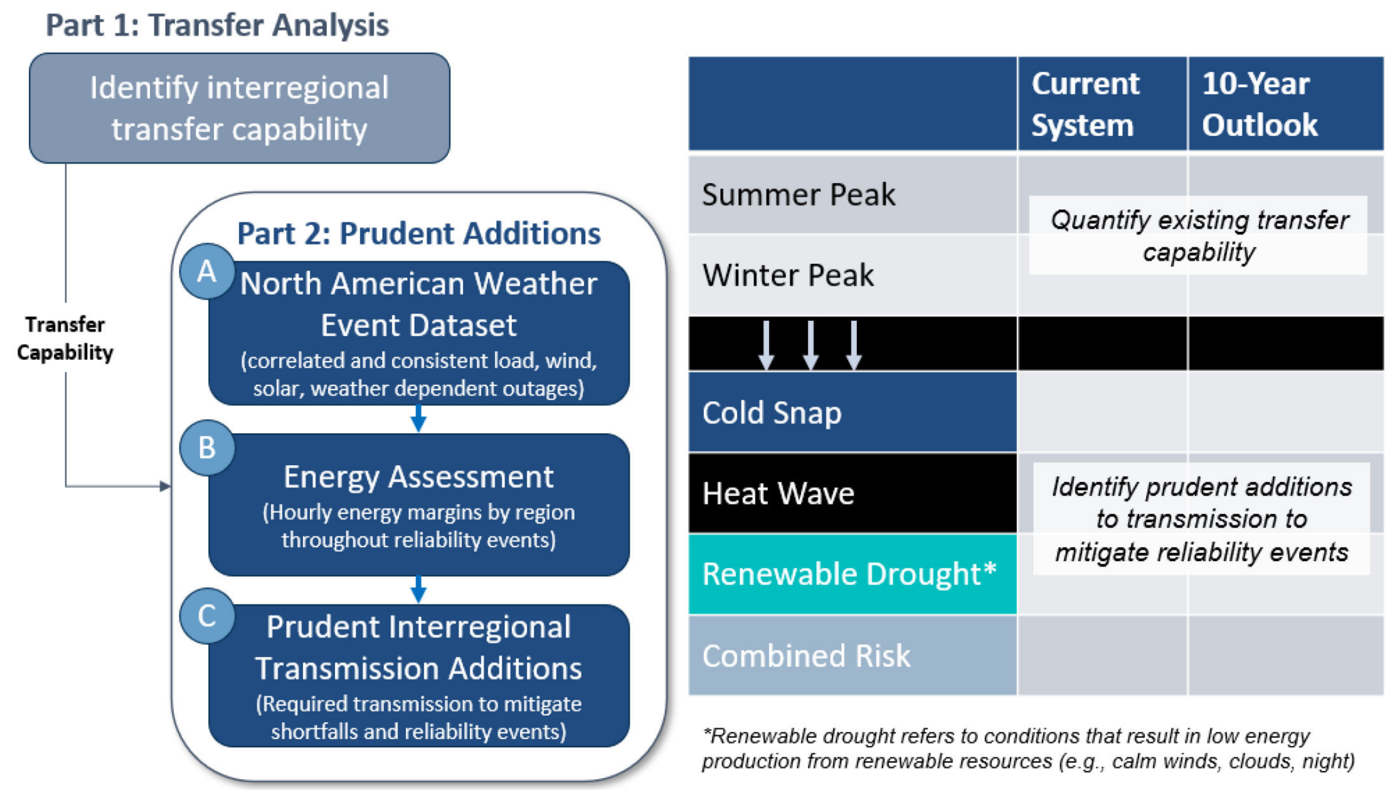

Figure 2.1: Additional Part 2 Details

Part 2 was divided into four tasks to further develop these recommendations:

1. Develop a North American dataset of consistent, correlated, time-synchronized load, wind and solar generation output, and weather-dependent outages.
2. Conduct an energy margin analysis to identify periods of tight supply conditions and potential resource deficiencies to be further evaluated.
3. Develop metrics and methods to identify which TPRs would benefit from increased transfer capability.
4. Quantify the amount of additional transfer capability recommended as prudent between each pair of TPRs to mitigate the resource deficiencies, deliberately evaluating whether neighboring TPRs had surplus energy available to transfer.

The following items were intentionally out of scope for this analysis:

- Probabilistic resource adequacy analysis was not conducted. While 12 years of weather conditions were considered, the study did not attempt to sample hundreds or thousands of potential generator outages and load conditions, nor did it assign probabilities to potential loss of load events. In short, the ITCS should not be considered a North American resource adequacy assessment.
- The relative merits of additional transfer capability versus local resource additions were not considered. Per the congressional directive, the ITCS focused on transfer capability as a mitigation for energy deficiencies. In practice, strengthening the energy adequacy of the BPS should consider a multi-faceted approach that can include adding new local resources (generation or storage), improving load flexibility (demand response), and/or increasing transfer capability.

- Part 2 used a simplified transmission model – often referred to as a "pipe and bubble" model – and did not perform a full nodal, security-constrained economic dispatch or power flow analysis. Instead, it leveraged the TTC values from the power flow analysis conducted in Part 1.

The Part 2 study used large hourly datasets, both publicly available and NERC proprietary, to quantify and visualize energy adequacy for each TPR across North America. These datasets were used to conduct an energy margin analysis that was used as part of the prudent additions process. Data was compiled to create a multi-year, hourly, time-synchronized dataset of load, wind, solar, hydro, and weather-dependent outages of thermal resources that collectively determine energy margins. The Part 2 scope[41] document contains additional details.

Stakeholder Participation

The Fiscal Responsibility Act of 2023 required that NERC, working with the full ERO Enterprise in the performance of the ITCS, consult with each transmitting utility that has facilities interconnected with another transmitting utility in a neighboring TPR. The Federal Power Act defines a transmitting utility as follows:

> *The term "transmitting utility" means an entity (including an entity described in section 201(f)) that owns, operates, or controls facilities used for the transmission of electric energy—*
> *(A) in interstate commerce*
> *(B) for the sale of electric energy at wholesale*

Even though a subset of utilities classified as transmitting utilities were required to be consulted, NERC has adopted a broader approach to consult with and inform all stakeholders, such as Transmission Planners, Planning Coordinators, Transmission Operators, Transmission Owners, state/provincial/federal regulators, and industry trade groups. Due to the sheer size and number of stakeholders involved, as shown in **Figure 2.2**, a comprehensive stakeholder management plan was developed to keep each stakeholder informed and engaged.

[41] ITCS SAMA Study Scope - Part 2 (nerc.com)

Figure 2.2: ITCS Stakeholder Engagement

An ITCS Advisory Group was assembled with functional and geographic diversity to gather industry input and ensure a comprehensive study. Participants represented stakeholders including FERC, DOE, National Resources Canada, the Electric Power Research Institute (EPRI), Independent System Operators, and a variety of utilities.[42] The monthly meetings were open with meeting schedules and materials posted publicly. The ITCS Advisory Group's role is to provide input to the ERO Enterprise regarding ITCS design, execution, and recommendations.[43] This group provided insights, expertise, and inputs to the study approach, scope, and results.

In addition, an ITCS letter was broadly distributed to the industry on February 9, 2024, to provide direct outreach to all transmitting utilities. A second letter was distributed on September 24, 2024, to remind entities of the study results available. Each Regional Entity also worked closely with Planning Coordinators and other industry technical groups in their respective regions.

Throughout the ITCS process, NERC reviewed stakeholder comments and incorporated input where appropriate.

[42] A full roster is posted at ITCS_Advisory_Group_Roster.pdf (nerc.com).
[43] ITCS_Advisory_Group_Scope.pdf (nerc.com)

Transmission Model

The TPRs used for this study are shown in **Figure 2.3**. In some cases, traditional planning areas defined in FERC's Order No. 1000,[44] which generally do not follow state boundaries, were sub-divided to provide more granular analysis of potential transfer capability limitations, especially under specific weather scenarios. For example, SPP has an expansive geographic footprint stretching from the border of Saskatchewan into parts of Texas. Weather and other operating conditions vary widely over this extended region. Further, construction practices can vary based on expected temperatures, as noted in the Winter Storm Uri report. Significant transmission constraints exist within these larger planning areas, some of which have played a major factor in weather events, and it is important for the ITCS to reflect such limitations to interregional transfer capability. Additionally, this more granular approach allows recommendations at more precise locations. The studied TPRs were large enough to analyze interregional reliability issues while avoiding an overly granular analysis of local constraints.

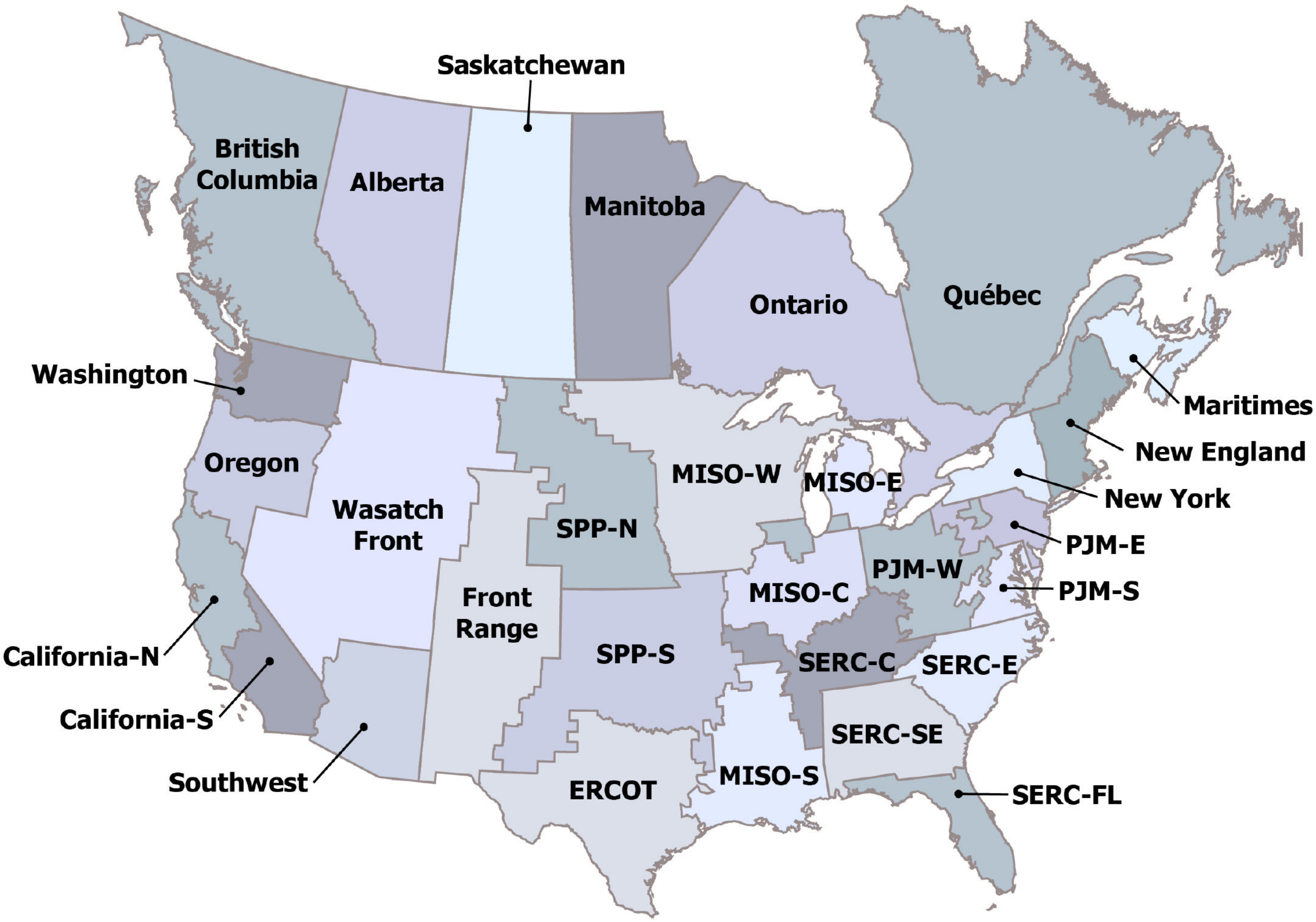

Figure 2.3: Transmission Planning Regions

In Part 1, a set of interfaces was identified that included all pairs of neighboring TPRs so that transfer analysis from source (exporting) TPR to sink (importing) TPR and vice versa could be performed. In this context, only electrically connected neighboring systems were evaluated.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import capabilities of each TPR. Though not part of the mandate, which directed evaluation of transfer

[44] More information can be found on FERC's website at www.ferc.gov.

capability between neighboring TPRs, this evaluation is technically necessary to appropriately model system capability in Part 2 of the ITCS.

For Part 2, a representation of the transmission system was created, with transfer capability limits applied to each interface and a total import interface constraint for each TPR. These transfer capability limits were calculated in Part 1, which analyzed 2024 summer and 2024/25 winter conditions. The Part 2 model is not intended to represent actual energy flows, nor does it calculate generation shift factors, line impedances, individual line loadings or ratings, or other transmission considerations.

A visual representation of the transmission topology is provided in **Figure 2.4**, which shows each of the existing transmission interfaces represented as a solid line. Dotted lines represent existing dc-only interfaces between TPRs, including connections between Interconnections, the Oregon to California South dc tie (Path 65), and between MISO West and MISO East near the Straits of Mackinac.

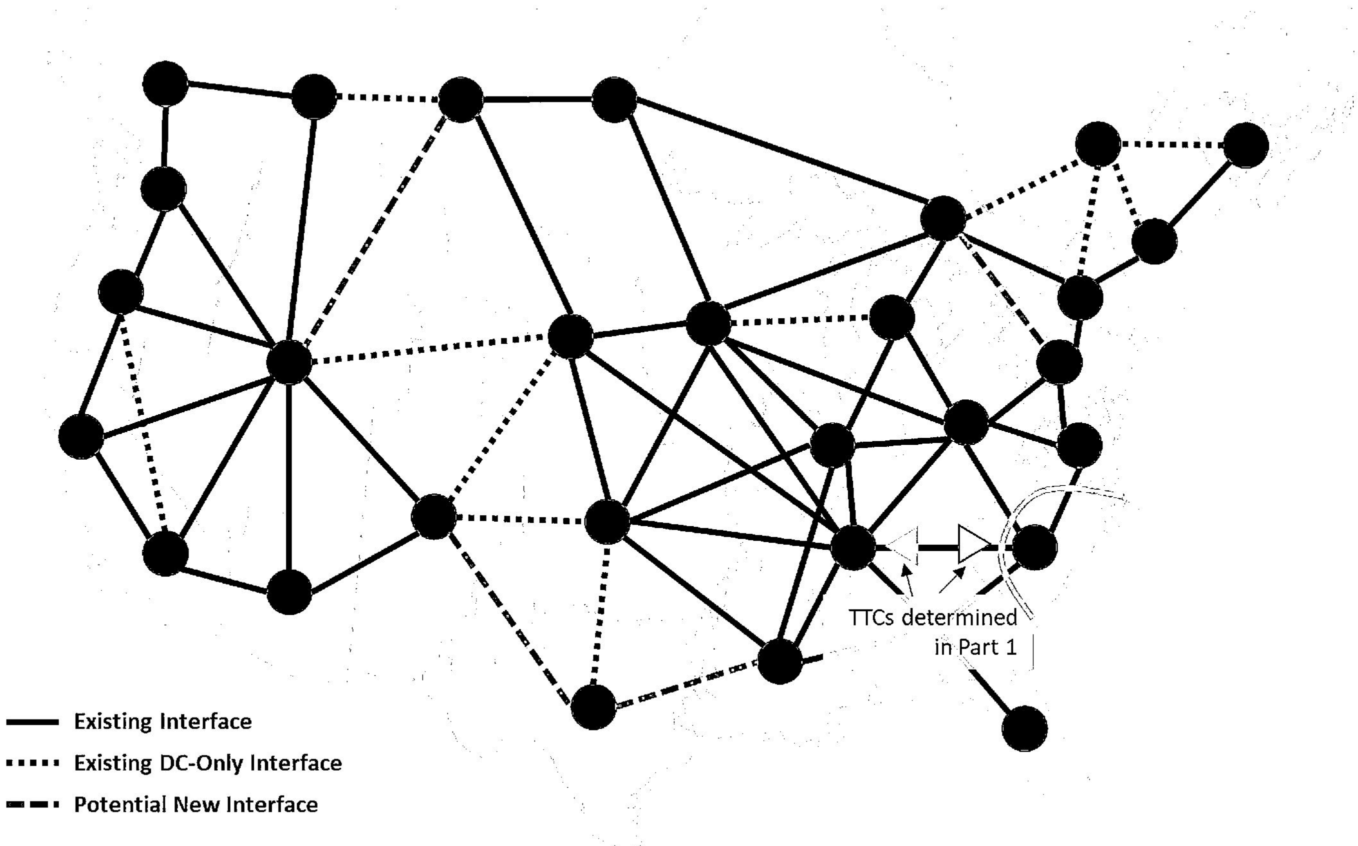

Figure 2.4: Transmission Interfaces

The model also included potential new transmission interfaces between geographically adjacent TPRs even if no transmission linkage currently exists. These candidates for prudent additions are represented as dashed grey lines in **Figure 2.4**.

In the Part 2 model, each interface has a transfer limit in the forward flow direction (e.g., from SERC-C to SERC-E) and a potentially different limit in the reverse flow direction (e.g., from SERC-E to SERC-C). A total import interface was also included in the model, represented by the yellow arc in **Figure 2.4**. In addition to the limits across individual interfaces, this total import interface limited the simultaneous imports from all neighboring TPRs. This limit was also calculated in the Part 1 Transfer Analysis by decreasing generation in each sink (importing TPR) and increasing generation proportionally across all neighboring sources (exporting TPRs). Since the Part 2 model does not consider the physics of energy flows across the transmission network, this interface was necessary to reflect limitations to simultaneous transfer capability.

Transfer Capability

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW. In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or region, or a portion thereof.[45]

However, while the transfer capability is a measured amount in MW, it does not have a one-to-one correspondence with what new transmission facility (or facilities) could be added. For example, to increase transfer capability by 200 MW between two areas, the areas may evaluate and find that a single new line with a rating of 200 MW would not be the sole change to the network and a combination of facilities may need to be added or improved to support the increase in energy transfers between areas. Determining a solution is complex and may involve additions or modifications to multiple transmission facilities, while taking into account the other planning considerations.

In both the planning and operation of electric systems, transfer capability is one of several performance measures used to assess the reliability of the interconnected transmission systems and has been used as such for many years. System planners use transfer capability as a measure or indicator of transmission strength in assessing interconnected transmission system performance. It is often used to compare and evaluate alternative transmission system configurations. System operators use transfer capability to evaluate the real-time ability of the interconnected transmission system to transfer electric power from one portion of the network to another or between control areas. In the operation of interconnected systems, “transfer” is synonymous with “interchange.”[46]

The intent of a transfer capability calculation is to determine a transfer value with the following general characteristics:

- Represents a realistic operating condition or expected future operating condition
- Conforms with the requirements of the transfer capability definitions
- Typically considers single contingency facility outages that result in conditions most restrictive to electric power transfers[47]

Transfer capability is calculated using computer network simulation software to represent anticipated system operating conditions. Each such simulation reflects a snapshot of one specific combination of system conditions. Transfers between two areas are determined by increasing transfers from a normal base transfer level until a system limit is reached.[48]

The ITCS calculated TTC by determining the amount of additional energy transfers that can be added to base transfers already modeled while respecting contingency limits. Reliable operation insists that the grid must be operated to withstand the worst single contingency while remaining within system operating limits, noting that the most severe

[45] NERC Transmission Transfer Capability Whitepaper, 1995, at Transmission Transfer Capability May 1995.pdf (nerc.com)
[46] Ibid.
[47] Ibid.
[48] Ibid.

single contingency may be in a neighboring area. Category P-1 single contingencies were used in this study, as defined in NERC Reliability Standard TPL-001-5.1.[49]

TTC is the total amount of power that can be transferred between two areas. TTC is made up of two parts, as shown in **Figure 2.5**:

- Base Transfer Level (BTL): Typically, scheduled power flows between areas in the starting case. These are usually referred to as base flows.
- First Contingency Incremental Transfer Capability (FCITC): FCITC simulates an incremental transfer between areas under a single contingency until a system limitation is reached. In other words, it is the amount of energy that can be reliably transferred.

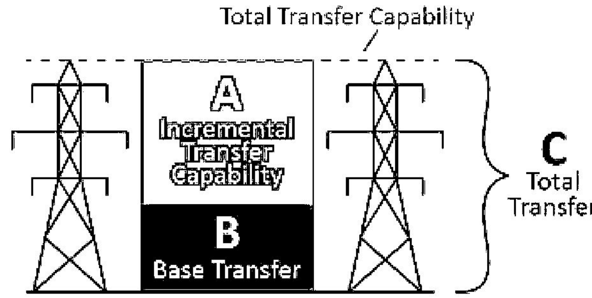

Figure 2.5: Total Transfer Capability

In simple terms, **TTC = BTL + FCITC**. The TTC method enables a consistent calculation across the entire study footprint, although these calculations are different than path limits which are used by some entities.

In Part 1, the BTL for each interface was derived, where available, from the scheduled interchange tables provided with each of the study cases. This was compared to the desired interchange provided in the study cases to cross-check. Where required, adjustments were made to account for additional schedules and market re-dispatch based on load ratio where a Balancing Authority spanned multiple TPRs. Where the detailed scheduled interchange tables were unavailable, BTL was approximated using the actual line flow across each interface and cross-checked against the scheduled interchange. This approach was endorsed by the ITCS Advisory Group.

The transfer analysis, which calculates the FCITC, involves simulating an incremental increase in transfers from source to sink while applying relevant contingencies and monitoring criteria (both described in **Chapter 3**), until a criteria violation is found. The last incremental step prior to finding a criteria violation is reported as the FCITC. A voltage screening was performed for each transfer analysis to validate the FCITC limit found. Models reflecting this transfer amount were created and screened for voltage violations using applicable contingencies. If a voltage violation was found, the FCITC was reduced, and the process repeated until the voltage violation was resolved. All results were vetted by the Regional Entities through the respective Planning Coordinators.

Prudent Additions to Strengthen Reliability

The Fiscal Responsibility Act of 2023 requires a recommendation of technically prudent additions to transfer capability between neighboring TPRs that would demonstrably strengthen reliability. Reliability is a broad concept, and significant aspects of required reliability are defined by NERC Reliability Standards and continually implemented through entities' planning, investment, and compliance processes. The ITCS examines transfer capabilities between adjacent TPRs under a variety of weather scenarios and operating conditions that reflect potential extreme conditions, such as those observed during recent events. For this reason, the ITCS goes beyond existing reliability studies and is an avenue to improve the delivery of energy under extreme conditions. In fact, when NERC assesses system reliability, it often reviews capacity and energy scenarios to identify system risk. This is a foundational activity at NERC, as a part of its mandate as the ERO, to assess risks to the BPS in the coming seasons and years.

[49] TPL-001-5 (nerc.com)

Determining exactly how much additional transfer capability is "prudent" can depend on the totality of factors and circumstances. FERC precedent[50] reflects that prudence means a determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances and at the relevant point in time. FERC has considered prudence in the context of specific, fact-based scenarios involving rates. For example, as part of examining the totality of circumstances, FERC has considered matters such as whether activities have enhanced the ability to restore service, achieved significant efficiencies, reduced costs or time delays, and/or made efficient use of resources to ensure reliability.

The ITCS identified where there are reasonable additions to transfer capability that would be expected to improve energy adequacy and thereby strengthen reliability. This is not intended to preclude entities from considering other factors, such as cost allocation or economic advantages.

To determine prudent additions to transfer capability and maintain focus on strengthening reliability, NERC, working with the Regional Entities, developed an approach so that consistent, objective, reasonable criteria could be applied. This process is described in **Chapter 6**.

Important Study Considerations

While the ITCS used engineering study approaches deployed within industry planning processes, it is not a planning study. Reliability, in the form of energy adequacy and operating reliability, is the sole focus of the ITCS and aligns with the ERO Enterprise scope and obligations, as well as the parameters defined in the Fiscal Responsibility Act. Unlike the ITCS, planning studies ensure that electricity is generated, transmitted, and distributed in a cost-effective, reliable, and sustainable manner, while meeting environmental and regulatory requirements.

Similarly, this reliability-focused study did not provide economic justification for new and/or upgraded transmission facilities. Rather, the study identified increases in transfer capability that can improve energy adequacy during extreme conditions. NERC recognizes that additional transmission has more quantifiable benefits than purely the reliability benefits referenced in this study. For example, these benefits may include factors such as cost savings by providing access to lower-cost sources of generation, voltage support, blackstart, and policy goal implementation. Nothing in the study is intended to preclude stakeholders and governmental authorities at federal, state, and local levels from evaluating those additional considerations.

The Fiscal Responsibility Act specifically required that prudent additions to transfer capability be recommended. Local solutions, such as additional resources in an energy-deficient TPR, were not considered in the ITCS. This study also does not recommend any particular transmission or generation projects, which may take the form of, but are not limited to, new ac or dc transmission facilities, upgrades to enable higher ratings, grid-enhancing technologies,[51] or a combination thereof.

The ITCS considered a range of scenarios to ensure robust study results. Sensitivity analysis was also performed to programmatically explore underlying risks. However, the ITCS is not an exhaustive study of all transmission limitations that may occur during real-time operations or under simultaneous transfers across multiple TPRs.

Due to the unprecedented scope of this study, Part 1 efforts were limited to steady-state power flow analysis using P-0 (no contingency) and P-1 (single contingency) scenarios as defined in NERC Reliability Standard TPL-001-5.1.[52] This approach is consistent with many other similar studies and was reasonable to meet the ITCS study needs and timeframe. In addition to the contingency analysis, a voltage screening was performed for each transfer at the valid

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[50] See, e.g., *New England Power Co.*, 31 FERC ¶61,047 at p. 61,084 (1985); and *Potomac-Appalachian Transmission Highline, LLC,* 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).

[51] This term references advanced technologies that include dynamic line ratings, power-flow control devices, and analytical tools.

[52] TPL-001-5 (nerc.com)

limit found using category P-1 contingencies. Notably, while known stability limits were included, the team did not complete short-circuit or stability analysis (i.e., voltage, transient, frequency). These limitations can be more restrictive than the results presented, which focus primarily on thermal and voltage limits. Further analysis is recommended in the future to determine appropriate solutions after a more comprehensive analysis is performed.

Similarly, in Part 2, a deterministic energy assessment of challenging weather conditions was chosen, rather than a probabilistic resource adequacy assessment. This industry-supported approach enables holistic evaluation of the impacts of actual extreme weather events.

This study does not satisfy any registered entity's obligation to perform studies under enforceable NERC Reliability Standards. This report also does not attempt to determine load or generator deliverability, available transfer capability (ATC), available flowgate capacity (AFC), the availability of transmission service, or to provide a forecast of anticipated dispatch patterns.

Finally, the ITCS represents a point-in-time analysis using the best available time-synchronized data. Changes to future resource additions, resource retirements, and/or transmission expansion plans have the potential to significantly alter the study results. As such, the study team recommends performing this study, documented in NERC's future LTRA reports, on a periodic basis to identify trends.

Chapter 3: Transfer Capability (Part 1) Study Process

This section details the study design, tools, case development, and analysis parameters for calculating current transfer capability. The study details were reviewed by various industry groups, including the ITCS Advisory Group and Regional Entities' technical groups and committees.

Base Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. System models representing Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[53] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

Base cases are not required for the ERCOT and Québec Interconnections for this study, as they are only tied with the Eastern Interconnection via dc ties. Also, the dc ties from the Electric Reliability Council of Texas (ERCOT) to Mexico are treated as static, and the ERCOT-Mexico interface is not included in the scope of this analysis.

NERC issued data requests in November 2023 to all Planning Coordinators in the Eastern and Western Interconnections to provide base case updates. Planning Coordinators and Transmission Planners were requested to review these cases and to supply updates, including:

- New generation – At a minimum, generation with a signed Interconnection Service Agreement was included in the applicable cases.
- Planned retirements – Generation that has retired or has announced retirement was removed from the applicable cases.
- Load forecast adjustments – Cases were updated to use the most current load forecasts.
- Resource dispatch – Changes to reflect the most current resource plans were included.
- Facility ratings – Rating changes received, including enhancements since the cases were built, were included in the cases.
- Expected long-term facility outages – Facilities expected to be out of service were removed from the applicable cases.
- Transmission system topology updates – Changes to topology, including new facility construction, were included in the cases.
- Base transfers (interchange) – New or updated firm transfers were accounted for in the cases.

Contingencies

The transfer analysis simulated contingencies, namely the unplanned outage of system elements, to ensure that the system would remain reliable during the energy transfer. The following NERC Reliability Standard TPL-001-5.1[54] category P1 contingencies (100kV and above) were used for the transfer studies, namely:

- P1-1: Loss of individual generators,
- P1-2: Loss of a single transmission line operating at 100 kV or above, and

[53] MOD-032-1 (nerc.com)
[54] TPL-001-5.1 (nerc.com)

- P1-3: Loss of a single transformer with a low-side voltage of 100 kV or above

All contingencies meeting the above criteria within the source and sink TPRs were included in each transfer study, along with all contingencies within five buses from either the source or sink TPR.

Monitored Facilities and Thresholds

Facility monitoring criteria and thresholds were established to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements. These practices followed industry-accepted methods to ensure that transmission facilities only minimally participating in an interregional transfer do not artificially constrain the transfer limits. Additional detail regarding these criteria can be found in the Part 1 scoping document.[55] Some entities performed additional studies while monitoring lower voltage facilities to ensure there were no significant differences.

Modeling of Transfer Participation

Transfers were simulated by scaling up the available generation in the source TPR in proportion to each unit's remaining availability, namely the difference between maximum generating capacity (P_{MAX}) and its modeled output (P_{GEN}), while scaling down the generation in the sink TPR proportional to its modeled output. Each transfer was simulated until a valid thermal limit was reached while enforcing the source system's maximum generation capacity. If the transfer did not report any transfer limits, meaning that the source TPR was resource-limited, the transfer was repeated without enforcing the source TPR's maximum generation capacity. Invalid limits, such as overloads on generating plant outlets due to not respecting these P_{MAX} values, were ignored.

Special Interface Considerations

Several interfaces have known operating procedures or other special circumstances. In many cases, these are remedial action schemes and/or flow control devices (e.g., phase angle regulators (PAR) or dc lines). The project team worked closely with industry subject matter experts to ensure that these situations were fully understood and properly reflected in the study results.

Power flows over dc lines do not change during transfer analysis; however, these lines are typically designed to carry large quantities of energy over long distances and across asynchronous Interconnections. Where an interface consists solely of dc tie lines, the TTC was calculated as the sum of the dc tie line ratings except where limitations on the ac system near the dc terminals were known to be more restrictive. Where an interface includes one or more dc tie lines as well as ac tie lines, the transfer analysis was conducted with the dc lines at the flow levels in the base cases.

Similarly, many interfaces include one or more PARs. For example, the PJM East to New York Interface is partially controlled by several PARs. Operating manuals describe how transfers across this interface are controlled, including the target percentage of flows across each line. This flow distribution was modeled in the base case development and transfer analysis to reflect the operating agreements between PJM and the New York Independent System Operator (NYISO).

Finally, there are several situations where one or more units at a power plant can connect to two different Interconnections. These units were modeled as provided in the base cases. The associated capacity was not added to the interface TTC, as this could lead to an overstatement of transfer capability, such as when the units are offline.

[55] ITCS Transfer Study Scope Part 1 (nerc.com)

Chapter 4: Transfer Capability (Part 1) Study Results

TTC results are highly dependent on the precise operating conditions, including dispatch, topology, load patterns, and facility ratings. This study did not attempt to optimize dispatch or topology to maximize TTC values. Observed transfer capability may be higher or lower depending on the operational conditions.

Results are presented by Interconnection for each season, proceeding from west to east as follows:

Western Interconnection Results

Western – Eastern Interconnection Results

ERCOT – Eastern Interconnection Results

Eastern Interconnection Results

Québec – Eastern Interconnection Results

Within the Western and Eastern Interconnections, results are generally presented from west to east, then north to south. A list of the interfaces and their ordering is included at the outset of each section.

The ITCS also analyzed an additional set of transfers into each TPR. These **Total Import Interface Results** reflect the simultaneous transfer limits into a TPR from all its neighbors.

Finally, the ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000. While these larger geographic areas were not used for the purpose of determining prudent additions, the **Supplemental Results Between Order 1000 Areas** are provided for completeness.

Western Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface W1: British Columbia -> Washington

Interface W2: Washington <-> Oregon

Interface W3: Washington <-> Wasatch Front

Interface W4: Oregon <-> California North

Interface W5: Oregon <-> Wasatch Front

Interface W6: California North <-> California South

Interface W7: California North <-> Wasatch Front

Interface W8: California South <-> Wasatch Front

Interface W9: California South <-> Southwest

Interface W10: Alberta -> Wasatch Front

Interface W11: Wasatch Front <-> Southwest

Interface W12: Wasatch Front <-> Front Range

Interface W13: Southwest <-> Front Range

Interface W14: Oregon <-> California South (dc-only)

The interface between British Columbia and Alberta will be covered in the Canadian Analysis.

The TTC results in this study, which are based on a combination of source and sink TPRs, may differ from the path ratings that have been established throughout the Western Interconnection. Path ratings examine a specific subset of facilities, whereas this study method considers all facilities connecting the source and sink TPRs, including third-party connections.

Figure 4.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.2** similarly depicts the results from the 2024/25 Winter case.

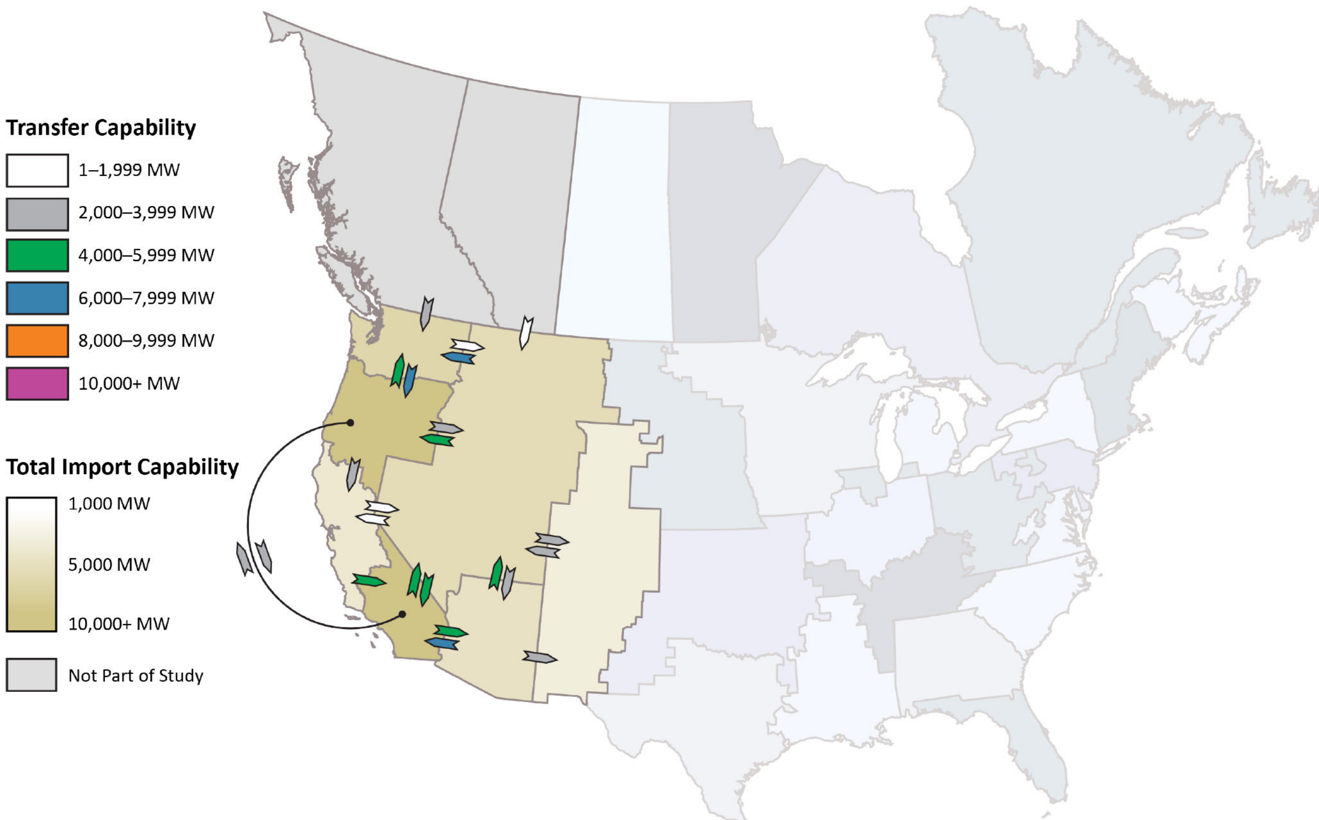


Figure 4.1: Transfer Capabilities for Western Interconnection Interfaces (Summer)

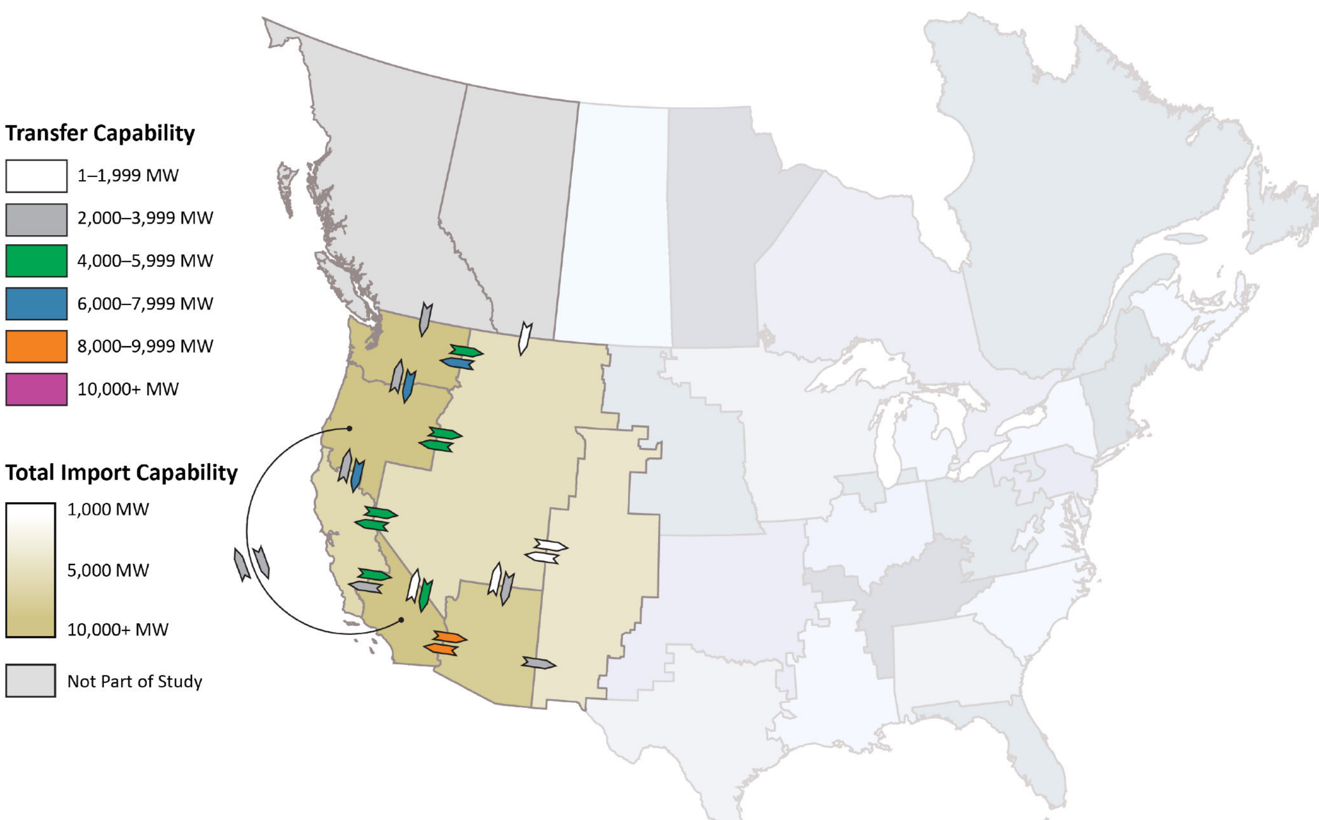
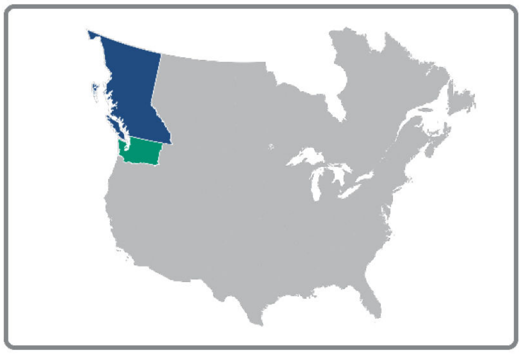


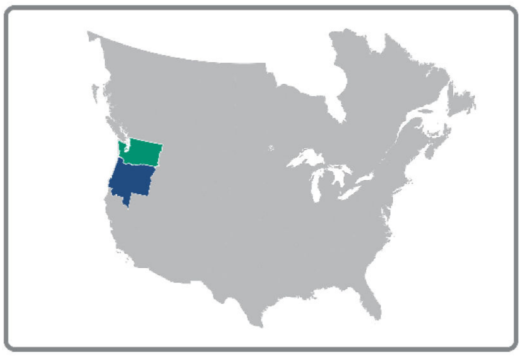
Figure 4.2: Transfer Capabilities for Western Interconnection Interfaces (Winter)

Interface W1: British Columbia -> Washington



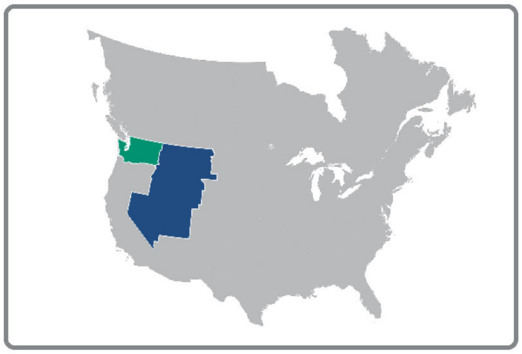
Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Washington	2,358 MW	2,170 MW

Interface W2: Washington <-> Oregon



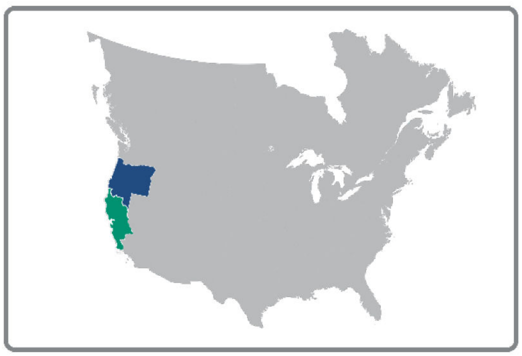
Interface Direction	2024 Summer	2024/25 Winter
Washington -> Oregon	7,085 MW	7,496 MW
Oregon -> Washington	4,103 MW	2,713 MW

Interface W3: Washington <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Wasatch Front	1,925 MW	4,498 MW
Wasatch Front -> Washington	7,377 MW	7,030 MW

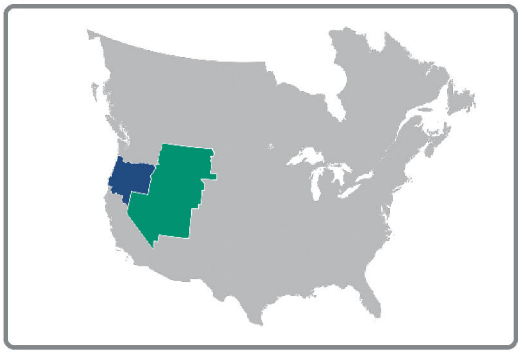
Interface W4: Oregon <-> California North



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California North	3,972 MW	6,175 MW
California North -> Oregon	0 MW	2,548 MW

Explanatory Note: Flows from south to north (California North to Oregon) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,675 MW.

Interface W5: Oregon <-> Wasatch Front



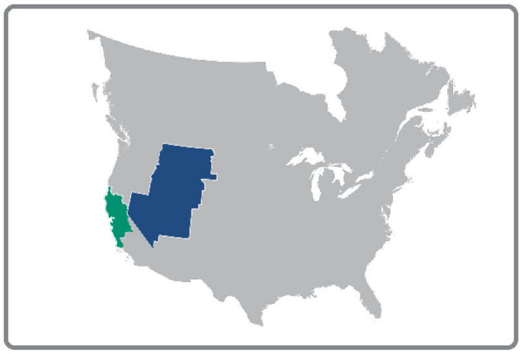
Interface Direction	2024 Summer	2024/25 Winter
Oregon -> Wasatch Front	2,525 MW	5,339 MW
Wasatch Front -> Oregon	4,748 MW	5,079 MW

Interface W6: California North <-> California South

Interface Direction	2024 Summer	2024/25 Winter
California North -> California South	4,647 MW	5,676 MW
California South -> California North	0 MW	3,861 MW

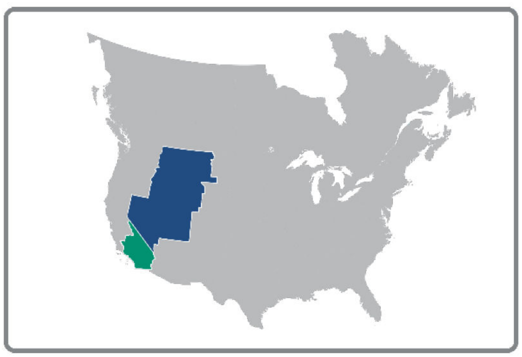
Explanatory Note: Flows from south to north (California South to California North) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,000 MW.

Interface W7: California North <-> Wasatch Front



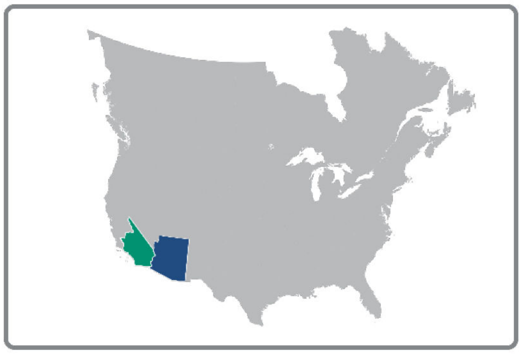
Interface Direction	2024 Summer	2024/25 Winter
California North -> Wasatch Front	1,961 MW	4,980 MW
Wasatch Front -> California North	116 MW	5,388 MW

Interface W8: California South <-> Wasatch Front



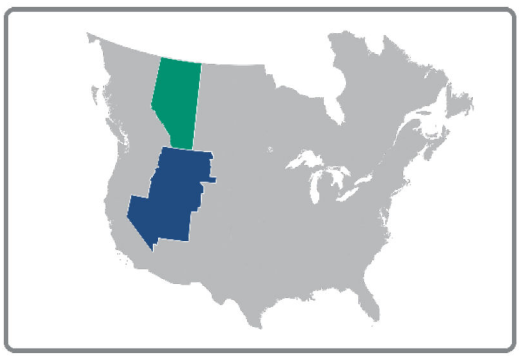
Interface Direction	2024 Summer	2024/25 Winter
California South -> Wasatch Front	5,965 MW	984 MW
Wasatch Front -> California South	5,419 MW	5,568 MW

Interface W9: California South <-> Southwest



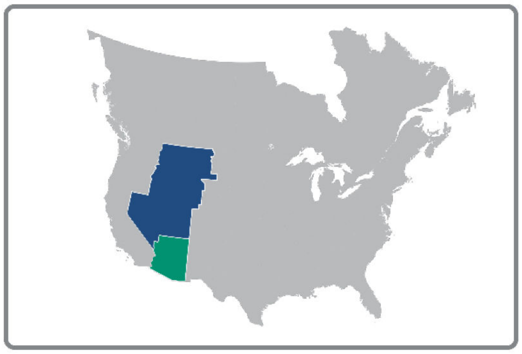
Interface Direction	2024 Summer	2024/25 Winter
California South -> Southwest	5,247 MW	8,470 MW
Southwest -> California South	7,667 MW	8,752 MW

Interface W10: Alberta -> Wasatch Front



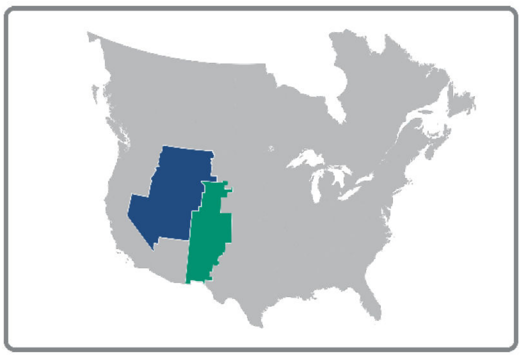
Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Wasatch Front	957 MW	1,280 MW

Interface W11: Wasatch Front <-> Southwest



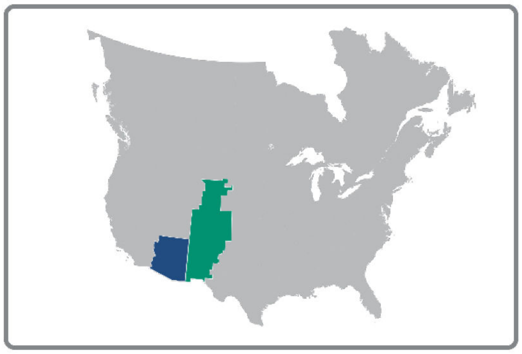
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Southwest	2,351 MW	2,095 MW
Southwest -> Wasatch Front	5,821 MW	1,295 MW

Interface W12: Wasatch Front <-> Front Range



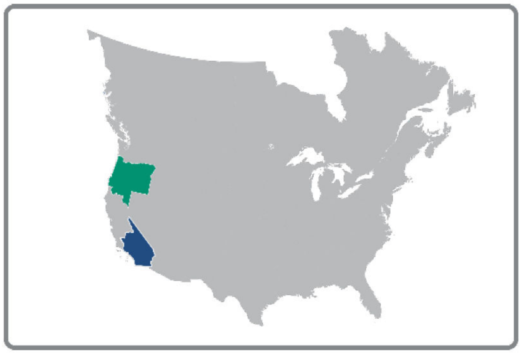
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Front Range	2,032 MW	1,984 MW
Front Range -> Wasatch Front	2,437 MW	477 MW

Interface W13: Southwest <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Southwest -> Front Range	3,284 MW	3,751 MW
Front Range -> Southwest	0 MW	0 MW

Interface W14: Oregon <-> California South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California South	3,220 MW	3,220 MW
California South -> Oregon	3,100 MW	3,100 MW

Western – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface WE1: Wasatch Front <-> SPP North (dc-only)

Interface WE2: Front Range <-> SPP North (dc-only)

Interface WE3: Front Range <-> SPP South (dc-only)

The interface between Alberta and Saskatchewan will be covered in the Canadian Analysis.

Figure 4.3 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.4** similarly depicts the results from the 2024/25 Winter case.

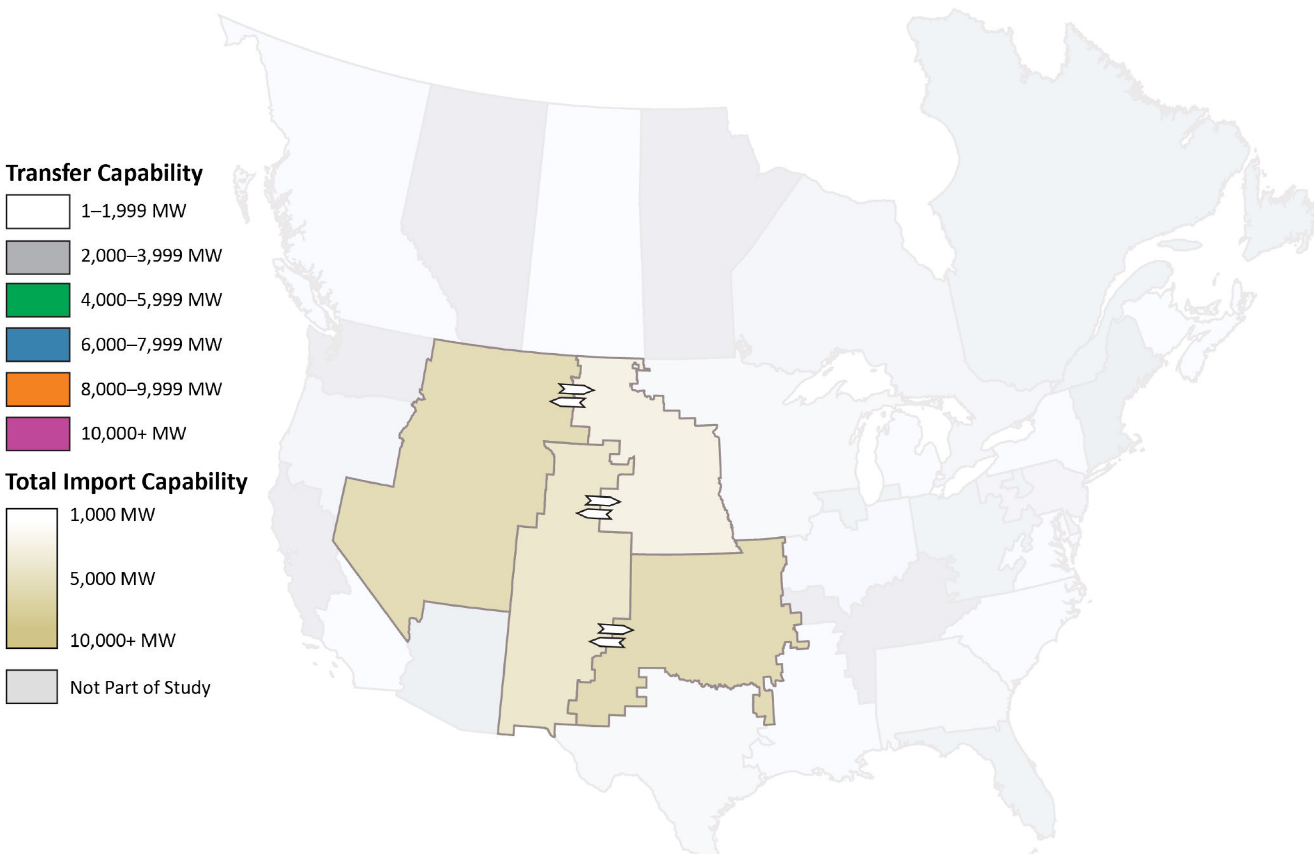


Figure 4.3: Transfer Capability Between Western and Eastern Interconnections (Summer)

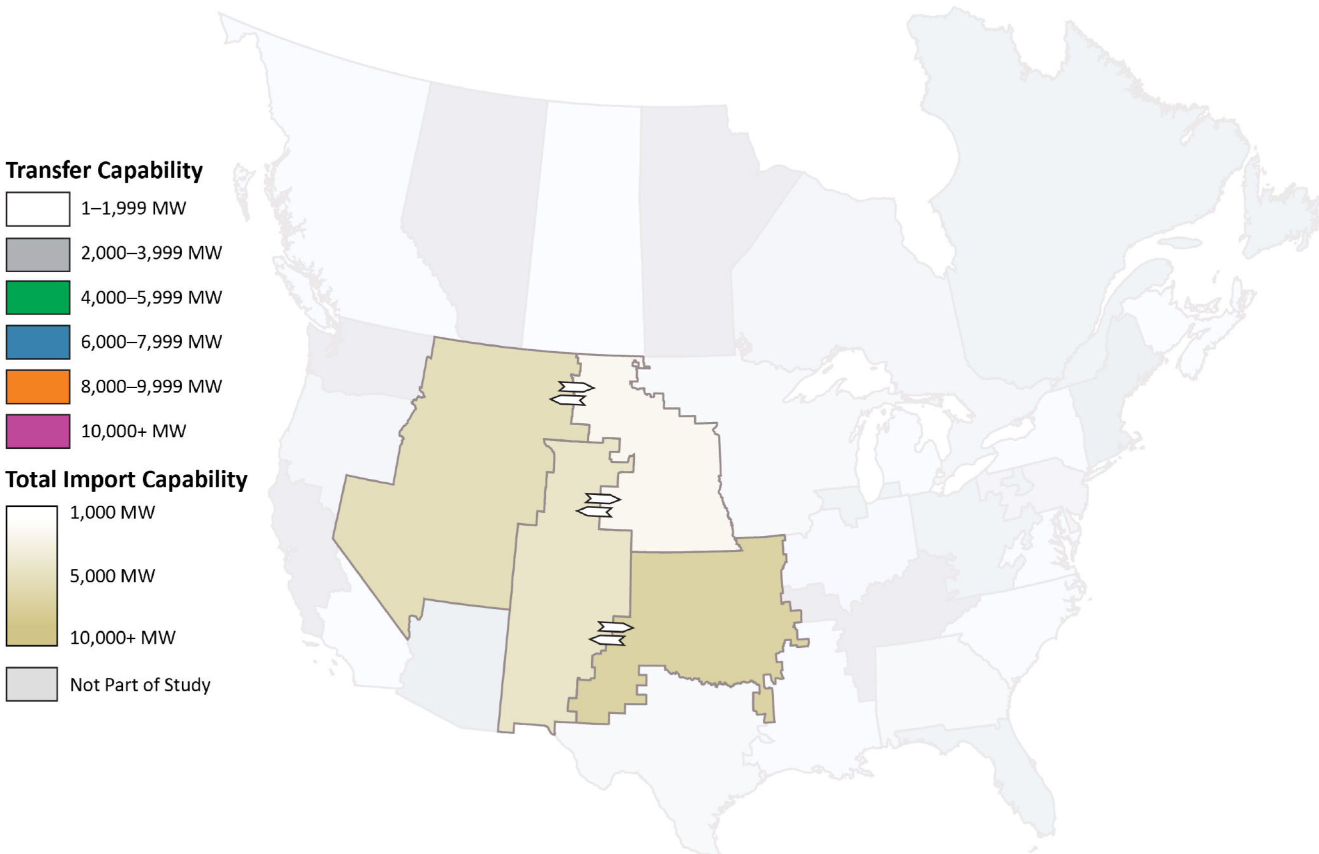
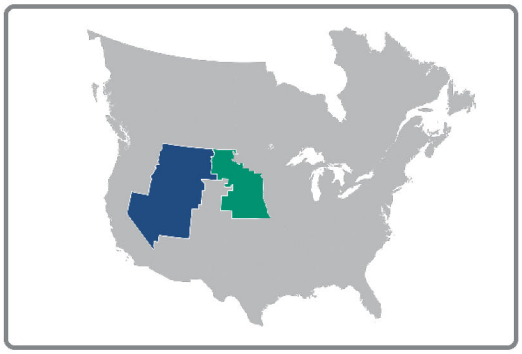


Figure 4.4: Transfer Capability Between Western and Eastern Interconnections (Winter)

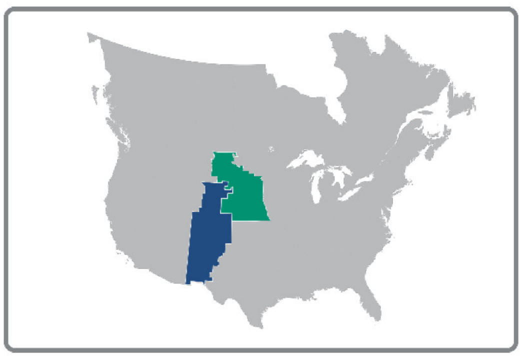
Interface WE1: Wasatch Front <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> SPP North	150 MW	150 MW
SPP North -> Wasatch Front	200 MW	200 MW

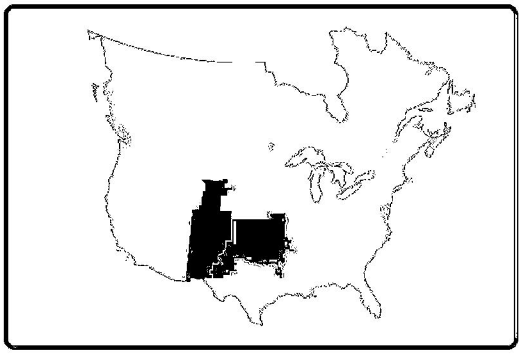
Interface WE2: Front Range <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP North	510 MW	510 MW
SPP North -> Front Range	510 MW	510 MW

Interface WE3: Front Range <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP South	410 MW	410 MW
SPP South -> Front Range	410 MW	410 MW

ERCOT – Eastern Interconnection Results

TTC results for the following interface are presented in this section:

Interface TE1: ERCOT <-> SPP South (dc-only)

Figure 4.5 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.6** similarly depicts the results from the 2024/25 Winter case.

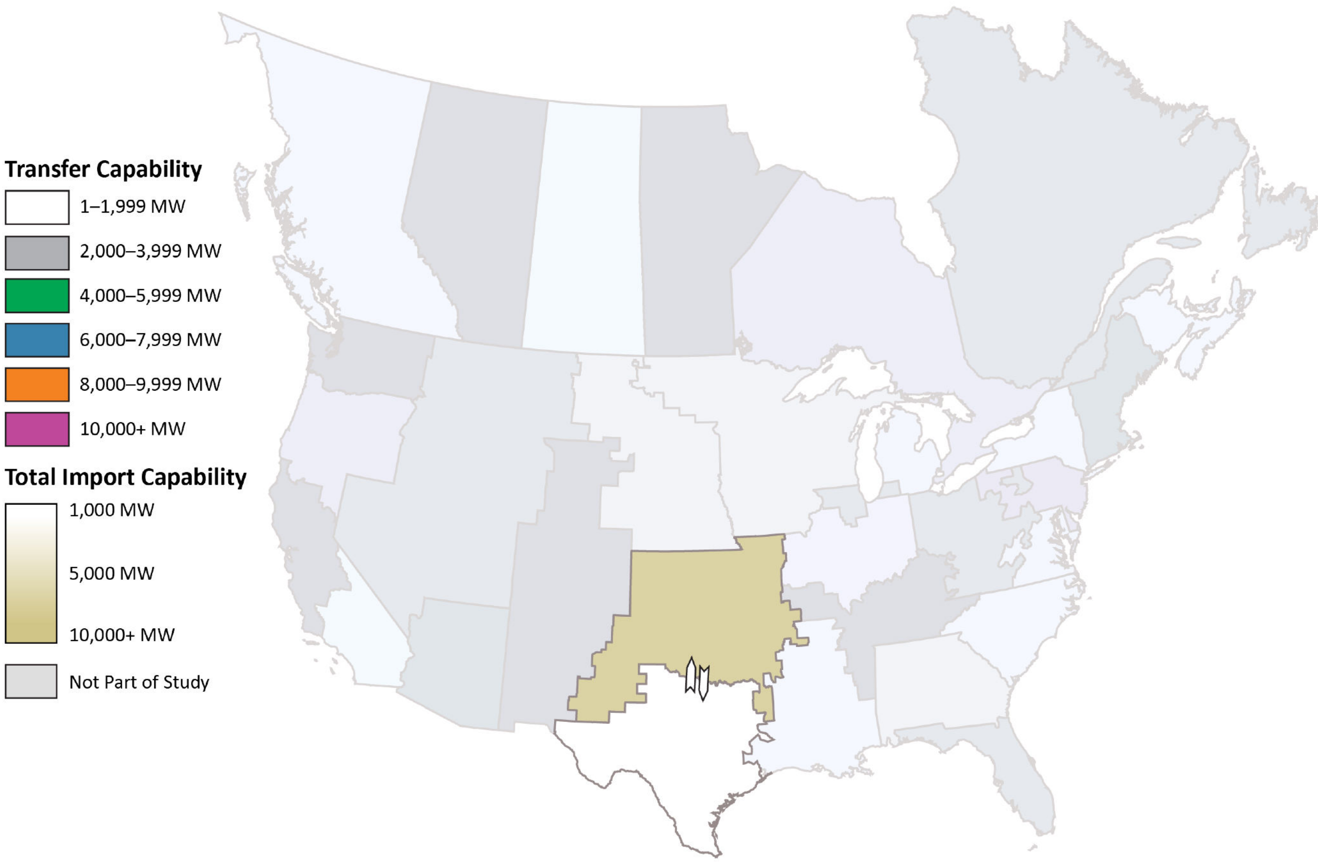


Figure 4.5: Transfer Capability Between ERCOT and Eastern Interconnections (Summer)

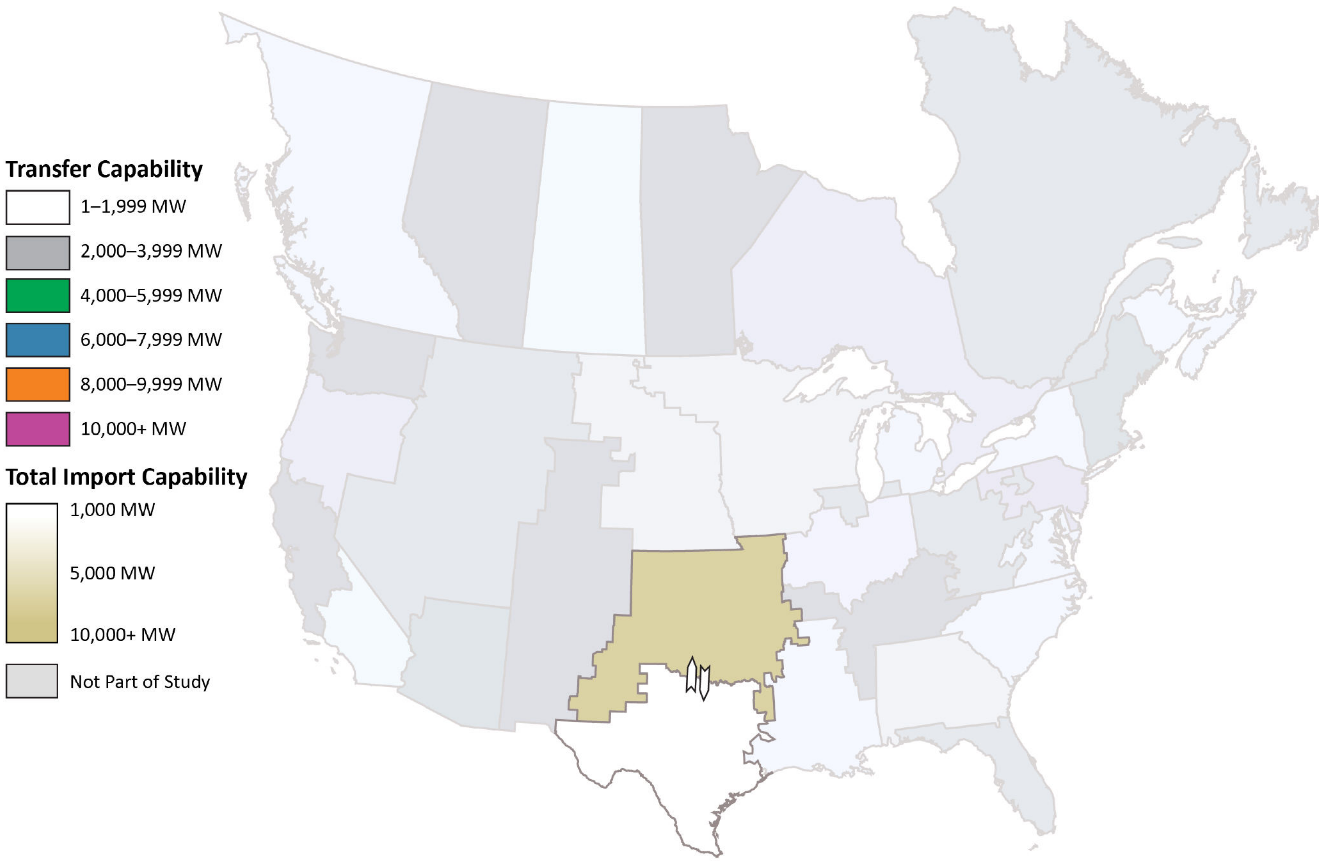
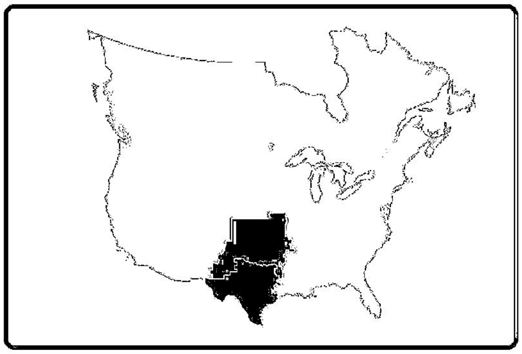


Figure 4.6: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

Interface TE1: ERCOT <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
ERCOT -> SPP South	820 MW	820 MW
SPP South -> ERCOT	820 MW	820 MW

Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

Interface E33: PJM East <-> New York

Interface E34: Ontario -> New York

Interface E35: New York <-> New England

Interface E36: Maritimes -> New England

Interfaces between Saskatchewan and Manitoba and between Manitoba and Ontario will be covered in the Canadian Analysis.

Figure 4.7 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.8** similarly depicts the results from the 2024/25 Winter case.

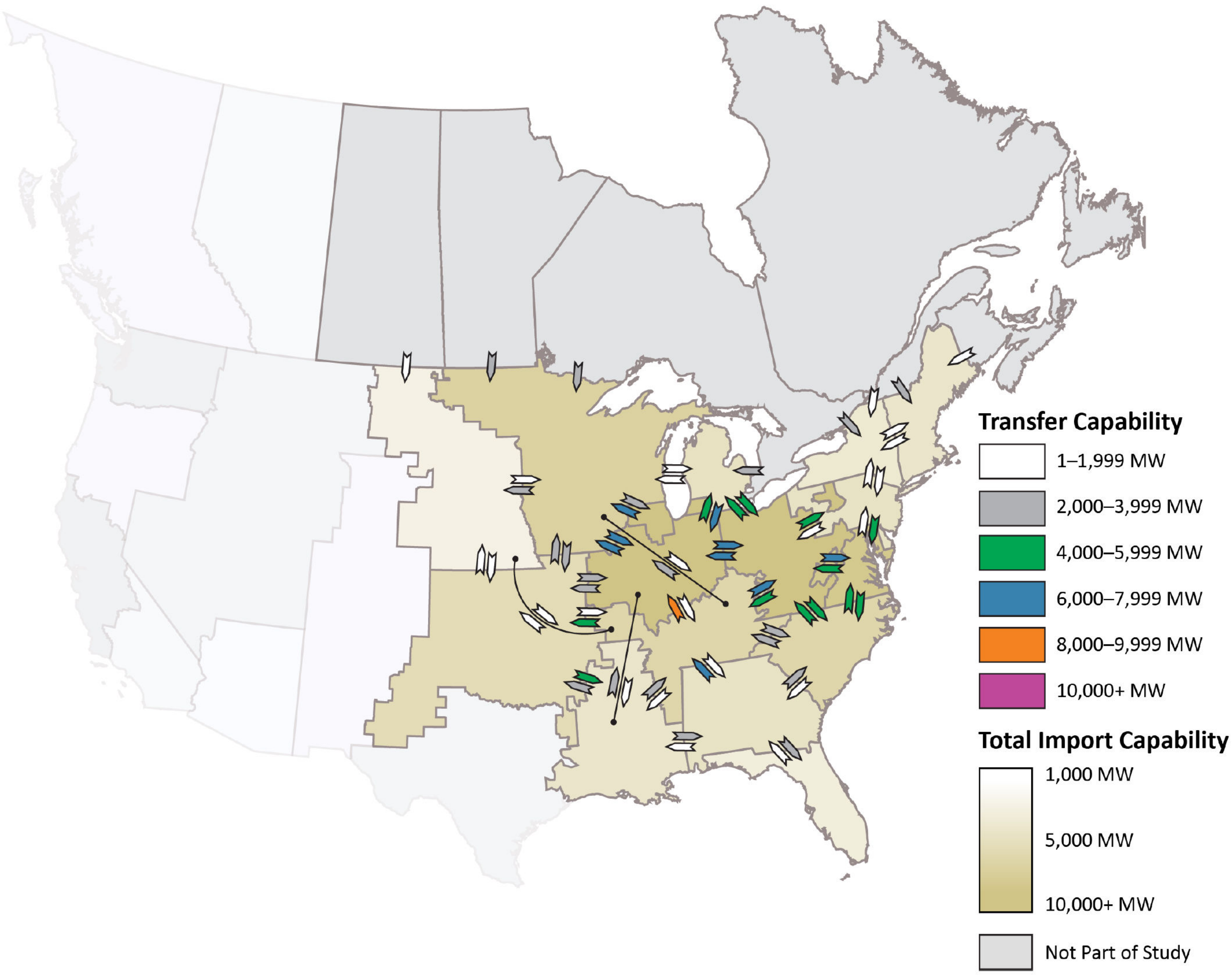


Figure 4.7: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

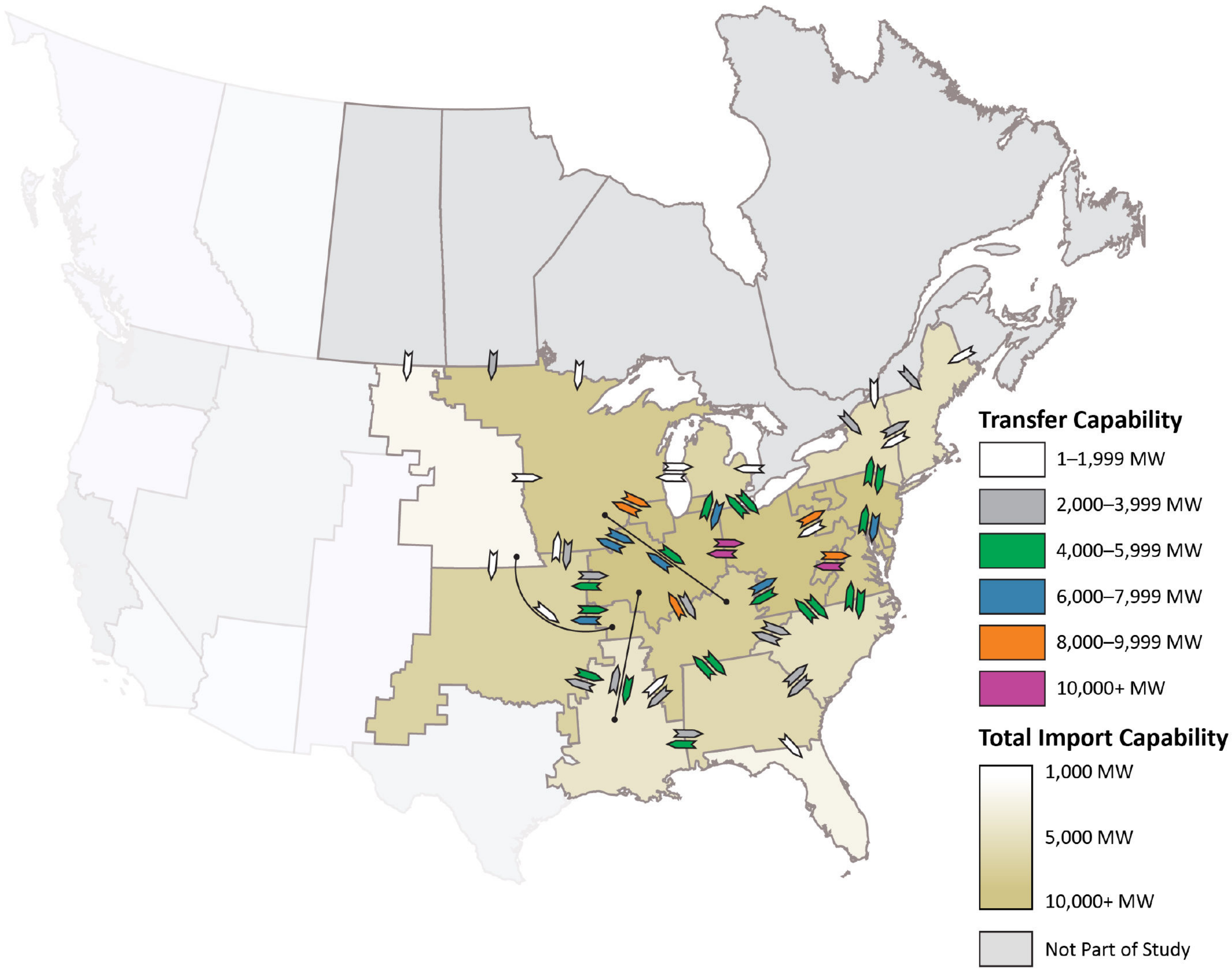
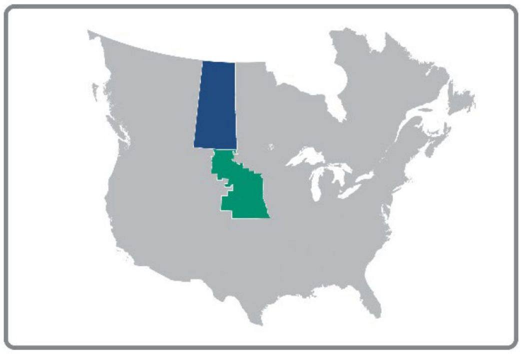


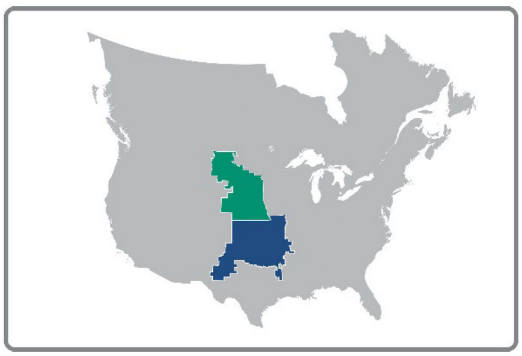
Figure 4.8: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

Interface E1: Saskatchewan -> SPP North



Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP North	165 MW	663 MW

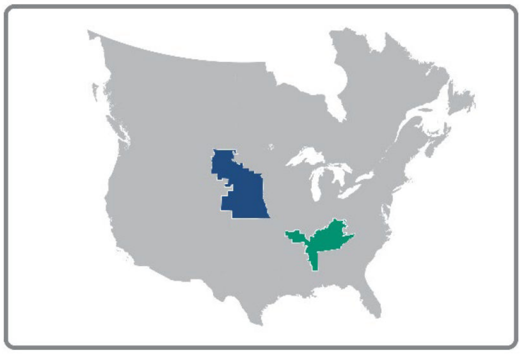
Interface E2: SPP North <-> SPP South



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SPP South	1,501 MW	1,785 MW
SPP South -> SPP North	1,705 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SPP South to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

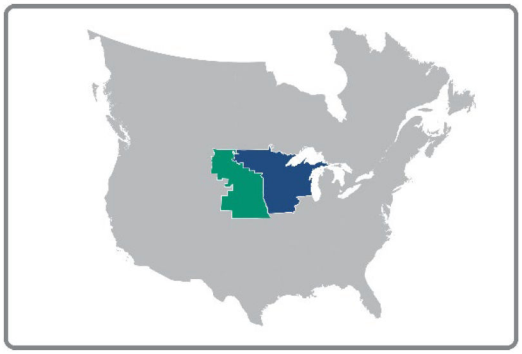
Interface E3: SPP North <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SERC Central	128 MW	1,102 MW
SERC Central -> SPP North	1,183 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SERC Central to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

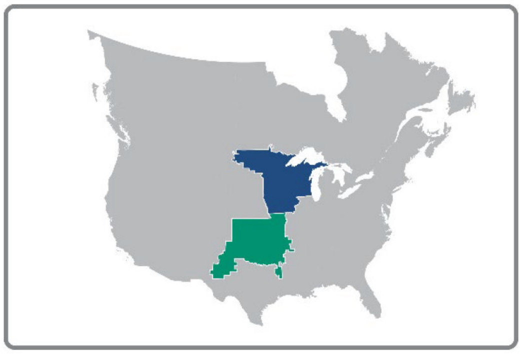
Interface E4: SPP North <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> MISO West	623 MW	778 MW
MISO West -> SPP North	2,209 MW	0 MW

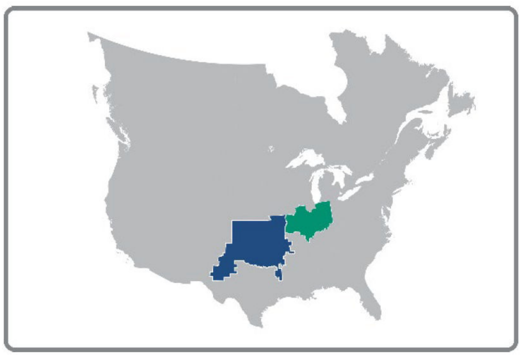
Explanatory Note: Under the studied winter peak conditions, transfers from MISO West to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E5: SPP South <-> MISO West



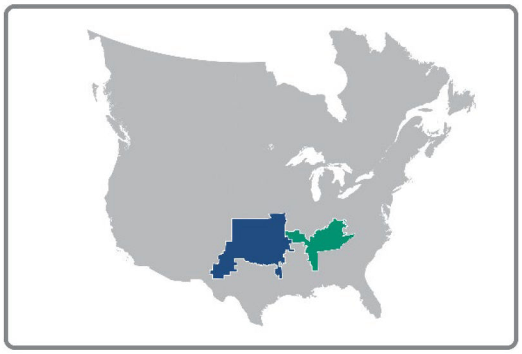
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO West	3,323 MW	1,196 MW
MISO West -> SPP South	2,086 MW	3,801 MW

Interface E6: SPP South <-> MISO Central



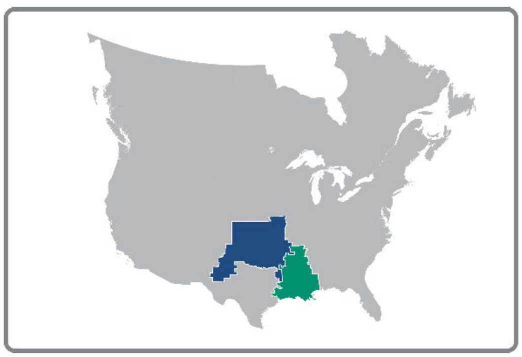
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO Central	2,481 MW	2,420 MW
MISO Central -> SPP South	3,873 MW	5,635 MW

Interface E7: SPP South <-> SERC Central



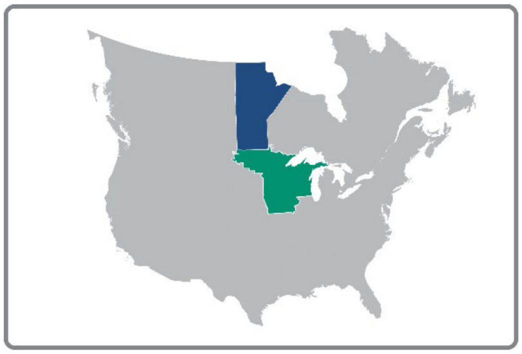
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> SERC Central	859 MW	5,591 MW
SERC Central -> SPP South	5,042 MW	6,445 MW

Interface E8: SPP South <-> MISO South



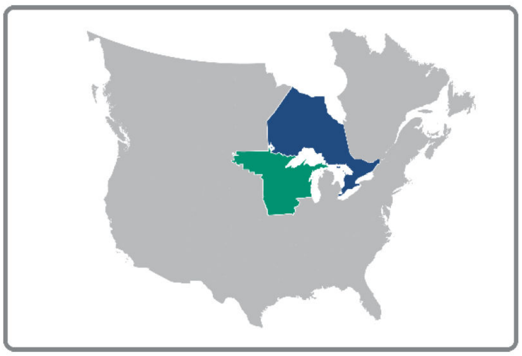
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO South	4,295 MW	4,336 MW
MISO South -> SPP South	3,033 MW	3,878 MW

Interface E9: Manitoba -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO West	3,772 MW	3,633 MW

Interface E10: Ontario -> MISO West



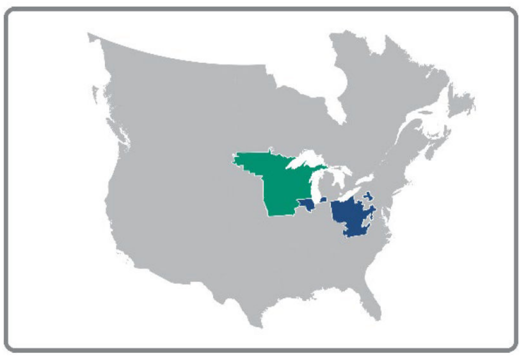
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW

Interface E11: MISO West <-> MISO East

Special Information: dc-only interface

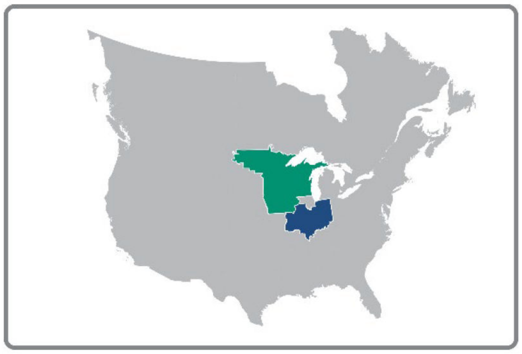
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO East	160 MW	160 MW
MISO East -> MISO West	160 MW	160 MW

Interface E12: MISO West <-> PJM West



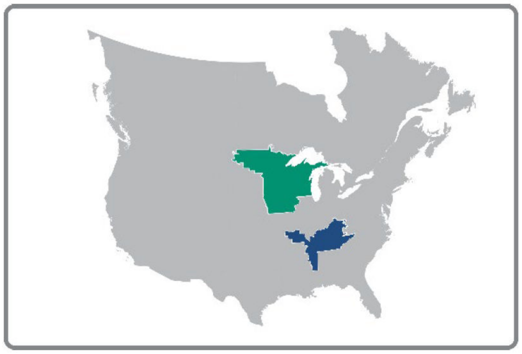
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> PJM West	2,518 MW	8,011 MW
PJM West -> MISO West	7,791 MW	9,086 MW

Interface E13: MISO West <-> MISO Central



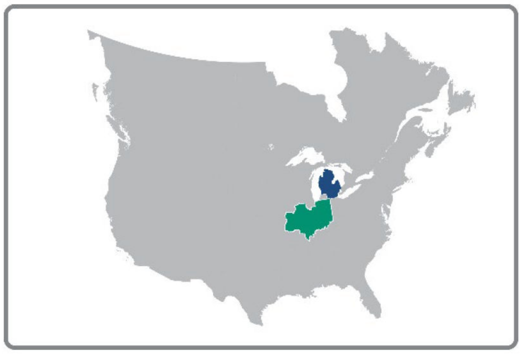
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO Central	6,199 MW	7,306 MW
MISO Central -> MISO West	7,602 MW	7,341 MW

Interface E14: MISO West <-> SERC Central



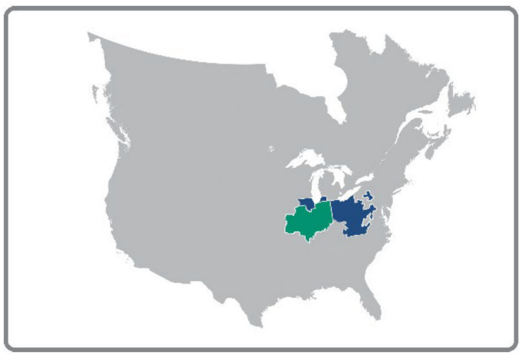
Interface Direction	2024 Summer	2024/25 Winter
MISO West -> SERC Central	150 MW	4,141 MW
SERC Central -> MISO West	3,671 MW	6,877 MW

Interface E15: MISO Central <-> MISO East



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO East	4,864 MW	5,585 MW
MISO East -> MISO Central	6,344 MW	6,531 MW

Interface E16: MISO Central <-> PJM West

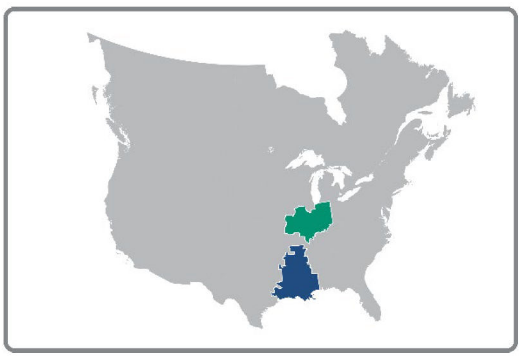


Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> PJM West	6,572 MW	10,790 MW
PJM West -> MISO Central	6,986 MW	20,449 MW

Interface E17: MISO Central <-> SERC Central

Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> SERC Central	235 MW	3,903 MW
SERC Central -> MISO Central	8,288 MW	8,441 MW

Interface E18: MISO Central <-> MISO South

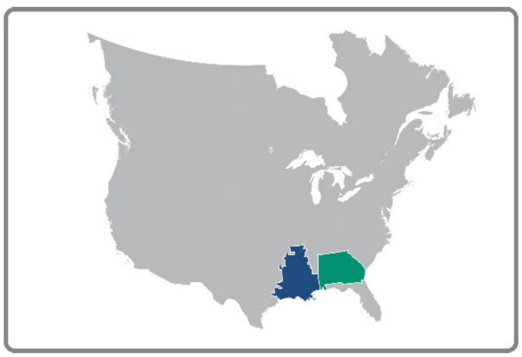


Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO South	1,797 MW	4,067 MW
MISO South -> MISO Central	2,117 MW	1,093 MW

Interface E19: MISO South <-> SERC Central

Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Central	2,468 MW	1,361 MW
SERC Central -> MISO South	1,457 MW	3,342 MW

Interface E20: MISO South <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Southeast	3,600 MW	3,392 MW
SERC Southeast -> MISO South	1,638 MW	4,028 MW

Interface E21: Ontario -> MISO East

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO East	2,348 MW	1,649 MW

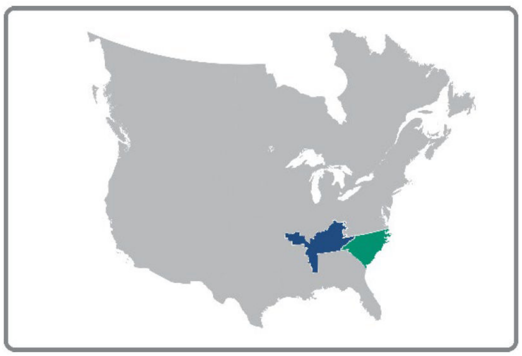
Interface E22: MISO East <-> PJM West

Interface Direction	2024 Summer	2024/25 Winter
MISO East -> PJM West	5,603 MW	5,940 MW
PJM West -> MISO East	4,345 MW	5,608 MW

Interface E23: SERC Central <-> PJM West

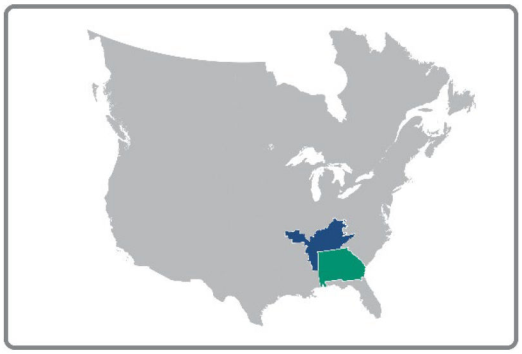
Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> PJM West	6,646 MW	6,710 MW
PJM West -> SERC Central	5,444 MW	5,786 MW

Interface E24: SERC Central <-> SERC East



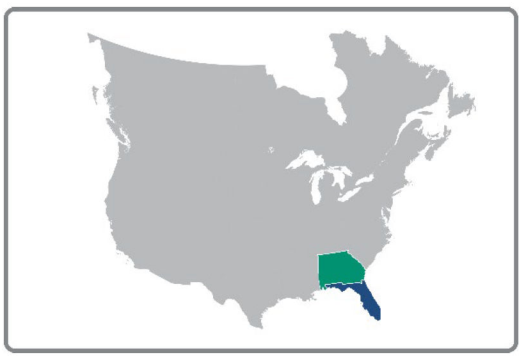
Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC East	2,419 MW	3,311 MW
SERC East -> SERC Central	3,257 MW	2,675 MW

Interface E25: SERC Central <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC Southeast	1,095 MW	5,387 MW
SERC Southeast -> SERC Central	6,579 MW	4,639 MW

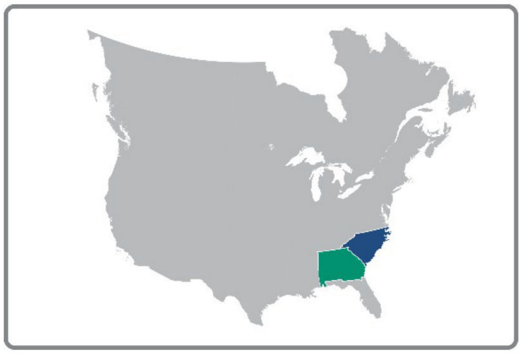
Interface E26: SERC Southeast <-> SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC Florida	2,958 MW	1,807 MW
SERC Florida -> SERC Southeast	1,322 MW	0 MW

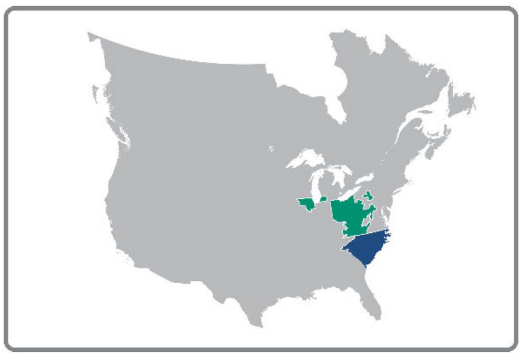
Explanatory Note: Flows from South to North (SERC Florida to SERC Southeast) are not typical under winter peak conditions.

Interface E27: SERC Southeast <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC East	2,397 MW	3,669 MW
SERC East -> SERC Southeast	1,703 MW	3,536 MW

Interface E28: SERC East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM West	5,185 MW	4,448 MW
PJM West -> SERC East	5,318 MW	4,286 MW