NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Transfer Capability Analysis (Part 1)
August 2024

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

Congress enacted legislation requiring an Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission capacity between regions for reliability. Signed into law in June 2023, section 322 of the Fiscal Responsibility Act of 2023[1] directs NERC, as the ERO under section 215 of the Federal Power Act[2] to conduct the ITCS:

> *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 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. The study must be filed with the Federal Energy Regulatory Commission (FERC) by December 2, 2024,[5] with a FERC public comment period to follow. This report, which builds on the *Overview of Study Need and Approach* (ITCS Overview) published in June 2024,[6] communicates the Part 1 study process details and the transfer capability analysis.

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[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, 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).

[5] See Fiscal Responsibility Act (adding that, "Not later than 12 months after the end of the public comment period in subsection (b), the Federal Energy Regulatory Commission shall submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes.").

[6] Readers are encouraged to review the ITCS Overview of Study Need and Approach, found here, for a more complete understanding of this Part 1 report.

Executive Summary

A Complex Grid

The North American grid is a complex machine that integrates a network of generation, transmission, and distribution systems across vast geographic areas that has evolved over many years.[7] A strong, flexible, and resilient transmission system is critical for the reliable delivery of electricity and is an essential component of grid reliability. As the ERO, NERC remains focused on assuring reliability throughout the ongoing energy transformation. Recent operational events[8] on the BPS show that more needs to be done to support energy adequacy to continuously meet customer demand. Ensuring sufficient transfer capability[9] of the transmission system to support energy adequacy[10] is the reliability gap that the ITCS seeks to address.

KEY OBSERVATIONS

- 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 magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resource availability.

Study Need

NERC assessments[11] have identified the need for more transmission capacity to support the energy transformation and the ongoing electrification of the economy, including transportation, industry, and data centers. The situation is further compounded by more frequent extreme weather events. While always important, the need for reliable energy supply – in the interest of public health, safety, and security – becomes most pronounced under these conditions. The combination of these factors emphasizes the criticality of adequate and informed planning that will support future grid reliability. Transmission assessments, like the ITCS, are crucial to managing and mitigating future reliability risks. The ITCS will examine the extent of transfer capability, any prudent recommendations for additional transfer capability to strengthen reliability, and how to meet and maintain such capability as enhanced by any additions. Consistent with the ERO's mission, the ITCS focuses on reliability and will not include economic justification for new and/or upgraded transmission facilities.

[7] An explanation of the electric power grid can be found here (Source: *Electricity Explained – U.S. Energy Information Administration*, *April 2024*).
[8] The ITCS Overview of Study Need and Approach includes examples of the critical role of transfer capability during the Western Interconnection Heatwave (2020), Winter Storm Uri (2021), and Winter Storm Elliott (2022).
[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] Energy adequacy is the ability of the BPS to meet customer demand at all times.
[11] NERC's assessments can be found here.

The first ITCS document – *Overview of Study Need and Approach*[12] – was released in June 2024. It provides background and context on the study, including details regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. As discussed therein, while an essential component of reliability is ensuring that a planned resource portfolio can deliver an adequate amount of energy at all hours of the year, the interconnected nature of the North American grid often results in energy transfers between neighboring regions. The fundamental question assessed by the ITCS is the ability of the BPS to reliably support these energy transfers.

This report – *Transfer Capability Analysis (Part 1)* – addresses the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring Transmission Planning Regions (TPR).[13] The results from this Part 1 analysis will be applied to Parts 2 and 3 of the study. Prudent Additions Recommendations (Part 2) of the ITCS will suggest increases to the transfer capability between neighboring TPRs to improve reliability during, for example, an extreme weather event. Meet and Maintain Recommendations (Part 3) will discuss how to meet and maintain transfer capability as enhanced by these prudent additions. Parts 2 and 3 will be issued together, and the final consolidated report will be submitted to FERC on or before December 2, 2024.

Significance of Transfer Capability

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuels, such as wind and solar, the ability to transfer electrical energy from areas of fuel adequacy to areas experiencing fuel constraints has become essential to maintaining reliable delivery of electricity to end-use customers. **Chapter 1** contains additional details regarding the calculation of transfer capability.

Recognizing the importance of transfer capability, there have been calls for industry regulators to require plans for a minimum transfer capability as a certain percentage of load. While the ITCS considered this approach, in practice, each TPR faces unique challenges such as its resource mix, each neighbor's resource mix, and probable weather impacts, each of which require careful consideration. As a result, a TPR with relatively low transfer capability may not experience resource deficiencies, while another TPR with relatively high transfer capability may experience resource deficiencies. A deliberate and holistic approach to coordinated resource and transmission planning will optimize the reliability provided by increased transfer capability. The recommendations for prudent additions in the Part 2 report will reflect a TPR-specific approach to transfer capability rather than a percentage-based minimum requirement.

Holistic Approach to Transfer Capability

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 difficulty, or resistance, 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.

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

[13] This is not a defined term in the NERC Glossary of Terms, but for the purposes of the ITCS, this term refers to the study regions that are described in the ITCS Overview and in **Chapter 1** of this report.

> The magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resources.

While the ITCS examines transfer capability as one side of the reliability equation, resource availability must also be considered. When extreme conditions challenge the BPS, they often impact a large geographic area. As a result, when one system is running short on resources, its neighboring systems may be facing the same dilemma simultaneously. System planners must consider various weather conditions impacting not only their own systems but also the neighboring systems they might rely on to transfer energy. Building transfer capability between systems that need more resources simultaneously will not enhance reliability during those extreme conditions. Only coordinated resource and transmission planning can ensure that the risks to the BPS are well understood and appropriately managed.

Limitations of Transfer Capability

Planners must also carefully evaluate potential impacts of increased transfer capability. Increased transfers of energy between TPRs can benefit reliability in some situations, but large transfers also have reliability implications that must be considered. When a large amount of energy is transferred, certain aspects of reliable system operations, such as system stability, voltage control, and minimizing the potential for cascading outages, must also be considered, including the ability to withstand unplanned facility outages. This evaluation is crucial as an increased transfer capability may benefit neighboring TPRs under stressed conditions, but it can also potentially create some reliability issues that must be carefully considered in the planning process.

> Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.

Finally, 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.

Transfer Capability Analysis (Part 1) Summary

The Part 1 transfer capability analysis between each pair of neighboring TPRs focused on two different base cases:[14]

- 2024 Summer
- 2024/25 Winter

These base cases were chosen from readily available seasonal peak load models and updated by industry to reflect future conditions. Further details regarding base case development can be found in **Chapter 1**. All electrically connected neighboring systems were evaluated, and results are presented by Interconnection proceeding from west to east as follows:

Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.

- Western Interconnection (**Chapter 2**)
- Ties between the Western and Eastern Interconnections (**Chapter 3**)
- Ties between the Electric Reliability Council of Texas (ERCOT) and Eastern Interconnections (**Chapter 4**)
- Eastern Interconnection (**Chapter 5**)
- Ties between the Québec and Eastern Interconnections (**Chapter 6**)

Figure ES.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure ES.2** similarly depicts the results from the 2024/25 Winter case.

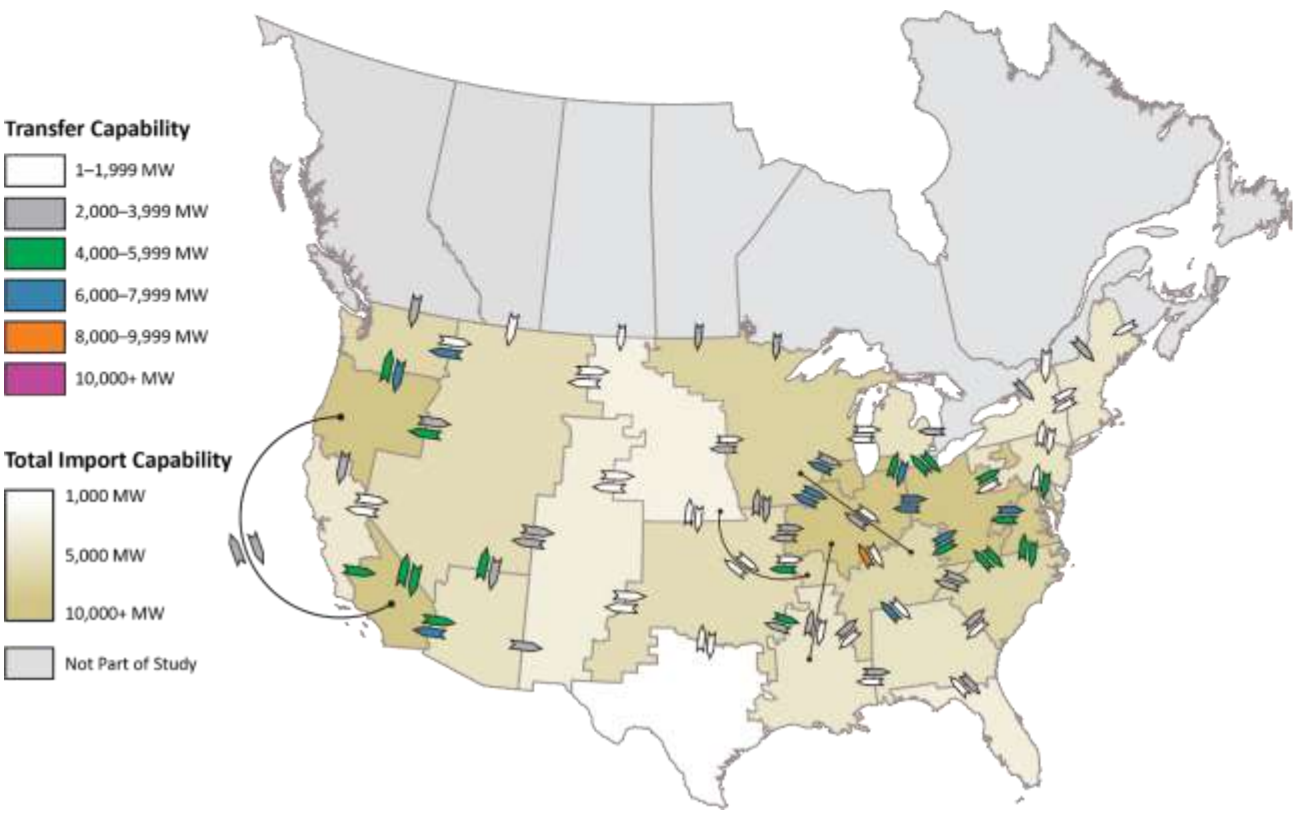


Figure ES.1: Transfer Capabilities (Summer)

[14] Base cases are computer models that simulate the behavior of the electrical system under various conditions.

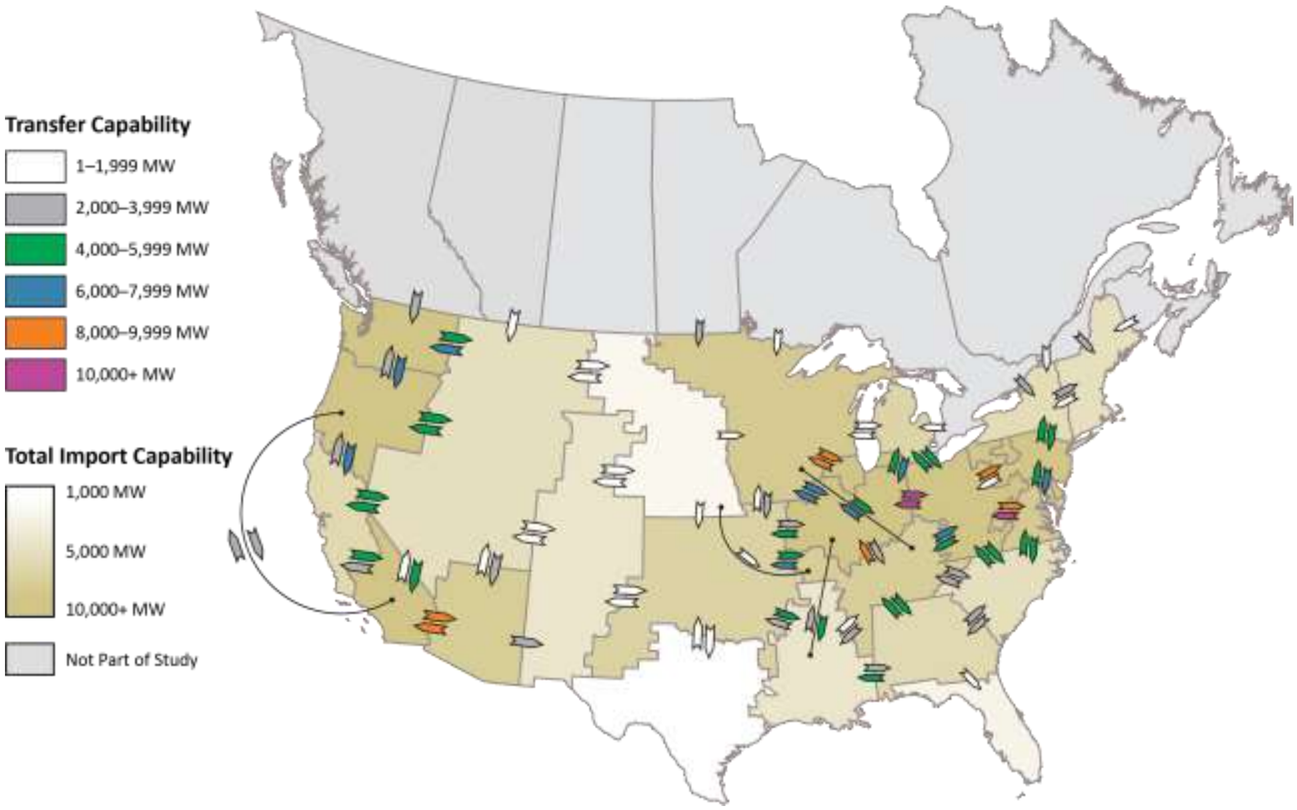


Figure ES.2: Transfer Capabilities (Winter)

Part 1 analysis also includes transfer capability between planning areas as defined by FERC's Order No. 1000.[15] Since the ITCS is being conducted under NERC's authority from section 215 and provides a more detailed reliability focus, these larger geographic areas will not be used to determine prudent additions.[16] Nonetheless, the current transfer capability results between these areas are provided for completeness in **Chapter 7**.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import interfaces, which are provided in **Chapter 8** of this report. The use of these total import interfaces, while not part of the mandated evaluation of transfer capability between pairs of neighboring TPRs, is technically necessary to increase the accuracy of the Part 2 results by reducing the likelihood of overstating import capability.

This study is unique in terms of its geographic magnitude and overall approach to evaluating energy adequacy under extreme conditions. It revealed several challenges and highlighted associated opportunities to improve processes, data collection, and coordination for future studies. These key study opportunities are listed in **Appendix A**.

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

[16] Order No. 1000 was issued by FERC in relation to Transmission Planning and Cost Allocation under FERC's authority under section 206 of the Federal Power Act. As a result, the Order No. 1000 planning regions do not, for example, include Texas.

Stakeholder Engagement and Reporting

To ensure a comprehensive and inclusive study, an ITCS Advisory Group of stakeholders was formed, including transmitting utilities across North America. Throughout the ITCS process, industry and stakeholders have been kept informed through regular updates posted on the ITCS web page, and through open project and Advisory Group meetings. To provide further opportunities for stakeholder engagement and consultation, the project has been divided into several stages, each with an accompanying report. In addition to this *Transfer Capability Analysis (Part 1)* report, the other documents are:

- ***Overview of Study Need and Approach***[17] **(completed)**: Provides background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Prudent Additions Recommendations (Part 2) and Meet and Maintain Recommendations (Part 3):** Identification of prudent additions to transfer capability between neighboring areas (Part 2) and the recommendations to meet and maintain transfer capability (Part 3). (November 2024)
- **Canadian Analysis:** A study of transfer capabilities from the United States to Canada and between Canadian provinces. While this part is outside the specific congressional directive,[18] the interconnectedness of the North American BPS[19] warrants analysis of Canada. (Q1 2025)

[17] The ITCS Overview of Study Need and Approach can be found here.

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

[19] 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.

Chapter 1: Part 1 Study Process Details

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.

Transmission Planning Regions

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.

In general, this study's scope is interregional transfer capability analysis between source/sink TPRs.[20] As described in the ITCS Overview, during the process of defining TPRs for the purposes of this study, some areas defined in FERC's Order No. 1000,[21] which generally do not follow state boundaries, were sub-divided to provide more granular analysis of potential transfer capability limitations. The Canadian TPRs largely follow provincial boundaries. These TPRs, shown in **Figure 1.1**, have been carefully selected to identify key constraints to interregional transfer capability.

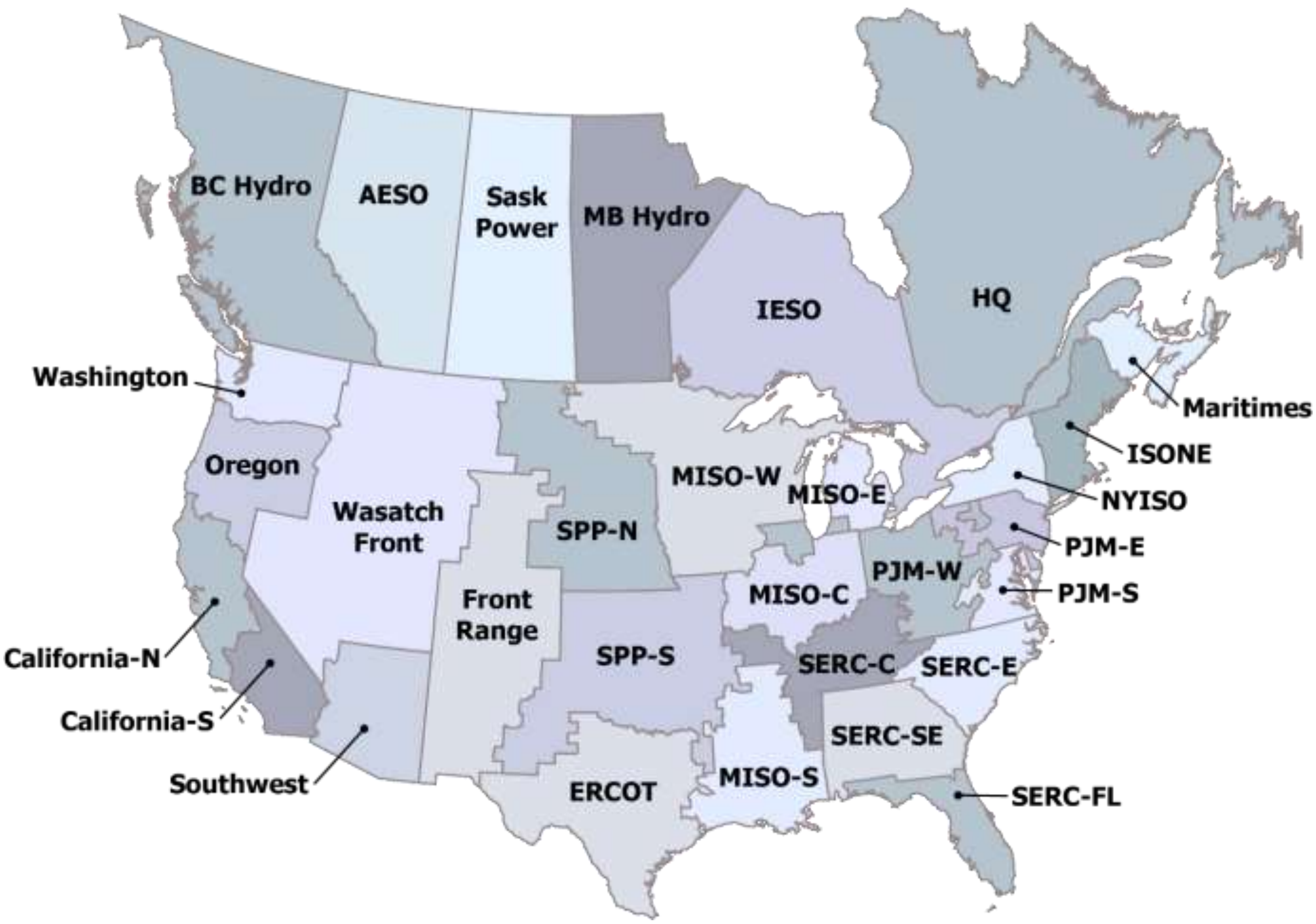


Figure 1.1: Transmission Planning Regions

[20] While the congressional directive applies to the United States, any analysis would be incomplete without a thorough understanding of the Canadian limits and available resources.
[21] More information can be found on FERC's website at www.ferc.gov.

Results for areas defined in FERC's Order No. 1000 are provided in **Chapter 7** of this report. These areas will not be part of the Part 2 Prudent Additions analysis, as the selected TPRs will provide more precise and meaningful recommendations for increases to transfer capability. While the Los Angeles Department of Water & Power (LADWP) is part of WestConnect, for the purposes of this study, LADWP was included as part of CAISO due to its geographic location within California.

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 capability between neighboring TPRs, this evaluation is technically necessary to appropriately model system capability in Part 2 of the ITCS. Total import interface transfer capability results are reported in **Chapter 8**.

Canadian systems were included in this analysis to perform the transfer capability calculations from Canada to the United States. Analysis of transfer capability from the United States to Canada and between provinces will be performed subsequently, with the associated report expected to be published in the first quarter of 2025.

Total Transfer Capability

As described further in the ITCS Overview, Total Transfer Capability (TTC) is calculated as the sum of the Base Transfer Level (BTL) and First Contingency Incremental Transfer Capability (FCITC). In other words, **TTC = BTL + FCITC**. This enables a consistent calculation method across the entire study area, although TTC calculations are different than path limits which are used by some entities.

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 for each area 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. For each area in the study cases 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 later), until a criteria violation is found. PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) software was used for this transfer analysis. 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.

Base Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. 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. More information can be found in the Part 1 scoping document.[22]

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

System models representing Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[23] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

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[24] 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
- 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.[25] Some entities performed additional studies while monitoring lower voltage facilities to ensure there were no significant differences.

[23] MOD-032-1 (nerc.com)
[24] TPL-001-5.1 (nerc.com)
[25] ITCS Transfer Study Scope Part 1 (nerc.com)

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 are 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.

Study Results

As noted earlier, the TTC values below will be used in Parts 2 and 3 of the ITCS. Part 2 will recommend prudent additions to the amount of energy that can be moved or transferred between neighboring TPRs, while Part 3 will provide recommendations on how to meet and maintain transfer capability as enhanced by any prudent additions.

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
- Ties between the Western and Eastern Interconnections
- Ties between the ERCOT and Eastern Interconnections
- Eastern Interconnection
- Ties between the Québec and Eastern Interconnections

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.

Chapter 2: Western Interconnection Results

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

- W1: British Columbia -> Washington
- W2: Washington <-> Oregon
- W3: Washington <-> Wasatch Front
- W4: Oregon <-> California North
- W5: Oregon <-> Wasatch Front
- W6: California North <-> California South
- W7: California North <-> Wasatch Front
- W8: California South <-> Wasatch Front
- W9: California South <-> Southwest
- W10: Alberta -> Wasatch Front
- W11: Wasatch Front <-> Southwest
- W12: Wasatch Front <-> Front Range
- W13: Southwest <-> Front Range
- W14: Oregon <-> Southern California (dc)

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

Figure 2.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 2.2** similarly depicts the results from the 2024/25 Winter case.

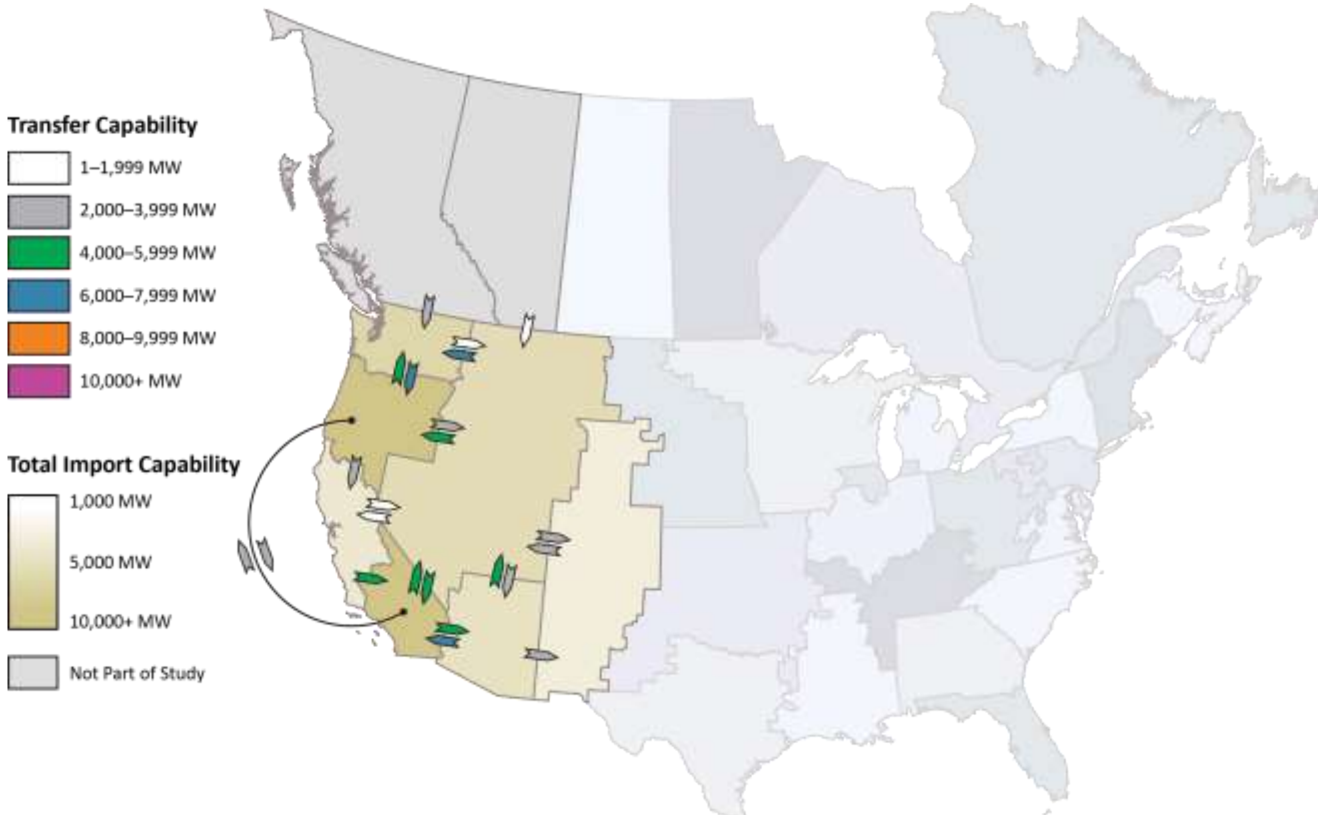


Figure 2.1: Transfer Capabilities for Western Interconnection Interfaces (Summer)

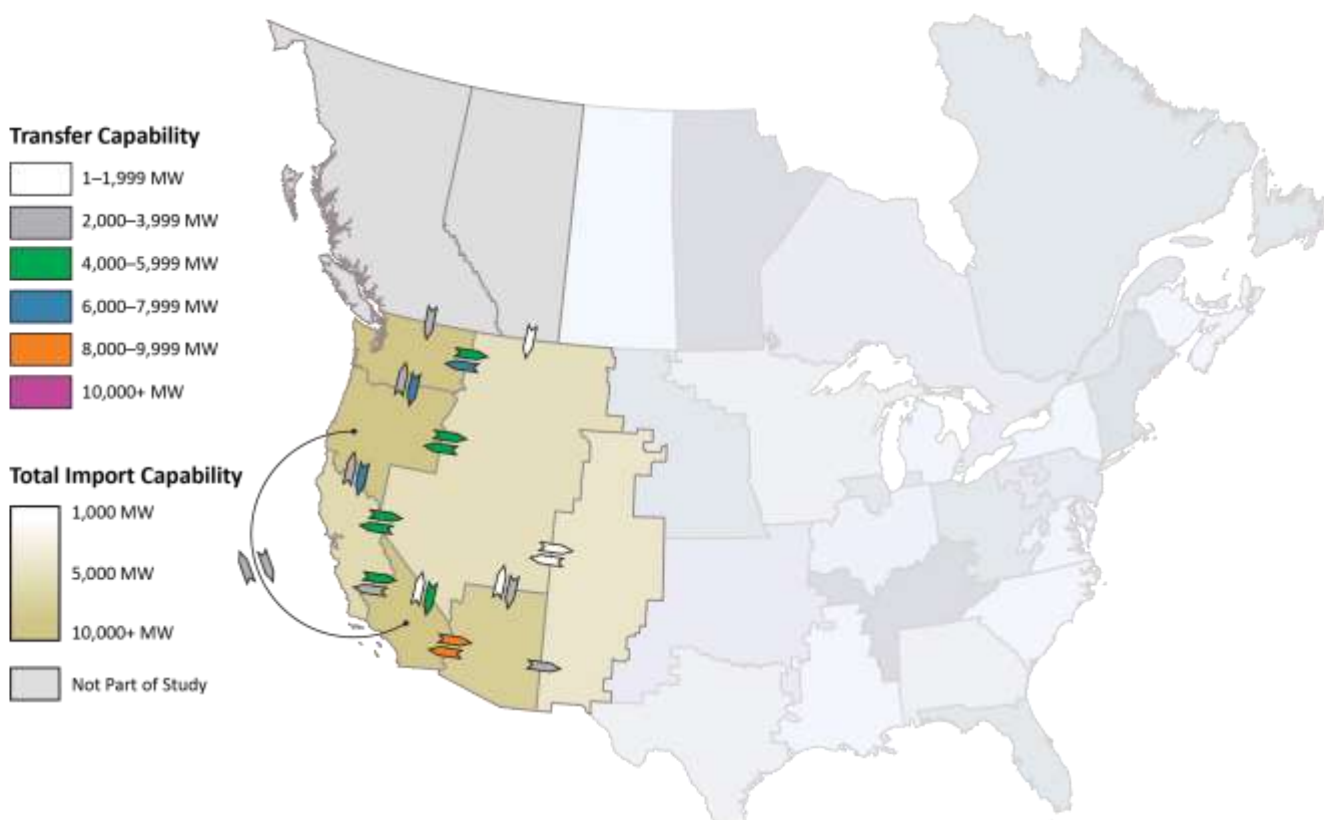
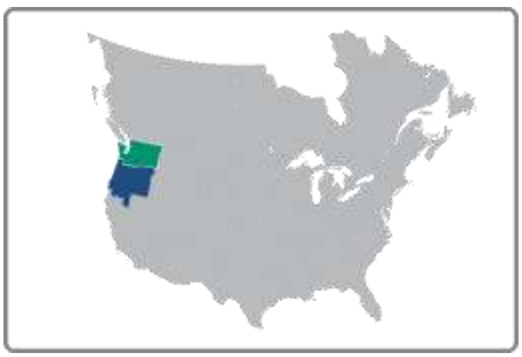


Figure 2.2: Transfer Capabilities for Western Interconnection Interfaces (Winter)

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

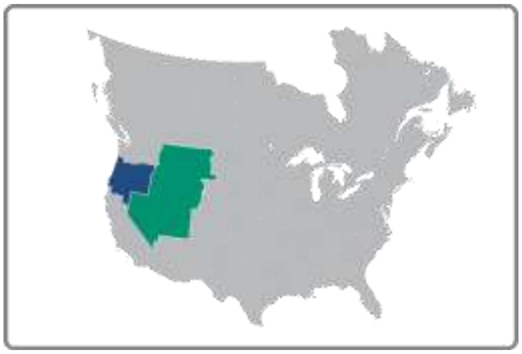
Interface Direction	2024 Summer	2024/25 Winter
Washington -> Wasatch Front	1,925 MW	4,498 MW
Wasatch Front -> Washington	7,377 MW	7,030 MW

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

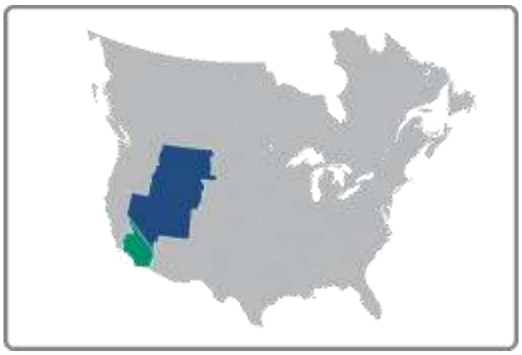
Interface Direction	2024 Summer	2024/25 Winter
California North -> California South	4,647 MW	5,676 MW
California South -> California North	0 MW	3,861 MW

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

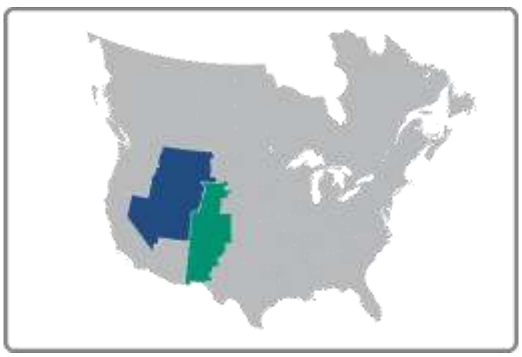
Interface W10: Alberta -> Wasatch Front

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

Interface W11: Wasatch Front <-> Southwest

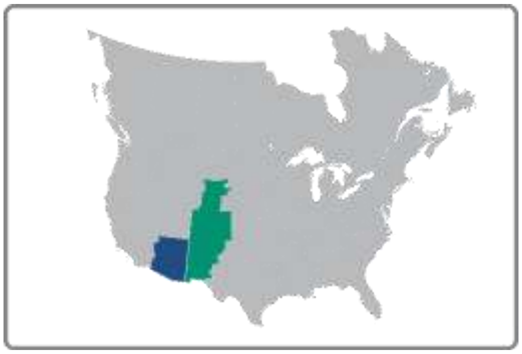
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Southwest	2,351 MW	2,095 MW
Southwest -> Wasatch Front	5,821 MW	1,295 MW

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

Chapter 3: Western – Eastern Interconnection Results

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

- WE1: Wasatch Front <-> SPP North (dc)
- WE2: Front Range <-> SPP North (dc)
- WE3: Front Range <-> SPP South (dc)

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

Figure 3.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 3.2** similarly depicts the results from the 2024/25 Winter case.

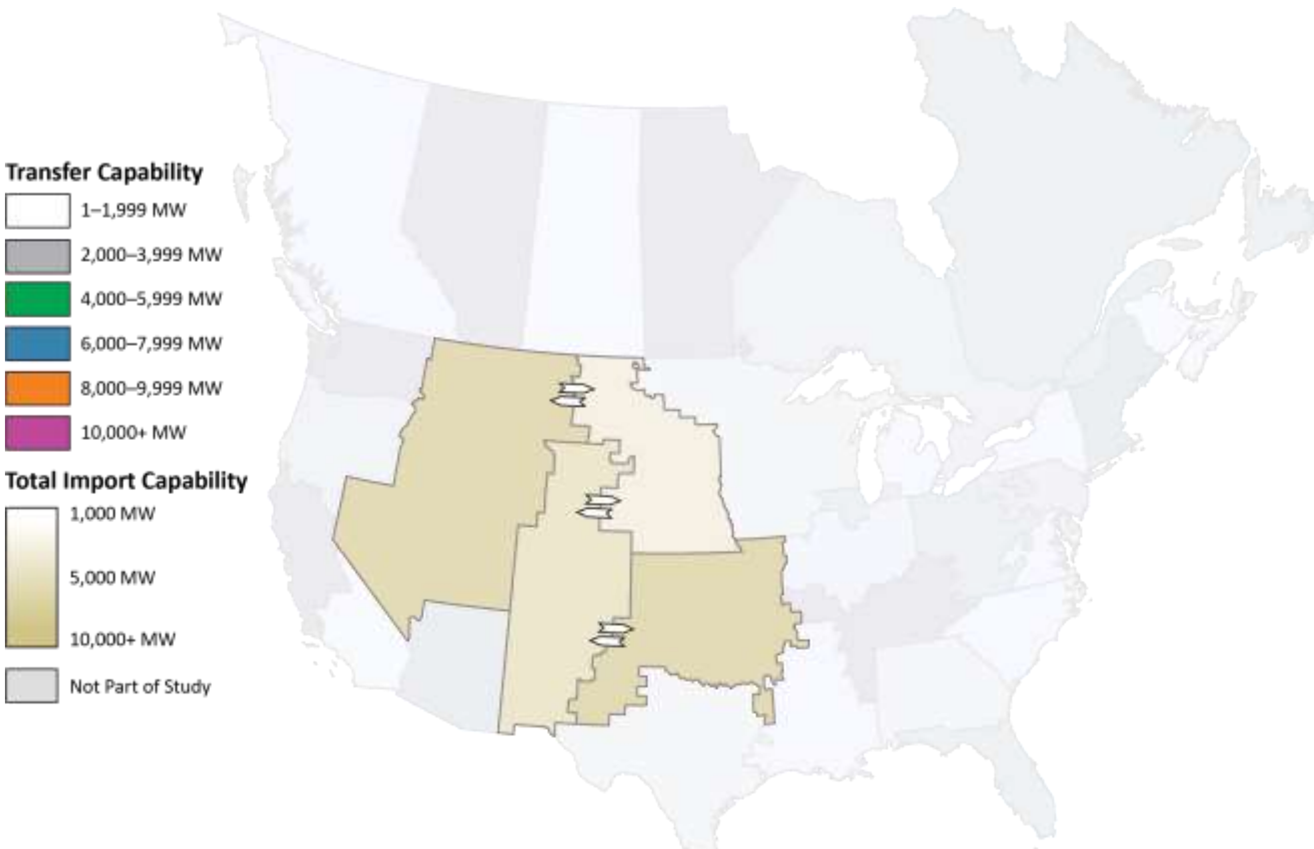


Figure 3.1: Transfer Capability Between Western and Eastern Interconnections (Summer)

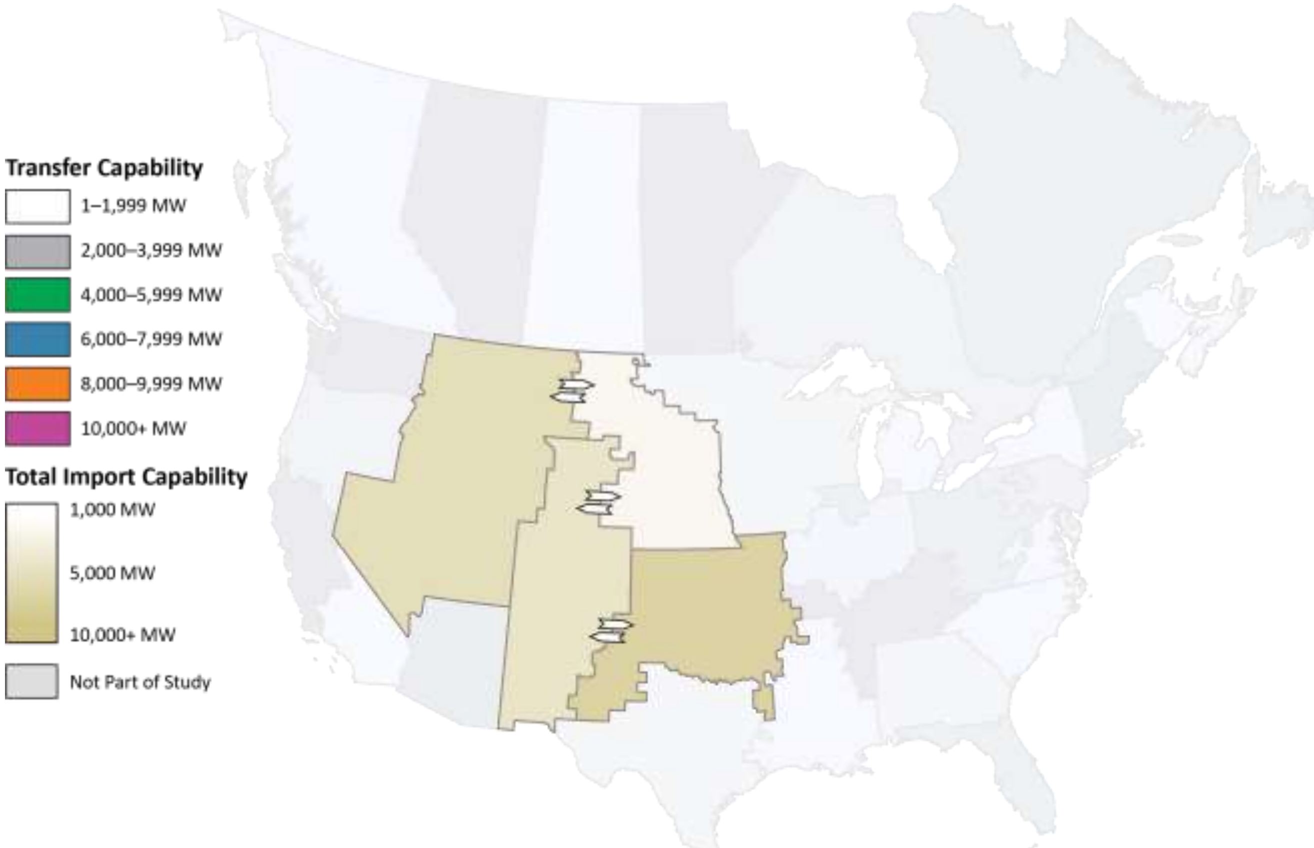
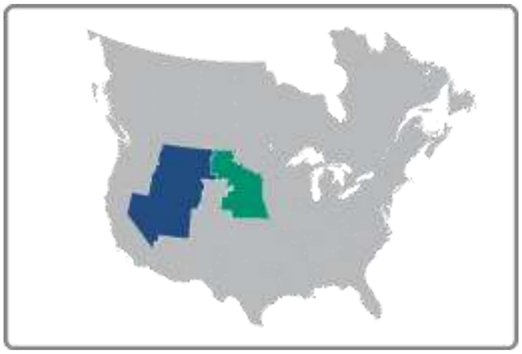


Figure 3.2: Transfer Capability Between Western and Eastern Interconnections (Winter)

Interface WE1: Wasatch Front <-> SPP North



Special Information: dc-only interface

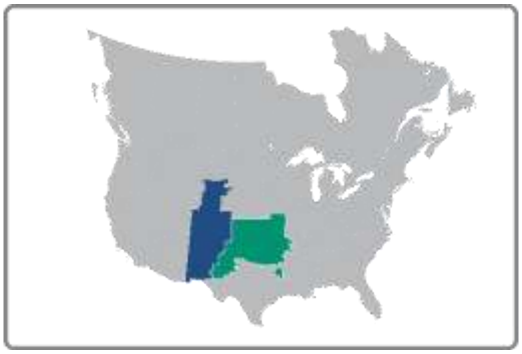
Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> SPP North	150 MW	150 MW
SPP North -> Wasatch Front	200 MW	200 MW

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

Chapter 4: ERCOT – Eastern Interconnection Results

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

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

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.

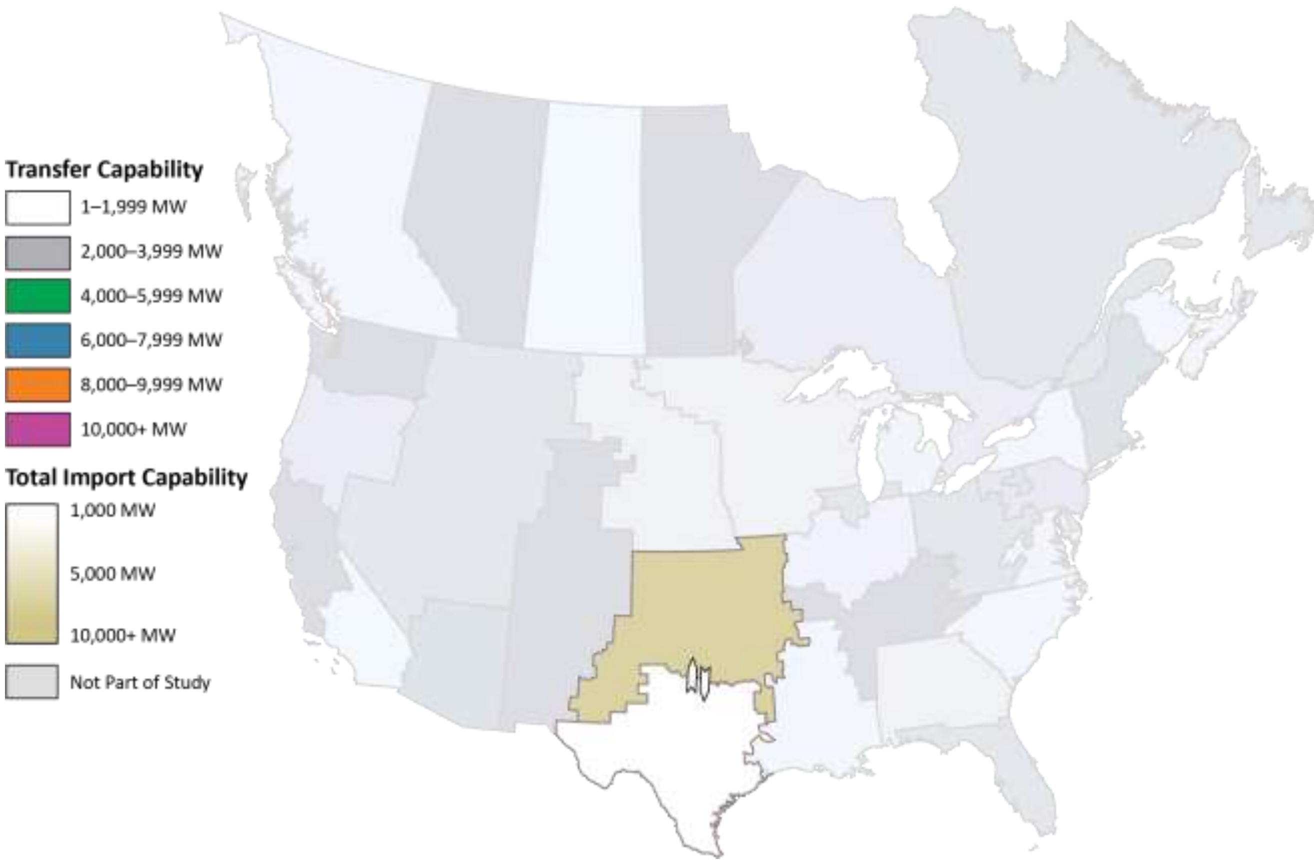


Figure 4.1: Transfer Capability Between ERCOT and Eastern Interconnections (Summer)

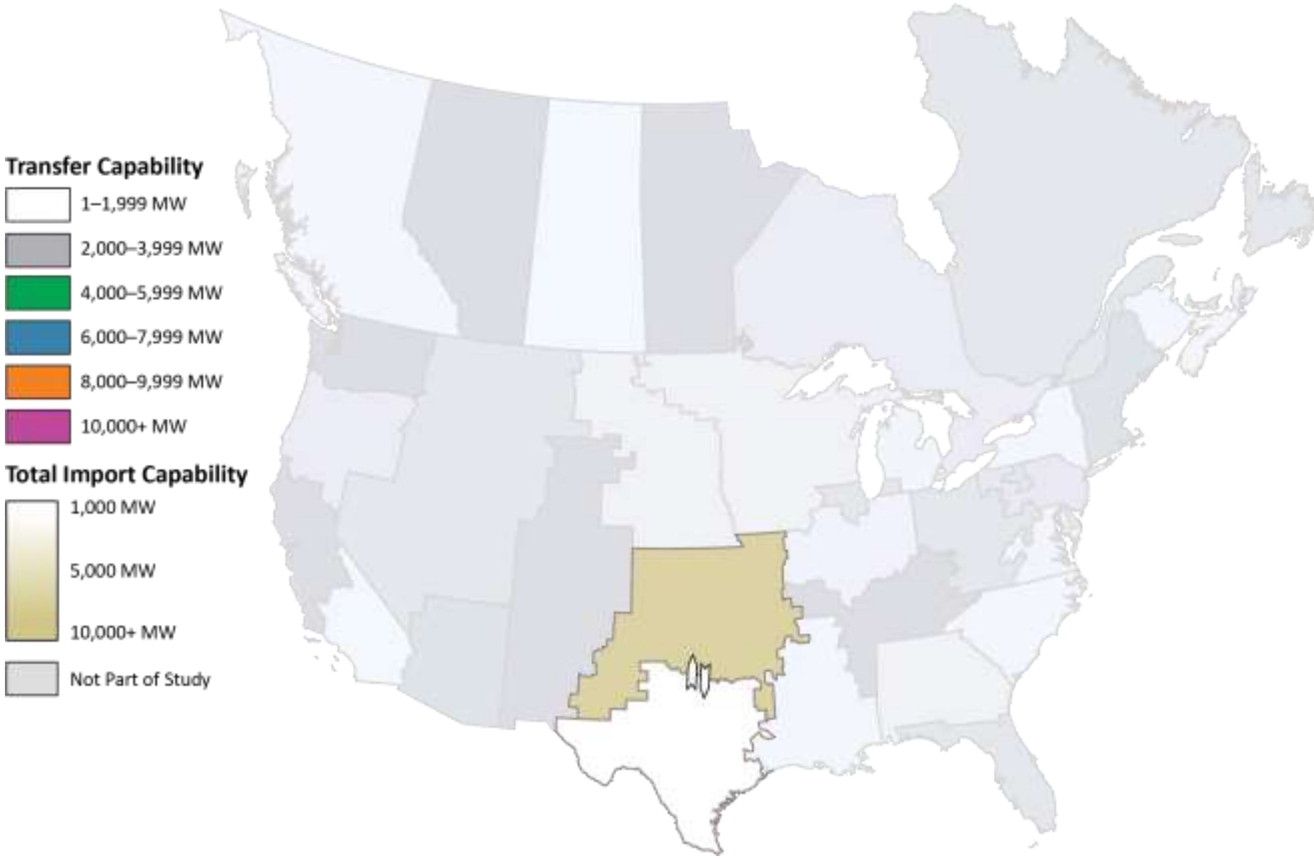
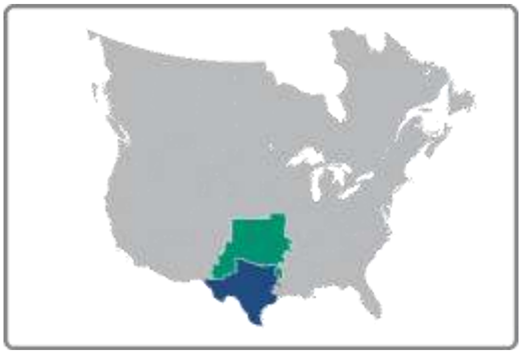


Figure 4.2: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

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

Chapter 5: Eastern Interconnection Results

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

- E1: Saskatchewan -> SPP North
- E2: SPP North <-> SPP South
- E3: SPP North <-> SERC Central
- E4: SPP North <-> MISO West
- E5: SPP South <-> MISO West
- E6: SPP South <-> MISO Central
- E7: SPP South <-> SERC Central
- E8: SPP South <-> MISO South
- E9: Manitoba -> MISO West
- E10: Ontario -> MISO West
- E11: MISO West <-> MISO East (dc)
- E12: MISO West <-> PJM West
- E13: MISO West <-> MISO Central
- E14: MISO West <-> SERC Central
- E15: MISO Central <-> MISO East
- E16: MISO Central <-> PJM West
- E17: MISO Central <-> SERC Central
- E18: MISO Central <-> MISO South

E19: MISO South <-> SERC Central
E20: MISO South <-> SERC Southeast
E21: Ontario -> MISO East
E22: MISO East <-> PJM West
E23: SERC Central <-> PJM West
E24: SERC Central <-> SERC East
E25: SERC-Central <-> SERC Southeast
E26: SERC Southeast <-> SERC Florida
E27: SERC Southeast <-> SERC East
E28: SERC East <-> PJM West
E29: SERC East <-> PJM South
E30: PJM West <-> PJM East
E31: PJM West <-> PJM South
E32: PJM East <-> PJM South
E33: PJM East <-> New York
E34: Ontario -> New York
E35: New York <-> New England
E36: Maritimes -> New England

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

Figure 5.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 5.2** similarly depicts the results from the 2024/25 Winter case.

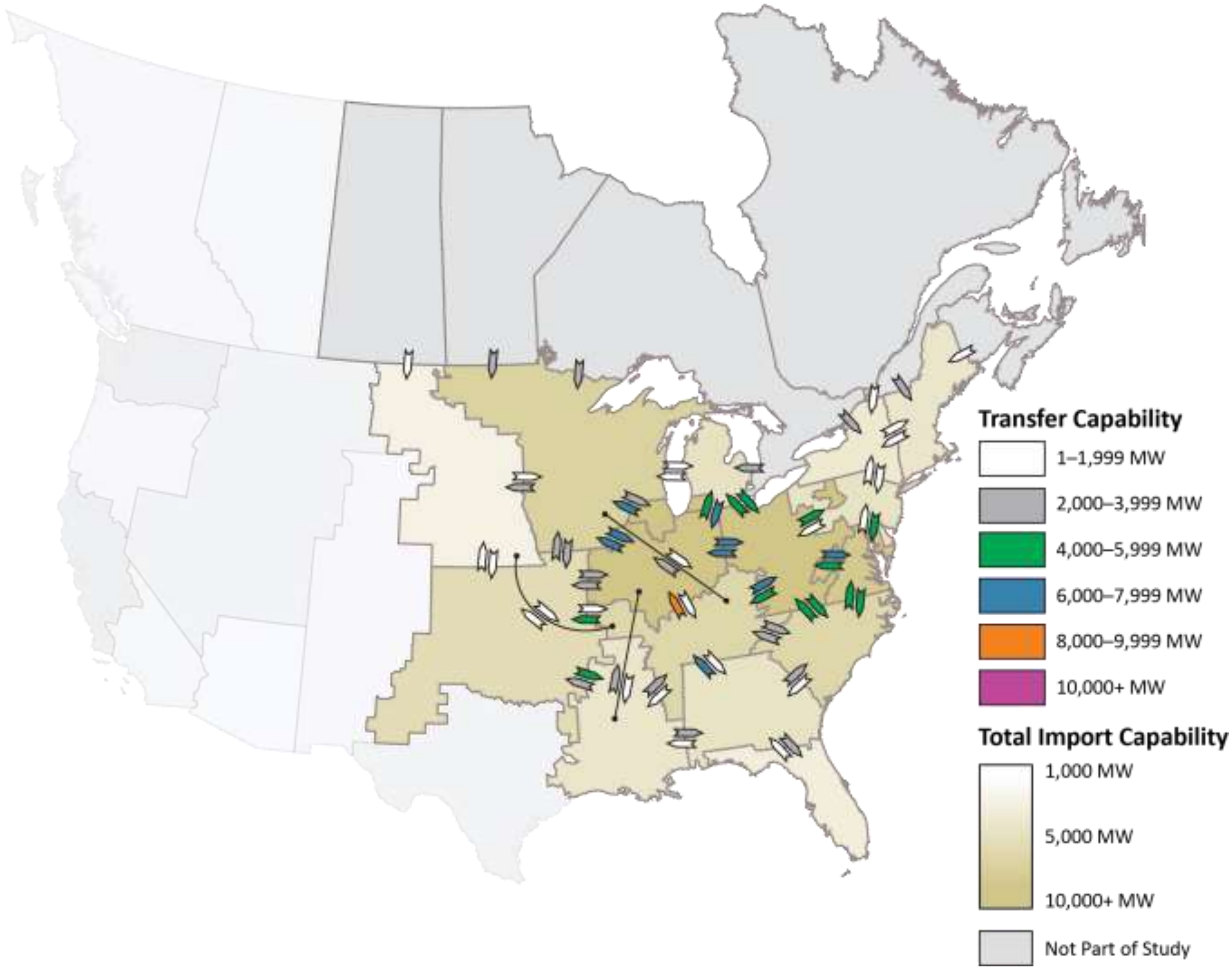


Figure 5.1: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

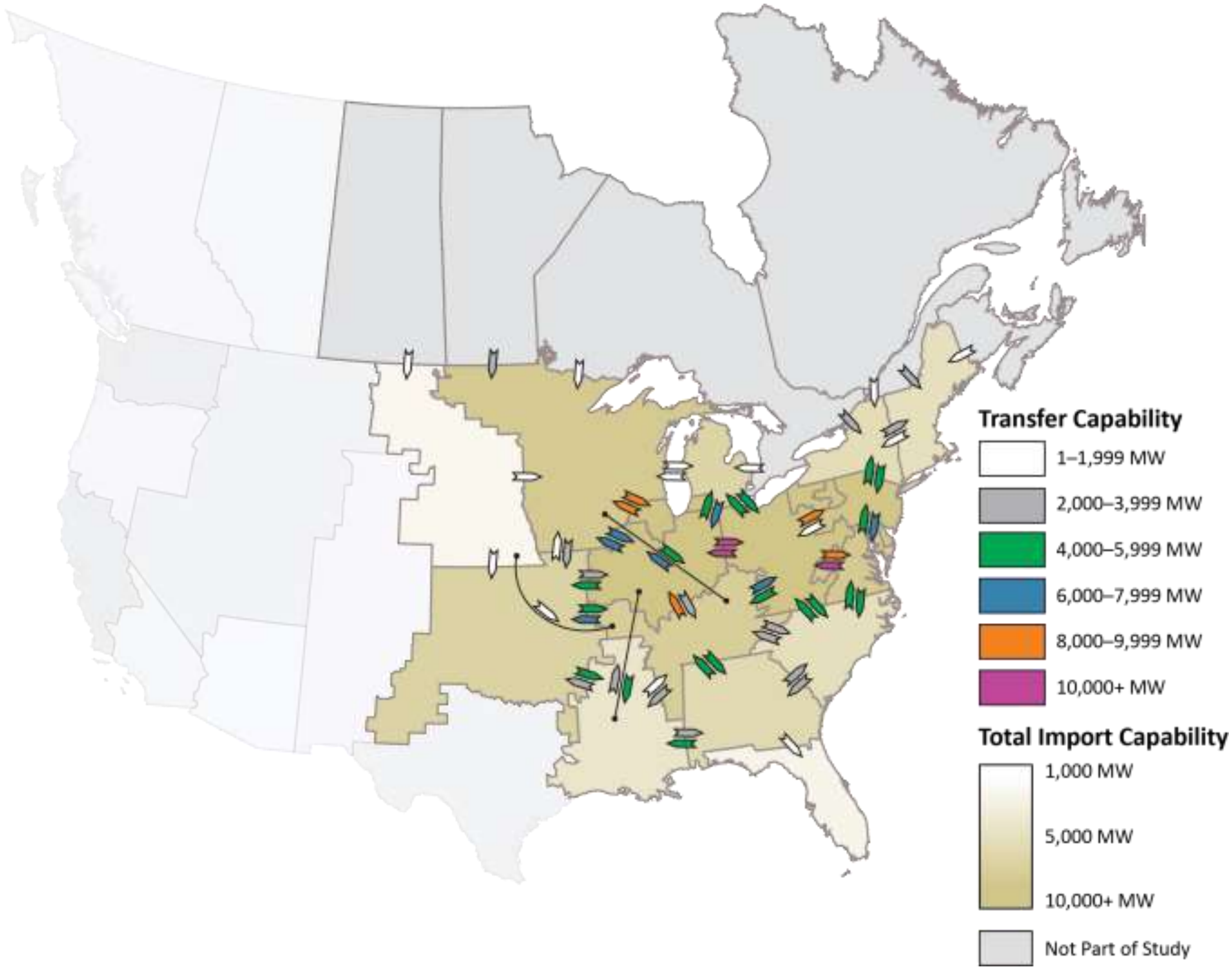
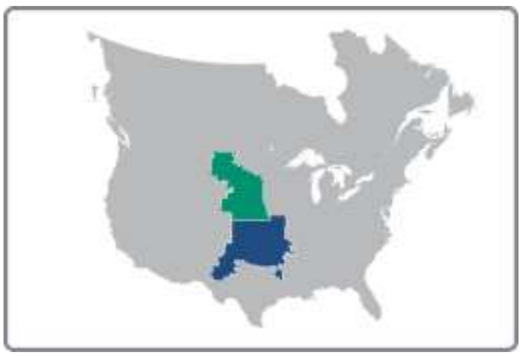


Figure 5.2: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

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.

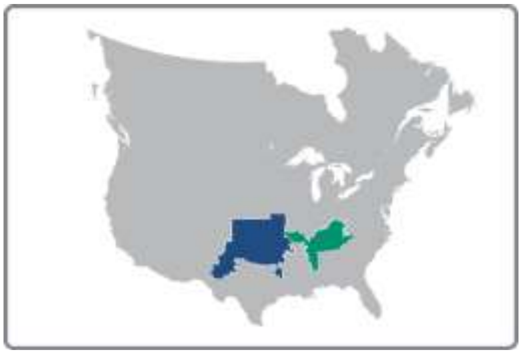
Interface E5: SPP South <-> MISO West

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

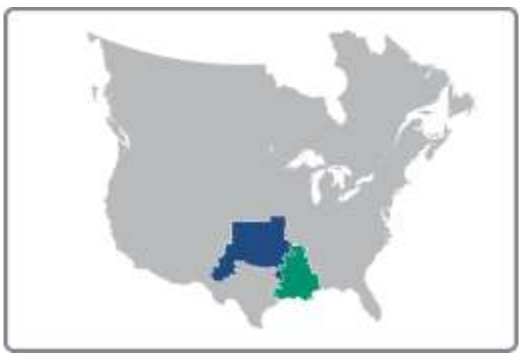
Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO Central	2,481 MW	2,420 MW
MISO Central -> SPP South	3,873 MW	5,635 MW

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

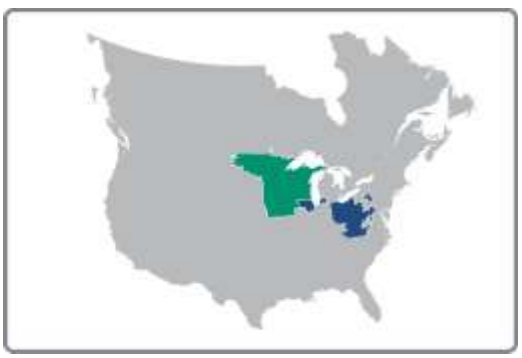
Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW

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

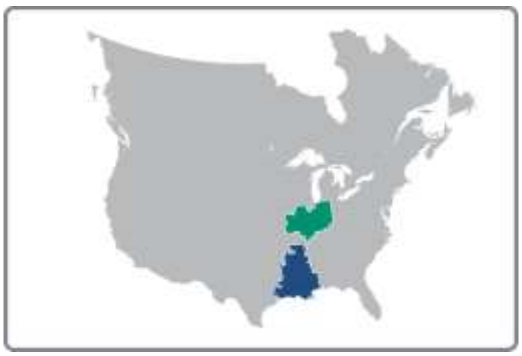
Interface E16: MISO Central <-> PJM West

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

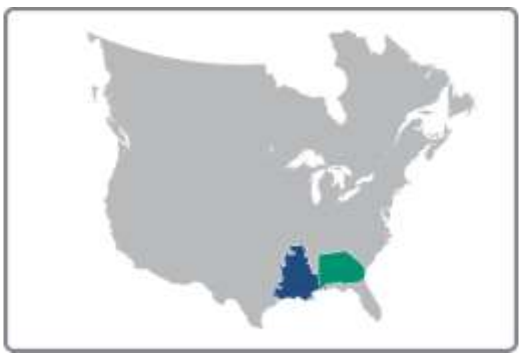


Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO South	1,797 MW	4,067 MW
MISO South -> MISO Central	2,117 MW	1,093 MW

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

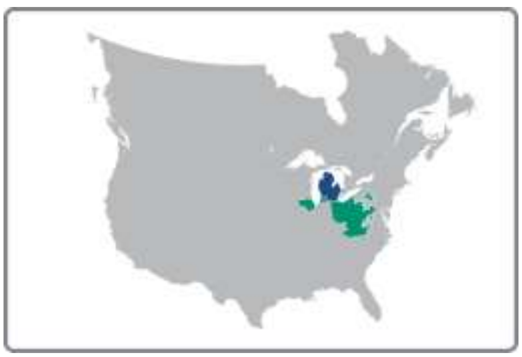


Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Southeast	3,600 MW	3,392 MW
SERC Southeast -> MISO South	1,638 MW	4,028 MW

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

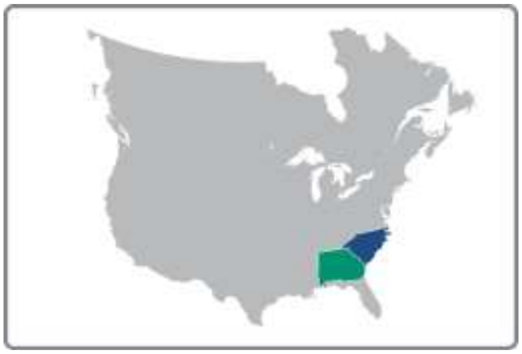
Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC Southeast	1,095 MW	5,387 MW
SERC Southeast -> SERC Central	6,579 MW	4,639 MW

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

Interface E29: SERC East <-> PJM South

Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM South	4,596 MW	4,963 MW
PJM South -> SERC East	4,665 MW	5,463 MW

Interface E30: PJM West <-> PJM East

Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM East	4,762 MW	9,815 MW
PJM East -> PJM West	1,443 MW	166 MW

Interface E31: PJM West <-> PJM South

Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM South	7,041 MW	9,035 MW
PJM South -> PJM West	5,347 MW	10,942 MW

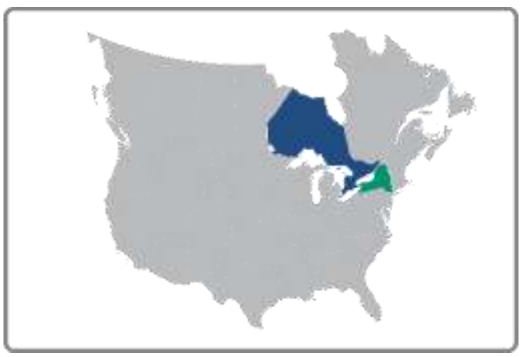
Interface E32: PJM East <-> PJM South

Interface Direction	2024 Summer	2024/25 Winter
PJM East -> PJM South	5,094 MW	6,770 MW
PJM South -> PJM East	1,605 MW	4,166 MW

Interface E33: PJM East <-> New York

Interface Direction	2024 Summer	2024/25 Winter
PJM East -> New York	1,356 MW	4,814 MW
New York -> PJM East	913 MW	4,019 MW

Interface E34: Ontario -> New York



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> New York	2,286 MW	2,719 MW

Interface E35: New York <-> New England

Interface Direction	2024 Summer	2024/25 Winter
New York -> New England	1,303 MW	2,432 MW
New England -> New York	1,660 MW	1,359 MW

Interface E36: Maritimes -> New England

Interface Direction	2024 Summer	2024/25 Winter
Maritimes -> New England	1,127 MW	1,265 MW

Chapter 6: Québec – Eastern Interconnection Results

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

- QE1: Québec -> New York (dc)
- QE2: Québec -> New England (dc)

Interfaces between Québec and Ontario and between Québec and the Maritimes will be covered in the Canadian Analysis.

Figure 6.1 depicts the calculated transfer capabilities for the 2024 Summer case. Figure 6.2 similarly depicts the results from the 2024/25 Winter case.

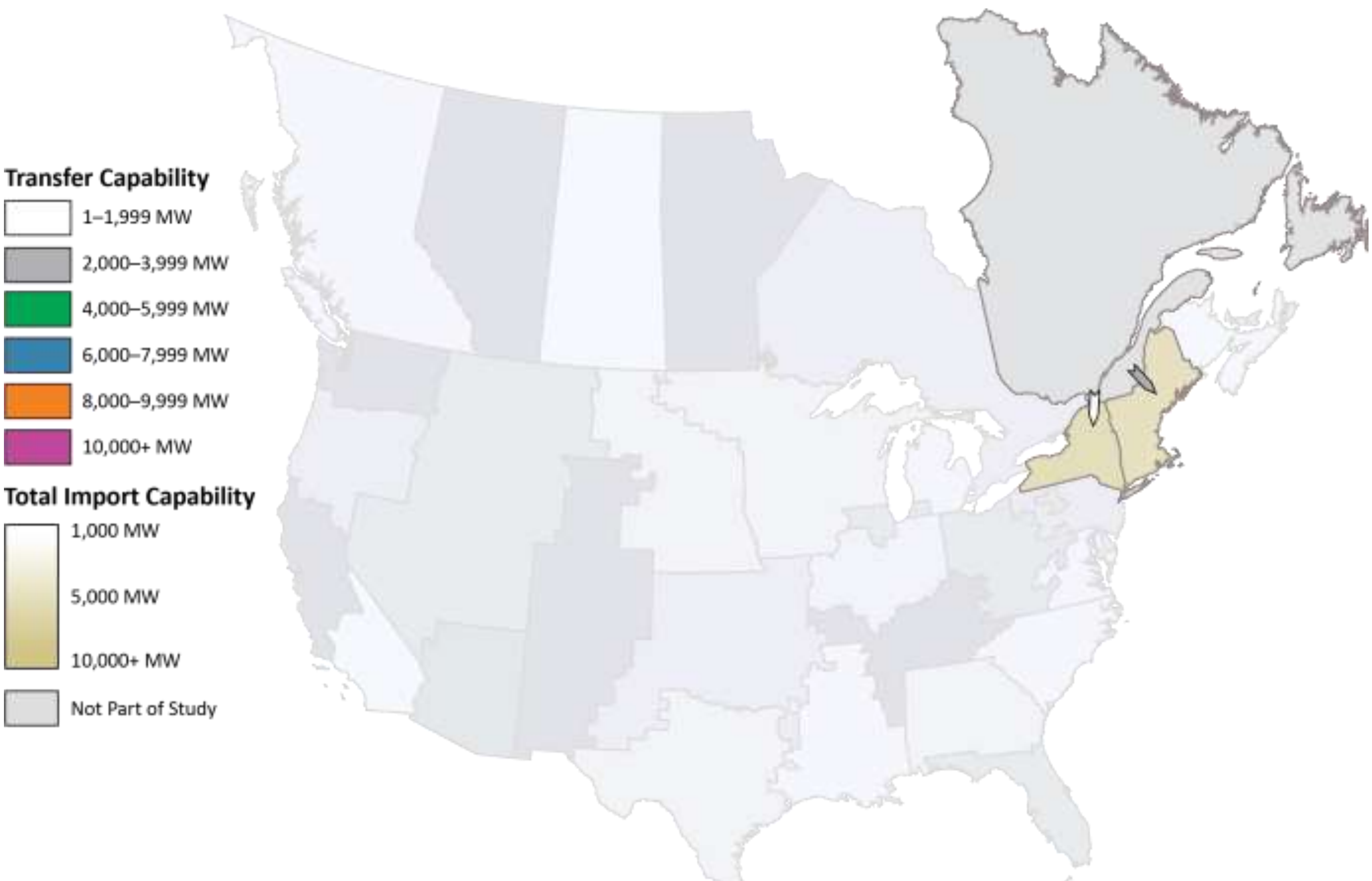


Figure 6.1: Transfer Capability Between Québec and Eastern Interconnections (Summer)

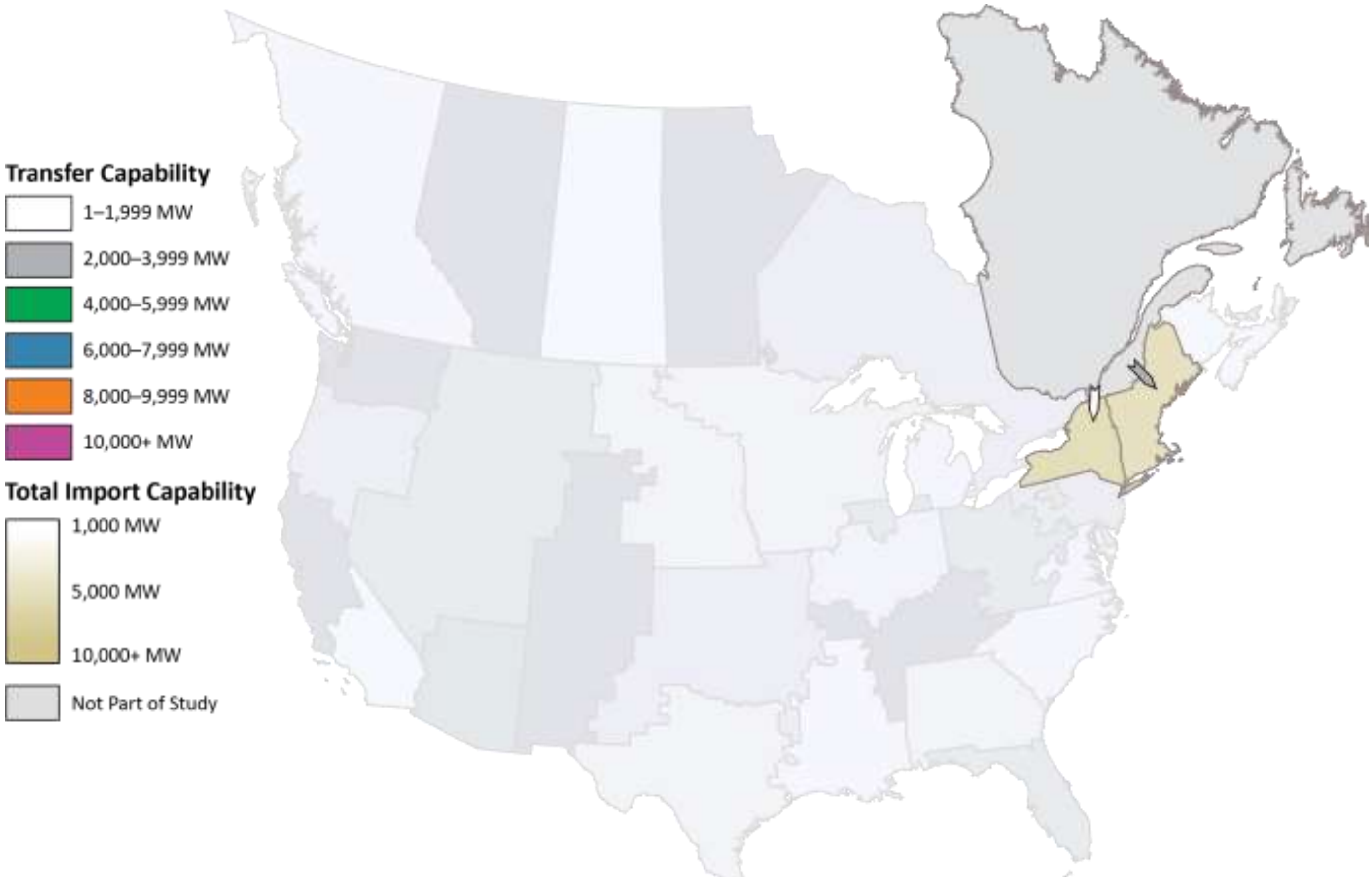
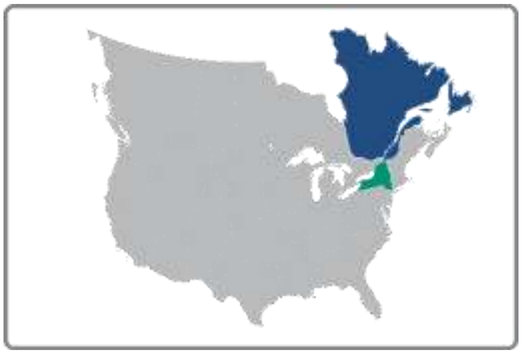


Figure 6.2: Transfer Capability Between Québec and Eastern Interconnections (Winter)

Interface QE1: Québec -> New York



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New York	1,000 MW	1,000 MW

Interface QE2: Québec -> New England

Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New England	2,225 MW	2,225 MW

Chapter 7: Supplemental Results Between Order 1000 Areas

The ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000 (see **Figure 7.1**). While these larger geographic areas will not be used for the purpose of determining prudent additions, the current transfer capability results are provided for completeness. Where results were previously presented, they are not repeated here. TTC results for the following interfaces are presented in this section:

- W1001: British Columbia -> Northern Grid
- W1002: Alberta -> Northern Grid
- W1003: Northern Grid <-> California ISO
- W1004: Northern Grid <-> West Connect
- W1005: California ISO <-> West Connect
- E1001: Saskatchewan -> SPP
- E1002: SPP <-> MISO
- E1003: SPP <-> SERTP
- E1004: Manitoba -> MISO
- E1005: Ontario -> MISO
- E1006: MISO <-> PJM
- E1007: MISO <-> SERTP
- E1008: SERTP <-> PJM
- E1009: SERTP <-> SCRTP
- E1010: SERTP <-> FRCC
- E1011: PJM <-> New York

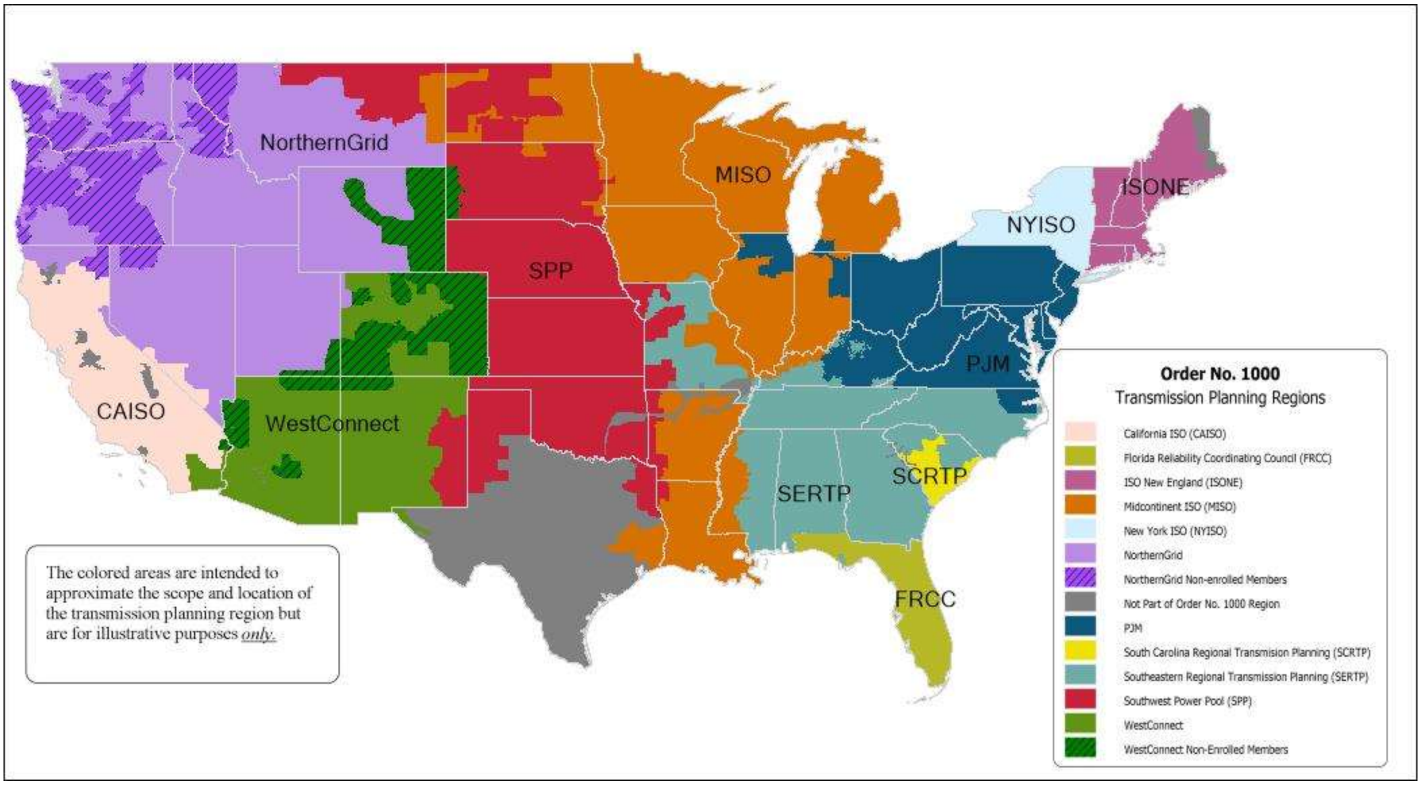


Figure 7.1: Areas Defined in FERC Order 1000

Interface W1001: British Columbia -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Northern Grid	2,435 MW	2,164 MW

Interface W1002: Alberta -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Northern Grid	981 MW	1,286 MW

Interface W1003: Northern Grid <-> California ISO

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> California ISO	4,140 MW	8,705 MW
California ISO -> Northern Grid	1,985 MW	5,208 MW

Interface W1004: Northern Grid <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> West Connect	2,842 MW	3,326 MW
West Connect -> Northern Grid	5,710 MW	1,865 MW

Interface W1005: California ISO <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
California ISO -> West Connect	2,534 MW	2,375 MW
West Connect -> California ISO	2,967 MW	3,912 MW

Interface E1001: Saskatchewan -> SPP

Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP	0 MW	665 MW

Interface E1002: SPP <-> MISO

Interface Direction	2024 Summer	2024/25 Winter
SPP -> MISO	7,058 MW	1,513 MW
MISO -> SPP	5,308 MW	6,403 MW

Interface E1003: SPP <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
SPP -> SERTP	4,857 MW	2,814 MW
SERTP -> SPP	2,822 MW	6,324 MW

Interface E1004: Manitoba -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO	3,058 MW	3,058 MW

Interface E1005: Ontario -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO	2,419 MW	1,834 MW

Interface E1006: MISO <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
MISO -> PJM	5,593 MW	12,552 MW
PJM -> MISO	9,146 MW	10,771 MW

Interface E1007: MISO <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
MISO -> SERTP	6,976 MW	9,543 MW
SERTP -> MISO	0 MW	9,801 MW

Interface E1008: SERTP <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> PJM	8,609 MW	9,782 MW
PJM -> SERTP	7,704 MW	7,905 MW

Interface E1009: SERTP <-> SCRTP

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> SCRTP	1,767 MW	1,948 MW
SCRTP -> SERTP	2,415 MW	2,335 MW

Interface E1010: SERTP <-> FRCC

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> FRCC	2,918 MW	1,803 MW
FRCC -> SERTP	1,058 MW	0 MW

Interface E1011: PJM <-> New York

Interface Direction	2024 Summer	2024/25 Winter
PJM -> New York	635 MW	858 MW
New York -> PJM	3,136 MW	3,394 MW

Chapter 8: Supplemental Total Import Interface Limits

The ITCS also analyzed an additional set of transfers into each TPR. These total import interfaces analyze the simultaneous transfers into a TPR from all its neighbors. In instances where the calculated total import interface transfer capability was lower than that from any neighboring TPR, the highest neighbor-to-neighbor results were reported to avoid understating the total import capability. The definitions of these interfaces exclude connections via dc-only interfaces, which can typically be scheduled independently. TTC results for the following interfaces are presented in this section:

- WTI01: Into Washington
- WTI02: Into Oregon
- WTI03: Into California North
- WTI04: Into California South
- WTI05: Into Wasatch Front
- WTI06: Into Southwest
- WTI07: Into Front Range
- ETI01: Into SPP North
- ETI02: Into SPP South
- ETI03: Into MISO West
- ETI04: Into MISO Central
- ETI05: Into MISO South
- ETI06: Into MISO East
- ETI07: Into SERC Central
- ETI08: Into SERC Southeast
- ETI09: Into SERC Florida
- ETI10: Into SERC East
- ETI11: Into PJM West
- ETI12: Into PJM East
- ETI13: Into PJM South
- ETI14: Into New York
- ETI15: Into New England

Interface WTI01: Into Washington

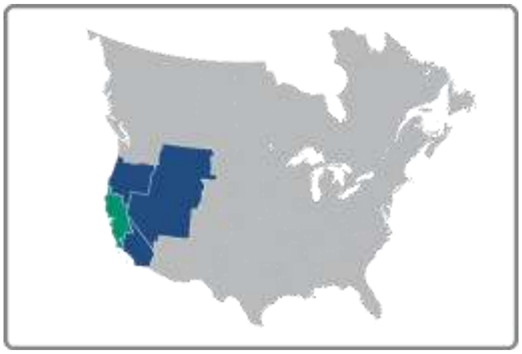
Interface Direction	2024 Summer	2024/25 Winter
Into Washington TTC	7,377 MW[26]	10,297 MW
Percentage of Peak Load	43%	50%

Interface WTI02: Into Oregon

Interface Direction	2024 Summer	2024/25 Winter
Into Oregon TTC	8,004 MW	7,534 MW
dc-only interfaces	3,100 MW	3,100 MW
Total of TTC and dc-only interfaces	11,104 MW	10,634 MW
Percentage of Peak Load	92%	89%

[26] Value is from the Wasatch Front to Washington interface, as the total import interface calculation was more limiting.

Interface WTI03: Into California North



Interface Direction	2024 Summer	2024/25 Winter
Into California North TTC	3,972 MW[27]	6,631 MW
Percentage of Peak Load	14%	29%

Interface WTI04: Into California South

Interface Direction	2024 Summer	2024/25 Winter
Into California South TTC	7,829 MW	11,288 MW
dc-only interfaces	3,220 MW	3,220 MW
Total of TTC and dc-only interfaces	11,049 MW	14,508 MW
Percentage of Peak Load	28%	69%

[27] Value is from the Oregon to California North interface, as the total import interface calculation was more limiting.

Interface WTI05: Into Wasatch Front

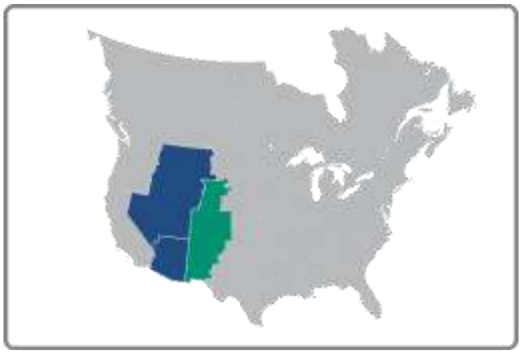
Interface Direction	2024 Summer	2024/25 Winter
Into Wasatch Front TTC	5,965 MW[28]	5,558 MW
dc-only interfaces	200 MW	200 MW
Total of TTC and dc-only interfaces	6,165 MW	5,758 MW
Percentage of Peak Load	23%	35%

Interface WTI06: Into Southwest

Interface Direction	2024 Summer	2024/25 Winter
Into Southwest TTC	5,247 MW[29]	8,470 MW[30]
Percentage of Peak Load	22%	66%

[28] Value is from the California South to Wasatch Front interface, as the total import interface calculation was more limiting.
[29] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.
[30] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.

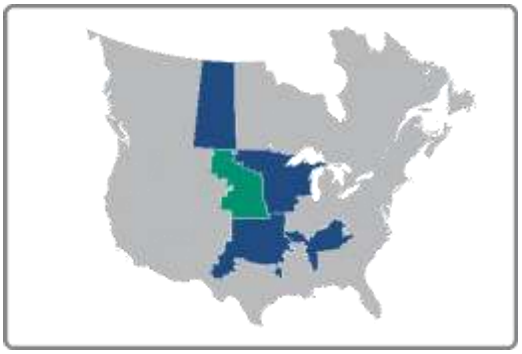
Interface WTI07: Into Front Range



Interface Direction	2024 Summer	2024/25 Winter
Into Front Range TTC	3,284 MW[31]	3,751 MW[32]
dc-only interfaces	920 MW	920 MW
Total of TTC and dc-only interfaces	4,204 MW	4,671 MW
Percentage of Peak Load	21%	30%

[31] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.
[32] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.

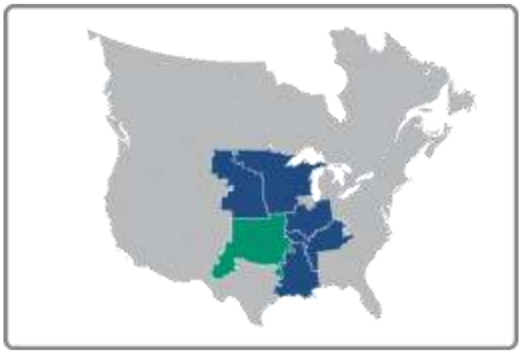
Interface ETI01: Into SPP North



Interface Direction	2024 Summer	2024/25 Winter
Into SPP North TTC	2,209 MW[33]	663 MW[34]
dc-only interfaces	660 MW	660 MW
Total of TTC and dc-only interfaces	2,869 MW	1,323 MW
Percentage of Peak Load	21%	11%

[33] Value is from the MISO West to SPP North interface, as the total import interface calculation was more limiting.
[34] Value is from the Saskatchewan to SPP North interface, as the total import interface calculation was more limiting.

Interface ETI02: Into SPP South



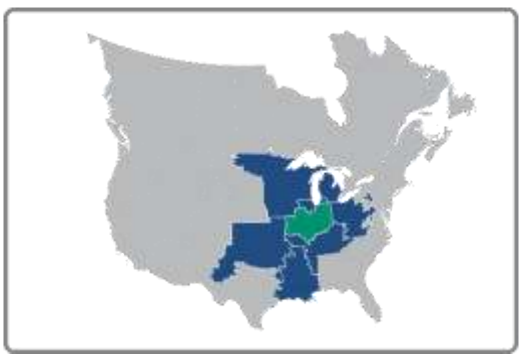
Interface Direction	2024 Summer	2024/25 Winter
Into SPP South TTC	5,042 MW[35]	6,445 MW[36]
dc-only interfaces	1,230 MW	1,230 MW
Total of TTC and dc-only interfaces	6,272 MW	7,675 MW
Percentage of Peak Load	13%	20%

[35] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.
[36] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.

Interface ETI03: Into MISO West

Interface Direction	2024 Summer	2024/25 Winter
Into MISO West TTC	7,791 MW[37]	9,086 MW[38]
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	7,951 MW	9,246 MW
Percentage of Peak Load	19%	26%

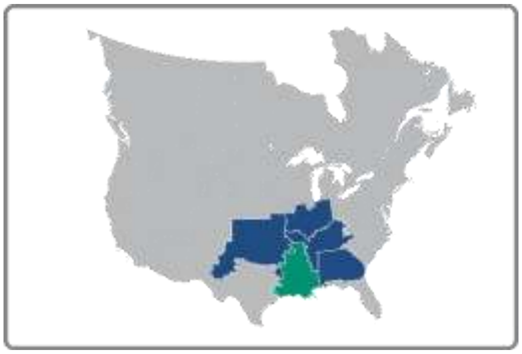
Interface ETI04: Into MISO Central



Interface Direction	2024 Summer	2024/25 Winter
Into MISO Central TTC	12,714 MW	20,449 MW[39]
Percentage of Peak Load	35%	63%

[37] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[38] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[39] Value is from the PJM West to MISO Central interface, as the total import interface calculation was more limiting.

Interface ETI05: Into MISO South



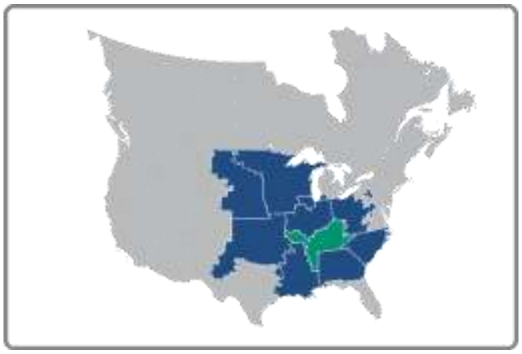
Interface Direction	2024 Summer	2024/25 Winter
Into MISO South TTC	4,295 MW[40]	4,336 MW[41]
Percentage of Peak Load	12%	13%

Interface ETI06: Into MISO East

Interface Direction	2024 Summer	2024/25 Winter
Into MISO East TTC	5,139 MW	7,019 MW
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	5,299 MW	7,179 MW
Percentage of Peak Load	25%	44%

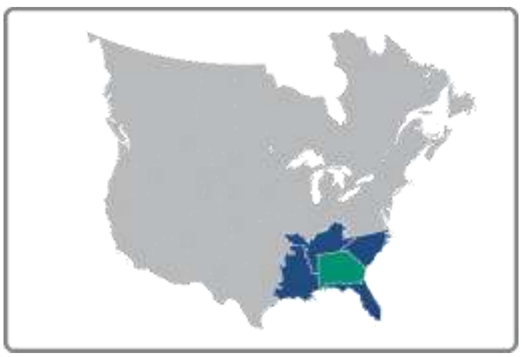
[40] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.
[41] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.

Interface ETI07: Into SERC Central



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Central TTC	6,878 MW	8,443 MW
Percentage of Peak Load	15%	18%

Interface ETI08: Into SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Southeast TTC	4,900 MW	6,525 MW
Percentage of Peak Load	11%	15%

Interface ETI09: Into SERC Florida

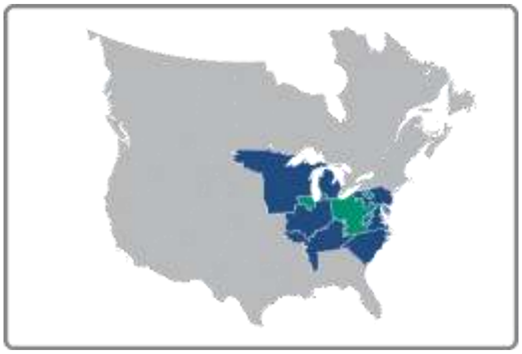
Interface Direction	2024 Summer	2024/25 Winter
Into SERC Florida TTC	2,958 MW	1,807 MW
Percentage of Peak Load	6%	4%

Interface ETI10: Into SERC East

Interface Direction	2024 Summer	2024/25 Winter
Into SERC East TTC	6,959 MW	5,463 MW[42]
Percentage of Peak Load	16%	12%

[42] Value is from PJM South to SERC East interface, as the total import interface calculation was more limiting.

Interface ETI11: Into PJM West



Interface Direction	2024 Summer	2024/25 Winter
Into PJM West TTC	21,773 MW	10,942 MW[43]
Percentage of Peak Load	28%	16%

Interface ETI12: Into PJM East

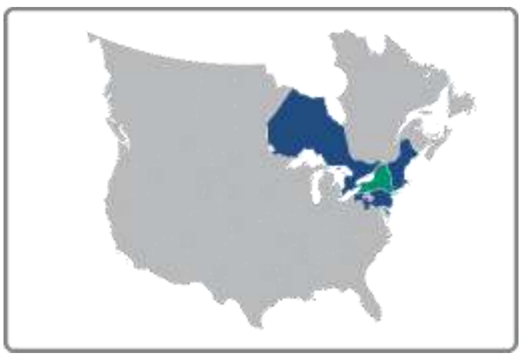
Interface Direction	2024 Summer	2024/25 Winter
Into PJM East TTC	4,762 MW[44]	9,815 MW[45]
Percentage of Peak Load	11%	28%

[43] Value is from the PJM South to PJM West interface, as the total import interface calculation was more limiting.
[44] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.
[45] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.

Interface ETI13: Into PJM South

Interface Direction	2024 Summer	2024/25 Winter
Into PJM South TTC	9,578 MW	9,035 MW[46]
Percentage of Peak Load	28%	27%

Interface ETI14: Into New York



Interface Direction	2024 Summer	2024/25 Winter
Into New York TTC	2,802 MW	4,814 MW[47]
dc-only interfaces	1,000 MW	1,000 MW
Total of TTC and dc-only interfaces	3,802 MW	5,814 MW
Percentage of Peak Load	12%	24%

[46] Value is from the PJM West to PJM South interface, as the total import interface calculation was more limiting.
[47] Value is from the PJM East to New York interface, as the total import interface calculation was more limiting.

Interface ETI15: Into New England

Interface Direction	2024 Summer	2024/25 Winter
Into New England TTC	2,313 MW	3,033 MW
dc-only interfaces	2,225 MW	2,225 MW
Total of TTC and dc-only interfaces	4,538 MW	5,258 MW
Percentage of Peak Load	19%	25%

Chapter 9: Acknowledgements

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Appendix A: Key Study Opportunities

Observation 1: There is an opportunity to develop guidance for subdividing large areas and standardizing data sources for future studies.

One challenge was selecting appropriately sized and electrically connected TPRs. It is essential to strike the right balance to identify significant limitations of interregional transfers. As the BPS evolves, these TPRs should be reviewed and modified as appropriate. In a few instances where Balancing Authorities are split into multiple TPRs, there are opportunities to enhance available data to more efficiently account for each TPR, improving the data quality in future studies.

Observation 2: There is an opportunity to improve coordination with NERC's Long-Term Reliability Assessment (LTRA) process.

Some differences in load forecasts and resource assumptions were noted when comparing study cases to LTRA data. Standardizing case-building processes and associated content could ensure consistency and improve the efficiency of future studies.

Observation 3: Future studies may need special cases to study additional conditions.

This transfer analysis used cases designed for transmission planning assessments.[48] This study revealed a potential need to develop additional cases, such as to study heavy transfers in both directions of an interface.

Observation 4: Future studies should include stability analysis.

Part 1 studies included power flow analysis, voltage screening, and known stability limits. Future studies should include more expansive stability analysis to identify potentially more restrictive limits, especially because stability limitations can become more prominent when there is increased reliance on heavy transfers across large areas.

Observation 5: A future study evaluation schedule is needed.

The study results are highly dependent on the point-in-time information used to develop the cases. Since generation construction and retirement, transmission expansion plans, and load forecasts are constantly evolving, it would be beneficial to repeat this transfer analysis on a regular basis. Further, given the long lead time required for transmission additions, consideration should be given to future study horizons.[49]

[48] For example, [TPL-001-5 (nerc.com)]
[49] The study horizon for ITCS Part 2 is 2024 and 2033.