Annual U.S. Transmission Data Review

October 2016

United States Department of Energy
Washington, DC 20585

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Acknowledgements

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Acronyms and Abbreviations

ARRA	American Recovery and Reinvestment Act
BES	Bulk Electric System
CAISO	California Independent System Operator
CARIS	Congestion Assessment and Resource Integration Study
CCTA	Common Case Transmission Assumptions
CREZ	competitive renewable energy zone
DOE, the Department	U.S. Department of Energy
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
ERCOT	Electric Reliability Council of Texas
ES&D	Electricity Supply and Demand
FERC	Federal Energy Regulatory Commission
FFE	Firm Flow Entitlement
FRCC	Florida Reliability Coordinating Council
FTR	Financial Transmission Rights
GADS	Generating Availability Data System
ICC	Initiating Cause Code
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
ISO	Independent System Operator
ISO-NE	ISO New England
JOA	Joint Operating Agreement
LAP	load aggregation points
LTSA	Long-Term System Assessment
MISO	Midcontinent Independent System Operator
MM	Market Monitor
MTEP	MISO Transmission Expansion Plan
MVL	Marginal Value Limits
NERC	North American Electric Reliability Corporation
NYCA	New York Control Area
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric
RNA	Reliability Needs Assessment (NYISO)
RPCG	Regional Planning Coordination Group (WECC)

RTO	Regional Transmission Organization
RTP	Regional Transmission Plan
SCE	Southern California Edison
SCRTP	South Carolina Regional Transmission Planning
SDG&E	San Diego Gas & Electric
SERTP	Southeastern Regional Transmission Planning
SPP	Southwest Power Pool
SRI	System Reliability Index
TADS	Transmission Availability Data System
TCDC	Transmission Constraint Demand Curve
TEPPC	Transmission Expansion Planning Policy Committee
TLR	Transmission Loading Relief
UFM	Unscheduled Flow Mitigation
WECC	Western Electricity Coordinating Council

1. Introduction and Overview

The transmission system is a vast engineered network that transmits electricity from generators to local substations for distribution to end-use consumers.[1] Many factors affect its operational success, including the mix of equipment that presently exists; the reliability of the system's individual components and of the system as a whole; how the transmission system is currently being utilized (*e.g.*, how much electricity flows through it); to what extent these flows are constrained by specific components that are being utilized up to their physical or operating limits (which could be contract path limited); the economic costs created by these constraints; and the processes by which future changes and additions to the system are planned.

The U.S. Department of Energy (DOE, or the Department) has broad responsibility for developing and supporting the implementation of energy policies that serve the public interest.[2] Ensuring that timely and accurate data on key subjects is widely available to the public is one of those responsibilities. With that responsibility in mind, this report presents an integrated summary of publicly available data and information on the above list of factors affecting the U.S. transmission system.

This report does not draw conclusions about the transmission system—it is, instead, an effort to gather publicly available data in one place and to present it in a unified framework as comparably as possible. Given the diversity of the transmission system itself—in ownership, operation, planning, and physical characteristics—presenting the data in a unified framework is challenging. In addition, questions about what information is useful, and for what purpose, had to be examined closely. Consequently, this report also suggests data-related topics that may be explored in future iterations.

This report focuses on six areas: transmission infrastructure, transmission reliability, transmission utilization, transmission constraints, economic congestion, and transmission planning. Where possible, the Department has relied on sources of national-scale information on transmission because by definition they are the most comprehensive. However, of necessity, the Department also relied on interconnection-specific and wholesale market-specific sources for information that is not available uniformly at a national scale.

Specifically, the Department first reviewed publicly available sources of national information that are already routinely collected and published by the Energy Information Administration (EIA), Edison Electric Institute (EEI), the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission

[1] In 2014, the North American Electric Reliability Corporation (NERC) finalized its definition of the Bulk Electric System (BES) to include all transmission elements operated at 100 kV of higher, except for those elements primarily used in local distribution of electricity. See NERC (2014a): http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

[2] For example, the Federal Power Act directs the Department to conduct triennial studies of transmission congestion.

(FERC).[3] The Department then identified, in consultation with industry stakeholders, specific information in regional sources that were appropriate for inclusion. The result is a report that presents a combination of information analyzed and presented by others in their published reports and charts and graphs that the Department developed from primary data sources.

The remainder of this report is organized into the following sections:

Existing and Planned Transmission Construction and Investment, which presents data on existing and planned transmission lines, trends in transmission additions, and investment in transmission.

Transmission System and Equipment Reliability, which contains information about the overall reliability of the transmission system and of transmission system elements (*e.g.*, equipment outages).

Transmission System Utilization, which includes measures at various regional granularities of how the system is used (*e.g.*, how much electricity flows over certain interfaces).

Management of Transmission Constraints, which presents information on where the system is heavily loaded and where usage is at the operating limit, as indicated by both administrative procedures and Regional Transmission Organization (RTO)-market-based metrics.

Economic Costs of Congestion, which describes the economic congestion measures published about RTO markets, and presents average hub prices across the country.

Transmission Planning Processes, which summarizes wide-area transmission planning activities.

The topics presented in this report are interrelated. Transmission *reliability* is maintained by enforcing *constraints* when some users seek to transmit more power over the affected facilities than they can reliably carry, and by the use of operating procedures that will ensure the *utilization* of the system will be efficient and not cause reliability problems. Transmission *congestion* arises when constraints prevent system users from transmitting as much power as they desire or that would otherwise be economically efficient. Transmission *planning* activities are undertaken to enable future reliable and efficient *utilization* of transmission facilities by addressing, among other things, *reliability* concerns, *constraints*, and *congestion*.

[3] As this report was being finalized, FERC released a report on performance metrics for RTOs, ISOs, and individual utilities for the 2010-2014 reporting period. Reporting on an established set of common performance metrics (covering both reliability and system operations activities) outlined in its August 2014 report, FERC collected information from RTOs and ISOs and non-RTOs and ISOs primarily from FERC-922; additional market-specific data was provided by the RTO/ISOs. Relevant information from the performance metrics report will be included the 2017 U.S. Transmission Data Review. See http://www.ferc.gov/industries/electric/indus-act/rto/rto-iso-performance.asp.

In some cases, discussing such interrelated topics in isolation can be awkward. For instance, transmission constraints and economic congestion are closely related phenomena, but are presented separately in this report. The framework used here is likely to evolve over time, and the Department welcomes suggestions for improvements.

2. Existing and Planned Transmission Construction and Investment

2.1. Introduction

Transmission infrastructure refers to the transmission lines, transformers, circuit breakers, capacitor banks, and other equipment that make up the transmission system. The transmission system, as described in the introduction, is now generally defined as equipment used to transmit electricity from generators to distribution networks that is operated at 100 kV or above (*i.e.*, it does not include the local distribution of electricity to consumers).[4]

This section presents information from national sources on how much transmission infrastructure currently exists and is planned. It also presents readily available information on the investment represented by recent and planned construction of transmission facilities.

Some of the data relied upon in this section are compiled by NERC in coordination with regional reliability entities. The names of these entities sometimes correspond closely to those of organizations that operate as RTO/ISOs. Accordingly, information compiled by NERC and attributed to regional reliability entities should not be confused with information available from these latter organizations.

2.2. Existing Transmission

Information regarding existing transmission is taken from the NERC Transmission Availability Data System (TADS). The TADS contains data collected quarterly on existing equipment and on outages experienced by equipment.[5] Data for TADS are provided by transmission owners[6] and are reviewed by regional entities and NERC. The data are

[4] NERC (2014a): http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

[5] See NERC (2016c): http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx. The inventory can be found here: http://www.nerc.com/pa/RAPA/tads/Pages/ElementInventory.aspx.

[6] The definition and functions of transmission owners are described in the NERC Functional Model (see http://www.nerc.com/pa/Stand/Pages/FunctionalModel.aspx), and a list of NERC Compliance Registry Entities is available at http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

collected by voltage level by NERC. Figure 2-3 shows existing transmission infrastructure at 200 kV or above as of the last day of 2015.[7,8]

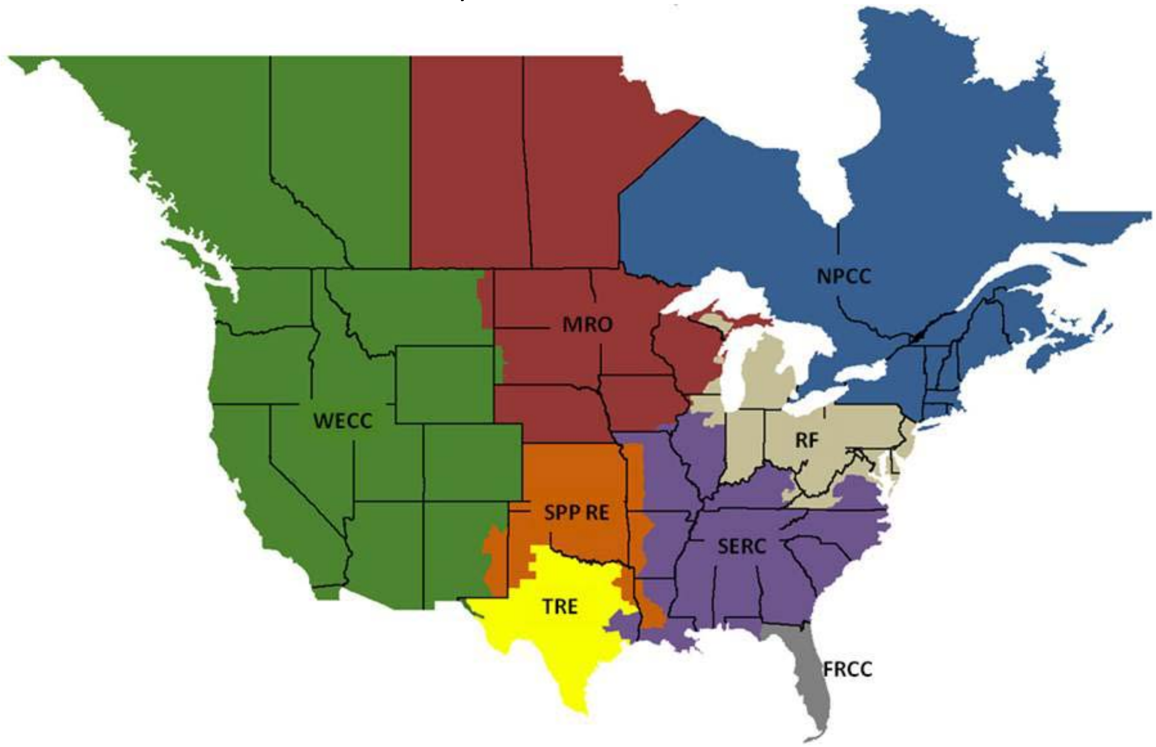


Figure 2-1. NERC Regions

Source: NERC: http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx

[7] On March 20, 2014, FERC approved the NERC definition of Bulk Electric System (BES), which includes system elements down to 100 kV, with provisions for including lower voltage equipment if operated as a transmission facility, or excluding higher voltage equipment if not operated as a transmission facility. This definition became effective July 1, 2014. See http://www.nerc.com/pa/RAPA/Pages/BES.aspx. Starting in January 2015, TADS began collecting information on system elements included in the new BES definition; Q4-2014 TADS data included reporting of all elements 200 kV and above, and Q1-2015 data included reporting of all elements 100–199 kV and above, commencing with all outages beginning on January 1, 2015. See http://www.nerc.com/pa/RAPA/tads/Key_TADS_Documents/TADS%20FAQ%202016.pdf.

[8] While NERC began collecting data on transmission in the 100–199 kV category in 2015, this data has not yet been incorporated in all NERC studies; studies relating to below-200 kV elements are available in the State of Reliability Report (see http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf).

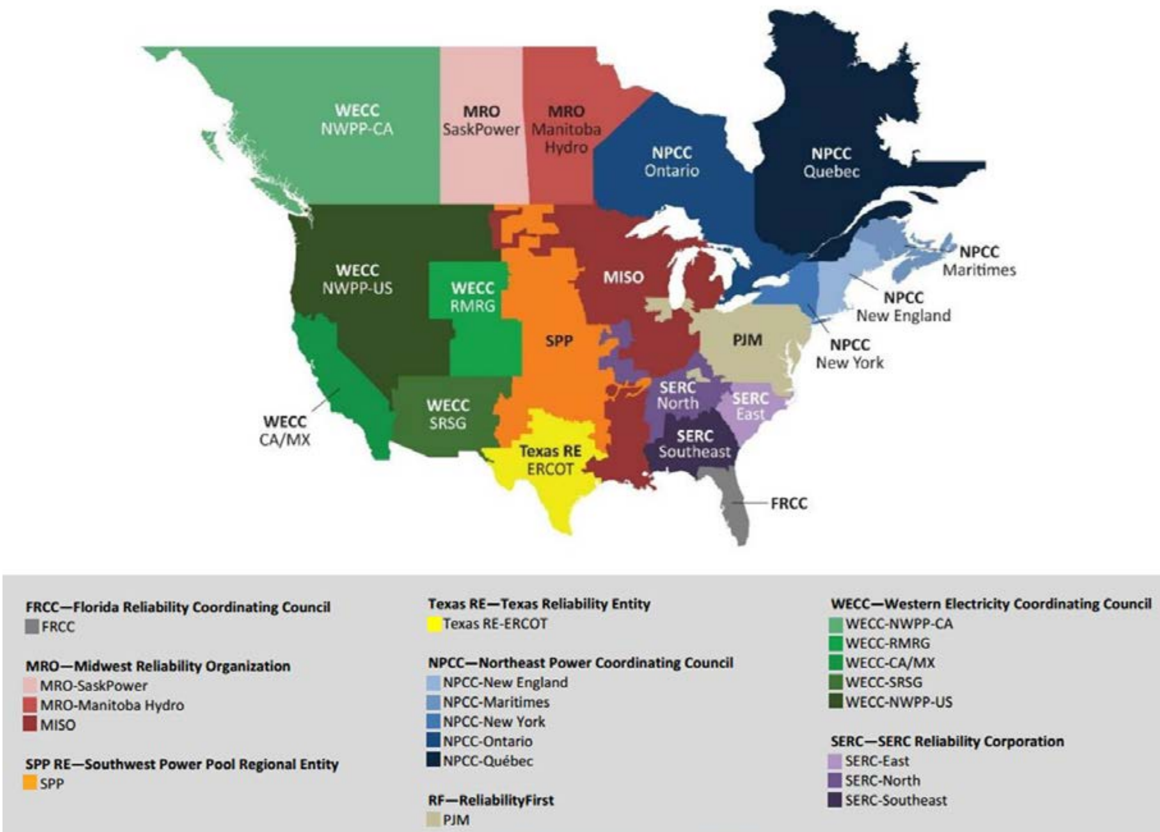
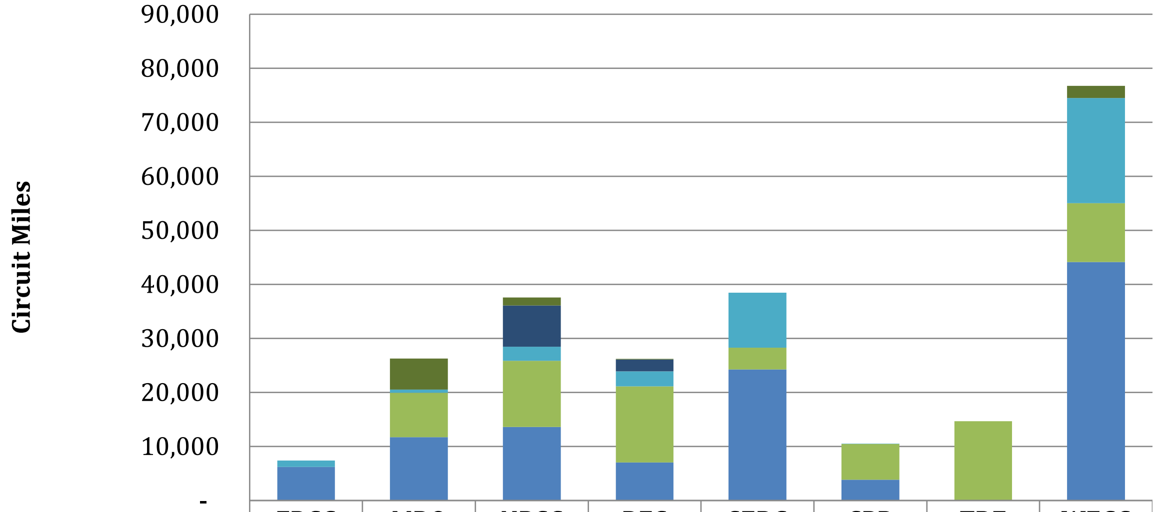


Figure 2-2. NERC Assessment Areas (as of March 2016)

Source: NERC: http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx



	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
Total DC	-	5,773	1,452	66	-	-	-	2,252
600 kV - 799 kV	-	-	7,671	2,201	-	-	-	-
400-599 kV	1,201	600	2,570	2,776	10,132	94	-	19,477
300-399 kV	-	8,218	12,270	14,132	4,049	6,614	14,679	10,852
200-299 kV	6,200	11,705	13,597	7,018	24,267	3,834	-	44,171

Figure 2-3. Existing transmission as of last day of 2015

Source: Developed by DOE from NERC (personal communication from NERC received on March 25, 2016)

2.3. Transmission *Under Construction*, *Planned*, and *Conceptual*

Information on existing and future transmission projects are taken from the NERC Electricity Supply & Demand (ES&D) database.[9] The ES&D includes data collected annually to develop NERC's long-term reliability assessments. Since 2014, existing transmission (aggregated for each NERC Region) is provided using inventory data from NERC's Transmission Availability Data System (TADS).

The data are collected from the assessment areas shown in Figure 2-2. Note that the names and boundaries for these areas differ from those of the regional entities that provide information to TADS (see Figure 2-1).

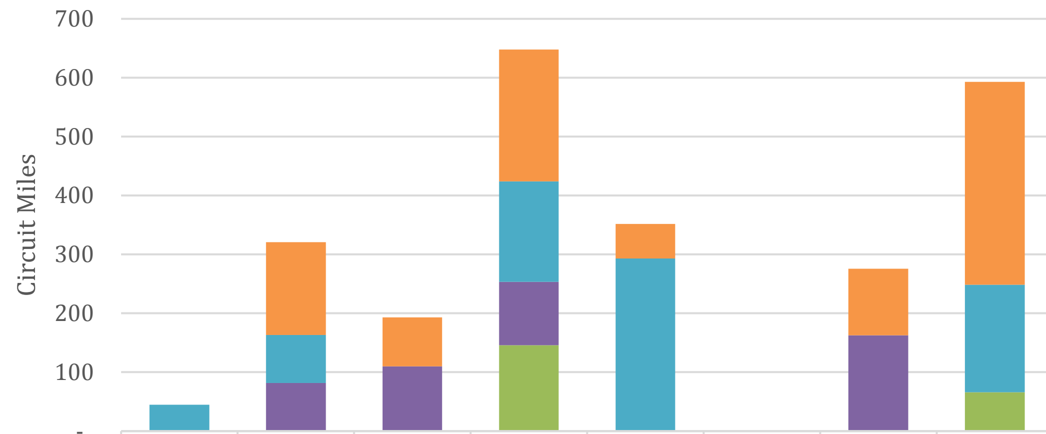
The ES&D database reports information on three categories of transmission infrastructure not yet in service:

- *Under construction* refers to projects where construction of the line has already begun (see Figure 2-4).

[9] NERC (2016a). "Electricity Supply & Demand (ES&D)." http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

- *Planned* (reported separately for the years 2019 and 2024) refers to projects where (a) permits have been approved, (b) a design is complete, or (c) the project is necessary to meet a regulatory requirement (see Figure 2-5 and Figure 2-6).
- *Conceptual* lines are those that are in a project queue, but not included in a regional transmission plan (see Figure 2-7 and Figure 2-8).[10, 11]

Note that information presented in Figure 2-3 through Figure 2-8 refer only to transmission within the United States.



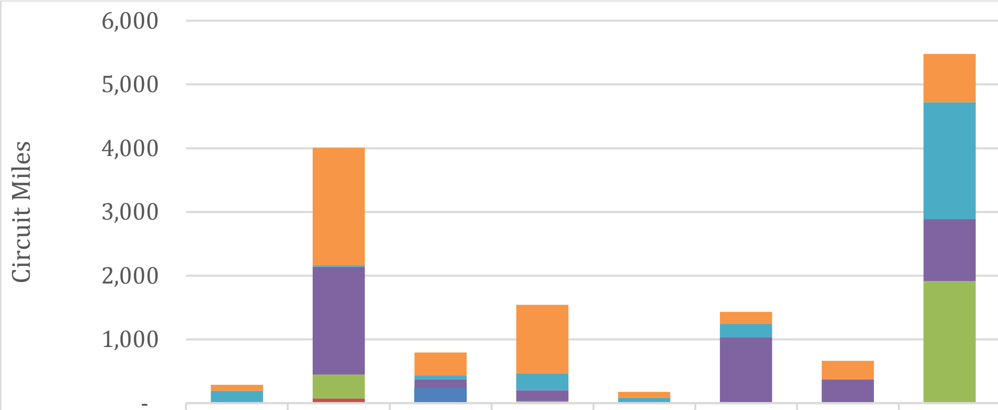
	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kV	-	158	83	224	59	-	113	344
200-299 kV	45	81	-	171	293	-	-	183
300-399 kV	-	82	110	108	-	-	163	-
400-599 kV	-	-	-	146	-	-	-	66
600 kV+	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-

Figure 2-4. Transmission under construction as of first day of 2016

Source: Developed by DOE from NERC (2016a): http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

[10] See http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2016LTRA_Data_Instructions.pdf.

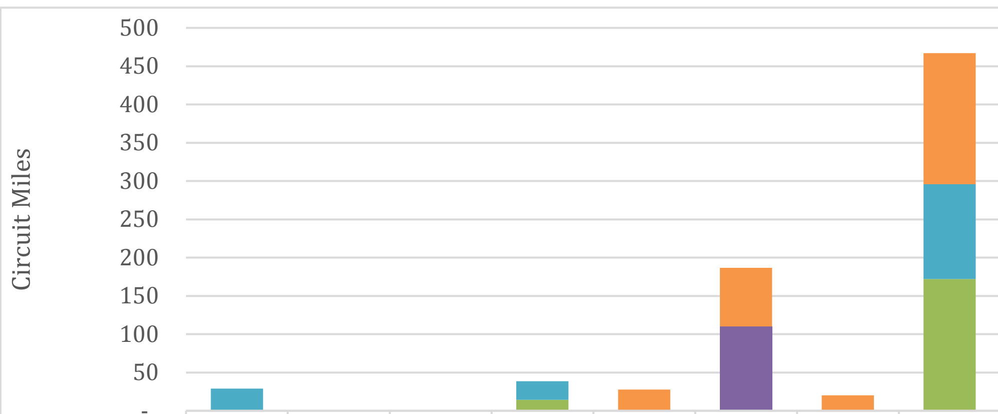
[11] NERC recognizes that its definitions for project categories (such as "conceptual") may vary from the definitions used internally by the entities that provide information on the status of transmission projects.



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kV	95	1,842	359	1,074	94	188	291	759
200-299 kV	193	29	62	263	81	209	-	1,834
300-399 kV	-	1,690	134	171	-	1,034	372	974
400-599 kV	-	380	-	19	-	-	-	1,913
600 kV+	-	69	-	14	-	-	-	-
Total DC	-	-	237	-	-	-	-	-

Figure 2-5. Planned lines expected to be completed by 2020

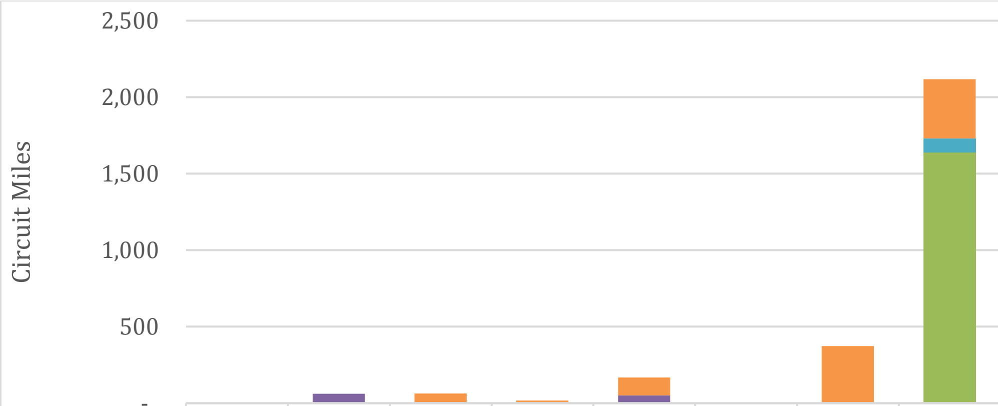
Source: Developed by DOE from NERC (2016a): http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kV	-	-	-	-	28	77	20	171
200-299 kV	29	-	-	24	-	-	-	124
300-399 kV	-	-	-	-	-	110	-	-
400-599 kV	-	-	-	15	-	-	-	172
600 kV+	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-

Figure 2-6. Planned lines expected to be completed 2021-2025

Source: Developed by DOE from NERC (2016a): http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx



	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kV	-	-	56	17	117	-	370	387
200-299 kV	-	-	-	-	-	-	-	91
300-399 kV	-	61	7	-	50	-	4	-
400-599 kV	-	-	-	-	-	-	-	1,640
600 kV+	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-

Figure 2-7. Conceptual lines expected to be completed by 2020

Source: Developed by DOE from NERC (2016a): http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kV	-	-	-	(1)	4	-	40	340
200-299 kV	-	-	-	-	-	-	-	294
300-399 kV	-	-	-	-	-	-	113	479
400-599 kV	-	-	-	-	-	-	-	746
600 kV+	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-

Figure 2-8. Conceptual lines expected to be completed 2021-2025

Source: Developed by DOE from NERC (2016a): http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

2.4. Transmission Investment

Information on transmission investment is taken from EEI, which publishes an annual summary of information on transmission investment by member IOUs (investor-owned utilities), which includes investment and projected investment figures derived from EEI surveys and investor presentations, supplemented with additional data from FERC Form 1 filings (See Figure 2-9.). Note that the investment totals are presented in nominal dollars. Investment by public power and cooperative utilities is not included.

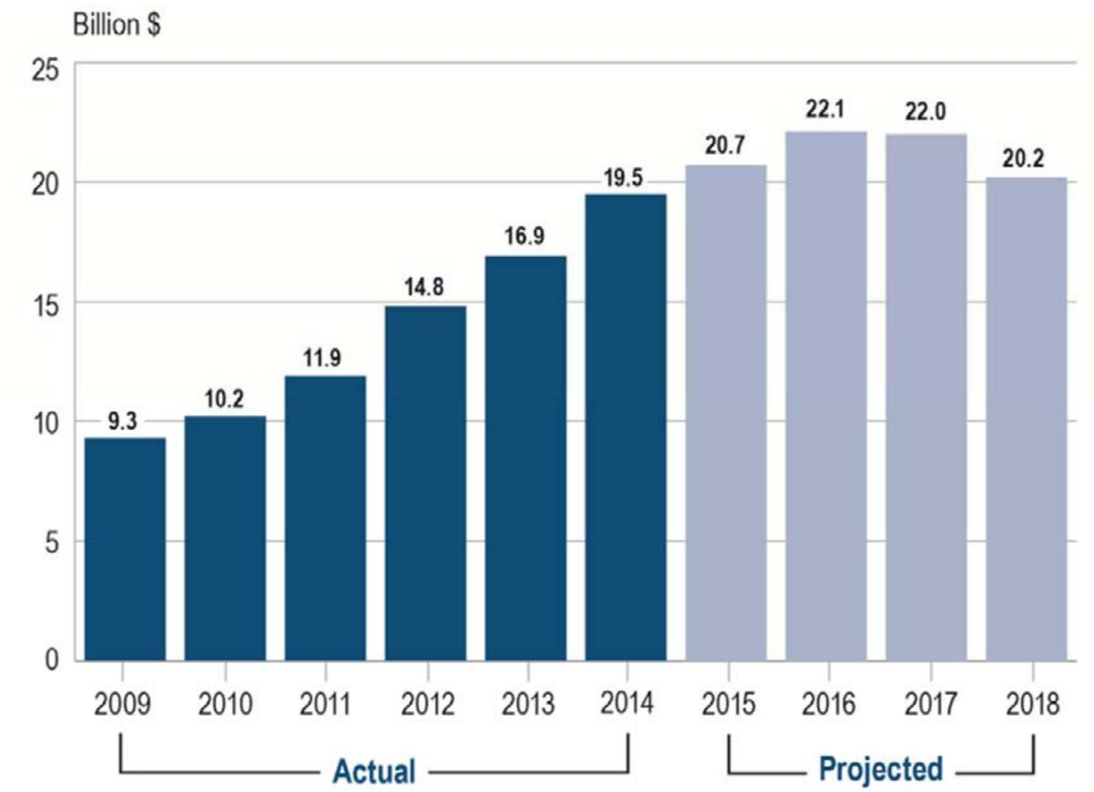


Figure 2-9. Historical and projected transmission investment by shareholder-owned utilities

Source: EEI (2015): http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf

3. Transmission System and Equipment Reliability Performance

3.1. Introduction

The reliability of the transmission system can be assessed by considering either how it has been operated (*i.e.*, retrospective reliability performance) or how it might be operated in the future (*i.e.*, prospective or planned reliability). This section focuses on retrospective reliability performance in recent years.[12]

The reliability performance of the transmission system, in turn, may be assessed by considering either the performance of the system as a whole or the performance of individual elements comprising the transmission system. This section presents information on both of these aspects of reliability performance. NERC is the principal source of information.

3.2. Transmission System Reliability

Information on transmission system reliability is taken from NERC's annual *State of Reliability* report. This report presents information both on an overall metric of system reliability, called the Severity Risk Index (SRI), as well as on fourteen additional metrics for characteristics that together constitute an "adequate level of reliability."[13,14] The SRI was developed by NERC in 2010 as a way to quantify the impact of various reliability events on, and the overall performance of, the bulk power system on a daily basis. The SRI itself is a composite metric that involves weighting together three underlying measures: generation loss, transmission loss, and load loss.[15]

- The *generation loss* component is the normalized number of generators lost reported in percent. The information is taken from NERC's Generating Availability Data System (GADS).[16]
- The *transmission loss* component is the normalized number of transmission lines lost, reported in percent. The information is taken from NERC's TADS (see Section 2).
- The *load loss* component is taken from information collected by the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group

[12] Planned reliability is addressed both in Section 2 (Existing and Planned Transmission Construction and Investment), and in Section 7 (Interregional and Emerging Regional Transmission Planning Processes) of this report.
[13] See http://www.nerc.com/docs/standards/ALR_Definition_clean_081215.pdf.
[14] The *State of Reliability 2015* report describes how the fourteen "M-x" performance metrics align with the original ALR metrics; see NERC (2015b), page 26.
[15] Definitions are from NERC (2014b): http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI%20Enhancement%20Whitepaper.pdf.
[16] See http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

from voluntary reports by its members on power interruptions caused by the loss of supply.[17]

Figure 3-1 presents the daily SRI for the years 2010 to 2015. Note that the y-axis is logarithmic in order to present the small number of very high SRI values on the same graph. The highest daily SRI values are shown in an inset and are described individually in Table 3-1.

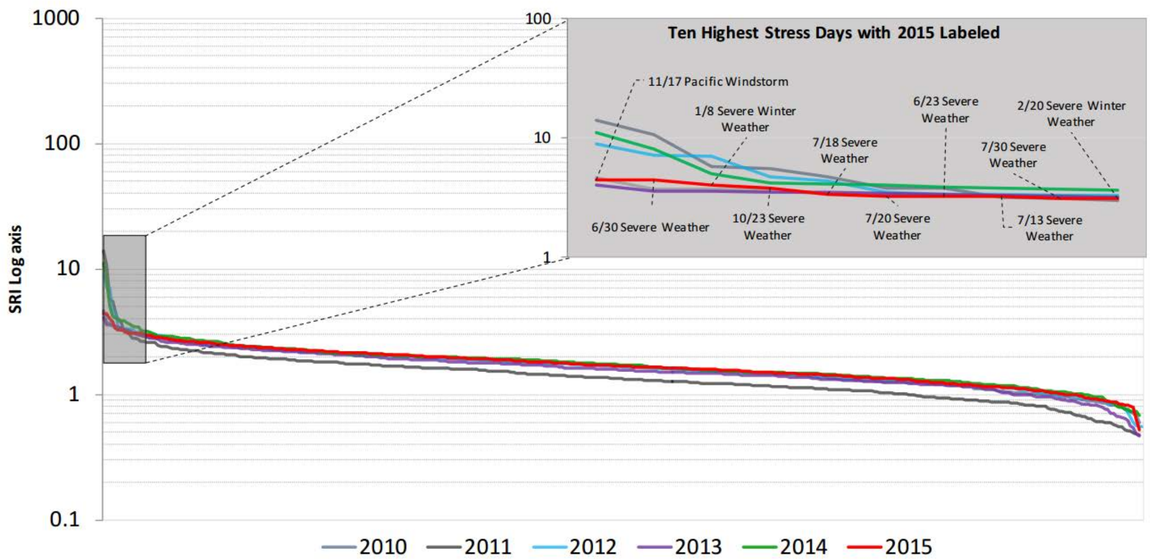


Figure 3-1. NERC Annual Daily Severity Risk Index (SRI), descending by year, 2010-2015

Source: NERC (2016b), page 10: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

Table 3-1. NERC 2015 top ten SRI days

Date	NERC SRI and Components				G/T/L	Weather Influenced Verified by OE-417[1] or Other sources[2]	Rank	Event Type	Region
	SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss					
11/17/2015	4.45	1.24	1.49	1.72		Yes[1]	1	Storm, Flooding, Straightline Winds	WECC
6/30/2015	4.40	2.87	1.47	0.10		Yes[1]	2	Severe Weather	WECC
1/8/2015	4.02	3.52	0.25	0.24		Yes[1]	3	Severe Winter Weather	SERC
10/23/2015	3.79	1.32	2.43	0.43		Yes[2]	4	Excessive Rainfall, Thunder/Lightning Storm	TRE, SPP, SERC
7/18/2015	3.38	1.37	1.20	0.80		Yes[1]	5	Severe Weather	MRO, WECC
7/20/2015	3.30	1.89	1.31	0.05		Yes[2]	6	Thunderstorm/Showers	Widespread
6/23/2015	3.24	1.49	0.81	0.94		Yes[1]	7	Severe Weather	RFC, NPCC
7/13/2015	3.20	2.12	0.70	0.42		Yes[1]	8	Severe Weather	RFC
7/30/2015	3.10	2.06	0.68	0.37		Yes[2]	9	Summer Weather	Widespread
2/20/2015	3.10	2.73	0.21	0.18		Yes[1]	10	Severe Winter Weather	SERC

Source: NERC (2016b), page 11: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

[17] In 2013, the IEEE began collecting information voluntarily provided by its members on reliability that is segmented so that reliability events caused by the loss of supply could be counted separately from all other causes, which originate from within the distribution system.

3.3. Transmission Element Reliability

As was first noted in Section 2, NERC's TADS also collects information on the reliability performance of transmission system elements, including the causes of equipment outages. Figure 3-2 presents the percentage of time that the transmission elements were not available due to planned, operational,[18] and automatic sustained outages during the years 2011 through 2014. Since planned outage data collection in TADS was discontinued in 2015, only unavailability due to operational and automatic outages is shown for 2015. Figure 3-3 presents the percentage of time that transformers were not available, again by outage type, for these same years. Tabular information on the number of the automatic outage events of AC circuits by initiating cause code is presented in Table 3-2.

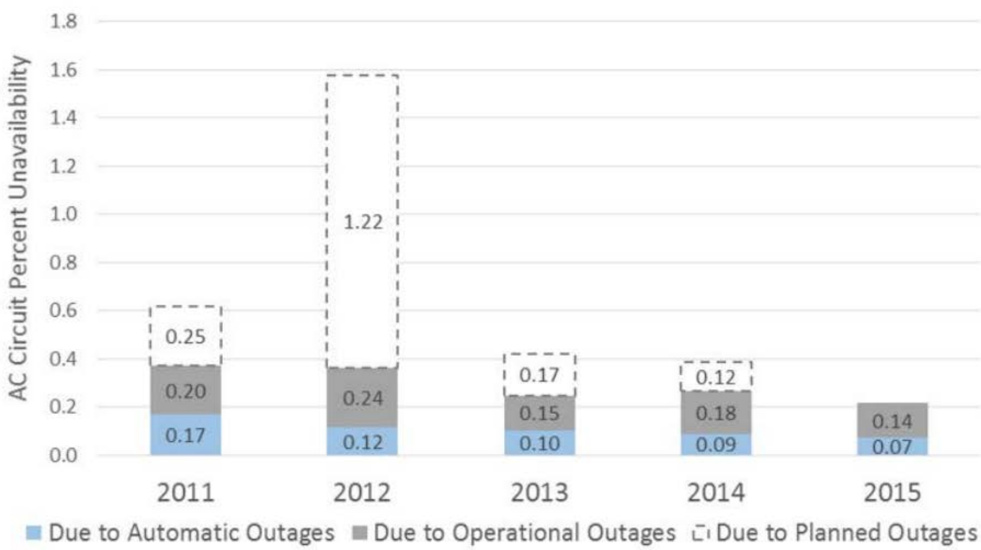


Figure 3-2. AC circuit unavailability by year and outage type, 2011-2015[19]

Source: NERC (2016b), p. 47: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

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[18] 200kv and above.

[19] An Automatic Outage is "[a]n outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State." A Sustained Outage is "[a]n Automatic Outage with an Outage Duration of a minute or greater." See http://www.nerc.com/comm/PC/Transmission%20Availability%20Data%20System%20Working%20Grou/DRAFT-TADS_Appendix_7_Definitions_with_proposed_Event_Type_Numbers__v20100510a.pdf.

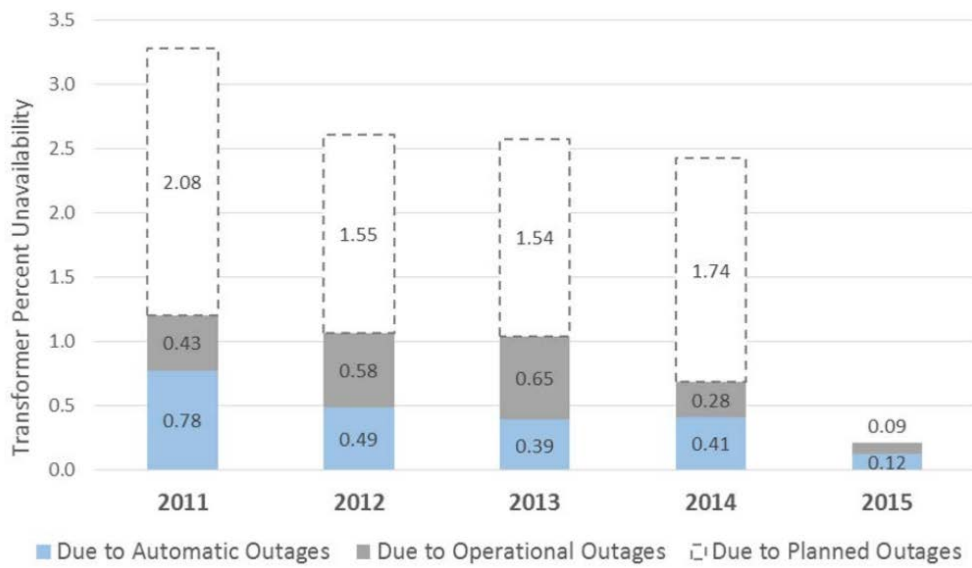

Figure 3-3. Transformer unavailability by year and outage type, 2011-2015

Source: NERC (2016b), p. 48: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

Table 3-2. TADS outage events and hourly event probability by initiating cause code (ICC), 2012-2015

Initiating Cause Code	2012	2013	2014	2015	2012–2015	Event Initiation Probability/Hour
Lightning	852	813	709	783	3157	0.090
Unknown	710	712	779	830	3,031	0.086
Weather excluding Lightning	446	433	441	498	1,818	0.052
Misoperation	321	281	314	165	1,081	0.031
Failed AC Circuit Equipment	261	248	224	255	988	0.028
Failed AC Substation Equipment	248	191	223	221	883	0.025
Foreign Interference	170	181	226	274	851	0.024
Human Error (w/o Type 61 OR Type 62)	212	191	149	132	684	0.020
Contamination	160	151	149	154	614	0.018
Power System Condition	77	109	83	96	365	0.010
Fire	106	130	44	65	345	0.010
Other	104	64	77	77	322	0.009
Combined Smaller ICC groups	57	53	49	37	196	0.006
Vegetation	43	36	39	32	150	0.004
Vandalism, Terrorism, or Malicious Acts	10	9	8	1	28	0.001
Environmental	4	8	2	4	18	0.001
All with ICC assigned	3,724	3,557	3,467	3,587	14,335	0.409
All TADS Events	3,753	3,557	3,477	3,587	14,374	0.410

Source: NERC (2016b), page 86-87: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2016_SOR_Report_Final_v1.pdf

4. Transmission System Utilization

4.1. Introduction

Transmission utilization, for the purposes of this report, refers to how the transmission system, as a whole, is used in day-to-day operations to facilitate electricity flows. Metrics for transmission utilization are based on the amount of electricity flowing over a transmission line or group of transmission lines that connect defined regions or areas to one another. There are regional differences in how these groupings of lines and regions are defined.

To varying degrees, the amount of electricity that flows over a line or group of lines can be measured in relation to pre-established limits that set an upper bound on such flows. Limits can vary seasonally and hourly. These measurement practices, too, vary by and within each of the three interconnections.

4.2. Eastern Interconnection

There is no regularly updated, single repository of public information on electricity flows over the transmission system of the Eastern Interconnection.[20]

In 2014, EIA released Form 930, which collects hourly information on electricity flows among balancing authorities. Data collection began in March 2015. Currently all U.S. balancing authorities are reporting. Public access to a beta version of EIA-930 webpages is available on EIA's website.[21]

There are instances in which entities publish summaries of this type of information. New England's Independent System Operator (ISO), ISO New England (ISO-NE), publishes information on transmission utilization in a compact and standardized manner that shows how this information can be represented. ISO-NE develops summaries of flows among sub-regions both internal and external to its footprint, which are reviewed by its Planning Advisory Committee (see Figure 4-1).

Figure 4-2 and Figure 4-3 present examples of this information. Figure 4-2 shows the distribution of hourly flows by month across the interface between Southwest Connecticut and the rest of the system. Figure 4-3 presents this same information sorted in rank order (from highest to lowest percentage of the interface limit) separately for on- and off-peak hours.

[20] See OATI (2015): http://emp.lbl.gov/sites/all/files/oati-assessment-of-historical-transmission-schedules-2015.pdf.
[21] See http://www.eia.gov/beta/realtime_grid.

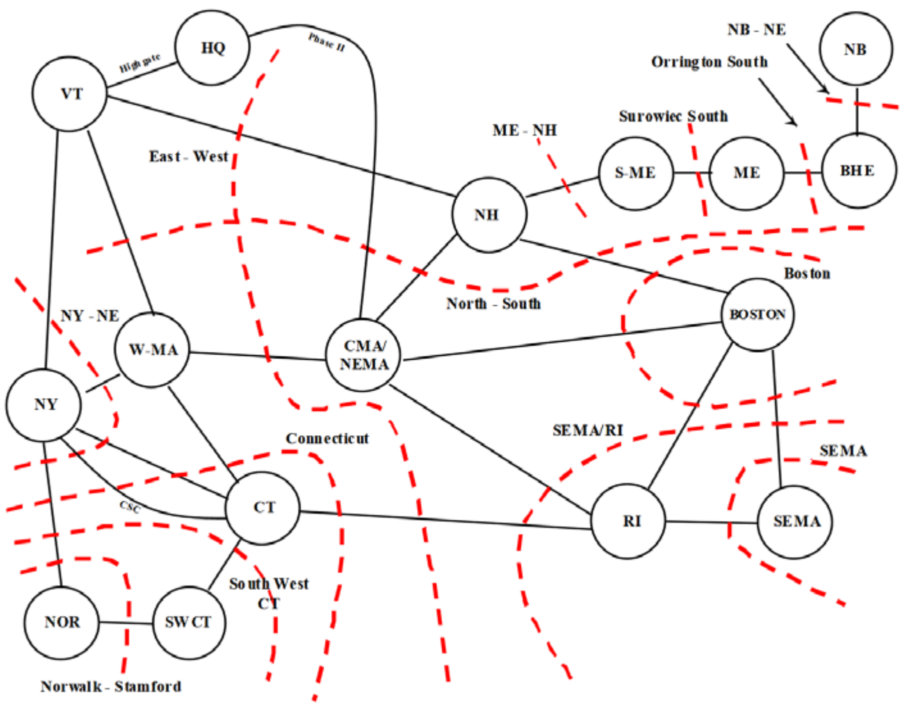

Figure 4-1. New England sub-area model

Source: Ehrlich (2016), p. 3: http://www.iso-ne.com/static-assets/documents/2016/01/a3_2015_interface_flows_and_other_system_perormance_summaries.pdf

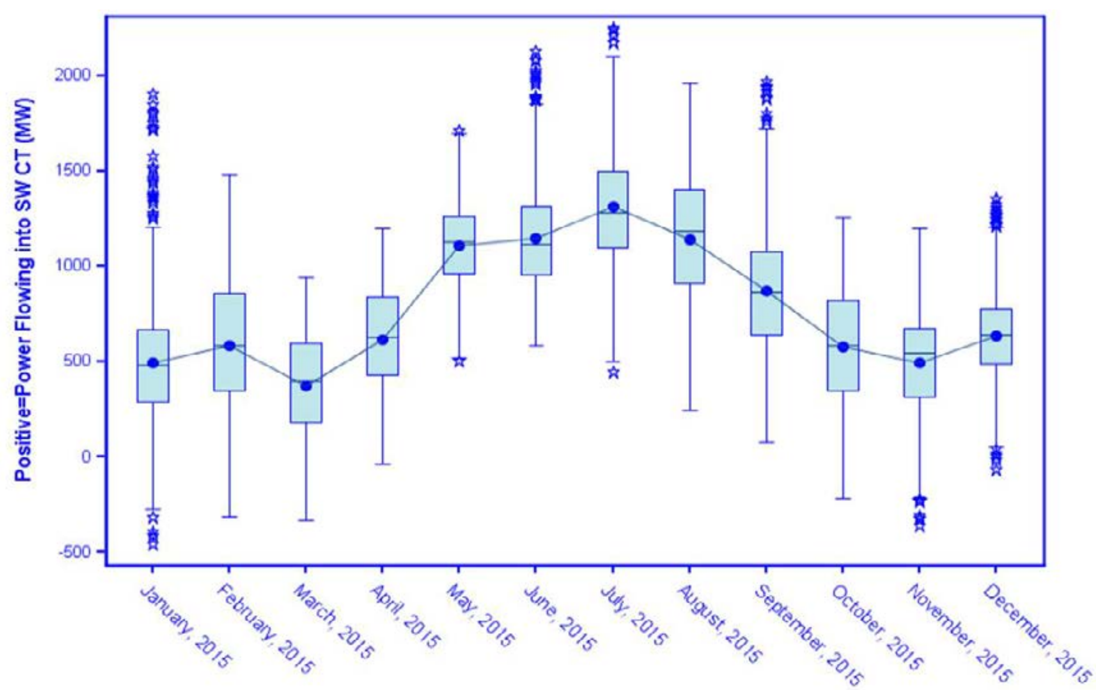

Figure 4-2. Southwest Connecticut import interface net flow by month, 2015

Source: Ehrlich (2016), p. 30: http://www.iso-ne.com/static-assets/documents/2016/01/a3_2015_interface_flows_and_other_system_perormance_summaries.pdf

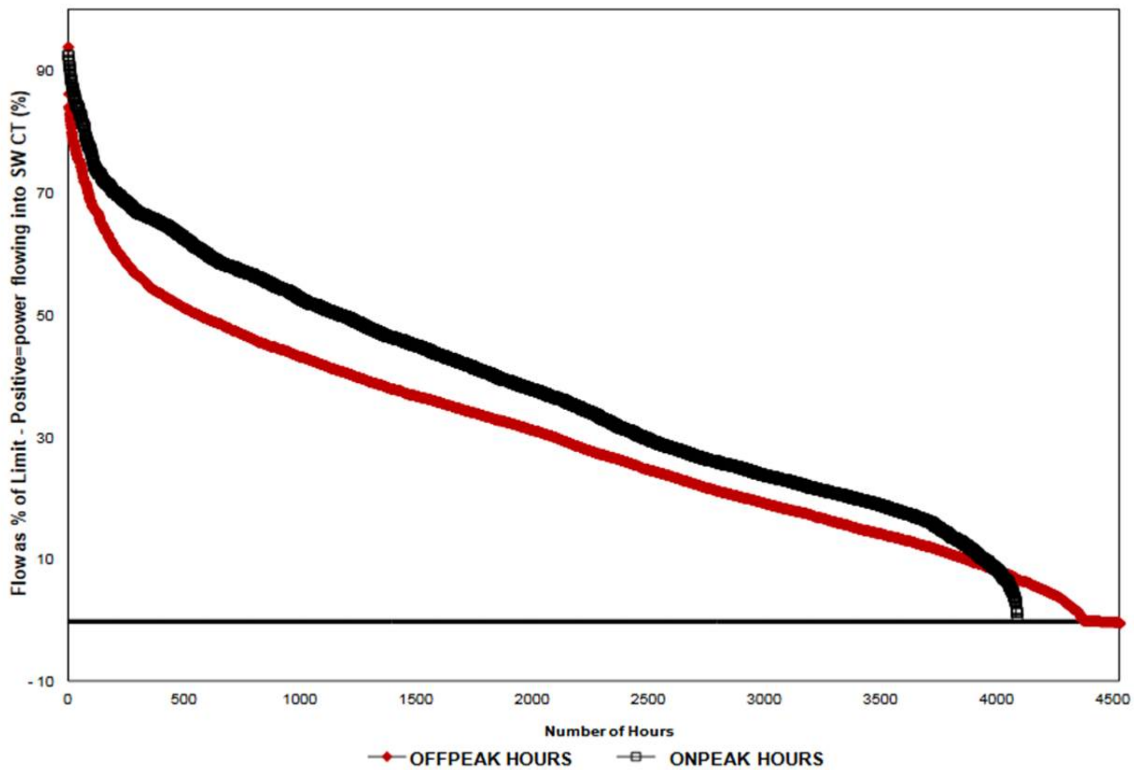

Figure 4-3. Southwest Connecticut import interface duration curve: net flow as % of interface limit, 2015

Source: Ehrlich (2016), p. 42: http://www.iso-ne.com/static-assets/documents/2016/01/a3_2015_interface_flows_and_other_system_perormance_summaries.pdf

4.3. Western Interconnection

The Western Electricity Coordinating Council (WECC) prepares a biennial report on transmission utilization within the Western Interconnection. The information is organized according to transmission paths that are used in both planning and operations. The paths represent aggregations of transmission lines connecting geographic sub-regions within the interconnection to one another. In its *2013 WECC Path Reports* document, WECC defined 67 such paths, and collects and reports hourly electricity flow information across 39 of them (see Figure 4-4).[22]

[22] While there have been no changes to the defined paths since publication of the 2013 report, WECC has run production cost studies on several specific study cases, available at https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Transmission-Plan.aspx.

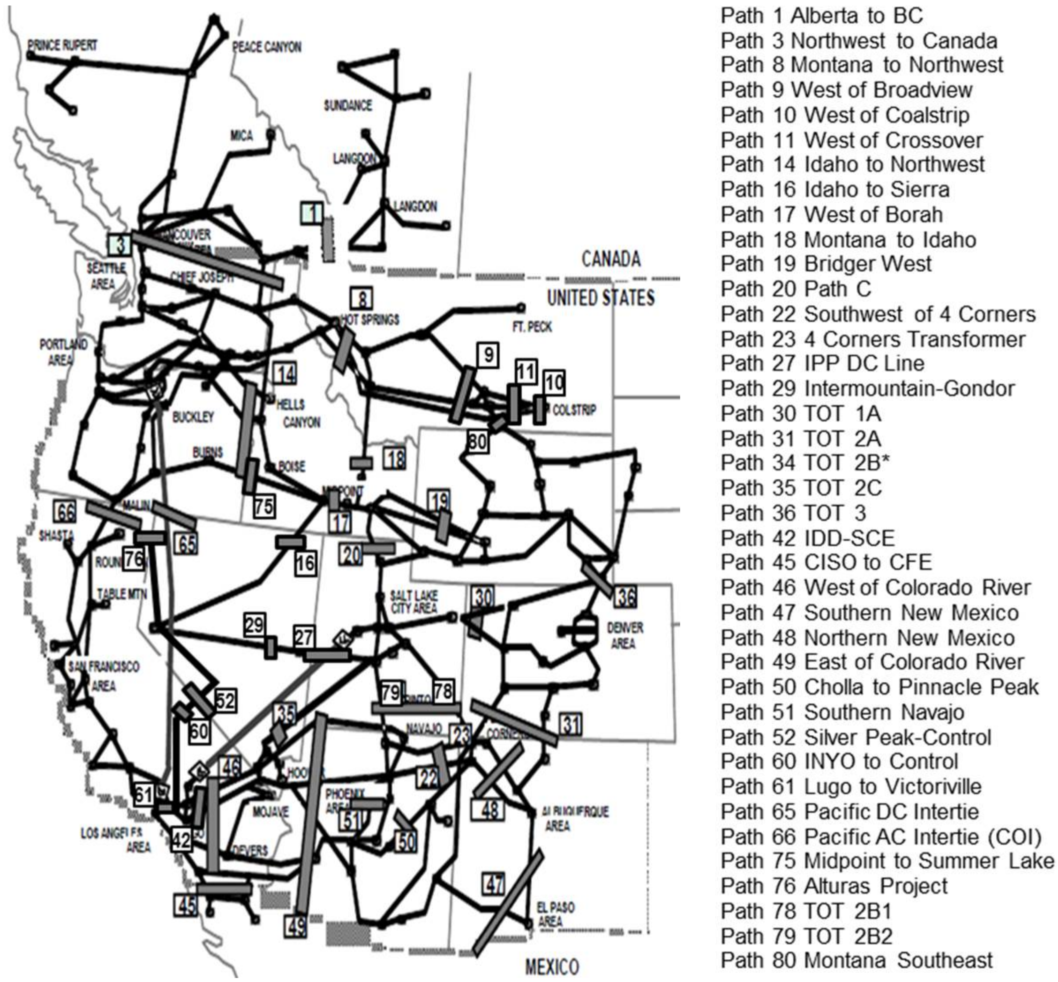

Figure 4-4. Major high-voltage transmission in the West, and WECC-rated paths

Source: WECC (2013), p. 2: https://www.wecc.biz/Reliability/TAS_PathReports_Combined_FINAL.pdf

4.4. Electric Reliability Council of Texas (ERCOT)

The Electric Reliability Council of Texas (ERCOT) does not currently make available regular, comprehensive summaries of information on transmission utilization in a manner similar to the other materials presented in this section.

5. Management of Transmission Constraints

5.1. Introduction

The term "transmission constraint" can be used to refer to several concepts in electric power systems related to limitations on power flows. These include:

1. An element of the transmission system (either an individual piece of equipment, such as a transformer, or a group of closely related pieces, such as the conductors that link one substation to another) that limits power flows, or the physical rating of that element;
2. An operational limit imposed on an element (or group of elements) to protect reliability;[23] and
3. A limit in the amount of physical (or rated) transmission system capacity available to deliver electricity from one area to another while meeting reliability criteria for system contingencies.

Transmission constraints establish the levels at which the power system may be operated in a safe, reliable, and secure manner consistent with reliability standards. Reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by FERC specify how equipment or facility ratings should be considered to avoid exceeding thermal, voltage, and stability limits following credible contingencies. Transmission operating limits, which constrain throughput on affected transmission elements or paths, are established to maintain reliable operating levels consistent with NERC reliability standards. Thus, constraints reflect a transmission flow threshold for reliable operations. When constraints frequently limit desired flows, transmission enhancements may be warranted to enable the desired level of flows.

The existence of a constraint reflects the fact that the capacity of the transmission system is limited by design. Whether it is appropriate to alleviate a constraint through, for example, construction of new transmission facilities, depends on whether such construction is justified based on economic or other considerations.

Transmission constraints are managed by two means: administrative procedures and market-based procedures. This section presents information on administrative procedures used in the Eastern Interconnection (called Transmission Loading Relief, or TLR) and in the Western Interconnection (called Unscheduled Flow Mitigation, or UFM). It also presents information on market-based procedures used by the operators of organized wholesale markets.

[23] This could include limits on individual equipment, groups of equipment, or based on multiple variables (*e.g.*, a nomogram).

5.2. Transmission Loading Relief in the Eastern Interconnection

Transmission Loading Relief (TLR) procedures are administratively determined congestion management procedures used by Reliability Coordinators in the Eastern Interconnection to limit flows over the system to safe operating levels. The number, level, and location of TLRs can give an indication of where the transmission system is being used heavily. NERC publishes information on the use of TLRs on its TLR Log website. The information includes the identity of the flowgate[24] that is constrained; the start and end times of the TLR; the level of the TLR; and the MWs affected.[25, 26]

Figure 5-1 shows the geographic regions covered by the Reliability Coordinators. Figure 5-2 shows the number of the higher levels of TLRs called for the period 2009-2015. Figure 5-3 shows the number of higher levels of TLRs called during 2015, by Reliability Coordinator.

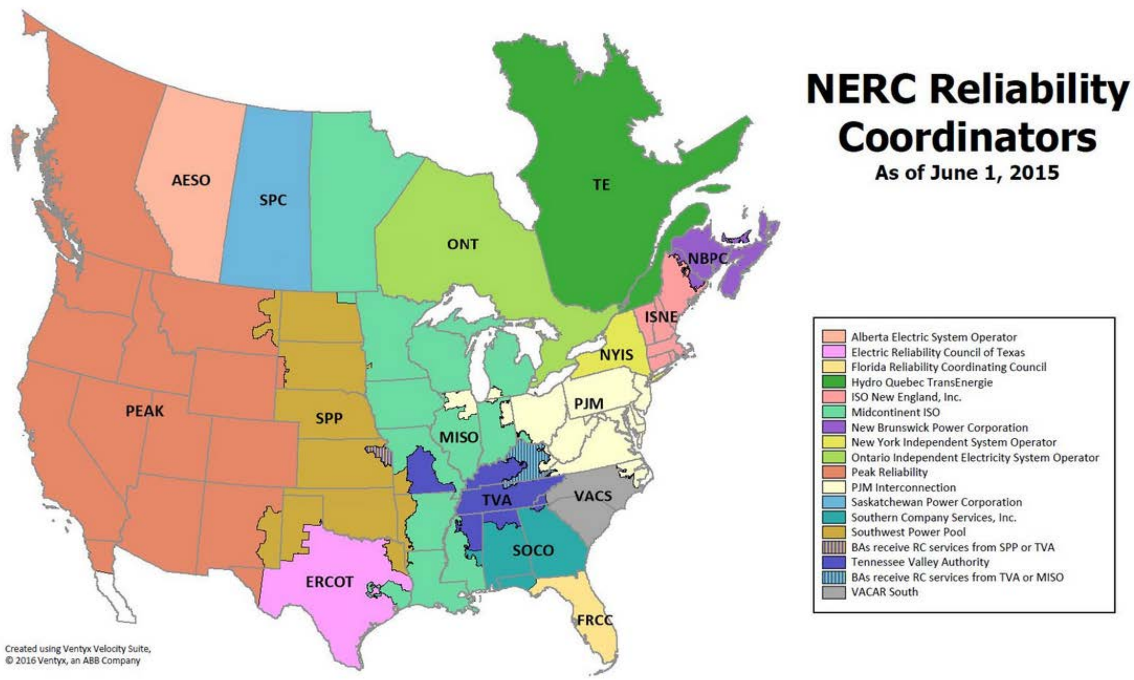

Figure 5-1. NERC Reliability Coordinators, as of June 1, 2015

Source: NERC (2016d): http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx

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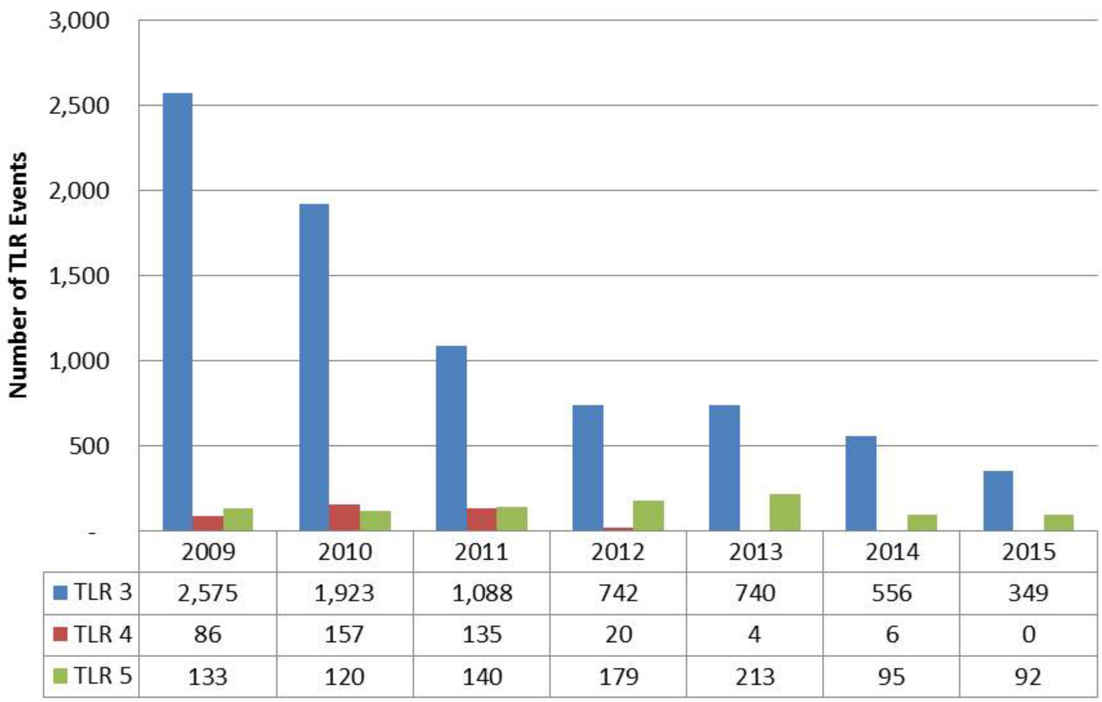
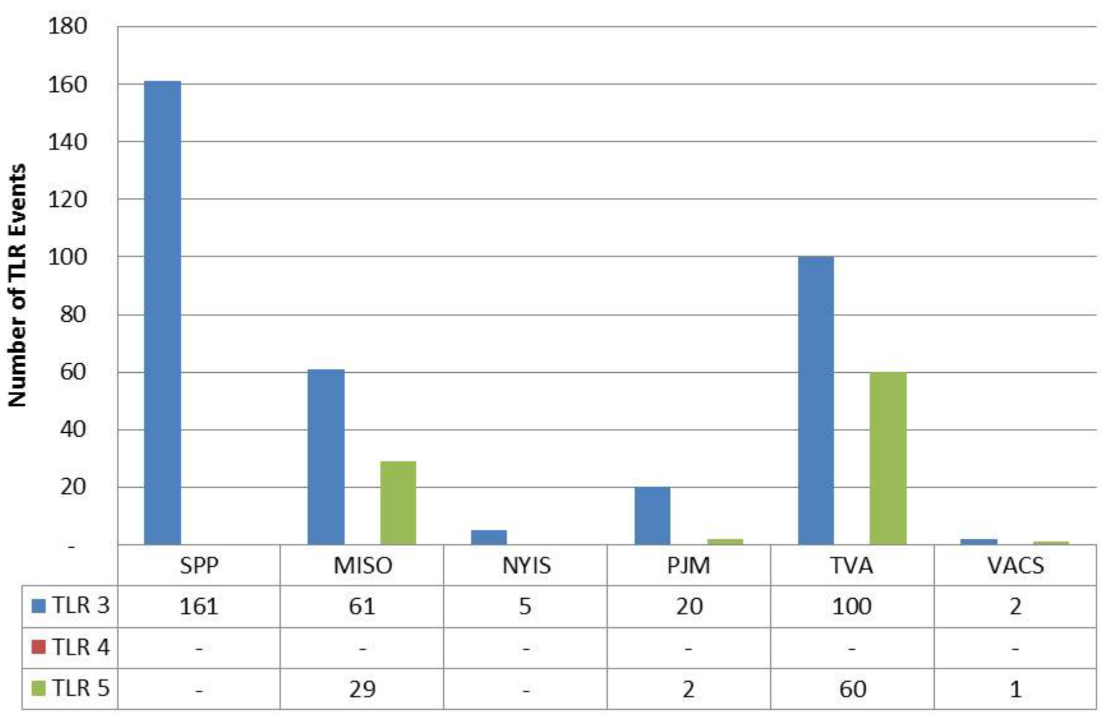
[24] A flowgate refers to a single or group of transmission facilities that jointly can be used to model electricity flow impacts relating the transmission limitations and transmission service usage.
[25] See http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.
[26] The Department is aware that there may be differences in TLR data, which arise due to the means by which they are accessed from NERC.



	2009	2010	2011	2012	2013	2014	2015
TLR 3	2,575	1,923	1,088	742	740	556	349
TLR 4	86	157	135	20	4	6	0
TLR 5	133	120	140	179	213	95	92

Figure 5-2. Eastern (total) TLR events, 2009-2015

Source: Developed by DOE from NERC (2016d): http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.



	SPP	MISO	NYIS	PJM	TVA	VACS
TLR 3	161	61	5	20	100	2
TLR 4	-	-	-	-	-	-
TLR 5	-	29	-	2	60	1

Figure 5-3. Year 2015 TLR events by region

Source: Developed by DOE from NERC (2016d): http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.

5.3. Unscheduled Flow Mitigation in the Western Interconnection

Unscheduled Flow Mitigation (UFM) is an administrative procedure used by transmission operators in the Western Interconnection to manage unintended flows on certain paths that are electrically parallel to scheduled paths—in the Western Interconnection these paths are primarily on the west side and between the north-south paths on the east side of the Interconnection. Initially, the procedures involve controlling phase shifters to manage power flows. When these procedures alone are not enough to mitigate the unscheduled flows, curtailments are invoked following protocols specified in NERC reliability rules.

Table 5-1. Western Interconnection unscheduled flow mitigation events, 2015

	Total COPS[27] (Hours)	Curtailments (Hours)
Path 22	0	0
Path 23	0	0
Path 30	184	55
Path 30 & 66	5	5
Path 31	124	24
Path 31 & 30	1	1
Path 36	124	41
Path 36 & 66	0	0
Path 66	332	105
Total	**770**	**231**

Source: Personal communication from WECC dated March 10, 2016

5.4. Market-Based Procedures for Managing Transmission Constraints

Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) manage transmission constraints through centralized security-constrained economic dispatch of generators. Figure 5-4 shows the geographic boundaries of the markets served by the ISO/RTOs of North America. As part of annual reporting on the operation of these markets, ISO/RTOs (or the market monitors for their markets) sometimes report information on selected constraints.

This section presents information on constraints identified by the RTO/ISOs. The constraints are often accompanied by information on the economic costs of congestion associated with these constraints. Information on total economic congestion costs will be presented in Section 6.

[27] Coordinated Operation of Phase Shifters (COPS); in order to manage transmission congestion, coordinated operation of various phase shifters is used in the interconnection to push or pull power in a certain direction.

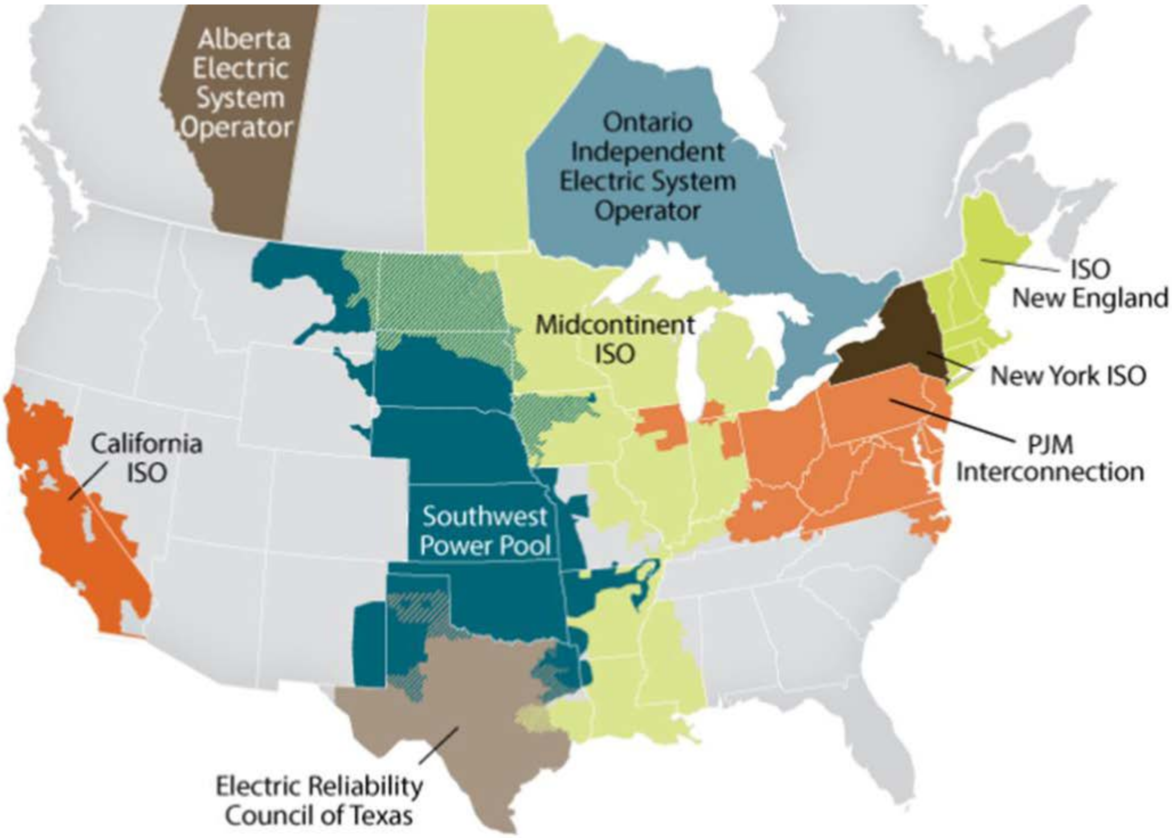


Figure 5-4. ISO/RTO Council Members

Source: See IRC ISO/RTO Council, "IRC Members," at http://www.isorto.org/About/Members/allmembers.

5.4.1. California ISO (CAISO)

The California Independent System Operator (CAISO) produces an *Annual Report on Market Issues and Performance,*[28] which includes the information on the frequency and percent of annual hours of congestion on interties and on internal constraints. Figure 5-5 shows changes in the percent of total hours interties are constrained.

Table 5-2 presents the impacts of these constrained periods on congestion costs, and Table 5-3 lists internal constraints and provides information on their frequency and impact on day-ahead prices.

[28] See CAISO (2016): http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

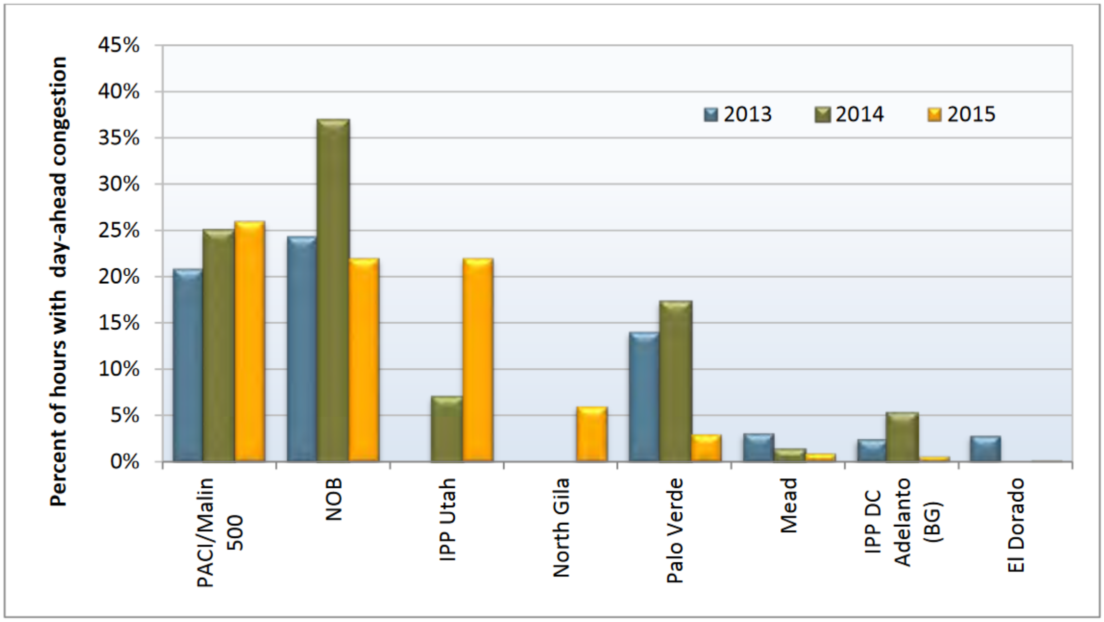


Figure 5-5. CAISO percent of hours with congestion on major interties, 2013-2015

Source: CAISO (2016), p. 167: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

Table 5-2. CAISO summary of import congestion, 2013-2015

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2013	2014	2015	2013	2014	2015	2013	2014	2015
Northwest	PACI/Malin 500	21%	25%	26%	$8.6	$17.0	$6.2	$34,026	$88,731	$37,687
	NOB	24%	37%	22%	$9.8	$12.7	$6.4	$27,823	$58,902	$12,375
	Cascade	14%	6%	2%	$13.5	$10.6	$7.5	$1,280	$490	$101
	COTPISO		1%	1%		$17.8	$36.2		$37	$97
	Tracy 500	2%	3%	0.1%	$21.3	$27.3	$6.2	$1,292	$2,262	$20
	Summit	1%	1%	0.2%	$10.6	$16.4	$2.8	$38	$57	$3
	Tracy 230		0.1%			$72.5			$17	
Southwest	Palo Verde	14%	17%	3%	$13.2	$15.1	$13.2	$26,438	$36,551	$9,261
	North Gila			6%			$47.0			$3,728
	Mead	3%	1%	1%	$7.7	$8.5	$14.4	$2,181	$1,206	$1,278
	IPP Utah		7%	22%		$7.2	$2.9		$879	$1,079
	West Wing Mead		1%	1%		$30.1	$34.3		$280	$330
	Market Place Adelanto		0.3%	0.3%		$16.6	$18.9		$261	$330
	IPP DC Adelanto (BG)	2%	5%	1%		$8.5	$3.7		$1,727	$77
	El Dorado	3%		0.1%	$6.3		$3.0	$1,639		$14
	Sylmar AC		0.4%			$9.7			$251	
	IID - SCE	3%	0.5%		$49.8	$53.0		$5,735	$1,005	
	Other							$169	$142	$3
Total								***$100,621***	***$192,797***	***$66,381***

* The IPP DC Adelanto branch group is not an inter-tie, but is included here because of the function it serves in limiting imports from the Adelanto region and the frequency with which it was binding.

Source: CAISO (2016), p. 166: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

Table 5-3. CAISO impact of congestion on day-ahead prices during congested hours, 2015

Area	Constraint	Frequency				Q1			Q2			Q3			Q4		
		Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3				3.6%										$0.60	-$0.47	-$0.61
	PATH15_S-N		9.1%	0.5%	2.5%				$4.05	-$3.65	-$3.42	$0.63	-$0.52	-$0.49	$1.17	-$0.97	-$0.90
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P				2.4%										$0.32	-$0.35	-$0.35
	30050_LOSBANOS_500_30069_L.BANS M_ 1.0_XF_1				0.3%										$1.26	-$1.05	-$0.99
	RM_TM21_NG			7.0%								$0.54		-$0.47			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1			1.4%								$3.24					
	30055_GATES1 _500_30900_GATES _230_XF_11_P		2.7%	0.7%					$0.70	-$0.60	-$0.59	$0.73	-$0.60	-$0.59			
	LOSBANOSNORTH_BG			0.2%								$6.49	-$5.71	-$5.27			
	PATH15_BG	6.2%	27.6%			$4.02	-$3.29	-$3.06	$4.54	-$3.86	-$3.64						
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		2.3%						$1.97	-$1.72	-$1.63						
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1		1.5%						$2.02								
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2		1.3%						$4.13	-$6.42	-$6.20						
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.6%						$2.96	-$1.36							
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3		0.3%						$4.13	-$3.82	-$3.62						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	0.8%	3.9%	12.4%	-$0.95	$0.92	$1.51	-$1.78	$2.51	-$0.41	-$0.43	$0.86	-$2.68	-$0.65	$1.14	-$0.49
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.9%	0.9%	1.5%	1.5%	-$0.74	$1.00	-$0.59				-$0.44	$0.57		-$0.51	$0.72	-$0.41
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.2%						-$0.41	$0.49	$0.40						
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		2.4%	2.4%	11.1%						-$2.11			-$2.24			-$1.20
	22768_SOUTHBAY_69.0_22352_IMPRLBCH_69.0_BR_1 _1				3.7%												$0.25
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1	0.5%		1.3%	2.5%			$6.85						$2.26			$3.36
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				1.7%												$0.74
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			2.3%	1.3%									-$1.83			-$1.18
	OMS 2319325 PDCI_NG				1.2%										-$2.60	$2.24	$2.78
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1			1.3%	1.1%									$1.14			$1.40
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1				0.8%												$1.51
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1		1.3%	0.3%	0.7%						$9.18			$5.55			$10.61
	22408_LOSCOCHS_69.0_22412_LOSCOCHS_138_XF_2				0.2%												$5.20
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1		0.6%	6.1%							$5.26			$1.30			
	22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1			2.1%										$0.50			
	22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1			1.0%										$1.06			
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		2.8%	0.6%							-$2.14			-$2.36			
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.3%	0.05%					-$5.06	$3.49	$7.21	-$13.67	$8.54	$12.63			
	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1		0.2%							$0.70	-$5.89						
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%	1.3%					-$0.47	-$0.72		$1.17						
	SLIC 2584248 50002_OOS_TDM		0.6%								$4.70						
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	24.7%						$5.04									
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.1%				-$2.80	$1.70	$5.15									
	IVALLY-ELCNTO_230_BR_1_1	1.7%				-$0.05		$1.47									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.5%				-$3.81	$2.35	$6.50									

Source: CAISO (2016), p. 169: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

5.4.2. Electric Reliability Council of Texas (ERCOT)

ERCOT produces an annual "constraints and needs" report, which includes a list of the top constraints, as well as supporting tables and maps of these constraints.[29] Table 5-4 and Figure 5-6 show the geographic area served and the location of constraints identified by ERCOT.[30] In addition, the market monitor for ERCOT includes information about constraints in its annual *State of the Market* report.[31] Figure 5-7 shows the frequency of active constraints for different load levels, annually for 2012–2014. Figure 5-8 displays the ten areas that generated the most real-time congestion.

[29] See ERCOT (2015): http://ercot.com/content/news/presentations/2015/2015ERCOTConstraintsAndNeedsReport.pdf.

[30] Section 4 of the *2015 Report on Existing and Potential Electric System Constraints and Needs* shows transmission projects in ERCOT (as of December 2015) that, among other things, are designed to address these constraints. See ERCOT (2015).

[31] See Potomac Economics (2016b): http://potomaceconomics.com/index.php/markets_monitored/ERCOT.

Table 5-4. Top 15 congested constraints on the ERCOT system, Oct 2014–Sept 2015

Map Index	Constraint	Congestion Rent
1	North to Houston Import	$39,316,039
2	Heights 138/69 kV transformer	$35,902,821
3	Rio Hondo-East Rio Hondo 138 kV line	$20,894,616
4	Harlingen Switch-Oleander 138 kV line	$19,245,752
5	Moss-Westover 138 kV line	$17,791,984
6	Hockley-Betka 138 kV line	$12,809,188
7	San Angelo College Hills 138/69 kV transformer	$12,124,531
8	La Palma-Villa Cavazos 138 kV line	$10,681,931
9	San Angelo Power 138/69 kV transformer	$10,622,923
10	Collin Switch 345/138 kV transformer	$9,098,021
11	Lon Hill-Smith 69 kV line	$8,504,021
12	Pflugerville-Gilleland Creek 138 kV line	$7,592,286
13	Cedar Hill-Mountain Creek 138 kV line	$7,469,997
14	Marion-Skyline 345 kV line	$7,358,307
15	East Levee-Reagan Street 138 kV line	$6,600,415

Source: ERCOT (2015), p. 6: http://ercot.com/content/news/presentations/2015/2015ERCOTConstraintsAndNeedsReport.pdf

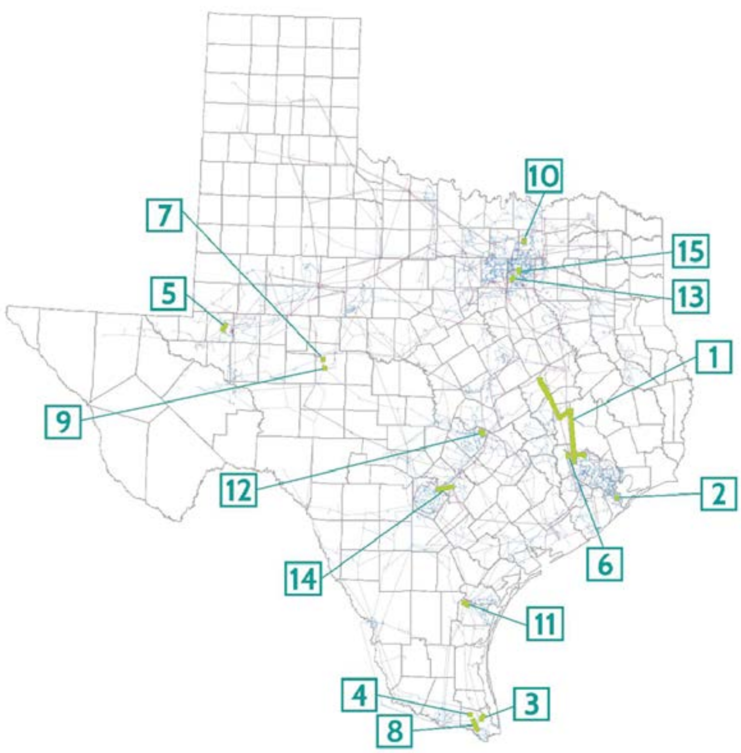


Figure 5-6. Top 15 congested constraints on the ERCOT system, Oct 2014–Sept 2015

Source: ERCOT (2015), p. 7: http://ercot.com/content/news/presentations/2015/2015ERCOTConstraintsAndNeedsReport.pdf

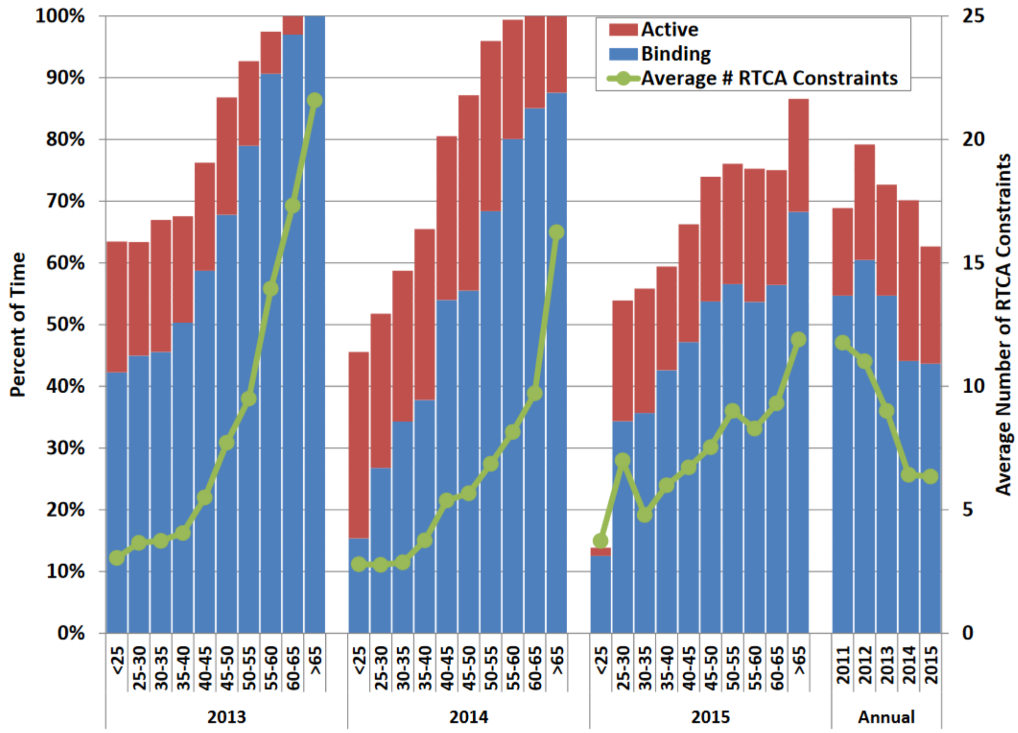


Figure 5-7. Frequency of binding and active constraints, 2013-2015

Source: Potomac Economics (2016b), p. 50: http://potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

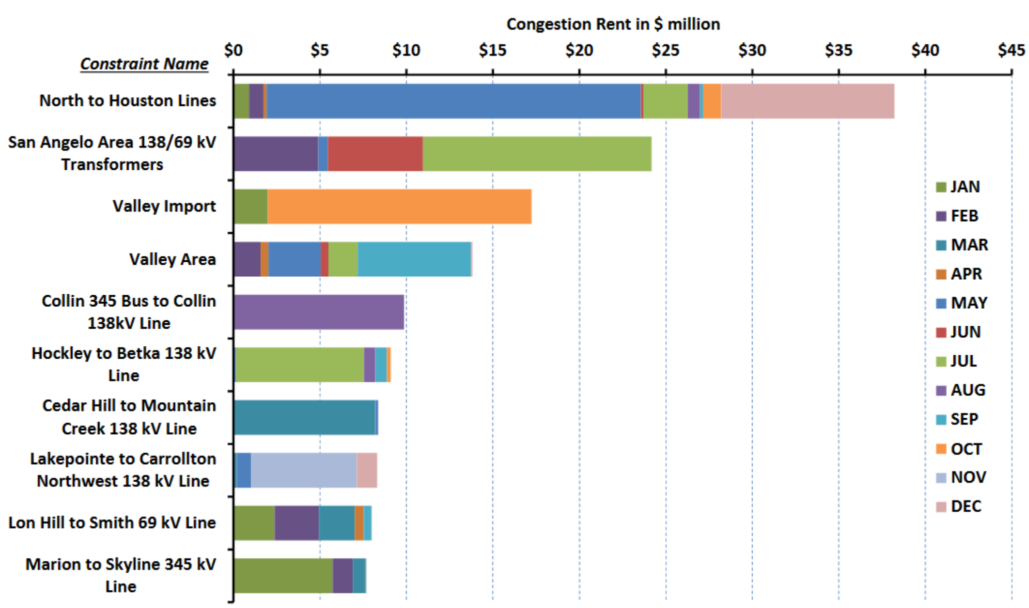


Figure 5-8. ERCOT top ten real-time constraints, 2015

Source: Potomac Economics (2016b), p. 52: http://potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

5.4.3. ISO New England (ISO-NE)

ISO-NE reports on system constraints in its annual *Regional System Plan*.[32] Constraints are also described in presentations made by the ISO-NE Planning Advisory Committee and in reports by the regional planning entities within New England. Figure 4-1 shows the geographic area served and the location of constraints identified by ISO-NE.[33]

In its *2015 Regional System Plan*, ISO-NE includes the following comments on potential future constraints, as identified in planning studies:

- *The ISO conducted a strategic transmission analysis for wind resource integration in subareas of Maine and Vermont. The studies identified transmission system constraints of both the local and regional transmission systems, and the analysis demonstrated the benefits of including robust local voltage-control capability to the wind-generation sites. The studies showed conceptual transmission improvements that would reliably integrate the wind resources while meeting NPCC bulk power system (BPS) requirements.*
- *The results of the Strategic Transmission Analysis: Wind Integration Study will be used in the 2015 economic studies of onshore wind development in Maine. These studies will show the economic benefits of relieving transmission constraints in the Keene Road area and other areas of Maine. The results also may be used to identify the need for future market-efficiency transmission upgrades and for projects facilitating the integration of wind resources.*[34]
- *The constraints observed in the transfer of power into the SENE area were found to be on or near the interface of the boundary formed by the combined existing SEMA/RI and NEMA/Boston capacity zones. These constraints were observed for the contingency loss of either generating resources or other transmission elements on or near the boundary formed by the combination of the capacity zones. Resources in both NEMA/Boston and SEMA/RI are on the downstream side of the import constraints (and thus would unload the constraints) observed for the combined zone… However, now that the "stand-alone" SEMA/RI issues have been relieved, both zones share the same remaining constraints located on the outer boundaries of the combined SENE zone. For the conditions studied, no constraints were observed between NEMA/Boston and SEMA/RI within the SENE zone.*
- *The overall limiting condition in setting the new transfer limits is the system's stability response to faults in southern New England. The new transfer limits have been adopted in the appropriate planning and capacity market processes. The resulting new transfer limits indicate that the constraints within Maine will likely continue to limit the ability of the system to deliver some existing and new capacity.*[35]

[32] See ISO-NE (2015b): http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

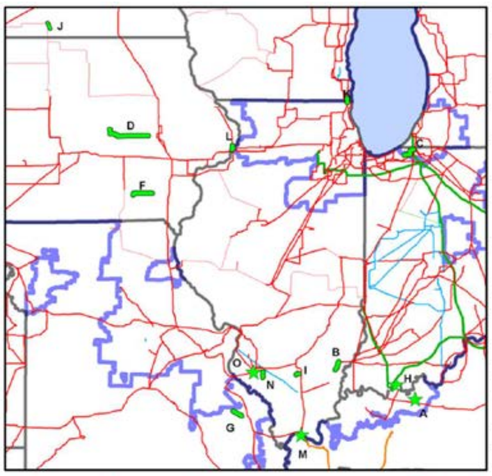
[33] Section 6 of the *2015 Regional System Plan* shows transmission projects in ISO-NE (as of November 2015) that, among other things, are designed to address these constraints. See ISO-NE (2015b).

[34] ISO-NE (2015b), p. 13: http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

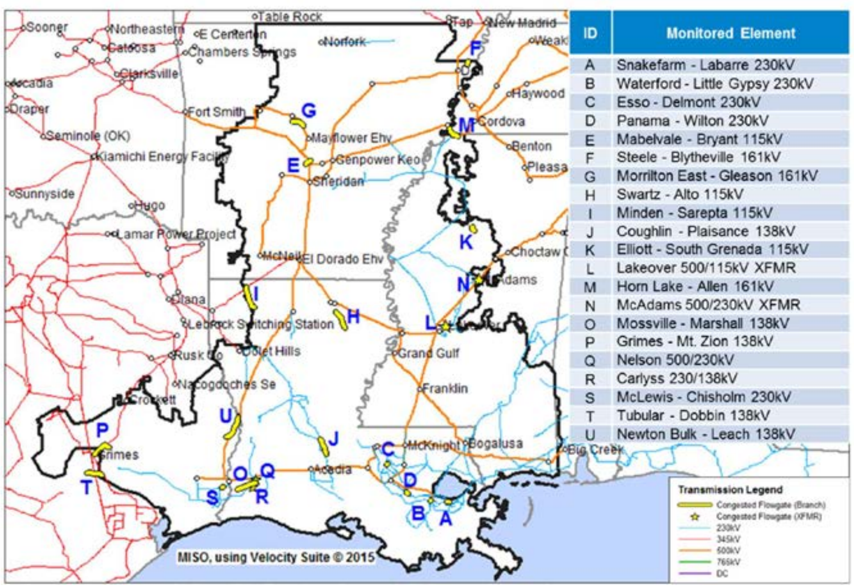
[35] See ISO-NE (2015b), Page 62-63: http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

5.4.4. Midcontinent ISO (MISO)

The Midcontinent ISO (MISO) produces an annual *Market Congestion Planning Study*[36] that contains an analysis of historical and projected future congestion. MISO makes public a list of projected top future congested flowgates; the top projected future congested flowgates reported in the *2015 MISO Transmission Expansion Plan* (MTEP) are shown in Figure 5-9.



FG ID	Monitored Element
A	New Hardinsburg 138/161kV Transformer
B	Albion - Crossville 138kV
C	New Carlisle – Bosserman 138kV
D	Marshalltown - Blairstown Jct 115kV
F	Wapello - Jeff 161kV
G	Fredericktown - Fredericktown Tap 161kV
H*	Newtonville 138/161kV Transformer
I	Nason Point - Ina 138kV
J	Winnebago - Blue Earth 161kV
K	Pleasant Prairie – Zion EC 345kV
L	Quad City–Rock Creek 345kV
M	Joppa 345/161kV xfmr
N*	Tilden - Sparta Tap 138kV
O*	Baldwin 345/138kV xfmr



ID	Monitored Element
A	Snakefarm - Labarre 230kV
B	Waterford - Little Gypsy 230kV
C	Esso - Delmont 230kV
D	Panama - Wilton 230kV
E	Mabelvale - Bryant 115kV
F	Steele - Blytheville 161kV
G	Morrilton East - Gleason 161kV
H	Swartz - Alto 115kV
I	Minden - Sarepta 115kV
J	Coughlin - Plaisance 138kV
K	Elliott - South Grenada 115kV
L	Lakeover 500/115kV XFMR
M	Horn Lake - Allen 161kV
N	McAdams 500/230kV XFMR
O	Mossville - Marshall 138kV
P	Grimes - Mt. Zion 138kV
Q	Nelson 500/230kV
R	Carlyss 230/138kV
S	McLewis - Chisholm 230kV
T	Tubular - Dobbin 138kV
U	Newton Bulk - Leach 138kV

Figure 5-9. Projected top future congested flowgates in 2015 MTEP (Top: North/Central Area; Bottom: South Area)

Source: MISO (2016), p. 124: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP15/MTEP15%20Full%20Report.pdf

5.4.5. New York ISO (NYISO)

[36] Prior to 2014, this report was known as the *Market Efficiency Planning Study*.

The New York Independent System Operator (NYISO) biennially performs *Reliability Needs Assessment* (RNA) as part of its Reliability Planning Process (RPP).[37] The RNA assesses resource adequacy and both the transmission security and adequacy of the New York Control Area (NYCA) bulk power transmission system. The transmission security analyses specifically are utilized to identify regions of New York in which the bulk transmission system would not meet reliability criteria under peak load conditions due to thermal overloads.

NYISO also produces an annual *Power Trends* report summarizing data and providing analysis of major factors, including transmission, affecting the electric system in New York.[38] Figure 5-10 shows the congested transmission corridors in New York. In addition, NYISO publishes detailed statistics on historic congestion, which can be found on the planning section of its website.[39]

In addition, NYISO conducts a biennial economic planning process and publishes corresponding *Congestion Assessment and Resource Integration Study* (CARIS) reports. In the 2015 CARIS report, top congested constraints are identified based on five years of historic data plus ten years of projected congestion, which are shown in Table 5-5.[40, 41]

Table 5-5. Number of congested hours by constraint, actual and projected

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
Constraint	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CENTRAL EAST	2,968	2,166	1,471	3,374	3,022	4,678	4,215	4,527	4,425	4,416	3,466	3,624	3,365	3,469	3,203
DUNWOODIE TO LONG ISLAND	4,513	6,219	4,777	6,031	5,583	7,869	7,667	7,778	7,502	7,517	7,840	7,920	7,908	8,056	8,108
LEEDS PLEASANT VALLEY	673	514	392	624	384	961	546	629	475	410	325	349	353	404	767
GREENWOOD	2,705	4,338	2,983	3,415	1,438	8,096	7,591	7,693	7,873	7,817	8,392	8,357	8,402	8,430	8,442
NEW SCOTLAND LEEDS	156	774	69	264	173	145	17	29	7	9	9	11	17	13	6
PACKARD HUNTLEY	-	-	-	-	308	3,604	4,729	4,816	5,019	4,809	4,449	4,326	4,209	4,291	4,112
DUNWOODIE MOTTHAVEN	765	828	644	504	190	0	0	0	1	0	0	0	0	0	0
RAINEY VERNON	3,131	3,785	2,166	2,166	641	410	4,953	5,308	5,409	5,388	5,142	5,381	4,930	5,223	5,070
E179THST HELLGT ASTORIAE	3,371	4,880	2,432	2,182	990	410	787	864	796	728	563	740	719	737	736
EGRDNCTY 138 VALLYSTR 138	1,880	2,812	2,934	5,908	5,142	2,183	5,491	5,962	5,727	6,086	5,009	5,491	5,574	5,791	5,780

Source: NYISO (2015), p. 54: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf

[37] See NYISO (2014): http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2014%20RNA_final_09162014.pdf

[38] See NYISO (2016): *http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2016-power-trends-FINAL-070516.pdf*

[39] See "NYISO Historic Congestion Costs" at http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

[40] NYISO does not use number of constrained hours in economic planning.

[40] See NYISO (2015), p. 54: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf

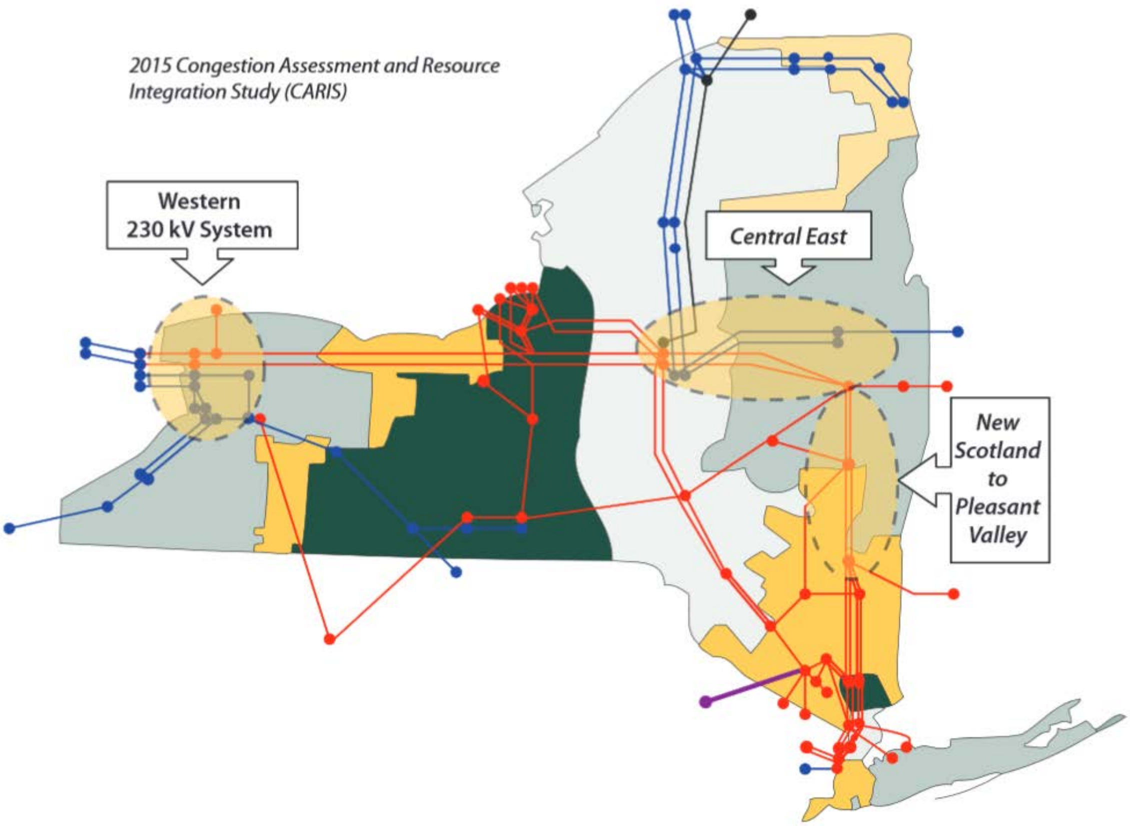


Figure 5-10. Transmission congestion corridors in New York State

Source: NYISO (2016), p. 30: http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2016-power-trends-FINAL-070516.pdf

5.4.6. PJM

Monitoring Analytics, the external market monitor for PJM, reports top constraints based on a number of criteria in its annual *State of the Market* report.[42] Figure 5-11 shows the location of the top 10 constraints affecting PJM's congestion costs in 2015. Table 5-6 shows the top 25 constraints with frequent occurrence, Table 5-7 shows the top 25 constraints with largest year-to-year change in occurrence, and Table 5-8 shows the top 25 constraints affecting congestion costs.

[42] See Monitoring Analytics (2016a) and (2016b) at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml.

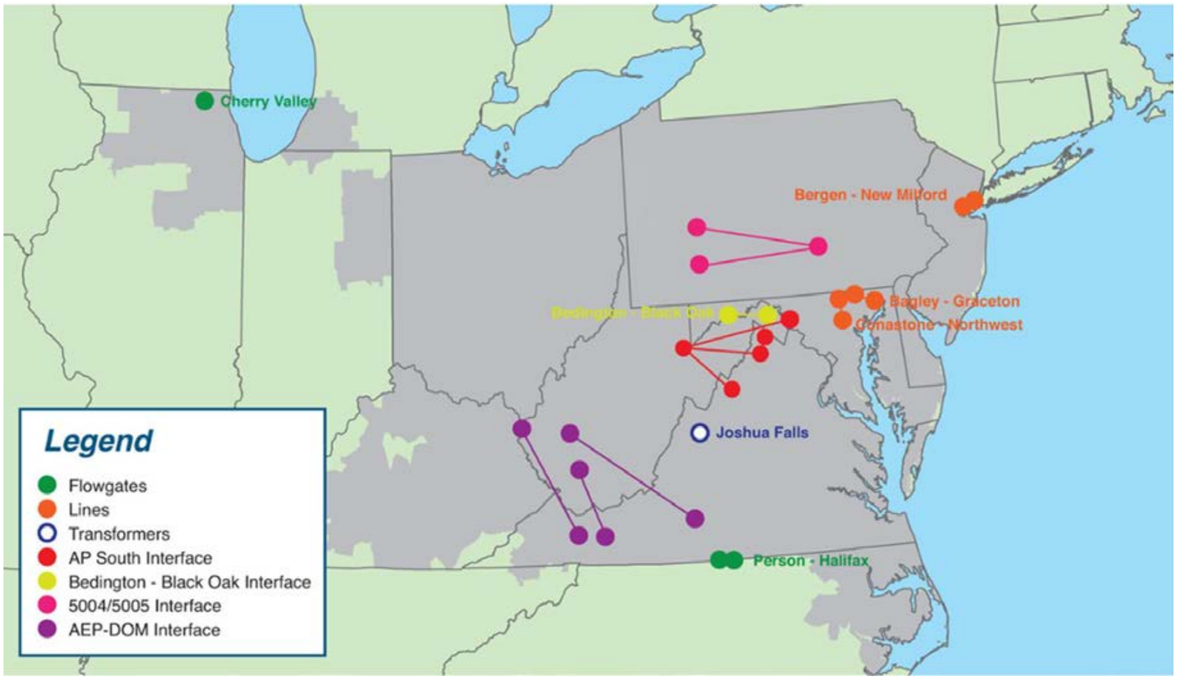


Figure 5-11. Location of the top 10 constraints by PJM congestion costs 2015

Source: Monitoring Analytics (2016b), p. 431: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

Table 5-6. PJM top 25 constraints with frequent occurrence, 2014-2015

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Bagley - Graceton	Line	4,584	3,544	(1,040)	1,884	1,973	89	52%	40%	(12%)	22%	22%	1%
2	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
3	Bunsonville - Eugene	Flowgate	2,244	3,762	1,518	675	748	73	26%	43%	17%	8%	9%	1%
4	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
5	Maywood - Saddlebrook	Line	1,511	3,456	1,945	186	509	323	17%	39%	22%	2%	6%	4%
6	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
7	Bergen - New Milford	Line	4,745	2,970	(1,775)	331	795	464	54%	34%	(20%)	4%	9%	5%
8	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
9	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
10	Monroe - Vineland	Line	1,348	3,121	1,773	24	197	173	15%	36%	20%	0%	2%	2%
11	Bedington - Black Oak	Interface	2,796	2,933	137	323	344	21	32%	33%	1%	4%	4%	0%
12	Easton	Transformer	1,758	3,099	1,341	0	0	0	20%	35%	15%	0%	0%	0%
13	Sayreville - Sayreville	Line	2,869	3,077	208	0	0	0	33%	35%	2%	0%	0%	0%
14	East Bend	Transformer	5,082	2,808	(2,274)	0	0	0	58%	32%	(26%)	0%	0%	0%
15	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
16	Michigan City - Laporte	Flowgate	3,111	1,879	(1,232)	0	0	0	36%	21%	(14%)	0%	0%	0%
17	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
18	Burnham - Munster	Flowgate	341	1,748	1,407	0	0	0	4%	20%	16%	0%	0%	0%
19	Miami Fort - Willey	Line	79	1,585	1,506	32	112	80	1%	18%	17%	0%	1%	1%
20	Cherry Valley	Transformer	2,762	789	(1,973)	324	885	561	32%	9%	(23%)	4%	10%	6%
21	49 Street - Hoboken	Line	394	1,643	1,249	0	0	0	4%	19%	14%	0%	0%	0%
22	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)
23	Braidwood - East Frankfort	Line	1,245	1,449	204	25	58	33	14%	16%	2%	0%	1%	0%
24	Elwood - Elwood	Other	2,160	1,464	(696)	0	0	0	25%	17%	(8%)	0%	0%	0%
25	Bergen - Leonia	Line	2,128	1,456	(672)	0	0	0	24%	17%	(8%)	0%	0%	0%

Source: Monitoring Analytics (2016b), page 429: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

Table 5-7. PJM top 25 constraints with largest year-to-year change in occurrence 2014-2015

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Miami Fort	Transformer	8,820	815	(8,005)	23	3	(20)	101%	9%	(91%)	0%	0%	(0%)
2	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
3	Clinch River	Transformer	6,618	478	(6,140)	0	0	0	76%	5%	(70%)	0%	0%	0%
4	Kendall Co. Energy Ctr.	Transformer	5,488	121	(5,367)	0	0	0	63%	1%	(61%)	0%	0%	0%
5	Monticello - East Winamac	Flowgate	3,511	0	(3,511)	1,440	0	(1,440)	40%	0%	(40%)	16%	0%	(16%)
6	AP South	Interface	5,090	1,285	(3,805)	981	42	(939)	58%	15%	(43%)	11%	0%	(11%)
7	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
8	Huntington Junction - Huntington	Line	4,508	26	(4,482)	0	0	0	51%	0%	(51%)	0%	0%	0%
9	Burlington - Croydon	Line	4,971	880	(4,091)	544	214	(330)	57%	10%	(47%)	6%	2%	(4%)
10	Wolf Creek	Transformer	5,102	710	(4,392)	131	171	40	58%	8%	(50%)	1%	2%	0%
11	Sunbury	Transformer	4,344	29	(4,315)	0	0	0	50%	0%	(49%)	0%	0%	0%
12	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
13	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
14	Nelson - Cordova	Line	4,107	414	(3,693)	279	69	(210)	47%	5%	(42%)	3%	1%	(2%)
15	Sporn	Transformer	3,560	36	(3,524)	0	0	0	41%	0%	(40%)	0%	0%	0%
16	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
17	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
18	Mardela - Vienna	Line	4,627	1,365	(3,262)	76	86	10	53%	16%	(37%)	1%	1%	0%
19	Fort Robinson - Wolf Hills	Line	3,185	0	(3,185)	0	0	0	36%	0%	(36%)	0%	0%	0%
20	Keeney	Transformer	3,099	9	(3,090)	58	0	(58)	35%	0%	(35%)	1%	0%	(1%)
21	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
22	Gould Street - Westport	Line	3,867	789	(3,078)	0	23	23	44%	9%	(35%)	0%	0%	0%
23	Beckjord	Transformer	3,040	145	(2,895)	0	0	0	35%	2%	(33%)	0%	0%	0%
24	Benton Harbor - Palisades	Flowgate	3,025	283	(2,742)	137	0	(137)	35%	3%	(31%)	2%	0%	(2%)
25	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)

Source: Monitoring Analytics (2016b), p. 429: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

Table 5-8. PJM top 25 constraints affecting PJM congestions costs (by facility), 2015

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2015
1	Conastone - Northwest	Line	BGE	$100.9	($2.4)	$1.6	$105.0	($1.6)	($8.1)	($2.7)	$3.8	$108.8	7.9%
2	Bagley - Graceton	Line	BGE	$99.5	$5.6	$5.0	$98.9	($0.2)	($12.4)	($3.2)	$9.0	$107.9	7.8%
3	5004/5005 Interface	Interface	500	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	6.4%
4	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	6.3%
5	Cherry Valley	Flowgate	MISO	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	5.7%
6	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	4.1%
7	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	3.8%
8	Joshua Falls	Transformer	AEP	$9.7	($35.9)	($4.7)	$40.9	$0.7	($0.1)	$2.3	$3.1	$44.0	3.2%
9	Bergen - New Milford	Line	PSEG	$25.2	$18.4	$17.9	$24.7	($7.6)	$9.3	($51.2)	($68.1)	($43.5)	(3.1%)
10	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	2.9%
11	Maywood - Saddlebrook	Line	PSEG	$8.9	$3.9	$7.5	$12.5	($4.7)	$9.0	($22.2)	($36.0)	($23.4)	(1.7%)
12	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	1.6%
13	Easton	Transformer	DPL	$29.0	$6.6	($0.5)	$21.9	$0.0	$0.0	$0.0	$0.0	$21.9	1.6%
14	Glenarm - Windy Edge	Line	BGE	$3.3	($13.0)	$1.0	$17.3	$1.9	($1.9)	($0.7)	$3.2	$20.5	1.5%
15	Oak Grove - Galesburg	Flowgate	MISO	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	1.4%
16	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	1.4%
17	East Danville - Banister	Line	AEP	$8.1	($7.6)	$2.0	$17.7	$0.5	($1.5)	($0.6)	$1.4	$19.1	1.4%
18	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($3.0)	$2.1	($13.7)	($18.8)	($18.8)	(1.4%)
19	BCPEP	Interface	Pepco	$15.3	($3.0)	$0.1	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1.3%
20	Braidwood - East Frankfort	Line	ComEd	($2.3)	($21.0)	$0.6	$19.4	$0.3	$0.4	($1.2)	($1.3)	$18.1	1.3%
21	Valley	Transformer	Dominion	$17.4	($0.2)	$0.0	$17.7	$0.0	$0.0	$0.0	$0.0	$17.7	1.3%
22	Cloverdale	Transformer	AEP	$6.6	($9.8)	($1.4)	$15.0	$0.0	$0.0	$0.0	$0.0	$15.0	1.1%
23	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.0%
24	Miami Fort - Willey	Line	DEOK	($0.8)	($12.4)	$1.2	$12.8	$1.2	$0.7	($0.3)	$0.2	$13.0	0.9%
25	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	0.9%

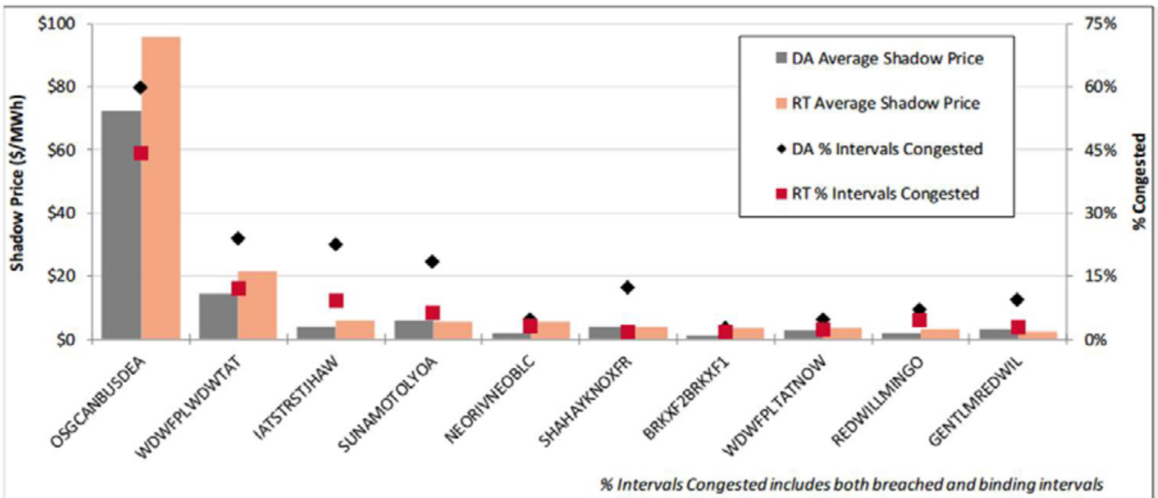
Source: Monitoring Analytics (2016b), p. 430: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

5.4.7. Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) internal market monitor provides information about constraints in its annual State of the Market report.[43] Table 5-9 shows principal congested flowgates by area. The criterion used to identify top constraints is shadow price.

The footprint for SPP, as an RTO, expanded in October 2015 to include WAPA/Basin IS (see Figure 5-4). Future editions of this report will reflect these changes following updates to the underlying data used to develop this report.

Table 5-9. SPP congestion by shadow price, 2014



Flowgate Name	Region	Flowgate Location
OSGCANBUSDEA	Texas Panhandle	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230) [SPS]
WDWFPLWDWTAT	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward EHV-Tatonga (345) [OGE]
IATSTRSTJHAW*	KC-Omaha Corridor	Iatan-Stranger Creek (345) ftlo St. Joe-Hawthorn (345) [KCPL-WR-GMOC]
SUNAMOTOLYOA	Texas Panhandle	Sundown-Amoco (230) ftlo Tolk-Yoakum (230) [SPS]
NEORIVNEOBLC	SE Kansas	Neosho-Riverton (161) [WR-EDE] ftlo Neosho-Blackberry (345) [WR-AECI]
SHAHAYKNOXFR	Central Kansas	South Hays - Hays (115) ftlo Knoll Xfmr (230/115) [MIDW]
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 1 (345/161) [AECI] ftlo Brookline Xfmr 2 (345/161) [SPRM]
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward EHV-Northwest (345) [OGE]
REDWILLMINGO*	West SPP N-S Corridor	Red Willow [NPPD] - Mingo [SECI] (345)
GENTLMREDWIL*	West SPP N-S Corridor	Gentleman-Red Willow (345) [NPPD]

** Reciprocally Coordinated Flowgate with MISO*

Source: SPP (2015), p. 97: *http://www.spp.org/documents/29399/2014%20state%20of%20the%20market%20 report.pdf*

[43] For the most recent version of this report, see https://www.spp.org/markets-operations/market-monitoring/.

6. The Economic Cost of Congestion

6.1. Introduction

There is a close relationship between transmission utilization, constraints, and congestion. Congestion is defined as occurring when and where transmission constraints limit the ability of system users to transfer power in the amounts they desire.

Electricity markets administered by RTO/ISOs manage congestion through locational prices in day-ahead and real-time electricity markets.[44] Operators of these markets accept offers to sell energy from generators, bid to buy energy from loads (mainly load serving entities), and clear the market by matching the most economically efficient offers and bids while still respecting operating constraints of the system. This process produces separate prices for each connectivity point, or node, in the system—called locational prices.[45]

Locational prices consist of an energy component, a loss component, and a congestion component. The *energy* component reflects the marginal cost of providing energy from a designated reference node (either an actual physical node or a composite) and is the same at all locations. The *loss* component is the cost of marginal real losses between the pricing node and the reference node. The *congestion* component is the additional cost of delivering power to the pricing node; this component is non-zero if, in order to deliver the power, generators must be re-dispatched away from the lowest cost dispatch in order to respect constraints in the transmission system.[46, 47]

[44] See EISPC (2012): http://www.naruc.org/grants/Documents/EISPC%20Market%20Structures%20 Whitepaper_6_15_12.pdf .

[45] In contrast to such financial markets, operators in non-RTO regions generally operate physical transmission markets conveying the right to transmission customers taking long-term firm service to transfer physical power among locations in accordance with such firm commitments. Consistent with the provision of these physical rights to firm customers, the transmission systems for non-RTOs are generally planned, expanded, and operated with the aim that those long-term firm service commitments will be served without congestion or constraint. Since a primary objective of transmission planning and expansion in non-RTO markets is to allow firm transmission customers to receive service without congestion, congestion cost concepts, in the sense that they are used and applied in RTO regions, cannot be calculated for non-RTO regions.

[46] There is a large literature on the theory of locational pricing. See, *e.g.*, Schweppe, et al. (1988), at http://link.springer.com/book/10.1007%2F978-1-4613-1683-1; and Stoft, S. (2002), at http://www.wiley.com/WileyCDA/WileyTitle/productCd-0471150401,miniSiteCd-IEEE2.html.

[47] RTO/ISO markets also feature congestion hedging mechanisms, which are called financial transmission rights (PJM, ISO-NE, MISO), transmission congestion contracts (NYISO), transmission congestion rights (SPP), or congestion revenue rights (ERCOT, CAISO). While the specific rules differ in different regions, these mechanisms are intended primarily to return congestion to the loads that have already paid for the transmission system. In operation, a transmission or congestion right held between two specific points for a specific magnitude entitles the holder to the difference in day-ahead congestion components between those two points, times the magnitude of the right held. Thus, these rights are also important financial tools that help participants manage risk in these markets. Nevertheless, data or information about them does not, by themselves, provide information about the magnitude or value of congestion in the system. It is, however, possible that analyzing transmission or congestion rights purchases and payments could provide information on where market participants are anticipating congestion, which may be a topic to explore in future iterations of this report.

This report presents information on the economic cost of congestion developed by individual market operators.[48] It is important to recognize that practices for measuring the economic cost of congestion are specific to each market. Hence, it is inappropriate to compare reported costs among markets without understanding and taking these differing practices into account. We also report comments on these costs offered by the monitors for each market.

While this report focuses on aggregate measures of economic congestion calculated and produced in other reports, a wealth of granular information is publicly available from each RTO/ISO. Prices at regional and market hubs are also available, and the differences in these prices can indicate congestion or barriers (which can be physical, operational, or institutional) that prevent electricity from moving freely between regions.

6.2. California ISO (CAISO)

CAISO runs day-ahead and real-time electricity markets with nodal pricing for generators and zonal pricing for loads. There are four load zones, or load aggregation points (LAPs), which correspond to the service territories of Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Valley Electric Association.[49]

Nodal prices are made up of three components: the marginal cost of energy, the marginal cost of congestion (relative to the reference bus[50]), and the marginal cost of losses (relative to the reference bus).[51] Zonal prices are a combination of load-weighted nodal prices within a zone. Congestion revenue, which is collected by CAISO through the congestion component of the locational price, is based on day-ahead and real-time nodal payments (for generators) and zonal payments (for loads).

Factors specific to CAISO that affect the congestion cost or value calculation include:

- Use of unscheduled flow mitigation to manage some congestion prior to the operation of the day-ahead market. A major market redesign was also

[48] At this time, there is no on-going national source of information on the economic costs of congestion. In 2010 and 2011, the ISO/RTO Council prepared annual reports on market metrics for FERC that contained common information, for the period 2005-2010, on the economic cost of congestion and the extent to which market participants are able to hedge those costs. In August 2014, FERC issued a Staff Report that summarized the ISO/RTO metrics information, reported on metrics filed by five utilities located outside of ISO/RTO regions, and recommended a set of 30 'Common Metrics' for future reporting. FERC concurrently issued a notice seeking comments on the staff recommendation to update the same metrics data through 2014. FERC issued a final Information Collection Statement in 2015 (see http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201409-1902-008). Respondents submitted information in Docket No. AD14-15 between October 2015 and February 2016, but the Commission has not yet released an analysis of those responses.

[49] Valley Electric Association, the first out-of-state utility to join CAISO, became a participating transmission owner on January 3, 2013. See https://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/ValleyElectricAssociation.aspx.

[50] The reference bus in CAISO is a disaggregated one.

[51] See CAISO (2013): http://www.caiso.com/Documents/AppendixC_LocationalMarginalPrice_Jul1_2013.pdf.

implemented in 2009 that instituted nodal pricing. Prior to 2009 the market cleared for large zones, and congestion was managed outside of the financial market.

- Bilateral trades pay congestion price, although the allocation between seller and buyer depends on the production/delivery locations specified in the contract.[52]
- Real-time scheduling includes transmission constraint relaxation—in 2013 the value of the constraint was decreased from $5,000 to $1,500.

Table 6-1 reports total congestion costs for 2006-2014. Figure 6-1 presents import congestion charges on major interties for 2013-2015.

Table 6-1. CAISO congestion costs, 2006-2014 ($M)

	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAISO: pre-MRTU	263	181	350						
CAISO: MRTU, Day Ahead Congestion Cost + Real Time Congestion Costs				128	110	219	534	450	483

Note: CAISO does not make total congestion costs publicly available. This table (above) shows the most recent congestion cost information as obtained by the Department.

Source of data: U.S. Department of Energy (DOE) (2014), p. 39: http://www.energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf

[52] See CAISO (2007): https://www.caiso.com/Documents/AttachmentC-Seller%E2%80%99sChoiceContractsunderNodalVirtualBidding.pdf.

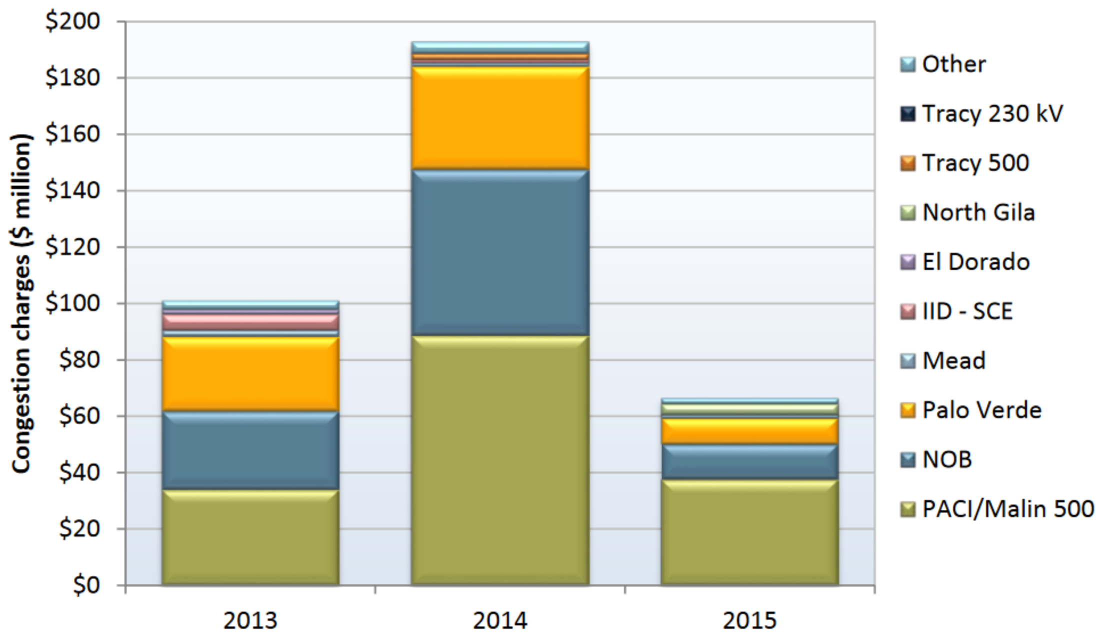


Figure 6-1. CAISO import congestion charges on major interties, 2013-2015

Source: CAISO (2016), page 167: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

In its *2015 Annual Report on Market Issues & Performance*, CAISO's department of Market Monitoring reports the following findings on congestion:

- *Congestion on transmission constraints within the ISO system was low and had a limited impact on average overall prices across the system.*
- *The overall impact of congestion increased prices in the PG&E area above the system average by about $0.43/MWh (1.3 percent) in the day-ahead market and $0.86/MWh (2.6 percent) in the 15-minute market. Much of the impact in the PG&E area was related to Path 15 planned maintenance during most of the second quarter.*
- *Congestion decreased average day-ahead prices in the SCE area below the system average by about $0.28/MWh (0.9 percent), and decreased real-time prices by $0.55/MWh (1.8 percent).*
- *Prices in the SDG&E area were impacted the least overall by internal congestion. Average day-ahead prices in this area increased above the system average by about $0.20/MWh (0.6 percent) while real-time congestion decreased prices by about $0.19/MWh (0.6 percent).*
- *The frequency and impact of congestion was lower in 2015 than 2014 on most major inter-ties connecting the ISO with other balancing authority areas, particularly for inter-ties connecting the ISO to the Pacific Northwest and Palo Verde.*
- *Total day-ahead congestion rents fell 50 percent to $230 million in 2015 from $460 million in 2014. This dramatic decrease in day-ahead congestion*

contributed significantly to improvements in a variety of metrics related to congestion revenue rights.

- *Congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2015, ratepayers received about 45 percent of the value of their congestion revenue rights that the ISO auctioned. This represents an average of about $130 million per year less in revenues received by ratepayers than the congestion payments to entities purchasing these rights over the last four years. In 2015 this difference was $45 million.*
- *As indicated in [CAISO's] prior annual reports, entities purchasing congestion revenue rights are primarily financial entities not purchasing these rights as a hedge for any physical load or generation.*[53]

6.3. Electric Reliability Council of Texas (ERCOT)

ERCOT runs day-ahead and real-time markets with nodal pricing for generators and zonal pricing for loads. There are four competitive load zones: North, South, West, and Houston. Generators are paid nodal prices and consumers pay zonal prices, which are a combination of load-weighted nodal prices within a zone. ERCOT launched its nodal market in December 2010. Congestion rent, which is collected by ERCOT through the congestion component of the locational price, is based on day-ahead and real-time nodal (for generators) and zonal (for loads) payments.

Factors specific to ERCOT that affect the congestion cost or value calculation include:

- Conversion from a zonal to a nodal market in 2010.
- Irresolvable constraints—when no feasible generator dispatch can meet demand, nodal prices are set based on predefined rules. ERCOT employs administratively set prices to deal with irresolvable constraints.[54]

Table 6-2. ERCOT reported congestion costs, 2011-2015

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of $)				
		2011	2012	2013	2014	2015
ERCOT Market Monitor	Total Congestion Revenue	407	480	466	708	352

Sources: Developed by DOE from Potomac Economics (2011a), (2012a), (2013b), (2014b), (2015b), and (2016b) available from https://www.potomaceconomics.com/index.php/markets_monitored/ERCOT.

[53] CAISO (2016), p. 163: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf
[54] Potomac Economics (2014b), p. 46: https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

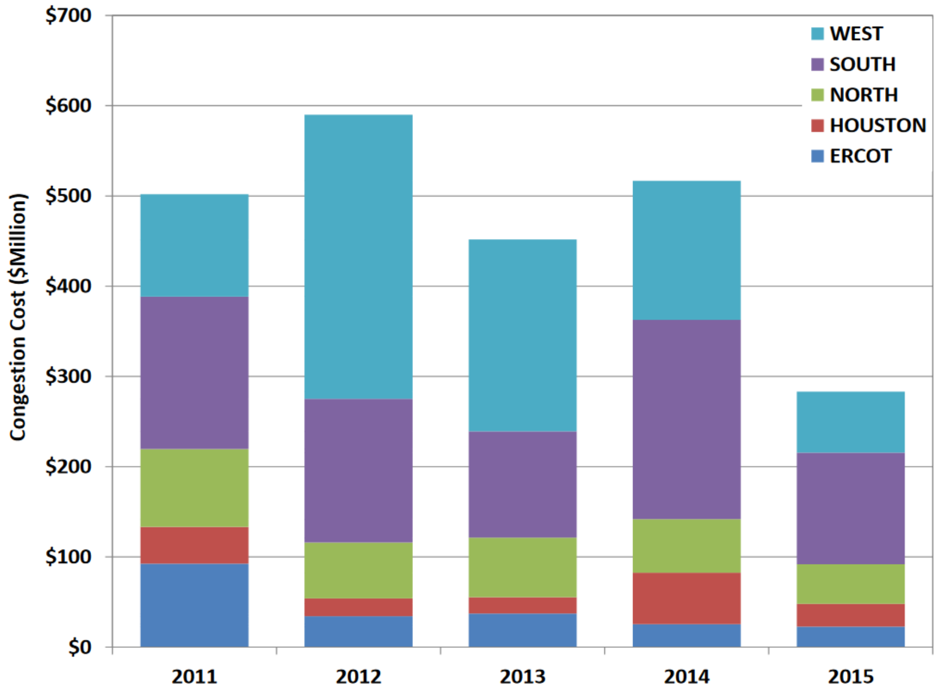


Figure 6-2. ERCOT day-ahead congestion costs by zone, 2011-2015

Source: Potomac Economics (2016b), p. 58: http://potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

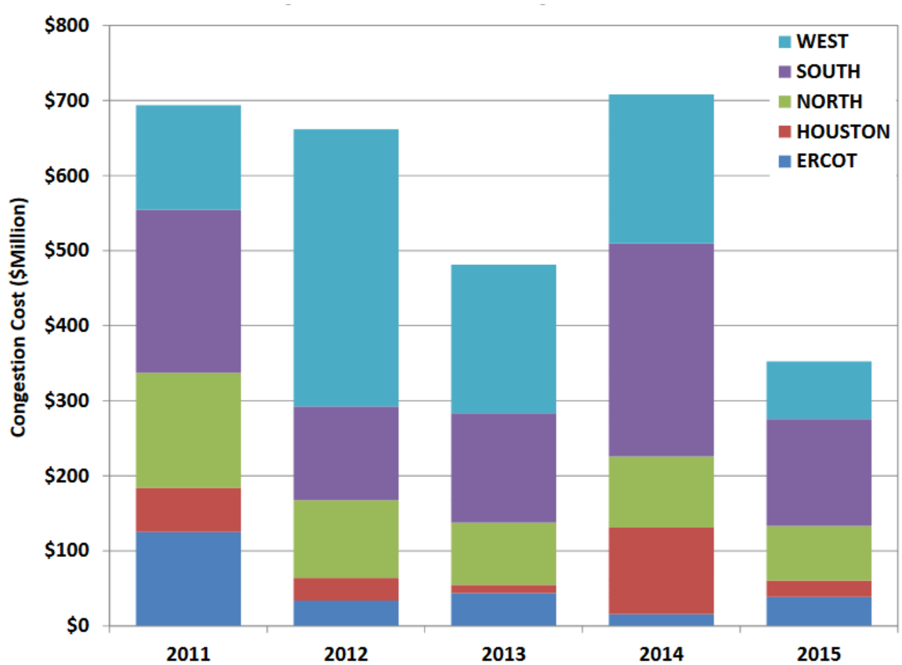


Figure 6-3. ERCOT real-time congestion costs 2011-2015

Source: Potomac Economics (2016b), p. 51: http://potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

In its *2015 State of the Market Report*, ERCOT's market monitor includes the following observations about congestion:

> *The total congestion costs generated by the ERCOT real-time market in 2015 was $352 million, a 50 percent reduction from 2014 values. Although the price impacts of congestion were greatly reduced, the frequency of congestion was similar to 2014. Congestion between the North and Houston zones increased, while congestion within all zones decreased in 2015.*
>
> *…Binding transmission constraints are those for which the dispatch levels of generating resources are actually altered in order to maintain transmission flows at reliable levels. The costs associated with this re-dispatch are the system's congestion costs and are included in nodal prices. Active transmission constraints are those which the dispatch software evaluated, but did not require a re-dispatch of generation.*
>
> *…Constraints were activated much less frequently in 2015, only 63 percent of the time compared to 70 percent of the time in 2014. The reduction in frequency of binding transmission constraints is most notable at the very highest load levels. There was a binding transmission constraint 68 percent of the time when load exceeded 65 GW in 2015. This compares to 88 percent of the time at the same load levels in 2014 and 100 percent of the time in 2013. These reductions in frequency are likely attributed to transmission construction, most notably completion of Competitive Renewable Energy Zone (CREZ) lines reducing congestion in lower load (high wind) periods. Other transmission projects to improve the high load growth areas associated with increased oil and gas development in the Permian Basin and Eagle Ford Shale have likely contributed to reduced congestion frequency during high load periods.*
>
> *…Although the frequency of binding transmission constraints remained similar to 2014 at 44 percent, the congestion costs in 2015 were much lower. The much lower congestion costs were a direct result of the low natural gas prices in 2015 because natural gas resources are generally the resources re-dispatched to manage network flows.*
>
> *…While cross zonal congestion was higher in 2015 versus 2014, all other intra-zonal congestion has decreased. Annual congestion costs in 2015 were the lowest since the start of the nodal market. This is largely due [to] the significant reduction in natural gas prices and the cumulative benefits of large investments in transmission facilities.*[55]

6.4. ISO New England (ISO-NE)

ISO-NE runs day-ahead and real-time electricity markets with nodal pricing for generators and zonal pricing for loads. There are eight load zones: Maine, New Hampshire, Vermont, Connecticut, Rhode Island, and three in Massachusetts. There is also a "trading hub," which contains thirty-two pricing nodes in the geographic center

[55] Potomac Economics (2016b), pp. 49-51: http://potomaceconomics.com/uploads/ercot_documents/2015_ERCOT_State_of_the_Market_Report_-_FINAL_update_6.21_.16_.pdf

for New England. The Hub price is an average of prices at these thirty-two pricing nodes, which has been published by the ISO to disseminate price information that facilitates bilateral contracting. Generators are paid nodal prices and consumers pay zonal prices, which are a combination of load-weighted nodal prices within a zone. Congestion revenue, which is collected by ISO-NE through the congestion component of the locational price, is based on day-ahead and real-time nodal payments (for generators) and zonal payments (for loads).

Factors specific to ISO-NE that affect the congestion cost or value calculation include:

- ISO-NE is not exposed to unscheduled loop flow[56] because it is connected radially to the rest of the Eastern Interconnection.[57] Therefore, unscheduled loop flow does not have a significant impact on systems flows, congestion management, or congestion costs, and ISO-NE does not need to use TLR procedures to manage loop flow.[58]
- All usage of the transmission system, including flows from entities that self-schedule or take part in bilateral transactions, occurs in the day-ahead and real-time markets, and therefore all pay the congestion component price.[59]

Table 6-3 reports congestion costs for 2008-2015. Table 6-4 shows simple average and load-weighted prices for 2015, and Table 6-5 shows ISO-NE simple average hub and load zone prices for 2015.

[56] Parallel flow (or loop flow), is defined as "the difference between scheduled and actual flows on a contract path. Parallel flows are a function of the interconnection's operating configuration, line resistance, and physics." For more information, see http://www.ferc.gov/legal/staff-reports/2014/AD14-15-performance-metrics.pdf.

[57] CAISO et al. (2011), p. 81: http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/ad10-5-00_8-31-11_joint_iso-rto_metrics_report.pdf

[58] TLR procedures alleviate transmission congestion in a way that is not accounted for in locational pricing, resulting in congestion measurements that may under-estimate congestion.

[59] See Likover (2014a): http://www.iso-ne.com/support/training/courses/wem101/17_reserve_market_overview.pdf; and Likover (2014b): http://www.iso-ne.com/static-assets/documents/support/training/courses/wem101/18_reserve_market_settlement.pdf

Table 6-3. ISO-NE reported congestion costs, 2008-2015

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of $)							
		2008	2009	2010	2011	2012	2013	2014	2015
ISO-NE Internal and External Market Monitors†	Total Congestion Revenue	121	25	38	18	30*	46*	n/a	31.2
ISO-NE Internal Market Monitor	Day-Ahead Congestion Revenue	125	27	37	18	29.3	46.2	34.2[60]	30.0

**Only represents value reported by external market monitor; no reporting of total congestion revenue by internal market monitor for 2012 or 2013.*

†Internal and external market monitor reported identical values, except in 2012 when internal market monitor report does not report total congestion revenue.

Sources: Developed by DOE from ISO-NE (2010), (2011), (2012), (2013a), (2014a), (2015a), and (2016), available from http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor; and Potomac Economics (2010a), (2011b), (2012b), (2013a), (2014a), (2015a), and (2016), available from http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor.

Table 6-4. ISO-NE simple average and load-weighted prices, 2015 ($/MWh)

	Simple Average		Load-Weighted Average	
Month	**Day-Ahead**	**Real-Time**	**Day-Ahead**	**Real-Time**
Jan 2015	71.14	65.59	73.43	67.90
Feb 2015	122.77	126.70	125.04	128.39
Mar 2015	64.25	57.93	66.36	59.77
Apr 2015	28.43	25.88	29.34	26.83
May 2015	24.92	26.12	26.14	28.05
Jun 2015	21.16	19.61	22.39	21.21
Jul 2015	26.44	25.40	29.07	28.40
Aug 2015	30.06	35.35	32.12	38.78
Sep 2015	30.82	35.83	33.43	41.34
Oct 2015	37.01	32.62	38.29	33.72
Nov 2015	29.42	26.12	30.40	27.35
Dec 2015	22.42	21.35	23.56	22.72
Annual Average	**41.90**	**41.00**	**44.13**	**43.71**

Source: ISO-NE (2016), p. 58: http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf

[60] For 2014 ISO-NE's Internal market monitor reports that day-ahead congestion revenue was $34.2M (see ISO-NE (2015a), p. 64), its external market monitor reports day-ahead congestion revenues of $32.0M (see Potomac Economics (2015a), p. 2).

Table 6-5. ISO-NE Simple average hub and load zone prices, 2015

	2015	
Zone	**Day-Ahead**	**Real-Time**
Hub	41.90	41.00
Maine	40.81	39.23
New Hampshire	42.11	40.20
Vermont	41.58	40.22
Connecticut	41.23	40.58
Rhode Island	42.20	41.03
SE Mass	42.23	41.21
WC Mass	41.93	40.96
NEMA Boston	42.56	41.58

Source: ISO-NE (2016), p. 58: http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf

In its *2015 Annual Markets Report*, the Internal Market Monitor for ISO-NE provided the following discussion on congestion:

> *Total day-ahead and real-time congestion revenue in 2015 was $31.2 million. Day-ahead congestion revenue is much higher than real-time congestion revenue because approximately 98% of the energy transacted in New England is settled in the day-ahead market. In addition to congestion revenue FTR[61] holders contributed approximately $15.0 million in negative allocations, and were paid approximately $43.6 million in positive allocations. FTRs were fully funded in 2015, with a total congestion revenue fund surplus of $2.6 million at the end of the year. This was an improvement from 2014, when only 96.5% of positive FTR allocations were paid because of a shortfall in the congestion revenue fund. As mentioned previously, congestion is relatively infrequent in New England. Day-ahead and real-time congestion revenue was only approximately 0.53% of the total cost of energy during 2015. This was only slightly higher than the average over the previous five years, 0.46%.*
>
> *…In 2015, the year-end marginal loss revenue fund balance was approximately $48 million. This is the smallest year-end balance in the last five years. One reason for the difference from previous years is a decrease in the total value of the energy purchased during the year. Low fuel prices and mild weather contributed to the decrease in total energy costs. The year-end marginal loss revenue fund balance was 0.8% of the total cost of energy in 2015. This is consistent with 2014, and slightly lower than the prior years.*[62]

[61] Financial Transmission Rights. See http://www.iso-ne.com/markets-operations/markets/financial-transmission-rights.

[62] ISO-NE (2016), pp 90-92: http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf.

6.5. Midcontinent ISO (MISO)

MISO runs electricity markets and operates the transmission grid in fifteen U.S. states and one Canadian province. MISO runs both day-ahead and real-time markets and manages congestion primarily through locational prices in day-ahead and real-time electricity markets. The day-ahead prices are calculated hourly and the real-time prices every five minutes. All entities that buy (or sell) power through the day-ahead and real-time markets pay (or receive) the congestion component of price. MISO settles day-ahead and real-time electricity trades for both generators and loads at nodal prices.[63] Bilateral trades (or financial settlements as they are called in MISO) must pay congestion costs as well.[64] Virtual trades are settled at day-ahead and real-time nodal prices, and therefore also pay the congestion component of the locational price.[65]

Factors specific to MISO that may also affect the congestion cost or value calculation, include:

- Two kinds of transmission usage do not pay congestion costs: unscheduled loop flow, and PJM's usage of the MISO system under the Joint Operating Agreement (JOA).[66]
- PJM Firm Flow Entitlement (FFE) payments reduce the amount of congestion cost reported.[67]
- Holders of "grandfathered" transmission service agreements can choose among options that involve rebates for congestion.[68] Payments to these grandfathered rights are paid from the congestion revenue collected by MISO.[69]
- Some unscheduled loop flow on the MISO transmission system is managed with TLR procedures and will not be reflected in congestion costs.
- The MISO footprint has changed over time, which complicates comparisons of the total amount of economic congestion costs from year to year.
- MISO has used a variety of mechanisms for dealing with unmanageable constraints. Until November 2013, marginal value limits (MVL) were used to limit the cost of redispatch to comply with constraint limits. At that point they were replaced with transmission constraint demand curves (TCDC)—a two-step curve,

[63] Chu (2011), p. 26: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/MP%20200/Market%20Settlements%20Training%20-20Virtual%20and%20Financial%20Schedules.pdf
[64] Chu (2011), p. 143.
[65] Chu (2011), p. 26.
[66] See Potomac Economics (2010b), p. 41 and p. 79: https://www.misoenergy.org/Library/Repository/Report/IMM/2009%20State%20of%20the%20Market%20Report.pdf; and Potomac Economics (2012c), p. A-76: https://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf.
[67] Potomac Economics (2013c), p. 47: https://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf
[68] See Potomac Economics (2012c), p. A-81; Potomac Economics (2013c), p. 47; and Chu (2011), p. 186.
[69] See MISO (2014b), pp. 33-36. Available from https://www.misoenergy.org/Library/BusinessPractices Manuals/Pages/BusinessPracticesManuals.aspx

as opposed to MVLs which were one-step. These procedures impact the congestion component of locational prices used in the calculation of congestion costs, and the constraint shadow price used in the calculation of congestion value.

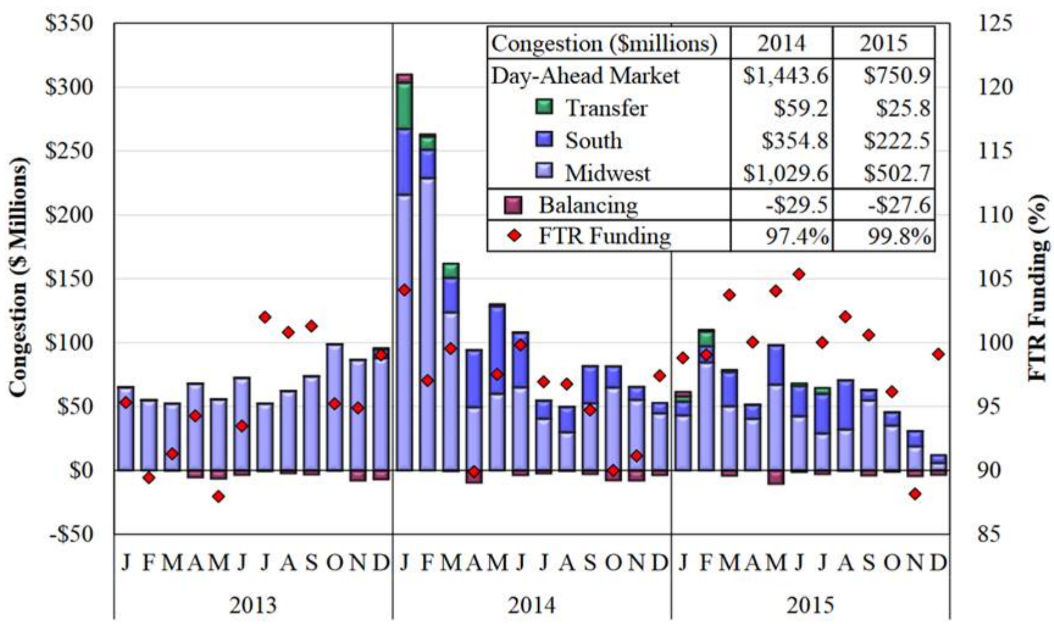
Table 6-6 reports congestion costs and value for 2008-2015, and Figure 6-4 presents day-ahead and balancing congestion and payments to FTRs for 2013-2015. Figure 6-5 presents the value of real-time congestion by coordination region for 2014-2015.

Table 6-6. MISO reported congestion costs and value, 2008-2015*

Congestion Cost Definition	Reported Congestion Cost (millions of $)							
	2008	2009	2010	2011	2012	2013	2014	2015
Day-Ahead Congestion Cost	500	305	498	503	778	842	1,440	751
Real-time Congestion Cost	7	18	-0.3	-16	20	n/a	n/a	n/a
Real-time Congestion Value	938	863	1,080	1,240	1,300	1,590	2,430	1,341

**If there are discrepancies in congestion values for a given year, the value from the most recent report is used.*

Sources: Developed by DOE from Potomac Economics (2011c), (2012c), (2013c), (2014c), (2014d), (2015c), and (2016c) available from http://potomaceconomics.com/index.php/markets_monitored/Midcontinent_iso.



Note: Funding Surplus or Shortfall may be more or less than the difference between day-ahead congestion and obligations to FTR Holders because it includes residual costs and revenues from the FTR auctions, such as the net settlements in the monthly FTR market.

Figure 6-4. MISO day-ahead and balancing congestion and payments to FTRs, 2013-2015

Source: Potomac Economics (2016c), page 50: http://potomaceconomics.com/uploads/midwest_reports/2015_SOM_Main_Body_Final_Rev.pdf

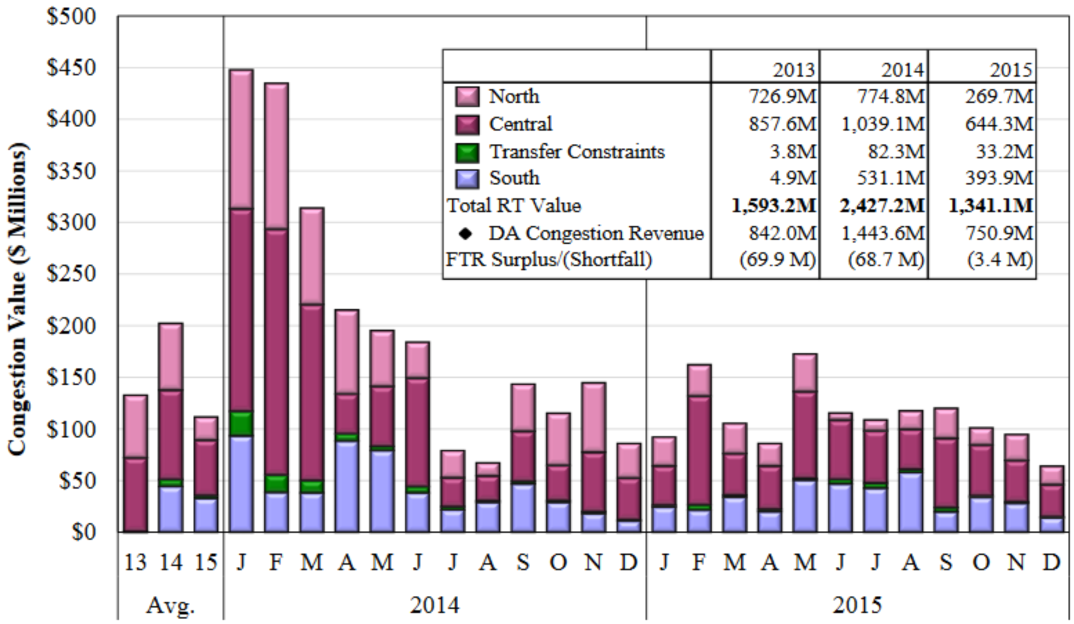


Figure 6-5. Value of real-time congestion and payments to FTRs, 2014-2015

Source: Potomac Economics (2015c), p. 53: https://www.potomaceconomics.com/uploads/midwest_reports/2015_SOM_Main_Body_Final_Rev.pdf

In its *2015 State of the Market Report*, MISO's external market monitor, made the following observations about congestion:

> *Day-ahead congestion costs fell nearly 50 percent to $751 million in 2015. Much of the annual reduction in congestion in the year-over-year comparison occurred during the first quarter (the Polar Vortex occurred in the first quarter of 2014). Day-ahead congestion after March was 30 percent lower than the same period in 2014 because conditions were mild and fuel prices were relatively low. Natural gas prices, in particular, were very low in 2015. This reduces congestion costs because natural gas-fired units are generally the resources that are dispatched to manage the power flows over binding constraints.*
>
> *Of this, 33 percent corresponds to congestion on constraints in MISO South or congestion on the transfer constraints between the regions. MISO South and Midwest regions have diverse load patterns and mixes of generation. Differences in weather, load, generation and transmission availability, and regional gas prices affect the transmission congestion patterns within each region and between the regions over the transfer constraints.*
>
> *…FTR obligations exceeded congestion revenues by $3.4 million, a shortfall of less than one percent and a substantial reduction from last year when they were underfunded by 2.6 percent. While slight shortfalls occurred in a number of months, the only significant shortfall occurred in November at $16 million. Over half of this underfunding was caused by two transmission outages not modeled (or fully modeled) in the annual and monthly auctions.*

> *…As was the case in November 2015, the most significant causes for underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. Underestimated loop flows also account for the some of the shortfalls because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets.*
>
> *…Balancing congestion costs in 2015 remained a small share (3.6 percent) of total congestion costs. …[in 2015] balancing congestion shortfalls totaled nearly $11.5 million (excluding JOA uplift of $16.1 million) in 2015. JOA uplift payments are made to pay for market flows on coordinated market-to-market constraints. MISO had positive balancing congestion surplus of nearly $1 million during the first quarter, but balancing congestion shortfalls of $28.6 million during the last nine months of the year. These levels of balancing congestion costs are relatively low and indicate that MISO is doing a good job of maintaining consistency between the day-ahead and real-time market models.*
>
> *…real-time congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.3 billion in 2015. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and entitlements on the MISO system granted to JOA counterparties, including PJM, SPP, and TVA. For example, PJM does not pay for its power flows on MISO's market-to-market constraints up to PJM's entitlements.*
>
> *…The value of real-time congestion in 2015 was 45 percent lower than in 2014 because lower natural gas prices reduced the cost of redispatching generation to manage congestion. While congestion declined during most of the year, the largest percentage declines were in the first quarter when the 2014 Polar Vortex produced unusually severe congestion.*
>
> *…the FTRs issued through the annual FTR market were substantially unprofitable beginning in summer of 2014 and through the spring of 2015, and again in the winter of 2015/2016. In both periods, this occurred because less congestion occurred than was anticipated by the FTR market. The day-ahead congestion value was $133 million less than the annual auction valuation in the first three seasons of the 2015-2016 auction year (June 2015 through February 2016), most of which occurred in the winter.*[70]

6.6. New York ISO (NYISO)

NYISO administers the wholesale electricity markets and operates high-voltage transmission in the state of New York. NYISO manages congestion primarily through locational prices in day-ahead and real-time electricity markets. Locational prices—

[70] Potomac Economics (2016c), Page 50-54: http://potomaceconomics.com/uploads/midwest_reports/2015_SOM_Main_Body_Final_Rev.pdf

consisting of an energy component,[71] a congestion component, and a loss component—are calculated for each market. The day-ahead prices are hourly, and the real-time prices are calculated every five minutes.

Generators are paid nodal prices and consumers pay zonal prices, which are a combination of load-weighted nodal prices within a zone.[72] "Demand$ congestion" represents the congestion component of load payments. For a load zone, the Demand$ congestion of a constraint is the product of the constraint shadow price, the load zone shift factor on that constraint, and the zonal load. Congestion revenue, which is collected by the ISO through the congestion component of the locational price, is based on day-ahead and real-time nodal payments (for generators) and zonal payments (for loads). Transmission usage by entities making bilateral (outside of the market) trades schedule transmission usage through the day-ahead and/or real-time markets, and therefore also pay the congestion component price.[73]

Factors specific to NYISO that affect the congestion cost or value calculation include:

- Some unscheduled loop flow on the NYISO transmission system is managed with TLR procedures. This practice started in 2009 when high levels of clockwise unscheduled Lake Erie loop flow were exacerbating congestion on the system. The NYISO's ongoing collaboration with its neighboring market areas to improve regional market efficiency through the Broader Regional Markets initiatives was initiated in part to address the impacts produced by the unscheduled Lake Erie Loop Flows as well as to remove barriers to more efficient interregional trading in order to improve the volume of trading. The various components of that regional collaboration have resulted in significant reductions in unscheduled flows during the reporting period.[74]
- In January 2013, NYISO implemented a coordinated congestion management procedure between NYISO and PJM, which was used to manage congestion on selected transmission constraints in the two markets.[75]
- In November 2014 and December 2015 respectively, NYISO activated Coordinated Transaction Scheduling ("CTS") with PJM and ISO-NE which

[71] The energy component is the marginal price for electricity at the reference bus, physically located at the Marcy substation in Marcy, New York. The congestion and loss components at the Marcy bus location are both zero. See Porter (2015): at www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Market_Overview_MT_101/Locational%20Based%20Marginal%20Pricing.pdf

[72] Porter (2015).

[73] See http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp; and Potomac Economics (2012d), p. 24: https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2011_SOM_Report-Final_4-18-12.pdf.

[74] See 2015 ISO/RTO Metrics Report, filed with FERC on 10/30/15, Docket AD14-15, Page 222 at: https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing1071/Attachments/2015_10_30_ISO_RTO_Metrics_Report.docx

[75] Potomac Economics (2013e), p. 55: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/MMU_Quarterly_Reports/2013/NYISO%20Quarterly%20Report%20-%20Quarter%202.pdf

incorporates prices from these neighboring control areas into dispatch to allow Market Participants to schedule transactions based on the price differences between regions.[76]

- A graduated transmission demand curve was implemented in February 2016 to more properly reflect the severity of the transmission shortage.[77]

Table 6-7 presents congestion costs and value for 2008-2015, and Table 6-8 presents Demand$ congestion for 2008-2015. Note that the congestion costs in Table 6-7 represent the net congestion costs collected and paid by NYISO to loads, generators, exports, and imports. Conversely, the Demand$ congestion values in Table 6-8 represent the congestion costs incurred by New York Control Area (NYCA) loads.

Figure 6-6 presents day-ahead and real-time congestion by transmission path for 2014-2015. Figure 6-7 presents congestion revenues and shortfalls for 2014-2015.

Table 6-7. NYISO reported congestion costs and value, 2008-2015

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of $)							
		2008	2009	2010	2011	2012	2013	2014	2015
NYISO Market Monitor	Day-Ahead Congestion Revenue	952	376	419	407	301	664	578	540

Sources: Developed by DOE from Potomac Economics (2009), (2010c), (2011d), (2012d), (2013d), (2014e), (2015e), and (2016e) available from https://www.potomaceconomics.com/index.php/markets_monitored/new_york_iso.

Table 6-8. NYISO reported Demand$ congestion, 2008–2014

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost [millions of $]						
		2008	2009	2010	2011	2012	2013	2014
NYISO Operating Committee	Demand$ Congestion	2,613	977	1,141	1,169	765	1,693	1,367

Sources: Developed by DOE from NYISO (2012): http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/Caris_Final_Reports/2011_CARIS_Final_Report__3-20-12.pdf; NYISO (2013). http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg_iptf/meeting_materials/2013-08-12/2013%20CARIS%20Draft%20Report%20%20rev.pdf, and NYISO (2015): http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf

[76] See NYISO Broader Regional Markets Report, July 13, 2016 at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2016-07-13/BRM_2016-07-13_BIC_FINAL.pdf
[77] See FERC Letter Order issued in Docket ER15-485-001 on March 3, 2016 at: https://nyisoviewer.etariff.biz/ViewerDocLibrary//FercOrders/546.pdf.

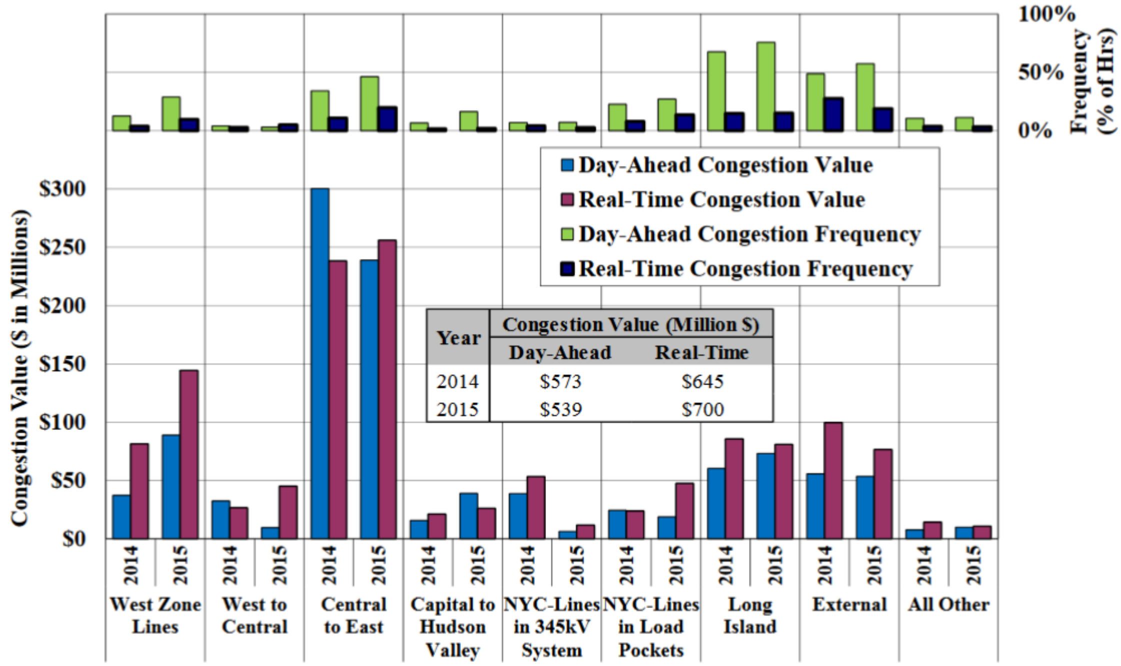


Figure 6-6. NYISO day-ahead and real-time congestion by transmission path, 2014-2015

Source: Potomac Economics (2016e), p. 10: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf

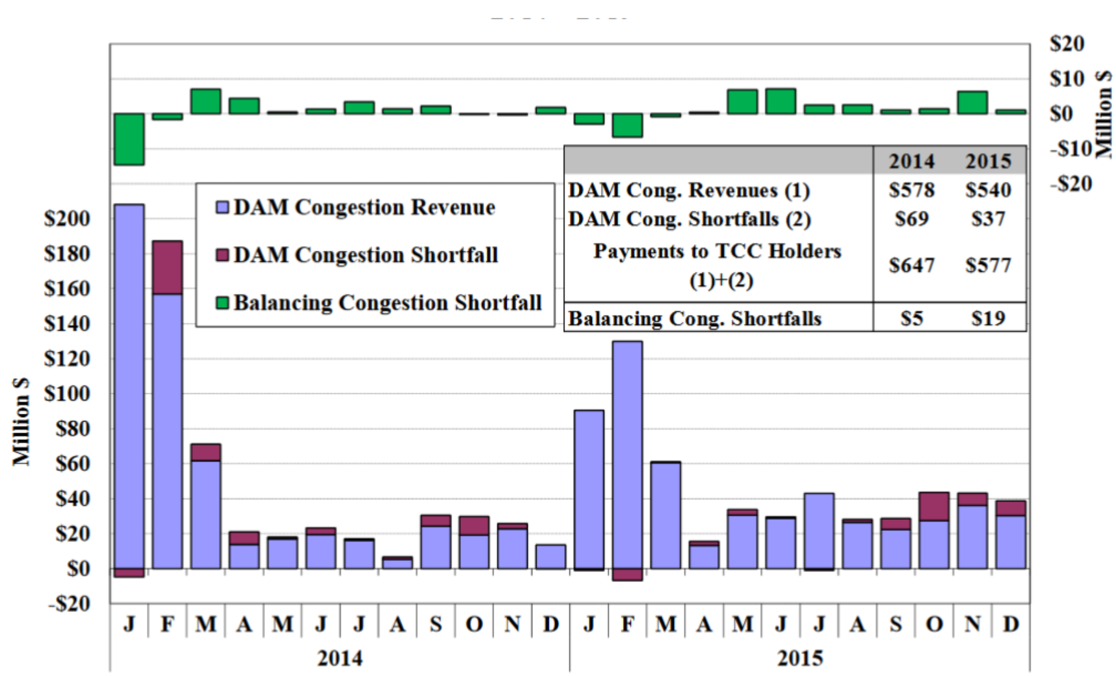


Figure 6-7. NYISO congestion revenues and shortfalls, 2014-2015

Source: Potomac Economics (2016e), p. 40: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf

In its *2015 State of the Market Report*, NYISO's market monitor made the following observations about congestion:

> *…The figure shows that the overall congestion revenues and shortfalls fell from 2014 to 2015.Congestion revenues collected in the day-ahead market fell by 7 percent from 2014 to $540 million in 2015. Similarly, day-ahead and balancing congestion revenue shortfalls fell by 24 percent to a total of $56 million in 2015.*
>
> *…Day-ahead congestion revenues fell 34 percent year-over-year in the first quarter of 2015 primarily because of the 45 to 70 percent reduction in average natural gas prices across the state over the same period. However, day-ahead congestion revenues rose 139 percent year-over-year in the third quarter of 2015 largely because of a 6 percent increase in average load and a 5 percent increase in peak load from 2014.*
>
> *…Higher gas price spreads between Western and Eastern New York generally result in higher levels of west-to-east congestion. Accordingly:*
>
> - *$239 million (or 44 percent) of day-ahead congestion revenues accrued on the Central East interface in 2015, down from $300 million in 2014 when gas price spreads were larger.*
> - *$279 million (or 52 percent) of day-ahead congestion revenues accrued in the first quarter of 2015, when gas price spreads were largest.*
>
> *…Congestion on 230kV lines in the West Zone rose notably from 2014 to 2015, accounting for the second largest share (17 percent) of day-ahead congestion revenues in 2015. Most of this congestion occurred along the Niagara-Packard, Packard-Sawyer, and the Huntley-Sawyer transmission lines, which have become more congested following the mothballing of capacity at the Dunkirk plant and retirement of several PJM units that had previously helped relieve congestion on this corridor. In addition, increased congestion in 2015 was also attributable to higher load levels, higher Ontario imports and reduced PJM imports (both of which increase flows over these lines), and more transmission outages. In 2016, this congestion has been further exacerbated by retirements at the Dunkirk plant in January and at the Huntley plant in March, although transmission upgrades are expected in the second quarter of 2016 that will help reduce this congestion by diverting more flows on to parallel facilities.*
>
> *…Day-ahead congestion shortfalls fell notably from $69 million in 2014 to $37 million in 2015 primarily because of fewer costly transmission outages. Nonetheless, transmission outages were still the primary driver of day-ahead congestion shortfalls in 2015.*[78]

[78] NYISO (2016e), pp. 40-42: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf

6.7. PJM

PJM runs electricity markets and operates transmission across thirteen states and the District of Columbia. PJM manages congestion primarily through locational prices in day-ahead and real-time electricity markets. Locational price—consisting of an energy component, a congestion component, and a loss component—are in both markets for each point (or node) in the system and for twenty transmission zones. The day-ahead prices are hourly and the real-time prices are calculated every five minutes. Generators are paid nodal prices and consumers pay zonal prices, which are a combination of load-weighted nodal prices within a zone. Congestion revenue is collected by PJM through the congestion component of the locational price. It is based on day-ahead and real-time nodal payments (for generators) and zonal payments (for loads).[79]

Factors specific to PJM that may affect the congestion cost or value calculation include:

- The PJM footprint increased in 2011 to include FirstEnergy in northern Ohio, and in 2012 to include Duke Energy in the Cincinnati area.
- PJM uses TLR procedures to manage some congestion on its system, primarily related to imports and exports.

Table 6-9 presents congestion revenue for 2008–2015, and Table 6-10 presents total congestion for 2008-2015. Table 6-11 presents hub real-time, load-weighted average LMP components, and Table 6-12 presents hub day-ahead, load-weighted average LMP components.

Table 6-9. PJM reported congestion revenue, 2008-2015

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost [millions of $]							
		2008	2009	2010	2011	2012	2013	2014	2015
PJM MM	Day-Ahead Congestion Revenue/Cost	2,597	901	1,713	1,245	780	1,011	2,231	1,632
PJM MM	Total Congestion Revenue/Cost	2,052	719	1,423	999	529	677	1,932	1,385

Sources: Developed by DOE from Monitoring Analytics (2012), (2013), (2014b), (2015b), and (2016b) available from http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml

[79] Effective as of June 1, 2015, load pays either nodal price or residual zone price. Load congestion payment will be calculated using congestion component of nodal price or congestion component of residual zone price. See http://www.pjm.com/~/media/training/rzp-stakeholder-training.ashx.

Table 6-10. Total PJM congestion ($M), 2008-2015

Congestion Costs (Millions)				
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%

Source: Monitoring Analytics (2016b), p. 422: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

Table 6-11. Hub real-time, load-weighted average LMP components ($/MWh), 2014-2015

	2014				2015			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$43.51	$53.25	($6.46)	($3.28)	$32.44	$37.65	($3.08)	($2.13)
AEP-DAY Hub	$46.29	$53.41	($5.69)	($1.43)	$33.67	$36.90	($2.24)	($1.00)
ATSI Gen Hub	$47.22	$51.92	($4.47)	($0.23)	$33.04	$35.83	($2.43)	($0.36)
Chicago Gen Hub	$39.52	$50.46	($7.68)	($3.25)	$27.91	$34.41	($4.16)	($2.34)
Chicago Hub	$42.68	$52.35	($7.11)	($2.56)	$30.42	$36.13	($3.75)	($1.95)
Dominion Hub	$64.29	$56.55	$7.84	($0.10)	$41.12	$37.33	$3.63	$0.16
Eastern Hub	$61.27	$52.20	$6.29	$2.78	$40.03	$35.29	$3.03	$1.71
N Illinois Hub	$41.20	$51.02	($6.98)	($2.84)	$29.35	$34.83	($3.44)	($2.04)
New Jersey Hub	$56.21	$51.22	$3.05	$1.94	$36.09	$35.66	($0.62)	$1.06
Ohio Hub	$46.25	$53.32	($5.80)	($1.28)	$32.88	$36.08	($2.32)	($0.87)
West Interface Hub	$50.60	$51.86	($0.42)	($0.83)	$34.67	$36.00	($0.71)	($0.62)
Western Hub	$57.23	$55.07	$2.14	$0.02	$40.83	$38.59	$1.94	$0.30

Source: Monitoring Analytics (2016b), p. 420: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

Table 6-12. Hub day-ahead, load-weighted average LMP components ($/MWh), 2014-2015

	2014				2015			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$42.22	$48.97	($4.25)	($2.50)	$30.66	$33.21	($1.17)	($1.38)
AEP-DAY Hub	$46.64	$52.38	($4.83)	($0.91)	$32.77	$35.73	($2.32)	($0.64)
ATSI Gen Hub	$50.09	$52.42	($2.47)	$0.14	$29.05	$29.71	($0.60)	($0.05)
Chicago Gen Hub	$43.01	$55.95	($10.23)	($2.71)	$26.65	$32.83	($4.46)	($1.72)
Chicago Hub	$42.50	$51.94	($7.85)	($1.58)	$29.09	$34.97	($4.51)	($1.37)
Dominion Hub	$59.15	$54.48	$5.14	($0.47)	$42.57	$37.38	$4.96	$0.24
Eastern Hub	$64.43	$53.17	$8.65	$2.61	$42.19	$36.99	$3.71	$1.49
N Illinois Hub	$42.47	$52.94	($8.44)	($2.02)	$28.72	$34.91	($4.60)	($1.59)
New Jersey Hub	$59.41	$51.99	$5.66	$1.77	$37.29	$36.26	$0.18	$0.85
Ohio Hub	$46.59	$52.22	($4.97)	($0.66)	$32.60	$35.61	($2.46)	($0.55)
West Interface Hub	$49.78	$50.56	($0.05)	($0.72)	$35.10	$35.43	$0.05	($0.38)
Western Hub	$52.65	$50.52	$2.31	($0.18)	$38.34	$36.29	$2.11	($0.06)

Source: Monitoring Analytics (2016b), p. 420: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

In its 2015 *State of the Market Report for PJM*, PJM's market monitor reports the following observations on congestion:

- ***Total Congestion.*** *Total congestion costs decreased by $546.9 million or 28.3 percent, from $1,932.2 million in 2014 to $1,385.3 million in 2015.*
- ***Day-Ahead Congestion.*** *Day-ahead congestion costs decreased by $599.1 million or 26.9 percent, from $2,231.3 million in 2014 to $1,632.1 million in 2015.*
- ***Balancing Congestion.*** *Balancing congestion costs increased by $52.2 million or 17.5 percent, from -$299.1 million in 2014 to -$246.9 million in 2015.*
- ***Real-Time Congestion.*** *Real-time congestion costs decreased by $668.2 million or 30.7 percent, from $2,173.0 million in 2014 to $1,504.9 million in 2015.*
- ***Monthly Congestion.*** *In 2015, 31.0 percent ($429.8 million) of total congestion cost was incurred in February and 14.6 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in 2015 ranged from $58.4 million in August to $429.8 million in February.*
- ***Geographic Differences in CLMP.*** *Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the 5004/5005 Interface, the Bedington - Black Oak Interface, the Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.*
- ***Congestion Frequency.*** *Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2015. The number of congestion event hours in the Day-Ahead Energy Market was about six times higher than the number of congestion event hours in the Real-Time Energy Market.*

  Day-ahead congestion frequency decreased by 49.2 percent from 363,463 congestion event hours [in] 2014 to 184,713 congestion event hours in 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency decreased by 1.0 percent from 28,802 congestion event hours in 2014 to 28,524 congestion event hours in 2015.
- ***Congested Facilities.*** *Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease[d] on flowgate and interface facilities. The Conastone – Northwest Line was the largest contributor to congestion costs in 2015. With $108.8 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015.*
- ***Zonal Congestion.*** *ComEd had the largest total congestion costs among all control zones in 2015. ComEd had $311.3 million in total congestion costs,*

comprised of -$688.9 million in total load congestion payments, -$1,029.4 million in total generation congestion credits and -$29.2 million in explicit congestion costs. The Cherry Valley Flowgate, the Oak Grove - Galesburg Flowgate, the Braidwood - East Frankfort Line, the Bunsonville - Eugene Flowgate and the Rising Flowgate contributed $150.4 million, or 48.3 percent of the total ComEd control zone congestion costs.

- ***Ownership.*** *In 2015, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In 2015, financial entities received $133.1 million in congestion credits, a decrease of $93.6 million or 41.3 percent compared to… 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014. UTCs are in the explicit congestion cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2015, the total explicit cost is -$127.3 million and 122.4 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$155.9 million.*[80]

6.8. Southwest Power Pool (SPP)

Prior to March 2014, SPP operated only an energy imbalance market, in contrast to the other ISO/RTOs, which also operate a day-ahead market. However, in March 2014, SPP began operating a so-called “Day 2” or day-ahead market and information on the operation of this new market will be included in future reports.

SPP reports on two measurements to assess the magnitude of congestion on its system. The first is *congestion revenue*, which is the difference between what is collected from loads and what is paid out to generators. This is the revenue that is used to compensate TCR (Transmission Congestion Rights) holders in the integrated marketplace. The second is *system redispatch payment*, which is the production cost reduction that would occur if increased energy transfer across congested paths were allowed. Information on both of these aspects of congestion is reported in SPP’s annual *State of the Market Report*.[81]

In its *2014 State of the Market Report*, SPP’s internal market monitor made the following observations on congestion:

> *The most limiting element in the Texas Panhandle area and the most frequently congested point in the market was represented by the flowgate Osage-Switch to Canyon East for the loss of Bushland to Deaf Smith. It saw a higher average shadow price and more frequent congestion during the first year of the Integrated Marketplace at $95.86/MWh and 44.4%, respectively, compared to $44.13/MWh and 36.7% for 2013. Transmission system changes in the area and new wind*

[80] Monitoring Analytics (2016b), pp. 46-47: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2.pdf

[81] For the most recent version of this report, see SPP (2015) at http://www.spp.org/documents/29399/2014%20state%20of%20the%20market%20report.pdf.

generation on the loading side of the flowgate contributed to higher shadow prices.

Upgrades to the transmission system in 2013 and 2014 alleviated some bottlenecks in the Texas Panhandle. For example, a new 230 kV line from the Randall County Interchange to the Amarillo South Interchange has eliminated the SPS North-South constraint from the top ten flowgate list. The most limiting transmission element in the southern part of the Texas Panhandle became Sundown to Amoco for the loss of Tolk to Yoakum. The addition of a 345 kV line from the Tuco Interchange to Woodward, OK in September 2014 lowered the average shadow price on OSGCANBUSDEF to about $50/MWh in the RTBM and under $40/MWh in the Day-Ahead Market for December 2014 through February 2015, an almost 50% drop from the 12 month average.

The most significant change to the SPP transmission system in 2014 was the addition of the 345 kV double circuit from Hitchland to Woodward, which went into service in May 2014. It complemented the new Tuco to Woodward line described above. Hitchland to Woodward enables SPP to move more energy from the wind corridor in the west to the load centers in the east. The west-east price differentials in this area created a new bottleneck at Woodward, as indicated by two new top ten flowgates. Woodward to FPL Switch for the loss of Woodward EHV to Tatonga had the second highest shadow price, at $21.33/MWh in the RTBM and $14.45/MWh in the Day-Ahead Market. Further expansion to the 345 kV system in Western Oklahoma may mitigate this congestion.

The Kansas City area has been another long-standing bottleneck in the SPP 345 kV system. The north-south flow from Nebraska and Iowa meets just north of Kansas City in the market's effort to meet Kansas City and Topeka load with lower cost energy. This area was particularly sensitive to loop flows from MISO. The second and third most congested flowgates for 2013 were in this area. Upgrades, especially to the Eastowne transformer, reduced congestion in this area from historic levels. Iatan to Stranger Creek for the loss of St. Joe to Hawthorne remained in the top ten flowgate list. It had an average RTBM shadowprice of $5.86/MWh. A 345 kV line from Iatan to Nashua, which went into service in April 2015, is expected to reduce congestion in this area.[82]

[82] SPP (2015), pp. 98-99: http://www.spp.org/documents/29399/2014%20state%20of%20the%20market%20report.pdf

7. Interregional and Regional Transmission Planning Processes

7.1. Introduction

Transmission planning occurs at a variety of levels ranging from individual utility system studies, to regional and interconnection-wide studies. Robust planning processes and analyses are necessary for building and maintaining a transmission system that supports reliable, economically efficient electricity delivery into the future.

Transmission planning has traditionally been done at a local or regional level in order to anticipate potential reliability issues. Over time, trade of electricity between regions has grown, and transmission investment expenditures have come under greater scrutiny. Both of these trends have encouraged the industry to expand the geographic scope of planning regions and the entities with which they coordinate and collaborate, and to place a higher emphasis on improving broader economic operation of the grid while meeting reliability standards.

To this end, in 2009 DOE issued a series of grants, as part of the American Reinvestment and Recovery Act (ARRA), to support interconnection-wide transmission planning.[83] These grants supported existing entities (or the creation of new entities) in conducting technical analyses to examine transmission expansion under a variety of future scenarios.[84] This report summarizes the current status of these planning processes.

Additionally, in 2011, FERC issued Order No. 1000,[85] which, among other requirements, mandates regional transmission planning and interregional coordination. This report identifies the groups of public utility transmission providers that complied with Order No. 1000. Future reports will summarize aspects of the plans prepared by these entities pursuant to this Order.

7.2. Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative was formed in early 2009 in order to foster an open and collaborative process for conducting technical analyses of transmission planning within the Eastern Interconnection. EIPC was awarded ARRA funding to conduct analyses of transmission requirements under a broad range of alternative future scenarios. The first phase of analysis was conducted during 2010 and

[83] See http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act.
[84] See http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act.
[85] See http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

2011,[86] and included interregional analysis and macroeconomic analyses on eight future scenarios. In 2012, the second phase of analysis was completed to develop a possible future transmission system that would support three of those future scenarios. The second phase of analysis was extended in 2013 to consider the interface between the natural gas delivery system and the electric transmission system.[87] The results of the Gas-Electric System Interface Study provide a comprehensive analysis across the region of the adequacy of the natural gas pipeline delivery system to meet the needs of the gas-fired electric generation system under various conditions over a 10-year horizon. In addition, the study identified constraints on the natural gas pipeline system that may affect the delivery of gas to specific generators following a variety of postulated gas and electric system contingencies.

Beginning in 2013, EIPC undertook a new series of planning studies[88] to develop baseline "roll-up" cases to serve as integrated powerflow models containing the expansion plans for the Eastern Interconnection.[89] Three roll-up cases have now been developed—one for the 2018 summer peak load period, one for the 2023 summer, and a summer and winter powerflow model for the year 2025.

Identifying transmission projects that are likely to be built by 2018 or 2023 (the original study years) or by 2025 (in the most recent study) were key activities in developing the roll-up cases. Projects were evaluated for inclusion in the roll-up based on a variety of factors, including stage of development (conceptual, proposed, planned, committed, or in construction); status of relevant approvals (including planning authority and regional planning process approvals, ISO or RTO approvals); and the presence of any contractual obligations or inclusion in approved capital budgets. A report on the development of each of the roll-up cases is posted on the EIPC website, including a list of all the transmission projects that met these criteria.

[86] See http://www.eipconline.com/Resource_Library.html for reports and more information on the EIPC Phase 1 analysis.
[87] See http://www.eipconline.com/phase-ii-documents.html for reports and information on the EIPC Phase II analysis.
[88] This study was conducted independent of DOE funding.
[89] See http://www.eipconline.com/non-doe-documents.html.

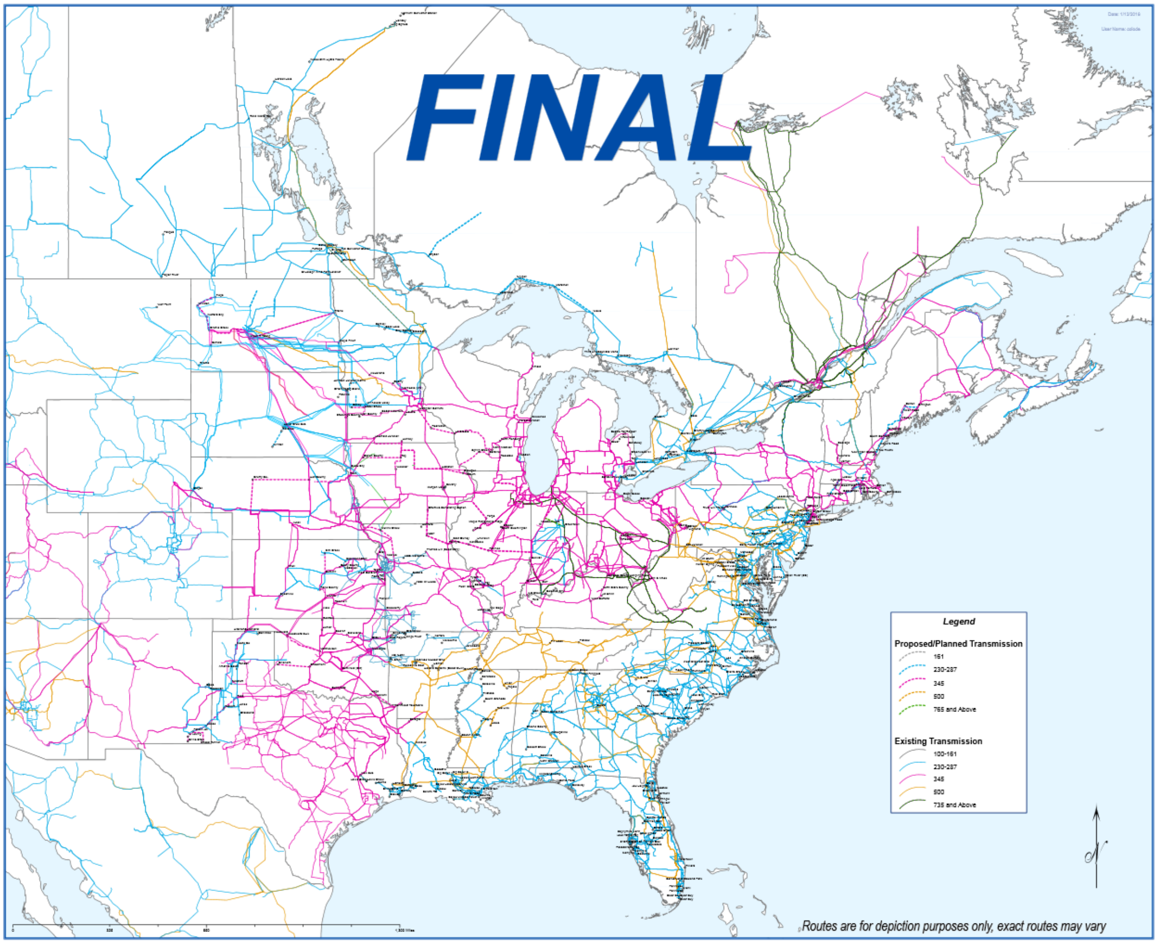


Figure 7-1. EIPC future transmission projects

Source: EIPC (2016): http://nebula.wsimg.com/941ee536512db2319b5be4cfa1445b6f?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

7.3. Western Electricity Coordinating Council (WECC)

The Transmission Expansion Planning Policy Committee (TEPPC), with the assistance of WECC, conducts an interconnection-wide planning activity every two years. This activity consists of developing input assumptions for the planning models; collecting and helping to develop planning scenarios; and running the planning models for 10- and 20-year scenarios.

The Regional Planning Coordination Group (RPCG), which advises WECC and is made up of the regional and sub-regional transmission planning groups in the West, has created a procedure and set of criteria to identify transmission projects that are highly likely to be built in a ten-year timeframe.[90] The list, known as the Common Case Transmission

[90] In the fall of 2013, the Subregional Coordination Group changed its name to the Regional Planning Coordination Group.

Assumptions (CCTA),[91] is used by WECC for its ten-year planning analysis (with a few additional projects added as necessary to ensure a solvable power flow). Criteria for inclusion on the list include factors such as regional significance, whether it is under construction already, and whether a financial commitment has been made for construction.[92] Figure 7-2 lists the CCTA for use in the 2016 plan.

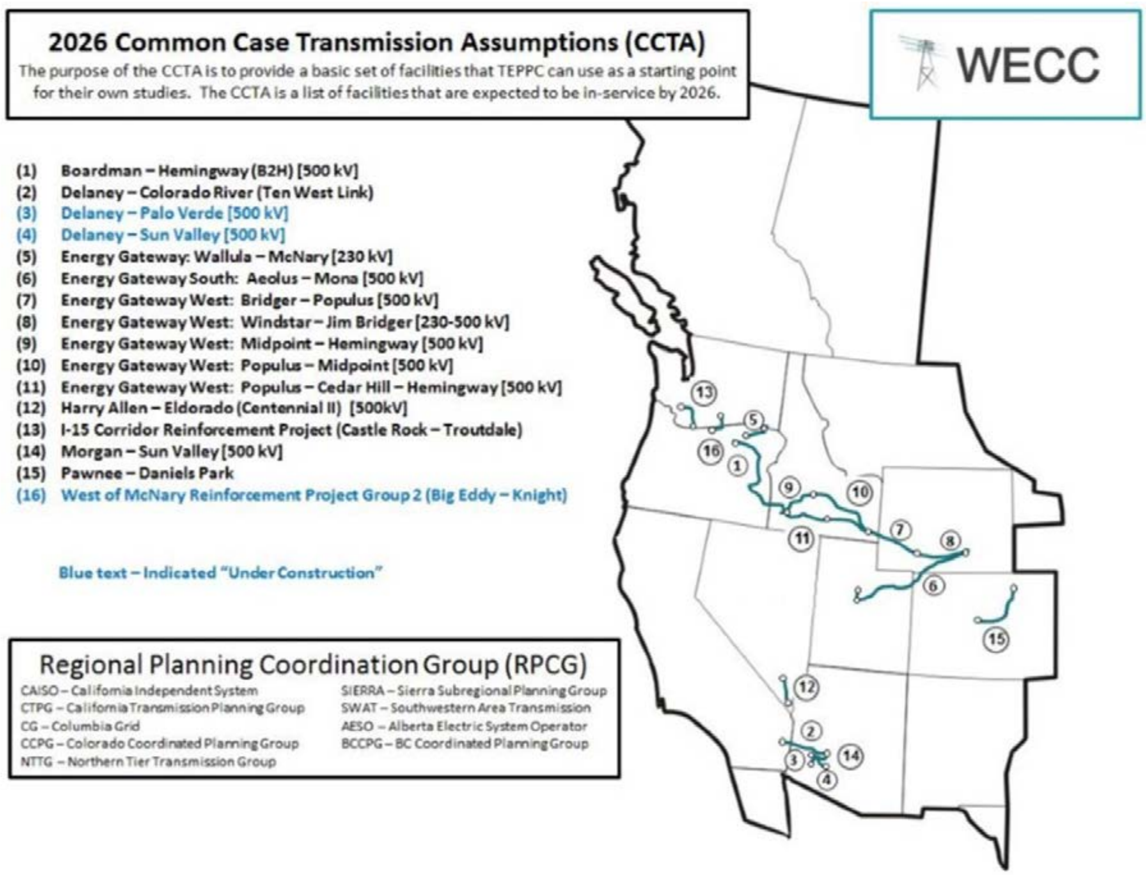


Figure 7-2. WECC 2026 Common Case Transmission Assumptions (CCTA)

Source: WECC (2016), p.iii: https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/RPCG%202026CCTA%20Report%202016%2006%2030.pdf&action=default&DefaultItemOpen=1

[91] See WECC (2014b), at https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx.
[92] WECC (2010b): https://www.wecc.biz/Reliability/100811_SCG_FoundationalTransmissionProjectList_Report.pdf

7.4. Electric Reliability Council of Texas (ERCOT)

ERCOT supervises and exercises comprehensive independent authority of the overall planning of transmission projects for the ERCOT System. Every year ERCOT performs a planning assessment of the transmission system. This assessment is primarily based on three sets of studies:

1. The annual Regional Transmission Plan (RTP) addresses region-wide reliability and economic transmission needs and includes the recommendation of specific planned improvements to meet those needs for the upcoming six years.
2. The Long-Term System Assessment (LTSA), conducted in even-numbered years, uses scenario-analysis techniques to assess the potential needs of the ERCOT System up to fifteen years into the future. The LTSA identifies upgrades that provide benefits across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs in the RTP development. The LTSA does not recommend the construction of specific system upgrades.
3. Stability studies are performed to assess the angular, voltage, and frequency response of the ERCOT System.

In addition, ERCOT also prepares an annual Electric System Constraints and Needs report to identify and analyze existing and potential constraints in the transmission system that pose reliability concerns or may increase costs to the electric power market and, ultimately, to Texas consumers. In the 2015 report,[93] ERCOT indicates that there are $4.7 billion of future transmission improvement projects that are planned to be in service between 2016 and the end of 2021.

Table 7-1 and Figure 7-3 show some of the improvements planned to be in service within the next six years.

[93] See ERCOT (2015): http://www.ercot.com/content/news/presentations/2016/2015ERCOTConstraintsAndNeedsReport.pdf.

Table 7-1. ERCOT planned transmission improvements, 2016-2021

Map Index	Transmission Improvement	In-service Year
1	New Lobo – North Edinburg 345 kV line (Valley Import)	2016
2	New North Edinburg – Loma Alta 345 kV line (Cross Valley)	2016
3	Add Midessa South 345/138 kV transformer	2016
4	Add second Jewett 345/138 kV transformer	2016
5	Add second Jordan 345/138 kV transformer	2016
6	Add second Twin Buttes 345/138 kV transformer	2016
7	Add second Meadow 345/138 kV transformer	2016
8	New Fowlerton 345 kV station with 345/138 kV transformer	2017
9	New Jones Creek 345 kV station with two 345/138 kV transformers	2017
10	Upgrade McDonald Road – Garden City 138/69 kV line	2018
11	Houston Import Project	2018
12	Add second 345 kV circuit in the Panhandle loop	2018
13	Add synchronous condenser in the Panhandle loop	2018
14	Add Zorn – Marion 345 kV transmission line	2019
15	Add second Hicks 345/138 kV transformer	2020
16	Add Salado Switch 345/138 kV transformer	2021

Source: ERCOT (2015), p. 18: http://www.ercot.com/content/news/presentations/2016/2015ERCOT ConstraintsAndNeedsReport.pdf

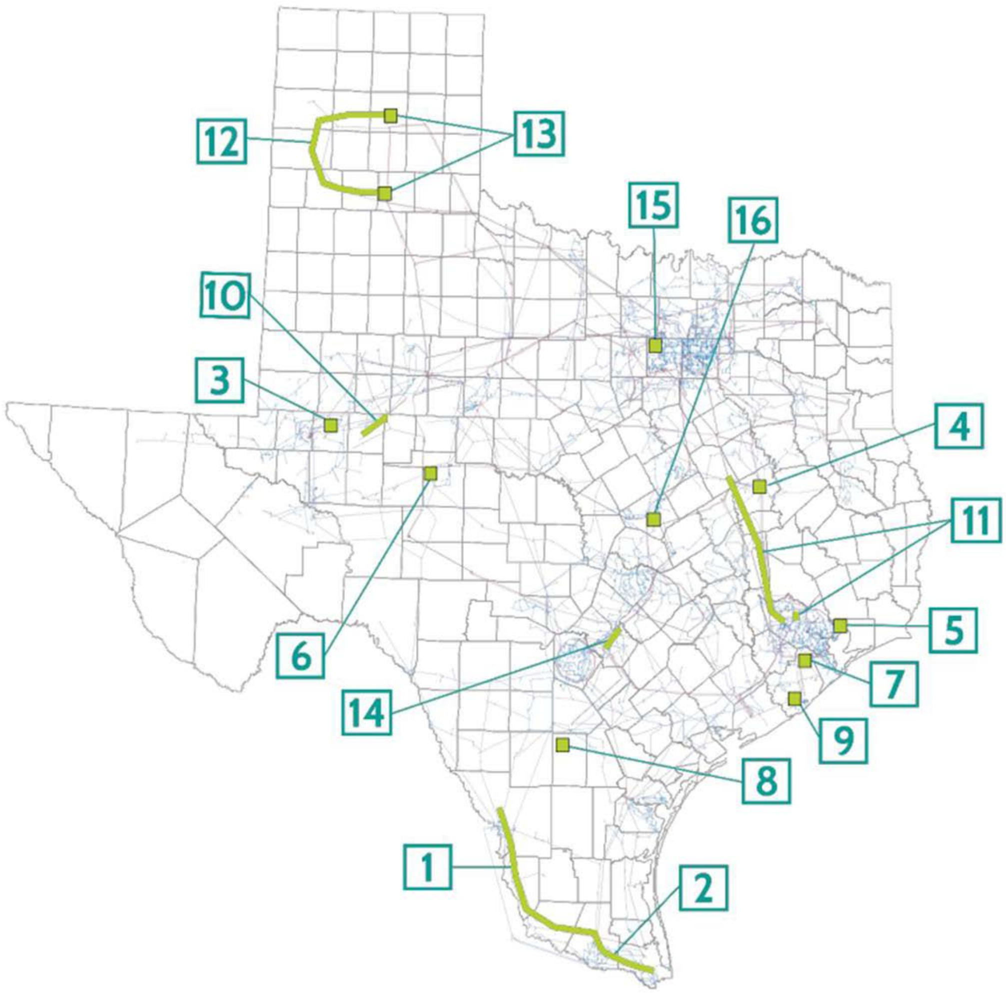


Figure 7-3. Planned transmission improvement projects in the ERCOT system, 2016-2021

Source: ERCOT (2015), p. 19: http://www.ercot.com/content/news/presentations/2016/2015ERCOT ConstraintsAndNeedsReport.pdf

7.5. FERC Order 1000

FERC Order Nos. 890 and 1000 placed new requirements on the public utility transmission providers that conduct transmission planning in each transmission planning region of the United States. FERC Order No. 890[94] (issued in 2007) directed public utility transmission providers to follow nine transmission planning principles:

1. *Coordination:* The transmission provider must meet with all of its transmission customers and interconnected neighbors to develop a transmission plan.

[94] See 118 FERC ¶ 61,119 (2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

2. *Openness:* Planning meetings must be open to all affected parties including, but not limited to, all transmission and interconnection customers, state commissions and other stakeholders.
3. *Transparency:* The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its transmission system plans.
4. *Information Exchange:* Transmission customers are required to submit information on their projected loads and resources, and the transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.
5. *Comparability:* The transmission system plan should meet the specific service requests of transmission customers and otherwise treat similarly-situated customers comparably.
6. *Dispute Resolution:* The transmission providers must develop a dispute resolution process.
7. *Regional Participation:* The transmission provider is required to coordinate with interconnected systems to share system plans and ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and identify system enhancements that could relieve significant and recurring transmission congestion.
8. *Economic Planning Studies:* The transmission provider is required to annually prepare studies identifying "significant and recurring" congestion and to post such studies on OASIS.
9. *Cost Allocation for New Projects:* Planning processes must address cost allocation for new projects.

FERC Order No. 1000[95] (issued in 2011) established new requirements for regional transmission planning and interregional transmission coordination:

1. Public utility transmission providers are required to participate in a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by local, state or federal laws or regulations.
3. Public utility transmission providers in each pair of neighboring transmission planning regions within each interconnection must coordinate to determine if more efficient or cost-effective transmission solutions are available within the pair of regions.

[95] See 136 ferc ¶ 61,051, http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

4. Public utility transmission providers in each transmission planning region must produce a regional transmission plan reflecting solutions that meet the region's needs more efficiently or cost-effectively.
5. Stakeholders and any interested party must have a meaningful opportunity to participate in identifying and evaluating potential solutions to regional transmission needs.

Order No. 1000 also requires each public utility transmission provider to have a method, or set of methods, for allocating the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation. Such cost allocation methods must be consistent with six regional or interregional cost allocation principles, including that the costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.

Order No. 1000 also removes any federal right of first refusal with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to four limitations.

There are twelve regions of public utility transmission providers that together have responsibility for regional transmission planning in the continental United States, excluding Alaska and the portion of Texas served by ERCOT. See Figure 7-4.

In the portions of the country served by ISOs or RTOs, elements of these requirements had already been vested by transmission owners to these entities. Order Nos. 890 and 1000 expanded the transmission planning and cost allocation requirements that ISOs and RTOs must follow.

In the portions of the country served by vertically integrated utilities, few, if any, such regional planning responsibilities had been vested with a planning entity; however, vertically integrated utilities have developed regional transmission plans that involved joint facilities with neighboring utilities. Regions that were formed following Order No. 890 include Florida Reliability Coordinating Council (FRCC); Northern Tier Transmission Group (NTTG); WestConnect; South Carolina Regional Transmission Planning (SCRTP); and Southeastern Regional Transmission Planning (SERTP). A number of these regions did not create new legal entities; instead, such responsibilities remain with the transmission providers who participate in a regional planning process. ColumbiaGrid was formed prior to issuance of Order 890 to provide coordinated regional planning for its participants. Order No. 1000 expanded the transmission planning and cost allocation requirements that public utility transmission providers must follow.

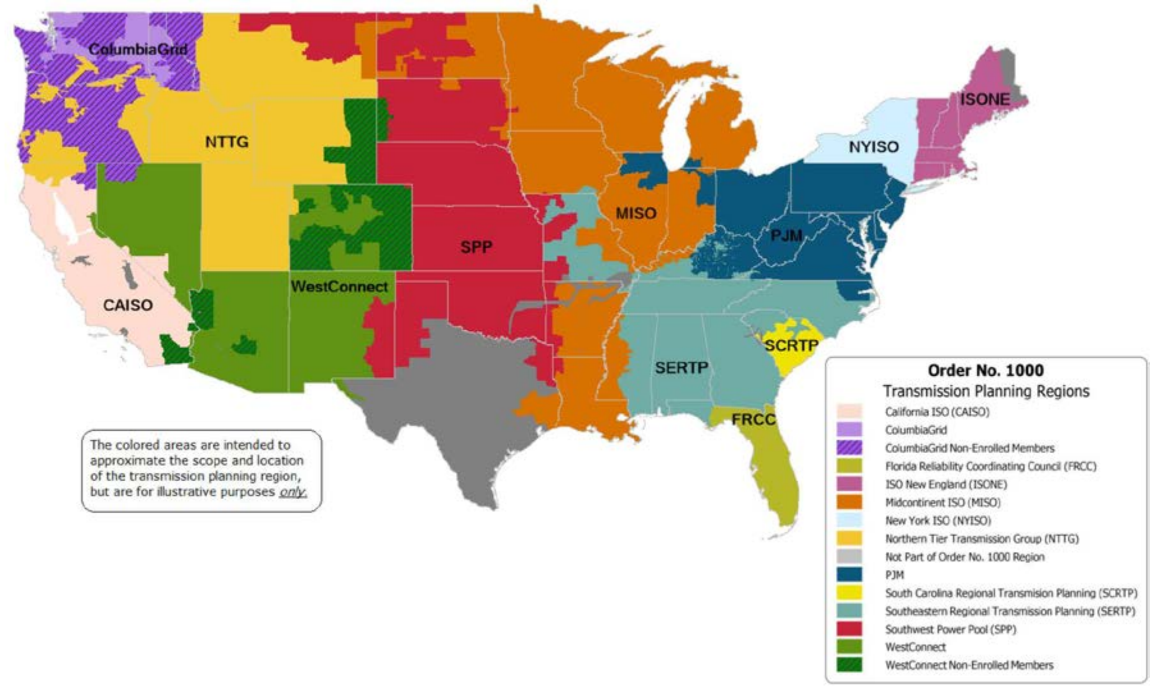


Figure 7-4. FERC Order 1000 Transmission Planning Regions

Source: FERC (2016): http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

FERC's jurisdiction for regional transmission planning applies to all public utility transmission providers. Some transmission planning regions also include non-public utility transmission providers (*e.g.*, ColumbiaGrid, SERTP, WestConnect, and NYISO).[96]

The regional planning processes are evolving in response to final compliance orders by FERC (see Table 7-2). For example, the most recent available documents on regional planning procedures describe processes and analysis activities—the results of which may not be seen for all regions until 2016 or beyond, as regions are in varying stages of implementation. At the same time, the regional transmission plans now available for review are sometimes based on processes and procedures that have since been or may soon be modified.

[96] Within the continental United States, the Electric Reliability Council of Texas (ERCOT) is not subject to FERC's transmission planning jurisdiction.

Table 7-2. Effective dates and regional transmission planning cycles

	FERC Regional Order No. 1000 effective date	Regional Transmission Planning Cycle	FERC Interregional Order No. 1000 effective date
California ISO (CAISO)	October 1, 2013	15-month cycle; New cycle begins every January (cycles overlap for 3 months)	October 1, 2015 (California ISO- ColumbiaGrid- NTTG- WestConnect)
ColumbiaGrid	April 5, 2016	Two-year cycle; Order No. 1000 project proposals are submitted during Jan/Feb of each year and reviewed in the annual system assessment	January 1, 2015 (ColumbiaGrid- California ISO- NTTG- WestConnect)
Florida Reliability Coordinating Council (FRCC)	January 1, 2015	Two-year cycle; New cycle begins January 2017	January 1, 2015 (FRCC- SERTP)
ISO New England (ISO-NE)	May 18, 2015	No set planning cycle – has a process that evaluates transmission needs and transmission projects on an on-going basis	January 1, 2014 (ISONE-NYISO-PJM)
Midcontinent ISO (MISO)	June 1, 2013	18-month cycle; New cycle begins each June (cycles overlap for 6 months)	January 1, 2014 (MISO-PJM); March 30, 2014 (MISO-SPP); January 1, 2015 (MISO-SERTP)
New York ISO (NYISO)	January 1, 2014[97]	Two-year cycle; New cycle begins January 2016	January 1, 2014 (NYISO-ISONE-PJM)
Northern Tier Transmission Group (NTTG)	October 1, 2013	Two-year cycle; New cycle begins January 2016	October 1, 2015 (NTTG- California ISO- ColumbiaGrid- WestConnect)
PJM Interconnection (PJM)	January 1, 2014	Two-year cycle; New cycle begins January 2016	January 1, 2014 (PJM-ISONE-NYISO); (PJM-MISO); January 1, 2015 (PJM-SERTP)[98]
South Carolina Regional	April 19, 2013	Two-year cycle; New cycle begins January 2017	January 1, 2015 (SCRTP- SERTP)

[97] NYISO Regional Compliance proceeding is pending at FERC.

[98] *See PJM Interconnection, L.L.C. & Duquesne Light Co.*, 150 FERC ¶ 61,046 at P 36 (2015) ("We find PJM and SERTP Filing Parties' requested January 1, 2015 effective date for revisions to SERTP Filing Parties' respective OATTs and to Schedule 6 of PJM's Operating Agreement to be reasonable. This date corresponds to the planning cycle subsequent to SERTP Filing Parties' effective date for their regional compliance filings. We also find PJM Transmission Owners requested effective date of January 1, 2014, for Schedule 12-B of the PJM OATT to be reasonable. This effective date is consistent with an earlier Commission order conditionally accepting PJM Transmission Owners' proposed Schedule 12-B, effective January 1, 2014, subject to the outcome of this order.").

	FERC Regional Order No. 1000 effective date	Regional Transmission Planning Cycle	FERC Interregional Order No. 1000 effective date
Transmission Planning (SCRTP)			
Southeastern Regional Transmission Planning (SERTP)	June 1, 2014	One-year cycle; New cycle begins each January	January 1, 2015 (SERTP- MISO); (SERTP-PJM); (SERTP-FRCC); (SERTP-SCRTP); (SERTP-SPP)
Southwest Power Pool (SPP)	March 30, 2014	Three-year cycle; New cycle begins January 2017	March 30, 2014 (SPP-MISO); January 1, 2015 (SPP-SERTP)
WestConnect	January 1, 2015	Two-year cycle; New cycle begins January 2016	October 1, 2015 (WestConnect-California ISO-ColumbiaGrid- NTTG)

Note: As of April, 2016, FERC had accepted effective dates for interregional coordination for all region pairs, but a final and substantive compliance order for one interregional pair (MISO-PJM) remained outstanding.

Source: Developed by DOE from FERC (2016). "Order No. 1000 Compliance Filings & Orders," updated May 14, 2015: http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp

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