Annual U.S. Transmission Data Review

August 2015

U.S. DEPARTMENT OF ENERGY

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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
CDM	common or dependent mode
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
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
LTRA	Long-Term Reliability Assessment
LTSA	Long-Term System Assessment
MISO	Midcontinent Independent System Operator
MM	Market Monitor
MVL	Marginal Value Limits
NERC	North American Electric Reliability Corporation
NPCP	Net Commitment-Period Compensation
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
RTO	Regional Transmission Organization

SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
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 as a whole, as well of the individual components of the system; 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 responsibilities 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

[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 North American Electric Reliability Corporation (NERC) (2014c). *Bulk Electric System Definition Reference Document, Version 2.* April 2014. 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.

Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission (FERC). 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*.

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).[3]

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.

2.2. Existing Transmission

Information regarding existing transmission is taken from the NERC Transmission Availability Data System (TADS). TADS contains data collected annually on existing equipment and on outages experienced by equipment.[4] Data for TADS are provided by transmission owners[5] and are reviewed by regional entities and NERC. The data are collected by voltage level by the regional entities (see Figure 2-1). At present this information is only available on existing transmission infrastructure at 200 kV or above.[6] (See Figure 2-2.)

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

[4] See NERC (2015b). "Transmission Availability Data System (TADS)." 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.

[5] 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.

[6] In March 2014, FERC approved the new 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 of BES became effective July 1, 2014. In future years, TADS will begin collecting information on system elements in the new BES definition (e.g., down to 100 kV).

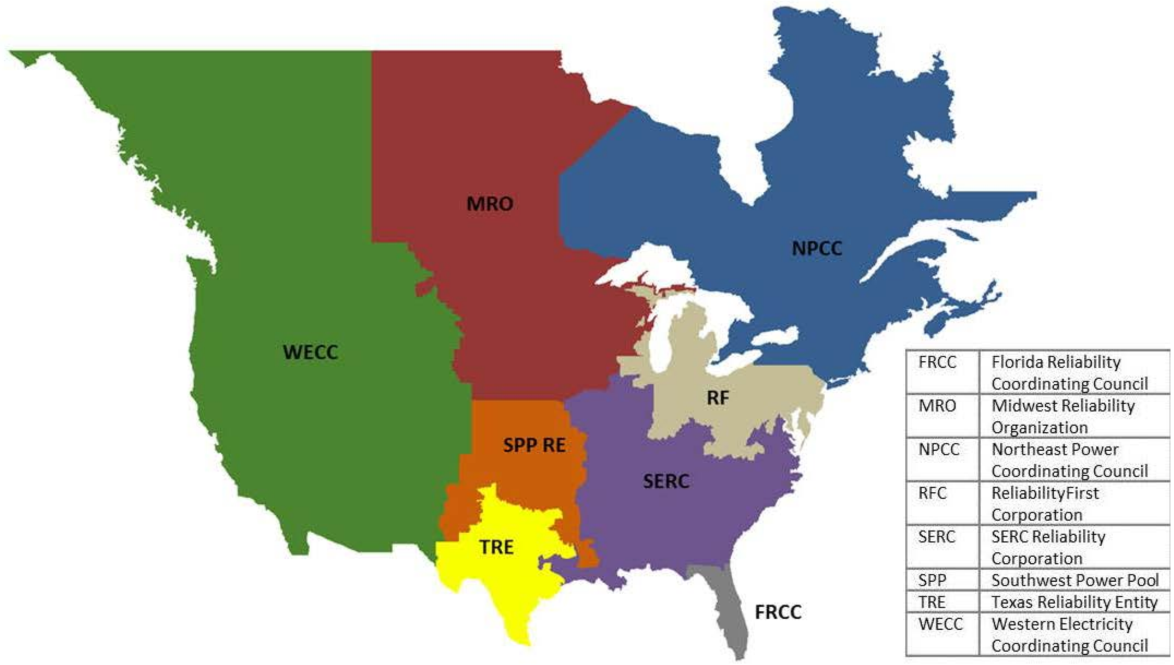
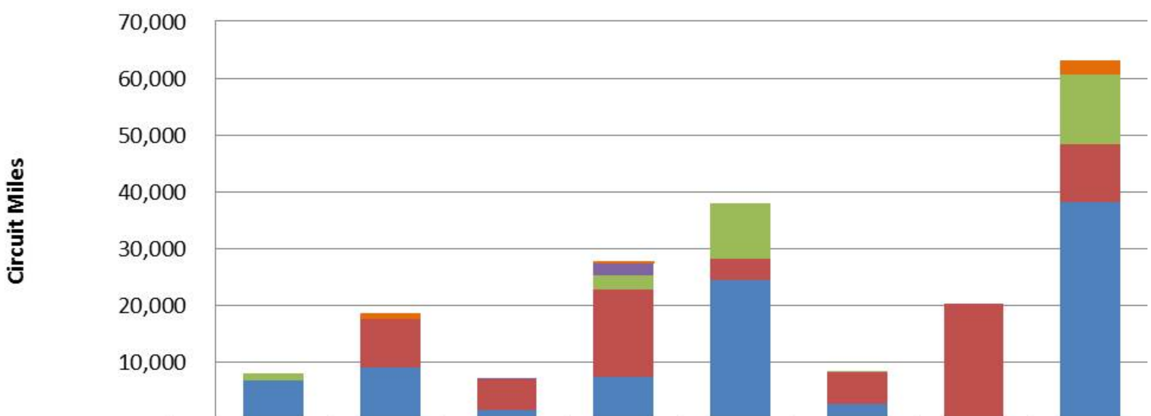


Figure 2-1. NERC Regions - organization of TADS reporting

Source: NERC (2015b). http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx



	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
Total DC	-	872	-	66	-	-	-	2,137
600 kV - 799 kV	-	-	190	2,201	-	-	-	-
400-599 kV	1,201	149	-	2,611	9,785	94	-	12,503
300-399 kV	-	8,458	5,507	15,344	3,921	5,701	20,396	10,244
200-299 kV	6,798	9,064	1,538	7,387	24,370	2,616	-	38,084

Figure 2-2. Existing transmission as of last day of 2014

Source: Developed by DOE from NERC (2015b). http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx

2.3. Transmission Under Construction, Planned, and Conceptual

Information on transmission under construction, planned, and under conceptual development is taken from the NERC Electricity Supply & Demand (ES&D) database.[7] The ES&D database contains information on existing and planned transmission infrastructure at 100 kV and above. The information is used by NERC to develop forward-looking reliability assessments, including its annual *Long Term Reliability Assessment* (LTRA).[8, 9] The data are collected from the assessment areas shown in Figure 2-3. 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).

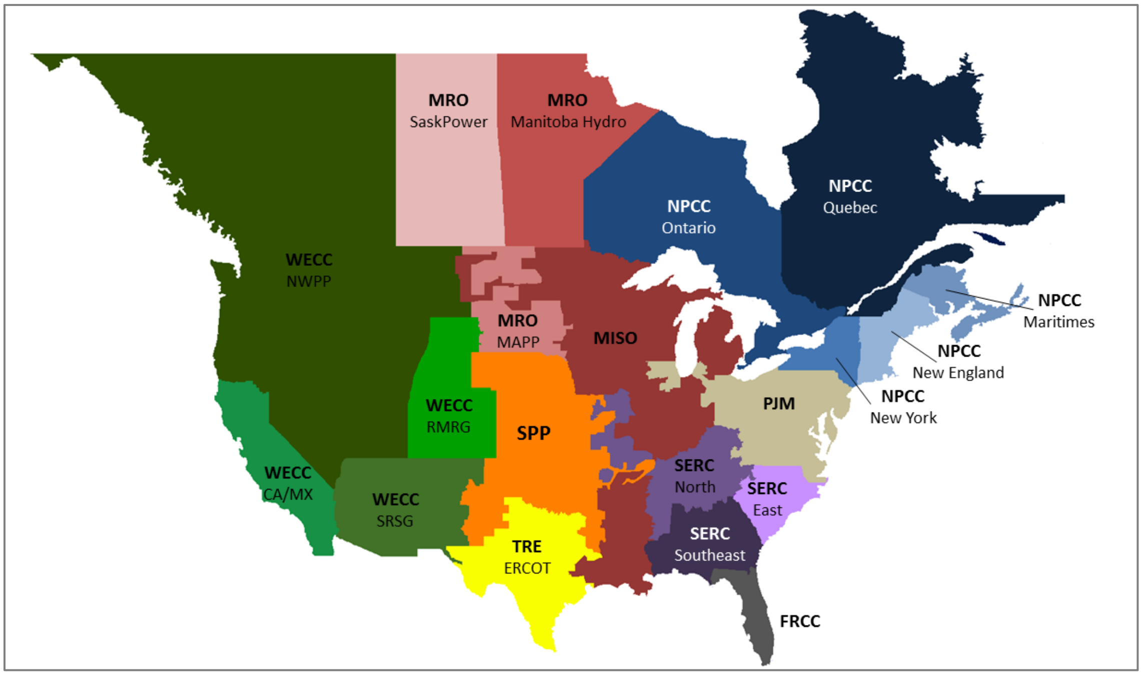


Figure 2-3. NERC Assessment Areas (as of January 2015) - organization for ES&D data

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

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).

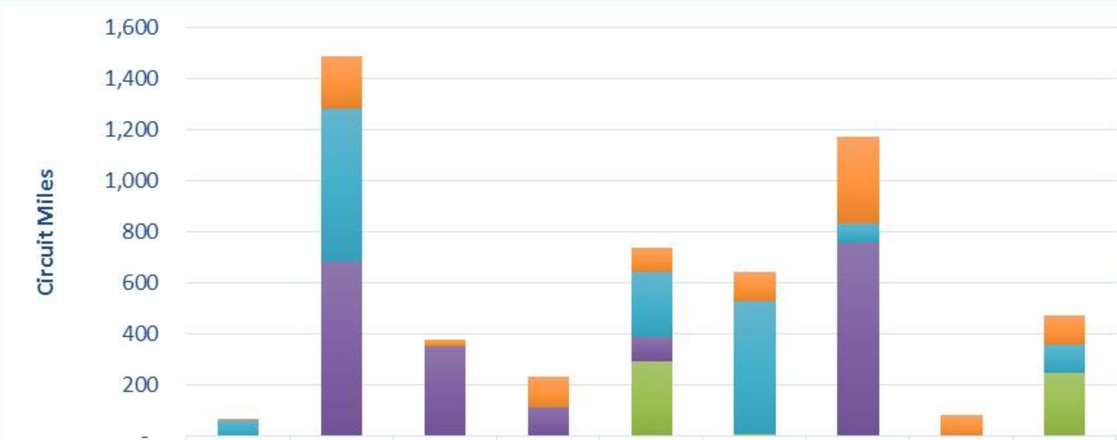
[7] NERC (2015a). "Electricity Supply & Demand (ES&D)." http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

[8] NERC (2013a). *2013 Long-Term Reliability Assessment.* December 2013. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

[9] For 2014, the LTRA data collection did not specifically collect data on existing infrastructure and will instead use the TADS inventory. This was part of an effort to gain consistency between the data sources and to reduce reporting burden on industry entities.

- *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 (a) projected in the transmission plan, (b) required to meet a NERC TPL standard, or (c) projected lines that do not meet the criteria for *Under Construction* or *Planned* (see Figure 2-7 and Figure 2-8).

Finally, the ES&D database also summarizes historical and projected infrastructure by total circuit miles (see Figure 2-9). Note that information presented in Figures 2-4 through 2-8 refer only to transmission within the United States.



	FRCC	MISO	MRO	NPCC	PJM	SERC	SPP	TRE	WECC
100-199 kV	3	209	25	122	99	113	336	85	117
200-299 kV	64	600	-	-	252	522	79	-	108
300-399 kV	-	681	354	111	97	-	756	-	-
400-599 kV	-	-	-	-	292	6	-	-	250
600 kV+	-	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-	-

Figure 2-4. Transmission under construction as of first day of 2014

Source: Developed by DOE from NERC (2015a). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

	FRCC	MISO	MRO	NPCC	PJM	SERC	SPP	TRE	WECC
100-199 kV	99	2,422	37	307	1,101	440	742	400	483
200-299 kV	155	49	4	151	329	147	119	-	2,509
300-399 kV	-	1,794	197	848	216	4	986	282	317
400-599 kV	-	-	-	-	19	60	-	-	2,299
600 kV+	-	69	-	-	14	-	-	-	-
Total DC	-	-	100	-	-	-	-	-	535

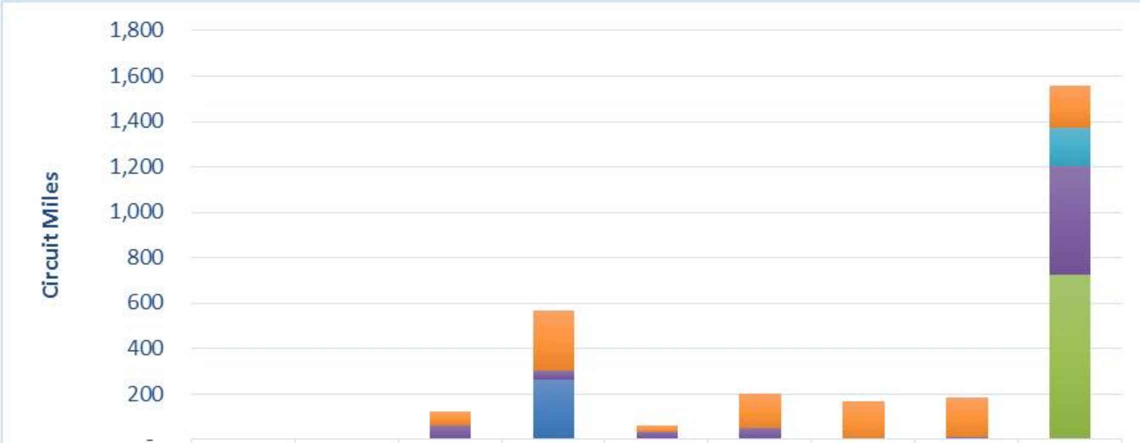
Figure 2-5. Planned lines expected to be completed by 2019

Source: Developed by DOE from NERC (2015a). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

	FRCC	MISO	MRO	NPCC	PJM	SERC	SPP	TRE	WECC
100-199 kV	-	88	-	75	-	28	-	0	131
200-299 kV	173	-	-	-	-	96	-	-	62
300-399 kV	-	103	-	-	-	-	159	-	170
400-599 kV	86	-	-	-	14	-	-	-	486
600 kV+	-	-	-	-	-	-	-	-	-
Total DC	-	-	-	-	-	-	-	-	-

Figure 2-6. Planned lines expected to be completed by 2024

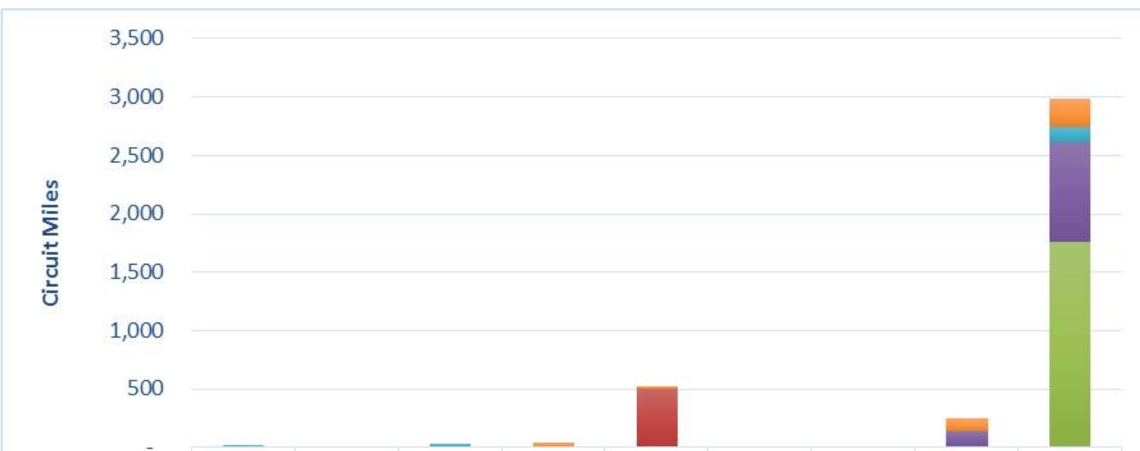
Source: Developed by DOE from NERC (2015a). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx



	FRCC	MISO	MRO	NPCC	PJM	SERC	SPP	TRE	WECC
100-199 kV	-	-	60	263	28	152	165	175	189
200-299 kV	-	-	-	2	-	-	-	-	169
300-399 kV	-	-	61	42	32	50	-	7	475
400-599 kV	-	-	-	-	-	-	-	-	724
600 kV+	-	-	-	-	-	-	-	-	-
Total DC	-	-	-	260	-	-	-	-	-

Figure 2-7. Conceptual lines expected to be completed by 2019

Source: Developed by DOE from NERC (2015a). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx



	FRCC	MISO	MRO	NPCC	PJM	SERC	SPP	TRE	WECC
100-199 kV	-	-	-	38	25	-	11	105	238
200-299 kV	20	-	31	-	-	-	-	-	132
300-399 kV	-	-	-	-	-	-	-	139	852
400-599 kV	-	-	-	-	-	-	-	-	1,759
600 kV+	-	-	-	-	499	-	-	-	-
Total DC	-	-	-	-	-	-	-	-	-

Figure 2-8. Conceptual lines expected to be completed by 2024

Source: Developed by DOE from NERC (2015a). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

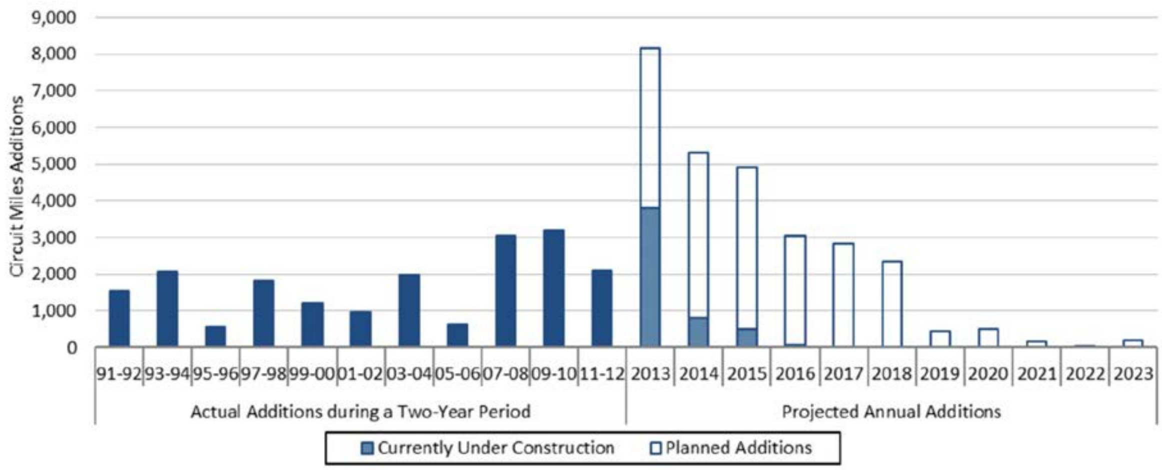


Figure 2-9. Historical actual miles added during each two-year period and 10-year projections

Source: NERC (2013a). 2013 Long-Term Reliability Assessment, *p. 13.* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

2.4. Transmission Investment

Information on transmission investment is taken from two sources:

- In 2012, the U.S. Energy Information Administration (EIA) published a compilation of information from FERC Form 1 (see Figure 2-10). Electric utilities jurisdictional to FERC are required to file with FERC on an annual basis a FERC Form 1, which is a comprehensive financial and operating report submitted for electric rate regulation and financial audits. EIA does not ensure the completeness of this information on a national scale or publish it regularly.
- EEI 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 2-11.) Note that the investment totals are presented in nominal dollars.

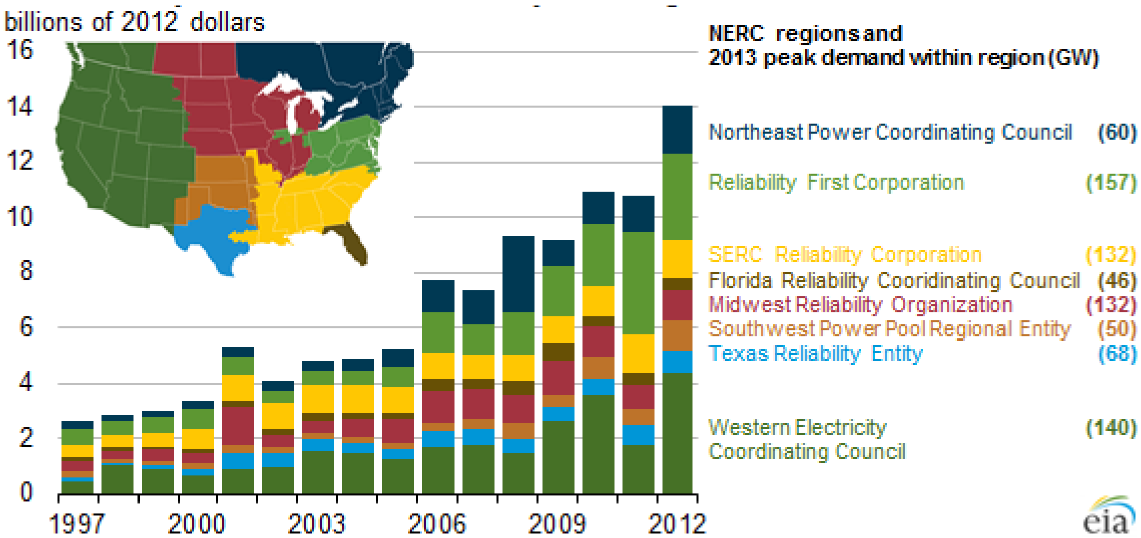


Figure 2-10. U.S. electricity transmission investment by NERC region, 1997-2012

Source: Energy Information Administration (EIA) (2014). "Electricity transmission investments vary by region." Today in Energy*, September 3, 2014. http://www.eia.gov/todayinenergy/detail.cfm?id=17811*

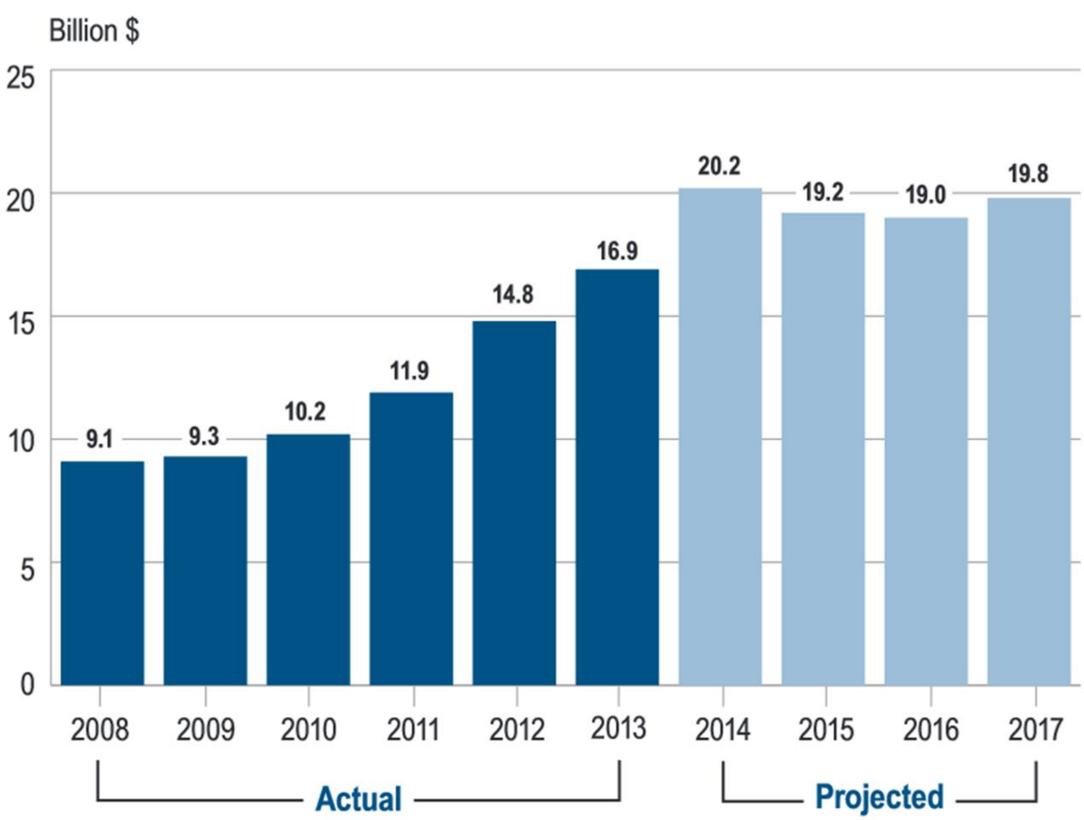


Figure 2-11. Historical and projected transmission investment by shareholder-owned utilities

Source: Edison Electric Institute (EEI) (2015). Actual and Planned Transmission Investment by Shareholder-Owned Utilities (2008-2017). *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.[10]

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 18 additional metrics for characteristics that together constitute an "Adequate Level of Reliability."[11]

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.[12]

- 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).[13]
- 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

[10] 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).

[11] See http://www.nerc.com/docs/standards/ALR_Definition_clean_081215.pdf

[12] Definitions are from NERC (2014b). *SRI Enhancement: NERC Performance Analysis Subcommittee.* April 2014. http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI%20Enhancement%20Whitepaper.pdf.

[13] 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. [14]

Figure 3-1 presents the daily SRI for the years 2008 to 2013. 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.

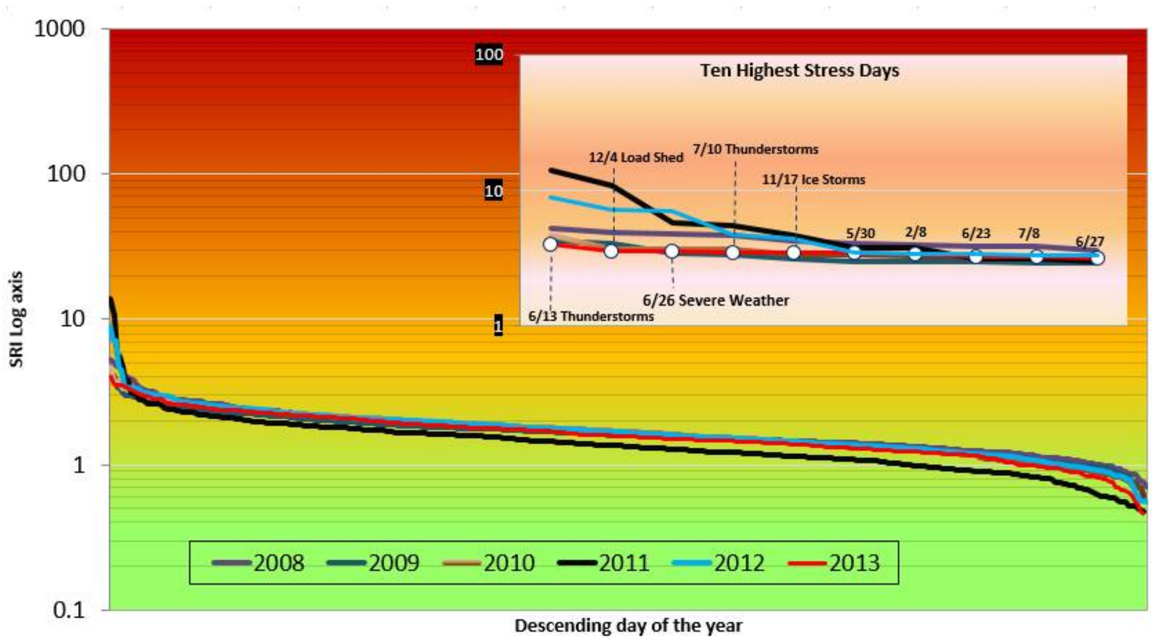


Figure 3-1. NERC Daily Severity Risk Index, descending by year, 2008-2013

Source: NERC (2014a). State of Reliability 2014, *p. 11.* http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

[14] 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.

Table 3-1. NERC 2013 top ten SRI days

Date	NERC SRI and Components				Weather Influenced (Y/N)	Cause Description	Interconnection
		Components and Weighting					
	SRI_{bps}	Generation (10%)	Transmission (30%)	Load Loss (60%)			
6/13/2013	4.1	14.5	4.4	2.1	Y	Severe Thunderstorms	Eastern
12/4/2013	3.6	11.1	1.7	3.3	Y	Cold/Load Shed	Western
6/26/2013	3.6	16.8	4.9	0.7	Y	Severe Weather	Eastern and Western
7/10/2013	3.5	18.9	3.0	1.2	Y	Severe Thunderstorms	Eastern
11/17/2013	3.5	7.9	3.5	2.8	Y	Severe Ice & Snow Storm	Eastern
5/30/2013	3.5	18.9	4.7	0.3	N	Power System Condition, Fire	Western and Eastern
2/8/2013	3.4	9.9	0.2	3.9	N	Equipment Failure	Eastern
6/23/2013	3.3	8.9	3.5	2.2	Y	Weather	Western
7/8/2013	3.2	14.8	5.5	0.2	Y	Rainfall Leading to Flooding	Eastern
6/27/2013	3.2	13.2	3.8	1.2	N	Fault and Equipment Failure	Western and Eastern

Source: NERC (2014a), p. 12. http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

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, and automatic sustained outages during the years 2010 through 2013. Figure 3-3 presents the percentage of time that transformers were not available, again by cause, for these same years. Tabular information on the number of these events by initiating cause code is presented in Table 3-2.

Figure 3-2. NERC transmission AC circuits unavailability by outage type, 2010-2013[15]

Source: NERC (2014a), p. 13. http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

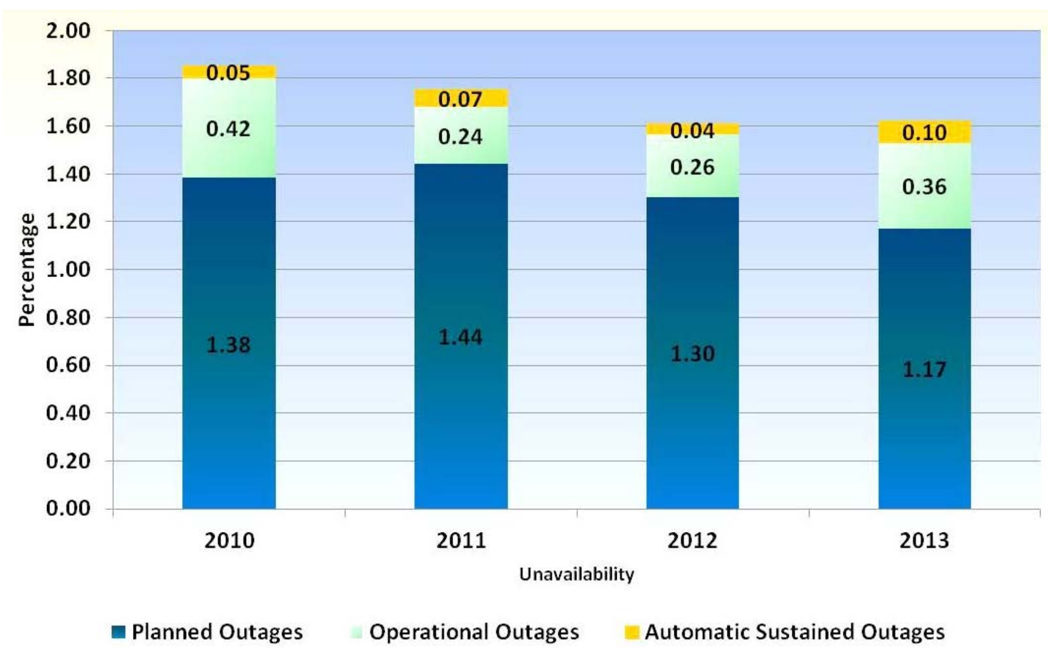


Figure 3-3. NERC transmission transformers unavailability by outage type, 2010-2013

Source: NERC (2014a), p. 13. http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

[15] 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

Table 3-2. TADS outage events by initiating cause code (ICC), 2009-2013

Initiating Cause Code	2009	2010	2011	2012	2013	2009–2013
Lightning	789	741	822	852	814	**4018**
Unknown	673	821	782	710	712	**3698**
Weather Excluding Lightning	534	673	539	446	434	**2626**
Human Error	291	305	291	307	280	**1474**
Failed AC Circuit Equipment	257	277	306	261	248	**1349**
Failed AC Substation Equipment	266	238	289	248	192	**1233**
Failed Protection System Equipment	229	234	234	226	188	**1111**
Foreign Interference	199	173	170	170	181	**893**
Contamination	96	145	132	160	152	**685**
Power System Condition	112	74	121	77	109	**493**
Fire	92	84	63	106	130	**475**
Other	107	84	91	104	64	**450**
Vegetation	29	27	44	43	36	**179**
Vandalism, Terrorism, or Malicious Acts	4	6	5	10	9	**34**
Environmental	5	11	5	4	8	**33**
Failed AC/DC Terminal Equipment	1	2	0	0	0	**3**
All TADS Events	**3705**	**3917**	**3934**	**3753**	**3557**	**18866**
All with ICC Assigned	**3684**	**3895**	**3894**	**3724**	**3557**	**18754**

Source: NERC (2014a), p. 31. http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.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.[16] In 2014, the Department, through the Lawrence Berkeley National Laboratory (LBNL), contracted with Open Access Technology International, Inc. (OATI) to identify and aggregate information describing scheduled transactions and actual flows in the Eastern Interconnection on an hourly basis for the years 2011, 2012, and 2013.[17] OATI aggregated the information based on sub-regions within the Eastern Interconnection, which had been defined originally by the Eastern Interconnection Planning Collaborative (EIPC) (see Section 7 of this report). The distinct sub-regions originally defined by the EIPC within MISO, NYISO, PJM, and SPP were aggregated so that the entire ISO/RTO became a single sub-region. (See Figure 4-1.)

For many, but not all of the sub-regions, OATI also obtained information that was used to estimate an approximate upper bound on expected flows among sub-regions.[18] OATI then estimated the percentage of time actual or scheduled flows were greater than 75% and 90% of the upper bound.

[16] See Open Access Technology International (OATI) (2015). *Assessment of Historical Transmission Schedules and Flows in the Eastern Interconnection.* http://emp.lbl.gov/sites/all/files/oati-assessment-of-historical-transmission-schedules-2015.pdf

[17] *ibid.*

[18] The upper bounds developed by OATI should not be equated with operational limits between neighboring regions due to the aggregation processes used by OATI to group all transmission lines involved in interchange with neighboring regions into a single schedule or flow.

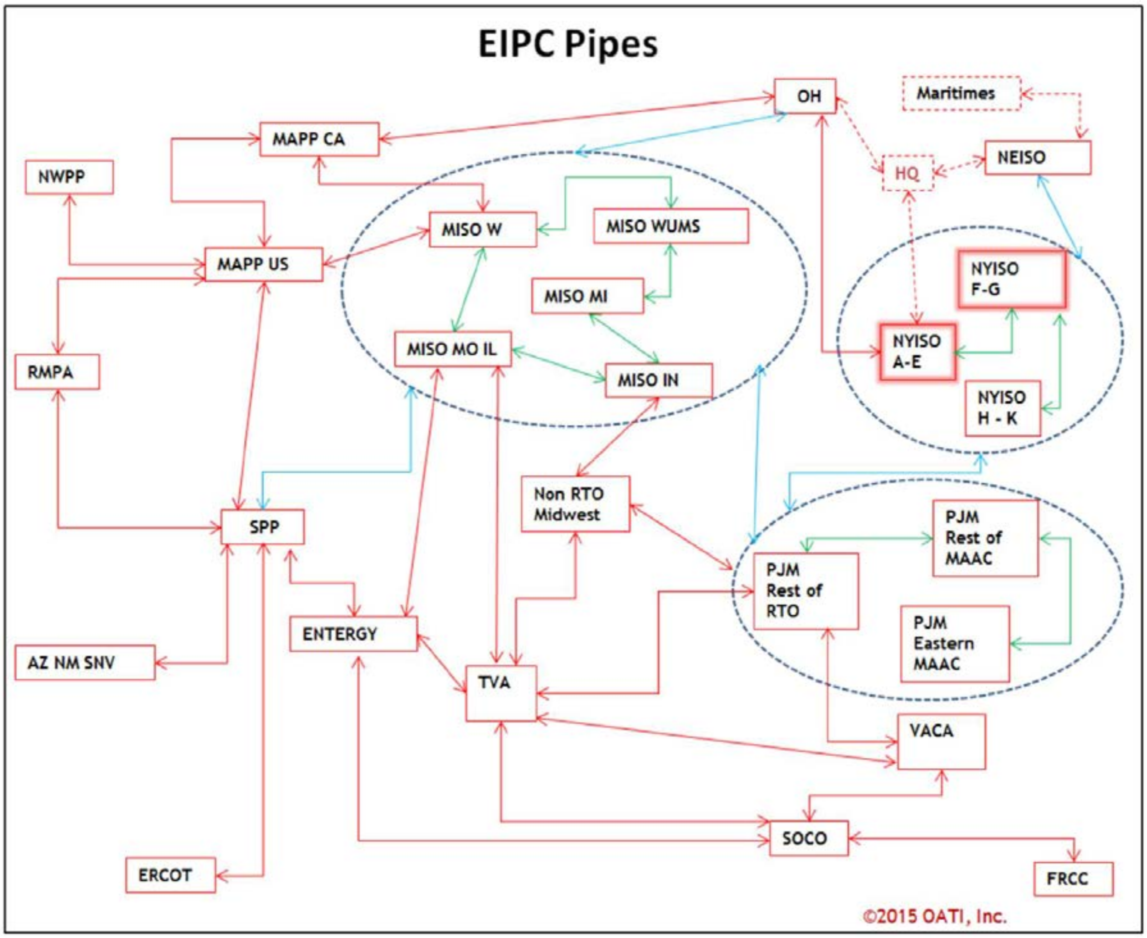


Figure 4-1. OATI sub-regions based on Eastern Interconnection Planning Collaborative used for the 2013 analysis

Source: OATI (2015) p. 9. http://emp.lbl.gov/publications/assessment-historical-tra

Table 4-1 shows an example of the results of OATI's analysis for actual flows between sub-regions that are not within an RTO/ISO and either (a) another sub-region that is also not within an RTO/ISO, or (b) a single sub-region that is within an RTO/ISO.[19, 20] Developing actual flow (and schedule) information is straightforward in these instances because both the sending and receiving sub-regions each correspond to a single NERC Balancing Authority, which collect and maintain this information on an on-going basis. All sub-regions of this type are shown in red. For the sub-regions for which OATI was able to estimate an approximate upper bound, the numerical value within each red box indicates the percentage of the hours of the year during which flows exceeded this estimate.

[19] A dashed red pipe is used to represent DC interties between sub-regions.
[20] In December2013, the Entergy system was integrated into the MISO footprint.

Table 4-1. OATI analysis of actual flows in 2013

©2015 OATI, Inc. U90 Actual for 2013	AZ_NM_SNV	ENTERGY	ERCOT	FRCC	HQ	MAPPCA	MAPPUS	Maritimes	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS	NEISO	Non_RTO_Midwest	NWPP	NYISO A-E	NYISO F-G	NYISO H-K	OH	PJM_Eastern_MAAC	PJM_REST_OF_MAAC	PJM_Rest_OF_RTO	RMPA	SOCO	SPP	TVA	VACA
AZ_NM_SNV																												
ENTERGY																									0	0	0	
ERCOT																												
FRCC																									0			
HQ														83						0								
MAPPCA																												
MAPPUS																								0		0		
Maritimes																												
MISO_IN																												
MISO_MI																												
MISO_MO_IL																												
MISO_W																												
MISO_WUMS																												
NEISO					94																							
Non_RTO_Midwest																												
NWPP																												
NYISO A-E																												
NYISO F-G																												
NYISO H-K																												
OH					0																							
PJM_Eastern_MAAC																												
PJM_REST_OF_MAAC																												
PJM_Rest_OF_RTO																												
RMPA							0																					
SOCO		0		0																							0	0
SPP		0					0																					
TVA		0																							0			60
VACA																									0		42	

Source: OATI (2015), p. 36. http://emp.lbl.gov/publications/assessment-historical-tra

In 2014, EIA released Form 930, which collects hourly information on electricity flows among balancing authorities. Summary information from Form 930, if not published separately by EIA, may be included in future editions of this report.

There are also 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 4-2).

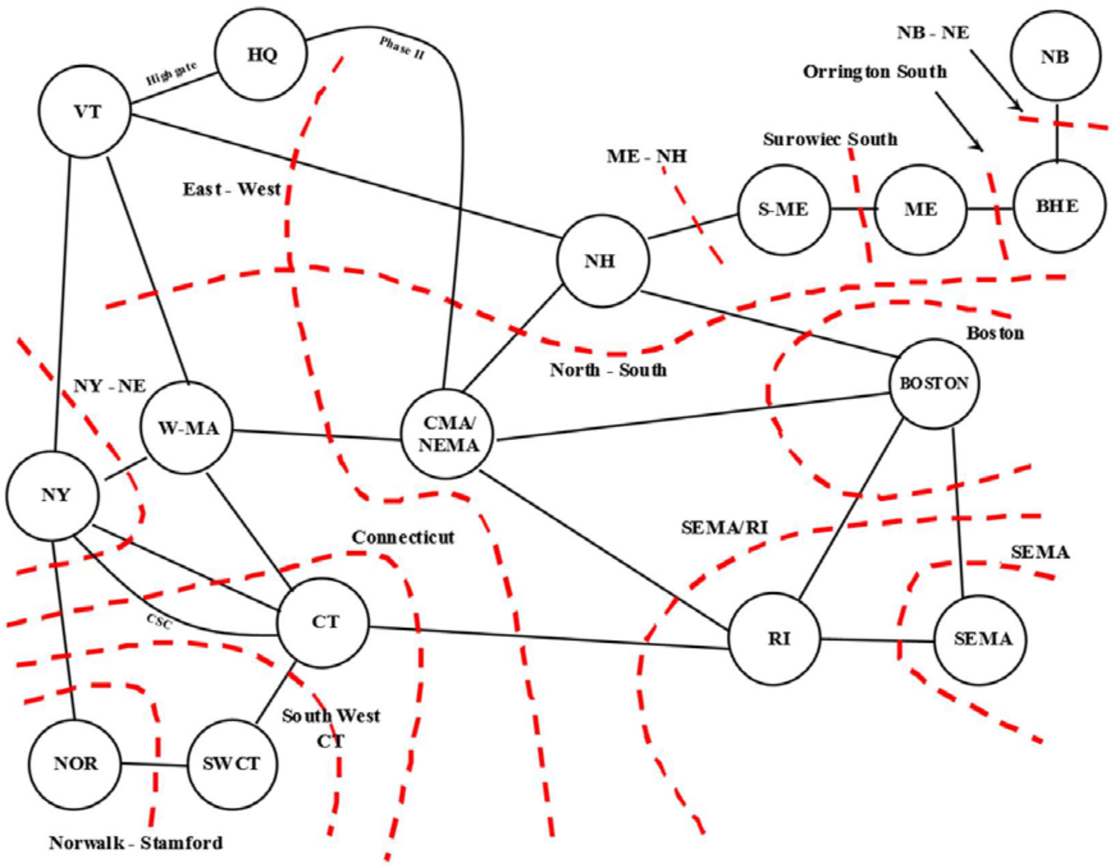


Figure 4-2. New England sub-area model

Source: Ehrlich, David J. (2014). "RSP14 – 2013 Historical Market Data: Locational Marginal Prices Interface MW Flows," p. 3. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a6_2014_lmp_interface_flows.pdf

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

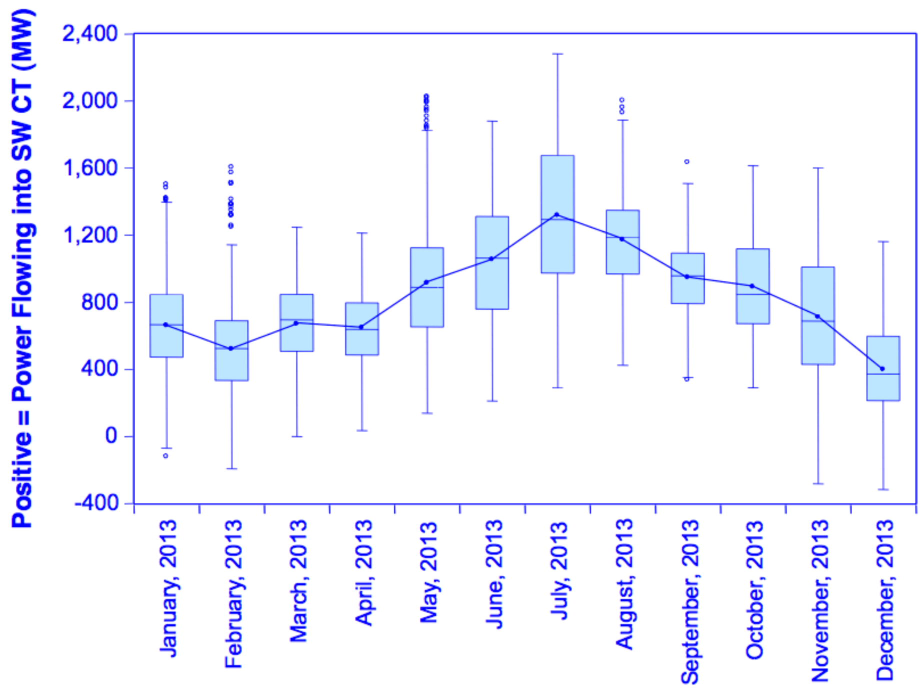


Figure 4-3. Southwest Connecticut import interface net flow by month, 2013

Source: Ehrlich (2014), p. 30. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a6_2014_lmp_interface_flows.pdf

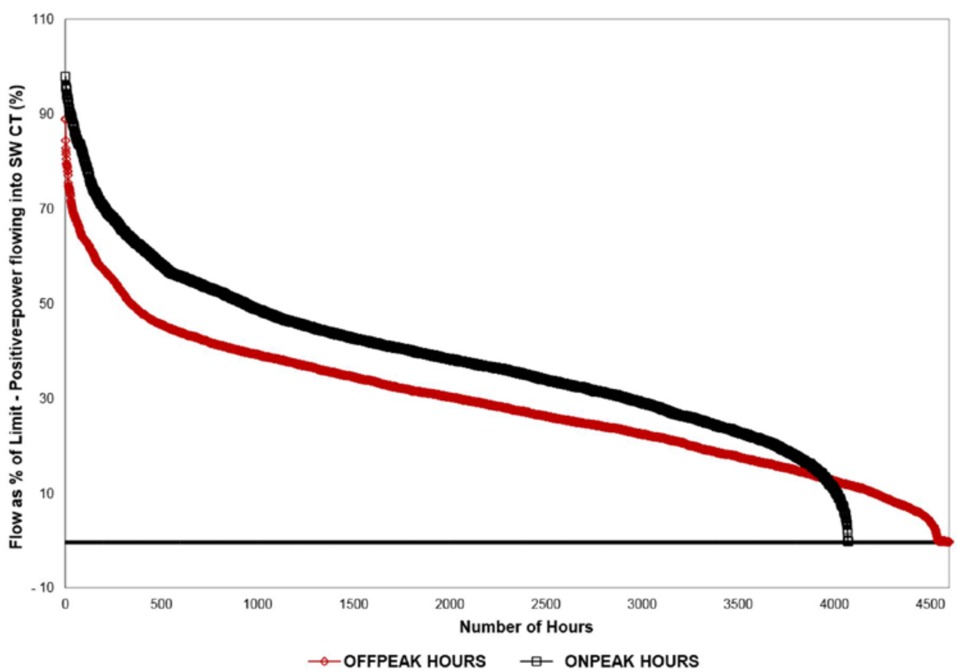


Figure 4-4. Southwest CT import interface duration curve: net flow as % of interface limit, January-December 2013

Source: Ehrlich (2014), p. 38. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a6_2014_lmp_interface_flows.pdf

4.3. Western Interconnection

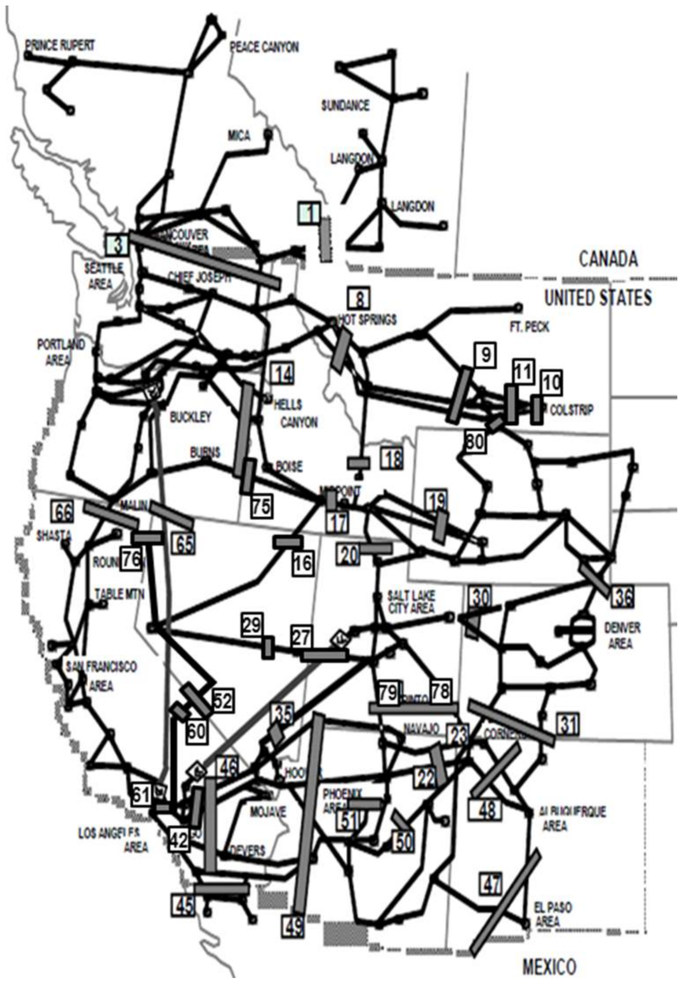
The Western Electric Coordinating Council (WECC) prepares a biennial report on transmission utilization within the Western Interconnection. The information is organized according to transmission paths that are used in both planning and operations. The paths represent aggregations of transmission lines connecting geographic sub-regions within the interconnection to one another. WECC has defined 67 such paths, and collects and reports hourly electricity flow information across 39 of them (see Figure 4-5).

WECC expresses flows over these paths by normalizing them to the operating limit established for the path. WECC reports utilization by tabulating the number of hours during the year when actual flows exceed a fixed percentage of this limit. For example, the U90 metric refers to the number of hours flows exceed 90% of the limit established for a path (see Table 4-2). Similarly, WECC also presents information on the number of hours flows exceed 75% of the limit established for each path (the U75 metric).

Table 4-2. WECC 20 Most utilized paths based on flow U90 for all hours in 2010

Path #	Path Name	U90 All Hours
75	Midpoint - Summer Lake	35.7
27	IPP DC Line	32.4
19	Bridger West	21.6
52	Silver Peak-Control 55 kV	0.0
8	Montana - Northwest	9.3
66	COI	3.8
23	Four Corners 345/500	3.8
65	Pacific DC Intertie	3.4
48	Northern New Mexico (NM2)	3.3
35	TOT 2C	3.0
1	Alberta - British Columbia	2.6
22	Southwest of Four Corners	2.0
50	Cholla - Pinnacle Peak	1.7
36	TOT 3	1.2
76	Alturas Project	0.8
47	Southern New Mexico (NM1)	0.6
20	Path C	0.5
9	West of Broadview	0.3
17	Borah - West	0.3
30	TOT 1A	0.3

Source: Western Electricity Coordinating Council (WECC) (2013b), 2013 WECC Path Reports, *p. 16.*
https://www.wecc.biz/Reliability/TAS_PathReports_Combined_FINAL.pdf



Path 1 Alberta to BC
Path 3 Northwest to Canada
Path 8 Montana to Northwest
Path 9 West of Broadview
Path 10 West of Coalstrip
Path 11 West of Crossover
Path 14 Idaho to Northwest
Path 16 Idaho to Sierra
Path 17 West of Borah
Path 18 Montana to Idaho
Path 19 Bridger West
Path 20 Path C
Path 22 Southwest of 4 Corners
Path 23 4 Corners Transformer
Path 27 IPP DC Line
Path 29 Intermountain-Gondor
Path 30 TOT 1A
Path 31 TOT 2A
Path 34 TOT 2B*
Path 35 TOT 2C
Path 36 TOT 3
Path 42 IDD-SCE
Path 45 CISO to CFE
Path 46 West of Colorado River
Path 47 Southern New Mexico
Path 48 Northern New Mexico
Path 49 East of Colorado River
Path 50 Cholla to Pinnacle Peak
Path 51 Southern Navajo
Path 52 Silver Peak-Control
Path 60 INYO to Control
Path 61 Lugo to Victoriville
Path 65 Pacific DC Intertie
Path 66 Pacific AC Intertie (COI)
Path 75 Midpoint to Summer Lake
Path 76 Alturas Project
Path 78 TOT 2B1
Path 79 TOT 2B2
Path 80 Montana Southeast

Figure 4-5. Major high-voltage transmission in the West, and WECC-rated paths

Source: WECC (2013b), 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;[21] 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) and in the Western Interconnection (called Unscheduled Flow Mitigation). It also presents information on market-based procedures used by the operators of organized wholesale markets.

[21] 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[22] that is constrained; the start and end times of the TLR; the level of the TLR; and the MWs affected.[23]

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 2009-2013. Figure 5-3 shows the number of higher levels of TLRs called during 2013, by Reliability Coordinator.

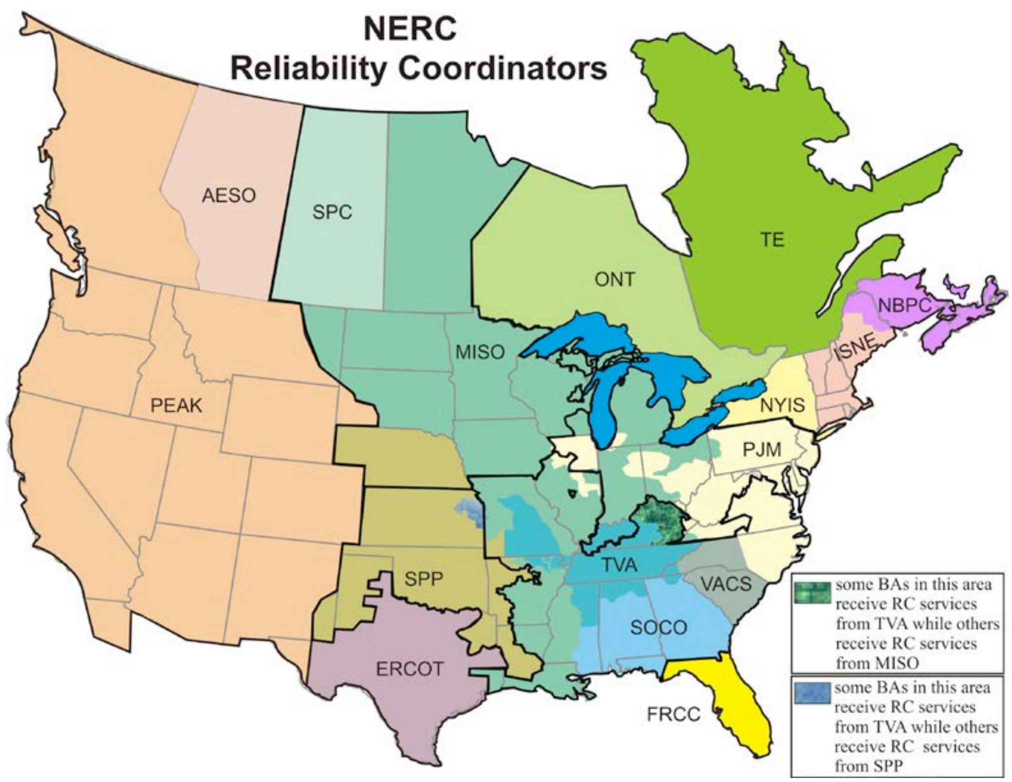
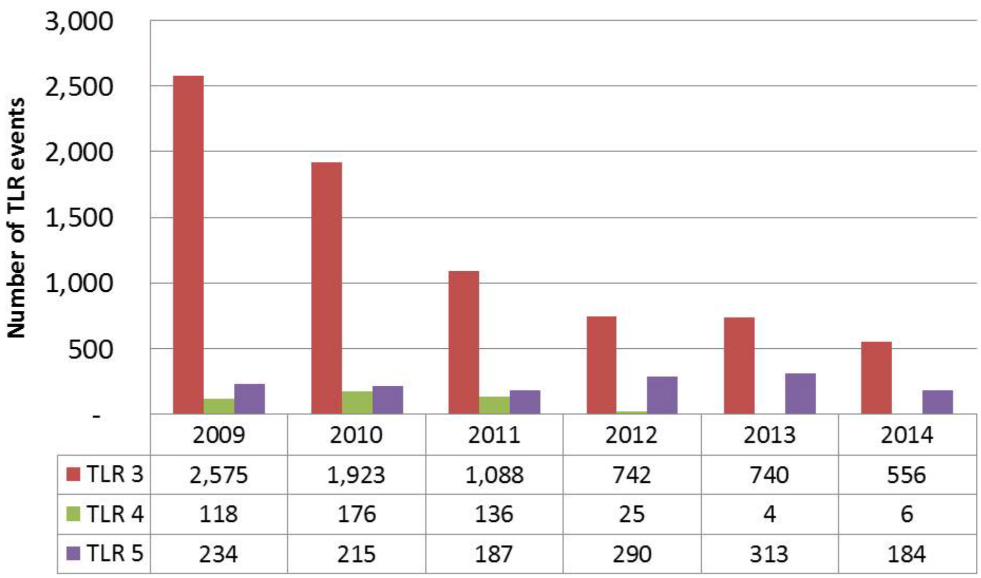


Figure 5-1. NERC Reliability Coordinators

Source: NERC (2013b). "Transmission Loading Relief Procedures," at http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx

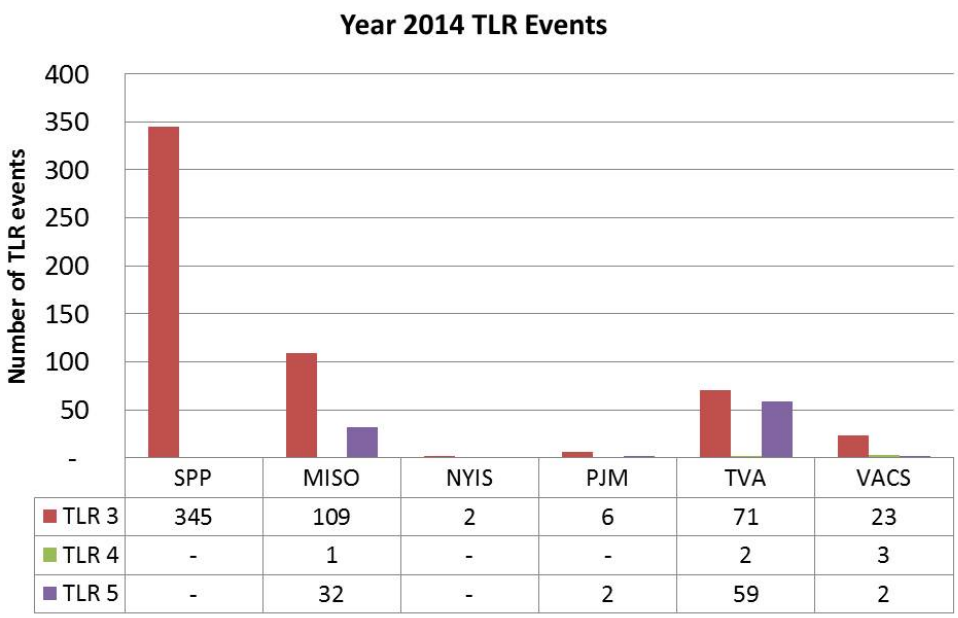
[22] A flowgate refers to a single or group of transmission facilities that jointly can be used to model electricity flow impacts relating the transmission limitations and transmission service usage.
[23] See http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx



	2009	2010	2011	2012	2013	2014
TLR 3	2,575	1,923	1,088	742	740	556
TLR 4	118	176	136	25	4	6
TLR 5	234	215	187	290	313	184

Figure 5-2. Eastern (total) TLR events, 2009-2014

Source: Developed by DOE from NERC (2013b). http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.



	SPP	MISO	NYIS	PJM	TVA	VACS
TLR 3	345	109	2	6	71	23
TLR 4	-	1	-	-	2	3
TLR 5	-	32	-	2	59	2

Figure 5-3. Year 2014 TLR events by region

Source: Developed by DOE from NERC (2013b). 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. The most recent year for which these data are available publicly is 2009.[24] See Table 5-1.

Table 5-1. WECC unscheduled flow mitigation procedures, 2009

Qualified Path Number	Qualified Path Name	Total Hours of Phase Shifter Control	Total Hours of Curtailment
22	SW of Four Corners	44	0
23	Four Corners Transformer	150	46
30	TOT 1A	99	5
31	TOT 2A	0	0
36	TOT 3	1	0
66	COI	61	23
	TOTAL	**355**	**74**

Source: WECC (2010a). 2009 Western Interconnection Transmission Path Utilization Study: Path Flows, Schedules, and OASIS ATC Offerings, *p. 40.* *https://www.wecc.biz/Reliability/09_WI_TrasnsPath_UtilizationStudy.pdf*

5.4. Market-Based Procedures for Managing Transmission Constraints

Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) manage transmission constraints through centralized 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.

[24] WECC (2010a). *2009 Western Interconnection Transmission Path Utilization Study: Path Flows, Schedules, and OASIS ATC Offerings.* https://www.wecc.biz/Reliability/09_WI_TrasnsPath_UtilizationStudy.pdf

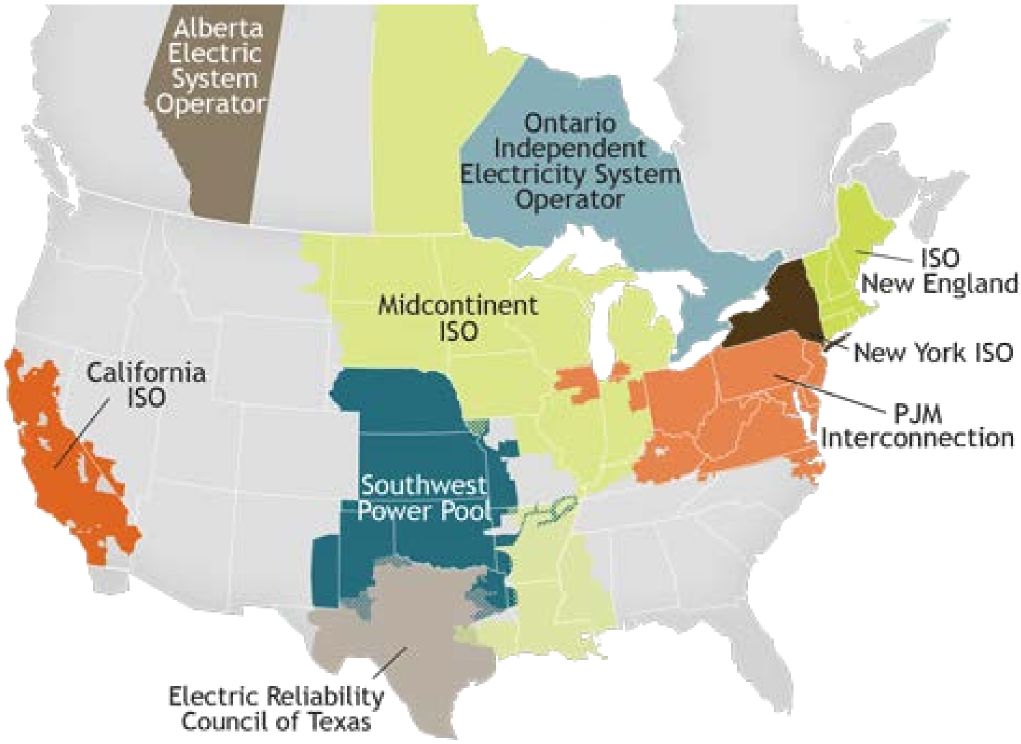


Figure 5-4. ISO/RTO Council Members

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

5.4.1. California ISO (CAISO)

CAISO produces an *Annual Report on Market Issues and Performance,*[25] 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. The CAISO report also presents a comparable table of these impacts on real-time prices (not shown here).[26]

[25] For the most recent version of this report, see CAISO (2014). *2013 Annual Report on Market Issues & Performance, at* http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.
[26] *ibid*., p. 188.

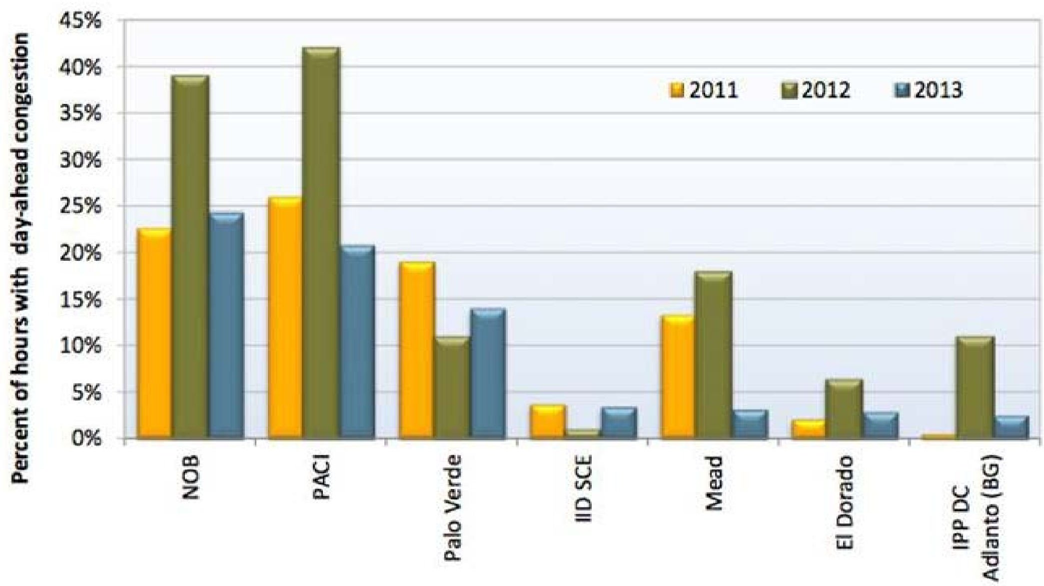


Figure 5-5. CAISO percent of hours with congestion on major inter-ties, 2011-2013

Source: CAISO (2014), p. 180. http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

Table 5-2. CAISO summary of import congestion, 2011-2013

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2011	2012	2013	2011	2012	2013	2011	2012	2013
Northwest	PACI	11%	42%	21%	$9.1	$10.5	$8.6	$48,903	$84,657	$34,026
	NOB	8%	39%	24%	$9.2	$11.6	$9.8	$25,471	$59,236	$27,823
	COTPISO	13%	8%		$24.7	$16.5		$629	$271	
	Summit	1%	2%	1%	$46.9	$19.6	$10.6	$317	$195	$38
	Cascade	32%	20%	14%	$12.0	$14.8	$13.5	$2,481	$2,086	$1,280
	New Melones	17%			$33.4			$6,788	$0	
	Tracy 230	1%	2%		$669.4	$232.4		$3,841	$1,164	
	Tracy 500			2%			$21.3			$1,292
Southwest	Palo Verde	19%	11%	14%	$10.2	$10.3	$13.2	$25,885	$19,177	$26,438
	Mead	13%	18%	3%	$7.1	$9.2	$7.7	$8,287	$15,248	$2,181
	IPP DC Adelanto (BG)	0%	11%		$11.7	$3.0		$186	$1,195	
	IID-SDGE_ITC		0%			$963.6			$1,095	
	IID - SCE	4%	1%	3%	$9.8	$53.8	$49.8	$1,579	$1,646	$5,735
	El Dorado	2%	6%	3%	$8.4	$10.1	$6.3	$2,183	$5,695	$1,639
	Mona IPP DC (MSL)	14%	6%		$3.9	$2.7		$631	$285	
	BLYTHE_ITC		1%			$62.0			$749	
	Other							$205	$156	$169
Total								***$127,386***	***$192,855***	***$100,621***

* 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 (2014), p. 180. http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

Table 5-3. CAISO impact of congestion on day-ahead prices during congested hours, 2013

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	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	30880_HENTAP2_230_30900_GATES _230_BR_2_1				9.7%										$0.47		
	SLIC 2100489_PVDV_Out_EDLG				8.2%										$0.38	-$0.24	-$0.71
	PATH15_BG	7.7%	9.8%	0.5%	2.2%	$1.68	-$1.43	-$1.43	$1.60	-$1.32	-$1.32	$2.26	-$1.86	-$1.86	$2.34	-$1.86	-$1.86
	30790_PANOCHE_230_30900_GATES _230_BR_1_1			0.7%	0.5%							$1.08	-$0.84	-$0.84	$1.90	-$1.45	-$1.45
	SLIC 2165838 ELDORADO_BUS_NG				0.4%										$0.86	-$0.65	-$0.91
	30875_MC CALL_230_30880_HENTAP2_230_BR_1_1		1.9%	28.2%					$0.57	-$0.45	-$0.45	$0.59	-$0.42	-$0.42			
	6110_TM_BNK_FLO_TMS_DLO_NG		0.6%	19.0%					$0.39			$0.94	-$0.88	-$0.88			
	LOSBANOSNORTH_BG		1.2%	0.1%					$2.74	-$2.09	-$2.09	$1.66	-$1.60	-$1.60			
	30735_METCALF _230_30042_METCALF _500_XF_13		1.3%						$2.26	-$1.92	-$1.92						
SCE	BARRE-LEWIS_NG	23.9%	5.3%	5.2%	3.1%	-$1.32	$1.84	$0.21	-$1.06	$1.29	$0.91	-$0.40	$0.51	$0.15	-$0.42	$0.55	$0.19
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2_1		0.8%	22.8%	1.3%	-$0.11	$2.14	-$0.11				-$0.30	$0.93	-$0.30		$3.97	
	SCE_PCT_IMP_BG	71.2%	51.2%	16.3%		-$3.93	$4.85	-$3.89	-$3.66	$4.29	-$3.63	-$2.00	$2.20	-$1.89			
	PATH26_BG	1.1%		1.9%		-$1.83	$1.47	$1.47				-$3.08	$1.97	$1.97			
	SLIC 2146366_VINCENTBUS			0.3%								-$3.14	$2.18	$2.57			
	SLIC 2088287_BARRE-LEWIS_NG	0.7%				-$1.28	$2.13										
SDG&E	SLIC 2100489_PVDV_Out_LGVN				5.1%										-$1.39	$0.99	$1.27
	SOUTHLUGO_RV_BG	0.4%	3.3%	0.7%	4.1%	-$3.24	$2.47	$4.42	-$5.15	$3.56	$5.43	-$4.60	$2.94	$4.33	-$3.68	$2.58	$3.69
	SLIC 2138237 TL50003_CFE_NG				2.4%												$12.13
	22372_KEARNY _69.0_22496_MISSION _69.0_BR_1_1				1.9%												$5.09
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1_1				1.4%												$6.63
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1_1		0.1%	1.5%	1.4%						$1.18			$1.31			$0.94
	SLIC 2164068 TL50001_NG				1.3%												$11.65
	7820_TL 230S_OVERLOAD_NG		13.6%		1.0%				-$1.01		$7.69	-$0.59		$5.31	-$0.22		$2.23
	22500_MISSION _138_22117_CARLTHT2_138_BR_1_1				0.8%												$5.29
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1_1				0.6%												$8.33
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1_1				0.3%										-$0.51		$3.53
	T-135 VICTVLUGO_LGVNDLO_NG			4.3%								-$2.14	$1.40	$1.75			
	22768_SOUTHBAY_69.0_22604_OTAY _69.0_BR_2_1		5.5%								$0.96			$0.26			
	24138_SERRANO _500_24137_SERRANO _230_XF_2_P		0.9%	0.3%					-$3.53	$1.88	$7.28	-$1.08	$0.64	$2.41			
	SLIC 2148149 TL23050_NG			0.3%										$11.36			
	24016_BARRE _230_24044_ELLIS _230_BR_3_1		0.7%	0.1%					-$0.47		$2.34	-$0.27		$1.19			
	SDGE_PCT_UF_IMP_BG		2.2%						-$0.76	-$0.76	$7.58						
	24016_BARRE _230_24044_ELLIS _230_BR_1_1		1.7%						-$2.46	-$0.67	$15.70						
	SLIC 2122013 BARRE-ELLIS-230S_NG		1.6%						-$0.46		$4.91						
	24016_BARRE _230_24044_ELLIS _230_BR_4_1		1.6%						-$0.45		$2.17						
	7830_SXCYN_CHILLS_NG	0.1%	1.3%					$0.56			$9.51						
	24138_SERRANO _500_24137_SERRANO _230_XF_1_P		0.8%						-$3.02	$1.67	$6.02						
	SLIC 2077347 TL50003_NG		0.6%								$6.05						
	SLIC 2067610 TL50001_NG		0.6%								$12.23						
	SLIC 2122013 Barre-Ellis DLO		0.6%						-$2.54		$15.20						
	SLIC 2111709_IV500North_BUS_NG		0.5%								$20.93						
	SLIC 2122013 Barre-Ellis DLO_20		0.4%						-$1.97		$12.42						
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1_1	3.4%	0.2%					$4.27			$6.81						
	IVALLYBANK_XFBG	2.6%						$0.84									
	SLIC 2051445 TL23050_NG	2.3%						$6.31									
	SLIC 2090466 and 2090467 SOL	2.3%						$15.29									
	SLIC 2112931 EL CENTRO BK1_NG	1.2%						$5.05									
	MIGUEL_BKs_MXFLW_NG	0.4%				-$1.04		$11.65									
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.4%				-$17.48		$41.61									
	SLIC 2094078 IV Bank81_NG	0.2%				-$3.54		$24.91									

Source: CAISO (2014), p. 183. http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.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.[27] Table 5-4 and Figure 5-6 show the geographic area served and the location of constraints identified by ERCOT.[28] In addition, the market monitor for ERCOT includes information about constraints in its annual *State of the Market* report.[29] Figure 5-7 shows the frequency of active constraints for different load levels, annually for 2011–2013. Figure 5-8 displays the ten areas that generated the most real-time congestion.

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

Map Index	Constraint	Congestion Rent
1	Heights 138/69 kV transformer	$63,917,791
2	Lytton Springs 345/138 kV transformer	$55,956,002
3	Midland East – Buffalo 138 kV line	$46,790,259
4	North to Houston Import	$31,806,449
5	Harlingen Switch – Oleander 138 kV line	$26,943,341
6	Odessa North 138/69 kV transformer	$23,944,433
7	Rio Hondo – East Rio Hondo 138 kV line	$23,683,772
8	Moss Switch – Westover 138 kV line	$19,511,591
9	Hockley – Betka 138 kV line	$15,850,200
10	Lon Hill – Smith 69 kV line	$14,052,406
11	Valley Import	$11,853,636
12	Hutto – Round Rock Northeast 138 kV line	$10,033,349
13	Paris Switch 345/138 kV transformer	$9,940,305
14	Marshall Ford – Lago Vista 138 kV line	$9,871,526
15	Gila – Hiway 9 138 kV line	$8,622,377

Source: ERCOT (2014c), p. 4. www.ercot.com/content/news/presentations/2015/2014_Constraints_and_Needs_Report.pdf

[27] For the most recent version of this report, see ERCOT (2014c). *Report on Existing and Potential Electric System Constraints and Needs*, at www.ercot.com/content/news/presentations/2015/2014_Constraints_and_Needs_Report.pdf

[28] Section 4 of the *2014 Report on Existing and Potential Electric System Constraints and Needs* shows transmission projects in ERCOT (as of December 2014) that, among other things, are designed to address these constraints.

[29] For the most recent version of this report, see Potomac Economics (2014b). *2013 State of the Market Report for the ERCOT Wholesale Electricity Markets,* at https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

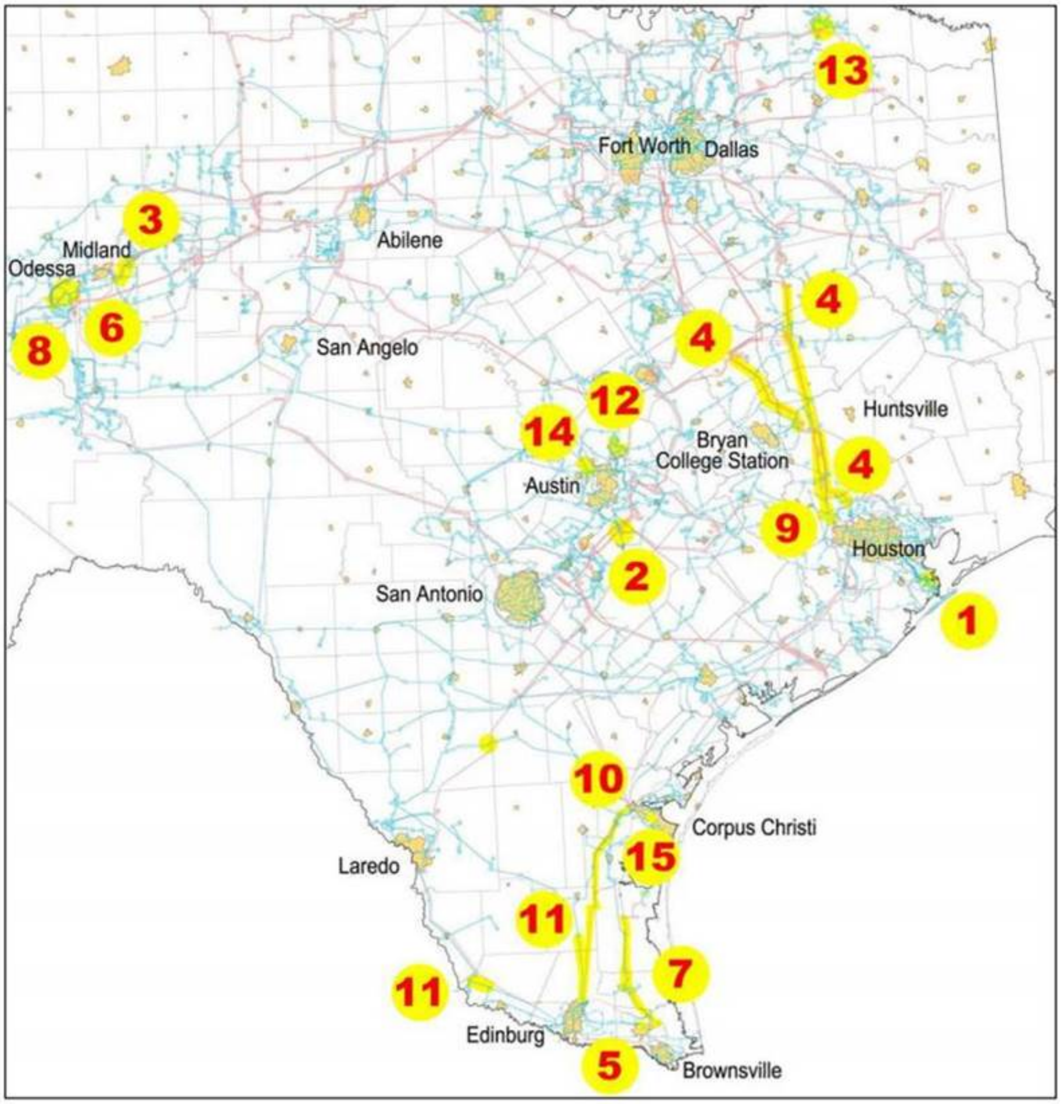


Figure 5-6. Map of top 15 congested constraints on the ERCOT system, Jan-Oct 2014

Source: ERCOT (2014c), p. 5. www.ercot.com/content/news/presentations/2015/2014_Constraints_and_Needs_Report.pdf

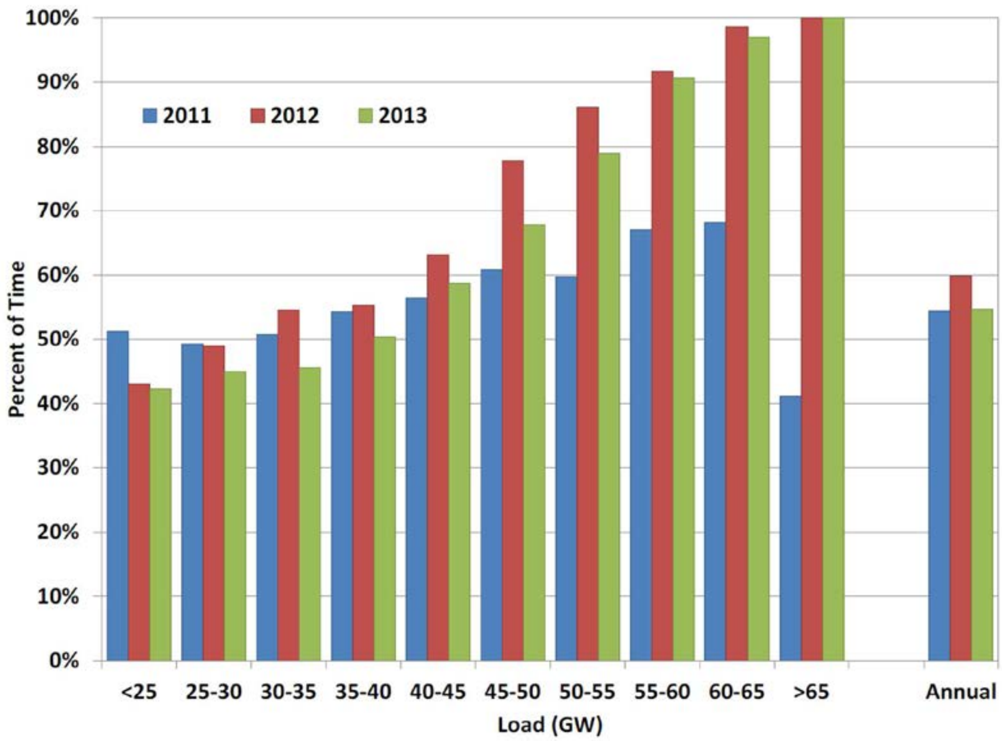


Figure 5-7. Frequency of active constraints, 2011-2013

Source: Potomac Economics (2014b), p. x. https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

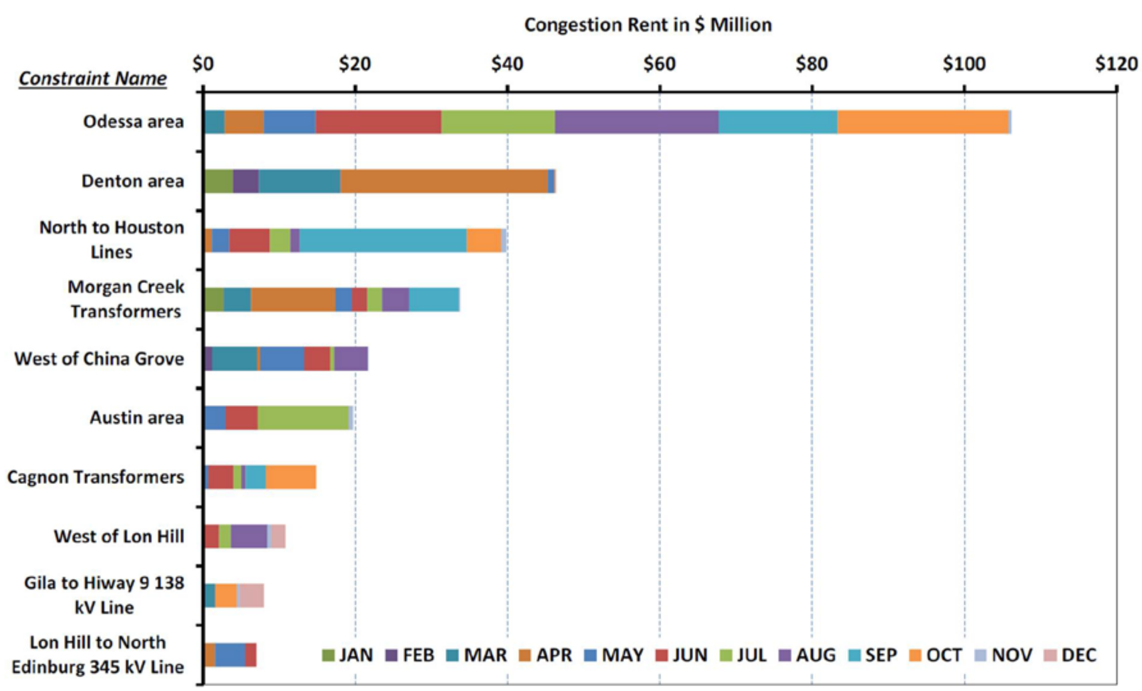


Figure 5-8. ERCOT top ten real-time constraints, 2013

Source: Potomac Economics (2014b), p. xi. https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

5.4.3. ISO New England (ISO-NE)

ISO-NE reports on system constraints in its annual *Regional System Plan*.[30] 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 4-2 shows the geographic area served and the location of constraints identified by ISO-NE.[31]

In its *2013 Regional System Plan*, ISO-NE comments on several constraints:

- Maine (north to South), which "…will likely continue to limit the ability of the system to deliver some existing and new capacity. Because of these continued constraining interface limits within Maine, subsequent study work will investigate the ability to further increase the north-to-south limits in Maine with the existing series capacitor at Orrington placed back into service."[32]
- Vermont and New Hampshire have some local constraints.[33]
- Southern New England east to west and between Massachusetts, Rhode Island, and Connecticut (see Figure 5-9).
- Local constraints are leading to some wind curtailment.[34]
- In addition, constraints in the New York ISO (NYISO) are expected to prevent exports from NYISO into Vermont.[35, 36]

[30] For the most recent version of this report, see ISO-NE (2014b). http://www.iso-ne.com/system-planning/system-plans-studies/rsp

[31] Section 5 of the *2014 Regional System Plan* shows transmission projects in ISO-NE (as of June 2014) that, among other things, are designed to address these constraints.

[32] *ibid*, p. 73

[33] *ibid*. pp. 74-75, and Vermont Electric Power Company (VELCO) (2012). *2012 Vermont Long-Range Transmission Plan*, http://www.velco.com/uploads/documents/2012LRTP_final_to_PSB.pdf

[34] Wilkinson, Eric (2013), "Summary of Wind Power and Curtailment in New England," http://www.iso-ne.com/pubs/pubcomm/corr/2013/curtailment_summary_2013.pdf

[35] ISO-NE (2013), p. 75. http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[36] NYISO comments that the constraints limit rather than prevent exports to Vermont. (Personal communication from J. Beuchler, NYISO, on May 15, 2015.)

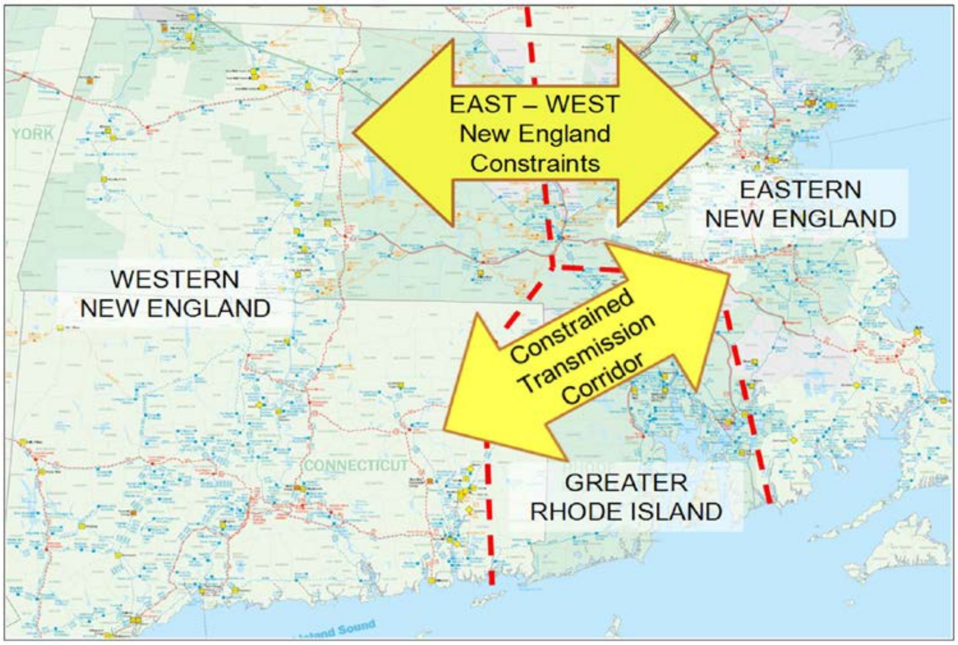


Figure 5-9. Constraints in southern New England

Source: ISO-NE (2014b). 2014 Regional System Plan, p. 101. *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*,[37] which contains an analysis of historical and projected future congestion. MISO also makes public a list of top historical congested flowgates[38, 39, 40] and a list of projected top future congested flowgates. In its 2013 report, a new method for projecting top future congested flowgates was used, which provides a better approximation of the economic value of mitigating future projected congestion. The top future congested flowgates reported in the 2014 report are shown in Figure 5-10.[41]

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

[38] "The top historically congested flowgates were selected using binding hours, shadow price, and congestion cost information from both the day-ahead and real-time markets. For each of the above congestion metrics, the top thirty binding flowgates were selected. The three lists were then merged to form a list of the top 75 congested flowgates." See MISO (2013), p. 18. https://www.misoenergy.org/Library/Repository/Study/MTEP/2013%20Market%20Efficiency%20Planning%20Study%20Report%20Draft.pdf

[39] A full list of the top 75 historical congested flowgates is included in the appendix of the MISO Market Efficiency Report, including flowgate description and area, day-ahead, and real-time binding hours ranking and shadow price ranking for April 2010-2012. See MISO (2013), pp. 18-19, 118-126.

[40] See MISO (2014a). "20131030 MEPS Midwest Top DA RT M2M Congested Flowgate Summary," at https://www.misoenergy.org/Events/Pages/MEPSTRG20131030.aspx.

[41] Sections 1 and 4 of MISO (2014c) describe transmission projects in MISO (as of July 2013) that, among other things, are designed to address these constraints.

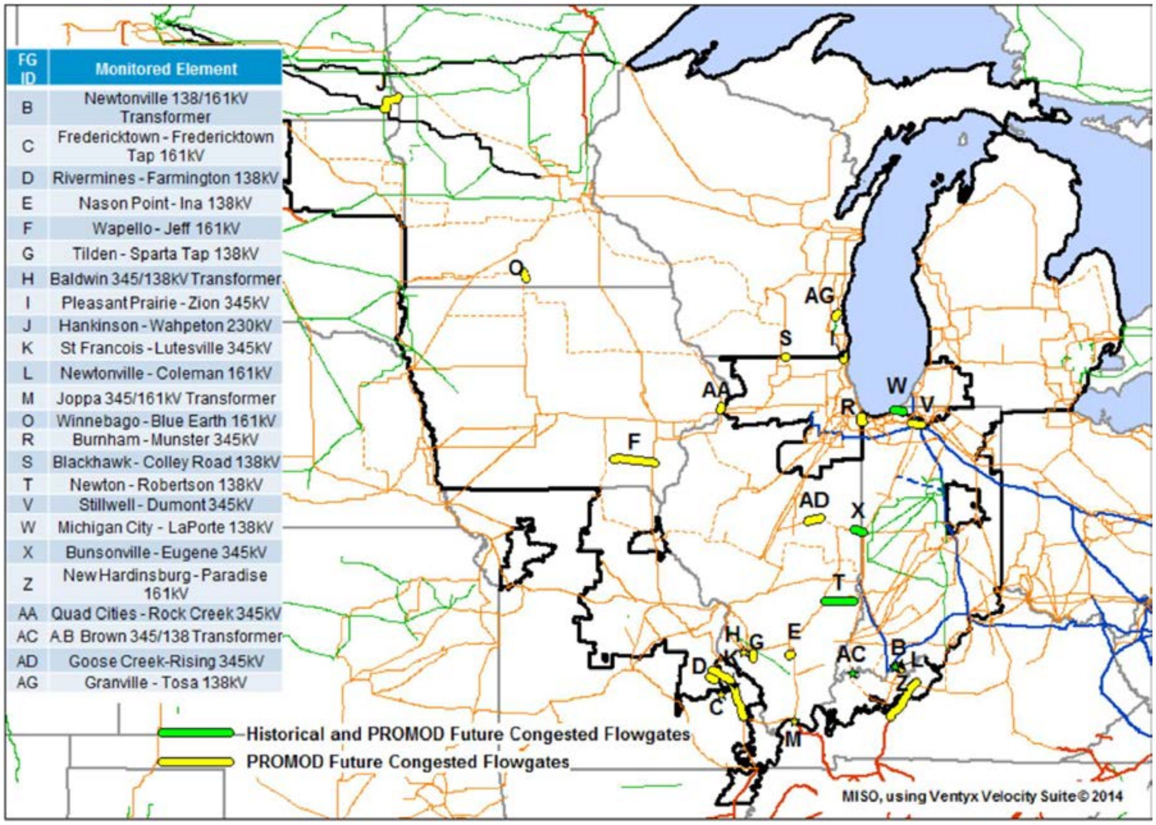


Figure 5-10. MISO 2014 top congested flowgates

Source: MISO (2014c), p. 129. https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP14/MTEP14%20Full%20Report.pdf

5.4.5. New York ISO (NYISO)

The NYISO biennially performs a Reliability Needs Assessment (RNA) as part of its Reliability Planning Process (RPP). 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. Figure 5-11 shows the geographic area served and the approximate locations of the violations identified by NYISO.

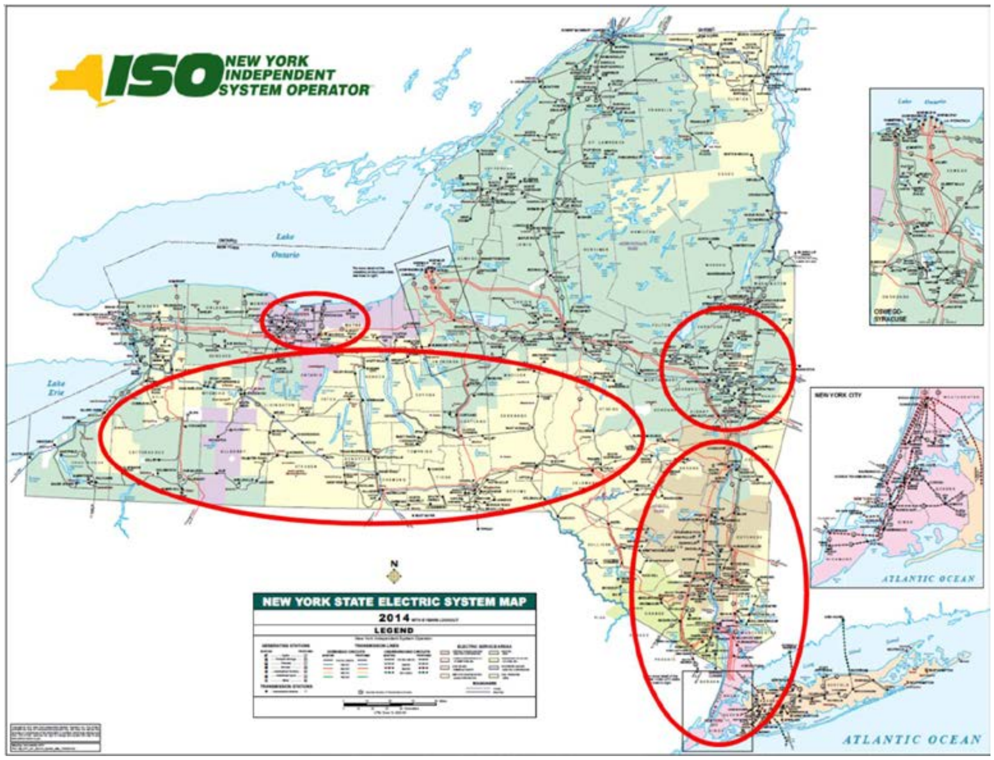


Figure 5-11. NYISO regions where loads may be impacted by transmission security constraints

Source: NYISO (2014b). 2013 Reliability Needs Assessment Final Report, p. 21. *http://www.nyiso.com/public/webdocs/media_room/press_releases/2014/Child_Reliability_Needs_Assessment/2014%20RNA_final_09162014.pdf*

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.[42] Figure 5-12 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.[43]

In addition, NYISO conducts a biennial economic planning process and publishes corresponding *Congestion Assessment and Resource Integration Study* (CARIS) reports. In the 2013 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.[44, 45]

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[42] For the most recent version of this report, see NYISO (2014a). *Power Trends 2014: Evolution of the Grid*. http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/ptrends_2014_final_jun2014_final.pdf.

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

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

[44] See NYISO (2013). *2013 Congestion Assessment and Resource Integration Study—Comprehensive System Planning Process (CARIS)—Phase 1*, p. 50. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg_iptf/meeting_materials/2013-08-12/2013%20CARIS%20Draft%20Report%20%20rev.pdf

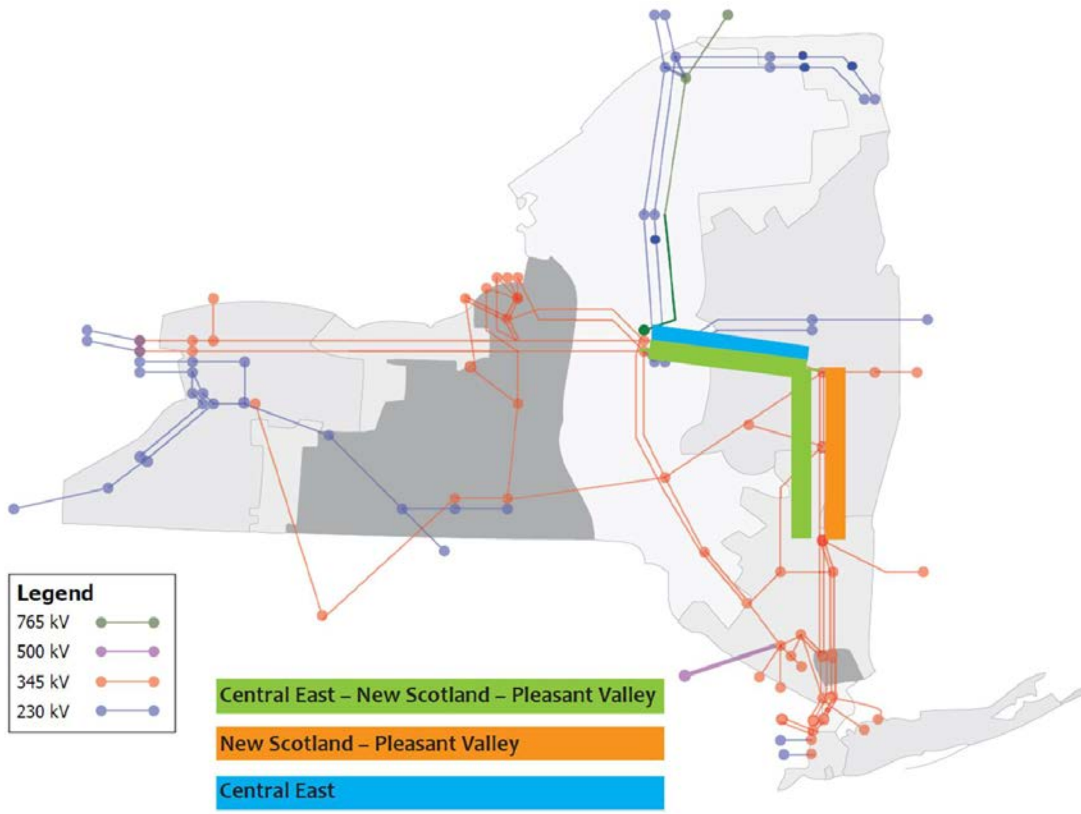

Figure 5-12. Transmission congestion corridors in New York State

Source: NYISO (2014a), p. 28. *http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/ptrends_2014_final_jun2014_final.pdf*

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**
CENTRAL EAST	2,964	2,164	1,467	3,068	3,457	3,615	3,205	3,770	3,795	4,000	2,932	3,168	3,025
MOTTHAVEN DUNWOODIE	1,424	1,550	930	-	-	-	-	-	-	-	-	-	-
DUNWOODIE SHORE ROAD	4,292	6,196	4,130	7,786	7,802	7,746	7,978	7,881	7,984	8,056	8,231	8,216	8,249
GREENWOOD	4,317	5,734	4,440	6,397	6,435	6,489	6,241	6,499	6,554	6,546	7,368	7,383	7,407
HUNTLEY PACKARD	-	-	1	1,241	726	813	851	762	921	979	1,710	1,811	1,735
NEW SCOTLAND LEEDS	156	774	69	392	266	240	104	76	24	63	253	192	437
LEEDS PLEASANT VALLEY	673	503	390	1,913	1,620	1,577	1,055	1,013	845	978	1,343	1,434	948
MOTTHAVEN RAINEY	895	754	415	27	41	59	6	8	-	2	-	1	-
RAINEY VERNON	3,078	3,510	1,556	1,615	1,463	1,579	460	597	735	780	560	690	589
VOLNEY SCRIBA	-	-	333	1,798	1,553	1,634	1,675	1,679	1,864	1,968	1,558	1,812	1,680

Source: NYISO (2013), p. 51. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg_iptf/meeting_materials/2013-08-12/2013%20CARIS%20Draft%20Report%20%20rev.pdf

5.4.6. PJM

The PJM external market monitor, Monitoring Analytics, reports top constraints based on a number of criteria in its annual *State of the Market* report.[46] Figure 5-13 shows the location of the top 10 constraints affecting PJM's congestion costs in 2014. Table 5-8 lists the top 25 constraints affecting 2014 congestion costs.

Table 5-6 lists the top 25 constraints as measured by frequency of occurrence. Table 5-7 lists the top 25 constraints with the largest year-to-year change in occurrence.

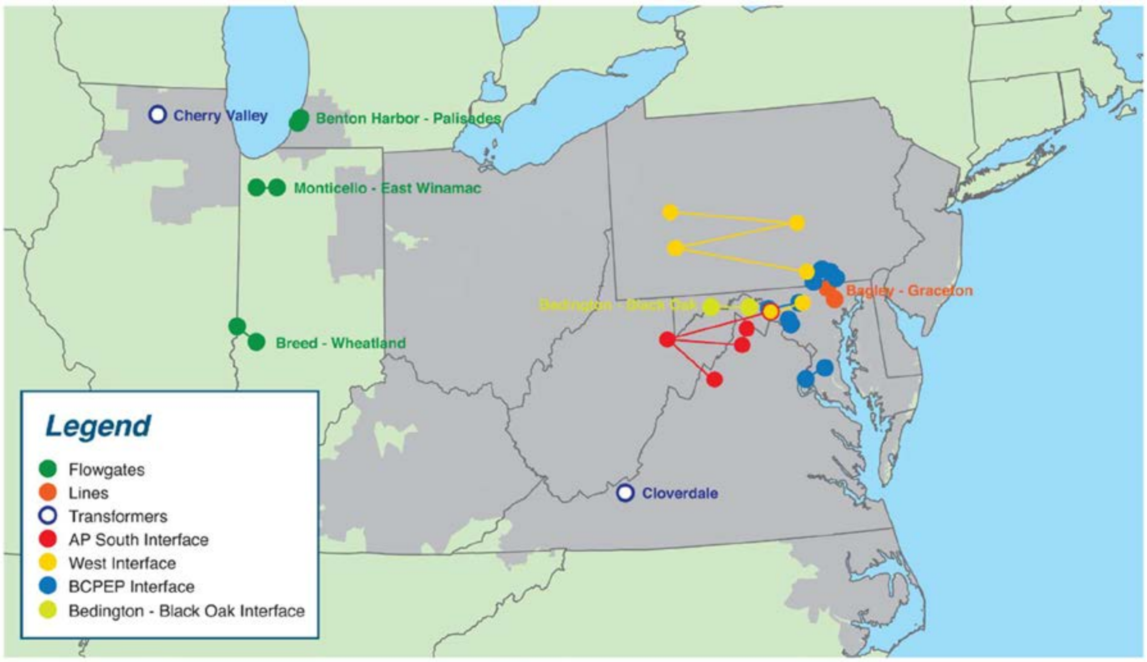

Figure 5-13. Location of the top 10 constraints affecting PJM congestion costs, 2014

Source: Monitoring Analytics (2015b). 2014 State of the Market Report for PJM, Volume 2: Detailed Analysis, *p. 405.* *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf*

[46] For the most recent version of this report, see http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014.shtml.

Table 5-6. PJM top 25 constraints with frequent occurrence, 2013–2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	2,333	8,820	6,487	29	23	(6)	27%	100%	74%	0%	0%	(0%)
2	Sporn	Transformer	8,676	3,560	(5,116)	0	0	0	99%	41%	(59%)	0%	0%	0%
3	Burlington - Croydon	Line	238	4,971	4,733	0	0	0	3%	57%	54%	0%	0%	0%
4	Bagley - Graceton	Line	2,087	4,584	2,497	440	1,884	1,444	24%	52%	28%	5%	21%	16%
5	Oak Grove - Galesburg	Flowgate	3,177	6,905	3,728	888	1,059	171	36%	79%	42%	10%	12%	2%
6	Readington - Roseland	Line	4,177	1,169	(3,008)	817	189	(628)	48%	13%	(34%)	9%	2%	(7%)
7	SENECA	Interface	0	3,562	3,562	0	0	0	0%	41%	41%	0%	0%	0%
8	Gould Street - Westport	Line	7,401	3,867	(3,534)	21	0	(21)	84%	44%	(40%)	0%	0%	(0%)
9	Kendall Co. Energy Ctr.	Transformer	2,071	5,488	3,417	0	0	0	24%	62%	39%	0%	0%	0%
10	Wolf Creek	Transformer	1,779	5,102	3,323	48	131	83	20%	58%	38%	1%	1%	1%
11	Seneca	Interface	0	0	0	0	3,227	3,227	0%	0%	0%	0%	37%	37%
12	Joshua Falls	Transformer	19	3,064	3,045	0	13	13	0%	35%	35%	0%	0%	0%
13	Bergen - New Milford	Line	1,690	4,745	3,055	0	0	0	19%	54%	35%	0%	0%	0%
14	Bridgewater - Middlesex	Line	3,046	223	(2,823)	257	31	(226)	35%	3%	(32%)	3%	0%	(3%)
15	Rocky Mount - Battleboro	Line	2,945	312	(2,633)	430	14	(416)	34%	4%	(30%)	5%	0%	(5%)
16	East Bend	Transformer	2,197	5,082	2,885	0	0	0	25%	58%	33%	0%	0%	0%
17	Haurd - Steward	Line	3,588	749	(2,839)	0	0	0	41%	9%	(32%)	0%	0%	0%
18	Sayreville - Sayreville	Line	44	2,869	2,825	0	0	0	1%	33%	32%	0%	0%	0%
19	Kenney - Stockton	Line	99	1,517	1,418	93	1,469	1,376	1%	17%	16%	1%	17%	16%
20	Cherry Valley	Transformer	12	2,420	2,408	8	252	244	0%	28%	27%	0%	3%	3%
21	Cook - Palisades	Flowgate	0	2,316	2,316	0	308	308	0%	26%	26%	0%	4%	4%
22	Zion	Line	3,018	488	(2,530)	0	0	0	34%	6%	(29%)	0%	0%	0%
23	Sunbury	Transformer	6,866	4,344	(2,522)	0	0	0	78%	49%	(29%)	0%	0%	0%
24	Keeney	Transformer	678	3,099	2,421	0	58	58	8%	35%	28%	0%	1%	1%
25	Electric Junction - Frontenac	Line	2,540	123	(2,417)	0	0	0	29%	1%	(28%)	0%	0%	0%

Source: Monitoring Analytics (2015b), p. 403. *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf*

Table 5-7. PJM's top 25 constraints with largest year-to-year change in occurrence, 2013–2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	2,333	8,820	6,487	29	23	(6)	27%	100%	74%	0%	0%	(0%)
2	Sporn	Transformer	8,676	3,560	(5,116)	0	0	0	99%	41%	(59%)	0%	0%	0%
3	Burlington - Croydon	Line	238	4,971	4,733	0	0	0	3%	57%	54%	0%	0%	0%
4	Bagley - Graceton	Line	2,087	4,584	2,497	440	1,884	1,444	24%	52%	28%	5%	21%	16%
5	Oak Grove - Galesburg	Flowgate	3,177	6,905	3,728	888	1,059	171	36%	79%	42%	10%	12%	2%
6	Readington - Roseland	Line	4,177	1,169	(3,008)	817	189	(628)	48%	13%	(34%)	9%	2%	(7%)
7	SENECA	Interface	0	3,562	3,562	0	0	0	0%	41%	41%	0%	0%	0%
8	Gould Street - Westport	Line	7,401	3,867	(3,534)	21	0	(21)	84%	44%	(40%)	0%	0%	(0%)
9	Kendall Co. Energy Ctr.	Transformer	2,071	5,488	3,417	0	0	0	24%	62%	39%	0%	0%	0%
10	Wolf Creek	Transformer	1,779	5,102	3,323	48	131	83	20%	58%	38%	1%	1%	1%
11	Seneca	Interface	0	0	0	0	3,227	3,227	0%	0%	0%	0%	37%	37%
12	Joshua Falls	Transformer	19	3,064	3,045	0	13	13	0%	35%	35%	0%	0%	0%
13	Bergen - New Milford	Line	1,690	4,745	3,055	0	0	0	19%	54%	35%	0%	0%	0%
14	Bridgewater - Middlesex	Line	3,046	223	(2,823)	257	31	(226)	35%	3%	(32%)	3%	0%	(3%)
15	Rocky Mount - Battleboro	Line	2,945	312	(2,633)	430	14	(416)	34%	4%	(30%)	5%	0%	(5%)
16	East Bend	Transformer	2,197	5,082	2,885	0	0	0	25%	58%	33%	0%	0%	0%
17	Haurd - Steward	Line	3,588	749	(2,839)	0	0	0	41%	9%	(32%)	0%	0%	0%
18	Sayreville - Sayreville	Line	44	2,869	2,825	0	0	0	1%	33%	32%	0%	0%	0%
19	Kenney - Stockton	Line	99	1,517	1,418	93	1,469	1,376	1%	17%	16%	1%	17%	16%
20	Cherry Valley	Transformer	12	2,420	2,408	8	252	244	0%	28%	27%	0%	3%	3%
21	Cook - Palisades	Flowgate	0	2,316	2,316	0	308	308	0%	26%	26%	0%	4%	4%
22	Zion	Line	3,018	488	(2,530)	0	0	0	34%	6%	(29%)	0%	0%	0%
23	Sunbury	Transformer	6,866	4,344	(2,522)	0	0	0	78%	49%	(29%)	0%	0%	0%
24	Keeney	Transformer	678	3,099	2,421	0	58	58	8%	35%	28%	0%	1%	1%
25	Electric Junction - Frontenac	Line	2,540	123	(2,417)	0	0	0	29%	1%	(28%)	0%	0%	0%

Source: Monitoring Analytics (2015b), p. 404. *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf*

Table 5-8. PJM top 25 constraints affecting PJM congestions costs (by facility), 2014

				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	2014
1	AP South	Interface	500	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	25.2%
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	9.4%
3	Bagley - Graceton	Line	BGE	$98.5	($9.5)	($1.7)	$106.3	$5.7	($4.0)	$4.5	$14.2	$120.5	6.2%
4	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	4.4%
5	Breed - Wheatland	Flowgate	MISO	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	4.1%
6	Benton Harbor - Palisades	Flowgate	MISO	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	2.9%
7	Cloverdale	Transformer	AEP	$23.3	($27.3)	$0.2	$50.7	$0.0	$0.0	$0.0	$0.0	$50.7	2.6%
8	BCPEP	Interface	Pepco	$15.6	($15.2)	($1.6)	$29.3	($1.6)	($14.2)	$1.5	$14.1	$43.4	2.2%
9	Unclassified	Unclassified	Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	2.2%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.7%
11	Oak Grove - Galesburg	Flowgate	MISO	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	1.6%
12	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.5%
13	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.4%
14	Cloverdale	Transformer	AEP	$23.1	($4.8)	($2.3)	$25.7	$0.0	$0.0	$0.0	$0.0	$25.7	1.3%
15	Cherry Valley	Transformer	ComEd	$20.1	($16.5)	$4.3	$40.8	($4.4)	$2.6	($9.7)	($16.7)	$24.2	1.2%
16	Wolf Creek	Transformer	AEP	$4.6	$1.3	$4.7	$8.0	$3.6	$5.6	($29.3)	($31.3)	($23.3)	(1.2%)
17	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.2%
18	SENECA	Interface	PENELEC	$5.6	$9.9	($6.5)	($10.9)	($3.0)	$1.2	($6.1)	($10.4)	($21.3)	(1.1%)
19	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.1%
20	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1.1%
21	Bergen - New Milford	Line	PSEG	$22.0	$13.2	$12.0	$20.7	$0.0	$0.0	$0.0	$0.0	$20.7	1.1%
22	Nelson - Cordova	Line	ComEd	($24.7)	($47.1)	$4.2	$26.6	($0.7)	$1.1	($4.3)	($6.0)	$20.5	1.1%
23	Bridgewater - Middlesex	Line	PSEG	$0.2	($22.2)	($3.0)	$19.4	($1.5)	$0.1	$1.4	($0.2)	$19.2	1.0%
24	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	0.9%
25	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.8%

Source: Monitoring Analytics (2015b), p. 404. *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf*

5.4.7. Southwest Power Pool (SPP)

The SPP internal market monitor provides information about constraints in its annual State of the Market report.[47] Table 5-9 shows principal congested flowgates by area. The criterion used to identify top constraints is shadow price.

Table 5-9. SPP principal congested flowgates by area

Region	Flowgate Name	Flowgate Location (kV)	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Projects Expected to Provide Some Positive Mitigation (Estimated In Service Date – Upgrade Type)
Texas Panhandle	OSGCANBUSDEA	Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]	$44.13	36.7%	• Tuco Int. – Woodward 345 kV line (May 2014 - Balanced Portfolio) • Castro County Int. – Newhart 115 kV line (April 2015 - Regional Reliability) • Tuco Int. – Amoco – Hobbs 345 lines (Currently on hold – ITP10)
	GRAXFRSWEELK	Grapevine Xfmr (230/115) [SPS] ftlo Sweetwater – Elk City (230) [WFEC]	$5.97	5.0%	• Bowers – Howard 115 kV line (June 2016 – ITPNT) • Grapevine Transformer (June 2014)
	SHAXFRELKXFR	Shamrock Xfmr (115/69) [CSWS} ftlo Elk City Xfmr (230/138) [WFEC]	$2.76	1.5%	• Elk City – Gracemont 345 kV line (March 2018 – ITP10) • Potter Co. – Tolk 345 kV line (December 2018)
	SPSNORTH_STH	5 element PTDF flowgate north to south through west Texas	$2.71	10.5%	• Randall County Interchange – Amarillo South Interchange 230 kV line (May 2013)
Kansas City – Omaha Corridor	EASXFREASSTJ	Eastowne Xfmr (345/161) ftlo Eastowne-St. Joe (345) [GMOC]	$13.15	7.7%	• Iatan – Nashua 345 kV (June 2015 - Balanced Portfolio)
	PENMUN87TCRA *PENMUNSTRCRA* *(see note below)*	Pentagon – Mund (115) [WR] ftlo 87th Street – Craig (345) [WR-KCPL]	$12.73	8.8%	• Tap existing Swissvale – Stilwell 345 kV line at West Gardner (in service December 2012) • Iatan – Nashua 345 kV (June 2015 - Balanced Portfolio)
	SUBTEKFTCRAU	Sub 1226 - Tekamah (161) ftlo Fort Calhoun - Raun (345) [OPPD/MEC]	$2.70	0.5%	• SUBTEKFTCRAU is a reciprocal coordinated flowgate with MISO. There are no planned projects to provide positive mitigation.
Western Nebraska	VICXFRWAYSTE	Victory Hill Xfmr (230/115) [NPPD} ftlo Wayside-Stegall (230) [WAUE]	$3.23	0.8%	• Victory Hill Transformer (December 2016) • Scottsbluff – Stegall 115 kV (June 2014)
Eastern Oklahoma	TAHH59MUSFTS	Tahlequah-Highway 59 (161) [GRDA-OGE] ftlo Muskogee-Fort Smith (345) [OGE]	$3.05	0.9%	• Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio) • Gore – Muskogee 161 kV (June 2018) • Gore – Sallisaw 161 kV (June 2018)
Tulsa Area	OKMHENOKMKEL	Okmulgee – Henryetta (138) ftlo Okmulgee – Kelco (138) [CSWS]	$2.70	1.7%	• Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio)

Note: PENMUN87TCRA replaced PENMUNSTRCRA on 4/1/13. Their history has been combined and is reflected as one entry on this table.

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2014), 2013 State of the Market Report, *p. 82.* http://www.spp.org/publications/2013%20SPP%20State%20of%20the%20Market%20Report.pdf

[47] For the most recent version of this report, see http://www.spp.org/section.asp?pageID=86.

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.[48] 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.[49]

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.[50, 51]

[48] Eastern Interconnection States' Planning Council (EISPC) (2012). *Market Structures and Transmission Planning Processes in the Eastern Interconnection.* http://www.naruc.org/grants/Documents/EISPC%20Market%20Structures%20Whitepaper_6_15_12.pdf

[49] 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 costs are neither calculated nor imposed.

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

This report presents information on the economic cost of congestion developed by individual market operators.[52] 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), and San Diego Gas & Electric (SDG&E).

Nodal prices are made up of three components: the marginal cost of energy, the marginal cost of congestion (relative to the reference bus[53]), and the marginal cost of losses (relative to the reference bus).[54] 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).

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[51] In addition, many RTO/ISO markets offer some kind of congestion hedging mechanism, such as 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 instruments are essentially financial tools for market participants to hedge exposure to paying congestion costs. For instance, 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. While these are important financial tools that help participants manage risk in these markets, data or information about them do 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.

[52] 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 is expected to issue a final Information Collection Statement in 2015. See http://www.ferc.gov/legal/staff-reports/2014/AD14-15-performance-metrics.pdf.

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

[54] California ISO (CAISO) (2013), *Fifth Replacement Electronic Tariff: Appendix C: Location Marginal Price,* http://www.caiso.com/Documents/AppendixC_LocationalMarginalPrice_Jul1_2013.pdf

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

- Use of UFM to manage some congestion prior to the operation of the day-ahead market. A major market redesign was also 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.[55]
- 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 2006-2011. Figure 6-1 presents import congestion charges on major interties for 2011-2013. Table 6-2 reports day-ahead congestion costs by local capacity area for 2012 and 2013.

Table 6-1. CAISO congestion costs, 2006-2011 ($M)

	2006	2007	2008	2009	2010	2011
CAISO: pre-MRTU	$263	$181	$350			
CAISO: MRTU, Day Ahead Energy and Congestion				$128	$110	$219

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). Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012, *p. 39.* *http://www.energy.gov/sites/prod/files/2014/02/f7/TransConstraints Congestion-01-23-2014%20.pdf*

[55] CAISO (2007). *Convergence Bidding: Department of Market Monitoring Recommendations, Attachment C – Seller's Choice Contracts under Nodal Virtual Bidding.*http://www.caiso.com/Documents/AttachmentC-Seller'sChoice ContractsunderNodalVirtualBidding.pdf

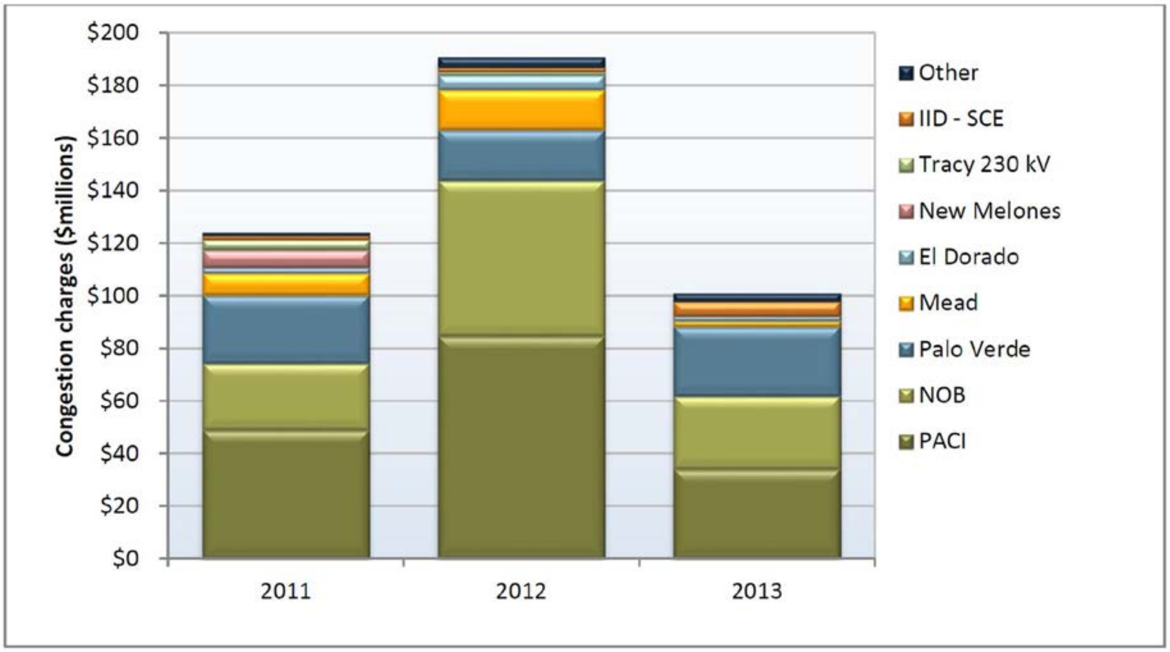


Figure 6-1. CAISO import congestion charges on major interties, 2011-2013

Source: CAISO (2014), p. 181. http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

Table 6-2. CAISO day-ahead congestion by local capacity area

		Average of congestion LMP as percent of system LMP			
LAP	LCA	2012 Avg. LMP (congestion)	2012 Avg.	2013 Avg. LMP (congestion)	2013 Avg.
PGAE	Bay Area	-$1.12	-3.7%	-$1.56	-3.6%
	Fresno	-$1.23	-4.1%	-$0.18	-0.4%
	Humboldt	-$1.78	-5.9%	-$1.63	-3.7%
	Kern	-$1.44	-4.8%	-$1.85	-4.3%
	NCNB	-$1.35	-4.5%	-$1.87	-4.3%
	Sierra	-$0.72	-2.4%	-$1.61	-3.7%
	Stockton	$0.34	1.1%	-$1.83	-4.2%
SCE	Big Creek-Ventura	$0.70	2.3%	$1.91	4.4%
	LA Basin	$0.88	2.9%	$1.62	3.7%
SDGE	San Diego-IV	$2.03	6.7%	$0.11	0.2%

Source: CAISO (2014), p. 186. http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

CAISO's department of Market Monitoring reports the following findings on congestion in 2013:

- *Congestion on transmission constraints within the ISO system decreased compared to prior years and had a lower impact on average overall prices across the system.*
- *Congestion in 2013 decreased significantly in the second half of the year as a result of improved contingency modeling, fewer outages and an upgrade of the Ocotillo 500 kV substation in the San Diego area.*
- *Prices in the SCE area were impacted the most by internal congestion, which increased average day- ahead and real-time prices in the SCE area above the system average by about $1.70/MWh or 4 percent. About 85 percent of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area.*
- *Congestion increased average real-time prices in the San Diego area above the system average by about $0.22/MWh or 0.5 percent. Day-ahead San Diego congestion did not have a significant impact on overall average prices over the year. This was because multiple constraints had offsetting effects, with some increasing congestion and others decreasing congestion.*
- *The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about 3 percent in both the day-ahead and real-time markets. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows into the SCE and SDG&E areas.*
- *Congestion on most major inter-ties connecting the ISO with other balancing authority areas was lower in 2013, particularly for inter-ties connecting the ISO to the Pacific Northwest.*
- *Average profitability of all congestion revenue rights was about $0.14/MW in 2013, compared to about $0.40/MW in 2012. This [decrease] was driven largely by lower levels of congestion in 2013. Overall, rights in the prevailing flow of congestion were less profitable than rights in the opposite, or counter-flow, direction of the prevailing flow. This is a change from 2012 when prevailing flow congestion was more profitable and is more consistent with the pattern of congestion revenue rights profitability in earlier years.*[56]

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

[56] *Source: CAISO (2014), p. 177.*http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

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.[57]

Table 6-3 reports congestion costs for 2008-2013. Table 6-2 presents day-ahead congestion costs, and Table 6-3 presents real-time congestion costs.

Table 6-3. ERCOT reported congestion costs, 2008 to 2013

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of $)					
		2008	2009	2010	2011	2012	2013
ERCOT MM report	Total Congestion Revenue	n/a	n/a	n/a	407	480	466

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

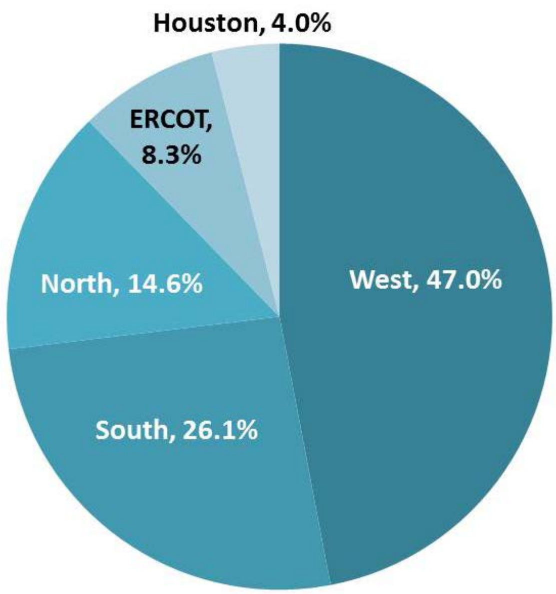


Figure 6-2. ERCOT day-ahead congestion costs

Source: Potomac Economics (2014b), p. 51. https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

[57] Potomac Economics (2014b), p. 46. https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

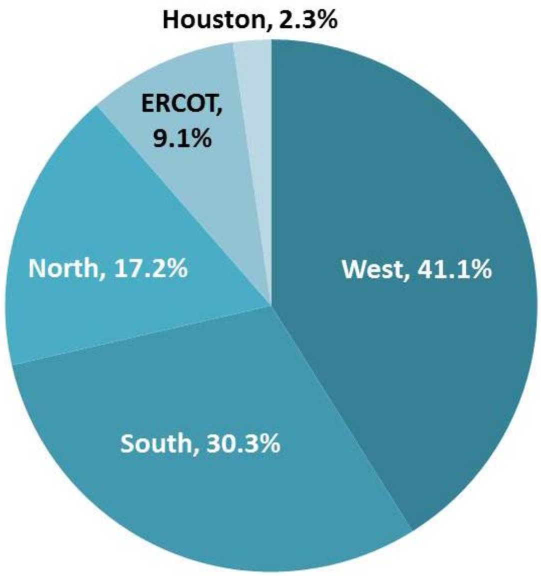


Figure 6-3. ERCOT real-time congestion costs

Source: Potomac Economics (2014b), p. 45. https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf

ERCOT's market monitor observations about congestion include:

> *Given increases in local loads and the increase in fuel prices, it is noteworthy that transmission congestion decreased in 2013. This reduction was due in large part to transmission improvements that decreased the congestion levels in the West zone. Annual prices for loads located in the West zone were $11 per MWh higher than ERCOT average in 2012. In 2013, West zone prices were $5 per MWh higher. By the end of 2013, the completion of the CREZ transmission lines virtually eliminated longstanding limitations affecting wind exports from the West zone.*[58]
>
> *…[Figure 6-3] displays the percentage of real-time congestion costs attributed to each geographic zone. Those costs associated with constraints that cross zonal boundaries, i.e., North to Houston, are shown in the ERCOT category. The amount of real-time congestion associated with facilities located in the West zone was more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 55 percent of real-time congestion costs were from the West zone. As the percentage of congestion attributed to the West zone decreased, the share of congestion attributed to the south zone increased from less than 20 percent in 2012 to 30 percent in 2013.*[59]
>
> *…To further emphasize the effects of West and South zone congestion in 2013, [Figure 6-2] highlights that, like real-time, day-ahead West and South zone congestion accounted for more than half the congestion in 2013. The amount of real-time congestion associated with facilities located in the West zone was*

[58] Potomac Economics (2014b), p. *x.* https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf
[59] *ibid*., p. 45.

more than 40 percent of the total congestion costs in 2013. This is a decrease from 2012 when more than 53 percent of real-time congestion costs were from the West zone.[60]

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 32 pricing nodes in the geographic center for New England. The Hub price is an average of prices at these 32 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[61] because it is connected radially to the rest of the Eastern Interconnection.[62] 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.[63]
- 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.[64]

Table 6-4 reports congestion costs for 2008-2013. Table 6-5 reports average day-ahead hub prices and load-zone differences for 2011-2013. Figure 6-4 presents monthly congestion revenue and target payments to FTR (financial transmission rights) holders for 2012-2013. Figure 6-5 presents average day-ahead prices by load zone for 2012-2013.

[60] *ibid*., p. 51.
[61] 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.
[62] 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
[63] 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.
[64] Likover (2014a). "Reserve Market Overview," http://www.iso-ne.com/support/training/courses/wem101/17_reserve_market_overview.pdf ; and Likover (2014b). "Reserve Market Settlement," http://www.iso-ne.com/static-assets/documents/support/training/courses/wem101/18_reserve_market_settlement.pdf

Table 6-4. ISO-NE reported congestion costs, 2008-2013

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of $)					
		2008	2009	2010	2011	2012	2013
ISO-NE Internal and External Market Monitors†	Total Congestion Revenue	121	25	38	18	30*	46*
ISO-NE Internal Market Monitor	Day-Ahead Congestion Revenue	125	27	37	18	29	46

**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), and (2014a), available from http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor; and Potomac Economics (2010a), (2011b), (2012b), (2013a), and (2014a), available from http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor.

Table 6-5. ISO-NE simple average day-ahead hub prices and load-zone differences, 2011–2013 ($/MWh)

Location/ Load Zone	2011	2012	2013
Hub	46.38	36.08	56.42
Maine	45.58	35.90	54.48
New Hampshire	45.94	35.92	55.98
Vermont	46.67	36.25	55.36
Connecticut	47.47	36.77	55.43
Rhode Island	45.77	36.24	57.79
SEMA	46.18	36.09	57.02
WCMA	46.92	36.98	56.37
NEMA	46.14	36.15	56.90

Source: ISO-NE (2014a). 2013 Annual Markets Report*, p. 75. http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf*

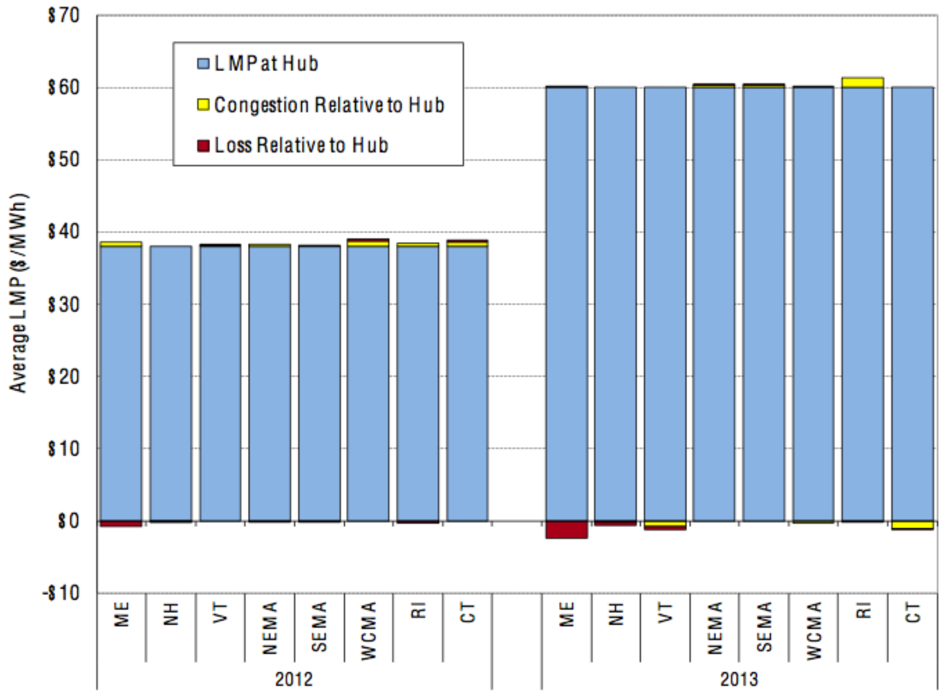


Figure 6-4. ISO-NE average day-ahead prices by load zone, 2012-2013

Source: Potomac Economics (2014a). 2013 Assessment of the ISO New England Electricity Markets, *p. 48.* [*http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf*](http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf)

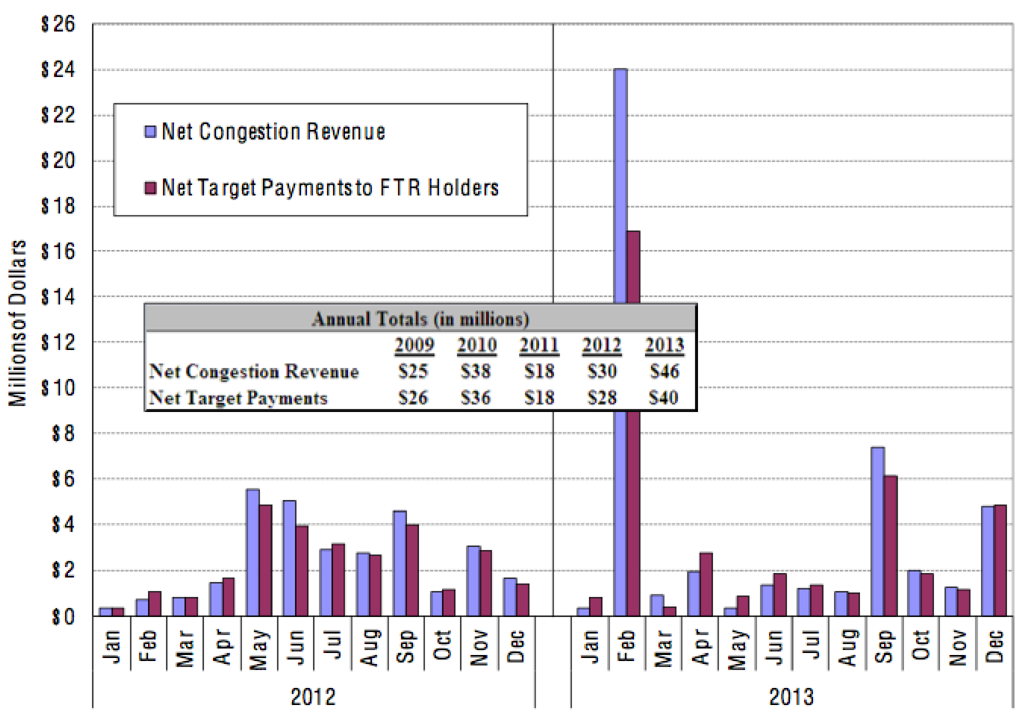


Figure 6-5. ISO-NE congestion revenue and target payments to FTR holders, 2012-2013

Source: Potomac Economics (2014a), p. 60. [*http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf*](http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf)

Potomac Economics, the External Market Monitor for ISO-NE, provided the following discussion on congestion in its *2013 State of the Market* report:

> *Historically, there have been significant transmission limitations between net-exporting and net- importing regions in New England. In particular, exports from Maine to the rest of New England have been limited by transmission constraints at times, while Connecticut and Boston were often unable to import enough power to satisfy demand without dispatching expensive local generation in the past. However, congestion has been very limited in recent years because of the transmission upgrades made in Boston, Connecticut, and Southeast Massachusetts from 2007 to 2009. These upgrades greatly increased the transfer capability into these areas and eliminated most of the congestion into these historically constrained regions. Consequently, the current levels of LMPs do not provide significant incentives for locating new resources in net-importing regions such as Boston.*[65]
>
> *…Total day-ahead congestion revenues totaled $46 million in 2013, up from $30 million in 2012. The increase in congestion revenue resulted primarily from high levels of congestion on two days in February when forced transmission outages limited flows from Connecticut to neighboring states and two days in September when planned transmission outages and unusually high loads led to severe congestion on flows through West-Central Massachusetts. The overall levels of congestion have been relatively low since the completion of transmission grades into historically constrained areas in 2009.*[66]
>
> *…Three months accounted for most of the increase in congestion in 2013:*
>
> - *February accounted for more than 50 percent (or $24 million) of congestion revenue in 2013 primarily because of the effects of Winter Storm Nemo. This storm dropped record snow across New England on February 8 and 9. It led to significant transmission outages and a total loss of more than 6,000 MW of generating capacity. These outages contributed to high congestion, particularly in Northeast Massachusetts, Southeast Massachusetts, and Rhode Island.*
> - *September had the second largest monthly congestion revenues because of the effects of a brief heat wave on September 11 and 12. The combined effects of high load levels and two planned transmission outages led to unusually high congestion into vicinity of the New England Hub (which is physically located within West-Central Massachusetts).*
> - *Congestion rose notably in December as a result of high natural gas prices which increased redispatch costs and associated congestion-related price differences. As a result, congestion costs were higher than in the same month of 2012.*[67]

[65] Potomac Economics (2014a), p. 47. http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf

[66] *Ibid*. p. 59.

[67] *Ibid*. p. 61.

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.[68] Bilateral trades (or financial settlements as they are called in MISO) must pay congestion costs as well.[69] Virtual trades are settled at day-ahead and real-time nodal prices, and therefore also pay the congestion component of the locational price.[70]

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).[71]
- PJM Firm Flow Entitlement (FFE) payments reduce the amount of congestion cost reported.[72]
- Holders of "grandfathered" transmission service agreements can choose among options that involve rebates for congestion.[73] Payments to these grandfathered rights are paid from the congestion revenue collected by MISO.[74]
- 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.

[68] Chu (2011). "Market Settlements Virtual and Financial Schedules (VF 201)," p. 26. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/MP%20200/Market%20Settlements%20Training%20-%20Virtual%20and%20Financial%20Schedules.pdf

[69] *ibid*, p. 143.

[70] *ibid*. p. 26.

[71] See Potomac Economics (2010b). *2009 State of the Market Report for the MISO Electricity Markets,* p. 41 and p. 79. https://www.misoenergy.org/Library/Repository/Report/IMM/2009%20State%20of%20the%20Market%20Report.pdf; and Potomac Economics (2012c) *2011 State of the Market Report for the MISO Electricity Markets*, p. A-76. https://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf.

[72] Potomac Economics (2013c). *2012 State of the Market Report for the MISO Electricity Markets,* p. 47. https://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf

[73] See Potomac Economics (2012c), p. A-81; Potomac Economics (2013c), p. 47; and Chu (2011), p. 186.

[74] See MISO (2014b). *Business Practices Manual 004: Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)*, pp. 33-36. Available from https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

- 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, 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 2008-2013, and Figure 6-6 presents total congestion costs for 2011-2013. Figure 6-7 presents day-ahead congestion and payments to FTRs for 2011-2013. Figure 6-8 presents the value of real-time congestion by coordination region for 2011-2013.

Table 6-6. MISO reported congestion costs and value, 2008-2013*

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

**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), and (2014d), available from https://www.misoenergy.org/MarketsOperations/IndependentMarketMonitor/Pages/IndependentMarketMonitor.aspx.

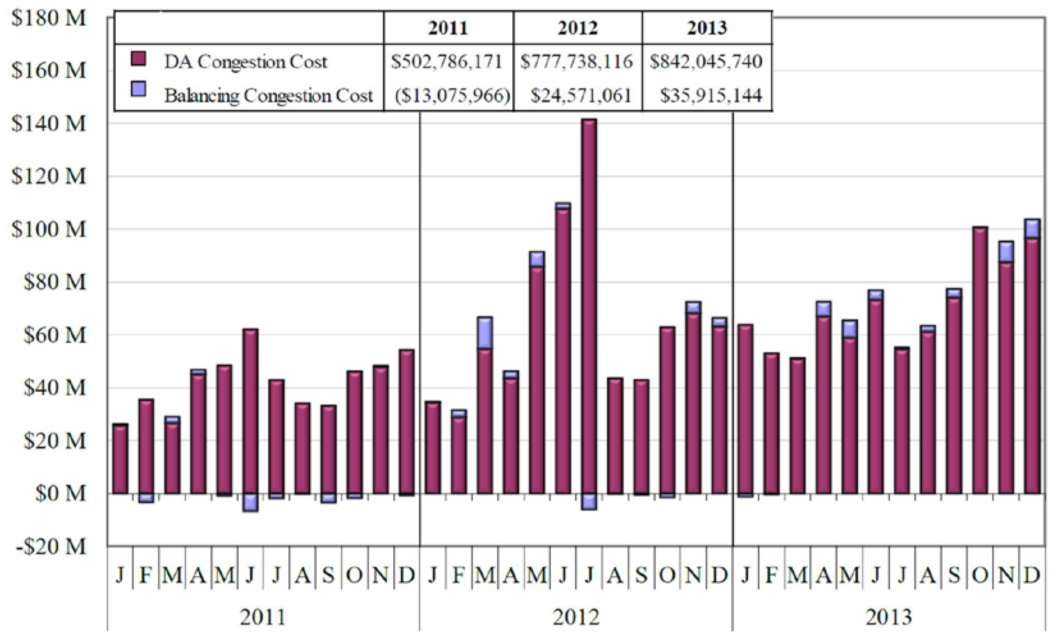
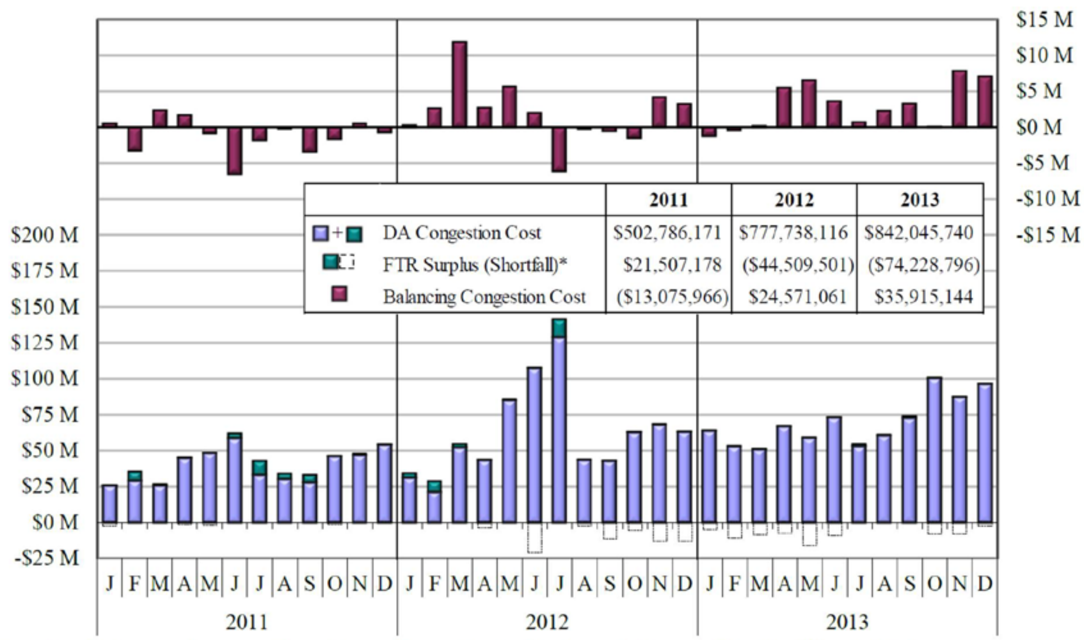


Figure 6-6. MISO total congestion costs, 2011-2013

Source: Potomac Economics (2014c). 2013 State of the Market Report for the MISO Electricity Markets*, p. A-102.* [*http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf*](http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf)



Note: * Excludes contributions of monthly auction residual collections which totaled $4.36 million in 2013.

Figure 6-7. MISO day-ahead congestion and payments to FTRs, 2011-2013

Source: Potomac Economics (2014c), p. 51. [*http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf*](http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf)

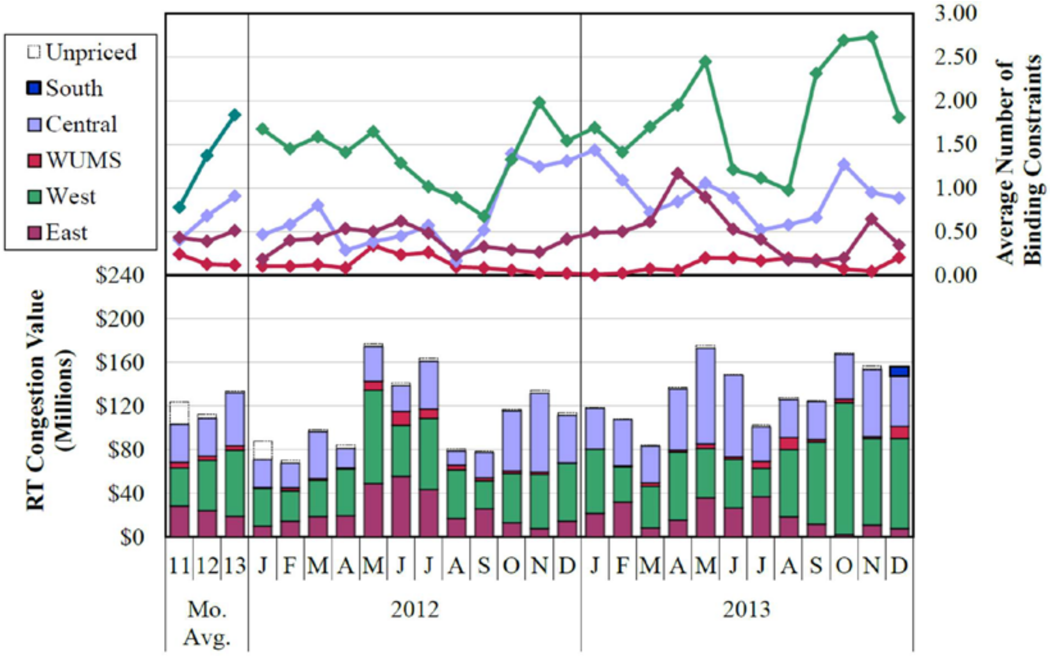


Figure 6-8. MISO - Value of real-time congestion by coordination region, 2012-2013

Source: Potomac Economics (2014c), p. A-110. http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf

Potomac Economics, MISO's external market monitor, made the following observations about congestion:

> *Day-ahead congestion costs rose 8.3 percent to total $842 million in 2013. The increase in day-ahead congestion coincided with increases in fuel prices that generally increase the cost of redispatching generation to manage network power flows. Much of the increase occurred on internal constraints in the West Region, many of which are affected by the increasing output from wind resources. MISO has continued to enhance its day-ahead processes to fully model potential transmission constraints in the day-ahead market.*[75]
>
> *…The total real-time congestion value increased 22.1 percent from 2012, the vast majority of which occurred on internal (including MISO-managed market-to-market) constraints. It was greatest in the fourth quarter because of significant outages in the West region. Increased fuel prices also contributed to the higher congestion value in 2013.*[76]
>
> *…The value of real-time congestion in 2013 rose 22 percent to $1.59 billion. This increase was due in part to higher fuel prices because higher fuel prices increase the costs of dispatch actions taken to manage network flows. Congestion rose fastest in the West Region due to significant outages. In addition, the full adoption of the dispatchable intermittent resource (DIR) type has substantially*

[75] Potomac Economics (2014c), p. 51. http://potomaceconomics.com/uploads/midwest_reports/2013%20SOM%20Report_Full%20Body_Final.pdf

[76] *ibid.*, p. 53.

> *improved MISO's ability to alter the dispatch of wind resources to manage congestion and allowed this congestion to be fully priced.*[77]

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—consisting of an energy component,[78] 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.[79] "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.[80]

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.
- 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.[81]

[77] *ibid.*, p. *v.*

[78] 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). "Locational Based Marginal Pricing," 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

[79] *ibid.*

[80] See http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp; and Potomac Economics (2012d). *2011 State of the Market Report for the New York ISO Markets,* p. 24. https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2011_SOM_Report-Final_4-18-12.pdf

[81] Potomac Economics (2013e). *Quarterly Report on the New York ISO Electricity Markets, Second Quarter 2013,* 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

- A single Transmission Shortage Cost of $4,000 is currently employed on all transmission constraints to limit their congestion costs.[82] A graduate transmission demand curve will be implemented soon to more properly reflect the severity of the transmission shortage.

Table 6-7 presents congestion costs and value for 2008-2013, and Table 6-8 presents Demand$ congestion for 2008-2012. 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.

Table 6-7. NYISO reported congestion costs and value, 2008-2013

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

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

Table 6-8. NYISO reported Demand$ congestion, 2008–2012

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

Sources: Developed by DOE from NYISO (2012). 2011 Congestion Assessment and Resource Integration Study—Comprehensive System Planning Process (CARIS)—Phase 1. *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; and 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.*

Figure 6-9 presents day-ahead and real-time congestion by transmission path for 2012-2013. Figure 6-10 presents congestion revenues and shortfalls for 2012-2013.

[82] Potomac Economics (2014e). *2013 State of the Market Report for the New York ISO Markets*, p. 65. https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf

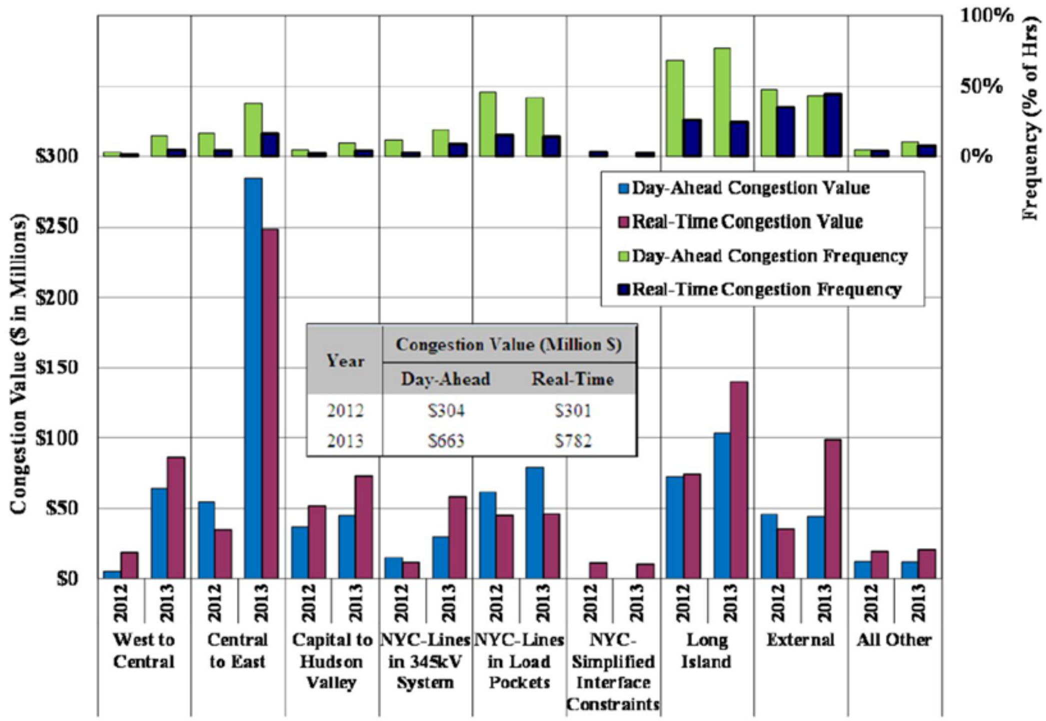


Figure 6-9. NYISO day-ahead and real-time congestion by transmission path, 2012-2013

Source: Potomac Economics (2014e), p. 9. https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf

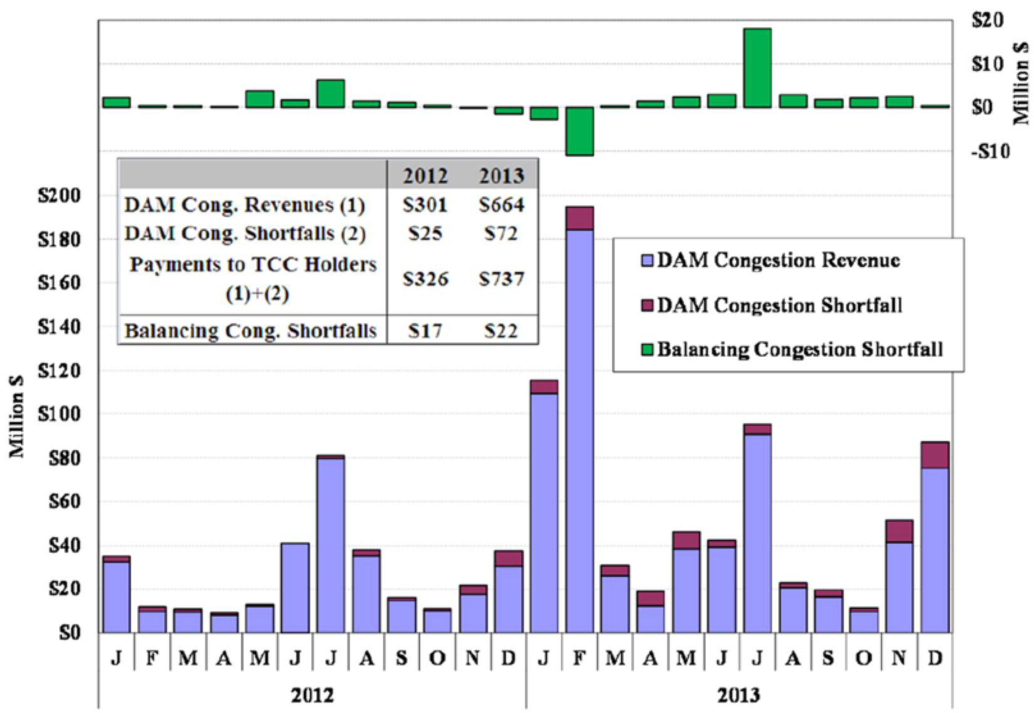


Figure 6-10. NYISO congestion revenues and shortfalls, 2012-2013

Source: Potomac Economics (2014e), p.38. https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf

In its *2013 State of the Market Report*, NYISO's market monitor observed that

> *…both the value and frequency of congestion rose from 2012 to 2013 on most transmission paths because:*
>
> - *Higher natural gas prices generally increased redispatch costs for managing congestion;*
> - *Larger spreads in natural gas prices between Western New York and Eastern New York increased flows on interfaces between the two regions, leading to increased west-to-east congestion;*
>   - *Congestion across the Central-East interface rose substantially from 2012 to 2013, accounting for nearly 40 percent of congestion values in both day-ahead and real-time markets in 2013,*
> - *Congestion across the external interfaces also increased in 2013, reflecting higher exports across the primary interface with New England, particularly in the winter months when natural gas prices in New England were significantly higher than in Eastern New York;*
> - *Congestion on the 230kV lines in the West Zone became more frequent in 2013 partly because of: (a) the retirement or mothballing of several coal units that relieve this congestion, (b) several lengthy transmission and generation outages, (c) changes in the TLR process due to the operation of the Ontario-Michigan PARs that prevent the NYISO from curtailing transactions that exacerbate congestion, and (d) inefficient utilization of some generation in the West Zone; and*
> - *Congestion into Long Island was also exacerbated by lengthy outages and deratings of the Neptune Cable and the 345kV transmission facilities from Upstate New York to Long Island."*[83]

6.7. PJM

PJM runs electricity markets and operates transmission across 13 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 20 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).[84]

[83] Potomac Economics (2014e), p. 9-10. https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf

[84] Effective 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.

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.

Table 6-9 presents congestion revenue for 2008–2014, and Table 6-10 presents total congestion for 2008-2014. Table 6-11 presents zonal and real-time, load-weighted average LMP components. Table 6-12 presents zonal and day-ahead, load-weighted average LMP components.

Table 6-9. PJM reported congestion revenue, 2008-2014

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

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

Table 6-10. Total PJM congestion ($M), 2008-2014

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$34,306	6.0%
2009	$719.0	(65.0%)	$26,550	2.7%
2010	$1,423.3	98.0%	$34,771	4.1%
2011	$999.0	(29.8%)	$35,887	2.8%
2012	$529.0	(47.0%)	$29,181	1.8%
2013	$676.9	28.0%	$33,862	2.0%
2014	$1,932.2	185.5%	$50,030	3.9%

Source: Monitoring Analytics (2015a), p. 49. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume1.pdf

Table 6-11. Zonal and PJM real-time, load-weighted average LMP components ($/MWh), 2013-2014

	2013				2014			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.11	$39.14	$0.27	$1.70	$55.77	$51.69	$2.11	$1.97
AEP	$35.56	$38.25	($1.78)	($0.92)	$47.81	$53.32	($4.32)	($1.19)
AP	$37.70	$38.39	($0.57)	($0.11)	$52.94	$53.88	($1.01)	$0.07
ATSI	$42.12	$38.43	$3.27	$0.42	$48.60	$52.07	($4.04)	$0.57
BGE	$43.52	$38.97	$2.79	$1.76	$67.78	$54.46	$10.86	$2.46
ComEd	$33.28	$38.65	($3.48)	($1.90)	$42.04	$51.56	($6.92)	($2.60)
DAY	$36.15	$38.61	($2.35)	($0.11)	$47.36	$53.07	($5.87)	$0.17
DEOK	$34.35	$38.57	($2.31)	($1.91)	$45.00	$52.87	($5.42)	($2.44)
DLCO	$35.70	$38.51	($1.61)	($1.20)	$44.22	$52.00	($6.12)	($1.66)
Dominion	$40.63	$38.84	$1.46	$0.33	$62.99	$54.58	$7.93	$0.48
DPL	$42.18	$38.96	$1.29	$1.93	$65.03	$54.72	$7.24	$3.07
EKPC	$33.96	$38.72	($2.73)	($2.02)	$47.88	$56.97	($6.57)	($2.52)
JCPL	$42.98	$39.54	$1.63	$1.81	$56.07	$52.18	$1.85	$2.04
Met-Ed	$39.72	$38.63	$0.34	$0.75	$56.08	$53.42	$1.55	$1.11
PECO	$39.70	$38.77	($0.11)	$1.03	$55.94	$52.73	$1.86	$1.35
PENELEC	$38.71	$38.18	($0.10)	$0.63	$51.90	$52.71	($1.31)	$0.50
Pepco	$42.78	$38.98	$2.62	$1.18	$65.61	$53.92	$10.09	$1.60
PPL	$39.26	$38.44	$0.18	$0.64	$56.97	$54.02	$2.03	$0.91
PSEG	$43.97	$38.93	$3.37	$1.67	$57.90	$51.43	$4.49	$1.99
RECO	$45.81	$39.65	$4.53	$1.63	$56.79	$51.34	$3.58	$1.87
PJM	$38.66	$38.64	$0.01	$0.02	$53.14	$53.13	($0.02)	$0.02

Source: Monitoring Analytics (2015b), p. 393. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf

Table 6-12. Zonal and PJM day-ahead, load-weighted average LMP components ($/MWh), 2013-2014

	2013				2014			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.48	$39.23	$0.61	$1.64	$57.24	$51.67	$4.04	$1.53
AEP	$36.44	$38.58	($1.26)	($0.88)	$48.83	$54.40	($4.59)	($0.98)
AP	$38.23	$38.62	($0.21)	($0.18)	$52.60	$54.21	($1.36)	($0.26)
ATSI	$38.13	$38.69	($0.85)	$0.29	$49.52	$52.63	($3.58)	$0.47
BGE	$44.32	$39.17	$3.46	$1.69	$68.52	$54.65	$11.97	$1.90
ComEd	$34.12	$38.86	($3.04)	($1.70)	$42.82	$52.38	($7.86)	($1.71)
DAY	$37.13	$38.89	($1.58)	($0.18)	$48.95	$53.95	($5.45)	$0.45
DEOK	$35.46	$38.70	($1.54)	($1.69)	$46.19	$52.68	($4.71)	($1.77)
DLCO	$36.35	$38.75	($1.17)	($1.22)	$44.95	$52.32	($5.52)	($1.85)
Dominion	$41.34	$39.15	$2.03	$0.16	$60.43	$54.75	$5.64	$0.05
DPL	$42.55	$39.10	$1.56	$1.89	$66.60	$54.56	$9.51	$2.52
EKPC	$35.65	$39.37	($1.68)	($2.04)	$48.80	$57.51	($6.32)	($2.39)
JCPL	$42.86	$39.48	$1.66	$1.73	$59.42	$52.87	$4.67	$1.87
Met-Ed	$40.04	$38.62	$0.83	$0.59	$57.42	$53.10	$3.71	$0.61
PECO	$40.14	$38.87	$0.32	$0.94	$57.60	$52.75	$3.87	$0.99
PENELEC	$39.29	$38.14	$0.38	$0.77	$51.32	$51.08	($0.21)	$0.44
Pepco	$43.16	$38.70	$3.33	$1.14	$64.04	$53.04	$9.85	$1.14
PPL	$39.67	$38.55	$0.65	$0.46	$59.04	$54.13	$4.47	$0.44
PSEG	$44.65	$39.17	$3.78	$1.70	$61.27	$52.09	$7.33	$1.84
RECO	$45.55	$39.37	$4.55	$1.62	$59.75	$51.71	$6.27	$1.76
PJM	$38.93	$38.79	$0.13	$0.00	$53.62	$53.38	$0.26	($0.02)

Source: Monitoring Analytics (2015b), p. 395. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf

In its *2014 State of the Market Report for PJM*, PJM's market monitor reports the following:

- ***Total Congestion.*** *Total congestion costs increased by $1,255.3 million or 185.5 percent, from $676.9 million in 2013 to $1,932.2 million in 2014.*
- ***Day-Ahead Congestion.*** *Day-ahead congestion costs increased by $1,220.0 million or 120.6 percent, from $1,011.3 million in 2013 to $2,231.3 million in 2014.*
- ***Balancing Congestion.*** *Balancing congestion costs increased by $35.3 million or 10.6 percent, from -$334.4 million in 2013 to -$299.1 million in 2014.*
- ***Real-Time Congestion.*** *Real-time congestion costs increased by $1,246.4 million or 131.8 percent, from $945.9 million in 2013 to $2,192.3 million in 2014.*
- ***Monthly Congestion.*** *In 2014, 42.7 percent ($825.1 million) of total congestion cost was incurred in January and 21.3 percent ($411.0 million) of total congestion cost was incurred in the months of February and March. Monthly total congestion costs in 2014 ranged from $54.3 million in April to $825.1 million in January.*
- ***Geographic Differences in CLMP.*** *Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AP South Interface, the West Interface, the Bagley–Graceton line, the Bedington–Black Oak Interface, and the Breed–Wheatland flowgate.*
- ***Congestion Frequency.*** *Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times higher than the number of congestion event hours in the Real-Time Energy Market.*
- *Day-ahead congestion frequency increased by 1.1 percent from 359,581 congestion event hours in 2013 to 363,452 congestion event hours in 2014.*
- *Real-time congestion frequency increased by 49.0 percent from 19,325 congestion event hours in 2013 to 28,796 congestion event hours in 2014.*
- ***Congested Facilities.*** *Day-ahead, congestion-event hours increased on all types of congestion facilities except transmission lines. Real-time, congestion-event hours increased on all types of congestion facilities.*
- *The AP South Interface was the largest contributor to congestion costs in 2014. With $486.8 million in total congestion costs, it accounted for 25.2 percent of the total PJM congestion costs in 2014.*
- ***Zonal Congestion.*** *AEP had the largest total congestion costs among all control zones in 2014. AEP had $454.0 million in total congestion costs, comprised of -$756.6 million in total load congestion payments, -$1,269.4 million in total generation congestion credits and -$58.8 million in explicit*

congestion costs. The AP South Interface, the West Interface, the Breed–Wheatland, Monticello–East Winamac and the Benton Harbor–Palisades flowgates contributed $299.8 million, or 66.0 percent of the total AEP control zone congestion costs.

- ***Ownership.*** *In 2014, 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 2014, financial entities received $231.2 million in congestion credits, an increase of $131.9 million or 132.8 percent compared to 2013. In 2014, physical entities paid $2,163.3 million in congestion charges, an increase of $1,387.2 million or 178.7 percent compared to 2013.UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2014, the total explicit cost is -$169.0 million and 118.5 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$200.2 million.*[85]

[85] Monitoring Analytics (2015a). *2014 State of the Market Report for PJM, Volume 1*, p. 49. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume1.pdf

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*.[86] (See Figure 6-11.)

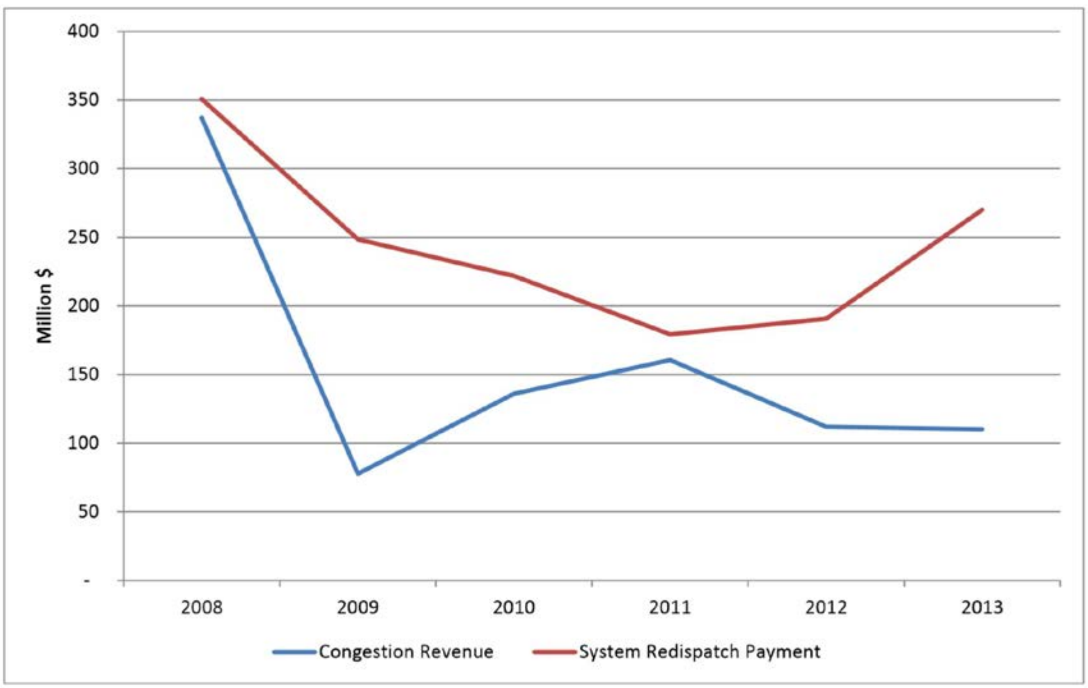


Figure 6-11. Congestion revenue and system redispatch payment, 2008-2013

Source: SPP (2014), p. 77. http://www.spp.org/publications/2013%20SPP%20State%20of%20the%20Market%20Report.pdf

In its *2013 State of the Market Report*, SPP's internal market monitor observed that:

> *Higher shadow prices in 2013 were caused in part by increased gas prices and resulting higher electric prices. The Texas Panhandle corridor continues to be the most congested area with the Osage Switch–Canyon East flowgate continuing to*

[86] For the most recent version of this report, see SPP (2014) at http://www.spp.org/publications/2013%20SPP%20State%20of%20the%20Market%20Report.pdf.

experience the highest shadow price: $44.13 during 2013, up from $12.16 in 2012. Limited import capability and low cost power north of the constraint continue to be the key factors driving this congestion. Some congestion relief is expected with the completion of Tuco to Woodward 345 kV line in mid-2014 and the Castro County to Newhart 115 kV in 2015.

The Omaha-Kansas City corridor is the second most congested area and is represented by three flowgates. This corridor is impacted by the large amount of low cost generation to the north and the limited transfer capability to move that power to the rest of the SPP market. Unaccounted for flow from outside the SPP system is another major factor. Historically this flow has been from the north to the south. The Eastowne Transformer flowgate was created to manage congestion that appeared in that Kansas City area when the transformer was installed in mid-2013. The shadow price for this flowgate was the second highest even though it only existed for half the year.

The remaining flowgates in the top-ten list are located in western Nebraska, eastern Oklahoma, and Tulsa areas and all have relatively low annual shadow price values.[87]

[87] SPP (2014), p. 81. http://www.spp.org/publications/2013%20SPP%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 to support interconnection-wide transmission planning. 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. This report summarizes the current status of these planning processes.

Additionally, in 2011, FERC issued Order No. 1000,[88] which, among other requirements, mandates regional transmission planning and interregional coordination. This report identifies the regional entities that were used to comply with this Order. Future reports will summarize aspects of the plans prepared by these entities pursuant to this Order.

7.2. Eastern Interconnection Planning Collaborative (EIPC)

EIPC was formed in early 2009 in order to foster an open and collaborative process for conducting technical analyses of transmission planning, on an Eastern Interconnection–level. EIPC was awarded funding from the American Reinvestment and Recovery Act (ARRA) to conduct analyses of transmission requirements under a broad range of alternative future scenarios. The first phase of analysis was conducted during 2010 and 2011,[89] 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

[88] See http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.
[89] See http://www.eipconline.com/Resource_Library.html for reports and more information on the EIPC Phase 1 analysis.

second phase of analysis was extended in 2013 to consider the interface between the natural gas delivery system and the electric transmission system.

EIPC undertook a new planning study, which started in 2013.[90] As part of this effort, the members of EIPC developed a baseline "roll-up" case that is an integrated powerflow model containing the expansion plans for the Eastern Interconnection.[91][92]

Identifying transmission projects that are likely to be built by 2018 or 2023 (the original study years) or by 2025 (in the current study) is a key activity in developing the roll-up cases. Projects are 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.[93] A report on the development of the roll-up cases for the 2013-2014 planning cycle is posted on the EIPC website, including a list of all the transmission projects that have met these criteria.[94]

[90] This new study is being conducted independent of DOE funding.

[91] EIPC (2014), http://www.eipconline.com/uploads/FINAL_EIPC_Roll-up_Report_Feb14-2014.pdf

[92] Two roll-up cases were developed—one for the 2018 summer peak load period and another for the 2023 summer. The cases developed in 2013 were used as the basis for scenario analysis in 2014 to stress-test the transmission system. EIPC has committed to a new cycle of roll-up case development and is currently working on a summer and winter powerflow model for the year 2025. (Personal communication from D. Whiteley, EIPC., dated May 20, 2015.)

[93] *Ibid.*, p. 24

[94] See http://www.eipconline.com/Non-DOE_Documents.html.

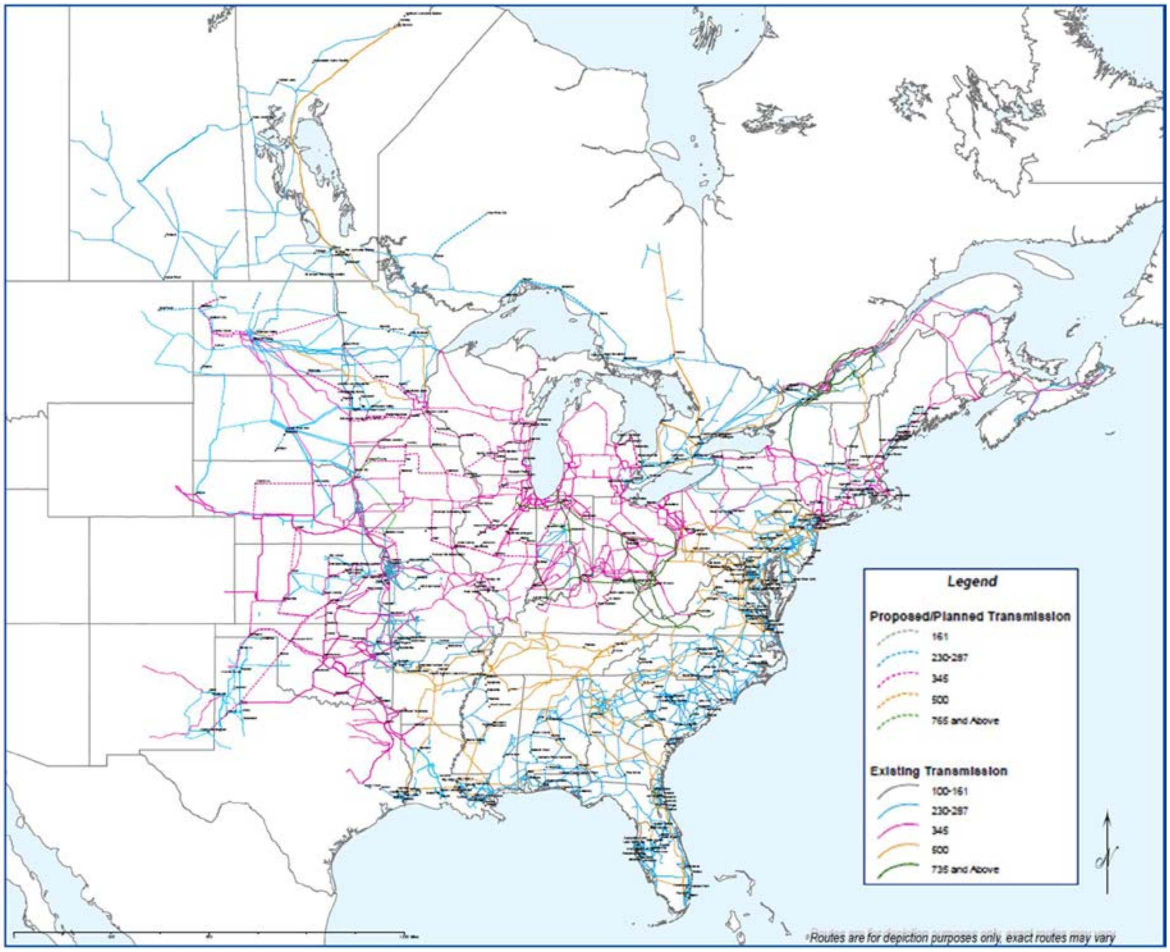


Figure 7-1. Map of EIPC future projects

Source: EIPC (2014). Steady State Modeling and Load Flow Working Group Report for 2018 and 2023 Roll-up Integration Cases, *Appendix A. http://www.eipconline.com/uploads/FINAL_EIPC_Roll-up_Report_Feb14-2014.pdf*

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.[95] The list, known as the Common Case Transmission

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

Assumptions (CCTA),[96] 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.[97]

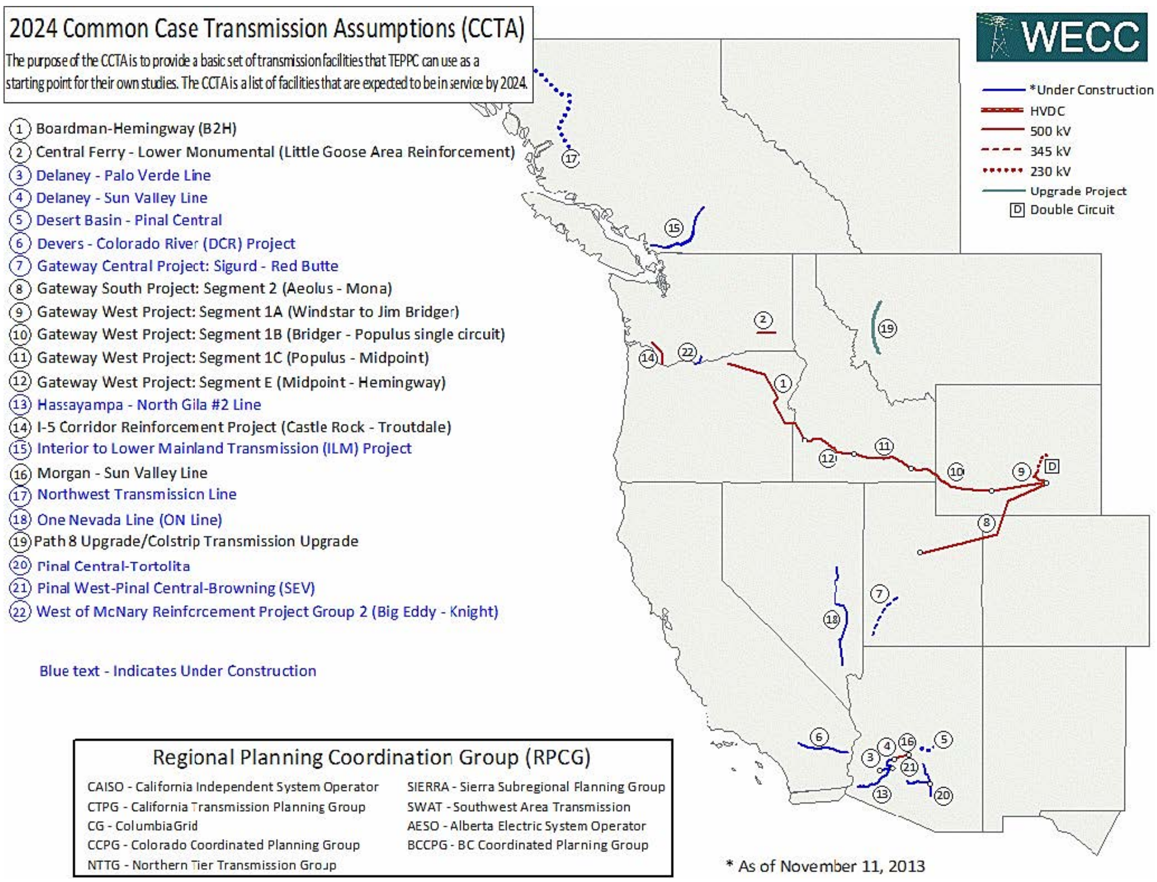


Figure 7-2. WECC 2024 Common Case Transmission Assumptions (CCTA), for use in 2015 plan

Source: WECC (2014c)."WECC Transmission Expansion Planning Datasets," *at https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx*

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:

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[96] See WECC (2014c), at https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx.

[97] WECC (2010b). *SPG Coordination Group (SCG) Foundational Transmission Project List.* https://www.wecc.biz/Reliability/100811_SCG_FoundationalTransmissionProjectList_Report.pdf

1. The 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 15 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 2014 report, ERCOT indicates that there are $4.7 billion of future transmission improvement projects that are planned to be in service between 2015 and the end of 2020. Table 7-1 and Figure 7-3 show some of the improvements planned to be in service within the next six years.

Table 7-1. ERCOT planned transmission improvements, 2015-2020

Map Index	Transmission Improvement	In-service Year
1	Temple Switch – Bell County East 345 kV line upgrade	2015
2	New Lobo –North Edinburg 345 kV line (Valley Import)	2016
3	New North Edinburg – Loma Alta 345 kV line (Cross Valley)	2016
4	New Fowlerton 345 kV station with 345/ 138 kV transformer	2017
5	Add second Jewett 345/ 138 kV transformer	2017
6	Add second Jordan 345/ 138 kV transformer	2017
7	Add second Twin Buttes 345/ 138 kV transformer	2017
8	McDonald Road – Spraberry 138/ 69 kV line upgrade	2017
9	New South McAllen 345 kV station with 345/ 138 kV transformer	2017
10	Tradinghouse – Sam Switch 345 kV line upgrade	2017
11	New Jones Creek 345 kV station with two 345/ 138 kV transformers	2017
12	Houston Import Project	2018
13	Venus – Navarro 345 kV line upgrade	2019
14	Big Brown – Navarro 345 kV line upgrade	2019
15	Trinidad – Watermill 345 kV line upgrade	2019
16	San Antonio Transmission System Addition Project	2019
17	Jack County 345/138 kV transformer addition	2020

Source: ERCOT (2014c), p. 21. http://www.ercot.com/content/news/presentations/2014/2014_Constraints_and_Needs_Report.pdf

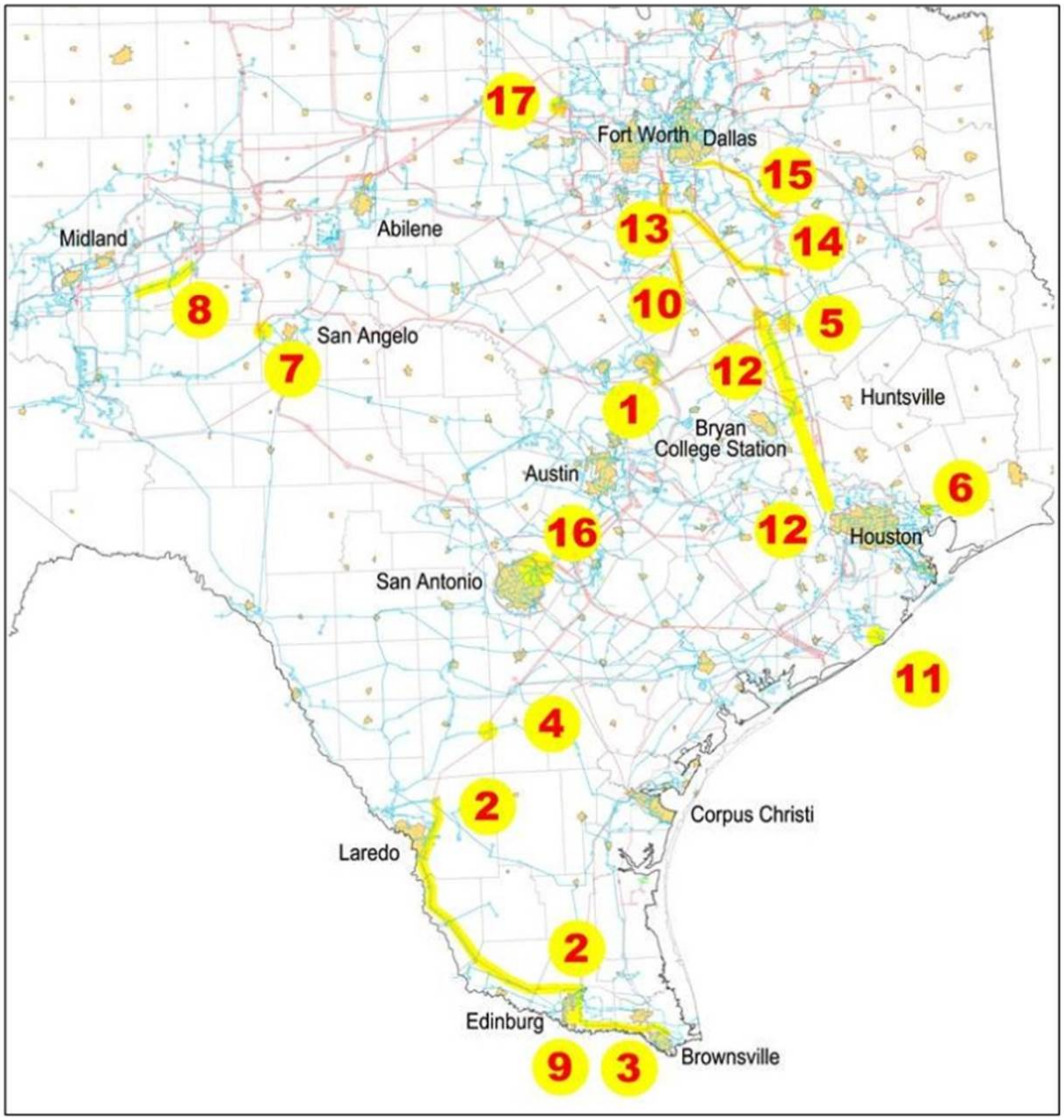

Figure 7-3. Map of Planned Transmission Improvement Projects in the ERCOT system

Source: ERCOT (2014c), p. 22. www.ercot.com/content/news/presentations/2015/2014_Constraints_and_Needs_Report.pdf

7.5. FERC Order 1000 Regional Entities

All initial compliance filings for FERC Order 1000 have been made, but many are still not final. As of January 2015, the Regional Entities for FERC Order 1000 are shown in Table 7-2.

Table 7-2. FERC Order 1000 regional entities

Region	Entity
South	SERTP
West	NTTG WestConnect ColumbiaGrid CAISO
East	ISO-NE NYISO PJM Florida South Carolina Maine Public Services
Central	MISO MAPP SPP

Source: Developed by DOE from FERC (2015). "Order No. 100 Compliance Filings & Orders," at http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp

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