

# Annual U.S. Transmission Data Review

March 2018



United States Department of Energy  
Washington, DC 20585



# Annual U.S. Transmission Data Review

## March 2018

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## Acknowledgements

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Data for this publication was sourced from documents available as of publication; in some cases draft documents may have been available, but were not included as they were not finalized at the time of this publication. All reference URLs were accurate as of November, 2017.

Comments on a draft of this report were provided by:

- California ISO (CAISO)
- Eastern Interconnection Planning Committee (EIPC)
- Electric Reliability Council of Texas (ERCOT)
- ISO New England (ISO-NE)
- Midcontinent Independent System Operator (MISO)
- Monitoring Analytics
- New York Independent System Operator (NYISO)
- North American Electric Reliability Corporation (NERC)
- Open Access Technology International (OATI)
- PJM Interconnection (PJM)
- Potomac Economics
- Southern Company
- Southwest Power Pool (SPP)
- U.S. Energy Information Administration (EIA)
- Western Electricity Coordinating Council (WECC)

# Table of Contents

Table of Contents.....	i
List of Figures.....	iii
List of Tables.....	iv
Acronyms and Abbreviations.....	v
<b>1. Introduction and Overview.....</b>	<b>1</b>
<b>2. Existing and Planned Transmission Construction and Investment .....</b>	<b>4</b>
2.1 Introduction.....	4
2.2 Existing Transmission.....	4
2.3 Transmission Under Construction, Planned, and Conceptual.....	6
2.4 Transmission Investment.....	11
2.4.1 FERC Transmission Metrics.....	11
2.4.2 FERC Common Metrics for RTOs, ISOs, and Individual Utilities.....	14
<b>3. Transmission System and Equipment Reliability Performance .....</b>	<b>16</b>
3.1 Introduction.....	16
3.2 Transmission System Reliability.....	16
3.3 Transmission Element Reliability.....	18
<b>4. Transmission System Utilization .....</b>	<b>21</b>
4.1 Introduction.....	21
4.2 Eastern Interconnection.....	22
4.3 Western Interconnection.....	25
4.4 Electric Reliability Council of Texas (ERCOT).....	26
<b>5. Management of Current Transmission Constraints.....</b>	<b>27</b>
5.1 Introduction.....	27
5.2 Transmission Loading Relief (Eastern Interconnection).....	28
5.3 Market-Based Procedures for Managing Transmission Constraints.....	31
5.3.1 California ISO (CAISO).....	31
5.3.2 Electric Reliability Council of Texas (ERCOT).....	34
5.3.3 ISO New England (ISO-NE).....	37
5.3.4 Midcontinent ISO (MISO).....	39
5.3.5 New York ISO (NYISO).....	40
5.3.6 PJM.....	41
5.3.7 Southwest Power Pool (SPP).....	44
<b>6. The Economic Cost of Congestion .....</b>	<b>45</b>
6.1 Introduction.....	45
6.2 FERC Common Metrics: Congestion Management.....	46
6.3 California ISO (CAISO).....	47
6.4 Electric Reliability Council of Texas (ERCOT).....	50
6.5 ISO New England (ISO-NE).....	52
6.6 Midcontinent ISO (MISO).....	56
6.7 New York ISO (NYISO).....	60
6.8 PJM.....	64

6.9 Southwest Power Pool (SPP) .....68

**7. Regional and Interconnection-Wide Transmission Planning.....70**

7.1 Introduction.....70

7.2 Selected Transmission Outcomes Emerging from Order No. 1000 Compliant Regional  
Transmission Planning Processes .....73

    7.2.1 *FERC Transmission Metrics* ..... 74

7.3 Interconnection-wide Transmission Planning Activities.....79

    7.3.1 *Western Electricity Coordinating Council Transmission Expansion Planning  
    Policy Committee* ..... 79

    7.3.2 *Eastern Interconnection Planning Collaborative (EIPC)*..... 80

**References.....83**

# List of Figures

Figure 2-1. NERC Regions ..... 5

Figure 2-2. Existing U.S. transmission (circuit miles) as of last day of 2016..... 6

Figure 2-3. NERC Assessment Areas (as of March 2016) ..... 7

Figure 2-4. Transmission under construction (circuit miles) as of first day of 2017 ..... 8

Figure 2-5. Planned lines (circuit miles) expected to be completed by 2020 ..... 9

Figure 2-6. Planned lines (circuit miles) expected to be completed 2021-2025..... 9

Figure 2-7. Conceptual lines (circuit miles) expected to be completed by 2020 ..... 10

Figure 2-8. Conceptual lines (circuit miles) expected to be completed 2021-2025..... 10

Figure 2-9. Historical and projected transmission investment by shareholder-owned utilities... 11

Figure 2-10. Incremental Load-Weighted Transmission Investment in the United States, 2008–2015..... 12

Figure 2-11. Summary of RTO Market Price Differential Metric for Select Areas..... 13

Figure 2-12. Number of transmission projects approved for construction for reliability purposes, 2010-2014..... 14

Figure 2-13. Percentage of approved transmission projects completed, 2010–2014 ..... 15

Figure 3-1. NERC Annual Daily Severity Risk Index (SRI), descending by year, 2010-2016 ..... 17

Figure 3-2. AC circuit unavailability by year and outage type, 2012-2016 ..... 19

Figure 3-3. Transformer unavailability by year and outage type, 2012-2016..... 19

Figure 4-1. NERC Interconnections..... 21

Figure 4-2. U.S. Electric System Operating Data Beta Tool status map detail for ISO-NE..... 22

Figure 4-3. Hourly actual interchange reported by ISO-NE with its three neighboring BAs ..... 23

Figure 4-4. New England sub-area model ..... 24

Figure 4-5. Southwest Connecticut import interface net flow by month, 2016 ..... 24

Figure 4-6. Southwest Connecticut import interface duration curve: net flow as a percent of interface limit, 2016 ..... 25

Figure 4-7. WECC Major Paths and U75 for 2016 ..... 26

Figure 5-1. NERC Reliability Coordinators, as of June 1, 2015 ..... 29

Figure 5-2. Eastern (total) TLR events, 2009–2016 ..... 30

Figure 5-3. Year 2016 TLR events by region ..... 30

Figure 5-4. ISO/RTO Council Members..... 31

Figure 5-5. CAISO percent of hours with congestion on major interties, 2014-2016 ..... 32

Figure 5-6. Top 15 congested constraints on the ERCOT system, Oct 2015–Sept 2016 ..... 35

Figure 5-7. Frequency of binding and active constraints, 2014–2016 ..... 36

Figure 5-8. ERCOT top ten real-time constraints, 2016..... 36

Figure 5-9. Key study areas in ISO-NE ..... 38

Figure 5-10. Projected top future congested flowgates in 2016 MTEP (Top: MISO North/Central Region; Bottom: MISO South Region) ..... 39

Figure 5-11. Transmission congestion corridors in New York State..... 41

Figure 5-12. Location of the top 10 constraints by PJM total congestion costs, 2016 ..... 42

Figure 5-13. SPP congestion by shadow price, top ten flowgates (2016) ..... 44

Figure 6-1. Annual congestion costs per megawatt-hour of load served and percentage of annual congestion costs hedged ..... 47

Figure 6-2. CAISO import congestion charges on major interties, 2014–2016 ..... 49

Figure 6-3. ERCOT day-ahead congestion costs by zone, 2011-2016..... 51

Figure 6-4. ERCOT real-time congestion costs 2011-2016 ..... 51

Figure 6-5. ISO-NE load-weighted and simple average hub prices, 2016 (\$/MWh) ..... 54

Figure 6-6. ISO-NE Annual simple average hub price, 2016..... 55

Figure 6-7. MISO day-ahead and balancing congestion and payments to FTRs, 2014-2016 ..... 58

Figure 6-8. Value of real-time congestion and payments to FTRs, 2015-2016 ..... 58

Figure 6-9. NYISO day-ahead and real-time congestion by transmission path, 2015–2016..... 62

Figure 6-10. NYISO congestion revenues and shortfalls, 2015–2016 ..... 63

Figure 7-1. FERC Order No. 1000 Transmission Planning Regions ..... 71

Figure 7-2. Percentage of Competitive Proposals by Incumbents vs. Nonincumbent Transmission Developers (2013–2016) ..... 75

Figure 7-3. Number of Unique Transmission Developers and Average Proposals per Developer 76

Figure 7-4. Number and Percentage of Awards Made to Nonincumbents..... 77

Figure 7-5. Average Number of Participants Attending Regional Transmission Planning Meetings (FY 2015 and FY 2016) ..... 78

Figure 7-6. Average Number of Nonincumbent Transmission Developers Attending Regional Transmission Planning Meetings (FY 2015 and FY 2016) ..... 78

Figure 7-7. WECC 2026 Common Case Transmission Assumptions (CCTA) ..... 80

Figure 7-8. EIPC future transmission projects from final 2015 Study Report ..... 82

## List of Tables

Table 3-1. NERC top ten SRI days, 2016 ..... 18

Table 3-2. TADS outage events and hourly event probability by initiating cause code (ICC), 2012-2016 ..... 20

Table 5-1. Transmission Loading Relief (TLR) Levels ..... 28

Table 5-2. CAISO summary of import congestion, 2015–2016 ..... 32

Table 5-3. CAISO impact of congestion on day-ahead prices during congested hours, 2016..... 33

Table 5-4. Top 15 congested constraints on the ERCOT system, Oct 2015–Sept 2016 ..... 34

Table 5-5. Number of congested hours by constraint, actual and projected ..... 40

Table 5-6. PJM top 25 constraints with frequent occurrence, 2015-2016..... 42

Table 5-7. PJM top 25 constraints with largest year-to-year change in occurrence 2015-2016 .. 43

Table 5-8. PJM top 25 constraints affecting PJM congestions costs (by facility), 2016 ..... 43

Table 6-1. CAISO congestion costs, 2006-2014 (\$M) ..... 48

Table 6-2. ERCOT reported congestion costs, 2011–2016 ..... 50

Table 6-3. ISO-NE reported congestion costs, 2009-2016 ..... 54

Table 6-4. MISO reported congestion costs and value, 2009-2016\* ..... 57

Table 6-5. NYISO reported congestion costs and value, 2009–2016 ..... 61

Table 6-6. NYISO reported Demand\$ congestion, 2008–2014 ..... 62

Table 6-7. PJM reported congestion revenue, 2009–2016 ..... 65

Table 6-8. Total PJM congestion (\$M), 2008–2016..... 65

Table 6-9. Hub real-time, load-weighted average LMP components (\$/MWh), 2015–2016 ..... 66

Table 6-10. Hub day-ahead, load-weighted average LMP components (\$/MWh), 2015-2016 .... 66

Table 7-1. Effective dates and regional transmission planning cycles ..... 72

## Acronyms and Abbreviations

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

<b>RTO</b>	Regional Transmission Organization
<b>RTP</b>	Regional Transmission Plan
<b>SCE</b>	Southern California Edison
<b>SCRTP</b>	South Carolina Regional Transmission Planning
<b>SDG&amp;E</b>	San Diego Gas & Electric
<b>SERTP</b>	Southeastern Regional Transmission Planning
<b>SPP</b>	Southwest Power Pool
<b>SRI</b>	System Reliability Index
<b>TADS</b>	Transmission Availability Data System
<b>TCDC</b>	Transmission Constraint Demand Curve
<b>TEPPC</b>	Transmission Expansion Planning Policy Committee
<b>TLR</b>	Transmission Loading Relief
<b>UFM</b>	Unscheduled Flow Mitigation
<b>WECC</b>	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.<sup>1</sup> Many factors affect transmission system operation, including the mix of equipment currently installed; the reliability of the system's individual components and of the system as a whole; how the transmission system is currently being utilized (*e.g.*, how much electricity flows through it); to what extent these flows are constrained by specific components that are being utilized up to their physical or operating limits (which could be contract path limited); the economic costs created by these constraints; and the processes by which future changes and additions to the system are planned.

The U.S. Department of Energy (DOE, or the Department) has broad responsibility for developing and supporting the implementation of energy policies that serve the public interest.<sup>2</sup> 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 upon nationwide transmission information sources 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

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<sup>1</sup> In 2014, the North American Electric Reliability Corporation (NERC) finalized its definition of the Bulk Electric System (BES) to include all transmission elements operated at 100 kV of higher, except for those elements primarily used in local distribution of electricity. See NERC (2014a): [http://www.nerc.com/pa/RAPA/BES%20DL/bes\\_phase2\\_reference\\_document\\_20140325\\_final\\_clean.pdf](http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf)

<sup>2</sup> For example, the Federal Power Act directs the Department to conduct triennial studies of transmission congestion. See 16 U.S.C. § 824p(a) (2012).

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 to include. The result is a report that presents a combination of information analyzed and presented by others in their published reports, 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 the state that the design, planning, and operations of the Bulk Electric System (BES) achieve when the reliability performance objectives are met. 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, federal and state policies, *constraints*, and *congestion*.<sup>3</sup>

In some cases, discussing such interrelated topics in isolation can be challenging. For instance, transmission constraints and economic congestion are closely related phenomena, but are presented separately in this report. The framework used here is

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<sup>3</sup> For detailed descriptions and definitions of these and other terms, see the *Federal Energy Regulatory Commission Reliability Primer* at <https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf>.

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 elements (i.e., 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 operated at 100 kV and above and used to transmit electricity from generators to distribution networks; however, it does not include the local distribution of electricity to end-use consumers.<sup>4</sup>

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

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

Additional information for this section was obtained from two reports issued by FERC staff in 2016: one outlining metrics for use in evaluating transmission investment patterns, and one describing common performance metrics for RTOs, ISOs, and individual utilities.<sup>5</sup>

### 2.2 Existing Transmission

Information regarding existing transmission is taken from the NERC Transmission Availability Data System (TADS). The TADS contains data collected quarterly on existing equipment inventory and on outages experienced by equipment.<sup>6</sup> Data for TADS are voluntarily provided by transmission owners<sup>7</sup> by voltage level. The data are reported by

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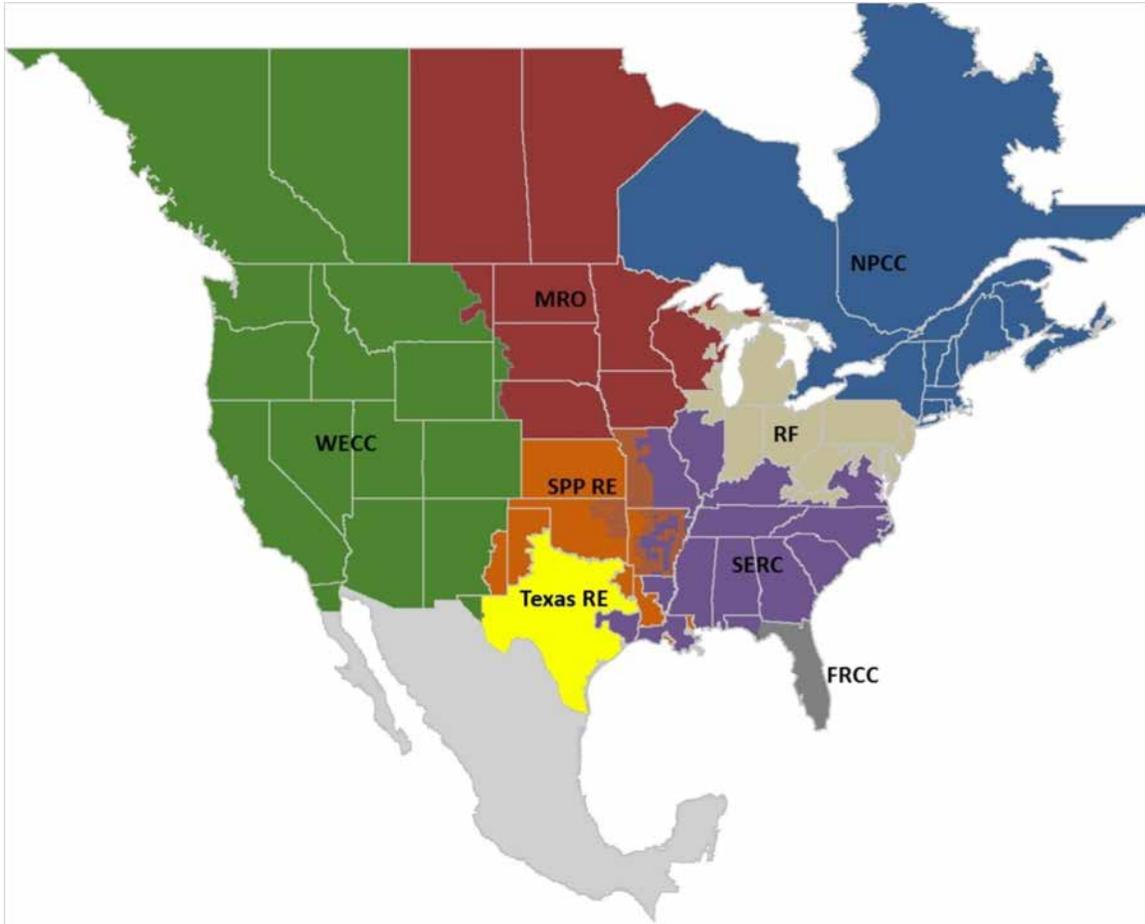
<sup>4</sup> NERC (2014a): [http://www.nerc.com/pa/RAPA/BES%20DL/bes\\_phase2\\_reference\\_document\\_20140325\\_final\\_clean.pdf](http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf).

<sup>5</sup> See FERC (2016b): <https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf>; and FERC (2017a): <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>.

<sup>6</sup> See NERC (2016c): <http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx>. The inventory can be found here: <http://www.nerc.com/pa/RAPA/tads/Pages/ElementInventory.aspx>.

<sup>7</sup> 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>.

the eight regional reliability entities shown in Figure 2-1, and are reviewed by the appropriate regional reliability entities and NERC. Both the regions and NERC have access to the TADS data, but NERC maintains the database.



**Figure 2-1. NERC Regions**

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

Figure 2-2 shows existing transmission infrastructure circuit miles (at 100 kV or above) as of the last day of 2016.<sup>8</sup>

Note that information presented in Figure 2-2 through Figure 2-8 refer only to transmission within the United States, and these figures rely on data that is self-reported to NERC by transmission owners through each NERC regional reliability entity.

<sup>8</sup> On March 20, 2014, FERC approved the NERC definition of Bulk Electric System (BES), which includes system elements down to 100 kV, with provisions for including lower voltage equipment if operated as a transmission facility, or excluding higher voltage equipment if not operated as a transmission facility. This definition became effective July 1, 2014. See <http://www.nerc.com/pa/RAPA/Pages/BES.aspx>.

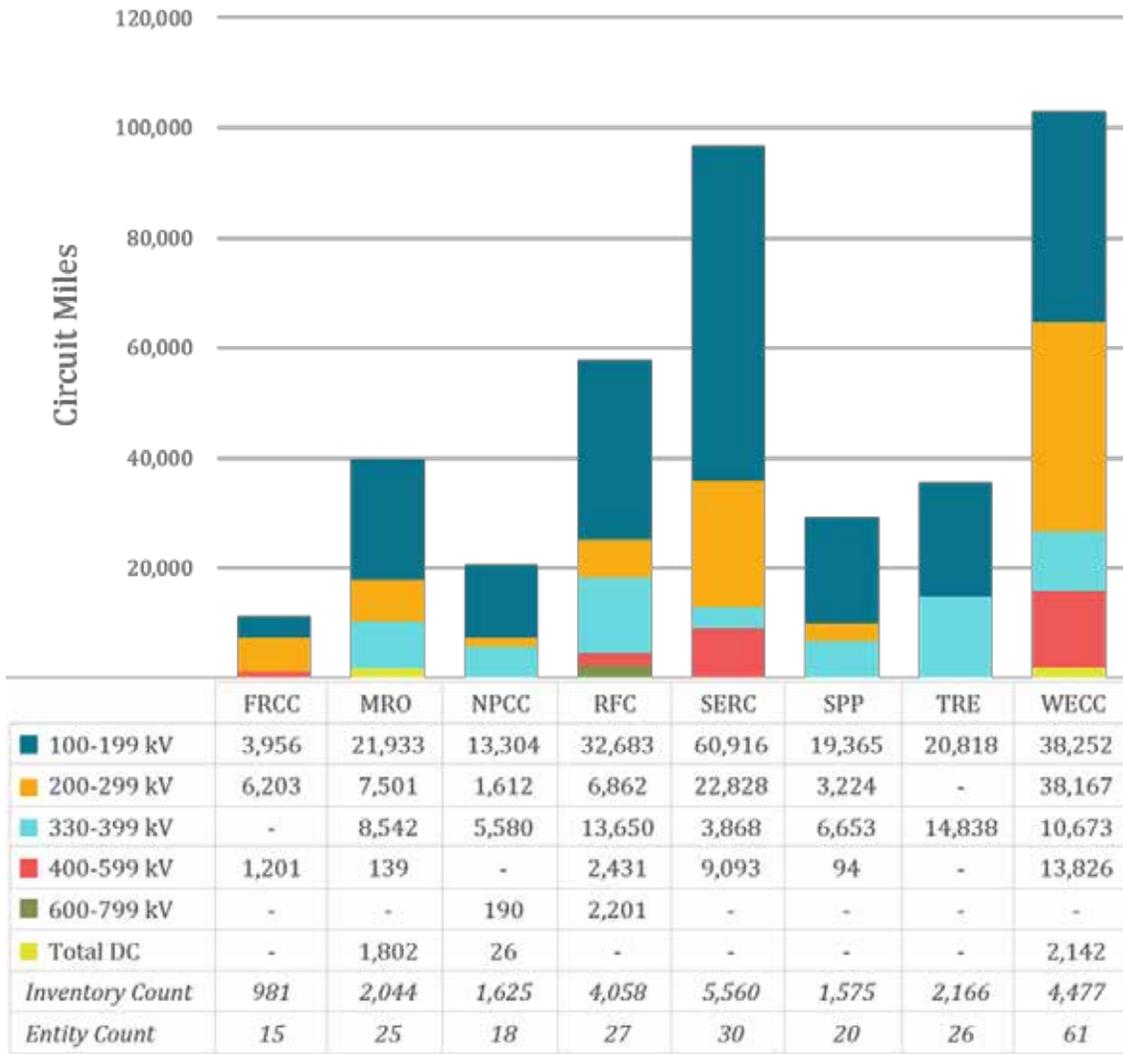


Figure 2-2. Existing U.S. transmission (circuit miles) as of last day of 2016

Note: Inventory Count includes the number of elements reported by voltage class for each year; Entity Count includes the number of reporting entities for each year

Source: Developed by DOE from NERC TADS Inventory (personal communication from NERC received on September 29, 2017)

### 2.3 Transmission Under Construction, Planned, and Conceptual

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

<sup>9</sup> NERC (2016a). “Electricity Supply & Demand (ES&D).” <http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx>

The data are collected from the NERC Assessment Areas shown in Figure 2-3. Note that the names and boundaries for these areas differ from those of the regional reliability entities that provide information to TADS (shown in Figure 2-1).<sup>10</sup>

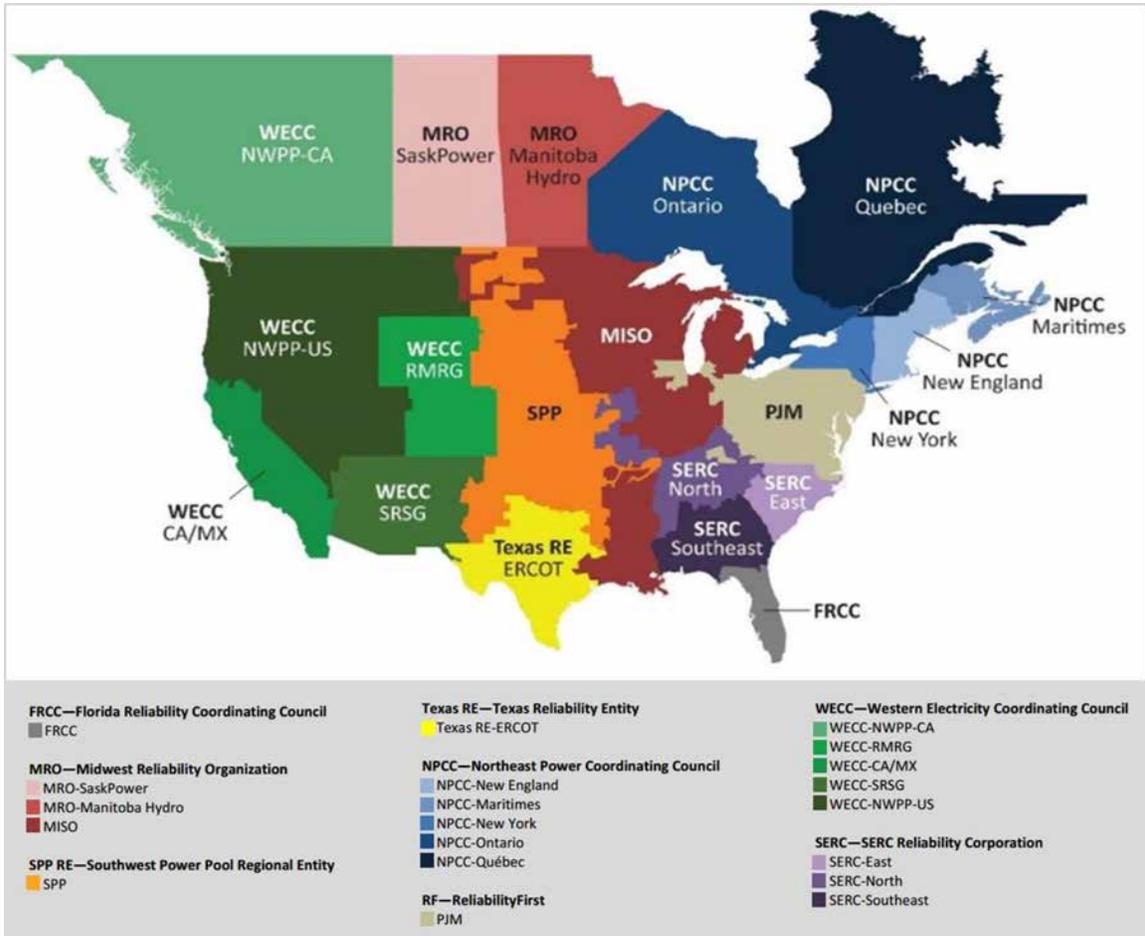


Figure 2-3. NERC Assessment Areas (as of March 2016)

Source: NERC: <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).
- *Planned* (reported separately for the years 2020 and 2025) refers to projects where the line is included in a regional transmission plan, or 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).

<sup>10</sup> NERC Assessment Areas are based on existing RTO/ISO footprints, individual Planning Coordinator boundaries, or groups of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.

- *Conceptual* lines are those that are in a project queue, but not included in a transmission plan, or where (a) a line is projected in the transmission plan; (b) a line is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”; or (c) projected lines that do not meet the requirements of “Under Construction” or “Planned” (see Figure 2-7 and Figure 2-8).<sup>11, 12, 13</sup>

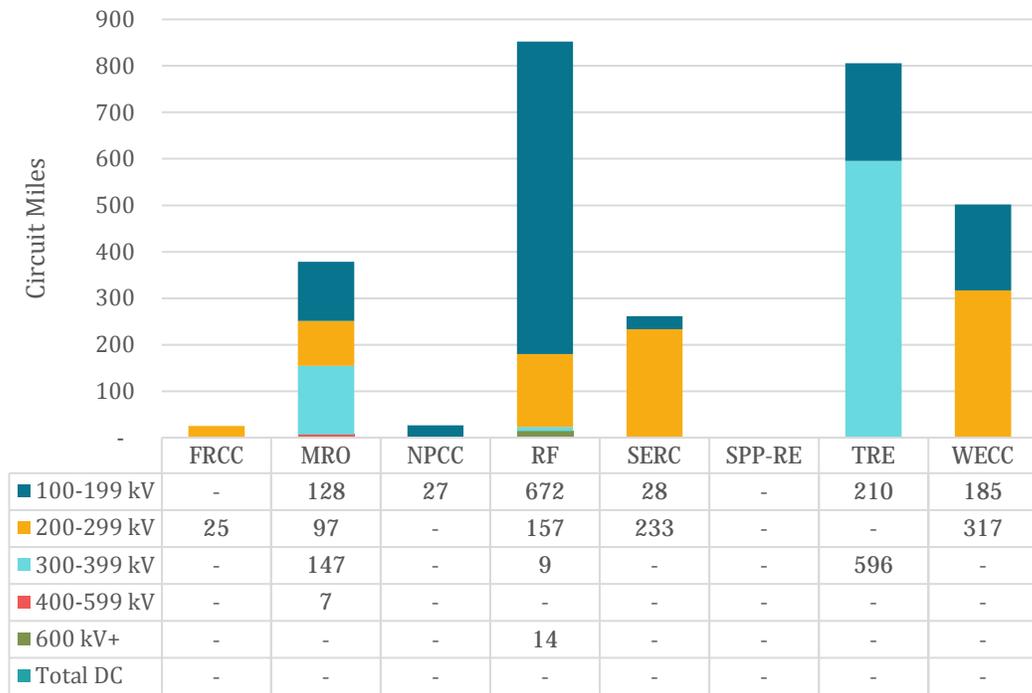


Figure 2-4. Transmission under construction (circuit miles) as of first day of 2017

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

<sup>11</sup> See the NERC Reliability Assessment Subcommittee’s 2017 Long-Term Reliability Assessment Data Form Instructions, Form D, at [http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2018LTRA\\_Data\\_Instructions.pdf](http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2018LTRA_Data_Instructions.pdf).

<sup>12</sup> NERC recognizes that its definitions for project categories (such as “conceptual”) may vary from the definitions used internally by the entities that provide information on the status of transmission projects.

<sup>13</sup> These figures illustrate circuit miles that are *under construction*, *planned*, and *conceptual* as reported to NERC. They are not indicative of the numbers of projects that may be *under construction*, *planned*, or *conceptual* because data on transmission projects submitted to NERC includes equipment replacements and other upgrades that may have no circuit miles associated with them.

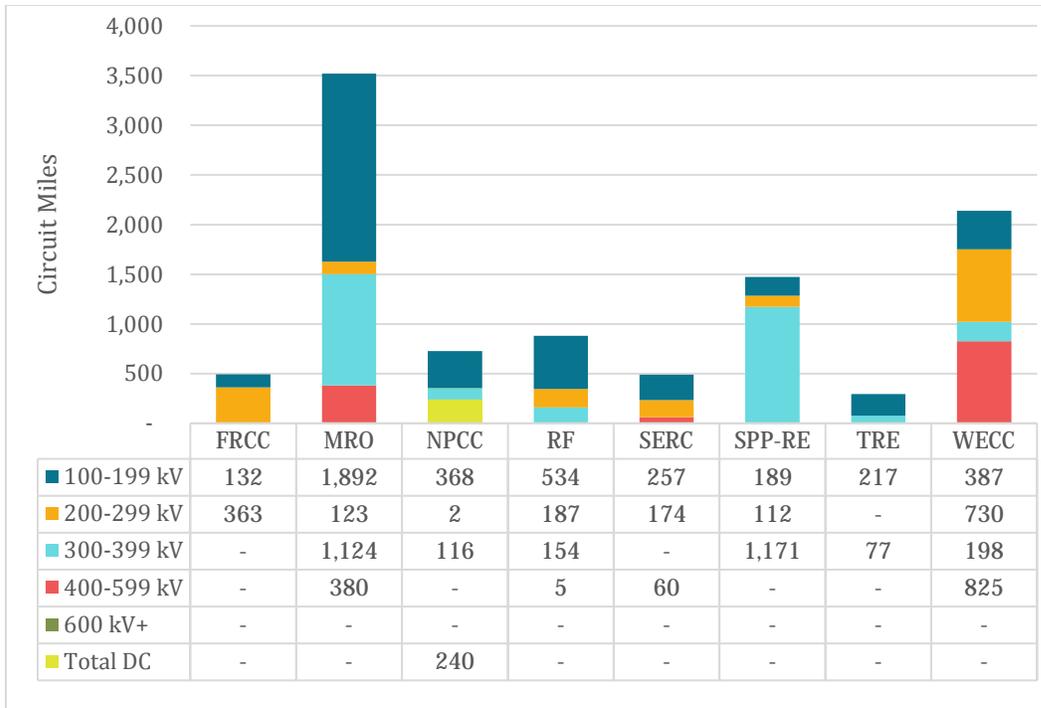


Figure 2-5. Planned lines (circuit miles) expected to be completed by 2020

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

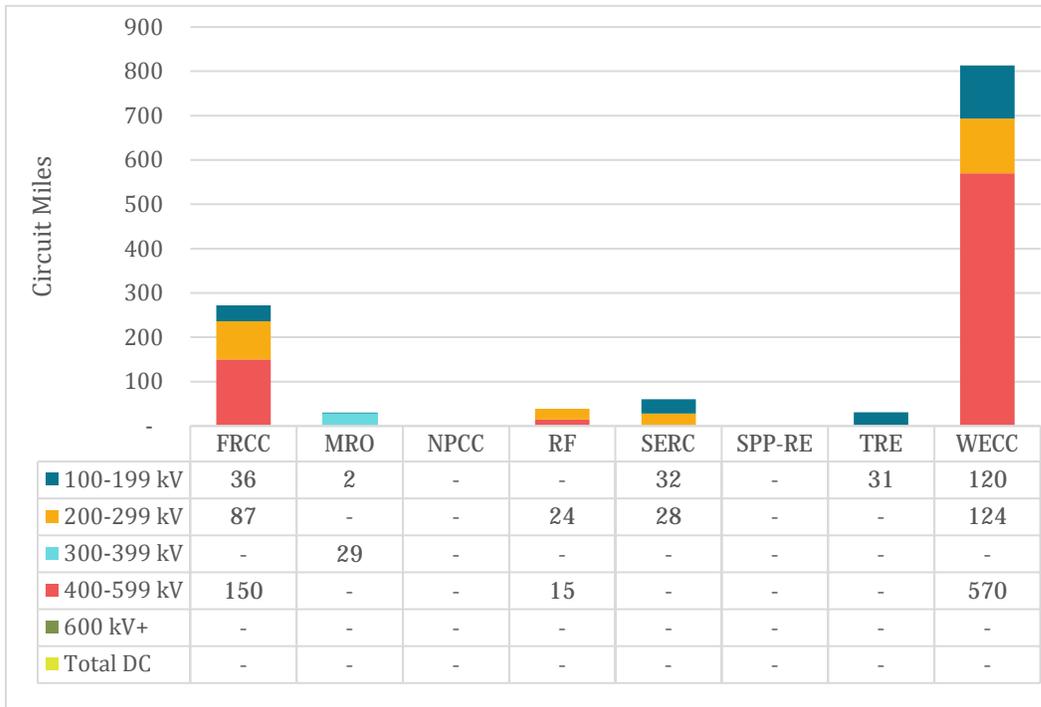


Figure 2-6. Planned lines (circuit miles) expected to be completed 2021-2025

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

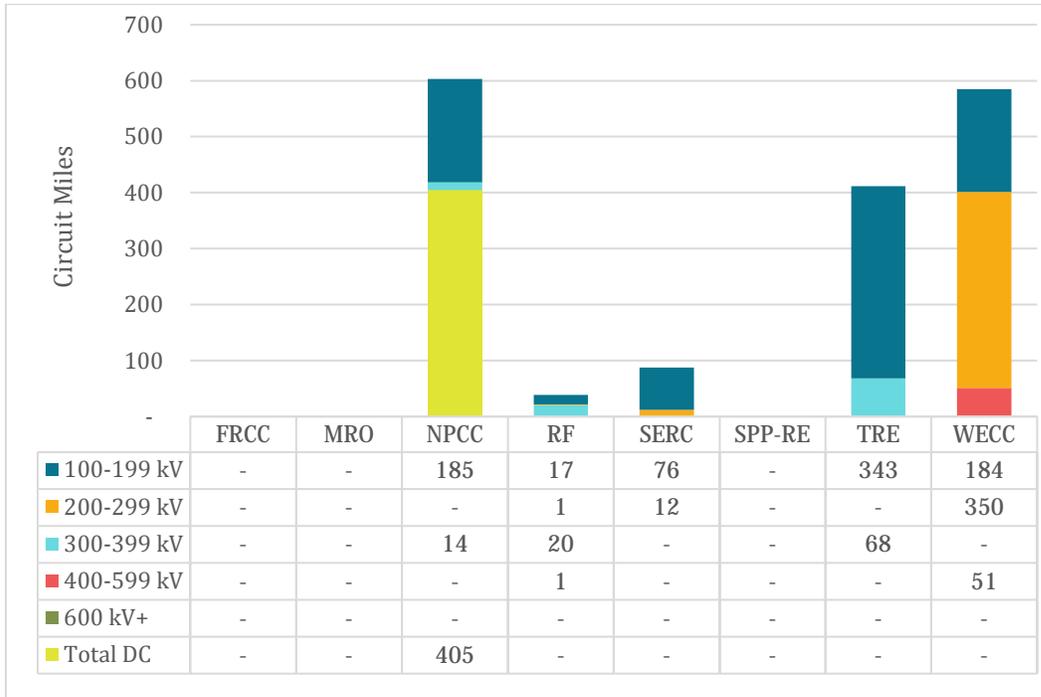


Figure 2-7. Conceptual lines (circuit miles) expected to be completed by 2020

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

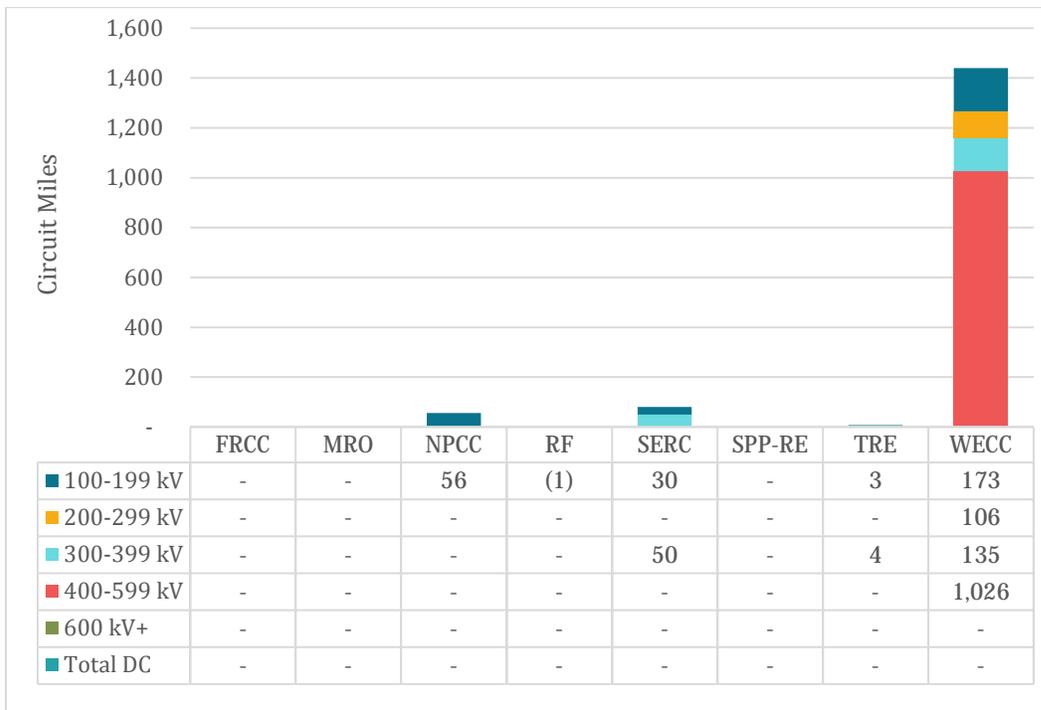


Figure 2-8. Conceptual lines (circuit miles) expected to be completed 2021-2025

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

## 2.4 Transmission Investment

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

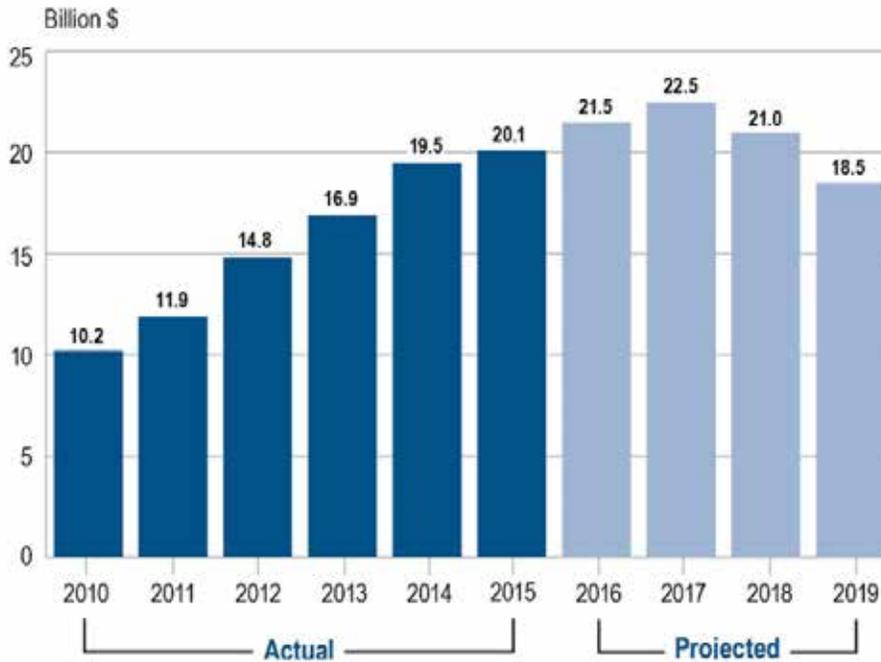


Figure 2-9. Historical and projected transmission investment by shareholder-owned utilities

Source: EEI (2016): <http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx>

### 2.4.1 FERC Transmission Metrics

In March 2016, FERC staff issued an initial report on transmission metrics that assessed transmission investment patterns to inform whether additional FERC action would be necessary to facilitate more efficient or cost-effective transmission development in the United States that is sufficient to satisfy the nations’ transmission needs. This report was subsequently updated in October 2017.<sup>14</sup> In the 2016 report, six metrics were developed to evaluate key Order No. 1000 goals, indicate whether appropriate levels of transmission infrastructure exist in a particular region, and permit analysis of the impact of FERC policy changes by comparing key values before and after changes take place.<sup>15</sup> Three additional metrics were developed for the 2017 report.<sup>16</sup>

<sup>14</sup> FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

<sup>15</sup> FERC (2016b), p. 6.

<sup>16</sup> See FERC (2017b), p. 6-7.

In this report, we review three of the original six transmission metrics: *Load-Weighted Transmission Investment* (see below), *RTO/ISO Price Differential* (see below), and *Percentage of Nonincumbent Transmission Project Bids or Proposals* (see Section 7) as well as the three new metrics from the 2017 Report: *Number of Unique Developers Submitting Proposals*; *Number and Percentage of Selected Nonincumbent Proposals*; and *Stakeholder Participation in Regional Transmission Planning Processes* (see Section 7).

*Load-Weighted Transmission Investment*

The *Load-Weighted Transmission Investment* metric describes “the load-weighted dollar value of transmission facilities added (i.e., that went into operation) each year from 2008–2015 in the eight NERC regions of the contiguous United States. Weighting transmission investment dollars by associated retail load allows for comparisons between entities of different sizes... While more load-weighted investment may not always be better than less load-weighted investment, tracking how these values adjust to changes in [FERC] policy may be informative.”<sup>17</sup>

Between 2008 and 2015, load-weighted transmission investment averaged \$2.43 per megawatt hour (MWh) of retail load for all NERC regions—up from a load-weighted average of \$2.19 per MWh of retail load between 2008 and 2014 (as noted in the 2016 Report).<sup>18</sup> (See Figure 2-10.)

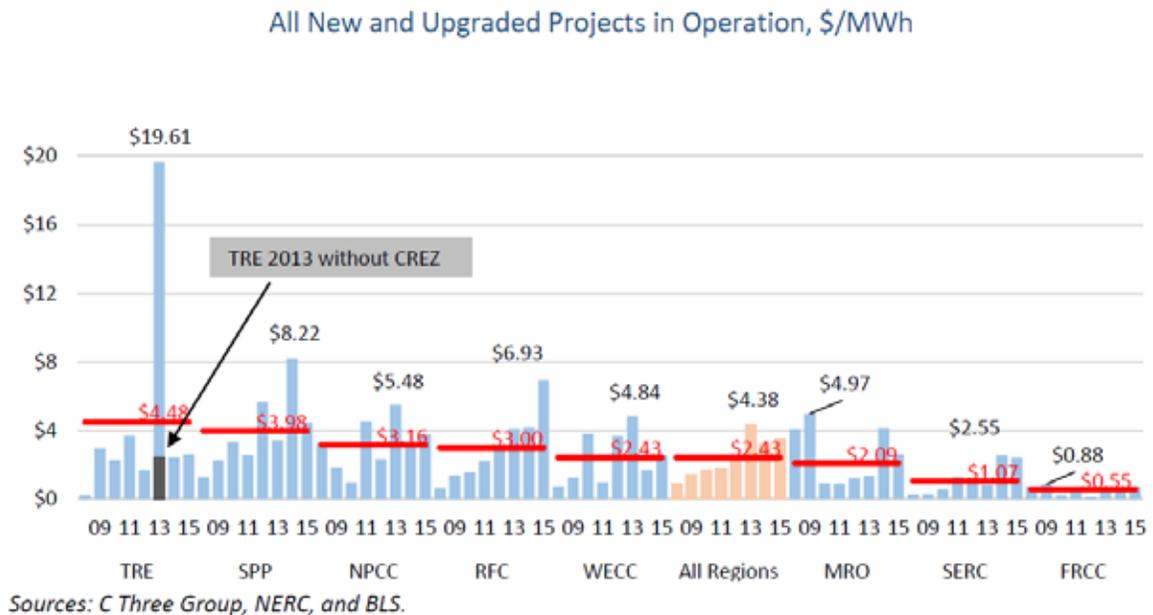


Figure 2-10. Incremental Load-Weighted Transmission Investment in the United States, 2008–2015

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

<sup>17</sup> FERC (2017b), p. 43.

<sup>18</sup> FERC (2017b), p. 5.

*RTO/ISO Price Differential*

The *RTO/ISO Market Price Differential* metric, from FERC’s Transmission Metrics report (see FERC 2017b), indicates whether appropriate levels of transmission infrastructure exist. This metric

“...attempts to use price data to assess whether transmission investment in the RTOs/ISOs is adequate. Price differentials between areas within an RTO/ISO may be the result of inadequate transmission capacity, capacity that is necessary to deliver power from areas with lower prices to those with higher prices. However, not all price differentials can be addressed economically; in some cases, the costs associated with the transmission infrastructure necessary to reduce a price differential may exceed the benefits that alleviating that congestion could provide. In such cases, persistent price differentials do not necessarily indicate insufficient transmission investment.”<sup>19</sup>

They key finding for this metric from the 2017 report is that relatively high or low real-time locational marginal prices occurred persistently (i.e., for at least two years) at 1,482 generator or load points since 2005—a decline from 1,986 points as reported in the 2016 Report. (See Figure 2-11.)

Area Identified by Staff	RTO/ISO	Price Direction	Start of Area’s Longest Occurrence of Ongoing Price Differentials <sup>70</sup>	Metric (Years of persistence through 2015)
Baltimore	PJM	High	2005	11
Upper Peninsula	MISO	High	2005	11
North-Central MISO	MISO	Low	2005	11
		High	2005	11
Delmarva	PJM	High	2006	10
New York-Canada Border Region	NYISO	Low	2006	10
Northern New York	NYISO	Low	2006	10
Northwestern New Jersey	PJM	High	2007	9
		Low	2007	9
Greater Chicago	PJM	High	2012	4
		Low	2009	7
Long Island	NYISO	High	2009	7
Western Texas	SPP	Low	2010	6
		High	2010	6
West-Central North Dakota	MISO	Low	2010	6
ND-SD-MN Border Region	MISO	Low	2010	6
Central California	CAISO	High	2013	3

Source: Staff analysis of ABB Velocity Suite price data from 2000 through 2015 and SPP price data between 2014 and 2015.

**Figure 2-11. Summary of RTO Market Price Differential Metric for Select Areas**

Source: FERC (2017b), p. 16: <https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf>

<sup>19</sup> FERC (2017b), P. 34.

2.4.2 FERC Common Metrics for RTOs, ISOs, and Individual Utilities

In August 2016, FERC staff issued a report on performance metrics for RTOs, ISOs, and certain self-selected individual utilities for the 2010–2014 reporting period.<sup>20</sup> Reporting on an established set of common performance metrics (covering both reliability and system operations activities) outlined in a report issued in August 2014,<sup>21</sup> FERC collected information from RTO/ISOs and non-RTOs and ISOs, primarily from FERC-922; additional market-specific data was provided by the RTO/ISOs. In this section, we will review two of these common metrics: *Transmission Projects Approved for Construction* and *Transmission Projects Completed*.<sup>22</sup>

*Transmission Projects Approved for Construction*

This metric measures “the number of transmission facilities approved for construction for reliability purposes; each of the respondents has a role in approving transmission projects through their respective local and regional reliability planning processes. In reviewing this metric, it is important to consider that the size of the transmission system varies across respondents.”<sup>23</sup>

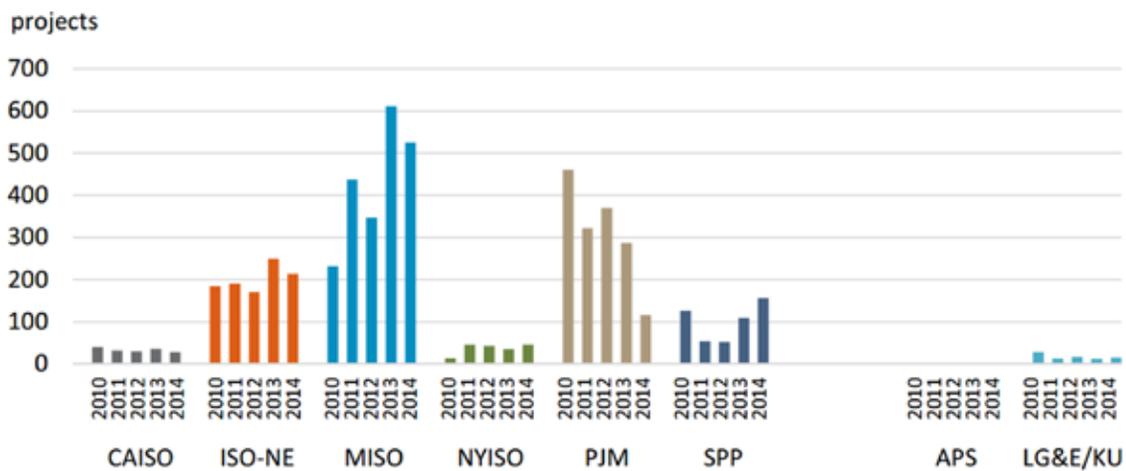


Figure 2-12. Number of transmission projects approved for construction for reliability purposes, 2010-2014

Source: FERC (2017a) Common Metrics Report, p. 30: <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>

Note: Besides the RTO/ISOs, only Arizona Public Service Company (APS) and Louisville Gas and Electric Company/Kentucky Utilities Corporation (LG&E/KU) submitted data consistent with this metric and so were included in this table

<sup>20</sup> This report was revised and updated in August 2017; see FERC (2017a): <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>

<sup>21</sup> See <https://www.ferc.gov/legal/staff-reports/2014/AD14-15-performance-metrics.pdf>

<sup>22</sup> ERCOT is not subject to the jurisdiction of FERC in the area of markets, and is therefore not discussed in this section.

<sup>23</sup> FERC (2017a), p. 29.

As shown in Figure 2-12, MISO reports more approved transmission projects than any other respondent—2,153 transmission projects were approved for reliability purposes over the reporting period.

*Transmission Projects Completed*

This metric measures “transmission planning performance and represents the percentage of approved construction projects completed and on schedule... RTOs and ISOs report the percentage of projects approved in each year that were completed by the end of the reporting period.”<sup>24</sup>

As shown in Figure 2-13, ISO-NE reports the highest annual average percentage of approved projects completed over the reported time period.

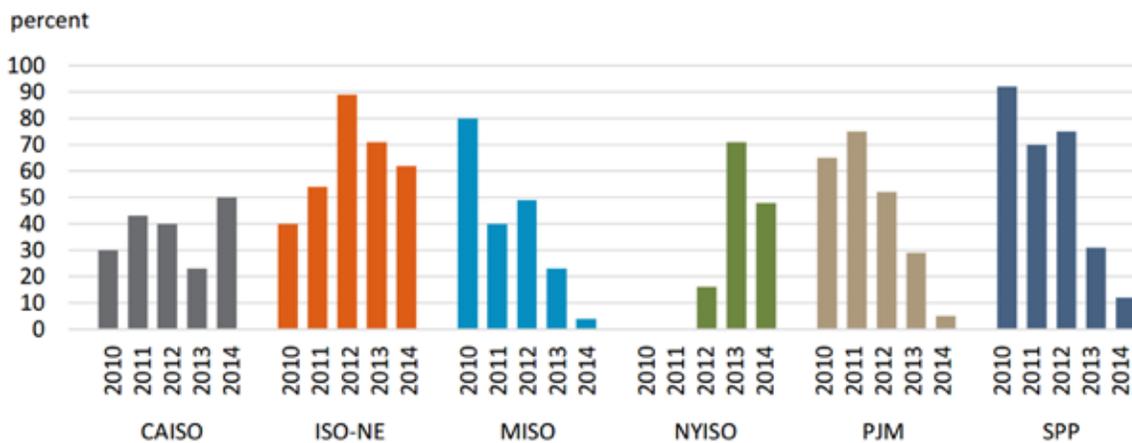


Figure 2-13. Percentage of approved transmission projects completed, 2010–2014

Source: FERC (2017) *Common Metrics Report*, p. 31: <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>

<sup>24</sup> FERC (2017a), p. 30.

## 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.<sup>25</sup>

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 this information.

### 3.2 Transmission System Reliability

Information on transmission system reliability is from NERC's annual *State of Reliability* report. This report presents information both on an overall metric of system reliability, called the Severity Risk Index (SRI), as well as on fourteen additional metrics for characteristics that together constitute an "adequate level of reliability."<sup>26,27</sup> 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.<sup>28</sup>

- 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).<sup>29</sup>
- The *transmission outage* component is the normalized number of transmission lines lost, reported in percent. The information is taken from NERC's TADS (see Section 2).
- The *loss of load* component is taken from information collected by the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working

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<sup>25</sup> Planned reliability is addressed both in Section 2 (Existing and Planned Transmission Construction and Investment), and in Section 7 (Interconnection-wide and Emerging Regional Transmission Planning Processes) of this report.

<sup>26</sup> See [http://www.nerc.com/docs/standards/ALR\\_Definition\\_clean\\_081215.pdf](http://www.nerc.com/docs/standards/ALR_Definition_clean_081215.pdf).

<sup>27</sup> The *State of Reliability 2017* report describes how the fourteen "M-x" performance metrics align with the original ALR metrics; see NERC (2017a), page 26.

<sup>28</sup> Definitions are from NERC (2014b): <http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI%20Enhancement%20Whitepaper.pdf>.

<sup>29</sup> See <http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx>.

Group from voluntary reports by its members on power interruptions caused by the loss of supply.<sup>30</sup>

Figure 3-1 presents the daily SRI for the years 2010 to 2016. Note that the y-axis is logarithmic in order to present the small number of very high SRI values on the same graph. The highest daily SRI values are shown in an inset and are described individually in Table 3-1.

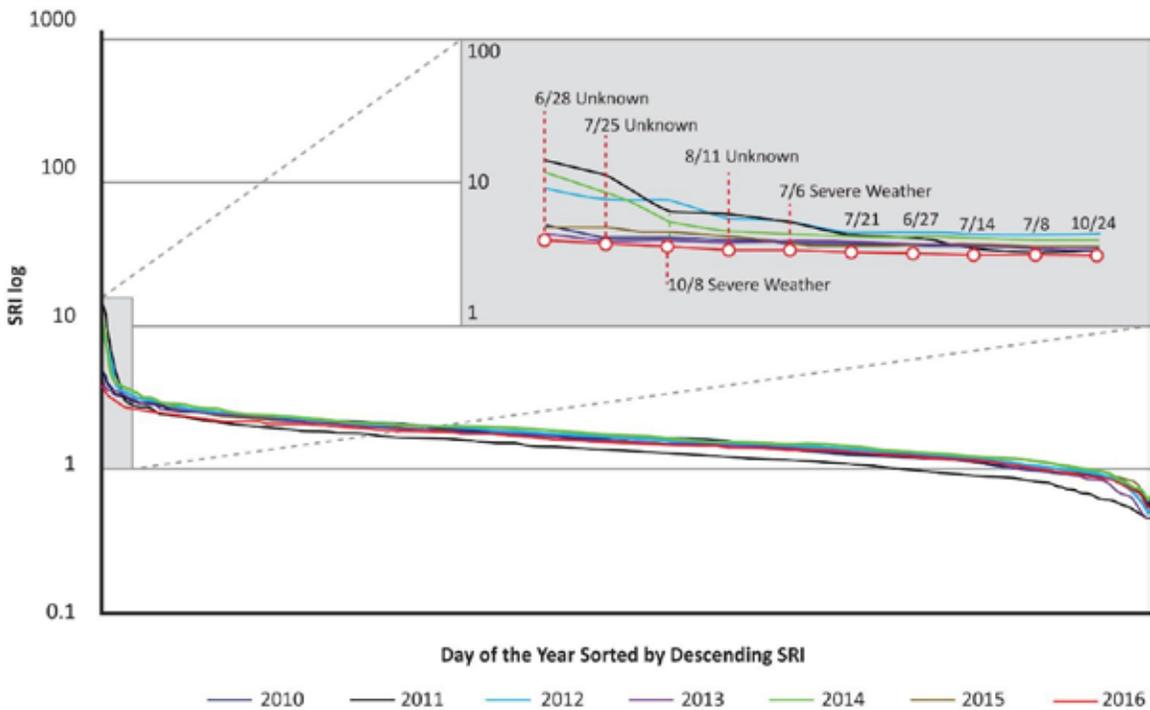


Figure 3-1. NERC Annual Daily Severity Risk Index (SRI), descending by year, 2010-2016

Source: NERC (2017a), page 14: [http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR\\_2017\\_MASTER\\_20170613.pdf](http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf)

<sup>30</sup> 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 top ten SRI days, 2016

Date	NERC SRI and Weighted Components 2016				G/T/L	Weather Influenced (Verified by OE-417)?	Rank	Event Type	Region
	SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss					
6/28/2016	3.57	2.64	0.88	0.09			1		
7/25/2016	3.38	2.61	0.64	0.07			2		
10/8/2016	3.14	0.77	2.33	0.13		✓	3	Severe Weather	SERC
8/11/2016	3.06	2.39	0.53	0.08		✓	4	Severe Weather	RFC
7/6/2016	2.99	2.33	0.59	0.01			5		
7/21/2016	2.90	1.92	0.89	0.29			6		
6/27/2016	2.82	1.84	0.82	0.08			7		
7/14/2016	2.79	1.49	0.83	0.06		✓	8	Severe Weather	SERC
7/08/2016	2.73	1.64	0.89	0.14			9		
10/24/2016	2.71	2.18	0.37	0.23			10		

Source: NERC (2017a), page 15: [http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR\\_2017\\_MASTER\\_20170613.pdf](http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.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,<sup>31</sup> and automatic sustained outages during the years 2012 through 2016. Since planned outage data collection in TADS was discontinued in 2015, only elements unavailable due to operational and automatic outages are shown for the years 2015 and later.

Figure 3-3 presents the percentage of time that transformers were not available, again by outage type, for these same years. Tabular information on the number of the automatic outage events of AC circuits by initiating cause code is presented in Table 3-2.

<sup>31</sup> 200kv and above.

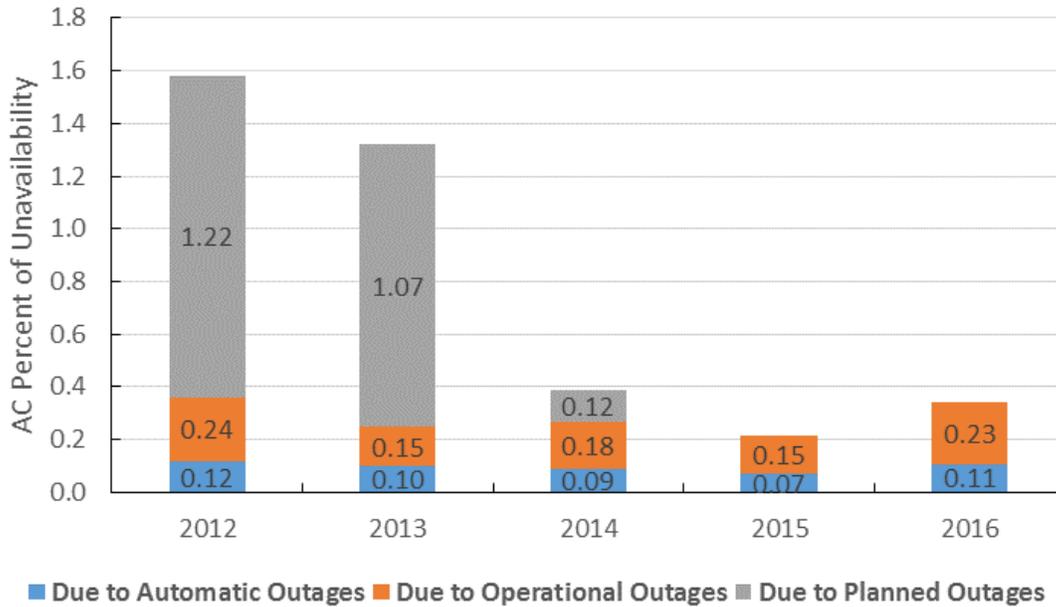


Figure 3-2. AC circuit unavailability by year and outage type, 2012-2016<sup>32</sup>

Source: NERC (2017a), p. 41:

[http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR\\_2017\\_MASTER\\_20170613.pdf](http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf)

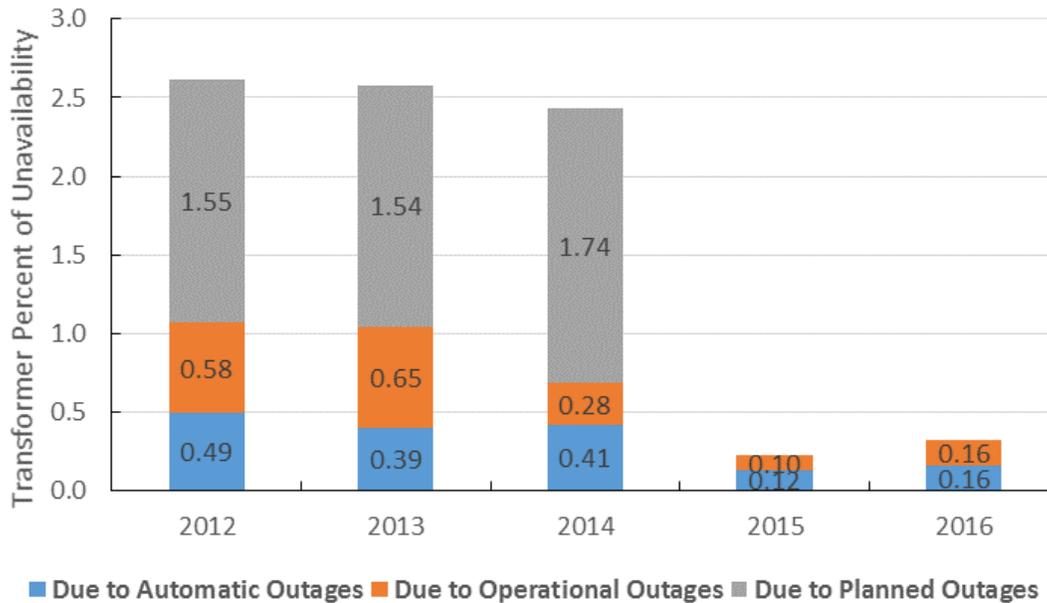


Figure 3-3. Transformer unavailability by year and outage type, 2012-2016

Source: NERC (2017a), p. 41: [http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR\\_2017\\_MASTER\\_20170613.pdf](http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf)

<sup>32</sup> 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](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 and hourly event probability by initiating cause code (ICC), 2012-2016

Initiating Cause Code	2012	2013	2014	2015	2016	2012–2016	Event Initiation Probability/Hour
Lightning	852	813	709	783	733	<b>3,890</b>	0.089
Unknown	710	712	779	830	773	<b>3,804</b>	0.087
Weather (excluding lightning)	446	433	441	498	638	<b>2,456</b>	0.056
Failed AC Circuit Equipment	261	248	224	255	362	<b>1,350</b>	0.031
Misoperation	321	281	314	165	249	<b>1,330</b>	0.030
Foreign Interference	170	181	226	274	258	<b>1,109</b>	0.025
Failed AC Substation Equipment	248	191	223	221	214	<b>1,097</b>	0.025
Contamination	160	151	149	154	289	<b>903</b>	0.021
Human Error (w/o Type 61 OR Type 62)	212	191	149	132	153	<b>837</b>	0.019
Power System Condition	77	109	83	96	81	<b>446</b>	0.010
Fire	106	130	44	65	72	<b>417</b>	0.010
Other	104	64	77	77	78	<b>400</b>	0.009
<b>Combined Smaller ICC Groups Study 1-3</b>	<b>57</b>	<b>53</b>	<b>49</b>	<b>37</b>	<b>47</b>	<b>196</b>	<b>0.006</b>
<i>Vegetation</i>	43	36	39	32	34	<b>184</b>	0.004
<i>Vandalism, Terrorism, or Malicious Acts</i>	10	9	8	1	7	<b>35</b>	0.001
<i>Environmental</i>	4	8	2	4	6	<b>24</b>	0.001
<b>All with ICC Assigned</b>	<b>3,724</b>	<b>3,557</b>	<b>3,467</b>	<b>3,587</b>	<b>3,947</b>	<b>18,282</b>	<b>0.417</b>
<b>All TADS Events</b>	<b>3,753</b>	<b>3,557</b>	<b>3,477</b>	<b>3,587</b>	<b>3,947</b>	<b>18,321</b>	<b>0.418</b>

Source: NERC (2017a), p. 86-87: [http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR\\_2017\\_MASTER\\_20170613.pdf](http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.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 U.S. interconnections: Eastern, Western, and Texas (or ERCOT). See Figure 4-1.

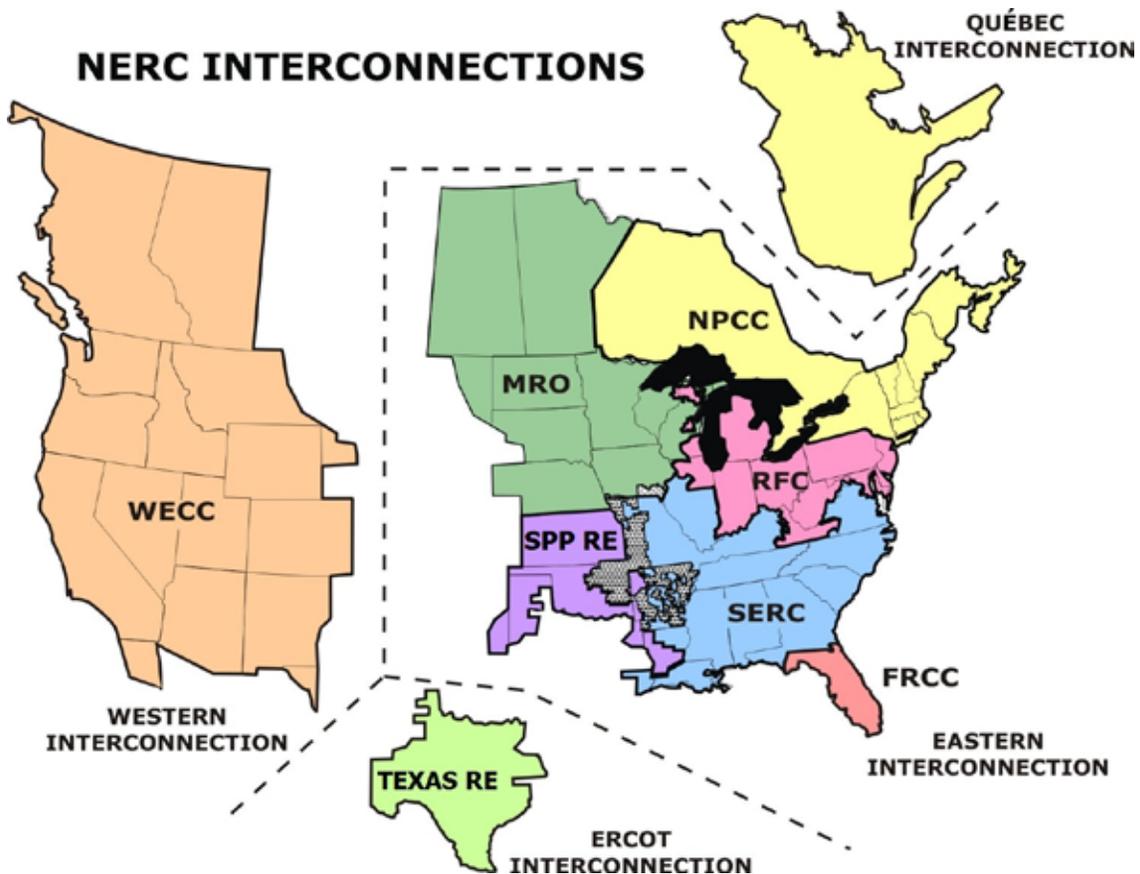


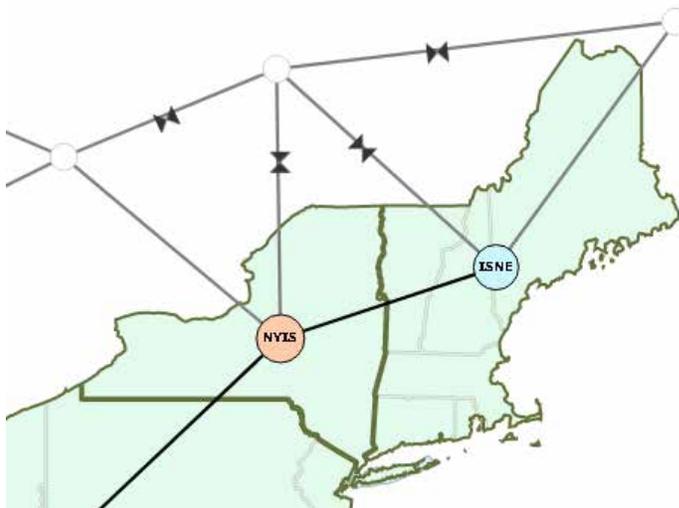
Figure 4-1. NERC Interconnections

Source: [http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC\\_Interconnections\\_Color\\_072512.jpg](http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC_Interconnections_Color_072512.jpg)

## 4.2 Eastern Interconnection

In 2014, EIA launched Form 930, to collect hourly information on electric system operations from balancing authorities (BAs).<sup>33</sup> Data collection began in July 2015, and all 68 U.S. balancing authorities in the lower 48 states are currently reporting. An online tool, called the U.S. Electric System Operating Data Tool, provides near-real-time data on hourly, daily, and weekly electricity supply and demand, as well as analysis and data visualizations, on both national and regional scales. Public access to a beta version of the tool is available on EIA's website.<sup>34</sup>

For example, Figure 4-2 shows a detail of ISO New England's (ISO-NE) transmission connections from the status map page of the web tool. Balancing authorities report hourly actual interchange with their directly connected neighboring BAs. Figure 4-3 shows hourly actual interchange reported by ISO-NE with its neighboring BAs: New York ISO (NYISO), New Brunswick System Operator (NBSO), and Hydro Quebec (HQT). These values represent the hourly net metered flow of electric energy on physical tie lines that connect BAs. Negative values represent electric energy flowing into ISO-NE.



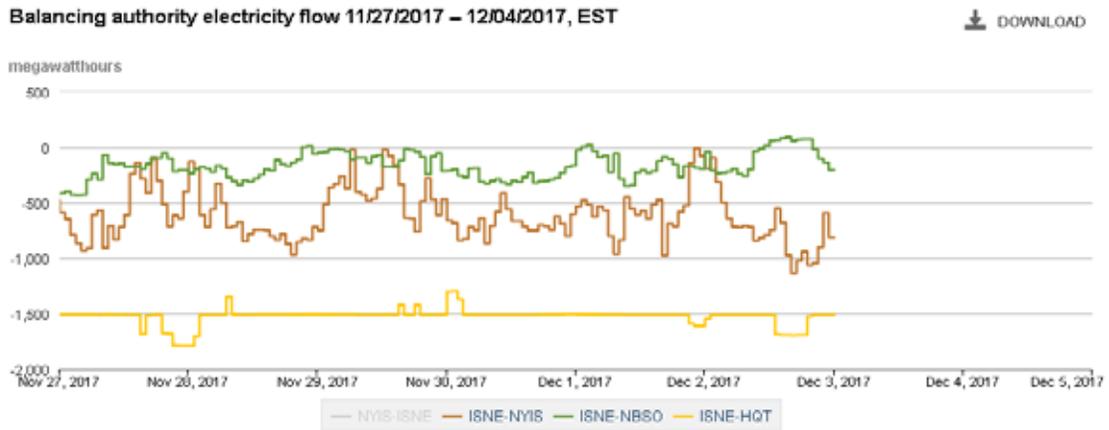
**Figure 4-2. U.S. Electric System Operating Data Beta Tool status map detail for ISO-NE**

Source: EIA (2017): U.S. Electric System Operating Data: [https://www.eia.gov/realtime\\_grid/#/status?end=20180119T17](https://www.eia.gov/realtime_grid/#/status?end=20180119T17)

<sup>33</sup> In FERC's *Reliability Primer*, a Balancing Authority is defined as "the entity that is initially responsible for maintaining the balance between generation and load within a "balancing authority area," which is its defined electric boundary. Approximately 105 balancing authorities across the United States collectively make-up the areas where generation and load need to be kept in balance." See <https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf>.

<sup>34</sup> [https://eia.gov/beta/realtime\\_grid/#/status](https://eia.gov/beta/realtime_grid/#/status)

Balancing authority Interchange *(BA-to-BA interchange data available up to two days prior to current day.)*



Source: U.S. Energy Information Administration

**Figure 4-3. Hourly actual interchange reported by ISO-NE with its three neighboring BAs**

Source: EIA (2017): [https://www.eia.gov/realtime\\_grid/#/status?end=20180119T17](https://www.eia.gov/realtime_grid/#/status?end=20180119T17)

There are also instances in which entities publish summaries of this type of information. New England’s Independent System Operator, ISO New England (ISO-NE), publishes information on transmission utilization in a concise 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 4-4).

Figure 4-5 and Figure 4-6 present examples of this information. Figure 4-5 shows the distribution of hourly flows by month across the interface between Southwest Connecticut and the rest of the system; the red circles represent outliers from the box-plot representation. Figure 4-6 presents this same information sorted in rank order (from highest to lowest percentage of the interface limit) separately for on- and off-peak hours.

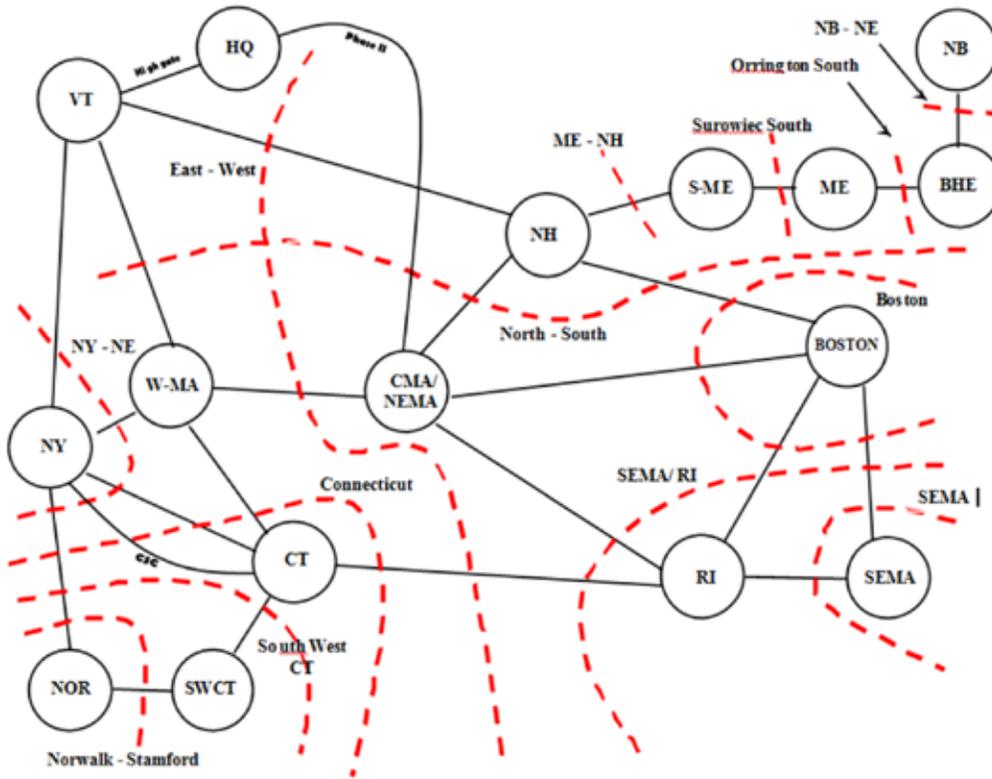


Figure 4-4. New England sub-area model

Source: Rojo (2017), p. 3: [https://www.iso-ne.com/static-assets/documents/2017/04/a8\\_2016\\_interface\\_flows\\_and\\_other\\_system\\_performance\\_summaries.pdf](https://www.iso-ne.com/static-assets/documents/2017/04/a8_2016_interface_flows_and_other_system_performance_summaries.pdf)

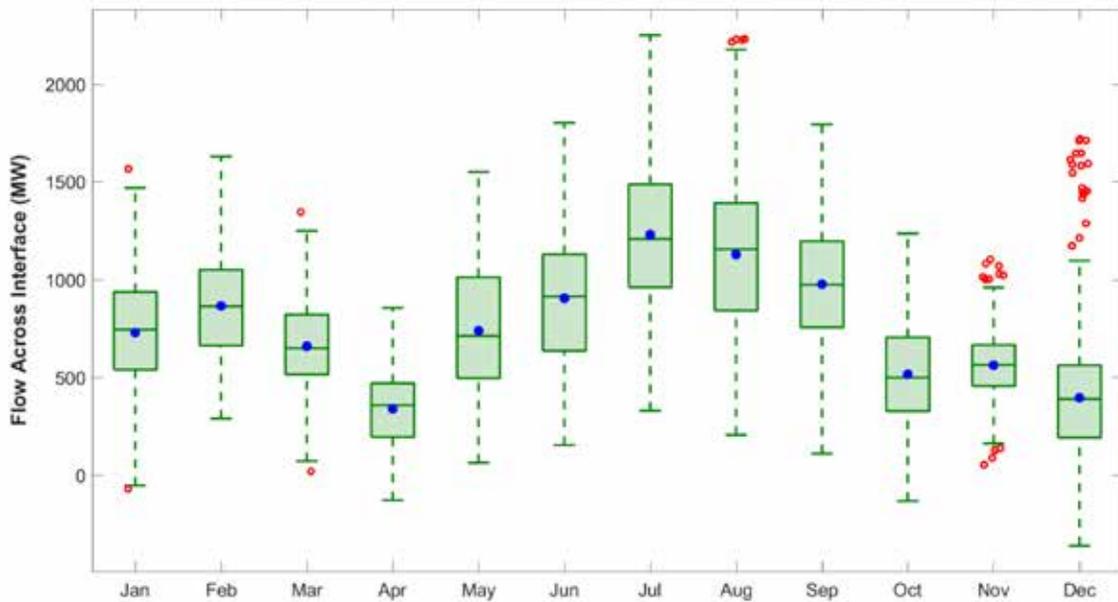


Figure 4-5. Southwest Connecticut import interface net flow by month, 2016

Source: Rojo (2017), p. 32: [https://www.iso-ne.com/static-assets/documents/2017/04/a8\\_2016\\_interface\\_flows\\_and\\_other\\_system\\_performance\\_summaries.pdf](https://www.iso-ne.com/static-assets/documents/2017/04/a8_2016_interface_flows_and_other_system_performance_summaries.pdf)

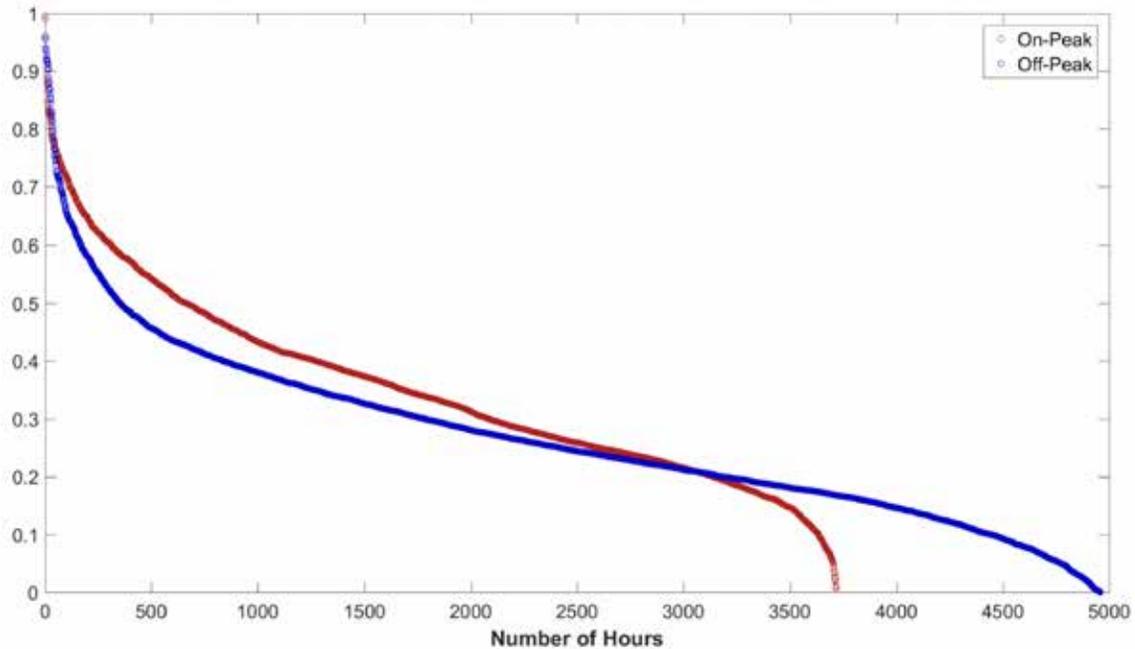


Figure 4-6. Southwest Connecticut import interface duration curve: net flow as a percent of interface limit, 2016

Source: Rojo (2017), p. 32: [https://www.iso-ne.com/static-assets/documents/2017/04/a8\\_2016\\_interface\\_flows\\_and\\_other\\_system\\_performance\\_summaries.pdf](https://www.iso-ne.com/static-assets/documents/2017/04/a8_2016_interface_flows_and_other_system_performance_summaries.pdf)

### 4.3 Western Interconnection

The Western Electricity Coordinating Council (WECC) reports annually on transmission utilization within the Western Interconnection. Key transmission lines in the Western Interconnection are grouped into numbered paths for planning and operational purposes (see Figure 4-7). WECC's U75 metric measures congestion on these paths, which represents the percent of time that flow on the path is above 75 percent of its operating limit. Many factors determine operating limits, and a low U75 does not necessarily indicate a path is underutilized, nor does a high U75 necessarily indicate congestion.<sup>35</sup>

<sup>35</sup> While there have been no changes to the defined paths since publication of the 2013 report, WECC has run production cost studies on several specific study cases, available at <https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Transmission-Plan.aspx>.

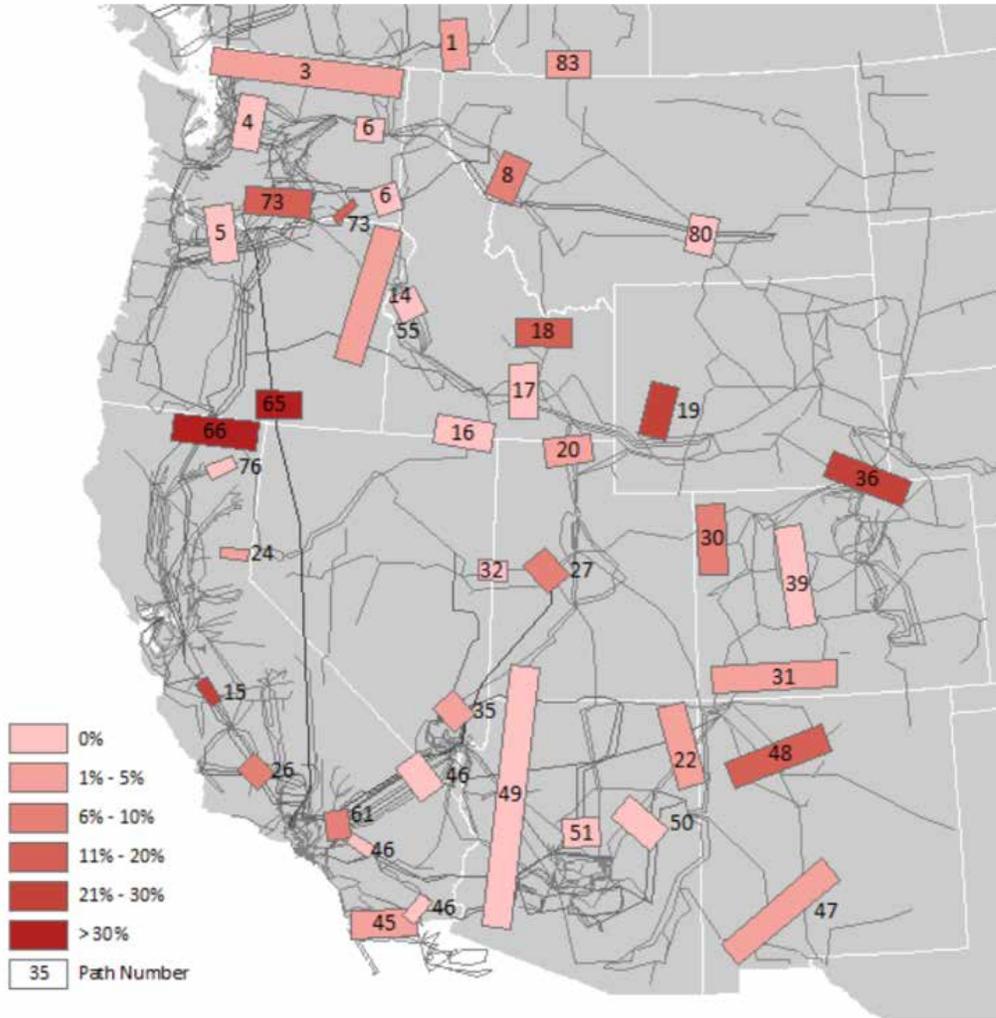


Figure 4-7. WECC Major Paths and U75 for 2016

Source: WECC (2017): <https://www.wecc.biz/epubs/StateOfTheInterconnection/Pages/Overview.aspx>

#### 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 materials for the other two interconnections presented in this section.

## 5. Management of Current 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;<sup>36</sup> 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 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 force operators to re-dispatch generation to relieve flow on affected transmission elements or paths, are established to maintain reliable operating levels consistent with NERC reliability standards. Thus, constraints reflect a transmission flow threshold for reliable operations. When constraints frequently limit desired flows, transmission enhancements may be warranted to enable the desired level of flows.

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

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

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<sup>36</sup> This could include limits on individual equipment, groups of equipment, or based on multiple variables (e.g., a nomogram).

## 5.2 Transmission Loading Relief (Eastern Interconnection)

Transmission Loading Relief (TLR) procedures are commercially determined congestion management procedures used by Reliability Coordinators in the Eastern Interconnection to force generation re-dispatch to limit flows over the system to maintain safe operating levels.

The number, level, and location of TLRs is not a complete indicator of where the transmission system is being utilized beyond the projected capabilities of the existing facilities. TLRs do not capture congestion within the transmission systems for which a Reliability Coordinator is responsible, but instead only capture congestion between Reliability Coordinators—which include multiple utilities’ transmission systems. In addition, TLRs only serve to identify congestion between two regions without organized wholesale markets or between an RTO/ISO and a region without an organized wholesale market. Most RTO/ISOs have congestion management protocols with neighboring RTO/ISOs and do not need to use TLRs; for example, MISO, PJM, and SPP utilize a process that avoids the use of TLRs by coordinating re-dispatch of generation units whose flows are known to contribute to a constraint.

NERC publishes information on the use of TLRs on its TLR Log website. The information includes the identity of the flowgate<sup>37</sup> that is constrained; the start and end times of the TLR; the level of the TLR; and the MWs affected.<sup>38, 39</sup>

Table 5-1 shows the TLR levels as defined by NERC. 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 in the Eastern Interconnection for the period 2009-2016. Figure 5-3 shows the number of higher levels of TLRs called in the Eastern Interconnection during 2016, by Reliability Coordinator.

**Table 5-1. Transmission Loading Relief (TLR) Levels**

TLR Level	Reliability Coordinator Action/Comments
1	<b>Notify</b> Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations.
2	<b>Hold</b> Transfers at present level to prevent SOL or IROL violations. Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held.
3a	<b>Reallocation</b> of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority

<sup>37</sup> 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.

<sup>38</sup> See <http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx>.

<sup>39</sup> The Department is aware that there may be differences in TLR data, which arise due to the means by which they are accessed from NERC.

TLR Level	Reliability Coordinator Action/Comments
	Transmission Service. Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process.
3b	<b>Curtail</b> Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation. Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service.
4	<b>Reconfigure</b> transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue. There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service.
5a	<b>Reallocation</b> of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point. Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced (“pro rata”) level. Pro forma tariff also requires curtailment/reallocation on pro rata basis with Network Integration Transmission Service and Native Load.
5b	<b>Curtail</b> Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation. Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load.
6	<b>Emergency Procedures.</b> Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding.
0	<b>TLR Concluded.</b> Restore transactions.

Source: NERC TLR levels: <http://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx>

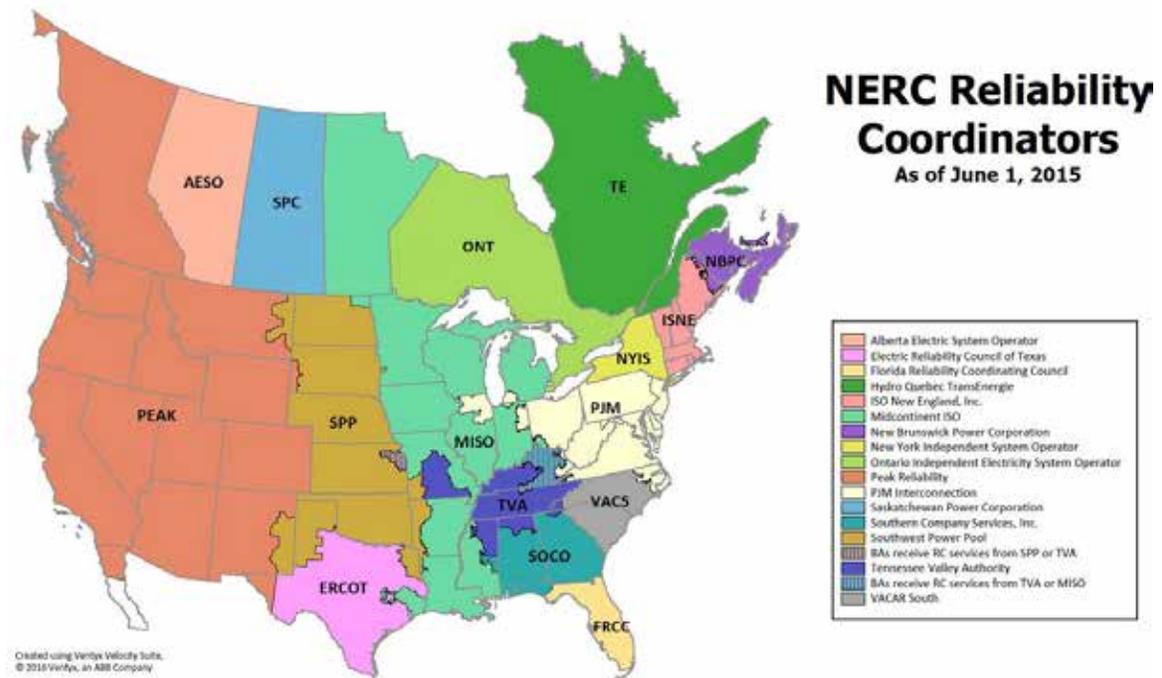


Figure 5-1. NERC Reliability Coordinators, as of June 1, 2015

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

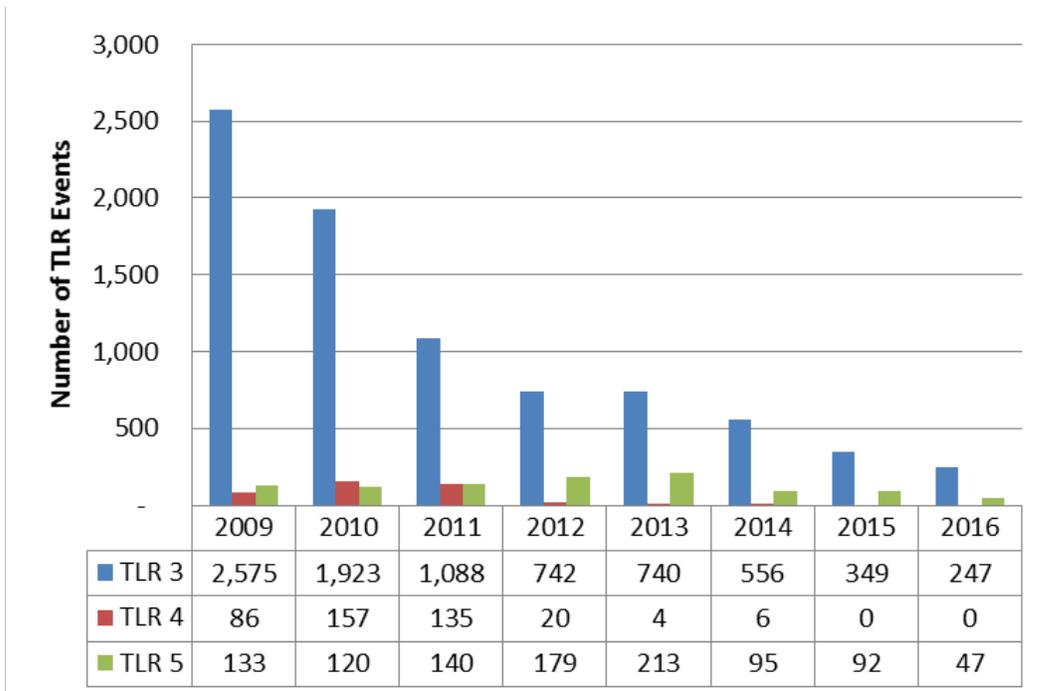


Figure 5-2. Eastern (total) TLR events, 2009–2016

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

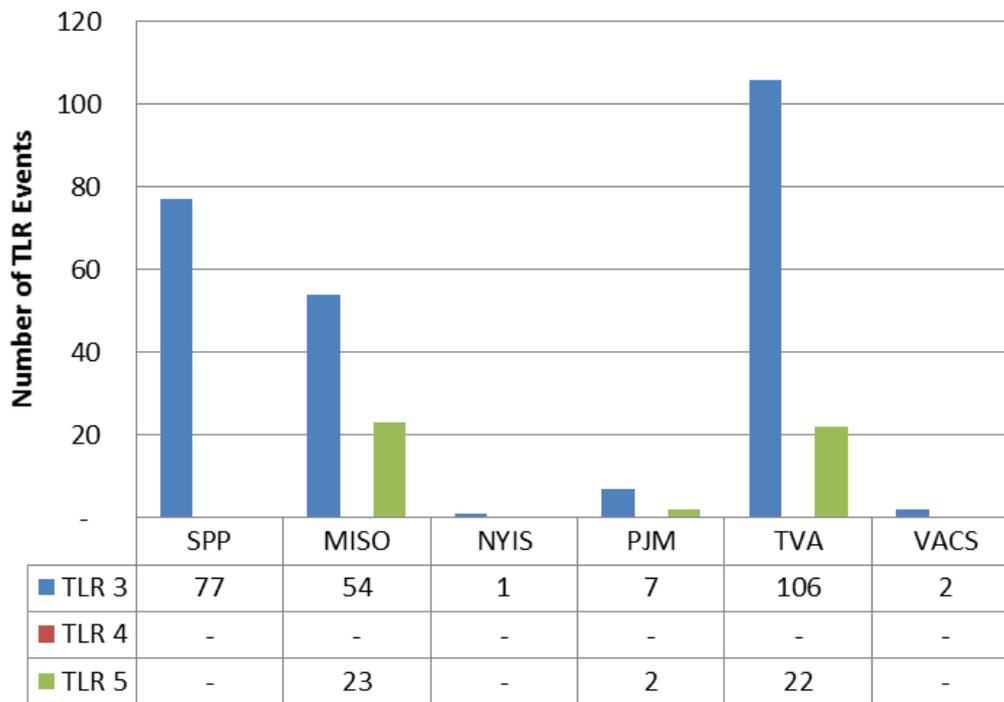


Figure 5-3. Year 2016 TLR events by region

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

### 5.3 Market-Based Procedures for Managing Transmission Constraints

All balancing authorities manage transmission constraints through centralized security-constrained economic dispatch of resources. RTOs and ISOs accomplish this using bid-based optimizations. Figure 5-4 shows the geographic boundaries of the markets served by the RTO/ISOs of North America. As part of annual reporting on the operation of these markets, RTO/ISOs (or the market monitors for their markets) sometimes report information on selected constraints.



**Figure 5-4. ISO/RTO Council Members**

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

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.

#### 5.3.1 California ISO (CAISO)

The California Independent System Operator (CAISO) produces an *Annual Report on Market Issues and Performance*,<sup>40</sup> 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.

<sup>40</sup> See CAISO (2016): <http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf>.

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.

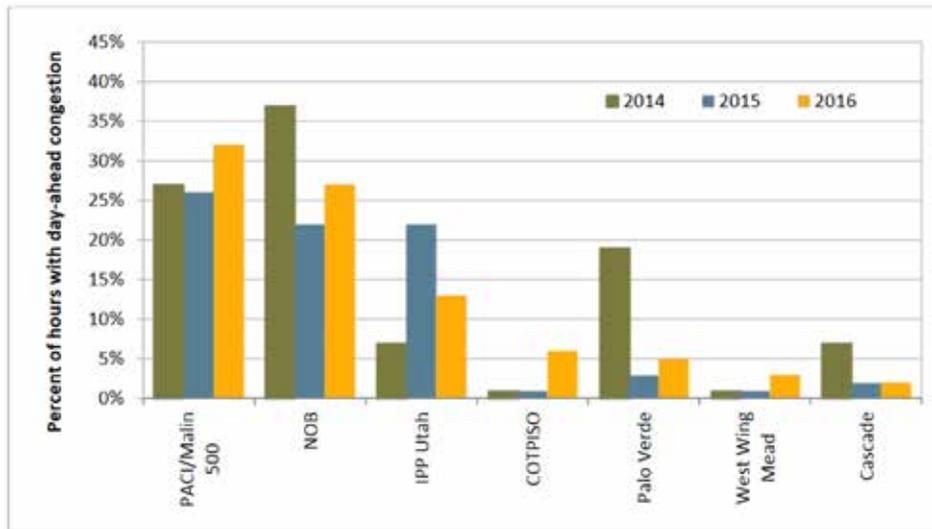


Figure 5-5. CAISO percent of hours with congestion on major interties, 2014-2016

Source: CAISO (2017): <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

Table 5-2. CAISO summary of import congestion, 2015–2016

Import region	Intertie	Frequency of import congestion			Average congestion charge (\$/MW)			Import congestion charges (thousands)		
		2014	2015	2016	2014	2015	2016	2014	2015	2016
Northwest	PACI/Malin 500	27%	26%	32%	\$17.0	\$6.2	\$7.4	\$88,731	\$37,687	\$51,139
	NOB	37%	22%	27%	\$12.7	\$6.4	\$6.7	\$58,902	\$12,375	\$24,346
	Cascade	7%	2%	2%	\$10.6	\$7.5	\$19.5	\$490	\$101	\$244
	COTPISO	1%	1%	6%	\$17.8	\$36.2	\$12.7	\$37	\$97	\$158
	Tracy 500	3%	0.1%		\$27.3	\$6.2		\$2,262	\$20	
	Summit	1%	0.2%		\$16.4	\$2.8		\$57	\$3	
	Tracy 230	0.1%			\$72.5			\$17		
Southwest	Palo Verde	19%	3%	5%	\$15.1	\$13.2	\$19.5	\$36,551	\$9,261	\$12,942
	Mead	1%	1%	1%	\$8.5	\$14.4	\$12.2	\$1,206	\$1,278	\$1,023
	West Wing Mead	1%	1%	3%	\$30.1	\$34.3	\$34.4	\$280	\$330	\$865
	IPP Utah	7%	22%	13%	\$7.2	\$2.9	\$3.6	\$879	\$1,079	\$803
	North Gila		6%	0%		\$47.0	\$68.5		\$3,728	\$201
	CFE_ITC			0%			\$138.0			\$56
	Sylmar AC	0.4%		0.2%	\$9.7		\$4.8	\$251		\$70
	Market Place Adelanto	0.3%	0.3%		\$16.6	\$18.9		\$261	\$330	
	IPP DC Adelanto (BG)	5%	1%		\$8.5	\$3.7		\$1,727	\$77	
	El Dorado		0.1%			\$3.0			\$14	
	IID - SCE	0.5%			\$53.0			\$1,005		
Other							\$142	\$3	\$92	
<b>Total</b>								<b>\$192,797</b>	<b>\$66,381</b>	<b>\$91,939</b>

\* The IPP DC Adelanto branch group is not an intertie, 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 (2017), p. 179: <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

Table 5-3. CAISO impact of congestion on day-ahead prices during congested hours, 2016

Area	Constraint	Frequency				Q1			Q2			Q3			Q4				
		Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E											
PG&E	PAT115 5_N	2.3%	1.0%	4.3%	8.4%	\$2.34	\$2.05	\$1.92	\$4.04	\$3.32	\$3.10	\$2.74	\$2.22	-\$2.06	\$4.32	\$3.62	\$3.32		
	30055_ROUND MT 500_30015_TABLE MT 500_BR_1_2				0.6%										\$1.26	\$0.92	\$1.34		
	OVS 4186537 Pat115_5_N				0.5%										\$5.40	\$4.65	\$4.24		
	OVS 4008879 Pat115_5_N				0.5%										\$1.51	\$1.21	\$1.11		
	OVS 4008893 Pat115_5_N				0.3%										\$5.07	\$4.19	\$3.90		
	OVS_3843093_LBN_5N				0.3%										\$3.74	\$3.13	\$2.84		
	OVS 3959238 Pat115_5_N				0.2%										\$2.06	\$1.67	\$1.55		
	30055_GATES1_500_30900_GATES_230_XF_11_P				1.5%							\$0.32	-\$0.25	-\$0.24					
	30915_MORROBAY_230_30916_SOLARES_230_BR_2_1				1.0%							\$1.96							
	6310_S013_NC_SUM				1.4%							-\$0.80	\$0.65	\$0.60	-\$0.96	\$0.76	\$0.69		
	OVS 4059507 Pat115_5_N				0.4%							\$2.39	-\$1.78	-\$1.65					
	OVS 3938352 LBN_5_N				0.3%							\$1.93	-\$1.56	-\$1.42					
	OVS 3969865 Pat115_5_N				0.1%							\$3.46	-\$2.78	-\$2.60					
	6110_S010_NC				16.2%							\$0.07	-\$0.07	-\$0.07					
	OVS 3602720_Pat115				8.3%							\$6.10	-\$4.73	-\$4.49					
30915_MORROBAY_230_30916_SOLARES_230_BR_2_1				1.1%							\$2.01	-\$2.05							
LOS BANOS NORTH_B0				0.7%							\$4.60	-\$3.80	-\$3.52						
30750_MISSISSIP_230_30790_PANOCHE_230_BR_1_1	78.6%										\$1.18	-\$0.98	-\$0.95						
OVS 2592148 P15_HARD				1.8%							\$3.44	-\$2.87	-\$2.69						
30060_MIDWAY_500_29402_WIRI WIND_500_BR_1_2	0.5%										-\$1.57	\$1.40	\$1.29						
24016_BARRE_230_24154_VILLA PK_230_BR_1_1	6.1%	1.2%	1.8%	5.9%	-\$1.05	\$1.52	-\$0.50	-\$0.99	\$1.08	\$1.30	-\$0.39	\$0.48		-\$1.08	\$1.71	-\$6.28			
24086_LUGO_500_26105_VICTORIA_500_BR_1_1				3.0%	3.8%	5.7%		-\$1.75	\$1.44	\$1.07	-\$1.07	\$0.61	-\$0.53	-\$1.03	\$0.84	\$0.82			
OVS 4158636 BID-41100				2.5%										-\$0.71	\$0.76	-\$0.18			
24016_BARRE_230_25201_LEWIS_230_BR_1_1	2.2%	1.1%	1.8%	1.1%	-\$1.15	\$1.50		\$0.62	\$0.90	\$1.05	-\$0.39	\$0.53		-\$0.88	\$1.02				
PATH26_B0	0.3%			1.9%	0.5%	-\$2.54	\$2.13	\$2.01				-\$5.77	\$3.66	\$3.45	-\$4.91	\$3.56	\$3.34		
24086_LUGO_500_24092_MIRALOMA_500_BR_3_1				1.2%	0.5%						-\$4.23	\$3.25	\$4.72	-\$2.63	\$1.84	\$2.83			
24156_VINCENI_500_24155_VINCENI_230_XF_4_P				3.7%							-\$6.20	\$4.41	\$4.69						
24156_VINCENI_500_24155_VINCENI_230_XF_1_P				0.5%							-\$2.93	\$1.93	\$1.94						
SDG&E	22356_JIMPLEVLY_230_22360_JIMPLEVLY_500_XF_81				11.4%												\$1.50		
	OVS 4179177 IVNLEYBNS1_NG2				9.1%												\$5.33		
	7820_IL_2405_CVWLOAD_NG	1.9%	2.8%	3.7%	8.1%	-\$0.70		\$2.13	-\$0.25		\$3.30	-\$0.32		\$3.86	-\$0.53		\$6.02		
	22192_DOUBLET138_22300_FRENCH_138_BR_1_1				1.0%							\$5.09					-\$1.30		
	23040_CROSSBWP				3.0%												-\$0.22	\$3.43	
	MIGUEL_B0s_MEXFLW_NG				1.0%												-\$0.53	\$8.00	
	22476_MIGUELIMP_69.0_22456_MIGUEL_69.0_BR_1_1				0.7%	1.0%											\$8.52	\$1.74	
	22596_OLD TOWN_230_22504_MISSION_230_BR_1_1				0.8%													\$4.36	
	OVS 4250740 Devers 230 Nilus				0.7%													\$24.06	
	BID SCE_B0	3.7%			0.5%			\$2.35										\$1.67	
	OVS 4497618 TL23055_NG				0.4%													-\$0.32	\$5.28
	OVS 4391827 TL50003_NG				0.3%													-\$0.52	\$5.33
	OVS 4392033 TL50003_NG				0.3%													\$0.55	\$5.40
	OVS 4489686 TL23055_NG				0.3%													-\$0.40	\$6.02
	OVS 4402394 TL50003_NG				0.2%													-\$0.59	\$5.62
OVS 4008872 DVSB_NG3				2.7%													-\$1.92		
22256_ESCONDIDO_69.0_22724_SANNARCOS_69.0_BR_1_1				0.9%													-\$3.28		
22464_MIGUEL_230_22504_MISSION_230_BR_1_1				0.8%													\$2.24		
22464_MIGUEL_230_22504_MISSION_230_BR_2_1				0.7%													\$3.24		
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	1.5%	5.2%	0.7%				\$2.35				\$5.94						\$3.64		
Miguel_reactive_SOL2				0.4%													\$6.71		
OVS 4143457 TL50004_NG				0.3%													\$0.40	\$6.74	
OVS 4169254_Cline_ELD_P15G_SQT				0.3%													-\$6.42	\$3.56	\$4.78
OVS 4282482 CHY_NV_SQT				0.3%													-\$4.43	\$2.32	\$3.55
OVS 4235148 TL50001_NG				0.2%													\$0.56	\$8.00	
OVS 4216681 TL500010UT_NG				0.1%													\$1.09	\$13.44	
22500_MISSION_138_22120_CARLTONS_138_BR_1_1	1.2%	5.4%					\$2.52										\$3.21		
22604_OTAY_69.0_22616_OTAYUTP_69.0_BR_1_1				3.2%													\$0.46		
22464_MIGUEL_230_22468_MIGUEL_500_XF_B1	5.0%	3.0%					-\$1.83		\$11.38	-\$1.62							\$11.97		
22820_SAVETVTR_69.0_22475_MIGUELTP_69.0_BR_1_1				1.1%													\$6.99		
OVS 3725346 IV_NG1A				1.1%													-\$1.18	\$3.87	\$1.20
OVS 3725348 50002_OCS_TDM				0.7%														\$3.48	
OVS 4079303 TL50001_NG				0.4%														-\$1.01	\$12.95
22692_ROSCOWTP_69.0_22696_ROSE CVN_69.0_BR_1_1				0.1%														\$89.43	
22462_M60 TAP_138_22772_SOUTH BAY_138_BR_1_1	2.5%																	\$6.82	
OVS 2319325 PDCO_NG	2.0%						-\$1.74	\$1.43	\$1.78										
22464_MIGUEL_230_22472_MIGUELIMP_1.0_XF_1	1.3%						-\$1.14		\$7.33										
OVS 3624990 TL50001_NG	1.3%						-\$0.35		\$4.20										
24016_BARRE_230_24044_HILLIS_230_BR_4_1	0.9%						-\$0.32		\$3.38										
OVS 3636555 M-C-WL_8510	0.9%						-\$3.55	\$3.01	\$3.66										
24016_BARRE_230_24044_HILLIS_230_BR_1_1	0.8%						-\$1.12		\$5.31										
22468_MIGUEL_500_22472_MIGUELIMP_1.0_XF_B0	0.6%						-\$1.05		\$6.87										
22464_MIGUEL_230_22461_MIGUEL160_138_XF_1	0.6%																	\$3.17	
24138_SERRANO_500_24137_SERRANO_230_XF_2_P	0.3%						-\$4.86	\$3.21	\$6.51										

Source: CAISO (2017), p. 183: <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

5.3.2 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.<sup>41</sup> Table 5-4 and Figure 5-6 show the geographic area served and the location of constraints identified by ERCOT.<sup>42</sup> In addition, the market monitor for ERCOT includes information about constraints in its annual *State of the Market* report.<sup>43</sup> Figure 5-7 shows the frequency of active constraints for different load levels, annually for 2014–2016. 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, Oct 2015–Sept 2016

Map Index	Constraint	Congestion Rent
1	North to Houston Import	\$64,141,507
2	Meadow 345/138 kV Transformer	\$47,958,057
3	Fort Worth-West Denton 138 kV Line	\$29,740,294
4	Loma Alta-Los Fresnos 138 kV Line	\$26,946,998
5	Lower Rio Grande Valley Import Limit	\$21,736,088
6	Morris Dido-Rosen Heights Tap 138 kV Line	\$15,045,333
7	Panhandle Export Limit	\$12,289,182
8	Morris Dido-Eagle Mountain 138 kV Line	\$10,484,213
9	Carrollton Northwest-Lakepointe 138 kV Line	\$10,437,559
10	Jim Christal-West Denton 138 kV Line	\$10,434,358
11	Eagle Mountain 345/138 kV Transformer	\$10,252,471
12	Javelina-Molina 138 kV Line	\$9,644,364
13	Hockley-Betka 138 kV Line	\$8,004,064
14	La Palma-Villa Cavazos 138 kV Line	\$7,870,782
15	Bellaire-San Felipe 138 kV Line	\$7,119,923

Source: ERCOT (2016c), p. 6: [http://www.ercot.com/content/wcm/lists/89476/2016\\_Constraints\\_and\\_Needs\\_Report.pdf](http://www.ercot.com/content/wcm/lists/89476/2016_Constraints_and_Needs_Report.pdf)

<sup>41</sup> See ERCOT (2015): [http://ercot.com/content/news/presentations/2015/2015ERCOTConstraintsAndNeeds\\_Report.pdf](http://ercot.com/content/news/presentations/2015/2015ERCOTConstraintsAndNeeds_Report.pdf).

<sup>42</sup> Section 4 of the *2015 Report on Existing and Potential Electric System Constraints and Needs* shows transmission projects in ERCOT (as of December 2015) that, among other things, are designed to address these constraints. See ERCOT (2015).

<sup>43</sup> See Potomac Economics (2016b): [http://potomaceconomics.com/index.php/markets\\_monitored/ERCOT](http://potomaceconomics.com/index.php/markets_monitored/ERCOT).

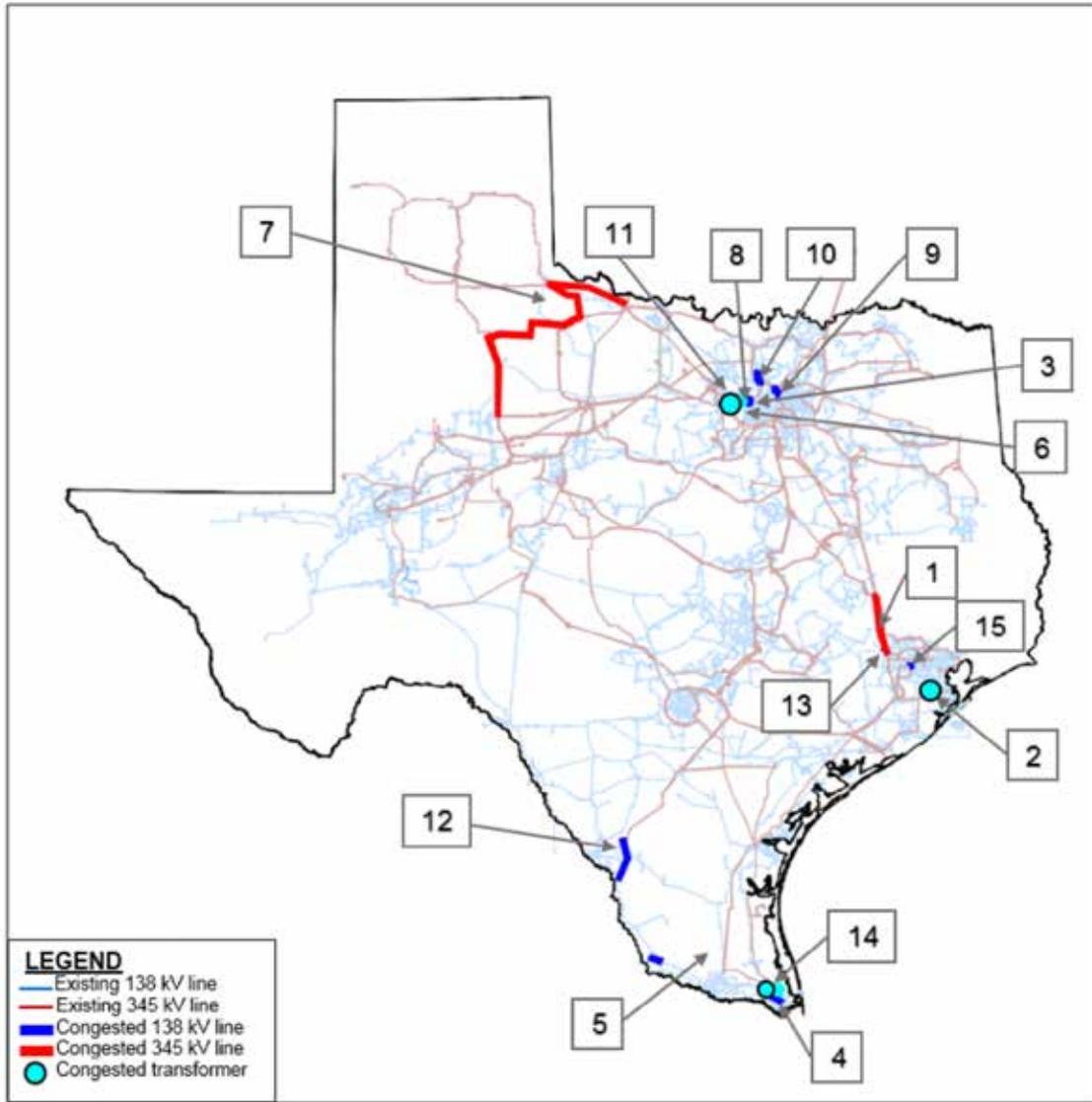


Figure 5-6. Top 15 congested constraints on the ERCOT system, Oct 2015–Sept 2016

Source: ERCOT (2016c), p. 7: [http://www.ercot.com/content/wcm/lists/89476/2016\\_Constraints\\_and\\_Needs\\_Report.pdf](http://www.ercot.com/content/wcm/lists/89476/2016_Constraints_and_Needs_Report.pdf)

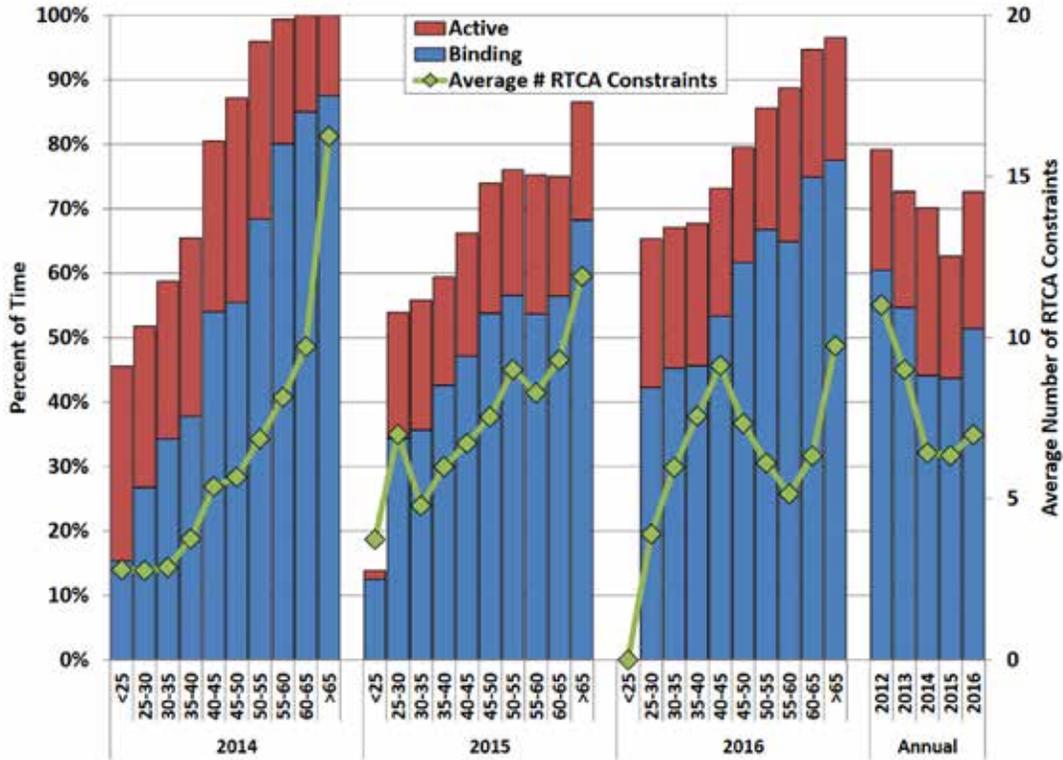


Figure 5-7. Frequency of binding and active constraints, 2014–2016

Source: Potomac Economics (2017b), p. 46: <https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf>

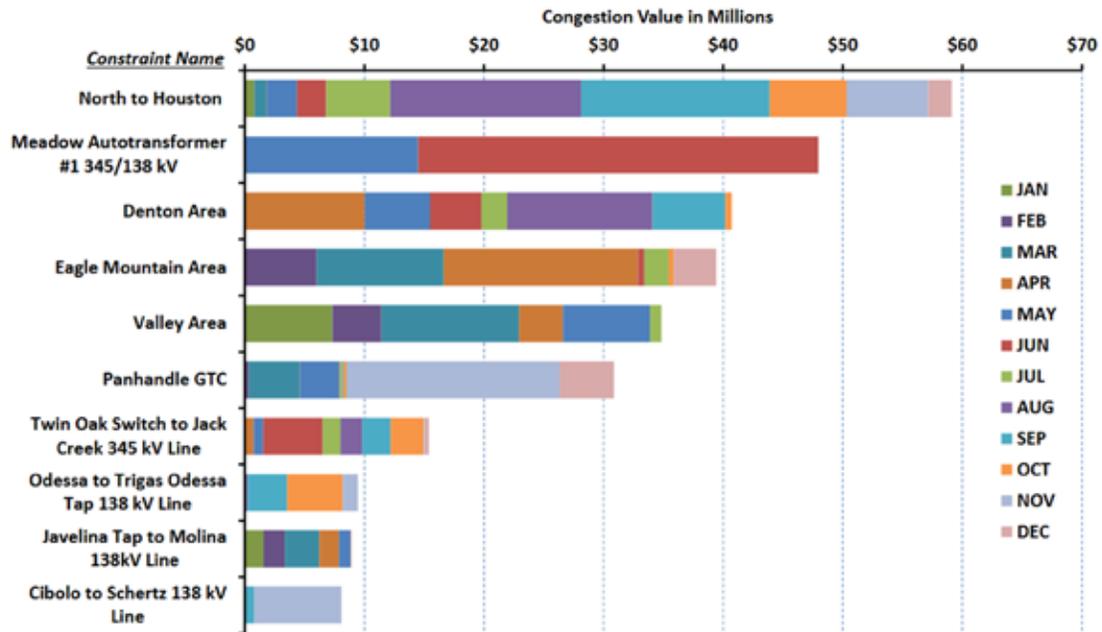


Figure 5-8. ERCOT top ten real-time constraints, 2016

Source: Potomac Economics (2017b), p. 49: <https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf>

### 5.3.3 ISO New England (ISO-NE)

ISO-NE reports on prospective system constraints in its annual *Regional System Plan*.<sup>44</sup> Constraints are also described in presentations made by ISO-NE to the Planning Advisory Committee and in reports by the planning entities within New England. Figure 5-9 shows the geographic area served and the location of key study areas identified by ISO-NE.

In its *2017 Regional System Plan*, ISO-NE includes the following comments on potential future constraints, as identified in planning studies:

- *In 2014 and 2015, the ISO conducted Strategic Transmission Assessments of the integration of new wind resources in Maine and in Vermont. The study found that transmission system improvements are necessary to address a combination of local and regional transmission constraints and address BPS performance concerns. Small amounts of additional 115 kV-connected wind resources planned in Maine for the Wyman Hydro and Rumford regions could likely be accommodated without a major new transmission line to the local regions. However, the Keene Road and Bangor regions cannot support much additional wind capacity beyond the amount studied without major new transmission facilities. Large wind generation projects proposed in western Maine would also require major new transmission additions.*
- *Northern Vermont would require new reactive support to accommodate additional wind resources and would still be thermally constrained below the amount of wind studied but less so in the winter than in other seasons. Central Vermont showed no constraints to the amount of wind in the queue studied (165 MW), and the study determined that this area would be capable of integrating about 231 MW of wind. Southern Vermont showed only minor constraints. Some risk of curtailment remains at higher wind production levels in the northern and southern regions if only modest upgrades are applied. Major upgrades would be necessary to eliminate the maximum wind-condition restrictions; however, no curtailment would be required at typical wind levels.<sup>45</sup>*
- *... Approximately 320 MW of wind resources were located in the Keene Road area, and over 90 MW of additional future development were proposed for interconnecting to the 115 kV system in the area. The first economic study developed metrics to quantify the effects of curtailments expected on the post MPRP system. The effect of potential improvements in the Keene Road area were then evaluated to quantify the possible benefits associated with market-efficiency transmission upgrades that could allow the wind resources to operate without the current level of constraints. Additional analysis beyond the economic study was then conducted, and the ISO determined that METUs were not justified.*
- *The second economic study investigated scenarios of wind-resource development and showed the effect of the conceptual transmission system*

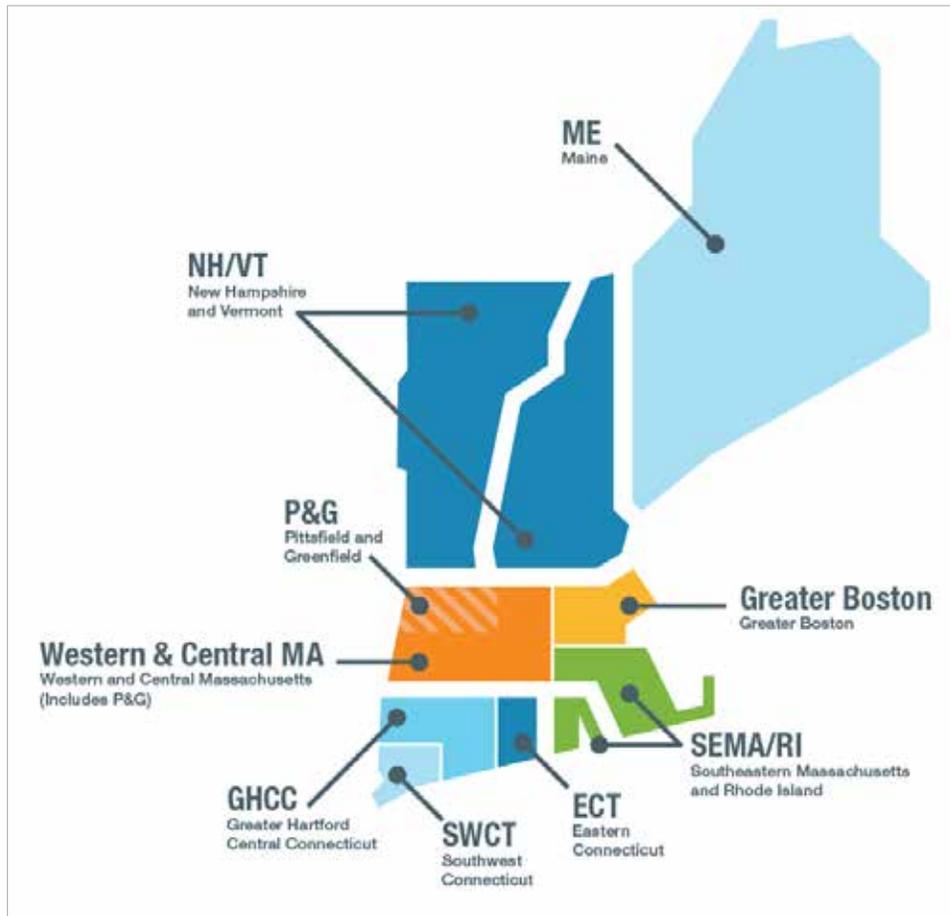
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<sup>44</sup> See ISO-NE (2017): <http://www.iso-ne.com/system-planning/system-plans-studies/rsp>.

<sup>45</sup> See ISO-NE (2017), p. 124.

*expansion in Maine. ...the Strategic Transmission Analysis: Wind Integration Study identified a number of conceptual transmission upgrades that could relieve constraints to existing and planned onshore wind development throughout Maine. This study may inform stakeholders on the cost and benefits of pursuing these transmission upgrades.<sup>46</sup>*

In addition to the above studies, the ISO filed with FERC and FERC accepted revised interconnection procedures to allow for clustering of new resources. The clustering approach will facilitate the completion of interconnection studies in Maine and other areas of the system should similar conditions evolve in the future.



**Figure 5-9. Key study areas in ISO-NE**

Source: ISO-NE (2017), p. 71: <https://www.iso-ne.com/system-planning/system-plans-studies/rsp>

<sup>46</sup> See ISO-NE (2017), p. 129.

5.3.4 Midcontinent ISO (MISO)

The Midcontinent ISO (MISO) produces an annual *Market Congestion Planning Study*<sup>47</sup> that contains an analysis of historical and projected future congestion. MISO makes public a list of projected top future congested flowgates; the top projected future congested flowgates reported in the *2016 MISO Transmission Expansion Plan* (MTEP)<sup>48</sup> are shown in Figure 5-10.

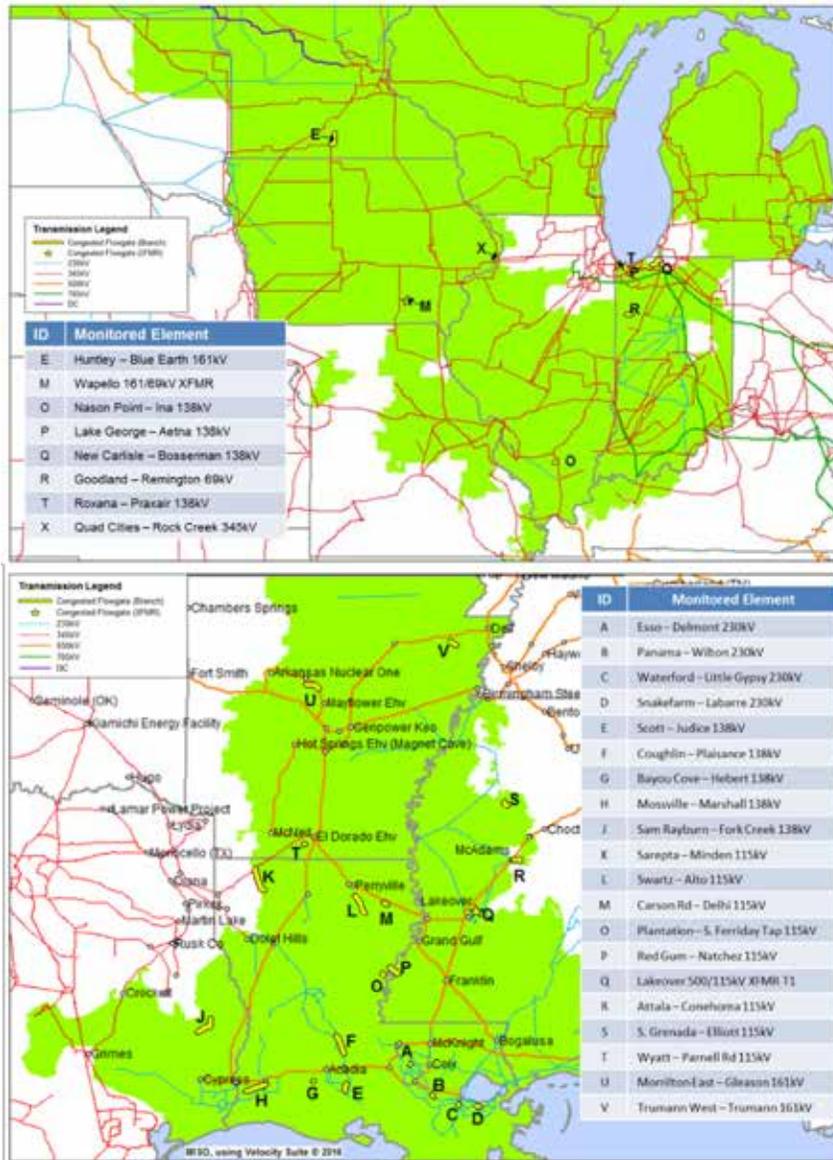


Figure 5-10. Projected top future congested flowgates in 2016 MTEP (Top: MISO North/Central Region; Bottom: MISO South Region)

Source: MISO (2016), p. 108: <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>

<sup>47</sup> Prior to 2014, this report was known as the *Market Efficiency Planning Study*.

<sup>48</sup> See MISO (2016): <https://old.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP16.aspx>.

5.3.5 New York ISO (NYISO)

The New York Independent System Operator (NYISO) biennially performs a *Reliability Needs Assessment* (RNA) as part of its Reliability Planning Process (RPP).<sup>49</sup> 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.

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.<sup>50</sup> Figure 5-11 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.<sup>51</sup>

In addition, NYISO conducts a biennial economic planning process and publishes corresponding *Congestion Assessment and Resource Integration Study* (CARIS) reports. In the 2015 CARIS<sup>52</sup> 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.<sup>53, 54</sup>

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

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CENTRAL EAST	2,968	2,166	1,471	3,374	3,022	4,678	4,215	4,527	4,425	4,416	3,466	3,624	3,365	3,469	3,203
DUNWOODIE TO LONG ISLAND	4,513	6,219	4,777	6,031	5,583	7,869	7,667	7,778	7,502	7,517	7,840	7,920	7,908	8,056	8,108
LEEDS PLEASANT VALLEY	673	514	392	624	384	961	546	629	475	410	325	349	353	404	767
GREENWOOD	2,705	4,338	2,983	3,415	1,438	8,096	7,591	7,693	7,873	7,817	8,392	8,357	8,402	8,430	8,442
NEW SCOTLAND LEEDS	156	774	69	264	173	145	17	29	7	9	9	11	17	13	6
PACKARD HUNTLEY	-	-	-	-	308	3,604	4,729	4,816	5,019	4,809	4,449	4,326	4,209	4,291	4,112
DUNWOODIE MOTHAVEN	765	828	644	504	190	0	0	0	1	0	0	0	0	0	0
RAINEY VERNON	3,131	3,785	2,166	2,166	641	410	4,953	5,308	5,409	5,388	5,142	5,381	4,930	5,223	5,070
E179THST HELLGT ASTORIAE	3,371	4,860	2,432	2,182	990	410	787	864	796	728	563	740	719	737	736
EGRDNCTY 136 VALLYSTR 138	1,880	2,812	2,934	5,908	5,142	2,183	5,491	5,962	5,727	6,086	5,009	5,491	5,574	5,791	5,780

Source: NYISO (2015), p. 54: [http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Economic\\_Planning\\_Studies\\_%28CARIS%29/CARIS\\_Final\\_Reports/2015\\_CARIS\\_Report\\_FINAL.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf)

<sup>49</sup> See NYISO (2016): [http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Reliability\\_Planning\\_Studies/Reliability\\_Assessment\\_Documents/2016RNA\\_Final\\_Oct18\\_2016.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2016RNA_Final_Oct18_2016.pdf)

<sup>50</sup> See NYISO (2017): [http://www.nyiso.com/public/webdocs/media\\_room/publications\\_presentations/Power\\_Trends/Power\\_Trends/2017\\_Power\\_Trends.pdf](http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf)

<sup>51</sup> See "NYISO Historic Congestion Costs" at [http://www.nyiso.com/public/markets\\_operations/services/planning/documents/index.jsp](http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp).

<sup>52</sup> This biannual report is completed in every odd-numbered year; a draft of the 2017 CARIS was released in February 2018 (see NYSIO 2018).

<sup>53</sup> NYISO does not use the number of constrained hours in economic planning.

<sup>54</sup> See NYISO (2015), p. 54: [http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Economic\\_Planning\\_Studies\\_%28CARIS%29/CARIS\\_Final\\_Reports/2015\\_CARIS\\_Report\\_FINAL.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf)

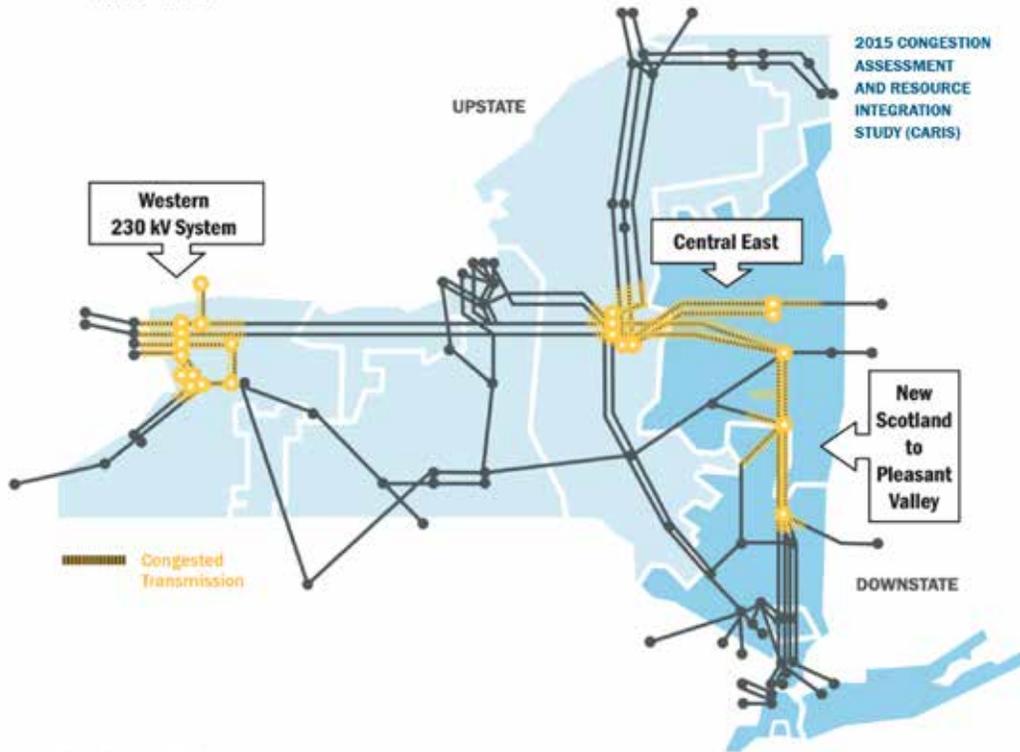


Figure 5-11. Transmission congestion corridors in New York State

Source: NYISO (2017), p. 46: [http://www.nyiso.com/public/webdocs/media\\_room/publications\\_presentations/Power\\_Trends/Power\\_Trends/2017\\_Power\\_Trends.pdf](http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf)

### 5.3.6 PJM

Monitoring Analytics, the external market monitor for PJM, reports top constraints based on a number of criteria in its annual *State of the Market* report.<sup>55</sup> Figure 5-12 shows the location of the top 10 constraints affecting PJM's congestion costs in 2016. Table 5-6 shows the top 25 constraints with frequent occurrence, Table 5-7 shows the top 25 constraints with largest year-to-year change in occurrence, and Table 5-8 shows the top 25 constraints affecting congestion costs.

<sup>55</sup> See Monitoring Analytics (2017a) and (2017b) at [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml).

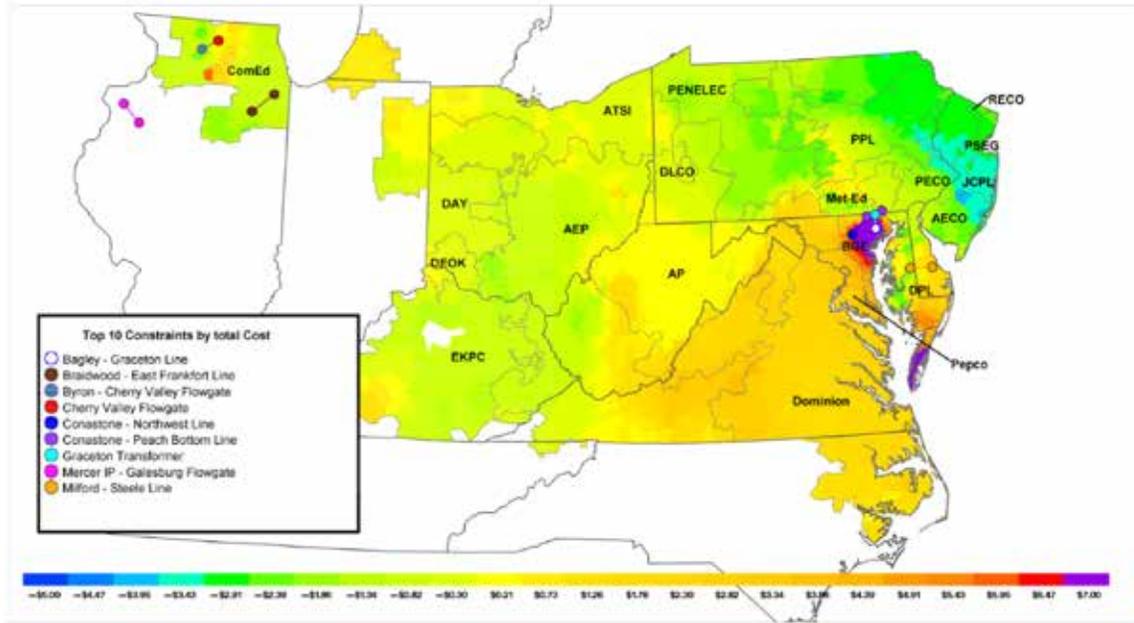


Figure 5-12. Location of the top 10 constraints by PJM total congestion costs, 2016

Source: Monitoring Analytics (2017b), page 474: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml)

Table 5-6. PJM top 25 constraints with frequent occurrence, 2015-2016

No.	Constraint	Type	Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
			2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Cherry Valley	Transformer	789	5,319	4,530	885	774	(111)	9%	61%	52%	10%	9%	(1%)
2	Olive	Other	0	6,092	6,092	0	0	0	0%	69%	69%	0%	0%	0%
3	Monroe - Vineland	Line	3,121	5,354	2,233	197	439	242	36%	61%	25%	2%	5%	3%
4	Bagley - Graceton	Line	3,544	3,313	(231)	1,973	1,685	(288)	40%	38%	(3%)	23%	19%	(3%)
5	Mercer IP - Galesburg	Flowgate	816	3,510	2,694	206	1,155	949	9%	40%	31%	2%	13%	11%
6	Conastone - Northwest	Line	2,536	2,776	240	1,734	1,840	106	29%	32%	3%	20%	21%	1%
7	Graceton	Transformer	270	3,117	2,847	88	1,298	1,210	3%	35%	32%	1%	15%	14%
8	Howard - Shelby	Line	1,370	4,169	2,799	0	0	0	16%	47%	32%	0%	0%	0%
9	Braidwood	Transformer	3,727	4,138	411	0	0	0	43%	47%	5%	0%	0%	0%
10	Flwood - Elwood	Other	1,464	3,849	2,385	0	0	0	17%	44%	27%	0%	0%	0%
11	West Moulton-City Of St. Marys	Line	447	3,718	3,271	0	0	0	5%	42%	37%	0%	0%	0%
12	East Danville - Banister	Line	3,465	3,643	178	126	20	(106)	40%	41%	2%	1%	0%	(1%)
13	Maywood	Transformer	0	3,422	3,422	0	0	0	0%	39%	39%	0%	0%	0%
14	Conastone - Peach Bottom	Line	230	2,407	2,177	73	699	626	3%	27%	25%	1%	8%	7%
15	E.K.P Hebron - Hebron	Line	215	3,016	2,801	0	0	0	2%	34%	32%	0%	0%	0%
16	Miami Fort	Transformer	815	3,002	2,187	3	4	1	9%	34%	25%	0%	0%	0%
17	Emilie - Falls	Line	1,159	2,617	1,458	268	329	61	13%	30%	17%	3%	4%	1%
18	Zion	Line	607	2,929	2,322	0	0	0	7%	33%	26%	0%	0%	0%
19	Gould Street - Westport	Line	789	2,782	1,993	23	27	4	9%	32%	23%	0%	0%	0%
20	Hudson	Transformer	511	2,795	2,284	0	0	0	6%	32%	26%	0%	0%	0%
21	Mardela - Vienna	Line	1,365	2,267	1,002	86	380	294	16%	27%	11%	1%	4%	3%
22	Reynolds - Magnetation	Flowgate	650	2,062	1,412	208	680	472	7%	23%	16%	2%	8%	5%
23	East Bend	Transformer	2,808	2,700	(108)	0	0	0	32%	31%	(1%)	0%	0%	0%
24	Clinch River	Transformer	478	2,557	2,079	0	0	0	5%	29%	24%	0%	0%	0%
25	Tanners Creek	Transformer	1,838	2,548	710	0	0	0	21%	29%	8%	0%	0%	0%

Source: Monitoring Analytics (2017b), page 471: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml)

Table 5-7. PJM top 25 constraints with largest year-to-year change in occurrence 2015-2016

No.	Constraint	Type	Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
			2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Olive	Other	0	6,092	6,092	0	0	0	0%	69%	69%	0%	0%	0%
2	Bunsonville - Eugene	Flowgate	3,762	0	(3,762)	748	0	(748)	43%	0%	(43%)	9%	0%	(9%)
3	Cherry Valley	Transformer	789	5,319	4,530	885	774	(111)	9%	61%	52%	10%	9%	(1%)
4	Graceton	Transformer	270	3,117	2,847	88	1,298	1,210	3%	35%	32%	1%	15%	14%
5	Maywood - Saddlebrook	Line	3,456	29	(3,427)	509	0	(509)	39%	0%	(39%)	6%	0%	(6%)
6	Bergen - New Milford	Line	2,970	72	(2,898)	795	1	(794)	34%	1%	(33%)	9%	0%	(9%)
7	Mercer IP - Galesburg	Flowgate	816	3,510	2,694	206	1,155	949	9%	40%	31%	2%	13%	11%
8	Maywood	Transformer	0	3,422	3,422	0	0	0	0%	39%	39%	0%	0%	0%
9	West Moulton-City Of St. Marys	Line	447	3,718	3,271	0	0	0	5%	42%	37%	0%	0%	0%
10	Oak Grove - Galesburg	Flowgate	3,356	1,336	(2,020)	1,306	174	(1,132)	38%	15%	(23%)	15%	2%	(13%)
11	Conastone - Peach Bottom	Line	230	2,407	2,177	73	699	626	3%	27%	25%	1%	8%	7%
12	E.K.P Hebron - Hebron	Line	215	3,016	2,801	0	0	0	2%	34%	32%	0%	0%	0%
13	Howard - Shelby	Line	1,370	4,169	2,799	0	0	0	16%	47%	32%	0%	0%	0%
14	Easton	Transformer	3,099	397	(2,702)	0	0	0	35%	5%	(31%)	0%	0%	0%
15	Monroe - Vineland	Line	3,121	5,354	2,233	197	439	242	36%	61%	25%	2%	5%	3%
16	Elwood - Elwood	Other	1,464	3,849	2,385	0	0	0	17%	44%	27%	0%	0%	0%
17	Zion	Line	607	2,929	2,322	0	0	0	7%	33%	26%	0%	0%	0%
18	Hudson	Transformer	511	2,795	2,284	0	0	0	6%	32%	26%	0%	0%	0%
19	Waukegan	Transformer	124	2,326	2,202	0	0	0	1%	26%	25%	0%	0%	0%
20	Miami Fort	Transformer	815	3,002	2,187	3	4	1	9%	34%	25%	0%	0%	0%
21	Mainesburg - Mansfield	Line	107	2,098	1,991	0	141	141	1%	24%	23%	0%	2%	2%
22	Bellefonte - Grangston	Line	82	2,203	2,121	0	0	0	1%	25%	24%	0%	0%	0%
23	SENECA	Interface	938	0	(938)	1,182	0	(1,182)	11%	0%	(11%)	13%	0%	(13%)
24	Clinch River	Transformer	478	2,557	2,079	0	0	0	5%	29%	24%	0%	0%	0%
25	Gould Street - Westport	Line	789	2,782	1,993	23	27	4	9%	32%	23%	0%	0%	0%

Source: Monitoring Analytics (2017b), page 472: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml)

Table 5-8. PJM top 25 constraints affecting PJM congestions costs (by facility), 2016

No.	Constraint	Type	Location	Congestion Costs (Millions)										Percent of Total PJM Congestion Costs
				Day Ahead				Balancing				Grand Total	2016	
				Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total			
1	Conastone - Northwest	Line	BGE	\$114.8	\$7.4	(\$4.6)	\$102.8	\$3.9	(\$2.4)	\$6.5	\$12.7	\$115.5	11.3%	
2	Graceton	Transformer	BGE	\$53.1	(\$21.0)	(\$0.9)	\$73.3	(\$0.9)	(\$4.7)	\$1.8	\$5.6	\$78.9	7.7%	
3	Bagley - Graceton	Line	BGE	\$72.5	\$5.8	(\$1.9)	\$64.8	\$2.7	(\$2.7)	\$2.2	\$7.7	\$72.5	7.1%	
4	Cherry Valley	Transformer	ComEd	\$20.4	(\$27.9)	\$3.9	\$52.3	(\$3.0)	\$2.6	(\$5.7)	(\$11.3)	\$40.9	4.0%	
5	Cherry Valley	Flowgate	MISO	(\$5.7)	(\$44.0)	(\$0.5)	\$37.8	\$0.0	\$0.0	\$0.0	\$0.0	\$37.8	3.7%	
6	Conastone - Peach Bottom	Line	500	\$27.9	(\$0.2)	\$0.8	\$28.9	\$1.3	\$0.9	\$0.0	\$0.4	\$29.3	2.9%	
7	Braidwood - East Frankfort	Line	ComEd	(\$3.8)	(\$38.2)	\$0.8	\$35.2	\$0.5	\$3.3	(\$3.5)	(\$6.3)	\$28.9	2.8%	
8	Mercer IP - Galesburg	Flowgate	MISO	(\$17.1)	(\$49.9)	(\$8.9)	\$23.9	(\$0.2)	\$3.6	\$2.2	(\$1.6)	\$22.3	2.2%	
9	Byron - Cherry Valley	Flowgate	MISO	(\$5.5)	(\$22.6)	\$0.9	\$18.0	\$0.0	\$0.0	\$0.0	\$0.0	\$18.0	1.8%	
10	Milford - Steele	Line	DPL	(\$8.6)	(\$26.7)	\$0.1	\$18.1	\$2.2	\$1.4	(\$1.7)	(\$0.9)	\$17.2	1.7%	
11	AP South	Interface	500	\$13.8	(\$4.9)	(\$1.9)	\$16.8	\$0.1	\$0.1	\$0.0	\$0.0	\$16.8	1.6%	
12	Dixon - McGirr Rd	Flowgate	MISO	(\$5.0)	(\$22.9)	(\$1.2)	\$16.7	\$0.0	\$0.0	\$0.0	\$0.0	\$16.7	1.6%	
13	Reynolds - Magnetation	Flowgate	MISO	(\$5.1)	(\$23.9)	\$0.9	\$19.8	\$0.5	\$1.5	(\$2.6)	(\$3.5)	\$16.2	1.6%	
14	Bedington - Black Oak	Interface	500	\$9.5	(\$6.2)	(\$0.6)	\$15.2	\$0.2	\$0.2	\$0.1	\$0.1	\$15.3	1.5%	
15	Coolspring - Milford	Line	DPL	\$1.3	(\$11.8)	(\$0.0)	\$13.1	(\$1.0)	(\$1.8)	\$0.3	\$1.1	\$14.1	1.4%	
16	Loudoun	Transformer	500	\$1.1	(\$9.8)	(\$0.2)	\$10.6	\$1.5	\$2.2	\$3.4	\$2.7	\$13.3	1.3%	
17	Person - Halifax	Flowgate	MISO	\$29.9	\$16.1	(\$0.2)	\$13.5	\$0.0	\$0.0	(\$0.2)	(\$0.2)	\$13.3	1.3%	
18	Kanawha River - Matt Funk	Line	AEP	\$2.7	(\$17.1)	(\$1.1)	\$18.8	(\$0.7)	\$2.5	(\$3.3)	(\$6.6)	\$12.2	1.2%	
19	Plymouth Meeting - Whitpain	Line	PECO	(\$0.6)	(\$10.9)	(\$0.1)	\$10.2	(\$0.1)	\$0.1	\$0.2	(\$0.0)	\$10.1	1.0%	
20	AEP - DOM	Interface	500	\$3.5	(\$4.5)	\$0.2	\$8.2	\$0.3	(\$0.0)	\$0.1	\$0.3	\$8.5	0.8%	
21	Braidwood - East Frankfort	Flowgate	MISO	(\$0.1)	(\$7.7)	\$0.7	\$8.4	\$0.0	\$0.0	\$0.0	\$0.0	\$8.4	0.8%	
22	Cherry Valley - Silver Lake	Flowgate	MISO	(\$1.8)	(\$9.4)	\$0.8	\$8.4	\$0.0	\$0.0	\$0.0	\$0.0	\$8.4	0.8%	
23	Brambleton - Loudoun	Line	Dominion	(\$2.9)	(\$10.2)	\$0.2	\$7.5	\$0.2	(\$0.1)	\$0.4	\$0.6	\$8.1	0.8%	
24	Kanawha	Transformer	AEP	\$0.1	(\$7.1)	\$0.7	\$7.9	\$0.0	\$0.0	\$0.0	\$0.0	\$7.9	0.8%	
25	Stockton - Kenney	Line	DPL	(\$2.5)	\$3.4	(\$1.9)	(\$7.8)	\$0.0	\$0.0	\$0.0	\$0.0	(\$7.8)	(0.8%)	

Source: Monitoring Analytics (2017b), page 473: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml)

5.3.7 Southwest Power Pool (SPP)

The internal market monitor for the Southwest Power Pool (SPP) provides information about constraints in its annual *State of the Market* report.<sup>56</sup> Figure 5-13 shows principal congested flowgates by area. The criterion used to identify top constraints is shadow price.

The footprint for SPP, as an RTO, expanded in October 2015 to include WAPA/Basin IS<sup>57</sup> (see Figure 5-4). Future editions of this report will reflect these changes following updates to the underlying data used to develop this report.

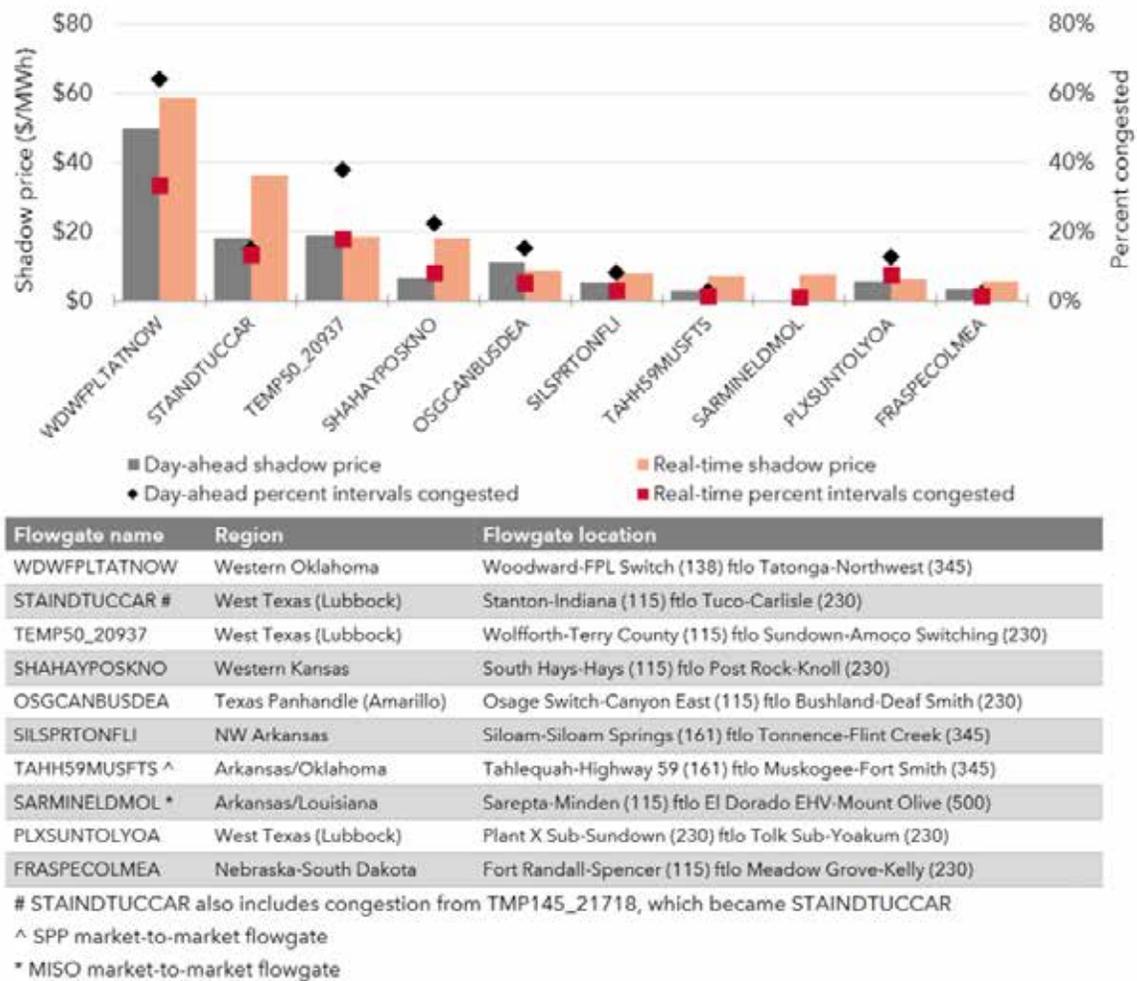


Figure 5-13. SPP congestion by shadow price, top ten flowgates (2016)

Source: SPP (2017), p. 96: [https://www.spp.org/documents/53549/spp\\_mmu\\_asom\\_2016.pdf](https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf)

<sup>56</sup> For the most recent version of this report, see <https://www.spp.org/markets-operations/market-monitoring/>.

<sup>57</sup> See <https://www.ferc.gov/CalendarFiles/20141110183532-ER14-2850-000.pdf>.

## 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 reflect congestion through locational prices in day-ahead and real-time electricity markets.<sup>58</sup> Market systems accept offers to sell energy from generators, bid to buy energy from loads (mainly load serving entities), and clear the market using a multilateral optimization algorithm 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.<sup>59</sup>

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 price 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.<sup>60, 61</sup>

<sup>58</sup> See, for example, <https://www.ferc.gov/market-oversight/guide/energy-primer.pdf> and <https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=784>.

<sup>59</sup> In contrast to such markets, transmission utilities in non-RTO regions generally sell physical rights to transmission customers to transfer physical power among locations in accordance with firm or non-firm commitments. Consistent with the provision of these long-term 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 transmission service commitments will be served without congestion or constraint. Since a primary but not sole objective of transmission planning and expansion in non-RTO markets is to allow firm transmission customers to receive transmission service without congestion, congestion cost concepts, in the sense that they are used and applied in RTO regions, cannot be calculated for non-RTO regions.

<sup>60</sup> There is a large amount of literature on the theory of locational pricing. See, e.g., Schweppe, et al. (1988), at <http://link.springer.com/book/10.1007%2F978-1-4613-1683-1>; and Stoft, S. (2002), at <http://www.wiley.com/WileyCDA/WileyTitle/productCd-0471150401,miniSiteCd-IEEE2.html>.

<sup>61</sup> RTO/ISO markets also feature congestion hedging mechanisms, which are called financial transmission rights (PJM, ISO-NE, MISO), transmission congestion contracts (NYISO), transmission congestion rights (SPP), or congestion revenue rights (ERCOT, CAISO). While the specific rules differ in different regions, these mechanisms are intended primarily to return congestion revenues to the loads that have already paid for the transmission system. In operation, a transmission or congestion right held between two specific points for a specific magnitude entitles the holder to the difference in day-ahead congestion components between those two points, times the magnitude of the right held. Thus, these rights are also important financial tools that help participants manage risk in these markets. Nevertheless, data or information about them does not, by themselves, provide information about the magnitude or value of congestion in the system. It is, however, possible that analyzing transmission or congestion rights purchases and payments could provide information on where market participants are anticipating congestion, which may be a topic to explore in future iterations of this report.

This report presents information on the economic cost of congestion developed by individual market operators.<sup>62</sup> 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.

## 6.2 FERC Common Metrics: Congestion Management

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 RTO/ISO metrics information, reported on metrics filed by five utilities located outside of RTO/ISO 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-922, the final Information Collection Statement, was issued in 2015.<sup>63</sup> Respondents submitted information in Docket No. AD14-15 between October 2015 and February 2016, and a revised Common Metric report was issued in August 2017.<sup>64</sup>

RTO/ISOs report to FERC on several additional metrics that are not part of Information Collection FERC-922 because they are not common metrics that are applicable to the entire industry. These include metrics related to coordinated wholesale power markets, such as congestion management. The Congestion Management metric provides an indication of the efficiency of the overall RTO/ISO system, as well as the effectiveness of RTO/ISO efforts to manage congestion costs through transmission expansion planning and other efficiency measures.

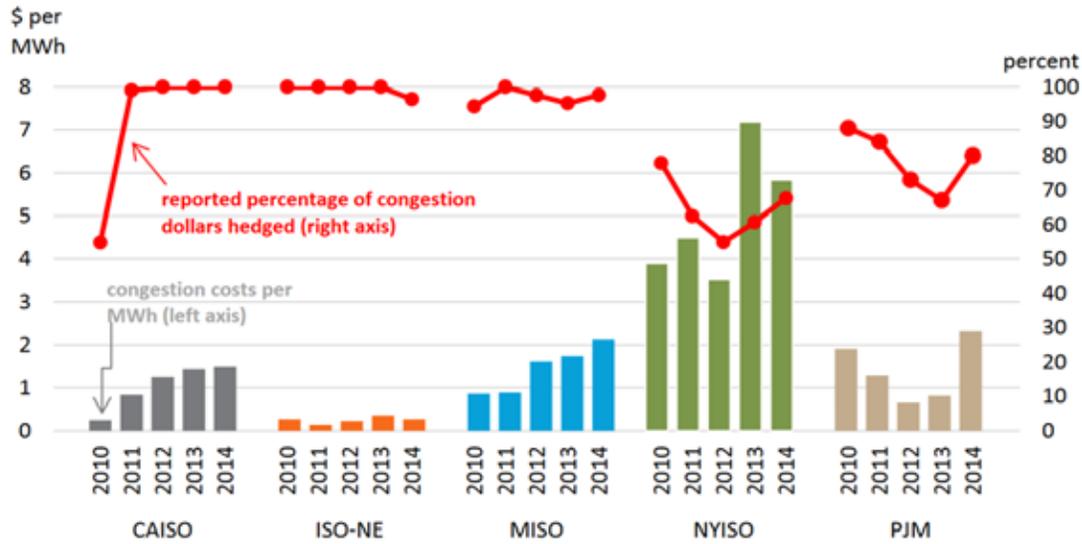
This metric can be measured in two ways—either as cost trends as relative to load growth, or in terms of congestion revenues as a percent of congestion costs—and RTO/ISOs have varying methods for calculating this metric. Figure 6-1 shows annual congestion costs by RTO/ISO for 2010–2014.

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<sup>62</sup> See <https://www.ferc.gov/industries/electric/indus-act/rto/rto-iso-performance.asp> for more information.

<sup>63</sup> See [http://www.reginfo.gov/public/do/PRAViewICR?ref\\_nbr=201409-1902-008](http://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201409-1902-008).

<sup>64</sup> FERC (2017): <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>



Source: Commission staff based on October 2015 RTO and ISO metrics report.  
 Notes: (1) Congestion costs are expressed in nominal dollars per MWh. (2) SPP (not shown) reports data for 2014 only. For 2014, SPP reports \$2.11 of congestion costs per megawatt-hour of load served, and 85.9 percent of congestion costs hedged through congestion management markets.

Figure 6-1. Annual congestion costs per megawatt-hour of load served and percentage of annual congestion costs hedged

Source: FERC (2017) Common Metrics Report, p. 66: <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>

### 6.3 California ISO (CAISO)

CAISO manages day-ahead and real-time electricity markets with nodal pricing for generators and zonal pricing for loads. There are four load zones, or load aggregation points (LAPs), which correspond to the service territories of Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Valley Electric Association.<sup>65</sup>

Nodal prices are made up of three components: the marginal cost of energy, the marginal cost of congestion (relative to the reference bus<sup>66</sup>), and the marginal cost of losses (relative to the reference bus).<sup>67</sup> 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).

<sup>65</sup> Valley Electric Association, the first out-of-state utility to join CAISO, became a participating transmission owner on January 3, 2013. See <https://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/ValleyElectricAssociation.aspx>.

<sup>66</sup> The reference bus in CAISO is a disaggregated one.

<sup>67</sup> See CAISO (2013): [http://www.caiso.com/Documents/AppendixC\\_LocationalMarginalPrice\\_Jul1\\_2013.pdf](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 unscheduled flow mitigation to address 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 not reflected in day-ahead prices.
- Bilateral trades pay congestion price, although the allocation between seller and buyer depends on the production/delivery locations specified in the contract.<sup>68</sup>
- Real-time scheduling includes transmission constraint relaxation—in 2013 the value of the constraint was decreased from \$5,000 to \$1,500.

Table 6-1 reports total congestion costs for 2006-2014. Figure 6-2 presents import congestion charges on major interties for 2013-2015.

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

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

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

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

<sup>68</sup> See CAISO (2007): <https://www.caiso.com/Documents/AttachmentC-Seller%E2%80%99sChoiceContractsunderNodalVirtualBidding.pdf>.

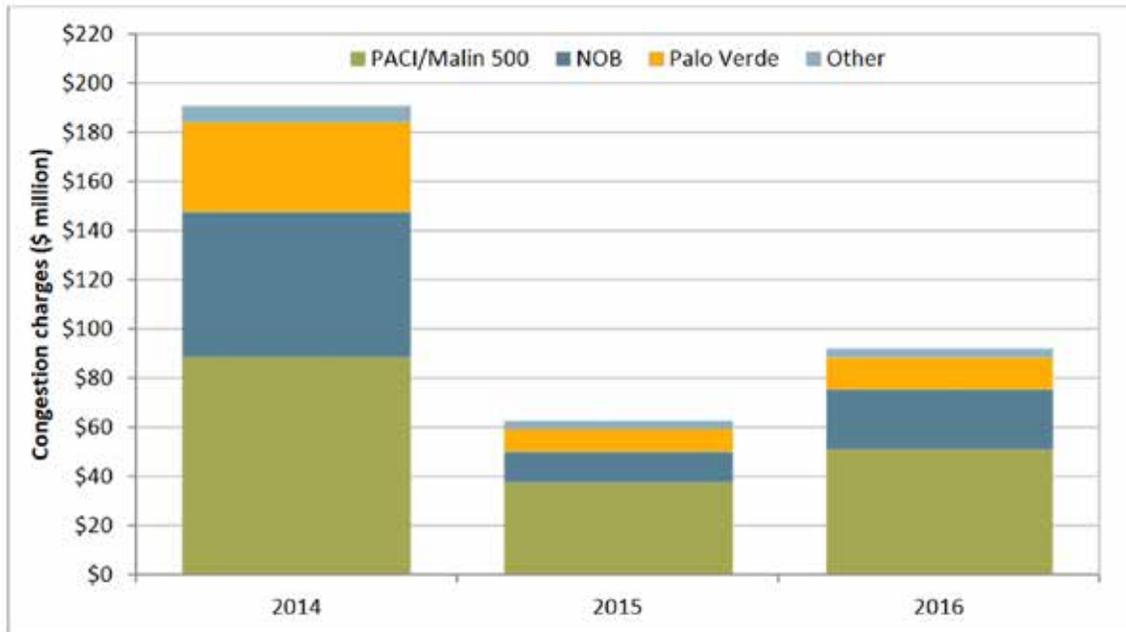


Figure 6-2. CAISO import congestion charges on major interties, 2014–2016

Source: CAISO (2017), page 180: <https://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

In its 2016 Annual Report on Market Issues & Performance, CAISO's department of Market Monitoring reports the following findings on congestion:

- In 2016, congestion on transmission constraints within the ISO system was relatively low and had a small impact on average overall prices across the system, similar to 2015.
- Prices in the San Diego Gas and Electric area were the most impacted by internal congestion. Average day-ahead prices in this area increased above the system average by about \$0.80/MWh (2.5 percent) and real-time congestion increased prices by about \$1.60/MWh (5.4 percent).
- Congestion decreased average day-ahead prices in the Southern California Edison area below the system average by about \$0.13/MWh (0.4 percent), and increased real-time prices by \$0.40/MWh (1.4 percent).
- Pacific Gas and Electric area prices were the least impacted by congestion in 2016. Congestion increased day-ahead prices above the system average by about \$0.14/MWh (0.5 percent) and had a very low impact on 15-minute prices.
- The frequency and impact of congestion was higher in 2016 than 2015 on most major interties connecting the ISO with other balancing authority areas, particularly for interties connecting the ISO to the Pacific Northwest and Palo Verde.

- *Congestion revenue rights not allocated to load-serving entities that were sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2016, ratepayers received about 49 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about \$48 million in 2016 and more than a \$500 million shortfall since 2012.*
- *Entities purchasing congestion revenue rights are primarily financial entities that do not purchase these rights as a hedge for any physical load or generation. DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off “excess transmission capacity” remaining after the congestion revenue right allocations.<sup>69</sup>*

### 6.4 Electric Reliability Council of Texas (ERCOT)

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

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

- Conversion from a zonal to a nodal market in 2010.
- Irresolvable constraints—when no feasible generator dispatch can meet demand, nodal prices are set based on predefined rules. ERCOT employs administratively set prices to deal with irresolvable constraints.<sup>70</sup>

Table 6-2. ERCOT reported congestion costs, 2011–2016

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of \$)					
		2011	2012	2013	2014	2015	2016
ERCOT Market Monitor	Total Congestion Revenue	407	480	466	708	352	497

Sources: Developed by DOE from Potomac Economics (2012a), (2013b), (2014b), (2015b), (2016b), and (2017b) available from [https://www.potomaceconomics.com/index.php/markets\\_monitored/ERCOT](https://www.potomaceconomics.com/index.php/markets_monitored/ERCOT).

<sup>69</sup> CAISO (2017), p. 177: <https://www.aiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

<sup>70</sup> Potomac Economics (2014b), p. 46: [https://www.potomaceconomics.com/uploads/ercot\\_documents/2013\\_ERCOT\\_SOM\\_REPORT.pdf](https://www.potomaceconomics.com/uploads/ercot_documents/2013_ERCOT_SOM_REPORT.pdf)

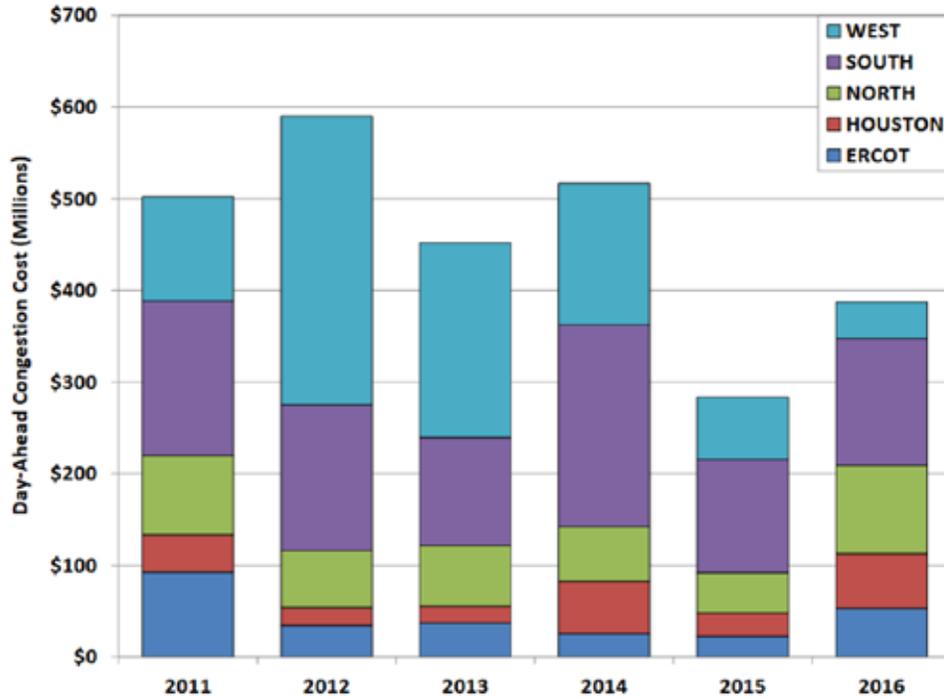


Figure 6-3. ERCOT day-ahead congestion costs by zone, 2011-2016

Source: Potomac Economics (2017b), p. 56: <https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf>

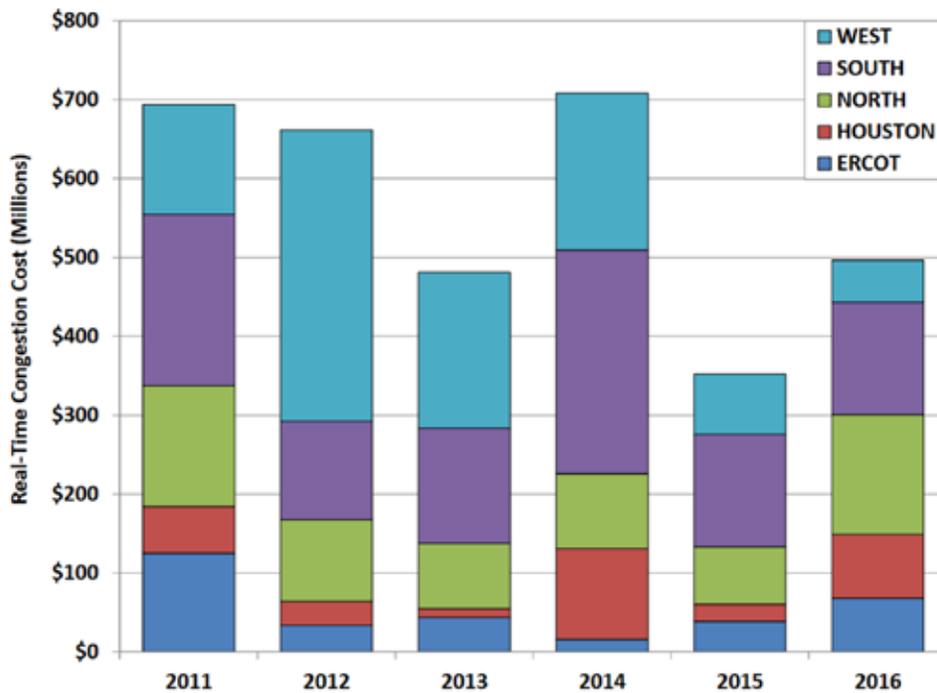


Figure 6-4. ERCOT real-time congestion costs 2011-2016

Source: Potomac Economics (2017b), p. 48: <https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf>

In its *2016 State of the Market Report*, ERCOT's market monitor includes the following observations about congestion:

*The total congestion costs experienced in the ERCOT real-time market were \$497 million in 2016, a 40 percent increase from 2015 values. This is a substantial increase, especially given the reduction in natural gas prices that would typically reduce transmission congestion. The increase in congestion occurred as constraints were binding in 8 percent more intervals in 2016. The North and Houston zones experienced an increase in price differences between the two zones and within each zone in 2016. The costs of congestion in the West and South zones in 2016 were similar to 2015.*

*...Binding transmission constraints are those for which the dispatch levels of generating resources are actually altered in order to maintain transmission flows at reliable levels. The costs associated with this re-dispatch are the system's congestion value and are included in nodal prices. Active transmission constraints are those which the dispatch software evaluated, but did not require a re-dispatch of generation.*

*Constraints were activated more frequently in 2016—73 percent of all hours compared to 63 percent in 2015. The percent of time with active constraints in 2016 is very similar to 2013. There was more constraint activity at nearly all load levels in 2016 except for load levels below 25 GW. The most notable difference between 2016 and 2015 is that, while RTCA on average showed fewer constraints in 2016, the percentage of time with an active constraint in each load level, except for the very lowest loads, was higher than 2015. This is explained by the number of SCED intervals with an active Generic Transmission Constraint (GTC) which increased by 66 percent in 2016 as compared to 2015.*

*...Cross zonal congestion in 2016 was the most costly since 2011 due to the increased frequency and cost associated with Houston import constraints. The North and Houston zones experienced an increase in price impacts between and within the two zones in 2016. Congestion costs for the West and South zones were very similar to 2015. Most of the increased congestion was attributable to a variety of transmission outages, some of which were taken to perform system upgrades. The completion of these upgrades is expected to reduce associated congestion.<sup>71</sup>*

## 6.5 ISO New England (ISO-NE)

ISO-NE manages day-ahead and real-time electricity markets with nodal pricing for generators and zonal pricing for loads. There are eight load zones: Maine, New Hampshire, Vermont, Connecticut, Rhode Island, and three in Massachusetts. There is also a "trading hub," which contains thirty-two pricing nodes in the geographic center for New England. The Hub price is an average of prices at these thirty-two pricing nodes, which has been published by the ISO to disseminate price information that facilitates

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<sup>71</sup> Potomac Economics (2017b), pp. 45-48: <https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf>

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<sup>72</sup> because it is connected radially to the rest of the Eastern Interconnection.<sup>73</sup> 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.<sup>74</sup>
- 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.<sup>75 76</sup>

The vast majority of congestion is in the day-ahead market, as most transactions occur there. Table 6-3 reports congestion costs for 2009-2016. Figure 6-5 shows load-weighted and simple average hub price for 2016, and Figure 6-6 shows annual simple average hub price for 2016.

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<sup>72</sup> 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>.

<sup>73</sup> 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](http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/ad10-5-00_8-31-11_joint_iso-rto_metrics_report.pdf)

<sup>74</sup> 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.

<sup>75</sup> See Likover (2014a): [http://www.iso-ne.com/support/training/courses/wem101/17\\_reserve\\_market\\_overview.pdf](http://www.iso-ne.com/support/training/courses/wem101/17_reserve_market_overview.pdf); and Likover (2014b): [http://www.iso-ne.com/static-assets/documents/support/training/courses/wem101/18\\_reserve\\_market\\_settlement.pdf](http://www.iso-ne.com/static-assets/documents/support/training/courses/wem101/18_reserve_market_settlement.pdf)

<sup>76</sup> This is not a distinguishing factor for ISO-NE, but rather is the case in most, if not all RTO/ISOs.

Table 6-3. ISO-NE reported congestion costs, 2009-2016

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of \$)								
		2009	2010	2011	2012	2013	2014	2015	2016	
ISO-NE Internal and External Market Monitors <sup>†</sup>	Total Congestion Revenue	25	38	18	30*	46*	n/a	31.2	38.9	
ISO-NE Internal Market Monitor	Day-Ahead Congestion Revenue	27	37	18	29.3	46.2	34.2 <sup>77</sup>	30.0	34.3	

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

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

Sources: Developed by DOE from ISO-NE (2010), (2011), (2012), (2013a), (2014a), (2015a), (2016), and (2017) available from <http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>; and Potomac Economics (2010a), (2011b), (2012b), (2013a), (2014a), (2015a), and (2016), available from <http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor>.

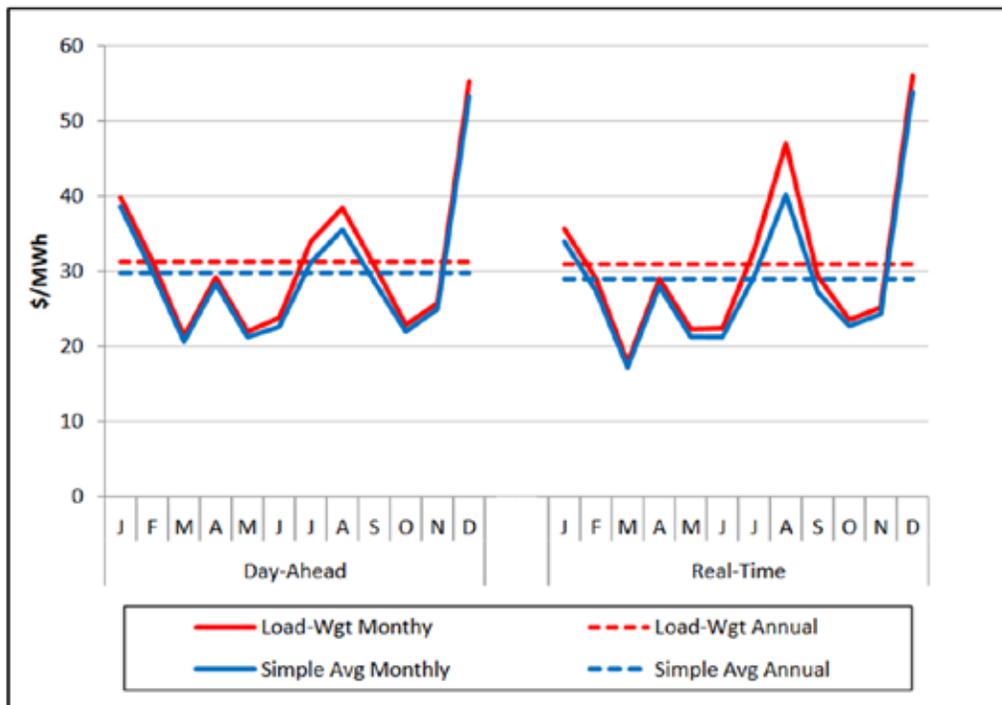


Figure 6-5. ISO-NE load-weighted and simple average hub prices, 2016 (\$/MWh)

Source: ISO-NE (2017), p. 61: [https://www.iso-ne.com/static-assets/documents/2017/05/annual\\_markets\\_report\\_2016.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/annual_markets_report_2016.pdf)

<sup>77</sup> For 2014 ISO-NE’s internal market monitor reports that day-ahead congestion revenue was \$34.2M (see ISO-NE (2015a), p. 64), its external market monitor reports day-ahead congestion revenues of \$32.0M (see Potomac Economics (2015a), p. 2).

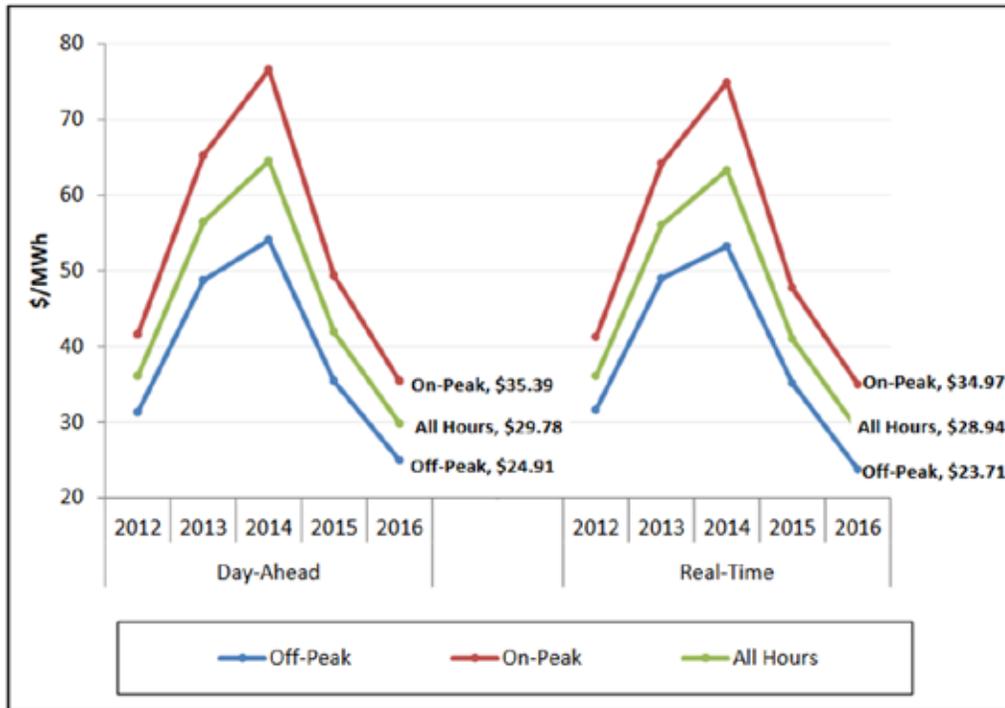


Figure 6-6. ISO-NE Annual simple average hub price, 2016

Source: ISO-NE (2017), p. 59: [https://www.iso-ne.com/static-assets/documents/2017/05/annual\\_markets\\_report\\_2016.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/annual_markets_report_2016.pdf)

In its 2016 Annual Markets Report, the Internal Market Monitor for ISO-NE provided the following discussion on congestion:

*Total day-ahead and real-time congestion revenue in 2016 was \$38.9 million. This represents an increase from \$31.2 million dollars in 2015; as a percentage of total energy cost (labels) the congestion revenue was slightly higher than in the previous five years. Day-ahead congestion revenue is much higher than real-time congestion revenue because approximately 98% of the energy transacted in New England is settled in the day-ahead market. The frequency with which the Boston interface (a collection of transmission lines surrounding Boston) was binding was a large driver of day-ahead congestion revenue in 2016. The average day-ahead congestion revenue in the 308 hours the Boston interface was binding was \$60,495, compared to the average of \$1,845 in hours in which it was not binding. Although it was only binding in 3.5% of all hours, the congestion revenue within these hours comprised 54% of the total day-ahead congestion revenue. Ongoing transmission work in the Boston area was one reason for the number of intervals in which the Boston interface was binding.*

*As mentioned previously, congestion is relatively infrequent in New England. Although day-ahead and real-time congestion revenue increased to 0.94% of the total cost of energy in 2016, from 0.53% in 2015, as a percentage of total energy payments, congestion remains small at under 1%.*

*...Natural gas was the marginal fuel for 77% of all pricing intervals in the real-time market in 2016. This is an increase compared with 2015 (75%). One reason for this*

*increase is that gas helped displace oil as the price-setting fuel in a noticeable percentage of intervals. The displacement of coal and oil over the past few years is, in part, due to lower gas prices. These lower prices make gas-fired generators more economically viable than oil- and coal-fired generators, particularly in non-winter months.*

*The “other” category also had a noticeable increase between 2015 and 2016. Almost all of the price-setting units in the “other” category in 2016 were wind units, which set price 4% of the time. This is a significant increase compared to 2015 where wind set price <1% of the time. The increase is driven by the Do Not Exceed (DNE) dispatch rules, which went into effect on May 25, 2016. DNE incorporates wind and hydro intermittent units into the unit dispatch and pricing process, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price.*

*Most of the marginal wind units in 2016 were located where the transmission system is regularly export-constrained. This means that the wind units frequently set price within their constrained regions while another unit(s) set price for the rest of the system. Though wind was marginal 4% of the time in 2016, wind was the single marginal fuel type on the system in <1% of all five-minute intervals.<sup>78</sup>*

## 6.6 Midcontinent ISO (MISO)

MISO manages electricity markets and operates the transmission grid in fifteen U.S. states and one Canadian province. MISO administers both day-ahead and real-time markets and congestion is reflected in 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 the price. MISO settles day-ahead and real-time electricity markets for both generators and loads at nodal prices.<sup>79</sup> Bilateral trades (or financial settlements as they are called in MISO) must pay congestion costs as well.<sup>80</sup> Virtual bids and offers are settled at day-ahead and real-time nodal prices, and therefore also pay the congestion component of the locational price.<sup>81</sup>

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

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<sup>78</sup> ISO-NE (2017), pp 90-92: [https://www.iso-ne.com/static-assets/documents/2017/05/annual\\_markets\\_report\\_2016.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/annual_markets_report_2016.pdf).

<sup>79</sup> Chu (2011), p. 26: <https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/MP%20200/Market%20Settlements%20Training%20-20Virtual%20and%20Financial%20Schedules.pdf>

<sup>80</sup> Chu (2011), p. 143.

<sup>81</sup> Chu (2011), p. 26.

- 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).<sup>82</sup>
- PJM Firm Flow Entitlement (FFE) payments reduce the amount of congestion cost reported.<sup>83</sup>
- Holders of “grandfathered” transmission service agreements can choose among options that involve rebates for congestion.<sup>84</sup> Payments to these grandfathered rights are paid from the congestion revenue collected by MISO.<sup>85</sup>
- Some unscheduled loop flow on the MISO transmission system is managed with TLR procedures and will not be reflected in congestion costs.
- The MISO footprint has changed over time, which complicates comparisons of the total amount of economic congestion costs from year to year.
- MISO has used a variety of mechanisms for dealing with unmanageable constraints. Until November 2013, marginal value limits (MVL) were used to limit the cost of re-dispatch 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 6-4 reports congestion costs and value for 2009-2016, and Figure 6-7 presents day-ahead and balancing congestion and payments to FTR holders for 2014-2016. Figure 6-8 presents the value of real-time congestion by coordination region for 2015-2016.

**Table 6-4. MISO reported congestion costs and value, 2009-2016\***

Congestion Cost Definition	Reported Congestion Cost (millions of \$)							
	2009	2010	2011	2012	2013	2014	2015	2016
Day-Ahead Congestion Cost	305	498	503	778	842	1,440	751	737
Real-time Congestion Value	863	1,080	1,240	1,300	1,590	2,430	1,341	1,398

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

Sources: Developed by DOE from Potomac Economics (2011c), (2012c), (2013c), (2014c), (2014d), (2015c), (2016c), and (2017c), available from [http://potomaceconomics.com/index.php/markets\\_monitored/Midcontinent\\_iso](http://potomaceconomics.com/index.php/markets_monitored/Midcontinent_iso).

<sup>82</sup> See Potomac Economics (2010b), p. 41 and p. 79: <https://www.misoenergy.org/Library/Repository/Report/IMM/2009%20State%20of%20the%20Market%20Report.pdf>; and Potomac Economics (2012c), p. A-76: [https://www.potomaceconomics.com/uploads/midwest\\_reports/2011\\_SOM\\_Report.pdf](https://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf).

<sup>83</sup> Potomac Economics (2013c), p. 47: [https://www.potomaceconomics.com/uploads/reports/2012\\_SOM\\_Report\\_final\\_6-10-13.pdf](https://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf)

<sup>84</sup> See Potomac Economics (2012c), p. A-81; Potomac Economics (2013c), p. 47; and Chu (2011), p. 186.

<sup>85</sup> See MISO (2014b), pp. 33-36. Available from <https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx>

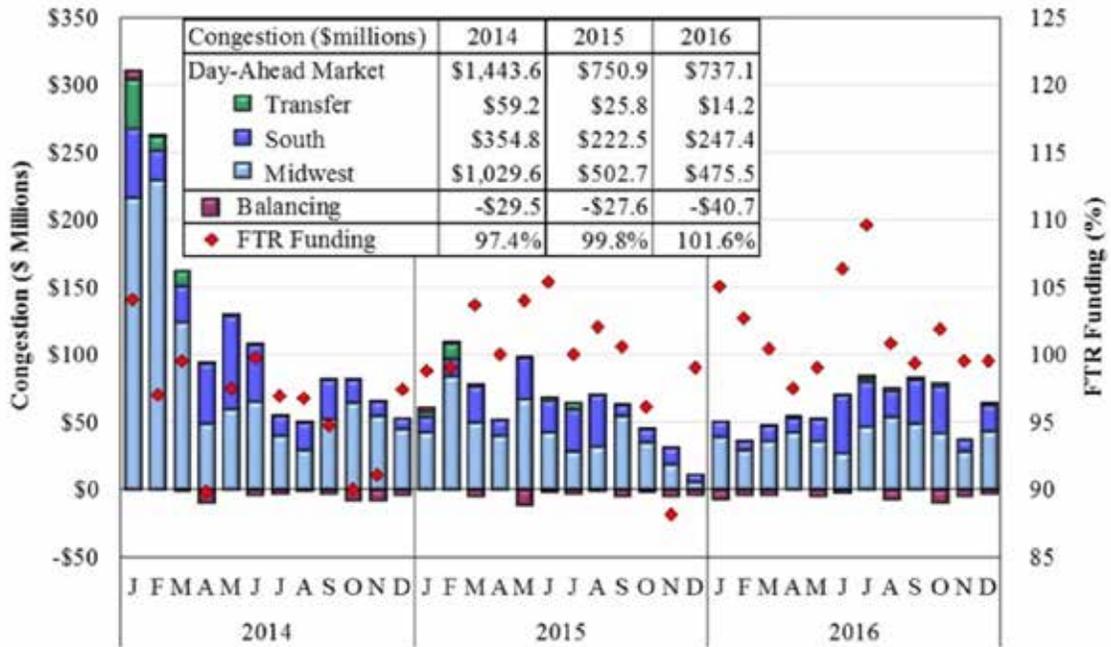


Figure 6-7. MISO day-ahead and balancing congestion and payments to FTRs, 2014-2016

Source: Potomac Economics (2017c), p. 50: [https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM\\_Report\\_Final\\_6-30-17.pdf](https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_6-30-17.pdf)

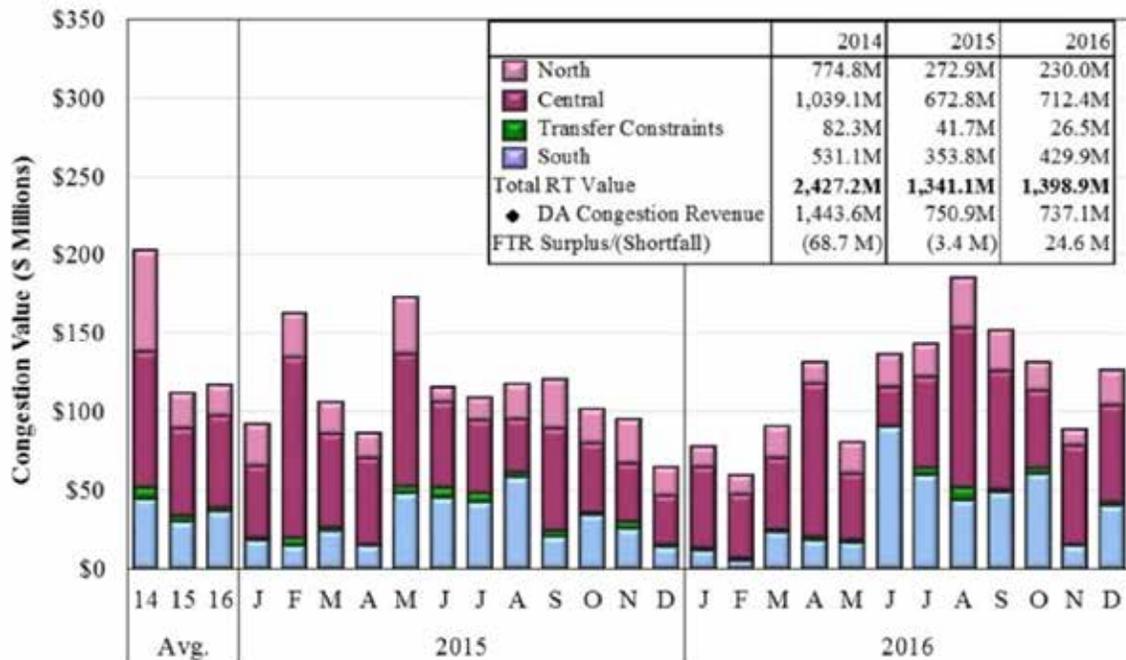


Figure 6-8. Value of real-time congestion and payments to FTRs, 2015-2016

Source: Potomac Economics (2017c), p. 49: [https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM\\_Report\\_Final\\_6-30-17.pdf](https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_6-30-17.pdf)

In its *2016 State of the Market Report*, MISO's external market monitor, made the following observations about congestion:

*Day-ahead congestion costs fell two percent to \$737.1 million in 2016. Much of the reduction in congestion occurred during February when day-ahead congestion was 60 percent lower than the prior year. The decline in 2016 was caused by lower gas prices, mild weather conditions early in the year, and reduced congestion on transfer constraints.*

*The congestion costs collected through the MISO markets are much less than the value of real-time congestion on the system, which totaled \$1.4 billion in 2016. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network, as well as entitlements on the MISO system granted to JOA counterparties, including PJM, SPP, and TVA. For example, PJM does not pay for its power flows on MISO's market-to-market constraints up to PJM's entitlements.*

*Congestion on constraints in MISO South and the transfer constraints between the Midwest and South regions accounted for 35 percent of all day-ahead congestion. The MISO South and Midwest regions have diverse load patterns and mixes of generation. Differences in weather, load, generation and transmission availability, and regional gas prices affect the transmission congestion patterns within each region and between the regions over the transfer constraints.*

*In the Fall of 2016, generation outages in MISO South led to several operational challenges and increases in day-ahead congestion, as nearly 40 percent of the total generating capacity was on outage in October. Three-quarters of these outages were planned. An additional 3.4 GW of capacity was derated. The high level of outages in the South also led to flows primarily North-to-South after late September, a reversal in the typical pattern.*

*...Congestion revenues exceeded FTR obligations by \$24.6 million—a surplus of 1.6 percent—a slight increase in funding from 2015 when FTRs were underfunded by 0.2 percent. Nearly half of the surplus (\$12 million) occurred in July, while several other months experienced slight shortfalls. Over- and underfunding is caused by discrepancies in the modeling of the annual and monthly auctions compared to the transmission constraints and outages that actually occur.*

*The most significant causes for underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. Underestimated loop flows also account for the some of the shortfalls, because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets. In 2016, these factors were more than offset by FTR surpluses produced on constraints whose capability were not fully sold in the FTR auctions.<sup>86</sup>*

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<sup>86</sup> Potomac Economics (2017c), Page 51: [https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM\\_Report\\_Final\\_6-30-17.pdf](https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_6-30-17.pdf)

## 6.7 New York ISO (NYISO)

NYISO administers the wholesale electricity markets and operates high-voltage transmission in the state of New York. NYISO reflects congestion in locational prices in day-ahead and real-time electricity markets. Locational prices—consisting of an energy component,<sup>87</sup> 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.<sup>88</sup> “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). 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.<sup>89</sup>

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

- Some unscheduled loop flow on the NYISO transmission system is managed with TLR procedures. This practice started in 2009 when high levels of clockwise unscheduled Lake Erie loop flow were exacerbating congestion on the system. The NYISO’s ongoing collaboration with its neighboring market areas to improve regional market efficiency through the Broader Regional Markets initiatives was initiated in part to address the impacts produced by the unscheduled Lake Erie Loop Flows as well as to remove barriers to more efficient interregional trading in order to improve the volume of trading. The various components of that regional collaboration have resulted in significant reductions in unscheduled flows during the reporting period.<sup>90</sup>

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<sup>87</sup> The energy component is the marginal price for electricity at the reference bus, physically located at the Marcy substation in Marcy, New York. The congestion and loss components at the Marcy bus location are both zero. See Porter (2015): at [www.nyiso.com/public/webdocs/markets\\_operations/services/market\\_training/workshops\\_courses/Training\\_Course\\_Materials/Market\\_Overview\\_MT\\_101/Locational%20Based%20Marginal%20Pricing.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/market_training/workshops_courses/Training_Course_Materials/Market_Overview_MT_101/Locational%20Based%20Marginal%20Pricing.pdf)

<sup>88</sup> Porter (2015).

<sup>89</sup> See [http://www.nyiso.com/public/about\\_nyiso/understanding\\_the\\_markets/energy\\_market/index.jsp](http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp); and Potomac Economics (2012d), p. 24: [https://www.potomaceconomics.com/uploads/nyiso\\_reports/NYISO\\_2011\\_SOM\\_Report-Final\\_4-18-12.pdf](https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2011_SOM_Report-Final_4-18-12.pdf).

<sup>90</sup> See 2015 ISO/RTO Metrics Report, filed with FERC on 10/30/15, Docket AD14-15, Page 222 at: [https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing1071/Attachments/2015\\_10\\_30\\_ISO\\_RTO\\_Metrics\\_Report.docx](https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing1071/Attachments/2015_10_30_ISO_RTO_Metrics_Report.docx)

- 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.<sup>91</sup>
- In November 2014 and December 2015 respectively, NYISO activated Coordinated Transaction Scheduling (“CTS”) with PJM and ISO-NE which incorporates prices from these neighboring control areas into dispatch to allow Market Participants to schedule transactions based on the price differences between regions.<sup>92</sup>
- A graduated transmission demand curve was implemented in February 2016 to more properly reflect the severity of the transmission shortage.<sup>93</sup>

Table 6-5 presents congestion costs and value for 2009–2016, and Table 6-6 presents Demand\$ congestion for 2008–2014. Note that the congestion costs in Table 6-5 represent the net congestion costs collected and paid by NYISO to loads, generators, exports, and imports. Conversely, the Demand\$ congestion values in Table 6-6 represent the congestion costs incurred by New York Control Area (NYCA) loads. Figure 6-9 presents day-ahead and real-time congestion by transmission path for 2015–2016. Figure 6-10 presents congestion revenues and shortfalls for 2015–2016.

**Table 6-5. NYISO reported congestion costs and value, 2009–2016**

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost (millions of \$)							
		2009	2010	2011	2012	2013	2014	2015	2016
NYISO Market Monitor	Day-Ahead Congestion Revenue	376	419	407	301	664	578	540	438

Sources: Developed by DOE from Potomac Economics, (2010c), (2011d), (2012d), (2013d), (2014e), (2015e), (2016e) and (2017e) available from [https://www.potomaceconomics.com/index.php/markets\\_monitored/new\\_york\\_iso](https://www.potomaceconomics.com/index.php/markets_monitored/new_york_iso).

<sup>91</sup> Potomac Economics (2013e), p. 55: [http://www.nyiso.com/public/webdocs/markets\\_operations/documents/Studies\\_and\\_Reports/Reports/MMU\\_Quarterly\\_Reports/2013/NYISO%20Quarterly%20Report%20-%20Quarter%202.pdf](http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/MMU_Quarterly_Reports/2013/NYISO%20Quarterly%20Report%20-%20Quarter%202.pdf)

<sup>92</sup> See NYISO Broader Regional Markets Report, July 13, 2016 at [http://www.nyiso.com/public/webdocs/markets\\_operations/committees/bic/meeting\\_materials/2016-07-13/BRM\\_2016-07-13\\_BIC\\_FINAL.pdf](http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2016-07-13/BRM_2016-07-13_BIC_FINAL.pdf)

<sup>93</sup> See FERC Letter Order issued in Docket ER15-485-001 on March 3, 2016 at: <https://nyisoviewer.etariff.biz/ViewerDocLibrary//FercOrders/546.pdf>

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

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

Sources: Developed by DOE from NYISO (2012): [http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Economic\\_Planning\\_Studies\\_%28CARIS%29/Caris\\_Final\\_Reports/2011\\_CARIS\\_Final\\_Report\\_3-20-12.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/Caris_Final_Reports/2011_CARIS_Final_Report_3-20-12.pdf); NYISO (2013): [http://www.nyiso.com/public/webdocs/markets\\_operations/committees/bic\\_espwg\\_iprf/meeting\\_materials/2013-08-12/2013%20CARIS%20Draft%20Report%20%20rev.pdf](http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg_iprf/meeting_materials/2013-08-12/2013%20CARIS%20Draft%20Report%20%20rev.pdf), and NYISO (2015): [http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Economic\\_Planning\\_Studies\\_%28CARIS%29/CARIS\\_Final\\_Reports/2015\\_CARIS\\_Report\\_FINAL.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/CARIS_Final_Reports/2015_CARIS_Report_FINAL.pdf)

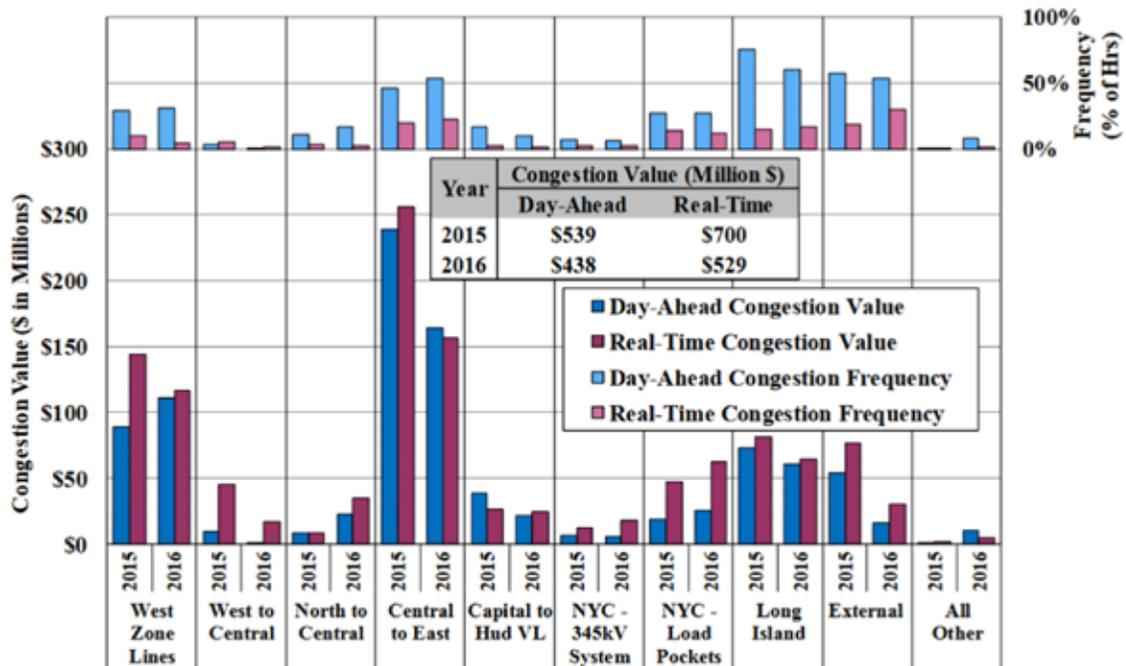


Figure 6-9. NYISO day-ahead and real-time congestion by transmission path, 2015–2016

Source: Potomac Economics (2017e), p. 20: [http://www.nyiso.com/public/webdocs/markets\\_operations/documents/Studies\\_and\\_Reports/Reports/Market\\_Monitoring\\_Unit\\_Reports/2016/NYISO\\_2016\\_SOM\\_Report\\_5-10-2017.pdf](http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf)

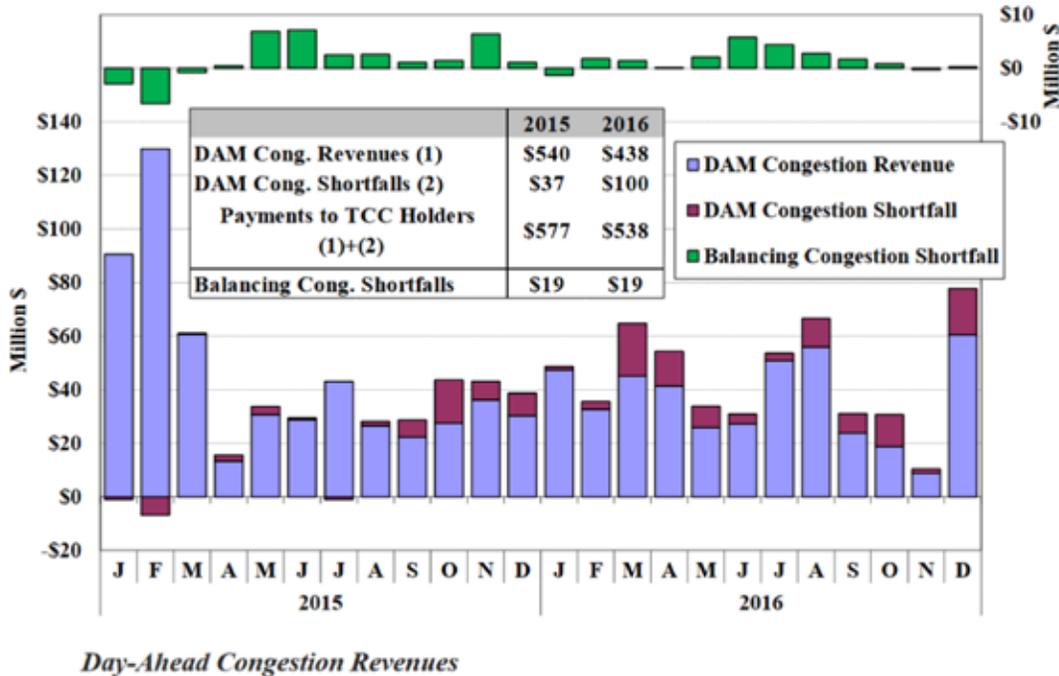


Figure 6-10. NYISO congestion revenues and shortfalls, 2015–2016

Source: Potomac Economics (2017e), p. 38: [http://www.nyiso.com/public/webdocs/markets\\_operations/documents/Studies\\_and\\_Reports/Reports/Market\\_Monitoring\\_Unit\\_Reports/2016/NYISO\\_2016\\_SOM\\_Report\\_5-10-2017.pdf](http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf)

In its 2016 State of the Market Report, NYISO’s market monitor made the following observations about congestion:

*Congestion revenues collected in the day-ahead market fell by 19 percent from 2015 to \$438 million in 2016. However, day-ahead congestion shortfalls rose by 170 percent in 2016 to \$100 million, while balancing congestion shortfalls were unchanged.*

*Variations in natural gas prices have significant impact on congestion patterns and revenues because they determine the costs of the resources that must be moved to manage transmission flows. In addition, large gas price spreads between regions increase congestion by raising the cost trade-offs of moving units to manage interregional flows. Hence, day-ahead congestion revenues were down 55 percent year-over-year in the first quarter of 2016 as natural gas prices across the state fell 18 to 70 percent. However, day-ahead congestion revenues rose 21 percent in the remaining nine months of 2016 because of:*

- Higher load levels in the summer months, which increased flows across the network and resulted in more frequent transmission bottlenecks;
- Costly transmission outages across the Central-East interface, between New Jersey and the Hudson Valley, on Long Island, and from the North Zone to Central New York; and
- The implementation of the GTDC Project in February 2016, which increased the congestion shadow prices on most transmission constraints during

*transmission shortages, leading to similar increases in the day-ahead market based on expectations.*

*Congestion on 230kV lines in the West Zone has been significant, accounting for the second largest share (25 percent) of day-ahead congestion revenues in 2016. Congestion in the West Zone was affected by offsetting factors in 2016.*

*...Day-ahead congestion shortfalls rose substantially from \$37 million in 2015 to \$100 million in 2016 primarily because of more costly transmission outages. Notable examples include:*

- \$34 million of shortfalls on the Central-East interface, most of which was attributable to outages from January to May to facilitate the completion of the TOTS project and one 345 kV line outage in December that reduced the interface limit by up to 900 MW;*
- \$17 million of shortfalls on the transmission paths that typically flow power from North to Central New York, due primarily to outages of 765 kV transmission facilities at the Marcy station in April, May, September and October;*
- \$11 million of shortfalls on Long Island lines, primarily from the Y49 line outages from late May to early July and from early August to late September; and*
- \$11 million of shortfalls on West Zone lines because several facilities along the Niagara-Packard-Sawyer-Huntley path were out of service intermittently during the year.<sup>94</sup>*

## 6.8 PJM

PJM manages electricity markets and operates transmission across thirteen states and the District of Columbia. PJM reflects congestion in locational prices in day-ahead and real-time electricity markets. Locational price—consisting of an energy component, a congestion component, and a loss component—are in both markets for each point (or node) in the system and for twenty transmission zones. The day-ahead prices are hourly and the real-time prices are calculated every five minutes. Generators are paid nodal prices and consumers pay zonal prices, which are a combination of load-weighted nodal prices within a zone. Congestion revenue is collected by PJM through the congestion component of the locational price. It is based on day-ahead and real-time nodal payments (for generators) and zonal payments (for loads).<sup>95</sup>

<sup>94</sup> NYISO (2017e), pp. 37-40: [http://www.nyiso.com/public/webdocs/markets\\_operations/documents/Studies\\_and\\_Reports/Reports/Market\\_Monitoring\\_Unit\\_Reports/2015/NYISO%202015%20SOM%20Report\\_5-23-2016-CORRECTED.pdf](http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf)

<sup>95</sup> Effective as of June 1, 2015, load pays either nodal price or residual zone price. Load congestion payment will be calculated using congestion component of nodal price or congestion component of residual zone price. See <http://www.pjm.com/-/media/training/rzp-stakeholder-training.ashx>.

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

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

Table 6-7 presents congestion revenue for 2009–2016, and Table 6-8 presents total congestion for 2008–2016. Table 6-9 presents hub real-time, load-weighted average LMP components, and Table 6-10 presents hub day-ahead, load-weighted average LMP components.

**Table 6-7. PJM reported congestion revenue, 2009–2016**

ISO/Entity	Congestion Cost Definition	Reported Congestion Cost [millions of \$]							
		2009	2010	2011	2012	2013	2014	2015	2016
PJM MM	Day-Ahead Congestion Revenue/Cost	901	1,713	1,245	780	1,011	2,231	1,632	1,100
PJM MM	Total Congestion Revenue/Cost	719	1,423	999	529	677	1,932	1,385	1,024

Sources: Developed by DOE from Monitoring Analytics (2012), (2013), (2014b), (2015b), (2016b) and (2017b) available from [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2015.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml)

**Table 6-8. Total PJM congestion (\$M), 2008–2016**

Year	Congestion Costs (Millions)		Total PJM Billing	Percent of PJM Billing
	Congestion Cost	Percent Change		
2008	\$2,052	NA	\$34,306	6.0%
2009	\$719	(65.0%)	\$26,550	2.7%
2010	\$1,423	98.0%	\$34,771	4.1%
2011	\$999	(29.8%)	\$35,887	2.8%
2012	\$529	(47.0%)	\$29,181	1.8%
2013	\$677	28.0%	\$33,862	2.0%
2014	\$1,932	185.5%	\$50,030	3.9%
2015	\$1,385	(28.3%)	\$42,630	3.2%
2016	\$1,024	(26.1%)	\$39,050	2.6%

Source: Monitoring Analytics (2017b), p. 464: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016/2016-som-pjm-volume2.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf)

Table 6-9. Hub real-time, load-weighted average LMP components (\$/MWh), 2015–2016

	2015				2016			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	\$32.44	\$37.65	(\$3.08)	(\$2.13)	\$27.97	\$29.67	(\$0.47)	(\$1.23)
AEP-DAY Hub	\$33.67	\$36.90	(\$2.24)	(\$1.00)	\$29.08	\$29.41	\$0.01	(\$0.34)
ATSI Gen Hub	\$33.04	\$35.83	(\$2.43)	(\$0.36)	\$28.99	\$28.81	(\$0.00)	\$0.18
Chicago Gen Hub	\$27.91	\$34.41	(\$4.16)	(\$2.34)	\$25.97	\$28.65	(\$1.35)	(\$1.33)
Chicago Hub	\$30.42	\$36.13	(\$3.75)	(\$1.95)	\$28.13	\$29.45	(\$0.44)	(\$0.89)
Dominion Hub	\$41.12	\$37.33	\$3.63	\$0.16	\$31.68	\$29.61	\$2.21	(\$0.13)
Eastern Hub	\$40.03	\$35.29	\$3.03	\$1.71	\$28.74	\$28.68	(\$0.72)	\$0.78
N Illinois Hub	\$29.35	\$34.83	(\$3.44)	(\$2.04)	\$27.21	\$28.92	(\$0.64)	(\$1.07)
New Jersey Hub	\$36.09	\$35.66	(\$0.62)	\$1.06	\$26.32	\$29.39	(\$3.35)	\$0.28
Ohio Hub	\$32.88	\$36.08	(\$2.32)	(\$0.87)	\$28.93	\$29.08	\$0.07	(\$0.22)
West Interface Hub	\$34.67	\$36.00	(\$0.71)	(\$0.62)	\$29.87	\$29.18	\$0.90	(\$0.22)
Western Hub	\$40.83	\$38.59	\$1.94	\$0.30	\$31.63	\$30.58	\$1.00	\$0.05

Source: Monitoring Analytics (2017b), p. 462: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016/2016-som-pjm-volume2.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf)

Table 6-10. Hub day-ahead, load-weighted average LMP components (\$/MWh), 2015-2016

	2015				2016			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	\$30.66	\$33.21	(\$1.17)	(\$1.38)	\$28.11	\$29.60	(\$0.32)	(\$1.17)
AEP-DAY Hub	\$32.77	\$35.73	(\$2.32)	(\$0.64)	\$28.89	\$29.18	\$0.06	(\$0.35)
ATSI Gen Hub	\$29.05	\$29.71	(\$0.60)	(\$0.05)	\$26.12	\$25.98	\$0.10	\$0.03
Chicago Gen Hub	\$26.65	\$32.83	(\$4.46)	(\$1.72)	\$25.71	\$28.49	(\$1.62)	(\$1.16)
Chicago Hub	\$29.09	\$34.97	(\$4.51)	(\$1.37)	\$27.77	\$29.17	(\$0.73)	(\$0.68)
Dominion Hub	\$42.57	\$37.38	\$4.96	\$0.24	\$32.44	\$29.87	\$2.64	(\$0.07)
Eastern Hub	\$42.19	\$36.99	\$3.71	\$1.49	\$30.84	\$29.79	\$0.29	\$0.76
N Illinois Hub	\$28.72	\$34.91	(\$4.60)	(\$1.59)	\$27.38	\$29.04	(\$0.75)	(\$0.91)
New Jersey Hub	\$37.29	\$36.26	\$0.18	\$0.85	\$26.65	\$29.76	(\$3.45)	\$0.34
Ohio Hub	\$32.60	\$35.61	(\$2.46)	(\$0.55)	\$28.85	\$29.08	\$0.04	(\$0.27)
West Interface Hub	\$35.10	\$35.43	\$0.05	(\$0.38)	\$30.31	\$29.68	\$0.93	(\$0.30)
Western Hub	\$38.34	\$36.29	\$2.11	(\$0.06)	\$30.41	\$29.17	\$1.31	(\$0.06)

Source: Monitoring Analytics (2017b), p. 462: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016/2016-som-pjm-volume2.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf)

In its 2016 *State of the Market Report for PJM*, PJM's market monitor reports the following observations on congestion:

- **Total Congestion.** Total congestion costs decreased by \$361.6 million or 26.1 percent, from \$1,385.3 million in 2015 to \$1,023.7 million in 2016.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by \$531.7 million or 32.6 percent, from \$1,632.1 million in 2015 to \$1,100.4 million in 2016.
- **Balancing Congestion.** Balancing congestion costs increased by \$170.1 million or 68.9 percent, from -\$246.9 million in 2015 to -\$76.8 million in 2016.
- **Real-Time Congestion.** Real-time congestion costs decreased by \$451.3 million or 30.0 percent, from \$1,504.9 million in 2015 to \$1,053.6 million in 2016.

- **Monthly Congestion.** Monthly total congestion costs in 2016 ranged from \$48.0 million in November to \$121.4 million in September.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone – Northwest Line, the Graceton Transformer, the Bagley – Graceton Line, the Cherry Valley Transformer, and the Cherry Valley Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2016. The number of congestion event hours in the Day-Ahead Energy Market was about ten times higher than the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014. However, day-ahead congestion frequency increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.

Real-time congestion frequency decreased by 7.6 percent from 28,524 congestion event hours in 2015 to 26,369 congestion event hours in 2016.

- **Congested Facilities.** Day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers. Real-time, congestion-event hours increased on flowgates and decreased on interfaces, lines and transformers.

While Bedington - Black Oak, SENECA and AP South were in the list of constraints that were most frequently binding in the day-ahead market in 2015, interfaces did not bind as frequently in the day-ahead market in 2016.

The Conastone – Northwest Line was the largest contributor to congestion costs in 2016. With \$115.5 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2016.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2016. ComEd had \$303.6 million in total congestion costs, comprised of -\$155.5 million in total load congestion payments, -\$471.9 million in total generation congestion credits and -\$12.8 million in explicit congestion costs. The Cherry Valley Transformer, the Cherry Valley Flowgate, the Braidwood - East Frankfort Line, the Mercer IP – Galesburg Flowgate, and the Byron - Cherry Valley Flowgate contributed \$154.0 million, or 50.7 percent of the total ComEd control zone congestion costs.
- **Ownership.** In 2016, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges.

*In 2016, financial entities received \$9.4 million in congestion credits compared to \$132.1 million in 2015. In 2016, physical entities paid \$1,033.0 million in congestion charges, a decrease of \$484.3 million or 31.9 percent compared to 2015.<sup>96</sup>*

## 6.9 Southwest Power Pool (SPP)

Prior to March 2014, SPP operated only an energy imbalance market, in contrast to the other RTO/ISOs, 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*.<sup>97</sup>

In its *2016 State of the Market Report*, SPP’s internal market monitor made the following observations on congestion:

*...the two most congested corridors on the system were the west-to-east flows through the Woodward, Oklahoma area, and the north-to-south flows through west Texas and the Texas Panhandle. Both areas are significantly impacted by inexpensive wind generation in those regions of the market.*

*The Woodward, Oklahoma, and surrounding areas, had extensive 345kV buildouts energized in 2014, allowing higher transfers of wind generation to the more populated and higher-cost eastern portion of SPP. However, new wind generation keeps pace with transmission improvements. It is important to note that the Woodward constraint was congested in around two-thirds of all intervals in the day-ahead market and around one-third of all intervals in the real-time market.*

*The Texas Panhandle corridor relies mainly on 230kV transmission lines between Amarillo and Lubbock, Texas. The transmission corridor is impacted by the predominantly natural gas-fired generation in the south that is more expensive than the wind generation to the north. Texas Panhandle and west Texas constraints are congested in close to 40 percent of all intervals in the day-ahead market and 20 percent in the real-time market.*

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<sup>96</sup> Monitoring Analytics (2017b), pp. 56-57: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2016/2016-som-pjm-volume2.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf)

<sup>97</sup> For the most recent version of this report, see SPP (2017) at <https://www.spp.org/spp-documents-filings/?id=18512>.

*The area around Hays, Kansas is congested in 20 percent of all intervals in the day-ahead market and just under 10 percent of all intervals in the day-ahead market. Constraints in all other areas of the footprint are congested less than 10 percent of all intervals in both the day-ahead and real-time markets.*

*...One of the most significant changes to the SPP transmission system in the past three years was the addition of the 345kV double circuit from Hitchland to Woodward, which went into service in May 2014. The line enables SPP to move more energy from the wind generation corridor in the west to the load centers in the east. This buildout appears to have resulted in complications on the lower voltage system in the Woodward area, as reflected in the significant increase in congestion. The west-east price differentials in this area create a transmission bottleneck at Woodward, as evidenced by the most congested flowgate in 2016. The average Woodward-FPL Switch flowgate shadow price for 2014 was about \$19/MWh, increased to about \$39/MWh in 2015, and then to nearly \$59/MWh in 2016.*

*...The west Texas and Texas Panhandle area from Lubbock down into southeast New Mexico has historically been the most congested transmission corridor in the SPP market. In 2016 it was the second most congested area, with four of the top ten flowgates in this area. The Stanton-Indiana 115kV flowgate had the highest real-time market shadow price at \$36/MWh. Of particular note is the Osage Switch-Canyon East 115kV flowgate, which was the fifth most congested in 2016 with a \$9/MWh shadow price in the real-time market. The 2015 real-time market shadow price for this flowgate was about \$36/MWh compared to nearly \$80/MWh in 2014 and around \$44/MWh in 2013. The day-ahead market also realized a similar magnitude decrease from about \$73/MWh for the first 12 months of the market to \$28/MWh in 2015 and then \$11/MWh in 2016. This significant decline in the cost of congestion for this is as would be expected given the additional 345kV transmission facilities in the area and the overall lower electricity prices.<sup>98</sup>*

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<sup>98</sup> SPP (2017), pp. 97-98: [https://www.spp.org/documents/53549/spp\\_mmu\\_asom\\_2016.pdf](https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf).

## 7. Regional and Interconnection-Wide Transmission Planning

Section 7 reviews information both on a regional transmission planning outcome that emerges from FERC Order No. 1000 compliant regional transmission planning processes and on supporting information that emerges from interconnection-wide planning activities (which are not required by Order No. 1000).<sup>99</sup>

### 7.1 Introduction

Prior to the emergence of RTO/ISOs, regional transmission planning activities generally involved coordination by utilities through the regional reliability entity and joint planning at interfaces.<sup>100</sup> The development of regional transmission projects tended to be location-specific arrangements involving the utilities involved in developing the projects. A “regional” project, in this context, simply meant that there was a bi- or multi-lateral agreement among two or more parties (typically, incumbent transmission owners adjacent to one another) to share in developing a project.

The costs of developing the project and the ownership shares governing the use of the project were normally allocated among the partners as part of their contractual agreements, and the details of these agreements were typically included in filings with FERC. The partners, in turn, recovered their costs through their respective FERC- or state-approved tariffs or via FERC-approved contractual arrangements with others seeking to transmit or receive power over the lines. Public or stakeholder scrutiny—by a state public utility commission, for example—could take place through a FERC proceeding regarding ownership or usage agreements, as part of a retail rate-setting process, a state siting proceeding, or an integrated resource planning process.

Following the emergence of RTO/ISOs, transmission planning activities in RTO/ISOs regions took on a more public character consistent with the formal role that stakeholder involvement plays in RTO/ISO activities. Approval of regional cost allocation for certain transmission projects also emerged as an outcome of these regional transmission planning activities. By and large, transmission projects receiving regional cost allocation were proposed by one or more incumbent transmission owners within one or more of their footprints. Each RTO/ISO developed and evolved region-specific approaches to establish the need for (and selection of) solutions and/or projects that qualified for regional cost allocation. The standards used to judge or select these projects, consequently, varied by region. The outcomes also varied. Some regions’ plans identified projects for regional cost allocation; other regions’ plans did not. Interregional coordination in the form of information exchange also took place to varying degrees.

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<sup>99</sup> This information complements and does not replace the more comprehensive reporting on future transmission contained in Section 2.

<sup>100</sup> Some power pools coordinated planning activities over a broad footprint.

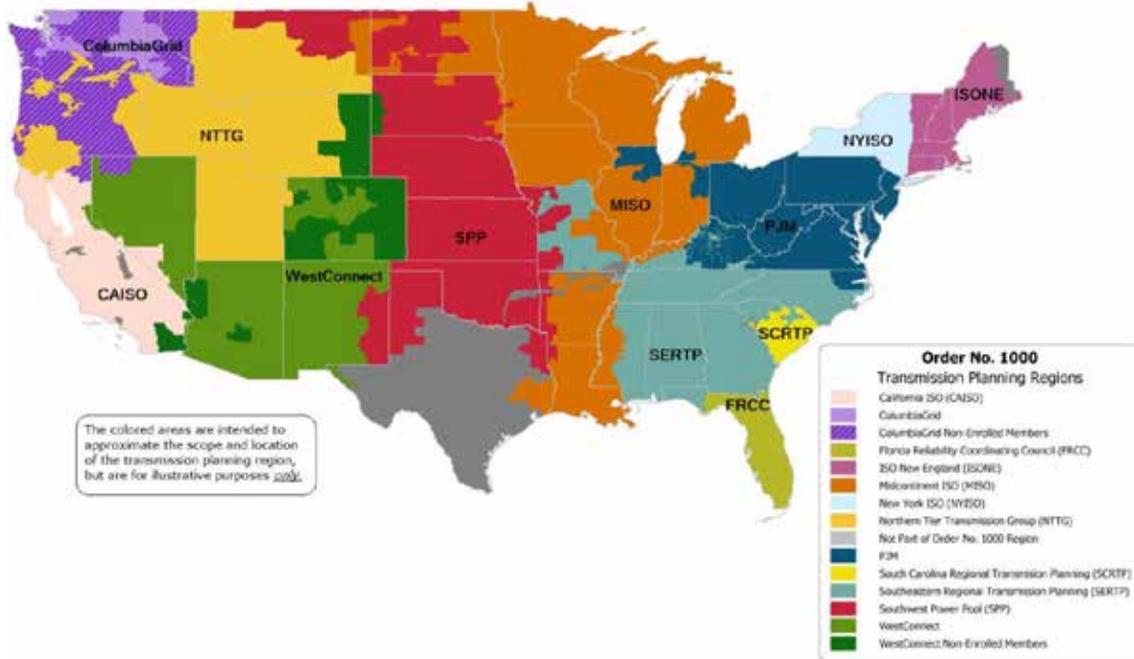


Figure 7-1. FERC Order No. 1000 Transmission Planning Regions

Source: <https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>

Together, FERC Order Nos. 890 and 1000<sup>101</sup> established requirements that transmission planning regions must follow in planning all, and allocating the costs of some, new transmission facilities. Order No. 890, issued in 2007, outlined general requirements for local as well as regional transmission planning practices and procedures. Order No. 1000, issued in 2011, laid out specific requirements for: (1) regional transmission planning; (2) consideration of transmission needs driven by public policy requirements; (3) non-incumbent transmission development;<sup>102</sup> (4) interregional transmission coordination; and (5) cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation. Figure 7-1 shows the approximate portions of the country represented by the 12 transmission planning regions that FERC has recognized as compliant with Order No. 1000.<sup>103</sup>

<sup>101</sup> See Order No. 1000: <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf> and Order No. 890: <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>

<sup>102</sup>Order No. 1000 defines a “nonincumbent transmission developer” as either: (1) a transmission developer that does not have a retail distribution service territory or footprint; or (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project [see 136 FERC ¶ 61,051 at P 225 (2011)].

<sup>103</sup>A transmission planning region is made up of the transmission providers that have enrolled in the region, and depending on what processes have been adopted, it may be a transmission planning region or the transmission providers within that region that administer the competitive transmission development process.

Table 7-1. Effective dates and regional transmission planning cycles

	FERC Regional Order No. 1000 effective date	Regional Transmission Planning Cycle	FERC Interregional Order No. 1000 effective date
<b>California ISO (CAISO)</b>	October 1, 2013	<ul style="list-style-type: none"> <li>15-month cycle</li> <li>New cycle begins every January</li> <li>Cycles overlap for 3 months</li> </ul>	October 1, 2015: California ISO-ColumbiaGrid-NTTG-WestConnect
<b>ColumbiaGrid</b>	January 1, 2015	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>Order No. 1000 project proposals are submitted during Jan/Feb of each year and reviewed in the annual system assessment</li> </ul>	January 1, 2015: ColumbiaGrid-California ISO-NTTG-WestConnect
<b>Florida Reliability Coordinating Council (FRCC)</b>	January 1, 2015	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle begins January of each odd-numbered year</li> </ul>	January 1, 2015: FRCC-SERTP
<b>ISO New England (ISO-NE)</b>	May 18, 2015	<ul style="list-style-type: none"> <li>No set planning cycle</li> <li>Evaluation of transmission needs and transmission projects is performed on an on-going basis</li> </ul>	January 1, 2014: ISONE-NYISO-PJM <sup>104</sup>
<b>Midcontinent ISO (MISO)</b>	June 1, 2013	<ul style="list-style-type: none"> <li>18-month cycle</li> <li>New cycle begins each June</li> <li>Cycles overlap for 6 months</li> </ul>	January 1, 2014: MISO-PJM March 30, 2014: MISO-SPP January 1, 2015: MISO-SERTP
<b>New York ISO (NYISO)</b>	January 1, 2014 <sup>105</sup>	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle for reliability and public policy begins January of each even-numbered year</li> <li>New cycle for economic planning begins in odd-numbered years</li> </ul>	January 1, 2014: NYISO-ISONE-PJM
<b>Northern Tier Transmission Group (NTTG)</b>	October 1, 2013	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle begins January of each even-numbered year</li> </ul>	October 1, 2015: NTTG-California ISO-ColumbiaGrid-WestConnect

<sup>104</sup> On November 19, 2015, FERC accepted the RTO/ISO filings (ISO-NE, PJM, and NYISO) for interregional planning, including the Amended Planning Protocol and cost-allocation methodology, as compliant with the interregional requirements of Order No. 1000. See FERC, Docket Nos. ER13-1957-001, ER13-1942-001, ER13-1946-001, ER13-1960-001, ER13-1947-001, and ER15-2200-000, Acceptance for Filing (November 19, 2015); see also ISO New England Inc., 151 FERC ¶ 61,133 (2015).

<sup>105</sup> A NYISO Regional Compliance proceeding is pending at FERC.

	FERC Regional Order No. 1000 effective date	Regional Transmission Planning Cycle	FERC Interregional Order No. 1000 effective date
<b>PJM Interconnection (PJM)</b>	January 1, 2014	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle begins January of each even-numbered year</li> </ul>	January 1, 2014: PJM-ISONE-NYISO and PJM-MISO January 1, 2015: PJM-SERTP <sup>106</sup>
<b>South Carolina Regional Transmission Planning (SCRTP)</b>	April 19, 2013	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle begins January of each odd-numbered year</li> </ul>	January 1, 2015: SCRTP- SERTP
<b>Southeastern Regional Transmission Planning (SERTP)</b>	June 1, 2014	<ul style="list-style-type: none"> <li>One-year cycle</li> <li>New cycle begins each January</li> </ul>	January 1, 2015: SERTP-MISO; SERTP-PJM; SERTP-FRCC; SERTP-SCRTP; and SERTP-SPP
<b>Southwest Power Pool (SPP)</b>	March 30, 2014	<ul style="list-style-type: none"> <li>Three-year cycle</li> <li>Most recent cycle began January 2017</li> </ul>	March 30, 2014: SPP-MISO January 1, 2015: SPP-SERTP
<b>WestConnect</b>	January 1, 2015	<ul style="list-style-type: none"> <li>Two-year cycle</li> <li>New cycle begins January of each even-numbered year</li> </ul>	October 1, 2015: WestConnect-California ISO- ColumbiaGrid- NTTG

Source: Developed by DOE from FERC (2016a): <https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>

This section reviews information both on a regional transmission planning outcome that emerges from these processes (Section 7.2), and on supporting information that emerges from interconnection-wide planning activities (which are not required by Order No. 1000) (Section 7.3). Information from both sources complements and does not replace the more comprehensive reporting on future transmission contained in Section 2.

## 7.2 Selected Transmission Outcomes Emerging from Order No. 1000 Compliant Regional Transmission Planning Processes

This section reviews recent information on selected outcomes that have emerged through or as part of Order No. 1000 compliant regional transmission planning processes. The source of this information is newly revised transmission metrics developed by FERC staff.<sup>107</sup> The focus is on transmission projects that have been

<sup>106</sup> See *PJM Interconnection, L.L.C. & Duquesne Light Co.*, 150 FERC ¶ 61,046 at P 36 (2015) (“We find PJM and SERTP Filing Parties’ requested January 1, 2015 effective date for revisions to SERTP Filing Parties’ respective OATTs and to Schedule 6 of PJM’s Operating Agreement to be reasonable. This date corresponds to the planning cycle subsequent to SERTP Filing Parties’ effective date for their regional compliance filings. We also find PJM Transmission Owners requested effective date of January 1, 2014, for Schedule 12-B of the PJM OATT to be reasonable. This effective date is consistent with an earlier Commission order conditionally accepting PJM Transmission Owners’ proposed Schedule 12-B, effective January 1, 2014, subject to the outcome of this order.”).

<sup>107</sup> FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

selected in a regional transmission plan for purposes of cost allocation and, in particular, the role of non-incumbent transmission developers in sponsoring regional projects included in the Order 1000 regional transmission plans.<sup>108</sup> At this time, five of the 12 planning regions have conducted competitive processes that lead to selection of projects for regional cost allocation: CAISO, PJM, MISO, NYISO, and SPP.

### 7.2.1 FERC Transmission Metrics

In addition to the six original Transmission Metrics, three new metrics were developed by FERC for the 2017 Transmission Metrics Report: *Number of Unique Developers Submitting Proposals*; *Number and Percentage of Selected Nonincumbent Proposals*; and *Stakeholder Participation in Regional Transmission Planning Processes*.

#### *Percentage of Nonincumbent Transmission Bids or Proposals*

Another of the nine FERC Transmission Metrics described in Section 2.4.1, this metric measures

“...the percentage of proposals that nonincumbent transmission developers submitted in competitive transmission development processes. For the purpose of this report and to be consistent with Order No. 1000, staff includes as nonincumbents any new consortium or joint venture as long as the project is located outside of all of the associated entities’ retail distribution service territories or footprints.<sup>13</sup> Staff notes that this metric addresses only regional transmission projects; it does not reflect projects proposed outside of the regional transmission planning process or any interregional transmission projects. This metric is intended to measure nonincumbent participation in regional transmission planning processes, which the Commission concluded in Order No. 1000 was necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, thus helping to ensure just and reasonable rates for transmission customers.”<sup>109</sup>

The key findings for this metric from the 2017 report are shown in Figure 7-2. A total of 703 proposals were submitted to the five transmission planning regions that held proposal windows during the reporting period:

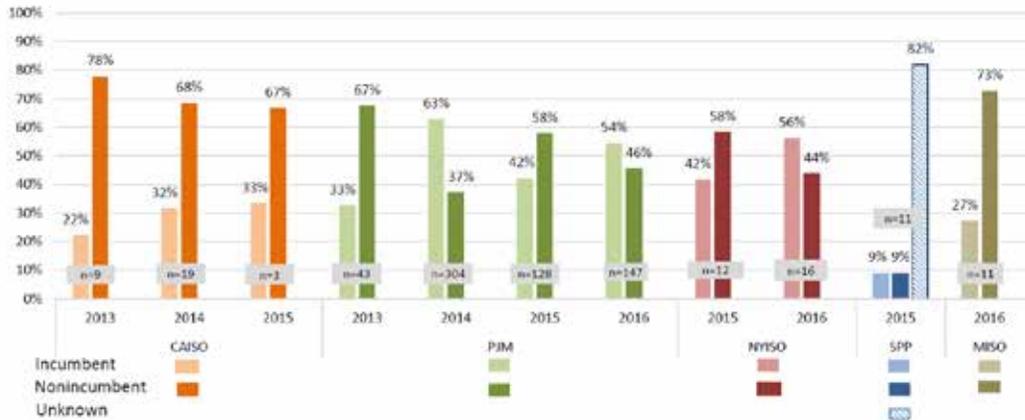
- PJM held five new competitive proposal windows in 2015 and 2016; 46 percent of the proposals received between 2013 and 2016 were submitted by nonincumbent transmission developers.

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<sup>108</sup> As discussed in recent reviews of these regional transmission planning processes (see, for example, Eto 2017), transmission projects that have been selected in a regional transmission plan for purposes of cost allocation are not the only transmission infrastructure outcome that emerges from or in parallel with some of these processes. Hence, the information presented on these transmission projects is intended to complement the more comprehensive information on planned transmission projects reviewed in Section 2.

<sup>109</sup> FERC (2017b), pp. 9-10.

- NYISO received a higher percentage of proposals from nonincumbents than incumbents in 2015; however, in 2016, more proposals were received from incumbents than nonincumbent transmission developers.<sup>110</sup>
- For MISO’s first execution of its competitive transmission development process in 2016, the majority of proposals were submitted by nonincumbent transmission developers.<sup>111</sup>



Sources: CAISO’s 2012-2013 and 2013-2014 transmission plans; PJM’s Transmission Expansion Advisory Committee and RTEP proposal websites; NYISO’s transmission planning needs reports; SPP’s Integrated Transmission Planning 10-Year Study (ITP10), meeting minutes from the Board of Directors/Members Committee, and recommendation report from an industry expert panel; and MISO’s Competitive Transmission Administration website.

**Figure 7-2. Percentage of Competitive Proposals by Incumbents vs. Nonincumbent Transmission Developers (2013–2016)**

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

### Number of Unique Transmission Developers Submitting Proposals

This metric, designed to measure the competitiveness of transmission development processes, describes “the number of unique developers that participate in transmission planning regions’ competitive transmission development processes by submitting proposals, regardless of their incumbency status.”<sup>112</sup>

Key findings for this metric from the 2017 report are shown in Figure 7-3:

- Between 2013 and 2016, the number of unique transmission developers in a given transmission planning region in any year ranged from 3 to 22 entities,

<sup>110</sup> The majority of the “incumbent proposals” received by NYISO in 2016 were actually joint proposals between incumbent and non-incumbent developers.

<sup>111</sup> FERC (2017b), p. 4.

<sup>112</sup> FERC (2017b), p. 21.

while most of the totals hovered between 6 and 11 unique transmission developers.<sup>113</sup>

- In PJM, the number of unique transmission developers submitting proposals was comparatively low compared to the total number of proposals received.
- In CAISO, NYISO, and MISO, unique transmission developers submitted roughly 1–2 proposals each.<sup>114 115</sup>

RTO/ISO	2013		2014		2015		2016	
	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)
CAISO	9	7 (1.3)	19	9 (2.1)	3	3 (1.0)	---	---
PJM	43	10 (4.3)	304	22 (13.8)	128	11 (11.6)	147*	16* (9.2)
NYISO	---	---	---	---	12	7 (1.7)	16	6 (2.7)
SPP	---	---	---	---	11	N/A**	---	---
MISO	---	---	---	---	---	---	11	11 (1.0)

\* Includes the 2016 RTEP 1, 2016 RTEP 2, 2016 RTEP 3, and 2016 RTEP 3 Addendum proposal windows, but excludes the 2016/17 RTEP Long Term Proposal window.

\*\* The total number of unique developers in SPP is not known since the identities of the developers were masked in the selection report and SPP announced the names of the winner and runner up in a press release on its website.

**Figure 7-3. Number of Unique Transmission Developers and Average Proposals per Developer**

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

### *Number and Percentage of Selected Nonincumbent Proposals*

Designed to assess whether nonincumbent transmission developers are likely to have continued interest in participating in future competitive transmission development processes, this metric measures the number of nonincumbent transmission developer proposals selected by each transmission planning region each year, and shows the percentage of the total selected proposals submitted by nonincumbent transmission developers.<sup>116</sup>

Key findings for this metric from the 2017 report are shown in Figure 7-4:

- Other than in CAISO, most of the proposals selected by the transmission planning regions were submitted by incumbent transmission developers.

<sup>113</sup> FERC (2017b), p. 22.

<sup>114</sup> FERC (2017b), p. 4.

<sup>115</sup> In October 2017, NYISO selected a nonincumbent as the developer for the Western NY Transmission Facilities as a result of its 2015 Public Policy solicitation.

<sup>116</sup> FERC (2017b), p. 25.

- For all of the transmission planning regions that had competitive proposal windows, the percentage of selected proposals submitted by nonincumbent transmission developers declined from 20 percent in 2013, to 6 percent in 2014, to 3 percent in 2015, and to zero in 2016.
- CAISO had the largest increase in the share of selected nonincumbent transmission developer proposals between 2013 and 2015.<sup>117</sup>



\* Only Market Efficiency Proposals in PJM were selected in 2013. While the review of Artificial Island proposals continued into 2015, the final selections associated with that project were counted under the 2013 proposal window year.

\*\* Covers PJM's 2016 RTEP 1, 2016 RTEP 2, and 2016 RTEP 3 and are only TEAC recommendations to the PJM Board. Thus, the selections for the 2016 year are not final.

\*\*\* NYISO has yet to select a proposal from its two solicitations.

**Figure 7-4. Number and Percentage of Awards Made to Nonincumbents**

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

### Stakeholder Participation in Regional Transmission Planning Processes

This metric, which measures stakeholder participation in regional transmission planning processes, was based on a requirement in FERC's Strategic Plan that staff assess the success of Order No. 1000 in encouraging greater participation in the regional transmission planning processes.<sup>118</sup>

Key findings for this metric from the 2017 report are shown in Figure 7-5 and Figure 7-6:

- Stakeholder attendance was relatively stable at regional transmission planning process meetings during fiscal year 2015 (FY 2015) and fiscal year 2016 (FY 2016).
- Nonincumbent transmission developer participation in stakeholder meetings increased in 4 of the 12 transmission planning regions from FY 2015 to FY 2016.

<sup>117</sup> FERC (2017b), p. 4.

<sup>118</sup> FERC (2017b), p. 28.

- Average attendance by all stakeholders dropped slightly in most transmission planning regions from FY 2015 to FY 2016.

Region	Average Number of Participants in Attendance		
	FY 2015	FY 2016	Difference
CAISO	57	55	-2
ColumbiaGrid	20	16	-4
NTTG	24	29	5
WestConnect	33	32	-1
MISO	90	89	-1
SPP	43	35	-8
NYISO	44	39	-5
ISO-NE	28	30	2
PJM	85	80	-5
FRCC	11	14	3
SERTP	26	29	3
SCRTP	8	10	2
<b>Total</b>	<b>469</b>	<b>458</b>	<b>-11</b>

Figure 7-5. Average Number of Participants Attending Regional Transmission Planning Meetings (FY 2015 and FY 2016)

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

Region	Average Number of Nonincumbents in Attendance		
	FY 2015	FY 2016	Difference
CAISO	11	11	0
ColumbiaGrid	4	1	-3
NTTG	1	2	1
WestConnect	6	6	0
MISO	19	7	-12
SPP	4	6	2
NYISO	Unavailable	Unavailable	n/a
ISO-NE	0	0	0
PJM	4	4	0
FRCC	3	4	1
SERTP	1	2	1
SCRTP	0	0	0
<b>Total</b>	<b>53</b>	<b>43</b>	<b>-10</b>

Figure 7-6. Average Number of Nonincumbent Transmission Developers Attending Regional Transmission Planning Meetings (FY 2015 and FY 2016)

Source: FERC (2017b): <https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf>

### 7.3 Interconnection-wide Transmission Planning Activities

The 12 regional transmission planning processes recognized by FERC through the compliance orders associated with Order No. 1000 emerged against a backdrop of interconnection-wide regional planning activities that pre-dated, but now support, the regional transmission planning processes to varying degrees.

#### 7.3.1 Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee

The Transmission Expansion Planning Policy Committee (TEPPC), with the assistance of WECC, conducts an interconnection-wide transmission 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.<sup>119</sup> The list, known as the Common Case Transmission Assumptions (CCTA),<sup>120</sup> 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.<sup>121</sup> See Figure 7-7.

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<sup>119</sup> In the fall of 2013, the Subregional Coordination Group changed its name to the Regional Planning Coordination Group.

<sup>120</sup> See WECC (2014b), at <https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx>.

<sup>121</sup> WECC (2010b): [https://www.wecc.biz/Reliability/100811\\_SCG\\_FoundationalTransmissionProjectList\\_Report.pdf](https://www.wecc.biz/Reliability/100811_SCG_FoundationalTransmissionProjectList_Report.pdf)

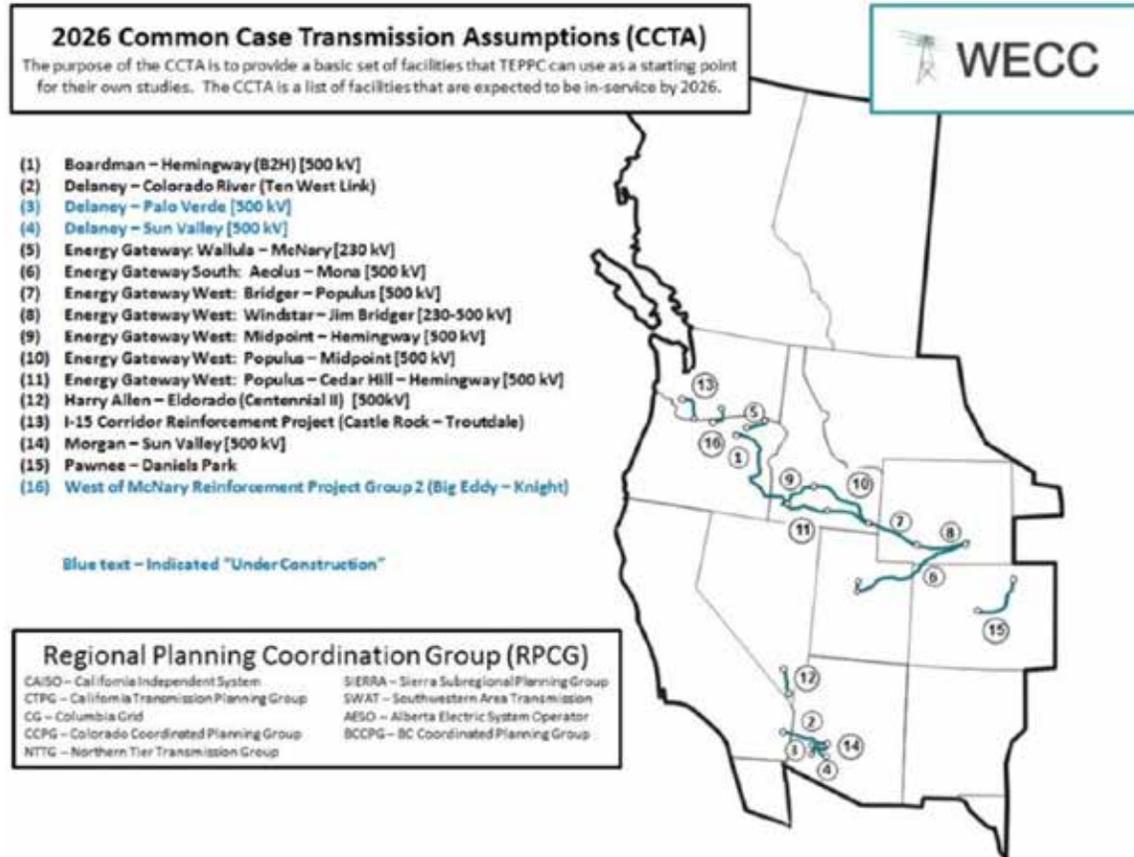


Figure 7-7. WECC 2026 Common Case Transmission Assumptions (CCTA)

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

### 7.3.2 Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative was formed in early 2009 in order to foster an open and collaborative process for conducting technical analyses of transmission planning within the Eastern Interconnection. EIPC was awarded American Recovery and Reinvestment Act (ARRA) funding to conduct analyses of transmission requirements under a broad range of alternative future scenarios. The first phase of analysis was conducted during 2010 and 2011<sup>122</sup> and included interregional analysis and macroeconomic analyses on eight stakeholder-developed future scenarios. In 2012, the second phase of analysis was completed to develop a possible future transmission system that would support three of those future scenarios. The second phase of analysis was extended in 2013 to consider the interface between the natural gas delivery system and the electric transmission system.<sup>123</sup> The results of the Gas-Electric System Interface

<sup>122</sup> See [http://www.eipconline.com/Resource\\_Library.html](http://www.eipconline.com/Resource_Library.html) for reports and information on the EIPC Phase I analysis.

<sup>123</sup> See <http://www.eipconline.com/phase-ii-documents.html> for reports and information on the EIPC Phase II analysis.

Study<sup>124</sup> provide a comprehensive analysis across the region of the adequacy of the natural gas pipeline delivery system to meet the needs of the gas-fired electric generation system under various conditions over a 10-year horizon. In addition, the study identified constraints on the natural gas pipeline system that may affect the delivery of gas to specific generators following a variety of postulated gas and electric system contingencies.

Beginning in 2013 EIPC undertook a new series of planning studies<sup>125</sup> to develop baseline “roll-up” cases to serve as integrated powerflow models containing the expansion plans for the Eastern Interconnection.<sup>126</sup> Three roll-up cases have now been developed—one for the 2018 summer peak load period, one for the 2023 summer, and a summer and winter powerflow model for the year 2025.

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

Appendix B to the Final 2015 Study Report lists new or upgraded transmission facilities in the EIPC 2025 Roll-Up Cases—all new/upgraded facilities 161 kV and above that are projected to be in service by 2025.<sup>127</sup> This list includes almost 300 projects across 35 states. See Figure 7-8.

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<sup>124</sup> See <http://www.eipconline.com/gas-electric.html>.

<sup>125</sup> This study was conducted independent of DOE funding.

<sup>126</sup> See <http://www.eipconline.com/non-doe-documents.html>.

<sup>127</sup> See <http://www.eipconline.com/non-doe-documents.html>.

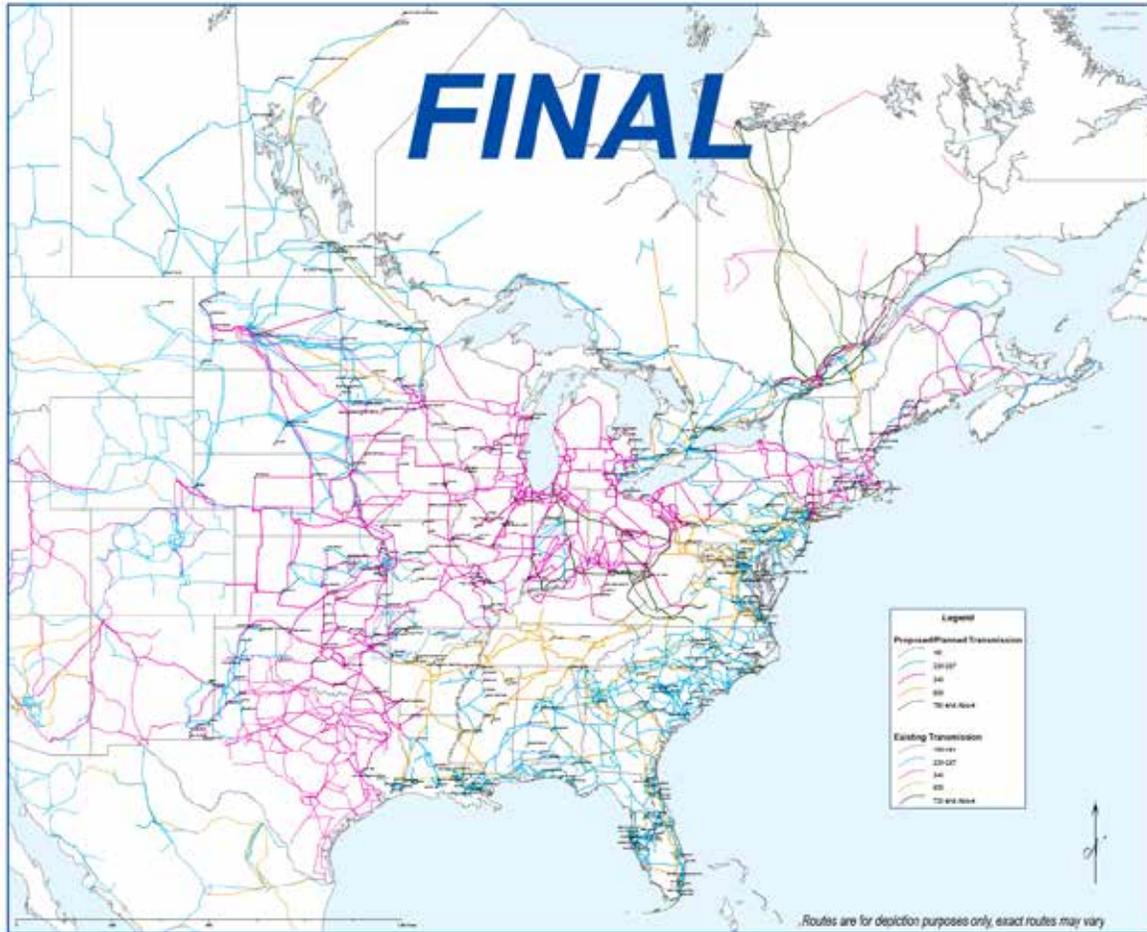


Figure 7-8. EIPC future transmission projects from final 2015 Study Report

Source: EIPC (2015): *Final 2015 Study Report: Appendix A*: <http://www.eipconline.com/non-doe-documents.html>

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