U.S. DEPARTMENT OF ENERGY

National Electric Transmission Congestion Study

September 2015

United States Department of Energy
Washington, DC 20585

Message from the Secretary

In this study, the U.S. Department of Energy (DOE, the Department) seeks to provide information about transmission congestion by focusing on specific indications of transmission constraints and congestion and their consequences. The study focuses primarily on a specific time frame: historical trends over the past few years, and looking into the future to the extent available studies permit. It does not apply congestion labels to broad geographic areas such as the “critical congestion areas,” “congestion areas of concern,” and “conditional congestion areas” identified in earlier studies. For analytic convenience, the study’s results are presented and discussed in relation to four large regions of the United States: the West, Midwest, Northeast, and Southeast. The area covered by the Electric Reliability Council of Texas (ERCOT) is excluded by law from this study.

This study identifies (to the extent supported by publicly available data as of 2012, with limited updates in December 2013) where transmission constraints and congestion occur across the eastern and western portions of the U.S. electric power system. All of the conclusions presented in this study are based on (and limited to) the data reviewed, which are all publicly available data series, studies, analyses, and reports. The Department reviewed more than 450 sources in preparing this report, all of which are listed by name in Appendix E. DOE did not conduct independent modeling for this study. The Department of Energy does not endorse and has not independently validated the data and information compiled and reported in this study.

The transmission constraints and congestion identified in this study represent a snapshot in time. The study focuses on transmission constraints and congestion in the recent past as well as current expectations for the future to the extent available studies permit. Congress directed the Department to conduct a congestion study every three years. The Department plans to initiate a fresh study of transmission constraints and congestion impacts in 2015. In addition to the triennial congestion studies, the Department will work with the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) to prepare an annual *Transmission Data Review* summarizing publicly available data and information on transmission matters, including congestion.

This study is being provided to the following Members of Congress:

- **The Honorable Thad Cochran**
  Chairman
  Senate Committee on Appropriations

- **The Honorable Barbara Mikulski**
  Ranking Member
  Senate Committee on Appropriations

- **The Honorable Lisa Murkowski**
  Chair
  Senate Committee on Energy and Natural Resources

- **The Honorable Maria Cantwell**
  Ranking Member
  Senate Committee on Energy and Natural Resources

- **The Honorable Lamar Alexander**
  Chairman, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

- **The Honorable Dianne Feinstein**
  Ranking Member, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

- **The Honorable Harold Rogers**
  Chairman
  House Committee on Appropriations

- **The Honorable Nita Lowey**
  Ranking Member
  House Committee on Appropriations

- **The Honorable Mike Simpson**
  Chairman, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Marcy Kaptur**
  Ranking Member, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Fred Upton**
  Chairman
  House Committee on Energy and Commerce

- **The Honorable Frank Pallone**
  Ranking Member
  House Committee on Energy and Commerce

- **The Honorable Ed Whitfield**
  Chairman, Subcommittee on Energy and Power
  House Committee on Energy and Commerce

- **The Honorable Bobby L. Rush**
  Ranking Member, Subcommittee on Energy and Power
  House Committee on Energy and Commerce

If you have any questions or need additional information, please contact me or Mr. Brad Crowell, Assistant Secretary for Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Ernest J. Moniz

Note to Reader

This document is the Department of Energy's third *National Electric Transmission Congestion Study*. These studies are prepared every three years pursuant to a requirement established by the Energy Policy Act of 2005. The first Congestion Study was published in 2006, and the second was written in 2009 and released in early 2010. The 2006 and 2009 studies had two principal components: data and information of various kinds related to the nation's transmission networks and transmission congestion, and the Department's comments and conclusions about the implications of the data and information.

While preparing the current Congestion Study, however, the Department decided to release two separate documents: the Congestion Study itself (this document), and a stand-alone document presenting publicly available data and information on the nation's transmission assets and how they are used, with particular attention to transmission constraints and congestion, *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012* (January 2014). The Department plans to produce an annual *Transmission Data Review* summarizing publicly available data and information on transmission matters, including congestion. A *2015 Transmission Data Review* is in preparation.

Acronyms and Abbreviations

BPA	Bonneville Power Administration
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CARIS	NYISO's Congestion Assessment and Resource Integration Study
CCR	EPA's Coal Combustion Residuals Rule
CEC	California Energy Commission
CIM	Common Information Model
COI	California-Oregon Intertie
CPUC	California Public Utilities Commission
CSAPR	EPA's Cross-State Air Pollution Rule
CWA	EPA's Clean Water Act
CWIS	Cooling water intake systems
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables & Efficiency
EIA	Energy Information Administration
EISPC	Eastern Interconnection States Planning Council
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
FPA	Federal Power Act
FPL	Florida Power & Light
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse gas
GW	Gigawatt (1 billion or 10^9 watts)
HAPS	Hazardous air-pollutants
HVDC	High-voltage direct current
ICTE	Entergy's Independent Coordinator of Transmission
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
LADWP	Los Angeles Department of Water and Power
LIPA	Long Island Power Authority
LMP	Locational marginal price
LNG	Liquefied natural gas
LTRA	Long-Term Reliability Assessment
MAPP	Mid-continent Area Power Pool
MATS	EPA's Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MRO	Midwest Reliability Organization
MTEP	Midwest Transmission Expansion Plan
MVP	Multi-value projects
MW	Megawatt (1 million or 10^6 watts)
MWh	Megawatt-hour (1 million or 10^6 watt-hours)
NAAQS	U.S. EPA's National Ambient Air Quality Standards
NARUC	National Association of Regulatory Utility Commissioners
National Corridor	National interest electric transmission corridor
NDEX	North Dakota Export Limit

NEMA	National Electric Manufacturers Association
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NO_x	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
OE	Office of Electricity Delivery and Energy Reliability, DOE
PAR	Phase-angle regulators
PATH	Potomac-Appalachian Transmission Highline
PDCI	Pacific DC Intertie
PJM	Pennsylvania New Jersey Maryland Regional Transmission Organization
PSC	Public Service Commission
PUC	Public Utility Commission
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Certificate
ROI	Return on Investment
RPS	Renewable Portfolio Standard
RTEP	PJM's Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SERC	Southeast Reliability Corporation
SERTP	Southeastern Regional Transmission Planning Process
SIRPP	Southeast Inter-Regional Participation Process
SO_2	Sulfur dioxide
SONGS	San Onofre Nuclear Generating Station
SPP	Southwest Power Pool
STARS	New York's State Transmission Assessment and Reliability Study
TADS	Transmission Availability Data System
TEPPC	WECC's Transmission Expansion Planning and Policy Committee
The Department	U.S. Department of Energy
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
UFM	Unscheduled Flow Mitigation
VFT	Variable Frequency Transformer
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association

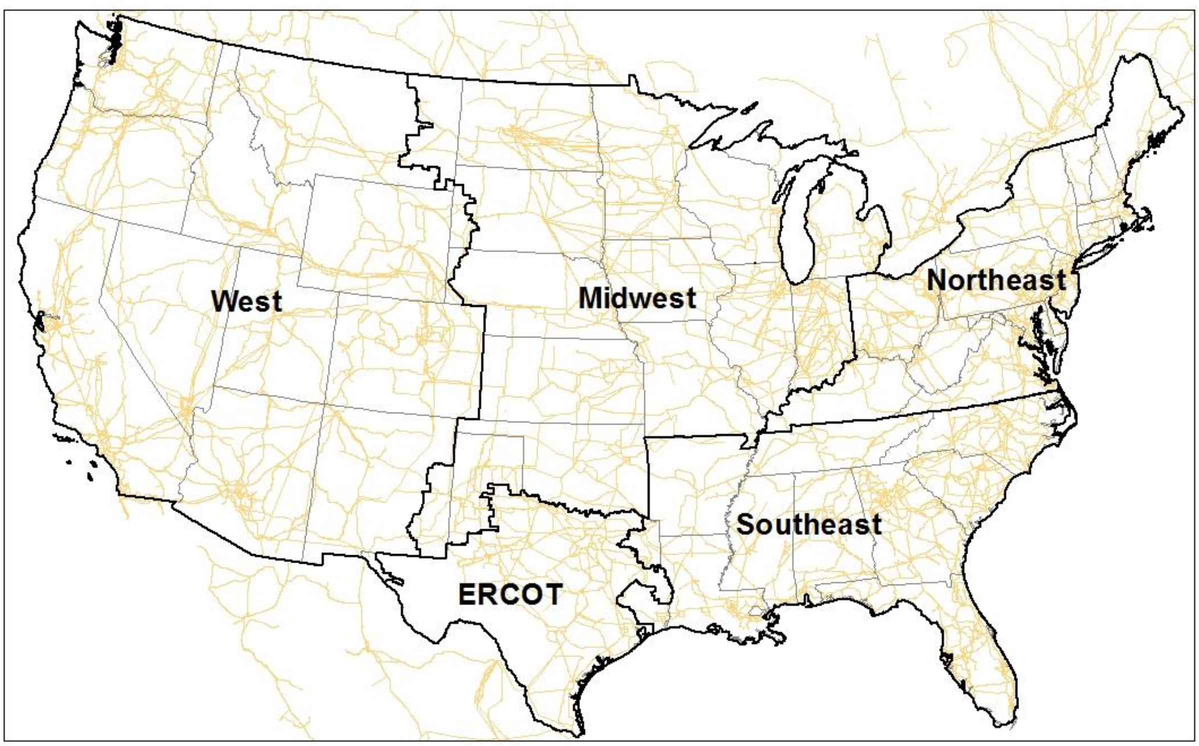
Executive Summary

The Energy Policy Act of 2005 amended the Federal Power Act (FPA) to require the U.S. Department of Energy (DOE, the Department) to conduct a transmission congestion study every three years, in consultation with the states and appropriate regional reliability entities. DOE published its first study in 2006, and a second for 2009, which was released in early 2010. This is the Department's third congestion study. It is based on publicly available data through 2012, with limited updates in December 2013.

Differences between this Study and Previous Congestion Studies

In this study the Department seeks to provide information about congestion by focusing on specific indications of transmission constraints and congestion—and their consequences. It focuses primarily on a specific time frame: historical trends over the few years prior to 2012 (with limited updates in 2013), and looking into the future to the extent available studies permit. It does not apply congestion labels to broad geographic areas such as the "critical congestion areas," "congestion areas of concern," and "conditional congestion areas" identified in earlier studies. For analytic convenience, the study's results are presented and discussed in relation to four large regions of the United States: the West, Midwest, Northeast, and Southeast (see Figure ES - 1).[1] The area covered by the Electric Reliability Council of Texas (ERCOT) is excluded by law from this study.

Figure ES - 1. Regional boundaries used for this study



[1] *Map regions are drawn to show geographic boundaries and not necessarily electrical ones. Transmission facilities shown in stated regions are not necessarily owned or operated by entities within that region. Note: the area covered by ERCOT is excluded by law from DOE congestion studies.*

This study identifies (to the extent supported by publicly available data as of 2012, with limited updates in December 2013) where transmission constraints and congestion occur across the eastern and western portions of the United States' electric power system. All of the conclusions presented in this study are based on (and limited to) the data reviewed, all of which are publicly available data series, studies, analyses, and reports. DOE reviewed more than 450 sources in preparing this report, all of which are listed in Appendix E. In addition, the data used to develop the analysis and conclusions in this document is compiled in a companion report released by the Department in early 2014.[2] DOE did not conduct independent modeling for this study. The Department does not endorse and has not independently validated the data and analyses referred to in this study.

The transmission constraints and congestion identified in this study represent a snapshot in time that is dependent on available information. Recognizing the changeability of circumstances and information, Congress directed the Department to conduct a congestion study every three years. The Department plans to initiate a fresh study of transmission constraints and congestion impacts in 2015. In addition to the triennial congestion studies, the Department will work with the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) to prepare an annual *Transmission Data Review* summarizing publicly available data and information on transmission matters, including congestion.

Transmission Constraints and Congestion

Transmission constraints and congestion are related but distinctly different concepts. The term "transmission constraint" may refer to:

(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;

(2) An operational limit imposed on an element (or group of elements) to protect reliability; or

(3) The lack of adequate transmission system capacity to deliver electricity from potential sources of generation (either from new sources or re-routed flows from existing sources when other plants are retired) without violating reliability rules.

Transmission constraints, as defined above in (1), are a result of many factors including load level, generation dispatch, and facility outages. Jointly, these conditions establish a specific level or limit—as in (2)—to the permissible flow over the affected element(s) in order to comply with reliability rules and standards established to ensure that the grid is operated in a safe and secure manner. Reliability standards, developed by the North American Electric Reliability Corporation

[2] United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.

(NERC) and approved by FERC, specify how equipment or facility ratings should be calculated to avoid exceeding thermal, voltage, and stability limits following credible contingencies.

Transmission operating limits, which constrain throughput on affected transmission elements, are identified to comply with these rules and practices. Thus, although it is commonly thought that transmission constraints indicate reliability problems, in fact, constraints result from compliance with reliability rules. However, when constraints frequently limit desired flows, or when these limits are violated to avoid shedding firm load, they may indicate reliability problems that warrant mitigation.

The term "congestion" refers to situations where transmission constraints reduce transmission flows or throughput[3] below levels desired by market participants or government policy (e.g., to comply with reliability rules). A high degree or level of transmission system utilization alone does not necessarily mean congestion is occurring. Congestion can only arise when there is a desire to increase throughput across a transmission path, but such higher utilization is thwarted by one or more constraints. Transmission congestion has costs—they may induce higher costs for consumers on the downstream side of the transmission constraint if the consumers' electricity supplier(s) must rely on higher-cost generation sources, and they may make it more difficult to achieve policy goals such as increased reliance on renewable generation resources. Transmission congestion may also cause reliability problems where such constraints impact operations by limiting access to reserves.

The Department has defined these terms narrowly for the purpose of this study, to ensure that they are used consistently here; these terms sometimes have different meanings in industry usage.

This Study Does Not Make Recommendations to Address Transmission Constraints and Congestion

This study's assessment of transmission constraints and congestion does not address whether or how to fix constraints or the congestion they may cause. The presence of transmission congestion reflects only a desire or demand for increased transmission system utilization.

Whether it is appropriate to mitigate transmission congestion requires information and judgment about the purposes or objectives that would be served which goes beyond this study's snapshot of physical constraints and congestion in the transmission system. For example, increased flow of electricity from lower-cost generation sources could reduce the overall cost of supplying electricity to consumers, while increased flow of electricity from remote renewable generation could help meet state energy policy goals. The point is that determining whether to address congestion requires determining first what objectives would be met by doing so. These objectives may conflict. For example, new generation could create new transmission congestion and raise electricity supply costs if it is located upstream of a constraint, at the same time that it helps to

[3] Throughout this study, the terms "transmission flows" and "transmission throughput" are used interchangeably to refer to the transport of electricity over transmission lines.

satisfy an energy policy goal. The differing objectives relative to transmission congestion should be recognized in determining whether and how to relieve transmission constraints. This study seeks to inform these discussions but does not seek to resolve the questions that underlie them.

Further, the transmission system is dynamic. Transmission flows change continuously as load, generation, fuel prices, reliability rules and other factors change. The magnitude, duration and impact of constraints and congestion change by time of day, day of the week, season, and year. Both past experience and expectations for the continued persistence of transmission constraints and congestion should be considered when evaluating solutions.

This study's snapshot of current conditions does not capture the full value that may be provided by mitigating the congestion identified, because congestion solutions typically bring multiple benefits over a long time horizon—such as improved reliability, more efficient generation dispatch, increased usage of variable renewable resources, or lower customer bills (from energy efficiency or other factors) on the load-side of a congested path. For example, one of the most strategically significant aspects of major new transmission projects that is seldom taken into account explicitly in the planning phase is that transmission may serve multiple purposes over a long life – typically 40 years or more. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks, in turn, create real options to use the transmission system in ways that were not originally envisioned. In the past, these unexpected uses have often proven to be highly valuable and in some cases have outweighed the original purposes the transmission enhancement was intended to serve. Past examples have included enabling grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters. The options created by a strong and flexible transmission network are real. These benefits are important and should be recognized in a full assessment of potential solutions.

Moreover, it will not be appropriate to mitigate every transmission constraint or the congestion it causes. One must evaluate whether the benefits of mitigation—in monetary, policy, consumer impact, or other terms—outweigh or otherwise justify the costs involved. Such an evaluation should consider the ever-changing flows over the transmission grid, the length of time needed to design, site and build transmission solutions, transmission's long asset lifetime, and its many benefits over a lengthy time horizon. When the monetary, policy, or adverse consumer consequences of constraints and congestion rise to levels that warrant action, decision- and policy-makers will look at a variety of options to moderate or mitigate these costs, including creation of financial hedging mechanisms for congestion, deployment of energy efficiency or demand response to lower demand, construction of new generation, changes in other market mechanisms or operational rules, and the construction of new transmission facilities. This study does not evaluate or recommend particular solutions.

Indicators of Transmission Constraints and Congestion

Transmission constraints and congestion vary over time and location as a function of many factors, including changes in the patterns of electricity consumption, changes in the relative prices of the fuels and thus generating units used to generate electricity, and changes in the real-time availability of specific grid-related assets (such as power plants or transmission lines). There is also significant variation between and within regions in practices to manage congestion. This means that different kinds of indicators of congestion are relevant.

Some empirical indicators of congestion are:

- Frequent usage by grid operators of transmission loading relief (TLR) or equivalent procedures to mitigate congestion. These procedures typically involve shifting to a different combination of generation and transmission facilities so as to mitigate potential or actual operating security-limit violations while respecting transmission service reservation priorities.
- Frequent or recurrent disparities in wholesale electricity prices across regional markets, as seen in congestion costs reported by Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), differentials in locational marginal prices (LMPs), differentials in forward prices for generation capacity, and differences in prices at wholesale electricity trading “hubs.” For example, in a market operated by an RTO, when low-cost power is fully subscribed, higher cost sources are tapped, and LMP goes up. In such markets, persistent price separation between sub-regions is an indicator of delivery problems from the low-cost to the high-cost sub-regions. RTO markets reflect the economic cost effect of the congestion in the locational marginal prices for the different sub-regions. See Figure ES - 2 for an example of such price disparities across the Midwestern and Northeastern states.[4] It is possible to identify the consistent impacts of a few specific constraint points and congestion hot spots from pricing maps—in particular the Upper Michigan Peninsula, the Delmarva Peninsula, and New Jersey and New York City, and the constraints that follow the Appalachian Mountains from Pennsylvania and western Maryland into Virginia.
- “Queues” of proposed generation projects seeking interconnection studies by relevant regional or sub-regional grid planning authorities are indicators of potential transmission demand. Figure ES - 3 and Figure ES - 4 are maps of interconnection queues.[5] Large queues are not in and of themselves indications that transmission is or will become constrained. In particular, new generation interconnecting on the load-side of a traditionally constrained region may help to relieve congestion. Some proposed projects may never reach commercial viability or finalize interconnection.

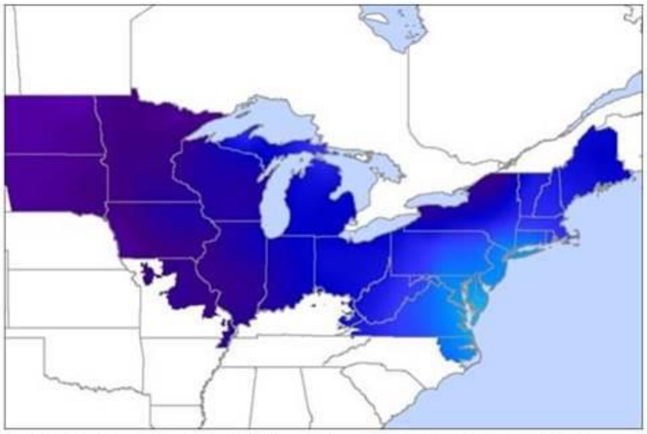
[4] While the four organized markets pictured in these Figures dispatch their regions separately, there is some expectation that trades between systems are made on an economic basis, which makes price patterns spanning these markets relevant to examining potential congestion across seams.

[5] These maps show queues as of 2012, and were developed for the stand-alone companion report, *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, released in January 2014.

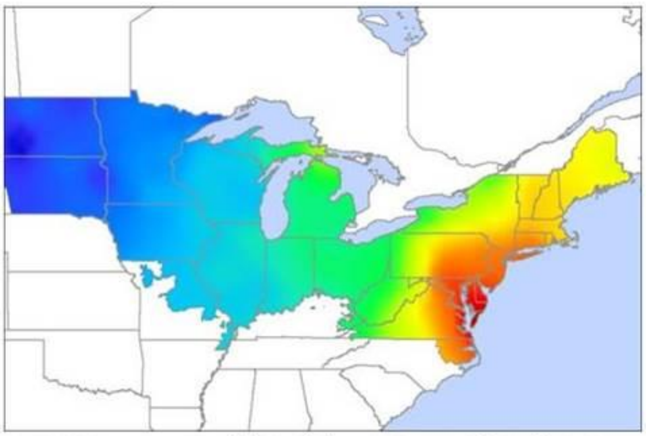
However, when the aggregate capacity in the queue is larger than available or projected transmission capacity connecting it to load regions, it is an indication that transmission may be or will become constrained depending on how many of these projects materialize and how capacity interconnection and energy delivery is pursued.[6]

[6] Generators seeking interconnection are responsible for certain transmission system upgrades, depending on the type of interconnection service they request. (FERC (2003). *Standardization of Generator Interconnection Agreements and Procedures*. Docket No. RM02-1-000; Order No. 2003, July 24, 2003, at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp, p. 23)

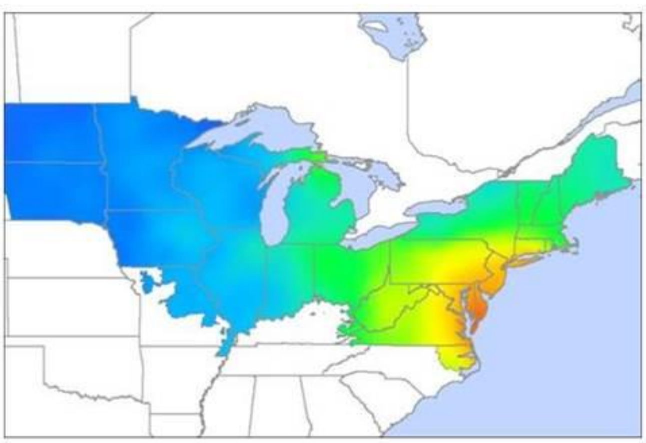
Figure ES - 2. Summer peak LMPs for 2009, 2010, and 2011 ($/MWh)



2009 Summer Peak (Weekdays 3-7 pm, Jul-Sep) LMPs



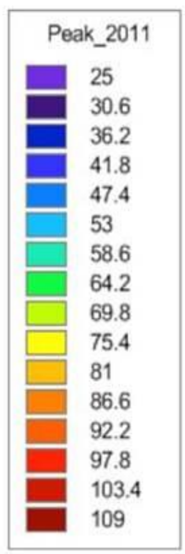
2010 Summer Peak (Weekdays 3-7 pm, Jul-Sep) LMPs



2011 Summer Peak (Weekdays 3-7 pm, Jul-Sep) LMPs

This figure maps average hourly day-ahead LMPs across the MISO, PJM, New York and New England markets for the peak hours of 2009, 2010, and 2011. Peak hours are defined here as non-holiday weekday afternoons (3-7 pm, eastern standard time) July through September. This comparison reveals several points:

- Energy prices are lowest in the western part of the region, where there is extensive low-cost wind and coal generation, and increase to the eastern region, where most of the load is concentrated.
- The highest prices are concentrated in the heavily populated stretch from upper North Carolina through coastal Virginia, Maryland, Pennsylvania, Delaware, New Jersey, New York City, and southwest Connecticut – all areas that have limited supplies of low-cost generation and long-standing transmission constraints to the west across the Appalachian Mountains, although in some cases congestion may be due to planned transmission outages.
- LMPs were highest in 2010 (when natural gas prices were slightly higher and consistently higher temperatures pushed loads very high) and lowest in 2009.



Average hourly LMPs [$/MWh]

Source: Ventyx (2012). "Ventyx Velocity Suite."

Figure ES - 3. Midwest interconnection queue map (created June 2012)

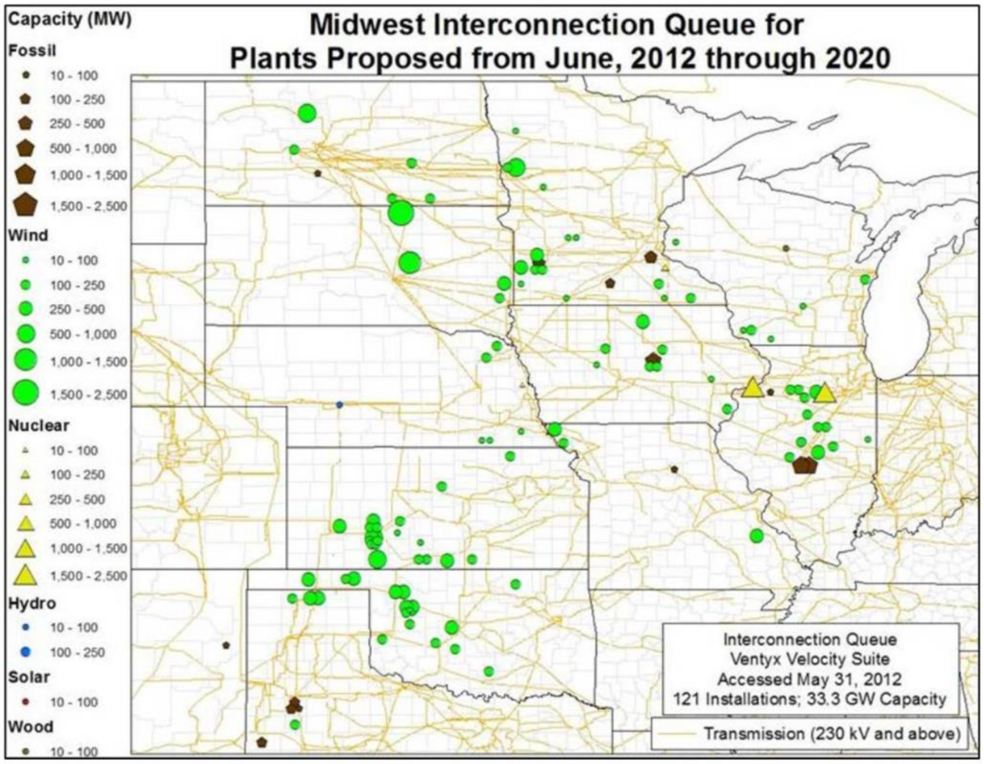
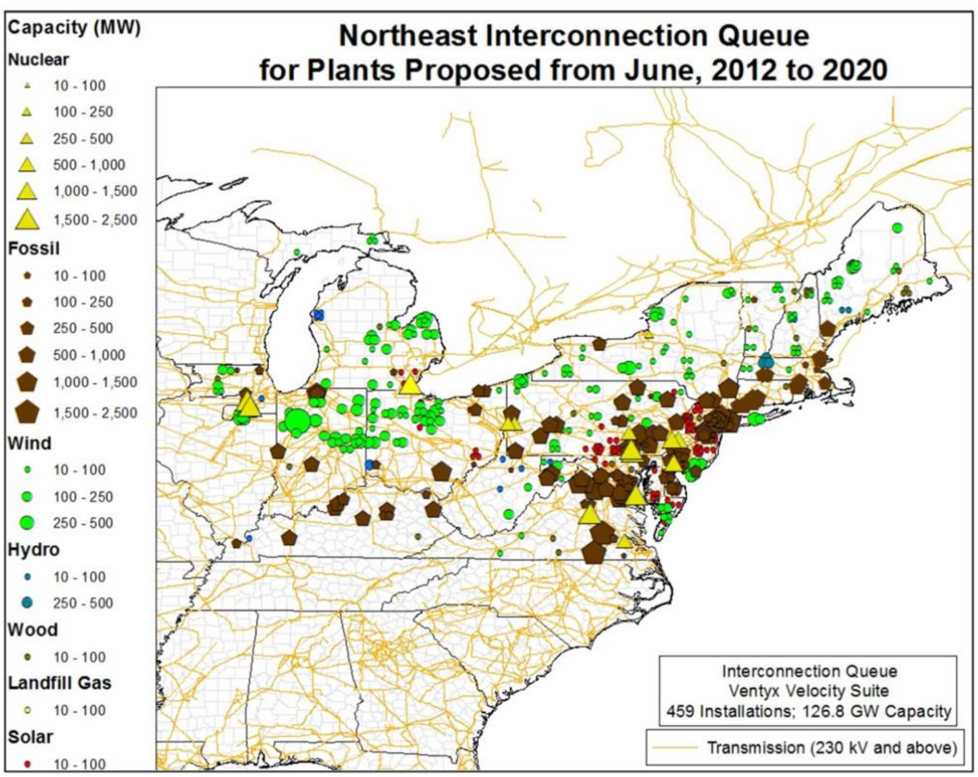


Figure ES - 4. Northeast interconnection queue map (created June 2012)



Recent Nation-Wide Trends Affecting Transmission Constraints and Congestion since the 2009 Congestion Study

Transmission constraints and congestion are influenced by both broad, economy-wide trends or conditions, and unique regional and sometimes local circumstances. The Department found that several broad, nation-wide trends have affected transmission usage patterns since the publication of the 2009 Congestion Study. In most areas, the net effect of these trends has been a reduction in the incidence of congestion and its economic costs. These trends are:

- The economic recession of 2008–2009 reduced electricity demand significantly. In the ensuing economic recovery, electricity demand growth has still been lower than its long-term historical trend, relative to the rate of economic growth. All else equal, lower electricity demand frequently means lower transmission usage and lower congestion.
- State and federal governments and many utilities are implementing policies to improve energy efficiency. These improvements in efficiency put downward pressure on electricity demand across the country. Many utilities, ISOs and RTOs have implemented robust demand response programs to pay loads and reduce consumption during periods of peak demand, which has tended to lower system peak demands and energy consumption, and therefore, to lower congestion.
- Sustained investment in transmission and construction of major new transmission projects in many areas has also helped to reduce congestion.
- Compliance with state renewable portfolio standards (RPSs) and goals has been significant. In response to the RPSs, renewable output has risen sharply. Responsibility for who pays for the transmission to interconnect this new generation has not been definitively settled in all areas. Increased generation from renewables in remote locations, though generally beneficial, is increasing congestion in some areas (between prime resources and load centers). For example, Figure ES - 5 shows the North Dakota Export Limit (NDEX), a long constraint that crosses parts of North Dakota, Minnesota, and South Dakota limiting the flow of major new wind resources out of the constrained area. In other regions, congestion on the high voltage transmission system is less of a concern for interconnection and operation of renewable resources.[7]

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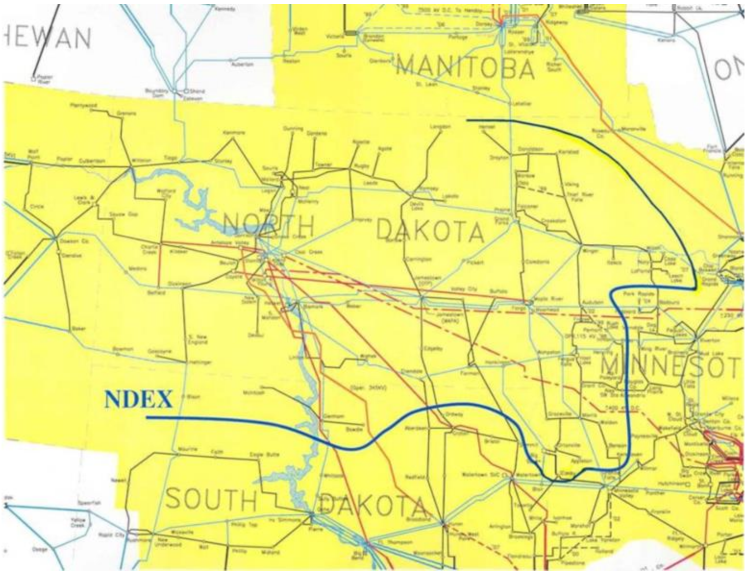
[7] RPSs do not directly require investment in infrastructure. In some regions, like ISO-NE, the owners of the new capacity or Renewable Energy Certificate (REC) marketers are required to ensure adequate transmission capacity to deliver the resources or the load serving entity may make Alternative Compliance Payments, which also serve as a cap on the price of RECs. In other regions, sufficient transmission capacity already exists or is being added based on approved plans. For instance, a NYISO wind study indicates no major high voltage transmission additions would be necessary to accommodate additional wind resources, although certain contingencies and local transmission facilities cause some "bottling" of wind production.
NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Rensselaer, NY: NYISO. September 2010, available at http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf

Figure ES - 5. The North Dakota Export Limit (NDEX)



Source: Lein, J. (North Dakota Public Service Commission) (2011). "U.S. Department of Energy National Electric Transmission Congestion Study Workshop." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops" at http://energy.gov/sites/prod/files/Presentation%20by%20Jerry%20Lein%2C%20ND%20PSC.pdf*, p. 8.*

- Abundant supplies of natural gas at low prices. This trend has had two effects:
  1. Some gas-fired generators are being used more intensively, and some coal-fired generators are being used less intensively. Because gas plants are often sited closer to load centers than the capacity being displaced, transmission usage and congestion patterns shift.
  2. Lower natural gas costs mean somewhat lower overall fuel costs for generation, and lower overall wholesale electricity prices. This means that even if a transmission constraint forces a buyer in a congested area to purchase from an alternate generator, the economic cost premium to the buyer may be lower than previously.
- Recent trends in retirement of both nuclear and coal-fired power plants have been changing transmission flows in many areas of the country.
- New environmental regulations—some still under development—affect the composition and usage of regional generation fleets. As coal-fired and other plants are retired or retrofitted, grid operators will modify dispatch patterns according to the economics of available generation and transmission capacity in relation to fluctuating electricity demand. Appropriate actions will be taken to maintain grid reliability, but congestion may increase or decrease in specific locations.

Regional Findings: Western Interconnection

The Western region contains one organized wholesale electricity market, which is operated by the California Independent System Operator (CAISO); the rest of the Western region consists of vertically integrated utilities, public power entities, and independent generators that trade bilaterally and cooperate for regional planning purposes.[8] There are many common issues across the West, but there is more extensive data availability within the CAISO than elsewhere, so that region is discussed separately in portions of this report. The CAISO serves an estimated 35% of electric load in the western interconnection.[9]

The Department's findings regarding congestion in the West are:

- Although a number of paths in the Western Interconnection are heavily utilized, most of these do not appear to be operating at such consistently high levels that they act as persistent, reliability-threatening transmission constraints. In 2009 (the only year for which data is publicly available), unscheduled flow mitigation procedures were used less than 0.5% of the hours of the year.
- With respect to the economic consequences of congestion, there is only information available about the area covered by CAISO. That information indicates that individual transmission constraints limit system operations in at most 8% of the year, and that these constraints do not increase electric prices and congestion costs by a significant amount.
- There has been a marked increase in transmission construction and project completions across the West over the past three years, and equal progress in planning and coordination of new transmission project proposals. These completions have already improved western transmission throughput, reducing usage on many key interfaces and reducing congestion and associated costs.
- In addition, the permanent closure of the San Onofre Nuclear Generating Station has created some local reliability challenges for Southern California. A preliminary inter-agency plan has proposed several near- and longer-term transmission, resource and regulatory solutions to ensure reliability in this area, and to address existing congestion that was exacerbated by the plant closure.
- Although current congestion in the West is relatively low, in the next few years more congestion is expected due to transmission constraints related to new development of renewable resources and upcoming generator retirements. This is evidenced by WECC's list of Common Case Transmission Projects, which are not yet built or operational, but are assumed to become so within ten years for the purposes of WECC's interconnection-wide planning studies. Congestion resulting from these constraints could be exacerbated by higher demand growth induced by extreme weather or economic activity.

[8] The western provinces of Canada and the northern portion of Mexico are also part of this electrically interconnected system, but they are not included in this analysis.
[9] California ISO (CAISO) (2012e), "The ISO grid," at http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx.

- Many factors make future congestion patterns hard to predict—these complications include the impacts of environmental regulations (both federal and state level), state RPS compliance requirements, the pace of general economic recovery, relative fuel prices for electricity generation, new natural gas, nuclear, and other generation construction, and the feasibility of building long high-voltage transmission lines across federal lands.

Regional Findings: Midwest

The Midwest area contains the Midcontinent ISO (MISO),[10] Southwest Power Pool (SPP),[11] the far western portion of PJM, and some areas that are not part of an RTO or organized wholesale power market. Although the ISOs and RTOs in the Midwest collect data about transmission constraints, congestion costs, and LMPs, these terms are defined and calculated differently in each ISO and RTO. For this reason, transmission constraints and congestion matters are considered on an RTO- or ISO-specific basis.[12]

The Department's findings regarding congestion in the Midwest are:

- Congestion results from high and growing levels of wind generation that cannot be delivered from the western side to more distant, eastern loads, and the lack of additional transmission to enable further development in renewable-rich areas. These factors resulted in higher real-time congestion costs in central MISO.
- Congestion is also due to generation and capacity reserves that are higher in the western and central side of MISO than they are in the eastern part of the Midwest region, increasing west-to-east flows.[13] These factors resulted in higher real-time congestion costs at some locations on the interface between MISO and PJM.
- Congestion is also due to administrative and institutional differences that create "seams" between and among the western RTO/ISOs (MISO, PJM, and SPP) and the eastern RTO/ISOs (PJM and New York ISO via the "Lake Erie Loop"), which lead to loop flows, and pricing and scheduling inconsistencies. These RTOs/ISOs are aware of these issues and in many cases are actively working to address them.
- Real-time congestion costs increased to $1.24 billion for MISO in 2011, up 20% from 2010. In PJM, total congestion costs decreased to $1 billion in 2011, down 30% from 2010.

[10] In April 2013, Midwest ISO changed its name to Midcontinent ISO to reflect its broadening geographic scope.
[11] In 2015, Western Area Power Authority/Basin Integrated System will be joining the SPP.
[12] In this study, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)
[13] Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*. Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p.13.

- Interconnection queues for the Midwest, as of 2012, were dominated by siting requests for wind generation, generally in locations distant from population centers.

Regional Findings: Northeast

The Northeast region includes the footprints of the New York and New England ISOs and the eastern portion of PJM.[14]
The Department's findings regarding congestion in the Northeast are:

- Transmission constraints have limited flows across the Northeast for fewer hours per year (comparing 2009–2011 to 2008 and before).
- Generation and transmission additions across the Northeast in recent years have contributed to lower overall congestion, particularly within New England and PJM.
- Congestion is also down due to lower demand reflecting the economic recession of 2008–2009, aggressive energy efficiency and demand response, lower natural gas prices, and the resulting smaller price differentials between natural gas and competing generation fuels (e.g., coal). This reduces the economic incentive to use transmission to displace electricity from one source with electricity from another source using less costly fuel.
- Congestion costs for NYISO in 2012 were 50% below the $2.6 billion reported in DOE's previous congestion study (2009). Congestion costs for ISO-NE in 2012 were less than 10% of the ~$0.5 billion reported in 2009 by DOE.
- However, some congestion still exists. Much of the congestion that remains in the Northeast reflects three factors:
    - Transmission constraints continue to restrict delivery of power into load centers in central New York and the New York City and Long Island areas.
    - Increased quantities of low-cost onshore wind generation in concentrated locations remote from major load centers are shipped during off-peak hours as "as available capacity," because they exceed the throughput capability of existing transmission facilities. These facilities were designed to meet the on-peak demands of load centers rather than deliver off-peak generation from the remote wind locations.[15]
    - Administrative and institutional issues arising from different market rules, scheduling practices, and transmission reservations hinder more effective use of facilities between neighboring RTOs and ISOs and result in congestion at locations

[14] As mentioned above, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014) *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)

[15] As noted above, increases in remotely-located renewables is not a concern in all regions, e.g. NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Rensselaer, NY: NYISO. September 2010, available from http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf.

along the seams between markets. RTOs and ISOs in the Northeast are aware of these issues and in many cases are actively working to address them.[16]

Regional Findings: Southeast

The Southeast region covers North and South Carolina, Tennessee, Arkansas, Georgia, Alabama, Mississippi, Louisiana, Florida, and parts of (non-ERCOT) Texas. It includes some or all of the NERC regions of SERC (Southeast Reliability Corporation), SPP, and FRCC (Florida Reliability Coordinating Council).

The Department's findings regarding congestion in the Southeast are:

- There are no clear trends in the application of administrative congestion management procedures over the period 2006–2011, with the exception of an increase in level 5 TLRs (the most severe TLR level because it involves curtailment of firm transactions), called by ICTE (Entergy's Independent Coordinator of Transmission).
- There is one report of a persistent transmission constraint within the region.[17]
- As with the portions of the Western Interconnection outside of CAISO, there are no reports on the economic cost of congestion because no organized wholesale electricity markets operate in the Southeast which produce locational marginal prices that reflect differences in production costs due to congestion. Transmission is being built in coordination with generation additions following long-standing planning practices overseen by state and regional protocols.
- Interconnection queues indicate that future generation will consist largely of fossil-fuel and nuclear generation in Georgia, Alabama, and Florida, wind generation in the western part of the interconnection and in Tennessee, and solar in Florida.

The Need for Better Transmission Data

Table ES - 1 summarizes the main sources of information relied on to develop the transmission constraints and congestion data and to develop the findings presented in this report. Despite widespread agreement on the strategic importance of electric transmission infrastructure—to our economy, our quality of life, and our national security—there is little comprehensive, consistent information available on transmission usage, congestion and its economic consequences, or transmission investment. Transmission Open Access and the formation of ISOs and RTOs over the past two decades have dramatically increased the transparency of planning and operations information in various areas of the country. However, certain challenges remain. In particular:

[16] For instance, the development of Coordinated Transaction Scheduling between ISO-NE and NYISO, which will be described in more detail below. While FERC permits regional differences in strategies for system operations and market rules, FERC generally encourages coordination between different regions to support economically efficient trade. See, e,g., The Energy Daily (2013b). "FERC steps into 'seams' fight between MISO, PJM." December 23, 2013; The Energy Daily (2014). "FERC moves to defuse mushrooming SPP-MISO fight." April 1, 2014.

[17] Florida Municipal Power Agency (FMPA) submitted comments on the draft study that the Florida-Georgia interface is constrained. FMPA also provided information on OASIS service queues and available transmission capacity.

- Data are not available uniformly across the country. The most evident differences reflect the fact that portions of the country use organized and transparent markets to manage transmission system use, while others use administrative, non-public means. While there is a great deal of publicly available data on constraints and congestion within the regions with organized markets (i.e., CAISO, ISO-NE, MISO, NYISO, PJM, and SPP), the non-RTO/ISO regions have different methods for managing congestion and thus different kinds of data are available.
- Due to organizational or market-specific practices, each RTO and ISO has its own definitions, conventions, and practices for how LMPs and annual congestion costs are calculated and presented to the public. Similarly, differences in regional practices affect whether and how administrative congestion management procedures, such as unscheduled flow mitigations (UFMs) and TLRs, are used to manage transmission scheduling conflicts in operations.
- Data and practices can change over time, limiting trend assessment. The California ISO, for example, changed its market design in 2009, so pre-2009 market information is not directly comparable to later information. The PJM Interconnection's footprint expanded dramatically in 2004, creating another data discontinuity. Data comparisons and trend analysis must recognize and account for fundamental changes in a region's market organization and operation.

These issues make it difficult to compare transmission infrastructure availability, usage, investment, constraints, and congestion on a nation-wide basis. The discrepancies in data are of particular concern when the data cannot be compared among neighboring regions within the same interconnection; the impact of changes in one region on its connected neighbors cannot be correctly identified if the data are not comparable. Moreover, the data shared among regions within the same interconnection do not always follow the same database definitions. This makes it difficult to ensure that studies conducted by different parties are using the same nomenclature, models, connectivity, control settings, etc. for the same equipment, and makes it more likely that neighboring regions will produce conflicting analytical results.

Public Comment on the Draft Congestion Study

In the fall of 2014, the Department invited public comment on the draft Congestion Study with reference to several specific questions.[18] The questions on which the Department requested input, the other topics on which comments were provided, and the conclusions reached by the Department are summarized below.

In the draft study, the Department said that it

[18] The Department received a total of 97 public comments on the draft study, from 13 organizations and 82 individuals. The entities and individuals submitting these comments are listed in the appendices to this report and their comments are on posted on the Department's website http://www.energy.gov/oe/public-comments-received-draft-congestion-study. In addition, in its consultation with states and regional reliability entities, the Department received 13 comments addressed to its three questions.

> *… is particularly interested in comments on the reliance on publicly available data to assess congestion and transmission constraints. In Chapter 3 this study discusses the limitations of available data and indicates actions the Department intends to take to improve data quality and availability in the future. The Department invites comments on these plans, insight into whether such data would have value for other parties, and comment on possible issues relating to the collection and public availability of the targeted data.*

After reviewing and considering the public comments, the Department's findings and conclusions regarding data are:

(1) The Department concludes that relying on publicly available data is appropriate and necessary for the preparation of its Congestion Studies. Doing so ensures transparency in the Department's analysis and would help to address questions that would likely arise in the event the Department seeks to designate National Corridors based on the findings of such analyses. Accordingly, the Department will continue to rely on publicly available data to assess transmission congestion and constraints in future congestion studies. It will, however, also consider incorporating previously non-public data in future studies, if the source agrees to make the data public via their inclusion in the study.

(2) The Department agrees that some additional public information was available on topics relevant to the study, and that the information was not included in the initial draft study. As noted below, additional data or information provided to the Department through the comment process has either been incorporated into the final study or will be considered by future congestion studies.

(3) The Department will continue to work with stakeholders to refine existing or new sources of publicly available data, in part through the vehicle of DOE's new annual *Transmission Data Review*.

In the draft study, the Department also invited comments on two questions related to the usefulness of the Congestion Studies and National Corridors:

> *Do the Congestion Studies continue to serve a useful purpose in informing the national discussion of transmission infrastructure needs? Should the scope and process for conducting such studies be modified to better serve this objective?*
> *Does the possible designation of National Corridors, under the statutory language as presently written and interpreted by the courts, help to ensure that adequate and appropriate transmission infrastructure is built in a timely manner? Should the concept of such corridors, or the process for their designation be modified to better serve this objective?*

After reviewing and considering the public comments, the Department's conclusions concerning the usefulness of triennial Congestion Studies are:

(1) Publication by DOE of an annual *Transmission Data Review* should be continued, as a means of making transmission data and information available to the public on a timely basis.

(2) Triennial Congestion Studies can serve a useful purpose other than providing a basis for designation of National Corridors, by focusing national attention on aspects of transmission infrastructure that may warrant other forms of federal attention and action.

(3) The Department recognizes that future Congestion Studies should be coordinated with regional transmission planning efforts, including those mandated by FERC Order No. 1000, and that some of these efforts are still being developed.

The Department's responses to comments concerning the designation of National Corridors will be presented in a separate document, *Report by the U.S. Department of Energy Concerning Designation of National Interest Electric Transmission Corridors* (forthcoming).

The Department also received and considered comments on a number of other topics related to the draft study. The Department's responses to these comments are:

(1) The suggestions for edits, corrections, and clarifications in the draft study have been considered and in most cases incorporated into the final study.

(2) The suggestions for improving future congestion studies are generally reasonable and will be taken into consideration when the Department prepares its next Congestion Study.

Finally, the Department received a number of comments on topics related to transmission development and construction. After considering these comments, the Department's responses to these comments are:

(1) Some of these comments refer to ways to improve the content of future Congestion Studies and the Department will take them into account in preparing future studies.

(2) Some of these comments, such as those pertaining to the use of eminent domain, burdens associated with easements, federal or state laws, regulations or policies concerning energy resource development are outside the scope of this Congestion Study.

Table ES - 1.Transmission Constraints and Congestion—Applicability and Availability of Major Sources of Data

	Congestion Management					Resource-Driven Transmission Constraints			Transmission System Utilization
	Administrative Procedures	**Operationally Limiting Constraints**	**Economic Congestion Cost**	**Locational Marginal Prices**	**Wholesale Electricity Price Differentials**	**Local Reliability**	**Interconnection Queue**	**Renewable or Clean Energy Zone[a]**	**% Utilization[b]**
					West				
Non-RTO	WECC/ TEPPC	Not applicable	Not applicable	Not applicable	FERC	NERC	WECC	WGA	WECC/ TEPPC
CAISO	WECC/ TEPPC	CAISO	CAISO	CAISO	FERC	NERC	WECC	WGA	WECC/ TEPPC
					Midwest				
MISO	NERC	MISO	MISO	MISO	FERC	NERC	MISO	Not available; in progress	Not available
SPP	NERC	SPP	SPP	SPP	FERC	NERC	SPP	Not available; in progress	Not available
PJM	WECC/ TEPPC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
Non-RTO	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available
					Northeast				
ISO-NE	NERC	ISO-NE	ISO-NE	ISO-NE	FERC	NERC	ISO-NE	Not available; in progress	ISO-NE Planning Advisory Committee
NYISO	NERC	NYISO	NYISO	NYISO	FERC	NERC	NYISO	Not available; in progress	Not available
PJM	NERC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
					Southeast				
SERC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available
FRCC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available

Note: WGA = Western Governors Association; cells highlighted in green denote a parameter and source for which information has been gathered for this study.

Source: US DOE (2014). Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012, Jan 2014.

[a] In the Eastern Interconnection several regional renewable or clean energy studies have been undertaken; however no interconnection-wide study on this subject has been completed to date. The Eastern Interconnection States Planning Council has provided conceptual support and other inputs to the development of a Clean Energy Zones mapping tool by Argonne National Laboratory.

[b] Transmission utilization information is available for some specific regions in the Eastern Interconnection, but not for the entire interconnection.

National Electric Transmission Congestion Study

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1. Legislative Language

This report responds to legislative language set forth in the Energy Policy Act of 2005 (EPAct), which added section 216(a) to the Federal Power Act (FPA), which directs the Secretary of Energy to "conduct a study of electric transmission congestion" by August 2006 and every three years thereafter. These studies are to identify transmission congestion in the Eastern and Western Interconnections. The FPA specifically excludes the geographic area covered by the Electric Reliability Council of Texas (ERCOT) from the studies.[19]

Further, the FPA specifies that, based on the congestion study, and comments from states and other stakeholders, the Secretary:

> *…shall issue a report…, which may designate any geographic area experiencing electricity transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor" (National Corridor).*[20]

In determining whether to designate an area as a National Corridor, the Secretary may consider whether:

> *A. The economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;*
> *B. (i) Economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted;*
> *C. The energy independence of the United States would be served by the designation;*
> *D. The designation would be in the interest of national energy policy; and*
> *E. The designation would enhance national defense and homeland security.*[21]

Designation of an area as a National Corridor is one of several preconditions required for possible exercise by the Federal Energy Regulatory Commission (FERC) of "backstop" authority to approve the siting of transmission facilities in that area. (See text box on page 8 for details on these preconditions.)

This study identifies geographic areas that are currently experiencing transmission capacity constraints and congestion, and presents information on the nature and magnitude of these constraints and congestion. To the extent feasible, the information is presented relative to the above statutory considerations. This study, however, does not propose or recommend the designation of National Corridors. The Department may take additional steps at a later date to designate National Corridors through actions distinct from the publication of this study.

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[19] *ibid* § 824p(k).
[20] *ibid* § 824p(a)(2).
[21] *ibid* § 824p.

2. Introduction and Overview

Congestion occurs on the electric transmission system when flows of electricity across a portion of the system are restricted or constrained below desired levels. The term "transmission constraint"[22] refers either to a piece of equipment or an operational limit imposed to protect reliability that restricts these flows, or to a lack of adequate transmission capacity to deliver expected new sources of generation without violating reliability rules. Because power purchasers generally seek to buy the least expensive electricity available, transmission constraints impose real economic (or congestion) costs upon electricity consumers when they limit the amount of lower cost electricity that can be delivered. In the instances where transmission constraints are so severe that they prevent or limit the deliverability of electricity, grid-related public policies may be compromised and grid reliability may be threatened.

Transmission constraints and congestion vary over time and location as a function of many factors, including changes in the patterns of electricity consumption, changes in the relative prices of the fuels used to generate electricity, and changes in the availability of specific grid-related assets (such as power plants or transmission lines). This analysis focuses on recurrent and significant trends—i.e., areas where transmission constraints and congestion are frequent, *and* lead to increases in electricity costs to consumers or hinder the realization of grid-related public policy objectives, such as supply diversity, environmental protection, or increased reliance on renewable generation resources. It also notes where constraints have become less severe and congestion has abated in cost and magnitude.

This study identifies (to the extent supported by publicly available data as of 2012, with limited updates in December 2013) where transmission constraints and congestion occur across the eastern and western portions of the United States' electric power system. All of the conclusions presented in this study are based on (and limited to) data published in a companion report released by the Department in early 2014.[23] The Department of Energy does not endorse and has not independently validated the data and analyses compiled and reported in these studies. DOE is unable to examine constraints and congestion in certain parts of the country due to the lack of public data.

[22] "Transmission constraint," "transmission capacity constraint," or simply "constraint" are typically used interchangeably in electricity literature, and are so used in this report.

[23] United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.

2.1. Differences between this study and previous congestion studies

This Congestion Study differs from previous studies in the manner in which state consultation has been sought throughout the preparation of the study,[24] the nature and focus of the assessment of congestion that is presented, and the exclusive reliance on publicly available data.

In this study, as in the preparation of the 2009 Congestion Study, the Department began by issuing a notice in the *Federal Register*,[25] and announced that it would host a series of pre-study workshops with the states and other stakeholder groups to discuss the initiation of the current Congestion Study. At each workshop, the Department presented its study plan and invited comments on the plan and suggestions about relevant analyses, databases, state or utility programs, etc. that the Department should review as input to the study.[26]

The Department sent letters with the workshop announcement to all states inviting participation and comment. The letters extended an offer to meet privately with state officials, by request, either as part of the workshops or via an open invitation to meet at any point during the preparation of the current Congestion Study.

For this Congestion Study, the Department created additional opportunities for consultation with the states. It presented and sought comment on the study process and initial findings at the National Association of Regulatory Utility Commissioners (NARUC) Summer Meeting in July 2012 and through webinars for state officials in August 2012. In addition, the Department circulated a consultation draft of the Congestion Study to the states and regional reliability entities in January 2014. After reviewing and considering comments and suggestions concerning the consultation draft, the Department prepared and released a draft of the Congestion Study for public comment. After reviewing and considering the public comments, the Department has released this final version of the current Congestion Study, in which it has responded to the comments received.

[24] In *California Wilderness Coalition v. U.S. Department of Energy*, 631 F.3d 1072 (9th Cir. 2011), the Ninth Circuit of the U.S. Court of Appeals vacated the 2006 Congestion Study after finding that the Department did not adequately consult with states in the preparation of the study.

[25] United States Department of Energy (2011f*). 76 FR 70122 - Plan for Conduct of 2012 Electric Transmission Congestion Study*. Federal Register volume 76, Issue 218. November 10, 2011, at http://www.gpo.gov/fdsys/search/pagedetails.action?granuleId=2011-29189&packageId=FR-2011-11-10&acCode=FR.

[26] Appendix A contains the agendas and lists of participants at the four public workshops conducted in December 2011 to initiate the current study. Appendix D lists the entities that provided comments during the public comment period, which ended in January 2012.

Prerequisite Conditions for FERC to Exercise its Authority to Site Transmission Facilities in National Corridors

After the Department of Energy has designated a National Interest Electric Transmission Corridor pursuant to the Federal Power Act, if a transmission project developer seeks state permit and siting approval within the area covered by the Corridor, then FERC "may, after notice and an opportunity for hearing, issue one or more permits for the construction of modification of electric transmission facilities in a national interest electric transmission corridor designated by the Secretary under subsection (a)," if FERC finds that:

(1)(A) A State in which the transmission facilities are to be constructed or modified does not have authority to--
- (i) approve the siting of the facilities; or
- (ii) consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the State;

(B) The applicant for a permit is a transmitting utility under this Act but does not qualify to apply for a permit or siting approval for the proposed project in a State because the applicant does not serve end-use customers in the State; or

(C) A State commission or other entity that has authority to approve the siting of the facilities has—
- (i) withheld approval for more than 1 year after the filing of an application seeking approval pursuant to applicable law or 1 year after the designation of the relevant national interest electric transmission corridor, whichever is later; or
- (ii) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible;

(2) The facilities to be authorized by the permit will be used for the transmission of electric energy in interstate commerce;

(3) The proposed construction or modification is consistent with the public interest;

(4) The proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers;

(5) The proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and

(6) The proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.

Source: Federal Power Act, 16 U.S.C. § 824p(b).

The assessment presented in this Congestion Study consists of information on recent instances of transmission constraints and congestion and, where feasible, their implications for the statutory considerations regarding National Corridors cited above. The study focuses specifically on what can be said at present based on the information presently available. It does not draw conclusions pertaining to broad regional areas.[27] In contrast to prior DOE congestion studies, this study does not identify "critical congestion areas," "congestion areas of concern," or "conditional congestion areas."

The current Congestion Study is based on publicly available analyses and data available through 2012 (with limited updates in 2013 and in response to comments submitted during the public comment period that closed October 20, 2014).[28] It recognizes that there are gaps or deficiencies in publicly available data and differences among regions regarding how certain terms are defined and data pertaining to them are reported. The study discusses how these gaps and differences have affected the Department's assessment. It also makes recommendations to improve the availability and consistency of data needed to, among other things, conduct future congestion studies.

The transmission constraints and congestion identified in this study represent a snapshot in time that is dependent on available information.[29] Recognizing the changeability of circumstances and information, Congress directed the Department to conduct a congestion study every three years. Thus, in 2015 the Department will issue a fresh study of transmission constraints and congestion impacts. In addition, the Department will work with the Energy Information Administration (EIA) and FERC to prepare an annual Transmission Data Review, presenting publicly available data and information on transmission matters, including congestion.

[27] This point is illustrated by statements made by Edward Finley of the North Carolina Utilities Commission at the DOE workshop for the 2012 congestion study: "The EISPC [Eastern Interconnection States' Planning Council] effort and the DOE Congestion Study are, in my opinion, two practically unrelated activities. EISPC has been working to define three scenarios of what the electric grid might be and might be needed in the 20-year horizon. DOE's Congestion Study is to address transmission congestion that is occurring right now, in our opinion a very different task." E. Finley. (North Carolina Utilities Commission) (2011). "Comments of the North Carolina Utilities Commission." Presented at the U.S. Department of Energy, National Electric Transmission Congestion Workshop, Philadelphia, PA, December 6, 2011, at http://energy.gov/sites/prod/files/Presentation%20by%20Edward%20Finley%2C%20%20NCUC.pdf.

[28] United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.

[29] This approach is reflective of several recommendations from state officials, including the New England States Committee on Electricity, which commented, "… future scenarios, whether EIPC [Eastern Interconnection Planning Council] or others, are not and should not be viewed as reasonable proxies for the presence of congestion." (New England States Committee on Electricity (NESCOE) (2012)). "New England States' Comments on Preparation of the 2012 Congestion Study", January 31, 2012, at http://energy.gov/sites/prod/files/New%20England%20States%20Committee%20on%20Electricity%20-%20Comments%20to%20the%202012%20Congestion%20Study.pdf.

2.2. This study does not make recommendations to resolve transmission constraints and congestion

Separate from and after publication of this Congestion Study, the Department may propose one or more National Corridors. Any proposed National Corridor would then become the subject of an environmental analysis as required by the National Environmental Policy Act (NEPA). No final decision on the designation of a National Corridor would be made until after the completion of the environmental analysis.

This study's assessment of transmission constraints and congestion does not address whether or how to fix constraints or the congestion they cause. The presence of transmission congestion reflects only a desire or demand for increased transmission system utilization.

Whether it is appropriate to mitigate transmission congestion requires information and judgment about the purposes or objectives that would be served. For example, increased flow of electricity from lower-cost generation sources could reduce the overall cost of supplying electricity to consumers, while increased flow of electricity from remote renewable generation could help meet state energy policy goals. The point is that determining whether to address congestion requires determining first what objectives would be met by doing so. These objectives may conflict. For example, depending on its location, new generation could create new transmission congestion and raise costs, at the same time that it helps to satisfy a renewable energy policy goal. The differing objectives relative to transmission congestion should be recognized in determining whether and how to relieve transmission constraints. This study seeks to inform these discussions but does not seek to resolve the questions that underlie them.

An important reason why this study's assessment of current constraints and congestion cannot resolve these conflicts is that the transmission system is dynamic. Transmission flows change continuously as load, generation, fuel prices, reliability rules, and other factors change. The magnitude, duration and impact of constraints and congestion change by time of day, day of the week, season, and year. Both past experiences and expectations for the continued persistence of transmission constraints and congestion should also be considered when evaluating solutions.

This study's assessment of current conditions does not capture the full value that may be provided by mitigating the congestion identified; congestion solutions typically bring multiple benefits over a long time horizon—such as reliability improvement, more efficient generation dispatch, increased use of variable renewable resources, or lower customer bills (from energy efficiency or other factors) on the load-side of a congested path—beyond the congestion reduction benefit. These benefits are important and should be recognized in a full assessment of potential solutions.

Moreover, it will not be appropriate to mitigate every transmission constraint or the congestion it causes. One must evaluate whether the benefits of mitigation—in monetary, policy, consumer impact, or other terms—outweigh or otherwise justify the costs involved. Such an evaluation should consider the ever-changing flows over the transmission grid, the length of time needed to design, site and build transmission solutions, the long lives of transmission assets, and transmission's many benefits over a lengthy time horizon.

When the monetary, policy, or adverse consumer consequences of constraints and congestion rise to levels that warrant action, decision- and policy-makers will look at a variety of options to moderate or mitigate these costs, including creation of financial hedging mechanisms for congestion, deployment of energy efficiency or demand response to lower demand, construction of new generation, changes in other market mechanisms or operational rules, and the construction of new transmission facilities. Most of these options are under state regulatory jurisdiction. This study does not recommend particular solutions.

Construction of major new transmission facilities, in particular, raises unique issues because transmission facilities have long lives—typically 40 years or more. Evaluating the merits of a proposed new facility is challenging, because common practices take into account only those expected costs and benefits from a project that can be quantified with a high degree of perceived certainty. This has two effects:

First, it leads to a focus on the subset of cost and benefits that can be readily quantified. Not taking into account the costs and benefits that are hard to quantify has the effect of setting their value to zero in a comparison of costs and benefits.

Second, common practices to forecast costs and benefits are generally based upon extrapolations drawn from recent experiences. Projections based only on recent experiences will not value the costs and benefits a transmission project under varying assumptions or scenarios regarding the future because they ignore or discount the likelihood of these possibilities. Such a narrow view of the range of transmission costs and benefits provides a false and limiting sense of precision.

For example, major new transmission projects serve multiple purposes that are not always recognized or quantified in planning. While a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B, it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks, in turn, create real options to use the transmission system in ways that were not originally envisioned. To date, these unexpected uses have often proven to be highly valuable and in some cases have outweighed the original purposes the transmission enhancement was intended to serve. Some of the transmission benefits that have not been quantified in prior transmission planning exercises are that the expanded grid enables grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters. The options created by a strong and flexible transmission network are real. Failure to take explicit account of these options in the planning process will severely understate the potential value of transmission projects.

2.3. Overview of the current Congestion Study

This Congestion Study consists of five chapters following the two introductory chapters.

Chapter 3 describes the approach used by the Department to conduct this Congestion Study, including a review of transmission constraint and congestion concepts that are fundamental to the study. The chapter also provides an overview of the publicly available sources of data used in this analysis, and discusses ways to improve the public availability of data for future analyses of transmission constraints and congestion.

Chapter 4 reviews recent national developments that affect transmission constraints and congestion across the major regions of the country. This discussion provides a context for the region-specific findings presented in subsequent chapters.

Chapter 5 assesses transmission constraints and congestion in the Western Interconnection. It provides an overview of transmission usage trends in the region. This discussion links the national trends of Chapter 4 to the regional characteristics of the West. The chapter concludes with a description of infrastructure updates and investment since the previous congestion study.

Chapter 6 assesses transmission constraints and congestion in the Eastern Interconnection. Given the larger size and more complicated structure of the Eastern Interconnection, Chapter 6 also discusses the interconnection in terms of three regions: the Midwest, the Northeast, and the Southeast. The discussions follow the same structure as Chapter 5.

Chapter 7 provides information about comments sought by the Department and its responses to the comments received, and describes the Department's next steps regarding the possible designation of National Corridors.

Five appendices follow: Appendix A contains the agendas and lists of participants of the four public workshops conducted in December 2011 to initiate the present study. Appendix B lists the entities that submitted comments to the DOE website. Appendix C lists the entities submitting comments to DOE through the Consultation Process. Appendix D lists the entities and individuals who provided comments during the public comment period, which ended in January 2012. Appendix E lists all the references that were reviewed in preparing this study.

3. Transmission Constraints and Congestion: Concepts, Measurement, and Sources of Publicly Available Data

This chapter describes the methods and approaches used by the Department to conduct this Congestion Study. It begins by reviewing transmission constraint and congestion concepts that are fundamental to the study. Next it describes the measures or indicators the Department has used to identify, characterize, and gauge the impacts of current transmission constraints and congestion. The chapter concludes by reviewing the data used in this analysis, and discusses ways to improve the data available for future assessments of transmission constraints and congestion. The Department has defined these terms based on industry practices, but has done so narrowly for the purpose of this study to ensure that they are used consistently herein. Instances where these terms have been used differently in particular industry sources relied on by the study are flagged, when appropriate.

3.1. Transmission constraint and congestion concepts

Transmission constraints and congestion are related but distinctly different concepts. The term "transmission constraint" may refer to:

(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;

(2) An operational limit imposed on an element (or group of elements) to protect reliability; or

(3) The lack of adequate transmission system capacity to deliver electricity from potential sources of generation (either from new sources or re-routed flows from existing sources when other plants are retired) without violating reliability rules.

Transmission constraints, as defined above in (1), are a result of many factors including load level, generation dispatch, and facility outages. Jointly, these conditions establish a specific level or limit—as in (2)—to the permissible flow over the affected element(s), in order to comply with reliability rules and standards established to ensure that the grid is operated in a safe and secure manner. Reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by FERC specify how equipment or facility ratings should be calculated to avoid exceeding thermal, voltage, and stability limits following credible contingencies. Transmission operating limits, which constrain throughput on affected transmission elements, are created to comply with these rules and practices. Thus, although it is commonly thought that transmission constraints indicate reliability problems, in fact, constraints result from compliance with reliability rules. However, when constraints frequently limit desired flows, or when these limits are violated so as not to shed firm load, they may indicate reliability problems that warrant mitigation.

Transmission constraints can be relieved by increasing the electrical rating of an element, increasing the operating limit, or adding new equipment that increases transmission capacity to deliver additional electricity. However, relieving transmission constraints to increase transmission flows requires consideration of the transmission network as a system. For example, while increasing the electrical rating of a particular element may relieve a particular constraint, doing so may only shift the location of the constraint to the next most limiting element such that the net increase in transmission flow along the entire route may be only marginal.

Transmission constraints also can be relieved by changing generation dispatch, changing the operation of the transmission system, or by adding generation or reducing load on the "downstream" side of the constraint.

The term "congestion" refers to situations when transmission constraints reduce transmission flows or throughput[30] below levels desired by market participants or government policy (e.g., to comply with reliability rules). A high degree or level of transmission system utilization alone does not necessarily mean congestion is occurring. Congestion can only arise when there is a desire to increase throughput across a transmission path, but such higher utilization is thwarted by one or more constraints. Transmission congestion has costs—they include higher costs incurred by consumers on the downstream side of the transmission constraint, and difficulties achieving policy goals such as increased reliance on renewable generation resources. Transmission congestion may also cause reliability problems where such constraints impact operations by limiting access to reserves.

3.2. DOE's assessment of transmission constraints and congestion

The statutory language directing the Department to prepare triennial congestion studies does not define or detail what aspects or consequences of transmission constraints and congestion are to be studied. However, the language concerning designation of National Corridors offers guidance on aspects of transmission constraints and congestion that are important for purposes of corridor designation.

The FPA specifies that if the Department wishes to designate a geographic area as a National Corridor, it must issue a "report" based on the Congestion Study in which it finds that the identified transmission constraints or congestion "adversely affects consumers." The statute allows the Secretary, when determining whether the constraints or congestion support the designation of a National Corridor, to consider economic vitality, economic growth, energy

[30] Throughout this study, the terms "transmission flows" and "transmission throughput" are used interchangeably to refer to the transport of electricity over transmission lines.

independence, national energy policy, national defense, and homeland security.[31] Many of these factors provide a frame of reference for determining which aspects of transmission constraints and congestion should be the focus of this study.

The Department's assessment of the significance of transmission constraints and congestion is based exclusively on data that are publicly available and as much as possible upon quantitative indicators. This study, therefore, gives particular attention to economic and public policy-related aspects of transmission constraints and congestion because these aspects are the most apparent in data that are both publicly available and can be meaningfully quantified. Indicators for factors such as the national security impacts of a transmission constraint are difficult to find in the public record; while such needs may exist, absent public data, DOE does not address national security impacts in this study.

3.3. Summary of publicly available data on transmission constraints and congestion, and data issues the Department intends to address

All of the data and information used in the preparation of this study are publicly available. Table 3 - 1 summarizes the main sources of information relied on to develop the transmission constraints and congestion data and to develop the findings presented in this report. All data sources and other references reviewed in preparing this study are listed in Appendix E. This section discusses several issues associated with availability and utilization of publicly available data on transmission constraints and congestion and how they have affected the preparation of this study.

- First, data are not available uniformly across the country. The most evident differences reflect the fact that portions of the country use organized and transparent markets to manage transmission system use, while others use administrative, non-public means. While there is a great deal of publicly available data on constraints and congestion within the regions with organized markets (i.e., CAISO, ISO-NE, MISO, NYISO, PJM, and SPP), the non-RTO/ISO regions have different kinds of data available.
- Second, data that may appear at first glance to be comparable may differ upon closer examination due to organizational or market-specific practices. Each RTO and ISO has its own definitions, conventions, and practices for how locational marginal prices (LMPs) and annual congestion costs are calculated and presented to the public. Similarly, differences in regional practices affect whether and how administrative congestion management tools, such as Unscheduled Flow Mitigation and Transmission Loading Relief procedures, are used to manage transmission scheduling conflicts in operations.
- Third, data and practices can change over time, limiting comparability and trend assessment. The California ISO, for example, changed its market design in 2009, so pre-2009 market information is not directly comparable to later information. PJM's footprint

[31] Federal Power Act, 16 U.S.C. § 824p(a)(2) & (4). See also section I.

expanded dramatically in 2004, creating another data discontinuity. Data comparisons and trend analysis must recognize and account for fundamental changes in a region's market organization and operation.

The issues above make it difficult to compare measures of transmission infrastructure availability, usage, investment, constraints, and congestion on a nation-wide basis. This discrepancy in data is of particular concern when the data cannot be compared among neighboring regions within the same interconnection; the impact of changes in one region on its connected neighbors cannot be correctly identified if the data are not comparable. Moreover, the data shared among regions within the same interconnection do not always follow the same database definitions (e.g., a common information model like Europe's CIM). This makes it difficult to ensure that studies conducted by different parties are using the same nomenclature, models, connectivity, control settings, etc. for the same equipment, and makes it more likely that neighboring regions will produce conflicting analytical results.

These particular congestion-related data challenges, however, are only part of a broader set of data problems pertaining to the regulation and management of this vital but changing industry. The planners and operators of tomorrow's electricity systems will have to deal with many new challenges and complexities, such as:

- Integration of increasing amounts of variable renewable generation resources and demand response resources.
- The retirement of some coal plants and the sources of generation that will replace them.
- Projecting future load trends, given new energy efficiency technologies, rising deployment of roof-top photovoltaics and other forms of distributed generation, and changes in the composition of economic activity.
- The need to enable and support multi-directional flows of energy and information across these networks.[32]
- The emergence of consumers and consumer-owned equipment as active agents on the networks.
- The need for new system control software, analytic models, and other tools that will enable operators to better visualize their current situation, flag trends or events of concern, and take timely countermeasures.[33]
- The need to design cyber security into the architecture of these systems.

[32] Currently some multidirectional power flows do occur; however, as multidirectional flows increase or occur in new places or times, planning and operating issues arise and must be addressed.
[33] These tools are needed for the interface between electric and gas systems, as well as for the electricity system itself.

Development and deployment of the tools and capabilities needed to address these challenges will require the collection, validation, and sharing of many kinds of data that are not readily available today. The Department believes that new authorization may assist in structuring and guiding this data collection and data-sharing process, and is considering the development of a proposal on this subject. The types of data that could be covered in such a proposal include:

- Flow and capability (rating) data for consistently defined and monitored flowgates, interfaces, or paths within regions and across seams, considering the implications of potential system changes over time.
- Definitive source and contact information for modeling and physical data for bulk power system facilities.
- Operational limits of critical 230 kV+ facilities which are rated below conductor emergency loading capabilities and transformer, circuit breaker and other equipment nameplate ratings.
- Price spreads between nodes across existing seams, especially for those that are geographically close but electrically distant.
- Identification of system capability not shown in model data, e.g., facilities designed for higher capability (unused circuit positions or right-of-ways, operating voltage less than design voltage).
- Remaining life (condition) of critical facilities.
- Unique substation identification based on industry-adopted standardized naming conventions with GIS coordinates for bulk power facilities to ensure consistency across various applications and tools.
- Consistent and publicly accessible data concerning proposed generation capacity in interconnection queues, as well as expected retirements, de-rates, and outages to enable retrofits of existing resources.

Table 3 - 1. Transmission constraints and congestion: applicability and availability of major sources of data

	Congestion Management					Resource-Driven Transmission Constraints			Transmission System Utilization
	Administrative Procedures	Operationally Limiting Constraints	Economic Congestion Cost	Locational Marginal Prices	Wholesale Electricity Price Differentials	Local Reliability	Interconnection Queue	Renewable or Clean Energy Zone[a]	% Utilization[b]
					West				
Non-RTO	WECC/ TEPPC	Not applicable	Not applicable	Not applicable	FERC	NERC	WECC	WGA	WECC/ TEPPC
CAISO	WECC/ TEPPC	CAISO	CAISO	CAISO	FERC	NERC	WECC	WGA	WECC/ TEPPC
					Midwest				
MISO	NERC	MISO	MISO	MISO	FERC	NERC	MISO	Not available; in progress	Not available
SPP	NERC	SPP	SPP	SPP	FERC	NERC	SPP	Not available; in progress	Not available
PJM	WECC/ TEPPC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
Non-RTO	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available
					Northeast				
ISO-NE	NERC	ISO-NE	ISO-NE	ISO-NE	FERC	NERC	ISO-NE	Not available; in progress	ISO-NE Planning Advisory Committee
NYISO	NERC	NYISO	NYISO	NYISO	FERC	NERC	NYISO	Not available; in progress	Not available
PJM	NERC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
					Southeast				
SERC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available
FRCC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Utility OASIS	Not available; in progress	Not available

Note: WGA = Western Governors Association; cells highlighted in green denote a parameter and source for which information has been gathered for this study Source: US Department of Energy (2014). Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012, January 2014.

[a] In the Eastern Interconnection several regional renewable or clean energy studies have been undertaken; however no interconnection-wide study has been completed to date. The Eastern Interconnection States Planning Council has provided conceptual support and other inputs to the development of a Clean Energy Zones mapping tool by Argonne National Laboratory.

[b] Transmission utilization information is available for some specific regions in the Eastern Interconnection, but not for the entire interconnection.

4. Recent Nation-Wide Trends Affecting Transmission Constraints and Congestion

Transmission constraints and congestion occur in particular locations and affect individual regions. They are influenced both by broad national or economy-wide trends and by the unique circumstances of each region. This chapter introduces seven such trends to provide a context for the region-specific findings presented in Chapters 5 and 6 and explains how these trends affect transmission congestion. The trends are:

(1) The economic recession of 2008-2009 and the relatively slow rate of electricity demand growth during the economic recovery,

(2) State and federal policies to increase energy efficiency,

(3) State policies to increase use of renewable generation,

(4) Low natural gas prices,

(5) Construction of additional transmission capacity in many areas,

(6) New environmental regulations that may affect the composition of regional generation fleets, and

(7) Trends in generation retirements.

4.1. The economic recession and lower electricity demand growth during the recovery

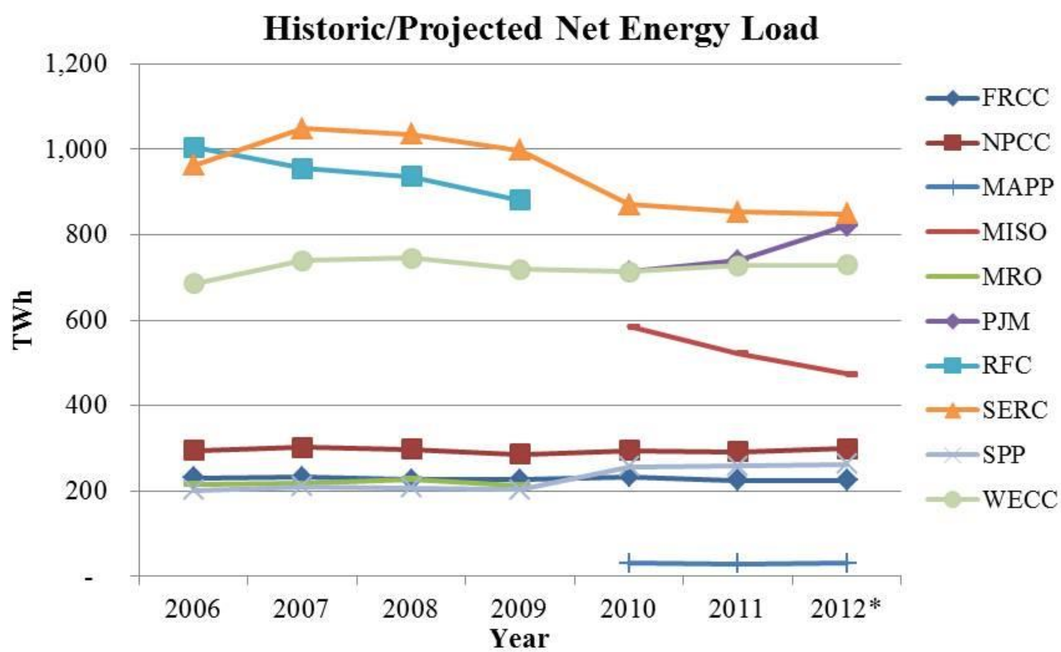
The economic recession of 2008-2009 and subsequent recovery had major impacts on transmission constraints and congestion. Lower economic activity and higher unemployment reduced the demand for electricity and the rate of demand growth.[34]

Figure 4 - 1 and Figure 4 - 2 show seven years of annual electricity generation and electricity peak demand, by NERC assessment areas.[35] They confirm that in most areas demand has either declined in absolute terms or grown little since 2008.

[34] As discussed next, growth in energy efficiency, as well as demand response programs, have also contributed to this trend. See, for example, ACEEE (2012b). *Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States*. June 27, 2012, at http://www.aceee.org/research-report/u123.

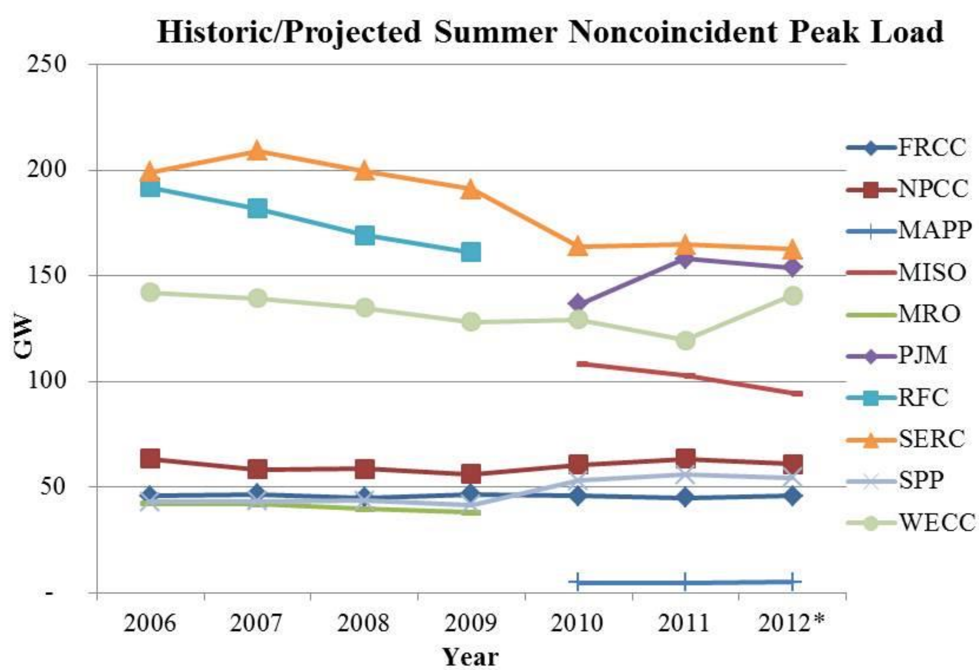
[35] Note that NERC assessment areas were reconstructed between 2010 and 2011 to ensure alignment with existing operating and planning processes. In some instances, boundaries that used to correspond to regional entities were simply relabeled according to the name of the operator; in other instances former entities within a regional entity were reassigned to a new operator to reflect a change in membership. These reassignments, however, do not change the overall trends presented in the two figures.

Figure 4 - 1. Historic and projected net energy to meet load



Source: EIA (2013c). "Coordinated Bulk Power Supply Program Report Data." Form EIA-411 database downloaded November 2013, at http://www.eia.gov/electricity/data/eia411/.

Figure 4 - 2. Historic and projected non-coincident summer peak demand



Source: EIA (2013c). "Coordinated Bulk Power Supply Program Report Data." Form EIA-411 database downloaded November 2013, at http://www.eia.gov/electricity/data/eia411/.

Lower electricity demand allows utilities to reduce their reliance on the most expensive sources of generation. This changes transmission patterns, both into load centers and from generation sources, which in turn can alter the location and the significance of transmission constraints and congestion.

The impacts for specific regions or local areas, however, depend on price differentials in these areas among generation sources. The relationships and patterns shown in this study are snapshots of recent and current conditions and these relationships will change over time in ways that are not reflected or predicted in this review.

4.2. State and federal policies to increase energy efficiency

In addition to macroeconomic factors reducing activities that use electricity, policies and standards targeted at improving energy efficiency are fostering more productive use of electricity. These improvements in efficiency put downward pressure on electricity demand across the country as these measures take effect. There are a variety of measures in play now, including federal energy efficiency appliance standards, state-level energy efficiency targets, building energy codes, an extensive efficiency labeling program (ENERGY STAR®), and a temporary but substantial government investment in efficiency through the American Recovery and Reinvestment Act (ARRA).[36]

Recently, the President emphasized the importance of energy efficiency standards for appliances by including it in his Climate Action Plan. Since 2009, 18 appliance energy efficiency standards have been implemented or updated, which are anticipated to save electricity equivalent to consumption of 85 million homes for two years.[37] Appliance energy efficiency standards have been implemented by the Department of Energy at the direction of Congress since the 1980s. More than 50 types of energy-consuming products, covering 90% of home energy use, 60% of commercial building use, and nearly 30% of industrial energy use, have energy efficiency standards that are revised at least every six years.[38] Most recently, DOE issued two proposed standards, for commercial refrigeration equipment and walk-in coolers and freezers.[39]

[36] Barbose, Goldman, Hoffman and Billingsley, (2013). "The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025." LBNL-5803e, January 2013, at http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf.

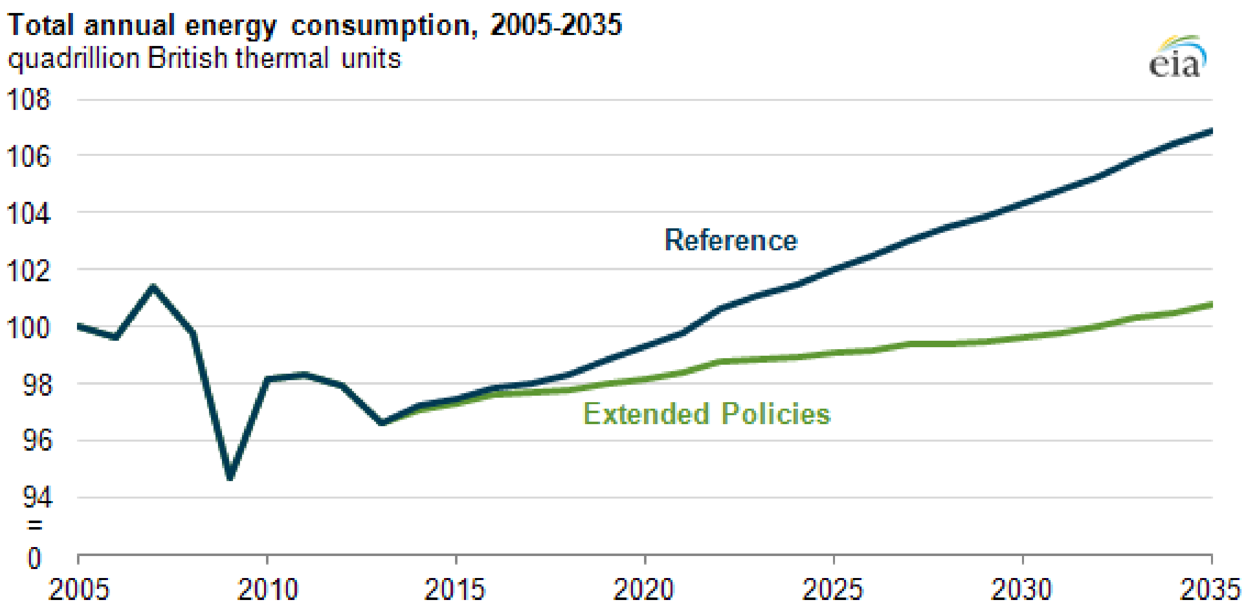
[37] Executive Office of the President (2013). "The President's Climate Action Plan." June 2013, at www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf, United States Department of Energy, Office of Energy Efficiency & Renewable Energy (2013a). "Appliance and Equipment Standards Result in Large Energy, Economic, and Environmental Benefits." Website information at http://www1.eere.energy.gov/buildings/appliance_standards/.

[38] United States Department of Energy, Office of Energy Efficiency & Renewable Energy (2013b). "History and Impacts." Website information at http://www1.eere.energy.gov/buildings/appliance_standards/history_and_impact.html.

[39] Zichal, H. (2013). "Historic Energy Efficiency Rules Would Save Consumers Money and Cut Carbon Emissions." The White House Blog, August 29, 2013, at http://www.whitehouse.gov/blog/2013/08/29/historic-energy-efficiency-rules-would-save-consumers-money-and-cut-carbon-emissions.

Projections by the Energy Information Administration (EIA) indicate that energy savings from expanding appliance efficiency standards, in combination with extending other programs, may reduce national total energy consumption by nearly 6%, and electricity consumption by over 8%, by 2035, as shown in Figure 4 - 3.[40]

Figure 4 - 3. Projected annual energy consumption under business as usual and extended efficiency program scenarios



Source: EIA (2012c). "Extension and expansion of efficiency programs could reduce US. Total energy usage." June 27, 2012, *http://www.eia.gov/todayinenergy/detail.cfm?id=6870.*

Other analysis indicates that appliance standards implemented since 1987 will have resulted in cumulative savings of over 700 terawatt-hours by 2035—a 14% decrease in consumption compared to what electricity usage would be without the standards.[41]

In addition to promoting appliance efficiency standards, the President's plan calls for strengthening standards for federal buildings and a 20% improvement of commercial and industrial building efficiency by 2020.

At the state level, 20 states have implemented energy efficiency resource standards that require reduction in electricity sales or demand by a certain year.[42] (Seven states have goals

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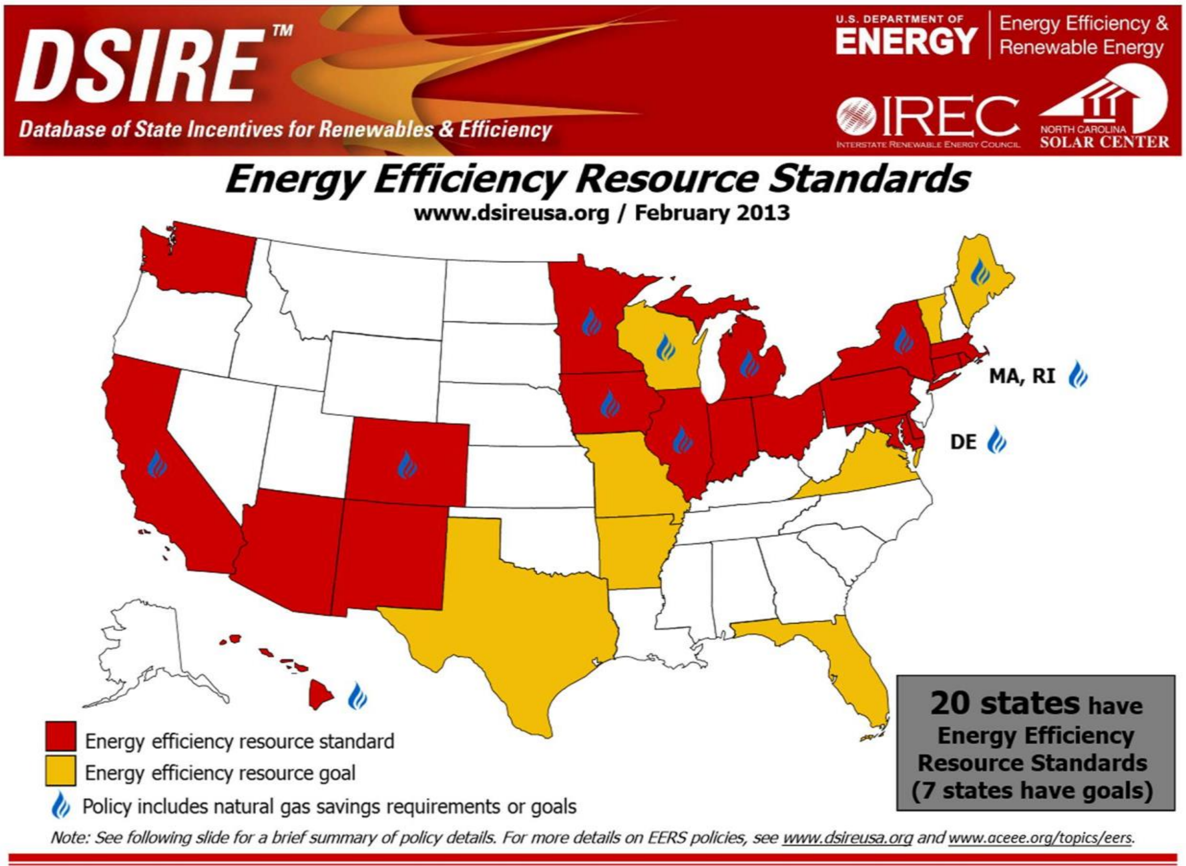
[40] EIA (2012b). *Annual Energy Outlook 2012*, June 2012, at *www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf*, pg 20.
[41] American Council for an Energy-Efficient Economy (2012c). "The Efficiency Boom: Cashing In on the Savings from Appliance Standards," Research Report A123, March 8, 2012. http://www.aceee.org/research-report/a123
[42] Several regions have also developed and implemented demand response programs. These programs vary from compensating customers for reducing consumption (on their own or under direct control of their utility) during emergency conditions to programs that allow customers to participate directly in capacity, ancillary services and day-ahead electricity markets. See FERC (2013). *Assessment of Demand Response & Advanced Metering.* Staff Report. October 18, 2013, at http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.

which target certain levels of reductions, but do not require them.) The states with standards and goals are shown in Figure 4 - 4. Reconsideration of these provisions is occurring in some states.[43]

Figure 4 - 4. U.S. states with energy efficiency standards



Source: DSIRE (2103a). "DSIRE Energy Efficiency Resource Standards map", DSIRE website. Raleigh, NC: NC Solar Center, NC State University. February 2013, at http://dsireusa.org/documents/summarymaps/EERS_map.pdf

These standards and goals, in combination with current utility energy efficiency plans, are projected to save between 20 and 33 terawatt-hours annually in 2015, depending on additional state programs and spending on efficiency programs.[44]

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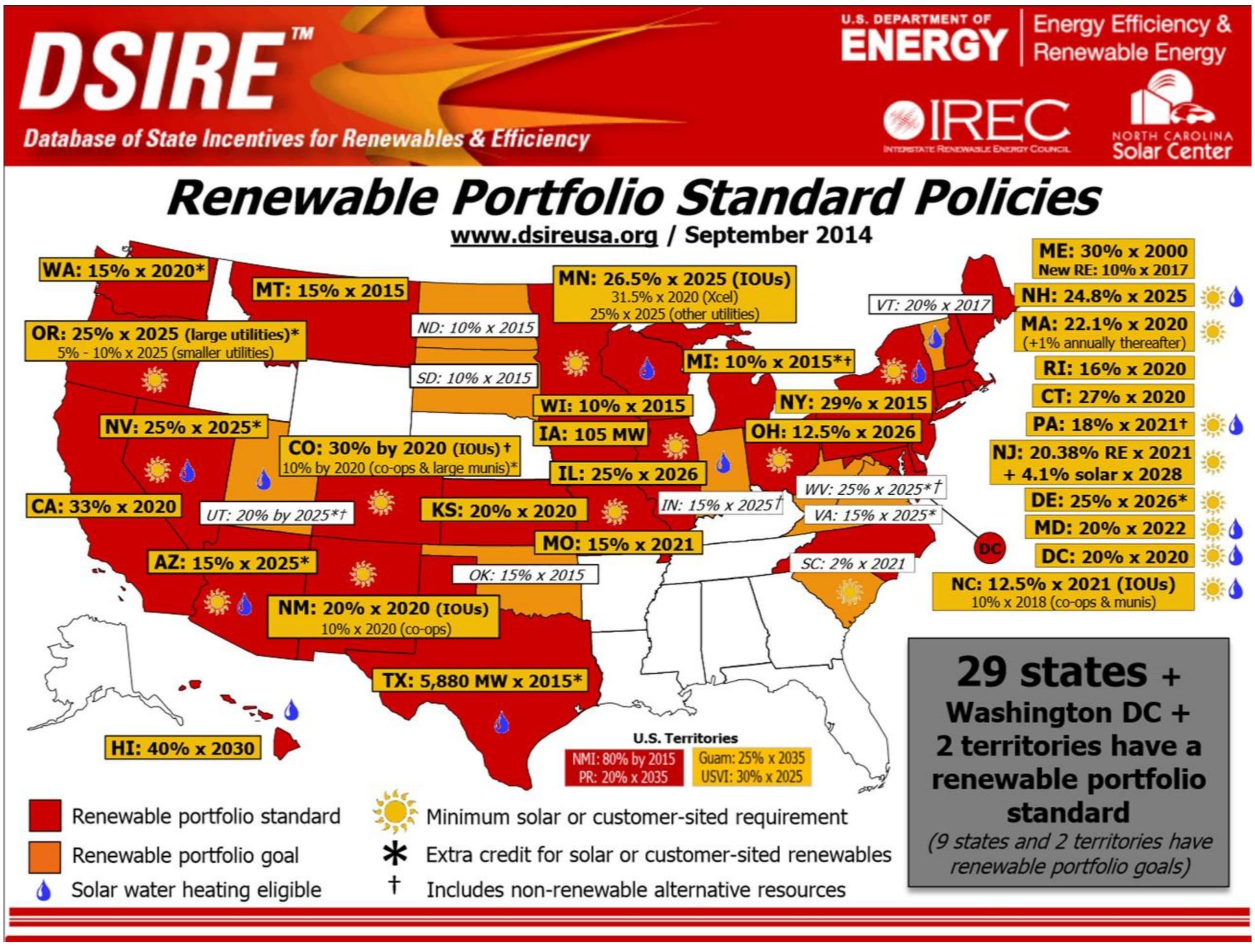
[43] In Ohio, the state legislature has recently altered its energy efficiency targets, freezing the level for two years and making other changes. (Holly, C. (2014). "Ohio moves to freeze, reduce RPS, efficiency goals." *The Energy Daily.* June 2, 2014, at http://www.theenergydaily.com/alternative_energy/11138.html)

[44] Barbose, Goldman, Hoffman and Billingsley (2013). "The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025." LBNL-5803e, January 2013, p. 22, at http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf.

4.3. State clean energy policies are spurring renewable generation development

As of 2012, 29 states and the District of Columbia had adopted statutes or rules requiring their utilities to acquire some mandatory or targeted level of renewable energy on behalf of their customers. An additional eight states have renewable energy goals (see Figure 4 - 5). Demand for renewable energy created by state RPSs is expected to triple from 2010 levels by 2020.[45]

Figure 4 - 5. Renewable portfolio standards across the United States



Source: DSIRE (2013b). "DSIRE RPS Policies map." DSIRE website. Raleigh, NC: NC Solar Center, NC State University. March 2013, at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

In the 2006 and 2009 studies, the Department identified several regions of the nation as "Conditional Congestion Areas." Each such area has a rich potential for resource development, but lacks sufficient transmission to enable much development of those electric generation resources. In those reports, the Department pointed to the existence of proven resources as

[45] Reishus, S. (2012). "State Renewable Portfolio Standards," Presentation at NARUC conference, July 22, 2012, IHS CERA, slide 6.

sufficient justification for identifying Conditional Congestion Areas.[46] Numerous studies since then have identified economic benefits from such development—for instance, a recent Illinois State University study indicated that Illinois' 28 largest wind farms will add $5.8 billion to local economies over the life of the projects,[47] and Kansas officials describe wind farms as "strong economic development in small counties that have seen shrinking economic bases for decades" given construction jobs, lease payments, and contributions to local governments.[48]

Although this study does not identify Conditional Congestion Areas, it nonetheless looks at areas with high renewable resource potential, and which of those areas may be under-served by transmission capacity relative to the potential generation development. One recent study suggests that several regions (New England, New York, and PJM) will miss their 2020 RPS goals due to transmission constraints and transmission congestion limiting their ability to ship adequate renewable generation within or between regions.[49] This is not a universally accepted finding. In New York, for instance, a study finds the existing high voltage transmission system can accommodate up to 8 GW.[50] In New England, the RPS goals can be met in a variety of ways—developing resources already in the queue, imports, behind-the-meter projects, and alternative compliance payments—that may not face transmission constraints.[51]

4.4. Domestic natural gas is currently abundant, inexpensive, and reducing dependence on foreign sources

Perhaps the single most dramatic factor influencing transmission constraints and congestion in 2012 was the recent abundance of domestic sources of unconventional (or shale) gas. Shale gas accounted for more than 25% of U.S. natural gas production, up from 5% in 2007.[52] Natural gas prices have fallen dramatically (see Figure 4 - 6). As a result, U.S. liquefied natural gas (LNG) imports plummeted—in the first quarter of 2013, the active US LNG terminals operated at only

[46]See chapter 4 of previous study. United States Department of Energy (2009). *2009 National Electric Transmission Congestion Study*. Washington, D.C. December 2009, at http://congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf.

[47] Ford, M. A. (2012). "Wind farms add billions of dollars to local economies," *Bloomington Illinois Pantagraph, McClatchy-Tribune Regional News*, July 18, 2012.

[48] Voorhis, D. (2012). "Wind farms a cash crop for rural Kansas counties," *Wichita Eagle, McClatchy-Tribune Regional News*, July 12, 2012.

[49] Reishus, S. (2012). "State Renewable Portfolio Standards," IHS CERA presentation at NARUC conference, July 22, 2012, slide 8.

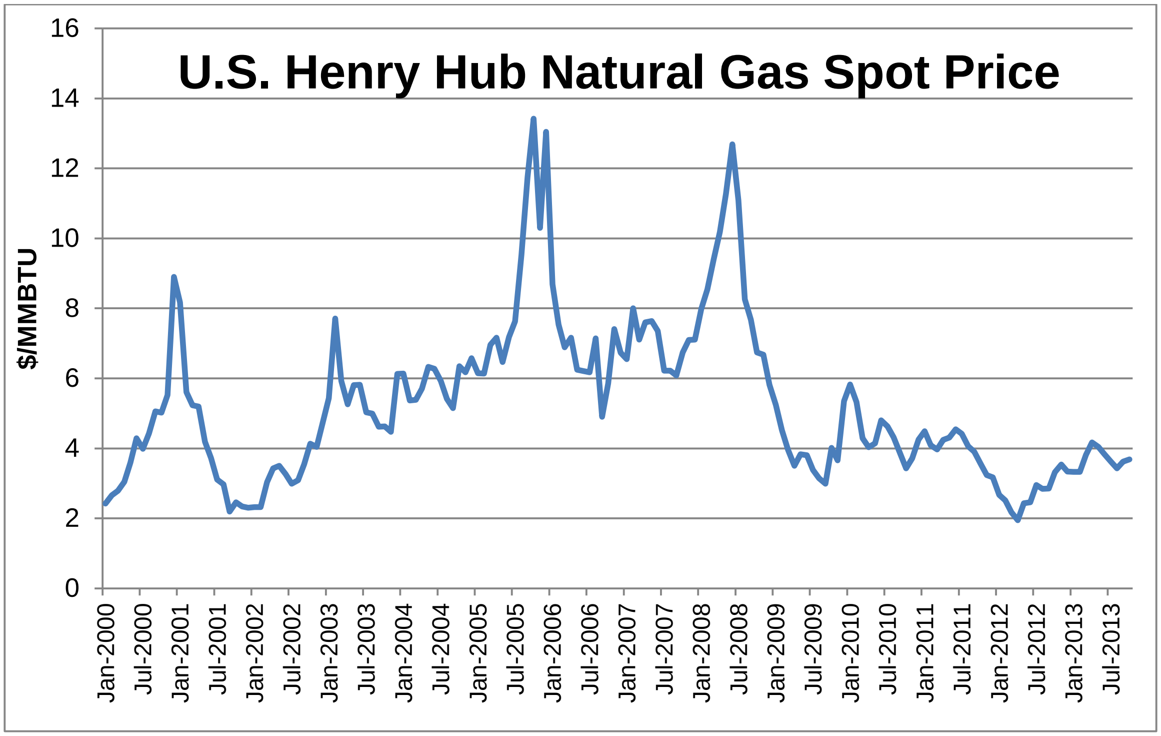
[50] Certain constraints and local transmission facilities were found to cause "bottling" of wind production. NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Renesselaer, NY: NYISO. September 2010, available from http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf.

[51] See ISO-NE (2011b). *2011 Regional System Plan*. Holyoke, MA: ISO-NE. October 2011, at http://iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc, pp 11.

[52] FERC (2011g). *Winter 2011-12 Energy Market Assessment*. October 20, 2011, at http://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2011/10-20-11.pdf, slide 6.

2% of their total import capacity[53] and as of November 2013 36 LNG export facilities had been approved by DOE, one of which has begun construction.[54]

Figure 4 - 6. Natural gas prices in United States

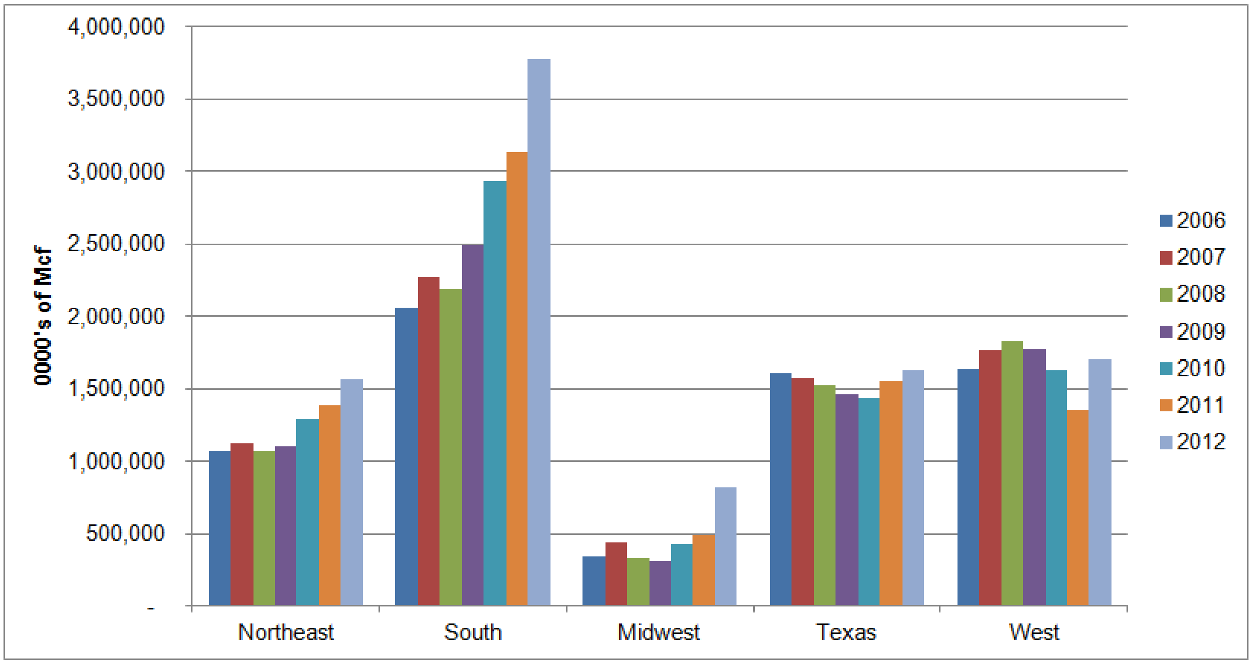


Source: EIA (2013d). "Selected National Average Natural Gas Prices." EIA website. November 2013, at http://www.eia.gov/naturalgas/monthly/.

Abundant supplies of domestic natural gas at low cost have led to a major increase in natural gas-fired electricity generation. This trend is particularly evident in the Northeast and Southeast (see Figure 4 - 7). FERC reports that power generation used 22% more natural gas in 2012 than 2011, due primarily to low natural gas prices.[55] NERC reports that changes in fuel mix will continue, with "gas-fired generation as the premier choice for new capacity with almost 100 GW expected over the next 10 years."[56]

[53] *Ibid*, slide 8.
[54] United States Department of Energy, Office of Fossil Energy (2013). "Quarterly Liquefied Natural Gas (LNG) Status Report", July 2013.
[55] FERC (2012h). *Winter 2012-13 Energy Market Assessment.* November 15, 2012, at http://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2012/11-15-12.pdf, p. 7.
[56] NERC (2012g). *2012 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf, p. 19.

Figure 4 - 7. Historic trends in natural gas by U.S. region: natural gas consumed to produce electricity



Source: Data from Ventyx Velocity Suite, accessed November 2013.

Given flat or declining electricity demand and lower natural gas prices, increased natural gas-fired generation has displaced a comparable amount of coal-fired generation. Because gas-fired plants are often sited closer to load centers than coal-fired plants, this shift directly affects transmission constraints and reduces congestion. NERC projects that approximately 64 GW of fossil-fired power plant capacity will be retired by 2017, and comments that:

> *The retirement of larger and/or strategically situated generating units will cause changes to the power flows and the performance of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission systems to provide reactive and voltage support, address thermal constraints, and provide for system stability.*[57]

4.5. Construction of new transmission has increased

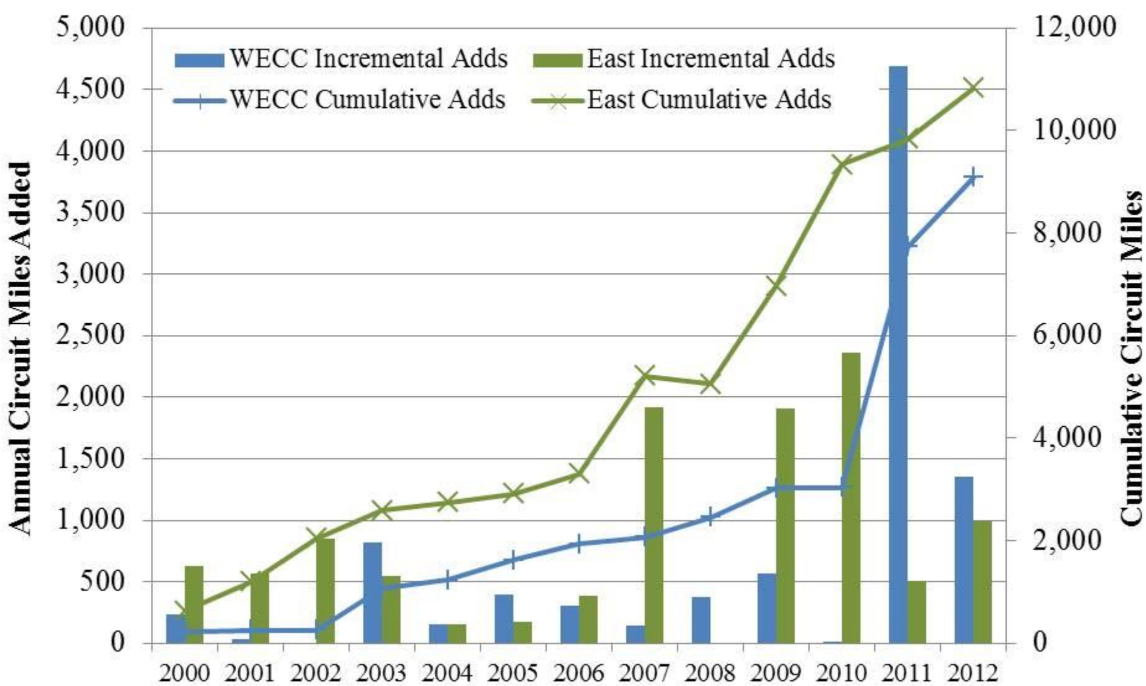
When the Department issued its 2006 Congestion Study, the U.S. electric industry was still in a long period of relatively low investment in additional transmission facilities. Transmission planning was conducted independently by individual utilities and by ISOs and RTOs, and most new transmission projects were built to serve local needs only. Multi-utility, multi-state transmission cost allocation methodologies were still being negotiated in the East, and while the West had in the 1970s and early 1980s built a number of large transmission projects, it did not add much new capacity thereafter. During the first part of the decade (2000-2006),

[57] *Ibid.*, p. 8-9.

transmission project construction levels sat at relatively low levels and observers were concerned that if transmission investment continued to lag behind the growth in demand, grid reliability could be at risk.[58]

The policy context for building new transmission has changed significantly in the intervening years, and the rate of new transmission construction has risen noticeably. As Figure 4 - 8 shows, following a period of slow growth between years 2000-2005, transmission construction increased steadily from 2006-2010. Projected growth in new construction is still higher for 2011 through 2015. NERC reports that from 2006 through 2011, the electric industry built over 2,300 circuit-miles of new transmission per year (compared to about 1,000 circuit-miles per year previously), and that current plans anticipate a build-rate of over 3,600 MW of additional transmission circuit-miles over the next five years.[59] Figure 4 - 9 shows that planned shareholder-owned utility transmission investment in 2012 was 70% higher than the investment dollars spent in 2006.

Figure 4 - 8. High-voltage (>200-kV) transmission line circuit mile additions

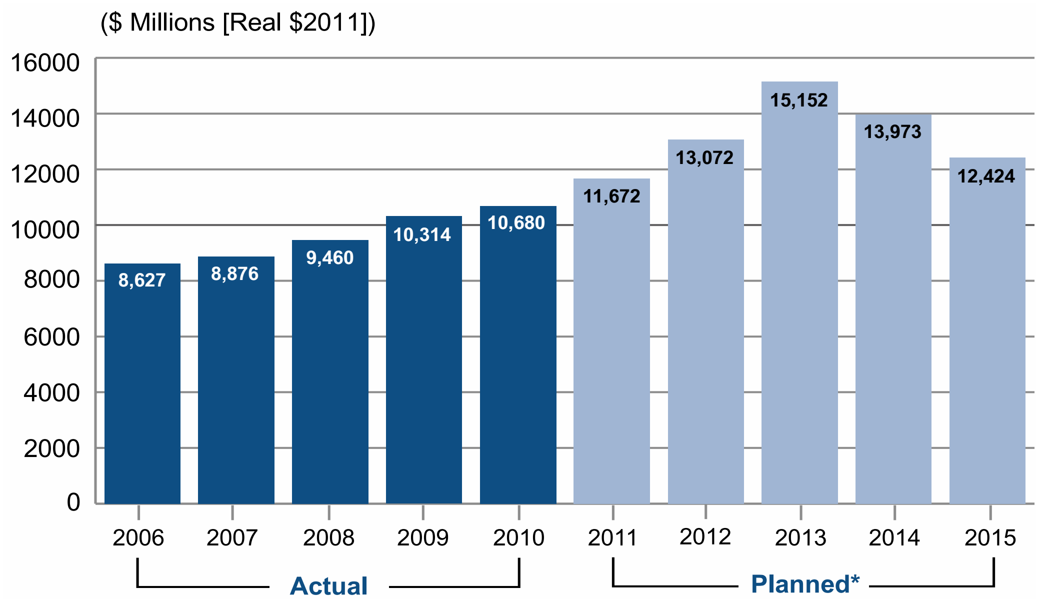


Sources: Years 2000-2008 taken from NERC (2012b). "Electricity Supply & Demand (ES&D) Dataset," Princeton, NJ: NERC, at http://www.nerc.com/page.php?cid=4%7C38; years 2009-2012 taken from NERC (2012d). "Transmission Availability Data System (TADS)," Princeton, NJ: NERC, available at http://www.nerc.com/comm/PC/Pages/Transmission%20Availability%20Data%20System%20Working%20Group%20%28TADSWG%29/Transmission-Availability-Data-System-Working-Group-TADSWG.aspx . The TADS data are only available starting in year 2009.

[58] Edison Electric Institute (EEI) (2012). *Transmission Projects at a Glance*. Washington, D.C.: EEI. Updated March 2012, at http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx.

[59] NERC (2012g). *2012 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf, p. 36.

Figure 4 - 9. Actual and planned transmission investment by shareholder-owned utilities (2005-2014); Edison Electric Institute, September 2011



Source: Edison Electric Institute Business Information Group (2012). "Actual and planned transmission investment by shareholder-owned utilities". Washington, D.C.: EEI. March 2012, at *http://www.eei.org/ourissues/ElectricityTransmission/Documents/bar_Transmission_Investment.pdf, as retrieved December 2013.*

Some of the factors contributing to a higher rate of development are:

- FERC awarded many regulated projects higher levels of return on investment (ROI) as an incentive for new transmission construction under Order 679; for the years 2012-2016, $22.9 billion of transmission investment has been approved for transmission incentive rates.[60]
- Many of the projects that were approved in early RTO and ISO regional transmission plans have been completed, and many more transmission projects are now working their way through RTO and ISO system plans.
- FERC adopted a series of orders that require RTOs and ISOs (and regulated utilities outside RTOs and ISOs) to begin wide-area coordination of transmission plans, and to consider factors beyond reliability as justification for new transmission construction.
- Several regions adopted new methods for transmission project cost allocation that reduce uncertainty surrounding transmission cost recovery.
- Transmission owners across the country are grappling with the implications of their aging transmission infrastructures. Many have begun planning and implementing programs to replace and expand facilities that are many decades old.

[60] Lum, R. and K. Knutson (2012). "FERC Order 679 responsible for $23bn of transmission infrastructure investment in 2012-2016 period: $50bn of proposed investments had been made by May 2011." *Transmission Hub*. July 13, 2012.

- Transmission-only and merchant transmission firms have been expanding their efforts to build new transmission projects in every region.
- As will be discussed later in this chapter, many states adopted renewable portfolio standards (RPSs) with requirements or goals to use more renewable-sourced electricity. Because much of the best utility-scale renewable resource potential is relatively remote from the load centers, the states then had to authorize new transmission construction to enable the desired renewable-based electricity to reach the grid.

All of these factors have contributed to the significant growth in transmission investment over the past six years. That new infrastructure has expanded the grid's throughput capability in almost every region, resolved numerous past transmission constraints, and helped reduce transmission congestion on the grid.

4.6. National environmental policies are affecting the composition of the electricity generation fleet

In the past few years, and in the timeframe covered by this report, the Environmental Protection Agency (EPA) has finalized three environmental regulations under the Clean Air Act that affect coal- and oil-fired power plants, one of which was judicially stayed before sources were required to comply. In addition, the EPA has proposed several other regulations under the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act, one or more of which would affect coal and gas-fired plants and many nuclear plants. (See text box.) Because only three of these regulations have been finalized, it is not clear which existing power plants will be affected by the remaining rules that have not been finalized, the requirements that these rules may impose, or the timing of those requirements—making it difficult to assess the potential impact of these rules on existing plants.[61] There are a variety of compliance actions plant owners can take, including retrofitting with pollution abatement technologies, re-powering, or closing a plant. For newer plants, it may be economically advantageous to retrofit a plant to comply with the new rules. Due to market forces, including low natural gas prices and low growth in electric demand, many owner operators are taking steps to retire or mothball older, relatively less efficient coal- and oil-fired power plants. For these older, relatively fuel-inefficient plants, owner operators may be less likely to make investments required to comply with known and yet-unknown environmental modifications, which may provide a further rationale for retiring or mothballing some plants.

[61] When the 2011 Cross-State Air Pollution Rule was stayed by the U.S. Court of Appeals for the D.C. Circuit in December 2011, the court ordered the EPA to continue implementing the 2005 Clean Air Interstate Rule. The D.C. Circuit subsequently vacated the rule, but that judgment has been reversed by the Supreme Court. In addition, on June 26, 2014, the EPA asked the D.C. Circuit to lift the stay that was entered in December 2011.

EPA's Suite of Electric Utility Sector Environmental Regulations

The Environmental Protection Agency (EPA) is in the process of releasing a suite of environmental regulations impacting the electric utility sector. Some of the affected generators may need to retrofit with control technologies to meet the new requirements. In some cases it may be uneconomic to retrofit, and units may be retired—especially as demand growth is weak and multiple regulations compound the retrofit requirements and resulting economic cost.

Generator retirements, in addition to outages for environmental retrofits, are not expected to create wide-spread reliability issues, but there is the potential for localized reliability impacts, particularly during the period when plants are taken out of service for retrofits. Timely coordination between stakeholders will be necessary to minimize such impacts and maintain reliability while implementing these environmental regulations.

	Federal Regulation	Impacts	Status
Air	Cross-State Air Pollution Rule (CSAPR)	Establishes pollution caps for SO_2, annual NO_x and seasonal NO_x for 28 states in the eastern half of the U.S. to reduce transported pollution that significantly affects downwind nonattainment and maintenance problems with National Ambient Air Quality Standards (NAAQS). Following vacatur of the rule by the Court of Appeals, it is not clear how the rule will be revised or when a new regulation will go into effect. Per the Court's order, EPA's 2005 Clean Air Interstate Rule (CAIR) remains in place.	Finalized 7.6.2011 supplemental rule finalized 12.15.2011; technical revisions finalized 2.7.2012 and 6.5.2012; stayed on 12.30.2011 and vacated 8.21.2012 by U.S. Court of Appeals, D.C. Circuit; vacatur reversed by the Supreme Court 4.29.2014, remanded to the D.C. Circuit.
	Mercury and Air Toxics Standards (MATS) Rule for Electric Generation Units	Establishes national emission standards for hazardous air pollutants (HAPs), including mercury and acid gases Will affect existing and new coal- and oil-fired plants.	Finalized 2.16.2012; updated standards for new plants finalized 4.24.2013. Compliance date of April 2015, with options to petition for extensions.
	Carbon Pollution Standards for New Power Plants	Establishes new source performance standards which set national limits on CO_2 emissions from new fossil fuel-fired power plants (electric utility steam generating units and natural gas-fired stationary combustion turbines).	Final rule released 8.3.2015 for publication in the *Federal Register*.
	Clean Power Plan for Existing Power Plants	Requires state plans with enforceable measures to limit CO_2 emissions from existing fossil fuel-fired power plants and sets rate-based emissions goals for each state.	Final rule released 8.3.2015 for publication in the *Federal Register*.
	Carbon Pollution Standards for Modified and Reconstructed Power Plants	Establishes national limits for CO_2 emissions from modified or reconstructed fossil fuel-fired plants.	Final rule released 8.3.2015 for publication in the *Federal Register*.
Waste	Coal Combustion Residuals (CCR) Rule	Regulates disposal of CCR (coal combustion wastes) in existing and new landfills and surface impoundments; establishes technical requirements for disposal units; addresses the risks from coal ash disposal, and protects against blowing of CCR into the air as dust.	Rule finalized12.19.2014 and published 4.17.2015 in the *Federal Register*.
Water	CWA §316(b) – Cooling Water Intake Structures	Establishes national standards for impingement mortality and a process for establishing site-specific entrainment controls.	Finalized 5.19.2014.

Source: Environmental Protection Agency

Current plants may comply with the new rules through retrofits rather than retirement. It is expected that these modifications will be carefully choreographed within each region in order to maintain grid reliability,[62] but because many of these plants provide both operational capacity and day-to-day ancillary services that are location-specific, uncertainties remain about how plant compliance decisions will affect future transmission constraints and congestion. NERC states that:

> *Complying with proposed environmental regulations may result in generation capacity not being available during shoulder months and off-peak times during the operating day in the near-term (2013-2016). Within this timeframe, some generators may not have enough time to acquire permits, procure engineering services, design equipment, and systematically shut down units for the purpose of retrofitting, while concurrently meeting reliability goals…. Taking multiple units out of service for extended outage periods can aggravate resource adequacy and reduce system flexibility and dispatch options, especially during seasons considered "off-peak".*[63]

In this study NERC did not attempt to predict the impact of these regulation-driven decisions by plant owners on future congestion patterns and transmission constraints, nor did they identify any localized reliability problems due to the rules; rather they raised the possibility that such problems could occur.

[62] NERC (2011e). *Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/EPA%20Section.pdf.
[63] NERC (2012g). *2012 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf, pp. 24-25.

Cross-State Air Pollution Rule (CSAPR)

After the Cross-State Air Pollution Rule (CSAPR) was finalized in July 2011, EPA issued a supplemental rule adding six states to the list of those that must reduce ozone-season NO_x emissions under the July 2011 rule. Several states expressed concerns regarding the sufficiency of allowances provided for under the final rule and the feasibility of achieving compliance by January 1, 2012. Using additional information provided by states and utilities, EPA reviewed the state allowance budgets and finalized technical changes in February and June of 2012. On December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit (DC Circuit Court) issued a stay of the CSAPR.[1] In a decision issued on August 21, 2012, the Court vacated the rule and remanded it to EPA. The Court also ordered EPA to continue implementing the Clean Air Interstate Rule (CAIR).[2] On April 29, 2014, the U.S. Supreme Court reversed the lower court vacatur and remanded the rule to the D.C. Circuit.

Mercury and Air Toxics Standards (MATS)

Before finalization of the Mercury and Air Toxics Standards (MATS), EPA and the DOE each conducted analyses of electric generation resources.[3] Both of these analyses demonstrate that the vast majority, if not all, sources would be able to meet the MATS requirements within the timeframes provided under the Clean Air Act. These studies indicated that large-scale reliability problems as a consequence of MATS were extremely unlikely. In response to concerns about possible local-scale reliability impacts, and consistent with a December 2011 Presidential Memorandum addressing MATS implementation, EPA is working closely with DOE and FERC, grid planning authorities, state public commissions, and a range of other power-sector stakeholders to ensure early and coordinated planning and implementation of MATS requirements in a manner that maintains electric reliability.[4] As part of this, EPA has provided significant flexibilities with regard to compliance timing.

Under the Clean Air Act, facilities have three years to come into compliance (up until April 2015) but eligible sources may seek a one-year extension from their state permitting authority (the "fourth year"). The state permitting authorities (generally state air regulators) can grant a fourth-year extension for compliance where necessary for the installation of controls. In the final rule, EPA indicated that permitting authorities should make this fourth year broadly available and it described in detail the wide range of situations where EPA believes they can do so—including when additional time is needed to install pollution control equipment, to construct on- or off-site replacement power, or to upgrade transmission to avert reliability problems. EPA has reached out to state permitting authorities regarding the fourth year for compliance. Based on this outreach, and according to a survey performed by the National Association of Clean Air Agencies, it is clear that requests for the fourth-year extension for air toxic standards have been granted by the states in most cases.[5] EPA is not aware of any concerns. In addition, EPA provided a clear pathway for units that are shown to be critical for electric reliability to obtain a schedule to achieve compliance within an additional year beyond the four years mentioned above. This pathway is set forth in a policy memorandum from EPA's Office of Enforcement and Compliance Assurance.[6] So far there have been no formal requests to use this pathway.

[1] U.S. EPA (2011c). U.S. Court of Appeals Order regarding EME Homer City Generation, L.P. v. Environmental Protection Agency, No. 11-1302 (D.C. Cir. Dec. 30, 2011), at http://www.epa.gov/airtransport/pdfs/CourtDecision.pdf. (Order granting stay of CSAPR, without ruling on the merits of the regulation, for further consideration of the regulation).
[2] *Ibid*.
[3] U.S. EPA (2011a). "Resource Adequacy and Reliability in the IPM Projections for the MATS Rule," at http://www.epa.gov/ttn/atw/utility/revised_resource_adequacy_tsd.pdf; United States Department of Energy (2011e). Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations. December 2011, at http://energy.gov/sites/prod/files/2011%20Air%20Quality%20Regulations%20Report_A_120911.pdf.
[4] The White House (2011). "Presidential Memorandum—Flexible Implementation of the Mercury and Air Toxics Standards Rule." December 21, 2011, at http://www.whitehouse.gov/the-press-office/2011/12/21/presidential-memorandum-flexible-implementation-mercury-and-air-toxics-s.
[5] See http://4cleanair.org/Documents/MATSextensionrequests-table-May1-2014.pdf.
[6] U.S. EPA (2011b) "The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders in Relation To Electric Reliability and the Mercury and Air Toxics Standard." EPA memorandum, December 16, 2011, available from http://www2.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.

Carbon Pollution Standards for New, Existing, and Modified and Reconstructed Plants

When the U.S. Supreme Court decided Massachusetts v. EPA, 549 U.S. 497 (2007), it ruled that (1) the Clean Air Act term "air pollutant" includes GHGs; (2) that EPA must decide whether tailpipe emissions of GHGs contribute to air pollution that may endanger public health and welfare; and (3) that if EPA's answer was affirmative, the agency would be required to regulate those emissions. The Supreme Court remanded the case to EPA. On remand, EPA found that six greenhouse gases "in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare." This finding was challenged by several states, but the U.S. Court of Appeals, District of Columbia Circuit, dismissed these challenges and unanimously upheld the EPA's finding.[7]

On March 27, 2012, EPA proposed a new source performance standard (NSPS) for electric utility steam generating units (EGUs).[8] Over 2 million comments were received on the proposed rule, leading EPA to reconsider its approach to the rule.

On June 25, 2013, President Obama introduced his Climate Action Plan outlining several initiatives through which the United States would address climate change, including cutting carbon pollution from power plants. The President also issued a Presidential Memorandum (PM) directing EPA "to work expeditiously to complete carbon pollution standards for both new and existing power plants."[9] The PM called for EPA to issue a proposed rule regulating carbon emissions from new sources by September 2013, and a proposed rule for existing power plants by June 2014. On September 20, 2013, EPA released a new proposed rule for new sources and concurrently withdrew its March 2012 proposal. The new proposed rule was published in the Federal Register on January 8, 2014. EPA released its proposed rule for existing plants, and one for modified and reconstructed plants, on June 2, 2014. EPA released its final rules for new sources, modified and reconstructed sources, as well as existing sources on August 3, 2015. Additionally, EPA released its proposed federal plan and model trading rules for publication in the *Federal Register*.[10]

Coal Combustion Residuals (CCR) Rule

In 2010, EPA co-proposed two options to regulate coal combustion residuals based on different legal authorities within the Resource Conservation and Recovery Act (RCRA). One option is drawn from statutory authority under Subtitle C of RCRA, which creates a comprehensive program of federally enforceable requirements for hazardous waste management and disposal. The second option includes remedies under Subtitle D of RCRA, which gives EPA authority to set performance standards for non-hazardous solid waste management facilities. Many of the technical requirements would be the same under either option (e.g., disposal unit liner requirements, groundwater monitoring requirements). The main differences between the options involve how the rule would be implemented and enforced. Under both options, coal combustion residuals that are beneficially used (e.g., used in concrete or wallboard) would not be subject to the regulations. EPA must finalize this regulation by December 2014.

Cooling Water Intake Structures (CWIS), Clean Water Act § 316(b)

Because power plant cooling water intake structures can harm local fish populations, EPA proposed a bifurcated regulation for CWIS in 2011 covering both impingement (harm at intake screen) and entrainment (harm when drawn through the cooling system). The final rule, signed May 19, 2014, establishes national standards for impingement mortality and a process for establishing site-specific entrainment controls. The rule affects existing and new large fossil and nuclear steam units not already equipped with adequate controls. Under the rule, after issuance of a final permit establishing the entrainment requirements, impingement and entrainment compliance is expected as soon as practicable (based on schedules of requirements established by the state permitting authority), which may include intermediate milestones. The flexibilities built into this rule include discretion for state permitting authorities to set compliance schedules, affording ample consideration of local grid reliability concerns, such that they should not be an issue for the 316(b) requirements.

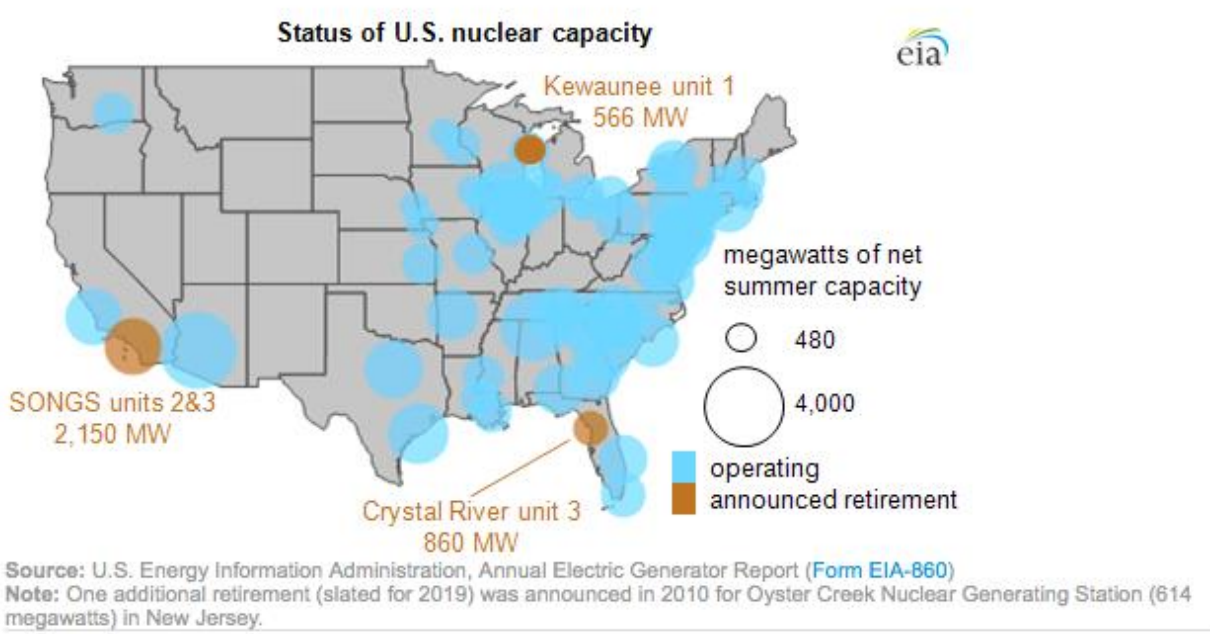
[7] Coalition for Responsible Regulation, Inc. v. EPA, No. 09-1322 (D.C. Cir. Jun. 26, 2012).
[8] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012).
[9] http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards
[10] For additional information about the proposed federal plan and model trading rules, see http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

4.7. Trends in generation retirements

In addition to retirements in reaction to the environmental regulations mentioned above, trends in generation retirements are also related to economics, safety, and other factors.

Since October 2012, utilities have announced the retirement of five nuclear reactors: San Onofre Nuclear Generating Station Units 2 and 3 (Southern California), Kewaunee Power Station (Wisconsin), Crystal River Nuclear Generating Plant Unit 3 (Florida), Oyster Creek Nuclear Generating Station (New Jersey), and Vermont Yankee (Vermont). These retirements, four of which are pictured in Figure 4 - 10 and Figure 4 - 11, have been prompted by lower profitability because of lower wholesale electricity prices (due in part by low natural gas prices), the significant cost of repairing or maintaining plants, and concerns over safety.[64] The Indian Point Energy Center, a two-unit nuclear facility generating up to 2065 MW, is facing pressure from state officials and activist groups to close after the existing operating license expires, and contingency plans are being made.[65]

Figure 4 - 10. Announced retirements at U.S. nuclear power plants

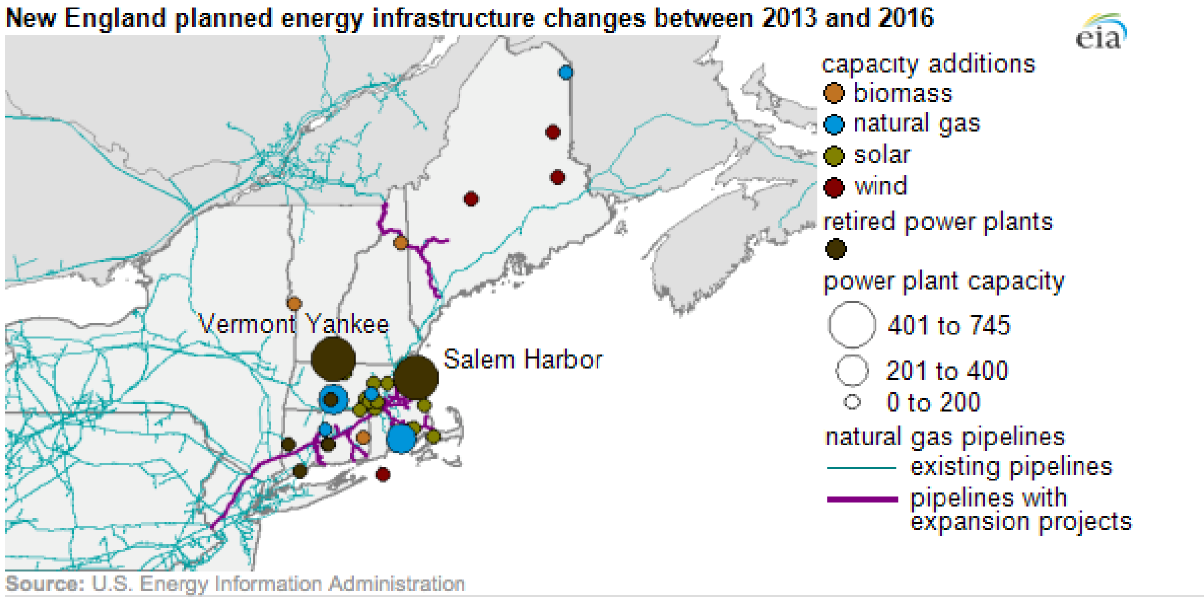


Source: EIA (2013a). "Lower power prices and high repair costs drive nuclear retirements." Today in Energy, July 2, 2013. http://www.eia.gov/todayinenergy/detail.cfm?id=11931.

[64] EIA (2013a). "Lower power prices and high repair costs drive nuclear retirements." *Today in Energy*, July 2, 2013. http://www.eia.gov/todayinenergy/detail.cfm?id=11931; EIA (2013b). "Vermont Yankee nuclear plant closure in 2014 will challenge New England energy markets." *Today in Energy*, September 6, 2013. http://www.eia.gov/todayinenergy/detail.cfm?id=12851.

[65] Beattie, J. (2013). "New York OKs 'contingency plan' for nuke plant closure." *The Energy Daily*. October 18, 2013.

Figure 4 - 11. Generation retirements and other infrastructure changes in New England



Source: EIA (2013b). "Vermont Yankee nuclear plant closure in 2014 will challenge New England energy markets." Today in Energy, September 6, 2013, at http://www.eia.gov/todayinenergy/detail.cfm?id=12851 .

Several projects to upgrade nuclear facilities have been canceled recently as well.[66] Several analyses have identified challenges facing the nuclear industry: increasing operating costs at aging plants nearing the end of their useful life; increasing frequency of unplanned outages; and economic conditions that discourage major investment in plants.[67] These factors have led to some predictions that nuclear retirements will become more common.[68]

In addition, utilities have announced a significant number of coal generator retirements for the next several years. Announced retirement capacity totals nearly 9% of the national coal capacity in 2011. These retirements are occurring, in part, because of low capacity and power

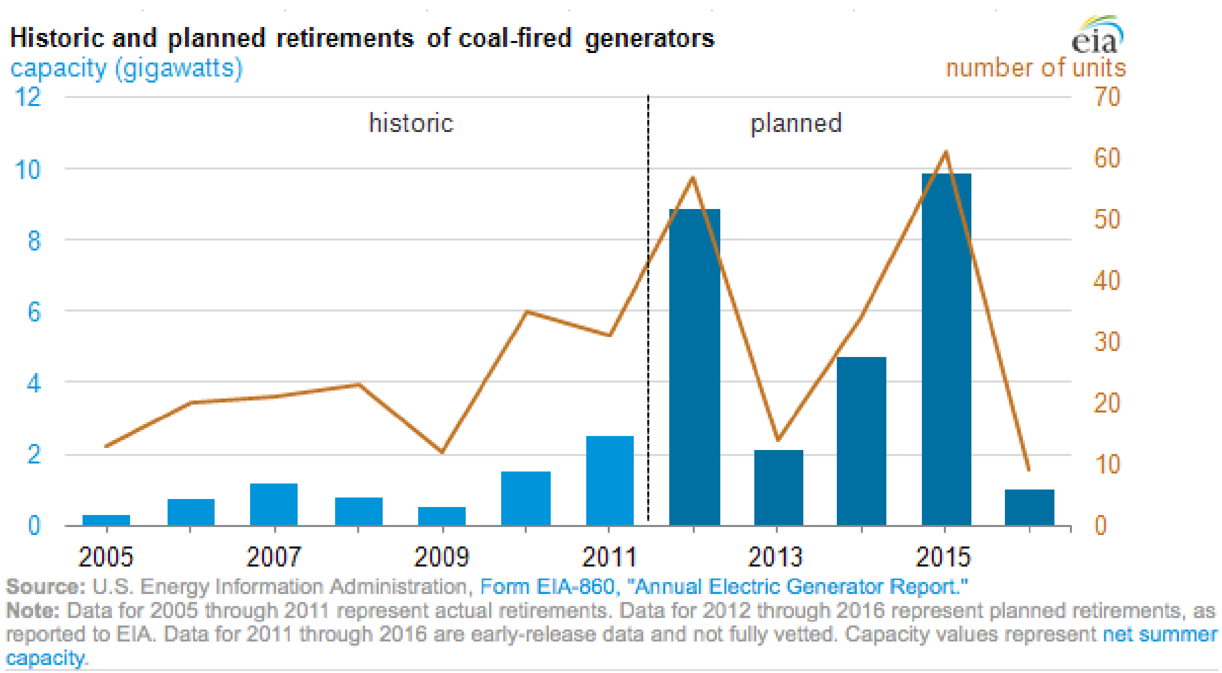
[66] Platts (2013b) "Exelon cancels power uprates for LaSalle, Limerick nuclear plants." June 12, 2013, at http://www.platts.com/latest-news/electric-power/washington/exelon-cancels-power-uprates-for-lasalle-limerick-21152061.

[67] Credit Suisse (2013). "Nuclear….The Middle Age Dilemma? Facing Declining Performance, Higher Costs, Inevitable Mortality." February 19, 2103; Platts (2013a) "Some merchant nuclear reactors could face early retirement: UBS." January 9, 2013, at http://www.platts.com/latest-news/electric-power/newyork/some-merchant-nuclear-plants-could-face-early-6007202; UBS (2013). "In Search of Washington's Latest Realities (DC Fieldtrip Takeaways)", UBS research, February 20, 2013; Moody's Investor Service (2012). "Announcement: Moody's: Market conditions masking US nuclear plant reliability issues." November 9, 2102, https://www.moodys.com/research/Moodys-Market-conditions-masking-US-nuclear-plant-reliability-issues--PR_259631.

[68] Cooper, M. (2013). "Renaissance in Reverse: Competition pushes aging US nuclear reactors to the brink of economic abandonment." Vermont Law School, July 18, 2103.

prices; the latter can be attributed to lower-priced competing fuels, such as natural gas.[69] Figure 4 - 12 below shows coal retirements reported to EIA in 2011. This level of anticipated plant retirements, and shifts in resource fuel profiles, will affect transmission system usage and resulting congestion.[70]

Figure 4 - 12. Historic and planned retirement of coal-fired generators



Source: EIA (2012d) "27 gigawatts of coal-fired capacity to retire over next five years." Today in Energy, July 27, 21012, *http://www.eia.gov/todayinenergy/detail.cfm?id=7290*.

4.8. Other national trends and policies that affect transmission constraints and congestion

4.8.1. Job growth and economic development

Due to the severity of the recession, many state officials have become more sensitive to the impact of energy production on an area's delivered-energy costs, jobs, and overall economic well-being. To this end, both industry and governmental executives see new (and especially renewable) generation as important sources of jobs and economic development. They recognize that low delivered-electricity costs makes their area more competitive for

[69] The Energy Daily (2013a). "New England coal plant closing over low power, capacity prices." October 9, 2013; EIA (2013b). "Vermont Yankee nuclear plant closure in 2014 will challenge New England energy markets." *Today in Energy*, September 6, 2013, at http://www.eia.gov/todayinenergy/detail.cfm?id=12851

[70] In addition to the retirement projections included here, many regions, including MISO and SPP, have released studies dealing with the reliability and economic implications of carbon regulation. See, for instance, Southwest Power Pool (2014) "SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan." October 8, 2014, and MISO (2014) "GHG Regulation Impact Analysis – Initial Study Results." September 17, 2014.

manufacturing and service jobs, and they value new utility or generation capital assets as important tax base additions. Thus, many state and local officials are welcoming local solar and wind development or new power plant construction as positive additions that benefit and protect the local economy's health.

As states welcome more new renewable and traditional utility-scale generation (and more local distributed generation), this new generation, with its various cost profiles and locations, will alter transmission flows and affect transmission constraints and congestion patterns.

4.8.2. Fuel dependency and national energy security

In 2011 the United States imported 45% of its petroleum, down from 58% in 2008[71] and 60% in 2005. (More recently, the level of imports has dropped sharply—see note below.[72]) In the early 1970s and later, the nation suffered significant economic damage due to short-term price shocks resulting from international oil supply disruptions.[73] After September 11, 2001, Americans became more sensitive to the vulnerability of U.S. energy infrastructure to physical and cyber-attack, as well as to the potentially severe impacts on the economy of disruptions in energy supply or sharp increases in energy costs.

Three recognized prescriptions for enhancing energy security are:

(1) Reduce U.S. (or a state's) vulnerability to physical supply disruptions of fuel imports by producing more energy, including oil and gas, at home and putting more electricity production close to load centers;

(2) Reduce the nation's vulnerability to fuel-price spikes in global markets by producing more energy from renewable sources, which have essentially free fuel and highly predictable prices, and by electrifying the vehicle fleet; and

(3) Increase physical and cyber security protection for domestic energy facilities and systems to make them less vulnerable to attack and harm.

Much of U.S. energy policy for the past three decades has incorporated some or all of the above considerations to promote American energy security and reduce our economic and societal vulnerability to energy-related disruptions or disasters. As the United States continues to develop more domestic renewable energy and domestic fossil fuels (or imports them from our neighbors), this will further change the cost profile of our generation fleet and alter transmission flows—easing some existing transmission constraints while exacerbating others—and changing congestion costs.

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[71] Banerjee, N. (2012). "U.S. Report: Oil imports down, domestic production highest since 2003," *Los Angeles Times*, March 12, 2012, at http://articles.latimes.com/2012/mar/12/news/la-pn-report-us-oil-imports-down-domestic-production-highest-since-2003-20120311.

[72] Since the timeframe covered by this report, domestic production of petroleum fuel has increased substantially. In 2013, the U.S. imported 33% of petroleum consumed. (See http://www.eia.gov/tools/faqs/faq.cfm?id=32&t=6)

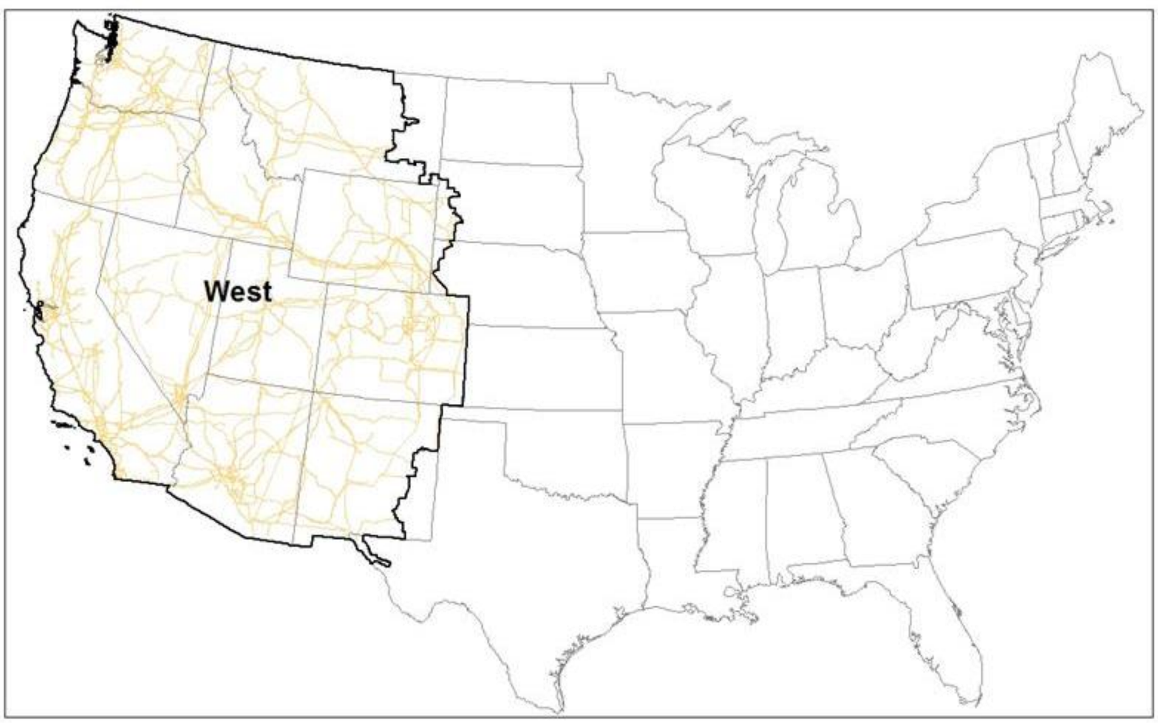
[73] Roubini, N. and B. Setser (2004). *The effect of the recent oil price shock on the U.S. and global economy*. Draft report, August 2004, at http://pages.stern.nyu.edu/~nroubini/papers/OilShockRoubiniSetser.pdf.

5. Transmission Congestion and Constraints in the Western Interconnection

5.1. Overview of the West region

The West region considered in this report is the U.S. portion of the Western Interconnection (see Figure 5 - 1). The western provinces of Canada and the northern portion of Mexico are also part of this electrically interconnected system, but they are not included in this review. This region under review contains only one organized wholesale electricity market—operated by the California Independent System Operator (CAISO). The rest of the West region consists of vertically integrated utilities, public power entities, and independent generators that trade through bilateral agreements. There are many common issues across the West, but there is more extensive data availability within the CAISO than elsewhere, so that region is discussed separately in portions of this section. The CAISO serves an estimated 35% of the electric load in the Western Interconnection.[74]

Figure 5 - 1. Map of the West region



Transmission path usage in the West has been dropping over the past several years for many reasons: lower demand (primarily driven by economic conditions, population and temperature, and demand-side programs); location of generation (affected by new plant construction,

[74] California ISO (CAISO) (2012e), "The ISO grid," at http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx.

retirements and outages); generation price differentials (caused by relative changes in fuel prices); and new transmission construction and upgrades. These developments reverse earlier trends that were driven mainly by population growth, particularly in hotter climate areas.

Demand has been flat or dropping throughout the West and in the CAISO footprint; this is mainly because of the economic recession of 2008, as well as increasing energy efficiency and demand-response efforts (particularly in West Coast load centers). Lower demand decreases pressure on the transmission system in general, but it can cause changes in transmission flow patterns that may be counter-intuitive—for instance, lower demand in major load centers can free up lower-cost electricity, which then flows to other destinations. In 2011, the combination of lower loads and larger amounts of low-cost hydro generation (due to a good hydro year) in the Pacific Northwest allowed more power from that region to flow elsewhere into higher-priced areas.[75] However, these conditions, along with higher wind production in the region, led to changes in normal dispatch patterns, including curtailment of thermal and wind generation.[76]

Relatively flat aggregate demand levels do not mean that demand patterns have remained static over time. Rather, while loads within California and Nevada declined or stayed flat under the impact of the economic recession, both population and loads have increased in Arizona. Population has grown and electricity usage patterns have shifted between the two major population centers of the Pacific Northwest; Portland winter loads are now similar to those of Puget Sound, and Portland summer loads are now higher than those of Puget Sound.[77]

Two long-term demand changes affect transmission patterns across the entire West:

- Most of the major north-south transmission capacity along the West Coast between California, the Pacific Northwest, and British Columbia was built in the 1960s through 1980s to enable seasonal power exchanges by shipping excess low-cost hydropower south to help meet California's high summer loads, and excess California and Arizona

[75] California ISO (CAISO) (2012b). *2011 Annual Report on Market Issues & Performance.* Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[76] Abundant hydro was cited as a reason for wind curtailment that year. In May 2011, Bonneville Power Administration (BPA) curtailed wind generation in order to accommodate minimum hydro flow. The combination of wind production, need to maintain stream flow, and low load was cited by BPA as the reason to spill wind during the months of May, June and July. (Bonneville Power Administration (2012). "BPA's Proposed Oversupply Management Protocol." February 14, 2102, at http://www.bpa.gov/Projects/Initiatives/Oversupply/OversupplyDocuments/20120207-proposed-protocol/Feb14WorkshopPresentation.pdf. BPA has since proposed a protocol for managing situations of oversupply which would compensate curtailed generators. (https://www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx) As of December 2013, this proposal was under regulatory review. (Lobsenz (2013). "FERC again faults BPA grid policies on wind generators." *The Energy Daily*, November 25, 2013.)

[77] ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan*. Portland, OR: ColumbiaGrid. February 15, 2012, at http://www.columbiagrid.org/download.cfm?DVID=2563, p. 52.

gas-, coal-, and nuclear generation north to help meet the Northwest's high winter loads. Population growth in Washington and Oregon, along with increased air conditioner usage, has meant that more of the region's low-cost hydropower is used locally and less is available to flow south during the hotter months. Increased wind production in the area is helping to offset this trend.

- Much of the transmission connecting Southern California to the east was built in the 1970s and 1980s to deliver low-cost coal and nuclear generation built in New Mexico and Arizona (Four Corners coal and Palo Verde nuclear) to the plant owners in Southern California: Los Angeles Department of Water & Power (LADWP); Southern California Edison (SCE); and San Diego Gas & Electric (SDG&E).[78] Those lines were built to accommodate additional transfers from other generation sources selling low-cost excess energy to California. Since that time, Arizona and Nevada have become major population centers and much of the increased generation fleet in the Southwest is used to serve local markets, reducing the availability and raising the cost of energy available for export to California. At the same time, lower gas prices have made in-state California generation less expensive compared to out-of-state coal imports.

Based on transmission usage trends through 2009, electricity flows were highest into California, although the actual level depends on demand levels, fuel prices, and hydro availability (which can be unpredictable from year to year). Flows were also high on certain lines by design (e.g., Colstrip and Bridger West, which were designed and built to interconnect and deliver the full output from dedicated power plants). However, as these areas become more attractive to renewable generation developers, high path usage may indicate that these paths are becoming constrained due to new generation and associated demands for transmission.

Western transmission infrastructure has changed in the past several years; many lines, substations and groups of equipment have been upgraded, capacitors installed, and other improvements made to increase capacity of certain interfaces without building new lines. In addition, some new lines have been built, are in construction, or are in the final stages of permitting; these are discussed in Section 5.2 below.

Inter-regional transmission is still difficult to build in the West, however, in part because the large amount of federally-owned land complicates line routing and permitting.[79] New transmission has been built in some regions of the West (notably within states such as California and Arizona), but other large projects that cross state borders have not been completed because of the challenges and delays involved in accessing federal land, and difficulties in coordinating sponsorship among transmission owners and utilities. There are also

[78] California Energy Commission (CEC) (2003). *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*. CEC 700-03-009. Prepared by Consortium of Electric Reliability Technology Solutions. Sacramento, CA: CEC. October 2003, at www.energy.ca.gov/reports/2003-10-23_700-03-009.PDF.

[79] The Department is co-leading a Rapid Response Transmission Team to address these issues and improve coordination among federal agencies involved in these permitting activities.

some state policies, such as the California Governor's Clean Energy Jobs Plan and California's renewables policy,[80] that encourage building primarily in-state renewable generation, which may reduce the need for inter-state and inter-region transmission.

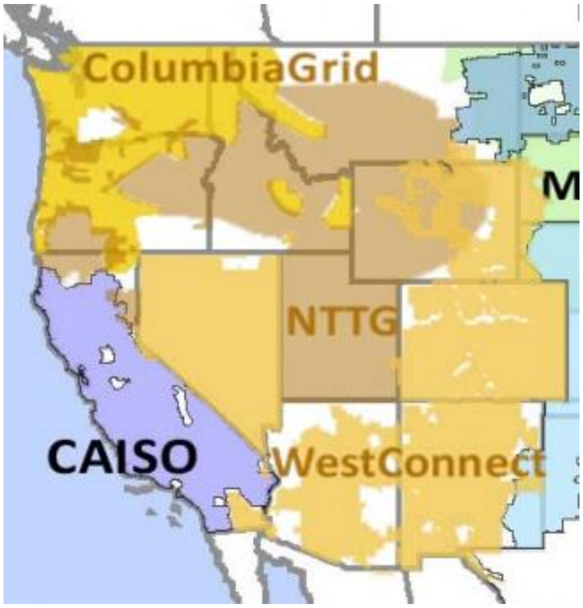
There are few sources of transmission congestion data in the West. The Western Electricity Coordinating Council (WECC) performs periodic assessments of historic transmission usage and conducts stakeholder-driven forward-looking scenario evaluations to inform regional transmission planning and policy development. WECC's forecasts reach out ten years and are more appropriately viewed as scenario analyses than as a formal forecast of future system conditions and costs (and thus they are not used as data sources for this study, except for the purpose of illuminating current stakeholder thinking about resource-driven congestion). While these data are integral to the WECC process, these kinds of scenario analyses are not ideal for illustrating the near-term congestion that is of particular interest for this Congestion Study. Nonetheless, WECC's results provide insights into stakeholder thinking on this general subject, although for a longer time period.

5.2. Infrastructure Update

Entities in the West have been building transmission since the 2009 Congestion Study (see Figure 4 - 8 in Chapter 4). All transmission projects affecting the reliability of the interconnection are coordinated through WECC. The comparatively recent formation of the Transmission Expansion Planning and Policy Committee (TEPPC) within WECC and the parallel formation of sub-regional transmission planning groups (see Figure 5 - 2) have contributed to increased information sharing among parties for projects in earlier stages of development.

The NERC 2011 Long Term Reliability Assessment (LTRA) indicates that there were 104,558 circuit-miles of transmission in service within the West region in 2011, and nearly 4% more circuit-miles in the planned or conceptual stages between 2011 and the end of 2015 (see Figure 5 - 2. Subregional transmission planning regions in Western Interconnection

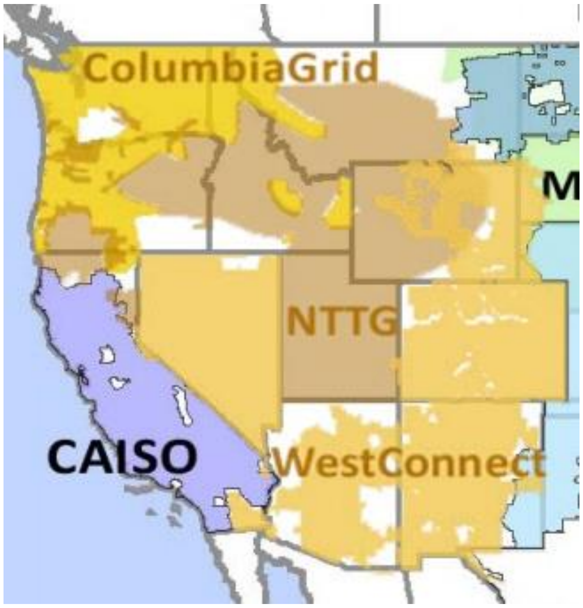
[80] California Public Utilities Commission (2011). *PUC Rulemaking 11-05-005, "Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program."* May 5, 2011, at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/134980.pdf; California Energy Commission (CEC), (2012b). *California's Renewable Portfolio Standard*, CREPC-SPSC Webinar. July 12, 2012, available from https://westgov.adobeconnect.com/_a976899620/p880svtnama/?launcher=false&fcsContent=true&pbMode=normal.



Source: Federal Energy Regulatory Commission (FERC) (2011f). "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities: Briefing on Order No. 1000 Presented by Federal Energy Regulatory Commission Staff." July 2011, at http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-presentation.pdf, p. 4.

Table 5 - 1There is no way to tell how much of the planned and conceptual transmission will actually go into service (and when) until construction begins on a specific project.

Figure 5 - 2. Subregional transmission planning regions in Western Interconnection



Source: Federal Energy Regulatory Commission (FERC) (2011f). "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities: Briefing on Order No. 1000 Presented by Federal Energy Regulatory Commission Staff." July 2011, at http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-presentation.pdf, p. 4.

Table 5 - 1. Circuit-miles of transmission (> 100kV) in-service and planned within the West, 2010–2015

Region	In-service in 2011 year end and under construction	Planned or conceptual transmission for 2012-2017
WECC	104,558	4,093

Source: NERC (2012g). 2012 Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2012,Table 31; available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf.

Still, important challenges remain in the West. Vast distances between generation and load can make transmission projects costly and complicated. Projects that span multiple jurisdictions can face difficult permitting processes that must be coordinated with one another.[81] Environmental regulations, particularly on federal land, make transmission project development time-consuming and expensive. Transmission challenges have been identified by some as a significant impediment to meeting California's RPS goals.[82] Planners in the West are finding some solutions to these challenges, including building new lines and making upgrades to existing lines and infrastructure.

[81] Dombek, C. (2012b). "Incoming Chair of WGA outlines the West's energy strategy." *Transmission Trends*, Issue 24, Volume 2. June 19, 2012.
[82] Dombek, C. (2012d). "SCE: Lack of transmission, lengthy approval process, inhibiting renewable integration" *Transmission Hub*. June 1, 2012.

The remainder of this section discusses a subset of major completed projects and projects under construction in the West. This discussion focuses on projects that are or will address congestion in the geographic areas identified by DOE in the 2006 Congestion Study as critical, of concern, and conditional.[83] This discussion is followed by an overview of the much larger list of projects identified by the WECC Subregional Coordination Group as likely to be built in the next ten years. Finally, citations and links are provided to references that identify other transmission projects that are in either the planning or conceptual phase.

Southern California

The 2009 Congestion Study identified Southern California as a critical congestion area. Since that time, several major transmission projects have been built or are near completion that will address the issues identified in the 2009 study.

The Sunrise Powerlink project was completed in June 2012; it will initially provide 800 MW—and ultimately 1,000 MW—of capacity into San Diego.[84] The early completion of this project helped to to ease the potential energy shortfall in the Southern California region due to the outage of the San Onofre Nuclear Generating Station (SONGS)—a benefit not anticipated during the project's development. While it would not have prevented the September 8, 2011 blackout in the Southwest, the Sunrise Powerlink will contribute materially to the reliability of the region.[85] (See text box on the following page.)

The California portion of the Devers–Palo Verde 500 kV No. 2 line began construction in June 2011; it was completed in September 2013 and is operational. The line connects the existing Valley substation in western Riverside County, California, to the new Colorado River substation in the eastern part of the same county.[86] The Arizona portion of this project, which would connect the Colorado River substation to Palo Verde and enable transport of more Arizona renewable resources to Southern California, is currently inactive.[87]

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[83] As noted in Ch 1, the present Congestion Study does not identify critical congestion areas, congestion areas of concern, or conditional congestion areas.

[84] San Diego Gas & Electric (SDG&E) (2012). "SDG&E Energizes Sunrise Powerlink." San Diego, Ca. June 18, 2012, at http://regarchive.sdge.com/sunrisepowerlink/release26.html.

[85] Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) (2012). *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations.* April 2012, at http://www.nerc.com/files/AZOutage_Report_01MAY12.pdf.

[86] California ISO (CAISO) (2012a). *2011-2012 Transmission Plan.* Prepared by Infrastructure Development. March 23, 2012, at http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf, p. 171; California Public Utility Commission (CPUC) (2012) "Southern California Edison's Devers-Palo Verde 500 kV No. 2 Transmission Line Project." at http://www.cpuc.ca.gov/environment/info/aspen/dpv2/dpv2.htm; https://www.sce.com/wps/portal/home/about-us/reliability/upgrading-transmission/dpv2/.

[87] WestConnect (2012). *2012 WestConnect Annual Ten-Year Transmission Plan, 2012-2021.* Prepared by MAPPCOR. February 16, 2012, at http://westconnect.com/filestorage/final_2012_wc_annual_ten_year_transmission_plan_021612.pdf, p. 46-47.

Several other projects have been built in this region to connect renewable resources to load. These include North Gila-Hassayampa 500 kV, Hassayampa-Mesquite #2 500 kV, and Midway-Bannister 230 kV.[88] The Tehachapi project, a complex of lines identified as critical to meeting California's RPS, is under construction with an in-service date of 2015; the project has the potential to bring 4,500 MW of renewable resources into the Los Angeles region.[89] Also, several conductor upgrades and capacitor installations have been made to increase usage of existing transfer capability from the Pacific Northwest to California and ensure more full usage of the existing California-Oregon Intertie (COI) and Pacific DC Intertie (PDCI) capacity.[90]

The permanent closure of SONGS in June 2013 has created some local reliability challenges for Southern California. SONGS had served an important role in providing not just electricity to consumers, but also voltage support in the area. A preliminary plan created by the California Public Utility Commission (CPUC), the California Energy Commission (CEC), and CAISO has identified both near-and longer-term transmission, resource (including demand response, efficiency storage and renewables, as well as conventional), and regulatory solutions to ensure reliability in this area. Several infrastructure installations have been proposed to support reactive power in the region: a synchronous condenser at the Talega substation (in service targeted before summer 2015); a static VAR compensator at San Onofre Mesa substation (which requires additional regulatory approvals); and the possibility of converting one of the SONGS generators into a synchronous condenser. A new 230 kV transmission line from Sycamore Canyon to Penasquitos, with an online target date of 2017, has been approved by CAISO (although a builder still needs to be identified and regulatory approval sought) and would relieve some existing congestion in the region that has been exacerbated by the SONGS shutdown.[91] [92]

[88] California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance.* Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf, p. 146.

[89] California ISO (CAISO) (2012a). *2011-2012 Transmission Plan.* Prepared by Infrastructure Development. March 23, 2012, at http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf, p. 8.

[90] California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance.* Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf, p. 146; ColumbiaGrid (2011a). *2011 System Assessment*. Portland, OR: ColumbiaGrid. July 1, 2011, at http://www.columbiagrid.org/download.cfm?DVID=2273, pg 65.

[91] California Public Utilities Commission (CPUC), California Energy Commission (CEC) and California Independent System Operator (CAISO) (2013). "Preliminary Reliability Plan for LA Basin and San Diego." Draft August 30, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-08-30_prelim_plan.pdf

[92] San Diego Gas & Electric (SDG&E) provided information through the public comment regarding the effect of the closure of SONGS on congestion in that region. They commented that even with the approved transmission upgrades there will be congestion during extreme weather conditions. In addition, they commented, the retirement of SONGS may limit the amount of renewable generation able to be exported from the Imperial Valley to other areas. For more, see the comments filed by SDG&E.

Sunrise Powerlink and the Challenges Involved in Forecasting Transmission Impacts

The controversy surrounding San Diego Gas and Electric's (SDG&E) Sunrise Powerlink (Sunrise) predated preparation of the first DOE Congestion Study in 2006.[1] Much of this controversy centered on whether the line was needed in order to access renewable generation from the Imperial Valley. After a highly publicized decision process, the CPUC authorized construction, and in Spring 2012 the $1.9 B Sunrise Powerlink was energized. Despite the extensive range of issues considered during that decision process, the line today serves a purpose that was not a focus during those discussions.

Currently, Sunrise is not fully subscribed with renewable resources, as some of these resources have not yet come on-line. However, with the recent outage of the San Onofre Nuclear Generating Stations, Sunrise is providing California and the Southwest with an extra degree of flexibility that the state needs now that these plants are out of service.

Without Sunrise, power imports to the San Diego area were delivered primarily through two points of interconnection: the 500-kV Southwest Powerlink at SDG&E's Miguel substation (which accesses power from the east and south), and a series of 230-kV lines (Path 44) connecting through the San Onofre switchyard to the north. Neither of these paths (without San Onofre running) were capable of serving the full peak load requirements of SDG&E's local reliability area if the other was out of service.

CAISO President and CEO Steve Berberich has reported that the Sunrise Powerlink's completion "could not come at a more critical time" and that the project "is more valuable today than when it was conceived because of the significant reliability benefits it brings helping to compensate for the loss of power from the San Onofre power plant this summer." Still, according to CAISO, Sunrise would not have prevented the Arizona-Southern California outages of September 8, 2011.

The Sunrise Powerlink is an example of the "optionality" or insurance-value that transmission projects have many times provided to the power system in the form of positive benefits not envisioned when the projects were first conceived. It illustrates how transmission projects may increase system flexibility and resilience in unforeseen ways, and enable system operators to cope more smoothly and efficiently with unanticipated developments. It also illustrates the potential limitations of planning long-lived transmission assets on the basis of more narrowly-defined studies that focus only on the next few years. See Budhraja, Dyer, Hess (2003) for other examples drawn from California.[2]

[1] Transmission Weekly (2012c). "SDG&E's Sunrise Powerlink energized just in time to provide summer reliability." *Transmission Weekly*. June 25, 2012.
[2] Budhraja, V., J. Dyer, and S. Hess. (2003). *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues and Policy Recommendations*. October 2003. http://certs.lbl.gov/pdf/ca-grid-plan.pdf.

San Francisco Peninsula

The 2009 Congestion Study identified the San Francisco Peninsula as a congestion area of concern. Since that time, two major transmission projects have been energized that address the issues identified in the 2009 study. The Trans Bay Cable went into commercial operation in November 2010, and the Oakland Underground Cable was completed in May 2010. Both of these projects connect the load center of San Francisco to the East Bay area and improve reliability and congestion in the Bay Area. The Trans Bay Cable also enabled the shut-down of the Potrero power plant, which had been running under reliability must-run designation.[93]

Seattle-Portland

The 2009 Congestion Study identified the Seattle to Portland region as a congestion area of concern. The main transmission solution under discussion at that time was the I-5 Corridor Reinforcement Project, which specifically aimed to reduce congestion between the Seattle and Portland areas.[94] The project is currently under environmental study and routing alternatives are being considered. It has an expected in-service date of 2016.[95] The project was included in the ColumbiaGrid Ten-Year Study plan, which consists of projects that are deemed committed and likely to be built.[96]

The McNary to John Day line (also called the West of McNary reinforcement) was completed 10 months ahead of schedule by the Bonneville Power Administration (BPA).[97] This transmission line was built to meet transmission service requests in BPA's queue, including from wind power east of the Cascades for load centers west of the Cascades. BPA and other utilities in the ColumbiaGrid area recently completed several substation and transformer upgrades.

Common Case Transmission Assumptions and west-wide planned and conceptual projects

The Regional Planning Coordination Group, which advises WECC and is made up of the subregional 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.[98] The criteria for projects on the list (called the Common Case Transmission Assumptions, or CCTA) include factors such as regional significance; whether it is under construction already; and whether a financial commitment has been made for construction.[99]

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[93] California ISO (CAISO) (2011a). *2010 Market Issues & Performance Annual Report.* Folsom, CA: CAISO. April 2011. http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf., p. 125.

[94] Landauer, M. (ColumbiaGrid) (2011). "Comments of Marv Landauer." Provided at the United States Department of Energy (2011a). *National Electric Transmission Congestion Study Workshop*. Portland, Oregon, December 13, 2011, available at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Portland%20Workshop.pdf, p. 64.

[95] Bonneville Power Administration (BPA) (2012a). *I-5 Corridor Reinforcement Project: Project Update.* January 2012, available at http://www.bpa.gov/Projects/Projects/I-5/Pages/default.aspx

[96] ColumbiaGrid (2011a). *2011 System Assessment*. Portland, OR: ColumbiaGrid. July 1, 2011, at http://www.columbiagrid.org/download.cfm?DVID=2273, pp. 7-8.

[97] Bonneville Power Administration (BPA) (2012c). "BPA completes McNary-John Day line ahead of schedule and under budget." March 1, 2012, at http://www.bpa.gov/corporate/BPANews/ArticleTemplate.cfm?ArticleId=article-20120301-01; ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan.* Portland, OR: ColumbiaGrid. February 15, 2012, at http://www.columbiagrid.org/download.cfm?DVID=2563, p. 53.

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

[99] Western Electricity Coordinating Council (WECC) (2010). *SPG Coordination Group (SCG) Foundational Transmission Project List.* Salt Lake City, UT: WECC. August 2010, available from https://www.wecc.biz/Reliability/2011Plan_SCGFoundationalTransmissionProjectListReport.pdf.

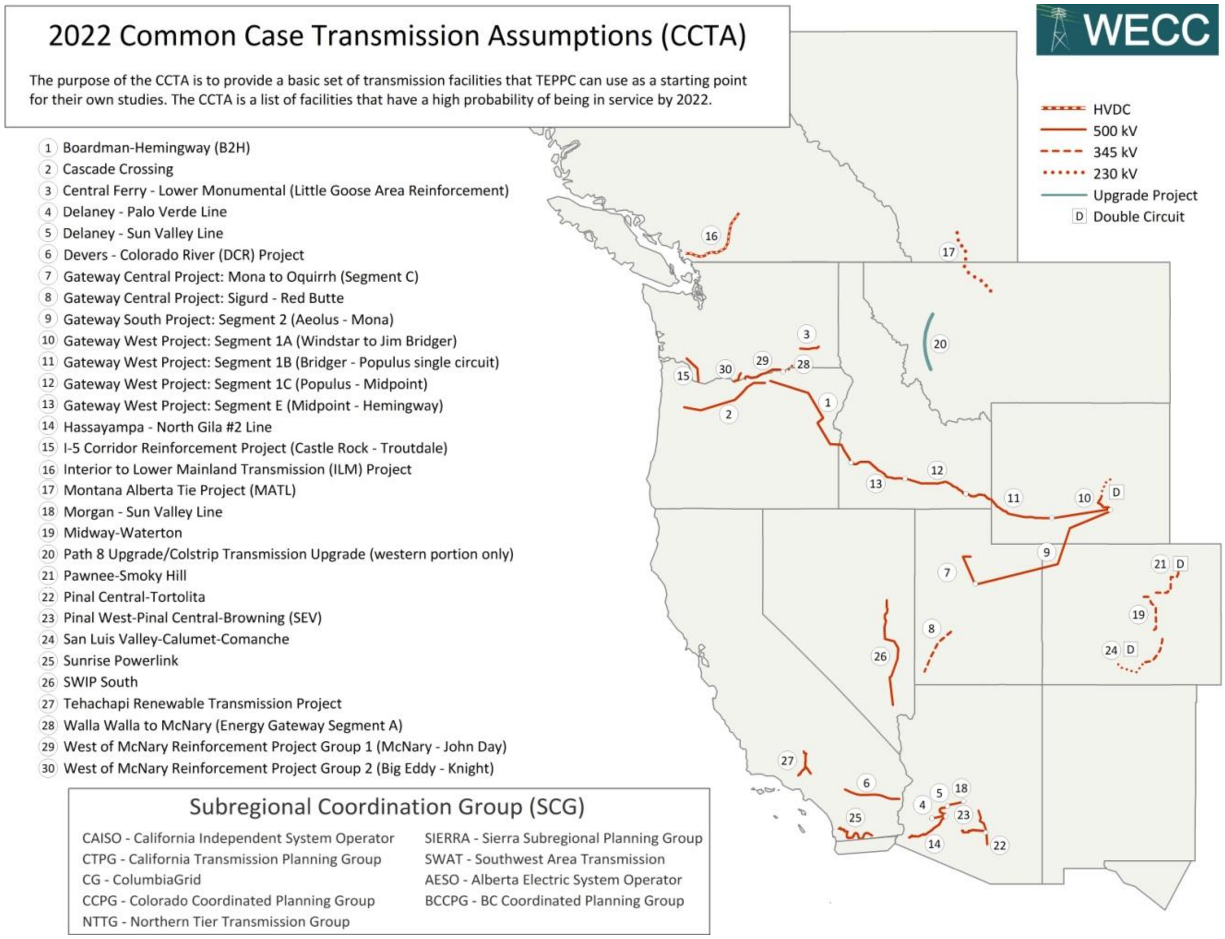
TEPPC uses this list in their ten-year planning analysis, adding a few projects as necessary to ensure a solvable power flow (see Figure 5 - 3).

While this list identifies projects that are expected to be built in the next decade, there are many other projects being studied and planned by a variety of entities across the West.[100] WECC also maintains an online list of transmission projects that are self-reported by project developers.[101] These projects in the planning or conceptual phase address many objectives, ranging from improving reliability and reducing congestion to integrating or transporting renewable power to load centers and creating high voltage backbone lines in the West.

[100] See for instance, ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan.* Portland, OR: ColumbiaGrid. February 15, 2012, at http://www.columbiagrid.org/download.cfm?DVID=2563; WestConnect (2012). *2012 WestConnect Annual Ten-Year Transmission Plan, 2012-2021.* Prepared by MAPPCOR. February 16, 2012, at http://westconnect.com/filestorage/final_2012_wc_annual_ten_year_transmission_plan_021612.pdf; Northern Tier Transmission Group (NTTG) (2011). *2010-2011 Biennial Transmission Plan.* December 1, 2011, at http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1437&Itemid=31; New Mexico Renewable Energy Transmission Authority (RETA) (2011). *RETA Annual Report: 2010-2011.* http://www.nmreta.com/images/stories/pdfs/retaannualreport2011.pdf; Montana's Governor's Office of Economic Development (2010). *Montana Transmission For America.* Helena, MT. http://commerce.mt.gov/content/Energy/docs/BrochureTransmission.pdf.

[101] Western Electricity Coordinating Council (WECC) (2012c). "WECC Transmission Project Informational Portal." Salt Lake City, UT: WECC. August 2012, available at https://www.wecc.biz/TransmissionExpansionPlanning/Lists/Project%20Portal/AllItems.aspx .

Figure 5 - 3. Map of 2022 Common Case transmission assumptions projects



Source: Subregional Planning Group Coordination Group (2012). 2022 Common Case Transmission Assumptions (CCTA). February 2012, available from https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/TEPPC_2022_StudyReport_PC1%20Common%20Case.docx&action=default&DefaultItemOpen=1

Note: Recent utility filings and communications have stated that the San Luis-Calumet-Comanche project (number 24 in this figure) will not be built.

5.3. Regional Findings

The Department's findings are based on consultation with state officials and industry stakeholders, as well as a review of publicly available documents and data available through the end of 2012, with limited updates in December 2013.[102] The Department finds:

- Although a number of paths in the Western Interconnection are heavily utilized, most of these do not appear to be operating at such consistently high levels that they act as

[102] As described in the Note to Readers, the Department has published its compilation of this information for 2009-2012 in a standalone document (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf).

persistent, reliability-threatening transmission constraints. In 2009 (the only year for which data is publicly available), unscheduled flow mitigation procedures were used less than 0.5% of the hours of the year.

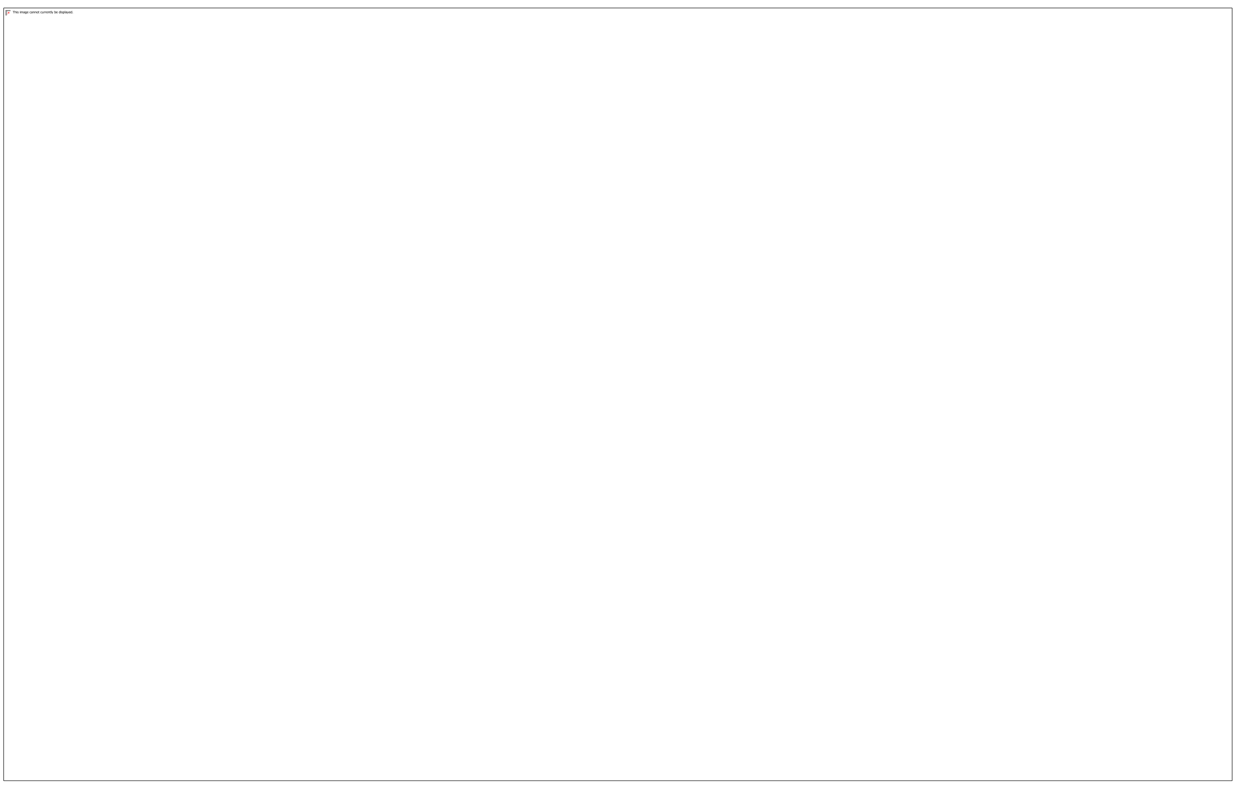
- With respect to the economic consequences of congestion, there is only information available about the area covered by CAISO. That information indicates that individual transmission constraints limit system operations in at most 8% of the year, and that these constraints do not increase electric prices and congestion costs by a significant amount.
- There has been a marked increase in transmission construction and project completions across the West over the past three years, and equal progress in planning and coordination of new transmission project proposals. These completions have already improved western transmission throughput, reducing usage on many key interfaces and reducing congestion and associated costs.
- In addition, the permanent closure of the San Onofre Nuclear Generating Station has created some local reliability challenges for Southern California. A preliminary inter-agency plan has proposed several near- and longer-term transmission, resource and regulatory solutions to ensure reliability in this area, and to address existing congestion that was exacerbated by the plant closure.
- Although current congestion in the West is relatively low, in the next few years more congestion is expected due to transmission constraints related to new development of renewable resources and upcoming generator retirements. This is evidenced by WECC's list of Common Case Transmission Projects, which are not yet built or operational, but are assumed to become so within ten years for the purposes of WECC's interconnection-wide planning studies. Congestion resulting from these constraints could be exacerbated by higher demand growth induced by extreme weather or economic activity.
- Many factors make future congestion patterns hard to predict—these complications include the impacts of environmental regulations (both federal and state level), state RPS compliance requirements, the pace of general economic recovery, relative fuel prices for electricity generation, new natural gas, nuclear, and other generation construction, and the feasibility of building long high-voltage transmission lines across federal lands.

6. Transmission Congestion and Constraints in the Eastern Interconnection

6.1. Overview of the Eastern Interconnection

This chapter reviews transmission congestion and constraints in the Eastern Interconnection. The opening section looks at broad patterns across the East; subsequent sections examine transmission congestion and constraints in the Midwest (section 6.2), Northeast (section 6.3) and Southeast (section 6.4) regions. Within each regional section, the study offers summary observations and data which support these observations and closes with a review of recent infrastructure developments within the region. Figure 6 - 1 shows the boundaries of each of these regions.

Figure 6 - 1. Midwest, Northeast, and Southeast regions[103]



Energy flows across the East have changed somewhat relative to 2009 because customer demand is down, fuel prices are lower, and wind generation from remote locations has increased. In addition, earlier transmission planning and permitting efforts have yielded infrastructure additions and upgrades over the past five years, enhancing the grid's capacity in

[103] Map regions are drawn to show geographic boundaries and not necessarily electrical ones. Transmission facilities shown in stated regions are not necessarily owned or operated by entities within that region.

load centers and at previously critical constraints. As a result of these changes, existing transmission constraints bind less often (and with lower congestion cost impacts) than they did during the periods leading up to the preparation of the 2009 and 2006 Congestion Studies. Nonetheless, total congestion costs still amount to hundreds of millions of dollars annually in the regions where such costs are calculated and published, warranting on-going efforts to understand and address them.[104]

Many points of transmission congestion today result from the need to deliver electricity from changing sources of generation. For example, generation sources are changing because of state-mandated RPSs; the best onshore wind resources (i.e., those with the highest potential capacity factors) tend to be located far from load and sometimes in areas with less transmission than desired for effective resource development.[105] Existing transmission constraints may deter development of these resources.[106] While this is not a challenge in all parts of the Eastern Interconnection, it is a principal cause of evolving congestion concerns in the Midwest.

Another example of changing generation portfolios arises from lower natural gas prices and new environmental regulation. The combination of inexpensive natural gas and new regulations has already caused a number of Eastern power plants to be taken out of service for major retrofits or retired. These changes in the generation fleet may create new short- and possibly long-term transmission constraints that cannot be predicted fully today.

It also appears that a significant portion of current congestion occurs at or near the seams between RTOs, ISOs and other grid operations areas (e.g., balancing authorities). At FERC's direction, the RTOs and ISOs are addressing the institutional and administrative differences between their respective market rules and operating practices, which create or exacerbate such congestion.[107]

[104] For instance, many organized markets publish information about congestion cost or congestion value calculated based on the congestion component of locational marginal prices. There is not universal agreement that this is the most informative way to calculate and measure congestion. NYISO, for instance, calculates and reports bid production cost savings as a measure of congestion.

[105] This is not always true, however. The best offshore renewable wind resource, for instance, can be located close to load centers, as is the case with New England.

[106] As Chapter 2 indicates, if there is a lack of adequate transmission capacity to deliver desired new sources of generation without violating reliability requirements, this is a resource-driven transmission constraint.

[107] Several initiatives have been implemented or are being planned for this region to address these issues including the following: NYISO interface pricing improvements aimed at reducing loop flow; PJM/NYISO market-to-market implementation intended to improve efficiency of congestion management and cross-border price convergence; a shift from hourly to 15-minute cross-region scheduling, which increases flexibility for responding to price impacts of unintended loop flow; and design and intended implementation of Coordinated Transaction Scheduling on the NYISO/PJM and NYISO/ISO-NE borders, which allows bidders to specify the price difference for which they are willing to schedule trades and is anticipated to result in production cost and consumer savings. See ISO-NE (2012d). *ISO New England, Inc. and New England Power Pool*, 139 FERC ¶ 61,047 (Docket No. ER12-1155) (April 19, 2012), at 24. http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf, and NYISO (2014). "Broader Regional Markets Informational Report" filed in compliance with the December 30, 2010 *Order on Rehearing and Compliance* in Docket No. ER08-1281.

The nature of congestion in the Eastern Interconnection is changing because of maturation of wholesale markets, implementation of state-level RPSs, and changes in resource mix. In response to these changing challenges, regions are modifying their planning processes.

The RTOs' multi-stakeholder regional planning efforts have now been in existence for as long as a decade, and have led to completions of major transmission projects that have eased some of the transmission constraints previously creating congestion within the RTOs' boundaries. However, constraints remain.[108] Constraints also continue to create transmission congestion at the boundaries between the RTOs or with other adjacent planning areas. A constraint in one region can affect operations (and hence costs) in a neighboring region. In addition to the market-rule-based initiatives to address the concerns described above, several interstate and inter-RTO planning efforts are now addressing these concerns.[109]

Figure 4 - 5 in Chapter 4 shows that most of the states across the Northeast and Midwest have some form of RPS or renewables procurement requirement. These requirements are changing the way the regions produces electricity and the patterns of congestion across the regions. Further cooperation may mitigate some of the complexity of implementing an RPS—for instance, the New England Governors signed a resolution directing the New England States Committee on Electricity to begin "coordinated competitive procurement" of renewable energy.[110]

In addition, the nature and function of the transmission system is changing as the electric system's resource mix changes. Although the current transmission system was designed primarily to deliver fully schedulable electricity supplies to serve peak loads, the growth in renewable generation is straining the peak-load-serving transmission model. Wind generation in particular is valued as an inexpensive source of energy, but has limited capacity value during system peak periods. Across the Eastern Interconnection, increasing levels of wind generation are causing off-peak congestion at specific flowgates, as this energy flows along lines that were designed to meet peak loads in load centers rather than deliver peak production from wind generation centers. Several recent studies on how to integrate variable renewable energy

[108] Studies conducted by the Northeastern ISO/RTO Planning Coordination Protocol have not identified a need for additional transmission investment that is not currently under development. See ISO New England (ISO-NE), New York ISO (NYISO), PJM (2014). *2013 Northeast Coordinated System Plan*. April 16, 2014, at http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2014/mar282014/2013_ncsp.pdf and ISO-NE, NYISO, PJM (2012). *2011 Northeast Coordinated System Plan*. May 31, 2012, at http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2011_ncsp.pdf.

[109] These include the Eastern Interstate Planning Collaborative and Eastern Interconnection States Planning Council; various multi-RTO seams coordination agreements and market-to-market coordination and management efforts such as MISO-PJM-NYISO Broader Regional Markets Study; 272; Quanta Technology (2010a). *Strategic Midwest Area Renewable Transmission (SMART) Phase I Study*. July 1, 2010, at http://www.smartstudy.biz/include/pdf/phase_one_report.pdf; and the cooperative efforts prompted by FERC's Order 1000 cross-region planning requirements.

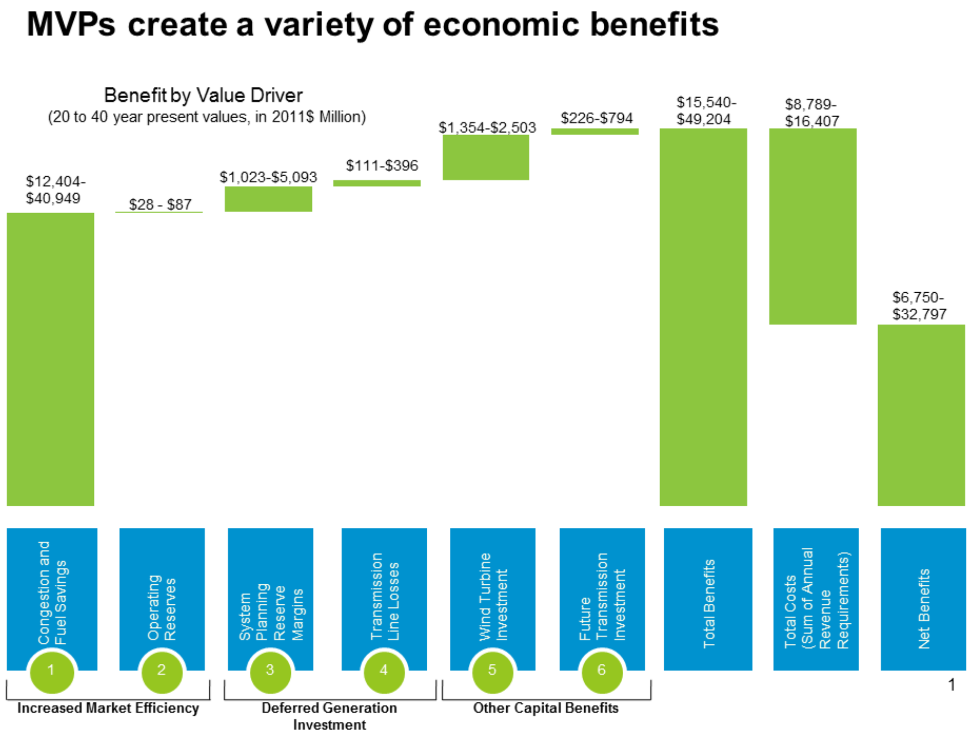
[110] New England Governors Conference (2012). "A Resolution Directing the New England State *[sic]* Committee on Electricity (NESCOE) to Implement a Work Plan for the Competitive Coordinated Procurement of Regional Renewable Power," July 2012, at http://www.nescoe.com/uploads/CP_Resolution_July_2012.pdf.

resources offer insight on how to modify and manage the Eastern transmission system to accommodate renewable generation better—see, for example, the *Eastern Wind Integration and Transmission Study* prepared by the National Renewable Energy Laboratory,[111] and several regional studies.[112] New demand-response resources are contributing to renewables integration and moderating transmission congestion in and around load centers.

These factors are affecting how transmission systems are planned and are addressed across the Eastern Interconnection in a manner that necessarily reflects regional differences in accordance with market structures and regulatory requirements. While non-RTOs address many of the economic ramifications associated with these changes through their integrated resource planning processes that, in turn, drive their transmission planning processes, some regions are responding to these challenges, in part, by changing their transmission planning processes. MISO, SPP, and PJM have modified their formal planning processes over the past few years to go beyond reliability considerations alone, and take account of a variety of potential system benefits as they assess a portfolio of alternative transmission opportunities.[113] MISO and SPP in particular have found that planning and designing a balanced set of transmission projects that ensure reliability and provide economic congestion relief can offer more benefits overall—of which economic congestion relief is the largest component at the time the analysis was conducted (as shown in Figure 6 - 2).[114]

[111] Enernex Corporation (2010). *Eastern Wind Integration and Transmission Study*. Prepared for the National Renewable Energy Laboratory. January 2010, at http://www.nrel.gov/docs/fy11osti/47086.pdf.
[112] NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Renesselaer, NY: NYISO. September 2010, http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf; GE Energy, Enernex AWS Truepower (2010). *Final Report: New England Wind Integration Study*. Prepared for ISO-NE, December 5, 2010, at http://www.uwig.org/newis_es.pdf.
[113] New England has an economic planning process, but has not seen the need for Market Efficiency Transmission Upgrades due to the low levels of congestion on its system.
[114] Osborn, D. (MISO) (2011). "Comments of Dale Osborn." Provided at the United States Department of Energy (2011e). *National Electric Transmission Congestion Workshop*. St. Louis, MO. December 8, 2011, at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf.

Figure 6 - 2. Economic benefits and benefit categories from MISO MTEP multi-value project portfolio



Source: Osborn, D. (MISO) (2011). "MISO Comments for the DOE Congestion Workshop." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops", at http://energy.gov/sites/prod/files/Presentation%20by%20Dale%20Osborn%2C%20MISO.pdf , pp. 10-11; MISO (2011e). MISO 2011 Transmission Expansion Planning (MTEP) report. Carmel, IN: MISO. Accessed December 2011, at https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP11.aspx.

6.2. Infrastructure Updates

6.2.1. Midwest

This section discusses a subset of major completed projects and projects under construction in the Midwest. After a brief review of overall trends in the Midwest, the discussion focuses on projects relevant to congestion in the geographic areas identified by DOE in the 2009 Congestion Study as conditional.[115]

The NERC 2011 LTRA indicates that there were 93,604 circuit-miles of transmission in service within the Midwest region in 2011, and about 4% more circuit-miles in the planned or conceptual stages between 2011 and the end of 2015 (Table 6 - 1). There is no way to tell how much of the planned and conceptual transmission will actually go into service (and when) until construction begins on a specific project. NERC's reporting areas do not correspond exactly with

[115] As noted in Chapter 2, this Congestion Study does not identify critical congestion areas, congestion areas of concern, or conditional congestion areas.

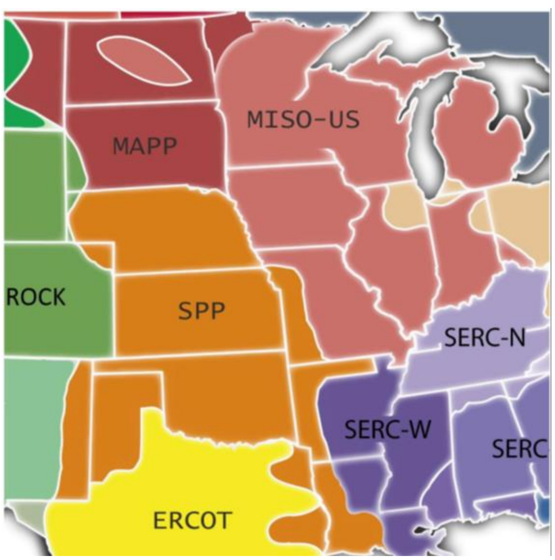
this study's geographic regions (see Figure 6 - 3), so these numbers may over-estimate the amount of new transmission to be built in the Midwest. Much of the MRO[116]–MAPP[117] construction will serve growing load in North and South Dakota associated with oil shale development and wind development in Minnesota. The SPP construction will better integrate new wind developments in the central and southern plains and enhance grid performance throughout the region.

Table 6 - 1. Circuit-miles of transmission (> 100kV) in-service and planned within the Midwest 2010–2015

Region	In-service in 2011 year end and under construction	Planned or conceptual transmission for 2012-2017
MISO	44,661	1,838
MRO-MAPP	10,496	716
SPP	33,519	1,613
Total	**88,676**	**4,167**

Source: NERC (2012g). 2012 Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf, Table 31.

Figure 6 - 3. Map of NERC LTRA regions in the Midwest



Source: NERC (2011c). 2011Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. iv.

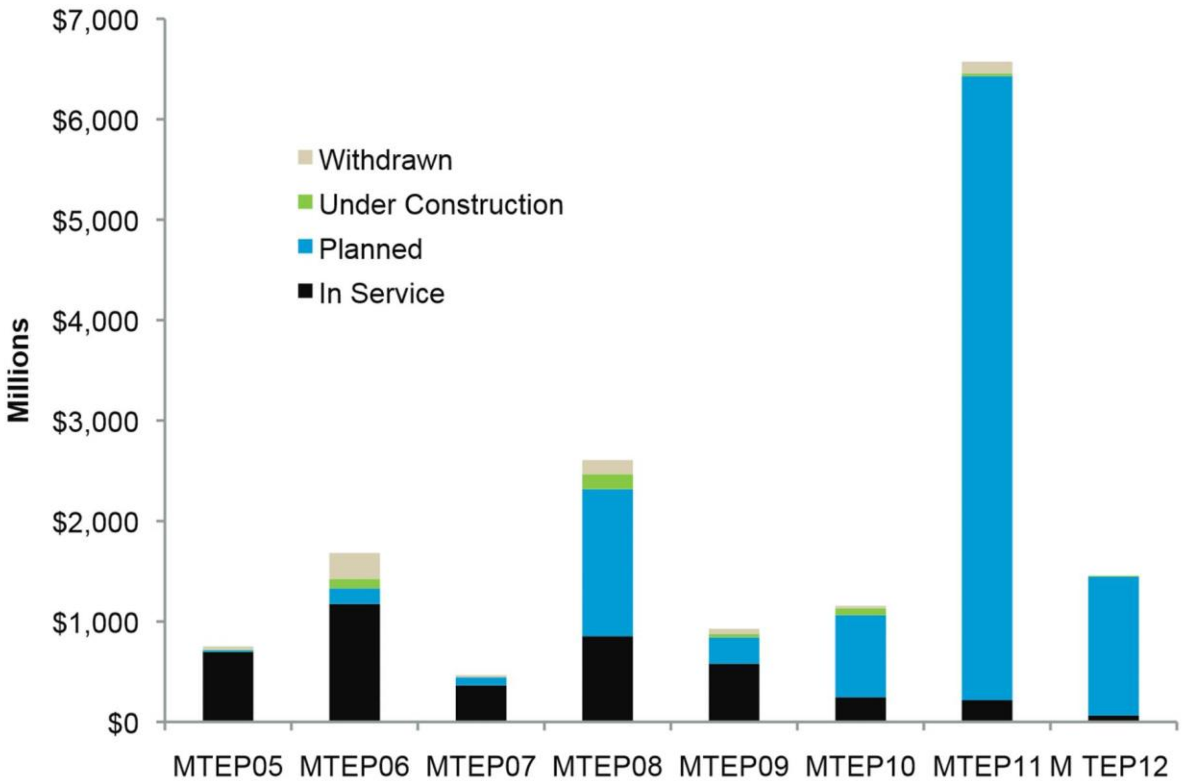
Figure 6 - 4 shows the amount of transmission investment approved and built within MISO since 2003. These projects are initiated in MISO's annual MISO Transmission Expansion Plan (MTEP) multi-stakeholder planning process, then approved by the MISO Board of Directors, and

116 Midwest Reliability Organization

117 Mid-continent Area Power Pool

eventually built by transmission owners. This figure illustrates two important points—that there is a significant lag time between a project's inclusion in the MTEP plan, approval, construction, and the in-service date,[118] and that the amount of approved investment has trended higher over time. Most of the MTEP projects through the MTEP2010 were justified on the basis of reliability needs alone; MTEP2011 was the first year in which MISO's stakeholders addressed and approved a portfolio of Multi-Value Projects (MVPs) that are justified in terms of economic benefits (such as congestion reduction), as well as enhanced grid reliability and policy measures (such as renewable generation mandates).[119]

Figure 6 - 4. Cumulative approved MISO Transmission Expansion Plan investments over time by facility status, through 2012



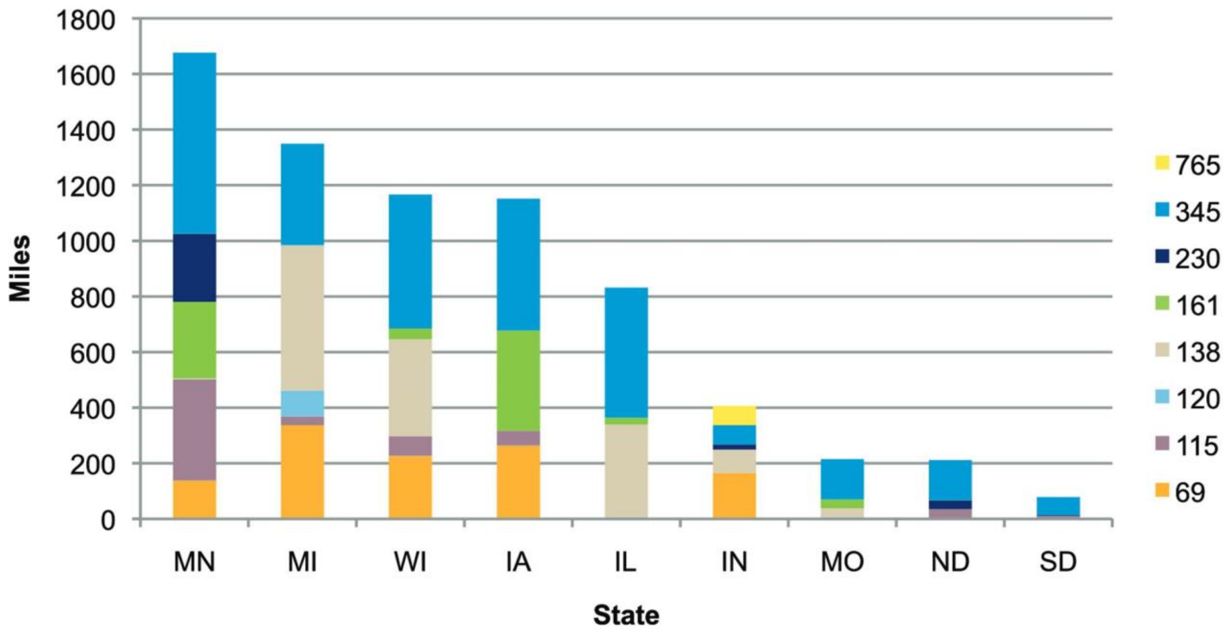
Source: MISO (2012). MISO Transmission Expansion Plan 2012, Executive Summary. Carmel, IN: MISO. December 3, 2012, p. 6.

With completion and approval of MISO's 2012 Transmission Expansion Plan, MISO's Transmission Expansion Process has now approved a total of $8.94 billion of new transmission

[118] NERC's 2011 Long Term Reliability Assessment observes that once transmission alternatives have been identified, it can take over ten years to complete the process from project identification through permitting, construction and energization. Source: NERC (2011c). *2011 Long-Term Reliability Assessment*. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. 33.
[119] Osborn, D. (MISO) (2011). "MISO Comments for the DOE Congestion Workshop." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops", available from http://energy.gov/sites/prod/files/Presentation%20by%20Dale%20Osborn%2C%20MISO.pdf, p. 8.

expansion and upgrade projects to be completed through 2022.[120] MISO reports that 17 of these are MVPs that "will create a regional network that provides reliability, public policy and economic benefits spread across MISO."[121] MISO estimates that, in total, this group of projects should mitigate over 650 reliability violations; enable delivery of 41 million MWh of renewable energy; deliver economic benefits 1.6 to 2.8 times in excess of their costs; reduce transmission congestion costs; and create over 17,000 jobs.[122] Figure 6 - 5 shows the miles of new or upgraded transmission projects expected online by 2021 (by state and voltage) that have been reviewed and approved to-date under MISO's transmission expansion planning process.

Figure 6 - 5. New or upgraded line-miles of transmission approved through MISO Transmission Expansion Plan 2012, by state and voltage class, expected in-service by 2022



Source: MISO (2012). MISO 2012 Transmission Expansion Planning (MTEP) report. Carmel, IN: MISO. December 2012, available from https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12/MTEP12%20Report.pdf*, Figure 2.1-5, p. 18.*

Although many traditional transmission projects are moving ahead in the MISO footprint (including such examples as the CapX2020 effort to open up wind development areas in Minnesota, ATC construction in Wisconsin, and the Thumb Loop 345 kV line in Michigan), there are a few unknowns on the horizon. For example, it is estimated that there is 700 GW of off-shore wind potential in the Great Lakes.[123] Although these projects will not be developed

[120] MISO (2012). *MISO 2012 Transmission Expansion Planning (MTEP) report*. Carmel, IN: MISO. December 2012, p. 20.

[121] MISO (2011e). *MISO 2011 Transmission Expansion Planning (MTEP) report*. Carmel, IN: MISO. December 2011, available from https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12/MTEP12%20Report.pdf p. 1.

[122] *Ibid*.

[123] Opalka, B. (2012). "Feds and states want to quicken Great Lakes offshore wind approvals." *Generation Hub*. March 30, 2012, at http://generationhub.com/2012/03/30/feds-and-states-want-to-quicken-great-lakes-offsho.

within the timeframe of this study, they represent the kind of development that could materially change the pattern of generation and transmission flows across the East.

Across the Midwest, transmission systems are based on legacy systems developed by independent, vertically integrated utilities. SPP comments that "[w]hile these systems may be functionally sufficient for their respective areas, they may not be sufficient for macro transfers across the region. SPP has been working with and coordinating transmission development throughout the region to increase the system's overall reliability, efficiency, and effectiveness."[124]

Within the SPP footprint, over $7.1 billion of proposed transmission upgrades and expansions have been approved by stakeholders and are now proceeding through permitting and construction. These projects are intended to meet expected reliability, economic, efficiency, and policy requirements, and interconnect new generation (see Figure 6 - 6).

As of July 2013, SPP was tracking a portfolio of 559 active transmission projects including 4,712 miles of new and re-conductored lines (voltages ranging from 69 to 345 kV) with a cumulative cost of $6.67 billion.[125] SPP expects that these projects will mitigate much of the current congestion on their system.

There are three proposed extra-high-voltage AC and HVDC projects in the SPP area that could have a significant effect on the lower Midwest's future transmission infrastructure and electricity flows:

- The Tres Amigas proposal would build a merchant transmission "superstation" in New Mexico to link SPP, WECC and ERCOT via extra-high-voltage AC and HVDC lines, in order to move low-cost generation between the three interconnections. Tres Amigas had expected that its first operational phase, linking WECC and SPP, would begin commercial operation in 2015, but the project groundbreaking has since been delayed.[126]
- The Plains & Eastern Line is an approximately 700-mile, HVDC line planned by merchant transmission developer Clean Line Energy, with a target in-service date of 2018. The line would originate in the Oklahoma Panhandle and will be capable of delivering 3,500 MW of wind power to an interconnection point in Tennessee and 500 MW to an interconnection point in Arkansas.
- Another proposed Clean Line Energy project, the Grain Belt Express Line, is an approximately 750-mile HVDC line from western Kansas to Indiana with a target in-

[124] Southwest Power Pool (SPP) Market Monitoring Unit (2012e). *2012 Transmission Expansion Plan (STEP) Report*, Little Rock, AR: SPP, Inc. January 31, 2012, at http://www.spp.org/publications/2012%20STEP%20Report.pdf, p. 29.

[125] Southwest Power Pool, Inc. (2013), *Fourth Quarterly Project Tracking Report,* October 2013, at http://www.spp.org/publications/SPP%20Project%20Tracking%20Report%20-%204th%20Quarter%202013.pdf, p. 3.

[126] Dombek, C. (2012a). "Tres Amigas delays groundbreaking." *Transmission Hub*. June 25, 2012.

service date of 2018. The line would be capable of delivering 500 MW of wind power to an interconnection point in Missouri and 3,500 MW to an interconnection point near the Illinois-Indiana border.[127]

- The proposed Rock Island Clean Line is an approximately 3,500 MW capacity, 500-mile HVDC line, planned to originate in northwest Iowa and terminate in northern Illinois.[128]

Although these projects will not come online within the timeframe of this study, if even one of them succeeds, its existence could materially change load flows, long-term congestion patterns, and transmission infrastructure plans within the Midwest and Southeast.

In addition to changes to the physical system, this region is experiencing changes in grid management. Two recent changes in particular to note include expansion of the MISO footprint, and the recent integration of Entergy and several other transmission owners and balancing authorities into the MISO system; these changes are likely to affect seams management between ISOs and RTOs as well as non-ISO/RTO areas in the region.[129] [130]

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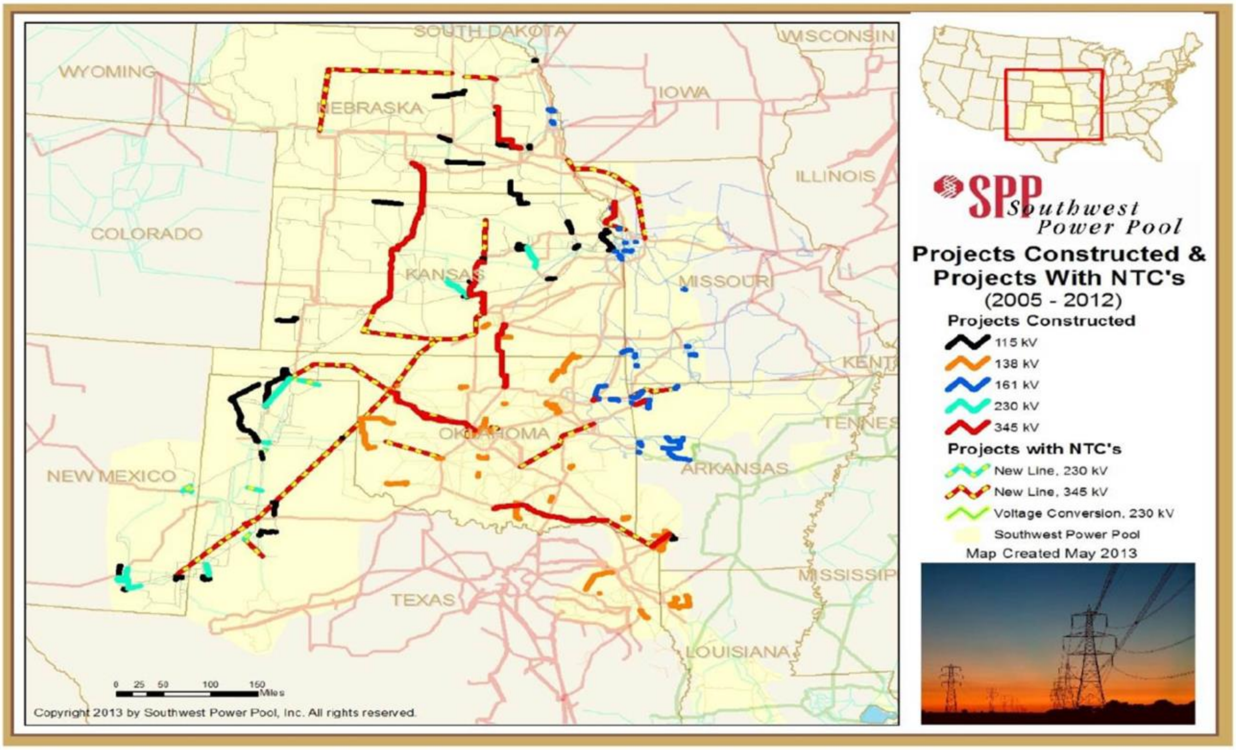
[127]Clean Line Energy Partners (2012b). "Grain Belt Express Clean Line" *Transmission project website*, at http://www.grainbeltexpresscleanline.com/site/page/project_description.

[128] Clean Line Energy Partners (2014). "Rock Island Clean Line." Transmission project website, at http://www.rockislandcleanline.com/site/page/project-description.

[129] MISO, (2013). "MISO completes largest-ever power grid integration." Press release on December 19, 2013, at https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOCOMPLETESLARGEST-EVERPOWERGRIDINTEGRATION.aspx.

[130] In addition, the more recent launch of the SPP Integrated Marketplace in March 2014 has allowed for different congestion management procedures and study opportunities. See, for instance, Potomac Economics (2013). "Frequently Constrained Areas." December 10, 2013, at www.spp.org/publications/BODAGD&BKGD121013.pdf.

Figure 6 - 6. SPP approved major transmission projects



Source: Nickell, L. (2013). Planning Summit Kick-off. May 15, 2103, at http://www.spp.org/section.asp?group=2753&pageID=27, p. 8.

6.2.2. Northeast

This section discusses a subset of major completed projects and projects under construction in the Northeast. The discussion highlights projects that are or will address congestion in the areas identified by DOE in the 2009 Congestion Study as critical.[131]

The NERC 2011 LTRA indicates that there were 71,047 circuit-miles of transmission in service within the Northeast region in 2011, and nearly 2% more circuit-miles in the planned or conceptual stages between 2011 and the end of 2015 (see Table 6 - 2). There is no way to tell how much of the planned and conceptual transmission will actually go into service (and when) until construction begins on a specific project. NERC's reporting areas do not correspond exactly with this study's geographic regions (see Figure 6 - 7), so these numbers may underestimate the amount of new transmission to be built in the Northeast.

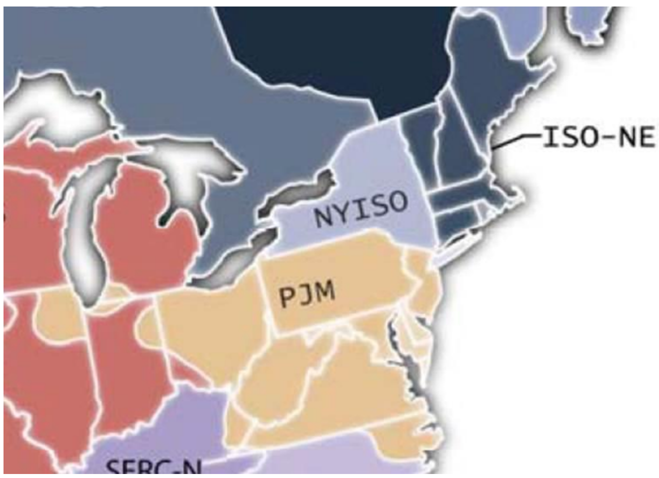
[131] As noted in Chapter 2, this Congestion Study does not identify specific areas as critical congestion areas, congestion areas of concern, or conditional congestion areas.

Table 6 - 2. Circuit-miles of transmission (> 100kV) in-service and planned within the Northeast 2010–2015

Region	In-service in 2011 year end and under construction	Planned or conceptual transmission for 2012-2017
NPCC–New England	8,288	458
NPCC–New York	10,992	138
PJM	51,767	709
Total	**71,047**	**1,305**

Source: NERC (2012g). 2012 Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf. Table 31.

Figure 6 - 7. Map of NERC LTRA regions in the Northeast



Source: NERC (2011c). 2011Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. iv. Note: Electrically speaking, Aroostook County, ME is served as if it were part of New Brunswick.

Lake Erie Loop Flow

Inter-RTO wheeling is an ongoing problem within the Eastern Interconnection, particularly with respect to "contract path" transaction scheduling between the four RTOs (New York, PJM, MISO, and Ontario's IESO) surrounding Lake Erie. While physical power flows along electrical paths, the settlements for those transactions follow the contract path; the inconsistency between schedule contract flows and actual physical flows is "loop flow" that must be recognized and managed by grid operators.[1, 2] Loop flows can cause significant congestion within MISO, PJM, and NYISO.

MISO's market monitor notes that electricity transactions from IESO to PJM through MISO in 2011 averaged 600 MW, creating significant loop flows—with half the energy flowing through NYISO.The IESO-to-PJM transactions remained substantial in 2011 (averaging over $10 per MWh) in part because they do not pay for the congestion they cause in NYISO. A portion of these transactions, however, were then scheduled back from PJM into MISO, earning much higher profits than simply scheduling from IESO to MISO.

This additional profitability is a function of PJM's external interface pricing that pays transactions based on the perceived congestion they relieve in PJM. Since roughly half of the power associated with these transactions is deemed to enter PJM from NYISO, it can relieve constraints in eastern PJM. If these constraints are market-to-market constraints that are reflected in MISO's real-time market as well, it is possible that both RTOs could be paying the transaction for relief of the same constraint under their interface pricing rules.[3]

In 2012, International Transmission Company energized a set of PARs (phase angle regulators) at the interface between Michigan and Ontario. Full operation of the PARs is expected to reduce loop flows around Lake Erie—controlling flows by up to 600 MW in each direction—facilitated by inter-RTO pricing methodologies to remove the incentives that create or exacerbate the loop flows.[4]

NYISO, PJM, MISO, and IESO worked with Potomac Economics to conduct the Analysis of the Broader Regional Markets Initiative in 2009-2010.[5] They concluded that if the RTOs can coordinate and price loop flows more effectively to eliminate scheduling flaws and better manage congestion, this could yield almost $300 million in savings.[6] NYISO has proposed a number of scheduling improvements to address these issues.[7]

[1] Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com /uploads/midwest_reports/2011_SOM_Report.pdf, p. A111.
[2] An alternate explanation: "A loop flow is a power flow through an interface or system that does not have a schedule and transmission service allocated to it. Loop flow is a characteristic of AC systems and the physics associated with the shift factors of generators and loads on an AC system. If a utility or a marketer purchased power and energy at the source of the loop flow on their system and sold the same power and energy on the sink side of the loop flow, and if the LMP difference or price of energy were higher at the sink than the source, the price difference times the energy flow would be a revenue to the utility or marketer. Transmission service would have to be purchased by a marketer to obtain the schedule to generate the revenue. A utility would use the existing or new transmission to provide the transmission service…. TVA has the necessary condition of having a positive price differential across the loop flows on their system. The prices are higher to the east of TVA and to the south of TVA than from the west and northwest…. [There is presently a] Midwest to Southeast loop flow bias…." Email from Dale Osborn of MISO, April 4, 2012. But changes in relative fuel prices can drive changes in the directions and consequences of such price differentials.
[3] Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/ midwest_reports/2011_SOM_Report.pdf, p. 48.
[4] *Ibid*., p. A112; Midwest ISO (MISO) (no date). Broader Regional Markets: Long Term Solutions to Loop Flow, Carmel, IN: MISO, p. 5. https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations %20and%20Whitepapers/Broader%20Regional%20Markets%20White%20Paper.pdf
[5] Monitoring Analytics (2011b). *State of the Market Report for PJM: 2010*. Norristown, PA: PJM. March 2011, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml. p 313.
[6] Patton, D.B., LeeVanSchaick, P., Chen, J. (2010a). Analysis of the Broader Regional Markets Initiative. Presentation to Joint NYISO-IESO-MISO-PJM Stakeholder Technical Conference. September 27, 2010, slide 13.
[7] These initiatives, described above, include more frequent inter-regional scheduling, PJM/NYISO market-to-market congestion coordination, and design and intended implementation of Coordinated Transaction Scheduling on the NYISO/PJM and NYISO/ISO-NE borders. See NYISO (2014) "Broader Regional Markets Informational Report" filed in compliance with the December 30, 2010 Order on Rehearing and Compliance in Docket No. ER08-1281.

PJM

Although much significant new transmission has been built within PJM in recent years, the time involved in building planned new transmission has affected both reliability and congestion costs in the Eastern states:

> *[In New Jersey] transmission constraints limiting the ability to import power into the State are a longstanding problem whose solution involves the uncertain strategy of higher voltage reinforcement of the interstate transmission lines. The delay of the Susquehanna-Roseland line … illustrates the intrinsic difficulties in relying upon transmission upgrades as a near-term solution to New Jersey's resource adequacy needs. … New Jersey has been left with little choice but to rely on in-state generation capacity resources and a market construct ostensibly designed to incentivize resource development in the presence of such scarcity.*[132] [133]

The 145-mile, 500 kV Susquehanna-Roseland line began construction in 2012 and is expected to go into service before summer 2015.[134]

Within PJM, a high proportion of the generation fleet is older, less efficient coal-fired plants that are becoming less economically viable due to the combined effect of low natural gas prices and pending environmental retrofit requirements. Within PJM, 1,197 MW of capacity retired in 2011, another 6,962 MW retired in 2012, and 2,858 MW is expected in to retire by the end of 2013. Between 2014 and 2015, 10,439 MW is expected to retire.[135] Pending retirements are shown in Figure 6 - 8.

It is not yet clear what long-term resource adequacy or economic impacts may result from the retirement of large amounts of older baseload generation. It is expected that these retirements will affect local generation and voltage support within East Coast load centers—for example, in 2012 Washington DC became wholly dependent on electricity generated in other states as in-district power plants were shut down.[136] In general, new generation and demand-side resources are being developed in many areas that will offset some of these retirements. Increasing imports into these areas could help address the increased retirements as well.

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[132] New Jersey Board of Public Utilities (2011a). *New Jersey Board of Public Utilities Board Staff Report on New Jersey Capacity, Transmission Planning, and Interconnection Issues*. December 14, 2011, at http://nj.gov/bpu/pdf/announcements/2011/capacityissues.pdf, pp. 3, 5.

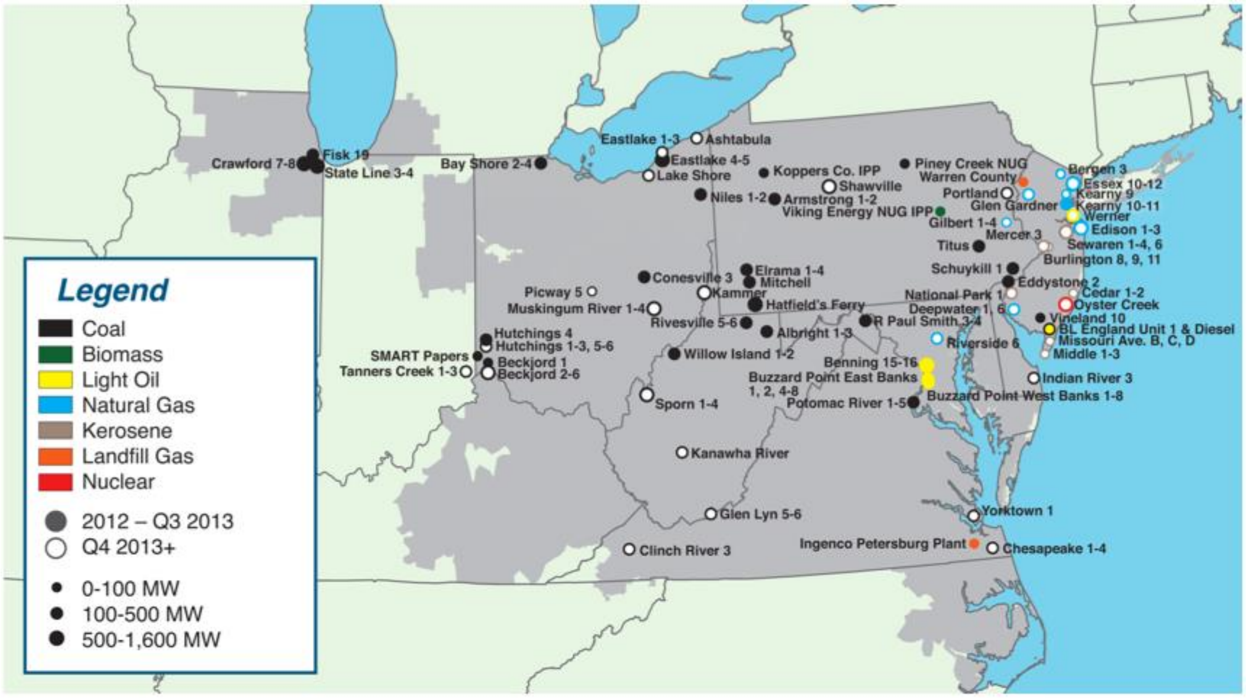
[133] The New Jersey system is part of PJM, which plans how to meet load in individual member states as part of an integrated plan across its footprint.

[134] PSEG, "Susquehanna Roseland – an electric reliability project", at http://www.pseg.com/family/pseandg/powerline/index.jsp; Lum, R. (2012h). "PPL to begin pre-construction on Susquehanna-Roseland line." *Transmission Hub*. June 20, 2012.

[135] Monitoring Analytics (2013). *2012 Q3 State of the Market Report for PJM*. November 14, 2013, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml, pp 313, 319.

[136] Kane, B. A. (PSC DC) (2011), "Statement of Betty Ann Kane, Chairman, Public Service Commission of the District of Columbia." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops", at http://energy.gov/sites/prod/files/Presentation%20by%20Betty%20Ann%20Kane%2C%20DC%20PSC.pdf.

Figure 6 - 8. Pending power plant retirements within PJM, 2012 through 2019



Source: Monitoring Analytics (2013). 2012 Q3 State of the Market Report for PJM. November 14, 2013, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml, pg. 320.

PJM Planning and the MAPP and PATH Projects

PJM conducts an extensive, analytically detailed, stakeholder-supported long-term system planning process that produces an annual Regional Transmission Expansion Plan (RTEP). The RTEP looks out over a long-term horizon across the region, reviews forecasted loads and supply- and demand-side resources, and recommends "transmission upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM's customers."[1]

PJM's RTEP process looks out over both a five-year and 15-year planning horizon. PJM explains that five-year planning "enables PJM to assess and recommend transmission upgrades to meet near-term demand growth for customers' electricity needs."[2] At the same time, they apply planning and reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns[3] that entail a longer planning horizon, using sensitivity analyses and other planning tools. The near- and long-term plans are integrated into a single plan. This process is repeated annually.

In 2007, PJM's board approved two new backbone transmission lines developed through the RTEP process—the Mid-Atlantic Power Pathway (MAPP) and the Potomac-Appalachian Transmission Highline (PATH).

The MAPP line was authorized by the PJM board in October 2007. At the time, the 150-mile, 500 kV line was needed "to resolve significant reliability violations within Maryland, Delaware and the Eastern mid-Atlantic region" and was routed from northern Virginia, across southern Maryland, under the Chesapeake Bay and Choptank River, and through eastern Maryland into Delaware.[4] PJM initially set a required in-service date of 2014 and then in 2010, revised that date to June 2015. On August 18, 2011, the PJM board placed the MAPP "in abeyance"; the "2011 RTEP generator sensitivity analysis indicated that the need for the line has moved several years later, beyond 2015, but as early as 2019."[5]

The Potomac-Appalachian Transmission Highline (PATH) project was designed as a 275-mile, 765 kV line to move power from western West Virginia to Kemptown, Maryland. The line was intended to address thermal and voltage violations and maintain grid stability in 2016 and beyond. In August 2011, PJM shifted PATH's on-line date from 2015 back to 2019-2021.[6]

In August 2012, PJM removed both projects from its regional expansion plans, explaining that:

> *Grid conditions have changed since the lines were originally planned, and the updated analysis performed by the transmission planning staff no longer shows a need for the MAPP project to maintain grid reliability. Lower load projections resulting from a slower economy, coupled with recent generation additions and increased demand response, are the factors that reduced the need for the two projects.*[7]

A letter from PJM's Transmission Expansion Advisory Committee to the PJM Board of Managers indicated that the MAPP and PATH projects were removed from the regional plan because analysis revealed that the reliability drivers for this project no longer existed.[8]

[1] PJM, "RTEP Development," at http://www.pjm.com/planning/rtep-development.aspx.
[2] PJM (2007). *2006 Regional Transmission Expansion Plan*, Norristown, PA: PJM. February 27, 2007. Section 1, Executive Summary, p. 7.
[3] *Ibid*., Section 3, PJM Board-Approved 15-Year Transmission Expansion Plans: 2006-2021, p. 39.
[4] Pepco Holdings, Inc., "PJM Reaffirms Need for Mid-Atlantic Power Pathway," press release, August 16, 2010.
[5] PJM, 2011 Regional Transmission Expansion Plan. February 28, 2012. Book 1: PJM Baseline Study Summary, p. 14.
[6] Rivera-Linares, C. (2012). "PJM: Recommendation to remove PATH, MAPP partly due to reduced load growth," *Transmission Hub*. August 9, 2012.
[7] PJM, "Mid-Atlantic Power Pathway (MAPP)", accessed at http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mapp.aspx.
[8] Herling, S. (2012). August 28, 2012 letter to the PJM Transmission Expansion Advisory Committee, RE: PJM Board of Manager Decision on MAPP and PATH.

PJM's MAPP and PATH projects

Source: PJM (2012f). "Transmission Expansion Advisory Committee presentation." August 9, 2012, at http://www.pjm.com/~/media/committees-groups/committees/teac/20120809/20120809-reliability-analysis-update.ashx, p. 4.

PJM noted that, "dramatic swings in economic forecasts, demand response, generation retirements and evolving public policies are adding greater uncertainty to PJM planning studies."[9, 10] But "[b]ackbone transmission projects, particularly those as complex as the PATH and MAPP projects, cannot be effectively planned, funded, approved and constructed if they are continually taken on and off the table based on updated data."[11] An industry trade article quoted Lisa Barton, Executive Vice President for AEP Transmission, and offered additional observations:

> *"It was interesting with PATH because [in] three consecutive RTEPs, it came up as being needed, and with the recession and decrease in load in the East, PJM determined the project was no longer necessary…."*

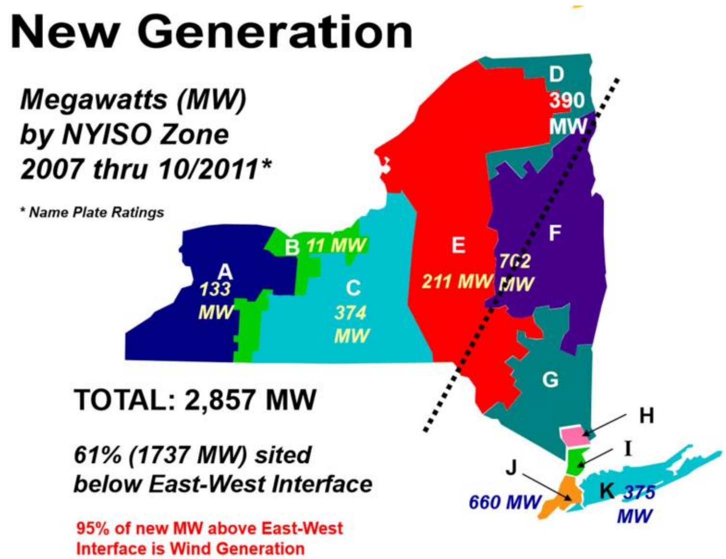
The demise of the PATH project provides an example for how RTOs should look at the transmission planning process more holistically—and proactively, rather than reactively, Barton said. Transmission planning in many regions of the country is reactive, meaning that the industry responds to demand changes and new generation projects instead of acting as the framework around which new generation is sited.[12]

[9] Rivera-Linares, C. (2012g). "PJM to review PATH in spring/summer", *Transmission Hub,* March 7, 2012.
[10] For instance, PJM's May 2012 capacity auction added 4,900 MW of new generation and 14,833 MW of demand response, much of it in eastern PJM.
[11] Rivera Rivera-Linares, C. (2012g). "PJM to review PATH in spring/summer", *Transmission Hub,* March 7, 2012.
[12] Lum, R. (2012i). "After PATH and with industry in flux, AEP focuses on short-term," *Transmission Trends*, September 17, 2012, p. 19.

New York

Figure 6 - 9 shows the locations of 2,857 MW of new generation added within New York State between 2007 and October 2011. Generation additions in 2011 included the Astoria Energy II gas-fired plant in Queens (550 MW), the LIPA Solar Farm on Long Island (31.5 MW) and new wind generation.

Figure 6 - 9. New generation added in New York State, 2007 through 2011



Source: Buechler, J. (NYISO) (2011). "NYISO Update for the 2012 National Electric Transmission Congestion Study," Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops", at http://energy.gov/sites/prod/files/Presentation%20by%20John%20Buechler%2C%20NYISO.pdf, p. 6.

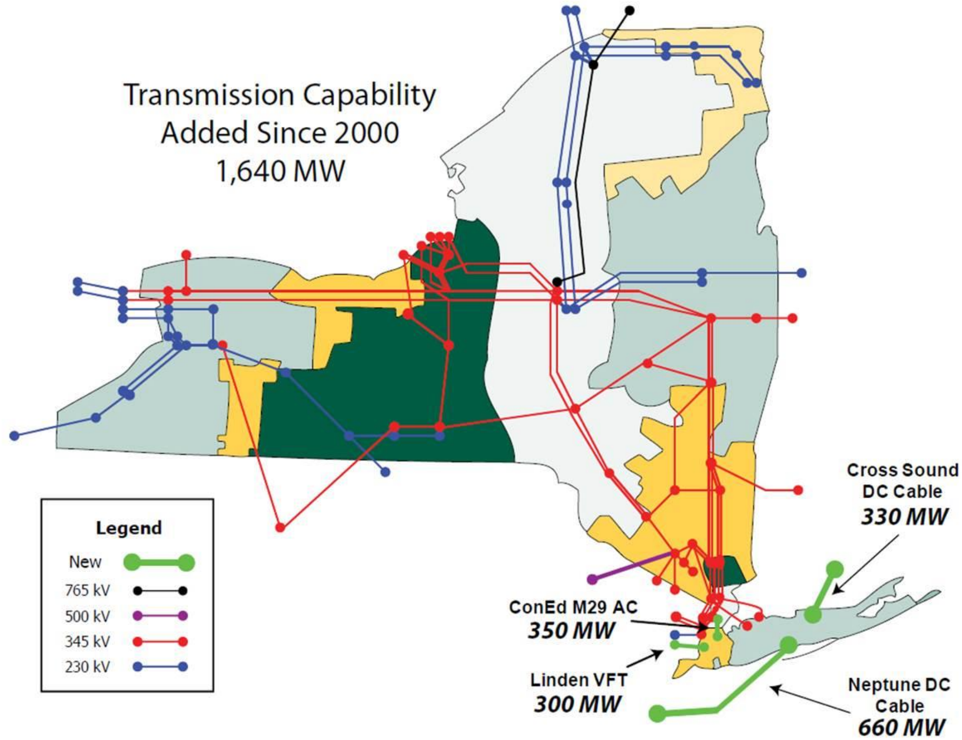
Recently completed transmission projects include the Linden Variable Frequency Transformer (VFT) and cable, which went online in 2009.[137] The VFT can transfer 315 MW of capacity from the Linden cogeneration plant in New Jersey to Consolidated Edison's Goethals substation on Staten Island. The Bayonne Energy Center in New Jersey, which started commercial operation in June 2012, is connected via a 345 kV, 6.5 mile submarine cable system to the Gowanus, Brooklyn substation, which was energized December 2011.[138] ConEdison's 9.5-mile, 345 kV M-29 transmission line went into operation in February 2011, delivering approximately 350 MW of power from Westchester into Manhattan.[139] Figure 6 - 10 maps the transmission added to the New York grid from 2000 to 2011.

[137] GE Energy Financial Services (2012). "GE Unit to Auction Electric Transmission Capacity Connecting New York city and PJM Power Grids," *Press release.* April 9, 2012, available from http://geenergyfinancialservices.com/press_releases/view/115.

[138] ESS Group (2013). "Bayonne Energy Center," accessed December 2013; available from http://essgroup.com/coastal-engineering-and-marine-sciences/bayonne-energy-center.html.

[139] Consolidated Edison (2006). Letter from Jeffrey Riback to Jaclyn A. Brilling, Public Service Commission of New York, October 6, 2006, available from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BEE6136AB-A971-4264-BB2B-

Figure 6 - 10. New transmission added to the New York grid, 2000-2011



Source: New York ISO (2012e), Power Trends 2012: State of the Grid, September 2012, Figure 5, p. 13.

The Hudson Transmission Project, a 660 MW back-to-back AC-DC-AC electric transmission link under construction between New York City and PSE&G in New Jersey, was completed in June 2013,[140] even though a key western transmission line necessary to feed that line (PJM's Branchburg-Roseland-Hudson project) is not active as of the timeframe of this report.[141] The Champlain Hudson Power Express project is a 1,000 MW, 320 kV, 385-mile DC line from the Quebec border south through Lake Champlain and farther south down the Hudson River to terminate near Astoria, Queens. The project has been approved by the state Public Service Commission (NYPSC), and is awaiting some federal permits and a final construction contract.[142]

23479A788450%7D, pg. 2; Edison Electric Institute (2012b). "Transmission Projects at a Glance," as accessed March 2012, at http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx, p. 27.

[140] Hudson Transmission Project webpage (2012). Webpage information at http://hudsonproject.com/project/.

[141] Recently, the Northeast Grid Reliability Project was planned to improve the 230 kV system in the area of Roseland and Bergen. (http://www.psegtransmission.com/reliability-projects/northeast-grid-reliability-project)

[142] Dombek, C. (2012k). "Joint proposal for Champlain Hudson Power Express sent to NY PSC." *Transmission Hub*, February 27, 2012, at http://transmissionhub.com/2012/02/27/joint-proposal-for-champlain-hudson-power-express; Dombek, C. (2012). "NY Commission Seeking Comment on Proposed 1 GW Underwater Transmission Line," *Transmission & Distribution World*, April 10, 2012, at http://tdworld.com/underground_transmission_distribution/ny-psc-underwater-line-comments-0412/; DiSavino, S. (2013). "UPDATE 5-New York PSC approves 1,000-MW Quebec-NY City power line." *Reuters*, April 18, 2013, at http://www.reuters.com/article/2013/04/18/utilities-blackstone-champlainhudson-idUSL2N0D51QA20130418.

For reliability purposes, New York system planners require that a large amount of generation be located inside the state's largest and most electrically vulnerable load centers. For the period of May 2012 to April 2013, Locational Minimum Installed Capacity Requirements were set at 83.0% of New York City's forecast peak load and 99.0% for Long Island.[143] These reliability requirements increase the significance of local power plant retirements and increase the value of demand response within New York's load centers. In-city generation will be facilitated by the addition of the Texas Eastern-Algonquin New Jersey-New York Spectra gas pipeline expansion project, which will transport 800 MMcf per day of firm natural gas into New Jersey and Con Edison's New York natural gas system. This pipeline was completed in November 2013[144] and is expected to lower the price of natural gas within the New York metropolitan area and thereby reduce in-area electric generation costs.[145]

New York has also been adding demand-response resources, as alternatives to new generation and transmission, to enhance system reliability. As of summer 2011, the state had 2,173 MW of emergency demand response and special-case resources subscribed to help meet short-term peak conditions and respond to emergency conditions.[146]

During the time period covered by this report, six generating facilities in New York State with summer capability of 307 MW have been retired,[147] and more retirements, as well as conversion to gas/coal fired-units, have been announced.[148] [149]

In addition, Nuclear Regulatory Commission (NRC) operating licenses for one of the two Indian Point nuclear units (2,000 MW in Westchester County) expired in 2013, and the other will expire in 2015; owner Entergy has applied for license extensions.[150] According to a NYISO

[143] NYISO Operating Committee, "Locational Minimum Installed Capacity Requirements Study," January 12, 2012, at http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/2012_LCR_OC_report_V4.pdf, p. 2.
[144] Spectra Energy (2013). "Spectra Energy Places New Jersey-New York Natural Gas Pipeline in Service," November 1, 2013, at http://www.spectraenergy.com/Newsroom/News-Archive/Spectra-Energy-Places-New-JerseyNew-York-Natural-Gas-Pipelie-into-Service/.
[145] Consolidated Edison (2011). "Motion to Intervene in Support of Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc., before the Federal Energy Regulatory Commission, Docket CP11-56-000," January 26, 2011.
[146] NYISO, "Power Trends 2012 – State of the Grid," 2012, at http://www.nyiso.com/public/webdocs/newsroom/power_trends/power_trends_2012_final.pdf, p. 10.
[147] NYISO (2010e). *NYISO Gold Book – 2010 Load and Capacity Data*. Rensselaer, NY: NYISO. April 2012, at http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2010_GoldBook_Public_Final_033110.pdf.
[148] Cassell, B. (2012h). "NRG plans to mothball big Dunkirk coal plant in New York." *Generation Hub*. March 15, 2012.
[149] NYISO updates its "Gold Book", or report of load and capacity, on an annual basis. More recent reports can be found on the NYISO planning website: http://www.nyiso.com/public/markets_operations/services/planning/index.jsp
[150] Indian Point No. 2 is operating under "timely renewal," meaning owners who applied for license renewal at least five years before the expiration of the existing license can continue to operate until the Nuclear Regulatory

analysis, shutting down those units without adequate replacement generation in southeastern New York would affect resource adequacy and transmission security for the New York City metropolitan area.[151] In November 2012, the NYPSC opened a proceeding to explore reliability contingency plans for the retirement of the Indian Point Energy Center.[152] New York utilities are developing plans—comprising transmission, energy efficiency, and demand reduction efforts—for maintaining reliable service in case the units are shut down.[153]

Potential capacity additions could moderate the impact of some of these retirements; for example, NRG Energy proposes to repower its existing 31 oil and gas-fired peaking units in Astoria, Queens (New York City) with 600 MW of high-efficiency, fast-cycling natural gas-fired combined cycle units that could help reduce the need for new transmission into New York City.[154] [155] NRG Director of Development John Baylor comments that New York City is "… a very unique market, it's a very constrained market…. A load pocket like this absolutely has to have generation inside the load pocket because if you have a single line failure or something like that, you're going to have problems. If the city starts to rely too much on transmission, they're going to have a potential scenario where if a line goes out, they're going to have a critical problem in the city."[156]

The Department's 2006 and 2009 Congestion Studies noted concern over southeastern New York as an important area that is vulnerable to transmission constraints and congestion. New York Governor Cuomo's recent $2 billion "New York Energy Superhighway" proposal would "transport surplus power supplies in upstate New York and north of the border in Quebec to high-demand regions in downstate New York."[157] The Governor's plan recognizes that electrical infrastructure needs a fresh, large infusion of capital to upgrade, replace and strengthen the area's aging infrastructure. After the New York Energy Highway Task Force issued a Request for Information on ways to support an energy highway, they received "130 ideas to upgrade and revitalize the state's aging infrastructure, totaling more than 25,000 megawatts" including 51

Commission rules on a renewal. (http://www.nrc.gov/reactors/operating/licensing/renewal/applications/indian-point.html)

[151] NYISO (2012d). *2012 Reliability Needs Assessment, Final Report*. September 18, 2012, at http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2012_RNA_Final_Report_9-18-12_PDF.pdf, p. 42.

[152] This proceeding has recently resulted in authorization of transmission upgrades. See New York Public Service Commission (2013). "Indian Point Contingency Plans Move Forward." Press release, October 17, 2013.

[153] Beattie (2013). "New York OKs 'contingency plan' for nuke plant closure." The Energy Daily. October 18, 2013.

[154] Rivera-Linares, C. (2012h), "NRG: Repowering Astoria units obviates need for 'more expensive transmission'." *Transmission Hub*. June 22, 2012.

[155] For more information on proposed and in-service generation see NYISO "Gold Book": http://www.nyiso.com/public/markets_operations/services/planning/index.jsp.

[156] Rivera-Linares, C. (2012h), "NRG: Repowering Astoria units obviates need for 'more expensive transmission'." *Transmission Hub*. June 22, 2012.

[157] NYISO (2012e). "Power Trends 2012: State of the Grid," p. 30, at http://www.nyiso.com/public/webdocs/newsroom/power_trends/power_trends_2012_final.pdf.

suggestions for generation, 29 for transmission, and four on gas pipelines.[158] In October 2012, the Energy Highway Task Force issued a blueprint calling for another 3,200 MW in new generation and associated transmission, another $1 billion investment in new transmission capacity, and acceleration of $800 million in existing transmission projects. The NYPSC subsequently opened a proceeding on AC Transmission to elicit proposals to upgrade UPNY/SENY and Central East corridors. The Energy Highway blueprint also called for development of Reliability Contingency Plans in advance of potential resource retirement (including Indian Point Energy Center, mentioned above).[159] In response to the blueprint and related NYPSC proceedings, several new transmission projects are moving forward.[160]

[158] Governor's Press Office (2012). "Governor Cuomo Announces 85 Entities Respond to Energy Highway Task Force RFI," Albany, NY. June 29, 2012, at http://www.governor.ny.gov/press/062912energytaskforcerfi.
[159] New York Energy Highway Task Force (2012). *New York Energy Highway Blueprint*. November, 2012, at http://www.nyenergyhighway.com/PDFs/BluePrint/EHBPPT/, pp. 16-17.
[160] These are: reconfiguration of substations to "un-bottle" Staten Island generation; improvements in efficiency of Marcy South lines and 22 miles of re-conductoring from Fraser to Coopers Corner; and building a second 345 kV line from Rock Tavern to Ramapo. For information on this and other developments in New York see NYISO comments on public draft of this study, as well as filings under New York PSC Case Nos. 12-T-0502, 13-T-0488, 13-T-0454, 13-T-0455, 13-T-0456, 13-T-0457, 13-T-0461.

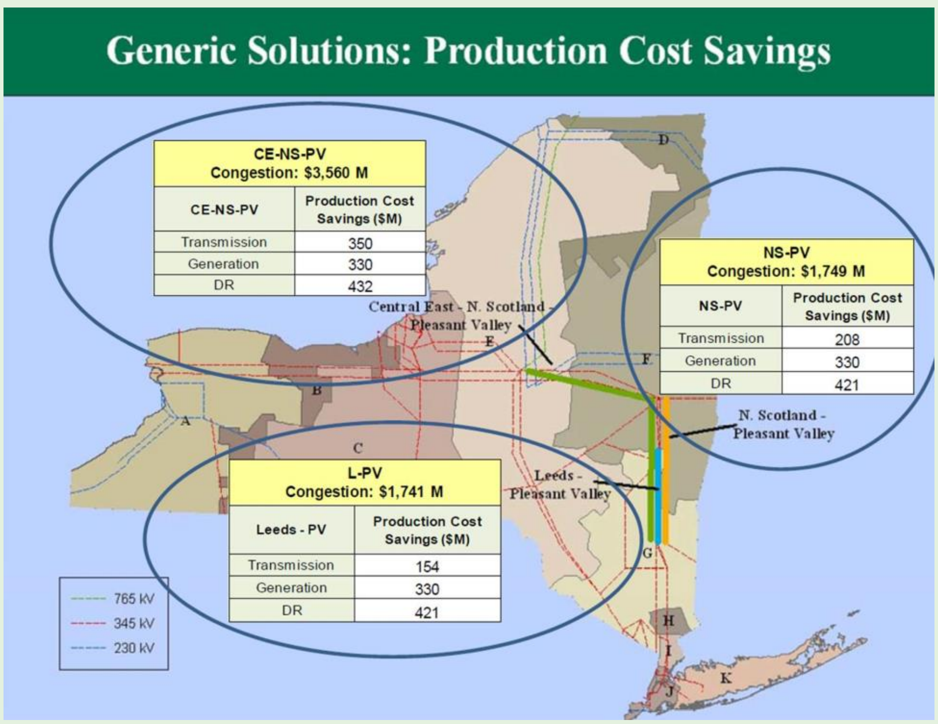
Transmission Planning Perspectives

Two studies examining transmission options for the New York region highlight the importance and role that different planning perspectives have on transmission infrastructure evaluations. While cost effectiveness is at the core of both studies, differences between perspectives taken by the two studies lead to different conclusions on the need for new transmission.

On the one hand, the NYISO's *2011 Congestion Assessment & Resource Integration Study (CARIS), Phase 1*, released in March 2012,[1] looked at the top three sets of transmission constraints in NY over a ten-year horizon and tested different sets of transmission, demand response, and generation projects to identify benefits in terms of transmission usage, statewide production cost savings, capacity cost savings, and emissions. The study concluded that based on these forecasts, most of the congestion within New York is uneconomic to mitigate—and in particular, that transmission solutions are the least cost-effective of the congestion mitigation options.

The graphic below shows the CARIS study's generic solutions by region, with the net present value of the production cost savings estimates shown in the table. Since almost all of the estimated benefit-cost ratios for these transmission, generation, and demand response scenarios fall below one for the hypothesized congestion solutions, this means that it would cost less for New Yorkers to bear the continuing congestion than to spend the money to mitigate it through the transmission, generation, and demand response solutions evaluated. It is also worth noting that the transmission solutions explored for congestion mitigation tended to produce lower benefit-cost ratios than demand response or generation solutions (although this varies depending on whether the solution cost estimates were high, medium, or low).

CARIS: Benefit-cost ratios by region from transmission congestion options and scenarios



Source: NYISO, (2012a). 2011 CARIS 2011 Congestion Assessment & Resource Integration Study, Phase 1. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report__3-20-12.pdf, p. 58

[1] More recent CARIS reports have been release subsequent to the time frame of this study, in particular the 2013 updated report. See http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

CARIS: Projected production cost savings from mitigating congestion in major New York regions

Study	Ten-Year Production Cost Savings (2011 $ M)		
	Transmission Solution	Generation Solution	DR Solution
Study 1: Central East-New Scotland-Pleasant Valley	350	330	432
Study 2: New Scotland to Pleasant Valley	208	330	421
Study 3: Leeds - Pleasant Valley	154	330	421

Source: ibid., p. 68.

Looking over a longer time horizon, New York's *State Transmission Assessment and Reliability Study* (STARS) found that, "based on a high level age-based condition assessment, nearly 4,700 miles of lines will approach end of life and may require replacement within the next 30 years," and recommends an aggressive replacement and upgrade effort to assure continuing transmission system reliability within the state. The study points to five factors—power plant age, transmission congestion, new Clean Air Act rules taking effect in 2015, the state's 30% renewable power mandate by 2015, and the potential closure of the Indian Point nuclear reactors— that together mean "the state has little choice but to upgrade a system that restricts electron movement from rural areas in the north to urban centers in the south." NYISO President and CEO Stephen Whitley explained that, "transmission bottlenecks due to narrow rights of way and a shortage of high-voltage lines limits the fuel diversity downstate. Upstate, nuclear, hydropower, natural gas and renewables keep the supply equation diverse and able to respond to crisis, but for New York City and its environs, the situation is quite different."[2] The transmission judged in need of replacement is shown in the map below.

The STARS study, conducted by New York's transmission owners, takes a different view of the factors affecting the value of transmission projects.[3]

When the NYISO's tariff-mandated planning process (CARIS) is augmented by a longer time horizon study such as STARS, additional effective and economical solutions for the state's mature power system (characterized by reduced load growth and aging facilities) can be identified.

The longer time horizon for planning is necessary to:

(1) Evaluate whether higher transmission voltage or new technology is necessary and economical;

(2) Incorporate the need to replace aging infrastructure (transmission lines and substations);

(3) Address existing limited rights-of-way and siting issues;

(4) Consider effective integration of renewable resources;

(5) Meet reliability needs across the New York Control Area system for various resource expansion scenarios; and

(6) Consider emerging technological and regulatory issues with longer-term implications, such as plug-in electric vehicles.

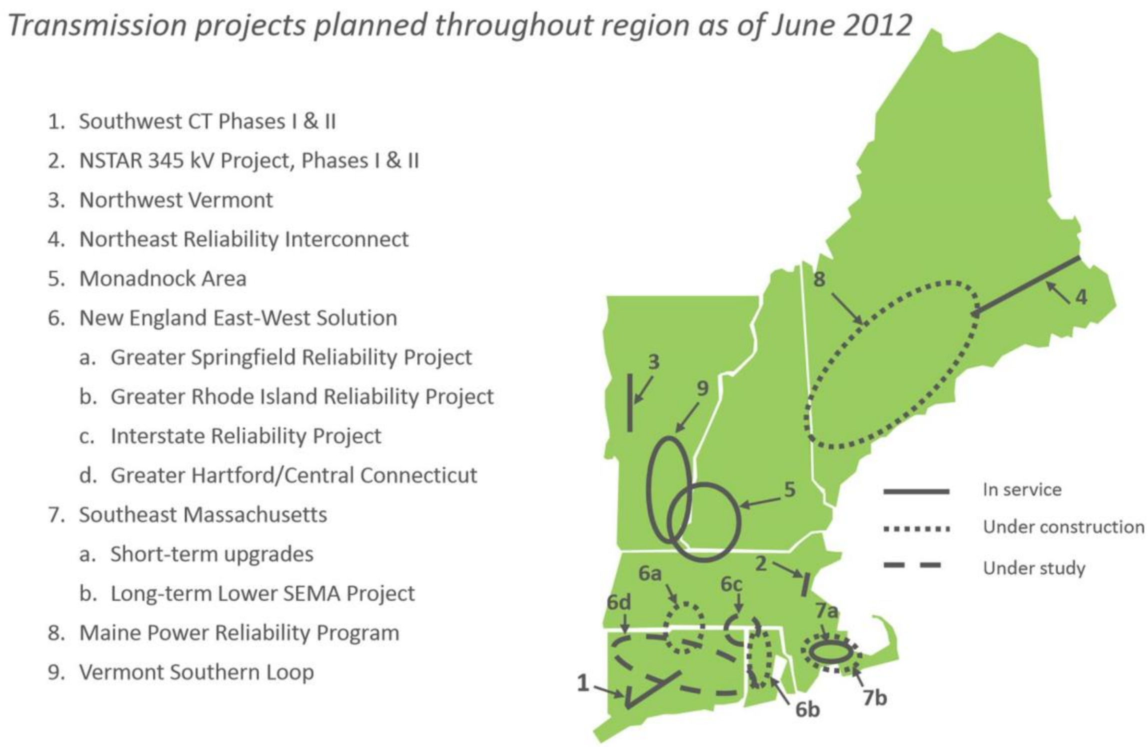
[2] Sullivan, C. (2012). "Wall Street, industry call for massive N.Y. transmission investment," E&E News, April 4, 2012, at http://www.eenews.net/Greenwire/2012/04/04/5.

[3] STARS Technical Working Group (2012). New York State Transmission Assessment and Reliability (STARS). Phase II Study Report. April 30, 2012, at http://www.nyiso.com/public/webdocs/services/planning/stars/Phase_2_Final_Report_4_30_2012.pdf

New England

New England has built a significant amount of new transmission over the past decade. From 2002 through 2012, 400 transmission projects were put into service, totaling approximately $4.8 billion of new infrastructure investment across all six states.[161] This new transmission included eight major 345 kV transmission upgrades finished, four under construction, and one in the siting process.[162] [163] Another $6.0 billion will be spent over the next decade, with nine additional major projects planned (see Figure 6 - 11).

Figure 6 - 11. Major transmission projects in New England: new projects in-service, under construction, and under study



Source: Rourke, Stephen, "ISO-New England 2012 Regional System Plan (RSP12), 2012 Regional System Plan Public Meeting," September 13, 2012, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/sep132012/rsp12_public_meeting_slides.pdf, slide 11. Note: Figure based on slide presented at US DOE National Electric Transmission Congestion Study Workshop Henderson, M. (ISO-NE) (2011). "ISO New England Comments on the National Electric Transmission Congestion Study." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre- Congestion Study Regional Workshops", at http://energy.gov/oe/services/electricity-policy-coordination-and- implementation/transmission-planning/national/2012, p. 8

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[161] ISO-NE (2012c), *2012 Regional System Plan.* Holyoke, MA: ISO-NE. November 2012, at http://www.iso-ne.com/system-planning/system-plans-studies/rsp p. ii, 102-103.

[162] *Ibid*. p 102.

[163] In 2013, one of the projects under construction was completed; one additional major project, the Maine Power Reliability Program, has entered the siting process; and a new major reliability project, the New England East West Solution, has been proposed. ISO-NE (2013), *2013 Regional System Plan.* Holyoke, MA: ISO-NE. November 2013, at http://www.iso-ne.com/system-planning/system-plans-studies/rsp, p. 99.

ISO New England explains that this new transmission has opened up import capability into load pockets that were previously capacity-short (Boston, southwest Connecticut, and Vermont) and created new interconnections with neighboring power systems. The region has also added 14,432 MW of new generation and 2,106 MW of demand-side resources since 1997. According to ISO-NE, "[a]lmost one-third of the region's existing generation was built during the last 11 years, and more than half of the region's electric energy production now comes from efficient, gas-fired combined-cycle generators."[164] In addition, the system also faces thermal and voltage support issues across much of the region, as well as fuel-supply issues given its growing dependence on natural gas. The existing regional planning process and planned improvements to the wholesale power markets are addressing these issues.

Additional new transmission is needed to interconnect new generation (including renewables) and to resolve transmission planning criteria violations in eastern and western New England and in Rhode Island. New England plans transmission upgrades to serve four types of system needs: reliability, market efficiency, generator interconnection, and self-financed elective upgrades that include merchant transmission additions.[165]

In Massachusetts, the Salem Harbor units 1 & 2 (158MW) were retired December 31, 2011, and Units 3 & 4 (587 MW) are scheduled to retire by June 1, 2014.[166] This is expected to increase New England's dependence on natural gas and natural gas markets and imports—the ISO reports that "[n]atural-gas-fired generating units most likely could replace many of the old coal, oil, and nuclear units in locations requiring relatively little additional transmission system infrastructure."[167] New England has been addressing the gas dependence and generator retirement issues as well as wind integration challenges through its Strategic Planning Initiative.[168]

New England's situation could be complicated by local reliability challenges under extreme summer weather conditions. In May 2012, ISO New England reported that an extended summer heat wave could push demand close to the limits of available resources, which include generation, demand response, and imports from neighboring regions;[169] fortunately such a

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[164] ISO-NE (2012c), *2012 Regional System Plan.* Holyoke, MA: ISO-NE. November 2012, at http://www.iso-ne.com/system-planning/system-plans-studies/rsp, p. ii, 1.
[165] *Ibid.,* pp. 70-72, 87.
[166] Cassell, B. (2012b). "Two Salem Harbor coal units shut, two more to go." *Generation Hub*, February 28, 2012, at http://generationhub.com/2012/02/28/two-salem-harbor-coal-units-shut-two-more-to-go.
[167] ISO-NE (2012c), *2012 Regional System Plan.* Holyoke, MA: ISO-NE. November 2012, at http://www.iso-ne.com/system-planning/system-plans-studies/rsp, p. 109.
[168] See http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/strategic_plan_initiative_roadmap_march_2012.pdf and the Strategic Planning Initiative discussion in the 2012 Regional System Plan, section 6, at http://www.iso-ne.com/static-assets/documents/trans/rsp/2012/rsp_final_110212.docx.
[169] Business Wire (2012). "New England's Power Grid Summer Outlook Announced." *Business Wire*. May 4, 2012. http://www.businesswire.com/news/home/20120504005936/en/England%E2%80%99s-Power-Grid-Summer-Outlook-Announced.

heat wave did not occur. The potential for local reliability issues due to extreme conditions does not necessarily indicate sustained or severe grid usage. Regional planners are aware of these kinds of situations and actively plan to address them.

6.2.3. Southeast

This section provides an overview of transmission infrastructure planning in the Southeast and discusses major new generation and transmission projects and relevant retirements across the region.

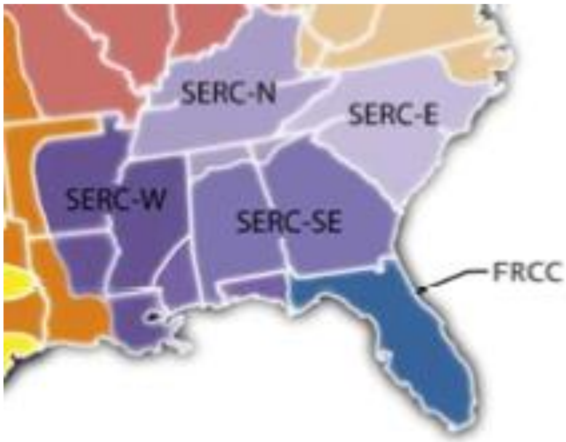
The NERC 2011 LTRA indicates that there were 98,291 circuit-miles of transmission in service within the Southeast region in 2011, and nearly 2% more circuit-miles in the planned or conceptual stages between 2011 and the end of 2015 (see Table 6 - 3). There is no way to tell how much of the planned and conceptual transmission will actually go into service (and when) until construction begins on a specific project. NERC's reporting areas do not correspond exactly with this study's geographic regions (see Figure 6 - 12), so these numbers may underestimate the amount of new transmission to be built in the Southeast.

Table 6 - 3. Circuit-miles of transmission (> 100kV) in-service and planned within the Southeast 2010–2015

Region	In-service in 2011 year end and under construction	Planned or conceptual transmission for 2012-2017
SERC–E	22,213	276
SERC–N	21,854	332
SERC–SE	27,780	305
SERC–W	14,367	414
FRCC	12,077	249
Total	**98,291**	**1,576**

Source: NERC (2012g). 2012 Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2012, available from http://www.seia.org/sites/default/files/resources/2012_LTRA_FINAL.pdf,Table 31.

Figure 6 - 12. NERC LTRA regions in the Southeast



Source: NERC (2011c). 2011 Long-Term Reliability Assessment. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. iv.

Of the transmission identified in Table 6 - 3, 10,000 circuit-miles are 500 kV lines, 3,500 circuit-miles are 345 kV lines, and over 24,000 circuit-miles are 230 kV lines. Another 2,680 circuit-miles of new transmission were planned for construction in SERC (Southeast Reliability Council) between 2012 and 2016. In 2010, there were 7,123 circuit miles in the Florida Regional Coordinating Council (FRCC) at 230 kV and above.[170] In the TVA system, several 500 kV lines form a backbone for a network of 161 kV lines, which can become heavily used and congested under some contingencies.[171] Across the Southeast as a whole, there is currently a high level of generation capacity relative to peak demand, with planning reserve margins going into the summer of 2012 between 22–44% across the various SERC and FRCC planning sub-regions.[172]

Many states in the region require utilities to produce integrated resource planning studies, which include assessment of transmission as well as generation needs.[173] Thus generation and

[170] NERC (2004). "High-Voltage Transmission Circuit Miles by Voltage (230 kV and above)—All NERC Regions and Subregions (2004)." File downloaded from NERC website extracted from ES&D database. Accessed December 31, 2004, at www.nerc.com/files/MilesByVoltage.doc. U.S. Energy Information Administration, *Electric Power Annual 2010 Data Tables*, "Table 4.5.A., Existing Transmission Capacity by high-voltage size, 2010," release date November 9, 2011.

[171] Till, D. (Tennessee Valley Authority) (2011). "Comments of David Till." Provided at the United States Department of Energy (2011e). *National Electric Transmission Congestion Workshop*. St. Louis, MO. December 8, 2011, at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf, p. 116.

[172] NERC, *2012 Summer Reliability Assessment*, May 2012, p. 21.

[173] Finley, E. (North Carolina Public Utility Commission) (2011). "Comments of Ed Finley." Provided at the United States Department of Energy (2011b). *National Electric Transmission Congestion Study Workshop.* Philadelphia, PA. December 6, 2011, at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Philadelphia%20Workshop.pdf, p. 16 and 22; Busbin, J. (Southern Company) (2011). "Comments of Jim Busbin." Provided at the United States Department of Energy (2011b). *National Electric Transmission Congestion Study Workshop.* Philadelphia, PA.

transmission development has been the purview of the utilities with oversight from the relevant state regulatory commissions.

Several Southeastern states encourage or require joint planning. The North Carolina Transmission Planning Collaborative provides an opportunity for utilities to study transmission options and get input from customers, municipal utilities, and co-ops. The Collaborative has updated its fifth report, which indicates that many of the proposed projects from the previous report are underway or completed, and calls for an additional $309 million in investment by 2021.[174] Within Florida, the FRCC has coordinated transmission planning activities.

Southern Company, the Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, Dalton Utilities, PowerSouth Energy Cooperative, and the South Mississippi Power Association, have participated in the Southeastern Regional Transmission Planning (SERTP) process.[175] The SERTP process is a coordinated, open, and transparent process that allows for stakeholder (e.g., any interested party) feedback regarding the current ten-year transmission expansion plans of these SERTP Sponsors.[176]

The lead utilities in the Southeast have also created the Southeast Inter-Regional Participation Process (SIRPP) as a vehicle to support "a more open, transparent and coordinated transmission planning process" between the utilities and their stakeholders."[177] The SIRPP sponsor group includes the Southern Company, Duke Energy Carolinas, South Carolina Electric & Gas, the Entergy Companies, the Tennessee Valley Authority, Dalton Utilities, Georgia Transmission Corporation, LG&E/KU, Municipal Electric Authority of Georgia, PowerSouth, Progress Energy Carolinas, Santee Cooper, and South Mississippi Electric Power Association. Since 2008, this group has conducted interregional economic planning studies requested by

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December 6, 2011, at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Philadelphia%20Workshop.pdf, p. 103.

[174] Finley, E. (North Carolina Utilities Commission) (2011). "Comments of Ed Finley." Provided at the United States Department of Energy (2011b). *National Electric Transmission Congestion Study Workshop.* Philadelphia, PA. December 6, 2011, at http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Philadelphia%20Workshop.pdf, p. 21; North Carolina Transmission Planning Collaborative, "NCTPC 2011 Collaborative Transmission Plan Update, September 2012," at http://www.nctpc.net/nctpc/document/REF/2012-09-06/2011_Collaborative_Transmission_Plan_Update_090512.pdf. .

[175] Southeastern Regional Transmission Planning (2014). Website accessed November 2014, at http://www.southeasternrtp.com/.

[176] Effective June 1, 2014, the SERTP has been expanded to include additional FERC-jurisdictional public utilities, municipal and cooperative utilities, and TVA. With this expansion, the SERTP now spans all or portions of fourteen states. As expanded, the SERTP now includes Southern Companies (Alabama Power, Georgia Power, Gulf Power and Mississippi Power); Associated Electric Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; the Municipal Electric Authority of Georgia; PowerSouth Energy Cooperative; the Tennessee Valley Authority; Louisville Gas & Electric and Kentucky Utilities; and Ohio Valley Electric Cooperative. SMEPA has since joined MISO.

[177] Southeast Inter-Regional Participation Process (2012). Website accessed August 2012, at http://www.southeastirpp.com.

stakeholders, which identify requirements needed to move large amount of power beyond exiting firm commitments and forecasted reliability needs.

SERC

Across the SERC region, utilities and merchant generators have been adding new generation capacity, and planning and building increments of new transmission—most at levels below 345 kV (although some lengthy new high voltage transmission is planned by 2021, most associated with new power plants).[178] In SERC-East, NERC reports that "shifts from the use of coal to natural gas as a generation fuel source due to the decreased costs of natural gas have led to non-typical transmission line power loadings. However, no transmission owners in the SERC-E assessment area have reported any negative impacts on transmission adequacy."[179]

Georgia Power is building two new nuclear reactors at the Plant Vogtle nuclear complex, for a total of 2,200 MW of additional generation capacity due online in 2016 and 2017, along with two 50-mile 500 kV lines to integrate the new generation.[180] The utility also obtained regulatory approval in November 2012 to buy 210 MW of solar power over the two subsequent years.[181] In January 2013 Georgia Power announced it would seek to retire over 2 GW of capacity from coal and oil-fired generating units,[182] and it previously announced the retirement of the oil-fired Mitchell Unit 4C plant in March 2012.[183] Georgia Power has completed three 840 MW combined cycle natural gas plants near Atlanta, to serve growing North Georgia load. These plants were built on the same site as two coal-fired units that were retired in September 2011 and February 2012.[184]

Alabama Power will be purchasing 404 MW of electricity from SPP wind generators under 20-year contracts.[185]

Progress Energy Carolinas has reported several coal plant retirements and new gas plants as part of its fleet modernization program. These include retirements of older, smaller coal plants

[178] NERC (2011c*). 2011 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. 185-187.
[179] NERC (2012d). *Summer Reliability Assessment 2012*. Princeton, NJ: NERC. May 2012, at http://www.nerc.com/files/2012SRA.pdf, p. 119.
[180] Southern Company, "Plant Vogtle Units 3 and 4 Background," at http://www.southerncompany.com/nuclearenergy/presskit/docs/GTF_onePager_Vogtle_3_4_Benefits.pdf.
[181] Georgia Power Company (2013a). "Advanced Solar Initiative." Website information, accessed December 6, 2013, at http://www.georgiapower.com/about-energy/energy-sources/solar/asi/advanced-solar-initiative.cshtml.
[182] Georgia Power Company (2013b). "Georgia Power seeks approval to retire generating units at four plants." January 7, 2013, at http://www.georgiapower.com/about-us/media-resources/newsroom.cshtml.
[183] Cassell, B. (2012e). "Georgia Power mulls fate of coal retirements, retrofits." *Generation Hub*, March 7, 2012.
[184] Southern Company (2012a). "Georgia Power brings second Plant McDonough-Atkinson natural gas plant into service," *PR Newswire*, April 30, 2012, at http://www.prnewswire.com/news-releases/georgia-power-brings-second-plant-mcdonough-atkinson-natural-gas-unit-into-service-149488845.html.
[185] American Wind Energy Association (2012). "Alabama Power recognized for saving its Southeastern customers money with wind power from TradeWind Energy of Kansas." Press release, November 20, 2012, at http://www.awea.org/MediaCenter/pressrelease.aspx?ItemNumber=4692.

such as the H.F. Lee (in NC) in September 2012; the W.H. Weatherspoon (in NC) plants in October 2011; the final two Cape Fear Plant (NC) [186] units; and Robinson (SC)[187] in October 2012, and the L.V. Sutton (NC) plant in November 2013; totaling 1,600 MW, these are all the units that do not have advanced environmental controls. But at the same time, the utility has added the 584 MW gas-fueled S.H. Smith plant (June 2011) and is building new gas-fired combined-cycle plants, including a 920 MW combined cycle plant at the H.F. Lee energy complex that came online December 2012.[188]

Duke Energy and Progress Energy are building a number of 100, 115, and 230 kV transmission lines and upgrades throughout their service territories in the Carolinas and Florida.[189] Duke Energy is also investing in several new gas-fired plants in North Carolina—at the Dan River Steam Station site and Buck Steam Station. Duke Energy retired three old coal units at Dan River in 2012[190] and built a new 620 MW gas-fired plant on the site, online in late 2012.[191] The 825 MW Cliffside advanced coal plant came online in December 2012[192] (to be followed by retirement of 1,000 MW of older, less efficient generation). A second 620 MW gas-fired plant was completed at Buck Station in November 2011, after which Duke retired the site's four existing coal-fired units.[193]

In March 2012, the NRC granted approval for South Carolina Electricity & Gas and Santee Cooper to build two new 1,100 MW nuclear reactors at the V.C. Summer site near Columbia, South Carolina. The two units are projected to go into service in 2017 and 2018.[194]

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[186] The 316-MW Cape Fear plant went into service in 1923, and four other units retired in 1977 and 2011. Duke Energy (2013a). "Cape Fear Plant." Website information, at http://www.duke-energy.com/power-plants/coal-fired/cape-fear.asp, accessed December 5, 2013.

[187] Duke Energy (2013b). "Robinson Plant." Website information, at http://www.duke-energy.com/power-plants/coal-fired/robinson.asp, accessed December 5, 2013.

[188] Sells, J. (2012). "Progress Energy to retire coal-fired power plant," *WBTV*, September 14, 2012, at http://www.wbtv.com/story/19544958/progress-energy-to-retire-coal-fired-power-plant; Duke Energy (2013c), "H. F. Lee Combined Cycle Plant." Website information, at http://www.duke-energy.com/power-plants/oil-gas-fired/hf-lee-cc.asp, accessed December 5, 2013.

[189] Duke Energy (2012b). "Electric Transmission Projects." *Website information,* at http://www.duke-energy.com/about-us/electric-transmission-projects.asp, accessed September 27, 2012.

[190] Duke Energy (2012a). "Dan River Steam Station." *Website information,* at http://www.duke-energy.com/power-plants/coal-fired/dan-river.asp.

[191] Duke Energy (2013f). "Dan River Combined Cycle Station." Website information, at http://www.duke-energy.com/power-plants/oil-gas-fired/dan-river-cc.asp, accessed December 5, 2013.

[192] Duke Energy (2013d). "Cliffside Steam Station." Website information, at http://www.duke-energy.com/power-plants/coal-fired/cliffside.asp, accessed December 5, 2013.

[193] Duke Energy (2011). "2010 Annual Report, Chairman's Letter to Stakeholders," at http://www.duke-energy.com/investors/publications/annual/ar-2010/letter/investing-in-our-future-modernization-strategy/; Duke Energy (2013e). "Buck Combined Cycle Station." Website information, at http://www.duke-energy.com/power-plants/oil-gas-fired/buck-cc.asp, accessed December 5, 2013.

[194] Smith, B. (2012a). "U.S. regulators approve new SCE&G nuke reactors." *Associated Press*, Charleston SC, March 30, 2012, at http://www.postandcourier.com/article/20120330/PC16/120339903&slId=7; and Barber, W. (2012a). "In 4-1 vote, NRC gives blessing to two new units at V.C. Summer." *Generation Hub*, March 30, 2012.

TVA owns and operates 15,900 circuit-miles miles of transmission across an 80,000 square mile territory spanning seven states. The utility began building coal-fired generation in the 1950s and now has 11 coal-fired power plants with 48 active generating units (see Figure 6 - 13). TVA reports that it will be retiring at least 2,700 MW of generation on its system by the end of 2017.[195] TVA recently had 18 planned or active transmission projects under way in Alabama, Georgia, Mississippi, and Tennessee, from local upgrades and possible new 500 kV lines to meet increasing loads and improve reliability.[196] TVA has signed contracts for at least 1,515 MW of wind generation.[197]

Mississippi Power is building a 582 MW lignite coal integrated gasification combined cycle plant with carbon capture and sequestration, and associated transmission.[198] The utility has also announced plans to switch at least two coal-fired units, Watson 4-5, from burning coal to natural gas around 2015.[199]

In Louisiana, Entergy is moving forward with construction of Ninemile Unit 6, a 550 MW, dual-fuel combined cycle gas turbine generator at its Ninemile Point Station, which is expected online in 2015.[200]

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[195] Tennessee Valley Authority (TVA) (2013), "Clean Air Act Agreement," Website information, accessed December 5, 2013 at http://www.tva.gov/news/keytopics/cleanairagreement.htm, access December 13, 2013; TVA 10-K annual report, November 2012, p. 15.

[196] Tennessee Valley Authority (TVA) (2012a). "Transmission System Projects." *Website information,* accessed September 27, 2012, at http://www.tva.com/power/projects/index.htm.

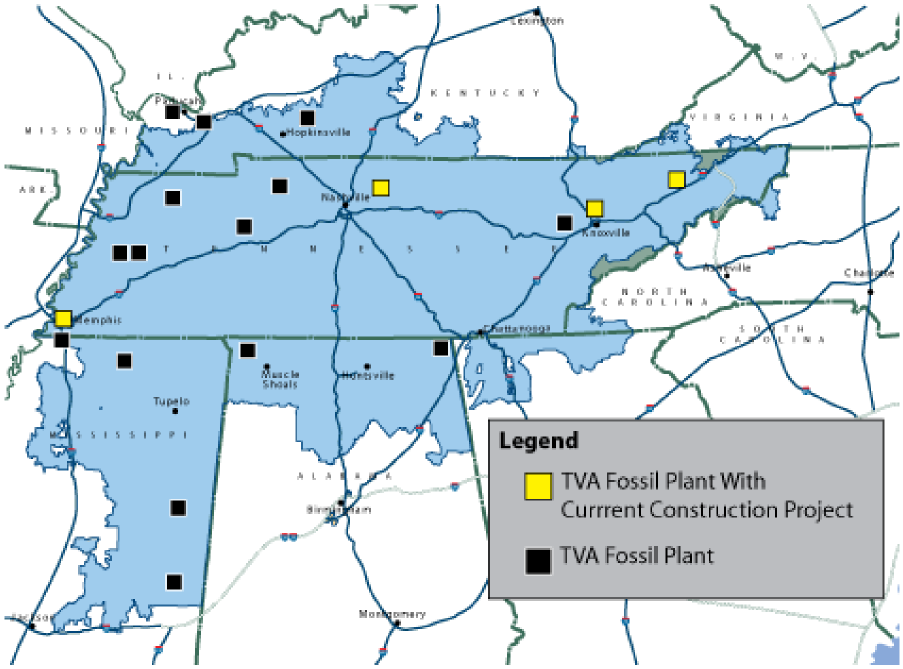
[197] Tennessee Valley Authority (TVA), "Renewable and Clean Energy," at http://www.tva.com/news/keytopics/renewable_energy.htm.

[198] Barber, W. (2012c). "Southern Co.: IGCC Plant 40 Percent Done," *Energybiz*, September 6, 2012, at http://www.energybiz.com/article/12/09/southern-co-igcc-plant-40-percent-done.

[199] Cassell, B. (2012i). "Mississippi Power plans to switch two coal units to gas in 2015," *Generation Hub*, March 8, 2012.

[200] Entergy (2012a). "Entergy Louisiana Moves Forward with Construction on State-of-the-art Generation Unit." *PR Newswire*. March 26, 2012, at http://www.prnewswire.com/news-releases/entergy-louisiana-moves-forward-with-construction-on-state-of-the-art-generation-unit-144193685.html.

Figure 6 - 13. TVA fossil generation plants



Source: Tennessee Valley Authority (TVA) (2012b). "Fossil Generation Development & Construction Projects." Website information, at http://www.tva.com/power/construction/index.htm, accessed September 27, 2012.

Entergy is actively addressing several areas of congestion (see Figure 6 - 14), and has 144 new lines and upgrade projects planned for 2012-2016.[201] Entergy, in combination with CLECO and Lafayette Utilities, has built a new 230 kV line and added 500-230 kV autotransformers to address the Acadiana load pocket congestion issues in southern Louisiana and relieve long-standing import constraints.[202] [203] Several new lines are being constructed in Central Arkansas to address congestion there.[204] Entergy is also building new transmission in southeast

[201] Powell, D. (Entergy) (2012). "U.S. Department of Energy Pre-Congestion Study Regional Workshop for the 2012 National Electric Congestion Study." Presentation by D. Powell of Entergy System at the Regional Congestion Study Workshop. St. Louis, MO, December 8, 2011, at http://energy.gov/sites/prod/files/Presentaion%20by%20Doug%20Powell%2C%20Entergy.pdf, slide 9.

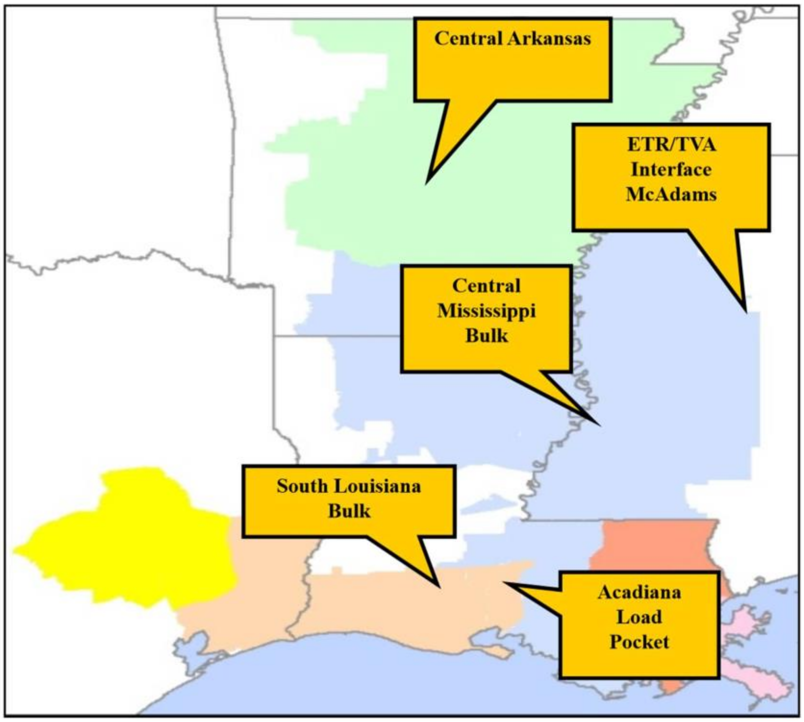
[202] Edison Electric Institute (2012b). *Transmission Projects at a Glance*. Updated March 2012. Washington, D.C. http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx, p.30.

[203] NERC (2011c). *2011 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. 433.

[204] Powell, D. (Entergy) (2011) "Comments of Entergy System." Presented at the U.S. Department of Energy, National Electric Transmission Congestion Workshop, St. Louis, MO., December 8, 2011, at, http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf, pp. 103-104; AEP Transmission (2014). "Benton County, Arkansas Transmission Project." *Transmission project website*, at http://www.aeptransmission.com/arkansas/BentonCounty/.

Louisiana; north Louisiana, east of Baton Rouge; and in the McAdams area of central Mississippi to address various reliability and economic needs across its territory.[205]

Figure 6 - 14. Entergy congestion regions



Source: Powell, D. (Entergy) (2012). "U.S. Department of Energy Pre-Congestion Study Regional Workshop for the 2012 National Electric Congestion Study." Presentation by D. Powell of Entergy System at the Regional Congestion Study Workshop. St. Louis, MO, December 8, 2011, at *http://energy.gov/sites/prod/files/Presentaion%20by%20Doug%20Powell%2C%20Entergy.pdf, slide 5.*

FRCC

The FRCC works to maintain grid reliability across most of the state of Florida, serving 16 million people in an area with 12,018 circuit-miles of transmission[206] and 51,082 MW of net winter nameplate generating capacity.[207] The FRCC expects that planned transmission systems within FRCC will be "adequate and reliable,"[208] although in the short-term:

> *Increased west-to-east flow levels across the Central Florida metropolitan load areas may cause transmission constraints in the Central Florida area, requiring remedial*

[205] Edison Electric Institute (2012b). *Transmission Projects at a Glance*. Updated March 2012. Washington, D.C. http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx, pp. 28-31.
[206] NERC (2011c). *2011 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, Table 4: Circuit-mile additions by assessment area," p. 43, adding 2010 Existing and 2011 Under Construction values.
[207] FRCC (2012). *2012 Regional Load & Resource Plan.* July 2012. Florida: FRCC at, http://www.psc.state.fl.us/utilities/electricgas/docs/FRCC_2012_Load_Resource_Plan.pdf, p. 22.
[208] *Ibid*., p. 39.

> *actions (depending on system conditions). Permanent solutions have been developed and are being implemented. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.*[209]

Florida Power & Light (FPL), which serves 8.8 million people, operates a generation portfolio that includes oil and gas, renewables, and nuclear power, under both utility and non-utility ownership. FPL has been moving toward natural gas generation for a decade, reducing its oil use from 40 million barrels to 10,000 barrels per year while building more natural gas-fired power plants and buying energy from others. Progress Energy Florida is responding to the federal MATS regulation by proposing the conversion of its Anclote Units 1 & 2 (1,100 MW) from oil and natural gas firing to natural gas-only use, projected for completion by the end of 2013.[210]

Capacity upgrades were planned at all three Florida nuclear plants, with current nuclear capacity of 3,947 MW to be increased by 636 MW spread across St. Lucie Units 1 & 2, Turkey Point Units 3 & 4, and Crystal River.[211] On February 5, 2013, Duke Energy announced its decision to retire the Crystal River Nuclear Plant,[212] reducing FRCC nuclear capacity in the FRCC region by approximately 860 MW.

6.3. Regional Findings

The Department's findings are based on consultation with state officials and industry stakeholders, as well as a review of publicly available documents and data available through the end of 2012, with limited updates in December 2013.[213]

Midwest

The Midwest area contains MISO, SPP, the far western portion of PJM, and some areas that are not part of any RTO or organized wholesale power market. Although the Midwest ISOs and RTOs collect data about transmission constraints, congestion costs and LMPs, it is important to note that these terms are defined and calculated differently in each ISO and RTO. For this

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[209] NERC, (2011c). *2011 Long-Term Reliability Assessment.* Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. 177.

[210] Cassell, B. (2012l). "Progress Energy Florida plans Anclote conversion to 100% gas," *Generation Hub*, March 30, 2012.

[211] FRCC (2012). "2012 Ten-Year Site Plan Workshop," FRCC Presentation by Dochoda, Stacy & John Odom to the Florida Public Service Commission, August 13, 2012, http://www.psc.state.fl.us/utilities/electricgas/docs/FRCC_08_13_2012.pdf, p. 24.

[212] Duke Energy (2014). "Crystal River Nuclear Plant." Website information, at http://www.duke-energy.com/power-plants/nuclear/crystal-river.asp, accessed November 5, 2014.

[213] As described in the Note to Readers, the Department has published its compilation of this information for 2009-2012 in a standalone document. (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)

reason, transmission constraints and congestion matters are considered on an RTO- or ISO-specific basis.[214]

The Department's findings regarding congestion in the Midwest are:

- Congestion results from high and growing levels of wind generation that cannot be delivered from the western side to more distant, eastern loads, and the lack of additional transmission to enable further development in renewable-rich areas. These factors resulted in higher real-time congestion costs in central MISO.
- Congestion is also due to generation and capacity reserves that are higher in the western and central side of MISO than they are in the eastern part of the Midwest region, increasing west-to-east flows.[215] These factors resulted in higher real-time congestion costs at some locations on the interface between MISO and PJM.
- Congestion is also due to administrative and institutional differences that create "seams" between and among the western RTO/ISOs (MISO, PJM, and SPP) and the eastern RTO/ISOs (PJM and New York ISO via the "Lake Erie Loop"), which lead to loop flows, and pricing and scheduling inconsistencies. These RTOs/ISOs are aware of these issues and in many cases are actively working to address them.
- Real-time congestion costs increased to $1.24 billion for MISO in 2011, up 20% from 2010. In PJM, total congestion costs decreased to $1 billion in 2011, down 30% from 2010.

Interconnection queues for the Midwest, as of 2012, were dominated by siting requests for wind generation, generally in locations distant from population centers.

Northeast

The Northeast region includes the footprints of the New York and New England ISOs and the eastern portion of PJM.[216]

[214] In this study, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)

[215] Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*. Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p.13.

[216] As mentioned above, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)

The Department's findings regarding congestion in the Northeast are:

- Transmission constraints have limited flows across the Northeast for fewer hours per year (comparing 2009–2011 to 2008 and before).
- Generation and transmission additions across the Northeast in recent years have contributed to lower overall congestion, particularly within New England and PJM.
- Congestion is also down due to lower demand reflecting the economic recession of 2008–2009, aggressive energy efficiency and demand response, lower natural gas prices, and the resulting smaller price differentials between natural gas and competing generation fuels (e.g., coal). This reduces the economic incentive to use transmission to displace electricity from one source with electricity from another source using less costly fuel.
- Congestion costs for NYISO in 2012 were 50% below the $2.6 billion reported in DOE's previous congestion study (2009). Congestion costs for ISO-NE in 2012 were less than 10% of the ~$0.5 billion reported in 2009 by DOE.
- However, some congestion still exists. Much of the congestion that remains in the Northeast reflects three factors:
    - Transmission constraints continue to restrict delivery of power into load centers in central New York and the New York City and Long Island areas.
    - Increased quantities of low-cost onshore wind generation in concentrated locations remote from major load centers are shipped during off-peak hours as "as available capacity," because they exceed the throughput capability of existing transmission facilities. These facilities were designed to meet the on-peak demands of load centers rather than deliver off-peak generation from the remote wind locations.[217]
    - Administrative and institutional issues arising from different market rules, scheduling practices, and transmission reservations hinder more effective use of facilities between neighboring RTOs and ISOs and result in congestion at locations along the seams between markets. RTOs and ISOs in the Northeast are aware of these issues and in many cases are actively working to address them.[218]

[217] As noted above, increases in remotely-located renewables is not a concern in all regions, e.g. NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Rensselaer, NY: NYISO. September 2010, available from http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf.

[218] For instance, the development of Coordinated Transaction Scheduling between ISO-NE and NYISO, which will be described in more detail below. While FERC permits regional differences in strategies for system operations and market rules, FERC generally encourages coordination between different regions to support economically efficient trade. See, e,g., The Energy Daily (2013b). "FERC steps into 'seams' fight between MISO, PJM." December 23, 2013; The Energy Daily (2014). "FERC moves to defuse mushrooming SPP-MISO fight." April 1, 2014.

Southeast

The Southeast region covers North and South Carolina, Tennessee, Arkansas, Georgia, Alabama, Mississippi, Louisiana, Florida and parts of (non-ERCOT) Texas. It includes some or all of the NERC regions of SERC, SPP and FRCC (Florida).

- The Department's findings regarding congestion in the Southeast are:There are no clear trends in the application of administrative congestion management procedures over the period 2006–2011, with the exception of an increase in level 5 TLRs (the most severe TLR level because it involves curtailment of firm transactions), called by ICTE (Entergy's Independent Coordinator of Transmission).
- There is one report of a persistent transmission constraint within the region.[219]
- As with the portions of the Western Interconnection outside of CAISO, there are no reports on the economic cost of congestion because no organized wholesale electricity markets operate in the Southeast which produce locational marginal prices that reflect differences in production costs due to congestion.
- Transmission is being built in coordination with generation additions following long-standing planning practices overseen by state and regional protocols.
- Interconnection queues indicate that future generation will consist largely of fossil-fuel and nuclear generation in Georgia, Alabama, and Florida, wind generation in the western part of the interconnection and in Tennessee, and solar in Florida.

[219] Florida Municipal Power Agency (FMPA) submitted comments on the draft study that the Florida-Georgia interface is constrained. FMPA also provided information on OASIS service queues and available transmission capacity.

7. Public Comment Process and Next Steps

In the five subsections below, the Department reviews and responds to the comments it received through the public comment process on the draft study, and it addresses some topics raised in an earlier consultation process with the states and regional reliability entities.[220] The first three subsections pertain to three topics posed for comment by the Department in the draft study. The fourth subsection discusses comments received on other aspects of the draft study, distinct from the three questions. The fifth subsection discusses all remaining comments received by the Department; most of the comments in that subsection address topics that fall outside the scope of the draft study, but they are listed here for completeness.

7.1. Data Questions

In the draft study, the Department said it

> *… is particularly interested in comments on the reliance on publicly available data to assess congestion and transmission constraints. In Chapter 3 this study discusses the limitations of available data and indicates actions the Department intends to take to improve data quality and availability in the future. The Department invites comments on these plans, insight into whether such data would have value for other parties, and comment on possible issues relating to the collection and public availability of the targeted data.*

ISO-NE, NYISO, and Southern Company commented that reliance on public data is preferred and that the data is adequate for the purpose of preparing the study. Edison Electric Institute (EEI) further commented that reliance on planning information developed by utilities and stakeholders is also appropriate. WIRES and NEMA (the National Electric Manufacturers Association)[221] commented that the Department should make more data available publicly on a timely basis, although they also urged balancing this effort with consideration for data security and the burden data collection could create. Clean Line commented that there may be instances when use of non-public data should be considered.

NextEra Energy and EEI commented that relying only on publicly-available data means the Department's study may not be offering any new information that is not already available to or being considered by decision-makers. During DOE's consultation process with the states and the regional reliability entities, ReliabilityFirst commented that relying only on public data may reduce the effectiveness of the study.

[220] The Department received a total of 99 public comments on the draft study, from 13 organizations and 80 individuals. The entities and individuals submitting these comments are listed in appendix D and their comments are on posted on the Department's website http://www.energy.gov/oe/public-comments-received-draft-congestion-study. In addition, in its consultation with states and regional reliability entities, the Department received 13 comments addressed to its three topics.

[221] WIRES and NEMA submitted comments jointly.

Comments varied in responding to the question about whether the Department should take action to improve data quality and availability. Clean Line, NYISO, WIRES and NEMA, SPSC/WIEB, the State of Colorado, NESCOE, and WECC supported the Department pursuing at least some additional data gathering, while Southern Company, EEI, and Alabama Public Service Commission (PSC) did not. ISO-NE commented that stakeholders and agencies are already working with the Department to collect data, and NYISO, SDG&E, and ReliabilityFirst commented that existing collaboration between the Department and stakeholders on data collection issues should be pursued further. Southern Company, FMPA, and SDG&E commented that additional publicly available data that could inform the study are available but were not used in the draft study.[222]

PJM commented that the Department's proposal in the draft study went beyond the information that may be needed to identify and analyze congestion. EEI and Southern Company commented that the pursuit of standardized metrics would go beyond the scope of the enabling legislation. EEI, Southern Company, and Duke opposed pursuit of new legislation to enable the Department to collect more information.

Clean Line commented that additional publicly available data would be useful to other parties.

Regarding possible issues that might arise in pursuing expanded data collection, EEI, WIRES, and ISO-NE commented doing so would impose additional burdens on the industry. Clean Line and WIRES and NEMA commented that some data may be sensitive for competitive or security reasons, which may make them harder to obtain or create other complications. Southern Company and Clean Line commented that obtaining or producing standardized metrics or information would not be possible given the diversity of the industry.

After considering these comments, the Department's findings and conclusions regarding data are:

(1) The Department concludes that relying on publicly available data is appropriate and necessary for the preparation of its Congestion Studies. Doing so ensures transparency in the Department's analysis and would help to address questions that would likely arise in the event the Department seeks to designate National Corridors based on the findings of such analyses. Accordingly, the Department will continue to rely on publicly available data to assess transmission congestion and constraints in future congestion studies. It will, however, also consider incorporating previously non-public data in future studies, if it is acceptable to the source to make the data public via inclusion in the study.

(2) The Department agrees that some additional public information was available on topics relevant to the study, but that the information was not included in the initial draft study. As noted below, additional data or information provided to the Department

[222] In cases where the comments included additional substantive information, the information has been included in the body of the final study. Also see discussion of responses under 7.2. Consideration of National Corridors.

through the comment process has either been incorporated into the final study or will be considered by future congestion studies.

(3) The Department will continue to work with stakeholders to refine existing or new sources of publicly available data, in part through the vehicle of DOE's new annual *Transmission Data Review*.

7.2. Consideration of National Corridors

In the draft study, the Department invited comments on whether

> *… the study's findings warrant consideration of National Corridors. Parties are invited to discuss potential corridors and explain whether the information provided in the study would help support designation of any specific location as a National Corridor, and why or why not. Parties are directed to Federal Power Act, 16 U.S.C. § 824p, also summarized in section I, for the factors the Secretary may consider in designating a National Corridor. Commenters who are aware of relevant, publicly available data and analyses not included in this study that could inform a decision on whether to designate a National Corridor should provide that information for the Department's consideration.*

Southern Company, Alabama PSC, and one individual commented that the findings in the report did not support designating corridors in specific regions. NYISO, ISO-NE, NYPSC, NARUC, and NESCOE commented that broader trends (including recent increased transmission construction and existence of robust planning processes) indicated there is no congestion or need to designate corridors in certain areas. Eighty-one individuals commented that they opposed corridor designation for a variety of reasons; typically, however, these reasons were not related to the findings in the draft study.

The American Wind Energy Association (AWEA) and Clean Line commented that corridors were justified. AWEA further commented that a corridor should be designated in the Western Interconnection, but did not identify either a specific geographic region or proposed line. Neither AWEA nor Clean Line referred to specific findings in the draft study in support of their recommendations.

NYISO and EEI commented that a major limitation of this study was that it primarily focused on data available through 2012 with limited updates through December 2013.

SPP, NYISO, SDG&E, Clean Line, Duke, FLMA, and Southern Company provided additional data and information (or references to information or types of information) on congestion and transmission constraints that were included in the draft study. This information has been incorporated into or referenced in the final study.

7.3. Usefulness of the Congestion Studies and National Corridors

In the draft study, the Department invited comments on two questions related to the usefulness of the Congestion Studies and National Corridors:

> *Do the Congestion Studies continue to serve a useful purpose in informing the national discussion of transmission infrastructure needs? Should the scope and process for conducting such studies be modified to better serve this objective?*
>
> *Does the possible designation of National Corridors, under the statutory language as presently written and interpreted by the courts, help to ensure that adequate and appropriate transmission infrastructure is built in a timely manner? Should the concept of such corridors, or the process for their designation be modified to better serve this objective?*

Several parties commented on useful purposes served by the Department's current Congestion Study. Southern Company commented that it provides a counterbalance to FERC's backstop siting authority. WIRES and NEMA commented that it provides a public forum for discussing congestion and congestion data issues. Clean Line and ISO-NE commented that it is a source of useful information. Clean Line further commented that it supports multi-region transmission planning and supports identification of development opportunities.

Several other parties commented on limits to the usefulness of the Department's Congestion Study. WECC, NYPSC, and NYISO commented that its usefulness is limited because the data relied upon are outdated. NextEra commented that the analysis does not provide information that is not otherwise available and that the study's findings are too general. SDG&E and SPP commented that a future time horizon of 3 to 5 years is too short to inform transmission decisions. NYISO commented that reporting on gross congestion rent (instead of bid production cost savings) is not the most appropriate measure of congestion.

The Pennsylvania Public Utilities Commission (PUC) and NESCOE commented that there have been changes in the industry since the first Congestion Study, (including FERC Order 1000, changes in NERC responsibilities, interconnection-wide transmission planning activities, and economic factors) that reduce the relevance of Department's Congestion Studies or require modifications to its scope in order to focus more on information dissemination.

NextEra Energy and AWEA commented that the Department should shift responsibility for the production of Congestion Studies to developers seeking to propose a transmission corridor. Such a Congestion Study would focus on congestion in a particular area that could be alleviated by a project in a National Corridor in that area. NextEra Energy also commented that the Department could require a proponent of a corridor to submit a draft Congestion Study, which could be shared with affected states for consultation.

EEI commented that the Congestion Studies should be based on more DOE outreach to states and the Order 1000 planning regions and stakeholders, rather than on improved or more uniform data collection. NYPSC commented that the Department should base future Congestion Studies on collaboration with states similar to existing planning processes.

NARUC commented that corridors should only be designated on the basis of strict adherence to the terms and processes cited in the statute. NYPSC commented that the draft study did not consider costs of congestion or potential costs of relieving the congestion, or alternatives to transmission for relieving congestion. It contended that these concepts are important in the decision to designate a National Corridor, and that a Congestion Study should contain all information needed to make a decision about corridor designation.

Southern Company, EEI and Alabama PSC commented that thus far designation of National Corridors has not been "proven necessary." Therefore, any determination about whether National Corridors are relevant to ensuring transmission adequacy would be speculative. ReliabilityFirst and NESCOE commented that designation of National Corridors alone would not ensure that adequate and appropriate infrastructure is built, and that existing planning processes are intended to ensure transmission adequacy. ReliabilityFirst also commented that corridor designation may be helpful in expediting regulatory siting processes. Pennsylvania PUC commented that the language of the statute has little impact on whether adequate and appropriate transmission infrastructure is built in a timely manner, and that National Corridors are no longer necessary.

Several parties commented on alternative processes for the designation of National Corridors. ISO-NE commented that designations should be based on analysis of transmission needs as produced by regional system planning processes and review of NERC violations. As noted above, NextEra commented that developers should be allowed to propose narrow, project-specific corridors, and to submit a draft Congestion Study that would demonstrate the existence of congestion in the region and that it would be alleviated by the project. AWEA commented that transmission developers should be allowed to request designation of specific corridors.

EEI commented that the Department should forego preparation of Congestion Studies and designation of National Corridors, in favor of streamlining federal permitting and siting processes when requested by utility applicants.

The Department's conclusions concerning the usefulness of triennial Congestion Studies are:

(1) Publication by DOE of an annual *Transmission Data Review* should be continued, as a means of making relatively fresh transmission data and information available to the public.

(2) Triennial Congestion Studies can serve a useful purpose other than providing a basis for designation of a National Corridor, by focusing national attention on aspects of transmission infrastructure that may warrant other forms of federal attention and action.

(3) The Department recognizes that future Congestion Studies should be coordinated with regional transmission planning efforts, including those mandated by FERC Order 1000, and that some of these efforts are still being developed.

The Department's responses to comments concerning the designation of National Corridors will be presented in a separate document, *Report by the U.S. Department of Energy Concerning Designation of National Interest Electric Transmission Corridors* (forthcoming).

7.4. Comments on Other Aspects of the Draft Congestion Study

The Department also received comments on a number of other topics related to the draft study:

(1) SDG&E and SPP both commented that focusing chiefly on a future 3-5 year time frame reduces the value of the report.

(2) Southern Company commented that compliance with reliability requirements does not cause constraints or congestion, that non-RTO markets are not more opaque than those managed by RTOs, and that non-RTOs in the Eastern Interconnection are also responding to new challenges facing the industry.

(3) NYISO commented that interconnection queues are not useful indicators of congestion.

(4) ISO-NE, Southern Company, Clean Line, FLMPA, NextEra Energy, NYISO, EEI, and Duke provided detailed feedback, factual corrections and clarifications on the content of the report.

The Department's responses to these comments are:

(1) The suggestions for edits, corrections, and clarifications on the draft study have been considered and in most cases incorporated into the final study.

(2) The suggestions for improving future congestion studies are generally reasonable and will be taken into consideration when the Department prepares its next Congestion Study.

7.5. General Comments on Topics Related to Transmission Development and Construction

Finally, the Department received a number of comments on topics related to transmission development and construction:

(1) One individual commented that the definitions of congestion and constraints were broad and ambiguous.

(2) One individual commented that it is concerning that DOE might find congestion that is contingent on potential generation development.

(3) One individual commented that it is concerning that the Department did not conduct independent analysis or validation of studies cited, and relied on industry publications.

(4) One individual commented that the study was not based on actual data, but on assumptions and information from the internet.

(5) Seventy-nine individuals commented that they oppose corridor designation.

(6) One individual commented that he or she supports corridor designation.

(7) Comments from Citizens and Common Sense and six individual commenters expressed concern with the use of eminent domain to obtain rights of way for new transmission projects.

(8) Seventy-two individuals commented that easements place undue burdens on landowners which cannot be compensated.

(9) Fifty-seven individuals commented that using private property for transmission lines to transport electricity to another state is a violation of property rights.

(10) Four individuals commented that existing rights-of-way exist and these should be explored before creating new rights-of-way.

(11) Four individual comments included concerns about potential health impacts of proximity to high voltage transmission lines.

(12) Four individuals commented that identifying corridors may create national security concerns and bring the location of important energy infrastructure to the attention of terrorists.

(13) Fifty-eight individuals commented that National Interest Electricity Transmission Corridors violate a state's right to regulate transmission lines, and that states should determine when to grant utility status.

(14) Sixty-four individuals commented that eastern states should develop utility-scale off-shore wind resources instead of transporting wind power from the Midwest.

(15) Three individuals commented that eastern state governors stated they did not want to import wind-based electricity from the Midwest into their states.

(16) Sixty-nine individuals commented that renewable energy should be developed and built within the region it is being used, eliminating the need for long-distance transmission.

(17) Eight individuals commented that new and alternative technologies should be considered before corridors for new transmission are designated.

(18) One individual commented that the growth in wind development, cited as a potential driver of congestion, was created by federal tax credits and other support.

(19) Thirteen individuals commented about specific transmission projects currently under development.

(20) Five individual comments stated concerns about potential conflicts of interest, or the Department being influenced by or supporting private interests of development companies over the interests of public citizens.

The Department's responses to these comments are:

(1) Some of these comments refer to ways to improve the content of future Congestion Studies and the Department will take them into account in preparing future studies.

(2) Comments such as those pertaining to the use of eminent domain, burdens associated with easements, federal or state laws, and regulations or policies concerning energy resource development are outside the scope of this study.

Appendix A. Organizations Participating in 2011 Congestion Study Workshops and Workshop Agendas

Ameren Transmission Company
American Electric Power
Arizona Corporation Commission
Arizona Public Service
Arkansas Public Service Commission
Bulk Power Southern Company
California Independent System Operator
California Public Utilities Commission
ColumbiaGrid
Coordinating Council
David C. Linton, LLC.
District of Columbia Public Service Commission
Ecology & Environment
Entergy
Great River Energy
ICF Incorporated
ICF International
Idaho Public Utilities Commission
ISO New England
Kansas Legislature
Lawrence Berkeley National Laboratory
LS Power
Maryland Public Service Commission
Michigan Public Service Commission
Midwest Independent System Operator
Missouri Public Service Commission
Nevada Public Utilities Commission
New York Independent System Operator
New York Public Service Commission
North Carolina Utilities Commission
North Dakota Public Service Commission
North East Power Coordinating Council
NV Energy
Oregon Public Utilities Commission
Pacific Gas & Electric
PJM Interconnection
Regulatory Assistance Project

San Diego Gas & Electric
South Dakota Public Utilities Commission
Southern California Edison
Southwest Power Pool
Tennessee Valley Authority
Tier Transmission Group
U.S. Department of Energy
Vermont Public Service Board
Washington Utilities & Transport Commission
Western Grid Group
Wyoming Public Service Commission
Xcel Energy

DRAFT

U.S. Department of Energy

National Electric Transmission Congestion Study Workshop – December 6, 2011

Hilton Philadelphia Airport, 4509 Island Avenue, Philadelphia, PA 19153

Agenda

8:00 am - 9:00 am	**Registration**
9:00 am – 9:20 am	**DOE Welcome and Presentation** *David Meyer, US Department of Energy, Session Moderator*
9:20 am – 10:30 am	**Panel I – Regulators** • *Garry Brown, Chairman, New York Public Service Commission* • *Edward S. Finley, Jr., Chairman, North Carolina Utilities Commission* • *Betty Ann Kane, Chairman, District of Columbia Public Service Commission* • *Douglas R. M. Nazarian, Chairman, Maryland Public Service Commission* • *James Volz, Chairman, Vermont Public Service Board*
10:30 am – 10:45 am	**Break**
10:45 am – 12:00 pm	**Panel II – Industry** • *Robert Bradish, Managing Director, Transmission Planning and Business Development, American Electric Power* • *John P. Buechler, Executive Regulatory Policy Advisor, New York Independent System Operator* • *Jim Busbin, Supervisor, Bulk Power, Southern Company* • *Mike Henderson, Director of Regional Planning & Coordination, ISO New England* • *Chuck Liebold, Manager, Inter-Regional Planning, PJM Interconnection*
12:00 pm – 12:30 pm	**Audience comments**
12:30 pm	**Adjourn**

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All of the panelists' presentations, and a transcript of the workshop, will be posted on the Department of Energy's website at http://energy.gov/oe/congestion-study-2012. Interested parties can submit comments or resource materials for the Congestion Study at this website.

Topics

Panelists have been asked to address the following questions, with emphasis as each panelist deems appropriate:

1) In its 2009 Congestion Study, DOE found that the entire Mid-Atlantic region remained a Critical Congestion Area and that there were large portions of the East with rich renewable resource development potential that merited recognition as Conditional Congestion Areas. The Study also found that the New England area no longer merited recognition as a Congestion Area of Concern. Do you think that the 2009 study came to the appropriate conclusions regarding congestion in this region in 2009-10? Based on current conditions, analyses and recent developments in your region, do you think your area has become more or less congested, and why?

2) What factors should DOE look at when evaluating congestion and identifying congestion areas in this region? How might each factor affect future congestion in this region?

3) Is there current or conditional congestion in your area or region today? What evidence -- quantitative or qualitative -- supports your conclusions regarding current or conditional congestion in your area or region today? (Please provide such evidence, or direct us to appropriate source materials.) To the extent that you believe your region has conditional congestion of national significance, what are the factors or conditions upon which that conclusion rests and how likely are these conditions likely to materialize?

4) If current or conditional congestion exists in your area, what are its consequences in terms of reliability, resource options, wholesale competition and market power, cost of electricity to consumers, environmental quality, or other? Are these consequences so significant that this congestion should be mitigated?

5) Assuming that it would not be economic or practical to mitigate all congestion, what is the range of options for mitigating severe congestion?

6) Are there particular data sources, analyses and organizations that DOE should look at for expertise and source material in preparing the 2012 congestion study? In particular, how should DOE best use the expertise and insight offered by the Eastern Interconnection States Planning Council (EISPC) and the Eastern Interconnection Planning Collaborative (EIPC)?

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U.S. Department of Energy

National Electric Transmission Congestion Study Workshop – December 8, 2011

Hilton St. Louis Airport, 10330 Natural Bridge Road, St. Louis, Missouri 63134

Agenda

8:00 am - 9:00 am	**Registration**
9:00 am – 9:20 am	**DOE Welcome and Presentation** *David Meyer, US Department of Energy, Session Moderator*
9:20 am – 10:30 am	**Panel I – Regulators** • *Kevin D. Gunn, Chairman, Missouri Public Service Commission* • *Jerry Lein, Staff Engineer, North Dakota Public Service Commission* • *Olan W. Reeves, Commissioner, Arkansas Public Service Commission* • *Tom Sloan, Representative, Kansas Legislature* • *Greg R. White, Commissioner, Michigan Public Service Commission*
10:30 am – 10:45 am	**Break**
10:45 am – 12:00 pm	**Panel II – Industry** • *Maureen Borkowski, President and CEO, Ameren Transmission Company* • *Jay Caspary, Director of Transmission Development, Southwest Power Pool* • *Laureen L. Ross McCalib, Manager, Resource Planning and former Manager, Regional Transmission Regulation, Great River Energy* • *Dale Osborn, Transmission Planning Technical Director, Midwest Independent System Operator* • *Doug Powell, Director, Transmission and Distribution Planning, Entergy* • *David Till, Transmission Strategy General Manager, Tennessee Valley Authority*
12:00 pm – 12:30 pm	**Audience Comments**
12:30 pm	**Adjourn**

DRAFT

All presentations, as well as a transcription of the workshop, will be posted on the Department of Energy's website at http://energy.gov/oe/congestion-study-2012. Audience comments and resource materials for the Congestion Study can be submitted at that site.

Topics:

Panelists have been asked to address the following questions, with emphasis as each panelist deems appropriate:

1) In its 2009 Congestion Study, DOE found that the entire Mid-Atlantic region remained a Critical Congestion Area and that there were large portions of the East with rich renewable resource development potential that merited recognition as Conditional Congestion Areas. The Study also found that the New England area no longer merited recognition as a Congestion Area of Concern. Do you think that the 2009 study came to the appropriate conclusions regarding congestion in this region in 2009-10? Based on current conditions, analyses and recent developments in your region, do you think your area has become more or less congested, and why?

2) What factors should DOE look at when evaluating congestion and identifying congestion areas in this region? How might each factor affect future congestion in this region?

3) Is there current or conditional congestion in your area or region today? What evidence -- quantitative or qualitative -- supports your conclusions regarding current or conditional congestion in your area or region today? (Please provide such evidence, or direct us to appropriate source materials.) To the extent that you believe your region has conditional congestion of national significance, what are the factors or conditions upon which that conclusion rests and how likely are these conditions likely to materialize?

4) If current or conditional congestion exists in your area, what are its consequences in terms of reliability, resource options, wholesale competition and market power, cost of electricity to consumers, environmental quality, or other? Are these consequences so significant that this congestion should be mitigated?

5) Assuming that it would not be economic or practical to mitigate all congestion, what is the range of options for mitigating severe congestion?

6) Are there particular data sources, analyses and organizations that DOE should look at for expertise and source material in preparing the 2012 congestion study? In particular, how should DOE best use the expertise and insight offered by the Eastern Interconnection States Planning Council (EISPC) and the Eastern Interconnection Planning Collaborative (EIPC)?

U.S. Department of Energy

National Electric Transmission Congestion Study Workshop – December 13, 2011

Sheraton Portland Airport Hotel, 8235 Northeast Airport Way, Portland, OR 97220

Agenda

8:00 am - 9:00 am	**Registration**
9:00 am – 9:20 am	**DOE Welcome and Presentation** *David Meyer, US Department of Energy, Session Moderator*
9:20 am – 10:15 am	**Panel I – Regulators** • *John Savage, Commissioner, Oregon Public Utilities Commission* • *Marsha Smith, Commissioner, Idaho Public Utilities Commission* • *Steve Oxley, Deputy Chairman, Wyoming Public Service Commission* • *Philip B. Jones, Commissioner, Washington Utilities and Transportation Commission*
10:15 am – 10:30 am	**Break**
10:30 am – 12:00 pm	**Panel II – Industry** • *Rich Bayless, Northern Tier Transmission Group, and TEPPC Vice Chair* • *Susan Henderson, PE, Manager, Regional Transmission Planning, Xcel Energy* • *Marv Landauer, Principal Planning Engineer, ColumbiaGrid* • *Steve Metague, Senior Director, Project Development, Pacific Gas & Electric* • *Brad Nickell, Director of Planning, Western Electricity Coordinating Council*
12:00 pm – 12:30 pm	**Audience comments**
12:30 pm	**Adjourn**

Panelists' presentations and a transcript of this workshop will be posted on the Department of Energy's website at http://energy.gov/oe/congestion-study-2012. Interested parties may submit comments and additional materials for the Congestion Study at that site.

Topics:

Panelists have been asked to address the following questions with emphasis as each panelist deems appropriate:

1) In its 2009 Congestion Study, DOE found that Southern California constitutes a Critical Congestion Area, that the Portland-Seattle region and the San Francisco Bay Area were congestion areas of concern, and that the Phoenix-Tucson area was no longer a congestion area of concern. The study also identified parts of the West with rich renewable resource development potential as Conditional Congestion Areas. Do you think that the 2009 study came to the appropriate conclusions regarding congestion in this region in 2009-10? Based on current conditions, analyses and recent developments in your region, do you think your area has become more or less congested, and why?

2) What factors should DOE look at when evaluating congestion and identifying congestion areas in this region? How might each factor affect future congestion in this region?

3) Is there current or conditional congestion in your area or region today? What evidence -- quantitative or qualitative -- supports your conclusions regarding current or conditional congestion in your area or region today? (Please provide such evidence, or direct us to appropriate source materials.) To the extent that you believe your region has conditional congestion of national significance, what are the factors or conditions upon which that conclusion rests and how likely are these conditions likely to materialize?

4) If current or conditional congestion exists in your area, what are its consequences in terms of reliability, resource options, wholesale competition and market power, cost of electricity to consumers, environmental quality, or other? Are these consequences so significant that this congestion should be mitigated?

5) Assuming that it would not be economic or practical to mitigate all congestion, what is the range of options for mitigating severe congestion?

6) Are there particular data sources, analyses and organizations that DOE should look at for expertise and source material in preparing the 2012 congestion study? In particular, how should DOE best use the expertise and insight offered by the Western Governors Association (WGA) and the Western Electric Coordinating Council (WECC)? What are the most relevant results from recent work, such as that done for the Western Renewable Energy Zones project, the designation of energy corridors on federal lands under section 368 of the Energy Policy Act (2005), the programmatic environmental impact statement for solar development on federal lands, and WECC's recent 2011 10-Year Regional transmission Plan?

U.S. Department of Energy

National Electric Transmission Congestion Study Workshop – December 15, 2011

Sheraton San Diego Hotel & Marina, 1380 Harbor Island Drive, San Diego, California 92101

Agenda

8:00 am - 9:00 am	**Registration**
9:00 am – 9:15 am	**DOE Welcome and Presentation** *David Meyer, US Department of Energy, Session Moderator*
9:15 am – 10:30 am	**Panel I – Regulators** • *Rebecca D. Wagner, Commissioner, Nevada Public Utilities Commission* • *Charles Hains, Chief Counsel, Arizona Corporation Commission* • *Keith D. White, Ph.D., Regulatory Analyst, Energy Division, California Public Utilities Commission*
10:30 am – 10:45 am	**Break**
10:45 am – 12:00 pm	**Panel II – Industry** • *Bob Smith, Director, Director, Energy Delivery Asset Management and Planning, Arizona Public Service* • *Jan Strack, Grid Planning, Regulatory & Economics Manager, San Diego Gas & Electric* • *Mario Villar, Vice President, Transmission, NV Energy* • *Xiaobo Wang, Ph.D., Senior Regional Transmission Engineer, Department of Market and Infrastructure Development, California Independent System Operator*
12:00 pm – 12:30 pm	**Comments from Participants**
12:30 pm	**Adjourn**

Panelists' presentations and a transcript of this workshop will be posted on the Department of Energy's website at http://energy.gov/oe/congestion-study-2012. Interested parties may submit comments and additional materials for the Congestion Study at that site.

Topics:

Panelists have been asked to address the following questions, with emphasis as each panelist deems appropriate:

1) In its 2009 Congestion Study, DOE found that Southern California constitutes a Critical Congestion Area, that the Portland-Seattle region and the San Francisco Bay Area were congestion areas of concern, and that the Phoenix-Tucson area was no longer a congestion area of concern. The study also identified parts of the West with rich renewable resource development potential as Conditional Congestion Areas. Do you think that the 2009 study came to the appropriate conclusions regarding congestion in this region in 2009-10? Based on current conditions, analyses and recent developments in your region, do you think your area has become more or less congested, and why?

2) What factors should DOE look at when evaluating congestion and identifying congestion areas in this region? How might each factor affect future congestion in this region?

3) Is there current or conditional congestion in your area or region today? What evidence -- quantitative or qualitative -- supports your conclusions regarding current or conditional congestion in your area or region today? (Please provide such evidence, or direct us to appropriate source materials.) To the extent that you believe your region has conditional congestion of national significance, what are the factors or conditions upon which that conclusion rests and how likely are these conditions likely to materialize?

4) If current or conditional congestion exists in your area, what are its consequences in terms of reliability, resource options, wholesale competition and market power, cost of electricity to consumers, environmental quality, or other? Are these consequences so significant that this congestion should be mitigated?

5) Assuming that it would not be economic or practical to mitigate all congestion, what is the range of options for mitigating severe congestion?

6) Are there particular data sources, analyses and organizations that DOE should look at for expertise and source material in preparing the 2012 congestion study? In particular, how should DOE best use the expertise and insight offered by the Western Governors Association (WGA) and the Western Electric Coordinating Council (WECC)? What are the most relevant results from recent work, such as that done for the Western Renewable Energy Zones project, the designation of energy corridors on federal lands under section 368 of the Energy Policy Act (2005), the programmatic environmental impact statement for solar development on federal lands, and WECC's recent 2011 10-Year Regional transmission Plan?

Appendix B. Entities Submitting Comments to the DOE Website as Input to the National Electric Transmission Congestion Study

American Clean Skies Foundation
American Wind Energy Association
AtlanticGrid Development
Citizens Against the Kemptown Electric Substation
Clean Line Energy
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities
Desert Conservation Program
Iowa Utilities Board
Kansas Corporation Commission
Maryland Department of Natural Resources
Massachusetts Department of Public Utilities
Michigan Public Service Commission
Minnesota Public Utilities Commission
National Audubon Society
Natural Resources Defense Council
New England States Committee on Electricity
North Dakota Transmission Authority
Northeast Power Coordinating Council
Pennsylvania Public Utility Commission
Piedmont Environmental Council
Public Service Commission of New York
Public Service Commission of Wisconsin
Public Service Electric and Gas (PSEG) Services Corporation
Public Utility Commission of Texas
San Diego Gas and Electric Company
Solar Energy Industries Association
Southern Company Services
StopPATH WV
Sugarloaf Conservancy
Transmission Access Policy Study Group
Vermont Public Service Board
Wyoming Infrastructure Authority

Appendix C. Entities Submitting Comments to DOE through the Consultation Process for the National Electric Transmission Congestion Study

Alabama Public Service Commission
Colorado Public Utility Commission and Colorado Energy Office
ISO New England
Midwest Reliability Organization
National Association of Regulatory Utility Commissioners
New England States Committee on Electricity
New York Independent System Operator
New York Public Service Commission
Pennsylvania Public Utility Commission
PJM
ReliabilityFirst
State-Provincial Steering Committee, Western Interstate Energy Board
Western Electric Coordinating Council

Appendix D. Entities and Individuals Submitting Public Comments to DOE on the Draft of the National Electric Transmission Congestion Study

Organizations

American Wind Energy Association
Citizens for Common Sense
Clean Line Energy Partners
Duke Energy
Edison Electric Institute
Florida Municipal Power Agency
ISO New England
New York Independent System Operator
NextEra Energy
San Diego Gas & Electric
Southern Company Services, Inc.
Southwest Power Pool
WIRES and the National Electric Manufacturers Association (NEMA)

Individuals

Hope Albright
Margie Anglen
Alinda Baker
Wayne Beach
Sharon Bean
Austin Bird
John D. Bixenman
Doris Brown
Phillip Brown
Duane Burnett
Matthew Burnett
Jerry & Marcie Christensen
Patrick Crommett
Noralie Crow
Carl Daffron
Celia Daniels
Kamra DeFries
John Doughty
Cynthia Fickess
Madra Fischer

Ashley Foreman
Cameron Foreman
Kay Foreman
David and Elysa Free
Jennifer Gatrel
Rod Gore
Pam Hartwig
Patricia Holland
Justin Imhof
Curt Jacobs
Carol Johnson
Theresa Kellogg
Audrea Keninger
KK Producers, Inc.
Jackie Leavell
Janice Lee
Deborah Long
Eric Lovelace
Chrissy Lowenstein
Luke Lowenstein
Gary and Theresa Mareschal
Mary Mauch
Katie McKay
Mary McKeown
Mary Ellen Harshbarger McVicker
Beatty Mengel
Doug Merrill
Marje Merrill
Martin Meyer
Randy & Roseanne Meyer
Kathy Mikels
Alison Millsaps
Alan & Connie Morgan
Stephanie Morgan
David Newacheck
Keryn Newman
Edwin and Jarman Norman
Jessi O'Bannon
Russ Pisciotta
Diane Ragsdale
Carol Munson Ross
Karen Saadeh

Susan Sack
David Schaefer
Lynn Schieni
Ann Schriever
Pete and Carolyn Schumann
Angie Smith
Dennis Smith
Laurie Smith
Deborah Stallbaumer
Warren Stephens
Janna Swanson
Alfred and Edith Talley
Carrie Talley
Scott Thorsen
Bruce Trammell
Linda Trammell
Dave Ulery
Jane Wilsdorf
Leroy & Joyce Wortmann

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