U.S. DEPARTMENT OF ENERGY

National Electric Transmission Congestion Study

September 2020

United States Department of Energy
Washington, DC 20585

NOTE TO READERS

The Energy Policy Act of 2005 requires the Department of Energy to publish national-scale studies of electric transmission congestion every three years for public comment. The comment period for this study will be 60 days, and comments are due no later than Monday, November 23, 2020. Comments may be delivered by e-mail to 2020congestionstudy@hq.doe.gov. Comments may also be delivered in paper form to

Mr. David Meyer, OE-20
Office of Electricity
U.S. Department of Energy
1000 Independence Avenue, SW
Washington DC 20585

National Electric Transmission Congestion Study

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Acronyms and Abbreviations

ATC	available transmission capacity
CAISO	California ISO
DOE, the Department	U.S. Department of Energy
EES	Entergy
EIA	U.S. Energy Information Administration
EPAct	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FPA	Federal Power Act
GW	gigawatt
ICTE	Independent Coordinator Transmission – Entergy
ISO	independent system operator
MISO	Midcontinent Independent System Operator
MRO	Midwest Reliability Organization
MW	megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO
PCI	protected critical infrastructure
PJM	PJM Interconnection
RF	ReliabilityFirst Corporation; formerly abbreviated as “RFC”
RTO	regional transmission operator
Secretary, the Secretary	The U.S. Secretary of Energy
SERC	SERC Reliability Corporation
SPP/SWPP	Southwest Power Pool
TLR	transmission loading relief
TVA	Tennessee Valley Authority
TWh	terawatt hour
VACS	VACAR-South
WECC	Western Electric Coordinating Council

Executive Summary

Section 216 of the Federal Power Act (FPA), as amended by section 1221(a) of the Energy Policy Act of 2005 (EPAct), directs the U.S. Department of Energy (DOE, the Department) to conduct assessments of national transmission constraints and congestion one year after enactment of EPAct and every three years thereafter. The legislation also gave the Department and the Federal Energy Regulatory Commission (FERC) new authority: the Department was authorized to designate any geographic area experiencing electric energy transmission capacity constraints or congestion adversely affecting consumers as a National Interest Electric Transmission Corridor (National Corridor), and FERC was authorized to site transmission within those corridors if

> (1) 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;
>
> (2) the applicant for a permit is a transmitting utility under [the Federal Power 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
>
> (3) 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 Corridor, whichever is later; or
> > (ii) conditioned 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.

DOE's 2002 *National Transmission Grid Study*[1] documented the slow pace of transmission construction starting in the 1990s and identified existing major transmission bottlenecks.

More than a decade has passed since the Department began preparing and publishing congestion studies. Since the 2005 enactment of FPA section 216, FERC issued Order No. 679,[2] which created financial incentives for transmission investment, and Orders No. 890[3] and 1000,[4]

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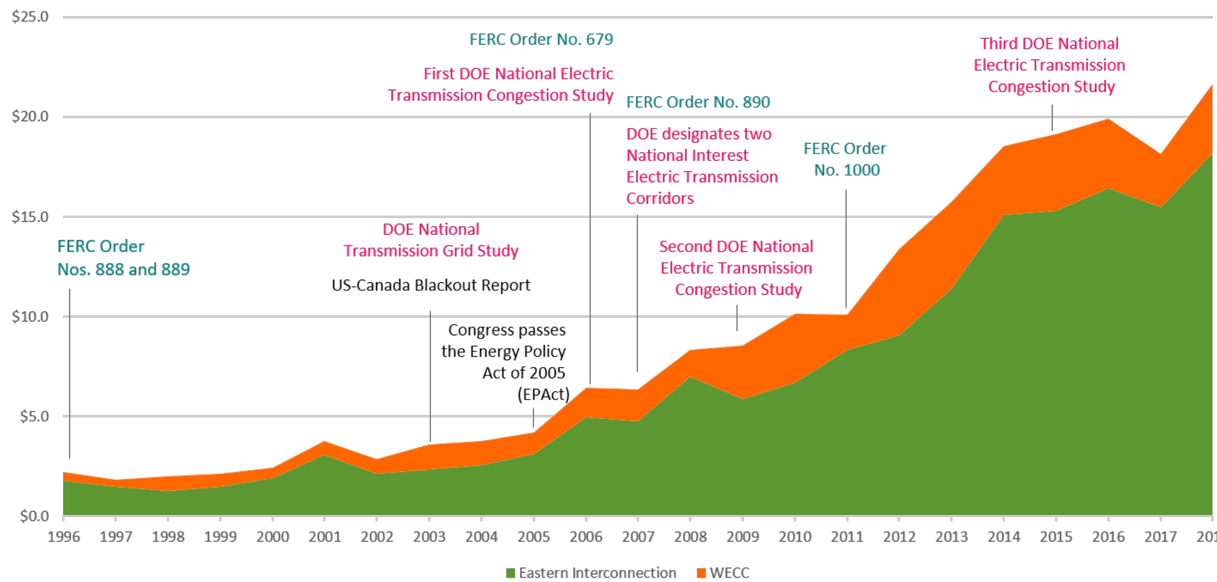
[1] *See* U.S. Department of Energy, *National Transmission Grid Study*, https://www.energy.gov/oe/downloads/national-transmission-grid-study-2002. May 2002.
[2] 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).
[3] 118 FERC ¶ 61,119 (2006), *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,119 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).
[4] 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

which established requirements for regional and interregional transmission planning and principles for regional cost allocation. Over this period, there has been a dramatic increase in transmission investment. Annual investment in transmission today is more than five times greater than it was during the years prior to 2005 (Figure ES - 1).

Figure ES - 1. Transmission Infrastructure Investment ($ Billions, Nominal)

Source: Developed by DOE from FERC Financial Reports, as accessed by ABB Velocity Suite



The Department acknowledges the importance of obtaining information on current transmission constraints and congestion as a means for understanding whether and how the Nation's transmission system affects the critical national interests outlined in EPAct. Accordingly, this study—consistent with Congress' original direction—once again updates, reviews, and assesses information on current transmission constraints and congestion and effects on transmission investment, based on the best available public information.

In this study, the Department has not identified transmission congestion conditions that would merit proposing the designation of National Corridors. If an advocate of a proposed transmission project wishes to seek the designation of a National Corridor, the Department suggests that the appropriate organization provide relevant supporting information.

At the same time, DOE recognizes that critical issues facing the electricity system today go beyond understanding transmission constraints and congestion as these terms are defined and used routinely by industry. Accordingly, with the publication of this fourth study of transmission constraints and congestion, the Department proposes a new approach, subject to Congressional approval, for conducting future triennial transmission studies.

Periodic assessments of a broad range of issues around the resilience of the U.S. transmission system are needed. These issues include the U.S. transmission system's resilience to emerging threats posed by cyber and physical attacks, severe weather, natural disasters, and geo-magnetic disturbances. For example, recent hurricanes affecting Texas and Louisiana and the combination of extreme heat and wildfires in California have underscored that a robust transmission network is critical for coping with such challenges. Other important issues include transmission's role in reliably, securely, and economically adjusting to anticipated changes in the composition and location of the future fleet of electricity generators. As the electricity sector continues to evolve, unanticipated events could drive further changes in transmission needs.

The North American Energy Resilience Model (NAERM) is a DOE initiative to develop a comprehensive resilience modeling system for the North American energy sector infrastructure, including the United States and interconnected portions of Canada and Mexico. In coordination with FERC, other Federal agencies, the regional transmission operators (RTO)/independent system operators (ISO), and industry partners, the Department is developing the NAERM as an integrated modeling approach to study the impact of critical energy and other infrastructures, including all forms of generation, on the electric power system. The NAERM initiative is focused on addressing the impacts of both natural disasters, such as hurricanes, earthquakes, tsunamis, wildfires, and flooding, and man-made threats, such as cyber-attacks, combined cyber-physical assaults, and electromagnetic pulses, drawing upon a more robust base of information in preparing more comprehensive assessments of the critical national interests served by transmission. (See text box for additional information.)

North American Energy Resilience Model (NAERM) Initiative

The United States is increasingly experiencing threats, natural and man-made. The NAERM will enable prediction of the impact of threats, evaluation and identification of effective mitigation strategies, and support for black start planning,* benefiting the United States by enhancing energy security and resilience.

The NAERM will advance existing capabilities to model, simulate, and assess the behavior of electric power systems, as well as associated dependencies on natural gas, and other critical energy infrastructures. Integration of significant expertise at the National Laboratories, plus data integration and collaboration from all stakeholders, will support threat characterization for the energy sector across varying geographic areas and supporting sectors. The NAERM effort will engage with industry experts to get a better understanding of issues and practices on a regional basis in order to ensure threat and consequence models are realistic and representative of actual system responses.

**A black start is the process of restoring a portion of an electric grid to operation without relying on the external power transmission network and generators. The electricity needed to start the area's system is produced from internal sources.*

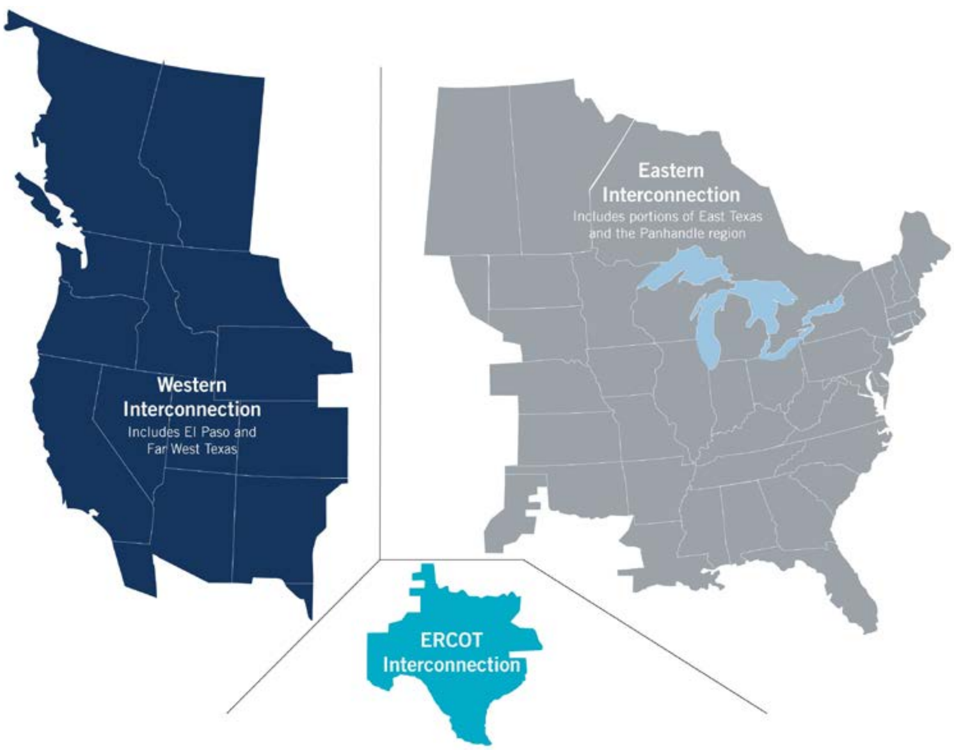
Accordingly, a wider range of information and data—much of which is not now coordinated systematically or collected comprehensively—is needed to assess comprehensively how the critical national interests identified in EPAct are being affected by the ongoing evolutionary changes in the relationship between transmission networks and the broader electricity system. This study outlines the rationale for the additional information and the change in scope needed for such triennial reports to provide useful and actionable data.

1 Legislative Language

This study responds to Section 1221(a) of the Energy Policy Act of 2005 (EPAct), which added section 216(a) to the Federal Power Act (FPA) directing the Secretary of Energy (the Secretary) to "conduct a study of electric transmission congestion" by August 2006 and every three years thereafter. These studies are to identify geographic areas experiencing transmission congestion in the U.S. portions of the Eastern and Western Interconnections. *See* Figure 1-1. The FPA specifically excludes the geographic area covered by the Electric Reliability Council of Texas (ERCOT) from the studies.[5,6]

Figure 1-1. The Three U.S. Interconnections

Source: ERCOT, at http://www.ercot.com/news/mediakit/maps.



FPA section 216 also states 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.*[7]

[5] 16 U.S.C. § 824p(k).
[6] Unless noted, data and graphics presented in this study refer only to the U.S. portions of the Western and Eastern Interconnections.
[7] 16 U.S.C. § 824p(a)(2).

In determining whether to designate an area as a National Interest Electric Transmission Corridor (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.[8]

In this study, the Department has not identified conditions that would merit proposing the designation of National Corridors. If an advocate of a proposed transmission project wishes to seek the designation of a National Corridor, the Department requests relevant supporting information that explains:

1. Where transmission congestion is occurring, or is very likely to occur, in a specific geographic area, with adverse impacts on consumers;
2. How the proposed transmission project would alleviate the congestion;
3. How the proposed National Corridor would be bounded, and the rationale for those boundaries; and,
4. In this particular case, the reason it would be in the national interest for the Secretary of Energy to intervene in a matter that is normally wholly under the jurisdiction of the affected state(s).

[8] *ibid* § 824p(a)(4).

2 Introduction

EPAct directed the Department and FERC to take specific actions aimed at accelerating the pace of electricity transmission investment. EPAct directed the Department to conduct assessments of national transmission constraints and congestion every three years. EPAct gave the Department and FERC new authority: The Department was authorized to designate appropriate geographic areas as National Corridors, and FERC was authorized to site transmission within those corridors if

> (1) 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;
>
> (2) the applicant for a permit is a transmitting utility under [the Federal Power 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
>
> (3) 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 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.

Congress deemed these actions necessary to protect critical national interests, including economic vitality, economic growth, energy independence, national energy policy, and national defense and security. Congress' action was a result of the Department's 2002 *National Transmission Grid Study*,[9] which documented the slow pace of transmission construction starting in the 1990s and identified existing major transmission bottlenecks. The need for congressional action was further bolstered by the 2003 U.S.-Canada blackout—the largest blackout in U.S. history—which affected more than 50 million customers and caused an estimated $5–10 billion in economic damages. *See* Figure ES - 1.

This study is the Department's fourth assessment of national transmission constraints and congestion. This study presents DOE's findings on transmission investment, constraints, and

[9] *See* U.S. Department of Energy, *National Transmission Grid Study*, https://www.energy.gov/oe/downloads/national-transmission-grid-study-2002. May 2002.

congestion, building upon those from the last National Electric Transmission Congestion Study published in September 2015,[10] and is organized as follows:

Section 3 introduces the physical factors and grid-reliability considerations that lead to constraints within the transmission system and clarifies the relationship between transmission constraints and congestion. The text then reviews regional variations in the approaches used to manage congestion in the Eastern and Western U.S. Interconnection transmission systems. These regional variations determine the types of information used to inform the Department's assessment of transmission constraints and congestion.

Section 4 presents DOE's key findings on transmission investment and impacts on current transmission constraints and congestion.

Section 5 discusses critical, non-congestion-related factors that also influence or are affected by transmission investment. These factors have grown in importance in recent years. These include new and growing threats to the resilience of the transmission system and the acceleration of changes affecting the composition and geographic distribution of the Nation's generation fleet.

Section 6 reviews the Department's process in preparing this study. The text summarizes the Department's efforts to ensure broad stakeholder input on the preparation of the study, including DOE's public workshop on transmission issues held on November 15, 2018. The section also describes the Department's consultation with the states and reliability entities on a draft of the study, as specified by EPAct. EPAct also requires DOE to solicit and respond to public comments on the study and issue a report indicating whether any National Corridor designations will be proposed based on the study. (See inside front cover for information on how to submit comments on this study.)

Section 6 is followed by appendices that contain supporting information about the process of developing this study, including the agenda for the Department's transmission workshop and lists of organizations that provided input during the preparation of the study, participated in the workshop, or commented on a consultation draft of the study.

[10] *See* U.S. Department of Energy, *National Transmission Grid Study*, https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf. September 2015.

3 Transmission Constraint and Congestion Concepts, and Regional Practices for Managing Congestion

This section introduces the physical factors and grid-reliability considerations that lead to constraints within the transmission system and clarifies the relationship between transmission constraints and congestion. The section also reviews regional variations in the approaches historically used to manage congestion in the Eastern and Western U.S. interconnection transmission systems. These regional variations determine the types of information that were used in the Department's assessment of current transmission constraints and congestion.

3.1 Transmission Constraint and Congestion Concepts

Transmission constraints and transmission congestion are closely related but are different concepts. Transmission constraints are physical limits on the amount of electricity flow the system is allowed to carry in order to ensure safe and reliable operation. Transmission congestion refers to the economic impacts on the users of electricity that result from operation of the system within these limits.

The term "transmission constraint" may refer to:

1. An element of the transmission system, e.g., 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 in order to avoid an overload that could cause one or more elements to fail and thereby jeopardize reliability; or
2. An operational limit imposed on an element or group of elements to ensure that the system, as a whole, will continue to operate reliably following the failure of one or more elements.

Transmission constraints as defined above are a result of many factors, including load level, generation dispatch, and the possibility of equipment failure. Jointly, these conditions establish a specific level or limit—as defined above (in 2.), to the permissible flow of electricity over the affected element(s) under specific operating conditions, to ensure safe and secure operations in compliance with reliability rules.[11] Transmission operating limits, which specify the maximum throughput allowable on affected transmission elements, are created to comply with these nationally established and enforced rules.

A fundamental responsibility of transmission system operators is to ensure reliable operation of the transmission system within these limits. This responsibility is executed by referring to these limits when approving or denying transmission service requests by parties seeking to use the transmission system. The practices operators follow are called congestion management.

[11] Reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by FERC specify how equipment or facility ratings are to be established in order to avoid exceeding thermal, voltage, and stability limits.

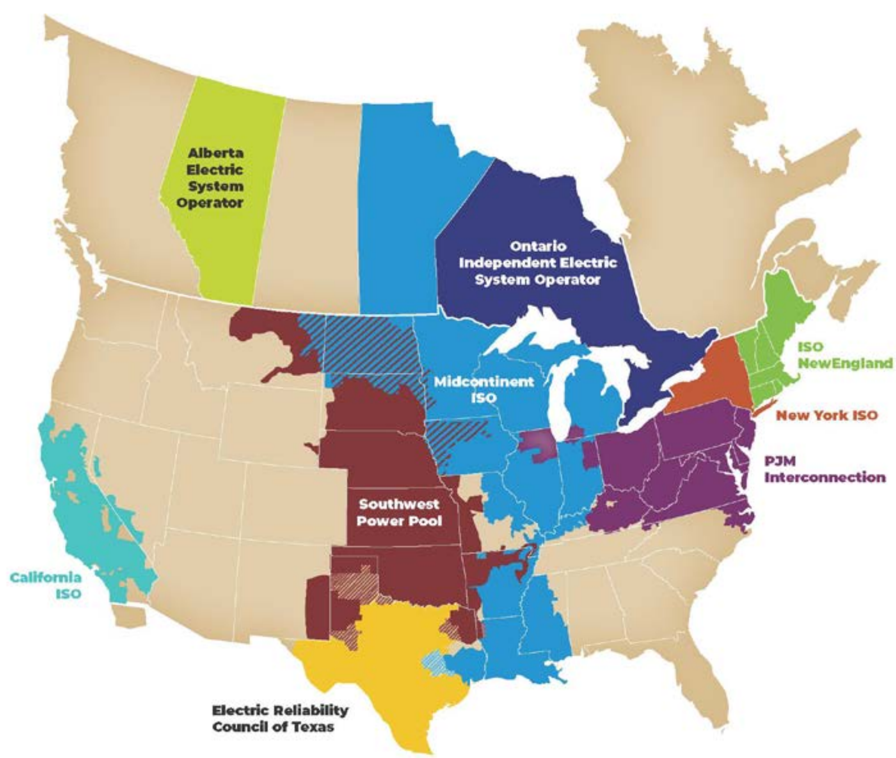
3.2 Regional Practices for Managing Congestion

FERC Orders No. 888 and 889 promulgated rules and procedures for the use of the U.S. portions of the transmission systems in the Eastern and Western Interconnections. The orders sought to ensure non-discriminatory practices by transmission system operators and provide open access to the transmission system for all qualified parties. Pursuant to these orders, transmission system operators established two broad classes of business practices for providing transmission service to parties in advance of real-time operations.

The first class of practices, which are relied upon by regional transmission organizations and independent system operators (RTO/ISOs), involves the use of market-based approaches for allocating available transmission capability based on users' expressed willingness to pay for transmission services. *See* Figure 3-1. The second class of practices, which are relied upon by transmission operators whose systems lie outside the footprints of the RTO/ISOs, involves the use of administrative approaches where the availability of transmission service is announced and requests for such service are then accepted. Both RTO/ISO and non-RTO/ISO transmission system operators also rely on specialized procedures for managing the operations of the systems in real time.

Figure 3-1. RTO/ISO Footprints

Source: ISO/RTO Council, at https://isorto.org/.



3.2.1 RTO/ISO Congestion Management Practices

RTO/ISOs use centralized dispatch procedures driven by competitive offers from generators to sell electricity to purchasers. These procedures account for all transmission constraints to form a marginal price at each point within the transmission system, i.e., the point at which wholesale electricity is either injected into the system by a seller or withdrawn by a purchaser.

Ignoring the effect of transmission losses, when no transmission or generation constraints are restricting economic dispatch and all desirable transactions are occurring, all the marginal prices at all points will be identical. If there is a constraint, the marginal prices on the two sides of the constraint will differ. The difference in price is an economic measure of the cost of the congestion.

Congestion costs are directly affected by transmission investment. If transmission investment removes a transmission constraint to relieve congestion, then the investment will reduce congestion costs.[12] The congestion costs avoided are a direct measure of the economic benefit from, or value of, this investment. In actual cases these benefits, by themselves, may or may not be sufficiently large and recurrent to warrant the investment.[13]

3.2.2 Non-RTO/ISO Congestion Management Practices

Transmission system operators outside of RTO/ISOs publicly post the availability of transmission service, called available transmission capacity (ATC), on the systems long in advance of real-time operations. These operators then receive, review, and either accept or deny users' requests for transmission service on either a firm or non-firm basis at rates approved by FERC.

ATC is a direct reflection of how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

Denials of requests for transmission service provide a direct, but incomplete, measure of congestion. Denials are a direct measure because they reflect a desire to use the transmission system that was foregone because of one or more transmission constraints. But denials are an incomplete measure because they do not provide information on the value of the services that are being sought and that have been foregone. That is, denials provide no information on the economic significance of the congestion they represent and no information on the value of transmission or other efforts to relieve the constraints that underlie this congestion.[14] Denials are also an incomplete measure because a desired service may not be requested because the ATC had already been set to zero.

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[12] Reducing load or increasing generation on the load-side of a constraint will also have a similar effect in reducing congestion costs.

[13] Reducing congestion costs is not the only economic benefit that might justify a transmission investment.

[14] Information on denials of requests for transmission service is also an incomplete measure because it does not capture requests that were not made because of users' perceptions of the availability of services. That is, the availability of transmission services is routinely updated. Potential users seeking those services might forego requesting them at times of limited availability, in part because of past experience of requests being denied under these conditions.

3.2.3 Specialized Congestion Management Practices Used in Real-Time Operations

System operators of both types of transmission classes (i.e., ISO/RTO and non-RTO/ISO) also rely on specialized procedures for managing congestion during real-time operations. These procedures are necessary to ensure reliable operation of the power system when unforeseen events occur that alter the capabilities of the transmission system from those that were assumed when the requests for transmission service were made (e.g., unexpected outage of a transmission facility), or when conflicts arise among the services agreed upon by different transmission system operators.

In the Eastern Interconnection, principally but not exclusively in the regions served by non-RTO/ISOs, transmission operators use an administrative procedure called transmission loading relief (TLR) to address congestion that arises in real-time.[15] Five levels of TLR procedures can be invoked. TLR level 3 is the lowest level that involves curtailments of transmission service to ensure that constrained transmission facilities are not loaded beyond safe reliability operating limits. TLR level 5 is the most severe level; it involves reducing the levels of firm transmission services. Information on TLRs is posted publicly by NERC.[16]

TLRs of level 3 and above all involve curtailments of or reductions to previously agreed-upon transmission services. These are a direct measure of transmission congestion, as introduced in Section 3.1, since the measurement represents transmission services that must be foregone because of a transmission constraint. These are not an economic measure of congestion because, like denials of requested transmission service, they do not provide information on the value of the transmission services that have been foregone.

[15] In the Western Interconnection, the real-time administrative counterpart to the TLRs used in the Eastern Interconnection is called "unscheduled flow mitigation." Unlike in the Eastern Interconnection, information on unscheduled flow mitigation in the Western Interconnection is not posted publicly.
[16] *See* https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.

4 Key Findings: Transmission Investment, Constraints, and Congestion

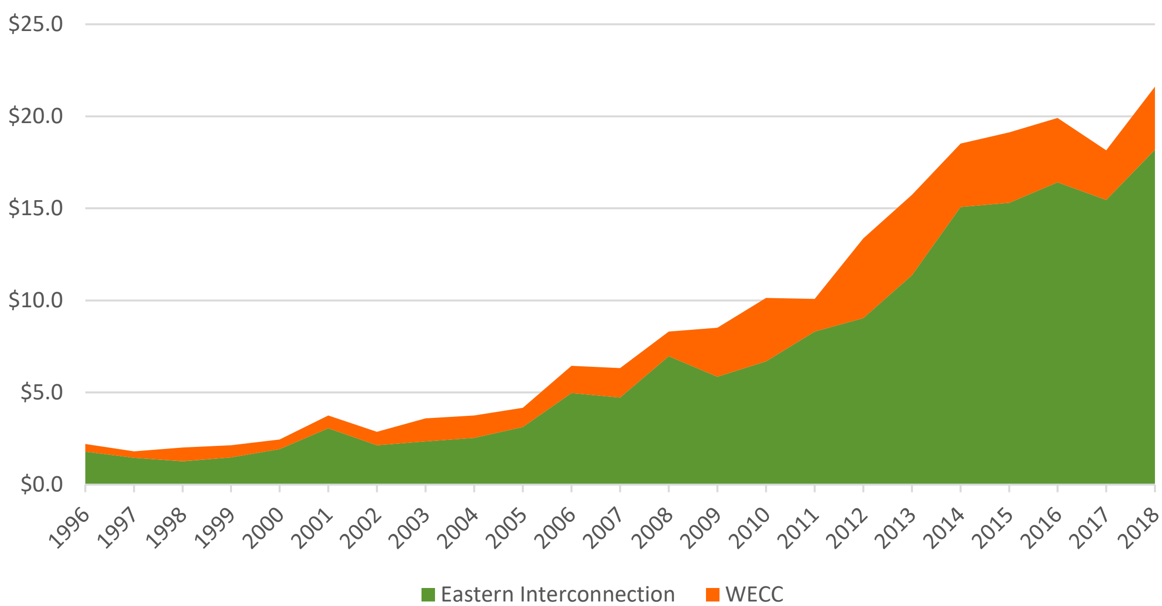
This section presents the Department's findings on transmission investment, constraints, and congestion building upon those from the last National Electric Transmission Congestion Study, which was published in September 2015.[17]

4.1 Transmission Investment Has Increased

Figure 4-1 presents information collected by FERC that has been analyzed and published by the U.S. Energy Information Administration (EIA) on annual investment in transmission from 1996 to the most recent year for which data are available in the Eastern and Western Interconnections. The figure documents the increases in annual investment in transmission that have taken place since 2005 when Congress directed the Department to prepare regular reviews of transmission constraints and congestion.

Figure 4-1. Transmission Infrastructure Investment, 1996-2018 ($ Billions, Nominal)

Source: Developed by DOE from data derived by EIA from FERC Financial Reports, as accessed by Ventyx Velocity Suite.



Investment in transmission was consistently less than $5 billion per year before 2005. In fact, it was less than approximately $3 billion per year throughout the last half of the 1990s. Annual investment first exceeded $5 billion per year in 2006—the year after EPAct was enacted—and has increased consistently since that time. Annual investment had doubled to more than $10

[17] *See* U.S. Department of Energy (2015b).

billion per year by 2010 and then had doubled again by 2016. Annual investment has been between $18 billion and $22 billion annually since 2014.

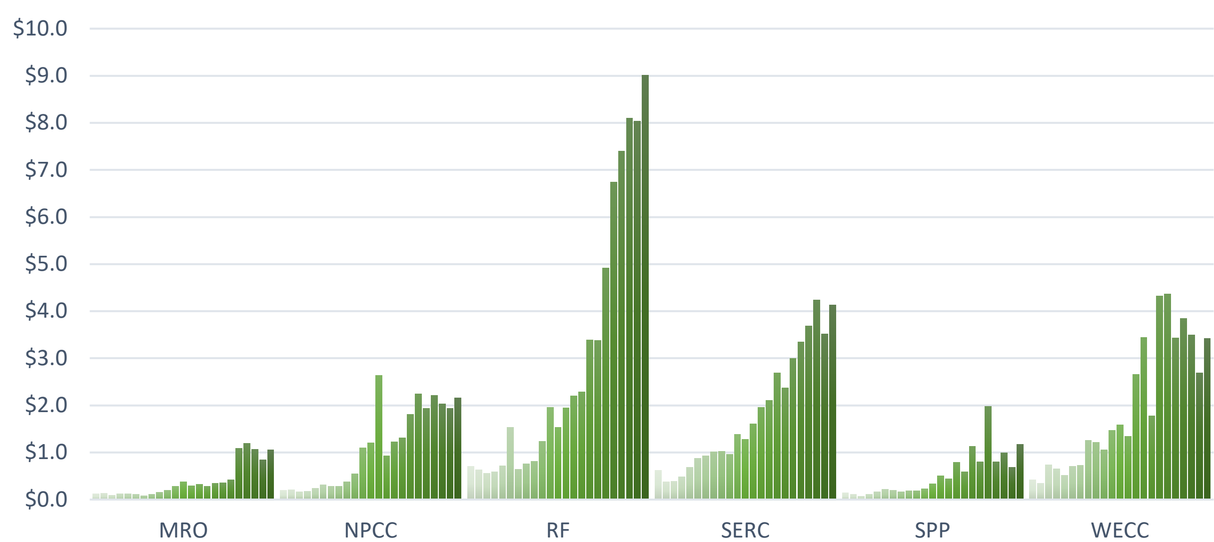
Figure 4-2 depicts annual transmission investment for each of the NERC assessment areas for the years 1996 through 2018. The figure shows that annual transmission investment has increased consistently in every region, especially since 2005.[18]

In the Eastern Interconnection, the greatest growth in annual transmission investment since 2005 has taken place in ReliabilityFirst Corporation (RF), followed by Southwest Power Pool (SPP) and Midwestern Reliability Organization (MRO). In the Western Interconnection, annual transmission investment is more than three times what it was in 2005.

Currently, in absolute terms, the highest levels of annual investment are taking place within RF, SERC Reliability Corporation (SERC), and Western Electricity Coordinating Council (WECC).

Figure 4-2. Transmission Infrastructure Investment, by NERC Assessment Area, 1996–2018 ($ Billions, Nominal)

Source: Developed by DOE from FERC Financial Reports, as accessed by Ventyx Velocity Suite.



The highest levels of total transmission investment since 1996 have been in the RF footprint, followed by the WECC footprint—which covers the entire Western Interconnection—and then the SERC footprint and the NPCC footprint.

Against this backdrop of dramatic increases in transmission investment, we review below the impacts of these investments on transmission constraints and congestion.

[18] In May 2018, FERC approved the dissolution of the SPP Regional Entity and the transfer of members to MRO and SERC.

4.2 Transmission Investments Have Addressed Transmission Constraints in a Timely Manner

Transmission constraints arise when the use of a group of transmission facilities or pathway cannot be increased without violating a limit that has been set to ensure that the facilities or pathway are operated in compliance with mandatory reliability rules. A national assessment of individual transmission constraints is not possible because of the limited amount of information that is publicly available. Therefore, we first briefly review the information that is available and then turn to a more direct means of assessing the adequacy of transmission investments to address constraints that might threaten reliability.

Figure 4-3 summarizes the utilization of the major transmission paths in the Western Interconnection in 2016. These paths represent groups of transmission facilities that are monitored to track the major flows of electricity among the transmission systems in the interconnection.[19]

WECC uses a metric called U75 to gauge the amount of electricity flowing over a path compared to the levels permitted by the reliability rules. The designation U75 is defined as the percent of time that electricity flows are greater than 75 percent of the levels permitted by the rules. WECC also uses a similar metric, U90, which indicates the percent of time for a given period in which flows are 90 percent or higher of the permitted levels. Figure 4-3 shows the values of U75 in 2018 for each of the major paths in the interconnection.

Figure 4-3 shows several paths that were operated at more than 75 percent of the levels permitted by the reliability rules for more than 10 percent of the hours in 2018. U75 and U90 are only partial measures of the extent to which paths in the interconnection are constrained. WECC does not publish information on the portions of the year when paths have been fully constrained; that is, when or if operated at 100 percent of the reliability limits. [20]

Comparable information does not exist on the operation of the transmission systems across the Eastern Interconnection.[21] Instead, public information on the most constrained transmission facilities within the respective footprints is published regularly by each of the RTO/ISOs; this information is linked directly to the congestion management practices employed. These

[19] Each of the shaded bars in Figure 4-3 spans several related transmission facilities that together comprise a "path." The electricity flows on the facilities are generally perpendicular to the bars, and most of the electricity moves toward urban load centers.

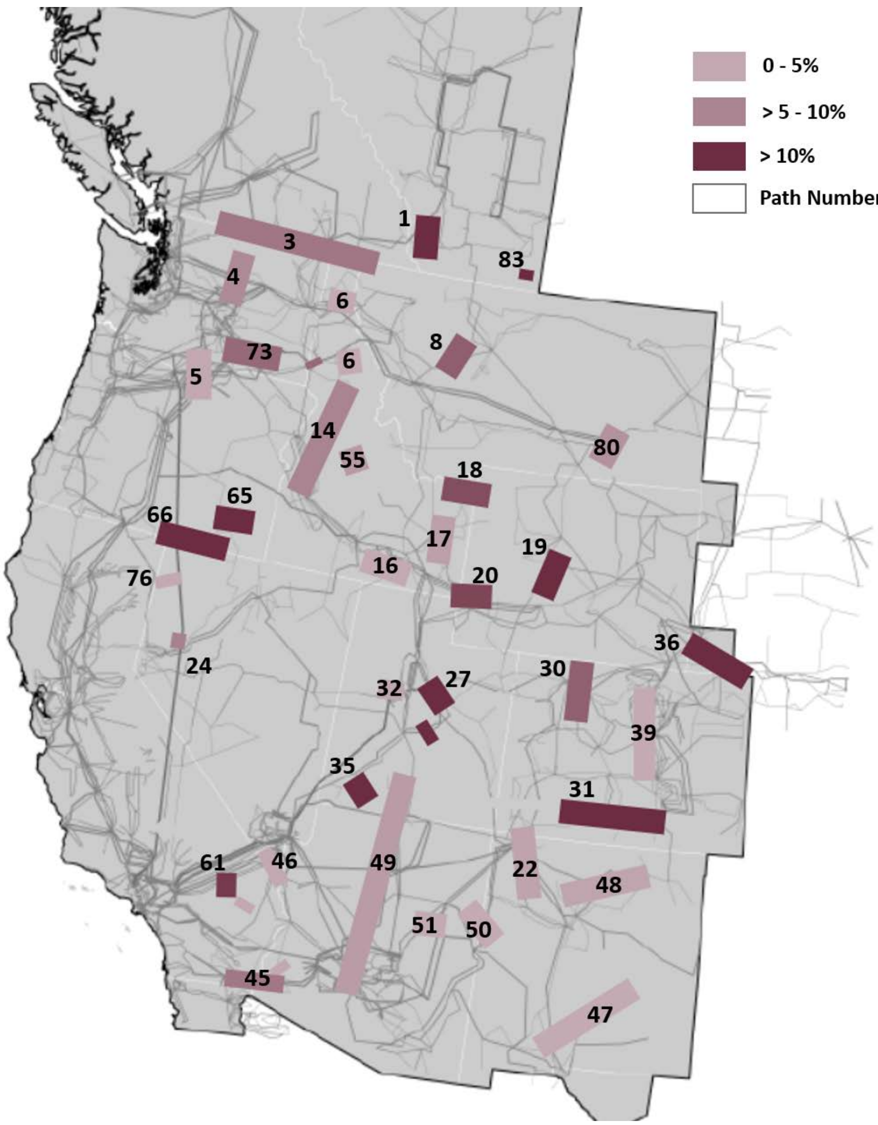
[20] In 2019, WECC completed a reliability assessment study program that considered potential future BPS conditions using data provided by its members to support the development of power flow cases and production cost model cases. One of these assessments considered the most likely year 10 (2028) future and did not identify any significant congestion issues. Paths that showed higher utilization in WECC's assessments either were designed for higher utilization or the higher flows were a function of the security constrained economic dispatch. See *Reliability Impacts Most Likely Year 10 Future*, draft dated January 22, 2020, available at https://www.wecc.org/RAC/Pages/StS.aspx.

[21] Beginning in July 2016, EIA has made available a basis for a possible future source of information on transmission constraints (*see* https://www.eia.gov/realtime_grid/). Currently, EIA collects and displays near real-time information on flows of power among balancing authorities. Adding a display of information on the maximum flows permitted by reliability rules would enable a preliminary estimate of the extent to which these flows were at or close to these limits.

constraints will be addressed in the next subsection, which discusses how transmission congestion has been affected by transmission investment.

Figure 4-3. Percent of Time Major Transmission Paths in WECC Are Operated at 75% or More of Their Rated Capacity (2018)

Source: From WECC, at https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Transmission-Adequacy.aspx.



Despite the absence of consistent information on current transmission constraints, there are other means for assessing the impacts of transmission investment on these constraints. This involves reviewing compliance with reliability rules that prescribe mandatory transmission planning practices.

NERC's standards direct transmission planners to study the expected future operation of systems to identify reasonably plausible situations in which reliability might be threatened. If such situations are identified, planners are required to develop plans that describe the actions to be taken to prevent these situations from arising in real-time operations. As discussed in Section 3, investment in transmission facilities, in some instances, can be a means for complying with these planning requirements.

Compliance with NERC's standards has been mandatory since 2007. Violations of NERC's standards are publicly posted on the NERC website. [22] As of January 1, 2020, approximately 1 percent of the total noncompliances were related to the transmission planning family of standards. Of these, only 0.6 percent were assessed as serious risk infractions. For the past five years, all the transmission planning noncompliances were assessed as posing minimal risk to the grid reliability.

4.3 Transmission Investment Has Contributed to Reduced Transmission Congestion

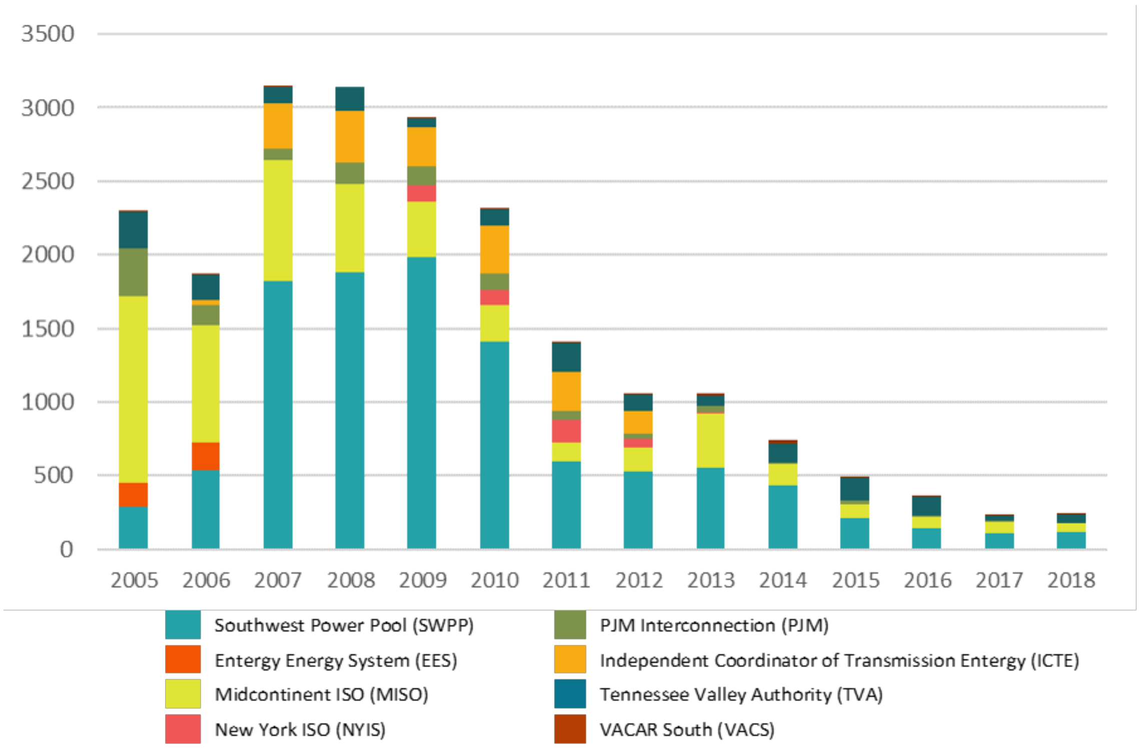
Figure 4-4 presents information on transmission loading relief (TLR) actions of Levels 3, 4, and 5 from 2005 to 2018.[23] The figure documents the reductions in TLR actions during this period. By 2018, the total number of TLR actions had decreased to less than one-tenth of the number in 2009. Market reforms have contributed to some of these reductions, but transmission investment has also had a role in reducing the need for TLRs.

[22] *See* https://www.nerc.com/pa/comp/CE/Pages/Actions_2019/Enforcement-Actions-2019.aspx.

[23] TLR Level 3 is the lowest TLR level at which transmission service may be curtailed.

Figure 4-4. Total TLRs (Levels 3, 4, and 5) by Reliability Coordinator[24] (2005–2018)

Source: Developed by DOE from NERC TLR Logs, https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.[25]



[24] SPP transferred reliability coordination functions for EES to MISO on December 1, 2012 and for ICTE to MISO on June 1, 2013. *(Source: Personal communication from SPP on October 15, 2019.)*

[25] Note that NERC only makes the last five years of TLR data available on its website.

4.4 Economic Transmission Congestion Measures

Figure 4-5, Figure 4-6, and Figure 4-7 show information on annual congestion costs from 2005 to 2017 for 5 of the 6 U.S. RTO/ISOs in the Eastern and Western Interconnections.[26] As shown in these figures, congestion costs, as reported by each RTO/ISO, have decreased over time.[27] In the Eastern Interconnection (*see* Figure 4-5 and Figure 4-6), congestion costs in ISO-NE have been virtually non-existent dating back at least the past ten years. Prior to significant transmission construction activities completed in 2006, congestion costs in ISO-NE were routinely in the hundreds of millions annually. Congestion costs in MISO spiked to nearly $1.5B in 2014 when it integrated the large Entergy system into markets. Since that time, congestion costs have been consistently far less than $1.0B annually. Congestion costs in NYISO are also lower today than in past years. This is true for either of the measures of congestion costs that were available for this study. Finally, congestion costs for PJM are also lower today than in the past. PJM reports the spike in 2014 was due to the Polar Vortex event during the winter of that year.

In the Western Interconnection (*see* Figure 4-7), CAISO congestion costs exceeded $0.5 billion during the years 2012-2014. These costs were less than $0.5 billion during the years 2015-2017 and rose above $0.5 billion in 2018.[28] Note that CAISO redesigned the market in 2009, shifting from one based on zonal pricing to one based on nodal pricing, so comparisons between the period prior to 2009 and the period starting in 2009 do not provide insight into a trend across these two time periods.[29]

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[26] Southwest Power Pool (SPP) only began operating an organized wholesale market in 2014. Congestion costs from SPP are therefore not presented or discussed in this study because the historical record against which to compare these costs is too brief to provide insight into the effects of the past 10 or more years of transmission investment.

[27] Note that direct comparisons of congestion costs across RTO/ISOs can be misleading. First, the information on congestion costs published by the RTO/ISOs varies. Most publish information on day-ahead congestion. Some also report information on real-time (or day-of) congestion, but some do not or only report it combined with day-ahead congestion (as total congestion). Second, the designs of the markets they operate vary, sometimes considerably from one another. These differences are reflected in the different terms they use to describe the aspects of their congestion costs they report. Third, the magnitude of congestion costs is also influenced by the size of the market. For example, while congestion costs in PJM are consistently the highest in the country, PJM is also the largest RTO in the country; when expressed on a dollars-per-megawatt-hour basis, PJM's congestion costs are among the lowest in the country.

[28] According to WECC, the recent increase in CAISO congestion costs may reflect the effects of the Energy Imbalance Market (EIM), which mainly seeks to balance the high penetration of solar resources in the CAISO footprint. During the non-summer seasons, there is often surplus solar energy that is exported to other regions. The difference between the daily load profile and the solar shape also creates the need for imports of energy from other regions in the mid-morning and evening hours. As more solar resources are added and as more entities join the EIM, these imports and exports may increase. Source: WECC comments to DOE on consultation draft.

[29] CAISO's market redesign was called "Market Redesign and Technology Update" or MRTU. Hence, the congestion costs presented in Figure 4-8 are labeled "pre-MRTU" and "post-MRTU."

Figure 4-5. Historic Congestion Costs, ISO-NE and MISO, 2005–2018 ($ Billions, Nominal)

Sources: ISO-NE: Data obtained from ISO-NE Monthly FTR Summary Reports, at https://www.iso-ne.com/isoexpress/web/reports/billing/-/tree/cong-rev-summary; and MISO: External Market Monitor, at https://www.potomaceconomics.com/markets-monitored/miso/.

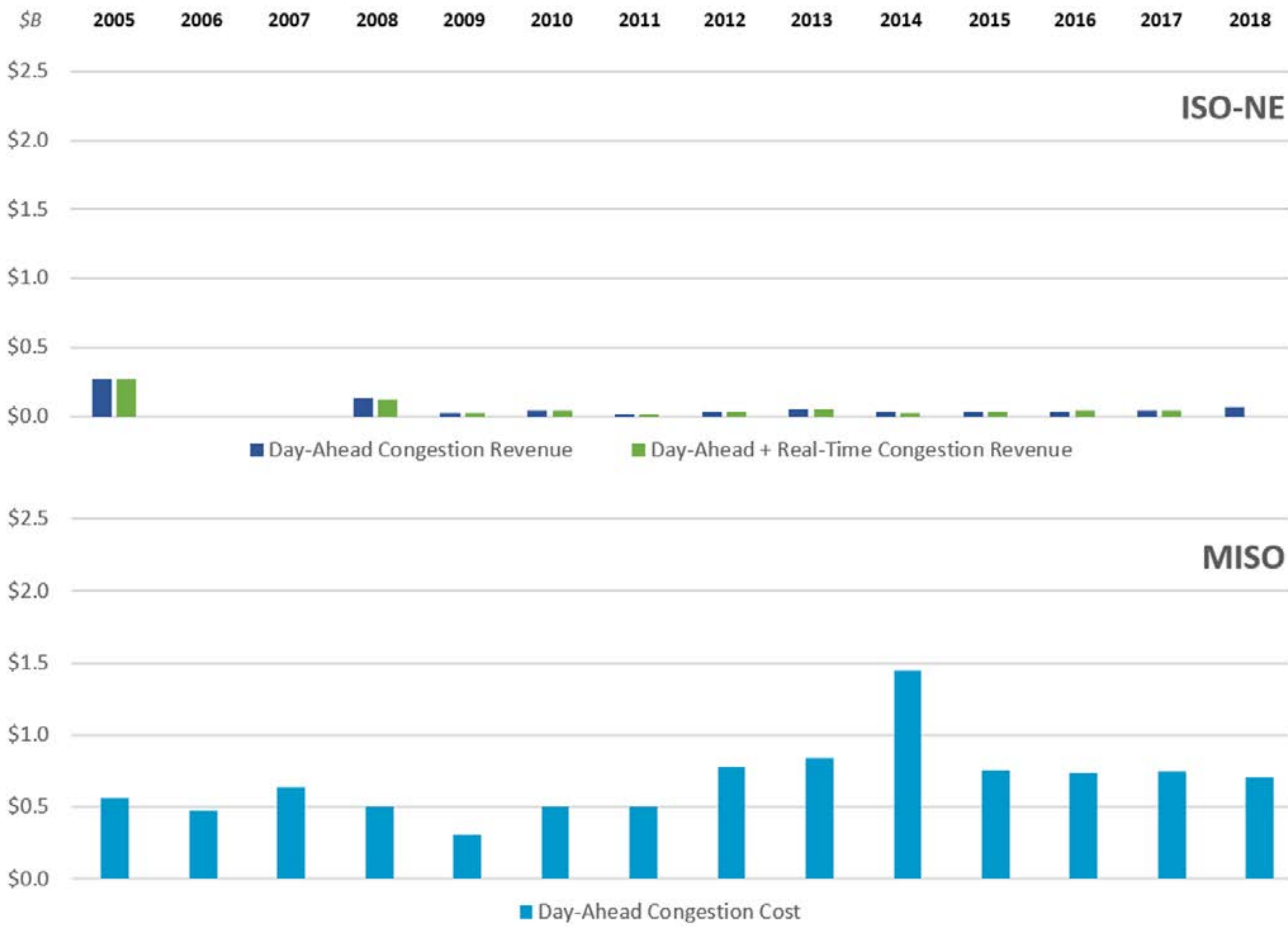
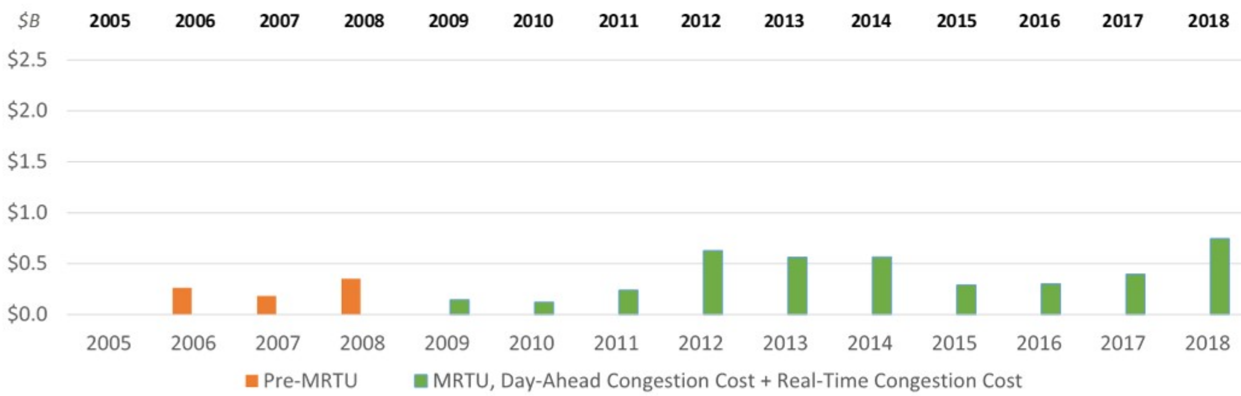


Figure 4-6. Historic Congestion Costs, NYISO and PJM, 2005–2018 ($ Billions, Nominal)

Sources: NYISO: External Market Monitor, at https://www.potomaceconomics.com/markets-monitored/new-york-iso/, with additional data obtained from NYISO and PJM: External Market Monitor, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml.

Figure 4-7. Historic Congestion Costs, CAISO, 2005–2018 ($ Billions, Nominal)

Note: Data not available for 2005.
Source: Personal communications from CAISO dated February 21, 2019 and September 13, 2019.



4.5 Factors Other than Transmission Investment Have also Contributed to Reducing Congestion

Although increases in transmission investment have contributed to reductions in congestion, other factors can lower congestion, including the rate of electricity demand growth, the relative costs of the fuels or sources of energy used to generate electricity, relative location of generation and demand, and public policies.

Growth in electricity demand can be a principal driver for both transmission congestion and the need for transmission investment to alleviate this congestion.

Figure 4-8 shows net electricity generation for load from 1996 to 2016 in both the Eastern and Western Interconnections, as reported by EIA. Electricity demand grew steadily from 1996 to 2005 at a rate of about 2.0 percent per year and 1.7 percent per year in the Eastern and Western Interconnections, respectively. Then, from 2006 to 2016, the growth in electricity demand fell to 1.2 percent per year and 0.7 percent per year in the Eastern and Western Interconnections, respectively. DOE concludes that demand growth has not been a major factor influencing either transmission congestion or the need for additional transmission investment in recent years.

The price of natural-gas-fired electricity generation relative to the price of coal-fired generation is a principal determinant of the mix of generation used to serve load. Historically, a significant amount of congestion was caused by the desire to import lower-cost, coal-fired generation from locations distant from load to displace higher-cost, natural-gas-fired generation located closer to loads.

More recently, the price of natural gas has dropped and has remained low compared to the consistently high levels observed prior to 2009 (*see* Figure 4-9). Since 2009, natural gas has been roughly half the cost it was during the period from 2005 to 2008. Today, the cost of gas-fired electricity generation is in many locations on par with, or cheaper than, the cost of coal-fired generation. As a result, natural-gas fired generation has increased, and coal-fired generation has decreased.

Figure 4-8. Net Electricity Generation for Load, Eastern and Western Interconnections, 1996-2016 (with estimated data to 2018) (TWh)

Source: Developed by DOE from EIA, 411 Data, https://www.eia.gov/electricity/data/eia411/.

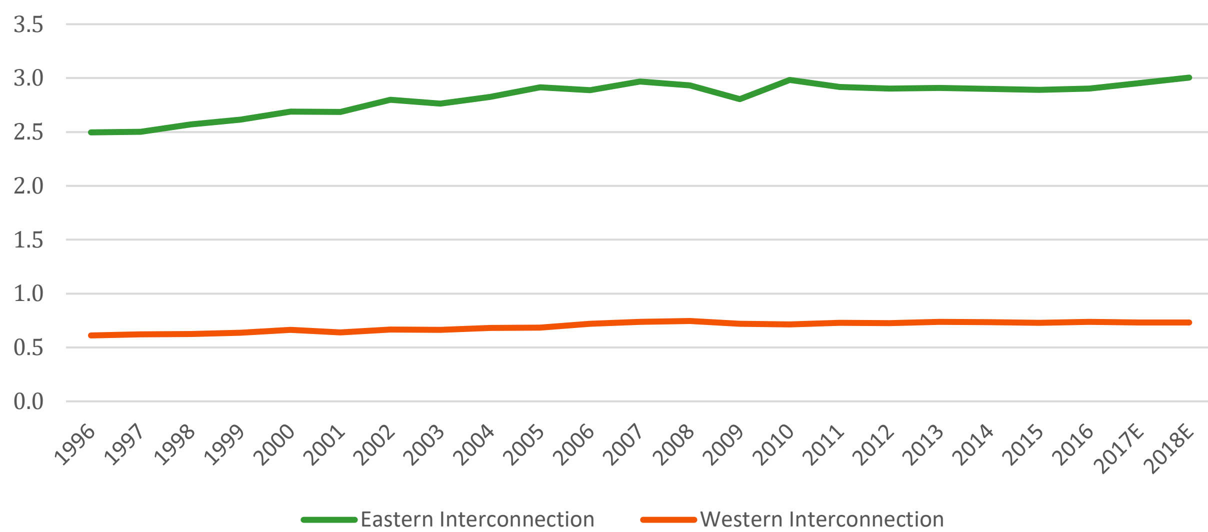
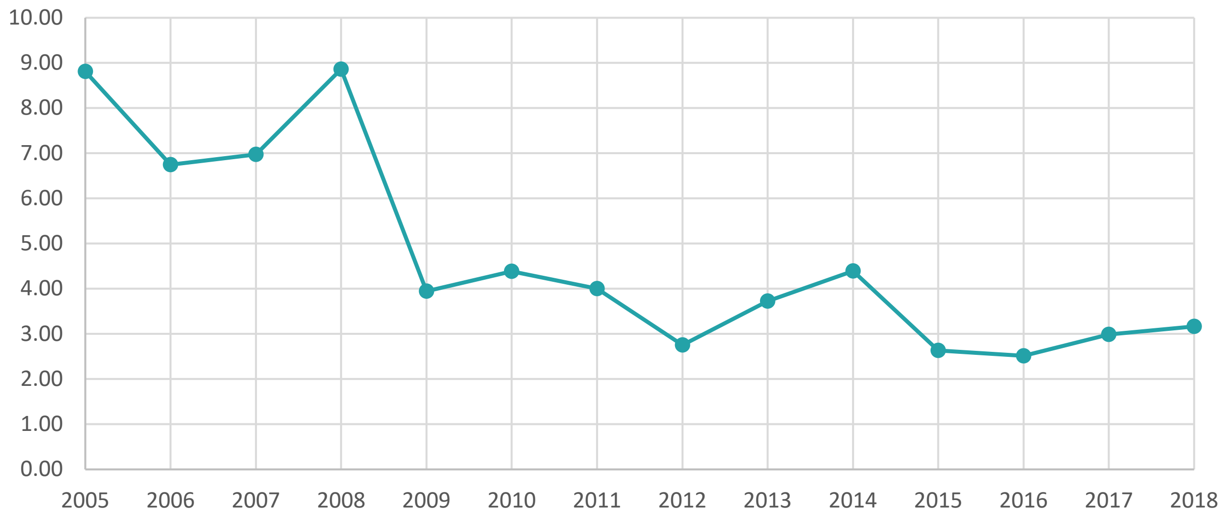


Figure 4-9. Average Annual Natural Gas Price, 2005–2018 ($/Million Btu, Nominal dollars)

Source: Developed by DOE from EIA, Henry Hub Natural Gas Spot Price dataset: https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.

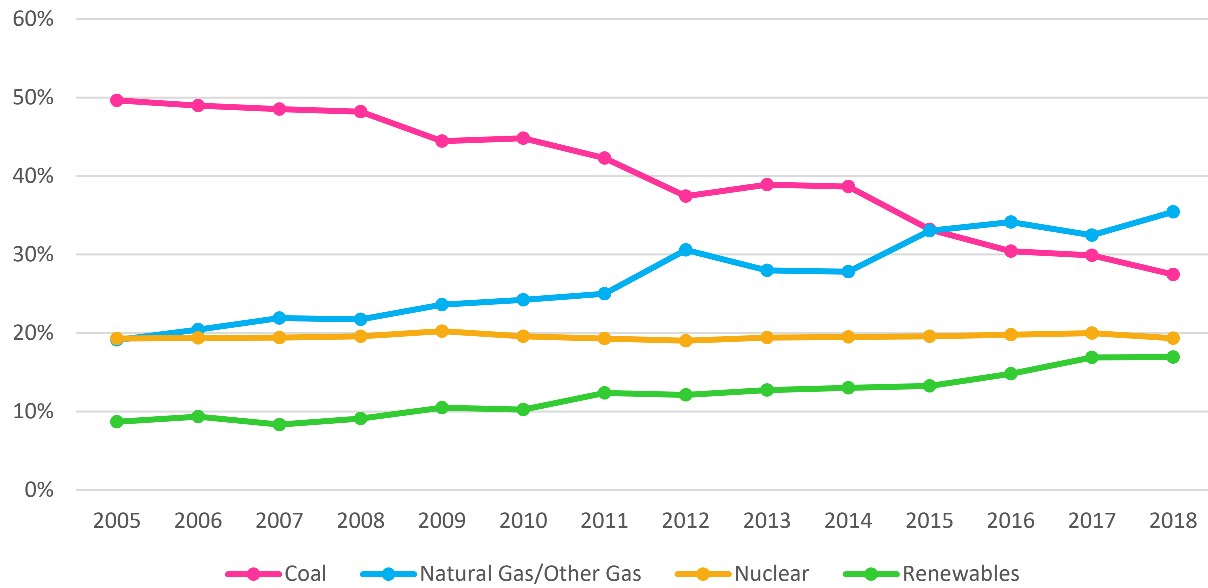


The substitution of gas-fired for coal-fired generation can be seen in Figure 4-10. Starting in 2015, natural-gas-fired generation began to exceed coal-fired generation, reducing congestion due to lower coal-fired generation imports and increased local natural-gas-fired generation.

Figure 4-10 also documents an increase in the contribution of renewable sources to the electricity generation mix. Renewables accounted for approximately 10 percent of total generation in 2005 and nearly 18 percent in 2017. Renewable generation that is distant from the load it serves requires transmission. If transmission investment had not kept pace with the increase in renewable generation, congestion would be the expected result. Congestion overall decreased over this time period. Thus, at least to date, transmission investment has generally kept pace with the growth in generation from renewable sources.

Figure 4-10. Percent of Total Net U.S. Generation for Selected Sources (2005–2018)

Source: Developed by DOE from EIA, Monthly Energy Review, Table 7.2a: https://www.eia.gov/totalenergy/data/monthly/.



4.6 Summary

Transmission investment has increased since Congress first directed DOE to conduct triennial reviews of transmission constraints and congestion in 2005. The Department's review of available information confirms that transmission constraints and congestion have abated, in large measure because of these investments. The Department also confirms that related factors, including lower rates of growth in electricity demand and lower prices for natural gas, have contributed to reducing transmission congestion.

5 Looking Forward: The Resilience of the Transmission System Is a Critical National Interest

Reliability and resilience of the North American electric power system need to be understood concurrently. Reliability focuses on assuring day-to-day grid operations—such as real-time balancing of load and generation, operating equipment within defined limits, adequate operator training, and tree trimming—in typical conditions. By contrast, resilience is the ability to prepare for and adapt to changing conditions, and to withstand and recover rapidly from disruptions.[30] Emerging areas of resilience concerns include threats posed by cyber and physical attacks, severe weather, natural disasters (such as earthquakes, tsunamis, and floods), geo-magnetic disturbances, increasing infrastructure independencies, and changes in the Nation's resource mix and uses of electricity.[31]

Studying constraints and congestion means focusing only on the operation of the Nation's transmission system under normal or routine conditions. Collecting information about constraints and congestion does not provide insight into the impacts of unexpected large events that can affect the transmission system. For example, when severe weather affects the transmission system, normal operations are suspended, and operators shift to more conservative operating practices. If weather events are so severe as to overwhelm and damage the existing system, power can be interrupted.

Current planning standards, which lead to identification of transmission constraints, have been designed to address the variety of unexpected circumstances that might compromise day-to-day reliability. These standards were not designed to ensure the transmission system can withstand extremely severe or long-lasting circumstances that threaten reliability. Planning approaches intended to ensure resilience of the electric power system will need to take greater account of the realities that components of electricity infrastructure have long lifetimes and are not easily replaced. How the grid and the various institutions, technological features, legal structures, and economics that pertain to it will change is inherently uncertain.[32]

There is broad recognition that, in physical terms, no transmission system can be perfectly reliable. Further, there is recognition that the cost of building a transmission system approaching perfect reliability would be prohibitive. The decision making that led to today's reliability standards is predicated on decades-long experience with hazards that have been encountered routinely in operations. The process of devising the standards also incorporated

[30] *See Presidential Policy Directive (PPD)-21: Critical Infrastructure Security and Resilience*, which defines resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats of incidents."
[31] Federal Energy Regulatory Commission, *Reliability Primer,* https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.
[32] *See* National Academy of Sciences, *Enhancing the Resilience of the Nation's Electricity System,* at https://www.nap.edu/catalog/24836/enhancing-the-resilience-of-the-nations-electricity-system.

judgments regarding the reasonableness of the costs associated with building and operating a transmission system capable of withstanding the vast majority of these threats.

Today, there is ample evidence that, in addition to relying on past experience, assessments of the system's adequacy should include increased attention on new and growing threats to reliability.[33] Deliberate cyber and coordinated physical attacks on the Nation's transmission system were not contemplated when the system was planned and built. The potential for extreme events initiated by our nation-state adversaries is a matter of serious concern in the national security community.

A 2019 report by the U.S. Director of National Intelligence notes that malware and related cyber threats directed at the power grid continue to evolve and grow.[34] Adversaries with knowledge of our infrastructure and a desire to maximize impacts could exploit potential vulnerabilities to cause widespread and long-lasting damage to our electric infrastructure and to the reliable delivery of electric power.

Today, as our knowledge and awareness of the nature and significance of these threats increases, NERC Critical Infrastructure Protection (CIP) and Operations/Planning (O&P) reliability standards follow a rigorous stakeholder process and take time to incorporate responses to rapidly-evolving threats. NERC also uses other tools to respond to rapidly-evolving threats, such as, Reliability Guidelines, Lessons Learned, and NERC Alerts. As resilience investments often contribute to enhanced transmission system reliability, metrics for resilience need to be developed that allow for consideration of the value of those investments that avoid or minimize electric service disruption in normal operating conditions, which may inform transmission planning standards and decisions.

Severe weather has long been recognized as posing a challenge to reliability. Storm-hardening, backup generation, and mutual assistance have figured strongly in the responses to recovery of electric service following severe weather events. Today, there is evidence that the impacts of severe weather events are increasing as a result of our growing dependence on electricity and by the population growth in regions of the country most exposed to these weather-related threats to reliability. The recent hurricanes affecting Texas and Louisiana and the combination of extreme heat and wildfires in California have underscored that a robust transmission network is critical for coping with such challenges. *See* Figure 5-1.

Taken together, the potential for deliberate attacks and our increased vulnerability to severe weather pose new and growing threats to reliability. These matters of national significance demand focused attention when we evaluate the adequacy of the Nation's transmission system. Informed consideration of these threats requires far more information than a review

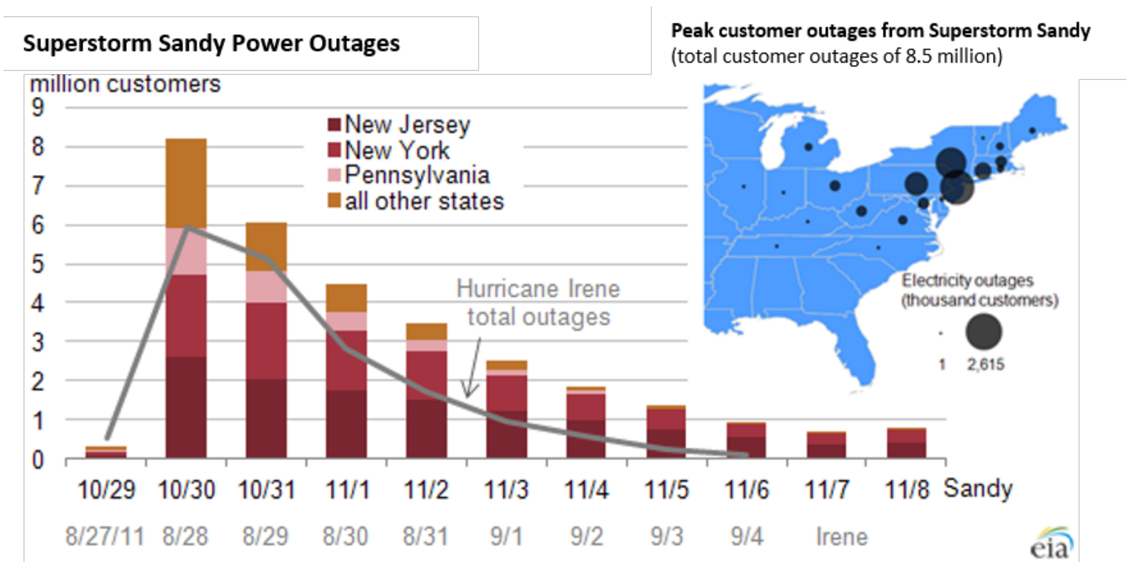
[33] These concerns were expressed by many parties in comments to the Department. *See, e.g.*, panelist remarks and public comments provided at the November 15, 2018 workshop from Exelon, Black Forest Partners, and Grid Strategies, and written comments received from the American Wind Energy Association (AWEA), WIRES-NEMA, and Idaho Power Company.

[34] *See Worldwide Threat Assessment of the US Intelligence Community*, https://www.dni.gov/files/ODNI/documents/2019-ATA-SFR---SSCI.pdf.

of current transmission constraints and congestion. An additional perspective on transmission system resilience and transmission investment is required to obtain a comprehensive understanding of the state of, and vulnerabilities associated with, a power grid subjected to extreme events in real time, especially considering multi-faceted events, such as a cyber-attack during extreme weather.

Figure 5-1. Number and Duration of Power Outages Related to Superstorm Sandy, 2012

Source: EIA, at https://www.eia.gov/todayinenergy/detail.php?id=8730.



As our society continues to be increasingly dependent on reliable electricity supply, it is important to recognize the new threats to reliability to which the transmission system is exposed, as well as the role of transmission in responding to threats that affect related aspects of the economy. Resilience investments avoid or minimize service disruptions, even in the absence of an event or attack. There is a need to think about the value of transmission going forward and to consider the less readily quantifiable benefits. It is important to be able to maintain the options a robust transmission system provides, while keeping in mind how much the loss of reliable electricity costs individuals, businesses, and society.

5.1 Rapid Changes in the Composition and Location of the Nation's Generation Fleet Require Ongoing Assessment of Transmission Investment

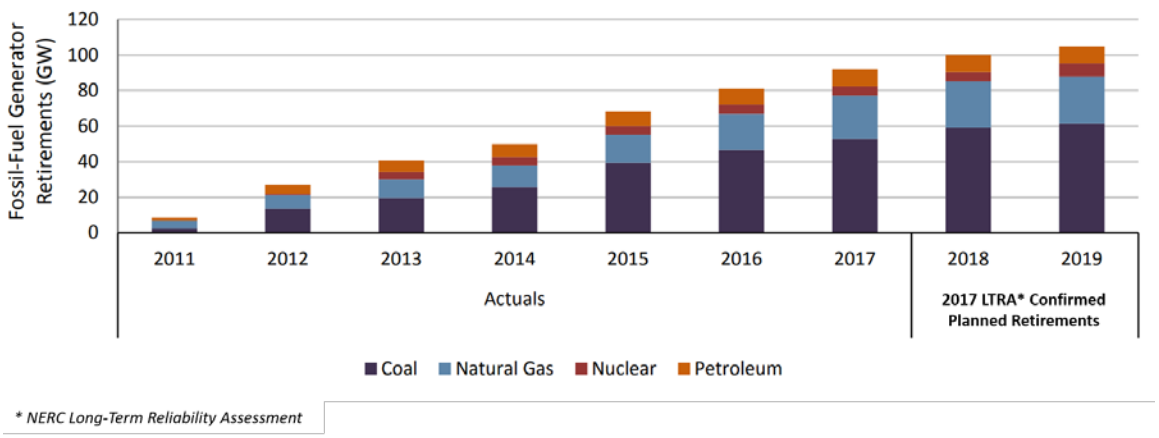
Understanding the impacts of shifts in generation requires information on the future uses of and needs for transmission, for two reasons.[35]

[35] Both concerns were expressed by many parties in their comments to the Department. *See, e.g.*, panelist remarks and public comments provided at the November 15, 2018 workshop from Exelon, American Municipal Power, PJM, ITC Holdings, Grid Strategies, and EDF Renewables, and written comments received from AWEA, WIRES-NEMA, Americans for a Clean Energy Grid, the Town of Stark/Vernon County Wisconsin Inter-Municipal Energy Planning Committee, and the Town of Vermont/Dane County Wisconsin Advisory Committee on Energy Planning.

First, shifts in generation will be increasingly driven by retirements of existing sources, which will affect the location of generation and therefore the need for transmission. *See* Figure 5-2. To date, the impacts of lower natural gas prices have mainly involved shifting generation from existing coal-fired generators to existing or newly constructed gas-fired generators. In recent years, persistent low natural gas prices and environmental regulations have led some coal-fired generators to announce early retirements. Low natural gas prices have contributed to operators retiring nuclear generators as well.

Figure 5-2. Cumulative Retirements of Fossil-Fueled and Nuclear Generators by Fuel Type Since 2011

Source: NERC, Generation Retirement Scenario Special Reliability Assessment Report, at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf.



Retirements mean these generators will not be available to provide reliability services to the surrounding transmission systems that were built based on the assumed availability of these services. Timely replacement of these services by other generators and modifications to portions of the transmission system may be required. Also, generation capacity margins could be at risk in some regions. Transmission and resource adequacy planners will need to continue to assess and manage location-specific trends to ensure the ongoing reliability of the system.

Second, growth in renewable generation may both increase and decrease the need for new transmission. Renewable generation, when built far from loads, requires transmission to deliver its output to users. While continued construction is required to address specific constraints, to date, transmission to support delivery appears to be adequate from the perspective of overall impacts on current transmission constraints and congestion. State policy initiatives continue to push for increased generation from renewable sources and may require increased transmission. Related to this growth, reliability rules and interconnection requirements guiding the performance of the technologies used to interconnect renewable generation to the transmission system also must be reviewed and revised as appropriate.

State-driven requirements for renewable generation are also leading to localized development of renewable sources, often located within the distribution or sub-transmission system. These developments will reduce loading on the transmission system and could reduce the need for new transmission. At the same time, increased local sources of generation will also create new types of requirements for the surrounding transmission system.

5.2 Ongoing, Periodic Review of Issues Affecting the Adequacy and Security of the Nation's Transmission System Is Needed

Growing concerns regarding the resilience of the transmission system and the changing composition of the generation fleet require consideration of factors affecting the adequacy of the Nation's transmission system that extend well beyond those that can be evaluated by studying only current transmission constraints and congestion.[36] Our current ability to analyze the value of investments in the resilience of transmission infrastructure is limited, due to the lack of details regarding potential threats; data and predictions on resulting impacts; tools required to model multiple infrastructures; and details concerning the coordination of numerous utilities and stakeholders involved in regional and national-scale energy system operations.

Recognizing the need for advanced analytics to rapidly identify vulnerabilities to the North American energy system and to enhance decision support, the Department is developing the North American Energy Resilience Model (NAERM)[37]—an integrated modeling approach to study the impact of critical energy and other infrastructures, including natural gas, renewables, coal, and others, on the electric power system.[38]

Application of the NAERM will provide real-time situational awareness and analysis capabilities for emergency events so the Federal government can respond quickly to potential threats to critical electric infrastructure and the North American energy system as a whole. The effort will advance the state-of-science in planning and operations of electric supply and delivery in extreme events and provide more rigorous resilience and associated economic metrics for the energy and other sectors.

Accordingly, the Department proposes to change, subject to Congressional approval, the scope of information it assesses on a regular basis for ongoing evaluation of issues affecting the capacity of the Nation's transmission system to serve critical national interests. Further, DOE expects that the assessments called for in this study will be synonymous with assessments the Department will prepare through applications of the NAERM currently under development.

[36] Concerns regarding the inadequacy of present sources of data to evaluate and assess transmission adequacy were expressed by many parties in their comments to the Department. *See, e.g.*, panelist remarks and public comments provided at the November 15, 2018 workshop from American Municipal Power, Grid Strategies, California Public Utilities Commission, LS Power Development, and EDF Renewables, and written comments received from ITC Holdings, WIRES-NEMA, NextEra Energy, and Americans for a Clean Energy Grid.

[37] *See* https://www.energy.gov/sites/prod/files/2019/07/f65/NAERM_Report_public_version_072219_508.pdf.

[38] The Department is developing NAERM in coordination with FERC, other federal agencies, the RTO/ISOs, and industry partners.

6 Process for Preparing the Fourth National Electricity Transmission Congestion Study

This section reviews the process the Department followed to prepare this study. It summarizes the Department's efforts to seek broad stakeholder input on the preparation of the study, including DOE's public workshop on transmission issues held on November 15, 2018. It also describes the Department's consultation with states and reliability entities on a draft of the study, as called for in EPAct.

6.1 Federal Register Notice Issued August 23, 2018

DOE posted a notice in the *Federal Register* on August 23, 2018, announcing initiation of a process to prepare the fourth National Electricity Transmission Congestion Study. Among other things, the notice described the forms of congestion to be considered and requested public input on the study, including public data sources the Department should consider for review in preparing the study. Appendix A-1 lists the organizations that provided input on the preparation of the study in response to the *Federal Register* Notice.

6.2 Public Workshop held on November 15, 2018

The Department held a public workshop on November 15, 2018, in Arlington, Virginia, to receive public input on plans to prepare the fourth National Electricity Transmission Congestion Study and on other matters related to transmission and affecting the national interest. The workshop was composed of separate sessions organized around three themes. Each session began with prepared remarks from a group of panelists responding to a series of questions posed by the Department under each theme. These remarks were followed by the panelists' responses to additional questions posed by the panel moderator and then questions and comments from the audience.

The panelists were selected by the Department based on their qualifications for, and interests in, addressing the themes of each panel. The themes were:

1. Are there unmet needs for additional long-distance, high-voltage transmission lines?
2. What are the challenges to building transmission facilities where and when needed, including permitting/siting issues?
3. Are existing remedies adequate?

A detailed public summary of the workshop discussion is available at https://www.energy.gov/sites/prod/files/2019/01/f59/DOE%20November%202018%20Transmission%20Issues%20Workshop%20%20Meeting%20Summary%20January2019.pdf. Appendix A-2 contains the workshop agenda, participants, the questions panelists were asked to address, and the list of organizations whose representatives registered to participate in the workshop.

6.3 Consultation with States and Regions Conducted in January 2020

As directed by EPAct, the Department consulted with both states and reliability entities in preparing this study. Consultation took the form of circulating a "consultation draft" of the fourth National Electricity Transmission Congestion Study to each state and reliability entity, along with an invitation to provide written comment on the draft or to meet with DOE staff, in person or by phone, to convey comments. In addition, DOE briefed the states and reliability entities via webinars on the consultation draft. Appendix A-3 lists the organizations that provided comments to the Department in response to this invitation.

APPENDIX A-1: List of Organizations that Submitted Comments in Response to Federal Register Notice

Comments were received from the following entities in response to the August 23, 2018 *Federal Register* Notice:

ABB
Ameren
American Wind Energy Association (AWEA)
Americans for a Clean Energy Grid
Dane County Wisconsin Advisory Committee on Energy Planning
Idaho Power Company
Inter-Municipal Energy Planning Committee
ITC Holdings
NextEra Energy
Southern Company Services
StopPathWV
WIRES-NEMA

Public comments received by the Department in response to the *Federal Register* Notice, as well as a link to the August 23, 2018 Notice, are available at https://www.energy.gov/oe/downloads/public-comments-august-2018-notice-procedures-conducting-electric-transmission.

APPENDIX A-2: Agenda for Public Workshop held November 15, 2018 and List of Organizations

Agenda, Page 1:

DOE Workshop on Electric Transmission Development and Siting Issues

Thursday, November 15, 2018
National Rural Electric Cooperative Association Conference Center
4301 Wilson Boulevard, Arlington, VA, 22203
9:00 a.m. – 4:00 p.m.

Final Agenda

8:30	**Registration opens**
9:00	**Welcome.** David Meyer (DOE) will provide welcoming remarks and explain the purposes and mechanics of the workshop.
9:10 – 9:30	**Trends from TDRs.** DOE has published an *Annual Transmission Data Review* (TDR) since 2015. Katie Jereza, Deputy Assistant Secretary at DOE's Office of Electricity, will draw upon this data and discuss major transmission trends and issues.
9:30 – 11:00	**Panel I. Are there unmet needs for additional long-distance, high voltage transmission lines?** • Are recent or current system-level trends (e.g., rising incidence of extreme weather, concerns about physical and cyber security, increasing reliance on distributed energy resources (DERs)) increasing or reducing the need for transmission capacity? • Are we underbuilding (or overbuilding) long-distance, high-voltage transmission facilities, either regionally or inter-regionally? • If so, what are the indicators? Please cite specific measures and explain how they support your assessment. If appropriate, clarify regions or projects to which your assessments apply. • What additional information is needed to provide further support for your assessments? Is this information publicly available? **Moderator:** David Meyer, Senior Advisor, Office of Electricity, DOE **Panelists:** • Steve Naumann, Vice President, Transmission and NERC Policy, Exelon Corporation • Ed Tatum, VP for Transmission, American Municipal Power • Kenneth Seiler, Executive Director, System Planning, PJM • Alan Myers, Director, Regional Planning, ITC Holdings
11:00 – 11:15	**Break**

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Agenda, Page 2:

11:15 – 12:45 **Panel II. Challenges to building transmission facilities where and when needed: Permitting/siting issues**

- Have recent worthwhile major transmission projects been thwarted by "pass-through" states?
- Or by anticompetitive owners of existing generation or transmission assets?
- Or by controversy over the proposed distribution of the likely costs or benefits of the transmission project?
- Other obstacles?

Moderator: Julie A. Smith, Office of Electricity, DOE

Panelists:

- Rich Sedano, President, Regulatory Assistance Project (RAP)
- Dan Belin, Director, Electric Transmission, Ecology & Environment, Inc.
- Georgeann Smale, Senior Realty Specialist, Washington Office, Bureau of Land Management, Department of Interior
- Bess Gorman, Assistant General Counsel, National Grid

12:45 – 2:00 **Lunch on your own** (please be seated and ready to resume by 2:00)

2:00 – 3:30 **Panel III. Are existing remedies adequate?**

- Are regional transmission planning processes under FERC Orders No. 890 and 1000 sufficiently effective to address unmet needs?
- For merchant transmission lines being developed outside or in parallel with these processes, are the needs of pass-through states being balanced fairly and efficiently with respect to regional and inter-regional needs?
- Are there other considerations that impede addressing unmet needs for additional long-distance transmission lines in a timely manner?
- Is Federal action required to address any of the issues identified above? If so, what form of action is required?

Moderator: Joe Eto, Staff Scientist, Lawrence Berkeley National Laboratory

Panelists:

- Rob Gramlich, President, Grid Strategies LLC
- Traci Bone, Attorney, California Public Utilities Commission
- Sharon Segner, Vice President, LS Power Development
- Omar Martino, Director, Transmission Strategy, EDF Renewables

3:30 – 4:00 **Final remarks, major takeaways (including questions), and next steps.**

The meeting will be recorded to support preparation of a detailed meeting summary.

Note: DOE invites all who are interested in the topics discussed at this workshop (i.e., those who attended in person, those who listened to the webcast, and those who were unable to do either) to submit written responses to the questions listed above by November 21, 2018. All written submissions will be posted on DOE's congestion study website, and will be taken into account in the preparation of a written summary of the workshop. Send such submissions to congestion.study2018@hq.doe.gov, and please indicate the workshop-related transmission issues or questions you wish to address.

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Organizations Represented at the November 15, 2018 Workshop:

In-Person Attendees

ABB
ACES Power Marketing
Alabama Public Service Commission
Ameren Transmission
American Electric Power (AEP)
American Public Power Association (APPA)
American Wind Energy Association (AWEA)
Americans for a Clean Energy Grid
AMP
Basin Electric Power Cooperative
Berkshire Hathaway Energy
Black Forest Partners/Southline Transmission Project
British Columbia Utilities Commission
Bureau of Land Management, Department of Interior
Burns & McDonnell
California ISO
California Public Utilities Commission
Consolidated Edison
Duke Energy
Ecology & Environment, Inc.
EDF Renewables
Edison Electric Institute
Electric Power Research Institute (EPRI)
Electricity Consumers Resource Council (ELCON)
Engleman Fallon, PLLC
Exelon
Federal Energy Regulatory Commission
FirstEnergy
Georgia Transmission Corporation
Grid Strategies LLC
Hoosier Energy
Hunt Power, LP
Husch Blackwell
ICF
Idaho Power Company
Independent Contractor
ITC Holdings Corp.
Jennings Strauss & Salmon
Lawrence Berkeley National Laboratory
Louis Berger
LS Power Development
Midwestern Governors Association
Midwestern ISO (MISO)
Minnkota Power Cooperative, Inc.
National Association of State Energy Officials
National Governors Association
National Grid
National Rural Electric Cooperative Association
New Jersey Board of Public Utilities
North Carolina Electric Membership Corp
Office of Congressman Peter DeFazio
Old Dominion Electric Cooperative
Paul Hastings LLP
Pennsylvania Public Utility Commission
Pepco Holdings
PJM Interconnection LLC
Public Utilities Commission of Ohio
Regulatory Assistance Project
Salt River Project
San Diego Gas & Electric
Spiegel & McDiarmid LLC
State Corporation Commission
Thompson Coburn LLP
Transmission Agency of Northern California
Tri-State Generation and Transmission Assoc.

Tucson Electric Power
U.S. Department of Energy
University of Pennsylvania
Virginia State Corporation Commission
Wheeler, Van Sickle & Anderson, S.C.
WIRES

Remote Participants (via web conference)

American Transmission Company (ATC)
Apex Clean Energy
Arizona Public Service
Associated Electric Cooperative Inc. (AECI)
Avangrid, Inc.
California Energy Commission
Central Iowa Power Cooperative
CTC Global Corporation
Dairyland Power Cooperative
East Kentucky Power Cooperative
Entergy
ERCOT
Golden Spread Electric Coop
Great River Energy
GridLiance
ISO New England
JEA
Minnesota Power
Mitsubishi Electric Power Products, Inc.
North American Transmission Forum
Northern Indiana Public Service Commission
Northern Virginia Electric Cooperative
Northwest Public Power Association
Oklahoma Gas & Electric
Omaha Public Power District
Orange & Rockland (ORU)
Otter Tail Power Company (OTP)
Pacific Gas and Electric Company
Portland General Electric
PowerSouth Energy Cooperative
PPL Electric Utilities
Public Service Commission of Wisconsin
Public Utility District No. 1 of Snohomish County
Puget Sound Energy
RTO Insider LLC
Seminole Electric Cooperative, Inc.
Southern California Edison (SCE)
Southwest Public Power Agency
Sunflower Electric Power Corporation
Tennessee Valley Authority
Terra Institute
The Energy Authority
Tradewind Energy Inc.
Valley Electric Association, Inc.
Vectren
Western Area Power Administration
Xcel Energy

A detailed public summary of the workshop discussion is available at https://www.energy.gov/sites/prod/files/2019/01/f59/DOE%20November%202018%20Transmission%20Issues%20Workshop%20%20Meeting%20Summary%20January2019.pdf.

APPENDIX A-3: List of Organizations that Provided Comments on the Consultation Draft of the Study

Midwest Reliability Organization (MRO)
North American Electric Reliability Corporation (NERC)
Northeast Power Coordinating Council (NPCC)
ReliabilityFirst (RF)
SERC Reliability Corporation (SERC)
Texas Reliability Entity (TRE)
Western Electricity Coordinating Council (WECC)

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