Transmission and Distribution System Planning and Reliability

Historically, transmission infrastructure enabled utilities to locate power plants near inexpensive sources of fuel and transmit electricity over long distances to consumers. By interconnecting different utilities' transmission systems, utilities were able to access additional sources of generation and backup each other's generating capacity, thus improving overall reliability and also reducing overall operating costs. Ultimately, the power grid grew into an interstate system subject to both federal and state regulation. Under the Federal Energy Policy Act of 1992 and Federal Energy Regulatory Commission (FERC) Order No. 888 issued in 1996, any generator, independent or utility-owned, may request access to the transmission grid at rates and terms comparable to those that the owner-utility would charge itself. This access to the transmission grid led to the growth of wholesale power markets. Power generators were able to use the transmission system to send power to one another as needed to serve the loads of their customers, creating larger, more regional transmission networks. With the creation of regional transmission systems and competitive wholesale markets, utilities in many areas transferred the functional control of their transmission lines to independent system operators (ISOs) or regional transmission organizations (RTOs), such as PJM, while maintaining ownership and maintenance responsibilities over their lines. Utilities retain sole control of their distribution systems.

History of FERC

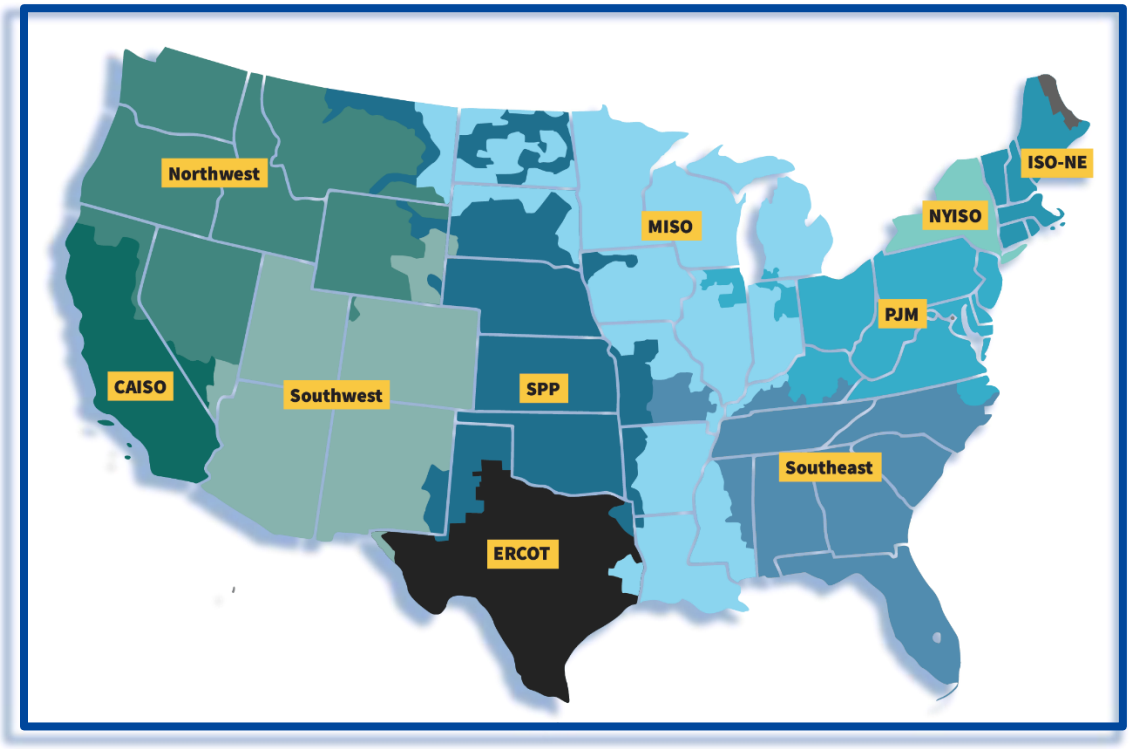
FERC is an independent regulatory arm of the U.S. Department of Energy (DOE). FERC authority derives from the Commerce Clause (Article I of the U.S. Constitution) and a large set of federal statutes, primarily the Federal Power Act, the Natural Gas Act, the Energy Policy Act of 2005, and the Interstate Commerce Act. FERC's authority specifically includes (1) hydroelectric projects on interstate waterways (those not otherwise regulated by other federal entities such as the U.S. Army Corps of Engineers); (2) interstate natural gas pipelines and certain types of gas storage, transmission and wholesale sales of electricity in interstate commerce; and (3) import and export facilities for liquefied natural gas (LNG) (a responsibility shared with the U.S. Coast Guard). FERC also has authority over wholesale energy rates, natural gas pricing, interstate oil pipeline rates, electric reliability at a national level, and reviews of certain mergers and acquisitions by energy companies. FERC does not have authority over the following: local or otherwise non-interstate reliability; retail electricity and natural gas rates; mergers and acquisitions related to natural gas and oil companies; energy facilities; or energy issues regulated by state energy authorities (such as state public utility commissions) or regional energy authorities (such as the Tennessee Valley Authority).

Electricity Transmission

FERC jurisdiction over wholesale transmission applies to entities that own, control or operate interstate transmission facilities, primarily investor-owned utilities (IOUs), but could include electric cooperatives, municipal utilities and public power agencies. In addition, FERC jurisdiction over federal agencies is limited and FERC jurisdiction does not extend to regions not engaged in interstate commerce, which includes the region of Texas within the Electric Reliability Council of Texas (ERCOT) and the states of Alaska and Hawaii. FERC has primary jurisdiction over all U.S. ISOs and RTOs with respect to both the ISO/RTO-administered

wholesale electricity markets and the ISO/RTO regional transmission planning activities (except in ERCOT). The North American ISOs and RTOs are shown in Figure 1. Regulation of transmission owners outside of an ISO/RTO varies on a case-by-case basis.

Figure 1 U.S. RTOs and ISOs



Source: Federal Energy Regulatory Commission. https://www.ferc.gov/power-sales-and-markets/rtos-and-isos

Transmission Planning and Cost Recovery

FERC originally issued Order No. 888 in April 1996, establishing requirements for transmission use and planning on both a local and regional level. Within this order, FERC outlined several broad planning principles for transmission providers such as PJM, but these were mainly focused on meeting reliability needs and promoting wholesale competition through establishing open access transmission service on a nondiscriminatory basis to all wholesale customers. In February 2007, FERC issued Order No. 890, which strengthened the *pro forma* Open Access Transmission Tariff by requiring public utility transmission providers to participate in open transmission planning processes. Order 890 noted that transmission investment relative to load growth had declined in the decade following Order 888, and that transmission constraints had become common occurrences. Order 890 also outlined new criteria for transmission planning.

In July 2011, FERC issued Order No. 1000 to amend some of the transmission planning and cost allocation requirements established in Order 890. FERC noted that regional transmission planning processes had improved following the issuance of Order 890, but some deficiencies

remained. Order 1000 included several reforms with respect to transmission planning processes and cost allocation methods by FERC-jurisdictional entities, including:

- A requirement for all public (i.e., under FERC jurisdiction) transmission providers to participate in a regional transmission planning process that evaluates both transmission and non-transmission solutions and includes consideration of public policy requirements; and
- Each public utility is required, through the regional planning process, to coordinate with neighboring transmission planning regions and create an interregional transmission planning agreement.

Order 1000 also established principles to align transmission planning and cost allocation. Under the rule, each public utility transmission provider is required to develop regional and interregional cost allocation methodologies consistent with FERC's six cost allocation principles, including that costs must be allocated in a manner roughly commensurate with estimated benefits and that entities that receive no benefit should not be allocated costs.

The Eastern Interconnection

North America is comprised of two major and three minor alternating current (AC) power grids or "interconnections." The Eastern Interconnection, one of the major grids, reaches from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida and west to the foot of the Rockies (excluding most of Texas). All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency at an average of 60 hertz (Hz). The other major interconnection is the Western Interconnection. The three minor interconnections are the Québec Interconnection, Alaska Interconnection and Texas Interconnection.



Source: powermag.com/the-odd-couple-renewables-and-transmission/?pagenum=2.

PJM submitted its Order 1000 compliance filings in 2012 and 2013, and FERC subsequently approved revisions to PJM's regional and interregional transmission planning and cost allocation processes. PJM's regional transmission cost allocation framework allocates costs based on the type of transmission project (e.g., reliability, market efficiency, or public policy-driven) and the beneficiaries of the project as determined through PJM's modeling processes. Interregional planning and cost allocation between PJM and neighboring regions, including the Midcontinent

Independent System Operator (MISO) and New York Independent System Operator (NYISO), are governed through joint operating agreements and FERC-approved interregional coordination procedures.

Various utilities and the National Association of Regulatory Utility Commissioners (NARUC) have sued FERC, arguing that some of the provisions in Order 1000 are beyond FERC's authority. In September 2013, FERC argued before the U.S. Court of Appeals, District of Columbia Circuit that it does have the authority to reform the planning of high-voltage power transmission. FERC argued that the appeals court should dismiss claims against its requirement in Order 1000, which states that FERC-jurisdictional electric transmission providers must participate in a regional planning process that takes into account state and local public policy when outlining a regional plan and requires them to also coordinate with other adjacent providers to find better ways to boost efficiency and reliability. FERC argued that its rule did not intrude on state authority and that its public policy directive to regulate in this area is sufficiently clear.

The Court heard oral arguments in March 2014 and issued a decision in August 2014 to uphold Order 1000, stating that FERC acted within its authority and that the rule was not arbitrary and capricious.

Although Order 1000 was viewed as a landmark order, it has not produced the expected results. Order 1000 was intended to expand transmission to meet the increase in renewable generation, and while new transmission has come online since the order went into effect, 70 percent of the system is 25 years or older.

Hydroelectric and Liquefied Natural Gas

Unless a project has a valid pre-1920 federal permit, nonfederal hydroelectric projects are subject to FERC jurisdiction if the project:

- Is located on navigable waters of the United States;
- Occupies public lands or reservations of the United States;
- Uses surplus water or hydropower from a federal dam (such as a U.S. Army Corps of Engineers facility); and/or
- Is located on a body of water over which the U.S. Congress has Commerce Clause jurisdiction and was constructed on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

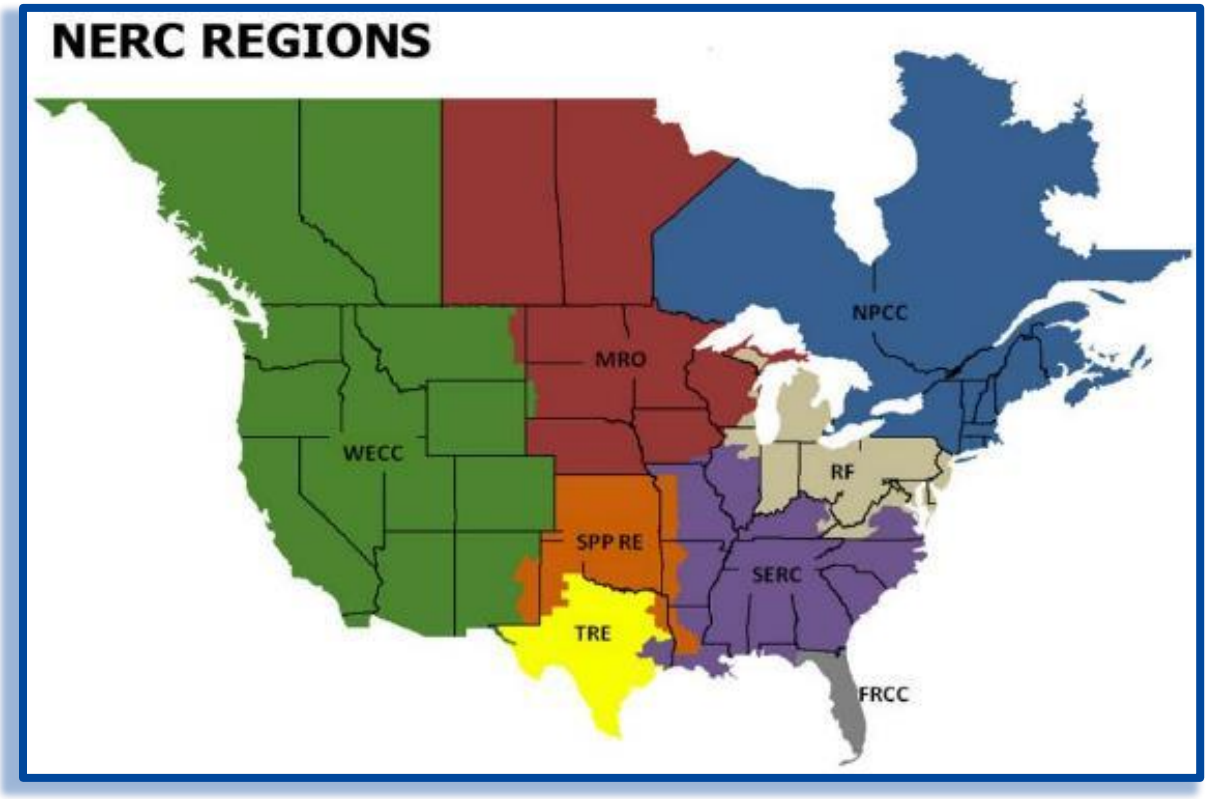
FERC issues licenses for projects for up to 50 years and has a complex licensing procedure that incorporates interagency processes such as the U.S. Fish and Wildlife Coordination Act and local public consultation.

FERC also has authority under the Natural Gas Act to authorize the siting of facilities used to import or export LNG, which are constructed and/or operated inside the state waters limit. State waters are generally three nautical miles from shore, but this distance varies in some areas, such as the Gulf of Mexico and Puerto Rico where this limit is nine nautical miles.

Reliability

The North American Electric Reliability Corporation (NERC) is charged with developing and implementing reliability standards and periodically assessing the reliability of the bulk power system. NERC, which is governed by a 12-member independent board of trustees, develops mandatory reliability standards that are reviewed and ultimately approved by FERC. The Energy Policy Act of 2005 requires electricity market participants to comply with NERC reliability standards. If participants are found in violation of the Energy Policy Act, participants are subject to fines of up to $1 million per day, per violation. NERC delegates enforcement authority to eight regional reliability councils, including the ReliabilityFirst Corporation (RF) which serves the PJM RTO (Figure 2).

Figure 2 NERC Reliability Councils



Source: North American Electric Reliability Corporation.

One of the NERC reliability standards applicable to PJM is the Resource Planning Reserve Requirement. This standard requires that each load-serving entity (LSE) participating in PJM has sufficient resources such that there is no loss of load more than one day in 10 years. To maintain compliance under this reliability standard, PJM conducts annual resource planning exercises to ensure all LSEs have sufficient generation resources (either owned or contracted) to supply their peak electricity load, plus a specified annual reserve margin. In addition to long-term resource planning, PJM is responsible for operational reliability functions, including seasonal reliability assessments, emergency operations and energy emergency alerts, generator performance requirements, transmission reliability studies under applicable NERC standards, and system restoration planning.

Transmission Congestion

The economic impacts of transmission congestion are described in Section 6.1.1 of CEIR 23; however, congestion may also affect reliability if a transmission line nears or exceeds its transfer limit (the physical limit of the transmission system) and there are no supplemental generation resources downstream of the constraint. If this occurs, system operators might ask large customers to voluntarily curtail their loads or, in extreme situations, may even be forced to reduce electricity deliveries to consumers. Economic congestion that results in higher electricity costs is far more common than a loss of load, or a blackout event, caused by insufficient transmission or generation resources. Economic congestion results when a transmission path is unable to provide access to the lowest-cost generation to serve load requirements in particular locations. This circumstance entails more expensive generation located along an uncongested path to be used to meet load requirements. The difference in generation cost between the lowest-cost (but unavailable) generation and the higher-cost (but available) generation represents the congestion cost.

Eliminating or reducing key constraints can alleviate congestion. This may be achieved through the construction of new transmission lines, building new generation within a load pocket, upgrades to existing facilities or demand side management. PJM routinely conducts transmission planning to ensure reliability is maintained. In that regard, congestion that threatens reliability will be addressed in PJM's transmission planning process. Economic congestion is congestion that produces localized increases in electricity prices, but does not trigger a reliability event. Economic congestion is not addressed in PJM's reliability planning since it is considered an economic decision rather than a reliability problem. However, depending on the total economic impact and benefits, PJM may suggest corrective projects as part of its competitive planning process to improve market efficiency.

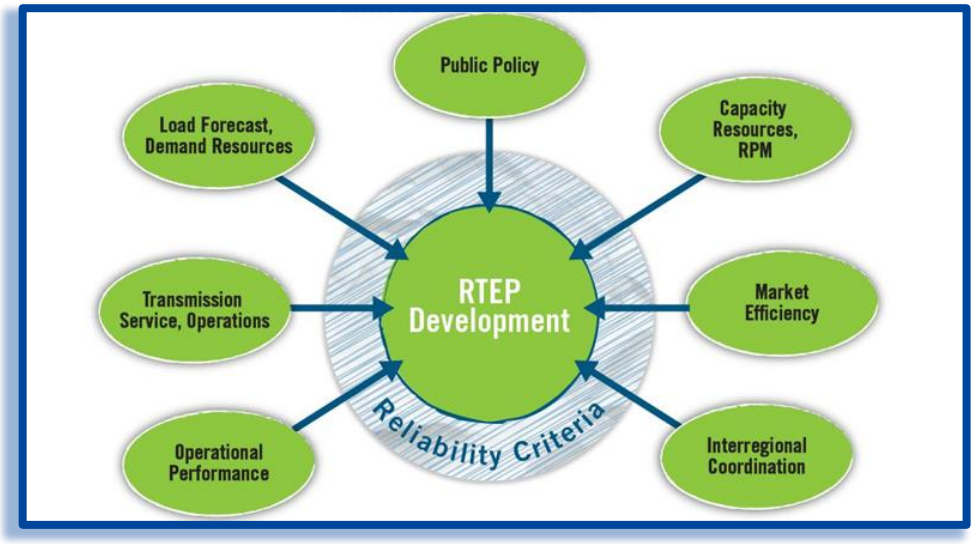
PJM Transmission Planning

PJM conducts ongoing regional transmission planning through its Regional Transmission Expansion Plan (RTEP) process. The RTEP is updated annually, and models projected future load, generation and transmission system conditions to identify and evaluate potential reliability, market efficiency and public policy-driven transmission projects. PJM has authority over the transmission system and is responsible for maintaining system reliability; however, PJM does not have authority to require the construction of generation or demand-side resources. Transmission solutions identified through the RTEP process are incorporated into the plan following stakeholder review and PJM Board approval. Demand response resources that clear in PJM's Reliability Pricing Model (RPM) are recognized for purposes of reliability assessments.

PJM develops a 15-year planning horizon within the RTEP that includes transmission upgrades designed to address identified reliability violations, economic congestion and public policy requirements. Once a transmission need is identified, PJM evaluates potential solutions and, upon approval, authorizes construction and cost recovery of transmission upgrades (Figure 3). PJM authorization does not supersede state siting and permitting requirements, and a Certificate of Public Convenience and Necessity (CPCN) may be required under applicable state law. In addition to reliability and market efficiency considerations, PJM has incorporated public policy

requirements, such as state renewable portfolio standards and other legislated energy policies, into its planning process since its Order 1000 compliance.

Figure 3 PJM RTEP Transmission Planning Framework



Source: PJM Regional Transmission Expansion Planning (RTEP) Process (December 11, 2017).

State Distribution System and Reliability Planning

Following several incidents of storms and outages in Maryland during 2010 and 2011, the PSC initiated Rulemaking 43 (RM43) to consider revisions to state regulations in regard to electric distribution company reliability and service quality standards, "including, but not limited to: service interruption, downed wire repair and service quality standards; vegetation management standards; annual reliability reporting; and the availability of penalties for failure to meet the standards."[1] On April 17, 2012, new regulations were adopted, including the following:

- A requirement that utilities submit a Major Outage Event Report within three weeks following the end of the event. A "major outage" is defined as an event affecting more than 10 percent of a utility's customers or 100,000 customers in total, whichever is less.
- A set of reliability standards and a requirement to collect certain related data.
- Service interruption standards that require utilities to restore service within a defined period of time.
- Downed wire standards that require utilities to respond within four hours of notification by a fire department, police department or 911 emergency dispatcher at least 90 percent of the time.
- A communications standard that requires utilities to answer calls within a certain period.
- Vegetation management standards that aim to keep power lines clear of potential hazards.

[1] Maryland Public Service Commission, Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011.

- A requirement for periodic equipment inspections.

Utilities must submit an annual report outlining their performance with respect to these regulations. In addition, the utilities are required to have a Major Outage Event Plan on file with the PSC providing a description of and procedures for its response to major events, as well as performance measures associated with the assessment of the implementation of the Major Outage Event Plan.

The ability to detect outages during both storms and normal operations has been a challenge for utilities. Historically, utilities have relied on customers to report local outages. With the advent of new technologies, being able to "see" conditions on the distribution grid in real-time is becoming a reality. Maryland utilities with PSC-approved Advanced Metering Infrastructure (AMI) plans have either finished installing or are in the process of installing AMI in their respective service territories. While AMI allows for the electronic reading of customer meter information, the communication network created by the advanced meters also serves to provide much needed information on the current status of the distribution grid.

Damage from severe storms can be extensive and costly to repair. Some jurisdictions utilize a rider to fund storm-related repairs. In Maryland, the costs of storm repairs are included in the utility's overall revenue requirement which determines a utility's rates as approved by the PSC.

On December 2, 2015, the PSC adopted proposed regulations regarding reliability and service quality standards, expressed as the System Average Interruption Duration Index (SAIDI).[2] The regulations established numerical reliability standards in terms of an allowable duration of outages 2016 through 2019. Utilities in Maryland also have to measure and report the System Average Interruption Frequency Index, or SAIFI. SAIFI is the average number of times annually that a utility customer has an outage and is calculated by dividing the total number of customers interrupted by the total number of customers served. The reliability standards are updated regularly through rulemaking proceedings. In July 2023, the PSC adopted SAIDI and SAIFI standards for utilities in Maryland for 2023 through 2027 (see Table 1). [3] Most recently, on June 24, 2025, the Commission issued a notice of rulemaking to revise and update utility service reliability standards.[4]

[2] Maryland Public Service Commission, Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011.
[3] MD COMAR 20.50.12.02(D).
[4] Maryland Public Service Commission, Rulemaking 90, Case No. 9353. Mail Log No. 319859.

Table 1 SAIDI and SAIFI Standards for Maryland Utilities, 2023-2027

Baltimore Gas and Electric Company					
	2023	**2024**	**2025**	**2026**	**2027**
SAIDI	103.0	89.0	87.0	86.0	85.0
SAIFI	0.83	0.87	0.84	0.83	0.83
Delmarva Power & Light Company					
	2023	**2024**	**2025**	**2026**	**2027**
SAIDI	88.0	77.4	77.4	77.4	77 .4
SAIFI	1.09	1.03	1.03	1.03	1.03
Potomac Edison Company					
	2023	**2024**	**2025**	**2026**	**2027**
SAIDI	142.0	142.0	142.0	142.0	142.0
SAIFI	1.06	1.05	1.05	1.05	1.05
Potomac Electric Power Company					
	2023	**2024**	**2025**	**2026**	**2027**
SAIDI	86.0	72.0	68.4	66.0	66.0
SAIFI	0.89	0.80	0.74	0.70	0.70
Southern Maryland Electric Cooperative, Inc.					
	2023	**2024**	**2025**	**2026**	**2027**
SAIDI	133.2	132.9	132.7	132.6	132.5
SAIFI	1.28	1.27	1.27	1.26	1.26

Source: Maryland COMAR 20.50.12.02, https://dsd.maryland.gov/regulations/Pages/20.50.12.02.aspx.

The PSC also adopted a regulation requiring utilities to prepare a resilience plan to address such possible situations as pandemics, physical attacks, cyberattacks, electric supply shortages, weather events, significant infrastructure failures and other credible disturbances that could lead to large and widespread electric outages or loss of critical facilities.[5]

[5] Source: Maryland COMAR 20.50.12.15, dsd.maryland.gov/regulations/Pages/20.50.12.15.aspx.