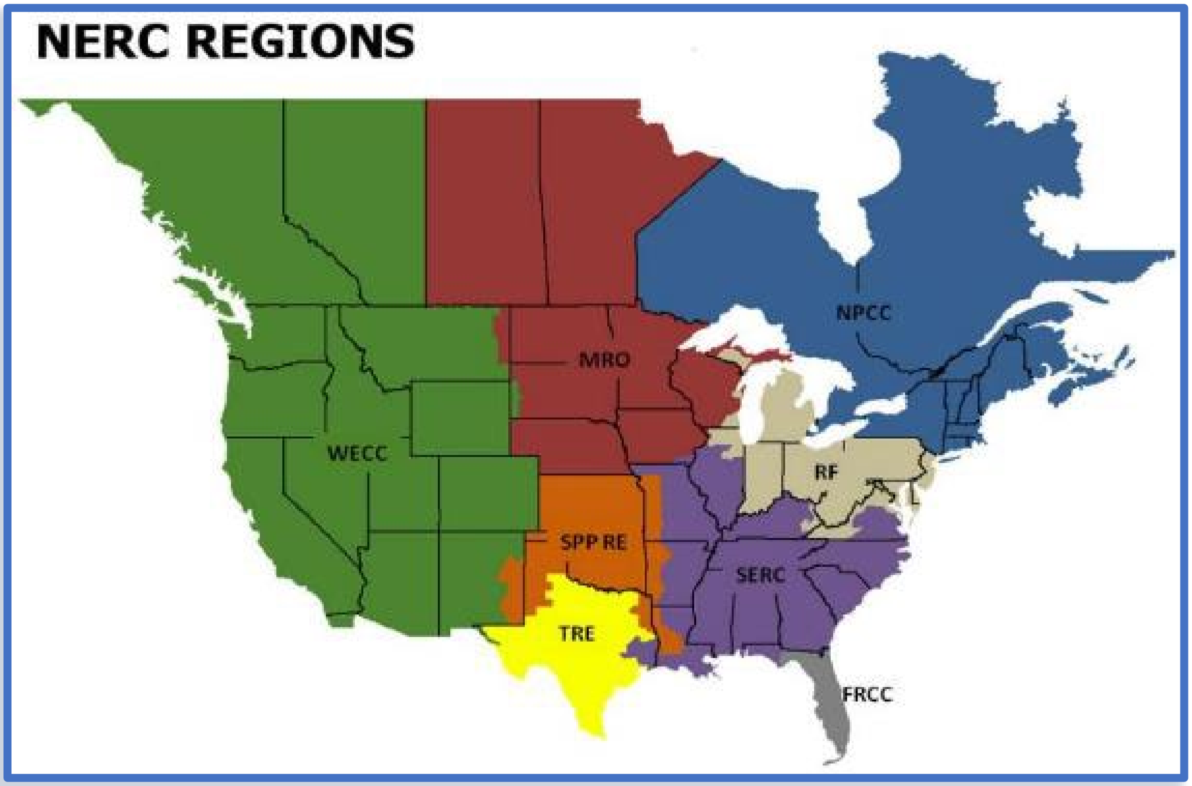
Transmission and Distribution System Planning and Reliability

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 back up 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 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.

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.

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.

Transmission Congestion

The economic impacts of transmission congestion are described in Section 4.1.1 of CEIR-21; 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-

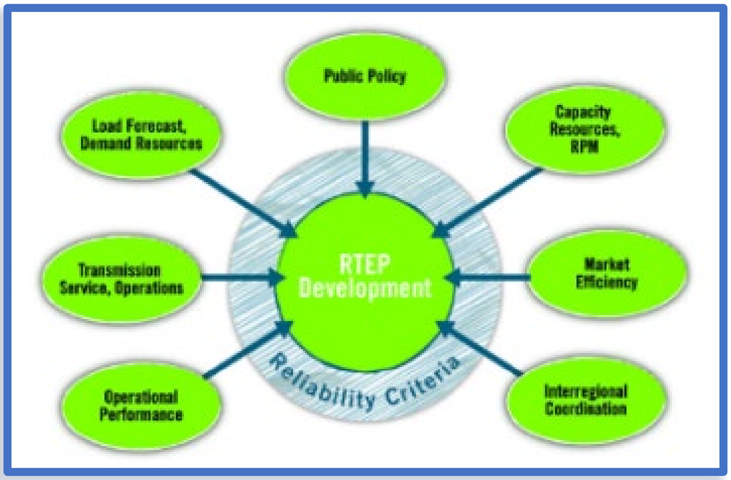
cost (but unavailable) generation and the higher-cost (but available) generation represents the congestion cost.
Eliminating or reducing key constraints can alleviate congestion. This may be achieved through the construction of new transmission lines, building new generation within a load pocket, upgrades 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 annual transmission planning to forecast and address potential reliability issues. PJM's Regional Transmission Expansion Plan (RTEP) planning process models future load and generation and identifies and evaluates possible new transmission projects or upgrades. PJM has authority over the transmission system and an obligation to maintain reliability. However, PJM can only put forward transmission solutions in RTEP. PJM cannot impose generation or demand response solutions and includes in the RTEP model only those generation projects that have requested interconnection to the PJM grid and are at a relatively late stage of development. Additionally, only demand response resources that have cleared in the RPM are recognized by PJM for purposes of reliability assessment.

PJM develops the 15-year Plan that includes upgrades to help alleviate constraints identified through the modeling exercise. Once a transmission constraint is identified, PJM authorizes construction and cost recovery of transmission upgrades to address the area of concern. PJM authorization does not supersede state regulation, so a CPCN may be required depending on state siting and permitting regulations. PJM also considers market efficiency upgrades designed to relieve economic congestion by reducing overall operating and supply costs for customers. Since the 2012 RTEP planning cycle, PJM has included public policy requirements (for example, state renewable portfolio standard policies) when considering transmission upgrades. (See figure below for the RTEP planning criteria.)

PJM RTEP Transmission Planning Criteria



Source: PJM 2015 Regional Transmission Expansion Plan.

State Distribution System and Reliability Planning

See Section 4.3.4 of CEIR-21 for background information on State Distribution System and Reliability Planning.

On December 2, 2015, the PSC adopted proposed regulations regarding reliability and service quality standards, expressed as the System Average Interruption Duration Index (SAIDI).[1] The regulations established numerical reliability standards in terms of an allowable duration of outages 2016 through 2019, and currently the PSC has extended the SAIDI reliability standard to 2027 and thereafter.[2] 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.

In July 2023, the PSC adopted SAIDI and SAIFI standards for utilities in Maryland for between 2023 and 2027.

[1] Maryland Public Service Commission, Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011. psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/RuleMaking/RM43//001.pdf

[2] MD COMAR 20.50.12.02(D)

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.[3]

---

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