DEPARTMENT OF PUBLIC UTILITIES
ADVANCED TRANSMISSION SOLUTIONS REPORT

2025

SUBMITTED TO THE JOINT COMMITTEE ON TELECOMMUNICATIONS, UTILITIES AND ENERGY PURSUANT TO SECTION 121 OF AN ACT PROMOTING A CLEAN ENERGY GRID, ADVANCING EQUITY, AND PROTECTING RATEPAYERS

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LIST OF ABBREVIATIONS

2024 Climate Act or Act	An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers, St. 2024, c. 239
AAR	Ambient-Adjusted Ratings
ACSR	Aluminum-Conductor Steel-Reinforced
Advancing GETs Act	Advancing Grid-Enhancing Technologies Act of 2024, S. 3918, 118th Cong. (2024)
APFC	Advanced Power Flow Control
BIG WIRES Act	Building Integrated Grids with Inter-Regional Energy Supply Act, H.R. 5551/S. 2827, 118th Cong. (2023)
CETA	Clean Electricity and Transmission Act, H.R. 6747, 118th Cong. (2023)
CIGRE	Conseil International des Grands Réseaux Électriques
Department or DPU	Department of Public Utilities
DERMS	Distributed Energy Resource Management System
DLR	Dynamic Line Ratings
DOE	U.S. Department of Energy
DOER	Department of Energy Resources
DSR	Distributed Series Reactor
EDC	Electric Distribution Company
EFSB	Energy Facilities Siting Board
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESMPs	Electric Sector Modernization Plans
FACTS	Flexible AC Transmission Systems
FERC	Federal Energy Regulatory Commission
GETs	Grid-Enhancing Technologies
GRIP	Grid Resilience and Innovation Partnerships
GW	Gigawatt
INL	Idaho National Laboratory
ISO	Independent System Operator

ISO-NE	ISO New England Inc.
LTTP	Longer-Term Transmission Planning
MassCEC	Massachusetts Clean Energy Center
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt Hour
NECEC	New England Clean Energy Connect
NERC	North American Electric Reliability Corporation
NOI	Notice of Inquiry or Investigation
NYISO	New York Independent System Operator
PFC	Power Flow Controller
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PSCs	Public Service Commissions
PUCs	Public Utility Commissions
RFF	Resources for the Future
RFP	Request for Proposals
RTO	Regional Transmission Organization
SATA	Storage as a Transmission Asset
SATOAs	Storage as Transmission-Only Assets
SCADA	Supervisory and Control Data Acquisition
SLRs	Static Line Ratings
SPP	Southwest Power Pool
TO	Transmission Owners

INTRODUCTION

The aging U.S. electric grid is experiencing a period of high, rapid electricity demand growth and an increased need to host new forms of generation (including solar and storage). According to ISO New England Inc. ("ISO-NE"), electricity demand in the region is projected to increase from approximately 25 gigawatt ("GW") summer peak in 2025 to 32 GW by 2045 (i.e., by almost 30 percent). Meanwhile, winter demand is expected to increase by approximately 74 percent from a 23 GW all-time winter peak recorded in 2004 to 40 GW by 2045.[1] Substantial additional investment will be necessary to both meet this demand growth and decarbonize the electric grid. According to the U.S. Department of Energy ("DOE"), the U.S. transmission system will need to expand 2.4 to 3.5 times the size of the 2020 system by 2050 to achieve 100 percent emission reductions while reliably meeting electricity demand at lowest power system costs.[2]

Faced with rising demand, the aging grid is not keeping up, leading to lengthening interconnection queues both regionally and nationally. An estimated 70 percent of transmission infrastructure is over 25 years old. In some cases, grid components are far past their 50-year life expectancy.[3] Meanwhile, demand to interconnect to the grid is leading to growing delays. As of April 2025, approximately 37 GW of proposed new generation resources have joined the ISO-NE interconnection queue.[4] Notably, the queue has grown by 80 percent in the last eight years.[5] As of 2024, over 1,570 GW of generation and an estimated 1,030 GW of storage capacity remain in the transmission interconnection queue nationally. National average interconnection timelines have increased from less than two years before 2007 to over four years for projects built after 2018.[6]

To meet the required needs, significant investments in distribution and transmission infrastructure are needed. According to ISO-NE, total investment needed to meet a winter high peak scenario of 57 GW will total between

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1 *See* ISO-NE, *Forecast Report of Capacity, Energy, Loads, and Transmission* (2025) *available at* https://isonewswire.com/2025/05/19/iso-ne-innovations-push-electricity-forecast-further-into-the-future/, last accessed August 29, 2025. (ISO-NE projects that New England will transition from a summer peak system, i.e., when highest electricity demand occurs in the summer, to a winter peak system by the mid-2030s).

2 DOE, *National Transmission Planning Study* (2024) at 2, *available at* www.energy.gov/gdo/national-transmission-planning-study.

3 NGA, *Advanced Grid Technologies: Governor Leadership to Spur Innovation and Adoption* (2025) at 5, *available at* www.nga.org/publications/advanced-grid-technologies-governor-leadership-to-spur-innovation-and-adoption/.

4 ISO-NE, *Resource Mix* (2025), *available at* www.iso-ne.com/about/key-stats/resource-mix, last accessed July 14, 2025.

5 ISO-NE, *FERC Accepts ISO-NE's Interconnection Process Changes* (April 2025), *available at* https://isonewswire.com/2025/04/09/ferc-accepts-iso-nes-interconnection-process-changes/, last accessed July 14, 2025.

6 LBNL, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection* (April 2024), *available at* https://emp.lbl.gov/publications/queued-2024-edition-characteristics.

$23-26 billion by 2050.[7] Such substantial investments would likely lead to significant increases in Massachusetts electricity bills. As of July 1, 2025, weighted average transmission costs comprise approximately 15.4 percent of a typical Massachusetts customer's electricity bill.[8] To maintain affordable rates while ensuring reliability and connecting clean energy resources, new cost-effective solutions to improve the transmission system are needed.

Recognizing the need for cost-effective solutions to meet growing electricity transmission needs, section 121 of the 2024 Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers, St. 2024, c. 239 ("2024 Climate Act" or "Act"), directed the Department of Public Utilities ("Department" or "DPU"), in coordination with the Department of Energy Resources ("DOER"), to conduct an independent investigation that examines the use of emerging grid solutions. Specifically, the Act calls for a review of advanced conductors, grid-enhancing technologies ("GETs"), and other advanced transmission technologies that can enhance the performance of the Commonwealth's transmission and distribution systems. The objective of the investigation is to review current industry trends and the potential costs and benefits of these technologies to determine whether and how they can improve Massachusetts electric transmission and distribution infrastructure. The Act also requires the DPU to identify jurisdictional and cost-sharing issues involved in requiring a transmission and distribution utility to implement such advanced transmission technologies.

On June 2, 2025, DPU opened an "Investigation into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction," docketed as D.P.U. 25-69. As part of the investigation, the Department cooperated with DOER and the Massachusetts Clean Energy Center ("MassCEC") to convene a stakeholder session on June 23, 2025, to discuss the key issues related to these technologies. MassCEC prepared a summary memorandum of the session, which is included in the appendix. The Department also requested written feedback from Massachusetts electric distribution ("EDC") and transmission companies and technology providers to further inform the investigation. Seventeen respondents, including the three Massachusetts EDCs,[9] have submitted written feedback, which is also included in the appendix.

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7 Clean Energy Transmission Working Group, *Report to the Legislature* (December 2023) at 16, *available at* www.mass.gov/doc/clean-energy-transmission-working-group-final-report/download.

8 DPU records based on Company filing.

9 The Massachusetts EDCs are Eversource, National Grid, and Unitil.

This report refers to all the grid technologies and applications identified in the legislation as "advanced transmission solutions."[10,11] Advanced transmission solutions include GETs and other solutions that can expand transmission capacity within the footprint of the existing grid, i.e., without building new electric transmission or distribution facilities. The report reviews the following advanced transmission solutions:

- Dynamic line ratings ("DLR");
- Advanced Power Flow Control ("APFC");
- Topology optimization;
- Advanced reconductoring; and
- Storage as a transmission asset ("SATA").

The report is organized as follows:

- Section 1 describes the current state of all relevant advanced transmission solutions, including the shared potential benefits and limitations;
- Sections 2-6 provide a focused analysis of each advanced transmission solution. Each section begins with an overview of the technology, followed by a review of industry trends, known benefits, cost-effectiveness considerations, and key limitations;
- Section 7 summarizes key findings of the report and offers a review of the next steps; and
- Appendix 1 includes MassCEC's summary memorandum of the stakeholder session and a copy of the presentation delivered during the session. Appendix 2 provides written responses received from stakeholders.

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10 This report uses the term "advanced transmission solutions" in line with industry practice (sometimes also referred to as advanced transmission technologies or "ATTs") and a common understanding that these solutions are currently deployed mostly on the transmission grid. DOE uses the same terminology in its 2024 report Pathways to Commercial Liftoff: Innovative Grid Deployment. However, as further identified in this report, these technologies may similarly apply to the distribution grid. The term also encompasses all grid-enhancing technologies (DLR, APFC, and topology optimization) as well as advanced reconductoring and storage as a transmission asset.

11 A common list of the technologies defined as advanced transmission solutions (or technologies) does not exist, which was an issue raised during the stakeholder session. Participants suggested that technologies such as clean-air breakers, DERs, or energy storage should be identified as GETs. They also suggested that technologies that can detect abnormalities in transmission lines should be included. FERC has not used consistent terminology from order to order, reflecting the evolving understanding and maturity of these technologies. Similarly, the Working for Advanced Transmission Technologies ("WATT") Coalition and Advancing Modern Powerlines ("AMP") Coalition, both industry groups, define high performance conductors as those with carbon or composite cores or superconducting capabilities, whereas the DOE considers any conductor that can increase line capacity by more than 50 percent and uses composite core a superconductor. The lack of a common definitions can be a barrier, but it also reflects rapid technological progress in the fields of transmission technologies and materials science.

1. CURRENT STATE OF ADVANCED TRANSMISSION SOLUTIONS

Overview

Increasing electricity demand from manufacturing, data centers, and the electrification of transportation and buildings, along with federal and state energy policy and regulatory objectives, are driving the need to invest in the U.S. transmission and distribution systems. Transmission plays a key role in integrating electricity generation sources across large geographies and time zones.

In Massachusetts, transmission will enable an increasing share of renewable energy resources in the state's electricity mix. For example, the New England Clean Energy Connect ("NECEC") transmission line, slated to be fully operational in 2026, will bring 1,200 megawatts ("MW") of renewable, non-emitting Canadian hydroelectricity into New England. In addition, on March 31, 2025, ISO-NE published a request for proposals ("RFP") to procure additional transmission capacity to bring wind resources from Northern Maine to high-load centers in southern New England, including in Massachusetts.[12] The RFP includes an in-service target date of December 31, 2035. More recently, ISO-NE and the New England states issued a new 2025 Longer-Term Transmission Planning ("LTTP") RFP, which aims to address long-term transmission needs and integrate new renewable resources.[13]

Adding new transmission facilities to the grid presents several challenges, including complex planning, siting, and cost-allocation processes. Construction of new transmission lines can take between ten and 15 years to complete and often face local opposition. Advanced transmission solutions may offer an option to bridge near-term- and long-term needs by expanding capacity without the need for new lines. If deployed rapidly, these solutions can help the U.S. meet its ten-year peak demand needs.[14]

The remainder of this section discusses issues related to jurisdictional authority, followed by current policy and industry trends, cost effectiveness, benefits, and challenges associated with advanced transmission solutions.

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12 Press Release, *DPU Approves Settlement for New England Clean Energy Connect* (January 27, 2025), *available at* www.mass.gov/news/dpu-approves-settlement-for-new-england-clean-energy-connect.

13 Press Release, *Massachusetts and Regional Partners Issue First-in-the-Nation Competitive Transmission Solicitation to Unlock Affordable Electricity in New England* (April 1, 2025), *available at* www.mass.gov/news/massachusetts-and-regional-partners-issue-first-in-the-nation-competitive-transmission-solicitation-to-unlock-affordable-electricity-in-new-england.

14 Massachusetts Executive Office of Energy & Environmental Affairs, *Pop-Up Forum on Grid-Enhancing Technologies* (July 24, 2023), *recording available at* www.mass.gov/info-details/pop-up-forum-on-grid-enhancing-technologies.

Jurisdiction

The federal and state governments share authority over interstate electricity transmission lines. Pursuant to the Federal Power Act of 1935, the federal government has jurisdiction over the interstate sale and transmission of electricity while state governments maintain jurisdiction over transmission siting and construction.[15]

The Federal Energy Regulatory Commission ("FERC"), an independent agency housed within the DOE, exercises federal authority over interstate sales and transmission of electricity. FERC plays a pivotal role in regulating interstate transmission as it is responsible for approving transmission rates and regional planning processes, including the adoption of advanced transmission solutions. FERC-approved transmission charges flow through to customers via the retail transmission charge on customer distribution utility electric bills.[16]

State governments regulate electric distribution via state public utility commissions ("PUCs") or public service commissions ("PSCs"), state energy offices, and siting authorities. In Massachusetts, these authorities include DPU, DOER, and the Energy Facilities Siting Board ("EFSB"). DPU Siting Division staff serve as staff to the EFSB and the DPU Commission on siting matters. EFSB is an independent board that has jurisdiction over large energy facilities, including high voltage electric transmission lines.[17] EFSB approval is required prior to the commencement of construction of any EFSB-jurisdictional facility in the Commonwealth, and no state agency may issue a construction permit for any facility unless EFSB has approved the petition to construct the facility.[18]

Current Policy Trends

Federal and state governments have taken an increasingly active role in facilitating the adoption of advanced transmission solutions. Key FERC initiatives and orders will lead to the inclusion of advanced technologies in transmission planning and potentially require DLR adoption by all regional transmission organizations. Many states are promoting advanced transmission solutions through mandates, incentives, and performance criteria.

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[15] 16 U.S.C. §§ 791 *et seq*.; 16 U.S.C. § 824(b)(1) ("[Part II of the Federal Power Act] shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but … shall not apply to any other sale of electric energy.").

[16] FERC regulates transmission charges pursuant to the Federal Power Act. 16 USCS § 791a. The 1997 Massachusetts Restructuring Act requires retail electric and gas bills to separately reflect transmission charges. G.L. c. 164, § 1D (added by St. 1997, c. 164, § 193).

17 Section 2016 of the Federal Power Act, grants FERC "backstop" siting authority whereby FERC may issue a permit for the construction or modification of electric transmission facilities in a DOE-designated national interest electric transmission corridor if a state siting authority—(i) has not made a determination on an application seeking approval by the later of—(I) one year after the filing of such application; or (II) 1 year after the designation of the relevant National Interest Electric Transmission Corridor; (ii) has conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion or is not economically feasible; or (iii) has denied an application seeking approval. 16 U.S.C. § 824p(b)(1)(C) (2021).

[18] G.L. c. 164, §§ 69H to 69Q; and §§ 69S to 69W. The EFSB's jurisdiction over energy infrastructure was expanded in 2024 with many of the changes going into effect on March 1, 2026, and applying to projects filed on or after July 1, 2026. *See generally*, St. 2024, c. 239.

Federal policy

FERC has considered advanced transmission solutions across several proceedings in the last five years. The most notable orders include:

- **FERC Order 881** (2021) requires transmission owners to implement ambient-adjusted ratings ("AAR") and requires market operators to establish and implement systems and procedures necessary to allow transmission owners to implement DLR;[19,20]
- **FERC Advance Notice of Proposed Rulemaking** (2024) may expand and build on Order 881 by requiring transmission providers to consider real-time variables, which would necessitate the implementation of DLR.[21] The proposed rulemaking introduces congestion-based metrics to identify candidate lines for the deployment of DLR;[22]
- **FERC Order 2023** (2023) requires transmission owners ("TO") to incorporate specific alternative transmission technologies into their interconnection study processes.[23] Notably, Order 2023 excludes DLR, partly because it depends on variable conditions;[24] and
- **FERC Order 1920** (2024) requires transmission providers, *e.g.*, ISO-NE, to consider DLR, APFC, advanced conductors, and transmission optimization as part of their potential solutions for long-term transmission system planning.[25,26]

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19 *See* AES, *Smarter Use of the Dynamic Grid* (April 2024) at 14, *available at* https://www.aes.com/sites/aes.com/files/2024-04/Smarter-Use-of-the-Dynamic-Grid-Whitepaper.pdf (The required systems and procedures include items such as monitoring equipment, software, and hardware to submit and host line data.).

20 Order No. 881, *Managing Transmission Line Ratings*, 177 FERC ¶ 61,179 (2021).

21 *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (June 27, 2024).

22 *Id*.

23 Order 2023 excluded DLR from the list. but a separate Notice of Inquiry (NOI) specific to DLR issued in 2022 could introduce further reform. FERC also issued a Notice of Proposed Rulemaking in 2022, proposing to require public utility transmission providers to include consideration of DLR and APFCs in transmission planning, which FERC recognizes may offer a more efficient or cost-effective alternative.

24 ESIG, Utility Perspectives on Making Grid-Enhancing Technologies Work (July 2025) at 10, *available at* www.esig.energy/wp-content/uploads/2025/07/ESIG-Grid-Enhancing-Technologies-report-2025.pdf.

25 Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 (June 11, 2024).

26 Brattle Group, *Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920* (April 2025), *available at* www.brattle.com/wp-content/uploads/2025/04/Incorporating-GETs-and-HPCs-into-Transmission-Planning-Under-FERC-Order-1920.pdf.

FERC may consider other policies in the future. For example, FERC held a technical conference considering a shared savings incentive for transmission technologies.[27]

Lawmakers in Congress have also proposed several bills, including:

- **The Clean Electricity and Transmission Act (CETA)** would require transmission providers to consider deploying grid-enhancing assets, broadly defined as technologies that can increase capacity, efficiency, and reliability and defer investment in transmission facilities. The bill would also enable interconnecting customers to request consideration of grid-enhancing assets.
- **Building Integrated Grids with Inter-Regional Energy Supply Act (BIG WIRES Act)** would require each interregional transmission planning region to incorporate GETs, energy efficiency, and demand response into its determination of interregional transfer capability.
- **Advancing Grid-Enhancing Technologies Act (Advancing GETs Act)** would require FERC to establish a shared savings mechanism to incentivize GETs deployment by returning some of the savings attributable to investments in grid-enhancing technologies to developers.

State policy

In the context of the distribution system, the Massachusetts DPU established a new cost allocation framework to approve and finance distributed generation ("DG") related infrastructure upgrades, called the Capital Investment Projects ("CIPs"). The DPU observed that where the interconnection of DG facilities triggered the need for upgrades of the electric power system, the significantly higher than historical interconnection costs associated with those upgrades routinely prevented projects in the interconnection queue from moving forward. Through the CIPs, the DPU adopted a cost allocation design whereby ratepayers will help fund the initial construction of these infrastructure upgrades, but will be partially reimbursed over time from fees charged to DG facilities that are able to interconnect due to the upgrades. In consideration thereof, the Massachusetts DPU recognized the potential benefits of advanced technologies and service offerings when considering infrastructure upgrades.[28]

Recent legislation also recognizes these benefits. In 2024, the Governor signed into law a requirement for cost-effectiveness and timetable analysis of GETs, among other strategies. Now, when proposing capital improvements or additions to the distribution system in base rate and other proceedings, the law: (1) directs

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27 FERC Docket Nos. RM20-10-000, AD19-19-000, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act* (The "Workshop to Discuss Certain Performance-based Ratemaking Approaches" was held on September 10, 2021 and is available at www.ferc.gov/news-events/events/workshop-discuss-certain-performance-based-ratemaking-approaches-09102021. This link includes the agenda and transcript, among other materials).

28 *See e.g., NSTAR Elec. Co. Capital Investment Project Proposal Petitions*, D.P.U. 22-52/22-53/22-54/22-55, at 146-150 (2024) (encouraging the EDC to consider advanced technologies where possible and to leverage its existing grid modernization and future electric sector modernization plan to coordinate the deployment of interconnection-related investments and to maximize the benefits of each). In other dockets before the DPU, stakeholders have proposed distribution investments similar GETs, for example DERMS. DPU, *Grid Modernization and AMI Resources*, www.mass.gov/info-details/grid-modernization-and-ami-resources#electric-sector-modernization-plans (last accessed August 14, 2025).

each EDC to conduct a cost-effectiveness and timetable analysis of multiple strategies, including the deployment of advanced transmission technologies, advanced conductors, grid-enhancing technologies, or energy storage used as a distribution or transmission resource; and (2) permits each company to propose a performance incentive mechanism recovered from ratepayers to provide a financial incentive for the company's cost-effective deployment of these investments.[29]

Current Industry Trends

Advanced transmission solutions are now commercially available but remain underutilized. Nationally, utilities have not adopted transmission grid-enhancing technologies including DLR, APFC, and topology optimization at scale.[30] Advanced conductors remain a niche choice for select reconductoring projects for challenging locations where traditional steel core conductors cannot meet the sag clearance allowances. Most storage solutions remain used as a generation asset rather than a transmission asset.[31] In Massachusetts, both National Grid and Eversource have deployed GETs, advanced conductors, and batteries on a limited scale. According to the DOE, six to twelve large operational, no regrets deployments across the nation for each technology can tip the scales. [32]

Globally, deployment and investment in advanced transmission solutions is greater than in the United States. In countries such as Belgium, the Netherlands, Italy, India, and China, large-scale advanced reconductoring projects have been deployed quickly expand transmission capacity.[33] China, in particular, has now deployed over 370 miles of advanced conductors.[34] European transmission operators have used GETs since the late 2000s and now have multiple scaled deployments. For example, Belgium's transmission operator, Elia, has over 30 active DLR deployments. Transmission operator in the United Kingdom, National Grid, has deployed 48 advanced power flow control devices across its grid, unlocking 1.5 GW of electric capacity and saving an estimated $500 million over seven years.[35]

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29 G.L. c. 164, § 150 (added by St. 2024, c. 239, § 82). S*ee also*, St. 2024, c. 239, § 60; G.L. c. 164, § 69H (EFSB, in its review of linear projects, must make a determination that "in the case of large clean transmission and distribution infrastructure facilities, small clean transmission and distribution infrastructure facilities and natural gas pipelines, due consideration has been given to advanced conductors, advanced transmission technologies, grid enhancement technologies, non-wires or non-pipeline alternatives, the repair or retirement of pipelines and other alternatives in an effort to avoid or minimize expenditures".)

30 DOE, *Pathways to Commercial Liftoff: Innovative Grid Deployment* (April 2024) at 34, available at www.energy.gov/sites/default/files/2025-07/LIFTOFF_DOE_Innovative-Grid-Deployment.pdf.

31 *Id*.

32 *Id*. at 5.

33 MIT, *A Roadmap for Advanced Transmission Technology Adoption* (September 2024) at 5, *available at* https://ceepr.mit.edu/wp-content/uploads/2024/09/MIT-CEEPR-RC-2024-06.pdf 5.

34 DOE, *supra* note 30.

35 MIT, *supra* note 33.

Cost-Effectiveness

Advanced grid solutions generally are more cost-effective than traditional transmission system upgrades. Nationally, deploying these solutions could help defer between five and 35 billion dollars in transmission and distribution infrastructure costs over the next 5 years.[36] Available evidence supports this estimate. In reviewing 28 projects from around the world for a 2022 report, the Idaho National Laboratory assessed that net savings far exceed the costs of GETs.[37] For example, a DOE study showed that DLR and APFC applications in New York cost less than 25 percent of traditional upgrades. In Pennsylvania, a DLR solution deployed on two transmission lines cost less than $1 million compared to a traditional upgrade estimated to cost between $13-68 million.[38] A study in Illinois, Indiana, Ohio, Pennsylvania, and Virginia estimated that adoption of three ATTs would cost about $100 million and yield about $1 billion in annual production cost savings.[39]

High costs associated with initial advanced technology deployments can pose barriers to the wider use of such technologies. Advanced technologies may require investment in additional foundational infrastructure and/or capacity. In other instances, the technologies simply cost more upfront. This can include expenses for specialized equipment, custom software development, integration with existing legacy systems, extensive testing and validation, and the high cost of initial pilot projects due to a lack of economies of scale. However, investments in advanced technologies often reduce the costs of future deployments and lead to long-term savings and efficiencies.

Cost-effective solutions are especially important given the transmission capacity needed to support future electrification. For example, in a high-winter-peak scenario, ISO-NE estimates that New England will need to invest $23-26 billion in transmission infrastructure in order to meet a 57 GW winter peak by 2050.[40] New England ratepayers already are subject to the highest transmission costs in the United States.[41] Between 2011 and 2020, annual average spending on transmission in New England reached $5.90 per every MW hour ("MWh") of annual load. In contrast, Floridians spent $0.17 per every MWh of annual load over the same period, the lowest in the country.[42] Advanced transmission solutions could help minimize the investment needed to add transmission capacity and thus help maintain affordability.

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36 DOE, *supra* note 30, at 25.

37 INL, *A Guide to Case Studies for Grid Enhancing Technologies* (October 2022), *available at* https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

38 DOE, *supra* note 30, at 20.

39 MIT, *supra* note 33.

40 ISO-NE, *2050 Transmission Study* (February 2024), *available at* www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

41 DOE, *National Transmission Needs Study* (October 2023), *available at* https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

42 *Id*.

Benefits

Advanced transmission solutions have three distinct advantages over traditional, wires-based solutions:

- **Lower cost and faster to install**. GETs can cost orders of magnitude less than traditional, wires-based solutions, with some deployments paying back in less than a year. Installing GETs takes between six months and two years, sometimes less, and in some instances (topology control, DLR) can be implemented without outages. Advanced conductors are often cheaper on a per unit cost basis (*e.g.*, dollar per MVA of transfer capacity). When used to reconductor along existing rights-of-way, advanced conductors can take nearly half the amount of time needed to reconductor compared to deploying conventional conductors. Building new lines with advanced conductors requires smaller rights-of-way and fewer towers.[43]
- **Complementary to existing equipment**. Unlike construction or refurbishment of major transmission lines, advanced transmission solutions can integrate into the existing grid without the need for extensive replacements or new rights-of-way. Because advanced transmission solutions complement existing facilities, transmission owners can enhance capacity, flexibility, and reliability of their systems at lower cost. These solutions can help maximize the value of existing assets while also offering a scalable and affordable option to expand capacity.[44] Advanced transmission solutions could support 20-100GW of incremental peak demand across the existing U.S. grid if installed individually and potentially more if installed in strategic combinations.[45]
- **Portable and reversible**. A subset of advanced transmission solutions (*e.g.*, DLR and APFCs) have a distinct advantage in that they are portable, and their installation is reversible. Thus, if installation at a specific location does not provide the expected benefits, the technology can be moved elsewhere. Topology optimization is entirely software-based and therefore does not require hardware installation. This reduces the investment risk and further enhances cost-effectiveness. Further, given the increasing need to expand transmission capacity quickly, portability can help ensure any changes to expected planning outcomes can be adjusted at a relatively low cost.[46]

Challenges

Advanced transmission solutions offer clear operational and economic benefits, but their deployment has been limited. In reviewing traditional planning processes, Brattle Group, a consultancy, has identified four key barriers to adoption, including:

- Lack of recognition;

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43 Brattle Group, *supra* note 26, at 14-15.

44 *Id*. at 15-16.

45 DOE, *supra* note 30, at 3.

46 Brattle Group, *supra* note 26, at 16-17.

- Misaligned incentives;
- Legacy planning; and
- Execution limitations.

Lack of recognition

Technology providers aver that transmission owners have not yet recognized and embraced advanced transmission solutions. They argue that transmission owners are typically more conservative in embracing new technologies, preferring certainty and reliability over something untested or unknown. Further, even if transmission solutions are recognized, transmission owners and regional transmission organizations might see these technologies as operational tools rather than key elements to consider in transmission planning.[47] For example, the Southwest Power Pool's ("SPP's") current transmission planning tariff does not recognize some technologies as potential solutions in transmission planning. Technologies like DLR are seen as less predictable because they do not provide the same firm capacity rating or could lead to an overly optimistic rating.[48]

Although industry reports and developers cite lack of recognition as a barrier, in Massachusetts this challenge is not as prominent. The state's two largest transmission owners, Eversource and National Grid, have recognized the benefits of advanced transmission solutions and have deployed several projects throughout Massachusetts and their other service areas. Both transmission owners report that the evaluation of grid-enhancing technologies is a standard step in federally regulated transmission planning process.[49] ISO-NE is also in the process of developing recommendations and issuing guidance on the application of GETs in the planning process. ISO-NE plans to issue a transmission planning technical guide addressing GETS by the end of 2025.[50]

Misaligned incentives

Misaligned incentives also deter the adoption of GETS. During DPU's stakeholder session, lack of incentives was among the first challenges mentioned.[51] Further, the conservative industry culture would tend towards penalizing failures rather than rewarding a successfully implemented innovative solution.[52] This leaves little incentive for utilities to take on the risk of adopting new technologies or solutions.

Although less costly than traditional upgrades, advanced transmission solutions can also have high initial investment needs. TOs may choose to avoid new technologies if they have to bear the initial costs associated with operationalizing them. For example, if the expenses related to preparing operations for reliable

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47 *Id*. at 32-33.

48 *Id*.

49 See Appendix 2.

50 ISO-NE, *Overview of Grid Enhancing Technologies: ISO New England Perspective* (June 2025), at Slide 14, *available* at https://www.iso-ne.com/static-assets/documents/100024/2025_06_18_gets_iso_presentation.pdf.

51 See Appendix 1. Page 5.

52 Brattle Group, *supra* note 26, at 32-33.

deployment of advanced transmission technologies do not qualify for cost recovery as capital expenses, the TOs would have to absorb these expenses. Such costs could be considerable from the TOs' perspective, including the time spent on training staff to understand the new technologies and how to incorporate them into existing operations and models to benefit ratepayers, as well as the need to design new cost recovery methodologies acceptable to regulators.

Legacy planning

Existing planning methodology does not fully capture the benefits of advanced transmission solutions, which make them less favorable in cost-benefit analyses. Legacy grid planning is based on static and deterministic methods over specified target years, which is not well suited to adequately assess dynamic conditions on the grid. For example, static methodology does not capture short-term issues like renewable energy fluctuations or the impact of growing electric vehicle adoption and DERs. As a result, it undervalues more cost-effective and scalable solutions in favor of long-term upgrades such as large transmission lines or substations.[53]

Execution limitations

Transmission providers face challenges in the deployment of advanced transmission solutions. From an operational perspective, adding advanced transmission technologies means departing from established practices and may increase the risk of unintended consequences. Some advanced transmission solutions can introduce system conditions that fall outside the scope of traditional contingency and stability assessments, which could create unexpected interactions and challenge system reliability. Operators already know how existing technologies operate, how to model them, how they interface with other assets, how to procure them, and their likelihood of recovering these costs in regulatory proceedings. Such familiarity supports predictable planning and stable operations, while new technologies introduce new uncertainties. Further, should anything go wrong, TOs risk incurring financial penalties for not meeting the required reliability and security standards.[54]

2. DYNAMIC LINE RATINGS

Overview

According to the DOE, DLR comprise several technologies and methodologies for determining conductor thermal ratings based on improved, more granular, or real-time data. DLR uses sensing devices and algorithms to calculate the amount of capacity a transmission line can safely carry (the "ampacity" of the line), which informs dispatch decisions.[55] A typical DLR system includes sensors on or near lines, communication gateways that relay information between the sensors and grid operators, analytical systems to process DLR data, and supervisory and control data acquisition ("SCADA") systems that enable operators to make final decisions.

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53 *Id*. at 32-34.

54 AES, *supra* note 19, at 16.

55 Clean Energy Transmission Working Group, *supra* note 7, at 37.

Figure 1 below depicts a typical DLR system.

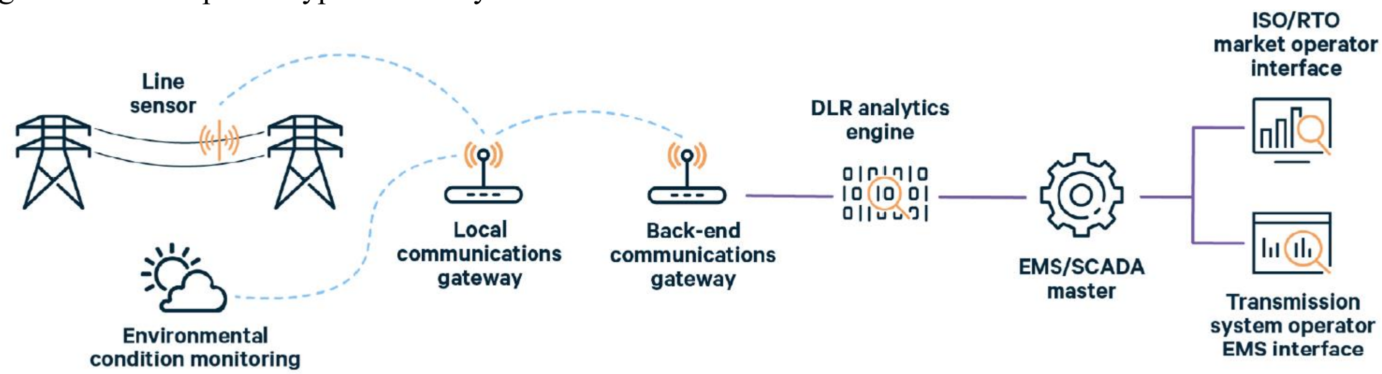

Figure 1 — Conceptual DLR system (Source: DOE)[56]

Traditionally, grid operators have relied on static line ratings ("SLRs") to measure the maximum ampacity.[57] SLRs are based on conservative assumptions about the transmission line operating environment, such as static weather conditions, average wind speeds and direction, average ambient temperatures, and solar conditions for summer and winter seasons.[58] This results in a theoretical, rather than actual or real-time, thermal rating based on expected environmental conditions. SLRs often vary by season, referred to as "seasonal static ratings."[59]

While DLRs use the same methods as SLR, DLRs incorporate a more-sophisticated time varying component, which provides a more accurate estimate of varying thermal limits.[60] Collectively, DLR technologies include dynamic thermal line ratings, AARs, real-time thermal ratings, forecasted dynamic line ratings, or analysis of existing lines with previously gathered data. DLR systems can be weather-based or asset-based, measuring environmental or conductor conditions, respectively.[61]

AARs, which are widely used across the United States, use line-specific data and ambient air temperature data to determine conductor thermal ratings. Although technically a subset of DLRs, AARs are less dynamic than

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56 DOE, *Advanced Transmission Technologies* (December 2020), *available at* www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf.

57 INL, *Dynamic Line Rating*, https://inl.gov/national-security/dynamic-line-rating/, (last visited July 3, 2025).

58 DOE, *Dynamic Line Rating: Report to Congress* (June 2019) at 11, *available at* www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf.

59 IRENA, *Innovation landscape brief: Energy as a Service, International Renewable Energy Agency* (2020) at 6*, available at* www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Energy-as-a-Service_2020.pdf.

60 DOE, *supra* note 58, at 4.

61 *Id*.

DLR because they do not monitor changes in real time. However, AARs are more dynamic than the traditional SLR. Figure 2 below shows how line ratings vary over time depending on the type of line rating used.

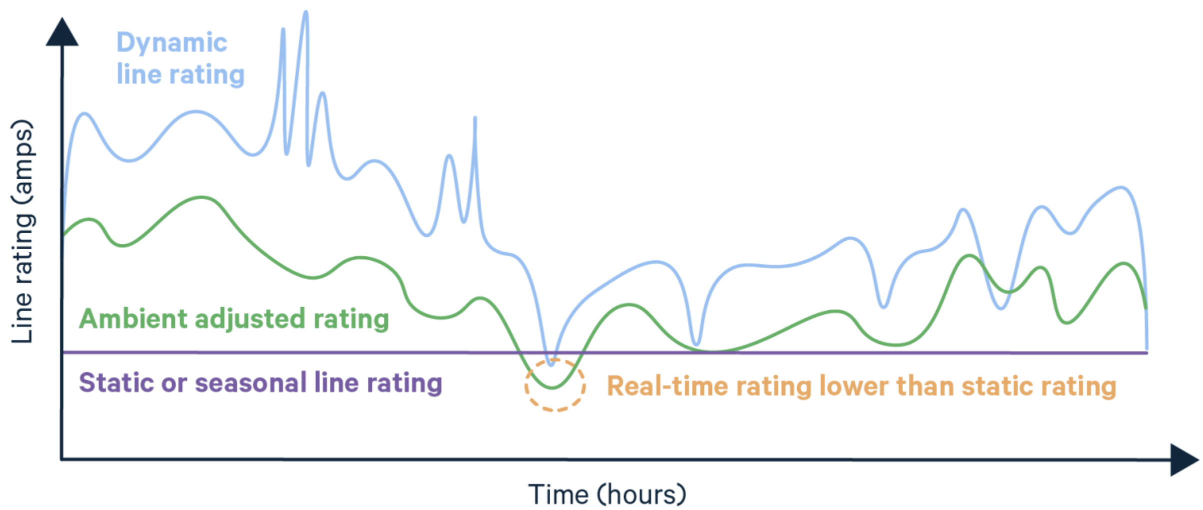

Figure 2—Line Rating Comparison (SLR, AAR, DLR) (Source: RFF)[62]

In principle, DLR systems allow grid operators to optimize line use. DLRs enable operators to relax line rating restrictions when conditions permit, therefore allowing operators to safely increase transfer capability of the individual line and, as a result, reduce congestion or help avoid curtailment. A joint study by DOE and Oncor found that DLRs can increase transfer capability by five to 25 percent, relative to SLR.[63] In addition, DLR devices can typically be installed faster and at a lower cost relative to reconductoring and rebuilding lines, which can take several years and require extended line outages. DLR technologies also protect the equipment from safety hazards by increasing situational awareness.[64]

Despite their benefits, DLR systems are not without limitations. According to a recent report by the Resources for the Future ("RFF"), DLR is likely most effective in cooler environments where it adds the most transfer capacity. Therefore, DLR is best suited to environments with plentiful wind or congestion during winter peaks

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62 RFF, *Expanding the Possibilities: When and Where Can Grid-Enhancing Technologies, Distributed Energy Resources, and Microgrids Support the Grid of the Future?* (September 2023) at 3, *available at* https://media.rff.org/documents/Report_23-13.pdf.

63 Brattle Group, *Unlocking the Queue with Grid-Enhancing Technologies* (January 2021), *available at* www.brattle.com/wp-content/uploads/2021/06/21200_unlocking_the_queue_with_grid_enhancing_technologies.pdf.

64 RFF, *supra* note 62, at 4.

rather than environments with high solar generation in high temperature conditions.[65] DLR technology is also subject to data and modelling errors.

The following sub-sections describe current industry trends, benefits, and limitations of DLR in more detail.

Current Industry Trends

DLR systems are reaching commercial maturity. The European Network of Transmission System Operators for Electricity ("ENTSO-E") has assigned DLR an eight-out-of-nine on its technology readiness level scale, indicating that operators have successfully deployed DLR across the European grid and validated its performance.[66] ENTSO-E also considers DLR as part of its ten-year network development plan, indicating possible future expansion.[67] LineVision, a Massachusetts based DLR provider,[68] states that its sensors have reached technology readiness level 9 with deployments over 500 sites across four continents, including projects with seven-of-the-ten largest utilities in the United States.[69] Broadly, the market supply of DLR systems is increasingly competitive. As of 2025, several companies around the world specialize in providing DLR systems, including LineVision,[70] Smart Wires,[71] Heimdall Power,[72] Ampacimon,[73] Sumitomo Electric,[74] and others.

DLRs have gained traction with transmission system operators worldwide, but Europe has emerged as an early adopter. In Europe, transmission organizations began piloting DLR in the late 2000s. Belgium has over 30

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65 *Id*. at 5.

66 ENTSO-E, *Technopedia. Dynamic Line Rating (DLR)* (March 2025), *available at* https://www.entsoe.eu/technopedia/techsheets/dynamic-line-rating-dlr/.

67 ENTSO-E, *Implementation Guidelines for TYNDP 2024* (April 2025), *available at* https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/foropinion/CBA_Implementation_Guidelines.pdf.

68 LineVision, *LineVision's Grid-Enhancing Technology*, www.linevisioninc.com/sensors-and-software (last accessed July 14, 2025).

69 See Appendix 2. Line Vision Response. Page 8.

70 *Id*.

71 SmartWires, *Smart Wires Cements Position as Grid Enhancing Technology Leader with New Dynamic Rating Offering* (August 2022), *available at* www.smartwires.com/2022/08/25/smart-wires-cements-position-as-grid-enhancing-technology-leader-with-new-dynamic-rating-offering/.

72 Heimdall Power, *What is Dynamic Line Rating?*, https://heimdallpower.com/dynamic-line-rating/ (last accessed July 14, 2025)

73 Ampacimon, *Dynamic Line Rating*, www.ampacimon.com/dynamic-line-rating (last accessed July 14, 2025).

74 Sumitomo, *Dynamic Line Rating System*,: https://sumitomoelectric.com/products/high-voltage-cable/dynamic-line-rating-system, (last accessed July 14, 2025).

active DLR deployments, while across Belgium and France, DLR has been deployed across 27 lines including all high voltage alternating current interconnection lines.[75, 76] As of 2017, Spain uses DLR sensors on existing 220 kV transmission lines.[77] Slovenia has deployed DLR systems across 27 high-voltage lines since 2013.[78]

While DLR deployment is not as prominent in the United States, there are several pilot programs underway. In Massachusetts, National Grid and Eversource are testing DLR technology on their respective systems. National Grid has proposed installing DLR on transmission lines that would help integrate offshore wind into Massachusetts. Across the region, National Grid has integrated DLR on two 115 kV lines in Rhode Island and four 115 kV lines in Western New York. The Company found that DLR can increase capacity for some transmission line segments by ten to 20 percent, especially valuable on higher voltage lines.[79] With funding from DOE, Eversource has partnered with the University of Connecticut ("UConn") to install DLR sensors strategic points on the 20.26-mile, 345 kilovolt transmission line between the town of Carver and the Cape Cod Canal.[80] In March 2024, Great River Energy, a not-for-profit wholesale electric power cooperative based in Minnesota and Wisconsin, and Heimdall Power, a technology provider, announced the largest DLR deployment in the U.S. to date with 52 sensors to be installed and the potential to increase transmission capacity by 42.8 percent.[81]

Through grant funding and support, the Federal government has been active in moving the industry towards more DLR deployment. DOE, through the Grid Deployment Office, is managing a $10.5 billion Grid Resilience and Innovation Partnerships ("GRIP") program aimed at enhancing grid flexibility, including through investment in DLR deployments.[82] In addition to providing funding for the DLR deployment with UConn and Eversource mentioned above, the DOE recently granted Dominion Energy in Virginia $33.7 million to alleviate transmission system congestion using DLR.[83] FERC has taken an active role in modifying the country's regulatory framework to permit, or even require, new line rating methodologies. FERC Orders No. 881 and 881-A require all transmission providers to adopt AAR for evaluating transmission service by July

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75 DOE, *Pathways to Commercial Liftoff: Innovative Grid Deployment* (April 2024) at 34, *available at* Pathways to Commercial Liftoff: Innovative Grid Deployment.

76 ENTSO-E, *supra* note 66.

77 *Id*.

78 *Id*.

79 See Appendix 2. National Grid Response. Page 6.

80 Jaclyn Severance, *UConn Receives Department of Energy Grant Supporting Offshore Wind Grid Integration*, UConn Today, November 20, 2023, *available at* https://today.uconn.edu/2023/11/uconn-receives-department-of-energy-grant-supporting-offshore-wind-grid-integration/.

81 DOE, *supra* note 75, at 36.

82 DOE, *Grid Resilience and Innovation Partnerships (GRIP) Program*, www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program (last accessed July 14, 2025).

83 DOE, *supra* note 75, at 36.

2025. The orders also require organized market operators to provide and maintain systems and procedures that allow transmission owners to implement DLR.[84, 85]

Currently, most organized electricity market operators in the U.S. use static seasonal line ratings. In line with Order 881 most now also accept AAR, including ISO-NE.[86] Four out of seven organized markets can accept DLR. Figure 3 below shows the map of organized markets in the United States and line rating methodologies each uses.

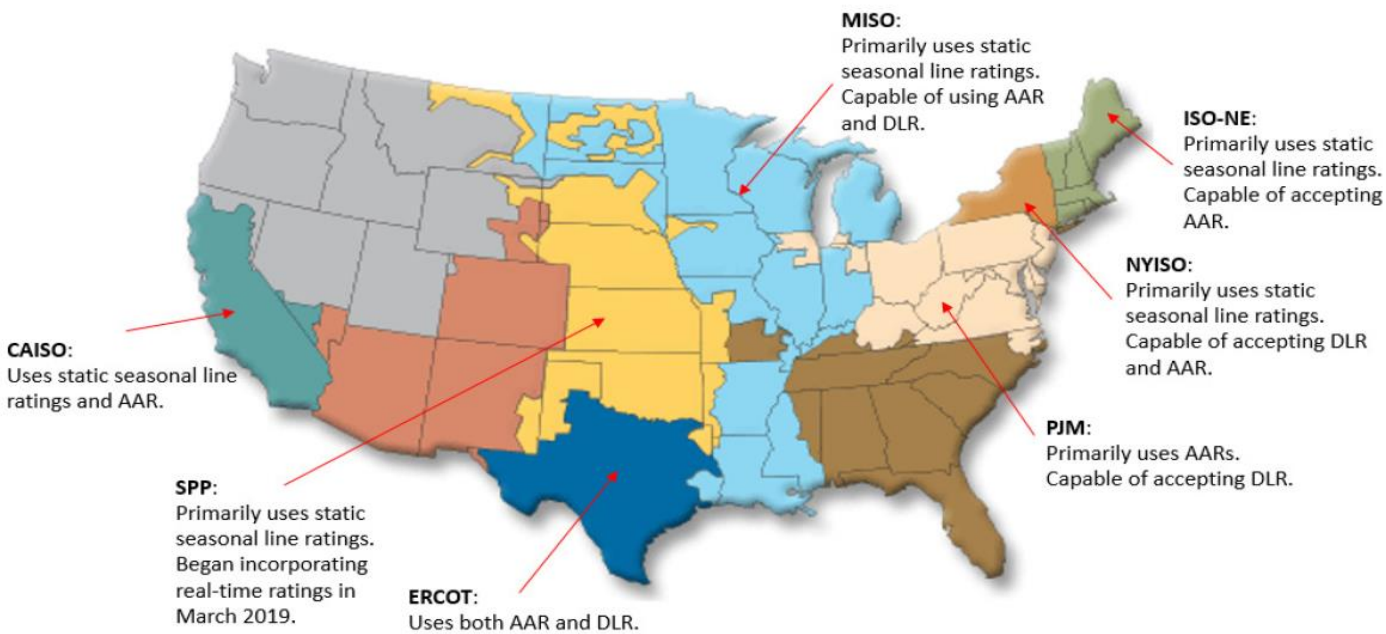

Figure 3—Line Rating Methodologies Across Organized Markets in the U.S. (Source: DOE)[87]

While DLR systems improve the overall economic efficiency of operating the electric power system and benefit end-users of electricity, they may negatively affect certain participants in wholesale markets.[88] For example, peaking and other generation plants that depend on a constrained network to maintain profitability may be disadvantaged if DLR reduces congestion. Notably, ISO-NE is actively engaged in understanding and

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84 FERC may introduce further changes following its June 28, 2024 Advanced Notice of Proposed Rulemaking on Dynamic Line Ratings.

85 Press Release, *FERC Rule to Improve Transmission Line Ratings Will Help Lower Transmission Costs*, December 16, 2021, available at www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs (FERC Docket No. RM20-16, Order No. 881).

86 DOE, *supra* note 56, at 10.

87 *Id*.

88 DOE, *supra* note 58, at 21.

considering the implications of DLR and other advanced transmission solutions for the region.[89] ISO-NE had previously installed DLR as a pilot project in mid-to late-1990s.[90] The technology did not receive widespread adoption as it was still in the early stages of development.

Benefits

The main operational feature of all DLR systems is increased visibility of real-time conditions on the transmission network. With additional visibility, operators can more accurately determine current carrying capacity limits of transmission lines and safely maximize line utilization. Efficient line utilization can, in turn, help increase capacity and defer some of the infrastructure investment that would otherwise be needed to relieve congestion. DLR also allows grid operators to ensure cost-efficient dispatch through more accurate transmission capacity forecasts, which can enable a favorable commitment of generators in day-ahead markets and improved dispatch within real-time markets. With enhanced situational awareness of the transmission system, DLR systems also help grid operators improve reliability and resilience.[91]

Reduced Generator Congestion

DLR helps reduce generator curtailment due to congestion by allowing transmission lines to carry more electricity when real-time conditions allow. Under typical operations and using traditional line rating methodologies, grid operators may be required to take protective actions (*e.g.*, load shedding, generator curtailment) to maintain spare capacity requirements that may result in interruptions and outages. With DLR, operators can calculate true thermal limits of the transmission lines and, under the right circumstances, allow additional headroom, which can in turn help avoid curtailment. According to the DOE, DLR can increase line capacity by ten to 30 percent on average.[92]

When conditions are favorable, DLR can help ensure cost-effective dispatch. Grid operators establish day-ahead and real-time dispatch based on expected transmission constraints and electricity demand. If constraints are expected to be lower due to DLRs, operators can establish a more favorable commitment of generators.[93] For example, when DLR estimates provide for periods of increased capacity, grid operators can commit lower

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89 Press Release, *ISO-NE Forum Will Explore Potential Use Of Grid-Enhancing Technologies*, April 28, 2025, available at https://isonewswire.com/2025/04/28/iso-ne-forum-will-explore-potential-use-of-grid-enhancing-technologies/.

90 ISO-NE, *supra* note 50, at Slide 8.

91 DOE, *supra* note 58, at 5.

92 DOE, *supra* note 75, at 5.

93 DOE, *supra* note 58, at 5.

cost electricity to flow and reduce congestion costs.[94] Similarly, periods of increased transmission capacity can enable more power trade across interconnected markets, resulting in reduced congestion and lower costs.[95]

Access to Lower Cost and Zero Carbon Electricity with Less Curtailment

DLR facilitates integration of renewable generation by reducing curtailment due to avoided grid congestion, most promisingly for wind generation.[96] In areas rich with wind resources, wind simultaneously spins the turbines and cools the nearby transmission lines.[97] During periods of peak wind generation, DLR enables transmission owners to safely increase transmission capacity and help avoid curtailment. For the same reasons, DLR may also lower interconnection costs for wind generators if smaller interconnection facilities are needed.[98] In 2022, National Grid launched a DLR system in western New York near two large wind farms. The project is expected to reduce wind curtailment in the region by 350 MW and increase overall transmission capacity by an average of 190 MW.[99, 100] In Belgium, DLRs have provided daily savings of €500,000 since 2008 amid an expansion in wind generation.[101]

Maximization of the Value of Planned Investments

When deployed under optimal circumstances, DLR offers a faster and more cost-effective solution to expanding transmission capacity than traditional wire upgrades. DLR can help increase effective transmission capacity by an average of ten to 30 percent at less than five percent of the cost of a traditional line capacity expansion.[102] The technology is relatively quick to deploy and can be scaled in fewer than three months after initial implementation.[103] As a result, DLR is particularly well suited to serve as a bridge between future expansion

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94 EPRI, *Dynamic Line Ratings* (June 2024) at 3, available at www.epri.com/research/products/000000003002030550.

95 IRENA, *supra* note 59, at 10.

96 *Id*.

97 *Id*.

98 FERC, *Managing Transmission Line Rating* (August 2019) at 18, *available at* www.ferc.gov/sites/default/files/2020-09/Managing-Transmission-Line-Ratings_Staff-Paper.pdf (FERC Docket No. AD19-15-000).

99 National Grid launched the project in 2022 for two 30-mile 115kV transmission lines in western New York, in partnership LineVision, which provides DLR sensors and software solutions.

100 DOE, *supra* note 75, at 79.

101 Neil Chatterjee, *Grid Technology Could Save Billions But For A Policy Vacuum*, Utility Dive, March 25, 2024, available at www.utilitydive.com/news/grid-technology-could-save-billions-Chatterjee/711068/.

102 DOE, *supra* note 75, at 5.

103 *Id*.

and near-term needs. However, for lines reaching the end of their useful life, it may be more cost-effective to invest in repairs or upgrades rather than in DLR.[104]

Improved Reliability

DLR technology can improve grid reliability by providing real-time data about line conditions. With improved data, operators can respond more accurately to changing conditions, optimize power flow, prevent overloading, and reduce the risk of outages. For example, in some instances DLR can result in lower transmission capacity when a line is above its safe operating limit. When this happens, DLR can inform the grid operator on the need to reduce power flow to prevent failures, which in turn improves safety and reliability.[105]

Improved Resilience

DLR can increase operational visibility of the grid, which improves decision making, especially during extreme conditions. Understanding when conditions may exceed constraints is critical in situations where lines may sag below clearances, making the system vulnerable to faults and safety hazards. DLR offers a way to improve situational awareness by providing a more granular picture of the current weather and asset conditions by location. With better situational awareness, operators in turn have an easier time ensuring the lines are operated safely even under extreme conditions.[106] For example, during the 13-day cold snap between December 25, 2017 and January 8, 2018, a "bomb cyclone" constrained a large portion of the Northeast U.S. grid due to high demand for natural gas for both heating and electricity generation.[107] As a result, the grid operator needed power from other available generation, which was limited due to transmission capacity constraints.[108] In response, ISO-NE increased transmission line ratings, knowing cold conditions allow for additional headroom in line with DLR principle. ISO-NE increased import limits from 1,400 MW to 1,600 MW from New York, which helped avoid blackouts and reduce congestion costs.[109]

Cost-Effectiveness

Existing studies and pilots indicate that DLR is a cost-effective solution, costing a fraction of conventional technologies. A recent DOE study of a DLR application in New York showed that it cost less than 25 percent

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104 FERC, *supra* note 98, at 18.

105 DOE, *supra* note 75, at 15.

106 DOE, *supra* note 58, at 6.

107 ISO-NE, *Cold Weather Operations: December 24, 2017–January 8, 2018* (January 2018), *available at* www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf.

108 NREL, *On the Road to Increased Transmission: Dynamic Line Ratings*, May 16, 2024, *available at* www.nrel.gov/news/detail/program/2024/on-the-road-to-increased-transmission-dynamic-line-ratings.

109 Brattle Group, *Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives* (June 2019) at 26, *available at* www.brattle.com/wp-content/uploads/2021/05/16634_improving_transmission_operating_with_advanced_technologies.pdf.

of traditional upgrades.[110] PPL Electric Utilities in Pennsylvania deployed DLR for less than $1 million on two congested lines for an expected $23 million in reduced congestion costs. Reconductoring or rebuilding the same lines would have cost an estimated $50 million.[111] In Pennsylvania-New Jersey-Maryland Interconnection ("PJM"), an RTO, one study found that deploying a $500,000 DLR system could save $4 million.[112] In an earlier 2017 study, American Electric Power found that a hypothetical DLR deployment on PJM's high-voltage lines would cost approximately $500,000 across three sections. The resulting net congestion savings from improved line management were estimated at $4 million over the same year, or a two-month payback period.[113]

Despite positive early results, successful deployments require favorable conditions to offer the most benefit. The technology is most economically viable in climates with meaningful temperature changes and high wind speeds.[114] Under optimal conditions, DLR can increase transmission capacity by ten to 30 percent upwards of 90 percent of the time.[115] Such results are most achievable on shorter lines that are congested or operate at or near their maximum rated capacity. Additionally, the potential benefits of DLR ascertained in studies have mostly relied on comparisons to SLR. As utilities move towards AAR following FERC Order 881, these previous studies may be outdated.

Costs associated with DLR implementation could erode the potential benefits if not managed carefully. To be effective, the number of devices along the line must be sufficient to enable a reliable and accurate rating for the entire line. Adding additional devices improves accuracy but not without additional cost. Therefore, DLR implementation requires a careful and systematic analysis of the critical segments of the line to be monitored against the potential costs of adding additional devices.[116] Operators must also consider equipment installation costs, as well as maintenance and calibration expenses, which increase overall expenditures.

DLR costs could also extend beyond direct project expenditures. DLR allows operators to utilize their assets at near full capacity, which accelerates aging and reduces thermal headroom. According to stakeholder feedback to the DOE, such use, if not managed carefully, can reduce asset lifespan and accelerate maintenance cycles. Historically, equipment designed for operation for 40 years could last up to 60 years when operated under the design limit. With new DLR schemes, assets could potentially be used at full capacity more frequently, which in turn, could require higher operations and maintenance and capital expenditures.[117]

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[110] DOE, *supra* note 75, at 16.

[111] Ampacimon, *The First U.S. Electric Utility to Integrate Dynamic Line Ratings into Real-Time and Market Operations*, http://www.ampacimon.com/success-stories/the-first-u-s-electric-utility-to-integrate-dynamic-line-ratings-into-real-time-and-market-operations (last accessed July 14, 2025).

[112] DOE, *supra* note 75, at 16.

[113] DOE, *supra* note 58, at 15.

[114] DOE, *supra* note 75, at 24.

[115] *Id*. at 15.

[116] DOE, *supra* note 58, at 14.

[117] *Id*. at 22.

Challenges

Accuracy Limits

DLR technology relies on monitoring equipment that is subject to potential measurement and modeling errors. Measurement errors occur when the direct-measurement sensors send faulty data or malfunction, for example, when communication connectivity is lost. Sensors may send imprecise or inconsistent data due to calibration issues. In some instances of light loading conditions, the sensors themselves have proven less accurate than anticipated.[118] Modeling errors occur when the underlying mathematical rating model provides inaccurate information. This can be caused by incorrect or inaccurate inputs, such as from erroneous weather forecasts or topological circuit and conductor data. Modeling input assumptions may also become outdated as the physical and mathematical properties of the overhead lines change over time through continuous use.[119] Conseil International des Grands Réseaux Électriques ("CIGRE") found that the emissivity of the line changes with age, which affects the impact of solar radiation and its thermal-radiative properties.[120] If not updated regularly, the models may become inaccurate.[121]

Operators have a few solutions available to ensure the reliability and accuracy of DLR systems. One solution to measurement error is to revert back to established line rating methods. For example, if system operators become aware of a malfunction, the operators can switch from DLR to SLR. To avoid modeling errors, system operators could perform robust transmission line characterization before implementing DLR solutions.[122] Another emerging solution is to use confidence intervals in DLR calculations that rate conditions on power lines more conservatively for lower confidence parameters such as weather predictions.[123]

Integration Complexity

Integrating DLR into grid operations requires changes to how control rooms operate, which can introduce new complexities. At a minimum, accommodating DLR systems requires adding a new terminal, a dedicated workstation or screen for the operator in the control room, and providing additional training for employees. Employees must also adapt to the learning curve and begin to trust the accuracy of the new system.[124] To overcome these challenges, grid operators must ensure that real-time information is accurate, and ease learning

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118 *Id*. at 13.

119 *Id*.

120 CIGRE, *Guide for Selection of Weather Parameters for Bare Overhead Conductor Ratings* (2006), *available at* www.scribd.com/document/458777917/CIGRE-Guide-for-Selection-of-Weather-Parameters-for-Bare-Overhead-Conductor-Ratings-pdf.

121 DOE, *supra* note 58, at 13.

122 CIGRE, *supra* note 120.

123 M. A. Bucher & G. Andersson, *Robust Corrective Control Measures in Power Systems With Dynamic Line Rating*, IEEE Transactions on Power Systems, vol. 31, no. 3, pp. 2034-2043, May 2016.

124 DOE, *supra* note 58, at 13.

by ensuring the new system is well integrated into existing operations. INL has suggested replacing the original static line limit information with the new DLR instead of adding a new terminal. This approach would limit the information introduced on display and reduce integration complexity for operators.[125]

DLR Risks

DLR may introduce new technology-specific operating risks that may be difficult to control. For example, if the weather unexpectedly changes after scheduling the transmission line to operate above the thermal limit based on the previous forecast, the decision may impose a safety risk. The line could be at risk of clearance-height violations or could even incur permanent damage due to overheating. This type of risk is new to standard operating procedures and means that additional variables must be incorporated into real-time dispatch operations. Further, if the conductors become overheated or damaged due to incorrect sensor placement, unforeseen conditions, or premature degradation, the net benefit of deploying DLR could erode.[126]

Cybersecurity

DLR deployment can increase the risk of exposure to cyberattacks. DLR relies on wireless communications across a network of monitoring equipment, which can be vulnerable to denial-of-service attacks.[127] According to the INL, compliance with the North American Electric Reliability Corporation's cybersecurity standards is challenging when deploying DLR systems. Operators also lack standard guidance for implementing cybersecurity for DLR.[128]

Technological Maturity

There is no uniform agreement on the technological maturity of DLR. LineVision considers DLR technologically mature, while ENTSO-E considers DLR to be nearing commercial maturity. According to the Electric Power Research Institute ("EPRI"), U.S. researchers continue to study the technological readiness and have not reached a final conclusion.[129] One reason agreement is lacking is because DLR does not currently have a consistent testing methodology to ensure unbiased results. As a result, existing studies may not be reliable. To remedy this and encourage further DLR adoption, EPRI recommends that authors and researchers of previous pilots and deployments share their technical results more widely.[130]

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125 INL, *Variable Transmission Line Ratings* (November 2024), *available at* https://inl.gov/content/uploads/2024/03/POWER_Variable-Ratings.pdf.

126 DOE, *supra* note 58, at 14.

127 *Id*. at 22.

128 INL, *Cybersecurity Considerations for Dynamic Line Rating Deployment* (November 2024), *available at* https://inl.gov/content/uploads/2024/03/Cybersecurity-Considerations-for-Dynamic-Line-Rating-Deployment.pdf.

129 EPRI, *Dynamic Line Ratings* (June 2024), *available at* www.epri.com/research/products/000000003002030550.

130 *Id*.

3. ADVANCED POWER FLOW CONTROL

Overview

Power flow is driven by four key parameters of the power system: (1) the voltage on the sending end of the line; (2) the voltage on the receiving end of the line; (3) the reactance of the line; and (4) the voltage phase angle difference between both ends.[131] APFCs can change power flow direction by adjusting line reactance.[132] APFCs are physical devices typically located at substations that automatically or manually adjust the impedance, or total resistance, of a power pathway.[133] According to the DOE, APFCs are most applicable on meshed networks with multiple transmission ties. The technology is best suited to longer lines ranging between 30 to 45 miles for voltages under 230 kV and 60 miles for voltages between 230-500 kV.[134] Notably, APFCs can be applied not only on the transmission grid but also on the distribution and sub-transmission grids.[135]

One key benefit of APFC is its ability to unlock additional capacity. Normally, power flows along the path of least resistance through the grid, with generation and demand creating a push-and-pull effect. Through this process, some lines may operate below or above their design capacity. For example, in a hypothetical case where three transmission lines share the same maximum design capacity, one might operate at 28 percent of capacity, the second at 40 percent capacity, and the third at 105 percent. With the use of APFCs, however, grid operators can redistribute power across all three lines closer to 98 percent, while also increasing the total transfer capacity, so that each is operating close to its design capacity. The result is a material increase in the amount of power carried by underutilized lines and a slight reduction on the overloaded line. The redistribution also keeps the previously overloaded line in service and maintains the reliability of the transmission system.[136] Figure 4 below, summarizes impacts before and after the introduction of APFC.

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131 DOE, *supra* note 56, at 16.

132 DOE, *supra* note 75, at 13.

133 WATT Coalition, *Unlocking Power: A Playbook on Grid Enhancing Technologies for State and Regional Regulators and Policymakers* (November 2024) at 13, *available at* https://watt-transmission.org/wp-content/uploads/2024/11/Unlocking-Power-What-are-Grid-Enhancing-Technologies.pdf.

134 DOE, *supra* note 75, at 24.

135 EPRI, *Benefits and Value of New Power Flow Controllers* (May 2018) at 1-1, *available at www.epri.com/research/products/000000003002013930*.

136 Clean Energy Transmission Working Group, *supra* note 7, at 38.

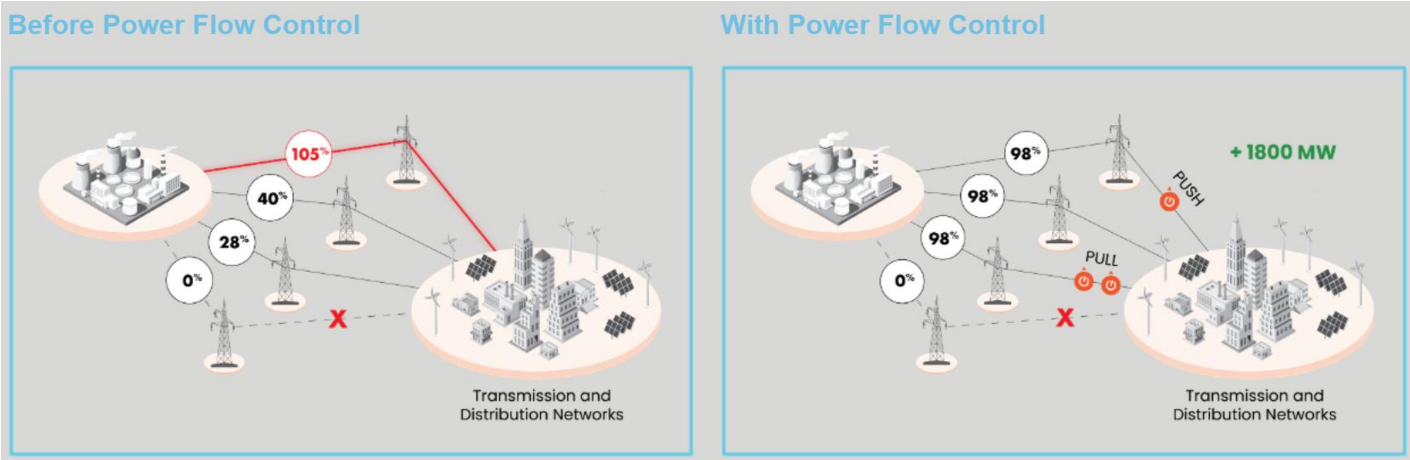

Figure 4—Illustrative Impact of APFC on the Grid (Source: WATT coalition)[137]

Best use cases for APFC are still being developed. In a recent study on implications of using multiple APFCs for system operations and reliability, INL and EPRI have found that while APFC solutions increase the complexity of system operations, they also create opportunities to enhance capacity and reliability of the grid and accommodate renewable energy deployment.[138]

Current Industry Trends

Traditional power flow controller ("PFC") technology has existed in the U.S. since the early 1900s and continues to be used today.[139] These technologies include phase-shifting transformers and load tap-changing transformers.[140] For example, the Michigan-Ontario power line uses five such phase-shifting transformers to counter loop-flows around Lake Erie.[141] While widely used, traditional PFCs offer limited control capability and a relatively slow response time.[142]

More recent PFCs introduced in the 1970s offer better controllability and faster performance, though they are comparatively more expensive and complex to implement.[143] These newer technologies, also considered traditional PFCs, include flexible AC transmission systems ("FACTS") devices and variable frequency transformers ("VFT").[144] Eversource states it has decades of experience operating numerous FACTS devices.

137 WATT Coalition, *supra* note 133.

138 INL, *Implementation and Operation of Power Flow Control Solutions for Transmission Systems* (May 2024), *available at* https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_111370.pdf.

139 DOE, *supra* note 56, at 16.

140 *Id.*

141 *Id.*

142 EPRI, *supra* note 135, at 1.

143 *Id.*

144 DOE, *supra* note 56, at 16.

In June 2023, the utility placed into service one of the world's first Static Synchronous Compensators with grid forming capabilities serving New York's first offshore wind farm.[145] American Electric Power, a utility which operates across eleven U.S. states, has been using FACTS devices since 1998. The use of PFCs has expanded transmission capacity and helped mitigate high power losses on American Electric Power's transmission system. The technology added 770 MW of transfer capacity where a new line would have added only 670 MW.[146]

APFCs as a technology is the newest development in power flow control. APFCs are smaller, cheaper, modular, and can be scaled or redeployed.[147] APFC improves upon traditional FACTS devices through the use of modular digital power flow control technology to enable fast and accurate control of power flow.[148] In some APFCs the ability to control both active and reactive power is limited relative to FACTS devices, however, their modular configuration and lower cost allows operators to install several devices to achieve the desired level of controllability and capacity.[149] One example of new APFC is the distributed series reactor ("DSR") technology in which multiple small, modular devices are installed along a transmission line to provide the same capability as a single, larger system.[150] APFCs offer a more cost-effective solution, are easier to deploy than older PFCs, and can save space. For example, SmartWires claims its APFCs increase transfer capacity using 25 percent less substation space than the traditional PFC solution.[151]

According to a 2018 EPRI report, APFC is reaching a point of maturity and is ready to be installed by utilities.[152] Some APFCs are already commercially available in various models and types. For example, PowerLine Guardian, a DSR developed by SmartWires, has already been installed on multiple high-voltage lines across North America and Europe.[153] The device enables utilities to better monitor and dynamically control the flow of power across transmission lines by adjusting magnetic properties of the line. SmartWires expects growing adoption, especially in light of FERC Orders 2023 and 1920, which require consideration of APFC in interconnection and transmission planning studies, respectively.[154]

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145 *See* Appendix 2, Eversource Response at 4.

146 DOE, *supra* note 56, at 16.

147 WATT Coalition, *supra* note 133.

148 AES, *supra* note 19, at 5.

149 EPRI, *supra* note 135, at 1.

150 DOE, *supra* note 56, at 16.

151 SmartWires, *What is Advanced Power Flow Control?* (February 2024), *available at* www.smartwires.com/2024/02/07/what-is-advanced-power-flow-control.

152 EPRI, *supra* note 135, at 1-1.

153 *Id*.

154 Smart Wires, *Technology in Focus: APFC and PSTs* (July 2024), *available at* www.smartwires.com/2024/07/22/technology-in-focus-apfc-and-psts/.

Benefits

APFCs offer operational, economic, and environmental benefits. APFCs help create a more flexible and resilient power grid, reduce congestion, allow for greater integration of renewables, and help maximize the value of existing transmission assets.

Reduced Congestion

APFCs' main benefit is enabling operators to manage real-time power flows across the transmission network. By helping balance the flow across lines more effectively, operators can use APFC to increase total power transfer capability and thus relieve congestion.[155] According to the DOE, APFCs can increase line capacity by ten to 25 percent on average.[156] Active control of power flows also provides more flexibility to manage congestion compared to passive measures.[157] In New York, 15 APFCs are helping NYISO manage congestion by expanding substation transfer capacity by 185 MW.[158] In Australia, APFCs are expected to allow an additional 170 MW of power to be transferred into New South Wales, which will deliver net benefits of up to $180 million to electricity customers.[159]

Maximization of the Value of Planned Investments

APFCs can help maximize the use of existing assets and defer upgrades in support of more effective and efficient transmission expansion.[160] A 2018 EPRI study of Southwest Power Pool found that, in most cases, APFCs cost several times less than traditional transmission upgrades. For example, where APFC costs for four cases examined ranged between $1.5 million and $5.2 million, traditional project costs for the same lines were between $7.15 million and $60.2 million.[161] Although the results are context-specific, the cost-saving potential is clear.[162]

APFCs also offer additional transmission expansion flexibility, which can help improve the efficiency of grid planning and reduce expansion costs. APFCs such as DSR are highly mobile, scalable, and can be deployed rapidly, allowing operators to install them gradually as the system evolves and needs change. In some cases, APFCs can defer conventional solutions until the need has fully materialized, saving ratepayers money.

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155 AES, *supra* note 19, at 5.

156 DOE, *supra* note 75, at 5.

157 DOE, *supra* note 56, at 17.

158 EPRI, *Presentation to ERCOT Technology and Security Committee: Introduction to Grid Enhancing Technologies* (August 2024) at Slide14, *available at* www.ercot.com/files/docs/2024/08/12/4-introduction-to-grid-enhancing-technologies-gets-.pdf.

159 WATT Coalition, *supra* note 133.

160 DOE, *supra* note 56, at 18.

161 EPRI, *supra* note 135.

162 DOE, *supra* note 56, at 18.

Further, in cases where the needs changed so much that the APFC solution is no longer needed, the device can be moved elsewhere in the system.[163]

Improved Reliability

APFCs can make the grid more flexible and responsive to faults, disturbances, and other unplanned situations, thereby making the grid more resilient. Compared to traditional PFCs, APFCs can better mitigate the effect of transients and other electrical phenomena that can destabilize the grid. The fast and controlled response can improve reliability by quickly and accurately responding to changing conditions and system violations, especially with the loss of system inertia. APFC can also provide reactive power support and other forms of compensation needed to accommodate intermittency of variable renewable energy resources on the grid.[164] The DOE recently provided a grant to Algonquin Power Fund America to use APFCs to improve grid stability and increase renewable energy delivery in Texas and Illinois.[165]

Access to Lower Cost and Zero Carbon Electricity

APFC solutions accelerate the integration of renewable resources by enabling faster deployment and unlocking additional transfer capacity. APFC can be deployed within one or two years compared to the significantly longer development timelines typical for traditional transmission upgrades. This enables faster connection of additional renewable power and facilitates access to zero carbon electricity.[166] In the United Kingdom, National Grid Electricity Transmission was able to enable over two GW of renewable capacity across Northern England by deploying 48 APFCs.[167] Additional capacity will accelerate the integration of new wind power in Scotland and can deliver an estimated $500 million savings in avoided curtailment costs.[168] In Colombia, APFC-enabled redistribution across overloaded lines unlocked 300 MW of capacity for renewable energy resources to connect reliably to the grid. Notably, the utility found that alternate solutions were more expensive, took longer to install, were more disruptive, and provided less flexibility.[169]

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163 *Id*. at 19.

164 *Id*.

165 WATT Coalition, *Case Studies and Modeling on the Value of Grid Enhancing Technologies* (January 2024), *available at* https://watt-transmission.org/wp-content/uploads/2024/01/Case-Studies-and-Modeling-on-the-Value-of-Grid-Enhancing-Technologies-%E2%80%93-January-2024-.pdf.

166 American Council on Renewable Energy, *Assessment and Evaluation of Grid Enhancing Technologies (GETs)* (February 2025) at 26, *available at* https://acore.org/resources/assessment-and-evaluation-of-grid-enhancing-technologies-gets/.

167 WATT Coalition, *supra* note 165.

168 WATT Coalition, supra note 133.

169 *Id*.

Cost-Effectiveness

Studies and research increasingly show that APFCs can be more cost effective than traditional upgrades. A 2018 EPRI study of APFC technologies examined how economic benefits varied with the number and size of phase angle controllers, a type of APFC, installed.[170] According to the results, one power flow device implemented in the PJM region offered annual cost savings of $39 million from reduced congestion, while 17 devices saved $196 million.[171, 172] EPRI concluded that APFCs can be economically sound as a congestion-reduction measure, but the cost-benefit depends on the specific technology used.[173] In another case, Vermont Electric Power Company is planning to install APFC to increase transfer capacity across regional borders and increase the useful life of other transmission assets.[174] Vermont Electric Power Company estimates that the APFC solution is 16 percent less expensive than a traditional option and can be deployed in half the time. The solution can also double the output of the affected substation within the same footprint in the future by adding additional devices if the upgrade is needed.[175] In Colombia, APFCs already help prevent outages, which has saved more than $70 million over a three-and-a-half-year period. By avoiding redispatch, the country has saved an estimated $20.5 million a year at the estimated cost of $1.5-4 million for the system.[176]

Challenges

Limited Deployments

According to the DOE, APFC deployments have been limited due to their physical characteristics (i.e., space requirements), the current level of technological maturity, and insufficient incentives. The solution is best suited for overhead transmission systems that have sufficient space for equipment, which limits its use in underground and otherwise spatially restricted transmission systems.[177] Current modeling tools and methods are inadequate in analyzing APFC effects on voltage and stability limits.[178] Planners may be unfamiliar with how to properly model the impact of APFCs on the grid and thus be reluctant to adopt them. Operators also do

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170 DOE, *supra* note 56, at 17.

171 DOE, *Next-Generation Grid Technologies* (November 2021) at 24, *available at* www.energy.gov/sites/default/files/2022-05/Next%20Generation%20Grid%20Technologies%20Report%20051222.pdf.

172 *See id*. (Notably, adding additional devices offered diminishing returns).

173 EPRI, *supra* note 135, at 1-1.

174 WATT Coalition, *supra* note 133, at 13.

175 Smart Wires, *supra* note 154.

176 WATT Coalition, *supra* note 165.

177 DOE, *supra* note 56, at 19.

178 *Id*. at 20.

not benefit from avoided congestion savings, which flow to consumers, and thus have little economic incentive to proactively investigate and deploy APFCs.[179]

System Planning and Regulatory Limitations

Current transmission planning processes and ownership structure may limit APFC implementation. According to the DOE, planners may be unfamiliar with how to properly model the impact of APFCs on the grid.[180] For example, an APFC solution would not be effective in directing power flows over a transmission path if the path is unavailable due to an unplanned outage.

There are exceptions with older and well-studied technologies, like phase shifting transformers, but newer PFCs (including APFCs) are more difficult to implement.[181] APFCs also require the consent of transmission owners to be installed, which adds another layer of integration and planning complexity. Third parties cannot install APFC system without the owners' approval, which could impede the ability of new market participants to propose APFC solutions in a competitive transmission solicitation.

Market Changes

Current market structure limits adoption, as it is not well suited to accommodate the additional flexibility provided by APFCs. Existing markets assume that transmission infrastructure is static, meaning the underlying transmission network remains unchanged or constant during the market interval (five or 15 minutes). Widespread deployment of APFCs will introduce dynamic changes to the grid. Altering power flows in real-time outside of market operations can lead to financial shortfalls and added complexity during settlement. Wider integration of APFC capabilities into system models that guide market prices has not been thoroughly investigated. New market mechanisms may be needed to accommodate additional flexibility before the technology can be deployed at scale.[182]

Unintended Risks

APFC can be difficult to manage as it requires deploying and maintaining numerous devices across a wide area.[183] Therefore, if mismanaged, APFC can result in widespread impacts due to sizeable adjustments to line impedances. As a result, a solution in one area may create conflicts or adverse effects in other areas.

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179 *Id*. at 19.

180 *Id*. at 20.

181 DOE, *supra* note 171, at 25-26.

182 DOE, *supra* note 56, at 20.

183 Grid Insights, Presentation, *Improving Grid Performance: Innovative Solutions for Evaluating Grid-Enhancing Technologies (GETs) in Generation Interconnection and Transmission Planning*, July 10, 2024, *available at* www.ferc.gov/media/presentation-improving-grid-performance-innovative-solutions-evaluating-grid-enhancing.

4. TOPOLOGY OPTIMIZATION

Overview

Topology optimization is a method of optimizing the layout of the electric grid system within a defined boundary, given load conditions and constraints, with the goal of maximizing the performance of the system. Optimization may correct for potential dispatch inefficiencies that result from built-in redundancies in the transmission network. While such redundancies support system reliability, they might not be needed during all operating periods. Traditionally, operators manage real-time congestion by redispatch of generation resources. Topology optimization improves this redispatch by including transmission infrastructure as a dispatchable asset using topology control.[184]

Topology control, an application of topology optimization, uses software solutions, including with the use of artificial intelligence or physical models of the grid, to identify ways to reconfigure the grid by rerouting power flows around bottlenecks, reducing congestion, and optimizing transmission capabilities. Operators reconfigure the grid through real-time switching of transmission branch elements (transmission lines and transformers) by opening and closing circuit breakers to redirect power flows.[185] Reconfiguring the grid at large scale is complex and represents a challenging mathematical problem requiring advanced computing and system-level methods.[186] Therefore, topology control software algorithms are used to automatically identify the best configuration options to manage congestion, respond to contingencies, such as overloads and constraints, and help with planning outages.[187]

Topology control works similarly to hardware-based FACTS devices in that they both redirect or optimize power flows across the network.[188] Software can also be used with existing equipment where the switching infrastructure is already in place and circuit breakers are controlled remotely over the SCADA.[189]

Current Industry Trends

Topology control has been used since the early 1980s, though mostly during extreme events. System operators would use topology control in certain emergency conditions as a corrective mechanism to address reliability concerns such as low voltage events or to maintain system reliability. However, the system functioned based on

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184 DOE, *supra* note 56, at 11.

185 RFF, *Expanding the Possibilities: When and Where Can GETS, DERs, and Microgrids Support the Grid of the Future?* (September 2023) at 7, *available at* www.rff.org/publications/reports/expanding-the-possibilities-when-and-where-can-grid-enhancing-technologies-distributed-energy-resources-and-microgrids-support-the-grid-of-the-future/.

186 DOE, *supra* note 171, at 14.

187 RFF, *supra* note 185, at 7.

188 *Id*.

189 *Id*.

sets of assumed and pre-defined system conditions that operators could refer to when the switch was needed. These pre-defined solutions were not necessarily optimized and/or could not handle unforeseen conditions.[190]

Traditional topology control methods are based on legacy topologies, limited sensing, and rudimentary control. For example, system operators use manual process and personal expertise to identify switching candidates ahead of events, often relying heavily on historical, documented switching actions evaluated under previous events.[191] As a result, topology control is time-consuming and switching actions must still be evaluated in real-time to avoid unintended consequences.[192] In practice, this requires operators to perform topology control on an ad hoc basis based on operator knowledge.[193]

The industry is changing as advances in artificial intelligence and improvements in algorithms help automate the topology optimization process. Modern algorithms can systematically and automatically identify optimal transmission control actions, which has increased the viability of topology control as a solution to transmission challenges. When integrated into control operations, the software can automatically provide the system's current state from existing operator tools, evaluate switching options, and present possible actions to the system operator as another means to mitigate abnormal conditions.[194]

In Massachusetts, the topology optimization developer NewGrid is developing key software features for technology optimization and demonstration purposes with $250,000 in grant support from MassCEC in the ISO-NE region. The project is expected to demonstrate the software's capability in devising solutions for grid congestion and wider integration of renewables to the Massachusetts grid.[195] NewGrid has deployed its topology optimization tool in other jurisdictions as well.[196]

The future of topology optimization may be tied to new advances in computing, including data-driven analysis, real-time analytics, machine learning, and artificial intelligence. For example, advanced software or "digital twin" models can provide the system's current state, evaluate switching options, and present possible control actions to operators. These capabilities assist with reducing costs, mitigating abnormal conditions, improving reliability, or increasing resilience.[197]

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[190] DOE, *supra* note 56, at 11.

[191] DOE, *supra* note 171, at15.

[192] *Id*. at 11.

[193] RFF, *supra* note 185, at 7.

[194] DOE, *supra* note 56, at 11.

[195] MassCEC, *Grid Technology Research & Development. Past Projects. NewGrid*, www.masscec.com/grid-modernization-and-infrastructure-planning/research-development (last accessed July 14, 2025).

[196] NewGrid, *Topology Optimization Case Studies* (May 2024), *available at* https://newgridinc.com/wp-content/uploads/2024/05/topology-optimization-case-studies.pdf.

[197] DOE, *supra* note 171, at 15.

Benefits

Reduced Generator Curtailment or Congestion

Topology optimization can help reduce congestion by increasing transmission capacity. According to DOE, topology optimization can increase line capacity between five-to-50 percent on average.[198] SPP piloted topology optimization to relieve congestion on transmission lines downstream from wind resources. High wind generation was creating real-time transmission congestion resulting in 285 MW of wind curtailment. SPP used topology optimization software to identify three switching actions that diverted power flows around the congested elements and provided enough relief to avoid the need for any wind curtailments, reducing congestion and overall production costs.[199]

Maximization of the Value of Planned Investments

Topology optimization improves the usage of the existing transmission system and does not require installation of new hardware, thus maximizing the value of existing assets. Topology optimization may also help defer investment in new, costly equipment by making more use out of existing lines. Although topology optimization is more applicable in the real-time operations and operations-planning environment, considering topology switching in system planning increases the long-term value of transmission upgrades and can be considered when making infrastructure investment decisions.[200]

Improved Resilience and Reliability

Topology optimization can be used when responding to contingencies to help eliminate overloads and violations, minimizing outages and increasing reliability. If a natural disaster disrupts the state of the lines, optimal corrective actions can accelerate recovery while keeping customer interruptions to a minimum, increasing overall system resilience. The technology also improves operations planning by finding reconfiguration solutions for outages and real-time disruptions.[201]

Cost-Effectiveness

Existing cost -benefit studies and pilot results of topology optimization are promising. Early research on topology optimization showed the potential for up to 25 percent production cost savings, though the impact is reduced to 16 percent when ensuring reliability (i.e., meeting N-1 criteria) of the proposed solution. In PJM, reconfigurations identified by optimization software led to a 50 percent decline in real-time congestion costs, with an estimated value of approximately $100 million per year across PJM.[202] In SPP, estimated real-time market savings from using topology optimization are three percent of the congestion costs, equivalent to savings

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198 DOE, *supra* note 75, at 5.

199 DOE, *supra* note 56, at 12.

200 *Id*. at 12.

201 RFF, *supra* note 185, at 8.

202 *Id*.

of between $18-44 million.[203] In the United Kingdom, National Grid found that adopting topology optimization would increase the transfer capability on thermally limited lines by as much as 12.3 percent, which could lead to estimated annual cost savings of approximately $50 million.[204]

Most important in cost assessment is the fact that topology optimization relies on algorithms designed to operate within existing systems, and thus does not require additional capital investments or hardware installations. This makes topology optimization a lower cost solution than other GETs that require physical equipment, such as APFCs, and may even reduce the need to build new lines.

Challenges

Data Accuracy

Underlying potential data inaccuracy is a limitation for topology optimization applications. Optimization algorithms use approximations and simplifying assumptions to model large systems such as the electric grid. If the underlying data are not precise or operators are not confident in the algorithms, opportunities for topology optimization might prove limited. Further development of algorithms and solutions to balance model size, speed, and accuracy are therefore needed to reduce the underlying risk and confidence in topology optimization software.[205]

System Strain

While topology optimization maximizes asset utilization, it also results in more wear and tear. Frequent switching of circuit breakers can expedite their aging, add to maintenance costs, and negatively impact reliability by increasing breaker failure rates. As more variable renewable energy and inverter-based resources are deployed, the combined effect of increased usage can lead to reliability problems. Ways to mitigate some of these challenges include incorporating parameters such as switching rates into algorithms and quantifying the costs of increased switching, although more studies are needed.[206]

Market Impact

Topology optimization impacts participants in existing electricity markets, creating winners and losers in the process. For example, transmission rights holders receive revenues from a share of congestion charges in day-ahead energy markets. Topology optimization changes and reconfigures congestion in real time, which can impact day-ahead market structures and lead to financial losses if market participants are unable to account for

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203 DOE, *supra* note 56, at 12.

204 *Id*.

205 DOE, *supra* note 171, at 17.

206 RFF, *supra* note 185, at 9.

these dynamic changes.[207] Market participants will need to adapt to a more active role by the market operator, or market structures may need reform to account for changes due to the use of topology optimization.[208]

5. ADVANCED RECONDUCTORING

Overview

Conductors and cables are the fundamental hardware that carries electricity across the transmission line. Advanced reconductoring refers to the process of replacing existing transmission lines with advanced conductors. Advanced conductors are more efficient and thus offer an opportunity to increase transmission capacity along existing lines without the challenges associated with new transmission line construction.[209] The best overhead conductors benefit from advances in new materials and manufacturing to offer better performance, lower losses, higher current-carrying capacity, lower weight, and lower sag at high temperatures.[210]

Utilities and transmission system operators have used reconductoring as part of basic maintenance for decades, however, the type of conductor used is changing. The Aluminum Conductor Steel Reinforced ("ACSR"), a conductor type with a steel core surrounded by aluminum, remains the most used conductor globally. In contrast, advanced conductors employ advanced aluminum alloys, steel, and composite materials in novel ways that provide enhanced performance over conventional overhead conductors. Advanced conductors are used in a variety of applications to increase transmission capacity and to provide enhanced strength and in harsh environments. Common types of new overhead conductors include Aluminum Conductor Composite Reinforced, Aluminum Conductor Composite Core, and Aluminum Conductor Carbon Fiber Reinforced.[211]

Current Industry Trends

While advanced conductors represent the newest technology, traditional aluminum conductors dominate the industry. Currently, approximately one percent of the existing transmission lines in the United States are reconductored each year. Of this one percent, an even smaller fraction of these projects use advanced conductors.[212]

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[207] *Id*.

[208] DOE, *supra* note 171, at 17.

[209] INL, *Advanced Conductor Scan Report* (December 2023) at 1, *available at https://inl.gov/content/uploads/2024/10/23-50856_R12a_-AdvConductorsScanProjectReportCompressed.pdf*.

[210] DOE, *supra* note 56, at 25-26.

[211] *Id*. at 26.

[212] Energy Innovation - Grid Lab, *Supporting Advanced Conductor Deployment: Barriers And Policy Solutions* (April 2024), *available at* www.2035report.com/wp-content/uploads/2024/04/Supporting-Advanced-Conductor-Deployment-Barriers-and-Policy-Solutions.pdf.

Advanced conductors offer better performance but remain largely untested, which is the main barrier to their deployment. Utilities are concerned about how to work with new materials and evaluate their durability. Despite these barriers, INL predicts that advanced conductors will most likely see widespread adoption in the future. Market competition is active, and new technologies are being actively introduced.[213]

Benefits

Maximization of the Value of Planned Investments

Advanced overhead conductors can help maximize the value of existing transmission corridors by leveraging existing assets to increase transmission capacity. Compared to traditional conductors, advanced conductors have up to two times the maximum current-carrying capacity and can be installed on existing transmission towers and rights-of-way. By reconductoring existing transmission lines, operators can often double the capacity without needing new approvals.[214] Relative to building new transmission lines, reconductoring is faster to complete and less expensive, in some instances half the cost of a new transmission line.[215]

Improved Resilience

Advanced overhead conductors can improve the overall resilience of the transmission grid due to their improved strength. For example, advanced conductors are more capable of withstanding stress from extreme natural conditions such as high winds, physical loading from snow and ice, or heat from wildfires or heatwaves. Overhead lines reconductored with advanced materials also experience less sag due to their robust nature. In emergency situations or during contingencies when lines operate above their design capacity limits, reduced sag can help avoid flashovers (a type of disruptive, electrical discharge event) and the resulting unintended consequences.[216]

Cost-Effectiveness

Given the large number of new and developing technologies, cost effectiveness depends highly on the specific type of new conductor used. Though there is not yet a systematic review of the cost and benefits of advanced reconductoring, early assessments are promising. Research from the University of California Berkeley and GridLab found that advanced reconductoring could be cost effective: wide-scale deployment of advanced conductors could quadruple the projected transmission capacity added by 2035 while saving $85 billion in energy system costs. By 2050, reconductoring combined with a robust build-out of new transmission could provide a total savings of $180 billion compared to a business-as-usual scenario.[217]

Advanced overhead conductors are more expensive upfront than conventional conductors. However, due to their improved properties and operational characteristics, advanced conductors can still reduce total project

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[213] INL, *supra* note 209.

[214] DOE, *supra* note 56, at 26.

[215] *Id*.

[216] *Id*. at 27.

[217] Energy Innovation - Grid Lab, *supra* note 212.

costs and offer more long-term benefits. For example, advanced overhead conductors have lower weight, and therefore require less robust and less costly transmission towers. Due to lower sag, the towers can be placed farther apart thus further decreasing project costs. Advanced overhead conductors also offer 25 to 40 percent fewer electrical losses to conventional conductors, which makes them more cost efficient over lifetime use.[218] Vermont Electric Power Company found that using advanced conductors reduced line energy losses enough to result in a lower lifetime expense despite the higher upfront cost.[219]

Challenges

Installation Complexity

Advanced reconductoring is new and thus utilities are less familiar with new material properties and designs. Installation of advanced conductors requires new tools and techniques for installation, especially for splicing and connecting two spans, and additional training for staff.[220]

Conductor Durability

Utilities have expressed concern regarding the lack of knowledge on the durability of new conductors. According to the INL, most utilities prefer to conduct multiple pilots and test programs deploying advanced conductors at a large scale.[221]

6. STORAGE AS A TRANSMISSION ASSET

Overview

Using storage as a transmission asset refers to the process of using energy storage systems, including batteries or pumped hydro, to support the transmission grid. Energy storage located along a transmission line can be operated to inject or absorb real and reactive power, mimicking transmission line flows. As a result, energy storage may be used in place of building a new transmission line.[222]

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218 DOE, *supra* note 56, at 27.

219 Energy Innovation - Grid Lab, *supra* note 212.

220 DOE, *supra* note 56, at 28.

221 INL, *supra* note 209.

222 Kumaraswamy *et al.*, *Redrawing The Network Map: Energy Storage As Virtual Transmission*, Fluence (2020), *available at* https://info.fluenceenergy.com/hubfs/Collateral/Storage%20as%20Transmission%20White%20Paper.pdf.

Energy storage is dual use as it can be deployed as a generation resource or as a transmission asset. When used as a transmission asset, energy storage can quickly add transmission capacity and thus help solve grid congestion or resolve transmission needs faster than building new lines.[223]

Current Industry Trends

As early as 2010, DOE identified energy storage as a potential solution to defer or avoid transmission and distribution upgrades. At the time, the technology was still maturing, and DOE emphasized the need to fully understand its potential costs and benefits. For example, few large-scale demonstrations had been implemented and their impacts were relatively unknown.[224]

Today, the technology is mature enough that multiple countries have made extensive plans to add more storage capacity as a transmission asset on their grids. According to Navigant, a cumulative 35.5 GW of energy storage for critical infrastructure, including approximately 25 percent for direct transmission and distribution needs, is expected to be deployed by 2027.[225]

The regulatory framework for storage as a transmission asset is evolving. In 2017, FERC issued a policy statement supporting the deployment of energy storage for the dual uses of regulated transmission service and competitive market service. This allowed storage owners to earn revenue through market operations when the storage asset was not required for transmission needs.[226] In 2023, FERC approved the implementation of storage as a transmission asset in the SPP and ISO-NE regions with certain limitations. For ISO-NE, the aggregate amount of storage cannot exceed 300 MW for charging and discharging capacity, and the total capacity at one single substation is limited to 30 MW. These limitations are intended to minimize the likelihood of transmission level storage causing sudden power impacts and associated disruptions.[227]

Utility Dive, a trade newsletter covering the utility industry, reports that energy storage remains underused in the U.S. transmission grid as there are unsolved regulatory and market design questions at the grid operator

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223 *Id*.

224 DOE, *Electric Power Industry Needs for Grid-Scale Storage Applications* (December 2010), *available at* www.energy.gov/oe/articles/electric-power-industry-needs-grid-scale-storage-applications.

225 Ian McClenny, *T&D Asset Operators Look to Critical Energy Storage,* Electricity Today, *available at* www.electricity-today.com/overhead-td/td-asset-operators-look-to-critical-energy-storage (last accessed July 14, 2025).

226 PNNL, *Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset* (February 2022), *available at* www.pnnl.gov/main/publications/external/technical_reports/PNNL-32196.pdf.

227 AFRY, *How Can Storage as Transmission Only Assets (SATOAS) Help Solve The Increasing Electric Transmission Challenges in The US?*, https://afry.com/en/insight/how-can-storage-transmission-only-assets-satoas-help-solve-increasing-electric-transmission (last accessed July 14, 2025).

level.[228] This is especially true with "dual-use" storage assets that provide both market and reliability services. A Quanta Technology report on the feasibility of the technology, prepared for the New York Battery and Energy Storage Technology, shares similar concerns for NYISO area.[229] In their report, Quanta Technology recommends changing the current market rules and transmission planning tariffs to improve the feasibility of storage, including allowing storage as a transmission asset recovery under ISO tariffs, allowing batteries as flexible system resources, and including storage in need and solution assessments for grid planning.

Benefits

Reduced Generator Curtailment or Congestion

Storage as a transmission asset can help reduce generator curtailment by increasing transmission capacity. The technology can increase transmission transfer capability by balancing individual transmission line loading and mitigating system voltage or stability issues under normal or contingency conditions.[230] Renewable energy output is often limited by the thermal ratings of a single transmission facility. Battery storage can help the transmission facility avoid exceeding thermal ratings and thus prevent curtailment.[231]

Maximization of the Value of Planned Investments

One benefit of using storage as a transmission asset is that it maximizes the use of existing infrastructure by providing operational flexibility. Storage offers a viable solution as it avoids the need for expansive transmission lines and provides an intermittent locational resource capable of responding to grid dispatch needs. When used this way, storage primarily controls power flows to achieve better load balancing among transmission facilities, which in turn enables more efficient use of existing transmission facilities.[232]

Storage is also modular and relatively quick to deploy, which can make it a cost-saving solution for immediate system needs. Depending on applicable regulations, battery storage can be deployed as much as 80 percent faster than transmission lines. A typical 100 MW or larger battery installation can be built in approximately one to two years.[233]

Storage can be planned flexibly and built incrementally, adapting as needs change. A 200-300 MW energy storage project deployed along a 220 kV transmission line can fit onto a site equivalent in size to 0.37 miles

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228 Brian Martucci, *Energy Storage Underused As Transmission Asset Amid Unresolved Questions, Experts Say*, Utility Dive, September 24, 2024, *available at* www.utilitydive.com/news/energy-storage-underused-transmission-asset-ferc/727946/.

229 Quanta Technology, *Storage as Transmission Asset Market Study* (January 2023), available at https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

230 *Id*. at 8.

231 Twitchell J.B., *Energy Storage as a Transmission Asset: Definitions and Use Cases*, 37 The Elec.J. 7-10 (December 2024), *available at* www.sciencedirect.com/science/article/pii/S1040619024000769.

232 Quanta Technology, *supra* note 229, at 7.

233 Kumaraswamy et al., *supra* note 222.

(600 meters).[234] Unlike traditional transmission lines, storage can be connected across multiple points on the grid and relocated if necessary. As a result, the risks of stranded assets and overbuilding of the transmission infrastructure are minimized.[235]

Improved Reliability

Transmission level- storage supports grid functionality through ensuring security and resiliency. Battery storage can preserve system performance in the event of a temporary transmission outage or even prevent blackouts.[236] Storage also provides a range of critical ancillary services, including frequency and voltage control and special protection schemes. Amid the increased retirements of synchronous generators, storage is a viable option to avoid otherwise-necessary costly transmission upgrades.[237]

Cost-Effectiveness

Deploying battery storage as a transmission asset has been increasingly cost effective in a number of applications globally. In Germany, installing 1,300 MW of storage capacity on the transmission grid is expected to lower redispatch costs by EUR 130 million (approximately $148.2 million in U.S. dollars) per year.[238] In Australia, deploying 100 MW of storage is expected to result in as much as AUD $34 million (approximately $23.5 million in U.S. dollars) in savings from the reduction in electricity prices due to storage during periods of peak renewable generation.[239] In Massachusetts, National Grid's $81 million six MW battery storage project in Nantucket, commissioned in 2019, is expected to defer investment in a $200 million submarine cable saving ratepayers $120 million.[240]

As of 2025, New York has conducted the most comprehensive cost-benefit assessment to date. The study assessed three use cases of storage as a non-wires alternative at the bulk transmission system level. The results have shown that battery projects can provide between $13 - $55 million in cost savings to the grid compared to traditional transmission solutions. Table 1 below, presents the cost estimates of the traditional solutions compared to the storage as transmission asset option and the associated annual cost savings.

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234 *Id*.

235 Quanta Technology, *supra* note 229, at 7.

236 Kumaraswamy et al., *supra* note 222.

237 Quanta Technology, *supra* note 229, at 7-8.

238 Kumaraswamy et al., *supra* note 222.

239 *Id*.

240 Quanta Technology, *supra* note 229, at 10.

Use Case	Battery Size	Estimated SATA Capital Cost ($M)	Estimated Wire Solution Capital Cost ($M)	Local Area Annual Cost Saving ($M)	NYCA-Wide Congestion Annual Cost Saving ($M)
#1	200 MW/ 200 MWh	120	700	9.9*	13.1
#2	50 MW/50 MWh + 1,500 MVAr Reactive Power Capacity	250	615	51**	55
#3	200 MW/ 200 MWh	120	533	30.4***	17.8

Table 1—Cost Comparison Storage as Transmission Asset (SATA) vs Traditional (Source: Quanta technology[241]).

Challenges

Currently, the main challenge to a higher adoption rate of storage as a transmission asset is the lack of clear planning criteria at the regional transmission organization level. According to the Pacific Northwest National Laboratory, regional transmission planning processes have been slow to incorporate storage technologies. The analysis identified five key barriers this has caused, including:

- Lack of clarity for how and when storage will be considered;
- Difficulty representing storage in power flow models;
- Weak links between transmission and generation planning processes;
- Financial disincentive for utilities to consider lower-cost options; and
- Lack of regulatory review procedures.[242]

7. CONCLUSION

Advanced transmission solutions are a useful addition to the transmission system toolkit. In the past, new transmission needs usually required investment in expensive and lengthy system expansions. However, the current pace of new electricity demand poses challenges for the traditional approach to system expansion. Advanced transmission solutions offer a flexible, cost effective, and scalable option transmission owners and planners can use to improve system performance and expand transmission capacity. Compared to traditional upgrades, advanced transmission solutions are faster to install, cost a fraction of the expense, complement the existing assets, and are reversible in some cases. Most importantly, all the technologies investigated in this report are ready to be deployed and can be cost-effective when applied in the right environment. Transmission system stakeholders in public and private sectors are actively studying the potential of advanced transmission

241 *Id.*

242 PNNL, *supra* note 226.

solutions to transform the grid by deploying pilots, developing new policies, and analyzing potential impacts and benefits.

The primary benefit of advanced transmission solutions is the potential to expand capacity on the transmission system. According to the DOE's estimate, deploying these technologies nationally could increase the capacity of the existing grid to support 20-100 GW of incremental peak demand when installed individually, or even more when installed in strategic combinations. GETs could increase incremental transmission capacity to support five to-15 percent higher peak load from 2023 levels when installed individually. Although an estimate for the potential benefit in ISO-NE is not readily available, given the New England region's projected 74 percent increase in peak demand to 40 GW by 2045, the potential for advanced transmission solutions to expand transmission capacity merits consideration given Commonwealth's significant clean energy deployment needs.[243,244] DLR is most effective in areas rich with wind resources, including offshore wind. National Grid in the United Kingdom was able to increase line ratings by nine percent using LineVision's DLR sensors on a critical double circuit connecting offshore wind to the grid.[245]

Advanced transmission solutions can deploy relatively quickly, enabling more interconnections while new transmission and distribution assets are being developed. Depending on the advanced transmission technology considered, typical deployment time is between six months and five years.[246] In contrast, traditional solutions take over a decade to complete. Given ISO-NE's 36.8GW interconnection queue, which includes 20.5GW in the Commonwealth, advanced transmission solutions could be a tool to bridge short-term needs with long-term solutions.[247] Over the long term, New England will need both gigawatts of new renewable energy generation and transmission capacity to meet increasing electricity demand and climate goals.[248] However, in the short term, these solutions could enable a faster path towards the state's energy objectives.

Advanced transmission solutions also offer increased resiliency, reliability, and adaptability. For example, DLR offers increased operational visibility of the grid, which helps improve decision making, especially during

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243 Massachusetts Executive Office of Energy & Environmental Affairs, *Clean Energy and Climate Plan for 2050,* December 2022, *available at https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.*

244 *See* ISO-NE, *Forecast Report of Capacity, Energy, Loads, and Transmission* (2025) *available at* https://isonewswire.com/2025/05/19/iso-ne-innovations-push-electricity-forecast-further-into-the-future/, last accessed August 29, 2025.

245 LineVision., *How Dynamic Line Ratings Accelerate Renewable Energy Integration*, www.linevisioninc.com/news/how-dynamic-line-ratings-accelerate-renewable-energy-integration (last accessed August 12, 2025).

246 In some cases, DLR deployment can take as little as three months.

247 ISO-NE, *ISO New England Overview and Regional Update*" (April 2025) at Slide 16, *available at* www.iso-ne.com/static-assets/documents/100023/isone_2025_04_23_nh_bia.pdf.

248 Synapse Energy Economics, *Transmission Congestion in New England: Planning for the Future*, June 9, 2025, www.synapse-energy.com/transmission-congestion-new-england-planning-future (last accessed July 23, 2025).

extreme conditions. ISO-NE used DLR principles to prevent blackouts and reduce congestion costs during the 2018 cold snap.[249] APFCs are designed to make the grid more flexible and responsive to faults, disturbances, and other unplanned events. Topology optimization can help grid operators find reconfiguration solutions during unplanned outages. Advanced conductors are better able to withstand extreme weather conditions due to lower sag, corrosion resistance, and better durability. High-temperature, low-sag conductors perform especially well in snowy conditions, which could be important if ISO-NE transitions to a winter peaking system.

Through pilots and studies, advanced transmission solutions have been proven a cost-effective solution under the right conditions, typically when used to relieve congestion. For example, PPL invested less than $1 million on DLR installation on two congested lines and saved an expected $23 million in reduced congestion costs.[250] In PJM, one APFC device offered annual cost savings of $39 million from reduced congestion, while 17 devices saved $196 million.[251, 252] In SPP, topology optimization is helping save three percent of the congestion costs, equivalent to savings of between $18-44 million.[253] While the potential savings from applications throughout the country are promising, in New England the benefits may be limited because the region is one of the least congested in the country due to previous investment in transmission.[254] New England is projected to invest another $6.5 billion in asset condition and reliability transmission projects through 2030.[255] While GETs are not necessarily well suited to replace assets that have reached the end of their useful life, advanced reconductoring and storage could be an alternative.[256]

Despite the many benefits of advanced grid solutions investigated in this report, these technologies have not been widely adopted in the U.S. and in Massachusetts, in particular. The state's two main transmission owners, Eversource and National Grid, have deployed a few pilots in the state and are both in the process of adopting AAR ratings in compliance with FERC Order 881. National Grid has adopted the use of ACSS, an advanced conductor, as standard practice across the Massachusetts transmission operations. National Grid also has installed two APFCs in central Massachusetts and has two DLR deployments in New England. Eversource, reports using advanced conductors and various power flow controllers, including APFCs, in the state, and is deploying a DLR project between the Cape Cod Canal and the town of Carver, Massachusetts. However, as is the case nationally, widescale adoption is not common. Eversource and National Grid note that advanced

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249 Brattle Group, *supra* note 109, at 26.

250 Ampacimon, *supra* note 111.

251 DOE, *supra* note 171, at 24.

252 *Id*.

253 DOE, *supra* note 56, at 12.

254 Synapse Energy Economics, *supra* note 248.

255 Connecticut Department of Energy & Environmental Protection, *Transmission Solutions White Paper* (February 2025), *available at* https://portal.ct.gov/-/media/deep/energy/transmission/transmission-white-paper-final.pdf.

256 To date, advanced conductors in Massachusetts have been limited to specific challenging locations.

transmission technologies are not the right solution for every situation and must be evaluated on a case-by-case basis.

Stakeholders and advisors involved managing the grid and deploying advanced transmission solutions note barriers and concerns regarding deployment of advanced transmission technologies. Currently, the benefits and advantages of advanced transmission solutions are not reflected in the transmission owner's business model. Ratepayers and other market participants may benefit, but utilities absorb increased operating and technology risks. GETs system modeling is not yet robust enough to be readily adopted into operations or to be included in planning. Additional concerns commonly cited in literature include challenges around accuracy limits for DLR and topology optimization, unintended risks and market changes for APFCs, and installation complexity and durability for advanced conductors.

Federal regulations and regional planning policies will strongly influence deployment of advanced transmission technologies. FERC has considered these technologies across four dockets in the last decade. In particular, FERC's regulations related to cost recovery for GETs will influence deployment of these technologies. ISO-NE is in the process of issuing recommendations for guidance on the application of GETs in the planning processes, tentatively expected by the end of 2025.[257] Once the guidance is issued, a broader assessment of needs and applicability of various advanced transmission technologies to specific segments will also likely be necessary in ensuring wider adoption.[258] Both federal and state legislatures have either passed or considered laws related to these technologies. DOE has supported pilots and studies with funding and expertise. As these examples show, entities with jurisdictional authority over advanced transmission solutions are active in developing new policies and regulations, and the decisions they make will ultimately shape the field for decades to come.

APPENDIX 1: TECHNICAL SESSION

APPENDIX 2: WRITTEN RESPONSES

DPU will append the included zip files to this document as a PDF when it is ready to submit.

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257 ISO-NE, *supra* note 50.

258 LineVision in its written response echoes this recommendation. *See* Appendix 2. LineVision.