Highlights

Grid-Enhancing Technologies: Progress, Challenges, and Future Research Directions

Omid Mirzapour,Xinyang Rui,Mostafa Sahraei-Ardakani

- Grid-enhancing technologies (GETs) are necessary for the future grid.
- GETs can enhance the transfer capability up to 50% over the existing grid.
- While some GETs rely on mature technology, industry adoption remains rather limited.
- GETs integration within energy management systems faces modeling challenges.
- Current market and regulatory structures provide little to no incentive for adoption and efficient operation of GETs.

Grid-Enhancing Technologies: Progress, Challenges, and Future Research Directions★

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ABSTRACT

The electric power sector is experiencing a rapid shift towards renewable energy resources. To accommodate this transition, the transmission system requires significant upgrades. Although enhancing grid capacity through transmission network expansion is always a solution, it can be very costly and requires a protracted permitting process. Grid-enhancing technologies (GETs)encompass a broad range of hardware and software tools that enable reconfiguration of the transmission grid and adjustment of its parameters. The proliferation of such technologies enhances transfer capability over the current transmission network, thus reducing the need for grid expansion. This paper offers a comprehensive review of grid-enhancing technologies. The paper discusses definitions of transmission flexibility and presents methods that are developed to quantify grid flexibility. The paper offers a comprehensive review of an extensive range of grid-enhancing technologies, including both principles of operation and state-of-the-art developments. Environmental impacts of grid-enhancing technologies, including renewable energy curtailment and carbon emission reduction, are also discussed. In addition to technical aspects of grid enhancing technologies, the paper also reviews the literature on the incentive challenges facing GETs adoption and efficient. Overall, the paper offers a comprehensive review of the advancements in grid-enhancing technologies, discusses the remaining critical challenges, and identifies directions for future research.

List of Abbreviations

AAR Ambient Adjusted Rating

AGC Automatic Generation Control

ATC Available Transfer Capability

BuSFI Bulk System Flexibility Index

CBM Capacity Benefit Margin

DLR Dynamic Line Rating

DR Demand Response

DSM Demand-Side Management

EMS Energy Management System

FACTS Flexible AC Transmission System

FTR Financial Transmission Right

GETs Grid-Enhancing Technologies

HVDC High Voltage DC

ISO Independent System Operator

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LCC Line Commuted Converter

LCOE Levelized Cost Of Energy

LMP Locational Marginal Price

MTDC Multi-terminal DC

PEV Plug-in Electric Vehicle

PST Phase Shifting Transformer

PTDF Power Transfer Distribution Factor

RES Renewable Energy Source

RUT Reliability Unit Commitment

RTO Regional Transmission Organization

SCUC Security-Constrained Unit Commitment

SSSC Static Synchronous Series Compensator

SVC Static VAR Compensator

TCSC Thyristor-Controlled Series Compensator

TEP Transmission Expansion Planning

TRM Transfer Reliability Margin

TS Transmission Switching

TSO Transmission System Operator

TTC Total Transfer Capability

UPFC Unified Power Flow Controller

VSC Voltage Source Converter

Nomenclature

α	Power transfer increment factor
γ_l	Partial switching on line l
Ω_{AR}	Admissible region
Ω_{ESSR}	Extended steady-state security region
Ω_{FR}	Grid flexibility region
b_l	Susceptance of line l
d_n	Demand at bus n
F_l	Active power flow on line l
L	Set of lines

L_{ik}	Load Shedding at bus *i under outage scenario k*
N	Set of buses
NF	Network Flexibility index
P_n	Active power injected into bus *n*
Q_n	Reactive power injected into bus *n*
S_l	Apparent power flow on line *l*
s_l	Marginal value of susceptance on line *l*
TC	Total generation cost
TF	Transmission Flexibility index
V_n	Voltage magnitude at bus *n*
λ_n	Locational marginal price at bus *n*
θ_n	Voltage angle at bus *n*
φ_l	Phase shifter angle installed on line *l*

1. Introduction

The electricity sector has evolved rapidly over the past two decades with steep production growth from renewable energy sources (RES). The reduced cost of harvesting renewable energy alongside the global push for a net-zero carbon grid has made renewable energy resources the prime alternative for electricity generation. Improvements in technology and economies of scale have resulted in levelized cost of energy (LCOE) from renewable energy resources to levels below that of cheap coal-fired power plants [1, 2]. Many countries, including the United States, have adopted targets for achieving a net-zero power grid [3, 4, 5, 6, 7], which requires massive integration of renewable generation. The transition from fossil fuels to renewable generation faces many challenges, including intermittency, uncontrollability, and dependence on weather. Another major challenge is the transfer of renewable power, which requires substantial upgrades to the transmission system [8, 9].

Increased congestion costs in the U.S. are clear indications of this necessity. Fig. 1 shows the reported annual congestion cost for six major regional transmission organizations (RTOs) during 2016-2022 [10, 11, 12, 13, 14, 15, 16]. These RTOs represent 58% of the U.S. electricity consumption; therefore, the congestion cost is a good indicator of the increasing trend in congestion patterns across the U.S. The congestion cost dropped below the 2016 levels, likely due to the electricity consumption reduction influenced by the COVID-19 pandemic, which later increased with a sharp surge during 2021 to an unprecedented level of $7.7 billion. This surge continued in 2022 with 56% increase in congestion cost compared to 2021. The astonishing $12 billion congestion cost clearly shows the inadequacy of the existing transmission infrastructure, and the need for upgrades to accommodate increased penetration of renewable generation.

The U.S. National Renewable Energy Laboratory (NREL), focuses on the renewable energy deployment and commercialization of energy efficiency technologies with the purpose of energy marketplace transition towards cleaner energy resources [17] A study conducted by NREL shows that the capacity of the U.S. transmission network should increase by a factor of 100-200% to accommodate the nation's renewable energy targets [18]. Energy Systems Integration Group (ESIG), a leading authority in the field of energy systems integration and energy transformation [19], in its transmission planning study for the U.S. electricity sector, suggests that the U.S. national grid requires doubling or tripling capacity to reach the carbon-free network vision [20]. Transmission expansion projects, as the primary solution for this problem, require astronomical levels of investment above other problems, including siting and permitting barriers and lack of incentive for private investors. Alternatively, grid-enhancing technologies (GETs) can effectively enhance transfer capability over the grid and therefore enhance economic efficiency and reliability besides streamlining the integration of renewable energy resources. While building new transmission lines is still necessary, GETs can offer a fast and cost-effective way of increasing transfer capability, which can reduce and postpone the need for new

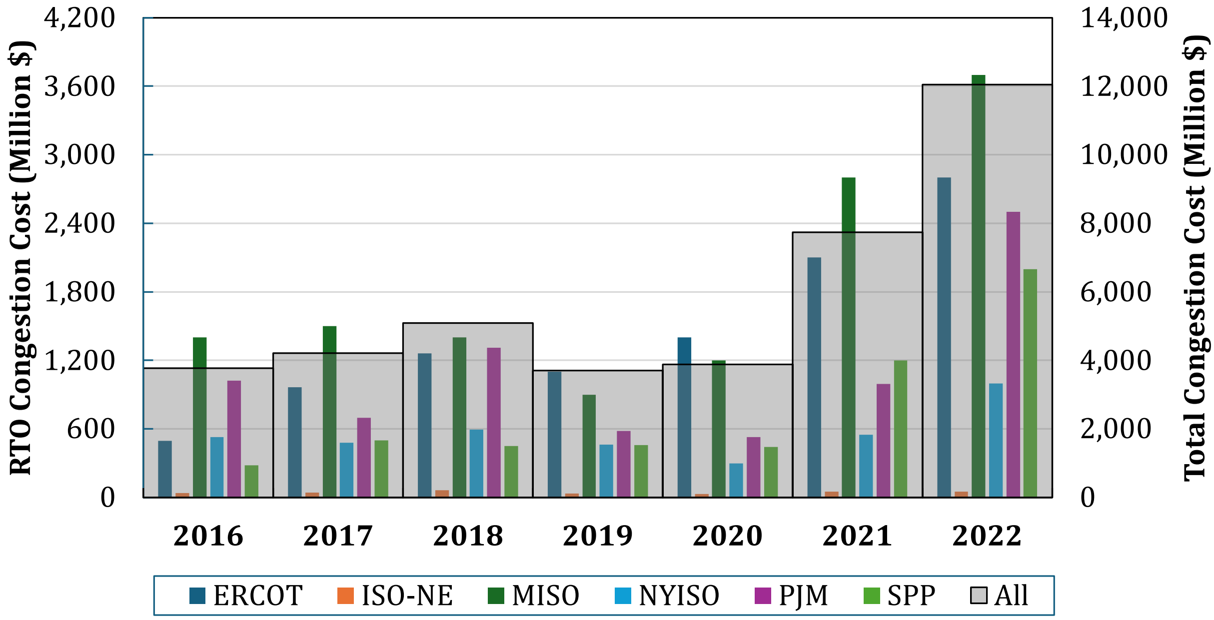

Figure 1: Congestion cost in the U.S. by ISO/RTO 2016-2022

transmission. Additionally, GETs can contribute to other aspects of grid operation, such as voltage stability [21] and reactive power balance [22], which cannot be achieved by simply adding extra capacity. Such contributions include over- and under-voltage regulation, frequency adjustments, and waveform corrections, which are discussed in detail in this study. Note that "flexible transmission" has been used in the literature to refer to "grid-enhancing technologies." The two terms are used interchangeably in this paper.

1.1. Motivation

GETs have recently received significant attention from academia, industry, and regulatory bodies. The U.S. Department of Energy (DOE) has recently announced $8.4 million in funding to advance GETs [23]. The U.S. DOE Advanced Research Projects Agency-Energy (ARPA-E) had previously invested around $40 million in GETs, through the Green Electricity Network Integration (GENI) program [24]. Idaho National Laboratory, funded by the U.S. DOE, has established the Transmission Optimization with Grid-Enhancing Technologies project, to advance GETs modeling and adoption [25]. ESIG, through funding from the U.S. Department of Energy Office of Electricity has formed a user group focused on GETs, to discuss specific technologies, their applications, and operations among the members [26] . Through the efforts mentioned here and many others across the globe, a considerable body of literature is produced to cover various aspects of GETs. Given the recent investments in GETs and the push for transition to a carbon-free power grid, more research activities are expected in this area. Unfortunately, a comprehensive review of the state-of-the-art, identifying challenges, and guiding future research is missing. This present paper intends to close this critical gap.

To the best of our knowledge, the only relevant review article is [27], which investigates mathematical formulations and metrics for grid flexibility and computational methods to solve operation and planning problems in presence of GETs. Despite being comprehensive in its particular aim, many important aspects of GETs are not covered. Several other review articles have focused on flexible AC transmission system (FACTS) technologies, including [28, 29]. However, their scope is limited to FACTS and other technologies are not discussed. This comprehensive review covers 1) various technologies that offer transmission flexibility, 2) quantification of transmission flexibility, 3) GETs modeling in operation, planning, and contingency analysis, 4) environmental impacts of GETs adoption, 5) incentives for adoption and efficient operation of GETs, 6) industry adoption and experience, and 7) challenges facing GETs proliferation. The paper hopes to inform researchers, practitioners, and regulatory bodies about the state of the art and challenges in GETS adoption and operation.

1.2. Contributions

The main contribution of this paper is a detailed discussion of the following :

- Definition of flexible transmission based on the most recent developments,
- Mathematical models for quantification and evaluation of transmission flexibility,
- Comprehensive review of technologies that enable transmission flexibility,
- Investigation of financial aspects of GETs, addressing the impact on current electricity markets and proper market tools for deployment,
- Environmental impacts of GETs in renewable energy deployment and carbon emission,
- A comprehensive review of the current industry adoption of GETs,
- Identification of remaining barriers and suggestions for future research directions.

To this end, Section 2 reviews the concept of flexibility in engineering and specifically in power systems. The section further addresses the challenges leading to transmission system flexibility and presents a definition of flexible transmission. Section 3 introduces various technologies and methods enabling transmission system flexibility. Section 4 presents reliability analysis of GETs under power system degraded mode. Section 5 discusses the impact of grid adjustments on carbon emission and renewable energy curtailment under different levels of renewable energy penetration and generation mix. Section 6 discusses current energy market structures and the impact of GETs on both energy and financial transmission right (FTR) markets. This is followed by industry adoption of GETs in Section 7. Section 8 addresses current adoption barriers and prospects of GETs. Finally, Section 9 summarizes the paper and presents final remarks and future research directions. The bibliography covers 265 up-to-date references covering various aspects of GETs. The industry survey is done through 81 articles including technical reports, executive summaries, regulatory proceedings, and monitoring agency evaluations from the past five years. The research articles represent a complete overview of each aspect through seminal work from 2000 to the most recent findings in 2023. 43 articles have been dedicated to the conceptual study of flexibility, 87 articles represent a full technical bibliography on various types of GETs, 16 articles focus on environmental benefits, and finally 57 articles address the regulatory issue and energy management system integration.

2. Transmission Flexibility Definition and Metrics

This section presents an overview of flexibility in engineering systems, followed by the definition of power system flexibility and necessity in response to electricity system transformation. Accordingly, GETs are introduced as a central part of power system flexibility, and the mathematical metrics for quantifying transmission system flexibility are reviewed.

2.1. Flexibility in Power Systems

Flexibility is a broad concept used in various systems and applications from different points of view. Therefore, presenting a single and general-purpose definition of flexibility is not appropriate to capture the nuances of the concept. Generally, flexibility is defined as the ability of a system to respond to a range of uncertain future states by taking an alternative course of action within an acceptable cost threshold and time window [30]. The International Energy Agency (IEA), from the perspective of balancing supply and demand, defines flexibility as the general ability of a system to react to changes in generation and demand over time [31]. Considering the most general definitions presented above, flexibility can be studied from different perspectives, including time horizon, type of variability, and sector. From the time horizon perspective, flexibility can be studied over the short-term or long-term, ranging from milliseconds to months or years. Short-term analyses are performed for operational studies to ensure the system's reliable operation within security margins [32, 33]. On the other hand, long-term flexibility analyses are performed in planning studies to ensure the system is robust against uncertainties in fuel prices or resource availability from an economic viewpoint

[34]. Technical flexibility studies focus on the system's secure operation [35], while economic flexibility studies seek to employ flexible resources to maximize surplus [36]. Finally, the variability in flexibility studies can be predictable or involve uncertainty. Predicted variations include planned outages of transmission or generation units for maintenance, which can be implemented in the deterministic optimal power flow or unit commitment models [37, 38]. However, for uncertain variations, including renewable generation output variations and forced outages due to contingencies, stochastic or robust models may be required to ensure the secure operation of the grid [39, 40].

Considering this framework, we can now review various definitions of power system flexibility in the literature. Reference [41] defines power system flexibility as the ability of the system to deploy its resources to meet changes in net load. This definition takes a technical approach toward power system flexibility. The net load in this definition is the difference between the electricity demand and variable renewable generation, i.e., wind and solar. The steep growth in the share of RES has led to increased volatility in net load and subsequently increased demand for power system flexibility to accommodate higher levels of uncertainty. Another technical definition of power system flexibility focusing on generation flexibility is presented in [42], which describes flexibility as the ability of power systems to provide enough ramping and capacity in response to demand variation on operational timescale. From an economic point of view, flexibility can be described as the system's competency to provide ample capacity in case of future uncertainties and variabilities at marginal cost [43]. Risk management criteria determine the compromise between the cost of extra capacity and flexibility value [44].

The most prevalent categorization of power system flexibility studies is by sector: generation, demand, and transmission flexibility. Generation flexibility is the most conventional area of power system flexibility studies. Fast response units are commonly dispatched to provide ramping requirements on the operational time horizons to maintain power and frequency within stability margins required for stability and reliability of the system [45, 46]. The primary frequency regulation is achieved through online generators' governor system to adjust the output in response to frequency deviations within 15-20 seconds. If the frequency deviation continues, in the secondary regulation, The automatic generation control (AGC) is further utilized to compensate for mismatches between load and generation by coordinated adjustment of multiple generation unit outputs within 200 seconds [47, 48]. If the online units are not sufficient for frequency regulation, in the tertiary regulation, the ISO brings additional reserve units online to compensate for frequency deviations. GETs can play a crucial role in frequency regulation by providing additional transfer capability for reserve deliverability and providing interconnections for external power and reserve exchange, which is discussed in details in the following sections. Demand flexibility, on the other hand, seeks to exploit flexible loads to enhance the regulation capability of the power system to cope with uncertainties in the operation of the power system [49]. Demand-side management (DSM) and demand response (DR) are the two well-known frameworks that make use of operational practices and guidelines, including shifting load to off-peak periods and consequently reducing generation cost and congestion in the network [50, 51]. Multiple practices have been proposed in the literature that can be utilized to leverage flexibility on the demand side, including time-of-use tariffs, critical peak pricing, demand bidding and smart metering [52, 53, 54, 55, 56]. Fig. 2 summarizes the various aspects of flexibility in power systems addressed in the literature. Reference [57] presents a comprehensive review of flexibility taxonomy and classification, considering the most recent publications.

2.2. Flexible Transmission Concept

Although there is a vast body of literature on generation and demand flexibility, transmission flexibility is more or less absent from flexibility studies. The reason is that the transmission network has historically provided sufficient capacity to deliver energy and accommodate standard reserve margins for reliability. Most of the existing literature in the power system flexibility area are centered around generation flexibility, and the transmission system is considered a constraint in dispatching generation flexibility [58]. However, the steep growth of renewable generation has pushed the legacy transmission network to its limits by introducing extra levels of uncertainty in the generation, new congestion patterns, and the need for security enhancements, including reactive power and voltage support requirements [59, 60]. Additionally, renewable generation provides lower flexibility levels than conventional thermal generation. Thus, higher penetration of renewable energy resources demands the enhanced operation of flexible transmission assets, i.e., FACTS devices, phase shifting transformers (PST), and circuit breakers, in providing flexibility at the grid level.

The current literature does not offer a consensual definition of transmission flexibility. A consensual definition with quantifiable metrics is crucial for stakeholders to evaluate their schedules and coordinate system-wide flexibility, ensuring effective information flow. Ref. [27] defines transmission system (grid-side) flexibility as the ability of a power network to deploy its flexible resources to cope with volatile changes in the power system state in operation.

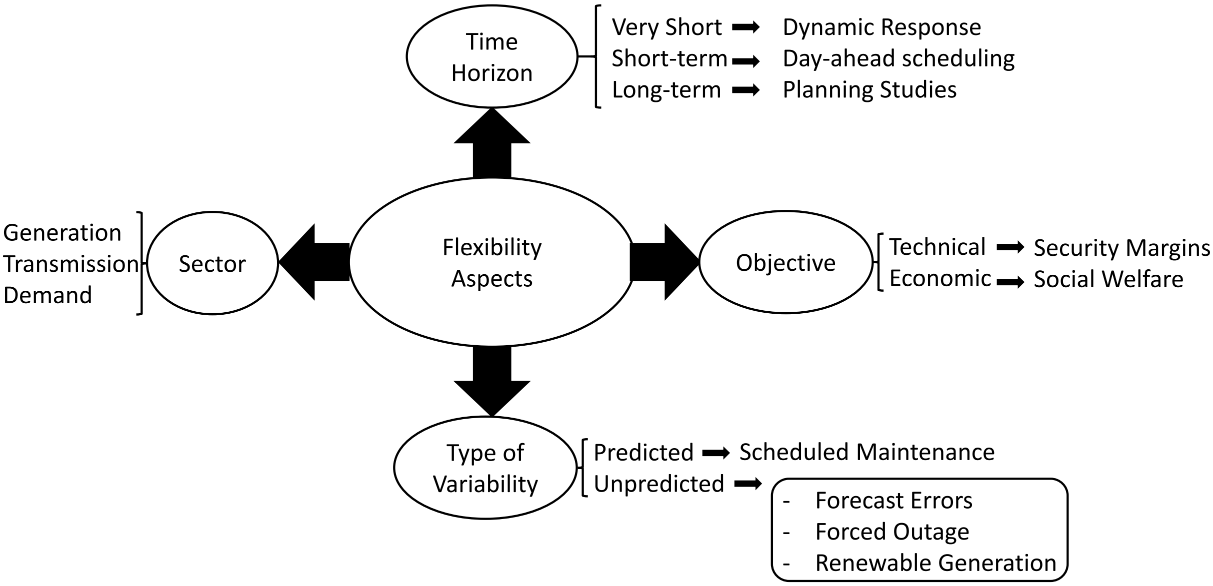

Figure 2: Various aspect of flexibility in power system studies

However, this definition is limited to operational flexibility and does not consider the long-term flexibility requirements of the transmission network. From the long-term perspective, [61] defines flexibility in transmission investment as the ability of investors to choose among an extended range of alternatives, including postponement, abandonment, and operational flexibility enhancement under uncertain market environments. Enhancing operational flexibility helps the investor handle the long-term uncertainties and risks in the deregulated environment.

We define transmission system flexibility as the ability of the network to reconfigure itself in response to expected or unexpected variations over various time horizons to achieve maximum transfer capability from generation to demand. Accordingly, flexible transmission refers to various technologies and business practices that enable the transmission network to adjust to generation and demand uncertainties. Flexible transmission can alleviate congestion by enhancing transfer capability over the current grid and postponing grid expansion costs [62]. A recent study by the Brattle Group over the Southwest Power Pool (SPP) grid shows that flexible transmission proliferation can leverage transfer capability by 100% [63]. A recent case study by the U.S. Department of Energy on NYISO shows that grid-enhancing technologies, namely dynamic line rating and power flow controllers reduce renewable energy curtailment by 43% and improve electricity rates for end-users by alleviating congestion in the 2030 New York state grid vision with 70% renewable energy penetration [64]. Allocating such savings to different stakeholders in different market structures requires further research.

Considering the definition presented above, several aspects of flexible transmission must be addressed. Flexible transmission can be studied over various time horizons, from seconds to several years. Transmission networks can be considered in stability studies in response to contingencies [65]. Several studies have been conducted to deploy transmission network flexibility sources on operational time horizons, hourly to day-ahead operation [66, 67]. Planning studies have incorporated flexible transmission to facilitate the integration of RER and prevent congestion in the long term [68, 69]. We further need mathematical metrics to quantify the flexibility of the transmission network and the impacts of flexible transmission. Generally, grid flexibility can be evaluated from two points of view: technical and economic. From the technical point of view, various mathematical indices and geometric representations have been proposed in the literature. An overview of these metrics is provided in the following subsection. From the economic point of view, a lack of flexibility in transmission networks creates congestion in the grid, which results in an out-of-merit generation schedule and therefore incurs extra costs on consumers, which is formalized as congestion cost. A detailed analysis of congestion cost and how it can represent grid flexibility is provided in Section 6.

2.3. Technical Metrics for Transmission System Flexibility

Available transfer capability (ATC) is one the most established metrics to evaluate the transmission network's ability to dispatch generated power to demand [70]. ATC measures the transmission system's capability to transfer extra power from the source to the sink. It is used for transmission expansion studies and operational constraints for day-ahead market scheduling [71]. In the U.S., Federal Energy Regulatory Commission (FERC) requires all ISO/RTOs to regularly calculate and report ATC to open access same-time information system (OASIS) for system upgrades and planning [72]. ATC is calculated based on Total Transfer Capability (TTC), transmission reliability margin (TRM), and capacity benefit margin (CBM) as follows [73]:

$$ATC = TTC - TRM - CBM. \tag{1}$$

TTC is the summation of maximum transfers allowable above base case power flow considering thermal, security, and contingency constraints. The calculation of TTC is the core of ATC calculation. This is a very important step, since overestimation of TTC puts the system at security risks and can lead to instability, while underestimation results in inefficient utilization of the transmission infrastructure and misleading signals for expansion [74]. TTC calculation can be formulated using continuation power flow [75]:

$$\text{maximize } \alpha \tag{2}$$

$$\text{s.t.: } P_i = \sum_{j=1}^{n} V_i V_j Y_{ij} \cos(\theta_j - \theta_i + \varphi_{ij}), \qquad \forall I; \tag{3}$$

$$Q_i = \sum_{j=1}^{n} V_i V_j Y_{ij} \sin(\theta_j - \theta_i + \varphi_{ij}), \qquad \forall i \in N; \tag{4}$$

$$V_i^{\min} \le V_i \le V_i^{\max}, \qquad \forall i \in N; \tag{5}$$

$$|S_{ij}| \le S_{ij}^{\max}, \qquad \forall (i,j) \in L; \tag{6}$$

$$P_i = P_i^0 (1 + \alpha k_i), \qquad \forall i \in N; \tag{7}$$

$$Q_i = Q_i^0 (1 + \alpha k_i), \qquad \forall i \in N; \tag{8}$$

$$TTC = \sum_{i \in \text{sink}} P_i(\alpha^{\max}) - \sum_{i \in \text{sink}} P_i^0, \tag{9}$$

The mathematical problem seeks to maximize the additional increment in power transfer, α, for each sink node subject to the network's physical constraints (3)-(6). The total transfer capability is calculated as the total transfer amount above the base case power flow (9). TRM is the transfer capability margin ISO reserves for coping with prevailing uncertainties, including renewable generation volatility, load forecast inaccuracies, and transmission contingencies. Maintaining sufficient TRM is necessary for reliable system operation and preventing curtailments [76]. CBM is allocated to ensure generation reserve deliverability in an interconnected system in case of a generation unit outage. The required amount of CBM is determined based on the historical value of loss of load expectation (LOLE) for each area. The areas with higher amounts of annual LOLE should maintain higher CBM margins for ensuring external reserve deliverability in case of generation outage [77].

To visualize grid-side flexibility, [27] defines grid flexibility region Ω_{FR} as the difference between admissible region Ω_{AR} before and after implementing grid flexibility.

$$\Omega_{FR} = \Omega_{AR} - \Omega_{AR0}. \tag{10}$$

Admissible region Ω_{AR} used in the literature is defined as the area where all the flexibility resources can accommodate every uncertain power injection without violating feasibility constraints [78, 79].

$$\Omega_{AR} = \{(P_U, Q_U) | \forall (P_U, Q_U) \in \Omega_{AR} \qquad \exists (P_C, Q_C) \in \Omega_{ESSR}\}, \tag{11}$$

where (P_U, Q_U) is the level of admissible uncertain active and reactive power injection that the grid can handle under the condition that ample flexibility from controllable power injection, e.g., generation control or FACTS devices, (P_C, Q_C), is available, such that there exists a feasible solution under network physical constraints (3)-(6) described as extended steady-state security region (Ω_{ESSR}).

Table 1
Transmission Flexibility Metrics

Flexibility Metric	Ref. No.	Time Horizon	Application	Computational Burden
Available Transfer Capability (ATC)	[73]	Operation/Planning	Day-ahead Schedule/Maintenance Schedule/Expansion Studies	Medium-High
Admissible Region (AR)	[27]	Operation	Visualization	High
Network Flexibility (NF)	[80]	Planning	Generation Expansion	Medium
Transmission Flexibility (TF)	[81]	Planning	Transmission Expansion	Low-Medium
Bulk System Flexibility Index (BuSFI)	[82]	Planning	Generation/Transmission Expansion	Medium-High

To evaluate the flexibility of the network on the planning horizon, deterministic indices have been proposed in the literature. Reference [80] evaluates the network flexibility under generation expansion scenarios based on the network capacity utilized by generation expansion.

$$NF(S_{ij}^{max}) = \frac{\sum_{ij\in N_l} S_{ij}^{max}(\sum_{k\in N_b} PTDF_k^{ij})}{\sum_{ij\in N_l} S_{ij}^{max}}. \tag{12}$$

Network flexibility (NF) metric for each transmission capacity level (S_{ij}^{max} is determined by the average usage of transmission capacity based on the total power transfer distribution factor (PTDF) for each injection, divided by total network capacity. The smaller value of NF means lower utilization of the network and, therefore, higher grid flexibility.

A similar metric for transmission expansion planning (TEP) has been proposed in [81], based on the expected load shedding due to line outage for peak load under high and low demand scenarios.

$$TF = E(\sum_{i\in N_b}\sum_{k\in N_l} L_{ik}P_k). \tag{13}$$

The transmission flexibility index (TF) is derived by calculating the expected value of load shedding at bus i due to line k outage for high and low peak demand scenarios. The smaller value of TF shows smaller load shedding and, thus, higher flexibility of the transmission grid against line outage contingencies.

Reference [82] proposes bulk system flexibility index (BuSFI) as the maximum allowable variation in the generation at a node that minimizes power margin on the transmission system.

$$\text{minimize} \sum_{ij\in N_l} P_{ij}^{max} - |\sum_{k\in N_b} PTDF_k^{ij}(P_k^0 + \Delta P_k)| \tag{14}$$

s.t.: (3)-(6)

$$BuSFI_k = \Delta P_k \qquad BuSFI_{tot} = \sum_{k\in N_g b} BuSFI_k. \tag{15}$$

This formulation allows for calculating the local flexibility index, $BuSFI_k$ for each generation bus that allows generation expansion without violating transmission system security margins and total system flexibility index $BuSFI_{tot}$. This index offers a signal to generation owners about the ability of the transmission network to accommodate generation expansion in each area. The overview of various transmission system flexibility evaluation measures is summarized in Table 1.

3. Sources of Transmission Flexibility

Transmission flexibility can be harnessed through various technologies and procedures. Prominent methods include power flow control through discrete adjustment in grid topology [83] or continuous control of transmission line impedance [84] or voltage phase [85]. This section presents an overview of each of the aforementioned technologies.

3.1. Flexible AC Transmission System (FACTS)

FACTS technology intends to provide more efficient and reliable dispatch of electricity by providing tighter control over power flows in the transmission network [86]. FACTS devices can be deployed to enhance transient stability, voltage regulation, and mitigate system oscillations [87, 88, 89]. The first studies regarding the application of FACTS technology for enhancing transmission system flexibility and stability were carried out by the Electric Power Research Institute (EPRI) in the U.S. [90]. FACTS devices can control different properties of transmission elements, including line impedance, bus voltage magnitude, and voltage phase angle. FACTS devices can be categorized based on the controller technology. The older FACTS devices use thyristor switches to control line impedance or shunt capacitors. Thyristor-controlled series compensators (TCSC) and static VAR compensators (SVC) are FACTS devices using thyristor controllers. A device similar to the TCSC is the continuously variable series reactor (CVSR), which provides positive series reactance changes using a low power rating AC/DC converter [91]. In contrast, the more recent technology uses self-commutated voltage source converters (VSC). Static synchronous series compensators (SSSC) and unified power flow controllers (UPFC) are VSC-based FACTS devices. Based on their functionality, FACTS devices can be connected in series configuration (e.g., TCSC and SSSC) or shunt configuration (e.g., SVC), or a combination of both (e.g., UPFC). Generally, series compensators are used for line impedance and active power flow control [84], and shunt devices provide reactive power compensation. The role of shunt devices, such as SVC, in Power Oscillation Damping (POD) is providing reactive power compensation in contingency states, which is critical to maintain power system stability [92]. The UPFC is a more versatile device providing both shunt and series compensations [28]. The recently developed distributed FACTS (D-FACTS) or modular FACTS (M-FACTS) provide the same functionality with the merit of modularity [93, 94]. Figure 3 summarizes FACTS classification based on controller, configuration, and functionalities.

In this paper, we focus on the power flow control functionalities of FACTS devices. Series FACTS devices can provide power flow control capabilities through line impedance adjustments, thus increasing the loading capability of the transmission system and alleviating congestion. Prominent FACTS technologies that can enhance the transfer capability include the TCSC, the CVSR, SSSC, and UPFC. Various types of FACTS devices use different techniques to alter the line reactance. TCSC and CVSR devices both directly alter the line reactance with the CVSR being a cheaper option but only capable of providing positive reactance change [91]. UPFC and SSSC devices use a voltage injection to emulate reactance adjustments [95, 96]. The first implementation of TCSC in Kayenta, Arizona, has shown a promising 30% improvement in ATC [97]. Unlike TCSC, there have been few implementations of UPFC due to its high investment cost. The first practical UPFC implemented in Kentucky, U.S., consisted of two 160 MVA VSC-based units, which provided voltage and reactive power support and enhanced power flow capability across the region [98].

The immediate economic benefit of series FACTS deployment in the transmission system is reducing the operational cost, as power flow control can enhance transfer capability and accommodate more generation from more cost-efficient units. Various existing literature has investigated the economic benefits of deploying FACTS devices and different levels of savings after solving power system operation problems with FACTS incorporated. In [84], the two-stage linear optimal power flow with variable-impedance FACTS devices in the IEEE 118-bus system shows up to 30% cost saving compared to the base case when 40 lines are equipped with FACTS devices and 90% of line reactance control is assumed.

Similarly, FACTS deployment can be an effective way of enhancing the integration of renewable generation. In [99], an optimal allocation problem for series FACTS devices and PSTs is solved. The results on the IEEE 118-bus system show that a 6.80% increase in renewable generation can be accommodated with the deployment of TCSC and PST devices. Similarly, D-FACTS and FACTS deployment can lead to cost savings and help reduce renewable energy curtailment in most cases, according to the results in [100]. It is worth noting that, as the results show in [100], the objective of power system operation models is to minimize the total operation cost; thus, FACTS deployment can lead to increased renewable curtailment in some cases. The effectiveness can be affected by the locations of FACTS devices and renewable generation, among other factors [101].

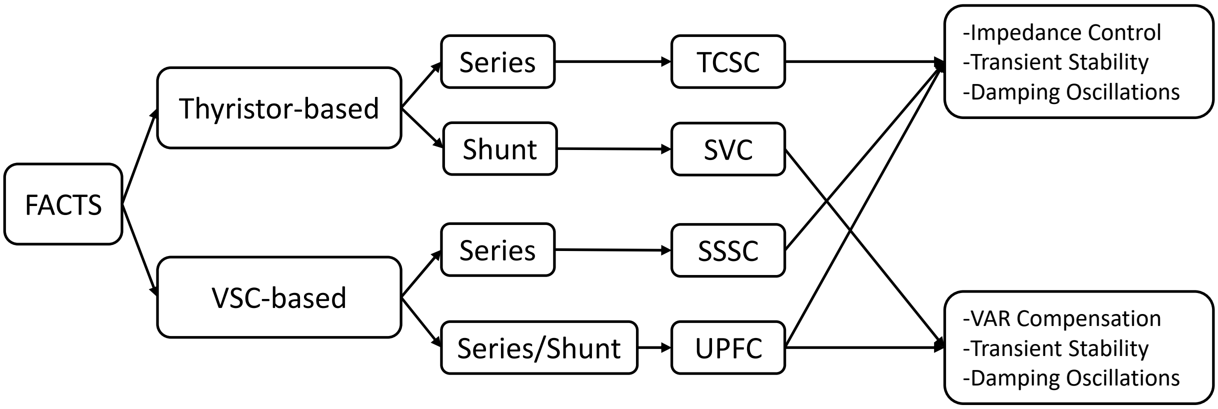

Figure 3: FACTS Technology Overview

Despite the technical benefits that FACTS devices offer to the grid, their deployment has been limited due to high upfront investment costs and insufficient compensation, which undermines the economic viability of these technologies [102]. While FACTS offers a host of benefits, including social welfare improvements, enhanced system flexibility, emission reductions, and enhanced renewable energy integration, the benefits are not financially values. FACTS is mostly treated as a part of the monopoly transmission system and receives regulated compensation. This issue is further discussed in Section 8.

Among the FACTS technologies, the SVC and STATCOM have been better received by the power industry, due to their superior dynamic performance and smaller area requirements [103]. The maturity of the technologies over time has reduced the capital costs associated with these technologies, which makes them even more attractive with the installation of 100 units worldwide [104]. The TCSC, despite its simple technology and reasonable investment cost, has received limited attention due to the limited range of applications compared to SVC and STATCOM and the technical challenges incurred including the risk of introducing fault currents and the need for a bypass protection system [105, 106]. Finally, the UPFC, which is the superior FACTS technology in range of applications and performance has been deployed only in six cases due to high investment and maintenance costs stemming from its complex design [107]. Overall, further FACTS adoption requires building trust and confidence in the industry and better mechanisms to quantify FACTS benefits and compensate the investors for them.

3.2. Topology Control

Transmission switching, also known as topology control, is an effective solution to enhance transfer capability. Transmission switching can be considered as an extreme case of impedance control, where the impedance of the switched element is adjusted to infinity sang2017interdependence. Transmission switching can be used for economic purposes or to enhance system reliability as a preventive or corrective action [108]. Northeast Power Coordinating Council (NPCC) has listed corrective transmission switching among remedial action schemes (RAS) for avoiding abnormal voltage conditions [109]. Corrective transmission switching has been used for loss reduction, transmission line overloading relief, and improving power system reliability in the literature [110, 111]. Although corrective transmission switching has been considered by ISO/RTOs for ad-hoc reconfiguration of the grid in response to contingencies, as in PJM's Special Protection Scheme (SPS) [112], it is not yet integrated into energy or market management systems.

Transmission topology is traditionally assumed to be fixed, with the exception of planned or unplanned outages. Given that existing circuit breakers can open a line or transformer, network topology can be adjusted to deliver economic or reliability benefits under normal and contingency operation. Although the redundancy built into the transmission system ensures reliable power system operation in the long term, it can lead to congestion in short-term operations. It is shown that reconfiguring the network by switching out specific lines under certain operational conditions will increase transfer capability. It is also well-known that switching out lightly loaded lines can alleviate voltage issues caused by such lines' capacitive components and enhance grid security.

With the main goal of increasing the economic efficiency of power dispatch, optimal transmission switching has been used to enhance operational efficiency under normal operating conditions and decrease losses in the system through discrete adjustments in network topology [113]. The cost saving achieved by optimal transmission switching has shown up to 25% [114] in the IEEE 118-bus system. However, the optimality of the solution is not guaranteed. Although transmission switching may seem to compromise network reliability by switching out transmission lines under normal operation, previous research has shown that co-optimizing transmission switching and generation dispatch saves cost while maintaining system reliability margins [115]. Co-optimizing network topology alongside N-1 optimal power flow shows that transmission switching can be implemented without endangering N-1 reliability criteria (system operation continuation under a single element outage) [116]. Despite the advantages that transmission switching introduces, its deployment has been rather limited. This is due to a number of reasons, including the computational burden of topology control problems, unpredictable distributional impacts on Locational Marginal Prices (LMP), and potential revenue inadequacy in FTR markets [117].

3.3. Grid Interconnection and HVDC

Traditionally, high-voltage AC (HVAC) systems have dominated the bulk power transmission grid, benefiting from the early development of high-voltage transformers that allow efficient power transmission over longer distances with minimal loss. However, with recent developments in DC technologies, including the introduction of insulated-gate bipolar transistor (IGBT) valves into the power industry, high-voltage DC (HVDC) transmission increased its share of the transmission market. Although thyristor valves benefit from higher voltage and current ratings, IGBT valves, due to self-commutation ability and controllability, are the primary option for VSC-HVDC applications [118]. After the first IGBT-based HVDC link project in 1997 [119], most VSC-HVDC projects relied on IGBT valves [120] and with expected 65% share of VSC from HVDC market the IGBT is to become more prevalent [121, 122]. HVDC benefits from several technical and economic advantages, which makes it the superior alternative in many cases and even the sole option in particular applications. Currently, HVDC lines can deliver power over 3000 km while the maximum point-to-point distance for AC links is reported to be 1049 km [123, 124, 125]. This is due to the absence of reactive power components in HVDC links which minimizes the losses to resistive loss and allows full utilization of the line's capacity up to its thermal limits [126]. Further, HVDC offers complete power flow controllability, making it the prime option for delivering renewable generation over long distances, e.g., offshore wind generation [127, 128]. The controllability of power flow in HVDC link is crucial for smooth integration of intermittent renewable generation as it enables bidirectional power exchange between remote renewable resources and the AC grid while maintaining the grid's stability and balance [129]. HVDC further provides grid flexibility by interconnecting regional transmission networks that are not synchronized. This will increase power supply security and enable interregional energy trading [130]. The EU has set the target of 15% capacity allocated for interconnection with neighboring markets by 2030 [131]. HVDC links are the only option for connecting asynchronous neighboring systems [132]. Finally, HVDC links can provide ancillary services, including power quality control and reactive power support [133].

HVDC systems consist of two main blocks: interface to AC system and HVDC transmission. HVDC systems can be categorized based on the technologies and methods used in each block. AC system interface consists of ac-to-dc and dc-to-ac converters and transformers adjusting converter input/output level to AC transmission voltage level. The converter station, as the backbone of the HVDC system, is designed based on either of two major technologies: line commutated converter (LCC) or voltage source converter (VSC). As the older technology, LCC stations operate based on the AC network configuration; therefore, they cannot participate in system cold start after blackouts [134]. LCC further entails technical challenges, including excessive reactive power consumption and voltage reversal requirement at the DC terminal, which makes it the less attractive choice for the prospect of DC grids [47]. The more recent technology, VSC is gradually dominating the HVDC links with its superior capabilities in providing ancillary service and power quality [135]. VSC offers enhanced controllability over peripheral in hybrid grids and multi-terminal DC (MTDC) networks [136].

Despite HVDC's advantages in power transmission, there are still challenges against deploying HVDC. The first challenge is the high cost of converter stations, especially the VSC technology [137]. The second is the lack of cost-efficient DC circuit breakers, which has slowed the pace of DC grid deployment. DC cables' high cost and limited voltage ratings are other barriers to developing HVDC [138]. Currently, the commercial rating for DC cables ranges from 200 to 1100 KV [139]. Regulatory hurdles and operational challenges further add to the complexity of

Table 2
HVAC, LCC-HVDC, VSC-HVDC Comparison [140]

	HVAC	HVDC
Conductor Cost	Higher (~$1.5 Billion for 6000 MW, 765 kV, 2000 km)	Lower (~$700 Million for 6000 MW, 800 kV, 2000 km)
Substation Cost	Lower (~$600 Million for 6000 MW, 765 kV, 2000 km)	Higher (~$1 Billion for 6000 MW, 800 kV, 2000 km)
Losses	Higher (~$1 Billion for 6000 MW, 765 kV, 2000 km)	Lower (~$500 Million for 6000 MW, 800 kV, 2000 km)
Right of Way	Higher (~240 m for 6000 MW, 765 kV, 2000 km)	Lower (~90 m for 6000 MW, 800 kV, 2000 km)
Maximum Span	Lower (~ 1049 km)	Higher (~ 3000 km)
Protection Scheme	Mature and Cost-efficient	Developing and Expensive
Power Flow Control	Lower	Higher
Asynchronous Interconnection Capability	No	Yes
	LCC-HVDC	VSC-HVDC
Cold-Start Capability	No	Yes
Reactive Power Consumption	Higher	Lower
Ancillary Service Procurement	Lower	Higher
Converter Cost	Lower	Higher

operating HVDC lines, especially in the case of MTDC, where multiple ISO/RTOs are engaged. The issues regarding multiple ownership, MTDC control and management, and technical standardization of DC grids are the subject of future research. Table 2 provides a techno-economic comparison of HVDC versus HVAC transmission and HVDC technologies comparison.

3.4. Voltage Phase Control

Voltage phase control over the transmission line allows active power flow rerouting throughout the AC transmission grid and can enhance the transfer capability. Two major technologies that allow voltage phase control over transmission lines include FACTS devices and phase-shifting transformers (PST). FACTS technology can provide voltage phase shift alongside other ancillary services. The most notable FACTS devices used for phase shift include thyristor-controlled phase shifters (TCPS), variable series capacitors (VSC), and unified power flow controllers (UPFC). FACTS phase shifters can provide dynamic response for transient stability and inter-regional oscillation mitigation [141, 142]. While FACTS devices can offer more versatile control over transmission grid parameters, their investment cost is much higher than ordinary PST. PST can increase the transfer capability of the transmission system to provide power flow control by controlling the relative voltage phase angle difference between different areas of the grid and preventing parallel and loop flows relatively inexpensively [143, 144]. PST can further be utilized to interconnect asynchronous systems and provide voltage regulation for enhancing supply security by adjusting the phase angle deviations at the point of interconnection that can be incurred by the frequency difference between the two systems [145]. PST, however, lacks the dynamic response for providing stability control for the grid. Reference [146] proposes an optimization framework for minimizing the risk of congestion by deploying PST on pivotal lines in the grid. This framework can further be utilized in broader planning studies where the requirements of transmission systems over longer time horizons need to be evaluated. Reference [147] proposes an index for prioritizing active power flow through lines using TCPS in a bilateral energy market. Reference [148] proposes an optimization model for coordinated congestion management over interconnected RTOs using PST and introduces indices for cross-border PST site selection. Reference [149] proposes an optimal location framework for PST to maximize wind energy penetration in the network. The impact of pivotal PSTs (close to interconnection) on cross-border power transactions and flexibility provision in each transmission system operator (TSO) is further discussed in [150]. PST has also been considered for enhancing the demand-side flexibility of plug-in electric vehicles (PEVs) in conjunction with tap-changing transformers [151]. The

24-hour optimal power flow simulation on a modified IEEE 118-bus system with 5 wind farms, 4000 PEV fleet with stochastic availability and on-line tap-changing transformers and phase shifting transformers show that coordinating the PEV flexibility with transmission flexibility resources through linearized ac optimal power flow can achieve 11% dispatch cost saving and 45% reduction of wind spillage.

3.5. Dynamic Line Rating

Transmission line ratings were initially defined as reliability measures to ensure that power flow on the lines does not incur security risk over the grid [152]. Line ratings are often based on the thermal limits of conductors to prevent line overheating. However, these ratings are conventionally set rather conservatively by line owners, based on nameplate ratings with limited consideration of ambient temperature or wires condition. The nameplate rating is based on worst-case ambient assumptions and is not updated during the transmission line's lifetime. Improving the methods for setting line ratings can increase efficiency in the transmission network and the entire power system on a larger scale [153]. With the growth of communication infrastructure and smart grid technology, it is now possible to set thermal limits using real-time weather data rather than the conservative ratings, the system operators use. This would allow more effective use of the current network capacity and enhance the transfer capacity of the grid [154]. To consider more realistic assumptions regarding the ambient temperature, some utilities update line ratings for summer and winter temperatures. Some ISO/RTOs, including PJM and ERCOT, use ambient adjusted ratings (AAR), which use online weather monitoring service data (including National Oceanic and Atmospheric Administration) to update line ratings based on atmospheric conditions [155]. This method calculates line ratings by step functions based on ambient data.

Dynamic Line Rating (DLR) considers the largest information set, including local weather conditions, wind speed and direction, solar irradiance, and line condition. Wind speed plays the most influential role among these factors as it can enhance line thermal capacity by 10%-40% through convective cooling [156]. This potential can be best achieved by coupling line loading and cooling in areas with high penetration of wind generation [152]. Accordingly, DLR requires the most extensive equipment upgrades as well. This equipment includes sensors for measuring ambient conditions as well as line conditions. These sensors can be installed on the lines or use remote sensing (LIDAR). Line-based sensors provide more direct and accurate information compared to ground-based sensors. However, installing and maintaining these sensors require line outages, and they are more vulnerable to tampering. The next upgrade must be implemented on the communication infrastructure to transfer data to the energy management system (EMS). The communication medium can be cellular, satellite, microwave, or radio network. The choice of the communication medium depends on the location of sensors, the data's size, and the data transmission rate. Fig. 4 shows one of the suggested DLR implementation schemes within ERCOT's EMS.

To effectively implement DLR, first, congested lines need to be identified based on the data provided by the system operator. Sensor placement depends on several factors, including line span and land diversity. Data communication must be implemented carefully since it is most susceptible to breaches and cybersecurity threats. The computational methods and coordination between DLR and more conventional line rating methods are important steps toward implementing DLR. Considering the intermittent nature of renewable energy resources and their interrelation with congestion in transmission systems, efficient forecasting methods need to be considered in rating calculation methods [154].

Implementing DLR entails economic benefits, which include avoided transmission expansion investment cost on congested lines, reduced generation cost by alleviating congestion and out-of-merit dispatch of units, increased renewable generation utilization and reduced renewable energy spillage, and finally, increased system reliability, improved reserve deliverability and system disturbance management during summer. In [158] DLR has been implemented in the stochastic day-ahead unit commitment model alongside transmission switching. The results on the RTS-79 system show that DLR can incur up to 20% dispatch cost saving and 72% wind energy curtailment reduction when co-optimized alongside network topology. DLR enhances market competitiveness by enhancing market participants' access to the transmission system. DLR also improves transmission system reliability by increasing flexibility in line ratings compared to static line rating and providing more informed decision-making for operators and line owners rather than ad-hoc uprating. A New York Power Authority (NYPA) study shows that dynamic line rating can increase line carrying capacity by 50% compared to static rating [159]. Another study by Oncor indicates that incorporating DLR into ERCOT's energy management system (EMS) increased wind utilization by 30-70% compared to static rating and 6-14% compared to AAR. Potomac Economics estimates a $128 million saving in 2020 accrued by implementing AAR in MISO [160].

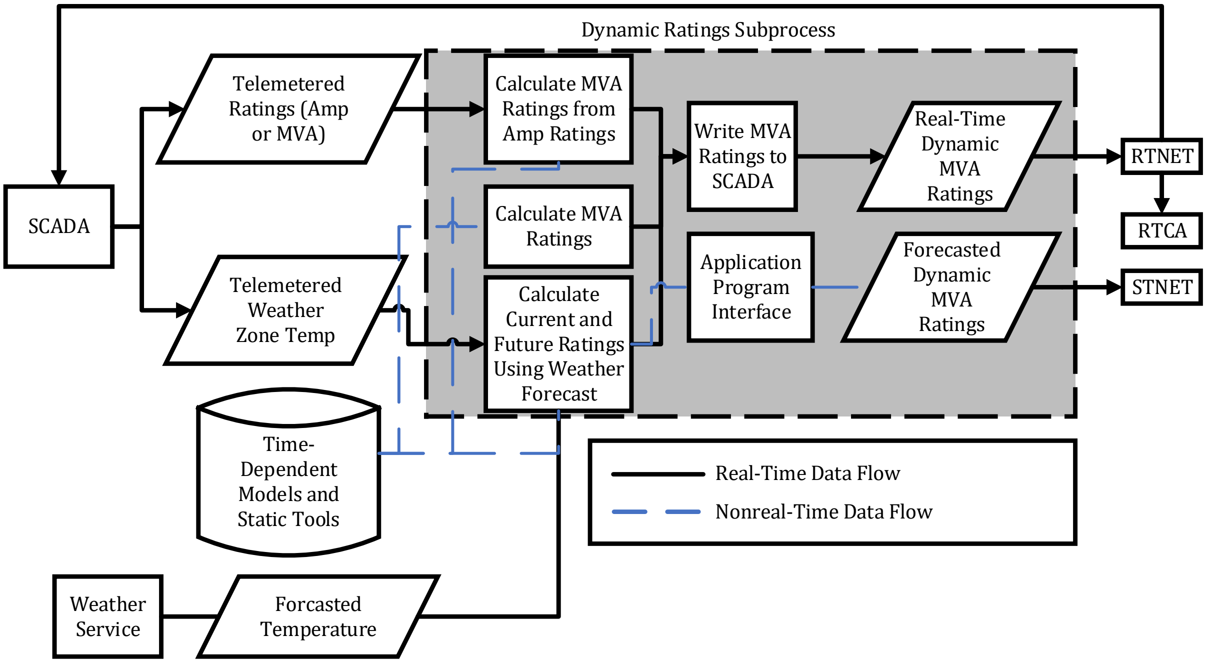

Figure 4: DLR implementation in ERCOT's real-time EMS [157]

Table 3
Flexible Transmission Technologies

Flexibility Source	Control Parameter	Adjustment Mode	Implementation Cost	Operation Cost Saving
FACTS	Line Impedance/Voltage Phase and Magnitude	Continuous	Medium-High	up to 30% [84]
TS	Grid Topology	Discrete	Low	up to 25% [114]
HVDC	Capacity/Full Power Flow Control	Continuous	High	up to 50% (loss reduction) [133]
PST	Voltage Phase	Continuous	Medium	~12% [151]
DLR	Capacity	Continuous	Low	~20% [158]

Currently, most system operators in the U.S., including CAISO, ISO-NE, MISO, NYISO, and SPP, use seasonal rating in compliance with FERC Order No. 881, which is closest to static rating, and line ratings are rarely updated in contingency situations upon system operator request [161, 162, 163, 164]. Although DLR and AAR can effectively increase the operational efficiency of the grid, they are still not considered in the planning and long-term scheduling of the grid. Federal Energy Regulatory Commission (FERC) Order No. 1000 requires transmission planning models incorporating advanced technologies, including dynamic line rating [165]. Table 3 reviews various sources of flexibility presented in this section.

3.6. Integrating Flexibility into Transmission Expansion Planning Models

Including other sources of flexibility, i.e. energy storage systems (ESS) and demand-side management, in Transmission Expansion Planning (TEP) provides the opportunity to increase the grid flexibility in longer time horizons (planning horizon). This will in turn allow postponing the expansion of the grid, which is economically less attractive and often opposed by the public due to environmental concerns. The recent FlexPlan project [166] has successfully established these alternative solutions in the TEP models as required by the European Commission's "Clean Energy for all Europeans" package [167] to leverage the flexible options instead of directly expanding the grid. The proposed model adds the environmental analysis to the conventional N-1 reliability criterion in the TEP. This model has further been applied to six European regional transmission systems to provide a view of the flexibility requirements of the grid and the potential of the proposed alternatives in the long run (2030, 2040, and 2050 planning horizons). The external sources of flexibility can be considered as complements to the TEP as well as alternatives. [168] discusses this interesting topic regarding the role of ESS in the TEP. The paper presents an MILP expansion model with ESS integration. The results on the 27-bus Chilean stylized system show that besides the roles of ESS postponing the need for expansion, they can promote the building of new lines that interact with the storage system in the most efficient way to leverage system flexibility and reduce the need for future investments. The integrated flexibility and TEP models can be improved by adding weather data, especially under high penetration of renewables in the generation mix. [169] incorporates enhanced spatiotemporal weather forecasts into the TEP alongside pumped hydro storage (PHS) and demand-side management as sources of flexibility. The study on the North Sea area, considering ENTSO-E 2030 scenarios, shows that more accurate information can improve the location and timing of transmission and PHS investments, considerably reducing operational and investment costs as well as renewable energy curtailment by up to 40%. Demand-side management is part of the wide range of energy efficiency programs. The energy efficiency programs are considered the most cost-effective solutions to provide flexibility to TEP as well as other benefits as they require low investment costs [170]. This source of flexibility can be modeled in TEP as a reduced demand or virtual source of power, which reduces the need for further expansion of the grid through local supply [171, 172]. Similar to other external sources of grid flexibility, energy efficiency programs should not be considered as alternatives to TEP; rather, they are complements to make the models more efficient and flexible [173]. Another approach to integrate flexibility into TEP models is joint generation and transmission expansions in multi-carrier energy systems (MCES). This approach has been implemented on a joint electricity and gas network expansion model with linearized flow models [174]. The results show that the mutual flexibility of gas and electricity networks can bring considerable savings in transmission investment as well as gas facilities through coordinated planning.

4. Reliability Analysis in Contingency Mode

Maintaining reliability is the primary goal of the system operators. To achieve reliable operation, the system should be able to withstand the loss of assets due to planned or unplanned outages and maintain power delivery to consumers. North American Reliability Council (NERC) has determined the $N-1$ criterion for the reliability, which is the ability of the system to maintain operation under the loss of one bulk element in the system [175]. GETs can play a substantial role in improving the power system reliability by enhancing voltage stability, increasing transmission capability, and rerouting power flow. [108] proposes corrective transmission switching in real-time contingency analysis (RTCA), which incurs considerable cost savings for the system operator by reducing the need for system redispatch. The extensive analysis of over 1.5 million contingency scenarios across TVA, ERCOT, and PJM shows that single transmission switching can eliminate violations in $10\% - 30\%$ of the cases leading to considerable redispatch savings in $58\% - 83\%$ of the cases. The role of TCSC, SVC and UPFC devices in enhancing power system reliability through mitigating power flow violations and power loss under system degraded mode has been demonstrated and compared in [176]. The paper further uses three metrics to quantify the severity of contingencies, namely, the number of contingencies, the contingency severity index (CSI), and the total severity of overloads (TSOL). The CSI metric used to rank the transmission lines based on their importance in contingency scenarios is calculated as follows:

$$CSI_j = \sum_{i=1}^{m} P_i u_{ij} W_{ij}, \tag{16}$$

where P_i represents the probability of jth branch outage under ith contingency, u_{ij} is the participation factor indicating the line overload under contingency, and W_{ij} is the ratio of contingency flow to base flow of the line. The other metric TSOL evaluates the total impact of all contingency scenarios on the grid based on the overload ratio and significance factor as follows:

$$TSOL = \sum_{c=1}^{m} \sum_{k=1}^{n} a_k (\frac{P_k}{P_k^{max}})^4. \tag{17}$$

The results on the Southern region of the Indian grid show that FACTS placement based on CSI can reduce generation cost by up to 2% which translates to \$ 37.6 k hourly operational cost saving and 33.5% loss reduction in the network. Furthermore, placing FACTS devices reduces the TSOL index from 34.76 to 15.70 which translates to severity reductions up to 55%.

DLR has been vastly studied for reliability enhancement in a degraded grid, as it can create instant capacity for post-contingency cases. [177] proposes a stochastic optimization framework for DLR to enhance grid capacity and alleviate congestion during contingencies under high penetration of wind energy in the system. The proposed framework demonstrates 15% wind utilization improvement during contingency scenarios. [178] combines transmission switching and DLR in security-constrained unit commitment to reduce the number of switching actions during the contingencies, which yield considerable improvement in switch lifespan and operational savings.

Although the aforementioned GETs can bring considerable improvements in the operation of power systems in degraded mode, they face limitations in computation, complexity, and installation. Transmission switching can create additional reliability issues under the new network configuration. Furthermore, analysis of multiple switching actions requires excessive computational capacity. FACTS installation requires additional investment costs and auxiliary installations for the protection system. Furthermore, corrective FACTS adjustment is a computationally demanding task, due to challenges in incorporating nonlinear FACTS models in optimization problems. Finally, DLR requires accurate weather forecasting models in contingency analysis, which adds to the operational complexity. Overall, the reliability improvement and complexity trade-offs should be carefully scrutinized for each technology.

5. Environmental Impacts

Besides the economic benefits, GETs can offer environmental advantages by contributing to the transition toward a carbon-free grid. GETs can accommodate intermittent renewable generation by adjusting the transfer capability accordingly and allow for higher levels of renewable energy penetration [151]. Accordingly, carbon emissions decline as fossil-fueled generation units are replaced by clean energy resources. Further considering transmission flexibility in the planning horizon leads to better generation and transmission expansion decisions. Various GETs have been studied for emission reduction. Reference [66] proposes variable-impedance FACTS devices co-optimization alongside a stochastic day-ahead unit commitment model to minimize wind energy curtailment. Transmission switching has been investigated in several studies to reduce carbon emissions. Reference [179] proposes a minimum-emission optimal dispatch by adding emission cost to the dispatch cost function. This approach has been applied to transmission planning and joint generation and transmission expansion to minimize renewable energy spillage in the long term [180, 181]. However, including emission costs in the objective function is not favored by current industry practices since it artificially increases total dispatch cost in the system and leads to inefficient economic signals for investment. Multi-objective optimization has been used to address this shortcoming [182]. Although this approach introduces better economic signals, it is computationally burdensome for large networks, especially for transmission switching scheduling, which already introduces binary variables to the problem. Another challenge with multi-objective optimization is the challenges of picking a solution from the set of Pareto optimal solution.

The literature has also addressed dynamic line rating to enhance renewable energy utilization [152]. The concerns regarding the power system reliability trade-off have been investigated in [183], where the authors introduce an optimization framework to minimize wind spillage through dynamic line rating while maintaining reliability criteria within the acceptable limit. Joint optimization of multiple sources of transmission flexibility can help leverage the environmental benefits while covering the shortcomings of each source with the other one. Reference [184] co-optimizes transmission switching and energy storage, leading to reduced wind curtailment and reduced load shedding. Dynamic line rating and transmission switching have also been utilized to minimize the dispatch cost while constraining carbon emissions within certain limits [185].

Although the literature suggests that flexible transmission leads to emission reduction and higher renewable energy utilization, under current market scheduling models with the primary objective of maximizing social welfare, flexible transmission optimization may lead to adverse environmental impacts under certain operational conditions. This happens when the flexible transmission co-optimization model finds accommodating cheap thermal units such as coal more economical compared to congested renewable resources and chooses to curtail renewable energy and dispatch thermal generation. Such conditions have been studied for variable-impedance FACTS devices [101, 186]. Similar studies for transmission switching show similar results under current market structures [184, 185].

6. The Incentive Problem and Market Integration

The electric power sector was heavily regulated before the 1970s. Following the deregulation of other industries, restructuring of the electric power sector, starting with generation, showed that market-based operation can promote enhanced efficiency through competition [187]. The distribution system has since evolved to also allow for some level of competition [188]. Transmission, however, has maintained its status as a "natural monopoly" and operates under regulation. Thus, transmission assets, including flexible transmission, do not participate in the market and do not receive payments that reflect their contribution to the system. This creates a major problem for adoption of GETs technologies. *The current regulatory structure offers little to no incentive for adoption of GETs.* First, an industry that receives a regulated rate of return on its investments prefers to invest more capital as long as the regulators approve the plan. In this case, a transmission owner and operator would prefer to build more transmission lines rather than enhance the efficiency of its existing system. The former would require billions of dollars worth of investment, while the latter is orders of magnitude cheaper, and thus results in substantially smaller returns. Second, even if a transmission owner does adopt a form of GETs, there is little to no incentive for efficient operation, because the payments are not based on performance. Unless this problem is solved, the outlook for GETs adoption remains grim.

This fundamental problem with the lack of incentive is part of the reason why current adoptions of GETs are heavily tilted towards reliability improvement, rather than economic efficiency. Additionally, this lack of incentive also explains why GETs are being pushed through regulatory mandates, such as FERC's mandates around dynamic line rating [189].

A preferred way of solving this problem is finding efficient ways to integrate GETs within the electricity markets. It is argued in the literature that, unlike transmission, flexible transmission does not pose the characteristics of a natural monopoly [190]. Thus, in theory, the operation of GETs can be left to the market. With a successful market integration, the market will offer an efficient price signal to flexible transmission similar to generation and load. The literature falls short in developing practical market models and formulations to incorporate GETs. There are two lines of research in this area.

The first line envisions the assignment of FTRs to owners and operators of GETs. FTRs were originally introduced as a financial tool to distribute congestion rent and hedge against congestion-related price volatility. FTRs can be considered as congestion payments based on the LMP difference between the point of injection and the point of withdrawal as long as the FTR assignment passes the simultaneous feasibility test (SFT). SFT ensures that power flows resulting from these financial contracts do not violate network constraints. Using the FTR framework, an owner and operator of GETs can be assigned an FTR, based on the additional transfer capacity it provides [190]. FTRs are calculated as follows:

$$FTR_l = F_l(\lambda_{l,to} - \lambda_{l,fr}), \tag{18}$$

where λ is the locational marginal price at each end of the line and F_l is the line flow obtained from the market economic dispatch solution. Reference [190] suggests that compensating power flow controller (PFC) owners through new FTR allocations will be revenue-adequate as long as the feasibility region remains convex.

The second line of research is based on the marginal value of GETs operation [191, 192, 193, 194]. Calculating the flexible transmission's marginal value depends on the type of power flow controller used. The marginal payments can be derived directly from the associated dual variables for GETs technologies incurring continuous adjustments to power flow variables, including variable impedance FACTS devices and voltage phase controllers. Considering the power flow equation and its associated dual variable in the DCOPF problem:

$$F_l - b_l(\theta_{l,to} - \theta_{l,fr}) = b_l\varphi_l \quad [s_l] \tag{19}$$

the marginal value of susceptance adjustment can be calculated as:

$$\frac{\partial TC}{\partial b_l} = s_l(\theta_{l,to} - \theta_{l,fr} - \varphi_l) \tag{20}$$

and similarly, the marginal value of voltage phase control can be calculated as follows:

$$\frac{\partial TC}{\partial \varphi_l} = b_l s_l. \tag{21}$$

Calculating the marginal value for switching action is complicated due to the presence of integer variables in the power flow equation. [195] proposes a fictitious continuous variable to account for the partial switching of each line:

$$F_l - b_l(1-\gamma_l)(\theta_{l,to} - \theta_{l,fr}) = b_l \varphi_l \quad [s_l] \tag{22}$$

Adding the constraint $\gamma_l = 0$ the DCOPF model yields the same results as the original DCOPF. However, the dual variable associated with the latter constraint can be used as an estimation of the marginal value of switching a specific line. However, since switching is discrete, this estimation brings large inaccuracies in calculating the value of switching actions [196].

While the current research has taken a few steps in envisioning a more complete electricity market design, which GETs can also participate, more research is urgently needed. An efficient market design for GETs, should align the individual incentives with social welfare improvements, be revenue-adequate, and be computationally tractable.

Another related challenge is the impact of GETs on existing market participants. As an example, [117] shows that transmission switching can lead to revenue inadequacy problems within the FTR market. An ideal market design should address such issues and make sure that the market remains efficient, as newer players are allowed to participate.

7. Industry Adoption of GETs Technologies

ISO/RTOs have adopted GETs, to a limited extent, to improve the efficiency, reliability, and security of the power system. Moreover, the benefits and potentials of GETs are acknowledged by multiple ISO/RTOs, and GETs adoption is expected to grow in the near future. For example, PJM anticipates that deploying emerging technologies such as FACTS and DLR to utilize the existing grid is an important part of the solution to facilitate power system decarbonization [197]. However, the current implementation of GETs is limited due to the challenges mentioned previously in this paper. Meanwhile, FERC has considered pushing for the adoption of GETs through regulation, with efforts in this direction including Order No. 1000, Order No. 881, and the workshop discussing performance-based ratemaking approaches to facilitate the adoption of transmission technologies [198]. Therefore, various discussions and proposals have been made to increase GETs implementation by ISO/RTOs [199, 200]. Additionally, developments have been made by the industry in recent years for GETs devices and solutions to allow more efficient deployments and operations. For example, the recently introduced D-FACTS or M-FACTS, which are cheaper, smaller, and more flexible than conventional FACTS devices [201, 202], as well as tools for optimizing DLR and transmission switching. In this section, we present a review of the current and planned implementation of GETs technologies by ISO/RTOs, and related technology development in the industry.

7.1. FACTS Technologies

Prominent shunt FACTS devices such as the SVC and the STATCOM are widely deployed in ISO/RTOs to provide a variety of functionalities [203, 204]. However, the adoption of series FACTS devices providing reactance adjustments, which is the focus of this paper, has been rather limited. Series reactors are deployed in ISO-NE, with some of them serving the purpose of power flow control for certain transmission lines [205]. Series compensation and other technologies are considered to alleviate thermal overloading in the area of CAISO with project proposals submitted by entities such as Smart Wires Inc. [206]. Similarly, series capacitors are deployed by PJM to maintain reliability and provide operational flexibility during outages [207]. However, there is no specific mention from the ISO/RTOs regarding whether the operation of these series compensation devices is optimized in operation models such as security-constrained unit commitment (SCUC). Additionally, it is unclear how and to what extent these resources are being utilized to alleviate congestion, reduce operation costs, and facilitate renewable generation integration. There have been deployments of series FACTS devices intended to solve transmission bottlenecks and help the integration of RES. An example of such deployments is the Marcy South series compensation project in NYISO, which was completed by the NYPA and New York State Electric Gas (NYSEG) in 2016 [208]. Series capacitors installed in this project can help enhance the transfer capability and facilitate delivery of power generated by wind and hydro units [122, 208]. However, whether the installed series capacitors are being dynamically controlled and adjusted in the operation models is unclear.

General Electric (GE) currently offers series compensation systems that can increase the power transfer capability of existing or newly built transmission lines and have been installed in different locations worldwide, such as Texas and Vietnam, to increase transmission systems' reliability, stability, and power transfer capability [209]. Hitachi Energy produces TCSC devices that can enable rapid dynamic modulation of the inserted reactance [210]. Siemens also manufactures a variety of FACTS devices, including the fixed series capacitor and UPFC [211]. The UPFC Plus devices by Siemens provide fast power flow control capabilities that can improve the utilization of existing transmission capacities [212]. Additionally, M-FACTS or D-FACTS devices have also emerged in the industry. The SmartValve manufactured by Smart Wires Inc. is a modular SSSC (M-SSSC) device that provides both inductive and capacitive transmission line reactance adjustments while providing more flexibility and scalability in deployments with its modular design [213].

7.2. Transmission switching

ISO/RTOs have participated in multiple studies to explore the potential benefits of implementing transmission switching. A pilot project, in partnership with PJM, used historical PJM market data to study the cost savings achieved and implications on FTR by implementing transmission switching [214, 215]. Case studies in SPP and ERCOT systems also have been carried out to demonstrate the effectiveness of transmission switching to reroute power flow to alleviate congestion and overloading [216]. The studies also revealed that transmission switching can allow higher utilization of newly built high-capacity transmission lines. Regarding the actual implementation of transmission switching, PJM provides a list of potential transmission switching solutions that may be utilized for solving congestion issues [217]. However, PJM states that the displayed transmission switching solutions are not guaranteed to be taken into action in market operations.

The industry has developed software tools for implementing transmission switching. The topology optimization software by NewGrid can help system operators reroute power flows through transmission switching to reduce congestion [218]. Results from the studies conducted between NewGrid and SPP show that topology control can achieve $18-44 million in market cost savings annually [219]. NewGrid has conducted case studies with SPP, NewGrid has identified ISO/RTOs, market participants, and transmission owners as their potential partners [218].

7.3. Dynamic Line Rating

Intending to improve power system efficiency, FERC Order No. 881 requires that organized market operators provide and maintain systems and procedures allowing transmission owners to implement DLR [189]. In response to the FERC order, ISO/RTOs have prepared compliances incorporating DLR in their transmission systems. Testing and implementation of DLR started before the issuing of the FERC order. NYPA demonstrated DLR technologies through the Smart Grid Demonstration Project and the results showed that up to 25% additional capacity can be provided for system operations [220]. PJM conducted studies with American Electric Power (AEP) from 2016 to 2018 on two transmission lines to better understand the impact and potential benefits of DLR technology [203, 221]. Pilot projects to test DLR have also been conducted by ERCOT and NYISO [222]. Additionally, ISO-NE achieved significant consumer savings to alleviate heavy congestion by increasing line ratings on transmission ties with New York in response to extreme weather conditions in 2018 [223]. FERC Order No. 881 specifies requirements and definitions that are different from historical ISO practices, which involve AAR periods and temperature settings [224].

The industry has also developed numerous DLR technologies. For example, the LineRate Suite by LineVision is said to provide up to 40% increase in transmission line capacity with accurate DLR calculations [225]. Additionally, Operato's software SUMO provides DLR algorithms and helps system operators optimize system operation [226, 227].

7.4. PST

PSTs are deployed by ISO/RTOs in various locations for power flow control. ISO-NE currently has PSTs at seven locations to control active (real) power flows on the transmission system within operating limits [205]. An example of PST deployment by CAISO is the installation of two parallel PSTs at Imperial Valley [228]. The operation of PSTs, along with other controllable transmission devices, are integrated into CAISO's security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC), meaning that the optimal positions of the PSTs are determined by CAISO's market systems [229]. Similarly, the operation of PSTs in NYISO operation is optimized by SCUC, thus adjusting the PST schedules to help power delivery into congested areas [230]. The Market Management System (MMS) of ERCOT is enhanced so that the tap settings of PSTs are automatically determined in the day-ahead market and the reliability unit commitment (RUC) to achieve efficient market solutions [231].

PSTs are manufactured by companies such as GE, Hitachi Energy, and Siemens to provide power flow control solutions. The products can be used for applications including stability enhancement, overloading prevention, and increasing transmission capacity. For example, PSTs by Siemens are used by TSOs in Germany as effective power flow control capabilities can help improve the stability of power system operation and reduce dispatch costs [232].

7.5. HVDC

ISO/RTOs plan multiple transmission projects that involve HVDC. CAISO currently has two HVDC projects planned for reliability purposes and four others to facilitate access to wind generation, with examples being the TransWest Express Transmission Project and the SunZia transmission [233]. Prominent HVDC projects for NYISO include the Clean Path New York (CPNY) and Champlain Hudson Power Express [234]. Both projects involve underground and underwater HVDC lines, thus providing benefits such as resilience enhancement and landscape protection [235, 236]. NYISO is also developing market rules for internal controllable lines as the CPNY project is internal to the New York Control Area (NYCA) [234]. A prominent HVDC project involving PJM is the SOO Green Project carried out by Direct Connect Development Company, which can deliver low-cost renewable generation from MISO areas to customers in PJM [237]. PJM also established the High Voltage Direct Current Senior Task Force (HVDCSTF), which studied the potential of allowing HVDC converters to participate in PJM's capacity market [238].

Prominent companies in the industry have made advances in HVDC technologies. GE manufactures both LLC and VSC, which have been deployed across the world [239]. Additionally, offshore HVDC projects in Europe are currently planned by GE and its partners to help deliver wind energy [240]. Hitachi Energy provides VSC, LLC, and HVDC control systems that can be utilized for various applications [241]. Siemens also offers two types of HVDC products: the HVDC classic [242] based on LLC and the HVDC plus [243] based on multimodule converters (MMC) VSC. They improve transmission capability, stability, and reliability.

7.6. Summary

Overall, GETs technologies have experienced different deployment patterns. They have been adopted or planned to enhance transmission capacity and facilitate access to renewable generation. However, incorporating the operation of flexible transmission devices in the existing power system operation models and changing the market structure to allow merchant flexible transmission market participation is essential to fully harness the benefits of GETs. It appears that state-of-the-art operation models can only optimize PST setpoints, although developments to model other GETs are currently underway.

8. Challenges Facing GETs Adoption

Implementing flexible transmission technologies is currently limited due to technical challenges and regulatory barriers. This section summarizes these challenges.

8.1. Regulatory Barriers and Lack of Incentive

As discussed briefly in Section 6, the transmission system is considered to be a natural monopoly and, thus, is tightly regulated. Flexible transmission, unlike the bulk transmission network, does not pose the characteristics of a natural monopoly. The investment required for flexible transmission is smaller, and the resulting capacity enhancement is incremental, compared to the construction of new lines. Thus, a competitive environment can be created to promote the adoption and operation of flexible transmission. It is essential to explore the deficiencies of the current regulatory structure around GETs.

First, it is important to note that at least some GETs are commercially available and mature. This includes a variety of FACTS devices and numerous DLR and topology control advisory tools. Even when the technology needs further development, the adoption is far behind the technology. This can be, at least partially, explained by the lack of incentive that the current regulator structure offers. As discussed in Section 6, the regulated rate of return paid to transmission owners does not provide the right incentive for GETs adoption, and may even create a disincentive, as investment in new lines is more profitable. An efficient market design can provide the opportunity for the proliferation of GETs and reduce the need for costly and time-consuming transmission expansion projects. Market mechanisms further provide the environment for active participation of GETs in power system operation and result in the efficient operation of transmission network [244]. This will ultimately lead to the transition to a more reliable grid and streamline renewable energy integration, with a reduced need for new transmission lines.

A solution to this challenge is pushing for GETs adoption through further regulation and mandates. A preferred solution would be a "complete market design" [245], where GETs can participate in the market and receive compensation based on its performance. Such a market would promote adoption and efficient operation of GETs, without the need for mandates. Such a market design should produce an efficient price signal for GETs that aligns profitable operation with social welfare enhancement (cost reduction). The market should also be revenue adequate and computationally tractable.

Three market mechanisms may have the potential to enable the incorporation of GETs into current electricity markets. First is the FTR market. This market mechanism only works for market designs with nodal market prices as it requires spatial distribution of LMPs to compensate FTR owners based on the congestion rent. The congestion rent cannot be calculated in markets with a single price or zonal prices, as the spatial price data is unavailable at the required resolution. For such cases, as in European market design, a market-based compensation has been proposed, using the cost-based redispatch signal prices [246]. The strength of this method compared to the FTR-based markets is that the investor profit is aligned with total welfare maximization. This means that any investment that increases the social welfare of the system will receive positive compensation from market clearing. This means that the cost-based redispatch compensation mechanism intrinsically overcomes the revenue adequacy problem in FTR markets [247, 248]. The third compensation method is the marginal value compensation of each transmission project. The main obstacle against this method is that it provides no hedging for the investor against the probable risks in system operation and may lead to negative revenue in some cases. Some research has also introduced mixed regulated and merchant transmission investment that can be fit into current market structures [249].

The current regulatory system is inefficient for the deployment of flexibility resources and GETs, due to several shortcomings, as the final proceedings of the Flexplan project suggests [250, 251]. First, the ownership of energy storage or other sources of flexibility and the operating parties (generators, load-serving entities, or both) needs to be clarified in market regulations. Second, The coordination between the transmission and distribution systems is insufficient in current market structures and certain regulations need to be added to leverage the data exchange between the two levels of the system for optimal exploitation of flexibility resources. Third, current cost-benefit analyses do not reflect the full value of flexibility as they do not account for the resilience evaluation, societal gains, and environmental benefits of enhanced grid flexibility upgrades in the long term. The fourth challenge that undermines the real value of GETs in the electricity markets is disregarding the voltage regulation and reactive power in the price calculations in electricity market designs in countries such as Columbia due to computational complexities in EMS integration [252, 253, 254]. This issue is one of the main factors leading to underinvestment in GETs that offer reactive power compensation. Therefore, new valuation methodologies need to be developed for the aforementioned resources to be integrated into the transmission infrastructure.

8.2. EMS Integration and Computational Challenges

Implementing GETs in the EMS and coordination with current procedures and emerging technologies, including energy storage systems, in a computationally efficient manner, is another aspect of future grid vision [255]. Power system equations are nonlinear and non-convex, making short-term and long-term optimization models computationally demanding, especially for large-scale systems [256, 257]. Co-optimizing the power flow controller's placement and operation further adds to this complexity [66]. Considering these complexities and the limited computational power available, current markets use simplified models with linearized equations for power flow. To ensure the reliable operation of the electricity market, the impact of intrinsic nonlinearities and power flow controllers on market efficiency should be identified. In case of a large mismatch, out-of-market corrections should be introduced.

A prominent example of the increased computational burden caused by optimizing GETs operation is the nonlinearity of the DC power flow equation resulting from considering the operation of variable-impedance FACTS devices such as TCSC. Previous studies have proposed algorithms and models to efficiently co-optimize FACTS operation with power system operation and planning [84, 95, 258]. Optimal transmission switching adds to the computational burden by introducing integer variables that yield a mixed-integer problem with higher computational demand. Efficient methods for solving AC and DC formulated co-optimization of transmission switching and optimal power flow are available in the literature [259, 260]. Efficient formulations and solution methods capable of addressing the nonlinearities of flexible transmission and acceptable solution time are interesting subjects of future studies.

8.3. Technical Challenges

Although GETs technologies have developed significantly during the past two decades, some technical issues still hinder their deployment. In HVDC interconnections, the DC circuit breaker technology is not mature and cost-effective compared to its AC counterpart. The LCC converter stations, the more dominant converter technology, lack the capability for weak AC grid support. Some of the studies in the research have proposed hybrid LCC/VSC-based links that benefit both VSC controllability and LCC cost-effectiveness. On the other hand, the VSC technology suitable for multi-peripheral DC networks is not cost-effective. Active circuit breakers are gaining attention for grid reconfiguration and HVDC link fault currents. Flexible converters and novel configurations are necessary to provide flexibility in AC and DC networks.

8.4. Communication Infrastructure and Smart Grid

Effective scheduling and optimization of flexible transmission assets require enhanced data flow and information exchange systems for proper coordination. Smart grid infrastructure is essential for effectively controlling GETs, which requires upgrades in the power system's current communication schemes. The role of the smart grid is also significant in long-term decision-making and flexibility planning. The recent FLEXITRANSTORE pilot project has been developed to enhance smart grid requirements for leveraging efficient flexibility to achieve low carbon power systems across Europe [261]. The importance of Information and Communication Technologies (ICT) becomes more significant as the decentralization trends increase in electricity markets and cross-border transactions are required to ensure supply security. Managing a multitude of uncertainties and sources of flexibility requires state-of-the-art communication schemes [262]. The role of the smart grid in managing demand-side flexibility in a competitive market environment has been shown in [263]. A similar scheme is missing in flexible transmission literature and should be addressed in future research. The final aspect of the smart grid's importance in flexibility is flexibility coordination between different sectors, especially demand-side and transmission flexibility schedules. As more distributed generation units are deployed in the distribution system, and demand response programs are increasing, scheduling these sources of flexibility with the transmission system is crucial and needs efficient information exchange between ISO/RTOs and Distribution System Operators (DSO) [264].

9. Conclusion

This paper offers a comprehensive review of GETs, including the concept, mathematical representations, technologies, environmental issues, and market prospects. The concept of flexibility in transmission networks was conceptually explained and further illustrated with mathematical indices and visualization. The technologies that can be utilized to enhance the flexibility of the grid are listed and reviewed in details, addressing both merits and shortcomings of each technology. The role of GETs in the electricity sector decarbonization is addressed by each technology and operational condition that can lead to an adverse impact on carbon emissions and renewable energy curtailment. The integration of GETs into current electricity markets is studied, addressing both impacts of GETs on energy and FTR markets as well as market tools for incentivizing GETs investment. Finally, current barriers against GETs deployment and future research roadmap are discussed. The main conclusions drawn from this study are listed below:

- GETs can offer considerable cost savings and reliability enhancement. Promisiong 10-30% operational cost savings have been reported by multiple papers in the literature;
- Although GETs leverage the environmental benefits of renewables in most cases including 5-20% increased renewable energy utilization and 30-70% carbon emission reduction, under certain market conditions, it can lead to increased levels of carbon emissions;
- there are still some technical challenges in various areas of GETs that need to be addressed, including DC circuit breakers and VSC technologies;
- under the current market environment, GETs investment is not compensated on a competitive basis, and the distributional impacts of GETs on LMP and FTR markets need to be thoroughly studied;
- Development of computational tools that can balance the computational time and optimal solution for the nonlinear GETs co-optimization is required.

- Current TEP and valuation methodologies need to be modified to account for GETs and external sources of flexibility including ESS and DSM.

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