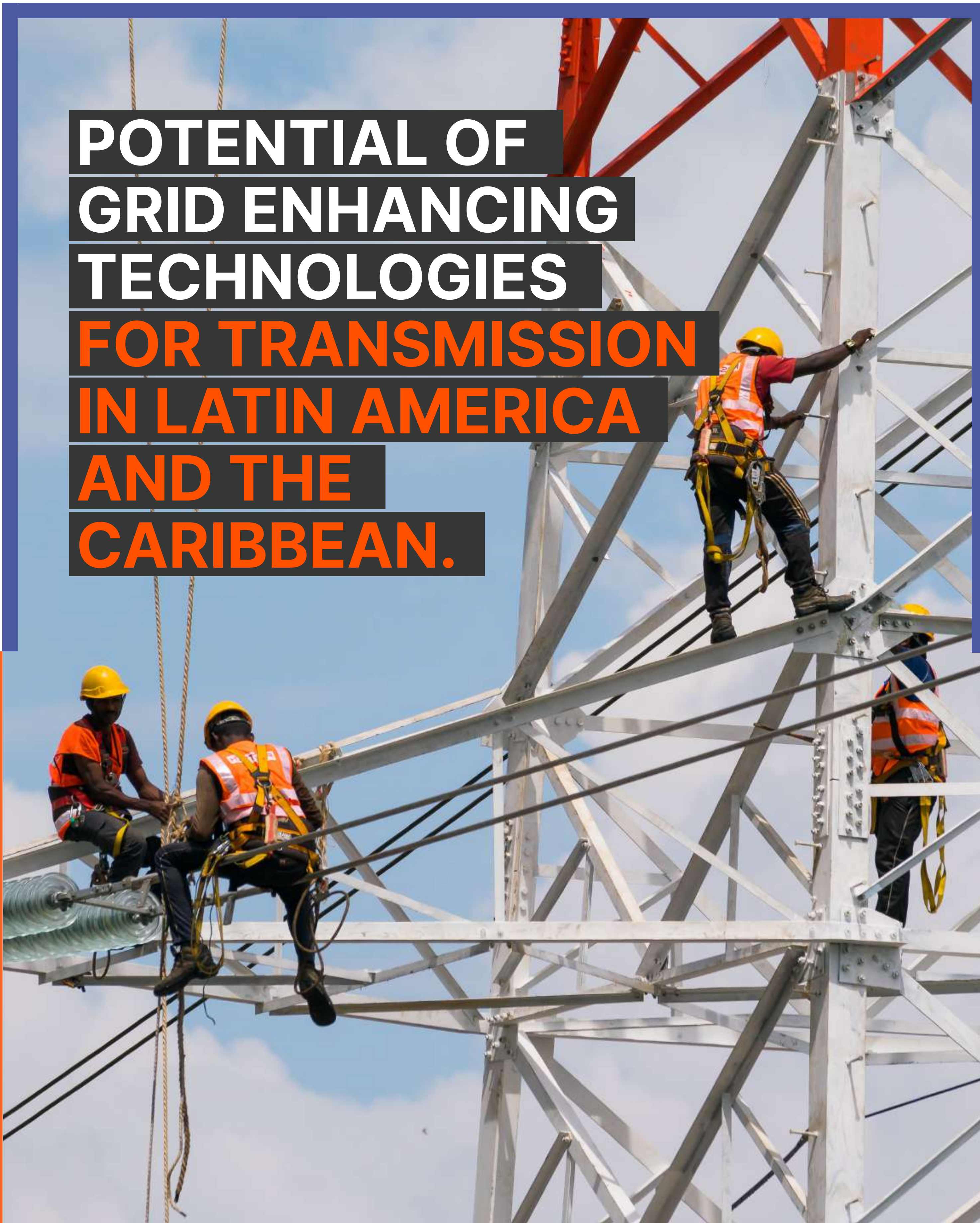
POTENTIAL OF GRID ENHANCING TECHNOLOGIES FOR TRANSMISSION IN LATIN AMERICA AND THE CARIBBEAN.



Artelys OPTIMIZATION SOLUTIONS

ISCI INSTITUTO SISTEMAS COMPLEJOS DE INGENIERÍA

IDB Group

This report is part of the knowledge agenda of the Energy Division of the Inter-American Development Bank (IDB) and the Climate and Environment Division of IDB Invest. It aims to generate analysis and technical assistance programs that strengthen public policies, private sector strategies and energy market management in Latin America and the Caribbean. These products seek to inform, guide, and offer a set of recommendations to policymakers, private executives, and key sector stakeholders, including consumers, utilities, and regulatory entities.

ACKNOWLEDGEMENTS

The report was prepared under the direction of Juan Paredes, Lead Energy Specialist, IDB, and Ricardo De Vecchi, Head of the Green Infrastructure Unit, IDB Invest, alongside Julián González and Mauricio Ayala from IDB Invest's Climate and Environment Division, whose involvement was instrumental in the development of the study. The authors are Melissa Alé, Mathieu Kretz, Cristóbal Mujica, Nicolas Omont, Rodrigo Federico Naranjo, and Tengxiang Ren from Artelys and ISCI (Instituto Sistemas Complejos de Ingeniería), with validation by Rodrigo Moreno from ISCI. The document also benefited from the review of Arturo Alarcón, Senior Energy Specialist, IDB.

The preparation of this report was supported financially by IDB's Strategic Infrastructure Development Program funded with Ordinary Capital, through the regional technical cooperation RG-T4513: "Digital Transformation in the Energy Sector and Grid of the Future" (ATN/OC-20954-RG), and IDB Invest's regional cooperation RG-T4149 "Preparation Support Facility for Sustainable energy Projects in LAC II" (ATN/LE-19355-RG) finance with resources from the contribution of the Global Energy Alliance for People and Planet (GEAPP).

Glossary

AAR	Ambient Adjusted Rating
AGC	Automatic Generation Control
AOM	Administration, Operation, and Maintenance
AVI	Asset Value Investors
BCR	Benefit-Cost Ratio
BESS	Battery Energy Storage System
BLPC	Barbados Light & Power Company Limited
BM	Balancing Mechanism
CBA	Cost Benefits Analysis
CEN	Chile's Coordinador Eléctrico Nacional
CETP	Clean Energy Transition Plan
CETR	Clean Energy Transition Rider
DLR	Dynamic Line Rating
DR	Dominican Republic
DSO	Distribution Service Operator
EMF	Electromagnetic Field
EMS	Energy Management System
EOI	Expression of Interest
FACTS	Flexible Alternating Current Transmission System
FERC	Federal Energy Regulatory Commission
GET	Grid Enhancing Technology
GFB	Grid-Forming Battery
GFC	Grid-Forming Controllers
GFM	Grid-Forming Converters
IBR	Inverter-Based Resources
LAC	Latin American and Caribbean
MEM	Mercado Eléctrico Mayorista

Glossary

NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory, USA
PST	Phase-shifting Transformer
RES	Renewable Energy Sources
RFI	Request for Information
ROCOF	Rate-of-change-of-frequency
ROE	Return on equity
ROI	Return on investment
SCL	Short Circuit Level
SPS	Special Protection Schemes
SSPD	Superintendencia de Servicios Públicos Domiciliarios
STATCOM	Static Synchronous Compensator
STN	Sistema de Transmision Nacional (Colombia)
SVC	Static VAR compensator
TRL	Technological Readiness Level
UK	United-Kingdom
UPFC	Unified Power Flow Controller
UPME	Unidad de Planeación Minero Energética (Colombia)

Executive summary

The rapid expansion of renewable generation across Latin America and the Caribbean (LAC) is imposing significant operational challenges on transmission networks. **Grid Enhancement Technologies** (GETs) are emerging as promising technologies to support grid enhancements and optimize grid operations. This market study on GETs aims to introduce the various technologies referred to as GETs; present the **size of the market for the GETs in the LAC region** and the impact of these technologies on network operations; **analyze the regulatory barriers** for the development of GETs and propose **recommendations**, based on best practices. This report is based on real-world **case studies** and regional stakeholder interviews conducted between February and April 2025, with key actors from: Ampacimon (worldwide DLR developer); Unidad de Planificación Minero Energética UPME (Energy planning unit of the Ministry of Energy and Mines) and ISA (private transmission company) in Colombia; Engie Chile (Synchronous Condenser and reconversions project developer), Coordinador Nacional (power system operator) and Comisión Nacional de Energía (energy sector regulator) in Chile.

Grid Enhancement Technologies are **software, hardware**, or a combination of both that **dynamically improve the capacity, efficiency and reliability** of the electrical transmission grid. Several key indicators – economic and technical benefits, deployment timeline, Technology Readiness Level (TRL), ease of implementation –

are detailed in section 1 of the report, for each of the main existing GETs: Dynamic Line Rating (DLR); Reconductoring; Synchronous Condenser (SC); Wide Area Monitoring Systems (WAMS); Synchro-Phasors; Flexible Alternating Current Transmission Systems (FACTS); Battery Energy Storage System (BESS). Remarkably, GETs feature lower deployment timelines, in contrast to the longer times needed for traditional reinforcement technologies, and feature better cost-benefits ratios.

The impact and the market potential of two different Grid Enhancement Technologies has been specifically studied: **Synchronous Condensers** (SC) and **Dynamic Line Rating** (DLR) equipment. SC is a hardware technology that provides inertia, Short-Circuit Level (SCL) and voltage support to strengthen system stability. DLR is a software technology that monitors or estimates the temperature of power lines and thus optimizes their maximum allowed power transfer capacity (line rating) so as to help alleviate transmission constraints. The technology is very relevant in windy areas, where the temperature, and thus the dynamic line rating, is usually significantly lower than the worst-case temperature used to compute the default static line rating. For these two technologies, we assessed the market potential in **Chile**, in **Colombia**, and then extended it to Latin America and Caribbean region.

To estimate the market size and potential impact of GETs implementation, the electricity sector in Chile and Colombia has been analyzed: by collecting projections of future demand and supply, assessing wind and solar additions, local transmission congestion, and grid stability issues arising from the retirement of conventional synchronous generators. For both SCs and DLRs technologies, we used a ratio-based approach, applying known benchmarks for how many MVAr of SCs are needed per MW of installed renewable capacity in weak grid areas (about 0.3 MVAr/MW, calibrated with real tender results in both countries), and estimating how many partially congested lines could benefit from DLR (based on each country's transmission expansion plans). Cost data came from case studies and official tenders, enabling us to extrapolate a credible market size in Chile and Colombia.

These findings have then been extended to the rest of Latin America and the Caribbean by correlating the scale of potential GET deployments with the region's significant renewable expansion plans through 2030. Several conclusions emerged from these calculations.

First, as **renewable generation (with grid-following inverters) displaces conventional synchronous generators, power systems lose inertia and short circuit strength.** To compensate, we estimate that Chile will need about **4 GVAr of new synchronous condenser capacity**, representing **roughly USD 1.2 billion in investment. Colombia** would require between **2.7 and 3.9 GVAr, equivalent to USD 0.8–1.2 billion.** These projects are economically attractive because they avoid costly redispatch and unlock additional wind and solar integration. Extrapolating the same needs across the region suggests **that more than USD 20 billion in synchronous condenser projects could be required in LAC by 2030.** However, **some of this demand can be met by alternative technologies**—such as existing thermal plants converted to condenser mode or grid forming batteries and STATCOMs— and the final market for new synchronous condensers may be smaller.

Second, while **DLR** shows a more modest overall capital requirement than building new lines or major substation upgrades, it remains a cost-effective, high-impact option for lines that are congested only a few hundred hours per year, and where fast deployment—on the order of **one to two years**—is critical. In **Chile**, about **36 lines** could feasibly adopt DLR, resulting in a **USD 12 million market size in terms of potential investments** (including a centralized management system). In **Colombia**, roughly **27 lines** might benefit from DLR at USD **10 million**. A broader **LAC extrapolation** puts the total DLR equipment market between **USD 132–141 million**, plus about **USD 30 million** for centralized systems (potential investments).

Table 1: ***Market potentials for SC and DLR in Chile, Colombia and LAC***

	Chile	Colombia	LAC
Synchronous Condenser – market potential (USD million)	600 – 1,200	810 – 1,170	7,500 – 25,110
Dynamic Line Rating – market potential (USD million)	12	10	162 – 171

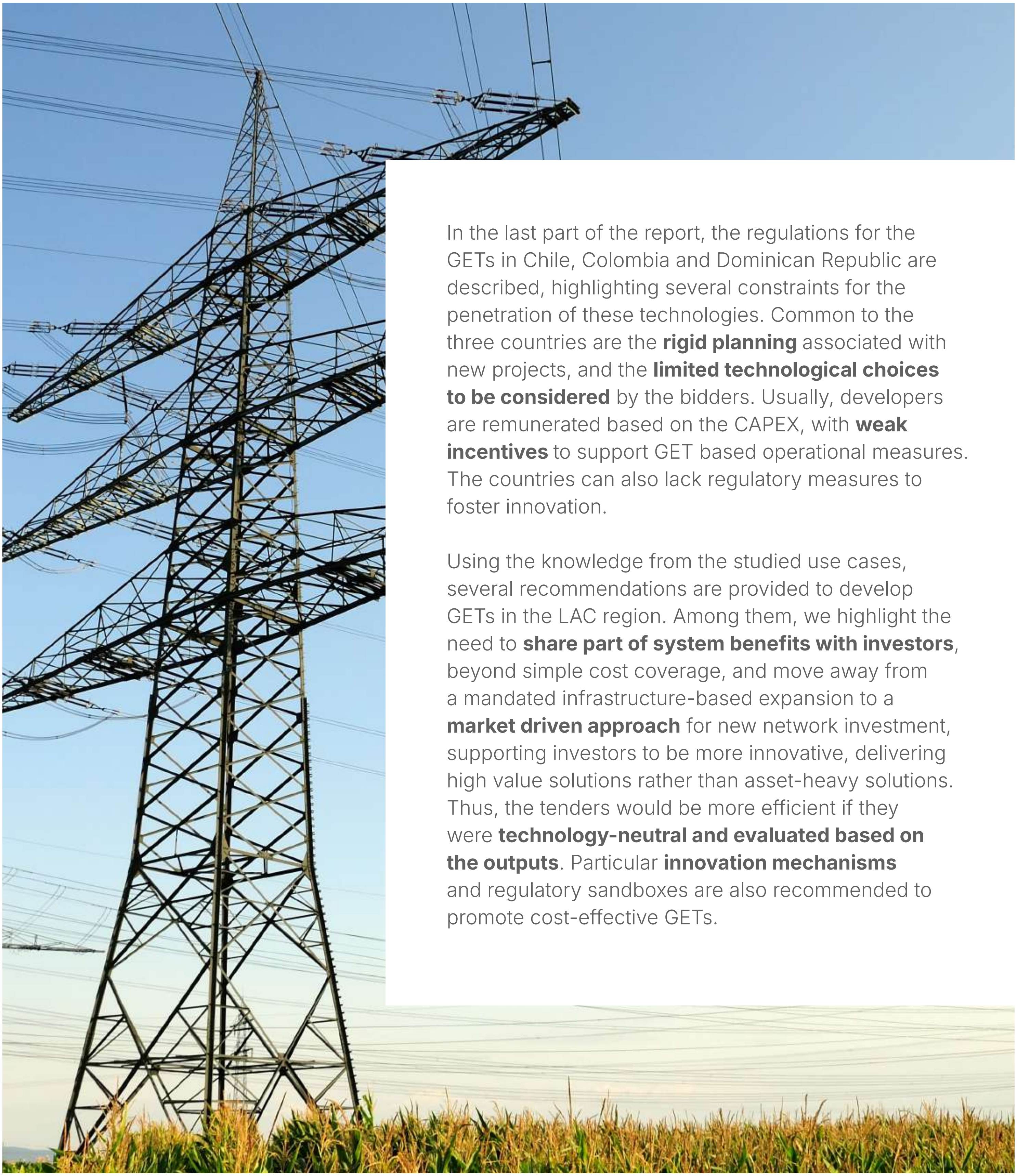
On the other hand, the benefits of GETS on the welfare of the system are significant. Regarding **DLR**, assuming that they are adopted on 50 % of the congested lines in windy areas, the congestion rent avoided would be of around **USD 22 million per year in Chile and USD 12 million per year in Colombia. Synchronous Condensers** benefits are evaluated based on the extra renewable energy that can be installed and dispatched, without the need to force the operation of hydro or thermal generators to stabilize the power systems. The increased welfare for the system, calculated as the difference between solar or wind vs. market marginal costs, range from **USD 130 million to USD 700 million per year in Colombia** (depending on the hydro availability), and around **USD 80 million per year in Chile** for the already tendered SC that will enter operation in 2027. In addition, the SC implementation could reduce the CO2 emissions, estimated at 13 million tons per year in Chile and 3.8 million tons per year in Colombia.

Table 2: ***Expected benefits of SC and DLR in Chile and Colombia***

	Chile	Colombia
Synchronous Condenser – benefit: increased welfare from production cost savings (USD million per year)	80	130-700
Synchronous Condenser – benefit: CO2 emission reduction (million ton per year)	13	3.8
Dynamic Line Rating – benefit: congestion reduction (USD million/year)	22	12

The study analyses two implemented case studies that have been widely acclaimed, and compares them with similar projects in the LAC region. The aim is to draw concrete examples of good practices for the development of GETs in Latin American and Caribbean. The first case study is the **Stability Pathfinder Phase 2**, in the UK. It is a **technology-neutral tender**, centered on increasing Short Circuit Level (SCL) and inertia in Scotland. Participants were evaluated on the price, the short circuit contribution, and the incremental inertia offered. In the end, most of the bidders proposed Synchronous Condensers, which got awarded half of the contracts (the other half being GFM batteries). For these reasons, we compared this use case to SC-related tenders in Chile and Colombia. It appears that the main drawbacks of these technology specific tenders in LAC were, according to stakeholders, **the focus on a single technology and the lack of clarity in the tender process.**

The same approach has been conducted for the second case study: the deployment of **DLR devices for the system operator PJM** in Pennsylvania, United States. The implementation took approximately **2 years** from congestion driver identification to go-live operation, for a total cost of about **USD 3.25 million. Benefits are massive**, with congestion rents reduced by around **USD 70 million per year**. In Chile and Colombia, DLRs have been under study since 2020. However, no operational device has been deployed yet. In December 2024, the Chilean regulator gave its authorization for equipping one line with DLR devices, for a cost of roughly USD 500000 and expected savings on congestion rent of USD 4.6 million per year. The comparison with the US case shows that the technology is ready for operational deployment: deployed DLRs have been fully **integrated into the market mechanisms**, optimizing their benefits. PJM is now used to operate the technology, implying faster deployment of DLRs in the future.



In the last part of the report, the regulations for the GETs in Chile, Colombia and Dominican Republic are described, highlighting several constraints for the penetration of these technologies. Common to the three countries are the **rigid planning** associated with new projects, and the **limited technological choices to be considered** by the bidders. Usually, developers are remunerated based on the CAPEX, with **weak incentives** to support GET based operational measures. The countries can also lack regulatory measures to foster innovation.

Using the knowledge from the studied use cases, several recommendations are provided to develop GETs in the LAC region. Among them, we highlight the need to **share part of system benefits with investors**, beyond simple cost coverage, and move away from a mandated infrastructure-based expansion to a **market driven approach** for new network investment, supporting investors to be more innovative, delivering high value solutions rather than asset-heavy solutions. Thus, the tenders would be more efficient if they were **technology-neutral and evaluated based on the outputs**. Particular **innovation mechanisms** and regulatory sandboxes are also recommended to promote cost-effective GETs.

Table of contents

01

TECHNOLOGICAL ANALYSIS OF GETS

02

CASE STUDIES ASSESSMENT

03

EVALUATION OF GETS MARKET POTENTIAL

04

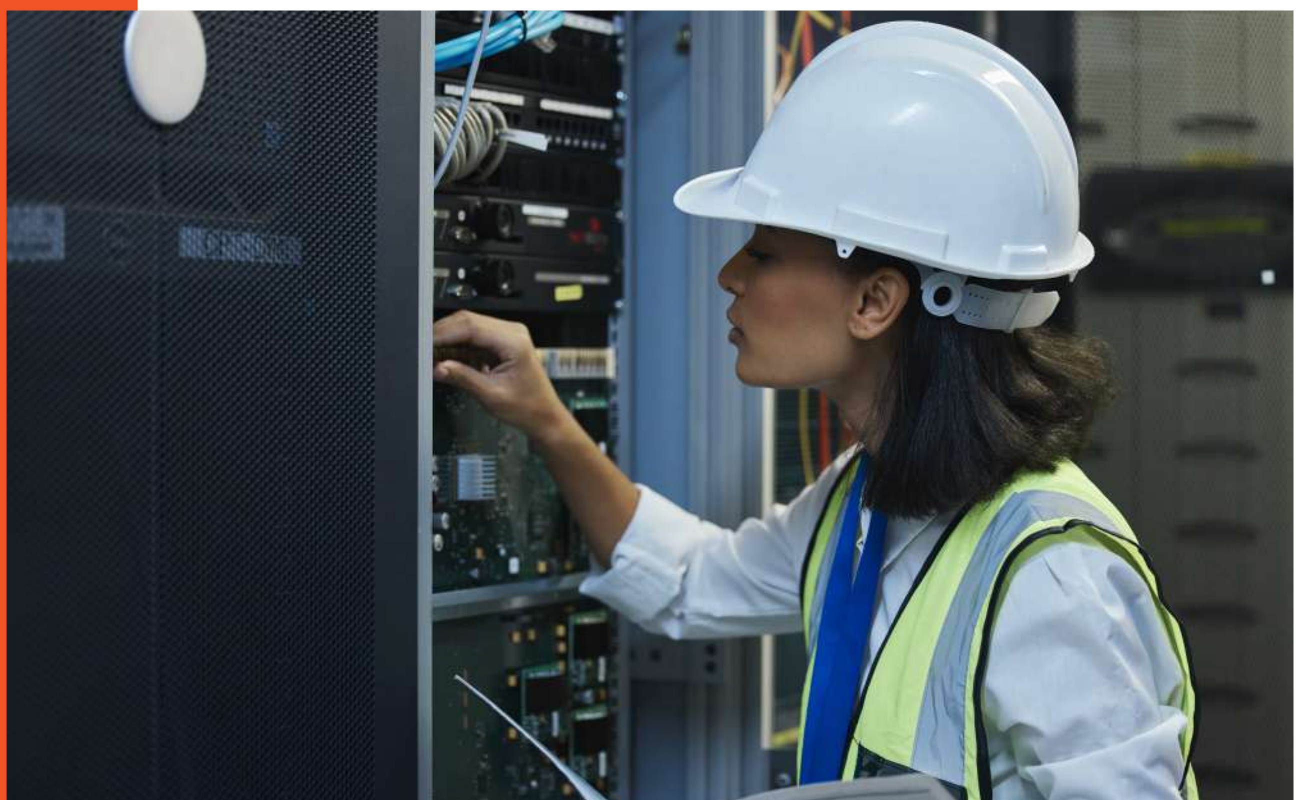
REGULATORY BARRIERS AND WAYS TO UNLOCK THEM

List of **figures**

List of tables

01

Technological analysis of GETs



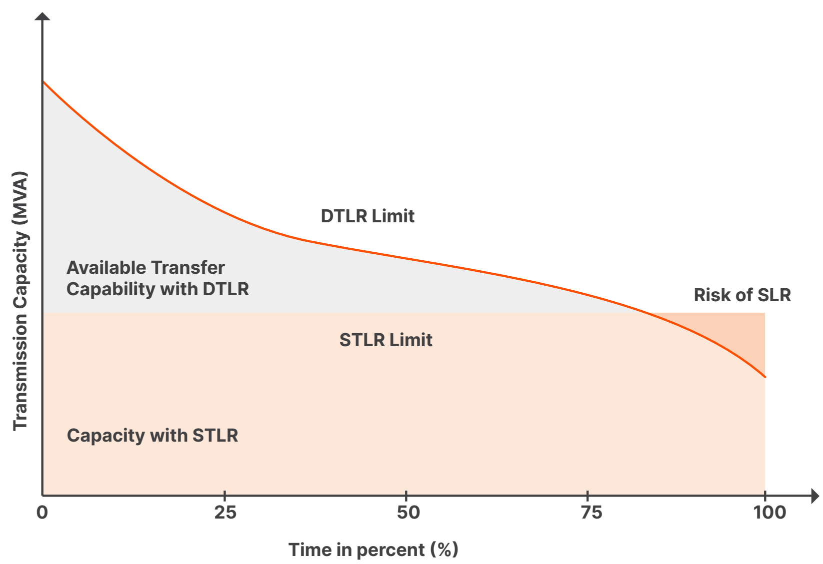
The first section of the report is dedicated to the most widely spread Grid Enhancing Technologies. The aim is to present each of these technologies, by explaining their functioning, their ease of implementation and management, the associated costs and benefits. Grid Enhancing Technologies are software, hardware, or combination of both that dynamically improve the capacity, efficiency and reliability of the electrical transmission grid.

1.1 Dynamic *line rating*

1.1.1 Principle of operation

Dynamic Line Rating (DLR) is the calculated transmission capacity (also known as ampacity) of the line based on real-time environmental and weather conditions, as opposed to Static Line Rating (SLR), which is based on conservative, worst-case weather conditions. Thus, DLR allows for a rapid change in line rating depending on actual, real-time conditions, while SLR maintain line rating constant for a longer period, usually seasons (Ambient Line Rating) or for the line lifetime. The aim of DLR is to maximize the ampacity at every point in time compared to SLR. DLR can also reduce the line's ampacity during extreme conditions, thereby limiting the risks of overloading with respect to SLR.

Figure 1.1: ***Transmission capacity of SLR and DLR (STLR: Static Thermal Line Rating). Source: Elad et al. (2024)[1]***



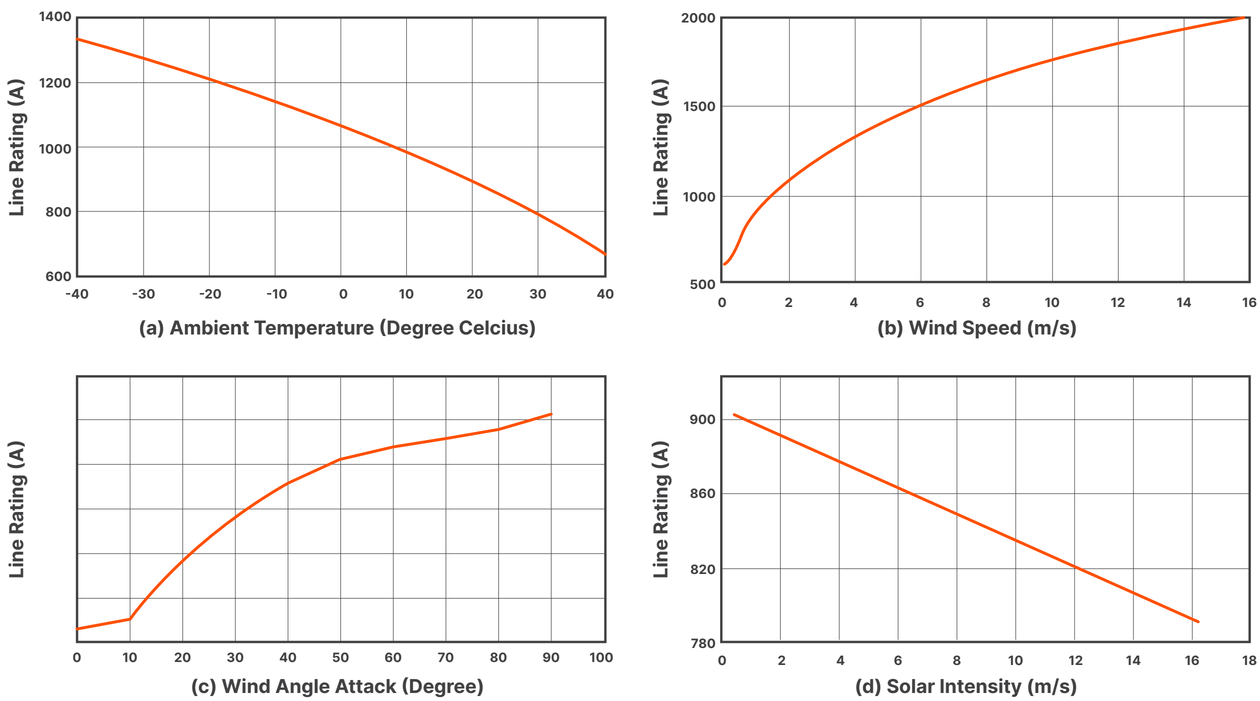
There are different categories of DLR depending on the types of measurement used for the estimation of the conditions. The more accurate methods are sensor-based methods, where devices are used to measure lines and weather conditions on-site. Sensor-based DLR can be further divided into contactless and line-mounted DLRs, with their own pros and cons[2].

[1] *A. Eladl, S. Fawzy, E. Abd-Raboh, A. Elmitwally, G. Agundis-Tinajero, J. Guerrero, M. Hassan, A comprehensive review on wind power spillage: Reasons, minimization techniques, real applications, challenges, and future trends, Electric Power Systems Research, 2024.*
[2] *Dynamic Line Rating, DOE 2019, [link]*

Less accurate sensor-less DLR methods use weather data from meteorological models: even though their implementation is faster and cheaper, a more important security margin must be reserved for operation[3].

DLR is influenced by weather factors such as wind speed, wind direction, solar radiation and ambient temperature, as well as physical and electrical factors such as line current, sag/tension, physical and electrical properties of the material and insulation. According to Hajeforosh and Bollen (2021)[4] the main factors influencing the DLR are **wind speed and ambient temperature**, with wind angle attack and solar intensity having a much lower impact, as shown in Figure 1 2 below.

Figure 1.2: ***Variation of the line rating with respect to (a) ambient temperature, (b) wind speed, (c) Wind angle attack and (d) solar radiation. Parameters:Max conductor temperature = 75°C, Ambient Temperature = 40°C, Wind Speed = 0.6m/s, Wind Angle Attack = 45°C. Source: Hajeforosh and Bollen, 2021***



1.1.2 Implementation and impact of technology

System requirements:

DLR technologies encompass three key components: DLR sensors, which monitor fluctuating operating conditions (optional for sensor-less DLR); a mature communication system for field data treatment and transmission (optional for sensor-less DLR); and a software that computes line ratings from the data.

[3] *The Benefits of Innovative Grid Technologies, CurrENT, 2021, [link]*
[4] *S. Hajeforosh, M. Bollen, Uncertainty analysis of stochastic dynamic line rating, Electric Power Systems Research, 2021*

DLR devices can be classified according to the magnitudes that are monitored:

- Weather monitoring
- Conductor temperature monitoring
- Tension monitoring
- Sag monitoring
- Vibration monitoring
- Electromagnetic field monitoring

Depending on what it monitors, the DLR device will transmit the measured field data to the software that will assess the DLR. System Operators would also need to adapt their models (SCADA, Energy Management Systems (EMS), line protection settings, etc.) to account for DLR[5]. Moreover, DLR can have material changes in economic dispatch, including operating reserves[6].

Implementation:

From the **field collection to the DLR's integration into System Operator's processes, there are multiple interfaces and compliances. A typical deployment timeline can span over 1 to 2 years[7] [8] .** Once the central system is established, it is rather convenient to scale with DLR and implement it on additional lines.

According to WATT Coalition's database[9], 27 out of 46 listed DLR projects use line-mounted sensors, 18 projects use contactless sensors and 1 project uses sensor-less DLR. The use cases are mostly located in Europe and North America, with limited deployment in each energy system. Therefore, **a TRL of 8 is assigned to sensor-based DLR and a TRL of 7 is estimated for the sensor-less DLR.**

Impacts:

DLR technology is well suited to addressing congestion caused by thermal constraint. The impacts of changing operating conditions on transmission line capacity were studied by the US department of Energy in 2014[10] and are shown in Table 1 below. Wind (most impactful when perpendicular to the line) is the key factor to increasing capacity with up to 44% increase of the line capacity compared to a static rating based on conservative environmental conditions. Specifically, during periods of strong winds, the power production of wind farms increases and the DLR increases concurrently[11]. This symbiotic relationship is advantageous as the enhanced DLR facilitates the transfer of the generated power through the lines efficiently. In addition, **DLR also helps to detect real-time anomalies** on the monitored lines, for example, unexpected sag that potentially jeopardizes grid reliability.

[5] *ENTSO-E Technopedia, Dynamic Line Rating (DLR), [link]*
[6] *Chen, Y., Teng, F., Moreno, R., and Strbac, G., "Impact of Dynamic Line Rating with Forecast Error on the Scheduling of Reserve Service", IEEE PES 2016 General Meeting, Boston, MA, USA, Jul 2016.*
[7] *PPL's Dynamic Line Ratings Implementation, PPL Electric Utilities, 2023, [link]*
[8] *DOE Office of Electricity TRAC, DOE, 2022, [link]*
[9] *WATT Coalition, [link]*
[10] *US Department of Energy (DOE), Dynamic Line Rating Systems for Transmission Lines, 2014 [Link]*
[11] *Chen, Y., Teng, F., Moreno, R., and Strbac, G., "Impact of Dynamic Line Rating with Forecast Error on the Scheduling of Reserve Service", IEEE PES 2016 General Meeting, Boston, MA, USA, Jul 2016.*

*Table 1: **Impact of changing operation conditions on transmission line capacity. Source DOE, 2014***

Operating conditions	Change in conditions	Impact on Capacity
Ambient temperature	2˚C decrease	+2%
	10˚C decrease	+11%
Solar radiation	Cloud shadowing	+/- few percent
	Total eclipse	+18%
Wind	3 ft./s increase, 45˚ angle	+35%
	3 ft./s increase, 90˚ angle	+44%

1.1.3 Costs and benefits

Four use cases illustrate the costs and benefits of implementing DLR technology:

- At the Pennsylvania Power and Land, USA, the deployment of 18 line-mounted sensors on three historically congested 230 kV lines (about 50 km) cost approximately USD 3.25 million. The project is expected to reduce the congestion costs of the three lines by USD 23 million for 2025, with an observed average increase of 18-19% for the normal capacity during the previous winter[12] .

- In Minnesota, Wisconsin and Colorado, USA, the ONRL laboratory implemented contactless DLR on three lines, using LiDAR and EMF sensors. The cost amounts to USD 850 000, and the capacity of the lines increased by 9-33% in winter and by 26-36% in summer. The financial elements of the project are not fully disclosed[13].

- Line Vision (DLR vendor) installed ground-based DLR systems on a 275 kV double circuit in North of England (Penwortham to Kirkby, 50km) for National Grid U.K in 2022 as stated by Watt Coalition[14]. This circuit has been experiencing congestion and curtailment because of surplus offshore wind generation with annual congestion costs of USD 1.75 million. The project estimates an increase in line capacity with the use of DLR compared to static line rating of 45% which corresponds to 500 MW more renewable power to be carried.

- The sensor-less DLR is implemented on 33 transmission lines at ELES, a Slovenian Transmission and Distribution System Operator. The Operator, who is also the technology developer claims a median increase of 15-20% for the nominal capacity.

[12] *PPL's Dynamic Line Ratings Implementation, PPL Electric Utilities, 2023, [link]*
[13] *DOE Office of Electricity TRAC, DOE, 2022, [link]*
[14] *Building a Better Grid: How grid-enhancing technologies complement transmission buildouts, Watt Coalition, The Brattle Group, 2023, [link]*

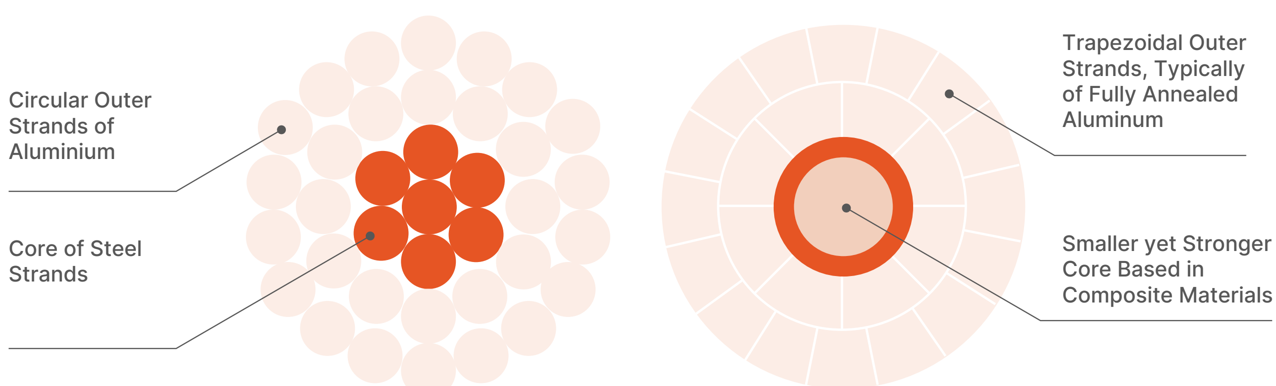
No operating expense were disclosed for the aforementioned use cases, but it mainly concerns the maintenance expenses for the sensors, the data transmission infrastructure and the software. Also, the financial benefits associated to the capacity increase are highly dependent of the initial congestion constraint on the line. The relationship between the capacity increase and the congestion cost reduction is not trivial. Therefore, the numbers above only serve an illustrative purpose. Nonetheless, notice that often DLR competes against major network enhancements such as new transmission lines, being DLR a much more cost-effective and faster to implement solution.

1.2 Reconductoring

1.2.1 Principles of operation

Reconductoring consists of replacing the wires of existing transmission or distribution lines while the other equipment, such as towers, remains unchanged. It allows the project developer to bypass many of the project steps that inhibit new constructions: no permitting and building of new assets are needed (or just minor arrangements and upgrades). Advanced Conductor Technologies (ACTs, also known as High Performance Conductors - HPCs) are more efficient, making it possible to increase the capacity of a line through reconductoring.

Figure 1.3: ***Conductor cross-section comparison between conventional cables (ACSR) and advanced technologies (ACT)*** [15]



[15] *Energy Innovation – 2035 Report Reconductoring, [link]*

There are many types of ACTs. Table 2 provides an overview of the available technologies, showcasing a performance comparison. The Aluminium Conductor Steel-Reinforced (ACSR) technology serves as reference as it is the most widely used conductor type. Comparatively, the ACTs offer better mechanical properties (less sag, higher breaking strength) and higher Maximum Operating Temperature (MOT). These enhanced properties allow more current to flow through the conductors, increasing their capacity at the same voltage. However, the electrical resistance usually grows as the material's temperature rises. Therefore, while the ACTs are more efficient at ambient temperature, they show higher line losses at MOT (when operated close to their capacity limit, which is much higher than ACSR's). The typical MOT for ACTs ranges between 180°C and 250°C, whereas the MOT for ACSR is about 93°C[16].

Table 2: ***Conductors listed by year introduced, high temperature sag profile, and other factors. Source: INL***[17]

		History	Mechanical			Capacity	Efficiency/Line Losses		Unit Cost
Conductor Type	Conductor	Year Introduced	More Sag than ACSR	Rated Breaking Strenght vs ACSR	Weight vs ACSR	Ampacity @ MOT Continuous vs ACSR	Resistance @ 20 C Continuous vs ACSR	Resistance @ MOT Continuous vs ACSR	Cost vs ACSR
ACSR	795 Drake	1900's	No	100%	100%	100%	100%	100%	100%
3M ACCR	795 T16	2002	No	102%	85%	158%	94%	129%	unknown
ACCR	1029 Drake	2003	No	129%	96%	165%	77%	99%	237%
ACCS/MA5	795 Drake	2007	Yes, @ MOT	103%	100%	174%	97%	146%	108%
ACCS/TW/C7	973 Everglades	2014	No	124%	92%	153%	82%	106%	unknown
ACCC/E3X	1029 Drake	2015	No	129%	97%	186%	77%	99%	237%
ACCS/TW/MA5	959 Suwanee	2015	Yes, @ MOT	123%	121%	191%	80%	121%	139%
ACCS/MA5 /E3X	795 Drake	2015	Yes, @ MOT	103%	100%	199%	97%	146%	135%
ACCS/TW/MA5	959 Suwanee	2015	Yes, @ MOT	123%	121%	218%	80%	121%	152%
TS Conductor	1051 Sun M3	2021	No	134%	96%	168%	75%	96%	unknown

1.2.2 Implementation and impact of the technology

System requirement:

By reusing a large amount of the infrastructure, reconductoring project costs are reduced and the project timeline accelerated. However, the line must undergo extended outage during the implementation, which should be analysed properly as it may increase congestions costs temporarily. In addition, as some ACTs may have more mechanical sag than the traditional ACSR conductor at MOT, the transmission towers might need to be raised to fully exploit the capacity of the ACTs.

[16] *Advanced Conductor Scan Report, INL, 2024,* [link]

[17] *Advanced Conductor Scan Report, INL, 2024,* [link]

Implementation:

The deployment timeline is impacted by the difficulty to replace the conductors and the length of the line. For illustrative purposes, PPL successfully reconductored 14 miles of 230 kV line within a few months[18]. While some other use cases can rollout over **2-3 years[19] depending on the distances.** In general, a reconductoring project reduces the timeline by several years, compared to an equivalent new construction project.
The reconductoring's TRL is estimated at 9, as worldwide adoptions of ACTs are reported.

However, the adoption rate can vary from one conductor type to another. The skepticism is usually present toward newly emerged conductor type, as the conductors are of key importance for the safe operation of the grid.

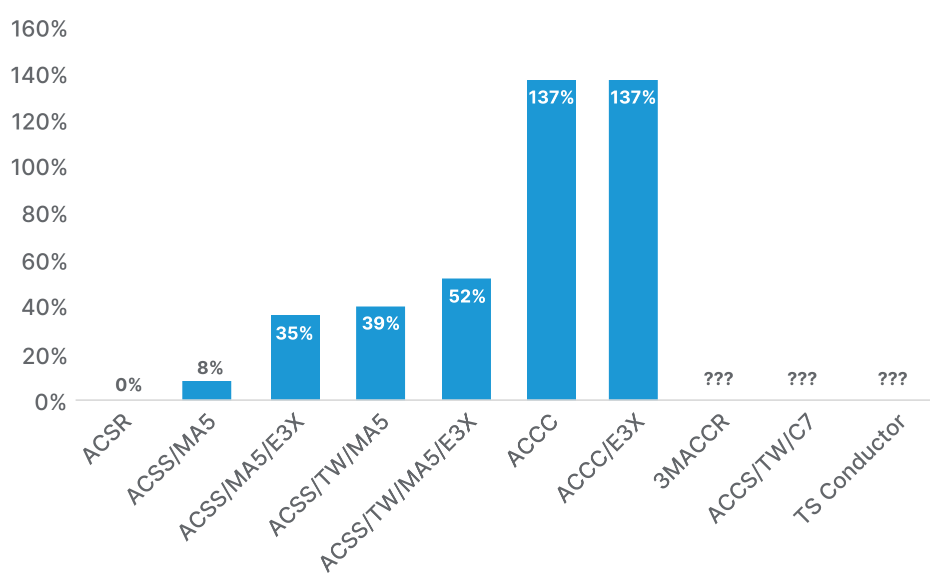
Impact:

Reconductoring offers an alternative that is faster and cheaper to implement than rebuilding, with less permitting burdens. These characteristics are particularly valuable in a context of rapid expansion of the grid. Beyond economic considerations, reconductoring could also be less constringent for the supply of materials and workforces.

1.2.3 Costs and benefits

The figure below provides the cost for the conductor itself. The CAPEX should also include infrastructure modification, labor costs etc. As illustrated below by a use case, the conductor cost only represents a minor share of the total cost.

Figure 1.4: ***Cost increment by conductor type, compared to 795 kcmil Drake ACSR, which is 13,866 USD/ mile.[20]***



[18] Docket Number: A-2022-3036291, Pennsylvania Public Utility Commission, [link]
[19] Project Status and Cost allocation, PJM, [link]
[20] Advanced Conductor Scan Report, INL, 2024, [link]

The total cost of a reconductoring project at PPL, USA, was estimated at USD 9 million . The project involves reconductoring 14.2 miles of a 230 kV line with 1272 ACSS/TW HS285 "Pheasant" conductor. The project includes some tower reinforcements and one structure replacement. With a short calculation, the cost associated with the conductor (assuming +50% cost per mile compared to ACSR) corresponds to USD 300 000, representing approximatively 3% of the total cost. When it comes to the benefits, PPL estimates that the project has a benefit-to-cost ratio of 11.28, with a 15-year net present value of USD 107 million.

1.3 Synchronous *condenser*

1.3.1 Principle of operation

A synchronous condenser (SC) is a DC-excited synchronous motor whose shaft is not connected to any load and spins freely. These machines are like conventional generation machines, except that they don't generate energy but provide inertia, voltage regulation and short-circuit power to the system. They have been historically used to maintain stability in regions far away from power generation hubs. Today, a renewed interest emerges for these machines as they tackle the challenges raised by renewable energy development and the early retirement of thermal power plants.

Different configurations of SC exist: round rotor or salient pole machine and with or without flywheel. Adding a flywheel to SCs allow them to store additional mechanical energy without further complicating the electrical design. The combination of a salient pole machine with a flywheel provides the highest inertia while the round rotor alone provides the least inertia, according to Andritz (equipment supplier)[22].

Similar in structure for the rotating masses, existing coal-fired power stations can be retrofitted to act as SC, which can represent a convenient investment strategy to reinforce power system stability while decarbonising power systems. In addition, retrofitting could offer faster implementation times, larger scale (existing generators typically have higher ratings than new SCs) and lower costs. However, the flip side of the coin is that retrofitting has lesser flexibility in choosing the location, and the emerging stability issues due to renewable expansion are usually localized in specific regions. The practical implementation has several technical options, to be chosen case by case depending on the existing generators (most of time, retrofit would take advantage of the existing foundation, point of connection and the generator/turbine; the thermal parts would not be repurposed)[23].

[22] *Boosting Inertia of Synchronous condensers – Flywheels, Serdar Kaam, [link]*
[23] *Repurposing existing generators as synchronous condensers, report on technical requirements, DigSilent, [link]*

1.3.2 Implementation and impact of the technology

System requirements:

Typical components of synchronous condensers are :

- Stator and rotor with solid integral pole tips
- Cooling system (hydrogen, air or water)
- Excitation system
- Lubrication supply
- Flywheel (optional for better inertia)
- thermal parts would not be repurposed)[24].

Implementation:

Synchronous condenser is a proven technology with a TRL of 9. The deployment is flexible, modular and takes 1 to 2 years.

In the studied use cases, the procurement of SC typically follows a top-down approach, initiated by system operators, planning agencies, or regulators. These entities identify the need for stability services and issue competitive tenders—either service-focused or asset-focused—with predefined capacity requirements and specified locations, which may range from individual nodes to broader regions.

Impacts:

SC provides several grid supports including inertia, short-circuit level (which reflects the grid's strength) and voltage support. These supports are relevant to accompany the system transition to host more inverter-based resources (wind, solar, battery), as traditional spinning masses (that also provide these supports) retire.

SC is also useful to integrate generations located in remote area, as the long transmission distance between generation and load requires voltage support.

1.3.3 Costs and benefits

- The South Australian transmission company, ElectraNet, installed 4 large SCs primarily to maintain system strength. The project took 3 years and cost USD 190 million[25].

- National Grid ESO, UK, invested over USD 400 million in SC and Grid-Forming Converters though Stability Pathfinder 2 in 2022. The tender resulted in 10 contracts over 10 years, providing the system with 11.55 GVA of SCL and 6.75 GVAs of inertia. A former tender, Stability Pathfinder 1 secured 12.5 GVAs of inertia over a period of 6 years at a cost of USD 328 million[26]. These acquired inertia and SCLs allow NGESO to successful integrate its massive rollout of wind power. More details can be found in the Case Study, section 2.1.

- The purpose of SCs is to allow the stable operation of the grid with an increasing share of the production coming from inverter-based resources. The system benefits are therefore estimated in terms of avoided forced thermal generation. The estimation for a use-case in Chile, presented in sections 2.1.6.1 and 3.1.2.2.1, highlights a USD 80 million savings per year for approximately 1 GVAr of SC.

---

[24] *Synchronous Condenser, ENTSO-E, [link]*
[25] *Rebirthing coal power stations into synchronous condensers, Australian Energy Council, [link]*
[26] *Scotland's wind success story bolstered by £323m stability investment, NGESO [link]*

1.4 Synchro phasors / Wide Area Monitoring System and Digital Twin / *AI condenser*

1.4.1 Principle of operation

Digital twin consists of building a digital model of the physical power system to enhance the system's observability, operability and efficiency. The model requires input data from the grid, and the quality of this data directly impacts the accuracy of the outputs. The **Wide Area Monitoring System** (WAMS) is responsible for data collection and aggregation. Phasor Measurement Units (PMUs) are part of the WAMS, they measure a quantity called a phasor, which is composed of a magnitude and a phase angle. Such quantity could be, for example, the voltage or the current at a specific branch in the grid. The measured phasors have the particularity of being precisely time-stamped with a shared time source between the different PMUs. Therefore, the phasors can be time-aligned, thus the name synchro phasors (it is common to use synchro phasors, the measured quantity, to designate PMUs, which is the measuring device). As a complement to the traditional SCADA, which delivers measurement every few seconds, the PMUs provide real-time data, reaching up to 60 measurements per second.
WAMS and Digital Twin work together as an integrated system, the models rely on the data to be operational and transform the raw observations into valuables insights.

Different digital models exist to serve different purposes. Simplifying hypothesis (DC-approximation, coarse granularity etc.) are taken according to the purpose of the model, to ensure the model's tractability while conserving its accuracy in representing one aspect of the power system. Artificial Intelligence can be incorporated in the most advanced digital models, as it further boosts the model's efficiency.

The most common applications are listed below.

Security Analysis / Dynamic Security Assessment

Security Analysis aims to assess the grid's security under different scenarios, representing the numerous possibles states of the grid, including contingencies. Dynamic Security Assessment is part of the Security Analysis, it has the particularity of covering the simulation of the grid during a perturbation, with a much finer time resolution (down to milliseconds), until the grid reaches a new state of equilibrium. Dynamic Security Assessments are used to assess grid stability issues (voltage, transient and small signal). Security Analysis is important in the context of energy transition, as the renewable penetration brings additional uncertainties and stability issues to the grid.

Topology Optimization

Topology Optimization (TO) is an algorithm that computes the optimal reconfiguration of the grid upon changes of the grid's conditions. TO allows to reroute the power flows around congested or overloaded transmission elements. The topology reconfigurations include **busbar splitting/merging and line switching.**

The mathematical optimization problem is computationally costly to solve, and Artificial Intelligence can facilitate the search for a solution[27]. TO can be implemented for day ahead management of the grid, and in the medium-long term, for example to adapt the topology to seasonal patterns. TO can also be combined with other GETs like DLR or FACTS (Flexible Alternating Current Transmission Systems[28]), to maximize the benefits of these technologies.

Special Protection Schemes / Remedial Action Scheme

Special Protection Schemes (SPS) are a set of protection schemes designed to handle contingencies, ensuring acceptable system performance after the occurrence of a perturbation.

SPS are designed to detect specific conditions in the system that are known to cause unusual stress, such as instability, overload, or voltage collapse, and to take predetermined action (or known as remedial action) to counter the observed condition, such as topology control, redispatch or automatic load shedding.

SPSs allow the grid to be operated closer to its limit without compromising the grid's reliability, thus making the best use of the existing capacity. Technically not a digital model, but to be operational, SPS is also reliant on the monitoring of the system.

[27] *Grid-enhancing technologies for clean energy systems, Nature Reviews Clean Technology, Tong Su, Junbo Zhao, Antonio Gomez-Exposito, Yousu Chen, Vladimir Terzija & Jake P. Gentle [link]*

[28] *A more exhaustive presentation of FACTS is provided section 1.5.*

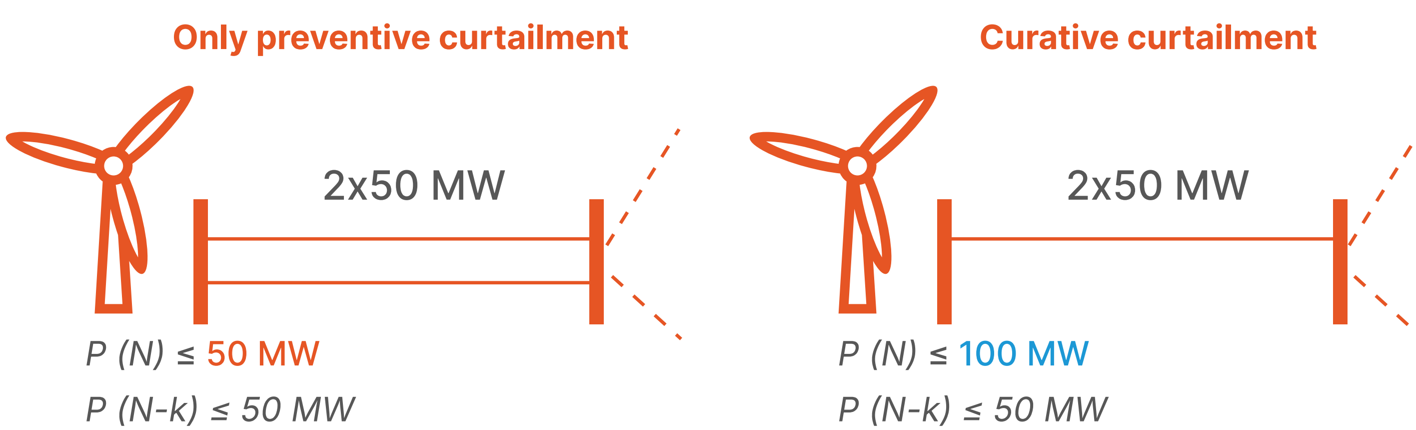
Real-time operation control/automation under N-k security criterion

A typical application of digital twin for real-time grid operation is short-term curtailment.

Short-term curtailment is the curtailment of renewable energy sources (RES) that only reduces the power of RES if a technical constraint of the grid is reached in **real-time** (or only minutes-ahead), as opposed to curtailment based on day-ahead or hours-ahead forecasts. Short-term curtailment can be used as a preventive measure if a constraint can be reached in the next minutes (identified using forecasting tools) or as a curative measure when it is used in response to a contingency detected in real-time by monitoring devices.

In particular, curtailments in the curative phase can increase the renewable energy accepted during the preventive phase (N state), as exemplified in the following figure of a wind farm connected via two 50 MW lines. To respect N-k security conditions, the wind farm would need to be limited to 50 MW in the N state if only preventive curtailments are available. However, if short-term curtailments are possible, the wind farm can be operated up to 100 MW, with curtailments happening only in rare case of the loss of one of the lines.

Figure 1.5: ***Illustration of the preventive vs. curative curtailments in the operation of renewable sources***



It is important to note that the more real-time information operators can collect, the better their operational decisions, potentially reducing congestion by allowing the grid to operate closer to its thermal, voltage, or stability limits without compromising system reliability. Conversely, the lack of high-resolution real-time data— as is often the case— introduces uncertainty, which must be mitigated through higher security margins, leading to increased network congestion.

1.4.2 Implementation and impact of the technology

System requirement:

At minimum, 3 main components are necessary for digital twin implementation:

- WAMS for data collection and processing treatment
- ICT infrastructure for data transmission
- Software
- Actuators (in the case of post-contingency remedial actions)

Implementation:

The **deployment timeline can be estimated to range between 1 to 5 years**, with some impacting factors: whether there is an established data collection and communication system, whether a tailored solution is required to cover particular specifications etc. The implementation is rather complex, for the same reasons of **interfacing and integration challenges,** as formerly mentioned for DLR. In addition, **trained staff is required for the operation** of the digital twin.

When it comes to the maturity of the technology:

- Security Analysis has been within the hands of the System Operators for decades across the world. The **TRL is estimated at 9.** However, new features and progress keeps being made, to shorten the computation time and to gain better computation accuracy.

- In the USA, NewGrid is a **Topology Control** software vendor that provides auditing, monitoring and mitigation services to relieve grid congestion. It helps identify operational solutions to re-route flow around bottlenecks. NewGrid has already worked with MISO (the Midcontinent Independent System Operator) and SPP (the Southwest Power Pool), two ISOs from the United States. A feasibility test project has been conducted at NESO, UK. The **TRL is therefore estimated at 9** for the use in planning (weeks ahead). In continental Europe, Artelys is involved in the deployment of a solution to perform topology optimisation in day-ahead and intra-day to maximize the French Spanish and Spanish Portuguese transmission capacity. The TRL is 8 for the day-ahead process and 7 for the intra-day process.

- Most of ISOs across the globe have developed mature processus to design and acquire **Special Protection Schemes / Remedial Action Schemes. The TRL is therefore estimated at 9 for SPS.**

- NAZA (New Adaptative Zone Automaton) is a fully software-based, real-time curtailment automaton co-developed by RTE and French DSOs that continuously ingests state-estimation data every few seconds and runs an Optimal Power Flow digital twin to monitor flows across roughly 100 substations at the 63–90 kV level. Instead of relying on static, hard-coded trigger rules like traditional SPS, NAZA's centralized AI engine dynamically adjusts renewable output only when a contingency threatens network security—thus virtually eliminating unnecessary preventive curtailments and unlocking additional hosting capacity for wind and solar. Deployed zone-by-zone, it coordinates all curtailment actions without prior rule configuration and can execute adjustments in under 30 seconds, enabling operators to defer costly grid reinforcements. The NAZA automata is a first of its kind but is already operational, the **TRL for short-term curtailment is estimated at 8.**

Impacts:
The digital twins do not affect the physical infrastructure of the grid (put simply, nothing is built except the cyber infrastructure: measurements units, telecommunication systems, data centres). Instead, the models try to optimize the usage of the existing physical infrastructures. The purpose can be either boosting the grid's hosting capacity by squeezing the margins, optimizing the transfer capacity on a given corridor (e.g. for renewable energy delivery) or simply enhancing reliability and efficiency. Furthermore, digital twins do not require the same resources (copper and workforces) as the physical GETs, which can help to relieve the constraints in the expansion of the grid.

1.4.3 Costs and benefits

The costs of digital twins are impacted by many factors, including the maturity of the existing tools, the necessity for customization (a development from scratch is more costly than an off-the-shelf solution), the standards in terms of interfacing and cybersecurity, etc.

- Assuming that the operators can already perform manual stability studies, a typical Dynamic Security Assessment software's CAPEX ranges between USD 400 000 to USD 1.5 million, depending on the complexity of the software. An implementation use case in ERCOT allowed the operator to determine the transfer limit every 15 minutes, based on real-time system data. This increase in capacity has an estimated benefit of reducing the congestion cost in ERCOT by USD 27 million in 2011[30].

- SPS's cost can be estimated at USD 250 000 / year for pure software solution. If hardware parts are involved in the SPS, the total cost estimate can reach USD 500 000 / (year - SPS). SPS allows to reduce preventive curtailment, providing up to 50% additional transmission capacity.

- A feasibility study[31] for Topology Optimization (TO) has been conducted in the UK for USD 185 000 over half of a year. An operational deployment could be estimated to cost USD 600 000 to USD 1.2 million over 2 to 4 years. Another study[32] shows that the deployment of TO in the UK could lead to an increase of transfer capacity between 3% - 12%, representing a welfare between USD 14 million and USD 40 million per year. The benefits are highly dependent of the existing congestion in the grid, as the same source puts forward a reduction between USD 18 million – 44 million /year for SPP and USD 100 million/year for PJM.

- NAZA is an AI-driven solution for rapid, short-term renewable curtailment. Its upfront cost sits at the high end of comparable tools, about USD 4–6 million in CAPEX plus roughly USD 60 000 for each automaton deployed. By avoiding costly preventive wind curtailments it allows for higher penetration

[29] *In the section below, sources provided are, by default, from Artelys's internal expertise, as the company is involved in some related projects.*
[30] *Software Technology, Maintaining Grid Security, PowerTech, [link]*
[31] *Transmission Network Topology Optimization, Energy Network Association, [link]*
[32] *New Constraint Management Techniques for Meshed Transmission and Active Distribution Networks, NewGrid, Brattle, Grid Strategies [link]*

and utilization of wind generation, while deferring grid investments[33]. Although exact savings are hard to calculate, RTE estimates that over a 10–15 year period, NAZA has enabled avoidance of approximately USD 7 billion in infrastructure investments, all while preserving the grid's full wind-hosting capability[34].

1.5 Advanced Power Flow *control equipment*

The advanced power flow control equipment changes the routing of the power flow to ensure that the electricity can be conducted from the generation site to the consumption site efficiently through the grid. An enhanced control of the power flow addresses problems like congestions or stability issues.
Two categories of technology are presented in this section: 1) Flexible Alternating Current Transmission Systems (FACTS), which directly control the power flow in the Alternating Current (AC) grid and 2) Direct Current Power Flow Control (DCPFC), which transit electricity through a Direct Current (DC) grid – typically through High Voltage Direct Current (HVDC) transmission system – in parallel to the AC grid.

1.5.1 Flexible Alternating Current Transmission Systems (FACTS)

1.5.1.1 Principle of operation

Flexible Alternating Current Transmission Systems (FACTS) represent a prevalent category of power-electronics-based devices and are modelled as a compensation device connected to the transmission

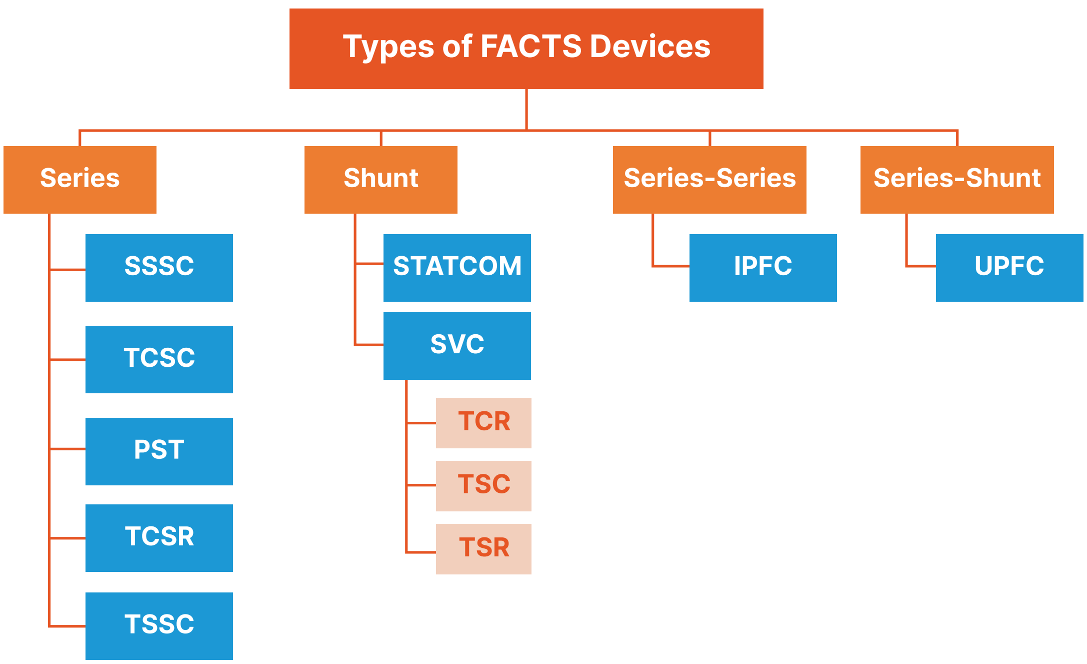
[33] For example, at least 150 MW of line capacity would be necessary without NAZA to host 100 MW of Wind capacity. With NAZA, it is possible to host the 100 MW Wind capacity with 100 MW line capacity, thus avoiding the investment for the additional 50 MW line capacity.
[34] NAZA, RTE, 2021 [link]

line (TL) to vary its overall reactance by voltage and/or current injections. By varying the TL's reactance, FACTS control the power flow on the TL, which is dictated by laws of physics.

These hardware solutions are primarily geared toward regulating power flow and share functional similarities with Phase Shifting Transformers (PST, also named Phase Angle Regulators in North America). By modulating the generation of reactive power as required, they enhance power transmission capacity and grid stability. Presently, the deployment of these power electronics devices remains relatively limited, with more significant adoption observed in regions like Europe and Australia.

FACTS devices can be classified into series, shunt, series-series, and series-shunt. Each technology has its own advantages and disadvantages, as well as different implementation costs.

Figure 1.6: ***Different types of FACTS devices. Source Elad et al, 2024***[35]



Advantages:

- Utilize existing grid infrastructure
- Versatile, applicable at any voltage level, scalable: suitable for both transmission and distribution systems
- Compact design: mobile applications if congestion shifts over time
- Lifetime exceeding 40 years
- Further application to reactive operation: TSOs can manually or automatically adjust injected voltages during grid element outages.

[35] *Luburic and Pandzic, FACTS devices and energy storage in unit commitment, International Journal of Electrical Power & Energy Systems, 2019 [link]*

1.5.1.2 Implementation and impact of the technology

Technical requirements:

- Control systems: FACTS devices require sophisticated control systems to regulate voltage, power flow, and other system parameters.
- Communication infrastructure
- Power electronics: FACTS devices rely on advanced power electronics technology to manipulate voltage and current levels in the power grid.

Implementation:

The EU-funded TWENTIES project mentioned in 2.2 also assessed the impact of FACTS in their pilot project FLEXGRID[36]. They use an overload line controller which controls the power flows in steady state and after contingency state. The main finding is that excess energy can be redirected to lines with spare capacity to use the transmission capacity more efficiently. The cost of device and maintenance is low compared with other power electronics solutions. This solution is easily applicable to another location and scalable. No quantified impact is given. However, implementation together with DLR was studied in this project and found to be beneficial, with no further quantification.

Impacts:

FACTS devices can contribute to reducing the overloading of elements in the power grid by rerouting flows from congested to uncongested lines. The implementation of FACTS for avoiding congestion and redispatch started in 1989 with the static synchronous series compensator (SSSC).

It is now more and more used for integration of renewable energy sources in the power grid as it allows flexibility.

1.5.1.3 Costs and benefits

- In 2015, Smart Wires analysed the potential benefits of modular FACTS devices to support construction of new transmission lines as stated by IRENA[37]. The utility needed to upgrade two 60kV lines to two 115kV lines with an estimated construction period of 3.5 years. Removing the two 60 kV lines required redispatch of generation, particularly in the summer season, to avoid overloading other nearby lines. The study identified that the redispatch could be avoided by installing modular FACTS devices that could reroute the flow from these otherwise overloaded lines. The annual costs of the modular FACTS devices were estimated to be between USD 1.5 million and USD 4 million, and the savings induced by avoiding redispatch were estimated to be over USD 20.5 million a year, therefore suggesting a savings of over USD 70 million (net-savings of USD 61.5 million to USD 69.7 million) over the construction duration period of 3.5 years (depending on when the construction starts). The USD 1.5 million to USD 4.0 million investment is significantly smaller than (between 2% to 6% of) the avoided USD 70 million of congestion costs.

- **The typical investment costs for some FACTs devices are provided in the literature[38]:**

- SVC: USD 60 000 - 100 000 /MVAr
- STATCOM: USD 100 000 - 130 000 /MVAr
- UPFC: USD 130 000 – 170 000 /MVAr
- TCSC: USD 70 000 – 130 000 /MVAr

---

[36] *TWENTIES project final report, June 2013, [link]*
[37] *IRENA, Innovation landscape for a renewable-powered future, 2019, [link]*
[38] *FACTS – For Cost Effective and Reliable Transmission of Electrical Energy, Klaus Habur and Donal O'Leary, [link]*

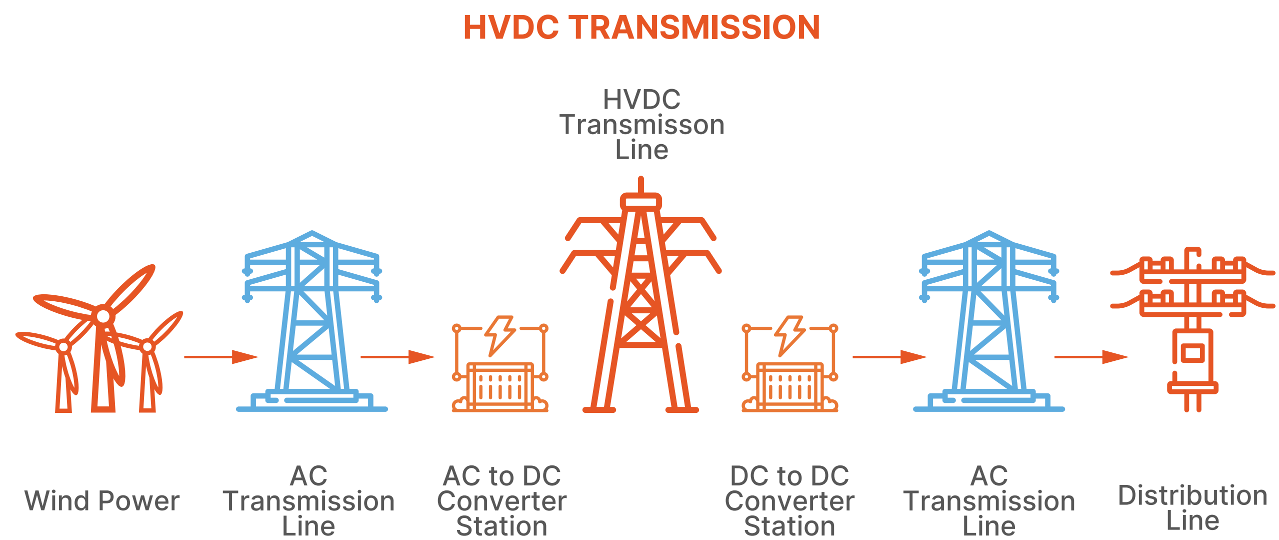
1.5.2High-Voltage Direct Current Transmission System

1.5.2.1 Principal of operation

A Direct Current (DC) transmission system is connected to the AC grid through back-to-back converters so that the electricity can be converted from AC to DC at the point of injection and converted back from DC to AC at the point of delivery. This allows the electricity to flow freely in either direction, independently of the phase angle between the source and the load.

HVDC systems are typically used in a bipolar configuration (i.e., two circuits) to transfer large amounts of energy over long distances, from one point to another, as they are more efficient and cost-effective than high-voltage AC systems in this case. Although the implementation of these systems is more limited than AC transmission technologies due to their cost and complexity, HCDV are used in strategic applications and in the integration of renewable energy sources. The applications include linking remote generation pockets with large demand centers or interconnecting asynchronous neighboring grids.

Figure 1.7: ***Explanatory scheme for HVDC. Source: Allumiax[39]***



1.5.2.2 Implementation and impact of the technology

Technical requirements:

- Converter stations at the endpoints
- Transmission medium: either overhead line or underground/underwater cable
- Grounding systems
- Control and Protection systems
- Reactive Power Compensation
- Harmonic Filters

[39] *High Voltage Direct Current HVDC Transmission, Allumiax,* [link]

Implementation:

The modern form of HVDC transmission uses technology developed in the 1930s. **It is considered a mature technology (TRL 9)** with worldwide application. However, innovations have not ceased in the field, especially since the development of solar and wind power. **New technologies like voltage-source converters or Ultra High Voltage Direct Current (UHVDC)[40]** transmission emerged in recent years, but their applications are more limited.

The implementation process is usually more complex than an equivalent AC line for the HVDC requires an additional layer of conversion. In addition, HVDC transmission systems are usually designed to connect distant and remote areas; geographical constraints (underwater passage, mountain-crossing pathways etc.) are of the most common challenges. Therefore, **the construction timeline can be very variable.** For instance, the Kimal-Lo Aguirre 600 kV line in Chile[41], of about 1500 km long, could take 7 years of construction while the Belo Monte – Rio de Janeiro 800 kV line in Brazil[42], of about 2500 km long, took only 2 years to be constructed.

Impacts:

HVDC impacts multiple aspects of the grid:

Remote areas can be connected with less energy loss: 3.5% of energy loss per 1000 km for HVDC versus 6.7% for equivalent AC lines[43]; a highway for location-constrained renewable energy.

- Asynchronous connections with neighbors and easy fault-isolation.
- Flexibility in operating the AC grid as the flow can be easily modulated on the DC grid according to the stress on the AC grid; HVDC enhances AC grid's stability.

1.5.2.3 Costs and benefits

- The 1500 km-long 600kV line in Chile is estimated to cost USD 1.5 billion (2021)[44]. The line is the major infrastructure project in the country for the last years and will be substantial in helping the country achieve its carbon-neutrality goal by 2050. The line will have a capacity of 3000 MW. Considering a 90% factor of charge, 23.6 TWh of electricity could transit through the line. The sole benefit from the saving on energy loss would already represent 1.13 TWh/year or USD 78 million/year with a historical spot price of USD 70/MWh in Chile.
- The 2500 km-long 800kV line in Brazil cost USD 2.14 billion (2019)[45]. With another UHVDC line, Belo Monte UHVDC Bipole I (completed in 2017), the two lines are structuring infrastructures for the country. This project delivers electricity to approximately 22 million people with its 4 GW capacity. Using the same approach as above, the estimated yearly saving on energy loss would be 2.5 TWh/year which corresponds to USD 176 million/year.

---

[40] HVDC's nominal voltage is typically between 100 kV and 800 kV and UHVDC's nominal voltage is superior to 800 kV
[41] Chile construirá una moderna línea de alta tensión de corriente continua para facilitar el transporte de energía renovable, Econo Journal, 2021, [link]
[42] Belo Monte-Rio de Janeiro UHVDC Transmission Project, NS Energy, 2020, [link]
[43] High-voltage direct current, Wikipedia, [link]
[44] Belo Monte-Rio de Janeiro UHVDC Transmission Project, NS Energy, 2020, [link]
[45] High-voltage direct current, Wikipedia, [link]

1.6 Battery Energy *Storage System*

1.6.1 Principles of operation

A battery energy storage system (BESS) is an electrochemical system that uses a battery to store and distribute electricity. A BESS collects energy from renewable energy sources, such as wind and solar, or from the electricity network, and stores it. The batteries discharge to release energy when necessary, such as during peak demands, power outages, or grid balancing. The most mature of the Battery Energy Storage Systems are the Lithium-Ion Battery Systems. This section focuses on **utility-scale storage systems**, and not in distributed-scale storage, even though the services provided to the system are similar.

BESS have quick response times, allowing them to quickly adapt their setpoints to provide services to the system in seconds or less (e.g., fast frequency regulation and virtual inertia).

BESS, due to the power electronics DC/AC converters, can provide both active and reactive power to the grid. Importantly, advanced BESS equipped grid forming converters instead of grid following converters can also provide stability services like inertia and short circuit level.
On the other hand, BESS are limited by its storage capacity, commonly measured in "hours" of storage capacity. Though customizable, BESS usually range from 2-hour to 6-hour storage capacity[46].

Advantages:

Battery Energy Storage Systems (BESS) have several applications and advantages:

- Ancillary services: frequency regulation, voltage support, black start, virtual inertia.
- Energy and capacity services: load shifting, output smoothing, bill management, renewable capacity firming.
- Transmission and distribution services: grid reliability, congestion mitigation, transmission upgrade deferral, congestion costs reduction[47].
- The most relevant advantage in this study is the reduction in renewable curtailment that is allowed by Battery Energy Storage Systems, and the associated congestion costs reduction.

[46] *Cole and Karmakar, Cost Projections for Utility-Scale Battery Storage: 2023 Update, NREL, 2023 [link]*
[47] *Compared to other storage solutions (like Pumped-hydro storage), BESS is more modular and flexible in location. Where BESS could provide storage-as-transmission services, other storage solutions could, on the contrary, add to the system congestion due to their localization constraint.*

1.6.2 Implementation and impact of the technology

System requirements:

In addition to the batteries (e.g., the storage components), BESS requires power electronics components that allow the system to be connected to an electrical network. A bidirectional converter or power conversion system is the main device that converts power between the DC battery terminals and the AC line voltage and allows for power to flow both ways to charge and discharge the battery. The other primary element of a BESS is an energy management system (EMS) to coordinate the control and operation of all components in the system.

Communication and/or local measurement devices are necessary to provide several services. For example, frequency measurement devices may be needed to provide frequency regulation services; or communication with the system operator might be needed to be able to relieve congestion in the grid.

Impacts:

The effectiveness of energy storage in reducing renewable power curtailment and system operating costs depends significantly on the wind and solar profile. It also depends on how the BESS is operated.

BESS can be used as a substitute for expensive upgrades to the transmission infrastructure. Indeed, utility scale batteries located in congested areas can provide back-up energy storage during a contingency event to relieve thermal overload. This would reduce the curtailment of renewable energy generation due to grid congestion.

Lately, grid forming converter equipped batteries[48] have been able to provide stability services associated with frequency and voltage stability, competing directly with synchronous condensers. There is a rich experience in the UK that is described in this report later.

The BESS technology has a TRL of 9, as it is present in many power systems. Two use cases in Chile had a **deployment timeline of roughly 1 year**, showcasing a convenient implementation[49,50].

1.6.3 Costs and benefits

The costs and benefits can be assessed on two Chilean use cases:

- The 35 MW/175 MWh San Andrés project costs USD 61.9 million (USD 1.77 million/MW or 0.35 million/MWh). It is expected to generate USD 8 million revenue per year, with operating expenses at USD 400 000/year[51].
- The 50 MW/250 MWh Salvador project costs USD 75 million (USD 1.5 million/MW or 0.3 million/MWh). It is expected to generate USD 8.2 million revenue per year, with operating expenses at USD 900 000/year[52].

[48] *This section focused on batteries, but other converter-based resources, like solar or wind unit, can also adopt grid-forming technology.*
[49] *Innergex Achieves Financial Close On Its San Andrés Battery Energy Storage Project in Chile, Innergex, 2023, [link]*
[50] *Innergex inaugurates 50-MW250-MWh BESS in Chile, Renewables Now, 2023, [link]*
[51] *Innergex inaugurates 50-MW250-MWh BESS in Chile, Renewables Now, 2023, [link]*
[52] *Innergex Announces the Commissioning of the Salvador Battery Facility in Chile, Innergex, 2023, [link]*

Also, the National Renewable Energy Laboratory's Annual Technology Baseline has studied the costs and performances of lithium-ion utility scale battery storage. Figures below detail the system costs in terms of energy capacity (USD/kWh) and in terms of power capacity (USD/kW). For a 4-hour duration - 60 MW-240 MWh Li-ion battery system, the total cost would be USD 446/kWh or 1 785/kW.

Moreover, Figure 1 10 shows significant costs reductions in the coming years, by approximately 30% by 2030 (with respect to 2022 values), and by around 50% by 2050 in the central scenario projections.

Figure 1.8: ***System cost(USD/kWh) for 5 types of 60 MW Li-ion Battery System in 2022. Source: NREL[53]***

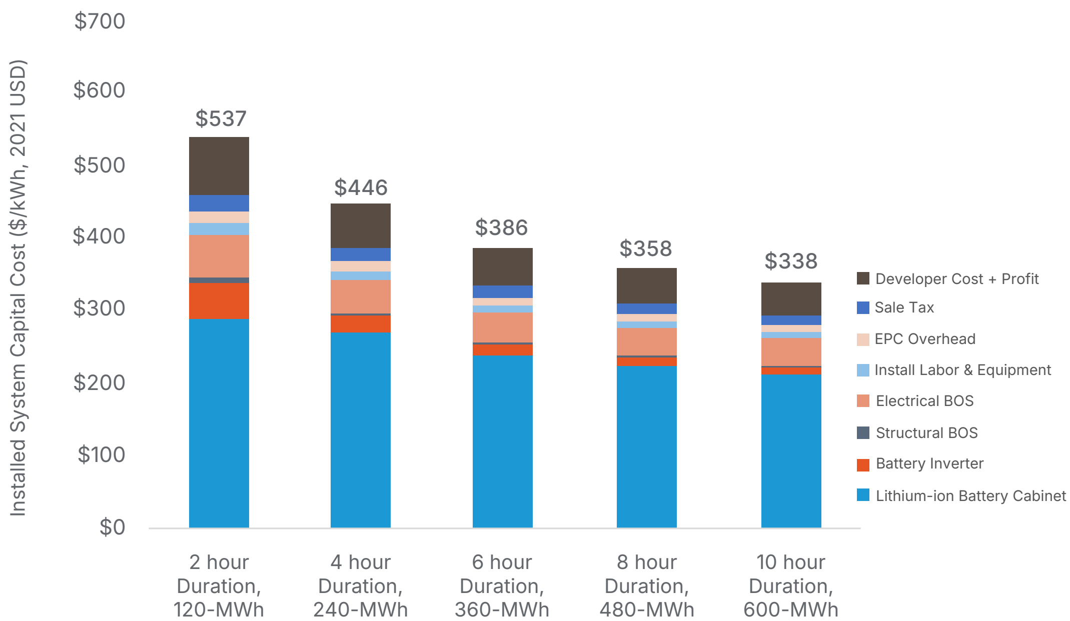
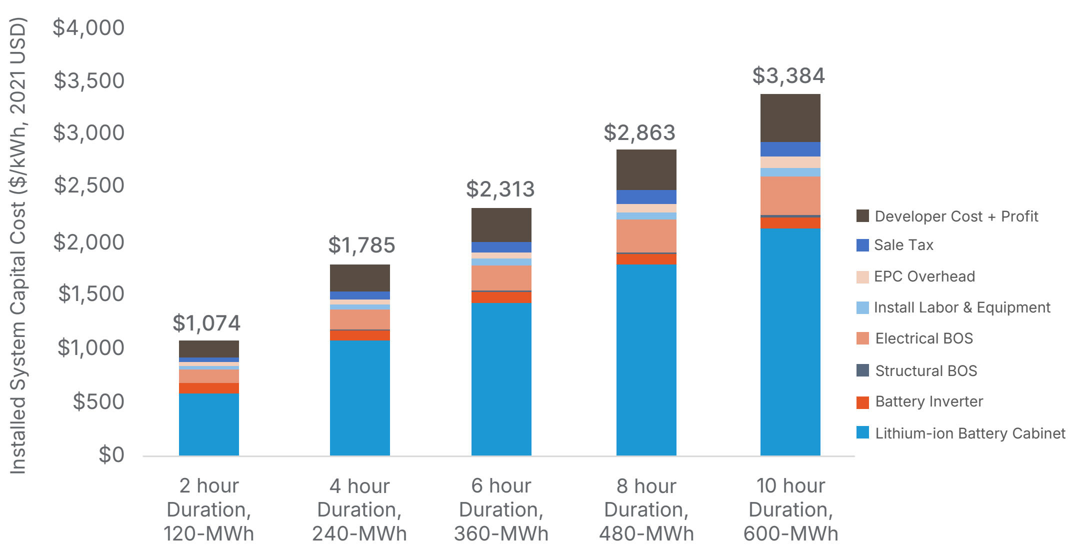
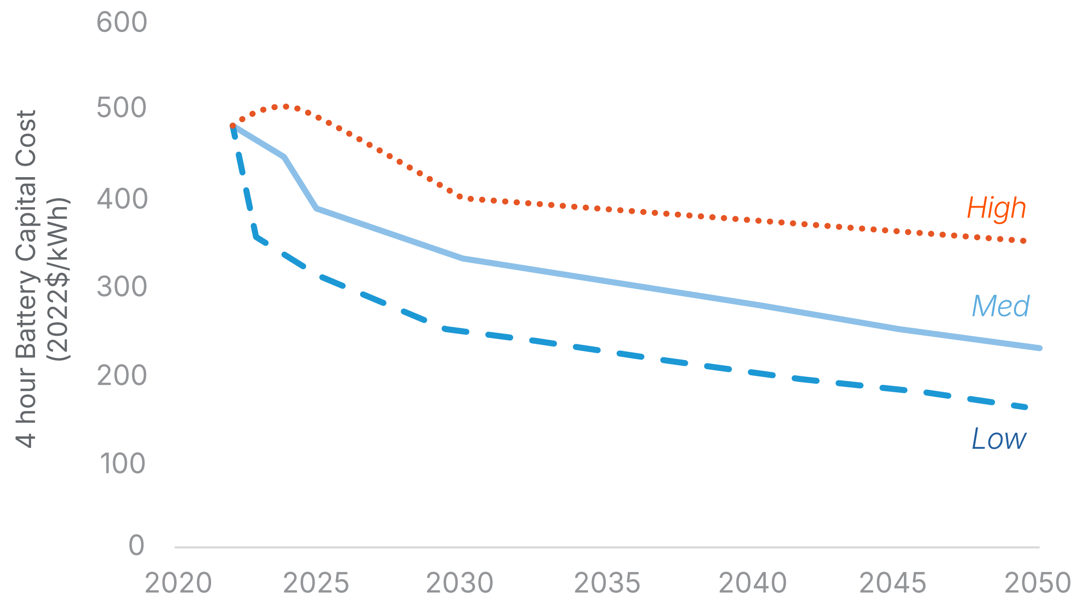


Figure 1.9: ***System cost(USD/kW) for 5 types of 60 MW Li-ion Battery System in 2022. Source: NREL***



[53] *Annual Technology Baseline, 2023, NREL, [link]*

Figure 1.10: ***Battery cost projections for 4-hour lithium-ion systems. Source: NREL***



1.6.4 Grid-Forming Technology: Benefits, Challenges, Current Status

Definition

Grid-forming converters differ from conventional "grid-following" inverters[54] in that they establish their own voltage waveform and can provide inertia and rapid fault-current injection without relying on an external voltage reference. When integrated with battery storage or hybrid schemes, these converters can potentially deliver both frequency and voltage support. This section focuses on batteries, but other converter-based resources, like solar, wind unit or even HVDC links or loads, can also adopt grid-forming technology.

[54] There is a common language misuse in the literature between "converter" and "inverter". Stricto sensu, a converter converts AC power to DC power and an inverter converts DC power to AC power.

Benefits and challenges

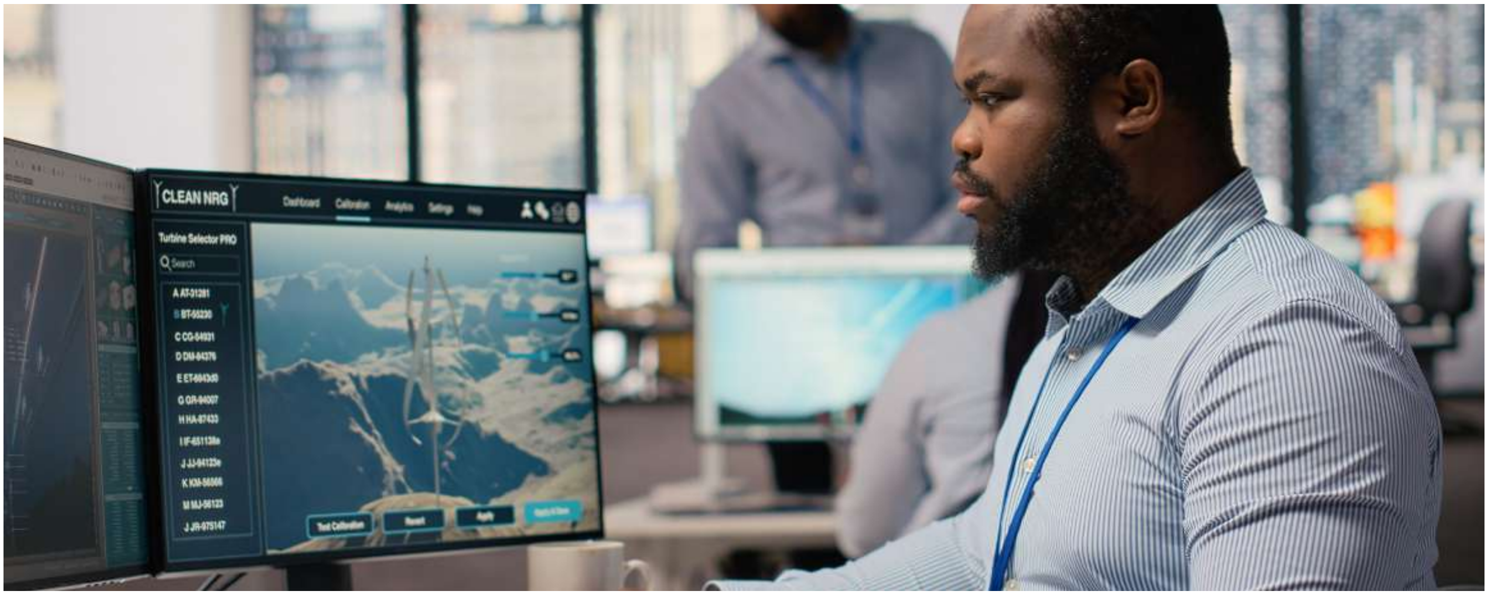
Grid-Forming Technology- Benefits, Challenges, Current Status

	Aspect	Description
Benefits	Enhanced System Stability	By injecting short-circuit current and regulating voltage autonomously, grid-forming converters emulate a synchronous machine's behavior, bolstering transient and dynamic stability.
	Synthetic Inertia	As demanded by the technical specification, they can respond to rapid rate-of-change-of-frequency (RoCoF) events, stabilizing system frequency in low-inertia conditions.
	Black Start Potential	If suitably configured with energy storage, grid-forming converters can help restore a de-energized grid without relying on a running synchronous generator.
Challenges	Capital and Operating Costs	Grid-forming inverters with high-fidelity controllers and supporting hardware can be more expensive relative to simpler grid-following units.
	Technology Maturity	While the theoretical foundation is robust, large-scale grid-forming deployments remain limited, so reliability and control schemes require ongoing validation.
	Operational Complexity	Introducing grid-forming behavior into areas with low inertia demands careful coordination with existing protection schemes, particularly under high RoCoF conditions.
	Grid Code Compliance	The UK Grid Code includes specific technical thresholds for voltage and fault ride-through capabilities; ensuring compliance can be more involved for novel converter designs.

Current Status

The global grid-forming converter market size was evaluated at USD 700 million in 2024; it is expected to double by 2032[55]. The market is currently dominated by Asia Pacific with a 57% share in 2024. The Scottish use-case presented in the section 2.1 involves some application of grid-forming technologies to solve inertia and short-current level issues in the British grid.

[55] *Grid-Forming Inverter Market, Fortune Business Insights, 2025, [link]*



1.7 Summary *chart*

Table 3: ***Provides a summary of the GETs reviewed during this task 1. The references can be found in the Appendix A.***

Technology		Problems addressed	TRL	Nature	Ease of implementation	Deployment timeline	Capex	Additional costs	Benefits	Comments
Dynamic Line Rating	Line mounted	Thermal congestion on overloaded lines Real-time anomalies management	8	Hybrid	Complex require: sensors, data transmission infrastructure data processing and modelling	1-2 years [1] [2]	$3.25M/18 sensors over 50km for 3 lines Correspon-ding to $5k/km for line monitoring + $2.5M for the central system (PPL, USA, 2020) [2A]	Sensors and software maintennance $0.235M/year for the 3 lines [2a]	9% - 19% increased capacity Welfare: $23M/year congestion cost reduction BCR: 84 (PPL, USA) [1]	Most sensible to wind speed and ambient temperature; Well suited to area with high variabilities regarding these factors; No outage during installation. The operational integration process can take 1-2 years while the sensor deployment and calibration can be achieved within months Difficulty to internalize the welfare surplus for project developers
	Contactless (e.g.,LiDAR, EMF		8	Hybrid			$0.85M for 3 lines $5.5k/km (ONRL, USA, 2021) [3]	Sensors and software maintennance. Expected to be close to line-mounted DLR	9% - 36% increased capacit Welfare $19.7M/year congestion cost reduction BCR: 267 (67 with hypothetical $2.5 central system costs) (ONRL, USA) [3]	same as above
Sensor less Dynamic Line Rating		Thermal congestion on overloaded lines	7	Software	Medium software integration to operation protocols; require weather data sources	few months	$300k-600k (estimation 2024)	Software maintennance. Weather data procurement $150k/year	15% - 20% increased capacit Welfare: Congestion relief over forced outage for $0.27M over 4 months.[4]	No line-span coverage issue (sensor less); More capacity margins are left for the security during operation

<table>
<tr><th colspan="2">Technology</th><th>Problems addressed</th><th>TRL</th><th>Nature</th><th>Ease of implementation</th><th>Deployment timeline</th><th>Capex</th><th>Additional costs</th><th>Benefits</th><th>Comments</th></tr>
<tr><td colspan="2">Reconductoring/ Advanced Conductor</td><td>Line capacity limit (Thermal sag)</td><td>9</td><td>Hardware</td><td>Easy</td><td>1-3 years for <30 km lines (PJM, USA) [5]</td><td>$400k/km at 230 kV with ACSS/TW conductor

A total cost of $9M for a 22.5 km long line

(PPL, USA, 2023) [5] [6]</td><td>Up to 25% less losses at 20°C
Up to 46% more losses at Maximum Operating Temperature [7]</td><td>53%-118% increased capacity [7]

Welfare: NPV of $ 107M over 15 years for congestion cost reduction
BCR: 11.28 (PPL, USA) [6]</td><td>Extended outage necessary;
Different technologies exist:
ACSS; ACCC, ACCR etc.

Less permitting burdens and shorter timeline compared to an equivalent rebuild project.</td></tr>
<tr><td colspan="2">Battery Energy Storage System</td><td>High-demand congestion; Planning uncertainty; Stability (Frequency Containment); Inertia (synthetic); Renewable curtailment avoidance</td><td>9</td><td>Hardware</td><td>Easy</td><td>1-2 years [8][9]</td><td>$ 1.5M - 1.77M / (MW - 5 MWh)

(Chile, 2023) [8][9]</td><td>$ 0.01M - 0.018M /(MW-5MWh) [8][9]</td><td>Benefits for developer:
$ 8.0M/year
BCR = 1.99
(35 MW/175 MWh) (Chile) [8]

$ 8.2M/year
BCR = 1.69
(50 MW/250 MWh) (Chile) [9]</td><td>BESS have multiple revenue streams (capacity, energy and ancillary services market) on top of the congestion relieving benefits.</td></tr>
<tr><td rowspan="4">Advanced Power Flow</td><td>Synchronous Condensers</td><td>Inertia; Voltage control; Short-circuit power;</td><td>9</td><td>Hardware</td><td>Easy</td><td>1-2 years</td><td>$ 300k/MVA [9a]

(Australia, 2023)</td><td>Energy consumption: 0.01 MW/MVA

0.003 MW/ (MW. s)

(Tasmanian Hydro)

Start cost: $ 100-1000s [10]</td><td>Increased hosting capacities for IBRs

Enhanced grid stability and strength</td><td>Suitable traditional thermal units can be reconverted into SC (50% cheaper according to interview)</td></tr>
<tr><td>FACTS/new digital devices</td><td>Congestion; Dynamic stability limits</td><td>9</td><td>Hardware</td><td>Easy</td><td>1-2 years [11]</td><td>SVC: $ 60k - 100k /MVAr
STATCOM: $ 100k - $ 130k /MVAr
UPFC: $ 130k - 170k /MVAr
TCSC: $ 70k - 130k /MVAr
[11]
(Siemens paper, 2005)</td><td>150 - 250 man-hours per year for maintenance Losses [11]</td><td>Welfare:
$ 39M/year congestion reduction with 1 PAC of 36 MVA

Up to $ 196M with 17 PACs for 2116 MVA (PJM study) [12]</td><td>Mobile, scalable and fast to deploy</td></tr>
<tr><td>DC power flow control (HVDC)</td><td>Congestion; Distance limitation</td><td>9</td><td>Hardware</td><td>Easy</td><td>2-7 years [13][14]</td><td>$ 2.14B for 2539 km 800kV/4GW (Brazil, 2019) [13]
$ 1.5B for 1500 km 600kV/3GW (Chile, 2021) [14]</td><td>3.5 % loss over 1000 km
+
maintenance expenses [15]</td><td>40% more capacity than same voltage AC [15]</td><td>The implementation ease depends on the topography of the pathway</td></tr>
<tr><td>Soft Open Point and Normally Open Point</td><td>Active power control; Reactive power compensation; Voltage; Fault Isolation; Service restoration</td><td>9</td><td>Hardware</td><td>Easy</td><td>1-2 years [16]</td><td>$ 160k-308k /MVA [17][18] (academic paper, 2017)</td><td>Maintenance: 3k/(MVA-year) Losses and operation: + 20k - 40k / (year - MVA) [17]</td><td>10-20% increased capacity [18]</td><td></td></tr>
</table>

Table 5: ***Summary of the GETs review. Color code: green for hardware, yellow for hybrid and purple for software solutions.***

<table>
<tr><th colspan="2">Technology</th><th>Problems addressed</th><th>TRL</th><th>Nature</th><th>Ease of implementation</th><th>Deployment timeline</th><th>Capex</th><th>Additional costs</th><th>Benefits</th><th>Comments</th></tr>
<tr><td colspan="2">Demand Response</td><td>Peak demand management</td><td>9</td><td>Hybrid</td><td>Medium
Require: distributed meters</td><td>5-6 years to install 110k meters [19]</td><td>$ 150/meter + software CAPEX [20]</td><td>Activation compensation: price-based or incentive-based + Software and meter maintenance</td><td>Reduce 2%-8% investment in generation, 1% - 4% energy consumption and 1.5% - 5% carbon emissions (EU) [19]</td><td></td></tr>
<tr><td colspan="2">Topology Optimization[56]</td><td>Congestion; Changing operational conditions;</td><td>8</td><td>Software</td><td>Complex: software integration, trained staff for operation Reliant on monitoring system</td><td>0.5 year for feasibility study (UK) [25]
2 - 4 years for operational deployment</td><td>$ 185k for feasibility study (UK, 2015) [25]

$ 600k to $ 1.2M for operational deployment (estimated, 2024)</td><td>100 per switch action [26]
+ Software maintenance and staff
$ 180k - $ 360k /year</td><td>UK: + 3% - 12.3% transfer capacity ($14-40M/year)
SPP: 26% flow relief ($18-44M/year)
PJM: $100M/year [27]</td><td>Can be coupled with DLR;
Financial benefits reside in the reduction of congestion costs, therefore system dependent
Well suited to grids with complex</td></tr>
<tr><td rowspan="3">Synchro phasors/ Wide Area Monitoring System + Digital Twin/AI</td><td>Security Analysis; Dynamic Security Assessment</td><td>Reliability and Stability studies (different temporal granularity)</td><td>9</td><td>Software</td><td rowspan="2">Complex: software integration and trained staff for operation; Require: monitoring system</td><td>1-3 years</td><td>$ 400k to $ 1.5M (estimated, 2024)</td><td>software maintenance + staff
$ 150k - $ 450k /year</td><td>$ 27M /year congestion cost reduction (ERCOT, USA) [22]</td><td>Costs are assuming the operators can perform dynamic stability studies manually and that automatic static security assessment are already in place</td></tr>
<tr><td>Real-time operation control (e.g., Naza automata)</td><td>Optimal grid operation</td><td>7</td><td>Software</td><td>3-5 years</td><td>$ 4M - 6M
$ 60k per automata (estimated, 2024)</td><td>Curtailed energy software maintenance and staff
$ 500k /year</td><td>Avoid $ 7B infrastructure investment over 10 years (FR) [28]</td><td></td></tr>
<tr><td>Special Protection Scheme / Remedial Action Scheme</td><td>Operational limit violations</td><td>9</td><td>Software</td><td>Same as above</td><td>1-3 years</td><td>Software: $ 250k / year
Software + hardware: $ 500k / year per SPS (estimated, 2024)</td><td>NA</td><td>Avoid preventive curtailment.
Up to 50 % more capacity through the lines</td><td>Allow the system to operate closer to its stability limits</td></tr>
</table>

02

Case studies assessment

In this section, we will present two case studies that showcase successful applications of Grid Enhancing Technologies (GETs) in transmission assets. The first case study deals with Synchronous Condensers in Scotland, while the second case study is about Dynamic Line Rating in Pennsylvania, USA. Both case studies are compared with similar technology applications in Latin America, and the advantages and disadvantages of the choices made are described.

2.1 Case Study 1: *Stability Pathfinder Phase 2 - UK*

2.1.1 Introduction to the UK Energy Transition

The United Kingdom's clean power strategy aims to accelerate the deployment of renewables and complementary technologies so that "once-in-a-generation levels of energy investment" can drive the nation toward decarbonization. According to the Clean Power 2030 Action Plan, the government envisioned 43-50 GW of offshore wind, 27-29 GW of onshore wind, and 45-47 GW of solar by the end of the decade, complemented by 23-27 GW of battery energy storage and 4-6 GW of longer-duration storage. Electricity demand is set to rise as transport, buildings, and industry are electrified to reduce reliance on fossil fuels. To manage these shifts, the UK government is streamlining planning processes, boosting network build-out, and adopting consumer-centric reforms, requiring about £40 billion per year (in undiscounted 2024 prices), including £30 billion in generation assets and £10 billion in transmission assets between 2025 and 2030. Government leadership is central to this approach, ensuring security of supply by balancing renewables, dispatchable low-carbon resources, and backup from unabated gas (with significantly reduced running hours by 2030)[57].

[57] *UK Clean Power 2030 Action Plan, Department for Energy Security and Net Zero, [link]*

The UK's drive toward net zero greenhouse gas emissions by 2050 also means a broader strategic transformation of its electricity system. The Electricity Networks Strategic Framework highlights how the British Energy Security Strategy and Ofgem's regulatory adaptations collectively accelerate low-carbon generation—both renewables and nuclear—while preparing the grid for a potential doubling of demand over the coming decades. Central to this framework is a more strategic approach to network expansion (covering both high-voltage transmission and local distribution), plus the establishment of a Future System Operator (FSO) to oversee system planning and resilience. By aligning regulation, investment, and operation with net zero targets, the UK aims to maintain reliability even as variable renewables dominate future generation[58].

The Clean Power 2030 Action Plan identifies a major challenge in the need to roughly double the pace of new transmission infrastructure by 2030 compared to the past decade. Without faster builds, constraint costs could surge from £2 billion per year in 2022 to around £8 billion per year (£80 per household per year) in the late 2020s[59], driven by projects unable to deliver power due to network bottlenecks. Grid connection queues have expanded tenfold over five years, prompting collaboration among the National Energy System Operator (NESO), Ofgem, and transmission owners to streamline connection processes. A key issue adding further complexity to the system is the structure of Transmission Network Use of System (TNUoS) charges. These charges, which recover the cost of building and maintaining the transmission network, vary by location to reflect the cost impact of generators and consumers on the system. However, this results in disproportionately high charges for generators in resource-rich but remote areas like Scotland, where long transmission distances and network congestion increase costs. This has created uncertainty and volatility for investors in renewables, particularly wind energy. To address this challenge, Ofgem has proposed a temporary cap-and-floor mechanism for TNUoS charges. This would set an upper limit (cap) on charges to prevent excessive costs for generators and a lower limit (floor) to ensure that necessary transmission investments remain financially viable, by reducing unpredictability and extreme cost fluctuations[60].

According to the Electricity Networks Strategic Framework, rapid demand growth (electric vehicles, heat pumps, industrial electrification) collides with the geographic mismatch of large-scale renewables far from load centers. Extreme weather, cybersecurity risks, and an increasingly complex balancing environment are additional pressures. Though flexible resources (storage, demand response, smart charging) can reduce the need for "traditional wires," significant onshore build-out remains necessary. The framework highlights resilience concerns as extreme weather events multiply, urging enhanced restoration protocols and more robust infrastructure. Constraining renewables due to insufficient transmission is costly both economically and environmentally, reinforcing the need for accelerated approvals and carefully targeted new lines[61].

---

[58] *Electricity Networks Strategic Framework, Department for Business, Energy and Industrial Strategy,* [link]
[59] *Clean Power 2030 Action Plan Excerpt, Department for Energy Security and Net Zero,* [link]
[60] *Clean Power 2030 Action Plan Excerpt, Department for Energy Security and Net Zero,* [link]
[61] *Electricity Networks Strategic Framework, Department for Business, Energy and Industrial Strategy,* [link]

2.1.2 Pathfinders initiative

To meet these ambitious targets and avoid unsustainable constraint costs, traditional grid expansion alone is not enough. Building new lines and substations at double the usual pace poses technical, logistical, and regulatory challenges—while rising demand from electric vehicles, heat pumps, and electrified industry further strains the existing network.

Against this backdrop, the National Grid Electricity System Operator (NGESO) introduced the Pathfinder initiatives with its first phase launched during October 2019. These competitive procurement rounds seek essential grid services such as voltage control, stability (fault current and inertia), and constraint management through market-based solutions. By soliciting innovative offerings like synchronous condensers, grid-forming converters, and constraint-management intertrip schemes, Pathfinders provide targeted fixes that can be deployed more quickly than large-scale transmission builds.

Crucially, these programs buy time for traditional infrastructure investments. Instead of waiting for multi-year construction projects, the UK can integrate innovative solutions including advanced power electronics, batteries with grid forming converters, or contractual solutions (intertrip services for constraint management) that optimize existing assets. In doing so, Pathfinders demonstrate how flexible, technology-neutral procurement can support high renewable penetration, reduce system costs, and enhance grid stability—all while the nation scales up to meet net zero ambitions.

2.1.3 Overview of the Pathfinders Program

National Grid ESO (NGESO) runs “Pathfinder” initiatives—competitive tenders that secure critical grid services (voltage control, stability, and constraint management) more rapidly and often at lower cost than building new transmission. Each Pathfinder targets a specific need—e.g., reactive power or intertrip services—and evaluates all feasible technologies on a level playing field. Table 5 summarizes key Pathfinders to date.

Table 6: ***Overview of Pathfinders for network services program, solutions and outcomes***

Pathfinder	Example Solutions	Key Outcome
Pennine Voltage (launched ~2021)	Synchronous condensers, TO-proposed reactors	Achieved ~£22.5 million in consumer savings by securing a mix of private and Transmission Owner (TO) solutions.[62]
Mersey Voltage (2022-2031)	Reactor-based + battery-based dynamic support	Two contracts awarded: a large reactor and a smaller battery, highlighting technological diversity and lessons on clear tender rules.[63]
Voltage 2026 (recent)	Synchronous condensers, advanced power electronics	Ongoing procurement to manage voltage in London and Northern England, "buying time" until major reinforcements.[64]
Constraint Management	Intertrip services, e.g., rapid disconnection signals to generators	Reduces unnecessary curtailment of renewables; defers or avoids major new network expansions. B6 Pathfinder alone saved consumers ~£30 million in the first four months of operation and 72.000 tons CO_2 in the first month of operation.[65]

[62] *NOA Voltage Pathfinder – Pennine tender, NESO, 2021, [link]*
[63] *First GB voltage management project goes live in world-first for independent business, NESO, 2022, [link]*
[64] *Voltage Network Services, NESO, [link]*
[65] *Letter from NESO: Results of B6 Constraint Management Pathfinder (2024/25) , NESO, 2024, [link]*

Why Pathfinders?

Speed & Innovation: They bring in new technologies (like synchronous condensers or grid-forming converters) more quickly than large infrastructure projects.

Cost Savings: Competitive bidding helps avoid or defer costly new lines or substations, passing savings to consumers.

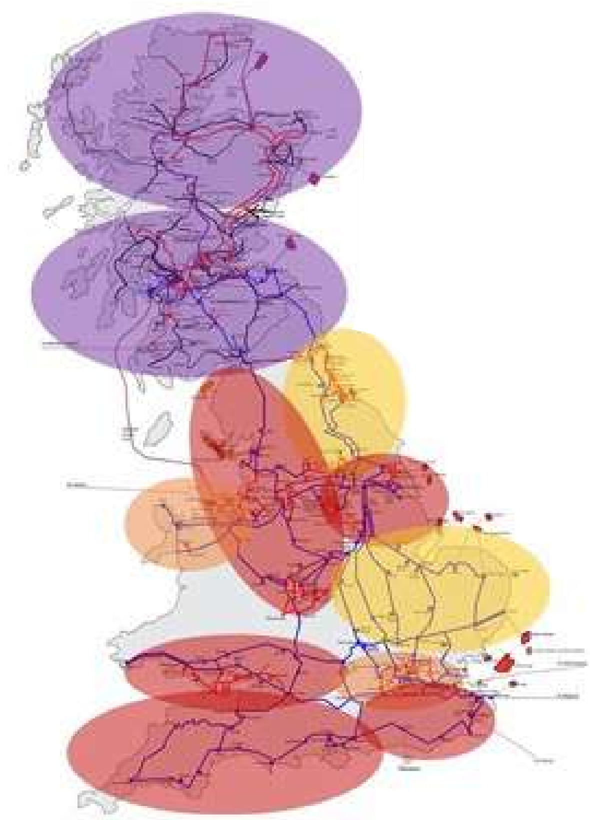
Reduced Emissions: Allow more renewables to run instead of curtailing them when the grid is constrained or needs extra stability.

Overall, these Pathfinders illustrate how market-based procurements can address acute grid challenges while traditional transmission expansions move forward in parallel.

2.1.4 Stability Pathfinders (All 3 Phases) - Status & Results

Phase 1 of the National Grid ESO Stability Pathfinder concluded in January 2020, awarding 12 contracts to five providers. This initial round sought "the most cost-effective way to increase inertia (stored energy) across Great Britain," following the decline in traditional synchronous generation. After launching a Request for Information (RFI) in July 2019 to gauge industry interest, an accelerated tender process was held to procure inertia services for delivery from April 2020 onward. The System Operator identified multiple projects capable of delivering fast-acting dynamic support—mainly from synchronous condensers and generators running in synchronous compensation mode—enabling the grid to manage its short-circuit levels, inertia, and voltage stability more efficiently.

Figure 2.1: **Identified regional stability needs in the UK network**[66]

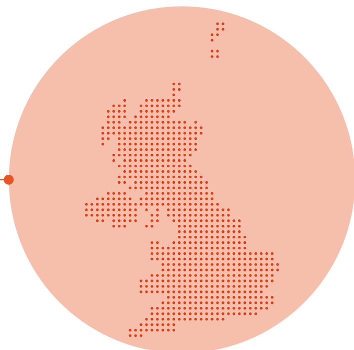


- Large growth in stability need
- Medium growth in stability need
- Small growth in stability need
- Detailed need specified in pathfinder project

[66] *Stability Deep Dive, NESO, 2023, [link]*

Figure 2.2: ***Overview of Stability Pathfinders phases 1, 2 and 3 (GFC: Grid Forming Controller)*** [67]

Phase 1



. 12.5GWs inertia procured across GB
. Paid for availity
. 90% availability is mandatory
. All are Sync Comps
. All units are now live and providing inertia to te system

Connection	Inertia (MWs)	Go live date
CRUA2	533.3	July 2020
RASS1	750	Feb 2022
CONQ4	1533	Jun 2021
CONQ4	1533	Jun 2021
KILL4	1430	April 2022
KILL4	1430	April 2022
KEIT1	450	Dec 2021
KEIT1	450	Jan 2022
GRAI4	1729	March 2023
GRAI4	1729	March 2023
LISD2	450	Feb 2023
LISD2	450	Feb 2023

Phase 2

. 6GWs inertia procured across Scotland
. SCL need is met
. Paid for availability
. 5 Sync comps and 5 GFC
. Will be in service between 2024’2026

Connection	Technology
CRUA2	533.3
RASS1	750
CONQ4	1533
CONQ4	1533
KILL4	1430
KILL4	1430
KEIT1	450
KEIT1	450
GRAI4	1729
GRAI4	1729
LISD2	450
LISD2	450

Phase 3

. 17.1GWs inertia procured across E&W
. SCL need is met
. Paid for availability
. 90% availability is mandatory
. 29 Sync comps
. Will be in service between 2025-2026

Phase 2 of the Stability Pathfinder[68] is focused on increasing short-circuit levels in Scotland, where traditional synchronous plants are being phased out and replaced by renewable sources that do not provide the same stabilizing properties. The System Operability Framework[69] highlighted emerging operability risks driven by the decline in synchronous generation over the next decade, prompting the need for solutions that could deliver sufficient Short Circuit Level (SCL).

On 23 November 2022, National Grid Electricity System Operator (ESO) announced the outcome of the third phase of its Stability Pathfinder. New contracts—collectively valued at £1.3 billion—were awarded to six companies for delivering long-term stability services across England and Wales. By securing this

[67] *Stability Deep Dive, NESO, 2023, [link]*
[68] *Stability Network Services – Stability market, NESO, [link]*
[69] *System Operability Framework, NESO, [link]*

capacity, the ESO projects substantial consumer benefits: an estimated £14.9 billion in savings from 2025 to 2035.

According to the official announcement, the **Phase 3** solutions will replicate or replace the stability outputs once supplied by synchronous fossil-fuel units, but without the associated carbon emissions. This transition aligns with ESO's broader aim to operate the transmission system at zero-carbon by 2025. Each contract focuses on delivering services such as inertia, short-circuit level, and dynamic reactive support—capabilities necessary to keep the grid resilient and cost-effective as renewable penetration increases.

2.1.5 Stability Pathfinder 2

This section presents the United Kingdom (UK) case study focusing on National Grid ESO's (NGESO) Stability Pathfinder Phase 2 initiative, with attention to its technical and commercial framework, as well as the outcomes and ongoing financial considerations. The discussion is informed by NGESO's published tender EOI and results documentation.

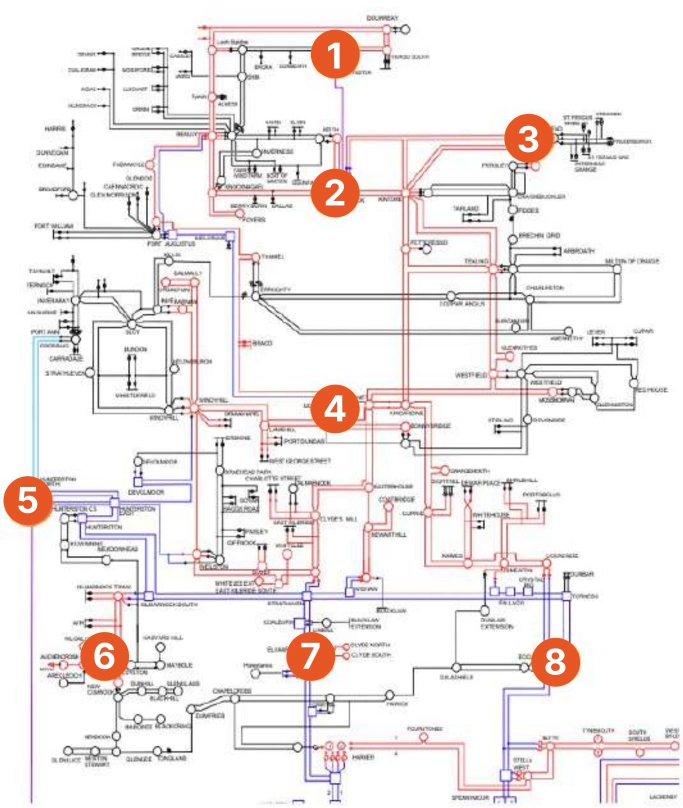
2.1.5.1 Description of Stability Pathfinder 2

Phase 2 of the Stability Pathfinder centers on increasing Short Circuit Level (SCL) in Scotland, where the retirement of synchronous coal and gas plants is eroding the grid's inherent fault-current capability. Crucially, the procurement framework is technology-agnostic, allowing any participants to offer solutions that met the requirements in terms of fault current and inertia contributions to participate as long as a TRL (Technology Readiness Level) of at least 5 was demonstrated. Welcoming a variety of innovative solutions as long as they deliver the required fault-current contribution. Participants range from Transmission Owners (TOs) proposing regulated assets to commercial entities offering an array of synchronous or power-electronic-based technologies.

1. System Need and Technology Neutrality

- As Britain transitions to renewable-heavy portfolios, National Grid ESO (NGESO) identified a shortfall in fault current—essential for stable operation under grid disturbances.

*Figure 2.3: **TElectric grid configuration in Scotland, highlighting the substations where SCL is being procured in Pathfinder 2 tender (marked in orange, numbered 1 to 8)** [70].*



[70] *NOA Stability Pathfinder Phase 2 Invitation for Expressions of Interest*

Table 7: ***SCL required per substation and total inertia requirement for Pathfinder 2 tender.*** [71].

Location	Ref	Requirement (MVA)
Spittal	1	600
Blackhillock	2	1,300
Spittal	3	1,300
Blackhillock	4	600
Spittal	5	1,200
Blackhillock	6	400
Spittal	7	1,800
Blackhillock	8	1,200
Total		**8,400**

	Requirement (MVA)
Blackhillock	6,000
Total	**6,000**

- **In Phase 2**, solutions can be traditional synchronous condensers, repurposed turbine technologies, or grid-forming power converters, including those integrated into battery-energy storage systems or hybrid setups. NGESO's focus is to secure reliable SCL from whichever technology can best provide it at least cost.

Table 8: ***Left: Proposed timelines and TRL requirements for Pathfinder tenders in England & Wales (E&W) and Scotland (Pathfinder 2 highlighted with a black box). Right: Definitions of the TRL levels used in Pathfinder tenders[72].***

	E&W short term	E&W long term	Scotland short term	Scotland long term
Tecnhology Readiness Level (TRL)	7-9	≥5	7-9	≥5
Solution Years	2020-2022	2023-2030	2020-2022	2023-2030
Next Steps	Tender for 2020*	Prioritisation based on RFI feedback	Tender for 2020*	Timeline proposed

Relative Level of Technology Development	TRL	TRL Definition	Description
System Operations	9	Actual system operated over the ful ange of conditions	Actual operation of the technology in its final form, under the full range of operating conditions. Integrated into operational system and processes.
System Commissioning	8	Actual system completed and qualified through test and demonstration	Technology has been proven to work in its final form under expected conditions. Examples include developmental testing and the evaluation of the system in an operational environment.
	7	Full-scale, similar (prototypical) system demonstrated in a elevant environment	Prototype full scale system. Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing the prototype using real system inputs.
Technology Demonstration	6	Engineering/pilot-scale, similar (prototypical) system validation in a relevant environment.	Representative engineering scale model or prototype system, which is well beyond the lab scale tested for TRL 5, is tested in a relevant environment.
Technology Development	5	Laboratory scale, similar system validation in a relevant environment	Integration and testing of basic technology components in a lab scale environment.
	4	Component and/or system validation in a laboratory environment	Basic technology components are integrated to establish that the pieces will work together. TRL 4 is the first step in determining whether the individual components will work together as a system.

[71] *NOA Stability Pathfinder Phase 2 Invitation for Expressions of Interest*
[72] *Stability Pathfinder Webinar, NESO, 2019, [link]*

2. RFI, EOI, and Feasibility

- The process began with a Request for Information (RFI), confirming stakeholder appetite for various technology approaches. Respondents highlighted both well-established synchronous options and newer power-electronic designs capable of high availability.

- An Expression of Interest (EOI) window closed in January 2021, during which both conventional assets (like reactors or condensers) and grid-forming inverters linked to storage projects were proposed.

3. Connections Review and Flexibility

To avoid excluding promising ideas simply for lacking formal connection offers, NGESO instituted a “connections review” to estimate realistic timeframes and cost requirements. This opened the door for developers who plan to integrate synchronous or converter-based solutions at existing or new substations, ensuring many technological types remained in play.

4. Tender Stage and Evaluations

- Given Phase 2’s emphasis on fault-level support, battery-centric proposals had to show equivalent short-circuit performance—often through grid-forming converter capabilities—while synchronous condensers or repurposed thermal plants provided a more conventional short-circuit source.

- During the tender stage, NGESO compared each bidder’s availability price and its demonstrated SCL performance at up to eight Scottish locations. According to the published methodology, solutions—both synchronous and converter-based—were evaluated on:

  - The short-circuit contribution (in MVA) at each node, factoring in “effectiveness multipliers” for network impedance.
  - The incremental inertia offered and how that contributes to NGESO’s national requirement.
  - Total cost, including availability fees, expected connection charges or TO-based capital expenditures, and any projected energy losses.

5. Resulting Awards

In April 2022, NGESO published final contract awards, selecting a mix of technologies that could collectively deliver sufficient SCL to Scotland. By using a unified metric—cost per settlement period and demonstrated SCL performance—diverse solutions proved viable, reinforcing the concept that “one size does not fit all” for grid-stability services.

Overall, Phase 2 encourages a range of technical approaches—from large-scale rotating machines to advanced power electronics—under a competitive framework designed to optimize cost, availability, and operability. This approach enables Britain’s grid to maintain robust fault-levels while continuing its broader shift toward low-carbon generation.

2.1.5.2 Results and Financials of Pathfinder 2

On 6 April 2022, NGESO released details of the Stability Pathfinder Phase 2 tender outcome in the "Tender Outcome" documentation. While exact contract values remain confidential, the final awards went to a range of providers offering sufficient SCL in strategic Scottish nodes.

According to NGESO's statements, each winning solution had to surpass the Balancing Mechanism (BM) cost counterfactual. In other words, only bids demonstrating net savings versus the projected cost of alternative BM actions were selected.

Cost Evaluation Approach

The evaluation of stability service bids for enhancing Scotland's short-circuit levels (SCL) distinguishes between commercial solutions and network-owner proposals. For commercial bids, capital expenditures are incorporated into the operational cost, which is then divided by the effective MVA of stability delivered. In contrast, network-owner proposals separate capital and operational costs using a present-value approach. Both cost structures are converted into a rate per effective MVA and benchmarked against the modelled cost of balancing mechanism (BM) actions, which is the current cost of solving stability constraints, mainly through a redispatch of out or merit order units that provide inertia and SCL.

Contracts, which can run for up to a decade within a 2020-2030 window, require providers to maintain availability for at least 90% of the year. Participants submit an availability price in pounds per settlement period that bundles all relevant costs—including transmission infrastructure, prospective balancing expenditures, and additional energy losses. And if they connect after 31 March 2024, they face incremental "late-start" cost penalties. When Transmission Owners propose regulated assets, their capital and operating expenses are converted into a £/settlement period figure to allow direct comparison with commercial bids.

The overall evaluation, following a linear optimization framework (Final Assessment Methodology v5), considers key cost components such as:

Availability Fees: A bundled rate that includes capital, operational, and network-use costs.

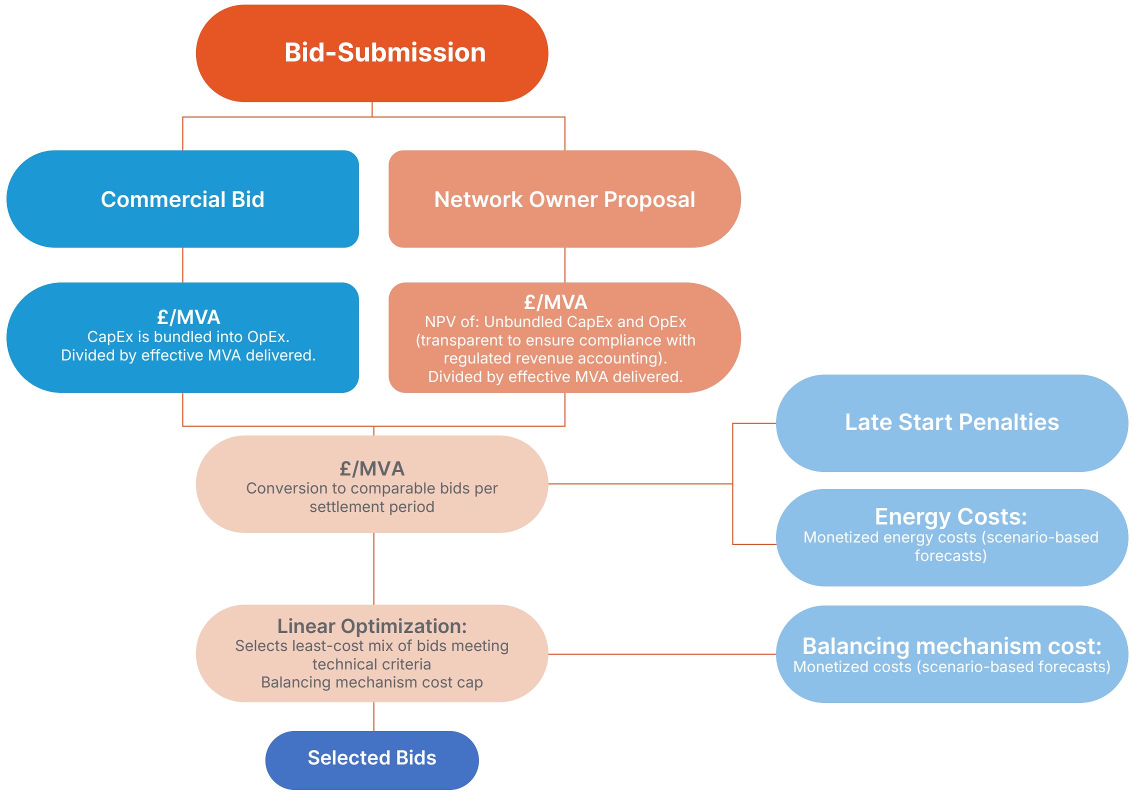
Connection Expenses: Costs for necessary infrastructure upgrades, factored within the availability fee for commercial bids or calculated via net present value for TO-led proposals.

Penalties for Late Start: Incremental additional cost factors for bids connecting after the 31 March 2024 deadline.

Energy Consumption: Costs related to standby energy usage for assets like synchronous condensers (friction losses, balance of plant, etc.) or grid-forming converters (switching losses, round trip efficiencies, balance of plant, etc.) monetized using scenario-based energy price forecasts.

If multiple bids satisfy the technical criteria at a given location, National Grid ESO selects the least-cost combination—taking into account potential synergies and the ability of a single solution to serve multiple nodes' SCL or national inertia requirements, but always with the modelled balancing mechanism cost as a cap—thus ensuring the most economically efficient portfolio of stability services while keeping consumer value at the forefront.

Figure 2.4: ***Cost Evaluation process used in Pathfinder 2.***



Financial Benefits and Operational Metrics

NGESO has indicated that the contracted services deliver cost savings by reducing the volume (and expense) of BM actions otherwise required to maintain short-circuit levels. Though public data on exact contract lengths, total volumes, and monetary amounts remain partial, the final portfolio is expected to enhance:

Inertia Levels: Awarded solutions collectively contribute to the national inertia target, reducing reliance on synchronous generators that might be out of economic merit in the energy market.

Short-Circuit Strength: With additional fault-current sources, the Scottish grid improves its capacity to recover from disturbances quickly, ultimately supporting reliability and power quality.

Network Investment Deferral: By procuring SCL in targeted areas, NGESO may avoid or defer certain network reinforcements, further contributing to long-term consumer savings.

Following the Phase 2 tender and feasibility process, 225 proposals were submitted across various technology categories, including synchronous condensers (some with flywheels), grid-forming battery storage systems, and hybridized solutions (e.g., synchronous condenser plus grid-forming battery).

According to the data tabulated, 215 of these offers were ultimately rejected, while 10 were accepted for contract award.

Technology Breakdown and Offer Characteristics

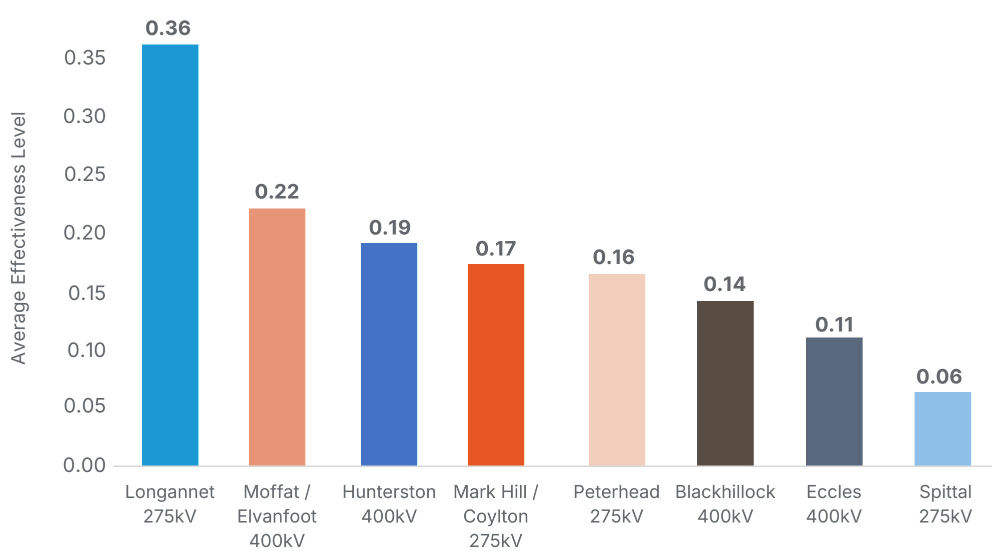
Synchronous Condensers (SC) accounted for the largest share of bids—128 submissions—often providing substantial short-circuit contribution (SCL) at nodes such as Blackhillock or Peterhead. A smaller subset combined synchronous condensers with flywheels for enhanced inertia, or paired synchronous condensers with grid-forming batteries for flexible support.

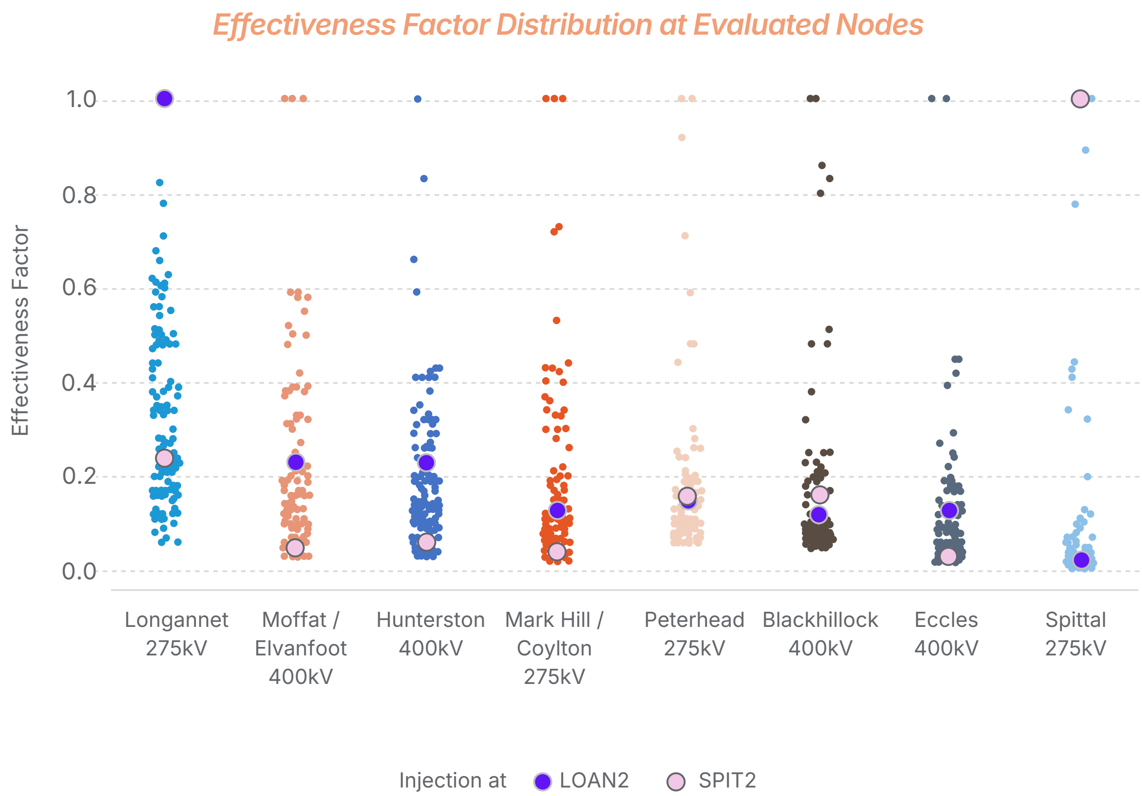
Grid-Forming Battery Storage (GFB) solutions made up 64 submissions, offering varying levels of short-circuit contribution and synthetic inertia. Some bids included supercapacitors or hybrid converter systems.

Other categories, such as Super Capacitors + Grid-Forming Converters or hybrid solutions, comprised a handful of bids.

Despite the diverse range of technologies, overall acceptance hinged on cost-effectiveness and the ability to meet location-specific SCL and availability criteria. Only those solutions outperforming the counterfactual Balancing Mechanism (BM) cost metric—after factoring in connection expenses, operating expenditure, energy-consumption impacts, and potential late-start penalties—advanced to contract.

Average Effectiveness Level at Evaluated Node





The plotted distributions of effectiveness factors —which indicate how strongly an injection of short-circuit capacity at one node impacts system stability across other nodes— illustrate how a proposed solution´s substation location on the network affects its ability to deliver short-circuit levels (SCL). **Highly interconnected central nodes** (e.g., Longannet 275 kV) generally exhibit consistently high effectiveness, benefiting large portions of the grid. **Regional central nodes** (such as Moffat/Elvanfoot 400 kV, Hunterston 400 kV, and Mark Hill/Coylton 275 kV) show a wider range—some connections offer high effectiveness while others are lower—indicating strong regional impact but diminishing benefits at greater distances. **Remote nodes** (e.g., Peterhead 275 kV, Blackhillock 400 kV) typically present lower average effectiveness, though they are still critical for local reliability. Finally, **end-of-line or branch nodes** (e.g., Spittal 275 kV, Eccles 400 kV) usually deliver minimal system-wide benefit given their limited connectivity, but can be indispensable for isolated loads or generation. The accompanying table highlights these differences, summarizing each node type’s connectivity, effectiveness profile, system impact, and relevant cost-benefit considerations.

	Highly Interconnected central nodes Longannet 275 kV	**Regionally Central Nodes** Moffat/Elvanfoot 400 kV, Hunterston 400kV, Mark Hill/Coylton 275kV	**Remote Nodes** Peterhead 275kV, Blackhillock 400kV	**End-of-Line/ Branch** Spittal 275kV Eccles 400kV
Connectivity	Centrally located, highly meshed area	Regionally well-connected but not truly central	Distant from main load centers or major substations	Network extremities or single-feed areas
	Strong connectivity to many nodes	Good local interconnections, weaker to distant nodes	Fewer high-capacity lines to the core grid	Very limited or single-line connections to main grid
Effectiveness	Generally high effectiveness across most locations	Wide range: some nodes very high, others much lower	Mostly low effectiveness with a few moderate/high outliers	Often negligible effectiveness for most of the grid, with singular high points
System Impact	Injecting SCL here benefits large portions of the network	Significant impact within its region, less effect on distant nodes	SCL injections mainly serve local reliability	Minimal system-wide benefit
	High "reach" due to strong interties	Dependent on specific circuit paths	Limited ability to support distant parts of the grid	Typically supports only local load or generation
Key Use Cases	Ideal for large-scale SCL support or inertia	Effective for addressing regional constraints	Critical for preventing blackouts or instability in remote areas	Deployed only when absolutely necessary
	Potential anchor for wide-area stability	May need parallel solutions for broader grid impact	May offset major transmission lines	Not cost-effective unless high local demand or strategic need
Cost-Benefit & Synergy	Large initial cost can be justified by broad benefits	Medium cost/benefit ratio; strong for regional issues	May appear expensive on a £/MVA basis, but essential locally	Often high cost per MVA with limited reach
	High synergy: improvements relieve multiple bottlenecks	Moderate synergy within the region	Low synergy for broader system	Minimal synergy unless grid expansions are made
Typical Approaches	Hosting large synchronous condensers or big "grid-forming" assets	Regional reliability enhancements	Essential for local SCL boost or inertia	Last-resort reinforcement for local reliability
	Economies of scale often possible	Ideal for moderate-size condensers, batteries, or hybrid solutions	Synchronous condensers or grid-forming battery systems	Might host small solutions if local load is critical
Additional Observations	Can reduce broader system constraint costs	Useful to combine with other enhancements	Targeted reinforcements often needed	Rarely supports adjacent areas
	Good candidate for grid-wide projects	Must be weighed against system-wide solutions	Even lower-effectiveness solutions can be critical locally	Only justified if no other option meets local reliability needs

Accepted Solutions

Out of the 10 contracts awarded five (5) were synchronous condenser-based projects, while the remaining five (5) were grid-forming battery proposals. Key observations include:

1. High SCL Sources

- One accepted synchronous condenser offered around 1,918 MVA of short-circuit capacity at Blackhillock, significantly reinforcing fault levels in northern Scotland.
- Another synchronous condenser bid delivering over 1,000 MVA at Blackhillock and Hunterston was likewise chosen, reflecting strong synchronous inertia and fault-current support at multiple nodes.

2. Cost and Contract Value

- Accepted synchronous condensers typically showed lower net present costs relative to their system benefit, with ESO_Contract_Spend (the projected 10-year cost to NGESO) averaging between £38 million and £56 million for the mid-range successful SC proposals. Although one synchronous condenser solution was considerably more expensive than other proposals, it still proved to be more cost-effective than the balancing mechanism (BM). Its optimal placement at a remote node enabled it to deliver the necessary level of SCL, leading to its selection over less costly options located in better-connected areas.

- Grid-forming batteries with strong availability (often above 90 percent) secured contracts primarily due to lower overall present-value costs (some in the £7 million - £25 million range) and flexible siting, mitigating high transmission upgrade charges. These low bid prices are likely due to the possibility of revenue stacking, where the asset owner can chase profits beyond the tendered services by providing other ancillary services or participating in arbitrage.

3. Inertia Contributions

Inertia values for winning synchronous condensers ranged from around 450 MVA.s up to 1,078 MVA.s (or comparable measures), helping address NGESO's national inertia requirement.
o Grid-forming batteries generally had lower nominal inertia capacities but compensated with advanced converter controls, high availability, and competitive per-settlement-period rates.

4. Overall Cost Efficiency

According to ESO_Contract_Spend_Efficiency, the selected projects demonstrated clear consumer value relative to the balancing or constraint-management counterfactual. Many synchronous condensers that were otherwise technically viable were rejected due to higher lifecycle cost projections or insufficient net savings over the 10-year horizon, when compared to the counterfactual.

Aggregate Insights

Most Submissions Were Synchronous Condensers: While SCs dominated the volume, only a fraction met the strict cost thresholds.

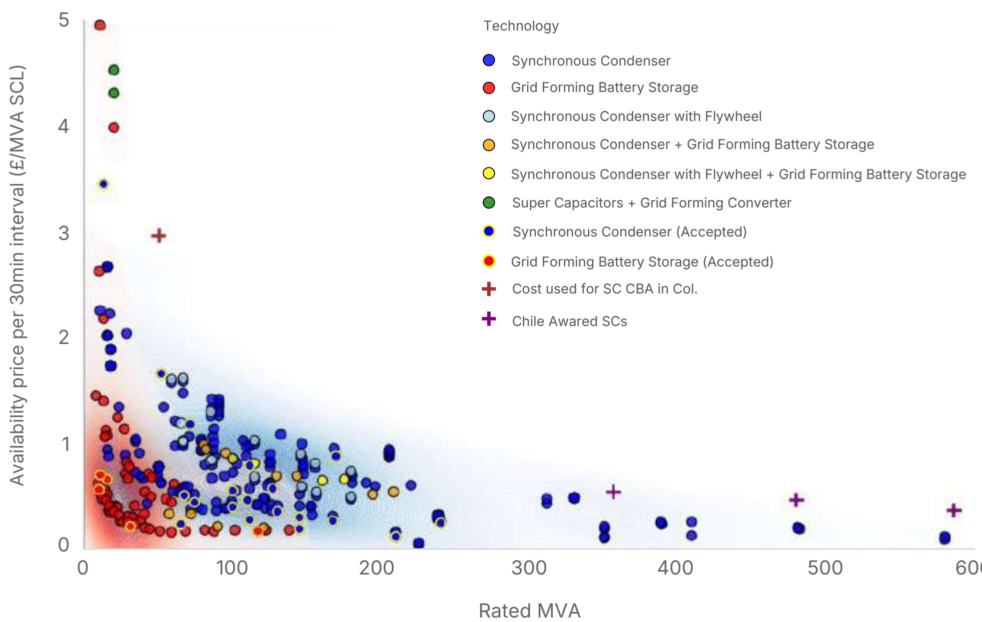
Batteries Filled Key Gaps: Grid-forming storage solutions offered cost-effective stability in certain nodes, especially where support was needed quickly.

Availability and Timing: High plannedavailability (≥90 percent) and on-time commissioning (no or minimal late-start cost penalties) were critical for success, as indicated by strong grid-forming battery and moderate-size condenser projects that could come online before or around April 2024.

Overall, NGESO's commercial assessment confirms that a mix of large synchronous condensers and agile grid-forming batteries can most economically provide the needed short-circuit strength and inertia in Scotland. Although numerous innovative proposals emerged, few achieved sufficiently low £/SP pricing and feasible connection timelines to outrank the Balancing Mechanism counterfactual—leading to the acceptance of only those 10 best-value solutions.

A summary of the bids for Pathfinder 1, 2 and 3 can be found in the following graph.

Figure 2.5: ***Bids for Pathfinder 1, 2 and 3. Circled by yellow are the winning bids***



1. Cost vs. MVA Size Trend

There is a clear downward slope in the "availability price per MVA" as the rated MVA grows. Smaller-rated machines or converters (under ~100 MVA) tend to be scattered at higher £/MVA prices, whereas larger-rated solutions often cluster at lower £/MVA levels.

2. Technology Clustering

Synchronous Condensers (Blue Dots) dominate across the full MVA range, but many smaller ones appear at moderate-to-high £/MVA. A handful of larger condensers (above 200-300 MVA) show relatively low £/MVA, suggesting economies of scale.

Grid-Forming Batteries (Red Dots) mostly congregate on the left side (smaller MVA ratings), with some outliers spanning up to ~200 MVA. They often have price points comparable to or lower than similarly sized synchronous condensers, reflecting differences in total cost structures.

3. Which Offers "Won"

- The accepted proposals (yellow for SCs, orange for GFB in the legend) consistently sit in the lower-price area of the chart for their respective MVA ratings, validating that cost per MVA is a key driver for selection.

Overall, the plot illustrates that larger synchronous condensers benefit greatly from economies of scale, whereas grid-forming batteries are much more limited on the size of solutions they can provide but benefit from revenue stacking allowing them to offer modular solutions at lower costs. In the future this might mean that big synchronous condensers might be the best suited to solve stability issues when there is a need for large SCL in a determined node, while grid-forming batteries might offer much more cost-effective solutions when the stability need is more disperse.

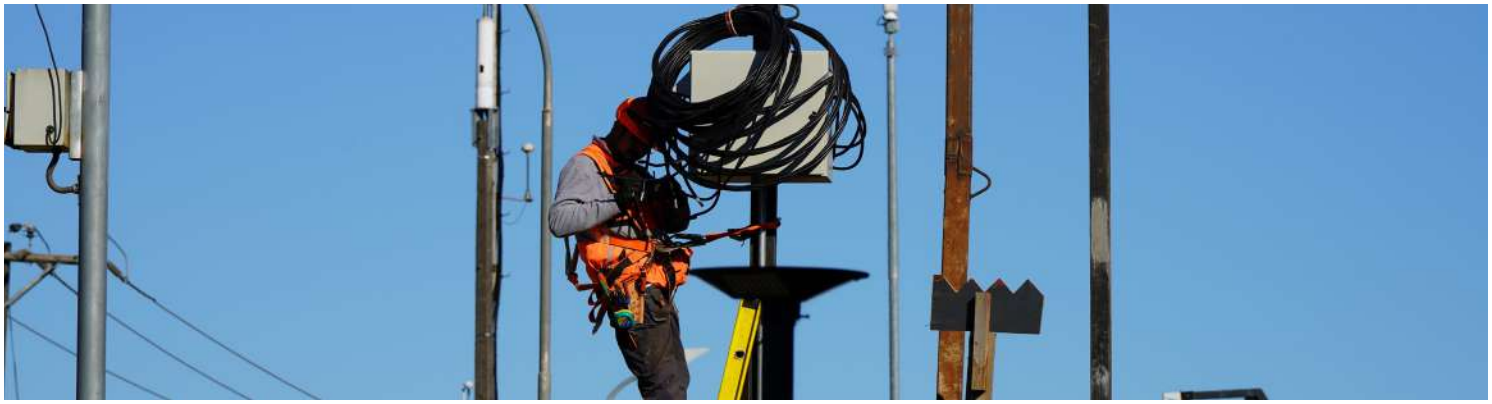
2.1.6 Introduction to Chile and Colombia SCL & Inertia Challenges

Many Latin American countries, including Chile and Colombia, face grid stability risks as they transition to high shares of renewable energy. While Colombia's challenges center on balancing large hydropower reserves with an expanding fleet of wind and solar often located far from the traditional load and generation locations, Chile's situation has been shaped by an accelerated phase-out of coal plants and rapid addition of inverter-based generation (primarily wind and solar).

According to the Chilean system operator (Coordinador Eléctrico Nacional"), the progressive retirement of conventional thermal units is causing a notable decline in short-circuit level (SCL) and synchronous inertia. In 2021, Chile saw approximately 459 GWh of curtailed renewable generation—almost double than of 2020—reflecting how insufficient system strength can limit the ability of wind and solar to remain online during disturbances[73].

Although new high-voltage lines and transformers are planned, a comprehensive grid-stability strategy must also address the decreasing fault-current contribution that once came from synchronous thermal units. Without adequate SCL, the national grid—especially in the Norte Grande region—risk experiencing voltage-control problems and potential disconnections of renewable plants if faults occur in "weak" conditions.

[73] *Transmission Expansion Plan 2022, CEN, 2022, [link]*



2.1.6.1 Chile Tender: Issues, Services, and Solutions

Chile's Coordinador Eléctrico Nacional (CEN) identified a significant shortfall in short-circuit levels (SCL) in the Norte Grande region due to the progressive retirement of conventional thermal generation and increasing capacity of IBR generation, mainly solar PV. To address this issue, a public international tender was launched for the "Servicio Complementario de Control de Tensión por Aportes de Potencia de Corto Circuito." The tender's objective was to ensure the necessary fault-current contributions at four critical 220 kV substations: Ana María, Nueva Chuquicamata, Likanantai, and Illapa, with a start date in 2025. Unlike the UK's technology-agnostic procurement model, the Chilean tender exclusively permitted synchronous condensers, either through new installations or the repurposing of existing thermal generators. GFC (GFM), a rising technology for voltage stability and inertia support, were excluded from participation due to perceived lack of maturity.

2.1.6.1.1 Key Tender Requirements:

Short-Circuit Contribution Limits for Greenfield Projects: Minimum 500 MVA, maximum 2,000 MVA per project (this requirement didn´t apply to reconversions).

Effectiveness Factor: Projects had to provide at least 40% of their SCL contribution at one of the designated substations.

Permitted Technologies: Only synchronous condensers and retrofitted thermal generators were eligible.

Required SCL Contributions Per Substation:

- Ana María (220 kV): 2,774 MVA
- Nueva Chuquicamata (220 kV): 543 MVA
- Likanantai (220 kV): 1,773 MVA
- Illapa (220 kV): 1,728 MVA

Flexibility in Location: Projects could be connected at other substations as long as they were within the defined influence zone (effectiveness factor ≥40%).

Technical Restrictions :

- Projects must be connected to substations operating at ≥110 kV.
- Minimum contribution of 500 MVA at one of the four substations (for greenfield projects).
- Maximum contribution of 2,000 MVA per substation.

This technology restriction limited competition and potentially increased costs, as alternative solutions with lower capital expenditures, such as grid-forming converters integrated with battery storage, were not considered.

2.1.6.1.2 Results and Limitations of the Tender

The tender concluded in June 2024, with 16 bids received. After an administrative and technical evaluation, 15 were deemed admissible, and 9 ultimately secured contracts. The adjudicated projects covered approximately 98.9% of the required short-circuit capacity while staying within the maximum allowable budget constraints.

Table (below) shows the initial inputs used in the Coordinador's optimization algorithm. It summarizes each bidder's short-circuit power contribution (COCI), annualized service cost (VASC), potential connection costs (VAPC), estimated energy expenses (CE), and a total project cost figure. These values formed the core data set for deciding which proposals could best meet the tender's technical requirements without overshooting regulated cost ceilings.

Table 9: ***KPIs used by the CEN in the tender process***

Bidder	Fault-Level Power (COCI) at Connection	VASC [USD]	VAPC [USD]	Energy Cost (CE) [USD/year]	Total Project Cost [USD/year]
Engie Energía Chile S.A.	479.3	3,824,807	NA	1,229,295	5,054,102
Engie Energía Chile S.A.	585.0	3,402,469	NA	1,598,775	5,000,244
Engie Energía Chile S.A.	355.7	3,283,162	NA	1,129,159	4,412,321
Celeo Redes Chile Limitada	1,993.0	15,640,081	228,832	953,171	16,822,084
Transelec Holdings Rentas Ltda	1,993.4	12,434,258	NA	869,029	13,303,287
Transelec Holdings Rentas Ltda	1,993.4	11,450,600	67,380	748,964	12,266,944
Consorcio Alupar	1,851.0	10,498,500	NA	2,914,712	13,413,212
Consorcio Alupar	1,493.0	8,989,500	228,832	1,750,852	10,878,184
Consorcio Alupar	1,155.0	8,748,500	NA	1,417,566	10,166,066

Notes

COCI refers to the short-circuit power (potencia de cortocircuito) contributed by the proposed solution at the designated connection bus.

VASC stands for Valores Anualizados de Servicio Complementario (Annualized Value of Complementary Service), representing the projected cost to provide the short-circuit service.

VAPC stands for Valores Anualizado de Construcción de Punto de Conexión (Annualized Value of Connection-Point Construction), referring to the cost of building or upgrading the connection facilities if required.

NA indicates that either no connection construction was needed (no cost reported) or the item does not apply.

Energy Cost (CE) captures the estimated annual expense of operating the equipment (e.g., electrical losses from running synchronous condensers).

Total Project Cost combines all cost components.

An initial observation from Table 9 is the wide variation in both short-circuit power and cost parameters. Engie Energía Chile S.A. submitted multiple offers, each with a unique balance of capacity and annual costs, while Celeo Redes Chile Limitada proposed the single largest short-circuit boost but at a notably high annual service cost. Transelec Holdings Rentas Ltda. and Consorcio Alupar both submitted multiple bids tailored to specific substations, reflecting how location and connection requirements affect cost-effectiveness.

Tender Phases :

1. **Administrative Evaluation:** 16 bids received, 15 passed.

2. **Technical Evaluation:** All remaining bids deemed admissible.

3. **Economic Evaluation:** 6 bids rejected due to exceeding cost limits.

4. **Optimization:** 9 bids used as input for the optimization algorithm.

5. **Final Awarding:** 5 bids selected.

6. **Outcome:** 98.9% of required short-circuit capacity awarded through a partial adjudication process.

Following this evaluation, the Coordinador discarded offers that exceeded maximum cost thresholds, then identified the least-cost combination of feasible bids. Next table highlights the final set of awarded proposals. These successful projects collectively achieved around 98.9% of the short-circuit target. But the competitiveness of the process and the effectiveness of the awarded portfolio remain in question due to limited competition and lack of alternative solutions.

Code	Company	SCL at interconnection point (MVA)	Type	Cost (USD/year)	Cost including energy (USD/year)	Energy cost as % of total	Unit cost per MVA capacity
ENG_05_RC	Engie	355.7	Retrofit	3,283,162	4,412,321	26%	12,404
TRS_01_NC	Transelec	1,993.4	New	12,434,258	13,303,287	7%	6,673
TRS_03_NC	Transelec	1,993.4	New	11,517,980	12,266,944	6%	6,153
ALU_01_NC	Alupar	1,851.0	New	10,498,500	13,413,212	22%	7,246
ALU_04_NC	Alupar	1,155.0	New	9,127,332	10,166,066	10%	8,801

2.1.6.1.3 Key Takeaways

1. Limited Technical Approaches:

The restriction on synchronous condensers prevented the consideration of GFM solutions, which have been successfully implemented in the UK and other markets. GFM technologies offer voltage stability and fast fault-current injection, potentially at a lower cost.

2. Rigid Cost Constraints and Partial Fulfillment:

Proposals exceeding regulator-approved cost thresholds were automatically excluded. This filtering approach resulted in a final awarded mix that fell short of full coverage (98.9%). The optimization relied on only nine options, which constrained competition and limited the solution space. By rejecting units primarily on individual cost, the process may have disregarded combinations that, while including higher-cost elements, could have yielded a more optimal overall outcome—an issue further examined in this paper[74].

3. Impact of Connection Costs:

The final awarded solutions accounted for both annual service and interconnection expenses to identify the most cost-effective overall package. Three of the nine bids considered in the optimization required interconnection upgrades to connect the projects, but the associated costs were relatively minor—ranging from 0.05% to 2% of total annual costs.

[74] *ISCI, "Medidas y tecnologías para preservar la estabilidad del Sistema Eléctrico Nacional en el contexto de la descarbonización", 2024, [link]*

4. Transparent, Multi-Stage Evaluation:

Much like other grid-services procurements (e.g., the UK Pathfinders), Chile's tender process publicly documented how bids were screened for feasibility and cost. This transparent approach helps to justify final decisions to market participants and consumers. It has allowed for detailed analysis and critique such as the one in (ISCI paper) which will be helpful for future processes.

Through this methodical evaluation, Chile secured essential short-circuit capacity—critical for voltage stability and fault response. It illustrates how a multi-step competitive process can address urgent grid-service needs under clear regulatory cost constraints.

Snapshot from the interviews conducted

- Some participants in Chile's first synchronous condenser (SC) tender faced several challenges due to regulatory inexperience and shifting rules, which caused uncertainty and delayed the process. This discourages participation and increases risk perception for international stakeholders.
- Reconversions offered faster delivery and cost savings (40–50% lower CAPEX), but faced distance-based effectiveness limitations and higher O&M costs, thus ending up priced similarly to new SC projects.
- Despite having shorter construction times and less permitting, reconversions had no incentive to offer early delivery. Tenders focused on capacity alone, not time-to-operation.

2.1.6.2 Colombia Tender: Early-Stage Planning for Grid Stability

The Mining and Energy Planning Unit (UPME) is the entity responsible for planning the country's electrical infrastructure. UPME's mid- and long-term expansion plans identify the future needs of the National Interconnected System (SIN) to ensure security and reliability of electricity supply. In the Caribbean region, especially in the sub-area that includes La Guajira, Cesar, and Magdalena (GCM), the Transmission Expansion Plan highlights challenges related to growing demand, inadequate voltage profiles, and vulnerability to phenomena such as FIDVR (Fault-Induced Delayed Voltage Recovery). Although multiple transmission expansion projects have been awarded via public tenders, many are delayed due to environmental permitting issues, preventing the timely resolution of operational constraints. This situation raises the risk of unserved demand and may create instability for inverter-based generation resources.

Current or Anticipated Inertia/ Fault Level Challenges in Colombia

Demand projections for the Caribbean operating area point to faster-than-average national growth, and the Transmission Expansion Plan document describes how accelerated development of renewable generation (wind and solar PV) in the GCM sub-area could exacerbate weak-grid conditions. Beyond requiring enhanced power exchange capacity between the Caribbean zone and the rest of the SIN, there is a drop in short-circuit contribution (SCL) and inertia support from potentially retiring conventional thermal units (e.g., Guajira 1 and 2). These conditions lead to voltage levels outside acceptable ranges and could trigger serious issues under N-1 contingencies, with lines or transformers out of service resulting in radial configurations and inadequate voltage or the complete disconnection of some substations.

Technologies Encouraged or Mandated (Synchronous Condensers)

To address voltage gaps and strengthen the grid, the proposed project calls for installing synchronous condensers rated between 30 and 60 MVAr in five 110 kV substations: El Banco, La Jagua, Guatapurí, Bureche, and Maicao (the latter replacing Riohacha to avoid surpassing local interruption limits). These compensators aim to provide reactive power support, improve voltage profiles, and deliver short-circuit current and inertia in the GCM sub-area. Per the Transmission Expansion Plan, the analysis considered demand growth through 2037, multiple generation scenarios, network topologies, and contingency (N-1) conditions. Evaluation metrics included the Euclidean norm of nodal voltages, the maximum voltage deviation, and the number of out-of-range events. A short-circuit study following IEC 60909 was also performed, concluding that, although short-circuit currents would increase, overall values would generally remain within each substation's interruption capability.

Details on the Economic Evaluation

A Benefit/Cost (B/C) ratio approach was taken, comparing total investment (construction plus connection costs) against the unserved energy avoided through improved voltage support and higher system reliability. The Transmission Expansion Plan indicates a resulting B/C ratio greater than 1, demonstrating the project's economic viability under the specific assumptions. Further, the study shows that 50 MVAr compensators—capable of covering the inertia lost if Guajira thermal units retire—strike a desirable balance of technical performance and net economic benefits. This setup achieved a high net present value of benefits while supporting short-circuit and inertia needs for reliable operation across both high and low demand conditions.

Overall Approach

Crucially, Colombia remains in the early phase of defining this tender. UPME and other stakeholders are still consulting on the Terms of Reference (ToR) before issuing a formal request for proposals. The ToR sets a 2028 in-service date for these synchronous compensators in the regional transmission system (STR) of the GCM area, aiming to address future demand requirements and align with delayed transmission works. The 110 kV substations selected include all necessary associated equipment to ensure proper connection to the SIN. Each compensator is valued under the rules of CREG 015 of 2017 and CREG 011 of 2009, and the tendering process follows standard procedures for transmission expansions. Ultimately, this approach seeks to reduce vulnerability to voltage dips, strengthen operational reliability, and sustain ongoing growth in both renewable energy and electricity demand in Colombia's Caribbean region.

2.1.7 Comparison of the different approaches

Despite sharing the goal of strengthening grid stability under high renewable penetration, the UK, Chile, and Colombia illustrate three distinct approaches to procuring system strength services. The table below summarizes key differences across technology scope, procurement models, and the services they target.

Dimension	UK Stability Pathfinders	Chile Short-Circuit Capacity Tender	Colombia Planned SCL Tender
Technology Scope	Fully technology-agnostic	Limited to synchronous condensers	Predefined synchronous condensers
Procurement Model	Competitive tenders; cost vs. Balancing Mechanism	Public tender; strict cost ceilings	Early-stage planning, B/C ratio-based
Flexibility & Innovation	High	Moderate	Narrow
Timeline & Incentives	Defined timeline with cost-adjusted delays	Fixed timeline, delays penalized	Fixed date, no early-entry incentives
Services Procured	Multi-service (SCL, inertia, voltage control)	Primarily short-circuit capacity	Voltage support & SCL (partial inertia)
Resulting Contracts	Mix of synchronous condensers & GFM	Only synchronous condensers	Yet to be tendered

Effective procurement for grid stability requires clear rules, robust stakeholder engagement, and alignment with local regulatory frameworks. The UK's technology-neutral Pathfinders encourage innovation and competitiveness but demand complex grid codes and transparent evaluations. Chile's narrower approach focuses on synchronous solutions and partial coverage, reducing costs but limiting technological variety. Colombia's early-stage tender planning can benefit from both models: it may accelerate deployment by using familiar synchronous compensators while preparing to adopt more advanced solutions as grid codes evolve. Over time, clearer environmental permitting, updated technical standards, and incremental procurement (rather than insisting on 100% coverage) can optimize costs and reliability.

Topic	Observation & Implications
Procurement Transparency	Publishing clear criteria, cost ceilings, and detailed tender results (as in UK and Chile) reduces uncertainty. Colombia can enhance credibility and competition by specifying evaluation methods and compensation upfront.
Technology Neutrality vs. Narrow Scope	UK's open model (including grid-forming converters) fosters innovation. Chile's synchronous-only format is simpler but limits options. Colombia, initially focusing on condensers, may expand to newer technologies later.
Regulatory & Licensing Hurdles	Environmental approvals and connection permits can delay projects in all three countries. Early planning and stakeholder involvement help avoid bottlenecks after contracts are awarded, particularly in Colombia.
Evolving Grid Codes	Grid-forming inverters need updated performance standards. Synchronous condensers face fewer code changes. Chile is moving forward for a new technology neutral tender that will allow for grid forming converters, but it in very early stages. Colombia's focus on rotating machinery can be a safe first step while it prepares for advanced inverters later.
Partial vs. Full Coverage	Chile's ~98.9% coverage highlights that aiming for near-total fulfillment can help reduce costs. However, its rigid approach—evaluating offers individually against strict thresholds—limited competition and may have excluded more efficient combinations. In contrast, the incremental approach used in the UK Pathfinder projects, if applied at a global portfolio level, could help Colombia avoid similar inefficiencies while still controlling costs and avoiding overpayment for marginal stability gains.
Adaptability to Market Maturity	The UK's advanced market supports complex multi-technology tenders. Chile and Colombia, with emerging frameworks, may start with simpler solutions, gradually broadening scope as their markets and codes develop.
Potential for Grid-Forming Solutions	Successful use of grid-forming converters in the UK suggests that such systems could eventually compete on cost and functionality in Latin America. Updating codes and offering dedicated service products would be required.

By combining clear procurement criteria, phased or partial coverage targets, and open dialogue with developers, LAC can build a flexible approach that meets immediate reliability goals while paving the way for more advanced technologies in future tenders.

2.1.8 Synthesis: Lessons and Transferability

2.1.8.1 High-Level Takeaways

1. Technology Neutrality vs. Prescriptive Approaches

The UK's Stability Pathfinder program illustrates the benefits of a technology-agnostic framework. By allowing a wide range of solutions—both synchronous and grid-forming—it enabled competitive outcomes across multiple services, including inertia, voltage support, and short-circuit contribution.

Chile's tender, while competitive, limited participation to synchronous condensers, which constrained innovation and potentially increased costs. Colombia's planned tender similarly predefines synchronous condensers, favoring a more conservative and familiar approach, though this could limit exposure to more cost-effective or scalable alternatives in the long term, it might be justified for urgent needs like is the case for this first tenders.

2. Incremental Procurement for Efficiency

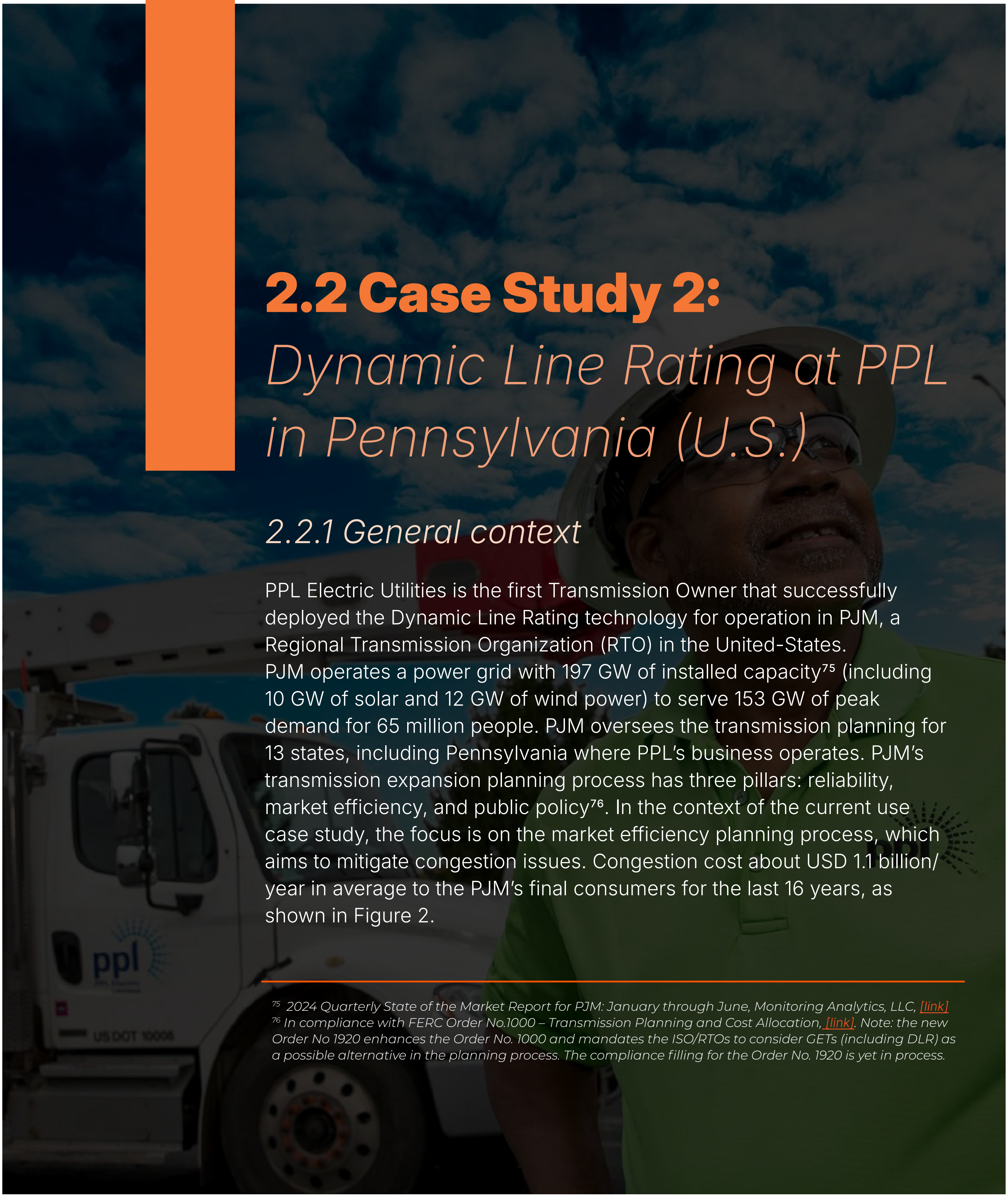
The UK adopted an incremental, portfolio-level approach—procuring only as much service as needed to beat the cost of redispatch or other balancing actions. This avoided over-procurement and encouraged economically efficient combinations.

In contrast, Chile applied rigid individual thresholds, excluding higher-cost units even when they could have contributed to more optimal system-level outcomes. Colombia's benefit-cost evaluation for its planned compensators is a positive step but would benefit from incorporating portfolio-wide optimization principles to avoid similar inefficiencies.

3. Transparency and Market Confidence

Both the UK and Chile have published detailed documentation of their procurement frameworks, evaluation criteria, and contract outcomes. Though as evidenced from some of our interviews, the lack of experience and modifications to the terms during the process increased the perceived risk or international developers.

In the case of the UK this transparency fosters trust, invites informed participation, and allows stakeholders to scrutinize and improve future processes, as evidenced by the multitude of participants and incremental improvements of the process during the different stages. LAC countries can strengthen its own processes by similarly disclosing cost assumptions, technical benchmarks, and evaluation methodologies in early phases, as well as adopting incremental approaches.



2.2 Case Study 2: *Dynamic Line Rating at PPL in Pennsylvania (U.S.)*

2.2.1 General context

PPL Electric Utilities is the first Transmission Owner that successfully deployed the Dynamic Line Rating technology for operation in PJM, a Regional Transmission Organization (RTO) in the United-States.
PJM operates a power grid with 197 GW of installed capacity[75] (including 10 GW of solar and 12 GW of wind power) to serve 153 GW of peak demand for 65 million people. PJM oversees the transmission planning for 13 states, including Pennsylvania where PPL's business operates. PJM's transmission expansion planning process has three pillars: reliability, market efficiency, and public policy[76]. In the context of the current use case study, the focus is on the market efficiency planning process, which aims to mitigate congestion issues. Congestion cost about USD 1.1 billion/year in average to the PJM's final consumers for the last 16 years, as shown in Figure 2.

---

[75] 2024 Quarterly State of the Market Report for PJM: January through June, Monitoring Analytics, LLC, [link]
[76] In compliance with FERC Order No.1000 – Transmission Planning and Cost Allocation, [link]. Note: the new Order No 1920 enhances the Order No. 1000 and mandates the ISO/RTOs to consider GETs (including DLR) as a possible alternative in the planning process. The compliance filling for the Order No. 1920 is yet in process.

Figure 2.6: ***Total congestion costs (USD million): 2008 through 2023. Source: Monitoring Analytics, LLC***

	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,960	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$41,690	1.4%
2020	$529	(9.4%)	$36,300	1.5%
2021	$995	(88.2%)	$54,100	1.8%
2022	$2,501	151.3%	$86,240	2.9%
2023	$1,069	(57.3%)	$48,610	2.2%

Back in 2020, 2 congestion drivers within PPL's business area were identified by PJM's market efficiency planning process. Those drivers led PPL to consider DLR as a fast-to-deploy and cost-effective solution to the congestion problem. Its implementation is further described in the following sections, but as of today, the real-time ratings of these lines are publicly accessible on PJM's website[78].

2.2.2 Dynamic Line Rating implementation in PPL, USA

2.2.2.1 Description of the case study

Back in 2020, PJM identified the Juniata-Cumberland 230 kV and the Harwood-Susquehanna 230 kV (double circuit) lines as one of the main congestion drivers that hinder PJM's market efficiency[79]. The combined congestion cost for 2025 was simulated to reach over USD 26 million with 1296 hours binding, as shown in Figure 2 7.

[78] *Ratings Information, PJM, [link]*
[79] *RTEP – 2020 Regional Transmission Expansion Plan, PJM, 2020, [link]*

Figure 2.7: ***2020-2021 Long-term Window Congestion Drivers. Source: PJM*** [80]

Constraint	From Area	to Area	Market Efficiency Basecase: Annual Congestion ($M), Simulated Year 2025	Market Efficiency Basecase: Annual Congestion ($M), Simulated Year 2028	Market Efficiency Basecase: Hours Binding, Simulated Year 2025	Market Efficiency Basecase: Hours Binding, Simulated Year 2028	Comment
Kammer North to Natrium 138 kV	AEP	AEP	$2.54	$12.22	105	249	Internal Flowgate
Maliszewski Transformer 765/138 kV	AEP	AEP	$4.02	$5.64	29	40	
Muskingum River to Beverly 345 kV	AEP	AEP	$1.08	$2.19	112	184	
Cherry Run to Morgan 138 kV	AP	AP	$3.46	$4.12	257	288	
Gore to Stonewall 138 kV	AP	AP	$25.07	$35.00	577	753	
Junction to French's Mill 138 kV	AP	AP	$4.97	$5.89	255	257	
Yukon to AA2-161 Tap 138 kV	AP	AP	$4.31	$5.39	1743	2043	
Charlottesville to Proffit Rd Del Pt 230 kV	DOM	DOM	$2.80	$2.92	116	96	
Plymouth Meeting to Whitpain 230 kV	PECO	PECO	$6.17	$6.40	150	145	
Cumberland to Juniata 230 kV	PLGRP	PLGRP	$5.77	$6.39	151	158	
Harwood to Susquehanna 230 kV	PLGRP	PLGRP	$20.39	$16.47	1145	878	
Duff to Francisco 345 kV	DUK-IN	DUK-IN	$0.86	$3.71	74	118	M2M
Gibson to Francisco 345 kV	DUK-IN	DUK-IN	$4.18	$3.59	195	200	
Quad Cities to Rock Creek 345 kV	ComEd	ComEd	$6.35	$9.01	148	172	

Note: Cumberland-Juniata and Harwood-Susquehanna congestion drivers may be impacted by DLR projects.

Three options were examined to solve the congestion problem: DLR, reconductoring and rebuilding. DLR stood out for three reasons.

According to the estimations, it offered the best cost-to-benefit ratio, it was the fastest to deploy (1 year against 2-5 years) and unlike the other two options, no planned outage was required on the lines during implementation.

After comparing several technology providers[81], PPL decided to implement DLR with Ampacimon, using 18 sensors on 50 km of the three 230 kV lines. The sensors were strategically positioned to optimize the span coverage along the lines and minimize the costs:

- Orientation between spans changes more than 15°
- Distance greater than 10 km
- Conductor change
- Span safety concerns, high risk spans

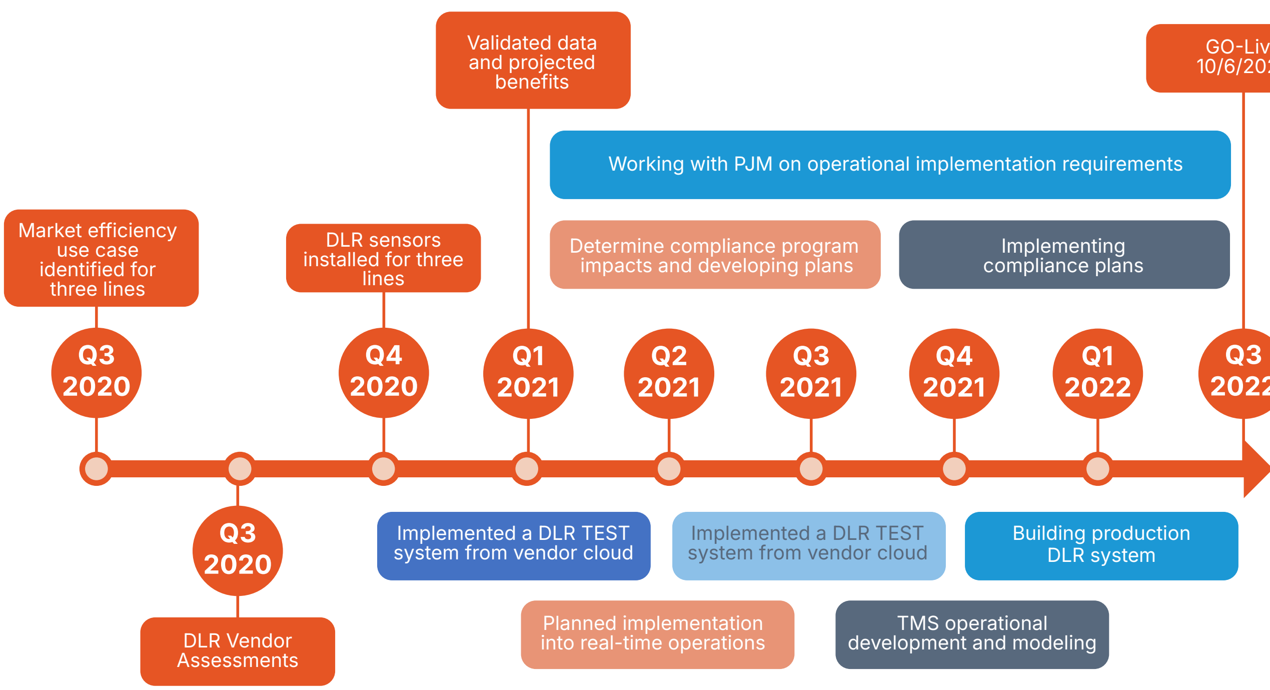
[80] *RTEP – 2020 Regional Transmission Expansion Plan, PJM, 2020, [link]*
[81] *To learn more on the selection process of DLR vendor by PPL, see Docket No. AD22-5-000, Initial comments of PPL Electric Utilities Corporation, April 2022, [link]*

The above-mentioned factors ensure that local variabilities are taken into account in computing the overall ampacity of the line, as the latter would be determined by the most constringent span.

The implementation took **approximately 2 years from congestion driver identification to Go-Live operation, for a total cost of about USD 3.25 million dollars[82].** There was no need for the lines to be disconnected during deployment. The sensors installation was performed via helicopter and required 5-10 minutes per sensor, with a few months leading time for delivery and 2-month calibration time afterwards. With 6 sensors per line, the associated cost amounts to USD 250 000 per line.

To comply with regulations and standards, PPL needed to develop an on-premises system instead of using a vendor-hosted cloud environment, which took approximately 2 years to be compliant and integrated with PJM's system, with a total cost of USD 2.5 million. The full project timeline is presented Figure 2 8. It is worth noting that the economy of scale applies well to DLR, as the system implementation costs would not scale significantly with additional deployment of DLR.

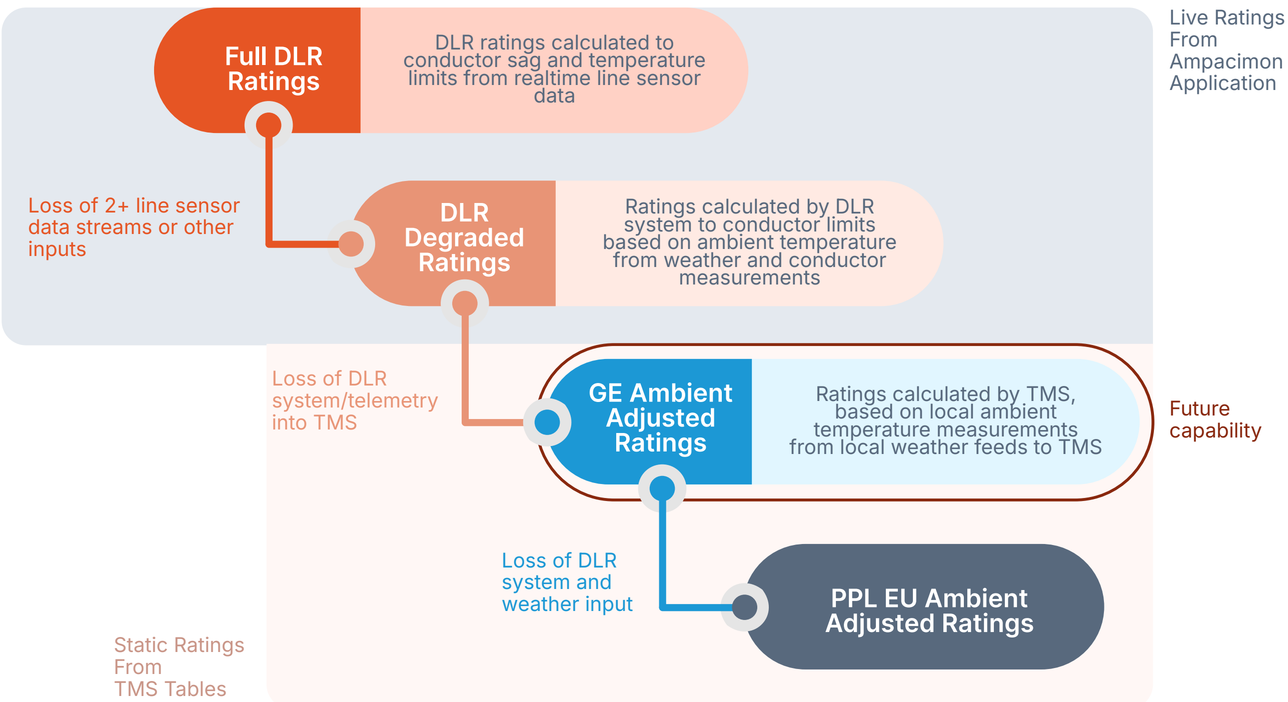
Figure 2.8: ***PPL's DLR project roadmap. Source: PPL[83]***



A fallback process was also developed to mitigate the outage risk of the DLR system, as shown in Figure 2 9. Put in simple words, Ambient Adjusted Ratings and static ratings serve as backup in case of DLR outage.

[82] Docket No. AD22-5-000, Initial comments of PPL Electric Utilities Corporation (April 22), p.16 [link]
[83] PPL's Dynamic Line Ratings Implementation, PPL, [link]

Figure 2.9: ***DLR Telemetry Fallback Process. Source: PPL*** [84]



From PJM's perspective, the operational integration of DLR necessitated a review of several processes and manuals[85]. PJM interviewed various internal groups, including Transmission Planning, Market Simulation, Day-Ahead Markets, Real-Time Markets, EMS & Telemetry Support, eDART Support, Transmission Services and Settlements. In the end, thanks to the previous adoption of Ambient Adjusted Ratings, as per FERC Order 881, the integration of DLR led to minor changes to the existing processes within PJM. This first operational integration of DLR provides PJM with valuable experiences and feedbacks that could be streamlined into application guides for future integrations. Future DLR deployment would be facilitated and less costly.

2.2.2.2 Results (technical, financial)

For Harwood - Susquehanna #1 and #2:

In the pre-deployment study, PJM projected a 65% decrease in congestion in simulated years 2025-2028 and removed these lines from the identified congestion drivers list. The operational deployment eliminated congestion on the lines, reducing USD 12 million in costs to the consumer in 2022. In the following table PPL presents the 15-minute average DLR capacity increase compared to AAR for 2023.

[84] *PPL's Dynamic Line Ratings Implementation, PPL, 2023, [link]*
[85] *Dynamic Line Ratings Overview, PJM, [link]*

*Table 10: **SUSQ - HARW 2023 DLR vs AAR average capacity increase. Source: PPL** [86]*

2023 DLR vs AAR		
Line Name	DLR Normal Rating average gain (%)	DLR Emergency Rating average gain (%)
SUSQ - HARW #1	17.25%	16.57%
SUSQ - HARW #2	16.85%	16.63%

For Juniata - Cumberland:

After deployment, the **congestion cost went from USD 66 million** (winter 21-22) **to USD 1.6 million** (winter 22-23). While DLR solved a major part of the congestions, it was not sufficient to remove the line from the PJM's Market Efficiency window for transmission planning. **To solve the remaining congestion problem, a reconductoring project was also approved and implemented** for this line (with an estimated cost-to-benefit ratio of 11[87]). It is possible to stack the benefits of both technologies by adapting the conductor model in the DLR system. The reconductoring project would increase the thermal limit of the line and DLR would factor in the weather variability. The use case showcases the synergy between **different GETs, that can be leveraged at once to cost-effectively solve a single challenge.**

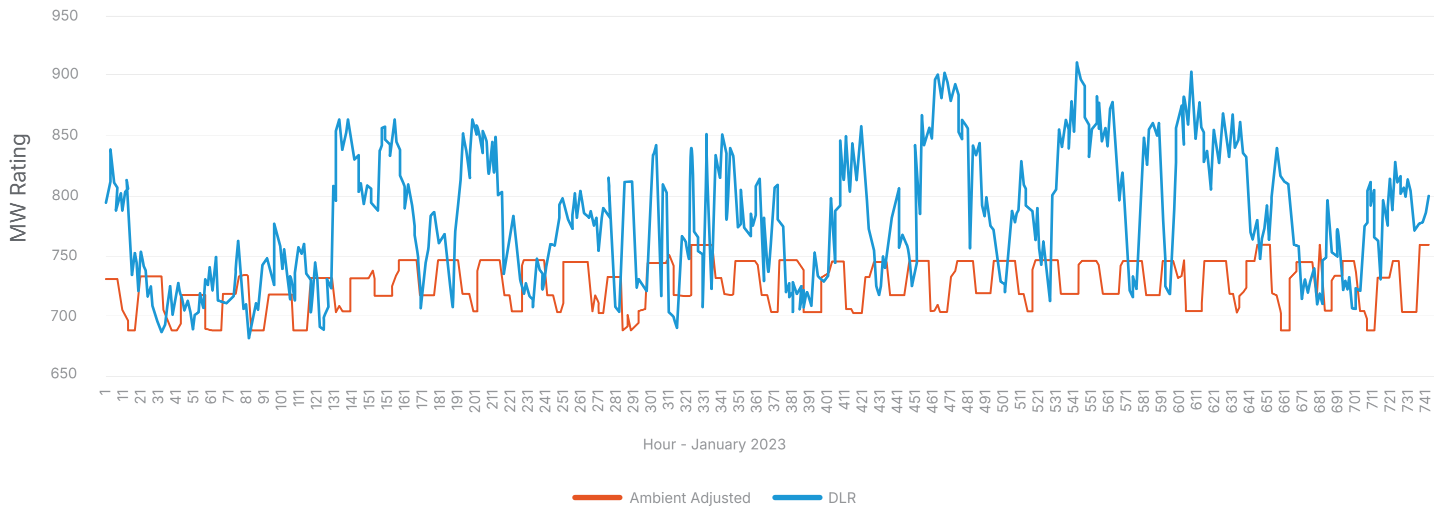
In addition, DLR also contributes to the **system's resilience to extreme weather.** According to PJM[88], without the additional capacity provided by DLR (relatively to AAR), PJM would have needed to conduct redispatching during the Winter Storm Elliott[89] to maintain reliability, which would have been very difficult due to the critical operating conditions caused by the winter storm. Table 11 presents the 15-minute average DLR capacity increase compared to AAR for 2023.

*Table 11: **JUNI - CUMB 2023 DLR vs AAR average capacity increase. Source: PPL** [90]*

2023 DLR vs AAR		
Line Name	DLR Normal Rating average gain (%)	DLR Emergency Rating average gain (%)
JUNI - CUMB	16.91%	8.49%

[86] *Docket No. AD22-5, Motion for leave to comment and first supplemental comments of PPL Electric Utilities Corporation (Feb 24), [link]*
[87] *See the corresponding reference in the summary chart, section 1.7.*
[88] *Implementation of Dynamic Line Ratings, FERC, [link]*
[89] *The winter storm took place in December 2022, causing 106 fatalities, USD 8.5 billion damage and power outage to 1.5 million customers (US), [link]*
[90] *Docket No. AD22-5, Motion for leave to comment and first supplemental comments of PPL Electric Utilities Corporation (Feb 24), [link]*

Figure 2.10: ***DLR and AAR emergency ratings for Juniata - Cumberland, January 2023***



Following the DLR project, PPL received the 2023 **Edison Award** from Edison Electric Institute and the **Excellence Award** for transmission line innovation from Southeastern Electric Exchange[91]. PPL planned **to implement DLR on 5 additional lines**[92]. Today, 3 of the planned DLR lines are already operational.

2.2.2.3 Remuneration

2.2.2.3.1 Remuneration for PPL's use case

DLR provides significant benefits to the system by reducing the congestion cost via capacity increase. However, it is difficult for the project developer to internalize the benefit under current regulations. Federal Energy Regulatory Commission is responsible in establishing incentives to remunerate transmission projects[93]. As summarized in Table 11, **all of the existing incentives are capital-based**. No communication has been documented over the remuneration of PPL's DLR use case; therefore, it is **very likely that the remuneration is still capital-based or even cost-based**, possibly with a bonification for the ROI, as per the ROI/ROE adder incentive.

[91] *Case study: The first US electric utility to integrate dynamic line ratings into real-time and market operations, Renewable Energy World, [link]*
[92] *Docket No. AD22-5, Motion for leave to comment and first supplemental comments of PPL Electric Utilities Corporation (Feb 24), [link]*
[93] *Finding Funding for Grid Enhancing Tech Including DLR, Ampacimon, [link]*

Table 12: ***FERC Transmission Incentives. Source: Ampacimon***[94]

Transmission	Description
Formula Rates	Automatically adjust transmission charges based on cost variation, including those associated with GETs deployment. By incorporating the costs of GETs into these rates, utilities can recover their investment without the need for a separate rate case filing.
Construction Work in Progress (CWIP) in Rate Base	CWIP allows utilities to recover the costs of building new projects, before they are fully operational. This reduces the financial burden during the implementation phase and allows utilities to earn a return on their investment sooner.
Deferred Recovery through Regulatory Assets	If a utility incurs expenses that it cannot immediately recover through rates, it may seek approval from FERC to classify them as regulatory assets. This allows the utility to defer the costs and recover them over time, spreading the financial impact on ratepayers.
Accelerated Depreciation	FERC may allow utilities to use accelerated depreciation, which shortens the period over which costs can be recovered. This allows utilities to recoup their investment more quickly.
Return on Investment/Return on Equity Adders	ROI/ROE provides the developer with a higher return on equity for the transmission projects that includes advanced GETs or AAR.

To access transmission incentives, the utilities must apply under FERC Order 679 and prepare a Section 205 filing. The filing must include:

- A detailed cost-benefit analysis that shows the system-wide benefits of GETs such as improved capacity utilization, reduced congestion and enhanced reliability.
- A specific incentive structure such as ROI/ROE adders, accelerated depreciation, or construction work in progress (CWIP) in rate base treatment.

In simple terms, the former 4 incentives are capital based and tackle different aspects of cost-recovery. The incentivizing effects would be minor on GETs like DLR. The last incentive is also related to capital expenditure, but the adder provides extra renumerations[95].

---

[94] *Finding Funding for GET including DLR, 2024, Ampacimon, [link]*
[95] *Historically, an additional 0.5% ROE has been awarded to utilities for their participation in an RTO. [link]*

2.2.2.3.2 Other examples of remuneration: Great Britain and the RIIO T2 price control approach

Because Great Britain's transmission owners (TOs) are also deploying Dynamic Line Rating, the RIIOT2 price control[96] offers a useful counterexample to the capital-based incentives available in the United States. RIIOT2 is founded on totex (capital + operating expenditure) allowances, with explicit efficiency sharing. The three remuneration mechanisms available for a DLR project are summarized in the following table.

Mechanism	Description	Application to DLR
Baseline Totex Allowance	Each TO receives an ex ante allowance covering both capex and opex. All allowable spending is capitalised into the regulator approved asset base; the TO then earns the regulator set rate of return plus depreciation.	If a DLR scheme is included in the TO's original business plan, its forecasted cost is added to it´s regulator approved asset base just like any other line upgrade and is remunerated at the allowed rate of return over the asset life.
Totex Incentive Mechanism	During the five year control period the TO keeps (or gives back) a fixed share of any underspend (or overspend) against its totex allowance. The RIIO T2 sharing factors are 33 % (National Grid ET), 36 % (Scottish Hydro Electric Transmission) and 49 % (SP Transmission).	Delivering a DLR project for less than its allowed cost lets the TO retain the relevant percentage of the saving; overspend is penalized on the same basis.
Re Opener Windows – Medium Sized Investment Project (MSIP)	For investments not foreseen at the price control settlement, the MSIP re opener provides an annual submission window. Once an MSIP is approved, its efficient cost is added to the regulator approved asset base of the operator.	A DLR scheme identified mid period can be funded through MSIP. After Ofgem approval, the cost enters the regulator approved asset base and is remunerated through the standard approved rate of return/depreciation route from the next regulatory year.

Capital based, but totex oriented. All three RIIO T2 routes ultimately roll the efficient cost of a DLR scheme into the RAV, so remuneration is still capital based. The key difference from the U.S. model is that opex as well as capex is capitalized, encouraging solutions that blend hardware, software and ongoing services rather than rewarding concrete and steel alone.

[96] *RIIO-T2 is the price control regulation for Britain´s electric transmission networks and gas transmission networks.*

Built in efficiency carrot (and stick). Whereas PPL relied on a one off ROE "adder," British TOs can lift returns permanently by delivering DLR below allowance through the Totex Incentive Mechanism. Conversely, overspend is penalized—an incentive symmetric with consumer interests.

Practical uptake. National Grid ET's RIIO T2 business plan includes six DLR packages (≈90 km on 12 circuits) under its baseline totex allowance, while Scottish Hydro Electric Transmission has flagged DLR as a likely MSIP candidate for 2025. Early cost benchmarking (£90–110 k per circuit km, inclusive of sensors, communications and control room integration) suggests 5–10 year paybacks purely from avoided constraint payments.

Relevance for LAC regulation. A totex plus sharing model lets regulators reward operational innovation without inventing technology specific incentives. By internalizing opex heavy digital solutions and exposing TOs to symmetrical cost risk, RIIO type frameworks could provide a template for remunerating GETs in Latin America and the Caribbean (see section 4.5, Recommendation 3).

2.2.3 Comparison with LAC case studies

2.2.3.1 Dynamic Line Rating in Colombia - Transelca with Ampacimon

Several Colombian companies have considered DLR in their planification in the past.

As early as 2019, **EPSA**, an electricity generation and distribution company in Colombia, proposed to install DLR on the **Yumbo-Chipichape-La Campiña 115 kV corridor**. The capacity increase would then allow to reduce the overload on the corridor in period of high generation from Termoecali and Termovalle, two combustion power plants[97].

Afinia, a subsidiary of Grupo EPM, is an electric utility company operating in Colombia's Caribbean region. In 2021, AFINIA investigated the possibility of installing DLR on the **Chinu Boston 1 110 k V circuit.**

However, no follow-up seems to emerge from the considerations. It is unclear whether these projects finally materialized.

In 2020, **Transelca**, a Transmission Owner, implemented a **pilot project with DLR**. In a CNO's Transmission Committee in 2024, it was suggested that Transelca present the results of its DLR pilot project[98]. While very few information is publicly available on the project, according to Watt Coalition, the DLR system is being moved to another line for operational deployment after the success of the pilot project.

Overall, **the DLR adoption is still a very preliminary phase in Colombia**, with limited public exposure.

[97] *Informe CON 560, Consejo Nacional de Operación, 2019, [link]*
[98] *Acta N° 730, CNO, 2024, [link]*

2.2.3.2 Dynamic Line Rating in Chile - Transelec with Ampacimon

Coordinador Electrico Nacional, in its 2023 Propuesta de Expansion de la Transmission, promoted the incorporation of DLR in the Chilean grid, as a mature and non-invasive (regarding the existing infrastructure) technology. Through a study, **CEN identified five candidate lines for DLR adoption**: 2x220 kV Ciruelos - Cautín, 2x220 kV Andes - Likanantai, 2x500 kV Lo Aguirre - Polpaico, 2x220 kV Rapel - Alto Melipilla y 1x66 kV Los Buenos Aires - Negrete. The study showed that **DLR provided higher ratings than Static Line Ratings for 96% of the time on the studied lines.**

Background and Need for DLR on the 2x220 kV Ciruelos-Cautín Line

In December 2024, a Sworn Statement announced the **go-live of the Project NUP 4109**[99] , which involves installing **Dynamic Line Rating (DLR) on the 2x220 kV Ciruelos-Cautin transmission line.** This 114-kilometer line runs through the Los Ríos and Araucanía regions, connecting Mariquina to Temuco, and passes through the Metrenco, Río Toltén, and Lastarria substations.

A congestion analysis showed that the Ciruelos-Lastarria section has a congestion probability of over 24% in all scenarios starting in 2025. Although a new 2x500 kV line between Entre Ríos and Ciruelos (initially energized at 220 kV) is expected to ease congestion starting in 2030, it won't fully resolve the issue.

The table below shows the projected congestion probabilities for the Ciruelos-Lastarria section from 2023 to 2037 across five supply scenarios. In every case, congestion exceeds 24% from 2025 onward and only begins to decline in 2030 with the addition of the new line—though some congestion remains present.

Table 13: ***Congestion probability for the 2×220 kV Ciruelos-Cautin line under different scenarios.***

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Esc A	0%	1%	26%	29%	27%	53%	51%	5%	5%	17%	17%	21%	26%	29%	30%
Esc B	0%	1%	24%	27%	26%	47%	46%	6%	7%	7%	8%	11%	24%	25%	30%
Esc C	0%	1%	25%	26%	24%	69%	70%	10%	11%	15%	15%	20%	19%	20%	20%
Esc D	0%	1%	34%	38%	78%	80%	83%	15%	16%	16%	15%	26%	28%	29%	29%
Esc E	0%	1%	36%	42%	40%	68%	69%	13%	14%	18%	20%	21%	21%	22%	22%

In light of these challenges and the impracticality of adding additional transmission infrastructure in the medium term, a DLR solution is being pursued. For the Ciruelos-Cautín line, sensors will monitor ambient temperature and wind speed, enabling real-time adjustments of the line's capacity. Preliminary analysis indicates that, based on meteorological data from the national air quality information system (SINCA), the line maintains a thermal capacity above 420 MVA for about 71% of the year—with maximum and minimum capacities of approximately 850 MVA and 350 MVA, respectively.

[99] *Letter from Transelec to CEN, December 2024, [link]*

Cost Estimates and Investment

For the 2x220 kV Ciruelos-Cautín line, preliminary cost estimates for the DLR project indicate:

Direct Costs: Approximately USD 378,000
Indirect Costs: Approximately USD 102,000
Contractor's Profit/Contingencies: Approximately USD 38,000
Total Project Cost: Approximately USD 517,000

By comparison, the PPL project in the PJM market—implemented with Ampacimon technology—had a total cost of about USD 3.25 million, which included not only sensor installation but also the development of an on-premise system to meet regulatory standards. In both cases, however, investment is seen as a cost-effective solution relative to the significant congestion avoided.

Benefit Estimates

Operational data are unavailable for this use-case, an estimation is provided, based on the following assumptions:

- The line is congested 2.5% of the time in the year, which corresponds to 219 hours
- The average capacity on the line is assumed at 420 MW.
- The price difference between the two ends of the transmission line is estimated at 50 USD/MWh (thermal generation on one end and renewable on the other, in accordance with historical price in Chile)

This corresponds to USD 4.6 million/year of savings on congestion cost.

2.2.4 Comparison to PPL

The comparison between PPL's Dynamic Line Rating (DLR) implementation in Pennsylvania and the Latin American (LAC) cases—specifically in Colombia and Chile—reveals key differences and similarities in project execution, regulatory frameworks, and financial structures

Factor	PPL (U.S.)	Chile	Colombia
Regulatory Framework	FERC incentives available under Order 679 (Formula Rates, ROI/ROE Adders, CWIP, Accelerated Depreciation). Capital-based incentives make DLR less favorable than traditional projects.	The transmission expansion plan includes DLR, but no direct financial incentives for its deployment. Similar issue, transmission investments follow a regulated remuneration framework. Capital-based incentives make DLR less favorable than traditional projects.	In Colombia, while pilot projects have been conducted, no large-scale DLR deployment has emerged.
Implementation Timeline	2 years (including regulatory compliance and system integration).	Planned for 2025+, but no confirmation of long-term adoption.	Pilot in 2020, but no widespread deployment so far.
Project Cost	USD 3.25 million total cost, including 5000 USD/km CAPEX for the monitoring system and USD 2.5 million for on-premises IT system development for compliance.	USD 517,000 total estimated cost for the Ciruelos-Cautín line or 4500 USD/km. Unknown system cost.	Unknown (pilot project only).
It Congestion Reduction	Eliminated congestion on Harwood-Susquehanna line, leading to ~USD 12 million annual savings. Over USD 60 million savings on Juniata Cumberland line.	Expected congestion relief for Ciruelos-Cautín, with 71% of the year above 420 MVA capacity, but full impact remains unverified.	Success of Transelca's pilot project suggests congestion relief, but no public data available.
Market & System Operator Integration	Fully integrated into PJM's market mechanisms, requiring adjustments to market rules, real-time operations, and planning processes.	CEN included DLR in the 2023 Expansion Plan, but no details available on how it has been integrated with the market system or the system operator. Although, the project is in operation since December 2024.	CNO reviewed the pilot project results, but no indication of market integration.
Scalability & Future Deployments	5 additional lines planned, 3 already operational. Future rollouts are expected to be cheaper since system integration is already complete.	5 candidate lines identified, but project approvals remain uncertain. Data on success of installed projects is unavailable.	DLR system is being moved to another line for operational deployment, but no large-scale expansion is planned.

Overall, while PPL's case provides a strong example of successful DLR integration, the Chilean and Colombian cases highlight the challenges of regulatory adaptation and market structure constraints in LAC countries. If LAC regulators develop specific incentives for GETs (Grid-Enhancing Technologies), DLR adoption could accelerate across the region.

2.2.5 Synthesis: Lessons and Transferability

As the PPL's use case is more advanced, some feedback from the project could be valuable for future DLR adoption in the LAC.

Transparency of successful project helps to build practical desktop guidance to promote the technology adoption. Local, accomplished and successful project could facilitate the implementation process for other DLR adopter. CNO indeed suggested Transelca to share the results of its pilot project. Nonetheless, the challenges as well as the unexpected obstacles could also be inspiring, when presented with their associated mitigating approaches.

PPL's success is the fruit of a tripartite collaboration between the Transmission Owner, System Operator and the Regulator. As seen in the PPL's use case, the adoption of a new technology is influenced by multiple aspects of the sector (methodological, organizational and regulatory), but conversely these aspects could also need to accommodate the new technology. Therefore, collaboration is a key of success.

Standards and security compliance may add unexpected delay and cost to DLR projects. Indeed, it is specific to the NERC standards to request for an on-premise system but this point is not to be neglected as it adds significant delay and unforeseen costs

Incremental deployments can spread the up-front investment. The DLR offers a great scalability in terms of costs and resources. It would cost PPL USD 250 000 and a few months to implement DLR on another line.

03

Evaluation of GETs market potential

Section 3 assesses the market potential for Grid-Enhancing Technologies (GETs) across Latin America, with a focus on Chile and Colombia as representative cases. After examining how the rapid growth of renewables is creating new transmission constraints and stability challenges, the solutions addressed by dynamic line rating and synchronous condensers are presented. Based on the forecasted stability needs and the congestion rate of the lines, estimates are made on the market size for DLRs and SCs in Chile and Colombia. The market scale is then scaled to LAC. We also develop on the benefits of GETs for the power systems, especially in terms of costs avoided.

3.1 Market Potential *in Chile*

3.1.1 Electricity sector in Chile

Chile's power sector has grown rapidly in renewable generation capacity, making it a regional leader in green energy. As of 2023, Chile's National Electric System had a total installed generation capacity of 37 GW, an increase of 3.3% from 2022[100]. Renewable energy (including large hydro) already accounts for about 63% of total electricity generation. Solar and wind have shown the most dynamic growth, with solar alone contributing around 19% of generation in 2023 and wind 12%.

Figure 3.1: ***Long term projected installed capacity by source in Chile according to the PELP 2023[101]***

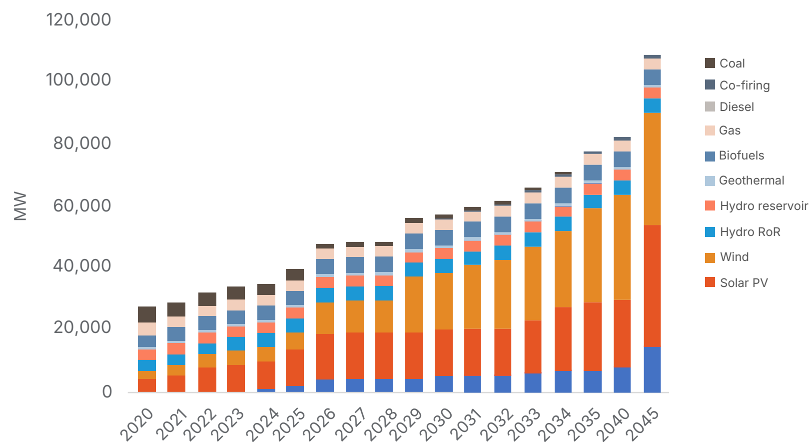
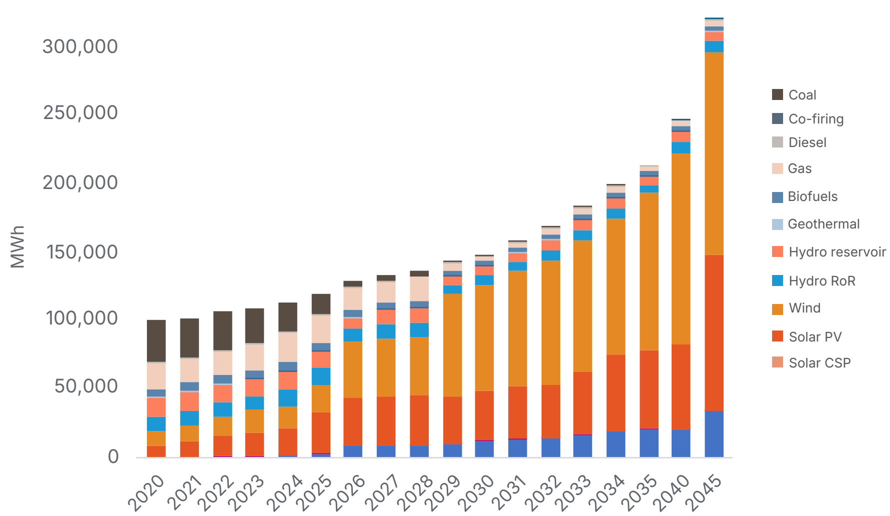


Figure 3.2: ***Long term projected yearly by source in Chile according to the PELP 2023[102]***



[100] *Proceso Quinquenal PELP 2023-2027, Ministerio de Energia, 2023, [link]*
[101] *Proceso Quinquenal PELP 2023-2027, Ministerio de Energia, 2023, [link]*
[102] *Proceso Quinquenal PELP 2023-2027, Ministerio de Energia, 2023, [link]*

While solar and wind will be the key drivers of new capacity, battery storage, hydro expansion, and grid-strengthening projects are also included in Chile's official planning scenarios. The long-term policy goal is to reach **80% renewable electricity by 2030[103](and 100% by 2050)**, building on the country's rich solar, wind, and hydro resources.

3.1.1.1 Demand

Recently, Chile's demand has been rising at 2% yearly, but it is envisioned to be on an upward trend, driven by economic growth, the mining sector, and electrification efforts. The system operator project continued robust demand growth, with the National Energy Commission (CNE) estimating a total consumption rising from ~80 TWh in 2024 to ~94 TWh by 2030[104]. Peak load in 2024 reached 12 GW[105]and is expected to climb steadily in parallel with demand to 15 GW in 2030[106].

While year-by-year official forecasts vary, the consensus is that Chile's power system will require a substantial expansion in both generating capacity and grid infrastructure to reliably serve loads, particularly as industrial and urban areas grow in central and northern Chile.

3.1.1.2 Power mix

Chile's generation mix is transitioning toward renewables at one of the fastest paces in Latin America, with already 1GW of battery storage and reaching 2GW by 2026[107]. The 37GW of installed capacity by early 2025 comprises:

Solar and Wind: 46% of generation (31% solar, 15% wind)

Hydropower (large + small): 21% of generation

Thermal (coal, gas, diesel): 31% of generation

Other renewables (biomass, geothermal, etc.): 2%

By 2030, official planning indicates a total capacity of 52GW, most of it in solar PV (14.8GW - 29%) and wind (18GW - 35%). This rise in renewable energy generation implies a growing share of **Inverter-Based Resources (IBRs)** in the grid.

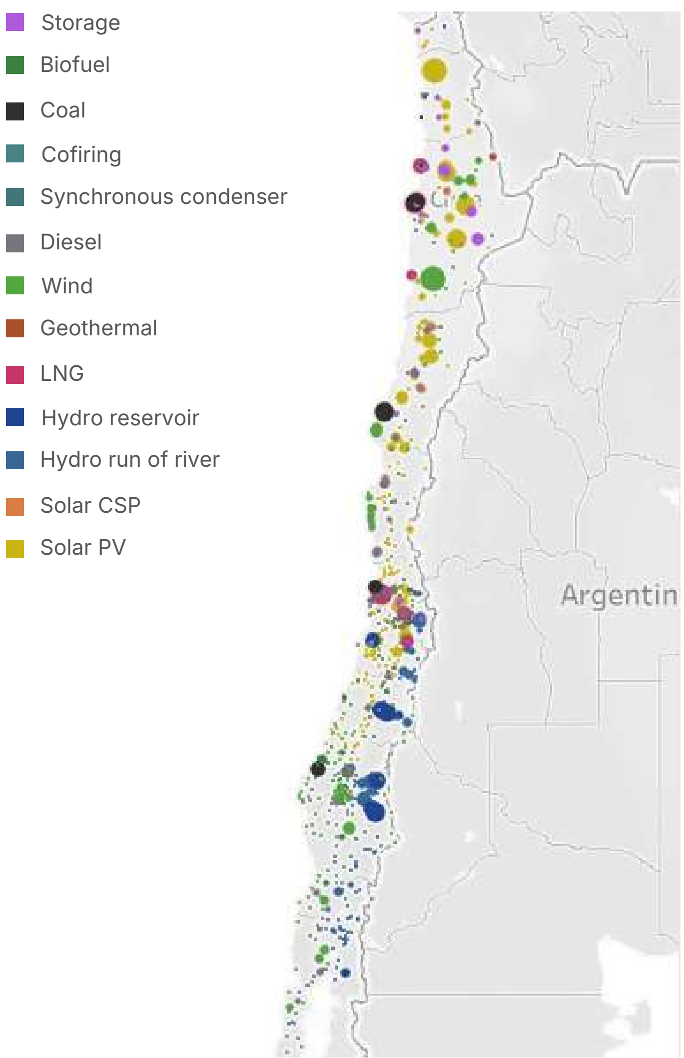
[103] *Proceso Quinquenal PELP 2023-2027, Ministerio de Energia, 2023, [link]*
[104] *INFORME TÉCNICO PRECIO NUDO PROMEDIO, CEN, 2024, [link]*
[105] *Reporte Energético, CEN, 2024, [link]*
[106] *Proyección de Demanda de Largo Plazo del Sistema Eléctrico Nacional, CEN, 2024, [link]*
[107] *Reporte Energia Abierta Ciudadana Almacenamiento, CEN, 2024, [link]*

Geographical Distribution

Northern Chile (Atacama Desert): Extremely high solar irradiation, home to large solar farms and new projects.

Central-South regions: Blend of wind projects (coastal and inland), hydro in the south, and industrial load centers around Santiago.

*Figure 3.3:. **Geographical distribution of generation in Chile for 2030**[108]*



3.1.1.3 Grid

Chile's transmission network is long and narrow, reflecting the country's geography, with major corridors running north-south to connect resource-rich areas with load centers. According to system operator (CEN) data:

- There are several high-voltage transmission corridors (500 kV and 220 kV) spanning from the Norte Grande region down to the Santiago metropolitan area, then continuing south.
- Grid congestion has become a critical issue, with renewable curtailment ("vertimientos") exceeding 2,600 GWh in 2023— primarily affecting solar generation.
- Multiple transmission expansion initiatives are underway or proposed via the "Proyecto de Transición Energética," aiming to strengthen north-south connectivity, reduce curtailment, and improve system flexibility (including better integration of battery storage).

The government and the Coordinador Eléctrico Nacional (CEN) have placed high priority on accelerating new transmission projects, but the rapid growth of variable renewables continues to outpace the development of new transmission lines. As a result, Grid Enhancing Technologies (GETs)—including Dynamic Line Rating (DLR), battery energy storage systems, and synchronous condensers—are viewed as valuable near-term measures to improve transfer capability, voltage control, and system stability.

[108] *Proyecciones Electricas y Emisiones - PELP, Ministry of Energy, [link]*

Figure 3.4: **Grid lines status in Chile**

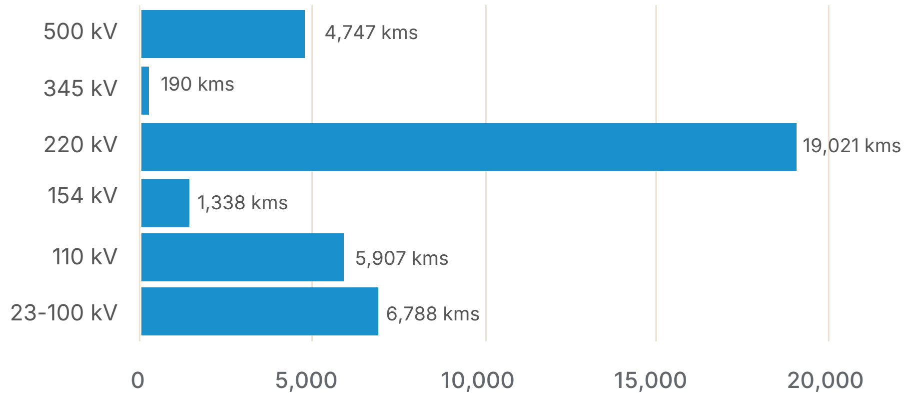


Table 14: **Characteristics of the Chilean grid. Source: CEN[109]**

Voltage (kV)	Number of line	Total length (km)	Average length (km)	Length percentage (%)	Average capacity [MW]
<100	455	6788	15	17.87%	26
110	283	5907	21	15.55%	87
154	48	1338	28	3.52%	94
220	381	19021	50	50.07%	236
345	1	190	190	0.50%	582
500	16	4747	297	12.50%	1265
Total	**1184**	**37991**	**32**	**100.00%**	**132**

3.1.2 Grid Enhancing Technologies in Chile

3.1.2.1 Existing or projected GETs projects

3.1.2.1.1 Dynamic Line Rating (DLR)

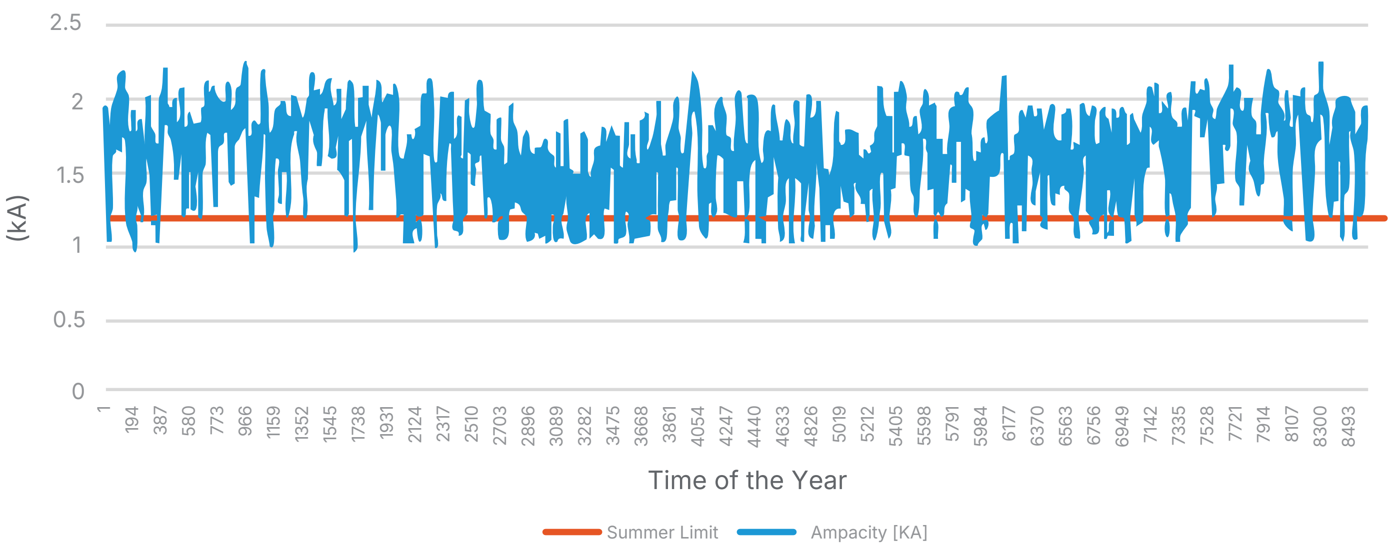
While large-scale commercial DLR deployments are still limited in Chile, transmission operators have piloted real-time monitoring systems on select 220 kV lines with high congestion. However, no major countrywide rollout has been completed or planned yet. Additionally, by the end of 2022, the Coordinador completed a study to identify candidate transmission lines for DLR monitoring. This study recommended specific lines for monitoring:

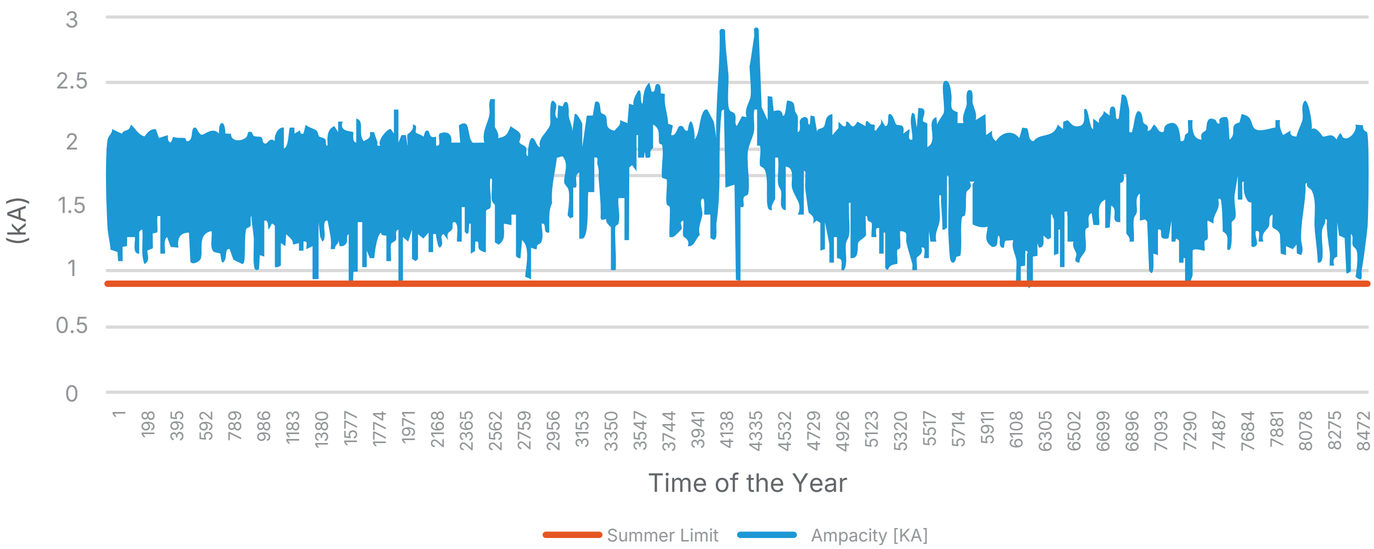
- 2x220 kV Ciruelos-Cautín,
- 2x220 kV Andes-Likanantai,
- 2x500 kV Lo Aguirre-Polpaico,
- 2x220 kV Rapel-Alto Melipilla,
- 1x66 kV Los Buenos Aires-Negrete

[109] *Infotechnica Instalaciones en Operacion, CEN, [link]*

The studies demonstrated that the dynamic capacity (calculated according to IEEE std. 738 at 25°C) exceeds the static capacity nearly 96% of the time[110]. Examples of the estimated improved capacity for two of the lines, the 2x220 kV Ciruelos Cautin and 2x220 kV Andes Likanantai are presented in the following figures, and the cost estimates for the 2x220 kV Ciruelos Cautin line are presented in the table afterwards:

Figure 3.5: ***Comparison of static line capacity and estimated dynamic line capacity***





[110] *Propuesta de expansión de la transmisión, CEN, 2023, [link]*

Table 15: ***Estimated costs for "DLR 2×220 kV Ciruelos - Cautín line" project.***

Description	Partial Cost (thousand of USD)
TOTAL DIRECT COSTS	378
TOTAL INDIRECT COSTS	102
CONTRACT SUBTOTAL	479
Contractor Profits, Contingencies, Interim Interests	38
TOTAL PROJECT COST	**517**

3.1.2.1.2 Synchronous Condensers (SCs)

In Chile, as thermal plants retire (particularly coal) and wind/solar share grows, synchronous condensers are increasingly considered to provide short-circuit capacity (Icc) and reactive power control. Some SC tenders have already been awarded in northern Chile, especially near large solar hubs.

As outlined in Section 2.1.6, the CNE determined that additional system-strength measures were needed to safely operate the grid at higher renewable penetration levels, and a Cost-Benefit Analysis identified the most effective solutions for maintaining acceptable grid strength and ensuring reliable, economical operation. This study[111] calculated the synchronous condenser capacity required in the North under a base case (with nearly zero synchronous generation in the northern regions and approximately 5-6 GW of inverter-based generation) and under various redispatch scenarios, in which more thermal units would run in the North while renewable generation was curtailed in the center of the country.

The following table summarizes the generation by region and technology, for the small redispatch case. In this case there is a total of 5.2 GW of IBR resources with only 0.3 GW coming from synchronous generators in the north.

[111] *Definición de Requerimientos para el Fortalecimiento de la Red en el Sistema Eléctrico Nacional en 2025, CEN, 2022, [link]*

Figure 3.6: ***Capacity in MW, per source of power and per region in Chile, for the small redispatch case[112].***

Red	*PV	*Wind	Biogas	Coal	Gas	Geot	Hidro	Oil	Wind Asm	Total
00-Norte Grande	2914	653	0	85	0	18	5	0	12	3687
01- Atacama	1628	28	0	183	0	0	5	0	0	1844
02-Coquimbo	262	456	0	0	0	0	5	0	10	1734
03-Chilquinta-Aconcagua	167	0	0	0	0	0	191	0	0	359
04-Enel distribución	250	0	0	0	15	0	415	0	0	679
05-Colbún	0	0	0	0	0	0	591	0	0	591
06- Troncal_Qui-Cha	0	146	146	0	398	0	790	0	0	1334
07-Sistema 154 - 66 KV (Centro)	0	0	0	0	38	0	585	3	0	626
08-Charrúa	0	41	4	0	0	0	1390	3	0	1439
09-Concepción	0	3	0	0	0	0	0	0	2	5
10-Araucanía	0	145	0	0	0	0	62	0	0	207
11-Araucanía 66KV	0	30	0	0	13	0	106	3	0	152
12-SIC-SING	36	99	0	0	0	0	0	0	0	135
12-Zona Interconexión	79	0	0	0	0	0	0	0	0	79
Total	5336	1602	4	268	463	18	4146	10	24	11871

The table below compares four scenarios—one baseline (no redispatch) and three scenarios with successively larger redispatch amounts—covering total synchronous/IBR generation, total inertia, and the MVA of synchronous condensers needed to meet system-strength criteria.

Table 16: ***Results of the optimization carried out by DIgSILENT for the Coordinador Electrico Nacional study on synchronous condensers for system stability in northern Chile.***

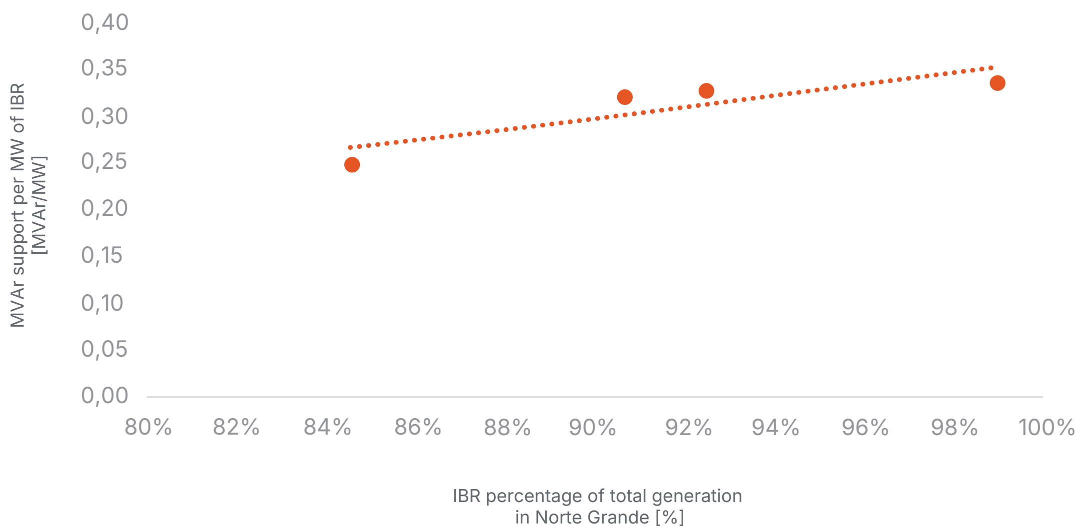
****Calculated values not taken from the report***

Scenario	Base Case	Small Redispatch	Medium Redispatch	Big Redispatch
Total Generation	11866	11871	11881	11900
Redispatch amount [MW]	0	276	352	619
Total Synchronous Generation [MW]	4633	4909	4985	5252
Thermal [MW]	495	763	848	1094
Hydro [MW]	4138	4146	4137	4158
Total IBR Generation [MW]	7233	6962	6896	6648
PV [MW]	5575	5336	5336	5168
Wind [MW]	1658	1626	1560	1480
IBR percentage of total generation [%]*	61,00%	58,60%	58,00%	55,90%
Total Inertia [GVAs]	22,5	27,05	28,3	32,6
Seconds of Inertia in the system [s]	1,9	2,3	2,4	2,7
Total Generation in Norte Grande [MW]	3602	3687	3772	4018
Optimal MVA Solution from Sync. Cond.	1212	1023	988	690
IBR percentage of total generation in Norte Grande [%]*	99%	93%	91%	85%
MVAr of SyncCond support per MW of IBR Generation*	0,34	0,30	0,29	0,20

[112] *Definición de Requerimientos para el Fortalecimiento de la Red en el Sistema Eléctrico Nacional en 2025, CEN, 2022, [link]*
[113] *Definición de Requerimientos para el Fortalecimiento de la Red en el Sistema Eléctrico Nacional en 2025, CEN, 2022, [link]*

There is a clear trend between the amount of MVAr support per MW of inverter-based generation and the percentage of total generation supplied by inverters in electrically remote regions. MVAr need is proportional to total generation and to the proportion between IBR and synchronous generation.

Figure 3.7: ***Optimal synchronous condenser MVAr capacity needed for stability in Northern Chile for different IBR percentages of total local generation.***



The required MVAr support per MW of total generation varies depending on the share of synchronous generators versus inverter-based resources (IBRs), ranging from 0.25 MVAr/MW to 0.35 MVAr/MW. For the purposes of this analysis**, an average requirement of 0.3 MVAr/MW is assumed.**

Inertia and short-circuit strength issues are generally expected to emerge when IBRs make up more than 60% of instantaneous generation. However, it is crucial to understand that this 60% threshold refers not to the entire country's generation but to localized conditions. **In regions where IBRs are heavily concentrated and the grid is relatively weak—**such as Chile's Atacama, Colombia's La Guajira, or Brazil's northeast—**stability issues may arise earlier**. This is especially true when these IBRs are electrically distant from conventional synchronous generation.

3.1.2.2 Tender results

3.1.2.2.1 Synchronous Condensers

A public tender was launched to provide the required short-circuit support services. Proponents submitted offers detailing (a) the synchronous condenser or related equipment size (in MVA), (b) short-circuit capacity (SCL) at the point of interconnection, and (c) annualized costs—both for the service itself and for any needed interconnection works. The final set of awarded bids is shown in the table below:

Table 17: ***Financial results of Chile tender for Synchronous condensers[114].***

Developer	Rated Capacity [MVA]	SCL at Interconnection [MVA]	Annualized Cost of Service [USD]	Annualized Cost of Interconnection [USD]
Total from 5 winning bids	1005.5625	8044.5	46,565,020.00	296,212.00
Expected from CBA	1023	6817	22,305,566.43	NA
Annualized Avoided Costs	NA	NA	80,499,047.92	NA

A total of 1,006 MVA of new rated capacity was awarded, corresponding to more than 8,000 MVA of short-circuit capacity at the interconnection points, with an aggregate annualized service cost of approximately USD 46.6 million and an additional annualized USD 296,000 for interconnection expenses. Although these awarded proposals surpass the cost-benefit analysis reference estimate of 1,023 MVA for roughly USD 22.3 million in annualized service cost, they reflect various practical considerations such as specific site designs, financing, technological choices, and associated risks. Nonetheless, the annualized avoided system costs—mainly reduced forced thermal generation—are estimated at about USD 80.5 million, so despite higher-than-anticipated service costs, the overall net benefit remains strongly positive.

This situation will become more representative of the LAC grids, as more renewables enter the system, first high RES potential regions will see several hours in which synchronous generation gets totally displaced by IBR generation, and then at system level there will be the need to provide system strength, either through conventional operational methods, such as redispatching out of merit thermal generation or by procuring ancillary services from synchronous condensers, grid forming converters or other technologies that provide real inertia and short circuit current to the system.

[114] *19_231-198_Acta Apertura Oferta Económica, CEN, 2024, [link]*

In the case of Chile´s Norte Grande region, the optimal solution was of 0.3MVA of support for every MW of IBR generation.

Main characteristics of the 2024 Chilean tender for Synchronous Condensers (full analysis available in 2.1.6.1)

Strict technology frame: Only synchronous condensers were admissible, either as green-field machines or thermal-unit reconversions; all power-electronic grid-forming options were ruled out.

Quantitative delivery rules: aggregated nodal targets were Ana María 2 774 MVA, Nueva Chuquicamata 543 MVA, Likanantai 1 773 MVA and Illapa 1 728 MVA.

Locational flexibility: Proponents could connect anywhere inside a CEN-defined influence zone if power-flow studies proved ≥ 40 % of their fault-current reached at least one of the four nodes, allowing cross-substation contributions and portfolio optimisation.

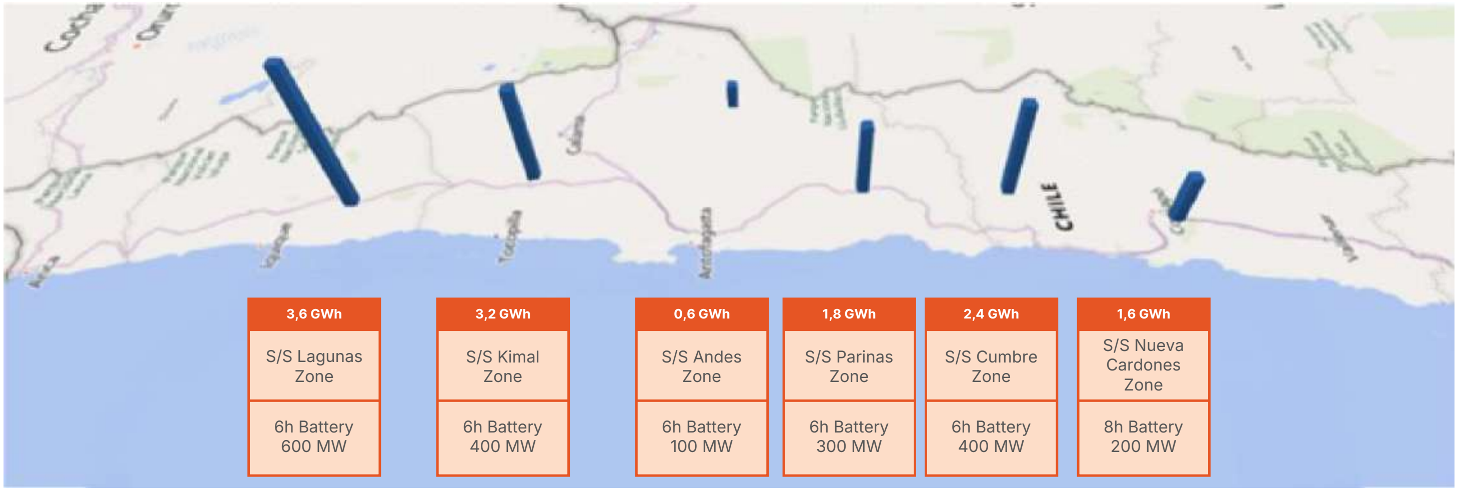
Cost-capped evaluation: Bids faced a sliding "VASC" ceiling (USD/MVA) and a global budget cap; offers breaching either limit were discarded before economic optimisation, and CEN's algorithm then selected the least-cost bundle that maximised short-circuit coverage (even if only partially).

Contract structure & term: Winning projects receive a regulated annual service payment (VASC) plus recognition of any connection works (VAPC) for the lifetime of the service contract, providing long-term revenue certainty in exchange for guaranteed fault-current availability.

3.1.2.2.2 Battery Energy Storage Systems (BESS)

Chile's push toward higher renewables and phased retirement of thermal plants has prompted growing interest in battery systems as transmission assets. An energy storage study for the national grid, Estudio de Almacenamiento de Energía en el SEN (August 2023), indicates that strategically located batteries can alleviate transmission constraints, provide short-circuit strength, and reduce renewable curtailment.

Figure 3.8: ***Identified battery needs for 2026[115].***



2,000 MW by 2026: Modeling shows that adding 2,000 MW of lithium-based battery storage by 2026 could reduce renewable energy curtailment by up to 40% and produce system-wide net benefits of around USD 513 million in net present value (NPV)[116].

13.2 GWh of Storage: The same analysis identifies an optimal long-duration battery capacity of roughly 13.2 GWh in the northern regions, with an estimated initial investment of **USD 3.1 billion**[117].

Transmission Congestion Relief: Deployed as a transmission solution, these battery systems can shift energy from off-peak to peak periods, thereby lessening the need for new lines or forced redispatch of thermal units.

Grid Services: Besides congestion relief, grid-forming battery technologies can supply voltage support, frequency regulation, and black-start capabilities, thereby enhancing overall system security.
Taken together, these findings highlight the robust potential of large-scale battery projects as efficient transmission assets in Chile, with immediate system benefits in reduced operational costs, improved renewables integration, and strengthened grid reliability.

[115] *Estudio de Almacenamiento de Energía en el SEN, CEN, 2023, [link]*
[116] *Estudio de Almacenamiento de Energía en el SEN, CEN, 2023, [link]*
[117] *Estudio de Almacenamiento de Energía en el SEN, CEN, 2023, [link]*

3.1.2.2.3 FACTS devices (e.g., SVCs, STATCOMs)

Chile's push to enhance grid reliability and optimize power flows has spurred growing demand for FACTS (Flexible AC Transmission Systems) solutions. Recently, two major FACTS-based projects were approved: one targeting the 220 kV Ciruelos-Nueva Pichirropulli corridor and another at the 220 kV Las Palmas-Centella lines. Combined, they had projected investment costs of over USD 57 million. Beyond boosting line capacities —e.g., allowing dynamic compensation of reactance from 4.7 Ω up to 19.5 Ω —these projects show FACTS technology's critical role in alleviating congestion and integrating new renewables without extensive new line construction. With Chile's ongoing grid modernization and a clear regulatory framework mandating open access and future expansion readiness, additional FACTS deployments are expected. This creates a growing market for technology providers and investors seeking robust returns from advanced transmission assets.

3.1.3 Future needs for GETs

Chile's large pipeline of renewable projects implies a steep need for innovative solutions to relieve congestion, increase transfer capacity, and maintain stability. In particular, the following factors drive GET investments:

1. High share of IBRs

- By 2030, Chile targets 80% renewable generation. A significant portion of the new capacity is envisaged to be wind (35%) and solar (29%), which are inverter-based. These sources do not inherently provide system inertia or short-circuit strength, leading to potential reliability gaps, unless they are built using inverters with Grid Forming Capabilities.

2. Transmission bottlenecks and curtailment

- Curtailment of solar has surged in recent years, primarily due to limited line capacity in the North-Central corridor. Faster deployment of DLR, advanced monitoring, or power flow control devices can partially alleviate these constraints without waiting for full line upgrades.

3. Voltage and short-circuit capacity (Icc) needs

- As older thermal plants retire, the grid loses synchronous generation that traditionally provided voltage support, short-circuit strength, and inertia.

4. Geographical mismatch of demand and supply

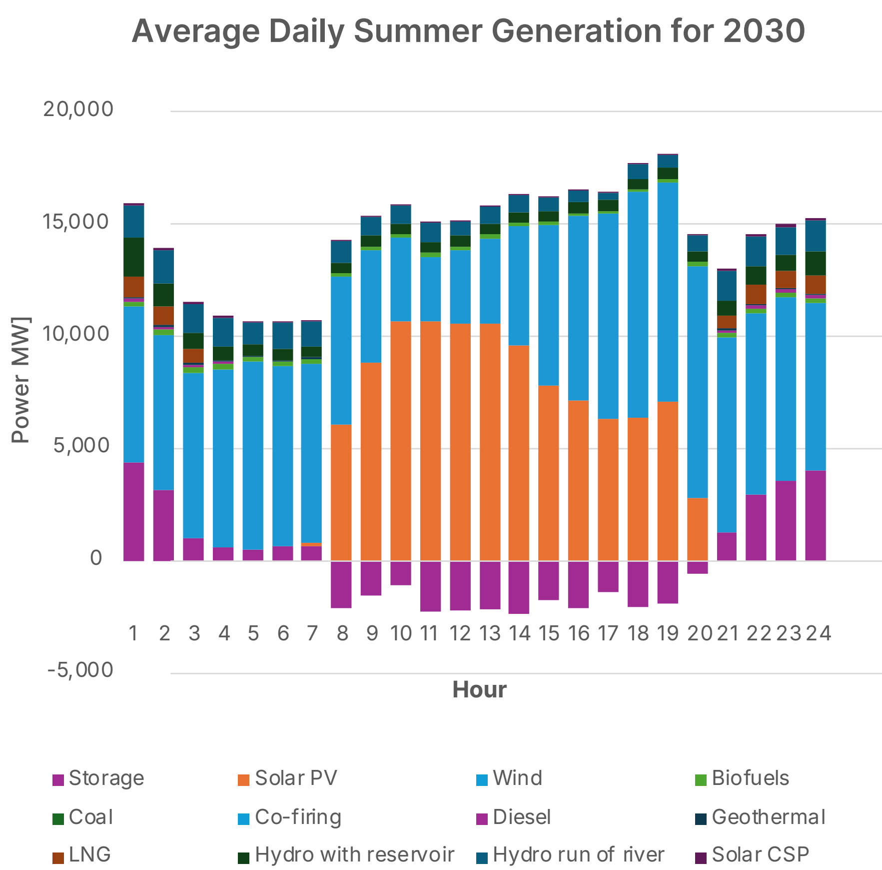
- Solar resources are concentrated in the north, wind resources in both northern and southern areas, and the main consumption centers near central Chile. This mismatch stresses further the key transmission corridors.

3.1.3.1 Potential Market Size for technologies that increase system strength

Using the estimates calculated with data from the tenders (0.3 MVAr needed for 1MW of IBR power flowing), a rough estimate can be made for Chile's future needs. Based on the projected hourly generation curve from the CEN for the 2030 carbon neutral scenario[118], the MVAr need can be estimated.

[118] *Proyecciones Electricas y Emisiones – Proceso Quinquenal PELP 2023-2027, Ministerio de Energia, [link]*

Figure 3.9: ***Projected daily generation curve for 2030 in Chile***



Wind turbines and solar panels are projected to contribute roughly 93% of the generation at peak hours in 2030, or 16.8 GW, as shown on Figure 3 . However, a **geographical heterogeneity** is expected in Chile, with about 10.8 GW of IBR capacity cohabiting with 8 GW of hydro capacity in the South and 22 GW of IBR capacity in the North[119]. According to the projected generation profile, only 1 GW of hydro capacity would be providing energy at peak hour. The rest of the hydro capacity could, however, provide grid support by operating as synchronous condensers. Therefore, **only IBR generations in the North are considered in the estimation of the future needs for synchronous condenser.** For this purpose, different generation scenarios are considered since the total installed IBR capacity (32.8 GW) exceeds by far the peak generation (16.8 GW):

Base case: the IBR generation allocation between the North and the South is proportionate to the installed capacity distribution. In practice, the northern region would be contributing 11.3 GW at peak hours (capacity factor of roughly 51%)

High North Generation: due to IBR's intermittency and variability, the generation in the North is higher than the base case, providing 13.2 GW at peak hours (capacity factor of 60% in the North).

[119] *Localizacion de infraestructura de generacion, PELP 2023-2027, Ministerio de Energia, [link]*

Low North Generation: the IBR generation in the North is lower than the base case, providing 10 GW at peak hours (capacity factor of 45% in the North). The lower generation could be allocated to renewable generation's intermittency or redispatch.

The synchronous condenser needs for these generation scenarios are presented in the table below:

Table 18: ***MVAr needs estimation in Chile for different generation scenarios***

	Base	Hight North Generation	Low North Generation
IBR generation in the North (GW)	11.3	13.2	10
Support needed (GVAr)[120]	2.4 ± 0.6	3.0 ± 0.7	2.0 ± 0.5
Investment cost on SC (2025 million USD)[121]	270	900	600

If hydro were not able to provide support in the southern region of Chile, for example due to critical hydrologic conditions (or similarly, if the IBR generation were entirely provided by the capacities in the North in the worst scenario), the support needs from **synchronous condensers would rise to 4 GVAr, or an investment cost of USD 1200 million.**

Chile would need to make an **investment between USD 600 million and USD 1200 million for 2 GVAr - 4 GVAr of synchronous condensers.** The base case estimation is around USD 720 million for 2.4 GVAr of additional synchronous condenser capacity, which is **closely matched with the CEN's 2022 estimate of 2.6 GVAr[122].**

Chile would need to carry out the equivalent of 3 new tenders for 1.000 MVAr synchronous condenser (which had a result of USD 46 million annualized cost for 1GVAr of SCs), like the one they held in 2024, or ~1.15 USD/MWh[123] if distributed evenly for projected demand. For context in march 2025 a regulated consumer pays roughly 13 USD/MWh (13 CLP/kWh) for transmission charges and 190 USD/MWh total, so this would be an increase of 8% in transmission costs or 0.6% in energy bills.

Additionally, **other technologies (GFC, STATCOMs, SVCs, etc.) can compete with synchronous** condensers in providing stability ancillary services. Nonetheless, synchronous condensers remain a proven, reliable solution—particularly favored by system operators to pair with high levels of wind and solar.

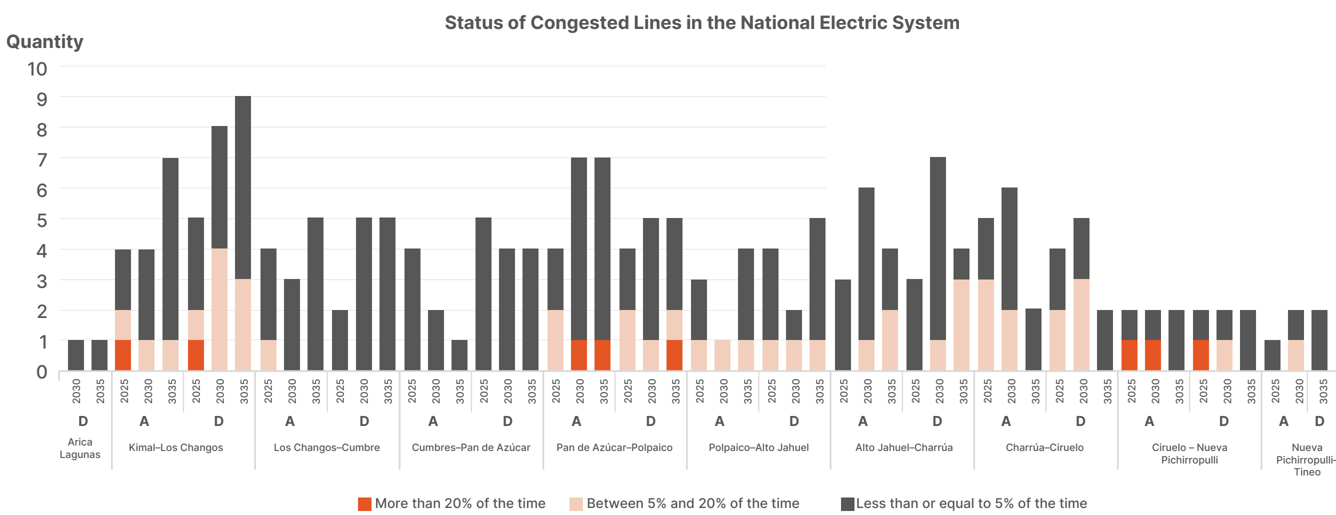
[120] *Calculated as 0.3 GVAr per GW minus 1 GVAr from existing SCs tendered in 2024 (Table 14)*
[121] *Assuming a cost of USD 300 000 per MVAr for SCs.*
[122] *Resumen de los Estudios y Definición de Requerimientos para el Fortalecimiento de la Red en el SEN, CEN, 2022, [link]*
[123] *Calculated based on a total yearly demand of 120 TWh for Chile, assuming similar costs of 46 million USD per GVAr.*

3.1.3.2 Potential Market Size for DLR

The recurring network congestion (over 2,600 GWh of curtailment in 2023) shows the potential for cost-effective DLR deployments. Given the geography (long lines connecting the north to central load centers), DLR can:

- Incrementally boost transfer capacity during favorable weather (e.g., cooler ambient temperatures in certain regions).
- Reduce curtailment by allowing more solar/wind energy to flow in real time.
- Defer or supplement large-scale line projects.

Figure 3.10: ***Projected congestion in transmission lines by geographical region in Chile.***



The figure illustrates the projected number of transmission lines expected to experience congestion at different durations: less than 5% of the time, between 5% and 20% of the time, and more than 20% of the time. In total, 73 lines will face some level of congestion, with 58 of them experiencing it for less than 5% of the time. Lines with prolonged congestion may justify major interventions such as reconductoring or new infrastructure. However, for lines congested only 5% of the time, traditional upgrades are likely to yield a negative return on investment. In contrast, Dynamic Line Rating (DLR) can provide net positive benefits. For instance, if DLR increases the capacity of a congested line of 200 MW by 20%, it would relieve the congestion by 40 MW. Assuming that the line is congested for 2.5% of the hours in a year, and a congestion cost of 70 USD/MWh[124], this would translate to an annual cost saving of USD 600 000.

[124] *The marginal cost for a typical combined cycle gas turbine in Chile. Deduced from historical marginal prices. Source: Coordinador Electrico Nacional, [link]*

Given these conditions, the market potential for DLR is significant, given the increasing integration of renewables and the need to optimize existing transmission infrastructure. **Assuming a 50% adoption rate**[125] (corresponding to the least congested lines) and an estimated cost of USD 250,000 per line[126], the market potential for DLR amounts to approximately USD 9 million for the CAPEX of the monitoring systems on the lines (73 * 0.5 * 250 000). Additionally, the implementation of a centralized system adds an extra USD 1 million to USD 2 million[127] in capital expenditure per technology adopter. **Overall, the total investment potential for DLR in Chile could reach USD 12 million**[128] , presenting a compelling opportunity for grid optimization and cost-effective congestion management.

Snapshot from the interviews conducted regarding GETs potential in Chile

1. For the Chilean branch of Engie, GETs are essential for achieving reliability amid coal phaseout and growing renewable integration. Engie Chile is closely watching upcoming tenders for opportunities.

2. Chile's National Energy Commission (CNE) sees growing value in GETs—such as storage, DLR, flow controllers, and synchronous condensers—due to geographical constraints, urgent grid needs, and the rapid pace of renewable integration. Chile's narrow geography and difficult permitting environment make traditional grid expansion slow and socially contentious. As a result, non-traditional solutions are increasingly attractive.

3.1.4 Forecasted impact of the GETs in Chile

3.1.4.1 Synchronous Condensers in Chile

Synchronous condensers (SCs) in Chile can provide the short-circuit current, inertia, and voltage control critical for integrating large shares of inverter-based resources (IBRs) in pursuit of the country's renewable goals—targeting 80% renewables by 2030 and 100% by 2050. By supplying short-circuit current, SCs help to maintain stable voltage profiles, especially in areas dominated by grid-following solar and wind technologies that require strong "grid strength" to avoid oscillations under weak-grid conditions. Meanwhile, their inertia contribution supports frequency stability by limiting rapid changes in system frequency when fluctuations in load or renewable output occur. Lastly, their voltage control function ensures reliable phase-angle stability and protects transmission equipment, thereby improving overall grid efficiency and resilience.

In the case of the already tendered synchronous condensers, they will allow for operation with less than 5% of thermal generation in the renewable-rich north of the country. Without the

[125] The adoption rate in the most advanced country (Belgium) with DLR is about 30% of the entire grid, according to an interview with Ampacimon. For the estimation here, only lines that may be congested in the near future are considered, therefore the adoption rate is estimated at 50%, which is higher than the overall rate. Brought back to the entire grid, the 36 lines estimated to adopt DLR would represent less than 5% of the grid.
[126] The cost is taken from PPL's use case, section 2.2. It is typically for a line about 50 km long (assuming 6 sensors).
[127] The cost is taken from PPL's use case, section 2.2. The number can be lower in Chile because PPL faced challenges to comply with North American Electric Reliability Corporation's Standards while developing the central system.
[128] Only near-term (i.e. by 2030) transmission needs are considered. The OPEX is not included, which would be about USD 1-3 million/year (estimation based on the PPL's use case).

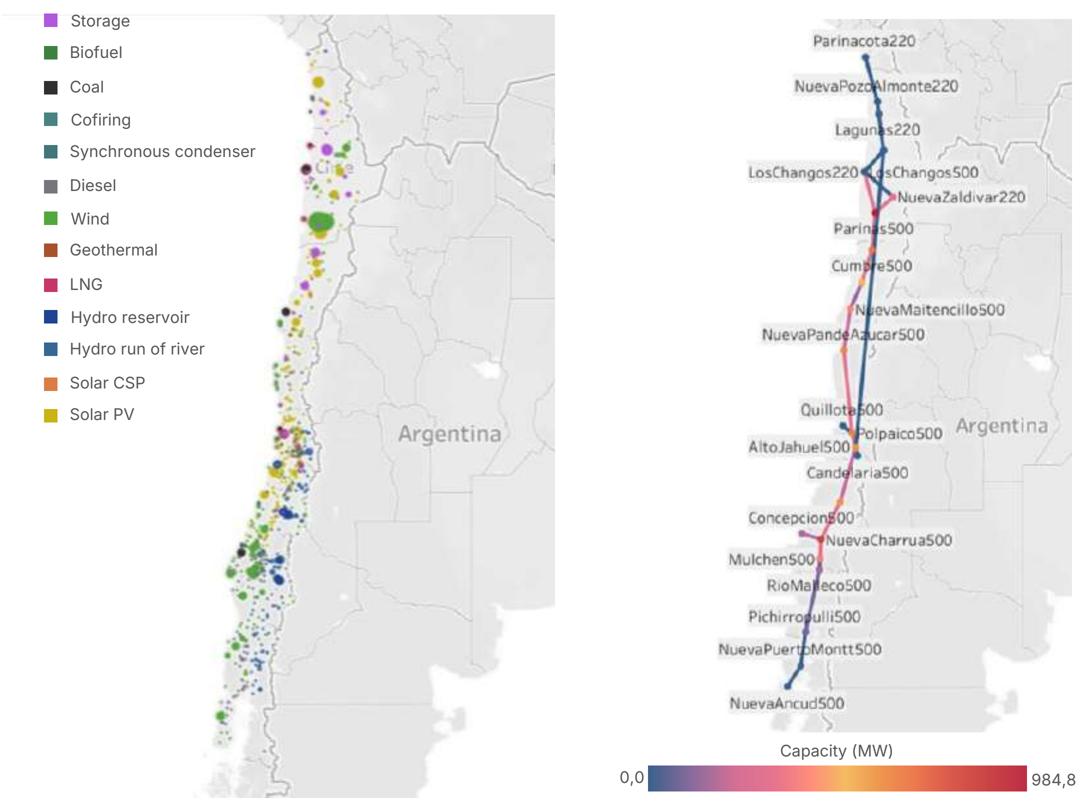
services they provide this percentage would need to increase. At 2027 scenarios, the estimated avoided costs are around 80 million USD per year (see section 3.1.2.2.1) for the tendered 1 GW synchronous condensers.

A comparative approach is used to estimate the SCs' contribution to emission reduction. If the same system support were to be provided by synchronous machines, one third[129] of the projected renewable generation would have been displaced by thermal units. Figure 3 2 shows that Chile projects to have 92 TWh of solar and wind generation in 2030. Then, assuming an emission rate of 0.434 ton CO2/MWh[130] for the gas-based thermal units, the SC implementation would have reduced the emissions by 13 million tons of CO_2 per year[131].

3.1.4.2 Dynamic Line Rating (DLR) in Chile

The additional capacity unlocked by DLR depends on each line's microclimate; on average, DLR can raise a line's capacity by **15-20%** above its static rating, with real-time ratings exceeding static values at least **90%** of the time[132]. When applied to Chile's north-south corridors—where renewable generation is rapidly expanding—this extra headroom can reduce curtailment and push back the need for costly line upgrades.

Figure 3.11: ***Geographical location and capacities of generation by source and transmission and lines.***



[129] This is a rule of thumb estimate that captures the order of magnitude. An accurate evaluation would have required a dedicated dynamic model.
[130] 0.96 pounds per kWh for gas-based thermal units, source: EIA, [link]
[131] 92 * 1/3 *0.434 = 13.18 million ton CO2.
[132] Propuesta de expansion de la transmision, CEN, 2023, [link]

The following assumptions will be used to quantify the order of magnitude for the reduction in congestion costs:

- The adoption rate of DLR on the congested lines reaches 50% (36 out of 73 identified lines)
- Each line is congested for 2.5% of time per year (219 hours/year)
- Each line has a capacity of 200 MW (approximately the average value at 220 kV, see Table) and DLR increases the capacity by 40 MW (20%)
- The congestion cost is estimated at 70 USD/MWh (with gas-fuelled units on one end and solar/wind on the other end)

Under these hypotheses, **the deployment of DLR on 36 lines would yield USD 22 million/year[133] of reduction in congestion.**

3.2 Market Potential *in Colombia*

3.2.1 Electricity sector in Colombia

Major shift in the Colombian electricity sector is expected in the coming years. These changes are characterized by soaring demands (16% by 2030), a shifting power mix (solar and wind from 23.9% of the installed capacity in 2024 to 42.7% in 2030) and significant transmission expansions. The dynamism of the sector is accompanied by challenges for the grid, which also means investment opportunities for GETs.

3.2.1.1 Demand

In Colombia, the demand is projected to grow over 16.5%, from 82.4 TWh in 2024 to 96 TWh in 2030 (Table). The projection factors in the grid's natural growth, Large Energy Consumers (GCE), Electric Mobility (ME) and Distributed Energy Resources (GD).

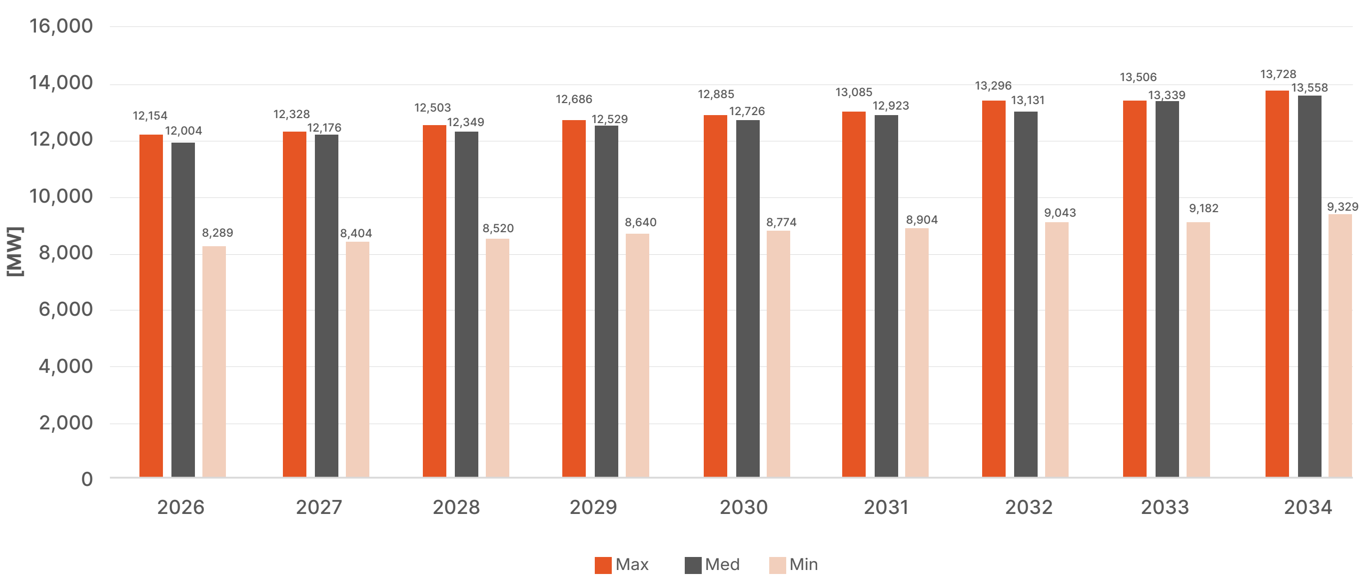
[133] *Reduction in congestion = number of congested hours x capacity increase (MW) x congestion cost (USD/MWh) x number of line. This calculation corresponds to the value of avoided incremental cost due to curtailed renewable generation. A more common approach would consist in evaluating the avoided congestion rent but since the Chilean market has a single price, such an approach would not be relevant.*

Table 19: ***Demand Projection for the Colombian power system. The boundaries for 95% and 68% confidence intervals are also provided. Source: UPME[134].***

	SIN + GCE + ME + GD_UPME (GWh-year)				
	Medium Scenario	**Upper CI 95%**	**Lower CI 95%**	**Upper CI 68%**	**Lower CI 68%**
2024	82,462	82,944	81,981	82,726	82,199
2025	84,967	88,562	81,395	86,393	83,006
2026	88,620	94,093	83,199	91,623	85,644
2027	90,824	97,786	83,942	94,644	87,045
2028	92,611	100,898	84,434	97,158	88,120
2029	94,617	104,130	85,247	99,839	89,469
2030	96,065	106,745	85,561	101,928	90,292
2031	98,040	109,872	86,420	104,537	91,652
2032	100,059	113,016	87,356	107,175	93,071
2033	102,213	116,275	88,493	109,939	94,635
2034	104,844	120,036	89,983	113,382	96,665
2035	107,690	124,010	91,745	116,660	98,912
2036	110,591	128,045	93,556	120,101	101,210
2037	113,992	132,618	95,832	124,233	103,989
2038	117,402	137,201	98,120	128,290	106,778

The peak load, which is dimensioning for the grid, is projected to grow from 11 475 MW in 2023[135] to 12 726 MW in 2030 (medium scenario).

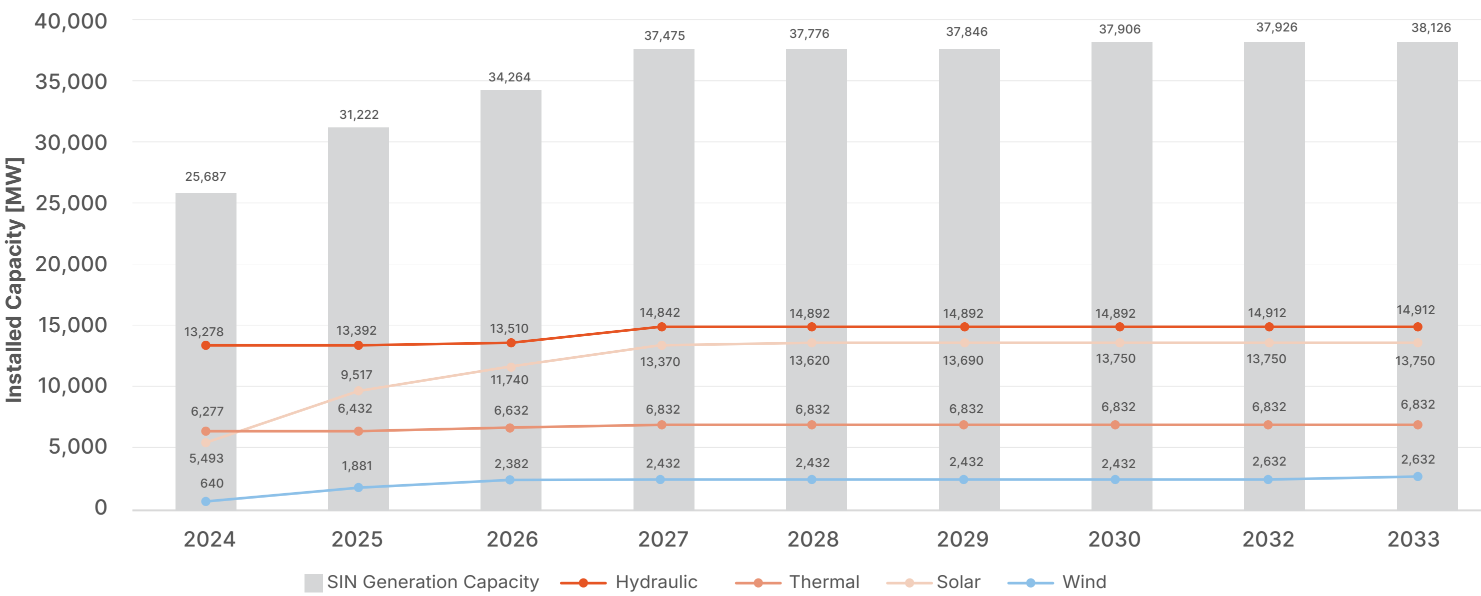
Figure 3.12: ***Peak Demand projection in Colombia for different scenarios, through 2034. Source: XM [136].***



[134] *Proyeccion de la demanda de energia electrica y potencia maxima 2024 – 2038, UPME, [link]*
[135] *Reporte Integral de Sostenibilidad, Operacion y Mercado 2023, XM, [link]*
[136] *Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]*

3.2.1.2 Power mix

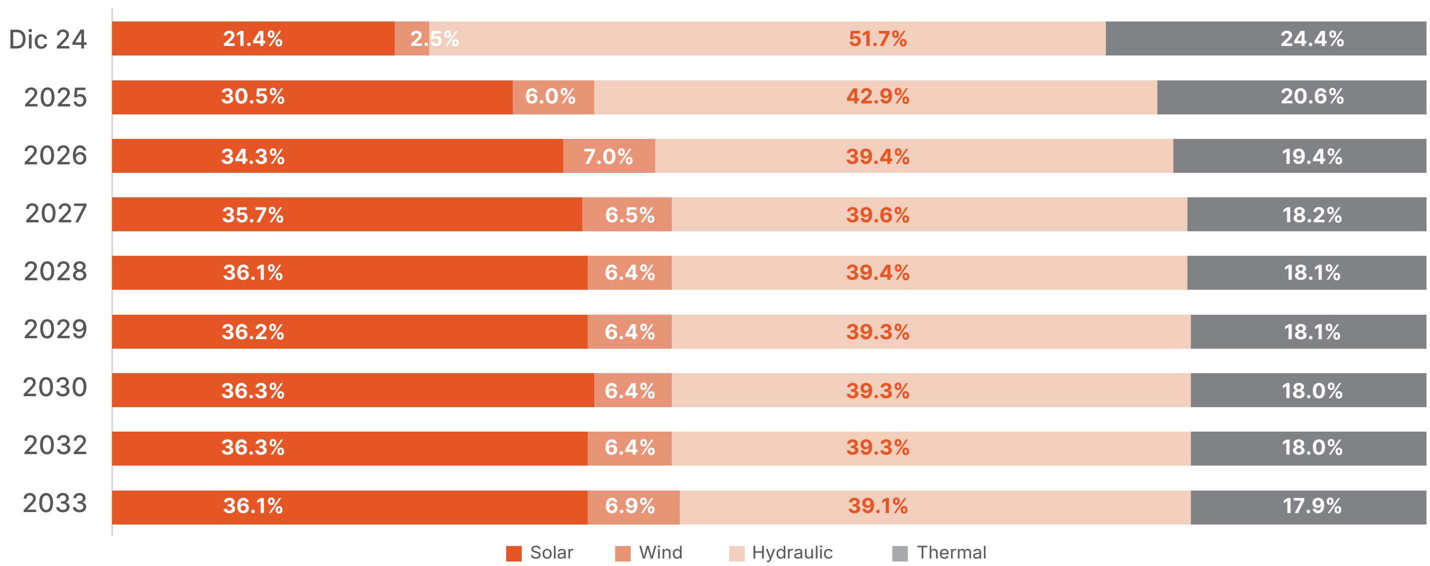
Figure 3.13: ***Power mix projection in Colombia, through 2034. Source: XM[137]***



As a response to the demand growth, a significant capacity rollout is expected through 2030. In 2024, hydropower represents 51.7% of the installed capacity in Colombia with 13.3 GW. Thermal units take the 2nd position with 6.3 GW (24.4%), followed by 5.5 GW (21.4%) of PV and 0.6 GW (2.5%) of wind turbines. By 2030, while hydropower and thermal capacities remain stagnant, the expected installed capacities for PV and wind turbines soar respectively to 13.8 GW and 2.4 GW. **The percentage of inverter-based resources in the system's capacity will shift from 23.9% in 2024 to 42.7 % in 2030.** The major increments will have been accomplished as soon as 2027.

[137] *Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]*

Figure 3.14: ***Power mix projection in Colombia (in %), through 2034. Source: XM[138]***



3.2.1.3 Grid

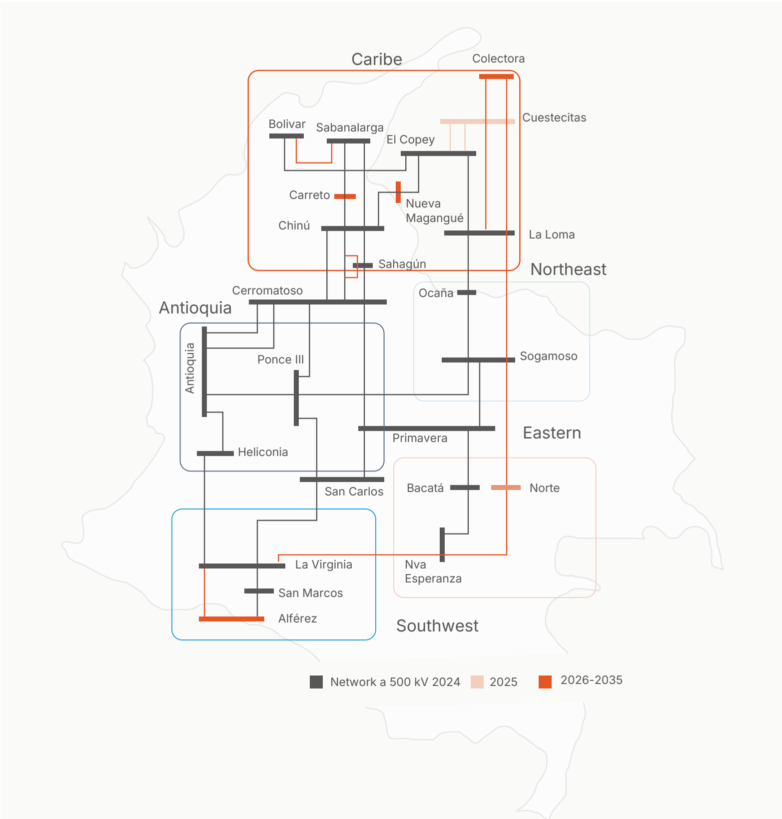
To reliably link the generation sources to the demand sites, the transmission system needs to expand. In 2025, Colombia counts approximately 27,800 km of power lines, distributed across different voltage levels, as shown in Table. Today, the 500 kV grid is composed of 29 circuits and 19 substations. Through 2034, these numbers are expected to increase to 39 and 23[139] .

Table 20: ***Power lines in Colombia, 2025. Source: Artelys, from XM database[140]***

Voltage [kV]	Number of line	Total length [km]	Average length [km]	Percentage [%]	Total Capacity [MW]	Average capacity [MW]
34.5	10	33	3	0.12%	187	19
44	4	3	1	0.01%	97	24
57.5	5	44	9	0.16%	166	33
66	28	221	8	0.79%	888	32
110	187	3268	17	11.74%	11343	61
115	404	6441	16	23.14%	27925	69
138	1	15	15	0.06%	89	89
230/220	236	14263	60	51.23%	50933	216
500	29	3549	122	12.75%	31978	1103
Total	**904**	**27837**	**31**	**100.00%**	**123605**	**137**

[138] *Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]*
[139] *Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]*
[140] *Paratec, XM [link]*

Figure 3.15: ***The Colombian 500 kV grid in 2024, 2025 and 2026-2035. Source: XM***[141]



There are 13 prominent projects underway for the 500 kV grid. The go-live date could be as early as 2025 for the most advanced projects. The implementation of these projects would add 2000 km of 500 kV power lines to the system. When it comes to the lower voltage grids (<500 kV), investments will follow up, as further branching of the network is necessary for the resource interconnection and power delivery to final consumers.

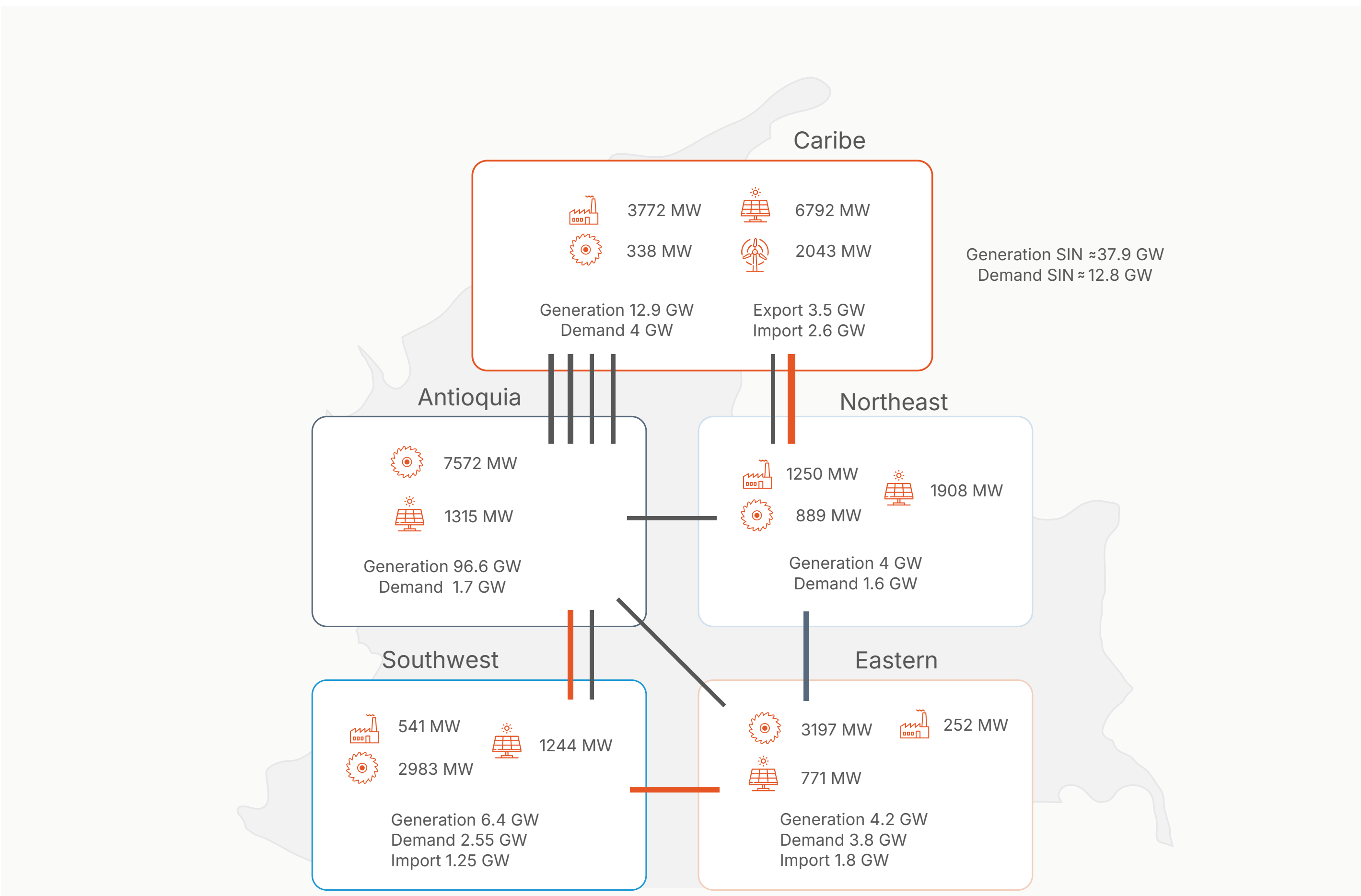
Table 21: ***Planned projects for the 500 kV grid. Source: XM***

Área	Código	Proyecto	km	FPO
Caribe	PTRA00779	El Copey - Cuestecitas 2 500 kV	215	31/01/2025
Oriental	PTRA00075	La Virginia - Nueva Esperanza 500 kV	190	31/07/2025
Caribe	PTRA00325	Cuestecitas - La Loma 500 kV	220	30/10/2025
Nordeste	PTRA00924	La Loma - Sogamoso 500 kV	200	18/04/2026
Caribe	PTRA00325	Colectora - Cuestecitas 500 kV	220	31/07/2026
Caribe	PTRA00325	Colectora - Cuestecitas 2 500 kV	220	31/07/2026
Oriental	PTRA00070	Sogamoso - Norte 500 kV	245	31/10/2026
Oriental	PTRA00070	Norte - Nueva Esperanza 500 kV	74	31/10/2026
Suroccidental	PTRA00073	La Virginia - Alférez 500 kV	183	30/09/2026
Caribe	PTRA00482	Cuestecitas - La Loma 2 500 kV	220	27/06/2026
Caribe	PTRA09546	Cerromatoso-Sahagún y Chinú-Sahagún 2 500 kV	-	30/06/2026
Caribe	PTRA01139	PTRA01139 Chinú - Carreto y Sabanalarga - Carreto 500 kV	-	31/03/2027
Caribe	PTRA00483	Circuito de transmisión HVDC VSC (UPME)	-	Por definir

[141] *Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]*

It is worth noting that 8 projects out of 13 are located in the Caribe region. The reinforcement of the North - South corridor can be explained by the heterogenous distribution of generation and demand. Indeed, the Caribe region in the North of Colombia will become an inverter-based generation pocket, with a total installed capacity of 12.9 GW (including 8.8 GW of IBR) against a local demand of 4 GW, as shown in Figure 3.

Figure 3.16: ***Demand, Generation and Import/Export capacity - year 2030. Source: XM***



Finally, the only congestion rents in Colombia are in the Ecuador Interconnection, with USD 3.4 million for 2022 and USD 18 million for 2023. The impacts are therefore minor in the estimation of the potential for GETs in Colombia[142].

[142] *Reporte Integral de Sostenibilidad, Operacion y Mercado 2023, XM, [link]*

3.2.2 Grid Enhancing Technologies in Colombia

3.2.2.1 Existing GETs projects

Synchronous Condenser:

An ongoing tender seeks to install synchronous condensers in the Caribe region. Inertia and short-circuit current provision are the core services to be tendered. More details can be found in section 2.1.6.

Dynamic Line Rating:

To date, there is only one pilot project for DLR in Colombia, which is migrating to operational deployment. More details regarding the case can be found in the section 2.2.3.1.

Nevertheless, different stakeholders show a growing interest for DLR, including XM (the system operator) and Unidad de Planeacion Minero Energética (the governmental body in charge of the transmission planification). Other private actors such as Afinia or EPSA made DLR proposition as early as 2019. In February 2024, the Transmission Committee of the Consejo Nacional de Operacion suggested to Transelca, the pilot project developer, to present its results from the pilot project. The valuable hands-on feedback would provide guidance for future adoption. The dynamism and the attention given to DLR are important, the operational deployment would require the participation of stakeholders from diverse horizons.

3.2.3 Future needs for GETs

From the information collected in the above section, an estimation of the future needs for GETs can be derived. In summary, the Colombian projects will add by 2030:

- 10 GW of solar and wind; solar and wind will represent 42.7% of the total installed capacity in 2030
- 2000 km of 500kV power lines
- 14 TWh of annual demand and 1000 MW of peak demand

In addition, XM identified limiting elements of the grid through 2034 with simulations, summarized in the table below.

Table 22: ***Limiting elements of the Colombian grid through 2034, without mitigation projects. Source: XM***

Region	Lines with capacity shortage in N and N-1	Substations with Icc shortage	Substations requiring voltage control
Caribe	25	26	9
Antioquia	9	5	0
Suroccidental	18	4	1
Oriental	18	13	2
Nordeste	19	4	10
Total	89	52	22

3.2.3.1 Synchronous Condenser

To estimate the need for SCs in Colombia, it is assumed that MVAr and SCL from hydro will support stability in the Antioquia, east, and southwest region due to having an installed capacity of 13.6GW of Hydro vs just 3.2GW of Solar, as shown in Figure 3 16. Dispatching hydro resources will likely be a more economical solution than building new infrastructure in this region.

For the North-East and Caribe regions, this trend is the opposite, the generation in these regions will be highly IBR dependent and it is electrically distant from most of the hydro resources. In the region roughly 10.7GW of renewables are being planned to be installed by 2030, as shown in Figure 3 16. In a high production scenario, where they are producing at a peak of 90% of their rated capacities, this means **9 GW of IBR generation in a weak section of the grid**. Following the numbers estimated from the Chile tenders for stability service (Table 14), the need for synchronous condensers would be close to **2.7 GVAr**. At a country level, with an installed capacity of 16.1GW of wind and solar, this means it is highly likely that the peak demand of 13GW could be covered by virtually 100% wind and solar. Being able to support this **without the use of hydro for support** in the hydro rich regions would **increase the need to approximately 3.9 GVAr.**

Assuming a cost of USD 300 000 per MVAr[144], the total cost of the solution would be around USD 810-1,170 million.

3.2.3.2 Dynamic Line Rating

XM identified **89 lines with capacity limitation** (mostly for N-1 grid) through 2034. There is no long-term mitigation plan identified for these limitations; instead, some lines are covered by short-term solutions like generation redispatch, generation control and SPS. Two aspects of these limitations are in favour of DLR:

- The timeline is short; many limitations could materialize as early as 2026.

The limitations covered by short-term solution don't pose a critical reliability issue, making DLR a suitable solution[145].

Since **Colombia is much less windy than Chile** (according to Global Wind Atlas[146]), the adoption rate of DLR on the congested lines is assumed to be at 30%[147].

This corresponds to 27 out of the 89 congested lines. With costs at USD 250 000/line[148], the market potential for DLR is estimated at **USD 6.75 million**. In addition to the costs per line equipped, the centrale system implementation adds about USD 1 million – USD 2 million to the capital expenditure per technology adopter. The **total investment potential in Colombia could reach USD 10 million**[149] for DLR.

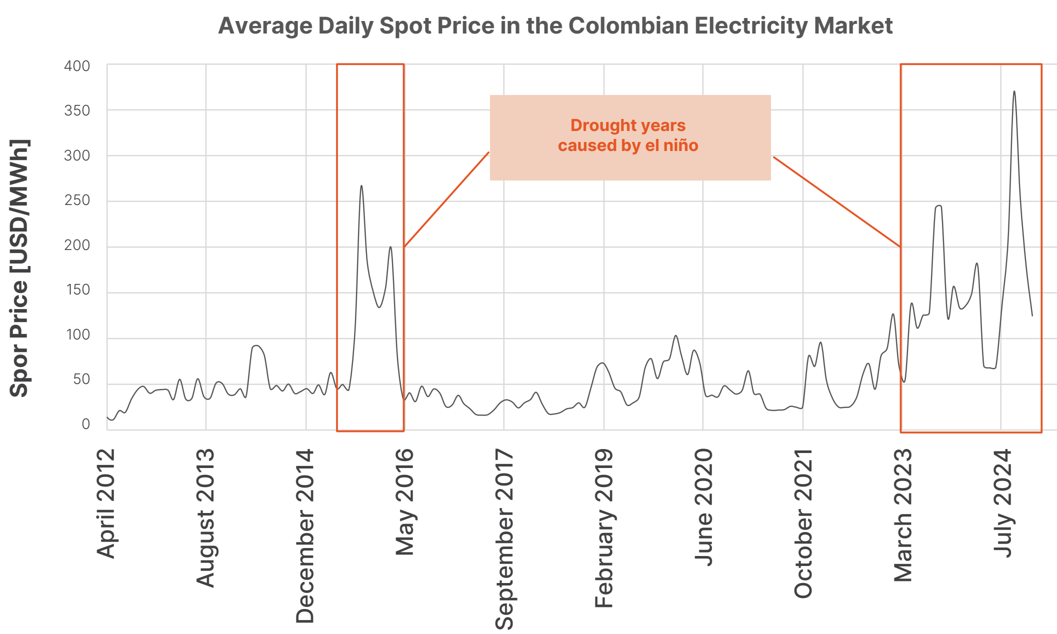
[143] Including the 2nd and final step of the Hidroituango project, as explained in the section 5.3 of this source: Informe de planeamiento operativo electrico de largo plazo, segundo semestre 2024, XM [link]
[144] From Task 1, section 1.3. Also coherent with the Chilean use case.
[145] There is no guidance on how DLR should be factored in the compliance to reliability standards.
[146] Global Wind Atlas, [link]
[147] Belgium is one of the most advanced countries in DLR adoption, according to an interview with Ampacimon, its adoption rate is about 30%.
[148] The cost is taken from PPL's use case, section 2.2. It is typically for a line about 50 km long (assuming 6 sensors).
[149] The OPEX is not included, which is estimates at USD 1-2 million/year, based on PPL's use case.

3.2.4 Forecasted impact of the GETs in Colombia

3.2.4.1 Synchronous condensers in Colombia

The synchronous condensers proposed in the ongoing tender could support stable operation with an extra 2150 MW of renewables in the northern regions. Without the services they provide, this generation would have to come from hydro or thermal resources. The increased welfare for the system, (calculated as the difference between solar or wind marginal costs and the marginal cost of the market) would be around USD 134 million for a year of high hydro availability (spot price 50 USD/MWh) and low solar-wind capacity factor (15%) or up to USD 700 million for a year with low hydro availability (spot price 150 USD/MWh) and high solar-wind capacity factor (25%).

Figure 3.17: ***Average daily spot price in the Colombian electricity market and the effect of the El Nino-Southern Oscillation***[150]



The SCs' impacts can also be quantified in terms of emission reduction. The approach used for Chile in the section 3.1.4.1 can be reapplied. Meanwhile, there is no access to the generation projections, the generations are then estimated using capacity factors. According to Caravajal-Rom et al.[151], the wind and solar capacity factors in Colombia are respectively estimated at 67% (a local value for the future wind capacity hosting regions) and 20%. Another structuring difference consists in the abundance of hydro

[150] *"The El Niño-Southern Oscillation (ENSO) is a recurring climate pattern involving changes in the temperature of waters in the central and eastern tropical Pacific Ocean. On periods ranging from about three to seven years, the surface waters across a large swath of the tropical Pacific Ocean warm or cool by anywhere from 1°C to 3°C, compared to normal."* [link]

[151] *Carvajal-Romo, G., Valderrama-Mendoza, M., Rodríguez-Urrego, D. y Rodríguez-Urrego, L. (2019). Assessment of solar and wind energy potential in La Guajira, Colombia: Current status, and future prospects. Sustainable Energy Technologies and Assessments, 36. DOI: 10.1016/j. seta.2019.100531*

plants in Colombia, therefore the system needs in term of SCL and inertia supports are specifically localized in the Caribe and Northeast regions. 2 GW of wind and 8.7 GW of solar capacities are planned for these regions, corresponding respectively to 11.7 TWh and 15.2 TWh of annual generation. If one third of these generations were to be displaced by gas-fueled synchronous machines, in order to provide system support, this would represent 8.9 TWh of thermal generation.

Assuming an emission rate of 0.434 ton CO2/MWh for gas-fueled generation, the SCs would have contributed to 3.9 million tons of CO2 emission reduction per year.

3.2.4.2 Dynamic line rating in Colombia

The capacity increment from DLR depends on the climate of the location. Colombia has limited wind resources. Therefore, **the average capacity increase is estimated at 15%**. The main benefit of DLR is to provide a fast-to-deploy solution to solve line congestion.

In order to quantify the benefits brought by DLR, some hypotheses are assumed:

- The adoption rate of DLR on the congested lines is about 30%[152](27 out of 89)
- Each line is congested for 2.5% of time per year
- Each line has a capacity of 200 MW (the average value in Colombia at 220 kV, Table) and DLR increases the capacity by 40 MW (20%)
- The congestion cost is estimated at 50 USD/MWh according to Figure 3 17 (with gas-fuelled units on one end and solar/wind on the other end)

Under these hypotheses, the deployment of DLR over 27 lines would yield a congestion reduction of approximatively **USD 12 million per year**[153].

3.3 Potential Adoption of GETs *and Market Size for LAC*

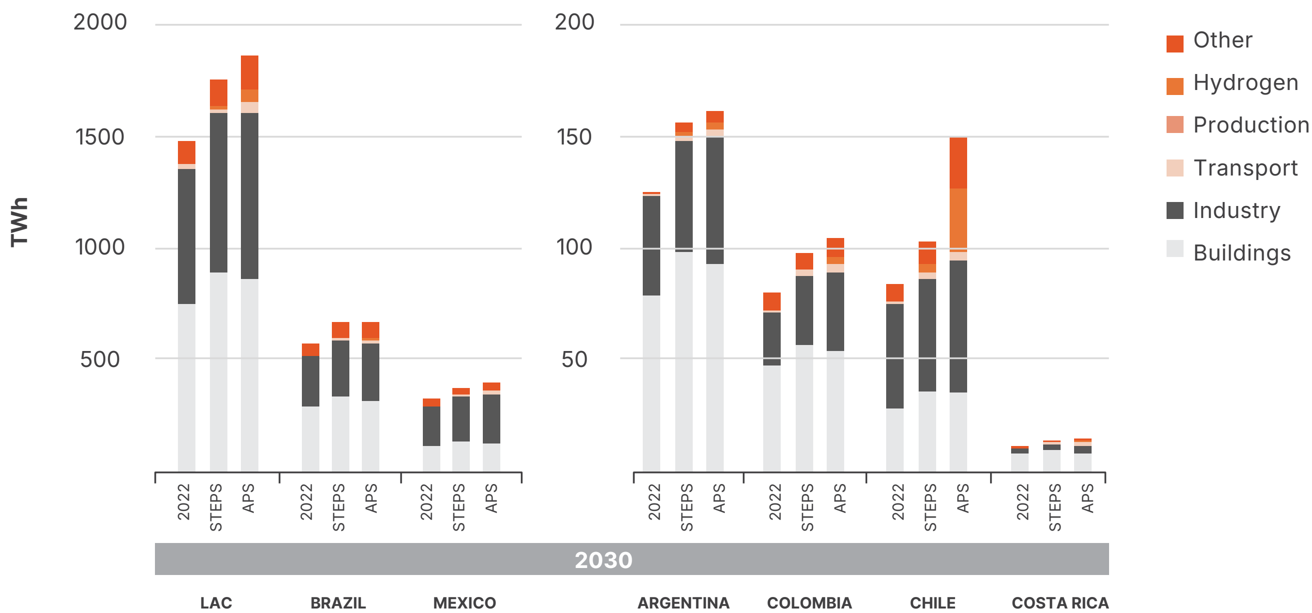
3.3.1 Market Drivers for GETs Adoption

3.3.1.1 Rapid expansion of the electricity systems

The electrical systems in the LAC are expanding rapidly. According to IEA, the annual demand in the region is projected to grow from 1500 TWh in 2022 to 1750 - 1850 TWh in 2030.

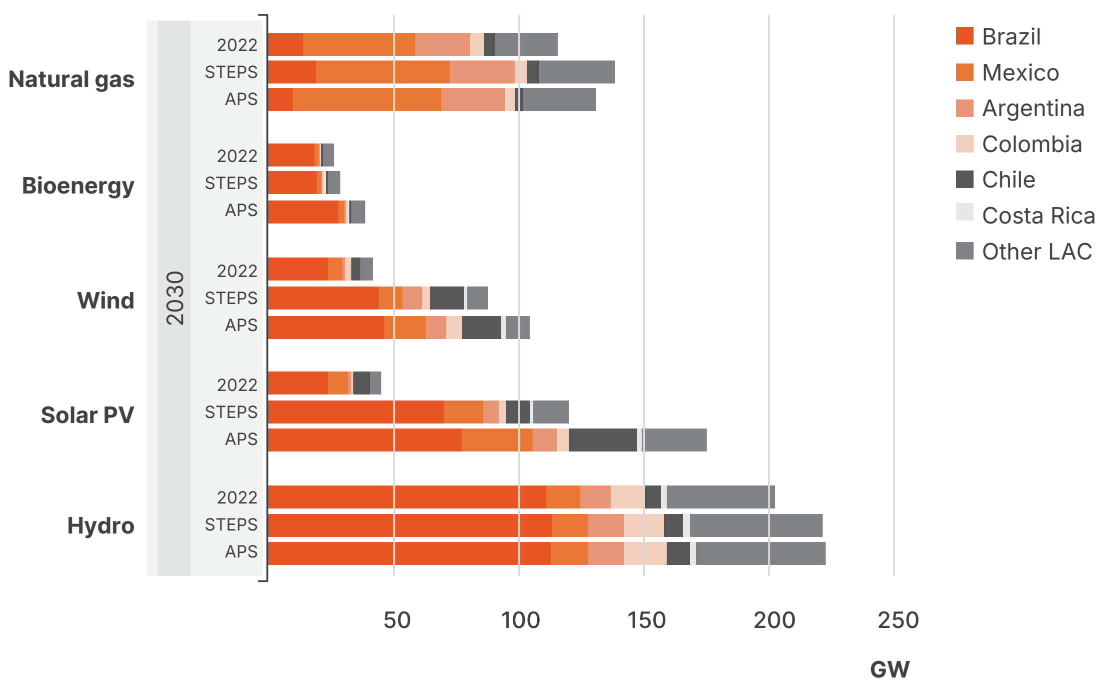
[152] *Colombia is less windy than Chile, thus a lower adoption rate.*
[153] *Same calculation as for Chile, refer to Section 3.1.4.2 for more details.*

Figure 3.18: ***Demand projection in the LAC region for 2022 and 2 projected scenarios for 2030. Source: IEA***



At the same time, the installed capacities are projected to reach 700 GW - 800 GW in 2030 from 480 GW in 2022, where solar and wind capacities represent the major contributions to the growth.

Figure 3.19: ***: Installed capacity in the LAC region for 2022 and 2 projected scenarios for 2030. Source: IEA[154]***



[154] *Latin America Energy Outlook 2023, IEA, [link]*

3.3.1.2 Grid Congestion and Stability Challenges

Latin America's rapid renewable deployment is outpacing grid expansion, leading to transmission bottlenecks and stability issues. Wind capacity grew 17-fold and solar 1300-fold in the 2010s, yet grid investments lag behind. As a result, power lines in high-resource areas are saturated - for example, insufficient transmission in northern Chile has caused local prices to plummet to zero due to oversupply. Grid congestion is also emerging in Argentina, Panama, and others with concentrated renewables. These constraints force curtailment of cheap clean energy (Chile curtailed a record 735 GWh of solar in Jan-May 2023) and threaten reliability.

3.3.1.3 Geographical Mismatch of Resources, Traditional Generation and Demand

Many of LAC's best renewable resources are far from population centers, straining the grid. In Chile, vast solar farms in the Atacama Desert (north) and wind in Patagonia (far south) must transmit power over 1,500 km to central demand nodes. A major 1,500-km HVDC trunk line (Kimal-Lo Aguirre) was deemed "urgent" to connect the solar-rich north with the center, after delays in permitting slowed its construction. Similarly, Argentina's wind belt in Patagonia and solar in the northwest sit far from Buenos Aires and industrial hubs. Brazil's northeast - rich in wind and solar - is distant from the southeast load centers. Delays in infrastructure buildout to increase transmission capacity from the northern region of La Guajira to the traditional load center in the Andes of Colombia has delayed the development of several GWs of renewables.

These geographical gaps mean existing lines are often overloaded. And without upgrades, renewable power gets bottled up: Chile, despite relatively low network losses, saw severe congestion in its northern solar zone. This regional pattern - resources on the periphery, loads in the center - is a key driver for deploying Grid-Enhancing Technologies (GETs) to increase transfer capacity and relieve congestion.
These high-resource regions frequently lack synchronous generation, making them pockets of weak grids. Traditional generation sources like coal and natural gas plants, which provide inertia and short-circuit current (SCL), are concentrated near urban and industrial centers, and big hydro generation is not often located near Solar and Wind generation. As a result:

- Atacama (Chile), Guajira (Colombia), Patagonia (Argentina), Northeast Brazil, future offshore grid and many other high renewable potential regions face increasing congestion as well as grid stability issues as wind and solar replace synchronous generators.
- The lack of local fault current and voltage regulation requires additional grid-forming converters (GFCs), synchronous condensers (SCs), and battery energy storage (BESS) to maintain grid stability.
- These "weak-grid pockets" are particularly vulnerable to voltage instability, and renewable curtailment if not reinforced with appropriate GETs.

3.3.1.4 Displacement of Synchronous Generation (Inertia & Fault Current)

High renewable penetration not only causes congestion but also displaces traditional generators that provided inertia and short-circuit power. Many LAC grids are hydro or thermal dominated, but as wind and solar supply a larger share, the system's inertia and fault current reserves diminish. This weakens grid stability (lower inertia makes frequency control harder, and low short-circuit levels impede protection systems). To compensate, operators are turning to Synchronous Condensers (SCs) and starting to consider Grid-Forming Converters (GFCs). For example, the previously discussed Chile's tender to install large synchronous condensers in the northern grid. As wind and solar surge in northern Chile, SCs are deemed critical to provide needed inertia and short-circuit strength to avoid blackouts. Brazil has similarly added SCs - at least seven units in the past seven years - to strengthen weak grid areas as more wind comes online. In smaller island grids, battery energy storage systems (BESS) with grid-forming inverters are being installed to provide instantaneous reserves. The World Bank, for instance, is supporting battery storage in Belize to help integrate solar PV into the grid. Overall, as conventional plants reduce output or retire (e.g. coal closures in Chile, oil units in Caribbean islands), investment in these grid-support technologies (SCs and GFC-equipped storage) becomes essential to maintain adequate inertia and fault current levels.

3.3.1.5 Transmission Expansion Limitations vs. GET Solutions

Upgrading the grid via new transmission lines is a lengthy and capital-intensive process, often constrained by licensing, land acquisition, scarcity of resources or equipment[155], and social opposition. Major line projects in LAC can take 5-10 years from planning to operation. For example, Chile's 1,500 km HVDC project mentioned above has an expected 7-year construction timeline after award. Similarly, Brazil plans over 15,000 km of new lines by 2028 to connect renewables, but such expansion requires steady auctions and may face delays. Given the urgency to integrate renewables, Grid-Enhancing Technologies offer a faster alternative to boost capacity on existing infrastructure, as their deployment time is around 1 to 2 years (see section 1). In sum, the difficulty of building new transmission in time to meet 2030 renewable targets is a major driver for LAC utilities to adopt GETs

Snapshot from the interviews conducted regarding market drivers

1. 1. ISA, the largest energy transmission company in Latin America, based in Colombia, considers the GETs as a complementary tool to new infrastructure, that buy time and streamline system expansion. ISA is shifting from a kilometer-based mindset to one focused on GW-km or other indicators, reflecting the need to increase capacity and flexibility rather than just distance.

2. 2. ISA has deployed Static Synchronous Series Compensators (SSSC) projects in several countries. They found a trade-off in modular solutions, which allow for quick and flexible deployment. If future grid expansions make the solution redundant, SSSCs can be reused and transported to be deployed at a different location. However, these solutions become expensive at bigger scales, motivating a preference for custom or non-modular devices in high-capacity applications.

[155] *World's largest transformer maker warns of supply crunch, Financial Times, [link]*

3. 3. For ISA, a massive transformation is underway, with urgent demand for more resilient and flexible grids. GETs are a viable way to meet short-term needs, reduce congestion costs, and bridge delays in large projects.

4. 4. Ampacimon, a DLR developer, shares the same vision as ISA: DLR buys some time when building new lines, as their deployment time is much lower, but it should not be seen as a replacement. This is amplified with the scarcity of resources for building new lines.

3.3.2 Market Size Estimations

3.3.2.1 Synchronous Condensers

The need for short-circuit level and inertia is poised to create a large SC and GFC market in LAC. A common planning guideline, confirmed by our analysis of the Chile tender for Synchronous Condensers[156], is that every 1 MW of inverter-based renewable capacity should be supported by roughly 0.3 MVAr locally (through synchronous machines or equivalent) to maintain stability. The solar and wind capacities are forecast to reach 279 GW in the LAC region by 2030. This implies a demand of roughly **83.7 GVAr for synchronous condensers**. However, this number could be an **overestimation** since the **countries rich in hydro** and the **countries with less ambitious solar and wind generation goals** would need **less support for their grids**. To factor in these considerations, two additional estimates are derived **assuming that only 60% and 30% of the wind and solar capacities would need support** from synchronous condensers. These estimates correspond respectively to **50.2 GVAr and 25.1 GVAr.**

At an indicative capital cost of about USD 300 000 per MVA of rated capacity for SCs, this represents a market between **USD 7.5 billion and USD 25 billion** in the long term for the CAPEX investment. If financed through tenders like the cases in Colombia and Chile, this would represent a yearly cost between USD 0.6 billion and USD 2 billion USD or 10%-33% of all projected yearly transmission grid investments. Even if only a fraction of renewables receives full short-circuit support, the opportunity is significant. Major manufacturers (GE, Siemens, ABB, etc.) are already positioning - GE Vernova[157]noted that "the synchronous condenser is a key technology to help with grid challenges", highlighting recent orders in Chile and prior installations in Brazil. We expect Brazil, Chile, Mexico, and high-wind smaller countries (Uruguay, Dominican Republic, etc.) to be leading markets for new SC units.

3.3.2.2 Grid-Forming Converters (GFCs) and Battery Energy Storage

Another way to provide inertia and fast frequency response is to deploy battery energy storage systems (BESS) and other inverter-based resources with grid-forming capabilities. These advanced inverters can mimic the behavior of synchronous machines, stabilizing frequency and voltage during disturbances. Grid-forming battery systems are especially valuable in smaller grids and island systems, but larger countries are also beginning to procure them for ancillary services.

[156] *See section 3.1.2.3*
[157] *GE Vernova to supply synchronous condensers equipment to help improve grid stability in Northern Chile, GE Vernova, 2024, [link]*

Industry projections for LAC suggest on the order of 20 GW of battery storage could be installed by 2030[158]. For instance, the Caribbean islands are aggressively pursuing batteries to improve resilience - the World Bank is financing battery projects in Haiti and Belize to help integrate renewables. Several countries (Chile, Brazil, Mexico) have included battery storage in their expansion plans or grid codes.

Given that at 30% penetration of GFC, the benefit from extra GFC capacity significantly diminishes. **A first estimate to market size for GFC-enabled storage is 6 GW.** This includes both large-scale BESS at transmission nodes and smaller units at hybrid wind/solar + BESS plants equipped with grid-forming inverters. Beyond batteries, some of the new solar and wind plants themselves may incorporate grid-forming controls. Even so, achieving reliable 70%+ renewable grids will require dedicated grid-forming capacity.

It's important to highlight that total market size estimates for grid stability solutions will vary significantly across regions and should not be considered additive. **Investments in synchronous condensers and grid-forming converters (GFCs) will compete to provide overlapping services**, meaning that deploying one technology can reduce the need for the other. However, this estimate assumes that a share of planned BESS will be grid-forming and the SCL/inertia needs currently forecasted to be covered by synchronous condensers will not be displaced (and eventually covered by BESS). Moreover, operational improvements—such as enhanced grid management, better dispatch coordination, and dynamic reactive power support—may help reduce the overall need for new infrastructure. Future technologies could also emerge and compete in this space, adding further uncertainty to long-term projections. The potential for battery energy storage systems (BESS) with GFC capabilities to stack revenues by participating in other ancillary services or energy arbitrage adds another layer of complexity.

Determining the optimal mix of solutions is beyond the scope of this analysis, as it depends on country-specific system characteristics, policy frameworks, and market design. These factors will strongly influence which combinations of technologies are most cost-effective and scalable in each context.

3.3.2.3 Dynamic Line Rating (DLR) and Other Advanced Transmission Technology

The market opportunity for DLR is promising as the grids will rapidly become the main bottlenecks for electrifying the countries.

To estimate the potential for DLR in the LAC, **the estimation for Colombia and Chile will be extrapolated.** Broadly speaking, the approach consists in linking the market potential to the

[158] *Announced pledges scenario, Latin America Energy Outlook, IEA, 2023, [link]*

increment of installed capacity (all technologies). This indicator translates the expansion speed of the grid and the increased needs in terms of electricity transit. A ratio between the number of lines that would adopt DLRs and the capacity increment will be computed for the two countries. Leveraging IEA's capacity projections for the LAC, the market size for the region can be derived.

The installed capacities are projected to grow from 521 GW in 2022 to 756 GW in 2030 for the LAC region (taking IEA's Announced Pledges scenario[159]). The capacity increment between 2022 and 2030 is therefore around 235 GW.

The ratio between the DLR potential and the installed capacity increment between 2024 and 2030 for Chile and Colombia are respectively 2.4 and 2.25. Applying these ratios to the LAC region, **the number of lines that would be equipped with DLR is estimated at between 529 and 564 lines.** Therefore, the DLR potential in the LAC region has a range between USD 132 million and USD 141 million for monitoring lines[160], on top of which **USD 30 million can be added for central system expenditure.**

No difference for DLR would be considered between Latin America and the Caribbean region. The primary differences between the former and the latter lie in the system's size and the degree of interconnectedness. These factors are not determining for DLR adoption as the technology deals with individual line's thermal limit. However, some influencing factors can be used to estimate the adoption rate for a specific country:

- DLR has better performance in windy regions, thus the adoption rate would be accordingly higher.
- DLR is valued for its rapidity to provide a near-term solution. The adoption rate would therefore be positively correlated with the expansion rate of the electric system and negatively correlated with the current margins of the grid.
- For DLR being attractive for its cost-effectiveness, the adoption rate would be higher with harder limitations on the capital or on the supply chain.

In addition to DLR, utilities are considering power flow controllers (FACTS devices) to shift loads between circuits. Smart valve technologies (like modular FACTS from Smart Wires Inc.) have been tested in Colombia and Mexico to route power around bottlenecks. Advanced conductors, as noted, can roughly double capacity when reconductoring old lines - these are more expensive per km than DLR but still cheaper than building new routes. If even a quarter of aging lines in LAC are reconductored with high-temperature low-sag (HTLS) or composite-core wires, that could be another multi-billion-dollar market.

[159] Announced pledges scenario, Latin America Energy Outlook, IEA, 2023, [link]

[160] Assuming USD 250 000/line. The archetype is a 50 km line at 220 kV (approximately 6 sensors). The length of the lines shouldn't vary much on average because it would be more interesting to increase the voltage for longer distances. The DLR could also apply to higher voltages, but usually they represent a small portion of the grid (e.g. between 10% -15 % of the total length of the grid at 500 kV for Chile and Colombia). And lower voltages are less interesting for DLR, as the costs are independent of the voltage and the absolute gain in capacity would be smaller. Therefore, the assumption allows to capture the right order of magnitude.

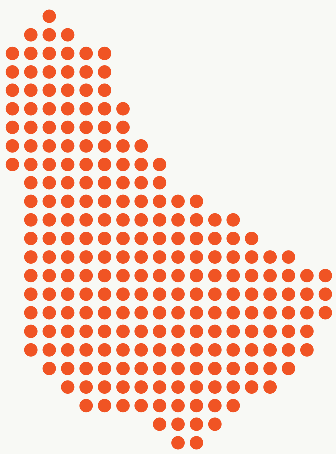
3.3.2.4 Extending Synchronous Condenser Analysis to Small, Isolated Caribbean Island Nations

Small, isolated power systems in the Caribbean face challenges similar to those observed in larger countries like Chile or Colombia. However, their reduced scale and geographical isolation amplify the need for careful management of inertia, short-circuit capacity, and voltage regulation. Many island nations are committing to aggressive renewable energy targets to reduce reliance on imported fuels such as diesel or heavy fuel oil. Because these grids have limited interconnections—often no external tie-lines at all—any deficiency in inertia or reactive power support translates rapidly into reliability risks.

A defining feature of these grids is their heightened vulnerability to contingencies. While a 100 MW loss in a large, 10 GW system represents only a small fraction of total capacity, it can amount to 20% or more of a 500 MW island grid. This disparity can trigger exceptionally steep rates of change of frequency (RoCoF) in smaller systems, which make operational solutions like SPS, RAS, Load Shedding, etc. unfeasible due to voltage collapse or cascading failures before this system can react. In the past, diesel or steam generators provided both inertia and short-circuit current, but as these units retire or remain offline for economic reasons, the grid loses these stabilizing services. Consequently, synchronous condensers (SCs) become valuable because they supply genuine rotating inertia and fault current, thereby limiting frequency deviations and ensuring more reliable protection systems. They also furnish reactive power, helping manage voltage fluctuations that arise with high solar or wind penetration.

The economic calculus for synchronous condensers in smaller island grids can look different from that of larger systems. Because of limited economies of scale, costs per MVAr of capacity are typically higher, yet these costs may be offset by avoided fuel expenses and reduced operating hours for diesel units. Studies conducted on several islands, such as Barbados or Guadeloupe, indicate that once solar and wind penetration surpass a certain threshold, inertia and voltage stability can become critical constraints. If local diesel generators do not remain online, system operators often need alternative sources of inertia and short-circuit support. In that context, synchronous condensers serve as a proven way to maintain stability. For instance, in Barbados, once solar installations approached 120–130 MW, planners began considering a 90 MW hybrid BESS + Synchronous condenser to maintain stability.

The following sections examine the rationale for deploying synchronous condensers on small islands, then present Barbados as a concrete example of how one utility is seeking both technical solutions and regulatory approval to manage these very challenges.



Barbados as a Case Study

A prime illustration of these concepts is found in **Barbados**, where The Barbados Light & Power Company Limited (BLPC) recently submitted an **Application for Preapproval of Investments and Cost Recovery**[161] under the Clean Energy Transition Rider (CETR) mechanism. The CETR, approved by the Fair Trading Commission (FTC) in May 2023, is designed to recover the capital costs needed to support the island's energy transition toward the goals set out in the **Barbados National Energy Policy 2019–2030 (BNEP)**[162], which envisions 100% renewable energy by 2030.

In that Application, BLPC identifies a portfolio of new investments collectively referred to as its first "Clean Energy Transition Plan (CETP) Project." Among them are:

Battery Energy Storage Systems (BESS) (90 MW): These storage units will smooth the variability of intermittent generation, reduce the need for conventional spinning reserves, and manage thermal loading on transmission lines.

Synchronous Condensers (4 units at 20 MVAr each): Citing the projected displacement of conventional synchronous generators, BLPC emphasizes the need for devices that can provide reactive power, short-circuit strength, inertia, and frequency stability. The company's own analyses, as well as the Integrated Resource and Resiliency Plan (IRRP), confirm that multiple synchronous condensers are crucial to maintaining reliable service as solar PV surpasses 100 MW.

Automatic Generation Control (AGC): AGC systems will automatically regulate power output from the remaining thermal units and new storage resources, compensating in real time for fluctuations in solar and wind production.

Distributed Energy Resources Aggregation & Control Platform (a pilot project): This initiative aims to coordinate and monitor numerous small-scale

[161] *BLPC - APPLICATION FOR PREAPPROVAL OF INVESTMENTS AND COST RECOVERY THROUGH THE CETR, Fair Trading Commission, 2023, [link]*
[162] *Barbado National Energy Policy 2019-2030, Ministry of Energy and Water Resources, [link]*

batteries and rooftop PV, treating them as "virtual power plants" for ancillary services. It is especially relevant as Barbados continues to add distributed generation rapidly.

Transmission & Distribution Interconnection Upgrades: As more Independent Power Producers (IPPs) submit proposals, BLPC must expand and reinforce transmission lines, substations, and distribution feeder infrastructure, including conductor upgrades from 336 MCM to 795 MCM in high-demand corridors. Under the FTC's order, part of these network costs are socialized and partially recovered from IPPs.

Figure 3.20: ***Projected Yearly Electricity Generation in Barbados (GWh)*** [163]

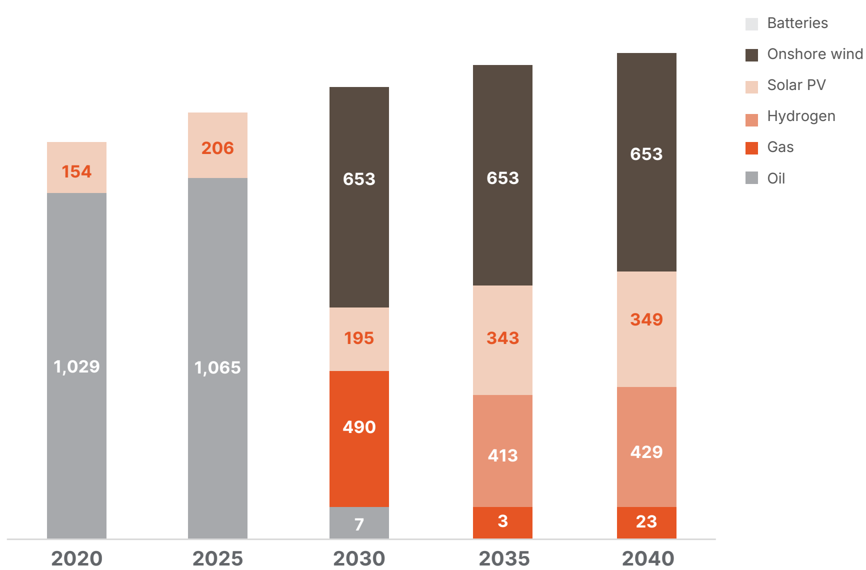
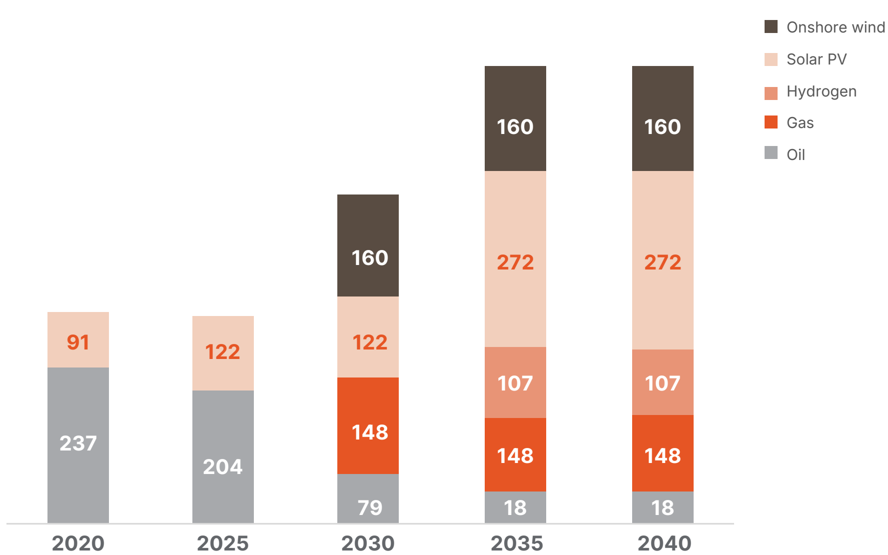
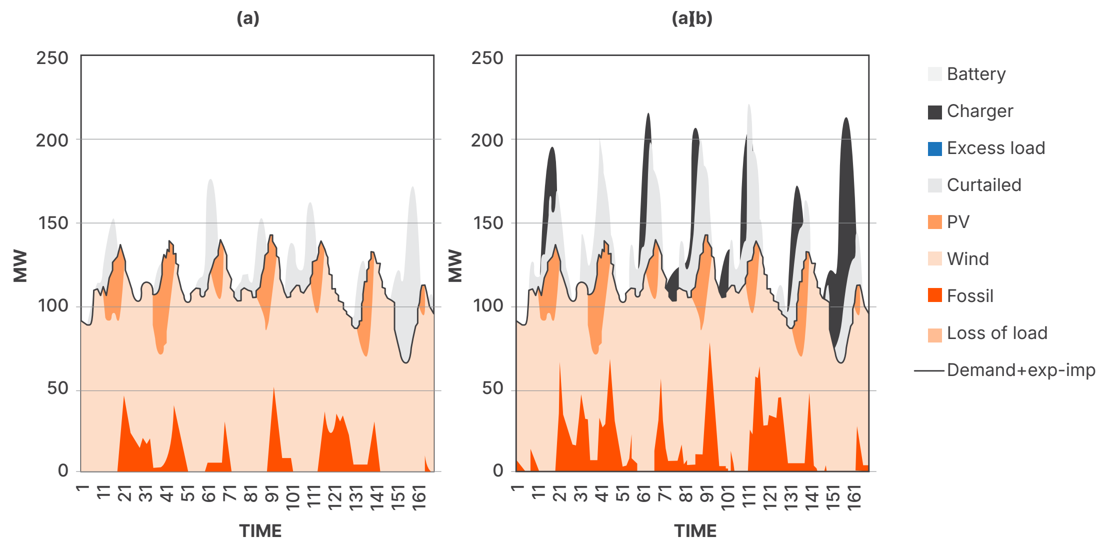


Figure 3.21: ***Projected Installed Generation Capacity (MW)*** [164]



[163] Energy Transition and Investment Plan, Ministry of Energy, [link]
[164] Energy Transition and Investment Plan, Ministry of Energy, [link]

Figure 3.22: ***Power system flexibility analysis in 2030 in Barbados for different scenarios.*** [165]



From the figures above we see roughly a peak IBR based generation of 110 MW and 130 MW. The proposed 80 MVAr of Synchronous Condensers proposed would mean a 0.61-0.72 MVAr/MW of synchronous condenser support for IBR generation. This cost is the double what was estimated from the Chile case study, reflecting the much higher needs for inertia in smaller systems, where maintaining acceptable RoCoF given the possible contingencies is the main bottleneck in stability.

Outcome of the FTC Decision (May 6, 2024)
The Fair Trading Commission approved portions of BLPC's CETP Project 1 but rejected the synchronous condenser component as proposed. The Commission's official Order (Document No. FTCUR/DECCETP1/2024-1) set forth the rationale:

1. Approved (in part):

- Interconnection Infrastructure – Deemed necessary to accommodate Independent Power Producers (IPPs), consistent with the IRRP and enabling high renewable targets.
- 15 MW of the 90 MW BESS – The Commission agreed that battery storage is crucial for mitigating intermittent RE but required BLPC to submit detailed cost-benefit analyses for the remaining capacity.
- Automatic Generation Control (AGC) – Recognized as vital for frequency regulation amid growing solar and wind.
- DER Aggregation & Control Pilot – Endorsed as an initial step to coordinate distributed battery and solar resources.

2. Rejected: Four Synchronous Condensers –

While acknowledging that synchronous condensers can provide critical inertia, fault current, and reactive power, the Commission did not approve BLPC's request for immediate cost recovery. The FTC found that BLPC had not sufficiently examined retrofitting older retiring thermal units into SCs, which could

[165] *Energy Transition and Investment Plan, Ministry of Energy, [link]*
[166] *BLPC - APPLICATION FOR PREAPPROVAL OF INVESTMENTS AND COST RECOVERY THROUGH THE CETR, Fair Trading Commission, 2024, [link]*

be more cost-effective than procuring brand-new synchronous condenser equipment. The Commission thus withheld approval pending further evidence of cost-effectiveness and a thorough assessment of retrofit alternatives.

3. Why the Application for SCs Was Not Approved

Despite the IRRP's recommendation for synchronous condensers, the Commission concluded that BLPC must demonstrate it has considered more economical options (e.g., converting existing retired diesel generators to SCO duty). New SCs can cost USD 300,000 – USD 400,000 per MVAr, whereas retrofits can sometimes be done more cheaply if the mechanical condition of the old generator remains sound. Because BLPC's application did not submit a robust cost-benefit analysis comparing new units vs. repurposing old ones, the Commission was unwilling to authorize cost recovery for the full USD 50+ million SC proposal.

4. Broader Implications

For Caribbean islands generally:

SCs Remain a Key Technology The Commission's decision does not dispute the technical importance of synchronous condensers; it simply underscores the need for cost-effectiveness and thorough exploration of alternatives. Any future SC project—whether new or retrofitted—will likely be judged on similar grounds.

Cost Recovery Mechanisms Barbados's CETR mechanism is similar to a tracker for large capital investments that exceed normal utility expenditures. It expedites recovery (reducing regulatory lag) but demands rigorous scrutiny. In smaller islands, such riders or alternative regulation may also emerge as the pace of solar and wind expansions forces urgent grid-support investments.

Retrofit vs. New Many Caribbean islands have older diesel or steam units that might be suitable for conversion to SCs. That approach can save money if the generator frames, rotors, and auxiliaries remain structurally sound. Regulators will likely ask for such analysis moving forward. A key thing to consider, is that from what was examined in the Chile tender, where retrofits were taken into account, is that one of the main disadvantages of these systems was their distance from the need for SCL support. In the islands case, this is much likelier to be a minor issue, since the distances are smaller. On the other hand, inertia need doesn´t get derated due to electrical distance to nodes since it is provided at system level. Retrofits are likely more cost-efficient solutions than new SCs.

Complementarity With BESS Even in places that do eventually proceed with SCs, battery storage will remain critical for fast response and energy shifting. The synergy between SCs (for inertia and fault current) and BESS (for fast frequency response and load shifting) is often the backbone of a high-RE island grid.

5. Conclusion: Lessons for Other Islands

Synchronous condensers are frequently highlighted as a **key element** for small grids transitioning to high shares of renewable energy. They address the inherent shortfall of inverter-based generators (limited fault current, no inherent inertia) and help keep voltage and frequency within safe limits. But, as the **Barbados Fair Trading Commission** illustrated, **justifying the cost** of new synchronous condensers requires:

1. A **detailed cost-benefit study** comparing retrofits vs. new builds.
2. Consideration of how other technologies (e.g., grid-forming batteries, STATCOMs) might meet or partly meet the same needs.
3. Clear evidence that the solution is the most economical for customers, especially when financed through a special rider that passes costs on quickly.

Until such a thorough analysis is provided, regulators may **deny or defer** approval for SC projects to protect ratepayers from unnecessarily high capital expenses. By contrast, smaller or differently structured proposals—like partial BESS capacity, pilot control systems, or incremental grid upgrades—can proceed if their costs are shown to be prudent, timely, and essential for near-term reliability.

In short, **Caribbean islands do need synchronous condensers or equivalent "grid-strength" measures** as they approach high renewable penetration. However, the Barbados example shows that **regulatory bodies will scrutinize cost-effectiveness.** Proponents of SCs must provide robust support for why new synchronous condensers, as opposed to alternative or hybrid solutions, best balance reliability goals with consumer protections.

3.4 Summary *table*

Table 23: ***Summary of the market potential estimates for Chile, Colombia and the LAC region***

<table>
<tr><th></th><th colspan="2">Chile</th><th colspan="2">Colombia</th><th colspan="4">LAC</th></tr>
<tr><td>Year</td><td>2024</td><td>2030</td><td>2024</td><td>2030</td><td>2022</td><td colspan="3">2030</td></tr>
<tr><td>Total capacity (GW)</td><td>37</td><td>52</td><td>25.7</td><td>37.9</td><td>521</td><td colspan="3">756</td></tr>
<tr><td>Solar and Wind capacity (GW)</td><td>17</td><td>32.8</td><td>6.1</td><td>16.2</td><td>86</td><td colspan="3">279</td></tr>
<tr><td>Wind (GW)</td><td>5.5</td><td>18</td><td>0.6</td><td>2.4</td><td>41</td><td colspan="3">104</td></tr>
<tr><td>Solar (GW)</td><td>11.5</td><td>14.8</td><td>5.5</td><td>13.8</td><td>45</td><td colspan="3">175</td></tr>
<tr><td rowspan="2">Synchronous Condensers Market potential ([MVAr] [USD])</td><td rowspan="2">/</td><td rowspan="2">2 - 4 GVAr
USD 600 M – 1200 M</td><td rowspan="2">/</td><td rowspan="2">2.7-3.9GVAr
USD 810 M - 1170 M</td><td rowspan="2">/</td><td>30% of IBR need support from SCs</td><td>60% of IBR need support from SCs</td><td>100% of IBR need support from SCs</td></tr>
<tr><td>25.1 GVAr
USD 7 500 M</td><td>50.2 GVAr
USD 15 000 M</td><td>83.7 GVAr
USD 25 110 M</td></tr>
<tr><td>DLR market potential ([number of lines] [USD])</td><td>/</td><td>36 lines
USD 12 M</td><td>/</td><td>27 lines
USD 10 M</td><td>/</td><td colspan="3">529 - 564 lines
USD 162 M - 171M</td></tr>
</table>

[167] *LAC SC needs = 0.3 * Solar and Wind Capacity = 0.3 * 279 = 83.7 GVAr*
*Investment cost = LAC SC needs * USD 300M/GVAr*

04

Regulatory Barriers and ways to unlock them

This section describes the regulatory framework regarding GETs for Chile, Colombia and the Dominican Republic. Following these descriptions, reviews are made on the current barriers for developing GETs. In a last part, based on the previous analyses and on the case studies displayed in Section 2 Technological Analysis of GETs, recommendations are provided for fostering GETs adoption in a beneficial for all approach.

4.1 Colombian Electricity *Transmission Regulatory Landscape*

The regulation of electricity transmission in Colombia follows a structured approach designed to ensure the reliability, efficiency, and financial sustainability of the grid. As a natural monopoly, transmission is subject to strict regulatory oversight, balancing the need for private investment with mechanisms that prevent excessive costs and ensure service quality. The current regulatory framework integrates centralized planning, competitive procurement, and cost-based remuneration, with specific rules governing tariff structures, investment recovery, and service obligations. However, the framework has yet to fully incorporate incentives for new technologies, such as Grid-Enhancing Technologies (GETs), that could improve grid efficiency, reliability and reduce operational costs.

This section examines the legal and institutional framework governing transmission, the regulatory mechanisms shaping market operations, and the challenges and opportunities associated with adopting advanced technologies within the existing regulatory structure.

4.1.1 Overview of the Colombian electricity sector, responsibilities and entities.

Colombia's electricity transmission sector operates under a regulated monopoly model where both private and public entities can own and operate assets under regulatory oversigh[168]. The framework prioritizes cost efficiency, system reliability, and long-term investment security through centralized planning.

Regulatory oversight is primarily carried out by the Energy and Gas Regulatory Commission (CREG), which sets tariff methodologies, access rules, and service quality standards. The Mining and Energy Planning Unit (UPME) is responsible for transmission expansion planning, as well as organizing and managing the competitive bidding process for new transmission infrastructure projects. XM, as the system operator, ensures real-time grid operation and market administration, while the Superintendencia de Servicios Públicos Domiciliarios (SSPD) oversees compliance and enforcement of service quality regulations.

The legal framework mandates that transmission expansion be centrally planned and awarded through competitive processes. This approach aims to promote cost efficiency and ensure that investment decisions align with national energy policies. However, it has been acknowledged that the rigid nature of this structure may limit flexibility in adopting emerging technologies that could enhance grid performance.

The tables below provide a summary of the principles governing the planning and the operation of the electric system (left) as well as the involved institutions and their responsibilities (right).

---

[168] Companies participating in transmission may be public, mixed, or private, depending on the origin and share of their capital (Law 142/94, Art. 14). They must be incorporated as joint-stock companies and are subject to both commercial and public utilities regulations.

Table 24: ***Summary of the governing principals for the electric system (left) and the involved institutions with their responsibilities (right)***

Legislation	Description
Article 365 of the Constitution	Declares electricity as a public service that must be delivered under efficiency, quality, and coverage principles.
Law 142 of 1994 (Public Services Law)	Establishes the legal basis for private participation in public services, ensuring transparency in regulation and competition where feasible.
Law 143 of 1994 (Electricity Law)	Introduces a competitive electricity market model and mandates the separation of generation, transmission, distribution, and commercialization activities.
Decree 2253 of 1994	Defines CREG's role as the primary regulatory authority responsible for setting tariffs, service quality standards, and market rules.

Institution	Responsibilities
Ministry of Mines and Energy (MME)	Establishes sector policies and long-term strategies.
Energy and Gas Regulatory Commission (CREG)	Defines transmission tariff methodologies, access conditions, investment recovery mechanisms, and service quality regulations.
Mining and Energy Planning Unit (UPME)	Conducts long-term transmission planning and administers competitive tenders for new infrastructure projects.
XM (Market Operator & System Operator)	Operates the national grid, ensures real-time system reliability, and administers wholesale electricity transactions.
Superintendence of Public Utilities (SSPD)	Monitors regulatory compliance and enforces penalties for non-compliance.

4.1.2 Transmission Market Structure and Expansion Planning

Colombia's electricity transmission sector is structured as a regulated monopoly, where both private and public entities can own and operate assets under long-term concessions. While ownership is open to private investors, all expansion and operation decisions are subject to regulatory approval. New transmission projects are identified through the National Transmission Expansion Plan (PENT), which is updated periodically by UPME based on demand forecasts, grid stability requirements, and renewable energy integration targets.

The expansion process follows a competitive bidding mechanism, where transmission companies compete for long-term concessions awarded by UPME. Winning bidders commit to developing, operating, and maintaining transmission assets in exchange for a regulated revenue stream determined by CREG. This revenue is based on the expected cost of investment and operational expenses, ensuring that transmission companies recover their costs while maintaining efficiency incentives.

Despite the structured approach to expansion planning, challenges remain in the permitting process, social and environmental licensing, and the technological flexibility of the bidding process. The current system prioritizes traditional infrastructure solutions over alternative approaches considering innovative technologies, such as GETs, that could provide cost-effective and scalable solutions to transmission congestion and reliability challenges.

Snapshot from the interviews conducted:

1. Colombia faces strong delays to develop new grids (over 10 years). It affects its renewable energy development, especially in the Caribbean region where several offshore wind projects are queuing to be connected to the grid.

2. To unlock the situation, UPME is very keen to develop new grid technologies. However, the regulation is rigid and prevents UPME for taking into account GETs in their long-term planning.

3. To put pressure on CREG, UPME developed a reinforcement plan with the needed GETs: over the 98 projects forecasted in this plan, only 19 are currently aligned with the regulation.

4. More broadly speaking, UPME regrets a lack of skills and human resources to follow up correctly with the grid development.

4.1.3 Current Mechanisms

Regulatory compensation for electricity transmission assets in Colombia follows two main paths:

1. Competitive Tenders for new expansion projects (greenfield assets) awarded via public bidding.

2. Standard Regulatory Mechanisms for: Legacy assets (in operation prior to new tender mechanisms), assets whose public-tender contracts have expired and regulator-approved reinforcements or modernizations (when work to be done is performed by a transmission operator on their own assets). Under this standard framework, operators are remunerated via: Replacement Cost of Electric Assets (CRE for Costo de Reposición de los Activos Eléctricos), Administration, Operation, and Maintenance (AOM) and Service Quality Adjustments.

The following sections detail each mechanism.

Competitive Tenders for New Expansion Projects

When the regulator (in coordination with the planning authorities) identifies a new transmission expansion need, it launches a public tender (convocatoria pública). These tenders define the project scope—dimensions, location, technology, capacity, timelines, and other technical specifications—so that bidders can propose a Yearly Expected Revenue (Ingreso Anual Esperado or IAE).

Key features:

- The winning bidder's IAE forms the basis for monthly payments, which are indexed to the Producer Price Index (IPP).

- Payments start the month after commercial operation (as certified by the National Dispatch Center, CND).
- Underperformance or poor availability may trigger payment reductions (depending on particular terms of each tendering process).
- Once the tender payment period ends (from 20 to 25 years), the asset's remuneration transitions to the standard regulatory framework (explained in the next section).

Aspect	Description
Applicable Assets	New expansions awarded via public tender (greenfield projects).
Remuneration Basis	IAE (Yearly Expected Revenue) bid by the winning participant.
Payment Adjustments	Adjusted by IPP; subject to penalties for performance shortfalls (availability targets).
Post-Tender Transition	After the tender contract expires, assets move to CRE + AOM + Service Quality remuneration.

Standard Regulatory Framework

After a public-tender contract expires—or for assets not originally built via competitive tenders (legacy assets), as well as regulator-approved reinforcements or modernizations—remuneration is governed by:

- Replacement Cost of Electric Assets (CRE)
- Administration, Operation, and Maintenance (AOM)
- Service Quality Adjustments

Replacement Cost of Electric Assets (CRE)

Under **Resolution CREG 011 of 2009**, "CRE" (Costo de Reposición de los Activos Eléctricos) represents the recognized value of a transmission operator's assets in the National Transmission System (STN). **Definition of Unidades Constructivas (UC)** – Each transmission asset is broken into standardized UC types (lines, substations, transformers, compensation equipment, control centers, etc.). **Standard Cost Tables** – Resolution 011 publishes official cost tables for each UC, expressed in thousands of December 2008 pesos.

$$CRE_j = \sum_{i=1}^{UR_j} (NUC_i \times CU_i \times PU_{j,i})$$

Where:
CRE_j is the total **Replacement Cost** of the operator j's electric assets (in December 2008 pesos).
UR_j is the total count of **Unidades Constructivas** (UC) reported by operator j.
NUC_i is the number of units of UC type i.
CU_i is the cost unit (in pesos) of UC type i, defined by the regulator in the resolution's tables.
PU_{j,i} is the percentage of UC type i that belongs to (and is operated by) the given transmission operator j.
Assets part of Competitive tenders that are still being remunerated through the tender mechanism must be excluded from the calculation of the asset base of transmission operators.

The CRE approach is designed to reflect the cost of replacing existing transmission assets with equivalents that meet or exceed current technical standards. This methodology covers all STN assets not constructed under the free-concurrency ("public tender") process or remunerated through other agreements.

It also establishes how to handle multi-owner situations and expansions that do not fall under tendered rules. The corresponding operator's annual revenue (Ingreso Anual) for these assets is then computed:

- Multiplies the quantity of each UC by its unit cost
- Accounts for partial ownership shares and any portion excluded from the tariff
- Annualizes the resulting cost by applying a capital-recovery factor over the recognized asset lifetime at the regulated return rate.

Key Points from Resolution 011 of 2009

Annual Revenue Calculation – Combines the cost of UCs, recognized AOM, land/servitudes, and performance-based adjustments to form a regulated annual income.

Quality Incentives – Ties part of the monthly remuneration to service availability (quality metrics).

Administration, Operation, and Maintenance (AOM)

AOM covers the ongoing expenses to administer, operate, and maintain the STN. The regulator recognizes these costs annually, subject to audits and specific exclusions.

Recognized AOM Calculation

$$V\ AOM_j = CRE_j \times PAOMR_j$$

CRE_j : Replacement Cost of Electric Assets for operator j.
PAOMR_j: The AOM percentage recognized for operator j.

Exclusions

Certain expenses are not recoverable, such as:

- Costs for **tendered** (public-bid) assets under current contracts
- Connection assets or non-transmission activities
- Services to third parties
- Depreciation, or any cost unrelated to actual AOM of STN infrastructure

Annual Adjustment

The recognized AOM percentage is updated each year to reflect actual spending. If an operator does not submit the required AOM information or provides inconsistent data, the recognized AOM percentage is automatically penalized (reduced by 0.5%).

AOM Summary Table

Itemt	Description
Formula	VAOM_j = CRE_j*PAOMR_j
Annual Adjustment	PAOMR_{j,a} = PAOMR_{j,a-1} + 0.5* (AOMD_{j,a-1} - PAOMR_{j,a-1}) If costs are reduced, TO gets remunerated for its yearly costs plus half of the savings. If costs increase, TO gets remunerated for its yearly costs minus half of the cost increase.
Excluded Costs	- Active tendered assets - Connection or non-transmission costs - Depreciation or unrelated expenses - Services to third parties
Non-Compliance Penalty	0.5% reduction of recognized PAOMR if data is missing or inconsistent

Service Quality Adjustments

To drive reliability and availability, operators face penalties if their performance falls short of mandated standards. These adjustments tie remuneration to key indicators:

1. Hours of Indisposition (HI) – Measures total asset downtime.
2. Energy Not Supplied (ENS) – Quantifies demand unserved (MWh) due to outages.

If the operator exceeds the allowed limits for HI and/or ENS, monthly compensation (Ingreso Mensual) is reduced. Resolution 011 of 2009 details formulas for:

- Maximum annual hours of indisposition allowed for each type of UC
- IPP indexing for monthly calculations
- Steps to exclude certain events (e.g., force majeure or terror attacks) under strict conditions
- Compensation Caps to ensure penalties do not exceed a percentage of total yearly revenue.

Aspect	Description
KPI 1: HI (Hours)	Cumulative downtime for each asset, monitored via monthly and annual thresholds.
KPI 2: ENS (MWh)	MWh not delivered to end users; if >2% of forecast demand, triggers formal investigation (SSPD reviews).
Penalties	Deduct from monthly revenue if either HI or ENS exceeds regulatory benchmarks.
Exclusions	Certain events (e.g., catastrophic natural disasters, terrorism) may be excluded up to defined durations, with partial remuneration during repair
Capping Mechanism	Penalties cannot exceed specific percentages of annual regulated income (to prevent total revenue collapse).

4.2 Chilean Electricity Transmission *Regulatory Landscape*

4.2.1 Overview of the Chilean Electricity Sector, Responsibilities, and Entities

Chile's electric transmission framework is rooted in a consolidated legal regime that treats transmission as a critical, open-access service. As a natural monopoly, it remains under close regulatory oversight while encouraging private investment via competitive procurement. Modern legislation—most notably Law No. 20.936 of 2016—reshaped the sector by introducing an independent system operator (Coordinador Eléctrico Nacional) and revising cost allocation methods. While Chile's regulations methodically plan for expansion and tariff-setting, the adoption of emerging Grid-Enhancing Technologies (GETs) is still evolving. Regulatory provisions do not explicitly prohibit advanced solutions like dynamic line ratings or power flow controllers; however, clearer incentives and planning criteria are needed to mainstream their use.

This section examines the legal and institutional foundations of Chile's transmission sector, the market structure that governs expansion, and how the current regulations enable—yet also challenge—the adoption of innovative transmission technologies.

Chile's electricity transmission sector is governed by the Ley General de Servicios Eléctricos (LGSE, DFL No. 4/2006, as amended) and subsequent decrees. Key responsibilities are split among:

Ministry of Energy (MINENERGÍA): Establishes national energy policy, conducts 30-year Long-Term Energy Planning (Planificación Energética de Largo Plazo, or PELP) at least every five years, and defines transmission corridors of public interest. Through decrees (e.g., DS 134/2017, DS 139/2017), the Ministry sets out planning processes, corridor designation, and strategic directives for transmission development.

Comisión Nacional de Energía (CNE): Serves as Chile's technical regulatory body, overseeing annual transmission expansion planning (with a 20-year outlook), setting regulated tariffs, and defining cost-allocation methodologies (including valuations under DS 10/2020). The CNE ensures expansions and pricing reflect efficiency, competition, and reliability goals.

Coordinador Eléctrico Nacional (Coordinator): The independent system operator, responsible for real-time grid operation, open-access administration, and least-cost dispatch. Created by Law 20.936, the Coordinador also proposes expansion projects to the CNE each year and manages competitive tenders for building new transmission facilities once these projects are officially approved.

Superintendencia de Electricidad y Combustibles (SEC): The supervisory authority that enforces compliance with technical standards, safety, and construction norms. It oversees concession grants for new transmission lines, can sanction noncompliance, and ensures operators meet quality-of-service requirements.

Panel de Expertos: A specialized dispute-resolution body with quasi-judicial powers. It addresses conflicts over regulation, tariff calculations, expansion planning decisions, or operational disputes. Its rulings are binding, subject to limited judicial review, thereby ensuring prompt resolution of sector disagreements.

4.2.2 Transmission Market Structure and Expansion Planning

Regulated Monopoly with Competitive Asset Development

Chile's transmission assets remain under a regulated monopoly structure. However, the framework promotes competition in **ownership and construction** through open tenders for new projects. Both local and international investors can bid on expansions, reducing the risk of monopoly rents.

Centralized Planning: Ministry and CNE

Long-Term Energy Scenarios (PELP) — Ministry of Energy

Under DS 134/2017, the Ministry leads a 30-year scenario-based planning exercise at least every five years. These scenarios project demand growth, renewable "development poles," and policy objectives, forming the strategic vision for the grid.

Annual Transmission Expansion Plan — CNE

Each year, the CNE (with technical input from the Coordinador) conducts a 20-year forward-looking study to determine which new lines or substation upgrades are needed in the National and Zonal systems. Public consultation—where generators, transmission companies, consumers, and other stakeholders can propose or comment on projects—ensures transparency. Ultimately, the CNE finalizes an expansion plan, which is approved via ministerial decree.

Corridor Definition and Environmental Assessments

For major new lines, DS 139/2017 outlines "Preliminary Transmission Corridors" (franjas) to identify routes of public interest and streamline permitting. The Ministry's corridor studies include a Strategic Environmental Assessment and indigenous consultations. Once corridors are set, a decree formalizes the projects that move to tender.

4.2.3 Current Mechanisms

Chile's regulatory system provides two primary paths for remunerating transmission infrastructure:

1. Competitive Tenders for new (greenfield) assets.
2. Standard Regulatory Mechanisms under DS 10/2020 for existing and upgraded facilities once concession contracts expire—or if the upgrade is inherently tied to an incumbent asset.

Competitive Tenders for New Expansion Projects

When new projects are identified in the expansion plan:

Public Tender: The Coordinador Eléctrico Nacional organizes open, international bids. Technical specifications (capacity, voltage level, route corridor, timelines) are defined in the tender documents.

Award Criteria: Bidders typically compete on the lowest annual revenue required, ensuring cost efficiency. The winner is granted a long-term concession to build, own, and operate the asset, receiving a regulated income.

In-Service and Penalties: Once the project is completed and interconnected, the concessionaire starts collecting its annual tariff. Delays or noncompliance can trigger penalties or, ultimately, re-bidding.

Transition: After the tender's term, the asset may be integrated into the broader regulatory structure for tariff updates (similar to revaluation under DS 10/2020).

Aspect	Description
Applicable Assets	Greenfield projects identified in the annual expansion plan (National or Zonal).
Remuneration Basis	Lowest annual revenue requirement (or cost) bid by concessionaire.
Contract Indexation	Typically aligned with inflation or price indices, set in the tender terms.
Performance Penalties	Availability or completion delays can reduce payments or terminate concessions.
Post-Tender Transition	Concession eventually shifts to the standard framework, with revaluation studies.

This process has successfully attracted private and international investment, promoting timely, cost-competitive infrastructure while preserving open access and system security.

Standard Regulatory Framework

For assets not covered by active tender-based remuneration—or when upgrading existing lines—Chile uses the remuneration regime detailed in DS 10/2020. This decree implements the LGSE's directives on classification, valuation, and tariff calculation for transmission facilities.

Valuation of Transmission Assets

Classification: Each asset is deemed part of the National, Zonal, or Dedicated system, influencing how costs are shared among users.

Valorización (Valuation Studies): The CNE periodically conducts studies to determine an asset's new replacement value using standardized reference costs.

Annual Value of Investment (AVI): From the replacement cost, the regulator calculates a capital recovery plus return on investment (WACC). This forms the basis of yearly remuneration.

Under DS 10/2020, expansions that were initially tendered can later be revalued at the next tariff review. If a project was self-funded by an incumbent operator (e.g., substation reinforcement), the CNE examines the cost for efficiency before adding it to the regulated asset base.

Administration, Operation, and Maintenance (AOM)

Operation and maintenance expenses are recognized as part of the annual tariff. Transmission companies must submit cost data to the CNE, which validates and approves prudent O&M.

Adjustment Mechanisms: While the Chilean framework does not precisely mimic a "shared savings" formula, periodic reviews ensure that if companies underspend or overspend relative to approved benchmarks, future allowances may be adjusted.

Excluded Costs: Non-transmission activities, services to third parties, or items already covered under tender contracts are excluded from these O&M calculations.

Service Quality Adjustments

Chile's regulations tie part of a transmission company's remuneration to reliability and availability performance:

Penalties for Downtime: Companies face reduced revenues if assets exceed allowed outages or fail to meet operating standards.

Compensation to Users: Since Law 20.936, consumers may receive direct compensation for supply interruptions caused by transmission deficiencies.

Coordinator Oversight: The Coordinador Eléctrico Nacional continuously monitors asset performance; significant deviations can trigger investigations or fines from the SEC.

While there is no one-to-one equivalent of "Hours of Indisposition" or "ENS" from other jurisdictions, the principle is similar: higher-than-allowed outages result in financial consequences, ensuring operators maintain reliability.

4.2.4 Special Mechanism for Urgent Transmission Expansion – Article 102 of the Law

The Chilean regulatory framework allows for an alternative expansion mechanism under Article 102 of the General Law of Electric Services (LGSE), which enables urgent transmission expansion projects outside the regular planning process.
This mechanism is only applicable when a transmission expansion project is deemed necessary and urgent but was not included in the centralized transmission planning process (Article 87 of the Law).
The CNE must authorize the project, based on a justified report from the Independent System Operator (Coordinador), which confirms the need and urgency of the project.

Process for Approval of an Article 102 Project:

1. Submission of a Justified Report

- The interested company must submit a detailed report justifying:
  - The necessity and urgency of the project.
  - Why it was not included in the regular planning process.
  - The expected impact on the security and reliability of the system.

2. Notification to Affected Transmission Owners

- The Coordinador must inform current asset owners about the proposed project within three business days.

3.Observations and Industry Feedback

- Asset owners have 10 business days to submit their comments and concerns.

4. Evaluation by the Coordinador

- The Coordinador has 30 business days to approve or reject the project.
- If additional technical information is required, the Coordinador may request further details.

5. Final Approval by the CNE

- The CNE reviews the Coordinador's decision and has 30 business days to approve or reject the project.
- If approved, the CNE sets construction deadlines, operational timelines, and guarantees for compliance.

Financial Considerations for Article 102 Projects

- If an Article 102 project is approved, the transmission asset is classified into the appropriate system segment (National, Zonal, or Dedicated Transmission).
- The project will be remunerated accordingly, ensuring cost recovery for the investor.

This process is critical as it enables market participants to promote new investments, thereby overcoming potential regulatory barriers associated with centralized planning. Such an approach aligns with cutting-edge practices adopted in other parts of the world, including regions like New York. Furthermore, it is consistent with established academic frameworks for effective transmission investment[169].

4.3 Dominican Republic Electricity *Transmission Regulatory Landscape*

4.3.1 Overview of the Dominican Republic Electricity Sector

The electricity sector in the Dominican Republic operates under a legal framework established by the Ley General de Electricidad No. 125-01, amended by Ley No. 186-07. This law regulates the generation, transmission, distribution, and retail of electricity in the country, ensuring a structured and competitive environment while maintaining regulatory oversight.

The sector's key regulatory and operational institutions include:

Superintendencia de Electricidad (SIE):
The SIE is the primary regulatory body responsible for overseeing electricity tariffs, service quality, and compliance with legal and technical standards. It also establishes mechanisms for cost recovery in transmission and distribution.

[169] *See: Strbac, G., Pollitt, M., Konstantinidis, C. V., Konstantelos, I., Moreno, R., Newbery, D., & Green, R. (2014). Electricity transmission arrangements in Great Britain: Time for change? Energy Policy, 73, 298-311*

Comisión Nacional de Energía (CNE): The CNE is tasked with formulating and executing national energy policies. It oversees the long-term planning of energy infrastructure and ensures alignment with the country's economic and environmental objectives.

Coordinating Body (Organismo Coordinador): This entity operates the Mercado Eléctrico Mayorista (MEM), managing electricity dispatch and ensuring the economic efficiency of generation and transmission operations.

Empresa de Transmisión Eléctrica Dominicana (ETED): ETED is the state-owned entity responsible for managing and operating the high-voltage transmission network. It plays a crucial role in maintaining system reliability and expanding transmission capacity to meet demand.

The Sistema Eléctrico Nacional Interconectado is the backbone of the national grid, integrating generation, transmission, and distribution infrastructure. The CNE and SIE ensure that transmission services operate within a regulated framework that balances efficiency, competition, and consumer protection.

4.3.2 Transmission Market Structure and Expansion Planning

The electricity transmission market in the Dominican Republic is characterized by a monopolistic, state-controlled model, with ETED serving as the exclusive operator of the national transmission grid. The market structure is based on the following principles:

Sole Operator Model: ETED holds complete control over high-voltage transmission lines, substations, and interconnections, ensuring a centralized approach to system planning, investment, and operation. The law explicitly states that the transmission function cannot be privatized.

Limited Private Participation: While private entities may construct transmission lines to connect their generation plants or large consumption centers to the grid, these assets are usually transferred back to ETED after commissioning. This transfer process is regulated through agreements that establish technical and financial conditions.

Expansion Planning and Investment: The expansion of transmission infrastructure follows a regulated planning process, led by ETED in coordination with the CNE and Organismo Coordinador. Expansion projects prioritize grid stability, loss reduction, and increased capacity to integrate renewable energy sources.

Revenue Structure: ETED's cost recovery is based on two primary fees:

- Derecho de Uso: A regulated fee for accessing the transmission network.
- Derecho de Conexión: A fee covering the costs of new connections to the grid.
- These fees are regulated by the SIE and are intended to cover ETED's operational, maintenance, and investment costs.

4.3.3 Current Mechanisms

The Dominican Republic's transmission system operates under a **centralized regulatory framework**, focusing on system reliability, cost recovery, and expansion. The key regulatory mechanisms include:

Centralized Asset Ownership

- ETED is the exclusive owner of high-voltage transmission assets.
- Private investments in transmission infrastructure are restricted to specific projects, with ownership reverting to ETED.

Cost Recovery and Tariff Mechanisms

The total remuneration for transmission is calculated by determining the overall long-term cost of the transmission system and then "splitting" that cost between the two tariff components—the right of use (derecho de uso) and the right of connection (derecho de conexión). In practice, the process works as follows:

1. Determination of the Base Cost:

- The starting point is to calculate the total long-term cost of the transmission system. This cost is the sum of the annualized investment—computed using the "Valor Nuevo de Reemplazo" (VNR), which is the new replacement cost of the assets, multiplied by a capital recovery factor (taking into account a typical useful life of 30 years and an opportunity cost rate)—plus the annual operation and maintenance (O&M) expenses.

2. Splitting into Two Components:

- The total transmission toll (peaje de transmisión) is defined as the sum of the two rights:

$$PT = DU + DC$$

where:
DU (Derecho de Uso): Represents the remuneration for the use of the transmission facilities (essentially covering the O&M costs and part of the investment recovery), and
DC (Derecho de Conexión): Represents the residual component, calculated as the difference between the total annual cost and the estimated "derecho de uso."

3. Setting the Base Value:

- A base value is established for the transmission toll based on the assets that were in service at a specific reference date. For example, in this resolution the base value for December 2016 is set at USD134 million per year, which translates into a monthly toll of roughly USD 11 million.

4. Indexation and Adjustment Mechanism:

- **Monthly Updating:** The monthly transmission toll is not fixed; it is adjusted using an indexation formula. This formula uses several economic indices such as:
  - U.S. Producer Price Indices (PPI) for specific groups (e.g. communication wires, iron and steel, transformers, etc.)
  - The U.S. Consumer Price Index (or the local Dominican CPI)
  - The exchange rate between the U.S. dollar and Dominican peso
- **Adjustment Cap:** The adjustment factor is designed to reflect changes in the costs of materials, labor, and other expenses but is capped to a maximum of a 2% increase per month to prevent abrupt variations.
- **Conversion to Local Currency:** Once the adjusted value is computed in U.S. dollars, it is converted to Dominican pesos using the average exchange rate of the previous month.

5. Periodic Reassessment:

- In addition to the monthly indexation, the methodology for calculating the toll—including the components of investment, O&M, and the related indices—is re-evaluated every four years. This periodic review ensures that the toll reflects both updated cost information and any structural changes in the transmission system.

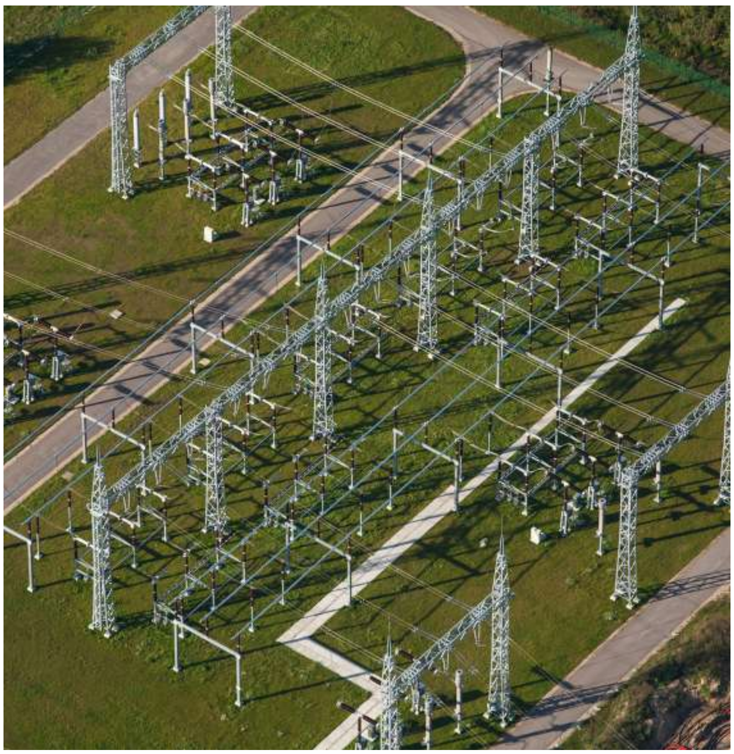
Reliability and Service Quality Requirements

- ETED must ensure uninterrupted electricity transmission under normal and emergency conditions.
- The Reglamento para la Aplicación de la Ley General de Electricidad (Decree 555-02) outlines minimum service quality standards, but lacks specific performance-based incentives for improving reliability.
- Key regulatory articles (149, 150, 156) mandate that ETED must prevent blackouts, but do not impose penalties for failures such as high system congestion or prolonged outages.
- Unlike some international models, there are no explicit financial penalties or incentives based on:
  - ENS (Energy Not Supplied)
  - HI (Hours of Indisposition)
  - Real-time congestion management

ETED has authority over real-time grid operations, including:

- Forced dispatch of generation
- Voltage regulation actions
- Load shedding under emergency conditions

The regulatory framework mandates contingency planning, but does not establish penalties for high operational costs associated with emergency measures.



4.4 Recap of the regulatory *barriers in LAC*

4.4.1 Colombia

Planning

Centralized Planning: The Mining and Energy Planning Unit (UPME) leads the National Transmission Expansion Plan (PENT), identifying new projects to meet demand and reliability needs.

Competitive Bidding: Expansion projects are awarded via public tenders; winning bidders develop and operate assets under concession contracts.

Remuneration

Competitive Tenders: Operators receive a Yearly Expected Revenue (IAE) that they bid for new (greenfield) projects. After the tender period ends, assets move to the “standard” regime.

- **Standard Regime:**

- **Replacement Cost (CRE):** The asset base is valued using regulator-published standard costs.

- **Administration, Operation, and Maintenance (AOM):** Operators recover ongoing expenses, with partial cost-sharing incentives.
- **Service Quality Adjustments:** Penalties or bonuses apply based on availability (Hours of Indisposition – HI) and unserved demand (Energy Not Supplied – ENS).

Colombian snapshot

Centralized planning + competitive tenders for new assets. Once contract periods end, assets are paid for via replacement-cost valuation, AOM coverage, and service quality incentives/ penalties.

4.4.2 Chile

Planning

Centralized planning: Ministry of Energy forms the strategic vision for the grid through its 30-year scenario-based planning (PELP); on a yearly basis, CNE publishes Annual Transmission Expansion plan to identify the needs.

Competitive tenders: Expansion projects are awarded via public tenders; winning bidders develop and operate assets under concession contracts.

Article 102 (Urgent Projects): A special mechanism for fast-track approval/remuneration when immediate upgrades are needed outside the regular cycle.

Remuneration

Competitive tenders: bid winners receive an annual revenue that they bid for new (greenfield) projects. After the tender period ends, assets move to the Standard Regulatory Framework

Upgrades to Existing Assets: Incumbent owners usually undertake reinforcements; cost-based regulated return.

Chilean snapshot

Centralized planning + competitive tenders for new assets. Operators earn a regulated return based on auction bids or cost-based frameworks. Scenario analysis aims to capture future uncertainties. Urgent Projects framework where projects can be proposed outside the centralized planning process.

4.4.3 Dominican Republic

Planning

Single State Operator: The Empresa de Transmisión Eléctrica Dominicana (ETED) fully owns and operates high-voltage transmission.

Regulated Expansion: ETED, the Superintendencia de Electricidad (SIE), and the Comisión Nacional de Energía (CNE) coordinate expansion based on reliability, loss reduction, and renewable integration goals.

Remuneration

Monopolistic Model: Private lines (built for specific projects) typically transfer back to ETED.

Transmission Toll (Peaje de Transmisión):
- Derecho de Uso (DU): Recovers O&M and part of investment costs.
- Derecho de Conexión (DC): Covers the remaining share of annualized investment.

Indexation: Monthly adjustments based on U.S. inflation indices, exchange rates, and periodic four-year methodology reviews.

DR snapshot

A single, state-run transmission operator (ETED) covers all assets. All costs roll into a regulated toll split into a "use" fee and "connection" fee, updated monthly and reassessed every few years.

4.4.4 Summary table

Topic	Colombia	Chile	Dominican Republic
Ownership & Market Structure	Both private and state owned companies can own and operate transmission assets. Assets are awarded via concession mechanisms.	Regulated monopoly with open tenders for new projects destined to local and international investors. Concession mechanism.	State Owned Monopolistic Model at high voltage. Empresa de Transmisión Eléctrica Dominicana (ETED) is the exclusive owner of the main transmission grid. Private investors may build lines for specific projects, but these typically revert to ETED's ownership once completed.
Key Regulatory Entities	CREG (Energy and Gas Regulatory Commission): Sets tariff methodologies, approves tenders, and defines service quality metrics. UPME (Mining and Energy Planning Unit): Leads expansion planning. XM (System Operator): Manages dispatch and market operations. SSPD (Superintendencia de Servicios Públicos): Enforces compliance with service quality regulations.	MINENERGIA (Ministry of Energy): establishes energy policy, conducts long-term planning, defines transmission corridors. CNE (National Energy Commission): technical regulatory body, oversees annual transmission planning, sets tariffs and defines cost-allocation methodology. CEN (National Electric Coordinator): operates the grid and manages competitive tenders SEC (Superintendencia de Electricidad y Combustibles): enforces compliance with technical standards, safety and quality-of-service requirements.	SIE (Superintendencia de Electricidad): Main regulator setting tariffs and enforcing service standards. CNE (Comisión Nacional de Energía): Develops and coordinates long term energy policies. Organismo Coordinador: Operates the wholesale market (MEM). ETED: State owned operator of the high voltage network, responsible for expansion and maintenance.
Expansion Planning Approach	National Transmission Expansion Plan (PENT): Updated periodically by UPME. Identifies new projects based on demand forecasts, grid stability, and renewable integration. Awards new assets through competitive public tenders.	Long-Term Energy Scenarios (PELP): published by the Ministry of Energy at least every five years, over-looking the next 30 years to form the strategic vision for the grid. Annual Transmission Expansion Plan: conducted by CNE each year, over-looking the next 20 years to determine the needs in transmission expansion Corridor Definition and Environmental Assessments: conducted by the Ministry to identify routes of public interest and streamline permitting process.	Single Operator Planning: ETED coordinates expansion with SIE and CNE. Priorities include reliability, loss reduction, and renewable integration. Private lines built for specific projects eventually revert to ETED control.

Topic	Colombia	Chile	Dominican Republic
Tender/Awards Mechanisms	Public Tenders for new greenfield projects. Winning bidders propose a Yearly Expected Revenue and receive monthly payments once operational. After the tender period, assets shift to a standard regulatory regime (CRE + AOM).	Competitive Tenders for new greenfield projects. Competition on the lowest required annual revenues and the winner starts collecting regulated income upon project completion. After the tender's term, asset shifts to a standard regulatory structure. Standard Regulatory Mechanisms for the existing and upgraded facilities.	No open tenders for high voltage transmission since ETED is the sole owner. Private entities can build lines for specific projects but must transfer them to ETED, following a regulated planning process coordinated with SIE/CNE.
Asset Valuation Method	Tendered Projects: IAE is set by the awarded bid. Standard Regime: Replacement Cost of Electric Assets (CRE) is determined using official cost tables (Resolution CREG 011/2009). Assets are broken into standardized Unidades Constructivas (UC) with regulator defined unit costs.	Tendered Projects: Annual revenue is set by the awarded bid. Standard Regulatory Framework: CNE periodically conducts studies to determine an asset's new replacement value using standardized reference costs. Note: projects are classified into National, Zonal or Dedicated system for cost allocation.	Valor Nuevo de Reemplazo (VNR): The new replacement cost is periodically computed. Annual cost includes a capital recovery factor (over ~30 years) plus O&M. The regulated toll is then split into Derecho de Uso (DU) for O&M and part of investment, and Derecho de Conexión (DC) for the remaining investment cost. Private-built assets revert to ETED.
Remuneration Mechanics	Tendered Projects: Payment equals the IAE (Yearly Expected Revenue) indexed by the Producer Price Index (IPP). Post Tender or Legacy Assets: Revenue is determined by CRE (capital recovery), AOM (administration, operation, maintenance) with cost sharing adjustments, and service quality adjustments (penalties or bonuses).	Tendered Projects: Payment equals to the Annual revenue indexed by inflation or price indices (set in the tender's terms) Standard Regulatory Framework: a capital recovery plus return on investment (WACC) is calculated from the replacement value. Operation and maintenance expenses are periodically reviewed against benchmark and the allowances may be adjusted	Single Tariff Approach: Total cost (investment + O&M) is recovered through a regulated transmission toll divided into Derecho de Uso (DU) for O&M and partial investment, and Derecho de Conexión (DC) for the remaining investment. There is no separate project specific concession revenue.
Tariff Indexation & Adjustments	For Tendered Assets: IAE is indexed to the IPP. In the Standard Framework, CRE cost tables are periodically updated and AOM percentages adjust annually based on cost submissions.	Tendered Projects: aligned with inflation or price indices, set in the tender terms. Standard Regulatory Framework: the replacement value is periodically updated and operation and maintenance expenses	Monthly Indexation: Transmission tolls are adjusted monthly using U.S. Producer Price Indices, CPI, and exchange rate fluctuations, with a 2% monthly cap. A major review is conducted every 4 years to reassess costs and indexation methodology.

Topic	Colombia	Chile	Dominican Republic
Performance Incentives / Penalties	Performance Metrics: Hours of Indisposition (HI) and Energy Not Supplied (ENS) are monitored. Exceeding thresholds results in monthly revenue penalties, with strict conditions for force majeure exemptions.	Penalties for Downtime: revenues are reduced if assets exceed allowed outages or fail to meet operating standards. Overseen by the Coordinator.	No Explicit Penalties: While ETED is required to ensure reliability, there are no built-in financial penalties (such as for ENS or HI) for outages or availability lapses.
Special/Unique Mechanisms	Competitive Tenders encourage private investment in new lines; assets transition to a standard rate of return scheme after tender contracts expire.	Urgent Transmission Expansion: allows urgent transmission expansion outside the standard planning process. Project needs to be proven urgent and necessary by CEN and authorized by CNE. The remuneration is similar to the standard framework.	Sole Operator System: ETED exclusively owns and operates high voltage assets. Privately built lines revert to ETED, and the transmission toll is calculated using the Valor Nuevo de Reemplazo method with a Derecho de Uso/Derecho de Conexión split.
Typical Concession Period	Tendered assets typically have concession periods of 20 to 25 years, after which the standard CRE based remuneration applies.	Tendered assets typically have concession period of 20 years.	ETED does not operate under a concession model; assets are state owned indefinitely.
Observations	Emphasis on cost efficiency, competitive procurement, and service quality through performance metrics (ENS, HI). The framework is evolving to better incorporate emerging technologies (e.g., GETs).	Emphasis on cost-efficiency, competitive procurement (accepting international bidders) and service quality through penalties. Urgent Transmission Expansion efficiently complements the centralized planning process to lift regulatory barriers when addressing burning issues.	A centralized, state run system with direct cost passthrough via regulated tolls. Limited private participation and fewer performance-based penalties characterize the model, with future expansions focused on renewable integration and grid reliability.

4.5 Recommendations for *developing GETs in LAC*

4.5.1 Common Gaps Across All Three Jurisdictions

CAPEX-Focused Remuneration

- All three countries primarily compensate transmission owners via capital-intensive expansions (e.g., Replacement Cost in Colombia and the Dominican Republic, capital-based auction revenue in Chile). There is limited or no explicit mechanism to reward and thus incentivize operational measures (OPEX) such as some of the grid-enhancing technologies (dynamic line ratings, advanced flow control, real-time monitoring) that could defer or optimize large capital builds.

Insufficient Incentives for Innovation

- None of the frameworks offer a robust innovation allowance or ring-fenced mechanism that actively supports pilot projects or rapid adoption of advanced grid technologies. While Colombia and Chile rely on competitive bidding for expansions, the tender design rarely includes points for innovative approaches or TOTEX (total expenditure) consideration[170]. The Dominican Republic's state-run model (ETED) focuses on traditional infrastructure and does not provide clear monetary incentives for advanced solutions. In an auction framework, like the one in Chile, innovation has to be mandated.

Limited Flexibility in Procurement & Planning

Colombia: The competitive tenders focus on "large assets" with pre-defined technical specifications, leaving little room to propose operational or technology-based alternatives (GETs) that could be more cost-effective.

[170] In practice, it means that CAPEX evaluations should be completed with OPEX estimation based on social welfare gains. In this way, instead of requiring a high firm transmission capacity, the design would allow for DLR to show lower TOTEX through lower CAPEX and limited OPEX.

Chile: Though it has scenario-based national transmission planning, expansions are still mostly physical lines or substation upgrades. Article 102 (urgent expansions) also leans toward conventional reinforcements.

Dominican Republic: With a single state transmission operator (ETED) and minimal private competition, expansion is largely top-down and capital-driven, giving few incentives to test or incorporate advanced technologies.

Cost-Recovery Mechanisms That Are Not Fully Performance-Based

Colombia does have partial performance metrics (Hours of Indisposition, Energy Not Supplied), but these penalties/bonuses are modest.

Chile imposes penalties for delays or reliability shortfalls but does not explicitly reward ongoing improvements in operational efficiency or advanced technology adoption.

Dominican Republic lacks explicit penalty or incentive mechanisms tied to reliability or efficiency KPIs (like ENS, congestion costs). Consequently, there is little impetus to adopt advanced, real-time operational measures.

Constraints on Non-Wire Solutions

- Across all three jurisdictions, non-wire alternatives (e.g., advanced software, dynamic ratings) receive little or no regulatory attention. Asset-heavy transmission expansions are still the default answer to congestion, with limited space for GETs solutions.

Underdeveloped Technology-Neutral Auctions

Colombia and Chile hold competitive tenders, but the processes typically specify the design of the specific solution: a line or substation technology rather than allowing the market to propose alternative solutions (like advanced power flow controllers or dynamic ratings) that could solve the same congestion problem at lower total cost.

Dominican Republic does not run open technology tenders for core transmission expansions, as ETED handles expansions internally.

Snapshot from the interviews conducted

1. Ampacimon, a DLR developer with projects in South America and worldwide, considers that the main brakes for DLR adoption are its complexity of operation and its need for change management. It also requires starting from a "sound" situation in which the security doctrine is not operationally violated.

2. ENGIE Chile awaits new tenders but notes a lack of clear definitions and norms for newer technologies like grid-forming converters (GFCs) and BESS. While CNE is supportive of GETs, it acknowledges the need for stronger technical tools, clearer norms, and more flexible regulations to fully unlock their potential.

3. Chile's National Energy Commission (CNE) regrets that Chile lacks a formal regulatory sandbox, limiting the ease of testing novel technologies. The CNE is studying international approaches but sees political barriers to quick adoption.

4. ISA, the system operator in Colombia (and other countries in LAC), sees a clear shift toward flexibility solutions due to high costs of network restrictions. They emphasize that regulatory frameworks must reward proactive grid-optimization efforts

5. Some Chilean actors notice that there is no active resistance from the system operator to GETs, but a lack of internal capacity and resources slows down adoption. FACTS, HVDC, and other advanced technologies are increasingly evaluated in tandem with standard expansions

6. UPME, the Colombian energy planner, regrets a regulation too rigid regarding GETs. Historically, over 70% of Colombia generation comes from hydroelectric plans, giving enough flexibility to the system

4.5.2 Country-Specific Gap Highlights

Colombia

Transition from Tender Period to Standard Regime: Once the tender contract expires, assets move to a replacement-cost scheme that does not reward continuous efficiency gains or advanced upgrades.

Rigidity in Bidding Specifications: New expansions define capacity, location, and technology. This rigidity discourages alternative (operational) solutions that might be more agile or cost-effective.

Chile

Scenario Planning Not Fully Holistic: While the multi-scenario approach is evolving, the planning process still emphasizes building new transmission lines rather than systematically comparing with operational efficiency improvement (e.g. with GETs).

Article 102 for Urgent Projects: Designed for quick expansions, but typically triggers conventional reinforcement rather than exploring advanced grid technologies or non-wire alternatives.

Incentives based on Penalties Focused on Delivery Delays: Ongoing operational performance incentives (e.g., real-time congestion management, advanced operation) are less prominent.

Dominican Republic

Sole Operator Model: ETED's state monopoly structure, combined with a cost pass-through approach, offers little impetus to deploy innovative solutions or reduce operational costs.

No Explicit Performance Penalties: Reliance on basic reliability rules without strong financial incentives for advanced technology adoption or energy not supplied (ENS) improvements.

4.5.3 Recommendations

4.5.3.1 Introduce service market and competition in the bidding process

Adopt TOTEX Approaches

- Introduce regulation that treats both CAPEX and OPEX solutions equally for revenue purposes. For example, let a transmission owner receive a premium for installing a dynamic line rating system (an OPEX measure) in the same way that a new physical line is remunerated and rewarded.
  - In the UK, the RIIO project analyses CAPEX and OPEX solutions equivalently for determining allowed revenue, thus removing the bias toward large infrastructure projects[171]

Technology-Neutral Tenders

- Restructure competitive tenders to specify the functional, service or capacity requirements rather than prescribing the type of infrastructure, giving bidders the flexibility to define the optimized solutions if they meet performance benchmarks at lower cost (whether wire or non-wire alternatives).
  - In UK – see Pathfinder use case, section 2.1, Australia[172] and some parts of the US, bidders are given a functional requirement (e.g., "provide 500 MW of additional transfer capacity across corridor X by year Y") rather than a prescriptive line design. This approach opens the door to non-wire alternatives, advanced power-flow technologies, or partial OPEX solutions.

Involve private stakeholders

- Similar to Chile's framework, permit private parties (e.g., data centers, large renewable clusters) to propose and fund expansions outside the standard plan if they can demonstrate system benefits or urgent need.

- The system operator and regulator verify technical feasibility, safety, and potential externalities. If approved, the builder can secure its own remuneration (e.g., direct contracts with clients to reduce congestion or curtailment) rather than depending solely on regulated tariffs.

Snapshots from the interviews conducted

1. For Ampacimon, output-based approaches are an interesting idea, but it is difficult to calculate the gains owed to DLRs. Two calculation methods exist currently: based on the operational benefits compared to what would be the congestion rent without the technology (difficult to assess in reality); or based on cost of solution compared to a mature one (difficulty: two different technologies never have the same pros/cons).

2. Another way to develop DLR could be to include them from the inception of the power projects, notably wind farms projects. In this way, the costs for grid connections of the new power plant would be much reduced.

[171] *Network Price Controls 2021 – 2028 (RIIO 2), Ofgem, [link]*
[172] *Network planning and investment, Parliament of Australia, Parliament of Australia, [link]*

4.5.3.2 Enhance Reliability & Service Quality Incentives

Strengthen or Introduce Performance Metrics

- Expand the use of "Energy Not Supplied" (ENS) or "Hours of Indisposition" (HI) metrics and calibrate them with deterrent financial penalties, and/or bonuses.

- In the Dominican Republic, embed explicit metrics in ETED's remuneration formula to incentivize improved operational performance and reliability—e.g., if ENS remains below a threshold, ETED could earn a bonus.
  - In Brazil and some European countries, Remedial Action Schemes & Special Protection Schemes are recognized as valid ways to meet reliability criteria if they are proven effective and safe, potentially deferring large CAPEX expansions.
  - NERC in the US[173], National Grid in the UK[174], apply strong penalties for reliability Violations, defined such as real-time availability, forced outages, or critical event performance.

Snapshots from the interviews conducted

1. ISA in Colombia is exploring new reliability metrics that capture the broader societal benefits of robust grids (e.g., synergy with water supply systems). ISA noticed that reliability is often undervalued in conventional cost-benefit analyses.

2. UPME lacks a clear and standardized methodology to technically evaluate reinforcement projects. For now, projects are evaluated one by one, not by considering their combined advantages. UPME compares the benefit that each solution will bring (the benefit that the regulator allows to quantify) with the project budget. If the benefits are superior to the project budget, then the project is approved.

3. CNE in Chile is working on new norms to assess grid strength and inertia provision, which will help formalize the role of advanced technologies like grid-forming converters.

OPEX Factor for Demand-Side and Operational Tools

- Provide an automatic cost pass-through for proven demand-side or real-time control solutions, ensuring that a TSO or grid operator who invests in them will recover costs plus an incentive for excellence. Ideally, these solutions should also receive a premium over the costs to incentivize them accordingly.

[173] *Sanction Guidelines of the North American Electric Reliability Corporation, NERC, 2014,* [link]
[174] *NGET_A9.11 ENS Incentive, National Grid, 2019,* [link]

- Create “efficiency incentives” so that if GETs or operational measures yield overall system savings, the TSO can retain part of those savings as profit.
  - In Italy, the UK and part of US, TSOs can earn additional returns if they deliver higher capacity, reduce congestion costs, or reduce curtailments below certain benchmarks.

4.5.3.3 Foster innovation

Innovation Allowances

- Reserve a percentage of the allowed revenue for R&D or pilot projects related to dynamic line rating, grid-forming converters, advanced flow control, etc.
  - Great Britain or Norway have set up network innovation funds, which guarantee budgets to support demonstration projects in advanced technologies, dynamic line ratings, virtual inertia, grid-forming converters, etc.

Streamline Planning & Procurement for Flexibility

- Require that expansion plans systematically incorporate GETs in the identification of new projects. Conventional projects and advanced or operationally flexible solutions should be compared, this comparison including externalities such as environmental and social impacts, system resilience, and potential cost savings from deferring large investments.
  - In New Zealand, whenever a transmission need is identified, the responsible planner or bidder must evaluate at least one “Grid-Enhancing Technology” scenario, comparing its cost and performance to conventional expansions.

- Provide “fast-track acceptance” in one country once a GET or pilot is proven successful in another (regional standardization of acceptance).
  - France, Singapore and Australia set up Fast-Track Approval / “Regulatory Sandboxes”: temporary exemptions from certain regulations to test novel solutions. If successful, the pilot can be scaled quickly without waiting for a full regulatory cycle.

Encourage Non-Wire Alternatives (NWA)

- Mandate a “compare and justify” requirement: before approving a new line, the regulator must be provided with evidence that advanced operational measures and demand-side solutions were fully assessed.

---

[173] *Sanction Guidelines of the North American Electric Reliability Corporation, NERC, 2014, [link]*
[174] *NGET_A9.11 ENS Incentive, National Grid, 2019, [link]*

- In Colombia's PENT and the Dominican Republic's planning, incorporate an explicit step to evaluate DLR, dynamic ratings, or special protection schemes.

Expand funding eligibility for GETs

- For all three countries, expand public funding eligibility (e.g., special lines of credit, climate funds, or modernization funds) to explicitly include advanced grid solutions.
- Simplify or create clearer guidelines on how GETs can qualify as part of system expansions or reinforcements.

Snapshots from the interviews conducted

1. ENGIE emphasized the need for stable regulatory frameworks and greater openness to industry expertise to accelerate the deployment of innovative technologies. They also stressed the importance of aligning tenders with both local and system-wide needs.

4.5.4 Section highlights

Transmission regulation in Colombia, Chile, and the Dominican Republic demonstrates structural maturity but also consistent limitations when it comes to integrating innovation, performance-driven incentives, and flexible planning. While these jurisdictions have embraced centralized planning and structured remuneration, their frameworks remain overly CAPEX-focused, leaving significant potential from Grid-Enhancing Technologies (GETs) and operational flexibility untapped.

Planning Rigidity and Limited Technology-Neutral Procurement

All three systems base their transmission needs on top-down, infrastructure-heavy planning. Colombia's tendering system mandates fixed project specs; Chile's expansion scenarios still lead predominantly to new lines or substations; and the Dominican Republic maintains a fully centralized model under ETED, where private involvement is minimal and only as temporary contributors. In none of these settings do tenders or planning require systematic consideration of GETs or alternative (non-wire) options.

Best Practice Response: Implement function- or service-based procurement frameworks, as practiced in parts of the U.S. and Australia. Rather than prescribing technical solutions, tenders should define performance needs (e.g., "add 300 MW of capacity") and allow bidders to propose any compliant solution, including software-based or modular enhancements.

CAPEX Bias and Weak Operational Incentives

Remuneration models across all three countries reward asset deployment over operational efficiency. While Colombia and Chile offer some performance-linked penalties (HI, ENS), these remain modest. The Dominican Republic lacks explicit metrics altogether. Operational improvements such as congestion relief via advanced power flow control, dynamic line rating (DLR), or topology optimization are not rewarded—even if they offer equal or better outcomes at lower cost.

Best Practice Response: Adopt TOTEX (total expenditure) regulation, as seen in the UK's RIIO framework. Reward outcomes rather than investment scale. Let OPEX-based solutions receive the same regulated returns as traditional lines and include performance-based bonuses for reducing system costs or improving reliability.

Innovation & GET Integration Remains Fragmented or Absent

Colombia and Chile permit new technologies but do not systematically assess or fund them. Tender rules lack innovation scoring or fast-track pilot provisions. The Dominican Republic's model is particularly rigid, offering no formal channels for innovation unless government-driven.

Best Practice Response: Establish mandatory GET evaluation (e.g., the "New Zealand rule"); include at least one GET-based alternative in all feasibility studies. Ring-fence funds or incentives for innovation trials (like the UK's Network Innovation Competition), and create regional acceptance pathways where successful pilots in one country are fast-tracked in another.

Limited Private-Led Development Pathways

Even when private entities are willing to fund needed expansions (e.g., renewables seeking better interconnection), frameworks in all three countries provide no clear route outside central planning. Chile's Article 102 is a partial exception, but remains underused and biased toward conventional fixes.

Best Practice Response: Expand "Article 102" mechanisms regionally, enabling developers or industrial users to propose and fund transmission projects independently subject to regulatory review and technical feasibility. This unlocks faster development timelines and distributes investment risk.

Underdeveloped Grid Service Markets

There are no mechanisms for compensating services like congestion relief, real-time monitoring, or reactive power support as standalone offerings. This blocks solutions like FACTS, demand response, or energy storage from participating in transmission optimization.

Best Practice Response: Transition toward grid service markets. Define services (e.g., congestion relief, inertia) and assign transparent price signals. Let TSOs or third parties compete to provide those services, supported by a regulatory backstop for critical gaps. This approach—successfully implemented in ISOs like PJM or ERCOT—fosters efficiency and rapid innovation.

05

Appendix A

References for the Task 1 Technological Analysis.

*Table 25: **References for Task 1 Technological Analysis***

Technology		Reference
Dynamic Line Rating	Line-mounted	[1]: PPL's Dynamic Line Ratings Implementation, PPL
		[2]: Dynamic Line Rating, Installation on Three PPL Circuit, RTR Energy Solutions
		[2a]: Docket No. AD22-5-000 Initial Comments of PPL Electric Utilities Corporation
	Contactless	[3]: DOE Office of electricity TRAC
Sensor less Dynamic Line Rating		[4]: System-wide rollout of Dynamic Line Rating Technology, Operato
Reconductoring/Advanced Conductor		[5]: PJM projects status and cost allocation
		[6]: Docket Number A-2022-3036291, Pennsylvania Public Utilities Commission
		[7]: Advanced Conductor Scan Report, INL
Battery Energy Storage System		[8]: Financial Close On Its San Andrés Battery Energy Storage Project in Chile, Innergex
		[9]: Innergex Announces the Commissioning of the Salvador Battery Facility in Chile, Innergex
Advanced Power Flow Control	Synchronous Condensers	[9a]: Rebirthing coal power stations into synchronous condensers, Australian Energy Council
		[10]: Guide on the assessment, specification and design of synchronous condenser for power system with predominance of low or zero inertia generators, CIGRE
	FACTs/new digital devices	[11]: For Cost Effective and Reliable Transmission of Electrical Energy, Klaus Habur and Donal O'Leary
		[12]: Benefits and Value of New Power Flow Controllers, EPRI
	DC power flow control (HVDC)	[13]: Belo Monte-Rio de Janeiro UHVDC Transmission Project, NS Energy
		[14]: Chile construirá una moderna línea de alta tensión de corriente continua para facilitar el transporte de energía renovable, Econo Journal
		[15]: Advanced Transmission Technologies, DOE
	Soft Open Point and Normally Open Point	[16]: Active Response Project Progress Report - July to December 2021, UK Power Network
		[17]: Coordinated Control Method of Voltage and Reactive Power for Active Distribution Networks Based on Soft Open Point, P. Li, H. Ji, C. Wang, J. Zhao, G. Song, F. Ding y J. Wu
		[18]: Comparative analysis of services from soft open points using cost-benefit analysis, M. Deakin, I. Sarantakos, D. Greenwood,, J. Bialek, P. Taylor y S. Walker

Technology		Reference
Demand Response		[19]: Demand response experience in Europe: Policies, programmes and implementation, J. Torriti, M. Hassan y M. Leach,
		[20]: The power to choose - Demand response in liberalised electricity markets, IEA
		[21]: Economic and environmental impacts from the implementation of an intelligent demand side management system at the European level, G. Papagiannis, A. Dagoumas, N. Lettas y P. Dokopoulos
Synchro phasors/Wide Area Monitoring System + Digital Twin/AI	Security Analysis; Dynamic Security Analysis	[22]: Software Technology, Maintaining Grid Security, PowerTech
	Special Protection Scheme / Remedial Action Scheme	[23]: System Protection Schemes: Limitations, Risks, and Management, PSERC
		[24]: Cost-Benefit Analysis of Unreliable System Protection Scheme Operation, J. Calvo, P. Ramírez, S. Tindemans y G. Strbac
	Topology Optimization	[25]: Transmission Network Topology Optimisation, National Grid
		[26]: Building a Better Grid: How Grid Enhancing Technologies Complement Transmission Buildouts, Brattle Group
		[27]: New Constraint Management Techniques for Meshed Transmission and Active Distribution Networks, New Grid, Brattle Group, Grid Strategies
	Real-time operation control (e.g., Naza automata)	[28]: R&D Roadmap for 2021-2024, RTE

@idbinvest

www.idbinvest.org