Prospects for innovative power grid technologies

Final report

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Outline

Key findings

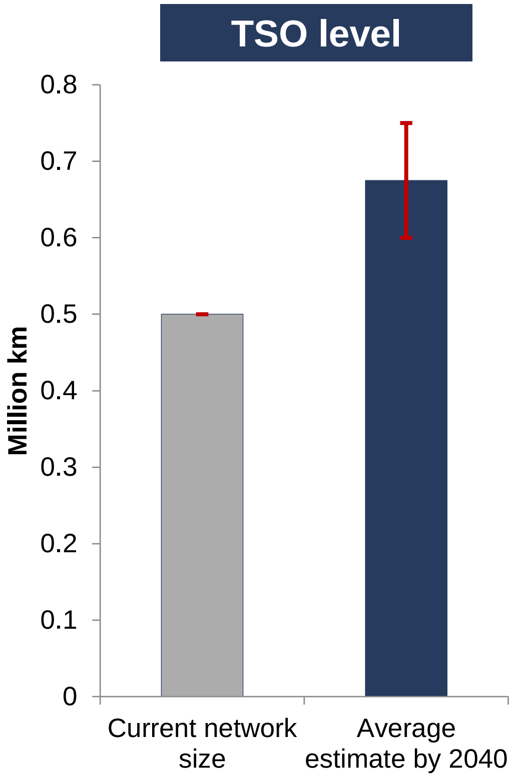
Context: A considerable expansion of electricity networks is required for the energy transition

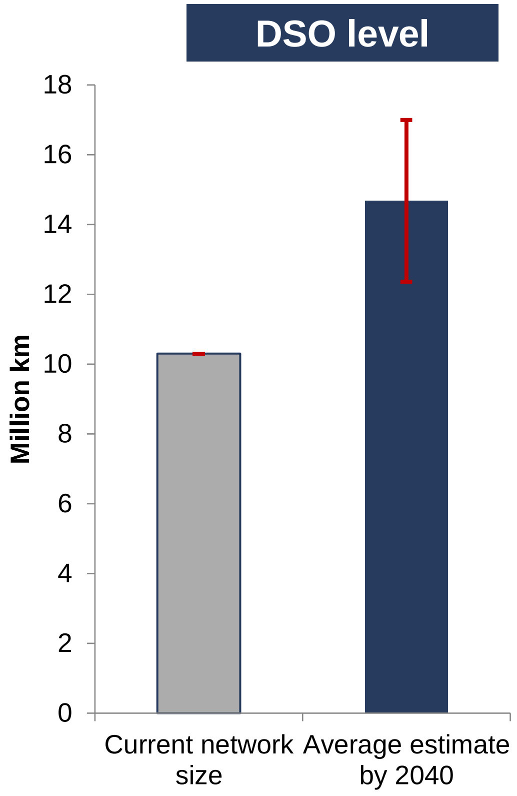
A significant expansion of the network is required for the energy transition in Europe, to integrate 2,000 GW[1] of renewables in 2040, compared to around 400 GW today:

- The total current size of the EU grid is **0.5 million km** at transmission level and **10.3 million km** at distribution level.
- By 2040, transmission grids might need to be expanded by **20-50%** to a total length of **0.6-0.8 million km**, and distribution by **20-65%** to a total length of **12.4-17.0 million km**, in the context of the energy transition – range based on an extensive review of prospective studies and CL analysis.

The required buildout needs to happen 3 to 20 times faster than past buildout rates, and the delivery capacity of TSOs and DSOs, and related supply chains might be under strain.

- In recent years, annual network built out in Europe has been approximately **500 km/year[2]** at the transmission level and **80,000 km/year[3]** at the distribution level.
- The buildout required by the energy transition might need to jump to **10 000 km/year** on average at transmission level, and **250,000 km/year** distribution level, a jump 20 and 3 times, respectively.



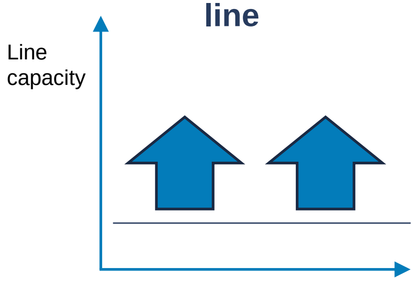


Source: CL analysis, [1] based on ENTSO-E Distributed Energy Scenario, [2] based on ENTSO-E inventory of transmission database, [3] 0.8% increase in the length of the distribution network in 2021-2022 according to Eurelectric (2024) Grids for Speed

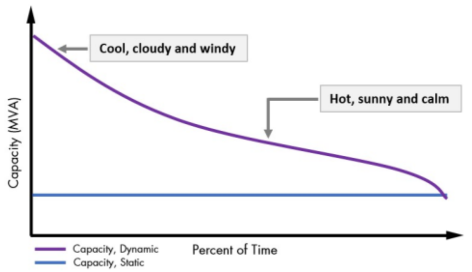
Opportunity: Innovative Grid Technologies (IGTs)[1] can support the required network buildout

Superpowers:

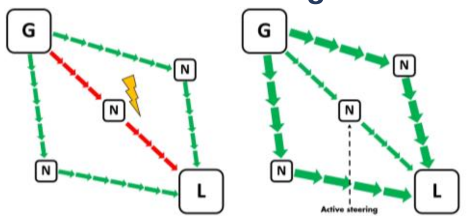
Capacity increase for a given line



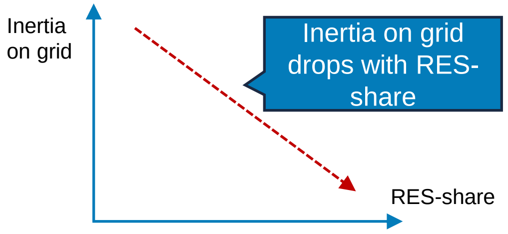
Better understanding of actual line limits



Dynamically controlling power flows on the grid



Better understanding of actual inertia limits/stability limits



Innovative Grid Technologies:

Advanced conductors **High Temperature Superconductor** **Storage as a transmission asset** (SATA)	**Dynamic line rating** (DLR)	**Advanced Power Flow Control** (APFC)	**Grid inertia measurements**

Digital Twin, Flexibility Management Systems

Note: [1] The US term "Grid Enhancing technologies" can also be use to describe technologies that "maximise the transmission of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools", according to the DoE (see US DoE (2022)). ***IGTs can hence also be referred as GETs+.***
this theoretical framework does not provide an exhaustive classification of IGTs, and of their effects. Other technologies and effects could potentially be considered.

Benefit 1: Reinforcing existing electricity infrastructure

Assuming a fast deployment, IGTs could increase overall network capacity btw. 20% to 40%, based on inputs from technology experts

- Current electricity infrastructure capacity stands at least at 550 GW in the EU[1]
- Case studies from actual application of IGTs demonstrate significantly **increased capacity figures**
- Overall, by assuming a fast deployment of several IGTs on the grid, based on discussions with technology experts, **a 20% to 40% overall capacity improvement (e.g. on the wider network) by 2040, seems realistic**, enabling from approximately 100GW to 200GW of additional capacity.

IGT	Capacity increase achieved	Case study example
Advanced power flow control	**5%** increase in overall network capacity	UK
Advanced conductors	**100%** increase in capacity of a line	Belgium
Storage as a transmission asset	**40%** increase in capacity of a line	Germany
Dynamic Line Rating	**30%** increase in capacity of a line	USA
Grid Inertia Measurement	Reduced RES curtailment thanks to +30% higher assumed inertia	UK
High temperature superconductors	**400% to 1000%** increase in capacity of a line[2]	Germany

20%-40% capacity improvement of overall network would be achievable

Note: [1] EU peak demand (see for instance ENTSO-E (2018) Electricity in Europe 2017), [2] compared to conventional lines

Benefit 2: Faster deployment of grid capacity at system level

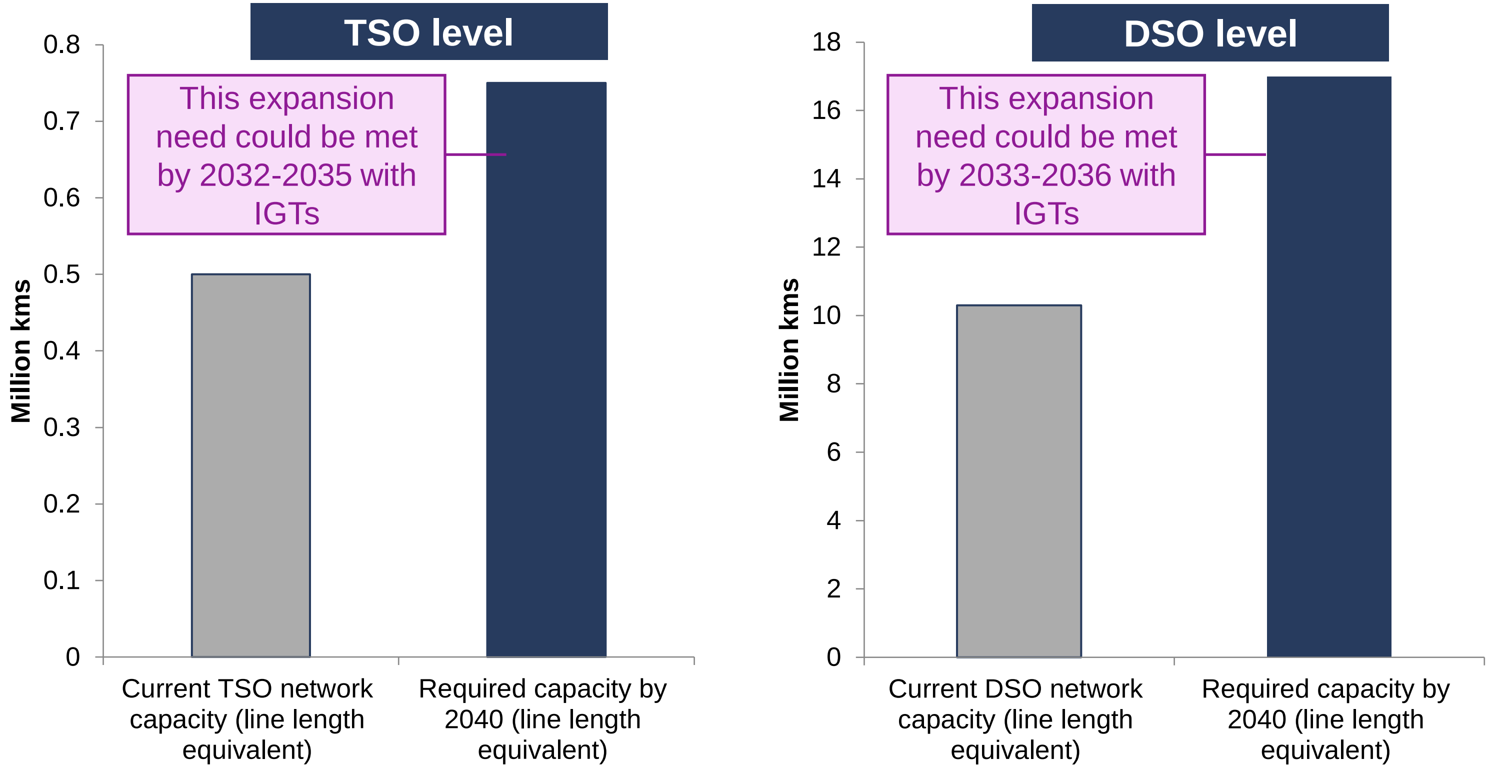
A conservative 10-20%[1] increase in network capacity through IGTs would already yield major benefits

IGTs – in combination with conventional grid expansion - can support adding the required capacity faster.

By considering a **10% to 20%[1] increase** in the capacity of the existing grid assets achieved by 2030, and by considering **that similar improvements is applied to all new grid assets built in the future**, we see that:

- **Transmission grids** expansion can be accelerated **by 5 to 8 years**
- **Distribution grids** expansion can be accelerated **by 4 to 7 years**

Comparison of current network size and size required by 2040 in the EU (upper range)



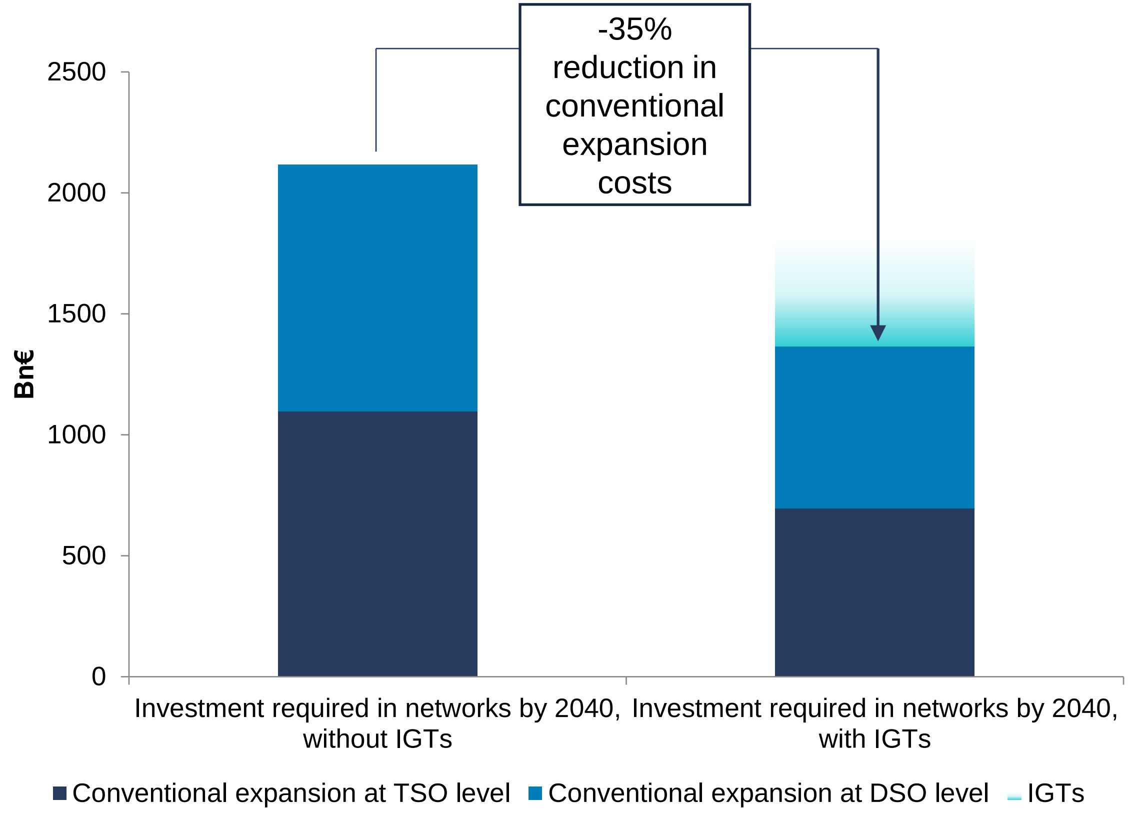
Note: [1] To avoid overstating capabilities or underestimating unforeseen challenges, a conservative 10% to 20% (halved) overall increase is used in the rest of the study. *[2]* The upper range of network expansion need is considered here to avoid overstating IGTs capabilities

Benefit 3: Reduction in required investments

By investing in IGTs in parallel to conventional grid buildout, gross cost savings of 700 Bn€ in conventional expansion might be achieved by 2040

- The required investments in electricity networks, if IGTs are not deployed at scale, might amount to approximately **1000 Bn€[1] in the transmission network** and **1000 Bn€[2] in the distribution network** in Europe by 2040.
- Installing IGTs (with the assumptions described in the previous page) could reduce the need for network buildout by approximately 35% by 2040, and hence achieve overall **gross savings of 700 Bn€ in conventional expansion costs.** However, this figure doesn't take into account the costs of IGT deployment themselves.
- Nonetheless, these **gross benefits** may be **significantly higher than the costs of deploying the said IGTs** – for instance, the US DoE indicates that IGT can indeed achieve an increase in capacity at a lower cost than conventional reinforcements[3].

Gross benefits of IGT deployment - Saved investments in network expansion



Note: [1] CL estimate, based on the projected cost of onshore network buildout per km of new lines in Germany, Italy and Spain, and the need for network buildout presented in this study [2] 67Bn€/year for EU27+NO according to Eurelectric (2024) Grids for Speed, [3] For instance, for APFC and DLR, see: DoE (2022) Grid-Enhancing Technologies: A Case Study on Ratepayer Impact

Despite these substantial benefits IGTs could provide to the energy transition, their deployment is currently hindered by several barriers

Barriers for IGT deployment

1	Lack of incentives to opt for non-CAPEX intensive solutions	▪ **Incentive to opt for CAPEX solutions rather than OPEX solutions due to a difference in the regulatory treatment between OPEX and CAPEX.**
2	Insufficient output incentives and incentives for innovation	▪ **Lack of incentives for network operators to use overall cheaper solutions** ▪ **Lack of incentives for innovations that may cost-efficiently increase output**
3	Investment doctrine and methodologies of network operators	▪ The investment doctrine of T/DSOs might include **bias towards predetermined solutions to fix the issues identified, rather than adopting a technology-neutral approach to answer system needs**.
4	Death-by-pilot risk	▪ **IGT adoption is hindered by long processes for network companies to trial and then adopt new innovative solutions**.
5	Funding schemes' eligibility issues	▪ **Some of the potentially available funding schemes cannot easily be accessed by IGTs yet, due to eligibility issue of IGTs.**

Sources: Compass Lexecon

Regulatory solutions exist to remove these barriers, and have already been implemented in some European countries

Barriers for IGT deployment	Examples of best practices and solutions
1 Lack of incentives to opt for non-CAPEX intensive solutions	▪ TOTEX regulation ▪ Introduction possibility of OPEX increase for network operators
2 Insufficient output incentives and incentives for innovation	▪ Output-based remuneration, decoupled from CAPEX/OPEX spent
3 Investment doctrine and methodologies of network operators	▪ NOVA principle: grid optimisation has priority over grid reinforcement, which has priority over grid expansion ▪ Technology-neutral planning approach, e.g. with CBAs
4 Death-by-pilot risk	▪ Lump-sum innovation Funding / WACC premiums ▪ Regulatory sandboxes ▪ Transfer of best-practices and standards
5 Funding schemes eligibility issues	▪ Widen eligibility of national and EU-financing schemes to IGTs

Executive Summary

The energy transition is a major challenge for transmission and distribution networks, for which considerable investments are expected

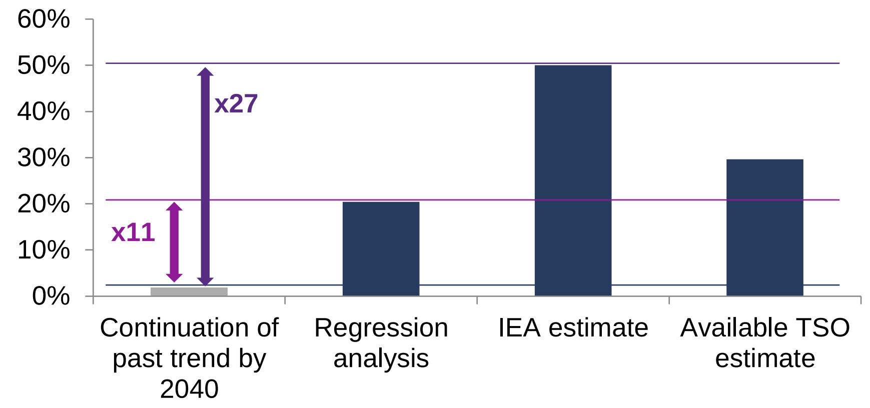
A significant expansion of the network is required for the energy transition in Europe

- Between 2015 and 2022, the size of the transmission network has been increasing by ~0.1% annually on average across the seven countries included in the scope of this study[1].
- An accelerated grid expansion would be required in the next decades for the energy transition. Considering a wide range of estimates in the literature and a panel regression analysis, we find that the length of the transmission network might need to increase between 20% and 50% by 2040 in Europe[2,3] The speed of TSO network buildout would hence need to increase by a factor of 11 to 27.
- Similarly, at the distribution level, network length might need to increase by 20%[3] to ~65% by 2040. The speed of DSO network buildout would hence need to increase by a factor of 1.4 to 4.6.

Given that this required buildout is significantly faster compared to historical buildout rates, the delivery capacity of TSOs and supply chains might be under strain.

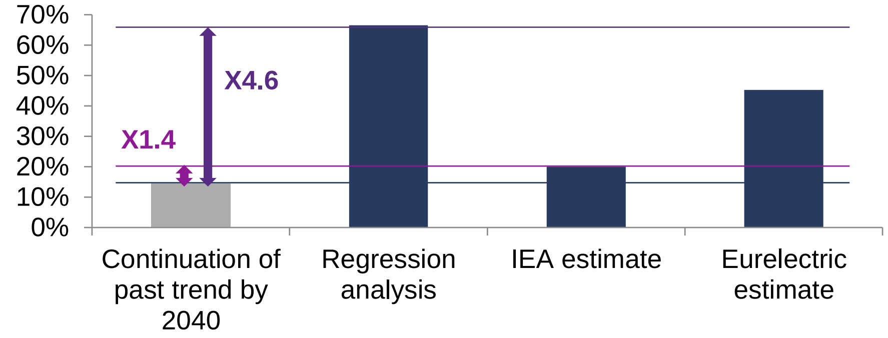
Network expansion needs of TSOs by 2040 according to several sources, compared to a scenario where past network expansion trends continue until 2040

In total by 2040: +20% to + 50% increase in TSO network length in Europe



Network expansion needs of DSOs by 2040 according to several sources, compared to a scenario where past network expansion trends continue until 2040

In total by 2040: +20% to + 65% increase in DSO network length required in Europe



Note: [1] France, Germany, Spain, Italy, Denmark, Netherlands, UK [2] the seven countries account to approximately 70% of the total electricity demand of EU27+UK and might constitute a reasonable picture of the need for network expansion in Europe [3] IEA (2023) Electricity grids and secure energy transitions – based on IEA estimation of installed line length in the Announced Pledges Scenario, between 2021 and 2050. 2040 datapoint estimated by CL as the average between 2030 and 2050, Eureletric (2024) Grids for Speed
Source: CL analysis

ENTSO-E studies indicate that investment needs in offshore transmission capacity and interconnection by 2040 are also considerable

Investments in offshore network are also necessary to harness the offshore wind potential in Europe.

- ENTSO-E estimated that up to 371.6 bn€ of CAPEX[1] for transmission network infrastructure will be needed between 2025-2040 to connect an expected offshore wind capacity of 270 GW by 2040 in the EU.

ENTSO-E finds that a significant increase in interconnection capacity would provide major benefits to EU consumers.

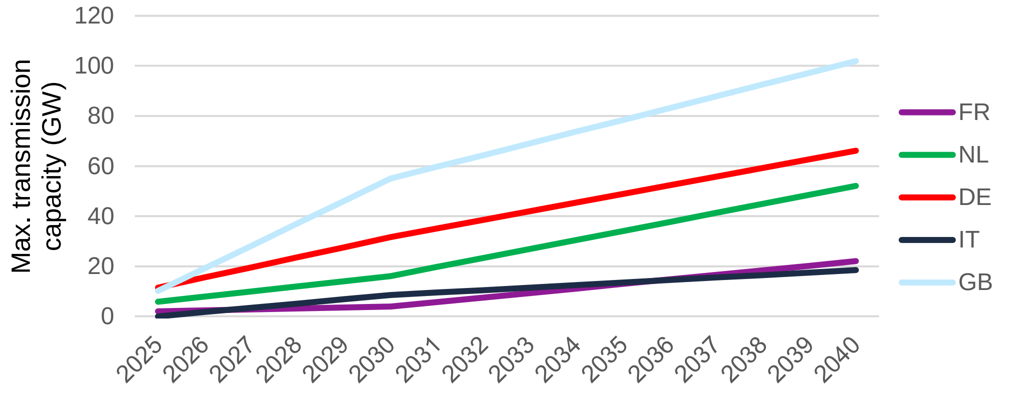
- In the System Needs study from 2023, ENTSO-E finds that developing an additional 88 GW of cross-border capacity between 2025 and 2040 in Europe would be economically efficient.

The need for offshore and interconnection infrastructure might even be underestimated in these studies, compared to the scale required to reach net-zero by 2050:

- National offshore RES targets might not be fully aligned with decarbonisation pathways yet.
- The "National Trends" scenario is assumed in the System Needs study, which is based on national and EU policies of past years, instead of a net-zero decarbonisation pathway.

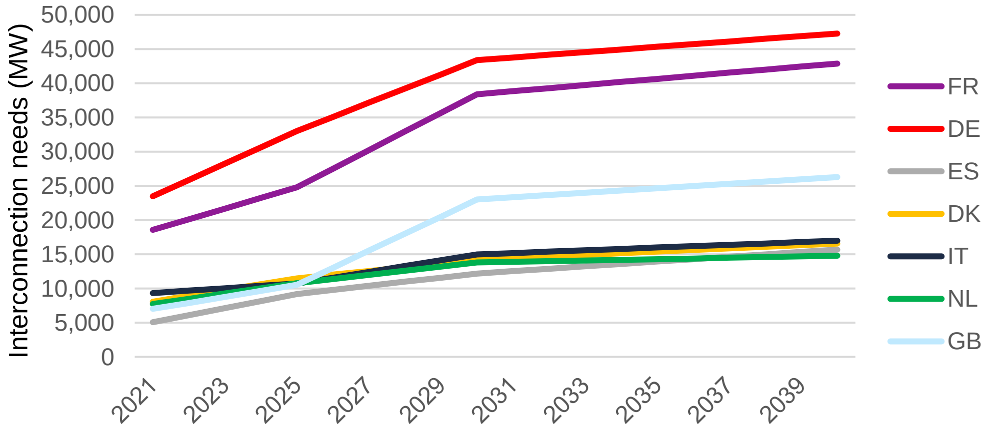
Maximum transmission offshore capacity (GW) – ENTSO-E ONDP

At least 54,000 km of additional offshore transmission infrastructure by 2050



Interconnection needs (MW) – ENTSO-E IoSN TYNDP 2022

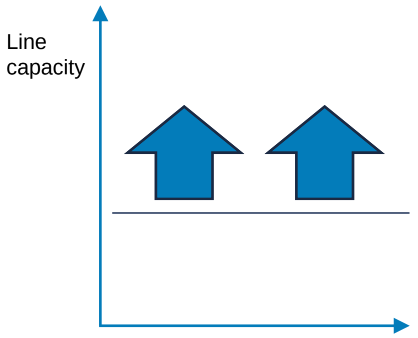
At least a 100% increase in interconnection capacity required by 2040



Innovative Grid Technologies (IGTs)[1] allow for a better use of the grid, and could therefore help achieving the network buildout targets

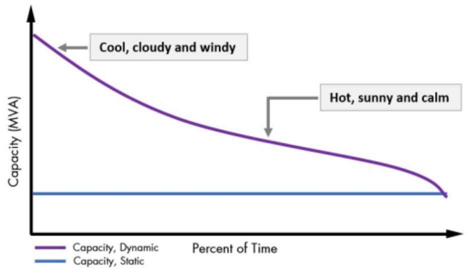
Main methods to increase grid capacity:

Capacity increase for a given line



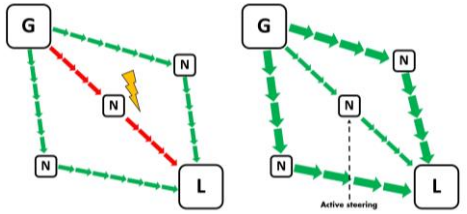
- Direct capacity improvement compared to conventional technologies

Better understanding of actual line limits



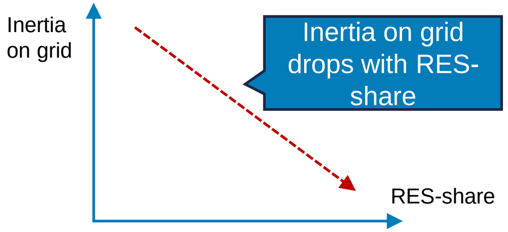
- A static limit must be very conservative, to not overload lines in adverse (hot) conditions;
- Dynamic ratings exploit natural line cooling

Dynamically controlling power flows on the grid



- Power flows through a network are often limited by its weakest line
- By dynamically controlling power flows (e.g. like road traffic management) more capacity is unlocked on the existing grid

Better understanding of actual inertia limits/stability limits



- Inertia on the grid decreases with more RES in the system, which may cause stability issues and RES curtailment
- Precise measurement of inertia allows curtailment to only happen when necessary

Techno-logical foundation:

- **Advanced conductors**
- **High Temperature Superconductor**
- **Storage as a transmission asset** (SATA)

- **Dynamic line rating** (DLR)

- **Advanced Power Flow Control** (APFC)

- **Grid inertia measurements**

- **Digital Twin, Flexibility management software solutions**

*Note: [1] The US term "Grid Enhancing technologies" can also be used to describe technologies that "maximise the transmission of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools", according to the DoE (see US DoE (2022)). **IGTs can hence also be referred as GETs+.** this theoretical framework does not provide an exhaustive classification of IGTs, and of their effects. Other technologies and effects could potentially be considered.*

IGTs are typically complementary with one another, and are also complementary with conventional network reinforcement

IGT technologies are not mutually exclusive	▪ IGT technologies are not mutually exclusive, different IGTs can be used dependent on network needs, a range of solutions can make supply and installation easier, and they can typically be combined to offer greater capacity/benefit
IGTs are well-suited for incremental capacity improvements	▪ IGTs can achieve smaller capacity improvements more quickly compared to building new power lines – this can be useful to anticipate the investment need (if delivery is challenging for some reason) or to bridge the time until the investment comes through.
IGTs are complementary with network reinforcement works	IGTs would ease, not slow other projects (e.g. new circuits) to meet the full need for network capacity growth. This is because: 1) IGTs can provide capacity improvements quickly, which can in turn make it easier to schedule outages for the installation of larger projects like reconductoring or new circuits. 2) By being "grid multipliers" that make existing and newly installed physical grid infrastructure more effective, IGTs can make achieving buildout targets more realistic – both in terms of the scale of work required and in terms of costs. Moreover, in some network locations, IGTs would complement conventional reinforcements – e.g. additional connections at the distribution level.

Using IGTs to increase and/or anticipate network capacity buildout could provide a range of benefits

Short development lead time	▪ Project development lead time amounts to typically 1 to 2 years for most of the technologies, significantly shorter than the time needed to construct extra grid capacity
Limited environmental footprint	▪ Deploying IGTs allows for a lower environmental footprint compared to building new overhead lines / underground cables as IGTs typically use existing substation space or transmission / distribution corridors
Most IGTs are less capital cost intensive	▪ The scale of most IGTs projects is lower than conventional network reinforcement, leading to lower capital costs (incl. through reduced need for new infrastructure / new assets)
Reduced reliance on supply chain bottlenecks	▪ IGTs have for example a reduced impact on supply chain bottlenecks for copper or transformers compared to conventional grid expansion projects

Case studies of IGTs application to existing assets demonstrate significant increased network capacity

The case studies reviewed illustrate an order of magnitude of feasible grid improvements which could be achieved by IGTs.

- IGTs can increase the capacity on a certain line by up to about 170%, adding the possible effects of advanced conductors, dynamic line rating and SATA.
- In addition, advanced power flow control systems can increase the overall system capacity by about 5% and grid inertia measurement can significantly reduce RES curtailment.
- Note that those figures are general estimations, and actual figures can significantly differ on a case-by-case basis as electricity networks are location-specific.

Technology	Country	Range - % increase in line / system capacity	Case study description
Advanced power flow control systems		5% increase in wider network capacity	UK – Deployment of 48 SmartValves in congested network areas
Advanced conductors		100% increase in line capacity	Belgium – Upgrade of 380 kV connection with HTLS conductors
Storage as a transmission asset		40% increase in line capacity	Germany – 250 MW Gridbooster planned at grid hub “Kupferzell”
Dynamic Line Rating		Over 30% increase in average transmission capacity	USA – DLR software and sensor platform deployed on 115 kV lines in New York
Grid Inertia Measurement		Measured inertia was up to +30% higher than assumed values used before, allowing for higher share of RES and reduced curtailment	UK – commercial service operational since 2022, saving ~5.5% UK National CO_2 emissions annually
High temperature superconductors	High Temperature Superconductors allow for bulk transport of electricity. For instance, a 400% to 1000% increase in line capacity could be achieved		

Expert interviews suggest a 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network

The overall benefits of IGTs deployment on the wider network have been estimated based on a range of expert interviews by combining:

- **Effect on a certain line – Improvement per circuit:** These effects have been analysed for each technology and summarised on the previous slide.
- **The maximum coverage of an IGT on a network:** Because of their costs and because network issues are always highly location specific, it seems unlikely that all IGTs will be rolled-out to every line on the network.

Overall, a 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network could be achieved:

- Expert interviews were used to estimate reasonable maximum coverage factors for IGT technologies as summarised in the Table on the right.
- These estimates combined with potential improvements derived from case studies show an overall 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network as presented in the Table.*
- To avoid overstating capabilities or underestimating unforeseen challenges, a conservative 10% to 20% (halved) overall increase is used in the rest of the study, allowing for growth in experience with IGTs being deployed at such scale.

Examples of how a 20% - 40% overall effect can be achieved

	Improvement per circuit	IGT coverage	Possible effect on overall system ()
Example 1 – 20%			**20%**
DLR	30%	17%	5%
SATA	40%	10%	4%
APFC			5%
Adv. Conductors	100%	5%	5%
Superconductors	400%	0.25%	1%
Example 2 – 20%			**20%**
DLR	30%	10%	3%
SATA	40%	17%	7%
APFC			5%
Adv. conductors	100%	4%	4%
Superconductors	400%	0.25%	1%
Example 3 – 40%			**40%**
DLR	30%	40%	12%
SATA	40%	20%	8%
APFC			8%
Adv. conductors	100%	10%	10%
Superconductors	1000%	0.2%	2%
Example 4 – 40%			**40%**
DLR	30%	25%	8%
SATA	40%	25%	10%
APFC			10%
Adv. conductors	100%	10%	10%
Superconductors	1000%	0.2%	2%

Source: CL analysis based on discussion with IGT experts and based on IGT real case studies (see previous slide)

** Please note that this is an indicative estimation under some uncertainty that is caused by the limited experience with IGTs and limited available data. We recommend detailed bottom-up modelling studies to further explore the effects.*

Assuming a 10-20% increase in network capacity by 2030 through IGTs could boost substantially grid capacity expansion

If deployed at scale, IGTs could cover a significant share of network expansion needs. For the sake of illustration, the following scenario is assumed:

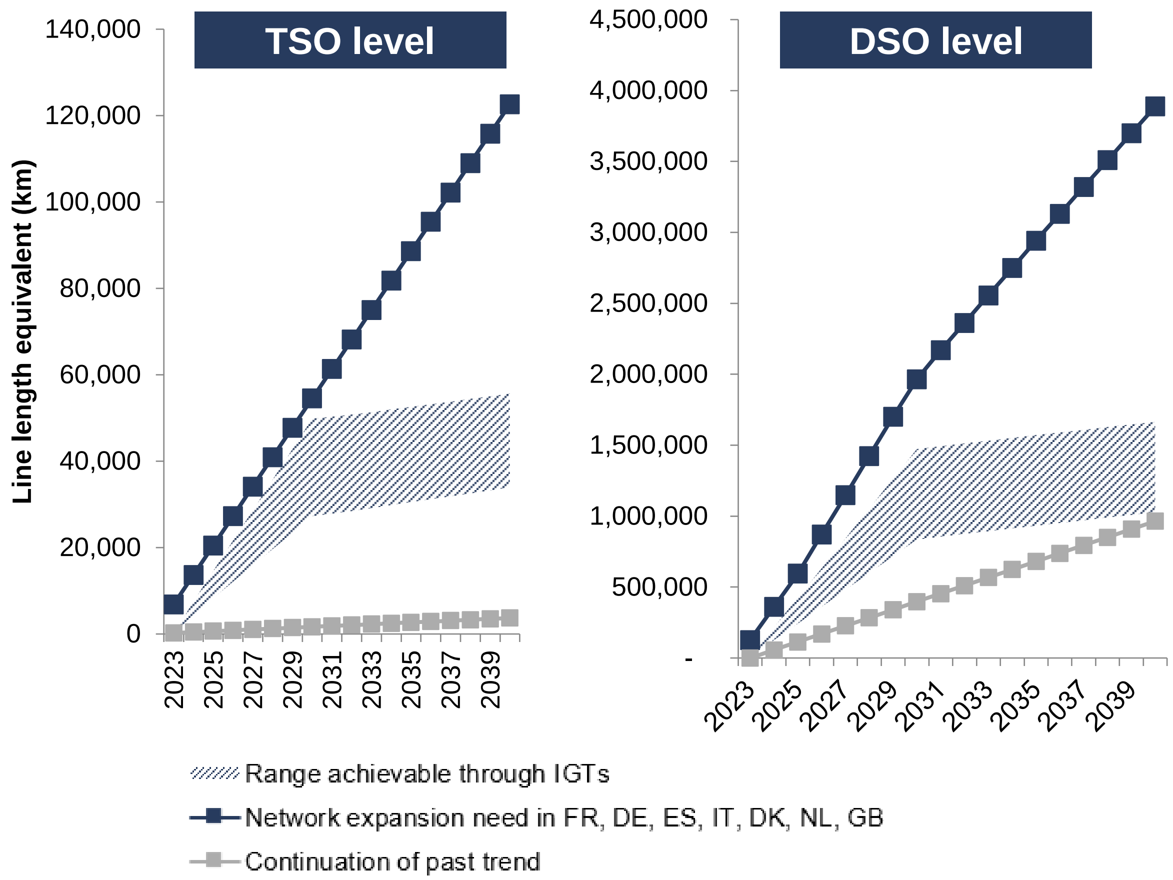
- An initial targeted deployment of IGTs in the existing grid by 2030: In 2030, a 10% (low scenario) to 20% (high scenario) increase in the capacity of the existing network is achieved, due to a roll-out of IGTs in specific grid locations/bottlenecks.
- The remaining network expansion need is met with new grid buildout which include IGTs: New network assets built by 2040 are boosted with IGTs, which provide a 10% (low scenario) to 20% (high scenario) capacity improvements compared to conventional technologies.

In this scenario, deploying IGTs would provide a significant boost to the required increase in network capacity, as highlighted on the right hand-side:

Overall in these 7 countries by 2040:

- At TSO level: 28% to 45% of network expansion needs would be covered by IGTs, and network expansion would be accelerated by 5 to 8 years
- At DSO level: 26% to 43% of network expansion needs would be covered by IGTs, and network expansion would be accelerated by 4 to 7 years

Benefits of IGTs compared to network expansion needs and past trend (line length equivalent), in FR, DE, ES, IT, DK, NL and GB



Despite the substantial benefits IGTs could provide to the energy transition, their deployment is currently hindered by several barriers

Barriers for IGT deployment

1 **Lack of incentives to opt for non-CAPEX intensive solutions**	• Historical regulatory systems for electricity networks were typically designed to finance large amounts of capital expenditure, so CAPEX is often remunerated with a regulatory cost of capital, and more advantageous than OPEX. • In several regulatory regimes, there is a bias against OPEX solutions, towards CAPEX.
2 **Insufficient output incentives and incentives for innovation**	Regulated networks often face incentives that may not provide for optimal operational and investment decisions: Revenue is often directly linked to costs and not to output. Innovation and (calculated) risk-taking is often not rewarded, with two effects: • First, network operators may not have incentives to use overall cheaper solutions – even less so, if those solutions involve innovation and/or a manageable increase in operational risk. • Second, innovations that may increase output while leaving costs constant are not financially encouraged either. Again, even less so, if those innovations involve a different approach to risk management.
3 **Investment doctrine and methodologies of network operators**	• The investment doctrine of T/DSOs might include bias towards predetermined solutions to fix perceived issues, rather than adopting a technology-neutral approach to answer the system needs identified. • In particular, using IGTs as an alternative solution to fix network constraints may not be adequately reflected in the doctrine, its practical application and in the incentive given to decision makers.
4 **Death by pilot risk**	• T/DSOs are responsible for ensuring security of supply for consumers and have hence an incentive to maintain high reliability standards with regards to network components. IGT adoption is hence often hindered by long processes for network companies to trial and then adopt new innovative solutions. • Moreover, the need for (several) demonstration projects to convince TSOs of the reliability/accountability of a technology before it can be rolled-out can create financial risks for IGT providers, creating funding challenges without a clear visibility on future revenues.
5 **Funding schemes eligibility issues**	• Some of the potentially available funding schemes cannot easily be accessed by IGTs yet, compared to other energy technologies such as hydrogen or CCS, due to eligibility issues of IGTs.

Sources: Compass Lexecon, based on interviews with IGT representatives and industry members, as well as regulators, Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, CurrENT (2023) Delivering on electricity grids – CurrENT recommendations for the European Commission

Regulatory solutions exist to remove these barriers, and have already been implemented in some European countries (1/3)

Barriers for IGT deployment	Potential solutions and case studies
1 Lack of incentives to opt for non-CAPEX intensive solutions	**TOTEX Regulation** ▪ Similar treatment of CAPEX and OPEX, wrt. regulatory cost audits, capitalisation rules and potential efficiency factors or sharing factors, can remove a possible incentive to prefer CAPEX over OPEX solutions, as in the UK
	Introduce possibility of OPEX increase ▪ Allowing an OPEX-benchmark that rises during the regulatory period can solve the distortion coming from delays in getting rising OPEX into the allowed regulated revenue, compared to a preferential treatment of CAPEX. This can be done by: – Basing the OPEX-benchmark on cost projections (For example based on forward-looking budgets business plans as demonstrated by the UK example) – By allowing additional OPEX increase based on measurable factors (e.g. installed RES capacity)
2 Insufficient output incentives and incentives for innovation	**Make remuneration output-based if possible** ▪ Within the limits given by the regulated nature of network companies, the remuneration of networks should be output-based, e.g. connected to achieving certain targets. ▪ The Italian incentive to increase cross-zonal capacity is a very good example in case, since it gives the TSO directly the incentive to focus on one of the outputs that matter: transfer capacity.
	Decouple remuneration from CAPEX ▪ Benefit-based regulation and the Italian premium for the use of capital-light solutions represent ways in which the remuneration of network operators is decoupled from actual CAPEX. This creates the possibility and the incentive for the network company to seek for alternative solutions that also fulfil the needs. Thereby, a win-win situation between customers and network companies can be created, in which a) costs are decreased and b) the company can achieve higher reward. This is conceptually very similar to the general idea of incentive regulation, but specifically applied to CAPEX. ▪ Such regulatory regime has also been implemented in the UK

Source: Compass Lexecon

Regulatory solutions exist to remove these barriers, and have already been implemented in some European countries (2/3)

Barriers for IGT deployment	Potential solutions and case studies
3 Investment doctrine and methodologies of network operators	**Obligation to implement the NOVA principle** ▪ According to German TSOs' NOVA principle, grid optimisation must be considered over grid reinforcement, over grid expansion. This should be applied following a technology-neutral approach. This provides a framework for solving network needs by maximising the use of existing assets and limiting the need for major infrastructure works. This principle, is key in limiting the environmental impact of network upgrades, and could be implemented as a rule for network operators when evaluating interventions.
	Technology-neutral approach to solve grid constraints, with toolbox of possible interventions defined in advance ▪ System planning could benefit from a technology-neutral approach to system planning, with for instance the following standardised steps each time a constraint is identified: 1/ identification of the root causes of the issue, 2/ mapping of the different alternative solutions, 3/ comparison of the solutions based on a multi-dimensional assessment ▪ Moreover, following the UK example, a list of standard interventions could be defined in advance for the planning of network investments, in could be used to assess the most relevant one.
4 Death by pilot risk	**Lump-sum innovation funding / WACC premiums to account for specific risks** ▪ Lump-sum innovation funding for the recovery of costs incurred during demonstration projects for the adoption of new technologies could compel network operators to spend more on riskier projects. E.g. implemented in Norway and in the UK
	Regulatory sandboxes ▪ The adoption of new technologies could be favoured by the implementation of regulatory sandboxes, for instance granting exemption to the current regulatory framework, hereby facilitating the experimental deployment of innovative technologies
	Transfer of best-practices and standards ▪ The transfer of best practices/standards between countries in Europe could avoid lengthy adoption process to be repeated, every time another network operator is investigated into a new technology, hereby facilitating the early adoption of IGTs

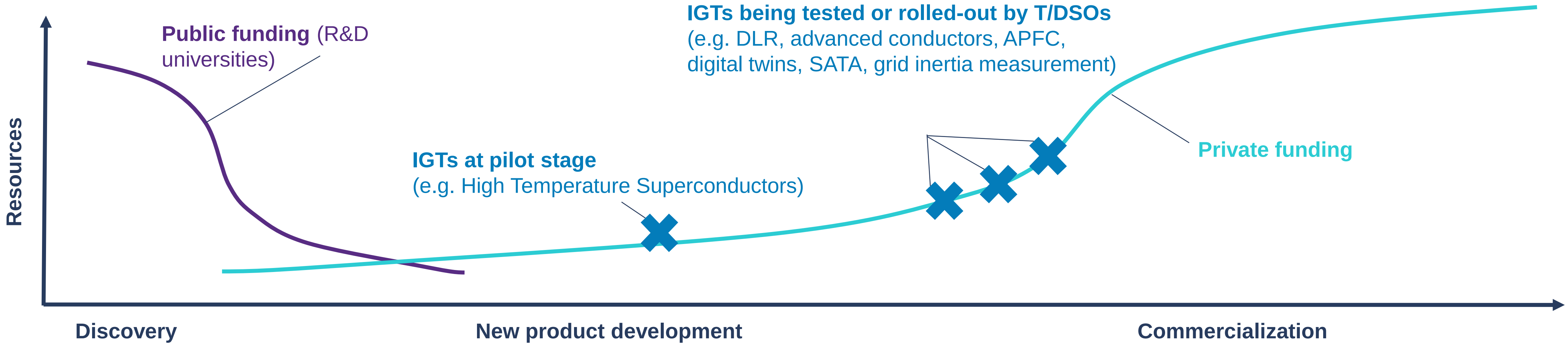
Source: Compass Lexecon

Regulatory solutions exist to remove these barriers, and have already been implemented in some European countries (3/3)

Barriers for IGT deployment	Potential solutions and case studies
5 Funding schemes eligibility	**Widen eligibility of EU-financing schemes to IGTs,** ▪ By making sure all sources of funding do explicitly include IGTs, access to financing could be made easier. Sector-specific calls for IGTs, with adjusted award criteria / requirements could play a key role as well, as foreseen in recent changes in the Innovation Fund Delegated Act .

Source: Compass Lexecon

Depending on the technological / commercial maturity of the technology, different measures are suitable to allow for faster IGT adoption



IGT adoption is facing different barriers, depending on its technological and commercial maturity. Each of them could be tackled with appropriate regulatory measures

4 **Death-by-pilot risk**	Lump-sum innovation funding / WACC premiums, regulatory sandboxes, Transfer of best-practices and standards
1 **Lack of incentives for non-CAPEX intensive solutions**	TOTEX regulation, possibility of OPEX increase
2 **Insufficient output incentives**	Output-based remuneration, decoupled from CAPEX spent
3 **Network operators investment doctrine**	NOVA principle, Technology-neutral planning approach
5 **Eligibility issue of IGTs within funding schemes**	Widen eligibility of national and EU-financing schemes to IGTs

Source: Compass Lexecon, adapted from Hartley & Medlock (2017) The Valley of Death for New Energy technologies

Conclusion: an update of regulatory incentives could foster the roll-out of IGTs and provide major benefits to the system

Regulators and network companies are currently locked in a lose-lose situation:

Network companies have limited incentive to innovate, as it comes with additional risks which might not be rewarded

Regulators have limited appetite to change regulatory approaches, for fear of a) it not being effective and b) of potential side effects of substantial changes

- **Network companies operate under incentives that don't reward or even punish them for innovating**, which might favour institutional conservatism towards conventional technology solutions.
- **Regulators are focussed on historical regulatory approaches, and may fear that any substantial change could have negative effects** and lead to political criticism. The implementation of regulatory schemes for network operators which set targets, give incentives and allow flexibility for how those targets are reached might seem risky to them.

Regulators and network companies could be in a win-win situation, should the proper regulatory incentives be implemented

Network companies could have the freedom to find the most efficient solutions and be rewarded for it

Regulators could see results more quickly, and network challenges and bottlenecks addressed more quickly

- **Network companies could use the new technological possibilities** and the more flexible regulation to speed-up the rollout of innovative grid technologies and provide major benefits to the system.
- **Regulators could learn from existing experience with the introduction of appropriate incentives and implement updated regulatory approaches**. Encouraging results like lower constraint costs and reduced bottlenecks to network deployment could soon follow.

1.

Indicative estimation of grid capacity expansion in timeframe 2025, 2030 and 2040

1.1

Overview of existing studies

A review of network development plans shows significant network expansion needs in the near to medium term

Network development plans across European countries are aligned on the need for significant network expansion

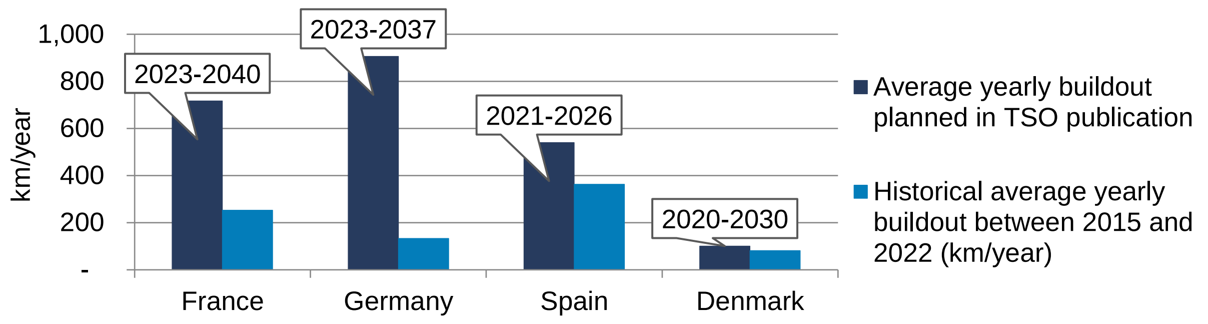
- Between 2015 and 2022, the size of the transmission network has been increasing by ~0.5-1.5% on average across the countries included in the scope of this study.
- Relative to that, TSOs are planning an accelerated grid expansion in the next decade: TSOs publications reveal that, on average across France, Germany, Spain and Denmark, **the buildout of additional grid (measured in km/year) needs to at least triple.**
- Given that required buildout is faster compared to historical buildout rates, the **delivery capacity of TSOs and supply chains** might be under strain.

  This comes at a significant cost for consumers – depending on the countries, investment volumes in grid expansion range from 6 m€/year per GW of peak demand, to **more than 100 m€/year.**

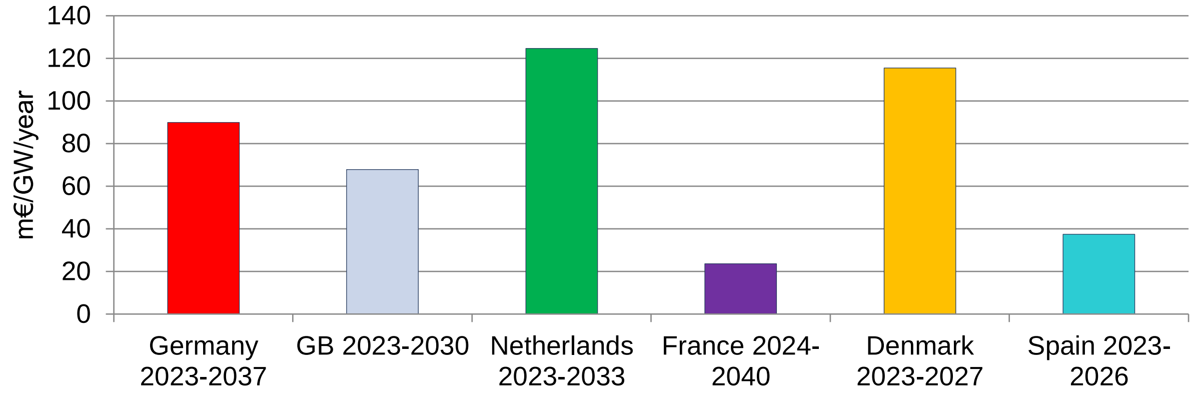
Transmission network development plans typically only cover investment needs for the next ten years, and might not always reflect decarbonisation objectives

- TSO's investment plans typically cover a 10-year period, such that extrapolation is needed to estimate network investment costs up until 2040.

Average growth in TSO network size – Past and planned yearly buildout (km/year)



Annual investment in onshore network expansion / adaptation compared to 2022 peak demand (m€/GW/year)[1]



Source: CL analysis based on a review of TSOs investment plans and publications, and ENTSO-E network length data. [1] Approximation for France, share of investments dedicated to adaptation in 2027 (~35%), applied to the total projected investment between 2025 and 2040 (100 bn€)

Investment in offshore networks is necessary to harness the offshore wind potential in Europe

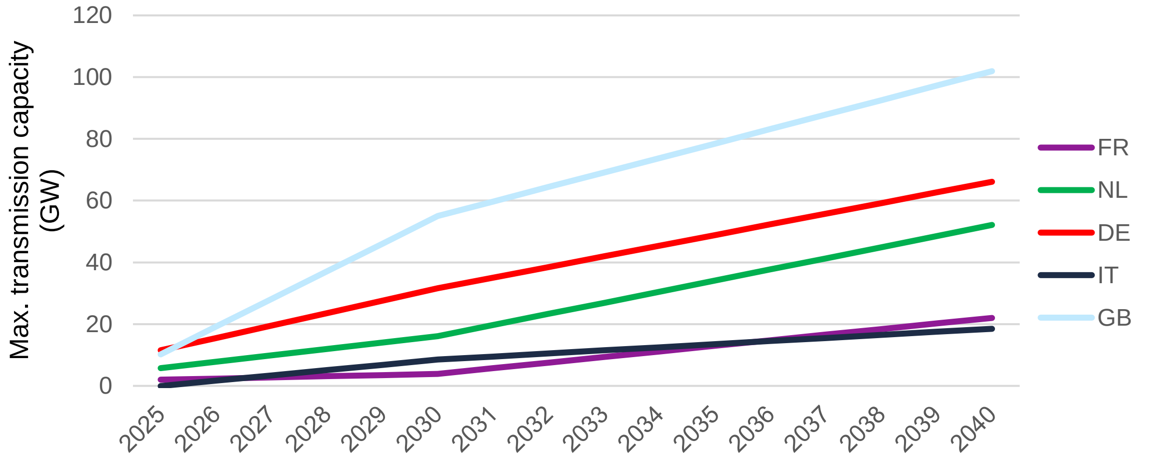
Making use of Europe's offshore wind potential requires substantial investments in offshore networks

- Offshore infrastructure development needs are assessed by ENTSO-E in the Offshore Network Development Plan (ONDP) published in 2024.
- The plan builds on the European Member States' non-binding agreements on offshore goals as of January 2023 and assesses the necessary future capacity increase of the offshore grid.
- At the EU-level, up to **371.6 bn€ of CAPEX**[1] for transmission network infrastructure will be needed between 2025 and 2040 to connect an expected offshore wind capacity of **270 GW by 2040 in the EU.**
- However, this first iteration of the ONDP does not consider onshore investments needed to connect the additional power produced offshore, as onshore implications are part of the TYNDP 2024 needs identification. In addition, it is based on non-binding offshore RES goals of the member states and uses a high-level linear optimisation approach that does not allow the evaluation of single projects.

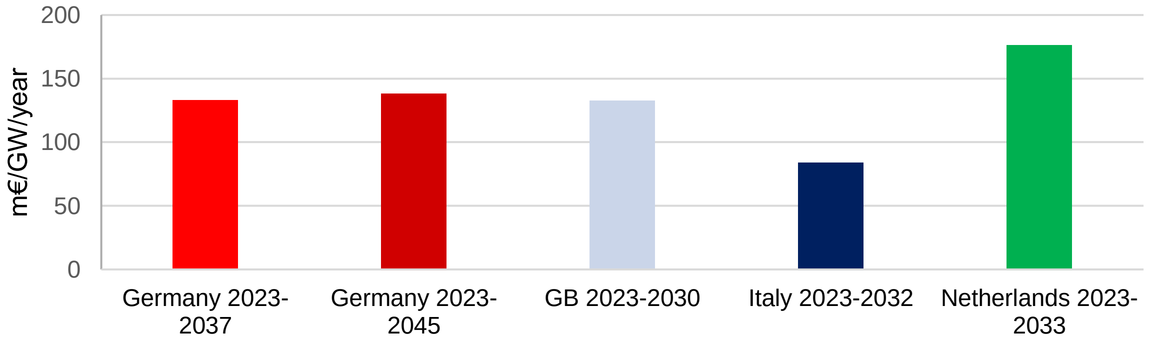
The integration of offshore wind farms to the grid also comes at a significant cost for consumers, which is already considered in TSOs investment plans

- On average, across Germany, GB, Italy, and the Netherlands, **each GW of offshore wind capacity** connected to the grid requires **around 130 m€ of investments in offshore grid on average.**

Maximum transmission offshore capacity (GW) – ENTSO-E ONDP



Planned investments in offshore grid compared to offshore wind capacity



Source: CL analysis based ENTSO-E (2024) Offshore Network Development Plans, ENTSO-E (2024) ONDP methodology, and on a review of TSOs investment plans and publications

Increasing interconnection capacity is a key enabler of the decarbonisation of electricity systems in Europe

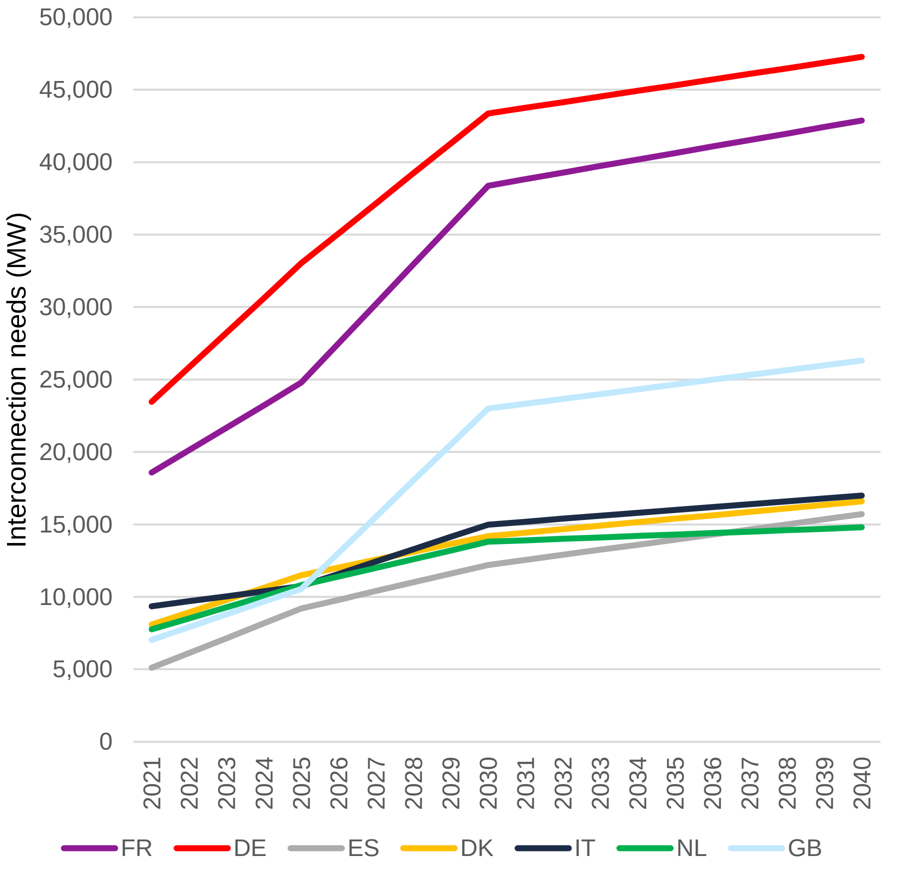
Increasing interconnection between EU countries is key to reach EU climate targets

- In the System Needs study from 2023, ENTSO-E finds that developing **an additional 88 GW of cross-border capacity between 2025 and 2040** in Europe would be **economically efficient.**[1]
- This represents a 95% increase compared to the total cross-border transmission capacity in 2022 (93 GW).
- **Such interconnection capacity would provide major benefits to consumers.** Compared to a situation in which the interconnection capacity would remain constant, this additional interconnection capacity would for instance allow for:
  - **Avoided curtailment that increases over time, reaching 17 TWh/year of avoided curtailment in 2030 and 42 TWh/year in 2040 (-53%),** compared to a scenario where no additional interconnection capacity is built after 2025.
  - **Savings in generation costs that increase over time, reaching 5 bn€/year in 2030 and 9 bn€/year in 2040 (-7%),** compared to a scenario where no additional interconnection capacity is built after 2025.

However, ENTSO-E System Needs study might underestimate the interconnection capacity required to reach net-zero targets

- The “National Trends” scenario is assumed, which is based on national and EU climate policies of past years, instead of a decarbonisation pathway, (such as the Distributed energy scenario). This scenario might hence not reflect a pathway ambitious enough for the EU to reach net-zero by 2050.

Interconnection needs (MW) – ENTSO-E IoSN TYNDP 2022



Note: [1] The estimation of 88GW is based on the cost of line development, and not on IGTs development

Source: CL analysis based on ENTSO (2023) TYNDP 2022 System Needs Study - Opportunities for a more efficient European power system in 2030 and 2040, and CurrENT (2023) Response 2024 TYNDP scenarios

Substantive investments in distribution networks are necessary to push the energy transition forward

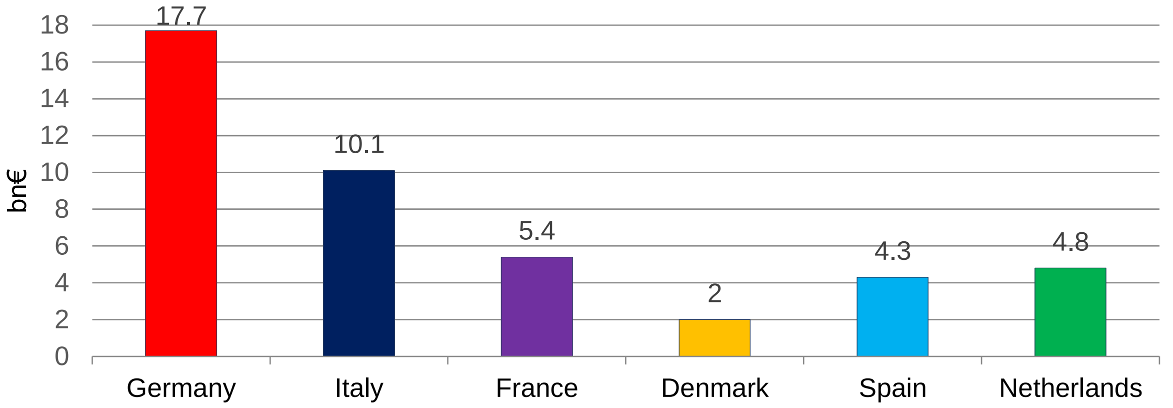
Eurelectric's "Grid for Speed" study shows the significant need for investment in the distribution grid until 2050 on a country-level

- To achieve the net zero goal by 2050, Germany, Italy and France are estimated to account for the highest necessary investments. Investments in these three countries make up 50% of EU-wide distribution grid investments until 2050.
- The investment per capita necessary until 2050 is highest in Norway, Denmark and the Netherlands.
- In countries with multiple and diverse DSOs, the investment needs for distribution networks tend to be higher.

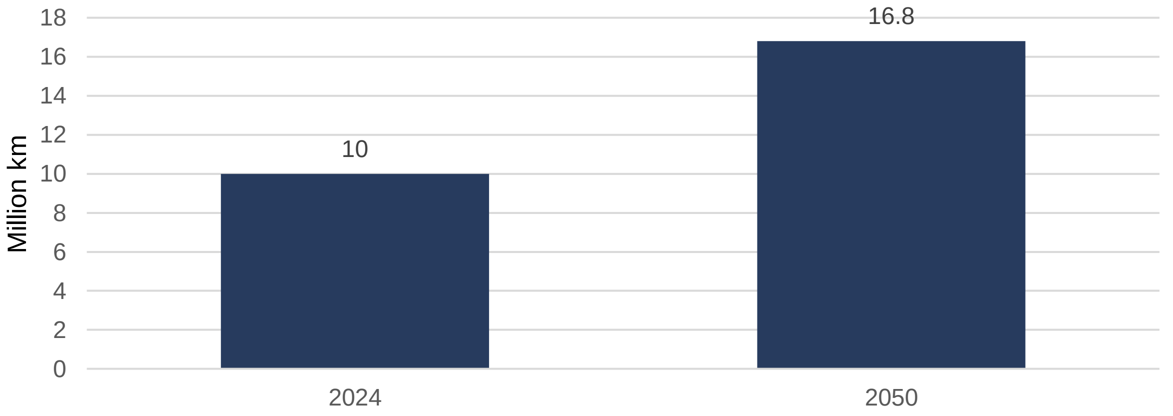
The distribution network length is estimated to grow 1.7-fold by 2050

- Reaching the energy transition requires the distribution grid's size to grow substantially. From 2025 to 2050, the annual additions to the distribution network length amount to 262,000 km in the EU27 + Norway.
- In addition to the network length, the number of transformers needs to double by 2050.

Annual distribution grid investment from 2025 – 2050 by country (bn€)



EU27 + Norway distribution grid length in 2024 and necessary length in 2050 for a successful energy transition (Million km)



Source: CL analysis based on Eureletric (2024): Grids for Speed

1.2

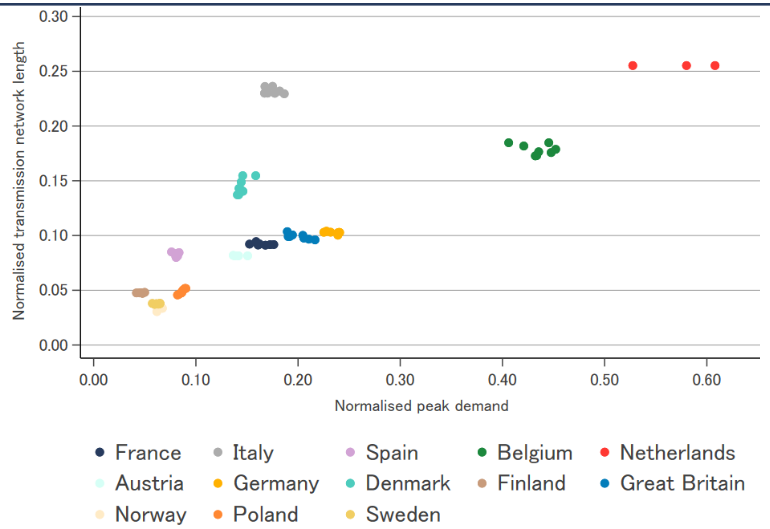
Drivers of grid capacity expansion and how they will develop

Historically, the length of the electricity transmission network has shown a positive relation with installed RES capacity and peak demand

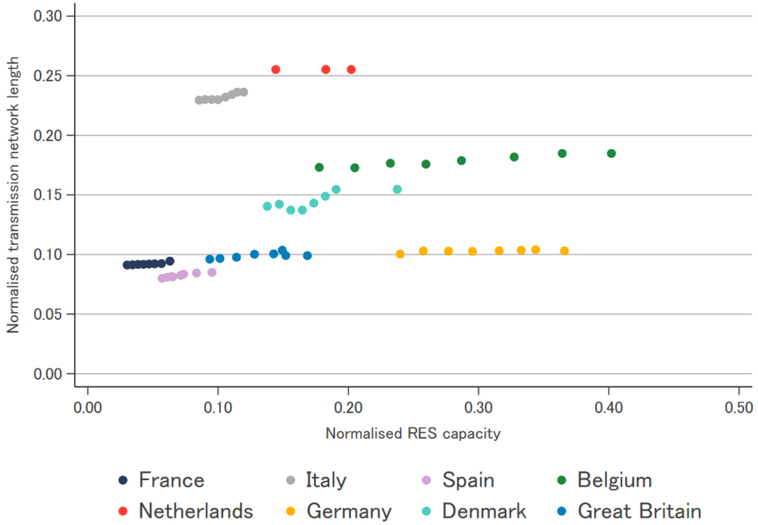
Evidence from selected European countries from 2015-2022

- Historically, the length of the transmission network has shown a positive relation with peak demand and installed RES capacity.
- Furthermore, in the short term, year-on-year changes in national peak demand are quite volatile and mainly driven by weather conditions (e.g. occurrence and intensity of cold/heat waves). However, at the cross-country level, the magnitude of average peak demand appears to be strongly correlated with the length of the transmission network. The electrification of new end uses such as heating and transport could lead to an increasing trend in peak demand, which would translate into a need for additional network capacity.
- With regards to RES capacity, countries with more RES-capacity also tend to have more transmission length - although this is likely also driven by the fact that larger countries tend to have more transmission length and RES capacity. However, RES-buildout seems to also trigger an increase in network length within the respective countries. Possibly RES-buildout triggers an increase in congestion costs in countries before network investment can catch-up (see next page).

Transmission network length (km/km²) vs. Peak demand (MW/km²), normalised by country size



Transmission network length (km/km²) vs. RES capacity (MW/km²) normalised by country size

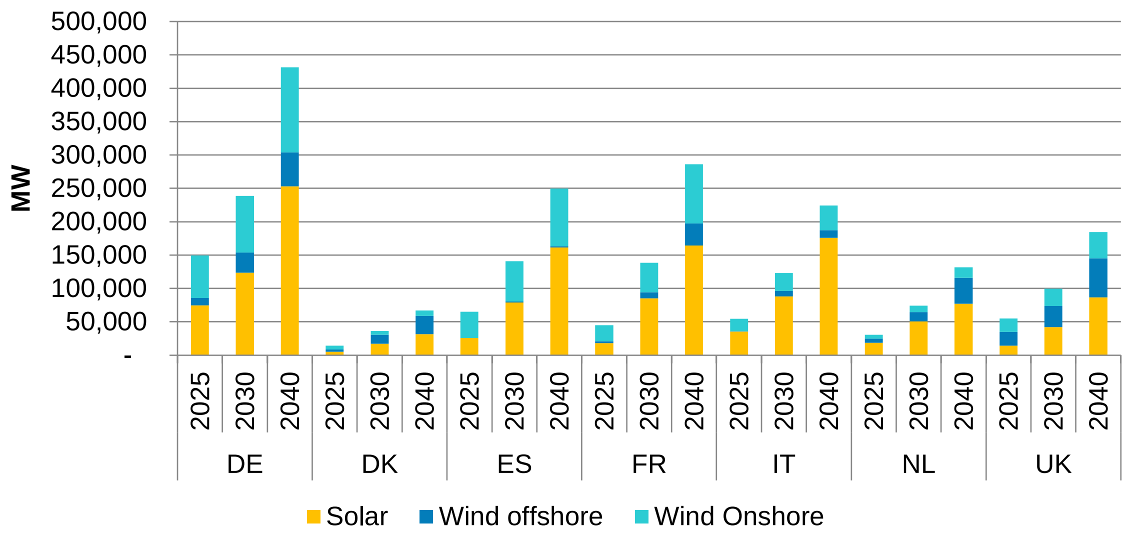


The increasing RES capacity is expected to create massive infeed in electricity networks, and hence a need for grid reinforcement

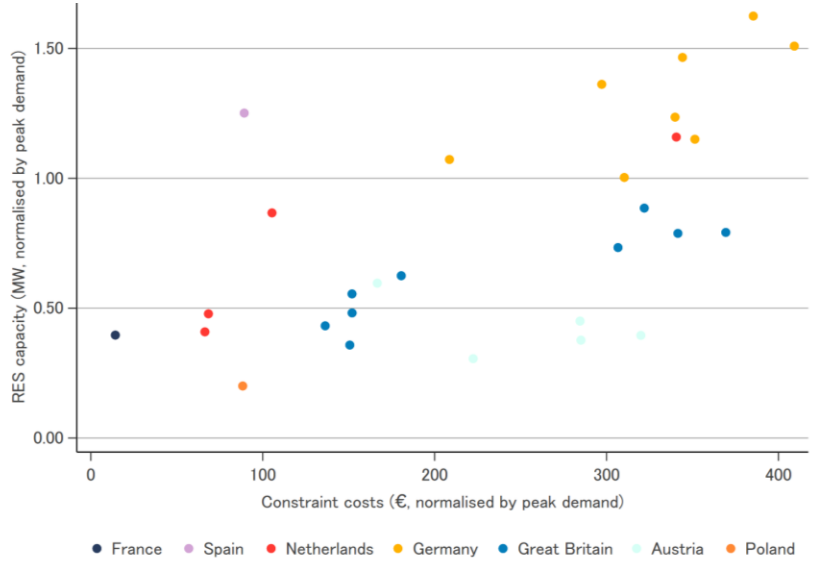
Onshore and offshore RES capacity is expected to significantly increase by 2040, leading to growth in RES infeed into the distribution and transmission grid

- For instance, the intermittent RES capacity is expected to increase by **325% on average between 2025 and 2040 in the selected countries**, as of the TYNDP 2022 distributed energy scenario. In the EU, RES capacity is expected to increase by 325% during the same period. From 2025 to 2050, the increase in total RES-capacity in the EU is expected to be made up by solar increasing from 225 GW to 1,150 GW, onshore wind from 230 GW to 670 GW, and offshore wind from 25 GW to 200 GW.
- Historically, the increase in RES capacity was associated with an increase in congestion costs, as shown in the right-hand side graph below. Resolving congestion constraints, and hence reducing congestion costs, requires additional grid capacity and better utilisation of existing grid assets.

Projected RES capacity in selected countries – TYNDP 2022 – National Trends (2025) and Distributed Energy scenario (2030 and 2040)



Relationship between RES capacity and congestion costs > 1 m€ (normalised by peak demand), 2015-2022

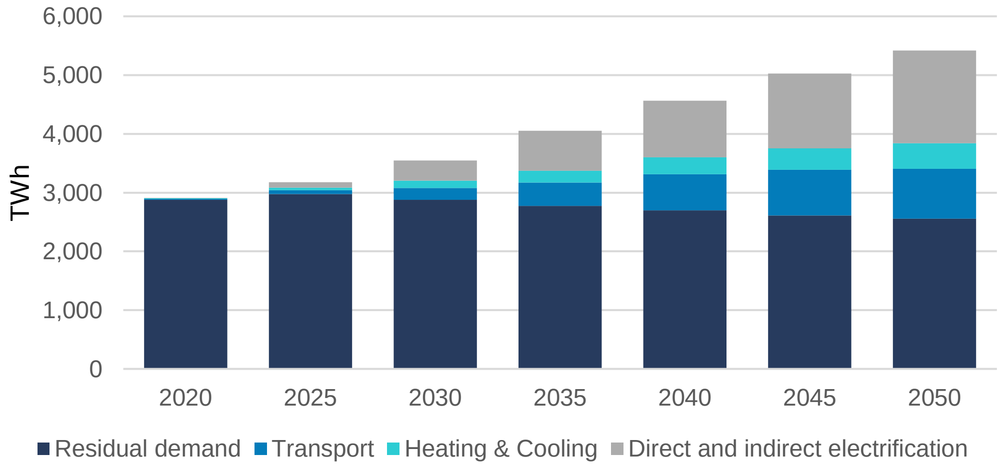


Source: CL analysis based on ENTSOE TYNDP 2022 and ENTSO-E transparency data

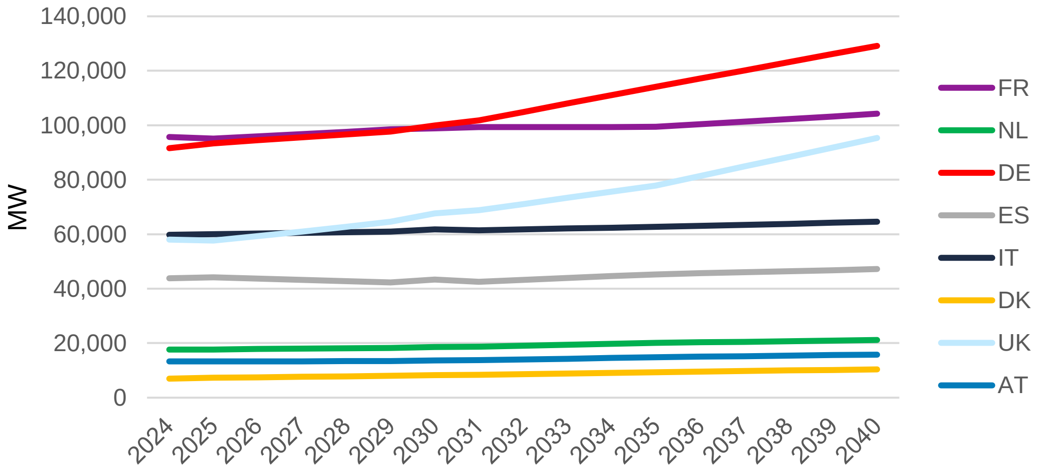
Despite the growing flexibility of electricity consumers, the electrification of new end uses is expected to increase peak demand

- Electricity demand is expected to increase from around 3,000 TWh today to around 5,500 TWh in 2050 in the CL reference scenario, driven by the electrification of new end uses, for instance in the transport, heating and industrial sector.
- Despite the growing flexibility of electricity consumers, peak demand is expected to significantly increase in this period. This can typically lead to network reinforcement needs, for instance in urban or industrial areas. According to Compass Lexecon in-house modelling, **peak demand could increase by 15%** in the EU **between 2025 and 2040, from approximately 550 GW to more than 630 GW**, and by 26% on average across the selected countries for this study. In GB, peak demand is even expected to increase by 68%.
- This estimation already assumes that the consumption of a given share of EVs, HPs and electrolysers will be flexible in the future, hereby mitigating the increase in peak demand. Peak demand is hence expected to grow to a lesser extent than total demand.

EU 27 Projected demand – CL reference scenario



Projected Peak demand – Assuming climatic year 2009



Source: CL analysis based on ENTSO-E climate database, based on national policy targets and TSOs scenarios

1.3

Need for grid expansion in Europe by 2030-40

A panel regression model can be used to estimate future network expansion needs (1/2)

The historical evolution of network length can be explained with a panel regression model, with RES capacity, peak demand, constraint costs, countries and years as key regression factors:

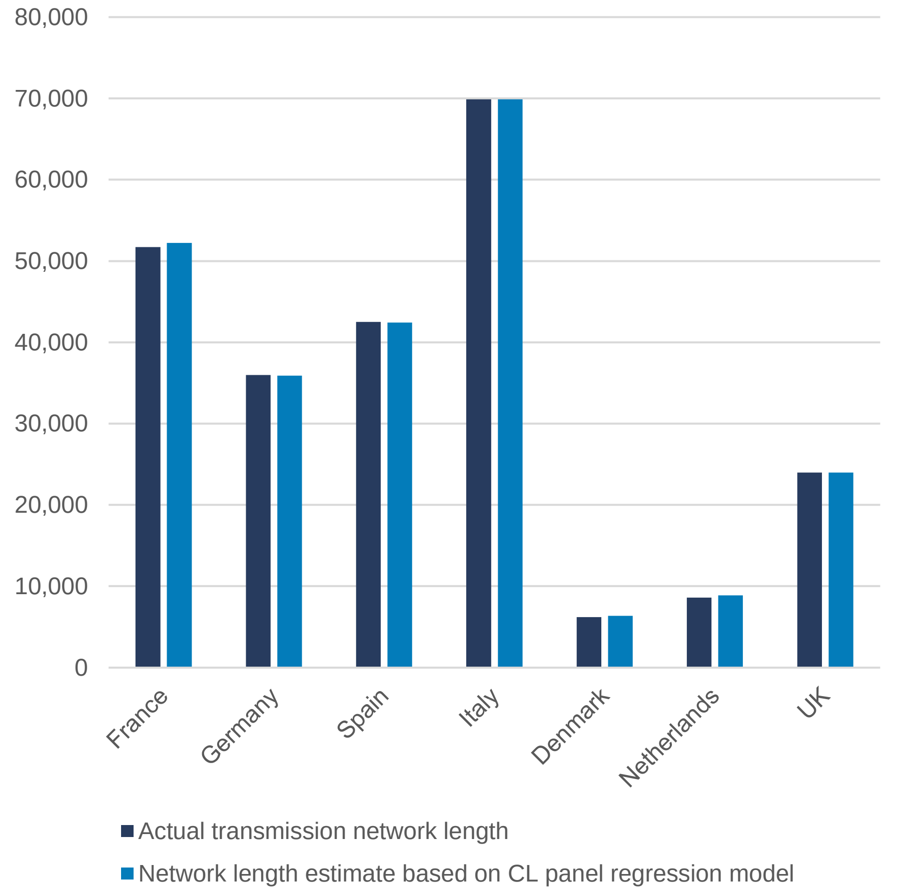
- Network length is determined by several key factors, among which RES capacity, peak demand, and constraint costs.
- In addition, specific factors can be introduced in the regression to capture country- and time-specific differences in the data. Indeed, country-specificities for which no data is available, but which are still crucial to determine the network length play a role and can be considered through country-fixed effects ($Country_i$). The same holds for unobserved effects on the network length in certain years, which can be accounted for through year-fixed effects ($Year_t$).
- For each country i and year t, the following regression equation can hence be calculated:

$$\boxed{\begin{aligned}&Network\ length_{i,t}\\&= \beta_0 + \beta_1 * RES_{i,t} + \beta_2 * Peak\ demand_{i,t} + \beta_3 * Constraint\ costs_{i,t} + Country_i + Year_t + \varepsilon_{i,t}\end{aligned}}$$

Such model can be trained on publicly available data to estimate the respective weights of each factor

- We gathered coherent data on 12 different countries in Europe over the period of 2015-2022, from various publicly available sources, including the ENTSO-E inventory of transmission, the ENTSO-E Transparency platform and Eurostat.
- Using this data in a regression analysis, we were able to set up a prediction model for the future required network length at the TSO- and DSO-level. By achieving a close match to actual historic network lengths for countries where regression data is available (see graph on the right-hand side), we were able to get sufficient comfort on this regression equation.

Panel regression model – Estimated vs. actual length of transmission network length in 2022 (km)



A panel regression model can be used to estimate future network expansion needs (2/2)

The regression analysis can then be used to estimate the potential future trend of network length, mainly driven by the increasing domestic peak demand and RES capacity presented in section 1.2.

- To forecast network lengths up to 2040 based on the estimation using historic data, we used the closely matched network length in 2022 as a starting point, adding the estimated increases in network length in each subsequent year.
- The table on the right-hand side shows the coefficient ranges used to estimate the increases in future transmission network length (coefficients for the distribution network length are provided in Appendix 1.C). Ranges are built based on the estimates that most closely fit the TSO buildout-plans in the different countries observed. For both, transmission and distribution network lengths, this holds true for the regressions with country-fixed effects (detailed results can be found in Appendix 1.A and 1.B, an explanation of the econometric approach is provided in Appendix 1.D).
- Except for a slightly negative estimate for the Peak-demand coefficient at the minimum, the coefficients have the expected signs, representing a positive effect of higher RES and peak demand on the transmission network length in a country. The impact of congestion costs on transmission network length is negative, meaning that higher congestion costs are associated to a lower network length, which is what one would expect. Reassuringly, these relationships also hold in most other specifications we considered to predict the network length (see Appendix 1.A and 1.B).
- The assumption for future peak demand and future RES capacity between now and 2040 are respectively based on CL in-house modelling and the ENTSO-E TYNDP 2022 distributed energy scenario.

Estimated coefficients used to forecast transmission network length – Country-fixed effect specification

Variable	Coefficient	
	Min	Max
RES	0.045	0.057
Peak demand	-0.002	0.008
Constraint costs	-0.00007	-0.00003
Austria	-8,437	-8,235
Belgium	-10,080	-9,912
Germany	15,346	17,964
Denmark	-9,658	-9,386
Spain	24,089	24,243
Finland	-799	-530
France	33,558	34,389
UK	7,424	8,640
Italy	51,784	52,262
Netherlands	-6,801	-6,661
Norway	-3,260	-3,090
Poland	-705	-484
Constant	14,732	15,165

The trend of the underlying drivers of network length[1] would lead to a +5% to +30% transmission network expansion need by 2040

Results

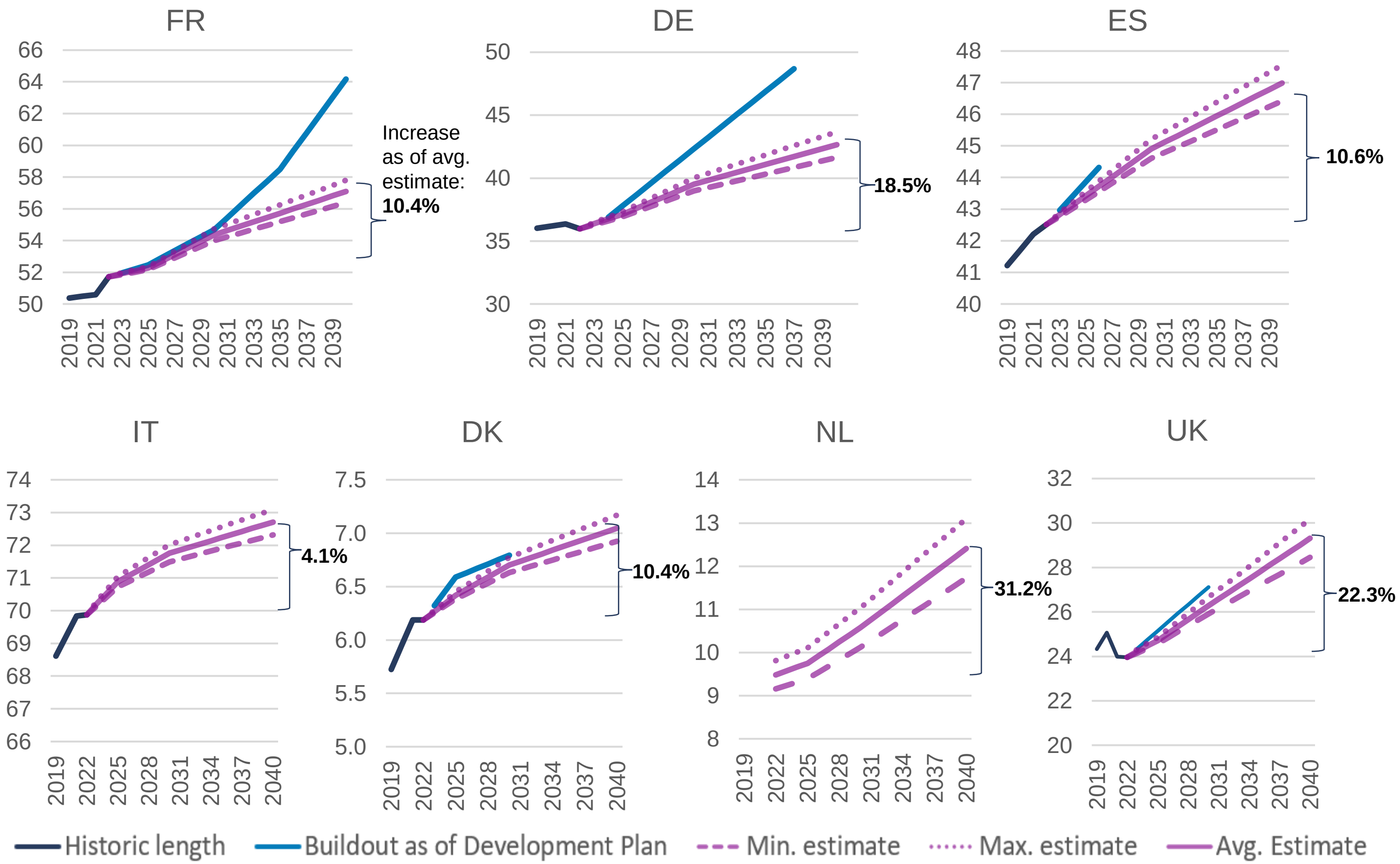
- Depending on the countries, the methodology and assumptions described on the previous page lead to a ~5% (in Italy) to 30% (in the Netherlands) increase in network length at the transmission level by 2040 – 18% on average between the 7 countries in the scope of this report.
- Differences between countries are driven by the different trends of RES capacity and peak demand assumed.

Limitations

- This regression analysis matches some network development plans of TSOs reasonably well, for instance for Denmark and the UK (blue lines).
- For others, this estimation of network expansion needs is lower, for instance in Germany or France. This estimation is indeed based on the continuation of past trends into the future. However, the unprecedent scale of RES integration challenges may result in grid expansion needs whose nature and scale cannot be compared with past observations. Moreover, the IEA estimates that the length of the transmission grid in the EU would need to increase by 50% by 2040.[3]

Overall, this tends to indicate that this estimate of expansion needs based on a regression analysis could be a very conservative estimate.

Extrapolation of transmission network length (thousand km)



Source: CL analysis, [1] the assumptions for the evolution trend of peak demand and installed RES capacity are presented in section 1.2, [2] for instance, in Germany, most of onshore investments by 2045 are planned between now and 2037 – Netzentwicklungsplan 2037/2045 (2023) [3] IEA (2023) Electricity grids and secure energy transitions – estimate based on IEA estimation of Installed line length, transmission and distribution, by region in the Announced Pledges Scenario, between 2021 and 2050. 2040 datapoint estimated as the average between 2030 and 2050.

The trend of the underlying drivers of network length[1] would lead to a +25% to +100% distribution network expansion need by 2040

Results

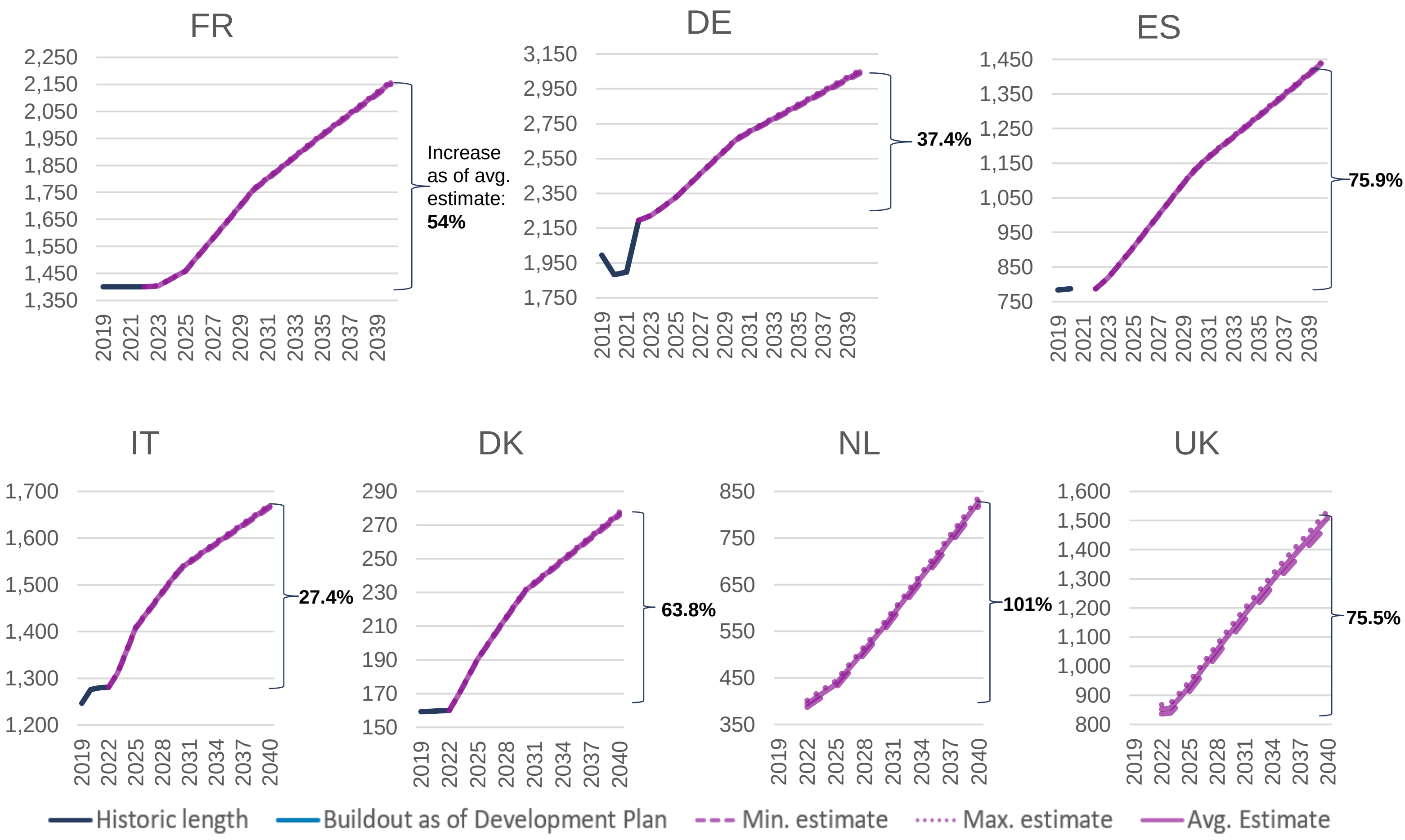
- Depending on the countries, the methodology and assumptions described in the previous page lead to a 25% to 100% increase in network length at the distribution level – 60% increase on average by 2040.
- Differences between countries are driven by the different trends of RES capacity and peak demand assumed.
- This estimate at the distribution level is higher than at the transmission level. This is consistent with the fact that most investments are expected at the distribution level. For instance, the IEA[2] estimates that ~85% of grid investments are expected at the distribution level in advanced economies

Limitations

- This estimation is above IEA's estimate of distribution network buildout for the EU (31% by 2050)[2], and above Eurelectric's estimate (68% increase until 2050)[3].
- However, this estimation is in line with IEA's global estimate, at around 67% by 2040[2].

This regression analysis might hence overestimate expansion needs at the distribution level.

Extrapolation of distribution network length (thousand km)



Source: CL analysis, [1] the assumptions for the evolution trend of peak demand and installed RES capacity are presented in section 1.2, [2] IEA (2023) Electricity grids and secure energy transitions – estimate based on IEA estimation of Installed line length, transmission and distribution, by region in the Announced Pledges Scenario, between 2021 and 2050. 2040 datapoint estimated as the average between 2030 and 2050. [3] Eureletric (2024) Grids for Speed

2.

The potential of innovative grid technologies

2.1

Overview and use cases of innovative grid technologies

8 Innovative grid technologies (IGTs) are included in the scope of this report, among which 6 Grid-Enhancing Technologies (GETs)

Key technologies in the scope of the project

	Technology	Description	Technology Readiness Level (TRL) [1]	
1	Dynamic Line Rating (DLR)	Improve utilisation by providing greater visibility to system operators and allowing them to react to actual temperature and sag of a power line	TRL 9	GETs
2	Advanced Power Flow Control (APFC)	Unlock capacity by dynamically controlling power flows across the grid	TRL 9	GETs
3	High Temperature Superconductors (HTS)	Allows transmission of very high amounts of line capacity	TRL 9 at the distribution level TRL 5 at the transmission level	
4	Storage as a Transmission Asset (SATA)	Backup batteries allow for the override of the N-1 criterion [2]	TRL 9	GET
5	Advanced Conductors	Improved cables allow for higher capacities per line, and can often simply replace old power lines	TRL 9	
6	Digital Twins	Digital Twin technologies allow for a better understanding of what is happening on the grid	TRL 9	GETs
7	Flexibility management software solutions	Flexibility management solutions allow grid operators to manage and control the flow of electricity efficiently by actively managing the supply and demand of grid connected assets.	TRL 9	GETs
8	Grid inertia measurements	One grid constraint is, that a sufficient amount of inertia (rotating turbines stabilising the grid) must be present. Measuring inertia in real-time allows a) higher renewables operation on the grid / less redispatch for inertia reasons, and b) more targeted inertia procurement.	TRL 9	GETs

Among IGTs, Grid-Enhancing Technologies (GETs) is a term used mainly in the US, referring to technologies used to “maximise the transmission of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools”, according to the DoE (see US DoE (2022)). **IGTs can also be referred as GETs+.**

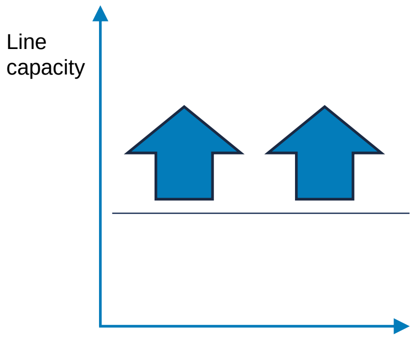
Notes: [1] The TRL indicates to what extent a technology is established in the market. TRL 9 reflects the highest technology readiness with an actual system being proven in an operational environment, while TRL 7 refers to a system prototype being demonstrated in an operational environment. (EC 2017)

[2] (N-1) criterion’ means the rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits. (EC 2017)

IGTs allow for a better utilization of the grid through four main effects

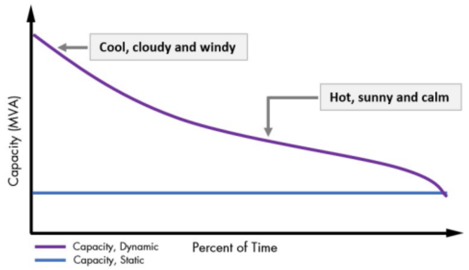
Main methods to increase grid capacity:

Capacity increase for a given line



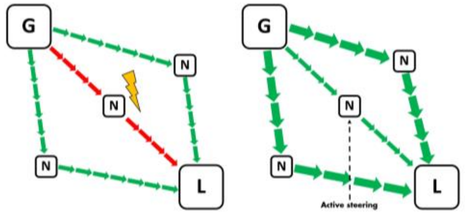
- Direct capacity improvement compared to conventional technologies

Better understanding of actual line limits



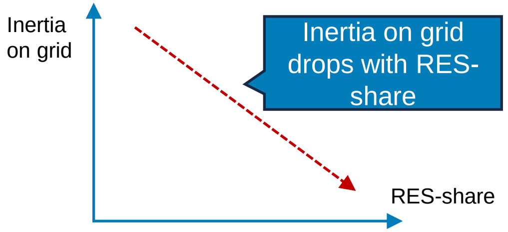
- A static limit must be very conservative, to not overload lines in adverse (hot) conditions;
- Dynamic ratings exploit natural line cooling

Dynamically controlling power flows on the grid



- Power flows through a network are often limited by its weakest line
- By dynamically controlling power flows (e.g. like road traffic management) more capacity is unlocked on the existing grid

Better understanding of actual inertia limits/stability limits



- Inertia on the grid decreases with more RES in the system, which may cause stability issues and RES curtailment
- Precise measurement of inertia allows curtailment to only happen when necessary

Techno-logical foundation:

- **Advanced conductors**
- **High Temperature Superconductor**
- **Storage as a transmission asset** (SATA)

- **Dynamic line rating** (DLR)

- **Advanced Power Flow Control** (APFC)

- **Grid inertia measurements**

- **Digital Twin, Flexibility management software solutions**

*Note: [1] The US term "Grid Enhancing technologies" can also be used to describe technologies that "maximise the transmission of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools", according to the DoE (see US DoE (2022)). **IGTs can hence also be referred as GETs+.***
this theoretical framework does not provide an exhaustive classification of IGTs, and of their effects. Other technologies and effects could potentially be considered.

IGTs can release capacity from existing grid assets in a relatively granular way

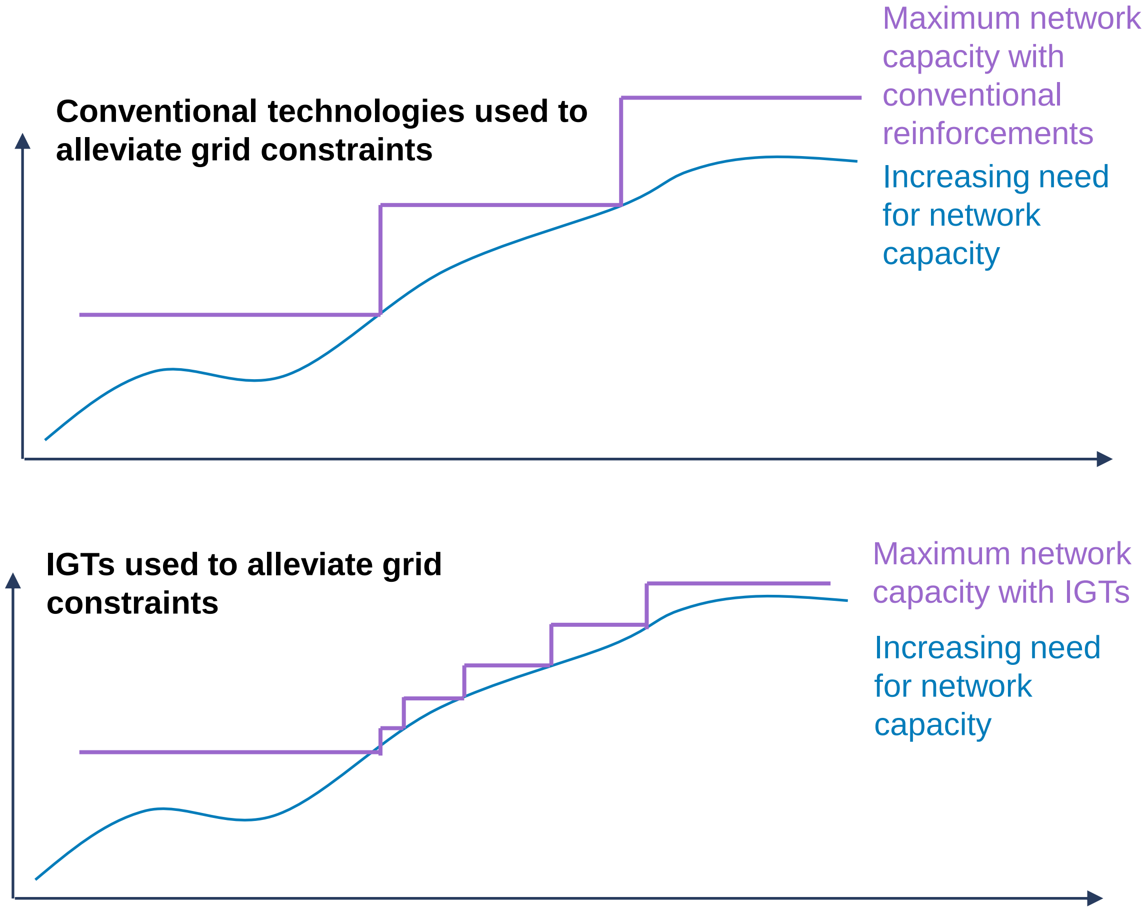
We previously estimated that the need for network buildout, in terms of the required expansion in line length equivalent, would amount to between 5% and 30% for transmission lines, and about 100% for distribution and interconnectors. From network development plans, we understand that:

- Excluding offshore, most increases in circuit length are to strengthen already existing links
- The European HV (transmission and distribution) network is meshed with two or more circuits in parallel, with very few truly radial connections. Security standards (e.g. static thermal rating, N-1) require these parallel circuits to operate well below their design limit, e.g. to allow for the loss of a circuit.
- For example, with two matched lines in parallel, the usable capacity is half (50%) the circuit's maximum rated capacity, such that, following a circuit loss, the remaining circuits are utilised less than 100%. Therefore, once the lines are loaded to 51%, a third line is required.

Compared to building new lines, IGTs can release capacity from existing grid assets in a relatively granular way:

- IGTs will add capacity that can be released on existing circuits, because lines are typically not fully utilised as of now.
- With conventional reinforcements, a 30% increase in circuit length for transmission would ultimately accommodate a 30% rise in the use of network capacity but would be triggered by a much smaller marginal need. The increase in capacity might not be required for several years.

Alleviating grid constraints with conventional technologies vs. IGTs



IGTs are typically complementary with one another, and are also complementary with conventional network reinforcement

IGT technologies are not mutually exclusive	▪ IGT technologies are not mutually exclusive, different IGTs can be used dependent on network needs, a range of solutions can make supply and installation easier, and they can typically be combined to offer greater capacity/benefit
IGTs are well-suited for incremental capacity improvements	▪ IGTs can achieve smaller capacity improvements more quickly compared to building new power lines – this can be useful to anticipate the investment need (if delivery is challenging for some reason) or to bridge the time until the investment comes through.
IGTs would be complementary with network reinforcement works	IGTs would ease, not slow other projects (e.g. new circuits) to meet the full need for network capacity growth. This is because: 1) IGTs can provide some capacity improvements quickly, which can in turn make it easier to schedule outages for the installation of larger projects like reconductoring or new circuits. 2) By being "grid multipliers" that make existing and newly installed physical grid infrastructure more effective, IGTs can make achieving buildout targets more realistic – both in terms of the scale of work required and in terms of costs. Moreover, in some network locations, IGTs could not be a substitute for conventional reinforcements – e.g. additional connections at the distribution level.

Using IGTs to increase and/or anticipate network capacity buildout could provide a range of benefits

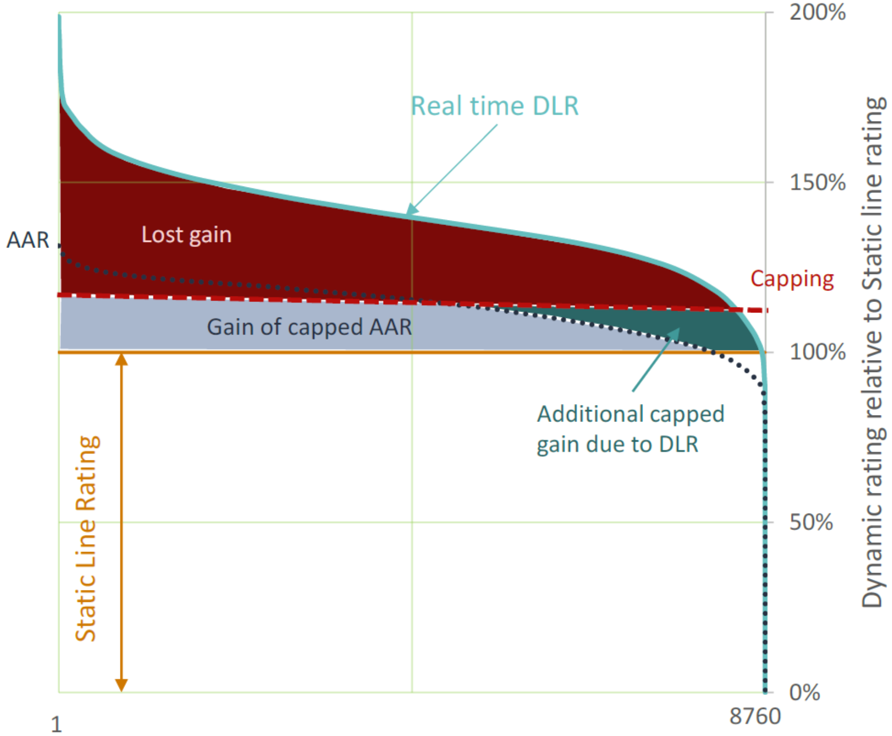
Short development lead time	▪ Project development lead time amounts to typically 1 to 2 years for most of the technologies, significantly shorter than the time needed to construct extra grid capacity
Limited environmental footprint	▪ Deploying IGTs allows for a lower environmental footprint compared to building new overhead lines / underground cables as IGTs typically use existing substation space or transmission / distribution corridors
Most IGTs are less capital cost intensive	▪ The scale of most IGTs projects is lower than conventional network reinforcement, leading to lower capital costs (incl. through reduced need for new infrastructure / new assets)
Reduced reliance on supply chain bottlenecks	▪ IGTs have for example a reduced impact on supply chain bottlenecks for copper or transformers compared to conventional grid expansion projects

Dynamic Line Rating – Description

Dynamic line rating maximises the transmission capacity of high-voltage lines

Principles	▪ Dynamic line rating (DLR) refers to the use of weather parameters, including wind, to increase the amount of current through conductors. Weather effects, such as wind cooling, ambient temperature, and solar irradiation, typically have a cooling effect which is neglected when not measured or modelled.
Benefits	▪ Better understanding of actual line limits
Details	▪ DLR goes beyond **static line rating** and **ambient adjusted rating (AAR)**: – **Static line rating** applies uniform weather conditions to all lines and is generally lower than AAR and DLR, to ensure a secure network operation – **AAR** requires line-specific, typically historical data to estimate the transmission capacity for given conditions. ▪ DLR uses **real-time sensor data or a simulation of the line condition** to identify the line capacity in any given moment based on line temperature, line sagging and ambient conditions (humidity, solar irradiance, wind, precipitation etc.) ▪ Sensors typically transmit the data to a **cloud/centralized control system** determining the line's current capacity ▪ Access to real-time data allows the system operator to **dynamically adjust** line capacity as well as to forecast dynamic capacity ▪ DLR can also be developed with digital twins ▪ **TRL 9** - DLR is an established, well-proven technology **employed by several TSOs**, among others Belgian "Elia", French "RTE", and Norwegian "Statnett".

Schematic comparison of static and dynamic current limit



Source: [1] Interview with Heimdall Power, [2] Ampacimon

Dynamic Line Rating – Benefits

DLR enables higher integration of RES by enabling TSOs to optimise line utilisation

Benefits of DLR

Reduction in congestion through optimisation of asset utilisation

- Enables TSO to dynamically adjust operational line limits while ensuring **network safety** and **reliability**
- Implementing DLR is estimated to **increase a line's capacity on average by ~10-45%**
- Supporting **integration of Renewables** by allowing for a reduced RES curtailment
- Can support **cost effective generation dispatch**

Examples from the literature

Source	KPI – Capacity increase
Elia (2019) "Smart grid world of innovations: dynamic line rating" ENTSO-E	• ~**30% increase** in a line's current
Pavlinić, A. and V. Komen (2017) "Direct monitoring methods of overhead line conductor temperature"	• Average **increase in transmission capacity of 10–15%**
Bhattari, B. et al (2018) "Improvement of transmission line ampacity utilization by weather-based dynamic line rating"	• Average **22% capacity increase over static ratings 76% of the time**
Brattle (2023) "Building a better grid: How grid-enhancing technologies Complement transmission buildouts"	• DLR provides **20% capacity gain** above static ratings for **90% of the time**
PR Newswire (2022) "National Grid and LineVision Deploy Largest Dynamic Line Rating Project in the United States"	• Average **increase in transmission capacity of over 30%**
LineVision (2022) "Duquesne Light Company Further Enhances Transmission Capacity, Reliability with Grid-Enhancing Technology"	• Dynamic line rating system sees **average 25% capacity increase across power lines**
Statnett (2023) "Increasing line capacity by 20% using data science"	• Increase the capacity of power lines with **up to 20%** • **Average increase of around 10-15%**
GlobeNewsWire (2020) "Multiple U.S. Utilities […] Adopt Dynamic Line Rating Technology […]"	• Safely increase **transmission capacity by over 15%** during peak load times
ENTSO-E (2024) "Dynamic Line Rating (DLR)"	• Ampacity **gains in Europe of 10–15%** can be expected over **90% of the time**

Source: CL analysis based on interview with Heimdall Power, IRENA (2020) DLR – Innovation landscape brief, Brattle (2023) "Building a better grid: How grid-enhancing technologies complement transmission buildouts"

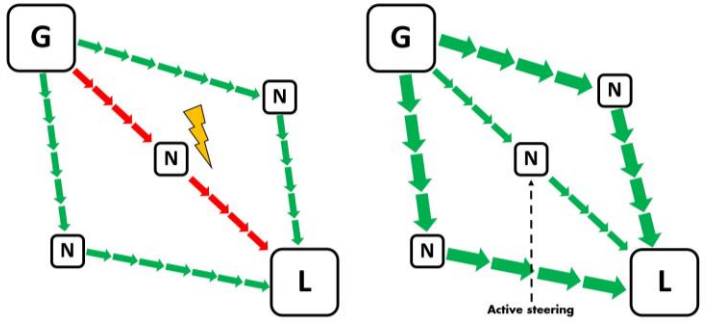
Advanced Power Flow Control – Description

Advanced Power Flow Control solutions redirect power from overloaded lines to underutilized lines

Principles	▪ Advanced Power Flow Control solutions redirect power from overloaded lines to underutilized lines, hence solving grid bottlenecks and creating extra grid capacity.
Benefits	▪ Dynamically controlling power flows on the grid
Details	▪ Power grids have historically operated as one-way nonflexible routes of energy. Power flows through the path of least resistance (impedance) which means that even if only one circuit reaches capacity the entire network is unable to absorb any more power. ▪ Advanced Power Flow Control solutions allow system operators to control the power flow of certain lines or parts of a transmission network, hence adapting flows to local constraints and unlocking additional grid capacity: − These systems are typically **modular Static Synchronous Series Compensators** (m-SSSC), which can be deployed in a range of different configurations, to meet the evolving needs of grid operators − These devices inject a voltage in quadrature with the line current, creating a capacitive or inductive reactance, which either ”push” power off overloaded lines, or “pull” power onto underutilized lines ▪ Advanced Power Flow Control can typically be controlled in real-time. ▪ **TRL 9** - already deployed in several countries including the UK, US, Australia and Colombia[1]

Smart Wires’ m-SSSC solution (SmartValve™)

Illustration – Dynamically controlling power flows on the grid



Source: CL analysis based on Smart Wires
[1] Smart Wires (2024) What is advanced power flow control?

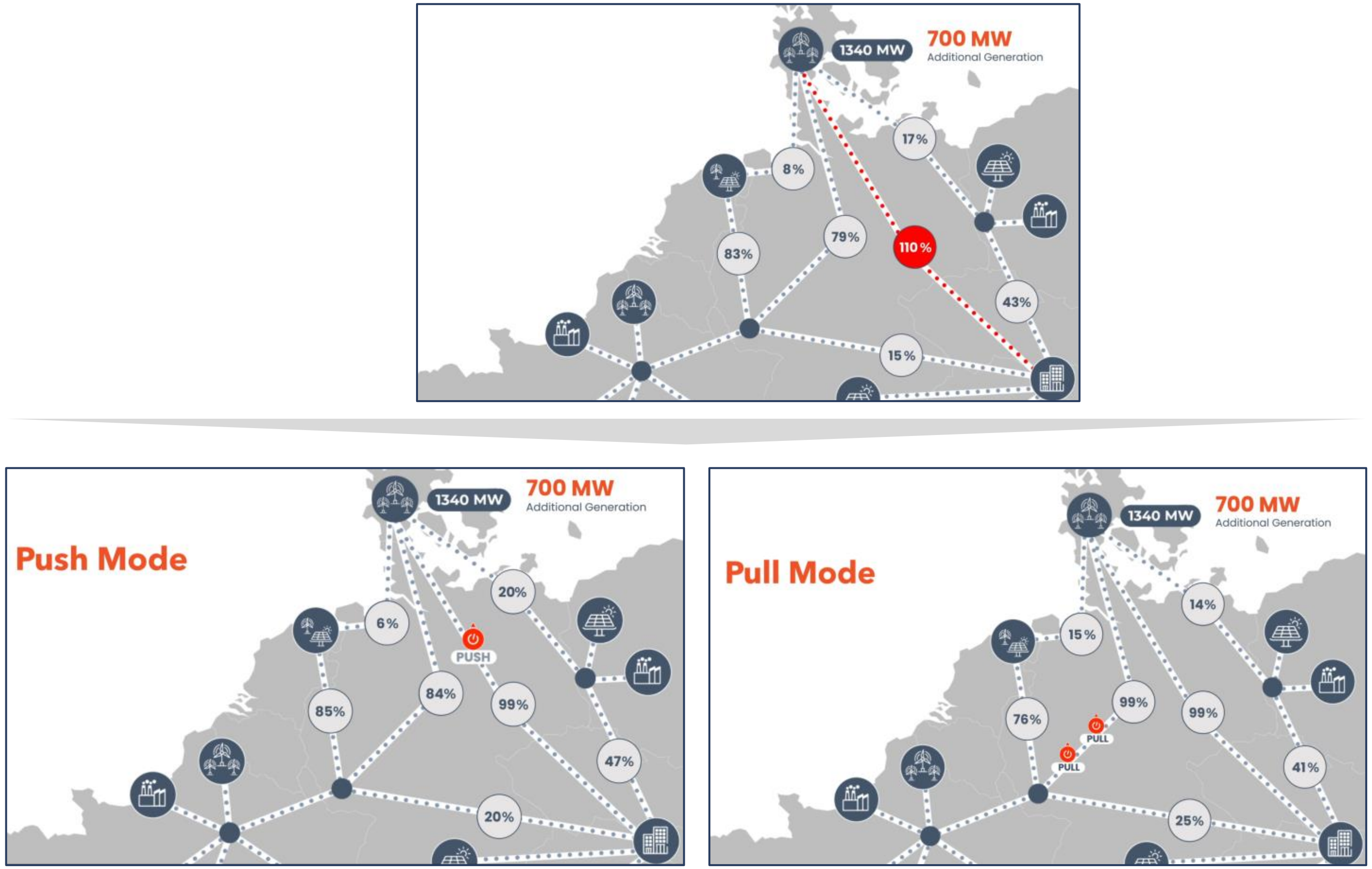
Advanced Power Flow Control – Benefits

APFC solutions allow system operators to limit grid congestion issues, hence unlocking extra grid capacity

Benefits of Advanced Power Flow Control solutions

- **Solve grid bottlenecks / Congestion management**
- **APFC solutions allow for quick reaction when congestion appears**
  - Project development lead time typically 1 to 2 years, significantly lower than conventional grid solutions to create grid capacity, e.g., building a new line.
- **Create extra grid capacity:**
  - For instance, in the UK, three deployments of SmartValves have created 2 GW of extra grid capacity. This amounts to 10% of grid capacity in the area where SmartValves have been deployed.
- **Modular and future-proof congestion management solution:**
  - This solution can be installed very quickly and can be moved from one location to another in case of changing system needs. APFC solutions can also help system operators to fully utilize new infrastructure once it is built.

Illustration – Grid congestion solved with power flow controllers



Source: CL analysis based on Smart Wires, National Grid, IAEW (2020) Modular power flow control enhancing German transmission grid capacity: an investigation

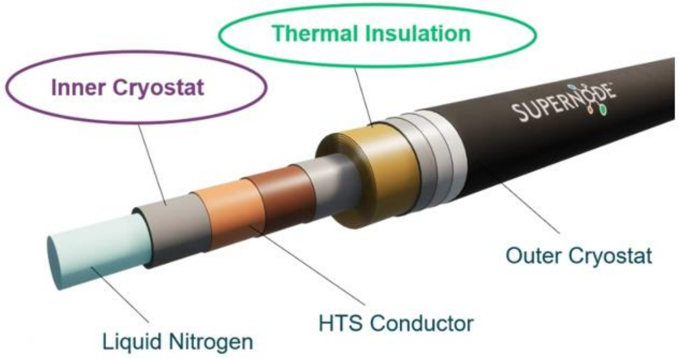
High Temperature Superconductors - Description

Superconducting cables can conduct electricity without energy loss and with high power density

Principles	▪ Superconducting cables are electrical cables designed to carry electric current with zero electrical resistance and high power density, by leveraging the properties of superconducting materials.
Benefits	▪ Superconducting cable systems can carry large quantities of electrical power, typically 5 to 10 times that of a conventional power cable. They operate at lower voltages and require far less raw materials and space.
Details	▪ Superconductors can conduct electricity without energy losses, and with high power density, when cooled below their critical temperature (ca. -200°C for high temperature superconductors) ▪ The main components of superconducting cables include – **Superconducting material** – **Liquid nitrogen** to cool down the superconducting material – **Cryogenic insulation** to maintain superconductors at low temperatures ▪ Relatively high Technology readiness level. No scale manufacturing yet. – **At the distribution level (1st generation): TRL 9** - There are already 15 projects around the world, mainly for the relief of urban network congestions (e.g. in Germany[1,2], South Korea[3], and the US[4]) – **At the transmission level (2nd generation)**: **TRL 5** - Prototype validation expected by 2025 for Supernode. Commercial availability expected by 2030.

Size comparison of copper and superconductor for an equivalent current carrying capability

Illustration of next generation superconducting cable



Source: CL analysis based on interviews with Supernode
[1] Industrie Energieforschung (2023) SuperLink: Innovatives Hochtemperatursupraleiter-Konzept in München
[2] Ministry of Economics of the state Northrhine-Westphalia (2020) Supraleiter Ampacity
[3] Transformers Magazine (2021) Korea's KEPCO commercializes superconducting transmission solution
[4] AMSC (2021) ComEd and AMSC Announce Successful Integration of Resilient Electric Grid System in Chicago

High Temperature Superconductors – Benefits

Superconducting cables facilitate bulk power transfer in marine and terrestrial environments with reduced losses, system costs and environmental footprint

Benefits of high temperature superconductors compared to standard cables

- **Facilitate bulk power transfer (Multi-GW)** in marine and terrestrial environments with reduced losses, costs and footprint
- **Reduced reliance on supply chain bottleneck**: Reduced reliance on copper compared to conventional cables (85% less copper). The technology benefits from healthy supply chains for each component of superconducting cables.
- **Smaller rights-of-way needed and reduced environmental footprint.** High power-density can be an advantage in urban, offshore and rural areas.
- **Savings in total system costs** due to lower operating voltages, compared to conventional cables.
- **High scalability.** Superconducting cables can be designed to deliver significantly higher power throughput without any geometry change. They can be scaled from 1 – 10GW capacity in a single cable within the same cryostat geometry and at minimal increases in CAPEX and OPEX.
- **Enabler of meshed DC Overlay Grid:** High temperature superconductors could be used to deliver a meshed DC overlay grid in Europe, to enable efficient dispatch of remote resources across a wide geography (more details here).

Illustration – Reduction of copper need in superconducting cables (kg / km) [1]

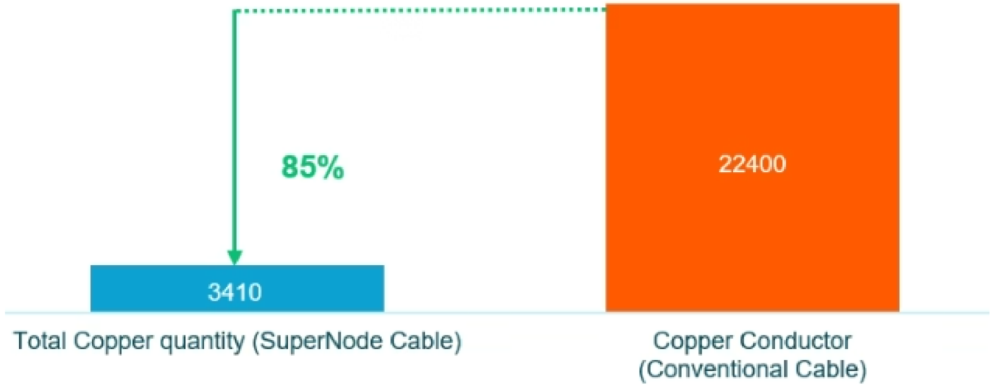
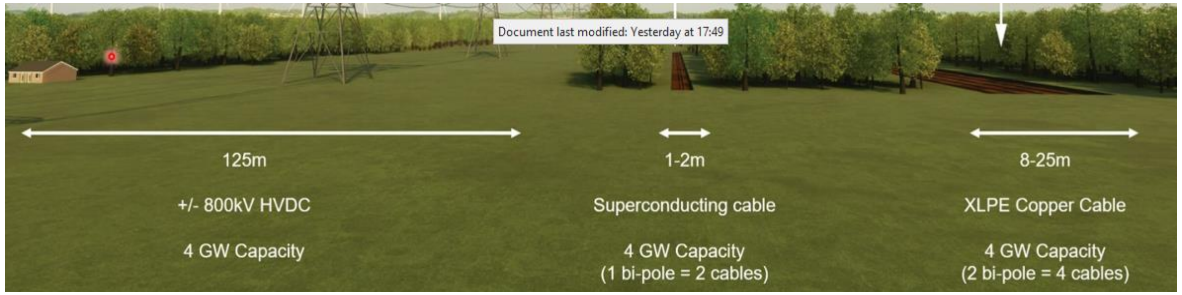


Illustration – Footprint comparison of conventional cables and superconducting cables[1]



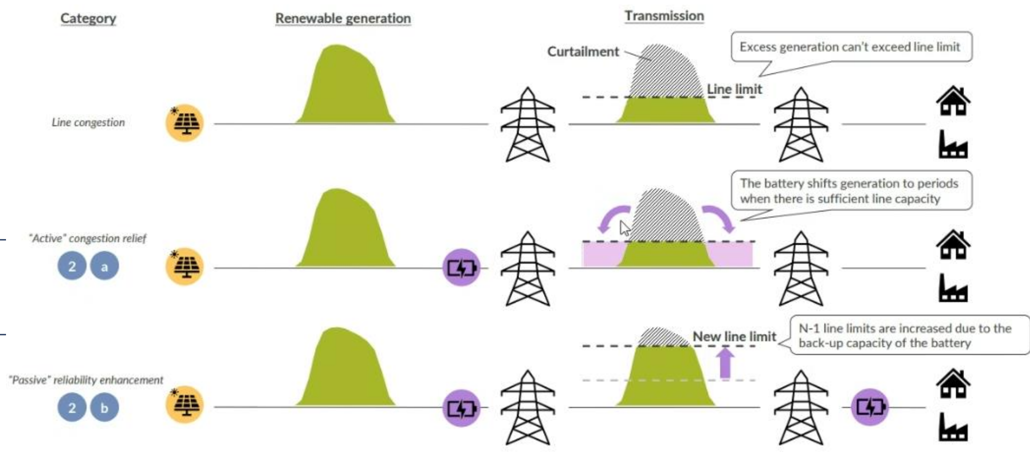
Source: CL analysis based on [1] interviews with Supernode

Storage as a Transmission Asset (SATA) - Description

Storage can be used as a Transmission Asset to provide congestion relief and backup capacity

Principles	▪ Storage as a Transmission Asset (SATA) can avoid congestion and curtailment in case of excess generation. This can be done in two ways: ▪ Active congestion relief: Means using the battery to **shift excess load** in the network to less congested periods. ▪ Passive congestion relief: also called grid boosters, means that **more capacity** on the line can be made available because the **battery is replacing the part of the line that would otherwise have to be used as a backup** (N-1 criterion).
Category	▪ Active: Avoided congestion through forward-looking capacity management ▪ Passive: Capacity increase for a given power line
Details	Passive congestion relief: ▪ The N-1 criterion dictates that power systems must be capable to continue normal operation in case of a single contingency event, such as the unplanned loss of a transmission line. For this reason, transmission lines usually consist of two cables, such that one can take over the full transmission capacity if the other one fails. ▪ However, this leads to both lines only transmitting 50-70% of their capacity, to be ready to take over full capacity in case of an outage. ▪ **Grid boosters** take over these grid security requirements, freeing up additional line capacity that was previously needed for security reasons. ▪ **TRL 9** - Large number of projects using the passive approach in the form of grid boosters (e.g. in Lithuania[1], Germany[2], and Spain[3]). ▪ The active approach has so far only been applied in demonstration projects (e.g. in the UK[4] and the US[5]).

Active vs. passive storage as transmission modes



Sources: CL analysis based on interview with Fluence
[1]: Energy storage news (2023): Lithuania TSO on storage-as-transmission project: 'can be an example to other countries'
[2]: TRANSNET BW (2021) Netzbooster-Pliotanlage Kupferzell
[3]: Red Eléctrica (2021) Transmission network development plan
[4]: UK Power Networks (2016): Smarter Network Storage (SNS)
[5]: UtilityDive (2017): APS to deploy 8 MWh of battery storage to defer transmission investment

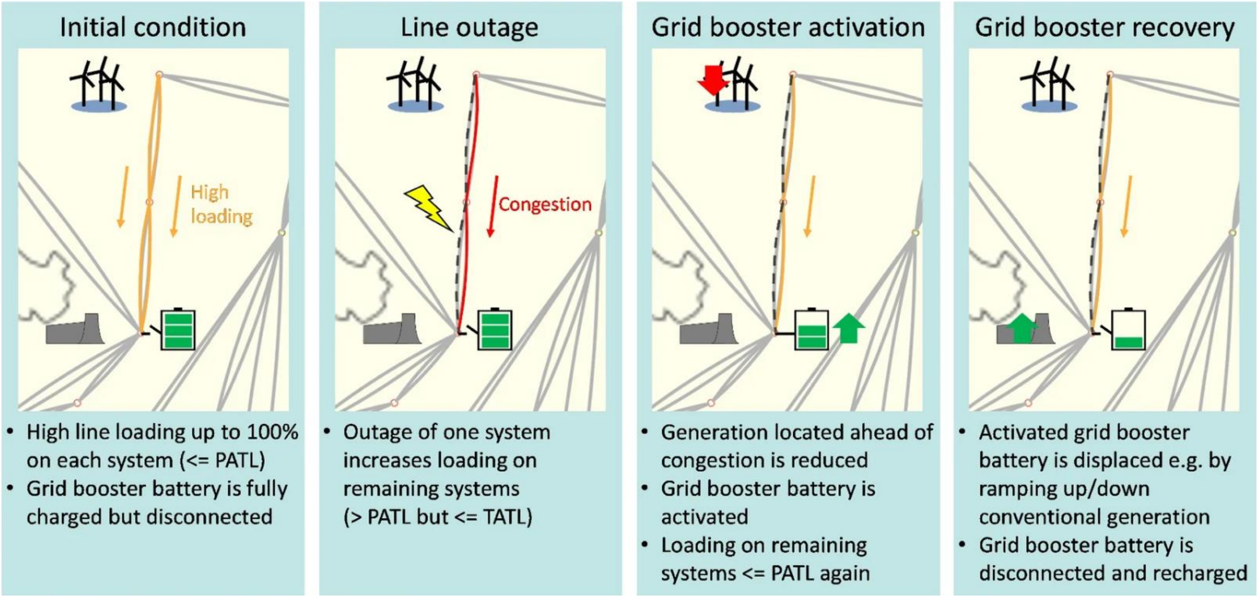
Storage as a Transmission Asset – Benefits

Storage as a Transmission Asset provides congestion relief and can reduce curtailment

Benefits of Storage as a Transmission Asset

- **Active storage** provides **congestion relief** for heavily loaded grids by moving power to less congested periods.
- **Passive storage** enhances the **reliability** of the network (e.g. through grid boosters), allowing continued power supply in case of line outages.
- Using SATA can increase the **transmission capacity** of existing transmission networks and provide a **solution for renewable curtailment**, facilitating the energy transition.
- **Batteries** can adjust their injection to the grid / offtake from the grid almost instantaneously, allowing for more flexibility in the system.

Grid booster: Replacing n-1 requirement in grid operation



Source: CL analysis based on interview with Fluence

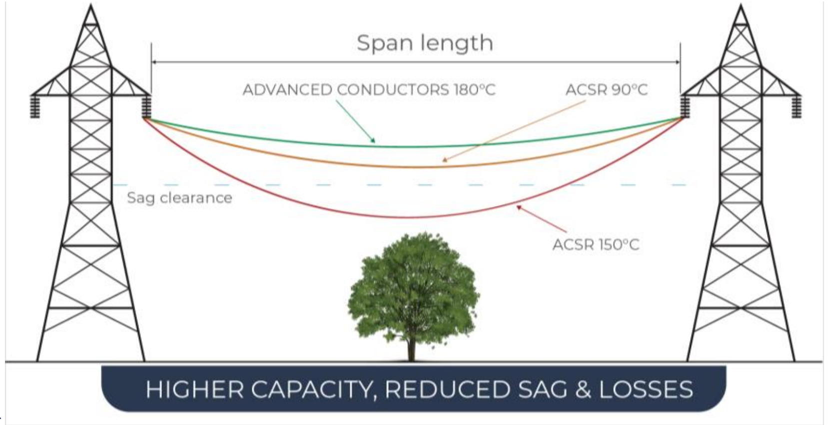
Advanced conductors - Description

Advanced conductors refer to innovative cables employed to enhance the efficiency, capacity, and reliability of power lines, compared to conventional cables

Principles	▪ Advanced conductors refer to innovative materials and/or designs employed to enhance the efficiency, capacity, and reliability of power lines in the transmission and distribution network, compared to conventional cables, by using lighter, stronger and thermally stable composite core
Benefits	▪ **Capacity increase for a given line specification**
Details	▪ The main components of advanced conductors typically include: – **Composite core**, stronger and lighter than steel – **Trapezoidal design**, which allows for added aluminium content / higher filling ratio, increasing capacity ▪ Key features include: – **Increased capacity**: A lower CTE (Coefficient of Thermal Expansion) core enables higher operating temperatures and higher ampacity with less sag, which increases power capacity. – **Stronger cable:** Higher strength core enables greater spans between towers and fewer and/or lower towers, which reduces environmental impact and cost. – **Reduced line losses:** A lighter weight core allows ~30% more aluminium without weight or diameter penalty to reduce line losses induced by Joules Effect. ▪ **TRL 9** - Approaching 20,000km of advanced conductors installed in Europe. > 175,000km worldwide (11kV -1,100kV)

Comparison of conventional cables (right) and advanced conductors (left)

Sag comparison – advanced conductors compared to conventional ACSR conductors



Source: CL analysis based on interview with CTC Global and review from Epsilon cable

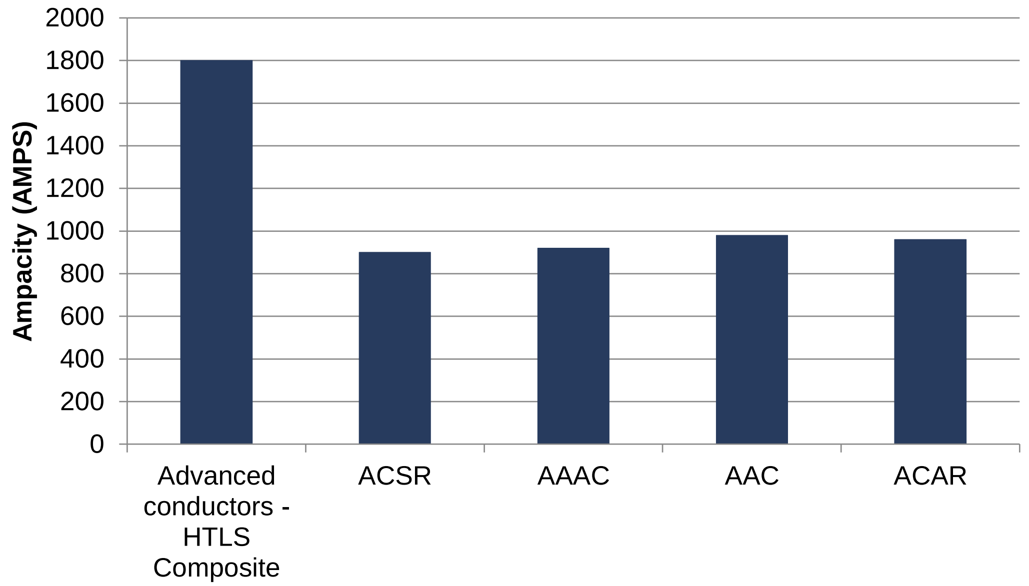
Advanced conductors – Benefits

Reconductoring projects with advanced conductors allow to increase the capacity of existing lines at relatively low cost, as the need for tower strengthening is limited

Benefits of advanced conductors compared to conventional cables

- Advanced conductors give the option to increase grid capacity while utilising existing infrastructure through reconductoring. This can lead to an (up to) **doubling of line capacity on an existing route, compared to conventional lines** due to higher thermal limits.
- **Minimal** (if any) **tower strengthening on reconductoring projects** are necessary, which can lead to lower overall project costs despite higher costs per km of conductor.
- **Easier permitting & construction in congested / dense areas**, compared to building new lines.
- **Shorter development lead time** compared to building new structures with conventional reinforced conductors (e.g. 18 months compared to 48 in the SCE Big Creek Reconductor Project, in the US[2]).
- **Increased energy efficiency:** Reduction in power line losses by ~15%-30%[3,4], resulting in electricity savings for the same amount of power transported. Those reduced losses are due to ~28% more conductive aluminium[3]. This **reduces the lifetime CO2** emissions by **about 30% the** reduction in resistive losses.
- **Increased resilience:** Reduced thermal sag allows for more reliable / future proof grid.

Ampacity comparison – Typical advanced conductors vs conventional conductors with the same overall diameter and weight[1]



Note: Ampacity is defined as the maximum current, in amperes, that a conductor can carry continuously under the conditions of use without exceeding its temperature rating.
Data is representative of standard Drake size conductors (US standard terminology) at maximum recommended operating temperature. Environmental conditions are based on IEEE 738 standards.
Source: Adapted from CTC Global

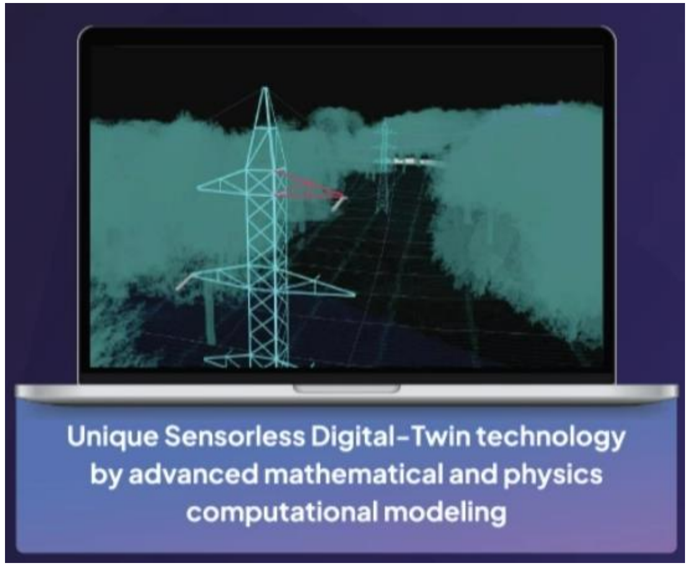
Source: [1] CTC Global, [2] Electricity Today 2022 [3] Interview with CTC Global [4] insights from Epsilon

Digital twins – Description

Digital twins are virtual representations which can model the status of the network in real time and predict future behaviour, with limited physical sensors

Principles	▪ Digital twins are virtual representations that use data on the network (e.g. voltage level) and exogenous data (e.g. topography, weather, generation) to model the status of the network in real time, with limited data from physical sensors available.
Benefits	▪ Technological foundation for a better utilisation of the grid
Details	▪ Digital twins can provide a meter-by-meter estimate of the grid status, for example in terms of power flow, temperature, vegetation and fire hazard. The algorithms typically use AI, based on network data (e.g. voltage level, grid architecture, electromechanical data) and exogenous data (topography, weather, generation). ▪ This allows for grid monitoring without physical intervention on the equipment or infrastructure. It is leveraging existing data from sensors and meters and providing insights also where there are no sensors available. ▪ Digital twins add additional capability for simulating future behaviour of the grid to traditional control systems and can analyse the impact of changes such as load and generation growth as well as changes to grid infrastructure. ▪ Digital twins can also be combined with physical grid sensors to increase the reliability of estimates. ▪ Flexibility platforms are also IT solutions, which allow network operators to leverage the flexibility of grid users by procuring flexibility services, e.g. to manage congestions or defer investments in additional grid capacity. Although these platforms can provide substantial cost savings, market-based solutions are beyond the scope of this study. ▪ **TRL 9** - Technology already installed in several countries, e.g. for line capacity monitoring, capacity planning, satellite-based vegetation management and scenario monitoring.

Illustration – Enline's Digital twin technology



Source: CL analysis based on interview with Enline

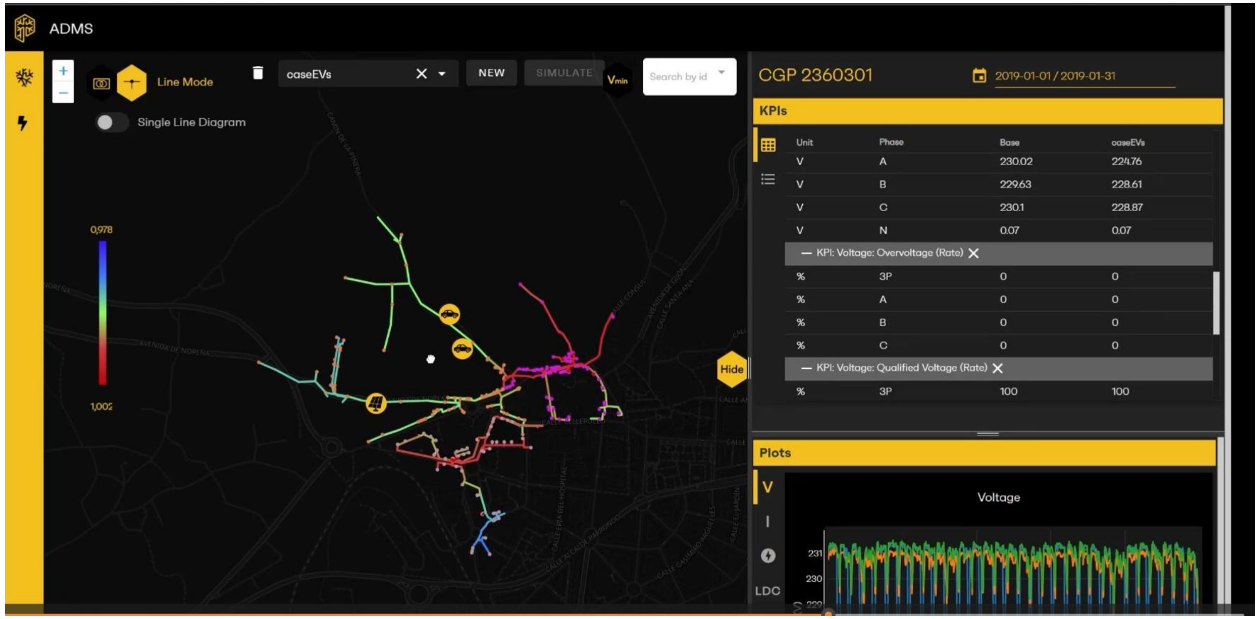
Digital twins – Benefits

Digital twins allow for reduced system costs, both in terms of OpEx and CapEx

Benefits of digital twins

- **Reduced OpEx:**
  - Reduced field operations by faster and more accurate detection of faults and outages
  - Reduced outage time and customer compensation cost
  - Provides visibility of low voltage networks and customer level
- **Reduced CapEx:**
  - Reduced need for sensors / hardware to monitor grid status
  - Enable grid operators to forecast congestions and voltage violations
- **For new lines under planning:** Digital twin technology can be used to model the operational behaviour of a line before its physical installation.
- **Increased reliability and safety** due to accurate monitoring, allowing for the implementation of preventive measures.
- **Extension of asset lifespans,** e.g. by 25% in Enline's projects[1], with a 15% reduction in maintenance costs.
- **Improved utilization of existing assets**

Example from the Plexigrid Digital Twin simulating bottlenecks arising from increased PV and EV penetration



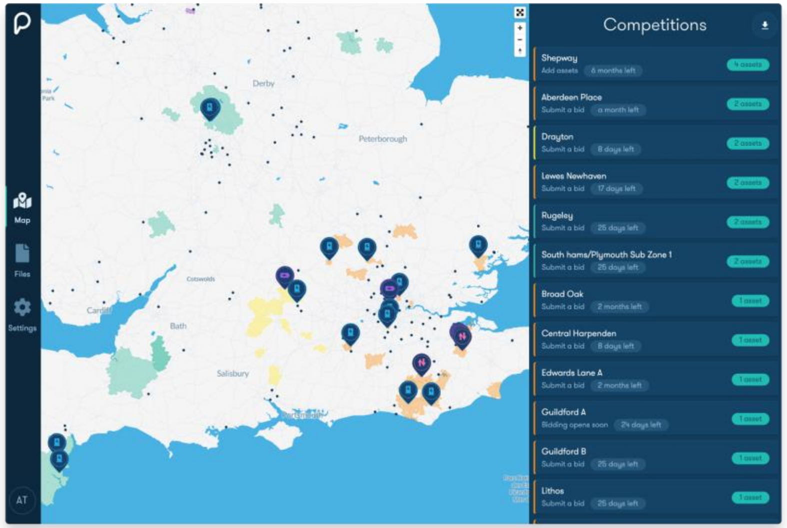
Source: CL analysis based on [1] interview with Enline, [2] Plexigrid's internal expertise

Flexibility management software solutions – Description

Flexibility management software enables the use of flexible customer demand and generation to alleviate grid congestions and voltage violations

Principles	▪ Flexibility management allows grid operators to manage and control the flow of electricity efficiently by actively managing the supply and demand of grid connected assets.
Benefits	▪ Active network management
Details	▪ Flexibility management software solutions can allow TSOs and DSOs to actively manage grid constraints, forecast congestions and voltage violations and select the most appropriate flexibility-based solution to solve the constraint identified. ▪ Moreover, flexibility platforms allow network operators to leverage the flexibility of grid users by procuring flexibility services, e.g. to manage congestions or defer investments in additional grid capacity. ▪ These solutions, combined with bilateral agreements or market-based procurement of flexibility, allow aggregators to leverage domestic flexibility from low voltage customers with EV chargers, rooftop PV, heat-pumps and storage. ▪ Moreover, using such tools, flexible connections/non-firm connections can be activated directly by the system operator to curtail generation or reduce load. ▪ Provides advice on how to optimize traditional ways of solving constraints such as switching, OLTC setpoints in combinations with DERs. ▪ **TRL 9** - Technology already installed in several countries, e.g. for line capacity monitoring, capacity planning, and scenario monitoring.

Piclo flexibility marketplace



Source: CL analysis based on Plexigrid's internal expertise and Piclo.

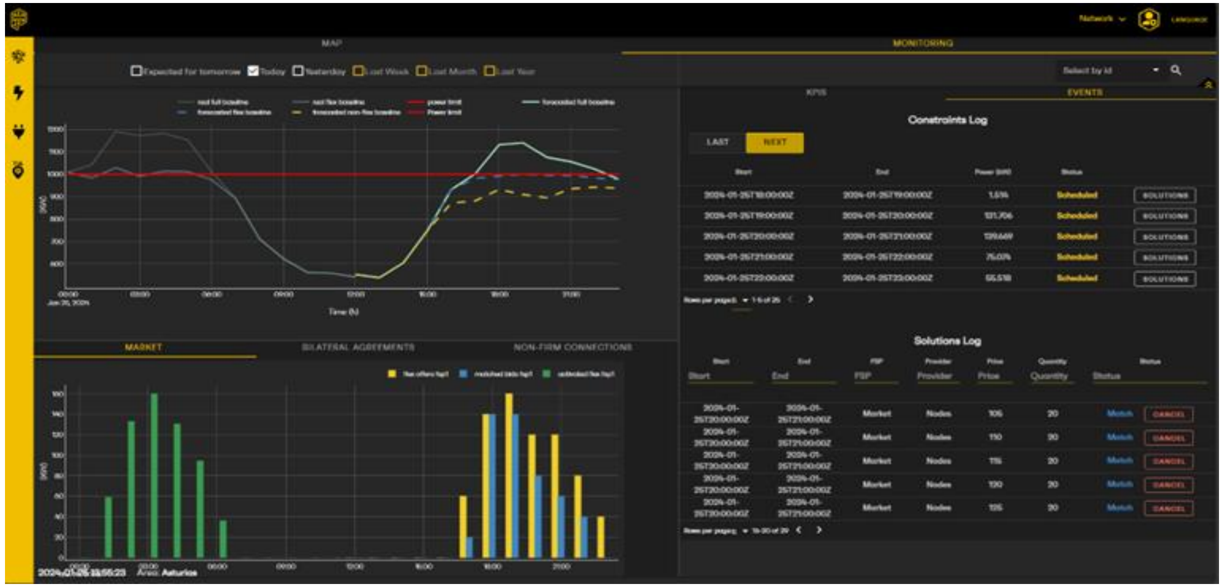
Flexibility management software solutions – Benefits

Flexibility is an alternative to grid reinforcements in the long term and enables faster grid connections in congested grids in the short term

Benefits of flexibility management solutions

- **Reduced CapEx:**
  – Reduction of grid investments due to better utilization of existing assets leading to avoidance or deferral of investments.
- **Increased hosting capacity of DERs[1]**
  - Solves overvoltage issues allowing for increased export of renewable energy to the grid.
  - Peak shaving and shifting to enable more electrified loads within the capacity of existing grid assets.
- **Reduce time for grid connections**
  - Deploying flexible solutions can be faster than reinforcing the grid to accommodate new connections in congested grids.
- **Increased reliability and safety** by reducing demand, utilizing energy storage or increasing generation in situations of planned or unplanned outages, weather or other events.

Plexigrid congestion management activating demand side flexibility to reduce substation overload



Source: CL analysis based on Plexigrid's internal expertise
Note: [1] Distributed Energy Resources

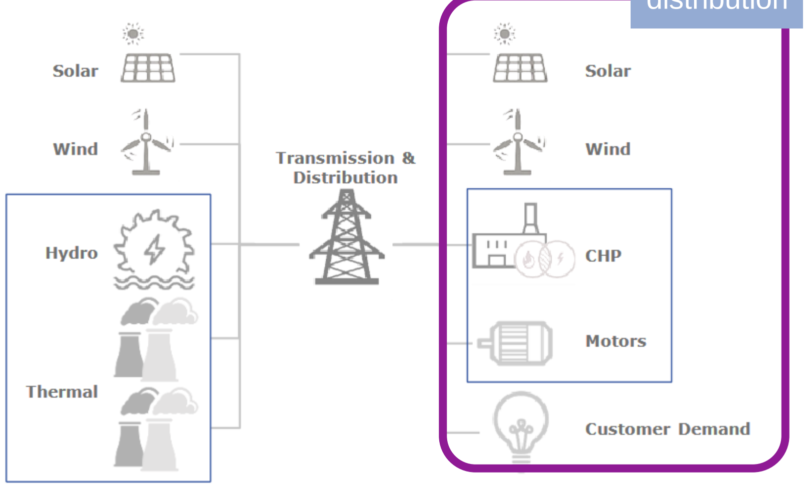
Grid Inertia Measurement - Description

Advanced grid inertia measurement technology enables Grid Operators to maximise RES safely through real-time and accurate grid inertia data.

Principles	▪ Grid inertia measurement enhances decision-making and enables system operators to optimize the utilization of renewable power more effectively, by generating real-time and accurate grid inertia data through frequency modulation.
Benefits	▪ Better understanding of actual grid inertia limits to maximise use of RES
Details	▪ The electricity sector is undergoing a significant change, shifting away from synchronous, centralized fossil fuel plants to a higher share of non-synchronous, decentralized generation. Fossil fuel plants have historically ensured a high level of inertia, derived from rotating turbines in generators being synchronized to the same frequency. This inertia tends to stabilize the grid in case of power failure and frequency drop. However, renewables such as solar PV and wind do not contribute to system inertia, and the roll-out of renewables is a significant challenge for grid stability in this regard. ▪ Inertia has historically been measured in electricity systems during system stress events (i.e. power station trips), allowing for partial inertia data. In contrast, GridMetrix, developed by Reactive Technologies allows for real-time and accurate inertia measurement. – Modulator induces imperceptible frequency stimulations in the power system by injecting power pulses into the grid – Distributed throughout the grid, Frequency Measurement Units (XMUs) monitor the minute changes in the system frequency caused by the power pulses from the modulator, which enables continuous inertia measurement ▪ Can either be used in network planning or in network operation. ▪ **TRL 9** - Already deployed in several countries, including the UK, Australia and Japan.

Illustration – Sources of inertia

Up to 30%+ "hidden" inertia in distribution



Continuously calculate to measure from generation and demand side

Illustration – Functioning of GridMetrix

Source: CL analysis based on interview with Reactive Technologies

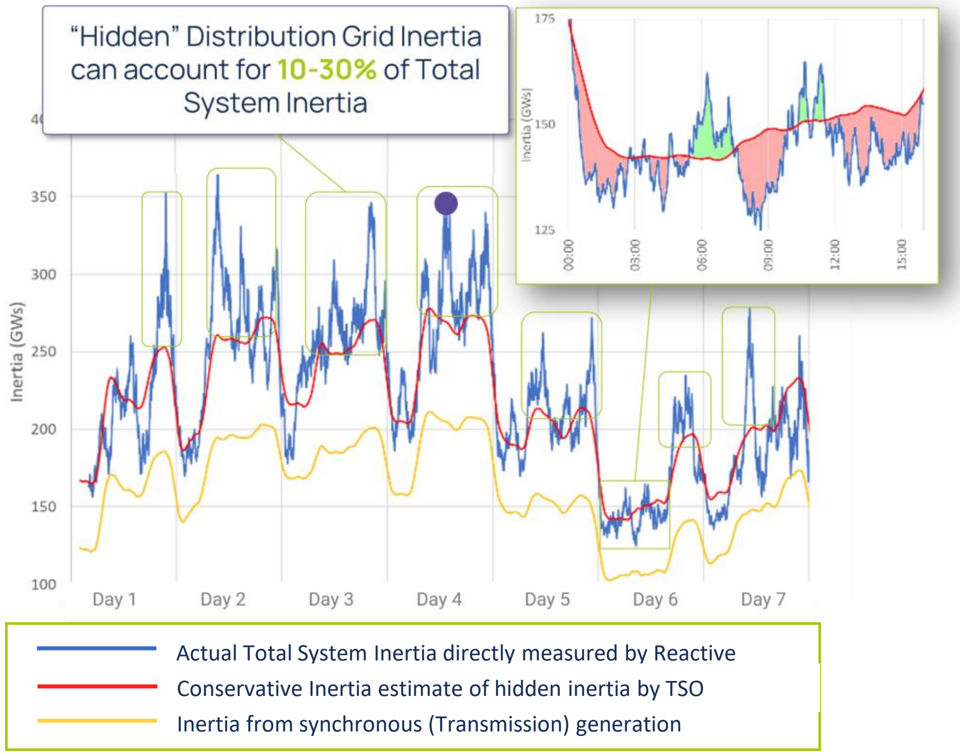
Grid Inertia Measurement – Benefits

Grid inertia measurement enhances decision-making and enables system operators to optimize the utilization of renewable power more effectively

Benefits of grid inertia measurement

- **Maximisation of renewables infeed and reduction of curtailment, redispatching, balancing costs:**
  - In the absence of accurate and real-time data on the actual inertia in the system, networks need to be operated with significant security margins to ensure system resilience. This can lead to excessive curtailment of renewables. For instance, traditional inertia estimates limit RES penetration in the grid to 60-70% of the real time electricity mix[1]. Above this, renewable output typically needs to be curtailed.
  - On the other hand, having accurate and real-time inertia data allows grid operators to plan the optimal amount of energy needed for inertial reserve ensuring cost-effectiveness and efficiency at the lowest points. Real case studies show a 30% increase in assumed inertia by moving from estimates to measuring inertia.[1]
  - In the UK, NGESO & Reactive estimate Reactive's Inertia Measurement technology is saving 18 m tonnes CO2 annually (more details in section 2.2).
- **Accurate measurement data improves system investment planning by allowing better sizing of additional stability assets** (e.g. synchronous condensers)
  - This can provide substantial investment savings, as it corresponds to significant investment volumes (e.g. in the UK, procurement by NGESO of inertia services from synchronous condensers to ensure grid stability[2]).

Active grid inertia measurement is done continuously and in real-time, as compared to imprecise measurements based on estimates[1]



Source: CL analysis based on [1] interview with Reactive Technologies, [2] see for instance: NGESO - NOA Stability pathfinder, [3] Reactive Technologies (2024)

2.2

Estimation of the potential of IGTs through case studies

nationalgrid

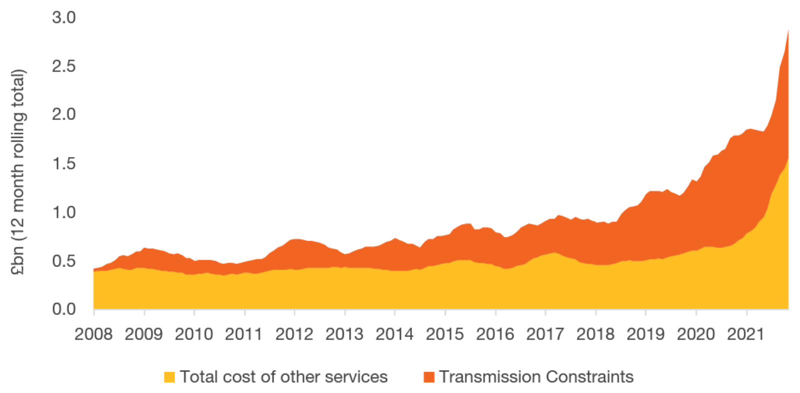
Advanced Power Flow Control – Case study

In the UK, National Grid has deployed SmartValves across five circuits in congested network areas to free-up 2 GW of additional grid capacity.

Context of introduction

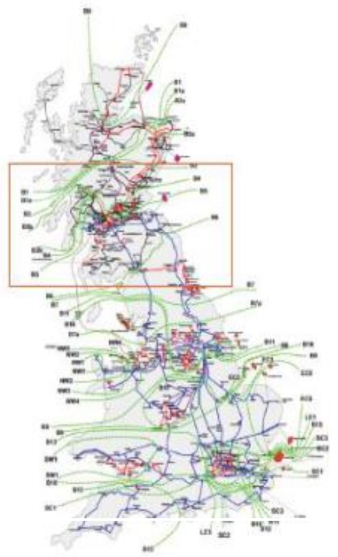
- The UK is facing congestion issues due to the increasing penetration of renewables and the locational mismatch between production and generation in the country. Rising congestion in the UK has led to a steep increase in annual transmission network constraint costs going from 170 m£ in January 2010 to 1.3 bn£ in January 2022.
- Mainly driven by RES deployment and especially onshore and offshore wind, NGESO projections indicate that transmission congestion costs will rise steeply in the first half of this decade, independently of the scenario, and could reach 2.3 bn£ per year by 2026 (estimation prior to energy crisis, not considering its potential price effect).

Constraints and other balancing services' costs in the UK



Project description

- **48 modular SSSC** (SmartValves) were initially deployed by National Grid and Smart Wires in 2021 on **five circuits** across **three substations**, at 275kV and 400 kV.
- In a second stage, a project extension was decided in Autumn 2021 following the success of the initial deployment, involving the **deployment of additional SmartValves** at two of the substations.



KPIs

- These two deployments of SmartValves respectively free up **1,5GW and 0,5 GW of additional grid capacity**, **without the need for new infrastructure projects**
- This targeted deployment represent **~5% of the total peak demand in the UK** (46 GW in 2022)
- **This can be interpreted as a 5% increase in overall network capacity**

Source: CL analysis based on Smart Wires, National Grid, National Grid ESO, WindEurope (2020) making the most of Europe's grids

Advanced conductors – Quantified case study

In Belgium, advanced conductors enable a twofold increase of load transfer capacity in high-voltage lines

Context of introduction

- Located in the centre of Europe, Belgium's 150 kV to 380 kV transmission network is an important connection between electricity markets in northern and southern Europe. More transmission capacity is needed, because of the nuclear phase-out (to be completed by 2035[1]) and the rise in electricity imports and exports (see picture below).
- As owner of the entire transmission system and 94% of the high-voltage distribution network, Belgian TSO ELIA has the responsibility to accommodate the increasing electricity demand, which is projected to grow by 70% until 2050. As such, ELIA executed the Stevin-project between Zeebrugge and Zomergem, which aims at the four main goals presented in the figure below.

Project description

- After the project start in 2015, the 380kV high-voltage connection between Zeebrugge and Zomergem was put into service at the end of 2017.[2]
- With one of the main project goals being the construction of a 47 km high-voltage connection (380 kV), Elia relied on two types of **High Temperature Low Sag (HTLS) conductors** enabling a doubling of the load transfer capacity.[3]

The importance of Stevin for the Belgian electricity grid[2]

1. Essential link for the energy supply at the port of Zeebrugge
2. Enables additional decentralized power generation in coastal region
3. Connects 2000 MW offshore wind power
4. Strengthens interconnection with UK through subsea cables

KPIs

- Increase in load transfer capacity through advanced conductors by a **factor of two**
- Consistent with Elia's objective of increasing load transfer capacity of some circuits in the existing 380-kV overhead line transmission system from approximately **2000 A to 4000 A**[3]
- Consistent with information from manufacturer of ACCC-conductors[4]
- This can be interpreted as **a 100% increase in line capacity**
- Consistent with the **50%-150% range** found in the literature

Sources: CL analysis based on:
[1] World Nuclear Association (2024) Nuclear Power in Belgium
[2] Stevin (2024)
[3] T&D World (2017) Elia Addresses the Need for More Capacity in Belgium
[4] CTC Global (2023) ACCC Conductor

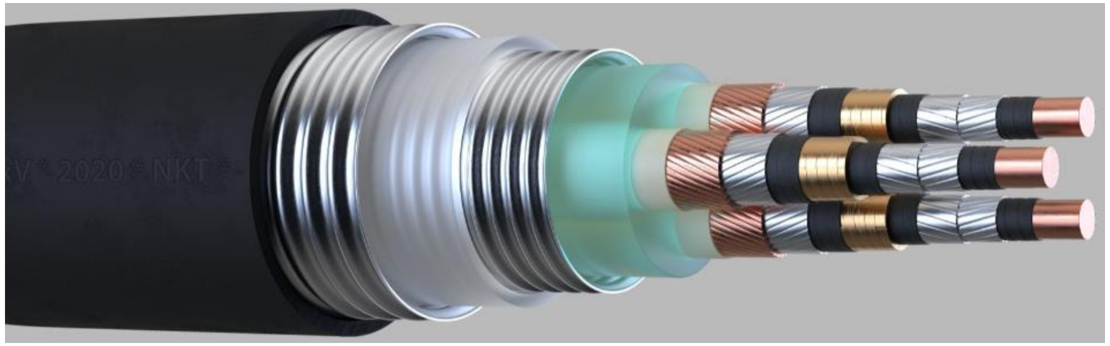
High Temperature Superconductors – Quantified case study

In Germany, superconductors are installed and tested to prepare larger-scale applications

Context of introduction

- Large cities are facing the challenge of rapidly increasing electricity demand, but at the same time having limited space for construction works.
- Superconductors can provide a solution for this problem: Without significant additional construction, they can be laid out in the existing underground conduits of the electricity network. In addition, they can transmit power at lower voltages than conventional cables and therefore require far smaller substations.[1]
- Wires made from superconductor materials conduct well over 150 times the amount of electricity that can be conducted by copper or aluminium wires of the same size, making superconductors a way of reducing the need for network expansion.[2]

Illustration of a superconductor



Project description

- In the project “SuperLink”, local energy utility SMW is installing a superconductor of 12 km length in Munich, making it the longest superconductor in the world.
- The superconducting cables will be designed such that they fit into already existing underground conduits.

KPIs

- **10% lower energy losses** compared to conventional conductors with 400 kV[3]
- **30% lower energy losses** compared to conventional conductors with 110 kV[3]
- **0.5% lower total system losses** when transmitting energy at a distance of **500 kilometres**[1]
- **30% reduction in congestion costs** estimated, if superconductors were to be implemented in Germany’s North-South EHV connection “SuedLink”[1]

Source: CL analysis based on:
[1] Consentec (2021) The Benefits of Innovative Grid Technologies
[2] SWM (2023) Das können Hochspannungs-Supraleiter
[3] Industrie Energieforschung (2023) SuperLink: Innovatives Hochtemperatursupraleiter-Konzept in München

Storage as a Transmission Asset – Quantified case study

In Germany, Gridbooster batteries provide an alternative to costly redispatch

Context of introduction

- The German transmission network is highly congested, with increasing transmission needs from generation sites in the North to industrial end users in the South bringing the network closer to its limits. Congestions are mainly managed using redispatch mechanisms to increase power generation behind the congested line and decrease generation before it.
- Managing congestion by decreasing cheap generation in the North (redispatch) and increasing more expensive conventional generation in the South resulted in congestion management costs of 3.1 bn€ in 2023[1]. While grid expansion is stuck in permitting procedures, Gridbooster batteries can balance the system in case of contingencies and reduce congestion management costs – by freeing up additional line capacity that was previously reserved for security reasons (under the N-1 criteria).[2]

Conceptual model of the “Kupferzell” Gridbooster

Project description

- The 250 MW Gridbooster to be constructed throughout 2024 at the grid hub in “Kupferzell” (Southern Germany) is expected to start regular operation in 2026.[3]
- It will serve as a reactive safety buffer for EHV-lines in the transmission grid, providing relief to congested parts of the network in case of line outages. This way, lines can be used at full capacity as the Gridbooster battery takes care of maintaining system security.

KPIs

- In typical configurations with double circuit transmission lines, a failure of the parallel circuit may well result in a 30% increase in line loading. To prevent a violation of operational limits in such a case, lines have a maximum loading of roughly 70% of their thermal rating[2]
- Hence, with Gridboosters, lines could be operated at full capacity, representing a ~**40% increase in maximum line capacity**[4]
- 1300 MW of storage capacity on the German transmission grid could reduce **redispatch costs by 130 m€ per year**[5]

Source: CL analysis based on:
[1] Bundesnetzagentur (2024) Quartalsbericht Netzengpassmanagement, Viertes Quartal
[2] Consentec (2023) Grid Boosters as innovative solution to optimize power grids
[3] TRANSNET BW (2021) Netzbooster-Pliotanlage Kupferzell
[4] Note: 100%/70%-1 =40%
[5] Fluence (2020) Redrawing the Network Map: Energy Storage as Virtual Transmission

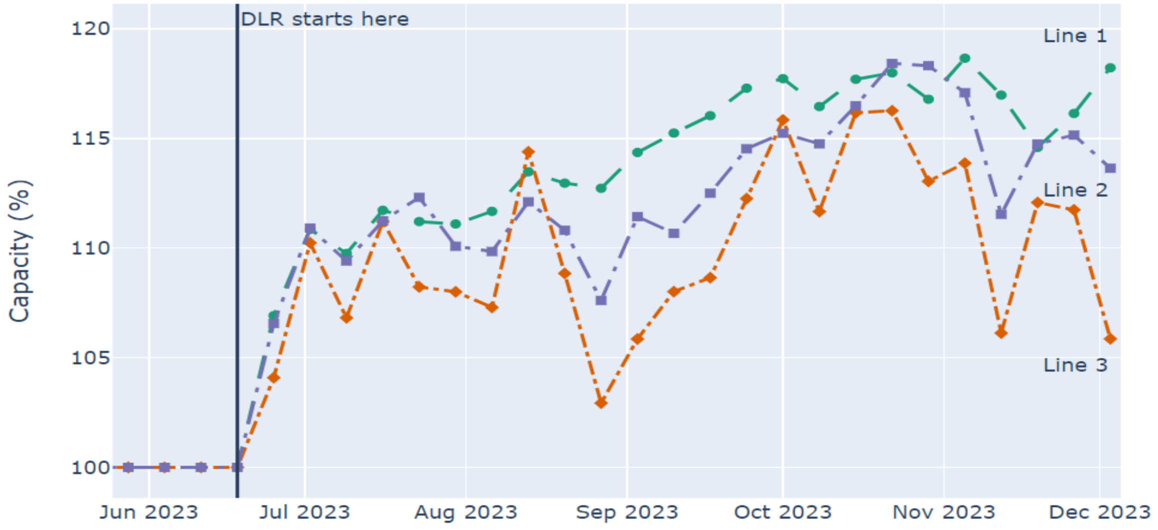
DLR – Quantified case study

In Norway, DLR allows to take full advantage of transmission line capacities

Context of introduction

- Confronted with an increasing electricity demand that is projected to double by 2050, the Norwegian grid is close to its maximum capacity. In addition, large price differences persist between Norwegian regions.
- While planned measures including the installation of new power lines and the upgrade of existing lines to higher voltages are being pursued in Norway, they take several years to complete. On the contrary, Dynamic Line Rating (DLR) can be implemented very quickly.

Capacity of three lines since the implementation of DLR in June 2023



Project description

- The first sensors for DLR were installed in 2019. So-called limit forecasts maximising the current that can be transported on the respective lines have been used for the first time in June 2023.
- Although a maximum capacity increase of 20% can be achieved, there is a large variation in the maximum line capacity increase that comes through DLR. The most important factor explaining the maximum capacity is the average wind speed. Statnett aims to improve capacity predictions through more granular models in the future.

KPIs

- **Maximum of 20%** increase in line capacity through DLR
- Average capacity increase of the three lines through DLR roughly consistent with ENTSO-E findings, where DLR leads to typical **ampacity gains in Europe of 10–15%** over 90% of the time

Source: CL analysis based on:
[1] Statnett (2023) Increasing line capacity by 20% using data science
[2] Statnett (2022) Smarter Transmission Grid Capacities with Weather Data
[3] ENTSO-E (2024) Dynamic Line Rating (DLR)

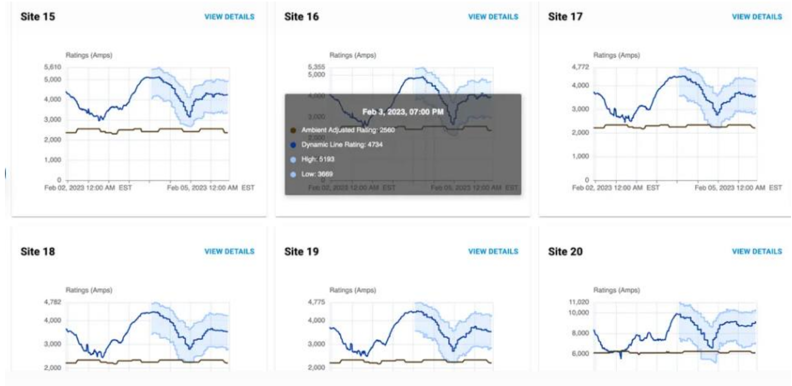
DLR – Quantified case study

In the US, DLR allows to take full advantage of transmission line capacities

Context of introduction

- As the first instance in New York where DLR technology will be used to operate transmission lines in real-time, LineVision partnered with National Grid to bring DLR to four 115kV transmission lines in congested Upstate New York. DLR deployment was critical to transmit power from a growing number of renewable energy projects that would otherwise be stuck waiting for interconnection.[1]
- In the long term, National Grid plans to invest 4 bn$ to build substations and rebuild transmission lines in New York's power grid[2]. However, alleviating grid congestion in the short-term is done cheaper and faster by using DLR because the technology can be installed in only a few months, as stated by LineVision's CEO Hudson Gilmer[3].

LineVision's DLR Site Dashboard with forecasted ratings[1]



Project description

- The project has become fully operational in May 2024[1]. It marks the largest operationalization of DLR in the US and the first in New York State.
- The installed "LineRate" DLR software and sensor platform provide data being continuously refined through machine learning, informing on conductor temperature and hourly DLR forecasted up to 240 hours into the future.[1]
- According to a report from the department of energy, DLR investments come with a payback period of one year, compared to 13-15 years for traditional upgrades.[3]

KPIs

- **Average transmission capacity increase of over 30%** through DLR.[4] At maximum, LineVision estimates that DLR can increase the line capacity **up to 40%**[1]
- Along with five miles of circuit rebuilds, the DLR project is projected to reduce **curtailments by over 350 MW** while **increasing capacity by 190 MW**[4]

Source: CL analysis based on:
[1] LineVision (2024) [LineVision Operationalizes Dynamic Line Ratings in New York to Increase Transmission Capacity and Grid Safety for National Grid]
[2] Utility Dive (2024) [National Grid announces $4B plan to upgrade upstate New York power grid]
[3] Power Grid International (2024) ['Low-hanging fruit': Inside the U.S.' largest grid-enhancing tech deployment]
[4] PR Newswire (2022) [National Grid and LineVision Deploy Largest Dynamic Line Rating Project in the United States]

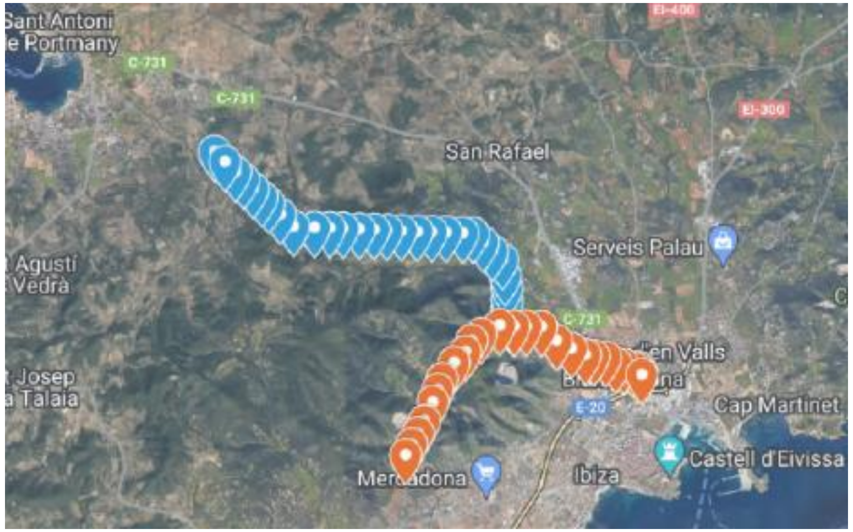
Digital twins – Quantified case study

In Spain, a digital twin is used for a precise estimate of the transmission capacity

Context of introduction

- Ibiza's transmission lines are heavily loaded in summer due to the number of tourists. Additionally, in terms of their location, they differ from regular 400 kV and 220 kV transmission lines. Part of the lines are in areas with dense vegetation, while others are in urban areas, making the ampacity calculation for the lines challenging.
- To help the Spanish TSO REE optimise their future investments in transmission lines and evaluate the maximum capacity that the lines can transport, Enline was tasked to set up a digital twin of the lines in Ibiza, enabling more precise capacity estimates.

Two of the four transmission lines modelled through the digital twin



Project description

- The project was executed with the tool "Enline Live View", which allows to monitor energy assets in real-time, without requiring sensors or other hardware.[1] It was executed on four transmission lines in total, a 400 kV, a 220 kV and two 66 kV city-nested distribution-like lines.
- It involved the quantification of the maximum power transmission considering the physical, regulatory and operational limitations of each transmission asset.
- The data used for the quantification included customer-supplied electrical data from two connecting substations and meteorological data from virtual/physical weather stations.

KPIs

- The use of digital twin resulted in this case in a **~20% increase in transmission capacity**, on average

Source: CL analysis based on:
[1] Enline (2022) Enline LiveView

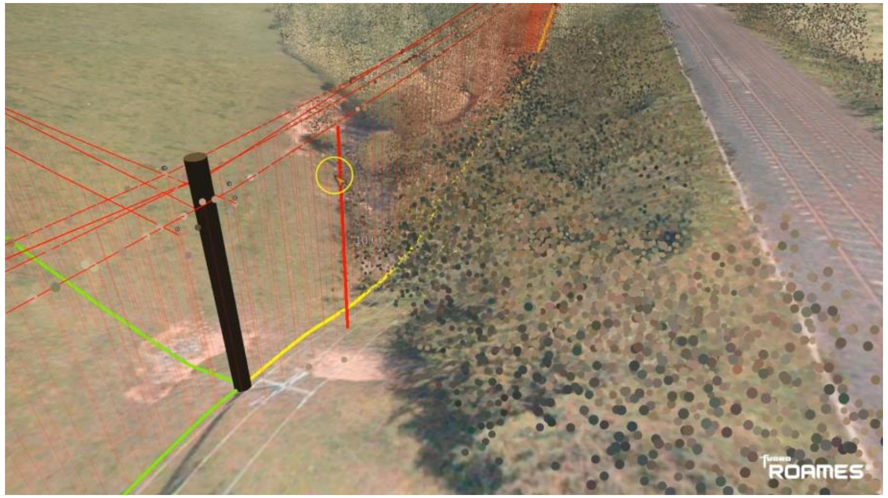
Digital twins – Quantified case study

In Switzerland, a digital twin of the transmission network helps to maintain security of supply

Context of introduction

- The Swiss power network owned by Swissgrid extends for 6,700 km, including 380 and 200 kV lines. Given Switzerland's mountainous terrain, ensuring security of supply at all times and providing maintenance in the network when necessary can be challenging.
- To account for increasing electricity demand and to ensure timely maintenance, Swisgrid hired Fugro to create a complete 3D-model of Swissgrid's power lines and their surroundings, enabling conduction modelling, condition analyses, timely maintenance and grid simulations.

Digital view of power lines through Fugro's 3D-model of the grid



Project description

- At the beginning of the project, the entire grid was documented during flights with helicopters equipped with laser systems and infrared cameras.
- Based on this data, Swissgrid is now using the software tool "Fugro Roames", to create digital twin solutions that support the planning of grid expansion, maintenance and vegetation management.
- Through the accurate 3D-model of the Swiss power lines and with the help of additional software, the model also applies clearance calculations of the power lines to all objects, ground and vegetation, allowing Swissgrid to simulate different operational conditions and detect problems at an early stage.

KPIs

- This can be interpreted as lowering the **cost of operational vegetation management by up to 40%**

Source: CL analysis based on:
Fugro (2023) [Swissgrid boosts efficiency using 3D power grid model]

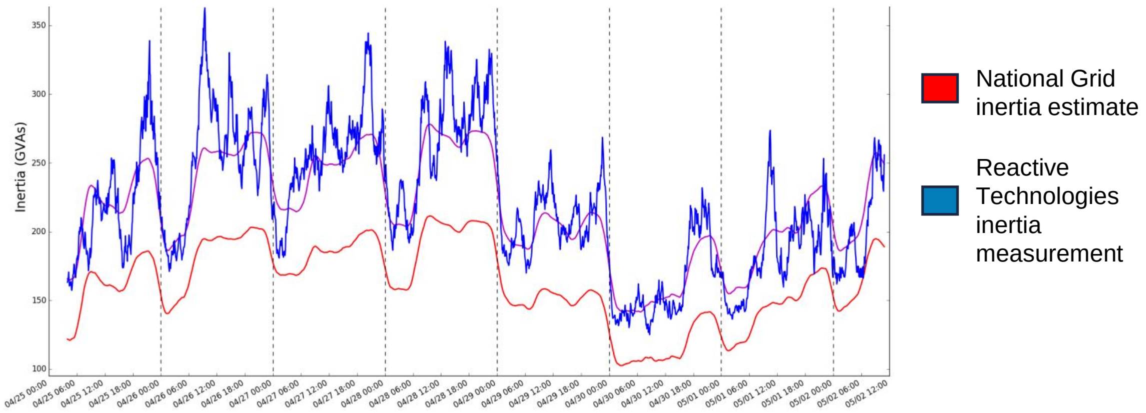
Grid Inertia Measurement – Quantified case study

In Great Britain, continuous precise grid inertia measurement decreases curtailment costs

Context of introduction

- With an increasing integration of Renewables in the electricity grid, inertia in the system decreases. This holds the risk of higher rates of frequency changes, in turn increasing the risk of generation losses and power oscillations.
- To prevent these risks, Reactive Technologies has developed a measurement technology with which inertia from the generation- and demand-side is continuously measured through small power changes.
- Using this technology, Reactive Technologies and the National Grid ESO in Great Britain have partnered in the project on System Inertia Measurement ("SIM"), which led to a 6-year agreement to provide live operational inertia measurement.

Blind test results from project SIM[3]



Project description

- Project "SIM" was successfully completed in July 2017 and demonstrated that inertia of the electricity grid can be measured in a safe, reliable, and cost-effective manner. In "Blind tests" comparing Reactive Technologies' inertia measurements with estimates from National grid ESO, the technology proved to be one of the world's first continuous ways to measure system inertia.
- **Reactive Technologies now provides live operational inertia measurement within a 6-year agreement** to National Grid ESO. It measures and identifies actual inertia of the whole system. This enables better planning and modelling as well as operation of high-renewables systems, and constitutes a key tool in NGESO's commitment to a "zero-carbon" operation by 2025.

KPIs

- Operational data shows that traditional inertia techniques underestimate inertia by 10-30% in GB. The use of inertia measurement ensures that significant financial and CO2 savings are achieved.
- Financial savings come from minimising costs of curtailment and reserve services and amount to at least **14 m£ annually**.[2]
- CO2 savings come from minimising curtailment and minimising the need to replace curtailed RES with additional synchronous fossil generation. Saving **18 million tonnes CO2/annum**. [2]

Source: CL analysis based on:
[1] E-Cigre (2019) https://www.e-cigre.org/publications/detail/symp-aal-2019-symposium-aalborg-2019.html
[2] Reactive Technologies (2023) Reactive Technologies and National Grid ESO Recognised as Clean Power Energy Transition Changemakers at COP28
[3] National grid – Reactive Technologies (2017) Project SIM – Inertia Measurement

These technologies, when applied to existing assets, have significantly increased network capacity without the need for new infrastructure

Technology	Country	Range - % increase in line / system capacity	Case study description	Comment on additionality
Advanced power flow control		5% increase in wider network capacity	UK – Deployment of 48 SmartValves in congested network areas	The total increase in capacity depends on the level of congestions.
Advanced conductors		100% increase in line capacity	Belgium – Upgrade of 380 kV connection with HTLS conductors	Progressive roll-out, replacement of ageing power lines first.
Storage as a transmission asset		40% increase in line capacity	Germany – 250 MW Gridbooster planned at grid hub “Kupferzell”	CAPEX intensive solution, typically used in the most congested zones.
Dynamic Line Rating		Over 30% increase in average transmission capacity	USA – DLR software and sensor platform deployed on 115 kV lines in New York	Increase depends on specific weather conditions.
Grid Inertia Measurement		Up to 30% assumed grid inertia, allowing for higher share of RES and reduced curtailment	UK – Commercial service operational since 2022, saving ~5.5% of UK’s CO2-emissions annually.	Increase comes from additional inertia from system load. Only achievable through inertia measurement.
High temperature superconductors	High Temperature Superconductors allow for bulk transport of electricity. For instance, a 500% to 1000% increase in line capacity can be achieved			

- IGTs can increase the capacity on a certain line by up to about 170%, adding the possible effects of advanced conductors, dynamic line rating and SATA.
- In addition, advanced power flow control systems can increase the overall system capacity by about 5% and grid inertia measurement can significantly reduce RES curtailment.
- Note that those figures are general estimations, and actual figures can significantly differ on a case-by-case basis as electricity networks are location-specific.

Expert interviews suggest a 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network

The overall benefits of IGTs deployment on the wider network have been estimated based on a range of expert interviews by combining:

- **Effect on a certain line – Improvement per circuit:** These effects have been analysed for each technology and summarised on the previous slide.
- **The maximum coverage of an IGT on a network:** Because of their costs and because network issues are always highly location specific, it seems unlikely that all IGTs will be rolled-out to every line on the network.

Overall, a 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network could be achieved:

- Expert interviews were used to estimate reasonable maximum coverage factors for IGT technologies as summarised in the Table on the right.
- These estimates combined with potential improvements derived from case studies show an overall 20% to 40% capacity/line length improvement for the overall effect of IGTs on the wider network as presented in the Table.*
- To avoid overstating capabilities or underestimating unforeseen challenges, a conservative 10% to 20% (halved) overall increase is used in the rest of the study, allowing for growth in experience with IGTs being deployed at such scale.

Examples of how a 20% - 40% overall effect can be achieved

	Improvement per circuit	IGT coverage	Possible effect on overall system ()
Example 1 – 20%			**20%**
DLR	30%	17%	5%
SATA	40%	10%	4%
APFC			5%
Adv. Conductors	100%	5%	5%
Superconductors	400%	0.25%	1%
Example 2 – 20%			**20%**
DLR	30%	10%	3%
SATA	40%	17%	7%
APFC			5%
Adv. conductors	100%	4%	4%
Superconductors	400%	0.25%	1%
Example 3 – 40%			**40%**
DLR	30%	40%	12%
SATA	40%	20%	8%
APFC			8%
Adv. conductors	100%	10%	10%
Superconductors	1000%	0.2%	2%
Example 4 – 40%			**40%**
DLR	30%	25%	8%
SATA	40%	25%	10%
APFC			10%
Adv. conductors	100%	10%	10%
Superconductors	1000%	0.2%	2%

Source: CL analysis based on discussion with IGT experts and based on IGT real case studies (see previous slide)

** Please note that this is an indicative estimation under some uncertainty that is caused by the limited experience with IGTs and limited available data. We recommend detailed bottom-up modelling studies to further explore the effects.*

2.3

Indicative extrapolation of the benefit of IGTs

Approach – How do we estimate the broader benefit of IGTs? (I)

Our modelling of the relationship between network length, network demand drivers and constraint costs, allows us to extrapolate the main benefits of IGTs

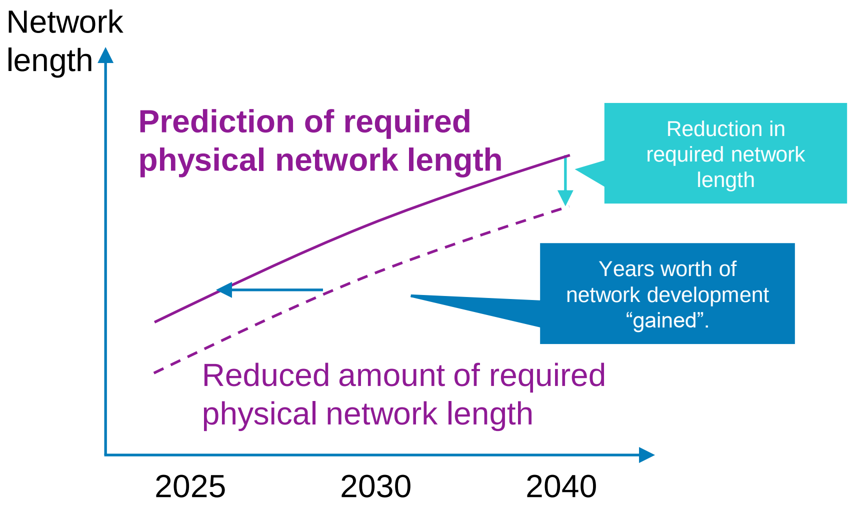
Saved network expansion needs and **bought time:**

Prediction of required physical network length: We use the prediction of required network length in the different countries based on the regression analysis in work package 1.3. It is an estimation of how much more network length will be needed, given the substantial planned further buildout of renewable capacities, and the assumption that constraint costs should decrease over time. At the transmission level, as the regression analysis seems conservative compared to the literature, national network expansion needs are scaled up to match the estimate from the IEA (~50% increase in network length by 2040 compared to 2021).

Reduced amount of required physical network length: Applying the grid reduction factors to the estimated buildout gives us the savings in future network length arising from IGT-deployment. Of course, this is a simplified metric that is based on several assumptions. In particular, we assume that capacity improvement on the wider network would – other things equal – save the same amount in overall line length as physical buildout. E.g., if IGTs could improve the overall system capacity by 10%, then 10% less physical line length would be required.

Reduction in required network length: Shows with how much less network length one could get the same capacity in a given year, assuming that a) the grid reduction factors are correct (at least on average) for the whole grid and time period shown here b) the IGTs are applied to the whole network at once, which will typically not be the case and c) network investment stops after, such that savings are actually "realised". In reality, building the network is a continuous process, which brings us to the next metric.

Years of network development "gained": IGTs' improvement in de-facto network length can be related to the rate of grid buildout in a country. That way, one can see how many years worth of network buildout can be gained by applying IGTs.

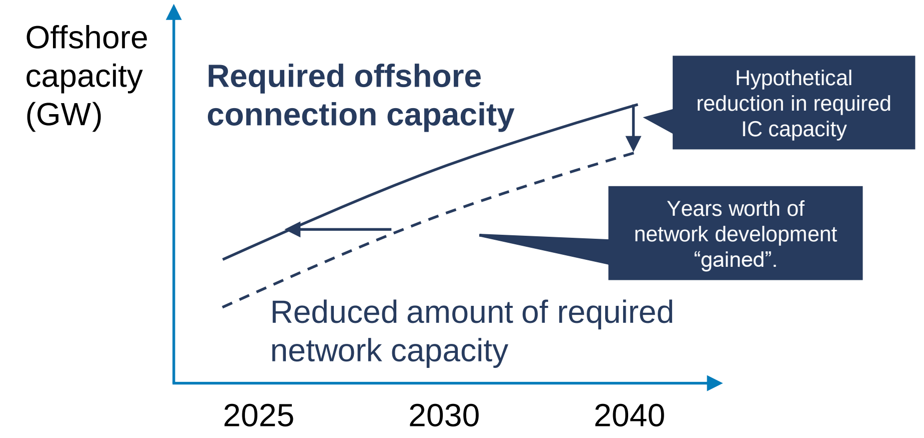


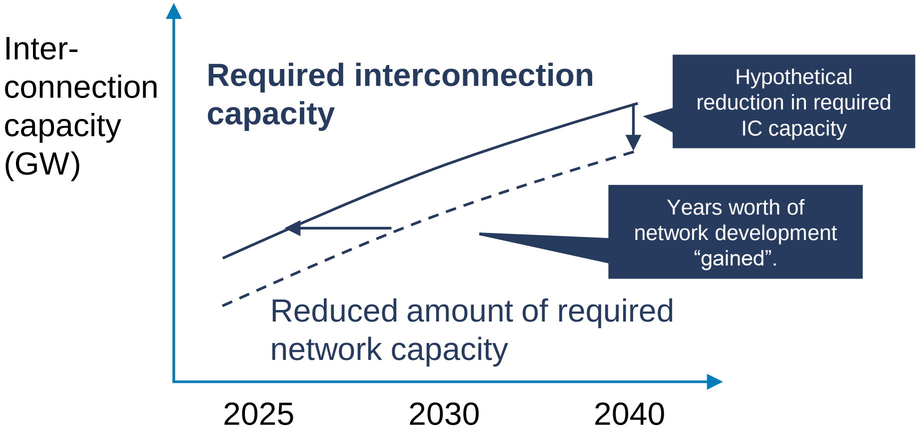
Approach – How do we estimate the broader benefit of IGTs? (II)

Our modelling of the relationship between network length, network demand drivers and constraint costs, allows us to extrapolate the main benefits of IGTs

Interconnections and offshore:

- We use a slightly simplified approach for quantifying the benefits of IGTs on offshore and interconnector capacities.
- The TYNDP IoSN study and the ONDP study give an estimation of the required increase in offshore connection capacity and interconnection capacity (although this may be a conservative estimate compared to what is required to meet decarbonisation targets, as these studies might not be fully aligned with decarbonisation scenarios).
- When IGTs are applied, this required buildout can be achieved either with fewer physical cables, or alternatively, years of capacity buildout can be saved. This relationship is similar to the one we established for TSO and DSO network length.
- Hence, by applying “improvement factors”, we can calculate saved capacity and bought time.





Based on an estimated capacity increase of 10–20% from section 2.2, two scenarios are used to estimate the potential benefits of IGTs

Low scenario – assumes 10% increase in overall network capacity achieved with IGTs

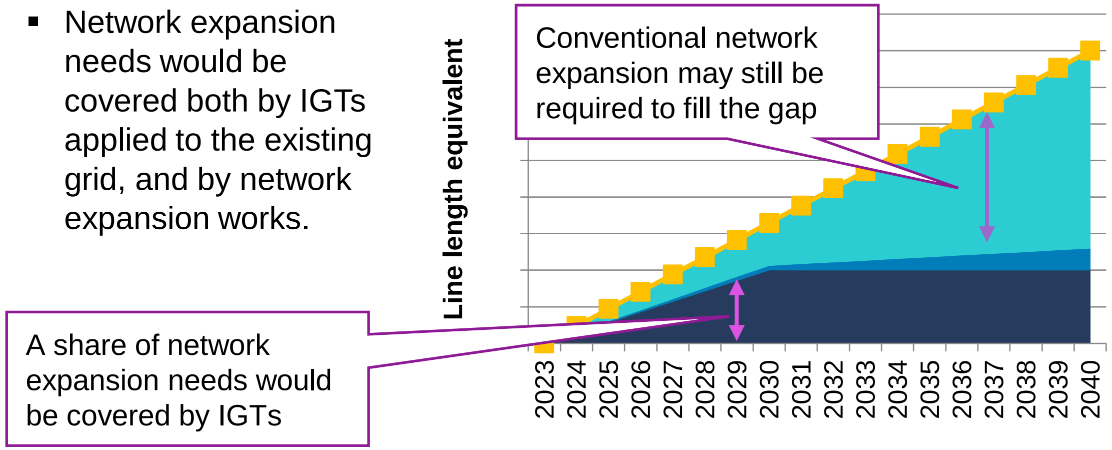
- **An initial targeted deployment of IGTs in the existing grid by 2030:** In 2030, a 10% increase in the capacity of the existing network is achieved, due to a roll-out of IGTs in specific grid locations/bottlenecks. Beyond this point, we assume that network expansion is required.
- **The remaining need is met with new grid buildout which include IGTs**: New network assets built by 2040 are boosted with IGTs, which provide a 10% capacity improvements compared to conventional technologies.

High scenario – assumes 20% increase in overall network capacity achieved with IGTs

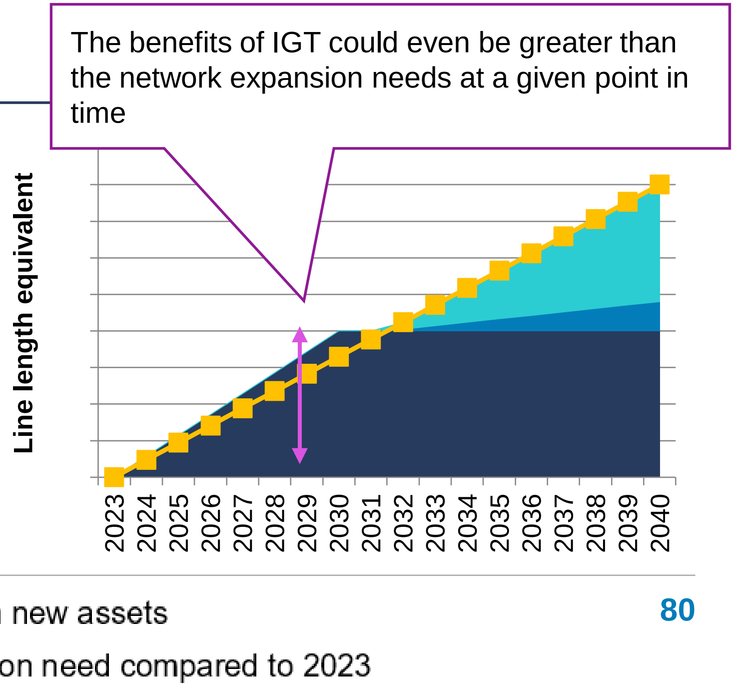
- **An initial targeted deployment of IGTs in the existing grid by 2030:** Same as low scenario, but a 20% increase is assumed.
- **The remaining need is met with new grid buildout which include IGTs**: Same as low scenario, but a 20% capacity improvement is assumed compared to conventional technologies.

Benefits of IGTs compared to network expansion needs (line length equivalent) – Illustrative charts

- Network expansion needs would be covered both by IGTs applied to the existing grid, and by network expansion works.



- The greater the assumption of network upgrade from IGTs, the smaller the need for network expansion
- *Note: Assumption of 40% increase in grid capacity in these graphs*



Assuming a 10-20% increase in network capacity by 2030 through IGTs could boost substantially grid capacity expansion at the transmission level

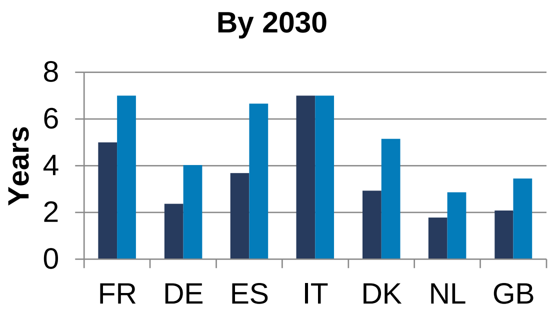
Fast-tracking network development (years saved)

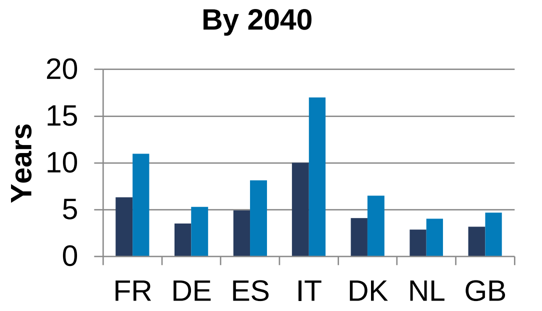
- Assuming that **a)** the installation of **IGTs achieve a 10-20% increase** in the capacity of the **existing grid by 2030** and that **b)** the **remaining need for capacity increase** is **covered by conventional technologies upgraded with IGTs**, we can compute how many years of network development are saved when IGTs are deployed at such scale.
- **This suggests that deploying IGTs in the transmission grid could accelerate network expansion by 5 to 8 years across the different countries, by 2040**

Network capacity unlocked through IGT-deployment

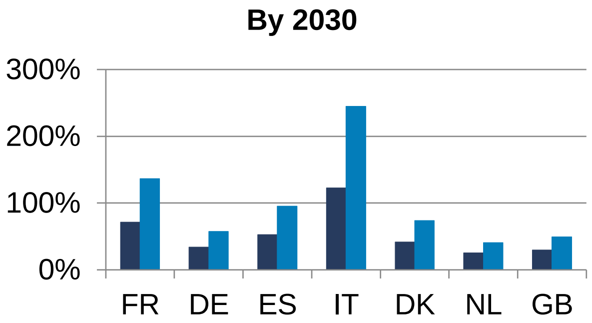
- Comparing the necessary increase in network length with the additional network capacity unlocked by IGT-deployment, we find that the **IGTs could significantly accelerate the reaching of those buildout targets**.
- This share would amount to **28% in the low scenario**, where a 10% increase in network capacity is assumed, and reach **45% in the high scenario**, with a 20% increase in network capacity assumed.

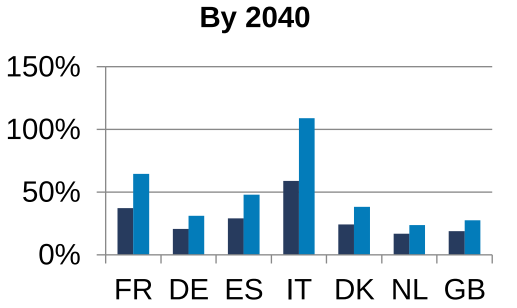
Fast-tracking (years) achieved if IGTs are deployed at scale from now on: network expansion acceleration, assuming a 10-20% capacity increase – Transmission grid





Acceleration towards transmission network expansion target: Share of total expansion need met by IGTs by 2040 (%), assuming that a 10-20% capacity increase is achieved – Transmission grid





Scenario low - 10% increase in network capacity | Scenario high - 20% increase in network capacity

Caveat: under some assumptions, more than 100% of the capacity needs at the transmission level could be met by IGTs, but **this would not be the case in reality. Grid constraints are location specific and, in some locations, physical grid reinforcement will be necessary** – for example if IGTs are fully deployed already. Nonetheless, this calculation shows that IGTs **could play a substantial role to meet grid expansion needs**, going forward.

Deploying IGTs could provide an increase in network capacity, and fast-track investments in grid expansion in the distribution grids as well

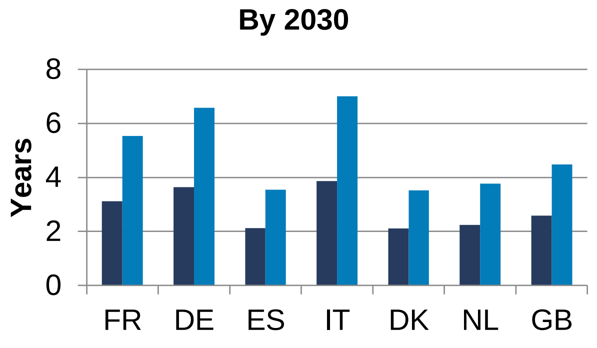
Fast-tracking network development (years saved)

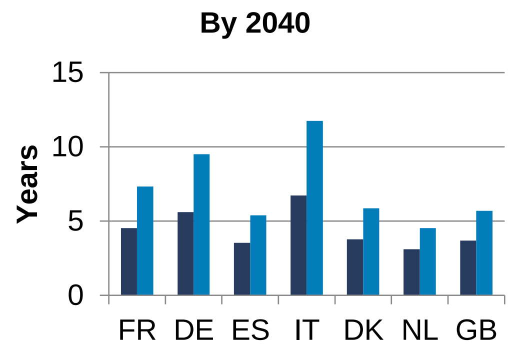
- Assuming that **a)** the installation of **IGTs achieves a 10-20% increase** in the capacity of the **existing grid by 2030** and that **b)** the **remaining need for capacity increase** is **covered by conventional technologies upgraded with IGTs**, we can compute how many years of network development are saved when IGTs are deployed at such scale.
- **This suggests that deploying IGTs in the transmission grid could accelerate network expansion by 4 to 7 years across the different countries, by 2040**

Network capacity unlocked through IGT-deployment

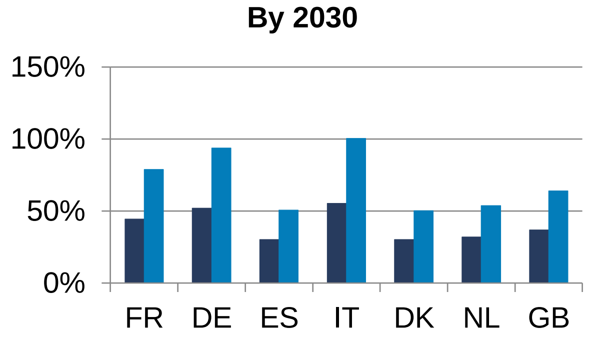
- Comparing the necessary increase in network length with the additional network capacity unlocked by IGT-deployment, we find that the **IGTs could significantly accelerate the achievement of those buildout targets**.
- This share would amount to an average of **26% by 2040 in the low scenario**, where a 10% increase in network capacity is assumed, and reach **43% in the high scenario**, with a 20% increase in network capacity assumed.

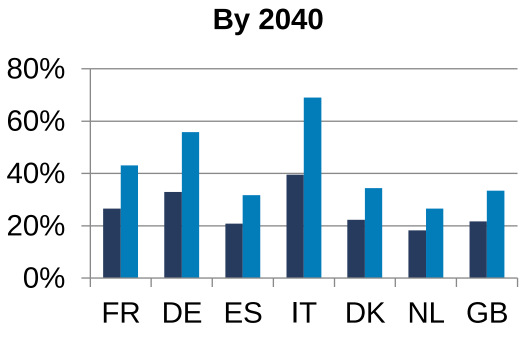
Fast-tracking (years) achieved if IGTs are deployed at scale from now on: network expansion acceleration, assuming a 10-20% capacity increase – Distribution grid





Acceleration towards transmission network expansion target : Share of total expansion need met by IGTs by 2040 (%), assuming that a 10-20% capacity increase is achieved – Distribution grid





■ Scenario low - 10% increase in network capacity ■ Scenario high - 20% increase in network capacity

IGTs could be used to unlock additional capacity from interconnections, hereby reducing the need for additional infrastructure

Fast-tracking network development (years saved)

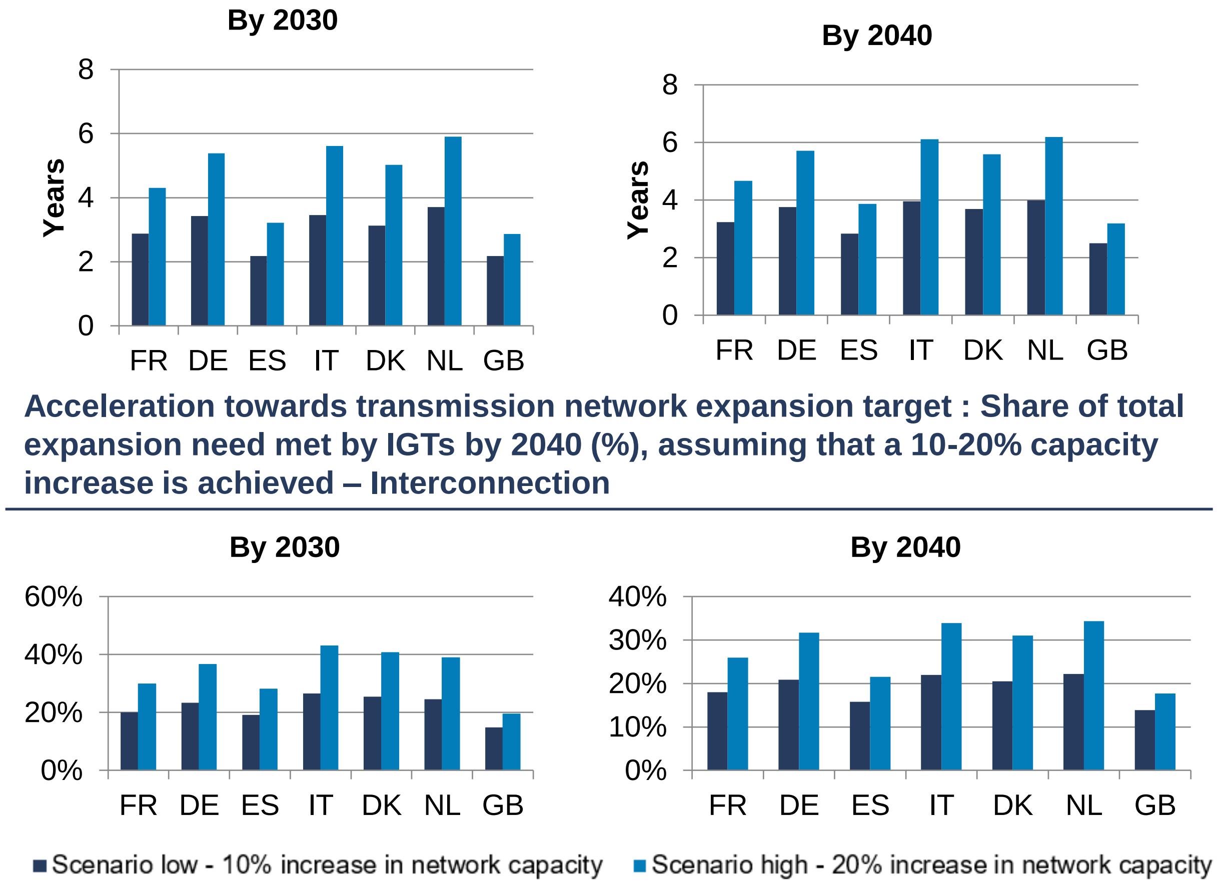
- Assuming that **a)** the installation of **IGTs achieve a 10-20% increase** in the capacity of the **existing grid by 2030** and that **b)** the **remaining need for capacity increase** is **covered by conventional technologies upgraded with IGTs**, we can compute how many years of network development are saved when IGTs are deployed at such scale.
- **This suggests that deploying IGTs on interconnections could accelerate network expansion by 4 years across the different countries in the low scenario, and 5 years in the high scenario, by 2040.**

Network capacity unlocked through IGT-deployment

- Comparing the necessary increase in interconnection capacity from the ENTSO-E System Needs study with the additional network capacity unlocked by IGT-deployment, we find that the **IGTs could significantly accelerate the reaching of those buildout targets**.
- This share would amount to an average of **19% by 2040 in the low scenario**, where a 10% increase in network capacity is assumed, and reach **28% in the high scenario**, with a 20% increase in network capacity assumed.

Fast-tracking (years) achieved if IGTs are deployed at scale from now on: network expansion acceleration, assuming a 10-20% capacity increase – Interconnections

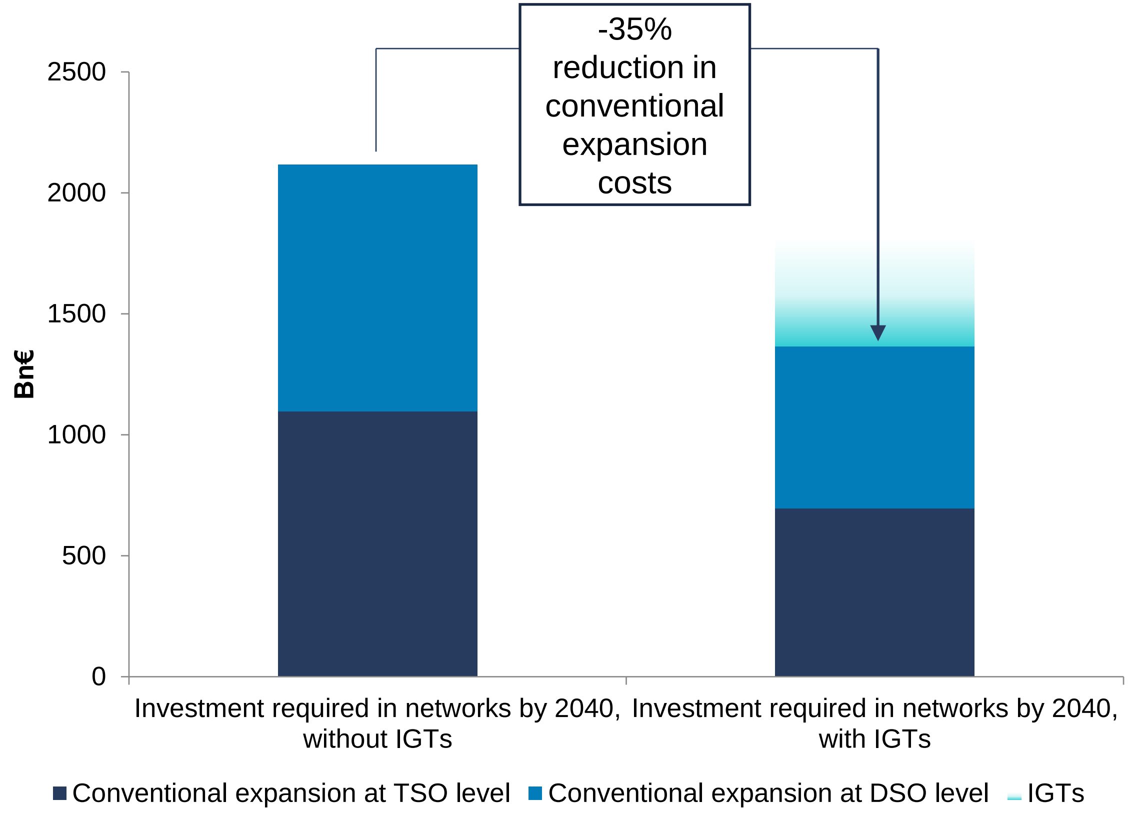
Acceleration towards transmission network expansion target : Share of total expansion need met by IGTs by 2040 (%), assuming that a 10-20% capacity increase is achieved – Interconnection



By investing in IGTs in parallel to conventional grid buildout, gross cost savings of 700 Bn€ in conventional expansion might be achieved by 2040

- The required investments in electricity networks, if IGTs are not deployed at scale, might amount to approximately **1000 Bn€[1] in the transmission network** and **1000 Bn€[2] in the distribution network** in Europe by 2040.
- Installing IGTs (with the assumptions described in previous slides) could reduce the need for network buildout at the transmission and distribution level by approximately 35% by 2040, and hence achieve overall **gross savings of 700 Bn€ in conventional expansion costs.** However, this figure doesn't take into account the costs of IGT deployment themselves.
- Nonetheless, these **gross benefits** may be **significantly higher than the costs of deploying the said IGTs** – for instance, the US DoE indicates that IGT can indeed achieve an increase in capacity at a lower cost than conventional reinforcements[3].

Gross benefits of IGT deployment - Saved investments in network expansion



Note: [1] CL estimate, based on the projected cost of onshore network buildout per km of new lines in Germany, Italy and Spain, and the need for network buildout presented in this study [2] 67Bn€/year for EU27+NO according to Eurelectric (2024) Grids for Speed, [3] For instance, for APFC and DLR, see: DoE (2022) Grid-Enhancing Technologies: A Case Study on Ratepayer Impact

3.

How to unlock the benefits of Innovative grid technologies?

3.1

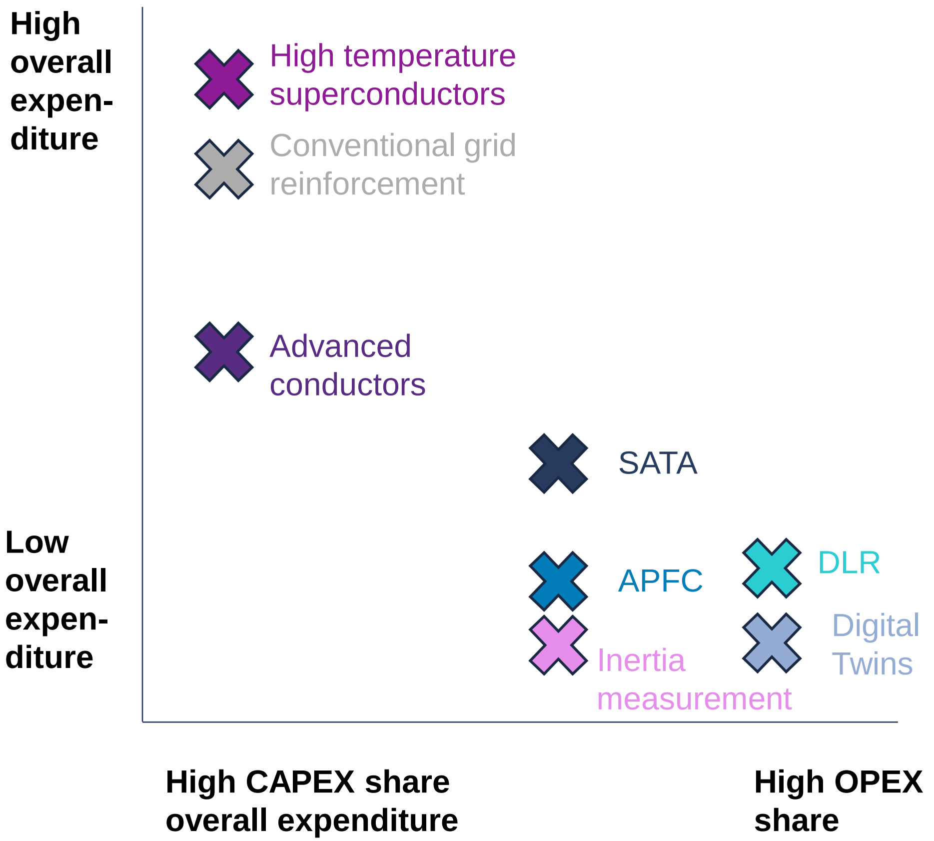
Identification of key barriers for the uptake of IGTs

Innovative grid technologies share distinct features compared to their substitute of conventional grid reinforcements

IGTs and conventional reinforcement differ in several respects, in particular:

- **The impact in terms of costs for network operators is typically different between IGTs and conventional grid enforcement:** Some IGTs tend to achieve an increase in network capacity and reduce grid bottlenecks at a **lower total cost** (for instance highlighted by the US Department of Energy in a recent paper[2]). Moreover, some IGTs have comparatively **higher OPEX** costs for network operators.
- **IGTs typically increase system utilization:** IGTs often create capacity by increasing system utilisation, which contrasts with conventional grid reinforcement. This means the system approaches its physical limits and more attention to all system parameters is required (i.e. a more sophisticated operation of the system). Moreover, to answer grid constraints, IGTs tend not to be standalone solutions, but rather need to be simultaneously applied, and require consideration of the system operation to provide the same service as conventional solutions. This **can increase the complexity of system operation**, and hence translate into perceived operational risks.
- **The experience network operators have with operating IGTs is significantly less developed than for conventional technologies:** Demonstration projects are typically required by network operators before a technology can be deployed widely.
- **Different levels of maturity:** Most IGTs in the scope of this study are already considered very mature technologies and have reached technology readiness level 9 (TRL 9). Only high-temperature superconductors are still in pilot stage, i.e. TRL 5.

Categorisation of costs of IGTs and conventional technologies – Illustration[1]



Sources: Compass Lexecon, based on interviews with industry members, Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, [1] Interviews with IGT representatives, [2] DoE (2022) Grid-Enhancing Technologies: A Case Study on Ratepayer Impact

The deployment of IGTs is currently hindered by several barriers

- Interviews with IGT representatives and regulators, complemented with literature research showed that several barriers to the deployment of IGTs remain. When conducting the research, we found that practical experiences brought to us through the interviews often matched with known theoretical regulatory concepts.
- Nevertheless, the majority of TSOs have already deployed IGTs to some extent[1]. Moreover, around a third of the NRAs indicated that they deploy monetary incentives to their regulated TSO(s) to use advanced and innovative solutions that reduce total expenditures (TOTEX) compared to traditional solutions achieving the same benefit.

Barriers for IGT deployment

1	**Lack of incentives to opt for non-CAPEX intensive solutions**	• Historical regulatory systems for network regulation were designed to finance large amounts of capital expenditure, so CAPEX is remunerated with a regulatory cost of capital, and often scrutinized less compared to OPEX. • In several regulatory regimes, there is a bias against OPEX solutions, towards CAPEX.
2	**Insufficient output incentives and incentives for innovation**	Regulated networks often face incentives that may not provide for optimal operational and investment decisions: Revenue is often directly linked to costs and not to output. At the same time, (calculated) risk-taking is not rewarded but rather discouraged. While there are good reasons for that, this can have two effects: • First, network operators may not have incentives to use overall cheaper solutions – even less so, if those solutions involve innovation and a modest increase in operational risk. • Second, innovations that may increase output while leaving costs constant are not financially encouraged either. Again, even less so, if those innovations involve some risk.
3	**Investment doctrine and methodologies of network operators**	• The investment doctrine of T/DSOs might include bias towards predetermined solutions to fix perceived issues, rather than adopting a technology-neutral approach to answer the system needs identified. In particular, using IGTs as an alternative solution to fix network constraints may not be adequately reflected in the doctrine, its practical application and in the incentive given to decision makers.
4	**Death by pilot risk**	• T/DSOs are responsible for ensuring security of supply for consumers and have hence an incentive to maintain high reliability standards with regards to network components. IGT adoption is hence hindered by long processes for network companies to trial and then adopt new innovative solutions. Moreover, the need for (several) demonstration projects to convince TSOs of the reliability/accountability of a technology before it can be rolled-out can create financial risks for IGT providers, hindering them from sustained fundings without a clear visibility on future revenues.
5	**Funding schemes eligibility issues**	• Some of the potentially available funding schemes cannot easily be accessed by IGTs yet, compared to other energy technologies such as hydrogen or CCS, due to eligibility issues of IGTs.

Sources: Compass Lexecon, based on interviews with IGT representatives and industry members, as well as regulators, Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, [1] CurrENT (2023) Delivering on electricity grids – CurrENT recommendations for the European Commission

3.2

Description of barriers and identification of best practices / solutions

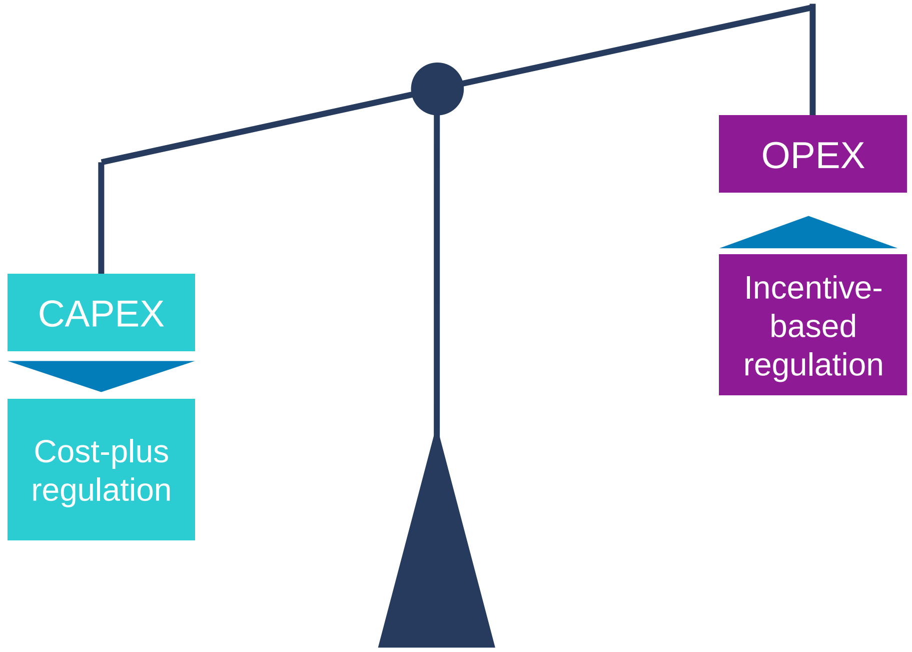
Barrier 1 - Lack of incentives to opt for non-CAPEX intensive solutions

The differences in the regulatory treatment of OPEX and CAPEX creates a favourable environment to invest in CAPEX-heavy solutions

ACER estimates that the attractiveness of innovative solutions, which are usually of lower (total) costs and often more OPEX intensive, is currently far from optimal for the TSOs and needs to be adequately increased.[1]

- The differences in the regulatory treatment of operational expenditure (OPEX) and capital expenditure (CAPEX), creates a favourable environment to invest in CAPEX-heavy solutions.
  - **Incentive-based regulation is often focussed on OPEX:** The network operator is expected to improve the efficiency of its operations according to a predefined factor while regulatory allowed OPEX are decoupled from actual OPEX. That means due to both regulatory expected efficiency improvements (regulatory stick), as well as due to regulatory incentives to outperform the cost benchmark (regulatory carrot), there are often strong incentives not to increase OPEX. In addition to that, network operators sometimes report that OPEX are scrutinised more heavily during regulatory cost audits.
  - **Cost-plus regulation is often applied to CAPEX:** This means that, once the new investment is approved by the regulator and included in the Regulatory Asset Base (RAB), the regulated company is guaranteed recovery of the investment, including an appropriate return on the invested capital.
- More than 50% of European NRAs who took part in the 2023 CEER annual survey apply a factor X to the allowed revenues to cover OPEX, while efficiency requirements on CAPEX are applied only by 20% of the responding NRAs.

Illustration – CAPEX bias



Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, [1] ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, [2] CEER (2023), Report on Regulatory Frameworks for European Energy Networks 2022

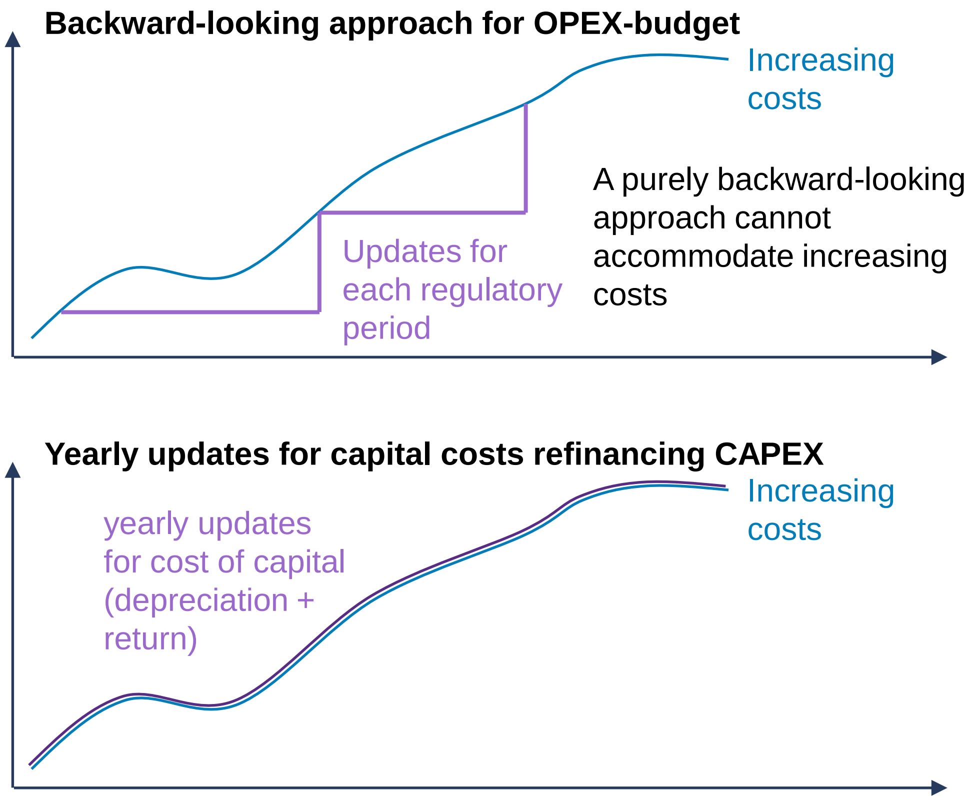
Case study: CAPEX/OPEX bias in the German regulatory system for TSOs makes investments in innovation harder

CAPEX and OPEX are not treated equally in the German regulatory framework for TSOs. CAPEX can be remunerated through the revenue cap, whereas OPEX suffers from the so-called "base year problem".

- **CAPEX-heavy solutions may be favoured in the German regulatory system:** For TSOs it could therefore often be difficult to invest into OPEX-intensive solutions. This can be a problem as necessary investment in efficiency improvements (e.g. innovation and IT-solutions) become more difficult.
- **Base year problem:** If OPEX-intensive investments are made in non-reference years, these investments are not reflected in the allowed revenues until the next base-year cost update.
- **Revenue Cap:** Contrary, investments for expansion or restructuring (typically CAPEX-heavy) expand the revenue cap ("Erlösobergrenze") also within a regulation period.

This can incentivise investments into CAPEX-heavy solutions even if an OPEX-intensive solution might have lower overall costs*

Illustration – CAPEX bias in the German regulation system



Sources: Study on incentive regulation, TransnetBW; BNetzA: Revenue Cap; BNetzA: Regulation framework
*Note: *We define "lower overall costs" here as lower overall net-present-value of a certain solution to a network issue, considering all relevant costs to the regulated company. We assume that such an assessment is done correctly – for example assuming correct capital costs and a proper definition of factual and counterfactual. For the argument made here, cost effects on the wider electricity system, that would be an external effect for the network operator, do not need to be considered.*

The recovery of TSOs' and DSOs' CAPEX and OPEX and setting their regulated allowed revenue can follow 3 main archetypes

Cost-plus regulation
How much did it cost?

- Allowed revenue equal to historical costs
- The regulator may decide (or threaten) to disallow costs

Revenue-cap regulation
Can you do it cheaper

- Allowed revenue is decoupled from costs for a certain period
- This creates incentive to save costs

Companies and Consumers share cost saving:

Output/benefit-based regulation
How much value was created?

- Allowed revenue based on the value (welfare) that a regulated company creates for users of the network

Companies and Consumers share value created:

Central Planning ⟷ Market

- **<u>Goal:</u>** Foster **investment in infrastructure and innovation** through secured investment framework

- **<u>Goal:</u>** Increase **cost efficiency**

- **<u>Goal:</u>** Maximise **output**, control costs and foster **innovation**

- **<u>Often used for CAPEX</u>**

- **<u>Often used for OPEX</u>**

- **<u>Not widely used</u>**
- **<u>For instance:</u>** Part of the RIIO framework for transmission and distribution network regulation

Source: Compass Lexecon analysis

Decision: 2010 - First period started in 2013

ofgem

Case study: RIIO played a key role in fostering the development of IGTs in GB (1/3)

Context

- In 2010, OFGEM found that a change in the regulation of energy networks was **necessary to deliver value for network users and support the transition to decarbonised energy.**
- The objective was to **strengthen the role of network companies in the transition** while improving **value-for-money** for consumers.
- There was a perception that innovation in the network industry had been reduced during the years of incentive regulation relative to when the industry was run as a public service.

Regulation

The RIIO concept: Revenues = Incentives + Innovation + Outputs.
A TOTEX based approach to solve the CAPEX/OPEX trade-off:

- RIIO addresses the CAPEX bias by implementing a **TOTEX-based approach** to the calculation of allowed costs. Independently from the actual expenditures of the regulated company, a **fixed share of the total cost, set ex-ante by the regulator, is treated as CAPEX and contributes to the formation of the RAB**, while the rest is treated as OPEX and remunerated within the book year. In practice, this means that part of the spending on OPEX for flexibility measures or other smart solutions would also be added to the RAB.

Challenges identified by Ofgem at the time of RIIO implementation

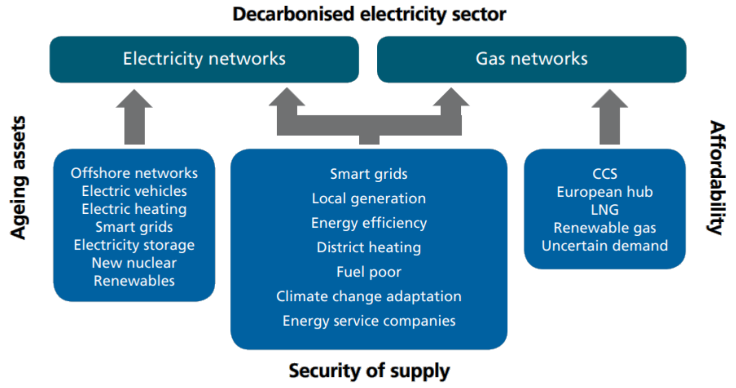
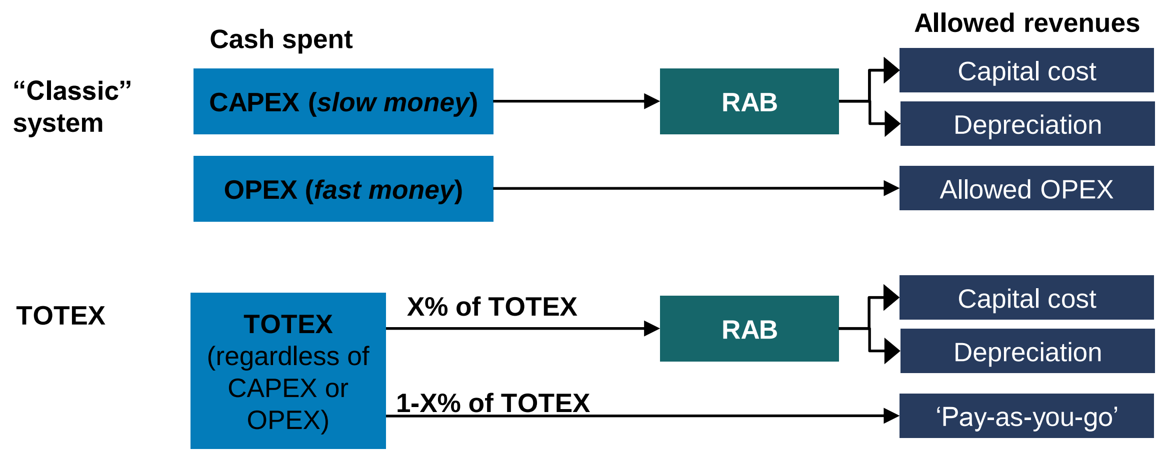


Illustration of a TOTEX regulation*



Note : 'Pay as you go' refers to costs that are recovered every year or during the control period, and therefore are treated similarly to OPEX in the "classic" system.

Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, Ofgem (2010), 'RIIO: A new way to regulate energy networks: final decision', October, Chondrogiannis (2022) Local electricity flexibility markets in Europe

*Note: *In some countries, regulatory systems that apply the same efficiency factors to operational and capital costs are also called TOTEX regulation. However, a regulatory system only truly treats CAPEX and OPEX the same, when all aspects of CAPEX and OPEX are treated the same, in particular also capitalisation rules.*

Decision: 2010 - First period started in 2013

ofgem

Case study: RIIO played a key role in fostering the development of IGTs in GB (2/3)

A regulation based on forward looking budgets:

- RIIO is based on **long-term vision with price control based on forecasts** of output requirements, demand for network services over time, and the cost of delivery (including input prices) and financing costs. NOs submit **business plans** which set out how (and at what cost) they intend to meet the outputs desired by Ofgem over the period.

A regulation based on incentives:

- RIIO **departs from the classical input-based regulation** towards a more **output-based regulation** (see slide before on regulatory archetypes).

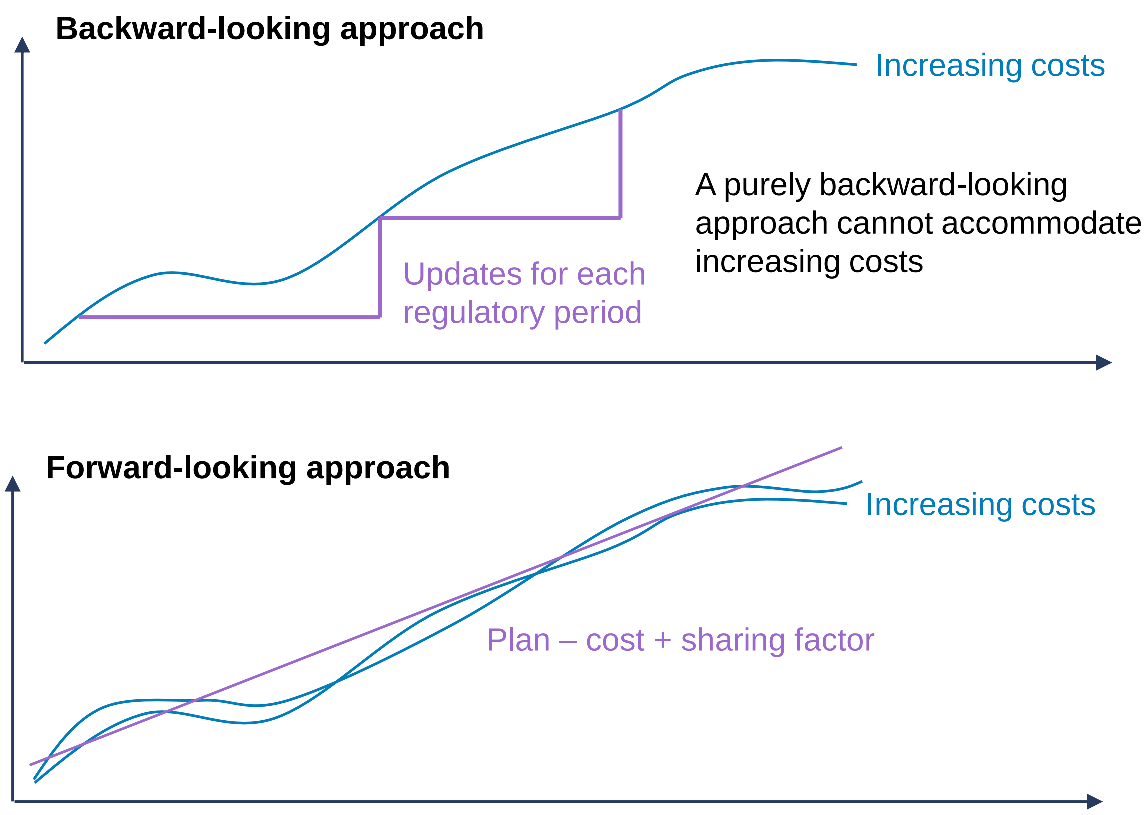
RIIO network innovation funding aimed at facilitating funding for innovative projects via three funding streams:

- The **Network Innovation Allowance (NIA)** is a set amount that each RIIO network licensee receives as part of their price control allowance.
- **Electricity Network Innovation Competition (NIC)** was an annual opportunity for electricity network companies to compete for funding for the development and demonstration of new technologies, operating and commercial arrangements.
- The same applied for gas transmission and distribution network companies via the **Gas Network Innovation Competition (NIC).**

RIIO encouraged network operators to consider holistic solutions for grid management, reducing the CAPEX/OPEX trade-off:

- → Operators' incentives for CAPEX/OPEX trade-offs are aligned with those of the public sector.

Illustration of the backward-looking versus forward-looking cost targets approach



Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, Ofgem (2010), 'RIIO: A new way to regulate energy networks: final decision', October, Chondrogiannis (2022) Local electricity flexibility markets in Europe.

Decision: 2010 - First period started in 2013

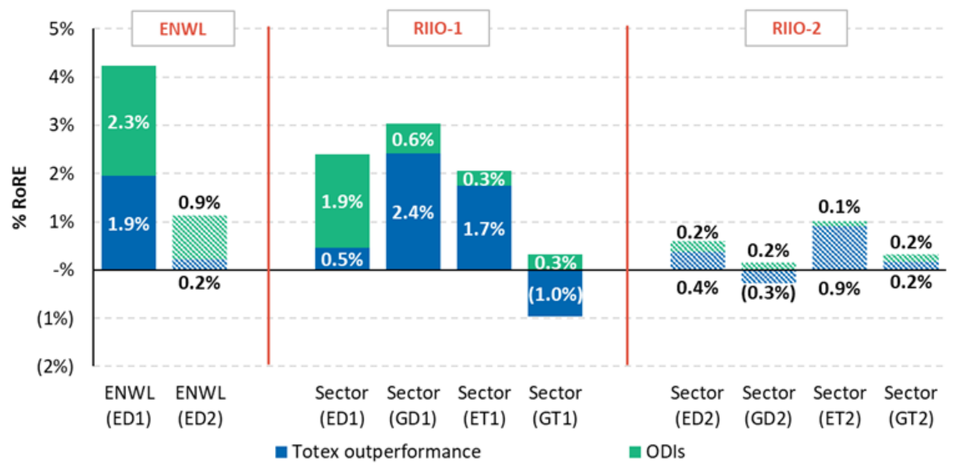
ofgem

Case study: RIIO played a key role in fostering the development of IGTs in GB (3/3)

Impact

- For DSOs more specifically, RIIO helped ignite the development of **DSO local flexibility markets during the period 2015-2023**, by:
  - **Reducing the CAPEX-bias**
  - Including **several provisions to incentivise innovation** and use **flexible resources as an alternative to grid reinforcements**.
- RIIO introduced **incentives to outperform TOTEX.** Under RIIO 1 (the first version of RIIO) companies had an overall budget covering all expenditure. Several companies managed to **underspend their TOTEX allowances** by postponing investment projects while still achieving the outputs. This led to significant financial outperformance for some companies (see middle part of figure to the right – "Totex outperformance") and substantial criticism in the public debate. It did also, however, incentivise companies to seriously consider innovative network solutions.
- In RIIO 2, this incentive was left in place, but the rules were refined further such that a simple postponing of investments would not translate into outperformance.

RoRE under three different schemes[1] (%)



Limitations

- **Departure from the traditional input-based regulation was not that large in the end**: The total value of the output-based rewards still represents a small fraction of the overall revenues.
- **Outputs need to be defined precisely**: Regulated companies generally have **easily achieved the targets**, getting higher than expected returns.
- The incentive to **underspend the budget led to delayed investment** → Challenge to **implement a scheme that incentivises real outperformance**.
- **Complexity** of RIIO has **not significantly reduced the information asymmetry** between regulator and companies.
- **Long duration of the regulatory period** led to a more difficult forecasting exercise, with an increased risk of over- or under-incentivising the network companies.
- The Network Innovation Allowances were not fully spent.

Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, Ofgem (2010), 'RIIO: A new way to regulate energy networks: final decision', October, Chondrogiannis (2022) Local electricity flexibility markets in Europe.
[1] "ENWL (ED1)" refers to the framework that determines what power prices can be set by the DSO "Electricity Northwest" in England, which was in place from 2015-2023. Its successor, ED2, will run from 2023-2028, see „ENWL (2024) Regulatory information".

OPEX factor ("Betriebskostenfaktor)"

Case study: Austria ensures allowed OPEX rise with investments by granting automatic additional OPEX for specific CAPEX invested.

Context

- **Additional OPEX tasks** due to investments for the energy transition have increasingly shown that OPEX can increase during a regulatory period for DSOs**.**
- Network operators had to expense these **increasing OPEX without compensation, because the OPEX level included in the revenue cap** was based on **historic OPEX** levels. Only when the level of OPEX would be updated during the next regulation period, costs from additional OPEX tasks were included.
- Consequently, there was a risk of avoided investments for the energy transition to avoid an OPEX-shortfall.

Regulation

- An **OPEX expansion factor** has been included in the allowed revenue calculation to reflect OPEX resulting from new investments during a regulatory period.
- This factor is determined as the product of **norm costs** times the number of selected additional installations.
- The selected additional installations concern: (i) **system length**, (ii) **metering points** and (iii) **connection of RES** differentiated by plant capacity.
- The norm costs for system length and metering points are identified by **regression analysis** with the OPEX as dependent and the DSO installations as explanatory variables.
- The OPEX factor can also take **negative values**, which is a **de facto punishment** if necessary investment is not made.
- Only **actual realised investments** are considered when applying the factor.

Impact

- The OPEX expansion rate per unit of installation sets an incentive for new investments and compensates the DSO.

Calculation of the OPEX expansion factor

1. Norm costs are derived from a regression analysis across all DSOs

$$\text{OPEX} = \alpha + \beta_1 \text{ Weighted network length} + \beta_2 \text{ Number of meters} + \varepsilon$$

2. Calculation of expansion factor in regulatory formula

$$\boxed{\text{Expansion factor}} = \beta_1 \boxed{\triangle \text{ Meter}} + \beta_2 \boxed{\triangle \text{ Network length}}$$

Legend

α: Constant;
β_1: Estimated cost per unit length;
β_2: Estimated cost per meter;
ε: error term

Sources: E-Control: 3rd Regulation Period; E-Control: 5th Regulation period; BNetzA: Comparison of Regulation systems; Statement Thüga

Barrier 1 - Lack of incentives to opt for non-CAPEX intensive solutions

Recommendations

Barrier 1 - Lack of incentives to opt for non-CAPEX intensive solutions

TOTEX Regulation

True TOTEX regulation, which treats CAPEX and OPEX the same w.r.t. regulatory cost audits, capitalisation rules AND potential efficiency factors or sharing factors, can remove a possible incentive to prefer CAPEX over OPEX solutions. The classic example where this principle has been applied thoroughly is the UK.

Introduce possibility of OPEX increase

In some countries, a distortion between CAPEX and OPEX comes more from delays in getting rising OPEX into the allowed regulated revenue than from a particularly preferential treatment of CAPEX.
This problem can be solved by allowing the company an OPEX-benchmark that rises during the regulatory period.
This can be done by basing the OPEX-benchmark on cost projections:

- For example, based on forward-looking budgets as demonstrated by the UK example.
- It can also be done by allowing additional OPEX based on measurable factors, like for example new meters installed, RES installed or additional network length.

Barrier 2 - Insufficient output incentives and incentives for innovation

Network operators may not be sufficiently incentivised to opt for cheaper and innovative solutions (I)

When addressing a need to invest, the decision of network operators is sometimes strongly influenced by regulatory rules.

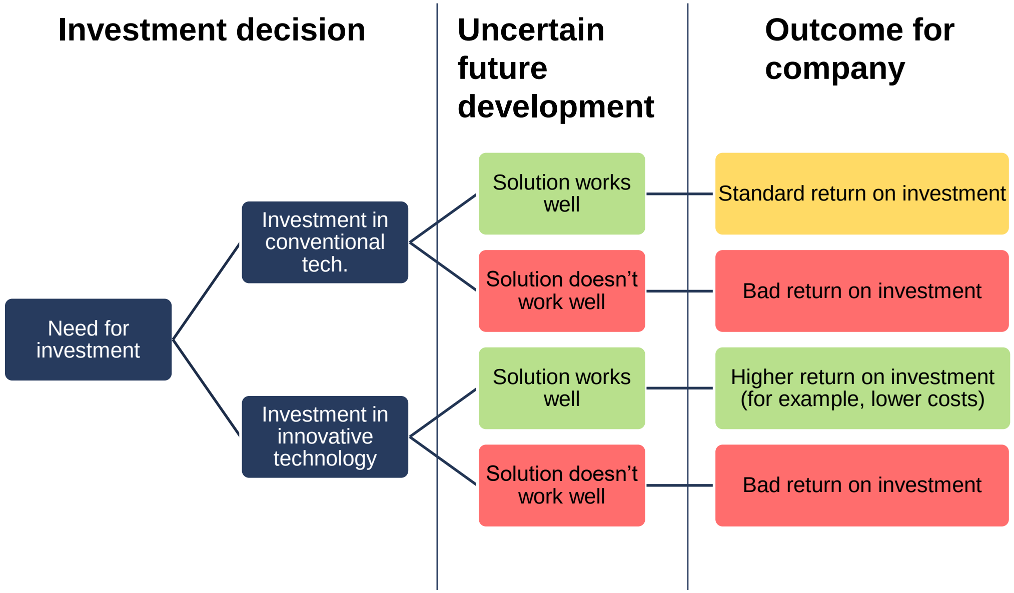
Incentive on a "normal" competitive market:

- Firms operating on a competitive market, typically make investment decisions based on a risk-return trade off. While this investment decision is often very complex, we present it in a simplified manner here, as it serves as a benchmark to the investment incentives regulated network companies operate under.
- Consider the figure to the right. If the returns of the investment, coming either from lower costs or better-quality output, seems worth the (calculated) risk, a company would choose technologies that either increase the efficiency of the production process, increase the quality of the output, or both. Often, those technologies would be innovative.

T/DSOs incentive to innovate under current network regulation:

- Revenue is often directly linked to costs and not to output. That means that overall cheaper* solutions do not necessarily translate into a better financial outcome for regulated companies, reducing the incentive to pursue them. This effect is often more pronounced for CAPEX (see last section), but not necessarily limited to this.
- Innovations that may increase output while leaving costs constant are not strongly financially encouraged in some regulatory systems. Hence, from the viewpoint of a network company, the positive effect that network capacity increases have on – say – electricity trade become an external effect that they do not necessarily need to consider in their investment decisions. Output-based regulation can fix this problem by incentivising companies to consider such effects. *[continued on next page]*

Incentive to innovate on a "normal" market (benchmark)



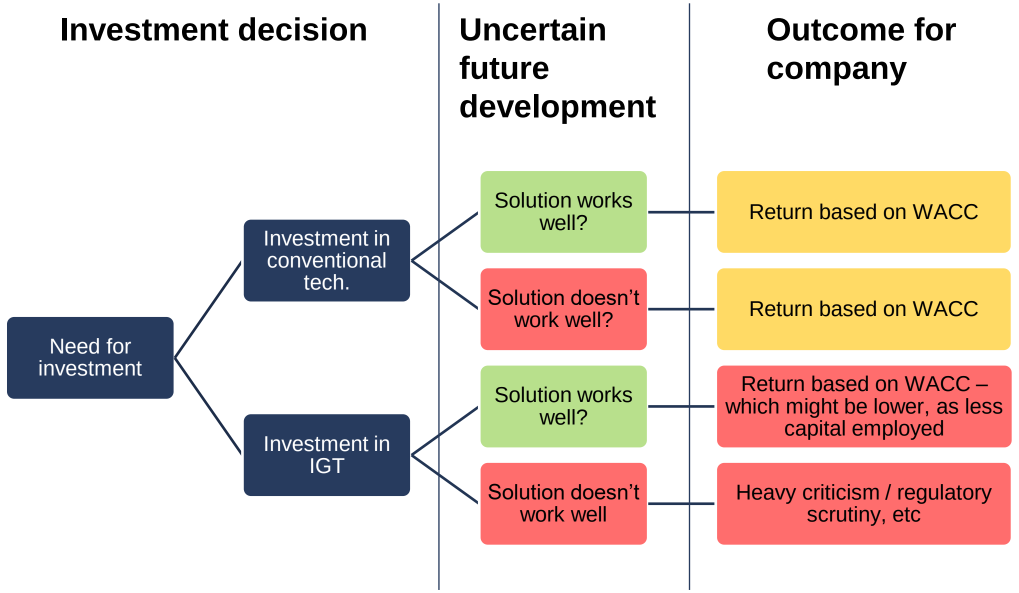
On a "normal" market, companies should be able to reap the returns of investments made, incentivising them to take an appropriate level of risk.

Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, [1] ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, CEER (2023), Report on Regulatory Frameworks for European Energy Networks 2022
Note: *We define "lower overall costs" here as lower overall net-present-value of a certain solution to a network issue, considering all relevant costs to the regulated company. We assume that such an assessment is done correctly – for example assuming correct capital costs and a proper definition of factual and counterfactual. For the argument made in this paragraph, cost effects on the wider electricity system, that would be an external effect for the network operator, do not need to be considered.

Network operators may not be sufficiently incentivised to opt for cheaper and innovative solutions (II)

- *[continuation from previous page]* To summarise, network companies under current network regulation often have no incentive to reduce costs, because their remuneration is linked to costs. Also, they often have no incentive to directly consider their outputs, like transmission capacity achieved, in their decisions because their remuneration is often not linked to outputs.
- Both effects are reinforced by the risk/return trade-off that regulated companies typically face. If an innovation is successful, and either costs are reduced or outputs increased, the reward for companies is typically limited by the regulatory system.
- Regulators - often fearing criticism or political pressure – typically have a strong incentive to limit economic profits of regulated companies. While this is part of the role of regulators, it can be an issue when the limitation of profits also reduces the incentives to innovate.*
- This dilemma is demonstrated well by the critical discussions around the introduction of RIIO regulation in the UK. While RIIO was successful in compelling the network operators to innovate and seek alternative solutions to conventional network expansion, it also triggered a fierce debate about whether some of the profits it allowed network companies were justified (see RIIO case study).
- *[continued on next page]*

T/DSOs incentive to innovate under current network regulation



Companies under current network regulation often have little incentive to innovate, since a) returns are capped, b) revenues are based largely on inputs and c) issues may lead to more heavy regulatory scrutiny.

Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, [1] ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, CEER (2023), Report on Regulatory Frameworks for European Energy Networks 2022

*Note: *This dilemma a regulator faces is illustrated well by the effects of RIIO and the discussions around RIIO in the UK.*

Network operators may not be sufficiently incentivised to opt for cheaper and innovative solutions (III)

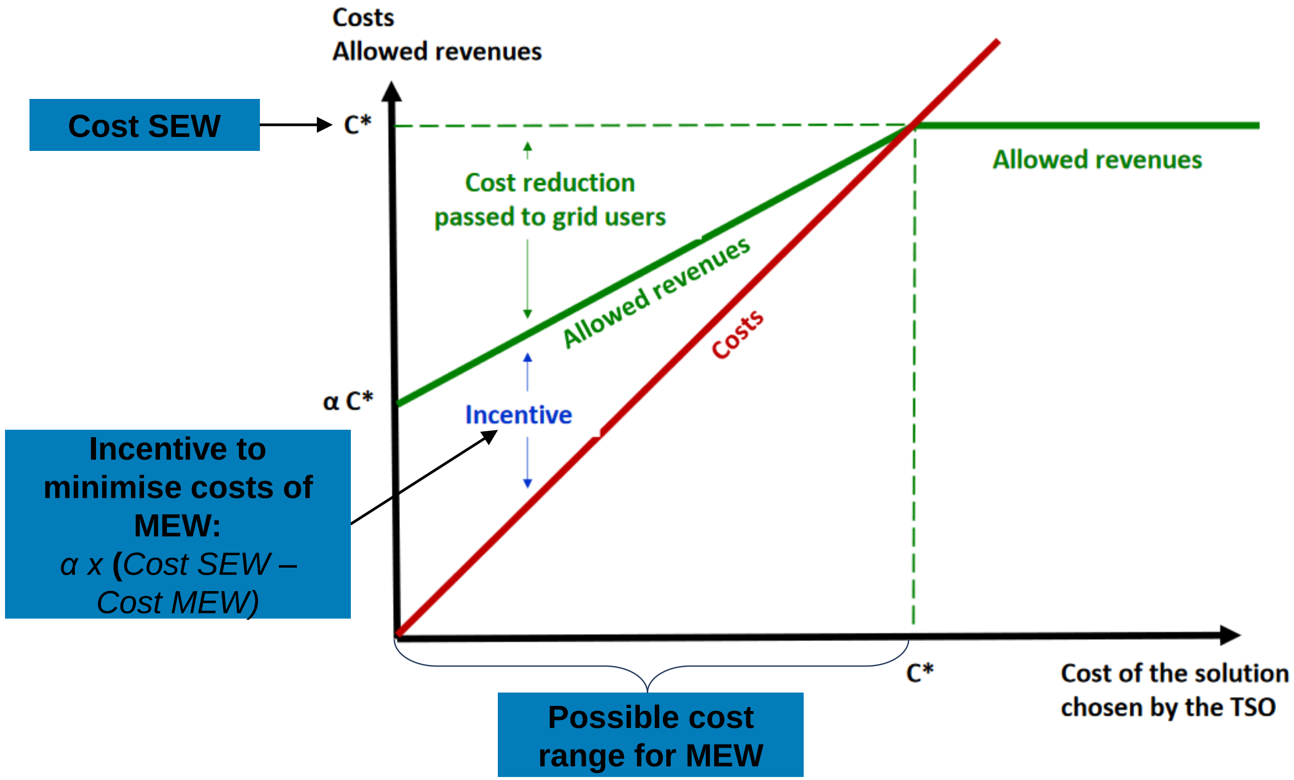
- *[continuation from previous page]*
- Apart from the lack of incentives through possible profits, network operators also are dependent to a certain degree on the goodwill of politics and regulators. If an innovative approach were to fail and to produce adverse outcomes, for example in the form of outages, network operators may face strong criticism and additional scrutiny.
- To summarize, under most regulatory systems network operators appear to have more to lose than to gain from innovative solutions. Hence, while several NRAs have deployed monetary incentives to their regulated TSO(s) for advanced and innovative solutions that reduce total expenditures (TOTEX) compared to traditional solutions achieving the same benefit (35% of the NRAs responding to a survey by ACER[1]), there is a perception that more could be done.
- However, TSOs' expected profit may remain in many cases higher for a conventional infrastructure investment (e.g. an overhead line) compared to an innovative solution achieving the same benefit (e.g. dynamic line rating).

Sources: Florence School of Regulation (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs, [1] ACER (2021), Position on incentivising smart investments to improve the efficient use of electricity transmission assets, CEER (2023), Report on Regulatory Frameworks for European Energy Networks 2022.

A benefit-based incentive regulation could further promote efficiency and innovation in addressing system needs

- Once a set of system needs is identified by the regulator, the regulator defines a "**standard efficient way (SEW)**" of addressing these needs, considering possible cost advantages when addressing multiple needs with one measure at the same time.
- Then, OPEX, CAPEX, and the period over which allowed revenues of the SEW of addressing system needs are identified by the regulator
- As an alternative to the standard efficient way identified by the regulator, the TSO would be required to present a "**more efficient way (MEW)"** of addressing the need(s) and the associated costs to be approved by the regulator.
- **Allowed revenues** for the TSO are then set to:
  - Cover the costs of the TSO's more efficient solution.
  - Include an incentive represented by a share of the net present value of the positive difference in costs when comparing the SEW and the MEW identified by the TSO.
    - The cost difference is assessed over the economic life of the longest-living asset in the standard efficient way.
  - The cap for allowed revenues would be set at the costs of the SEW of addressing the identified system needs.

Benefit-based incentive regulation for network operators proposed by Pototschnig & Rossetto (2023)[1]



Sources: [1] Florence School of Regulation - Alberto Pototschnig and Nicolò Rossetto (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs - 9th edition of the Energy Infrastructure Forum

Case study: Italy has introduced an output-based regulation to incentivise Terna to maximise cross-zonal transfer capacity

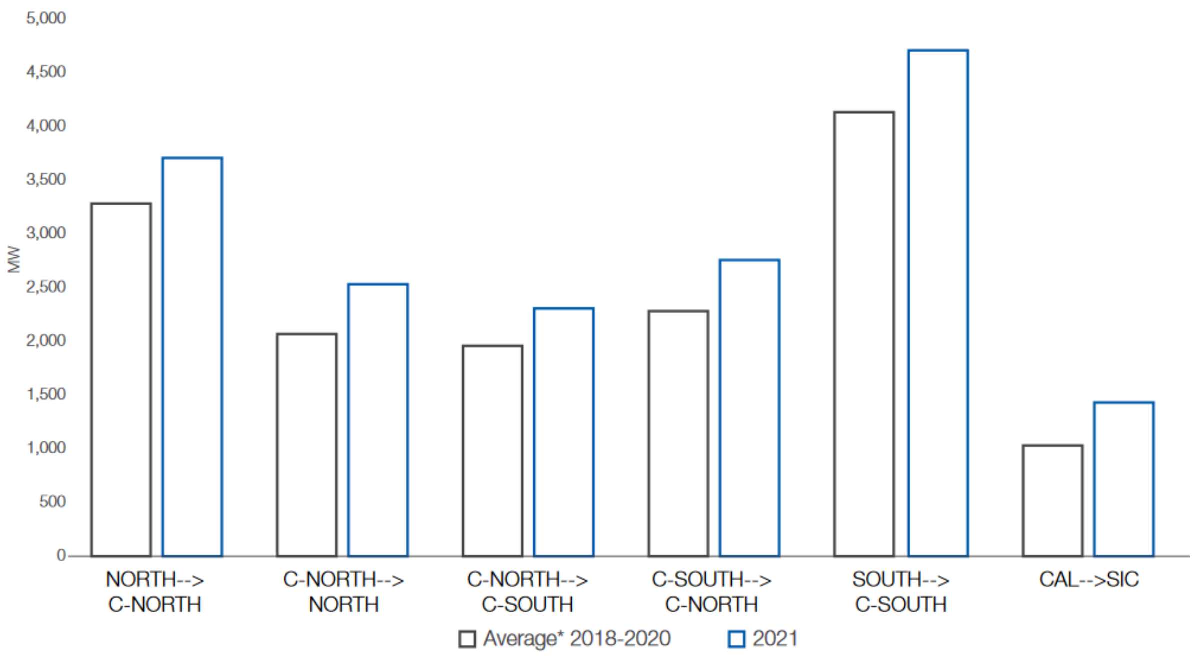
Regulation

- Italy introduced output-based regulation for electricity transmission in 2015. Among the outputs identified by this new regulatory framework, there is the increase of the cross-zonal transfer capacity that the TSO makes available to market parties. To promote the integration of the various market zones cost-efficiently, both within Italy and cross-border, two dedicated incentives were offered to the TSO until the end of 2023:
  1. A reward if the TSO can expand the transfer capacity up to a certain level, which is approved by the regulator based on an assessment of the system needs.
  2. On the other hand, the TSO receives a further reward if the solution adopted entails smaller CAPEX than a reference value set by the regulator for each border.

Impact

- By implementing a series of low-CAPEX solutions (e.g., new protection schemes and dynamic line rating), the Italian TSO was able to increase cross-zonal transfer capacity by 1450 MW in 2020 at comparatively low cost (roughly 5.5 m€), generating an expected benefit for the system of more than 1 bn€.
- Based on these results, the Italian regulator has awarded a premium of roughly 143 m€: 103 m€ linked to the increase of the transfer capacity and 40 m€ linked to the use of capital-light solutions.

Average cross-zonal transport capacity made available for the day-ahead market (DAM) between 2018 and 2020 and in 2021[1]



Source: Florence School of Regulation - Alberto Pototschnig and Nicolò Rossetto (2023) Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs - 9th edition of the Energy Infrastructure Forum, [1] Terna (2023) 2023-2032 Grid development plan

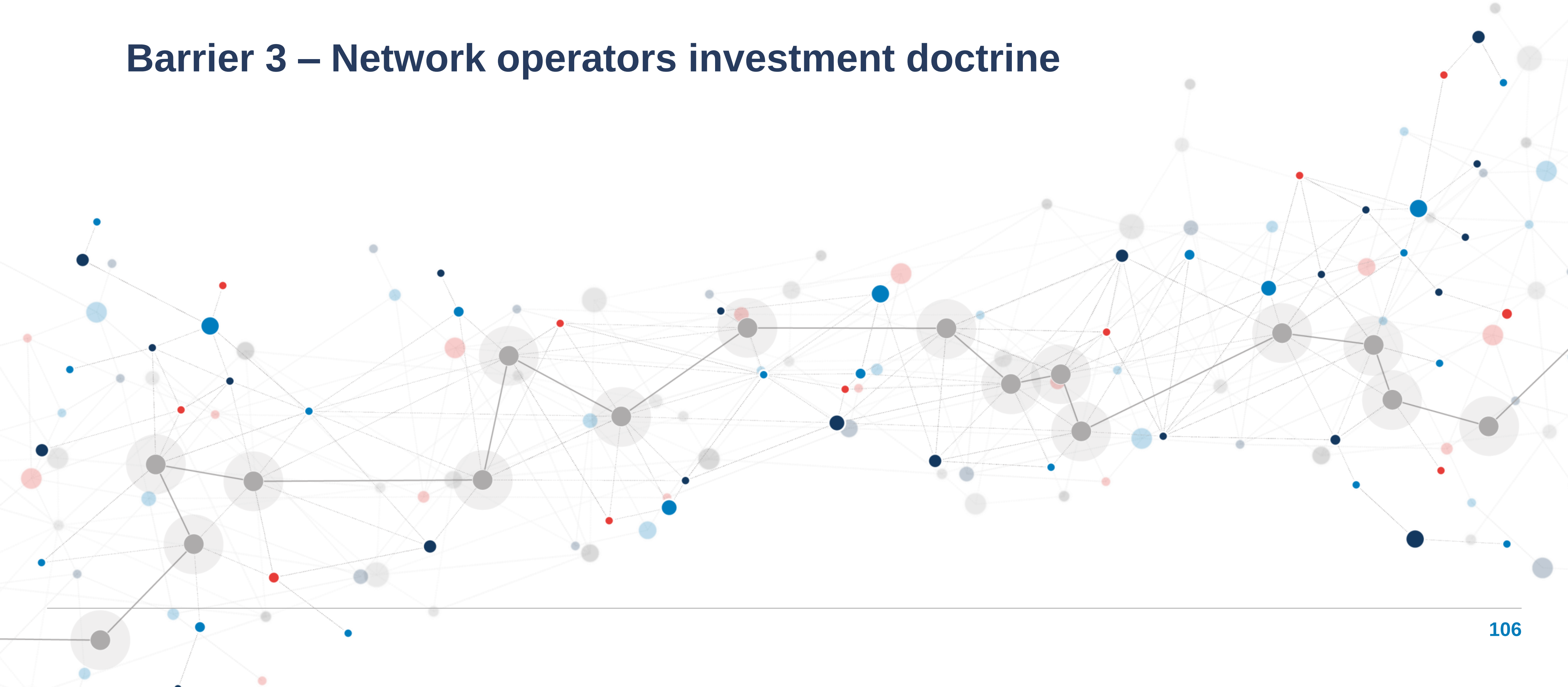
Barrier 2 - Insufficient output incentives and incentives for innovation

Recommendations

Barrier 2 - Insufficient output incentives and incentives for innovation	Make remuneration output-based if possible	Within the limits given by the regulated nature of network companies, the remuneration of networks should be output-based, e.g. connected to achieving certain targets. The Italian incentive to increase cross-zonal capacity is a very good example in case, since it gives the TSO directly the incentive to focus on one of the outputs that matter: transfer capacity. In economic terms, this can also be called an internalisation of an external effect.
	Decouple remuneration from CAPEX	Benefit-based regulation and the Italian premium for the use of capital-light solutions represent ways in which the remuneration of network operators is decoupled from actual CAPEX. This creates the possibility and the incentive for the network company to seek for alternative solutions that also fulfil the needs. Thereby, a win-win situation between customers and network companies can be created, in which a) costs are decreased and b) the company can achieve higher reward. This is conceptually very similar to the general idea of incentive regulation, but specifically applied to CAPEX. The UK example of RIIO has shown that such regulatory regimes are powerful, but also can lead to significant economic profits of network operators. That in turn can lead to criticism and political backlash. The likely conclusion from this is that the precise design of regulatory systems that decouple remuneration from actual CAPEX must be done carefully.

A word of caution: Network companies are part of the essential infrastructure, and as such should not be compelled to engage in excessive risk taking.

Barrier 3 – Network operators investment doctrine



The investment doctrine of T/DSOs might include bias towards predetermined solutions to fix perceived issues, to the detriment of IGTs

The investment doctrine of T/DSOs might include bias towards predetermined solutions to fix perceived issues, rather than adopting a technology-neutral approach to answer the system needs identified.

- 1) Firstly, not all technologies are mentioned / investigated as a potential option to consider. For instance, among the list of countries on the right-hand side, SATA is only considered explicitly in the grid development plan of Germany, and high temperature superconductors are not mentioned by any of these TSOs in their grid plans.
- 2) Secondly, even when IGTs are mentioned, the methodology for network planning may not take them into account **as a substitute / alternative for network reinforcement and expansions**, and IGTs may not be systematically deployed across the grid – compared to deployed locally, e.g. for pilot projects.

Therefore, although TSOs are investigating several IGTs, some of them being mentioned in their respective network development plans, their potential may be only partially considered.

- The position of IGTs compared to conventional technologies in network planning methodologies is also a result of the regulatory barriers identified previously in this presentation, **especially the lack of incentive to maximise output at the cheapest cost possible**. This regulatory incentives might also translate into a lack of incentive for staff members to consider technologies for which the level of expertise / control within the company is lower.

IGTs mentioned by TSOs in their respective network development plans, in selected European countries

IGTs / Country	NL	UK	DE	IT	BE
Latest network development plan	Link	Link	Link	Link	2024 2034 Link
DLR					
Advanced Power Flow Control		*			
High Temperature Superconductors					
SATA					
Advanced conductors					
Advanced sensors / Digital Twin					
Grid inertia measurements		*			

This benchmark may be completed with additional countries to show a more complete picture

*Note: *Not mentioned explicitly, but projects being developed*

Sources: CL analysis based on TSO's network development plans, interviews with CurrENT members, Investors Dialogue on Energy (2022) Availability of financial instruments for transmission & distribution

Case study: According to German TSOs' NOVA principle, grid optimisation must be considered over grid reinforcement, over grid expansion

Context

- In Germany there is a huge social acceptance problem with network expansion - the NOVA is built recognizing this, to make sure that expansion comes last

Methodology for network planning – NOVA principle

- German TSOs follow a network planning principle which favours firstly optimising and strengthening the existing network, and secondly extending the network.
- Each category contains different options which are examined before moving on to the next : The NOVA procedure ensures that the most efficient solution is implemented and that no new lines are built where the network could be strengthened at lower cost.

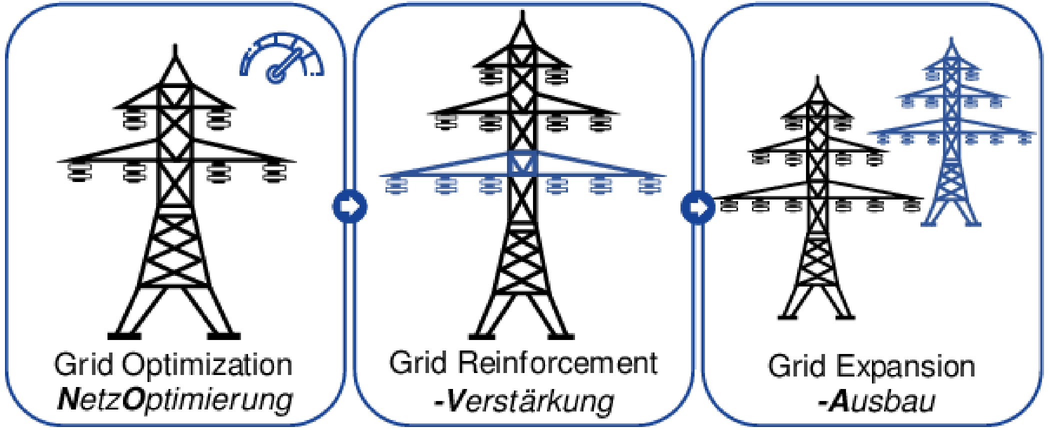
Impact

- DLR is now considered for all lines where possible, to avoid expansion – and realized where needed and technically feasible.

Limitations

- Not all IGTs are considered yet in the planning process (mainly DLR) for grid optimisation. A similar approach is followed by Elia in Belgium, in which advanced conductors and phase-shifter transformers are also systematically considered for grid optimisation, before considering any reinforcement and expansion.
- It is not clear if the NOVA-principle is applied in a strictly technologically-neutral way using joint optimisation, which would be an important precondition for it to be optimal.

Grid Planning Principle "NOVA"[1]



Grid Optimization	Grid Reinforcement	Grid Expansion
▪ DLR ▪ Voltage level upgrade ▪ …	▪ New lines on existing routes ▪ Renewing of assets	▪ Construction of new lines

Sources: Interview with 50 Hz, [1] Wagner et al (2020) NOVA Measures in Suburban Low Voltage Grids with an Inhomogeneous Distribution of Electric Vehicles

Case study: In the UK, grid planning includes a systematic comparison of standardised solutions to answer system needs, with IGTs included

Methodology for network planning – NOA methodology

- In the UK, investment planning includes a comparison of several standardised solutions, including some IGTs. The process for optimising investments in the terrestrial network is based on a standardised process presented in the NOA
- For each network constraint identified, the system operator selects at least three options which could potentially resolve it. These options are selected among a list of options standardised in advance
- This list includes conventional network reinforcement and expansion works, but also more innovative solutions aiming at optimising and maximising the capacity of the existing network, including advanced power flow control systems, DLR, reconductoring of existing lines with advanced conductors. These solutions can be categorised as follow

Potential transmission solutions included in NOA methodology (non-exhaustive list)

Development of new circuits	Reconductoring of lines with advanced conductors	Upgrade of circuits	Dynamic Line Rating	Advanced power flow control systems	Advanced power flow control systems	Contracted commercial flexibility

- The cost of option is then modelled and compared. In addition, planned outages on certain parts of the network, maintenance and potential outages required to implement the option are taken into account to determine its viability.
- Moreover, the options to be studied are selected by the network operator and then passed on to a third party, NGESO. NGESO can also make suggestions to the network operator about additional solutions, including commercial flexibility solutions.

Limitations

- Despite the existence of a preliminary list of technologies that can be taken into account, there is no obligation on the network operator to pre-select innovative solutions over conventional ones.
- The monitoring power of the third party, NGESO, is limited insofar as it does not have the same capacity as the network operator to model and understand the system. The increase in iterations between various parties in the network is also a source of cost for the system.

Sources: National Grid ESO (2022) Network Options Assessment Methodology

Barrier 3 – Network operators investment doctrine and methodologies

Recommendations

Barrier 3 – Network operators investment doctrine

Obligation to implement the NOVA principle

The NOVA principle provides a framework for solving network needs by maximising the use of existing assets and limiting the need for major infrastructure works.
This principle, as applied by German TSOs, is key in limiting the environmental impact of network upgrades and in enhancing public acceptance for network projects.
Such a principle could be implemented as a rule for network operators when evaluating the necessary interventions, provided a joint-optimisation approach is retained.

Technology-neutral approach to solve grid constraints, with toolbox of possible interventions defined in advance

System planning could benefit from a technology-neutral approach to system planning, with for instance the following standardised steps each time a constraint is identified:

- 1/ identification of the root causes of the issue
- 2/ mapping of the different potential alternative solutions
- 3/ comparison of the solutions based on a multi-dimensional assessment, taking into account costs and different sources of benefits from a system point of view (including reduction in total system costs)*

Moreover, following the UK example, a list of standard interventions could be defined in advance for the planning of network investments, and could be used to assess the most relevant one. This list could include conventional reinforcement and expansion works, as well as the introduction of IGTs in specific parts of the network. When a need for intervention arises, TSOs could compare several interventions and assess the most beneficial one to solve system needs.
This solution would come with additional complexity, and might require to put in place new decision tools / processes / incentives on managers.

Note: This assumes that either the network operator is incentivised through output-based regulation to consider total system costs on top of his own costs, or that a cost-benefit is done before a project is cleared for investment by the regulator (something that is often done in the course of doing network-development plans). A combination of output-based regulation and cost-benefit analysis is possible as well and might be the best solution given that both approaches have their strengths and weaknesses.*

Barrier 4 – Death by pilot risk due to long processes for network companies to trial and then adopt new innovative solutions

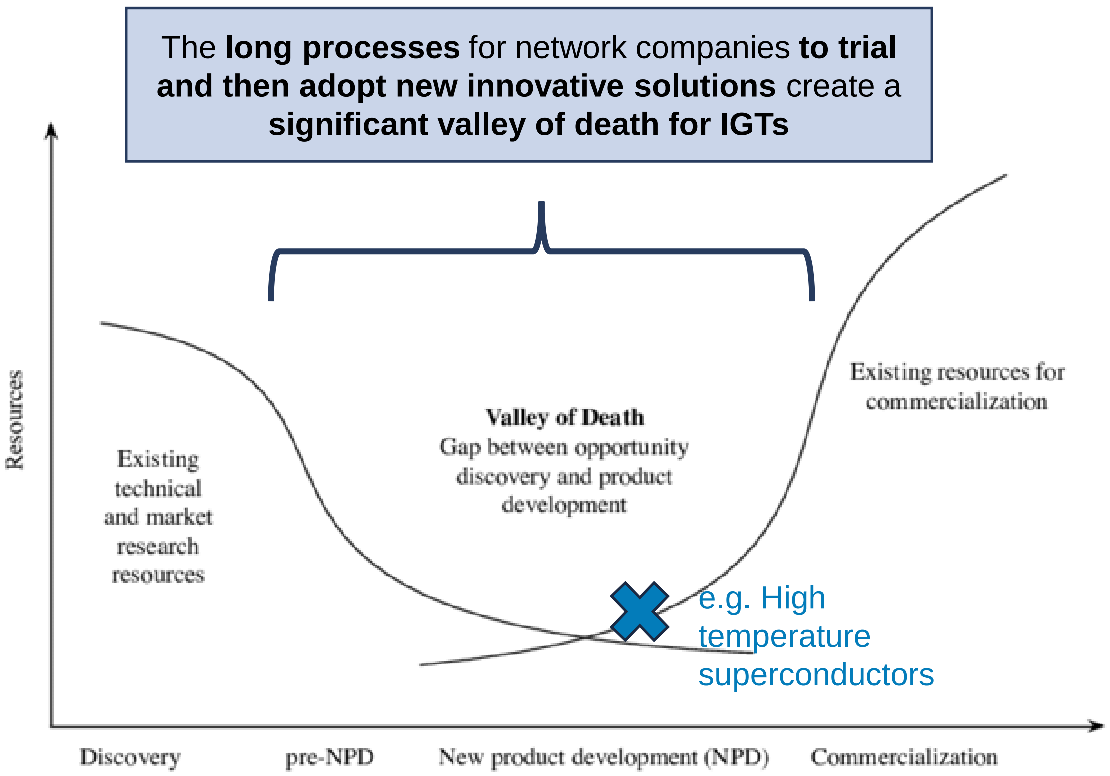
IGT adoption is hindered by long processes for network companies to trial and then adopt new innovative solutions, creating a *death by pilot* risk

The relatively complex and lengthy testing and industrial demonstration processes among network operators creates a barrier for the adoption of IGTs, especially for less mature technologies

- The transition (or rather the gap) **between invention and commercial** application is commonly referred as the '**valley of death**' in the literature on technology innovation and transfer of innovation
- In the context of energy networks, this valley of death is particularly significant, due to the **long processes for network companies to trial and then adopt new innovative solutions**, which presents challenges for start-ups finances in the early years.[1]
- Indeed, new and unproven methods present uncertainties and risks whereas conventional methods do not. Uncertainties are related to the outcome (and chances of success), the complexity, the timing and the required resources, among other things.[2]

Most of the technologies included in the scope of this report are already TRL 9 and hence one could argue that they do not face the death-by pilot risk anymore. However, we understand that, even when IGTs are very mature, this risk is always present for IGT providers, due to the long duration of the test phases required for the implementation in each new country, as well as the waiting time for pilot projects to lead to industrial implementation.

The Valley of Death for IGTs[3]



Sources: [1] CSEI Working Paper (2020) Energy Network Innovation for Green Transition: Economic Issues and Regulatory Options; [2] ENTSO-E (2022) Position paper – Innovation uptake through regulation, [3] Hartley & Medlock (2017) The Valley of Death for New Energy technologies

Implemented in 2013

NVE – RME

Case study: Lump-sum approach for innovative network technologies in Norway (1/2)

Context

- NV-RME wants to stimulate **increased participation in R&D activities** to support a more efficient operation and utilisation of the electricity network.

Regulation

Costs for R&D are treated as passthrough costs when they fulfil certain conditions to avoid short term disincentives.

- NVE-RME has designed a scheme where **distribution companies receive full financial coverage for up to 0,3% of their regulatory asset base for R&D projects** that meet certain criteria. The costs are recovered **outside the revenue-cap regulation scheme**.
- **Criteria**:
  - The project must be able to contribute to a **more efficient operation, development or utilization of the power grid**.
  - The project must be found **worthy of support by an institution** that provides grants for R&D (e.g. the Research Council of Norway, Innovation Norway, Enova, etc.).
  - **Information** about project goals and results must be made publicly available.
  - The project must follow the **Accounting Act's rules on conducting R&D**
- Project costs include **all costs that the network company has in connection with the project**, regardless of whether it is user financing, own efforts or capital costs.
- NVE-RME have **implemented some exemptions** (for the assessment of the project's value and the financial framework) to make better **arrangements for pilot and demonstration projects** to be included in the funding scheme for R&D

1. The DSO applies for project approval from a grant institution such as The Research Council of Norway, Innovation Norway, Enova or EU's different funding bodies.
2. The grant institution assesses the R&D-projects relevance, the degree to which it can lead to efficiency gains and the innovative/research value. If the R&D-project is found to be relevant/innovative, the grant institution approves the project.
3. Only if the DSO receives an approval from the grant institution, can the DSO apply to NVE-RME to include the project in the R&D-scheme.
4. NVE-RME approves or rejects the R&D project proposal. NVE-RME also provides a publicly available list of all approved projects on their web page.

Source: NV-RME (2016) Incentive scheme for R&D

Case study: Lump-sum approach for innovative network technologies in Norway (2/2)

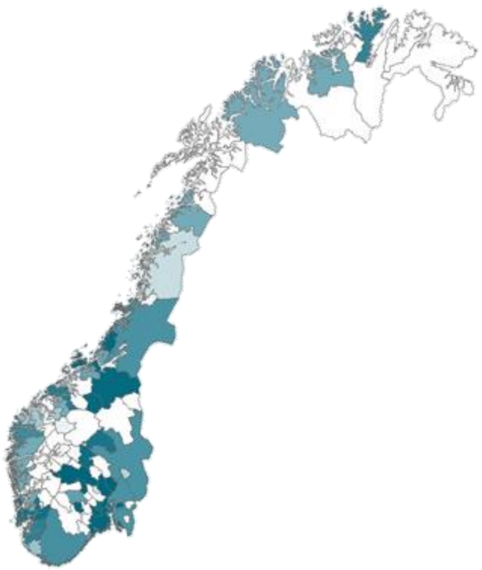
Impact

- An **industry-wide development effort aimed at digitalisation of the DSOs in Norway** has been observed.
- As of 2020, 7 years after the implementation of the scheme, **49 DSOs out of 101 had participated in R&D projects funded by the scheme**.
- As of October 2021, **NVE-RME has approved 215 projects in the scheme**
- Among others, the **NorFlex project** has received particular attention. The objective is to develop tomorrow's power grid by enabling flexible power consumption. Over 3 years Agder Energi, Glitre Energi, Statnett, and NODES test **different technological solutions to enable local flexibility to be available to the grid both locally and centrally**. The project will demonstrate how flexibility offered at a **local level can be made available to the existing TSO reserve market**.

Limitations

- Over the years, the Norwegian regulator NVE-RME has been observing an **increasing number of new project proposals from different market participants**; and the **dedicated framework** (0.3% of the industry RAB) **was not enough**. As a result, NVE-RME developed an **additional framework for pilot and demonstration projects in 2019: Regulatory sandboxes**.

R&D projects implemented in 2020



*Note: The map demonstrates to which extent DSOs participate in the scheme. White colour indicates no participation, and **darker blue colour indicates high use compared to potential**. Statnett, the Norwegian TSO, also has several projects funded by the scheme.*

Sources: DNV (2023) Study on the regulation of electricity and gas system operators, NVE: Mechanisms to support innovation in Norwegian electricity networks, NODES: NorFlex, https://euniversal.eu/wp-content/uploads/2022/01/EUniversal_D10.3_Regulatory-recommendations-for-flexibility-options-and-markets-2.pdf, Euniversal: Regulatory recommendations for flexibility options and markets

Energy & Climate Law (2019) + Deliberation (2020)

Case study: The regulatory sandboxes in France allowed the development of innovative technologies by removing legal and regulatory barriers (1/3)

Context

- The **intermittent** nature of renewable energies increases the need for a **flexible electricity system**. **New uses** such as electric vehicles and self-consumption requires **smarter, more flexible networks**.
- The objective is to **conduct experiments to deploy innovative technologies and services** to promote energy transition and smart gas and electricity networks and infrastructures.

Regulation

- Regulatory experimentation system (also called “sandbox”): CRE can **grant exemptions from the conditions of access to and use of networks** and facilities for the experimental deployment of innovative technologies or services to promote the energy transition and smart networks and infrastructures.
- This new mechanism provides a legal framework that is suited to projects **enabling the testing of innovations that would ultimately require changes** to the applicable regulatory and legislative framework.
- Derogations are **temporary**: they are granted for a **maximum of four years**, renewable once for the same duration and under the same conditions as the derogation initially granted.
- Projects were first selected via **application windows and** are now **selected on a continuous basis.**

Eligibility criteria

- Contribute to the objectives of the energy policy
- Present an innovative dimension
- Face a clearly identified legislative or regulatory obstacle
- Present a potential for subsequent deployment, particularly if the experiment achieves its objectives
- Present a benefit for the community if the solution is eventually deployed.

Sources: CRE (2020) Délibération de la Commission de régulation de l'énergie en date du 4 juin 2020 portant décision sur la mise en œuvre du dispositif d'expérimentation réglementaire prévu par la loi relative à l'énergie et au climat, CRE (2022) Délibération de la Commission de régulation de l'énergie du 24 novembre 2022 portant modification de la délibération n°2020125 en date du 4 juin 2020 portant décision sur la mise en œuvre du dispositif d'expérimentation réglementaire prévu par la loi relative à l'énergie et au climat

Energy & Climate Law (2019) + Deliberation (2020)

Case study: The regulatory sandboxes in France allowed the development of innovative technologies by removing legal and regulatory barriers (2/3)

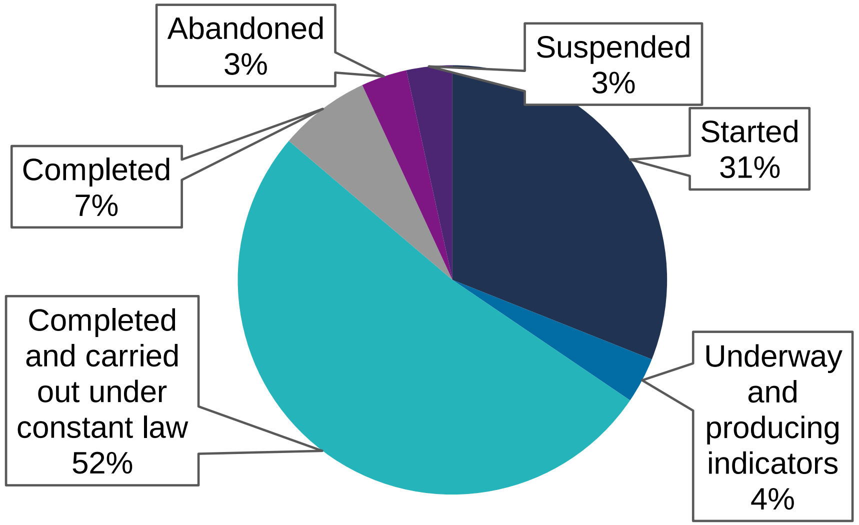
Impact

- Scheme monitored by the **publication of an annual report on the progress and results** of projects benefiting from exemptions, as well as on all **applications** for exemptions that have been refused or are awaiting a decision. 93 exemption requests were received, of which 54 were deemed eligible and **29 granted**.
- On a general note, CRE "notes that the projects **are progressing satisfactorily overall and** is delighted with the **involvement of both gas and electricity network operators** in supporting these projects."
- The projects are bringing benefits various fields including:
  - **Use of flexibility on electricity grids**
  - **Renewable energy sources connection**
  - **Storage and demand-side flexibility**

Limitations

- **Lack of coordination and slow decision making-process** for authorities responsible for examining and granting exemptions
- **Time required to obtain authorisations** (environmental, construction) is significantly delaying some experiments, which **limits the role of the regulatory sandbox in facilitating** the introduction of innovative solutions.
- **Difficulties to obtain information** from some project developers on the progress.

Current state of the regulatory sandbox projects



Sources: CRE (2022) Délibération de la CRE du 17 novembre 2022 portant communication de l'avancement des projets bénéficiant de dérogations accordées dans le cadre du dispositif d'expérimentation réglementaire, Enedis (2021) Appel au marché dans le projet REFLEX, CRE (2024) Délibération de la Commission de régulation de l'énergie du 28 mars 2024 portant communication de l'avancement des projets bénéficiant de dérogations accordées dans le cadre du dispositif d'expérimentation réglementaire

Energy & Climate Law (2019) + Deliberation (2020)

Case study: The regulatory sandboxes in France allowed the development of innovative technologies by removing legal and regulatory barriers (3/3)

Zoom: The Enedis REFLEX project

The REFLEX projects aims at using flexibility to optimise network sizing

- Enedis is testing the **use of flexibilities** (in particular the combination of generation and consumption, cross-industry combinations, curtailment, local flexibilities) to **optimise network sizing and accommodate more renewable energy at a constant level of investment**.
- The regulatory sandbox system framing the project was validated on 16 July 2021, for 4 years.

The exemption allows a more optimised and flexible approach of network connections

- The Energy Code stipulates that renewable energy production facilities must be connected to the electricity distribution network using "standard" **connection solution at the nearest substation**.
- The exemption allows Enedis to **propose connection offers that integrate the optimisation of HV/HVB transformer substations** and to speed up the connection of electricity production facilities from renewable energy sources by **releasing new connection capacities beyond what is allowed by conventional sizing rules**.
- These connection offers include the possibility that the **injection of electricity may be limited as a result of this optimisation**, with a **remuneration for the producer**.

Expected gains for the Enedis network are major

- The network could immediately accommodate up to 2.5 GW of additional capacity
- By 2035, the additional capacity would reach 7.4 GW, equivalent to a third of the new HV/MV transformer capacity to be created in the reference situation;

Enedis, at the CRE's request, is now planning a generalisation of the project

- Enedis is planning a **gradual roll-out** of the experiment, with a generalisation to all **substations from 2028 onwards**.
- A suitable regulatory and financial framework will be **discussed between CRE, the Ministry, Enedis and the producers by end 2024**.

Expected increase in connection capacity due to the use of flexibility (%)

Sources: CRE (2022) Délibération de la CRE du 17 novembre 2022 portant communication de l'avancement des projets bénéficiant de dérogations accordées dans le cadre du dispositif d'expérimentation réglementaire, Enedis (2021) Appel au marché dans le projet REFLEX, CRE (2024) Délibération de la Commission de régulation de l'énergie du 28 mars 2024 portant communication de l'avancement des projets bénéficiant de dérogations accordées dans le cadre du dispositif d'expérimentation réglementaire, Enedis (2021) L'appel au marché dans le projet REFLEX – Septembre 2021

The "Net Zero Industry Act" (NZIA) gives the option for Member States to introduce regulatory sandboxes to test IGTs while gaining regulatory knowledge

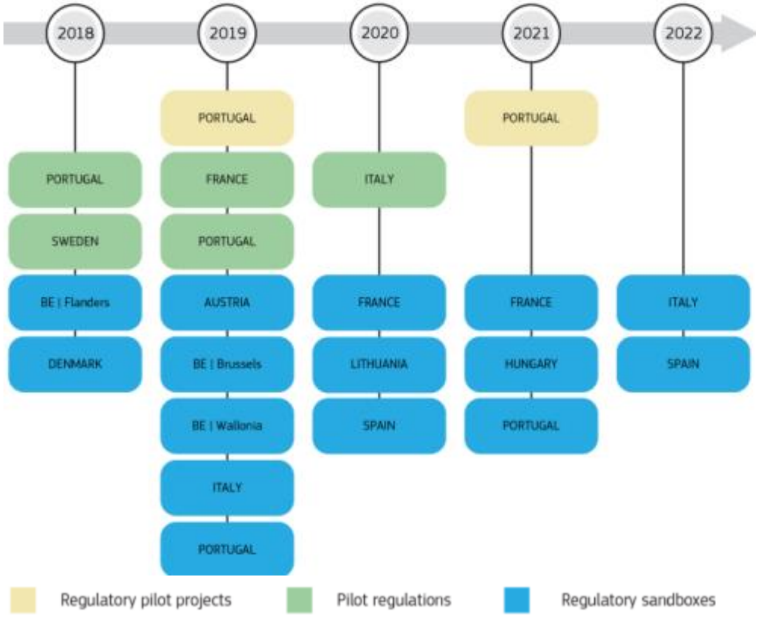
The NZIA issued in 2023 establishes a framework to strengthen net-zero technologies (including grid technologies)

- In the regulation, the European Commission defines the goal that by 2030, the energy system's manufacturing capacity of **strategic net-zero technologies (**which include **grid technologies)** should reach at least "40% of the Union's annual deployment needs"[1].
- A particular focus is set to **"innovative net-zero technologies"**, defined as net-zero technologies that: (i) Have a TRL lower than 8, (ii) are not currently available on the market, (iii) are advanced enough to be tested in a controlled environment

The NZIA gives member states the possibility to establish regulatory sandboxes, to test innovative net-zero technologies in a controlled environment for a limited amount of time, with the objective of removing regulatory barriers[2]

- Regulatory sandboxes should allow "for the development, testing and validation of innovative net-zero technologies, in a controlled real-world environment for a limited time before their placement on the market"[1].
- The identification of regulatory barriers can be done by innovators, but the regulator can also identify legislative provisions for testing.
- In this process, Member states should:
  - Introduce implementing acts giving guidance to developers of innovative net-zero technology that apply for regulatory sandboxes
  - Design sandboxes such that regulatory lessons learnt can be shared between the national competent authorities

Adoption timeline of regulatory experimentation initiatives in the EU[3]



Regulatory sandboxes implementation phases[3]

Sources:
[1] Eur-Lex (2023) REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on establishing a framework of measures for strengthening Europe's net-zero technology products manufacturing ecosystem (Net Zero Industry Act)
[2] EC (2023) Regulatory learning in the EU - Guidance on regulatory sandboxes, testbeds, and living labs in the EU, with a focus section on energy
[3] JRC (2023) Making energy regulation fit for purpose. State of play of regulatory experimentation in the EU

Barrier 4 – Death by pilot risk due to the long processes for network companies to trial and then adopt new innovative solutions

Recommendations

Barrier	Recommendation	Description
Barrier 4 – Death by pilot risk due to T/DSO risk aversion	Lump-sum innovation funding / WACC premia to account for specific risks	**Lump-sum innovation funding for the recovery of costs incurred during demonstration projects for the adoption of new technologies could incentivise network operators to spend more on (slightly) risky projects.** Lump-sum innovation funding is already used in Norway for example, to incentivise network companies to invest in R&D and pilots. In the UK, there is an elaborate system of innovation funding for networks. To help overcome the risk aversion of regulated companies, innovation funding could be expanded to larger amounts and extended to the wider deployment of innovative solutions. To compensate for the higher risk of early-commercialisation projects, WACC-premia could also be used.
	Regulatory sandboxes	**The adoption of new technologies could be favoured by the implementation of regulatory sandboxes**, for instance granting exemption to the current regulatory framework, hereby facilitating the experimental deployment of innovative technologies. Member States could use the options provided by the Net-Zero Industry Act.
	Transfer of best-practices and standards	**The transfer of best practices and standards between countries in Europe could facilitate the early adoption of IGTs.** Indeed, the demonstration processes of network operators, before a technology can be deployed, are relatively complex and lengthy. This is justified by the need ensure that the technology risks for consumers are minimised. However, lengthy adoption process typically needs to be repeated several times, every time another network operator is investigated into a new technology. Transfer of best practices and standards between network operators could reduce this lead time. Moreover, a European reference process to assess the maturity level of grid technologies could be introduced. Once a technology is assessed to be mature enough for use, its inclusion in network planning could become mandatory.

Barrier 5 – Eligibility of IGTs in the list of technologies supported by funding schemes

IGTs may not be eligible to public funding, for their demonstration and adoption throughout Europe to be adequately supported

We reviewed a list of key funding schemes dedicated to energy infrastructure (or at least partly) and /or innovation, and estimated that these key schemes may be not fully open to IGTs (see table on the right), in contradiction with the technology-neutrality principle for public support.

Moreover, the vast majority of financial support for transmission and distribution projects is made available for mature technologies that are already in roll-out stage (see figure on the far right-hand side).

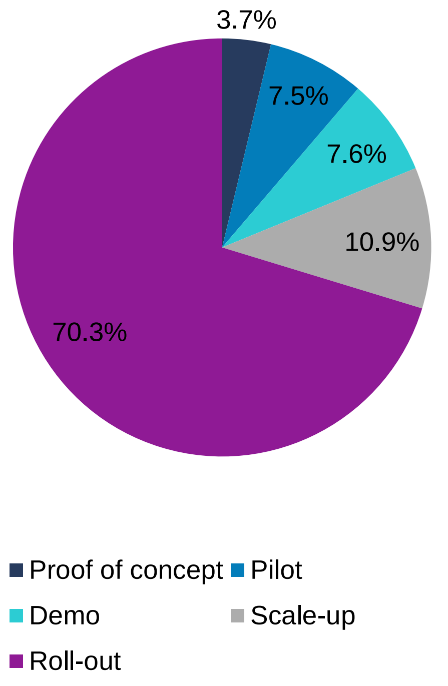
- Recent analysis for the EU's investors dialogue on Energy indicates that only 30% of the fundings available for transmission and distribution projects are available for innovative projects.
- These more limited fundings is partly explained by the fact that demonstration / scale-up projects with less-mature technologies typically tend to be of smaller scaler / involve smaller capex.
- However, discussions among stakeholders within this working group indicate that **support for lower-TRL and innovative T&D project is limited and should be increased**[1]

Widen eligibility of EU-financing schemes to IGTs	By making sure all sources of funding do explicitly include IGTs, access to financing could be made easier. **Sector-specific calls** for IGTs, with adjusted award criteria / requirements could play a key role as well, as foreseen in recent changes in the Innovation Fund Delegated Act .

Eligibility of selected EU funding schemes to finance IGT[2]

Funding source	Eligibility to support IGT-deployment
EU ETS Modernisation Fund	Partly eligible
EU ETS Innovation Fund	Not eligible
InvestEU Fund	Partly eligible
European Regional Development Fund (ERDF)	Partly eligible
Recovery and Resilience Facility (RRF)	Not eligible
Horizon Europe	Eligible
European Innovation Council (EIC)	Partly eligible
Connecting Europe Facility (CEF)	Not eligible
EIB – Energy lending policy	Partly eligible

Volume of financing targeting a specific development stage, based on 155 instruments in the EU Member States (in EUR M)[1]



Sources:
[1] Investors Dialogue on Energy (2022) Working Group Report N.3 - Availability of financial instruments for transmission and distribution, [2] Compass Lexecon assessment

Eligibility of EU funding sources for IGT-deployment (1/3)

We reviewed a list of key funding schemes (at least partly) dedicated to energy infrastructure and/or innovation. For each funding scheme, we assessed to what extent projects that implement IGTs are eligible for funding by using 3 categories:

- **Eligible**: IGTs are explicitly mentioned to be part of the funding mandate
- **Partly eligible**: IGTs are not explicitly mentioned to be part of the funding mandate but IGT-projects have been supported through this funding scheme
- **Not eligible**: IGTs are not explicitly part of the funding mandate, and there is no evidence of projects that support IGTs

Funding source	Description	Eligibility to support IGT-deployment	Reasoning for eligibility
EU ETS Modernisation Fund	• Funds for modernization of the energy system aimed at 13 lower-income member states (Source) • Total revenues could amount to 25 bn€ from 2021-2030, financed through auctions of EU ETS allowances (Source)	**Partly eligible**	• Energy networks are specifically targeted (Source) • Projects that have received funding: – DLR-installation in transmission networks (Source) – Power quality monitoring system that will be integrated into the smart grid platform of the TSO (Source)
EU ETS Innovation Fund	• Support for innovative projects available for EU member states, Norway, and Iceland. • Budget: 40 bn€ to invest from 2020-2030, with 6.5 bn€ awarded so far	**Not eligible**	• Energy networks **not** specifically targeted (Source) • No evidence of IGTs supported through this fund (Source) • Moreover, the GHG avoidance eligibility criteria used to select projects is typically more suited to carbon emitting technologies with vast emission reduction potentials, compared to IGTs.
InvestEU Fund	• EU programme dedicated to supporting, via guarantees to implementing partners (such as EIB Group): – Sustainable Infrastructure: i.a. storage, digital and transport system, improving energy infrastructure interconnection level – Research, product development and innovation • Budget: 9.9 bn€ for the area of sustainable infrastructure	**Partly eligible**	• IGTs not specifically mentioned to be supported • But, under the Policy area “Sustainable infrastructure”: – Modernising energy infrastructure at T&D-levels (Source) – “Promote trans-European network infrastructure, equipment and **innovative technologies** […]” (Source) • Project on “Digital Twin for grid operation” supported (Source)

Sources: Investors Dialogue on Energy (2022) Working Group Report N.3 – Availability of financial instruments for transmission and distribution

Eligibility of EU funding sources for IGT-deployment (2/3)

Funding source	Description	Eligibility to support IGT-deployment	Reasoning for eligibility
European Regional Development Fund (ERDF)	• One of five priority areas: "A greener, low-carbon Europe" (Policy Objective (PO) 2) (Source) • Budget: 226 bn€ allocated to ERDF for 2021-27 → 30% need to be spent on PO2 (Source)	**Partly eligible**	• Part of the scope: "Developing smart energy systems, grids and storage" (Source) • Under-utilised for funding electricity grid projects (Source), although there is evidence of co-financing for a project involving, e.g., **high-temperature superconductors** (Source) • Distribution grids eligible for funding (Source)
Recovery and Resilience Facility (RRF)	• Finance member states' investments as part of their national recovery and resilience plans (NRRPs) (fund expiring at the end of 2026) (Source) • 13 bn€ planned to be allocated to grids in EU member states (Source)	**Partly eligible**	• Under-utilised, but important funding source for projects on distribution grid projects, including smart energy systems (Source) • Covers investments in grid infrastructure, digitisation of distribution and transmission networks (Source), but IGTs are not specifically mentioned.
Horizon Europe	• Research and innovation funding programme • Budget for Energy and mobility research projects from 2023-24: **310 m€**	**Eligible**	• Put in place to finance innovative, less mature technologies (Source) Various IGT-projects supported, such as: • Connecting the electrical grid with superconductivity (Source) • Grant provided for setting up a Digital twin of EU power grid (Source) • Project on advanced software for optimal operation of the hybrid AC/DC system (e.g., avoidance of circular flows) → Advanced power flow control (Source)
European Innovation Council (EIC) Fund	• The EIC Fund is the venture investment arm of the European Innovation Council. It supports start-ups developing innovative technologies, including IGTs. • Budget for work programme 2024 amounts to 605 m€ (Source)	**Partly eligible**	• Support for technologies from TRL 2 up to TRL 6 (Source) • But funding aimed at: ""deep tech" innovations in critical fields such as generative artificial intelligence (AI), space, critical raw materials, semiconductors and quantum technologies" (Source) • Innovative technologies providing efficient cooling for superconductors are part of the scope, just as digital twins (Source)

Sources: Investors Dialogue on Energy (2022) Working Group Report N.3 – Availability of financial instruments for transmission and distribution

Eligibility of EU funding sources for IGT-deployment (3/3)

Funding source	Description	Eligibility to support IGT-deployment	Reasoning for eligibility
Connecting Europe Facility (CEF)	• Supports the development of trans-European energy networks (Source) • 2021-2027 period, budget for energy projects of **5.84 bn€** (Source)	**Not eligible**	• Put in place to finance innovative, less mature technologies (Source) • Supported projects mostly include interconnection projects and smart grid deployment, but **no IGTs supported specifically** (Source)
European Investment Bank Group	• EIB Group is a major provider of financing (using its own capital InvestEU guarantees) for: – Modernisation and expansion of DSO and TSO networks in the EU, including deployment of intelligent operation and management, – Increasing network interconnection capacity – Financing of development and implementation of IGTs • **3.8 bn€ of lending** for electricity networks in 2023 (Source)	**Partly eligible**	• T&D projects are eligible, where projects aiming at digitalisation and smart grid investments are prioritised (Source) • Lending policy for innovative technologies is rather focussing on financing on those with higher TRLs (Source) • Large number of projects aimed at modernisation of T&D networks (Source)

Sources: Investors Dialogue on Energy (2022) Working Group Report N.3 – Availability of financial instruments for transmission and distribution

3.3

Summary and recommendations

Conclusion: an update of regulatory incentives could foster the roll-out of IGTs and provide major benefits to the system

Regulators and network companies are currently locked in a lose-lose situation:

Network companies have limited incentive to innovate, as it comes with additional risks which might not be rewarded

Regulators have limited appetite to change regulatory approaches, for fear of a) it not being effective and b) of potential side effects of substantial changes

- **Network companies operate under incentives that don't reward or even punish them for innovating**, which might favour institutional conservatism towards conventional technology solutions.
- **Regulators are focussed on historical regulatory approaches, and may fear that any substantial change could have negative effects** and lead to political criticism. The implementation of regulatory schemes for network operators which set targets, give incentives and allow flexibility for how those targets are reached might seem risky to them.

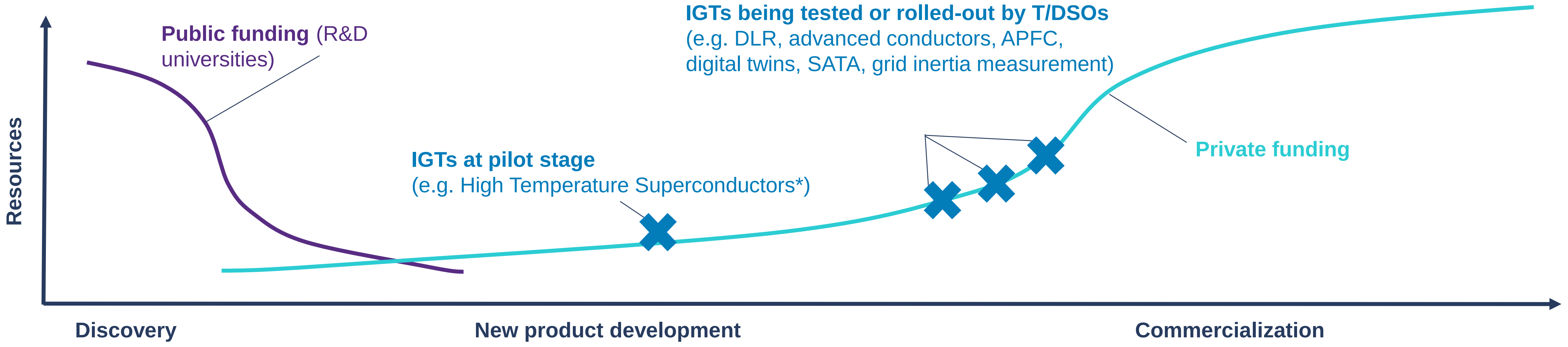
Regulators and network companies could be in a win-win situation, should the proper regulatory incentives be implemented

Network companies could have the freedom to find the most efficient solutions and be rewarded for it

Regulators could see results more quickly, and network challenges and bottlenecks addressed more quickly

- **Network companies could use the new technological possibilities** and the more flexible regulation to speed-up the rollout of innovative grid technologies and provide major benefits to the system.
- **Regulators could learn from existing experience with the introduction of appropriate incentives and implement updated regulatory approaches**. Encouraging results like lower constraint costs and reduced bottlenecks to network deployment could soon follow.

A mix of regulatory measures could allow faster IGT adoption, different measures are suitable depending on technological / commercial maturity



IGT adoption is facing different barriers, depending on its technological and commercial maturity. Each of them could be tackled with **appropriate regulatory measures**

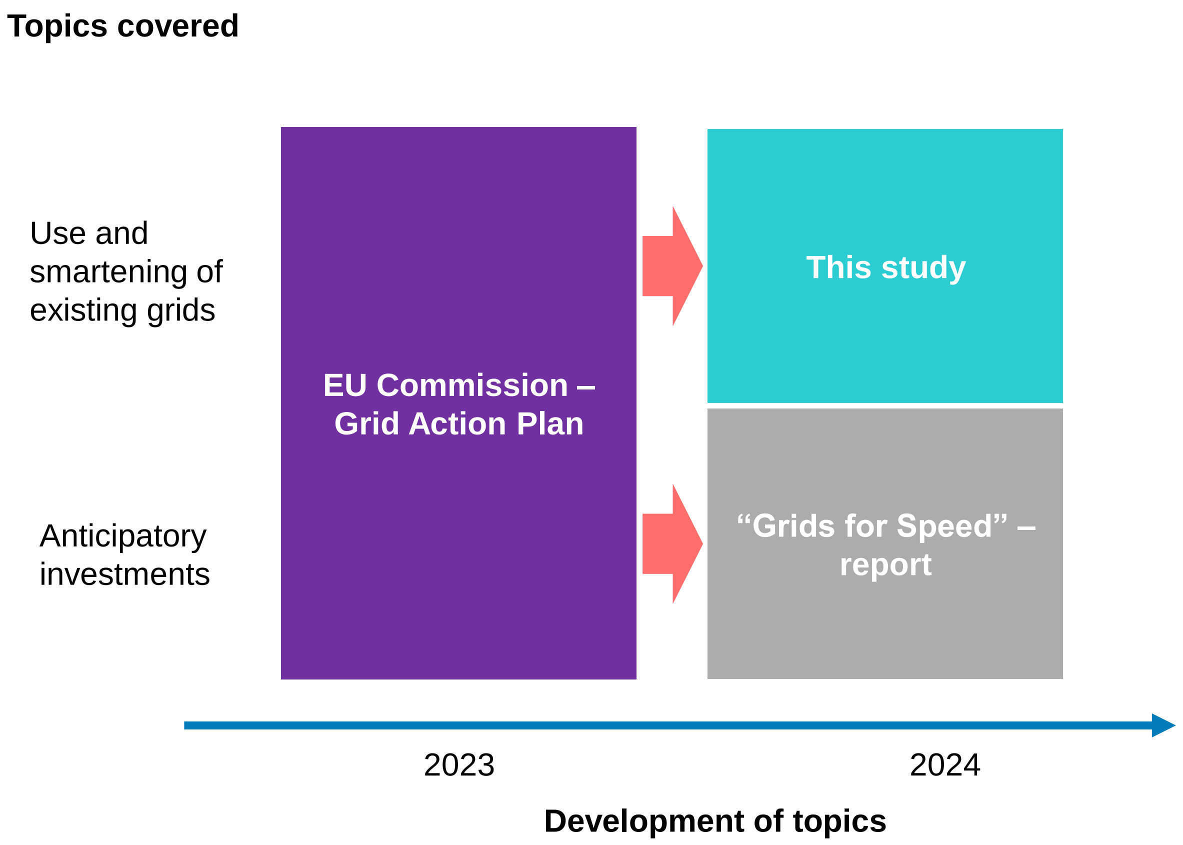
Barrier	Regulatory measure
4 **Death-by-pilot risk**	Lump-sum innovation funding / WACC premiums, regulatory sandboxes, Transfer of best-practices and standards
1 **Lack of incentives for non-CAPEX intensive solutions**	TOTEX regulation, possibility of OPEX increase
2 **Insufficient output incentives**	Output-based remuneration, decoupled from CAPEX spent
3 **Network operators' investment doctrine**	NOVA principle, Technology-neutral planning approach
5 **Eligibility issue of IGTs within funding schemes**	Widen eligibility of national and EU-financing schemes to IGTs

Sources: Compass Lexecon, adapted from Hartley & Medlock (2017) The Valley of Death for New Energy technologies

How our recommendations are related to the grid action plan of the commission and recent other studies

In 2023, the European Commission has published its grid action plan, providing forward guidance on how to accelerate the buildout of grids

- Amongst several helpful recommendations, like the introduction of a network development plan for DSOs, and better access to financing (also taken up in this report), two recommendations can be considered the most important:
  - **Anticipatory investments:** When planning and dimensioning the grid, future growth should be properly anticipated. This has important implications for the regulatory treatment of investment costs and efficiency benchmarking. Anticipatory investments are crucial for the required buildout of conventional lines, transformers, etc. While the Grid Action plan mentioned anticipatory investments, they were also taken up by the Grids for Speed study and developed further. In this study, we work on the presumption that anticipatory investments are going to happen.
  - **Use and smartening of existing grids:** In addition to the required grid buildout driven by anticipatory investments, this report makes further suggestions for how the smartening of existing grids can be achieved, which the Commission has demanded in their Grid Action Plan.
- As such, the Grid Action plan, the Grids for Speed study and this study can be understood as building on top of each other and should be seen as complementary.



Source: CL analysis based on Eureletric (2024): Grids for Speed; European Commission (2023): European Commission - Grid Action Plan

Appendix

Appendix 1.A – Detailed estimation results – Transmission network length

Estimated coefficients by specifications considered – Transmission network length

Variable	Baseline regressions				Multivariate regressions			
	OLS	Country Fixed effects	Year Fixed effects	Country- and Year Fixed effects	Base	Country Fixed effects	Year Fixed effects	Country- and Year Fixed effects
RES	0.597***	0.057***	0.626***	0.005	0.659***	0.045***	0.708***	-0.013
Peak demand	0.473***	0.008	0.461***	0.018	0.454***	-0.002	0.437***	0.004
Constraint costs	-0.00236***	-0.00003	-0.00243***	-0.00001	-0.00257***	-0.00007	-0.00270***	-0.00001
Austria		-8235***		-7971***		-8437***		-8318***
Belgium		-9912***		-10007***		-10080***		-10313***
Germany		15346***		19380***		17964***		21737***
Denmark		-9386***		-9218***		-9658***		-9723***
Spain		24089***		25411***		24243***		25758***
Finland		-530		-856*		-799		-858
France		33558***		33814***		34389***		34926***
UK		7424***		8211***		8640***		8754***
Italy		51784***		52721***		52262***		53380***
Netherlands		-6661***		-6331***		-6801***		-6535***
Norway		-3090***		-2982***		-3260***		-3203***
Poland		-484**		-452*		-705***		-675***
2015			0	0			0	0
2016			-3398	308			-5072	426**
2017			-942	377**			-1908	516**
2018			-1282	461**			-2677	533**
2019			-2744	739***			-6963	884***
2020			-1869	1036***			-3956	1264***
2021			-1841	1112***			-1718	1236***
2022			-4096	1248***			-4081	1514***
Constant	2674.8*	14732.3***	4668.1	14211.7***	2708.2	15164.5***	6000.2	14702.1***
Observations	80	80	80	80	66	66	66	66

*Notes: ***, **, and * represent significance of the estimated coefficient at the 1%-, 5%-, and 10%-level, respectively*

Appendix 1.B – Detailed estimation results – Distribution network length

Estimated coefficients by specifications considered - Distribution network length

Variable	Baseline regressions				Multivariate regressions			
	OLS	Country Fixed effects	Year Fixed effects	Country- and Year Fixed effects	Base	Country Fixed effects	Year Fixed effects	Country- and Year Fixed effects
RES	10.141***	7.692***	10.563***	7.717***	9.658***	7.761***	9.941***	7.429***
Peak demand	12.243***	-2.412	12.012***	-3.095	12.186***	-2.625	12.047***	-3.096
Constraint costs	-0.011**	-0.006*	-0.012**	-0.006*	-0.010*	-0.007**	-0.010*	-0.006*
Austria		-331054***		-341826***		-327472***		-335661***
Belgium		-404644***		-413744***		-407603***		-416509***
Germany		880163***		911887***		896862***		941299***
Denmark		-447659***		-461093***		-451946***		-462623***
Spain		46645		54147		48030		62183
Finland		-143969***		-152290***		-145997***		-153434**
France		816978***		859577***		829559***		863737***
UK		152231		167289		161239*		172988*
Italy		547864***		564155***		551768***		569853***
Netherlands		-312759***		-315264***		-309019***		-305511***
Norway		-205360***		-209598***		-207141***		-209502***
Poland		274727***		273032***		275039***		273473***
2015			0	0			0	0
2016			-47814	-11345			-45659	-11338
2017			-36396	-7512			-35169	-6066
2018			-50837	-6930			-20821	-4661
2019			-47560	5226			-20038	9886
2020			-44635	-14228			-36359	-10776
2021			-76872	-19533			-72723	-13543
2022			-79431	-856			-65703	10452
Constant	100688.0***	566086.0***	149417.0**	591202.0***	119421.0***	571131.0***	154750.0**	590635.0***
Observations	73	73	73	73	66	66	66	66

*Notes: ***, **, and * represent significance of the estimated coefficient at the 1%-, 5%-, and 10%-level, respectively*

Appendix 1.C – Detailed estimation results – Distribution network length

Estimated coefficients used to forecast distribution network length - Country-fixed effect specification

Variable	Coefficient	
	Min	Max
RES	7.692	7.761
Peak demand	-2.625	-2.412
Constraint costs	-0.00663	-0.00621
Austria	-331,054	-327,472
Belgium	-407,603	-404,644
Germany	880,163	896,862
Denmark	-451,946	-447,659
Spain	46,645	48,030
Finland	-145,997	-143,969
France	816,978	829,559
UK	152,231	161,239
Italy	547,864	551,768
Netherlands	-312,759	-309,019
Norway	-207,141	-205,360
Poland	274,727	275,039
Constant	566,086	571,131

Appendix 1.D – Econometric approaches for network length estimation

To obtain the estimation of network length in the future, we have varied the inclusion of country- and year-fixed effects in the following regression equation:

$$Network\ length_{i,t} = \beta_0 + \beta_1 * RES_{i,t} + \beta_2 * Peak\ demand_{i,t} + \beta_3 * Constraint\ costs_{i,t} + Country_i + Year_t + \varepsilon_{i,t}$$

To estimate the future network length, we have applied the above regression equation in two alternative econometric approaches:

- **Ordinary Least Squares (OLS)**
  - With this approach, transmission and distribution network length are estimated in two separate regression models, where they are regressed on the set of variables included on the right-hand side of the above equation.
  - The OLS-approach aims to minimise the sum of the squared differences between the observed and the predicted network length. In that way, it produces coefficients for the three explanatory variables that yield the closest fit to the actual network length observed.
- **Multivariate regression (MV)**
  - In this approach, only a single regression model with two outcome variables (transmission network length and distribution network length) is estimated.
  - The MV-approach leads to fewer observations, as it only uses observations for the estimation where both, transmission and distribution network length are available in the data. Using both of the outcome variables, it enables us to test the significance of coefficients across the two equations for transmission and distribution network length.

Appendix 1.E – TSO investment plans and publications – Sources

Country	Investment plan	Source
France	RTE (2022) - Futurs énergétiques 2050 RTE (2019) – SDDR	Link Link
Germany	Bundesnetzagentur (2023) – Confirmation of grid development plan	Link
Spain	Red Eléctrica (2022) – Transmission network development plan Government of Spain (2022) – Confirmation of the “Planificación Eléctrica en el horizonte 2026”	Link Link
Italy	Terna (2023) - Development plan for the national electricity grid	Link
Denmark	Energinet (2020) – Long-term development needs in the Danish power grid Reglobal (2020) - Denmark’s Energinet.dk explores grid solutions to enable green energy transition	Link Link
Netherlands	TenneT (2023) - Investment plan on land 2024 – 2033	Link
UK	NationalGrid ESO (2024) – Beyond 2030	Link

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