Modernising Grids in the Age of Electricity

Scaling digital technologies and AI for better use of existing networks

International Energy Agency

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Abstract

The world has entered the Age of Electricity, with electricity becoming the central energy carrier for modern economies and the primary driver of energy transitions. Grids are the backbone of electricity systems. With electricity demand rising and both demand and supply becoming more variable, it is essential to expand networks. But new infrastructure is increasingly slow and costly to build, which means that making better use of existing assets has to be given equal priority.

Artificial intelligence (AI) is having a growing impact on the electricity sector. The relationship runs both ways: the data centres behind AI are a fast-growing source of demand that can worsen grid congestion, while AI applied to energy systems holds the promise of huge potential benefits for system reliability and efficiency. Both sides are explored in the IEA's Energy and AI analysis. This report builds on that work by focusing on electricity grids and examines how network operators can leverage digital technologies (including AI) to make better use of existing grids. In this context, AI's value lies in strengthening optimisation, forecasting, situational awareness, resilience and risk management, helping networks use existing capacity more safely and efficiently.

The report presents a portfolio of digital tools (the digital grid toolkit) that allow greater value to be derived from the transmission and distribution network and can improve how it is planned, built, maintained and operated, identifying where improvements transfer most readily from one country to another, and where regulatory reform can have the greatest impact. Demand-side flexibility and storage are also important routes to higher network utilisation, but are treated as a complementary topic covered in other IEA work. While AI is the driver of the current momentum, the report is not confined to it. The surge in data, investment and attention can lift a wider family of proven but underdeployed solutions to achieve better use of grids, from proven grid-enhancing technologies to emerging AI-enhanced applications.

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Table of contents

Executive summary

Grid expansion and better use of existing infrastructure must go hand in hand

Secure and affordable electricity systems that support economic growth and development depend on grid infrastructure. Electricity demand has grown at roughly twice the rate of overall energy demand over the past decade, driven by the electrification of end uses, by cooling and industrial expansion, and in some markets by data centres. Meeting its expected growth by 2035 requires grid capacity to increase by at least 30%, equivalent to adding or replacing 25 million kilometres of lines. Three quarters of the increase to 2035 is expected in emerging market and developing economies, where expanding networks will remain indispensable, while in many advanced economies demand is growing again after years of stagnation, adding pressure to networks that often also require modernisation.

Grid expansion is not keeping pace with rising electricity demand and the broader transformation of energy systems. The consequences are already visible: at least 1 700 GW of advanced-stage renewable projects and 600 GW of utility-scale batteries were awaiting connection in 2025, while congestion cost USD 12 billion in the United States and EUR 4.3 billion in the European Union in 2024. Permitting procedures, supply-chain bottlenecks, labour shortages and rising equipment costs all constrain delivery.

Expansion alone would not be the most cost-effective solution even if networks could be built faster. Removing all congestion would mean sizing the grid for peak conditions at all times, and because wind, solar, and many new loads run at full output only part of the time, such a network would be used well below capacity for most of the year. A degree of congestion is therefore efficient, and since network costs make up a substantial share of consumer bills, how well existing capacity is used directly affects affordability.

While grids are expanding, they are also becoming more complex to operate. Distributed resources, bidirectional flows and increasingly variable and concentrated sources of supply and demand are making network conditions change more quickly and less predictably. Operators increasingly need to actively manage voltage and stability alongside power flows and thermal limits, often with incomplete visibility.

Existing networks could be used more efficiently and carry more than they do today, both by changing how risk is managed in operation and by getting more from grid assets. Operators maintain margins below the network's physical limits to cover risks they cannot fully observe, so improved information can allow those margins to be narrowed safely. Getting greater output from existing assets means both carrying more power through equipment already in service and keeping that equipment available more of the time, by reducing outages and shortening restoration and replacement times. This report focuses on these network-based solutions, where the underlying physics and many operating practices are common across countries. Digitalisation, grid-enhancing technologies and AI together provide a toolkit for identifying and using this capacity safely and efficiently.

More efficient use of existing networks could allow up to 330 GW of new supply, storage and demand to connect, in months rather than years

IEA analysis estimates that dynamic ratings, topology optimisation and advanced power-flow control could allow up to 330 GW of additional generation, storage and demand to connect to existing networks without reinforcement. This is roughly equivalent to the combined installed electricity generation capacity of France and Korea. Connecting this volume through network expansion instead would require around USD 100 billion of investment. The estimate covers the three technologies most widely deployed in transmission networks: dynamic ratings, which adjust how much power lines and transformers can safely carry according to actual weather conditions; topology optimisation, which reconfigures the network to route power around congested lines; and advanced power-flow control, which pushes power onto underused paths. Other digital and grid-enhancing technologies would add further capacity.

These solutions complement grid expansion rather than replacing it. Most can be deployed in months rather than years, relieving constraints while new infrastructure is being built. They can also be added to networks already in service, while asset replacement provides the lowest-cost opportunity to embed much of the required digital capability. Where conditions are favourable they can defer or avoid individual reinforcements, but the capacity they release is bounded by the physical network and varies with weather and system conditions, so they cannot deliver the step change in capability that demand growth requires.

Digitalisation and grid-enhancing technologies are already delivering measurable benefits in real networks. Reported results include USD 64 million a year in avoided congestion costs from dynamic ratings in the United States, more than 2 GW of additional transfer capacity from advanced power-flow control in Great Britain, and a 70% reduction in the time needed to analyse reinforcement options using a digital twin, a detailed virtual model of the network.

However, proven technologies do not yet move consistently from individual projects to standard practice. Deployment remains highly uneven, and technologies proven at one site frequently stall between pilot deployment and standard practice, since each deployment has to be justified afresh in the absence of established methods for valuing benefits or transferring experience between projects.

AI adds new applications and can make the wider toolkit easier to target, operate and scale. Network operators have used AI-based methods for many years for forecasting, inspection, maintenance and planning, and recent advances allow models to process much larger and more diverse operational, weather and imagery datasets. AI can help operators identify where unused capacity exists, forecast when it can be used safely and test whether it would remain if equipment failed or other system conditions changed, but adoption varies by function. Planning and asset-related applications are relatively mature, while safety-critical operational control remains constrained by explainability, auditability and accountability.

Action on five fronts will determine whether these gains are captured

The main obstacles to wider deployment are institutional and organisational, rather than technological performance. Among surveyed network operators, 64% identified skills and organisational readiness as a major barrier, 60% availability and quality of data, 60% trust-related issues and 56% regulatory frameworks. These four conditions apply across digitalisation, grid-enhancing technologies and AI, though AI places the highest demands on data quality, specialist skills, testing and assurance, and governance. Each condition points to a front for action, and international co-operation is a fifth opportunity that cuts across all of them, allowing much of what each country needs to be built once rather than developed repeatedly. Priorities will differ across countries according to market structure, development priorities and the age and digital maturity of infrastructure, but the underlying challenges are widely shared.

Regulatory frameworks should allow operators to propose whichever solution best addresses a given network need and efficiently recover its costs. Operators often face clearer pathways to deploy new physical infrastructure than digital or operational alternatives addressing the same network need. Solutions include funding rules that do not favour capital spending on new equipment over digital or operational solutions, incentives linked to measurable outcomes such as the unlocking of capacity and avoision of congestion, and credible methods for valuing system-wide benefits that would support more efficient investment decisions. Regulatory sandboxes, which let operators trial new approaches under temporary exemptions from normal rules, and innovation funding offer a route to building evidence for tools that have yet to prove themselves.

Better data and greater visibility are most urgently needed at distribution level, where operators have limited information and the need for data is increasing fastest, by rooftop solar, electric vehicles and heat pumps being connected in growing numbers. Many distribution network operators lack visibility over large parts of their network, and information that does exist frequently sits in incompatible formats across organisational silos. Improved data quality and visibility, and interoperable data models allowing information to move between systems and trusted mechanisms for sharing data would support both digitalisation and AI. Meanwhile, shared data infrastructure and testing environments can also lower costs and spread learning.

Utilities and regulators need to build combined power-system and digital expertise, and to adapt the processes around it. Professionals who combine the two disciplines remain scarce and the grid workforce is ageing, with the number of workers aged 55 and over rising by nearly 50% between 2015 and 2024, compared with 20% for those under 55. Training should be accompanied by changes to workflows and operational processes so that proven tools move beyond pilots and become part of routine operations.

Assurance and security should be built in from the outset and calibrated to the criticality of each application. 70% of surveyed operators use AI widely for maintenance, but only 23% use AI in real-time operations. This is a reflection of the explainability, auditability and accountability requirements when AI informs safety-critical decisions, because operators remain accountable. Common approaches to validation, certification and human oversight would support wider adoption, with cybersecurity treated as a core design requirement and particular attention to where operational data are stored, who controls the models used in critical functions and how strategic dependencies are managed.

International co-operation can reduce costs, accelerate deployment and widen access to proven solutions, helping countries make more efficient use of existing infrastructure, improve affordability and accelerate electrification in a secure way. Deployment of grid-enhancing technologies has so far been concentrated in Europe and North America. Sharing expertise, testing facilities and approaches to validation and certification helps countries build trust in new technologies and manage strategic dependencies as grids come to rely more heavily on software, data and AI. For emerging market and developing economies, proven regulatory approaches, shared technical resources and targeted grants and below-market loans can help utilities deploy digital solutions earlier, build visibility and controllability through asset replacement cycles and access skills that are difficult to develop alone.

Chapter 1. The need for modern grids

This chapter sets the scene: it explains why, as electricity demand is rising faster than grids can be expanded, this creates an opportunity to use existing networks better, and how digitalisation, grid-enhancing technologies and artificial intelligence (AI) can be combined to capture it. It introduces the concepts used throughout the report, a shared toolkit and a framework of three layers of grid optimisation.

Grids in the Age of Electricity

The grid is the critical enabling infrastructure on which the energy transition depends for security, decarbonisation and affordability, as economies around the world increasingly rely on electricity. Electrification of end uses is a core pillar of the strategy selected by many jurisdictions to strengthen their energy security and cut emissions, making electricity the backbone of the transition.

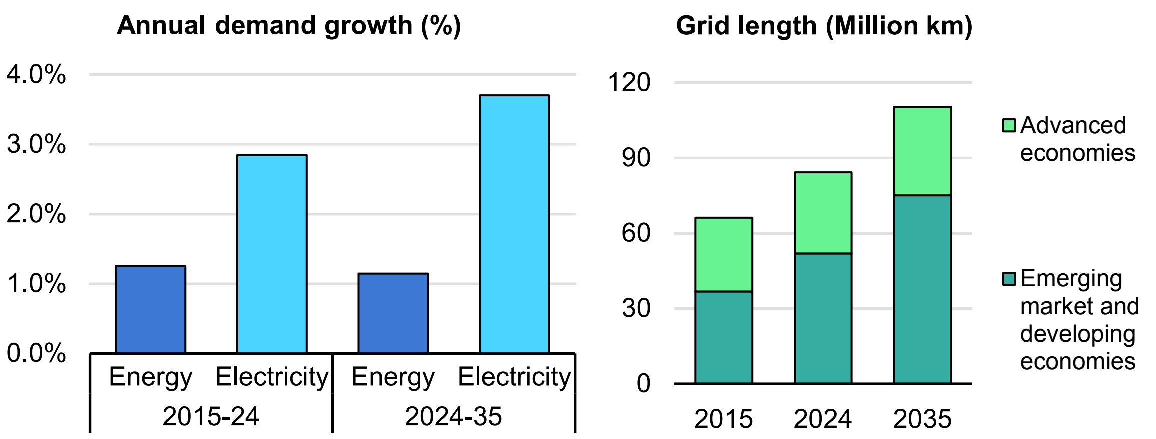
Demand for electricity is rising rapidly. Electricity demand has grown at roughly twice the rate of overall energy demand over the past decade, driven in part by electrification, data centres, cooling and industrial growth. This ratio continues to widen, while new renewable generation, often built far from demand centres, is adding further need for transmission. To meet these needs, 25 million kilometres[1] of lines are expected to be added under the IEA's Current Policy Scenario (CPS), equivalent to boosting grid capacity by 30% by 2035. This is why the current period is termed the Age of Electricity: electricity demand is decoupling from energy demand, and electricity is fast becoming the backbone of the energy system.

This transformation is also changing the conditions the grid has to cope with, not only how much it carries. Distributed energy resources such as rooftop solar, batteries, electric vehicles (EVs) and flexible demand have turned many grids from unidirectional systems into systems with dynamic two-way flows, while large inverter-based power sources and vast data centres[2] represent a new, more concentrated form of generation and demand. Both trends are increasingly evident at the distribution level as much as at the transmission level, creating new challenges for voltage management, transformer loading, feeder capacity and

[1] Grid additions include new lines (expansion) and replacement of existing assets (refurbishment and modernisation).
[2] Data centres are among the grid users with the highest spatial concentration as they cluster near cities, near fibre networks and close to their clients.

protection settings, and both can produce sharp peaks that grids historically built for steady, predictable conditions are not designed to absorb without being actively managed.

Demand growth and the need for grid expansion to 2035 in the Current Policies Scenario



Sources: IEA (2026), Electricity; IEA (2025), World Energy Outlook.

Where the grid cannot keep pace, the consequences are well documented: lengthening connection queues, new housing and industrial development competing with data centres and generation projects for scarce grid capacity, and, in the most severe cases, service disruption. Left unaddressed, these circumstances risk slowing electrification plans just as they need to accelerate, with knock-on costs for competitiveness and climate goals.

Stability adds a further dimension to this complexity: operators need to ensure not only that flows stay within the thermal limits, but that the system retains enough strength to ride through disturbances. As converter-connected resources displace synchronous generators, several stabilising properties traditionally provided by synchronous machines, including inertia, voltage support, fault current contribution and damping (collectively known as system strength), come under pressure. Some of these, such as inertia, are inherently linked to rotating mass; others, such as voltage support and damping, can also be delivered by appropriately designed converter-connected resources or dedicated equipment. These variables are faster-moving and harder to observe and model than thermal limits, raising the bar for the quality of data and validation that grid operators need to manage them. This is particularly important as AI-based tools are increasingly used to support grid operations, because their performance depends heavily on the quality of the data and models they rely on.

Meeting this growth in demand will require higher grid capacity. The question this report addresses is how to achieve this capacity growth given that expansion, that is the buildout of new infrastructure, is struggling to keep pace.

The limits of traditional grid expansion

New grid infrastructure is failing to keep pace with the growth in new supply and demand-side assets, even as record volumes of new supply and demand are being connected. Lengthy permitting procedures, supply-chain bottlenecks, labour shortages and rising costs all weigh on the pace of new lines.

This becomes evident in two ways. Connection queues are lengthening: at least 1 700 GW of renewables and 600 GW of utility-scale battery projects at an advanced stage[3] were awaiting connection in 2025. And network congestion[4] is becoming more frequent and costly for grid users: in 2024, grid congestion cost USD 12 billion in the United States and EUR 4.3 billion in the European Union, with Germany alone accounting for over half of the EU total. Curtailment of surplus renewables also carries an environmental cost as fossil-based production is not displaced; curtailment reached over 10 TWh in the European Union in 2024 (enough to power around three million homes for a year), while India recorded 2.3 TWh of curtailed solar generation in 2025.

Grid expansion alone is not the economically efficient answer. Building grids to eliminate all congestion would mean matching peak needs at all times, leading to low average grid usage and uneconomical outcomes; given the low load factor of many renewable and demand assets, a certain level of congestion is in fact efficient. As a result, a growing share of total grid spending will go towards the tools and resources required to dynamically operate the system, meaning that how well the existing network is used has become just as important as how much new capacity it is built.

Making better use of grids to complement grid expansion

Where grids cannot be built fast enough, the answer lies in delivering more energy, securely, with the existing networks. Existing grids typically contain meaningful untapped capacity, spare capacity that varies by location and time. Not all of it is usable, because it must be weighed against power quality, system

[3] Projects are defined as being at an advanced stage if they are at least under review by the grid operator. This classification excludes projects in the early stages, deemed speculative or unlikely to materialise, and gives a more realistic sense of the scale involved.
[4] Grid congestion occurs when the network lacks the capacity to safely and reliably transfer electricity from where it is generated to where it is needed, forcing the operator to take actions to balance electricity security and economics.

flexibility, stability and resilience, but it can be unlocked by improving how the system is planned and operated.

The digital grid toolkit: Digitalisation, grid-enhancing technologies and AI

Three complementary tools can unlock the untapped grid capacity: digitalisation, grid-enhancing technologies (GETs) and artificial intelligence (AI), collectively referred to here as the "**digital grid toolkit**". This section introduces what each is and how they relate; Chapter 2 gives a fuller technical treatment of each.

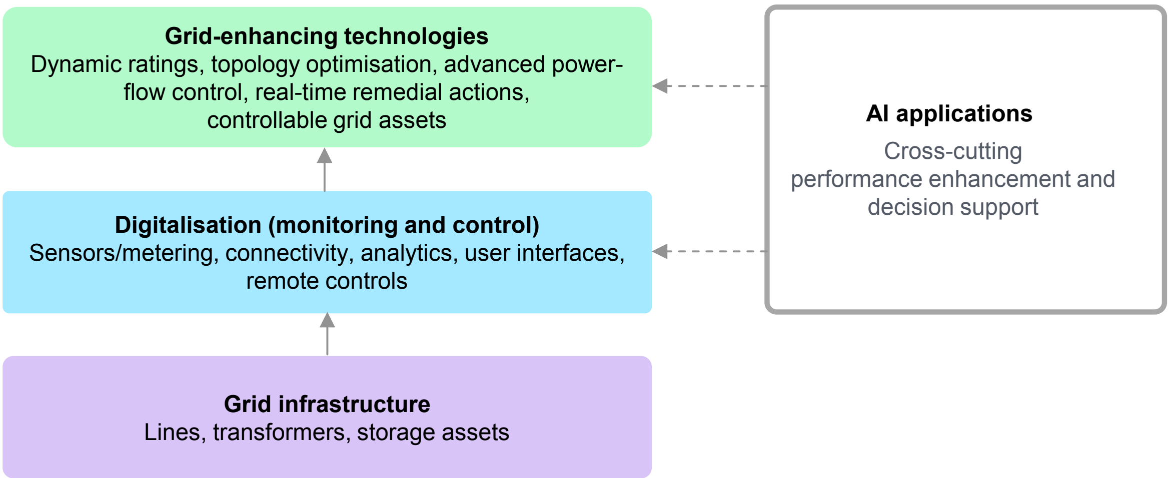
Digitalisation is the foundation. Better sensing, data and connectivity, for example through supervisory control and data acquisition (SCADA) and advanced metering, allow operators to see their networks far more fully and control assets remotely, enabling them to route flows, manage congestion, and support voltage and stability actively.

GETs build directly on that foundation. GETs are hardware, software or hybrid solutions that cost-effectively raise the capacity, flexibility, stability or resilience of electricity grids by revealing latent headroom and system limits, redirecting flows or making existing assets more controllable. This report focuses on GETs that offer the greatest potential for digitalisation and AI and that are deployed and controlled directly by grid operators, such as dynamic ratings, advanced power-flow control, topology optimisation and fast corrective controls, rather than the wider set of technologies (including advanced conductors, voltage uprating[5] and storage) sometimes included under the GET label in the literature.

AI adds a further, cross-cutting layer. It spans a spectrum from rules-based systems through machine learning to generative and, increasingly, agentic AI, capable of planning and acting across several steps with limited prompting. AI has been used by network operators for two decades, but what is different about the current wave of AI solutions is that new AI architectures can process large, diverse data streams, graphics processing units (GPUs) and cloud computing have sharply improved the speed and cost of model training and inference, and utilities now hold more operational, asset, weather, imagery and customer data than in previous technology cycles. AI can therefore support operators managing the growing grid complexity in unprecedented ways.

[5] Voltage uprating is a grid modernisation process that involves increasing the operating voltage levels of existing grid infrastructure to boost its transmission capacity.

The relationship between digitalisation, GETs and AI



Notes: AI = artificial intelligence. Each layer builds on the one below it. AI enhances both digitalisation and digital services.

None of these substitutes for continued grid expansion. Digital, GET and AI-enabled solutions unlock capacity more quickly and, in many cases, at lower cost, but traditional buildout remains indispensable; the two should be used together to prioritise, defer or target new infrastructure where appropriate.

Three layers of grid optimisation

Better use of the existing grid, at both transmission and distribution level, can be understood as three layers, each resting on the layer below, each with a different balance between human judgement and AI, and sharing one goal: enabling higher system utilisation, in a secure way.

Three layers of grid optimisation and the role of AI

Flexibility

Matching load and distributed resources to spare capacity, in time and place

Human
sets rates, products, connection terms, market design

AI
forecasts and co-ordinates resources; sub-second remedial action

Examples
demand response, managed EV charging, storage, energy efficiency, flexible/non-firm connections, siting new load where headroom exists

Report focus

Network assets

Getting more from assets already in service securely (**capacity**) and minimising their downtime (**availability**)

Human
validates and supervises

AI
optimises ratings, flows and configuration; predicts failures and guides operators

Examples
Capacity: grid-enhancing technologies, storage as a transmission asset, real-time remedial actions
Availability: predictive/condition-based maintenance, optimised repairs and restoration

Operational security criteria

How risk is assessed and operating margins are set (across thermal, voltage and stability limits)

Human
sets standards and limits; retains authority

AI
monitors and forecasts limits; advises

Examples
Planning methodologies, contingency analysis and reserve setting, real-time monitoring and forecasting of stability
Currently dynamic, data-driven limit assessment within existing frameworks
In the future alternatives to the deterministic N-1 criterion

Notes: The layers are stacked from the operational security criteria at the bottom to flexibility at the top, each resting on the layer below. The two lower layers are the focus of this report.

Sources: IEA, adapted from: Brattle Group (2026), The Untapped Grid; A. Svendsen and R. Nyiredy (2026), The future power grid.

At the base is the **operational security criteria layer**, which determines how risk is assessed and operating margins are set. Traditionally, grids have been planned and operated with deterministic security margins: networks were sized to cope with the expected highest demand hour of the year, while also accounting for a defined list of likely outages that could reduce network capacity. A risk-based approach instead asks how often, and by how much, the grid could be pushed further without increasing the chance of a fault, thereby replacing implicit margins with explicit, quantified decision criteria. This is a fundamental change, requiring new planning and operational methods, but it is where the highest long-term returns for utilisation, reliability and resilience are likely to sit. The operational security layer sets a ceiling on what the two layers above it can safely achieve.

The IEA's Electricity 2026 report found that the largest gains from GETs arise precisely when they are combined with a risk-based approach to grid operation. AI and digital tools can monitor, forecast and advise on limits, but secure operation still rests on validated models, clear rules, operator authority and the ability to act under contingencies.

The **network asset layer** above draws more from the assets in service, through GETs, including automation and decision-support tools, and keeps assets available through predictive maintenance, early warning of developing faults and faster restoration; here AI helps optimising and predicts, while the operator validates and supervises.

The **flexibility layer** at the top matches demand-side resources, batteries and EVs, whether behind or in front of the meter, to spare capacity in time and place; co-ordination can rely on market or price signals, but flexibility can also be delivered without an explicit signal, for example through pre-agreed operating protocols. Here AI forecasts and co-ordinates, and can act within sub-seconds, while the operator sets rules, products and market design.

Across all three layers, the respective roles of human and AI are expected to evolve, but human oversight remains structural: operators stay accountable for system security even as AI takes on a larger operational role, and sustaining that accountability requires operators to retain sufficient understanding, tools and authority to intervene at any point, a theme this report returns to when discussing trust in AI-based decision-support tools.

Because the layers draw on the same physical headroom, gains overlap rather than add up; as the network asset layer pushes assets harder, the binding constraint can move from thermal capacity to stability, so operational security margins must keep pace. This is why capacity-unlocking measures need to be assessed against the operational security framework that makes them usable, and why regulators and operators need transparent methods for quantifying uncertainty, approving risk-based limits and validating remedial actions before new headroom is reflected in planning, markets or real-time operation.

This report concentrates on the two lower layers: the network itself and how it is operated, since the physics and operating practices involved are broadly common across countries and improvements transfer relatively easily. This is where the IEA's work with energy regulators can most directly help operators use existing capacity better.

While the flexibility layer is an equally important route to higher utilisation, it is more specific to each market's design and involves many actors beyond the network operator; it is therefore the focus of complementary IEA work and is treated here as context.

Moving from long-term planning to real-time operations

The opportunity to make better use of grids arises across all timeframes: long-term planning, operational planning over horizons ranging from several weeks ahead to day-ahead, and real-time operation. Each rests on different assumptions as uncertainties narrow as the system approaches real time, but the same underlying transition applies throughout: from static, worst-case assumptions towards methods that represent a wider set of conditions, including evolving climate conditions, more realistically. The digital grid toolkit can add value at every timeframe, but only delivers that value where it is actually used. A tool proven and used in real-time operations, for instance, but absent from the planning studies conducted months or years ahead, never influences the decisions made on the basis of those studies.

Making better use of the grid across planning and operational timeframes

	Long-term planning and connection studies	Operational planning (from weeks ahead to day-ahead)	Real-time operation
Decisions	What to build, defer or connect, and location (investment focus)	Allocating market capacity between nodes or zones, and developing remedial action plans to manage outages (security focus)	Curative actions to keep the system secure as conditions evolve, including automatic responses faster than any operator can act (operational continuity focus)
Uncertainties	Load growth, generation and grid projects materialising or being delayed, policy shifts, technology maturity, demand flexibility and climate conditions	Forecast error on variable demand and supply, and unplanned outages, against largely known generation schedules	Evolving real-time conditions and instantaneous disturbances
How practice is evolving	From deterministic firm-capacity cases sized to annual minima and maxima, towards finer granularity (some operators already run cases on an hour-by-hour basis) and increasingly probabilistic and stochastic methods that represent variable demand and supply, realistic outages, and the remedial actions and technologies available	From preventive margins held in reserve, towards accounting for the large set of remedial actions already standard in many systems (topology, PST and HVDC setpoints, redispatch and countertrading) to minimise congestion management costs rather than holding conservative headroom in reserve	From fixed seasonal or static limits, towards dynamic limits and pre-planned curative sequences, supported by tools that simulate many events and advise the operator on the best response

How the digital grid toolkit helps (digitalisation, GETs and AI)	Rationalise new build: identify faster or cheaper options and defer or avoid reinforcement, on the condition that GETs are represented in planning studies	Increase the transfer capacity made available to the market by default, while also widening the set of low-cost remedial options available should unplanned outages occur; continuously evaluating physical constraints so that assets can safely operate at their true maximum, managing line congestion dynamically	Deliver additional headroom in real time so curative actions are needed less often, and allow system operators to securely operate closer to true network limits when needed and where conditions allow

Notes: GET = grid-enhancing technology; HVDC = high-voltage direct-current; PST = phase-shifting transformer. The digital grid toolkit includes digitalisation, GETs and artificial intelligence.

Proven benefits of the digital grid toolkit

Real-world deployments show measurable benefits across the digital grid toolkit, including higher transfer capacity, lower congestion costs, faster connection studies, improved forecasting and greater reliability.

How the digital grid toolkit delivers system benefits

Benefit category	Technology	Reported outcome	Jurisdiction
Connection studies	Digital twin	70% less time to analyse and decide where to reinforce	United Kingdom
Transfer capacity	Dynamic line rating	EUR 180 000 saved over four hours, with EUR 44 million projected annually	Belgium
Congestion	Dynamic line rating	USD 64 million a year in congestion savings for under USD 1 million invested	United States
Transfer capacity	Advanced power-flow control	More than 2 GW of additional capacity to move power from north to south region	United Kingdom
Congestion	Topology optimisation	USD 113 million in regional congestion cost savings in 2025	United States
Stability	BESS with grid-forming capability	GBP 170 million consumer savings over 15 years and avoided 2.6 million tonnes CO_2 through reduced stability, balancing, curtailment and congestion costs.	United Kingdom
Forecasting accuracy and balancing costs	AI-assisted wind forecasting	Forecast error cut from 16.8% to 10.1%, saving USD 49 million over five years	United States
Reliability	AI-assisted vegetation management	30% fewer customers interrupted and 55% fewer outage minutes	United States

Notes: AI = artificial intelligence; BESS = battery energy storage system. Reported outcomes are illustrative examples from specific deployments and depend on local network conditions, the constraint addressed, the baseline, and the extent to which the tool is integrated into planning, operational planning and real-time operations. They should therefore be read as evidence of achievable gains under suitable conditions, not as transferable performance benchmarks.

These examples show that the digital grid toolkit can deliver measurable gains when applied to a clearly identified system need and integrated into routine network processes. The size of the benefit, however, depends on the local constraint being addressed and on whether the technology is treated as part of planning and operations. This is why deployment should start from a system-needs assessment: identifying the system constraints, and then selecting the appropriate combination of digital, operational and physical measures.

What this report sets out to answer

This chapter has set out the challenge and the opportunity: electricity demand is rising rapidly, grid expansion alone cannot keep pace, meaningful untapped capacity exists in the networks that are already in place, and there is a suite of digital tools which could help unlock this capacity. The rest of this report examines how these digital tools might be used. Chapter 2 looks at the state of deployment across the digital grid toolkit, including the fuller technology landscape only introduced briefly here. Chapter 3 provides an estimate of the potential gains at the global level and examines the conditions needed to deploy these tools more widely and scale these gains. Finally, Chapter 4 sets out policy recommendations for operators, regulators and governments.

Chapter 2. State of play

This chapter sets out the current status of the digital grid toolkit. The central message is that the technologies needed to make existing grids more visible and controllable and allow them to be dynamically operated are increasingly available, but deployment remains uneven and slower than the progress in technology performance. The chapter is organised around three groups of functions, in deliberate order:

- sensing and measurement, communications and data, monitoring, analytics and control systems provide the visibility and controllability that everything else depends on
- grid-enhancing technologies (GETs) then use that foundation to reveal headroom, redirect flows and automate corrective actions while maintaining secure operation
- AI-enhanced solutions add a layer on top of both, improving forecasting, screening, optimisation, maintenance and decision support across the stack.

Functional taxonomy of the digital grid toolkit in scope of the report

Category	Core function	Examples of technologies and applications
1. Monitoring and control systems	**Sensing and measurement** Measure conditions across the network	Meters and sensors, PMUs, weather sensors
	Communications and data Move, store and integrate measurements and operational data	Communication network, data platform
	Monitoring, analytics and controls Monitor system conditions, analyse performance and operate assets	SCADA/EMS, WAMS, (A)DMS, DERMS, digital substation, situational awareness platform
2. Grid-enhancing technologies	**Dynamic ratings** Set thermal limits from actual operating and ambient conditions rather than fixed assumptions	DLR, DTR
	Capacity allocation Allocate available capacity to network users	SATA, active network management, dynamic operating envelope
	Power flow management Redirect flows from congested to underused paths and control transfer levels	Phase-shifting transformer, advanced power-flow control, topology optimisation, SSSC, TCSC, controllable HVDC
	Stability-constrained capacity enhancement Address voltage and stability constraints that limit usable network capacity	Grid-forming inverter capability, SVC, (e-)STATCOM
	Protection and restoration Act preventively or when faults occur	Real-time remedial action scheme, FLISR

3. AI-enhanced solutions	**Forecasting and screening** Anticipate system conditions and assess options faster	AI-based load and renewable forecasting, AI-enabled mapping, connection screening and contingency screening
	Asset analytics Assess asset condition, predict risks and determine when to intervene	Predictive maintenance, inspection analytics, vegetation management, outage prediction and analytics
	Operational decision support Rank and recommend actions to the operator	Topology-optimisation support, remedial-action ranking, AI-assisted corrective control
	Network modelling and simulation Represent and simulate the network for planning and operational analysis	AI-enhanced digital twin, AI-assisted hosting capacity analysis, grid foundation models

Notes: In this report, grid-enhancing technologies (GETs) are defined broadly to cover the technologies listed above. Other literature and jurisdictions sometimes define GETs more widely or narrowly. (A)DMS = (advanced) distribution management system; AI = artificial intelligence; DERMS = distributed energy resource management system; DLR = dynamic line rating; DTR = dynamic transformer rating; EMS = energy management system; (e-)STATCOM = (enhanced) static synchronous compensator; FLISR = fault location, isolation and service restoration; HVDC = high-voltage direct-current; PMU = phasor measurement unit; SCADA = supervisory control and data acquisition; SATA = storage as a transmission asset; SSSC = static synchronous series compensator; SVC = static VAR compensator; TCSC = thyristor-controlled series capacitor; WAMS = wide-area monitoring system.

Across all three categories, technical capability is advancing faster than deployment. As the examples at the end of Chapter 1 show, many tools have already delivered measurable gains in specific contexts. The constraint is therefore rarely whether the technology can work, but whether it is matched to the right system need, embedded in routine processes and scaled beyond pilots. The maturity of AI applications is generally lower but also varies, from widely adopted forecasting and asset maintenance tools to emerging applications to support control room decision making and the development of grid foundation models. Digital maturity is also highly uneven across countries and utilities, meaning that the barriers to scaling up differ by national context as much as by technology.

This chapter draws primarily on deployment experience in advanced economies and the People's Republic of China (hereafter, "China"), where the majority of real-world applications are concentrated. Emerging-market experience is treated in a dedicated section highlighting the opportunity for leapfrogging.

Digitalisation policies

Digital technologies are evolving quickly, and policy is adapting to this innovation while balancing two objectives: capturing benefits for the system needs, such as grid modernisation, better use of existing assets, faster connection and interoperability, while managing the risks it introduces, including data governance and cybersecurity.

Digitalisation policies are building the data, cyber and interoperability foundations for smarter grids. In the United States, the 2022 Inflation Reduction Act and the 2024 Grid Modernization Strategy support sensors, communications and intelligence at the interface with grid users. Europe's Digitalisation of the Energy System action plan (2022), Network and Information Systems Directive (NIS2), General Data Protection Regulation (GDPR), Critical Entities Resilience Directive and 2025 Clean Industrial Deal emphasise energy-data spaces, cybersecurity and digital sovereignty, which the newly adopted Strategic Roadmap for Digitalisation and AI in Energy Sector translates into an implementation strategy. China's 15th Five-Year Plan, which outlines the country's development objectives for the period 2026 to 2030, places digital platforms and real-time sensing at the centre of its power system transformation, while India's Revamped Distribution Sector Scheme (RDSS) and 2025–2026 India Energy Stack show a similar push toward digital public infrastructure for distribution grids.

GET-supportive policies are increasingly focused on using existing networks more efficiently while new infrastructure catches up. In the United States, FERC Order No. 1920 requires transmission planners to consider advanced transmission technologies in regional transmission planning, while FERC Order No. 881 requires transmission providers to implement hourly ambient-adjusted ratings, a step towards dynamic line rating (DLR). In Europe, the Grids Package and Electricity Market Design reform and Electrification Action Plan promote non-wire solutions, storage, and smarter planning. Australia's Dynamic Operating Envelopes workstream, and Brazil's ANEEL transmission modernisation and non-wire alternatives provide further examples. Several of these policies, along with the 2024 VoltAIc initiative, the USD 1.9 billion DOE SPARK program and India's 2019 Central Electricity Authority guidelines on high-performance conductors, also cover advanced conductors and reconductoring, hardware upgrades outside this report's core GETs scope but part of the same broader push to boost grid capacity.

There is a growing realisation that AI use in critical infrastructure requires different governance, distinguishing lower-risk, productivity-focused applications from safety-critical uses that affect system decisions and control. **AI policy** is still catching up with this realisation: general AI strategies are increasingly common, often focused on promoting innovation while protecting users in a context of seeking autonomy for critical AI uses, but policies and regulations specific to AI in the energy sector remain comparatively rare. Even so, the field has moved from broad principles to more energy-relevant governance within only a few years. The United States moved from the 2023 NIST AI Risk Management Framework and AI Executive Order to DOE's 2024 AI and Energy Strategy and its 2025 Genesis Mission, which frame AI as a tool for accelerating scientific discovery, grid modelling, infrastructure planning and energy-system resilience. The European Union issued in 2024 its AI Act, the world's first comprehensive legal framework that regulates AI based on a tiered risk system, followed in 2026 by its Strategic Roadmap for Digitalisation and AI in Energy, mentioned above, extending this approach to the energy sector specifically. In the United Kingdom, the energy regulator Ofgem has been overseeing AI in the energy sector since 2023 and published its guidance on ethical AI use in 2025. China's AI-energy plans frame AI as a core tool for dispatch, forecasting and renewable integration. The G7's own attention to this nexus, and growing engagement from Singapore, Japan and the International Solar Alliance, shows the agenda is widening beyond the largest power systems.

These policy efforts are growing and laying the groundwork for enabling the digital grid toolkit. However, where these enabling conditions are weak, they become barriers to deployment, as examined in Chapter 3.

Monitoring and control systems

Digital infrastructure has enabled the transition from a passive, periodically surveyed network to one that can be observed, analysed and acted on in close to real time. However, not all networks have digitalised at the same pace. As power systems transform around the world, the replacement and modernisation of assets is an opportunity to accelerate digitalisation.

Visibility and controllability are the foundations of modern grids

Modern grids require real-time visibility and responsive control. Better sensing, connectivity and data systems enable operators to see network conditions more clearly, while remotely controlled assets allow operators to act in near-real time and optimise system performance.

Data and situational awareness

Network operators cannot optimise what they cannot measure. Real-time visibility of the network is therefore the foundation for every downstream application. Traditional SCADA-EMS are being complemented by wide-area monitoring systems (WAMS), which combine high-frequency measurements across broad network areas to give operators a system-wide view of voltage, frequency, power flows and dynamic stability, allowing a wider array of advanced decision support tools. The value of data depends as much on its volume as on its quality, consistency and accessibility, which remain uneven even within a single utility. Unfortunately, a joint study of the European associations of transmission system operators (TSOs) and distribution system operators (DSOs) found that utilities tend to treat data management as a series of disconnected processes rather than a continuous, integrated flow across departments and operators.

Digital twins (see box) are emerging to connect real-time visibility to the network studies that underpin planning and operations. As monitoring and data quality improve, a digital twin can keep the underlying network model current as the system itself changes, rather than relying on periodic manual updates. It can also support control-room simulation grounded in actual measured conditions, rather than assumptions or a manually set system state.

Controllability: Turning visibility into action

Visibility only creates value once operators, or automated systems acting on their behalf, can act on what they see. This depends on remotely controllable grid assets (breakers, switches, tap changers, protection relays and power-electronic devices), integrated with SCADA and EMS so that a detected condition can trigger a response in seconds rather than requiring a field crew to be dispatched. Controllable grid assets are not rolled out everywhere; in particular, many older distribution feeders rely on manual switching and legacy protection, constraining the response capability of the operators.

Digital twins: Virtual replicas that enable multiple grid solutions

A digital twin is a virtual version of an asset or network, kept in step with the real thing by field data. In the case of grids, the twin can combine electrical data (voltages, flows) with other information such as terrain, weather, generation and demand to mirror the state of the network and simulate how it behaves under different conditions. A digital twin is rarely a solution in its own right, but a building block that other applications run on. Digital twins are mature and already in service in a number of countries. What varies is the application built on top. Operators typically start with a narrow use case and expand from there. Current applications include:

- **Asset monitoring:** Individual transformers or cables are modelled to monitor condition and set safe loading limits. Projects delivered by Enline in Spain report a 15% cut in maintenance costs and a 25% extension of asset lifespans.
- **Line capacity:** Thermal ratings are estimated section by section, in some cases without new sensors. On Ibiza, where summer loading is heavy and lines run through woodland and urban areas, a digital twin of four lines raised average capacity by around 20%.
- **Vegetation risk management:** Terrain, conductor sag and vegetation growth are modelled together to manage clearances and wildfire risk. Swissgrid has recorded its entire 6 700 km network in a 3D model, so that vegetation is cut where the risk is highest rather than on a fixed cycle.

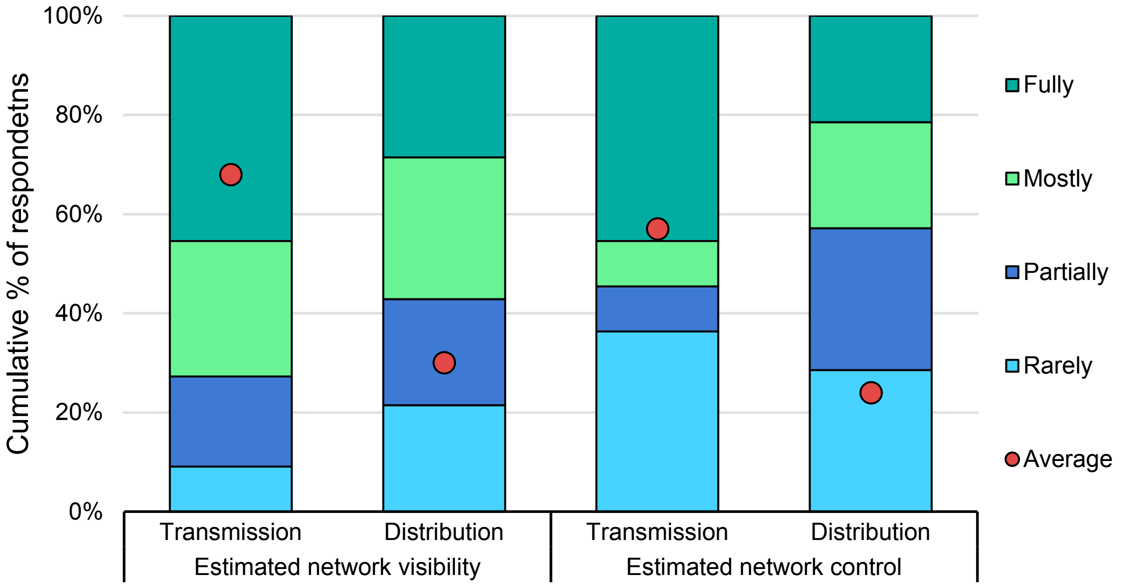
- **Network planning studies:** Lines, flows and contingencies are modelled for reinforcement studies. In the United Kingdom, National Grid's Triton brings together data from distribution operators and transmission owners and has cut the time needed to decide where to reinforce by 70%. Chile's national system operator cut simulation time by 86%, now runs 30 scenarios at once, and has used the tool in annual transmission expansion planning since 2025.
- **Connection queue management:** Application data and study models are consolidated into one network model. In the United States, PJM screened 811 applications representing 220 GW in under an hour.
- **Whole system modelling:** National twins are linked to test resilience and cross-border co-ordination, the aim of the TwinEU project across 15 countries.

Digital maturity varies considerably across grid segments and regions, and distribution is where the largest gap remains

Digital adoption is highly uneven among network operators, shaped by system needs, regulatory frameworks, investment cycles and institutional capacity. Data in this report comes from an IEA-conducted global survey of network operators in 2026, that received 25 responses: 11 from transmission operators and 14 from distribution operators across Europe, North America, South America, East and Southeast Asia, and Oceania. While the sample is not statistically representative, it provides a geographically diverse snapshot of current digital maturity, deployment priorities and perceived barriers. The starkest divide is between transmission and distribution: transmission is comparatively data-rich and easier to digitalise, since transmission networks have fewer, larger and more standardised assets to instrument than the myriads of dispersed low-voltage assets found in distribution. It is in distribution networks, closest to fast-growing distributed resources, where data gaps are the largest. Many surveyed DSOs report having high ambition, including for the low-voltage grid,[6] with most aiming to digitalise over 50% of their low-voltage substations by 2035, even for entities starting from close to zero today.

[6] The survey did not systematically collect separate figures for digitalisation of substations at the mid- and low-voltage levels, but many respondents provided information spontaneously.

Digital maturity across grid segments among surveyed network operators, 2026



Notes: The vertical axis represents the breakdown of network operators by response, and the colour represents the fraction of their network which they have visibility of or control over. Estimated visibility and control correspond to the following responses to the survey: Mostly = 51 to 75% of the network; Partially = 26 to 50% of the network; Rarely = under 25% of the network. For example, 60% of distribution operators have no controllability over at least half of their network.
Source: IEA survey conducted for this report (2026), based on 25 network operator responses: 11 transmission operators and 14 distribution operators. Given the small sample size, these results should be read as indicative of broad patterns rather than as statistically representative.

Transmission grids

Digital technologies already play a significant role in modern transmission grids. SCADA and EMS provide real-time monitoring and control of major assets, while digital sensors, PMUs and weather measurements add higher-resolution data on flows, voltage, frequency, equipment condition and operating limits. The use of drones and satellite-based technology enables inspection of power lines and vegetation management with lower effort and reduces exposure of staff to potentially hazardous conditions.

Traditional SCADA-EMS relies on few data combined with asset and system models or estimated variables. For example, a line capacity is estimated based on conditions along the conductor itself, typically approximated from weather data and static assumptions, rather than continuous direct measurement of its actual condition, such as temperature, icing or ageing. The growing level of digitalisation in transmission opens the door to advanced tools such as DLR and control-room decision support. The priority is to keep pushing the integration of SCADA, EMS, PMUs, WAMS and weather and asset data into trusted planning and operational workflows, so that operators can manage flows, stability, congestion and dynamic rating across meshed networks. The main challenge is breaking down data silos, extending monitoring to the asset level where it matters most, and giving operators confidence to act on more dynamic information.

Distribution grids

Traditionally, distribution grids had unidirectional flows and were operated in a static way, with manual switching and limited automation. As more variable supply and demand connects, the flows become bidirectional and networks need to be managed more dynamically.

The challenges in distribution are similar to those in transmission, with one major addition: far more assets to instrument, finer granularity, and the task of combining fragmented feeder, substation, transformer and smart meter data into operational capability. This task is assigned to digital platforms: distribution management system (DMS), advanced distribution management system (ADMS) and distributed energy resource management system (DERMS), which coordinates rooftop solar, batteries, electric vehicles and flexible demand so they can support, rather than stress, local networks.

Distributed energy resource management system deployment snapshot

Country	Operator	Deployment example	Reported outcome
Australia	Ausgrid	Dynamic operating envelopes replacing fixed export limits on low-voltage feeders	Raises solar hosting capacity without breaching voltage or thermal limits
United States	Hawaiian Electric	DERMS aggregating customer solar, batteries and water heaters for grid services	Customer-sited resources contracted for capacity and fast frequency response
United Kingdom	UK Power Networks	Active network management supporting flexible connections for distributed generation	More than GBP 80 million in connection costs avoided since 2014

Notes: DERMS = distributed energy resource management system.

Digitalisation priorities in distribution are to strengthen low-voltage visibility, putting smart meter data to operational use (not only for billing use) and deploying automation. Smart meters support load flow visibility while making consumers more aware of their consumption and enabling new billing structures. Smart meter data need to be reliable and integrated with ADMS and DERMS data into operational workflows to deliver value, but many datasets are currently isolated. Most emerging market and developing economies (EMDEs) have an even more basic priority: improving feeder and transformer visibility, digitising asset registers, expanding communications and building the operational capability to use data consistently.[7]

[7] Distribution-level challenges in EMDEs are discussed in more depth in the dedicated section later in this chapter.

Distribution-level technologies that convert digital visibility into operational capability

Capability area	Key technologies	What they enable	Main scaling constraint
Data and monitoring foundations	Smart meters, secondary substation monitoring, feeder sensors, asset registers and distributed energy resource registers	Visibility of loading, voltage, outages, asset condition and distributed energy resource location	Data quality, low-voltage topology gaps and communications coverage
Operational platforms	DMS, ADMS and DERMS	Integration of network models, switching, outage management, voltage control and distributed energy resource co-ordination	Legacy system integration, vendor interoperability and operating process change
Local constraint management	Voltage control, dynamic transformer rating and dynamic operating envelopes	More dynamic use of feeders and transformers while maintaining voltage and thermal limits	Reliable forecasts, controllable devices and transparent operating rules
Remote asset control	Feeder automation, reclosers, switches, FLISR and outage analytics	Faster fault location, isolation and restoration, and better response to changing conditions	Communications, protection co-ordination, field device availability and operator trust

Notes: ADMS = advanced distribution management system; DERMS = distributed energy resource management system; DMS = distribution management system; FLISR = fault location, isolation and service restoration.

Regional digitalisation adoption

The Smart Grid Index (SGI), run by Singapore's power network owner and operator SP Group, highlights the pattern of improving but uneven digital maturity.[8] The 2024 benchmark covers 92 utilities across 36 countries and assesses multiple dimensions of grid smartness across seven dimensions:

- monitoring and control
- data analytics
- supply reliability
- distributed energy resource and storage integration
- renewable and EV integration
- cybersecurity
- customer-facing services.

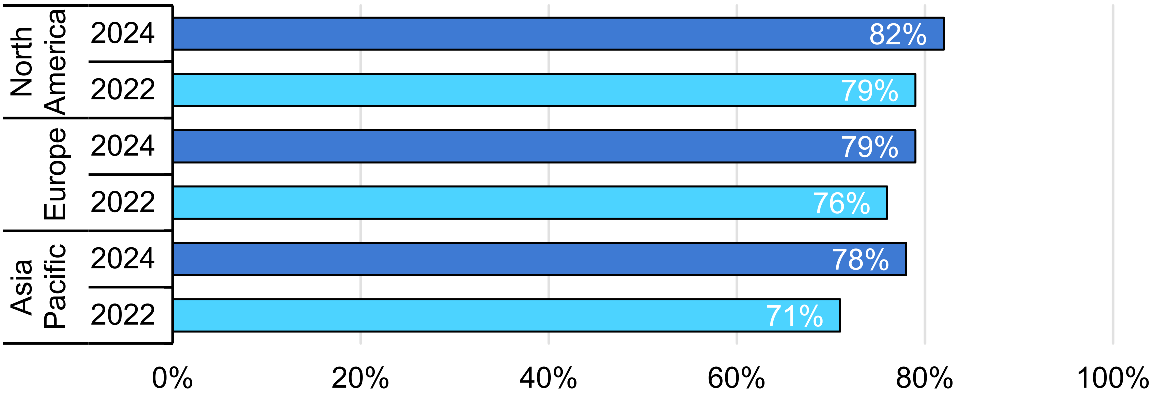
The merit of the index is that it does not reward the installation of sensors or meters, but rather how far the data have been put into operational use, such as hosting-capacity assessment, voltage and congestion management, active

[8] The SGI should be read as an indicative benchmark and not as a definitive assessment of utility performance. The SGI is compiled and published by SP Group based on publicly available information about each utility, and not through independent audit or verification. SP Group's methodology acknowledges that the index criteria and weighting will need to evolve over time to keep pace with new technologies, and has not been subject to independent academic peer review.

network management, outage restoration, dynamic operating limits and secure co-ordination with distributed resources.

North America records the highest regional average score, supported by strengths in data analytics and distributed energy resource integration, while Europe shows more balanced performance across categories. Asia Pacific is closing the gap fastest, helped by rapid gains in supply reliability, a dimension where the region has improved significantly over the past decade, and rapid progress in advanced metering. Utilities in Asia Pacific narrowed the gap thanks to alignment in investment, data systems and operational priorities.

Smart Grid Index maturity level by region, 2022 and 2024



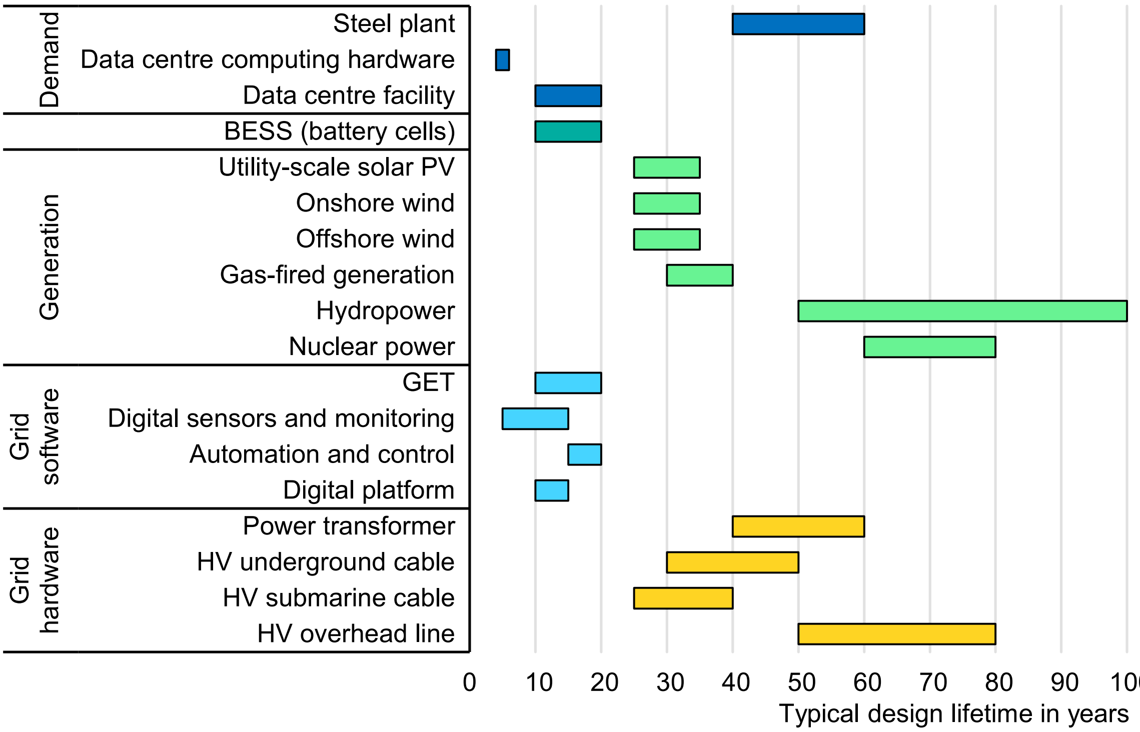
Source: IEA analysis based on SP Group (2026), Smart Grid Index.

Asset replacement is the cheapest moment to modernise the grid, but does not need to wait for the end of asset lifetime

Replacing or refurbishing an asset is the moment to build in digital readiness, by embedding sensing, measurement, communications and monitoring tools and controls at a fraction of the cost of a separate retrofit programme later. Missing this window is costly: once new equipment goes in without it, operators are typically locked out of embedding these capabilities for another full asset lifetime, which can run to several decades, incurring higher costs and delays later on. Since a large share of network spending is already committed to asset replacement, embedding sensors, controls and GET compatibility into these renewal programmes makes modernisation part of planned investment, rather than a separate upgrade requiring its own business case.

Grid assets and the demand they serve operate on very different investment timelines. Power lines, transformers, substations and protection systems typically turn over across decades, far more slowly than the pace of change on the demand side. This mismatch also applies within the digital layer itself: sensing and measurement devices, communications and data systems, and monitoring and control platforms can often be refreshed faster than primary grid equipment, but their value depends on whether the underlying assets were designed to host them.

Typical design lifetimes across grid hardware and software, and grid user technologies

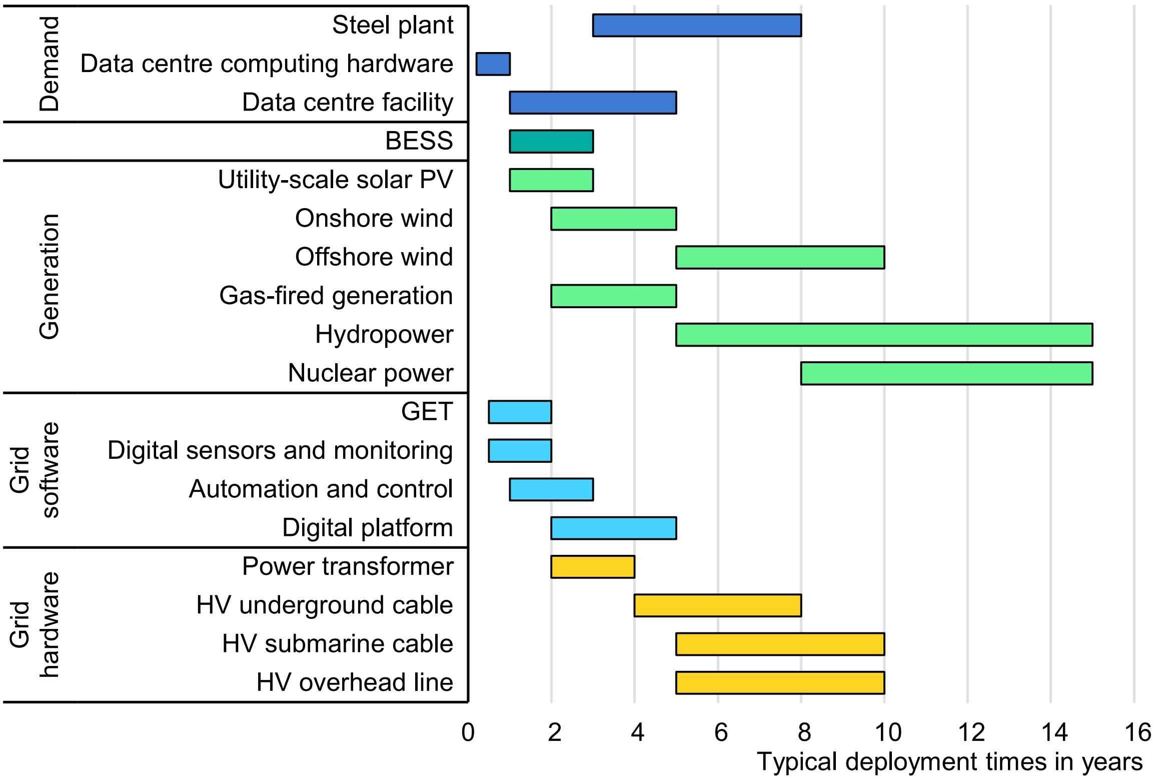


Notes: Lifetimes represent typical design or refresh cycles and can vary by voltage level, asset duty, regulatory framework, maintenance practice and local conditions. Data centre computing hardware includes graphics processing unit (GPUs) and servers. "Digital platforms" refers collectively to systems such as SCADA, ADMS and DERMS, as described in this chapter. ADMS = advanced distribution management system; BESS = battery energy storage system; DERMS = distributed energy resource management system; GET = grid-enhancing technology; HV = high voltage; PV = photovoltaic.

In advanced economies, there is an opportunity to modernise grids in the coming years. Much of the asset base is ageing: in Europe and North America, a significant share of the lines and cables are approaching the end of their typical operational lifetime. In EMDEs the asset age profile is younger, with roughly 40% commissioned in the past decade and around 35% more than 20 years old. Ageing assets are more prone to faults and require investment to extend their lives, so replacement needs are increasingly converging with demand for new capacity.

Capturing the modernisation opportunity does not mean waiting passively for assets to reach end of life. Where the case is strong, for example on corridors facing the sharpest capacity or stability pressure, utilities can bring modernisation forward, replacing or upgrading assets ahead of schedule specifically to embed digital and GET-ready capability sooner, rather than only opportunistically as natural replacement cycles fall due. The same long asset lives that create this opportunity also constrain how quickly it can be captured: primary equipment often remains in service for more than 40 years, and control and protection systems are typically refreshed only every 15-20 years. Modernisation therefore needs to be managed across overlapping investment cycles: conventional buildout where clearly needed, digital-by-default replacement cycles that embed sensing and measurement tools, communication, data, and monitoring systems, analytics and control capabilities, and GETs and AI-enabled tools that can act as near-term bridges while slower infrastructure, regulatory and manufacturing cycles catch up.

Typical time to deploy and commission grid hardware and software, and grid user technologies



Notes: Ranges reflect typical projects commissioned in the past five years in advanced economies. For grid assets, deployment time includes planning, procurement, approvals, installation and commissioning where relevant; for digital tools, they reflect installation and commissioning only. Data centre computing hardware includes graphics processing unit (GPUs) and servers. BESS = battery energy storage system; GET = grid-enhancing technology; HV = high voltage; PV = photovoltaic.

Grid-enhancing technologies

GETs are digitally enabled tools that increase the capacity, flexibility and efficiency of existing networks without waiting for major new infrastructure.[9] As shown in the examples in Chapter 1, they can deliver substantial gains when they address a specific constraint. Their safe and scalable use, however, depends on co-ordination across planning, operational planning and real-time operations, and integration within network companies' processes.

In practice, GETs and AI are increasingly complementary. GETs create new controllable options for operators, for example by revealing dynamic thermal headroom, redirecting flows or identifying alternative topologies, while AI can improve the forecasts, screening and decision support needed to use those options more consistently.

GETs give operators a proven, fast-acting tool alongside grid buildout

Overview of selected GETs

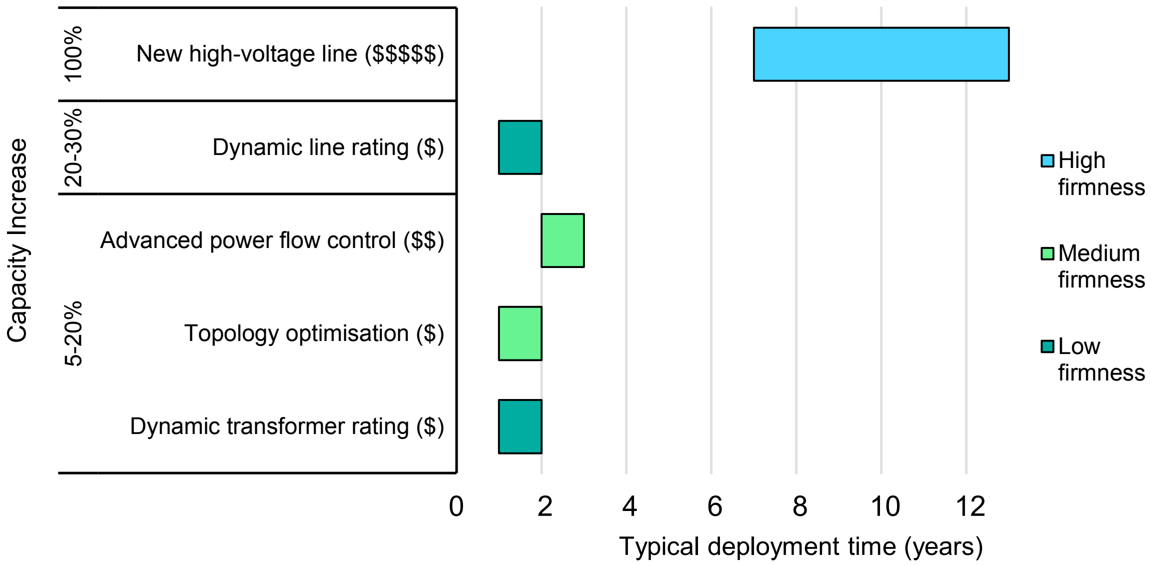
Technology family	Primary function	Maturity (TRL) and deployment status	Typical benefit
Dynamic ratings	Reveals real-time thermal headroom in lines and transformers	TRL 9 commercially available; strongest evidence base among GETs	Higher transfer capacity, lower curtailment, deferred reinforcement
Advanced power-flow control	Redirects power away from congested circuits toward underused paths	TRL 9 with targeted deployments on congested corridors and modular devices still at limited scale	Raises boundary capacity and reduces congestion costs
Topology optimisation	Uses switching and busbar configurations to reroute flows	TRL 8-9 technically proven; but operator trust in switching is still developing	Low-CAPEX congestion relief and better use of existing assets
Real-time remedial actions	Acts rapidly to keep the system secure	TRL 9 (5~7 for AI forms) AI-enabled forms are at an early stage and need stronger validation and override rules	Allows operation closer to limits with validated safeguards
Active network management	Coordinates feeders, voltage, switching, outages and distributed resources through DMS, ADMS and DERMS	TRL 9 mature platforms, but scaling limited by feeder visibility and IT/OT integration	Higher distributed resource hosting, better voltage management and faster operations

Notes: This report focuses on the GET applications where digitalisation and AI add the most value and that are deployed and controlled directly by grid operators. Other technologies sometimes included under the broader GETs label, such as advanced conductors and voltage uprating, are not addressed in this report. ADMS = advanced distribution management system; AI = artificial intelligence; CAPEX = capital expenditure; DERMS = distributed energy resource management system; DMS = distribution management system; GET = grid-enhancing technology; IT = information technology; OT = operational technology; TRL = technology readiness level.

[9] See Chapter 1 for the full definition and the report's scope, including why conductors, voltage uprating and storage are treated separately.

A decade of deployment shows that GETs can reliably unlock substantial capacity from existing networks. Typical installation is measured in months and costs an order of magnitude less than building new lines, making GETs an important complement to grid buildout, able to act on a shorter timescale. Industry coalitions and specialist initiatives, such as the Global Power System Transformation Consortium (G-PST), CurrENT in Europe, the Utilize Coalition in North America and the WATT Coalition, are also helping build the evidence base, standardise use cases and share deployment experience across operators, regulators and technology providers.

Comparison of technologies to add or unlock capacity



Note: Time to deploy covers the full path to operation, including feasibility and network studies, integration into planning and control-room tools, updates to operating processes and procedures, and, where applicable, deployment of physical assets. Firmness indicates how consistently the additional capacity is available. Low firmness means the gain depends on operating conditions, so it cannot be relied on at all times. $ signs indicate relative deployment cost, from lowest to highest.
Sources: IEA (2026), Electricity 2026.

GETs deployment remains geographically concentrated. In the case of DLR, for example, three-quarters of deployment is concentrated in Europe and North America. There are several reasons for this pattern, including congestion levels, the prevalence of older grid assets that make optimisation more valuable relative to new build, and the maturity of the regulatory frameworks needed to credit these technologies in planning and markets. However, the relationship is not purely a function of grid age: some fast-growing systems face similar congestion pressures and deploy these technologies for different reasons.

Dynamic line rating and dynamic transformer rating

Dynamic ratings reveal capacity that conservative, fixed assumptions leave unused. The capacity available between any two points on the network is set by the most limiting piece of equipment along that path – lines, transformers or substation equipment – so unlocking capacity generally requires rating across the whole path. Utilities have long used seasonal ratings set to normal ambient conditions, leaving real headroom unused when actual conditions are more favourable.[10]

Dynamic rating replaces fixed or seasonal assumptions with time-varying thermal limits for lines and transformers, using weather, loading and asset-condition data to reveal usable headroom. For overhead lines (dynamic line rating [DLR]), capacity depends on how well the conductor sheds heat, so it rises in cool or windy conditions and falls in still, hot ones. For transformers (dynamic transformer rating [DTR]), the limit is set by winding and oil temperature. Utilities have long varied transformer loading with operating conditions; what is newer is the automation and integration of this into real-time systems. Ratings can be estimated from weather data alone, measured directly with line or transformer sensors, or both combined for greater confidence; the trend for lines is towards forecast-led methods, reserving sensors for the most constrained corridors.

Dynamic rating deployment snapshot

Country	Operator	Deployment example	Reported outcome
United States	PPL Electric	DLR on multiple 230 kV lines	Reported 15-17% capacity increase and USD 64 million in annual congestion savings
Belgium	Elia	Around 150 sensors across 30 transmission lines	Reported short-duration savings of EUR 180 000 over four hours and projected annual savings of EUR 44 million
Norway	Statnett	Operational use of limit forecasts since 2023	Reported line capacity increases of up to 20%
United Kingdom	National Grid	DLR on a 275 kV circuit	Reported average capacity increase of 45% and estimated operating cost savings of GBP 1.4 million
Finland	Fingrid	Sensorless DLR across around 5 500 km of 400 kV lines	Additional capacity made available to day-ahead energy markets from April 2026
United States	Various utilities	DTR deployed on 50 existing power transformers ranging from 5 MVA to 50 MVA	Extended the useful life of existing infrastructure, provided more flexibility during planned or unplanned outages, and enhanced situational awareness through device health monitoring

Notes: DLR = dynamic line rating; DTR = dynamic transformer rating; kV = kilovolt. Sensorless DLR operates based on publicly available weather data and AI/machine learning correction models rather than physical sensors.

[10] Ratings are set conservatively to cover a wide range of likely conditions. Occasionally, in unusually hot weather, they may however exceed the true limits.

Advanced power-flow control

A newer class of modular devices is making power-flow control faster and cheaper to deploy. Operators have been aiming to redirect power from congested circuits towards underused paths: phase-shifting transformers and flexible alternating-current transmission system (FACTS) devices (including TCSC, STATCOMs, static VAR compensators, series compensation and unified power-flow controllers) have done this for decades, and high-voltage direct-current (HVDC) links have long moved bulk power over long distances and subsea. What has changed is the emergence of modular, series power-flow controllers that clamp onto existing lines without new civil works or substation rebuilds, making deployment a matter of months rather than the years a full FACTS installation or new phase-shifting transformer typically requires.

HVDC is also taking on a broader role. Embedded and multi-terminal links let operators adjust power flows independently of the surrounding alternating-current network, and, with grid-forming control, contribute to system strength and stability, not only bulk transfer. As these schemes multiply into multi-terminal grids and offshore hubs, the co-ordinated control of these assets becomes both more valuable and more complex, which is what makes them a natural fit for AI-assisted co-ordinated control, optimising setpoints across multiple links and devices at once, something not practical to do manually at this scale.

Advanced power-flow control deployment snapshot

Country	Operator	Deployment example	Reported outcome
United Kingdom	National Grid	Modular series controllers on five circuits at three substations	Over 2 GW of north-south capacity unlocked and GBP 390 million of estimated savings over seven years
United States	Central Hudson	Fifteen series controllers on an underused 345 kV circuit	Around 185 MW unlocked, chosen over a fixed series capacitor for lower resonance risk
Australia	Transgrid	Series controllers at two substations on the Victoria to New South Wales interconnector	170 MW of additional transfer capacity for AUD 45 million without building new lines

Notes: FACTS = flexible alternating-current transmission system; GW = gigawatt; kV = kilovolt; MW = megawatt.

Topology optimisation

Reconfiguring the network to relieve congestion is an old idea made newly practical by faster computation. Grid reconfiguration has traditionally been a rudimentary process, decided manually by operators based on past experience and operational guidelines. Using mathematical modelling to identify the best switching action instead of relying on operator judgement is not itself a new idea; what has changed is tractability. Finding the network configuration that best relieves congestion is a genuinely hard computational problem, and faster computing and modern optimisation methods, increasingly AI-based, now solve it fast enough to be useful in operations, seconds to minutes, rather than only as an offline planning exercise. This is what is moving topology optimisation from research into real deployment.

Topology optimisation now supports long-term planning, operational planning and real-time decision making in several US system operator regions, with case studies concluding that recommended reconfigurations can typically be identified in seconds to minutes, expanding effective grid capability by around 5-25% while meeting reliability requirements and delivering material congestion and curtailment reductions in operational settings.

Topology optimisation deployment snapshot

Country	Operator	Deployment example	Reported outcome
United States	MISO	Economic reconfiguration process developed to facilitate use of topology optimisation	USD 113 million in regional congestion cost savings in 2025
United States	ERCOT	Topology optimisation tool used to support contingency plan development	Identified a reconfiguration solution that replaced a prior plan relying on load shedding
Colombia	Interconexión Eléctrica S.A.	Reconfiguration at two substations to raise import capacity into Bogotá	Import capacity increased by 7% without additional infrastructure, mitigating transmission project delays
Netherlands	TenneT	GridOptions decision-support tool using AI-based remedial actions	Estimated 10-20% congestion reduction, with day-ahead plans generated in minutes

Notes: ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator.

Real-time remedial action

Real-time remedial action allows operators to comply with operational security criteria without holding large headroom in reserve for every contingency. A pre-approved automatic action, such as tripping a specific line or adjusting a setpoint, executes within milliseconds once a defined trigger condition is detected. Traditionally, this kind of rapid predefined response was reserved for rare, high-impact contingencies; contingencies were instead typically handled preventively, by holding headroom in reserve. Greater data availability and computing power now make it possible to address likely contingencies in real time, either correctively after the event, or preventively through continuous risk-based assessment.

Real-time remedial action deployment snapshot

Country	Operator	Deployment example	Reported outcome
China	SGCC	Deep reinforcement learning for fast remedial control	Reported decision times below 30 ms for resolution of violations in trials and around 4% average loss reduction
Australia	United Energy	Automated fault location, isolation and service restoration	Tenfold return on investment over five years and average fault fix time reduced by 30 minutes
France	RTE	Model-predictive control for zonal congestion management, using battery storage and curtailment	Provides rapid response to renewable surges and helps prevent local collapses
Multiple countries	Several locations in South America	Dynamic congestion management using predictive AI and fast-responding assets	More than 3 GW of grid assets under management

Notes: ms = millisecond; GW = gigawatt; RTE = Réseau de Transport d'Électricité; SGCC = State Grid Corporation of China.

Multiplying benefits by combining solutions

Combining GETs can multiply their benefits when each addresses a different constraint on the same network. The benefits of advanced technologies are greatest when they are deployed in co-ordination. Some gains overlap, where technologies draw on the same underlying headroom, while others compound, since capacity and stability are mutually dependent: extra headroom is only useful if voltage, protection, dynamic stability and restoration risk remain within secure limits, so line ratings, power-flow devices, topology actions and automation need to be assessed together.

Benefits resulting from combining solutions on the network

Country	Operator	Deployment example	Reported outcome
Slovenia	ELES	DLR + DTR System-wide deployment of the platform dynamically rating 38 overhead transmission lines and 10 substation power transformers simultaneously	Unlocked a 15% to 20% median transmission capacity uplift across monitored corridors and resolved approximately 500 N-1 thermal overload situations annually
United Kingdom	National Grid	APFC + DLR Co-ordinated deployment pairing modular series compensators across northern substations with non-contact DLR sensors on the Penwortham-Kirkby transmission corridor	Unlocked over 2 GW of boundary transfer capacity and delivered an estimated GBP 390 million in constraint cost savings and deferred capital expenditure
United States	Southwest Power Pool	DLR + APFC + TO Modelling combining DLR, modular series power-flow controllers and TO switching software across Kansas and Oklahoma	Doubled available interconnection headroom by adding 3.7 GW of renewable capacity, saving USD 175 million annually in regional production costs with a 6-month payback period

Notes: APFC = advanced power-flow control; DLR = dynamic line rating; DTR = dynamic transformer rating; GW = gigawatt. Examples are illustrative and show how combined deployment can address different constraints on the same network.

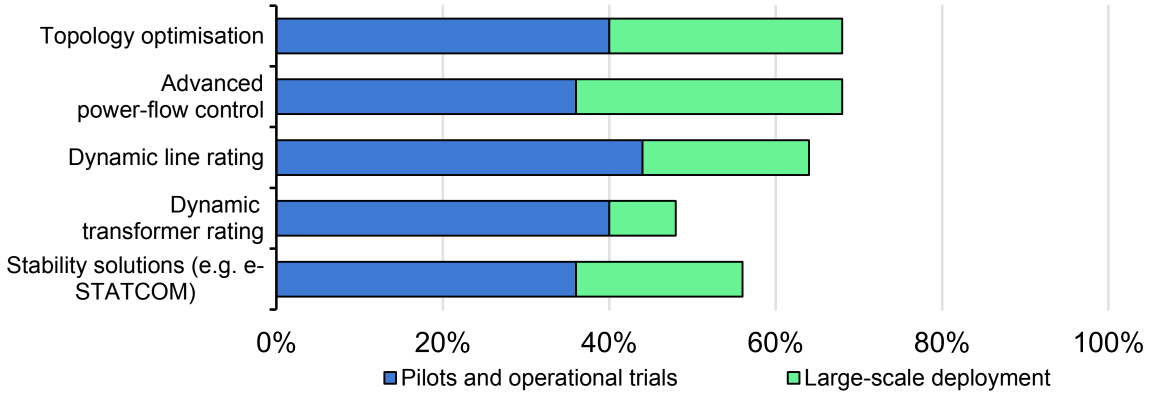
Unlocking capacity safely means assessing the whole network, not one constraint at a time

For every GET discussed in this chapter, revealing or creating headroom is not the same as being able to use it. How much can be credited in planning, operations or markets depends on the operational security layer discussed in Chapter 1: validated safeguards, operator trust and integration into control-room processes. GETs can also shift constraints rather than remove them: dynamic rating can move a bottleneck from a line to a transformer, while topology optimisation may require updated protection settings and switching procedures. Capacity unlocking therefore needs to be assessed against the network's full operating limits, not only against local constraints. This is where AI can become most valuable for GET deployment: identifying when a technology creates usable headroom, or when it simply moves the constraint elsewhere.

Stability limits also need to be considered as grid capacity is unlocked. Higher utilisation is only useful if the system can still withstand disturbances, maintain voltage and frequency, and recover securely after faults. Wide-area monitoring, drawing on PMUs and other high-speed measurements, gives operators visibility of how the system behaves dynamically, not just how loaded it is. Converting that visibility into secure headroom depends on assets that can actively support stability, including devices that provide rapid voltage support and oscillation damping. Increasingly, it will also depend on converter-connected resources such as batteries, wind and solar operating in grid-forming mode, contributing the voltage- and frequency-setting behaviour traditionally provided by synchronous generators. As more of the system's capacity comes from converter-connected resources rather than conventional generation, this stability-support function becomes an increasingly necessary complement to technologies that unlock thermal capacity or redirect flows.

GET priorities differ by network segment. In transmission, the main value is usually relieving congestion, increasing transfer capacity and reducing curtailment, by revealing dynamic headroom, redirecting flows or automating corrective actions. In distribution, the priority is often to connect more demand and host more distributed resources while maintaining voltage quality, protection co-ordination and reliability. The underlying functions are therefore similar, but the operational problems, data requirements and relevant technologies differ by network level and local constraint. Deployment also varies considerably even among technically mature GETs. Chapter 3 examines why this gap between proven capability and actual deployment persists, and what would close it.

Deployment stage of selected grid-enhancing technologies by surveyed network operators, 2026



Source: IEA survey conducted for this report (2026), based on 25 network operator responses: 11 transmission operators and 14 distribution operators. Given the small sample size, these results should be read as indicative of broad patterns rather than as statistically representative.

Replication challenge

The survey results show that technical maturity does not automatically translate into widespread deployment. Although many of the underlying engineering principles are broadly common across countries, deployment remains highly uneven. This suggests that successful replication depends not only on technology performance but also on local conditions and the institutional environment. At the same time, each technology has physical preconditions that decide whether it is suitable for a particular site, and these are not barriers that policy can remove.

DLR, which estimates how much power a line can safely carry under actual weather and operating conditions, illustrates the point. Because a circuit's capacity is determined by its most restrictive element, DLR creates value only where the conductor is the main constraint and cannot address limitations elsewhere in the circuit, such as substation equipment or stability limit. Corridors with limited variation in wind speed and direction may offer little additional headroom, while under less favourable conditions the dynamic rating can temporarily fall below the static limit it replaces.

DTR applies the same principle to transformers, using their thermal behaviour to determine when short-term loading can safely exceed a static rating. Transformers have enough thermal mass that their temperature lags the current flowing through them, and that lag can allow a short peak to be carried before the transform cools again. The load profile therefore has to be cyclical for the method to work, as under a daytime solar profile. A flat load at full capacity leaves no opportunity for cooling.

Advanced power-flow control redirects electricity away from constrained lines and towards parts of the network with spare capacity. It therefore needs somewhere to send the power: a parallel path with enough headroom to absorb the redirected flow. On a radial line there is no alternative route, and where the parallel circuits are themselves near their limits, the diverted flow simply creates a new overload.

Topology optimisation changes the electrical configuration of the network by opening and closing breakers to route flows more efficiently. It depends on the same meshed structure and adds a further demand: network model accuracy. The model has to represent what happens inside substations, rather than treat each substation as a single point. Topology optimisation also requires live breaker status and remotely operable switchgear, since a reconfiguration identified in the control room is of little use if it cannot be executed from there.

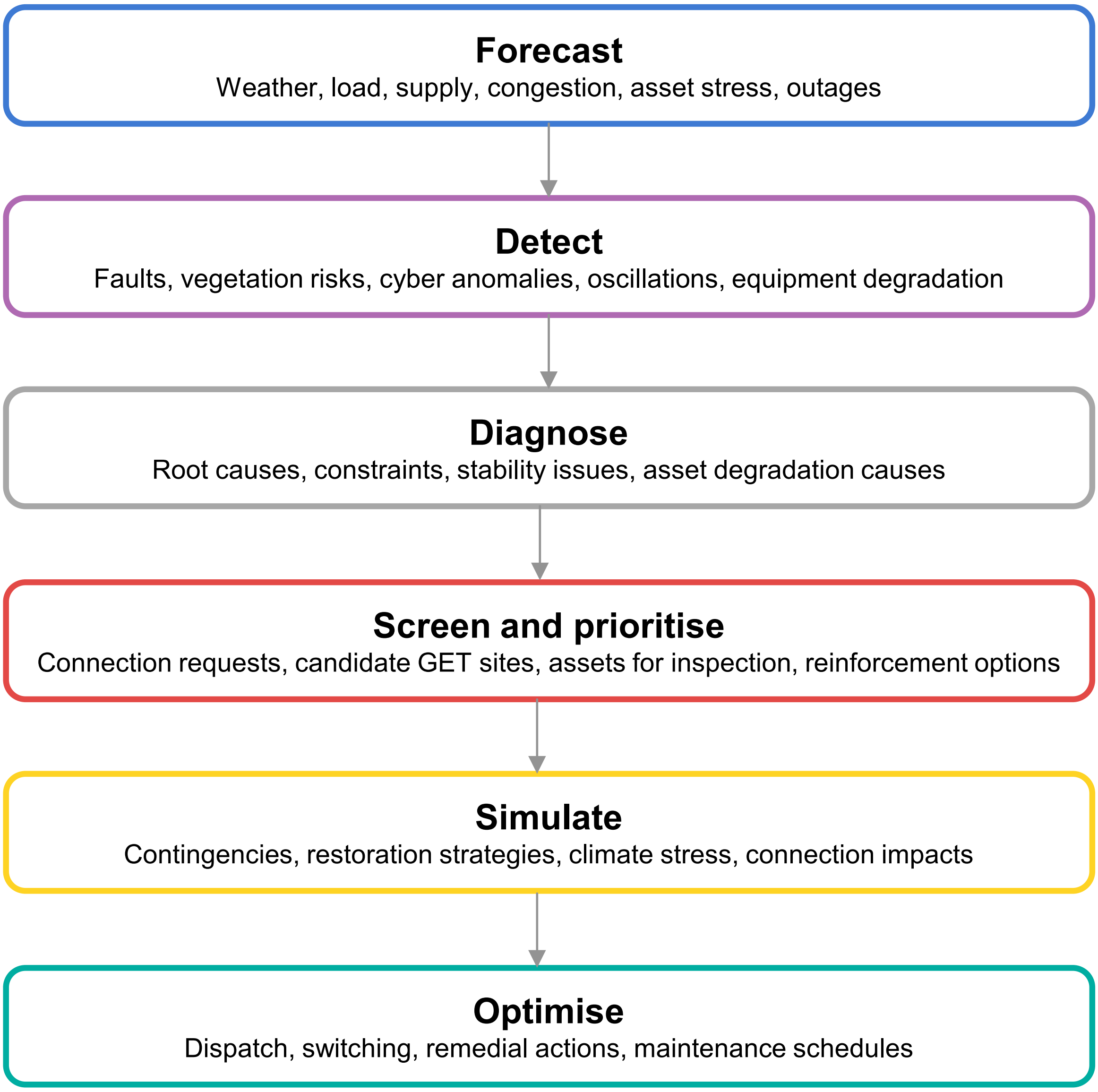
The transferable lesson for replication is therefore not the headline figure but the conditions that produced it. Operators first need to establish whether the site suits the core function the technology is meant to perform: revealing dynamic headroom, redirecting flows, automating corrective actions or supporting stability. They then need to test whether that technical fit translates into usable value: whether congestion economics justify the investment, whether data and forecasting are good enough, whether protection and control procedures can accommodate the change, and whether the regulatory framework lets the operator capture the benefit. Chapter 3 examines the conditions that enable this kind of replication: regulatory frameworks, data foundations, skills and organisation, and trust and security.

AI-enhanced solutions

AI not only adds a new set of applications to the digital grid toolkit; it also helps make monitoring and control systems and GETs easier to target, operate and scale. AI's main functions are to forecast, detect, diagnose, screen and prioritise, simulate and optimise. Applied to monitoring and control systems, these functions improve forecasting, data validation, anomaly detection and asset analytics. Applied to GETs, they help identify where latent capacity exists, forecast when it can be used, screen whether that headroom remains secure under contingencies, and rank feasible remedial actions.

AI in the power sector spans a spectrum from rules-based systems through machine learning to generative and, recently, agentic AI capable of planning and acting across several steps with limited prompting. Network operators have used AI for two decades. What has changed is the scale and diversity of what models can process. New architectures can handle larger operational, asset, weather, imagery and customer data streams; GPUs and cloud computing have sharply cut the cost of training and inference; and utilities now hold more digital information than in previous technology cycles. This is opening more of the grid to AI, but not all applications raise the same operational risk. As AI moves from forecasting, detection and workflow support towards automated control, the validation, explainability, cybersecurity, fallback rules and accountability requirements become more stringent.

Functional roles of AI in network planning and operations



Note: These functional categories do not necessarily reflect a hierarchy in maturity of applications nor the governance requirements.

AI already works for planning, maintenance and forecasting, and is fast becoming a default productivity tool

Lower-risk AI applications, such as forecasting, maintenance, inspection and planning tools, are scaling first because they improve decisions and workflows without directly controlling the power system. Forecasting is a partial exception, since it already feeds automated market and operational processes with limited human intervention. These applications have advanced furthest where three conditions coincide: enough historical or operational data are available to train and validate models; errors (a missed inspection cycle, a forecast error) are visible and recoverable; and the output can be checked by planners, engineers or operators before it affects the system. Visual intelligence illustrates this pattern. Utilities use computer vision and deep-learning models to process drone, satellite, LIDAR and inspection imagery, helping identify vegetation encroachment, ice sleeves, asset wear, corrosion, fatigue and storm damage more quickly, and in some cases more precisely, than manual review.

Beyond network-specific applications, generative AI is also becoming a default productivity tool across utilities, as in most sectors, supporting drafting, coding, data analysis and internal knowledge management. These uses are not specific to grid operations, but they can accelerate the analytical and organisational work that surrounds them.

Early deployment of AI applications across selected network operators

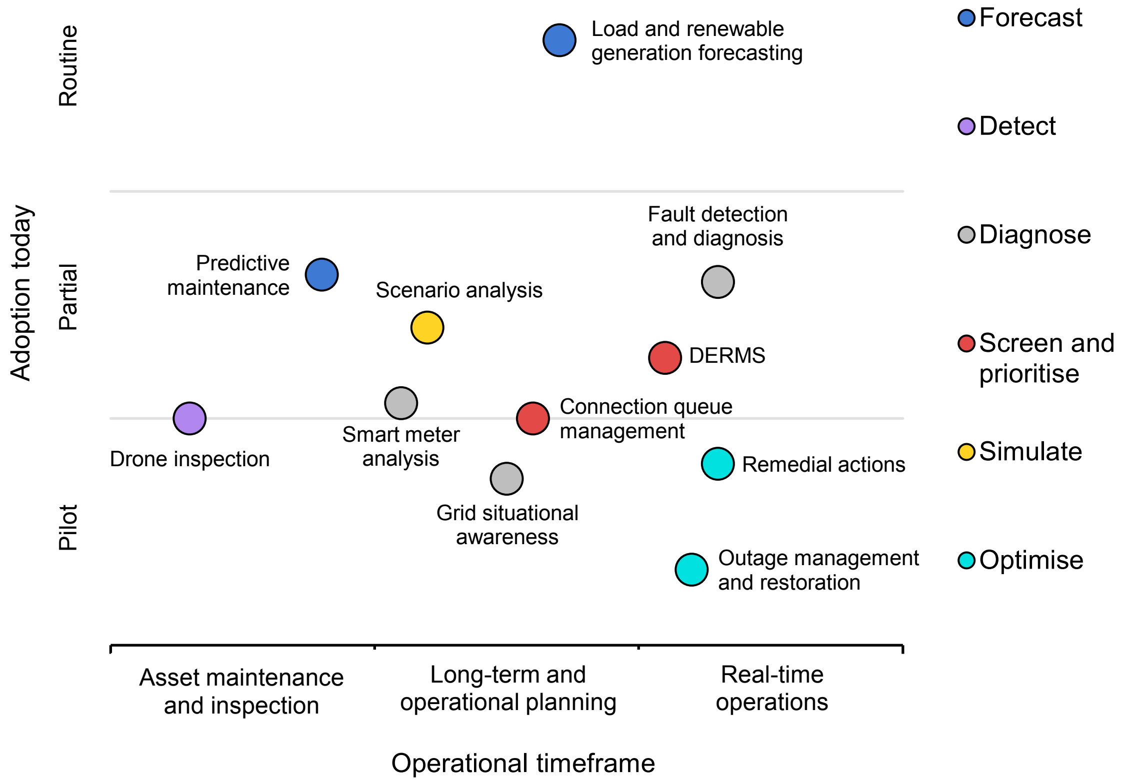
Country	Operator	Deployment example	Reported outcome
France	RTE	Contingency screening	Around 20x faster than manual security assessment
India	Utilities	AI data platform to clean legacy grid data and create dynamic maps	Around 80% faster grid planning where legacy data gaps existed
China	China Southern Power Grid	Visual intelligence for transmission line inspection	Line length nearly doubled over a decade while inspection staff grew from around 60 to 80
United Kingdom	NESO	Solar forecasting	Estimated GBP 30 million a year in reserve cost savings
United States	CAISO	Outage processing	Cut processing time from several hours to a few minutes
United States	PJM	Interconnection and planning studies	First workflow deployed in 2026, aimed at speeding up studies
United States	Southwest Power Pool	Interconnection studies	Targets 80% faster analysis; moving to production in 2026

Notes: CAISO = California Independent System Operator; NESO = National Energy System Operator; RTE = Réseau de Transport d'Électricité.

Real-time controls are AI's frontier, constrained by trust and auditability rather than accuracy

The adoption of AI is advancing unevenly and the reason is not model performance. In lower-risk applications, AI is already trusted because it forecasts, detects, diagnoses or prioritises information for decisions still made by planners and operators. Safety-critical AI, closer to real-time control, remains far more tentative. Here, accuracy is necessary but not sufficient: models also need to be explainable, auditable, secure against manipulation, bounded by deterministic fallback rules and embedded in clear chains of accountability before operators can rely on them for decisions with immediate system consequences.

Adoption of selected AI applications in electricity networks across operational timeframes and AI functional roles, 2026



Notes: DERMS = distributed energy resource management system. Adoption today is derived from the IEA survey conducted for this report (2026). The adoption score reflects a weighted sum of the maturity stage reported by surveyed network operators for each technology: routine full deployment (3), operational trial (2), or pilot (1).

Overview of selected AI applications

Technology	Primary function	Maturity (TRL) and deployment status	Typical benefit
Lower-risk AI applications	Improve maintenance, inspection and forecasting, planning workflow	TRL 7–9 Most mature category of AI use; scaling fastest in production where data quality is adequate and skilled workforce is available	Better decisions, faster studies and lower operational costs
Safety-critical AI applications	Support contingency screening, remedial actions and control-room decisions	TRL 3–6 Emerging in pilot/decision-support stage; full scaling requires robust explainability, deterministic fallback rules and verification frameworks	High potential value, higher governance burden

Notes: AI = artificial intelligence; TRL = technology readiness level.

Operational security

The clearest opportunity, and the clearest test, sits in the operational security layer introduced in Chapter 1's three-layer framework. This is where the long-term potential is the greatest, because it is where the sector could move from deterministic, worst-case margins towards more risk-based and probabilistic decisions about how grid assets can be used safely. AI can support this shift by synthesising large volumes of probabilistic information, flagging risk-relevant conditions and ranking feasible remedial actions for operators but the operator retains authority and accountability throughout. Widespread deployment at this level will therefore depend on stronger data, validation, governance and trust. In the near term, AI is more likely to augment engineering judgement than replace it.

Emerging control-room and planning applications

Emerging applications sit at the frontier between planning and control-room operation. In the control room, AI can help screen contingencies, prioritise alarms, identifying topology actions and translate simulations into clearer recommendations in the control room. In planning, it can accelerate power-flow studies, scenario generation and connection assessments. None of this removes the need for engineering judgement; the near-term role is to help operators and planners examine more options, more quickly, and focus human attention on the decisions that matter most.

Market-related applications are emerging too, including price forecasting and anomaly detection in bidding and dispatch, although public evidence remains limited. Disruption-preparedness tools follow the same lower-risk pattern: by combining weather, asset, terrain and customer data, they help operators pre-position crews and plan outage response more quickly, without taking direct control-room decisions. This makes them well suited to today's evidence and trust constraints, and a possible template for higher-consequence resilience applications once validation improves.

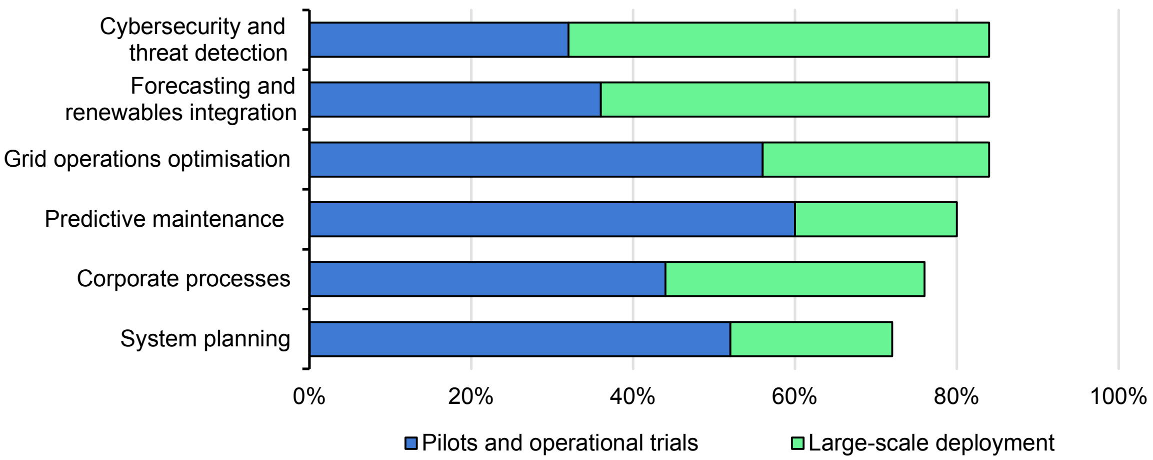
For policy makers, the practical implication is staged adoption: decision-support tools can scale first, while automated switching or self-learning operation require validated limits, cybersecurity assurance and clear accountability before they can be trusted in safety-critical environments, requirements that are feeding the emerging field of trustworthy AI.

AI moving toward system-critical grid functions

Country	Operator	Application	Reported outcome
China	State Grid	Guangming power model: Multi-modal model across planning, operations, asset management and customer service (see China box)	Overload risk analysis in Fujian reduced from around 20 working days to five; transformer diagnostics drawing on 154 measurement points
Netherlands	TenneT	Situational awareness and operator decision support, including a topology optimisation workstream	Significant gains expected; no public performance figures available yet
Australia	AEMO and other operators	Operations technology and control-room capability roadmaps	Roadmap towards integrated operational technology platforms and advanced situational awareness
United States	ERCOT	Energy price anomaly detection	Pilot stage; no public figures available yet

Notes: AEMO = Australian Energy Market Operator; ERCOT = Electric Reliability Council of Texas.

Deployment stage of selected AI applications by surveyed network operators, 2026



Source: IEA survey conducted for this report (2026), based on 25 network operator responses: 11 transmission operators and 14 distribution operators. Given the small sample size, these results should be read as indicative of broad patterns rather than as statistically representative.

Governance and network readiness

AI also introduces risks that governance needs to address directly before applications move deeper into grid operations. These risks differ by use case. Consumer-facing automation raises concerns around bias, discrimination and poorly automated decisions. Utility-level deployment raises cybersecurity, safety and accountability risks. Market-facing tools can create risks around algorithmic collusion or distorted competition. At system level, AI also has indirect effects on grids due to rising data-centre electricity demand and environmental pressures. Frameworks such as the EU AI Act, which sets obligations where AI is classified as a "safety component", and guidance from regulators such as Ofgem in the United Kingdom point to the same conclusion: governance requirements rise as AI moves closer to safety-critical grid functions.

In both transmission and distribution, scaling depends less on the AI model than on whether the network is observable, data are reliable and outputs can be integrated into operational systems. A model can only forecast, detect, optimise or prioritise conditions that the operator can observe and act on. In distribution, this makes feeder visibility, data granularity, controllable assets and integration with DMS, ADMS and DERMS platforms especially important.

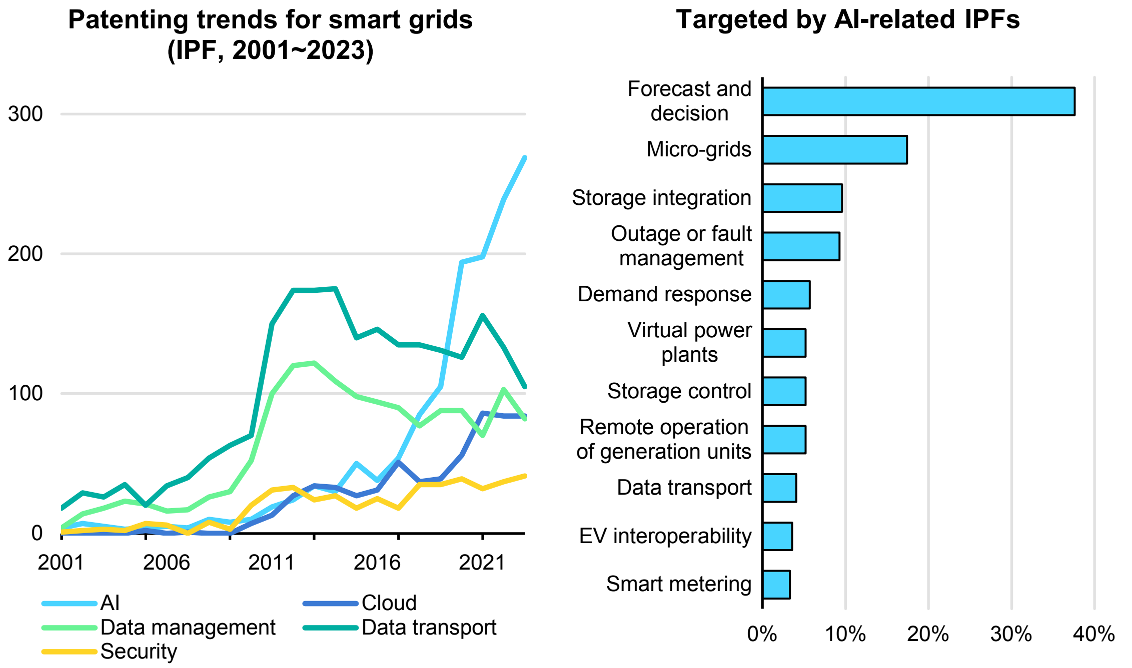
AI priorities according to network segment

Segment	Priority applications
Transmission	Renewables and demand forecasting, dynamic-rating forecasts, contingency screening and dynamic security assessment, topology recommendations, congestion management, year-ahead grid planning including interconnection studies and control-room decision support
Distribution	Local forecasting, asset inspection, outage management, voltage control, hosting-capacity analysis and distributed energy resource co-ordination through DMS, ADMS, DERMS, FLISR, dynamic operating envelopes and smart-meter analytics

The pace of adoption depends on the enabling conditions around it: regulatory frameworks, data foundations, skills and organisational readiness, and trust, cybersecurity and interoperability. These conditions apply to the digital grid toolkit as a whole, but AI faces them in a sharper form. Models depend on data quality and continuity in ways static hardware and software do not, their outputs can be harder to explain and audit, and the resulting questions of accountability are more demanding when recommendations begin to affect operational decisions.

This operational caution should not obscure the scale of innovation underway. Grid-related AI patenting grew by more than 500% in the five years to 2022 and is now the most active area of patenting among enabling digital technologies, led by the United States and China. The research and investment momentum is therefore already substantial, even while deployment in safety-critical grid functions remains more cautious.

The growing impact of AI on grid innovation



Note: IPF = International patent families; AI = Artificial Intelligence; EV = Electric vehicle
Sources: IEA and European Patent Office (2024), Patents for Enhanced Electricity Grids; updated figures from the European Patent Office (2026)

A more ambitious generation of AI agentic systems and foundation models is emerging but not yet operational

Most existing AI applications in grids are narrow models built for a specific role, such as forecasting demand or detecting equipment faults from imagery. Two more ambitious directions point beyond this. Agentic AI (see box) moves from advising on a single task towards pursuing a goal across several tools and steps, observing conditions, co-ordinating systems and taking contextual decisions with limited prompting, still under human oversight. Grid foundation models (see box) move from one model per task towards a general-purpose model pre-trained on broad grid data and adapted to many downstream uses. Both remain at proof-of-concept or pilot stage. Neither removes the trust and auditability gate described above; they raise the stakes, because a system able to act across several tasks needs validation, fallback rules and operator override safeguards across a wider operational surface.

Emerging AI solutions (research or pilot stage)

Solution	Problem it tries to solve	Promise and challenges
AI decision-support agents	The control room receives large volumes of alarms, forecasts and constraint warning, but the choice of remedial action depends on operator judgement. As networks become more dynamic, the number of switching, redispatch and setpoint combinations can become too large to assess manually in the time available.	AI agents could screen many feasible actions and present ranked options for operator approval, helping reduce response times and make better use of existing assets. Their use in real-time operations remains constrained by the need for explainability, auditability and clear accountability, and robust safeguards against unsafe recommendations.
Grid foundation models	Many AI tools for grids are still developed for one task at a time, such as forecasting, asset inspection, dynamic ratings or fault diagnosis. This can make deployment costly and slow, especially when models need to be rebuilt or retrained as network conditions, data sources or operating practices change.	Foundation models could provide a common model base that is adapted to multiple grid tasks with limited fine-tuning, lowering development costs and spreading learning across applications. Their value will depend on access to high-quality and representative grid data, strong validation against physical constraints, cybersecurity protection and operator confidence in how results are produced.
World models	Contingency assessment and what-if analysis mostly rely on detailed physical simulators run case by case. Screening very large numbers of disturbances, operating points and remedial actions can be computationally demanding, limiting their use close to real time.	World models could learn how the grid responds over time and make scenario exploration much faster, supporting operational planning and decision support. The core challenge is that learned dynamics approximate system behaviour rather than guaranteeing physical consistency, so extensive testing, boundary checks and integration with trusted simulators would still be needed.
Neuro-symbolic AI	Conventional machine-learning models can detect useful patterns in operational data but may not know why an answer follows or whether it respects grid rules. In critical operations, this creates a risk that recommendations appear accurate statistically but breach operating limits or are difficult for operators to trust.	Neuro-symbolic AI could combine pattern recognition with explicit grid rules, operating limits and physical constraints, making outputs easier to trace and keep within safe bounds. The approach is promising for trust and assurance, but integrating symbolic logic with deep learning at full network scale remains technically complex and still largely at research stage.
Federated learning	Training stronger AI models often requires pooling data from several operators, but operational data is sensitive and may be restricted by cybersecurity, privacy, commercial or sovereignty concerns. As a result, each utility may have too little data to train robust models on uncommon but important events.	Federated learning allows models to be trained across several organisations without centralising the underlying data, which could support shared learning while reducing data-sharing barriers. Its deployment still requires common data standards, strong governance, secure model exchange, careful treatment of bias across participants and agreement on how benefits and responsibilities are shared.

Note: Examples are illustrative and mostly reflect research or early-stage demonstrations rather than widespread utility deployment. These solutions are complementary and hybrid designs are an active research area. World models and grid foundation models, for example, describe different axes and are not mutually exclusive: the first refers to what a model learns – an internal predictive representation of a system's dynamics, enabling counterfactual roll-out – while the second refers to how a model is trained, through broad self-supervised pre-training on grid data adapted to many downstream tasks. A grid foundation model can also be a world model. Physics coupling is a separate question: in both approaches dynamics are learned from data, whereas neuro-symbolic AI encodes physical constraints and operational grid rules.

The potential for an agentic grid

Most AI in grids today advises or optimises within a single defined task. Agentic AI points to systems that pursue a goal across several tools and steps: observing their environment, adapting to changing conditions, co-ordinating with other systems and taking contextual decisions with little prompting, albeit still under human oversight.

Early examples are beginning to appear but remain at proof-of-concept or pilot stage: customer support agents, agents that help with equipment fault diagnosis by combining data ingestion with specialised analytical tools and workflow automation, operator-support agents layered over advanced distribution management systems that gather data and brief the operator, and agents that synthesise risk information ahead of extreme weather.

The promise is to alleviate cumbersome tasks, such as assembling data and juggling tools, so that operators can focus on judgement. The vision can be illustrated with an agent that detects a transformer anomaly, schedules a repair crew, reroutes power to limit customer impact and logs the event for review, with a human able to step in at any point.

For the operator, the role shifts from manual control towards strategic oversight: supervising autonomous systems and owning governance, compliance and assurance. This could preserve expert knowledge as the workforce ages and free staff for higher-value work. But it demands new skills and continuous training, and sharpens questions of explainability, accountability and the power to override in safety-critical moments. In a profession built on caution and clear lines of responsibility, such change may meet resistance and should be phased, auditable and supported by evidence before it is adopted more widely.

Sources: Framing draws on S. K. Simon and B. Soehren Jones (2026), “The Agentic Grid: The Next Evolution of Energy Infrastructure”, Climate and Energy, Vol. 42, Issue 10; examples from Eurelectric AI use-case catalogue.

Grid foundation models: A future step up for AI applications

Most AI in power systems today is task-specific where a separate model is built and maintained for each application. Foundation models adopt the opposite approach where a single large model is pre-trained on broad grid data (network topology, time series from SCADA and phasor measurement units, weather, and text such as logs and manuals) and then adapted to many tasks with relatively little extra data. Tasks could include forecasting, power-flow and contingency analysis, state estimation, predictive maintenance and anomaly detection, congestion management and planning. Unlike the large language models that dominate public use, a grid foundation model is built for the physics and numerical data of the network rather than for text, and a central research challenge is to keep what it learns consistent with physical laws.

The appeal goes beyond faster computation. A single model trained once can transfer knowledge across utilities, lowering the cost of applying AI for smaller operators who hold too little data to train a capable model of their own, in principle giving every utility a path to benefit from AI, not only those able to invest heavily upfront. The same underlying model can also support a wider range of tasks than the narrow, single-purpose tools this is replacing, from forecasting and situational awareness to security assessment and decision support.

The principle is promising but still largely pre-deployment. Progress depends on both data and modelling, and neither is solved. On data, foundation models need large, high-quality, interoperable datasets that no single operator holds; so progress depends on the willingness to share data – directly or through synthetic data, data spaces and federated learning – and on the governance that makes this possible. On modelling, genuine open challenges remain specific to this domain: embedding physical laws and conservation constraints, handling networks whose topology varies from one system to another, quantifying uncertainty, and validating a model's outputs before it can be trusted in operations

Two initiatives illustrate the field. GridFM, hosted by LF Energy, is an open-source effort to build a shared foundation-model technology base, originated by IBM with Hydro-Québec and contributors including Argonne National Laboratory. In Europe, AI.grids, co-ordinated by CRESYM under the European Commission (DG ENER), aims to build the first pan-European AI foundation model for grid operations, bringing together some 48 organisations, including TSOs, DSOs, research organisations and industry associations, trained on European data and run on EuroHPC AI Factories and Energy Testing and Experimentation Facilities. Both confront the same data-sharing and governance questions that will determine whether the technology reaches operation.

AI: An opportunity for emerging market and developing economies to leapfrog

In EMDEs, AI and digital tools offer the opportunity to leapfrog parts of the traditional grid development path, and indeed some utilities are already doing so. Rather than waiting to complete the capital-intensive rollout of metering, sensing and control that earlier grid development relied on, some operators are using AI-based estimation and simulation, drawing on satellite and drone imagery, computer vision and third-party behind-the-meter data to gain partial visibility where SCADA or metering coverage remains incomplete.

This does not mean AI can substitute for data quality: as set out earlier in the report, data quality remains a determining factor for how far AI can be pushed, in EMDEs as much as anywhere. What leapfrogging changes is the path to adequate data. Waiting for full metering rollout before acting would delay the benefits of digitalisation. EMDE utilities are therefore sequencing investment differently: they first use lower-cost proxy data sources to reach the data quality a specific limited application needs, and then direct scarce capital to the parts of the network where better data or control would create the most value. As the benefits become clearer, this can strengthen the case for further digital investment.

Starting points and priorities for emerging markets and developing economies differ from advanced economies

Distribution system reliability and efficiency are lagging in EMDEs, so priority AI applications are directed at loss reduction (including energy theft), predictive maintenance, self-healing and service quality. These applications can deliver visible benefits to consumers quickly, which matters for sustaining political and public support, and where utilities are vertically integrated, as they are in many EMDEs, the operator captures the gains directly, easing some of the incentive problems seen in unbundled systems.

Regional AI development overview

Region	Status	Illustrative deployments	Main constraints
Southeast Asia	Multi-speed: mostly pilots; Malaysia and Thailand advancing faster	Wide-area monitoring (EGAT, Thailand); centralised substation monitoring and automation (NGCP, Philippines); AI asset and climate-risk monitoring (AboitizPower, Philippines); third-party behind-the-meter data in place of mass smart metering; widespread solar forecasting (Philippines, Malaysia, Thailand)	CAPEX-biased regulation; fragmented data/AI rules; markets too small for bespoke solutions

India	Large ambitions, sharp public-private divide	Predictive maintenance and renewable forecasting led by private utilities (Tata Power, Adani); rapid smart-meter rollout	Limited public-sector capability; cross-subsidised tariffs; smart-meter data underused
Latin America	Piloted around renewables integration; some tools moving into operational use	AI-enabled transmission planning and real-time tools (ONS, Brazil); AI-enhanced fault detection and monitoring (Eletrobras, Brazil); proof of concept for AI forecasting and congestion prediction, and a transmission planning tool (CEN, Chile); regulator-led AI pilots (Costa Rica)	CAPEX-biased regulation; thin innovation ecosystems; data quality and observability

Notes: Examples are illustrative and not exhaustive. CEN = Coordinador Eléctrico Nacional; EGAT = Electricity Generating Authority of Thailand; NGCP = National Grid Corporation of the Philippines; ONS = Operador Nacional do Sistema Elétrico.
Sources: IEA analysis based on public utility and regulator material (links), and discussions with regional stakeholders.

A CAPEX bias in regulation is a recurring feature across EMDE regions. Tariff frameworks reward new physical assets more clearly than software and data investment, echoing the regulatory gap identified across this report, leaving thin cost recovery for the operational tools that would extract more value from existing networks. In Latin America this is compounded by relatively thin innovation ecosystems; and in Southeast Asia by fragmented national data, cyber and AI rules and by underfunded ageing grids. Regulatory sandboxes are controlled spaces where a utility can test a new tool or process outside standard rules before regulators decide whether to extend it more broadly (discussed further in Chapter 3). They are gaining interest in both regions as a way to give risk-averse utilities room to experiment, though few regulators yet offer them. Chile's national operator, CEN, has a partnership with an external AI developer for transmission planning, a rare example of a project moving from prototype towards planned operational use in 2027.

Progress is uneven, both between countries and within them. In Southeast Asia, Malaysia and Thailand are advancing faster than other emerging economies on the back of stronger digital infrastructure, and private utilities across the region often move ahead of state-owned ones, reading their networks through alternative data sources rather than waiting for full instrumentation. India shows the same pattern: leading private utilities such as Tata Power and Adani are already applying AI in operations, while many state distribution companies face tighter capability and financial constraints, and progress varies widely from state to state.

A further pattern is the gap between collecting data and using it. India's smart-meter rollout is expanding rapidly under the national Revamped Distribution Sector Scheme, but converting these data into operational value has lagged behind installation; even the more advanced utilities use less than a quarter of the data now available to them, a gap attributed mainly to a shortage of dedicated analytics teams and institutional capacity. This is not an EMDE-specific problem: similar underuse of smart-meter data has been reported in advanced-economy rollouts, suggesting a pattern of underinvestment in analytical and organisational capacity.

Skills and financing hold adoption back

The opportunity in EMDEs is real, but realising it is more dependent on enabling conditions than in advanced economies. A decisive question is whether digital and AI solutions can be treated as investable grid assets earning a regulated return, rather than discretionary IT expenditure. The conditions that determine this are as set out in Chapter 3, but two weigh most heavily in EMDEs, and especially in state-owned public-sector utilities: skills and financing.

Skills are a major constraint in most EMDEs, though not universally – India's leading private utilities are a notable exception – and are generally more acute than in advanced economies (as elaborated in Chapter 3). The energy sector already trails other sectors in digital talent: in the period 2018-2024 the share of workers in AI-related roles in utilities, oil, gas and mining ran around 40% below sectors such as finance, technology and media, and the gap is wider still in EMDE utilities, especially state-owned ones, where pay and career structures make specialists hard to attract and retain. This deepens dependence on vendors and reinforces caution about entrusting AI with core operations, strengthening the case for capacity-building to be embedded in projects from the outset and for pooling skills regionally.

Financing is another cross-cutting constraint, and is tightly bound up with how networks are regulated. High costs of capital, tariff structures biased towards CAPEX, and limited or slow cost recovery for software and data mean that even where a digital investment would pay for itself quickly in operational terms, utilities often cannot recover the cost from consumers fast enough to justify it upfront, particularly where public budgets are stretched.

International co-operation to ease skills and financing constraints

International co-operation can ease skills constraints by pooling scarce capability and spreading proven approaches across utilities rather than leaving each to build capacity alone. The IEA and its Technology Collaboration Programmes, including ISGAN, already support cross-country knowledge exchange on grid digitalisation and AI, alongside platforms such as the Global Power System Transformation Consortium (G-PST) and Mission Innovation's work on power system digitalisation. Open-source initiatives like LF Energy's GridFM support pooling in a different way, making shared tools and models openly available rather than requiring each utility to build its own capability from scratch.

International co-operation can also help spread learning. Mission Innovation’s work on power system digitalisation and related smart-grid collaborations provides a model for pooling use cases, test environments, standards and lessons across countries, so that smaller utilities and emerging economies do not have to develop every tool, dataset or assurance process from scratch.

Blended or concessional finance can ease the financing constraint: grants, below-market-rate loans and guarantees can de-risk early digital and AI deployment and cover the higher up-front costs or longer payback periods that a purely commercial lender might not accept, particularly where tariff structures do not allow full or fast cost recovery.

Development finance and philanthropic programmes often address both constraints, as they usually attach technical assistance to a financed project, allowing proven approaches to cascade between utilities.

China: Rapid, co-ordinated and sequenced AI deployment

China provides one of the clearest examples of large-scale AI deployment in electricity networks. National policy documents increasingly position AI as a strategic tool for power-system planning, operation and asset management, while major utilities have launched dedicated programmes to integrate AI across their business functions.

The first wave of deployment has focused on applications with immediate operational benefits and limited implications for system security. China Southern Grid reports extensive use of AI-assisted inspection and monitoring tools, including computer vision applications for transmission assets and equipment condition assessment. Similarly, State Grid Corporation of China has developed the Guangming power model, a sector-specific foundation model designed to support planning, grid operations, asset management, customer services and business processes.

According to publicly reported information from State Grid, the Guangming model has been applied across more than 600 use cases. Reported examples include reducing overload-risk assessment times in Fujian Province from around 20 working days to five days and supporting transformer diagnostics using more than 150 operational parameters.

These deployments confirm the pattern observed throughout this study. Utilities are scaling lower-risk applications first, including forecasting, inspection, diagnostics, planning support and workflow automation. These applications generate operational benefits while helping utilities improve data quality, develop internal expertise and build confidence in AI systems.

More operationally critical applications, such as congestion management, remedial-action support, dynamic operating limits and real-time decision support, are also being explored but remain subject to stronger requirements for validation, explainability, operator oversight and cybersecurity.

Sources: China's 15th Five-Year Plan; High-Quality development of the "AI Plus" strategy in the Energy Sector; State Grid Corporation of China; China Southern Power Grid; Guangming power model public information.

Chapter 3. Estimating and unlocking the potential

This chapter first estimates the scale of that potential globally, then examines why technologies that are technically proven and based on broadly shared engineering principles remain unevenly deployed. Realising the potential of the digital grid toolkit depends on four enabling conditions: regulatory frameworks, data foundations, skills and organisational readiness, and trust, accountability and security. These conditions apply to the toolkit as a whole, but AI tests each of them most acutely. Where they are weak, they become barriers to deployment; where they are strengthened, they allow proven technologies to move from pilots and local successes to routine operational use.

Estimating the potential of the digital grid toolkit

Individual deployments of the digital grid toolkit already show measured benefits at the level of a network corridor, substation, control area or utility, including higher transfer capacity, lower congestion costs, faster connection studies and improved reliability, as summarised in Chapter 1. These examples demonstrate that the toolkit can unlock real system value when applied to a clearly identified constraint. They should not, however, be read as directly transferable benchmarks for global scaling. The estimate in this section is therefore not derived by extrapolating reported project outcomes, but from an IEA assessment of where selected GETs could technically unlock additional capacity on existing networks.

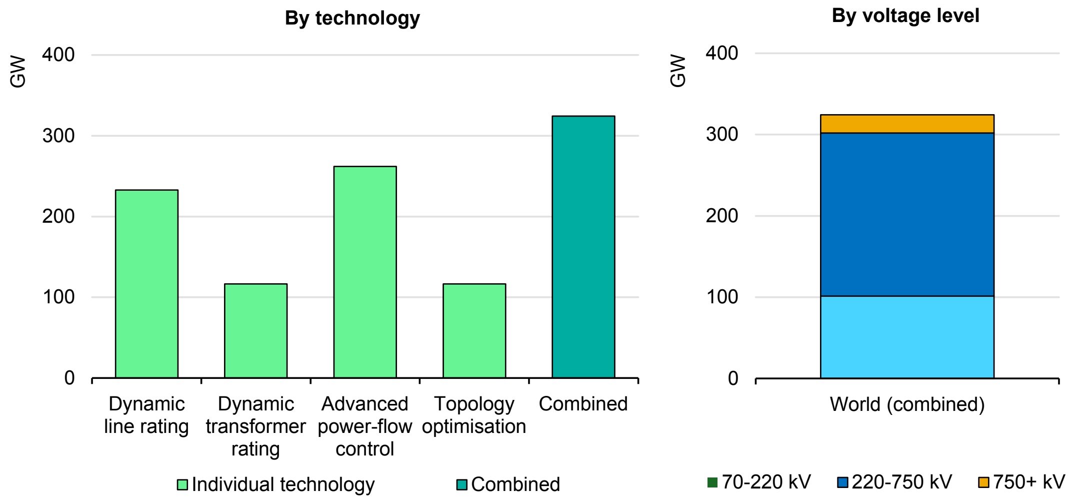
The digital grid toolkit can unlock substantial hosting capacity and expansion savings

IEA analysis estimates that GETs – dynamic ratings, topology optimisation and advanced power-flow controls – could unlock up to **330 GW of additional hosting capacity globally today** for generation, storage and demand on existing network while maintaining secure operation. These capacity gains are equivalent to those that would otherwise require around **USD 100 billion in grid expansion investment,** but could be delivered at a fraction of that cost. The avoided or deferred investment could instead be redirected toward modernising ageing networks.

This potential is highly relevant to the pressures facing policy makers today: mounting connection queues that delay new supply, demand and storage assets, and rising grid infrastructure costs caused by project delays, supply-chain constraints and higher equipment prices. GETs do not remove the need for new grid infrastructure, but they can help use existing assets more efficiently while slower buildout catches up.

AI adds to this potential, although its contribution is difficult to estimate separately because it is closely intertwined with the digital tools it enhances. Sharper forecasting, faster screening and AI-assisted analytics can improve how GETs are targeted and operated: identifying dynamic-rating opportunities more accurately, locating available capacity faster and screening remedial actions more efficiently in operational timeframes. Some of these enhancements are already delivering benefits. As AI capabilities continue to improve, they may raise the practical potential of GETs further, but this analysis does not quantify a separate AI uplift.

Estimated grid hosting capacity that can be unlocked globally with grid-enhancing technologies, 2025



Notes: Values represent indicative global hosting-capacity gains from deploying grid-enhancing technologies in existing networks at voltage levels 70 kV and above. The combined estimate is lower than the sum of individual technology estimates because multiple technologies may address the same network constraint. Estimates are based on regional network characteristics and technology-specific assumptions regarding capacity increases and deployment coverage. Results exclude system-specific constraints such as voltage limits, fault levels, substation capacity and local generation-load characteristics, which require detailed network studies.

Methodology and assumptions

The estimate presented here is derived from the IEA's Electricity 2026 assessment retaining only the technologies that fall within this report's definition of GETs. Electricity 2026 found a combined global potential of 450-700 GW for a broader portfolio of technologies and network upgrades, including GETs, storage as a transmission asset (SATA), reconductoring and voltage uprating. The estimate presented in this report is a subset of that broader assessment. Applying the same methodology and assumptions as Electricity 2026, but restricting the scope to dynamic ratings, topology optimisation and advanced power-flow control, yields an estimated potential of 190-330 GW, of which the upper end (330 GW) is used as the headline figure throughout this report.

The ranges in Electricity 2026 reflect different assumptions regarding the capacity increase delivered by each technology and the share of the network on which it can be deployed with meaningful gains. This report uses the upper end of that range as its headline figure. The estimated hosting capacity is then converted into an equivalent length of new transmission line avoided and priced against representative unit construction costs.

The combined potential should not be interpreted as the sum of the individual technology potentials. Multiple GETs may address the same network constraint and their impacts can overlap. As a result, the combined capacity gain is lower than the arithmetic sum of standalone estimates.

The underlying model estimates, for each technology, how much additional capacity could be unlocked across the network segments where it applies. It is based on:

- high-voltage network characteristics as of 2025, covering networks of 70 kV and above, including network length, voltage levels, loading levels and congestion indicators
- technology-specific assumptions on achievable capacity increases and applicable network coverage, consistent with the deployment and maturity evidence discussed in Chapter 2
- exclusion of system-specific characteristics, such as generation-load patterns, detailed contingency constraints and local operating limits, which would require detailed, network-specific studies.

Non-firm grid connections: Unlocking the flexibility layer

The IEA's Electricity 2026 report found that non-firm grid connection arrangements could unlock an **additional 750-900 GW** of grid capacity globally, beyond the potential unlocked through GETs and larger physical upgrades (SATA, voltage uprating and reconductoring). Together, these approaches could unlock 1 200 to 1 600 GW of hosting capacity, enough to connect a large share of the advanced-stage generation, storage and demand projects currently waiting in grid connection queues.

A non-firm connection is an arrangement between a network operator and a grid user, such as a generator, storage facility or electricity consumer, that enables earlier or larger grid access on the condition that output or consumption can be limited when network constraints arise. Unlike GETs, which increase the amount of power the network can safely carry, non-firm connections increase the utilisation of available network capacity by managing how and when users access available capacity.

Because non-firm connections rely on market design, contractual arrangements and regulatory frameworks that vary considerably across jurisdictions, they are not analysed further in this report but in other IEA work.

Digitalisation is a pre-condition to non-firm connections, as grid users must be responsive to signals reflecting the network conditions, but AI can strengthen the value of non-firm connections. More accurate forecasting of demand, renewable generation and network conditions allows operators to estimate available capacity more precisely and reduce unnecessary curtailment. AI-enabled hosting-capacity assessment, congestion forecasting and dynamic operating envelopes can also increase confidence that additional users can be connected while maintaining secure operation.

In the three-layer framework introduced in Chapter 1, GETs assessed in this chapter operate mainly within the network asset layer by increasing the capacity that the network can safely carry. Non-firm connections increase the extent to which that capacity can be shared across grid users over time and belong primarily to the flexibility layer. This illustrates an important feature of the three-layer framework: gains in grid utilisation can be achieved by pursuing improvements in each of the layers, but the largest gains come from addressing all three in symphony.

Three layers of grid optimisation

Flexibility Matching load and distributed resources to spare capacity, in time and place	Demand response, managed EV charging, storage, energy efficiency, flexible/non-firm connections, siting new load where headroom exists

Report focus

Network assets Getting more from assets already in service securely (**capacity**) and minimising their downtime (**availability**)	**Capacity**: grid-enhancing technologies, storage as a transmission asset, real-time remedial actions **Availability**: predictive/condition-based maintenance, optimised repairs and restoration
Operational security criteria How risk is assessed and operating margins are set (across thermal, voltage and stability limits)	Planning methodologies, contingency analysis and reserve setting, real-time monitoring and forecasting of stability **Currently** dynamic, data-driven limit assessment within existing frameworks **In the future** alternatives to the deterministic N-1 criterion

Technical capability runs ahead of deployment: only a fraction of the toolkit's proven capacity, documented in Chapter 2, is used today. The central challenge is moving solutions already proven at individual sites into routine grid planning and operation everywhere else.

Unlocking the potential of the digital grid toolkit rests on four critical enablers

The barriers to scaling the digital grid toolkit are largely structural rather than technical. Four themes emerge consistently across the evidence reviewed for this report, which determine whether the potential just estimated is actually captured: regulatory frameworks, data foundations, skills and organisational readiness, and trust, accountability and security. In its interim report, the United Kingdom's AI Champion for clean energy reached the same conclusion. These findings are reinforced by the IEA survey conducted for this report, in which network operators most frequently identified skills and organisational readiness (64% of respondents), data foundations and trust-related issues (both 60%), and regulatory frameworks (56%) as major barriers to deployment.

Enabler 1: Regulatory frameworks

Regulatory frameworks emerged as a recurring concern among surveyed network operators, with more than half identifying them as a significant barrier to wider deployment. The challenge is the difficulty of valuing and remunerating operational, software and data-driven solutions within frameworks historically designed around physical asset investment.

Transmission and distribution networks are natural monopolies, and their development is shaped in large part by the regulatory and policy framework within which they operate. Regulatory frameworks determine what operators invest in, how they recover their costs, and the balance between better use of existing assets and building new infrastructure. Even when digital solutions create substantial system-wide value, they are unlikely to scale beyond demonstration projects unless that value can be recognised and rewarded within the regulatory model.

Key regulatory frictions between how digital tools create value and how regulator frameworks recognise them

1 Capital expenditure bias

Regulated returns often attach more directly to physical assets, while digital and operational solutions may sit outside the spending categories that earn a return

2 Mismatch between risk and reward

Operators bear deployment and performance risks, but capture only part of the system-wide benefit, weakening the incentive to act

3 Measurement gap

Many benefits are preventive: reliability metrics record failures that occurred, while congestion, outages or instability that were avoided may remain invisible

4 Evidence-before-approval barrier

Approval rules may require proven benefits before a tool enters routine operation, yet that evidence can often only be built through staged, real-world deployment

Four frictions often recur between how digital tools create value and how regulatory frameworks recognise them. These frictions are especially acute in distribution. Many of the investments needed to modernise distribution networks, from data and communications technologies through to the automation and co-ordination tools described in Chapter 2, are software-heavy, data-intensive or operational in nature. If these are treated as discretionary IT or short-lived operating costs – rather than being eligible for capitalisation, recognised in network development plans and assessed as alternatives to physical reinforcement – DSOs will struggle to scale up the visibility and controllability they need for active distribution management.

This section sets out where the mismatch creates barriers, the mechanisms that can realign incentives, and the valuation and assessment practices on which many of them depend. Approaches differ widely across systems, and the examples below are illustrative of both advanced and emerging economies alike.

Main regulatory framework models and their implications for the digital grid toolkit

Regulatory framework model	Incentive implications for the digital grid toolkit	Examples
Cost-of-service/cost-plus The operator recovers its actual costs and earns a rate of return on the expenses included in the regulated asset base. Other eligible costs are passed through to consumers but do not generate profits.	**Weak incentives for efficient decision considering all existing alternatives** Software and service costs are by default excluded from the regulated asset base. They can be passed through to consumers and recovered, but without a profit, so are less attractive than building new assets, even when cheaper.	Several US states, Croatia, Ukraine
Price cap A maximum yearly price for the use of the network is set for each operator, for a period of several years ahead. Revenue therefore rises with throughput.	**Moderate in the period** As the operator keeps savings, it rewards any cheaper option, including digital ones. But because revenue follows volume, solutions that reduce throughput work against the operator's interest.	Netherlands
Revenue cap Maximum yearly revenues for each network operator are set for a period of several years ahead. Contrary to a price cap, revenue is in principle independent of volume delivered.	**Removes the volume disincentive of a price cap** Decoupling revenue from throughput removes the disincentive to reduce volumes observed in a price cap.	France, Germany, Norway, Sweden, Great Britain

Frameworks built for capital investment hold back better use of existing assets

The remuneration scheme a regulator adopts strongly shapes whether operators favour building new assets or making better use of existing ones, alongside the scope allowed by planning and approval processes and the operator's own capability to optimise the network. The two most common schemes pull in different directions.

Under **cost-of-service** (or cost-plus) models, the operator typically earns a return only on the capital added to the regulated asset base (RAB). Other costs, including software and digital services, are passed through to consumers but earn no margin. As a result, building new physical assets is often more rewarding to the network operator than a cheaper digital alternative.

Price- and revenue-cap schemes attempt to correct this. Under these schemes, the network operator keeps a share of cost savings made within a given regulatory period. This rewards the use of cost-efficient solutions. However, in absence of performance or output measures, improvements in service quality and innovation that benefit customers or the wider system rather than reducing the operator's own costs go unrewarded.

CAPEX bias and the treatment of digital expenditure

A CAPEX bias can occur when CAPEX and operational expenditure (OPEX) are remunerated differently through the regulatory framework of network operators. In such frameworks, CAPEX is typically added to the RAB, on which the operator can earn a profit margin. By contrast, OPEX costs are often recovered in the period in which they are incurred but earn no additional return. Where CAPEX and OPEX are remunerated differently, an operator that could lower total expenditure through OPEX solutions may still find the physical asset build-out the more rewarding regulatory choice.

This bias is particularly relevant for digital tools. Indeed, digital tools such as cloud software, AI models and communication platforms are more often treated as OPEX, particularly when they are procured as a service, such as cloud computing, software subscriptions and access to AI models, rather than owned outright.

In addition, differences in asset lifetimes can also affect the choice of CAPEX- or OPEX-based solutions, even in absence of remuneration treatment. Digital equipment can become obsolete within four to six years as technology progresses, especially for frontier AI, whereas frameworks are calibrated to physical assets with design lives of several decades, such as 50 to 80 years for high-voltage overhead lines and 40 to 60 years for transformers, as presented in Chapter 2. Long asset lifetime in the RAB ensures a long-term revenue stream to network operators, while shorter term solutions bear greater risk.

Assessing traditional network solutions against all alternatives

As a safeguard against CAPEX bias in network investment decisions, several systems embed an assessment of non-wire options before new physical infrastructure is approved. The emerging regulatory practice is to mandate operators to conduct a cost-benefit analysis of non-wire solutions as an alternative to new build with incentives to support efficient infrastructure deployment.

Through the Distributed Resource Plan and Integrated Distributed Energy Resources proceedings, launched by the California Public Utilities Commission, the state requires utilities to assess and report on non-wire alternatives so that distributed energy resources can be competitively procured in place of upgrades. A number of US states use the National Standard Practice Manual (NSPM) to apply cost-benefit methods consistently, with Colorado weighing non-wire options in distribution planning and Hawaii modelling avoided costs.

Great Britain applies a standardised cost-benefit analysis framework called the Network Options Assessment, which compares forecast capital costs against monetised benefits in future energy scenarios and identifies the combination of options delivering the most value to consumers. In the United States, FERC Order No. 1920 makes the comparison itself mandatory, requiring transmission providers to evaluate dynamic line ratings and advanced power-flow control in their planning, and to explain how they do so.

Obligations to consider non-wire solutions

Going beyond options assessments, some regulatory frameworks are starting to embed direct obligations to deploy mature non-wire solutions. For instance, in the United States, FERC Order No. 881 requires deployment of ambient-adjusted ratings and corresponding hourly adjusted transmission capacities.

In Germany, the NOVA principle goes one step further, requiring network planners to prioritise optimisation before reinforcement and expansion. This obligation stems from a working assumption that optimisation solutions are cheaper and faster to deploy than grid reinforcement and expansion.

Performance-based regulation and benefit-sharing can realign incentives

Addressing the CAPEX bias places digital and innovative solutions on a more equal footing with conventional network reinforcement. Neutral cost treatment alone does not, however, secure an efficient choice. The operator carries the delivery risk of a contracted or digital solution, while much of the resulting value, whether deferred investment, lower bills or additional system flexibility, accrues to consumers and other market participants. Regulators have therefore layered complementary instruments onto the underlying revenue framework, including output-based performance incentives and shared-savings arrangements that allow the operator to retain part of the value it delivers. The Netherlands offers one example: redispatch and congestion-management costs of the TSO TenneT are benchmarked against efficient allowances, so costs above the benchmark are not automatically passed through to tariffs. This exposes the TSO to part of the cost of inefficient congestion management and incentivises lower-cost operational solutions.

The table below summarises how selected regulatory mechanisms influence grid operator behaviours towards innovation, enabling better use of existing assets.

Selected regulatory mechanisms and their implications for the digital grid toolkit

Regulatory mechanism	Incentive implications for the digital grid toolkit	Examples
Benchmarking or yardstick regulation Allowed costs are set by reference to the performance of comparable operators rather than to the operator's own costs.	**Pulls the lagging utilities up towards peers** Where peers deploying non-wire solutions set the benchmark, others have an incentive to follow.	Germany, Netherlands, Norway
TOTEX (total expenditure) Capital and operating expenditure are treated as a single envelope, with a fixed share capitalised whichever way it is spent.	**Strong on cost neutrality** Spending on digital tools or operational expenditure is assessed on the same basis as capital, so all solutions compete on cost rather than on accounting category.	Italy, Germany, Norway, Sweden, Great Britain
Output or performance-based mechanisms Part of allowed revenue is tied to delivered outcomes (such as system performance) rather than to expenditure.	**Values benefits delivered** Rewards what the solution delivers rather than what it costs. This requires careful calibration of the baseline and incentives of the mechanism.	Hawaii, Great Britain
Benefit sharing The operator retains a share of the assessed net benefit delivered, such as avoided reinforcement, paid over a defined number of years.	**Extends the reach of the incentive** Digital solutions deliver value that does not always appear as the operator's own saving. Benefit sharing rewards it, but depends on a counterfactual the operator largely supplies.	Italy, Slovenia

Note: A regulatory framework can combine more than one mechanism to achieve its goals.

Misalignment between risk and reward for network operators

In unbundled systems much of the system-wide value that digital tools create, such as reduced congestion, avoided renewables curtailment and lower balancing costs, accrues mainly to generators and consumers rather than to the operator that deploys the tools. Through simple cost-of-service or revenue-cap models, the operator may capture little of the value it creates, which leads to weak incentives to invest adequately.

This issue is particularly acute for digital tools, or innovative solutions more generally. The operator funds the deployment upfront and carries the technology and performance risk, recovering the cost only through subsequent allowances, while a digital technology that substitutes for new build also forgoes the return the avoided asset would have earned. The investment case therefore does not provide the same financial incentives as the conventional alternative.

A misalignment between risk and reward can also occur due to inflexibilities in multi-year regulatory periods. Price and revenue caps are calibrated against the baseline outputs defined at the start of the regulatory period, so where a new obligation is imposed mid-period, for instance a mandated smart-meter rollout whose benefits accrue mainly to others, the allowance does not automatically follow it, and the operator may carry the new cost until allowances are next reset, unless the framework provides a within-period mechanism.

AI tools add their own version of the problem. AI models need regular updating to counter drift, yet frameworks that fix operating budgets for several years at a time leave little room for that adaptation. Multi-year control periods give operators a stable, predictable basis to plan and invest, but often lack adjustment mechanisms within it.

TOTEX mechanism

A total expenditure (TOTEX) approach aims to overcome the CAPEX bias by treating capital and operating spend as a single envelope, so an operator can choose the digital or physical option on its merits and, in a price- or revenue-cap framework, keep a share of any efficiency gain.

Great Britain was among the first to adopt a full TOTEX scheme for electricity, under Ofgem's RIIO model (see box), and it remains the most developed example. The use of TOTEX regulation is not universal, however. In Europe, ACER notes that 17 of 28 countries surveyed still have no mechanism in revenue setting to remove or reduce CAPEX bias for distribution networks.

The successful implementation of TOTEX is not straightforward. Setting the revenue allowance for several years ahead requires robust cost assessments for regulators, since they hold less information than the operators they assess. This is particularly challenging for digital tools and innovative solutions, as a TOTEX regulatory framework requires regulators to assess the potential efficiency gains from optimising across CAPEX and OPEX to set the revenue allowance.

Simpler measures also exist as an alternative to a full transition to TOTEX. A ring-fenced digital cost item within the revenue cap can protect qualifying investments, such as the regulatory proposal for Spain's 2026-2030 period. OPEX capitalisation can place a defined share of operating or innovation costs into the asset base to earn a regulated return, as applied to research and pilot costs in Italy and the United Kingdom. Another option is explicit cost-recovery treatment for software, cloud services, licences, model maintenance, data cleansing and cybersecurity, so that digital and AI tools are not disadvantaged simply because they are procured as services or require recurring expenditure. The key principle is regulatory neutrality when a digital or operational measure delivers the same network output more efficiently than conventional reinforcement.

Performance-based regulation

Performance-based, or output-based, regulation help address the risk and reward mismatch. Under these mechanisms, part of the revenue earned by network operators is tied to delivered outcomes rather than to expenditure. As a result, system benefits such as quality of service, reduced losses, customer satisfaction and innovation to accelerate electrification of end uses can be rewarded alongside cost control. Operators that meet their outputs for less than the attached rewards increase their return, which creates a direct reward for efficient and innovative choices.

Ofgem's experience with the RIIO framework

RIIO, short for revenue = incentives + innovation + output incentives, combines a TOTEX approach with output-based incentives for reliability, customer satisfaction and network efficiency. It has been applied to the electricity transmission system (RIIO-ET) in Great Britain since 2013 and the electricity distribution system (RIIO-ED) since 2015.

During the first transmission period (RIIO-ET1, 2013-2021), transmission owners earned GBP 180 million in cumulative incentive payments. Total expenditure came in below the adjusted allowance across all three owners, and Ofgem calculated returns on regulated equity at between 9.4% and 11.3%, against an allowed cost of equity of 6% to 7%.

During the first electricity distribution period (RIIO-ED1, 2015-2023), Ofgem reduced distribution operators' proposed spending by GBP 1.43 billion through benchmarking of costs, and operators identified a further GBP 700 million in savings themselves, including through the deployment of smart grids. Service quality improved over the same period: customer interruptions fell by 20% and their average duration of interruptions by 13%.

Across much of the first RIIO, operators consistently outperformed their targets and earned returns well above the baseline. This was not a flaw in TOTEX itself (letting operators keep genuine savings within a period is a deliberate feature of TOTEX, meant to reveal efficient costs), but the result of specific design choices, allowances and performance targets that, in hindsight, proved easier to outperform than expected.

Ofgem responded for the second period by lowering the baseline return, setting more ambitious output targets, capping total returns and shortening the control period from eight years to five. Enhancements in RIIO-ED2 (2023-2028) include a wider range of rewards and penalties, and a mechanism protecting both consumers and operators against large deviations from the performance expected at the outset.

Benefit-sharing mechanisms

Some countries incentivise cost savings from digital tools or innovative solutions through benefit-sharing mechanisms. Under price- and revenue-cap regulation an operator can retain part of the efficiency savings it achieves against its initial allowed revenue across a regulatory period. Benefit-sharing mechanisms go further, allowing network operators to retain a share of the net benefits of choosing a cheaper solution than a defined traditional solution counterfactual.

For instance, in Italy, realised investment outcomes are benchmarked against a reference conventional solution to test whether the same functional benefit could be delivered more efficiently. The TSO earns a premium for meeting its capacity targets, and a second premium for meeting them below the reference costs the regulator has set. Since 2020 this approach has delivered around ten capital-light projects, unlocking over 3 GW of cross-zonal capacity. One such project involving dynamic line rating and digital upgrades to defence systems raised cross-zonal capacity by 1 450 MW and earned Terna, the Italian TSO, a premium of around EUR 143 million against estimated system savings above EUR 1 billion.

Slovenia has recently introduced a comparable mechanism: the net benefit of choosing an advanced grid solution over the conventional one is split between consumers and the operator at a nationally set ratio, measured against the cost difference between the two options, so that the more efficient the choice, the greater the operator's reward.

Two design questions become decisive for any such scheme. The first is how the counterfactual baseline is set, since the reward depends entirely on what the alternative is assumed to have cost. The second is how the sharing ratio is struck: a larger share for the operator strengthens the incentive to adopt the efficient solution but leaves a smaller, less immediately visible saving for consumers, so regulators need to balance driving adoption against maximising the near-term consumer benefit. Incentives of this kind also need care where value is not immediate: investment made ahead of demand, or for resilience, may reduce measured utilisation in the short term, but can still lower long-run consumer costs and reliability risks by avoiding emergency reinforcement, curtailment or outage impacts.

Robust valuation of benefits help build the regulatory case

Addressing the risk-reward mismatch discussed above requires regulatory frameworks that reward the outcomes digital solutions deliver. Yet such mechanisms depend on the ability to quantify those outcomes. The challenge is that many of the applications of the digital grid toolkit remain only partially visible through existing regulatory metrics.

Issues with existing metrics

Incentives need measurable outcomes, but the reliability indices most widely used on the grid do not fully capture the full value of digital tools. The applications whose benefits are captured by existing metrics are precisely the ones already scaling. Meanwhile, the applications with the largest system value are often the ones the measurement framework cannot see at all. Where the digital grid toolkit shortens or prevents an interruption, its benefit registers directly in the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) or energy not served, giving the operator a clear, verifiable business case.

However, the metrics do not yet measure other benefits that the digital grid toolkit can actually deliver, such as curtailment avoided, congestion relieved before it ever causes an outage, or capacity utilisation improved without any interruption occurring at all. None of this shows up in traditional reliability indices because nothing was interrupted, so operators struggle to build a credible business case and regulators struggle to verify one.

AI raises a further, more specific difficulty. Its behaviour can be probabilistic, in that identical inputs do not always produce identical outputs, and where models are retrained their performance shifts over time. This makes it harder to isolate the counterfactual – what would have happened without the tool – since the tool itself is not a fixed reference point the way a piece of conventional equipment is.

Standardised metrics and credible baselines

Monitoring the benefit of better grid use means shifting from input metrics towards output indicators, judged against a credible counterfactual (a simulated reference case of conventional operation or investment) so that gains can be attributed to the digital toolkit rather than to other factors. ACER, the EU Agency for the Cooperation of Energy Regulators, has proposed a small set of output indicators for transmission grids that compares available capacity, the cost of remedial action and total investment cost against standardised conventional baselines. The current emphasis is on agreeing what to measure and against which baseline to build the evidence that performance-based regulation will eventually require.

Regulatory mechanisms can also support earlier-stage innovation

Effective regulatory frameworks need to support innovation across its full lifecycle. Incentive mechanisms can encourage deployment once value is proven, but earlier-stage technologies can also face funding, regulatory and operational barriers that prevent them from progressing beyond pilots. Specific mechanisms in the regulatory frameworks can help bridge this gap.

Innovation funding in regulatory frameworks

At the discovery and pilot stages, operators whose incentives are built around controlling costs and maintaining reliability have weak incentives to carry the risk of unproven solutions. Explicit innovation funding helps address this gap. For instance, Ofgem's Network Innovation Allowance provides ring-fenced funding for small-scale projects, and operators can also compete for a separate, larger innovation fund, which de-risks innovation and supports a culture of experimentation that short-term cost pressure would otherwise discourage. Combined with appropriate incentives to roll out efficient solutions in regulatory frameworks, innovation support is more likely to sustain innovation across its full cycle, from early risk-taking through to mature, rewarded deployment.

Regulatory sandboxes and structured experimentation

Regulatory sandboxes can help unlock the deployment of digital tools where existing rules and regulations are a barrier. Sandboxes give operators a safe space to test a tool, service or business model with real customers for a limited time, under temporary exemption from rules that might otherwise block it. This allows operators and the regulator to learn before any permanent regulatory change occurs. For instance, Ofgem's Innovation Link supports trials of new products, and Germany's SINTEG programme offered an experimentation clause to test new market designs. Sandboxes are also being formalised at the European level specifically for AI under the EU AI Act, requesting member states to set up at least one AI regulatory sandbox to support evidence-based regulatory learning.

Experience with sandboxes emphasises the need for careful design. Early results from programmes such as SINTEG were judged disappointing, and the Netherlands, an early mover, has since closed its sandbox programme. Sandbox design features include who administers the scheme, which derogations are allowed, how operators apply and, crucially, how lessons are reported back. The recurring weakness is the latter. Feeding positive experimentation results into the standard framework can face barriers because responsibility for experimentation and implementation may sit across different parts of the regulator. This leads to promising trials failing to scale to the point where they would reach consumers.

Where performance or innovation incentives exist, they may be too weak or even pull in the wrong direction. In many jurisdictions, innovation costs are typically only passed through, with no reward attached to what they deliver, leaving the incentive signal far weaker than guaranteed returns on capital. More targeted instruments are emerging to close that gap. Proposals developed for German transmission operators include an experimentation budget to compensate third parties for taking part in a trial, a regulatory innovation trial that tests changes to the rules themselves before they are written into law, and a pioneer bonus that lets several operators co-fund one that runs an innovation on their behalf. A shared feature is that they can operate across operators, which opens the door to cross-border collaboration.

Enabler 2: Data foundations

Data foundations were identified by 60% of surveyed operators as a major barrier to scaling digital solutions. This reflects a common challenge across both transmission and distribution systems: data are increasingly available, but often remain fragmented across platforms, incomplete, inconsistent or difficult to access in operational workflows.

Data are fundamental to making better use of the grid, and need to be gathered in the first place, be of high quality and be accessible to those who need them. This applies to the entire digital toolkit, but the constraint is particularly acute for AI, the most data-hungry of these tools. Across electricity networks, datasets remain uneven, fragmented and hard to share, and these gaps are worst at the distribution level, precisely where demand and distributed resources are growing fastest.

Data quality and availability are a binding precondition and both are the weakest in distribution

Transmission networks are generally well instrumented, but many distribution operators still lack observability over large parts of their network (see Chapter 2). This observability gap is the greatest data obstacle to AI delivering value at the distribution level, where demand is growing fastest. Low-voltage grids are the least visible of all. Distributed resources such as rooftop solar, EVs and heat pumps often behave as "black boxes", creating blind spots during disturbances and weakening load forecasts, while actual consumption from large new loads such as data centres is not always known. More data are not the sole answer: small, physics-informed models are easier to understand and validate than large, generic AI models, and need less data to deliver improved visibility.

The biggest data gap, therefore, sits in distribution. What is needed is granular, feeder-level visibility. Without trusted feeder, transformer, smart-meter and distributed energy resource data, AI cannot support hosting-capacity analysis, flexible connections, voltage management or local congestion management. Distribution-level data foundations need to be built as an operational asset. This means accurate, up-to-date network and asset data and models, from topology and meter readings to registers of distributed energy resources; secure interfaces with aggregators and flexibility providers; and clear governance covering data ownership, access, quality and responsibility.

Operators may be rich in data but poor in insights as data quality can be insufficient. During a pilot project to evaluate AI-based forecasting, Chile's national system operator (CEN) identified data quality as the main implementation challenge: approximately 30-50% of data incoming from renewable power plants required validation or correction before model training, extending project timelines and resource needs. Such upstream data quality problems are widespread in data science, where practitioners commonly spend around 80% of their time finding and cleaning data rather than analysing it, a figure echoed by distribution operators that described dedicating teams to several months of data cleaning before a single project could begin.

Open data for third-party innovation is scarce: only around a tenth of the world's electricity is covered by open-data policies, limiting the data available to train and validate independent tools. New sensing and digital infrastructure can narrow this gap, but only if paired with the governance to make the data usable. The United Kingdom's Data Sharing Infrastructure initiative is one example, providing the secure, standardised connections that allow data to be discovered and shared across the sector.

Fragmentation and weak interoperability deny AI the system-wide view it needs

Even where data exist, they are dispersed across legacy systems and organisational silos, so operators hold large volumes of data yet struggle to align, link and standardise it. These silos persist even within a single vertically integrated utility, with reported barriers to exchanging data between the transmission and distribution divisions of the same company. The TSO-DSO interface is a recurring weak point, and it matters more as new actors such as aggregators come to need access to distribution-connected assets.

The IEA survey conducted for this report shows why stronger TSO-DSO data sharing is becoming urgent. Among surveyed operators, distribution networks remain much less visible and controllable than transmission networks: 60% of DSOs report having no controllability over at least half of their networks, and low-voltage grids are the least digitalised. Yet distributed energy resources such as EVs, heat pumps and flexible demand are making distribution conditions increasingly relevant for system-wide operation. TSOs need more granular distribution data to forecast flows and manage security, while DSOs need better information on transmission constraints and market signals to manage local flexibility and connections. Without common data models, interoperable platforms and clear governance for operational data exchange, AI tools will struggle to provide the system-wide view needed to optimise the grid safely.

Some operators are beginning to overcome this fragmentation by consolidating data at scale. China's State Grid has built its Guangming model (see Chapter 2) on a unified data foundation spanning planning, operation and maintenance, integrating large volumes of previously siloed data across its vast network – the kind of system-wide view that AI needs but most operators lack. Elsewhere, where no single operator holds enough data, the route is federated rather than centralised. Shared environments such as the European AI.grids initiative pool heterogeneous data, from time-series measurements and network topology to market signals, weather forecasts and operational reports, from across many operators to assemble a comparable foundation without consolidating it in one place. The challenge here is not only the number of operators involved, but the heterogeneity of their data.

Semantics and interoperability are greater constraints than the volume of data. Underlying this is the absence of common data models: inconsistent formats, protocols, labels and timestamps, often proprietary to individual vendors, make integration costly and slow. Utilities struggle to reconcile inconsistent asset definitions and formats across departments and tools, which is more difficult to resolve than simply collecting more data. Efforts to develop common standards and interfaces are multiplying, although the critical industry need is less for heavier top-down standardisation than for practical, open and interoperable interfaces: machine-readable registries paired with documented, vendor-neutral application programming interfaces (APIs) that let operators combine and swap tools without being locked into one vendor. The TROLIE specification is one example: an open standard developed under Linux Foundation Energy for exchanging transmission line rating data. It was created to meet the United States' FERC Order No. 881, which requires transmission providers to use ambient-data ratings instead of static seasonal ratings. The legacy point-to-point approach proved unable to carry the required data volumes, since an hourly 240-hour forecast for every line would otherwise demand hundreds of SCADA points per circuit. Vendors are responding with similar “data hubs” and orchestration architectures that connect existing systems around a common meta-model, without replacing or updating legacy tools.

Sharing data for AI means managing security, sovereignty and privacy, not avoiding them

Many AI applications need timely, granular information on network status, yet access is constrained by cybersecurity, commercial and national security considerations. Operators face strict obligations on the security of operational technology, which can directly limit the data sharing that real-time AI would require. In some jurisdictions, legal rules prevent operators from releasing data even when they are willing to. For consumer data, the trend is to consider the consumer as the data owner and to require its consent for data to be used. Data sovereignty requirements and privacy rules add further constraints across borders, and these are especially acute in distribution, which sits closest to consumers. The same considerations can also require systems to be kept on-premises rather than in the cloud, as under some critical-infrastructure security standards. This adds cost and can cap the size of models an operator is able to run. These are tensions to be managed, not ignored.

Trusted environments offer a way to keep sharing data while managing these risks. Anonymisation, synthetic data and federated approaches, which train models without moving raw data, let an operator contribute without exposing itself to commercial or security risk. Such environments can also work with imperfect data while gradually improving their quality, turning data sharing from an all-or-nothing decision into a graduated one. These approaches have their own limitations: synthetic data can fill gaps or protect sensitive information, but models trained on it may be misleading if the generated data do not reproduce the physical behaviour of real networks. Federated learning avoids moving raw data, but participants' datasets often differ in structure, quality, time resolution and network representation, making the shared model harder to train, validate and transfer. It also requires repeated exchanges of model updates, adding operational complexity and cybersecurity requirements even when raw data are not shared.

Shared infrastructure, benchmarks and governance can lower costs and spread learning

Power systems still lack standardised benchmarks against which AI tools can be objectively validated before deployment. As a result, each operator often has to re-validate new tools against its own legacy models, existing tools, historical cases and engineering judgement before they can be trusted. Real-world performance can diverge from vendor claims and pilot results, which points to a broader need for shared, collectively built performance data rather than each operator generating its own. Sharing failure data, too, such as faults, near-misses and extreme-weather and cyber events, is especially valuable for training robust models, yet such data are rare and seldom pooled, so collective learning suffers.

Governance frameworks that enable trusted sharing are emerging but are not yet standard, although they are beginning to shift from voluntary codes towards mandated frameworks. The Common European Energy Data Space and federated initiatives such as the European AI.grids effort point the way, as does the United Kingdom's Data Sharing Infrastructure, which builds the common connections that allow data to be discovered and shared across operators. Underlying all of this is clarity on data ownership and access terms, without which sharing stalls.

Fragmentation across many operators raises the fixed cost of digital infrastructure and slows the spread of learning, making a strong case for shared platforms and cost-sharing. A shared testing framework, built around common baseline scenarios and metrics with utilities involved from the outset, could let this benchmarking happen collectively rather than operator by operator. The point is sharpest for grid foundation models (see box in Chapter 2): no single operator holds sufficient high-quality interoperable data to train them alone, which is why the leading initiatives are collaborative by design.

Enabler 3: Skills and organisational readiness

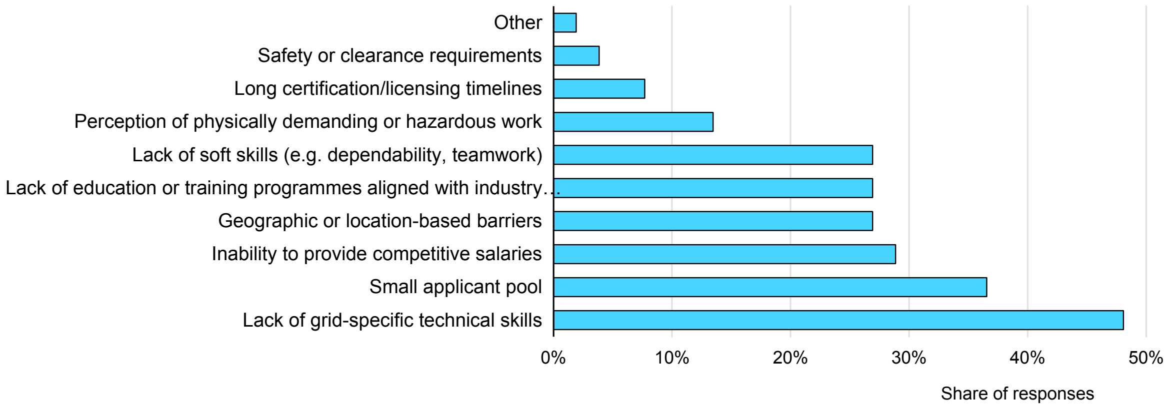
Skills and organisational readiness were the most frequently cited barrier in the survey, identified by 64% of respondents. While many of the technologies discussed in this report are commercially available, deploying them at scale requires new capabilities that combine power-system expertise, data science, software engineering and change management, skills that remain scarce across much of the sector.

Staff who bridge power systems and data science are a scarce resource

Building the workforce is as decisive as the technology itself, as network operators face a chronic shortage of professionals who combine power system expertise with data science skills. Power grids already employ around 8.5 million people globally, a figure rising with record grid investment (USD 450 billion in 2025), and the availability of adequately trained personnel is becoming a limiting factor in both delivering infrastructure on time and integrating new technologies. The constraint is most acute for the rare professionals who combine power system expertise with data science, and it is compounded by an ageing workforce: the IEA's World Energy Employment report finds that, globally between 2015 and 2024, the fastest-growing age groups in the grid workforce were the older age groups: the workforce aged 55 and over grew by nearly 50%, while the workforce aged under 55 only grew by 20%.

Network operators struggle to hire, held back by a lack of grid-specific technical skills and a limited pool of qualified applicants. The IEA's 2025 Industry Employment Survey found that over 40% of surveyed grid companies report "high" or "very high" competition for skilled staff, regularly losing candidates to other employers. The most cited recruitment barriers are a lack of grid-specific technical skills (48%), too small an applicant pool (37%) and an inability to offer competitive salaries (28%), and half of respondents (51%) have already had to lower or adjust hiring requirements because of shortages. The problem is not only attracting data scientists, but also finding people who understand the grid, too. Part of the difficulty is self-inflicted: utilities have been slower than other sectors to seek digital talent at all. IEA labour market analysis shows that digital roles represented only around 11% of utility job postings, well below finance (approaching 16%), and demand for the newest skills, in AI and machine learning, remains very low even where firms have invested in digital equipment. Hiring intensity varies sharply between countries, suggesting the gap reflects strategy as much as scarcity.

Barriers to hiring or retaining qualified AI and digital talent among grid operators, 2025



Source: IEA (2025), Industry Employment Survey.

Training across field, control room and planning

AI and digital tools can scale only as fast as an organisation is ready to use them responsibly, which makes workforce readiness as much a constraint on deployment as data availability or regulation. The sector's needs span the whole workforce, not just specialist hires for digital tasks. Field crews need to install and maintain new equipment, control-room operators need to interpret and challenge AI outputs, and planners need to weigh options such as GETs that are not yet routine in interconnection studies. Some operators are building this capability through dedicated training academies, university partnerships and "AI ambassador" schemes that spread practical AI literacy across operational teams rather than concentrating it in a single specialist unit. However, public-sector and smaller operators often lack the capacity to train at all, making targeted capability-building and pooled programmes especially important.

DSOs need a distinctive capability model. Compared with TSOs, they operate at far greater scale, with more assets, more distributed assets, more customer interfaces and more smart meter devices. This raises the need for DSO data-engineering teams, field crews trained to install and maintain sensors and communications and automated equipment, planners able to use hosting-capacity and flexibility tools, control-room staff able to operate advanced distribution management system (ADMS) and distributed energy resource management system (DERMS) platforms, and cybersecurity specialists focused on operational technology across thousands or millions of devices.

Institutional capacity matters beyond utilities, too: regulators need to understand how these technologies create value in order to assess them with confidence. China offers a contrasting example of co-ordinated workforce development, with the state, utilities, industry and academia aligned through sector-specific AI programmes, university partnerships and training pipelines that link business needs to deployment. This does not remove the need for validation, explainability and operator trust, but it shows how skills can be built deliberately across the sector rather than left to individual utilities.

Organisational processes must adapt to capture AI’s full value

Even where regulation does not stand in the way, the organisational processes built around traditional grid planning and operation can default to conventional grid expansion, leaving GETs and AI tools underused or assessed too narrowly. The main challenge is not only to procure new tools, but to absorb them into the way planners and operators actually work.

Most AI uses in grids today still focus on automating existing tasks: improving a forecast, detecting an anomaly, identifying vegetation near a line or accelerating a connection study. Larger gains are possible when operators redesign processes around what AI can do. In connection queues, for example, AI can do more than speed up individual studies: it can screen applications, group projects that create similar constraints, fast-track low-impact connections and identify where flexible or non-firm offers may avoid reinforcement. In asset management, predictive models create value only if they change inspection schedules, spare-parts planning, crew allocation and replacement priorities. In vegetation management, image recognition matters most when it enables a shift from fixed-cycle cutting to risk-based intervention. Many deployments simply substitute AI in place of conventional algorithms without rethinking the workflow, capturing only a fraction of the available value.

The redesign of business processes is a cultural shift, and operators are finding it has to be managed actively. Elia Group (Belgium and Germany), for example, established its AI centre of excellence in 2018, and has recently paired it with a central "AI enablement and governance" function tasked with building staff capability while ensuring compliance, addressing what it describes as the challenge of enabling and complying at the same time through a risk-based approach to every use case. Embedding change agents or "AI ambassadors" within operational teams, as done in several European TSOs, allows trust in new tools to be earned incrementally, spreading through peers who understand both the technology and the control room.

Enabler 4: Trust, accountability and security

Trust, accountability and security concerns were identified by 60% of respondents, placing them alongside data foundations as one of the most significant barriers to deployment. These concerns become more acute as solutions move closer to operational decision making and real-time control, where explainability, governance and cybersecurity become prerequisites for adoption.

Realising the digital grid toolkit's potential for system efficiency, resilience and consumer outcomes, set out earlier in this report, is not unconditional. It depends on network operators being able to rely on, explain and defend the tools they adopt, with security that is designed in from the outset rather than retrofitted, as connectivity broadens the grid's attack surface.

AI adds further, more specific conditions. Because its outputs are harder to interpret and audit than those of conventional tools, accountability for an AI-assisted decision, and protection for the consumers ultimately affected by it, must remain clear when something goes wrong. Ethical AI in grids is not only a matter of regulatory compliance: it requires judgement about whether AI-assisted decisions are safe, fair, transparent, robust and accountable, including who benefits from them and who bears the risks when they fail. Because its behaviour is probabilistic and can drift over time in a way physical equipment does not, human oversight, validation and certification need to keep pace with the tool rather than be fixed once at approval. And because AI is increasingly supplied and hosted by vendors, and in some cases governments, outside an operator's own jurisdiction, the ability to maintain genuine control over the tool becomes a prerequisite for its safe use – a concern that digitalisation raises too, but which AI sharpens further given how central it is becoming to critical decisions.

For safety-critical applications such as control-room decision support, the bar is higher as they may carry direct consequences for system reliability and safety. AI enhancements are the most difficult to validate from a security and accountability perspective because AI's outputs are the least transparent. Answers to these questions remain in their infancy, but are gaining increased attention: assurance, oversight, security design and sovereignty-conscious choices can help operators and regulators earn a place for AI in their toolbox.

Explainability and accountability constrain AI use in critical operations

Investment in explainability, uncertainty quantification and audit trails is more likely to unlock wider adoption of AI for real-time applications than further gains in raw model performance alone. Operators have already adopted AI for tasks that do not bear directly on real-time control. According to the survey in the IEA's 2025 report Energy and AI, 54% of surveyed operators use AI for long-term planning and 70% for maintenance, but only 23% use it in real-time operations, reflecting a cautious culture that places system reliability and human safety above all else. The barrier is rarely the model's accuracy; it is trust and auditability – whether an operator can understand why a tool produced a given output (explainability) and verify that reasoning after the fact (auditability).

Accountability for AI-assisted decisions rests primarily with the human operators, utilities and regulators overseeing them.[11] Most current frameworks require a written, auditable justification for operational decisions that today's models cannot reliably produce on their own. The EU AI Act reinforces this by classifying grid monitoring and operation as "high risk", mandating transparency, technical documentation and rigorous risk management. To trace decisions back to their origin, operators increasingly look to audit trails that log data sources, model versions, decision logic and human interventions. Jurisdictions are beginning to codify sector-specific rules, such as Ofgem's guidance on ethical AI use in the United Kingdom or China's "6541" framework that includes the electricity sector's first dedicated Power AI Ethics Guide.

The concern is sharpened by how AI can fail. Large language models can "hallucinate", producing plausible-sounding but false outputs with no signal to the user that anything is wrong; more broadly, any model, including forecasting tools that are not language models, can produce a confidently wrong output outside the conditions it was trained on. In the electricity system, where a single fault can cascade into further disturbances and reactions elsewhere, an initially small model error can compound into consequences well beyond the point where it first occurred. Models may also disregard the physical laws operators must respect. This is why explainable and physics-informed models, whose outputs an engineer can check against the underlying assumptions (such as grid foundation models), are widely seen as the precondition for trusting AI in critical roles.

[11] Responsibility can be shared with vendors or platform providers depending on the regulatory regime and how a failure occurred.

Trust is built incrementally, through human oversight, validation and certification

In the near term, trust is preserved by keeping the human at the centre of decision chains, with AI augmenting rather than replacing operator judgement. The IEA survey of grid operators conducted for this report found a near-unanimous preference for keeping humans firmly in the loop, treating AI as decision support rather than an autonomous agent. Where operators look further ahead, they foresee the same workforce pressures discussed in this chapter's skills section, not a preference for automation over people: as demand for skilled engineers grows faster than utilities can hire, some operators expect more autonomous agentic tools to become a necessary complement to a workforce that cannot scale as fast as the tasks in front of it, rather than a substitute for it. Frameworks that distinguish between degrees of human oversight – informing, supervising, or fully automating a decision – help here because they let regulators govern the function and the level of autonomy rather than prescribe a particular technology, as in Ofgem's guidance on the ethical use of AI. This keeps the accountable human in place while the technology matures.

Beyond oversight, the tools for assurance are largely missing: standardised safety-validation and certification frameworks for AI in critical operations barely exist, and their absence holds adoption back. Network operators are unlikely to assume a vendor-supplied AI component is safe simply because it was successfully deployed elsewhere; often they are constrained to selecting from certified lists of suppliers and products co-ordinated at the national level or through network operator associations. Because AI can be probabilistic, as noted above, and its performance can shift as models are retrained, certification cannot be a one-off event in the way it can for a piece of conventional equipment; it needs to be lifecycle-based, with version tracking, defined rollback procedures, and reapproval triggered whenever a model changes materially. In practice, trust in any new tool is earned incrementally: operators monitor a tool closely before relying on it, and relax oversight only once it has proven reliable.

Shared testing environments can accelerate trust and validation of AI models. EU-funded projects[12] are building networked Testing and Experimentation Facilities for energy and AI, offering a pre-deployment setting in which tools are validated against realistic conditions before they touch live systems; for emerging approaches, such as grid foundation models, common benchmarks and safe test beds of this kind will be essential to move them out of the laboratory (see box in Chapter 2). Certification and testing for AI specifically remains a young but fast-growing field of attention across sectors, not only electricity; the staged approach

[12] The EU is funding three projects in parallel: EnerTEF, AI-EFFECT and EnergyGuard.

already described above, where oversight relaxes only as a tool proves itself, echoes how aviation and automotive safety certification build trust incrementally for autonomous and semi-autonomous systems. What is largely absent today is the connective layer between these efforts: shared standards, certification schemes and the means to carry a validated tool from one operator's test bed into another's control room, so that trust, once earned, can travel rather than being rebuilt operator by operator. Regulatory sandboxes, discussed in the regulatory frameworks section above, can play a role here too, giving operators and regulators a structured space to test AI-enabled tools and work through the risk questions before wider deployment.

Security becomes a core design requirement as AI enters operations

Greater connectivity and software-defined control expand the attack surface across devices, substations, aggregators and platforms. Millions of customer metering assets, such as EV chargers, solar inverters, batteries, metering infrastructure and digital platforms, become potential entry points, and some of them are never fully patched: vendors may stop releasing firmware updates for equipment when the product is no longer sold, and utilities may lack the staff to patch myriads of ageing devices even where a fix exists. Software vulnerabilities can translate into physical consequences such as remote outages or equipment damage, and the convergence of information and operational technology exposes SCADA systems that were once isolated. The United Kingdom's National Risk Register rates a cyberattack on critical infrastructure as of moderate likelihood but potentially devastating consequence, up to loss of life.

The distribution edge makes this challenge sharper. EV chargers, smart inverters, behind-the-meter batteries, aggregators, DERMS platforms and smart meters create new cyber interfaces close to consumers and outside traditional control-room boundaries. Distribution data are also more sensitive because they can reveal consumer behaviour. Security and privacy governance therefore need to cover third-party platforms and smart meter devices, not only utility control centres, including the growing use of cloud-hosted AI models whose provider and data location may sit outside the operator's own jurisdiction, a point developed below.

Cybersecurity is increasingly becoming a core design requirement, rather than an add-on applied after digital systems are installed. For example, Portuguese distribution operator E-REDES runs a dedicated cybersecurity training centre for its staff, alongside continuous vulnerability testing and a team monitoring its grids around the clock from an integrated supervision centre. Protection is cheaper and more effective when it is built into systems from the start. This means checking who and what can access critical systems, separating the most sensitive control functions from less critical networks, protecting communication links, and embedding security requirements in procurement and supply-chain management so that vulnerabilities are reduced before equipment, software or services are deployed. Established standards such as NERC's Critical Infrastructure Protection requirements and the NIST framework are being adapted so that AI and digital tools are subject to protections comparable to those applied to physical grid assets.

As AI is embedded into system operations, the integrity and robustness of AI models become more important. Adversarial attacks such as data poisoning – deliberately corrupting the data a model learns from so that it later makes a wrong decision when triggered – exploit weaknesses that conventional cybersecurity does not fully address, and a model's failure modes can stay hidden until they matter in a way a physical asset's typically do not. Countermeasures such as adversarial training, deliberately exposing a model to manipulated inputs during development so it learns to resist them, are one response, drawing on wider work securing industrial control systems.

Sovereignty and strategic dependence

Sovereignty drives domestic development of AI and cloud-based services to mitigate risk of dependency on foreign suppliers and governments. AI is increasingly delivered as a cloud-based service controlled by a vendor, and in some cases a foreign government, sitting outside the operator's own jurisdiction. This creates a risk that a tool an operator has learned to validate and rely on can be withdrawn for reasons entirely outside its control. Switching to an alternative is rarely quick given how deeply an AI tool can become embedded in operational workflows once adopted, a form of vendor lock-in that compounds the underlying dependency. Where data also leave the operator's jurisdiction for processing or storage by that vendor, jurisdictional control adds a further layer to the risk, since the operator may have limited visibility or legal recourse over how those data are handled once they cross a border.

Operators already navigate this trade-off in practice, not only in theory. Data-protection and security rules can limit how much an operator relies on cloud-hosted AI services, and by extension the size and sophistication of the model it can run, since the most capable models are typically cloud-based and impractical to run on an operator's own infrastructure. Keeping a model on-premises avoids the jurisdictional and continuity risks described above but is markedly more expensive and constrains which tools an operator can access, a reminder that sovereignty, security and capability are directly linked, not three separate choices made independently of one another.

AI, like other strategic technologies before it, can become a point of geopolitical leverage precisely because it is so widely relied upon. GPS (Global Positioning

System) offers a precedent: US military control of the system led other jurisdictions to build independent alternatives, including the EU's Galileo and the Russian Federation's GLONASS. The AI-specific version of this risk was demonstrated in June 2026, when a US export control directive forced a leading AI provider to suspend global access to two of its most advanced models for all foreign users with only hours' notice, reportedly the first such use of export controls against a commercially available AI service. Governments are responding accordingly. The EU's Tech Sovereignty Package and proposed Cloud and AI Development Act, both published in June 2026, aim to reduce dependence on third-country cloud and AI providers for critical infrastructure such as grids.

Chapter 4. Policy recommendations

Grids have constrained the energy transition for over a decade, and building new physical infrastructure takes longer than the changes occurring around it; anticipatory investment and improved planning help accelerate the buildout, but do not close the gap entirely. The digital grid toolkit, a family of solutions including grid-enhancing technologies (GETs), digitalisation and artificial intelligence (AI), gives operators an additional, faster-acting level: it can release substantial additional capacity from existing networks securely, often in months rather than years and at a fraction of the cost of new build. Building more grid capacity remains necessary but it is not sufficient, and the toolkit is a complement to it, buying time and lowering cost while new infrastructure is built.

Capturing this opportunity means creating the conditions for these technologies to succeed at scale. A central finding of this report is that many solutions in the digital grid toolkit rely on engineering principles that are broadly common across power systems, yet deployment remains highly uneven. For proven and emerging technologies alike, what holds them back is regulation that rewards building more over improving efficiency, weak data foundations, scarce skills and weak organisational capacity, and, particularly in the case of AI, unresolved questions of trust, security and dependency.

Addressing these barriers requires co-operation across the sector's stakeholders, and policy makers and regulators play a significant role. The policies that matter most depend on local context: the prevailing market structure, the age and digital maturity of existing infrastructure, and the gap between advanced and emerging economies all shape what should be done first.

Notwithstanding local context, five priority areas of action can unlock the digital grid toolkit: reforming regulatory frameworks and incentives, building robust data foundations, investing in skills and organisational readiness, building trust, assurance and security, and strengthening international co-operation.

Reform regulatory frameworks

Regulation strongly influences whether operators make better use of existing networks or default to building additional capacity. Traditional frameworks governing grid monopolies were calibrated for physical infrastructure: capital expenditure enters the regulated asset base and earns a return, whereas digital tools are treated as operating expenditure without returns. Operators respond by favouring the physical option even where a digital one would lower total system cost.

Further gaps reinforce the bias between solutions. The regulatory framework can create a mismatch between the benefits brought by the digital grid toolkit and the costs and risks borne by network operators, which may disincentivise their use. In addition, evidence of these benefits are hard to assemble without agreed valuation methods and credible baselines. Finally, rules that require proven benefits before a tool can enter operation constrain solutions whose evidence base can only be built through staged deployment.

Reforming these frameworks is a high-effort, high-impact lever available to policy makers. Priorities for regulatory reform are:

- **Calibrate regulatory frameworks to incentivise efficient network operator decisions across all possible solutions, including the digital grid toolkit.** Reform regulatory frameworks that bias network operators to favour physical grid investments where other solutions are more cost-efficient. Consider technology-neutral total expenditure frameworks that incentivise network operators to select the most efficient solutions across software, digitalisation, GETs and conventional solutions.
- **Incentivise decisions and investments that better reflect the value delivered to the system, not only the expenditure incurred.** Shift towards output- and performance-based regulation that links allowed revenues and incentives to measurable outcomes, such as capacity unlocked, grid capacity utilised, congestion, curtailment and connection queues reduced, and reliability delivered.
- **Require advanced technologies to be assessed in planning.** Mandate that GETs, digital tools and non-wire alternatives be evaluated in connection studies, reinforcement decisions and asset replacement programmes, recognising that these solutions complement rather than replace new build. This requires planning methods that can represent them: more granular and increasingly probabilistic methods able to credit variable conditions, realistic outages and remedial actions. In the case of technologies with a well-established case, consider direct obligations instead of relying on incentives alone.
- **Develop standardised valuation methods for advanced grid technologies,** covering avoided congestion, deferred reinforcement, reduced curtailment, improved reliability, faster connections, greater resilience and operational risk reduction. These valuation methods would help assess solutions in the digital grid toolkit against conventional ones, and build regulatory mechanisms able to incentivise the delivery of additional system benefits.
- **Use regulatory sandboxes and dedicated innovation funding** to trial technologies and rule changes in controlled real-world settings, with clear pathways to feed successful trials into standard practice rather than leaving them as isolated pilots.

Build robust, shared data foundations

Data scarcity holds back better use of grids. The digital grid toolkit can only be trained, validated and trusted on data that are of good quality and accessible, yet across most networks datasets are uneven, fragmented and hard to share. They are weakest at the distribution level, where demand and distributed resources are growing fastest. Where data exist, quality is often the deeper problem.

Fragmentation compounds scarcity. Data typically sit in incompatible formats and organisational silos, including between transmission and distribution functions, so the system-wide view that AI needs is rarely available. Sharing data raises legitimate concerns over cybersecurity, sovereignty and privacy, and the benchmarks and shared infrastructure that would let operators validate tools and pool costs are largely absent. These are no-regrets enablers: stronger data foundations pay off whichever technologies ultimately scale.

Priorities for building robust, shared data foundations are:

- **Extend monitoring and instrumentation at the distribution level, where visibility is weakest.** Build on the replacement cycle to embed sensors, secondary-substation monitoring and – alongside privacy protection – smart-meter data for operational use, not only billing.
- **Prioritise data quality** through validation, cleansing and standard data-quality metrics.
- **Support interoperability through common data models, documented application programming interfaces (APIs) and vendor-neutral architectures,** favouring practical, open interfaces over heavier top-down standardisation, and developing them collaboratively, as in open standards such as LF Energy's TROLIE.
- **Enable trusted data sharing**, pairing data-quality requirements with frameworks that move from voluntary codes to mandated rules, and defining governance that balances transparency with cybersecurity, privacy and national security.
- **Support shared and pooled data infrastructure** to spread fixed costs and learning across operators, and develop mechanisms to share lessons from failed pilots as well as successes.

Invest in skills and organisational readiness

People and processes strongly influence whether technology is able to deliver its potential, and both are under strain. The professionals who combine power system expertise with data science are scarce, and utilities compete for them against better-paying sectors while their own workforce ages. The sector has also been slow to seek digital talent, leaving gaps across the whole deployment chain, from control-room operators and planners to field crews, cybersecurity teams and regulators.

Skills alone are not enough. The way operators procure and adopt technology can blunt its value. The largest gains may come from going beyond automating existing tasks, and redesigning the processes around what the technology can do. This is a more difficult organisational change that deployment typically fails to address, meaning that pilots stall at the point of integration into control rooms and existing workflows. Developing a skilled grid workforce and the organisational capacity to deploy their skills effectively requires deliberate action.

Priorities for skills and organisational readiness are:

- **Treat digital and AI skills as a strategic workforce priority.** Take stock of existing skills, define digital career paths and make utility roles attractive against the tech-sector competition. Invest across the full deployment chain, including operators, planners, protection engineers, field crews, cybersecurity teams, regulators and suppliers, and not only data scientists.
- **Build and retain combined power system and data science capability** through training academies, university partnerships and cross-disciplinary roles; require project budgets to include appropriate training as a condition for scaling; pool scarce capability regionally; and plan for workforce renewal as much of the workforce nears retirement.
- **Make replacement investment digital by default.** Require sensors, communication interfaces, interoperable data structures, cybersecurity provisions and control-room integration to be considered whenever major substations, lines, transformers, protection systems or distribution assets are refurbished or replaced. Capturing the replacement cycle is often the lowest-cost route to building observability, controllability and data quality over time, provided digital requirements are specific early in asset and procurement.
- **Treat the digital grid toolkit deployment as an organisational and process project, planned over the long term, not a technology purchase.** Budget for workflow redesign and control-room integration, the point where most pilots stall. Build the internal culture with dedicated teams that support and oversee AI adoption (AI ambassadors and central governance functions), so that new tools are trusted and adopted incrementally and securely. This also means planning over longer horizons than a single technology cycle, while keeping the flexibility to adopt rapidly evolving tools continuously, and embedding structured pathways that move proven solutions from pilot into standard operating practice.
- **Move towards more dynamic operating and market rules.** Implement probabilistic ratings, risk-based congestion management, probabilistic security assessment and dynamic operating limits, and ensure regulatory acceptance of these methods to enable improved grid utilisation, as they provide a systematic basis for identifying and managing usable operational headroom.

Build trust, assurance and security

Trust and security set the pace at which AI enters critical operations, and both are underdeveloped. Operators have adopted AI readily for tasks that do not bear directly on real-time control, but remain cautious where errors could threaten supply, because accountability cannot be delegated to an algorithm and many AI outputs cannot be fully explained or audited. The tools that would build confidence, namely standardised validation and certification, barely exist, so trust accrues only slowly.

Cybersecurity concerns need to be considered at the design stage: as grids become more connected and software-defined, the attack surface expands across grid-edge devices, substations and platforms, and the convergence of information and operational technology exposes systems that were once isolated. AI adds risks of its own, from data poisoning to opaque failure modes, that conventional cybersecurity does not fully address. A related trend is the growing reliance of AI tools on vendors and platforms outside an operator's own jurisdiction, raising the same kind of dependency risk long familiar with other strategic technologies such as navigation systems and defence.

Priorities for building trust, assurance and security are:

- **Calibrate AI governance and human oversight to the criticality of the grid function.** Adopt function-based governance that focuses on what a system does, rather than what technology it uses, distinguishing between tools that inform, supervise or automate decisions. Governance should keep an accountable human in place as tools mature, while clarifying approval processes, model change controls, incident reporting, audit trails and fallback arrangements for safety-critical functions.
- **Clarify accountability, liability and risk allocation for AI-assisted decisions.** Extend existing legal and regulatory frameworks to grid applications of AI, including product-liability approaches such as the EU's 2024 Product Liability Directive, which explicitly covers software and AI systems. Regulators and governments should also examine whether insurance, guarantees or other risk-transfer mechanisms are needed for harms linked to AI in critical infrastructure, without allowing them to substitute for robust assurance, cybersecurity and operational accountability.
- **Embed cybersecurity by design**, including in replacement investment decisions, server architectures and supply-chain and procurement requirements, building on established frameworks such as NERC CIP and NIST.
- **Apply risk-based governance** that assures the integrity and robustness of models in proportion to the criticality of each function, protecting the system without needlessly blocking the data-sharing that AI depends on.
- **Favour explainable, physics-informed model design to ease explainability and strengthen trust.** Direct funding, procurement criteria and research support

towards models that embed known grid physics rather than learn system behaviour purely from data, particularly at the distribution level where data are scarcest. This can reduce data requirements, improve auditability and give operators outputs that they can check directly against underlying engineering assumptions, complementing the data foundation work above rather than substituting it.

- **Manage AI and cloud dependency through diversification, predictability and co-operation.** The same principles that underpin energy security apply to AI: diversify providers, models and deployment options rather than relying on a single vendor or jurisdiction; seek predictable, transparent terms of engagement with technology and data partners; and use international co-operation to share experience and de-risk dependency collectively rather than through unilateral retreat. Weigh these risks deliberately when adopting AI in critical operations, without treating dependency itself as a reason to avoid the benefits AI can bring.

Strengthen international co-operation

Some of the recommendations in this report can be built once and shared, rather than repeated by every country and utility independently, both for the shared technical foundations AI increasingly depends on, and for the wider deployment challenge, where advanced economies have already tested approaches that emerging market and developing economies (EMDEs) can adapt rather than reinvent. The barriers set out in Chapter 3 are more constraining in EMDEs: skills are scarcer, while financing is limited by high capital costs and weak cost recovery for software and data.

Priorities for strengthening international co-operation are:

- **Pool data, compute and expertise to build shared AI foundations for grids.** Support international collaboration, including open-source initiatives, shared benchmarks and research partnerships, to develop and validate general-purpose grid AI models and physics-informed approaches jointly, rather than duplicating this costly effort in every country; embed interdisciplinary co-operation between power-system and AI specialists as a design principle underlying these efforts, not an afterthought.
- **Develop standardised validation and certification** procedures for AI and digital tools in critical operations, using shared test environments, such as the EU's Testing and Experimentation Facilities, and common benchmarks.
- **Adapt proven approaches rather than reinventing them**, particularly for EMDEs. Successful deployment of a technology in advanced economies provides evidence that it works, reducing perceived risks and technology costs in other countries, and proven regulatory templates – from output-based remuneration to sandboxes – can be adapted to local conditions.
- **Mobilise international co-operation and blended finance for EMDEs.** Use concessional finance and regional capability pooling to de-risk early deployment;

share scarce skills, tools and the cost of experimentation across utilities, funders and technology providers.

- **In EMDEs, place strong emphasis on distribution-level applications with visible consumer benefits**, such as loss reduction and improved reliability, to build the political and public support that sustains digital investment.
- **Build observability through the replacement cycle in EMDEs**, applying the digital-by-default principle as a low-cost way to accumulate visibility over time, rather than through wholesale new instrumentation that strained budgets cannot fund.

Abbreviations and acronyms

ADMS	advanced distribution management system
AI	artificial intelligence
API	application programming interface
BESS	battery energy storage system
CAPEX	capital expenditure
CIP	critical infrastructure protection
DERMS	distributed energy resource management system
DLR	dynamic line rating
DMS	distribution management system
DSO	distribution system operator
DTR	dynamic transformer rating
EMDE	emerging market and developing economy
EMS	energy management system
e-STATCOM	enhanced static synchronous compensator
EV	electric vehicle
FACTS	flexible alternating-current transmission system
FLISR	fault location, isolation and service restoration
GET	grid-enhancing technology
GPU	graphics processing unit
HVDC	high-voltage direct-current
IEA	International Energy Agency
IT	information technology
NERC	North American Electric Reliability Corporation
NIST	(US) National Institute of Standards and Technology
OPEX	operational expenditure
OT	operational technology
PMU	phasor measurement unit
PST	phase-shifting transformer
PV	photovoltaic
RAB	regulated asset base
RDSS	Revamped distribution sector scheme
RIIO	revenue = investment + innovation + output incentives
SATA	storage as a transmission asset
SCADA	supervisory control and data acquisition
SGI	Smart Grid Index
SSSC	static synchronous series compensator
STATCOM	static synchronous compensator
TCSC	thyristor-controlled series capacitor

TOTEX	total expenditure
TRL	technology readiness level
TROLIE	transmission ratings and operating limits information exchange
TSO	transmission system operator
UPFC	unified power-flow controller
V2G	vehicle-to-grid
WAMS	wide-area monitoring system

GW	Gigawatt
km	Kilometre
kV	Kilovolt
ms	Millisecond
MW	Megawatt

See the IEA glossary for a further explanation of many of the terms used in this report.

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