Power Systems Transformation:

Delivering Competitive, Resilient Electricity in High-Renewable Systems

Executive Summary | July 2025 | Version 1.0

Energy Transitions Commission

Executive Summary

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

Our Commissioners come from a range of organisations – energy producers, energy-intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is chaired by Lord Adair Turner who works with the ETC team, led by Ita Kettleborough (Director), and Mike Hemsley (Deputy Director).

The ETC's *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems* report briefing was developed in consultation with ETC Members, but it should not be taken as members agreeing with every finding or recommendation. The ETC team would like to thank the ETC members, member experts and the ETC's broader network of external experts for their active participation in the development of this report.

This report is accompanied with a supplementary Insights briefing, *Connecting the World: Long-Distance Transmission as a Key Enabler of a Zero-Carbon Economy*, which focuses on the potential for long-distance transmission in high variable renewable power systems and identifies leading global opportunities.

The ETC Commissioners not only agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century but also share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision-makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C. Many of the key actions to achieve these goals are clear and can be pursued without delay.

This report should be cited as: ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems.*

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Contents

Key messages from the report

Technical feasibility

▶ It is technically possible to operate stable power systems with very high shares of wind and solar generation (e.g., 70 to 80 %), provided that key investments are made in grid stability technologies and appropriate procurement is implemented.

Enabling policies and actions

▶ Delivering low-cost, high-wind and solar power systems will require:

- Setting a strategic vision supported by appropriate planning.
- Ensuring that key aspects of market design reduce investor risk and support efficient capital allocation by incentivising the deployment of grid and flexibility technologies.
- Implementing grid regulations that minimise delays in the connection and integration of new technologies into the system.
- Applying digital and AI-based capabilities to manage power systems more efficiently.
- Addressing potential supply chain and workforce bottlenecks.
- Enabling demand side flexibility through consumer engagement and product design.

Balancing electricity supply and demand

▶ Energy supply and demand can be balanced in high wind and solar systems using a range of already available storage and flexibility technologies:

- For short durations (up to eight hours), batteries are likely to be a low-cost solution, and demand-side flexibility (DSF) has significant potential.
- For medium-long durations, multiple increasingly cost-effective solutions are available.
- The highest costs will be associated with delivering ultra-long-duration balancing.

Total system costs

▶ Future total system costs per kWh in high wind and solar systems can be comparable to or lower than today's fossil fuel-based systems in almost all countries. These costs will be:

- Lowest in countries with strong solar resources and predominantly short-duration balancing needs (e.g., the low-latitude global sunbelt such as India, Thailand, Mexico, Australia).
- Highest in countries primarily dependent on wind and with significant long-duration balancing needs (e.g., the high-latitude global wind belt such as the UK, Japan, Germany).

In the near and medium term, transitional costs (e.g., from legacy contracts and initially expensive technologies) could be significant and must be carefully managed.

Last mile decarbonisation

▶ The final stages of power system decarbonisation will be the most expensive, especially in high-latitude, wind-dependent countries , given the higher costs of low-utilisation assets to ensure security of supply. Governments should strike a pragmatic balance between:

- Driving towards complete power system decarbonisation.
- Shifting the primary policy focus to accelerating electrification once a very low carbon intensity (e.g., below 30 grams per kWh) has been achieved.

Grid expansion and costs

▶ Major investments will be needed in both transmission and distribution grids, with total grid length and annual investment requirements expected to grow two to three times by 2050. However, costs can be significantly reduced through the deployment of innovative grid technologies (IGTs) and demand side flexibility (DSF).

Rapid electrification is essential to scale electricity demand in line with grid expansion, enabling lower grid costs per kWh.

Introduction

Massive clean electrification will be the foundation of the transition to a global net zero economy. It will require both the substitution of electricity for fossil fuels in most of industry, transport and buildings, and the near total decarbonisation of electricity supply. In most sectors, direct electrification will be the most cost-effective route to decarbonisation. In some sectors, hydrogen produced via electrolysis, therefore, relying on clean electrictity, is likely to play a significant role. There will also be a small role for carbon-based molecules (as an energy source and material feedstock) and it can be made zero emissions through bioresources and the application of carbon capture.

Latest updates to the ETC scenarios suggest that the share of direct electricity use could increase from approximately 20% of global final energy demand in 2023 to approximately 60-70% by mid-century[1]. Total global electricity generation could potentially reach around 90,000 TWh by 2050, compared to 31,000 TWh in 2024[2].

It is essential that this electricity is generated almost entirely from zero-carbon sources. Many countries have large hydropower resources, and both nuclear power and geothermal resources could play a role in providing continuous zero-carbon power. The ETC will publish a report on the role of nuclear power and geothermal resources in energy transition in 2026. However, in most parts of the world the dominant sources of zero-carbon generation are likely to be wind and solar. Many countries are already generating over 40% of electricity from these variable renewable electricity (VRE) sources and many scenarios for cost-effective power decarbonisation project that the share of wind and solar generation will reach 70% or even higher.[3]

This reflects the dramatic reductions in the cost of solar PV over the last 10 years, and the less dramatic but still significant fall in wind power generation costs, which mean that the cheapest way to produce a kWh of electricity in most regions is from wind or solar resources.[4] But, low cost per kwh delivered still leaves the challenge of what to do when the sun doesn't shine and the wind doesn't blow i.e. how to balance variable supply versus fluctuating demand.

Previous ETC publications in the *Barriers to Clean Electrification* series have addressed several hurdles to scaling up wind and solar, including the need to address planning and permitting, supply chains and materials requirements, as well as finance needs.[5] This report addresses the question of how electricity systems with a very high share of wind and solar generation can balance supply and demand, how grids need to change, and what the implications will be for the cost of electricity remove bold. It explores:

1. The system balancing challenges of power systems based on wind and solar generation and the implications for total system generation and balancing costs in different regions.
2. The need for grid expansion and the implications for grid costs per kWh.
3. Bringing this together to infer the long term total system cost implications by region.
4. Key enablers for cost effective power system development.

1 Systemiq analysis for the ETC; ETC (2023), *Fossil Fuels in Transition: Committing to the phase-down of all fossil fuels. IEA (2024), World Energy Outlook 2024*. Note: Updates referenced in the text will be included in the upcoming ETC report on the role of low-carbon molecules in the energy transition, which will be published in 2025 Q4.

2 Systemiq analysis for the ETC; Ember (2025), *Global Electricity Review 2025*

3 IEA (2021), *Net Zero by 2050: A Roadmap for the Global Energy Sector;* IRENA (2023), *World Energy Transitions Outlook 2023.*

4 Today, countries such as Germany, Ireland, Spain, Uruguay, Denmark, and Portugal already generate over 40% of their electricity from wind and solar, with Denmark leading the group with nearly 70% ; See Ember (2025), *Electricity generation – Wind and solar*. Available at *https://ember-energy.org/data/electricity-data-explorer/* [Accessed April 2025]; IRENA (2023), *Renewable Power Generation Costs in 2022;* Lazard (2023), *Levelized Cost of Energy Analysis – Version 16.0;* BNEF (2023), *New Energy Outlook.*

5 ETC (2021), *Making Clean Electrification Possible;* ETC (2023), *Streamlining planning and permitting to accelerate wind and solar deployment;* ETC (2023), *Material and Resource Requirements for the Energy Transition.*

1. Managing the system balancing challenge

It is technically and economically feasible to balance power systems with high shares of wind and solar (e.g., 70-80%+) existing technologies, delivering system stability and round-the-clock electricity at costs below or comparable to today's fossil-based systems. In particular, ETC analysis shows that:

- Grid stability is a critical challenge but can be addressed with existing technologies.
- The balancing challenge varies by region as a result of differences in natural resource as short-duration balancing needs dominate in sun-rich regions, while long-duration needs are more significant in wind-rich regions.
- Commercially viable flexibility solutions, including storages, can support high wind and solar shares in all regions, but the cost of balancing rises with the duration of required balancing action with ultra long duration balancing being the most expensive.
- Total system generation and balancing costs vary by region, with the lowest costs in sun-rich countries. However, in all regions, costs could be below or comparable to today's fossil fuel based systems.
- The final stages of decarbonisation are the most expensive and a pragmatic approach to the last mile of decarbonisation is therefore required.

1.1 The technical challenge: ensuring stable system operation

It is technically feasible for power grids to maintain second-by-second stability in systems with very high shares of wind and solar generation, but this requires a fundamental transformation in how power systems manage core operational parameters, especially frequency and voltage control.

In traditional grids, these services were inherently provided by large synchronous generators as part of thermal and nuclear plants, whose rotating mass offers inertia to resist frequency deviations and support voltage stability through reactive power. As the combined share of fossil fuel and nuclear generation declines, these functions must be deliberately engineered into the system using new technologies, carefully designed market and regulatory frameworks.

This shift entails moving from a system of bundled services, where inertia, voltage support, and fault response came as a package with conventional generation, to one of unbundled grid services. It requires both the deployment of voltage and frequency management technologies, such as synchronous condensers, grid-forming battery energy storage systems, and advanced inverter controls as well as the development of new procurement models and grid codes that ensure that these services are available and correctly valued in high wind and solar generation systems.

Lessons from the Iberia April 2025 Blackout

On April 28 2025, a major blackout occurred across the Iberian Peninsula power system, initiated by a sudden voltage spike following successive generation outages near Granada, Seville and Badajoz from 12:30 pm CET. While the system is designed to manage such events through mechanisms such as primary response, voltage control

and interconnection balancing, the disturbance escalated beyond the system's ability to contain it. According to the Government of Spain's preliminary report,[6] the blackout was caused by a combination of factors acting in close succession. These included low levels of synchronous generation, which left the system vulnerable to frequency and voltage oscillations as well as the sequencing of automatic protections and controls triggered in response to the initial disturbances. The report does not identify a single root cause but emphasises the complexity of the event and the need for further technical investigation.

The event reinforces the importance of embedding grid stability into system design from the outset through:

- Addition of synchronous condensers for rotational inertia and voltage support, grid-forming battery energy storage systems capable of providing synthetic inertia and fast frequency response, and advanced inverter control technologies.
- Strong regulatory and operational foundations. This includes robust grid codes that mandate features such as high-voltage ride-through (HVRT) and frequency response capabilities for inverter-based resources, ensuring they support rather than disconnect during disturbances.
- System-wide coordination, including protection schemes, real-time monitoring, and automated control strategies to ensure the grid remains resilient under stress.

These technical foundations must be supported by market mechanisms and regulatory frameworks that ensure stability services are procured, valued, and delivered reliably as renewable penetration rises.

1.2 Matching supply and demand over different timescales

Electricity supply and demand must be matched across multiple timescales, each of which create distinct challenges for system needs and the solutions required to meet them. In addition to the second-by-second system operation challenge, we define three categories of balancing requirements [Exhibit 1].

- **Short duration (up to 8 hours):** typically intra-day, requiring flexibility to manage solar diurnal cycles, wind variability and daily demand peaks.
- **Medium–long duration (8–50 hours):** day-to-day or week-to-week balancing needs, influenced by changing weather patterns, weekends, or temperature-driven load variations.
- **Ultra-long duration (50+ hours**): seasonal or multi-week imbalances, such as "dunkelflaute" effects during low-wind periods coinciding with peak winter electricity demand if residential and building heating have been electrified.

Exhibit 1

Balancing durations across different timespans

System operation	Short duration balancing (up to 8 hours)	Medium-long duration (8 hours to 50 hours)	Ultra-long (50+ hours)
Inertia, frequency response, voltage control, fault ride through.	• Predictable daily: e.g., large daily solar outputbut significant demands during the evening. • Unpredictable daily: deviations from average generation patterns (e.g., cloudy days in summer).	Variations (e.g., seasonal) driven by either: • Demand (e.g., winter heating peak in Europe, air conditioning (AC) peak in southern China or India in summer). • Or supply (e.g., Indian wind during monsoon, European sun in summer).	Primarily unpredictable variations driven by: • Demand (e.g., above normal AC peak from heatwaves; cold period heating demand). • Or supply (e.g., anticyclone wind drought).

SOURCE: Systemiq analysis for the ETC.

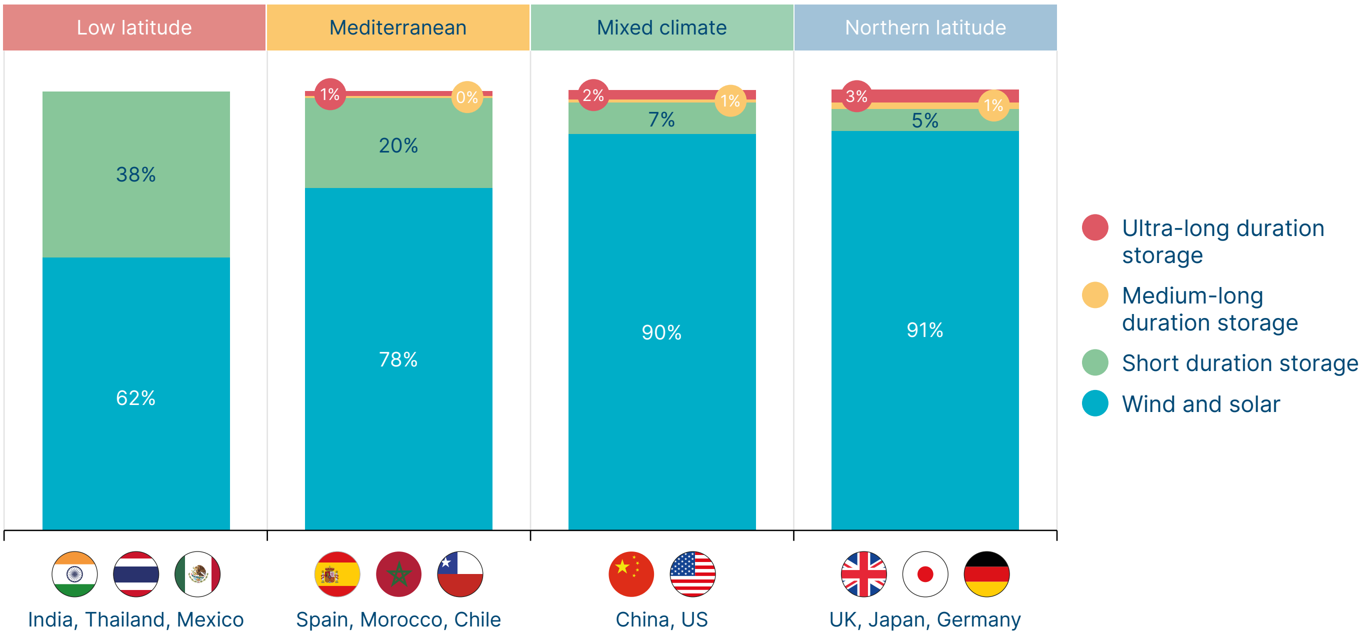
6 Ministerio para la Transición Ecológica y el Reto Demográfico (2025), *Informe no confidencial del Comité para el análisis de las circunstancias que concurrieron en la crisis de electricidad del 28 de abril de 2025.*

The importance of these different balancing challenges varies by country/region as a result of different patterns of both electricity demand and wind and solar supply, which reflect different climatic conditions and resource availability. We have, therefore, modelled the scale and nature of the balancing challenge in four different countries which illustrate different regional archetypes [Exhibit 2]: Spain (Mediterranean), India (Low latitude), China (Mixed climate) and the UK (High latitude).

Exhibit 2

System balancing needs varies across regions

Balancing needs differ by region



SOURCE: Systemiq analysis for the ETC (2025).

The ETC analysis assesses the scale of required balancing by duration if 100% of electricity supply was from domestic wind and solar generation. This is clearly an unrealistic assumption since optimal decarbonisation will almost always include a role for one or more of hydro power, nuclear generation, the continued use of fossil fuels in dispatchable generation combined with carbon capture and storage (CCS), or interconnection with other countries.

But analysis of the implications of 100% wind and solar generation helps highlight the inherently different nature of the challenge facing different regional archetypes:

- In India, our modelling suggests that approximately 40% of demand is met through electricity which has been time-shifted using storage, mainly from day to night. This reflects the dominant cost effective role of solar within the generation mix. Medium to ultra long duration balancing is not required due to strong solar resource availability, daily demand patterns, and limited seasonal variation.
- Spain requires mainly short-duration balancing (20% of supply), with ultra-long needs equal to 1% of all hours generated.
- China requires mostly short-duration balancing (7%) given the large solar potential, but also some ultra-long (2%) given that wind remains significant in the generation mix.
- The UK has modest overall balancing needs (9%), but a larger share (3%) occurs at ultra-long duration.

While the ultra-long duration balancing requirement is in all cases only a small proportion of total hours, meeting it can add significantly to total system cost.

1.3 Balancing technologies and costs

A range of commercially available technologies and approaches make it possible to balance supply and demand across all durations required. Exhibit 3 illustrates four key categories of solution.

- Running dispatchable generation on a flexible basis (rather than baseload) to provide power when wind and solar supply is insufficient to meet demand. This can achieve very significant decarbonisation: the UK power system for instance, has seen carbon intensity fall from 500g per kWh in 2010 to 125 g per kWh in 2024, despite minimal Investment so far in storage based solutions.
- Interconnecting countries and regions which have a combination of different patterns of wind and solar supply, cheaper power generation or different intraday demand profiles. The ETC report *Connecting the World: Long-Distance Transmission as a Key Enabler of a Zero-Carbon Economy* sets out the opportunity for long-distance transmission to provide balancing.[7]
- Different storage technologies which are optimal for different durations, depending on their capital cost per kWh and round-trip efficiency
- Demand side flexibility, with multiple opportunities for residential commercial and industrial users to shift demand away from peak hours, reducing balancing needs and grid costs. The ETC paper on *Demand side flexibility – unleashing untapped potential for clean power* discusses these opportunities in detail:[8] and Exhibit 9 in Section 2.3 provides an illustration of the potential in the UK and India.

Exhibit 1.3

Balancing technology suite across different durations

			System operation	Short duration (0-8 hours)	Medium-long duration (8-50 hours)	Ultra-long duration (50+ hours)
Grid stability technologies		Synchronous condensers	✓ (green)			
		Grid-forming inverters	✓ (green)			
Dispatchable generation	Other zero carbon	Hydro, nuclear	✓ (green)	✓ (green)	✓ (green)	✓ (yellow)
	Fossil	Fossil (or bioenergy) + CCS	✓ (green)	✓ (green)	✓ (green)	✓ (green)
		Fossil – low/very low utilisation	✓ (green)	✓ (green)	✓ (green)	✓ (green)
		Power-to-X (i.e. H_2)	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Interconnection		Accessing complementary weather patterns and time shifting generation	✓ (yellow)	✓ (yellow)	✓ (yellow)	✓ (yellow)
Energy storage		Pumped hydro	✓ (green)	✓ (green)	✓ (green)	✓ (yellow)
		Lithium-ion battery	✓ (green)	✓ (green)	✓ (yellow)	
		Other technology (i.e. CAES, liquid air, etc.)	✓ (green)	✓ (green)	✓ (green)	✓ (yellow)
Demand side flexibility		EV (smart charging, V2G)		✓ (green)	✓ (yellow)	
		Heating load		✓ (green)		
		Industrial load		✓ (green)	✓ (green)	

NOTES: Green tick: The technology is well-suited or fully capable of providing the balancing service for the function. Yellow tick: The technology can partially or conditionally support the balancing function, but may have limitations or reduced effectiveness in that timescale. Limited nuclear capacity for flexible ramping considered. Lithium-ion storage is utility-scale and behind-the-metre. Emerging tech includes gravitational storage and molten sands storage and CAES refers to compressed air energy storage. Examples of Power-to-X include the production of H_2 from electrolysis and re-conversion of hydrogen to electricity via gas turbines or fuel cells. V2G means vehicle to grid technology. Heating load includes residential and commercial standard heating needs. Industrial load includes hydrogen electrolysis, where production can be shifted to optimal times.

SOURCE: Climate Policy Initiative for the ETC (2017), *Low-cost, low-carbon power systems.*

7 ETC (2025), *Connecting the World: Long-Distance Transmission as a Key Enabler of a Zero-Carbon Economy.*

8 ETC (2025), *Demand side flexibility – unleashing untapped potential for clean power.*

The relative costs of these different balancing options will vary by specific circumstance and will evolve with future technological developments. As a result, it is neither possible nor necessary to predict what the relative role of the different solutions will be. This should instead result from competition within the framework of well-designed energy and capacity markets. In addition, it is notable that today the absolute cost of several technologies is much lower in China than in other countries, with costs in India also being lower for some technologies (e.g., pumped hydro).[9]

Exhibit 4 sets out wide ranges for the possible future cost of the different technologies per MWh of delivered electricity.[10] It illustrates important differences between the likely relative costs for different duration of balancing need:

- **Short duration balancing** is likely to be primarily provided by lithium-ion or sodium-ion batteries, or via demand side flexibility. Battery costs per kWh storable have fallen dramatically over the last three years and will further decline in future. As a result, battery storage is becoming economic in many countries and will become even more so over time. Some forms of DSF are essentially zero cost since no investment in equipment is required to enable the demand shift, while others may require new investment (e.g., additional CAPEX for a bi-directional wall charger, in the case of Vehicle-to-Grid technology), but are still likely to be low cost solutions. Cost estimates for short duration balancing range from $0-150 per MWh in 2035, falling further to $0-75 in 2050.[11]
- **Medium-long duration balancing** is likely to be provided by a more diverse set of technologies, with considerable uncertainty about the relative costs. Lithium-ion based solutions typically involve higher cost per kWh at this duration, and are therefore disadvantaged as the number of charge/discharge cycles reduces, but further reductions in battery cost per KWh could make them economic over gradually rising durations.
  - Technologies such as compressed air energy storage (CAES), pumped hydro and thermal storage typically have lower round-trip efficiency, but may be economic relative to batteries as a result of lower capital cost per kWh (while typically involving larger capital cost per project simply because of much larger scale).
  - Long distance transmission to interconnect regions within a country or between countries will often be an economic solution, as well hydropower plants, where they are available. A wide range of costs is possible, from $15–$255 per MWh in 2035 and with some further reduction by to $15–190 in 2050, but with the range remaining higher than for short duration solutions.
- **Ultra-long duration balancing** solutions are likely to be the most expensive as a result of the need to invest in assets which are only lightly utilised. All of the options considered involve keeping a lightly utilised gas turbine fleet, whether burning natural gas or hydrogen. The alternative variants of this approach are:
  - Burning hydrogen made from electrolysis in periods when VRE is in surplus supply. Our estimates suggest that in 2035, this could be the most expensive option at $425–$770 per MWh but if electrolyser capital expenditure (CAPEX) costs can be reduced or efficiency rates increased, costs may fall below this range in subsequent years.
  - Applying CCS to plants which continue to burn natural gas. Here significant costs will result from the need to invest in very lightly used carbon capture plants, whether used in open cycle gas turbines (OCGT) working only when needed to meet ultra-long duration balancing requirements , or in more efficient combined cycle gas turbines (CCGT) running at somewhat higher utilisation and also meeting some medium-duration balancing needs. Costs for these options could be $200–400 per MWh.
  - Continuing to burn gas without applying CCS at the power plant, and offset the resulting residual emissions by paying for carbon dioxide removals elsewhere. This could be a cheaper option than the plant level CCS options, if the cost of removal were below $50 per tonne.

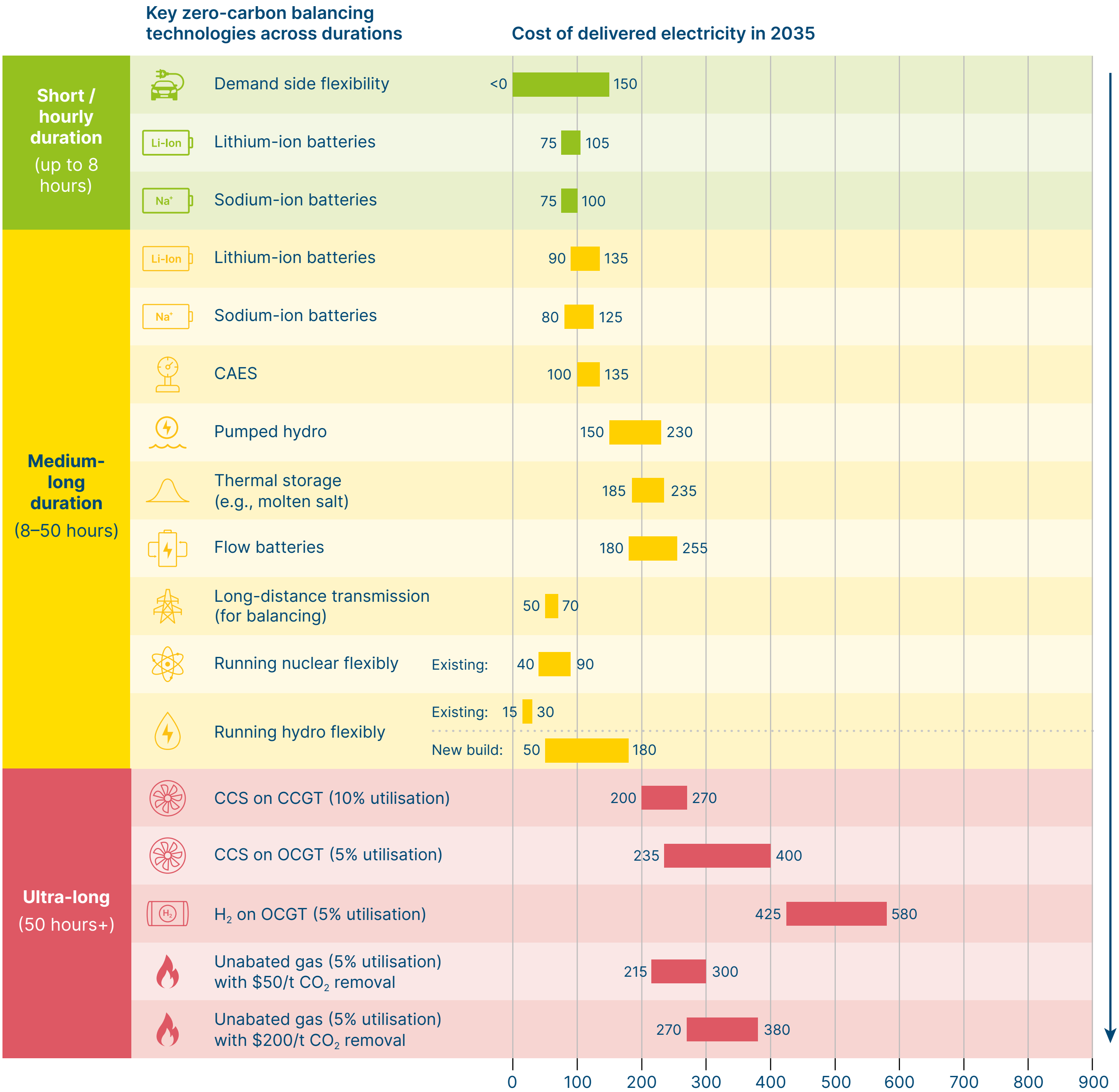
9 Ember (2024), *Drivers to Coal Phase-Down in India: Part 1 – Battery Cost Declines.*

10 Because of round trip efficiency losses in storage and discharge (which vary by technology) the cost of storage varies with the input cost of electricity. In the full report we should what the cost of delivered electricity from storage would be for a number of different input cost assumptions. The figures in Exhibit 4 all assume an input cost of $40 per MWh.

11 Note: All costs cited in this page are based on an electricity input cost of $40/MWh.

Exhibit 4

Cost comparison of balancing technologies – Electricity cost of $40/MWh (applies only to selected technologies)



NOTE: The following assumptions are used for the following technologies: Hydrogen based on a 5% utilisation factor for OCGTs and a 50% electrolyser utilisation rate. Interconnectors assume no electricity cost input.

SOURCE: Systemiq analysis for the ETC; BNEF (2024), *Energy Storage System Cost Survey;* BNEF (2024), *Long duration energy storage cost survey;* PNNL (2025), *Pumped Hydro Energy Storage;* BNEF (2024), *Electrolysis System Cost Forecast 2050: Higher for Longer;* BNEF (2025), *LCOE Data Viewer;* Liu et al. (2021), *Development status and prospect of salt cavern energy storage technology.* D. Mullen (2024), *On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.*

1.4 Total system generation and balancing costs by regional archetype

In power systems with high shares of variable renewables, total balancing costs will depend on the proportion of generation that must be time-shifted and the cost per MWh of shifting electricity across different durations. The ETC modelling estimates what this cost might be for the four different regional archetypes on the assumption that (i) all supply ultimately derives from solar and wind (ii) only the storage options are utilised. Some demand side flexibility is implicitly assumed but system cost impacts could be significantly higher if maximised. No allowance for the potential low cost impact of interconnection is included.

Given the illustrative assumptions, our modelling represents a technical upper bound on balancing costs in fully renewable systems. By excluding firm low-carbon sources (as used in dispatch models) and interconnection, it captures the full cost of covering even rare, extreme shortfalls in supply. To contextualise this, we compare our results with dispatch model estimates for each archetype.

Exhibit 5 shows the result, which highlight that:

- **India (Low latitude)** could run a solar dominant system at an eventual (2050) total system generation and balancing costs of $27 per MWh with $12 MWh for generation (primarily solar) and $15 per MWh for balancing (almost entirely short duration). This compares with TERI's estimate of $43 per MWh which makes less optimistic assumptions about cost reductions achievable for both solar panels and battery storage.[12]
- **Spain (Mediterranean)** is likely to face somewhat higher total costs but still well below those of today's system. Generation cost could be $41 per MWh and balancing cost $20 per MWh, reflecting the need for some ultra-long duration balancing/flexibility alongside short duration. Our estimate is slightly higher than the $53 per MWh suggested by Aurora's dispatch model, which assumes some continued role for nuclear and gas generation.[13]
- The ETC estimates for **China (Mixed climate**) suggest similar total system generation and balancing costs to India, with slightly higher generation cost, but lower balancing cost. This reflects both China's lower equipment and installation costs across many technologies, and its ability to balance the system via long distance interconnection between regions with different weather patterns, without facing the complexities created by international interconnection. Modelling by ICCSD indicates a cost of $35–47 per MWh versus our $26 per MWh estimate.[14]
- For **UK (High latitude),** the ETC analysis suggests that the high latitude countries are likely to face higher costs than other regions, with an estimated total system generation cost of $80 per MWh in 2050 and beyond. This reflects the high cost of achieving ultra long duration balance. While only 3% of all generation hours need to be time shifted, achieving this shift results in 18% of total system generation and balancing costs. The UK's Climate Change Committee's (CCC) dispatch model suggests somewhat lower costs at $73 per MWh;[15] this reflects a more diverse assumed generation mix, less need to overbuild solar and wind, and some lower cost assumptions. Both the ETC and the CCC's estimates are below recent costs of electricity in the UK.

  These costs could be reduced if significant electrolyser CAPEX cost reductions and efficiency improvements can be achieved, or if the alternative ultra-long duration options considered in Exhibit 4 are deployed.

Overall, these results suggest that:

- Systems with high shares of wind and solar can deliver electricity at total costs in 2050 comparable to or below today's wholesale electricity prices.
- Total system generation and balancing costs will be lowest in low latitude "sun belt" countries due to the rapidly falling cost of solar generation and battery storage, and shorter balancing duration needs.
- In high latitude "wind belt" countries, costs will be higher because of the higher cost of longer-duration balancing. However, these systems could still deliver affordable, stable, and secure electricity, particularly with the right policy, market, and innovation frameworks in place.
- Costs in China are expected to be as low as in India, given existing industrial capacity and established supply chains for equipment and installation, and the potential for long distance transmission within a continental scale country with multiple climate zones.

12 TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights*.

13 Aurora (2023), *Long Duration Energy Storage in Spain*.

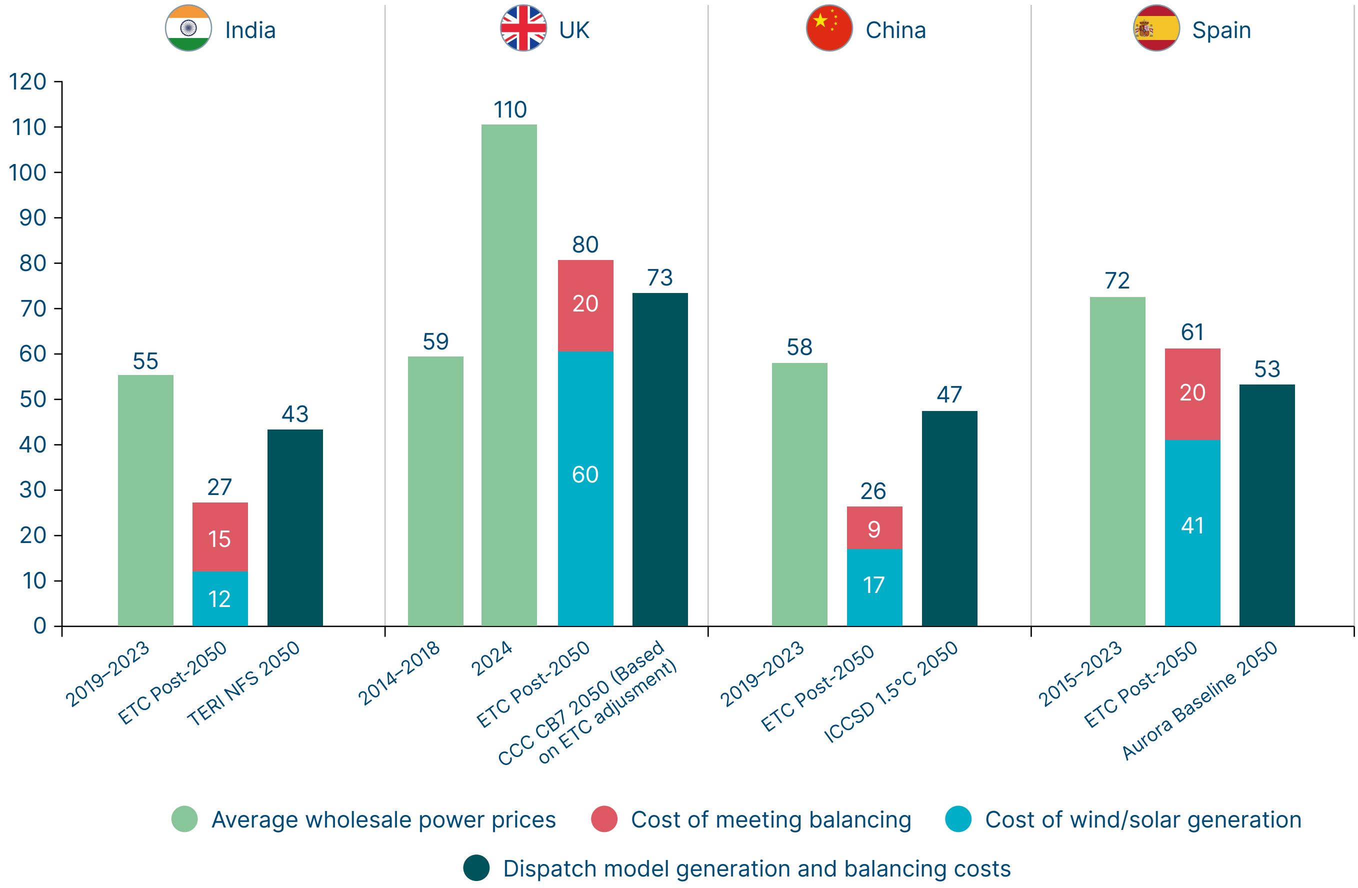
14 ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways*.

15 CCC (2025), *The Seventh Carbon Budget*.

Exhibit 5

Total system generation and balancing costs are likely to be lower than today's wholesale prices

Total system generation and balancing, recent vs. post-2050
$/MWh (real 2024$)



SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer;* Ofgem (2025), *Wholesale market indicators – Electricity Prices: Forward Delivery Contracts – Weekly Average (GB);* IEA (2023), *Electricity Market Report – Update 2023;* Statista (2024), *Average electricity prices for enterprises in China from September 2019 to September 2024;* Ember (2025), *Wholesale electricity prices in Europe;* CCC (2025), *The Seventh Carbon Budget;* TERI (2024), *India's Electricity Transition Pathways to 2050: Scenarios and Insights;* ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways;* Aurora (2023), *Long Duration Energy Storage in Spain.*

1.5 Last mile decarbonisation costs: the need for a pragmatic approach

In all power systems, the cost of decarbonisation will tend to increase as the carbon intensity of electricity generation (measured in grams per kWh) reaches very low levels. Analysis by TERI in India, for instance, showed that the total system cost per kWh would be minimised at a wind and solar share of 80%, but could increase at higher levels.[16]

A pragmatic approach to the achievement of the last mile decarbonisation is therefore appropriate, particularly in high latitude countries facing high costs for ultra-long duration balancing. This pragmatic approach should include a careful assessment of the relative merits of the alternative options considered in Section 1.3 above, burning hydrogen in gas turbines, using natural gas combined with CCS, or continuing to allow a small percentage of hours to be supplied by gas turbines without CCS.

The latter option would imply less than complete decarbonisation of the power system itself, but it could be compatible with whole economy decarbonisation if combined with high-quality removals (whether nature based or direct air capture), and it might be the most cost effective option if the cost of high quality removals were sufficiently low.

16 TERI (2021), *The Potential Role of Hydrogen in India.*

If, in the UK in 2050, 2.5 % of 600 TWh of demand were met with unbated gas turbines, this could result in about six million tonnes of residual emissions, leaving the UK with a power system carbon intensity of 10g per kWh. If these emissions were offset by removals costing $100 per tonne, paying for these removals would add just $1.0 per MWh to total system generation and balancing costs.

Governments should therefore remain open to flexible approaches for ultra-long duration balancing, and should carefully consider the potential trade-off between:

- Driving for complete decarbonisation of the power system.
- Switching the primary policy focus to driving faster electrification once a very low (e.g., less than 30g per kWh) carbon intensity has been achieved.

Acceptance of a role for unabated gas should however be underpinned by carbon pricing to minimise its scale and by regulation to ensure high quality removals.

2. Managing grid expansion to minimise costs per kWh

Rapidly growing electricity demand and rising wind and solar generation shares will require large scale investment in both transmission and distribution grids. However, costs per kWh could be reduced through well designed policies and technical innovation. We set out in turn:

- New challenges for grid management resulting from shifts in the pattern of demand and supply.
- Large scale investments needed in transmission and distribution.
- Opportunities to minimise the increase in total grid needs and costs.
- The potential to reduce grid cost per kWh if electrification progresses in line with decarbonisation.
- Implementation and policy priorities.

2.1 The changing shape of grids given new patterns of supply and demand

Power decarbonisation and wider electrification are changing the shape of electricity networks by increasing the complexity of grid design and operation through:

1. **Growing renewable generation and the reduced role for large thermal plants**, which is producing a more dispersed generation system with many more generation assets often distant from major demand centres.
2. **Electrification of road transport, buildings, and industry,** which is increasing average and peak power supply needs at household and local distribution level, and is creating new locations of industrial demand (including for artificial intelligence (AI) data centres).
3. **Growing rooftop solar PV generation**, sometimes combined with battery capacity, is moving generation supply "behind the metre," potentially reducing the need and revenue of distribution network companies.
4. **Multiple forms of storage capacity are becoming more important** and could connect at different levels of the distribution and transmission grids.

These factors have implications for the pattern and scale of demand, the scale of investment, and the implementation challenges faced at different network levels.

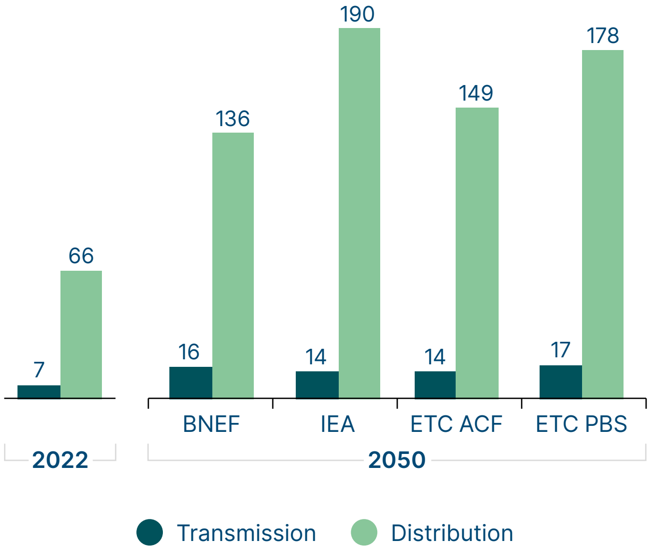
2.2 Scale of required investment for distribution and transmission grids

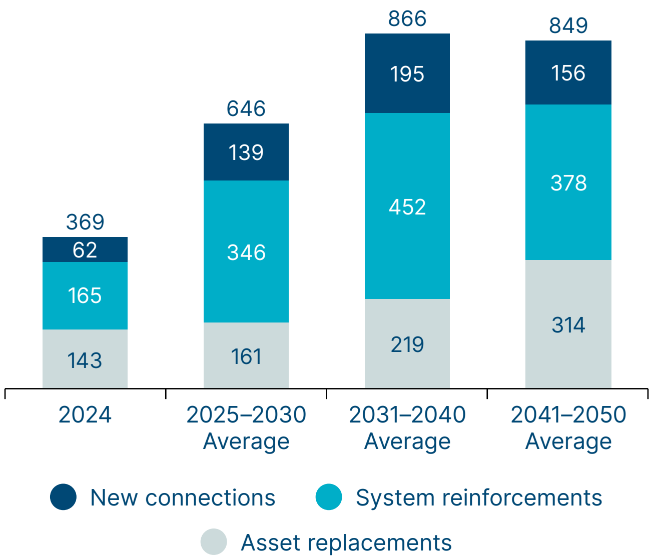
Rapid growth in electricity demand, together with the changing shape of grids, will require very significant investment in grids at both the transmission and distribution level [Exhibit 6]:

- For the transmission network, published scenarios suggest the total length of wires may need to more than double from around 7 million km today to 14–17 million km by 2050
- Distribution networks could need to more than double from around 60 million km today to 140–190 million km by 2050

Exhibit 6

Global grid investments: projected transmission and distribution buildout





NOTE: BNEF data used represents NZS (Net-Zero Scenario). The Accelerated but Clearly Feasible (ACF) scenario is clearly technically and economically feasible, but in some sectors will require more forceful policy support than currently in place. We have included 50% of hydrogen demand in these estimates. The Possible But Stretching scenario (PBS) Scenario is also technically and economically feasible but would require significant strengthening of current commitments and policies.

SOURCE: BNEF (2023), *NEO grids;* BNEF (2023), *NEO data viewer;* IEA (2023), *Electricity Grids and Secure Energy Transitions.*

In many developed countries, significant investment is needed to replace and modernise existing grids. In developing countries many new grid connections will be built for the first time but in all regions significant investment is required. Total global investment in grids could grow from around $370 billion in 2024 to a peak of $870 billion per annum in the 2030s and 2040s, with about 55% of the total required in the distribution network and 45% in transmission.

2.3 Optimisation to reduce grid investment needs

The key levers that could reduce the total grid investment required include demand side flexibility, innovative grid technologies, and improving the optimal location of generation, storage and large-scale demand.

2.3.1 Demand side flexibility: a major opportunity to reduce distribution network investment

Capacity in distribution networks and substations needs to be sized to meet peak electricity demands which could grow even faster than average electricity use, for instance, if EVs all tend to be charged at the same time of day: or if winter peak demands in high latitude countries increase because of the electrification of residential heat.

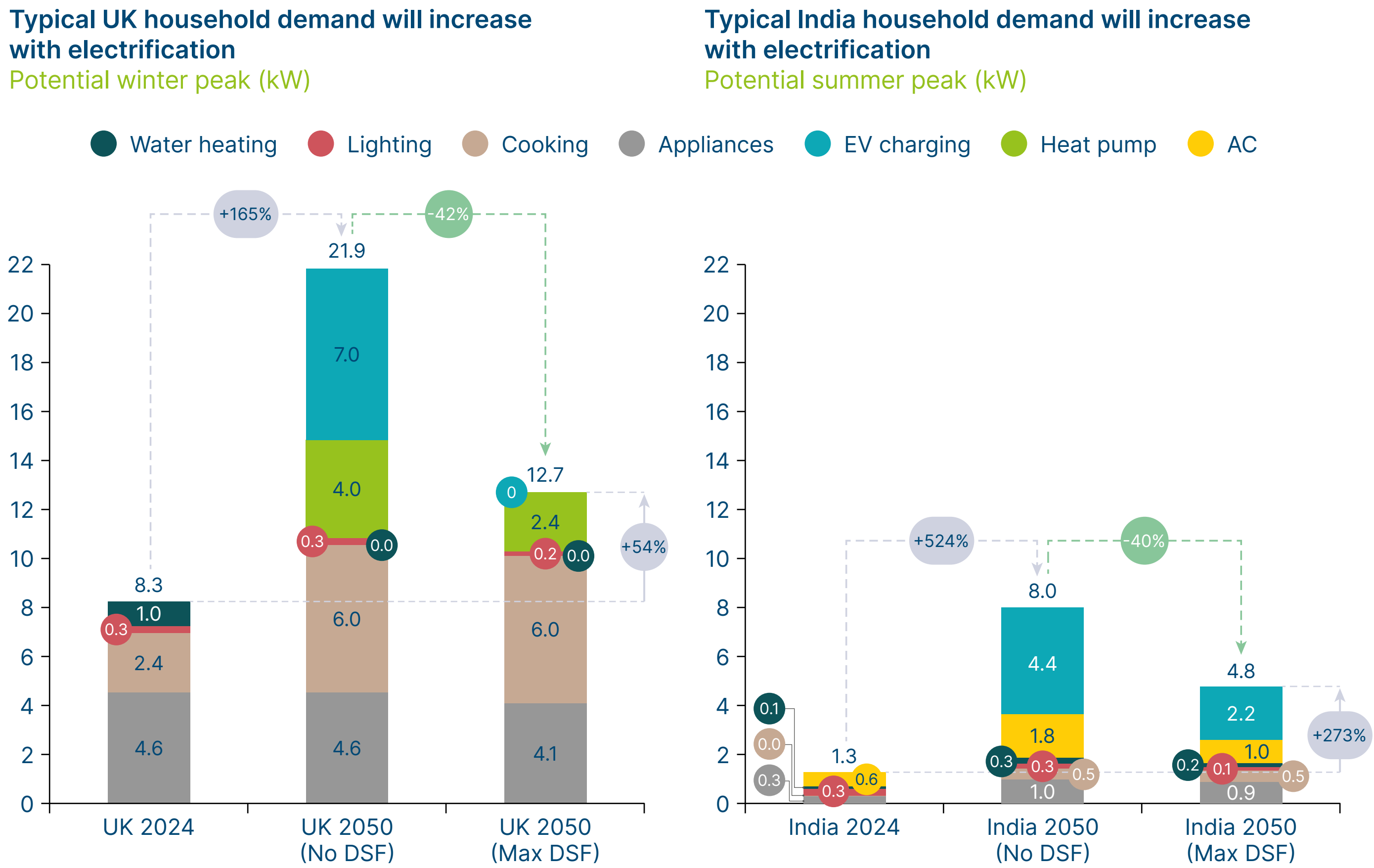
But households and businesses could shift electricity demand to other times of day, while still enjoying the same energy services benefits [Exhibit 7]:

- In the UK, a typical household's peak winter demand (most likely in the early evening) could rise 165% between now and 2050 because of the electrification of road transport, space heating and cooking, but this increase could be limited to 54% via DSF.
- In India, EV charging and expanding use of AC could increase peak demand in summer by around 520% but this increase could be limited to 270% via shifts in the timing of demand.

It is therefore essential to enable maximum demand side flexibility via the time of day pricing, smart metreinstallation, and other actions described in the ETC's briefing note, *Demand side flexibility – unleashing untapped potential for clean power.*[17]

Exhibit 7

Increases in household-level peak power demand are expected, however demand side flexibility can partially offset this increase



Driven by the electrification of:
- Household heating: Heat pumps draw approximately 4 kW of flexible demand.
- Personal vehicles: EV charging could contribute around 7 kW of flexible demand.

Driven by increased appliance penetration and electrification:
- AC: AC units draw around 3 kW of flexible demand
- Personal vehicles: EV charging could contribute around 4 kW of flexible demand (accounting for high proportion of three-and-two-wheelers).

NOTE: Indian data accounts for the penetration of appliances throughout the population, therefore these are averaged values which don't directly correlate with appliance consumptions.

SOURCE: Systemiq analysis for the ETC; TERI (2024), *India's Electricity Transition Pathways to 2050;* US Department of Energy (2018), *Department of Energy Announces $19 Million for Advanced Battery and Electrification Research to Enable Extreme Fast Charging;* Contemporary Structures (2023), *How Much Electricity Does a Heat Pump Use?*

17 ETC (2025), Demand-side flexibility an important route alongside electricity grids and storage https://www.energy-transitions.org/bitesize/demand-side-flexibility-an-important-route-alongside-electricity-grids-and-storage/

2.3.2 Innovative grid technologies (IGTs) to reduce network investment needs

There are multiple new grid technologies available which could significantly reduce overall grid investment [Exhibit 8]. These include both:

- Hardware solutions such as advanced conductors which can double the maximum capacity of a pylon line and reduce line losses by 25–50%
- Software solutions such as dynamic line rating which can increase line capacity by 10–45%

Analysis by CurrENT found that implementing innovative grid technologies could unlock 20–40% capacity improvements in European networks by 2040. BNEF analysis suggests that 10–35% of Europe's network expansion costs to 2050 could be eliminated via IGTs [Exhibit 9].

Exhibit 8

Innovative grid technologies – Key hardware solutions

IGT	Benefits	TRL[A]	Network capacity increase (% of line capacity)
Advanced Conductors	Increases the efficiency, capacity, and reliability of power lines enabling higher capacities per line and reduced sag and losses.	9	100–300%
Superconductors	Eliminates electrical resistance, allowing for zero resistive losses during transmission.	7 at Dx 5 at Tx	400–1000%
Voltage Upgrade	Increases the voltage of power cables reduces losses, enabling higher power transfer.	9	30–400+%
Storage as Transmission Asset (SATA)	Avoids congestion and curtailment during periods of excess generation, via active congestion relief.	9	40%

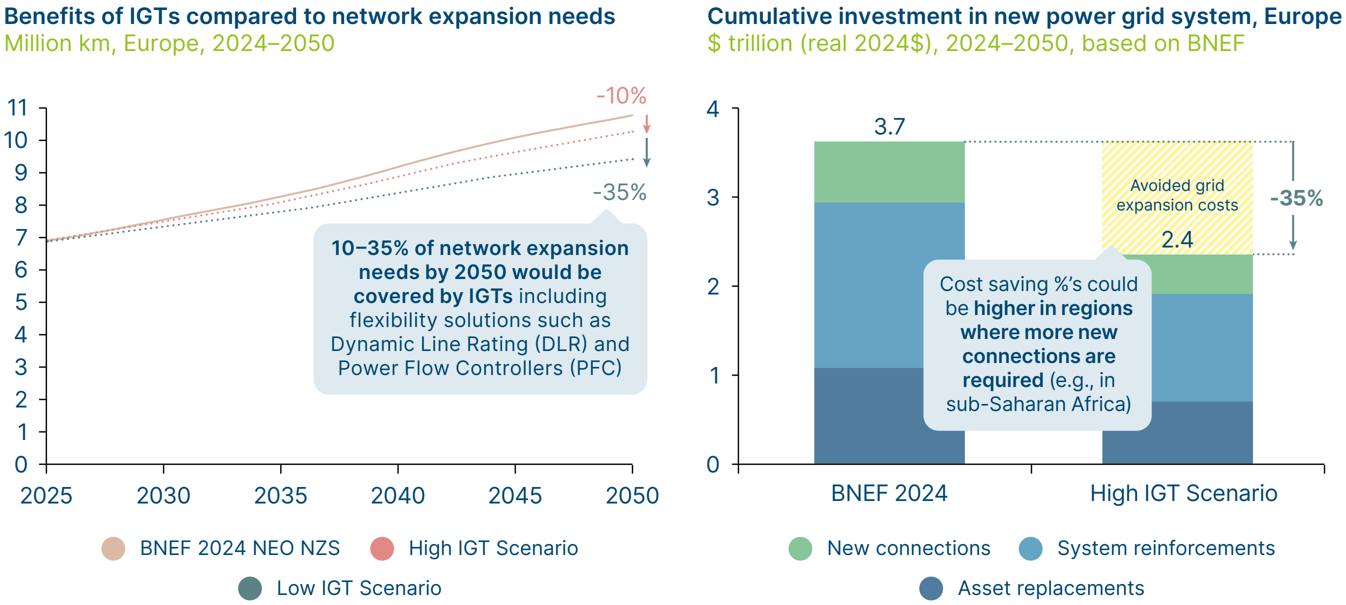
Innovative grid technologies – Key software solutions

IGT	Benefits	TRL[A]	Network capacity increase (% of line capacity)
Grid Inertia Measurements	Generates live and accurate grid inertia data through frequency modulation, improving the understanding of inertia and stability limits in the system.	9	30%
Flexible AC Transmission Systems (FACTS)	Enable dynamic controlling of power flows on the grid. Includes Advanced Power Flow Control, Static VAR Compensators (SVCs), and Static Synchronous Compensators (STATCOMs).	9	30%
Dynamic Line Rating (DLR)	Improves network efficiency by providing better visibility and understanding of actual line limits.	9	30%
Flexibility management software	Integrates network data and external factors (e.g., weather) to simulate real-time and future grid conditions.	9	30%

SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies;* BNEF (2023), *New Energy Outlook Grids;* New Civil Engineer (2024), *National Grid publishes plan to invest £35bn in UK transmission from 2026 to 2031;* Quanta Technology (2023), *Storage as Transmission Asset Market Study;* Energies (2025), *Energy Storage as a Transmission Asset—Assessing the Multiple Uses of a Utility-Scale Battery Energy Storage System in Brazil.*

Exhibit 9

Innovative grid technologies could significantly reduce grid build and investment



NOTE: We have assumed that IGTs impact all three investment categories: IGTs lower new connection needs by maximising existing and new infrastructure use (though some remote renewables still need connections, new connections leveraging IGTs will require fewer upgrades in future); IGTs delay system replacements by extending grid asset life; and IGTs reduce reinforcement requirements by improving line capacity and utilisation.

SOURCE: Systemiq analysis for the ETC; CurrENT (2024), *Prospects for innovative power grid technologies*; BNEF (2024), *New Energy Outlook*.

2.3.3 Optimal location of generation, storage and large scale demand

Optimal location of generation, storage and large scale demand can significantly reduce the need for grid capacity at both the transmission and distribution levels. Incentives for locating new sources of demand and supply close to existing network capacity are therefore important. One high potential opportunity in some countries is to locate new large sources of supply or demand in the location of decommissioned coal power plants, enabling utilisation of already existing high capacity grid connections.

2.4 Potential fall in grid costs per kWh – provided rapid electrification occurs

Even with significant application of demand side flexibility and innovative grid technologies, and optimal siting of new supply, demand and storage, there will still be very significant grid investment needs. Total grid costs will therefore rise and so too will grid service prices charged to customers, which usually reflect total assets multiplied by an allowed rate of return.

But these higher total grid costs will support a rapidly rising volume of electricity demand, and grid cost per kWh could therefore remain close to today's levels, with an initial rise as grid companies invest ahead of demand, and a subsequent decline [Exhibit 10].

It is therefore vital to ensure that electrification and decarbonisation of electricity supply occur in parallel.

- In China, where electricity demand has soared from 5,850 TWh in 2015 to 10,000 TWh in 2024,[18] the crucial priority is to ensure that decarbonisation of power generation is achieved as rapidly as possible.
- In Europe and the US, by contrast, electricity demand has been flat and in some countries declining over the last 15 years, while significant grid decarbonisation has already been achieved.

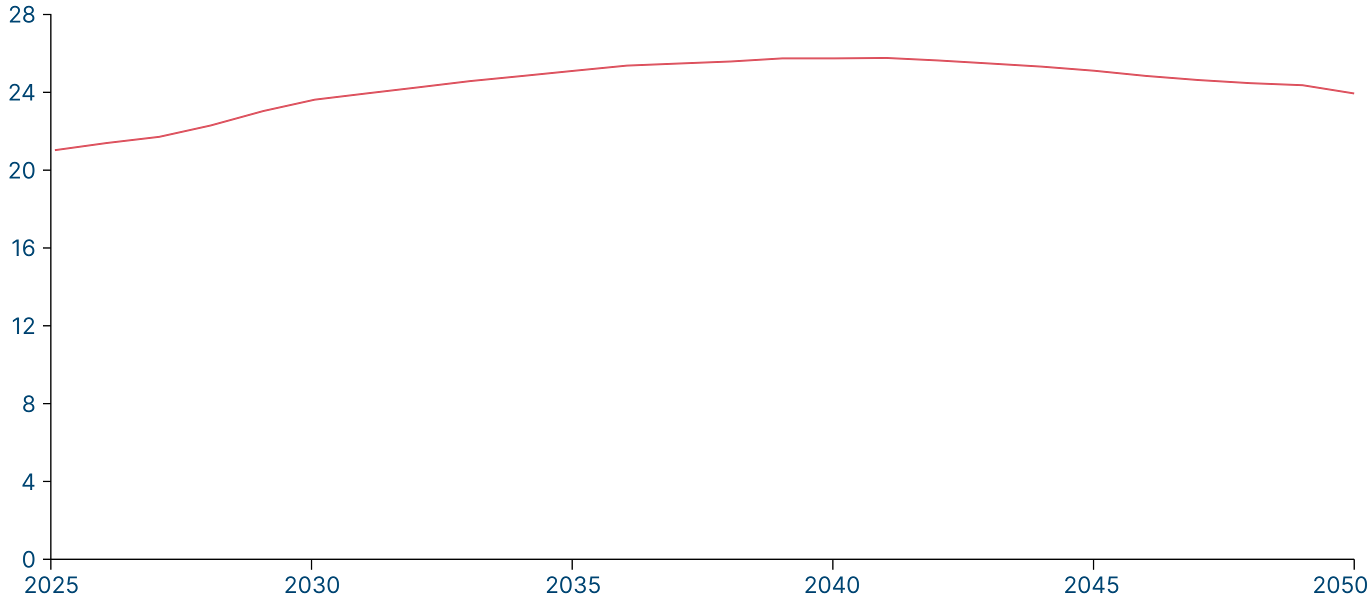
Looking forward it is essential that developed countries electrify as rapidly as they decarbonise and take the pragmatic attitude towards last mile decarbonisation discussed in Section 1.5 above. Without that balance there is a danger that increased investment in balancing mechanisms and grid capacity could increase the per kWh cost of electricity, reducing the incentives for electrification.

18 IEA (2025), *Electricity 2025 Analysis and forecast to 2027.*

Exhibit 10

Global Electricity Supply

Grid CAPEX costs (Tx & Dx) per demand unit, 2025–2050
$/MWh (real 2024$) for payments per unit demand



NOTE: The old system represents all grid built pre-2024, while the new system represents all grid built during and post-2024. Payment projections assume a 5% interest rate in real terms and 30-year CAPEX repayment timeline. 50% of indirect use for hydrogen production in the ETC's Accelerated but Clearly Feasible (ACF) scenario is included. Differences in 2050 demand projections compared to the hourly demand data used in the balancing analysis arise from the different assumptions baked into BNEF and ETC demand trends, and the data sources used for the detailed 2050 breakdown.

SOURCE: IEA (2023), *Investment in transmission and distribution grids in selected countries, 2015-2022*; BNEF (2024), *New Energy Outlook 2024*; CCC (2020), *The Sixth Carbon Budget*; NESO (2024), *Future Energy Scenarios*; TERI (2024), *Electricity Transition Pathways to 2050.*

2.5 Implementation and policy priorities

Meeting decarbonisation commitments and electrification targets requires major expansion and upgrade of transmission and distribution networks. But the scale and cost of this investment can be significantly reduced with the right planning and policy frameworks. Key priorities include:

- Integrating strategic spatial planning for generation, demand, and grid investment to ensure timely and efficient buildout, avoiding over or underbuilding, relative to demand growth, reducing the cost of grid services per kWh.
- Reforming regulatory frameworks to enable anticipatory investment, incentivise innovative grid technologies, in the short-term to prioritise "low-regret" grid upgrades and support demand side flexibility through time of day pricing.
- Accelerating planning and permitting processes to reduce delays, especially for long distance transmission and grid modernisation projects.
- Introducing robust locational signals to guide new generation and large demand users towards areas with available or easily expandable grid capacity.
- Addressing supply chain bottlenecks and workforce shortages, including for transformers, cables, and skilled engineers.

3. Total system generation, balancing and grid costs in the long-term and during transition

In the long-term, total system costs per kWh in power systems with high shares of wind and solar could be below the cost of today's fossil fuel-based systems.

But in the higher cost countries in particular, transitional costs need to be carefully managed to avoid increases in consumer price which could undermine support for the transition and discourage electrification.

3.1 Total system generation, balancing and grid costs per kWh in the long term

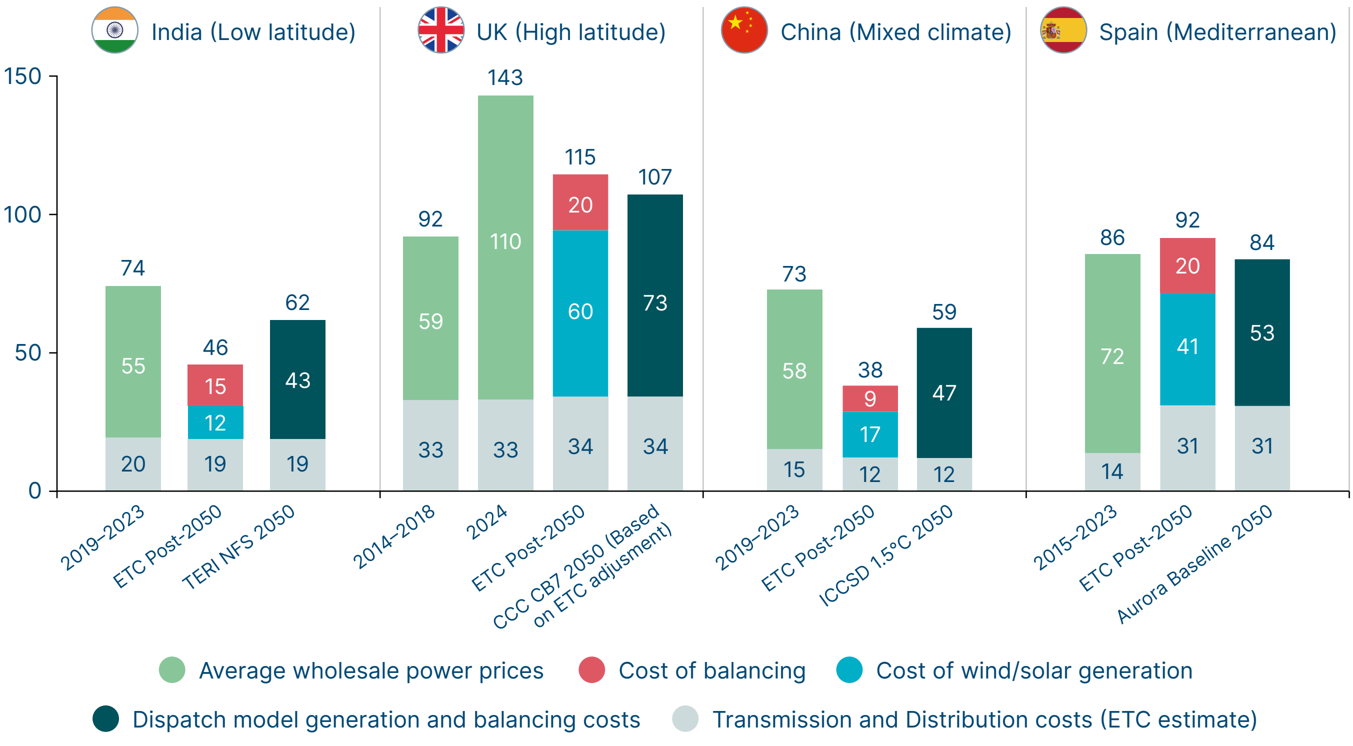
Exhibit 11 combines the total system generation and balancing costs considered in Section 1.4, and the grid cost per kWh considered in Section 2. The numbers show the projected cost of enerating and delivering electricity at the country level, excluding the retail costs of marketing, customer service, and billing, and excluding any taxes/levies imposed by government.

The ETC projections show the potential cost of wholesale electricity from 2050 onwards, and are compared with dispatch model estimates of possible costs in 2050.

Exhibit 11

Total system generation, balancing, and grid costs could be lower than current wholesale prices

Total system costs (generation, balancing, and grids), recent vs post-2050
$/MWh (real 2024$)



NOTE: T&D = Transmission and distribution. T&D costs per MWh have been assumed based on ETC modelling outlined in Chapter 2.

SOURCE: Systemiq analysis for the ETC; BNEF (2025), *LCOE: Data Viewer;* Ofgem (2025), *Wholesale market indicators – Electricity Prices: Forward Delivery Contracts – Weekly Average (GB);* IEA (2023), *Electricity Market Report – Update 2023;* Statista (2024), Average electricity prices for enterprises in China from September 2019 to September 2024; Ember (2025), *Wholesale electricity prices in Europe;* CCC (2025), *The Seventh Carbon Budget;* TERI (2024), India's Electricity Transition Pathways to 2050: Scenarios and Insights; ICCSD (2022), *China's Long-Term Low-Carbon Development Strategies and Pathways;* Aurora (2023), *Long Duration Energy Storage in Spain.*

The total system costs vary by region:

- **For low–latitude, sunny countries** (e.g., India), both the ETC projection and TERI's dispatch model results suggest future costs for a high wind and solar-based system well below the cost of today's fossil fuel dominated system.
- **For Mediterranean climates** (e.g., Spain) both the ETC analysis and Aurora's dispatch based model suggest total costs similar to the recent past.
- **In China (continental scale countries with multiple climatic regions)** both our analysis and ICCSD's model results suggest that costs could be significantly below today's wholesale prices.
- **For high latitude countries** (e.g., UK) both our analysis and the CCC's modelling suggests that costs could be significantly below wholesale prices in 2024, but potentially higher than in the period 2014-18. The ETC figures presented here do not, however, allow for the potential benefit of maximising demand side flexibility or of new international long-distance interconnectors which together could significantly reduce costs.

While all long-term projections are inherently uncertain, and dependent on future trends in technology, the overall picture is still clear. High share of wind and solar power systems could in most countries deliver power at costs below today's fossil fuel systems: and costs will be lowest in countries where solar is the predominant source of electricity supply and where balancing needs are primarily short term.

This implies a major opportunity for low cost clean electrification in many countries in the "global sun belt" and, as highlighted in Mission Possible Partnership's report, *Clean Industry: transformational trends* and may in turn create opportunities for those countries to develop cost competitive low carbon industry.[19]

In all countries, clean electricity systems would also deliver a major benefit in the form of reduced price volatility. While fossil-based electricity systems are exposed to fuel price shocks, as seen during 2022–23, wind- and solar-based systems have low and stable marginal costs. Over time, this stability will significantly improve energy security and economic resilience.

3.2 Managing the cost of the transition

Exhibit 12 shows that in the long-term, power systems with high shares of wind and solar generation are likely to be lower cost than today's fossil fuel based systems in most countries. But costs in the early stages of the transition could be increased by:

- Legacy contracts (e.g., feed in tariffs or contracts for difference (or CfDs)) to support technologies which in the early stages of development have been higher cost.
- Investments in balancing capacity and grids ahead of the increase in electricity demand.
- Policy-related levies and taxes which, in some countries, place the cost of transition on electricity prices but not fossil fuels (e.g., UK carbon prices applied to gas based generation but not to direct residential gas use, and levies to cover public policy costs (such as energy efficiency schemes or renewable subsidies) which in many cases fall disproportionately on electricity bills but not on gas bills.

Multiple policy levers should therefore be used to avoid and offset these transitional costs. These levers include:

- Reducing the number of hours where gas sets the wholesale price, for example, by rapidly scaling renewables supply via auctions with two-way CfDs or corporate Purchase Power Agreements (PPA).
- Rebalancing low-carbon policy costs away from electricity to either gas bills or general taxation.
- Time-of-use tariffs, real-time pricing, or other wholesale price signals which can incentivise household and business customers to shift their electricity use to low cost, off-peak times.
- Incentivising self-reliance (e.g., through solar and batteries) across residential and industrial properties.
- Extending amortisation periods for grid assets, and lengthening CfD contracts, to reduce annualised capital costs.
- Supporting rapid electrification and following a pragmatic approach to last mile decarbonisation.

19 MPP (2025), *New 'industrial sunbelt' set to overtake the world's biggest economies in clean industry race.*

4. Key enablers for cost-effective power system development

It is possible to develop power systems which are much larger than today, which depend primarily on wind and solar generation and deliver round the clock electricity at costs similar to or below today's fossil fuel based systems. However, achieving this will require six key enablers [Exhibit 12].

Exhibit 12

Six key enablers for power systems transformation

SOURCE: Systemiq analysis for the ETC.

Strategic vision and system planning must become more integrated and forward looking. Planning frameworks should align grid infrastructure, generation, and flexibility investments with national decarbonisation and electrification goals. They must be based on a granular understanding of future system balancing needs, guiding the least cost mix of technologies and ensuring grid expansion occurs in anticipation of demand, not in reaction to it. Clear institutional mandates and cross-sectoral coordination will be essential to align delivery with strategic objectives.

Electricity market design must evolve to reflect the characteristics and value of new flexibility technologies. Current market structures often fail to adequately remunerate resources such as long duration storage, demand response, and grid forming inverters. Reforms are needed to ensure these technologies can access wholesale, ancillary, and capacity markets on equal terms, and that market signals reward their contribution to system adequacy, speed, and locational value. Mechanisms that reduce investor risk, such as CfDs, cap-and-floor models, or long term procurement, will be essential to scale capital intensive assets.

Grid regulation, digitalisation, and supply-side and consumer readiness must all support system transformation. Grid regulation should enable timely and cost-efficient infrastructure development, streamlining connection processes, allowing non-firm access, and removing disincentives such as double-charging for storage. Digitalisation and data-driven tools, including AI-based forecasting, smart metres, and digital twins, can improve grid operation, reliability, and flexibility.

Supply chains and workforce capacity must be scaled in line with rising infrastructure needs, and consumers enabled to play a greater role in system balancing through dynamic tariffs, automation, and behind-the-metre assets, supported by strong data protection and interoperability standards.

Top actions for policymakers, businesses and investors

Strategic vision and planning

▶ Establish an integrated strategic vision that sets clear, time-bound targets for renewables, storage, flexibility, and grid infrastructure.

▶ Governments should develop whole-system planning frameworks to coordinate investments across generation, transmission, and flexibility. Planning should be based on a granular understanding of the specific balancing needs each country will face and should define the least-cost mix of flexibility options to address these.

▶ Clear institutional mandates and anticipatory investment strategies are essential to deliver infrastructure ahead of need and in line with electrification trajectories.

Grid regulations

▶ Modernise regulatory frameworks to unlock timely investment in transmission and distribution infrastructure and accelerate project delivery.

▶ Streamline grid connection processes with transparent timelines and milestone-based queue management that prioritises viable projects.

▶ Reform grid fee structures to eliminate double-charging for storage and enable non-firm access models that reduce costs and connect assets faster.

▶ Regulations must support grid operators in deploying innovative grid technologies (e.g., dynamic line rating, smart transformers) that increase capacity utilisation and defer costly reinforcement.

Supply chain and workforce

▶ Address critical bottlenecks by aligning national infrastructure plans with long-term demand signals to enable anticipatory investment in key technologies (e.g., transformers, HVDC systems, battery storage).

▶ Use public-private partnerships to expand manufacturing and installation capacity, and launch coordinated workforce strategies focused on grid engineering, digital operations, and flexibility deployment.

Market design

▶ Reform electricity market structures to enable emerging flexibility technologies compete on equal terms with incumbent assets.

▶ This requires ensuring full access to all relevant markets (wholesale, ancillary, capacity) and reforming existing markets, where necessary, to value and remunerate new technologies based on their contribution to system adequacy and reliability, not on legacy operational profiles.

▶ Introduce de-risking mechanisms such as two-way CfDs, long-term PPAs, or cap-and-floor contracts to lower the cost of capital for capital-intensive assets.

▶ Close innovation gaps through targeted public support for earlier-stage technologies with high system value.

Data and AI modernisation

▶ Leverage AI and advanced digital tools to improve power system planning, optimise grid operations, and enhance system stability and safety.

▶ AI-driven forecasting and scenario modelling enable better anticipation of demand, generation, and congestion patterns–supporting more efficient investment decisions.

▶ Real-time data and automation improve fault detection, system resilience, and the safe integration of variable renewables and distributed assets. Smart meters and digital controls are critical enablers of responsive demand and grid flexibility.

Consumers

▶ Build consumer trust in demand-side flexibility by ensuring transparency, data privacy, and user control, alongside strong consumer education on the benefits of participation.

▶ Design intuitive, automated, and interoperable flexibility products that reduce friction and cater to diverse user needs, enabling large-scale adoption across residential, commercial, and industrial users.

▶ Scale DSF through coordinated national and local action, supported by targeted policy, investment, and governance, including digital infrastructure, local flexibility markets, and public sector procurement standards.

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