

THE UK ENERGY STRATEGY NEEDS URGENT REVIEW

A position paper from the Institution of Engineers in Scotland.

Version A.2 • October 2026

IES
A MULTI-DISCIPLINARY ENGINEERING INSTITUTION

About the Institution and this paper

The Institution of Engineers in Scotland was founded in 1857 as a forum where engineers from different disciplines could exchange experience, challenge ideas and contribute to technical progress. Its membership has included many of Scotland's leading engineers, scientists, academics and industrialists, and it has hosted presentations from recognised authorities across a wide range of fields. That tradition of evening paper presentations continues today, alongside close links with the Institution of Civil Engineers (ICE), the Institution of Mechanical Engineers (IMechE) and the Institution of Engineering and Technology (IET).

This paper has been prepared by engineers from a range of disciplines, drawing on decades of industrial experience. It combines analysis of published energy-policy statements with a gap analysis of issues that are integral to implementation but are not always addressed explicitly. It also draws on the practical experience of contributors who have worked in electricity generation, transmission and distribution.

The technical analysis, judgements and recommendations in this paper originate from the contributing expert group. AI-assisted tools have been used to support editing, consistency and presentation. Responsibility for the content and conclusions remains with the authors.

The Institution of Engineers in Scotland (IES) thanks the following for their input in preparing this paper:

- The late Professor Iain MacLeod, BSc (Hons), PhD, CEng, FIStructE, FIES
- The late Mr Colin Gibson BSc, CEng, CMgr, FIET, CCMI
- Mr Charles Scott ARCST, BSc, DipTP, CEng, FICE, MIMechE
- Mr Norman McNab BSc (Eng) C Eng MIET FIES
- Mr Robin MacLaren BSc (Hons) CEng, FIEE, AMIEEE, FIES, FRSSA

Executive Summary

The United Kingdom has committed to Net Zero by 2050, while electricity demand is expected to rise substantially as transport, heating and industry become more electrified. It is challenging to achieve the transition to low carbon electricity and deliver at the same time lower costs, system security and resilience.

Britain has some of the highest domestic and industrial electricity prices in the developed world.[11,24] Bringing those costs down should therefore be a central objective of energy policy. That means looking beyond the generating cost of individual technologies and asking a more important question: what does it cost to deliver reliable electricity to the consumer? Generation, networks, storage, balancing, constraint payments, backup capacity and system-security services all contribute to that final cost.

Key messages

- **Electricity costs must fall.** A successful Net Zero transition must deliver internationally competitive electricity prices for industry and affordable electricity for households.
- **Whole-system cost matters more than individual generation costs.** Technologies should be compared on their contribution to the cost, security and performance of the complete electricity system.
- **Wind and solar variability must be engineered into the system.** Extended periods of low renewable output can last for several days and, under some meteorological conditions, considerably longer. The system must be designed explicitly for these events.
- **Storage and firm generation must be planned together.** Government, Ofgem and NESO are already developing long-duration storage and other flexibility measures, but the required scale of storage depends fundamentally on the amount of firm generation available. Nuclear, other firm generation, storage, interconnection, hydro and demand flexibility should therefore be optimised as an integrated portfolio.
- **The storage requirement must be quantified in energy as well as power.** Government and NESO should publish the required storage power (GW) and energy capacity (GWh/TWh), assumed discharge durations, technology mix, expected utilisation, indicative capital and infrastructure requirements, land-use implications and delivery programme, assessed transparently against explicit national security-of-supply and resilience standards.
- Nuclear has an important system role. In addition to providing low-carbon electricity, nuclear offers weather-independent firm generation, contributes to system stability and has a very high energy density and comparatively small physical footprint. A greater nuclear contribution would reduce the requirement for stored energy and other flexibility during prolonged periods of low renewable output. The planned closure of Torness in 2030 therefore requires explicit policy attention: Scottish and UK energy policy should address the loss of approximately 1.2 GW of firm, synchronous, low-carbon generation and assess replacement firm low-carbon capacity, including the potential for new nuclear at or near the existing site.
- **System stability must remain a primary engineering requirement.** High penetration of inverter-connected generation changes system dynamics, including inertia, fault response, voltage control and restoration. These capabilities can increasingly be provided electronically, but they must be demonstrated and engineered at system scale.
- **Environmental impacts should be assessed on a whole-system basis.** Generation, transmission, storage and supporting infrastructure all have land, landscape and ecological consequences. These should be considered alongside cost, carbon and security.
- **Long-term policy continuity is essential.** Major energy infrastructure is planned, financed and delivered over periods spanning several Parliaments. Sufficient cross-party and institutional continuity is needed to maintain investor and supply-chain confidence, control costs and reduce delivery risk, while allowing governments to change the technology mix used to meet enduring security, resilience and affordability objectives.

- **The UK needs an explicit electricity-system resilience standard.** Government and NESO should define the level of security required during prolonged periods of low renewable generation and demonstrate that the planned system can meet it.

The central requirement is therefore to move beyond individual technology targets and engineer the electricity system as a whole. Alternative pathways should be compared transparently on whole-system cost, security, resilience, deliverability and environmental impact.

Net Zero remains technically achievable. Its long-term economic and political sustainability, however, will depend on delivering a secure electricity system at a cost that households and industry can afford.

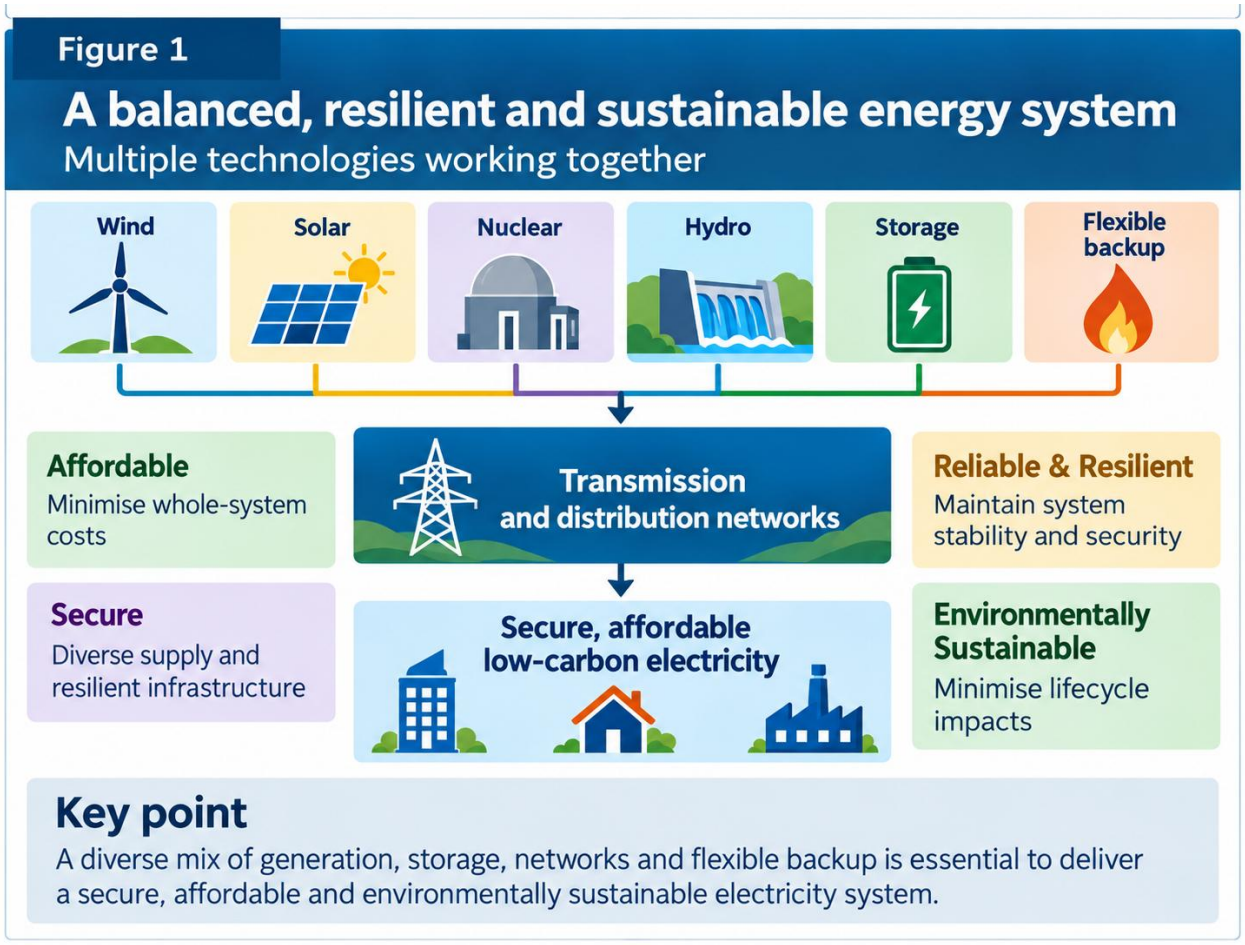


Figure 1. A balanced, resilient and sustainable energy system

Introduction

Electricity is essential to the functioning of modern society. Even brief interruptions can be disruptive and costly; prolonged interruptions can become life-threatening. Transport, water and wastewater services, healthcare, communications, finance and information technology all depend on a reliable supply. Electricity must also remain internationally competitive if the UK is to sustain economic growth and industrial capacity.

The UK's commitment to Net Zero greenhouse gas emissions by 2050 implies that electricity must be supplied almost entirely from low-carbon sources, primarily wind, solar, hydro, tidal, nuclear and geothermal. Electrification of transport, heating and industry will substantially increase both annual electricity consumption and peak electricity demand towards 2050. The generating capacity required to meet that demand will depend on the generation mix, plant availability, storage, interconnection and demand flexibility, and will necessarily differ from peak demand itself.[1]

NESO publishes Future Energy Scenarios (FES), which show how electricity generation and demand might develop on different paths to 2050.

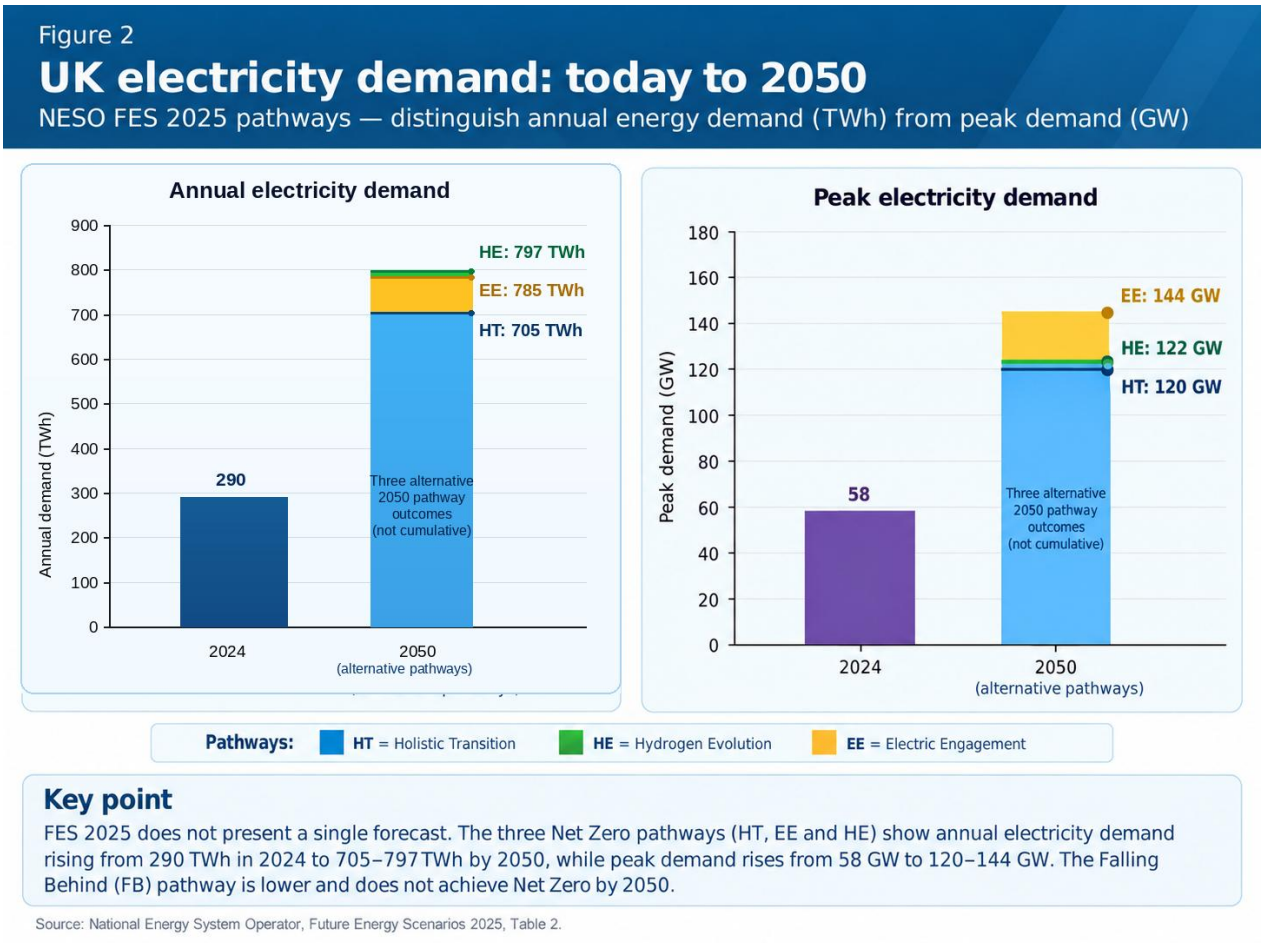


Figure 2. UK electricity demand: today to 2050 (NESO FES 2025 pathways)[2][3]

The Institution of Engineers in Scotland fully supports the long-term transition away from unabated fossil fuels. The health of the planet requires it, and the engineering profession has a central role in making it work. But supporting the destination does not mean that every part of the present route should escape scrutiny. In the

Institution's view, current policy carries a material risk of failing one or more of four tests that have to be met at the same time:

- **Affordable:** electricity prices must be competitive domestically and internationally.
- **Secure:** supply must be dependable and resilient to disruption.
- **Reliable and Resilient:** the system must maintain stability under all foreseeable conditions.
- **Environmentally Sustainable:** transition must minimise cumulative environmental and social harm.

The Institution is not opposed to wind, solar or other intermittent generation; it regards them as essential parts of the future energy system. The concern is about balance: how large a share of the generation mix they should provide, and whether enough firm low-carbon generation, storage, network capacity and system services are being built alongside them.

If these tests are not met, the consequences will extend beyond the electricity sector. Economic competitiveness will suffer, public support for the transition may weaken and, in the worst case, social stability could be affected. Government should therefore treat affordability, security, reliability and environmental sustainability as practical constraints on policy, not simply as aspirations.

Affordability and Whole-System Costs

Electricity Prices

For the UK to remain economically competitive, the cost of electricity to industry and consumers must be competitive with that faced by comparable economies.

UK industrial electricity prices are among the highest in comparable developed economies. Official UK analysis reports that, in 2024, industrial electricity prices including taxes were the highest among countries in the International Energy Agency comparison.[11] This is more than a temporary inconvenience. Without deliberate action, there is a real risk that the transition could lock in, rather than remove, a structural cost disadvantage.

Routes to Lower Electricity Costs

There is no single cause of the UK's electricity-cost disadvantage. Wholesale prices, network costs, policy costs, balancing and reserve requirements, constraint costs and the financing of major infrastructure all contribute. Bringing prices down therefore requires coordinated action across the whole system rather than one headline intervention.

- **Policy costs:** Review the policy costs carried through electricity bills and the way they are allocated, particularly where they materially affect international industrial competitiveness.
- **Network, balancing and constraint costs:** Improve the coordination of generation, storage, demand and network reinforcement so that avoidable congestion, curtailment and balancing costs are reduced.
- **Whole-system investment appraisal:** Assess major generation and policy choices using the cost of reliably delivered electricity, including attributable network reinforcement, storage, reserve, balancing and stability requirements, rather than generation cost alone.
- **Cost of capital:** Use financing structures appropriate to long-lived essential infrastructure where these can reduce risk and lifetime financing costs without transferring disproportionate risk to consumers or taxpayers.
- **Exposure to gas price-setting:** Reduce unnecessary exposure to volatile gas prices while ensuring that the replacement mix still provides adequate firm capacity and flexibility during periods of low renewable output.

Public debate often assumes that more renewable generation, particularly wind, will automatically reduce electricity bills. The Institution recognises that the levelised cost of energy from new wind and solar installations has fallen substantially. But generating a unit of electricity is not the same as delivering that unit reliably to a consumer. Network reinforcement, balancing, storage and system-stability measures all have to be paid for. It is the whole-system cost that ultimately matters to households and industry.

Current policy statements do not always make that distinction clearly enough. Integrating large volumes of intermittent generation requires substantial supporting infrastructure, and its cost should be identified transparently. Renewable generation, storage and transmission and distribution reinforcement should therefore be planned as one system programme, so that generation is not built significantly ahead of the network and flexibility needed to use it efficiently.

Whole-System Costs

Unlike conventional dispatchable generation, which is energy-dense, controllable and historically often located closer to major demand centres, renewable generation is geographically dispersed, lower-density and intermittent. Maintaining a secure and reliable system with high volumes of intermittent generation requires:

- **Significant expansion and reinforcement of transmission networks.**
- **Balancing services and reserve capacity to manage moment-to-moment fluctuations.**

- **Long-duration flexibility to cover extended periods of low renewable output.**
- **Technical measures and services to maintain frequency, voltage, system strength and stability.**
- **Management of constraints where generation cannot be absorbed by the network.**

These costs are not captured by comparisons based only on the levelised cost of individual generation technologies. Whole-system analysis must include them. The Institution therefore recommends that whole-system cost accounting should become the standard basis for energy-policy evaluation, with the resulting costs made visible to consumers and policymakers.

These measures also need to be considered together. Lower generation costs will not automatically produce lower consumer or industrial prices if network, balancing, flexibility, financing and market-design costs continue to rise. The strategic objective should be straightforward: reduce the whole-system cost of reliable electricity.

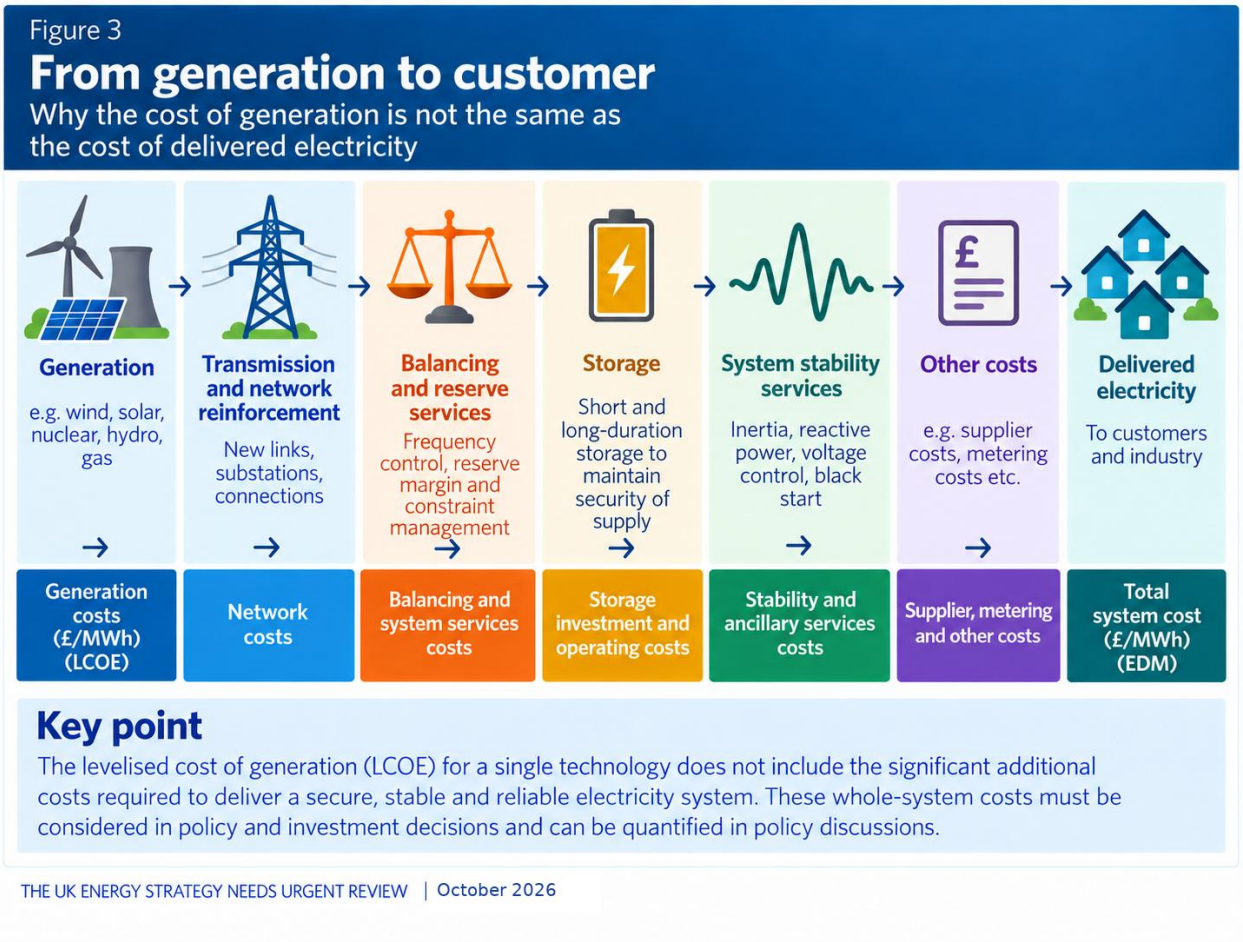


Figure 3. From generation to customer

Energy Storage and Long-Duration Flexibility: The Critical Challenge

Energy storage and other forms of flexibility are fundamental to a power system with a high proportion of intermittent generation. Supply and demand must be kept in balance continuously, using a portfolio of storage, flexible generation, interconnection, demand response and other system services.

Short-Duration Storage

Short-term fluctuations in renewable output, measured in hours, can be managed through a combination of battery storage, pumped hydro, liquid-air energy storage, gravity systems and flywheels. Hydrogen may also have a role, particularly in industry and potentially in long-duration storage and dispatchable generation. But the practical questions remain significant: conversion losses, infrastructure requirements, combustion-emissions control and the economics of hydrogen-to-power at the scale needed for system resilience have yet to be demonstrated. Proven flexibility technologies must therefore be delivered in step with renewable generation and network expansion.

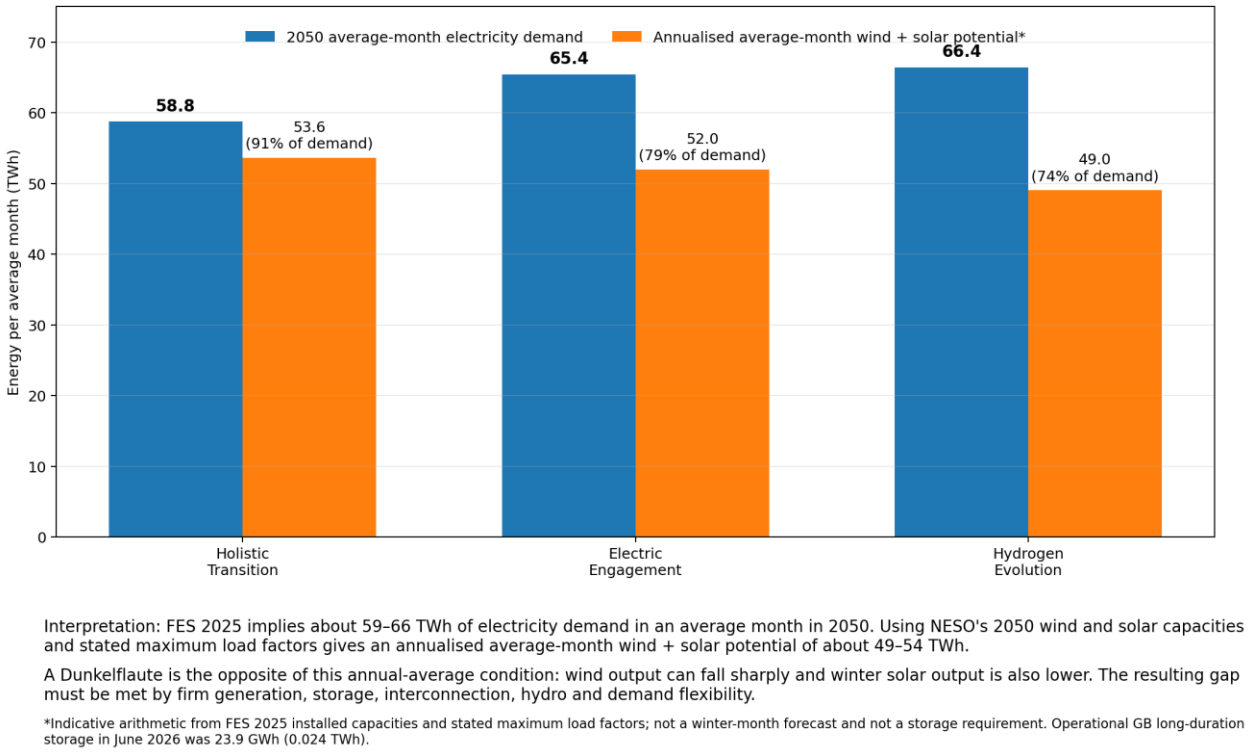
Long-Duration Storage: The Dunkelflaute Problem

The more serious and less widely understood problem is an extended period of low wind combined with minimal solar output. This phenomenon, commonly described as Dunkelflaute, is well documented and can persist for days or longer, particularly under persistent high-pressure conditions.[12] UK Government scientific advice chaired by the Met Office Chief Scientific Adviser notes that blocking events capable of suppressing wind generation often last one to two weeks, and that widespread wind droughts can occur across the UK and Europe at the same time. In those circumstances, interconnection may offer less help than expected.[12] Planning for such events requires a different order of flexibility from ordinary daily balancing.

A useful way to illustrate the scale of the challenge is to relate it to the 2050 electricity system described by NESO. FES 2025 gives annual electricity demand of 705 TWh in Holistic Transition, 785 TWh in Electric Engagement and 797 TWh in Hydrogen Evolution — equivalent to approximately 58.8–66.4 TWh in an average month.[2] These are scenario outputs, not forecasts.

The same FES scenarios contain very large wind and solar fleets by 2050. Using NESO's published 2050 capacities for offshore wind, onshore wind and solar together with the stated maximum load factors gives an annualised average-month wind-and-solar energy equivalent of approximately 49–54 TWh across the three Net Zero scenarios.[2] This is roughly three-quarters to nine-tenths of average monthly electricity demand. It is not a prediction of winter-month output: solar production is seasonally lower in winter, demand is typically higher, and during a Dunkelflaute wind output can fall far below its annual average.

Figure 4 – 2050 monthly electricity balance: why low-renewable periods matter



Interpretation: FES 2025 implies about 59–66 TWh of electricity demand in an average month in 2050. Using NESO's 2050 wind and solar capacities and stated maximum load factors gives an annualised average-month wind + solar potential of about 49–54 TWh.

A Dunkelflaute is the opposite of this annual-average condition: wind output can fall sharply and winter solar output is also lower. The resulting gap must be met by firm generation, storage, interconnection, hydro and demand flexibility.

*Indicative arithmetic from FES 2025 installed capacities and stated maximum load factors; not a winter-month forecast and not a storage requirement. Operational GB long-duration storage in June 2026 was 23.9 GWh (0.024 TWh).

Figure 4. 2050 monthly electricity balance: annual-average demand and wind/solar potential across NESO Net Zero scenarios

Source note: 2050 annual electricity demand and wind/solar capacities are from NESO FES 2025 [2]. The wind-and-solar monthly equivalents are IES arithmetic using NESO's stated 2050 maximum load factors (46% offshore wind, 28–29% onshore wind and 12% solar), divided by twelve. They are annualised averages, not winter-month forecasts. Operational GB long-duration electricity storage of 23.9 GWh in June 2026 is from the UK Government Clean Flexibility Roadmap [4].

The engineering question is therefore not how much storage would be needed if it supplied the entire system alone, but how much firm energy and flexibility are required when wind and solar fall well below their expected contribution for an extended period. Security during such events will require a portfolio of long-duration storage, firm dispatchable generation, interconnection, hydro, demand flexibility and residual renewable output. The required quantities depend on the severity, duration and geographic extent of the weather event and should be assessed against explicit national security-of-supply standards. The required scale of long-duration storage cannot therefore be determined independently of the amount of firm generation available: nuclear and other firm generation, storage, interconnection, hydro and demand flexibility should be assessed as an integrated portfolio against a defined national resilience standard.

Government, Ofgem and NESO are already pursuing long-duration electricity storage (LDES) options.

In June 2026, Ofgem provisionally selected 16 storage projects totalling 7.6 GW and 137 GWh, with final decisions expected later in autumn 2026.[4] The remaining question is whether the planned combination of storage, firm generation, interconnection, hydro and demand flexibility will provide enough power, enough stored energy and enough duration to keep the 2050 system secure through prolonged periods of low renewable output.

KEY RECOMMENDATION — QUANTIFY THE NATIONAL STORAGE REQUIREMENT

Government and NESO should publish a quantified assessment of the long-duration storage required to maintain security of supply, including:

- storage power capacity — GW
- stored energy capacity — GWh/TWh
- assumed discharge durations
- technology mix and expected utilisation
- indicative capital and supporting infrastructure requirements
- land-use implications
- a credible delivery programme

These requirements should be assessed transparently against explicit national security-of-supply and resilience standards, and alongside alternative combinations of firm generation, storage, interconnection, hydro and demand flexibility.

If the analysis points to storage at very large scale and for very long durations, the consequences could be substantial: capital cost, operating cost, new infrastructure, land use and environmental impact. Those effects need to be quantified because they could materially affect the ability to reduce electricity prices. The comparison should therefore include alternative combinations of storage, nuclear and other firm generation, interconnection, hydro and demand flexibility.

The 2050 challenge is important, but the first real test comes much sooner. The transition through the 2030s will show whether new low-carbon flexibility and firm capacity can be delivered quickly enough as reliance on unabated gas begins to fall.

The transition risk: 2030 to the mid-2030s

Current government plans do not assume an electricity-capacity gap before 2030. The Clean Power 2030 Action Plan explicitly retains approximately 35 GW of unabated gas reserve capacity and estimates that around 40–50 GW of dispatchable and long-duration flexible capacity may be required in 2030 to cover extended periods of low renewable output. The majority of that requirement is expected initially to be met by unabated gas, operating progressively less often as low-carbon alternatives are deployed.[22] NESO similarly states that around 35 GW of unabated gas will need to remain on standby during longer periods of high demand and low renewable output, and that this remains the case into the early 2030s until larger quantities of low-carbon dispatchable power and other flexible resources are connected.[23]

The critical issue is therefore the handover from gas-backed security to low-carbon flexibility during the early-to-mid 2030s. Government policy is that hydrogen-to-power, power CCUS, long-duration storage and other flexible technologies should increasingly displace unabated gas after 2030.[4][22] This does not imply that a supply shortfall is forecast to occur in a particular year; rather, it identifies a delivery risk. If replacement low-carbon dispatchable capacity, fuel infrastructure, storage and network capability are delayed, the system will either need to retain more unabated gas for longer or accept reduced security margins. The Capacity Market continues to procure firm capacity against a three-hour LOLE standard; the 2030/31 T-4 target is 40.9 GW.[19]

System Security and Reliability

System security and reliability are prerequisites for economic resilience and societal stability. The National Energy System Operator (NESO) has the competence and operational responsibility to manage system security on a day-to-day basis, and the Institution of Engineers in Scotland acknowledges the quality of NESO's technical work. The technical principles that govern power-system stability are not widely understood outside specialist disciplines, and this can lead to unrealistic public expectations about the ease and cost of

transitioning to a renewable-dominated system and non-technical regulatory and government pressure to compromise margins to accommodate change.

Inertia, Voltage Control and System Strength

The GB electricity system was historically designed around large synchronous generators connected at transmission level, with generation distributed across the system in relation to fuel supply, cooling requirements and major centres of demand. Synchronous machines inherently provide mechanical inertia and can provide substantial reactive-power, voltage-control and fault-level support. These characteristics have historically contributed to system stability.

Wind, solar and battery installations are generally connected through power-electronic converters and do not inherently provide mechanical inertia. Conventional grid-following converters depend upon an established grid waveform; appropriately designed grid-forming converters can, however, provide fast frequency response, voltage support and other stability services. As the generation mix changes, these stability capabilities must therefore be explicitly specified, engineered and procured rather than assumed to arise inherently from the generation fleet.

As conventional synchronous generation retires, an increasing proportion of the stability services historically provided by these machines will need to be supplied by alternative technologies or explicitly procured system services. Further increases in inverter-based generation must be accompanied by sufficient provision of system strength, voltage control, frequency response and other stability services to maintain defined security standards. Grid-forming converters and synthetic-inertia functions can provide important services, but a system with very high penetration of distributed inverter-based resources has different dynamics and control interactions from a predominantly synchronous system. Their collective performance and interaction must therefore be demonstrated, modelled and engineered at system scale rather than assumed to reproduce inherently the characteristics of synchronous generation.

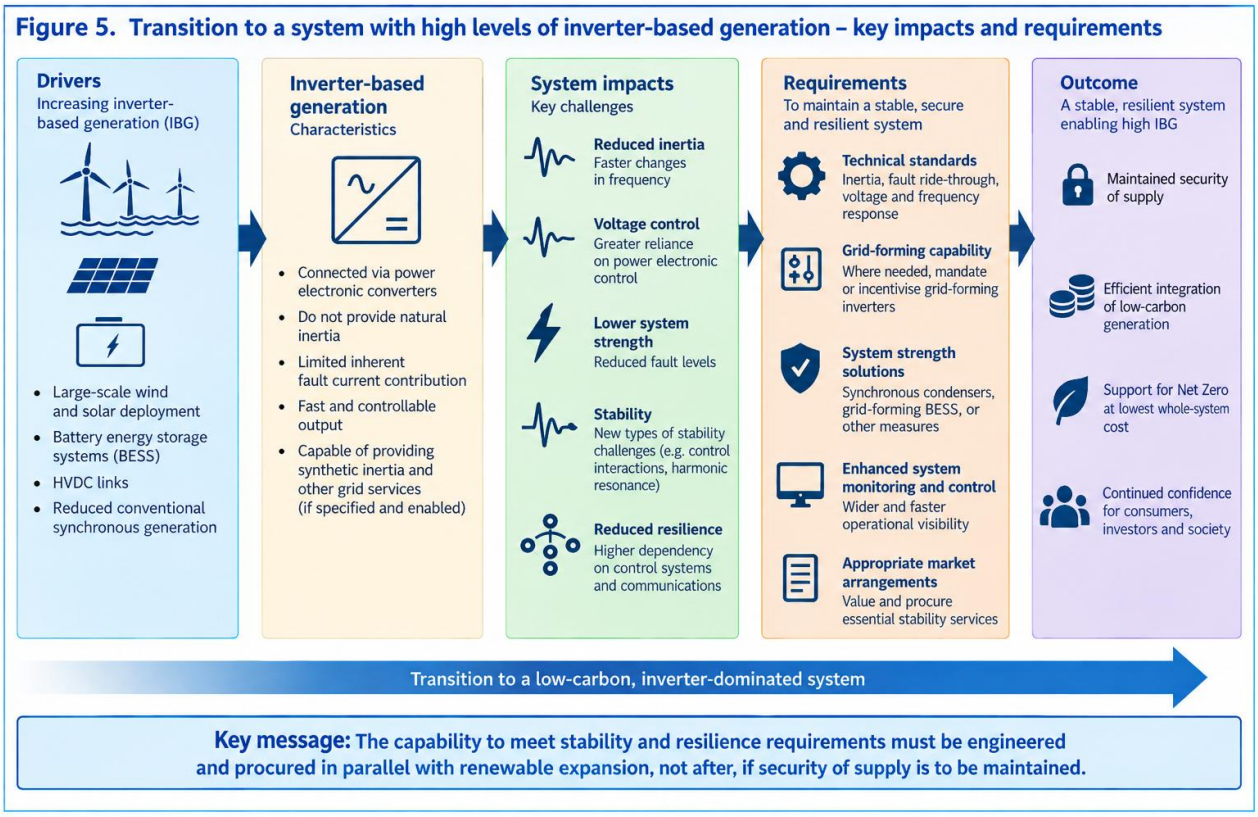


Figure 5. Transition to a system with high levels of inverter-based generation: key impacts and requirements

Scotland

In Scotland, that transition is especially important. Torness is currently expected to close in March 2030, removing about 1.2 GW of firm, synchronous, low-carbon generation from the Scottish system. Peterhead also matters: the existing gas-fired station may still be needed into the mid-2030s while lower-carbon sources of firm generation and flexibility are developed. The sequencing of these changes, together with new transmission infrastructure and stability services, will be critical to Scottish system security. Large hydro schemes will continue to provide valuable synchronous generation and flexibility, but they are only part of the answer.[5][6]

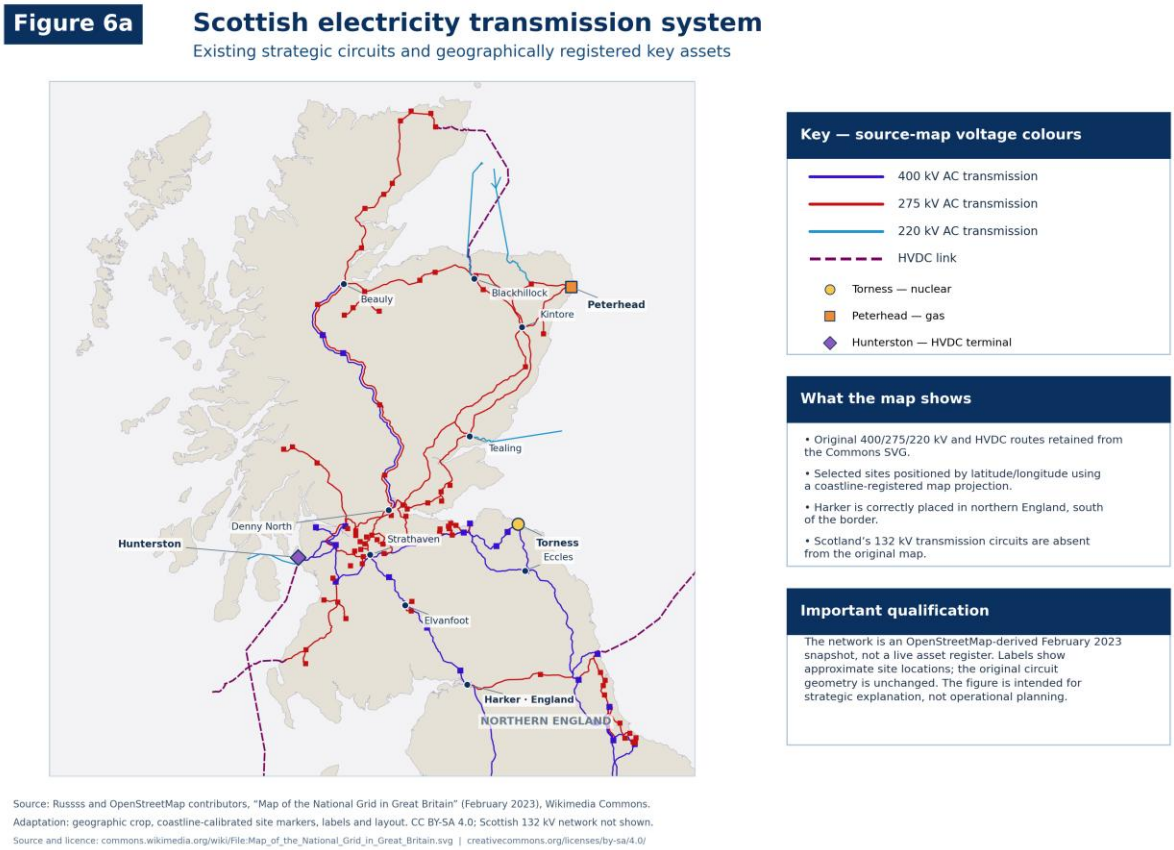


Figure 6a. Scottish electricity transmission system: current key assets and principal transmission routes

Figure 6b **Scottish electricity transmission system**
Indicative network development through the 2030s

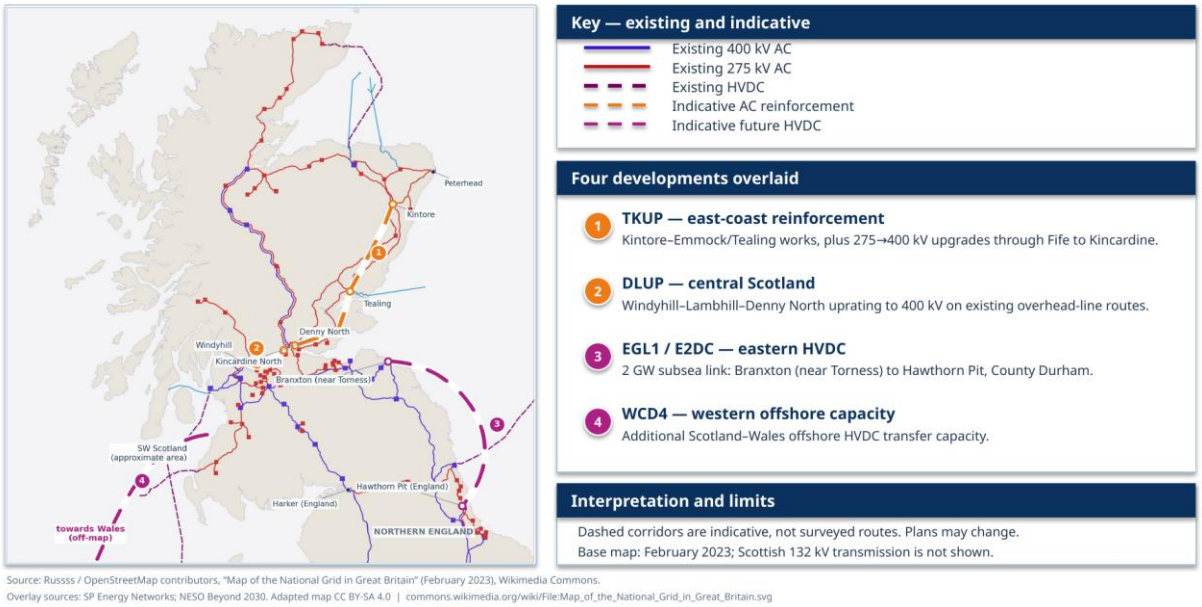


Figure 6b. Scottish electricity transmission system: indicative network development through the 2030s

Source note: Figures 6a and 6b adapt "Map of the National Grid in Great Britain" by Russss, based on OpenStreetMap data (February 2023), Wikimedia Commons, CC BY-SA 4.0. The original circuit geometry is retained; geographic site labels and figure layouts have been added. The base map depicts circuits at 220 kV and above and omits Scotland's 132 kV transmission network. Figure 6b overlays indicative schemes based on SP Energy Networks and NESO Beyond 2030 [13]; dashed corridors are schematic, not surveyed alignments. Adapted map panels are shared under CC BY-SA 4.0; source: https://commons.wikimedia.org/wiki/File:Map_of_the_National_Grid_in_Great_Britain.svg.

The Role of Nuclear Generation

Nuclear generation brings several characteristics that are particularly valuable in a low-carbon system: continuous weather-independent output, high energy density, a relatively small physical footprint for the energy produced, and an inherent contribution to inertia and stability. The Institution of Engineers in Scotland believes that a substantial contribution from nuclear generation should form part of a diverse low-carbon system capable of achieving Net Zero without compromising affordability, security or reliability. The Institution recognises that this position is at odds with the publicly stated policy of the Scottish Government to oppose the building of new nuclear power stations. There is an urgent need either to find ways to harness nuclear power in an acceptable manner or to identify alternative combinations of technologies capable of providing equivalent firm low-carbon energy and system services.

Acknowledging the Challenges

The Institution does not underestimate the difficulties of nuclear development. Recent large projects in Western Europe and the UK, most notably Hinkley Point C, have shown that new nuclear can carry significant construction risk, with costs and timescales exceeding early estimates. Those lessons should shape future procurement, contracting and governance. They are not, in themselves, an argument against nuclear; they are an argument for delivering it better.

Long lead times are sometimes used as a reason to postpone decisions on nuclear. The Institution reaches the opposite conclusion. If a project will take many years to consent, finance and build, delay today simply means capacity will not be available when it may be needed in the 2040s.

The Case for Brownfield Development

The Institution advocates that future nuclear development should prioritise existing nuclear sites where practicable. This approach offers substantial and concrete advantages:

- **Grid connection:** Existing nuclear sites are connected to high-capacity transmission infrastructure. New grid connection for a greenfield site can add years to a project timeline and substantial cost.
- **Cooling water:** Sites such as Torness were selected for reliable access to coastal cooling water, a resource not easily replicated at alternative locations.
- **Planning and community acceptance:** Communities adjacent to existing nuclear sites have lived alongside nuclear generation for decades. While consent cannot be assumed, the planning baseline differs fundamentally from a greenfield location.
- **Workforce and skills:** Existing sites retain trained operational and maintenance workforces and site knowledge.
- **Existing infrastructure and decommissioning:** Roads, buildings and support facilities may be reusable; in some cases redevelopment may also affect long-term decommissioning liabilities.

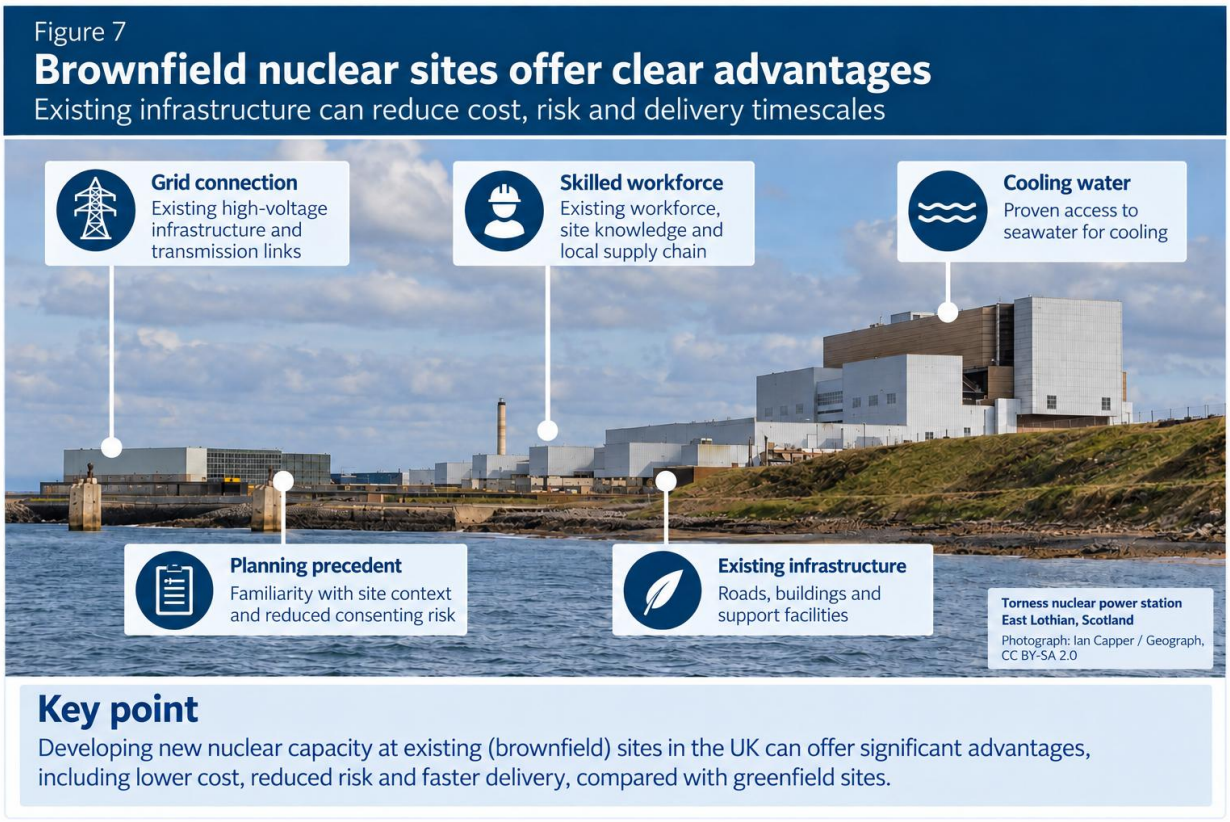


Figure 7. Brownfield nuclear sites offer clear advantages

Small Modular Reactors

The emergence of Small Modular Reactor (SMR) technology represents a significant opportunity to provide nuclear-based energy. SMRs are intended to exploit factory manufacture and design standardisation, with the potential for lower individual project capital requirements, shorter construction programmes and greater siting flexibility than conventional large reactors. These potential advantages have yet to be demonstrated through commercial-scale UK deployment. Several designs are under active development in the UK, and the Institution supports accelerated evaluation and deployment of proven SMR technology, prioritising existing nuclear sites where practicable.

SMRs should be considered as potentially complementary to, rather than necessarily substitutes for, large nuclear generation. They could offer a pathway to earlier deployment and make a meaningful contribution to system stability and security of supply within the timescales relevant to the energy transition. Their smaller unit size and potential siting flexibility may also create opportunities for deployment close to major industrial electricity and heat loads, subject to nuclear safety, security, licensing, cooling, planning and grid requirements.

Scotland Specifically

In Scotland, the scheduled closure of Torness in March 2030 makes the case for evaluating replacement firm low-carbon generation particularly urgent. The Institution considers it essential that Scottish and UK Government policy explicitly addresses the gap that closure will create, and that the case for new nuclear development at Torness or another existing Scottish site is formally and transparently evaluated without further delay.[5]

Ecological and Social Costs

Every form of electricity generation has environmental and social consequences across its lifecycle, from material extraction and manufacture through construction, operation, decommissioning and site restoration. A credible energy strategy should acknowledge those impacts openly rather than treating operational carbon emissions as the only environmental measure that matters.

Lifecycle Assessment

Comprehensive lifecycle audits are needed for all generation technologies, covering full lifetime emissions, land use, water consumption, material requirements and decommissioning costs. Current methodology often assesses impacts on a site-by-site basis and may not adequately capture the cumulative effect of multiple developments across regions or the national landscape.

Land Use, Landscape and Whole-System Spatial Impact

Land occupation and spatial footprint vary substantially between generation technologies and are highly sensitive to the methodology and system boundary used. Figure 8 uses selected low-carbon generation technologies as illustrative examples rather than as an exhaustive comparison. Nuclear generation has very high energy density and consequently a compact generating-site footprint. Ground-mounted solar uses a larger area broadly associated with the installation. Wind generation has a much larger overall project envelope, although only a proportion of that area is physically occupied by turbine foundations, access tracks, hardstandings, substations and associated electrical infrastructure; much of the intervening land can remain available for agriculture, forestry, recreation or other uses.

Figure 8 illustrates how the direct and wider spatial footprint can differ between these example technologies without assigning a single numerical land-use ratio. This avoids treating direct physical occupation and total project area as equivalent measures. The distinction is particularly important for wind, where the wider area across which turbines are distributed is not the same as land permanently occupied by the development.

Figure 8: Examples of the land-use characteristics of low-carbon electricity generation

Illustrative examples showing how the direct and wider spatial footprint can differ between generation technologies.

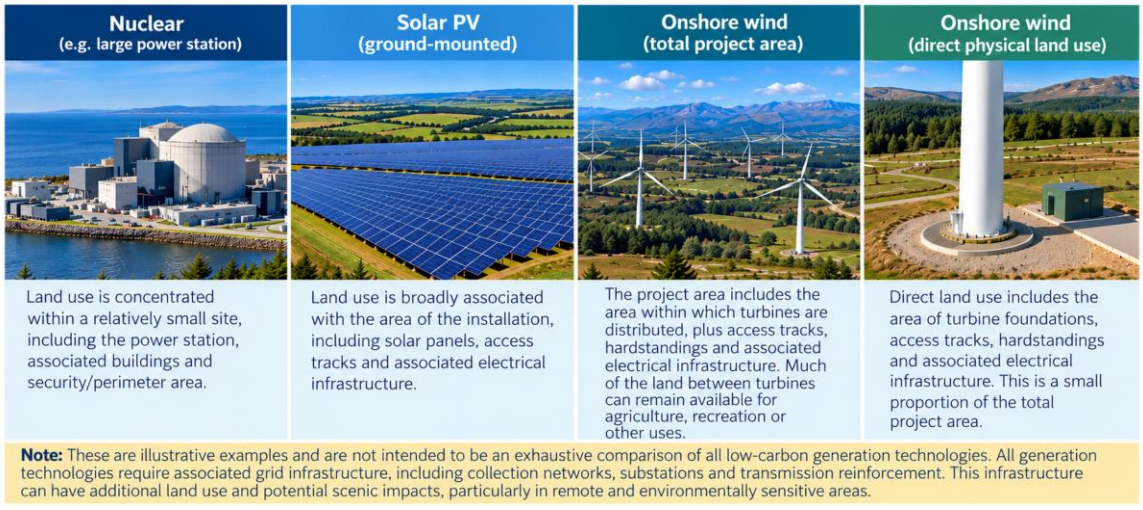


Figure 8. Examples of the land-use characteristics of low-carbon electricity generation

Source note: Figure 8 presents illustrative examples and is not intended to be an exhaustive comparison of all low-carbon generation technologies. The distinction between direct physical land occupation and the wider wind-project area is consistent with the methodological discussion in Our World in Data/UNECE and NREL.[7][25] All generation technologies also require associated grid infrastructure; its scale and landscape impact depend on location, technology and existing network capacity.

Wider spatial and landscape impacts

At the scale implied by 2050 targets, cumulative land-use and landscape effects should be an explicit part of whole-system planning, particularly in upland, wild-land and other areas of high landscape value. All generation sources also need grid connections, and new projects may require collection networks, substations and major transmission reinforcement. Where generation is remote from demand centres or strong existing grid connections, that supporting infrastructure can extend over large areas and create significant landscape and environmental effects.

These effects should be assessed on a whole-system basis and not attributed automatically to one technology. Network reinforcement can also be driven by demand growth, security requirements and replacement of ageing assets. NatureScot guidance on cumulative landscape and visual assessment explicitly includes associated access tracks and grid connections and requires consideration of combined and sequential effects across landscapes and along routes used by residents, visitors and recreational users.[20] Natural-capital appraisal provides one framework for valuing environmental assets and externalities alongside conventional economic costs.[21]

Community Impacts

The social cost of imposing any form of generation on a community must be considered, including effects on employment, quality of life, property values and local identity. Community benefit arrangements, while valuable, do not substitute for genuine engagement and consent.

Proportionality

The UK contributes approximately 1% of global greenhouse gas emissions; Scotland approximately 0.1%. This context does not diminish the importance of the UK's contribution to global Net Zero efforts; international leadership has value beyond its direct emissions impact. It does, however, require that local environmental costs be weighed carefully and honestly against the marginal global benefit of individual developments, particularly in areas of high ecological or landscape sensitivity.[8][9]

Governance and Strategic Oversight

The Emerging Governance Framework

Energy infrastructure is built for decades, while governments and policy priorities can change much faster. Since this paper was first framed, the arrangements for strategic energy planning have changed substantially, including the creation of NESO and the development of new national and regional planning processes.

Long-term policy continuity

Electricity infrastructure is planned, financed, consented and built over periods that span several Parliaments. Major generation, transmission and storage assets may then operate for many decades. Investors, network companies and the supply chain therefore need confidence that the broad direction of policy will survive an individual electoral cycle. Governments must remain free to change priorities and technology choices, but repeated changes to the underlying strategic framework add cost, delay projects and increase delivery risk.

Energy strategy should separate legitimate political choices from the enduring engineering requirements of the electricity system. Security standards, resilience requirements and the framework for major infrastructure investment should, as far as practicable, command enough cross-party support to remain stable across electoral cycles.

NESO is also developing a substantially more integrated strategic-planning framework. In August 2026 it submitted six pathway options for the first Strategic Spatial Energy Plan (SSEP) to the UK, Scottish and Welsh governments. The UK Government is to select a preferred pathway, after which a draft SSEP and its Strategic Environmental Assessment are expected to proceed to public consultation in early 2027.[15] The Centralised Strategic Network Plan (CSNP) is intended to provide an independent, coordinated and long-term whole-system approach to electricity and gas transmission and hydrogen transport and storage; Ofgem has approved the CSNP methodology, and the first CSNP is currently required to be published by 15 December 2028.[16]

Regional planning is also being developed. NESO published the transitional Regional Energy Strategic Plan in January 2026 to inform distribution-network investment for 2028-33, with the full Regional Energy Strategic Planning framework intended to provide 11 whole-energy plans for Scotland, Wales and the English regions.[17] At the same time, connections reform has moved the process away from a simple queue-based approach towards Gate 2 criteria and strategically coordinated network design, with the relevant methodologies maintained by NESO under its licence and subject to Ofgem oversight.[18]

These developments address much of the governance weakness identified by the Institution. The priority now should be to complete the emerging framework, make the different parts work together and ensure that plans translate into timely delivery at optimum cost rather than create another layer of institutions.

What Remains Incomplete

The new framework is not yet complete. The first Strategic Spatial Energy Plan has not yet been finalised; the first Centralised Strategic Network Plan is not currently due until the end of 2028; and the enduring Regional Energy Strategic Planning framework and its regional plans are still being developed.[15][16][17] Responsibility also remains distributed between Government, Ofgem, NESO and the network companies. NESO has substantial planning, system-operation, code and connections functions, but it does not unilaterally determine energy policy or exercise all regulatory enforcement powers.

Government, Ofgem, NESO and the network companies should therefore make responsibilities explicit for turning whole-system plans into coordinated delivery. Generation connections, transmission reinforcement, system-strength requirements, storage and other flexibility measures need to be sequenced so that one part of the system is not built years ahead of the others.

The connection and expansion of inverter-based generation should likewise be coordinated with the provision of sufficient system strength, voltage control, frequency response, network capacity, storage and other flexibility resources to maintain defined system-security standards. This is not an argument against renewable development; it is an argument for ensuring that generation and the wider system capabilities required to support it are delivered in a coordinated sequence.

Risk Standards

The UK already has an explicit electricity reliability standard through the Capacity Market. For the 2027/28 T-1 and 2030/31 T-4 auctions, the standard remains a Loss of Load Expectation (LOLE) of three hours per year.[19] That is an important benchmark for capacity adequacy. But it does not, by itself, define the resilience required during prolonged, correlated periods of low wind and solar output.

National planning should therefore go a step further. Government and NESO should define the resilience required during multi-day or multi-week periods of low renewable output across northern Europe, and quantify the combination of storage, firm generation, interconnection, hydro and demand flexibility needed to meet that standard.

Conclusions

- **A: The UK cost of electricity is too high and risks undermining both industrial competitiveness and public support for the energy transition.** Reductions are achievable through a review of market structures and whole-system costs, including subsidies and constraint payments. This should include the linkage of electricity prices to international gas markets and the cost of capital for essential infrastructure investment.
- **B: Intermittent renewables are an essential contributor to Net Zero, but generation cost alone does not determine the cost of electricity delivered to consumers.** Investment decisions must therefore be informed by transparent whole-system cost analysis and full-lifecycle environmental and social assessment, evaluated cumulatively as well as site by site. The Institution recommends that major generation proposals and policy announcements should publish both the generation cost and the attributable whole-system cost, including network reinforcement, balancing, storage, reserve and stability requirements, wherever these can reasonably be identified.
- **C: The scale of long-duration flexibility required to maintain security of supply during extended periods of low renewable output requires a quantified national assessment of acceptable risk to resilience and security.** Government should establish explicit standards for acceptable energy-supply risk and determine the appropriate integrated combination of storage, nuclear and other firm generation, interconnection, hydro and demand flexibility required to manage prolonged periods of low renewable output across northern Europe. Government and NESO should publish the required storage power (GW) and energy capacity (GWh/TWh), assumed discharge durations, technology mix, expected utilisation, indicative capital and infrastructure requirements, land-use implications and delivery programme, assessed transparently against those explicit national security-of-supply and resilience standards. The dimensioning of long-duration storage should be determined together with the planned contribution from firm generation rather than as a separate programme.
- **D: Increasing volumes of inverter-based generation change the technical characteristics of the electricity system.** System strength, voltage control, frequency response and other stability services must be engineered and procured in parallel with, rather than after, further renewable expansion. Grid connection and network development should be coordinated with the provision of these services.
- **E: A substantial contribution from nuclear generation should form part of a diverse low-carbon system capable of achieving Net Zero without compromising stability, security or affordability.** Development at existing Scottish nuclear sites offers significant potential advantages in grid connection, infrastructure, workforce and planning. In Scotland, the closure of Torness in March 2030 requires immediate strategic attention.

- **F: Long-term energy governance must provide continuity beyond individual political cycles.** The establishment of NESO and the development of SSEP, CSNP, RESP and strategic connections reform represent significant changes to the governance framework. The Institution recommends that the priority should now be to complete this framework, clarify responsibilities between Government, Ofgem, NESO and network owners, and ensure that whole-system technical, economic and security requirements translate into coordinated and enforceable investment and connection decisions.
- **G: Energy plans should be kept under continuous review** to ensure that whole-system costs to households and industry are transparently assessed and minimised, while maintaining security, reliability and environmental objectives.

Technical Terminology

Term	Meaning
Generating capacity (GW)	Rated instantaneous output capability of installed generation.
Peak demand (GW)	Maximum instantaneous system demand under the stated definition and planning criterion.
Electricity / energy demand (GWh or TWh)	Electrical energy consumed over a stated period.
Storage power (GW)	Maximum rate at which a storage asset can charge or discharge.
Storage energy capacity (GWh or TWh)	Quantity of electrical energy that can be stored and subsequently delivered, subject to efficiency and operating limits.

Acronyms and Abbreviations

The following acronyms, abbreviations and engineering units are used in the paper and its figures.

Term	Meaning
CCGT	Combined Cycle Gas Turbine
CSNP	Centralised Strategic Network Plan
ETYS	Electricity Ten Year Statement
FES	Future Energy Scenarios
HVDC	High Voltage Direct Current
IES	Institution of Engineers in Scotland
LCOE	Levelised Cost of Energy
LDES	Long-Duration Electricity Storage
NESO	National Energy System Operator
PV	Photovoltaic
RESP	Regional Energy Strategic Plan
SMR	Small Modular Reactor
SSEP	Strategic Spatial Energy Plan

Engineering units used

GW — gigawatt (10^9 watts) — unit of instantaneous power
GWh — gigawatt-hour — unit of electrical energy
kV — kilovolt — unit of electrical voltage
MW — megawatt (10^6 watts) — unit of instantaneous power
MWh — megawatt-hour — unit of electrical energy
TWh — terawatt-hour — unit of electrical energy

Sources and References

The references below support the principal numerical claims and quantitative figures in Version A.2. Figure 4 uses NESO FES 2025 scenario data to illustrate average monthly electricity demand and annualised wind-and-solar energy potential in 2050; it is not a winter-month forecast or a storage-only requirement.

[1] UK Government, The Climate Change Act 2008 (2050 Target Amendment) Order 2019. Amends the statutory 2050 greenhouse-gas reduction target to 100% relative to the 1990 baseline (Net Zero). Source

[2] National Energy System Operator (NESO), Future Energy Scenarios 2025: Pathways to Net Zero, July 2025. Table 23 gives 2050 electricity peak demand of 120 GW (Holistic Transition), 144 GW (Electric Engagement) and 122 GW (Hydrogen Evolution). Source

[3] NESO, “Future Demand Increase” supporting material for FES 2025. Gives 2024 annual electricity demand of 290 TWh, 2050 Net Zero scenario range of 705–797 TWh, 2024 peak demand of 58 GW and 2050 range of 120–144 GW.

[4] Department for Energy Security and Net Zero, Clean Flexibility Roadmap: July 2026 update; and Ofgem, Long duration electricity storage window 1: minded-to decisions, June 2026. The Roadmap reports operational LDES of 2.8 GW / 23.9 GWh in June 2026. Ofgem's minded-to portfolio comprises 16 projects totalling 7.6 GW / 137 GWh under the cap-and-floor regime; the consultation is closed and the final decision is expected later in autumn 2026. The Roadmap treats LDES as part of the longer-term flexibility requirement towards 2050.

[5] EDF Energy, Torness power station. Gives total supply to the national grid as 1,190 MW and estimated end of generation as 2030. Source

[6] SSE Thermal, Peterhead FAQ, updated March 2026. States that slower development of low-carbon flexibility may mean the existing station is required until at least the mid-2030s. Source

[7] Our World in Data, “How does the land use of different electricity sources compare?”, drawing principally on UNECE, Life Cycle Assessment of Electricity Generation Options (2021). Used to support the methodological discussion of land-use definitions and system boundaries in Figure 8.

[8] Department for Energy Security and Net Zero, 2025 UK greenhouse gas emissions: provisional figures, published April 2026. States that UK territorial greenhouse-gas emissions account for less than 1% of the global total. Source

[9] Scottish Government, Net-zero greenhouse gas emissions target year: information and analysis, section 4. Gives Scotland’s emissions as approximately 0.1% of the global total on the stated comparison basis. Source

[10] National Energy System Operator (NESO), Electricity Ten Year Statement 2025, Appendix A — System schematics and geographic drawings, ETYS2025 Y1 GB Existing Electricity Transmission Network — map view, produced 16 June 2026. Used as a supplementary source for existing-network context, not as the base map artwork in Figures 6a and 6b. NESO states that mapped routes and asset locations are illustrative and approximate.

[11] UK Government, British Industrial Competitiveness Scheme: consultation on scheme eligibility and approach, published 24 November 2025 and updated 30 September 2026. States that in 2024 UK industrial electricity prices including taxes were the highest of countries in the International Energy Agency comparison published by DESNZ.

[12] Kittel, M., Roth, A. and Schill, W.-P., “Long-duration electricity storage needs for coping with Dunkelflaute events in Europe”, Nature Communications 17, 4210 (2026); and UK Government Office for Science, “How well do we understand the impacts of weather conditions on the UK’s renewable wind and solar energy supplies?”, expert roundtable chaired by the Met Office Chief Scientific Adviser, 7 July 2023 (published 21 November 2023). The peer-reviewed study finds that severe low-renewable periods can persist for multiple days or weeks; the UK scientific advice notes that high-pressure blocking events disrupting wind generation often last one to two weeks and that widespread wind droughts can coincide across the UK and Europe.

[13] National Energy System Operator (NESO), Beyond 2030: A national blueprint for a decarbonised electricity system, March 2024, Central and Southern Scotland regional blueprint; and Beyond 2030 Electricity Transmission Update, 30 June 2026. These sources support the indicative reinforcement schemes shown in Figure 6b. NESO states that future options are illustrative and do not represent precise transmission routes or connection dates.

[14] UK Government, National Energy System Operator (NESO) framework document, July 2026; and Energy Act 2023, section 163. NESO's statutory objectives include Net Zero, security of supply, and efficiency and economy.

[15] National Energy System Operator (NESO), Strategic Spatial Energy Planning (SSEP), 2026. NESO submitted six pathway options to the UK, Scottish and Welsh governments on 28 August 2026; public consultation on the draft SSEP is expected in early 2027.

[16] Ofgem, Approval of NESO's CSNP Methodology, 15 April 2026; and Direction to NESO on CSNP publication timing, 15 April 2026 / updated direction 17 July 2026. The first Centralised Strategic Network Plan is currently required to be published by 15 December 2028.

[17] National Energy System Operator (NESO), transitional Regional Energy Strategic Plan (tRESP), 30 January 2026, and Regional Energy Strategic Planning programme. The transitional plan informs distribution-network investment for 2028-33 and is the bridge to the enduring regional planning framework.

[18] National Energy System Operator (NESO), Connections Reform design documents and methodologies, 2025-26. Gate 2 criteria, network-design and project-designation methodologies form part of the reformed connections process and are maintained under NESO's licence with Ofgem oversight.

[19] Department for Energy Security and Net Zero, Capacity Market auction parameters, 21 July 2026. The 2030/31 T-4 auction target is 40.9 GW and the Reliability Standard is three hours Loss of Load Expectation (LOLE) per year.

[20] NatureScot, Guidance: Assessing the cumulative landscape and visual impact of onshore wind energy developments, March 2021. The guidance requires cumulative assessment to consider associated access tracks and grid connections, and combined and sequential landscape and visual effects.

[21] Dieter Helm, Natural Capital: Valuing the Planet (Yale University Press, 2016), and Helm Talks: Natural Capital. Helm's natural-capital framework emphasises valuation of environmental assets, public goods and externalities within economic appraisal.

[22] Department for Energy Security and Net Zero, Clean Power 2030 Action Plan: A new era of clean electricity, December 2024 (updated April 2025). The plan retains an expected 35 GW of unabated gas reserve capacity to

protect security of supply to 2030 and estimates that 40–50 GW of dispatchable and long-duration flexible capacity may be required in 2030 during extended periods of low renewable output. It states that sufficient gas capacity should be retained until it can be safely replaced by low-carbon technologies.

[23] National Energy System Operator (NESO), Clean Power 2030, Annex 1: Electricity demand and supply analysis, 2024. NESO states that around 35 GW of unabated gas will need to remain on standby over longer periods of high demand and low renewable output, and that this requirement continues into the early 2030s until larger amounts of low-carbon dispatchable power and other flexible resources are connected.

[24] Department for Energy Security and Net Zero, Quarterly Energy Prices: September 2025, domestic electricity price comparisons with other IEA countries. Of the 28 IEA countries in Table 5.5.1, 27 reported domestic electricity prices in 2024; the UK had the second-highest price including taxes and levies.

[25] Denholm, P. et al., National Renewable Energy Laboratory (NREL), Land-Use Requirements of Modern Wind Power Plants in the United States, NREL/TP-6A2-45834 (2009). Distinguishes direct physical land impact from the much larger total project area of wind developments; used to support the methodological distinction in Figure 8.

Illustration provenance: Figures 1, 3, 5 and 8 were produced using OpenAI image-generation tools and reviewed and adapted for this report. The images in Figure 8 are illustrative representations, not photographs of identified installations.

Important note on Figure 8: the figure is illustrative and intentionally avoids a numerical ranking. Land-use estimates depend on definitions and system boundaries. For onshore wind, the wider project/site area is not equivalent to land permanently occupied: substantial areas between turbines can remain available for agriculture, forestry, recreation or other uses.

Institution of Engineers in Scotland

Scottish Engineering Suite, 105 West George Street, Glasgow G2 1QL

Tel: 0141 248 3721 secretary@engineers.scot www.engineers.scot



THE UK ENERGY STRATEGY NEEDS URGENT REVIEW

A position paper from the Institution of Engineers in Scotland.

Version A.2 • October 2026

IES
A MULTI-DISCIPLINARY ENGINEERING INSTITUTION