Clean Power 2030

Annex 1: Electricity demand and supply analysis

NESO
National Energy System Operator

1. Introduction

Consumer demand is the driver behind our electricity system and clean power offers an opportunity for consumers to help shape how the system manages this demand. This starts with harnessing the value of flexibility for households, businesses and suppliers by unlocking markets and removing wider barriers. Greater levels of flexibility will support the growing levels of renewables that will be the foundation for meeting clean power.

This section points to the following priorities for the clean power plan as set out in box 1 of our main report:

- **Unlock flexibility of demand and supply.** Flexibility is vital in a system with more inflexible, low carbon supplies. There are large opportunities to increase flexibility in both demand and supply for both residential consumers and in industry. However, flexibility is not currently valued in full and faces multiple barriers. Markets and processes must be redesigned, data and digital approaches embraced, enabling infrastructure delivered and barriers unblocked.
- **Manage demand growth.** Electricity demand will grow in line with decarbonisation of sectors such as transport, heat and industry. Adoption of more efficient technologies, such as lighting and appliances (on top of energy efficiency measures), can manage the growth in annual and peak demand.
- **Back offshore wind and renewables.** There is no path to clean power without mass deployment of offshore wind alongside onshore wind and solar. A sustained rollout of offshore wind is needed at more than double the highest rate ever achieved in Great Britain. An increased rollout will need to continue through the 2030s. Transparent and comprehensive investment signals, contracting arrangements and delivery environment for these projects will be key to the costs and success of the clean power programme as a whole.
- **Recognise the value of dispatchable low carbon plants.** These play a vital role and are different to intermittent and inflexible low carbon plants in that they match demand regardless of conditions. Biomass can shift into this role as can new carbon capture and storage (CCS) and hydrogen projects if these can come online by 2030. CCS and hydrogen are also key technologies for the global transition and are currently underdeveloped; progress in this area can help lead the global effort. Contracting arrangements should be developed with the expectation that these plants operate flexibly and not as baseload. More will be needed beyond 2030. This would be advantageous if delivered earlier, enabling a lower cost system that can take pressure off other delivery challenges.

As highlighted in our main clean power report, close collaboration will be needed between UK, Scottish and Welsh governments, particularly in relation to planning and consenting.

This section provides additional detail behind our demand, supply and system flexibility analysis, setting out methodology, where we are now, what is needed for clean power, the basis of our analysis, stakeholder feedback and enablers.

Further detail on our assumptions and the data outputs are in the assumptions log and data workbook respectively.

2. Electricity demand and demand side flexibility

Greater levels of energy efficiency and flexible demand can help reduce consumer energy costs. The capacity of flexible resources in our pathways is greater than the minimum level required for operability to help reduce the use of unabated gas.

2.1 Electricity demand

Widespread adoption of efficient products and energy efficiency measures are needed to manage the electrification of demand

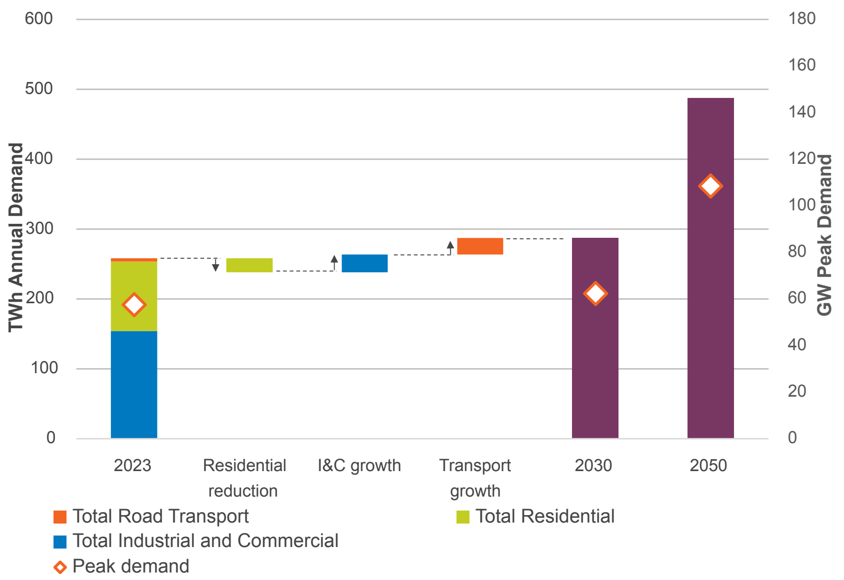

Figure 1: Changes in consumer electricity demand from 2023 to 2030

2.1.1 Great Britain today

Electricity demand today is split broadly evenly across residential, industrial and commercial. Demand increases throughout the morning, typically peaking in the early evening as industrial activity and home cooking overlap, before tailing off throughout the evening. Levels vary across the year, with increasing demand from lighting and heating in the winter months.

In 2023, electricity demand was 263 TWh across the year, with a peak demand of 58 GW.

2.1.2 Great Britain in 2030

Our pathways assume high levels of societal change and digitalisation, a very high number of personal electronic devices and data service needs. We assume high levels of development in artificial intelligence and offsite computation needs for a wider economy. This means a 5-fold growth in data centre electricity demand from today out to 2030. This investment will underpin the establishment of a smart energy system.

Electrification of transport, heat and industry will enable delivery of the UK's carbon targets. Our analysis assumes that sectors electrify at a sufficient pace to meet the Nationally Determined Contribution (NDC) emissions target for 2030 and the Climate Change Committee's (CCC) carbon budgets. This means an electricity demand growth of 11% to 287 TWh in 2030 (Figure 1).

Energy efficiency improvements reduce residential sector demand by around 20 TWh a year by 2030, predominantly through lighting and appliances. The transition to LED bulbs, for example, can reduce lighting demand by around 60%.

As the economy electrifies, industry, charging of electric vehicles (EVs) (excluding hybrids and hydrogen electric vehicles) and residential heating will contribute to peak demand if unmanaged. Electrified heating will also lead to demand growth in the winter months, although with a steadier daily pattern compared to today's gas boilers with some scope for flexibility. If measures are not put in place, this growth in electrification could lead to a greater increase in peak demand than our analysis shows.

2.1.3 Basis for our analysis

We have based demand on the Holistic Transition pathway from Future Energy Scenarios: ESO Pathways to Net Zero 2024 (FES 2024) with projected growth in the economy and the number of households, together with the required level of decarbonisation away from fossil fuels, predominantly to electrification to meet legal carbon targets.

Around 80% of the energy savings set out in our analysis come from improving both the efficiency of lighting and appliances. Installations of LED lightbulbs increase from 60% today to 92% in 2030. This data was obtained from Department for Energy Security and Net Zero (DESNZ) uptake and renewal estimates, alongside market product specifications from the European Product Registry for Energy Labelling database. The number of bulbs per home aligns with DESNZ's projections, in line with The Eco design for Energy-Related Products and Energy Information (Lighting Products) Regulations 2021. EU energy efficiency improvement directives and targets are in place to drive the continued growth of energy efficiency improvements in the near term. The UK Government is also consulting on achieving 140 lm/W sales weighted average of bulbs by 2027 and has set new energy performance labelling. 200 lm/W bulbs are already on the market, but LED bulbs have an approximate 15-year lifespan.

Trends in demand per appliance are based on using the energy consumption in the UK (ECUK) electrical product table data, with a forecast assuming highly engaged consumers that purchase efficient products due to the rescaled energy labelling for appliances.

Heat pump deployment achieves the previous Government's 2028 target of 600,000 installations a year. Similarly, improved insulation requirements in new builds and retrofit of insulation measures in residential buildings increases in line with previous Government ambitions, creating 2.5 TWh of annual electricity demand saving in 2030. Household insulation measures are rolled out at around twice the pace of the Warm Homes Plan to reduce demand for consumers and the energy system. This reduces electricity demand for residential heat by 11%.

We estimate that the demand suppression from the energy crisis caused an average 1.0 °C reduction to thermostat temperature settings. We assume this level increases back up by 0.5 °C. A difference of 0.5 °C in thermostat setting relates to approximately 1.5 TWh change in electricity demand in 2030.

Uptake of EVs in our analysis follows the zero emission vehicle (ZEV) mandate, using the Society of Motor Manufacturers and Traders (SMMT) central forecast on total car sales and increasing efficiency from 3.5 m/kWh in 2023 to 3.8 m/kWh in 2030. Other transport sectors decarbonise in line with proposed petrol, diesel and hybrid ban dates, with a ramp-up in ZEVs up to those dates.

Our analysis assumes continued growth in industrial demand. Growth in data centres (from 5 TWh today) is based on registers of planning and grid connection applications to 22 TWh in 2030.

Hydrogen demand grows to help decarbonisation targets. By 2030, 3.7 GW of electrolyser capacity is installed, creating an electricity demand of 11 TWh in 2030.

Further details on our assumptions can be found in our assumptions log.

2.1.4 Stakeholder views

Most stakeholders are broadly supportive of the different pathways to 2030 presented within the report, including our demand assumptions, noting that they must meet the ambition required to deliver UK decarbonisation targets.

Some stakeholders feel that the focus should be kept on electrifying heat and transport, not reducing demand. However, others have noted that reducing our demand was a quicker way to deliver clean power. Some stakeholders have called for clarification over the Government's proposed Warm Homes Plan and its impacts on energy efficiency.

2.1.5 What is needed

Markets and investment

In our modelling, electricity demand savings are largely driven by improvements in home appliances and lighting efficiency. If existing market trends are not deemed sufficient to deliver these energy savings, then increasing minimum standards could play a role. LEDs installed need to increase from 60% today to 92% in 2030.

Home insulation retrofit rates need to accelerate to deliver electrified heat demand savings before 2030, which will be crucial for maintaining clean power beyond 2030. Improvements in the efficiency of our housing stock will be needed or demand will be higher than the levels indicated in our modelling. Engaging consumers will also be key for unlocking this capacity. As the uptake of heat pumps and EVs increases, it will be important to ensure that these technologies are as efficient as possible and able to operate flexibly to manage increases in electricity demand sustainably.

Supply chain and workforce

Persistent supply chain and workforce challenges in delivering energy efficiency schemes (especially housing retrofit) are well documented elsewhere.[1] These are not the focus of our study. However, challenges in this area will need to be overcome to manage demand.

Other enablers

Energy efficiency has significant whole system and public policy benefits, which could be more appropriately valued in regulatory and public investment policy.

Additionally, the challenges of securing planning or development consent for infrastructure projects or connections reform are not present in realising the demand savings from the energy efficiency measures required in our pathways.

2.1.6 Impact

The electrification of transport, heat and industry is vital in putting the UK on the trajectory to the delivery of our domestic and international climate commitments from 2030 onwards.

Without these efficiency savings, there would be even higher growth of demand than expected through electrification, necessitating increased investment in generation capacity, fuel use and greater levels of reinforcements to the transmission and distribution network.

Energy efficiency measures will benefit both the energy system and, crucially, consumers. Reducing demand can reduce bills and help bring more people out of fuel poverty.

1 Green Jobs Taskforce (2021)

We expect electrification to accelerate after 2030, with demand growing at a pace of around 19 TWh per year throughout the decade. We forecast that, with continued growth of future data centre projects, this reaches up to 62 TWh in 2050. This is nearly as large as levels of demand for the entire commercial sector in 2023 (at 77 TWh). Optimising the location of some new data centres may reduce the requirement for additional electricity network infrastructure. Further analysis will be required to establish the feasibility of moving data centres and optimum locations at the planning stages of investment proposals.

Our analysis shows that, if demand is 5% higher (14 TWh), the annual percentage of unabated gas use increases by 0.65%. Without energy efficiency improvements, higher levels of electricity demand mean that it will be more challenging to achieve clean power.

2.2 Demand flexibility

2.2.1 Great Britain today

Today's flexible technology can contribute around 2.5 GW of demand flexibility. Additionally, storage heaters add around 4 GW although this is not operated as flexibly as other sources of demand side flexibility. Electrification of heat from heat pumps and district heating (both coupled with thermal storage), alongside a relatively smaller proportion of smart charging also offering opportunities in the short term.

Consumer engagement can shift or reduce peak demand even further during times of system stress and this has seen strong promise through the demand flexibility scheme (DFS). On the other hand, levels of industrial and commercial demand flexibility have been reduced or removed since the ending of Triad.

2.2.2 Great Britain in 2030

Engaging and empowering consumers to participate in demand flexibility is critical

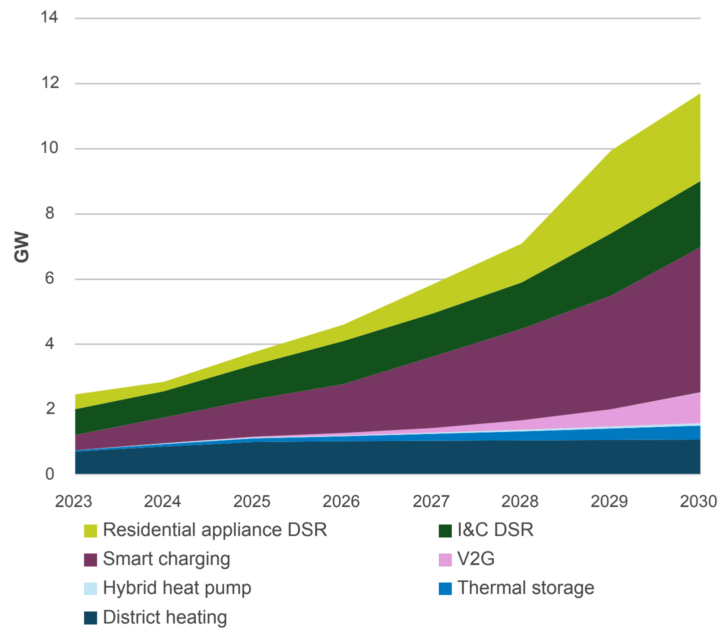

Figure 2: Demand side flexibility capacity at peak in our Further Flex and Renewables pathway

Taking aside storage heating, which we expect to slightly reduce on today's levels, demand side flexibility will need to grow by four-to-five times in the next five years. Nearly all demand side flexibility will be located on the distribution network.

Digitalisation, automation and consumer engagement will lie at the core of the 2030 system. Around 10 million more working smart meters in our homes and new market products will see around 9% of residential peak demand responsive to time-of-use-tariffs or other innovative flexibility incentives. A consistent coordinated approach that enables people to make more informed decisions will allow demand side flexibility to be unlocked. Using data science and targeted communication methods can provide consumers with the right signals at the right time that directly impact the choices they make on a day-to-day basis, such as when to turn on their appliances. In addition, by recognising the need for investment by individuals, appropriate marketing can also help to create demand which leads to widespread voluntary adoption of more efficient appliances, for example.

Smart charging of EVs could make the largest contribution to demand flexibility through 2030, reaching 4.5 GW of demand turn-down; its greater levels of demand turn-up also enable efficient use of surplus generation. EVs could support the grid further by providing 1 GW of vehicle-to-grid (V2G) in 2030 at peak. With EV flexibility having the potential to be higher when more cars are plugged in outside peak times, this could allow charging to follow renewable generation patterns, making it highly valuable to the grid.

Developments in the growing EV market could see V2G capacity become similar to that of a low carbon dispatchable power station through 2030 at 1 GW, without large additional investments. However, V2G functionality would need to be commonplace in vehicles before this point, alongside affordable bidirectional charging infrastructure and payment mechanisms to reward consumers for participation.

Home storage heaters should transition from traditional devices (operating on timers) to modern devices or the equivalent, which can behave in a smart way, reacting to market signals in a more flexible and efficient manner.

Demand turn-up, where demand is increased at a time and location to utilise surplus renewable generation, also has strong potential, with 14.3 GW capacity in 2030. These additional potential benefits and cost savings have not been included in the modelling. The recent Crowdflex project,[2] with the incentive of discounted electricity, saw three times more engagement compared to turn-down events. Higher levels of demand turn-up must also consider how to avoid wasting energy and distribution network limitations where appropriate, which requires increased coordination with distribution network owners (DNOs).

In industrial and commercial settings, the amount of demand side response available at peak needs to double from around 0.8 GW to 1.4 - 2.0 GW.

2.2.3 Basis for our analysis

Our demand side flexibility ranges represent high levels of ambition on the required level of societal change from today, creating a low-cost solution to reducing peak demand and, therefore, system requirements.

Demand models are driven by consumer economics. We also consider other impacts and challenges of adopting to new technologies, including lack of incentive to change, high capital costs and unfamiliarity with the technology.

Most peak shifting capacity will be enabled by automation and digitalisation from a growth in smart appliances, the implementation of the Energy Smart Appliances Regulations in the Government's Smart Secure Energy System Programme and the Electric Vehicles (Smart Charge Points) Regulation 2021.

We include the current capacity of customer load active system services (CLASS) flexibility, which is a service that uses voltage control at DNO substations to manage demand loads. This remains a constant value out to 2030 in our modelling.

2 CrowdFlex project successfully completes first phase of large-scale consumer trials | National Energy System Operator (neso.energy)

We have seen growth of proven demand side response (DSR) in the capacity market from 156 MW to 279 MW over the last 4 years.[3] Our demand flexibility service (DFS) encourages consumers to shift demand. More than 2.4 million households signed up for winter 23/24, which delivered 500 MWh of demand reduction on 29 November 2023.[4]

We assume that the number of working smart meters grows from 62% (18 million) in 2023[5] to 86 – 90% (27 – 29 million) in 2030. We combined growth rates for smart installations and the breakdown of working and non-working meters with data around overcoming current technical and social issues. This was based upon stakeholder engagement with meter agents.

At present, 1.5% of residential demand at peak responds to innovative tariffs (other retail market offerings) or central dispatch signals. To achieve clean power by 2030, this needs to increase to between 8 and 9%. Residential demand shifting, in this case, mainly comprises households changing when they use their appliances, either through direct action from consumers or via automated scheduling of smart appliances.

Our modelling assumes that TOUTs are prevalent schemes underpinned by the market-wide half-Hourly Settlement (MHHS). However, similar outcomes could be achieved through innovation in the market. We do not specifically model which route to market will dominate this growth in customer engagement. We believe future markets will become far more dynamic, allowing consumers and aggregators to shift rapidly between pricing signals and centralised dispatch products from network operators.

Flexibility from heat is driven by economic modelling and the shift from a flat tariff to one with stronger TOUT profile over the years, to encourage the adoption of decarbonised heating technologies and the engagement in flexibility. The size of thermal storage, coupled with heat pumps, is modelled as hot water tanks, but could be considered as any type of thermal storage coupled with a heat pump.

Although most storage heaters installed are not smart, if the dwellings were on another type of electrified heating system, this would increase peak electricity demand. Storage heaters may also be considered as modern thermal storage, powered from direct electrical heating elements which households may switch to in order to reach greater levels of flexibility.

We forecast that 83% of EV cars and vans with off-street parking will engage with smart charging when using their residential charger and 81% of electric HGVs will smart-charge when using depots in 2030. This results in a 65% engagement in smart charging away from peak when we consider all vehicle and charger types.

V2G participation reaches 5.3% for cars with access to off-street parking. With 72% of vehicles having access to off-street parking, this leads to 275,000 EVs participating in V2G in 2030. We assume that 50% of those engaged are plugged in at peak time.

Industrial and commercial demand shifting and potential for process storage increases from 2% today to approximately 3% in 2030. This remains lower than the peak Triad response.

Further details on our assumptions can be found in our assumptions log.

3 emrdeliverybody.com/CM/Registers.aspx
4 neso.energy/data-portal/demand-flexibility-service
5 gov.uk/government/collections/smart-meters-statistics

2.2.4 Stakeholder views

There is a broad range of views from our stakeholders around the achievable levels of demand side flexibility. Some feel that consumers can be empowered to go much further and faster, while others think the levels are overly ambitious.

What was clear from all our stakeholders was that consumers should not be considered as one homogenous group. Empowering them to use energy differently will need to have tailored approaches. Examples were given of how low-income consumers can be supported to use energy differently, such as local authorities retrofitting council homes and putting in smart technology/energy appliances to ensure these residents have access to better tariffs.

Some stakeholders believe demand flexibility should not focus fully on direct energy or electricity use but should also consider flexibility in heating, both industrial and commercial and domestic. A wide variety in technologies should also be considered and should not be limited by a too-narrow or linear support policy. The potential of local energy initiatives to scale to provide heat capacity was also suggested.

Some stakeholders have emphasised the importance of technical and commercial coordination between NESO and DSOs to facilitate flexibility. They also highlighted the need to integrate distribution-level flexibility into market structures and address last-mile challenges with technical and policy considerations.

2.2.5 What is needed

Markets and investment

Reforms to the UK market, supported by digitalisation and innovation, are needed to unlock consumer and demand flexibility. Our pathways require demand side flexibility at peak to grow by 4 - 5 times current levels (when excluding storage heaters), which means building on the progress and innovation seen in recent years. Increased collaboration across Government, NESO, Ofgem, Elexon and industry is needed to ensure demand side flexibility holds the same significance as other clean power elements, such as network build and new technology investment. Digital infrastructure, product policies, standards and governance will underpin this transformation. New routes to markets for flexibility will be needed, whilst continued innovation will be key to ensuring consumers can reap the benefits. Consideration will need to be given to the distributional effects.

Access to data and digital infrastructure, such as smart meters and smart appliances, provides the foundations for consumer participation in demand side flexibility and can unlock benefits for both participants and the system. Automated data flows allow consumers to respond to real-time changes in electricity prices. Shifting this demand helps to flatten peak prices across the market and reduces the amount of energy generation and infrastructure needed in Great Britain.

Great Britain has already made significant progress in putting these data and digital foundations in place, but acceleration is now critical. For example, there are around 18 million operational smart meters in Great Britain today. To unlock the full value of flexibility, this figure needs to reach between 27 - 29 million (86% to 90% coverage) in the next five years. Policy levers should be explored to achieve higher levels of smart meter participation. The Data and Communications Company (DCC) will also have an important role to play in delivery.

Alongside this, consumer and industry concerns over access to data and privacy must be better understood and addressed. Acceleration of smart appliance policies and standards is also important to driving demand side flexibility in homes and businesses. Policy, regulation and innovation are already in flight across Government, Ofgem and industry to support rollout, including the Energy Smart Appliance Standards and Flexibility Innovation Programme. Acceleration of this essential work should be prioritised and refreshed to build on the digital foundations needed to achieve clean power by 2030. This includes accelerating Ofgem's Flexibility Market Asset Registration (FMAR).

Additionally, market design must ensure that flexibility is sufficiently rewarded to reflect its true value. Wholesale market reform is a key starting point to this, ensuring that demand side flexible assets are exposed to dynamic wholesale pricing that adequately reflects system needs to ensure that those market participants able to shift their demand are incentivised to do so.

Demand side flexibility is also a useful tool to help operate the electricity system. NESO must, therefore, ensure that demand side flexibility can compete in markets where it can meet system operability needs.[6] Market coordination is also required across NESO, DNOs and wider flexibility markets to ensure that flexibility providers can stack revenue and operate seamlessly.

In the energy retail market, the critical starting point to achieving the demand side flexibility levels shown in our pathways is ensuring the market-wide half-hourly settlement (MHHS) programme continues with no delay. Without this, there is no effective price signal to be passed on to suppliers and consumers. Markets must be open and accessible to ensure flexibility providers can construct offers to engage and incentivise consumers. A step change is also required to enable access for different kinds of businesses and business models to offer services and propositions to customers. Changes to network charges and how policy costs are recovered on bills should be considered and actioned, so that demand side flexibility can be appropriately valued and transparently passed through to consumers.

Consumers (including industrial and commercial) need to be able to respond to a price signal to benefit from demand side flexibility. Price signals need to adequately reflect the system value and incentivise a shift from business-as-usual activity to drive behaviour change. In the near term, this is expected through innovative tariffs and other retail market offerings, which could provide greater value. This is reflected in our pathways, which assume that these tariffs are the default from 2028. Innovation in the market, offering increased choice for consumers, could deliver greater volumes of flexibility. Common standards in flexibility markets will allow market participants, including flexibility providers and aggregators, to respond to changing conditions closer to real time, delivering savings and consumer benefits. Retail regulations may also be needed to ensure suppliers and retailers are incentivised to manage any complexity arising from multiple appliances and technologies responding to price signals on consumers' behalf, ensuring the value is fairly passed on to consumers. Any changes must consider the potential impacts on vulnerable and low-income consumer groups.

Digitalisation and innovation

Digital infrastructure will play a role in ensuring consumers can engage with a clean power system. Delivering the full benefits of flexibility will also require an increased focus on innovation projects, alongside enhanced digitalisation. Ongoing innovation projects, such as the Virtual Energy System and Crowdflex, seek to enable more efficient use of existing and planned assets and services.

The significant increase in digitalisation, along with research and testing of new innovation projects, will be important in operating a safe and secure system. This will also provide the best value for consumers.

Other enablers

Significant growth in distributed flexibility will be fundamental in delivering a decarbonised electricity system and ensuring clean and affordable energy for all. To deliver this goal at the pace required to reach clean power by 2030, greater alignment is needed between local and national markets and services to make this a reality. We look forward to supporting and working collaboratively with Elexon as the Market Facilitator, alongside Government, Ofgem and DNOs to develop more coordinated and collaborative market opportunities for all providers of flexibility in the future.

6 NESO will be publishing its 'Routes to Market' report in the coming months, which will expand on its commitments.

The critical importance of the Government, Ofgem, NESO, Elexon as the market facilitator and the wider sector was noted throughout our engagement: this is reflected in the markets and investment section above. Demand side flexibility is not subject to the same planning, development consenting, connections or supply chain challenges associated with building energy infrastructure projects. Therefore, it does not carry large cost burdens. Indeed, many of the interventions necessary to release the potential of demand side flexibility are administrative or regulatory.

2.2.6 Impact

Peak demand could be up to 11 GW higher without the demand side flexibility in the worst-case scenario. This would require additional low carbon dispatchable power or supply side storage, which would have a higher system cost and additional network reinforcement. Alternatively, the additional flexibility would be provided by unabated gas generators, which would result in a reduced clean power metric across the year.

Demand side flexibility has the potential to increase exponentially in the 2030s, reaching up to 57 GW by 2040. This is primarily driven by widespread access and use of V2G achieving 28 GW.

3. System/bidirectional flexibility

Greater levels of flexible generation help reduce the cost of the energy system by improving the utilisation of weather-dependent renewables. The capacity of flexible resources in our pathways is greater than the minimum level required for operability to help reduce the use of unabated gas.

System flexibility is needed to fill the gap between weather-dependent supply and demand

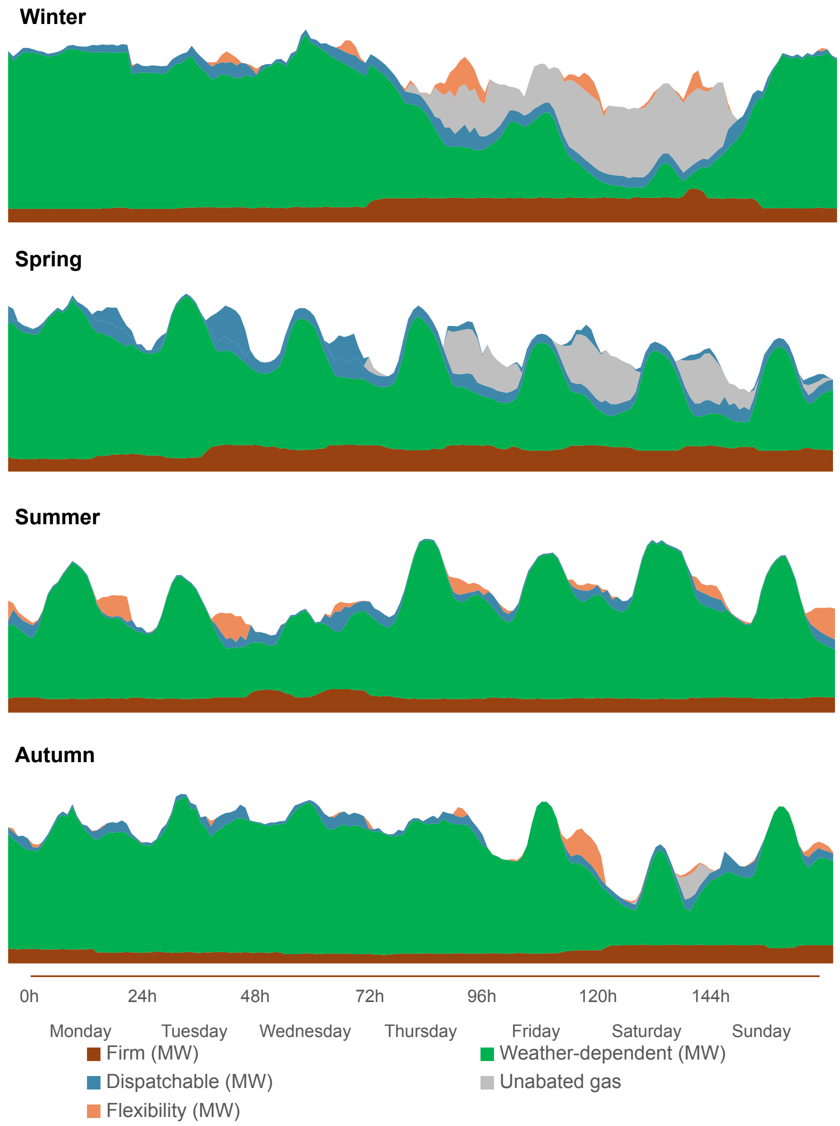

Figure 3: Generation, demand and flex stack for January in 2030, using weather year of 2013 for Further Flex & Renewables

Additional flexibility is needed during periods of low generation and high demand (for example, wind droughts in colder winter weather). Consumer engagement is a vital part of efficient and low-cost use of clean power and, in the first instance, regular demand side flexibility responsive to TOUTs would typically be used to reduce peak demand. Shorter-duration storage from batteries or V2G may then discharge before longer-duration storage. Interconnectors may start to import depending on the price differential and additional generation, such as low carbon dispatchable power or greater demand side flexibility and may also be brought online to reduce demand. Finally, if all other resources have been used, unabated gas will need to be used in 2030 to ensure consumer demand is met.

Accurate long-term forecasts and coordination with DNOs and all flexibility assets are important in ensuring the charging and discharging of storage can be effectively timed, discharging storage during the times of most need, leading to less unabated gas use in 2030.

3.1 Long Duration Energy Storage (LDES)

3.1.1 Great Britain today

Long-duration energy storage (LDES) contributes to security of supply, particularly during constrained periods (for instance, low weather-dependent renewable output). The maximum volume of LDES installed in the system is currently 28 GWh from 3 GW of installed capacity, (mainly driven by pumped hydro) with around 0.01 GW of new and innovative LDES.

3.1.2 Great Britain in 2030

The installed capacity of LDES needs to increase from 3 GW today to between 5 – 8 GW through 2030. This means building new pumped hydro energy storage (PHES) capacity in Great Britain for the first time in more than 40 years.

New and innovative LDES technologies, such as liquid air energy storage (LAES), compressed air energy storage and iron air batteries need to be deployed, giving Great Britain an opportunity to lead the way in new technologies.

Traditional batteries today could operate at reduced capacities to enable operation as a LDES, as required by the system needs.

3.1.3 Basis for our analysis

Our LDES generation mix is achieved largely through PHES and LAES across our pathways.

Pumped hydro is a mature technology with a global supply chain. Around 7 GW of projects with planning permission or an application have been submitted and a further pipeline of projects are under consideration. Acceleration of projects is needed to deliver by 2030. Our analysis assumes that the existing fleet of pumped hydro stations remain on the system.

Our engagement with industry has identified the opportunities for LAES and compressed air in Great Britain.

The 'cap and floor' funding mechanism is on track to be established next year. There has been successful delivery of small-scale, first-of-a-kind LDES technology with additional projects in the pipeline.

3.1.4 Stakeholder views

Multiple stakeholders believe LDES is important to secure a clean power system, but some stakeholders felt the role of hydrogen is currently underrepresented (note hydrogen's role in power generation is included in the Low Carbon Dispatchable Power section below). One stakeholder believed there could be untapped potential in redeveloping old hydro power stations across the country.

Stakeholders emphasised that the rapid delivery of the 'cap and floor' mechanism is critical for the deployment of LDES by 2030, acknowledging its high costs and long build times, with some views that LDES would take longer to arrive on the system. Many also highlighted the urgency of these policy decisions to support LDES development.

Stakeholders also suggested that action is needed to reform the connections process and speed up planning and consenting. With particular regard to PHES, they pointed to the need for more planning resource in local authorities, particularly in the Highlands, as well as careful management of impacts on local infrastructure and communities.

They also advised that the spatial generation and network plan needs to show how LDES assets will fit into the plan. It's important to ensure LDES assets of sufficient durations (8 - 10 hrs) are in optimal locations to provide the greatest system benefits.

3.1.5 What is needed

Markets and investment

The 'cap and floor' model for LDES must be developed as soon as possible to meet the level of ambition required to deliver clean power. Existing PHES capacity may need the implementation of previously planned Capacity Market reform to remain on the system in 2030.

Planning, consenting and communities

External research commissioned by ESO on planning and consenting did not explore LDES. However, PHES projects have relatively long build times of up to 5 - 7 years. Projects will, therefore, need to be approved via the planning system for construction as soon as practicably possible. Stakeholders noted, too, the capacity of the planning system in the Highlands to deal with applications could be a potential barrier.

Connections reform

Connections reform will need to support the delivery of the LDES capacity needed for clean power by 2030.

Supply chain and workforce

While PHES is a well-established technology across the world, there have been no new projects constructed since the 1980s. Additionally, the sector could face long lead times across the global supply chain for some of the equipment required. Given build times, construction would need to commence urgently and the risks associated with large infrastructure build managed if they are to be operational by 2030.

LAES is currently being pioneered in Great Britain and there is an opportunity for the country to establish itself as a world leader in this technology. The delays associated with innovative projects must be minimised where possible.

3.1.6 Impact

Without the growth in LDES, curtailment of renewables would increase alongside the use of unabated gas. Batteries could potentially play a greater role in assisting LDES requirements if set up and operated for longer durations. They would, however, be unlikely to completely fill the gap between traditional batteries and low carbon dispatchable power.

3.2 Battery Energy Storage

3.2.1 Great Britain today

There is currently 5 GW of operational battery storage capacity for within-day flexibility across Great Britain.

3.2.2 Great Britain in 2030

Batteries reach between 23 - 27 GW installed capacity by 2030. Battery technology is advancing at pace and they could provide an increasing contribution to system services.

3.2.3 Basis for our analysis

Battery projects typically have a 1 - 2 year deployment time. There is a strong pipeline for batteries in the connections queue, beyond what is required. Our capacities are based on our operability requirement from flexible assets, alongside dispatch modelling analysis.

3.2.4 Stakeholder views

Our stakeholders want to see continued investment and rollout of NESO's data and digital capability to facilitate batteries. They were pleased to see a target for storage.

Stakeholders did note that, as more batteries come onto the system with reduced costs, there will be an improvement of batteries operating over longer durations beyond 2 - 4 hours. Several stakeholders asked that NESO and Government clearly define the view on how small-, medium- and long-term storage should be categorised.

3.2.5 What is needed

Markets and investment

Appropriate market signals and incentives are critical for batteries to deliver efficient investment and dispatch. This includes the role of the wholesale market in sending accurate price signals. It is also important that batteries be easily accessed and transparently dispatched by NESO.

Planning, consenting and communities

External research commissioned by ESO suggested that decisions on standalone battery storage projects were, on average, reached within five months from initial application. Collocated sites, meanwhile, were decided within 8 months. Timescales from submission of planning to operational are, on average, 42 months for standalone battery storage sites and 36 months for collocated projects.

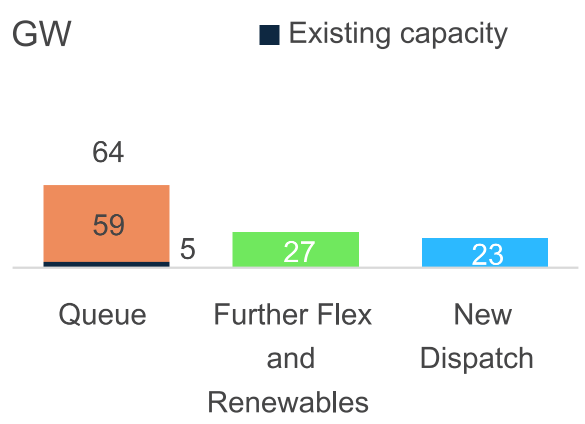

Figure 4: Connections reform

There is significantly more battery capacity in the current connections queue than is needed for the delivery of clean power by 2030. The connections proposals we set within technical report 2 address this.

Supply chain and workforce

Deployment rates must be accelerated. The current record is ~1.9 GW/year and our pathways require an average of ~4 GW/year.

Our engagement and analysis highlighted the following key supply chain challenges:

- Sourcing transformers.
- Accessing EPC providers.
- Ensuring that access to international supply chains remains open.

China is the global leader in battery manufacturing. There may be an opportunity to strengthen domestic manufacturing in batteries to add resilience to the supply chain, building on the UK's progress with gigafactories for EV batteries.

Digitalisation and Innovation

A continued focus on improving modelling for network conditions and scenarios for a decarbonised power system and use of battery storage is important. NESO has an ongoing NIA funded Battery Storage Modelling for Enhanced Connection Assessments (BatSeC) project to develop a new battery model, which will enhance capability to understand battery storage scenarios. More coordination and collaboration across industry would further support collective understanding of battery storage implementation and behaviours.

3.2.6 Impact

A lack of growth in installed battery capacity would make meeting within-day peak demand more challenging. Demand side flexibility may require greater levels of participation and LDES installed at greater capacities, but it is unlikely to completely fulfil the role of batteries. Short-term times where demand is greater than supply would need to be filled by unabated gas generation.

An additional study was undertaken on the total battery capacity (GWh) and power (GW) trialling, doubling each parameter separately and then doubling both values together, as well as halving both values together. This study showed that the overall capacity and power have a small impact on the clean power metric, with the largest impact from halving both variables increasing the amount of unabated gas by 0.04%. The doubling of battery capacity was for sensitivity study purposes only; this is unlikely to be deliverable given the current pipeline and the enabling work required. The analysis does show the value of batteries in shifting solar energy to the evening peak and that on consecutive days of low wind and solar needs longer-duration flexibility.

The efficiency of batteries was also investigated, with this being increased to a roundtrip efficiency of 85% compared to the standard 70% value in the model. This improved the clean power metric by 0.07%. This variable is more important than the overall capacity. Improving this efficiency does reduce the use of LDES, as batteries start to compete over longer periods in the analysis.

3.3 Interconnectors

3.3.1 Great Britain today

Interconnectors play a crucial role in the British energy market by linking the national electricity network with neighbouring countries. These high-voltage cables allow for electricity imports from and exports to Europe, with a current interconnector capacity of 8 GW. In 2023, Great Britain imported 33 TWh of electricity over the year and exported 10 TWh, leading to the region being a net importer, by 23 TWh over the year.

3.3.2 Great Britain in 2030

Increased capacity of interconnectors facilitates the integration of weather-dependent renewables, fulfilling any under supply from renewables. Interconnector capacity could grow from 8 GW today to 12 GW in 2030. This allows some surplus generation to be sold, reducing curtailment. Similarly, electricity can be purchased from neighbours during periods of low renewable generation, instead of switching on unabated gas plants.

3.3.3 Basis for our analysis

The interconnector capacity is based on the current pipeline achieving their target connection dates.

3.3.4 Stakeholder views

Numerous trade associations have said the role of interconnectors and exports and imports will be critical to how we achieve clean power. However, a cost assessment needs to consider how exporting renewable generation is of benefit to UK consumers. Several stakeholders have questioned the assumption made that interconnectors are 'clean power' and therefore question the description of clean power we use.

Some stakeholders have said how interconnectors are required to behave and the location of them should be considered so they are most beneficially sited to support the network and to ensure they do not add to the constraints on the system.

3.3.5 What is needed

Markets and investment

Rapid decisions on the 'cap and floor' mechanism for interconnectors are needed to ensure the required build out.

Other enablers

Interconnectors are generally assumed to connect in line with their current planned connection dates. Our analysis did not focus on any other specific issues.

3.3.6 Impact

Lower levels of interconnector capacity would lead to greater quantities of curtailed renewable generation during times of surplus generation and greater use of unabated gas generation during times of low wind and low sun.

Additional interconnector capacity in 2030 above the 12 GW was investigated using a range of individual and combinations of projects, up to a maximum of 3 GW additional capacity. Although the extra projects help with security of supply and reduce the amount of curtailment, they have little impact in our modelling on the share of clean power.

Our analysis shows that increasing the carbon price on unabated gas generation further prioritises importing instead of using gas generation. In extreme sensitivity studies, this can reduce the share of unabated gas to 1%. However, this leads to increasing imports during periods when the rest of Europe may also be going through a stress period which could, therefore, increase import costs. This may increase the use of lower efficiency gas generation from our neighbours or even coal generation in the short term. We have used carbon price as a modelling device not a policy recommendation. Careful consideration must be given to how much value is placed in interconnectors simply to meet higher clean power metrics.

4. Electricity supply

A huge scale-up in low carbon generation is needed to reach a clean power system through 2030

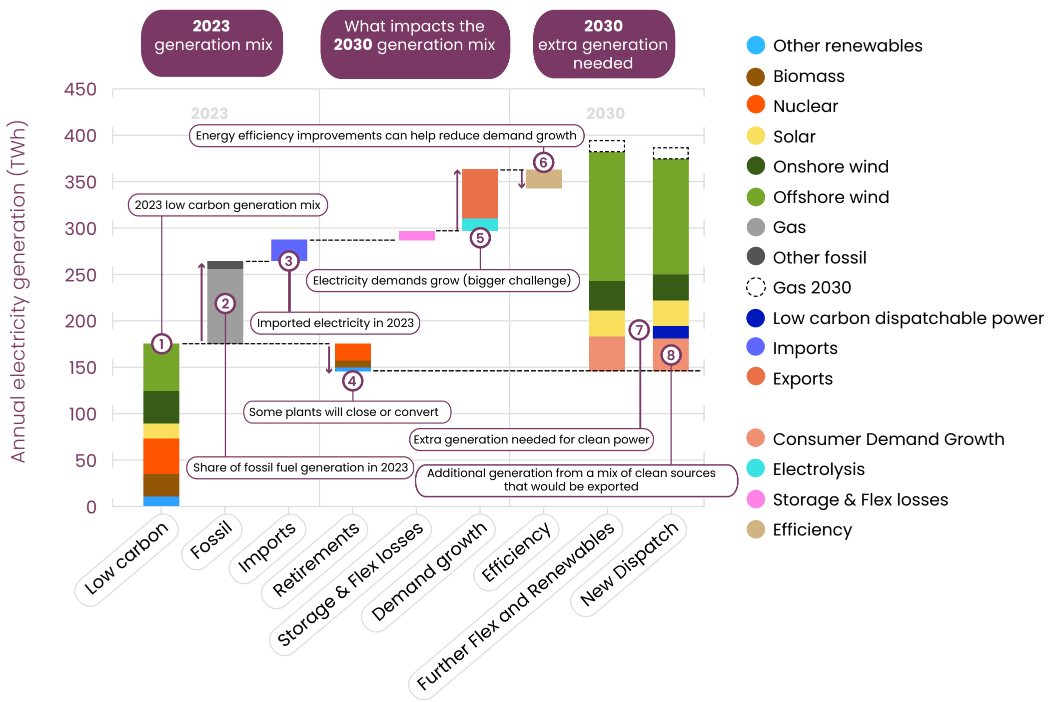

Figure 5: Changes in generation from 2023 to 2030

The left side of Figure 5 starts with the supply in 2023 from low carbon generation and high levels of unabated gas generation and net imports over interconnectors. The central section of the figure shows the changes between 2023 and 2030, with the retirement of low carbon capacity leading to net reduction in low carbon generation shown, followed by the growth in demand, losses from storage and flexibility and then reductions in demand from efficiency improvements. This results on the right side with the growth in low carbon generation required in 2030, which is higher than after the changes due to Great Britain becoming a net exporter in 2030.

Table 1: Changes in generation from 2023 to 2030

	Installed Capacities (GW)		
Technology	**2023**	**2030 Further Flex and Renewables**	**2030 New Dispatch**
Offshore wind	14.7	50.6	43.1
Onshore wind	13.7	27.3	27.3
Solar	15.1	47.4	47.4
Nuclear	6.1	3.5	4.1
Biomass/BECCS	4.3	4.0	3.8
Low carbon dispatchable power	0	0.3	2.7
Other renewables	4.7	5.7	5.7
Batteries	4.7	27.4	22.6
LDES	2.8	7.9	4.6
Interconnectors	8.4	12.5	12.5
Unabated gas	37.4	35.0	35.0

Generation capacity must grow across both the transmission and distribution networks

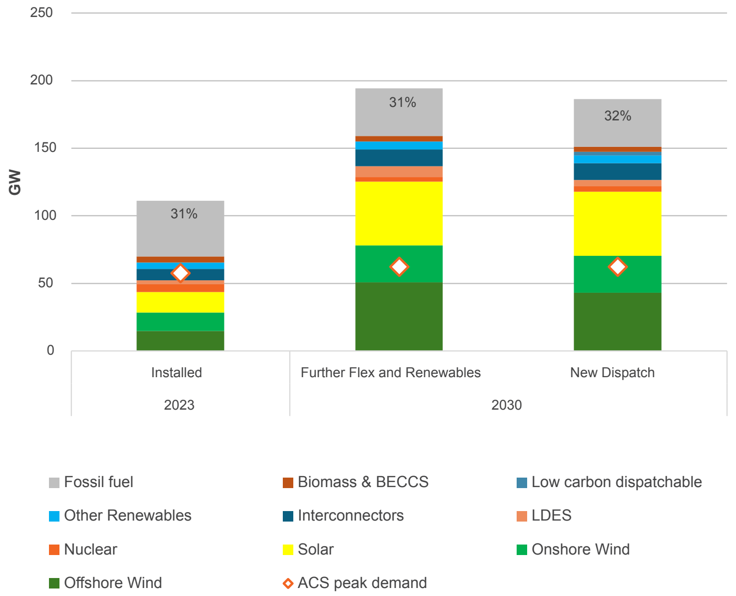

Figure 6: Capacity mixes for 2023 and 2030 with percentage of distributed connected capacity

4.1 Weather dependent renewables

4.1.1 Offshore wind power

4.1.1.1 Great Britain today

An installed capacity of 15 GW offshore wind provided around a quarter of Great Britain's total generation in 2023, generating 48 TWh.

4.1.1.2 Great Britain in 2030

Offshore wind will become the dominant factor of a clean energy system. The share of generation provided by offshore wind must grow sharply to provide around half of the supply in an average weather year. This means an additional 28 - 35 GW of offshore wind with load factors of 43% for offshore wind generating 167 - 187 TWh of clean power.

Wind power in Great Britain has a seasonal effect: more generation in winter is aligned to the seasonal increase in demand during the colder months.

4.1.1.3 Basis for our analysis

Offshore wind is a mature and well-established technology, with experienced developers operating in the British market. Long-term Government ambitions, backed by the well-established Contracts for Difference (CfD), have resulted in a strong pipeline of projects in Great Britain. More than 54 GW of offshore wind is in the connections queue for 2030, including current built capacity. We have considered additional project delivery and timeline information as part of our analysis.

4.1.1.4 Stakeholder views

All our stakeholders recognised that offshore wind would be the driving force powering Great Britain's future energy system. Most saw the benefits that wind power could bring; however, views did differ around deployment ranges by 2030, supply chain constraints and associated electricity network build to connect the offshore wind.

We began our interim analysis with three pathways, one of which tested the upper limits of offshore wind deployment by 2030. Many stakeholders fed back that deploying 55 GW of offshore wind by 2030 was not achievable, even with reforms. They felt that the lower range of our target of 43 – 50 GW was credible and deliverable. However, reaching the upper end of this would require a significant shift.

After adapting our pathways, energy generators believed the new primary pathways were more credible if supported with policy actions to deliver.

Stakeholders also raised concerns around global supply chain challenges and skills shortages. Some suggested repurposing second-hand turbines and developing wind engineers who understand grid requirements.

4.1.1.5 What is needed

Markets and Investment

The CfD has been critical to the success of bringing forward offshore wind investment in Great Britain. Providing sufficient investment support will be essential. With almost the entire pipeline required to deliver clean power, consideration must be given to how to maintain competitive pressure when awarding contracts.

Planning, consenting and communities

External research commissioned by ESO suggested that offshore wind projects took an average of 73 months from submission of planning to operational. The average time to issue a planning decision was faster in Scotland (15 months) compared to in England (21 months).

A substantial portion of this infrastructure is still awaiting planning consent. We want to support the Government in understanding and increasing awareness of the pipeline of generation projects on the critical path to 2030. Action, in line with our overarching messages on planning, consenting and communities, will also be required to ensure sufficient offshore wind capacity and its supporting network infrastructure can enter construction on accelerated timetables, while maintaining community support.

Connections reform

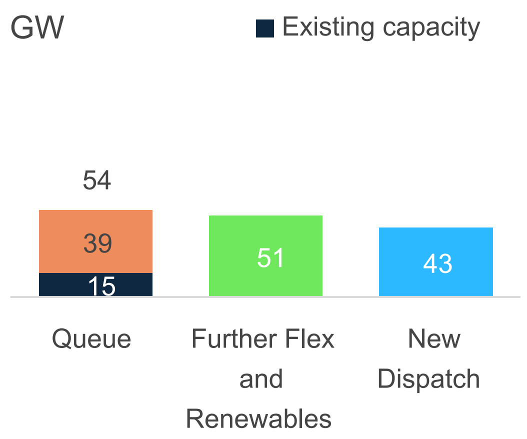

Figure 7: Connections reform

Connections queue reform will be required to enable the delivery of sufficient offshore wind capacity by 2030.

For more information on connections, see Network and Connections Annex.

Supply chains and workforce

The manufacturing lead times for offshore wind is 3 - 5 years, so projects need to be in the procurement phase within the next 2 - 3 years to achieve 2030 deployment. Supply chain certainty and assurance remain critical to build the required generation infrastructure for 2030.

Our engagement and analysis highlighted the following key supply chain challenges:

- Availability of substation components (particularly transformers), High Voltage Direct Current (HVDC) cables, foundations and turbines.
- Development of port infrastructure and capacity to enable floating offshore wind and to accommodate increasing turbine sizes.
- Securing sufficient installation vessels as soon as possible to mitigate the limited global supply.
- Providing more than 100,000 skilled roles to deliver 50 GW of offshore wind, up from 32,000. [7]

There is a domestic manufacturing capability in Great Britain, but reliance on global supply chains is strong. The country will need to remain internationally competitive to ensure availability and procurement of equipment out to 2030. Our research and engagement indicate opportunities for growing the domestic supply chain for offshore wind. More central and strategic coordination of the needs between networks and generation infrastructure could also help identify overlap of supply chain needs for offshore wind.

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Skills and workforce pressures are likely to increase across the whole renewables pipeline. Action is needed to unlock the skills and capabilities for addressing the skills gaps and attracting skilled workers to deliver on the clean power plan and, in the longer term, net zero.

Digitalisation and Innovation

NESO continues to progress innovation projects related to planning and forecasting weather-dependent generation. Further opportunities should be identified and pursued for innovation to improve the resilience of the system as the generation mix develops, with increased collaboration across NESO, industry, academia and technology providers. This would apply across all weather-dependent renewables.

4.1.1.6 Impact

Deployment of offshore wind has the largest impact within the generation mix in increasing the amount of clean power generation and it will be the backbone of a 2030 clean power system in Great Britain. Without the offshore wind generation, approximately 140 TWh of generation would be required from other sources (from allowing net exports to reduce to nil). This equates to around 20 GW of firm capacity operating at high load factors, which needs to be clean to meet the clean power target.

4.1.2 Onshore wind power

4.1.2.1 Great Britain today

An installed capacity of 14 GW onshore wind provided 13% of total generation in 2023, from 31 TWh.

4.1.2.2 Great Britain in 2030

The amount of generation provided by onshore wind power must grow by around 75%. This means an additional 14 GW of onshore wind. With load factors of 24% for onshore wind, this generates 58 TWh of clean power.

Wind power in Great Britain has a seasonal effect: more generation in winter is aligned to the seasonal increase in demand during the colder months.

4.1.2.3 Basis for our analysis

Offshore wind is a mature and well-established technology, with experienced developers operating in the British market. The CfD offers an effective support mechanism.

The connections queue for 2030 includes 32 GW of onshore wind including current built capacity, with additional project timeline information feeding into the pathway ranges. We have assumed there is 20 GW of onshore wind in Scotland in 2030, which is approximately double today’s value.

With planning restrictions lifted in England in July 2024, we expect further growth in the onshore wind pipeline. With faster development than offshore wind, new projects could still enter the pipeline and be delivered by 2030. Our pathways assume an additional 2 GW of onshore wind in England and Wales, reaching 7 GW in 2030.

4.1.2.4 Stakeholder views

Stakeholders across the energy industry have given a range of views around delivery of onshore wind in England and Wales due to previous Government's de facto moratorium on development outside of Scotland.

Some stakeholders felt that it is possible to scale up onshore wind at a distribution level across England and Wales and that it may be possible to locate up to 2 - 2.5 GW of onshore wind in Wales. However, this may not necessarily be deliverable by 2030 due to these projects being in the early stages of planning. Other stakeholders suggested that there is potential for 4 GW from repowering existing operational onshore wind farms, with additional capacity from new community-led projects. One stakeholder suggested that projects in the south of England could be sped up by 2030, but grid connections and appending up the queue was critical.

Another advised that it would be important to consider the viability of these pathways with and without policy interventions. For example, increased onshore wind capacity in England will be extremely challenging given the immaturity of the project pipeline and resourcing of planning officers, which was identified as a barrier.

Perceptions around the unpopularity of onshore wind with consumers were challenges. However, our stakeholders recognised the importance of community engagement. It was also noted that different communities need engaging differently. With some areas designated for large-scale wind already in place, it is important that overall land use planning aligns with energy planning, considering the best use of land.

4.1.2.5 What is needed

Markets and investment

It is vital to ensure sufficient onshore wind capacity can be unlocked through the next two CfD auctions.

Planning, consenting and communities

External research commissioned by ESO suggested that onshore wind projects take, on average, 15 months to receive a decision after application to local planners. National government took, on average, 35 months to issue a planning decision. The period between planning submission to operational is an average of 53 months at the local authority level and 84 months at the national level. Action, in line with our overarching messages on planning, consenting and communities, will be required to ensure sufficient onshore wind capacity and its supporting network infrastructure can enter construction on accelerated timetables, while maintaining community support.

Connections reform

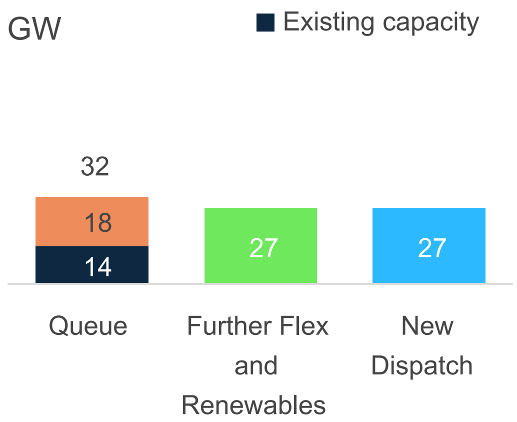

Figure 8: Connections reform

As with offshore wind, connections queue reform will be required to enable the delivery of sufficient onshore wind capacity by 2030.

Supply chain and workforce

Our engagement and analysis highlighted the following key supply chain challenges:

- Availability of electrical components, such as switch gear and transformers.
- Competition with the wider construction sector for key materials, such as concrete, machinery or cranes.

As with offshore wind, although the domestic manufacturing capability exists, reliance on global supply chains is strong. Stakeholders suggested that growing domestic supply chains of onshore wind would allow us to be more independent and create more certainty for investment. More central and strategic coordination of the needs between networks and generation infrastructure could also help identify overlap of supply chain needs for onshore wind.

Skills and workforce requirements will become more acute as renewable generation increases and targeted and prioritised action are needed to unlock the skills and capabilities for addressing the skills gaps and attracting skilled workers.

Digitisation and innovation

As with offshore wind, NESO's innovation projects related to planning and forecasting weather-dependent generation will need to progress. Further opportunities should be identified and pursued for innovation to improve the resilience of the system, with increased collaboration across NESO and industry.

4.1.2.6 Impact

Onshore wind is the second-largest source of clean power, providing 58 TWh of generation in 2030. Without onshore wind generation, this would require around 8 GW of firm capacity to be added to cover supply requirements.

4.1.3 Solar

4.1.3.1 Great Britain today

Around 15 GW of solar photovoltaic (PV) capacity is available on the system, providing 13 TWh and 6% of total generation in 2023. 99% of this is connected to the distribution network.

4.1.3.2 Great Britain in 2030

An additional 32 GW of solar capacity is needed for a clean power system through 2030 across both our pathways. Lower load factors of 11% for solar result in 47 TWh across the year. This generation is focused over the summer months and does not, therefore, align with Great Britain's annual demand profile. However, it does aid diversification of clean power supply compared to using wind alone.

We expected around 90% of solar on the system through 2030 to be connected to the distribution network.

4.1.3.3 Basis for our analysis

Globally, solar generation is the lowest cost source of electricity. In Great Britain, it is a mature and well-established technology with experienced developers. Evidence from solar PV deployment in the UK in August 2024 suggests that most recent deployment has been funded on a merchant basis. However, around 7 GW of solar PV has been contracted in the three most recent CfD Allocation Rounds (AR4, 5 and 6) for deployment in the next 4 years.

There is a large pipeline of projects across Great Britain, predominantly in the south and Midlands. The 2030 connection queue includes 68 GW of solar capacity and 38 GW of these have land (as of July 2024).

4.1.3.4 Stakeholder views

There was broad agreement on the need to deploy solar across Great Britain to achieve clean power. This aligns with polling shared by our stakeholders that show solar and onshore wind are the most popular form of energy with communities, but that high-quality engagement was needed to avoid residents feeling projects are imposed on them.

Views differed around the size and location of solar farms across Great Britain. Some raised concerns that the cumulative impacts of siting high concentration of renewable generation in certain areas will make it challenging to obtain consent and could alienate communities. For example, some land use representatives and planning experts advised that support for solar would be stronger if it was dispersed at distribution level; there is a perception that large solar farms at transmission level are clustering around certain substations.

Another societal group believed that it would be possible to deploy 28 GW of domestic rooftop solar PV alongside commercial and industrial rooftops, with a further 2 GW from ground-mounted solar.

When discussing enabling more solar farms to come forward, suggestions were made to CfD, such as setting a schedule of capacity targets per auction to align with the 2030 clean power ambition.

4.1.3.5 What is needed

Markets and investment

The CfD is an important mechanism for bringing forward large solar PV developments, with around 7 GW due to come online through the scheme in the next four years. There is a healthy pipeline which should ensure competition. Sufficient capacity needs to be brought forward through the CfD or merchant market.

Planning, consenting and communities

External research commissioned by ESO suggested that solar projects required an average of five months to receive a decision after submission to local planning authorities. National government took an average of 14 - 16 months to issue a decision. From submission of planning to operational took an average of 16 months in local planning. One nationally consented solar farm took 36 months to become operational. Action, in line with our overarching messages on planning, consenting and communities, will be required to ensure sufficient solar capacity enters construction to be available for 2030, while maintaining community support.

Connections reform

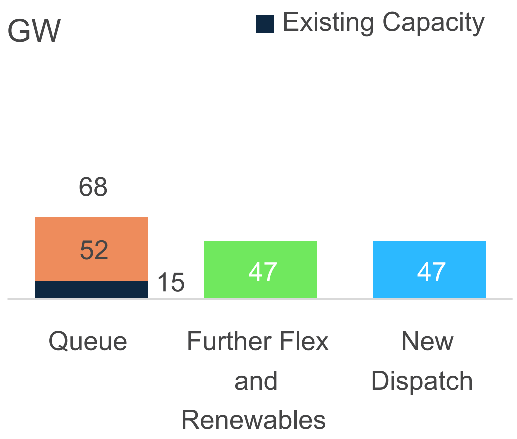

Figure 9: Connections reform

Connections queue reform is likely to be needed to bring forward sufficient volumes of solar capacity.

Supply chain and workforce

Supply chains are already well established for the installation of solar and we have anticipated minimal constraints in the supply of solar. There is continued reliance on global supply chains with China. The availability of key solar PV components and openness of global supply chains will need continual monitoring.

Digitalisation and Innovation

As above, NESO innovation projects to support weather-dependent generation will need to continue to progress.

4.1.3.6 Impact

Although solar provides less generation than offshore and onshore wind, it is a vital tool for providing clean power in the right proportions. Providing 45 TWh, the third largest source of clean power, in this quantity solar would need to be offset by other means. Solar also provides a diversity of clean power generation, with different generation profiles to wind.

4.2 Clean firm capacity

4.2.1 Nuclear

4.2.1.1 Great Britain today

Nuclear power remains a significant part of Great Britain's energy mix, supplying over 14% of demand in 2023. This is provided by current installed capacity of 6.1 GW. Hinkley Point C (3.2 GW) is still under development, with Unit 1 currently expected to start generating in 2029. Much of the current nuclear fleet will approach end of life before 2030 without extensions.

4.2.1.2 Great Britain in 2030

An installed capacity of 3.5 - 4.1 GW of nuclear operates through 2030 in our pathways. Operating at a load factor of 81% provides 25 - 29 TWh of clean generation, from a relatively consistent output across 2030.

Looking further ahead to 2050, significant development of nuclear capacity in Great Britain will be essential to deliver the UK's net zero targets.

4.2.1.3 Basis for our analysis

Several significant changes are expected in the capacity of the nuclear fleet over the next decade, including the closure of the last remaining advanced gas cooled reactor plants and alongside the opening of new large nuclear capacity at Hinkley Point.

In combination, we assume these see a reduction in Great Britain's nuclear capacity from 6.1 GW in 2023 to 3.5 - 4.1 GW in 2030, with scope for more new build beyond 2030. Our baseline assumption includes Sizewell B, one unit at Hinkley Point C and a lifetime extension of one AGR unit. There are uncertainties in the timescales for these. Our modelling reflects this with a range of capacity in our projected national nuclear capacity in 2030.

4.2.1.4 Stakeholder views

Stakeholders believe that significant levels of nuclear generation are likely to come online post-2030. To develop Great Britain's nuclear fleet, policy actions are required in the immediate term across areas such as planning and regulatory processes, supply chain and development of specialist skills.

4.2.1.5 What is needed

Overall nuclear capacity needs to be at least 3.5 GW by either plant extension or new units coming online by 2030. This underlines the importance of the existing AGR fleet and new capacity in Hinkley Point C. Any plant lifetime extensions rely on the Office of Nuclear Regulation.

Supply chain and workforce

Stakeholders raised the importance of ensuring the existing nuclear pipeline is completed. They also identified the challenges securing skills like engineering, data and construction across the sector, as well as the value of retaining skilled workers to take us to clean power by 2030.

As with the increase of offshore and onshore wind, there is a need to ensure targeted and prioritised action to unlock the skills and capabilities for addressing the skills gaps and attracting skilled workers to deliver on the clean power plan and Net Zero in the longer term.

4.2.1.6 Impact

Decreased nuclear capacity leads to a higher amount of unabated gas use to meet demand during low wind times. In our Further Flex and Renewables pathway, unabated gas share increases by 0.9% and New Dispatch 1.5% due to it originally having the highest nuclear capacity. In addition to higher levels of unabated gas use with less nuclear capacity, for adequacy, any reduction in nuclear capacity would also require a similar increase in gas capacity to ensure security of supply.

Additional firm generation, including 1.8 GW of additional firm capacity in 2030, such as from nuclear small modular reactors, would provide around 13 TWh of generation and reduce the share of unabated gas by 0.9 percentage points (3 TWh). Most of the remaining 10 TWh would be lost to curtailment or exported at low cost, implying an increase to overall costs of the power system. We have not explored sensitivities for this report that add firm capacity in place of variable renewables.

4.3 Low carbon dispatchable power

4.3.1 Gas with carbon capture and storage and hydrogen to Power

4.3.1.1 Great Britain today

No gas carbon capture and storage (CCS) or hydrogen to power plants operate in Great Britain. However, significant steps have been taken by Government and industry on the route to delivery in industrial clusters.

4.3.1.2 Great Britain in 2030

Our New Dispatch pathway includes 2.7 GW of low carbon dispatchable power through combination of hydrogen to power and gas CCS.

Low carbon dispatchable power can operate flexibly to meet demand over longer periods compared to storage, providing a clean form of firm capacity. Post-2030, we would expect these technologies to replace the need for unabated gas generation.

CCS coupled with biomass or gas requires the build-out of CCS after treatment, along with downstream transportation of the captured CO_2. This requires CO_2 pipelines for a large-scale solution and permanent downstream storage facilities. Hydrogen to power may require more than 1 TWh of hydrogen storage through 2030.

4.3.1.3 Basis of our analysis

Both gas with CCS and hydrogen to power are first-of-a-kind technology for Great Britain. There are only two operational gas CCS plants globally.

Industrial clusters offer the most suitable location through 2030 for many of the low carbon dispatchable power requiring CO_2 or hydrogen infrastructure as projects are already in train.

In October 2024, the Government announced the funding of around £22 billion for the first CCS clusters.

Low carbon dispatchable power connected to the distribution network can assist during periods of stress. Our analysis includes just under 0.3 GW capacity at low load factors where they may need to operate to reduce network constraints. This could be met by a range of fuels, including biomass, biomethane or hydrogen, depending on local access.

Our modelling assumes pure hydrogen and biofuel use only in low carbon generation. If fuel blending occurs for low carbon dispatchable generation, this will increase emissions. On the other hand, if this occurs for unabated gas generation, this will reduce emissions beyond our analysis, particularly if this hydrogen or biofuel would otherwise be vented.

4.3.1.4 Stakeholder views

Stakeholders developing hydrogen and gas CCS advised that development of this technology is challenging but could be possible at scale with quick decisions from Government regarding cluster sequencing.

We began our interim analysis with three pathways, one of which tested the upper limits of low carbon dispatchable deployment by 2030. BECCS was grouped within this category during this phase. Many stakeholders fed back that deploying ~3 GW was not ambitious enough and more could be deployed.

Other stakeholders within the thermal industry advised that this higher range of ~3 GW would be challenging to achieve due to funding, supply chain and storage facilities, with one of the most significant challenges being developing hydrogen and CO_2 storage.

After adapting our pathways to reflect higher levels of low carbon dispatchable generation, energy generator stakeholders believed the new pathways were more credible if supported with the right policy actions.

Many stakeholders raised the importance of these technologies for providing energy in the early 2030s and advised that that funding and policy decisions needed to be addressed now to ensure this new technology could continue to deploy at scale in the early 2030s.

Our stakeholders also acknowledged that, like other areas of industry, skills shortages will need to be addressed. Delays in sign-off of projects by the HSE and gaining planning consent in good time are also issues that need resolving.

4.3.1.5 What is needed

Markets and investment

Deployment of these technologies relies largely on Government decisions on investment support for both the generation capacity and supporting infrastructure. Rapid action is needed to enable progress on:

- Deployment of the supporting carbon transport and storage systems (we assume hydrogen will be from methane reformation with CCS up to at least 2030), as well as hydrogen storage for hydrogen to power. Given the relatively short timescale to 2030, we believe deployment would rely on the acceleration of one or more of the industrial clusters already selected by Government to provide the CO_2 transport and storage.
- Commencing build of gas CCS projects with funding as soon as possible, with Financial Investment Decisions (FIDs) and project build commencing quickly.
- Hydrogen to power business model to complete design and allocation to enable FID of the plant. This requires rapid action.
- Allocating hydrogen transport and storage business models to enable the build of the supporting infrastructure and bringing online for 2030.

Supply chain and workforce

The supply chain also presents a challenge given cross-dependencies and establishing this for first-of-a-Kind (FOAK) technologies. Stakeholders highlighted several supply chain challenges which would need to be overcome. These include:

- Compressors and gas blowers/tanks must be sourced from overseas.
- There is a limited pool of companies in the UK with capability to test seal integrity of storage.
- 100% hydrogen turbines would need to be ready ahead of 2030.

However, this is also a considerable opportunity for Great Britain. Transport and storage of CO_2 could utilise the country's well developed, world-leading petroleum exploration and production supply chain. It could also leverage the industry's considerable knowledge of the subsurface beneath the UK Continental Shelf (UKCS). This has one of the largest storage capacities in the world and presents a huge economic opportunity for the future.

4.3.1.6 Impacts

Out to 2030, higher levels of renewables and flexibility can help achieve 95% clean power. However, to reduce the final amounts on unabated gas generation, low carbon dispatchable power is of growing importance to flexibly meet the times of undersupply cost effectively.

Building on New Dispatch with 2.7 GW of low carbon dispatchable power that achieves 95% clean power with 18 TWh of unabated gas used, reducing the low carbon dispatchable power by 500 MW to 2.2 GW, has a 0.7% impact on clean power with 2.3 TWh more unabated gas.

Table 2: Low carbon dispatchable table

Low carbon dispatchable power capacity (gas CCS and hydrogen to power)				
	Low carbon dispatchable power capacity	Share of unabated gas	Unabated gas generation	Exports
	GW	**%**	**TWh**	**TWh**
-500 MW	2.2	5.6	20.4	52.9
New Dispatch	2.7	4.9	18.1	55.1
Very High Dispatch (+500 MW)	3.2	4.6	17.3	56.1
+1000 MW	3.7	4.4	16.5	56.8
+1500 MW	4.2	4.3	16.1	57.4

Increasing the low carbon dispatchable capacity above New Dispatch has diminishing returns increasing in 500 MW steps and reduces unabated gas share 0.3%, 0.2%, then 0.1%. Removing the last 5% of unabated gas share becomes more challenging in 2030.

4.3.2 Biomass and Bioenergy with Carbon Capture and Storage

4.3.2.1 Great Britain today

Biomass is the only low carbon dispatchable power currently operational at scale in Great Britain, at 4.3 GW capacity and generating 13 TWh. It currently operates at a high load factor of 79% in 2023. There are no bioenergy with carbon capture and storage (BECCS) sites operating beyond prototypes today.

Using Government carbon accounting methodology, BECCS is classed as a negative emissions technology, due to the whole lifecycle of the fuel absorbing more CO_2 than it releases.

4.3.2.2 The ambition for 2030

Sustainable biomass provides a renewable low carbon power source. Great Britain's units are currently incentivised to run for maximum output, under contracts that are due to expire in 2027. For those that fit CCS, high load factors will remain desirable, but the role of biomass (without CCS) should shift to dispatchable to help meet demand during times of low wind and solar output. This will make the best use of the limited sustainable biomass resource. In 2030, the biomass and BECCS capacity of 3.8 - 4 GW in our pathways is a reduction from the 4.3 GW in 2023, partly as we assume some converts to use CCS, which means a reduction in how much power is produced from the same unit.

The generation remaining as biomass is likely to operate more flexibly as greater levels of renewables come online and BECCS becomes higher value for emissions reduction.

BECCS has a high value in helping reach the 2030 Nationally Defined Contributions (NDC) emissions target. Conversion from current biomass sites to BECCS will lead to a reduction in capacity output due to the additional energy losses from operating the CCS system.

4.3.2.3 Basis of our analysis

The CCC included BECCS in its pathways to net zero as a means of removing carbon from the atmosphere, identifying this as the best long-term use of scarce bioenergy resources. In line with the CCC's 2020 advice on the Sixth Carbon Budget[8] and our July Future Energy Scenarios,[9] we assume conversion of at least one biomass unit to BECCS by 2030 in our pathways. We assume that this operates at high capacities to maximise carbon removal from the atmosphere.

4.3.2.4 Stakeholder views

There is broad agreement from stakeholders that biomass, alongside BECCS, could play a larger role than is currently forecast. However, for BECCS to be deployed at the ranges that may be required, carbon capture cluster decisions need to be made faster, alongside unblocking the current challenges around development of associated infrastructure.

Some stakeholders raised concerns about overreliance on biomass for future energy generation, particularly considering carbon accounting and the need for clearer decisions on project sequencing and technology scale. Accurate carbon emissions reporting and avoiding reliance on high carbon sources, like energy from waste, are critical for ensuring biomass remains a viable component of the energy mix.

Some advised that transitioning biomass into CCS was a sustainable longer-term solution for this technology. We also heard that from one stakeholder who suggested that biomass should be sourced from Great Britain, such as excess farming products.

8 Sixth Carbon Budget
9 Future Energy Scenarios

4.3.2.5 What is needed

Markets and investment

A rapid decision is required on the existing renewables obligation support for biomass that ends in 2027, regardless of whether the Government decides to support a transition to BECCS by 2030.

There are potential trade-offs of CCS transport and storage network between BECCS and other users of these assets.

Supply chain and workforce

For BECCS, similar issues to gas CCS projects need to be resolved.

Other enablers

There are no expected issues around planning, consenting or communities or connections reform as these are existing sites.

4.3.2.6 Impacts

Should there be no biomass CCS conversions by 2030, a clean power system can still be reached as the unconverted biomass plants would have slightly higher capacity and use slightly less fuel. These plants could still provide the required clean power when needed. However, there would be less removal of carbon from the atmosphere, making wider carbon targets harder to meet.

4.4 Unabated gas generation

4.4.1 Great Britain today

Unabated gas capacity in Great Britain is currently 37 GW (4 from heat driven gas CHPs), supplying around a third of demand in 2023. Unabated gas is currently a key contributor to Great Britain's electricity generation, operating at a 25% load factor over the year (excluding CHPs), generating every hour of the year and setting wholesale prices 97% of the time. The electricity system is on track to be able to operate free of fossil fuels and at 100% zero carbon for periods at a time in 2025.

4.4.2 Great Britain in 2030

The transition to clean power will see the role of gas-fired generation change. As renewable generation grows, the need for electricity from gas generation will reduce, but will still be needed for security of supply during periods of low wind and solar output.

Gas-fired power stations will be required, albeit less frequently, to fill a shortfall in clean supply, with the load factor reducing to 5% and supplying 14 - 15 TWh of generation through 2030 (in a typical weather year). Around 35 GW of unabated gas will need to remain on standby over longer periods of high demand and low renewable output. This will remain the case in the early 2030s, until larger levels of low carbon dispatchable power and other flexible sources are connected to the system.

4.4.3 Basis of our analysis

Gas-fired generation capacity is essential for security of supply until sufficient low carbon equivalents have been built up to decarbonise the last few percent of the power system.

In a clean power system, electricity from gas-fired generation should not be exported to meet demand under normal market conditions. Our modelling captures this by using a higher carbon price than neighbours.

4.4.4 Stakeholder views

We have held several sessions with gas network providers and thermal generators. These stakeholders need clarity and certainty on the future requirements of unabated gas and the potential associated low carbon technologies. Stakeholders reflected a general sense of nervousness among thermal workforce on the future prospects and the need for redeployment within new technologies.

As well as workforce concerns, stakeholders raised the importance of understanding the scale of challenge around operating an aging gas fleet and the reform needed to enable continued operation of unabated gas for security of supply. There were particular concerns raised in relation to the notice periods needed to turn on the gas generation fleet to enable the gas network's linepack to be prepared. Some advised that aging fleets may require several days or up to a week's notice to turn on in 2030 if operating at low load factors.

Some stakeholders raised questions around evaluating risks tied to delayed or non-delivery of clean power and the need for consideration of gas networks for security of supply. This is crucial in determining the readiness of generators, such as gas-fired power stations, to meet peak demand.

4.4.5 What is needed

Markets, investment, supply chain and workforce

Gas accounted for around 30% of Great Britain's power generation in 2023. In our 2030 pathways, that will be reduced to less than 5% in a typical weather year. However, gas generation will remain critical for security of supply. In all our pathways, we will need around 35 GW of gas capacity to ensure capacity adequacy.

Gas generators will run at significantly lower load factors than today. We would, therefore, expect them to become more dependent on revenue support from the Capacity Market or an alternative, such as a strategic reserve mechanism.

Plant efficiency and asset health vary greatly across the gas generation fleet and many plants are reaching the end of their natural life. Practical challenges, including retaining workforce expertise and sourcing increasingly scarce spare parts for older generators, will have a strong bearing on the way operators choose to maintain and run the existing fleet. These considerations will apply regardless of whether gas generators are supported by the Capacity Market or an alternative. The chosen support mechanism will, however, have implications on whether any increased costs and associated risks are borne by investors or consumers and the signals sent to potential investors and supply chains.

The impact on carbon emissions must also be considered. If gas plants continue to self-dispatch, effective market arrangements will be needed to create the conditions where they are only incentivised to run in times of scarcity. Taking plants out of the market into a strategic reserve type mechanism would require a central body to coordinate overall availability of the strategic reserve and schedule any running required.

The future of the Capacity Market and/or the introduction of a strategic reserve should be considered alongside wider market reforms through REMA. Government, NESO and Ofgem will need to constantly monitor the effectiveness and value for money of any arrangements, ensuring there is a plan in place to manage the impact of plant exits from the market on capacity adequacy. A decision is needed in time for the publication of the Capacity Market Parameters in July 2025.

Other enablers

As these are existing sites, connections and planning considerations are not deemed to pose a specific challenge.

Weather years - The dispatch modelling for our pathways to clean power considers what would happen in an average weather year. We have used weather from 2013.

We have also carried out modelling to assess security of supply (adequacy) requirement, which considers more extreme weather years, including extended periods of low wind, and variations in plant outages. This ensures that we have sufficient available generation to operate the system safely and securely under a range of different conditions. Our modelling shows that our generation portfolios provide a level of reliability that is similar to what we have today, based on loss of load expectation (LOLE), and are well within the current reliability standard of 3 hours LOLE per year.

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