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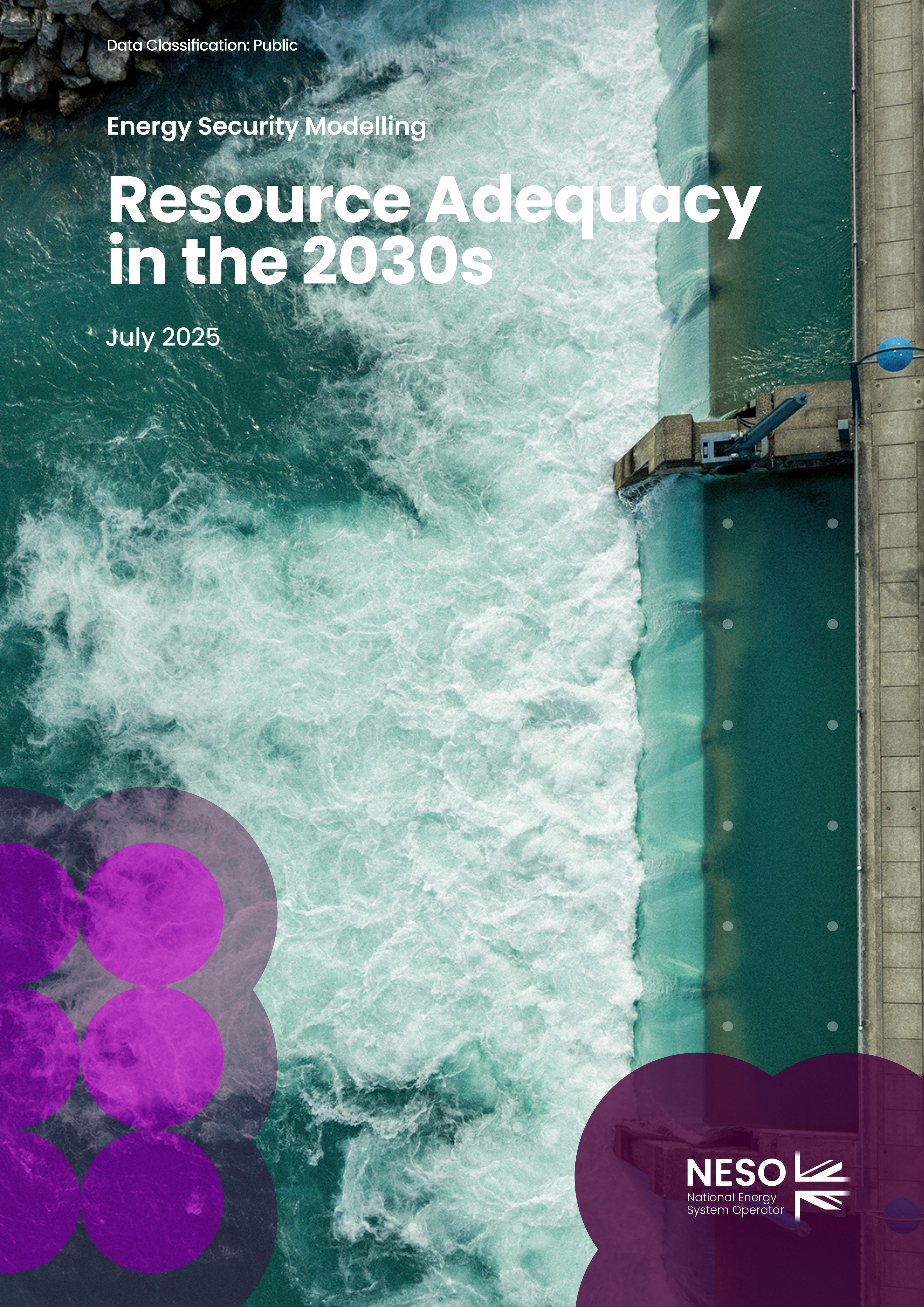
Energy Security Modelling

Resource Adequacy in the 2030s

July 2025



NESO
National Energy System Operator

Foreword

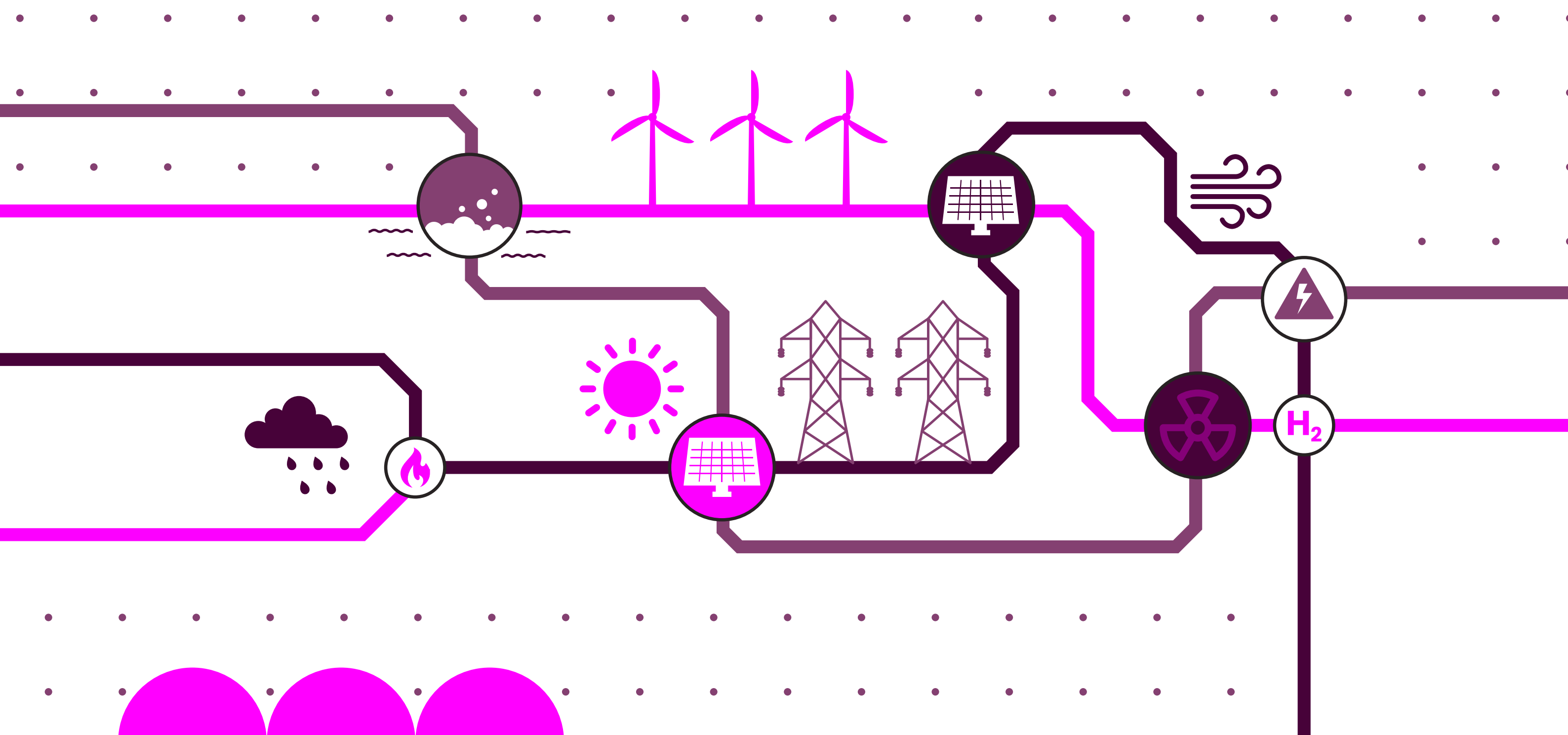
Reliable and resilient energy systems underpin society. We depend on reliable supplies in our daily lives and one of NESO's primary duties is ensuring security of supply for current and future energy customers. Resource adequacy is one important part of the broader set of activities needed to provide reliable and resilient energy systems.

Our energy system is expected to transform over the next decade, accelerated by the government's *Clean Power 2030 Action Plan*, as we decarbonise to meet our net zero targets and mitigate the threat of climate change. As with any transformation, there will be both opportunities and potential risks. NESO's work on resource adequacy aims to understand the availability of future energy supply and to identify actions that may be needed in advance to mitigate potential risks. Our approach enables us to work with partners to ensure that the right policy and regulatory frameworks are in place to bring forward necessary investment in new low carbon technologies, which typically have long lead times to deploy.

While the electricity system is the main focus of this study, ensuring reliable energy supplies for consumers requires a whole energy system perspective. Later this year, NESO will publish its first annual *Gas Supply Security Assessment*, which will assess gas security of supply 5 to 10 years ahead. In the future, we may also need to consider hydrogen security of supply.

Collaboration will be key to ensuring reliable energy supplies for consumers. We warmly welcome engagement and encourage feedback from stakeholders as we build and develop this work collaboratively over the coming weeks and months.

Dr Debs Petterson
Director
Resilience and Emergency Management



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Executive Summary

Reaching net zero is one of the defining challenges of our generation. Decarbonising the power system in Great Britain over the next decade is essential to meet the country's legally binding obligations on climate change. This transformation will deliver clean energy for consumers and reduce our reliance on fossil fuels. Delivering the *Clean Power 2030 Action Plan* will be an important milestone along the way. It is essential that we continue to maintain reliable energy supplies for consumers during this transition.

Consumers in Great Britain today benefit from one of the most reliable energy systems in the world. NESO's advanced modelling helps us understand the potential risks to resource adequacy in the future, so that actions can be taken ahead of time to give confidence that future consumers can continue to benefit from reliable energy supplies.

Our study shows that there does not need to be a trade-off between resource adequacy and decarbonising the power system. Reliable energy supplies can be maintained even when weather conditions lead to very low output from renewable generation in Great Britain and neighbouring countries. However, this will require investment in new low carbon technologies – including options such as new nuclear, carbon capture and storage, hydrogen power generation and long-duration energy storage – that can provide clean energy for extended periods, whatever the weather. These technologies typically have long lead times. While some investment is coming through, further action is needed to develop a pipeline of new low carbon technology projects ready for large-scale deployment in the 2030s.

Even with investment in new low carbon technologies, we still expect unabated gas to play an important role in adequacy throughout the decade. We are likely to still need capacity that is available to operate during a few short periods throughout the year. This reflects the conclusions in our *Clean Power 2030* (CP30) report and highlights the need for a longer-term strategy for these assets.

Our future decarbonised power system will be very different, dominated by weather-dependent renewables and supported by much higher levels of flexible resources such as storage, interconnection and demand-side flexibility. As a result, weather patterns are expected to become the primary driver of risks to resource adequacy. We will need the right tools and standards to assess and mitigate these risks to support long-term planning that ensures reliable and cost-effective energy supplies. We are already working with experts in academia and the Met Office to develop these capabilities, including new weather data sets.

Flexible resources such as storage, interconnection and demand-side flexibility will play an increasingly important role in resource adequacy. These resources can shift energy over time and across regions, helping consumers benefit by making better use of clean energy. Our modelling shows that we need to better understand how these resources will operate in the market and what market signals will be needed to ensure they support resource adequacy efficiently for consumers.

Key messages

1. There does not need to be a trade-off between adequacy and decarbonising the power system. While some investment is coming through, further action is needed to develop a pipeline of new low carbon technology projects ready for large-scale deployment in the 2030s.

- New low carbon technologies such as new nuclear, carbon capture and storage (CCS), hydrogen power generation and long-duration energy storage typically have long lead times, and some may still need to be proven at commercial scale. NESO will work with partners to identify barriers to deployment and to explore how this capacity can be delivered through the 2030s.
- If one or more of these technologies is not brought forward, this will increase dependency on a smaller number of new technologies. If no new low carbon technologies are delivered, we will remain reliant on existing and new-build unabated gas for adequacy.
- This study does not advocate for a preferred technology or a combination of technologies in the future resource mix. This will be a matter for policy, informed by recommendations in NESO's *Strategic Spatial Energy Plan*, due in 2026.

2. We expect unabated gas capacity to remain on the power system by 2040, even with deployment of new low carbon technologies. Operating at low running hours, this capacity will remain important for adequacy. A longer-term whole energy system strategy is needed to support the future role of unabated gas in meeting consumer demand when needed.

- Unabated gas is expected to remain important for adequacy throughout the 2030s. As in our *Clean Power 2030* (CP30) advice, these assets are expected to be used rarely, typically during a few short periods each year.
- A longer-term strategy will be needed to support the maintenance and operation of these assets in this way. This includes considering the mechanisms required to support their economic viability and the implications for the whole energy system, including both the gas markets and networks.

3. Weather patterns are expected to become the dominant driver of risks in a decarbonised power system. Understanding the nature and impact of these patterns will be critical to long-term system planning that delivers reliable supplies for consumers.

- Our modelling shows that system risks are increasingly driven by low-likelihood, high-impact events, often linked to a relatively small number of weather patterns.
- We are improving our weather data sets to reduce our reliance on historical weather and using new approaches that better reflect the effects of climate change. We are working with academia and the Met Office to develop this capability.
- As the system evolves, we will need to continue to develop new metrics to assess adequacy that can complement the use of existing ones such as Loss of Load Expectation (LOLE). Alongside appropriate standards, this can ensure we mitigate risks effectively and cost-efficiently.

01

Introduction

Purpose and scope

This report focuses on resource adequacy assessments for the 2030s, in which we aim to understand the risk of the electricity system being unable to fully meet customer demand. This helps us identify the resources (or technologies) needed to maintain reliable and clean electricity supplies throughout the 2030s and to drive actions to achieve this.

This report builds on the analysis we published with consultancy AFRY in December 2022. Since then, we have published two spotlight papers – one on metrics and one on demand-side flexibility – in response to the feedback we received. The metrics paper sets out what we mean by security of supply, which we revisit later in this report. In March 2025, we published our *Modelling Approach* for this study, explaining how we configured the model to focus on uncertainty and incorporate interconnector modelling. All publications can be found on the NESO Resource Adequacy webpage.

This new study reinforces and builds on the key messages from our 2022 report with AFRY to support long-term decision-making on the delivery of long lead-time projects required to ensure security of supply in the 2030s. As with that earlier report, this study does not recommend minimum or maximum capacity levels for any particular technology, but provides an indication of the types of resources that may be needed in the market.

To help identify the resources needed to ensure secure electricity supplies in the 2030s, we have considered a range of hypothetical portfolios of generation, electricity storage, interconnection and demand flexibility. These are not intended to be recommended pathways, but instead have been selected to be instructive – highlighting what it might take to maintain security of supply under different 'what-if' scenarios and stress tests.

The analysis accounts for uncertainties due to weather and technical outages using simulation methods.

We specifically examine three spotlight years – 2030/31, 2035/36 and 2040/41 – to illustrate the main challenges. These years were chosen to provide insight into how different choices might affect security of supply.

This report focuses exclusively on power security of supply. As such, we have not considered wider issues such as overall system resilience, market arrangements, network constraints or the availability of gas. Furthermore, this study does not provide a detailed evaluation of carbon budgets and emissions, as factors such as carbon dioxide removal rates in carbon capture and storage (CCS) and the use of biomethane are not considered.

How this report relates to other NESO publications

Energy security of supply modelling

This study assessing resource adequacy in the 2030s is one of several activities we carry out to identify, assess and mitigate risks to energy security of supply. Collectively, these activities help us prepare for a wide range of eventualities and give confidence in our ability to deliver reliable energy supplies to consumers as we approach real time.

Our assessment of resource adequacy in the 2030s – typically 5 to 15 years ahead – focuses on identifying longer-term risks to electricity security of supply and the types of resources needed in the generation mix to mitigate them. Early identification enables changes to policy and regulatory frameworks to allow sufficient time to bring these resources forward.

We produce the *Electricity Capacity Report* to support decisions made through the Capacity Market (CM) in Great Britain, which is the government's main policy mechanism for supporting electricity security of supply. Our modelling provides recommendations on the level of capacity to secure through the CM, while also accounting for capacity expected to operate outside the scheme. There are two auctions for each delivery year: the four-year ahead (T-4) auction and the one-year ahead (T-1) auction.

Following the T-1 auction, we shift our focus to the upcoming winter. This typically includes publication of NESO's *Early View* and *Winter Outlook* reports, setting out our expectations for the electricity system over the season ahead. These assessments reflect all the actions taken in advance to prepare for winter. While we also publish the *Summer Outlook* report, summer demand is generally much lower, so the focus is more on system operation than security of supply.

In relation to gas security of supply, NESO has a new licence obligation to publish a *Gas Supply Security Assessment* by 31 October each year, starting in 2025. This will assess the availability, deliverability and reliability of gas molecules needed to meet demand 5 to 10 years ahead. As we move closer to real time, National Gas Transmission is responsible for publishing the *Gas Summer Outlook* and *Gas Winter Outlook* reports.

Strategic energy planning

NESO also coordinates strategic system planning and design across the whole energy industry, supporting optimised investment and planning decisions that deliver Great Britain's net zero objectives at the lowest equitable cost to consumers. Our three overarching roles are:

- **Strategic Spatial Energy Planning (SSEP)** – mapping potential electricity and hydrogen generation and storage infrastructure for Great Britain
- **Centralised Strategic Network Planning (CSNP)** – developing and assessing electricity, gas and potentially hydrogen transmission networks
- **Regional Energy Strategic Planning (RESP)** – creating whole system, cross-vector regional plans with input from local actors

Complementary to these activities, our *Future Energy Scenarios* (FES) outlines credible energy supply and demand pathways for meeting Great Britain's net zero targets. These pathways also support longer-term planning and will build on the government's *Clean Power 2030 Action Plan*.

We can use the insight from our resource adequacy modelling to inform and support our strategic energy planning activities, including the development of the FES and SSEP pathways. These pathways need to consider how supply can meet demand throughout the year using full economic dispatch modelling up to 2050. As resource adequacy is mainly concerned with a relatively small number of critical periods in specific years (2030/31, 2035/36 and 2040/41 in this study), we can use a more streamlined modelling approach with a simplified dispatch that enables a wide range of stress tests and 'what-if' scenarios for these critical periods. This insight can help ensure that the resource mixes in the FES and SSEP pathways are adequate, without the need to apply the same range of stress testing in those particular activities.

Engaging with stakeholders

Stakeholder engagement has played an important role in shaping our thinking on the resource adequacy modelling approach. Since publishing our first study *Resource Adequacy in the 2030s* with AFRY, we have engaged with stakeholders through a combination of round-table discussions and bilateral meetings. We also established an expert advisory group, which has been valuable in helping us develop this work. Further details of the group's membership can be found in Appendix 5.

We remain committed to engaging with stakeholders as we continue to develop our work in this area. If you would like to discuss this further with us, or to provide feedback, please contact us at box.netzeroadequacy@neso.energy.

Details of our future engagement events on resource adequacy will be published on our Resource Adequacy webpage.

02

Study Approach

Our approach has been to create and analyse hypothetical but feasible portfolios of generation, interconnection, energy storage and flexible demand. These portfolios are not intended to represent new pathways, but instead to explore a range of 'what-if' scenarios – examining what it might take to maintain secure electricity supplies, even if some technologies do not deliver as expected.

By comparing and contrasting different portfolios and testing additional sensitivities, we can form a better view of the potential challenges and take early action to ensure consumers continue to receive reliable energy supplies. This enables us to prepare for a wide range of eventualities.

Overview of the approach

We have focused on three future spotlight years – 2030/31, 2035/36 and 2040/41 – each modelled from 1 April to 31 March to capture the full winter period. These years represent different stages of Great Britain's decarbonisation journey:

- **By 2030**, new technologies should be in the pipeline, although those with longer lead times might not yet be able to deliver. We assume that electricity supply and demand in 2030 align closely with the *Clean Power 2030* (CP30) report, reflecting growth in areas such as electrification and data centres. Much of the existing gas fleet is expected to still be available to operate during a limited number of hours when needed.
- **By 2035**, demand will have increased as sectors such as transport, heat, industry and commerce continue to electrify. Other sources of demand, such as data centres, are also expected to grow. Renewable capacity will have expanded further, and some new technologies may be coming online. However, some ageing gas plants may need to retire or be refurbished.
- **By 2040**, demand is expected to be even higher. However, new technologies should be more firmly established, and increased consumer engagement – supported by smart technologies and price signals – will help to suppress peak demand.

For each spotlight year, we created portfolios for Great Britain's electricity system. Each portfolio explores a different 'what-if' scenario and builds on a common starting point: the capacities we assume will be connected by 2030. This includes all existing plant not scheduled to retire, along with others likely to be operating by that year.

Summary of the five-step study approach

Step 1:	Step 2:	Step 3:	Step 4:	Step 5:
Define a starting point	**Create portfolios**	**Assess portfolios**	**Test uncertainties and sensitivities**	**Draw evidenced-based conclusions**
Define demand profiles and establish a set of existing and committed capacities, assuming a growth in weather-dependent renewables.	Build on the capacities identified in Step 1 to create a range of clean, secure and feasible portfolios for each spotlight year.	Use a range of metrics and methods to assess resource adequacy.	Assess system behaviour under a range of stress tests and alternative assumptions to draw insights into risks and choices.	Present the key messages and conclusions that emerge from the analysis of the portfolios and sensitivities.

We assessed how well these portfolios can meet demand on an hour-by-hour basis under varying weather conditions and across a wide range of plant failure scenarios (also known as 'unplanned plant outage patterns'). This helped us identify combinations of weather and plant failures that could be particularly challenging.

We assessed a set of sensitivities to explore additional uncertainties beyond those represented in the portfolios. These include scenarios such as reduced electricity imports from Europe, higher overall demand and lower consumer engagement.

The key messages of this report have been informed by our analysis of these combinations of 'what-if' portfolios and sensitivities. Our approach has allowed us to explore situations where, for a few hours of the year, electricity supply might not fully meet demand. These situations are intended to be illustrative rather than an indication of what we expect to happen. Through this, we have identified the key drivers of supply shortfalls and developed strategic recommendations to help mitigate those risks.

How we have assessed security of supply

Our analysis is based on running multiple simulations of Great Britain's power system using our resource adequacy dispatch model, which aims to identify the lowest-cost generation option to meet total demand across Great Britain. Each simulation reflects different weather conditions and randomly generated unplanned plant outages (or failures) throughout the year.

Using simulations in this way is common practice in the energy industry and across other sectors such as finance and engineering. It is particularly useful for assessing mathematical risk, as it enables evaluation of many different scenarios that cannot be known in advance – in this case, varying combinations of weather and plant failure.

Weather and plant availability are two key uncertainties that can significantly affect security of supply. To account for this , our modelling includes:

- **34 years of historical weather data**, covering 1984[1] to 2018 across Great Britain and north-west Europe[2]
- **100 plant outage patterns**, giving each plant in Great Britain (including interconnectors) 100 different hourly timelines showing when it is available or on outage (either unplanned or for maintenance)

In total, we used 3,400 simulations of each portfolio for each spotlight year – a level we found sufficient to ensure convergence of our key results. For each simulation, we identified the periods when electricity demand exceeded available supply. We refer to these as periods of 'lost load' or 'unserved energy'. During such periods, it is possible that some consumers might need to be disconnected, although this would only occur after all other mitigating actions have been exhausted. These mitigating actions include voltage reduction, the use of operational reserves and direct energy trading with system operators in interconnected countries.

This simulation data has allowed us to assess security of supply using a range of analytical approaches, as outlined below. These approaches have been guided by the findings set out in our *Spotlight on Metrics* report on security of supply.

We published our *Modelling Approach* in March 2025 to provide transparency on the model design, and some of the key details are summarised in Appendix 2. The metrics calculated by the model were among a wide range of potential measures presented and discussed in our *Spotlight on Metrics* in May 2024.

1 Some components of the 1984 weather data are synthetic rather than historical, due to data gaps in that year.

2 European weather data is used to estimate the level of supply that could be available for imports on an hour-by-hour basis. This weather-dependent time series is calculated using the method set out in our *Modelling Approach*.

Standard measures of security of supply

We have assessed each portfolio and sensitivity against two standard measures of security of supply – Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU):

- LOLE is the average number of hours of unserved energy across all simulations in a year.
- EEU is the average volume of unserved energy across all simulations in a year.

The Reliability Standard for Great Britain is based on LOLE and is currently set by the government at 3 hours per year. Capacity is secured through the Capacity Market in Great Britain to meet this standard. LOLE is a widely used metric for setting adequacy standards across Europe and in other regions globally. EEU is a useful complementary metric to LOLE, as it provides an additional indication of the scale and potential cost of unserved energy. It is one of several additional metrics presented in our *Spotlight on Metrics* report.

We have built each portfolio to maintain a LOLE of between 0.1 and 0.3 hours in each spotlight year.

This range aligns closely with recent outputs in NESO's *Winter Outlook* reports and is also consistent with the Base Case LOLE for the procurement of capacity through the Capacity Market. The LOLE range is a choice for this study and not an indication or expectation of the actual LOLE for the years we have considered. This choice helps us to draw insight from a wide range of situations on how to mitigate future potential adequacy risks.

Highlighting the impact of the weather

A key message in our *Spotlight on Metrics* report was that, in an increasingly weather-dependent power system, LOLE and EEU alone do not provide a complete assessment of security of supply. For example, the risk of lost load during a prolonged period of cold and low wind is much greater than during warmer, windier weather. Since LOLE and EEU average results across all historical weather years, this risk is not visible in those metrics alone.

To address this, we have introduced 'weather-conditional metrics' that focus analysis on individual weather patterns. In this study, we have reported on weather-conditional LOLE and EEU – for each historical weather year, this represents the average number of hours (for LOLE) or volume (for EEU) of unserved energy across 100 plant outage patterns.

Plotting these values across all historical weather years gives a clear picture of which weather conditions are more challenging and which present only a small risk of shortfalls.

We considered 34 years of historical weather data (1984–2018), which we have assumed to be a reasonable representation of future weather. However, this does not account for the impacts of climate change or for extreme historical weather patterns that are not included in the dataset. To improve our weather modelling, we are working with external experts, including the Met Office. Future studies may incorporate synthetic weather datasets that reflect climate change and a wider range of possible outcomes.

Highlighting the nature and likelihood of lost load events

The nature of lost load events is changing as the power system decarbonises. While historically, planning focused on plant unavailability during winter peak demand, we now also need to account for certain weather-driven events –for example, extended periods of low wind generation.

It is important to understand how these events might evolve, how likely high-impact scenarios could be, and what kind of effect they might have on consumers. To help answer these questions, we have presented plots that show both the range and the likelihood of outcomes across our simulations. These are intended to be illustrative and help identify the actions that can be taken ahead of time to mitigate potential risks.

Simulation horizons

Our analysis is based on simulations that cover one year at a time. Because stress conditions are most likely to occur in winter, we have defined each simulation year as running from 1 April to 31 March. Starting the modelling year on 1 April allows us to capture entire winters. It also enables us to simulate long-duration energy storage charging during the spring and summer, ready for use in the winter months.

We recognise that modelling multiple consecutive years could lead to different outcomes, particularly in systems that rely heavily on hydrogen storage. This was highlighted by the Royal Society in its *Large-Scale Electricity Storage* report.[3] To reflect this, we assume that hydrogen stores are empty at the beginning of each simulation year. This is equivalent to assuming that the previous winter was especially challenging, or that hydrogen storage was not available during that period. As resource adequacy assessments are designed to prepare for realistic but challenging scenarios, we consider this a reasonable and appropriate testing assumption for our study.

3 *Large-Scale Electricity Storage*, The Royal Society, September 2023.

03

Starting Point

To understand the resource needs of the 2030s, we first need to identify what electricity demand might look like and how much capacity is likely to be available.

With this in mind, we have selected an assumed hourly demand profile that we consider to be a reasonable representation of what could happen in the 2030s. Alongside this, we have identified a set of assumed committed capacities, which includes capacity that already exists or is considered very likely to be connected by the 2030s. Together, these form the starting point on which we build a range of portfolios. Each portfolio differs only in the technology mix added beyond these starting capacities.

Electricity demand

For each spotlight year, we use 34 hourly demand profiles – one for each year of historical weather data (1984–2018). These demand profiles broadly align with the Hydrogen Evolution (HE) pathway from NESO's *Future Energy Scenarios 2024* (FES) for 2030, and with the Holistic Transition (HT) pathway thereafter. In particular, our representative 2017/18 weather year matches the published Average Cold Spell (ACS) peak.

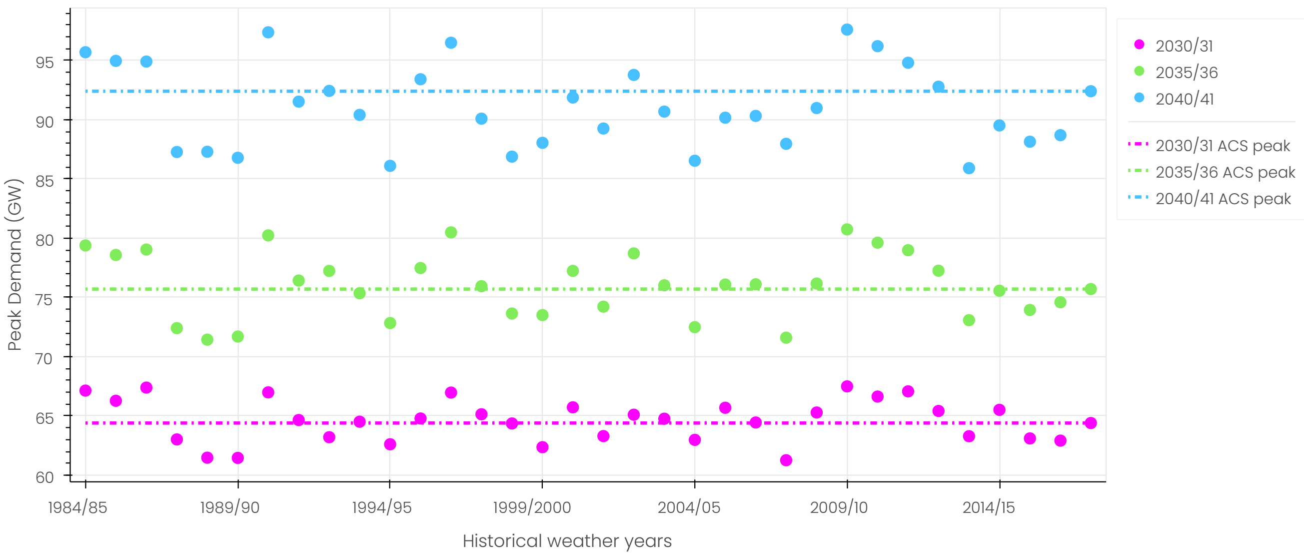


Figure 1: Modelled peak demands, and ACS peaks (dotted lines), for each spotlight year and each year of historical weather data. These values do not include the use of electrolysis for meeting hydrogen demand, although this is accounted for in the modelling.

We selected these FES 2024 pathways as they provide a mid-range view of future demand. However, they do not include the higher peaks seen in the Electric Evolution pathway from the same publication. To account for this uncertainty, we later apply variations and stress tests to our demand assumptions.

Figure 1 shows how demand varies with historical weather. Because temperatures differ year to year, peak demand also varies – and in some cases exceeds the ACS peak. Annual electricity demand is similar across all weather years.

The chart also accounts for the impact of some consumers choosing to shift electricity use to off-peak periods – such as running a washing machine at night instead of during the day. However, it does not account for more dynamic consumer responses to hourly (or half-hourly) market signals. These are reflected elsewhere in the modelling. (See the next section for more on this.)

Flexible demand

Given appropriate market signals, consumers might be willing to shift or reduce some of their electricity use. This currently takes place through mechanisms such as the Capacity Market, although half-hourly pricing and smart metering could play a more significant role in the future. In our modelling, we consider two types of price-responsive flexible demand:

- **Demand-side response (DSR) markets** – representing consumers who willingly agree to shift or reduce their demand on request. This could include schemes such as the Capacity Market.
- **Dynamic demand-shifting** – representing consumers who willingly adjust their demand in response to real-time prices. One possible mechanism for this is smart metering with half-hourly pricing. In our model, dynamic demand-shifting is applied to a proportion of heating demand, electric vehicle charging and vehicle-to-grid services.

Both mechanisms respond dynamically to changes in price. We assume that:

- consumers will only shift their demand by up to four hours
- there is an energy limit on the amount of flexibility available – DSR consumers, for example, reduce their electricity use for up to 2 hours per day at their full flexible power agreement (or for longer at a reduced power level)

These constraints are hypothetical but have been included to ensure that we are not relying on demand to turn down or shift indefinitely to ensure security of supply. This decision follows from our *Demand-Side Response Spotlight* report, which found that constraints of this type can have a significant impact on security of supply. We acknowledge that, in reality, some consumers may be more flexible than assumed. A strategic priority for NESO is to further unlock the potential of demand flexibility by removing barriers to its enablement.

We also consider a type of demand flexibility in which consumers adopt a broad behavioural pattern of shifting electricity use away from peak times. This might be supported by Time-of-Use tariffs. This behaviour is not modelled dynamically in our analysis but is incorporated into the demand profiles used. Further details on our flexible demand modelling approach can be found in the *Modelling Approach* report.

As a starting point, we assume that flexible demand capabilities match those of the CP30 New Dispatch pathway across all three spotlight future years, as summarised in Appendix 3.

Plant capacities

Each portfolio is built from a combination of existing and assumed committed capacities, while also accounting for expected plant retirements. Appendix 3 sets out the minimum capacities we assume will be connected to the power system in each spotlight year.

We have constructed six portfolios. For wind and solar, we have assumed a fixed growth rate across all portfolios – except for one portfolio, which includes a more accelerated build-out. This reflects current policy ambitions to increase renewable investment. Wind and solar are well-established technologies that are relatively quick to build and connect, and they will be essential to meeting the 2050 net zero target. A large number of renewable projects are currently in the pipeline ready for deployment at scale through the 2030s.

Our assumed wind and solar capacities are shown in Table 1. For 2030, these match the *Clean Power 2030* New Dispatch pathway. We assume the following growth rates:

- Offshore wind grows at approximately 3.4 GW per year
- Onshore wind aligns with the maximum FES 2024 pathway, growing at about 0.8 GW per year
- Solar grows at around 3.3 GW per year

Table 1: Assumed minimum wind and solar capacities (in GW)

Technology Type	2025 (Reference)	2030/31	2035/36	2040/41
Offshore wind	15.9	43.1	60.3	77.6
Onshore wind	16.2	27.3	31.2	35.5
Solar	17.8	47.4	63.8	80.2

We have included one new 1.4 GW interconnector with Germany in all portfolios, as this is expected to be operational before 2030. Some portfolios also include further interconnector build-out during the 2030s, aligned with projects that have received Ofgem support under cap and floor.[4]

As with all generation technologies, capacity lifespans vary by type. With this in mind, we expect part of the existing nuclear fleet to retire by around 2030 – this is reflected across all portfolios. We have also accounted for the retirement of some biomass plants and the conversion of others to include carbon capture and storage (CCS), which reduces their power output.

We are aware that some gas plants will also reach the end of their economic life during the 2030s. Our starting point for gas capacity is based on the Capacity Market register, which includes capacity already secured through long-term agreements. However, our portfolios assume higher levels of unabated gas from 2035 onwards. This suggests that there may be a case for incentivising the maintenance or refurbishment of existing plants to ensure continued security of supply throughout the 2030s.

4 'Cap and floor' is a financial arrangement approved by Ofgem, currently applied to interconnectors and proposed for certain long-duration energy storage schemes. It provides a minimum and maximum level of revenue for eligible projects.

04

‘What-if’ Portfolios and Sensitivities

To help identify the resources needed to ensure reliable electricity supplies in the 2030s, we have developed a range of hypothetical portfolios of generation, electricity storage, interconnection and demand flexibility. These are not intended as recommended pathways but have been designed to be instructive – by comparing and contrasting we can better understand what might be required to maintain security of supply under different 'what-if' scenarios and stress tests.

We have created six hypothetical portfolios for the spotlight years 2030/31, 2035/36 and 2040/41. Each is driven by a different 'what-if' question, allowing us to explore the actions that might be needed if certain technologies are delayed or do not deliver at all. All portfolios have been designed to be realistically achievable, and their underlying assumptions are broadly aligned with those used in *Clean Power 2030* (CP30) and *Future Energy Scenarios 2024* (FES).

Each portfolio is built from the assumed starting capacities (outlined in Appendix 3) to achieve a Loss of Load Expectation (LOLE) of 0.1–0.3 hours in each spotlight year. Demand assumptions broadly follow the Hydrogen Evolution (HE) pathway of FES 2024 for 2030/31 and the Holistic Transformation (HT) pathway from 2035 onwards.

The portfolios are designed to give insight into the effects of varying assumptions, even where they differ from central projections. As such, they do not follow a specific pathway such as those set out in FES 2024, although the 2030/31 portfolio broadly aligns with the CP30 High Dispatch pathway.

Portfolio 1 contains the most diverse mix of generation technologies. It assumes the timely delivery of several emerging technologies from 2035 onwards, alongside additional build-out of more established technologies. Portfolios 2 to 6 explore alternative actions that may be required if one or more technologies are unavailable or delayed.

Table 2: Summary of portfolios considered in this study. Each portfolio builds on our assumed committed capacities, set out in Appendix 3

	Description
Portfolio 1	All new technologies are available for deployment.
Portfolio 2	Build-out of only batteries, large-scale nuclear, renewables and gas.
Portfolio 3	No new deployment of long-duration energy storage (LDES), including pumped hydro.
Portfolio 4	No deployment of nuclear plants beyond assumed committed levels.
Portfolio 5	No deployment of hydrogen-to-power.
Portfolio 6	No deployment of interconnection beyond assumed committed levels.

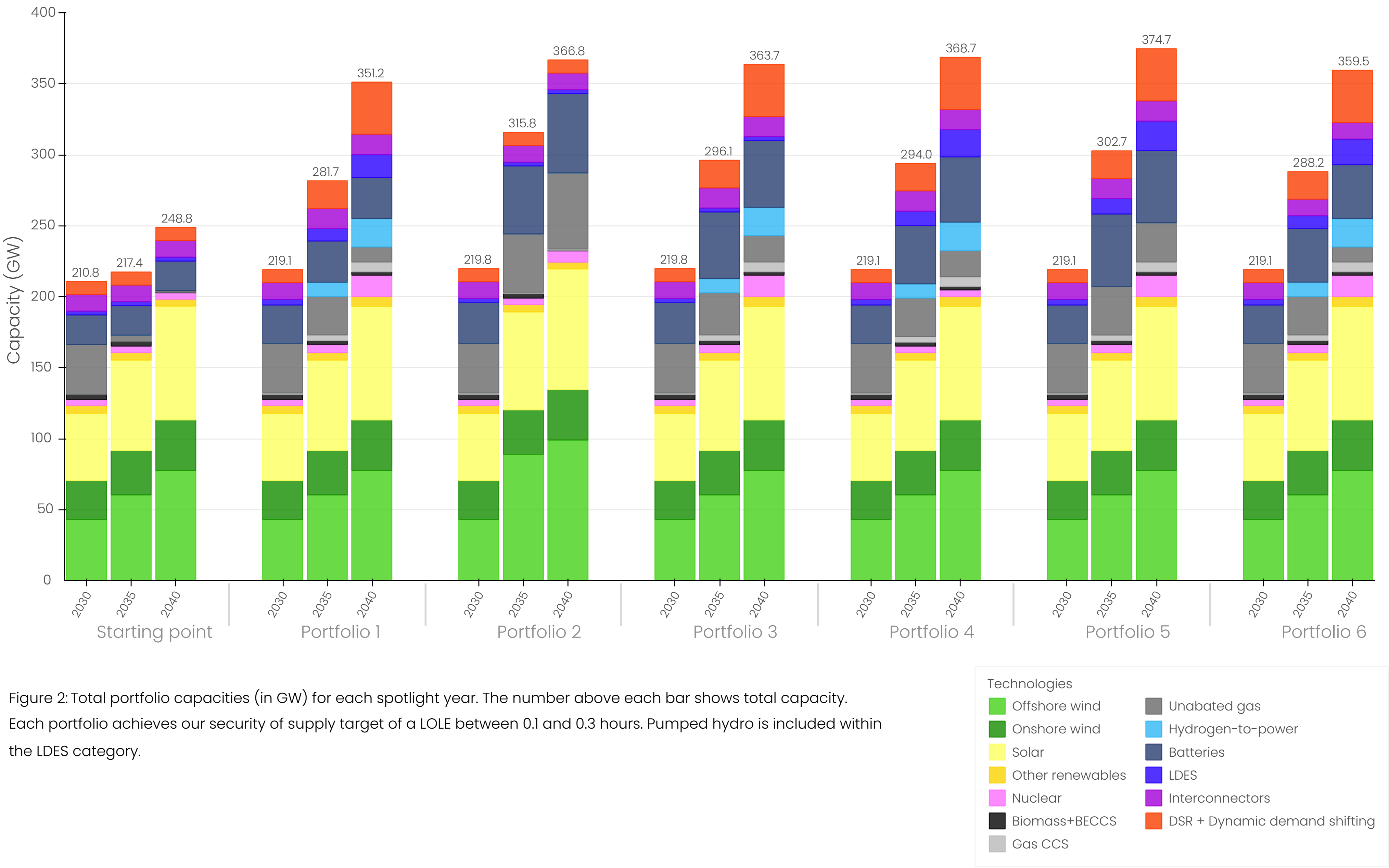


Figure 2: Total portfolio capacities (in GW) for each spotlight year. The number above each bar shows total capacity. Each portfolio achieves our security of supply target of a LOLE between 0.1 and 0.3 hours. Pumped hydro is included within the LDES category.

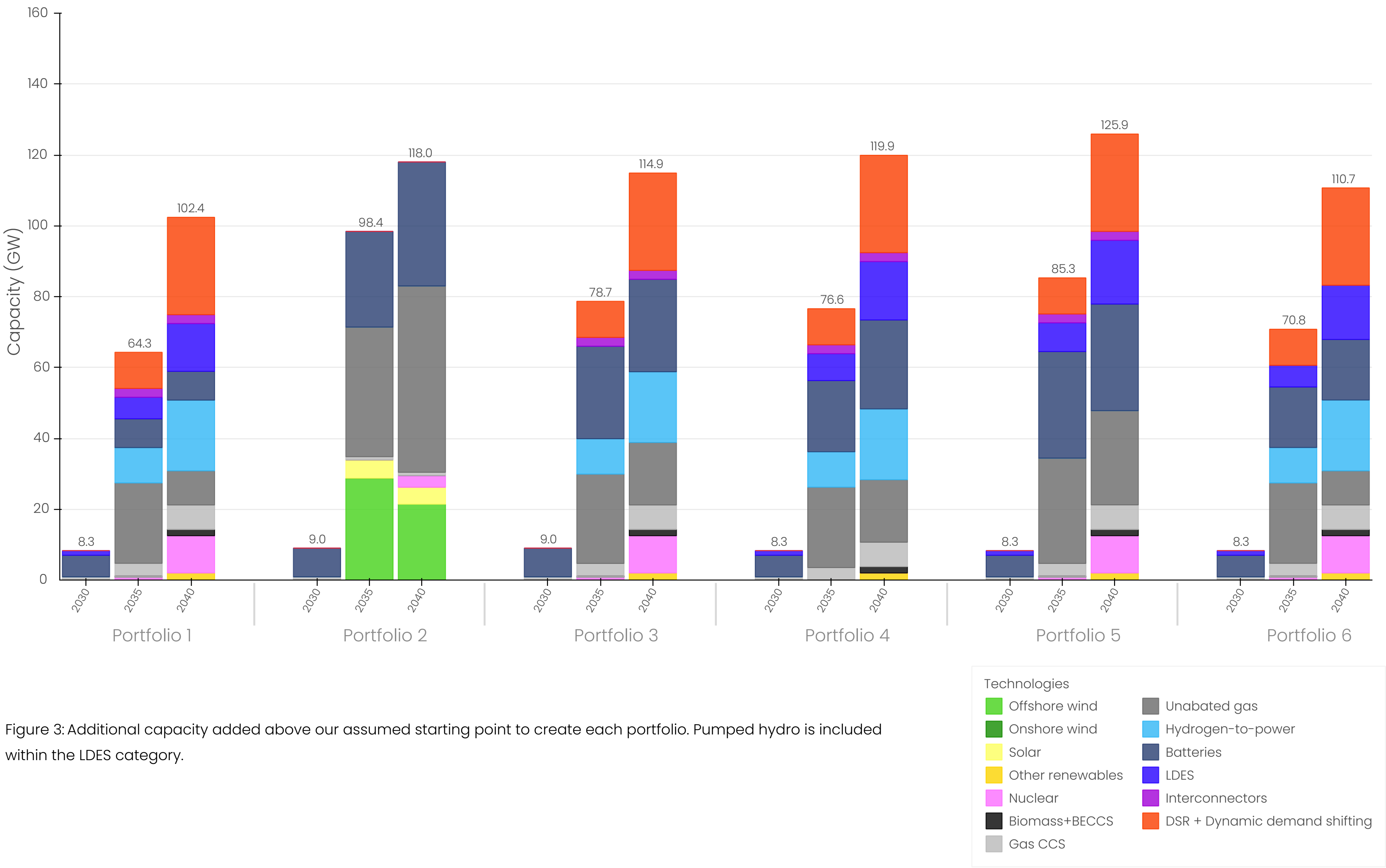


Figure 3: Additional capacity added above our assumed starting point to create each portfolio. Pumped hydro is included within the LDES category.

To further explore the impact of other potential stresses on security of supply, we have complemented several of the portfolios with additional sensitivity analysis, as summarised in Table 3. Most of these sensitivities represent conditions where the electricity system may be under additional stress – helping us explore additional uncertainties beyond those in the portfolios.

Table 3: Sensitivities considered in this study

Sensitivity	A Variation on...	Description
Sensitivity 1	Portfolio 2	Unabated gas maintained at 35 GW and batteries increased to 150 GW in 2035/36 and 2040/41.
Sensitivity 2	Portfolio 1	A 10% increase in electricity demand.
Sensitivity 3	Portfolio 1	A 20% increase in electricity demand.
Sensitivity 4	Portfolio 1	A 1% reduction in electricity demand.
Sensitivity 5	Portfolio 1	A doubling of unabated gas unplanned outage rates.
Sensitivity 6	Portfolio 1	Only 4 TWh hydrogen storage available from 2035.
Sensitivity 7	Portfolio 1	Only 2 TWh hydrogen storage available from 2035.
Sensitivity 8	Portfolio 1	All new interconnection removed (apart from those assumed to be committed).
Sensitivity 9	Portfolio 1	A 10% reduction in the capacities available for imports at all times.
Sensitivity 10	Portfolio 1	No imports across the year.
Sensitivity 11	Portfolio 1	Dynamic demand-shifting and DSR maintained at the assumed committed 2030 levels.
Sensitivity 12	Portfolio 1	Higher offshore wind capacity (80.5 GW by 2035 and 96 GW by 2040).

In presenting these portfolios and sensitivities, we are not recommending any particular pathway. Instead, we aim to draw insights and identify key messages. We have prioritised scenarios that we consider most instructive for this study. However, there is clear scope for further sensitivities, which we may explore in future work.

The capacities outlined in this report are intended to be representative of what we think could be achievable under different circumstances.

Switching technologies

Although each portfolio defines capacity levels for specific technologies, these are intended to be illustrative. In some cases, capacity could be switched from one technology to another with minimal impact on security of supply. We also acknowledge that other technologies not featured in this study may play an important role in the futurwe.

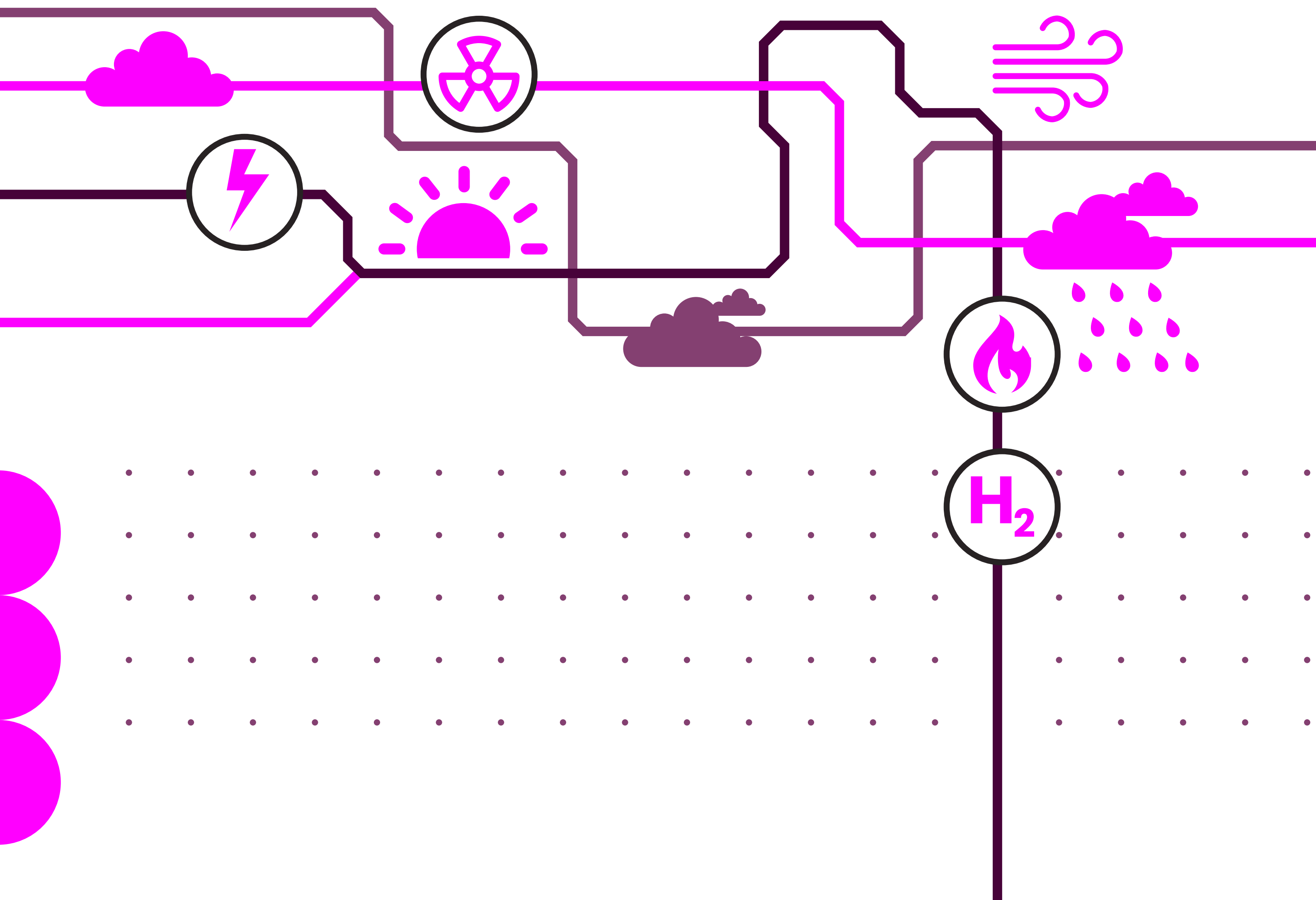
Gas

Gas plays a role in every portfolio to support security of supply, particularly in 2030 when other technology options are limited. After 2030, unabated gas capacity begins to decline. In all cases, unabated gas is only expected to run for a small number of hours in a typical weather year.

Some of the gas capacity can be met by existing plants, potentially through delayed retirements. However, new gas plants may also be required. These could be built with the flexibility to convert to lower-carbon options in the future by:

- fitting with carbon capture and storage (CCS) technology
- switching to hydrogen fuel, either fully or blended with natural gas
- switching to biomethane

Decisions on how to use gas will need to weigh the shorter-term cost benefits of delaying plant retirements – particularly as it may be harder to convert some older plants – against the longer-term value of building new gas plants that can contribute to a decarbonised power system beyond the 2030s.



05

Security of Supply Assessments

Summary of security of supply outputs

The headline security of supply outcomes for each portfolio and sensitivity are shown in Table 4 and Table 5. Later in this section, we explore these results using additional approaches and metrics to provide deeper insight.

Table 4 shows the LOLE and EEU values for the portfolios. The results confirm that all portfolios have LOLE values within the targeted range of 0.1–0.3 hours, demonstrating that there are resource mixes that deliver both decarbonisation and resource adequacy. Although the statutory Reliability Standard is 3 hours per year, we have chosen a lower LOLE target to reflect recent outcomes in our *Winter Outlook* reports and capacity procurement through the Capacity Market. The results for 2030/31 are all the same because the portfolios are very similar at this time horizon. As the resource mixes diverge from 2035 onwards, we see some small variation in results, although all remain within the target range. Table 5 shows the outcomes of the sensitivity studies. Since these explore more stressed system conditions, the resulting LOLE values lie beyond the target range. Further interpretations of these results are discussed in this section. The N/A values in Table 5 relate to spotlight years that were not modelled for that sensitivity.

Table 4: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU) for each portfolio[5]

	LOLE (h)			EEU (GWh)		
	2030/31	2035/36	2040/41	2030/31	2035/36	2040/41
Portfolio 1	0.26	0.23	0.18	2.13	1.68	1.79
Portfolio 2	0.26	0.22	0.24	2.13	2.01	2.81
Portfolio 3	0.26	0.17	0.23	2.13	1.23	2.22
Portfolio 4	0.26	0.14	0.22	2.13	1.11	2.56
Portfolio 5	0.26	0.19	0.18	2.13	1.70	2.35
Portfolio 6	0.26	0.20	0.20	2.13	1.51	2.23

Table 5: Loss of Load Expectation (LOLE) and Expected Energy Unserved (EEU) for each sensitivity

	LOLE (h)			EEU (GWh)		
	2030/31	2035/36	2040/41	2030/31	2035/36	2040/41
Sensitivity 1	0.26	0.41	7.18	2.13	4.23	124.36
Sensitivity 2	1.64	2.12	2.94	18.53	24.38	38.82
Sensitivity 3	N/A	N/A	15.60	N/A	N/A	262.36
Sensitivity 4	0.19	0.15	0.10	1.43	1.02	0.93

5 Portfolio 1 assumes that all new technologies are available for deployment; Portfolio 2 assumes the build-out of only batteries, large-scale nuclear, renewables and gas; Portfolio 3 assumes no new deployment of long-duration energy storage (LDES), including pumped hydro; Portfolio 4 assumes no deployment of nuclear plants beyond assumed committed levels; Portfolio 5 assumes no deployment of hydrogen-to-power and Portfolio 6 assumes no deployment of interconnection beyond assumed committed levels.

Sensitivity 5	0.59	0.48	0.28	5.51	4.01	2.82
Sensitivity 6	N/A	0.23	1.61	N/A	1.68	22.36
Sensitivity 7	N/A	0.23	7.52	N/A	1.68	119.69
Sensitivity 8	N/A	0.30	0.39	N/A	2.42	4.16
Sensitivity 9	0.30	0.28	0.27	2.50	2.13	2.80
Sensitivity 10	2.79	6.80	9.45	25.39	69.43	127.45
Sensitivity 11	N/A	0.32	0.38	N/A	2.71	4.14
Sensitivity 12	N/A	0.04	0.05	N/A	0.25	0.35

The investment needed to ensure security of supply in the 2030s

Finding 1: There does not need to be a trade-off between adequacy and decarbonising the power system. While some investment is coming through, further action is needed to develop a pipeline of new low carbon technology projects ready for large-scale deployment in the 2030s.

It is possible to maintain secure electricity supplies in the 2030s while aligning with national decarbonisation goals. We have demonstrated this through portfolios that include rapid growth in renewable energy (aligned with our *Clean Power 2030* advice), alongside a build-out of other clean technologies such as electricity storage, carbon capture and storage, hydrogen power generation and nuclear. The unabated gas usage in each of our portfolios (under typical weather conditions) is within the range of the 2024 FES net zero pathways. These pathways all meet the Sixth Carbon Budget and achieve net zero by 2050, based on a typical weather year.

On the demand side, each portfolio assumes future electrification of heat, transport and industrial sectors to support decarbonisation.

The portfolios are designed to help identify the resources required to maintain security of supply. Portfolio 1 includes the most diverse mix of generation types, while Portfolios 2 to 6 explore what alternative actions might be needed if one or more technologies do not deliver as expected.

In Portfolios 3 to 6, we examine situations in which only one technology fails to deliver. We found that security of supply remains achievable, but it will increase dependency on a smaller number of new technologies. Unabated gas in these portfolios remains below 35 GW in all spotlight years, meaning that this could be potentially met through maintaining or refurbishing existing and committed gas plants. However, new builds could offer the benefit of later conversion to cleaner fuels.

Portfolio 2 features a more restricted mix of technologies and a slower growth in demand-side flexibility. As a result, it was the only portfolio that required unabated gas capacity beyond the 35 GW assumed for 2030 – an additional 19 GW by 2040. To align with net zero goals, the use of this gas capacity would need to be minimised. Coupling significant investment in new gas plants with expected low running hours would require well-designed incentives. Without this additional gas, secure LOLE levels could not be maintained – even when 150 GW of batteries were added (see Sensitivity 1, Table 5). This reinforces the need for new clean projects that can be deployed at scale during the 2030s. Without them, reliance on unabated gas is likely to increase.

There is also a need for the low-carbon project pipeline to remain responsive to changes in projected electricity demand. Future demand is highly uncertain. If demand exceeds our baseline assumptions, capacity build decisions will need to adjust accordingly. For example, a 10% increase in demand would require an additional 8 GW of firm capacity in Portfolio 1 by 2040 to maintain the target LOLE of 0.1–0.3 hours. By 2040, it may even be plausible for demand to rise by 20%, in which case an additional 17 GW of firm capacity would be needed. These figures are set out in Table 6. The system impact of these demand increases without any additional capacity build is shown in Sensitivities 2 and 3 (Table 5).

Table 6: Estimated additional firm capacity required (GW) above Portfolio 1 levels to maintain a LOLE of 0.1–0.3 hours under higher demand scenarios[6]

Scenario	2030/31	2035/36	2040/41
10% demand increase	6.0	7.0	8.0
20% demand increase	N/A	N/A	17.0

By contrast, even a 1% reduction in demand almost halves the expected volume of unserved energy in 2040/41 (see Sensitivity 4, Table 5). It also significantly reduces the expected loss of load hours under the most challenging weather year (1985/86), from 5.6 hours to 3.3 hours in 2040/41. This highlights the potential value of even modest improvements in energy efficiency or demand reduction.

Finding 2: We expect unabated gas capacity to remain on the power system by 2040, even with significant deployment of new low carbon technologies. Operating at low running hours, this capacity will remain important for adequacy. A longer-term whole energy system strategy is needed to support the future role of unabated gas in meeting consumer demand when needed.

All our portfolios include unabated gas capacity until 2040, which we consider necessary to maintain security of supply. Portfolio 1 includes the lowest level of unabated gas, as its diverse mix of clean generation options reduces the need for gas generation.

Meeting these levels of unabated gas will require decisions on whether to extend the life of existing gas plants or to invest in new ones. As shown in Figure 4, many of today's gas plants were commissioned before 2000 and may be approaching retirement by the early 2030s. Continued operation through the 2030s would require investment in maintenance and refurbishment. Installing new gas turbines could offer future flexibility, enabling a switch to hydrogen or biomethane fuels, or retrofitting with carbon capture and storage.

In the case of Portfolio 2, around 19 GW of new gas plants would be required regardless, due to the more limited mix of low-carbon technologies.

Another factor to consider is that gas plant reliability may decrease if they are operated infrequently. We found (see Sensitivity 5, Table 5) that doubling the expected level of unplanned outages of unabated gas plants would cause Portfolio 1 to exceed the target LOLE range of 0.1–0.3 hours in all three spotlight years – though still remaining well within the statutory standard of 3 hours. This effect becomes less significant over time reflecting a gradual reduction in reliance on unabated gas as we progress through the 2030s.

6 Portfolio 1 assumes that all new technologies are available for deployment and Portfolio 2 assumes the build-out of only batteries, large-scale nuclear, renewables and gas.

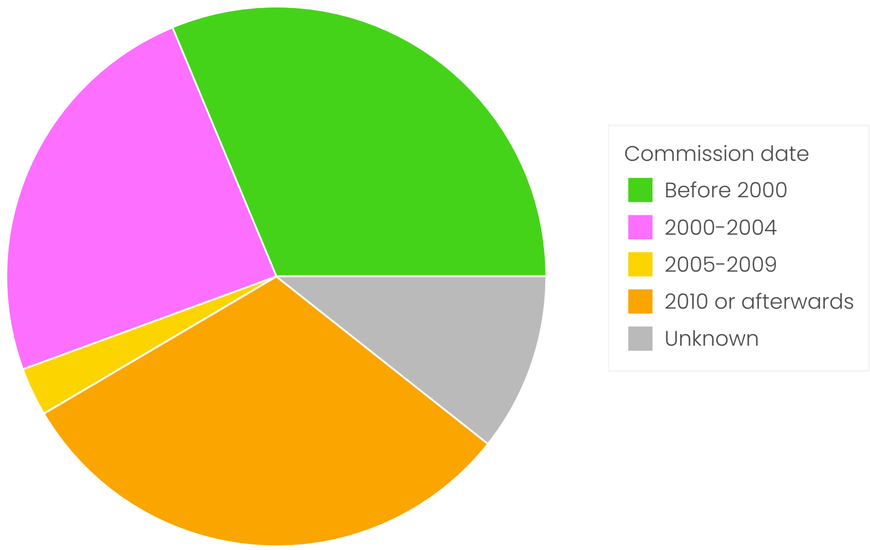


Figure 4: Profile of unabated gas plants, demonstrating that over half the existing gas fleet has already been operating for over 20 years. Data taken from the 2024 *Digest of UK Energy Statistics* (DUKES), based on published commissioning dates as of May 2023. Commissioning dates for smaller producers were not available. The total capacity shown in this figure is 34 GW.

Understanding the drivers of electricity system stress

Finding 3: Weather patterns are expected to become the dominant driver of risks in a decarbonised power system. Understanding the nature and impact of these patterns will be critical to long term system planning that delivers reliable supplies for consumers.

In an increasingly weather-dependent electricity system, periods of potential system stress are shifting away from the traditional evening peaks and towards prolonged spells of low wind and cold temperatures. This is due to three interrelated trends:

- As reliance on renewable energy grows, electricity supply becomes increasingly dependent on wind and solar – and extended wind droughts can last several days.
- As the heating sector electrifies, electricity demand becomes more temperature-sensitive, with cold snaps likely to produce the highest demand.
- Correlated weather patterns across north-west Europe mean that electricity imports may also be low during periods of widespread cold and low wind.

One way to assess the impact of the weather on security of supply is to examine the expected loss of load hours and volumes (in GWh) for each historical weather year separately. This is an approach we recommended in our *Spotlight on Metrics* report, where we called these metrics 'weather-conditional LOLE and EEU'.

The results of this approach for Portfolio 1 are shown in Figure 5. These graphs can be interpreted as follows:

- Each bar shows the expected number of hours (or volume) of lost load if a given historical year of weather were to occur again. These values are averaged across 100 randomly sampled outage patterns.
- The red lines show the LOLE and EEU values as applicable. These are averages across all weather years and 100 outage patterns.

Figure 5 illustrates the strong relationship between security of supply and weather patterns, and reveals two key insights:

- Most historically observed weather years bring very low risk of lost load under Portfolio 1.
- However, certain weather patterns could present significant challenges. In this case, a repeat of the weather from 1985/86 would result in an expected loss of load of around 5 or 6 hours across each spotlight year.

For the portfolios considered in this study, 1985/86 emerged as the most challenging weather year. In particular, our simulations identified a few days in February 1986 as the key contributor to lost load. According to Met Office archives,[7] during that month:

"Very cold continental air gave persistent frosts and bitterly cold conditions in most places", and temperatures were "well below normal throughout the United Kingdom."

Wind speeds were also generally low to moderate, compounding the impact.

The types of weather conditions that are most challenging depend on both demand assumptions and the generation mix. While February 1986 posed a challenge for this portfolio, the same may not hold true for other scenarios with different demand projections or generation build-outs.

As the system evolves, we will need to continue to develop new metrics to assess adequacy that can complement the use of existing ones such as Loss of Load Expectation (LOLE). Weather-conditional metrics, such as those presented here, are one potential approach. Our *Spotlight on Metrics* report outlined additional metrics and approaches that could support future assessments of security of supply.

In this study, we assume that historical weather from 1984 onwards is a reasonable representation of the 2030s. However, we acknowledge that this approach has limitations – the dataset spans only 34 years and does not reflect the likely impacts of climate change. To address this, we are working with external experts, including the Met Office, to enhance our weather modelling.

7 Met Office Digital Library and Archive

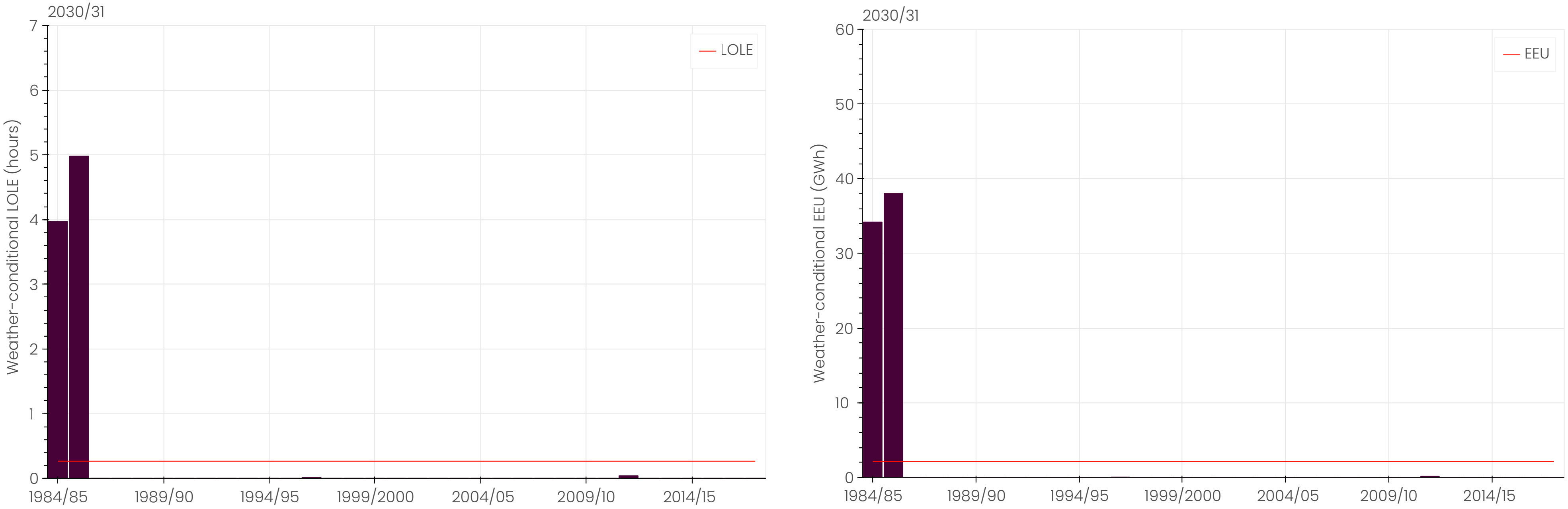


Figure 5: Weather-conditional LOLE and EEU for Portfolio 1. These are the expected hours and volume (respectively) of lost load, assuming a given weather year. Qualitatively similar results were observed for the other portfolios (not shown).[8]

8 Portfolio 1 assumes that all new technologies are available for deployment.

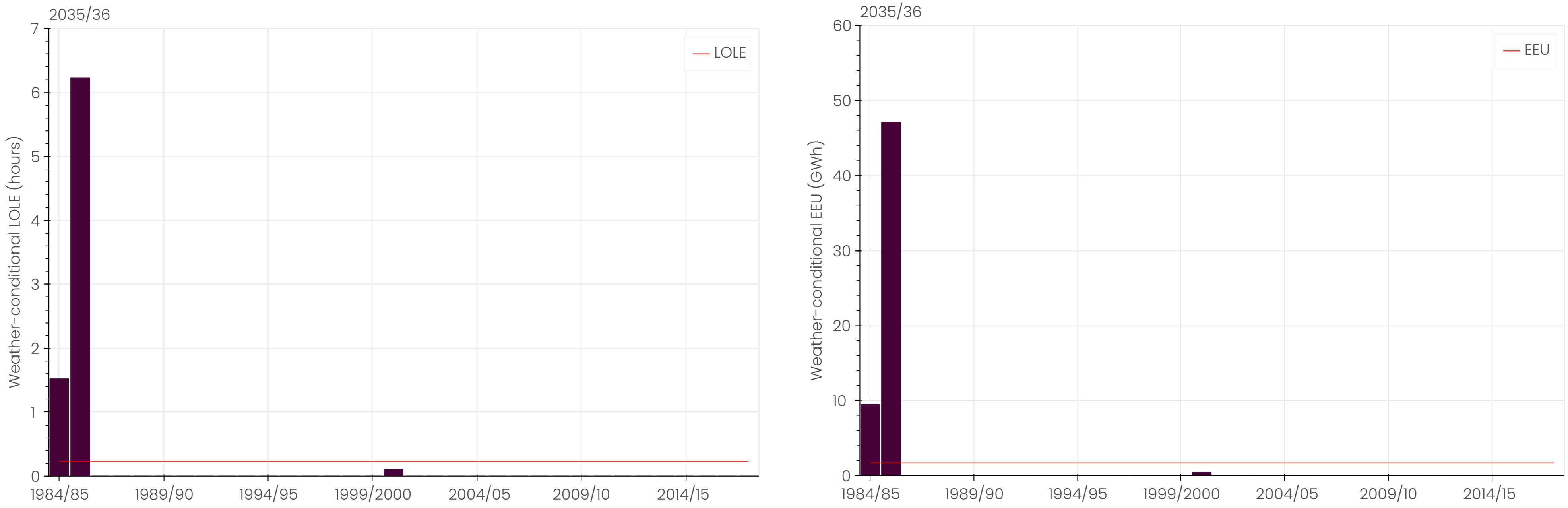


Figure 5 continued: Weather-conditional LOLE and EEU for Portfolio 1. These are the expected hours and volume (respectively) of lost load, assuming a given weather year. Qualitatively similar results were observed for the other portfolios (not shown).[8]

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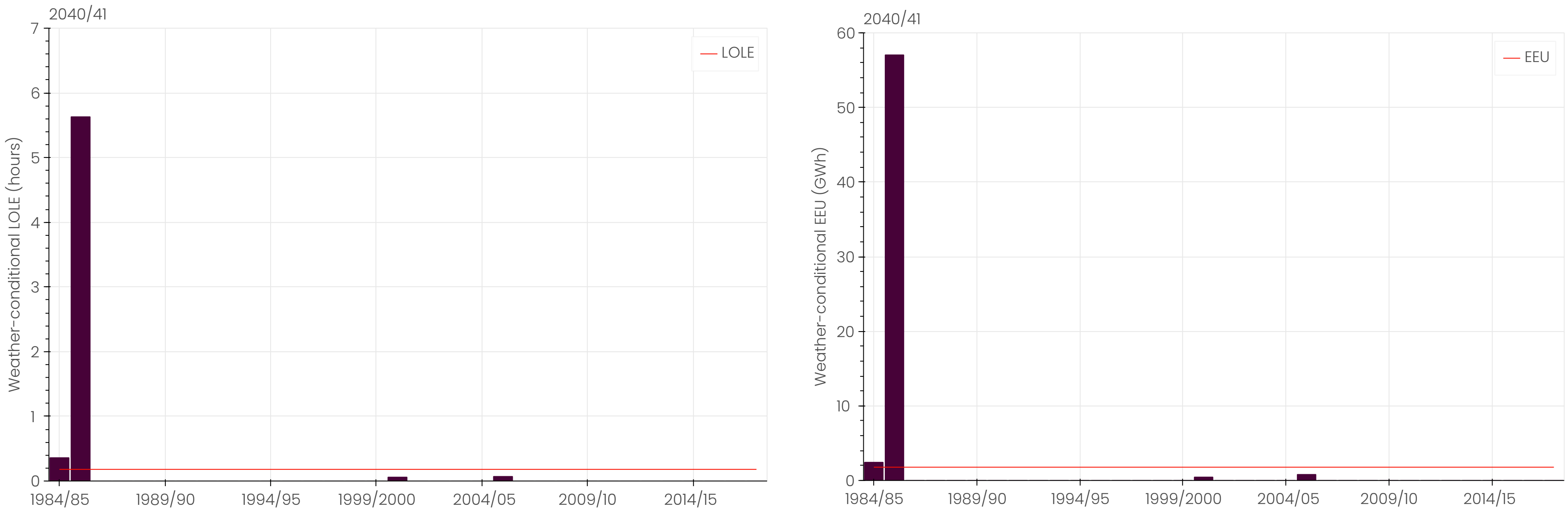


Figure 5 continued: Weather-conditional LOLE and EEU for Portfolio 1. These are the expected hours and volume (respectively) of lost load, assuming a given weather year. Qualitatively similar results were observed for the other portfolios (not shown).[8]

8 Portfolio 1 assumes that all new technologies are available for deployment.

Finding 4: Potential risks to security of supply generally require a combination of events to materialise, such as high levels of plant outages and adverse weather conditions. We should explore what actions are needed to improve the availability and reliability of plants during winter.

As outlined in Finding 3, weather can have a pronounced effect on security of supply. However, weather alone rarely causes shortfalls – it is the combination of challenging weather and high levels of plant outages that creates the greatest system stress.

This relationship between plant outages and security of supply is illustrated in Figure 6 for Portfolio 1. The plots show, across 100 simulations, the average capacity of plants on outage during the most challenging weather period in our dataset, and the resulting hours of lost load. This period – a 48-hour window in February 1986, which the Met Office described as exceptionally cold – was selected because it includes all instances of lost load in our simulations for the 1985/86 weather year. These outputs are intended to highlight the challenges that arise when plant outages coincide with certain weather conditions. While we cannot influence the weather, there may be significant benefits in improving plant reliability and availability during the most challenging winter periods.

The results indicate that, if a repeat of 1985/86 weather were to occur, Portfolio 1 would be likely to experience lost load if more than 5 GW of capacity is unavailable (on average) during that challenging two-day period. Should this occur, it would lead to supply disruptions for some customers, which would not be desirable. Based on our modelling, we can infer that this risk could be mitigated by actions such as improving plant reliability, securing more capacity to target a lower LOLE, or increasing support for customers willing to participate in demand-side flexibility services.

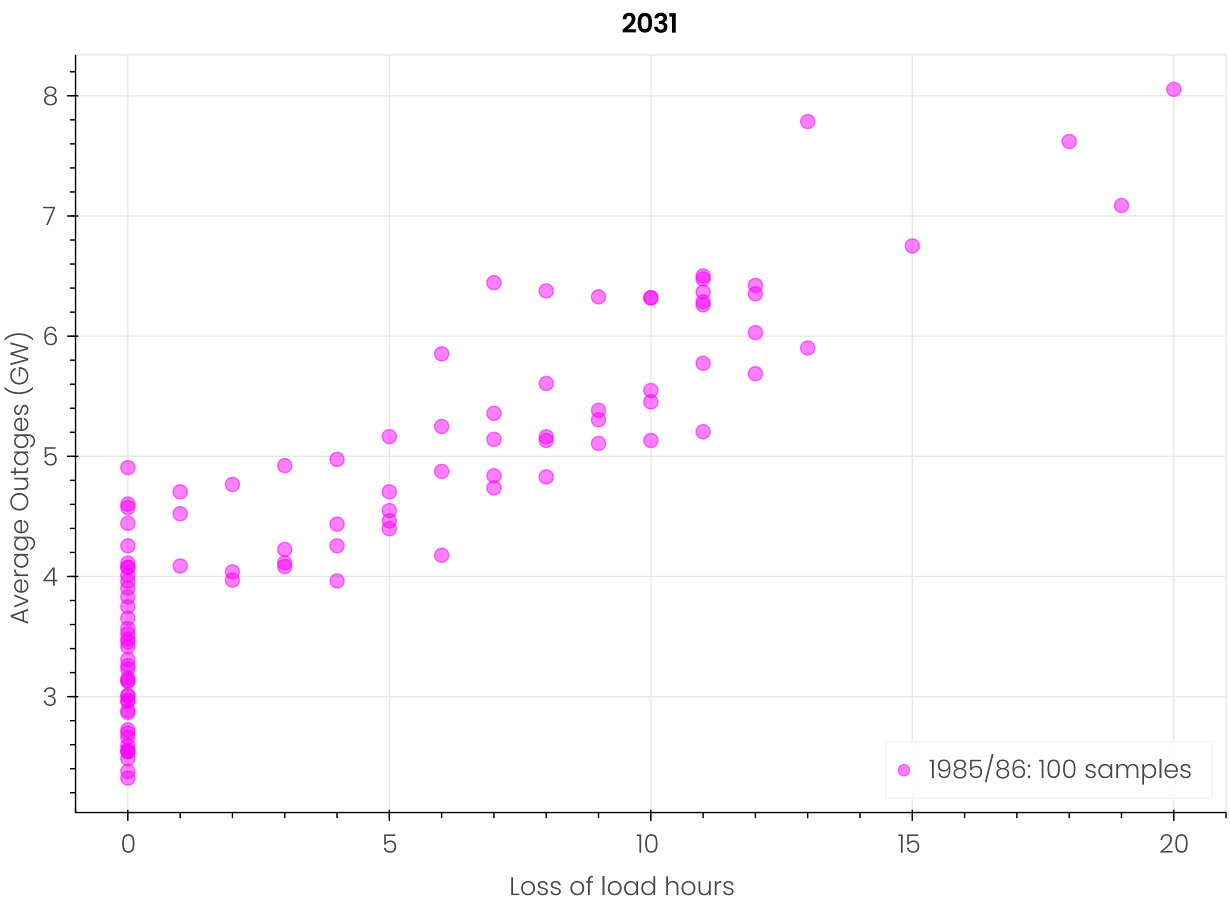
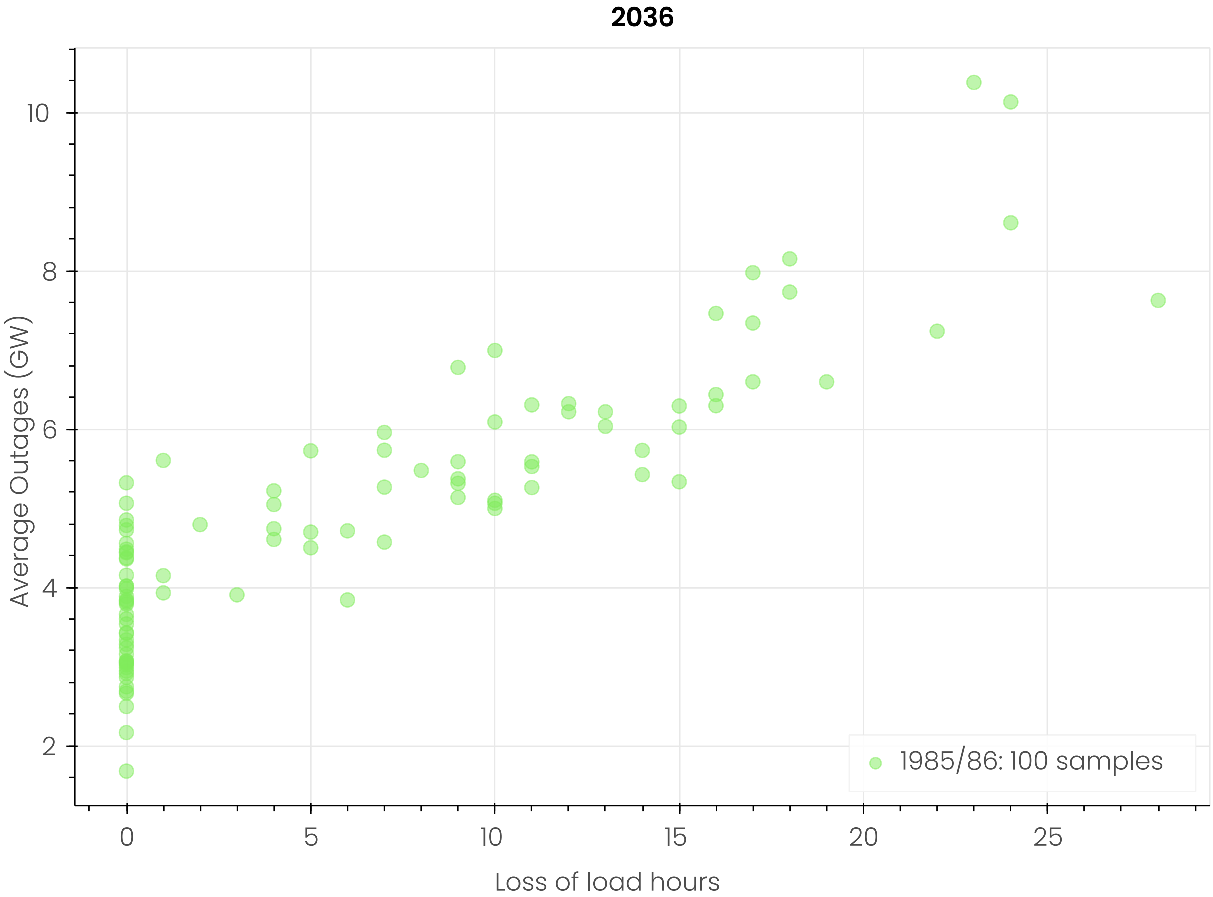


Figure 6: The relationship between the number of hours of lost load and coinciding outages, based on weather from February 1986. Each plot shows 100 simulations and compares the loss of load hours with the average plant unavailability during the 48-hour window preceding (and including) the period of highest system stress. Outages include both planned maintenance and unplanned plant failures.



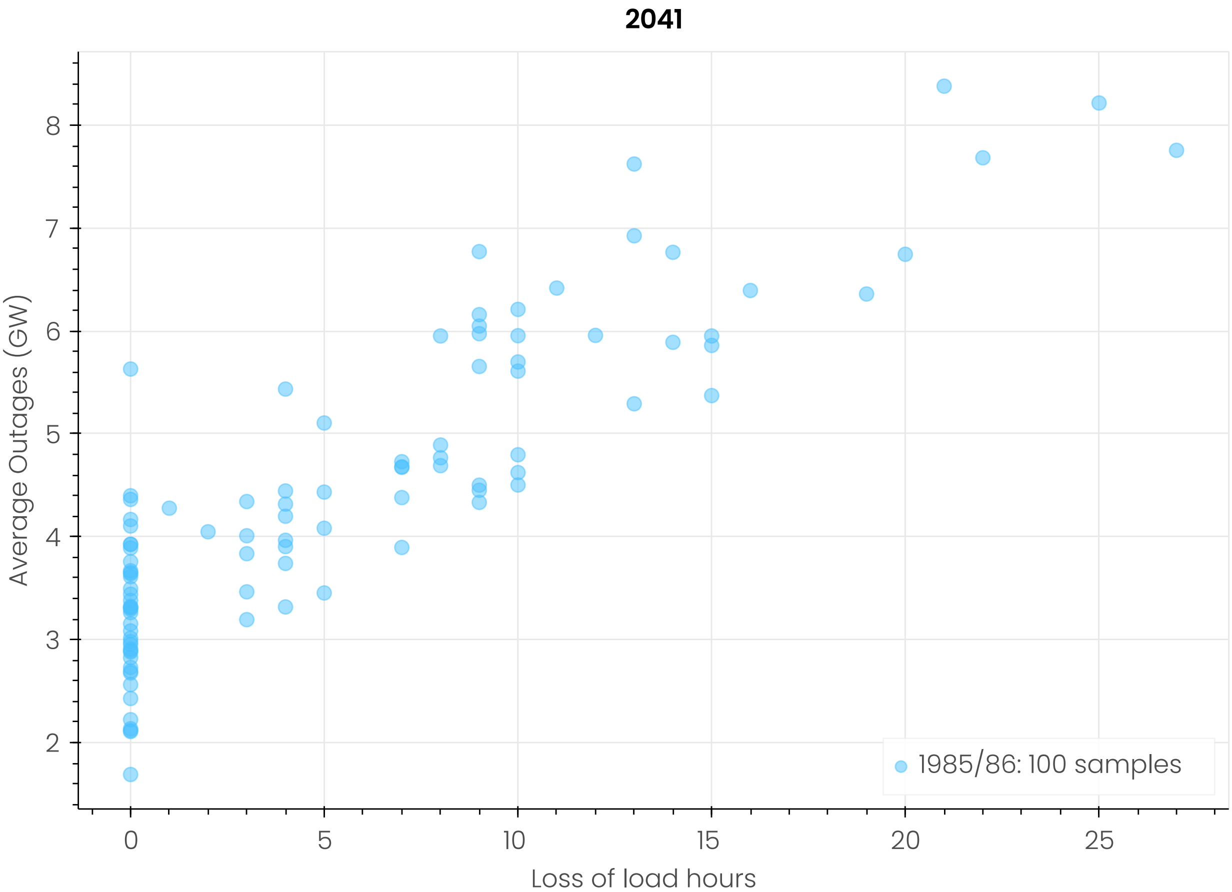
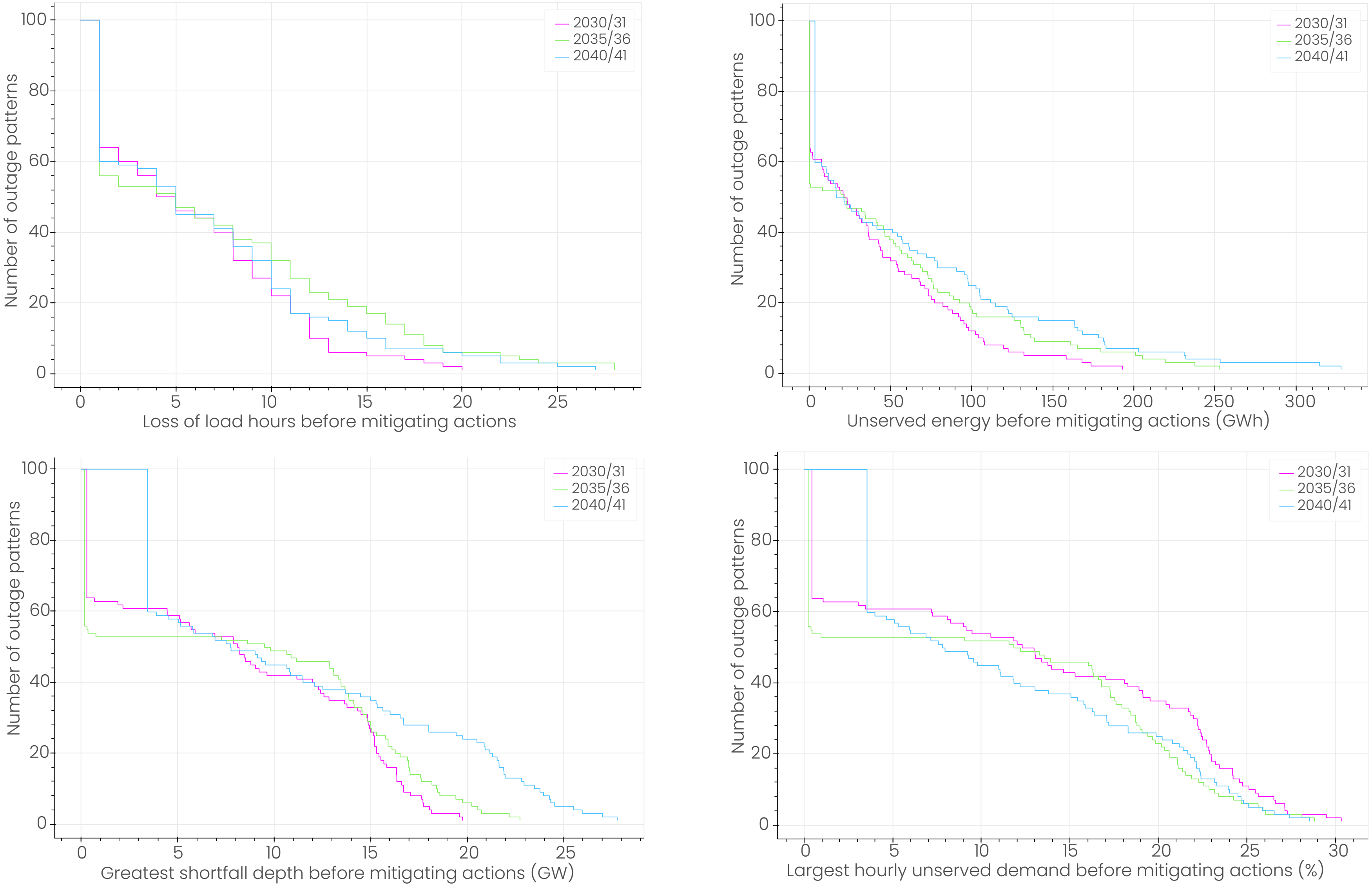


Figure 6 continued: The relationship between the number of hours of lost load and coinciding outages, based on weather from February 1986. Each plot shows 100 simulations and compares the loss of load hours with the average plant unavailability during the 48-hour window preceding (and including) the period of highest system stress.
Outages include both planned maintenance and unplanned plant failures.

These plots can be considered alongside those in Figure 7, which provide further insight into the likelihood and nature of potential stress events. The graphs show, for Portfolio 1 under the 1985/86 weather year, the number of simulations (out of 100) that exceed different levels of lost load – measured in hours, energy and shortfall depth. To illustrate, the top-left graph can be interpreted as follows:

- Suppose we want to understand the risk of 5-hour shortfalls in 2040/41, for Portfolio 1 under the 1985/86 weather year.
- The y-axis value corresponding to 5 hours is approximately 45 for 2040/41. This is the number of simulations (out of 100) which showed at least 5 hours of lost load across the year (again for Portfolio 1 and the weather of 1985/86).

This analysis demonstrates the importance of looking beyond headline figures such as LOLE and EEU. While the low LOLE values of around 0.1–0.3 hours indicate potential shortfalls of 5–20 minutes per year on average, we have seen that the risk looks very different in different weather years. Alternative approaches – like those presented in this study – can offer useful insights into the likelihood, drivers and characteristics of shortfall events and inform more targeted planning and resilience strategies.



For each spotlight year, the graphs show on the y-axis the number of outage samples for the relevant metric (such as loss of load hours without mitigating actions) that exceed (or equal) the value on the x-axis.

Figure 7: Characteristics of loss of load events across 100 simulations, based on the weather year 1985/86

These plots are intended to be illustrative and help identify the actions that can be taken ahead of time of mitigate potential risks.

The role of flexible resources: energy storage, interconnection and demand-side flexibility

Finding 5: Electricity storage can contribute to security of supply while playing a key role in decarbonisation and helping to reduce reliance on unabated gas.

Electricity storage supports decarbonisation by enabling low-carbon energy to be shifted to periods of higher demand. The large build-out of renewables in our portfolios suggests that storage could play a significant role in ensuring this energy is available when needed.

This is illustrated in Figure 8, which explores a scenario where no capacity is built beyond our assumed starting point. In this case, generation capacity is much lower than we anticipate it will be. Despite this, there appears to be sufficient renewable energy to match demand across the year, if it could be shifted to the times of shortfall. While this is only a broad picture, it strengthens the case for exploring how storage and demand-shifting can help ensure energy is available when needed.

Our portfolios include a mix of storage durations – from half-hour batteries to seasonal hydrogen storage. Two of the portfolios specifically explore the implications of no additional build-out of:

- long-duration electricity storage or pumped hydro (Portfolio 3)
- hydrogen storage (Portfolio 5)

In both cases, we found that while other forms of storage could partially compensate, additional unabated gas would likely be required to maintain security of supply.

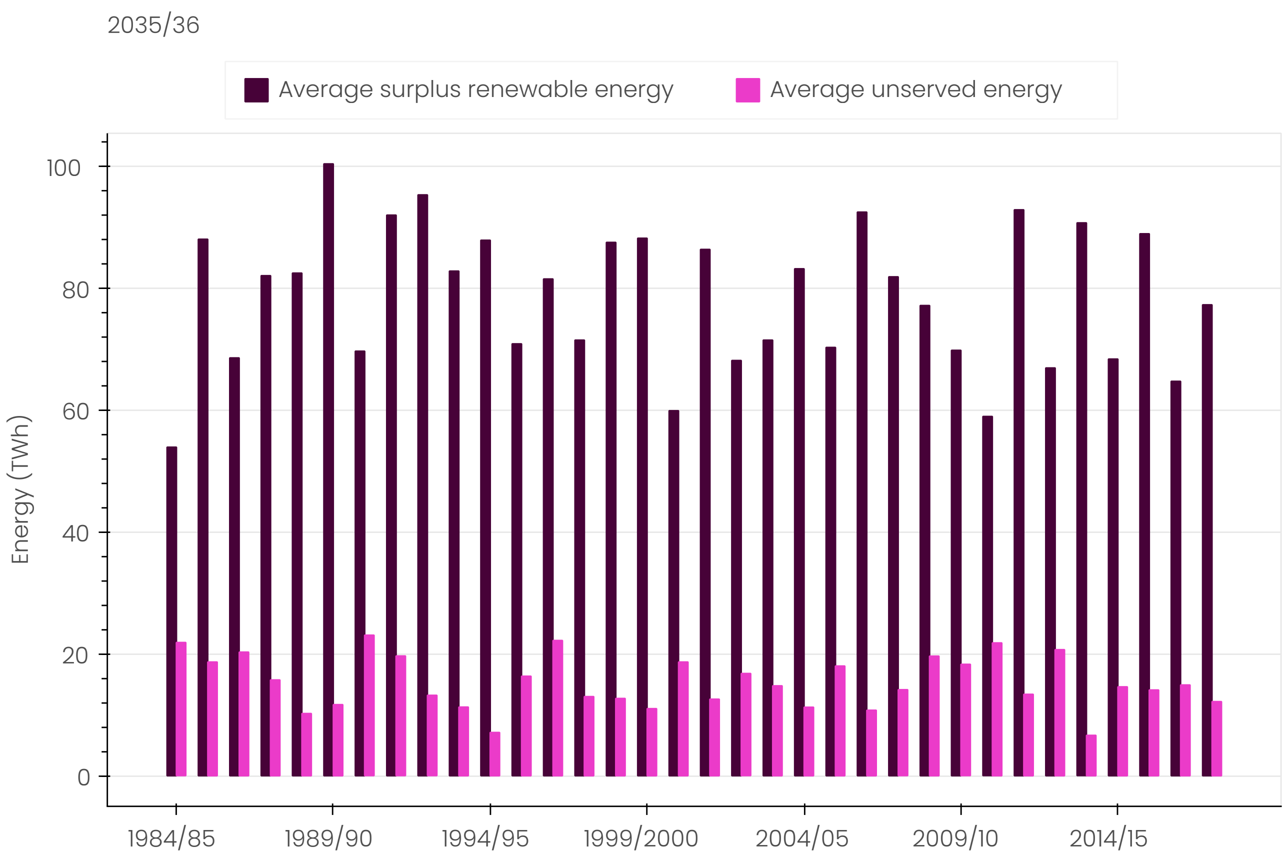


Figure 8: Renewable energy available to serve shortfalls in 2035/36 (averaged across 100 outage samples), assuming no build-out beyond our assumed starting point levels. Plotted alongside weather-conditonal Expected Energy Unserved.

The volume of energy that can be stored is just as important as the power capacity. This is shown in Sensitivities 6 and 7 (Table 5), where we assessed the impact of reducing hydrogen storage volumes to 4 TWh and 2 TWh in Portfolio 1 from 2035. These reductions led to higher LOLE and EEU outputs in 2040/41, indicating that storage volume limits can affect security of supply.

In contrast, these storage limitations had no impact in 2035/36. This can be explained by Table 7, which shows how much hydrogen storage was actually used in each simulation. As long as the available volume exceeds these levels, supply adequacy is maintained.

Table 7: Maximum hydrogen storage volume used in a year, across all simulations (in TWh)[9]

Portfolio	2035/36	2040/41
Portfolio 1	1.7	8.4
Portfolio 3	1.7	4.5
Portfolio 4	1.9	9.6
Portfolio 6	2.2	9.8

This table suggests that 9–10 TWh of hydrogen storage would be required for electricity generation by 2040, in addition to the storage needs of other sectors of the economy.

Finding 6: Our modelling shows that the assumptions we make on the way electricity storage is dispatched during periods of potential system stress can affect security of supply. It is important to understand how storage will operate, what behaviour best serves consumers, and what market signals are needed to incentivise that behaviour.

There is uncertainty around how storage will operate in future electricity systems, particularly during periods of stress. During such times, storage will dispatch its energy to keep the total volume of lost load as low as possible. When there is not enough stored energy to completely eradicate lost load, there is a choice around which hours to focus dispatch on. Different dispatch strategies can lead to different outcomes for consumers. For example, the way storage responds during stress events can affect both the duration and depth of shortfalls.

To explore this, we tested three alternative storage dispatch strategies under stress conditions:

1. **Immediate action** – storage is dispatched to reduce unserved energy as much as possible during the first hour of a shortfall event, then hour by hour until energy is depleted.
2. **Minimising shortfall durations** – storage is used strategically to reduce the number of hours in which shortfalls occur. This leads to fewer hours of lost load, but the potential shortfall in those hours would be higher.
3. **Minimising shortfall depths** – storage is used strategically to reduce the maximum depth of any single shortfall event. This leads to more hours of lost load, but the potential shortfall in those hours would be lower.

Our default strategy is 'immediate action', as it does not rely on foresight and could be applied in highly uncertain situations.

Table 8 shows the impact of these strategies for Portfolio 1 in 2035/36, assuming the weather of 1985/86. While the total energy shortfall remains largely the same, there is a clear trade-off

9 Portfolio 1 assumes that all new technologies are available for deployment; Portfolio 3 assumes no new deployment of long-duration energy storage (LDES), including pumped hydro; Portfolio 4 assumes no deployment of nuclear plants beyond assumed committed levels; and Portfolio 6 assumes no deployment of interconnection beyond assumed committed levels.

between reducing shortfall duration and reducing its depth. The expected greatest shortfall depth is the average of the maximum shortfall in each of 100 simulated outage patterns.

Table 8: Characteristics of shortfall events for Portfolio 1 in 2035/36, assuming 1985/86 weather

Strategy	Expected Loss of Load Hours	Expected Unserved Energy (GWh)	Expected Greatest Shortfall Depth (GW)
Immediate action	6.2	47.1	8.0
Minimising shortfall durations	4.6	47.1	10.6
Minimising shortfall depths	9.1	47.1	7.0

Another important consideration is how far storage operators will be able to cooperate. Our modelling assumes a whole-system approach where all market participants work together to minimise the total annual cost of generation – ultimately lowering costs for consumers. One result of this is that energy may be intentionally withheld in storage so it can be deployed during future shortfalls. This approach is built into our modelling, but it may not reflect a commercially optimised strategy for investors operating in the market.

It is important to recognise that different market conditions will lead to different patterns of storage operation, and to ensure that markets and policies are put in place to encourage the behaviour that best supports consumers and security of supply.

Finding 7: Interconnection can support security of supply, but low generation in Europe could lead to shortfall challenges in Great Britain.

Interconnectors expand our electricity trading pool and provide valuable economic opportunities for Great Britain. However, there may be times when electricity supplies from Europe are not available. This was highlighted in our previous study with AFRY, which found that correlated cold, low wind periods across north-west Europe were a key driver of unserved energy. In our current analysis, low imports were also a contributing factor to shortfalls, as shown in Appendix 1.

Despite this, we have found that new interconnection can play a meaningful role in supporting resource adequacy. Without new interconnection (other than a single new link contained within our starting point), our simulations show that both LOLE and EEU for Portfolio 1 would increase (Sensitivity 8, Table 5).

Modelling the contribution of interconnectors is challenging due to significant uncertainties in the availability of imports, driven by:

- variation in weather forecasting over short and long timescales across Europe
- uncertainty in future European generation and demand profiles

To explore these uncertainties, we considered a scenario (Sensitivity 9, Table 5) in which imports to Portfolio 1 were reduced by 10% in each hour. Even under these conditions, we remained within our target range of 0.1-0.3 hours across all spotlight years. This suggests that while interconnectors make a valuable contribution to security of supply, the system can be designed to withstand variations in projected supply from Europe.

However, further analysis would be beneficial to test this view under a wider range of conditions.

As a more extreme stress test, we explored the impact of no imports for an entire year (Sensitivity 10, Table 5). In this scenario, LOLE became unacceptably high, far exceeding the statutory standard from 2035 onwards. This indicates that, although the system can tolerate some variation in import availability, we would need to deploy additional capacity to maintain security of supply in Great Britain in the unlikely event that there was no interconnection at all.

This reinforces the view that interconnection plays an important role in ensuring reliable energy supplies in Great Britain, particularly during periods of system stress.

Finding 8: Demand-side flexibility can help improve security of supply, particularly during challenging weather conditions.

Our *Clean Power 2030* (CP30) advice to the government highlighted that a significant increase in demand-side flexibility is needed by 2030. Each of our portfolios has been designed to reflect this advice, with 2030 flexibility levels closely aligned to those in CP30.

If flexible demand does not grow beyond 2030, this could affect security of supply – especially under more extreme weather conditions. In Sensitivity 11 (Table 5), both LOLE and EEU increased in Portfolio 1 when demand-side response (DSR) and dynamic demand-shifting were held at 2030 levels. The effect was particularly pronounced when focused on the weather conditions of 1985/86, where expected unserved energy in 2040/41 nearly doubled from 57 GWh to 104 GWh. This suggests a much greater level of potential disruption and cost for consumers.

NESO recognises the important role of demand-side flexibility and is committed to removing barriers to its enablement, as outlined in our *Enabling Demand side Flexibility in NESO Markets* report.[10] Our modelling approach is also worth further exploration, as discussed in our *Spotlight on Demand-Side Response* report. For example, this study assumed that consumers would only shift demand for up to 4 hours. If this limit were extended to 6 hours or more, it could have an impact on security of supply and potentially reduce the level of capacity needed.

10 Enabling Demand Side Flexibility in NESO Markets, NESO, December 2024.

Appendices

Appendix 1: Illustrating the drivers of shortfalls: a scenario based on the weather of February 1986

It is important not only to quantify risks but also to understand the underlying drivers. Doing so helps ensure that the most appropriate mitigation strategies can be identified and planned. In this appendix, we highlight some of the conditions that have led to shortfalls in our analysis and show how the electricity system might respond to these situations.

February 1986

Across all portfolios, the weather of February 1986 emerged as the most challenging. During this period:

- peak electricity demands were high, at times exceeding average cold spell (ACS) peaks
- renewable generation was low
- import availability from Europe was also very low for a prolonged period, suggesting coincident stressful weather conditions across north-west Europe

The response of Portfolio 1 is illustrated in Figures 9-11.

Each set of plots should be read as follows:

- The top left plot shows electricity demand (excluding storage demand) and any unserved energy. Periods of unserved energy – when demand exceeds supply – are highlighted by a blue band for clarity.
- The top right plot shows the availability of renewable energy (solar, wind and tidal) and interconnector imports. These may not be available at full installed capacity due to weather conditions or limited supply from Europe.
- The bottom left plot shows how stored energy varies over time.
- The bottom right plot displays unabated gas generation. It also shows how much the plants were capable of generating ('available unabated gas'), accounting for plant failures and planned outages for maintenance. Gas generation is always lower than available capacity due to the simulation holding back approximately 2.1 GW of headroom for operational reserves.

The first three plots illustrate key drivers of system stress, helping to visualise the types of conditions that could lead to shortfalls.

The bottom right plot can be viewed as an indicator for system stress. Since our simulations only use unabated gas as a last resort, its usage indicates that margins are tight. In all three spotlight years, margins were tight over a prolonged period of several days, eventually resulting in unserved energy.

In each plot, the dates on the x-axis refer to the future years of 2031, 2036 and 2041, rather than the actual date when the weather occurred in 1986. This results in a slight shift in the timing of events between spotlight years.

Portfolio 1, 2031

Timeline of events:

1. **A period of stress followed by a shortfall (19–22 February)**
   A prolonged period of low renewables and high demand gradually depleted battery and pumped hydro stores. During the evening of 21 February, a drop in imports – combined with low levels of renewables and stored energy – meant that there was insufficient generation to meet demand.

2. **The system recovers (22 February – 4 March)**
   Margins remained tight for several days, sustaining the need for unabated gas, although this requirement dropped considerably once imports had sufficiently recovered. Batteries were able to charge briefly on 22 February to assist with a second particularly tight period. By 4 March, renewables and imports were high enough to allow storage to begin recharging.

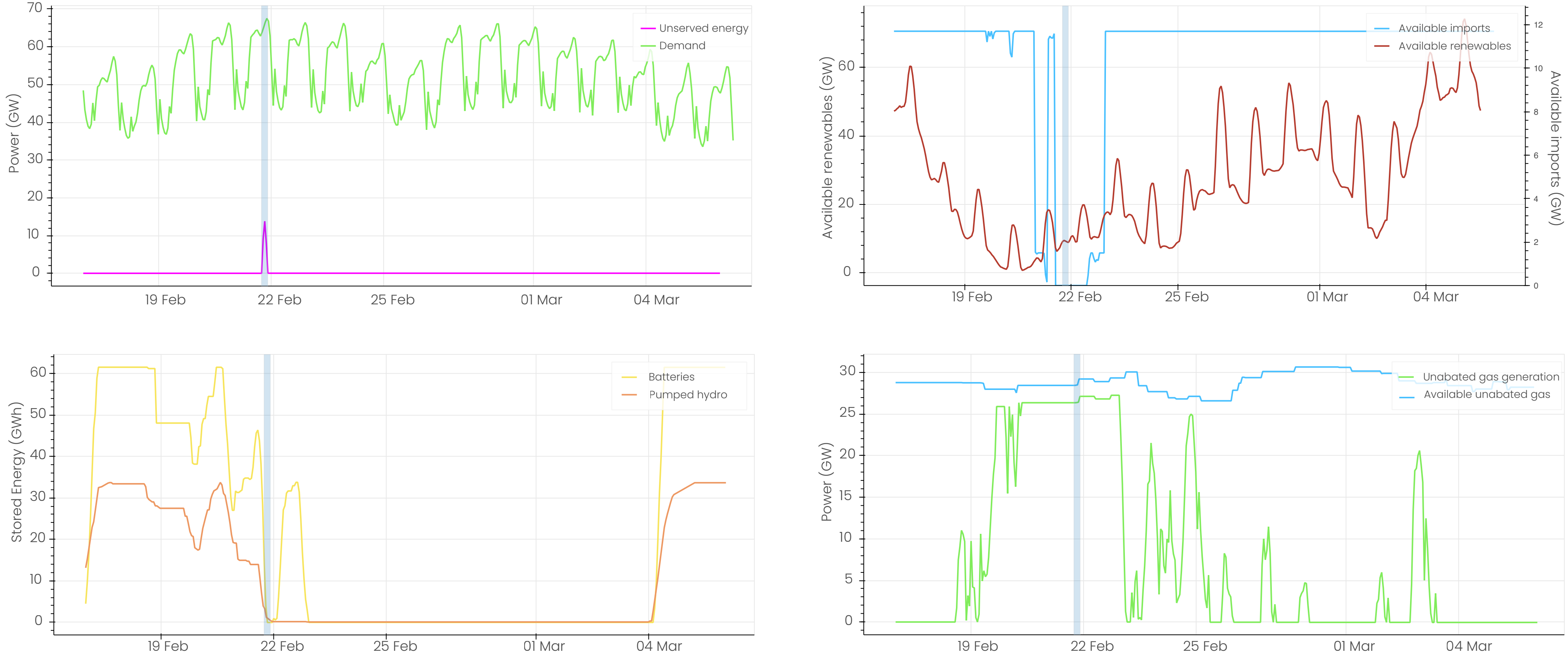


Figure 9: A shortfall event in February 2031 with the weather conditions of 1986

Portfolio 1, 2036

Timeline of events:

1. **A period of stress followed by a shortfall (19–22 February)**
   As in 2031, prolonged and challenging weather conditions led to a reduction in generation, imports and stored energy, resulting in a supply shortfall on 22 February. In this case, an extended period of outages also contributed to the stress on the system.
2. **A second shortfall (23 February)**
   With the system still under pressure for another day and very little energy available from imports, a second shortfall occurred when batteries and pumped hydro stores were exhausted of stored energy.
3. **The system recovers (23 February – 4 March)**
   Although the system remained tight for several days, batteries and pumped hydro were able to assist, while other energy stores began to replenish their reserves in case of future stress events. From 4 March onwards, unabated gas was no longer required and all stores were able to recharge.

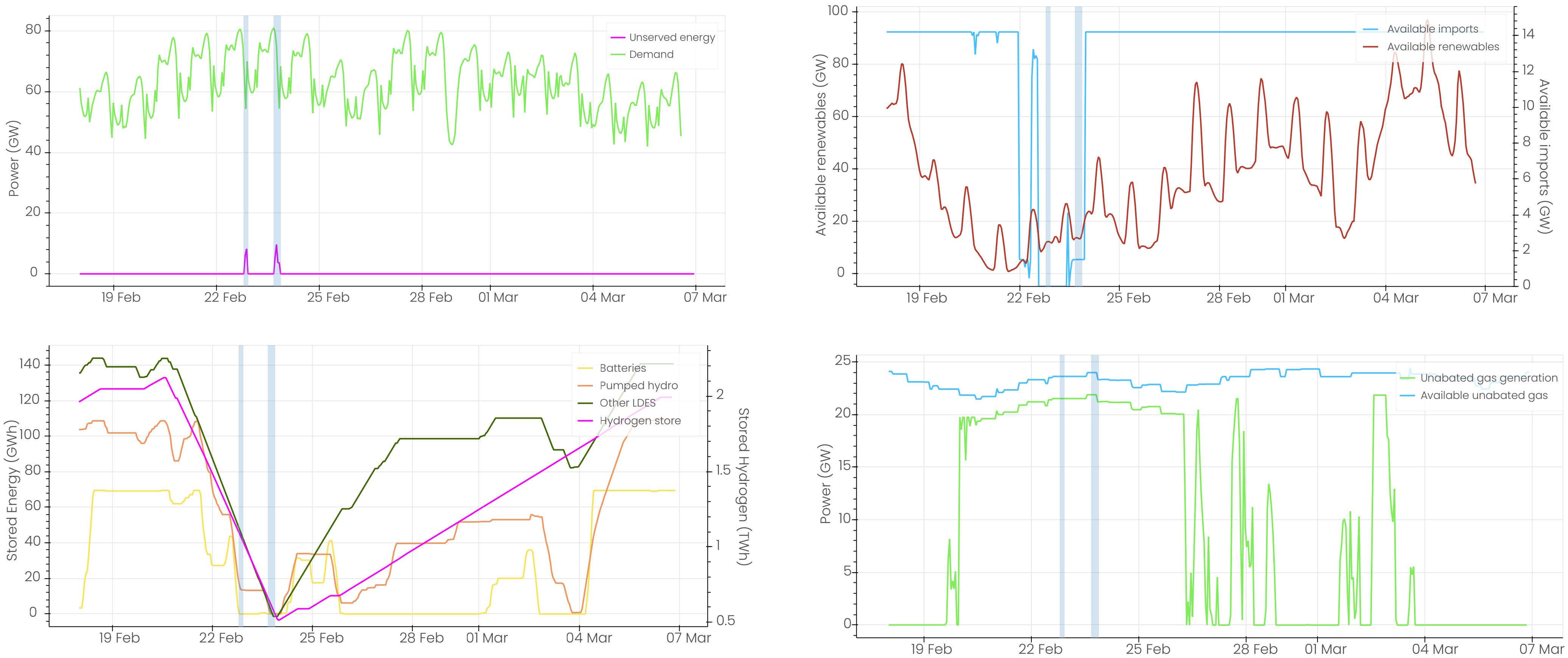


Figure 10: Shortfall events in February 2036 with the weather conditions of 1986

Portfolio 1, 2041

Timeline of events:

1. **A period of stress followed by a shortfall (19–22 February)**
   A sustained tight period led to battery storage being depleted. A coinciding drop in imports, together with low renewables and high demand, triggered an initial brief shortfall.
2. **Three more shortfalls in quick succession (22–23 February)**
   The system remained tight and other storage types (excluding hydrogen) were also depleted, resulting in three more shortfalls over two days.
3. **The system recovers (24 February – 4 March)**
   Imports increased significantly from 24 February. Hydrogen storage was used to recharge other, more efficient storage types during some of this period.

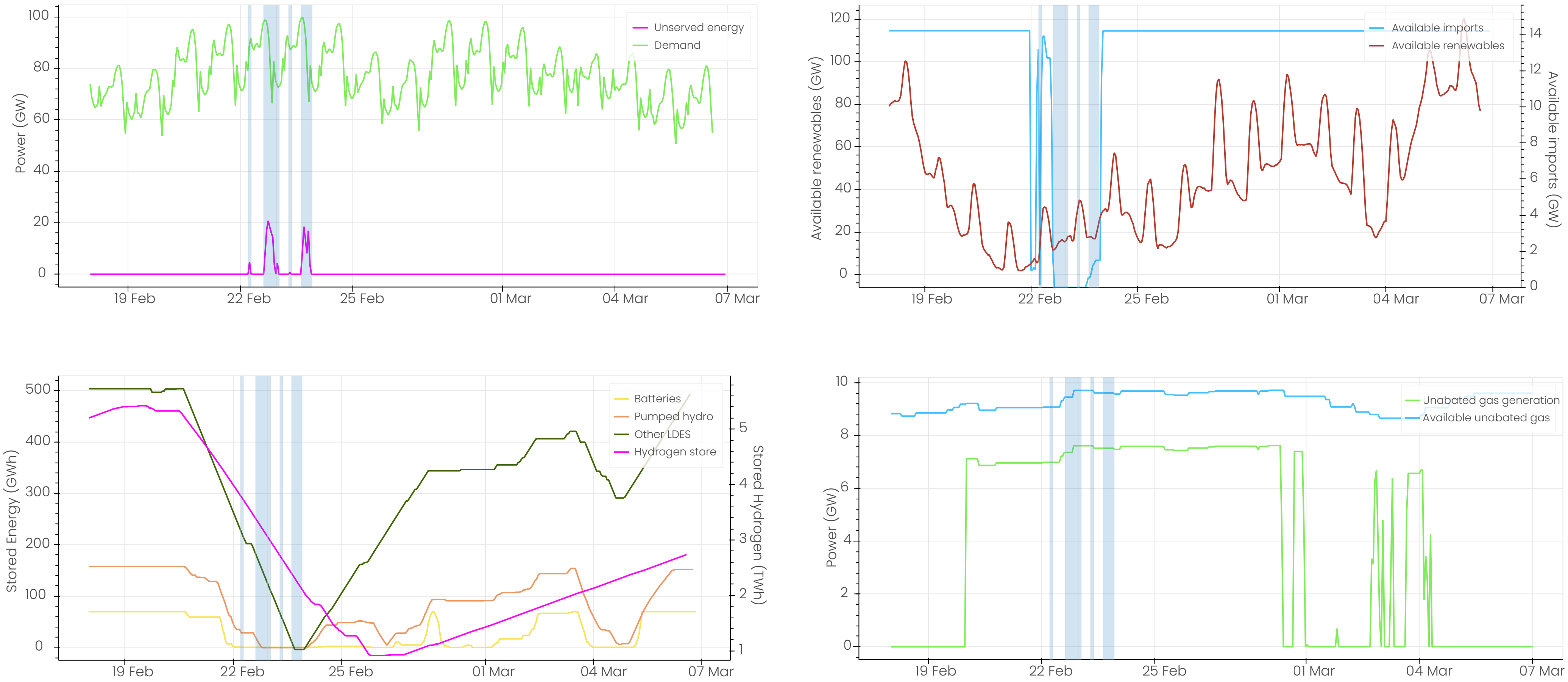


Figure 11: Shortfall events in February 2041 with the weather conditions of 1986

Appendix 2: Our modelling approach

All our analysis is underpinned by simulations of the power system using NESO's resource adequacy dispatch model. This model makes hourly dispatch decisions to meet electricity demand as closely as possible at the lowest cost, while maintaining a Loss of Load Expectation (LOLE) of no more than 0.3 hours.

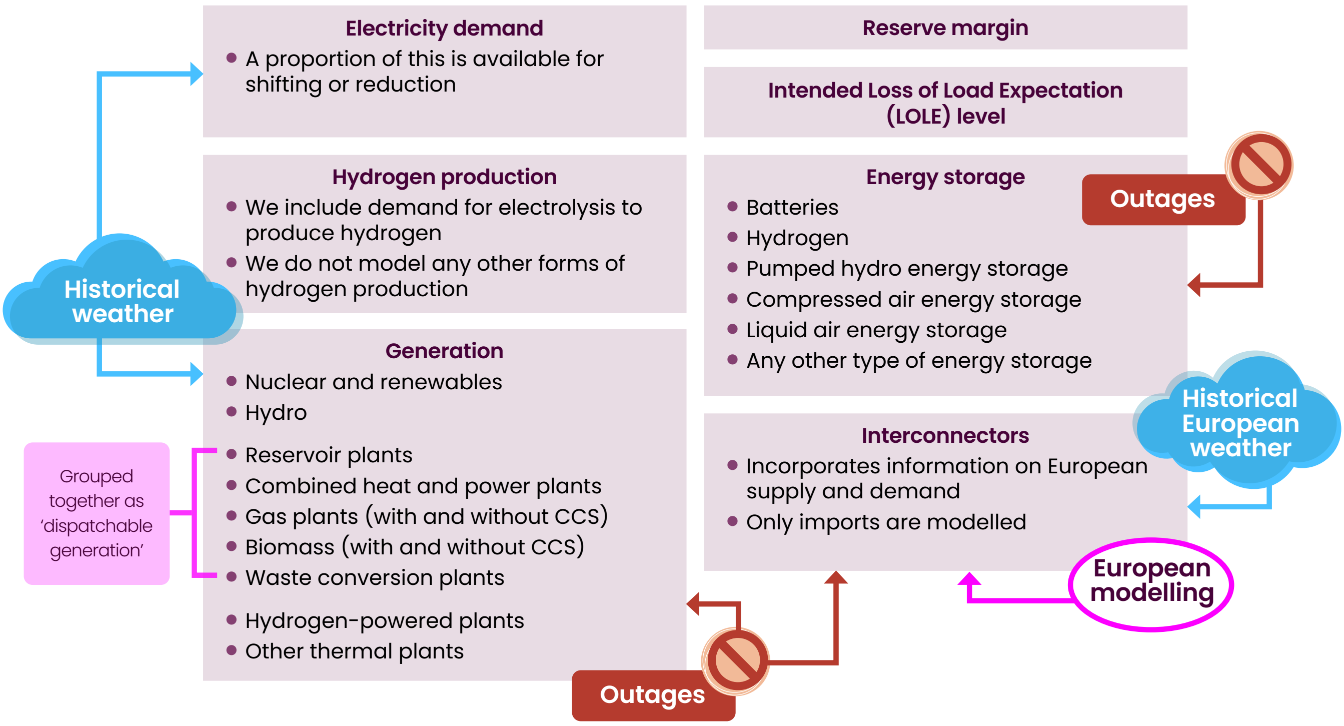


Figure 12: Components of the resource adequacy dispatch model

A full description of the resource adequacy model is provided in our *Modelling Approach* report. Some of its key features are summarised below:

- Dispatch decisions are made using rolling and uncertain foresight. This is important in systems with long-duration energy storage, where assuming perfect foresight could result in an overly optimistic view of security of supply.
- Some energy stores retain reserve capacity, holding back stored energy to be available during potential future stress periods. This behaviour is a consequence of the uncertain foresight assumption.
- For interconnectors, only imports are explicitly modelled, although it is assumed that any surplus generation is available for export.
- Network constraints are not included in the model.
- We do not include enhanced or emergency actions that might be used in real time, such as voltage reduction, maximum generation or emergency assistance from interconnectors.

Modelling new technologies

Some of our portfolios include technologies that are not currently connected to Great Britain's transmission network. As such, we do not yet have a working knowledge of how they will operate in practice. We have therefore made a number of modelling assumptions, which are summarised below.

Hydrogen-to-power plants are assumed to only use hydrogen that has been produced through electrolysis and then stored. This assumption ensures that our study sufficiently stress-tests the electricity system. While much hydrogen currently in use is 'blue' (produced through processes such as steam methane reforming), we do not expect this to play a major role in a fully decarbonised system. We assume that hydrogen-to-power plants are fuelled with pure hydrogen, although recognise that earlier versions may use a blend of hydrogen and natural gas. The impact of this assumption on security of supply is expected to be minimal.

Due to long lead times, we only model hydrogen storage as being available from 2035 onwards. In practice, some of this storage may need to be shared with other hydrogen end uses. We have not accounted for that interaction in this study, but we may explore it in future, as part of our expanding remit as the whole energy system operator.

Small modular nuclear reactors (SMRs) are assumed to have a unit size of 300 MW and greater operational flexibility than traditional nuclear plants.

Carbon capture and storage (CCS) can be fitted to biomass or gas plants. (It can also be fitted to biomethane plants, though we have not modelled this explicitly.) CCS reduces output capacity, which is directly reflected in our biomass assumptions – for example, some existing biomass capacity is modelled as converting to CCS by 2040. For gas, this reduction is considered to be implicit in our reported capacities. CCS is also expected to slow down ramp rates, though not to an extent that would impact resource adequacy. Ramp rates are not included in our analysis, as we assume there will be sufficient notice of upcoming system stress to prepare the relevant plants. Carbon Capture and Storage can include Carbon Capture Use and Storage (CCUS), where the captured carbon is used for some purpose, usually having been solidified first.

Long-duration energy storage (LDES) technologies considered include compressed air, liquid air and iron-air batteries. Rather than modelling specific technologies, we have assumed a generalised LDES type with:

- 72 hours of storage duration
- 65% round-trip efficiency

This reflects the lower efficiency of LDES technologies compared with batteries. While many real-world LDES schemes may fall in the 8-24 hour range, others may exceed 100 hours. Our 72-hour assumption is designed to be representative and instructive.

Pumped hydro is modelled separately, with a 75% round-trip efficiency and units of varying durations.

Appendix 3: Assumed capacities and portfolio construction

This appendix sets out our assumed capacities for generation, interconnection, energy storage and demand flexibility. It also explains how these assumptions compare with other NESO publications and describes how we have constructed our portfolios. Notes are included to aid interpretation of the accompanying tables.

Capacities

Our assumed capacities for this study are presented in Tables 10 and 11. These include our starting point capacities, which reflect existing and assumed committed capacities. These figures do not represent our view of the full future system, as we anticipate substantial build-out beyond these levels between now and 2040 – as demonstrated in the capacities developed for each hypothetical portfolio.

By 2030, we expect capacities to align closely with NESO's *Clean Power 2030* advice, an assumption that is reflected across all our portfolios.

Reading notes for Tables 10 and 11

- The **batteries** category includes a mix of durations, ranging from 30 minutes to 6 hours. (Duration refers to the the time taken to deplete a fully charged store when operating at full power.) While longer durations are possible with emerging technologies, we assume that these would fall under the LDES category. When adding batteries beyond the starting point to create portfolios, we have included only 4-hour duration batteries.
- We assume that hydrogen fuel for **hydrogen-to-power** plants must first be produced through electrolysis and then stored. Each portfolio assumes a fixed 12.4 GW of electrolysers across all spotlight years.
- The **LDES** category includes pumped hydro as well as other long-duration energy storage. The 'other LDES' subcategory does not refer to any specific technology and is assumed to have a 72-hour duration.
- The **nuclear** category includes both large nuclear plants and small modular reactors (SMRs).
- The **other renewables** category includes tidal, waste, hydro and advanced conversion technology (ACT) plants.
- For energy storage, the charging power (the rate at which energy is drawn from the grid) is generally assumed to be equal to the output power reported in Table 10. The exception is hydrogen storage, which has a fixed charging power (via electrolysis) of 12.4 GW.
- The stored hydrogen capacity in Table 11 is likely to be higher than what is required solely for electricity demand. This can be seen in Table 7. However, we have accounted for any additional storage required for other hydrogen end uses. If hydrogen storage is to be shared across sectors, then this will affect the volume needed.

Energy storage efficiencies

All types of energy storage incur losses when converting between electrical and stored energy. These losses are summarised in Table 9 as efficiencies:

- For each unit of electrical energy that passes through a store, only a fraction is converted into stored energy. This fraction is the 'charge efficiency'.

- When this (now reduced) stored energy is later discharged back onto the grid, only a fraction of it is converted back into the required electrical energy. This fraction is the 'discharge efficiency'.
- The 'round-trip efficiency' is the product of the above two efficiencies. It accounts for the total losses from charging through to discharging.

In the case of hydrogen storage, the charge efficiency reflects energy losses during electrolysis, while the discharge efficiency reflects losses during conversion back to electricity using gas turbines.

In many of our assumptions, we have set the charge efficiency to 1. However, it is the round-trip efficiency that is of most importance. If we had chosen lower charge efficiencies but retained the same round-trip efficiency, the results would have been equivalent – provided the energy storage volumes (in GWh) were scaled down accordingly.

Table 9: Assumed efficiencies of each storage technology type

Technology Type	Charge Efficiency	Discharge Efficiency	Round-Trip Efficiency
Batteries	0.85	1	0.85
Pumped hydro	0.75	1	0.75
Other LDES	0.65	1	0.65
Hydrogen	0.80	0.48	0.38

Portfolio construction

In each portfolio, our capacities have been informed by a range of sources, including FES 2024, CP30, our expert advisory group and NESO's market research. This has enabled us to define a set of upper feasible capacity limits for different technologies. In some of the 'what-if' portfolios, we have had to assume new projects reach capacity levels that we consider to be challenging. Action is needed now to ensure that these solutions can be in place when required.

Portfolio 1 was built up from the starting capacities shown in Table 10, using build rates that we consider to be achievable. The other portfolios have been adapted from Portfolio 1 by removing technologies from the generation mix and replacing them with others to create alternative portfolios. This substitution was made initially using 4-hour batteries and other electricity storage, up to a point where either we reached an assumed upper capacity limit or found that further additions made minimal impact on security of supply. Where necessary, we then added more unabated gas capacity. However, it is important to note that some of this gas could be replaced with other dispatchable technologies if available.

Table 10: Capacities used as a starting point and in each portfolio (in GW)

Technology Type	Year	Starting Point	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6
Batteries	2030	20.9	27	29	29	27	27	27
Biomass and BECCS[12]	2030	3.8	3.8	3.8	3.8	3.8	3.8	3.8
DSR and dynamic demand-shifting	2030	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Gas CCS	2030	0	0.9	0.9	0.9	0.9	0.9	0.9
Hydrogen-to-power	2030	0	0	0	0	0	0	0
Interconnectors	2030	11.7	11.7	11.7	11.7	11.7	11.7	11.7
LDES	2030	2.7	4.0	2.7	2.7	4.0	4.0	4.0
Nuclear	2030	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Offshore wind	2030	43.1	43.1	43.1	43.1	43.1	43.1	43.1
Onshore wind	2030	27.3	27.3	27.3	27.3	27.3	27.3	27.3
Other renewables	2030	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Solar	2030	47.4	47.4	47.4	47.4	47.4	47.4	47.4
Unabated gas	2030	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Batteries	2035	20.9	29.0	47.9	47.0	41.0	51.0	38.0
Biomass and BECCS	2035	3.2	2.8	3.2	2.8	2.8	2.8	2.8
DSR and dynamic demand-shifting	2035	9.3	19.5	9.3	19.5	19.5	19.5	19.5
Gas CCS	2035	0	3.9	0.9	3.9	3.9	3.9	3.9
Hydrogen-to-power	2035	0	10.0	0	10.0	10.0	0	10.0
Interconnectors	2035	11.7	14.2	11.7	14.2	14.2	14.2	11.7
LDES	2035	2.7	8.8	2.7	2.7	10.3	10.8	8.8
Nuclear	2035	4.6	5.8	4.6	5.8	4.6	5.8	5.8
Offshore wind	2035	60.3	60.3	89	60.3	60.3	60.3	60.3
Onshore wind	2035	31.2	31.2	31.2	31.2	31.2	31.2	31.2
Other renewables	2035	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Solar	2035	63.8	63.8	69	63.8	63.8	63.8	63.8
Unabated gas	2035	4.5	27.2	41.1	29.7	27.2	34.2	27.2
Batteries	2040	20.9	29.0	55.9	47.0	46.0	51.0	38.0

12 Bioenergy with Carbon Capture and Storage

Biomass and BECCS	2040	0.5	2.3	0.5	2.3	2.3	2.3	2.3
DSR and dynamic demand-shifting	2040	9.3	36.8	9.3	36.8	36.8	36.8	36.8
Gas CCS	2040	0	6.9	0.9	6.9	6.9	6.9	6.9
Hydrogen-to-power	2040	0	20.0	0	20.0	20.0	0	20.0
Interconnectors	2040	11.7	14.2	11.7	14.2	14.2	14.2	11.7
LDES	2040	2.7	16.2	2.7	2.7	19.2	20.7	18
Nuclear	2040	4.6	15.1	7.9	15.1	4.6	15.1	15.1
Offshore wind	2040	77.6	77.6	99	77.6	77.6	77.6	77.6
Onshore wind	2040	35.5	35.5	35.5	35.5	35.5	35.5	35.5
Other renewables	2040	4.8	6.8	4.8	6.8	6.8	6.8	6.8
Solar	2040	80.2	80.2	85	80.2	80.2	80.2	80.2
Unabated gas	2040	1.0	10.6	53.6	18.6	18.6	27.6	10.6

Table 11: Energy storage capacities used as a starting point and in each portfolio (in GWh)

Technology Type	Year	Starting Point	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6
Batteries	2030	37	62	70	70	62	62	62
	2035	37	70	145	142	118	158	106
	2040	37	70	177	142	138	158	106
LDES	2030	28	34	28	28	34	34	34
	2035	28	253	28	28	289	301	253
	2040	28	662	28	28	734	770	704
Hydrogen	2030	0	0	0	0	0	0	0
	2035	0	6000	0	6000	6000	0	6000
	2040	0	16000	0	16000	16000	0	16000

A comparison with FES 2024 and CP30

Our portfolios are intended to complement the pathways in NESO's other publications by exploring a range of 'what-if' scenarios and stress–tests. To support this, we have closely aligned with the CP30 advice for 2030 and have drawn on the FES 2024 pathways for the years beyond.

A comparison of capacities can be seen in Figure 13. The main differences between Portfolio 1 and the CP30 and FES 2024 net zero pathways are outlined below. The other portfolios show larger divergences in some areas, as they were built using a more restricted mix of technologies – requiring higher capacities elsewhere to compensate.

Pumped storage (2040): Portfolio 1 has a higher capacity of pumped hydro in 2040/41 than the 2024 FES pathways. NESO's market research indicates that the levels used in this study are achievable, though challenging.

Interconnection: We adopt a conservative view on interconnection build-out. This is informed by our finding that new interconnection makes a relatively small contribution to security of supply (Sensitivity 8, Table 5), and by the significant uncertainties around European imports not fully explored in this study. Our capacities match those that currently have Ofgem approval, though FES scenarios suggest that higher capacities may be achievable.

Nuclear: We assume delayed retirement of some existing nuclear plants beyond 2030 and the connection of Sizewell C by 2040. For small modular reactors (SMRs), our research suggests that a build rate of two 300 MW units per year from 2034 is feasible, increasing to four per year from 2036.

Biomass/BECCS: Although higher capacities could be possible, we adopt a conservative assumption reflecting the impact of retrofitting plants with carbon capture and storage (CCS), which reduces output. We assume existing biomass plants convert to BECCS in 2035, with a reduced capacity of 450 MW per unit.

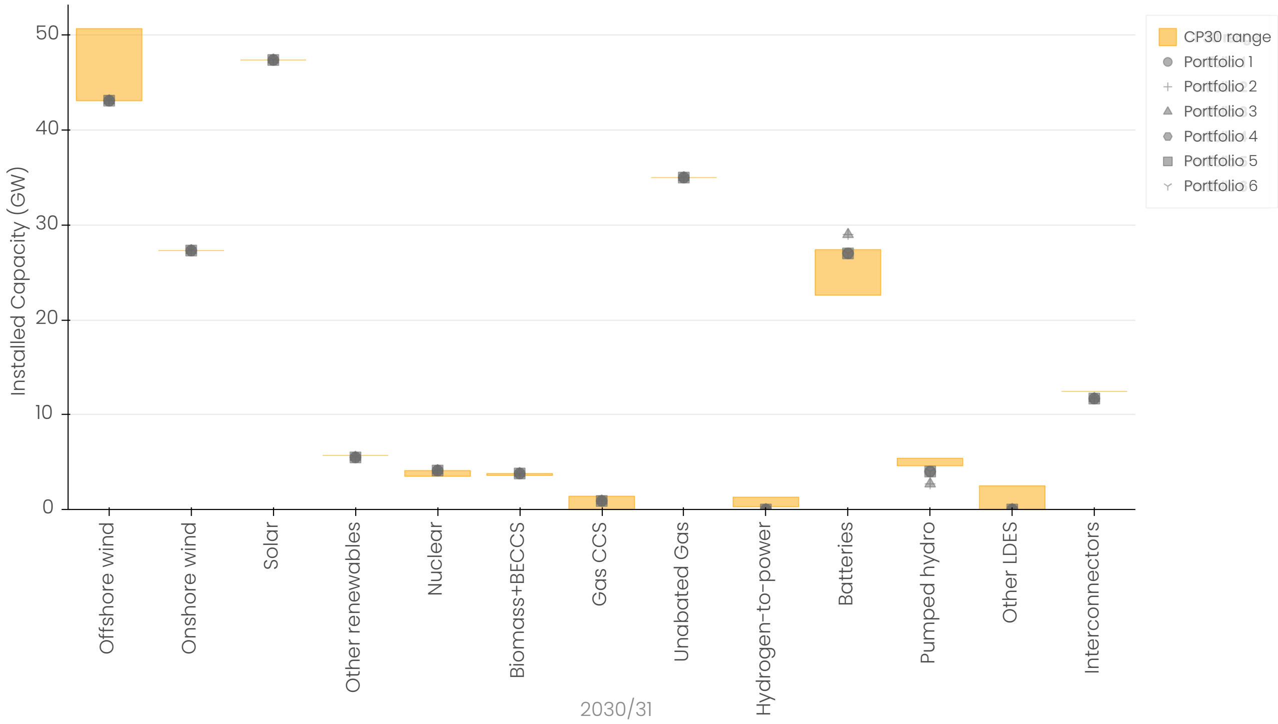
Gas: Additional firm capacity was required to meet our LOLE target of 0.1-0.3 hours. Our analysis suggests some of this may need to come from gas, though if other technologies could be scaled quicker, they could reduce this reliance. We emphasise throughout this report that our portfolios are intended to be instructive rather than predictive – and many technologies can be considered broadly interchangeable.

Renewables: Built out at the rate set out in Table 1 and matching CP30 advice for 2030. While additional renewable capacity could have been included in our portfolios, we found that increasing offshore wind by roughly 20 GW in Portfolio 1 reduced the need for unabated gas by only around 2 GW in order to meet the LOLE target. This is seen in Table 12, which considered offshore wind increases aligning with the mid-range capacities of the FES 2024 pathways. That said, further renewable deployment may have broader system or economic benefits, such as enabling electricity exports when not needed in Great Britain – but these factors are outside the scope of this study, which focuses on security of supply.

Table 12: Estimated reduction in unabated gas (in GW) from Portfolio 1[13] levels required to maintain a LOLE of 0.1–0.3 hours for a given increase in offshore wind capacity

Year	Increase in Offshore Wind (GW)	Reduction in Unabated Gas (GW)
2035/36	20.3	1.7
2040/41	18.4	2.2

13 Portfolio 1 assumes that all new technologies are available for deployment.



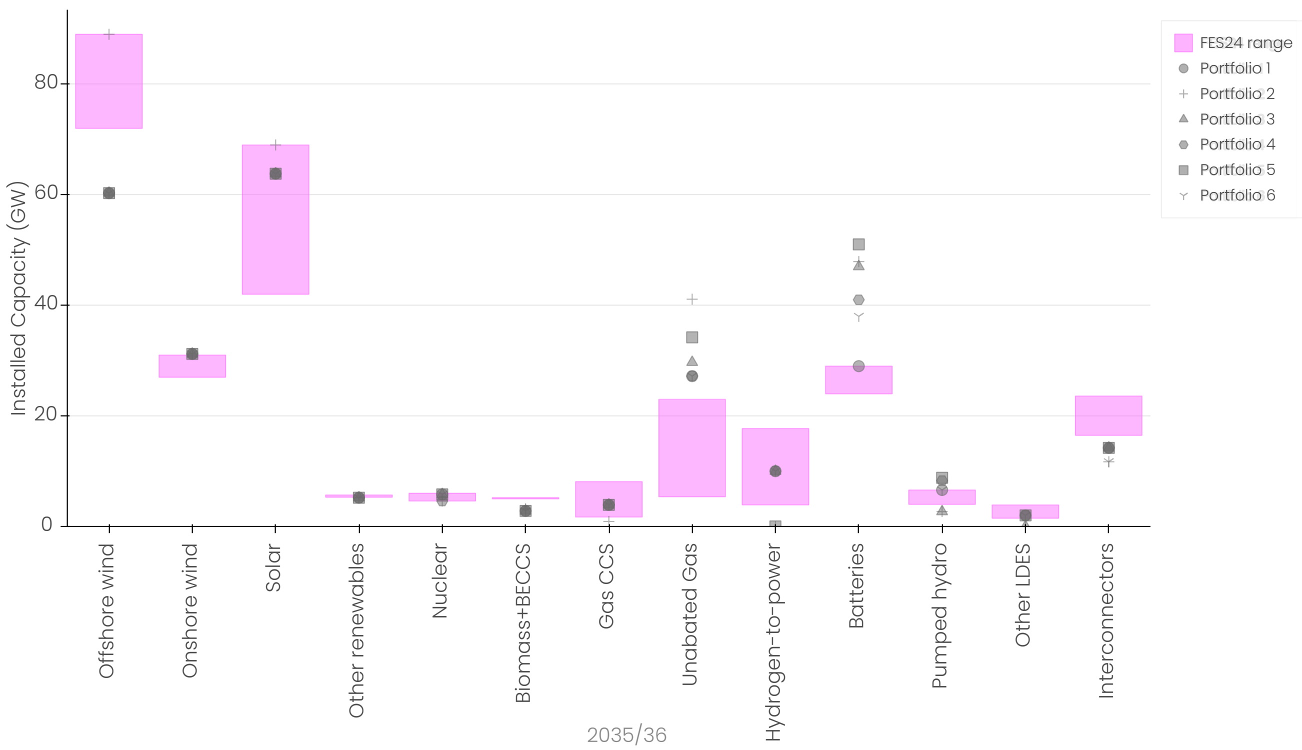


Figure 13: A comparison of the 'what-if' portfolios in this study with CP30 and the three net zero pathways in FES 2024

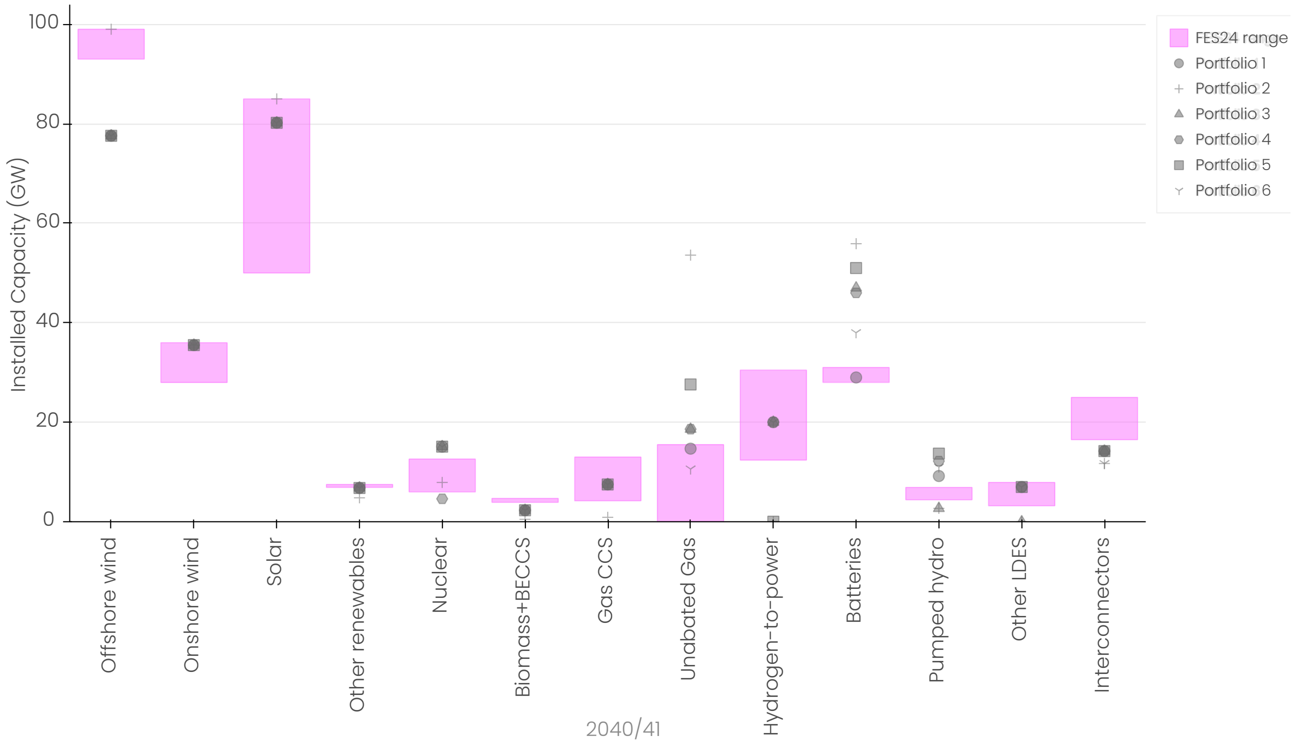


Figure 13 continued: A comparison of the 'what-if' portfolios in this study with CP30 and the three net zero pathways in FES 2024

Appendix 4: Plant availability

Sometimes, plants need to be taken out of operation for maintenance checks or repairs. Where possible, this is planned for times when the system is unlikely to be under stress. In our analysis, we have assumed one planned maintenance event per plant each year.

As with any equipment, plants can also fail unexpectedly. Including these failures in our modelling is a vital part of resource adequacy assessments, as we need to understand the impact of plant failures occurring during other periods of system stress.

For this study, we randomly sampled the timing of plant failures (unplanned outages) to generate 100 different outage patterns. These failures are assumed to occur independently, meaning a plant can fail at any time regardless of how recently it last failed.

The expected time a plant spends on unplanned outage over the course of a year is defined by the forced outage rates shown in Table 13. Each failure results in a fixed outage duration, also given in the table.

Table 13: The unplanned outage parameters for each technology type

Technology Type	Forced Outage Rate (%)	Outage Duration (h)
Large nuclear	5	168
Small modular reactors	5	168
Pumped hydro energy storage	6	123
Gas CCGT[14] and CHP[15]	5	60
Gas OCGT[16]	8	60
Biomass	10	60
Other thermal (steam oil and diesel engines)	8	60
Interconnectors	5	24
Hydrogen to power	5	60
Electrolysers	5	24

14 Combined Cycle Gas Turbine

15 Combined Heat and Power

16 Open Cycle Gas Turbine

Appendix 5: Expert Group

Membership of the Expert Group includes but is not limited to:

- Richard Deakin FNuCI , Board Director, Nuclear Institute
- Dr Paula LM Gonzalez, Senior Scientist, Industry Applications, Met Office
- Prof Chris Dent CEng FIET FIES SMIEEE FORS, Personal Chair in Industrial Mathematics, School of Mathematics, University of Edinburgh
- Dr Stan Zachary, Heriot-Watt University
- Dr Harold Anuta, Schneider Electric
- Barnaby Wharton, Director, Future Electricity Systems, RenewableUK
- Professor Derek W Bunn, London Business School

Membership of this expert group does not constitute endorsement of this report.

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