ELECTRICAL INFRASTRUCTURE RESEARCH HUB

HOW FAR DOES THE POWER NEED TO GO?

The impact of GB-wide transmission network capacity on wind curtailment and access to low carbon electricity

Executive summary

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In partnership with:

EXECUTIVE SUMMARY

Introduction

This project explores the question of how much capacity on the national, main transmission network is economically efficient given the likely capacity, type and spatial distribution of generation and the magnitude and location of demand in a decarbonised electricity system. It has been undertaken through a partnership between the University of Strathclyde, the Offshore Renewable Energy Catapult, and The Energy Landscape. The project explores some important consequences of our transition to a decarbonised electricity system, an ambition which the previous UK Government before the July 2024 General Election had targeted to achieve for 2035 [1] and which the new Government now aims to deliver by 2030 [2].

Networks play two important roles in the electricity system. Firstly, they allow the electricity market to operate efficiently, meaning that buyers of electrical energy can choose between generators wherever they are located, and ensures the cheapest available generation or flexible assets such as energy storage can be dispatched to meet demand. Secondly, they ensure a secure supply of electricity across the country by allowing different regions to share back-up, reserve generation.

Any network has a limited capacity. When and where a network's limit is reached, its ability to play those roles is restricted, which manifests as costs: a less efficient, more expensive, dispatch of generation; and, potentially, reduced security of supply.

Today, our limited transmission network capacity is most often discussed in terms of the curtailment of wind generation. Capacity limits between the north and south of Great Britain (GB) mean renewable generation in Scotland and northern England are often curtailed off and replaced with more expensive, higher carbon generation in the south. From the perspective of the production of electrical energy, curtailment is an operational inefficiency. It means that the cheapest generation cannot be used. Put another way, it means that the full value of investment in offshore wind, onshore wind and other renewables cannot be realised.

Given the importance placed on renewable generation and particularly on offshore wind, there is now a strong focus on investing in the GB transmission network to ensure that northern renewable generation continues to deliver value across the country. However, networks are not free, nor are they easy or quick to build. There are significant investment costs and, as in any infrastructure system, there will be a trade off: investment in network infrastructure should be balanced against reductions in the cost of operating the electricity system, reduction in emissions, and against the additional value it creates through greater confidence of secure supplies.

There is widespread agreement that we will need significantly more transmission network capacity in order to reach that balance point under any scenario which gets close to delivering a decarbonised electricity system in the 2030s. But questions remain: how much more network capacity do we need? By what date? And how should we assess the level of need?

Approach

This project took its inspiration from a 1962 study into the development of the first England and Wales 400kV transmission network [3]. The study, carried out by the Central Electricity Generating Board (CEGB), took an 'agile' and high-level approach to optioneering the design of a future electricity network. It also defined and made use of an intuitively helpful metric: the cost of transmission infrastructure per MW of network capacity and per mile of circuit. In modern, metric parlance, £/MWkm.

The current project embraces a similar agile, high-level approach, as a way to cut through the increasing complexity of electricity system modelling and, potentially, multi-vector whole energy system modelling. Many of the models used by system planners today are highly technical and detailed, and whilst this is important in many aspects of engineering design, it can obscure higher level trends and is opaque for all but the most technical of experts.

The project also makes extensive use of the concept of 'MWkm' as a clear and understandable metric for network costs, which can be used to compare network investment against operational benefits.

The modelling used by the project uses a standard DC Optimal Power Flow model, a basic electricity system modelling approach in which the market's actions in dispatching available resources to meet demand are represented by the optimisation. This is combined with a simplified 14-bus, 16-branch model of the GB electricity system.

The model structure is populated with data representing a pathway for the reduction of emissions from the generation of electricity in line with decarbonised electricity in 2035. The modelled pathway is drawn from pathways considered by the Climate Change Committee (CCC) and specifically from work carried out for the CCC by AFRY in 2022-23 to model a net-zero 2035 system [4].

The work reported here was carried out across late 2023 and early 2024. This means that the analysis and discussion reflect the industry situation, and the prevailing assumptions about the development of the electricity system, at that time. The scenarios are based on the Electricity System Operator's (ESO's) NOA7 and HND network plans [5], which have since been updated with publication of Beyond 2030 [6]. The discussion was developed before the transition of ESO to the National Energy System Operator (NESO) in October 2024 [7]. However, the output of the work remains valid and timely. The development of Clean Power 2030 advice [8], and the publication of the commission from UK Government to NESO to develop the Strategic Spatial Energy Plan (SSEP) [9], shows that the system is moving increasingly towards one where strategic planning is important and where a more nuanced understanding of the relationships between renewable generation capacity, transmission capacity and flexibility, will be critical.

Using this model two types of study are carried out: fixed network and build-out studies.

Fixed network studies use a given set of network boundary transfer capabilities and run an optimised generation dispatch for each hour of a year using appropriately correlated timeseries of renewable generation availability and demand in each part of the country. These studies calculate the overall cost of supply, the level of curtailment and the flow of power, measured in MWkm.

Build-out studies use a fixed network study as the starting point of an iterative process. Once a fixed-network study has been completed, the 'most constrained' network branch is identified, reinforced by 1 GW and the simulation of a year of operation is repeated. This allows the *change* in the cost of supply and curtailment to be identified and to be compared against the network investment for that branch.

Additional sensitivities are used to explore the impact of slower and faster rollouts of renewables and network capacity. Figure ES1 shows the structure of the main scenarios and sensitivities.

The outline process for these two types of study is shown in Figures ES2 and ES3.

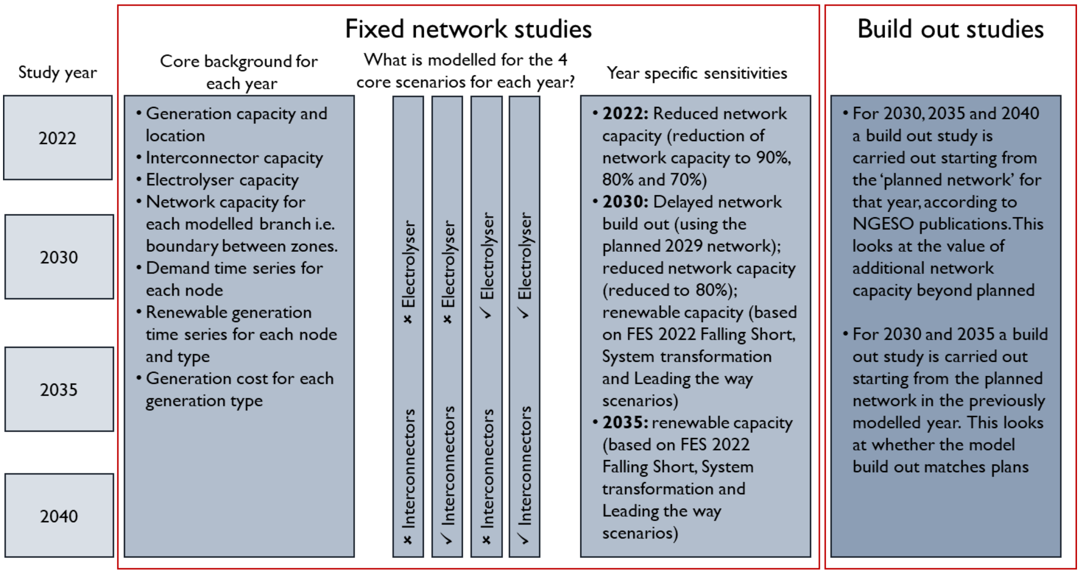


Figure ES1: Summary of the studies, scenarios and sensitivities run for the project.

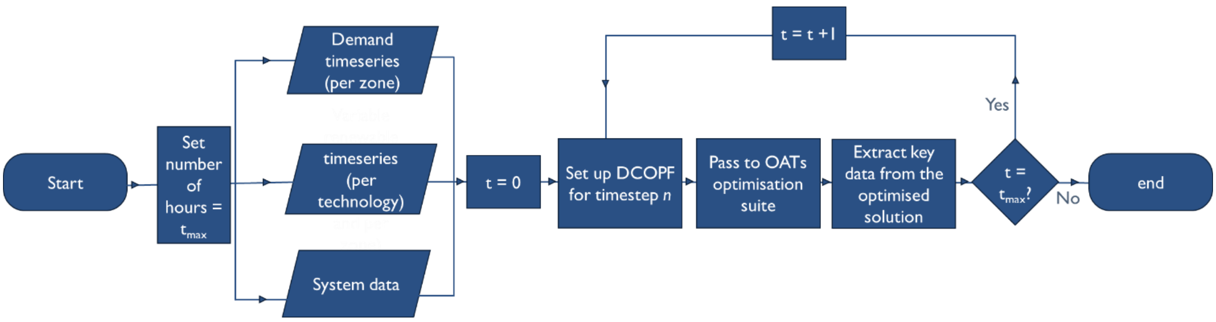


Figure ES2: Summary of the process for fixed network studies.

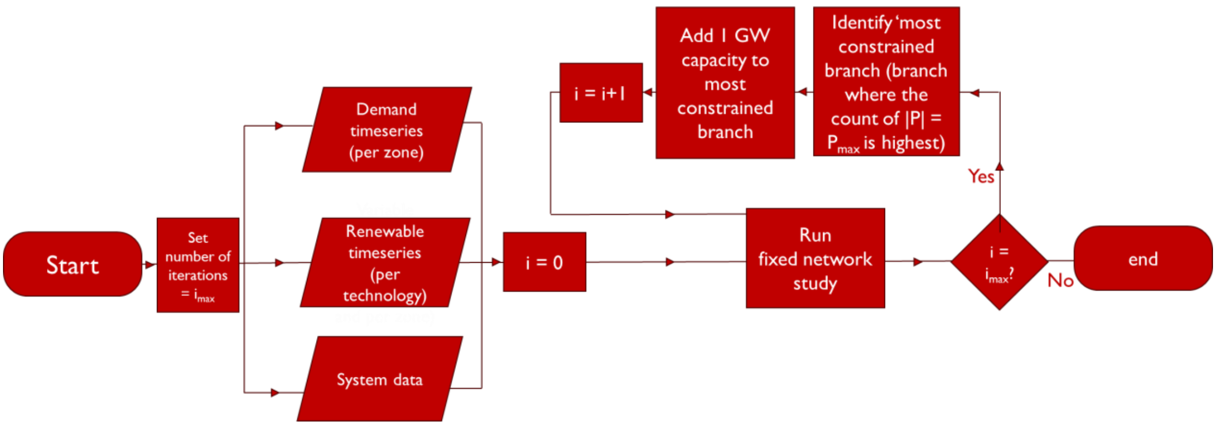


Figure ES3: Summary of the process for build out studies.

What do the results tell us?

This work has been carried out on a relatively small budget and has limited resource to explore all facets of system development and operation in detail. However, we believe that despite these limitations, the study provides some important, and some extremely stark, results. These highlight the very difficult challenges that we have in developing the GB transmission network in a way that is economically efficient relative to the cost of curtailing available low carbon and low marginal cost energy.

In keeping with the agile approach of the work, these results should not be treated as definitive but as important flags for system planners, for government and for the wider sector, and as a demonstration of an approach that could prove useful in the production of, for example, a Strategic Spatial Energy Plan.

Some of the most important outputs are summarised in the 'Key findings' section below and are expanded on in the main report.

To give a sense of the overall message of the work, the following paragraph summarises the main findings:

We should expect to see a significant increase in curtailment as we develop a decarbonised electricity system. This is consistent with an economically efficient trade-off between network investment and reducing operating costs. Flexibility will have an important role to play in managing curtailment. Build out and efficient operation of interconnectors is likely to be absolutely critical to keeping curtailment down to manageable and acceptable levels. Hydrogen electrolysis can play an important part. Short discharge duration (and low MWh volume) energy storage is likely to make only a limited difference to the impact of network constraints on curtailment. It is likely that, if we follow a pathway consistent with a 2035 decarbonised electricity system, the early 2030s will represent the most challenging part of the transition from an electricity system operation perspective. During this period, renewable generation is likely to be delivered ahead of large-scale electrification of demand, electrolysis and seasonal scale energy storage (with discharge duration in the days, weeks and months and energy storage capacity measured in the TWh rather than GWh).

What are the next steps?

The model developed here simulates the operation of inflexible, schedulable and variable generation (such as nuclear, gas CCGT and offshore wind respectively). It also includes the main electricity transmission network, hydrogen electrolysis and interconnection as part of the model. Demand growth and the changing temporal patterns of demand are also captured.

However, the modelling does not yet fully integrate energy storage and other forms of demand flexibility. Some of the impact of demand flexibility is built into the demand time series used. To account for the impact of energy storage, analysis is carried out 'off model'.

In order to develop the model and allow it to be used to better illustrate and explore future scenarios, we aim, in the future, to:

- Integrate energy storage through a multi-period approach to the optimisation.

- Apply a similar approach to additional forms of demand flexibility.
- Explore ways to soft-link GB studies to Europe-wide market simulations in order to more realistically represent interconnector costs and flows.
- Develop the build out studies from a heuristic “directed-search algorithm” approach to a full co-optimisation of network and operating costs.

We believe that the agile, high level, illustrative and exploratory approach developed here can be of significant value to the sector. We think it can help a wider group of stakeholders to understand the challenges, options and trade-offs inherent in developing the electricity system. And we believe that, with further development, it can be used to quickly explore issues and interactions between energy vectors, and flag the need to explore those issues in more depth with specialist, more detailed models.

To do this, it is important that those organisations involved in system planning, particularly the National Energy System Operator (NESO) and the Transmission Owners grow their willingness and ability to share information, work in an open and transparent way and collaborate across the energy sector. Recent developments, such as the significant growth of data on NESO’s data portal, point towards a growing attitude of openness which is a positive development for the whole sector. However, there remain areas where greater sharing of data and analysis would be beneficial. For example, as part of their network planning process, NESO carries out an analysis of curtailment costs that will include estimates of volume, turn up costs, and turn down costs on a boundary-by-boundary basis. This information is not shared publicly, but would be useful in supporting the wider sector in understanding the structure of the constraint issues, and in bringing forward solutions.

Key Messages

The modelling done in this project, using synthesised but realistically correlated patterns of availability of power from wind and solar, reveals a number of key insights about the future electricity system. (Note: in this short, exploratory project, a single, central 'weather year' using data for 2007 has been modelled).

1. **The scale of change we expect to see in the electricity system over the next 10-15 years has not been seen since at least the 1960s, and in order to deliver a decarbonised electricity system 2035 at the latest, change needs to be fastest during the next decade.** Our scenarios are based on the central scenario used by AFRY in their 2023 work for the CCC on Net Zero Electricity and Hydrogen [4]. In these scenarios, by 2040, annual demand increases to around 250% of current levels, and the output of variable renewables – offshore wind, onshore wind and solar – increase by a factor of five. Compared with today, interconnectors potentially play a more significant role both in meeting demand, with imports rising by a factor of 2.6 between 2022 and 2040, and in enabling exports of electricity. Output from variable renewables increases from 40% of annual demand to nearly 90% in 2030. Planning and delivering efficient network investment in the midst of such significant change is at the crux of the net zero challenge.

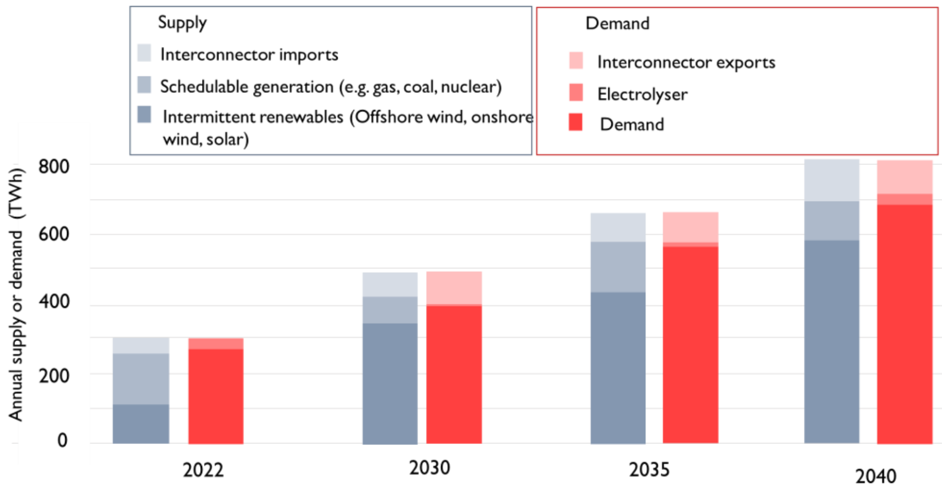
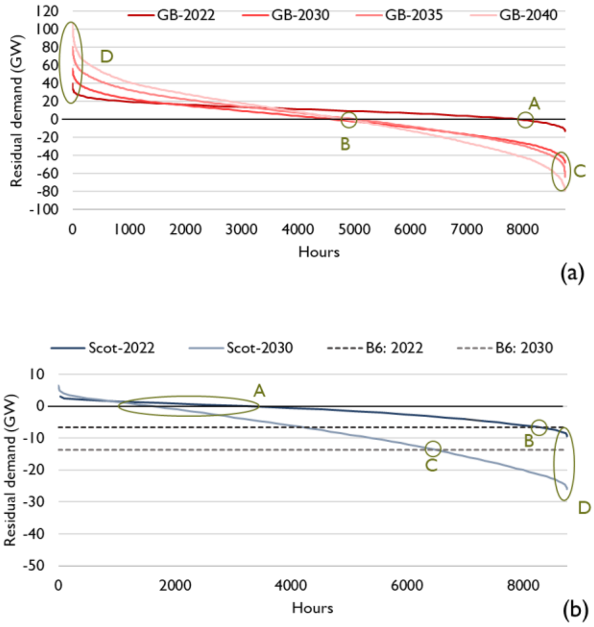


Figure ES4: modelled supply and demand balance.

2. **Residual demand is negative for much of the time in a net zero system.** The result of the changing mix of generation and demand is that, at national, GB scale, residual demand, i.e. underlying demand minus the power available from variable renewables and, in this study, inflexible generation, is negative on an increasingly regular basis, rising from 9% of the year in 2022 to 47% of the year in 2030. The magnitude of the negative residual demand in 2022 was sufficiently small to be largely within the current capability of our fleet of flexibility resources to absorb excess generation, in particular through interconnector export. However, by 2030, the magnitude of negative residual demand at a GB level is likely to exceed the capability of flexibility to absorb it during some hours.

Within some areas of the country, residual demand on a regional basis is already negative for the vast majority of the year and is increasingly larger than the transmission network's currently planned capacity to export power from that region.



(a)

A: In 2022, GB residual demand is positive for 7,966 hours or 91% of the year.
B: By 2030, GB residual demand is positive for 4651 hours, or 53% of the year. This value stays in the range 50% - 60% for the rest of the decade.
C: In 2022, Residual GB demand never falls below -13 GW. In 2030 this becomes more negative, with the minimum value falling to -48 GW. By 2040 it has fallen to -78 GW.
D: In 2022 the maximum residual demand is 34 GW, in 2030 this rises to 57 GW and 106 GW by 2040.

(b)

A: In 2022, Scottish residual demand is positive for 3257 hours or 37% of the year. This falls to 18% in 2030.
B: In 2022, Scottish residual demand falls below -6.6 GW, the secure transfer capacity of the network to export power, for just over 700 hours, or 8% of the year. The majority of this 'excess' negative residual demand can be managed through flexibility.
C: By 2030, Scottish negative residual demand exceeds the secure transfer capacity during 26% of the year despite the secure boundary capability increasing from 6.6 to13.2 GW.
D: The absolute difference between the minimum residual demand and the secure boundary capability also increases from 3 GW in 2022 to 13 GW in 2030.

Figure ES5: Residual demand duration curves for (a) GB as a whole in all years modelled and (b) for Scotland in 2022 and 2030. Duration curves show the number of hours in the year for which residual demand is greater than a particular value. They are created by reordering a year's timeseries in order from highest residual demand to lowest.

3. **Curtailment of renewables, including offshore wind, is likely to grow significantly by the 2030s even with planned transmission network reinforcements**. In the scenarios modelled here, by 2030, the minimum level of curtailment is 20.7 TWh, compared with an outturn of 3.5 TWh in 2020 and 2.3 TWh in 2021. This should be treated as a lower bound because it assumes that interconnectors operate perfectly to minimise GB curtailment. Minimum curtailment levels rise to 30.6 TWh in 2035 and 64.3 TWh in 2040 with current published network plans.

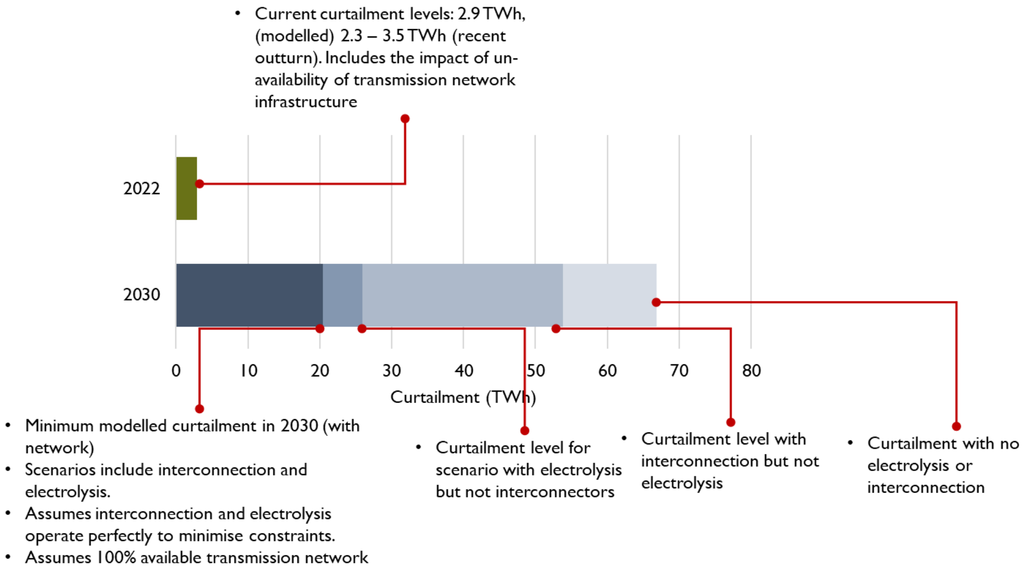


Figure ES6: Modelled curtailment levels for 2030 scenarios compared with 2022.

4. **By the 2030s, curtailment won't just be caused by transmission limits but also national 'energy balance' constraints: the inability, at certain times, to use all the available renewable energy within GB at all or to export or store it**. Energy-based curtailment in 2030 could be 8.0 TWh, around 2 – 3 times the network-based curtailment seen today.

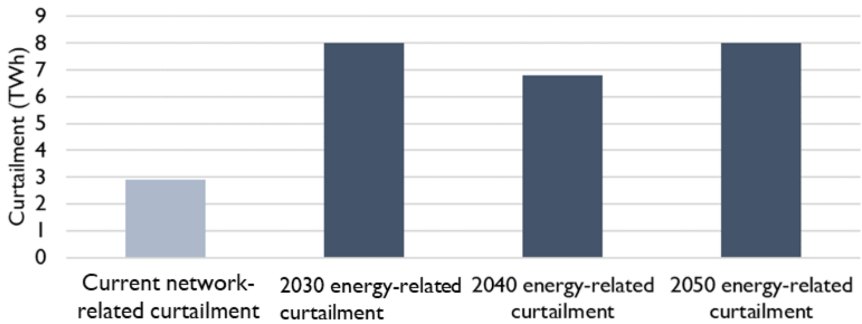


Figure ES7: Comparing current network-related curtailment to energy-related curtailment in 2030 – 2040.

5. **The average distance electricity will travel between generation and consumption is likely to increase significantly over the next few years**. Modelling results suggest this might be by as much as 58% by 2030. However, network limits will increasingly constrain travel distances over time with scenarios that include network limits showing significantly lower travel distance compared with unconstrained (or 'copper plate') scenarios. The scenarios we use also show a small drop in average distance travelled between 2030 and 2035, which reflects the fact that during those five years, unlike other periods, demand grows faster than renewable generation.

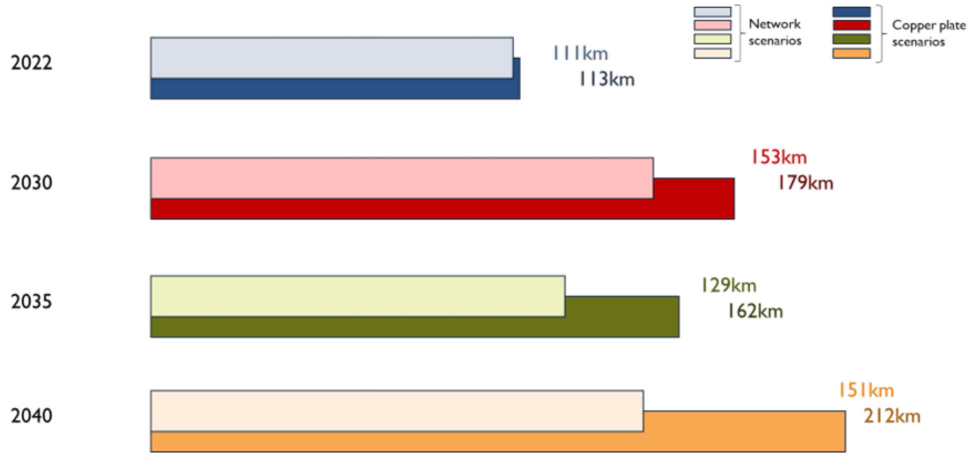


Figure ES8: Average travel distance for energy in core scenarios, including interconnectors and electrolysis. The lighter bar in each pair is the network scenario, the dark bar is the copper plate scenario[1].

6. **Absolute peak unconstrained MWkm flows (the largest hourly flow modelled within a year) could increase by a factor of more than three by 2035, but building transmission to facilitate full unconstrained MWkm flows will be impractical and economically inefficient.** Peak unconstrained flows will increase from 7 million MWkm in 2022 to 25 million MWkm in 2035. An alternative measure of high flows is to use the 90th percentile – the P90 – of the MWkm hourly distribution. This increases from 5 million MWkm (2022) to 18 million MWkm (2035). It will be important to get the right balance between curtailing output from the cheapest generation, and building transmission to facilitate high levels of flow for only a few hours per year.

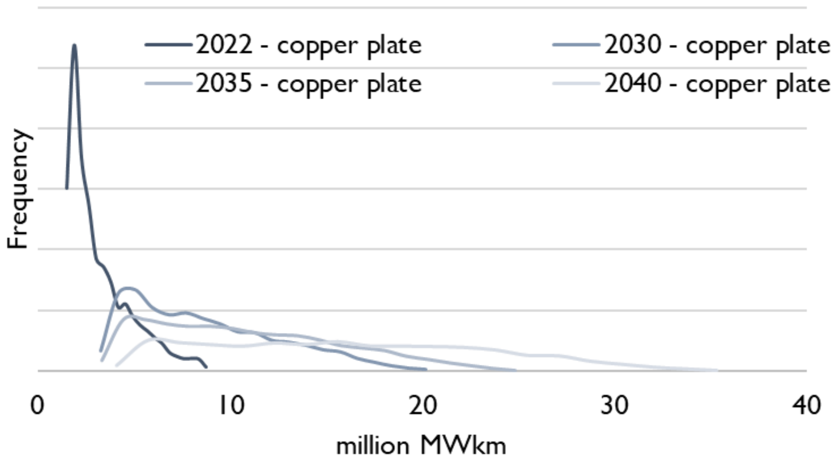


Figure ES9: Comparing MWkm flow distribution for copper plate scenarios.

[1] The term 'Copper Plate' is used throughout this report to mean an effectively infinite network capacity with no network constraints.

7. **The modelling suggests that the vast majority of current curtailment can be accounted for by network outages.** In recent years, planned outages have resulted in the typical operational power transfer capability of the network across key boundaries being around 75% of the nominal capability for an intact network. It is important to understand what future network availability levels will be and ensure system modelling accounts for these.

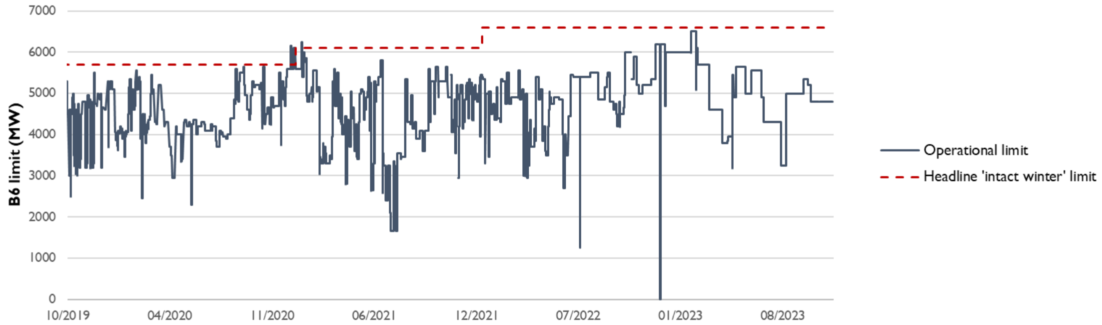


Figure ES10: Intact network winter transfer capability and day-ahead operational capability for the B6 boundary over recent years. Source: ESO Day ahead constraint flows and limits [10]

8. **Planned investment in the bulk-transportation element of the transmission network will more than double its physical capability by 2040, taking it from 9.0 million MWkm in 2022 to 21.9 million MWkm in 2040**. Even by 2030 investment will add 6.5 million MWkm of network capability, a 70% increase. Future transmission planning, including that listed in the ESO's Beyond 2035 report, published in Spring 2024, will likely see further capacity increased beyond 2035.

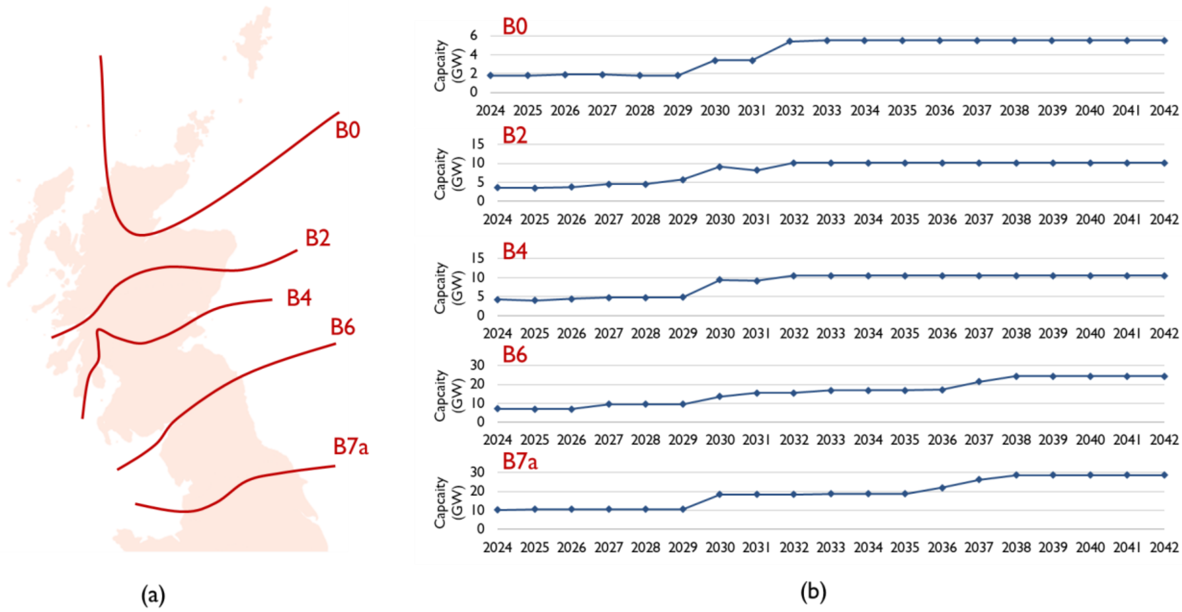


Figure ES11: Reinforcement of the main northern boundaries over the coming 13 years showing the step change on many boundaries in 2030. Source [11].

9. **For the generation background modelled, results suggest that financial considerations and the impact on renewable curtailment may justify further expansion of the transmission network, beyond current plans**. Model results suggest generation cost savings outweigh investment costs for additional network capacity beyond what is already planned. (Note that this work was carried out based on the prevailing NOA7 network plans. After the analysis was completed, the ESO published 'Beyond 2030', which includes significant additional network upgrades during the 2030s relative to the models used here.)

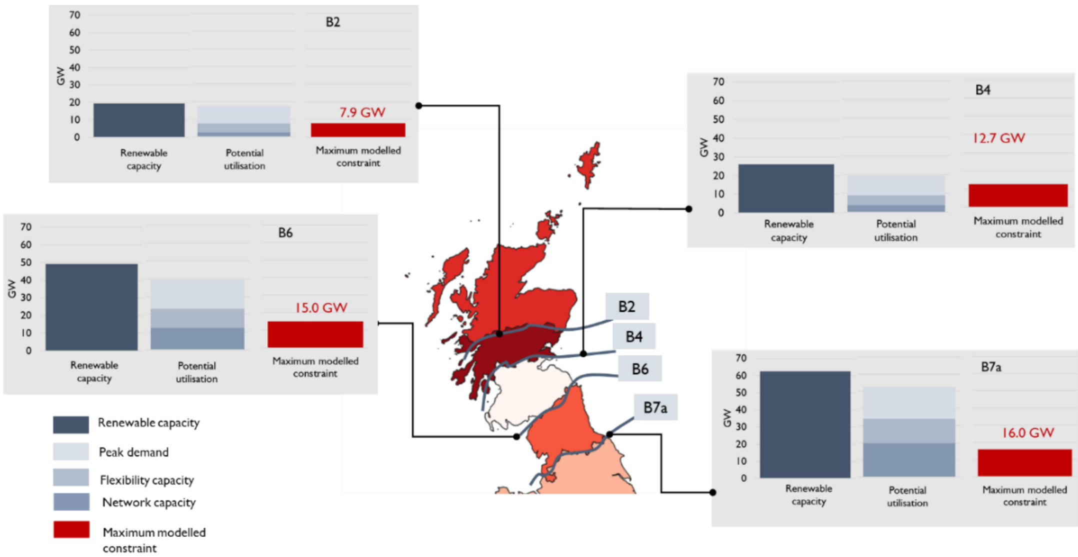


Figure ES12: Summary of capacities behind northern constraints and an indicative 'gap' calculation in the 2035. Renewable capacity, including onshore wind, offshore wind and solar. Flexibility includes storage, electrolysis and interconnector capacity. The maximum modelled constraint is taken from the copper plate study for the relevant year.

10. **Individual network investments are not made in isolation but need to be part of a coherent programme.** Build-out studies carried out for this report show that the need for a cascade of boundary upgrades is common with reinforcement of one boundary, revealing a need to upgrade another. There is also growing emphasis on strategic and spatial electricity and energy system planning from government, the regulator and NESO. It will be important that planning and regulatory decision making take a holistic approach, considering wide programmes for transmission upgrades and integrating these with other aspects of spatial energy system planning.

Branch Name	fromBus	toBus	Starting capacity (MW)	Branches reinforced over 50 iterations	Additional Capacity added (MW)	New Capacity (MW)
L1	northSHET	southSHET	6000		6000	12000
L2	southSHET	southScot	4400		7000	11400
L3	southScot	upperNorth	6600		9000	15600
L4	upperNorth	north	9500		8000	17500
L5	north	northMidlands	12000		5000	17000
L6	northMidlands	southEastMidlands	10320		0	10320
L7	northMidlands	southWestMidlands	2580		0	2580
L8	southWales	southWestMidlands	2900		0	2900
L9	southWestMidlands	southWest	1650		2000	3650
L10	southWestMidlands	south	3000		0	3000
L11	southWest	south	1650		1000	2650
L12	south	London	3000		1000	4000
L13	south	southEast	3000		0	3000
L14	southEast	london	5000		0	5000
L15	southEastMidlands	london	6628		4000	10628
L16	eastAnglia	southEastMidlands	4000		3000	7000
L17	eastAnglia	southEast	2000		3000	5000
L18	north	southWales	4000		1000	5000

Figure ES13: Interactive build out of the network found from an iterative network development algorithm starting from the 2022 network and the 2030 scenario with interconnection and electrolysis. The table shows the initial (2022) capacity together with the capacity added and the total capacity., highlighting reinforcement of one boundary triggers a need for reinforcement of another.

11. **Interconnectors are critical to managing curtailment levels.** If operated optimally from the perspective of the GB electricity market, they can significantly reduce curtailment. If interconnector capacity fails to materialise, or if once built they operate in a way that does not lead to the reduction of GB curtailment, the level of curtailment could be significantly higher.

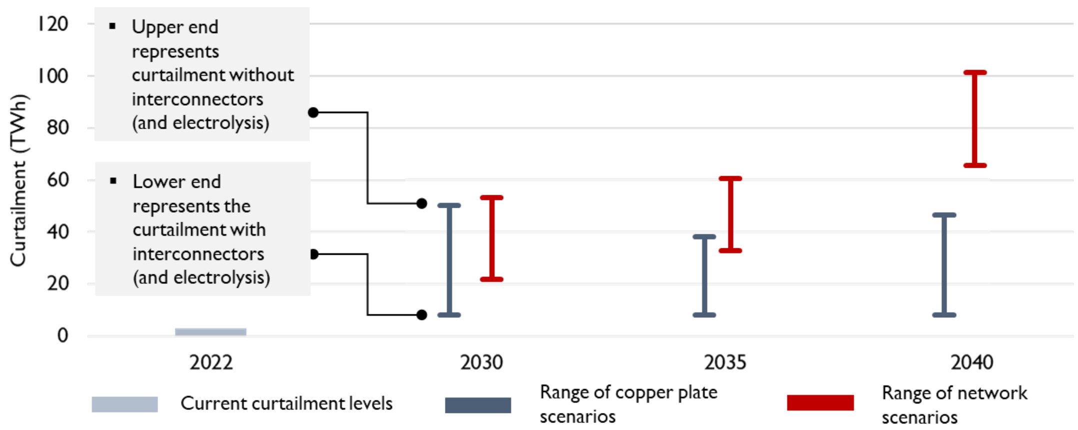


Figure ES14: Impact of interconnection on curtailment.

12. **Hydrogen electrolysis represents a potentially significant new and highly flexible demand for electricity.** It can be located behind network constraints and operated to reduce curtailment. For example, in 2035, 7.2 GW of hydrogen electrolysis is modelled to reduce curtailment by 13.4 TWh. Hydrogen is also used as a source of generation in a net zero power system and the two

have the potential to be linked. For this to be realised in practice, we will need a well-designed hydrogen system, including access to water resources and hydrogen storage.

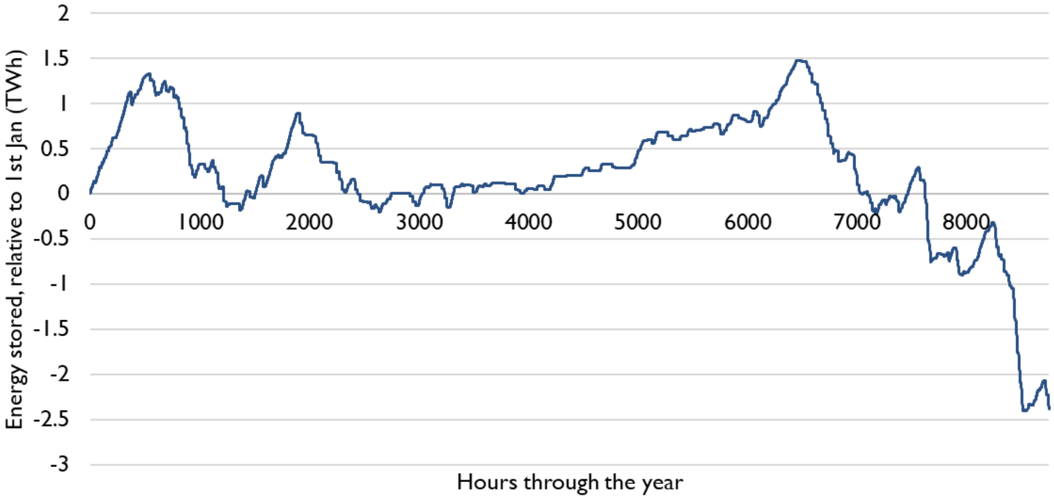


Figure ES15: Implied use of hydrogen storage because of operation of electrolysis (allowing addition of hydrogen to a store) and hydrogen power stations (drawing hydrogen from a store) in the 2035 network, with interconnectors, with electrolysis scenario.

13. **Electricity system energy storage (batteries, pumped storage) has a critical role to play in ensuring an operable and secure electricity system**. However, its ability to manage curtailment, particularly network-related, could be minimal. Network-related curtailment events in 2035 are modelled to have a median duration of 34 hours, well beyond the expected average energy export duration of this electricity-system energy storage.

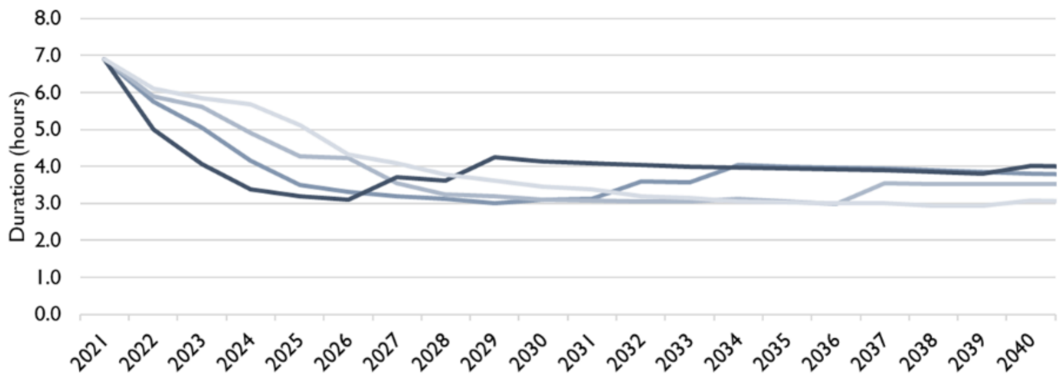


Figure ES16: The discharge duration of electricity system energy storage technology in FES2022. The drop in duration shows that more MW capacity is expected to be added than MWh capacity.

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