GAS GOES GREEN

A SYSTEM FOR ALL SEASONS

A HOLISTIC APPROACH TO DECARBONISATION

OCTOBER 2021

FOREWORD

We have made great strides in the journey to net-zero, but decarbonisation of heat represents possibly the greatest challenge we face as a nation.

We will need a mix of technologies to deliver net-zero, and so progress needs to be made on all fronts. Ensuring that our homes, businesses, and communities can access a choice of different technologies, is the best, least disruptive and most affordable way to do this. A one size-fits-all approach will not work.

It is crucial that the system we design around those technologies is not only capable of delivering that choice, but also capable of continuing to deliver the energy that people need at the levels of reliability that we enjoy today, for a reasonable price, to a set of expectations in terms of the work required in the home to transition away from natural gas and to ensure our businesses continue to be able to use the energy that is the lifeblood of our economy.

As a nation, we are blessed with an abundance of renewable energy resources. But to make the most of those resources, we need to ensure our energy system is designed to make the most of them when they are most available to us, to ensure that we can continue to reap the benefits of them on those days when the sun doesn't shine, or the wind doesn't blow, to keep our lights on, our homes warm and our businesses running.

To capitalise on them to the fullest extent, we need to think about how we design our decarbonised energy system holistically.

To do that, we need to build a System For All Seasons; a System that can meet the stretching demands of the coldest winter days but remain utilised for the rest of the year.

This report sets out the seasonal storage required by such a System, and identifies hydrogen as a key vector for the scale and duration of storage required. This in turn means that we need to progress both green and blue hydrogen integrated with technologies such as offshore wind, hydrogen boilers and heat pumps in order to be confident of meeting net-zero and the intermediary carbon budgets.

EXECUTIVE SUMMARY

We need a holistic approach to decarbonisation and a design for a net-zero system that delivers the same level of resilience that we enjoy today and maximises the use of installed capacity. Green hydrogen storage can complement variable renewable energy and help deliver a wind-based energy system that is both resilient and efficient. The analysis presented in this paper examines the resilience and efficiency of an energy system with and without access to seasonal storage.

The future energy generation mix will include a range of technologies such as nuclear, pumped hydro-electric storage, solar and biomass. However these technologies and resources are constrained by technical, physical or sustainability factors which means the future energy system will be largely based on wind.

There is a high degree of variability in wind generation which means that very often when the weather is coldest and heat demand highest, there is very little wind. Analysis of daily wind load factors across 2010-2019 winters shows that there are often sustained periods over several days where load factors are well below average. Additionally, there is an inverse correlation between solar generation and energy demand during the year. A net-zero energy system that is largely based on wind but includes no green hydrogen storage could be a viable solution for the warmer months from a system resilience perspective, but in colder months the amount of wind capacity required to meet demand and maintain resilience would be extremely high and therefore less efficient. Our analysis indicates that 500-600GW of installed wind capacity would be required to deliver a resilient energy system without green hydrogen storage.

Green hydrogen can be produced at times when renewable supply exceeds demand and unlike electricity it can be stored and discharged in large volumes for extended periods of time. Our analysis indicates that a system that includes green hydrogen storage would require significantly less amounts of installed wind capacity, in the range of 140 to 190GW and 115 to 140TWh of long-term storage via green hydrogen. Analysis of potential hydrogen storage facilities has shown that the UK has more than sufficient storage capacity to meet the the seasonal variations in demand for energy.

Overall this report concludes that a system that includes green hydrogen and seasonal storage is:

- **Resilient:** It provides confidence that there is sufficient energy available during cold winter days, when consumers need it the most
- **Efficient:** It maximises the use of installed capacity. Without seasonal storage, a significant amount of additional wind capacity would be necessary to meet the winter peaks, and it is likely that capacity would be unutilised for much of the year
- **Less disruptive:** It reduces the need for disruptive interventions in buildings that are not deemed suitable for electrification via electric heat pumps, and in the streets for network upgrades
- **More practical:** Without seasonal storage, a prohibitive amount of wind capacity would be necessary which would be challenging to deliver from a practical perspective
- **Cost-effective:** It can be delivered with minimal upgrades to existing infrastructure and it is all in all cheaper to deliver

Hydrogen is therefore the key enabler that allows a wind-based system to function effectively and is crucial to the creation of an energy system for all seasons.

SYSTEMS TRANSITION

In a net-zero system, the key energy sectors will no longer operate in silos and energy for all sectors will be derived from the same primary resources…

The rise of renewables and decentralisation of energy production has resulted in significant emissions reductions and led to structural changes in the power sector. But achieving net-zero requires emission reductions in other key sectors including buildings, industry and transport. The way energy is produced and delivered to consumers as well as the interaction between these sectors needs to change as the whole energy system goes through the transition.

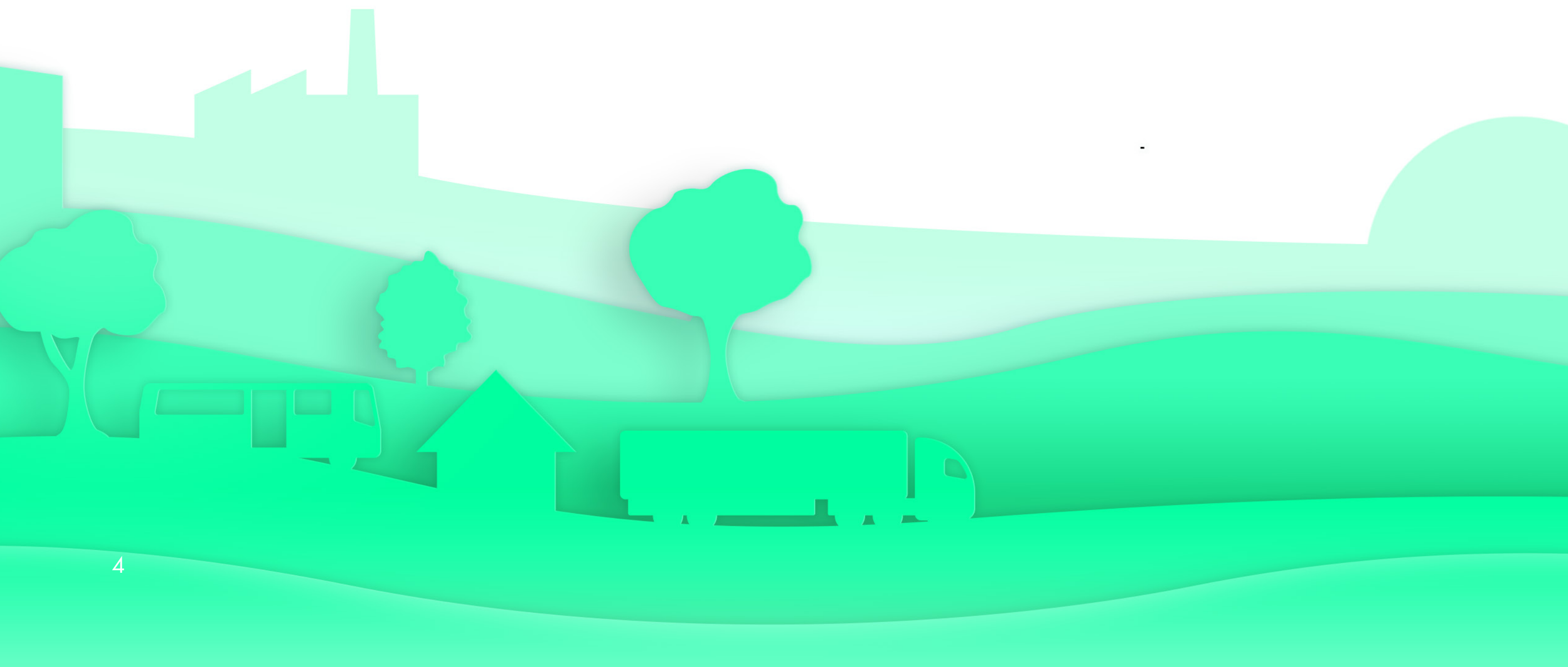
The energy system of today relies on three primary vectors, electricity, natural gas and petroleum to predominately satisfy our power, heating and cooling and transportation needs respectively. So far, the three sectors have operated in silos, (recognising that natural gas is also used for power generation) however moving away from fossil fuels means all our energy needs across the sectors will have to be met by the same set of primary resources and low-carbon technologies e.g. solar, wind, bioresources, nuclear, ambient heat and post-combustion capture.

Energy demand is seasonal, with peaks during winter and troughs during summer. This pattern is driven primarily by residential heating demand that is highest during cold winter days when consumers – both residential and non-residential – need to heat buildings, alongside power demand which is higher during the darker winter days, and to some extent transport where the less favourable weather drives those with a choice away from self-powered options. Equally, the reverse is true in summer as heat load drops in warmer days, power load reduces with lighter evenings and more to do outside, and transport benefits from a preference towards walking and cycling.

This coincidence of peaks and troughs across sectors means that in a world of similar primary energy vectors, the challenge posed by seasonality is exacerbated from today. Solving the decarbonisation challenge in this context is going to require a holistic whole systems approach, particularly in relation to ensuring that enough energy is available to meet peak demand and ensuring reliability is maintained, whilst minimising the excess of supply during troughs.

While moving to a fossil-free system will require radical and unprecedented changes at system level, the impact of the transition on consumers must be minimised and the quality of the services delivered to them maintained or improved. Importantly, we must design a system that considers not only the costs of producing and using energy but also the impact on customer experience. The customer impact and changes to the homes required for low-carbon heating technologies under different decarbonisation pathways was explored in the paper Decarbonising Heat in Buildings – Putting Consumer First[1]. In addition to the customer experience, it is imperative that the full costs of different decarbonisation paths – including the costs for preparing and installing systems in homes – are distributed such that no consumer is left behind, and that energy is accessible to all.

1 EUA, Leeds Beckett University et al (2021). Decarbonising Heat in Buildings – Putting Consumers First



RESOURCES AND CONSTRAINTS

The UK has access to vast natural resources. However, seasonal availability of some of these resources does not correlate well with demand…

The UK benefits from vast and diverse natural resources, particularly abundant offshore wind capacity. Additional wind capacity is anticipated to be built in the coming decades, with the Committee on Climate Change (the 'CCC') anticipating that up to 80% of total energy demand will be met by wind generation in 2050. The contribution of solar energy is also expected to increase to 85 TWh, or 15% of demand by mid-century.

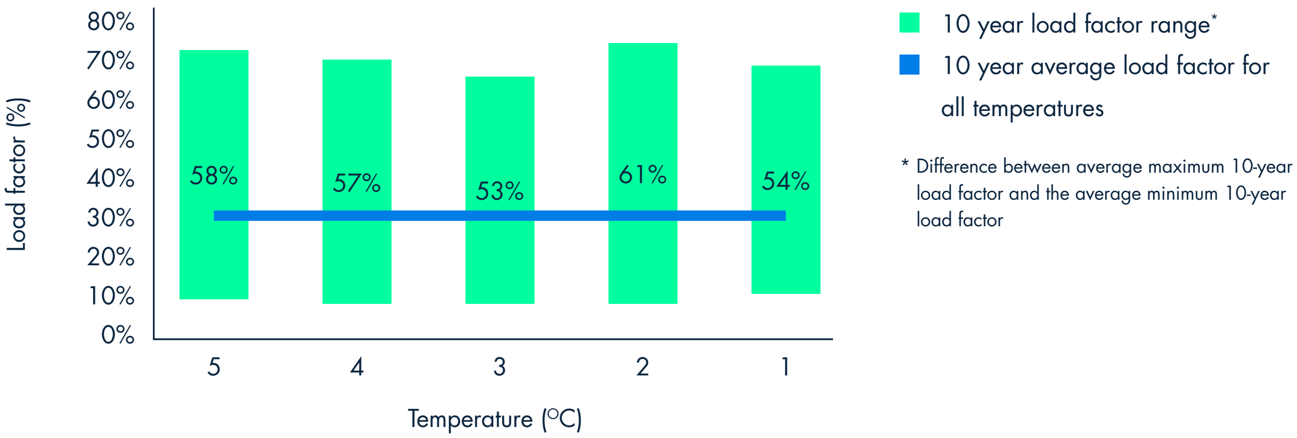
In addition, there is potential to grow nuclear, pumped hydro-electric storage capacity and energy from bioresources. However, there are physical and technical constraints to expanding conventional energy generation technologies such as nuclear and pumped storage and sustainability issues to consider that limit the potential of bioresources, which means that the energy system is going to rely largely on renewable resources such as wind and solar to satisfy the country's energy needs. A key issue with wind generation is that while it is plentiful, it is extremely variable, including at the point of highest energy demand when it is needed most.

Furthermore, there is a degree of inverse correlation between mean daily temperature and wind load factor. This is best articulated as the 'anti-cyclone' effect, or high pressure systems, which often occur in winter and are characterised by much lower than average temperatures, clear skies leading to frosty conditions and very little wind. Analysis of wind generation over the last ten winters, indicates that load factors are consistently below average at colder air temperatures, and that this is more prevalent as the air temperature drops towards zero. This phenomenon can last over long periods of time as for example in March 2021 when wind load factors dropped below 20% for eleven consecutive days. In short, this means that wind is typically less available during periods of high demand. Solar energy is more predictable than wind, however, solar output is lowest at the point of highest energy demand. Detailed analysis of wind and solar load factors is discussed in box 1.

BOX 1

Analysis of wind load factors between 2010 and 2019 indicates that the average wind load factor was 30% during that period. This is based on output from onshore and offshore wind plants across the UK. Chart 1 shows that at the average winter temperature of 5°C, load factors vary between 10% and 69%.

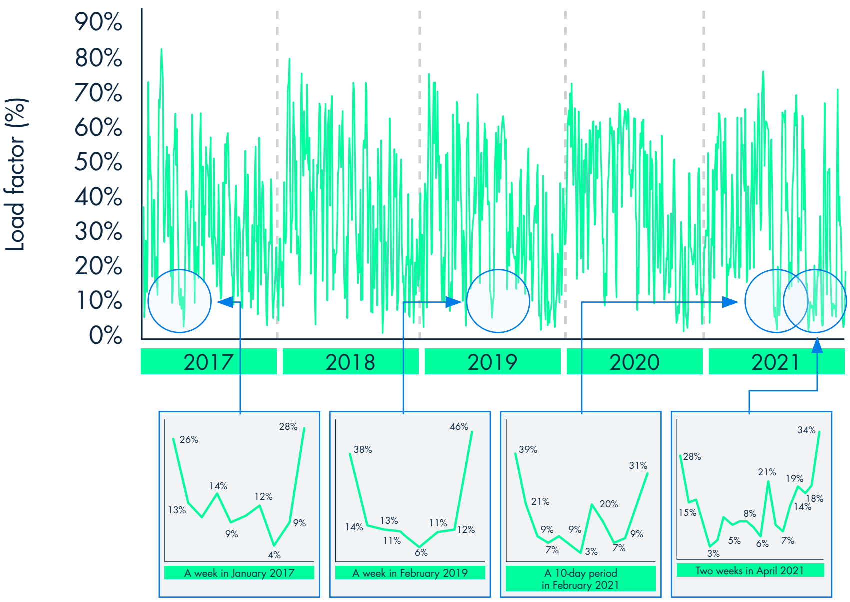
CHART 1: LOAD FACTOR VARIANCE ON COLD DAYS



The inference of this data is that **there is a high degree of wind load factor variability on cold days.**

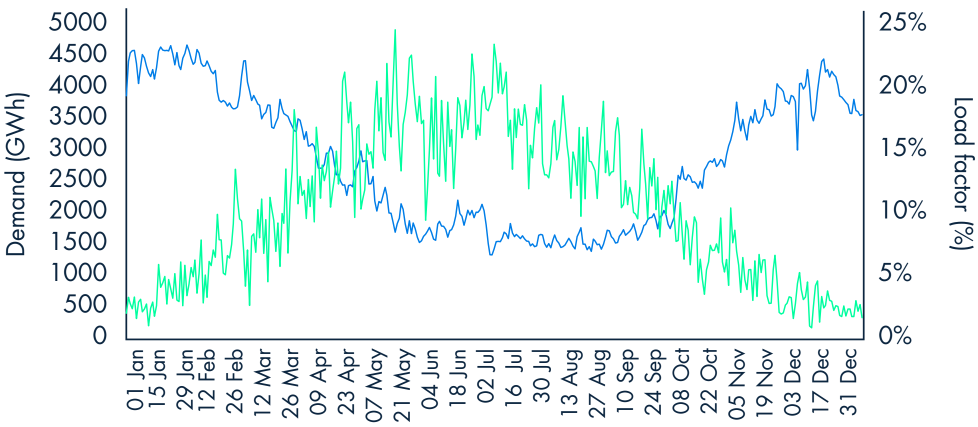
In addition, the period of low load factors can be significant. Analysis of daily load factors across 2010-2019 winters shows that there are often sustained periods over several days where load factors are well below average.

CHART 2: WIND LOAD FACTORS FROM DECEMBER TO APRIL



This means that **in every winter we can expect there to be periods of low wind.**

CHART 3: ENERGY DEMAND AND SOLAR LOAD FACTORS



** The demand profile shown in the chart is the combined average daily demand profile for electricity and gas for the last ten years – 2017 to 2019.

*** The solar PV load factors are the average daily load factors during the same period.

Comparing solar generation data between 2017 and 2019 with energy demand shows a clear mismatch between the two during the winter peak. This is because the availability and intensity of solar radiation in the UK is at the highest between May and September, when overall energy demand is at the lowest.

This means, somewhat intuitively, that whilst solar is more predictable than wind, it does not help with meeting the winter peak.

In summary, there is a high degree of variability in wind generation and the 'anti-cyclone' weather effect means that often when the weather is coldest and energy demand highest, there is very little wind. Additionally, solar generation is highest when the demand is lowest during the year.

Further detail on the analysis and methodology is presented in the technical appendix.

CASE STUDIES

A wind-based energy system may be the perfect solution on some days but is unlikely to be sufficient to ensure system resilience on others…

The energy system needs to meet net-zero emissions but also to be resilient and reliable. This means designing a system for all seasons, with sufficient generation available to meet our energy needs on every day of the year, including in the cold winter months, but not building so much generation that large amounts of production capacity are unable to be utilised for the rest of the year. It is helpful in this regard to think about some typical days in different seasons in the UK and how the system might need to be designed to ensure that demand can be met.

11TH – 17TH APRIL 2021

The week of the 11th – 17th April 2021 was a cloudy week in London with average temperature of 6.4°C and wind speed of 10 mph.

This translated into wind load factors between 3% and16% and on average load factor of 9%. This was below the average observed load factor of 32% over the year. Meanwhile, the average solar load factor during the week was around 20%.

Meeting energy demand from every consumer in 2050 during a week with these weather conditions with no access to dispatchable energy technologies would require ~1000GW of installed wind capacity.

This is if we assume that blue hydrogen would be available to meet demand from industrial clusters and that biomethane would be available for both transport and heating. The installed capacity requirement could be higher if the two solutions are excluded from the energy mix.

10TH – 16TH SEPTEMBER 2017

The week of the 10th – 16th September 2017 was a moderately cloudy week in Leeds with average temperature of 10°C and average wind speed of 21 mph.

This translated into wind load factors between 18% and 61% and on average load factor of 42%. This was above the average of 32%. Meanwhile, the average solar load factor during the week was around 12%.

Meeting energy demand from every consumer in 2050, during a week with these weather conditions in a system that includes non-dispatchable resource would be manageable given the availability of both solar and wind generation and the relatively low off-peak energy demand. The estimated required wind capacity would be ~60GW.

The case study days illustrate that a wind-based energy system could be a practical solution for the warmer months from an energy systems perspective, but in colder months the amount of offshore wind required to meet demand and maintain resilience is extremely high and would be challenging to install by 2050. It's important to remember that we need to design a system that can cope with the highest expected demand in a 20-year period, and **we cannot design a system that does not work during the coldest days of winter which is when access to reliable energy supply is most critical.**

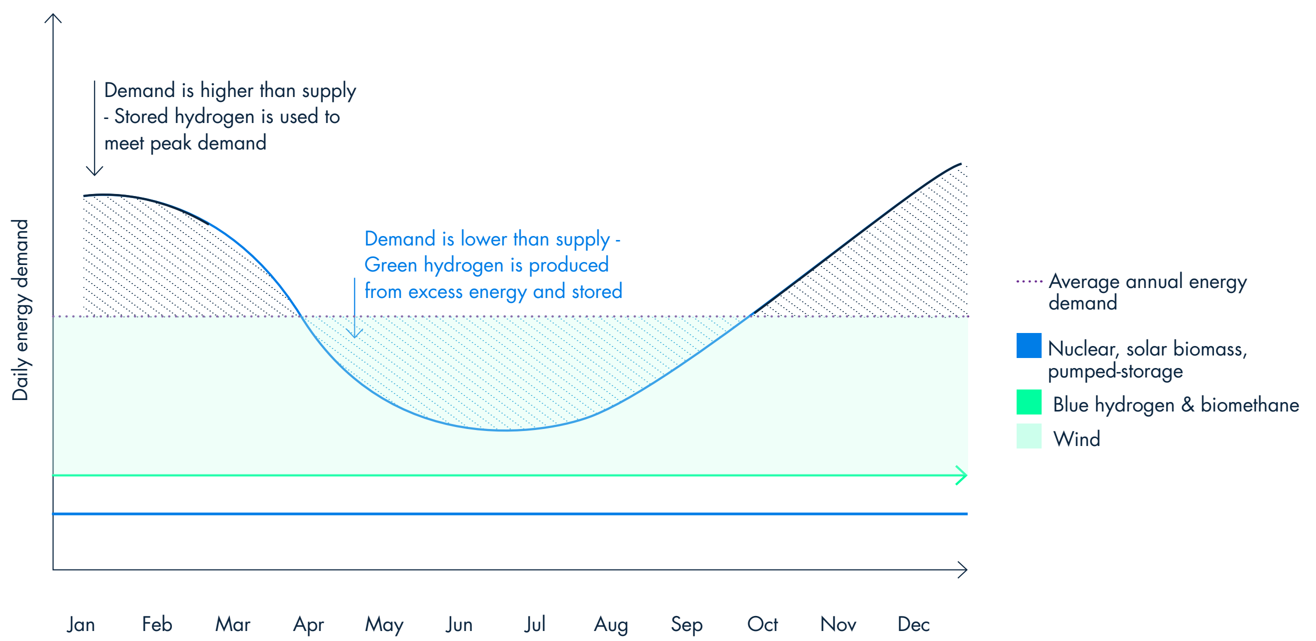
A SYSTEM FOR ALL SEASONS

Seasonal storage provides confidence that when demand is highest and generation from renewable sources is limited by natural constraints, there is sufficient capacity to meet the system requirements.

A net-zero system that relies primarily on wind generation but also includes seasonal storage is more resilient and maximises the use of installed capacity. This is because if seasonal storage is available, excess renewable generation - that would otherwise be unutilised for many months in the year – can be stored and discharged when energy demand is at the highest, typically during winter months. Chart 4 presents the energy mix in the optimised system.

To achieve the same level of resilience without seasonal storage, a significant amount of installed wind capacity would be necessary. Our analysis suggests that 500 - 600GW of installed wind capacity would be required to deliver the same level of resilience without energy storage. Installing such large amounts of wind energy would be challenging from a practical perspective and also inefficient as it is likely that it would be unused for much of the year.

CHART 4: ENERGY DEMAND IN THE OPTIMISED SYSTEM (ILLUSTRATIVE)



Seasonal storage brings two benefits. Firstly it reduces the overall amount of infrastructure that needs to be installed, and maximises the amount of utilisation of that infrastructure; and secondly it improves resilience as at the point of highest demand, most of the energy is coming from 'dispatchable' sources rather than 'intermittent' ones.

For the reasons discussed above, seasonal storage is a key component of an optimised energy system. While batteries are an effective way of storing electricity short-term, and other techniques such as load shifting can be used to flatten demand spikes within a day, there is currently no technology capable of storing electricity for entire seasons, or even a week. On the other hand, it is possible to store molecules, in the form of hydrogen for longer periods of time. Salt-caverns and disused oil and gas fields have the physical characteristics to store hydrogen long-term. Initial analysis of hydrogen storage sites indicates that the UK has sufficient capacity available to meet the seasonal variation in energy demand in an optimised system.

Our analysis indicates that the optimised energy system would require significantly less amounts of installed wind capacity, in the range of 140 to 190GW and 115 to 140 TWh of long-term storage via green hydrogen[2]. The optimised scenario also includes some blue hydrogen, which is produced and consumed primarily at industrial clusters. Biomethane plays a role to decarbonise heating in less densely populated areas.

Without seasonal storage it is going to be challenging to deliver resilience in a system that relies primarily on variable sources of generation such as wind and solar. The UK has more than sufficient storage capacity to meet the seasonal variation in demand.

BOX 2: DESIGNING THE END-STATE

This paper presents a possible version of a net-zero emissions end-state in 2050. The key constraint in the analysis is that in addition to being net-zero emissions, the energy system of the future must be resilient. This means that there must be sufficient generation to meet system energy needs from buildings, transport and industry, on every day of the year.

The shape and level of energy is projected to 2050, taking the Navigant Pathways[3] estimates as starting point. The shape of energy demand over the year is calculated based on the seasonal variation observed in the energy system over the last seven years.

There are a number of energy generation technologies which are limited by physical, technical or sustainability constraints and which capacity in 2050 is possible to forecast. This includes nuclear generation, pumped storage, bioresources and solar energy. The amount generated by these sources has been fixed in both scenarios and is set out on the right.

	ENERGY GENERATION MIX
NUCLEAR	220 - 270TWh
SOLAR	65 - 90TWh
PUMPED-STORAGE	5 - 7TWh
BIOMASS	15 - 30TWh
BIOMETHANE	50TWh
BLUE HYDROGEN	90 - 130TWh

The ranges reflect varying demand levels driven by different technology mixes at the consumer end. Blue hydrogen consumption will be used in larger amounts if there is an established hydrogen market and infrastructure across the country.

In the system that includes no green hydrogen, the remaining demand is met by wind generation. The wind capacity requirement is sized to meet the maximum daily energy demand. Meanwhile, in the optimised system, the wind capacity requirement is sized to meet average demand as above average demand is met by the low-carbon hydrogen produced during off-peak months.

	OPTIMISED SYSTEM	SYSTEM WITH NO GREEN HYDROGEN
WIND CAPACITY	140 - 190GW	500 - 600GW
GREEN HYDROGEN	60 - 80GW	-
BLUE HYDROGEN	25GW	15GW

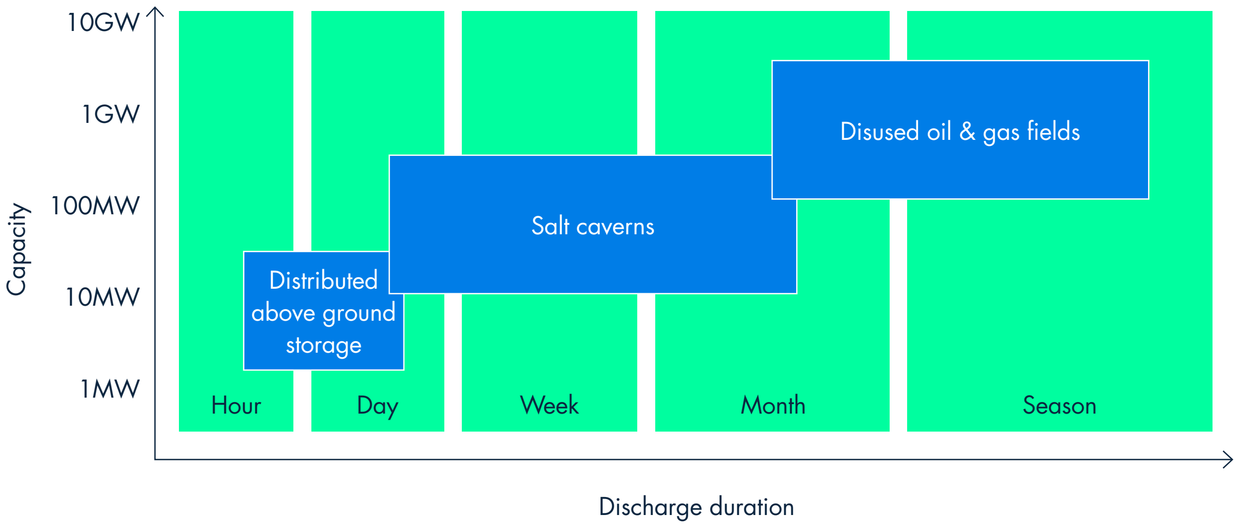
In the optimised system, the intra-day energy demand variation is met by grid-connected batteries and demand-side response.

2 Please note that the optimised energy system presented in this paper is only one scenario, there is optionality around the combination of wind production and storage capacity
3 Navigant (2019). Pathways to net-zero: Decarbonising the Gas Networks in Great Britain

BOX 3: HYDROGEN STORAGE POTENTIAL

Hydrogen can be produced from surplus renewables and unlike electricity it can be stored and discharged in large volumes for extended periods of time. Hydrogen storage technologies can provide several services ranging from the smoothing of daily peaks to storing excess renewable energy from summer months to utilise on a cold winter's day.

HYDROGEN STORAGE TECHNOLOGY GROUPS



The potential storage volume from salt fields ranges from >1TWh up to 30TWh based on each individual site consisting of multiple individual salt caverns. For disused oil and gas fields, the potential storage volume for individual sites ranges from ~1TWh up to 330TWh. **Overall our analysis suggests that there is sufficient hydrogen storage capacity to meet the variation in seasonal demand estimated in the optimised system.**

The wide range of storage potential for individual disused oil and gas sites is due to variations in the cavern size, the nature of the porous structure of the cavern, the pressure and temperature of the cavern, as well as the volume of natural gas that has been removed from the field. Scientific research to date has not revealed any insurmountable hurdles for delivering hydrogen storage in disused gas fields.

Salt cavern storage capacity is also largely dependent on the physical characteristics of the salt field including potential cavern size, salt field depth, and cavern pressure. A set volume of hydrogen (cushion gas) must also remain in the salt cavern at all times to maintain a stable pressure and protect the cavern structure which is dependent on the physical characteristics of each site.

The estimated levelised cost of hydrogen storage in disused oil and gas fields ranges from £16.7/MWh up to £80.8/MWh. The broad range for the levelised cost estimate is mainly driven by uncertainty surrounding the potential annual and total working volume of hydrogen that can be stored and delivered in each site. The analysis uses a conservative estimate for hydrogen storage capacity within disused gas fields assuming working gas volume of hydrogen is 50% of the working gas volume of methane.

MINIMISING DISRUPTION AND COSTS

The optimised system costs less to deliver, it is less disruptive and more equitable than a system without molecules…

Heat pumps are the primary decarbonisation route for heating in an energy system that includes no molecules. Independent analysis suggests that heat pumps are likely to be unsuitable for 37% to 54% of UK households and are only appropriate with the installation of highly disruptive and intrusive measures such as solid wall insulation. The optimised energy system introduces flexibility because it includes the option to install alternative heating solutions that run on hydrogen, in buildings that are unsuitable for heat pumps or would require disruptive measures to make the building heat pump ready.

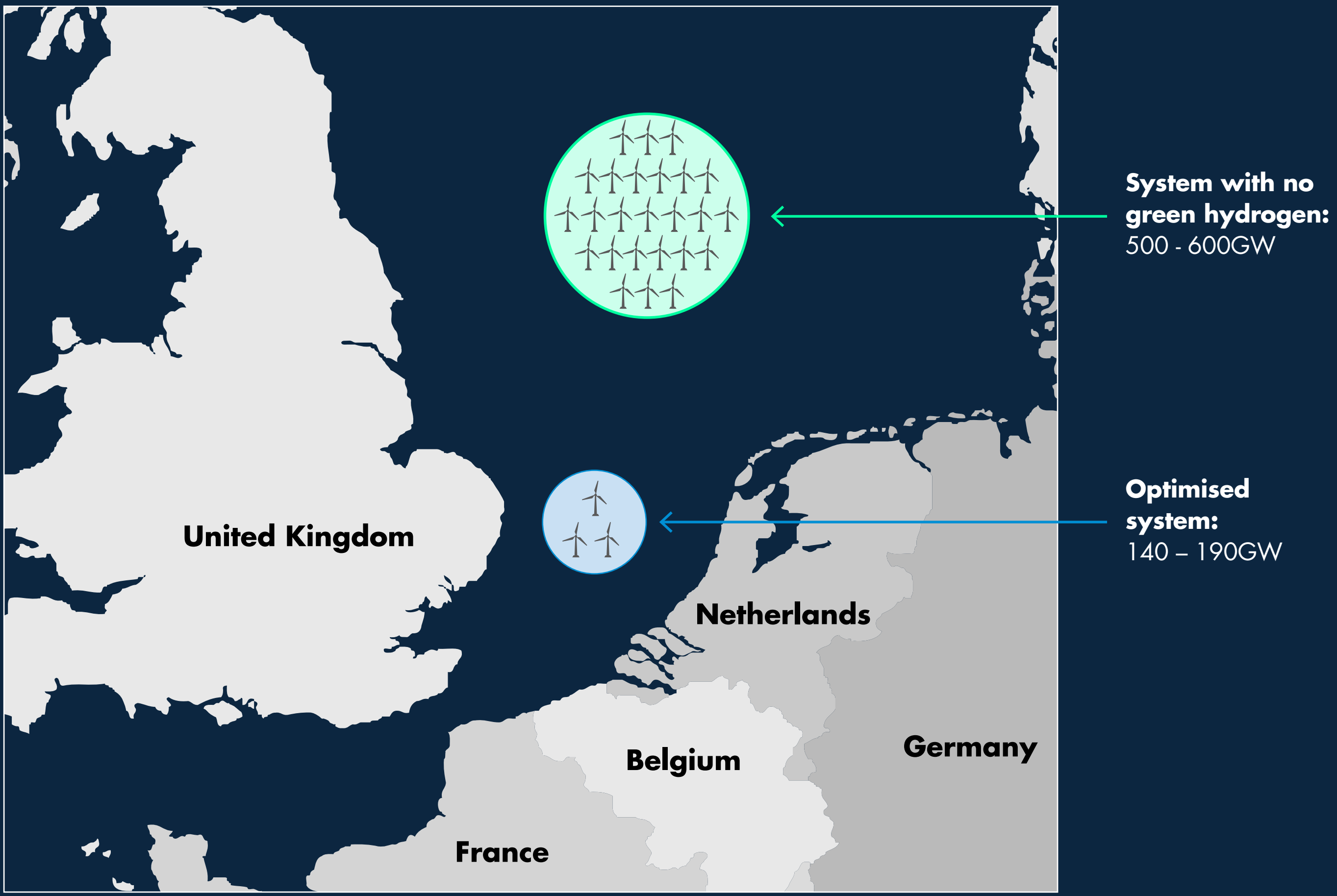
Installing a heat pump in buildings that are unsuitable to them would require costly interventions. While basic energy efficiency upgrades will be necessary independent of the heating system and should be installed in combination with every heating system replacement, more disruptive interventions such as radiator replacements, underfloor heating or solid wall insulation are only necessary for the efficient operation of a heat pump. Consumers that live in space-constrained and less modern homes are also more likely to be lower-income households and are also the ones that would have to incur the higher costs to make the building heat pump ready and install the technology. The optimised system not only reduces disruption but is also more equitable, as hydrogen-based heating systems do not need to be supported by the costly interventions needed to fit a heat pump.

Importantly, when energy production, storage and infrastructure costs are considered, the optimised system is cheaper to deliver than a system that includes no molecules. A recent paper prepared for BEIS estimates that the investment requirements to deliver the upgrades for the switchover to hydrogen networks would be around £50bn[4]. This estimate is at the high end of the range because it is assumed that the switchover would require entirely new transmission pipelines. In reality, preparing for the switchover is likely to require development of new transmission pipelines but also repurposing of existing ones.

Meanwhile, the integration of high amounts of variable generation without storage is likely to be more costly. A recent paper prepared for the CCC estimated that integration of wind and solar into the system would require cumulative investment of £50bn by 2035 for distribution network reinforcement[5]. This level of investment would support the integration of 80GW of wind and 54GW of solar, which suggests that significantly higher levels of investment will be needed to support the 500 to 600GW wind capacity estimated in this paper.

Our assessment of energy production and storage costs indicates that the optimised system and the one with no molecules would require similar new investment for the installation and operation of wind, green and blue hydrogen production and storage. All in all, when infrastructure costs are considered, the optimised energy system is cheaper to deliver than one that relies primarily on electrification.

4 Element Energy (2018). Hydrogen supply chain evidence base
5 Vivid Economics, Imperial College (2019). Accelerated electrification and the GB electricity system



BOX 4. THINKING ABOUT EFFICIENCY HOLISTICALLY

It is important to take a 'whole systems view' when thinking about efficiency too. We need to consider that in future the majority of primary energy producers will have no fuel costs, and hence the cost of energy in future will be much more correlated to the amount of installed capacity than the amount of energy used. In this world, system efficiency is about minimising the amount of infrastructure being built. This is an important shift in mindset, for example; there is an often referenced calculation that suggests that using a renewable electron to create green hydrogen for use in home heating is 6x less efficient than using that same electron to power a heat pump for the same purpose.

This is principally driven by an assumption that the heat pump is operating at a Coefficient of Performance (CoP) of 3 (e.g. it produces 3 times as much heat output as it consumes in electricity input), while the hydrogen boiler suffers from a number of conversion losses. It also makes the implicit assumption that there is a ready source of electrons when they are needed. These assumptions however are fundamentally flawed when considering the system operating at peak. This is because firstly, on a peak day the CoP of a heat pump is not 3. CoP is correlated to outside air temperature, so on the coldest days of the year, CoPs will be closer to 1. Secondly, as discussed in this report, at the point of peak demand, there is a shortage of electrons, meaning that increased generation capacity would need to be installed to meet that demand.

There are also a number of other assumptions in the calculation that are open to challenge but more fundamentally the calculation itself is not the right way to think about the concept of efficiency as it takes a narrow definition that is not reflective of the current or future operating requirements of the system.

Rather than thinking about efficiency in the abstract sense in terms of the journey of electrons in absence of real world constraints, it is instead better to think holistically about the total amount of infrastructure required to deliver the energy outcomes consumers want, at the point in time they want them. When we think of efficiency in this way, an optimised system that includes hydrogen for heat is much more efficient than a highly electrified system.

We need an optimised system that includes green hydrogen production and long-term storage to maximise the use of installed capacity and deliver system resilience. Without green hydrogen production and storage, a prohibitive amount of wind capacity would be needed to have enough confidence that there is sufficient generation available when demand is highest.

CONCLUSION

The energy system of the future needs to meet net-zero emissions but also to be resilient. This will not be easy to achieve in a system where the key sectors no longer operate in silos, but become intertwined and rely on the same primary resources.

There is the option to maximise existing capacity and increase resilience, by integrating green hydrogen production and seasonal storage into the system. Without this option, a significant amount of wind capacity – 500 to 600GW - will be needed to be confident that there will be enough capacity to satisfy energy system requirements.

The optimised energy system discussed in this paper not only is more resilient than a system with no green hydrogen, but is also less disruptive as it introduces flexibility to install heating systems that run or have the option to run on hydrogen as well as electricity. In addition, it is also more equitable, as it ensures that affordable, and comfortable heating systems can be installed in all property types.

From a cost perspective, when infrastructure investment is considered, the optimised energy system is cheaper to deliver than a system which assumes near full electrification. This is because the transition to hydrogen networks does not require the same level of investment needed to accommodate high penetration of variable generation but can be delivered mostly with minimal upgrades to existing pipelines.

TECHNICAL APPENDIX

WHOLE SYSTEMS ANALYSIS

The first step in the whole-system analysis was to estimate daily energy demand from power, heating, transport and industry and the energy generation mix in 2050. A range of sources including Navigant Pathways report, the Committee on Climate Change budgets and National Grid Future Energy Scenarioswere used to estimate these.

Daily variations in energy demand were obtained from National Grid ESO and National Grid Gas databases. The energy supply from nuclear power, biomass, solar, pumped hydro-electric storage, biomethane and blue hydrogen were assumed to be uniform throughout the year. Solar generation was estimated to follow the load factor variations typically observed during the year.

In the energy system with no seasonal storage, remaining demand is met by wind generation. Wind load factors are used to estimate the installed capacity that would be required to guarantee system resilience throughout the year. Because there is no access to long-term storage, the wind capacity is sized to ensure sufficient wind generation is available to meet energy demand during the coldest winter days, when wind load factors are at the lowest and demand is at the highest.

Similarly, in the optimised energy system, remaining demand is assumed to be met by wind generation. However, in this case wind capacity is sized such that there is sufficient generation available to meet average energy demand during the year and that there is sufficient excess generation that can be stored during the summer months for use during the winter peak. In contrast with the system that includes no seasonal storage, installed wind capacity does not need to be sized to meet the winter peak demand, because access to seasonal storage provides resilience to the system.

The required wind capacity, green and blue hydrogen as well as seasonal storage are costed, assuming a gradual increase in capacity between 2021 and 2050.

BOX 5. WIND LOAD FACTORS

Wind load factors are a key input to the whole-system analysis. They are not readily available on a daily basis and were estimated using a combination of data sources that cover the years 2010 – 2021.

Half hourly wind generation data was sourced from Elexon, while the installed wind capacity was sourced from BEIS. Wind capacity data is reported on a quarterly basis. The ratios of wind generation to installed capacity were initially calculated on a half hourly basis and then averaged to estimate a daily average.

The average of the daily averages was estimated on an annual basis and the percentage deviations from this annual average, calculated for each day of the year. In the last step, the percentage deviations were applied to the average annual load factors reported by BEIS to derive the daily load factors used in the analysis.

The results of the analysis presented in this paper are based on the load factor variations observed for the average year based on the 2010 – 2021 time series.

STORAGE CAPACITY METHODOLOGY

METHODOLOGY FOR CALCULATING DISTRIBUTED HYDROGEN STORAGE CAPACITY

The total storage capacity for distributed hydrogen storage facilities (low and high pressure tanks) is calculated based on the total mass of hydrogen gas that can be stored in the tanks. Storage of uncompressed hydrogen is comparatively inefficient in terms of land use per unit capacity and high pressure tanks are able to achieve a higher mass in kg per m^3 of storage capacity.

The total mass of hydrogen that can be stored in the tanks is converted to an energy value in MWh based on the energy density per kilogram of hydrogen stored.

METHODOLOGY FOR CALCULATING GEOLOGICAL HYDROGEN STORAGE CAPACITY

In order to determine the total hydrogen storage capacity of large-scale storage facilities such as depleted oil and gas field and salt caverns, it is necessary to understand the maximum volume of methane gas that can be stored in the space and the density with which it can be stored before converting to a hydrogen gas equivalent. The total volume of hydrogen gas that can be stored in a facility is dependent on the size excluding a set portion of the facility to accommodate a 'cushion' of methane gas that must sit at the bottom that ensures the structural integrity of the site.

Starting with the total volume of methane that has been taken out of a disused field, we can find the equivalent amount of H2 that could be injected into the field. Disused oil and gas fields require further adjustment to find the total amount of hydrogen that can be stored such as hydrogen has different physical properties which limits the actual amount that will fit into the porous structures of the facility. Having consulted with experts in the field of hydrogen storage, we have assumed a 50% reduction in the volume of the facility relative to the methane volume that can be occupied by hydrogen and the the high levelised cost of storage (LCOS) scenario is based off a 90% reduction in available volume.

After adjusting for these factors, the total amount of energy from hydrogen that can be stored by each facility can be calculated by taking the available volume that can be used for methane gas storage and converting this to the hydrogen gas equivalent that can be stored. The total mass of hydrogen gas that can be stored is dependent on the temperature and depth of the cavity below the surface which informs the level of pressure under which the gas is stored in the facility which dictates the density of hydrogen gas that can be stored per m^3 of available storage. The total mass of hydrogen gas in kilograms is finally converted to an energy value in MWh based on the energy density per kilogram of hydrogen.

LEVELISED COST OF STORAGE METHODOLOGY & ACKNOWLEDGEMENTS

METHODOLOGY FOR CALCULATING LEVELISED COST OF STORAGE

In order to calculate the LCOS per MWh, it is necessary to calculate the total energy value of hydrogen gas that is stored and released over the course of each year that the storage facility is operating alongside the total capital and operating, expenditure over the lifetime of the asset and discount the values to the present day.

The total energy value of hydrogen that is stored on an annual basis is calculated by dividing the total annual mass of hydrogen gas cycled through the storage by the energy density per kg of hydrogen. The total mass of hydrogen that is cycled on a annual basis is dependent on the number of days that the hydrogen storage is utilised over the course of the year and the maximum daily volume that can be cycled in and out of the storage.

The maximum daily volume that can be cycled into and out of the hydrogen storage depends on the physical characteristics of the storage technology used which dictates the safe amount of gas that can be cycled on a daily basis. For distributed storage, storage tanks can be fully cycled from full to empty on a daily basis with the ability to cycle twice or more if required whilst for geological storage, the maximum daily volume that can be cycled for salt cavern storage is limited to 5-10% of the total storage capacity in order to maintain the structural integrity of the facility. For disused oil and gas facilities, the volume will vary from field to field, but it is assumed the facility can cycle its full volume annually.

Capital expenditure is composed of the costs of setting up the hydrogen storage facilities with higher pressure storage options requiring one or multiple compressors to force the hydrogen into storage at the required pressure as well as piping to reach the storage with offshore geological storage facilities requiring extensive pipework.

Operating expenditure for hydrogen storage is mainly composed of the costs to cycle hydrogen in and out of the storage with higher pressure storage requiring compression with particular sensitivity to the input power price used for the compressor. The extent of this is dependent on the level of pressurisation required with low pressure tanks requiring no compressor which allows the technology to achieve the highest round trip efficiency out of the hydrogen storage options.

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