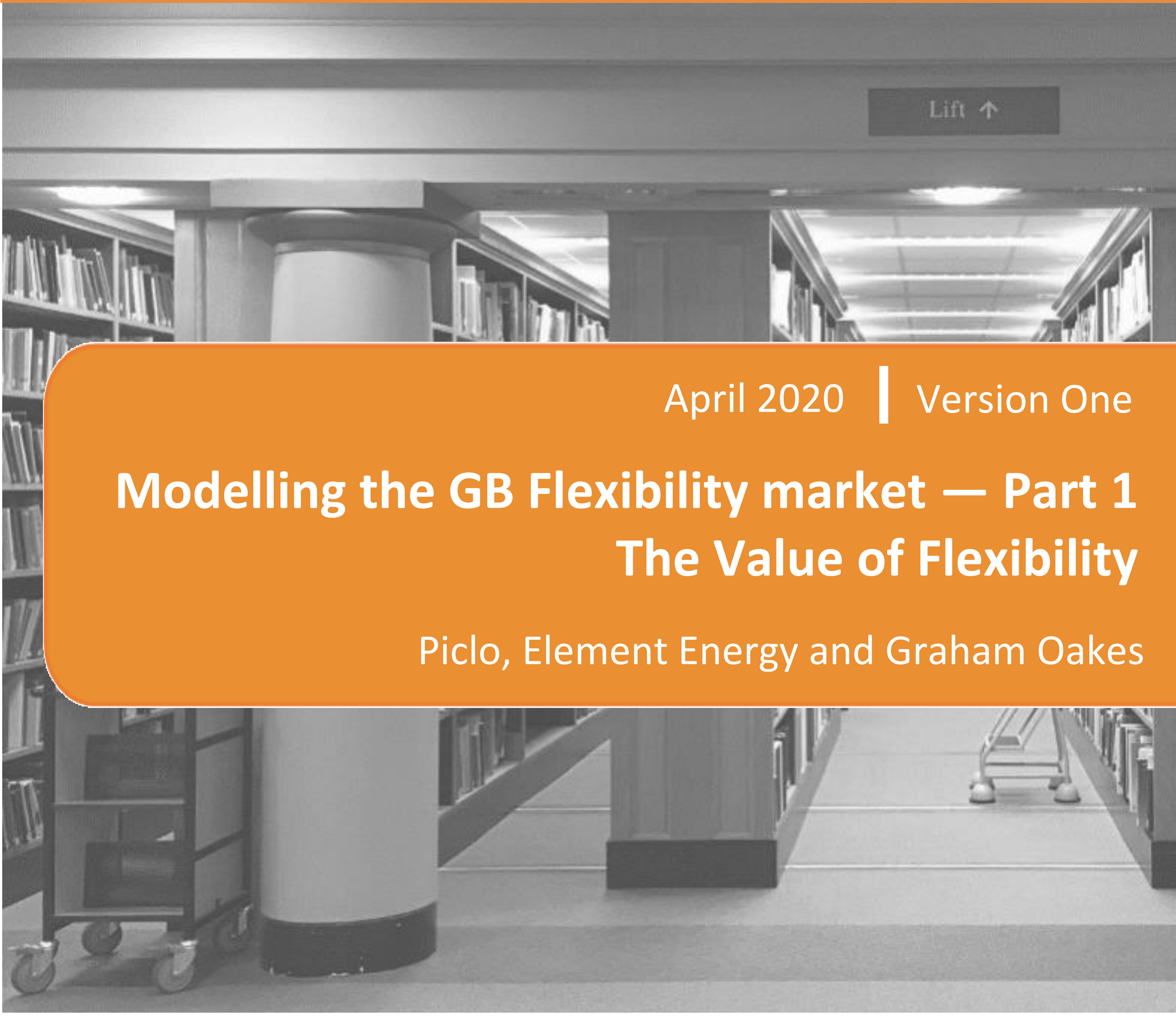
LEO Local Energy Oxfordshire



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Modelling the GB Flexibility market — Part 1
The Value of Flexibility

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Scottish & Southern Electricity Networks · piclo · EDF Energy · NUVVE · Industrial Strategy

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Executive Summary

This study set out to assess the value and whole-system impact of demand-side flexibility in a net-zero carbon energy scenario for the UK. Our analysis has produced the following key results, which are discussed in more detail in the body of the report.

1. Hitting net-zero requires significant investment in low-carbon generation, demand-side technologies (electric vehicles (EV), heat pumps, etc.) and electricity network capacity. The modelling showed that flexible demand will have a significant impact on system capacities and operation.

2. The modelling showed that a 'passive' approach to demand management represents the most expensive decarbonisation configuration in 2050. It also requires the greatest investment in expanding generation and network capacities over the same period. From a cost and feasibility perspective, continuing with a business-as-usual approach represents a higher cost and higher risk pathway than those which incorporate more flexibility.

3. Compared to a passive approach, flexibility can reduce the whole-system cost by £4.55bn per annum by 2050, through a combination of operational improvements and reduced capacity investments. Wider deployment of energy storage systems, either grid-scale or distributed, could extend this benefit to £5.0bn per annum.

4. Compared to the passive approach, flexibility is not only fundamental for achieving a viable capacity build-out to 2050 but delivers benefits across the power system characterised by:

    a. Reduced investment in and utilisation of expensive peaking plants (~15GW reduction).

    b. Reduction of dispatchable generation by 22TWh per annum.

    c. Reduced curtailment of low marginal cost renewable generation by 30TWh per annum (a 7% increase per annum in renewable energy system output).

d. Reduced network investment. Instead of the estimated 30GW capacity expansion required in a passive growth scenario, flexibility options could cost-effectively reduce network reinforcement by up to two-thirds.

It will be easier to monetise operational savings (such as fuel savings), but to avoid high-value network expansion investment, flexibility will need to mature and represent a proven asset.

5. Decarbonising the power grid with variable renewable energy sources (VRES) expands the market for flexible services. Deployment of flexibility and renewable energy sources is synergistic and should be part of any coordinated plan to achieve net-zero.

During the course of this study we noted that the capabilities of demand-side response (DSR), grid-scale storage and V2G technologies overlap, which will lead to competition between them. An accompanying report, "The Value of Centralised and Distributed Storage", examines some of the path dependencies and risk/reward trade-offs this may create.

1. Introduction

We know that the implications of demand-side response in a decarbonised energy system can be profound. Existing research has outlined the imperative for flexibility on the demand side in a decarbonised system that's based on variable renewable energy sources[1] (rather than nuclear). And other studies have illustrated that flexibility is a key determinant between the lowest and highest cost net-zero electrification pathway[2].

However, there are some limitations in prior work in this sector which we sought to address in this report. Firstly, the extent of demand-side flexibility is often assumed, for example expressed as a percentage of peak or daily demand. This approach fails to reflect the attributes and environment of flexible assets and the characteristic behaviour, if applicable, of consumers.

In this study, we took the approach of basing flexibility potential on real-world principles such as typical demand for electric vehicles and daily mileage and desired temperature of homes and buildings that are affected by heat loss and weather patterns. The level of flexibility delivered then emerges from the system analysis. This type of simulation improves our confidence in predictions for the scale of flexibility that's available from space heating and transport for example.

Secondly, many studies do not place equivalence on flexibility from supply and demand in managing power grids. This study deploys a whole-system model which couples demand and supply to test the scope for flexibility to optimise network asset utilisation and investment. The approach encompasses generation, networks, and flexible and inflexible demand from multiple sectors.

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[1] Power sector modelling: System cost impact of renewables Report for the National Infrastructure Commission, Aurora Energy, 24 May 2018

[2] Towards fossil-free energy in 2050, conducted by Element Energy and Cambridge Econometrics, March 2019

A variety of flexibility scenarios were developed to test our assumptions. These were based on a net-zero model that was built upon National Grid's Community Renewables scenario[3], modified to incorporate flexible assets such as smart EV and heat, utility-scale battery storage, and vehicle-to-grid (V2G) technology.

A whole-system model, including dispatchable and variable renewable generation sources, network- and demand-side, was created to identify the realistic potential and optimum contribution of demand flexibility to reduce whole-system costs.

The objective of this analysis was to estimate the full potential for flexibility from smart demand management in a decarbonised electricity system. By exploring the potential for flexibility at scale, we set out to understand the value - for economic and system benefit - of investing in flexibility services now.

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[3] National Grid, Future Energy Scenario - Community Renewables 2019

2. Flexibility scenarios and modelling approach

2.1. Creating a net-zero Baseline Scenario

To isolate the scale and impact of flexibility on the energy system, we drew upon a widely-available scenario for decarbonisation, National Grid's Community Renewables model from the 2019 Future Energy Scenarios (FES)[4].

We chose this scenario as the basis for our analysis because it achieves the 2050 decarbonisation target in a decentralised energy landscape and includes assumptions for a high degree of energy efficiency, which is required to achieve efficient net-zero carbon residential heating.

However, although Community Renewables incorporates participation and activity on the demand side to manage the grid, the scenario is not zero-carbon (the scenario reaches an 80% emissions reduction target by 2050).

To remedy this, adjustments were made to remove fossil fuels from supply and end-use technologies, as outlined below. Henceforth, we refer to the net-zero Community Renewables scenario as our Baseline scenario.

Adjusting demand to net-zero

The Community Renewables scenario assumes 5.2m natural gas boilers in 2050. These must be replaced with zero-carbon heating systems for a fossil-fuel free scenario. To adjust the demand, we built on recent analysis undertaken for the Committee on Climate Change (CCC) for residential heating that meets net-zero carbon targets[5].

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[4] Future Energy Scenarios 2019, National Grid, July 2019

[5] Net Zero Technical report, Committee on Climate Change May 2019

In our model, natural gas boilers are replaced with a mixture of air source heat pumps (ASHP), powered by electricity and hybrid heat pumps which combines a heat pump and gas condensing boiler to optimise energy efficiency. This implies a requirement for decarbonised gas (Hydrogen H2), which, compared to a scenario comprised of electric heat pumps only, already incorporates a degree of flexibility in heat demand related to the shiftable demand associated with the production of hydrogen gas.

The original and final configuration is illustrated below, and the CCC central scenario is included for reference.

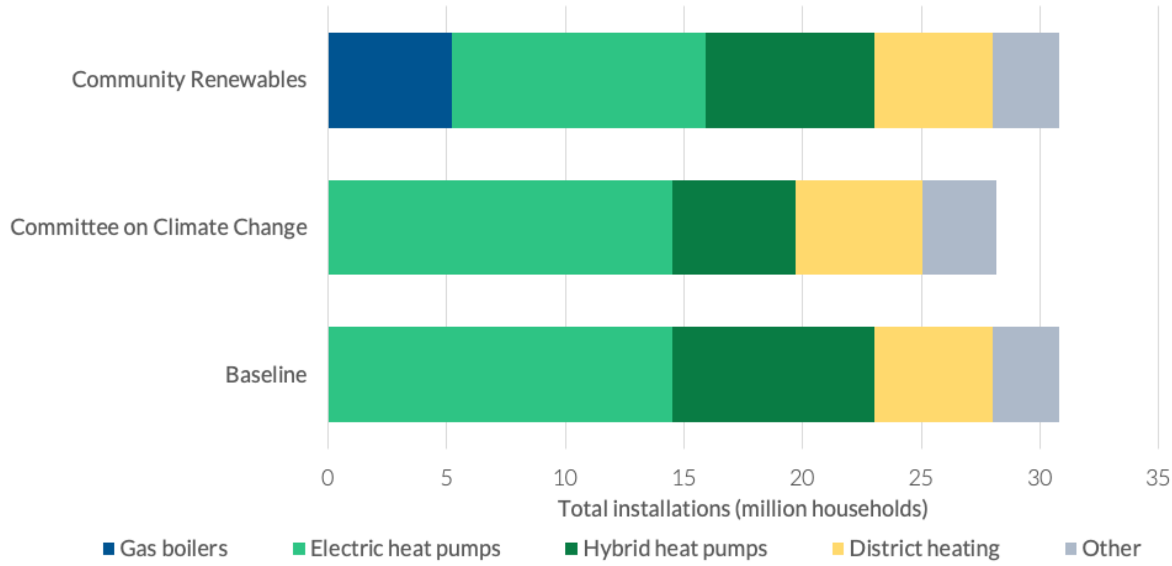


Figure 1: Comparison of heat demand scenarios in 2050, including our Baseline scenario.

Adjusting supply

The Community Renewables scenario retains capacity from fossil-fuel thermal power plants to provide supply flexibility in the form of backup dispatchable generation.

In the adjusted scenario, biomass and carbon capture, utilisation, and storage (CCUS) power plants are used to provide dispatchable generation capacity as an alternative to thermal power plants.

Reducing reliance on dispatchable low-carbon thermal altogether would increase system reliance on demand flexibility above the figures estimated in this report.

There is an increase in underlying demand due to the deployment of heat pumps to displace gas boilers. Consequently, supply capacities are adjusted upwards to maintain the share of renewable generation in the system.

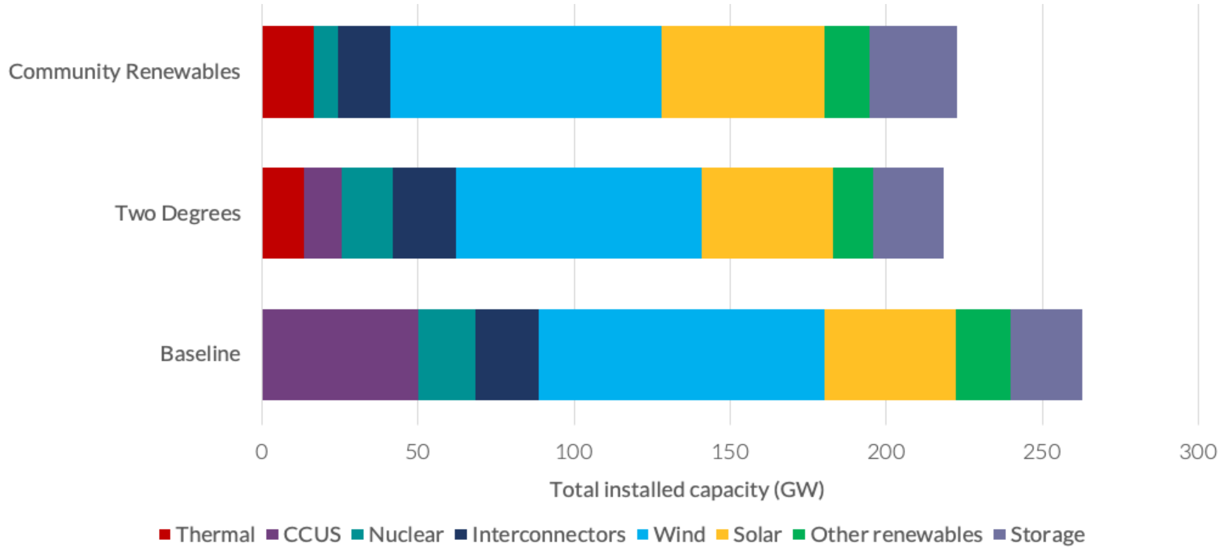


Figure 2: Comparison of projected energy supply scenarios in 2050.

2.2. Flexibility Scenarios

The Community Renewables 2050 scenario includes a range of flexibility assets, assuming a high level of consumer engagement and much-improved building efficiency. The flexibility sources included are:

- Industrial and Commercial (I&C) DSR of 6.7 GW (~14% of peak demand)
- Residential DSR of 1.6GW, including district heating (~5% reduction of peak demand)
- Smart EV charging (~50% reduction in peak demand)

- V2G generation (2.9m vehicles providing 10GW contribution at peak)

- Grid storage (28GW contribution at peak, including 40GWh from utility-scale battery storage and 91GWh pumped-storage hydroelectricity)

Baseline

In our Baseline scenario, the underlying level of DSR flexibility from I&C and residential electricity (non-heat related) outlined above are unchanged. However, contributions from smart EV charging, grid storage and V2G generation are removed.

These changes leave a demand side comprised of largely passive electric transport and electric heating that represent a continuation of business as usual.

In the following flexibility scenarios, we modify the remaining sources of flexibility to adjust peak demand and supply.

Basic Flexibility

Smart EV charging (but not V2G) is dispatched dynamically. The starting point is the passive daily demand profile where drivers plug in their vehicles to charge when they arrive home. In our Smart scenario, charging demand is adjusted for system benefit, while ensuring vehicles achieve the required state of charge in the morning.

Smart heat: electricity consumption from space heating is adjusted dynamically for system benefit while ensuring target internal heating temperatures are met.

A small percentage of Industrial and Commercial demand flexibility is added (5%).

Grid Storage

Smart EV and heat are adjusted dynamically as outlined in the Basic Flexibility scenario.

Utility-scale battery storage is deployed to a level where the marginal economic cost equals the marginal system benefit. This is deployed in addition to smart EV and heat so the economic level of battery deployment is lower than if these other flexible assets were absent.

Vehicle-to-Grid

Smart EV and heat are adjusted dynamically as outlined in the Basic Flexibility scenario.

Distributed storage within EVs is deployed as outlined in the Grid Storage scenario. In addition, V2G deployment (i.e. switching from a smart charger to V2G) is increased to the point at which the marginal cost is equal to the marginal system value gained by deployment.

We developed separate scenarios to explore how the dispatch and control of V2G can impact the service provided. V2G assets are modelled providing two distinct services to the power system, either by operating in a generation capacity avoidance or network-responsive mode.

- V2G gen - 75,000 generation-optimised electric vehicles (generation capacity avoidance mode)

- V2G net - 7million network-optimised electric vehicles (network-responsive mode)

2.3. Modelling Approach

Integrated Supply Demand Model (ISDM) is an energy model that was developed to determine the optimised configuration and operation of power systems with high penetration of renewable energy sources to ensure the security of supply.

For the purpose of this report, ISDM was selected because it operates as a whole-system model which includes the dispatch of generation assets (to abide by network constraints), and demand-side flexibility where available. It includes a range of flexibility assets, and the degree to which associated demand can be shifted, as shown below.

Heat pumps	**Up to one day**
Electric vehicle charging	**Typically one day, or optionally over several days**
District heating and resistance heating	**Up to one day**
Flexible power applications	**Up to one day**
Storage (batteries)	**Several days**
Power to gas	**Weeks or months**

Table 2: Time period by which flexible demands can be shifted.

ISDM allows us to project the availability of flexibility based on the demand assets themselves and their environment. This factors in the attributes of the assets to ensure adequate service delivery. For example,

- Flexibility from EVs accounts for daily driving demand, alongside EV efficiency and battery size.

- Flexibility from space heating factors in both the target temperatures of buildings and attributes such as the fabric of building and heat loss, as well as the local environment (e.g. hourly outdoor air temperatures).

This sophisticated simulation of the demand side means that flexible demand assets can be dispatched dynamically in the model to reduce overall system costs.

3. Key results

3.1. Flexibility reduces network investment to 2050 by 50%

Our Baseline is the Community Renewable scenario adjusted for net-zero emissions, in which supply accommodates a largely passive demand side. This reveals a net-zero pathway with 465TWh of consumption.

The electrification of heating with heat pumps and electric heat (night storage heaters) as well as transport adds a significant additional component to electricity loads, reaching a projected peak network demand of 91GW. This represents an increase of circa 30GW peak demand in 2050 - more than a 50% increase from today's level of 60GW.

Electrolyser demand associated with hydrogen-based transport and heating are also shown in Figure 3. However, there is potential to shift this demand away from the morning and evening peaks and into the overnight period, reducing the need for network investment to accommodate this additional demand. Consequently, it need not count towards the system peak.

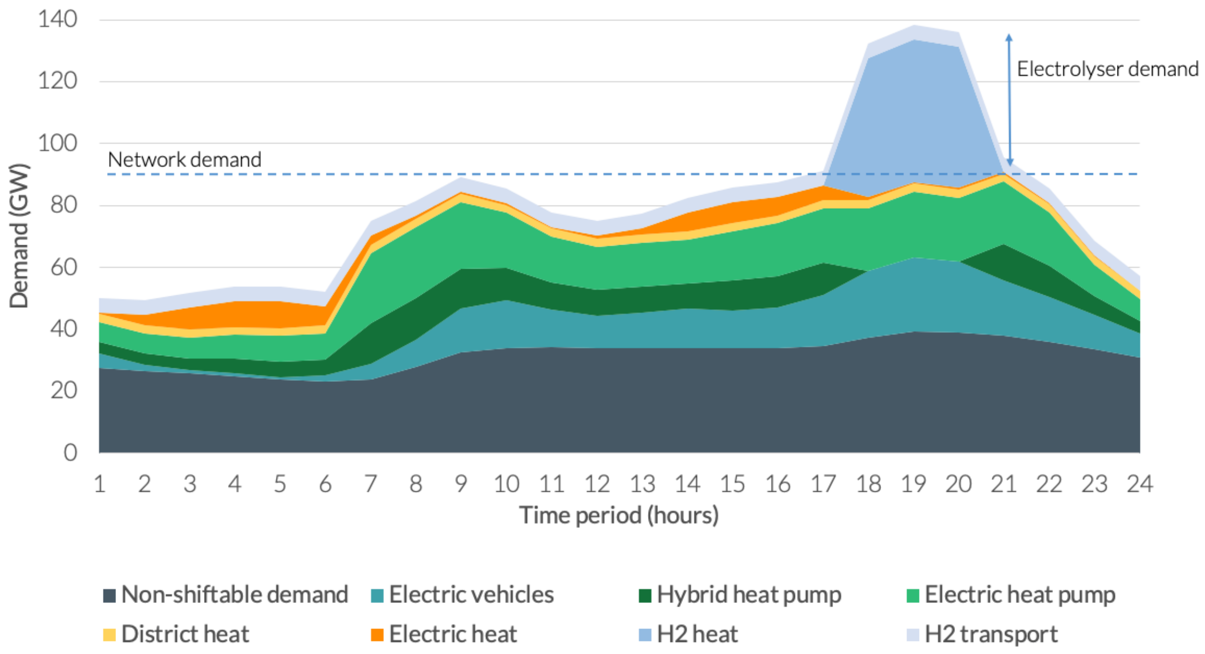


Figure 3: Peak day demand profile from the Baseline scenario, in which demand reaches 91GW.

The positive impact of flexibility is demonstrated by our Basic Flexibility scenario, below in Figure 4. Here, the passive demand from a system with little flexibility - from our net-zero Baseline scenario - appears as a dotted line (electrolyser demand is not included in figure 4).

The Basic Flexibility model includes some underlying DSR flexibility via I&C and residential electricity (non-heat related) from our Baseline scenario with the addition of smart electric heating and district heating and smart EVs. This demonstrates that flexibility from smart EV charging, smart heat pumps and daily demand-side response[6] has the potential to flatten demand and move it away from peak times. Heat pumps and smart EV are the big new demands on the system and are split out to determine their impact.

[6] The greatest effect comes from 'daily DSR', that is flexible assets where the associated demand can be shifted from between a few hours to up to a day.

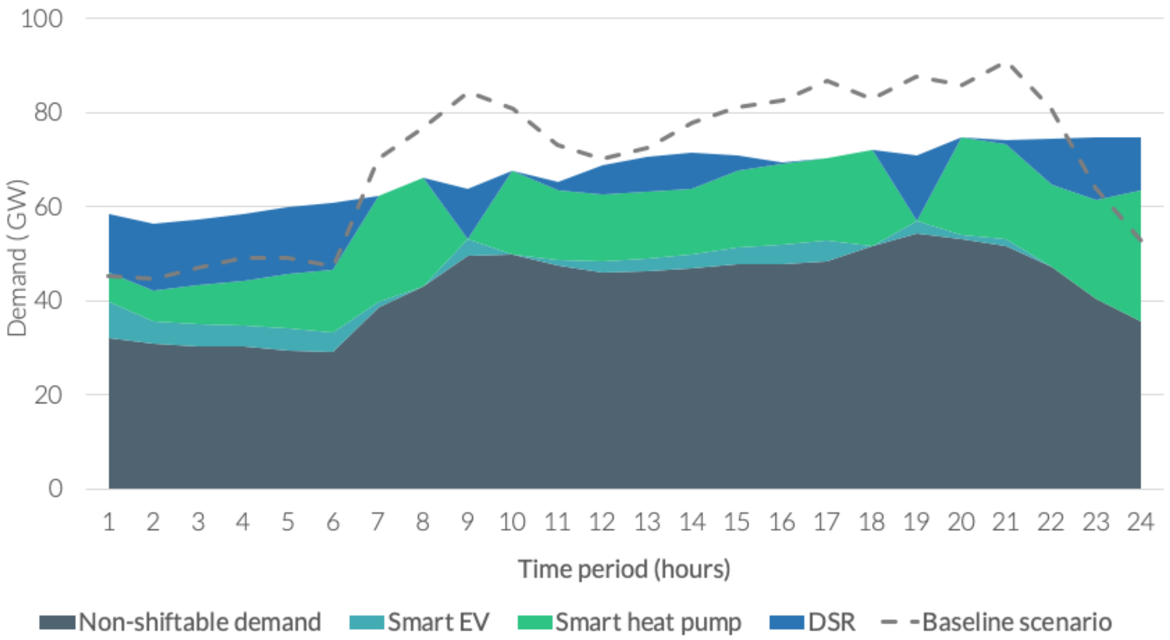


Figure 4: Peak day demand profile from the Basic Flexibility scenario, in which peak demand is reduced from 91GW to 75GW.

In this illustration, flexibility reduces the peak demand from 91GW to 75GW. This saving of 16GW represents an approximate 50% reduction in demand growth versus that projected without flexibility, up from 60GW today. This significant saving means a reduction of the costs associated with required network investment until 2050.

The impact of flexibility on the top 100 hours of network loads in the Baseline and Basic Flexibility scenarios is shown below. In the Baseline case (5.1), load drops from its maximum of 91GW to circa 80GW. Unmanaged electrified heating (electric heat pumps) are clearly the main driver for increasing demand during these hours of peak network demand.

The peak reduces by 16GW to 75GW in the Basic Flexibility scenario (5.2) and the reduced demand is held at a more constant level and maintained throughout the demand cycle. Thus, flexibility allows for much higher utilisation of existing network assets, with associated benefits for reducing costs associated with reinforcement to accommodate higher peaks. This also presents an opportunity to maximise the return on investment for flexibility assets.

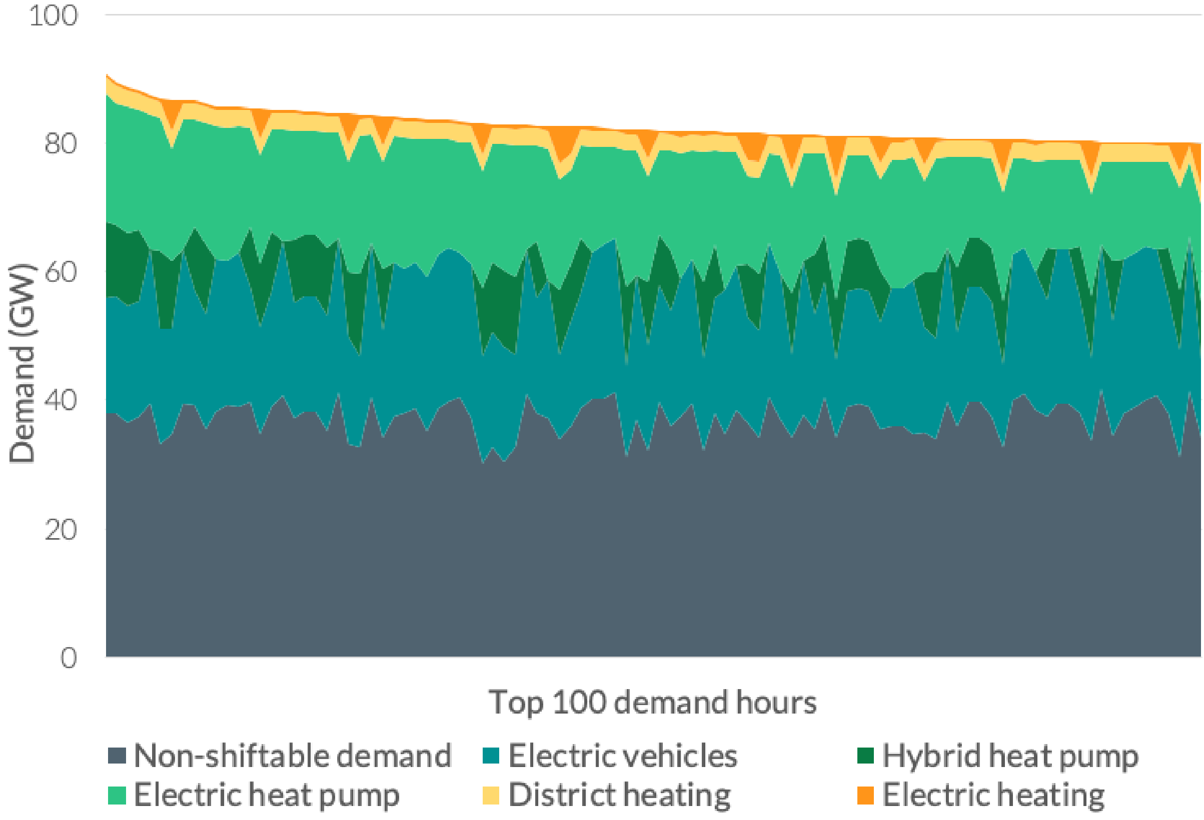


Figure 5.1: Top 100 hours of network demand over a year (note that these hours are not necessarily adjacent). From our Baseline scenario.

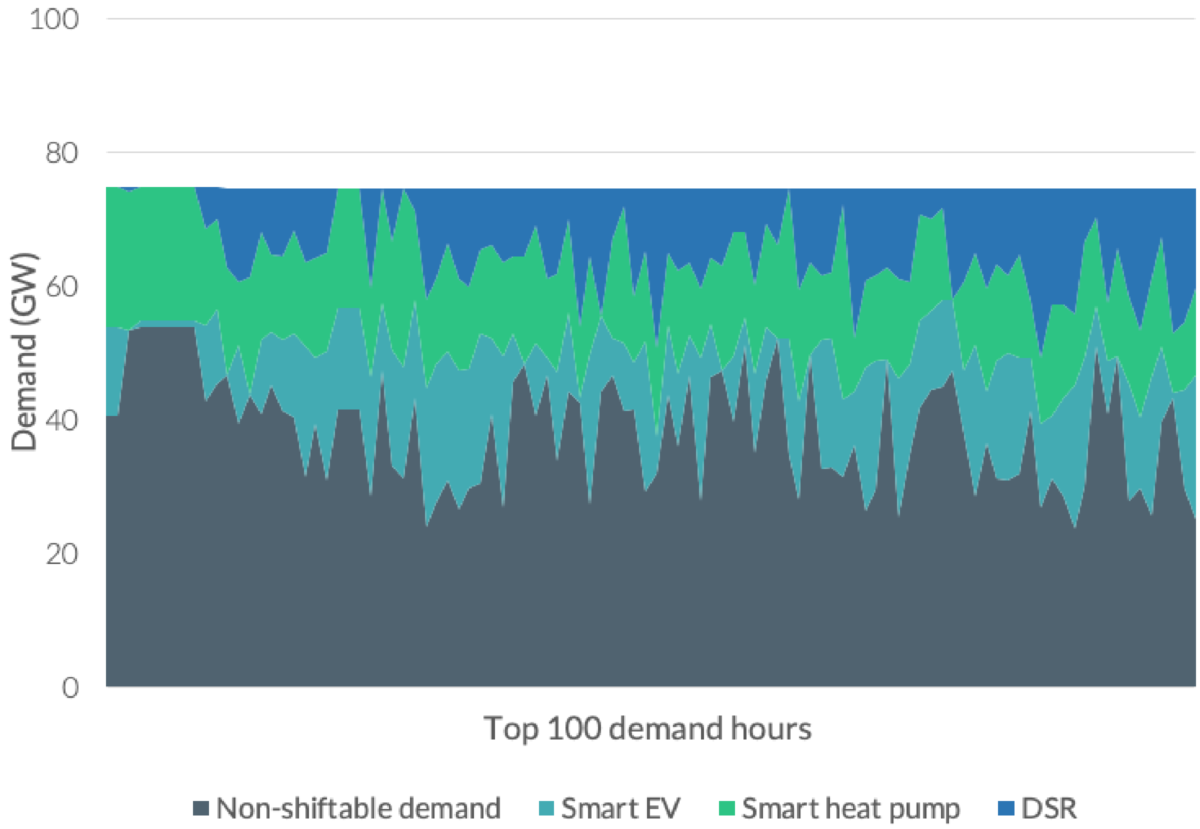


Figure 5.2: Top 100 demand hours from the Basic Flexibility scenario which comprises smart EV charging and smart heat pumps.

3.2. Smart Demand reduces peak dispatchable capacity by 17GW

The Baseline scenario requires a high level of dispatchable generation capacity (~67GWp) to backup the system during periods of peak demand. This is lower than the peak network load because some renewable generation offsets the overall dispatchable capacity that is required. However, it is predominantly supplied by gas combined cycle power plant (CCGT) as illustrated in figure 6.1 below.

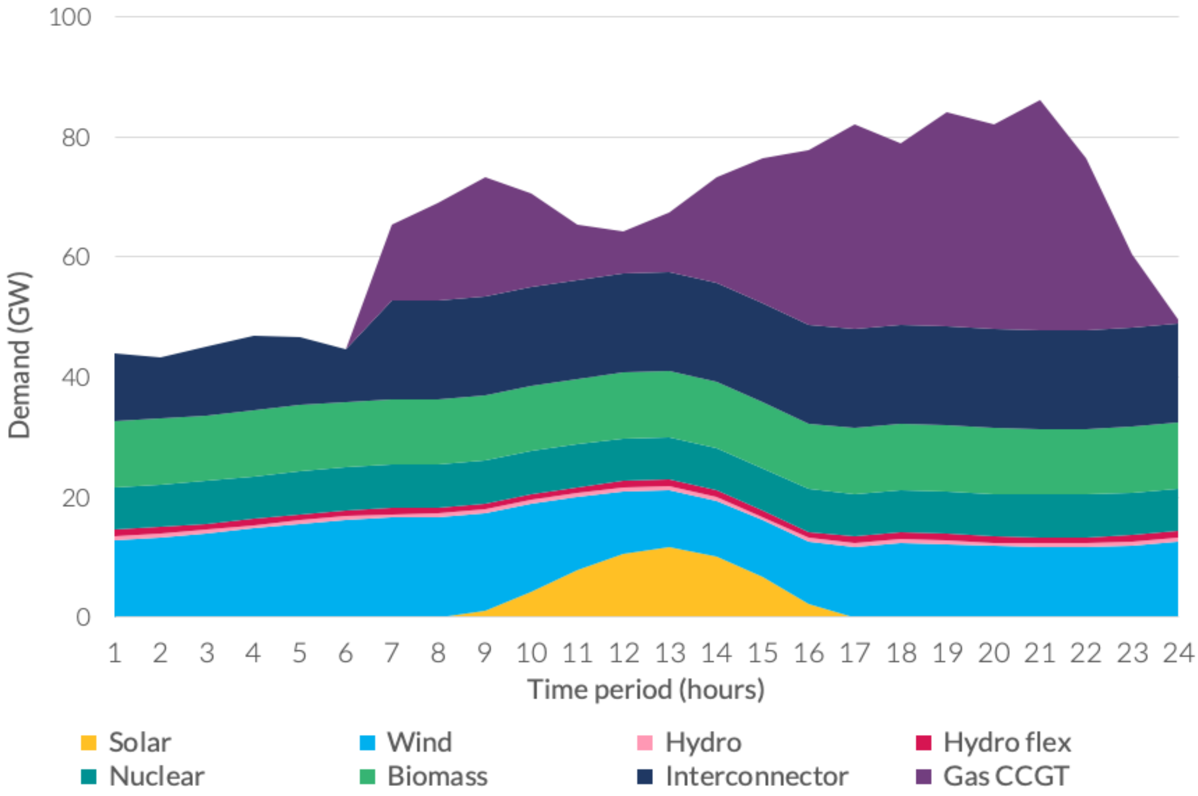


Figure 6.1: Day of peak dispatchable power requirements in the Baseline Scenario

In the Basic Flexibility scenario, flexible demand reduces peak capacity and also increases the run hours of the remaining capacity. Flexibility reduces peak dispatchable capacity by 17GW and reduces dispatchable (mostly thermal) generation energy by 22TWh/year. Adding utility-scale storage as a flexibility asset can improve these numbers further, most notably with an additional 2.4GW reduction in peaking generation.

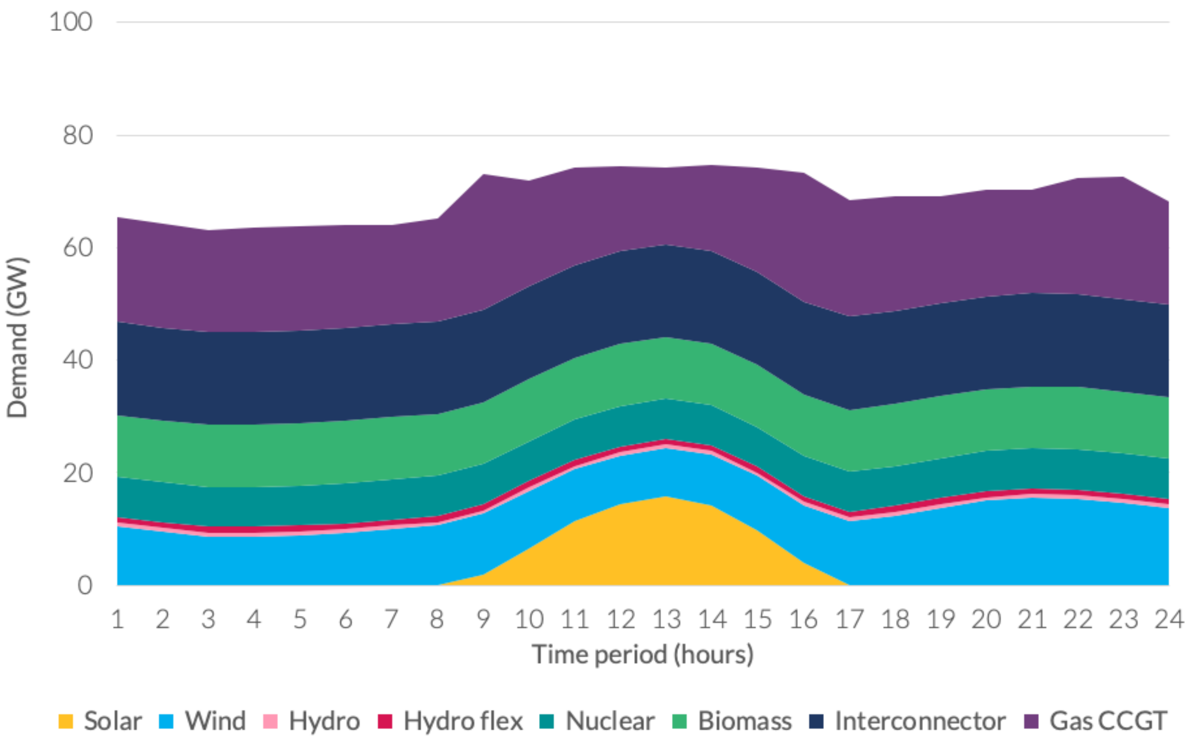


Figure 6.2: Day of peak dispatchable power requirements in the Basic Flexibility scenario.

3.3. Demand flexibility delivers benefits across the power system

Power systems which are predominantly supplied by thermal generation are sized to respond to peaks in demand. This means that annual operation is often displayed with hours arranged from maximum to minimum demand. By comparison, zero-carbon electricity systems with significant penetration of variable renewable energy sources will experience many hours of the year when energy supply will exceed hourly demand.

To balance supply in a zero-carbon system, there are three cost considerations: 1) renewable curtailment - the act of reducing or restricting energy delivery from a VRES generator when there is a VRES surplus, 2) the fuel and operational costs of running dispatchable assets required when there is a VRES deficit, and 3) the capital costs of peak dispatchable generation capacity. Alternatively, flexible demand assets can be dispatched to address all of these costs.

To present the annual performance of flexible systems, in this report we show net demand curves; the system demand after renewable energy supply has been accounted for and netted off. Net demand curves clearly display annual volume of curtailed energy, dispatchable energy, and peaking power requirements. Using flexible assets to flatten the net demand curve is a useful way to illustrate whole-system performance improvements.

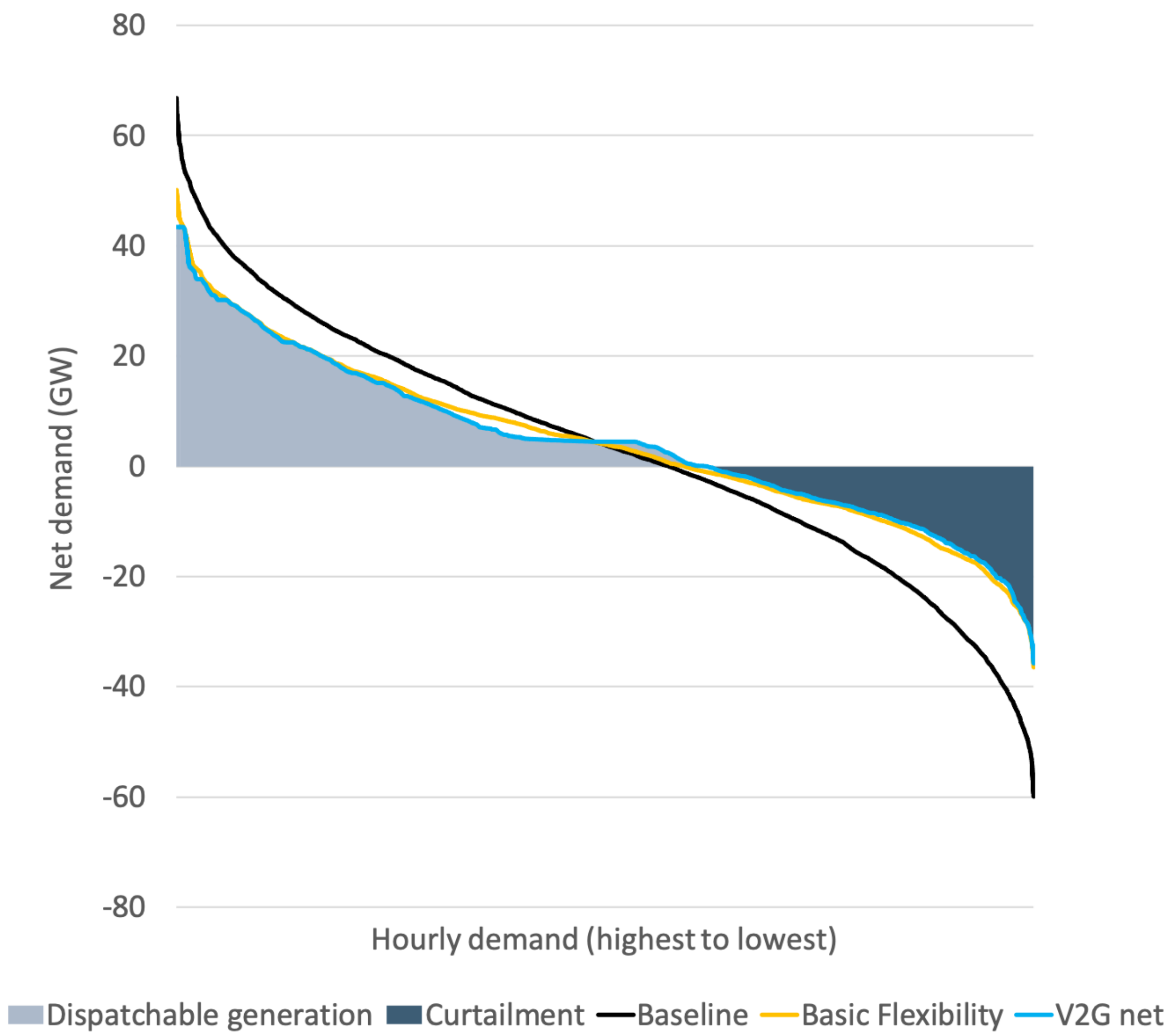


Figure 7: Annual net demand distribution from highest to lowest in the Baseline, Basic Flexibility and V2G net scenarios.

The annual net demand curve for a number of flexible scenarios is shown in figure 7. This shows the residual demand after netting off variable renewable energy production. The data is arranged from hour of greatest to lowest net demand which is an effective way to summarise and compare the annual performance of low-carbon power systems. Flattening the net demand curve reduces peak dispatchable generation (which may be utilised for limited periods), reduces dispatchable energy requirements, and reduces curtailment of renewable energy.

We are able to demonstrate that flexibility has the potential to reduce peak dispatchable generation capacity and network loads, and to reduce curtailment of renewable energy sources in decarbonised grids. The flexibility scenarios illustrated here (Basic Flexibility and a V2G scenario optimised for the network benefit) are shown to reduce the curtailment of variable renewable energy by 30TWh/year versus the Baseline scenario.

To demonstrate how effective flexibility is for supporting the power system, the table below shows that curtailment of VRES is reduced from 21% to 14% of annual generation, a significant improvement on revenues and economic viability of these energy sources.

Scenario	Wind+solar+hydro (TWh)	Network curtailment (TWh)	Demand curtailment (TWh)	Total curtailment share (%)
Baseline	314	1	66	21%
Basic Flexibility	314	9	36	14%

Basic Flexibility + V2G (high)	314	9	33	13%

Table 3: Flexibility significantly increases use of variable renewable energy.

We estimate that the Basic Flexibility scenario has the potential to reduce annual system cost by £.4.55bn, with savings from avoided network capacity, reduced peaking generation capacity, and reduced curtailment of VRES which in turn reduces fuel use. Widescale deployment of storage, either utility scale or distributed, has potential to extend these savings to £5.0bn per annum.

Total electricity system cost (£47bn/y)

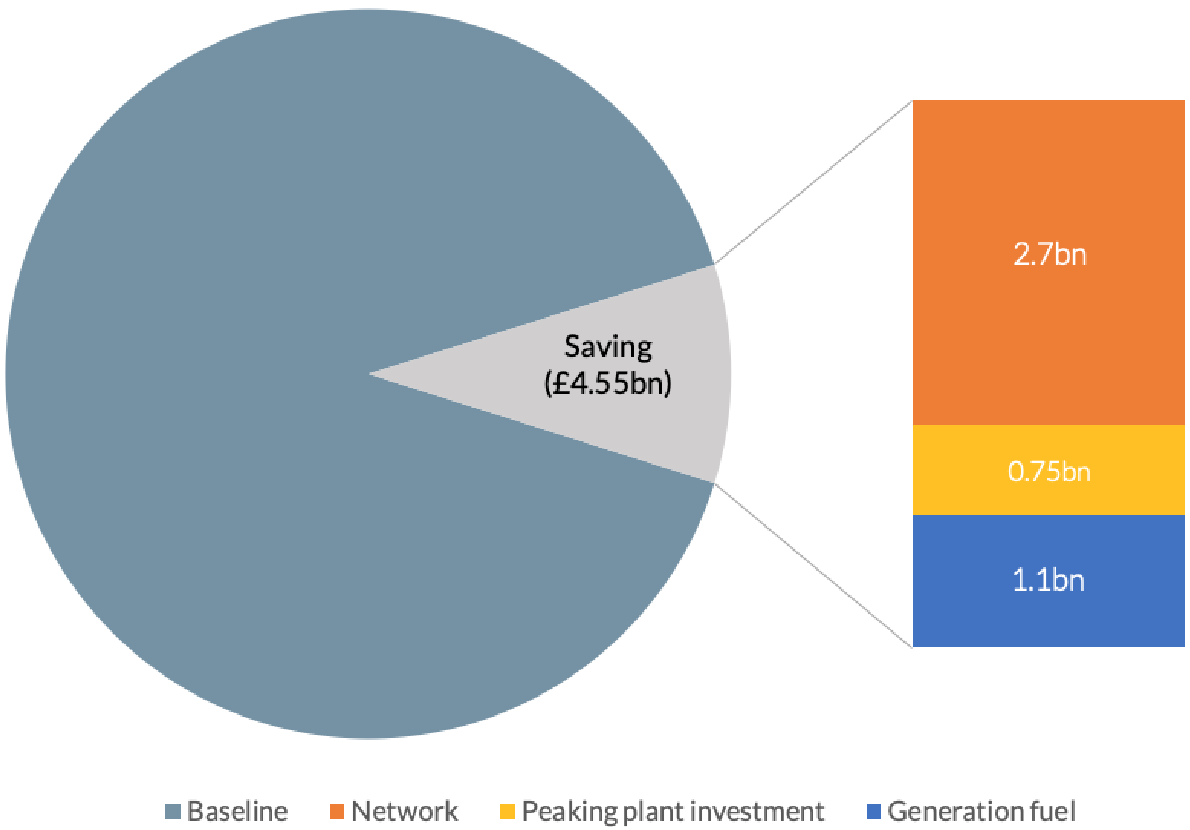
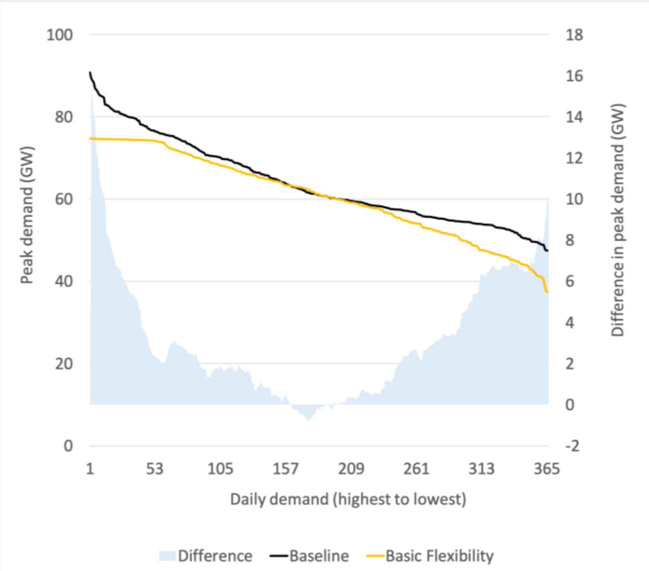


Figure 8: System cost analysis

3.4. Flexibility improves utilisation of distribution network assets

The daily peak demand on the network is shown in figure 9.1 for the Baseline and Basic Flexibility scenarios, where the capacity saving of circa 15GW is clear at the point of peak demand. This represents a reduction by 50% in the level of required network expansion, out to 2050.



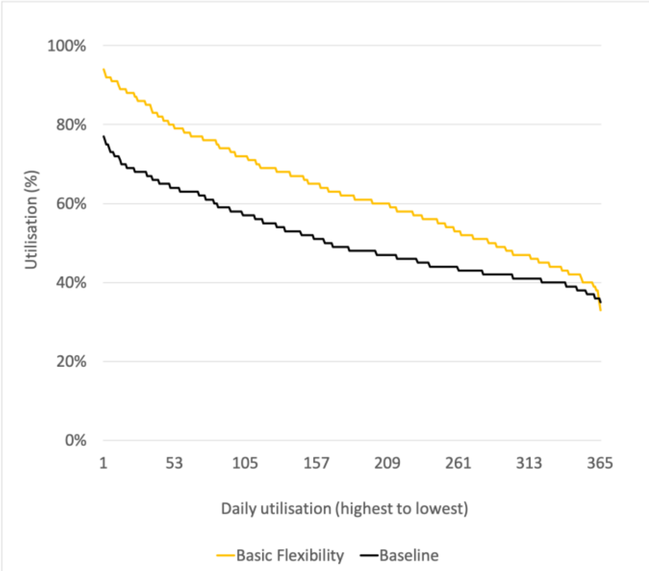


Figure 9.1: Daily peak demand | Figure 9.2: Daily utilisation

By limiting peak network loads and smoothing the demand profile, the utilisation rate of the (smaller and more efficient) network is increased. The daily utilisation is shown in 9.2 defined as the average utilisation per day divided by the firm network capacity. The average utilisation on the network is increased by circa 10%, which translates into greater revenues per unit of network capacity installed.

Figure 10 illustrates what this means for individual substations on the distribution network. Taking a sample of 439 substations from Northern Powergrid's published heat map data[7], it plots the peak demand[8] on each substation divided by its firm capacity[9] for two scenarios:

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7 Sample heat map data for Yorkshire Generation substations, accessible at: https://www.northernpowergrid.com/generation-availability-map (data assembled June 2019)

8 The maximum half hourly demand recorded at the substation during the previous regulatory year.

9 The capacity available at the substation immediately following the occurrence of a first circuit outage.

Baseline: Current substation utilisation, as given by the published heat map. The average utilisation for the sample of 439 substations at peak times is 56%, with a distribution slightly skewed towards the higher utilisation values. Even at peak times, we are using only about half of the network's capacity, on average.

Basic Flexibility: Substation utilisation after smoothing the demand profile and adding new demand to use capacity freed up by this smoothing. Smoothing will reduce the variance and so compress the load distribution more tightly about the mean. We can then add additional load without exceeding the peak capacity of the substations. The average utilisation can be increased from 56% to 67% (a 20% increase) without increasing the load on any substation above its peak capacity.

This is a simple illustrative model, but it demonstrates how smoothing the demand profile can create significant additional capacity in the network.

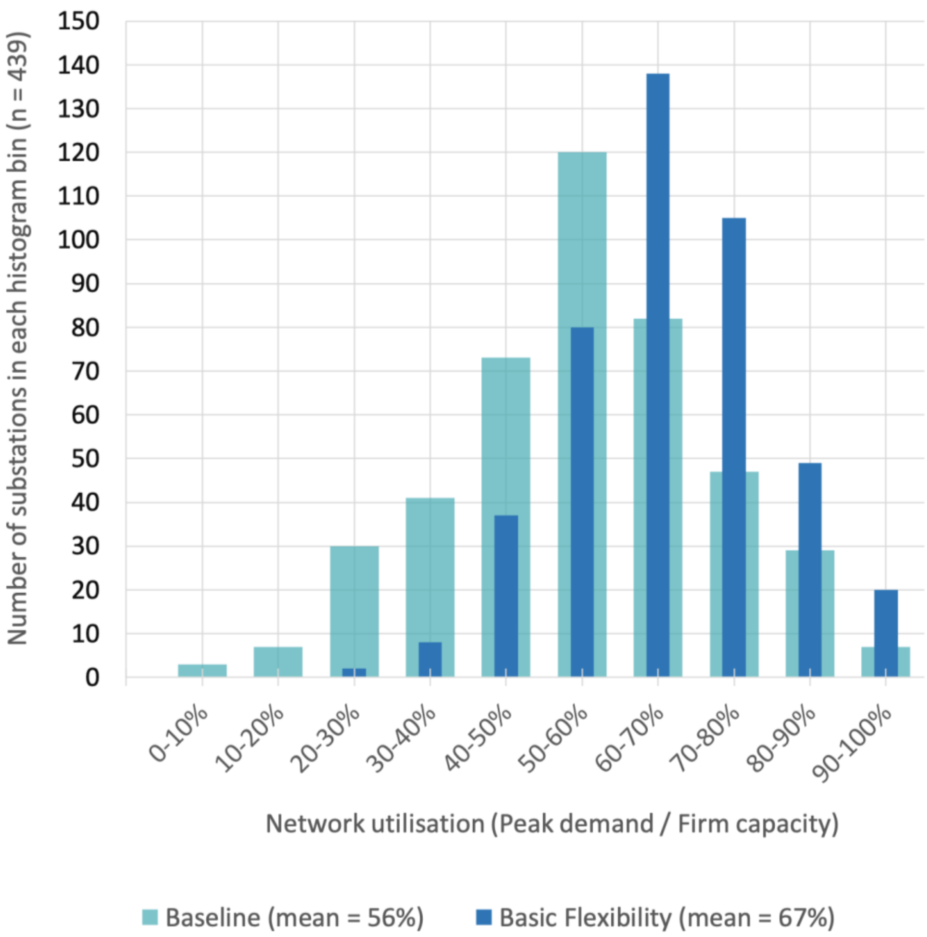

Figure 10: Histogram showing the distribution of substation utilisations under Baseline and Basic Flexibility scenarios.

3.5. Optimising storage assets to displace peak dispatchable generation or peak network demand

Flexible assets can provide savings across the power system. The way in which these assets are controlled will determine the size and distribution of the savings.

In figure 11.1, V2G assets are deployed until their cost equals the marginal benefit of displacing peaking generation. V2G assets (comprising 750,000 V2G-enabled EVs) operate at times of peak dispatchable generation for short periods. The result is that 15GWh behind-the-meter storage can displace 3.8GW of peaking generation.

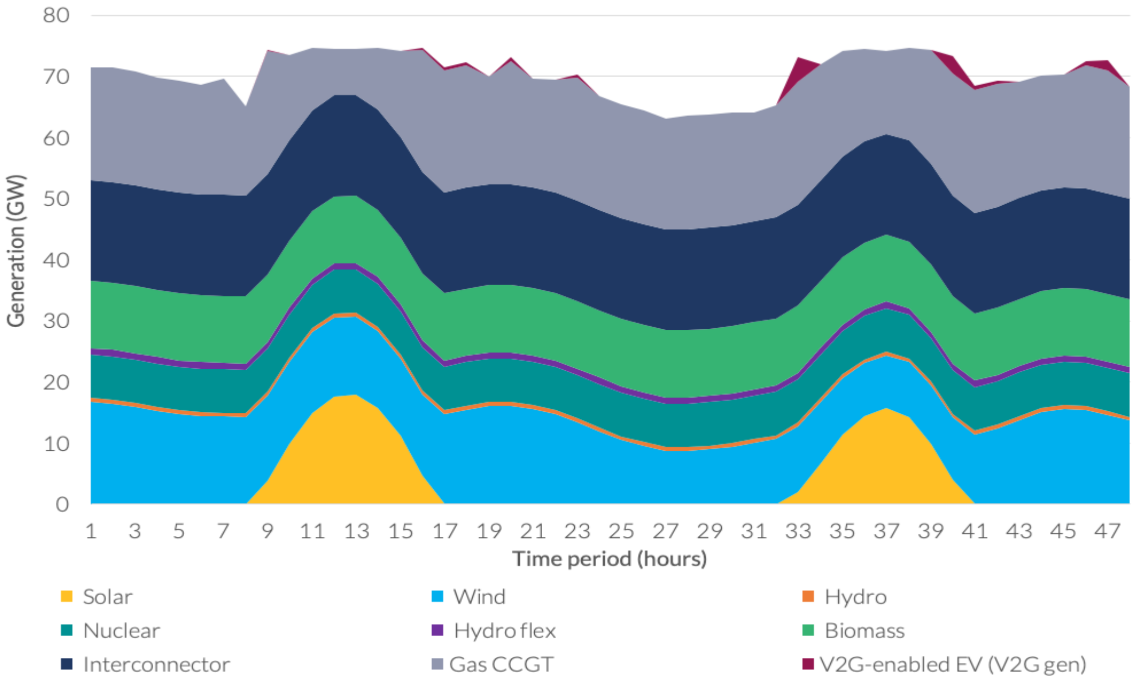

Figure 11.1: V2G assets optimised for the benefit of generation over two days (48 hours) are deployed here to reduce dispatchable peaking plant capacity by 3.8GW.

Although this displacement is impressive, this operational profile is not effective in reducing peak network demand. This is because the peak network demand profile, after flexibility, has contiguous periods of high demand with a duration of 15-20 hours. To reduce network demand, V2G assets need to provide flexible capacity over this duration. When valued against network capacity savings, and after factoring in the cost, V2G can provide savings up to a duration of 30 hours, as shown in figure 11.2. We estimate that 7 million V2G-enabled cars (~20% of the anticipated EV fleet in 2050) can be economically deployed to provide 140GWh of storage (20kWh per vehicle). This could reduce the peak network requirement (after flexibility) by 5GW and dispatchable generation capacity by 3GW. Note that this constitutes an approximate ten-fold increase in the V2G storage capacity to provide these network benefits.

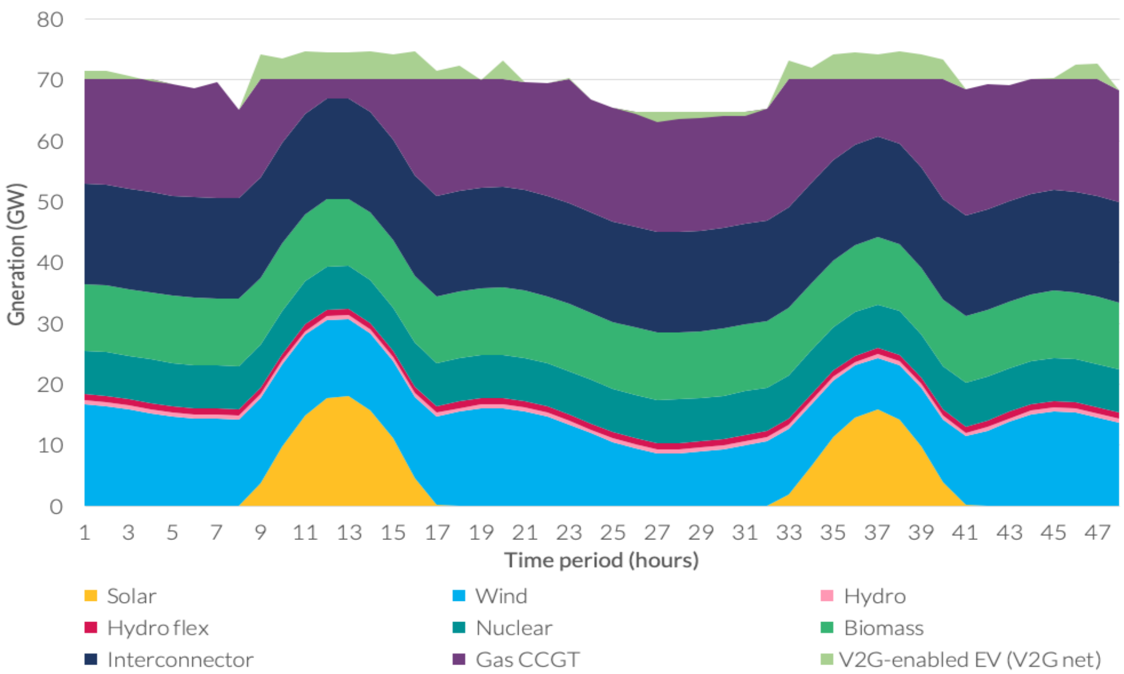

Figure 11.2: V2G assets optimised for the benefit of the network over two days (48 hours) shows that longer duration V2G assets are required to reduce network loads by ca. 5GW.

4. Conclusions

1. Flexibility generates significant savings across the system

Introducing flexibility via demand-side response and smart charging can reduce overall electricity system costs by circa £4.55bn/year. These savings arise throughout the system, comprising ~£2.7bn avoided network capacity, £0.75bn in avoided generation peaking capacity, and ~£1bn from reduced curtailment of renewable energy.

All our scenarios indicate that significant network investments will be required. However, flexibility can reduce the associated cost by 50% (network investment to handle an additional 30GW is required in a passive scenario, versus 15GW in a flexible scenario). Flexibility will be a key element in ensuring the build-out of network expansion to 2050 is feasible.

Backup from dispatchable generation is required to support an expanding system, even when flexibility of demand can reduce the peak by 15GW. Avoiding investment in low run-hour peaking plants brings significant system savings.

Flexibility can be effective in reducing the curtailment of variable renewable energy sources. The analysis predicts that 30TWh of VRES can be accommodated, which represents 10% of the potential (uncurtailed) annual output. This would reduce policy costs associated with curtailment-related payments to renewable generators.

2. Savings comprise operational and capacity avoidance

Of the savings identified above, the majority arises from reduced expenditure on capacity (generation and network). While operational savings may be easier to realise, the longer timescales associated with capacity investments means that avoiding such investments may be harder to achieve.

To generate these system savings, flexibility technology will need to demonstrate reliability to deliver system-critical services, compared to counterfactual technologies.

3. Network savings are maximised by distributed storage

We found that to reduce peaking plant capacity by 1GW requires flexibility assets to maintain this capacity for 2-3 hours.

To reduce network capacity by the same amount requires much longer duration of storage. This is because flexibility has already flattened the peaks in demand; the typical duration of peak loads after flexibility may be 20 hours or more, requiring an equivalent duration in storage.

A much larger flexible asset (in this case, a V2G fleet) was required to deliver the duration of storage required to achieve network benefit. Network savings are sufficient to justify a large V2G deployment of over 7 million passenger cars (~20% of the fleet). But only edge technologies such as V2G can deliver the full network benefit. Grid storage located at higher levels in the system cannot address issues on the distribution network.

4. Network utilisation can be increased

We found that flexibility reduced peak network loads and improved the average utilisation of network assets by ~10%. This significantly improves the economic return per unit of distribution network capacity deployed.

We note that the system is at this new (lower) peak more consistently, which may have implications for redundancy in the system. Our analysis of substation data from Northern Powergrid suggests, however, that smoothing the demand profile could increase average substation utilisation by 20% without impinging on existing redundancy arrangements, so this 10% increase in utilisation would seem entirely achievable. Studies by Imperial College[10] suggest

[10] http://www.dcode.org.uk/assets/uploads/IC_Report_exec_summary.pdf

that smart load management could also enable us to maintain network reliability even at reduced levels of redundancy, confirming that a 10% increase in network utilisation is well within the bounds of feasibility with smart management of flexible loads.

This analysis has also not considered the effect of losses, which will be increased at higher network utilisations. However, as losses vary with the square of current, they can be highest for peaky flows. Smoothing flows and increasing the average load by only 10% may not have a significant adverse effect. This area would warrant further investigation.

5. Implications for stakeholders

Network companies

- We estimate that a passive system would require 30GW of network expansion by 2050. This could be reduced to 15GW by deploying flexibility. And reduced further to 10GW with the successful and widespread deployment of V2G. This demonstrates that a coordinated approach of flexibility with network expansion is required.

- Furthermore, flexibility allows network companies to run their assets at a higher load factor and generate greater revenues per unit of capacity.

- Network companies must currently choose between two risks – undertake traditional reinforcement and face the risk of stranding assets or use novel flexibility solutions and face the risk of unknown levels of service reliability. However, as the above-referenced Imperial College studies suggest, there is an inherent conservatism within current network design codes that could be leveraged to offset the risk of choosing the flexibility pathway.

Policy makers

- System flexibility arising from smart electrification of demand can reduce annual electricity costs by £4.5bn, a ~10% reduction. The system benefits of smart flexible demands would increase with greater electrification of demand e.g. lower deployment of hybrid heat pumps, and greater deployment of variable renewable energy sources.

- Most of the system savings from flexibility relate to avoided capacity investments and it may be challenging to monetise these savings (e.g. in network-charging models). Capacity is often required at times of peak system stress, and the maturity and reliability of DSR will need to be proven so that it becomes a viable alternative to traditional capacity investments.

- It is vital to deploy and prove DSR at scale now so that it can become a viable alternative to traditional investments. The risk/reward profile of asset classes differs. Traditional assets have well understood characteristics and low operational risk (but higher risk of stranding). Flexibility is less well understood and so has higher operational risk (but lower stranding risk). In the current regulatory model, the distribution network operator (DNO) carries the operational risk while the stranding risk is essentially socialised. To achieve optimum deployment of flexibility, we need to either adjust this risk model or allow DNOs to earn greater returns on flexibility to compensate for the greater risk they are taking.

- The marginal value of flexibility and storage assets are reduced with increased deployment. The erosion of revenues and competition between technologies could disincentive necessary investment. However, there is a link between deployment of VRES and flexibility - increased VRES deployment helps to maintain grid conditions that support flexibility, and flexible technologies help to improve the economics of VRES deployment. Decarbonisation policy should recognise the benefit of parallel deployment and incentivisation of system flexibility and VRES.

Flexibility providers

- There is a large and growing need for flexibility services across all scales of the energy system. However, the analysis shows that different sources of flexibility can overlap in their services to the system, resulting in competition between technologies and cannibalisation of market share.

- To ensure flexibility is able to deliver whole-system value - by avoiding investment in traditional technologies for capacity - flexibility technology developers need to move quickly to deploy and prove their technology at scale.

- Flexibility technology developers should recognise the benefits of decarbonising via VRES, which expands the market need for flexibility (compared to nuclear). By linking the growth of flexibility to deployment of VRES, providers can show how their technology is vital, not only for reducing system costs but also for decarbonising the power system.

Appendix A: Integrated Supply + Demand Model

Integrated Supply Demand Model (ISDM) is a proprietary energy model developed and maintained by Element Energy. It was originally developed to determine the optimised configuration and operation of power systems to ensure the security of supply with very high penetration of renewable energy sources.

ISDM was developed to represent multi-vector low or zero carbon energy systems with high penetration of VRES. By placing equal emphasis on demand side and flexible system technologies as it does the supply side and so overcomes many limitations of traditional power dispatch models. The starting point for the modelling used is the set of hourly energy demand profiles. The model is populated with a detailed breakdown of the demand by end-use types. The demand is differentiated based on its hourly profile and potential for flexibility.

For heating, these demands are based on the building sector heat loss, heating technology and outside air temperatures. Weather data is taken from a 1-in-20 year cold period, but an alternative can be used. Some demand profiles are fixed (no flexibility), while others are able to be shifted over defined periods. Country-specific hourly weather data is also used to generate hourly load factors for wind and solar production.

An initial specification of the VRES generation fleet is used and combined with the demand data to generate initial net-load curves. In normal operation, demand shifting is deployed to minimise net demand and, therefore, minimise generation curtailment. Network capacity is adjusted to optimise between demand driven and network curtailment. Alternatively, the fleet can be dispatched to minimise network loads. The dispatchable generation fleet is then deployed in merit order to fill in the supply gap. Remaining unmet demand is supplied by seasonal storage, and generation capacities are updated to reflect this. Once all hourly demand is met, annual system performance metrics are evaluated (CO2, limits on biomass use) and generation inputs adjusted to meet targets. Final outputs are generator capacities, network capacities, electrolyser capacities, storage, and H2GT capacities, and associated costs.

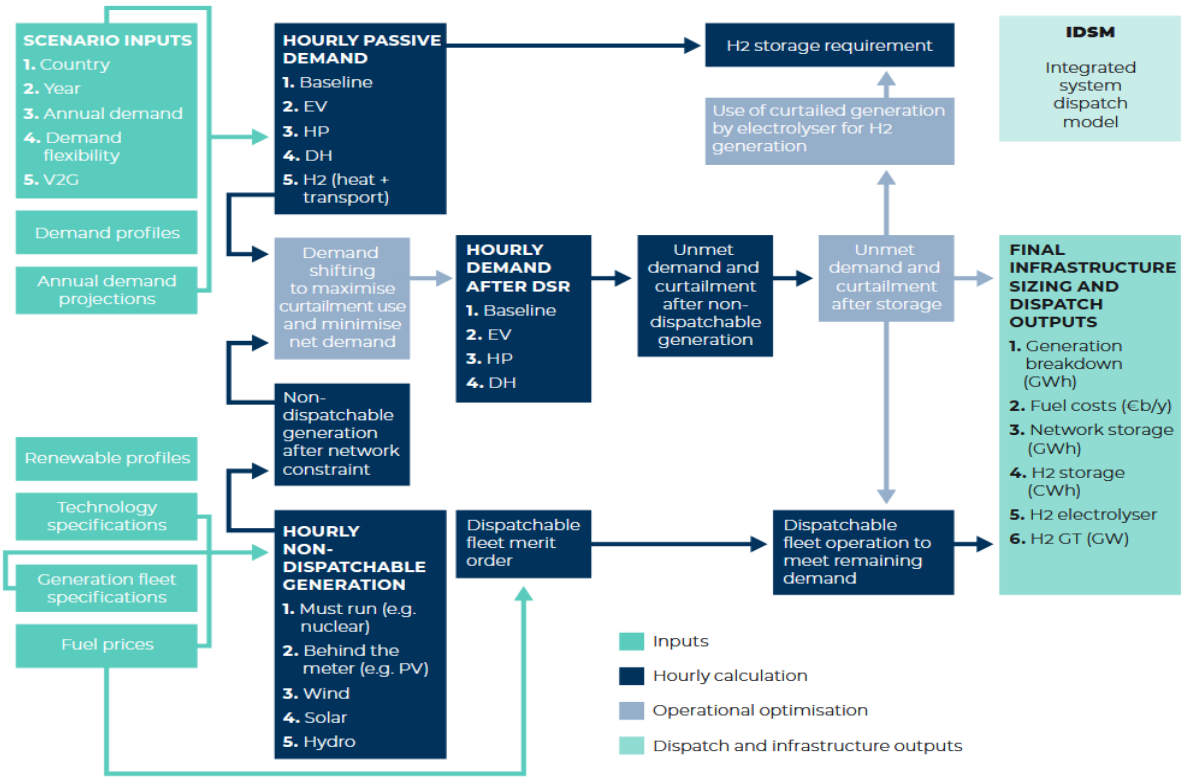

Figure 15: Integrated System Demand Model - primary modules

Credits

Element Energy

Element Energy is a dynamic and growing strategic energy consultancy. They specialise in the intelligent analysis of measures that can reduce carbon emissions in the built environment, energy and transport sectors. Since forming 18 years ago, they have grown to over 80 personnel and have become one of the largest low carbon-focused consultancies in the country.

Graham Oakes

Graham Oakes helps municipal, local and community energy systems identify and exploit the value of flexibility for the energy system. He founded Upside Energy in 2013, steering it to raise significant grant and equity funding and so develop an advanced flexibility platform. Since stepping down from Upside in early 2018, he has supported a number of projects across the UK and EU to develop flexibility-enabled products and services, and worked with regulators and policy makers to develop an environment where such products can succeed in the market.

Piclo

Piclo has been at the forefront of innovation in the fast-changing energy industry since 2013. Previously trading as Open Utility, Piclo's mission is to power the world with cheap, clean and abundant electricity. Piclo runs Piclo Flex, the UK's leading independent flexibility marketplace. Read more about Piclo's story.

Innovate UK

Innovate UK is part of UK Research and Innovation, a non-departmental public body funded by a grant-in-aid from the UK government.

They drive productivity and economic growth by supporting businesses to develop and realise the potential of new ideas, including those from the UK's world-class research base.

Project LEO

Project Local Energy Oxfordshire (LEO) is one of the most ambitious, wide-ranging, innovative, and holistic smart grid trials ever conducted in the UK. LEO will improve our understanding of how opportunities can be maximised and unlocked from the transition to a smarter, flexible electricity system and how households, businesses and communities can realise its benefits.

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