Annex 4.1
Scenarios and Investment Planning

Northern Powergrid: our business plan for 2023-28

Contents

Purpose

The purpose of this annex is to enable Northern Powergrid to:

- expand on the process for developing our scenarios and investment plan for the 2023-28 period in the context of the energy system's need to prepare our network for the transition to net zero by 2050, as summarised in the main 2023-28 business plan; and
- address Ofgem's additional guidance on the Load Related Expenditure Strategy.

We provide further details on the range of scenarios we have developed when considering our future pathway to net zero. Based on these scenarios, we identify a planning scenario, which forms the basis of our investment plan. We elaborate on the criteria used to select the planning scenario, as well as the process taken to develop our investment plan. Finally, we present our investment plan methodology and resultant strategy, as well as our approach to managing the inherent uncertainty associated with the ongoing transitions towards net zero.

Supporting documentation includes:

- Northern Powergrid 2023-28 business plan;
- Detailed engagement findings – scenarios and investment section;
- Distribution system operation (DSO) strategy;
- Network visibility strategy ;
- Whole systems strategy;
- Innovation strategy;
- Socialisation of costs – Access SCR and net zero service upgrades; and
- Engineering Justification Papers (EJPs) – relevant references included within the document.

Our role in the energy transition

We will efficiently open up all credible pathways to decarbonisation in 2023-28 and beyond, by embracing uncertainty and remaining adaptable to change, helping our customers realise the best value from their assets while optimising across the whole energy system.

Our network is key to facilitating the country and region's efforts to decarbonise, regardless of the decarbonisation pathway that materialises. In one state of the world where electrification plays a predominant role to facilitate the decarbonisation of the heat and transport sectors, we will need to ensure that our networks can meet the significant increase in electricity demand. This is due to a greater number of electric vehicles (EVs) and heat pumps (HPs) connecting to our networks, increasing the potential for network constraints and requiring more capacity to be made available. In other possible futures, alternatives to electrification, for example hydrogen or bio-fuels, may have varying degrees of importance alongside electrification. This is a key source of uncertainty in planning for the future.

Across all possible decarbonisation pathways, we expect to provide for increasing connections to the distribution network, alongside increasing penetration of smaller-scale, renewable generation; as well as sources of flexibility – ranging from energy storage to various types of dispatchable generation and demand - that will be required to address the increasing intermittency of renewable resources. In addition, we expect that increasing digitalisation will enable customers to modify their generation and/or consumption patterns in response to external signals (for example, a change in price). This will be supported by commercial developments such as aggregation or peer-to-peer trading that will help even the smallest customers' access and participate in energy markets and maximise value from their assets.

These developments will increase the number of customers on our grid who can actively manage their energy use and production to both reduce the bills they pay, and also, where possible, receive remuneration for providing flexibility to help us manage the complex power flows on our network. This customer flexibility will add to our existing toolkit of network flexibility and smart grid solutions that allow us to get the most out of our network assets on behalf of our customers.

By 2028, the end of the upcoming 2023-28 period, the country will need to be well on its way to a fully decarbonised energy system. So, the next five-year period is a significant phase in the path towards net zero. The overall objective of our investment strategy is to set us on the right track for achieving the UK government's net zero goal by 2050, while remaining able to adapt our plan to an evolving decarbonisation landscape.

In making these investments, we will ensure effective coordination across stakeholders not only in the electricity sector (including the electricity system operators (ESOs) and other DSOs), but also in the heat, transport and other relevant sectors, to ensure efficient investment from a whole system perspective (please refer to DSO strategy and Whole systems strategy for further detail around planned collaboration activities).

We have developed our response through a comprehensive engagement with our customers and other stakeholders

Our plans to prepare our network for decarbonisation have been devised through working with our customers and stakeholders, building on our DSO v1.1 DSO development plan published in October 2019, Emerging Thinking in August 2020, and distribution future energy scenarios (DFES) in May 2021.

We have engaged with as broad a range of stakeholders as possible, including not only those in the energy sector (the regulator, ESO, other DSOs) but also the heat and transport sectors, with local authorities, as well as a range of industrial, commercial and residential customers. We recognise that the transition will be customer driven and therefore sought feedback from our customers in particular to ensure that our strategy will empower them to lead the change. In planning our investment, we will continue our effective coordination across stakeholders to ensure efficient investment from a whole system perspective; refer also to DSO strategy and Whole systems strategy.

Our stakeholder engagement has revealed a high level of ambition for decarbonisation. A significant majority of our customers support the idea that we should pursue an accelerated decarbonisation pathway, reaching net zero by 2050 at the latest. We learnt that many of our communities and local authorities aspire to decarbonise before 2050. Given the uncertainty of national and local energy developments, as well as diversity in local net zero targets, stakeholders are overwhelmingly in favour of us developing our investment plans in a manner that would facilitate any decarbonisation pathway that emerges. They have conveyed an appetite for us to be ambitious in our net zero planning to enable a faster transition to net zero, which is socially equitable and does not put vulnerable and fuel poor customers at a disadvantage.

Our customers expect us to ensure that the required infrastructure is in place to facilitate renewable energy and new connections for low carbon technologies (LCTs), as well as to reduce connection costs and incentivise customers to encourage the widespread connection of LCTs to the network. Recent surveys of a range of our stakeholders (including local authorities, LCT installers, house builders and developers, auto and LCT manufacturers, car dealerships and other regional and energy sector influencers) found that customers were overwhelmingly in favour of EVs and HPs as compared to grid scale system technologies such as hydrogen.

These messages were reinforced in the stakeholder engagements we undertook as part of our DFES process in 2019 and 2020. We have incorporated feedback received from these engagements when considering possible future scenarios for our region, in determining our assumptions around customer flexibility, and in designing sensitivities to test the robustness of our investment plan. Further detail on this engagement process is included in 'scenarios' below with details of how we have addressed specific stakeholder feedback on DFES in Appendix 2, DFES stakeholder engagement. Further stakeholder insights are summarised in the detailed stakeholder engagement annex.

The stakeholder feedback will also feed into supporting the evolution of local area energy plans (LAEPs)[1] in our region. We hope to employ LAEP advisors, who can work collaboratively with local authorities and the wider energy sector to align our planning processes with those of local authorities in our region – please refer to our DSO strategy annex for further information (deliverable DSO3.2).

Our progress so far: we have already taken significant steps in preparing for this transition

A number of our current initiatives are supporting the transition to net zero. In the current 2015-23 period we are investing in our flagship smart grid enablers programme, creating the backbone of a smart grid which is transforming our ability to monitor, control and communicate with our field-based equipment. This allows us to operate the local network in a more active manner and use near real-time data to automatically reconfigure or adjust settings to release capacity where it is needed. It has improved our ability to respond to the take up of LCTs and allowed us to operate our network more flexibly with smarter, more efficient and cost-effective practices and technologies. This smart grid enablers programme was our first step in significantly upgrading our network visibility and a detailed breakdown of this approach is provided in our DSO strategy.

Through increased monitoring we have enhanced the data we capture about our network and improved processes for using this data in our decision making, enabling us to target network investment efficiently. We are committed to further modernising our data management practices and sharing information about our network with stakeholders, building on what we share today through our long term development statements, embedded capacity register, heat maps and publishing of our DFES through the Leeds Open Data Institute[2]. This includes granular data and a visualisation tool to primary substation and local authority level. Details about our plans to share and combine our data with external sources (like smart meters) are provided in our DSO strategy and Digitalisation strategy and action plan.

Since the start of the 2015-23 period, we have facilitated over 45,000 LCT connections[2] including HPs, EVs, solar and other distributed generation across our primary and secondary networks totalling at least 5GW and ensured that our network is ready for this additional demand and generation load. In May 2021 we published our green recovery plans[3] to invest a further £53 million to unlock network capacity for green growth boosting projects across our region. This is part

[1] LAEPs will define the optimal long-term energy solution for an area, by engaging a wide range of stakeholders. The operation and funding of LAEPs is not yet well-defined, and it is expected that a one size fits all approach would not be relevant for all local authorities. We recognise our role in facilitating the development of LAEPs and will continuously engage with our stakeholders and grow our capacity to support these local plans. Our joint commitments include providing expert advice to local projects that seek to explore and plan for a range of pathways; developing a joint plan for how to most effectively share data that will support LAEPs; and working closely with Ofgem and central government, to identify funding for LAEPs.

[2] Links to the interactive heat map and the open data: https://odileeds.github.io/northern-powergrid/2020-DFES/index.html; https://datamillnorth.org/dataset/northern-powergrid-dfes-2020

[3] https://www.northernpowergrid.com/green-recovery

of a national green recovery scheme making £300 million available for investment. This investment is in vital electricity networks across the country, following the economic impact of the COVID-19 pandemic and will enable the region to accelerate a number of projects, including regeneration and development at the Humber Freeport, large scale solar and wind generation, and rapid EV charging on our motorway network.

Network utilisation is increasing as consumption and generation patterns evolve

Net maximum demand dropped by around 24 per cent since its peak in 2005/06. This trend has been driven by increased energy efficiency and a series of economic events such as the global financial crisis, which affected heavy industrial demand, and increasing amounts of domestic generation (such as solar photovoltaics (PV)) embedded within our network, which has the effect of netting off demand.

Commercial generation on our network which operates at times of peak demand, in response to different market price signals has also increased each year, which has contributed to the widening difference between net and gross peak demands year-on-year. This has not happened in a uniform fashion across our network. We still have challenges to address particularly with notable load growth occurring in some of our metropolitan areas, and (where embedded generation patterns have changed) an increase in net demand. For this reason, we need to understand and manage the changing nature of demand and generation at a more local level. This drives increases in the amount of network visibility that we need to manage the network and the complexity of the associated analytical processes.

Network utilisation, measured at a more granular level than network-wide peak demand, has remained relatively stable throughout the current price control period. We monitor this using large data sets on load index (LI) utilisation bands, which assess peak demand versus firm capacity at major substations. Our strategy has been to maintain our overall risk position, dealing with highest risk substations (those closest to capacity). Our forecast for the end of the 2015-23 period has been updated to align with our new planning scenario and the latest network impact assessment done as part of this plan.

Our forecast LI position at the end of the current price control in both our Northeast and Yorkshire regions: at our major substations, 88 per cent are less than 80 per cent utilised, 10 per cent are 80-99 per cent utilised and two per cent are >99 per cent utilised. A breakdown by licence area is included in the table below. The total volume of sites has changed due to the inclusion of some substation groups.

			Number of substations		
LI rating	**Lower bound**	**Upper bound**	**2015-23 period to date**	*2015-23 period Forecast*	*Variance*
LI 1	0%	<80%	562	*537*	*-25*
LI 2	80%	<95%	40	*57*	*17*
LI 3	95%	<99%	3	*3*	-
LI 4	99% (<9 hours)	n/a	3	*7*	*4*
LI 5	99% (>9 hours)	n/a	4	*8*	*4*
		Total	**612**	***612***	***612***

Table 1: Load indices – primary substations

Looking ahead, the projected increase in EVs and HPs discussed below are expected to increase the utilisation significantly, in particular on the LV network. We set out the network utilisation forecasts for the 2023-28 period in the investment section below that align to our planning scenario.

It is important to note that headroom at 132kV/EHV level on the network does not necessarily mean that there is capacity available at lower voltage levels – in the same way that the motorway might be quiet whilst access roads are busy. We expect that customers connecting greater volumes of LCTs during ED2 will drive the greatest need for investment on the local networks operated at LV compared to other voltage levels. Refer to the investment section below for further detail.

For generation, we provide information to customers setting out the network utilisation for our major substations. We currently have the capacity to connect a typical smaller (5MW) generator to 88 per cent of our primary substations (this would only be possible at 39 per cent of substations without customer flexibility solutions such as active network management (ANM)). Ninety five per cent of our largest substations could accommodate a typical generation connection of 25MW when customer flexibility is used (51 per cent without). This means that capacity exists for cost-effective new generation connections on approximately 90 per cent of our extra high voltage (EHV)/HV network.

To optimise our investment to 2050, we are taking a flexibility first approach to our investment strategy for decarbonisation.

As shared with our stakeholders in our Emerging Thinking published in August 2020, flexibility first means that, where possible and cost-effective, we will prioritise investment in activities to facilitate and optimise customer and network flexibility ahead of more costly traditional reinforcement. All routes to decarbonisation require significant investment in our network; taking a flexibility first approach will ensure that this investment is targeted where our network needs it most and delivered efficiently to maximise value for customers.

The diagrams below (figure 1 and 2) show the generic process that we use for planning and operating the distribution network using a distribution system operation (DSO) approach. We've used this approach to create our business plan and we will continue to iterate the process across the 2023-28 period to respond to the changing external environment, validating the decarbonisation pathway as it unfolds and optimising our response to it. Over the following pages we set out in more detail how our DSO enablers underpin improvements in organisational capabilities across our processes for developing new flexibility markets, investing in innovative smart grid initiatives and network upgrades, developing our people, implementing leading edge information and operating technology systems. These will deliver efficiency and optimisation benefits to provide open data and operate a smart flexible network. This includes implementing innovative solutions that we and other DNOs have developed while seeking opportunities to embedded learning from innovation over the course of the next price control.

Our existing approach for planning the higher voltages is more sophisticated than that used at lower voltages due to the better level of network visibility and analytics used to identify deficiencies or constraints in network capability. Over the next period we will be making, through our DSO enablers, a step change in how our lower voltage networks are planned using more granular demand/generation forecasts and a platform of utilisation data derived from LV monitors, smart metering data and state estimation. Using these datasets in conjunction with asset health data and knowledge of customer flexibility availability we will create robust inputs into the process of solution optimisation. This optimisation process running across all voltage levels on the network on a consistent basis will ensure that the right selection of customer flexibility, smart grid solution or network reinforcement can be deployed. Please refer to the DSO Strategy and Network Visibility Strategy for further information.

Numbers 1-5 as shown on figure 1 are explored in more detail in figure 2 and 3.

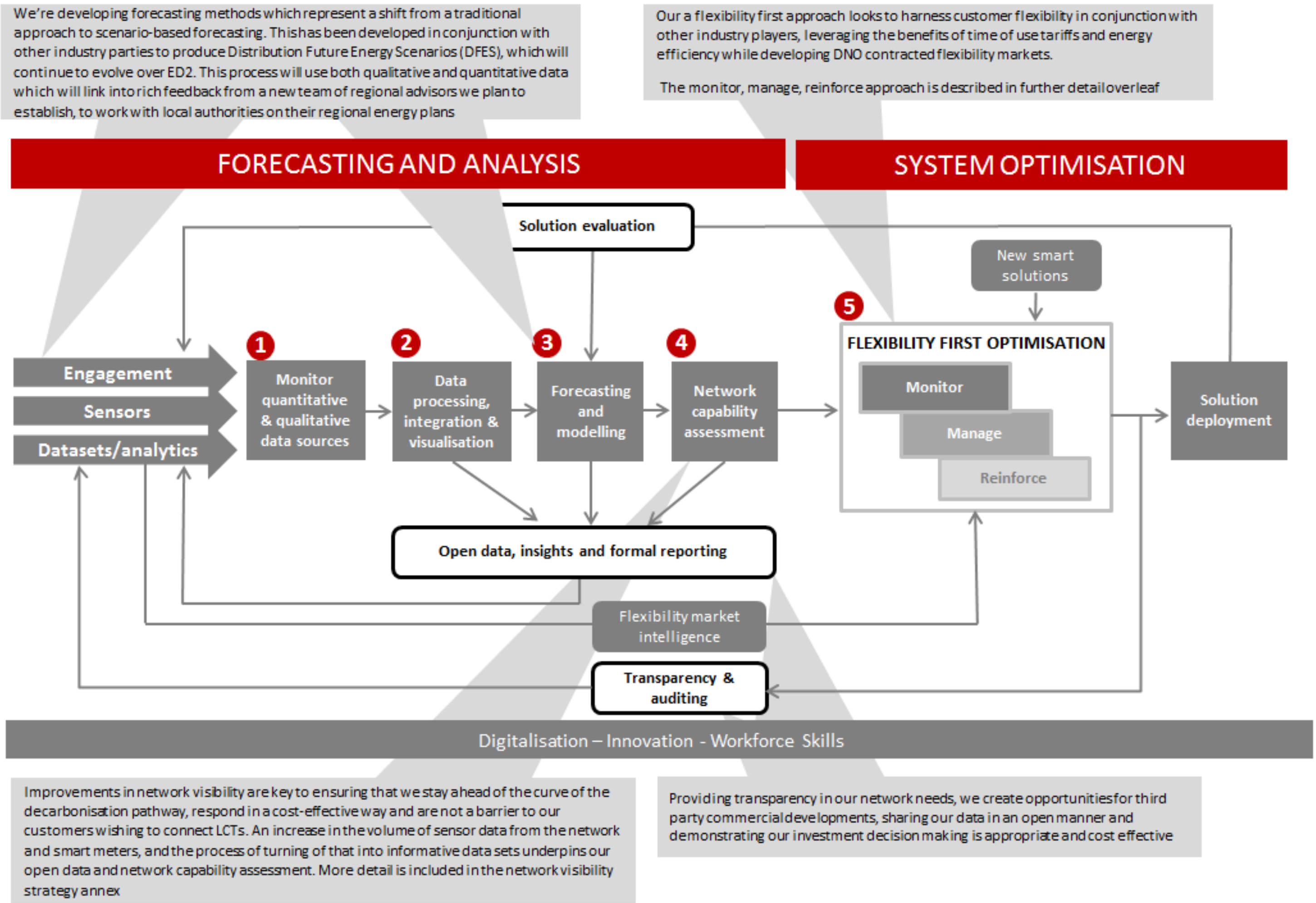


Figure 1: Delivery net zero: planning and operating the network

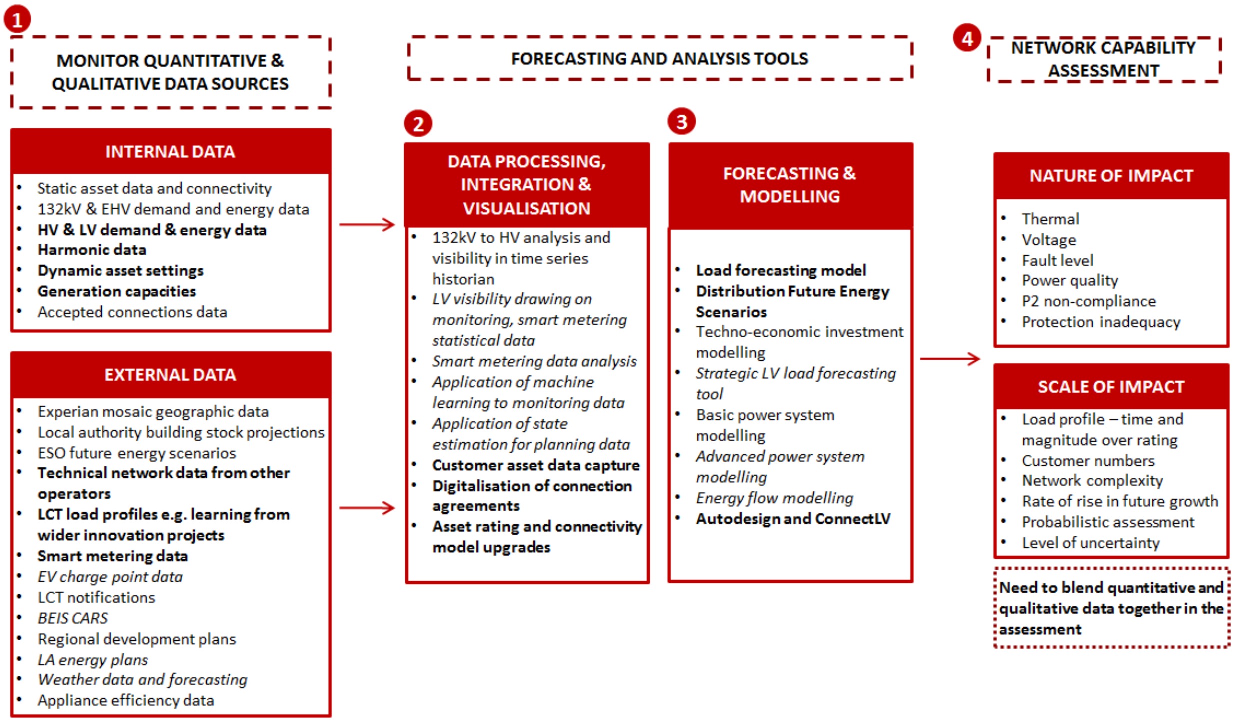


Figure 2: detailed forecasting and analysis steps

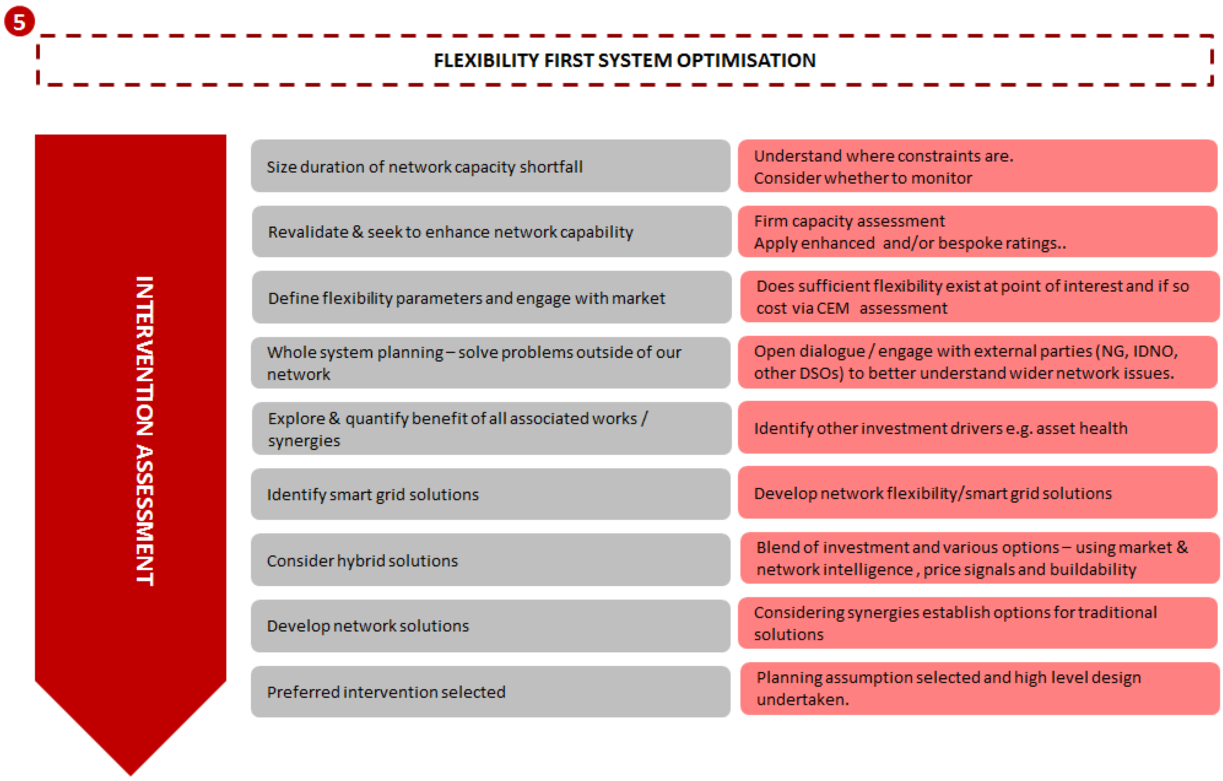


Figure 3: detailed system optimisation steps

Putting a flexibility first mind set into practice

As described in Figure 1 above, we have developed a three-pronged approach to deliver our flexibility first strategy that will allow us to manage the uncertainty, provide the opportunity for customers to engage directly in the benefits of the changing energy market and invest efficiently. This is shown in more detail in Figure 4 below:

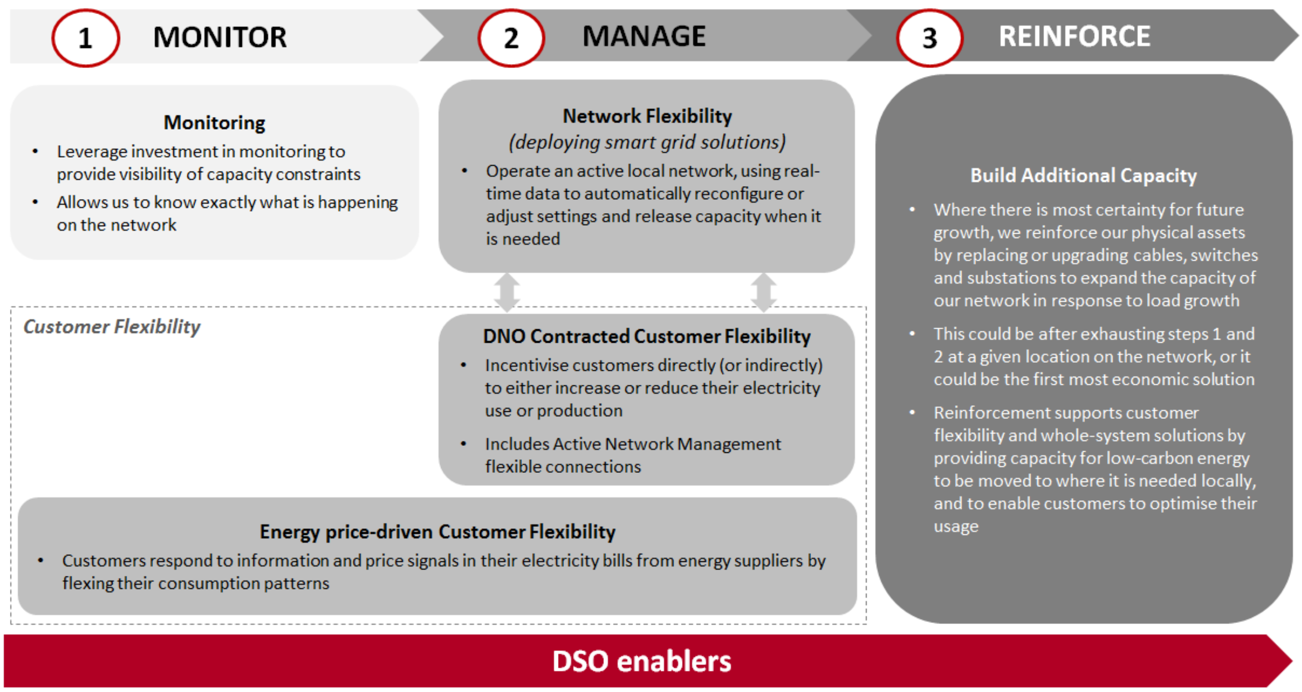


Figure 4: Delivering our flexibility first strategy

We see the use of flexibility as a fundamental means to efficiently manage well-targeted network utilisation and reinforcement needs. Optimising flexibility enables us to manage peaks in generation and demand on our network, which means we can get the best value out of our existing network and the investments we make, maximising cost efficiency for all customers.

We will support the development of different forms of flexibility and will need to be ready to harness them all, which is underpinned by the investment planned for our DSO strategy (please refer DSO strategy for further detail). We describe different types of flexibility in turn below. Further detail about each of the solutions described below and how they are considered in our investment planning are described later within this annex.

Stage one: monitor

The first stage lays the foundation for the efficient optimisation of the network that follows. By investing in digital capabilities on the low voltage (LV) network, to an equivalent standard that we have at high voltage (HV), we will have a far greater level of insight into the way patterns of energy use are changing.

The value of this stage should not be underestimated. In many cases, we expect that the deployment of relatively inexpensive digital technology will be enough to at least defer, maybe even avoid, more expensive interventions.

Without the network monitoring and associated analytical capability, we would not be able to understand the extent to which this 'peak flattening' was happening, and therefore we would not be able to take it into account in timing any intervention that became necessary.

As we explain in more detail below, we expect flexibility to take a number of forms. One of them is what we are calling 'energy-price driven customer flexibility'. This has the potential to be a great benefit to customers, since it represents the shift in energy usage patterns that they instigate in response to the price of the energy they are buying from their energy supplier. We also believe this will drive the adoption of energy efficiency measures and we will target working with third party providers of such services in areas that will benefit our customers, especially those in network areas supplying the vulnerable and fuel poor. Refer to the DSO strategy for more information on flexibility services alongside deliverables VN4.2 in vulnerable customers and WS4.2 in whole systems.

Not all of the price-driven signals will be associated with pressure on our network. There is good reason to expect there to be variations in the price of energy throughout the course of the daily cycle that are not necessarily related to the cost of running the distribution network. To the extent that those movements reduce the peak demand, the customers create a spin off benefit for free in terms of avoiding the cost of interventions we would need to make in order to deal with an increase in peak demand beyond the capacity of the network.

Stage two: manage

In some cases, it is possible that combination of price-driven customer flexibility and monitoring capabilities will be enough to support a growth in low carbon technology use by our customers. However, inevitably, there will be many situations where we need to undertake some form of intervention in order to deal with an increase in demand that exceeds the network's capacity.

At this point, we enter what we are calling the manage stage. Here, the sequence of solutions is more interactive than linear – but in all cases it involves the use of some form of flexibility rather than reinforcement. It may be that there is scope for an increased level of energy-price driven flexibility, where a sharper signal is factored into the energy price to reflect a signal created by our own tariffs. That may be combined with a more direct form of customer flexibility, where we enter into a specific contract to pay a customer to deploy flexibility to help manage the network. Alongside that, or instead of it, we may deploy flexible network solutions that use technology to help handle the peak in demand by using latent capacity.

Price-driven customer flexibility

In addition to the wholesale price related signals, we expect to see other electricity market actors (e.g. energy suppliers) using price-driven customer flexibility to incentivise customers to respond to price signals and correspondingly, increase or decrease their electricity consumption and/or generation. Incentives we expect to see being employed include using time of use (ToU) tariffs for domestic and industrial and commercial customers. These tariffs vary based on system conditions (e.g. the peak load or peak renewable generation on the network) and encourage customers to use energy at off-peak times or generate energy at peak times.

We also expect to see smart charging being employed to incentivise customers such as electric vehicle owners to charge during periods of low peak demand. We plan to work collaboratively with energy suppliers to ensure ToU distribution use of system (DUoS) tariffs and smart charging DUoS incentives are passed through to the final customer alongside wholesale price signals.

These measures will allow customers to flex their consumption patterns in response to system conditions (e.g. increasing consumption when there is a surplus of green electricity available). They have the potential to not only reduce energy bills for customers, but by shifting consumption away from peak periods also reduce our need to invest in network solutions to increase capacity or delay the need for investment until later.

Although not strictly price driven flexibility, there is the potential for technology changes to create similar effects on the demand profiles that we see. For example, the application of default settings in EV smart chargers or other devices have the potential to both create beneficial network impacts but also create network constraints due to a loss of demand diversity. The mechanisms to manage these situations are the same as price driven flexibility; improve monitoring of what is happening and work with industry parties on the wider implications of smart technology.

We set out the assumptions we have made in relation to price driven customer flexibility for the 2023-28 period in more detail in the ‘investment plan’ section.

DNO contracted customer flexibility – flexible connections

For several years now, as part of our ANM schemes, our customers have had the option to enter into flexible connections arrangements where their access to the distribution networks can be constrained during peak period, in return for a faster and/or cheaper connection due to reduced need for connection specific network reinforcement. This brings more flexibility to the network and reduces the need for wider network reinforcements, which can in turn reduce connection costs for customers. We expect to continue deploying ANM schemes in constrained regions and expect to have four ANM areas in operation by 2023 with an estimated 540MW of flexibility available.

You can read further about our plans around enhancing our ANM capabilities in the 2023-28 period in our DSO strategy (deliverable DSO4.2) and the connections plan section.

DNO contracted customer flexibility – flexibility services

In addition, we will contract with customers and pay them to provide a flexibility service by either increasing or reducing their electricity use or production. In contrast to ANM or flexible connections where the commercial arrangement is typically determined at the time of connection, contracts for the provision of standardised flexibility services, developed as part of the Energy Networks Association’s (ENA) open networks project, can be agreed at any time. We have worked with the ENA to develop four standard flexibility services, which we are now in the process of deploying for use cases set out in the table below.

Service	Definition	Use case
Sustain	A pre-agreed change in input or output over a defined time period to prevent a network going beyond its firm capacity.	Traditional reinforcement: defer spending on building new network.
Secure	A pre-agreed change in input or output based on network conditions close to real-time.	
Dynamic	A pre-agreed change in output following a network abnormality. In many cases this will coincide with long duration planned maintenance work.	Planned maintenance: manage the risk of power cuts during long duration construction periods.
Restore	Following a loss of supply, an arrangement under which the flexibility provider either remains off supply, or to reconnect with lower demand, or to reconnect and supply generation to support increased and faster load restoration under depleted network conditions.	Emergency support: provide support during unplanned power cuts.

Table 2: Flexibility services

We set out the assumptions we have made in relation to DNO contracted flexibility services for the 2023-28 period, including investment to defer reinforcement and investment to stimulate flexibility markets that we will require in 2028-33, in more detail in the ‘investment plan’ section.

Network flexibility

We will continue to invest in smart grid solutions, field-based equipment that will allow us to operate the local network in a more active manner, and use near real-time data to automatically reconfigure or adjust settings to optimise the power flows on our network and release capacity where needed.

Stage three: reinforce

The third stage in our process is to reinforce the network. In logical terms, this can be considered as the last stage. In practice, it may be obvious that the reinforcement solution is required quickly. We don't consider reinforcement in isolation and the health of the existing network assets or other investment drivers are incorporated in our decision making process as to how best to development the network. But our approach will always have explored the scope to use flexibility first.

Journey towards a low carbon future

Our strategic outcomes for the 2023-28 plan set out the vision for what success looks like in preparing for decarbonisation

In the Executive Summary of our main business plan document we set out Northern Powergrid's strategic vision for the 2023-28 business plan, which comprises achieving the following key outcomes in the period:

- Significant growth in customers connecting low carbon technologies
- Distribution system operation will be fully established
- Ready to support pathways to net zero
- Network will be inherently stronger, more intelligent and adaptable.

It is clear that decarbonisation is the key driver behind our strategic vision for the next price control period. The load related investment and the scenarios analysis that drives it, as set out in this annex, underpin how we intend to achieve the first and final outcomes of our strategic vision, enabled by achieving the second – delivering our DSO strategy (see also the DSO strategy) with a network that delivers the third as electricity becomes the main energy vector for our customers. The principles we have used to determine the appropriate decarbonisation scenario on which to base our investment plan are directly aligned with these goals – these are described in further detail under Step 2 below.

As set out in the scenarios and investment section of the main business plan, the outcomes we aim to achieve through our load-related investment, and how they will be measured, are:

	Customer outcomes	Benefits	Deliverables	Output measure/[1] *indicative input measure*	ED1 to date	ED1 forecast	ED2 target
SI1	**Efficiently put the network in a position to support LCT uptake and ensure all credible decarbonisation scenarios in our region remain open for delivering net zero by 2050 or sooner[2,3]**	— All pathways to decarbonisation will be kept open — Increased capacity for customers to connect LCTs	SI1.1) Publish our DFES annually and use it to continue the dialogue with our regional stakeholders to keep refining and updating our views about possible decarbonisation pathways in our region	**Ensure capacity is available**	✓	✓	✓
				Investment in creating capacity p.a.	*£17.5m*	*£19.5m*	*£103.1m*
				Network utilisation – % major substations > LI3	1.1%	2.5%	0.7%
				EVs accommodated (cumulative)	*31,000*	*110,000*	*941,000*
				HPs accommodated (cumulative)	*34,000*	*58,000*	*309,000*
SI2	**Deploy a flexibility-first approach, always choosing network and customer flexibility solutions where cost-effective and viable ahead of network reinforcement[4,5,6,7]**	— Increased capacity — Efficient decarbonisation — Quicker decarbonisation — Increased customer and network flexibility — Customers and stakeholders more actively engaged with the energy system	SI2.1) Run flexibility tender exercises where we will seek to use flexibility to defer reinforcement at our major substations and continue to seek to harness flexibility to defer reinforcement across all voltage levels SI2.2) Invest in market development to stimulate the use of flexibility so that we can defer future reinforcement costs across various network areas that will require intervention in the 2028-33 period SI2.3) Invest in smart grid solutions including LV monitoring SI2.4) Deploy DNO-contracted flexibility to shift peaks in demand on our network to enable deferment of traditional reinforcement	*Our suite of flexibility metrics are set out in our DSO Strategy*			

1. Measures are shown to track delivery of our customer outcomes. Whilst some measures may directly relate to deliverables, this may not be true in all cases. Numbers shown may be subject to rounding - see Annex 'A1.4 - key targets & measures' for profiled targets.
2. Cross reference Asset Resilience AR1) Enable an efficient long-term transition to net zero through maximisation of synergies between load-related and asset renewal expenditure.
3. Cross-reference Whole Systems WS2) Ensure our customers' future needs are met through cross-sector and cross-vector planning.
4. Cross-reference DSO Strategy DSO4) Enhance processes and systems for network operations to enable a step change in our capability to optimise a system with increasing customer and network flexibility.
5. Cross-reference DSO Strategy DSO5) Enable significant uptake of customer flexibility and facilitate development of new markets for customers providing services to networks.
6. Cross-reference DSO Strategy DSO3) Unlock new capabilities and benefits for customers through provision of open energy system data and engaging in joint planning with our stakeholders.
7. Cross-reference Whole System WS2) Ensure our customers' future needs are met through cross-sector and cross-vector planning.

Innovation
Data and Digitalisation
Workforce Resilience

Planning for the future

In order to achieve our strategic outcomes, we have developed our investment plan in three steps. First, we created a set of credible future pathways to envision possible energy futures and explore the issues they raise. Second, we modelled a planning scenario that captures our 'best view' of the future, based on a set of criteria we have developed. Third, we conducted a network impact assessment based on our planning scenario to develop an investment plan for the 2023-28 period.

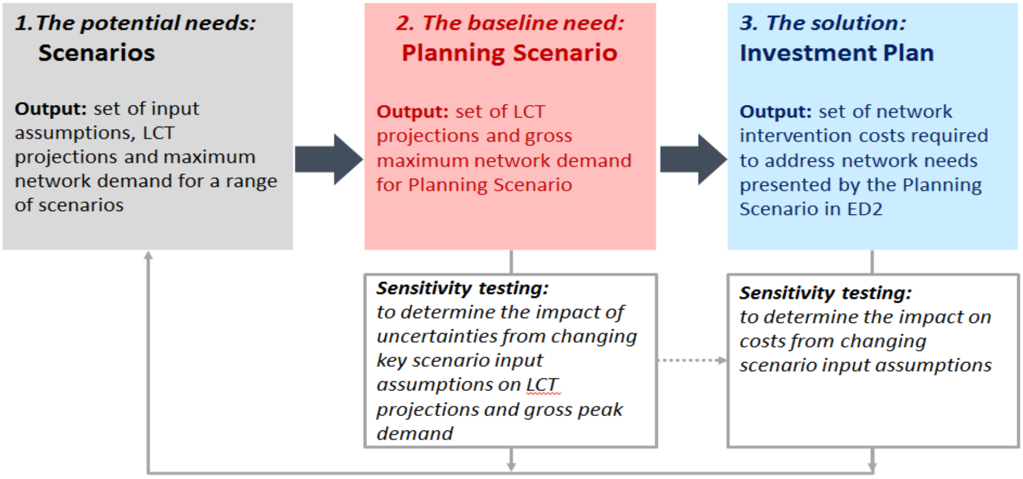


Figure 5: Planning for the future

This process was supported by extensive sensitivity testing to estimate the impact of modifying uncertain assumptions on our investment plan and ensure its robustness across possible future pathways. Appendix 3 - planning scenario input assumptions, provides further detail on the sensitivity testing we have conducted as part of developing our investment plan.

Each of these three steps is described in more detail in:

- Step 1: Scenarios;
- Step 2: Planning scenario; and
- Step 3: Investment plan.

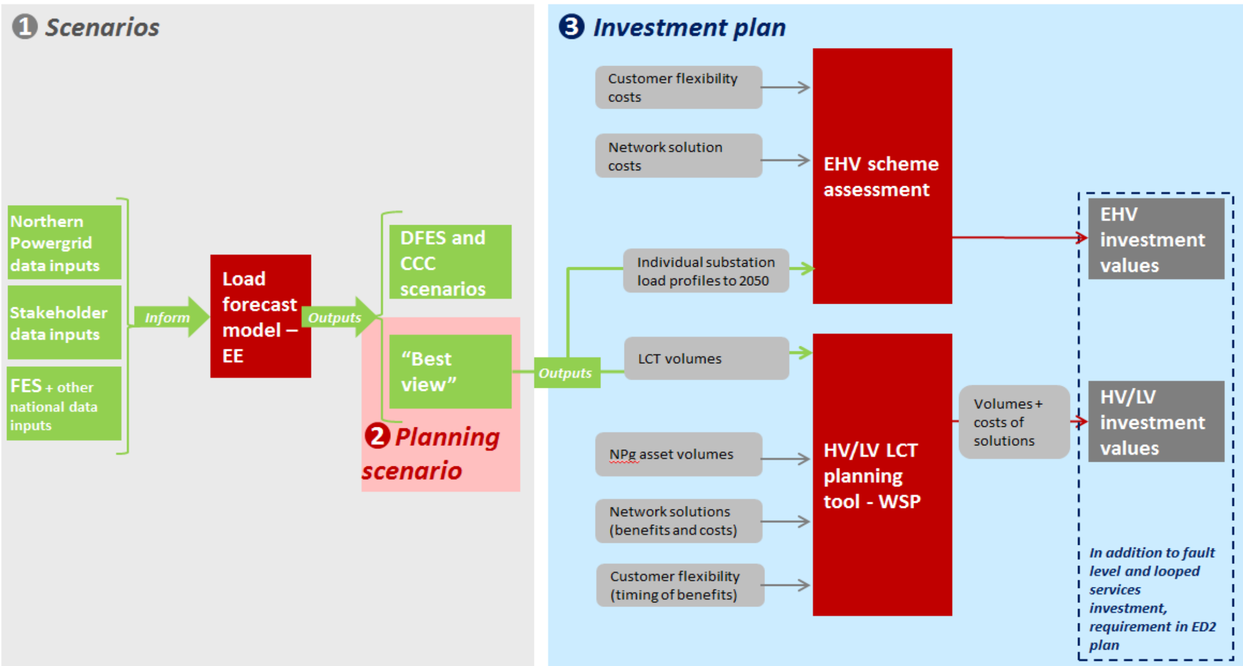


Figure 6: High-level scenarios and investment planning approach

Note:
EE: Element Energy, low carbon consultants who provide the load forecast model, described in further detail in section 'scenarios' and Appendix 1.
WSP: consultants who have developed LCT Planning Tool, described in further detail below and in HV/LV Network Reinforcement EJP-11.1

Step 1 - Scenarios

Defining the scenarios

We have developed a range of scenarios to forecast possible decarbonisation pathways to net zero. These scenarios range from a predominance of electrification in the heat and transport sectors to other states of the world where alternatives to electricity such as hydrogen can be expected to play a greater role.

Each scenario is made up of a set of assumptions about variables in the energy system including building blocks such as LCT uptake, peak load, generation, storage and energy efficiency. These assumptions are informed by government policy and targets at the national level, but also regional knowledge, market information and insights received from engagements with our customers, local authorities in our region, and various other stakeholders.

Our range of scenarios includes:

- Three National Grid future energy scenarios 2020 (FES)[4] for Great Britain, with our DFES[5] translating these into three regional scenarios for our licence areas. One of the FES scenarios does not meet net zero by 2050 target and has therefore been excluded.

- An additional scenario developed by us explores the possibility of reaching net zero ahead of the 2050 target in-line with regional aspirations for faster decarbonisation.

- Three additional scenarios based on pathways identified in the Climate Change Committee's (CCC's) Sixth Carbon Budget (Balanced Net Zero, Widespread Engagement, Headwinds).[6] Three of the CCC scenarios are very similar so we have modelled the ends of the CCC range, thereby covering all five scenarios.

Our scenarios analysis is based on National Grid's FES 2020. As part of the annual FES/DFES cycle, we are working on our DFES 2021 which reflects National Grid's FES 2021, which includes its latest assumptions about future energy pathways. Our DFES 2021 will be published separately in due course, which will provide a view on the impact of the updated assumptions in FES 2021.

These seven scenarios comprise the set of future energy pathways that we have considered as part of our business planning process. The broad set of assumptions, or 'world view', for each is shown in the figures below.

[4] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[5] https://www.northernpowergrid.com/asset/0/document/5836.pdf
[6] https://www.theccc.org.uk/publication/sixth-carbon-budget/

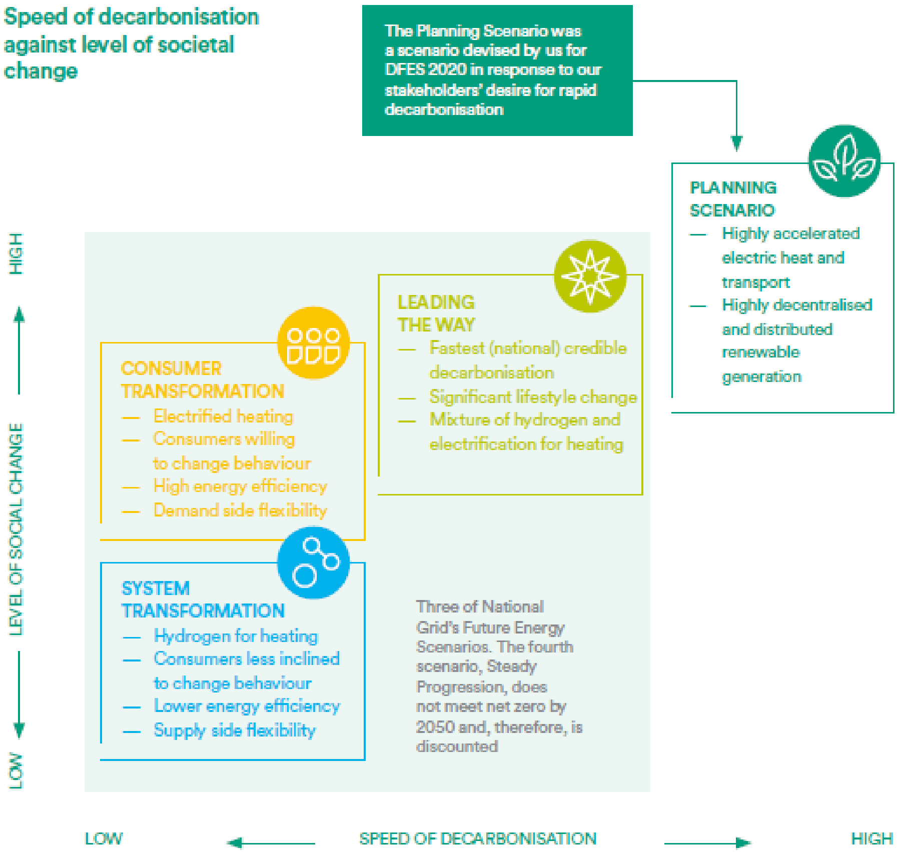


Figure 7: DFES scenarios

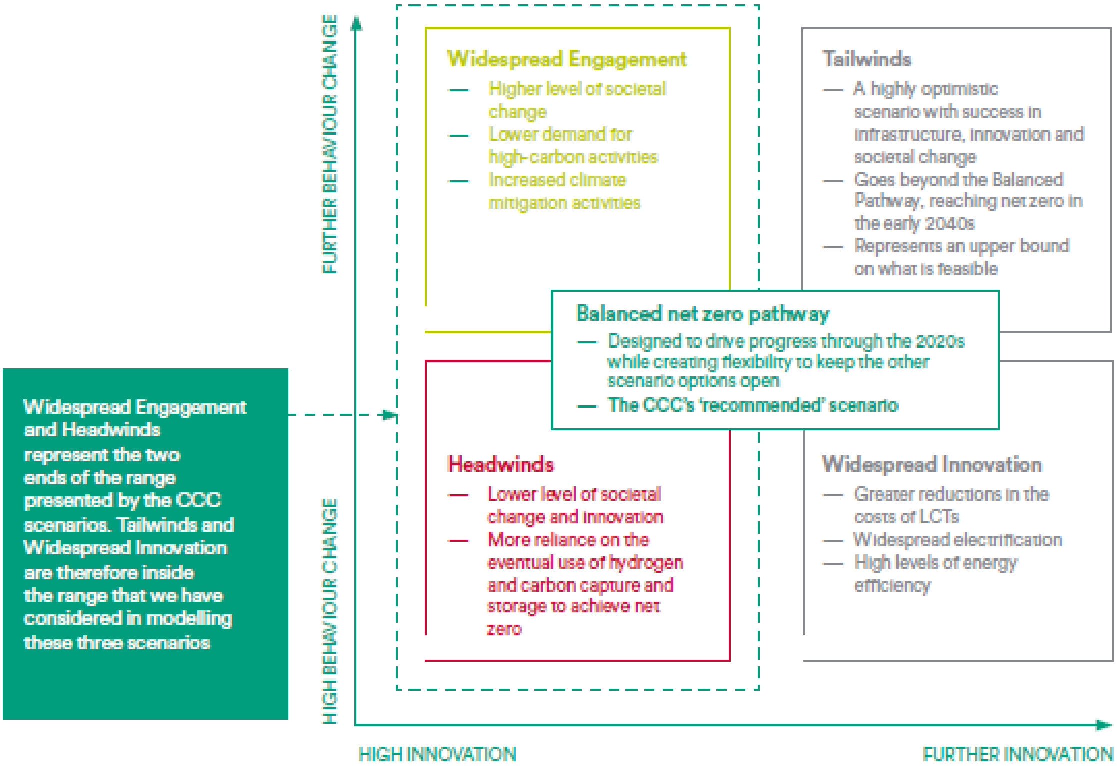


Figure 8: CCC scenarios

Stakeholder engagement

We have worked with industry partners and undertaken extensive customer engagement and industry consultation to ensure that the scenarios meet local aspirations and enable decarbonisation across our region. A key part of this is the stakeholder engagement process which forms part of the annual FES and DFES information exchange cycle.

Using an open data approach[2] we have invited our stakeholders to engage with the 2019 and 2020 DFES outputs and sought feedback to help us support their zero carbon ambitions through coordinated future network planning. Understanding that different stakeholders may wish to explore the data with a varying degree of granularity, we provided a number of datasets that would suit these various needs. Alongside providing forecasts for key locations on the distribution network (such as primary substations or grid supply points), we published datasets which display DFES at a local authority level. These include MS Excel workbooks with charting tools, which are useful for viewing the data behind different LCT forecasts.

DFES stakeholder engagement process

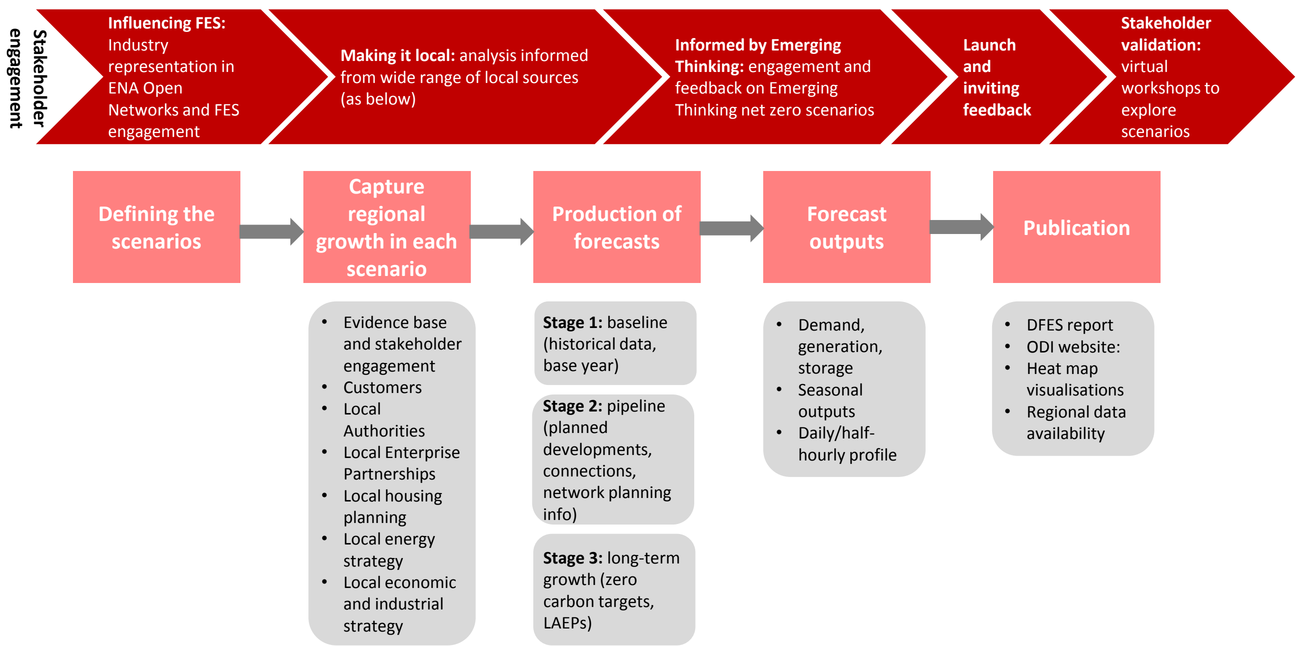


Figure 9: DFES **engagement process**

As part of the follow up to our DFES 2019 publication we ran a stakeholder consultation exercise involving two targeted events that took place in March 2020 at Leeds and Newcastle. The feedback received at these events formed the basis of our DFES 2020 forecasts. In August 2020, we published our Emerging Thinking about how we will best support our region's power needs as the country seeks to meet net zero targets by 2050 and sought feedback on our thinking from a broad range of stakeholders. This was reflected in the initial version of our DFES that was published in December 2020 alongside an updated version of our data visualisation tool. More specifically, an additional DFES scenario 'net zero early' was developed in response to stakeholder feedback as part of our Emerging Thinking development.

Following the publication of our DFES 2020, we contacted more than 11,000 stakeholders, including 6,687 connection stakeholders and encouraged them to engage with the scenarios and provide their feedback. In January 2021, the initial DFES 2020 was scrutinised by our technical panel. In addition, our audit team also assured reconciliation of the data and DFES was discussed at three local energy planning forums. We initiated a targeted outreach campaign to inform the next iteration of our DFES, approaching 100 individuals from identified stakeholder groups to take part in an online survey and telephone interviews. This included local authorities, house builders and developers, car manufacturers and dealerships, and LCT installers. Taking on board the feedback received across this extensive engagement process, we published a fully assured final DFES 2020 document in May 2021.

Since publishing our draft business plan, we have continued to engage with our stakeholders on decarbonisation pathways – in particular local authorities as they progress their own thinking. The dialogue in the July -November 2021 period has continued to support our direction to ensure that our actions are supporting net zero emissions by 2050 or sooner.

DFES stakeholder engagement interactions

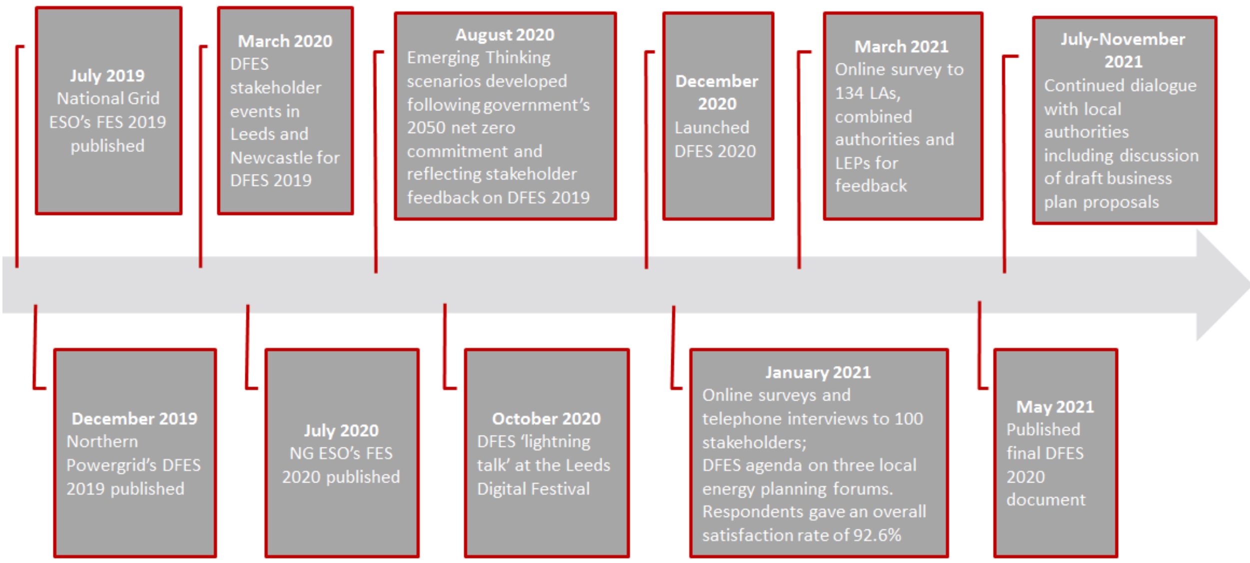


Figure 10: Stakeholder engagement interactions

As part of our 2023-28 business planning, we have incorporated feedback received from stakeholder engagements when considering possible future scenarios for our region, in determining our assumptions around customer flexibility, and in designing sensitivities to test the robustness of our investment plan. More details on our stakeholder engagements are provided in the separate decarbonisation annex.

Further detail about the stakeholder engagement conducted on DFES since 2019, how we have responded to feedback and how this has impacted our scenarios and NGESO's FES (including examples of specific impact on our modelling) is included in Appendix 2 – DFES stakeholder engagement. Additionally, please refer to the detailed engagement findings - scenarios and investment section for detail on the engagement undertaken for waves 1-4 of the 2023-28 planning process, which includes broader stakeholder views on our approach to decarbonisation investment and planning scenario (described further in the 'investment plan' section).

Scenarios modelling methodology and outputs

Our scenarios are built by considering assumptions about a range of building blocks including EVs, heat pumps, generation and energy efficiency and applying them to our electricity network between now and 2050, to create a scenario based load growth model, in partnership with low carbon energy consultants Element Energy.

The DFES scenarios use inputs from National Grid's FES in conjunction with regional knowledge and bottom up assumptions to build a regionalised view of the scenarios. Our DFES scenarios have been built by first using a top down approach that takes the national FES scenarios as a high-level baseline, then uses a bottom up approach, that inputs key parameters of our electricity network and supporting data, and sense checks our regional share of national inputs informed by what we know from our stakeholders and our own network knowledge.

The range of CCC scenarios has been disaggregated from national pathways and made more specific to the Northern Powergrid region. As part of this process, we scaled down the CCC's nationwide electric vehicle and heat pump uptake scenarios down to the Northern Powergrid licence areas to create scenarios applicable for our local area.

As part of this range of scenarios, we also model our planning scenario. Based on stakeholder feedback gathered about the range of seven scenarios set out above, we determine a hypothesis about our "best view" in relation to a set of key input assumptions. This hypothesis is additionally guided by principles regarding what we would like the planning scenario to reflect which are described further in step two below.

The load growth model that we have developed uses as its basis the peak demands observed on the network at the major substations EHV and 132kV – as reported through our distribution load estimates, and directly recorded from our half hourly (HH) data in SCADA. It incorporates accepted but not yet connected connections (demand and generation) and then overlays the future demand growth within the load growth model. The outputs from the load growth include highly granular peak demand forecasts through the 2023-28 period and beyond to 2050, for every major substation on our network. Furthermore, the load growth model produces outputs at secondary distribution substation level which are then utilised within the tools (LCT planning tool) used to assess load growth on the HV and LV networks.

The key steps used to build the scenarios are summarised in the table below. Further detail about the phases of the process, and key assumptions used, is included in Appendix 1.

Phase	Title	Description/purpose	Output
1	**Build "Year 0" demand and LCT profiles**	We build a view of HH demand and LCTs on our network by bulk supply point (BSP) and grid supply point (GSP) primary and secondary substation as of today (year 0 – i.e. 2020) as reported through our forecast load information[7].	Year 0 underlying demand profiles including LCTs for each secondary and primary substation, GSP and BSP.
2	**Build scenario building blocks**	We build decarbonisation scenarios by making assumptions about a range of building blocks that drive consumption and generation on the network in the future and other inputs. Building blocks relate to volumes (e.g. number of EVs) alongside other input assumptions (e.g. energy efficiency).	Set of building blocks and associated assumptions and inputs by scenario, e.g. LCT take up, generation.
3	**Run load growth model**	We run a load growth model that applies the inputs for each building block to our year 0 network data – this includes known accepted generation and demand connections not yet connected.	The load growth model produces highly granular data sets for annual future demand and generation profiles and LCT uptake projections by scenario in licence area view, GSP, BSP, primary and secondary view.

Table 3: Scenario building key steps

[7] Published through Appendix 5 of our Long-Term Development Statement (LTDS)

Scenario modelling results: key findings

The key outputs from our scenarios modelling process is a set of forecasts of LCT uptake and resulting load growth on our network from now to 2050. The uptake of EVs and HPs are the primary drivers for load growth across the range of scenarios. Below we provide key modelling results over the full modelling horizon (up to 2050), and subsequently, provide a more focused overview for the 2023-28 period and 2028-33 period.

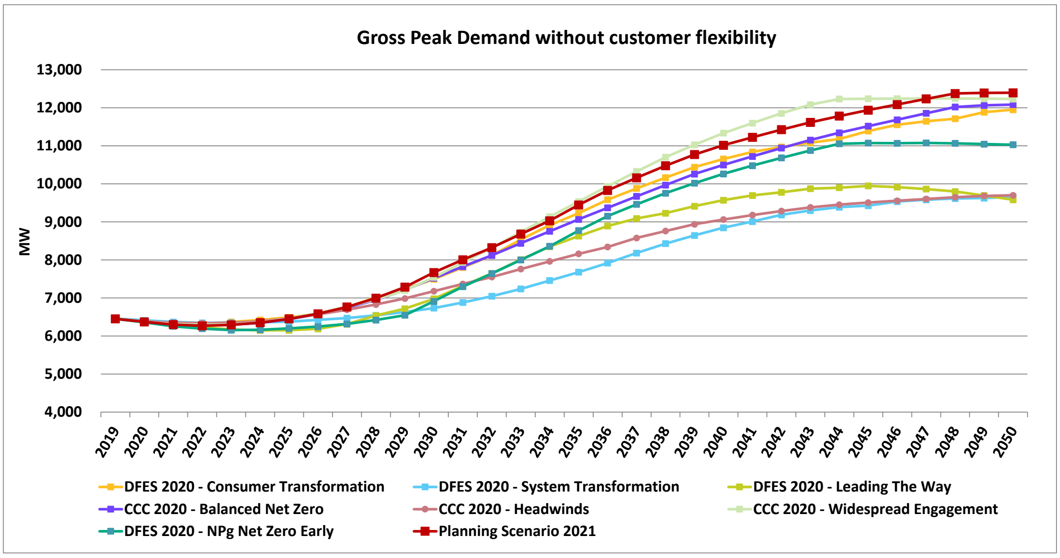


Figure 11: Modelling results 2019 to 2050

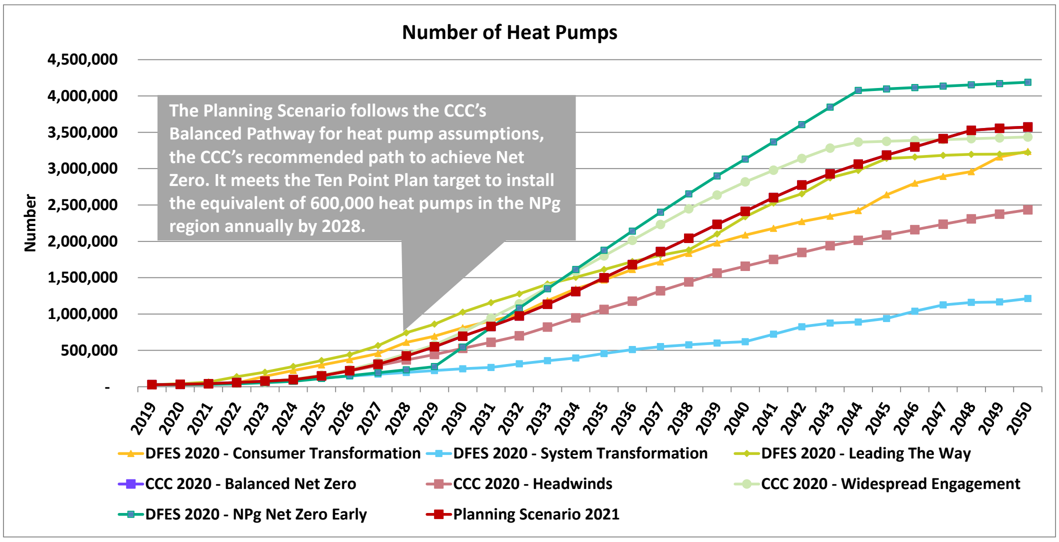


Figure 12: Heat pumps

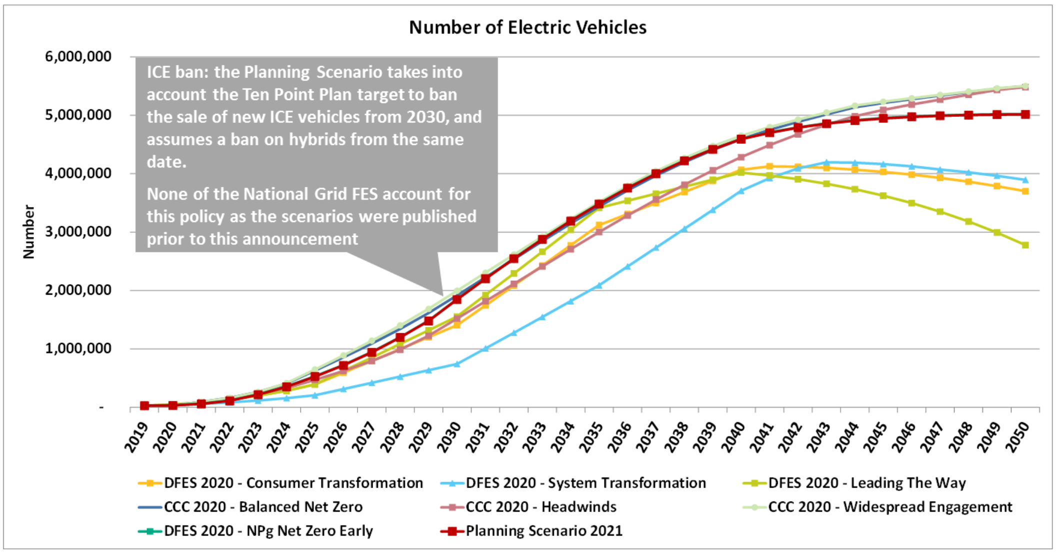


Figure 13: Electric vehicles

Modelling results – 2019 to 2033

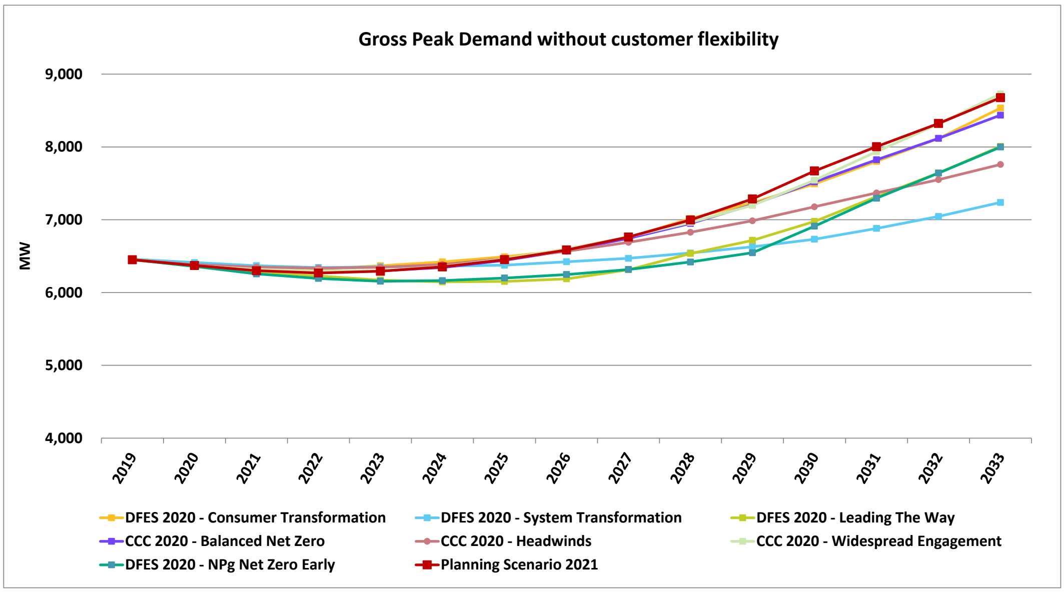


Figure 14: Modelling results – 2019 to 2033

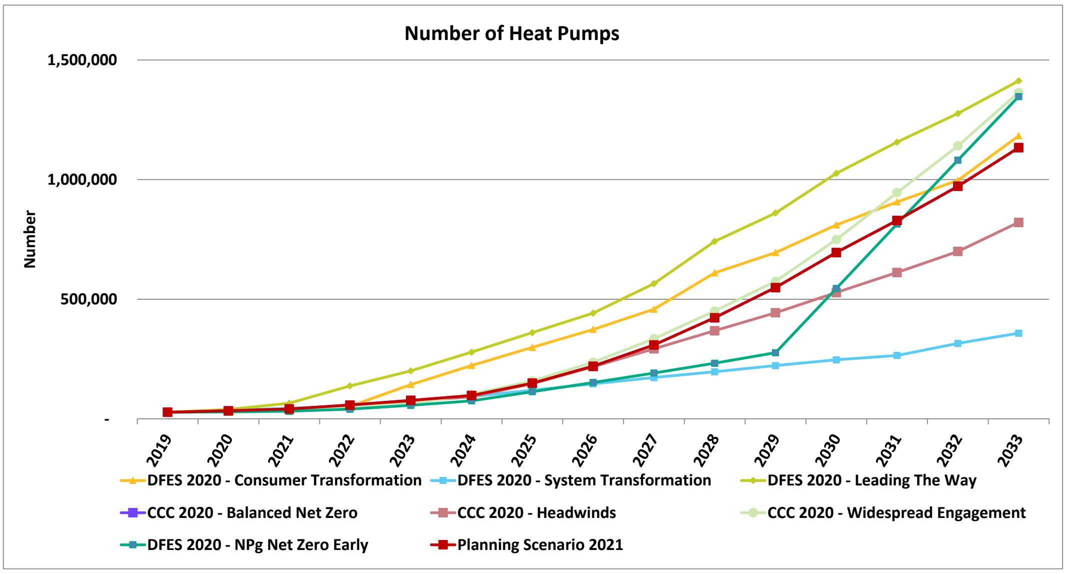


Figure 15: Heat pumps

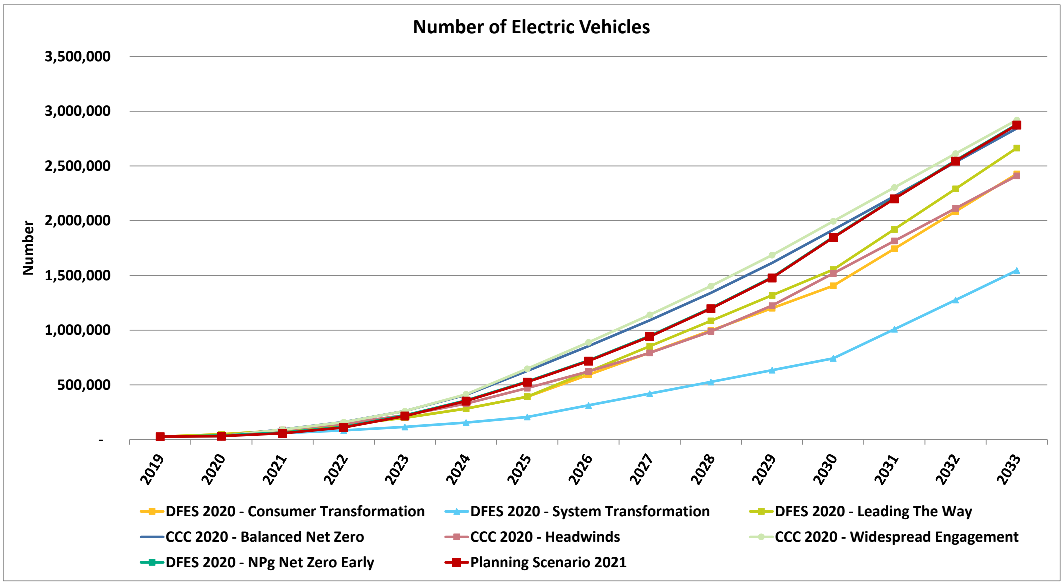


Figure 16: Electric vehicles

Category (2030 values)	Planning Scenario	FES Consumer Transfor-mation	FES System Transfor-mation	FES Leading the Way	CCC Balanced Net Zero	CCC Headwinds	CCC Widespread Engagement
Total electricity demand (TWh)	41.9	39.2	37.5	37.0	41.1	40.6	41.1
Total demand from HPs (TWh)	3.6	3.3	1.0	0.4	3.6	3.3	2.1
Total demand from EVs (TWh)	4.0	2.8	1.6	1.3	3.3	4.4	3.8
Peak demand (GW)	7.7	7.5	6.7	7.0	7.5	7.2	7.5
Number of HPs (thousands)	695	810	247	1,026	695	528	749
Number of EVs (thousands)	1,845	1,405	742	1,553	1,916	1,518	1,994
Renewable generation (MW)	5,200	5,375	4,409	5,129	5,375	5,375	5,375
CO2 emission savings facilitated ($MtCO_2$)	322.0	n/a	n/a	n/a	n/a	n/a	n/a

Table 4: Summary of key outputs by scenario

Refer to Appendix 1 for further detail about the modelling results of the range of scenarios.

The role of hydrogen is a key uncertainty in forecasting decarbonisation pathways for the 2020s and beyond

The long term potential for hydrogen to play a central role in whole system decarbonisation is significant, and it is highly likely to play a key role in the hard to decarbonise sectors such as heavy industry and heavy transport. Its role in decarbonisation of the ‘easier’ to decarbonise sectors such as light transport and domestic heating is likely to be far lower, at least in the next 10 years, given that the hydrogen sector is in its infancy, and that lower-cost, ready-to-adopt solutions such as electric vehicles and heat pumps are already starting to be, and are expected to continue to be increasingly adopted at scale.

We explore the value chain, covering production, storage, transport and usage in detail in Appendix 4 of this business plan annex. As we explore the value chain, we outline what we have assumed when preparing the 2023-28 business plan. These considerations point to hydrogen becoming a significant sector to support decarbonisation in the long term (especially for the areas ‘hard’ to decarbonise, beyond the 2020s). Innovation and market development for the hydrogen economy will develop at pace during the 2020s, and therefore on-going collaboration and whole-systems thinking is imperative during 2023-28. This collaboration will be spearheaded by our local area energy planning (LAEP) engineers, a team we plan to establish as part of our DSO strategy (see DSO3.2 in the DSO strategy).
Given the nascent stage of the hydrogen industry, the investment required during 2023-28 is low regret in that it is underpinned by decarbonisation of the ‘easy’ to decarbonise areas of the energy system.

Step 2 – Planning scenario

Principles guiding the planning scenario

Based on the range of possible future pathways and the assumptions used to build them, we have developed a single planning scenario guided by the following principles:

- it keeps all future credible pathways open, ensuring that we are not an obstacle to any decarbonisation pathway;
- it is within the range of Ofgem's reference scenarios, the three net zero compliant FES scenarios by National Grid and the CCC's Sixth Carbon Budget scenarios;
- it is aligned with the latest government policy particularly in relation to EVs and HPs detailed in the table below (note that the FES 2020 scenarios do not reflect these targets); and
- it reflects what we have heard from local stakeholders about the desire to facilitate an accelerated decarbonisation pathway.

In October 2021 the UK Government published its Net Zero Strategy and its Heat and Buildings Strategy, which set out plans to meet the CCC's carbon budgets to 2037 and a vision for a net zero economy by 2050. In line with the second principle stated above, our Planning Scenario meets the needs of the CCC's Sixth Carbon Budget and is therefore aligned with and designed to deliver the Government's latest policy commitments, in line with the third principle.

The planning scenario is based on a highly electrified decarbonisation pathway. The key assumptions driving the impact of the scenario on our network are described in the table below. These are highlighted because they are the variables that are particularly sensitive to changes in the assumptions, as explored in our sensitivity testing in appendix 3 – Planning scenario input assumptions. Detail of the full range of the key input assumptions about the planning scenario is also included in appendix 2 – DFES stakeholder engagement.

Assumptions for key inputs in the Planning Scenario

Key building block	Assumptions
Electric vehicle uptake	– In line with the government's Ten Point Plan, it assumes a ban on internal combustion engines (ICEs) by 2030 and includes a ban on hybrids by 2035.
Heat pump uptake	– In line with the CCC's Balance Pathway scenario, it meets the government's Ten Point Plan targets of 600,000 heat pumps being installed annually by 2028. – It assumes a ban on the sale of new gas boilers from 2025.
Energy efficiency	– Domestic thermal efficiency is assumed to be moderate. Appliance efficiency assumptions meet current EU targets for 2030. – I&C energy efficiency is aligned to EU energy efficiency targets.
Renewable energy sources	– Solar PV assumptions based on high large solar uptake and high domestic PV take up reaching 1013 MW by 2030 and 2146 MW by 2050. – Wind assumption supported by recent wind turbine sizes and behaviours reaching 748 MW by 2030 and 2015 MW by 2050.

Table 5: Assumptions for key inputs in the Planning Scenario

Planning Scenario modelling results

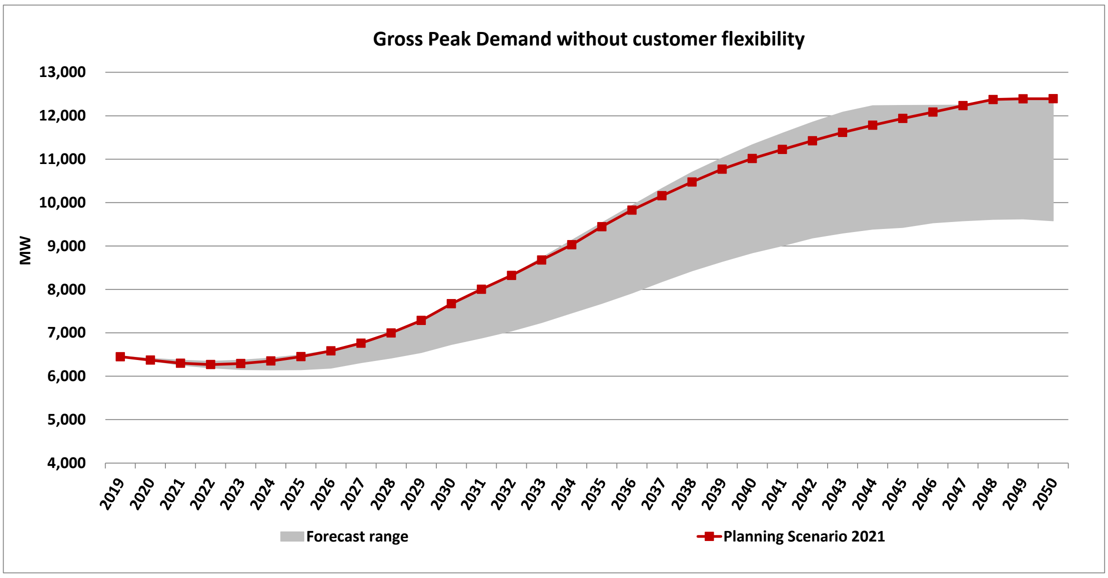


Figure 17: Planning Scenario gross peak demand within the range or scenarios

As presented in the scenarios, the above graph shows that gross peak demand is forecast to grow significantly between now and 2050 in all future views of the world, with the planning scenario near the top of the range due to it representing a highly electrified future energy pathway. It should be noted that whilst gross peak demand presents an interesting illustrative metric across the electricity system, it is local network peaks rather than gross peak demand that drive network investment, discussed further in the investment section below.

Category	End of 2023-28 period	2030	2050
Total electricity demand (TWh)	37.9	41.9	64.2
Total demand from HPs (TWh)	1.4	3.6	19.1
Total demand from EVs (TWh)	2.4	4.0	7.8
Peak demand (GW)	6.8	7.7	12.4
Number of HPs (thousands)	309	695	3,572
Number of EVs (thousands)	941	1,845	5,015
CO2 emission savings facilitated ($MtCO_2$)	255.3	322.0	447.0
Renewable generation (MW)	4,342.0	5,200.0	10,965.0

Table 6: Planning scenario modelling key outputs

Our planning scenario is at the higher end of the range of pathways, since it accounts for government targets which were set after the 2020 FES were published. It assumes that we will connect a further ca. 830,000 EVs and 251,000 HPs to our network over the course of the next price control period. It is also in line with our stakeholder vision of an accelerated electrification-heavy pathway to decarbonisation.

The planning scenario represents our 'best view' envisioned in Ofgem's business plan guidance. It is important to emphasise that this does not mean it is the most likely scenario, but rather the one best optimised for the inherent uncertainty in planning for all decarbonisation pathways. It ensures that our network will be in a position to effectively keep pace with any pathway that emerges by 2028 and therefore represents the most efficient way of keeping all pathways open. Refer to Appendix 3 in this document, detailed costs breakdown, for details on the sensitivity testing we have performed on the planning scenario.

If we were to plan for a slower transition in 2023-28 we would risk not being able to keep up with acceleration in future periods and therefore becoming an obstacle to our stakeholders achieving their decarbonisation ambitions. Additionally, we would risk not being able to deliver on new policy developments from the Government in the coming years. This is particularly the case in relation to the heat sector where the government is expected to provide more guidance in relation to how they expect to achieve the 600,000 p.a. electric heat pump installations target by 2028.

The 2023-28 period provides an opportunity to focus on making a high proportion of low-regrets investments (i.e. investments that are needed in any of the scenarios over the next two regulatory periods (i.e. to 2033)). The grouping of pathways is tighter in the early years, which reduces the level of uncertainty around the investment we are planning today for the 2023-28 period. Developed in this manner, our planning scenario ensures that we are an enabler of effective decarbonisation in the 2023-28 period, keeping all options open to achieve net zero. As revealed by sensitivity testing (detailed in Appendix 3, detailed costs breakdown below), the planning scenario is sensibly robust against a wide range of assumptions and possible decarbonisation pathways.

We present further detail on our planning scenario for some key technologies as follows.

Heat pumps (HPs)

Our planning scenario for HPs follows the CCC's balanced net zero pathway, revised to reflect the Northern Powergrid region based on modelling conducted by Element Energy. The planning scenario ensures that we achieve the government target of installing the equivalent of 600,000 HPs annually for the Northern Powergrid region by 2028. This target is reflected in the CCC scenarios but not the FES or DFES scenarios – as such our assumptions for HPs in the planning scenario are at the higher end of the range of scenarios as can be observed from the figure below.

We want to ensure that we do not impede the take up of LCTs such as HPs and therefore, seek to prepare our network for a possible realisation of a heavy electrification scenario efficiently. According to the Future Homes Standard, from 2025 all new housing is expected to have a low carbon heating system, such as a heat pump. We also assume that a range of policies and incentives will be rolled out in the coming years that will focus on improving building energy efficiency, thereby supporting the wide scale rollout of HPs.

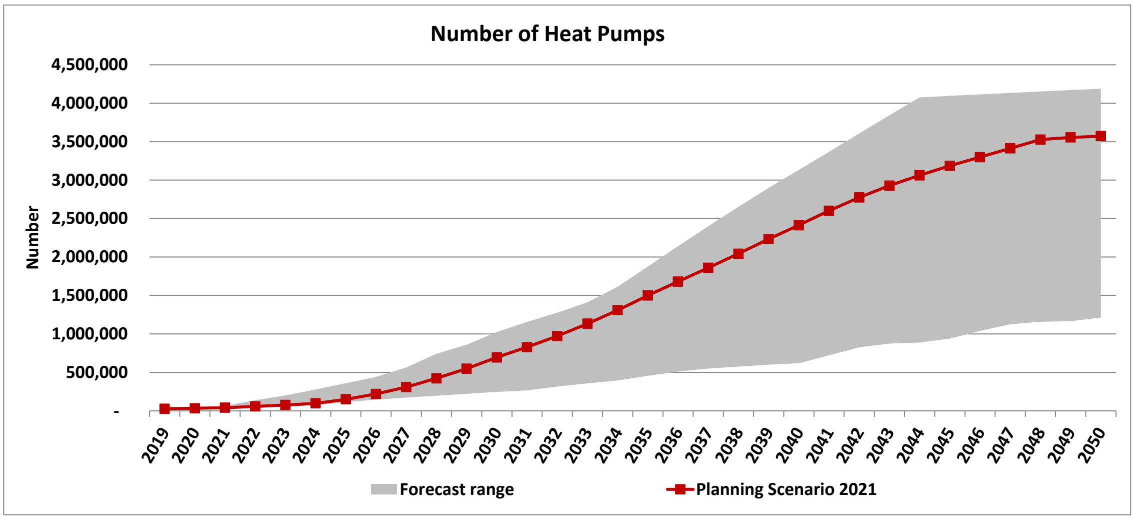


Figure 18: Heat pumps

Additionally, we expect higher HP installations in new build properties and those off the gas network, particularly in areas which experience a colder winter. The Northern Powergrid regions in particular experience cooler weather than the southern regions of the country and combined with local intelligence on housing stock, we would expect our region to have a higher heat pump demand compared to other networks. To improve our forecasts for heat pump installations, we are developing an innovation project on the deployment of HPs in our region the insights from which will inform our future DFES engagements.

The specific electrical assumptions relating to HPs that we assume in our load growth modelling is detailed in Appendix 1 and in our HV/LV Network Reinforcement EJP-11.1.

Electric vehicles (EVs)

In relation to EVs, our planning scenario assumes adherence to the recent government ban on the sale of ICE vehicles by 2030 and also assumes a ban on hybrid vehicles by 2030. This ban was moved forward from the 2040 target as part of the government's 10 point plan after the publication of the FES 2020 scenarios. As such, our estimate of EV uptake in the planning scenario is in line with both the DFES and CCC scenarios during the 2023-28 period but at the higher end of the range of scenarios over the longer term (as can be observed from the following figure). We assume that as a result of greater expansion of charging networks, electrification of commercial and public transport, as well as more stringent emissions targets, the adoption of EVs will be rapid during the 2020s when they are expected to achieve price parity with petrol and diesel cars.

The specific electrical assumptions relating to EVs that we assume in our load growth modelling is detailed in Appendix 1 – scenario methodology and in our HV/LV Network Reinforcement EJP-11.1.

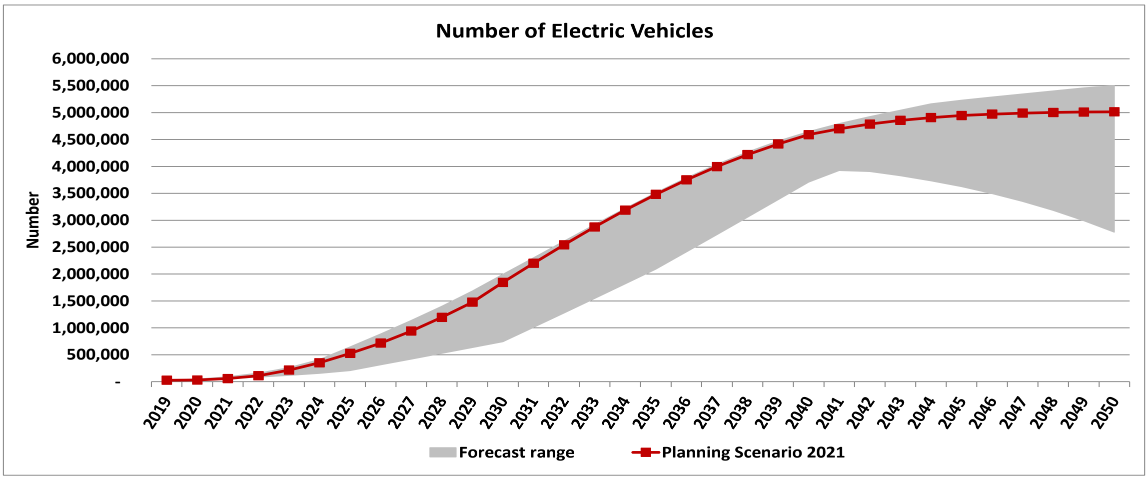


Figure 19: Number of electric vehicles

Carbon emissions savings

We can enable our region to save 255.3 $MtCO_2$ by 2028 by investing to facilitate the LCT uptake assumed in our planning scenario. By preparing for a faster pathway, we facilitate a greater saving of greenhouse gas emissions – it is the 'area under the curve' that matters in working towards net zero, not just the end goal. Planning for a pathway which meets the requirements of the CCC's sixth carbon budget means we are working towards making our region's essential contribution to national emissions reduction targets and beyond that to tackling global climate change.

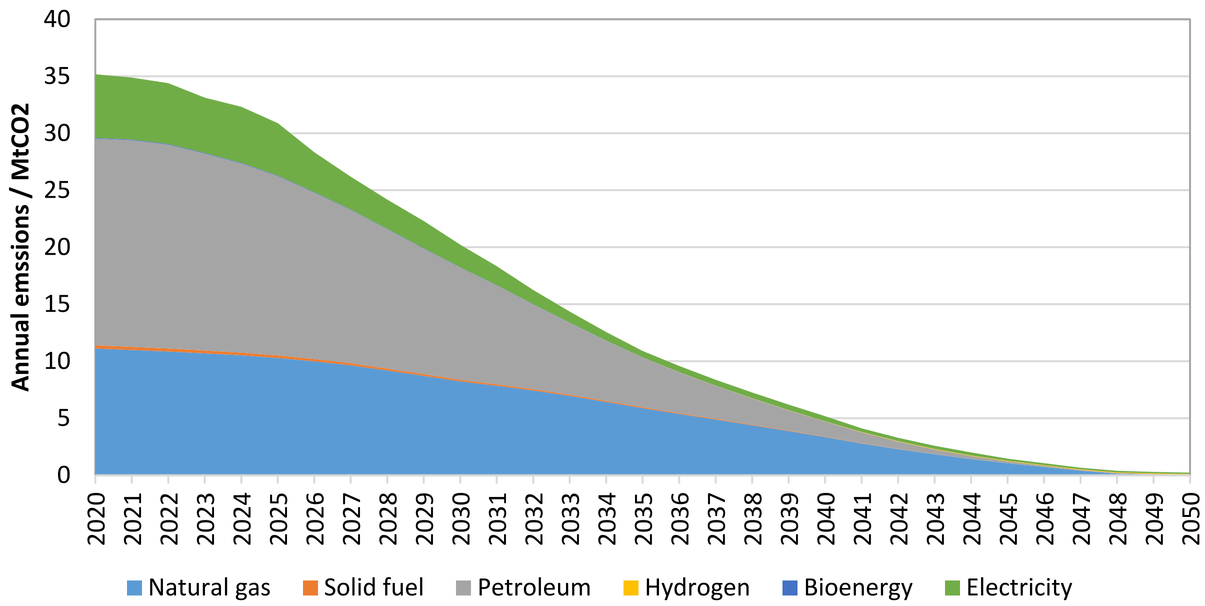


Figure 20: Annual greenhouse gas emissions

Step 3 – Investment plan

Overview

There are two parts to this investment plan section of the annex:

- detail of our methodology to determine the required investment; and
- the results of our investment modelling and assessment and the resultant investment strategy included in the 2023-28 plan.

The methodology and investment strategy are described below by each solution type:

- Monitor:
  - rollout of LV monitoring.[8]
- Manage:
  - customer flexibility - price driven flexibility;
  - customer flexibility – flexibility services and flexible connections; and
  - network flexibility – smart grid solutions.
- Reinforce: investment in traditional reinforcement, namely:
  - load-related reinforcement at EHV and 132kV level;
  - load-related reinforcement at HV/LV level;
  - fault level-related reinforcement; and
  - looped services.

Our strategy towards the blend of load-related investment solutions outlined above is underpinned by £92.4m investment in DSO enablers (of which LV monitoring accounts for £21.1m); please refer to our DSO strategy for further detail.

[8] 132kV, EHV and HV monitoring has already been installed on the network and improved during 2015-23 period so the focus in 2023-28 period is on improving the LV visibility

We must develop our network economically to meet planning standards

In enabling our network for net zero and creating additional LCT headroom it is first necessary to understand and then maximise, wherever possible, the utilisation or capability of our existing network. This is achieved by analysing the duties imposed on our assets (for example operating environment and demands including profiles and utilisation curves) and then seeking ways to maximise their output.

The capability of the network will vary at different times of the year dependent upon the seasonal rating of network assets, varying levels of output from distributed generation and cyclic nature of the load.

We must demonstrate at all times compliance with the relevant planning requirements and standards. Such requirements include, but not exclusively:

- The Distribution Licence, which obliges us to plan and develop our distribution systems to a standard not less than that set out in Engineering Recommendation P2/7 – 'Security of Supply';
- The Distribution Code which details the technical parameters and considerations for designing and operating the electrical network;
- The Electricity Act 1989 which requires us to 'develop and maintain an efficient, co-ordinated and economical system of electricity distribution';
- The ESQC Regulations 2002 which imposes a general requirement that the distribution system is 'sufficient for the purpose for and the circumstances in which it is used'; and
- The Health & Safety at Work Act 1974, which (amongst other commitments) requires us to ensure that circuits and plant have appropriate cyclic, continuous and short circuit ratings.

In practice, amongst other responsibilities, this means that we must ensure the network and its component parts have sufficient capacity for the load they are expected to carry, and switchgear can operate safely when carrying the fault currents that might arise at the location at which they are installed.

Ensuring that thermal capacity is available to support load growth on our network is one of the important requirements that we must account for. However, in addition to thermal capacity, we also must ensure that our network operates within statutory voltage limits, that the fault level duties are within the ratings of the network assets, that power quality is within national standards and that we ensure that network losses are as low as reasonably practicable.

We recognise our critical role, as an enabler, in helping the UK achieve its net zero ambitions. Our network intervention strategy to enable our network for decarbonisation is tailored to ensure that we consider the wide range of options before determining the appropriate solution.

Through our flexibility first strategy we target investment using network data gathered from monitoring, analysis and reporting paired with scenario based planning to quantify the risk of a substation/asset exceeding it declared capacity. We use a hierarchy of assessment and bespoke interventions to manage our legal obligations and any risks associated with our network.

By ensuring our business processes remain appropriate and aligned with our aspirations, and therefore our 2023-28 investment plan, we are ensuring that we provide sufficient capacity to meet with future network demands, wherever possible avoiding the risk of having to revisit a network before the end of an asset's life and actively working to reduce our overall carbon emissions.

Investment planning methodology

Overview

The table below provides a high-level summary of the methodology used for each of the components of our approach to planning network investment for decarbonisation. The follow pages provide further detail on the methodology for each element; references to the relevant engineering justification papers (EJPs) are also included below. An overview is also provided in the following charts.

Investment category	Investment type	High-level methodology	EJP reference
Monitor	DSO strategy – people and systems	– Identification of systems and skills required to deliver data and flexibility for optimum network investment. – Refer to DSO strategy for further detail.	n/a
	LV monitoring	– Use the planning scenario to identify LV network locations forecast to become constrained in 2023-28. – Optioneer volume of monitors appropriate to best manage 2023-28 period constraints and early 2028-33 constraints. – Preferred rollout volume established. – Refer to the network visibility strategy for further detail on how we use monitoring from across the network	EJP-5.3a
Manage	Price-driven customer flexibility	– Assumptions determined based on market intelligence and academic studies. – No associated cost to us.	n/a
	DNO contracted flexibility	– Considered as part of blend of solutions in reinforcement optioneering at all voltage levels. – Assumptions determined based on market intelligence and academic studies.	See references in detailed table in section below for EHV scheme assessment EJPs
	Network flexibility: smart grid-solutions	– Considered as part of blend of solutions in reinforcement optioneering assessment at all voltage levels.	EHV EJPs as above EJP-11.1
Reinforce	132kV and EHV load-related reinforcement	– Use Planning Scenario load growth model to undertake network impact assessment to identify specific constrained sites. – Optioneering by individual scheme assessments. – Preferred solution by site identified.	EHV EJPs as above
	HV/LV load-related reinforcement	– Use planning scenario load growth model to feed LCT planning tool to network impact assessment. – Optioneering in LCT planning tool with some adjustments for smart grid solutions. – Preferred solution identified.	EJP-11.1
	Fault-level reinforcement	– Use fault level analysis for entire network to identify constraints. – Optioneering by scale of approach and by individual site.	EJP-11.2

		– Preferred solution by site identified.	
	Looped service unbundling	– Assumptions made based on proportion of domestic properties with looped service linked to LCT take up rates as assumed in the planning scenario.	EJP-11.3
Go further, faster	DNO-contracted flexibility	– Use load growth model to identify EHV sites likely to be constrained in the 2028-33 period and determine appropriate market stimulation investment to prepare these sites for flexibility in 2028-33.	EHV EJPs as above
	Asset upsizing and synergies with asset replacement plan	– Synergies with asset replacement identified on scheme by scheme basis for 132kV/EHV sites. – Adjustments made to LCT planning tool output to cater for asset replacement synergies across HV/LV network solutions. – Asset upsizing assumptions made to asset replacement solutions.	Across suite of EJPs

Table 7: Investment plan methodology by solution type

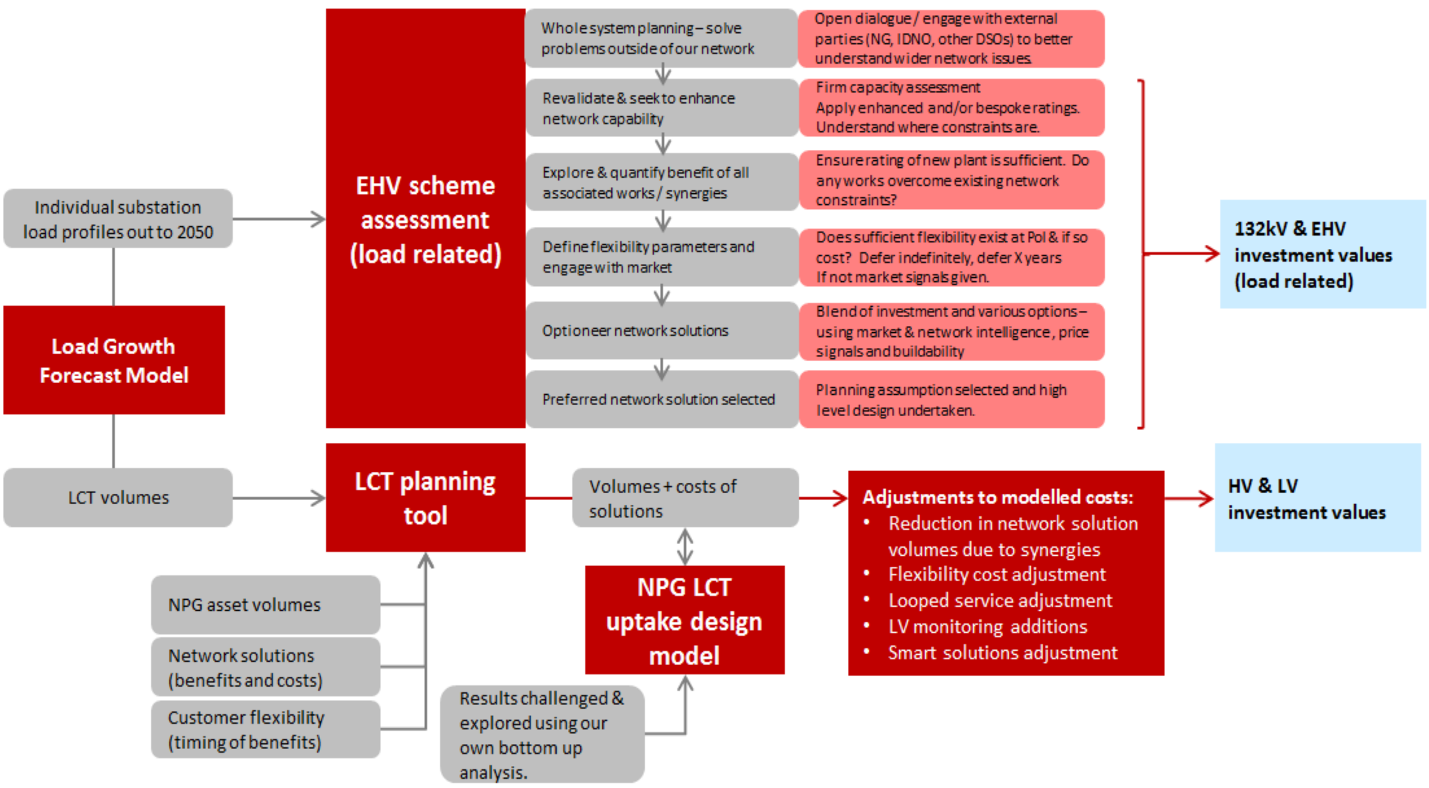


Figure 21: flow chart – load related reinforcement investment methodology

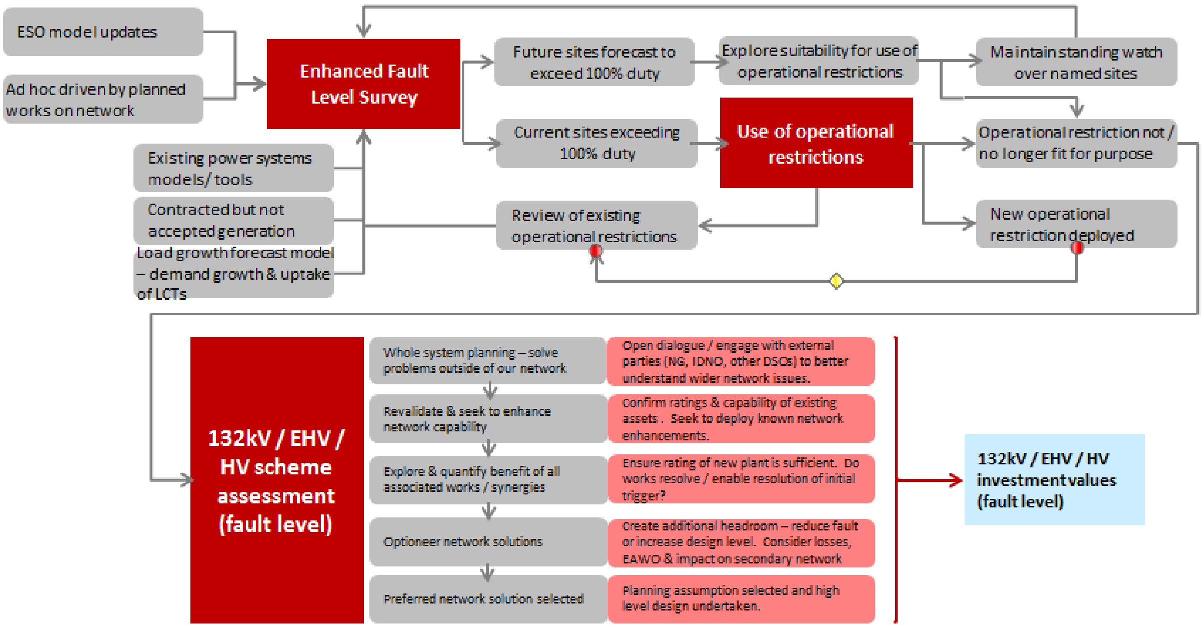


Figure 22: flow chart - fault-level reinforcement investment methodology

We follow a series of steps to determine the appropriate blend of solutions for load-related investment at each voltage level

In setting out the details of our Investment Plan, the following steps are considered and explained in detail for each of the reinforcement areas:

- identifying network constraints (Network Impact Assessment);
- optioneering; and
- preferred solution.

The approach taken at different voltage levels is different. The above steps are EHV/132kV and HV/LV level in turn below.

Load-related reinforcement at EHV and 132kV level

The approach that we discuss below is reflected in the EJPs that have been prepared for each of the network constraints identified at EHV and 132kV. One paper has been produced for each EHV constraint identified; refer later within this section for further details.

Identifying network constraints (network impact assessment)

On our EHV and 132kV network, the identification of constraints is informed from our planning scenario outputs from the load forecast model, such that we compare current and future demand on the network against the stated capacities of our network assets.

Our load growth model provides future demand profiles (assuming that that price driven customer flexibility has been taken up via suppliers' tariffs) which we use in conjunction with equipment ratings to determine the nature and magnitude of network constraints.

Where the current or future demand is shown to be exceeding the firm capacity of that section of the network during the 2023-28 period, then this identifies that a constraint exists. After identifying network constraints from our load growth analysis, we then validate the outputs from the analysis.

We use data available from our SCADA system to derive the HH demand data from each EHV site. This data is then corrected for normal network configuration, generation and temperature (as appropriate).

Using this data we then assess future forecast loading (from our planning scenario and across the range of potential decarbonisation pathways), to confirm those sites where the capacity is exceeding capability and where we need to ensure compliance with the relevant planning requirements and standards.

On the 132kV and EHV network the firm capacity of a substation (or a wider substation group) is defined as the network's ability to supply demand immediately following the occurrence of a first circuit outage (FCO) – this is the capacity that is immediately available without requiring manual intervention. This capacity can be provided by the network assets, distributed generation security contribution and/or any DNO-contracted flexibility.

The capability of the network will vary at different times of the year dependent upon the seasonal rating of network assets, varying levels of output from distributed generation and cyclical nature of the load. In accordance with our own internal guidance, we undertake a firm capacity review whenever the design of any potential system alteration could result in material impact on the firm capacity.

For each section of the network where we identify potential constraints, we complete a detailed firm capacity assessment. This allows us to better understand the existing capability of the network and revise the existing firm capacity where necessary. Knowing the capability of the existing network we identify the constraining asset and better understand the extent of intervention required to ensure the network remains fit for purpose. Throughout the process we apply any bespoke or enhanced ratings – wherever there is sufficient evidence to support their application, i.e. looking to maximise the utilisation of the existing assets. Therefore, the threshold for investment is 100 per cent of the applicable asset rating.

Whilst the firm capacity assessment reviews the capability of a substation or defined substation group (under a first circuit outage) it is also necessary to understand the capability of the wider network, and therefore the ability for network to restore post-fault. This helps ensure compliance with the standard of security not less than that laid down in Engineering Recommendation P2 and gives an overview of the existing levels of interconnection/mutual support (via the secondary network) that exist within the wider demand group.

This information is also reviewed regularly by our control room staff, and forms the basis of the network pickup plans. Each major substation has a pickup plan which confirms the actions necessary post fault to restore supplies and/or de-load the site.

Optioneering

Once the network validation has confirmed the details of the constraints, identification of appropriate options to resolve the constraints are then performed.

As our preferred investment strategy (as set out earlier in this section) we have committed to a flexibility first approach to overcome network constraints. This approach to network development helps us reduce the cost of new infrastructure investment, run existing networks more efficiently and creates a smarter, more flexible system for all.

The options that we consider are:

- DNO-contracted flexibility:
  - We consider at each site whether we are able to contract with customers to flex their energy generation or consumption in return for a fee such that the site would not be constrained. The viability of this depends on what is connected at the substation and the proposed cost of procuring flexibility from customers relative to the net present value of the cost of reinforcing the site. Flexibility also gives us option value for pursuing an alternative to traditional reinforcement depending on how the decarbonisation pathway evolves and where constraints appear on the network.
- Network flexibility - smart solutions:
  - At a high level, smart solutions are those which seek to make fuller use of the assets installed on our network, utilising technology to enhance their stated capabilities. During the identification of options to resolve the identified constraints on the 2023-28 the network, smart solutions are considered every time.
  - We continue to exploit and release the network benefits created by our smart grid enabling work during 2023-28. Our approach in takes advantage of the advances created in monitoring, control and automation to improve network flexibility.
  - A selection of the smart network solutions that we have incorporated into our design philosophy and intervention optioneering process are set out in the list set out below. At present, the thermal constraints are those for which we expect to deploy smart solutions to resolve during the 2023-28 period, whilst the smart solutions for voltage constraints and for other issues will be deployed as and when they are required.

Thermal constraints

Enhanced ratings on overhead lines and transformers. Using either bespoke ratings with enhanced monitoring or real-time thermal ratings (RTTR). We use temperature measurement and forecasting data to increase the asset rating (and thermal capacity). These solutions help maximise the capacity of an existing asset and/or benefit created under other smart solutions.

Automated load transfer technology – this technology actively monitors demand on individual feeders and then automatically switches normally open points on the network. This ensures a balance load and fully exploits underutilised capacity within a wider substation group. In future, these normally open points will use technology that allows them to operate in a soft fashion to manage power flows better; deployment will be dictated by the cost and complexity of the technology.

Voltage constraints

Enhanced automatic voltage control (EAVC). Deploying greater volumes of EAVC technologies ensures we best balance the relationship between voltage and demand. The use of technologies such as on load tap changers (OLTC) and enhanced voltage regulators. For example smart enabled units with bi-directional power flows and greater monitoring/controllability) either new, or by upgrading existing units allow us to minimise the impact of peak demand and generation predicted by the uptake of greater volumes of LCT.

Dynamic voltage optimisation improves the network voltage point and achieves the benefit of creating both additional network headroom and reducing network losses. By using capability delivered through our 2015-23 period smart grid enabler works (new, more powerful, AVC and RTU systems) we are able better manage network voltage. Benefit can be achieved through load drop compensation (LDC). To enhance this we will take learning from our flagship Boston Spa energy efficiency trial (BEET) which is seeking to further improve the current process by using real time data from domestic smart meters (refer to Whole systems strategy, deliverable WS3.2 for further detail on our plans around this in 2023-28 period).

Similarly other smart network technologies such as power-electronics, when correctly deployed, will be used to help maximise available headroom on the network or allow a higher uptake of disturbing loads. For example, deploying technology such a power factor correction can help optimise the energy flows on a network that suffer from a poor power factor – this would allow an increase in the flow of active power and therefore increase the capability of the network.

Throughout the 2023-28 period we will continue to deliver on our existing commitments and expand our current approach through continued observation and participation with the wider DNO community, embracing all opportunities to enhance and deploy the shared learning through our own and others innovation projects.

Traditional asset-based network intervention

As a counterfactual to all other options, we also consider the resolution of constraint issues on the network by intervening and creating additional capacity through the upgrading or installation of new assets (i.e. traditional reinforcement).

The traditional asset based network intervention considers solutions to install new capacity which is sufficient to accommodate future demand forecasts up to 2050. We don’t consider reinforcement in isolation and the health of the existing network assets or other investment drivers are incorporated in our decision making process as to how best to development the network.

In all possible views of the future, significant investment in traditional reinforcement is required – but our flexibility first approach ensures that it is well-targeted to parts of our network where it is most needed, and efficiently delivered.

Synergies with other work programmes

We have a duty of care to ensure that our equipment remains fit for purpose, safe and reliable – where this is not the case we intervene. This activity is covered by our inspection/maintenance regimes and asset refurbishment/replacement programmes to manage the underlying level of risk imposed by our asset base.

Much of the equipment that is scheduled for condition-based replacement during the 2023-28 period was originally constructed in the 1950 and 1960's. Unsurprisingly due to advances in the design and manufacture, the replacement plant is capable of operating to a higher level (for example thermal and fault interruption capability). Therefore, a secondary benefit of asset replacement driven investment is the improvement in the capability of individual assets.

Our network design philosophy is to upsize our assets wherever economical to do so (i.e. build additional network capacity where we are already intervening with assets on the network by, for example, installing a bigger cable which offers higher capacity at low additional marginal cost). This can produce an immediate benefit in loss reduction, allow customers to maximise their use of low carbon energy and remove future barriers to achieving net zero.

By co-ordinating our network development investment with other work programmes we are able to achieve three main objectives:

- where synergies exist, align investments to fully maximise the benefit gained through multiple work programmes;
- ensure that all new plant installed on the network, regardless of investment strategy or presence of synergy, is sufficient to meet the future demand on the network; and
- avoid any wasteful and abortive effort, for example the refurbishment of a transformer only for the unit to be replaced soon afterwards as the result of a different investment driver.

Preferred solution

Once all options have been identified, at each individual EHV site we assess the costs, benefits and net present value (NPV) of each option to determine the solution that is most economic and efficient in providing the required capacity at the required time to support the planning scenario load growth. This could be a blend of customer and network flexibility and smart solutions as well as traditional reinforcement.

Load-related reinforcement at HV and LV level

Whilst the approach described has historically been applied to the 132kV and EHV network, advances in the monitoring and storage of data gathered on the HV and LV networks (for example the uptake of greater levels of SCADA at distribution substations and deployment of LV monitoring) are making it possible to apply the same level of scrutiny at lower voltages. Therefore 2023-28 will see a significant uplift in planning and design capability for these lower voltage networks facilitated by our DSO enablers (as set out in our DSO strategy).

At HV/LV, we use our LCT planning tool developed on behalf of the Energy Network Association (ENA) and in conjunction with all the UK DNOs by WSP, to model using a techno-economic approach the network impacts and optimal solutions for resolving constraints across the network. The LCT Planning Tool has been further enhanced by WSP specifically for our 20kV network. We use this tool to inform our investment plan assumptions on solutions and costs for developing this part of the network.

Until such a time that LV monitoring and aggregated smart metering data is commonplace it will remain necessary to supplement these data sources using both existing transformer max demand indicators, where available, and a statistical method that uses annual metered consumption values for individual customers. This method uses the principles of ACE49 as modified by our customer led network revolution (CLNR) [9] project. This standard takes into account diversity and unbalance between customers and is the methodology deployed in both our DEBUT[10] and AutoDesign[11] (HV/LV) software design packages.

This approach is as set out in the HV/LV Reinforcement EJP, which provides significant detail of the WSP LCT Tool, the methods used to identify constraints on the network, the validation of the network data, the options to resolve the constraints and the recommended solutions.

Identifying network constraints (Network Impact Assessment)

We identify network constraints through both the LCT Planning Tool and our bottom-up model (developed in house for checking and review purposes).

Through the use of the LCT Planning Tool, which is made up of representation of our HV and LV networks, we use Heat Pump and EV take up numbers as defined in our planning scenario (outputs from the Load Growth model described above) to overlay the demand from these on the existing demand on the network.

The tool is set up to take into account customer flexibility from time of use tariffs (including vehicle smart charging).

By combining the load growth due to HPs and EVs and price-driven customer flexibility, the model then identifies when sections of the network are overloaded and hence constrained.

The validation of the network data is then performed by observing the outputs from the LCT model and comparing these with information that we have available (i.e. LV monitoring data, maximum demand indication (MDI data) and ACE49 statistical data).

Across a large volume of assets, it is important to recognise that the identification of constraints is performed at volumetric level.

Validation at this stage requires us to review and confirm the data and analysis for consistency. During 2023-28, as LV monitoring becomes more prevalent, the use of such monitoring data will become the first step to validating network data.

[9] http://www.networkrevolution.co.uk/
[10] A graphical analytical tool for LV network study
[11] A self-service connections tool for customers to obtain quotes in real time, https://www.northernpowergrid.com/auto-design

Optioneering

The optioneering that is performed is both within the LCT Planning Tool (i.e. utilising the Techno-Economic aspects of the model to identify the appropriate solution for the constraint identified and confirming the optimal year of implementation and the capacity of any solution), and outside of the model on the outputs by identifying where smart solutions can also be utilised. For example, enhanced transformer cooling, transformer re-rating, LV network meshing etc. We also consider the interactions with asset replacement volumes at an overall level for the HV and LV networks.

The LCT Planning Tool outputs and additional solutions are compared and contrasted with our bottom up model to confirm the appropriateness of the volumes and costs identified for the solutions.

At present, there are no DNO-procured LV flexibility solutions identified to resolve HV and LV constraints and hence flexibility as a solution is not considered as a business as usual solution for 2023-28 at this stage (although customer flexibility via time of use tariffs is fully embedded within our analysis). We will work with others to develop the market for these types of service via innovation projects and monitor the outcomes from other industry innovation projects, adapting our plan as necessary to use DNO contracted customer flexibility over 2023-28.

Preferred solution

By taking into account both the LCT Planning Tool outputs and also the bottom up modelling, this then enables us to confirm costs and volumes which are specified within the HV/LV Reinforcement EJP-11.1. Our evolving approach to select specific individual interventions over 2023-28 is also detailed within the EJP.

Fault level-related reinforcement

Our approach to fault level related reinforcement is similar to the approach for EHV and 132kV load-related reinforcement in that we identify the constraints, validate the network itself, consider options to resolve the constraints and then determine our preferred solution.

However, we recognise and emphasise that issues due to fault level on our network are intrinsically different to load related issues, where the solutions available to resolve these issues are not as straightforward as load related solutions.

Fault level, or prospective system short-circuit current, is an important network parameter but is a balance between several factors. A high fault level maintains power quality standards to customers by reducing flicker and ensures fast operation of protection; conversely, a low fault level reduces the safety implications of a short-circuit and limits damage to equipment. In practice, this balance results in short-circuit levels which are towards the upper end of the switchgear rating.

Identifying network constraints (network impact assessment)

We conduct a network analysis of the fault-level duty and capability across all our substations sites to identify constraints. These constraints are identified at 100 per cent of the respective make or break ratings.

The Northern Powergrid policy for the management of short-circuit currents states that, in respect of plant fault withstand capability, “the maximum prospective fault current must be reviewed and where potential issues are identified, the prospective fault level current should be managed or controlled such that no item of equipment on the system shall be over-stressed due to its fault interruption or making duties being greater than its assigned rating”.

Northern Powergrid has an absolute compliance requirement under the ESQCR[12] to ensure that no network assets are exposed to fault level make and/or break duties in excess of their capability. In order to comply with our duty, we undertake a biennial fault level survey across the whole network. We then complete a localised fault level review

[12] Electricity Safety, Quality and Continuity Regulations 2002

whenever we undertake any refurbishment, asset replacement or connections work. The former being a check, whilst the latter is our main risk control.

Fault level duties are calculated as part of our fault level survey process and also assessed during routine design activity for new connections or network alterations. All components that form the network need to be sufficiently rated such that they are able to withstand the duty imposed on them. Therefore the break and make prospective short circuit currents imposed on all switchgear, under both normal and abnormal operational configurations, need to be less than or equal to the capability of the equipment.

Under most cases the manufacturer's nameplate rating shall normally be taken to be the equipment capability and only where written assurance has been provided from the manufacturer can this be modified.

In accordance with our internal policy, the ability of major plant relative to the duty imposed on them are assessed as part of a periodic review and documented in the fault level survey. The purpose of this assessment is to establish the prospective short circuit currents, calculated in accordance with Engineering Recommendation G74, and to identify switchgear where the prospective duty exceeds its capability.

At present, we have limited fault level monitoring installed on our network. We therefore perform power system analysis using bespoke software products to both identify network constraints and to validate them. We see a future role for fault level monitoring in assessing sites that have been identified as being close to their rating but conventional analysis is a cheaper and more effective control measure.

The periodic review that is documented within the fault level survey performs network validation, by both reviewing and confirming data held and also reviewing and confirming the analysis outputs and actions.

Optioneering

It is important that, when identified, we take steps to best manage the issue. We develop and agree an action plan that strikes the correct balance between managing the fault level and other factors including system capacity, quality of supply and system security.

Traditionally we have applied operational routines known as operational restrictions or alternative network running arrangements to manage these constraints. Such an approach, whilst managing issues in the short term, does not provide a long-term solution, as these operational restrictions result in our network being run in a sub-optimal manner and not in the way in which it has been designed to be run.

Specifically, operational restrictions require additional operator actions when performing operational switching activities (both in response to faults on the network and also when preparing for maintenance and other outage activities), which in themselves require reduction in network security and even reduction in demand.

Our plan going forward is to target the removal of operational restrictions on the network to increase fault level headroom and network flexibility thereby removing barriers for the connection of low carbon generation.

As part of our optioneering, we have considered various intervention strategies which each offer incremental improvements. These seek to build on the success of the existing processes, remove barriers to the uptake of further LCTs and distributed energy resources (DERs), improve operational flexibility and enable our network to help achieve net zero in a co-ordinated and timely manner.

The consideration of these incremental improvements seeks to identify those solutions which provide the most efficient improvements.

Smart network solutions will play a critical role in better quantifying the volume of available fault level headroom in the system and then releasing it. As part of our optioneering to resolve fault level constraints, we also consider non-conventional solutions such as fault current limiters and sequential switching (SS).

– Fault current limiters (FCLs) are devices which are connected to the network and which operate in a manner to limit the prospective fault current flowing under fault conditions without complete disconnection. They act to limit the short-circuit current before the first current peak is reached so that the equipment rating is not exceeded. These devices can be solid state, inductive or super-conducting.

– Modern devices operate to isolate the fault affected part of the network within micro seconds; use of these devices helps facilitate flexible power distribution, power system expansion, independent power production, (fault limiting) reactor replacement and many more such applications without considering the equipment short-circuit withstand capability as a constraint.

– Sequential switching (SS) or enhanced protection schemes automate the network configuration process and safely, achieves a higher security of supply compared to a manual close-inhibit scheme. This solution utilises digital protection relays and functionality with the new RTUs installed as part of smart grid enablers work programme.

– Examples of SS schemes include automating the switching actions that would normally be performed by operational staff to address fault make duty constraints on switchgear (to reduce fault level on the network prior to switching). Such schemes are implemented through the use of additional inter-circuit breaker wiring on switchgear and the interface to a logic-based system that is designed to operate switching actions in a sequential manner to replicate those that would be performed by an operator in a more timely manner. This can also avoids the need for operators to be physically present at some sites where remote control has not previously been possible.

Preferred solution

In arriving at our chosen investment, we have considered various intervention strategies and selected an investment option that will achieve the best balance between timing, investment, benefit released, networks risk and maintaining a flexible network. Consideration of the existing health of the assets is also an important factor in the decision making process.

In selecting our preferred solution, we seek to remove all existing fault level operational restrictions (with the exception of two single customer sites). These works will enable the rollout of greater volumes of network automation, improve/maintain the current level of operational flexibility and remove unnecessary barriers in place that could delay the uptake of additional LCTs and DERs. Our preferred solution is one that provides a long-term acceptable network improvement.

Further detail can be found in the fault-level reinforcement EJP-11.2.

Looped services

Looped services are service arrangements where one or more premises are supplied not direct from the mains cable, but from the service supplying adjacent premises.

By their very nature, looped services can be a barrier to the connection of LCTs due to the limited capacity on these shared cables.

Approximately 25 per cent of our domestic customers' services are looped or shared between premises and we have assessed the coincidence of this type of connection with the predicted rate of installation of LCTs over the 2023-28 period based on the planning scenario. The optimal solution for these situations is to de-loop the services with new cables. This activity can be disruptive for our customers and our experience is that this is best done when a customer wishes to connect a LCT.

Identifying network constraints (Network Impact Assessment)

We assess the impact of LCT take-up specifically on the low voltage services to properties that are shared between customers. The projected increase in the connection of LCTs provides the main reasons for constraints being identified in the planning scenario. These devices are considered to have lower diversity than traditional loads because of the length of time they run for. Simply due to the peak load lasting longer, the chances of peaks being coincident rises.

We then validate this through the confirmation of the number of looped services on our network, the predicted take up of LCTs and hence confirmation of the potential impact on our network.

Optioneering

In forecasting when LCTs will be installed on our network, we then predict when and whether these will be installed at premises that are on looped services.

We have assessed costs and volumes of the potential of LCT connection requests that may require de-looping (two per cent, 10 per cent, 24 per cent of total looped services) during the 2023-28 period. The options that are then considered relate to the reactive or proactive nature of de-looping the services.

Preferred solution

The optimal solution for these situations is to de-loop the services with new cables. Refer to the modelling results section that follows and, further detail in the looped services EJP-11.3.

Investment plan modelling results and strategy

Overview

Following the methodology set out above, we have developed an investment strategy. Our plan aims to maximise the rate at which we can facilitate decarbonisation in the 2023-28 period whilst being cost efficient, and factors in synergies with other investment drivers in our asset replacement strategy.

As set out previously we take a flexibility first strategy, first investing in and optimising the use of network monitoring on the network to identify where constraints may arise; then managing potential constraints through network and customer flexibility; and deploying traditional reinforcement where economic and efficient.

Our approach is underpinned by £92.4m investment in the DSO strategy, investing in systems, skills and network technology to maximise our ability to extract value from data and flexibility to drive efficient and well-targeted network investment (refer to DSO strategy for further detail). This investment ensures we are able to determine a cost-effective blend of manage and reinforce network interventions.

To ensure we are equipped to continue to keep all options open on the decarbonisation pathway to 2028 and beyond, we are also planning investment to enable our region to go further, faster.

In the decarbonisation plan, this means spending to stimulate the flexibility market for future price controls to optimise how much traditional reinforcement we can defer or avoid. Investing in the development of a deep and liquid market for flexibility today will ensure efficient investment and option value in managing our network as decarbonisation accelerates into the 2030s. This is described in more detail in the assumptions detailed below.

In our plans to maintain our assets, this means upsizing our equipment to fit larger cables when we are already intervening to make routine assets replacements or repair network faults. This ensures that our assets are 'net zero ready' and where possible and we plan to only intervene at our assets once between now and 2050.

Investment category	Investment type	Headline investment strategy	EJP reference
Monitor	DSO strategy – people and systems	– We plan to invest £92.4m (of which £21.1m relates to LV monitoring, below) in skills and systems to enable us to optimally harness data and flexibility on the network, ensuring reinforcement investment is efficient and well-targeted.	Refer to DSO strategy
	LV monitoring	– By using LV monitoring on our ground-mounted secondary distribution substations, we will have much greater data to analyse demand and demand growth, thus enabling investment decisions on confirmed data, as well as the ability to re-rate assets based on the nature of the load observed. – We plan to install LV monitoring on a further 10,000 ground mounted distribution substations by 2028. Refer to DSO strategy annex for further information.	EJP-5.3a
Manage	Price-driven customer flexibility	– Based on findings from our CLDS innovation project and other market intelligence, we assume that customer price-driven flexibility will reduce demand by c. 6% and 5% at EHV and HV/LV respectively during peak hours on the network from 2025 at no cost to our customers. – Price-driven customer flexibility is dependent on time of use tariffs being offered by suppliers, enabled by introduction of market-wide half-hourly settlement.	See EHV EJPs referenced in detailed table below

Investment category	Investment type	Headline investment strategy	EJP reference
		– We assume that customer price-driven flexibility will reduce the required investment by up to £107.9m at all voltages over 2023-28.	
	DNO contracted flexibility	– We assume that we will spend £1.8m to procure customer flexibility at 23% of our EHV substations that are expected to be constrained in 2023-28, driving net savings of £12.2m in traditional reinforcement. – Our use of Active Network Management as a form of flexible connection is described in the Connections section of this plan.	EHV EJPs as above
	Network flexibility: smart grid-solutions	– Our smart solutions involve us deploying innovative solutions to use more of the inherent capacity in our network. By investing £8.4m in our smart solutions alongside LV monitoring, we expect to deliver net benefits of £48.6m (compared to traditional reinforcement).	EHV EJPs as above EJP-11.1
Reinforce	132kV and EHV load-related reinforcement	– Once all customer flexibility and smart grid solutions have been considered, we turn to asset-based interventions to install new assets of higher capacity. – Our projections show that we will need to invest £60.9m at EHV.	EHV EJPs as above
	HV/LV load-related reinforcement	– We will install additional circuits to provide capacity and network flexibility and prioritise the replacement and upgrade of assets in areas where we also have a need for condition-related investment. – A significant proportion of this investment is expected to be low regret given the greater likelihood for reinforcement needs at the lower voltage levels to provide for the increasing penetration of LCTs. – We expect to invest £348.2m at HV/LV in 2023-28.	EJP-11.1
	Fault-level reinforcement	– We are targeting the removal of operational restrictions on the network to increase fault level headroom and network flexibility, removing barriers for the connection of low carbon generation. – We expect that our investment in this area will be 58.9m.	EJP-11.2
	Looped service unbundling	– Driven by LCT volumes assumed in our planning scenario, we plan to invest £34.2m to target the replacement of 21,600 looped services to customer properties. – This is assumes that 2 per cent of the properties where LCT connections are deployed will require the service to be de-looped to minimise customer disruption.	EJP-11.3
Go further, faster	DNO-contracted flexibility	– We also plan to invest £3.2m in flexibility procurement to stimulate the flexibility market, seeking to prepare sites expected to be constrained in the 2028-33 period for flexibility deployment in the future.	EHV EJPs as above
	Asset upsizing and synergies	– We will revise our investment strategy to deliver capacity for future periods, installing assets sized to take into account load growth through to 2050, therefore ensuring we touch assets once where possible between now and 2050. – We will invest £11.5m EHV and 132kV of load related and £21.1m of fault level related expenditure which will provide synergistic benefits, where the investment for	Across a range of EJPs

Investment category	Investment type	Headline investment strategy	EJP reference
		decarbonisation also addresses other issues such as equipment condition. – We assume that £34.6m of HV/LV asset replacement expenditure driven by asset health will also address network constraints arising over 2023-28 under our planning scenario. Therefore we reduce our load related investment accordingly. – We assume that £24.1m of EHV and EHV/LV load related expenditure was brought forward into 2015-23 as part our Green Recovery scheme to accelerate net zero-driven stakeholder needs, and is therefore deducted from the 2023-28 investment total.	

Table 8: Summary of load-related network investment strategy by solution type

Network intervention costs (£m)					
	132/EHV	HV/LV	Fault level	Looped services	Total
DNO-contracted flexibility	1.8				**1.8**
Smart solutions	3.8	0.7	3.9		**8.4**
Traditional reinforcement	60.9	348.2	58.9	34.2	**502.3**
Total	**66.6**	**348.9**	**62.8**	**34.2**	**512.5**
Flexibility enablers - DSO strategy costs and go further faster flexibility investment					*95.6*
Total					***608.1***
Network intervention volumes (#)					
DSO-contracted flexibility	5				**5**
Smart solutions	5	168	3		**174**
Traditional reinforcement	12	12,000	26	21,638	**33,678**
Total	**22**	**12,168**	**29**	**21,637**	**33,857**

Table 9: Planning Scenario costs and volumes summary

Note 1: Costs in the above breakdown and throughout this annex include real price effects (RPE), which are excluded from the EJPs.

Monitor

Our overall approach to the development of network visibility and specifically monitoring is detailed in our network visibility strategy.

EHV and 132kV monitoring

At our major substations a wide range of monitoring is installed (e.g. volts, amps, power factor etc.) which is integrated into our data collection systems at the substations, and integrated into our PI data monitoring system.

Our PI data monitoring system enables us to collect and interrogate historical data on all areas of our primary distribution network. This allows us to obtain a rich level of granular data relating to network characteristics, which then enables us to gain greater clarity and insight into the performance of the network, providing supporting data for investment decisions.

During 2015-23 we have invested in improved monitoring at substations to see the bi-directional nature of power flow and at key locations down HV network feeders. We have enhanced our PI data monitoring system so as to provide better analytics, combined data from SCADA and external metering data flows for half hourly customers and introduced greater visualisation of data.

These tools also enable us to assess and determine the flexibility requirements for where we have constraints, as well as supporting decisions for smart solutions (e.g. real time thermal rating) and gaining greater understanding and insight into network capacity. It also provides the core system for sharing the data with third parties as explained in our DSO strategy and Digitalisation Strategy and Action plan.

LV monitoring

Through an investment of £21.1m, we plan to install 10,000 LV monitors in 2023-28, providing visibility of 50 per cent of our ground-mounted substations by the end of the 2023-28 period. In conjunction with operational technology platforms, this monitoring forms the infrastructure necessary to implement customer and network flexibility. It also provides the ability to assess whether customer price-driven flexibility is having the impact we predicted and provides the basis for better informed investment decisions. This all has the effect of improving our management of network risk.

Alongside smart solutions, commented on further below, investing £21.1m in LV monitoring is assumed to facilitate £45.4m of net benefits when compared to traditional reinforcement on the LV network.

Further detail is included in our DSO strategy and EJP-5.3a Monitoring.

Manage

Flexibility assumptions: price-driven customer flexibility

Customer price driven flexibility is the effect of customers shifting their consumption patterns in response to price signals from energy suppliers. We have made assumptions about two key types of customer flexibility which are likely to impact our investment planning:

- EV smart charging, where EV chargers will automatically set charging to take place when energy prices are favourable; and
- ToU tariffs, when customers will be incentivised to shift their consumption outside of peak times.

We have conducted market research and used the results of our CLNR[9] innovation project to determine appropriate assumptions to include in our investment modelling as follows:

- **Smart charging:** we have assumed that the proportion of electric vehicle users on our network that adopt smart charging will increase from two per cent in 2023, to 21 per cent by 2028. As a result of adopting smart charging, we assume that the gross demand of EVs at the peak period will reduce and shift by 75 per cent for a given electric vehicle.
- **Domestic ToU tariffs:** we assume that two per cent of domestic customers in 2023 and 26 per cent by 2028 will use domestic ToU tariffs to manage their electricity consumption. This will result in an average six per cent reduction in peak load at the EHV level and a five per cent reduction at the HV/LV level.
- **Industrial and commercial (I&C) ToU tariffs:** we assume that 15 per cent of I&C customers in 2023, 32 per cent in 2025, 51 per cent by 2028, and 58 per cent by 2035 will use I&C ToU tariffs to manage their electricity consumption. This will result in an average 3.2 per cent reduction in peak load as a result of using I&C ToU tariffs.

Customers are already being attracted to time of use tariffs being offered by some suppliers today, facilitated by smart metering data and more cost reflective energy pricing. From our CLDS innovation project we have learned that the price benefits being offered to customers and connectees by suppliers by taking advantage of time of use tariffs is more valuable than the financial benefits we are able to offer through flexibility services contracts. In work undertaken by Imperial College, whole system technoeconomic modelling has shown that for a smart flexible energy system, 70% of the capex savings are attributed to parties other than the distribution network.

Using time of use tariffs has the potential to provide significant financial benefits to customers by reducing the cost of supply of their energy, but it will also benefit them by reducing the amount of investment we need to make in our network to prepare for increased LCT uptake. Moving consumption outside of peak times benefits the distribution network by reducing peak load at no cost to us. We take this benefit for free before we consider deploying contracted flexibility, described further below.

Our investment planning assumes that we experience the benefit of shifting demand peaks through price-driven customer flexibility at no cost to us. Managing peaks in this way enables us to deliver £107.9m of savings during the 2023-28 period across all voltage levels.

We will monitor the extent to which customer flexibility materialises, through the investment in LV monitoring outlined above and existing monitoring at higher voltages, therefore managing the risk that we are taking in our investment planning if this flexibility were not to develop to the extent that we have assumed. This will ensure that we continue to target investment efficiently.

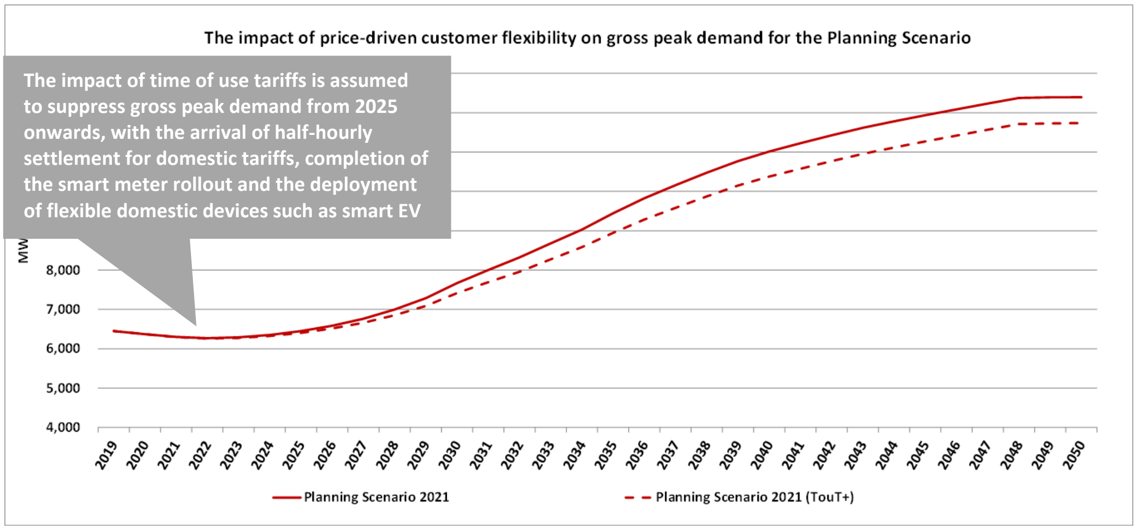


Figure 23: Impact of price driven customer flexibility

Flexibility assumptions: DNO contracted flexibility – flexibility services

As detailed, DNO contracted flexibility means we contract with customers to pay them to turn up or down their electricity consumption or generation in given circumstances. Of the four flexibility products outlined in our role in the energy transition detailed at the beginning of this annex, we assume that we procure secure flexibility which enables us to defer to avoid network reinforcement.

We have assumed that we will invest £1.8m to resolve constraints at five EHV constrained sites (23 per cent) in the 2023-28 period. (A breakdown of all EHV constraints is included in the reinforcement section below). This strategy is based on the following assumptions:

- Voltage level:

  - We assume that constraints at EHV can be resolved with flexibility. We will trial the use of flexibility for lower voltage constraints (HV/LV) during the 2023-28 period but we are not assuming widespread usage at present as part of our investment planning. We expect that significant technological innovation (for example in vehicle-to-grid schemes), as well as market and customer engagement, will be required before we are able to effectively deploy flexibility at lower voltage levels.

  - This will be explored further through our innovation strategy and investment in DSO enablers to facilitate development in the flexibility market (refer to DSO strategy and Innovation strategy for further information).

- Volume:

  - We assume that 23 per cent of EHV reinforcement costs in the 2023-28 period, across five of 22 EHV sites will be deferred as a result of procuring DNO contracted flexibility. This is assumed to start at 20 per cent in 2023, reaching 30 per cent by the end of the 2023-28 as markets mature over the regulatory period. We have used this volume as a planning assumption to determine costs and volumes, but we will approach the market for customer flexibility at all sites as part of our detailed investment planning process in period.

  - The constraints we expect to arise in 2023-28 are predominantly on the local networks as customers connect LCTs. As we do not expect that contracted flexibility will be widely available at LV level during ED2, the constraints that we expect to be able to resolve through DNO contracted flexibility are limited to the 132kV/EHV network. As a result, the volume of constraints resolved through DNO-contracted flexibility is expected to be low during the period. The savings that we expect to be available in 2023-28 from price-driven flexibility (discussed above) are therefore significantly higher than those from contracted flexibility. We will trial DNO contracted flexibility for LV constraints during 2023-28 ahead of it becoming a business as usual solution.

  - To determine our assumptions for the proportion of constraints that we expect to be able to resolve with flexibility during the 2023-28 period, we conducted an expression of interest in December 2020 - January 2021. This was based on an initial view of the EHV sites that we forecast as likely to be constrained in the 2023-28 period, with customers at 25 per cent of sites expressing interest in flexibility products. We have sense checked this assumption against market research including procurement conducted by other DNOs and by looking at the amount of dispatchable generation and load at various points on our network that could provide flexibility.

- Price:

  - We have assumed a flexibility procurement price of £300/MWh, comprising a £125/MWh availability fee (where the service is available for use on dates and times specified by the DNO) and a £175/MWh utilisation fee (for when the service is actually utilised by the DNO).

  - Prices paid are likely to be influenced by geographical location, market participation and cost of alternatives. In the future we will continue to engage formally and informally with flexibility providers and other stakeholders to seek views and feedback about what pricing level/structures could look like for flexibility products. We will also continue to closely monitor the results of other flexibility tenders run by DNOs with a view to using this market intelligence to evolve our own pricing strategy.

Further information on our strategy to stimulate further flexibility market development in the period 2023-28 for 2028-33 constraints is described in the ‘go further faster’ section.

Network flexibility: smart solutions

In conjunction with the £21.1m investment in LV monitoring described above we assume that investment of £8.4m in smart solutions across EHV and LV will deliver £56.5m of net benefits during the 2023-28 period as an alternative to traditional reinforcement.

As presented in the methodology above, we have a wide range of smart solutions embedded within our policies which enable us to address thermal constraints, voltage constraints and other power quality issues at HV, EHV & 132kV. The constraints that we have identified as part of the scenarios and load forecasting are all thermal and we therefore plan to deploy smart solutions during 2023-28. As and when other constraints become apparent, we will implement the appropriate smart solutions where viable.

No smart solutions are assumed at LV[13] due to current unavailability of appropriate data and cost effective solutions. Until such time as smart metering data and LV monitoring data at substations is available at scale, the identification of constraints on the LV network and smart solutions to address the constraints will require further development (expected during the 2023-28 period). Our micro-resilience initiatives (whole system strategy - deliverable WS2.5 and WS3.1) are considered to be niche solutions for 2023-28 and providing benefit against higher voltage issues rather than providing capacity at LV.

Reinforce

We have made provision for total traditional reinforcement costs of £502.3m in 2023-28. Each investment category is described in further detail below.

EHV and 132kV

EHV intervention costs total £66.6m in 2023-28, of which £60.9m (92 per cent) relates to traditional reinforcement across 14 sites (64 per cent), shown in the table below.

This blend of solutions represents a net benefit of £24.8m across EHV reinforcement compared to a traditional reinforcement approach, with 46 per cent of constraints resolved with eight per cent of the expenditure in the period.

The following table includes references to each EJP for each individual EHV site expected to be constrained during 2023-28 under the planning scenario, where the investment methodology for each location and resultant strategy are documented in more detail.

[13] We assume that smart solutions can be for HV/LV distribution transformers but not on the LV circuits

£m	DNO-contracted	Smart solutions	Traditional reinforcement	Total	EJP ref.
Harpswell	0.6	-		**0.6**	EJP-11.9
Ellifoot Lane	0.4	-	-	**0.4**	EJP-11.7
Kirkburn	0.3	-	-	**0.3**	EJP-11.13
Stourton 132/11kV	0.3	-	-	**0.3**	EJP-11.19
Wheatacre Road	0.3	-	-	**0.3**	EJP-11.21
Ferrybridge A 11kV	-	0.8	-	**1.9**	EJP-11.8
Moor Road	-	0.8	-	**0.8**	EJP-11.16
Norton	-	0.8	-	**0.8**	EJP-11.17
Crowle	-	1.1	0.8	**1.9**	EJP-11.6
High Barmston	-	0.6	1.7	**2.3**	EJP-11.11
Beverley 132/33kV	-	-	5.5	**5.5**	EJP-11.4
Commonside Lane	-	-	3.4	**3.4**	EJP-11.5
Hayton	-	-	1.8	**1.8**	EJP-11.10
Holme Upon Spalding Moor	-	-	3.0	**3.0**	EJP-11.12
Martongate	-	-	2.0	**2.0**	EJP-11.14
Monkseaton	-	-	4.7	**4.7**	EJP-11.15
Ripon	-	-	5.5	**5.5**	EJP-11.18
Southgate	-	-	3.0	**3.0**	EJP-11.12
Weeland Road	-	-	3.6	**3.6**	EJP-11.20
Hebburn	-	-	4.5	**4.5**	EJP-11.22
Wardley	-	-	4.5	**4.5**	EJP-11.22
Wetherby	-	-	17.0	**17.0**	EJP-11.24
Total	**1.8**	**3.8**	**60.9**	**66.6**	

Number	5	5	14	22
% of interventions	23%	23%	64%	100%
% of cost	3%	6%	92%	100%

Table 2: EHV substation investment for the period 2023-28

HV/LV

At £348.2m, reinforcement in the HV/LV network accounts for 68 per cent of total expenditure required during 2023-28.

We see more constraints appearing on our LV circuits and to a lesser extent on our distribution HV to LV transformers occurring over the period. This outcome is a consistent theme across a range of the potential pathways. Although there is a range of possible future scenarios, we can say with a high degree of confidence that demand at the lower voltage end of the network is set to increase significantly as the national program of transition towards electrification of heat and transport proceeds and customers connect increasing volumes of LCTs to our network.

This is an extremely important and valuable feature of the outlook. It means that digitalising and strengthening the network infrastructure at this local level is a low regret investment because it has a high probability of requiring additional capacity regardless of the pathway. Delivering these improvements for our customers allows them to maximise their use of LCTs and provide them with the ability to provide flexibility services to the wider energy system. Investments in monitoring the low voltage networks will provide us greater visibility to evolving network conditions and allow us to modify our investment strategy accordingly.

As described above, we have not assumed in our investment plan that flexibility at LV/HV will be used to resolve network constraints at this level (in contrast, we assume it may when aggregated enable reinforcement deferral on the EHV system). We will continue to explore this with our stakeholders including flexibility aggregators and support market development through the DSO strategy; however, we have prepared our approach on the basis that this will not be materially available in during the 2023-28 period.

Fault level

Fault level interventions are assumed to cost £62.8m in 2023-28, of which £58.9m (93 per cent) relates to traditional reinforcement across 26 sites with £3.9m of smart solutions at three sites.

This blend of solutions represents a net benefit of £2.6m across EHV and 132kV fault level reinforcement compared with a traditional reinforcement approach.

Looped services

We plan to invest £34.2m in the LV network for looped services unbundling in the 2023-28, 7 per cent of total expenditure.

This is based on assuming that two per cent of premises with a looped service connecting an LCT will be de-looped (which accounts for circa 25 per cent of households). This is based on the volumes of LCTs projected in the planning scenario. This is above the rate of 1.2 per cent we have seen to date through the 2023-28 period, taking into account an expected increase in LCT connection volumes.

Due to the nature of looped services, the solutions available to resolve them and the disruptive nature of the intervention from a customers' perspective, we have assumed only that we will intervene to replace looped services in a reactive manner following customers' decisions to install LCTs on their premises.

By choosing to replace looped services based on LCT connections requests, this enables us to focus resource where it is required. Whilst there will be a short delay for the customer whilst the works are completed, this ensures that only those customers who will be installing an LCT are targeted for the de-looping works.

Go further faster: DNO contracted customer flexibility stimulation investment

We expect up to 71 EHV sites will require intervention during 2028-33 compared to 22 by the end of 2023-28 (19 sites are proposed for intervention in 2023-28 due to being forecast to be >99 per cent utilised; the remaining three are identified for different reasons). To ensure we are able to harness flexibility to defer reinforcement required at these sites in the future, we plan to address forecast EHV reinforcement needs for the period 2028-33 by investing to prepare the flexibility market at these sites during the 2023-28 period. Of the 71 EHV sites assumed to be newly constrained during 2028-33, we assume we will offer restore and dynamic services to market at up to 48 of the EHV sites that are forecast to reach 99 per cent utilisation during 2028-33, and have developed a budget of £3.2m for this investment.

Ongoing stakeholder engagement will help develop our understanding of market needs and help us provide targeted support to stimulate deep and liquid local markets for flexibility. We want to ensure that all of our customers are able to financially benefit from offering flexibility to the energy system. Effectively adapting our business and driving this market development is at the heart of our DSO strategy.

The details of this are set out in our specific Engineering Justification Paper (EJP-11.25 load (Distribution Flexibility Services – Market Stimulation)), for the 2028-33 period flexibility provided separate to this document.

Go further faster: asset upsizing and synergies

Synergies of £465.0m are assumed across decarbonisation and the asset replacement plan (allocated £34.6m and £430.3m respectively to each plan section) and investment of £124.2m in incremental capacity through asset renewal programmes to enable savings in traditional reinforcement in 2028-50. Refer to the costs in detail annex for further information.

We assume that £34.7m of HV/LV asset replacement expenditure driven by asset health will also address network constraints arising over 2023-28 under our planning scenario. Therefore we reduced our load related investment accordingly.

We assume that £24.2m of EHV and EHV/LV load related expenditure is brought forward into 2015-23 as part our Green Recovery scheme to accelerate net zero driven stakeholder needs, and is therefore deducted from the 2023-28 investment total.

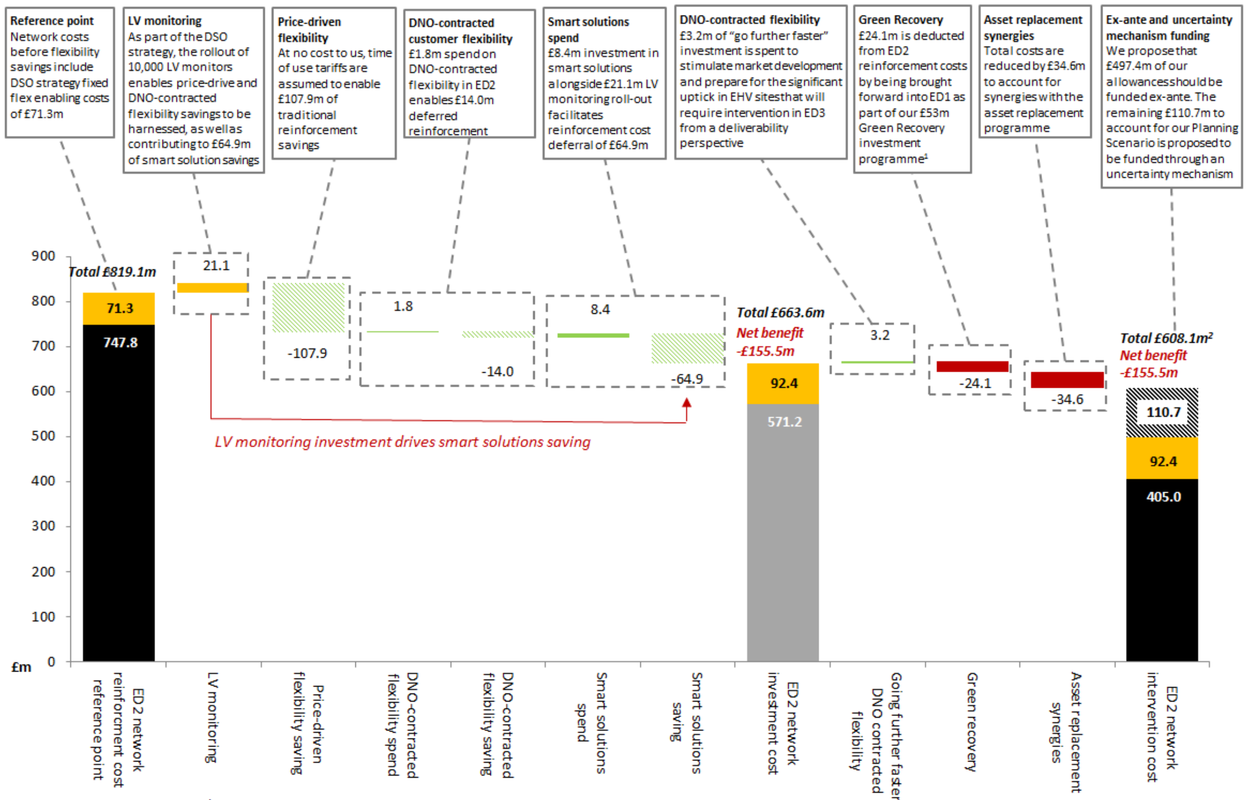
Conclusion: what this means for the 2023-28 plan

We plan to invest £607.9m in total in our network to enable our customers to decarbonise in 2023-28. Of this, investment of £92.4m in flexibility enabling actions drives potential net savings of £155.5m in traditional reinforcement over the course of the 2023-28 period compared to the alternative if we did not take a flexibility first approach. These net savings are described in the bridge chart that follows.

Our investment to enable decarbonisation, as well as innovation spend, yields synergies across a number of areas of our plan. We will continue to invest in innovation to drive flexibility, further enabling traditional reinforcement deferment, building on learning from existing innovation projects that we and other DNOs have undertaken. Please also refer to the costs in detail annex and our innovation strategy for further detail.

The figure below presents our investment cost and savings as a result of employing flexibility and smart solutions for the 2023-28 period. An investment of £92.4m in flexibility enabling actions drives potential total savings of up to £155.5m in traditional reinforcement over the course of the 2023-28 period.

Investment of £607.9mm delivers net benefits of £155.5m in 2023-28



Note 1: £53m green recovery in 2012/13 prices, aligned to ED1
Note 2: total for network investment costs and DSO strategy only; does not include whole systems

Figure 24: 2023-28 load-related investment and benefits

Please refer to the managing uncertainty section below for further information about the split of funding proposed between ex ante and uncertainty mechanisms, as shown on the chart above.

Sensitivity testing: our plan costs are in the middle of the range of the full spectrum of scenarios modelled

As part of our sensitivity testing (detailed further in Appendix 3 below – planning scenario input assumptions), we costed the range of scenarios considered and compare these against the costs for our planning scenario. For the extreme scenarios of system transformation and widespread engagement, we also did a comparison against the planning scenario after accounting for flexibility solutions.

Results of our sensitivity analysis indicate that hydrogen dominant scenarios have lower costs owing to a lower volume of HPs requiring less electricity network reinforcement. In comparison, electrification heavy scenarios and the planning scenario have similar costs, with some scenarios requiring higher investment than the planning scenario.

This sensitivity helps to highlight that our plan does not involve a risk of material asset stranding under any realistic scenario. This is because there is a high continuity of network solutions across the early years of all the pathways that could potentially be credible. For the most part, the solutions required in the five years of our plan under our planning scenario will still be required before the end of the 2028-33 period in the slowest pathway we have considered (DFES 2020 system transformation).

£m	Without flexibility solutions	With flexibility solutions
DFES System Transformation	273.2	217.3
CCC Headwinds	546.6	
Planning scenario	**747.9**	**571.2**
DFES Leading The Way	768.4	
DFES Consumer Transformation	757.2	
CCC Balanced Net Zero	762.2	
CCC Widespread Engagement	806.0	691.8

Table 11: Sensitivity testing: total network costs 2023-28 by scenario

Note: to ensure that scenarios are comparative, costs in the above table for the planning scenario equate to the total shown in Figure 24 before adjustments for flexibility market stimulation spend, green investment and asset replacement synergies totalling £(55.5)m.

Key considerations

Managing uncertainty

It is clear that our network is at the heart of the UK's net zero journey, but the extent of the impact on the network will remain unclear for some time. There are many considerable uncertainties in the pathway towards decarbonisation:

- The extent of electrification of heat and transport versus other alternatives like hydrogen - how electrical?
- The amount of locally distributed renewable generation connected to our network - how local?
- The speed at which renewables and LCTs will be adopted - how fast?
- The extent to which customer flexibility will be taken up - how flexible?

The answers to these questions will affect how we manage the network. For instance, we are aware of the possibility that there might be significantly less electrification of the heat sector than is currently assumed in our planning scenario, in a world where hydrogen and existing gas networks play a greater role in decarbonising space heating.

It is therefore essential that we continue to monitor the policy landscape and modify our planning assumptions at least annually to reflect the most recent developments. Although the scenarios we have considered are tightly bunched in the 2023-28 period, greater divergence is likely in the 2030s as uncertainty around policy and the uptake of LCTs increases. The commercial viability of LCTs, technological progress and challenges, regional characteristics such as building stock, and consumer behaviour will continue to drive uncertainties in the adoption of LCTs. As more LCTs are taken up and more data is gathered, this uncertainty will reduce.

We embrace this uncertainty by building an investment plan that is designed to be flexible to an evolving landscape:

- By adopting a flexibility first approach to planning network intervention we defer the need for reinforcement and give option value for the decarbonisation pathway that emerges.
- At EHV level where interventions and upgrades are the most costly, we will assess the need for intervention across multiple future energy pathways to minimise the risk of stranded assets.
- At the HV/LV levels, the infrastructure has a high probability of need regardless of the pathway, providing customers with the infrastructure necessary to maximise use of low carbon energy and provide flexibility for management of the whole energy system. The foundation of this approach is an investment in 10,000 additional LV monitoring units (as part of the DSO strategy). This will enable us to monitor the emergence of flexibility response amongst our customers and see when and where the need arises for investment on the network.

- Installing extra capacity on our network has the added benefit of improving energy efficiency by reducing electrical losses, which delivers economic benefits for customers from the perspective of the total cost of their energy, by reducing the need to install additional generation assets.

- In addition to harnessing synergies with asset replacement, our decarbonisation investment plan is underpinned by our principles that we will take the opportunity to upsize assets when we are investing in them. This adds additional capacity at low marginal cost, ensuring that wherever possible we are installing 'net zero ready' assets in order to minimise the likelihood of need to intervene at the same location again before 2050.

- If the pathway that unfolds during the 2023-28 period is not as steep as we anticipate, we still have the option to invest to prepare for the faster pathway, enabling us to efficiently reduce deliverability risks in the early 2030s.

Should price driven flexibility not materialise at the levels forecast, or load growth be greater than forecast, we will need to increase our investment in DNO contracted flexibility, smart network solutions and conventional reinforcement in that order. We will adopt the use of time-limited derogations to our network planning standards and use of temporary network assets as more extreme options if required. The additional costs imposed by these measures will be recompensed through the relevant uncertainty mechanism detailed in the Decarbonisation uncertainty annex.

Our assessment of the cost impact on the scenarios of the socialisation of net zero costs is discussed in the Socialisation of Net zero costs annex.

The costs in this plan – under our planning scenario – are based on the level of investment that we forecast will be necessary under the government's 10-point plan, and on the number of heat pumps being used in homes and electric vehicles on our roads that this plan would involve.

As shown in Figure 24, in this plan we have also distinguished:

- those costs that we think are necessary under any scenario for the low carbon transition, and that should be funded through up-front cost allowances; from

- those costs that could be funded through an uncertainty mechanism that counts the pace of uptake, and uplifts allowances if uptake is sufficiently high.

We give more details of our assessment to determine the baseline level of cost allowances and how the uncertainty mechanism arrangements could work in the decarbonisation uncertainty and Ofgem uncertainty mechanisms annex. This annex also covers future deliverability as the key reason for supporting this level of investment over 2023-28. The measures we are taking to ensure that the plan over 2023-28 is deliverable is covered in our delivery strategy.

A breakdown of this funding and associated volumes by investment category is shown in the table below, which shows that the majority of uncertainty mechanism funding is expected to be required to deliver investment on the HV/LV network as customers connect increasing volumes of LCTs.

Investment proposed to be funded ex ante

Network intervention costs (£m)					
	132/EHV	**HV/LV**	**Fault level**	**Looped services**	**Total**
DNO-contracted flexibility	1.8				**1.8**
Smart solutions	3.8	0.5	3.9		**8.2**
Traditional reinforcement	60.9	243.9	58.9	27.9	**391.7**
Total	**66.9**	**244.4**	**62.8**	**27.9**	**401.8**
Flexibility enablers - DSO strategy costs and go further faster flexibility investment					*95.6*
Total					***497.4***

Investment proposed to be funded through an uncertainty mechanism

Network intervention costs (£m)					
	132/EHV	**HV/LV**	**Fault level**	**Looped services**	**Total**
DNO-contracted flexibility	0.0				**0.0**
Smart solutions	0.0	0.2	0.0		**0.2**
Traditional reinforcement	0.0	104.2	0.0	6.3	**110.5**
Total	**0.0**	**104.4**	**0.0**	**6.3**	**110.7**
Flexibility enablers - DSO strategy costs and go further faster flexibility investment					*0.0*
Total					***110.7***

Ex ante volumes

Network intervention volumes (#)					
DNO-contracted flexibility	5				**5**
Smart solutions	5	117	3		**125**
Traditional reinforcement	12	8,894	26	17,741	**26,673**
Total	**22**	**9,011**	**29**	**17,741**	**26,803**

Table 12: Breakdown of funding and associate volumes by investment category

Our plan sees us building assets that will be used soon under any credible pathway to net zero and future deliverability is a further reason supporting higher investment over 2023-28 in line with our planning scenario which aligns with a pathway that needs the government's ten point plan to net zero. We have also ensured that can maximise the synergistic benefits between network reinforcement and asset replacement on both sides of the ledger. There are, however, some decarbonisation risks that we cannot control and we will work with Ofgem on the design of the necessary uncertainty mechanism. Our approach is described in our decarbonisation uncertainty annex.

Network utilisation forecasts

Our planned investment will provide extra capacity on our network to meet the needs of the additional demand. The table below shows that our network utilisation would be significantly higher by 2028 without our planned interventions, at both our major and distribution substations. Further, we will mitigate the need for further reinforcement with 29 projects to create fault-level headroom at our major substation sites for generation and to combat fault level constraints on the network.. Our DSO strategy and Connections sections of our main plan detail our intent to increase our capability to accommodate more flexible customer connections of generation or demand via solutions such as ANM.

Without the uncertainty mechanism funding, the network utilisation forecasts for the 2023-28 period under ex ante funding only would be higher on the HV/LV network than with total the total investment required to meet the needs of the planning scenario.

% substations	2023	2028				
		Without investment	With ex ante investment only	Difference vs. without investment	With total planning scenario investment	Difference vs. without investment
132kV & EHV substations						
<80% utilised	87.9%	82.7%	85.0%	2.3 ppts	85.0%	2.3 ppts
80-99% utilised	9.6%	14.4%	14.3%	0.1 ppts	14.3%	0.1 ppts
>99% utilised	2.5%	2.9%	0.7%	-2.3 ppts	0.7%	-2.3 ppts
HV/LV substations						
<80% utilised	94.1%	82.4%	85.8%	3.4 ppts	86.0%	3.6 ppts
80-100% utilised	2.9%	8.4%	9.0%	0.6 ppts	9.0%	0.6 ppts
>100% utilised	3.0%	9.2%	5.2%	-4.0 ppts	5.0%	-4.2 ppts

Table 13: Network utilisation forecast under Planning Scenario 2023-28

Impact on customers: we are mindful of the impact of changes in the energy system on customers. We will create opportunities for customers to be active participants and will ensure a just transition towards net zero

As a key facilitator in the net zero transition, we will enable our customers to become active participants in the energy system, allowing them to maximise the financial value of their energy resources. Our plans for building our own capabilities to harness flexibility and stimulate flexibility markets are set out in our DSO strategy.

It is also important that we develop a clear view of what is needed to ensure that the transition happens in a fair way for all customers. We will ensure a just transition by:

- Ensuring we keep our investment as efficient as possible to minimise increases in customer energy bills;
- Embracing digitalisation and open data to enable transparency in our decision making, giving customers the information they need to support their own decarbonisation agendas and benefit from the opportunities that the low carbon energy transition brings. Actively finding ways to ensure that the less wealthy and less well-engaged are able to access benefits from the energy transition as well as being particularly mindful of the impact on vulnerable customers, in particular promoting energy efficiency to aid customers in accessing behind the meter savings (refer to the customer vulnerability strategy for further information).
- Deploying talent by creating green jobs and developing skills in our region. This is detailed further in our workforce resilience strategy.

Continuing the dialogue with stakeholders: we will ensure a continuous dialogue with stakeholders as part of our annual planning process

We expect our plan to keep evolving as part of our annual planning process as society continues on the low carbon energy transition. We will use this annual process to capture broad developments in the policy environment, insights from system monitoring and data capture, and discussions with a broad range of stakeholders. This will enable us to ensure that our plan, including our strategic vision and outcomes, reflects the latest developments and stays relevant in the context of the national decarbonisation agenda. In particular, we will continue to engage with local and combined authorities in our region on their local area energy plan development; please refer to further detail on these plans in our DSO strategy.

As part of this, we will also continue participating in the National Grid FES process, engage with local authorities and other stakeholders, and reflect their feedback in the development of our DFES and investment planning scenarios. We will also undertake activities highlighted in our DSO strategy and whole systems strategy to ensure that our forecasts are continually updated based on stakeholder input. This continuous feedback loop reflects the planning and operating the network process flow shown on Figure 1 on page 8.

Appendix 1: Scenario modelling methodology

Methodology Overview

This modelling methodology appendix provides details of the key processes employed in load growth modelling, and covers:

- introduction;
- scenario development;
- Element Energy (EE) load growth model (EELG);
- building the EE load growth model; and
- running the EE load growth model and outputs.

Introduction

The purpose of this report is to provide an overview of the key processes that Element Energy and Northern Powergrid undertake to generate scenarios for future demand, generation and storage across Northern Powergrid's network, which is summarised in the diagram below. At high level, the process involves developing demand, generation and storage uptake scenarios for a range of technologies and customer behaviours and loading these into the Element Energy Load Growth (EELG) model which then produces a range of load forecasting outputs to high levels of geospatial and asset level resolution.

Scenarios for drivers of demand, generation and storage:

- **A variety of different uptake scenarios are produced for each demand, generation and storage technology use case.**
- **These scenarios are constructed from a range of literature sources and consumer choice modelling methods.**

Element Energy Load Growth Model:

- **A detailed load forecasting model that combines the scenarios for demand, generation and storage and applies these at high levels of geospatial and asset level resolution to the specific conditions of the Northern Powergrid network, customers and broader operating conditions.**

Load Forecasting outputs:

- **The outputs of the Element Energy Load Growth model include detailed and highly resolved demand, consumption, generation, storage and customer flexibility forecasts.**
- **Full sensitivity and scenario analysis options allow Northern Powergrid to understand in detail how different future possibilities would impact on their networks and how best to plan for and manage these.**

Figure 25: Process overview diagram

Overview of scenarios for drivers of demand, generation and storage

Uncertainty in future changes in the demand, generation and storage on the Northern Powergrid distribution network is captured through the use of scenarios. This includes scenarios for uptake of various technologies, as well as other aspects such as levels of economic growth, wider adoption of time-of-use-tariffs, penetration of smart EV charging and vehicle to grid (V2G).

While Northern Powergrid has the ability to run the EELG model and generate outputs for any combination of scenarios for the various model components, a scenario framework is also agreed between Northern Powergrid and Element Energy covering a set number of global scenarios ('scenario worlds'), representing pre-defined combinations of scenarios across all EELG model components. Two different types of approach are used to generate the uptake scenarios that underpin these global 'scenario worlds':

- A bottom up approach with consumer choice and willingness to pay uptake modelling (used in the emerging thinking Scenarios).[14]

- A top down approach involving national or grid supply point (GSP) level scenario analysis and disaggregation (used in the DFES and the CCC's sixth carbon budget scenarios).

Northern Powergrid has worked with Element Energy to produce one overarching scenario world that is the core scenario for Northern Powergrid's 2023-28 business plan. This scenario world, the planning scenario referred further on, builds upon a range of different uptake scenarios that were constructed for three different sets of scenario worlds constructed over the past year and a half as part of the business planning process. These three sets of scenario worlds used to inform the Northern Powergrid planning scenario, and the modelling logic that underpins them, are outlined in the table that follows.

The development of these scenarios has been informed by stakeholder engagement – further details of which are included in Appendix 2 – DFES stakeholder engagement of this annex.

Scenario world group	Main basis for scenario world development	Year developed
Emerging thinking (ET) scenarios	– Element Energy consumer choice and willingness-to-pay uptake modelling combined with literature and trial data.	2020
Distribution Future Energy Scenarios (DFES)	– Bespoke analysis to determine Northern Powergrid's regional view of National Grid's Future Energy Scenarios 2020.[15]	2020
Climate Change Committee's (CCC) sixth carbon budget scenarios	– Bespoke analysis to determine Northern Powergrid's regional view of some of the Climate Change Committee's UK-wide sixth carbon budget scenarios 2021.[16]	2021

Table 14: The scenario worlds used in the modelling approach

The Northern Powergrid planning scenario is based on a selection of uptake scenarios from the range of scenario worlds outlined above and was developed by taking into consideration the regional characteristics of the network, stakeholder feedback and Government policy. In the section that follows, we briefly outline each of the scenario worlds above, then we detail the scenarios used in the Northern Powergrid planning scenario. It is worth noting that while the Northern Powergrid planning scenario is the main scenario used by Northern Powergrid for business planning purposes, the full range of scenario worlds below can be used by Northern Powergrid as sensitivity analyses to test network implications of alternative future energy pathways.

Emerging thinking scenario worlds

In June 2019, the UK became the first major economy to pass net zero emissions targets into law which will require the UK to bring all greenhouse gas emissions to net zero by 2050. The focus of the emerging thinking scenarios, developed in early 2020, was to understand the impact of this legislation on the local electricity distribution network.

[14] Northern Powergrid published Emerging Thinking in August 2020, inviting stakeholders to engage on its considerations for the 2023-28 plan. It was necessary to create scenarios for this to meet the government's legally binding net zero target by 2050, because scenarios from DFES 2019 were created prior to this target and were therefore not compliant.
[15] National Grid ESO (2020), "Future Energy Scenarios", Available from: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents.
[16] Climate Change Committee (2021), "Sixth Carbon Budget", Available from: https://www.theccc.org.uk/publication/sixth-carbon-budget/

Three over-arching scenario worlds were considered in this work, each representing a cohesive view of a potential path to a decarbonised future. Each was created by developing different scenarios for the level of uptake of the main technological drivers behind the transition to a low carbon economy – for demand, generation and flexibility. Two of these scenarios, deep electrification and high hydrogen, are consistent with a net zero energy system in 2050 but achieve that decarbonisation via different pathways, especially for heating. The third scenario, net zero early, is more ambitious and is compliant with a net zero energy system in the mid-2040s. This additional scenario reflects the fact that many local authorities within Northern Powergrid's licence areas have committed to net zero emission targets significantly earlier than 2050. The scenarios are presented in more detail below:

- **Deep electrification:** This scenario achieves significant decarbonisation, consistent with the UK reaching a net zero energy system by 2050, via a high degree of electrification in both heating and transport achieved through a significant level of consumer engagement.

- **High hydrogen:** The high hydrogen scenario achieves significant decarbonisation, consistent with the UK reaching a net zero energy system by 2050, through the use of low carbon hydrogen to decarbonise the gas grid as well as to assist in decarbonising heavy duty vehicles.

- **Net zero early:** This scenario world is more ambitious, achieving net zero compliance in the mid-2040s. The scenario relies on intensive investment in low carbon technologies, as well as early action from government and a high level of engagement from consumers, in order to achieve aggressive rollout rates, especially of EVs and HPs.

Distribution Future Energy Scenario (DFES) 2020 worlds

Northern Powergrid's four core DFES 2020 worlds were produced by adopting the scenario framework published by National Grid in their latest Future Energy Scenarios.[17] Bespoke scenarios were developed for each driver of demand and generation and constructed into four overarching scenario worlds that align with the narratives of the pathways from National Grid. This task involves representing the scenarios put forward by National Grid, but with detailed analysis to understand how they would best be applied to Northern Powergrid's networks. By developing bespoke uptake scenarios with local knowledge, Element Energy is able to more accurately reflect Northern Powergrid's region, the customers within this region and the current deployment of low-carbon technologies. As detailed in scenario section of the main body of this annex, the four scenario worlds are structured as follows:

- **Steady progression:** general progress is made towards decarbonisation; however, this is the only scenario world that does not meet net zero by 2050.

- **System transformation:** the 2050 net zero target is met by relying on hydrogen to decarbonise the more difficult sectors of heat and heavy transport.

- **Consumer transformation:** the 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat.

- **Leading the way:** this is the fastest of the scenario worlds to achieve net zero with the highest level of societal change, utilising both hydrogen and electric low carbon technologies.

Climate Change Committee's (CCCs) sixth carbon budget scenario worlds

Ofgem's 2021 business planning guidance made specific mention of the CCC sixth carbon budget scenarios, especially in relation to the uptake of HPs and electric vehicles. The CCC scenarios are constructed around a similar set of drivers (level of societal change and decarbonisation) to the National Grid future energy scenarios, though they also take into consideration other factors such as the extent of innovation. The CCC developed a total of five scenarios, as shown

[17] National Grid ESO (2020), "Future Energy Scenarios", Available from: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents.

below. In the interest of producing analysis efficiently, Element Energy together with Northern Powergrid selected the CCC's central view (the balanced net zero pathway) as well as the two scenarios that captured the largest range of potential impact on the network (the headwinds and widespread engagement scenarios). These three scenarios were taken forward for further modelling:

- **Balanced net zero pathway:** this scenario keeps in play a range of ways of achieving net zero and is based on the CCC's central assumptions.
- **Widespread engagement:** this scenario involves high levels of societal shifts in behaviour, thereby reducing demand for high-carbon activities and increasing the uptake of various climate change mitigation measures.
- **Headwinds:** this scenario relies less on societal and behavioural shift and more on the use of large hydrogen and carbon capture and storage infrastructure to achieve decarbonisation.

All of the CCC scenarios are 2050 net zero compliant and are all consistent with the UK government's 10 Point Plan on fossil fuelled vehicle phase-out and on target heat pump deployment. A summary of key assumptions by scenario is included overleaf.

		NPg scenario	National Grid FES				CCC scenarios		
Category	**Sub-category**	**Planning Scenario**	**Consumer Transformation**	**Steady Progression**	**System Transformation**	**Leading the Way**	**Balanced Net Zero Pathway**	**Headwinds**	**Widespread Engagement**
Domestic	Stock growth	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Domestic	Thermal efficiency	Low	High	Low	Medium	V. High	Low	V. Low	Low
Domestic	Appliance efficiency	Medium	Medium	Low	Medium	High	Medium	Medium	Medium
I&C	Stock growth	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
I&C	Energy efficiency (all types)	High (rapid rollout pre 2030)	High (rapid rollout pre 2030)	Low	Medium	V. High	High (rapid rollout pre 2030)	Medium	High (rapid rollout pre 2030)
EV scenario	Uptake scenario	High	High	Low	Medium	High	High	High	High
HP scenario	Domestic HPs	Medium in ED2 rising to High in 2050	High	Low	Medium	High	Medium in ED2 rising to High in 2050	Medium	Medium in ED2 rising to V. High in 2050
HP scenario	I&C HPs	Medium in ED2 rising to High in 2050	High	Low	Medium	High	Medium in ED2 rising to High in 2050	Medium	Medium in ED2 rising to V. High in 2050
PV scenario	Solar generation (plant greater than 1MW)	High	Medium	Low	Medium	High	Medium	Medium	Medium
PV scenario	Solar generation (plant less than 1MW)	High	High	Low	Medium	Medium	High	High	High
Wind scenario	All	High	High	Low	Medium	High	High	High	High
mCHP scenario	All	High	Low	Low	Low	V High	Low	Low	Low
I&C CHP scenario	All	V. Low	Medium	High	Low	Low	Medium	Medium	Medium

		NPg scenario	National Grid FES				CCC scenarios		
Category	Sub-category	Planning Scenario	Consumer Transformation	Steady Progression	System Transformation	Leading the Way	Balanced Net Zero Pathway	Headwinds	Widespread Engagement
Other non-renewable generation (non-renewable engines, waste)	All	Low	Low	Medium	Low	Low	Low	Low	Low
Other renewable generation (renewable engines, biomass, hydro)	All	Medium	Medium	Low	Low	Medium	Medium	Medium	Medium
Energy Storage Scenario	All	High	Medium	Low	Medium	High	Medium	Medium	Medium

Table 15: Summary of key input assumptions by scenario

Northern Powergrid Planning Scenario

The Northern Powergrid planning scenario was constructed using what was assessed to be the most suitable set of scenario assumptions based upon a combination of modelling, research, stakeholder engagement and network knowledge. As seen, the planning scenario is largely centred on the net zero early world developed as part of the emerging thinking Scenarios. These scenarios are largely modelled bottom up to reflect the Northern Powergrid network and customers with the best possible geospatial resolution and accuracy. These net zero early uptake scenarios were favoured by many regional stakeholders as they provided the combination of ambitious decarbonisation with bottom up modelling to reflect the nuances of the region.

In some cases, however, more recent developments favoured the use of newer uptake scenarios. This was particularly true in the case of the heat pump uptake scenarios, where the announcement of the government’s 10 point plan and the publication of the CCC’s Sixth Carbon Budget led to more certainty around the government’s ambitions to encourage the uptake of HPs. As such, the CCC’s Balanced Net Zero Pathway, disaggregated to Northern Powergrid’s region from the CCC’s national level scenario, was adopted as the basis for heat pump uptake in the planning scenario. In the case of onshore wind, the analysis of the technical potential for the deployment of onshore wind in the Northern Powergrid region was updated as part of the DFES 2020 modelling work to reflect the latest technological developments. As such, it was felt that the newer DFES Leading the Way scenario, derived from National Grid’s national level scenarios, was the best option to represent the uptake of onshore wind in a highly ambitious decarbonisation world.

Element Energy Load Growth model

The EELG model is a tool which Element Energy provides to a number of UK DNOs. For each DNO, the EELG model is tailored to their specific network, customers and operational requirements. The model overview provided in this document is for the Northern Powergrid version of the EELG model, though many key aspects of the fundamental modelling approach are aligned with the EELG models provided to other DNOs. The EELG model is constructed using the specific network topology of each distribution network built up from the number of domestic and industrial and commercial (I&C) connections at each substation, all the way down to secondary substation level (including connectivity from secondary substations to primaries, bulk supply points and grid supply points). These domestic and I&C connections are mapped to customer archetypes using high geospatial resolution (postcode sector resolution) archetype data. Twenty domestic archetypes are defined according to variables such as heating fuel, location, household size, tenure type and a distinction between existing stock and future new builds. The EELG model makes use of industrial and commercial (I&C) archetypes (up to 15) based on different building use types and business sectors (e.g. offices, warehouses and wholesalers, schools and educational establishments, hospitals and medical establishments etc.). Using a detailed bottom up customer archetype approach means that the forecasts are able to capture the unique mix of customers and their behaviour at each distribution network asset. The customer archetype data is also important for ensuring the technology uptake projections are relevant to the mix of customers at each asset.

The regular update work for the EELG model consists of a number of aspects, these are outlined in more detail below. Firstly, the baseline data feeding into the EELG model is updated. This includes updating the network topology and connected customer numbers data from Northern Powergrid, as well as calibrating the demand at each asset based on the latest half-hourly demand data from Northern Powergrid. Other aspects of the EELG model calibration are also updated such as impacts of losses and total domestic demand profiles from data by Elexon class. Technology deployment data for EVs, solar and wind generation, etc. are also updated based on the most recent data at high geographical resolution from Northern Powergrid and other sources such as the Department for Transport (for EVs). Technology demand and generation profiles are also updated based on the most recent data as applicable. Finally, the technology uptake forecasts in the EELG model are also updated (including cost, performance, and policy inputs where appropriate and the consumer choice modelling and analysis is rerun accordingly for EVs, domestic HPs, domestic micro CHP, solar PV, wind and battery storage. The uptake trends for all other sectors (e.g. time-of-use-tariffs, smart charging, etc.) are also updated at this time. The scenarios within the EELG model that are based on National Grid and CCC projections (along with the assumptions used to disaggregate these scenarios across the Northern Powergrid network) are also updated as appropriate when new data becomes available. The components for which scenarios are included in the EELG model are as follows:

- core domestic customer demand (i.e. excluding EVs and HPs);
- core I&C customer demand (i.e. excluding EVs and HPs);
- EVs – both battery and plug-in hybrid electric vehicles;
- domestic heat pumps – both full and hybrid electric heat pumps;
- I&C heat pumps – both full and hybrid electric heat pumps;
- heavy industry fuel switching to electricity;
- electrolysers;
- heavy duty vehicles including buses, coaches and heavy goods vehicles;
- solar PV generation – both rooftop domestic and I&C as well as large-scale ground-mounted installations;
- wind generation;
- biomass and energy crops generation;
- renewable engines (landfill gas, sewage gas and biogas);
- hydro generation;
- domestic micro CHP and larger I&C CHP;
- waste incineration generation;
- non-renewable generation including diesel and gas engines;

- domestic battery storage (co-located with household solar PV);
- I&C battery storage (behind the meter); and
- large-scale battery storage.

For each component considered in the EELG model above, the future impact on network load is typically calculated based on a forecast of the annual kWh from the model base year to 2050. The calculation captures total volumes, efficiency, etc. as appropriate for each component, which is broken down across the Northern Powergrid region based on the location-specific customer archetype mix and a range of other factors such as historic deployment data, available greenspace (for solar PV and wind generation), etc. This is then combined with a profile shape to translate the annual kWh into half-hourly kW demand. Profile shapes are defined for each component, with each diurnal profile covering the 48 half-hours of a day, defined for each month of the year, on the day of maximum and minimum demand that month (i.e. each component has 24 profiles with each spanning 48 half-hours). Separate profile shapes are defined to capture the uptake of domestic time-of-use-tariffs as well as impacts from EV smart charging and vehicle to grid, as these become more prominent over time.

A summary figure of the EELG model functionality is as follows:

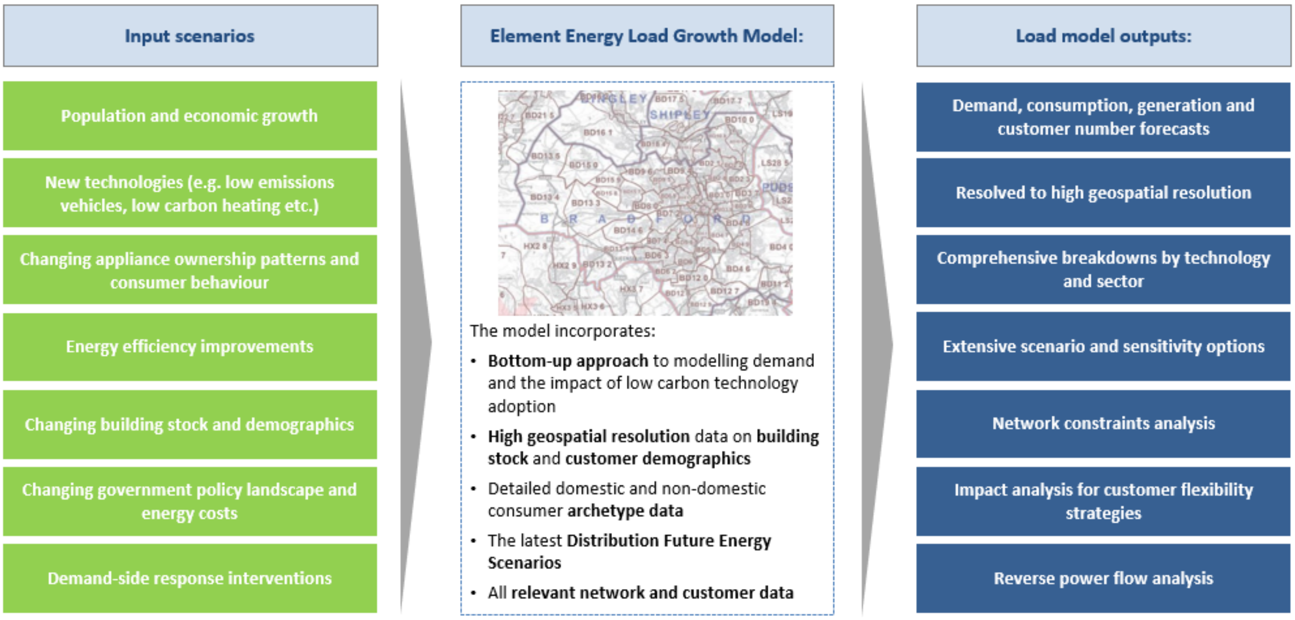


Figure 26: Functionality of the EELG model.

The following outlines the approach summarised in the EELG model. As described in the scenarios section of the main body of this annex, we have summarised the role of the EELG model in the Northern Powergrid business planning process in three key phases:

- build 'year 0' demand and low carbon technology (LCT) profiles;
- build scenario building blocks; and
- run EELG model.

For the scenario building blocks we provide more detail for three key sectors of electricity demand, namely:

- core demand;
- electric vehicles; and
- heat pumps.

Phase one: build ‘year 0’ demand and LCT profiles

The first step in the annual update of the EELG model is to accurately represent the current state of demand and generation across Northern Powergrid’s distribution network. This requires integration of a range of detailed datasets provided by Northern Powergrid as well as external datasets. Table 15 below describes the process of building an updated view of half hourly demand and LCTs on Northern Powergrid’s network by grid supply point, bulk supply point, primary and secondary substation as of the model base year (Year 0).

Step	Description
Prepare Year 0 demand data	– Demand data from Northern Powergrid’s SCADA system is prepared based on previous year actual results to give maximum and minimum demands. – The data is half hourly metered data by grid supply point, bulk supply point, primary substation and then calculated for secondary substations.
Create network topology	– The network architecture is represented in the EELG model. – Additional information is added, such as generation connected at each primary substation.
Create monthly demand profiles	– The demand data from the first step is used to populate the network topology from the second step. – The impact of connected generation is corrected for to get gross demand. – The impact of existing low carbon technologies is estimated based on deployment data to give a view of underlying demand (to be added back later). – This creates a view of monthly demand profiles as at “Year 0” (today) specific to all parts of the Northern Powergrid network.
Classify customer groups	– Northern Powergrid's customer numbers, broken down into domestic and I&C per secondary substation, are leveraged. – Secondary substation data by postcode is used to build customer groups at each substation. – Domestic customers are classified into archetypes based on attributes such as fuel type, location, dwelling size, tenure type and age of property. – I&C customers are broken down into business type.
Create underlying demand per secondary substation	– Domestic: Load profiles are produced by secondary substation based on electricity and heating demand for each archetype. – I&C: Annual electricity and heating demand by secondary substation are modelled from factors such as floor space and energy intensity capturing business type, efficiency, etc.
Calculate annual consumption by secondary and primary	– Domestic and I&C customer archetypes are used to calculate expected annual consumption by secondary. – Using the network topology created at step 2, consumption by secondary is summated up to primary level to obtain consumption by each primary substation.
Reconcile consumption at primary	– The sum of annual consumption at the secondary substations is then reconciled to the annual consumption that is billed to Northern Powergrid’s customers. – There are cross-checks between the secondary and primary substation consumption. – Losses are also accounted for.
Allocate	– Demand from LCTs is added back separately to give a clear separate profile of LCTs vs.

demand LCTs by secondary substation	underlying demand as a starting point for load growth modelling. – LCTs are allocated to secondary substations using geospatial modelling, customer numbers, EV owners, heat pumps, etc. all via national and regional data sets for Year 0
Build monthly demand profiles with LCTs	– The LCT data is overlaid onto the monthly underlying demand to create total monthly demand profiles. – The LCT data is based on half hourly profiles modelled from innovation projects including CLNR.
Apportioning FES data	– National Grid's Future Energy Scenarios provide technology performance data for some LCTs (e.g. EV peak demand profiles, which is applied to the Year 0 LCT numbers from the steps above).

Table 16: Process for building the 'year 0' demand and LCT profiles in the EELG model

Phase 2a: Build scenario building blocks - Core components of demand

The fundamental electricity demand of domestic and industrial and commercial (I&C) customers, excluding the impact of low carbon technologies such as EVs and HPs, is referred to as 'core demand' in the EELG model. Core demand captures the changing usage characteristics, energy efficiency and appliance ownership patterns of established technologies and customer behaviours within the Northern Powergrid region. Core demand is modelled separately for the domestic and I&C sectors within the EELG model and is primarily driven in each case by two overarching factors:

- the total number of customers connected to the network – assumed to be controlled by the size of the building stock; and
- the energy intensity of the customers within those properties.

The main drivers behind these two factors are outlined and additional detail on how these are modelled is provided below.

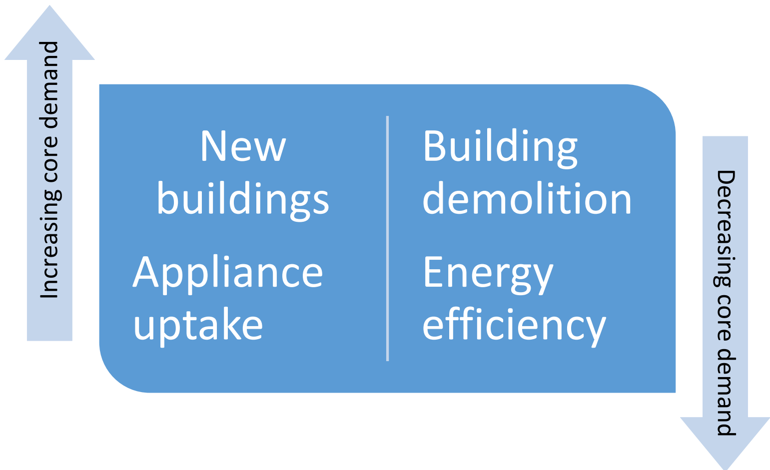


Figure 5: The impact of different drivers of core electricity demand.

Stock growth

The number of domestic properties and I&C premises connected to the distribution network are modelled as the net result of two competing factors – demolition of the existing stock and the rate of new build completions in each sector.

Domestic building stock

The medium domestic stock growth scenario is based on Ministry of Housing, Communities and Local Government household stock growth projections for each local authority to 2039. The low, principal and high population growth projections from the Office for National Statistics[18] (ONS) are used to produce low and high household stock growth projections for each local authority.

A demolition rate for each local authority is used to define the existing vs. new build proportion of the stock by year. This demolition rate is calculated from the Ministry of Housing, communities and local government net supply of housing statistics[19] on the number of demolitions per year. The user also has the option to define demolition rates for individual local authorities. An overview of this method is shown in figure 25, which follows.

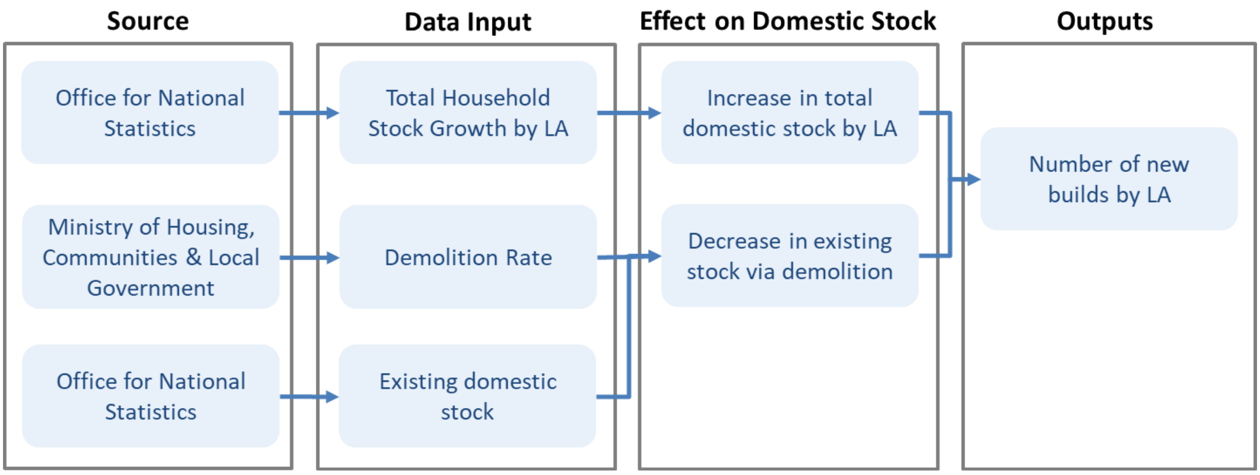
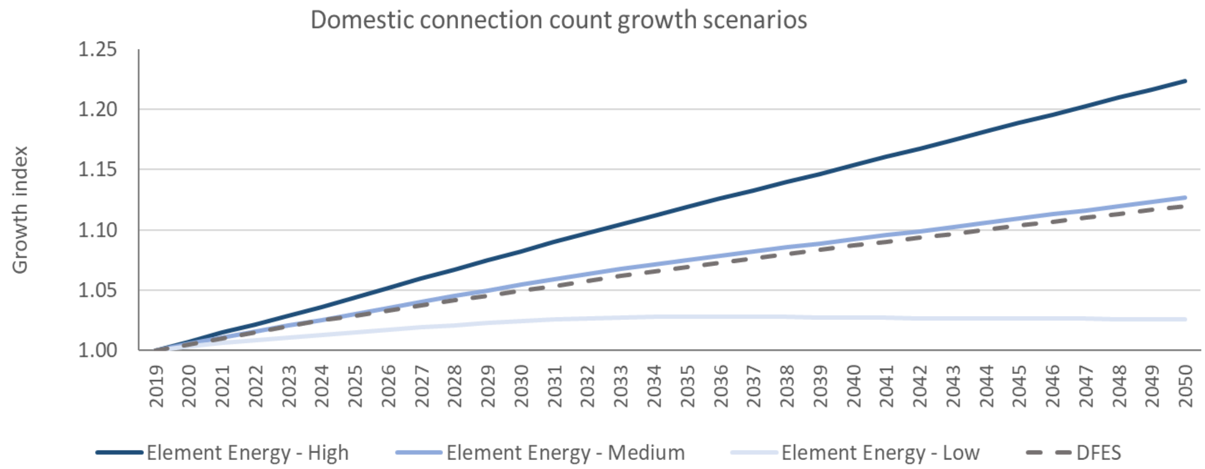


Figure 6: Method for producing the medium growth scenario for domestic building stock (LA: Local Authority).

The domestic connection count growth index scenarios are shown in figure 29, with National Grid's inferred GB-level scenario[20] overlaid.



[18] Office for National Statistics (2018), "National population projections: 2018-based", Available from: https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationprojections/datasets/localauthoritiesinenglandtable2
[19] Ministry of Housing, Communities and Local Government, "Housing supply: net additional dwellings", Available from: https://www.gov.uk/government/collections/net-supply-of-housing
[20] The National Grid's stock growth scenario shown is derived from their Future Energy Scenario dataset. National Grid ESO (2020), "Future Energy Scenarios", Available from: https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Figure 29: Domestic connection count growth index scenarios.

The Element Energy – medium stock growth scenario is used in the Northern Powergrid planning scenario world as this is the scenario developed directly based upon the Ministry of Housing, Communities and Local Government projections.

I&C building stock

Future growth of the I&C sector is defined for each local authority within the EELG model. This approach is based on historic trends in Gross Value Added[21] and floor space[22] in each local authority in the Northern Powergrid licence areas combined with future projections of gross domestic product from the Office for Budget Responsibility[23] and population growth from the ONS[24].

The process and sources are shown schematically in figure 27.

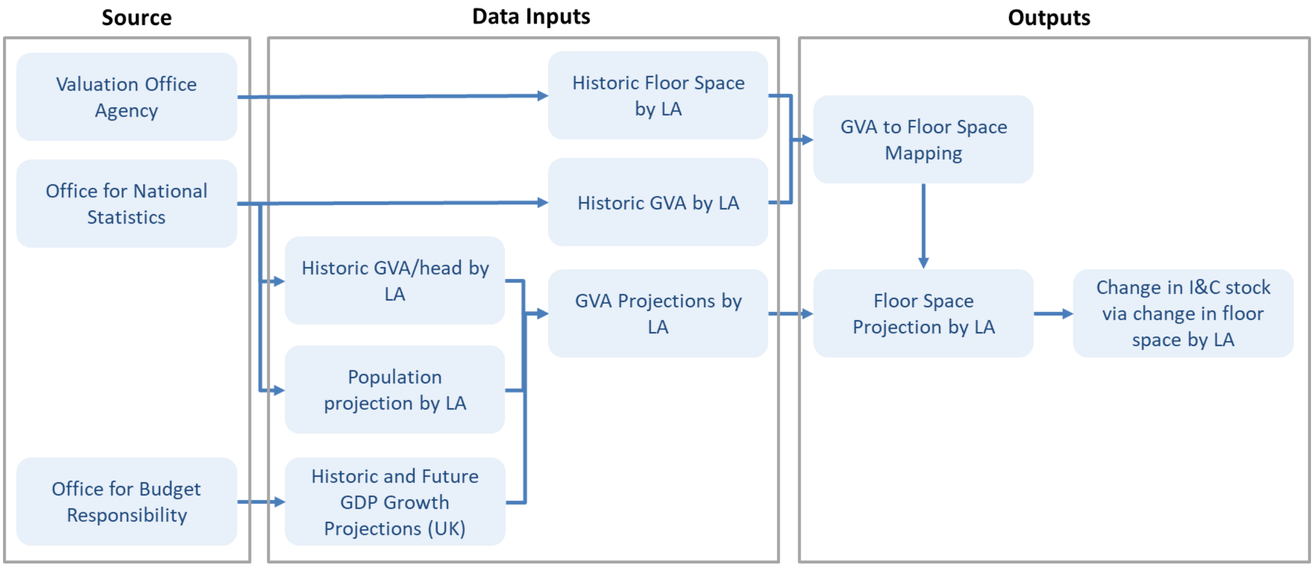


Figure 30: Method for developing local authority-specific growth scenarios for I&C floorspace.

The Element Energy – Medium stock growth scenario is used in the Northern Powergrid planning scenario world as this is the scenario developed directly based upon the central Office for Budget Responsibility Gross Domestic Product projection.

Energy efficiency

In determining scenarios for energy efficiency, the efficiency of building stock fabric (i.e. thermal energy efficiency) and appliances are considered separately in the domestic sector and in aggregate in the I&C sector.

[21] Office for National Statistics, “Regional Gross Value Added (Income Approach) by Local Authority in the UK”, Available from: https://www.ons.gov.uk/economy/grossvalueaddedgva/datasets/regionalgvaibylocalauthorityintheuk
[22] Valuation Office Agency (2019), “Business Floorspace projections”, Available from: https://www.gov.uk/government/statistics/non-domestic-rating-stock-of-properties-including-business-floorspace-2019
[23] Office for Budget Responsibility (2019), “Economy Charts and Tables”, Available from: https://obr.uk/data/
[24] Office for National Statistics (2018), “National population projections: 2018-based”, Available from: https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationprojections/datasets/localauthoritiesinenglandtable2

Domestic thermal energy efficiency

The EELG model uses two sets of thermal energy efficiency trajectories:

– One set is based on National Grid's future energy scenario datasets[25]. National Grid do not publish their thermal energy efficiency assumptions explicitly so additional analysis is conducted as part of the EELG modelling to obtain a best possible representation of the assumptions used by National Grid in this area.

– The other set is based on Element Energy building stock modelling.

The thermal demands of existing buildings, shown as an index relative to the base year, are displayed in figure 31 that follows.

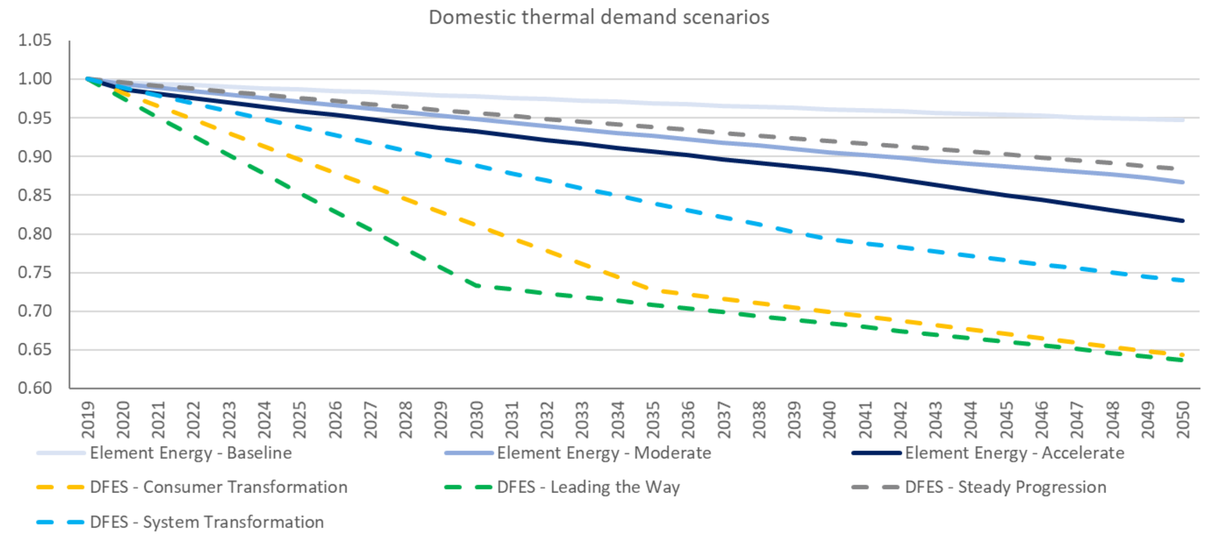


Figure 31: Thermal demand of existing domestic buildings.

The Element Energy Moderate scenario is assumed in the Northern Powergrid planning scenario world. The reason for this choice is that the Element Energy Moderate scenario is believed to be the most consistent[26] with the CCC's Balanced Net Zero Pathway, which is the heat pump uptake scenario assumed in the Northern Powergrid planning scenario world. Thermal efficiency and heat pump uptake are closely interlinked as energy efficiency retrofit is often a pre-requisite for heat pump deployment in many existing buildings; therefore, consistency is maintained across these scenarios.

Domestic appliance energy efficiency

In addition to domestic thermal efficiency, the EELG model also considers efficiency gains related to the transition to more efficient appliances, as well as the change in domestic electricity demand due to changing appliance ownership. This excludes electrification association with EV and heat pump adoption and excludes all heating appliance impacts (which are treated elsewhere). The net impact on domestic non-heating electricity demand is shown in figure 32 that follows for the DFES scenarios[27]. Consumer transformation is consistent with the EU Energy efficiency targets for appliances, whereas Leading the Way exceeds them. The Consumer Transformation scenario is assumed for the Northern Powergrid planning scenario world given its consistency with the latest EU targets.

[25] National Grid ESO (2020), "Future Energy Scenarios", Available from: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents.
[26] The CCC's thermal efficiency scenarios are not published and are therefore inferred from the data available in the CCC's Sixth Carbon Budget report.
[27] National Grid ESO (2020), "Future Energy Scenarios", Available from: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents.

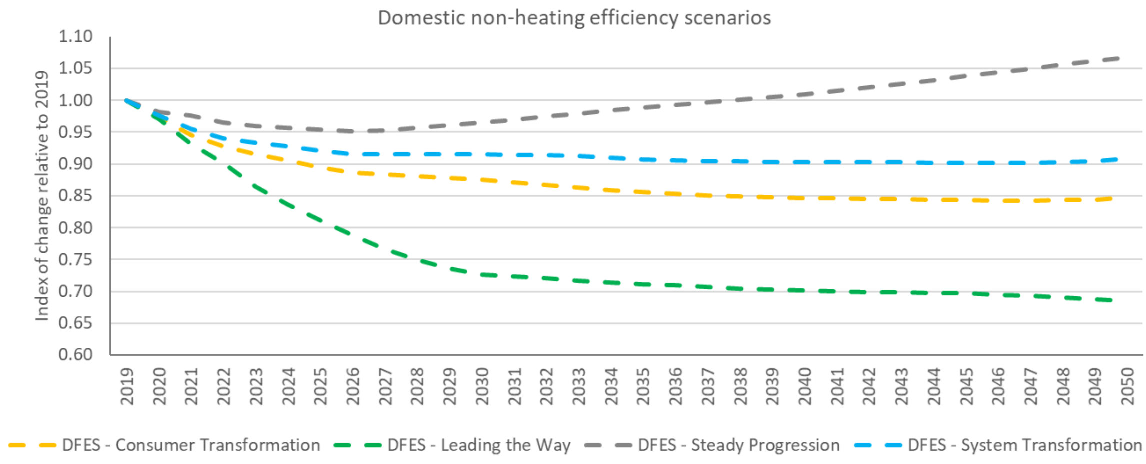


Figure 32: Domestic non-heating electricity demand scenarios[28]

I&C energy efficiency

The scenarios for I&C energy efficiency, which are target driven, are shown in the figure below. Both sets of scenarios (DFES and Element Energy) are based on EU energy efficiency targets, but the DFES scenarios have been inferred based upon a selection of data published by National Grid.

The DFES Consumer Transformation scenario and the Element Energy Future Policies scenarios meet the UK's Clean Growth Strategy[29] target of a 20 per cent increase in efficiency by 2030, from a 2015 baseline. The Northern Powergrid planning scenario world assumes the same level of I&C efficiency as the Element Energy Future Policies scenario.

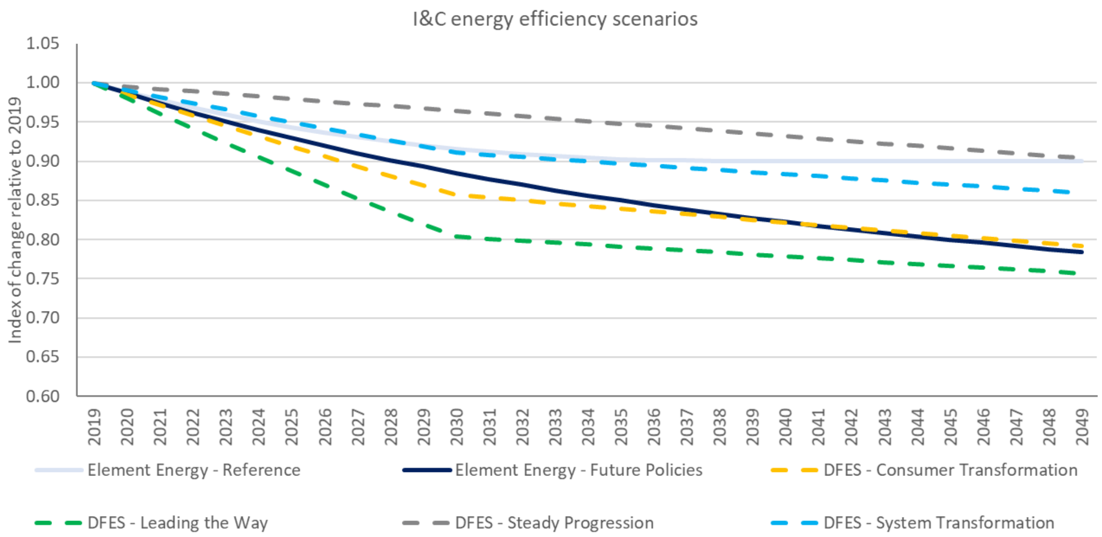


Figure 33: I&C energy efficiency

[28] Element Energy for Northern Powergrid (2021), "CCC and NPg planning scenarios".
[29] HM Government (2017), "The Clean Growth Strategy", Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf

Consumption

Electricity consumption of core domestic components is calculated using a building archetype-based approach to represent the characteristics of the housing stock in the areas served by Northern Powergrid. The building characteristics used to define the 20 domestic archetypes used in the EELG model include heating fuel type, urban vs rural location, along with house size, tenure and age. Domestic consumption is then calibrated against network level total measured electricity consumption by customer type. This refers to the EELG calibration step discussed above which utilises total domestic demand profiles from metering data by Elexon class for the current year.

The process for I&C components is similar, though archetypes are defined around 15 I&C sub-sectors (including offices, warehouses and wholesalers, schools and educational establishments, hospitals and medical establishments, etc.) using data specific to the Northern Powergrid network building stock. In addition, I&C consumption is split into low-voltage- and high-voltage-connected customers.

The allocation of electricity consumption from core demand across the network utilises the archetype distribution at each substation, which is based on postcode sector level building and customer type data. In this way, the customer archetype distribution is defined all the way down to secondary substation level (including connectivity from secondary substations to primary substations, bulk supply points and grid supply points).

Peak demand

Base year

As described in phase one above, for the EELG model base year, demand data is prepared based on previous year actual results to give maximum and minimum demands. The data is half hourly metered by grid supply point, bulk supply point, primary substation and then calculated for secondary substations.

Modelled years

For all future years, the contribution to peak demand of the core domestic and I&C load is calculated for individual substations on the Northern Powergrid network by multiplying their annual electricity consumption by a normalised peak day diurnal demand profile for the month of peak demand at that substation for each future year out to 2050. An example of a domestic peak day half hourly profile, derived from Northern Powergrid's domestic demand data, is shown in figure 34.

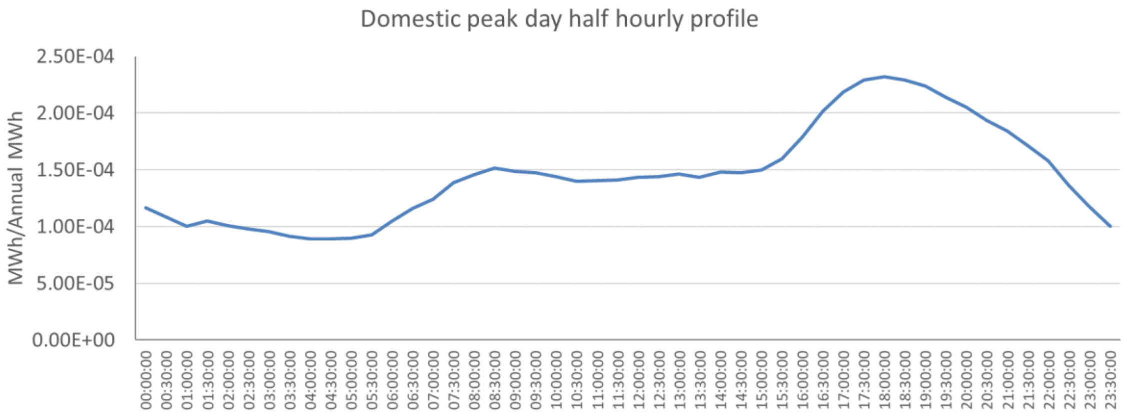


Figure 34: Example domestic peak day half hourly profile[30]

[30] Element Energy processing of Northern Powergrid's demand data for Elexon Profile Classes 1 and 2.

Phase 2b: Build scenario building blocks - low carbon technologies

Northern Powergrid's future energy scenario modelling covers a wide range of demand, generation and storage technologies as listed in the table below. Assessing the current distribution of low carbon technologies across network substations takes into consideration a wide range of input datasets provided by Northern Powergrid. For certain demand technologies (e.g. EVs), the current deployment data has geospatial resolution down to postcode sector level. For generation and storage technologies, the input data includes currently connected installations at primary substation and bulk supply point level.

To demonstrate the approach taken, this section focuses on two key drivers of demand, EVs and HPs, as examples of the approach that has been taken for each of the demand, generation and storage technologies.

Demand technologies	Generation technologies	Storage technologies
– Electric vehicles – both battery and plug-in hybrid electric vehicles.	– Solar PV generation – both rooftop domestic and I&C as well as large-scale ground-mounted installations.	– Domestic battery storage (co-located with household solar PV).
– Domestic heat pumps – both full and hybrid electric heat pumps.	– Wind generation.	– I&C battery storage (behind the meter).
– I&C heat pumps – both full and hybrid electric heat pumps.	– Biomass & energy crops generation.	– Large-scale battery storage.
– Heavy industry fuel switching to electricity.	– Renewable engines (landfill gas, sewage gas and biogas).	
– Electrolysers.	– Hydro generation.	
– Heavy duty vehicles including buses, coaches and heavy goods vehicles.	– Domestic micro CHP and larger I&C CHP.	
	– Waste incineration generation.	
	– Non-renewable generation including diesel and gas engines.	

Table 17: List of demand, generation and storage technologies modelled

Electric vehicles (EVs) (cars and vans)

In this section, the process of developing uptake scenarios for EVs and subsequently calculating consumption and peak network impact is discussed. As a case study example, the electric car and van uptake scenarios developed using the Element Energy Consumer Choice (ECCo) model are presented. These uptake scenarios are used in the Emerging Thinking Scenario worlds and in the Northern Powergrid planning scenario world.

The Element Energy Car Consumer model was originally commissioned by the Energy Technologies Institute in 2010 and has been updated regularly since for the Department for Transport as well as the Energy Technologies Institute. It supports the reviews of the Plug-in Car Grant and Plug-in Van Grant. Recent use cases have included:

– Employed by the UK Department for Transport to aid light duty vehicle policy design.

- Integrated into the Modelling Framework of the Energy Technology Institute's Consumers Vehicles and Energy Integration Project which simulates pathways to decarbonising the light duty vehicle sector from the perspective of the whole UK energy system.

- Used to provide UK Power Networks, Electricity Northwest, and Northern Ireland Electricity Networks with forecasts for the number of plug-in vehicles charging across their licence areas, including underpinning the load forecasting analyses undertaken by these organisations.

The ECCo model is used to generate uptake projections of battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) and hydrogen fuel cell electric vehicles (H2 FCEV) for each future year to 2050. The ECCo model takes in scenarios for a suite of parameters that influence the decisions made by vehicle purchasers such as vehicle costs, fuel costs, government subsidies, vehicle model availability and more. It then determines the decisions made by bespoke consumer groups when choosing between the different types of vehicles available. Low emission vehicle uptake is calculated at national level, i.e. for Great Britain (GB), as the correlation between consumer segments and geographical characteristics is not strong enough to support regional uptake modelling. For this reason, low emission vehicle uptake scenarios are developed at GB level, then disaggregated to Northern Powergrid's licence areas.

This disaggregation of the GB-level forecast down to each of Northern Powergrid's licence areas considers the current electric vehicle stock which is based on postcode district-level statistics from the Department for Transport. In the near term, current EV deployment levels are used to inform the proportion of the GB-level EV scenarios that belong in each of Northern Powergrid's licence areas. In the longer term, a blending approach is used to disaggregate based on the total car stock in each licence area, which is also based on the latest data from the Department for Transport.

The ECCo uptake modelling of low emission cars and vans produced three uptake scenarios (low, medium, and high), that reflect varying degrees of government ambition for the phase out of internal combustion engine (ICE) vehicles. Following the development of these scenarios, the Government increased their ambition for the phase out of vehicles that use fossil fuels; however, these targets are still yet to be passed into law so some uncertainty remains.[31] The table below gives a high-level overview of the main assumptions for each scenario. The low scenario represents a low level of ambition, where current legislation does not change and, therefore, policy does not follow recommendations from the CCC. It should be noted that, for the UK to meet its carbon budget targets, the recommended level of EV uptake by the CCC is the phase out of the sale of internal combustion engine, hybrid and plug-in hybrid electric vehicles by 2035 at the latest, which is consistent with the medium scenario. The medium scenario falls short, however, of the policy announced in the government's 10 Point Plan. The high scenario is consistent with the government's 10 Point Plan for ICEs and more ambitious than it for PHEVs (by five years).

Scenario	Level of decarbonisation ambition	End of sales	EV proportion of car sales in 2030
Low	Consistent with current legislation.	Sale of ICEs end by 2040. PHEVs still available in 2050.	48%
Medium	Consistent with the CCC's "at the latest" recommendation for the end of ICE sales.	Sale of ICEs and PHEVs end by 2035.	72%
High	Consistent with current government ambition for ICEs only and with the CCC's more ambitious vehicle recommendations.	Sale of ICEs and PHEVs end by 2030.	98% (2% hydrogen vehicles)

Table 18: Overview of electric car uptake projections (low, medium, high) and the targets that they meet

The scenarios are in line with national Department for Transport vehicle stock projections[32] which assume that the overall car stock grows steadily until 2040 (~one per cent per year).

[31] In November 2020, the Prime Minister confirmed that the UK will end the sale of new petrol and diesel cars and vans by 2030. However, the sale of hybrid cars and vans that can drive a significant distance with no carbon coming out of the tailpipe will continue to be allowed until 2035.
[32] Department for Transport (2018), "Road Traffic Forecasts 2018", Available from: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/834773/road-traffic-forecasts-2018.pdf

The Northern Powergrid planning scenario uses the high EV uptake scenario as it is the closest to the government's most recently stated ambition and the feedback from stakeholders was that it is the scenario that they are aiming for and would like Northern Powergrid to enable.

Uptake of battery across both Northern Powergrid licence areas is shown in the following figure [33].

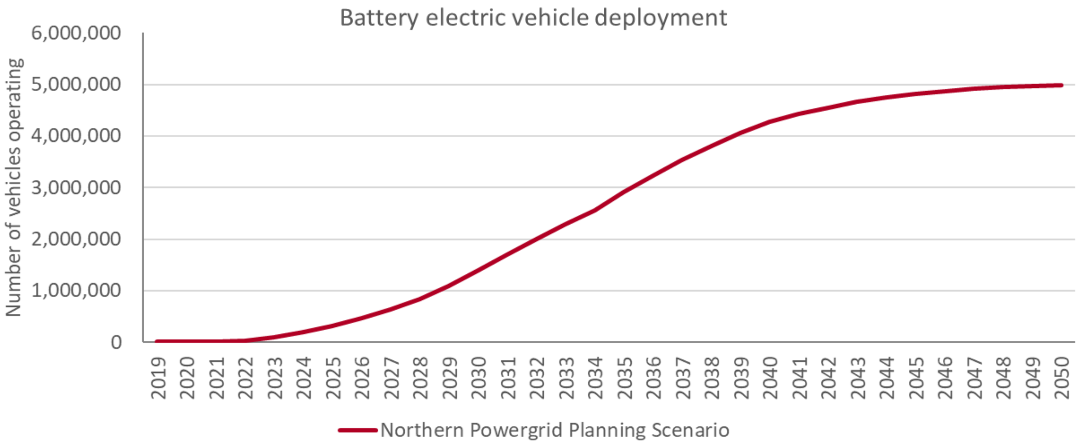


Figure 35: Battery electric vehicle deployment in Northern Powergrid's region

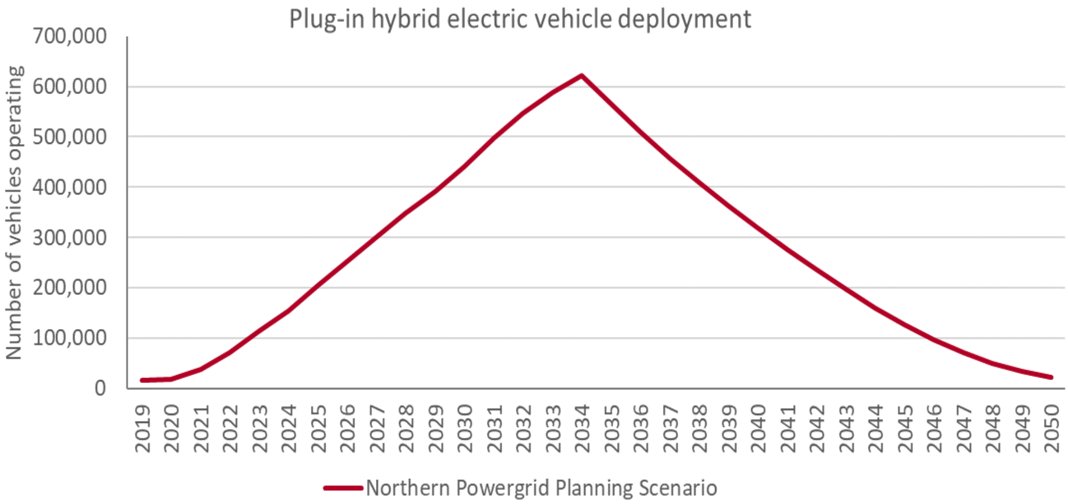


Figure 36: Plug-in hybrid electric vehicle deployment in Northern Powergrid's region

Geospatial disaggregation

A second geospatial disaggregation step is applied once the licence area-level uptake scenarios are defined; this step involves allocating EVs down to secondary substation level. Since the market for EVs is still in its early stages, there is not yet sufficient data to reliably predict which regions will show greater uptake of EVs in the long term. Therefore, in the base year of the EELG model, EVs are distributed to domestic connections according to the historic distribution of EV uptake in each licence area. This is based on Driver and Vehicle Licensing Agency data[33] by postcode district, and then in the long term we blend this with a distribution where uptake of EVs is distributed according to the present-day distribution of the car stock in the region, broken down by local authority.

[33] Northern Powergrid applies for data extracts from the Driver and Vehicle Licensing Agency which are shared with Element Energy.

Consumption

Electricity consumption of EVs is calculated bottom-up in the EELG model by taking into consideration the latest data on annual mileage, vehicle efficiency, battery range and distance covered in electric mode (for hybrid electric vehicles). The EV uptake scenarios produced by the ECCo model include forecasts for each of these variables. The proportion of electricity consumption from EV charging assigned to I&C connections vs domestic connections is also calculated, taking into consideration both the electrification of fleet vehicles and the charging of domestic vehicles away from the home.

The allocation of electricity consumption from EVs across the distribution network utilises postcode district level EV registration data from the Department for Transport, mapped onto the network connectivity data. This network connectivity data goes all the way down to secondary substation level (including connectivity from secondary substations to primary substations, bulk supply points and grid supply points).

Peak demand

The load from EV charging is distributed across the day using a variety of diurnal demand profiles:

- domestic standard charging (slow and fast);
- domestic smart charging;
- domestic V2G;
- I&C evening;
- I&C daytime; and
- I&C smart charging.

These EV charging profiles are derived from data from the Customer-Led Network Revolution[34] and Low Carbon London[35] trials as well as Element Energy modelling and National Grid's future energy scenarios assumptions. A typical diurnal profile for average daily EV charging demand in the month of December is shown in figure 34.

[34] CLNR was a network innovation project led by Northern Powergrid. The project was completed in 2014. More information available at: http://www.networkrevolution.co.uk/

[35] Low Carbon London was a network innovation project that ran from 2010 to 2014, led by UK Power Networks. More information available at: https://innovation.ukpowernetworks.co.uk/projects/low-carbon-london/

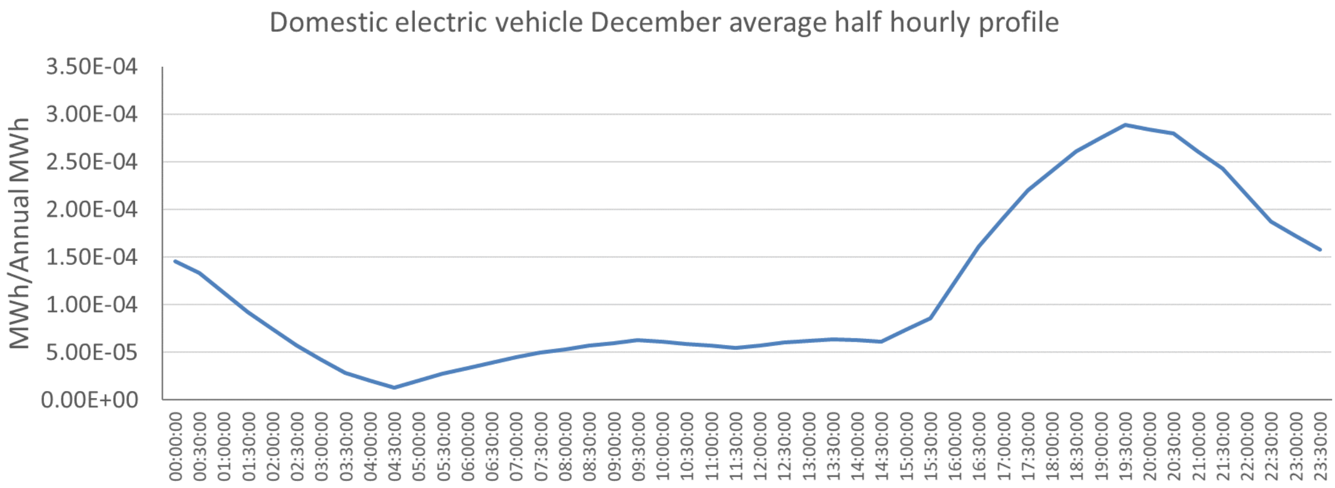


Figure 37: Average daily profile for electric vehicle charging demand for December[36]

Heat Pumps (HPs)

In this section, the process of developing uptake scenarios for HPs and subsequently calculating consumption and peak network impact is discussed. As a case study example, the domestic heat pump uptake scenarios developed using the CCCs UK-wide sixth carbon budget scenarios 2021[37] are presented. These uptake scenarios are used in the CCCs sixth carbon budget scenario worlds and in the Northern Powergrid planning scenario world.

The CCC's sixth carbon budget dataset[38] provides domestic heat pump uptake scenarios for each of the UK's devolved administrations. A three-step process is applied to disaggregate this uptake down to Northern Powergrid's licence areas, taking into account real-world deployment data and the regional characteristics of the building stock in Northern Powergrid's region.

[36] Element Energy processing of data from: CLNR (2014)
[37] Climate Change Committee (2021), "Sixth Carbon Budget", Available from: https://www.theccc.org.uk/publication/sixth-carbon-budget/
[38] Climate Change Committee (2021), "The Sixth Carbon Budget Dataset", Available from: https://www.theccc.org.uk/wp-content/uploads/2021/02/The-Sixth-Carbon-Budget-Dataset.xlsx

1. Disaggregate national-level scenarios to each Northern Powergrid licence area:	2. Allocate heat pumps to building archetypes	3. Disaggregate heat pump uptake to secondary substation level
- CCC uptake scenarios are published by devolved administration. - Disaggregate relevant scenarios using domestic building stock as a proxy. - Use regional RHI data and industry heat pump sales statistics on heat pump deployment to calibrate base year and near-term heat pump deployment.	- CCC uptake scenarios are broken down into new vs existing buildings and hybrid vs full-electric installations. - These categories are allocated to the 20 domestic building stock archetypes used in the EELG model. This distribution is based on the archetype distribution of heat pumps in the Element Energy consumer choice renewable heat uptake model, which was used in the bottom-up Emerging Thinking Scenario worlds.	- The distribution of domestic heat pumps across Northern Powergrid's network (down to secondary substation level) is then achieved by combining the domestic archetype distribution at postcode sector level with the distribution of heat pump uptake across the domestic archetypes.

Figure 38: Process applied to disaggregate national-level heat pump scenarios, allocate them to building archetypes and subsequently to network assets. RHI: Renewable Heat Incentive[39]

The EELG model allocates domestic heat pump uptake across the 20 domestic archetypes used in the model. The EELG model contains information on the distribution of archetypes at each substation, which allows the model to distribute HPs accordingly. This means that heat pump uptake levels vary across network assets depending on the mix of households in the region. For example, households without access to the gas network are more prevalent in rural areas, and are more likely to adopt HPs due to the higher cost of counterfactual technologies such as electricity, oil, etc. (which are more expensive overall than gas). Furthermore, it is assumed that government policy will target the decarbonisation of high carbon fossil fuels in the off gas building stock before on gas properties. This means that rural regions see higher uptake of HPs in the near term.

[39] Department for Business, Energy & Industrial Strategy, "Renewable Heat Incentive statistics", Available from: https://www.gov.uk/government/collections/renewable-heat-incentive-statistics

The resulting heat pump uptake scenario for the CCC's balanced net zero pathway, which is the scenario used in the Northern Powergrid planning scenario, is shown in following figure.

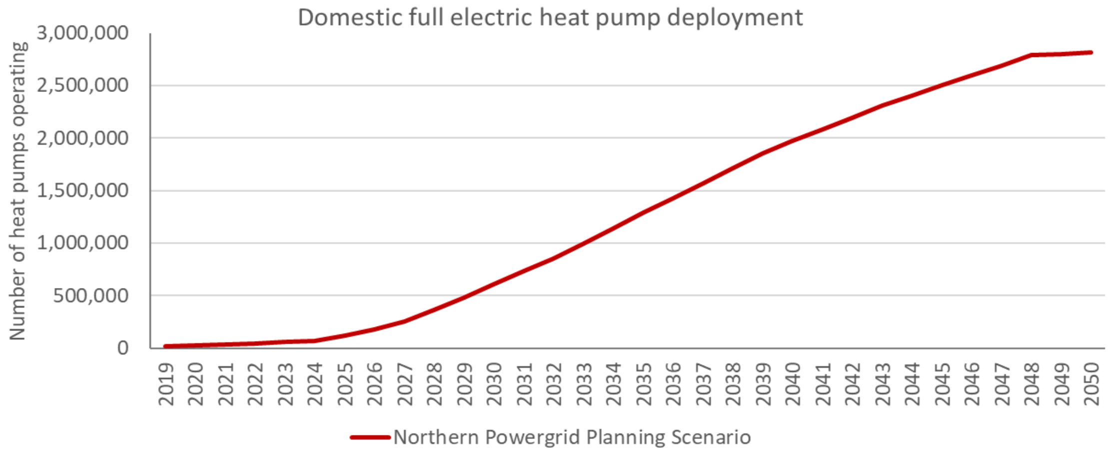


Figure 39: Domestic full electric heat pump deployment in Northern Powergrid's region.

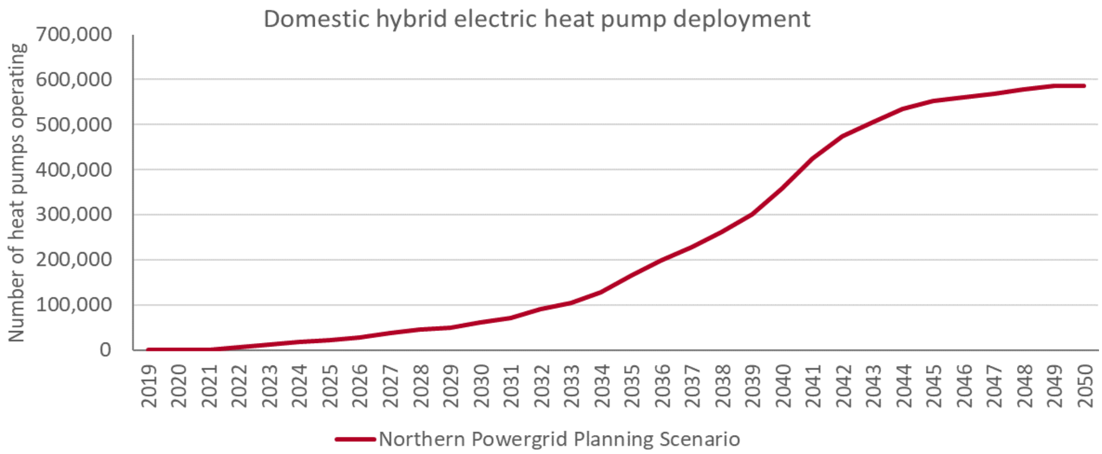


Figure 40: Domestic hybrid electric heat pump deployment in Northern Powergrid's region.

Consumption

Electricity consumption of HPs is calculated in the EELG model by considering the three following parameters:

- The thermal demand of building archetypes. Each building archetype is assigned a thermal demand which is based on Element Energy modelling of the average thermal efficiency of the different building archetypes. Future thermal demand is projected at archetype level, taking into account the deployment of thermal energy efficiency measures discussed above.

- The proportion of thermal demand met by electricity. Full electric heat pump systems are assumed to supply the total thermal demand of the archetype. For hybrid electric HPs the thermal demand is met partially by electricity.

– The coefficient of performance[40] of HPs. As the core heat pump technology is already at a mature stage, additional improvements in coefficient of performance are expected to be small relative to the changes in thermal energy efficiency outlined above, so the coefficient of performance is assumed to be constant.

The allocation of electricity consumption from HPs across the network utilises the building archetype distribution at each substation, which is based on postcode sector level building type data. In this way, the building archetype distribution is defined all the way down to secondary substation level (including connectivity from secondary substations to primary substations, bulk supply points and grid supply points).

Peak demand

The load from domestic HPs is distributed across the day using diurnal demand profiles. These are based on Element Energy's processing of data from the customer-led network revolution (CLNR) innovation project,[41] typical profiles from this work are shown below figure 41.

When calculating winter peak demand, the EELG model has the functionality to prevent hybrid heat pump installations from contributing to peak demand assuming that they meet thermal demands using the non-electric component of the system (for example a gas boiler) at the time of peak demand; this is the default setting used in all scenarios described in this report.

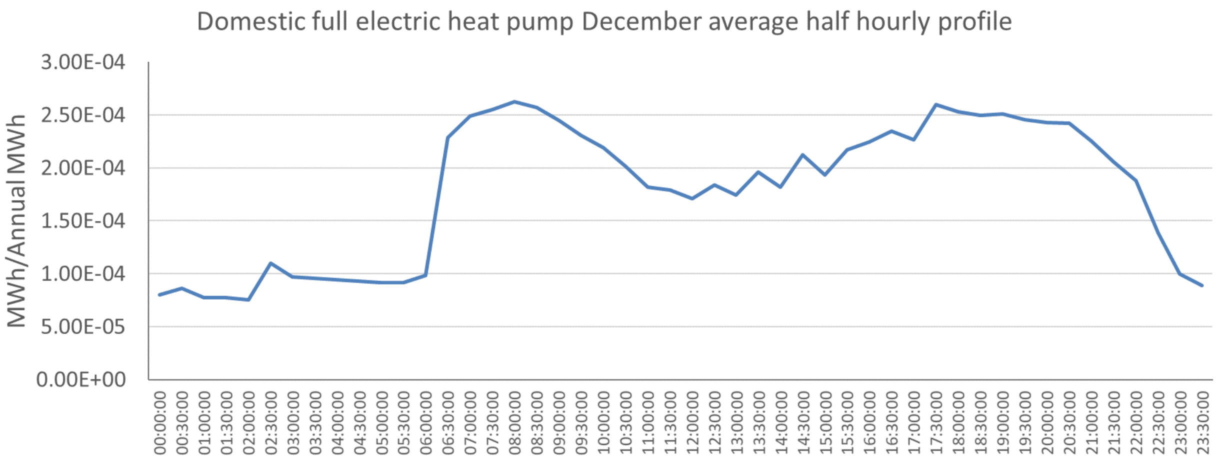


Figure 41: Average daily profile for heat pump demand for December.[42]

Phase 3: Run load growth model

The EELG model produces a wide range of outputs, ranging from customer counts, LCT uptake, consumption outputs, and generation outputs to peak demand outputs. A detailed list of outputs broken down into these categories is shown below.

The outputs are generated for up to 100 different scenario worlds and at four different network substation voltage levels: grid supply point, bulk supply point, primary substation and secondary substation[43].

[40] This is the typical power to heat ratio at which heat pumps operate.
[41] Customer-Led Network Revolution was a network innovation project led by Northern Powergrid. The project was completed in 2014. Further information is available at: http://www.networkrevolution.co.uk/
[42] Element Energy processing of data from: Durham Energy Institute and Element Energy for Northern Powergrid (2015), "Customer Led Network Revolution, Insight Report: Domestic Heat Pumps", Available from: http://www.networkrevolution.co.uk/wp-content/uploads/2015/01/CLNR-L091-Insight-Report-Domestic-Heat-Pumps.pdf

Depending on the type of output, the temporal resolution of the outputs is either annual resolution for each year from the model base year (2019) to the model end year (2050), or half hourly resolution for the case of diurnal profiles.

A full list of outputs is included overleaf. Once they are produced by the EELG model for the substations in the Northern Powergrid licence areas, these feed into Northern Powergrid's business planning procedures.

For example, this work includes analysis of future primary substation utilisation and identification of potential sites of future reinforcement under different possible futures (as set out in the main body of this annex – refer to Section 2c, Step 3 Investment Plan Load-related reinforcement at EHV and 132kV).

The LCT volume outputs from the EELG model are fed into load flow analysis tools that assess the expected impact of future LCT uptake on the LV network, as set out this annex – refer to Step three investment plan HV/LV Load-related reinforcement and the HV/LV Network Reinforcement EJP.

In this way the outputs from the EELG model enable Northern Powergrid to assess the expected impact of future load growth on our distribution network under different future scenarios, allowing Northern Powergrid to determine the most cost-effective route for meeting future demands on our network as well as how to most effectively support the ambition of regional stakeholders in achieving net zero.

Full list of outputs

Outputs	Description
Customer count outputs	– Number of domestic customers. – Number of I&C customers.
LCT uptake outputs	– Number of domestic full electric heat pumps. – Number of domestic hybrid heat pumps. – Number of I&C full electric heat pumps. – Number of I&C hybrid heat pumps. – Number of heat pumps (total). – Number of electric cars and vans (hybrid and full electric). – Number of full electric cars and vans. – Number of hybrid electric cars and vans. – Number of electric cars (hybrid and full electric). – Number of electric vans (hybrid and full electric). – Number of Micro CHP units.
Capacity installed outputs	– Total installed PV capacity - domestic (MW). – Total installed PV capacity - I&C and large (MW). – Total installed wind capacity (MW). – Total installed Large & Mini CHP capacity (MW). – Total installed biomass capacity (MW). – Total installed renewable engine capacity (MW). – CHP (MWh). – Other Generation (MWh). – Storage (MWh). – Total demand (MWh).
Peak demand outputs (also available 'with customer flexibility' assumed)	– Total peak demand (MW). – Total generation at peak demand (MW). – Total storage at peak demand (MW).

[43] Only load segments connected to the low voltage network are resolved down to secondary substation level.

	– Total minimum demand (MW). – Total generation at minimum demand (MW). – Total storage at minimum demand (MW). – Peak day total demand profile (MW). – Monitored demand at peak (MW). – Reverse power flow analysis (MW). – MDI-based demand at peak (MW). – MDI-based monitored demand at peak (MW). – Total installed hydro capacity (MW). – Total installed waste incineration capacity (MW). – Total installed other non-renewable capacity (MW). – Total installed renewable generation capacity (MW). – Total installed non-renewable generation capacity (MW). – Total installed generation capacity (MW). – Total installed storage capacity (MW). – Domestic storage installed capacity (MW). – V2G capacity (MW). – Domestic DSR load shifting capacity (MW). – Domestic EV smart charging capacity (MW). – I&C DSR load shifting capacity (MW). – I&C EV smart charging capacity (MW). – I&C battery capacity (MW).
Consumption and generation outputs	– Domestic (MWh). – I&C (MWh). – HPs - Domestic (MWh). – HPs - I&C (MWh). – EV - cars & vans (MWh). – EV - other transport (MWh). – Electrolysers (MWh). – Large industry (MWh). – PV (MWh). – Wind (MWh). – Capacity released - EV smart charging (MW). – Capacity released - ToUT (MW). – Capacity released - I&C DSR (MW). – Capacity released - battery storage (MW). – Domestic demand at peak (MW). – I&C demand at peak (MW). – Proportion of domestic load due to existing stock. – Proportion of I&C load due to existing stock. – Peak demand due to domestic heat pumps (MW). – Peak demand due to I&C heat pumps (MW). – Peak demand due to large industry (MW). – Peak demand due to buses and HGVs (MW). – Peak demand due to electrolysers (MW). – Proportion of peak load due to EVs. – Peak utilisation (per cent - whole number).

Table 19: Full list of outputs

Appendix 2: DFES stakeholder engagement results

The below table includes examples of specific feedback we have received from our stakeholders throughout the iterative DFES, Emerging Thinking and 2023-28 engagement process on our scenarios that has led to us making changes to our modelling assumptions. Broader stakeholder engagement on decarbonisation, how we balance the rate of investment with cost and stakeholder views on our planning scenario, are documented in our detailed stakeholder engagement annex.

You said	We did
Bradford Council asked for total renewable distributed generation (DG) within a Local Authority.	Improved the Element Energy modelling to categorise renewable and non-renewable generation.
Sheffield Council asked for a breakdown of cars and light vans.	Improved the Element Energy modelling to make the breakdown available, including also electric buses, HGVs, etc.
Large industrial customer informed us that they are looking to fuel-switch their furnaces.	Feedback to NGESO FES team for them to consider industrial fuel switching in GB FES. Improved DFES modelling to facilitate large industrial fuel-switching projections.
Domestic customers queried EV projections for Newcastle.	Improved modelling methodology to sense check against existing car stock better.
Feedback from Newcastle University that the decarbonisation journey matters too, not just the destination.	Added visibility of annual carbon emission reductions to DFES outputs.
Representatives of vulnerable customers groups asked for better breakdown of domestic and I&C and hybrid heat pumps.	Modelling updated to reflect this request in DFES 2020 and planning scenario.
Sunderland Council asked for support on new build and residential growth.	Updated modelling to reflect recently adopted local plan projections.
Insight sought into a view as to the penetration of EVs/HPs relative to the population to avoid skewing by densely populated areas.	Modelling updated to reflect this request in DFES 2020 and planning scenario.
Sunderland Council asked for substation capacity to support green belt development plans.	Modelling updated to reflect this request in DFES 2020 and planning scenario.
Rural stakeholders requested the ability to show farm-based electrification.	Modelling updated to reflect this request in DFES 2020 and planning scenario.
LAs indicated ambition for a pathway achieving net zero earlier than 2050.	Developed a set of net zero scenarios including a pathway reaching net zero in the 2040's (Emerging Thinking/DFES 2020 scenario Net Zero Early).
In NG ESO's FES assumptions, biomass generation was assumed to be discontinued in 2020s. Lynemouth Biomass station in our region is due to continue production; therefore this assumption required correction.	Adjustment to GB FES made to include Lynemouth Biomass station generation in DFES/planning scenario assumptions.
NG ESO's FES assumed collocated solar and storage allocation across our licence areas was predominantly in Yorkshire only. Our and our expert stakeholders' information suggested that this was incorrect.	Generation and storage redistributed across Yorkshire and Northeast licence areas.
Our Net Zero Early scenario designed for DFES 2020 had lower wind generation assumptions than NG ESO's Leading the Way, based on their information on latest technology. Our and our expert stakeholders' view was that our scenario should include most up to date information.	We update assumptions around wind generation (related to new technology improving turbine yield) in the DFES 2020 Net Zero Early scenario and subsequently the planning scenario.
Our CEG noted that we should consider hydrogen heavy scenario, to both reflect the likely importance of hydrogen in our region.	DFES System Transformation high hydrogen scenario included within range (also in line with Ofgem requirements).
Our technical panel noted that we should consider provision for high electrification scenario including demand from electrolysers.	High electrification and high electrolyser scenario considered through sensitivity testing (see Appendix 3).
Energy efficiency assumptions challenged in DFES 2020 Net Zero Early scenario.	Assumptions adjusted in planning scenario to be more in line with CCC's projections.

You said	We did
Our technical panel noted that we should consider the impact of COVID-19 on long-term forecasting.	We will continue to monitor the impact of the pandemic on energy futures but do not expect significant long-term impact.[44] No changes made to modelling.
The Technical Panel and CEG noted that we should consider the impact on our scenario modelling if flexibility does not materialise.	Customer flexibility tested in sensitivity testing - see Appendix 3 for impact on scenario costs with and without flexibility solutions. Refer also to the decarbonisation uncertainty appendix for further information on how we will manage flexibility.

Table 20: You said, we did

[44] https://nic.org.uk/studies-reports/behaviour-change-and-infrastructure-beyond-covid-19/

Appendix 3: Sensitivity testing

Overview

We have undertaken extensive sensitivity analysis to test our planning scenario assumptions as well as to test the investment costs proposed. We have done this in three phases.

- **Phase one:** tests the impact of uncertainties in key modelling parameters related to LCT uptake and gross peak demand. This helps refine and iterate our input assumptions for testing the robustness of our planning scenario and includes testing aspects such as the EV uptake profile, and impact of domestic appliance efficiencies on load decline.
- **Phase two:** determines the cost impact of changes to modelling assumptions such as EV charging profiles, electrolyser take-up in combination with high electrification of EVs and HPs.
- **Phase three:** produces cost estimates for the range of reference scenarios taking into account the range of inputs that drive costs in the EHV/HV/LV cost models.

We describe each of the three phases of sensitivity testing below.

Phase one

As part of phase one, we tested the impact of varying LCT volumes, LCT clustering and underlying demand assumptions and parameters such as energy efficiency on gross peak demand. Results are displayed in figures below. The first chart (figure 39) below presents the impact of parameters such as thermal, appliance and I&C efficiency on the gross peak demand. The tables 20 and 21 below compare the gross peak demand and number of constrained sites for each sensitivity against the planning scenario. The final figures (figure 42 and 43) and tables 22 and 23 present sensitivities to demonstrate the impact of changing LCT uptake rates in comparison to the planning scenario.

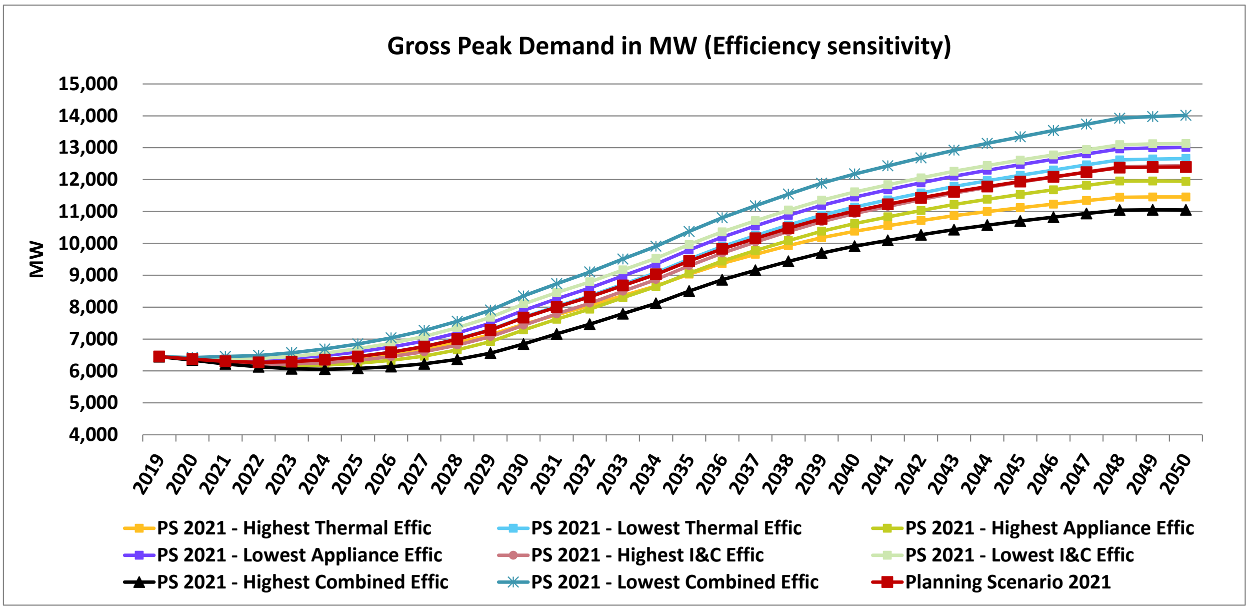


Figure 42: Parameter impact

Gross Peak Demand (MW)	Comparative Impact ED2 (%)	Comparative Impact ED2 (TouT) (%)	Comparative Impact 2030 (%)	Comparative Impact 2050 (%)
PS 2021 – Highest Thermal Efficiency	-1%	-1%	-3%	-8%
PS 2021 – Lowest Thermal Efficiency	0%	0%	0%	2%
PS 2021 – Highest Appliance Efficiency	-4%	-4%	-5%	-4%
PS 2021 – Lowest Appliance Efficiency	3%	3%	3%	5%
PS 2021 – Highest I&C Efficiency	-2%	-2%	-3%	0%
PS 2021 – Lowest I&C Efficiency	5%	5%	6%	6%
Planning Scenario 2021	0%	0%	0%	0%
PS 2021 – Highest Combined Efficiency	-8%	-8%	-5%	-4%
PS 2021 – Lowest Combined Efficiency	7%	7%	9%	13%

Table 21: Gross peak demand sensitivity

Number of constrained sites	Comparative Impact ED2 (%)	Comparative Impact ED2 (TouT) (%)	Comparative Impact 2030 (%)	Comparative Impact 2050 (%)
PS 2021 – Highest Thermal Efficiency	-13%	-11%	-17%	-10%
PS 2021 – Lowest Thermal Efficiency	0%	0%	1%	3%
PS 2021 – Highest Appliance Efficiency	-42%	-37%	-22%	-4%
PS 2021 – Lowest Appliance Efficiency	17%	32%	26%	7%
PS 2021 – Highest I&C Efficiency	-21%	-21%	-13%	0%
PS 2021 – Lowest I&C Efficiency	67%	63%	52%	14%
Planning Scenario 2021	0%	0%	0%	0%
PS 2021 – Highest Combined Efficiency	-50%	-37%	-52%	-14%
PS 2021 – Lowest Combined Efficiency	104%	137%	78%	21%

Table 22: Number of constrained sites sensitivity

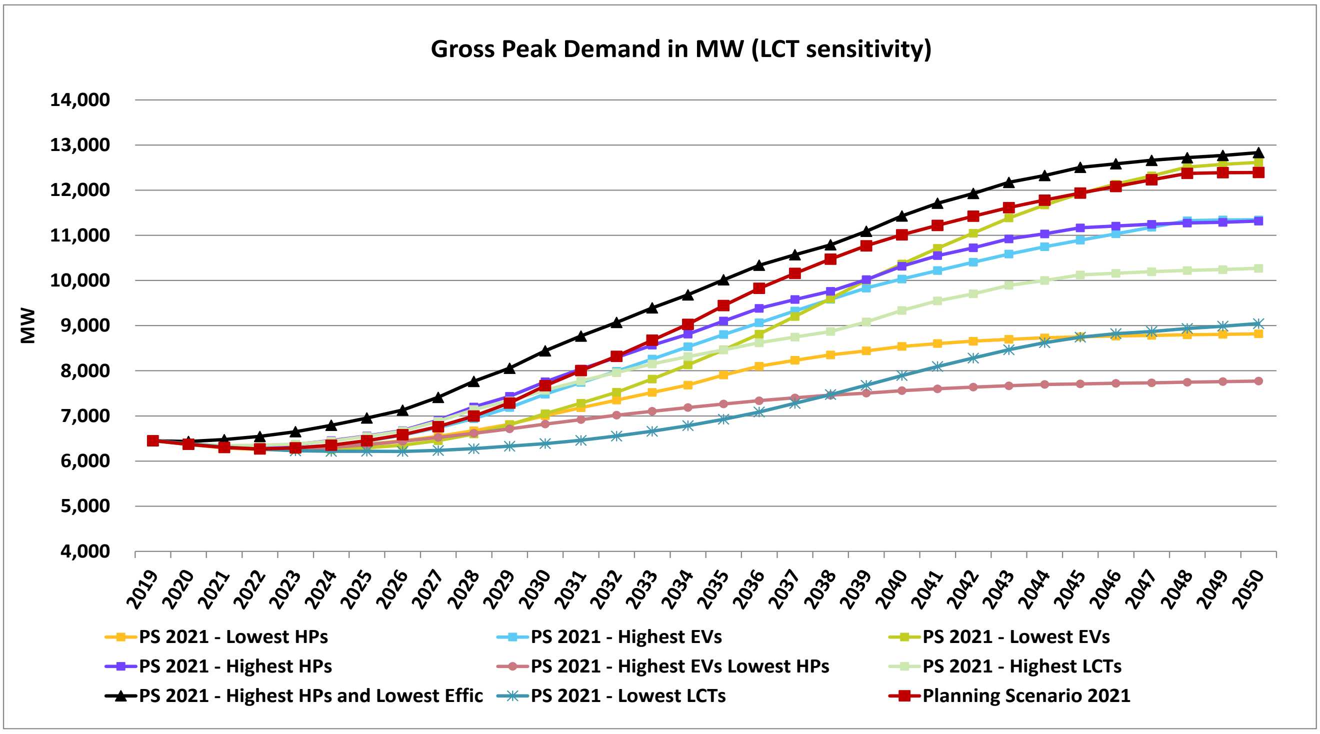


Figure 43: LCT sensitivity

Gross Peak Demand (MW)	Comparative Impact ED2 (%)	Comparative Impact ED2 (TouT) (%)	Comparative Impact 2030 (%)	Comparative Impact 2050 (%)
PS 2021 – Lowest HPs	-3%	-3%	-9%	-29%
PS 2021 – Highest EVs	0%	0%	-2%	-8%
PS 2021 – Lowest EVs	-5%	-4%	-8%	2%
PS 2021 – Highest HPs	2%	2%	1%	-9%
PS 2021 – Highest EVs Lowest HPs	-4%	-4%	-11%	-37%
PS 2021 – Highest LCTs	2%	2%	-1%	-17%
Planning Scenario 2021	0%	0%	0%	0%
PS 2021 – Highest HPs and Lowest Efficiency	10%	10%	-8%	2%
PS 2021 – Lowest LCTs	-8%	-7%	-17%	-27%

Table 23: Gross peak demand sensitivity

Number of constrained sites	Comparative Impact ED2 (%)	Comparative Impact ED2 (TouT) (%)	Comparative Impact 2030 (%)	Comparative Impact 2050 (%)
PS 2021 – Lowest HPs	-29%	-32%	-45%	-50%
PS 2021 – Highest EVs	0%	0%	-16%	-10%
PS 2021 – Lowest EVs	-46%	-32%	-51%	3%
PS 2021 – Highest HPs	33%	42%	12%	-11%
PS 2021 – Highest EVs Lowest HPs	-29%	-32%	-57%	-74%
PS 2021 – Highest LCTs	21%	26%	-7%	-26%
Planning Scenario 2021	0%	0%	0%	0%
PS 2021 – Highest HPs and Lowest Efficiency	121%	174%	97%	10%
PS 2021 – Lowest LCTs	-54%	-42%	-83%	-44%

Table 24: Number of constrained sites sensitivity

Results reveal that our planning scenario is relatively central during the 2023-28 period, moving to the higher end of the range post 2028. It is most exposed to uncertainty through assumptions on the uptake of HPs.

- In the case of energy efficiency, our planning scenario is well positioned in the centre of the range of sensitivities until 2050. This prevents us from getting locked-in into an extreme pathway.

- The uncertainty in the case of heat pumps is larger, with a wider range of outcomes. The planning scenario is centrally positioned in the 2023-28, rising to higher levels in the period up to 2050 to account for higher electrification (as explained in the planning scenario section above). Sparse information on heat pump uptake and usage profiles is a potential planning risk and needs to be addressed through future trials and real data. We have also modelled an extreme case of high heat pump deployment with low energy efficiency improvement. While this is an unlikely situation, it demonstrates the potential risk of the two technological developments not being tied together. We expect this to be an area requiring additional policy considerations and research in the near term.

- Uncertainty related to electric vehicle uptake is relatively lower, with a narrower range of outcomes compared to heat pumps. Recent uptake of EVs and evidence from other jurisdictions that like the UK have implemented similar policies to promote EV uptake (the ban on fossil fuel vehicles but also tax credits on EV purchases and establishment of clean air zones (CAZ)) suggest greater likelihood of EV adoption during the current decade. Our planning scenario relies on EV charging profiles from a number of network trials and we will continue to stay abreast with latest developments.

- Clustering of LCTs may mean that different parts of our network will end up with more LCTs than others. We expect to address this uncertainty through a combination of enhanced monitoring of our networks and relying on customer and network flexibility to manage situations where higher than expected load starts to materialize on various points of our network driven by higher LCT uptake. These considerations will help inform the refinement our investment plan in the future.

Phase two

As part of phase two of our sensitivity testing, we determined the cost impact as a result of manipulating modelling assumptions. We find that:

- For EVs, default overnight charging can provide short-term alleviation of demand, but the benefits decline over time as eventually the load growth and movement in peak shifts dominates.
- Electrolysers in a high electrification world could increase network costs by 10 per cent (see chart below).
- Uncertainty in domestic ToUT uptake is a result of a differential impact across different parts of our network.

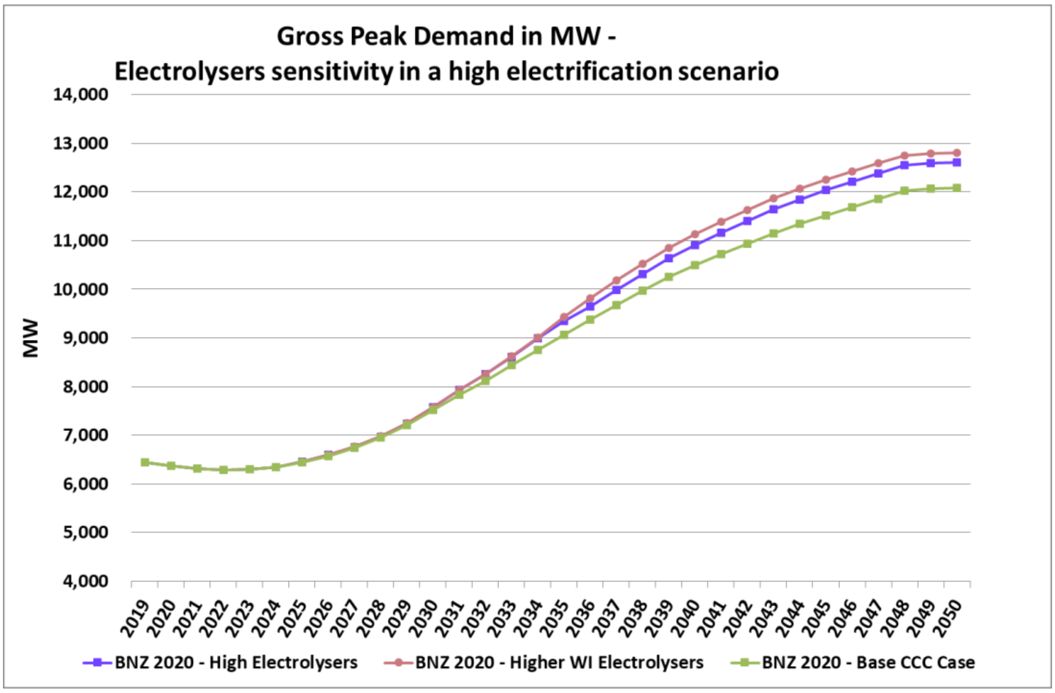


Figure 44: Electrolysers sensitivity in a high electrification scenario

Phase three

As part of phase three of sensitivity testing, we cost the range of scenarios considered and compare these against the costs for our planning scenario. For the extreme scenarios of system transformation and widespread engagement, we also do a comparison against the planning scenario after accounting for flexibility. Results of our sensitivity analysis indicate that hydrogen dominant scenarios have lower costs owing to a lower volume of heat pumps requiring less electricity network reinforcement. In comparison, electrification heavy scenarios and the planning scenario have similar costs, with some scenarios requiring higher investment than the planning scenario.

Sensitivity testing: total network costs 2023-28 by scenario

£m	Without flexibility solutions	With flexibility solutions
DFES System Transformation	273.2	217.3
CCC Headwinds	546.6	
Planning Scenario	**747.9**	**571.2**
DFES Leading The Way	768.4	
DFES Consumer Transformation	757.2	
CCC Balanced Net Zero	762.2	
CCC Widespread Engagement	806.0	691.8

Table 25: Sensitivity testing: total network costs 2023-28 by scenario

Our sensitivity analysis is subject to modelling risk, strategic investment planning risk, and plan implementation risk. We are comfortable that the modelling risk is low given that trends we observe in results across models for both EHV and LV networks are as expected. Strategic investment planning risk reflects uncertainty on the scale and shape of our investment. To mitigate this uncertainty, especially in the case of the assumptions on heat pumps and energy efficiency, we need to annually compare actual data against forecasts, research technology usage and other factors to improve our models, and monitor the progress of key drivers and policies towards targets assumed. Finally, the uncertainties identified have a knock on effect on the implementation of plans. Measures to monitor our network better will reduce this risk.

Appendix 4: Hydrogen and Heat Networks

The long term potential for hydrogen to play a central role in whole system decarbonisation is significant, and it is highly likely to play a key role in the hard to decarbonise sectors such as heavy industry and heavy transport. Its role in decarbonisation of the 'easier' to decarbonise sectors such as light transport and domestic heating is likely to be far lower, at least in the next ten years, given that the hydrogen sector is in its infancy, and that lower-cost, ready-to-adopt solutions such as electric vehicles and heat pumps are already starting to be, and are expected to continue to be increasingly adopted at scale.

We explore the value chain, covering production, storage, transport and usage below. As we explore the value chain, we outline what we have assumed when preparing the 2023-28 business plan. These considerations point to hydrogen becoming a significant sector to support decarbonisation in the long term (especially for the areas 'hard' to decarbonise, beyond the 2020's). Innovation and market development for the hydrogen economy will develop at pace during the 2020s, and therefore on-going collaboration and whole-systems thinking is imperative during 2023-28. This collaboration will be spearheaded by our local area energy planning (LAEP) engineers, a team we plan to establish as part of our DSO strategy (see DSO3.2 in the DSO strategy).

Given the nascent stage of the hydrogen industry, the investment required during 2023-28 is low regret in that it is underpinned by decarbonisation of the 'easy' to decarbonise areas of the energy system. In this regard our planning scenario aligns to the government's Net Zero Strategy.

Production of hydrogen today is almost completely dependent on use of fossil fuels, and there is almost no low carbon production in the UK or globally (with the exception of small-scale pilots). There are three classifications of hydrogen:

- **Grey hydrogen.** Hydrogen derived from fossil fuels (for example, via steam methane reformation), where emissions are unabated is known as grey hydrogen. The majority of hydrogen production today is grey hydrogen.

- **Blue hydrogen.** By application of carbon capture and storage (CCS) technology, the majority of the carbon emissions associated with hydrogen derived from fossil fuels can be captured, resulting in low carbon hydrogen. This type of hydrogen is known as 'blue' hydrogen.

- **Green hydrogen.** The production of hydrogen from renewable energy sources, using technology such as an electrolyser (which splits water into hydrogen and oxygen) is known as green hydrogen.

The government's ten point plan[45] sets out a clear ambition for 5 GW of UK hydrogen production capacity by 2030[46] (with support from industry as part of industrial 'superplaces'):

- The East CO2ast Cluster, which combines the Net Zero Teesside47 and Zero Carbon Humber48 'superplaces' sets out the ambition for at least 1.6 GW of blue hydrogen production capacity in our region by 2030. A final investment decision has not yet been made, and will be dependent on regulatory and market developments in the coming years.
- Green hydrogen production capacity is likely to lag behind that of blue hydrogen production capacity, noting that today, the levelised cost of production of green hydrogen is more than three times that of blue hydrogen;

[45] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/936567/10_POINT_PLAN_BOOKLET.pdf
[46] Noting that in the 2020, UK's annual energy consumption was roughly 1,900 TWh, of which 330 TWh was electricity, 811 TWh was natural gas (refer to https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1023276/DUKES_2021_Chapters_1_to_7.pdf); and 5 GWh of continuously operating hydrogen production capacity could generate a maximum of 44 TWh; equivalent to 3% of 2020 energy consumption.
[47] BP's H2Teesside project aims for 1 GW of blue hydrogen production capacity by 2030. https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-plans-uks-largest-hydrogen-project.html
[48] Equinor's H2H Saltend project aims for 600 MW of blue hydrogen production capacity by 2030; https://www.equinor.com/en/news/plan-for-world-leading-clean-hydrogen-plant-in-the-uk.html

however BEIS modelling identifies that by 2050, the costs should begin to converge49. The analysis from BEIS suggests that the most likely location of green hydrogen production will be co-located with renewable energy sources. Onshore renewables are typically connected to the distribution network, and therefore a sensitivity analysis has been undertaken as part of DFES50 for electrolysers co-located with renewable generation, where the materiality of this is seen mainly between 2040 and 2050. Offshore renewables are transmission-connected and therefore were not studied as part of this sensitivity.

Storage of hydrogen, particularly when integrated with the electricity system offers significant opportunities for decarbonising at lowest cost. A 2021 joint BEIS-Ofgem consultation on large-scale long-duration (LSLD) electricity storage[51], sought views from across the industry for a range of questions regarding energy storage. Recognising the synergies between electricity and hydrogen, and that hydrogen can be produced from electrical energy (via electrolysis), and then converted back to electricity (via either combustion or reverse-electrolysis, i.e. using a hydrogen fuel cell), the production, storage and later use of hydrogen could support the longer term decarbonisation of the system. Linking to the production of green hydrogen currently being uneconomical for wide-spread adoption during 2023-28, our modelling did not result in any investment related to hydrogen storage within this period (noting that storage consists of both electrical demand (to produce hydrogen) and a corresponding electrical demand (when converting hydrogen to electricity)).

Large-scale long-duration energy storage will increasingly play an important role to decarbonisation, particularly beyond 2030, driven by the rapid uptake of low carbon technologies together with the anticipated high penetration of renewable energy production (c.f. 40 GW offshore wind by 2030 as per Net Zero Strategy). This form of storage may be focussed in areas with salt caverns, such as Teesside (where it has been stored since the 1970s), and we will continue to engage with the industry regarding large-scale long-duration energy storage (including as part of our 2023-28 whole system strategy, c.f. deliverable WS1.1 of Annex 4.3 Whole systems strategy), and to maintain an overview of developments in the industry (for example, Project Centurion, a hydrogen salt cavern storage demonstration project).

Transport of hydrogen has not historically been required at scale, as it generally produced and used at the same location. Recognising that gas markets today rely on networks (of pipes) within the borders of a country, but increasingly via shipping (as liquefied natural gas) as part of the international trade; it is reasonable to envisage the long term hydrogen market resembling today's natural gas logistics infrastructure. In the long term, as hydrogen markets develop, international trade will likely become commonplace; however in the next ten years, due to the relatively small-scale of hydrogen production capacity (both in the UK and worldwide), transport of hydrogen is likely to be dominated by localised network infrastructure. During 2023-28, the majority of developments for hydrogen networks will be related to a) hydrogen blending with natural gas on the existing gas network, b) small-scale hydrogen trials (including in our region), and c) network upgrades related to the East CO_2ast Cluster.

Our on-going commitment to ensuring coordination across electricity and gas (including hydrogen) is supported by our March 2021 joint charter[52] with Northern Gas Networks (NGN). During the 2015-23 period, we have worked in collaboration with NGN on a whole systems incubator focussed on integration of electricity, gas (including hydrogen) and transport; known as the 'Integrated Transport Electricity Gas Research Laboratory' (InTEGReL).

Usage for heating is currently only at the trial stage. Noting that the government's ten point plan is to target the installation of at least 600,000 heat pumps per year by 2028, which more recently has been bolstered by the Heat and Buildings Strategy[53] which details the subsidisation of heat pumps as part of the boiler upgrade scheme. The decarbonisation of heat in our region (with the exception of heat networks which are discussed later in this appendix) is likely to be dominated by the adoption of heat pumps during 2023-28. Our modelling aligns to the governments ten point plan.

[49] Table 2.2 of UK Hydrogen Strategy; https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf
[50] 2021 DFES: https://www.northernpowergrid.com/asset/1/document/5836.pdf
[51] https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence
[52] https://www.northernpowergrid.com/asset/0/document/6056.pdf
[53] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1032119/heat-buildings-strategy.pdf

- **Hydrogen blending.** The UK Hydrogen Strategy[54] has outlined actions and milestones to support the potential blending of hydrogen with natural gas (up to 20%), with a policy decision targeted for late 2023. The second phase of the 'HyDeploy' trial, which is a key enabler to this policy change is taking place in Winlanton (in the northeast), and we will continue to track progress of this trial. The blending of hydrogen, could provide the required 'demand' to support the early production volume of low carbon hydrogen.

- **Hydrogen usage as a primary source.** The government's ten point plan is supporting industry to begin a large village hydrogen heating trial by 2025, and sets out plans for a possible pilot hydrogen town before the end of the decade.

Our modelling of heat pump uptake in our decarbonisation pathways during 2023-28 is primarily for customers and premises where this is likely to be most appropriate, and we recognise that customer choice along with affordability and practicalities will result in different technologies being more appropriate for different customers, and at different times. In the government's Heat and Building Strategy[53], the government has committed to outlining a strategic decision regarding the use of hydrogen in heating by 2026, and will recognise the different circumstances of different people and stakeholders. We will continue to work closely with all stakeholders (including government) to ensure that any policy decisions reflect the needs and aspirations of our region.

Usage for transport is in its infancy across both domestic and industrial transport. At a domestic level the price premium compared to EVs is likely to favour the continued adoption of EVs, whereas for industrial or heavy transport, the scalability of battery technology – and the subsequent weight and volume implication of the battery required to ensure a sufficient range – may favour the use of hydrogen in some situations.

- **Light transport.** The government's ten point plan has a target milestone to end sales of new petrol and diesel cars and vans by 2030, and for all new cars and vans to have zero-emissions from the tailpipe by 2035. The modelling undertaken for our 2023-28 business plan aligns with the ten point plan, where the decarbonisation of such vehicles is centred around electrification. Whilst the long term car and van transport energy usage may turn to hydrogen beyond 2030, during the 2023-28 period the infancy of the hydrogen sector will likely preclude this, and therefore our assumptions of high transport electrification aligned to the net zero strategy result in low regret investment.

- **Heavy transport electrification** was studied as a sensitivity, but does not underpin out 2023-28 business plan investments given the impact will be minimal during the period, alongside significant uncertainty regarding the decarbonisation pathway of this sector. In addition, the electrification of heavy transport would result in the need for these industrial and commercial customers to adjust their connection agreements to enable the significant power required for charging of vehicles, and therefore any network impact would be modelled as part of such applications. A potential use case for electrolysers would be for rural HGV depots, which was also considered in our sensitivities.

Sensitivity analysis (detailed in the 2020 DFES[55]) of decarbonisation of heavy goods vehicles highlights that the potential energy consumption increase during the 2020s is marginal, but could then increase rapidly between 2030 and 2040. By 2050, electrification of industrial energy usage could potentially add roughly 6 TWh of demand annually (compared to 20 TWh for heat pumps and EVs). This aggressive electrification is therefore unlikely to occur during 2023-28, and therefore the uncertainty (and options) around the timing and technology choices of the sector will be a key part of on-going collaboration and modelling during 2023-28 for future periods.

Usage for industrial applications is likely to expand from the existing industries already using it as a feedstock, to applications that currently rely on using fossil fuels to drive the process (e.g. steel production, and including those industries using hydrogen as a feedstock). Electrification is also likely to be part of the decarbonisation pathway for heavy industry, and the choice of electricity or hydrogen for (industrial fuel-switching to) low carbon energy supplies will depend on the specific requirements of each customer. Because much of the heavy industry in our region is concentrated in the 'superplaces' where hydrogen (or even CCS, therefore enabling use of fossil fuels if capture rate is sufficiently high), the industrial fuel switching to hydrogen is likely to be concentrated in the Humber and Teesside.

[54] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf
[55] https://www.northernpowergrid.com/asset/0/document/5836.pdf

Sensitivity analysis (detailed in the 2020 DFES) of decarbonisation of industrial energy use highlights that the potential energy consumption increase during the 2020s is marginal (but higher in absolute terms than HGVs), but could then increase rapidly between 2030 and 2040. By 2050, electrification of industrial energy usage could potentially add roughly 8 TWh of demand annually (compared to 20 TWh for heat pumps and EVs). This aggressive electrification is therefore unlikely to occur during 2023-28, and therefore the uncertainty (and options) around the timing and technology choices of the sector will be a key part of on-going collaboration and modelling during 2023-28 for future periods.

The role of heat networks

Heat networks, also referred to as district heating, have the potential to provide low carbon heating to customers where heat pumps (or even hydrogen) may not be the most effective. In our region, the Gateshead District Energy Scheme provides heat to the centre of Gateshead, and is currently being extended to reach 7.5km network length. There are other examples of heat networks across our region and the UK, which are generally not centred at providing heat to domestic customers.

The government's Heat and Building Strategy[53] outlines plans to invest £338m as part of its Heat Network Transformation Programme. This investment (over 2022/23 to 2024/25) will seek to create the market conditions in the first half of the 2020s by helping to overcome barriers to heat network market entry, providing an environment for regulation and market mechanisms to successfully support increased deployment in the second half of the 2020s and into the 2030s.

Through the Heat Network Transformation Programme, financial support will be provided through the Green Heat Network Fund, where there is a proposal to introduce heat network zoning in the latter half of the decade. This will provide local authorities with the powers to identify and designate areas best suited for heat networks as the lowest cost, low-carbon solution.

During 2023-28, we will continue to work closely across the energy sector, ensuring whole system coordination. This will be a primary objective of our LAEP advisors (deliverable DSO3.2 – please refer to the DSO strategy).

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