DEMAND SIDE RESPONSE: CONFLICT BETWEEN SUPPLY AND NETWORK DRIVEN OPTIMISATION

A report to DECC

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Pöyry were supported in this project by the University of Bath who have recently conducted a number of detailed modelling and analysis studies of the GB distribution network which resulted in University of Bath receiving the 2009 Rushlight Power Generation and Transmission Award, and a nomination by The Times Higher Education for the 2009 Award of Outstanding Contribution to Technology and Innovation for this research.

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

Context

The GB electricity market is expected to see some fundamental changes in the forthcoming years to 2020 and in particular beyond into 2030 and 2050 timeframes.

These changes are being driven in large part by environmental objectives set at both an EU and national level but also reinforced by both economic and technology drivers. As a consequence the nature of generation and demand could change in ways which will have a fundamental impact on the whole electricity sector in GB, particularly for the wholesale market and for network investment and operation.

The expectation is that a decarbonised generation sector could lead to the market containing large amounts of zero or negative marginal cost generation, much of it in the form of wind, which is also intermittent. The impact of intermittency on the electricity market in GB was first highlighted by Pöyry in its landmark multi-client study 'Impact of Intermittency' published in July 2009 examining the impact of intermittency on GB and Irish electricity markets.

At the same time as the decarbonisation of electricity generation, there would need to be significant electrification of the heat and transport sectors, particularly from the late 2020s onwards, in order to reach the 2050 emissions target.

DECC has set out six low-carbon pathways to 2050 within its 2050 Pathways report published in July 2010, each of which assumes a significant degree of electrification of heating and transport. This would entail challenges for matching generation to the profile of demand, particularly because heat demand varies most widely during the day dependent on temperature.

There are a number of implications that result from the move towards a low-carbon energy system:

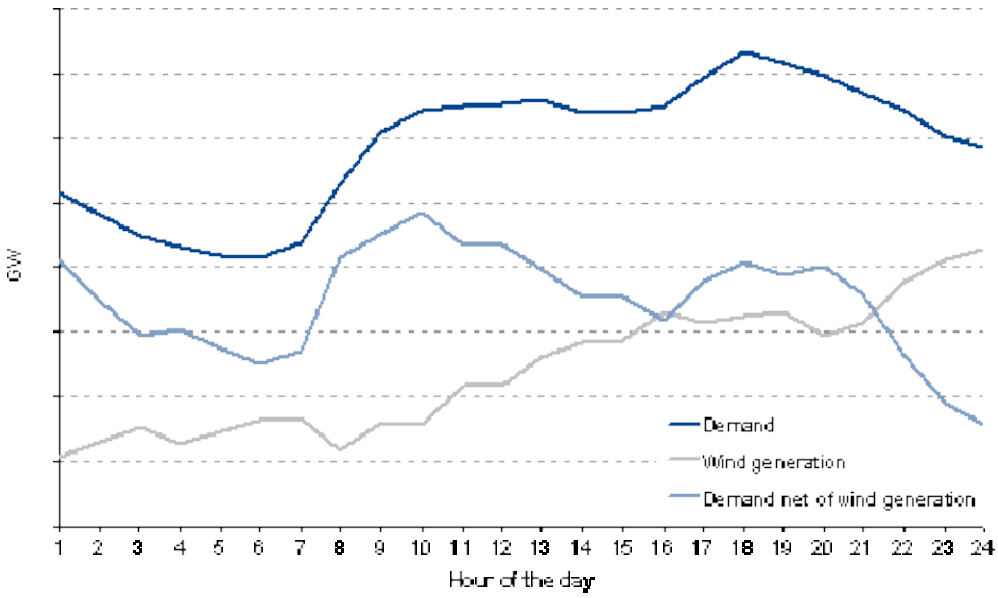
- the electricity generation sector could become more inflexible and intermittent, which places a greater premium on having load that can follow generation;
- electricity demand (pre demand side response) could have wider ranges of demand including higher peaks, which increases the benefits from shifting load away from peak periods; and
- electricity demand may have much greater potential for flexibility through the storage associated with heat (provided infrastructure investments in the home take place) and transport.

As a result, in the future, there could be both (1) substantially greater potential to provide demand side response (DSR); and (2) clear benefits from the implementation of demand side response in helping to deliver a low-carbon, affordable and efficient electricity supply.

This study is the first to seek to explicitly quantify in detail for both the GB electricity market and GB electricity networks the potential benefits of demand side response in 2030 and 2050 within a future GB electricity sector characterised by high electrification, decarbonisation and intermittency.

Potential roles of Demand Side Response (DSR)

High levels of intermittent generation will lead to changes in the relationship between prices and demand, in particular the timing of peak prices versus the timing of peak demand. An illustrative example of this for a winter day is provided in the figure below.



In this example the demand peak occurs at c.5pm but due to the profile and magnitude of wind generation on the day the highest electricity price is likely to occur at c.10am when the highest volume of conventional generation - which has higher marginal costs than intermittent generation - is operating (also known as the 'demand net wind' peak).

In future, whereas the timing of peak demand will remain highly predictable, the timing and level of peak prices will be strongly linked to wind patterns and the relationship between wind and the demand profile, otherwise known as 'demand net wind generation'. This relationship will be much less predictable as wind will vary both across and within days. In this context, DSR can potentially be deployed to either:

- flatten demand peaks and thus avoid investment in generation and networks; or to
- minimise production related costs within the wholesale market by balancing generation and demand.

These two fundamental roles of DSR can coincide but at times may conflict. This is especially the case given that DSR typically results in shifting demand but not necessarily reducing demand. Thus, for example in the illustrative day above, using DSR to flatten peak demand at 5pm might result in shifting demand to a period in the day, e.g. 10am, where overall demand is lower but where prices are higher than they are at peak such that the effect will be to further increase wholesale market costs.

The key question which this study seeks to address is thus

> *'Is it more efficient to target DSR to flatten peak demand and reduce network reinforcement costs, or to reduce the generation production cost underlying wholesale prices?'*

Basis of our assessment

In order to assess the relative merits of these different roles of DSR we examined the impact of DSR in 2030 and 2050 in the following way:

- As a baseline we used DECC's Pathway Alpha to assess the impact of demand levels and shapes and assumed levels of intermittent generation for 2030 and 2050 on generation, network and market costs without deployment of DSR.
- We then deployed DSR in two ways:
  1. to minimise production related costs within the wholesale market while network capacity is increased sufficiently to enable generation to meet peak demand whether or not demand side response takes place
  2. to reduce peak demands and thus reduce necessary investment in generation and network capacity.

DECC's Pathway Alpha has been used as the baseline for this study. Pathway Alpha assumes that GB electricity demand more than doubles from its current levels by 2050 to around 730TWh, largely driven by the electrification of heat circa 130TWh and transport circa 38TWh. We assume that 50% of electrified heat and 75% of electrified transport can be used for DSR. Also, generation output is assumed to have a broadly equal split between nuclear, CCS and renewables, requiring a total capacity of 250GW, more than 65% of which is intermittent in nature. In the baseline scenario our modelling identified an additional 38GW of conventional generation capacity required to maintain current security of supply levels in 2050.

Clearly when making predictions as far out as 2030 and especially 2050, there is a high level of uncertainty. Two of the key drivers of future uncertainty are (i) the level of intermittent generation; and (ii) the degree of electrification. Consequently within our assessment we examined the impact of each of these factors where lower levels were assumed to materialise versus those assumed under DECC's Pathway Alpha.

Whilst our assessment does not capture all of the components of electricity cost that would be seen by consumers – for example, it does not include on-going network asset replacement costs or supplier costs – it does go a long way to understanding the impact on electricity costs, seen by consumers, of DECC's Pathway Alpha; and in particular the impact of DSR. However, it is important to highlight that Pathway Alpha will also have a material downward impact on the costs of gas and oil (predominantly petrol & diesel) but this impact has not been assessed as part of this study.

Key findings

The study does not constitute a full cost-benefit analysis of DSR: in particular, we have not assessed the full cost of implementation. Nevertheless, we have completed an extensive assessment of the potential impacts of demand side response on generation, network and market costs, with the following key findings:

- There is potentially significant value in enabling demand side response to meet the challenges of managing intermittent generation and electrification:-
  - A circa 10% reduction in our overall modelled electricity costs per annum were achievable amounting to a circa-£8bn economic benefit against the baseline;
  - DSR also largely eliminates potential wind curtailment and thus maximises the carbon benefits of intermittent zero carbon generation.

- Prioritising DSR to shave peak demand is the optimum in terms of overall modelled electricity costs by enabling the avoidance of distribution network and generation investments;
  - This would require DSR to be deployed as required across the top 10% of demand periods.
- However, the difference between prioritising DSR to peak shave rather than minimise production costs is relatively small (<1% or c. £0.6bn) in the context of our overall annual electricity costs.
- Therefore it may be pragmatic to build networks to meet peak demand to ensure greater security of supply.
- Significant expansion and reinforcement of the distribution network will be required to meet peak demand by 2050; equivalent to a sustained level out to 2050 of circa 2-3 times the current level of distribution network investment.

The sensitivity analysis was conducted against two sources of future uncertainty, for the GB electricity market in 2030 and 2050, namely (i) level of intermittency and (ii) level of electrification, and shows that:

- The proportionate economic benefits (relative to overall modelled annual electricity costs) apply for deployment of DSR where either future levels of intermittent generation are lower or future levels of electrification are lower.
- The conclusions regarding choice of network investment strategy hold true for both lower levels of future intermittency and lower levels of future electrification than assumed under DECC's Pathway Alpha.
- Lower intermittency leads to a far smaller difference between using DSR for balancing or peak flattening.
- Lower electrification leads to a lower overall peak demand and therefore a smaller network as well as also narrowing the gap between the 2 DSR scenarios in terms of network capacity.
- In addition, under lower levels of future electrification of demand and high levels of intermittent generation; there is a particularly strong benefit from eliminating potential wind curtailment to maximise the carbon benefits of intermittent zero carbon generation i.e. DSR reduces otherwise high levels of wind curtailment.

There is substantial prospective change within the GB electricity sector that arises from the decarbonisation agenda, although there is considerable uncertainty over the future pathway and shape both of generation and demand when looking out to 2050.

We recognise that there exist other solutions to mitigate the impact of intermittent generation, such as interconnection, flexible generation and energy storage and that all of these will play a role in the future. Furthermore, we believe analysis of the associated implementation costs of DSR needs to be undertaken. Nonetheless, we believe our assessment clearly demonstrates that DSR will have an important role to play within the future decarbonisation of the GB electricity sector both in terms of helping to reduce electricity sector costs and in maximising the carbon benefits from zero carbon generation.

1. INTRODUCTION

1.1 Introduction

This report considers the trade-off between different responses to future electricity network and balancing challenges. Specifically this report seeks to examine the interaction of the wholesale market, demand side response (DSR) and network reinforcement; in order to understand the relative merits of using demand side response:

- to shave peak demand i.e. flatten demand peaks and thus avoid investment in generation and networks; or
- to balance generation / demand i.e. minimise production related costs within the wholesale market.

These two fundamental roles of DSR can coincide but at times may conflict. This is especially the case given that DSR typically results in shifting demand from one period to another, not reducing overall demand. Thus, for example, using DSR to flatten peak demand might result in shifting demand to a period in the day when overall demand is lower but prices are higher than they are at peak such that the effect will be to further increase wholesale market costs.

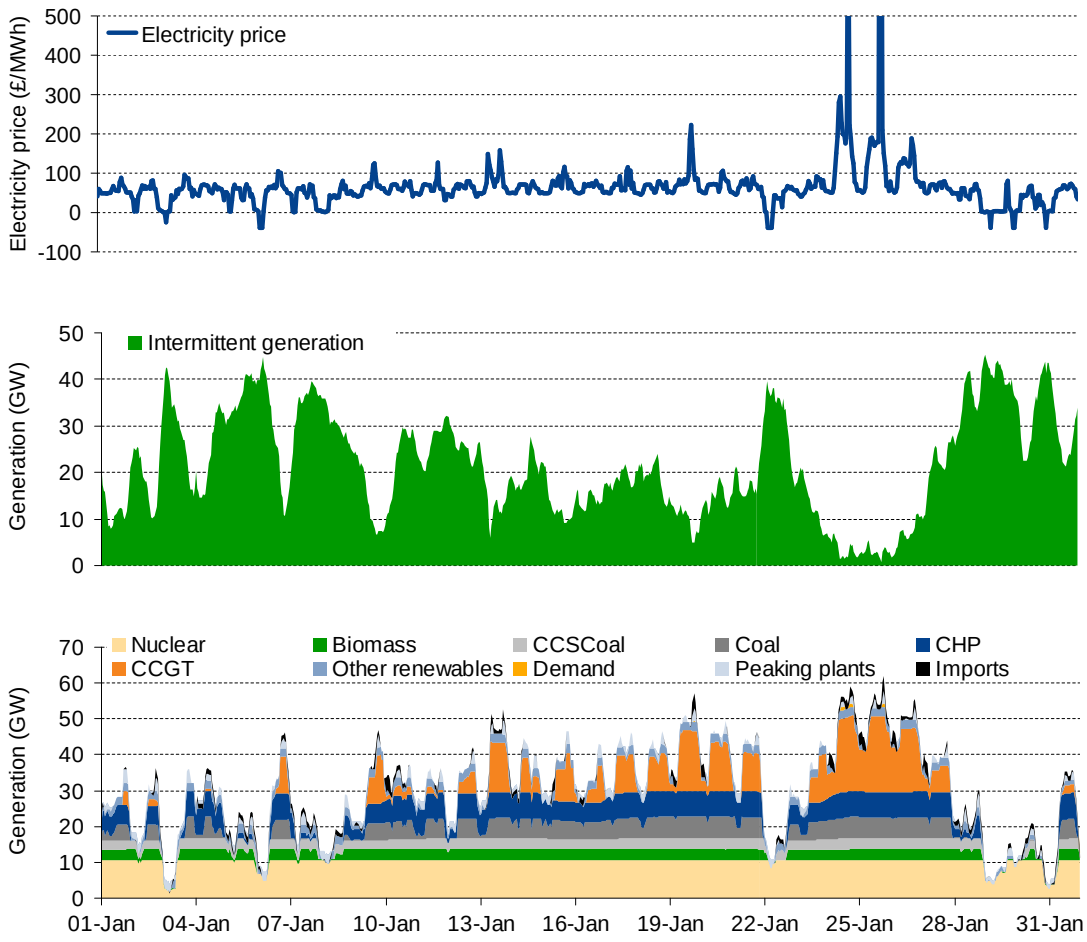
1.2 Background

The GB electricity market is expected to see some fundamental changes in the forthcoming years to 2020 and in particular beyond into 2030 and 2050 timeframes. This change is being driven in large part by environmental objectives set at both an EU and national level. However both economic and technology drivers are reinforcing this and the consequence is that the nature of generation and demand could change in ways which will have a fundamental impact on the whole electricity sector in GB, particularly for the wholesale market and for network investment and operation.

The expectation is that a decarbonised generation sector could lead to the market containing large amounts of low marginal cost generation, much of it in the form of wind, which is also intermittent. The impact of intermittency on the electricity market in GB was first highlighted by Pöyry in its landmark multi-client study published in 2009[1]. This study quantified the potential consequences for market prices and plant dispatch, as illustrated in Figure 1. This was the first study to raise awareness amongst policy makers and the industry, and stimulated discussions on implications for policy and business strategy.

[1] 'Impact of intermittency, how wind variability could change the shape of British and Irish electricity markets – summary report.' Pöyry Energy Consulting. July 2009.

Figure 1 – Intermittency behaviour and its impact on prices and dispatch of non-intermittent plant in 2030 with January 2000 weather



Concurrent with the decarbonisation of electricity generation, there is expected to be significant electrification of the heat and transport sectors, particularly from the late 2020s onwards, in support of the 2050 emissions target. DECC has set out six low-carbon pathways to 2050 – all of them assume a significant degree of electrification of heating and transport[2]. This could provide challenges for matching generation to the profile of demand, particularly because heat demand is more variable than existing electricity demand due to its dependence on temperature.

The delivery of a low-carbon generation sector could represent a significant departure from the status quo, which can be crudely characterised as being a market dominated by load-following generation with a relatively predictable pattern of demand and limited opportunity for demand-shifting.

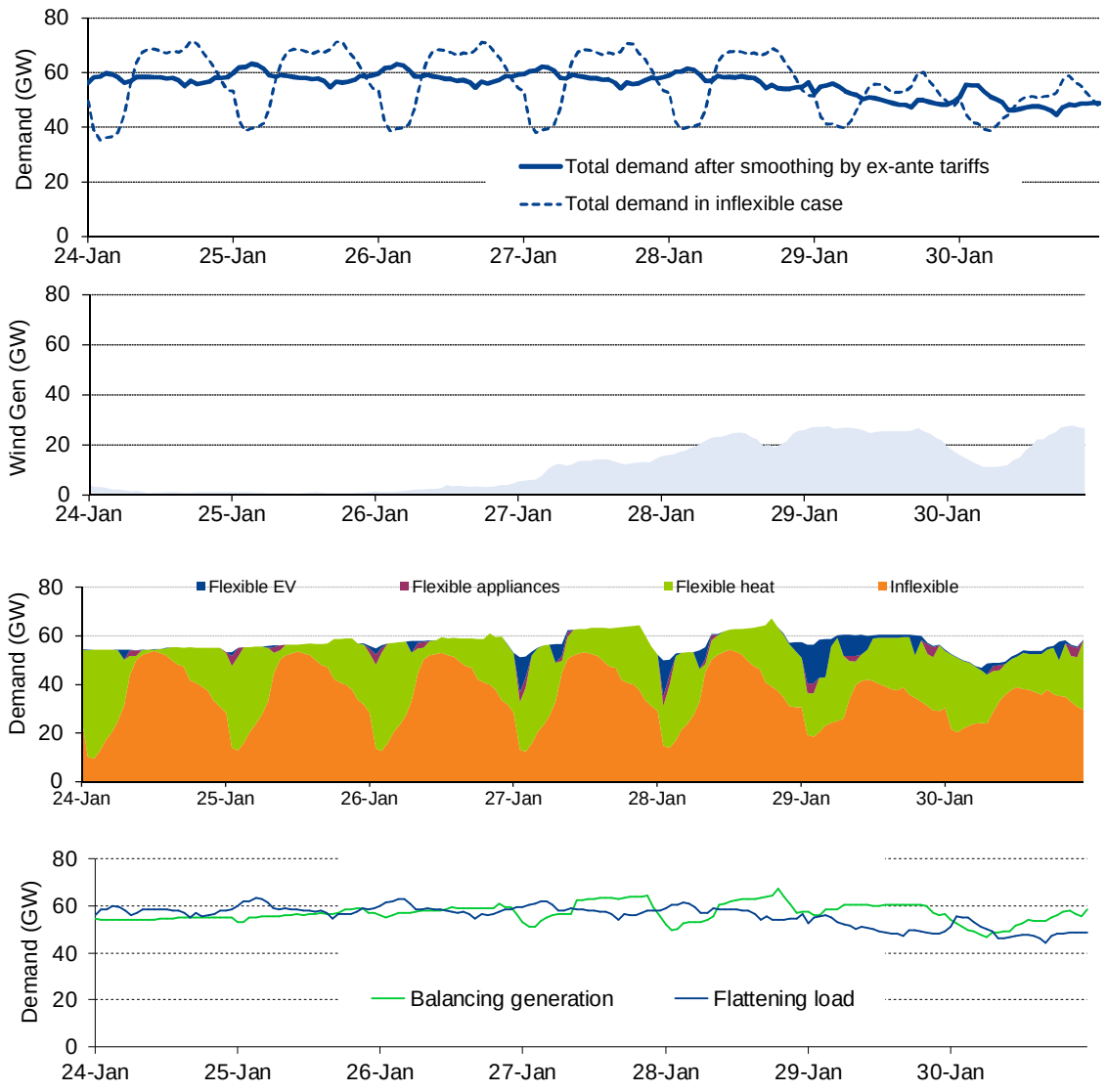
In contrast, the implications of a move towards a low-carbon energy system are that:

2 '2050 Pathways Report', Department of Energy and Climate Change, July 2010.

- the electricity generation sector could become more inflexible, which places a greater premium on having load that can follow generation;
- electricity demand could be more variable and more peaky, which increases the benefits of shifting load away from peak periods; and
- electricity demand may have much greater potential for flexibility through the storage associated with heat and transport.

Therefore, there would be clear benefits from the implementation of demand-side flexibility in helping to deliver a low-carbon, affordable and secure electricity supply.

Figure 2 – Comparison of demand patterns from load flattening and generation balancing (2030 with January 2000 weather, GW)



However, demand-side flexibility is one instrument trying to meet two policy objectives – tracking generation, especially wind, in order to take maximum benefit from zero fuel cost

generation (and reduce other generation costs); and flattening load in order to minimise network investment. At times, these policy objectives could be complementary, for example when wind is low and demand is high. However, at other times, they could conflict such as when wind is high and demand is high. This tension is illustrated in Figure 2, based on analysis undertaken with our Zephyr model.

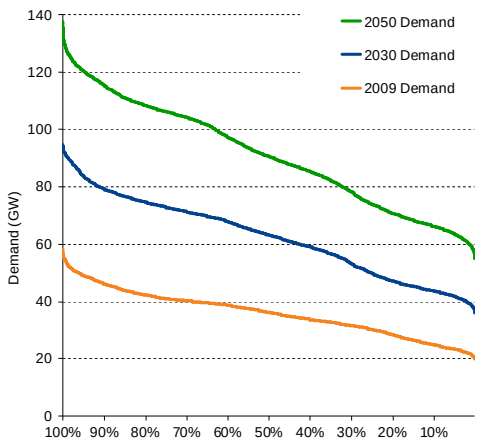
The top chart shows how the load curve can be flattened through demand shifting, particularly with respect to heating. The second chart illustrates how the pattern of wind generation can vary during a single week. Based on an assumed installed wind capacity of 31GW, output rises from an extended period of being at virtually zero to reach a load factor of nearly 100% in the latter half of the week. The third chart shows how different types of demand can be shifted in order to balance the change in wind generation. The final chart then compares the load flattening approach with the balancing approach. It shows that the two approaches produce similar results when the wind is low in the early part of the week. However, a 10GW difference in demand emerges between the two approaches in 29 January when wind output is at its peak.

This analysis highlights the potential benefits of demand side response for the wholesale market. However, it also raises the issue that the use of demand side response in this way could lead to the need for networks to have a higher capacity than necessary with an associated implication for overall system costs. The capacity of GB distribution networks may no longer able to accommodate the substantial demand created by the need to charge electric vehicles (EVs) or meet the demands of heat pumps (HPs).

1.3 Context of the study

As we discuss above the GB electricity market is expected to see some fundamental changes in the forthcoming years. The DECC 2050 Pathways Report (Pathway Alpha) estimates that electricity demand could double by 2050 as a result of the electrification of heat and transport, which is required to meet the decarbonisation targets. In Figure 3 and Figure 4 below we show the impact of changing demand in 2009, 2030 and 2050.

Figure 3 – Changes in peak demand

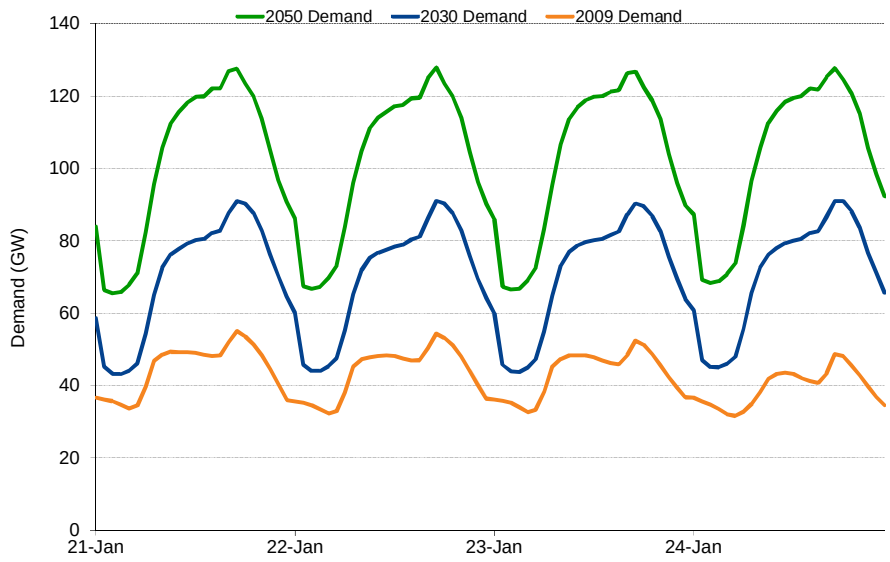


Year	Peak demand (GW)	Total demand (TWh)
2050	137	730
2030	96	505
2009	58	314

The demand duration curves shown in Figure 3 highlight that in general peak demand could grow at a slightly faster percentage rate than annual energy (this is quantified in the table in Figure 3), which would lead to a number of potential problems for electricity markets, including how to compensate generators with low load factors as they are required to run only at peak times[3].

The electrification of heat and transport would lead to an increase in the variation between the peak and minimum daily demand (assuming no use of demand side response), making it harder to plan and manage the electricity systems, as shown in Figure 4.

Figure 4 – Variation in daily demand



There are two drivers of this effect;

- the first is the overall increase in demand; and
- the second is the roll out of electric heating and electric vehicles.

The former means that average demand increases while the latter drives the peak up as the profile of electric heating and charging for electric vehicles amplifies demand at peak (i.e. heating systems are turned on and electric cars plugged in to charge during current peak demand hours – note that these are the effects before the application of DSR).

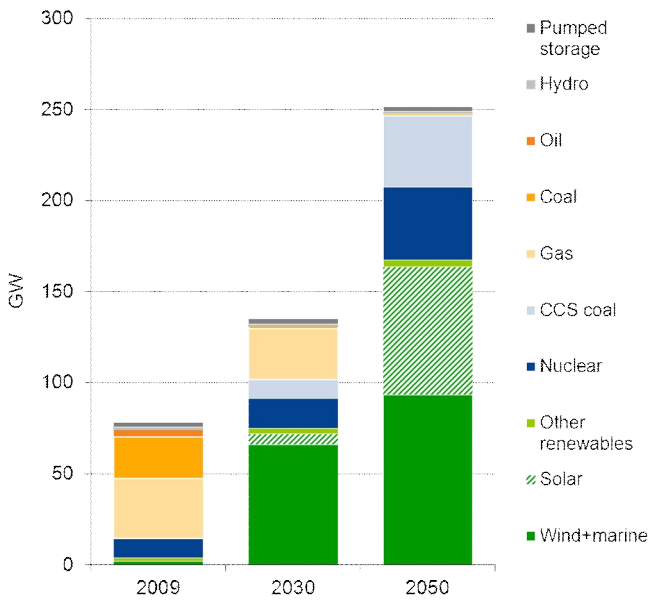
In the context of GB targets for decarbonisation of the electricity sector, this higher demand would need to be met by substantial new low carbon generation much of which is likely to be intermittent. Figure 5 presents the current capacity mix in 2009 with the capacity in 2030 and 2050 consistent with DECC Pathway Alpha.

Under Pathway Alpha it is assumed that total generation output in 2050 is 730TWh assumed to be broadly split equally between nuclear, CCS and renewables. This requires

3 This does not include losses (assumed at 8%) and was also calculated before DSR is applied.

250GW of generation capacity, 165GW (>65%) of which will be intermittent generation (see Figure 5).

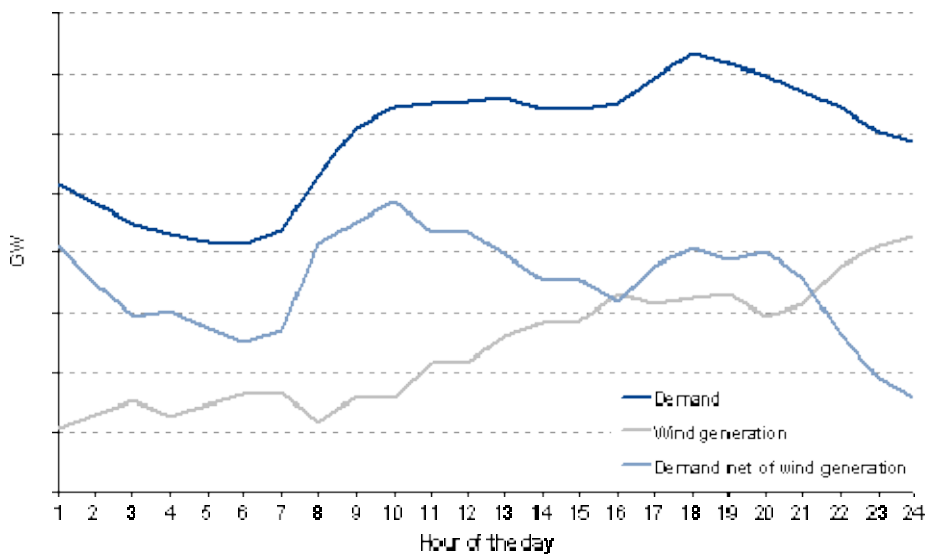
Figure 5 – Capacity mix over time



GW	2009	2030	2050
Wind+marine	1.9	65.9	93.3
Solar	0.0	5.8	70.4
Other renewables	1.8	3.3	3.7
Nuclear	10.9	16.4	40.0
CCS coal	0.0	10.2	39.0
Gas	32.6	28.3	0.0
Coal	23.0	1.3	1.3
Oil	3.8	0.0	0.0
Hydro	1.5	1.1	1.1
Pumped storage	2.7	2.8	2.8
Total	**78**	**135**	**252**

This level of intermittent generation will lead to changes in the relationship between prices and demand. Figure 6 shows this effect for an example day, with peak demand separating from peak net demand and hence peak price.

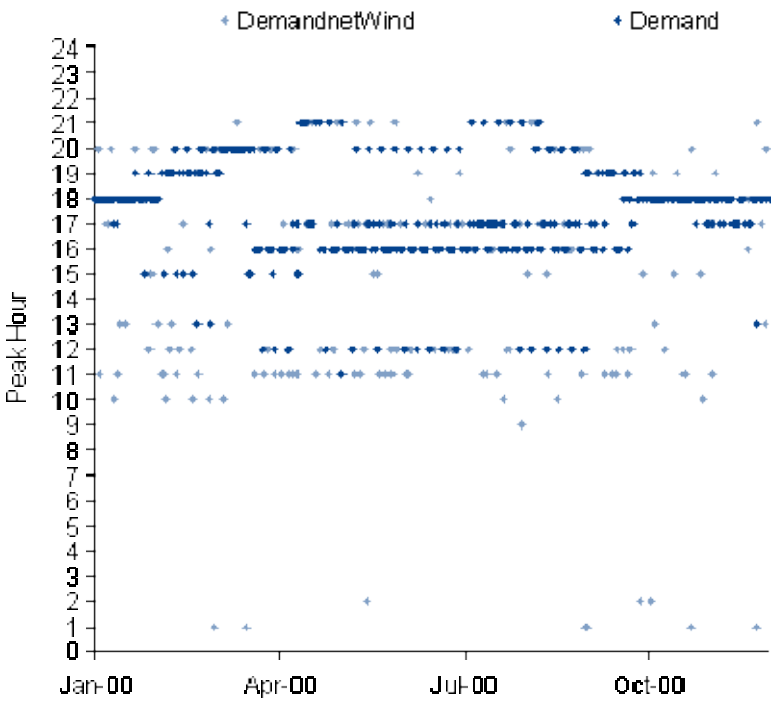
Figure 6 – Decoupling of peak demand and net demand for an example day



In this example the demand peak occurs at c.5pm but due to the profile and magnitude of wind generation on the day the pricing peak is likely to occur at c.10am when the highest volume of conventional generation – which has higher marginal costs than intermittent generation – is operating (also known as the 'demand net wind' peak).

A further complication will be that not only will demand decouple from price, but the timing of peak demand net of intermittent generation will become less certain. Figure 7 below shows the points at which peak demand (net of intermittent generation) occurs during the year. The results show that whereas peak demand will be contained within a 3 hour range in the evening (usually between 5pm and 8pm) as it is now, the peak of demand net of intermittent generation will occur over an 11 hour range (between 10 am and 9pm). These results also indicate that peak demand net of intermittent generation will, on some occasions, occur in the early hours of the morning, highlighting the variability in wind generation.

Figure 7 – timing of peak demand (net of intermittent generation)



This report will discuss and assess the extent to which demand side response can help mitigate the issues raised above. Although it is generally agreed that demand side response can help reduce overall costs of the electricity sector, it is uncertain what the best approach is. Therefore the focus of the study is to identify which of the approaches is preferred by measuring the overall electricity cost impact of deploying different levels of demand side response and network build on wholesale price, network costs, constraint costs and wind curtailment cost.

1.4 Structure of this report

The remainder of this report is split into the following sections

- Section 2 outlines our approach to this piece of work;
- Section 3 provides a description of each of our scenarios and sets out the high level technical and economic assumptions we have used in the modelling of this study;
- Section 4 presents the key findings from our scenario analysis;
- Section 5 presents the results of the sensitivity analysis;
- Annex A presents additional detail on our assumptions;
- Annex B outlines testing scenarios used to reinforce our conclusions;
- Annex C presents an analysis of wind and demand;
- Annex D presents further detailed results from the scenarios;
- Annex E presents further detailed results from the sensitivity cases;
- Annex F gives an overview of our market modelling approach; and
- Annex G gives an overview of our approach to modelling the distribution network.

1.4.1 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting.

2. APPROACH

2.1 Introduction

This section outlines the approach we have taken to evaluate the trade-off between deployment of demand side response for peak demand shaving and generation / demand balancing.

The assessment was carried out using the wholesale electricity model *Zephyr* that Pöyry Energy Consulting developed for use in our intermittency study in 2009. The demand-side modelling capability of *Zephyr* has been further enhanced for use in a study commissioned by the CCC and in this study. The distribution network modelling was developed by the University of Bath.

The overview of assessment methodology includes:

- modelling framework: wholesale market and transmission issues;
- approach for distribution network modelling;
- overview of modelling DSR, and
- we then present the outputs to be used to compare the DSR scenarios.

2.2 Objective of assessment methodology

This methodology has been formulated to enable a quantitative comparison of electricity sector costs under alternative demand side response scenarios. The key affected electricity sector costs include network investment costs, constraint costs and wholesale price costs (including generator costs) associated with meeting electricity demand for different DSR scenarios for network capability and demand side response.

Our methodology addresses the two basic trade-offs for the use of demand side response, specifically:

- peak demand shaving i.e. flatten demand peaks and thus avoid investment in generation and networks; or
- generation / demand balancing i.e. minimise production related costs within the wholesale market.

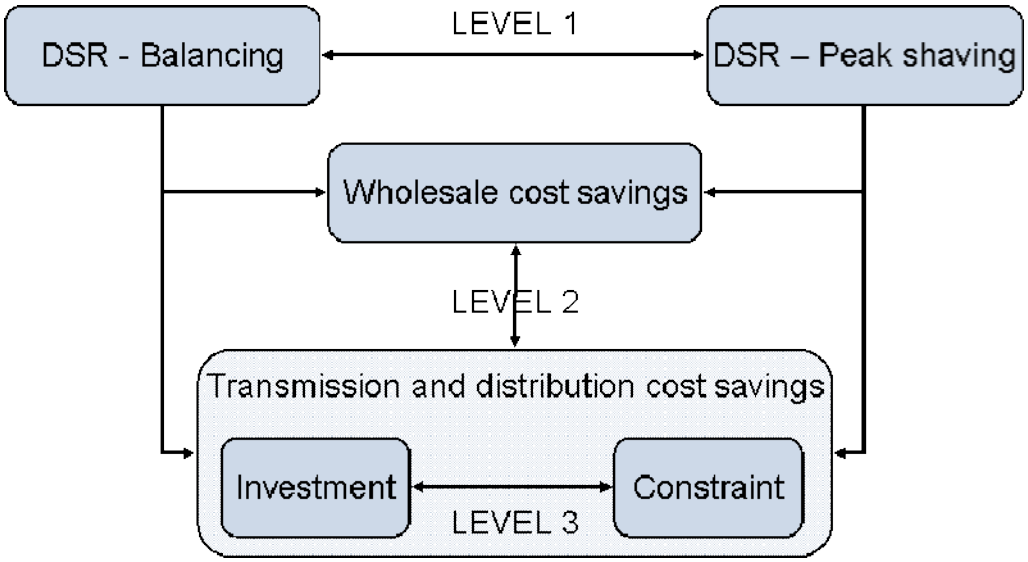
Fundamental to understanding the scale and relevance of the trade-offs is a detailed quantitative understanding of how far wind variability will correlate with the predicted load curve and therefore how much conflict there might be between using demand response for the purposes of peak shaving versus balancing. This was explored as part of our initial analysis, full details of which are provided in Annex C.

2.2.1 Problem formulation

This section presents the framework that we have developed to analyse the problem. To arrive at an appropriate balance to resolve the potential conflict, a whole system approach has been derived to assess the impact of the two approaches on the wholesale energy cost, Transmission & Distribution delivery cost and Transmission & Distribution investment cost. In assessing the impacts from each demand side response strategy, there are further trade-offs between the wholesale cost and, network cost; and within the network,

between investment and constraint cost. This means there are essentially three nested trade-offs; as illustrated in Figure 8 below:

Figure 8 – Overview of different levels of DSR trade-offs



In an ideal world, one would seek to simultaneously model wholesale market, transmission network and distribution network behaviour and impacts within a single model or process. However, in practice no such single model exists.

Consequently to capture the three strands of issues it is necessary to link separate models, each of reasonable detail; in particular the modelling of wholesale market and transmission costs and distribution network costs. We have created this capability by bringing together the respective expert modelling of Pöyry (wholesale markets and transmission) and the University of Bath (distribution networks).

2.2.2 Demand side response scenarios and sensitivity analysis

We have used scenario analysis to evaluate the impact the two uses of DSR have on key metrics and employed sensitivity analysis to reaffirm our conclusions hold under lower electrification and lower penetration of intermittent generation.

The three main scenarios are:

- Baseline: no DSR;
- DSR scenario 1: DSR used to minimise generation production costs as a priority; and
- DSR scenario 2: DSR used to peak shave i.e. flatten demand as a priority.

All of our scenarios are based on Pathway Alpha from the DECC Pathways Report. The baseline scenario has no DSR deployment and provides benchmark data with which to compare the results from DSR scenario 1 and DSR scenario 2, where DSR is deployed.

To support our conclusions, we have assessed the impact of DSR under three testing scenarios. Furthermore, we have used sensitivity cases to assess implications of changing key assumptions i.e. what happens to our conclusions if: (1) the level of demand

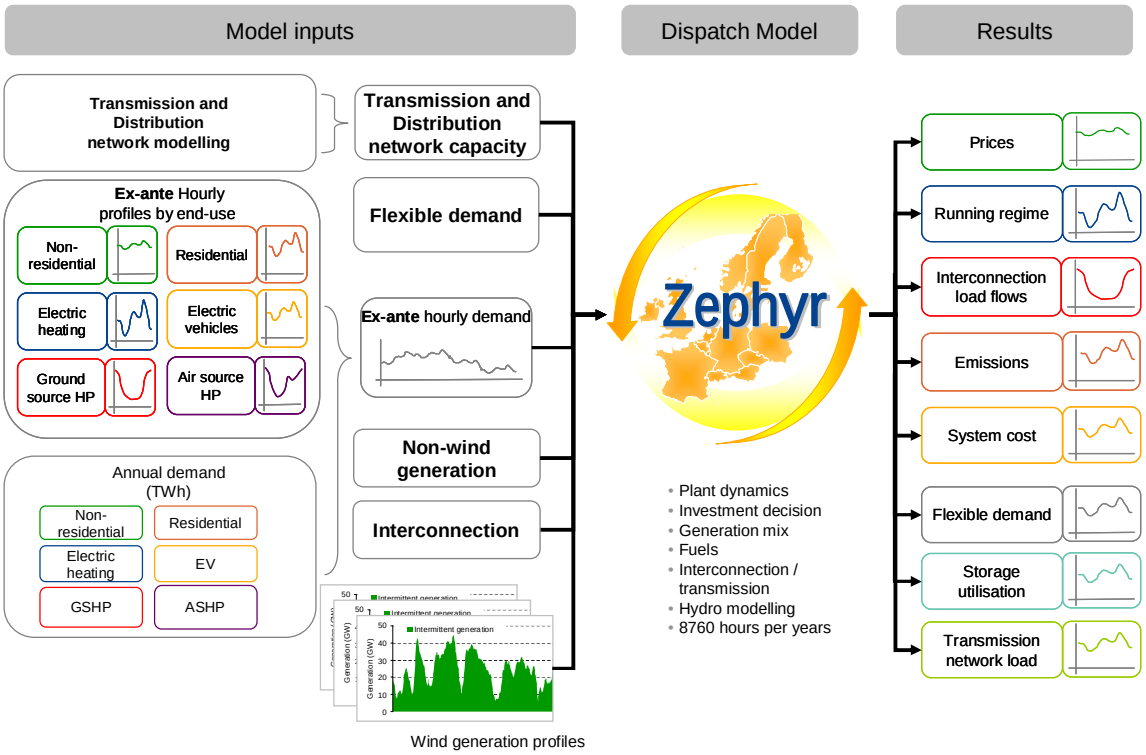
(electrification) or (2) intermittent generation penetration reduce from the levels used in the main scenarios. Single parameter sensitivity analysis brings the advantage of being able to isolate cause and effect more easily.

2.3 Modelling framework

The objective of the modelling framework is to accurately represent the future wholesale electricity market in GB. Figure 9 presents an overview of the modelling framework used to examine the alternative scenarios.

There are three main components, the inputs, the model engine and the outputs. The following sections touch briefly on each of these aspects.

Figure 9 – Overview of modelling framework



2.4 Wholesale market model

To capture both wholesale market and transmission costs we have adopted use of our Zephyr model[4]. This model allows us to capture the interaction between supply and demand based on wind, availability and demand profiles for 9 years. *Zephyr* was developed for use in Pöyry's intermittency study for GB and Ireland[5] and subsequently refined through a number of further studies. In particular, we have developed the

4 The Zephyr model is described in more detail in Annex F.

5 'Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', Pöyry Energy Consulting. July 2009.

demand-side modelling capability for use in this study. Figure 9 provides an overview of this unparalleled modelling platform backed by a wealth of historical data.

The model simulates the dispatch of each unit on the GB and Irish systems for each hour of every day – a total of 8,760 hours per year. The model is based on a mixed-integer linear programming platform[6]. This allows us to optimise to find the least-cost dispatch of plant accounting for fuel costs, the costs of starting plant and the costs of part-loading, in aggregate. For example, it may mean that the model will reduce the output of wind generation to avoid shutting down a nuclear plant and incur the cost of restarting it later. The model also accounts for minimum stable generation and minimum on and off times, which allows more realistic operational simulation of plant such as large coal or nuclear sets that, once running, must remain on for a certain number of hours, or, once shut down, cannot restart for a long period.

For each future year that is modelled, nine iterations are carried out, which represent the wind, availability and demand profiles for the historical years 2000-2008. This means that for any given future year, a total of 78,840 prices are created (8,760 x 9), giving a good representation of possible interactions between wind, availability and demand. The prices that result from the model are the result of the interaction of supply and demand in any given hour. As a result we have nine versions of each future year modelled, each containing consistent wind and demand and temperature relationships. This allows us to examine the average behaviour (a typical year) as well as the range associated with 9 years of wind and temperature patterns. As a result, our modelling captures relatively rare but important events such as prolonged periods of low wind generation, which the system must deal with in order for the scenario to be viable.

Generation from wind is based on 2.8 million hourly wind speed records at 35 locations across the UK and RoI plus an offshore site using 'reanalysis' of wave data, which are converted to generation using an aggregated power curve.

The inputs to Zephyr which ensures it provides quantitative modelling and analysis of the highest quality are:

- annual demand and availability;
- hourly wind, wave, solar and tidal profiles;
- commodity prices;
- plant dynamics;
- flexible demand profiles; and
- Transmission network constraints.

These inputs are covered in more detail in Annex F.

2.5 Transmission

The impact on transmission constraints costs and/or investment costs is derived from outputs of the Zephyr model which outputs power flows across key GB transmission network boundaries. Once we have the flows across boundaries, we calculate the trade-off between investment and constraint costs (i.e. the cost to reschedule electricity

6 Zephyr has also been run in what is known as 'relaxed mode', whereby the full mixed integer problem is approximated by continuous variables. Starts and part loading is still optimised, as are the mentioned plant dynamics constraints.

production to meet transmission constraint compared to the annualised cost to invest in additional network capacity) to determine optimum network investment.

2.6 Distribution

The purpose of the distribution modelling is to assess the capacity of the GB distribution networks in accommodating new load from the electrification of heat and transport, and determine the investment required for the expansion of these networks when new load exceeds the secure network capacity. To model the GB distribution network we have identified three types of relevant population area i.e. urban, semi-urban, and rural areas (defined by the level of energy supplied in each area and its population density) and combined these to create District Network Operator (DNO) regions and ultimately a network for GB. Within this framework the modelling captures:

- the extent to which the networks at different voltage levels will be impacted by the behaviour of demand side response in different topographical areas with the characteristics of an urban, semi-urban and rural network; and
- the consequent investment required for the expansion of these sub networks under different DSR scenarios.

For both EHV and HV networks AC load flow analysis for the representative network is used to assess the component loading levels and busbar voltages. The modelled investment required to meet future customer demand is designed to satisfy the network security and voltage limit constraints required by 'Engineering Recommendation P2/6' and 'The Electricity Safety Quality and Continuity Regulations'.

The model provides estimates of:

- the capacity and capability of demand side response that can be facilitated by the network at each of the low voltage (LV), high-voltage (HV), and extra-high voltage (EHV) systems; and
- the investment cost and build rate for increasing the MW in both the urban, semi-urban and rural networks and at each voltage level (EHV, HV and LV) within these sub networks.

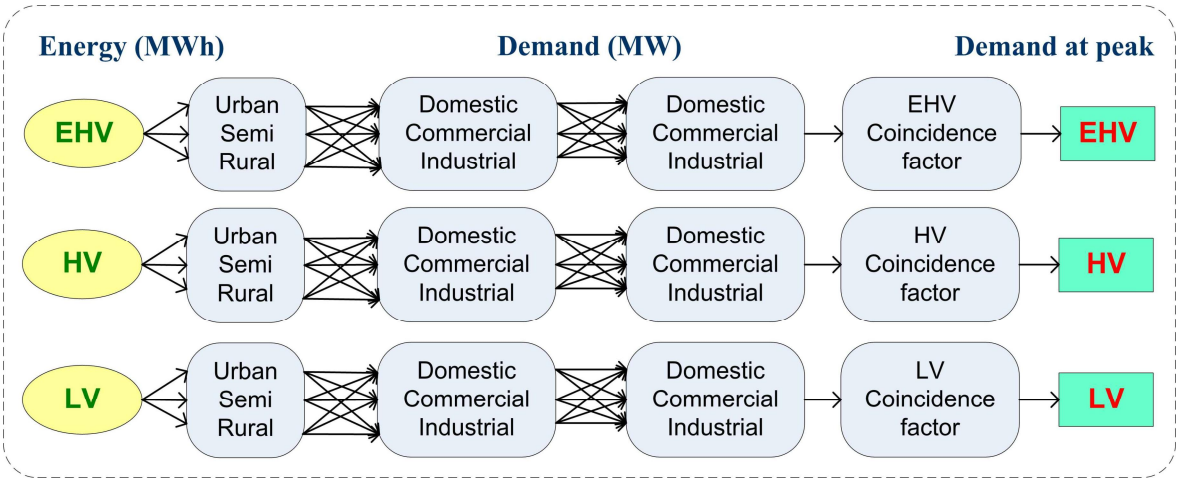
It should be noted that this study does not consider replacement of existing assets due to ageing, which is the greater part of current DNO investment programmes. Reference to each DNOs' assets is from their Long-term Development Statements and the ENA Common Distribution Charging Methodologies. The classification of urban, semi-urban and rural areas is based on the demographical information provided in the National Census and the regional energy sales given in DUKES.

At the distribution level the GB demand is split into urban, semi-urban, and rural areas based on the energy supplied in each area and its population density. The topographical network classification enables the allocation of new load to different voltage levels for the purpose of determining the necessary system capacity in 2030 and 2050. Each type of area will have different proportions of domestic, commercial and industrial customers. Responsive EV demand is attributed solely to domestic customers who are connected at LV, responsive HP load is shared by both domestic and commercial customers, whilst the electrification of industrial processes will impact all three voltage levels in the relevant networks albeit in differing proportions.

The conversion of energy to a MW demand is based on a bottom-up approach using average class load factors for the three customer sectors. The class load factor together

with the associated peak coincidence factor is used to convert the energy to demand at times of system peak which is taken as the driver for network investment. The approach is summarised in the following diagram. This assumes that when flows move EHV to HV to LV, the HV system demand is made up from both the final demand connected at the HV level and the demand on the LV system, and similarly for the EHV system demand.

Figure 10 – Conversion of distributed energy to capacity



2.7 Demand and demand side response

Demand-side modelling consists of two main components – ex-ante (fixed) demand profiles and the active demand-side response units. The total aggregate demand profile is a function of the ex-ante demand profiles and the flexible demand side response profiles (generated by the dispatch of the demand side response units). In scenarios where there is no demand side response, the total aggregate demand profiles are determined solely from the ex-ante (fixed) demand profiles. The following sections present each of these in turn.

2.7.1.1 Demand profiles

We split demand into the following profile groups, which map onto the breakdown of annual demand:

- residential (excluding heat and electric vehicles);
- non-residential (excluding heat and electric vehicles);
- direct electric heating;
- air source heat pump;
- ground source heat pump; and
- electric vehicles.

These profiles were devised as follows:

- **Residential (excluding heat and electric vehicles)** – the sample was based on Class 1 demand profile with Monte Carlo variations based on the 'unexplained' variations in the historical demand profile.
- **Non-residential (excluding heat and electric vehicles)** – the sample demand profile was based on the residual from the historical demand profiles once residential and direct heating demand had been removed with Monte Carlo variations based on the 'unexplained' variations in the historical demand profile.
- **Direct electric heating** – the daily demand in the Monte Carlo years is based on the analysis of heating demand from our gas intermittency study [7], with the within-day profile for storage heating based on Efficiency 7 (E7) and, where there is no storage, it follows the within-day heating demand profile.
- **Air source heat pump** – the daily demand in the Monte Carlo years is based on the analysis of heating demand from our gas intermittency study with adjustments made for the relationship between CoP and temperature, which increases the peakiness of the heating demand profile. The within-day profile for storage heating is based on E7 and, where there is no storage, it follows the within-day heating demand profile.
- **Ground source heat pump** – the daily demand in the Monte Carlo years is based on the analysis of heating demand from our gas intermittency study with an assumption that the CoP is flat across the year. The within-day profile for storage heating is based on E7 and, where there is no storage, it follows the within-day heating demand profile.
- **Electric vehicles** – within day electricity demand from electric vehicles is based on the shape assumed in the ENA/Imperial report[8].

In order to derive a daily heating demand profile, we built on work done as part of our gas intermittency study that allowed us to derive daily non-power demand for gas. This involved using historical daily temperatures that correspond to historical demand and wind speeds (Figure 11) to create a structural pattern of demand around which there are variations driven by deviations in wind speed and temperature from seasonal levels.

The flexible demand scenarios use revised demand profiles produced in response to ex-ante profiles. In general, we assume that heating demand could be shifted within the day whereas transport demand could be shifted between days (e.g. into the weekend).

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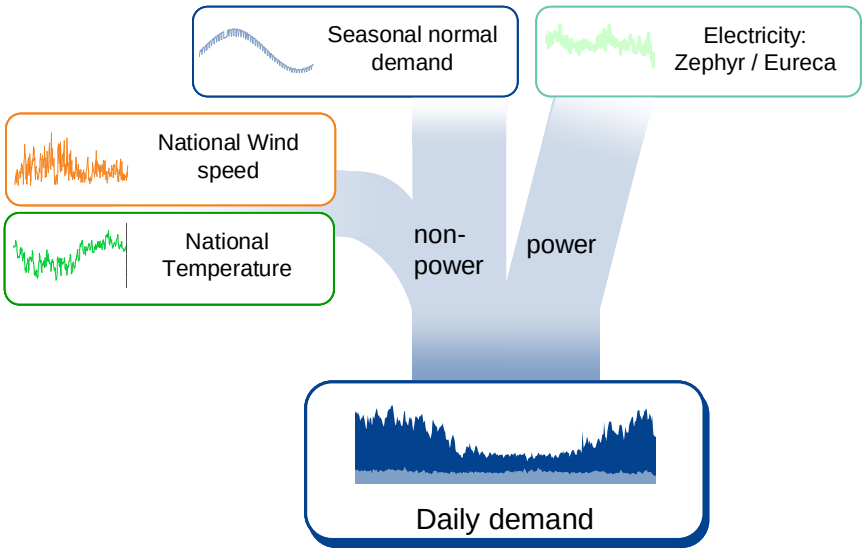
7 'How wind generation could transform gas markets in Great Britain and Ireland. A multi-client study. Public summary', June 2010, Pöyry Energy Consulting.

8 http://www.energynetworks.org/ena_energyfutures/Smart_Metering_Benerfits_Summary_ENASEDGImperial_100409.pdf

Figure 11 – Relationship between weather and demand for heating



2.7.1.2 Active demand-side units

In this study, *Zephyr* is used to model active demand-side units by splitting them into three categories – residential washing units, heating, and electric vehicles. For each category, we made an assumption about the magnitude of movable demand for each year. The fixed demand profile was adjusted to ensure that the sum of inflexible and movable demand (before fuel switching and storage losses) was consistent with total annual demand.

Table 23 in Annex A describes the types of modelling assumptions placed on these demand-side units. These constraints were then used by *Zephyr* to optimise the operation of these demand-side units under the conditions of the relevant DSR scenario, with the restriction that the underlying profile of energy demand must be met. In addition, we have also assumed that there is no owner override which would make the problem intractable.

2.8 Model outputs

The purpose of the model outputs is to impart a clear understanding of the scenarios to assess the impacts of demand side response and to provide a consistent robust basis on which to compare the two fundamental uses of DSR. In particular, model outputs include:

- the variation of wind on an hourly basis and its interaction with demand (and hence effect on demand net wind); and
- detailed modelling of demand side response and its impact on meeting demand net wind';
- the impact of different potential demand side response capability and behaviour on:
  - wholesale market prices;
    - generator production costs;
    - recovery of generator investment costs;

- transmission flows and thus the ability to estimate transmission constraints which are incurred and need to be offset (partially or wholly) by transmission investment; and
- flows in the distribution network and necessary investment in the distribution network.

Zephyr modelling results for transmission flows are used to calculate the potential transmission investment and/or constraints costs under each DSR scenario. To do this, we have calculated estimates of (i) transmission investment costs for a MW capacity increase across constrained transmission boundaries and (ii) transmission constraints costs per MWh of constraint volume across constrained transmission boundaries. These calculations are based on existing evidence including the National Grid work for the ENSG examination of the costs of integrating wind and the GB Seven Year Statement.

2.8.1 Key metrics for scenario comparison

In this section we briefly outline the key metrics that will enable a comparison of the scenarios;

- wholesale price cost; equivalent to the sum of the product of wholesale price and demand for all hours of the year; this consists of:

Generator production costs – marginal;

Producer rent – gained when the price set by the marginal generator exceeds production costs for lower cost generators;

- cost of generation annualised investment cost avoided / incurred i.e. investment costs required for any new generation plant to ensure security of supply;

we have calculated the additional subsidy payment that could be required for low carbon non-renewable generation to make an adequate return on investment;

- transmission network investment costs; annualised investment cost avoided / incurred to upgrade transmission network to specified level;
- transmission network constraint costs; annualised cost incurred from transmission network constraints;
- distribution network investment costs; annualised investment cost avoided / incurred to upgrade distribution network to specified level;
- wind and solar subsidy costs; annual cost to support wind and solar generation is based on the current approach under the Renewables Obligation Scheme; and
- wind curtailment costs; annual cost of wind curtailment.

Overall modelled electricity costs, for the purposes of this study, are defined as the sum of the above components. Thus it excludes, for example;

- supplier costs;
- network asset replacement costs (transmission and distribution); and
- operational and maintenance network costs (transmission and distribution).

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3. MAIN SCENARIOS AND KEY ASSUMPTIONS

In this section we describe the core scenarios we have formulated to evaluate the trade-offs between the two fundamental applications of demand side response.

This section presents scenarios to evaluate the combination of network build and deployment of demand side management that provides the lowest overall modelled electricity cost. Additional scenarios, used to reaffirm our conclusions are described in Annex A.

3.1 Main scenarios

There are three core scenarios:

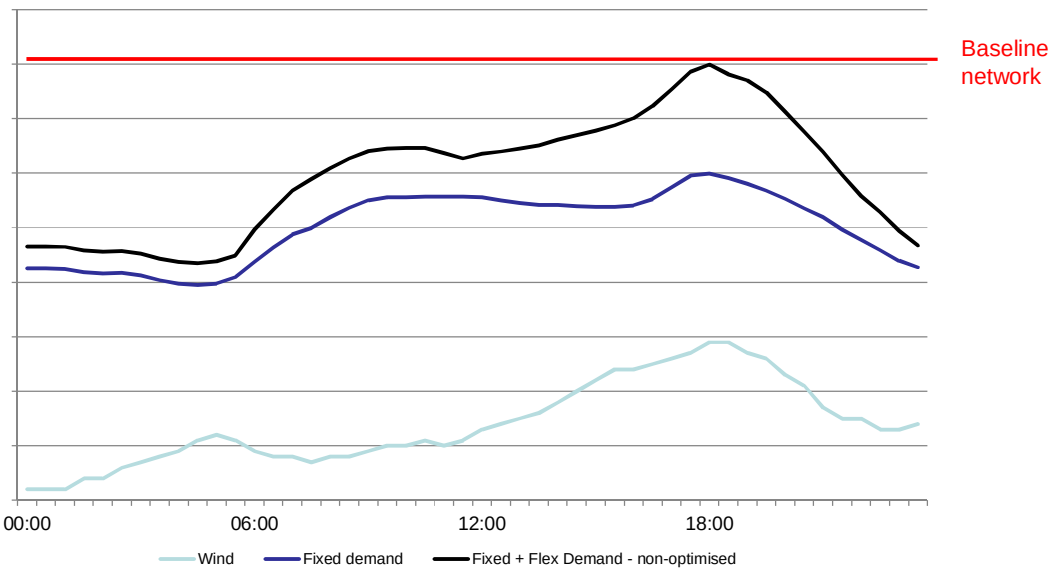
- Baseline scenario: no DSR;
- DSR scenario 1: DSR used to minimise generation production costs as a priority; and
- DSR scenario 2: DSR used to peak shave i.e. flatten demand as a priority.

We explain these scenarios in more detail in the following section. By comparing the latter two DSR scenarios we examine the impact of demand side response being applied for both balancing and peak-shaving purposes in a manner which optimises overall costs.

3.1.1 Baseline scenario

Our baseline scenario is consistent with Pathway Alpha from the DECC Pathways Report and further assumes there is no demand side response beyond that currently implicitly seen within the GB electricity market and network capacity is increased sufficiently to enable generation to meet residual demand. This scenario is shown in Figure 12 below.

Figure 12 – Network built to meet with increasing demand (Illustrative example)



3.1.2 Our two main demand side response scenarios

In this section we introduce our two main demand side response scenarios. These are:

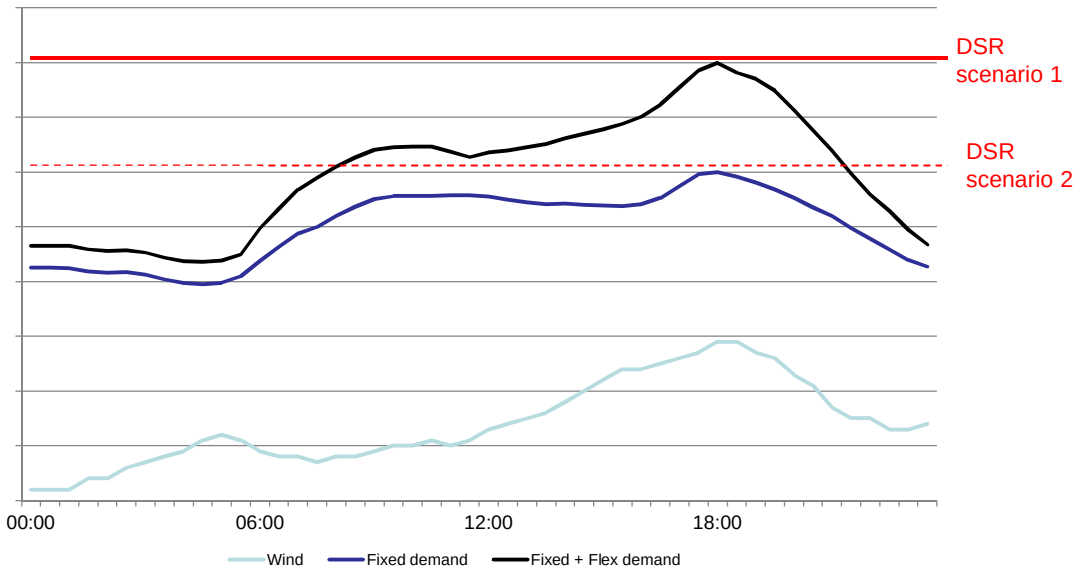
- DSR scenario 1 – demand side response is used to minimise generator production cost, while network capacity is increased sufficiently to enable generation to meet peak demand (assuming no demand side response takes place).
- DSR scenario 2 – demand side response is used to shave demand as a priority, while network capacity is set equal to peak of inflexible demand.

Both demand side scenarios are shown in Figure 13 to illustrate the difference between DSR scenario 1 and DSR scenario 2.

DSR scenario 1 describes a scenario where demand side response is used to balance wind as a priority, while network capacity is increased sufficiently to enable generation to meet peak demand (assuming no demand side response takes place). In Figure 13, DSR scenario 1, where demand side response is used to balance generation without any network constraint, is denoted by the solid red line. The resultant demand profile is denoted by the solid black line.

The dashed red line in Figure 13 describes DSR scenario 2, i.e. where demand side response is used to shave demand as a priority, while network capacity is set equal to peak of inflexible demand (solid dark blue line).

Figure 13 – DSR used to balance generation or to peak shave (Illustrative example)



3.2 Key assumptions

A comprehensive discussion of the modelling assumptions can be found in Annex A. This section presents the key input assumptions: generation mix and levels of fixed and flexible demand that we have used in the process of modelling the DSR scenarios.

3.2.1 Generation mix

Installed generation capacity is based on Pathway Alpha from the DECC 2050 Pathways Report. The generation mix is shown in Table 1. Any capacity shortfall between generation capacity and demand has been made up by peaking generation and conversely any reduction in peak capacity to lead to decrease in peaking generation. It should be noted that there are other means of meeting capacity requirement including storage and interconnection, however the focus of this study does not cover the optimal balancing generation mix.

Table 1 – Composition of baseline generation scenario (Pathway Alpha)

GW	2030	2050
Wind and Marine	65.9	93.3
Solar	5.8	70.4
Other renewables	3.3	3.7
Nuclear	16.4	40.0
CCS coal	10.2	39.0
Gas fired generation	28.3	0.0
Coal	1.3	1.3
Hydro	1.1	1.1
Pumped storage	2.8	2.8
Total	135.0	252.0

It should be noted that under Pathway Alpha the 70GW of solar in 2050 is assumed to be residential, and therefore installed directly to the distribution network.

3.2.2 Structure of demand

In this section we present the breakdown of demand by the categories of flexible demand and inflexible demand. Under each category we then define the constituent components of demand (e.g. heating, electric vehicles etc)

3.2.2.1 Fixed demand

There are two components of demand that are common to all scenarios: total fixed demand and the profiles for the fixed demand. DECC provided the figures for annual electricity demand in 2030 and 2050 (derived from Pathway Alpha). These are broken down as shown in Table 2. This highlights the increasing share of heat and transport in the electricity demand mix between 2030 and 2050. *Zephyr* uplifts electricity demand to take account of network losses when calculating the requirement for generation and imports.

Table 2 – Composition of annual electricity demand in each scenario

TWh	2030	2050
Non residential	288.2	461.0
Domestic (non heat)	82.6	93.5
Electric vehicles	32.2	38.4
Heat pump heating	76.9	126.3
Non heat pump heating	14.5	4.1
Cooling	10.9	12.8
Total	505.0	736.0

The profiles for fixed demand are based on historical decomposition and are explained in Annex A.

3.2.2.2 Flexible demand

Table 3 shows the levels of flexible demand assumed under each of the main scenarios. The table splits this demand into three categories:

- Heating demand (composed of space and water heating for domestic and commercial buildings);
- Electric vehicles; and
- Residential electricity demand.

Table 3 – Levels of flexible demand under each scenario

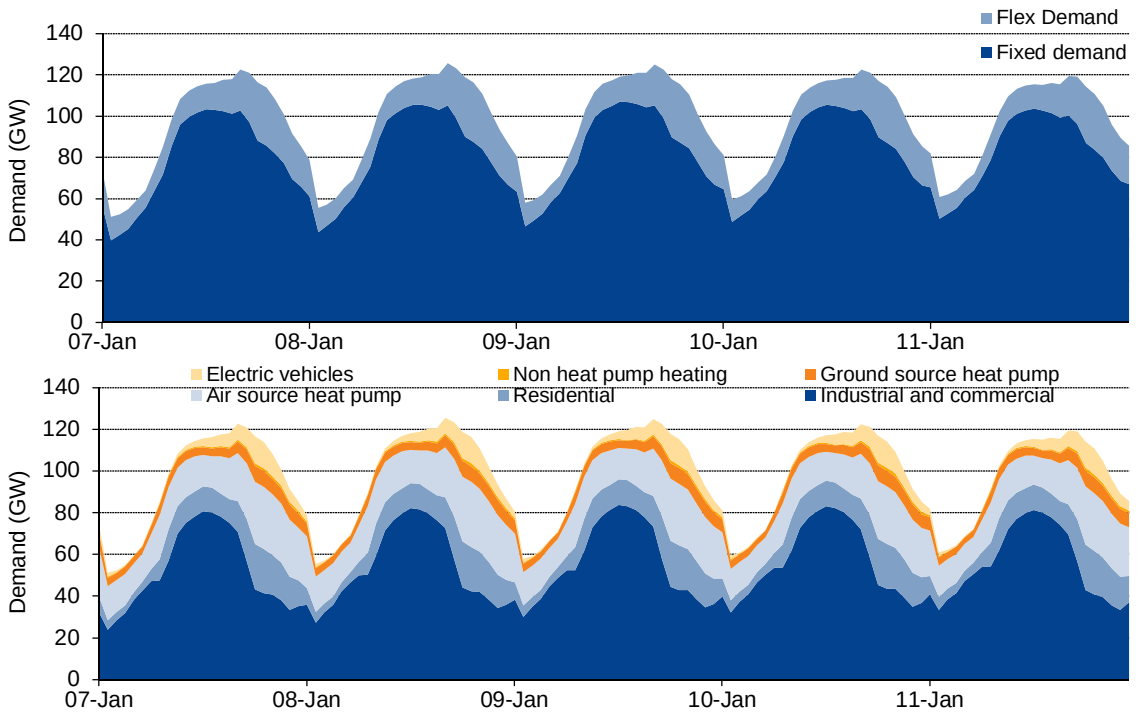
TWh	2030			2050		
	Flexible heat	Flexible residential	Electric vehicles	Flexible heat	Flexible residential	Electric vehicles
Baseline	0.0	0.0	0.0	0.0	0.0	0.0
DSR scenario 1	42.0	6.0	24.2	56.7	8.4	28.8
DSR scenario 2	42.0	6.0	24.2	56.7	8.4	28.8

In our baseline, we do not model the deployment of DSR. In DSR scenarios 1, and 2 we assess the impact of a realistic deployment of demand side response i.e. 50% of the potential flexible heat demand is actually flexible and 75% of EV demand is flexible. We have also examined the impact of higher levels of DSR in the additional scenarios, described in Annex A.

3.2.2.3 Baseline demand profile

Based on the above assumptions for fixed and flexible components of demand the demand profile for our Baseline scenario is illustrated in Figure 14.

Figure 14 – Demand profile split by component and flexible generation



3.2.3 Caveats

For our scenario analysis we have assumed a number of caveats and assumptions to ensure realistic deployment of technologies in the modelling. These caveats are provided below:

- We assume that the transmission network build economically balances network vs. constraint costs using values from National Grid SQSS review.
- While we have modelled current storage and interconnection, detailed analysis of extra storage and interconnection is outside the scope of the project. Therefore other solutions to mitigate the impact of intermittent generation, such as interconnection, flexible generation and energy storage could also be required in the future. While we have included some of these technologies in our analysis, we have not assessed their deployment trajectory in detail as part of this study.
- We have not sought to rebalance generation mix i.e. re-optimisation based on plant IRR's.
- Distribution network costs are built up from relevant aggregation of urban, semi-urban and rural network models using current asset costs.

- We have sought to minimise changes between scenarios in order to understand drivers of differences in results.
- The value of 1 ROC is assumed to be £39.5/MWh, and banding for relevant technologies is as per current Ofgem guidelines.
- In cases where required, we have calculated the subsidy payment required to allow low carbon generation such as nuclear and coal CCS to make a suitable return on investment.
- We have not undertaken a full cost benefit analysis of DSR i.e. we have not included the implementation cost of demand side management systems e.g. ICT equipment etc.
- The analysis is based on current views of the costs of generation technologies. For newer low carbon generation technologies including CCS one might expect these costs to become lower as the technology becomes more mature and achieves substantial scale of deployment.

The modelling in this study is based on the rational use of demand side response, in which we assume consumers have no ability to override the decision to deploy the demand side response. However, we assume that only a proportion of demand is flexible, therefore not all customers would be responding.

4. KEY FINDINGS

4.1 Overview

This section sets out the results from our scenario analysis of the trade-off between the deployment of demand side response for peak shaving and balancing. We have grouped the DSR scenarios (set out in section 3) to examine the three types of demand side response and/or network behaviour. These are:

- Baseline: no demand side response;
- DSR scenario 1: Demand side response used to minimize generation production costs; and
- DSR scenario 2: Demand side response used to shave peak demand.

For each of our scenarios we have assessed the four main costs that make up the overall modelled costs of electricity, these are shown in Table 4. This table also sets out the driver of each of our cost components together with the relationship to demand side response use.

Table 4 – Breakdown of overall modelled electricity cost

Type of cost	Driver of cost	Relationship to DSR use
Wholesale price production cost producer rent	Generation build Fuel and CO_2 Need for viable generation	Reduced when DSR used to minimise generation production costs
Subsidy for low carbon generation*	Volume of low carbon generation qualifying for subsidy	Largely independent of DSR – some effect based on running and form of subsidy
Network investment cost	T&D reinforcement needed to meet peak demand and network flows	Reduced when DSR used to flatten demand peak
Constraint cost**	Wind curtailment Constraint on and off of generation	-Wind curtailment reduced when DSR used to minimise generation production costs - Impact of DSR on transmission constraints is less simple

* Based on 2009 wind generation volumes reported in digest of UK energy statistics
**Includes wind curtailment

Table 5 presents the overall modelled electricity costs for each of the scenarios in 2050. These results show meeting 2050 demand without demand side response could lead to a five-fold increase in the overall modelled electricity cost compared to 2009 costs. However, it is important to highlight that Pathway Alpha will also have a material

downward impact on the costs of gas and oil (predominantly petrol & diesel) but this impact has not been assessed as part of this study.

The use of demand side response could reduce total electricity costs by as much as £8bn per annum (10%) by 2050, compared to meeting projected demand with no demand side response.

Table 5 – Overall modelled electricity costs for the DSR scenarios groups

Overall modelled electricity costs (£ billion)	2009	2030	2050
Baseline	14.60	61.00	83.90
DSR scenario 1	14.60	58.80	76.20
DSR scenario 2	14.60	58.00	75.60

4.1.1 Headline messages from core scenarios

Based on our analysis we have derived the following key messages:

- there is potential significant value in enabling demand side response to meet the challenges of managing intermittent generation and electrification.
  - a c.10% reduction in our overall modelled electricity costs per annum were achievable amounting to a c.£8bn economic benefit against DECC's Pathway Alpha;
  - DSR also largely eliminates potential wind curtailment and thus maximises the carbon benefits of intermittent zero carbon generation;
- prioritising DSR to shave peak demand is the optimum in terms of overall modelled electricity costs by enabling the avoidance of distribution network and generation investments;
  - this would require DSR to be deployed as required across the top 10% of demand periods;
- however, the difference in pure economic benefits we modelled between prioritising DSR to peak shave rather than minimise production costs is relatively small (<1% i.e. c. £0.6bn) in the context of our overall modelled annual electricity costs;
  - Given the collective scale of costs modelled it suggests that it may be pragmatic to build networks to meet peak demand without reliance on DSR to ensure greater security of supply.

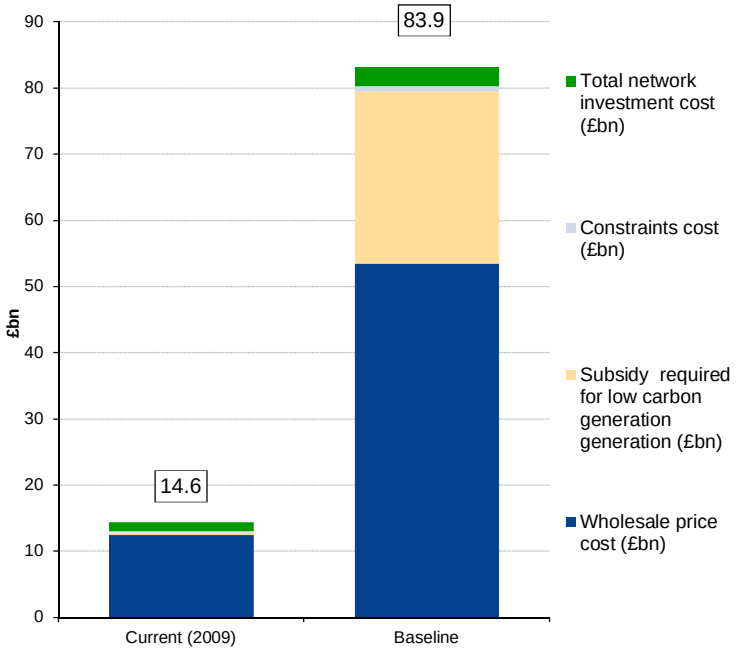
As we set out in Section 3, our baseline scenario allows us to measure the value of demand side response, as it reflects a case where there is no deployment of demand side response. This scenario is based on the DECC Pathway Alpha, with generation capacity adjusted to ensure security of supply at peak.

The results in Figure 15 show that meeting 2050 targets could lead to a five-fold increase (from £14.6bn in 2009 up to £83.9bn in 2050) in overall modelled electricity costs, with this increase caused by doubling of demand largely driven by electrification of heat and transport and consequential need for and investment in generation and network capacity. The investment in generation is significant to meet peak demand – in 2030 29GW of

additional OCGT is required compared to DECC baseline, and in 2050, 18GW OCGT and 20GW CCGT is required compared to DECC baseline.

However, while the absolute costs could rise by fivefold; it is important to understand that this could lead to a lesser impact on the unit cost per MWh of consumption. In this case the £/MWh value increases from £46/MWh to £115/MWh, i.e. ~2.5 times (due to increased demand consumption).

Figure 15 – Overall modelled electricity costs in 2009 compared to no DSR scenario in 2050



It is important to recognise there are savings in other energy use via reduced consumption of oil and gas for transport and heating respectively. However, this trade-off has not been examined as part of this study.

4.2 Main two demand side response scenarios

These two scenarios consider how the potential future deployment of demand side response should be used: for balancing wind, or for flattening demand peaks. The scenarios are defined below:

- DSR scenario 1 – demand side response is used to minimise generator production cost, while network capacity is increased sufficiently to enable generation to meet peak demand (assuming no demand side response takes place); and
- DSR scenario 2 – demand side response is used to shave demand as a priority, while network capacity is set equal to the peak of inflexible demand.

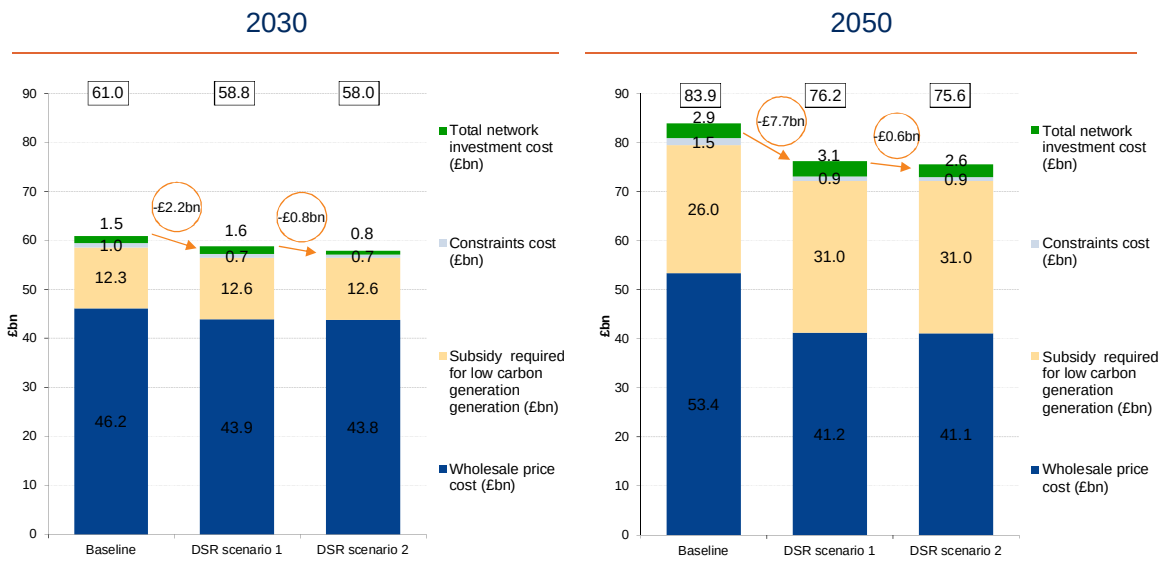
We have also considered two extreme uses of demand side response (deploying no demand side response through to full deployment of demand side response), results of which are presented in Annex D.

In the remainder of this section we consider costs, benefits and consequences of using demand side response for peak shaving compared to using demand side response for balancing wind.

4.2.1 Overall modelled electricity costs

Figure 16 below presents the overall modelled electricity costs, split into the individual cost elements, for DSR scenario 1 and 2 in 2030 and 2050.

Figure 16 – Overall modelled electricity costs for DSR scenarios 1 and 2



The key finding is that the deployment of demand side response under the assumptions set out in DSR scenario 2, could reduce total overall modelled electricity costs by as much as £8bn per annum (10%) by 2050[9]. This is equivalent to a reduction impact in the unit cost per MWh of consumption of £11.2/MWh from £114/MWh in the baseline scenario.

Although DSR scenario 1 also reduces absolute and per unit costs (£7.7bn and £10.4/MWh respectively in 2050) overall electricity supply compared to our baseline, it remains more expensive than DSR scenario 2.

The key difference between the two demand side response scenarios is the distribution network investment costs, which are lower under DSR scenario 2. The lower distribution network costs reflect the assumption that the network under DSR scenario 1 is only built to meet the peak of inflexible demand compared to DSR scenario 2 which allows unrestricted network build.

9 A full cost benefit assessment has not been done as part of this study

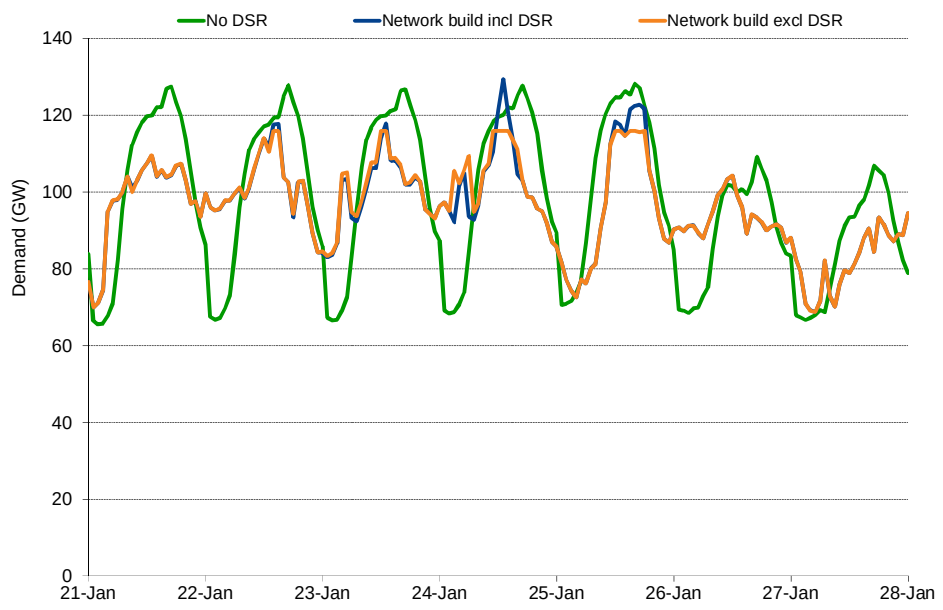
We have calculated the subsidy required for low carbon generation in all scenarios. The subsidy covers payments to intermittent generation and also to nuclear and CCS plant so the plants make an adequate return on investment; details are in Annex A.

The results in Figure 16 imply that by using demand side response to shave demand we can cut overall modelled electricity costs compared to using demand side response for balancing purposes. The following paragraph discusses why this is the case.

Using demand side response primarily for flattening peaks is economically optimal because of the small number of periods where higher demand peaks are reached. Figure 17 illustrates the relatively limited impact of restricting network build on demand side response deployment for a typical week within the height of winter when demand is at its highest.

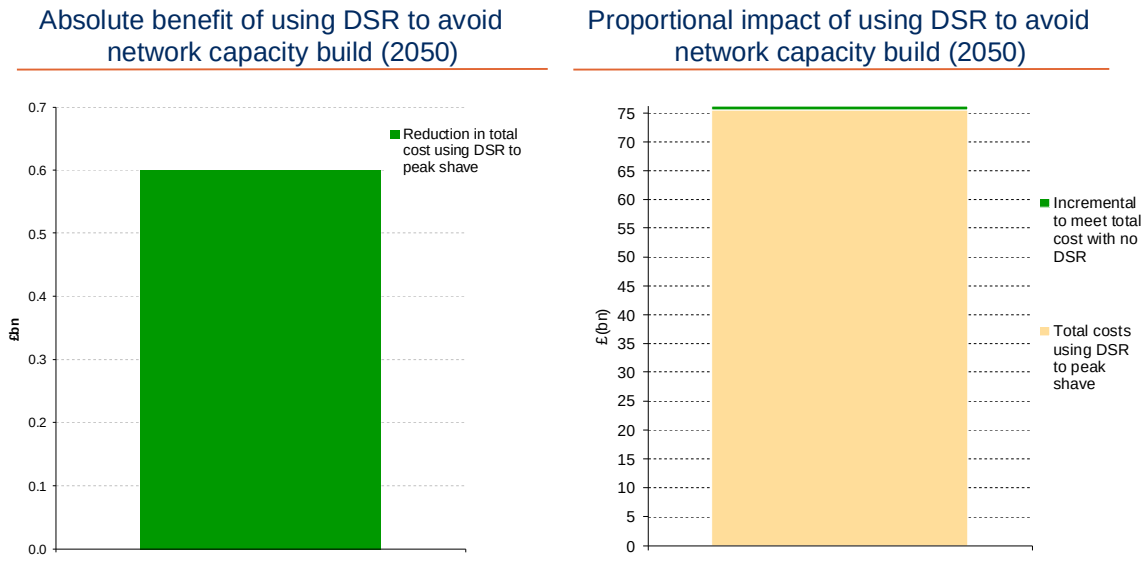
For much of the year, where underlying demands are lower, restricting network build has no impact on the effectiveness of demand side response.

Figure 17 – Demand profiles during example week in January



However as we show in Figure 18 the benefit of using of demand side response for peak shaving compared to balancing can vary. This is because different uses of demand side response can result in a significant annual saving in absolute terms but a relatively small difference in cost savings compared with the total of the costs we have modelled.

Figure 18 – Absolute versus proportional impact of using DSR



Finally, and having presented the case above for using demand side response for peak shaving, it is important to realise that there are risks of relying on demand side response at peak periods, which will need to be traded off against any potential cost savings from restricting network build. It is worth highlighting that under DSR Scenario 1 there is already as reliance risk from avoiding investment in some peaking generation capacity which is otherwise required under the Baseline scenario. This is magnified further under DSR Scenario 2.

4.2.2 Breakdown of wholesale price costs

Table 6 shows the cost to generators under the DSR scenarios. This is defined as the sum of generation costs (including variable other works costs and start up and no load costs). This confirms the general trend seen in Figure 16: that deploying DSR reduces costs – in this case costs incurred by the generator. However, constraining demand side response (by putting a network limit in place) imposes a minimal increase in generator production costs.

Table 6 – Production cost to generator across demand side response scenarios

£ bn	2030	2050
Baseline	17.13	16.10
DSR scenario 1	13.96	9.92
DSR scenario 2	13.97	9.94

The difference between the wholesale price cost and the production cost represents the additional revenue paid to the generators in order to cover fixed capital costs (also known as producer rent); this data is shown in Table 7.

Table 7 – Producer rent across demand side response scenarios

Producer rent (£bn)	2030	2050
Baseline	28.07	37.30
DSR scenario 1	29.94	31.28
DSR scenario 2	29.83	31.16

In the event that producer rent is not enough to make an adequate return on investment, we have calculated the additional subsidy required for generators to make the required rate of return on investment (details are in Annex A).

4.2.3 Breakdown of saving associated with DSR

Table 8 shows a breakdown of the saving in overall modelled electricity costs by component for the three main scenarios. The table shows that you end up paying more in terms of subsidy under DSR because intermittent generation is allowed to fulfil its potential (i.e. shift demand to periods of high wind) and hence thermal plant needs more support as the average wholesale price is lower. However, substantial savings are made due to the lower average wholesale price cost because DSR shifts demand to periods of high wind (low cost).

Table 8 – Where does the saving come from?[10]

£bn /annum	Baseline	Baseline + DSR[11]	DSR scenario 1	DSR scenario 2
Network investment[12]	0.00	0.00	-0.20	0.30
Subsidy	0.00	0.00	-5.00	-5.00
Constraint cost[13]	0.00	0.60	0.60	0.60
Wholesale price cost	0.00	2.50	12.20	12.30
Total saving	0.00	3.10	7.70	8.30

10 The convention in this table has been to take the saving as positive and additional costs as negative.

11 Baseline +DSR has the same installed capacity as baseline but also has levels of demand side response seen in DSR scenario 1 and 2.

12 Network investment costs include both transmission network investment and distribution network investment.

13 Constraint cost includes both transmission network constraint costs and wind constraint costs.

A further by product is that wind curtailment costs reduce which drives down constraint costs. The savings more than compensate for the additional subsidy costs and associated network reinforcement costs.

4.3 Assessing the impact of DSR

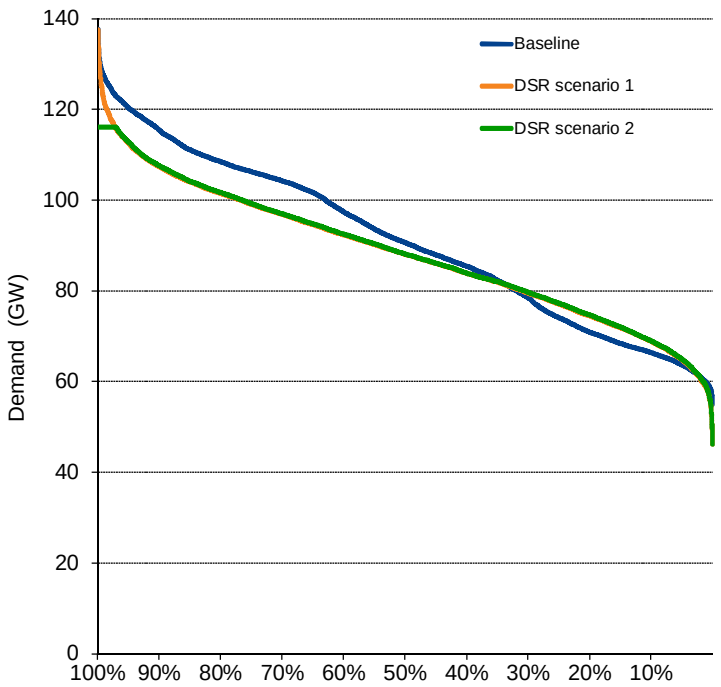
In this section we assess the baseline scenario and DSR scenarios 1 and 2 to further understand the impacts that demand side response can have on the electricity market. We have split this analysis to consider the impact on demand, generation capacity, price, wind curtailment, emissions and network investment costs.

4.3.1 What impact does DSR have on demand?

Figure 19 presents the demand duration curves for our two main demand side response scenarios and our base case scenario of no demand side response. The chart shows how the demand duration curve in the base case is flattened through peak shaving and wind balancing.

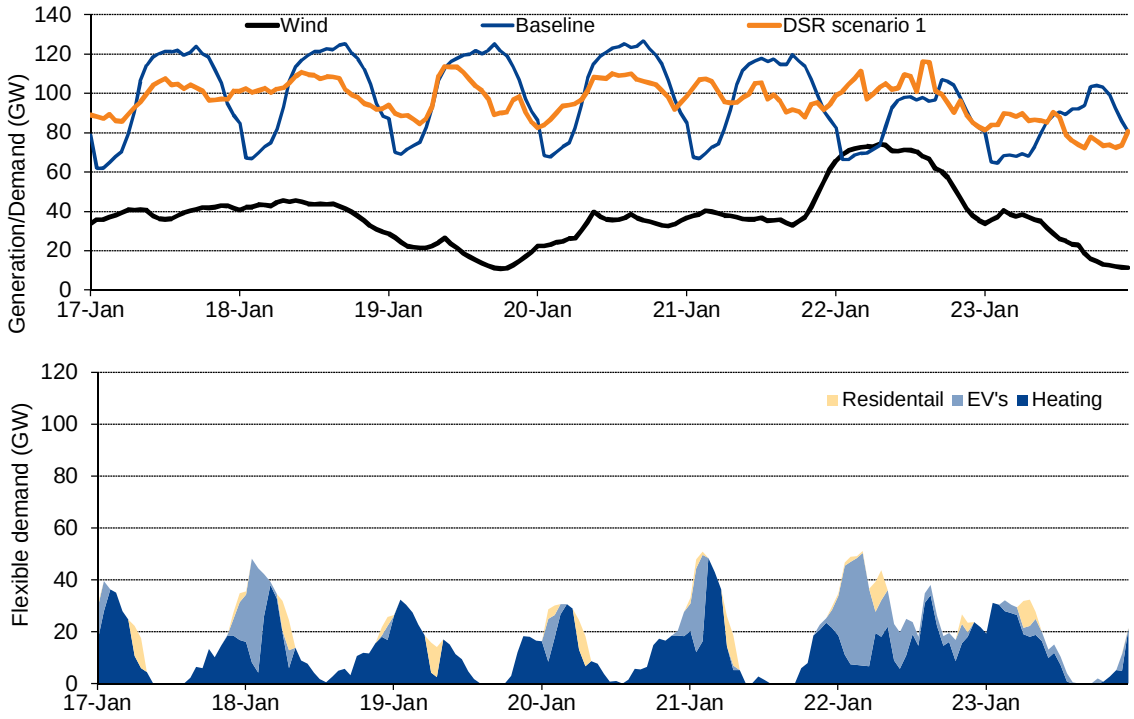
Results from our *Monte-Carlo* modelling also highlighted that using demand side response for peak shaving or wind balancing reduced the number of peak hours across the year, which ultimately reduces overall modelled electricity costs.

Figure 19 – Demand duration curve



The charts in Figure 20 below provide a typical example of the potential deployment of DSR under the DSR scenario 1 for a winter week in 2050 and the impact it has on the demand compared to the baseline scenario. These highlight the contribution substantive deployment of DSR can make in helping to flatten demand and reduce electricity costs.

Figure 20 – Flexible demand patterns are driven by wind conditions[14]



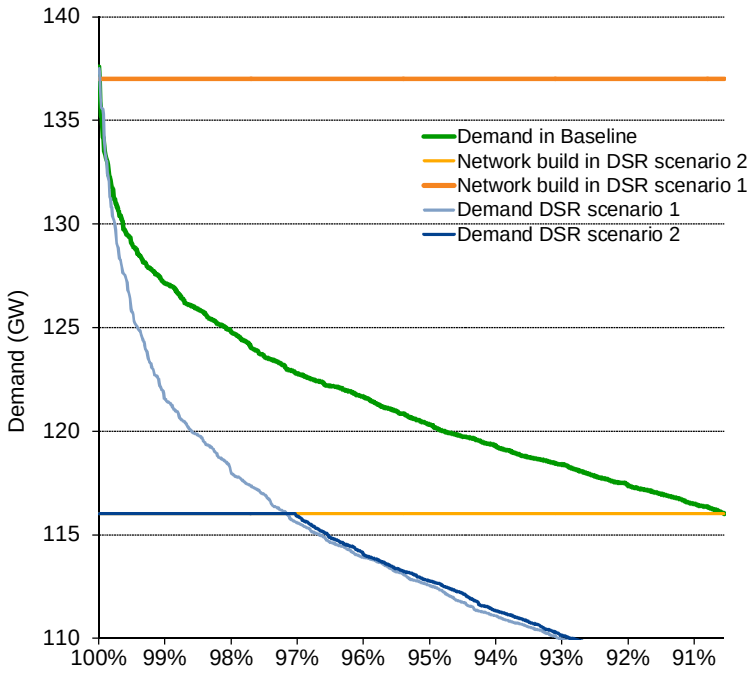
Further, Figure 21 shows that where demand side response is relied upon to enable reduced level of network build, in order to enable security of supply to be met, consumers would need to respond 10% of the year and deliver up to 30GW (>20%) of demand reduction on the coldest winter days. This equates to over 50% of flexible heating being shifted away from peak on the coldest winter days.

However, where demand side response is focused on balancing and network capacity is built to meet peak demand (assuming no demand side response) then although there is a little less investment in generation capacity (resulting from better utilisation of generation year round) this capacity is still sufficient to meet peak demand. The implication is that even where there is low wind, security of supply is much less exposed to reliability of consumer response.

Under this approach less demand side response is required from consumers. In particular this enables consumers to provide demand side response without significant involvement, but does allow them to choose not to provide demand side response in the most extreme cold days (unless wind is low).

[14] For modelled year 2050 with the weather of 2000

Figure 21 – Relying on DSR at peak – demand duration curve 2050.



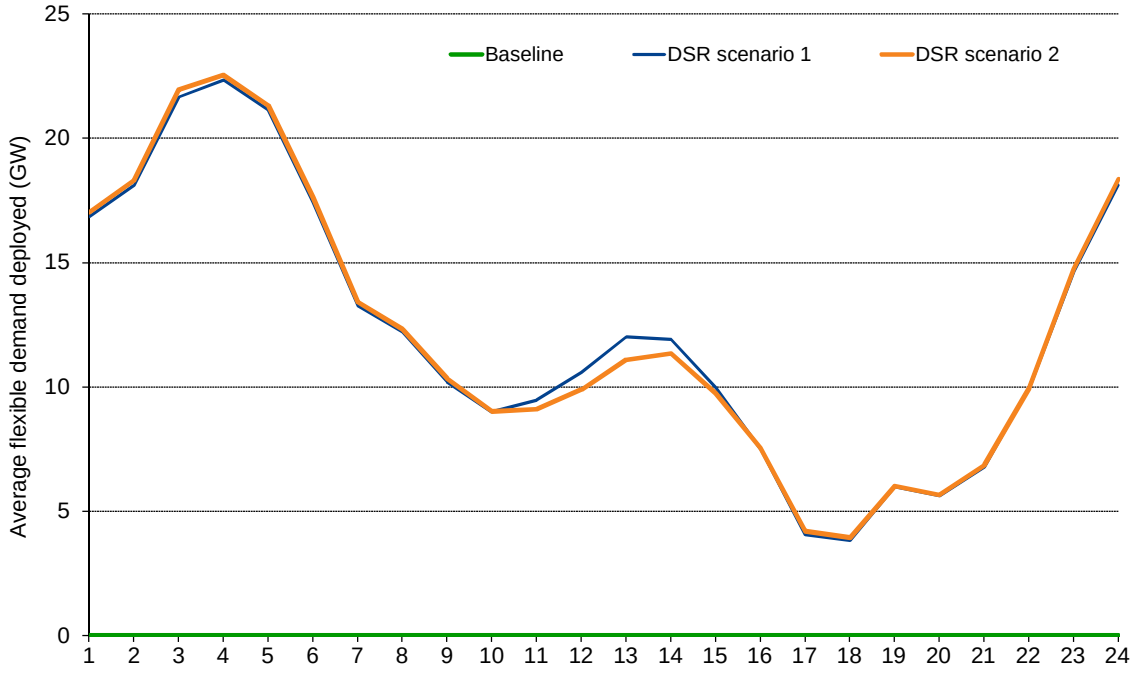
4.3.2 How differently is flexible demand dispatched?

As we have discussed throughout this report output from wind generation and consumer demand are not correlated. This means that in a world of intermittent generation, flexible demand would be dispatched at times when inflexible demand is low (i.e. overnight) to ensure that demand is met. Both profiles in Figure 22 show this pattern of high deployment overnight reducing during the day.

In general the two deployment lines (for DSR scenario 1 and 2) follow a similar profile but allowing demand side response more freedom causes it to dispatch more during the day. We have shown in our previous study on the impact of intermittency on the GB and Ireland electricity markets[15] that this result typically this coincides with periods of higher wind generation. This relates to the fact that on average it is generally windier in the afternoon than during the morning.

15 'Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', Pöyry Energy Consulting. July 2009.

Figure 22 – Utilisation of flexible demand



4.3.3 What impact does DSR have on incremental generation capacity requirement?

Demand side response reduces the need to build additional peaking generation by reducing periods of peak demand by switching flexible demand to hours where there is lower fixed demand. Therefore, when demand side response is available, the more wind generation there is the more additional peaking generation is saved (i.e. the difference between no demand side response and demand side response becomes larger).

In addition, lowering the distribution network capacity causes the peaking capacity to drop even further, as this counteracts the natural tendency of demand side response to boost peak demand (i.e. periods of high wind and low prices coinciding with periods of high demand). Ultimately, this could result in lower system costs due to avoided investment in new capacity.

The reduction in the requirement for CCGT's and OCGT's is shown in Figure 23 below. The chart shows that by 2050 the requirement for the additional generation capacity is halved from 38GW assuming no demand side response to around 15GW under DSR scenario 2. The chart also shows that by focusing demand side response on peak shaving rather than wind balancing, the requirement for generation is 5GW lower.

Figure 23 – Incremental generation capacity required

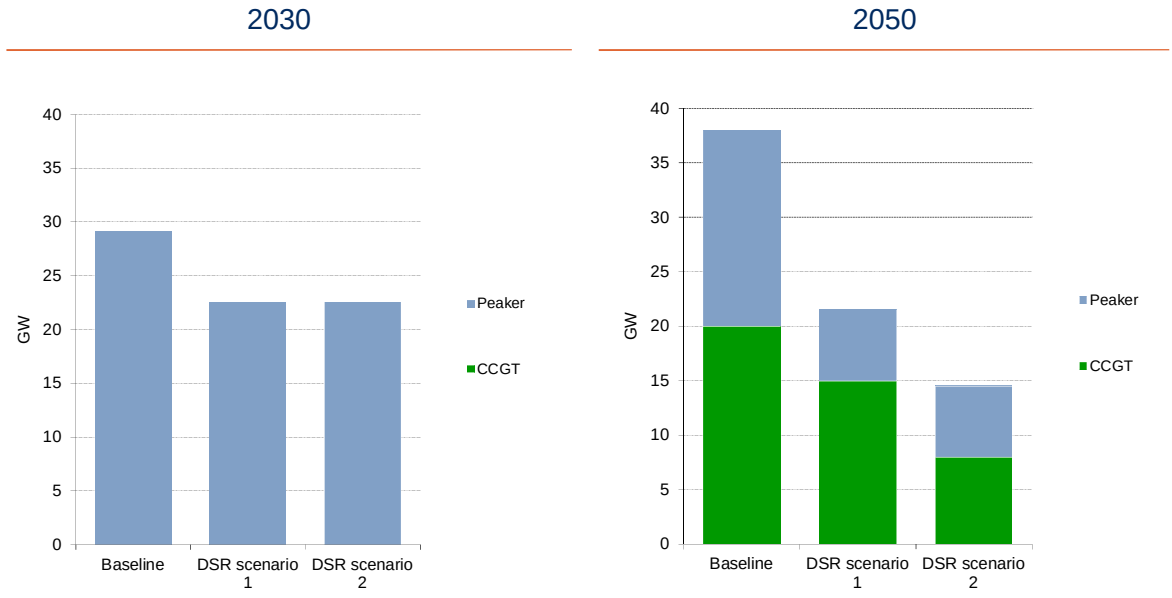


Table 9 presents the associated cost with the deployment of the incremental generation capacity required in 2050. This represents the additional cost over and above that required to deliver Pathway Alpha, equating to an additional £2.5 billion per annum by 2050 and a total additional investment cost of £24 billion. The introduction of DSR reduces the need and cost of additional thermal generation, by significant levels (between £1.1 and £1.8 billion depending on the DSR scenario).

Table 9 – Breakdown of cost incurred for additional thermal generation

Incremental generation cost in 2050	Annual cost (£bn/yr)	Total cost (£bn)
Baseline	2.50	24.00
DSR scenario 1	1.40	13.40
DSR scenario 2	0.70	6.90

4.3.4 What impact does DSR have on prices?

Price duration curves show the hourly wholesale price, which is set by the marginal plant. The two different lines represent the baseline scenario (no DSR) and scenarios where DSR is deployed. The two DSR cases are so close that you can observe the small difference in prices between the two.

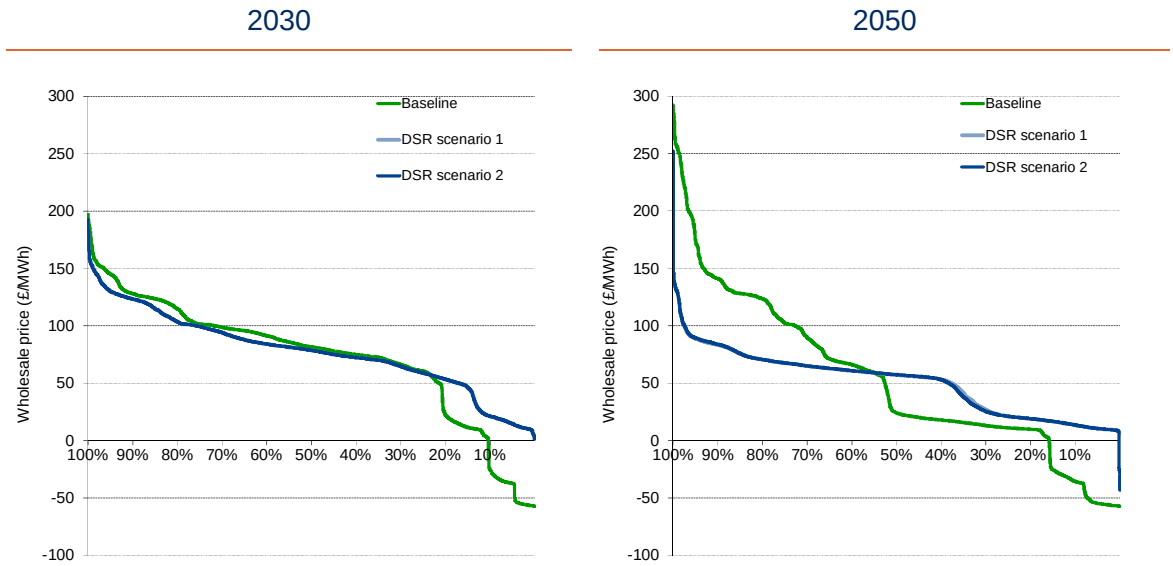
In the case of no DSR (green line) negative prices occur for 10% of the time in 2030 and approximately 15% of the time in 2050. The reason for negative prices is that wind plant is on the margin (i.e. meeting all of demand) and as we assume it bids in a -1ROC for

onshore and -1.5 ROCs for offshore, to ensure it runs when available. As the amount of wind on the system increases, the number of negative price periods also increases.

When deployed, DSR (blue line) increases the demand in periods of low prices by shifting flexible demand to low priced periods as this leads to a lower average price overall. As a result the number of negative price periods under the scenario where DSR is deployed decreases.

Demand side response flattens the price duration curve leading to lower prices in general. This is because demand side response reduces the periods of high demand by shifting demand to troughs, therefore the high prices associated with these periods of high demand are also reduced. Figure 24 also highlights that there is little difference in wholesale prices between the network investment case and the low network investment case.

Figure 24 – Price duration curves



Note: Due to the relatively small difference between prices in the two DSR scenarios, the price duration curves of DSR scenario 1 and DSR scenario 2 overlap

4.3.5 What impact does DSR have on volumes and patterns of wind curtailment?

Figure 25 below shows the impact of demand side response on the volume of wind curtailed and number of periods in which this wind curtailment occurs. The chart shows a significant reduction in the level of wind curtailment when demand side response is deployed compared to the levels shown under our baseline scenario.

The reductions in wind curtailment presented in Figure 25 below occur as a result of shifting demand from peak periods to periods of low demand. This leads to fewer coincidences of periods of high wind generation and low demand, ensuring that demand and wind generation are sufficiently balanced.

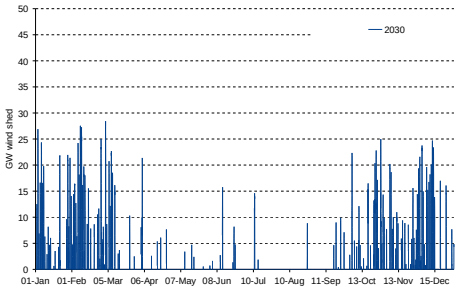
Under our baseline, the results for 2050 show that wind is curtailed on average one period in every seven, this leads to a requirement to curtail 15,731GWh of wind generation during the year. By enabling demand to be shifted into periods of high wind generation,

the volume of wind curtailed is reduced to 40GWh under DSR scenario 2 and eliminated under the assumptions of DSR scenario 1.

Figure 25 – Volume of wind curtailment

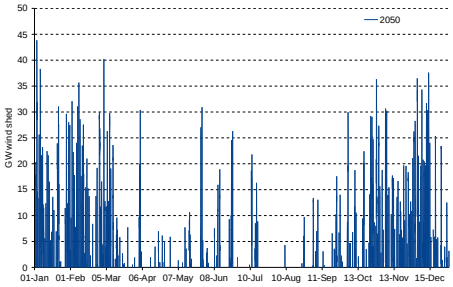
2030

	GWh shed	No. periods which shedding occurs
Baseline	7,910	850
DSR scenario 1	0	0
DSR scenario 2	0	0



2050

	GWh shed	No. periods in which shedding occurs
Baseline	15,731	1384
DSR scenario 1	0	0
DSR scenario 2	40	9



Note: the charts on the right hand side reflect wind shedding volumes in the baseline scenario

4.3.6 How does DSR affect CO_2 emissions?

With the very significant volumes of renewable generation in our demand side response scenarios, it is unsurprising that carbon emissions drop significantly, as shown in Table 10. In GB, emissions fall from 55.5MtCO_2 in our Baseline scenario to approximately 42.7MtCO_2 in 2030 and fall from 21.4MtCO_2 to 9.6MtCO_2 by 2050, a fall of more than half for DSR scenario 1 and DSR scenario 2 respectively. Table 10 also highlights the negligible difference between the two DSR scenarios in terms of CO_2 emissions.

According to the latest DECC energy statistics publication, UK emissions in 2009 from the power sector amounted to 480.9 MtCO_2, while 1990 emissions levels were 592.8MtCO_2. To place this in context, the statutory emissions target for 2050 is 155 MtCO_2e, the "e" denoting CO_2 equivalent emissions (this includes other greenhouse gases).

This leads to emissions intensity (the amount of CO_2 emitted per unit of generation) falling from 94.2 gCO_2/kWh in our Baseline scenario to approximately 73.9 gCO_2/kWh in 2030 and a fall from 25.3 gCO_2/kWh to 11.5 gCO_2/kWh by 2050 for DSR scenario 1 and DSR scenario 2 respectively.

Table 10 – Comparison of carbon emissions and intensity

Carbon emissions (Mt CO2)	Baseline	DSR scenario 1	DSR scenario 2
2030	55.5	42.7	42.7
2050	21.4	9.6	9.6

Carbon intensity (gCO2/kWh)	Baseline	DSR scenario 1	DSR scenario 2
2030	94.2	73.9	73.9
2050	25.3	11.5	11.5

4.3.7 What impact does DSR have on network investment costs and capacity?

We have modelled two components of network investment cost – distribution network investment costs and transmission network investment costs.

Figure 26 shows the distribution network capacity constraint under each of the scenarios. In our baseline, the distribution network is not constrained and is assumed to have adequate capacity to cope with peak demand. In DSR scenario 1 the network is constrained is such way that DSR cannot push peak demand above that observed in our baseline. In DSR scenario 2, the distribution network is constrained so that there is enough capacity to meet peak inflexible demand, and DSR must reallocate flexible demand so that the constraint is not breached in the most economical manner possible.

Figure 26 – Distribution network capacity

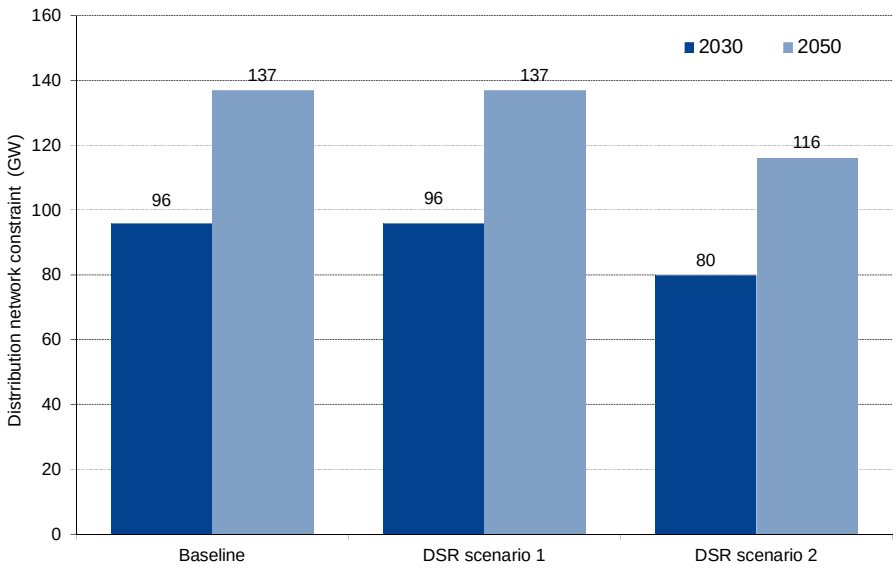
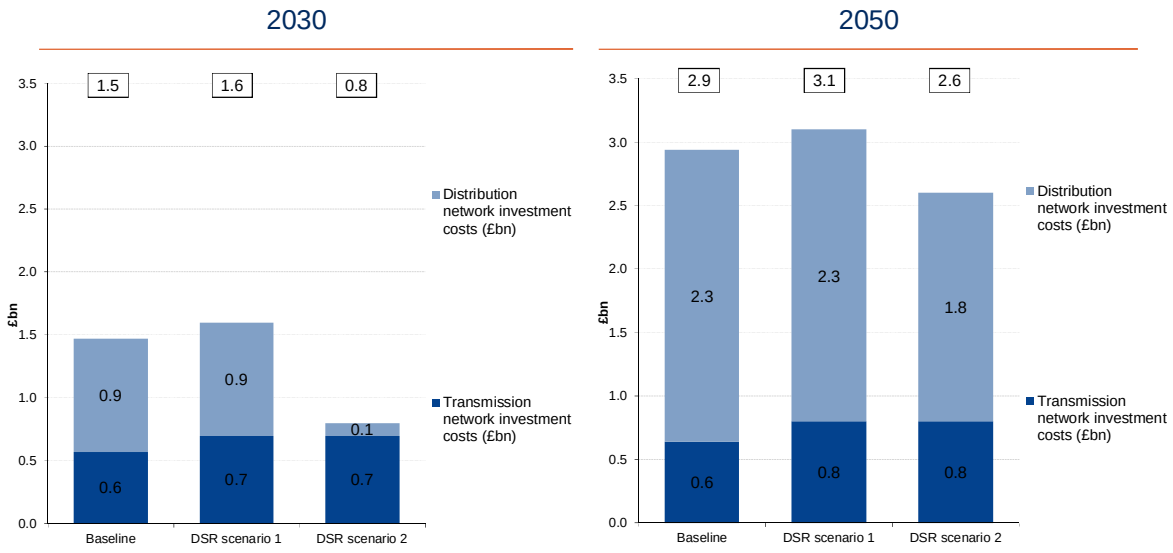


Figure 27 presents the costs associated with additional network investment to accommodate demand side response. Using demand side response to peak shave makes a relatively small difference in cost savings compared with total, but this is still a significant sum (£0.7 billion per annum in 2030 and £0.3bn in 2050). The chart also shows that using demand side response to balance wind results in an increase in network cost in both 2030 and 2050. This is based on an assumption of a distribution network cost

of 0.7-0.9 £ bn/GW installed resulting in a total cost of between £32 billion and £42 billion over the period from 2020.

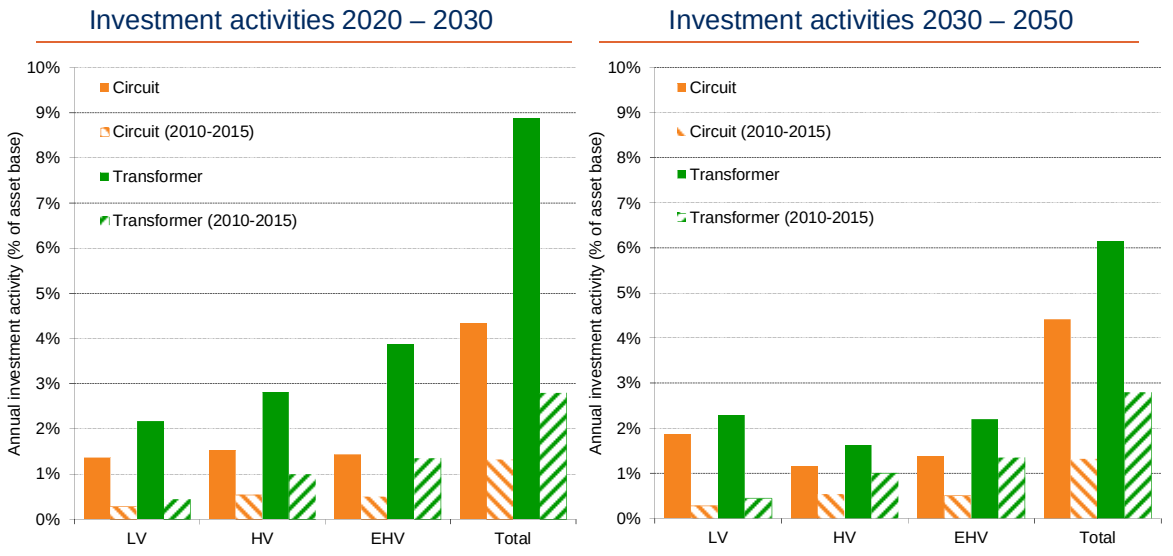
Figure 27 – Impact of DSR on network investment costs



4.3.8 *What impact does DSR have on distribution build rates?*

Investment activities of distribution networks measured as a percentage of their asset base would need to increase dramatically, this is shown in Figure 28 below (these charts assume network capacity is built to meet peak demand assuming no demand side response for the baseline scenario, therefore it is also applicable to DSR scenario 1).

Figure 28 – Distribution network investment activities 2020 - 2050



This is particularly true for the Low Voltage levels of distribution networks i.e. those to which residential consumers are connected, due to electrification of domestic heat and transport. For reference, the bars with diagonal hatching show the current anticipated investment activities for the 2010-2015 period. We have split out the investment required into 2 phases – 2020-2030 and 2030-2050. This suggests a more front heavy investment program is required to enable the distribution network to meet capacity requirements under the baseline scenario and DSR scenario 1.

4.3.8.1 Implications of overall distribution network build rate

Table 11 presents the average annual rate at which distribution network capacity must grow in order to achieve the network capacity levels in Figure 26. The data in Table 11 show a growth rate requirement of between 1.6% and 2.5% depending on the scenario.

Current growth rates of the distribution network are below 1%, and as such, these growth rates represent a substantial increase on the status quo. Therefore it is likely that to accommodate DSR, the distribution network will need to grow at a rate of 2-3 times its current rate of expansion to cope with peak demand. This has obvious knock-on implications for the amount of activity down to street level and the associated expansion of the supply chain.

Table 11 – Distribution network build rate required to meet 2050 network

	Additional distribution network capacity (GW/yr)	Growth rate (average additive % rate per year)
Baseline	1.8	2.3
DSR scenario 1	1.8	2.3
DSR scenario 2	1.2	1.6

Such overall network build rates are not unprecedented. In the 1970's the network build rate was approximately 7% per year. However, people were working with a smaller network making this an unreasonable expectation for the future percentage build rate against the larger distribution networks we have today.

Furthermore, we have discussed viability of build rates with a GB Distribution Network Owner, who indicated that the current network build rate is equivalent to 1% of current network capacity including asset replacement (implying a lower growth rate). They have indicated that they expect this rate to triple between 2020 and 2030 implying that an annual growth rate of approximately 2% (based against current network size on an additive basis) is not an unreasonable assumption. This has obvious implications for the amount of investment activity down to street level and associated expansion of the supply chain to provide supporting industry to ensure network. However, they believe the emerging clear message from the industry regarding the need for additional network capacity will send a clear signal to the supply chain to invest in more capacity (i.e. training new engineers and investing in suitable manufacturing capacity as required).

4.4 Conclusions

Although we have not conducted a full cost-benefit analysis of DSR: the following key findings can be drawn from our main scenarios:

- There is potentially significant value in enabling demand side response to meet the challenges of managing intermittent generation and electrification:-
  - A circa 10% reduction in our overall modelled electricity costs per annum were achievable amounting to a circa-£8bn economic benefit against DECC's Pathway Alpha;
  - DSR also largely eliminates potential wind curtailment and thus maximises the carbon benefits of intermittent zero carbon generation.
- Prioritising DSR to shave peak demand is the optimum in terms of overall modelled electricity costs by enabling the avoidance of distribution network and generation investments;
  - This would require DSR to be deployed as required across the top 10% of demand periods.
- However, the difference in pure economic benefits we modelled between prioritising DSR to peak shave rather than minimise production costs is relatively small (<1% i.e. c.£0.6bn) in the context of our overall modelled annual electricity costs.
- Given the collective scale of costs modelled it suggests that it may be pragmatic to build networks to meet peak demand without reliance (or at least limited reliance) on DSR; taking into account, for example, consumer impact issues.
- Regardless of the exact deployment of DSR at peak times, significant expansion and reinforcement of the distribution network will be required to meet peak demand by 2050; equivalent to a sustained level out to 2050 of circa 2-3 times the current level of distribution network investment. This has obvious implications for the amount of investment activity down to street level and associated expansion of the supply chain to provide supporting industry to ensure network.

5. SENSITIVITY CASES

5.1 Overview

We have developed two variant scenarios to test the sensitivity of our two main demand side response scenarios (see Section 4.2) to lower levels of intermittency and lower levels of electrification on the underlying modelling assumptions used in our scenario analysis. The approaches are described below:

- low intermittency – we assumed 2020 levels of wind and solar carry forward and that resultant displacement of zero carbon energy from wind and solar is replaced by nuclear; Sensitivity A – assess the impact on DSR scenario 1;Sensitivity B – assess the impact on DSR scenario 2;Sensitivity C – assess the impact on our baseline;
- low electrification – lower electrification of heat and transport ultimately leads to lower level of demand on the electricity network; Sensitivity D – assess the impact on DSR scenario 1;Sensitivity E – assess the impact on DSR scenario 2; and Sensitivity F – assess the impact on our baseline.

5.1.1 Headline messages from sensitivity cases

Based on our analysis we have derived the following key messages from the sensitivity analysis:

- Our sensitivity analysis shows that similar proportions of economic benefits (relative to overall modelled annual electricity costs) apply for deployment of DSR where either future levels of intermittent generation are lower or future levels of electrification are lower.
- Also the conclusions regarding choice of network investment strategy hold true for both lower levels of future intermittency and lower levels of future electrification than assumed under DECC's Pathway Alpha.
- Additional subsidy is required in order to support thermal generation.

In addition, under lower levels of future electrification of demand and high levels of intermittent generation; there is a particularly strong benefit from eliminating potential wind curtailment to maximise the carbon benefits of intermittent zero carbon generation

5.2 Low intermittency – Sensitivities A, B and C

This trio of sensitivities takes place within a future environment where zero carbon generation is largely delivered via nuclear generation and thus there are low levels of intermittent generation.

5.2.1 Description and assumptions

Table 12 below presents our assumptions for installed capacity under Sensitivities A, B and C. In this low intermittency world we have assumed that because there is no additional renewable capacity installed, as no binding targets for renewable energy are introduced post 2020. Hence additional intermittent generation (offshore and onshore wind and solar) does not attract investment. We assume that investment goes instead to

low carbon thermal generation that is deployed in order to meet 2050 carbon emissions targets.

Table 12 – Installed capacity for sensitivity cases (GW)

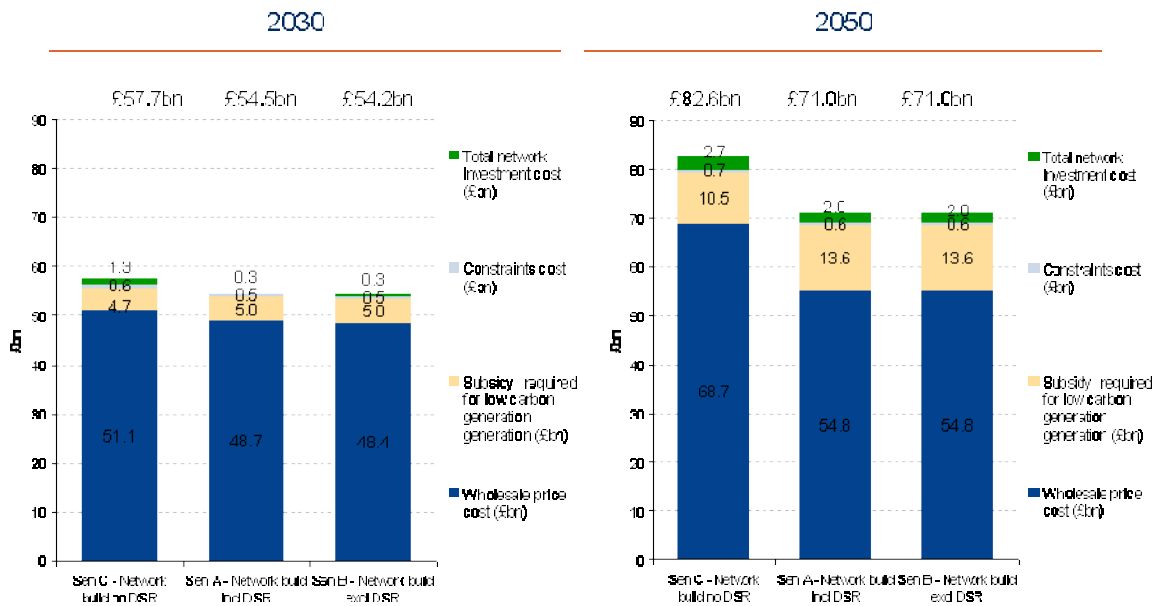
Installed capacity (GW)	2030	2050
Onshore wind	14.4	14.4
Offshore wind	16.0	16.0
Nuclear	33.6	62.4
CCS coal	10.0	39.0
CCGT	15.3	0.4
OCGT	24.7	6.5

Consequently wind generation capacity remains flat at c.30GW compared to c.60GW and c.90GW respectively under the DECC's Pathway Alpha assumptions used for our baseline scenarios. Furthermore there is no investment in solar generation compared to the c. 6GW and c. 70GW in 2030 and 2050 respectively in our baseline scenarios. Conversely nuclear capacity rises to 33.6GW in 2030 and 62.4GW by 2050 compared to c. 16GW and c.40GW in 2030 and 2050 respectively in our baseline scenarios.

5.2.2 Headline results for low intermittency cases

Figure 29 below presents the overall modelled electricity cost, split into the individual cost elements, for Sensitivities A, B and C in 2030 and 2050.

Figure 29 – Overall modelled electricity costs for sensitivities A, B, and C



The key finding is lower intermittency leads to a far smaller difference between using DSR for balancing or peak flattening.

Also by lowering the levels of intermittency the overall modelled electricity costs are lower compared to our DSR scenarios. The analysis suggests the sensitivities reduce overall modelled electricity cost by 7% compared to our original assumptions.

The main driver is a reduction in the subsidy required for low carbon generation, which offsets the increase in wholesale price costs. In 2030 the low intermittency scenarios have on average subsidy costs which are £7 billion lower while in 2050 the subsidy for low carbon generation is on average half the cost of our original scenarios.

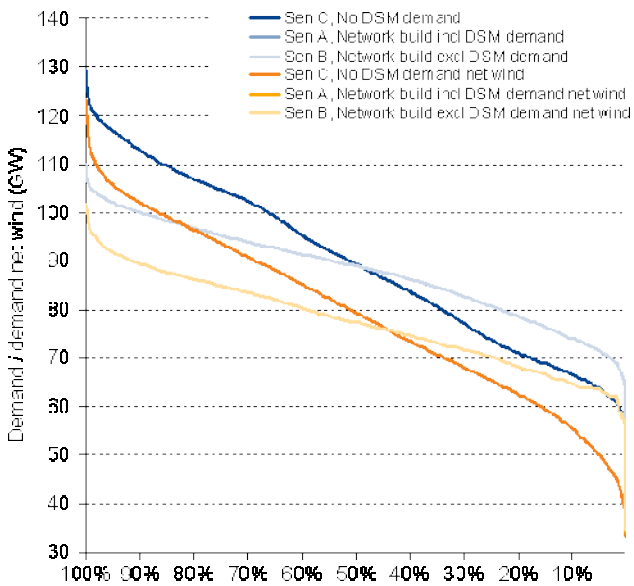
Three factors drive the lower subsidy requirement: firstly, higher average wholesale prices occur because of a reduction in installed capacity of intermittent generation. Secondly, load factors of thermal plant increase as there is less intermittent generation on the system driving periods where low carbon generation is displaced increasing revenue of low carbon generation. Finally lower subsidy payments are required to support intermittent generation.

The chart also highlights that there is very little difference between the peak shaving and wind balancing sensitivities (identical costs in 2050). Therefore, under this sensitivity the relative economic benefit of using demand side response to reduce network capacity versus balancing is very limited. However, overall modelled costs decrease with the introduction of DSR by 5-6% in 2030 and 14% in 2050, a greater reduction than when DSR is introduced under levels of high intermittent generation.

5.2.3 Demand

DSR still has a substantive impact on the annual demand load duration curve flattening it substantially. The same effect occurs for the annual demand net wind duration curve. However use of DSR to primarily reduce peak demand or instead to primarily minimise generation production costs has very little difference in impact on the overall demand and demand net wind curves (there is a very small different at the very highest demand levels). Figure 30 below illustrates these behaviours for 2050.

Figure 30 – Demand and demand net wind duration curves



5.2.4 Generation capacity

Table 13 shows the additional installed capacity required to meet demand in the low intermittency sensitivity cases. The reduction in intermittent generation and increase in firm nuclear capacity leads to a substantial reduction in the requirement for additional intermittent generation. As a result, there are significant savings on generation investment costs (£6 billion (annualised) in 2030 and £27 billion (annualised) in 2050).

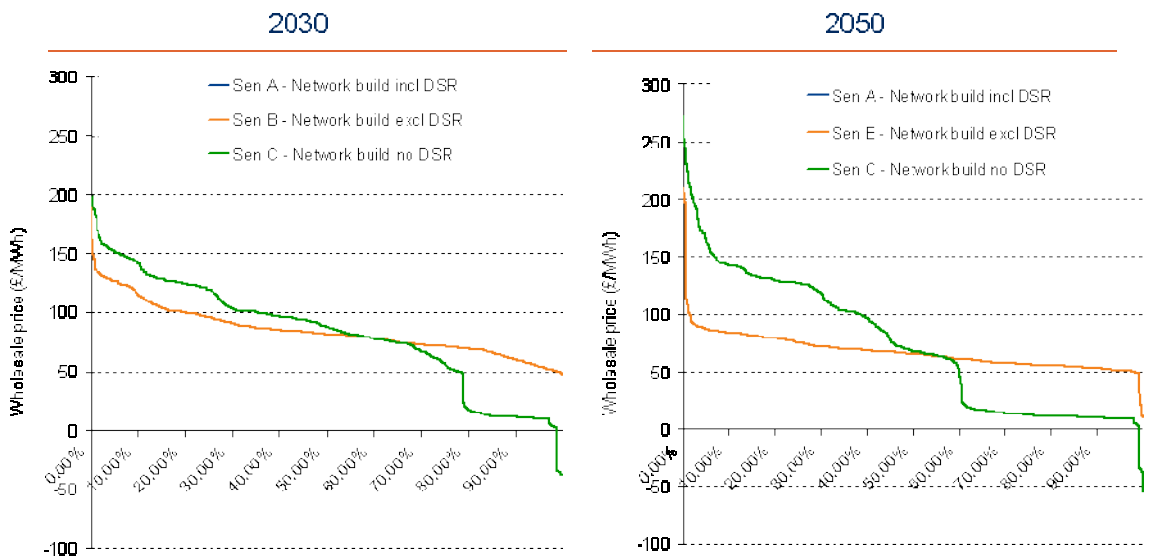
Table 13 – Additional installed capacity for sensitivity cases A, B and C

	2030		2050	
Scenario	CCGT	OCGT	CCGT	OCGT
Sensitivity A	0.00	11.80	0.40	6.50
Sensitivity B	0.00	11.80	0.40	6.50
Sensitivity C	1.40	21.20	6.50	15.00

5.2.5 Price duration curves

As for demand, deployment of DSR helps to substantially flatten the price duration curve but the use of DSR to prioritise either peak demand shaving or generation production cost minimisation does not create a material difference in the price curves. The key impact of the deployment of DSR is to all but eliminate zero and negative prices in the wholesale market and to keep high prices levels mostly below £100/MWh, especially by 2050.

Figure 31 – Price duration curves



5.2.6 Emissions

As expected in a scenario where the amount of no carbon intermittent generation is decreased (wind and solar), emissions go up. This is because despite the increase in nuclear capacity, due to the impact of its different running regime to intermittent wind

generation it replaces, non-zero carbon generation such as CCS and gas plant run more hours. As a result the cost associated with emissions goes up compared to all scenarios except the baseline. We can see that our previous conclusion that DSR reduces CO_2 emissions still holds, as this also reduces the requirement for thermal plant to run (by shifting demand to periods of high wind).

Table 14 – Carbon emissions and intensity for Sensitivity A, B and C

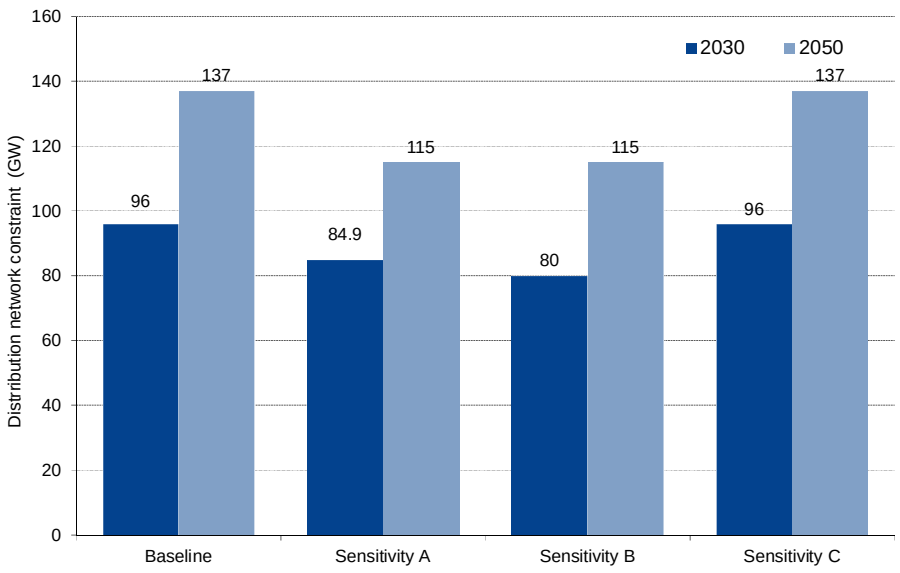
CO2 emissions (Mt CO2)	Baseline	Sensitivity A	Sensitivity B	Sensitivity C
2030	55.5	64.2	64.2	80.0
2050	21.4	16.1	16.1	30.1

CO2 intensity (gCO2/kWh)	Baseline	Sensitivity A	Sensitivity B	Sensitivity C
2030	94.2	36.6	36.6	45.4
2050	25.3	13.4	13.4	25.2

5.2.7 Network

Deployment of DSR substantially reduces network investment costs by reducing demand peaks. There is very little difference in demand peaks following use of DSR, whether DSR is specifically targeted at peak demand shaving or specifically targeted at production cost minimisation, as illustrated in Figure 32.

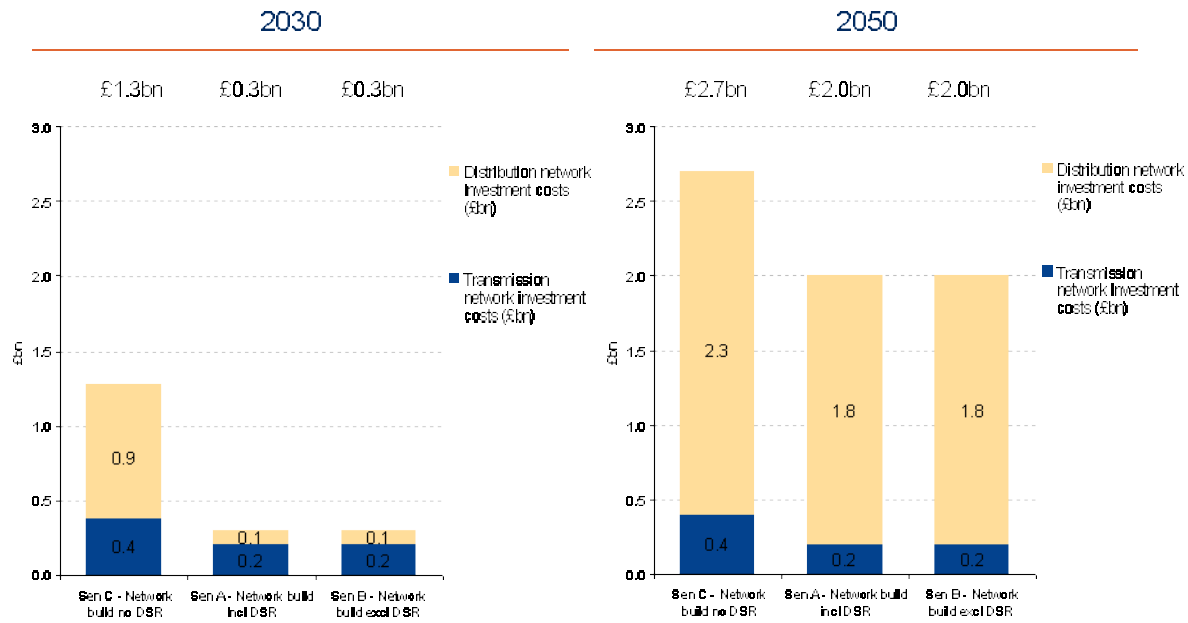
Figure 32 – Network capacity



Consequently there is no meaningful difference in network investment costs which arise between the two DSR scenarios in a low intermittency environment.

Figure 33 splits out the annual investment cost required to reinforce both the transmission and distribution networks to 2030 and 2050 respectively. Distribution network investment costs dominate total network investment costs in both scenarios due to a higher cost of reinforcement.

Figure 33 – Impact of DSR on annual network investment costs



5.3 Low electrification – Sensitivities D, E and F

This trio of sensitivities takes place within a future environment where electrification of transport and heat do not occur as rapidly as assumed under the DECC's Pathway Alpha which forms the basis for our baseline scenarios.

5.3.1 Scenario assumptions

In this section we introduce the lower demand sensitivity cases. The objective is to understand the impact the lower levels of electrification would have on the benefit of deploying DSR. In order to construct this scenario, we have used the DECC 2050 Pathways Report with the level of electrification for heat and transport at level 2 instead of level 3 under Pathway Alpha.

5.3.1.1 Fixed demand profile

Table 15 shows the total demand under the low electrification scenario. Comparing the total demand in Table 15 with that from the baseline in Table 2 shows that there is a reduction in overall demand of the order of 15% in 2030 and 16% on 2050 in the lower electrification scenario.

Table 15 – Demand under the low electrification scenario

TWh	2030	2050
Non residential	280.30	431.30
Domestic (non-heat)	82.60	93.40
Electric vehicles	17.50	37.80
Heat pump heating	27.10	44.40
Non heat pump heating	14.40	4.70
Cooling	9.30	12.10
Total	431.20	623.70

5.3.1.2 Flexible demand profile

Table 16 shows the amount of demand that is taken to be flexible in this scenario. This amount should be deducted from the total demand presented in Table 15 to give the remaining fixed demand profile.

In these scenarios, levels of flexible demand are reduced in comparison to the levels of flexible demand in the core scenario. In 2030 the lower demand scenario has 50% lower flexible heat pump demand, 4% lower flexible residential demand, and 45% less EV demand. By 2050, the scenarios separate further with a reduction of 58% of heat pump demand, and 4% lower flexible residential demand. Although demand for electric vehicles is approximately the same it should be noted that in this scenario the vast majority are PHEV (hybrid) vehicles, and not fully electric.

Table 16 – Demand under sensitivity cases D, E and F

TWh	2030			2050		
	Flexible heat	Flexible residential	Electric vehicles	Flexible heat	Flexible residential	Electric vehicles
Sensitivity D	20.7	5.8	13.2	24.3	8.1	28.4
Sensitivity E	20.7	5.8	13.2	24.3	8.1	28.4
Sensitivity F	0.0	0.0	0.0	0.0	0.0	0.0

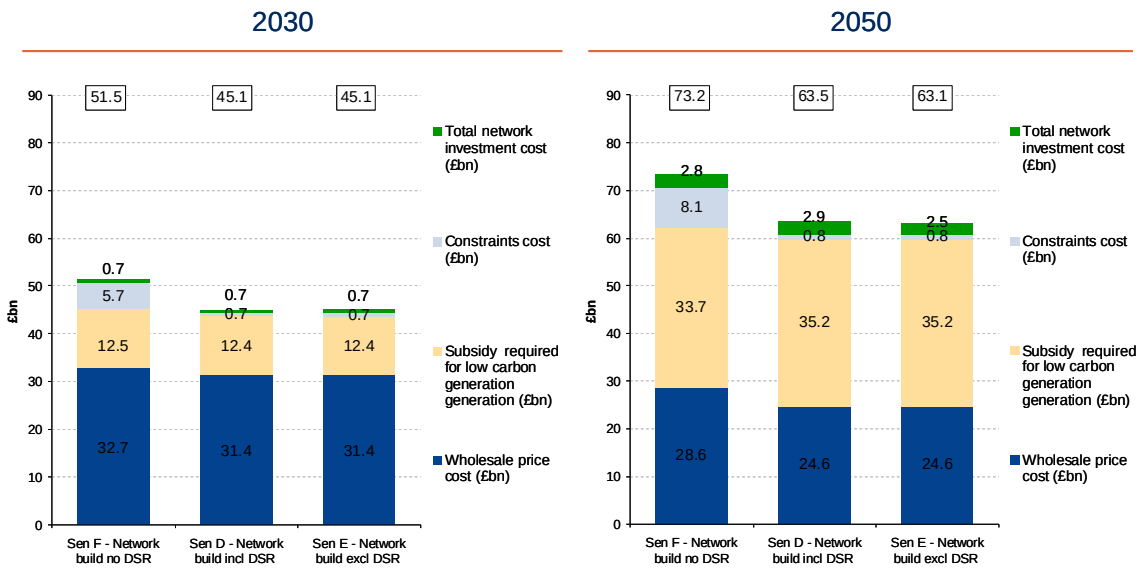
5.3.2 Headline results for low electrification case

Figure 34 below presents the overall modelled electricity cost, split into the individual cost elements, for Sensitivities C, D and E and the nuclear inflexibility in 2030 and 2050. The key finding is by lowering the levels of electrification there is a lower overall peak demand

and therefore a smaller network as well as also narrowing the gap between the 2 DSR scenarios in terms of network capacity.

he overall modelled electricity cost is clearly lower compared to our DSR scenarios. The analysis suggests the sensitivities reduce overall modelled electricity costs on average by 12% in 2030 and by 13% in 2050.

Figure 34 – Overall modelled electricity costs for sensitivities D, E, and F



The main driver is a decrease in the wholesale price cost which by 2050 is 50% lower than in our core scenarios. This is because lower demand levels lead to more occasions where demand is met by low cost intermittent generation. This is turn results in more low or zero price periods and as a result lower levels of wholesale market costs.

Counteracting the decrease in wholesale price cost is an increase in constraint costs and in 2050, additional subsidy costs. Constraint costs increase as this scenario contains the same level of intermittent generation as the baseline and DSR scenario 1 and DSR scenario 2, but has lower demand. This means that even with demand side response, there can sometimes be too much intermittent generation on the system.

By 2050, there is a significant increase in the subsidy that is required for low carbon generation to make a return on investment. This is mainly driven by lower overall demand meaning that there are more periods where wind either needs to be shed or where wind can meet demand. This means that nuclear and CCS plant does not get dispatched. The lost revenue for these plants needs to be compensated for by additional subsidy payments.

The obvious way to reduce the incurred subsidy costs would be for CCS capacity to be removed from the system, however, this has been deemed outside the scope of this study. Subsidy levels for intermittent generation remain the same as in the core scenarios as the same capacity of intermittent generation is deployed.

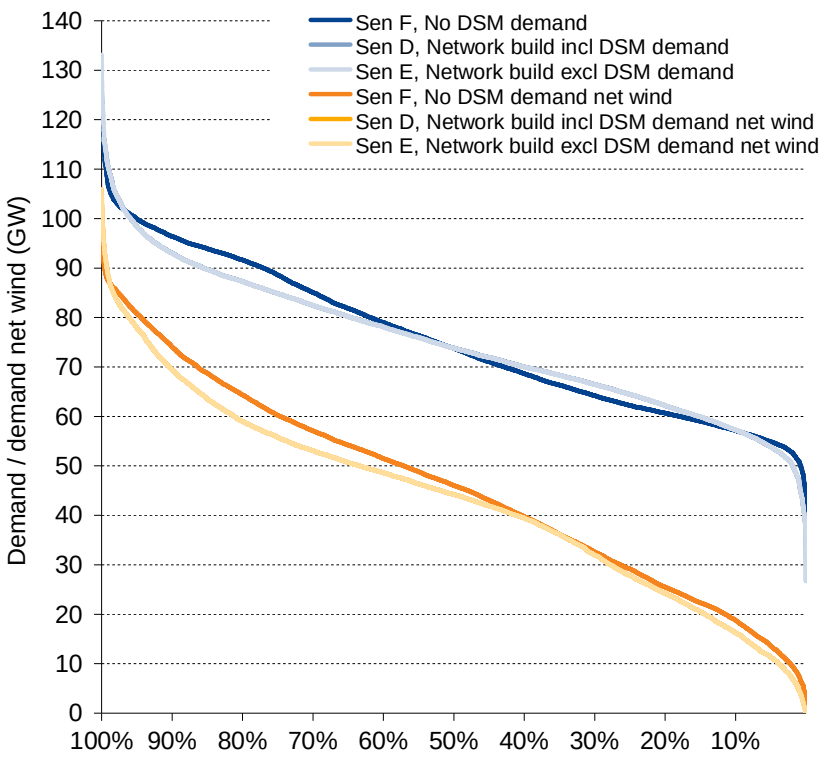
Finally, the chart also highlights that there is very little difference between the peak shaving and wind balancing sensitivities. However Sensitivity E, no demand side response, remains more expensive.

5.3.3 Demand

Under a future environment where there are relatively low levels of electrification of transport and heat, the overall demand duration curve is both lower and flatter than under our baseline scenarios. Furthermore as illustrated in Figure 38 below; the impact of DSR on the demand curve is much less substantial than for our baseline scenario. This reflects that fact that zero and low cost generation is able to meet most of the demand levels seen during a typical year; and thus:

- there is little value to be gained in optimising production costs; and
- it is only at the very highest of demand that difference between use of DSR for peak shaving versus a production cost minimisation arises.

Figure 35 – Demand and demand net wind duration curves



5.3.4 Generation capacity

As is to be expected in a future environment of less electrification than our baseline scenarios there is a reduction in required generation capacity required regardless of the deployment of DSR. Indeed the generation capacity requirements are less than assumed for DECC's Pathway Alpha which forms the starting point of our generation assumptions within our baseline scenarios.

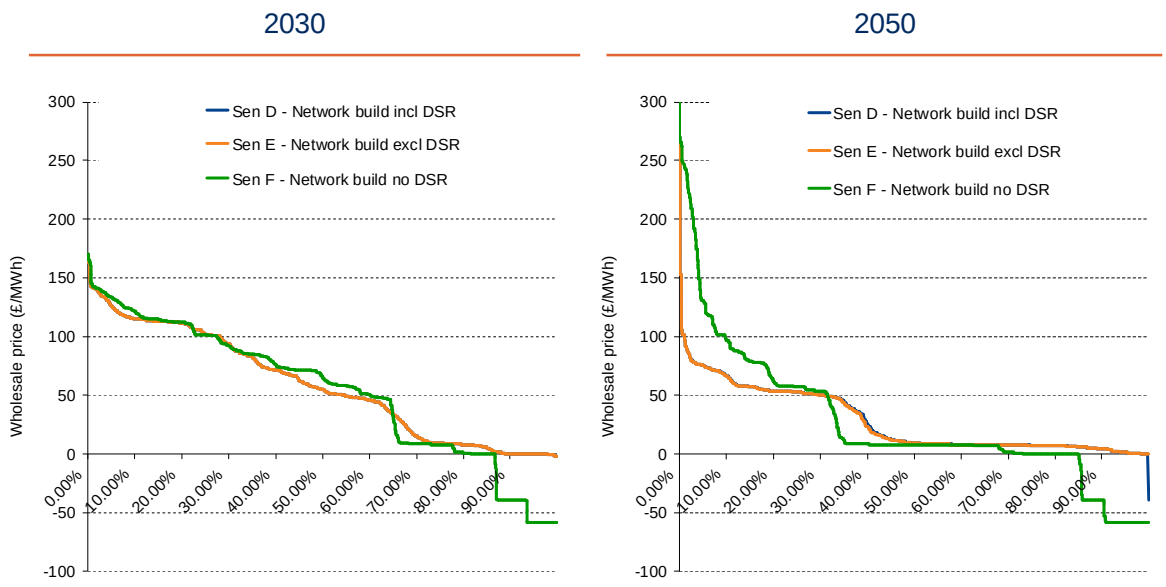
Table 17 – Additional capacity for sensitivity cases (GW)

	2030		2050	
Scenario	CCGT	OCGT	CCGT	OCGT
Sensitivity D	1.40	6.20	0.00	2.00
Sensitivity E	1.40	6.20	0.00	2.00
Sensitivity F	1.40	10.20	6.60	6.60

5.3.5 Price duration curves

The annual price duration curves in Figure 36 help to highlight why constraining DSR has more limited impact in an environment of less electrification than under the core scenarios. The price duration curve for 2030 without DSR is relatively flat and thus the value obtained from DSR is from boosting trough demand slightly to eliminate negative market prices created by curtailment of wind. There is greater convexity of the price duration curve in 2050 and thus deployment of DSR does have a more material flattening effect. For both future years there is very little difference in effect from deploying DSR with the two different emphases (peak demand shaving vs. generation production cost minimisation).

Figure 36 – Price duration curves



5.3.6 Emissions

As is to be expected under a lower electrification scenario overall carbon emissions are much lower than our baseline scenarios given the retention of high levels of zero carbon generation albeit much of it intermittent.

Table 18 – Carbon emissions and intensity for Sensitivity D, E and F

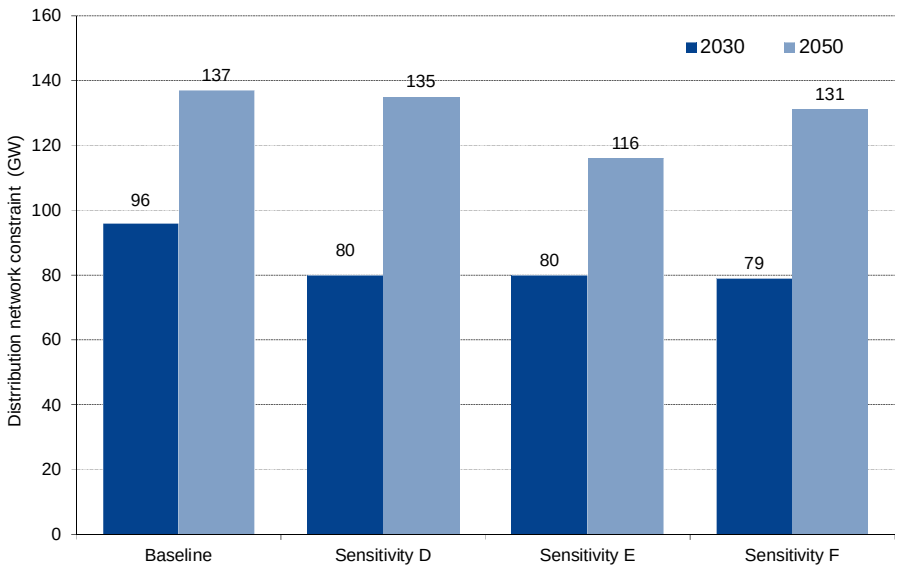
CO2 emissions (Mt CO2)	Baseline	Sensitivity D	Sensitivity E	Sensitivity F
2030	55.5	52.4	52.4	66.0
2050	21.4	8.3	8.3	13.0

CO2 intensity (gCO2/kWh)	Baseline	Sensitivity D	Sensitivity E	Sensitivity F
2030	94.2	25.9	25.9	32.2
2050	25.3	6.0	6.0	9.2

5.3.7 Network

As expected, lower demand leads to lower peak demand and as a result less additional network investment cost compared to the baseline. Given the lower levels of demand, but the original network constraints, DSR has the ability to shift demand around more freely in Sensitivity D, therefore we see that DSR actually has the effect of boosting the peak over and above that seen in Sensitivity F. This is a similar result to DSR scenario 3 in Annex B, and is explained by the fact that demand peaks are not necessarily the price peaks – therefore using DSR to reduce price peaks can increase demand peaks[16]. The result is a difference in demand peaks between Sensitivity D and Sensitivity E (as illustrated in Figure 37).

Figure 37 – Distribution network capacity required under low demand sensitivities



The additional costs of investment for both the transmission and distribution networks are shown in Table 19. Lower levels of demand mean that there is a less need for reinforcement of the distribution network beyond 2020 levels. However, as investment in the transmission network is dependent on reinforcements across National Grid zones,

16 This issue is highlighted in Figure 6 and the supporting text on pages 14-15 of this report

investment is also dependent on the location and capacity of intermittent generation, which is the same as in the core DSR scenarios.

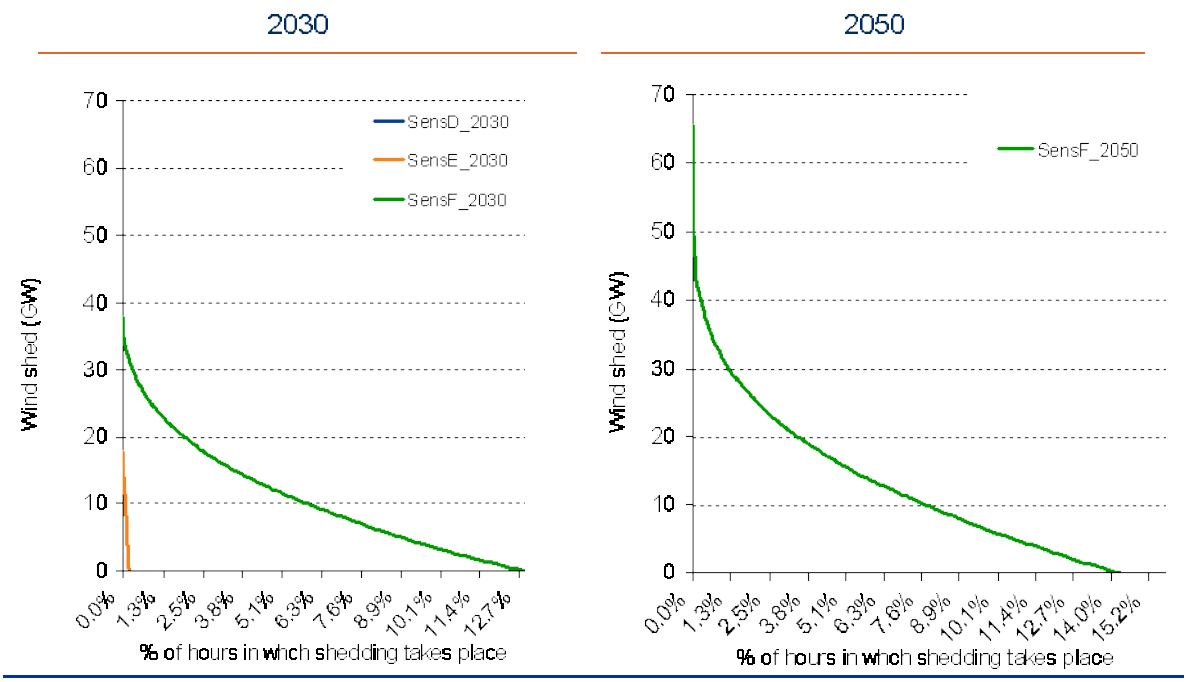
Table 19 – Impact of DSR on network investment costs

£bn	2030		2050	
	Transmission network investment	Distribution network investment	Transmission network investment	Distribution network investment
Sensitivity D	0.60	0.10	0.70	2.20
Sensitivity E	0.60	0.10	0.70	1.80
Sensitvity F	0.50	0.10	0.70	2.10

5.3.8 *Wind curtailment*

As is to be expected in a future environment where there is the same level of intermittent wind generation but a much lower level of demand than our baseline scenarios; there is substantial wind curtailment when no DSR is deployed. Thus utilisation of DSR provides a major benefit in largely eliminating wind curtailment.

Figure 38 – Wind curtailment duration curves



5.4 Conclusions

The sensitivity analysis reaffirms our key conclusions for deployment of DSR in the electricity sector:

- Our sensitivity analysis shows that proportionate economic benefits (relative to overall modelled annual electricity costs) apply for deployment of DSR where either future levels of intermittent generation are lower or future levels of electrification are lower than under our baseline set by DECC's Pathway Alpha.
- Also the conclusions regarding choice of network investment strategy hold true for both lower levels of future intermittency and lower levels of future electrification than assumed under DECC's Pathway Alpha.

Our sensitivity analysis suggests that whilst the numbers may vary these conclusions hold true for both lower levels of future intermittency and lower levels of future electrification than assumed under our baseline scenarios aligned to DECC Pathway Alpha. Furthermore:

- Lower intermittency leads to a far smaller difference between using DSR for balancing or peak flattening.
- Lower electrification leads to a lower overall peak demand and therefore a smaller network as well as also narrowing the gap between the 2 DSR scenarios in terms of network capacity.

In addition, under lower levels of future electrification of demand and high levels of intermittent generation; there is a particularly strong benefit from eliminating potential wind curtailment to maximise the carbon benefits of intermittent zero carbon generation i.e. DSR reduces otherwise high levels of wind curtailment.

Subsidy levels decrease when levels of intermittent generation are reduced as the number of low or zero price periods are reduced. Conversely under the low electrification scenario, the required subsidy increases as the relatively high levels of intermittent generation in Pathway Alpha are projected onto a system with lower demand.

Although it is outside the scope of this study to rebalance the generation mix, these results suggest that the generation mix in Pathway Alpha could be re-balanced to give a lower overall cost. In addition, the sensitivity analysis adds to the case, suggesting that coal CCS will struggle to make an adequate return on investment in a world where there is significant deployment of nuclear plant and intermittent generation regardless of whether or not DSR is deployed without support in the form of a subsidy.

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ANNEX A – ASSUMPTIONS

A.1 Overview

This section presents the input assumptions that we have used in the process of modelling the DSR scenarios. The assumptions are split into two main sections: those that are common to all DSR scenarios and those which are adopted for specific scenarios.

Data is used to characterise a source of flexibility and to build a scenario for running through our *Zephyr* model. Our assumptions are based on Pathway Alpha from the DECC 2050 Pathways Report which provided us with assumptions in terms of electricity demand; fuel prices and generation costs were combined with initial views on the installed capacity mix.

Our assumptions can broadly be categorised as demand, generation mix, transmission, distribution, border and interconnection and costs.

Table 20 – Overview of common and scenario specific assumptions

	Common assumptions	Scenario specific assumptions
Generation capacity mix	Baseline capacity from DECC Pathway Alpha	Peaking plant and CCGT as required to balance system
Costs	Assumptions agreed with DECC	None
Demand	Total demand taken from DECC Pathway Alpha Demand profiles from Pöyry work for the CCC and ENA report	Volume of flexible demand
Transmission network	Baseline capacity from ENSG Gone Green	Assumed that investment to relieve constraints occurs
Distribution network	Baseline 2020 scenario	Capacity varies by scenario
Interconnection	Interconnection between GB and the SEM, and GB and NWE	None

We have used DECC assumptions (based on data sourced from a study undertaken for DECC by Mott MacDonald entitled 'UK Electricity Costs Update') for generation plant characteristics where possible to ensure consistency with other work being undertaken by the department. In the remaining cases, we have used our own assumptions derived from our experience in modelling GB electricity markets.

A.1.1 Caveats

For our scenario analysis we have assumed a number of caveats and assumptions to ensure realistic deployment of technologies in the modelling. These caveats are provided below:

- We assume that the transmission network build economically balances network vs. constraint costs using values from National Grid SQSS review.
- While we have modelled storage and interconnection, detailed analysis of extra storage and interconnection is outside the scope of the project. Therefore other solutions to mitigate the impact of intermittent generation, such as interconnection, flexible generation and energy storage could also be required in the future. While we have included some of these technologies in our analysis, we have not assessed their deployment trajectory in detail as part of this study.
- We have not sought to rebalance generation mix i.e. re-optimisation based on plant IRR's.
- Distribution network are costs built up from relevant aggregation of urban, semi-urban and rural network models using current asset costs.
- We have sought to minimise changes between scenarios in order to understand drivers of differences in results.
- The value of 1 ROC is assumed to be £39.5/MWh, and banding for relevant technologies is as per current Ofgem guidelines.
- In cases where required, we have calculated the subsidy payment required to allow low carbon generation such as nuclear and coal CCS to make a suitable return on investment.
- We have not undertaken a full cost benefit analysis of DSR i.e. we have not included the implementation cost of demand side management systems e.g. ICT equipment etc.
- The modelling in this study is based on the rational use of demand side response, in which we assume consumers have no ability to override the decision to deploy the demand side response. However, we assume that only a proportion of demand is flexible, therefore not all customers would be responding.

A.2 Common scenario assumptions

- Generation plant characteristics – technical and economic plant assumptions in the reference cases were based on assumptions provided by DECC.
- Electricity demand – annual electricity demand (TWh) provided by DECC with demand profiles based on Pöyry analysis.
- Transmission and distribution network common assumptions.
- Border assumptions – these can take two forms, either exogenous assumptions about flows which will then affect prices within *Zephyr* or assumed border prices,

which will then be used in the optimisation process to determine flows. We used the first approach for the interconnectors with the SEM and with NW Europe.

- Fuel and carbon prices – based on assumptions produced by DECC.

A.2.1 Fuel and carbon costs

We have used DECC assumptions for fuel and carbon prices where possible to ensure consistency with other work being undertaken by the department. Where DECC does not produce data, we have sourced data from other government departments. The list below sets out these assumptions:

- Wholesale fuel prices (gas, coal, oil) are taken from Pathway Alpha within the DECC 2050 Pathways Report. This data projects prices out to 2030. Post 2030 prices are maintained at 2030 levels.
- Petrol price assumptions are taken from the Department for Transport road fuel price forecasting model. These prices are consistent with the DECC fossil fuel price assumptions.
- Carbon prices are based on DECC data published in July 2009. These prices assume a carbon price of £70/tCO2 in 2030 increasing to £200/tCO2 in 2050
- Exchange rates are equivalent to those used in the DECC energy model: 0.89£/€ and 1.57$/£.

Table 21 – Fuel and carbon prices

	2030	2050
Biomass (£/GJ)	3.2	3.2
Gas (£/GJ)	7.1	7.1
Coal (£/GJ)	3.1	3.1
LSFO (£/GJ)	10.8	10.8
MDFO (£/GJ)	19.2	19.2
Carbon dioxide (£/tonne)	70.0	200.0

Source: DECC

A.2.2 Demand plant characteristics

We have assumed 1 GW of voluntary demand side response which is equivalent to allowing industrial users to reduce demand for processes in periods of high system demand. This is separate from demand that is classified as flexible demand. This

assumption is consistent with recent studies for the CCC, with the following price-quantity combinations[17]:

- 760 MW reduction at 100 £/MWh;
- 170 MW reduction at 200 £/MWh; and
- 60 MW reduction at 500 £/MWh.

For each end-use, we have made an assumption about the magnitude of movable demand for each year. The amount of inflexible demand will then be adjusted to ensure the ex-ante sum of inflexible and movable demand (before fuel switching and storage losses) is consistent with total annual demand for each category in the reference cases.

A.2.3 Demand-side modelling

Demand profiles can be split into fixed demand profiles and flexible demand profiles.

A.2.4 Fixed demand profiles

We split demand into the following profile groups, which map onto the breakdown of annual demand:

- residential (excluding heat and electric vehicles);
- non-residential (excluding heat and electric vehicles);
- direct electric heating;
- air source heat pump;
- ground source heat pump; and
- electric vehicles.

Fixed demand profiles have been constructed for use in the scenarios based on data from Pathway Alpha in the DECC pathways model – these are then modified in each of the scenarios through changes in flexible demand in the modelling process. This means that the fixed demand profiles are designed to provide a baseline against which increased flexibility can be provided.

Heat pumps were modelled using different coefficients of performance depending on the type of pump and whether it was used for water or space heating (COPs of ASHP and GSHP for water and space heating are equal to those assumed in the DECC pathways work).

The split between water and space heating demand was taken from the DECC 2050 Pathways Report for Pathway Alpha. We also assumed that all new homes fitted with air source heat pumps or ground source heat pumps for space heating had under-floor heating and therefore follow a fixed demand profile.

Demand for space heating is much more seasonal than the demand for water heating, because it is more strongly linked to external temperatures. Therefore, the profile of heating demand across the year will be affected by the mix of space and water heating, which will itself be influenced by relative improvements in energy efficiency for each type

17 Figures are based on 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices', Global Insight, 2005.

of heating. For example, if relatively greater energy efficiency improvements are made in space heating than in water heating, there would be a fall in the share of heating demand related to space heating.

The profile for electric vehicle charging was taken from work undertaken for the Electricity Networks Association.

A.2.4.1 Flexible demand

In this study, *Zephyr* was used to model active demand-side units by splitting them into three categories –residential washing units, heating, and electric vehicles. For each category, we made an assumption about the magnitude of movable demand for each year. The amount of inflexible demand was adjusted to ensure the ex-ante[18] sum of inflexible and movable demand (before fuel switching and storage losses) was consistent with total annual demand for each category in the reference cases.

The flexible demand was allocated to a number of different units, as summarised in Table 23. These assumptions and constraints were then used by *Zephyr* to optimise the operation of these demand-side units, with the restriction that the underlying profile of energy demand must be met. For units with storage (heating and transport), this restriction was implemented by reducing the amount of electricity in storage in line with the underlying energy demand profile.

Table 22 – Levels of flexible demand under each scenario

TWh	2030			2050		
	Flexible heat	Flexible residential	Electric vehicles	Flexible heat	Flexible residential	Electric vehicles
DSR scenario 3	83.9	6.0	32.2	113.3	8.4	38.4
DSR scenario 1	42.0	6.0	24.2	56.7	8.4	28.8
DSR scenario 2	42.0	6.0	24.2	56.7	8.4	28.8

18 i.e. before any adjustments made to electricity demand from fuel switching and storage losses as part of the optimisation process in *Zephyr*.

Table 23 – Modelling assumptions and constraints for active demand units

Type of demand-side unit	Energy demand profile	Charging rate	Availability for charging/electricity demand	Minimum on time	Storage capacity	Minimum storage levels	Rate of energy loss in storage	Fuel switching capability	Returning electricity to the grid
Residential washing appliance	Daily energy demand must be met	Determined by energy demand as no storage capability	Defined 12 hour period (overnight or during the day)	2 hours (length of cycle)	No storage capability assumed	No	No storage assumed	No	No
Heating	Heating demand profile	Capacity can be filled in about 4 hours	All times	None (beyond hourly resolution of model)	Based on 25-30 hours of average demand	No	1% per hour	variable cost of gas if back-up boiler	No
Electric vehicles	Flat with three user categories (high, medium and low)	Battery filled in 4-5hours for dedicated EV, 3-5hours for hybrid	Three periods – overnight, daytime or 24 hour	None (beyond hourly resolution of model)	Battery range of 100-120km for dedicated EV; 60km for hybrids	By end of charging period, have 1.5 days of average use	No losses	Determined by variable cost of petrol (inc CO_2) if hybrid car	At 50% of charging rate; round trip efficiency of 75% (EV) and 50% (PH)

A.2.5 Distribution network assumptions

For consistency with existing network investment the cost of network assets for all EHV, HV and LV systems have been taken from those used to determine Ofgem's DPCR5 final proposals. The unit cost in these estimates includes both the asset cost and other related costs, such as communication requirements and civil works.

At the distribution level the GB demand is split into urban, semi-urban, and rural areas based on the energy supplied in each area and its population density. Detailed statistics taken from DUKES (2008) provide information on electricity consumption in each local service area (town/city) for domestic and non-domestic customers.

When combined with population densities for these areas, and per capita demands and load factors for each customer class, load densities in terms of MW/km^2 can be established. Service areas having a load density less than 0.5 MW/km^2 are designated as rural areas, those with load densities of 0.5 – 2.0 MW/km^2 are designated semi-urban, and those with load densities greater than 2 MW/ MW/km^2 are defined as urban areas.

The topographical network classification enables the allocation of new load to different voltage levels for the purpose of determining the necessary system capacity in 2030 and 2050. Each type of area will have different proportions of domestic, commercial and industrial customers. Responsive EV demand is attributed solely to domestic customers who are connected at LV, responsive HP load is shared by both domestic and commercial customers, whilst the electrification of industrial processes will impact all three voltage levels in the relevant networks albeit in differing proportions.

Figure 39 show the energy and capacity share between the three sectors at 2020, 2030 and 2050.

Figure 39 – Energy and capacity share between the three sectors

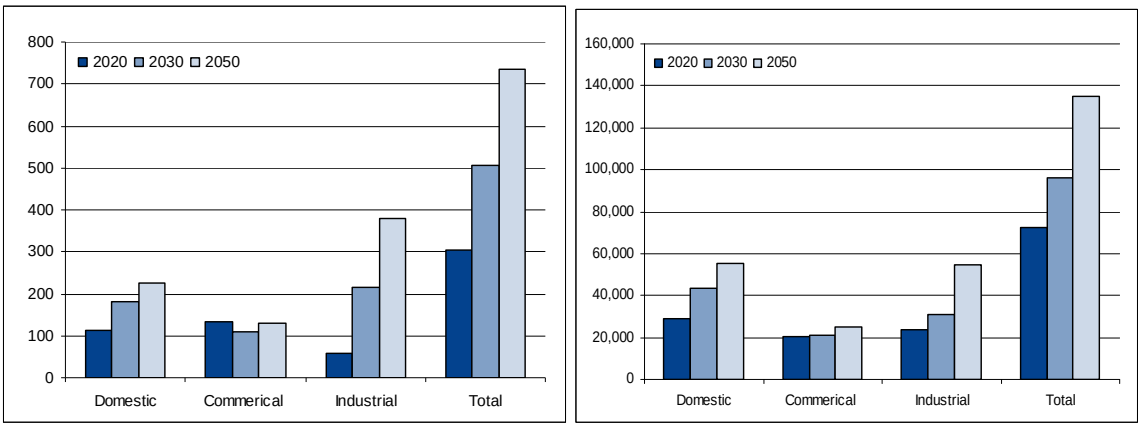


Figure 40 shows the energy and capacity share between urban, semi-urban and rural at 2020, 2030 and 2050.

Figure 40 – Energy and capacity share between urban, semi-urban and rural

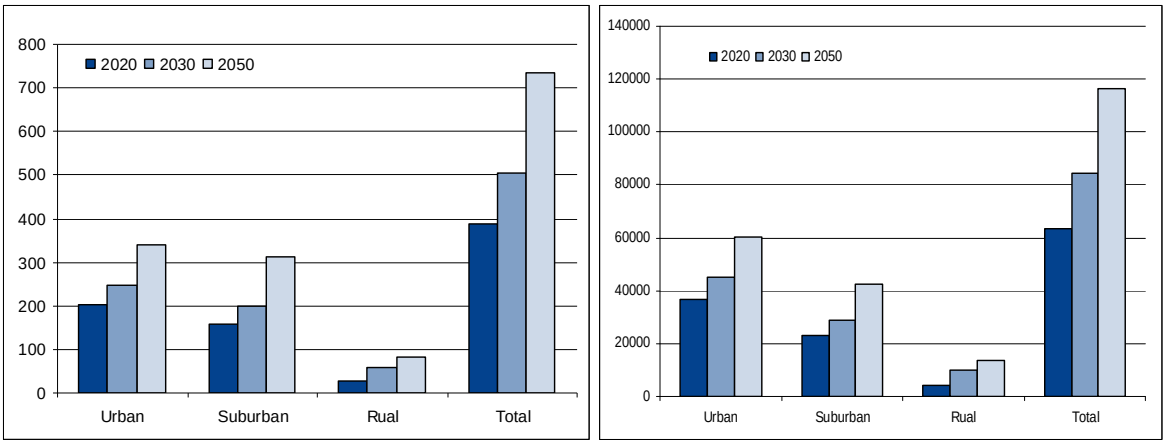
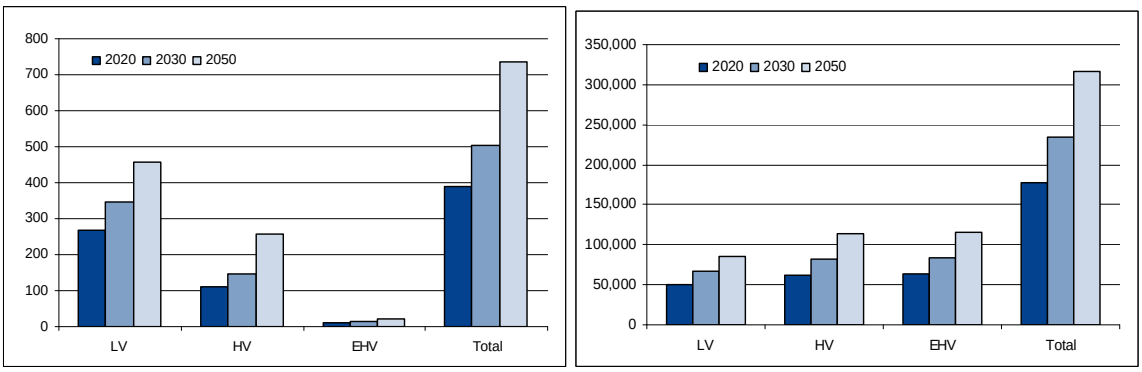


Figure 41 shows the energy and capacity share between LV, HV and EHV at 2020, 2030 and 2050

Figure 41 – Energy and capacity share between LV, HV and EHV



The levels of generation connected to the distribution network are based on pathway Alpha.

Based on assumptions under pathway Alpha we assumed that the levels of distributed generation remain at current levels with the exception of solar generation, which is assumed to increase significantly

A.2.6 Transmission network assumptions

We use estimates of (i) transmission investment costs for MW capacity increase across constrained transmission boundaries and (ii) transmission constraints costs per MWh of constraint volume across constrained transmission boundaries drawn from various sources.

The baseline transmission network capacity is taken from ENSG Gone Green Scenario 5c (11.4GW wind in Scotland) and the from the National Grid seven year statement while

data covering boundary depth was taken from the DECC costing note (the assumptions are set out in Table 24).

Although exact costs of reinforcement are expected to vary, we have assumed a value of £100/MWkm based on the SQSS review. We have set the cut-off to be 2% of annual energy.

Table 24 – Assumptions for transmission network modelling

Boundary number	Boundary name	Boundary capability (MW)	Boundary depth (km)	Reinforcement cost (£/MWkm)	Constraint cost (£/MWh)
1	SHETL North West	1,100	120	100	90
2	SHETL North South	2,750	120	100	90
3	SHETL Sloy	500	60	100	90
5	SPT North South	3,700	120	100	90
6	SPT NGET	5,500	150	100	90
7	NGET Upper North	7,500	150	100	90
8	NGET North to Midlands	10,600	93	100	90
9	NGET Midlands to South	9,000	155	100	90
13	NGET South West	3,000	160	100	90
15	NGET Thames Estuary	5,500	60	100	90

A.2.7 Border assumptions

Any model must have a geographical boundary, beyond which assumptions must be made about the operation of the 'outside world'. *Zephyr* was developed to cover Great Britain and Ireland. However, for this project, we limited the modelling to Great Britain in line with the project specification. Therefore, we had to make border assumptions for input into *Zephyr* with respect to

- the Single Electricity Market in Ireland (SEM),

- the CWE market covering North West Europe **(**NWE) including the markets of France, Netherlands and Belgium.

There are three key components to the modelling of the interconnectors – capacity, flexibility of operation (on an hourly basis) and determinants of flow (both direction and magnitude).

In all reference cases and flexibility packages, it is assumed that there are no technical restrictions of the ability of the interconnector to operate flexibly on an hourly resolution (i.e. it can swing freely from hour to hour).

A.2.7.1 Capacity

In all four reference cases, there was assumed to be 3GW of interconnection between GB and NWE, and 1GW of interconnection between the GB power market and the SEM. This was based on existing links and projects under development, such as the BritNed interconnection between GB and the Netherlands.

The 'imported flexibility' package is the only one in which capacity of the interconnectors is assumed to be increased, with the capacity reaching 3.95GW (in both 2030 and 2050):

- SEM – 0.95GW; and
- NWE – 3GW.

A.2.7.2 Determination of interconnector flows

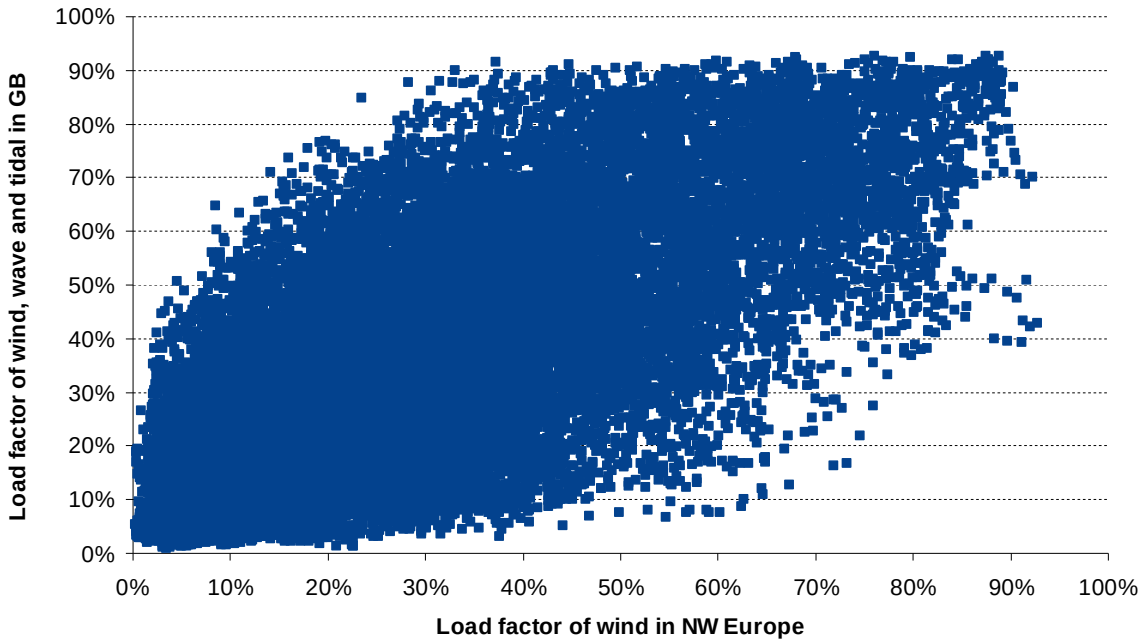
This can take two forms – either flows are determined before the *Zephyr* optimisation process and are used effectively as an exogenous input or assumed border prices are used by *Zephyr* to optimise flows. We used the first form for the interconnectors with SEM and NWE.

The flows across the interconnectors with SEM and with NWE are assumed to be driven by differentials in the wind load factor between GB and the relevant market. This reflects the fact that although the precise capacity mix in 2030 and 2050 is not modelled, swings in wind are assumed to be an important determinant of supply-demand balance in these areas.

This means that, for example, when ‘wind load factor’ is higher in GB than in the SEM, GB will export to the SEM. Consequently, these two interconnectors can only provide limited flexibility for the GB system – they are responsive only to wind and not to demand net wind. In addition, if wind is high in GB but higher in the foreign zone, then the interconnector will flow into GB exacerbating a potential over-supply. This means that additional capacity only helps to the extent that the flows were already helping to balance the wind. The flows are constrained so that over the year, imports equal exports on each interconnector.

Figure 42 shows the extent to which wind load factors in GB are correlated with those in NWE. A negative correlation would offer the most scope for flexibility so the pattern in Figure 42 suggests that the NWE interconnector would only provide limited flexibility, and could even make things worse at times.

Figure 42 – Correlation of wind load factors in Great Britain[19] and NW Europe



Source: Wind data for GB based on Met Office data, NWE wind data based on Anemos data

A.3 Scenario specific assumptions

In this section we set out those assumptions with vary across each of the six DSR scenarios.

A.3.1 Changes in flexible demand

Table 25 shows the levels of flexible demand assumed under each of the DSR scenarios. The table splits this demand into three categories:

- Heating demand (composed of space and water heating for domestic and commercial buildings);
- Electric vehicles; and
- Residential electricity demand.

These levels are increased / decreased depending on the level of demand side response assumed within each scenario, with the baseline, DSR scenario 3 and DSR scenario 4 showing the impact of 100% demand side from HP and EV's response compared to 0% and DSR scenarios 1 and 2 assessing the impact of a lower deployment of demand side response i.e. 50% of HP demand is flexible and 75% of EV demand is flexible.

19 Load factor for GB wind based on mix of offshore and onshore wind capacity in 2030 and 2050.

Table 25 – Levels of flexible demand under each scenario

TWh	2030			2050		
	Flexible heat	Flexible residential	Electric vehicles	Flexible heat	Flexible residential	Electric vehicles
Baseline	0.0	0.0	0.0	0.0	0.0	0.0
DSR scenario 1	42.0	6.0	24.2	56.7	8.4	28.8
DSR scenario 2	42.0	6.0	24.2	56.7	8.4	28.8
DSR scenario 3	83.9	6.0	32.2	113.3	8.4	38.4
DSR scenario 4	83.9	6.0	32.2	113.3	8.4	38.4

ANNEX B – TESTING SCENARIOS

B.1 Supporting scenarios

We have investigated two supporting scenarios to reinforce conclusions drawn from the core scenarios.

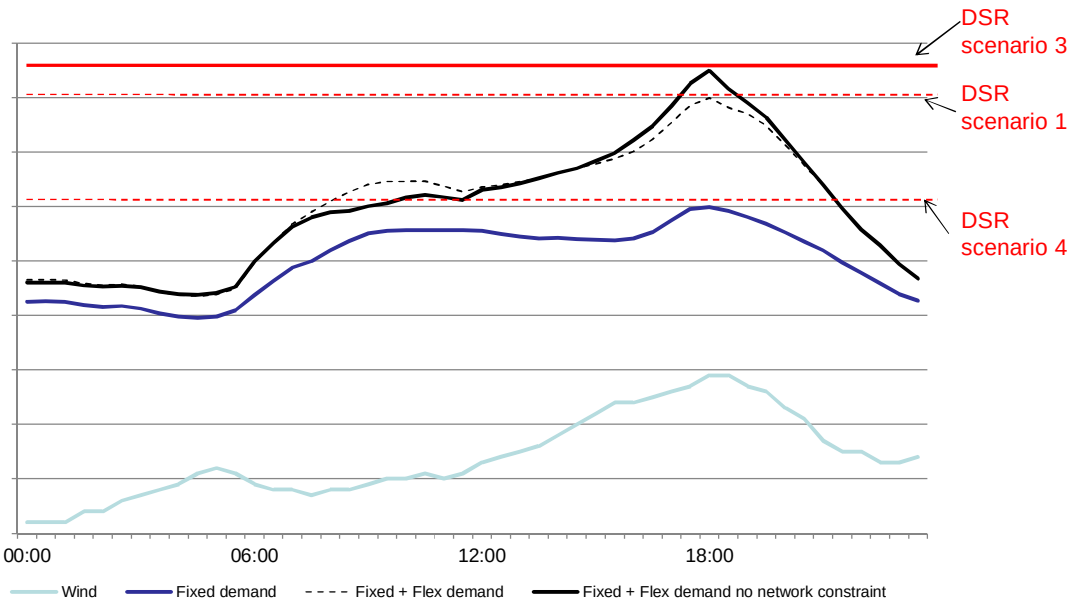
- DSR scenario 3 – unconstrained DSR: where DSR is allowed full rein and the network is built to cope; and
- DSR scenario 4 – network constrained DSR: where DSR is deployed but the network is not improved beyond 2020 levels.

The following section introduces the scenarios, with the results presented in Annex D.

B.1.1 Extreme DSR scenarios

Through these two scenarios we have modelled the impact of allowing maximum deployment of demand side response. These two network scenarios are shown in Figure 43.

Figure 43 – Maximum DSR, varying network build



DSR scenario 3 and 4 assumed demand side response deployment is unrestricted with varying levels of network build.

- In DSR scenario 3 – we allow full deployment of demand side response to reduce wholesale costs while allowing unrestricted network build to ensure there are no limits placed on the deployment of demand side response for this purpose.

- In DSR scenario 4 examines the impact where demand side response is applied to peak-shave sufficiently to minimise network capacity to the point at which it is still viable to enable demand to be met by economic generation (at a transmission level).

ANNEX C – WIND AND DEMAND INTERACTIONS

C.1 Overview

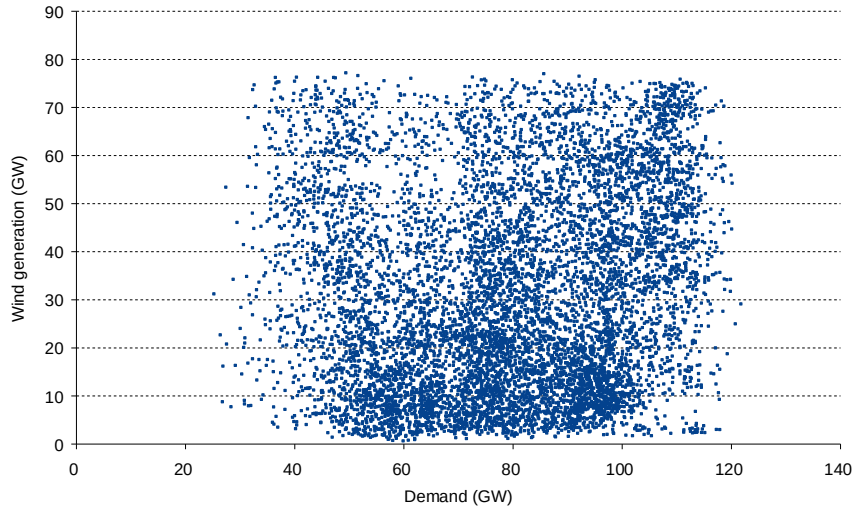
This section presents a brief overview of the interactions between wind and demand and how DSR influences these interactions. We have used our baseline and the testing scenarios (DSR scenario 3 and DSR scenario 4) to illustrate the findings.

This section clearly shows that DSR reacts to intermittent generation by reallocating demand to periods of high intermittent generation (avoiding periods where demand is less than intermittent generation) and DSR also reduces the variation in demand net wind which reduces the requirement on thermal plant to accommodate intermittent generation.

C.1.1 How correlated are wind and demand

Figure 44 plots wind and demand (no DSR) for a sample year (2000) in 2050. The figure illustrates that there is relatively little correlation between wind and demand, leading to the conclusion the point that wind cannot be consistently relied on to reduce demand at peak.

Figure 44 – Correlation of wind and demand (2050 with weather of 2000)



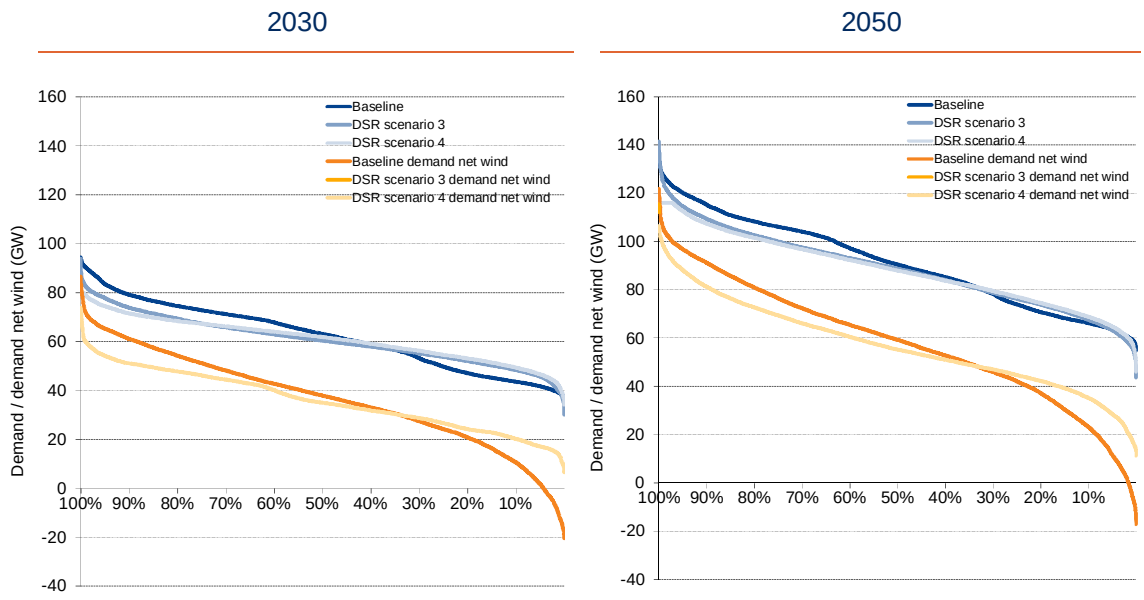
C.1.2 What impact does DSR have on demand and demand net wind profiles?

Figure 45 represents the demand and demand net wind duration curve for the GB market in 2030 and 2050. The diagram plots the cumulative probability of the demand and demand net wind as being below a certain value, hence hourly demand net wind in the UK market in 2030 is below 100GW for 100% of the time (in this example year), and below 30GW for approximately 30% of the time.

Comparing the dark blue line and the dark orange line shows the impact wind has before DSR – there are periods of time where demand net wind is negative – both in 2030 and 2050. Once DSR is deployed, we see that the wind net demand duration curve (light orange) does not become negative – this is because DSR allocates demand to periods of

high wind where prices are cheaper. DSR also reduces the number of periods where high demand is observed (compare the light orange and dark orange lines). Therefore DSR is managing demand to make the most of wind generation – this can be seen by looking at the demand duration curves – the dark blue line compared to the lighter blue lines. The installed capacity of wind generation in 2030 and 2050 is 66.7GW and 80.1GW respectively.

Figure 45 – Demand and demand net wind duration curves



C.1.3 What impact does demand side response have on ramping requirements?

Figure 46 and Figure 47 show the impact DSR has on the ramping requirement for thermal generation over one hour and four timescales.

The two charts show the change in demand net wind, which equates to the change in demand that thermal generation will need to deal with in order to meet demand. The dark blue line shows the change in demand net wind over the time period, while the lighter blue lines show the change in demand net wind when DSR is introduced.

The main observation is that DSR significantly reduces the variation in demand net wind over both the hourly and four hourly time horizons. This is because DSR is effectively flattening the demand net wind profile by reallocating flexible demand thereby reducing variation. The second observation is that the reduction in variation in demand net wind is far more pronounced over the four hourly timescale than the hourly timescale.

Figure 46 – Ramping requirement over a 1 hour timescale

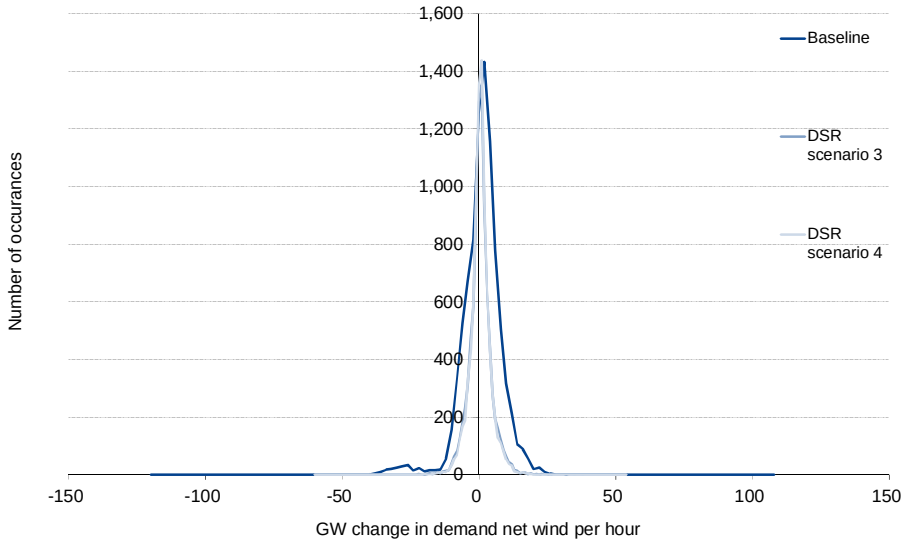
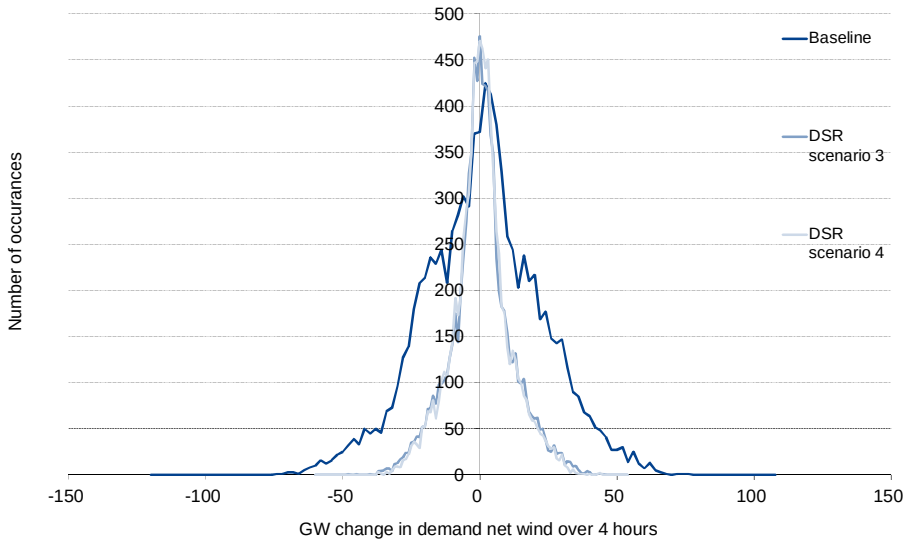


Figure 47 – Ramping requirement over a 4 hour timescale



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ANNEX D – FURTHER DETAILED SCENARIO RESULTS

D.1 Overview

This annex presents the full breakdown of the overall modelled electricity costs from each of the scenarios modelled. We present the breakdown of the headline results, before presenting the main results of the testing DSR scenarios.

D.2 Headline results

Table 26 and Table 27 present a summary of costs for each DSR scenario in 2030 and 2050 respectively. Note that emissions costs and additional generation costs are assumed to be represented by the wholesale price cost. Therefore the overall modelled electricity cost is calculated using the wholesale price cost.

Table 26 – Overall modelled electricity costs in 2030

£ (bn)	Baseline	DSR scenario 1	DSR scenario 2	DSR scenario 3	DSR scenario 4
Wholesale price cost	46.2	43.9	43.8	44.8	43.6
Additional generation investment cost	1.4	0.8	0.7	1.5	0.6
Emissions costs	3.8	2.9	2.9	2.7	2.8
Subsidy required for low carbon generation	12.3	12.6	12.6	12.6	12.6
Transmission network investment costs	0.6	0.7	0.7	0.6	0.6
Constraints cost	0.6	0.7	0.7	0.6	0.6
Distribution network investment costs	0.9	0.9	0.1	0.9	0.1
Wind curtailment cost	0.4	0.0	0.0	0.0	0.0
Overall modelled electricity costs	**61.0**	**58.8**	**58.0**	**59.5**	**57.5**

Table 27 – Overall modelled electricity costs in 2050

£bn	Baseline	DSR scenario 1	DSR scenario 2	DSR scenario 3	DSR scenario 4
Wholesale price cost	53.4	41.2	41.1	41.6	42.7
Additional generation investment cost	2.5	1.4	0.8	1.4	0.3
Emissions costs	4.3	1.9	1.9	1.9	1.9
Subsidy required for low carbon generation	26.0	31.0	31.0	31.1	30.0
Transmission network investment costs	0.6	0.8	0.8	0.7	0.7
Constraints cost	0.7	0.9	0.9	0.8	0.8
Distribution network investment costs	2.3	2.3	1.8	2.3	1.4
Wind curtailment cost	0.8	0.0	0.0	0.0	0.0
Overall modelled electricity costs	**83.9**	**76.2**	**75.6**	**76.4**	**75.5**

D.3 Outcomes from the extreme use of demand side response

In this group of scenarios we briefly assess unrestricted demand side response deployment with varying levels of network build (DSR scenarios 3 and 4). In general we find that our conclusions from the main scenarios hold.

In DSR scenarios 3 and 4 we model the impact of allowing maximum deployment of demand side response. In DSR scenario 3 we allow full deployment of demand side response to meet increasing demand, but in this case we allow unrestricted network build to ensure there are no limits placed on the deployment of demand side response to minimise generation production costs. In DSR scenario 4 we allow demand side response to deploy for peak shaving purposes, while allowing up to 30GW of additional CCGT and OCGT to be built to ensure demand is met.

D.3.1.1 Additional generation capacity

Table 28 shows the additional thermal generation required to meet demand in the two scenarios. As with the core scenarios, introducing DSR assuming no network constraint leads to a requirement for additional generation capacity to allow peak demand to be increased.

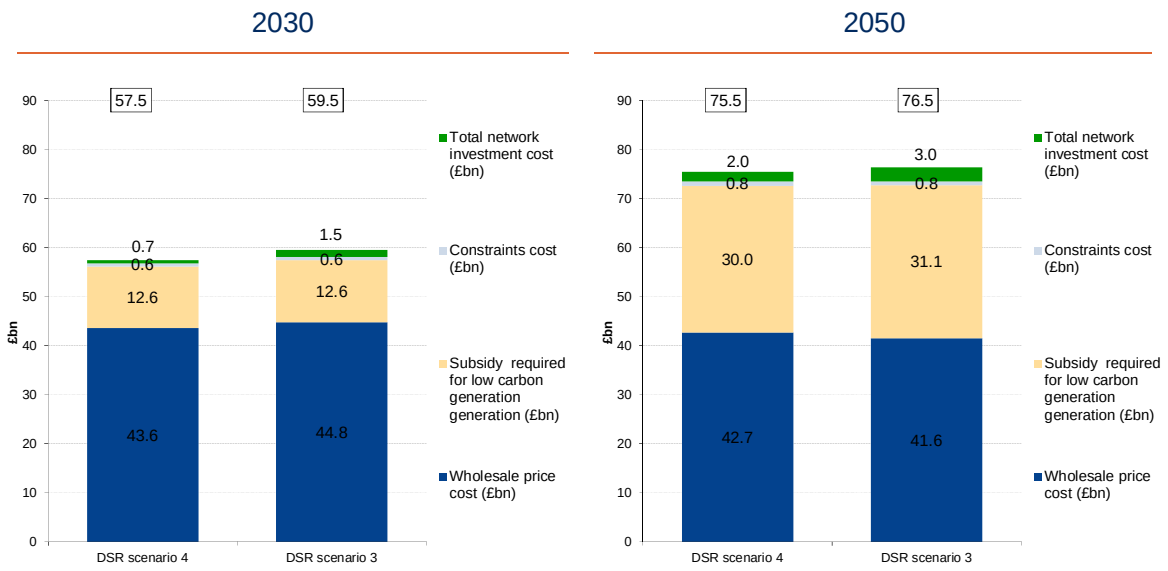
Table 28 – Additional generation capacity

	2030		2050	
Scenario	CCGT	OCGT	CCGT	OCGT
DSR scenario 3	0.00	13.60	3.00	15.00
DSR scenario 4	0.00	13.60	0.00	6.00

D.3.1.2 Headline results

As we show in Figure 48 deploying demand side response in this extreme manner would lead to lower overall modelled electricity cost compared to the opposite extreme of deploying no demand side response (baseline). This chart also shows that despite having lower wholesale price costs in 2050, overall modelled electricity costs in DSR scenario 3 are greater than DSR scenario 4.

Figure 48 – Overall modelled electricity costs for testing DSR scenarios

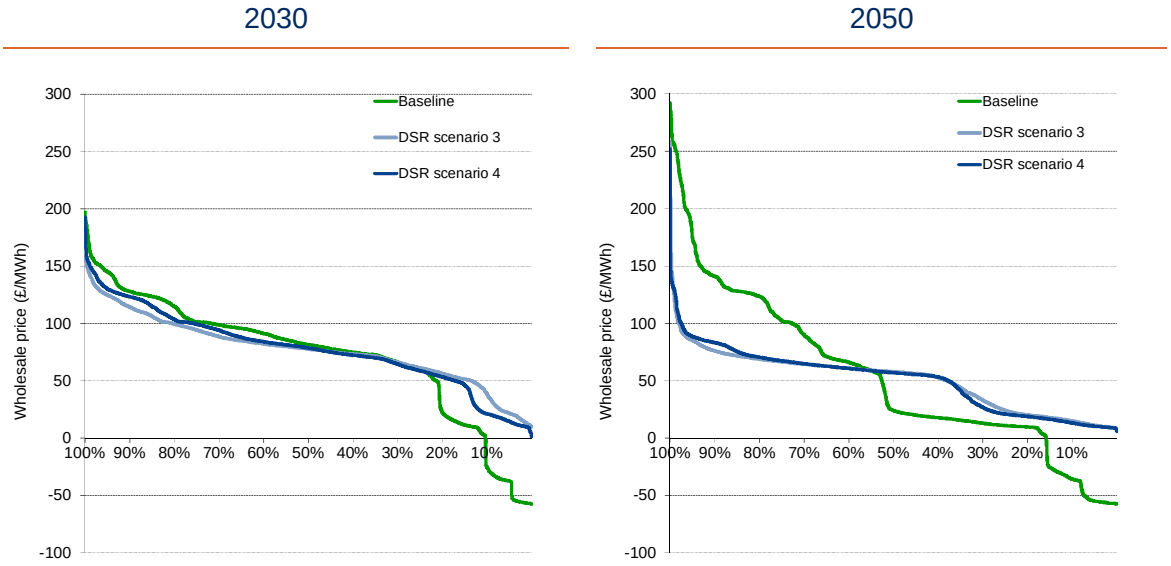


D.3.2 What is the impact of DSR on prices?

Figure 49 illustrates the trend observed in the core scenarios when DSR is deployed. In general deploying DSR flattens the price duration curve by reducing the number of hours of negative prices (periods of excess intermittent generation) by shifting flexible demand to these hours. In addition, the frequency of high prices is further reduced as demand is shifted away from these hours.

This observation matches the trend seen in our main scenario results, but magnifies the difference between wholesale prices when DSR is constrained by network capacity (dark blue line) or is allowed free rein (light blue line) i.e. when unencumbered by network constraints, DSR increases the number of low price periods and decreases the number of high price periods.

Figure 49 – Price duration curves



D.3.3 What is the impact of DSR on wind curtailment?

Figure 50 and Figure 51 show the wind curtailment duration curves for 2030 and 2050. In a market where there is a lot of installed wind capacity, it may be necessary to reduce wind output ('de-load') below what is possible for a number of reasons.

- If wind generation exceeds demand and the excess cannot be exported.
- If it is cheaper to de-load wind rather than turn off a power plant for a short period of time – for example it may be more economic to reduce wind output for a couple of hours than switch off a large coal or nuclear station and then restart it.
- If system operation constraints with reserve or response mean that wind has to be curtailed to keep sufficient thermal plant on the system to meet reserve constraints.
- If transmission constraints mean that wind generation in certain region has to be constrained off. The first three of these factors are modelled within Zephyr, with the transmission effects modelled in part with constraints between the model's four zones.

The issue of wind de-loading is driven by the volume of wind generation installed. Therefore wind shedding levels are greater in 2050 than in 2030. Increasing the amount of wind offshore – particularly in the North Sea – does increase the amount of wind de-loaded, as the wind generation becomes somewhat more correlated.

Figure 50 – Wind curtailment duration curve – 2030

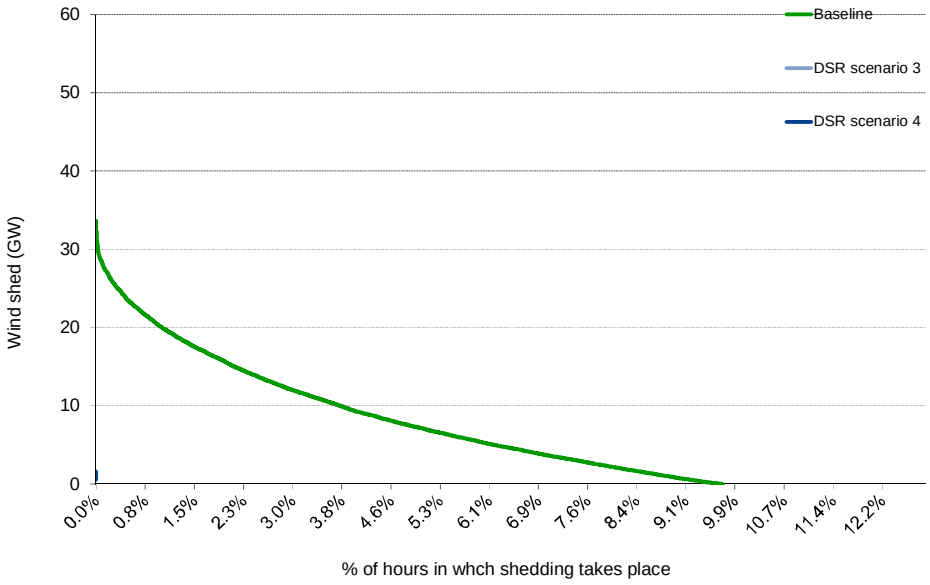
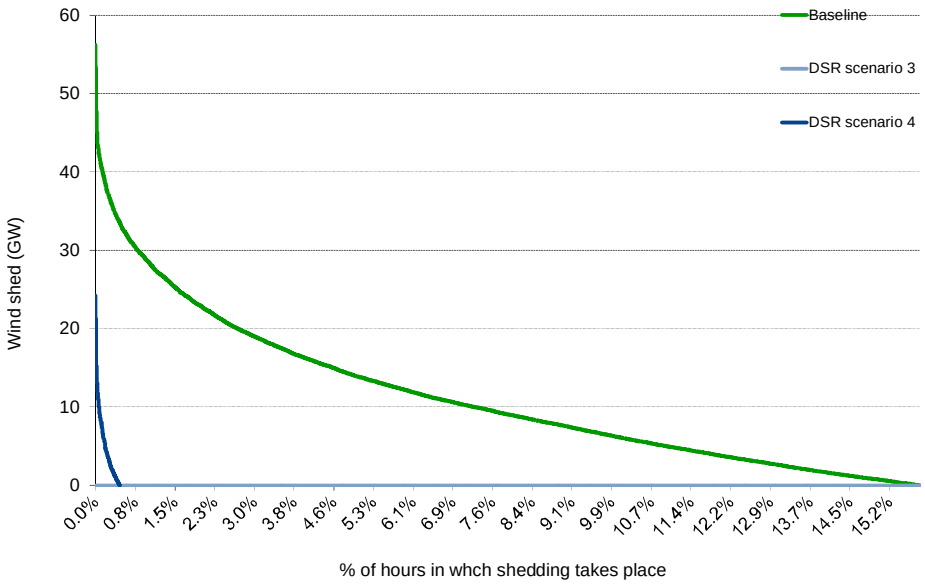


Figure 51 – Wind curtailment duration curve – 2050



D.4 Load factors of plant

Table 29 reports the load factors for different types of generation plant across the core and extreme scenarios for 2030 and 2050.

It is difficult to draw conclusions across all four scenarios as DSR scenarios 3 and 4 contain higher levels of DSR than DSR scenarios 1 and 2. In addition, the model dispatches generation and flexible demand in order to minimise the cost of meeting total demand over the modelled time horizon. Moreover, flexible demand is also dispatched according to the same criteria.

However, there are a few broad conclusions that fit across all of the scenarios:

- In general, deploying DSR increases the load factor of wind, as demand is re-dispatched to ensure less wind shedding. This can be seen by comparing the load factors for onshore and offshore wind in the DSR scenarios to the baseline.
- Deploying DSR increases the load factor of nuclear plant as the demand net wind profile is flattened.

Table 29 – Load factors by generation type across DSR scenarios

2030	Baseline	DSR scenario 1	DSR scenario 2	DSR scenario 3	DSR scenario 4
Nuclear	83.0%	85.3%	85.3%	88.8%	88.5%
CCS Coal	63.8%	69.3%	69.2%	70.8%	70.3%
CCGT	43.4%	39.9%	40.0%	37.9%	38.2%
Peaker	5.5%	3.4%	3.4%	2.8%	2.8%
Onshore wind	21.1%	24.1%	24.1%	24.1%	24.1%
Offshore wind	42.6%	43.2%	43.2%	43.2%	43.2%
Solar	9.5%	9.5%	9.5%	9.5%	9.5%
2050	**Baseline**	**DSR scenario 1**	**DSR scenario 2**	**DSR scenario 3**	**DSR sceanrio 4**
Nuclear	74.9%	80.9%	80.8%	83.5%	82.8%
CCS Coal	37.8%	29.0%	29.1%	27.6%	28.3%
CCGT	13.1%	0.4%	0.4%	0.4%	0.0%
Peaker	0.9%	0.0%	0.0%	0.0%	0.4%
Onshore wind	19.3%	24.1%	24.0%	24.1%	24.0%
Offshore wind	41.9%	43.2%	43.2%	43.2%	43.2%
Solar	9.5%	9.5%	9.5%	9.5%	9.5%

D.5 Return on investment

Table 30 presents the values for internal rate of return (IRR) by generation type across the scenarios. It should be noted that the figures reported in the table are stated prior to any additional subsidy that is required to ensure the plants meet their target IRR (we have used a value of 10%). The target IRR is a convention we have adopted to ensure that generation is viable from an investment perspective. The subsidy reported in the main text is the amount required in order to enable low carbon generation to meet target IRR's. It should also be noted that we have not examined methods of how such a subsidy might be delivered as part of this study. As we have modelled two types of nuclear plant, the European Pressurised Reactor (EPR) and the Westinghouse AP1000 (AP1000), these are presented separately in the table.

As with the discussion of load factors, it is difficult to draw conclusions across all four scenarios as DSR scenarios 3 and 4 contain higher levels of DSR than DSR scenarios 1 and 2 and also the impact of different network constraints. It should also be reiterated that the model dispatches demand side management to minimise the total cost of generation

over the modelled time horizon, even though this might be to the detriment of some types of generation.

Bearing in mind that deploying DSR reduces wholesale price, we can make a few general observations:

- Deploying DSR increases the IRR of onshore and offshore wind as it runs more and demand is shifted to periods of high wind generation; and
- In general, deploying DSR decreases all other IRR's except peaking plant – this is because although DSR drives down the wholesale price, this is more than compensated for, in the case of peaking plant, by the increase in load factor. The picture is further complicated by the ability of the model to dispatch flexible demand in the most optimal way (e.g. DSR may not be able to fully realise wholesale price reductions due to network constraints).

Table 30 – Internal rate of return by generation type across scenarios

IRR % 2030	Baseline	DSR scenario 1	DSR scenario 2	DSR scenario 3	DSR scenario 4
EPR	10.5%	9.8%	9.8%	10.2%	11.0%
AP1000	10.3%	9.7%	9.7%	10.1%	11.0%
CCS Coal	3.5%	1.3%	1.3%	1.3%	4.0%
CCGT	13.3%	10.3%	10.3%	10.6%	0.0%
Peaker	11.6%	11.6%	11.6%	15.4%	23.2%
OnshoreWind	9.7%	9.8%	9.8%	10.2%	9.6%
OffshoreWind	10.4%	11.0%	11.0%	11.4%	11.0%
IRR % 2050	**Baseline**	**DSR scenario 1**	**DSR scenario 2**	**DSR scenario 3**	**DSR scenario 4**
EPR	8.5%	6.4%	6.4%	6.5%	6.9%
AP1000	8.3%	6.4%	6.4%	6.5%	7.0%
CCS Coal	0.9%	-4.1%	-4.0%	-4.5%	-1.6%
CCGT	7.8%	3.5%	3.5%	3.5%	0.0%
Peaker	10.9%	10.3%	10.3%	10.3%	11.5%
OnshoreWind	8.0%	7.4%	7.4%	7.6%	6.8%
OffshoreWind	8.7%	8.8%	8.8%	9.0%	8.5%

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ANNEX E – DETAILED SENSITIVITY RESULTS

E.1 Overview

This annex presents the full breakdown of the overall modelled electricity costs from each of the scenarios modelled. We present the breakdown of the headline results, before presenting the main results of the testing DSR scenarios.

E.2 Headline results

Table 26 and Table 32 present a summary of costs for each DSR scenario in 2030 and 2050 respectively.

Table 31 – Overall modelled electricity costs in 2030

£bn	Sensitivity A	Sensitivity B	Sensitivity C	Sensitivity D	Sensitivity E	Sensitivity F
Wholesale price cost	48.7	48.4	51.1	31.4	31.4	32.7
Additional generation investment cost	-6.6	-6.6	-6.3	0.4	0.4	0.6
Emissions costs	2.5	2.5	3.2	1.8	1.8	2.3
Subsidy required for low carbon generation	5.0	5.0	4.7	12.4	12.4	12.5
Transmission network investment costs	0.2	0.2	0.4	0.6	0.6	0.6
Constraints cost	0.5	0.5	0.6	0.7	0.7	0.6
Distribution network investment costs	0.1	0.1	0.9	0.1	0.1	0.1
Wind curtailment cost	0.0	0.0	0.0	0.0	0.0	5.0
Overall modelled electricity costs	**54.5**	**54.2**	**57.7**	**45.1**	**45.1**	**51.5**

Table 32 – Overall modelled electricity costs in 2050

£bn	Sensitivity A	Sensitivity B	Sensitivity C	Sensitivity D	Sensitivity E	Sensitivity F
Wholesale price cost	54.8	54.8	68.7	24.6	24.6	28.6
Additional generation investment cost	-27.0	-27.0	-26.0	0.1	0.1	0.9
Emissions costs	2.6	2.6	5.0	1.2	1.2	1.8
Subsidy required for low carbon generation	13.6	13.6	10.5	35.2	35.2	33.7
Transmission network investment costs	0.2	0.2	0.4	0.7	0.7	0.7
Constraints cost	0.6	0.6	0.7	0.8	0.8	0.7
Distribution network investment costs	1.8	1.8	2.3	2.2	1.8	2.1
Wind curtailment cost	0.0	0.0	0.0	0.0	0.0	7.4
Overall modelled electricity costs	**71.0**	**71.0**	**82.6**	**63.5**	**63.1**	**73.2**

E.3 Load factors

Table 33 shows the load factors of plant across the sensitivity scenarios. As stated in Annex D, the model dispatches generation and flexible demand in order to minimise the cost of meeting total demand over the modelled time horizon. Flexible demand is also dispatched according to the same criteria.

In the low intermittency sensitivity scenarios, deploying DSR increases load factors of nuclear plant at the expense of CCGT load factors and sometimes CCS load factors. This is because there is less intermittent generation on the system but still a significant amount of DSR which means that demand is shifted to the benefit of nuclear and CCS plant. Load factors for onshore wind are also increased as demand is dispatched to avoid wind curtailment.

In the low demand scenario in general, deploying DSR increases wind load factors more dramatically as there is less demand to soak up wind generation in the first place. Nuclear load factors are also increased whereas CCS, CCGT and peaking plant load

factors decrease in 2050 suggesting that the lowest cost of generation, in this particular scenario, is achieved by allowing nuclear and wind to run more.

Table 33 – Load factors by generation type across the sensitivity scenarios

2030	Sensitivity A	Sensitivity B	Sensitivity C	Sensitivity D	Sensitivity E	Sensitivity F
Nuclear	90.2%	90.2%	86.0%	75.3%	75.3%	73.0%
CCS Coal	86.3%	86.3%	74.2%	50.9%	50.9%	50.9%
CCGT	45.1%	45.1%	48.8%	33.7%	33.7%	36.8%
Peaker	1.9%	1.9%	7.3%	6.2%	6.2%	6.7%
Onshore wind	24.1%	24.1%	23.5%	24.0%	24.0%	20.1%
Offshore wind	43.2%	43.2%	43.1%	43.2%	43.2%	42.0%
Solar	0.0%	0.0%	0.0%	9.5%	9.5%	9.5%
2050	**Sensitivity A**	**Sensitivity B**	**Sensitivity C**	**Sensitivity D**	**Sensitivity E**	**Sensitivity F**
Nuclear	90.3%	90.3%	80.6%	66.2%	66.2%	64.0%
CCS Coal	50.6%	50.6%	56.6%	10.1%	10.1%	17.0%
CCGT	1.5%	1.5%	13.1%	0.0%	0.0%	5.4%
Peaker	0.6%	0.6%	0.4%	0.1%	0.1%	0.6%
Onshore wind	24.1%	24.1%	23.6%	24.1%	24.1%	19.6%
Offshore wind	43.2%	43.2%	43.1%	43.2%	43.2%	41.5%
Solar	0.0%	0.0%	0.0%	9.5%	9.5%	9.5%

E.4 Return on investment

Table 34 presents the IRR's by generation type for the sensitivity scenarios. As stated in Annex D, the figures in Table 34 are those prior to any support from a subsidy payment. Details of the level of subsidy required for plant in the sensitivity cases to meet their target IRR (10%) can be found in Section 5.2.2 and Section 5.3.2.

As with the discussion of load factors, it is difficult to draw conclusions across all four scenarios. It should also be reiterated that the model dispatches demand side management to minimise the total cost of generation over the modelled time horizon, even though this might be to the detriment of some plants IRR's.

In general, deploying DSR reduces most IRR's due to the reduction in wholesale price. However, this general trend is not applicable to all results as other issues such as total levels of intermittent generation and demand play a significant role.

Table 34 – IRR's by generation type across sensitivity cases

IRR % 2030	Sensitivity A	Sensitivity B	Sensitivity C	Sensitivity D	Sensitivity E	Sensitivity F
EPR	12.2%	12.2%	12.1%	6.5%	6.5%	7.1%
AP1000	12.1%	12.1%	12.0%	6.3%	6.3%	6.8%
CCS Coal	2.8%	2.8%	5.0%	-1.1%	-1.1%	-0.7%
CCGT	9.3%	9.3%	16.2%	0.0%	0.0%	14.0%
Peaker	10.9%	10.9%	11.3%	11.1%	11.1%	11.7%
OnshoreWind	13.0%	13.0%	13.0%	7.2%	7.2%	6.9%
OffshoreWind	13.9%	13.9%	13.3%	8.4%	8.4%	7.5%
IRR % 2050	**Sensitivity A**	**Sensitivity B**	**Sensitivity C**	**Sensitivity D**	**Sensitivity E**	**Sensitivity F**
EPR	10.0%	10.0%	11.2%	2.2%	2.2%	3.7%
AP1000	10.0%	10.0%	11.2%	2.2%	2.2%	3.5%
CCS Coal	-2.6%	-2.6%	3.0%	-6.7%	-6.7%	-5.0%
CCGT	5.3%	5.3%	5.5%	0.0%	0.0%	5.7%
Peaker	11.1%	11.1%	11.3%	10.6%	10.6%	10.8%
OnshoreWind	11.5%	11.5%	12.9%	4.9%	4.9%	4.8%
OffshoreWind	12.4%	12.4%	12.9%	6.5%	6.5%	5.6%

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ANNEX F – WHOLESALE MARKET MODELLING

F.1 Overview of Pöyry's Zephyr model

Zephyr was developed for multi-client work to understand the impact of intermittency on the GB market[20].

The model simulates the dispatch of each unit on the GB and Irish systems for each hour of every day – a total of 8,760 hours per year. The model is based on a mixed-integer linear programming platform[21]. This allows us to optimise to find the least-cost dispatch of plant accounting for fuel costs, the costs of starting plant and the costs of part-loading, in aggregate. For example, it may mean that the model will reduce the output of wind generation to avoid shutting down a nuclear plant and incur the cost of restarting it later. The model also accounts for minimum stable generation and minimum on and off times, which allows more realistic operational simulation of plant such as large coal or nuclear sets that, once running, must remain on for a certain number of hours, or, once shut down, cannot restart for a long period.

For each future year that is modelled, nine iterations are carried out, which represent the wind, availability and demand profiles for the historical years 2000 - 2008. This means that for any given future year, a total of 78,840 prices are created (8,760 x 9), giving a good representation of possible interactions between wind, availability and demand. The prices that result from the model are the result of the interaction of supply and demand in any given hour.

Generation from wind is based on actual hourly wind speeds at 35 locations across the UK and RoI plus an offshore site using 'reanalysis' of wave data, which are converted to generation using an aggregated power curve.

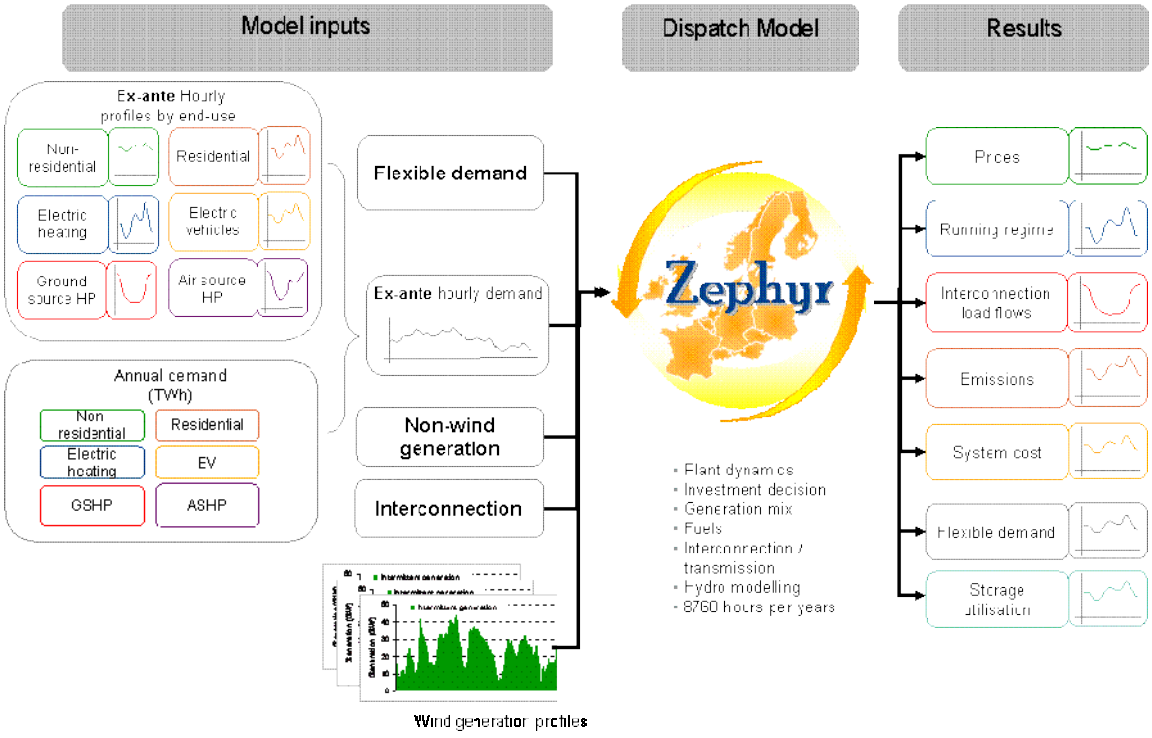
Further development

The model has since been further developed and enhanced to model the behaviour of demand quantify the benefits of DSR in addressing intermittency (i.e. 'demand NET wind' before DSR) as illustrated in Figure 52 below:

20 Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', Pöyry Energy Consulting. July 2009.

21 Zephyr has also been run in what is known as 'relaxed mode', whereby the full mixed integer problem is approximated by continuous variables. Starts and part loading is still optimised, as are the mentioned plant dynamics constraints.

Figure 52 – Overview of Pöyry's Zephyr model



This enhanced version of Zephyr is currently also being used in work for The Climate Change Committee – examining the sources, nature and value of 'flexibility' out to 2050

The key features of Zephyr which ensures it provides quantitative modelling and analysis of the highest quality are:

- Annual demand and availability – the hourly profiles of demand have been taken from National Grid and EirGrid data for demand from 2000 to 2008. Each annual profile is used in a separate Monte Carlo iteration. Thus peaks and troughs in demand will occur at different times in different iterations.
- Wind, wave and tidal – to ensure a consistent set of input data for wind generation, we worked with the UK Met Office to define 28 sites across GB that offer an accurate representation of future wind generation in the UK. These points are were chosen to represent sites where there is likely to be significant wind turbine deployment in the next 20 years based on known applications and licensing areas determined by the government.
- Commodity prices – to calculate commodity prices the model assesses variable costs (incurred by generation sets in the production of electricity; and in particular the variable costs of the most expensive set operating at any point in time) and fixed year-on-year costs of keeping sufficient plant open to ensure that demand is met in peak periods; or, in circumstances in which there is an impending shortage of capacity, the cost of bringing forward new entry; annual fixed costs and new entry costs are not included in Zephyr itself, but we tend to iterate new build and/or value of capacity based on these.
- Value of capacity – based on historical data ('backcasts').

- Plant dynamics – plant availability based on historical profiles (by plant type) for several individual years. This includes scaling for different properties (maximum output, minimum on and off time, minimum stable generation etc) estimated from historical MEL data. For Pumped Storage (PS) capacity we modelled a maximum generation, a maximum pumping, maximum and minimum reservoir levels, and the contribution of PS to reserve and response.

  The model also takes account of interconnection between GB and Ireland, so that flows between the two countries are optimised. Interconnection flows between GB and Continental Europe are modelled with an hourly price profile of the Continental countries, based on the underlying commodity values and prices from our pan-European EurECa model.

- Zonal data – the model can split the GB system into a number of zones which will which allow us to view transmission flows and thus estimates transmission constraints which are incurred and need to be offset (partially or wholly) by transmission investment.

- Reserve and response data – Optionally reserve and response constraints can be included. We assume that sufficient primary frequency up to 30 seconds after unplanned outage) response is provided in line with technical requirements for generation plants. For secondary frequency response (30 seconds to 30 minutes after an unplanned outage) and for reserve (30 minutes to 4 hours), we have used formulae to determine the ex-ante level of reserve required to be held by the system, which can be determined in a constrained run of the model, which looks at a number of factors such as hot plants, headroom available and OCGTs that are not running.

- Flexible demand profiles – the model includes respect to flexible demand-side units in three categories – residential washing units, heating, and electric vehicles.

One of the key updates to this modelling was the expansion of the scope of *Zephyr* with respect to flexible demand-side units. Demand-side units can be split into three categories – residential washing units, heating, and electric vehicles. For each category, we made an assumption about the magnitude of movable demand for each year, which followed the same energy profile as overall demand.

The ex-ante demand is then adjusted to ensure the sum of inflexible and movable demand (before fuel switching and storage losses) was consistent with total demand. This requires a number of assumptions in regard to these demand-side units; for example the total movable demand for each category was split between a number of different units for each demand-side category, some of which differed by the assumption made for each constraint (such as demand pattern or availability profile) and/or by technology (e.g. ASHP or GSHP). More detail is provided in Section 2.7.

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ANNEX G – DISTRIBUTION NETWORK MODELLING

G.1 Network model

DNOs may employ up to six voltage levels ranging from 132 kV - 415 V. In England and Wales all 132 kV circuits are classified as distribution networks whereas in Scotland these would be designated as transmission. For consistency this study has assumed that all 132 kV circuits will be part of the distribution system.

Three reference networks for each voltage level are developed for 2020 that reflect the different urban, semi urban and rural topologies that are found within a typical distribution area. To simplify the electrical and geographic complexity a lesser number of voltage levels has been chosen for the modelling that reflect the characteristics of extra-high voltage (EHV), high-voltage (HV), and low voltage (LV) parts of the system for the chosen networks.

The EHV and HV levels of the reference networks reflect actual asset configurations, but for the LV level the reference network is based on averages derived from the menu of LV assets employed in a distribution business. These include loading levels, feeder lengths, transformer numbers and typical impedances and ratings for underground cables and overhead lines. Parameters differ for urban, semi-urban and rural networks in accordance with the engineering of the system.

Networks in urban areas with high customer densities are assumed to be characterised by highly rated underground cables having short circuit lengths. Semi-urban networks are taken to have medium circuit lengths comprising both underground cables and overhead lines. Circuits in rural areas are the longest of all and are assumed to be solely overhead lines.

Future network reinforcement required under each of the chosen scenarios will be driven by the requirement to meet both thermal and voltage limits. Accordingly, two types of network expansion schemes are contemplated:

- reinforcement of a circuit or transformer if its thermal capacity limit is violated; and
- static var compensators (SVC) or shunt capacitors to bring busbar voltages back within the requisite range.

In modelling the impact of the DSR load on the GB distribution system we have extrapolated the results from the three reference networks that together form a representative Grid Supply Point. The GB distribution networks show a wide variation in their nature and it would be wrong to suggest that the modelled network reflects any particular part of the overall system. Nonetheless it is our view that the reference networks are typical of the average system found and thus the results should produce a reasonable estimate within the overall accuracy of the study.

G.2 2020 reference networks

The 2020 network configuration is based on the existing network design and energy mix varied by the anticipated growth in demand and distributed generation over the next decade. The 2020 network creates a starting point for the 2030 and 2050 evaluations. The extant mix of assets and customers has been assumed to remain constant in terms of their proportions but have been increased by the forecast change in system maximum

demand (SMD) over the period from 2008 to 2020 to create a baseline system for that year. Over this period SMD is anticipated to increase from 59.1 GW to 72.9 GW.

The energy shares in 2020 supplied through the 9 reference sub-networks (three voltage levels for urban, semi-urban and rural areas) are thus assumed to be similar to those for the extant GB system. They have been derived from national consumption data divided between the reference networks by both customer class and network type, and the forecast increase in system demand.

The results show that whilst virtually all electrical energy is transported through the EHV network the LV network, where the vast majority of customers are connected need cater for only 69% of the energy. Residential load predominates in the urban networks whereas commercial load is predominant in the semi-urban and rural networks. Residential and commercial (in this definition) load is assumed to be connected in similar proportions to the LV network whereas the majority industrial load is connected to the HV network.

The 2020 baseline networks are assumed to evolve from the extant 2008 networks by undertaking sufficient investment for the distribution system to meet the 72.9 GW peak SMD anticipated for that year, assuming that new demand has the same characteristics as the present demand.

Table 35 – Energy shares across network levels

Voltage level	Energy Proportion	Network Type	Energy share	Domestic Class	Industrial Class	Commercial Class
EHV	3%	Urban	52%	40%	36%	24%
HV	29%	Semi-Urban	41%	20%	18%	62%
LV	69%	Rural	7%	20%	17%	63%
All	100%	Total	100%	30%	27%	42%

G.3 2030 and 2050 demand projections

For the period from 2020 the growth in demand accelerates as a responsive market segment (DSR) based mainly on an increasing penetration by electric vehicles (EV) of the transport market, and the replacement or supplementing of fossil fuelled heating systems by electric heating systems (HP) emerges. There is also a substantial shift of industrial processes from gas to electric technologies in this period.

In the period from 2020 to 2050 our analysis considers separately the addition of load that is responsive to active management and is thus part of a growing DSR portfolio, and that which is unresponsive and thus cannot be employed to improve network utilisation. The scenarios considered in the next chapter of this report explore the investment required in the overall GB distribution networks to accommodate these demands under various scenarios.

The overall system maximum demand (SMD) that can be met by the GB distribution networks varies with each scenario depending upon how the responsive load is assumed to behave; i.e. (a) no response, (b) responding to reduce the network investment that would otherwise be needed, or (c) responding so as to reduce the wholesale energy cost.

The substantial growth in EV and HP responsive load is expected to connect predominantly to the LV network in urban networks. There is also a significant increase in demand which is not responsive resulting from the electrification of industrial processes. This connects mainly to HV networks in rural and semi urban areas where industrial demand predominates. As a consequence our modelling of the costs of network development for each scenario reflects a changing proportion of overall system demand served by each of the reference networks.

In the period to 2030 the proportion of demand served by rural networks increases reflecting the growth in industrial electrification. However, by 2050 the rural network proportion has stabilised as the growth in responsive demand in the urban and semi-urban networks increases. Demand served by semi-urban networks increase faster than that in urban networks.

Table 36 – Energy share

% of energy	2020	2030	2050
Urban	57.4	53.4	51.9
Semi-urban	36.4	34.5	36.4
Rural	6.2	12.0	11.7

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