A framework for the evaluation of smart grids

A REPORT PREPARED FOR OFGEM

March 2012

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Executive Summary

Ofgem appointed Frontier Economics and EA Technology to develop a framework to compare smart grid distribution network investment opportunities to conventional alternatives. This project forms part of the work programme of the Smart Grids Forum (SGF)[1]. Our aim has been to develop a practical evaluation framework which can help improve understanding of the likely value of smart grids under different scenarios, and which can be updated as new information arises.

We recognise that there is some uncertainty as to what a smart grid is. In this report and the evaluation framework that it describes, the term "smart grid" refers to the network solutions that have been specified as an input to the model. A set of conventional solutions are also specified. Therefore, the user of the framework decides what constitutes a smart grid and the conventional counter-factual.

We set out our proposed methodology for developing this framework for consultation in November 2011[2]. This report now sets out a revised modelling methodology, based on the comments received to the consultation, and presents an initial analysis of the costs and benefits of smart grids.

Alongside this report, we have produced an Excel-based modelling tool. This will allow those interested to input their own assumptions and test alternative scenarios. It is also hoped that producing the model will help promote further work to develop the framework, such as the work being undertaken by Workstream 3 (WS3) of the SGF to increase the granularity of the network modelling.

Overview of modelling approach

This report describes an analytical framework which can be used to increase understanding of the value drivers of smart grids. Two principles have informed its development.

- **Transparency.** Smart grid value will be driven by future demand and supply side developments in the electricity sector, many of which are highly uncertain. Given this uncertainty, producing a framework that enables a

1 The terms of reference for the SGF are available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=7&refer=Networks/SGF

2 Frontier Economics and EA Technology (2011), *A framework for the evaluation of smart grids*, http://www.frontier-economics.com/_library/publications/A%20framework%20for%20the%20evaluation%20of%20smart%20grids.pdf

better understanding of the factors that drive the value of smart grids is more useful than producing a single estimate of smart grid value. Our aim has been to ensure that the assumptions are explicit in our model, and that key inputs can be flexed.

- **Flexibility**. New information on the costs and benefits of smart grids will become available. For example, there is a large programme of trials on smart grid interventions being undertaken through the Low Carbon Network (LCN) Fund[3]. Our model has been built so it can be updated with new information.

We have focussed on building a framework which covers the most important drivers of smart grid value.

- **Model scope**. The model scope has been limited to those factors that are most likely to affect smart grid value. To maintain flexibility and transparency, we have not modelled all costs and benefits to a full level of granularity. In particular, we have taken a very simple approach to modelling transmission network costs and benefits and we have not included system operator costs and benefits. We have tried to be explicit about where, and why, we have limited the scope.

- **Data population.** This work has focussed on developing a robust and flexible appraisal methodology and formalising this in a model, rather than carrying out detailed research on the data to populate the model.

It is important that our model is seen as a tool to increase understanding of the costs and benefits of smart grids. It can be developed further as our understanding of the areas where more detailed modelling and data collection is warranted develops. The results of this modelling should therefore be seen as a first step, rather than as a definitive assessment of smart grid value.

Scope

Our model has the following scope.

- **Our framework compares the direct costs and benefits of smart grids to conventional investment alternatives**. We include:
  - investment costs associated with smart and conventional technologies;
  - changes in generation costs;

3 http://www.ofgem.gov.uk/networks/elecdist/lcnf/pages/lcnf.aspx

- a simplified representation of changes in transmission costs;
- changes in losses and security of supply associated with smart investments;
- a representation of customer inconvenience costs when demand side response (DSR) is employed; and
- direct impact on CO_2 emissions[4].

- **We consider both the overall costs to society and the distribution of those costs across the electricity sector.**
  - The overall assessment will help to inform whether a policy of pursuing smart grid technology makes sense for society as a whole.
  - Considering the distribution of costs across the electricity sector aims to identify whether costs and benefits are aligned between parties. If they are not aligned, this may act as a barrier to smart grid investment.
- **We take a long-term view but focus on the implications for today.** To span expected asset lifetimes, our model considers the implications of smart grid investments between 2012 and 2050. However, we use the model to consider what the long-term implications mean for current smart grid investment.

Some important aspects of policy associated with smart grids are outside the scope of this project.

- **Indirect costs and benefits.** We have not looked at indirect costs and benefits of smart grids, such as the potential for job creation, or the potential impact on the macro-economy of changing energy costs.
- **Assessment of the market arrangements.** We were not asked to consider the market arrangements required to deliver smart grids benefits, for example the required tariff types or commercial arrangements.

Methodology

Developing a smart grid evaluation framework involves challenges.

- **Smart grids are enabling technologies.** Our evaluation framework assesses the incremental costs and benefits of smart grids relative to conventional distribution grid technologies. It does not aim to capture the

[4] We value carbon emissions in line with Government guidance, http://www.decc.gov.uk/en/content/cms/about/ec_social_res/iag_guidance/iag_guidance.aspx

costs and benefits associated with decarbonising heat, transport or the electricity sector more widely. Our model therefore holds objectives such as overall emissions and supply reliability constant, and compares the costs and benefits associated with different means of achieving these outcomes. However, where applying different solutions leads to changes in security of supply or carbon emissions as ancillary benefits (or costs), we include these in our evaluation[5].

- **Uncertainty and option value.** Distribution network investments have long lifetimes, there are multiple potential future decarbonisation paths, and the different grid investment strategies entail different levels of flexibility. Assessing the impact of uncertainty is therefore a key part of this framework.
  - Given uncertainty over the future, we assess the value of smart grid strategies within three scenarios, which represent different states of the world to 2050. These aim to vary those factors that are most uncertain and have the greatest impact on smart grid value.
  - We have based our cost benefit analysis on the principles of "real options" analysis. This recognises the possibility that networks might be able to adapt their investment strategies in future years as new information becomes available. This allows the evaluation framework to take account of any option value associated with smart grid investments that avoid lock-in to a particular investment path.
- **Multiple solutions.** A smart grid could be made up of a range of smart and conventional technologies that can be applied in different combinations and at different scales. Rather than assessing the incremental costs and benefits of each individual smart grid technology in isolation, we assess two smart grid investment strategies. We compare these to a business as usual strategy, where only investments in conventional grid technologies are undertaken (over and above existing policies to rollout smart meters).
- **Scale and profile of investment required.** Some smart grid solutions (for example, the control and communications infrastructure) may need to be applied at a certain scale and in a holistic or top-down manner to minimise deployment cost. However, it may also be possible to efficiently deploy smart technologies in an incremental way, irrespective of the scale of investment. We assess both a top-down and an incremental approach to investment in our framework.

5 We recognise that increased electrification of heat and transport is likely to increase the value of lost load and hence the justification for security of supply improvements. However, assessing the

Detailed specification of scenarios and data

The smart grid model we have produced has been set up to allow users to update the most important data and scenarios it contains with new information. However, we have populated it with an initial set of scenarios and data.

Scenarios

Given uncertainty over the future, we assess our smart grid strategies against three scenarios, each of which represents a different state of the world to 2050.

The factors to vary across scenarios should represent the most important smart grid value drivers and those value drivers around which there is the most uncertainty. The analysis we set out in our November 2011 consultation document[6], and the responses we received to that consultation, suggest that these factors are the:

- electrification of heat and transport;
- increase in distributed generation;
- increase in intermittent and inflexible generation; and
- extent to which customers engage with DSR.

Therefore, we have developed three scenarios which vary the level of these value drivers.

- **Scenario 1** includes projections of heat and transport electrification consistent with meeting the fourth carbon budget and projections in the increase in distributed generation provided by SGF WS1.
- **Scenario 2** contains the same rollout of low-carbon technologies as Scenario 1. However, in this scenario, customers' willingness or ability to be flexible with the demand associated with each of these low-carbon technologies is lower.
- **Scenario 3** is consistent with a situation where the UK chooses to meet its carbon targets through action outside the domestic electricity sector, for example through purchasing international credits. In this scenario the rollout of demand-side low-carbon technologies is slower than expected, and the generation mix contains less inflexible and intermittent low-carbon plant.

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6 Frontier Economics and EA Technology (2011), *A framework for the evaluation of smart grids*, http://www.frontier-economics.com/_library/publications/A%20framework%20for%20the%20evaluation%20of%20smart%20grids.pdf

Data

WS1 of the SGF has developed a set of assumptions and scenarios to 2030 for each of the technologies most likely to have an impact on the value of smart grids. These data are consistent with those used in the Government's *Carbon Plan*, which sets out scenarios for meeting the UK's 4th carbon budget covering the period from 2023 to 2027[7]. We use data from WS1 for heat pumps, electric vehicles and solar PV.

Where possible, to ensure consistency with policy goals, we have based our scenarios on the Government projections provided by WS1. Where Government data is not available, we have used data from a range of other sources.

Model users can view and change key data inputs to the model.

Smart grid investment packages

Our model includes three investment strategies:

- **A top-down smart grid investment strategy** entailing an initial investment in control and communication infrastructure and lower associated costs of ongoing investment in smart technologies, with conventional technologies deployed where cost-effective.

- **An incremental smart grid investment strategy.** Once again, smart and conventional technologies are included as required on each feeder type, with the lowest cost solutions being chosen first. The incremental strategy differs from the top-down strategy by not including an upfront investment in the control and communications infrastructure. Because this infrastructure is not in place, all ongoing investments in smart technologies cost more than under the top-down investment strategy.

- **A conventional strategy.** This strategy differs from the top-down and incremental strategies in that it only includes conventional technologies.

To establish this evaluation framework, we have populated the model with five forms of representative smart grid technologies. These technologies cover a range of the key functionalities of smart grids, and fall into the following categories:

  - electrical energy storage;
  - dynamic thermal ratings;

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7 DECC (2011), *Carbon plan*, http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

- enhanced automatic voltage control;
- technologies to facilitate DSR; and
- active network management (dynamic network reconfiguration).

While the technologies and strategies included in our model represent the main types of smart grid technologies required for an evaluation, they do not form a comprehensive set of smart grid technologies. It should also be stressed that the cost and performance of these technologies has been estimated, and there is significant uncertainty associated with the levels used. Evidence to support and refine these estimates will become increasingly available as projects, including the LCN Fund projects, deliver learning.

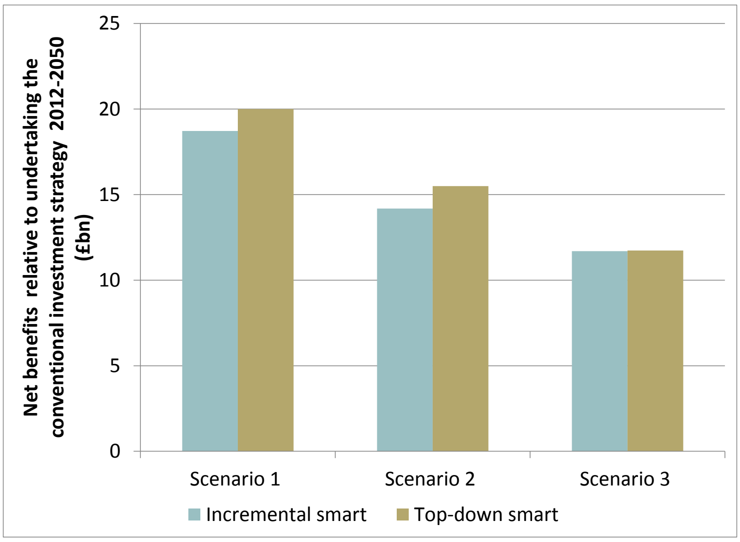
Results

Given the scope and level of granularity of this modelling, it is important that the results of this modelling are seen as a first step to better understand the drivers of the costs and benefits of smart grids, rather than as a definitive assessment of their value.

Core results

Given the set of assumptions used in the modelling, this analysis suggests that smart grid technologies can deliver significant savings over the period to 2050 relative to using only conventional alternatives. This is because including smart solutions in a strategy widens the set of options available to DNOs, and allows them to choose less costly solutions and defer conventional investment where appropriate. These results are shown in Figure 1.

Figure 1. Net benefits of smart strategies relative to conventional strategies, under default assumptions



Source: Frontier Economics

Figure 1 shows that these savings are demonstrated across all scenarios analysed, but are highest where low-carbon technologies have the greatest penetration, and where customer engagement with DSR is highest.

Decision tree analysis

The counterfactual underlying the results presented in Figure 1 was based on pursuing the conventional strategy to 2050, with no option to switch strategy.

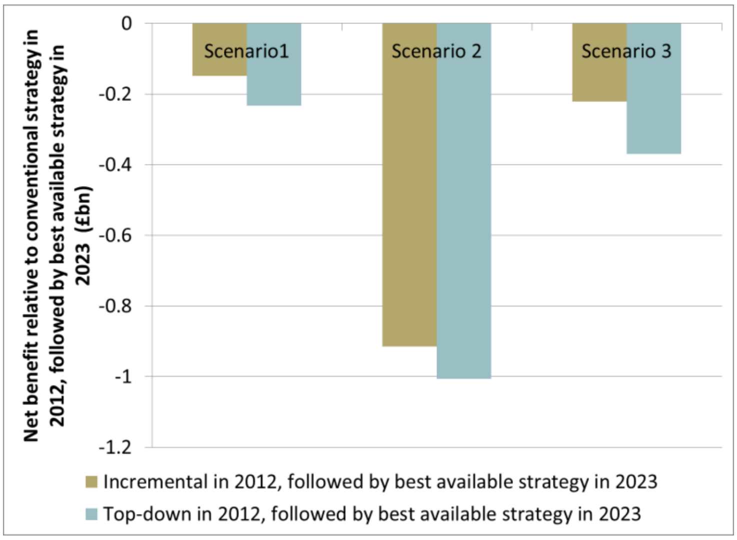
To take account of option value, we now apply a two-stage decision tree and assume the network investment strategy decision made in 2012 can be changed in 2023[8] in both the conventional counterfactual and the smart investment cases.

This means that the counterfactual against which we assess our choice of smart strategies may itself become smart at the decision point in 2023, if this turns out to be a better option than continuing to only employ conventional technologies.

Figure 2 sets out the results once a two-stage decision tree has been applied to this analysis.

8 We use the year 2023 for the decision point in our decision tree analysis as this may coincide with the beginning of the first price control period in the 2020s. However users can change the date of the decision point in the model.

Figure 2. Net benefits of choosing smart strategies in 2012 assuming the decision can be changed in 2023



Source: Frontier Economics

The results in Figure 2 suggest that there is not a clear case for *immediate* widespread rollout of smart grid technologies, based on the assumptions we use. Under all scenarios, the conventional strategy is marginally preferred in 2012, though the net cost of pursuing smart strategies is very small and is well within the range of uncertainty associated with the modelling assumptions.

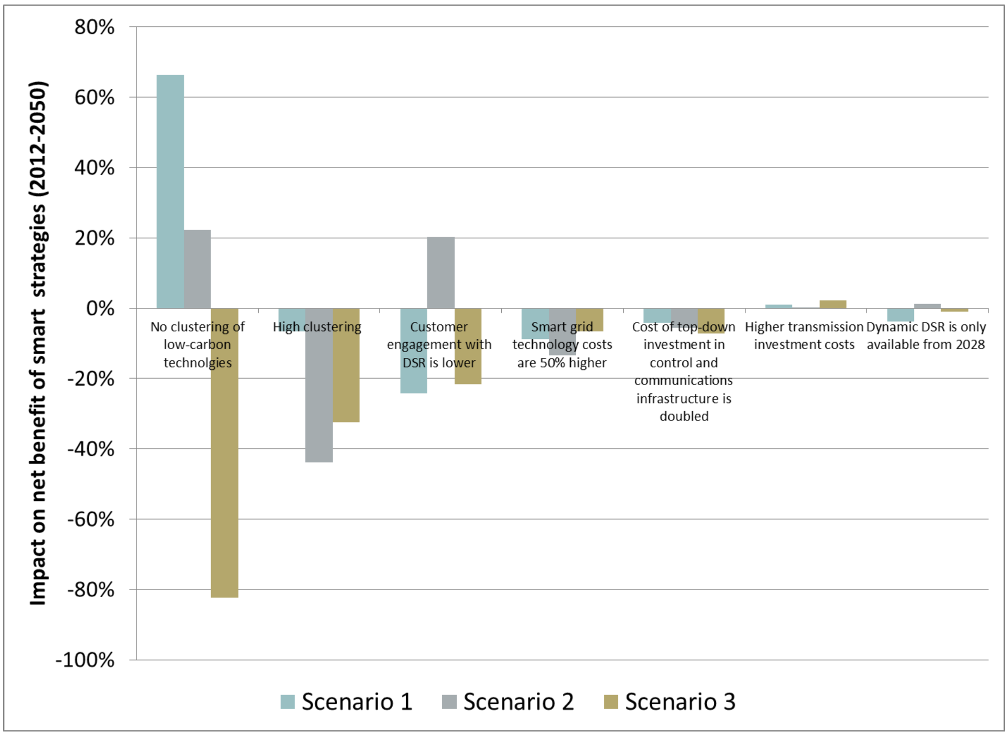
The large net benefits shown in Figure 1 are no longer present because we are now focussing on the impact that choosing a smart strategy can have in the period to 2023. The reduction in net benefits makes sense, given that the rollout of the value-driving technologies such as heat pumps, electric vehicles and distributed generation is unlikely to have a big impact across the system until the 2020s (although clustering will cause issues in particular areas).

The overall conclusion that can therefore be drawn is that smart grid solutions are expected to deliver benefits in the coming decades but more analysis is required to decide at what point their deployment should commence in a significant way.

Sensitivity analysis

We also looked at a range of sensitivities around the core results (presented in Figure 1). The results of the sensitivities are presented in Figure 3. While the results are sensitive to these changes, the positive net benefit of smart strategies relative to conventional strategies is maintained in each case.

Figure 3. Key results of the sensitivity analysis



Source: Frontier Economics

Figure 3 shows that the results are particularly sensitive to the assumptions made on the clustering of low-carbon technologies, and that the effect of changing this assumption differs depending on the scenario. This is because there are two impacts caused by reducing the clustering of low-carbon technologies.

- It reduces the pressure on the parts of the distribution network where low-carbon technologies were clustered. This will tend to reduce the net benefits of smart strategies.

- It increases the pressure on the parts of the distribution network that had fewer low-carbon technologies when clustering was in effect. This will tend to increase the net benefit of smart strategies.

In Scenario 3, the penetration of low-carbon technologies is low. In this case, the first impact dominates. A reduction in clustering reduces pressure on the feeders on which low-carbon technologies were clustered, but there are not sufficient low-carbon technologies to require widespread investment once these are spread evenly across the network.

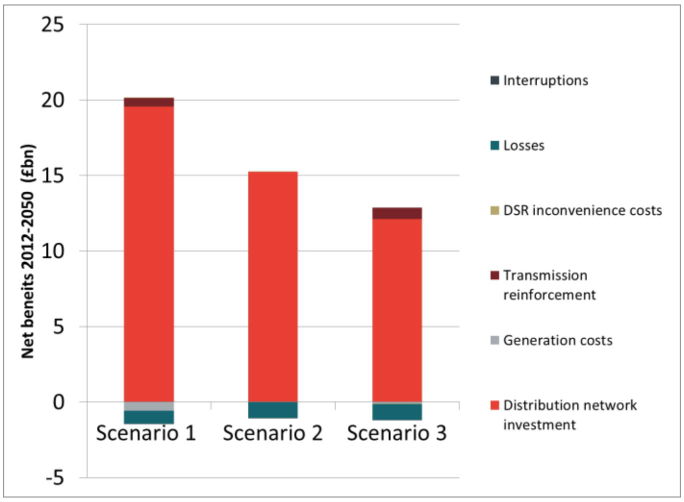
In Scenarios 1 and 2, the penetration of low-carbon technologies is higher. In these cases, the second effect dominates, and reducing clustering increases the benefit of smart grid strategies because the number of feeders that require smart or conventional investment increases.

Figure 3 also shows that increasing the technology costs of smart grid by 50% does not have a significant impact on the net benefits of smart technologies. This suggests that the results are relatively robust to the high degree of uncertainty around these costs. This is because most smart grid technologies included in the model turn out to be more cost-effective than the conventional alternatives under our base case assumptions about costs and network conditions and because the smart strategies contain significant levels of conventional investment. The smart grid technology cost assumptions will be looked at in more detail by WS3.

Distribution of costs and benefits

We also looked at whether the costs and benefits of smart grids are likely to be aligned between parties in the electricity sector. Where these are not aligned, there may be barriers to smart grid investments. The breakdown of the net benefits associated with each strategy, relative to the conventional strategy, is shown in Figure 4.

Figure 4. Net benefits broken down by source, under default assumptions



Source: Frontier Economics

Figure 4 shows that under these assumptions, the greatest proportion of net benefits are due to a reduction in distribution network investment costs, and suggest that the costs and benefits of smart grids are likely to be aligned to some extent. Since we are assuming for the purposes of this modelling that from 2023[9] smart meters already allow customers to respond to dynamic, system-wide signals (e.g. related to generation costs), the incremental impact of smart grids will be to additionally allow the demand side to respond to dynamic signals related to local network conditions. This locally-driven DSR will aim to reduce distribution network costs. The associated cost savings will fall primarily to DNOs and therefore the costs and benefits of smart grids will be well aligned.

Further work

The aim of our work was to establish a flexible and transparent framework for the evaluation of smart grids. We have produced an initial set of model results which help identify the conditions which drive the value of smart grids. However, this project has not aimed to produce a definitive assessment of the net benefits associated with smart grids, and further work will be required to provide a more granular assessment.

Some of this work is already being taken forward by WS3. The WS3 project will use the overall evaluation framework set out in this report but will also:

- increase the granularity of the network modelling;
- disaggregate network conditions by region and sub-region;
- increase the number of smart grid technologies considered; and
- incorporate new learning from the LCN Fund projects.

Beyond the work being taken forward by WS3, there are a number of other areas where further work may be useful.

- **Development of the framework.** There is scope to increase the coverage of the evaluation framework and its granularity.
  - Not all of the potential benefits of smart grids are included in the model. An important development would be to enable the evaluation framework to take account of differences in the speed of connection of low-carbon technologies, or fewer interruptions associated with these connections, associated with smart and conventional investments.
  - Not all aspects of DSR have been included in the model. In particular:
    - only within-day changes in demand have been modelled (as this is likely to represent the majority of DSR potential) even though benefits from shifting demand over longer periods could be possible; and

9 Users can change this date.

    - the model does not fully optimise between different types of DSR.
  - There is scope to increase the granularity at which the rest of the electricity sector is modelled. For example, the potential benefits of DSR and/or electrical energy storage to the system operator should be investigated further.
  - Not all potential value drivers have been characterised in the model. For example, the model does not include vehicle-to-grid capabilities on electric vehicles.
- **Data population.** Better information will become available, for example from LCN Fund projects and other trials and research

1 Introduction

Ofgem has appointed Frontier Economics and EA Technology to develop a framework that will allow smart grid investment opportunities to be evaluated.

This report:

- sets out the methodology we have used to develop the evaluation framework;
- describes the model we have developed;
- sets out the assumptions and data with which we have initially populated the model; and
- presents an initial set of results based on these data and assumptions.

1.1.1 Context of the project

This work has been commissioned to feed into the work programme of the Smart Grids Forum (SGF)[10]. The SGF was established by Ofgem and DECC in early 2011. It brings together key opinion formers, experts and stakeholders involved in the development of a GB smart grid, with the aim of providing strategic input to help shape Ofgem's and DECC's thinking and leadership in smart grid policy and deployment. It also aims to help provide the network companies and the wider stakeholder community with a common focus in addressing future networks challenges, and to provide drive and direction for the development of smart grids.

The SGF has chosen to include the provision of an evaluation framework for smart grid investment as part of its work. This reflects the current lack of understanding about what really drives the smart grid case, which could inhibit policy decisions and will make assessment of investments difficult in RIIO-ED1 if it is not addressed.

The evaluation framework is the second of five SGF work streams. The other workstreams cover:

- the development of scenarios for future demands on networks (WS1);
- the assessment of required network developments in the low-carbon economy, including detailed network modelling of smart grid options (WS3);

10 The terms of reference are available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=7&refer=Networks/SGF

- mitigation of the risk that short term smart meter and smart grid decisions may close off options (WS4); and
- development of future ways of working for the SGF (WS5).

1.1.2 Objectives of this project

The aim of this project is to produce a high level framework for the evaluation of smart grids. The intention is that the framework can be updated over time as new information becomes available.

In developing this framework, we are looking to help the industry reach a better understanding of:

- the drivers of the value of smart grids;
- the value of the flexibility smart grids may provide under conditions of uncertainty; and
- the parties in the electricity sector that may benefit from smart grid solutions.

In November 2011, we set out our proposed methodology for developing this framework for consultation[11]. Taking into account comments received in the consultation, we have now finalised the evaluation framework and produced an Excel-based model.

We have aimed throughout to build a flexible and transparent model.

- **Model scope**. We have limited the model scope to cover the most important factors that affect the smart grids across the electricity sector. To maintain flexibility and transparency, not all costs and benefits have been modelled to a full level of granularity. In particular, a simple approach has been taken to modelling transmission network costs and benefits, and system operator costs and benefits have not been included in this work.

- **Data population.** This work has focussed on developing a robust and flexible appraisal methodology and formalising this in a model, rather than on carrying out detailed research on each of the parameters included in the model.

It is important that our model is seen as a tool to increase understanding of the costs and benefits of smart grids. It can be developed further as the

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[11] Frontier Economics and EA Technology (2011), *A framework for the evaluation of smart grids*, http://www.frontier-economics.com/_library/publications/A%20framework%20for%20the%20evaluation%20of%20smart%20grids.pdf

areas where more detailed modelling and data collection is warranted become clearer. The results of this modelling should therefore be seen as a first step, rather than as a definitive assessment of smart grid value.

The model has been designed to provide an overall analysis of the costs and benefits of smart grids, rather than to inform specific investment decisions. Although our model can be used to identify the types of smart grid investments which are likely to be beneficial under different conditions, it has not been set up at a sufficient level of detail to be used to justify specific smart grid investment plans. The principles that sit behind the framework to enable this evaluation, however, are transferrable.

The production of a flexible and transparent model will allow those interested to input their own assumptions and test alternative scenarios. It is also hoped that it will promote further work to develop the methodology. Indeed, WS3 of the SGF is currently working to increase the sophistication of the network modelling.

1.1.3 Structure of the report

The report is structured as follows.

- Section 2 describes what we mean by smart grids, and sets out our assumptions on the functionality they are likely to deliver over and above smart meters.
- Section 3 presents an overview of the modelling approach, setting out the key assumptions and principles on which this work is based.
- Section 4 sets out the scenarios and data with which we have populated the model as a default.
- Section 5 describes the smart and conventional technologies currently included in the model, and the key assumptions associated with each.
- Section 6 presents the initial findings from the cost benefit analysis.
- Section 7 describes the areas where further work is recommended.

Further detail on the model and consultation responses is provided in the Annexes.

2 What is a smart grid?

In this section we first describe what we mean by a smart grid, and we then set out how we differentiate between the smart grid and smart meters in this work.

2.1 Definition of a smart grid

There is no single agreed definition of a smart grid. We use the *Smart Grid Routemap*[12] developed by the ENSG as our starting point, which states that:

[A] smart grid is part of an electricity power system which can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies.

Expanding on this, DECC identified that a smart grid is likely to have the following characteristics[13].

- **Observable:** the ability to view a wide range of operational indicators in real-time, including where losses are occurring[14], the condition of equipment, and other technical information.

- **Controllable:** the ability to manage and optimise the power system to a far greater extent than today. This can include adjusting some demand for electricity according to the supply available, as well as enabling the large scale use of intermittent renewable generation in a controlled manner.

- **Automated:** the ability of the network to make certain automatic demand response decisions. It will also respond to the consequences of power fluctuations or outages by, for example, being able to reconfigure itself.

- **Fully integrated:** integrated and compatible with existing systems and with other new devices such as smart consumer appliances.

We note that while many respondents to Ofgem's consultation were broadly content with the definition of smart grids, some respondents felt that the definition was not exhaustive and some felt it was too broad. Others argued that the definition should be more explicit about the role of suppliers and network operators. However, given the broad agreement with the ENSG definition, we continue to use it in this report.

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12 ENSG (2010) *A Smart Grid Routemap*

13 DECC (2009) *Smarter Grids: the opportunity*

14 We note that the prominence given to loss management in this definition has been questioned.

At the transmission level, the network is already relatively "smart", given its requirement to manage frequency, voltage and current in an active manner. Our model therefore focuses on "smart" investments at the distribution network level, where networks are currently more passive. Distribution Network Operators (DNOs), both in GB and internationally, have conventionally operated networks with relatively straightforward flows of electricity. Although DNOs can point to a few examples where they have made trade-offs between investment and active management options, DNOs have, in general, limited experience of active management. Many of the near term activities required to deliver a low-carbon energy sector require the current electricity distribution network to become more flexible. Smart grids are therefore likely to be focussed on the distribution networks.

The high-level definition set out above describes smart grids in terms of the functionality that they provide. For the purposes of the modelling, we also need to identify the mix of technologies that would be capable of providing this functionality. Section 5 below provides a detailed overview of the "smart" technologies we propose to initially include in our model. We recognise that this is not a fully comprehensive set and that the analysis provided by WS3 will allow the model to be populated with further technology options.

2.2 Smart meter assumptions

Smart meters are being rolled out to all domestic users by 2019, irrespective of whether any additional investment in smart grids takes place. Smart meters are a component of the wider smart grid and will potentially make electricity consumption significantly more observable, controllable and automated than it currently is.[15]

Our analysis needs to assess the incremental costs and benefits of the smart grid over and above the smart meters which Government has already committed to rolling out. Including all the benefits of smart meters within our evaluation framework would risk double-counting benefits which have already been considered as part of the smart meter impact assessment. Our analysis therefore draws a clear distinction between "smart grids" and "smart meters" and seeks to identify and measure the additional functionality that smart grids would provide, over and above the functionality provided by the planned smart meter rollout.

For the purpose of this modelling, the most important element of smart meter functionality relates to the type of demand side response (DSR) that can be facilitated by the smart meter.

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15 DECC (2010) *Impact assessment of GB-wide roll out of smart meters for the domestic sector* http://www.ofgem.gov.uk/e-serve/sm/Documentation/Documents1/DECC%20-%20Impact%20assessment%20-%20Domestic.pdf, p. 14

2.2.1 Types of DSR

We consider three types of DSR in this work.

- **Static DSR to reduce GB-level generation costs**. Static DSR is facilitated by system-wide signals set in advance. These signals do not change according to real-time conditions, but would be set to correspond to average predicted electricity cost and demand profiles. Economy 7, the tariff which offers customers cheaper electricity overnight, is an example of a static time of use signal. With smart meters, somewhat more sophisticated tariffs could be offered which update on a month-by-month basis to reflect seasonal patterns of demand.

- **Dynamic DSR to reduce GB-level generation costs.** Dynamic DSR in this context entails a real-time response to changing system-wide generation costs. This type of DSR may be particularly valuable in a system including a significant proportion of intermittent generation, where there is likely to be a value in encouraging customers to increase their use at times when output from the intermittent generation is highest, but where this output is not predictable far in advance. A dynamic time of use tariff aimed at minimising generation costs, could, for example, send a half hourly signal to customers based on half hourly wholesale generation costs.

- **Dynamic DSR to reduce local network costs.** Dynamic locally-driven DSR in this context means DSR that aims to reduce distribution network costs by shifting demand to smooth peaks. Again, this entails a real time signal and could be based on a half hourly signal to customers that reflects real time distribution network conditions. Unlike DSR which aims to minimise generation costs, this type of DSR would require the ability to adjust load on a local basis, to take account of the different loads and capabilities of a given feeder. The technologies required to send a signal based on local network costs may be different to those which can send a signal based on GB-level generation costs.

Smart meter assumptions included in the model

Some specific aspects of the detailed functionality of smart meter communications capabilities had not yet been decided[16], and there was no clear agreement among respondents to our consultation on the assumptions should be made on the capability of smart meters to facilitate dynamic DSR to reduce local

16 We note that the functionality of smart meters relating to the communications infrastructure is currently being examined by the Government as part of the DCC Service Providers Procurement Process.

network costs. Given the uncertainty around these specific aspects, we have decided to include three options for smart meter functionality in the model[17].

- In **Option 1** we assume that smart meters alone will allow dynamic system-wide signals to be sent from 2012. Additional smart grid investment by DNOs is required to facilitate dynamic DSR to reduce local network costs. This investment could include carrying out monitoring on the local networks to determine where DSR can be deployed, and any costs associated with communicating the data.

- In **Option 2** it is assumed that smart meters alone will only permit static DSR until the mid-2020s. During the 2020s,[18] we assume that additional smart meter communications infrastructure is installed which facilitates dynamic DSR to reduce system-wide generation costs. Additional smart grid investment by DNOs would still be required to facilitate dynamic DSR to reduce local network costs.

- In **Option 3** we again assume that smart meters alone can deliver only static tariffs. We now assume that the smart meter enhanced communications infrastructure installed in the 2020s could deliver both dynamic DSR to reduce system-wide generation costs and dynamic DSR to reduce local network costs from the mid-2020s onwards, without further smart grid investment.

These options are summarised in Table 1. This table shows the *additional* DSR functionality delivered by smart grids, which varies according to what is believed to be available without additional investment from smart grids. For example, no benefits arising from DSR are attributed to smart grids under Option 3.

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17 We had originally intended to include a fourth option in the model. This would allow users to assume that smart meters deliver only static system-wide DSR until 2050. Under this option, all of the costs and benefits of dynamic DSR to reduce GB-wide generation costs and dynamic DSR to reduce local network costs would be attributed to smart grid investments. However, a full optimisation of the different uses of DSR is beyond the scope of this project, and without this full optimisation, it is difficult to meaningfully examine this option using our model. Therefore we have not included the option in the model. We explain this further in Section 6.2.2.

18 For the purpose of the model, we assume that 2023 is the first year that smart meters are capable of facilitating dynamic DSR. This date is chosen to match the period in our model where the DNOs' investment strategy can be adjusted. It encapsulates the possibility that smart meter capabilities may grow over time.

Table 1. Smart meters and smart grids: functionality for DSR

	Smart meter DSR functionality to mid-2020s	Smart meter DSR functionality from mid-2020s	Additional DSR functionality from smart grid investments
Option 1	Dynamic DSR to reduce GB-level generation costs	Dynamic DSR to reduce GB-level generation costs	Dynamic DSR to reduce local network costs
Option 2	Static DSR to reduce GB-level generation costs	Dynamic DSR to reduce GB-level generation costs	Dynamic DSR to reduce local network costs
Option 3	Static DSR to reduce GB-level generation costs	Dynamic DSR to reduce GB-level generation costs and to reduce local network costs	None

2.2.2 Smart meter functionality assumed in this report

Our model includes three options for smart meter functionality, as described above. For the purposes of the results presented in this report, we have assumed that Option 2 holds. Therefore, we assume that smart meters can deliver static DSR signals to reduce generation costs until the mid-2020s and dynamic DSR signals to reduce generation costs thereafter. Specific smart grid investments are required to deliver dynamic DSR signals to reduce local network costs.

3 Overview of methodology

In this section, we provide an overview of our proposed framework for evaluating the costs and benefits of smart grids.

- We first discuss the need for transparency and flexibility in this work and the implications that this has for our approach.

- We then provide an overview of the main challenges associated with the appraisal of smart grids and explain how our analysis addresses them.

3.1 The need for transparency and flexibility

The aim of this piece of work has been to establish a quantitative framework for the appraisal of smart grids. Two main principles underlie the development of this framework.

- **Transparency.** The value of smart grids will be driven by future demand and supply side developments in the electricity sector, many of which are highly uncertain. Rather than focussing on producing a single overall estimate of the net benefits of smart grids from a black box model, it was felt to be more useful to produce a framework that allows better understanding of the factors that drive the value of smart grids by ensuring that:
  - all assumptions are explicit;
  - the assumptions can be flexed so the sensitivity of the results to each one can be understood.

- **Flexibility**. There is currently a large programme of trials on smart grid interventions being undertaken through the Low Carbon Network (LCN) Fund.[19] These, and other international developments in smart grid implementation, will mean that greater information on the costs and benefits of smart grids will become available over the next few years. For this reason, it is important that any framework can be updated as new information becomes available.

Our focus on delivering a flexible and transparent model has had the following implications.

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19 http://www.ofgem.gov.uk/networks/elecdist/lcnf/pages/lcnf.aspx

- **Model scope**. To maintain flexibility and transparency, each element has not been modelled to a full level of granularity:
  - a parametric rather than a nodal approach to distribution network modelling has been taken;
  - high level representations of generation, transmission and interconnection have been included,
  - we do not value the use of DSR or electrical energy storage for system balancing;
  - demand and wind patterns have been represented by using typical and peak days;
  - we consider the potential to shift demand within days, but not between days; and
  - full optimisation between different uses of DSR has not been carried out.
- **Data population.** This work has focussed on developing a robust and flexible appraisal methodology and formalising this in a model, rather than on carrying out detailed research on each of the parameters included in the model. We have populated this model with data, based on inputs from SGF WS1 and other published information. However, we do not consider this to be the definitive data set for use in this area and we envisage that the data in this model will be updated as new information becomes available.

The model simplifications and the fact that new data is likely to become available mean that the results of this modelling should be seen as a first step in understanding the drivers of the costs and benefits of smart grids, rather than as a definitive assessment of their value. As we set out above, the main purpose of this model is to increase our understanding of what drives the value of smart grids, and therefore where the results appear to be sensitive to the assumptions that are used.

In accordance with the aims of transparency and flexibility, the model has been produced in Excel. Users will be able to view the assumptions included in the model, and amend key assumptions to test alternative scenarios and to understand more about the drivers of the value of smart grids.

3.2 Overall scope of the analysis

Our analysis compares the costs and benefits of investing in smart grid technologies to the costs and benefits of continuing to invest in conventional technologies. We now discuss the scope of our analysis. In the interests of transparency we also highlight the aspects which we do not include in our model, and where further work to assess their impact may be warranted.

Our model has the following scope.

- **Our framework assesses the direct costs and benefits of smart grids**. These direct costs and benefits include the following:
  - investment costs associated with smart and conventional technologies;
  - changes in generation and transmission costs;
  - changes in losses and security of supply associated with smart investments;
  - customer inconvenience costs; and
  - direct CO_2 emissions implications (for example, if the changes in emissions that results from a smoothing in the demand profile due to DSR or embedded storage)[20].
- **We consider both the overall costs to society and the distribution of these costs across the electricity sector**
  - Our model allows assessment of the overall net benefits to GB of the investment strategies considered. This overall assessment will help inform the question of whether a policy of pursuing smart grid technology makes sense for society as a whole. Our initial estimates of these net benefits are set out in Section 6.
  - We also consider the distribution of costs between parties in the electricity sector. This analysis aims to identify whether costs and benefits are aligned between parties. If costs and benefits are not aligned, this may act as a barrier to investment.
- **We take a long-term view.** To span the lifetime of the assets under question, our model will consider the implications of smart grid investments between 2012 and 2050. However, our focus is very much on the near term and we will use the model to consider what these long-term implications mean about the current case for smart grid investment.

Some aspects of policy associated with smart grids are out of the scope of this analysis.

20 We value carbon emissions in line with Government guidance, http://www.decc.gov.uk/en/content/cms/about/ec_social_res/iag_guidance/iag_guidance.aspx

- **Indirect costs and benefits.** We do not consider indirect costs and benefits of smart grids, such as the potential for job creation, or the potential impact on the macro-economy of changing energy costs.

- **Assessment of the market arrangements.** We do not assess the market arrangements required to deliver smart grid benefits, for example the required tariff types or commercial arrangements.

- **Wider benefits associated with decarbonisation.** While we do assess the direct impact of smart grid investment on carbon emissions (e.g. through changes in the demand profile), our analysis assumes that key elements of decarbonisation policy (such as heat and transport electrification) could be accommodated through conventional grid investments as well as through smart grid investments (albeit at a potentially higher cost). We therefore do not include an assessment of the costs and benefits of general policy to decarbonise the GB economy.

In addition, we do not value all direct cost and benefits.

- **Other non-market goods.** We do not value the impact of all non-market goods in this analysis. For example, we have not valued the potential landscape benefits from reduced wirescape, or the reduced disruption and environmental impacts from reduced requirements for roadwork.

- **Benefits associated with shorter investment lead times for certain technologies.** We do not take account of differences between smart and conventional investments in the speed of connection of low-carbon technologies.

3.3 Key complexities

It is well recognised that developing a smart grid evaluation framework involves a number of challenges. The complexities include the following issues:

- smart grids as an enabling technology;
- uncertainty and option value;
- multiple solutions; and
- scale and profile of investment required.

We now discuss our approach to dealing with these complexities.

3.3.1 Smart grids as enabling technologies

There are a variety of ways in which smart grid technologies may allow benefits for society to be realised. For example, the smart grid might facilitate the connection of more low-carbon technologies (such as electric vehicles), displacing more polluting technologies and leading to a reduction in emissions. In addition, the increased monitoring of distribution networks could enable increases in the reliability of supply.

Our evaluation framework focusses on assessing the incremental costs and benefits of smart grids relative to conventional distribution grid technologies. It does not aim to capture the costs and benefits associated with decarbonising heat, transport or the electricity sector more widely.

We consider that such outcomes can generally also be achieved in the absence of smart grid investment (albeit potentially at higher cost), through traditional reinforcement. As such, our model holds objectives such as overall emissions and supply reliability constant, and simply compares the costs and benefits associated with different means of achieving these outcomes. However, where the application of different solutions leads to changes in security of supply or carbon emissions as ancillary benefits, we will include these in our evaluation[21].

The following examples may help illustrate this approach.

- Each of the scenarios considered in our framework contains a certain number of low-carbon technologies such as electric vehicles and heat pumps. We compare the costs of accommodating these low-carbon technologies with smart technologies and with conventional technologies. However, we do not assess the costs and benefits of the heat pumps and electric vehicles themselves.

- Each of our scenarios is associated with a certain generation capacity mix. If a smart grid technology changes the profile of demand and thereby changes how that generation capacity is used (or changes the overall generator capacity required), we include the value of the resulting change in emissions in our evaluation[22].

- Where a smart grid technology is applied to accommodate low-carbon technologies, but brings with it an improvement in quality of supply over and above today's standards, we note the associated improvement of quality

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21 We recognise that increased electrification of heat and transport is likely to increase the value of lost load and hence the justification for security of supply improvements. However, assessing the likelihood of such a change is beyond the scope of this project.

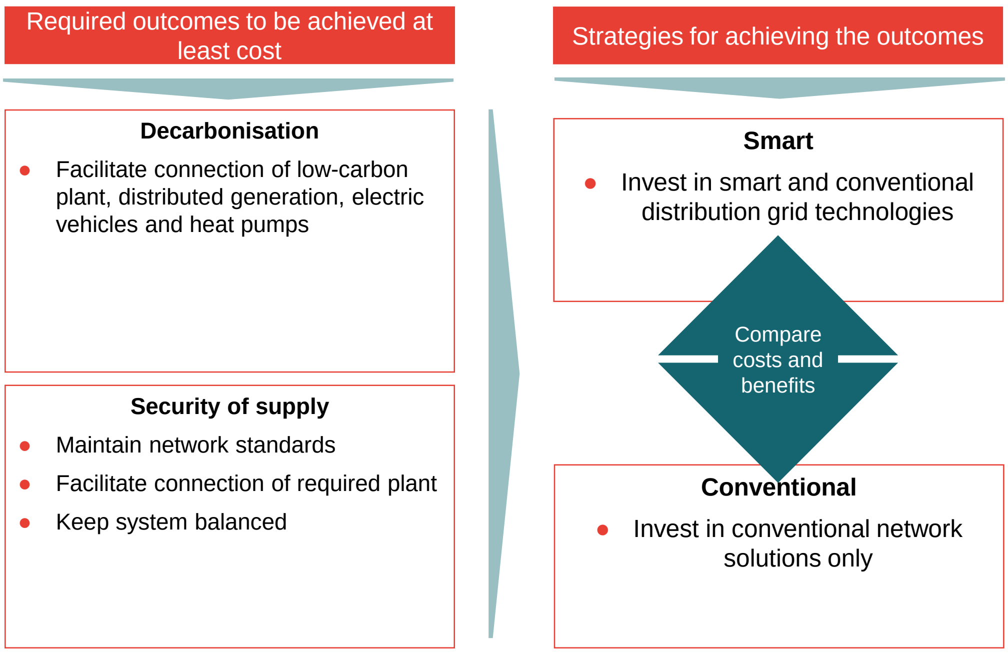
22 We value carbon emissions in line with Government guidance, http://www.decc.gov.uk/en/content/cms/about/ec_social_res/iag_guidance/iag_guidance.aspx

of supply in our assessment. However, we do not compare alternative ways of exceeding today's quality of supply standards.

We note that in some cases, accommodating low-carbon technologies without smart investment may result in connection delays or increased customer interruptions, due to the longer lead times potentially associated with conventional investments. While these potential additional benefits are not currently picked up in our model, we recommend that they are considered in future work.

Figure 5 sets out our approach. As described above, we have focussed on the potential of smart grids and conventional solutions as alternative means to achieving energy sector aims, rather than assessing the costs and benefits of these aims themselves.

Figure 5. Overview of our approach



Source: Frontier Economics

3.3.2 Uncertainty and option value:

There is considerable uncertainty about future demand and supply conditions in the electricity sector. Given the long timeframe of investments, the multiple potential future decarbonisation paths, and the different characteristics of grid investment strategies in terms of their flexibility in the face of uncertainty, our evaluation needs to take account of this.

This high degree of uncertainty has two important implications for our evaluation framework:

- first, it strengthens the case for considering **more than one possible scenario**; and
- second, it means that we should take account of the "**option value**" that arises from networks having the opportunity to modify their investment strategies in future years in response to new information about the value of smart grids.

We consider each of these implications in turn.

Multiple scenarios

Given uncertainty over the future, we assess the value of smart grid strategies within three scenarios, which represent different states of the world to 2050. These aim to vary the factors which are most uncertain and have the greatest impact on the value of smart grids. In Section 4, we describe the scenarios with which we have populated the model. These scenarios are informed by the outputs of WS1 of the SGF and vary:

- penetration levels of low-carbon technologies; and
- the extent to which customers engage with DSR.

Option value

The uncertain background against which smart grid investment decisions need to be taken makes conventional cost-benefit analysis techniques difficult to apply. In particular, a standard cost-benefit analysis may lead to misleading results when assessing options over time under conditions of uncertainty. For example, under a standard cost-benefit analysis, which implicitly assumes perfect foresight, a capital-intense option might have a higher net present value than an option that has high ongoing costs, but no upfront costs. Once uncertainty over the future outturn scenario is taken into account, the latter approach might look more sensible because of the flexibility associated with it: you can choose not to run it if it turns out not to be needed.

Given that smart and conventional options have different levels of capital intensity, a more innovative method of evaluation needs to be applied. This method needs to be able to factor in the option value associated with early investment in flexible solutions (i.e. potentially ahead of need) or delaying investment until more information is available.

We have based our cost benefit analysis on the principles of "real options" analysis. This recognises the possibility that, under some circumstances, networks might be able to adapt their investment strategies in future years as new information about the utility of smart grids becomes available. This allows the evaluation framework to take account of the option value associated with any smart grid investments that avoid lock-in to a particular investment path. Examples of investments with option value may include:

- investments that can be incrementally augmented in future periods;
- investments that promote learning, and which may therefore make future investments less costly or more feasible[23]; and
- investments that entail high upfront costs, but reduce ongoing investment costs.

Real options-based analysis allows the best strategy to be chosen in the face of uncertainty, by factoring in:

- the impact of new information on the state of the world into the analysis at a decision point in the future; and
- the extent to which the investment strategy today facilitates or limits the ability of networks to adjust their investment strategies when this new information becomes available.

We capture the differing option values associated with the different strategies by looking at the costs and benefits across two time periods. As a default assumption in the model, the first time period stretches from 2012 until 2023, and the second stretches from 2023 out to 2050. We use the year 2023 for the decision point in our decision tree analysis as this is likely to coincide with the beginning of the first price control period after the completion of the smart-meter rollout and so is likely to be a natural point for the industry to adjust its smart grids strategy if necessary[24]. However users can change the date of the decision point in the model.

Having identified these two time periods, the model first runs a standard cost-benefit analysis on the first period, where the costs and benefits of each strategy are assessed for each scenario.

The model then considers the second time period. For each strategy that has been chosen at the first decision point (2012), there are a set of strategies that are still possible at the second decision point (2023). However, not all will be possible: for example, if a top-down strategy has been chosen in 2012, it is not

23 While we do take account of the fact that the cost of smart technologies is likely to fall over time , learning is not modelled endogenously in our framework, on the basis that it is likely to be driven at least partly, by global rather than UK deployment.

24 Many, but not all consultation respondents agreed with the choice of date for the decision point. We note that the industry would begin to discuss any changes to its smart grid strategy for ED2 several years before 2023, however, the actual changes would be more likely to occur from the beginning of ED2 in 2023.

possible to change to an incremental strategy or conventional strategy to smart grids in the mid-2020s without stranding a number of assets.

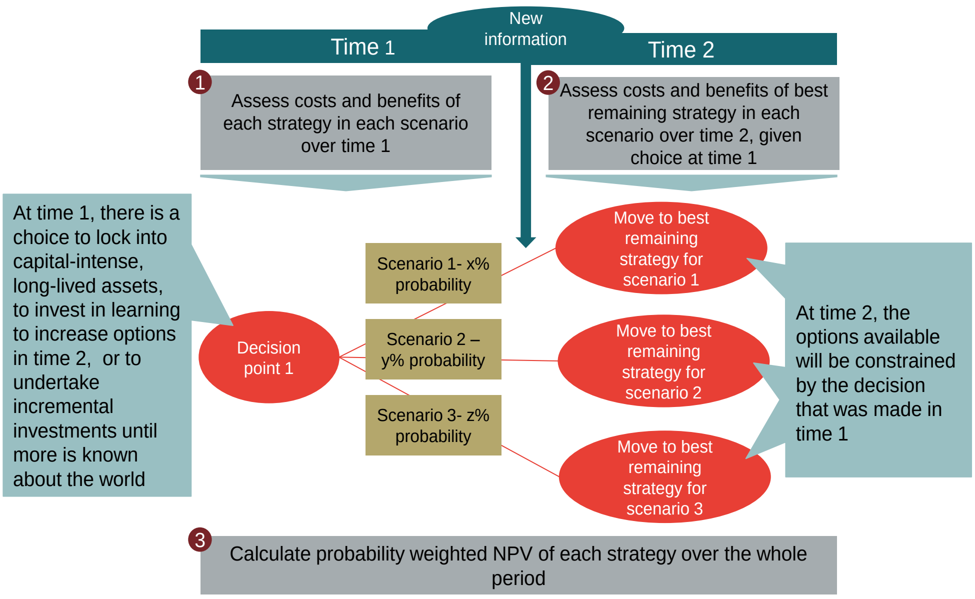
For each scenario, therefore, we identify the best available strategy at the second decision point (2023), given:

- the assumed scenario; and
- the optimal investment strategy associated with this scenario, subject to the constraints imposed upon the set of available strategies by the investment strategy chosen at the first decision point (2012).

The final step is to add together the results of the conventional cost-benefit analysis for the first period with the results of the cost-benefit analysis for the second period to identify a total net present value (NPV) benefit measure for each scenario and strategy. By weighting the NPV benefit estimates by assumed probability of each scenario occurring, we can identify a single probability-weighted NPV benefit estimate for each investment strategy.

Figure 6 below provides a diagrammatic illustration of our "real options" approach that we have described above.

Figure 6. Real options based approach



Source: Frontier Economics

We believe that this kind of decision tree analysis provides the right balance between accounting for uncertainty and avoiding the spurious accuracy which might be associated with a more data-intense modelling approach.

- Decision tree analysis takes the principles of real options analysis and ensures that path dependency is accounted for. This ensures that investments that keep options open are valued more highly than investments which lock-in to a certain path.

- At the same time this analysis maintains simplicity and transparency. Rather than requiring the inevitably subjective development of detailed probability distributions around key variables in the model and their interdependencies, decision tree analysis allows assumptions on the probability of each scenario to be kept explicit, and changeable for the use in sensitivities. By limiting the decision tree to two periods, we will be able to take account of the different option values associated with different smart grid investment strategies without allowing the evaluation framework to become too complex.

3.3.3 Multiple solutions

A smart grid is not just one technology, nor is it a well-defined package of technologies. Instead, a smart grid could be made up of a range of technologies that can be applied in different combinations and at different geographical scales.

Given interdependencies between the functionality of different smart grid technologies, the costs and benefits of each individual technology are likely to be dependent on whether other technologies have been rolled out. Because of these interdependences, rather than assessing the incremental costs and benefits of each individual smart grid technology in isolation, it makes sense to assess the costs and benefits of representative smart grid investment packages or strategies.

We assess two smart grid investment strategies. These are compared to a conventional strategy, where only investments in conventional grid technologies are undertaken (over and above existing policies to rollout smart meters). Each strategy assessed entails enough investment to at least maintain current levels of security of supply, and to facilitate the same amount of connections of low-carbon plant and demand side technologies (as illustrated in Figure 5). The strategies differ solely in terms of the means they use to deliver these outcomes.

These alternative strategies are described in Table 2. Further detail is provided in Section 5 below.

Table 2. Investment strategies

	Characteristics
Top-down smart grid investment strategy	Upfront roll out of control and communications infrastructure. Roll out of smart and conventional technologies when required.
Incremental smart grid investment strategy	Roll out of smart and conventional technologies, and associated control and communications infrastructure when required.
Conventional strategy	Roll out of conventional technologies only, when required

Source: Frontier Economics/EA Technology

3.3.4 Scale and profile of investment required

Smart grid and conventional solutions may differ in the following ways:

- the extent to which they need to be applied in a coordinated fashion to be effective; and
- the extent to which they involve up-front capital investment and the subsequent lifespan of these assets.

We discuss the potential relevance of each of these factors for our evaluation framework below.

- **Scale effects:** Some smart grid solutions (for example, the control and communications infrastructure) may need to be applied at a certain scale and in a holistic or top-down manner to minimise deployment cost. However, it may also be possible to efficiently deploy smart technologies in an incremental way, irrespective of the scale of investment. We assess both a top-down and an incremental approach to investment in our framework.

- **Capital-intensity:** Smart grid and conventional technologies have different levels of capital-intensity (i.e. different levels of upfront costs as a proportion of total costs) and different lifetimes. The higher the capital-intensity and the longer the lifetime, the greater the level of sunk costs associated with any investment and the less flexibility there will be to adjust the response to unexpected supply or demand side developments.

These considerations reinforce the case for considering more than one possible smart grid investment strategy. A top-down centralised investment strategy will typically involve a greater initial investment, but may be more cost-effective in the longer run than an incremental approach that upgrades each section of the network as necessary. Looking at more than one type of smart grid strategy will allow us to take account of the benefits that might arise from a more holistic or top-down approach to smart grid investment. For example, if there are significant scale effects associated with smart grid investment, then it might be that an incremental smart grid investment strategy delivers less value than a conventional investment strategy, but that a top-down smart grid rollout delivers more value than the conventional strategy. Conversely, under different conditions, the additional flexibility in the face of uncertainty provided by the incremental strategy may make it more cost-effective overall than the top-down alternative.

Table 3 summarises the difference between the investment strategies with respect to the importance of scale and the proportion of upfront cost.

Table 3. Investment strategies

	Scale effects	**Proportion of costs borne up front**
Top-down smart grid investment strategy	High	High
Incremental smart grid investment strategy	Low	Low
Conventional strategy	Low	Medium

Source: Frontier Economics/EA Technology

4 Detailed specification of scenarios and data

The smart grid model produced by this project has been set up in a way that will allow users to update the key data and scenarios it contains as new information becomes available. However, as a starting point, we have populated it with a set of data and scenarios. These are set out in this section and they underlie the results presented in Section 6.

In this section we:

- first describe the overall scenarios we are considering in the model and their rationale;
- then describe the data provided by WS1 of the SGF; and
- finally set out additional assumptions and data we have drawn upon to take the scenario data down to the required level of granularity.

4.1 Overview of scenarios

Given uncertainty over the future, we assess our smart grid strategies three scenarios, each of which represents a different state of the world to 2050.

4.1.1 Scenario definition

In this section, we set out the main factors which we vary across scenarios. The factors to vary across scenarios should represent:

- the most important smart grid value drivers: those factors which will most affect the value of smart grids in each scenario; and
- those smart grid value drivers around which there is the most uncertainty:. where the level of penetration could vary significantly.

Value driving technologies

Our Stage 1 report, published in November 2011[25], looked at the impact of a range of value drivers on the value of smart grid. Table 4 provides a high level summary of the technologies that we have built into our evaluation framework. Each of these technologies warranted inclusion in our analysis because:

- they are likely to become increasingly prevalent in future years (due to their ability to help decarbonise the economy); and

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25 Frontier Economics and EA Technology (2011), *A framework for the evaluation of smart grids*, http://www.frontier-economics.com/_library/publications/A%20framework%20for%20the%20evaluation%20of%20smart%20grids.pdf

- they are particularly likely to drive smart grid value for one of the following reasons:
  - they will increase peak load for distribution networks;
  - they will increase the complexity of distribution network flows/cause voltage issues; and/or
  - they will impact on the amount of demand that is flexible and can be used for DSR.

Based on the consultation responses to our Stage 1 report, we have also added representations of the following technologies to the set of technologies included in our model:

- electric storage heaters; and
- commercial air conditioners.

Table 4. Value-driving technologies that we have included in our evaluation framework

Technology	Prevalence to 2050?	Ways in which the technology may increase the value of smart grids		
		Increase peak thermal load on distribution networks	Cause voltage issues or increase the complexity of distribution network flows	Impact on the amount of demand that is flexible
Electric vehicles	High	✓	✓	✓
Heat pumps	High	✓	✓	
Heat pumps with storage	Uncertain	✓	✓	✓
Commercial heating and cooling	Uncertain	✓		✓
Electric storage heaters	Low	✓		✓
Solar PV	Low to medium		✓	
Distribution connected wind	High		✓	

Detailed specification of scenarios and data

Technology	Prevalence to 2050?	Ways in which the technology may increase the value of smart grids		
		Increase peak thermal load on distribution networks	Cause voltage issues or increase the complexity of distribution network flows	Impact on the amount of demand that is flexible
DG: Biomass[26]	High		✓	
Technologies which add flexibility on the supply side (bulk storage, interconnection)	Medium			✓

Source: Frontier Economics and EA Technology

We do not currently include a separate representation of vehicle to grid technologies in the model.

A range of other low-carbon technologies which could drive the value of smart grids were raised in the consultation responses, including:

- CHP;
- hydro generation;
- the European supergrid; and
- solar PV with storage.

We acknowledge that these technologies would impact on the value of smart grids, depending on the extent to which they are deployed. In particular, consultation respondents raised the fact that CHP might impact on the network when units following heat load operate in the early morning at times of low electricity demand. However the results presented in Section 6 do not include the impact of these additional technologies for the following reasons.

26 Generation from biomass is predictable and controllable. However, any DG has the possibility of causing voltage problems, because as it becomes more prevalent the voltage on networks where it is present will rise. In addition, network operators will need to consider in more detail the flows in these portions of the network as large amounts of DG have the effect of making load flows more complex to manage. Biomass DG encompasses small units that would connect at 11kV as well as large plants with capacities above 5MW that would connect at 33kV.

- CHP is not expected to be as prevalent as the other low-carbon technologies included in Table 4 out to 2050. For example, analysis by the CCC suggests that the role for natural gas CHP generation may be limited beyond the 2020s and that the costs of biomass CHP are relatively high compared to biomass boilers[27].

- The potential to add additional hydro generation is likely to be limited on a GB-wide basis.

- Extending the model to cover the European supergrid is not practical, as it would mean including a representation of European generation and transmission networks, and taking account of the correlation of weather, generation output and demand between countries. However, as explained in Annexe A, we do include a simple representation of interconnection in the model.

- While we have not included solar PV and storage together, they are included separately in the model.

Although we have not included them in this version of the model, we have extended the model to include spare slots for additional technologies which users may wish to add to the model themselves.

Other factors

Respondents to the consultation also highlighted the large degree of uncertainty over how customers would engage with DSR and the degree to which they would find it acceptable to move their demand around.

The extent to which DSR is possible will be an important determinant of smart grid value.

- The use of DSR to reduce generation costs could lead to increased peaks on the distribution networks. To the extent that smart grid investments may enable DNOs to upgrade their networks to cope with this at lower cost, DSR by suppliers will act as a value driver for smart grids.

- Smart grid investments will themselves facilitate DSR to reduce peak flows locally.

However, it is currently highly speculative as to what level of DSR may be feasible. For example, time-of-use tariffs by themselves may not be sufficient to encourage customers to adjust their demand. Automated or direct load control

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27 CCC (2010) *The fourth carbon budget,* http://www.theccc.org.uk/reports/fourth-carbon-budget

could ensure a higher level of response, although it is uncertain to what extent customers will accept these interventions.

In our model, we include simple assumptions regarding the responsiveness of demand. These are fully flexible to be changed by users of the model. This approach allows more accurate estimates of demand responsiveness to easily be inputted in the future as they become available (for example, from LCN Fund projects).

To further reflect this uncertainty, following the consultation, we have also included a scenario in the model where customers' engagement with DSR is lower as a proportion of moveable demand.

The amount of DSR under any scenario is driven by several assumptions in the model:

- the mix of technologies on the demand side (e.g. the quantity of electric vehicles, heat pumps, smart appliances etc.);
- the proportion of demand from each to these technologies that is assumed to be flexible;
- the hours which demand can be moved to and from in each day for each technology; and
- the penetrations of technologies to facilitate DSR (smart meter and smart grid technologies).

In our scenario with lower levels of DSR, we have reduced the proportion of demand from each of low-carbon or smart technologies that is assumed to be flexible. The overall level of DSR is then determined by the interaction of this assumption with the other factors listed above.

4.1.2 Summary of scenarios

Table 5 sets out the key value drivers to vary by scenario.

Table 5. Key value drivers to vary across scenarios

	Importance as a value driver	Level of uncertainty over future levels
Electrification of heat and transport	High	High
Increase in distributed generation	Medium	High
Increase in intermittent and inflexible generation	Depends on the functionality already delivered by smart meters[28]	High
Extent to which customers engage with DSR	High	High

Source: Frontier Economics

Given this assessment of the key value drivers we now set out the three scenarios with which we have populated the model. These are summarised in Table 6. Further detail on the actual data is provided in Section 4.2 below.

- **Scenario 1** includes medium DECC projections of transport electrification and of the increase in distributed generation and high DECC projections of the increase in heat electrifications. High projections were used for heat since the combination of medium transport and high heat allows the fourth carbon budget to be met.[29] **Scenario 2** contains the same roll out of low-carbon technologies as Scenario 1. However, in this scenario, the level of customer engagement with DSR is much lower.

- **Scenario 3** is consistent with a situation where the UK chooses to meet its carbon targets through action outside of the domestic electricity sector, for example through purchasing international credits. In this scenario the roll out of low-carbon technologies is slower than expected, and the generation mix contains less inflexible and intermittent low-carbon plant.

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28 If smart meters already facilitate dynamic DSR, the incremental impact of smarts grids in dealing with the issues caused by intermittent generation will be less significant.

29 Scenario 1, DECC (2011), *Carbon Plan*, http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

Table 6. Summary of scenarios

	Electrification of heat and transport	Increase in distributed generation	Increase in intermittent and inflexible generation	Extent to which customers engage with demand response
Scenario 1	Medium transport, high heat (consistent with Scenario 1 of the Government's Carbon Plan)	Medium	Medium	Medium
Scenario 2	Medium transport, high heat (consistent with Scenario 1 of the Government's Carbon Plan)	Medium	Medium	Low
Scenario 3	Low	Low	Low	Medium

Source: Frontier Economics

We have presented results for each of these scenarios in Section 6. We have also carried out sensitivities on a range of inputs around these.

We now go on to discuss the data that each of these scenarios is built upon.

4.2 Data provided by WS1

WS1 of the SGF has developed a set of assumptions and scenarios to 2030 for each of the technologies most likely to have an impact on the value of smart grids. These data are consistent with those used in the Government's *Carbon Plan*, which sets out scenarios for meeting the UK's 4th carbon budget covering the period from 2023 to 2027[30]. This section sets out how we use these scenarios in our model.

30 DECC (2011), *Carbon Plan*, http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

Technology specific scenarios from now until 2030 have been produced for the following technologies by WS1:

- heat pumps;
- electric vehicles; and
- solar PV.[31]

There is inevitable uncertainty attached to deployment of low carbon technologies but the low carbon technology ranges described represent boundaries of expectation based on current analysis and within a framework to deliver the 4th Carbon Budget.

4.2.1 Heat pumps

WS1 provided a set of scenarios for the take up of heat pumps. They, and other scenarios, have been generated using modelling developed for the Committee on Climate Change.

The heat pump scenarios have been described by DECC as follows.

- The **low scenario** assumes a strong focus on deploying larger heat pumps to commercial buildings, with residential uptake phased beyond 2030.
- The **medium scenario** assumes strong uptake in both domestic and commercial buildings, with heat pumps becoming a mainstream alternative to gas from 2020 onwards.
- The **high scenario** assumes a particularly strong uptake of heat pumps in commercial and domestic buildings, driven by popularity with consumers and lower costs.

The differences in the scenarios are driven by assumptions on suitability of sites, the available of biomass (to be used as an alternative means of decarbonising the heat sector), costs of heat pumps and their efficiency (or coefficient of performance).

These scenarios are presented in Figure 7. We assumed linear growth to 2020 and extrapolated linearly out to 2050.

To maintain consistency with the Government's *Carbon Plan*, we have used the high scenario for heat pumps in our Scenarios 1 and 2[32]. We have used the low scenario in Scenario 3.

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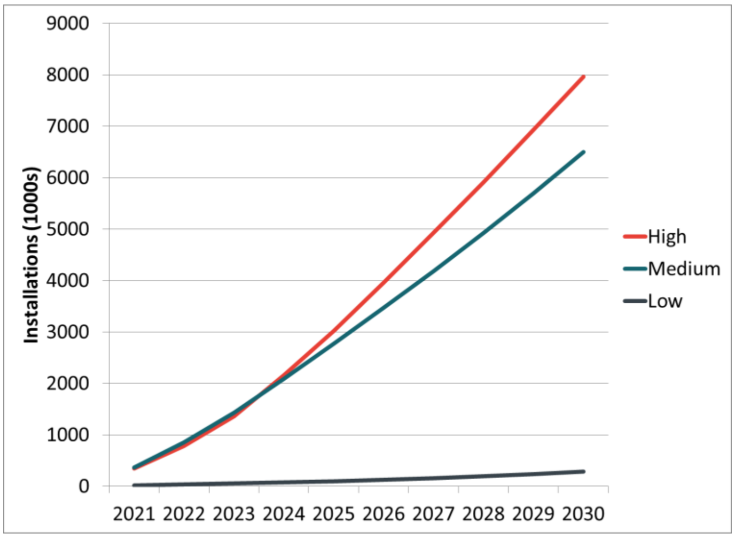
31 WS1 also produced scenarios for wind generation capacity at installations of less than 5 MW. However, these have not been used in this model. Instead, we have used the National Grid scenarios described in section 4.3. This is to ensure consistency within the generation mix used by the model.

Figure 7. WS1 Heat pump scenarios



Source: WS1

4.2.2 Electric vehicles

WS1 provided three scenarios for car and van emissions to 2050.

- The **high and medium scenarios** of EV uptake are calculated to be consistent with average emissions from new cars falling to 50gCO_2/km and 60gCO_2/km in 2030 respectively from 144gCO_2/km for new cars in 2010. This assumes, due to data limitations, that no other zero-emission vehicles, such as fuel-cell hydrogen cars, are available. In reality we do expect there to be some role for hydrogen vehicles. As such, these scenarios represent an upper bound of EV uptake.

- The **low scenario** is based on a 'bottom-up' analysis of the potential for electric vehicles in the UK undertaken by DfT using economic models developed for the Energy Technologies Institute and other sources to form a view on a 'base-case' level of uptake. This level of uptake can best be described as what the market is most likely to deliver without further policy intervention.

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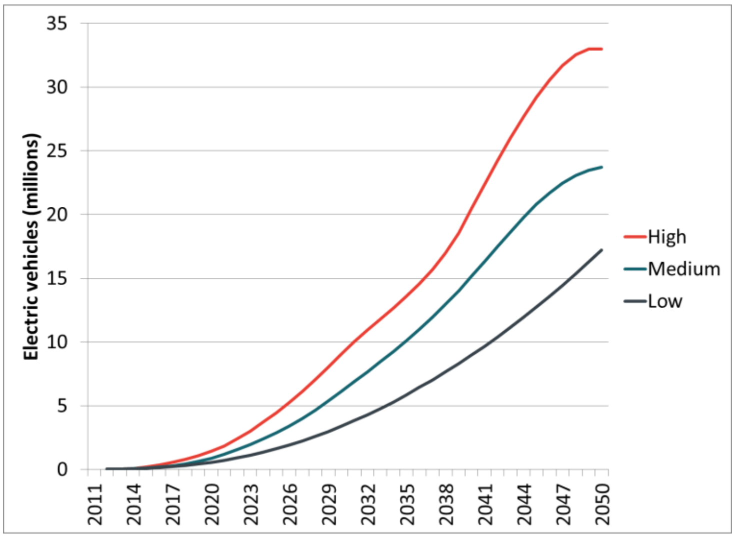
32 One combination that allows carbon budgets to be met is a high level of heat pump penetration combined with central levels of transport electrification (Scenario 1 in the *Carbon Plan*). We take this combination as our central level of heat and transport decarbonisation. Source: DECC (2011), *Carbon Plan*, http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

These scenarios are presented in Figure 8. The medium scenario for electric vehicles is used in our Scenarios 1 and 2, and the low scenario is used in Scenario 3.

Figure 8. WS1 electric vehicle scenarios



Source: WS1

4.2.3 Solar PV

The three scenarios provided by WS1 for solar PV can be described as follows.

- The **low scenario** is based on the assumption that there is very low growth of installations of solar PV across the UK. It would imply very high barriers to PV growth, financial and non-financial (though in the case of PV, barriers are overwhelmingly financial in the vast majority of locations).

- The **medium scenario** is based loosely on level 2 from the DECC *2050 Calculator*[33], which assumes that by 2050 there would be the equivalent of 4m^2 of photovoltaic panels per person in the UK. It results in roughly 1.8 million installations by 2030 (a tenfold rise over the levels at end of 2011).

- The **high scenario** is based on level 3 from the 2050 calculator work. This level assumes that by 2050 there would be the equivalent of 5.4m^2 of solar PV per person, generating roughly 80 TWh/year of electricity. This level of ambition is based upon a report written by the UK Energy Research Centre

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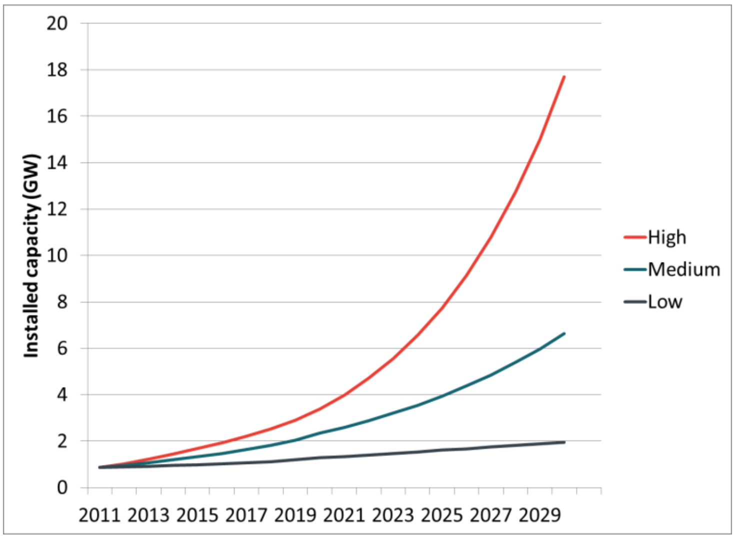
33 http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

in 2007, which estimates that the UK could realistically achieve 16 GW of installed capacity by 2030.

These scenarios are illustrated in Figure 9. As set out above, the medium scenario for PV is used in our Scenarios 1 and 2, and the low scenario is used in our Scenario 3. To extend these scenarios to 2050, we extrapolated linearly, using the trajectories over the 2025-2030 period.

Figure 9. WS1: Solar PV scenarios



Source: WS1

4.3 Other assumptions

Where possible, to ensure consistency with policy goals, we have based our scenarios on Government projections provided by WS1. Where Government data is not available, we have used data from other sources.

4.3.1 Generation mix

Since data on the generation mix consistent with the assumptions on the rollout of low-carbon technologies provided above was not available from WS1, we have instead drawn upon work undertaken by Redpoint for the ENA which collated a range of electricity sector scenarios to 2050.

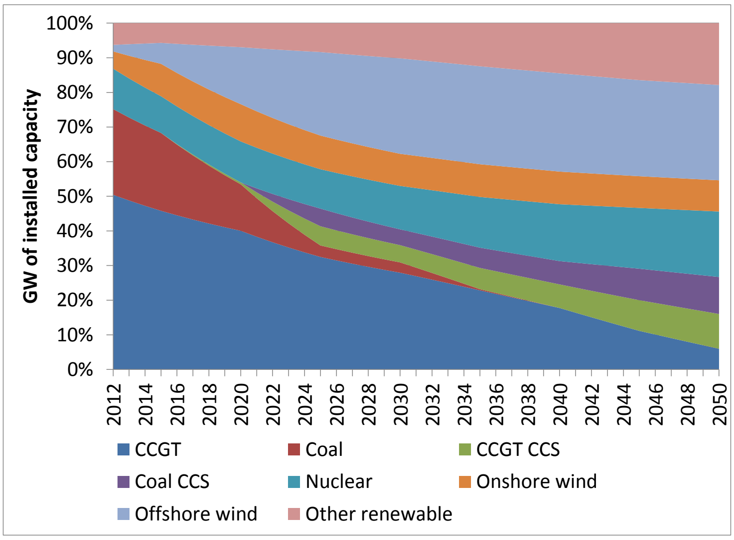
Two scenarios are included in our model (Figure 10 and Figure 11).

- **Medium decarbonisation scenario:** This scenario is based on National Grid's Gone Green scenario and entails a significant level of decarbonisation out to 2050, which could be consistent with meeting overall carbon targets (depending on the level of action in other sectors). Our Scenarios 1 and 2 are based on this scenario.

- **Low decarbonisation scenario.** This scenario is based on National Grid's Slow Progression scenario and entails a much slower rate of decarbonisation, with gas-fired plant (CCGT) continuing to dominate the mix out to 2030. We have extrapolated this scenario out to 2050, by assuming that the generation mix remains proportionately constant after 2030. Our Scenario 3 is based on this mix.

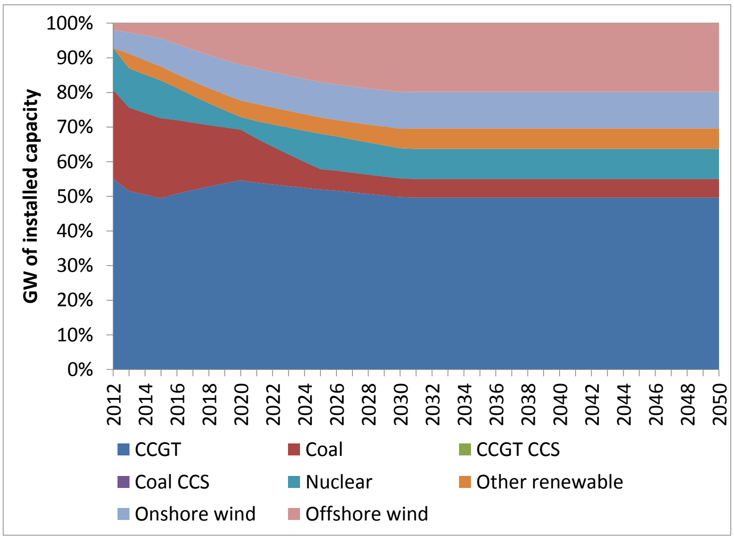
Since no single database was available across both the demand and supply sides of the electricity sector, we have set up the model so that the generation capacity scales automatically to changes in inputs on the demand side to ensure consistency.

Figure 10. Installed capacity: medium decarbonisation scenario



Source: Redpoint analysis for the ENA, based on National Grid Gone Green scenario

Figure 11. Installed capacity: low decarbonisation scenario



Source: Redpoint analysis for the ENA based in National Grid slow progress scenario to 2030 and extrapolated to 2050.

4.3.2 Base Case Networks

This section sets out the starting position of LV, HV and EHV distribution networks in the model.

LV Feeder demand

"Base" household demand profiles (i.e. excluding the other technologies such as EVs and wet appliances that we consider separately) were obtained by analysing a range of sources including profiles from Elexon and from the Strategic Technology Programme's[34] "Long Term Domestic Demands" project.[35] A profile for each of the three 24 hour periods (winter average, summer average and winter peak) was constructed.[36] These were aggregated up to the feeder level by taking an assumed number of households per feeder for the three feeder types.

In the case of the rural feeder, it was assumed that there are 40 properties connected, while for a suburban feeder there are 70 properties connected. The urban feeder is composed of 60 properties, only 45 of which are domestic while

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34 The Strategic Technology Programme is a collection of research and development projects directed and funded by DNOs within the UK and Ireland and coordinated by EA Technology.

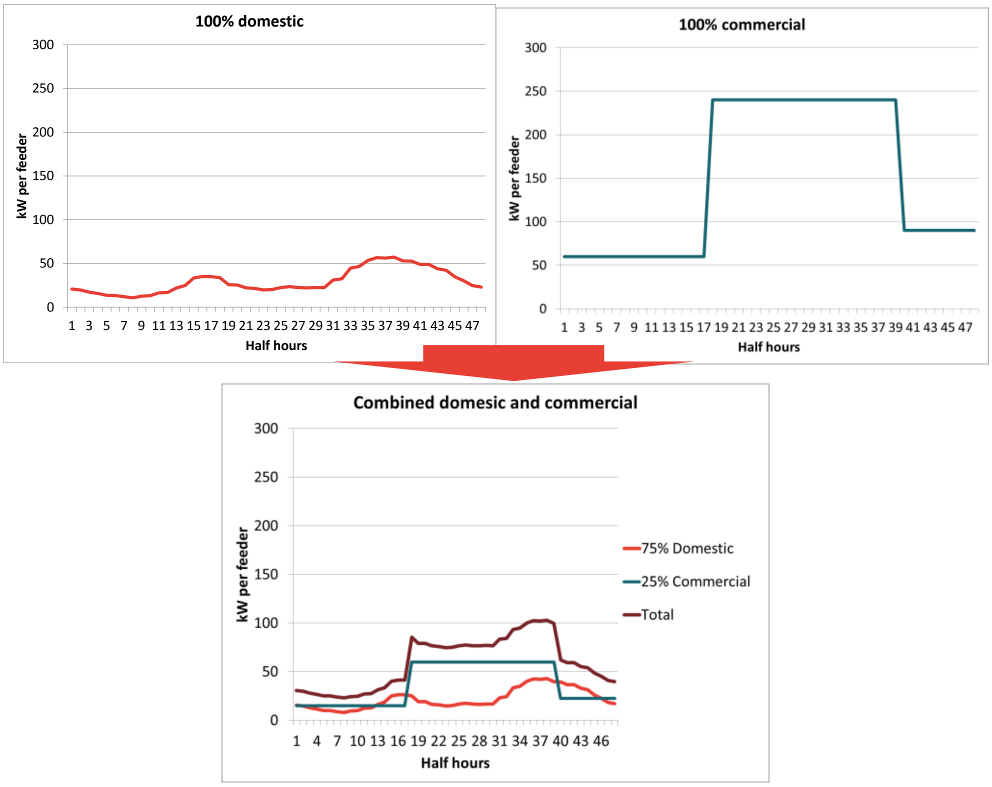
35 Strategic Technology Programme report S5207_2 "Long Term Domestic Demands", D Roberts (2010)

36 Further detail on this is presented in Annexe A.

the remaining 15 are commercial (hence with a different profile). The number of properties per feeder is customisable by the user within the model.

The way in which the urban profile is constructed is shown in Figure 12 where a domestic profile and commercial profile are scaled by 75% and 25% respectively and then combined to give the overall urban LV profile.

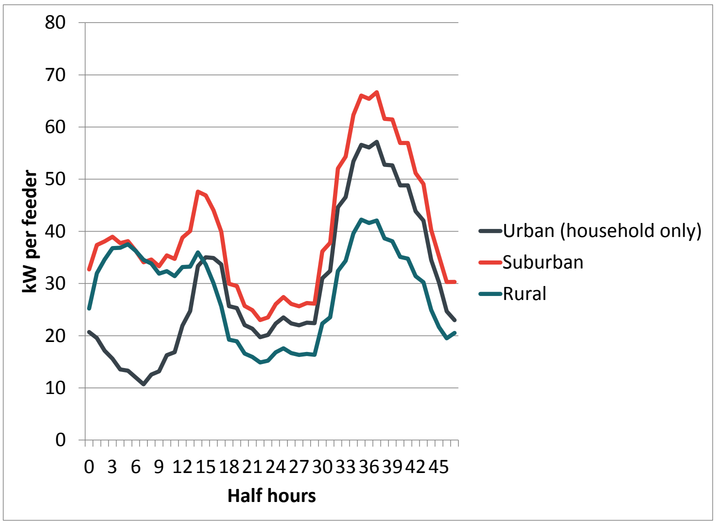
Figure 12. Constructing urban LV profile



Source: EA Technology

Household profiles are illustrated in Figure 13 for an average urban, suburban and rural feeder.

Figure 13. Winter average household feeder demand (kW)



Source: EA Technology

At present the model has been populated with three representative days: winter peak, winter average and summer average. It does not expressly consider the minimum demand in summer, although the minimum demand period during which export from photovoltaic generation will manifest itself is unlikely to differ greatly from summer average conditions. If a user wished to explore the effects at absolute summer minimum, the summer average profile could be replaced with a representative profile for summer minimum and the model could then be run on this basis. WS3 is currently considering whether to use a "summer average" or summer minimum profile in its modelling.

Typical LV networks

The physical electrical network infrastructure is not uniform across GB. Variations have resulted from the age profile (large city centres were electrified well before rural areas, and therefore have different network topologies, new housing estates are designed differently from pre-1950s), differing customer densities, and local geography.

To represent different types of networks used across GB today, three simplified models are used to characterise typical LV urban, suburban and rural areas. We have used the profiles described above with typical network topology data as our starting assumptions as described in Table 7.

Table 7. Assumptions on typical network topology[37]

	Proportion of GB networks	Network (feeder) Topology		
		Typical circuit components	Rating (Amps)	Rating (kW)
LV urban	45%	3 core 120mm² Al underground cable	237A	147
LV suburban	47%	3 core 150mm² Al underground cable	265A	165
LV rural	8%	3 core 0.06in sq equivalent copper overhead line	133A	83

Source: EA Technology

The ratings we have developed for each feeder type come from taking a representative conductor and making appropriate assumptions.[38] We then apply a 10% de-rating factor to account for the fact that experience tells us that cables are not balanced across phases and as such are not capable of running at their full rating. We estimate that a 10% reduction is a reasonably conservative amount by which to de-rate the cable and it may in reality need to be de-rated by more. Some of the activity in WS3 will look at this in more detail for different feeder types.

For each of the three LV feeder types, there is an associated distribution transformer. In each case, we have made assumptions regarding the size of the distribution transformer and the number of feeders it supplies. These are set out in Table 8. The demand experienced by the transformer is calculated by multiplying the appropriate feeder profile by the number of feeders the transformer is assumed to supply.

37 The kW rating is based on phase current multiplied by 230V (LV nominal voltage) multiplied by 3 (phases). We also factor in 10% phase imbalance by derating the result (we multiply by 0.9).

38 For underground cables the ratings were derived by assuming that the cables are Waveform BS7870-3.40:2001, Single Rubber Layer with XLPE insulation. The soil resistivity is assumed to be 1.5K.m/W and the soil ambient temperature to be 15 degrees Celsius. The cables buried at 500mm and the maximum conductor temperature 90 degrees Celsius.

Table 8. Assumptions on transformers

LV network type	Urban	Suburban	Rural
Transformer size (kVA)	1000	500	100
Number of LV feeders supplied	6	4	1

Source: EA Technology

Having determined our network base case, we then need to establish the starting levels of headroom that we expect to find on the various feeders.

Table 9 illustrates this by demonstrating the maximum demand on each of the feeders for each of the seasonal variations. By subtracting the maximum demand from the feeder capacity, we can determine the minimum amount of available headroom.

It should be noted that for the purpose of this model, the ratings of the three representative feeders are held constant across the seasons and continuous ratings (rather than those allowing for any uplift due to cyclic loads, for example) have been applied.

In addition, it is assumed that the security of supply standard (currently Engineering Recommendation P2/6) is held constant across the lifetime of the modeling period (i.e. to 2050). Revisions to this standard before 2050 are likely. However, it is difficult to predict the nature of these revisions and how the cost of interruptions to customers will be calculated in the future. To help reflect this uncertainty, the cost of customer interruptions can be flexed in the model.

Table 9. Assumptions on starting level of headroom[39]

	Number of houses per feeder	Starting Feeder Headroom		
		Summer 1 Apr – 30 Sep	Winter Average 1 Oct – 15 Dec 24 Dec – 31 Dec 11 Jan – 31 Mar	Winter peak 16 Dec – 23 Dec 3 Jan – 10 Jan
LV urban	60	$ADMD_{eq}$ = 1.4kW Total feeder = 83kW **Headroom = 64kW**	$ADMD_{eq}$ = 1.7kW Total feeder = 103kW **Headroom = 44kW**	$ADMD_{eq}$ = 1.8kW Total feeder = 110kW **Headroom = 37kW**
LV suburban	70	$ADMD_{eq}$ = 0.6kW Total feeder = 41kW **Headroom = 124kW**	$ADMD_{eq}$ = 1.1kW Total feeder = 80kW **Headroom = 85kW**	$ADMD_{eq}$ = 1.3kW Total feeder = 90kW **Headroom = 75kW**
LV rural	40	$ADMD_{eq}$ = 0.7kW Total feeder = 29kW **Headroom = 54kW**	$ADMD_{eq}$ = 1.3kW Total feeder = 51kW **Headroom = 32kW**	$ADMD_{eq}$ = 1.4kW Total feeder = 56kW **Headroom = 27kW**

Source: EA Technology

HV feeder demand

At the HV level, the demand is composed of two main elements:

- the sum of the representative LV demands; and
- the commercial load present at HV.

39 A single circuit rating is used for both summer and winter, as seasonal ratings are not applied to LV circuits.

We consider industrial load separately as we assume that a feeder serving an area of domestic and commercial customers will be separate from a feeder serving industrial customers.

The commercial load is constructed from the same profiles as that in the case of LV urban load, but is scaled to represent the fact that commercial load is more prevalent at the HV level.

Typical HV network

We have a representative HV feeder that supplies a number of distribution substations. These substations have the characteristics outlined above in terms of the number of feeders per transformer.

The model assumes that the representative HV feeder supplies four urban substations (each with six LV feeders), four suburban substations (each with four LV feeders) and five rural distribution substations (with a single LV feeder each).

We also consider the application of commercial load. This is done using the same basic profile as for the LV urban feeder, but is scaled up to reflect the fact that commercial load is prevalent at this voltage level.

The load from this group of distribution substations is added to the commercial load to determine the load profile on the HV feeder. The HV feeder is assumed to be a 185mm^2 XLPE cable with a rating of 430A (laid direct), equivalent to approximately 8MW.

The HV network is fed from a primary transformer (33/11kV) assumed to be rated at 24MVA with forced cooling fitted.

EHV feeder demand

There is no domestic or commercial load connected at EHV. The only load present here is a fixed amount of industrial demand.

Generation also connects at this voltage in the form of onshore wind and biomass.

Typical EHV network

We model one typical EHV feeder as supplying four HV feeders. Each of the HV feeders is identical and is as described above. The EHV feeder is considered to be 240mm^2 cable rated at 540A, equivalent to approximately 30MW.

The EHV network is supplied from a Grid Transformer (132/33kV) assumed to be rated at 60MVA.

4.3.3 Incremental demand assumptions

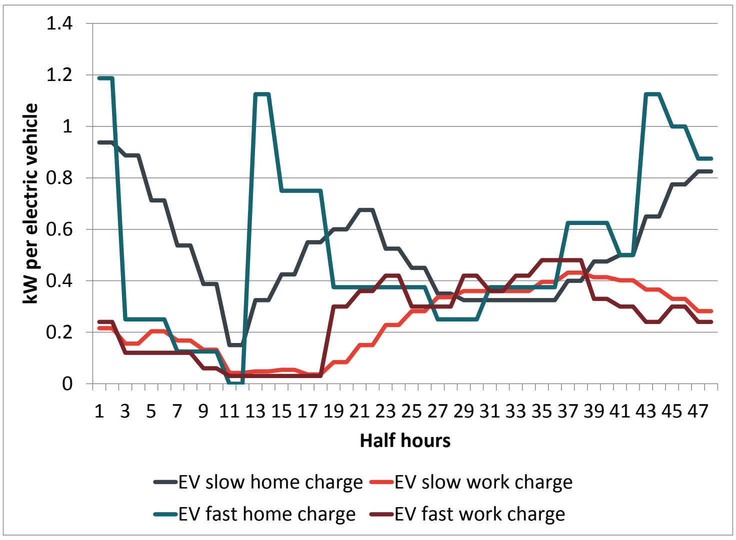
We now set out our assumptions on demand from low-carbon technologies.

Electric vehicle demand

Our assumptions on electric vehicle demand patterns are set out in Figure 14. In the absence of comprehensive published evidence in this area, these are based on our experience in previous projects. We note that some stakeholders have questioned the morning peak for fast home charging. The assumptions with which we have populated the model can be updated as new information becomes available.

The scenarios we have received from WS1 include bother PHEVs and pure EVs. We have assumed that both of these vehicle types have the same charging patterns but that PHEV have a smaller battery size.

Figure 14. Winter average EV demand (taking diversity into account)



Source: EA Technology

Heat pump demand

Figure 15 presents our estimate of winter average heat pump demand for domestic and commercial heat pumps.

Load from heat pumps is likely to be highest in winter and during the day. The domestic profiles used in the model are based on five days of load data taken during winter 2008 from an electricity substation supplying 19 properties, 18 of which had heat pumps installed.[40]

This data was obtained from a limited trial with only a small number of participants. The participants of the trial tended to be elderly, which means that the electricity usage is not the same as it would be in a household of two young professionals, for example. Instead, it is more likely that the houses were occupied for greater portions of the day and, as such, were likely to be heated for greater portions of time. This may represent a slightly pessimistic view and may be considered to be something of a worst case. However, it should be noted that even when houses are unoccupied or large proportions of the day, it will be necessary to heat the building in advance of need. It will be insufficient to have a heat pump switching on once the occupants return home from work owing to the time lag associated with heating.

Some stakeholders have suggested that a flat profile may be more representative of the likely shape of heat pump demand. However, there is currently insufficient data available to develop an alternative profile and hence we have populated the model with the profile in Figure 15. As better data becomes available from wider-scale trial implementations, then the model can be repopulated with this data.

The commercial heat pump profile has been based on a set of assumptions about the building, the weather and the technical characteristics of the heat pumps.[41]

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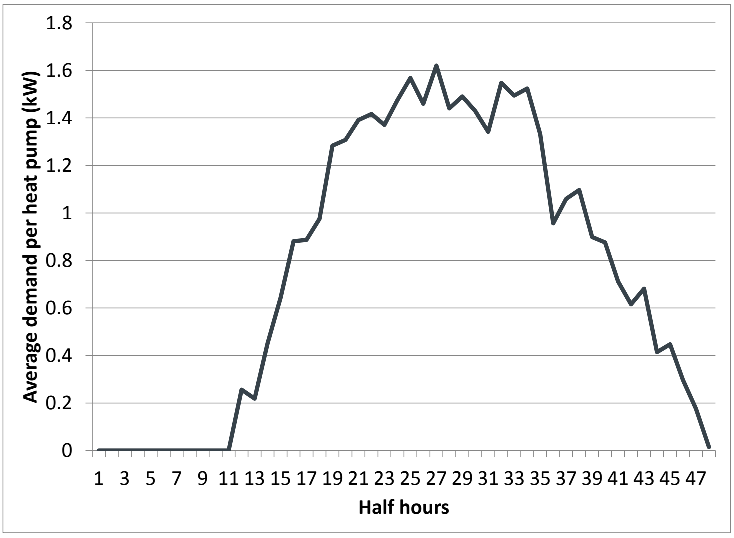
40 S.D. Wilson, Monitoring and Impact of Heat Pumps, Strategic Technology Programme, Project S5204_1, October 2010.

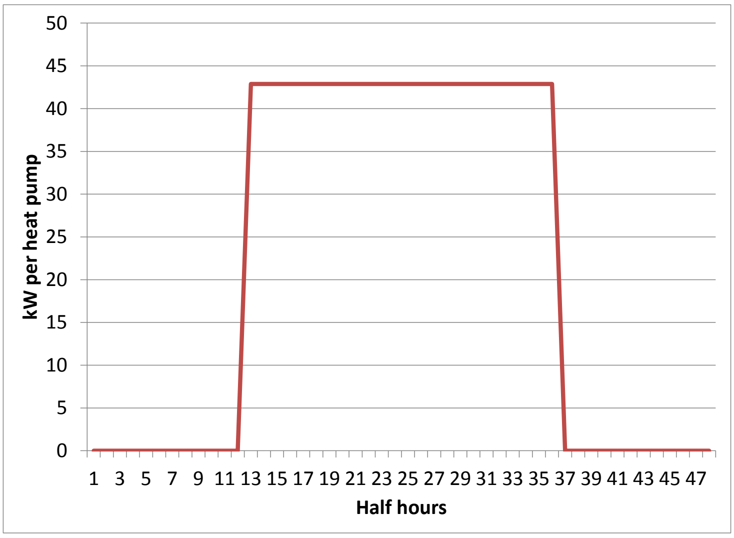
41 The profile has been developed based on several assumptions, which have allowed the UK service-sector average energy consumption for heating[41], 30W/m^2, to be related to a Winter's month. Assumptions are: Co-efficient of performance = 3.0, base temperature = 15.5°C, average daytime December air temperature = 2.8°C and December degree-days = 311[41]. A "Small" office has been defined as 1,000m^2, with "Medium" 5,000m^2 and "Large" 10,000m^2. Heating is required for 12 hours, 06:00 to 18:00, the effects of thermal mass and cooling requirements are neglected. A real profile would change due to many factors. Cycling would also be evident.

Figure 15. Winter average domestic heat pump demand



Source: EA Technology

Figure 16. Winter average commercial heat pump demand

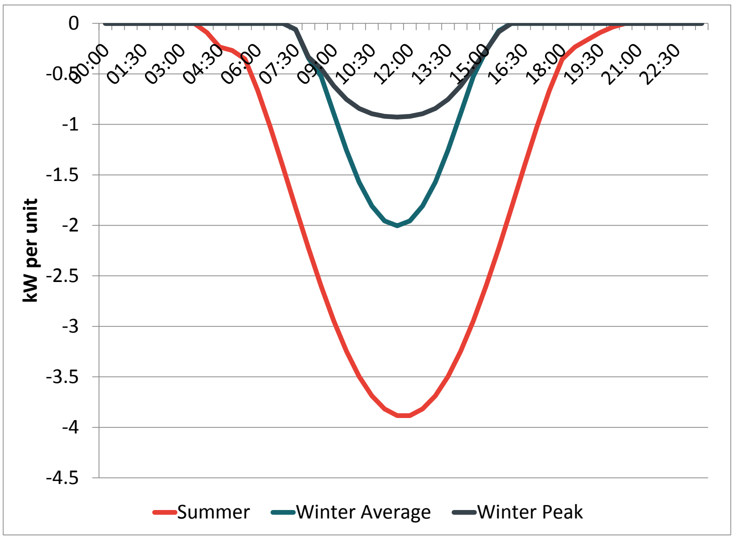


Source: EA Technology

Solar PV

The power from solar PV installations varies both with the time of day (peaking at midday) as well as the season (it is typically highest in mid-summer). Both of these elements can be captured by a half-hourly generation (or negative demand) profile for each season. This is illustrated in Figure 17.

Figure 17. Solar PV output.



Source: EA Technology

Proportion of demand that is flexible

Very little information is currently available on the proportion of demand that will be flexible in practice.

Our assumptions on the proportion of demand that is flexible for each technology are illustrated in Figure 18. These are based on the following:

- initially no demand is flexible, but smart meter roll out increases the proportion to 2020;
- a high proportion of electric vehicle demand is likely to be flexible, given driving patterns and charging times;
- storage heaters are extremely flexible, heat pumps without storage are completely inflexible and there is much less flexibility around the load of heat pumps without storage; and
- even when wet appliances are 'smart,' the flexibility of the load is likely to be limited[42].

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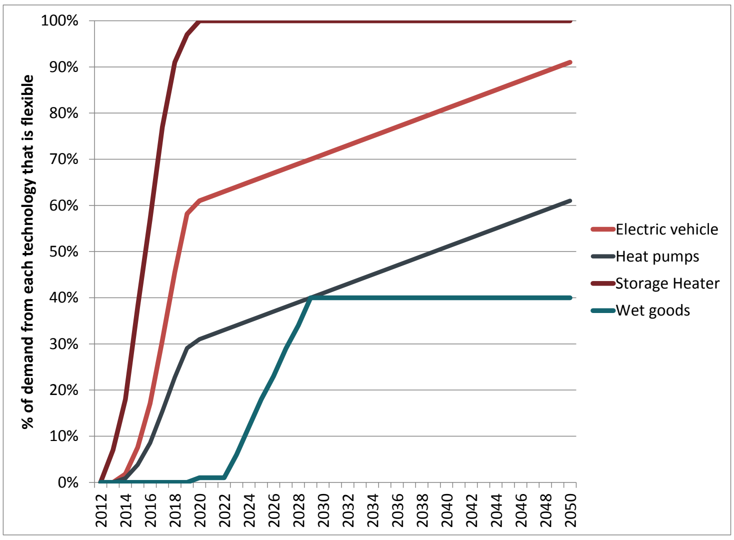
42 40% of consumers surveyed said they would be willing to move their wet appliance demand by up to 24 hours. Smart A (2008), *Synergy Potential of Smart Appliances*, http://www.smart-a.org/WP2_D_2_3_Synergy_Potential_of_Smart_Appliances.pdf

We have populated the model with a range of assumptions, based on our prior experience of work in this area.

Figure 18. Proportion of demand that is flexible



Source: Frontier Economics/EA Technology

We have also made assumptions about the hours of the day where demand is flexible. These vary by technology.

- We assume that electric vehicle demand is likely to be flexible within the night, but not during this day. This is based on the assumption that, given current driving patterns and the assumption that most charging will be at home, shifting overnight charging to the day is not likely to be possible.

- We assume that heat pump demand is only flexible within the day, while in contrast, storage heating is only flexible within the night time period. Where heat pumps do not have storage, we assume their load is not flexible at all. The assumptions in Figure 14, therefore apply to heat pumps with storage (and could also apply to heat pumps installed in highly efficient homes).

- We assume that wet appliance demand is likely to be fully flexible across the day and that only customers with smart wet appliances can flex their demand. Once appliances are smart, there is not likely to be a constraint on when they can be moved.

These assumptions are illustrated in Figure 19.

Figure 19. Flexibility of technologies by half hour

Half hour	Electric vehicle (charge at home)	Heat pumps	Storage Heater	Wet goods
1	flexible	inflexible	flexible	flexible
2	flexible	inflexible	flexible	flexible
3	flexible	inflexible	flexible	flexible
4	flexible	inflexible	flexible	flexible
5	flexible	inflexible	flexible	flexible
6	flexible	inflexible	flexible	flexible
7	flexible	inflexible	flexible	flexible
8	flexible	flexible	flexible	flexible
9	flexible	flexible	flexible	flexible
10	flexible	flexible	flexible	flexible
11	flexible	flexible	flexible	flexible
12	flexible	flexible	flexible	flexible
13	flexible	flexible	flexible	flexible
14	flexible	flexible	flexible	flexible
15	inflexible	flexible	inflexible	flexible
16	inflexible	flexible	inflexible	flexible
17	inflexible	flexible	inflexible	flexible
18	inflexible	flexible	inflexible	flexible
19	inflexible	flexible	inflexible	flexible
20	inflexible	flexible	inflexible	flexible
21	inflexible	flexible	inflexible	flexible
22	inflexible	flexible	inflexible	flexible
23	inflexible	flexible	inflexible	flexible
24	inflexible	flexible	inflexible	flexible
25	inflexible	flexible	inflexible	flexible
26	inflexible	flexible	inflexible	flexible
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39	flexible	flexible	inflexible	flexible
40	flexible	flexible	inflexible	flexible
41	flexible	flexible	inflexible	flexible
42	flexible	flexible	inflexible	flexible
43	flexible	flexible	inflexible	flexible
44	flexible	flexible	inflexible	flexible
45	flexible	flexible	inflexible	flexible
46	flexible	flexible	inflexible	flexible
47	flexible	flexible	flexible	flexible
48	flexible	flexible	flexible	flexible

4.3.4 Clustering of low-carbon technologies

It is widely recognised that the degree of clustering of low-carbon technologies has a dominant impact on the value drivers of smart grid investments.

Our previous experience of modelling the impact of low-carbon technologies on the distribution network shows that the dispersion of these technologies across different geographic areas, and different network topologies has a major impact on the costs and benefits of smart grids, particularly to 2020.[43]

Clustering may occur for several reasons: rational behaviour such as regional variations, of different social groups adopting technologies at different rates or irrational behaviour such as technology take up influenced by friends and neighbours (keeping up with the Jones').

In the previous modelling work carried out by EA Technology, the extent to which installations cluster was estimated using the 'Feed-in Tariff Installation Report 30 June 2011' (henceforth referred to as: FiT data) provided by Ofgem. This provides the first few digits of post code for each installation.

From inspection of the FiT data, we identified that it was appropriate to divide the data into 5 groups, which are shown in the table below.

Table 10. Low-carbon technology clustering, based upon FiT data

Percentage of network	Percentage of low-carbon technology installations
1%	9%
4%	17%
25%	48%
30%	22%
40%	5%

Source: EA Technology

No datasets were available in relation to clustering of EVs and HPs. In the absence of these data we have assumed that EVs and HPs will cluster in the same way as PVs. These assumptions can be easily changed in the model.

This information is used to calculate how rapidly five different groups will adopt the low-carbon technologies that are inputted into the model from the GB wide scenarios.

43 If clustering is not taken into account then models using the best available estimates of numbers of low-carbon technologies connected to the network show that there are many years before networks will show capacity problems, whereas some networks already are demonstrating capacity issues, because there is not a uniform distribution of connection of the technologies.

The model skews the GB wide scenarios to populate network feeders in accordance with the groupings. Once all connection points in a network group have been used, then those low-carbon technologies that can no longer be accommodated within that group are redistributed proportionally across the other groups.

The model assumes that the degree to which clustering occurs, for a given penetration of low-carbon technologies, is the same across the different scenarios. However, scenarios with a higher penetration of low-carbon technologies may be modelled as having a more uniform distribution of them. This is due to the issue explained above: once modelled penetration within a cluster reaches 100%, the model will have to allocate additional low-carbon technologies more widely across the feeders.[44]

Both the profile demands and the clustering assumptions described above are fully customisable within the model, and can be refined to reflect more accurate inputs as and when they become available.

The model does not currently distinguish between regions within GB to isolate specific regional impacts. The work being undertaken by WS3 will consider regional impacts further.

4.3.5 Distribution of load across voltage types

This section sets out our assumptions on the distribution of load across different voltage types.

Distribution of generation across voltage types

Estimates have been taken of the proportion of distributed wind and biomass generation that will appear on both the HV and EHV networks.

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44 This is simply due to the way in which (by definition) penetration cannot exceed 100% - it is not a result of headroom limits on the network.

Table 11. Distribution of generation across voltage types

	EHV	HV	LV (rural)
Onshore distributed wind	44.7%	51.8%	3.5%
Biomass	44.7%	51.8%	3.5%

Source: EA Technology

Distribution of demand across network types

In addition to generation, load demand is factored into the model in the following manner.

Table 12. Distribution of demand across network types

Load type	Distribution by network voltage level		
	EHV	HV	LV
Commercial load	0%	50%	50%
Residential load	0%	0%	100%

Source: EA Technology

5 Development of engineering solutions

In this section we set out our approach to including smart grid solutions in the model. We cover three sections.

- **Smart grid technologies.** A range of technologies could be included in a smart grid. In this section we set out the technologies we have currently populated the model with, and the key assumptions associated with each.

- **Conventional technologies:** Our model compares the costs and benefits of smart grid technologies to the costs and benefits of conventional grid reinforcement technologies. In this section we describe the conventional technologies we have included in the model and the key assumptions associated with each.

- **Technology investment strategies.** A smart grid is not a well-defined package of technologies. Here we describe how we develop packages of technologies for assessment in the model and how we treat the control and communications technologies that sit alongside them.

5.1 Smart solutions

This section describes the smart technologies that have been included in the smart grid strategies in our evaluation.

A detailed assessment of smart technologies is currently being undertaken by WS3 of the SGF. This assessment has not been duplicated in our evaluation. Instead, we have taken the following approach:

- we include five representative smart grid technologies in the model; and
- we include placeholders for each of the technology types currently being assessed by WS3, so that key technologies can be incorporated into the model once that assessment is complete.

5.1.1 What is a 'smart' solution?

We consider a distribution network solution to be "smart" rather than "conventional" if it has not yet been widely deployed. Even technologies which are well understood, and have been trialled are considered to be smart in this framework, since they have not yet been widely deployed.[45]

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45 For example, managing local voltage excursions by changing the fixed tap of the local distribution transformer then varying the voltage set point of the primary voltage control scheme is considered by us to be smart.

Similarly, some subsets of active network management (such as network automation) are arguably conventional network solutions, used to manage non-standard network operation in the presence of constraints caused by unplanned circuit outages (faults) or planned circuit outages for network maintenance or improvement work. However, using network automation (or dynamic network reconfiguration as it may also be termed) to manage time varying power flows across the network resulting from new loads and distributed generation is not a conventional solution[46]. Therefore, we classify network automation as 'smart' for the purposes of this analysis.

5.1.2 WS3 of the SGF

WS3 of the SGF is currently undertaking a detailed assessment of the cost and functionality of a wide range of smart grid technologies across eleven different smart distribution grid solution sets[47]. These solution sets are set out in Table 13.

Table 13. Smart grid solution sets[48]

Type of solution	Potential response for 2020	Potential responses for 2030
	Smartgrid Version 1.0 (pre 2030)	**Smartgrid Version 2.0 (2030+)**
Supply and power quality: Quality of supply, enhancements to existing network architecture	Enhanced Network Observability) Automatic LV reconfiguration to enhance quality of supply - capability at LV substation fuse boards and in link boxes Intelligent switching will require sensing, comms & monitoring including pollution source identification Options to deploy adaptive protection & control techniques Waveform monitoring and waveform correction devices - including: harmonic distortion, sags, surges, and flicker Real Time identification of fault positions for rapid rectification Phase imbalance sensors/correction (improve losses and capacity)	Integration of storage (P/Elec dual functionality for V and PQ Comprehensive waveform quality management Waveform tracking through smart meters or other sensors – including pollution source identification Location of fault positions for more rapid rectification Optimise national losses/carbon across multiple voltages and companies Use sensors to track, pinpoint and respond to high losses events.

46 We note that there are LCNF projects in progress and proposed to explore the use of automation in this way.

47 We are excluding smart transmission networks enhancements, which are included in the worktream 3 solution set paper.

48 Smart Grid Workstream 3, *Developing Networks for Low Carbon*

Active management: DG connections, management of 2-way power flows	Intelligent voltage control to manage 2-way power flows Fault Limiter devices to control short circuit currents Adaptive protection mechanisms Sensors and State Estimation for observability of flows/voltages Consumer volts measurement from smart meters or other sensors Data communications close to real time	Utilise storage at domestic, substation and community level LV and MV phase shifters to direct power flows Deployment of PMU sensors for dynamic stability monitoring DR services aggregated for LV & MV network management Forecasting & modelling tools for DNOs Integration between DNO/DNO/TSO for data and information
Intelligent assets: Plant & systems reliability, failure mode detection	Dynamic Ratings for all plant types and multi-element circuits Condition Monitoring for ageing assets - failure advance warnings for lines, cables, transformer and switchgear Status Monitoring for intelligent control systems - pre failure alerts Use of advanced materials to increase ratings of overhead lines Use of novel tower/insulation structures to enhance route capacity	Diagnostic tools for managing intelligent control Re-commissioning tools and techniques for extending/scaling systems Intelligent control systems Loss minimisation Fault localisation and diagnostic techniques
Security and resilience: **Security of networks including physical threats, utilising new network architecture**	Enhanced supply reliability by automatic network reconfiguration Use of meshed rather than radial architectures Greater use of interconnections & higher voltage system parallels Utilisation of 'last gasp' signals from smart meters and sensors - integrate data with SCADA systems and higher voltage levels Forecasting & modelling tools for DNOs to manage new demands Cyber & Data Security protection for network communications	Self-healing network diagnostics and responses Self-restoration and resynchronisation of islands Synthetic inertia devices to support dynamic stability Utilise storage for domestic, substation, community security EVs as network security support (V2G) Advanced network topology management tools for DNOs DC networks (eg home / community) integrated with AC system Self-islanding opens opportunities for new security/investment policies
Smart EV charging: EV charging/ discharging,	Open Systems with standardised communication protocols and standardised functionality for EVs/Charging	Integration of local storage to support charging capability Demand Response aggregated services (downward/upward) Aggregated V2G services

network management, demand response and other services	Points Architecture - distributed processing - street, substation or community level, distributed charging management, with aggregated reporting and supervision for reliability Commercial frameworks required	Forecasting and modelling, integrated for DNO/DNO/TSO Standardised functionality available for rapid wider roll-out
Smart storage: electricity storage at domestic, LV and MV levels and above (static storage devices)	Domestic, street, community and regional facilities Storage monitoring and tracking of energy status and availability Storage management & control to enhance network utilisation Tools for optimising location of storage on networks Optimised charging/discharging to extend life of storage medium Basic commercial frameworks required, particularly for merchant energy storage services	Seasonal and diurnal storage charge/discharge management Integration of storage management across the power system Standardised functionality available for rapid wider roll-out Storage management used to minimise overall system losses Deployment of multiple storage types, optimally integrated Full commercial frameworks likely to be required
Smart community energy : Geographic and social communities in existing built environment	Enhance network performance by forging closer links with those it serves Build a local sense of energy identity, ownership, and engagement Integrate Community Energy with Government's Localism agenda Develop a Technical, Commercial, and Social functionality set Energy from Waste and centralised CHP integration Trading of energy and services within local communities	Demand Response optimised with a Community group Exported domestic generation traded within group Standardised functionality available for rapid wider roll-out Vibrant 'energy engagement' that maintains interest & participation Trading of energy and services between local communities
Smart buildings and connected communities: SME C&I buildings and all aspects of new built environments	Building management systems with standard functional interfaces Buildings provide DR services and DG services Buildings provide energy storage (heat/elec) services Private networks in similar roles	Buildings and groups of buildings providing integrated services Communities managing their energy, integrated with networks Buildings with self-islanding and re-sync capability Private networks in similar roles
Smart ancillary services (local and national): ancillary services	Aggregation of domestic DR (downward response) Aggregation of EV charging (variable rate of charging) Commercial frameworks	Aggregation of domestic DR (downward/upward responses) Aggregation of EV charging (variable charging/discharging) DSOs manage local networks,

Development of engineering solutions

for the local and national system	Aggregation of DG (eg PV) to provide Virtual Power Plant (VPP) capabilities	offering integrated services to TSO National VPP capabilities. Responsive demand, storage and disptachable DG for wider balancing include post gate-closure balancing and supplier imbalance hedge New tools are increasing relevant as gen. reaches government targets
Advanced control centres: T&D control centres of the future	Visualisation and decision support tools Data processing at lowest levels, information passed upwards Modelling & Forecasting tools for new demands, in Ops timescales	GB system view, integrating TSO and DNO network management Whole GB system carbon optimisation (config., losses, storage) Architectures and Systems platforms that support hybrid combinations of distributed/centralised applications
Enterprise-wide solution: enterprise wide platforms within companies	Facilities that provide cost-effective outcomes, across Solution Sets This may apply to Enterprise-wide communications, data storage etc	Integration of Enterprise-wide solutions with dispersed niche provisions Flexibility to ensure that Enterprise-wide solutions do not constrain solutions to challenges not yet envisaged

Source: Smart Grid Forum WS3, Developing Networks for Low Carbon

The results of a more robust quantitative assessment will be expanded under the current WS3 activity, and are likely to be published.

Rather than duplicate this work, we have included five representative smart grid technologies in the model. Alongside these representative technologies, we have included placeholders for each of the technology types currently being assessed by WS3, so that key technologies can be incorporated into the model once that assessment is complete.

5.1.3 Representative smart grid technologies

We now describe the five representative technologies. These technologies have been chosen to cover a range of the key functionalities of smart grids. However, they do not form a completely comprehensive set, and therefore they should not be used to give a definitive answer on the net benefit of a "smart grid." The results presented in Section 6 should be seen in this light.

Solutions covered in this document are:

- Battery Electrical Energy Storage;

- Dynamic Thermal Ratings;
  - overhead lines;
  - underground cables;
  - transformers;
- Enhanced Automatic Voltage Control;
  - voltage regulators
  - advanced on-load tap-changers
  - switched capacitor banks
- Technologies to facilitate DSR to reduce local network costs; and
- Active Network Management (dynamic network reconfiguration).

We have chosen these to be our 'representative' technologies because, as Table 14 below illustrates, they collectively encompass what we understand to be the main services that smart grids can provide, namely:

- the provision of data on the distribution networks;
- assistance in optimising network power flows;
- assistance in controlling voltage;
- the facilitation of DSR to reduce local network costs; and
- demand smoothing through the provision of embedded storage.

Table 14. Summary of functionalities provided by key smart grid technologies

Smart grid technology	Provision of data on the grid	Optimisation of network power flows	Facilitation of DSR	Provision of embedded storage
Electrical Energy Storage		✓	✓	✓
Dynamic Thermal Ratings	✓	✓		
Enhanced Automatic Voltage Control	✓	✓		
Technologies to facilitate DSR	✓		✓	
Active Network Management (DNR)	✓	✓		

Source: Frontier Economics/EA Technology

5.1.4 Smart technology descriptions

We now provide an overview each of the five representative technologies. Specifically, we provide:

- a summary of the key assumptions included in the model;
- a description of the technology;
- an overview of the likely impact of the technology on headroom;
- an overview of the technology's lifetime and lead time; and
- a description of the technology's likely cost profile.

The costs of the technologies set out below exclude the cost of the control and communications infrastructure. We provide more details on the costs of this infrastructure below. They also exclude any ongoing costs.[49]

We also present the percentage increase in headroom associated with each of the technologies[50]. Headroom is the difference between the actual power flows, voltages and power quality measurements and the limits set by network design, equipment ratings, or legal / licence requirements.

Electrical energy storage (EES)

Table 15 sets out the key assumptions on Electricity Energy Storage which we have included in the model.

49 Smart and conventional investments are assumed to be of the "fit-and-forget" type and are therefore maintenance free until they are replaced at the end of their lives. There may be some ongoing costs associated with the devices if there is a need to log data from them on a regular basis, for example. For the purposes of this modelling, we have assumed that these ongoing costs are zero. However, users can change this assumption if they wish.

50 For example, where we have a voltage problem owing to levels of local PV generation, we calculate the net amount of generation on the feeder by subtracting the total load from the total generation. Let's assume we have 70kW of load and 90kW of generation then the net generation is 20kW. Our starting position for voltage is 252V, meaning that the available headroom is only 1V to stay within limits. We have determined that EAVC at the distribution transformer gives a voltage headroom increase of 100%. This means that the net generation on the feeder can be doubled and voltage limits will not be breached; i.e. we can increase to 40kW of net generation in the above example and the voltage will not exceed the upper limit of 253V.

Table 15. Electrical Energy Storage - key assumptions[51]

	EES
LV (100kW, 200kWh) costs, £k, 2012	173
HV (2.5MW, 5MWh) costs, £k, 2012	3,700
EHV (12.5MW, 25MWh), costs £k, 2012	18,500
Annual cost reduction	1%
Lifetime	15 years
Impact on headroom	Defers reinforcement by flattening demand, rather than increasing headroom.
Impact on losses	Increase of 6%
Impact on customer interruptions	0%

Source: EA Technology

(a) Description of technology

EES technology offers an alternative to conventional reinforcement where networks are constrained by the requirement to deliver peak power for only a few hours in a day or year. EES can deliver the peak required, being charged overnight or in other periods of low demand, thus avoiding lengthy or costly network upgrades. EES technologies could also be used as a balancing tool by the system operator. We have not included the potential benefits of using EES technologies for this service in our assessment.

Many EES technologies are, however, currently expensive and involve energy losses. Further, their performance degrades over time and with each discharge. They have a shorter life time than conventional assets.

The units described in the above table are sample units based on reasonable sizes. The LV unit is based on a device of 100kW with storage capacity of some 200kWh, while the HV device is a 2.5MW unit with 5MWh capacity. The EHV unit is equivalent to five HV units installed together, giving a 12.5MW device with 25MWH capacity. The increase in losses arises because energy is lost in the charge/discharge cycle of EES units. When making use of the units to peak lop, this actually reduces losses upstream of the EES unit by limiting the amount of

51 See text below the table for details on how to interpret the costs. The sizes of the Ba

current flowing through the network at peak times. This therefore goes some way to offset the losses incurred through lack of efficiency and results in the estimated figure of 6% losses increase overall.

The representative EES technology modelled here is assumed to be able to deliver in the 2-4hr discharge duration that is necessary for peak lopping and not to require any specific geographical or geological features (unlike for example, hydro based pump storage).

All EES technology requires grid connection via Power Conversion Systems (PCS). These are worthy of note as well-developed PCS are able to provide the capability to deliver or absorb reactive power to improve power factor (reduce losses), provide voltage control and act as a sink for harmonic currents (to improve voltage quality).

EES can be called upon to adjust any existing demand profile (subject to its actual location in the electricity supply chain) to bring it above/below network constraints. Note that to ensure longevity of the solution, the number of charge/discharge cycles should be minimised (i.e. one charge cycle per night and one discharge cycle at peak times). The comments that follow are generic, and would need to be refined for each specific EES technology.

(b) Headroom released

Each kW of storage invested in would release one kW of thermal headroom. At a constant 1% growth in load, this would provide six years of load-growth-deferral for an 800 kVA transformer.

In terms of LV voltage headroom, EES would typically be used to flatten peaks created by generation (e.g. high volts resulting from PV in the middle of the day) or load (e.g. low volts resulting from EVs at the early evening peak).[52]

(c) Lifetime and lead times

EES asset life is electrochemically limited by the number of charge/discharge cycles that the technology can sustain without severe performance degradation. The chemicals used in flow-cell batteries are highly reactive; with every cycle the chemically active parts pollute to some degree, such that over the course of time, performance suffers. In this respect, flow cells offer the greatest potential for longevity as the active parts can be replaced or refreshed to renew performance. As life depends on cycles, limiting the number of cycles necessary to provide upgrade deferment by a form of intelligent control may be necessary. Considering daily cycles used for peak lopping over one-quarter of a year, the various technologies would have calendar lives (determined from cycle numbers

52 Given an 800 kVA transformer of 5% impedance, a voltage of 12V is developed on 240V at full load (5%*240V). A 50 kW EES device would reduce power through the transformer *in both directions*, effectively creating a control range of 2 x (50kW / 800kW) x 5% x 240V = 1.5 V.

per year) of up to 15 years for lead-acid and up to 30 years for sodium metal-halide. We have assumed a lifetime of 15 years within our modelling.

In 2012, EES units are not readily available off-the-shelf, with typical lead-times of 6-18 months. This is about equivalent to the amount of time that should be allocated for pre-installation project and site preparation, fire, operation and safety procedures. Deployment requires suitable space to be available, which can be a premium, particularly in congested urban and suburban substations. Compared to reinforcement (e.g. the construction of new overhead lines or substations), planning processes should be reduced, although there may be additional complexities owing to the electrochemical nature of the units. Most types of EES could be relocated or expanded in a modular manner as the need to peak lop changes over time. Given the interest in EES and the relatively limited supply capacity for utility-scale applications, availability will be subject to global markets.

(d) Costs

In the absence of any firm evidence on the future evolution of storage costs, we have assumed that the costs of storage will decline slightly over the analysis period (by approximately 1% per year).

Costs in the model are based on real data (where EES has been deployed for trials) wherever possible. All of the assumptions on costs are fully flexible in our framework, and can be improved as more experience is gathered.

Dynamic thermal rating

Table 16 sets out the key assumptions on Dynamic Thermal Rating which we have included in the model.

Table 16. Dynamic thermal rating - key assumptions

	Underground Cables	Overhead Lines	Transformers
LV costs per installation (£k, 2012)	5	1	1 (Distribution Transformer)
HV costs per installation (£k, 2012)	10	2	2 (Primary Transformer)
EVH costs per installation (£k, 2012)	20	3	3 (Grid Transformer)
Annual cost reduction	1%	1%	1%
Lifetime	15 years	15 years	40 years
Impact on headroom	10%-30% on thermal headroom, depending on feeder type and voltage	10% on thermal headroom	10% on thermal headroom
Impact on losses[53]	Increase of 3%	Increase of 3%	Increase of 3%
Impact on customer interruptions	1%	1%	1%

Source: EA Technology

(a) Description of technology

Dynamic thermal ratings (or real time thermal ratings) refers to techniques by which the maximum capacity of various network components can be assessed in real time in response to local environmental conditions, such as temperature.

The focus of applications of dynamic ratings in the UK to date has been on overhead lines, primarily to facilitate more wind farm connections without costly

53 A negative number denotes a reduction in losses.

reinforcement. However, dynamic thermal ratings can also be applied to underground cables and transformers.

(b) Headroom released

Headroom can be released either by increasing the use that can be made of the asset for cables or by increasing use, or extending the life, of transformers. The impact on headroom is likely to be as follows.

- **Overhead lines**: The amount of thermal headroom that can be released depends on the topography of the network and the surrounding area. For example, lines across open fields can have their rating increased more than those running through wooded areas. The amount by which the rating is increased also depends on the speed of response of any associated demand or generation control. However, for a line across open ground an increase in rating of up to 30% can be expected and this is what has been assumed in the model.[54,55,56]

- **Underground cables:** At present this is not a well-defined quantity, but it is envisaged that ratings could be enhanced by up to 10% dependent upon the difference between the actual load profile and the profile of Engineering Recommendation P17 – 'Load Curve G' (Loss Load Factor = 5.061). It should be noted that the rating enhancement for underground cables is likely to be considerably less than that available via applying dynamic ratings to overhead lines. This will again be dependent to a degree on the speed of any available demand or generation control on the network.

- **Transformers:** The amount of headroom released depends on the control strategy implemented and whether the purpose of the dynamic thermal rating is primarily to reduce ageing or increase ratings. Additional capacity of 10-20% is claimed by manufacturers but few applications have yet published data. Recent studies indicate that distribution transformers are possibly the most highly stressed part of the LV network. If the scheme is installed in tandem with some DSR, the headroom release will also depend on the speed of response of load or generation control, i.e. how quickly demand could be reduced if necessary will govern how far the asset can be stressed above its nominal rating.

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54 T. Yip et al (2009), *Dynamic Line Rating Protection For Wind Farm Connections*, CIRED

55 H. J. Drager, D. Hussels & R. Puffer (2008), *Development and Implementation of a Monitoring System to Increase the Capacity of Overhead Lines*, CIGRE

56 CIGRE Study Committee 23 (2002), *Dynamic Loading of Transmission Equipment*.

(c) Lifetime and lead times

At present, asset life is something of an unknown. The equipment is designed to act in a "fit and forget" manner without the requirement for ongoing maintenance.

We have made the following assumptions in our modelling:

- the life of the equipment for overhead line dynamic thermal ratings solutions (i.e. "power donuts", current transformers etc.) is 15 years;
- for primary transformers the asset life should be matched to that of the transformer. We will base this on the outcome of Ofgem's recent decision on the economic lives of network assets (45 years)[57]; and
- for secondary transformers, there is less to base assumptions on, but if oil tank temperature probes are to be used, an asset life of 20 years seems a reasonable assumption.

Though physically installing these dynamic thermal rating solutions is likely to take less than six months, the lead times for the newer solutions such as underground cables and transformers are likely to be longer due to the need to demonstrate compliance with relevant equipment standards. Dynamic thermal rating for underground cables would also need to be trialled before large scale rollout. Lead times for application of these solutions are thus likely to be longer than the conventional alternatives.

We assume that the use of dynamic thermal rating has no impact on the degradation of the primary assets (the overhead lines, underground cables or transformers), i.e. no accelerated ageing.

(d) Cost profiles

The costs of dynamic thermal rating are likely to decline as the technology becomes more mature. For the purposes of our modelling, we have assumed a modest reduction of around 1% per year. However, this assumption will be flexible in the modelling.

Enhanced Automatic Voltage Control

Table 17 sets out the key assumptions on Enhanced Automatic Voltage Control (EAVC) which we have included in the model.

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57 http://www.ofgem.gov.uk/Networks/Policy/Documents1/assetlivedecision.pdf

Table 17. Enhanced Automatic Voltage Control – key assumptions

	EAVC at Distribution Transformer	EAVC at Primary Transformer	EAVC at Grid Transformer	Voltage regulator	Switched capacitator bank
LV costs per installation (£k, 2012)				12	N/A
HV costs per installation (£k, 2012)	25	30	35	12	440
EHV costs per installation (£k, 2012)				15	470
Annual cost reduction	1%	1%	1%	1%	1%
Lifetime	40 years	40 years	40 years	40 years	30 years
Impact on headroom LV	100% voltage headroom, 30% voltage legroom	12% voltage legroom		100% voltage headroom and legroom	12% voltage headroom
Impact on headroom HV		30% voltage headroom and legroom	12% voltage headroom and legroom	30% voltage headroom and legroom	30% voltage headroom and legroom
Impact on headroom EHV			30% voltage headroom and legroom	30% voltage headroom and legroom	12-30% voltage headroom and legroom
Impact on losses	Increase of 1%			Increase of 1%	Increase of 1%
Impact on security of supply	0%			0%	0%

Source: EA Technology

(a) Description of technology

Network voltages must be maintained within strict statutory limits, as set out in Electricity Safety Quality and Continuity Regulations 2002 (as amended). Manufacturers of equipment which connects to the network are obliged by this Directive to design and build products that can safely operate at any voltage within the specified limits. An EAVC system consists of a range of devices that can help a DNO to keep network voltages within required limits in the context of increased voltage-control challenges thrown up by new network developments.

Conventional DNO design assumes networks to be passive with unidirectional power flows. In this context, so-called Automatic Voltage Control (AVC) schemes acting upon the grid and primary transformers[58] are configured to work autonomously. However, the increasing penetration of various low-carbon technologies is likely to give rise to voltage changes that AVC schemes will struggle to manage. Moreover, the addition of certain smart solutions – such as electrical energy storage, dynamic thermal ratings and demand-side response – form additional subsystems within the network, which will need to work in concert with the voltage control devices. This will create further pressure on existing AVC schemes.

As the network starts to operate closer to these limits, however, DNOs may opt to introduce additional automatic voltage control devices over and above those located at the grid and primary transformers. Together these new and existing voltage control devices will constitute an EAVC system. Depending on specific network circumstances, investing in an EAVC system may prove a cost effective alternative to conventional network reinforcement as a means of circumventing the problems associated with voltage control.

The EAVC solutions included within the model are:

- grid and primary transformer (EHV/HV) solutions, i.e. modified control solutions to the conventional AVC relay, taking additional voltage sensing input from points on the network;
- in-line voltage regulators for LV, HV and EHV circuits;
- HV and EHV switched capacitor banks; and
- on-load tap-changers for distribution transformers (HV/LV).

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58 The Grid and Primary transformers are those that operate at 132/33kV and 33/11kV and similar voltages.

(b) Headroom released

The level of headroom to be released by EAVC solutions will vary, depending on the control system. It is likely that a target voltage will be set and the EAVC will operate so as to achieve this voltage. To some extent, therefore, the headroom released will be dependent on the severity of the voltage issue that the network is experiencing.

The EAVC solutions are not designed to release thermal headroom. Any thermal headroom that is released as a by-product of EAVC solutions would be negligible.

(c) Lifetime and lead times

At present, the asset life of the various EAVC solutions is unclear. However, they are primarily “fit and forget” maintenance-free devices that would be designed to have asset life coincident with that of the plant with which they are associated. Therefore, a reasonable assumption for the current carrying assets would be that all of the solutions named above have an asset life of 40 years, with the possible exception of the HV Switched Capacitor Bank, which may be slightly shorter and is assumed here to be 30 years. The indicative lead times for the equipment of each solution range from 2-4 months for primary EAVC control only, to 12-18 months for HV switched capacitor bank.

(d) Cost profiles

The costs of EAVC are likely to decline as the technology becomes more mature. For the purposes of our modelling, we have assumed a reduction of 1% per year over the analysis period.

Technologies to facilitate DSR

Table 18 summarises the key assumptions in the model on technologies to facilitate DSR to reduce local network costs.

These costs are the costs incurred in establishing the technology required to enable DSR on a feeder (for example to provide communications) rather than the costs paid to a supplier or customer when engaged in DSR. Such costs are captured separately in the model and are generally of the order of 0 – 4p per kWh.

Table 18. Technologies to facilitate DSR to reduce local network costs

	DSR
LV cost per installation (£k, 2012)	2
HV cost per installation (£k, 2012)	4
EHV cost per installation (£k, 2012)	6
Assumed annual cost reduction	0%
Lifetime	10 years
Impact on headroom	Defers reinforcement by flattening demand, rather than increasing headroom.
Impact on losses	0%
Impact on customer interruptions	0%

Source: EA Technology

DSR in this context relates specifically to measures that impact on the pattern of consumption.

DSR measures can take a number of forms:

- they can provide signals or interventions related to system-wide or local costs and
- they can take the form of:
  - price signals;
  - measures that control load automatically in response to changes on the electricity network, or price signals; and
  - measures that allow third parties to control demand directly.

In the case of DSR price signals, measures can take the form of static time-of-use price signals (tariffs that vary according to the time of day in order to discourage demand load at peak times) or dynamic time-of-use price signals (tariffs that vary in response to real-time information in order to discourage demand load at peak times).

To provide signals based on system-wide costs will require:

- electricity meters with smart functionality;
- an in-home display (IHD) for domestic customers;

- a wide area network (WAN) communications module to connect to the central communications provider; and
- a home area network (HAN) within customer premises to link smart meters with smart appliances and micro generation , the communications module and the IHD).

To provide signals to facilitate DSR to reduce local network costs will also require these technologies to be rolled out. However, locally-driven DSR will also require:

- sensing information on the network to trigger the DSR events; and
- an interface from the DNOs control infrastructure to the DSR head-end (either via a supplier, the DCC, or directly to the customer) to enact the DSR event.

In Section 2 we set out our proposed assumptions for the technology required to deliver DSR. As explained, it is not yet clear to what extent dynamic DSR will be delivered by smart meters.

Active Network Management – Dynamic Network Reconfiguration (ANM-DNR)

Table 19 summarises the key assumptions we have made on ANM-DNR in the modelling.

Table 19. Active network management (Dynamic Network Reconfiguration) – key assumptions

LV costs per feeder (£k, 2012)	10
HV costs per feeder (£k, 2012)	10
EHV costs per feeder (£k, 2012)	10
Annual reduction in cost	0%
Lifetime	15 years
Impact on headroom LV	40% on voltage headroom and legroom, 10% on thermal headroom
Impact on headroom HV	20% on voltage headroom and legroom, 30% on thermal headroom
Impact on headroom EHV	30% on thermal headroom, 10 on voltage headroom and legroom
Impact on losses	0%
Impact on security of supply	0%

Source: EA Technology

(a) Description of technology

Dynamic Network Reconfiguration (DNR) describes a set of potential solutions that could be implemented on networks. While some network automation is already deployed, we consider DNR to be a smart solution as the optimisation of network configuration in real-time, to manage constraints brought about by increased power flows (arising primarily from low-carbon technologies), has not yet been deployed.

In considering DNR, we look at the potential for networks to have monitoring in place that informs a central hub as to when overload conditions are occurring, or likely to occur imminently. The central hub can then reconfigure the network automatically via some pre-determined switching arrangement to alleviate the condition. Such a solution is only valid if the neighbouring portion of network has some headroom available, otherwise a successive chain of load transfers will take place throughout the entire area of network equipped with DNR in an effort to accommodate the excess load.

As DNR is dependent on monitoring, it is well-suited to network areas where a considerable amount of control and communications infrastructure is present. We discuss control and communication infrastructure in more detail in Section 5.3.2.

(b) Headroom released

The amount of headroom that can be released through DNR varies considerably from one implementation to another. This is because it is heavily dependent on the amount of load that is already present on adjoining portions of the network. In some rare cases, it may be possible to effectively double the capacity and release up to 100% headroom, however there will be many instances when only a nominal amount of headroom is available.

For the purposes of our model, we have assumed an average headroom release figure of 30% at higher voltages and up to 10% at LV depending on feeder type (with weaker, less well interconnected rural networks releasing a smaller amount).

(c) Lifetime and lead times

The lifetime of the solution is likely to be governed by the monitoring equipment that needs to be installed, in the first instance. However, the importance of load growth on adjacent feeders should not be discounted. This model does not deal with regional issues, and hence a lifetime of 15 years has been assumed. The work to be carried out in WS3 will consider regional variations and the likelihood of load growth occurring in neighbouring areas must be considered as part of the regional (or sub-regional) clustering effect.

The lead time of DNR solutions is fairly short as the technology exists to deploy them now; the "smart" nature of their deployment is in the way in which they are used.

(d) Cost profiles

The cost profile of DNR is likely to be fairly static. All figures relating to cost of the solutions are customisable as necessary.

5.2 Conventional solutions

The model also includes a range of conventional reinforcement options. The conventional strategy forms the counterfactual against which other strategies are assessed. Under the conventional strategy these are the only options available, while under the smart grid strategies they are still available, and can be chosen as part of smart strategies, where their costs are lower.

The following solutions are included:

- split the feeder (i.e. transfer half of the load of the existing feeder onto a new feeder);
- replace the transformer;
- new split feeder (i.e. run a new feeder from the substation to the midpoint of the already split feeder and perform some cable jointing to further split the load, resulting in three feeders each having approximately equal loads); and
- major works (the construction of new distribution transformers and LV circuits into an area where demand cannot be satisfied by simply 'tweaking' existing network infrastructure).

These solutions are available at all voltages (LV, HV and EHV). Unlike the smart solutions, the conventional options are considered to increase in cost over the years as material prices increase. The starting costs of these solutions are based on DPCR5 figures taken from Ofgem's analysis.

To derive specific costs for the "new feeder" and "split feeder" solutions, an assumption has been taken regarding the length of circuits. It is assumed that at LV circuits are 1km, at HV they are 4km and at EHV they are 15km. These assumptions are reflected in the costs attributed to these solutions. It is possible to alter the costs directly if a user wishes to consider circuits of different average length.

Beyond the three solutions outlined above, there is also the option for "major work" at LV, HV and EHV. This major work option is a last resort solution where all other reasonable solutions had already been implemented. It is particularly relevant for portions of the network that have undergone a significant period of load growth.

The costs associated with the "major work" options do not come directly from DPCR5 figures, but are assumed to be of a reasonable level to facilitate a wholesale reinforcement that would serve to increase headroom by an order of magnitude. Therefore, they are necessarily high and will appear at the lower end of the priority stack.

The lifetime of the conventional solutions exceeds that of the smart solutions and is assumed to be 40 years in the model.

The costs of the various solutions and the other parameters associated with them are summarised in Table 20.

Table 20. Conventional Solutions – key assumptions

	Split feeder	New transformer	New split feeder	Major works
LV costs (£k, 2012)	50	15	52	1,250
HV costs (£k, 2012)	206	43	214	5,000
EHV costs (£k, 2012)	1,901	150	1,977	25,000
Annual increase in costs	1%	1%	1%	0%
Lifetime[59]	40 years	40 years	40 years	40 years
Impact on headroom	100% on thermal headroom, 80% on voltage headroom and legroom	50-100% on thermal headroom, 40% on voltage headroom and legroom	50-100% on thermal headroom, 40% on voltage headroom and legroom	400% on all types of headroom
Impact on losses	2% reduction in losses	1% increase in losses	2% reduction in losses	5% reduction in losses
Impact on customer interruptions	0%	0%	0%	0%

Source: EA Technology

59 In the results presented in Section 6, we have assumed an asset life of 40 years for conventional technologies. This is shorter than the asset life in Ofgem's recent decision on the economic lives of network assets (45 years). Changing our assumption from 40 years to 45 years does not have a material impact on the results. However, we suggest that model users and the future WS3 work should use 45 years for consistency with Ofgem's decision.

5.3 Investment strategies

A smart grid is not just one technology, nor is it a well-defined package of technologies. Instead, a smart grid could be made up of a range of technologies that can be applied in different combinations and at different geographical scales.

Given interdependencies between the functionality of different smart grid technologies, the costs and benefits of each individual technology are likely to be dependent on whether other technologies (for example, the control and communications infrastructure) have been rolled out. Because of these interdependences, rather than assessing the incremental costs and benefits of each individual smart grid technology in isolation, it makes sense to assess the costs and benefits of representative smart grid investment strategies.

5.3.1 Description of investment strategies

Our model includes two smart grid investment strategies. These will be compared to a conventional strategy, where only investments in conventional grid technologies are undertaken (over and above existing policies to rollout smart meters). Each strategy assessed entails enough investment to at least maintain current levels of security of supply,[60] and to facilitate the same amount of connections of low-carbon plant and demand side technologies. The strategies will differ solely in terms of the means they use to deliver these outcomes.

These alternative strategies are described in Table 21 and the key differences are summarised below.

- **Top-down smart grid investment strategy.** This strategy entails an initial investment in control and communication infrastructure to support smart solutions in the future. The initial investment has the effect of reducing the cost of ongoing investment in smart technologies, because the costs of installing communications and monitoring equipment have already been borne in the top-down investment. Smart and conventional technologies will be included in this strategy as required on each feeder type, with the lowest cost solutions being chosen first (further details on this approach are provided in Annexe A below).

- **Incremental smart grid investment strategy.** Once again, smart and conventional technologies will be included in this strategy as required on each feeder type, with the lowest cost solutions being chosen first. The incremental strategy differs from the top-down strategy only in that it does not include an upfront investment in the control and communications

60 Where a smart technology has additional benefits for security of supply, this is also captured – see Table 15- Table 19.

infrastructure. Because this infrastructure is not in place, ongoing investments in smart technologies cost more than under the top-down investment strategy.

- **Conventional strategy.** This strategy differs from the top-down and incremental strategies in that it only includes conventional technologies. These will be included in the strategy as required on each feeder type, with the lowest cost out of the conventional solutions being chosen first.

Table 21. Investment strategies

	Characteristics	Proportion of costs borne upfront	Proportion of costs on an ongoing basis
Top-down smart grid investment strategy	Upfront roll out of control and communications infrastructure. Roll out of smart and conventional technologies when required.	**High** Investment in control and communications infrastructure occurs upfront.	**Low** The upfront investment in control and communications infrastructure means the costs of rolling out additional smart technologies are proportionately lower in this strategy
Incremental smart grid investment strategy	Roll out of smart and conventional technologies, and associated control and communications infrastructure when required.	**Low** No investment in control and communications infrastructure occurs upfront.	**High** The lack of upfront investment in control and communications infrastructure means the costs of rolling out additional smart technologies are proportionately higher in this strategy
Conventional strategy	Roll out of conventional technologies only, when required	**High** Conventional solutions tend to be more capital intense and release more headroom.	**Low** The higher headroom release associated with conventional solutions mean that ongoing costs of this strategy are likely to be proportionately lower

Source: Frontier Economics/EA Technology

5.3.2 Control and communication infrastructure

When considering the implementation of smart solutions, it is also necessary to consider the control and communications platforms that will enable the solutions to perform in a "smart" manner. There are a range of approaches that can be adopted to coordinate these smart activities, which can be generally classified into one of the following three groups: centralised, hierarchical, and distributed (or decentralised). Each of the classes has particular strengths and weaknesses and these are briefly outlined below.

In our analysis, the “top-down” strategy represents a centralised structure and the “incremental” strategy could refer to either the distributed or hierarchical structure, depending on the implementation.

These investment strategies represent the boundary cases for a range of possible strategies entailing a mix of top-down and incremental approaches. It is possible that investment in establishing a basic level of control and communications infrastructure should be assumed under either the top-down or incremental approaches. However, the strategies with which we have currently populated this model do not include this basic level of investment under the incremental strategy. This may mean that we are underestimating the costs of the incremental strategy and the results presented in Section 6 should be interpreted in this light.

Centralised

A centralised control infrastructure requires a hub with numerous communication links to all remote parts of the network. Regular updates will be requested by the “master” at the centre of the structure, or may be sent automatically by all of the remote “slave” nodes. Upon receiving the updates, the master will make decisions to optimise the network for some function (e.g. to maintain voltage at a certain level). Commands will be issued to the slave nodes that will then enact these commands and report back.

An advantage of this approach is that only one implementation is required as the control and communications infrastructure encompasses the entire network. This means that there is no issue with having to integrate multiple systems into the network as it can all be done on a common basis at the same time. However, this comes at considerable cost. Centralising means that the majority of the costs are borne up front and this may well be in advance of the emergence of smart solutions on the network.

This approach might favour a scenario where uptake of low-carbon technologies (and hence roll out of smart solutions) is high, as the cost of the implementation would be likely to be less over the whole life than the cost of installing multiple systems in quick succession. Further, if multiple systems are installed, some of them may have to be replaced as it becomes apparent that uptake is such that a more holistic view of the network is required.

Solutions which require a degree of monitoring and communication (such as DSR, for example), may favour a centralised approach over a distributed roll-out.

Distributed (Decentralised)

A distributed (or decentralised) structure is one in which responsibility for managing certain network conditions is devolved to a local control. In this case, the remote nodes will have been set up to operate within certain parameters and will respond if these parameters are breached.

For example, if nodes are designed to maintain voltage limits, they will be set with upper and lower bounds for voltage. If the voltage is observed to exceed one of these bounds, then some action will be taken (such as adjusting a voltage regulator). Unlike hierarchical or centralised implementations, this action can be taken without referring back to a senior or master node.

Distributed control infrastructure entails a much lower upfront cost than centralised, and can be bespoke to a certain portion of network. It may, therefore, be desirable if uptake of low-carbon technologies and smart solutions is low as there may only be a relatively small number of locations on the network where this control is required. Another case for its use is in an area of network with a very specific problem. It may be that there are special cases which may not be able to be adequately handled by a centralised control system and a more bespoke design implemented at a local level could be more attractive.

The potential drawback to distributed control is that there can be multiple implementations of slightly different architectures. This means that if, in the future, it was desired to combine these, it might prove difficult to coordinate the various control systems into a cohesive whole. The local and independent nature of the solutions can also cause problems as two adjoining areas of network could have their own control schemes, each with their own goals and, without some coordination, they could actually be working against each other. A more coordinated, centralised approach could look at the wider network and optimise both network areas simultaneously (taking account of what each area is doing).

Some solutions can work well in a distributed system; such as making use of electrical energy storage to manage a problem with load that is bespoke to a small portion of network.

Hierarchical

A hierarchical structure forms something of a middle ground approach. While it is not all encompassing in the way of the centralised structure, it does not devolve responsibility to the nodes at the remote ends in the same way as the distributed structure.

A hierarchical implementation involves remote nodes monitoring the network condition and flagging up to a "superior" or "manager" node any conditions which arise that require attention. It can be likened to a group of workers carrying on with their business but if something happens with which they are uncomfortable, they pass the information to their manager and wait for them to make a decision.

The "manager" node then instructs the remote nodes to respond in a certain way to alleviate or remedy the situation. The amount of data exchanged is less than that of the centralised structure as while in the case of the centralised implementation nodes are being constantly polled to determine their situation, in the hierarchical structure, the nodes only report back by exception.

This sort of structure can work well in, for example, a coordinated EAVC solution where a number of regulators and tap-changers are working to achieve a target voltage. Having a hierarchical approach, as opposed to distributed, could ensure that they do not work against each other.

The costs of the two control strategies included in the model are set out in Table 22, where it is assumed that to roll-out top-down control and communications infrastructure across GB has a cost of £500m. These costs are highly uncertain and are a key driver of the difference in net benefits accorded to the top-down and incremental strategies by the model. We therefore include sensitivities around these costs in Section 6.

Table 22. Assumed cost of control and communications infrastructures for GB

	Top-down	Incremental
One-off investment cost	£500m	0
Average additional cost of measures	0	38%

Source: EA Technology

5.3.3 Determining the technologies to be included in each strategy

The exact combination of technologies included in each investment strategy is not determined in advance. The different technologies (smart grid and conventional) are placed into 'priority solution stacks' for each feeder type and headroom problem. For example, one stack relates to the order of interventions to make under the BAU strategy when thermal headroom constraints on urban LV transformers are breached. The ordering of solutions is based upon a simple ranking of % headroom released per unit cost, with additional manual adjustments made to minimise the costs of each strategy. The model then applies these solutions in the order specified in the stack to accommodate different types of headroom excursion, for example, demand or generation conditions for each of the feeder types.[61]

The priority solution stacks will differ between strategies for the following reasons:

- Because of the upfront investment in control and communications infrastructure, the smart solutions will be associated with a lower unit cost in the top-down strategy than in the incremental strategy.

- The conventional priority solution stack will only contain conventional solutions.

The technologies included in the priority solution stacks are determined manually rather than through an automated process. We have not automated the generation of priority solution stacks in the model for two reasons.

- A full optimisation of the individual smart technologies is beyond the scope of this work. Including this optimisation in the model would greatly increase the model's processing time.

- Basing the population of priority solution stacks on heuristics, for example around cost per quantity of headroom released is challenging. This is because of the presence of outlying investment strategies such as major works which in reality would be a last resort measure, but which release very large quantities of headroom.

Automation of the generation of priority solution stacks will be looked at further in WS3. In the meantime, we have populated the model with a selection of default priority solution stacks which have been based on running the model multiple times to determine the most cost-effective ordering. Model users can change this ordering if they wish to test the sensitivity of the result to this.

5.3.4 Optimism bias

Government appraisal guidance provides advice on adjustments to the costs of investments to take account of project appraisers' tendencies to be over optimistic about the predicted costs, benefits and works duration of projects.[62]

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61 Specifically, as explained in more detail in Annexe A, when the trigger points for thermal or voltage headroom (or voltage legroom) on a feeder are reached, the model will select the next available smart or conventional investment solution from the "priority stack" and implement this solution so as to increase the available headroom.

62 HM Treasury, Supplementary Green Book Guidance on Optimism Bias, http://www.hm-treasury.gov.uk/green_book_guidance_optimism_bias.htm

We have scaled up both smart and conventional costs in the model according to this guidance, adjusting the costs presented in this report upwards by percentages which relate to the average historic optimism bias found at the outline business case stage for traditionally procured projects. The adjustment factors included in the model as a default are set out in Table 23. These assumptions can be changed by model users.

Table 23. Optimism bias assumptions

	Increase for optimism bias	Project category
Smart technologies	66%	Non-standard civil engineering projects
Conventional technologies	44%	Standard civil engineering projects

Source: HM Treasury, Supplementary Green Book Guidance on Optimism Bias

6 Overall cost benefit analysis

This section sets out the initial findings of the modelling exercise.

Rather than attempting to assign a value to smart grids, the focus of this work has been to establish an analytical framework that can be updated as new information on the rapidly developing smart grid technologies becomes available.

It is therefore important that the results are seen in this light and are not seen as providing a definitive assessment of smart grid value. Instead we believe that the greater value of our model comes from understanding the sensitivity of the results to changes in the assumptions.

This section covers the following.

- We first assess the performance of the investment strategies against each of the scenarios considered in this report over the period from 2012-2050, assuming that the strategy is held constant over the entire period.
- Next, we allow the strategy chosen in 2012 to be altered in 2023. This allows us to determine the best strategy to undertake today, given there is likely to be flexibility to change strategy in the future.
- We next present an analysis of the drivers of the value of the investment strategies in each of the scenarios, based on sensitivity analysis around key parameters.
- We then discuss the distribution of the costs and benefits across parties in the value chain.
- Finally, we present our conclusions.

All net benefits presented here represent an estimate of the total net benefits to society, including any changes in carbon emissions, which are valued according to Government guidance.[63] The following caveats apply to the results.

- **Limited granularity in some areas of the electricity sector.** Not all areas of the electricity sector are modelled in detail. In particular, the representation of the transmission network is very simple, and costs and benefits to system operators are not included (though an upper limit for the potential benefit to system operators is set out in Annexe B).

63 DECC (2011) *Valuation of energy use and emissions,* http://www.decc.gov.uk/assets/decc/statistics/analysis_group/122-valuationenergyuseggemissions.pdf

- **Not all non-market costs and benefits are included.** For example, the benefits of reduced wirescape are not included. We do not value the benefits which may be associated with the fact that, in some cases, smart grid technologies could potentially be rolled out more quickly than their conventional alternatives. This may mean that the net benefits of smart grids are underestimated in this assessment.

- **DSR has not been fully optimised**. The model does not fully optimise between different potential uses of DSR. We discuss the implications of this in more detail in Section 6.2 below.

6.1 The performance of each strategy against each scenario

We assess the costs and benefits associated with three investment strategies, described in detail in Section 5.

- We look at two smart strategies. Both of these strategies contain a mix of smart and conventional technologies. We include:
  - a **top-down** smart strategy, which includes an upfront investment in control and communications infrastructure; and
  - an **incremental strategy** with no upfront investment in control and communications infrastructure, but higher ongoing costs for each smart grid technology than in the top-down strategy.

- The costs and benefits of the smart strategies are assessed relative to a **conventional** investment strategy, which includes conventional technologies only.

The scenarios against which these strategies are assessed are summarised in Table 24 below (and are discussed in detail in Section 4).

Table 24. Description of scenarios

	Roll out of low-carbon technologies (electric vehicles, heat pumps, solar PV, wind generation)	Customer engagement with DSR
Scenario 1	Medium/High[64]	Medium
Scenario 2:	Medium/High	Low
Scenario 3:	Low	Medium

Source: Frontier Economics

6.1.1 Overall net benefits 2012-2050

In this section, we first discuss the overall net benefits from 2012-2050.[65] We then compare the results between scenarios and strategies.

Overall net benefits

Figure 20 shows the net benefits associated with smart strategies when compared to the conventional strategy over the entire period 2012 – 2050. This shows both the top-down and incremental strategies have a net benefit across all scenarios when compared to a strategy of conventional investments from now until 2050. These results suggest that, under the scenarios considered, the smart strategies result in significant savings relative to the strategy of conventional investments.

It makes sense that the two smart strategies provide this saving as they include both smart and conventional solutions, while the conventional strategy only includes conventional solutions. This means that the smart strategies will tend to have a positive net benefit relative to the conventional strategy as there are more technologies to choose from when building the solution stack within these strategies.

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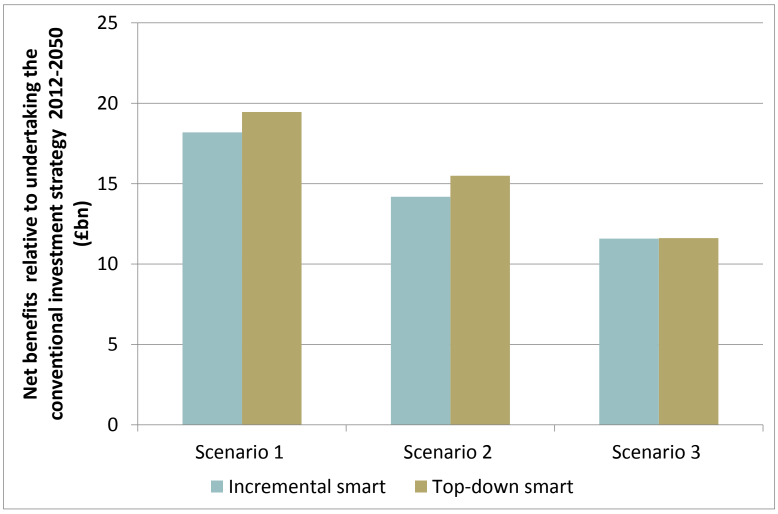
64 High heat penetration is assumed as this is included alongside the medium transport in Scenario 1 of the Government's *Carbon Plan*, http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx

65 Here we apply a standard cost-benefit analysis methodology. We present the results of the real-options based analysis in Section 6.1.2.

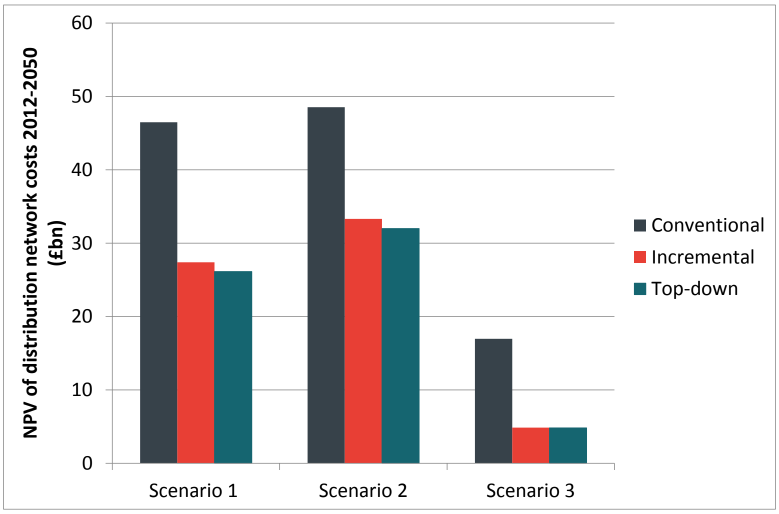
Figure 20. Net benefits by scenario, under default assumptions



Source: Frontier Economics

To put these net benefits in context, Figure 21 presents the gross distribution network costs associated with each strategy across each scenario.

Figure 21. Gross distribution network costs 2012-2050



Source: Frontier Economics

This shows that the impact of smart grid technologies on distribution network costs is highly significant, given the assumptions we have made on network conditions and on the costs and functionalities of smart technologies. It also shows that the smart grid net benefits presented in Figure 20 mask very significant differences in underlying investment across scenarios. As we set out below, this is driven to a large extent by the penetration of low-carbon technologies, which are much lower in Scenario 3 than in the other two scenarios.

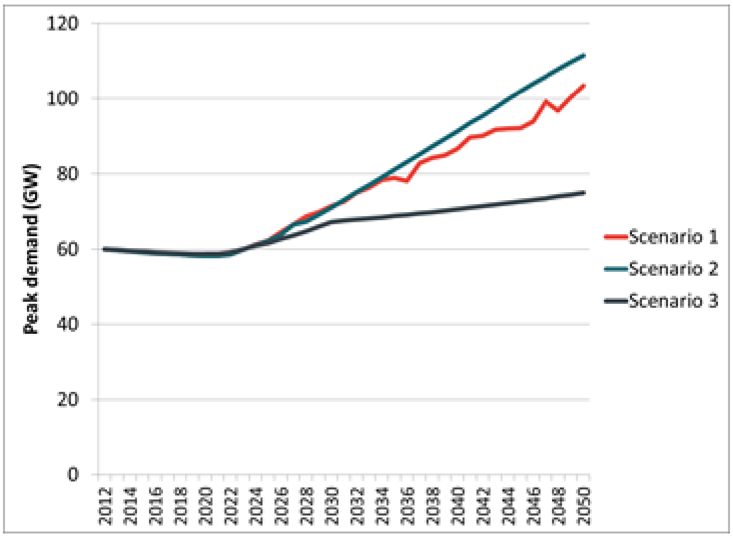
Comparing scenarios

Figure 20 above shows that the net benefit of smart strategies is significant across all scenarios, even when customer engagement with DSR is low (Scenario 2) and when the roll out of low-carbon technologies is much slower than would be required to meet carbon budgets through domestic abatement (Scenario 3).

The net benefits of smart strategies are highest for Scenario 1 in our analysis. Scenario 1 entails both a medium/high level of low-carbon technologies and a central level of customer engagement with DSR. This means that that there is both a significant level of smart grid value drivers present, and that those smart technologies that facilitate DSR are effective.

Figure 20 also shows that the net benefits of smart strategies are lowest for Scenario 3. This is because there are less low-carbon technologies present in Scenario 3. This means that peak demand is lower (as shown in Figure 22), and therefore that less investment is required. Though smart grid technologies save a large proportion of distribution network costs in this scenario, in absolute terms (as shown in Figure 21), the net benefits are smaller, because investment levels are lower overall. This result suggests that while the benefits of smart grids are driven in part by the rollout of low-carbon technologies, high penetration of these low-carbon technologies is not required for smart strategies to have a positive net benefit.

Figure 22. Peak demand by scenario[66]



Source: Frontier Economics. Note: Peak demand produced by the model has been calibrated to approximate current levels in 2012.

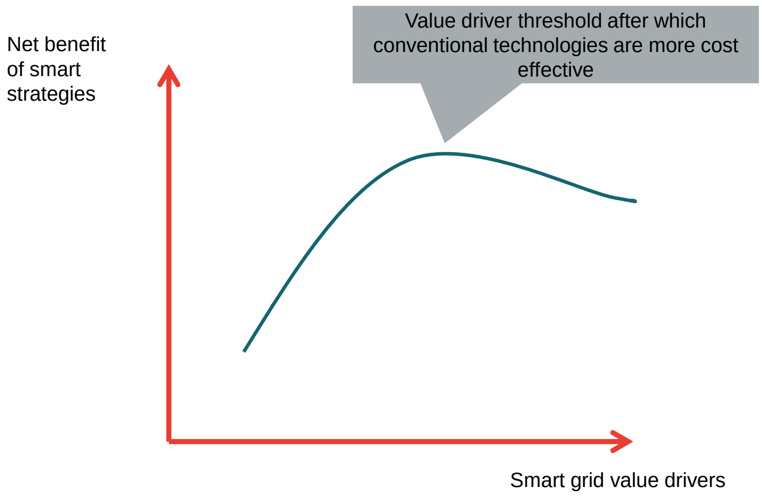
Scenario 2 includes medium/high levels of low-carbon technologies but low customer engagement with DSR. As shown in Figure 22, peak demand faced by distribution networks in Scenario 2 under the conventional counterfactual is higher than in Scenario 1. This illustrates an important point about the impact of customer engagement with DSR on the benefits of smart grids. As well as reducing the effectiveness of smart grid DSR investments, a reduction in customer engagement with DSR changes the counterfactual demand profile because it reduces the impact of smart meters. The lower the customer response to the DSR signals provided by smart meters, the peakier will be the demand profile on local networks before any smart grid technologies are applied. This means that in Scenario 2, reduced DSR means first, there is more pressure on local networks; and second, that the additional DSR facilitated by smart grids can alleviate this pressure less effectively.

66 The "lumpiness" of peak demand under Scenario 1 is due to the fact that more DSR is undertaken in this scenario (since customer engagement with DSR is at central levels, and low-carbon technologies are at medium-high levels). The gains made from DSR will depend in a non-linear way upon the costs and capacities of generation technologies and the level of demand from each technology in each period. Small changes in these factors may lead to a sudden change in the amount of DSR the model considers optimal (e.g. if demand in one period increases above a given threshold, it may no longer be possible to shift enough away in order to move down the merit order of plants). Such sudden changes in DSR lead to the observed pattern of peak demand. Under Scenarios 2 and 3, there is considerably less DSR available for suppliers, and so the pattern of peak demand is smoother.

Despite higher levels of peak demand, the net benefits of Scenario 2 are lower than in Scenario 1. This is because of threshold effects in network investment. When peak demand on the distribution network reaches a certain level, major conventional investment programmes can provide the most cost-effective solutions. This means that the net benefits for smart grids first rise as peak demand on the distribution network increases (for example due to the roll out of low-carbon technologies), but then decline once the level of value driving technologies reaches the point where major work is required. This effect is illustrated in Figure 23.

It is these threshold effects, rather than the fact that DSR is less effective due to a lower level of customer engagement, that drive the difference in net benefits between Scenario 1 and Scenario 2.

Figure 23. Illustration of threshold effects in estimating net benefits of smart strategies



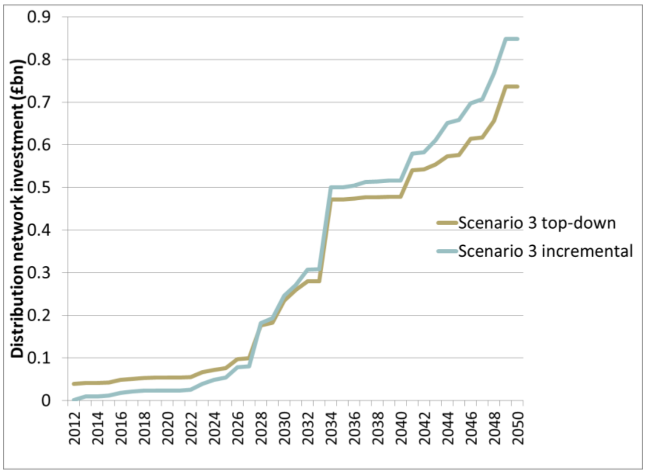
Source: Frontier Economics. Note: There may be more than one threshold.

Comparing strategies

Figure 20, on page 99, illustrates that the differences between the top-down and the incremental strategy are marginal, given the assumptions we have made about the costs and characteristics of each strategy set out in Section 6. The net benefits of the top-down strategy are slightly higher in all cases. This is even the case in Scenario 3, where the penetration of low-carbon technologies, and therefore distribution network investment levels, are lowest. This is because enough investment occurs for the higher up-front costs associated with the top-down strategy to be outweighed by the lower ongoing costs, as illustrated in Figure 24 below. However, the difference between strategies is well within the uncertainty associated with the model.

Overall cost benefit analysis

Figure 24. Annualised distribution network investment costs in the incremental and top-down strategies



Source: Frontier Economics

6.1.2 Real options-based decision tree analysis

The analysis described above implicitly assumes that the decision to undertake a particular strategy (conventional, incremental or top-down) in 2012 is irrevocable all the way to 2050. To take account of option value, we now apply a two-stage decision tree and assume the decision made in 2012 to undertake a certain investment strategy can be changed in 2023 in both the conventional counterfactual and the smart investment cases.

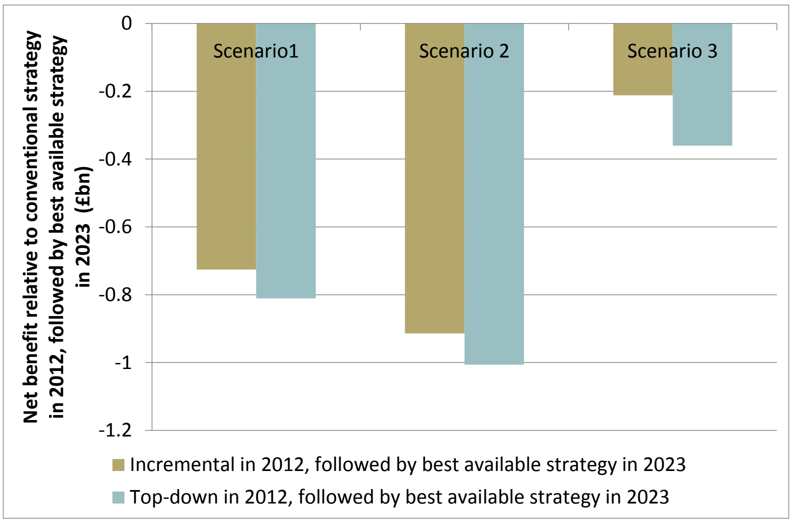
Our engineering analysis suggests that choice of strategy in 2012 only constrains the choice of strategy in one case: if a top-down strategy is chosen in the initial period, it must be pursued until 2050. This reflects the fact that the assets enabling the top-down strategy have a long lifetime and will remain on the system beyond the decision point. If either the incremental or conventional strategy is chosen in 2012, any strategy can then be chosen in 2023.

Under our default assumptions, the model finds that, under all scenarios, and no matter which strategy has been pursued in the first period, a smart strategy is optimal after 2023 (with the top-down strategy being marginally preferred to the incremental strategy). This makes sense, as after 2023, penetration of low-carbon technologies has reached significant levels in these scenarios.

In Figure 25, we present the results of the cost-benefit analysis once the decision point in 2023 has been taken into account. The net benefits shown here are negative, while those shown in Figure 20 on page 99 are large and positive. This is because the counterfactual against which we assess our choice of smart strategies itself becomes smart at the decision point in 2023, since this turns out to be a better option than continuing to only employ conventional technologies.

In contrast, the counterfactual underlying the results presented in Figure 20 was based on pursuing the conventional strategy right out to 2050, with no option to switch strategy.

Figure 25. Net benefits of choosing smart strategies assuming the decision can be changed in 2023



Source: Frontier Economics

The results in Figure 25 show that under all scenarios modelled, the conventional strategy is marginally preferred in 2012, though the net cost of pursuing smart strategies is very small and is well within the range of uncertainty associated with the modelling assumptions. This small net cost reflects the fact that up to 2023, the challenges faced by distribution networks are less acute than those faced in the post 2023 period, since roll out of low-carbon technologies remains relatively low. The relatively slow rate of growth in peak demand before 2023 is illustrated in Figure 22 above.

These results suggest that continuing with a conventional strategy in the shorter run does not lead to lock-in to a costly strategy over the long run and that there is not a clear case for *immediate* widespread rollout of the smart grid strategies, based on the assumptions we use. The results also suggest that the option value associated with smart grids is low since widespread rollout of smart strategies today does not increase the set of options available in 2023.

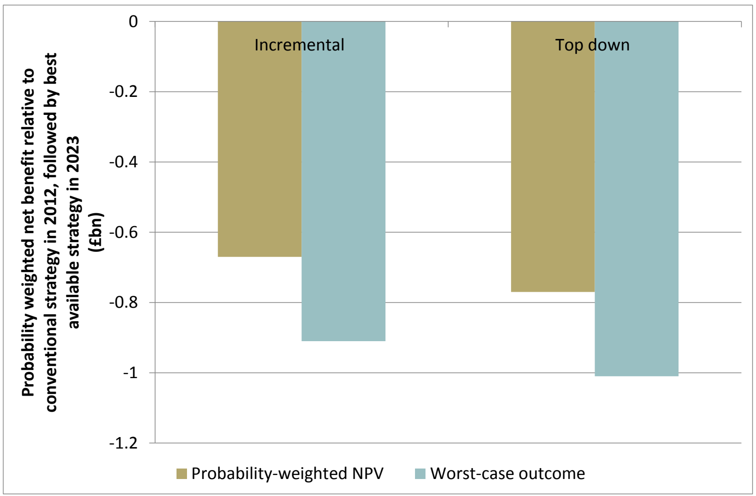
We note, however, that if there are long lead times associated with some aspects of the smart strategies, immediate action may be required in some areas. For example, experience with implementing the smart technologies (for example as part of LCN Fund projects) may be very helpful in driving down their costs.

Worst case outcomes

Policy makers may also be interested in the *worst case outcome*. The worst case outcome represents the worst outcome (in terms of net benefits) that can result from choosing each strategy. Taking account of the worst case outcome will be of interest to policy makers who wish to not only choose the strategy that is likely to be best, but also to minimise the risk of very high costs to society occurring.

The worst case outcomes for each strategy are compared to the expected net benefits of each strategy in Figure 26. The expected net benefits are based on the assumption that each scenario has equal probability, and so are simply the average of the net benefits presented in Figure 25[67]. The results show that over the scenarios we have modelled, the risks associated with alternative scenarios are low, as the net benefits associated with the worst case outcome are not very far from the expected outcome. Although the top-down strategy produces the worst case outcome, the difference between the top-down and incremental strategies are marginal, and well within the uncertainty associated with the model.

Figure 26. Expected net benefits and worst case outcomes



Source: Frontier Economics

6.2 Sensitivity analysis

We have looked at a range of sensitivities around the core results. The overall results of the key sensitivities are presented in Figure 27. We then go on to discuss each one in more detail.

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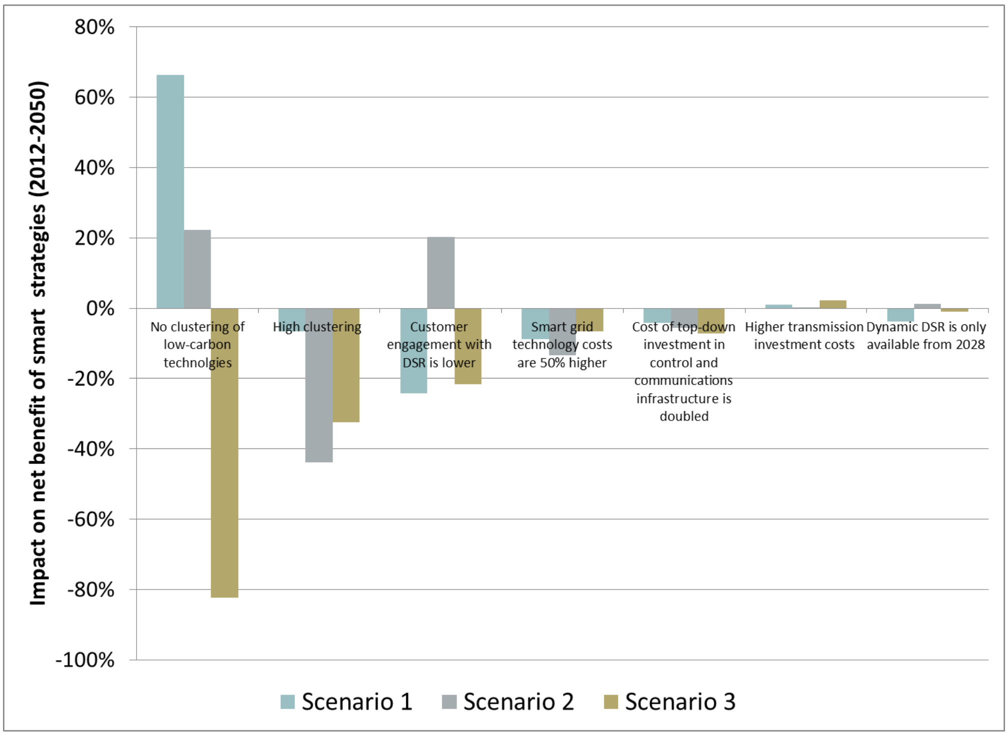
67 However, assumptions on the probabilities of each scenario occurring can be adjusted in the model.

Figure 27. Key results of the sensitivity analysis



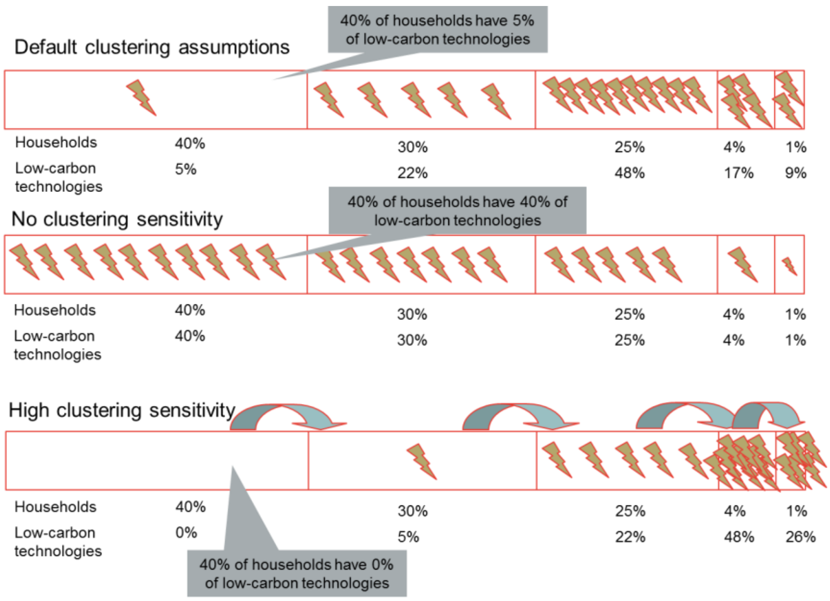
Source: Frontier Economics. Note all net benefits changes relate to the incremental strategy, excluding the sensitivity relating the cost of the top-down investment.

6.2.1 Sensitivity on clustering assumptions

Figure 27 above shows that the results are particularly sensitive to the assumptions made on the clustering of low-carbon technologies, and that the effect of changing this assumption differs depending on the scenario.

The clustering assumptions we have made in this analysis are set out in Figure 28. In addition to the default levels of clustering, we have looked at the scenario of no clustering and a scenario where low-carbon technologies are very highly clustered.

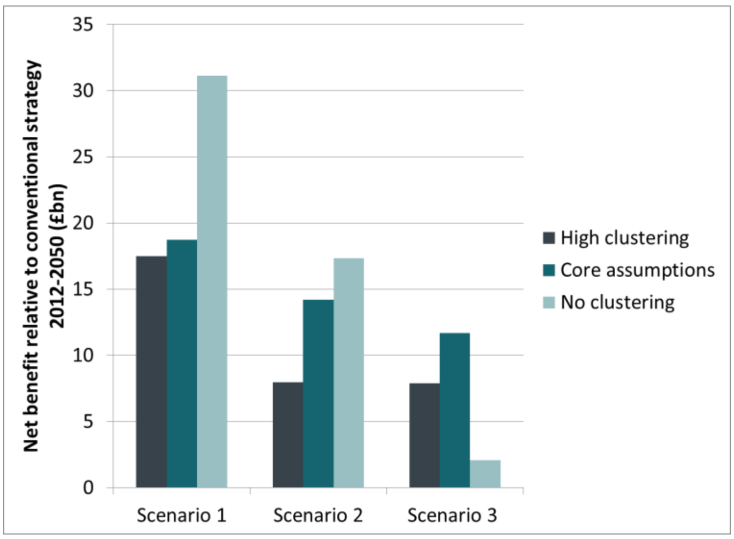
Figure 28. Assumptions on clustering



Source: Frontier Economics/EA Technology

Figure 29 illustrates the impact of changing clustering assumptions on the net benefits of the smart strategies.

Figure 29. Impact of changing clustering assumptions



Source: Frontier Economics. Note all results relate to the incremental smart strategy. The results relating to the top-down strategy are similar.

This shows that the when no clustering is assumed, the net present value of Scenarios 1 and 2 increases, but the net present value of Scenario 3 decreases.

This is because there are two impacts caused by reducing the clustering of low-carbon technologies.

- Reducing clustering reduces the pressure on the parts of the distribution network where low-carbon technologies were clustered. This will tend to reduce the net benefits of smart strategies.
- Reducing clustering increases the pressure on the parts of the distribution network that had fewer low-carbon technologies when clustering was in effect. This will tend to increase the net benefit of smart strategies.

In Scenario 3, the penetration of low-carbon technologies is low. In this case, the first impact dominates. A reduction in clustering reduces pressure on the feeders on which low-carbon technologies were clustered, but there are not sufficient low-carbon technologies to require widespread investment once these are spread evenly across the network.

In Scenarios 1 and 2, the penetration of low-carbon technologies is higher. In these cases, the second effect dominates, and reducing clustering increases the benefit of smart grid strategies because the number of feeders that require smart or conventional investment increases.

Figure 29 also shows that the net benefit of smart strategies decreases in all scenarios when clustering is increased. This is because the second impact listed above dominates, that is, increasing clustering concentrates the low-carbon technologies on a very small number of feeders, while pressure on the majority of the network decreases.

6.2.2 DSR

We now discuss the results of sensitivity analysis around our core assumptions on DSR.

Customer engagement with DSR

Even when they have been provided with smart grid or smart meter technologies that facilitate DSR, the extent to which customers will actually engage with DSR is very uncertain. We have already taken this uncertainty into account to some extent by including a scenario (Scenario 2) where customer engagement with DSR is lower. However, we have also tested a case where customer engagement with DSR is lower across all scenarios. Our core assumptions on customer engagement with DSR by technology type, and our assumptions for this sensitivity are set out in Table 25.

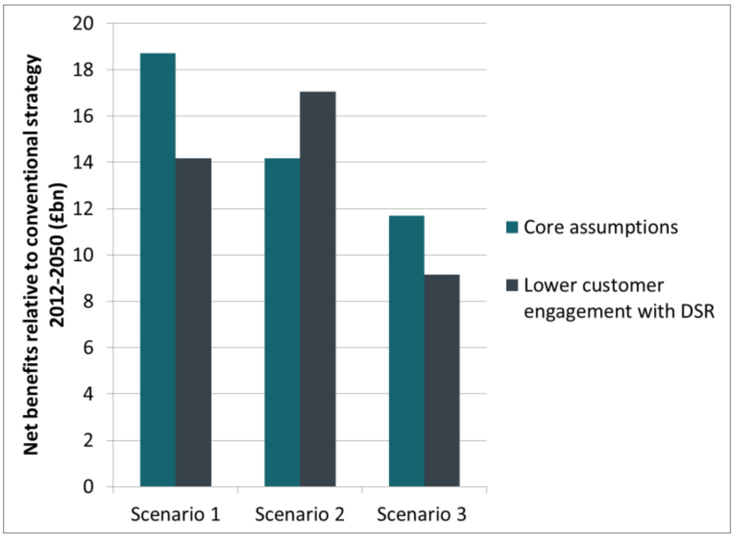
Table 25. Percentage of movable demand associated with each technology type by 2050

	Default assumptions		Low DSR sensitivity	
	Scenarios 1 and 3	Scenario 2	Scenarios 1 and 3	Scenario 2
Electric vehicles	91%	30%	30%	0%
Heat pumps with storage	61%	20%	20%	0%
Smart wet appliances	40%	10%	10%	0%
Electric storage heaters	100%	33%	33%	0%

Source: Frontier Economics/EA Technology

The results of the sensitivity testing for reduced customer engagement with DSR are presented in Figure 30. In Scenarios 1 and 3, reducing customer engagement with DSR reduces the net benefits of smart grids, while in Scenario 2, this reduction increases the net benefits.

Figure 30. Customer engagement with DSR sensitivity



Source: Frontier Economics. Note all results relate to the incremental smart strategy. The results relating to the top-down strategy are similar.

As set out above, as well as reducing the effectiveness of smart grid DSR investments, a reduction in customer engagement with DSR changes the counterfactual demand profile. This is because it reduces the impact that smart meters can have on demand profiles. The lower the customer response to the DSR signals provided by smart meters, the more peaky their demand profiles are likely to be.

Therefore, if customers engage less with DSR, peak demand on distribution networks is likely to be higher in the counterfactual, before any smart grid investments are applied. The impact that this will have on smart grid net benefits will depend on the threshold effects described in Figure 23 above. These threshold effects mean that the net benefits for smart grids first rise as the pressure on the distribution network increases, but then decline once the level of peak demand reaches the point where major work is required.

In addition, lower customer engagement with DSR will also impact on the effectiveness of those smart grid investments that facilitate DSR. This will tend to reduce the net benefits of smart grids.

Figure 30 shows that delaying the facilitation of dynamic DSR reduces savings from the smart strategy in Scenario 1 and Scenario 3. The biggest impact is in Scenario 1 where the penetration of low-carbon technologies (and therefore the amount of potentially flexible load) is highest. The delay has a minimal effect in Scenario 3 where the penetration of low-carbon technologies is lowest.

In Scenario 2, delaying the ability to implement dynamic DSR actually increases the savings from smart grid technologies. In this scenario, customers are less willing to flex their demand, even if they hold low-carbon technologies. The effect of the more peaky demand profiles may therefore dominate over the effect of the reduced benefits from smart grid DSR measures.

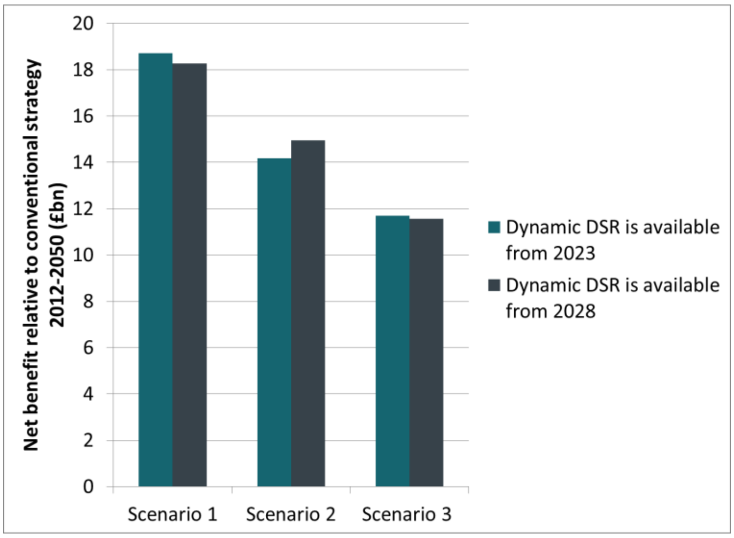
Availability of dynamic DSR

Under our core assumptions, dynamic DSR becomes available in 2023. We have also looked at a scenario where dynamic DSR is only possible from 2028. Figure 31 shows that delaying the potential for dynamic DSR has a small impact on the savings from the smart strategy. This small impact is because a large amount of the cost savings from smart grids are from non-DSR smart grid measures, and because much of the benefits of dynamic DSR occur in the later years, as penetration of wind and of low-carbon technologies increases.

As set out above, delaying the application of dynamic DSR affects both the counterfactual demand profile (for the conventional case) and the demand profile under the smart strategy. We would expect a delay in the facilitation of dynamic DSR to impact the net benefit of the non-DSR elements of smart grids, since it will lead to more peaky (wind following) demand profiles in the counterfactual. However, we would also expect it to reduce the benefits of the DSR-elements of smart grids. This combined with the presence of threshold effects in investment (as described in Figure 23) mean that the overall impact of delaying the facilitation of dynamic DSR could be positive or negative.

Figure 31 shows that delaying the facilitation of dynamic DSR reduces savings from the smart strategy in Scenario 1 and Scenario 3. Again, the biggest impact is in Scenario 1 where the penetration of low-carbon technologies is highest. The delay has a minimal effect in Scenario 3 where the penetration of low-carbon technologies is lowest. In Scenario 2, delaying the ability to implement dynamic DSR actually increases the savings from smart grid technologies.

Figure 31. Availability of dynamic DSR



Source: Frontier Economics. Note all results relate to the incremental smart strategy. The results relating to the top-down strategy are similar.

Limitations in the use of the model to test the value of DSR

Some stakeholders also requested that we look at a sensitivity where smart meters only enable static DSR. In this case, all of the benefits of both dynamic DSR to reduce generation costs and dynamic DSR to reduce distribution network costs would be attributed to smart grids. However, because our model does not enable DSR to be fully optimised between different uses, we are unable to investigate this sensitivity robustly.

DSR can be employed to reduce several costs, including:

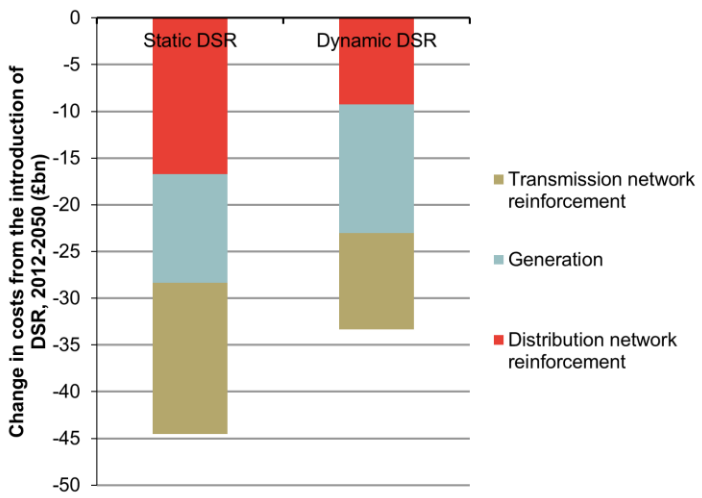
- the costs of generating sufficient electricity to meet demand at all times;
- the costs associated with reinforcing the distribution network; and
- the costs associated with reinforcing the transmission network.

Often, targeting DSR to reduce one of these costs will reduce the others. However, there are cases where these aims may conflict. For example, if it happens to be windy during the system peak, DSR targeted at generation costs may reduce the peak load on distribution networks (which drives reinforcement costs) less than is optimal from a distribution network point of view.

Ideally market mechanisms would ensure that DSR is targeted in such a way that lowers overall costs. However, calculating the optimal deployment of DSR in this way was outside the scope of this project. Instead, as explained in Annexe A, various heuristics are used in the model to separately reduce generation and distribution network costs through DSR. This is done in a sequential rather than in a fully optimised fashion. This means the overall deployment of DSR, and the split between its various uses, will not be optimal.

Figure 32, sets out the impact that enabling static and dynamic DSR aimed at minimising generation costs has on generation, transmission and distribution network costs in our modelling.

Figure 32. Impact of introducing DSR on costs



Source: Frontier Economics.

Figure 32 shows that holding all other factors constant, introducing static DSR to the modelling reduces overall generation, transmission and distribution network costs significantly. This is because, in the modelling, static DSR minimises average generation costs, and in doing so also reduces transmission and distribution network costs, by reducing peaks on these networks.

Holding all other factors constant and introducing dynamic DSR to reduce generation costs, also reduces transmission, generation and distribution network costs. Since this dynamic DSR is aimed at reducing generation costs, generation costs fall more than under the static case. However, distribution network costs fall less than in the static DSR case, and overall the cost saving from introducing dynamic DSR is lower than the cost saving from introducing static DSR in the modelling. This is because of the lack of full optimisation between different types of DSR in the modelling. Essentially under the dynamic case, more demand is being moved to reduce generation costs, than is optimal for transmission and distribution network costs.

For the purposes of comparing the value of different distribution network investment strategies (smart and conventional), this lack of optimisation is not problematic as it does not have a large impact on the results. We have verified that the gains from smart grid investment strategies exist under a wide range of different sensitivities (for example, without any DSR, without the ability to target DSR at actual wind output, or with different profiles of wind generation).

However, the results shown in Figure 32 illustrate that the model has not been designed to compare outcomes under different forms of DSR (e.g. determining what additional value comes from dynamic DSR that can follow wind patterns). In principle, it can be used to gain some understanding of these issues. However care should be taken to ensure that any results can be explained intuitively and are not simply the result of DSR not being fully optimised.

6.2.3 Technology costs

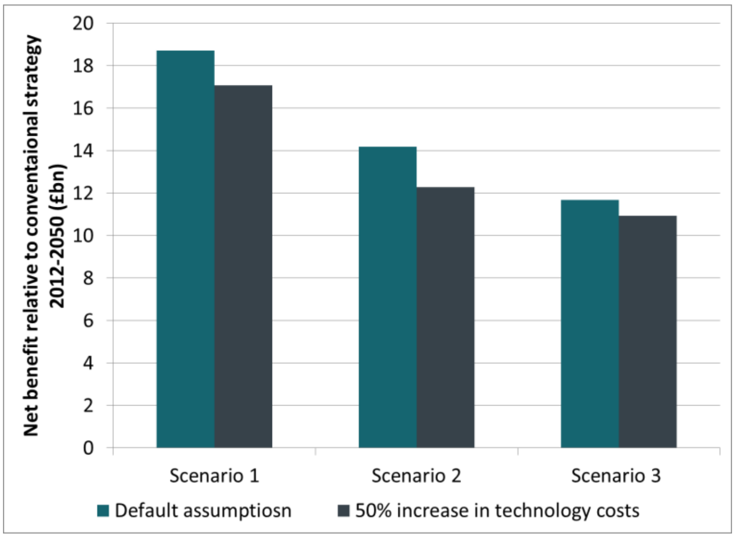
We also carried out a number of sensitivity tests around the technology costs, looking at sensitivities which vary the overall costs of smart grid technologies, and which vary the costs of the top-down investment in control and communications infrastructure.

Flexing the costs of smart grid technologies

Figure 33 presents the results of the sensitivity around the costs of smart grid technologies. This shows that increasing the technology costs of smart grid by 50% does not have a significant impact on the net benefits of smart technologies. This suggests that the results are relatively robust to the high degree of uncertainty around the costs of these technologies. This is because most smart grid technologies included in the model turn out to be substantially more cost-effective than the conventional alternatives under our base case assumptions about costs and network conditions, and because the smart strategies contain significant levels of conventional investment.

The assumptions on costs will be looked at in more detail by WS3.

Figure 33. Sensitivity to the smart grid technology costs

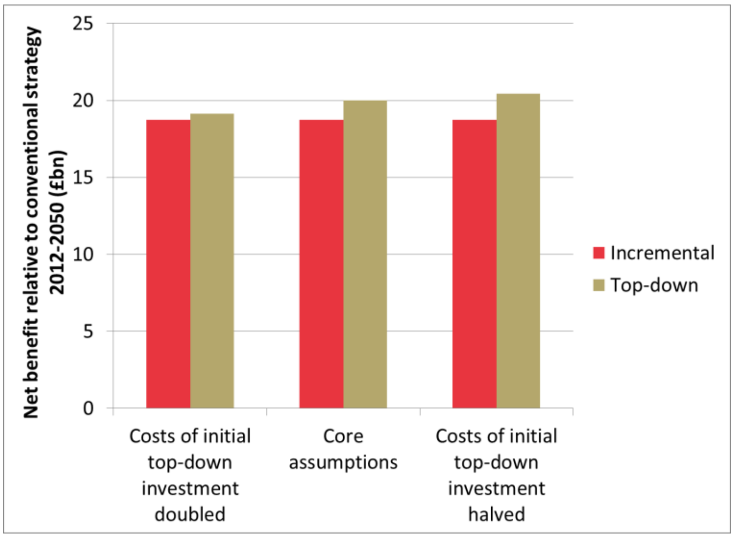


Source: Frontier Economics. Note all results relate to the incremental smart strategy. The results relating to the top-down strategy are similar.

Flexing the costs of the top-down technology

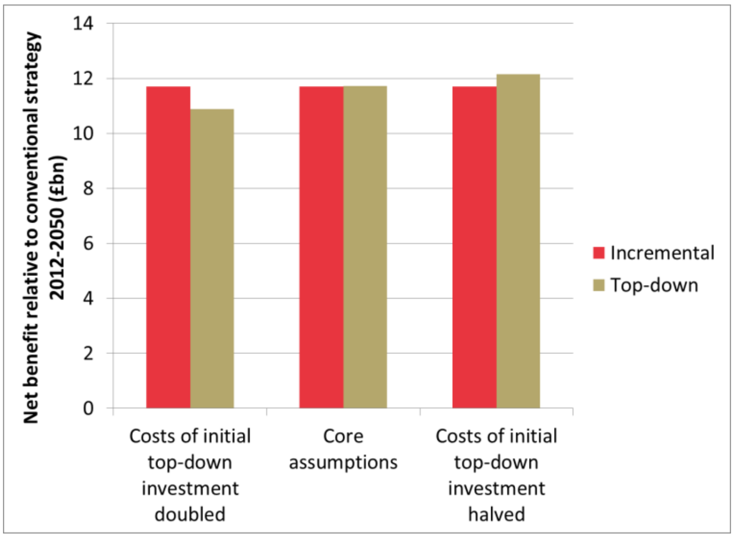
We also looked at the sensitivity of the differential between top-down and incremental strategies to increases and decreases and decreases in the initial top-down investment cost in control and communications infrastructure. The results of these sensitivities are presented in Figure 34 and Figure 35. These show that in Scenario 1, the top-down strategy remains marginally preferred to the incremental strategy, even when the costs of the initial investment are doubled (we have not showed Scenario 2 as the results are similar). In Scenario 3, the increase in top-down costs is enough to cause the incremental strategy to be preferred. However, in all cases, the difference between the incremental and top-down strategies remains marginal and well within the uncertainty of the model.

Figure 34. Sensitivity to the costs of top-down investment, Scenario 1



Source: Frontier Economics. Note: Results relate to the top-down strategy, since the costs of the top-down investment are not incurred in the incremental strategy.

Figure 35. Sensitivity to the costs of top-down investment, Scenario 3



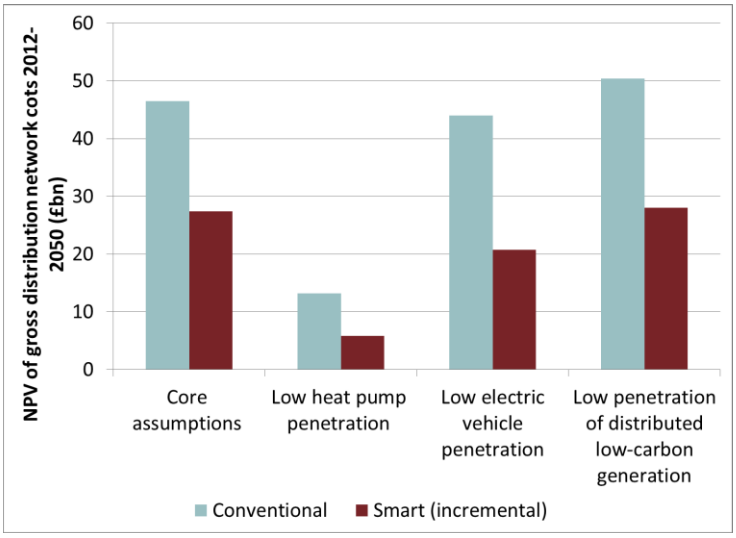
Source: Frontier Economics. Note: Results relate to the top-down strategy, since the costs of the top-down investment are not incurred in the incremental strategy

6.2.4 Penetration of low carbon technologies

Figure 20 on page 99 shows that in Scenario 3, where the penetration of low-carbon technologies is low, the net benefits of smart grids are significantly lower than in Scenarios 1 and 2, where the penetration of these value drivers is at central to high levels. Therefore the analysis presented above suggests that increasing the penetration of these value drivers increases the net benefit of smart grids. In addition, Figure 21 on page 99 showed that distribution network costs are much higher in both the conventional and smart strategies when the penetration of low-carbon technologies is higher.

In this section, we assess the impact of varying each of these value drivers in isolation, to determine which are having the greatest impact on the net benefit of smart grids. The results of this assessment are shown in Figure 36.

Figure 36. Impact on distribution network costs of reducing the penetration of individual value drivers [68]



Source: Frontier Economics

Figure 36 shows the following:

- Reducing heat pump penetration has a highly significant impact on gross distribution network costs, reducing them by more than two thirds, in both the conventional and smart strategies. The large impact of heat pumps on these costs is driven by our assumptions on the profile of heat pump demand, and the flexibility associated with this demand. As described in Section 4, we assume heat pump demand is highest during the day, and that only demand associated with heat pumps with storage is flexible.
- Reducing electric vehicle penetration has a much lower impact on distribution network costs under both conventional and smart strategies[69].

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68 Low levels of penetration of each value driver are based on the scenarios set out in Section 4.2.

This is because, as set out in Section 4, we assume that electric vehicle demand occurs primarily overnight, and is highly flexible.

- Reducing the penetration of distributed generation actually increases network investment costs under both the conventional and smart case. This is because, under our assumptions, the presence of distributed generation actually reduces pressure on distribution networks in some cases, since more demand can be met through locally connected generation.

Under our assumptions, therefore, heat pumps are the most significant drivers of distribution network costs, and have the greatest impact on the net benefits of smart grids.

6.2.5 Other sensitivities

We also tested the sensitivity of the results to changes in transmission network costs (assuming costs are 34% higher, in line with the high assumptions presented in Annexe A, Table 29), and to changes in the typical wind profile (assuming greater variability). This analysis suggests that the results are robust to our assumptions on these factors. The results are presented in Figure 27 on page 106.

6.3 The spread of costs and benefits across the electricity sector

It is important to take account of how the costs and benefits of smart grids are distributed across different parties in the electricity sector.

If those that bear the costs do not gain the benefits, this could act as a barrier to smart grid deployment. This would be the case if high transaction costs prevent individual parties contracting to apportion costs and benefits between each other, or if the incentive regime does not appropriately reward companies for doing this. The existence of these kinds of barriers drove the rationale for mandating the smart meter rollout.

It is therefore useful to understand more about how distribution network investment in smart grids may create costs and benefits that are borne elsewhere in the energy supply chain, as well as broader costs and benefits to society as a whole. This is likely to be an important input into the consideration of smart grid investment cases in RIIO-ED1.

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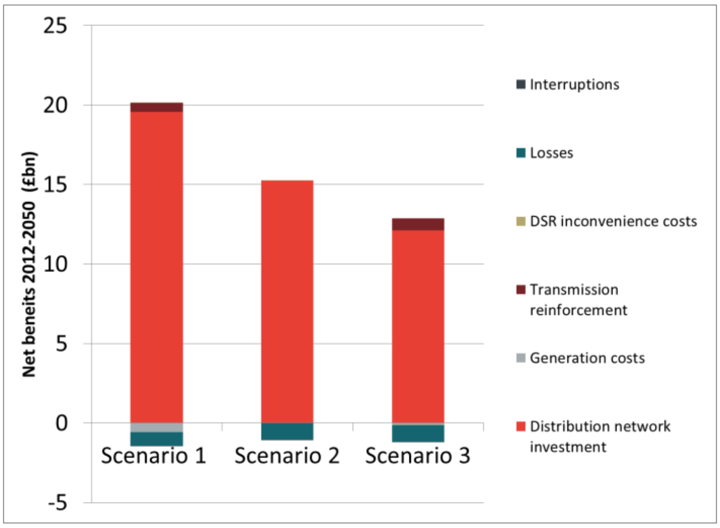
69 In fact, the net benefit of smart grids actually rises when the penetration of electric vehicles is reduced. This is due to the threshold effects set out in Figure 23.

Overall distribution of net benefits

Figure 37 shows the breakdown of the costs across the electricity sector found in our modelling[70].

Figure 37. Breakdown of net benefits, default assumptions



Source: Frontier Economics. Note: Results relate to the incremental strategy. The results relating to the top-down strategy are similar.

Under our default assumptions, by far the greatest proportion of net benefits is due to a reduction in distribution network investment costs. There are two reasons for this.

First, most smart technologies that we have included in the modelling (for example, EAVC, dynamic thermal ratings, active network management) only have an impact on the rest of the electricity sector through their effect on losses. A change in losses will affect the generation required to meet demand. However, the net impact on losses of the smart technologies considered here is small.

Second, our assumptions on smart meter functionality mean that the impact of smart grid technologies to facilitate DSR on the rest of the electricity sector is small. Since under our assumptions, smart meters already allow customers to respond to dynamic, system-wide signals (e.g. related to generation costs), the incremental impact of smart grid technologies will only be to additionally allow the demand side to respond to dynamic signals related to local network conditions. This locally-driven DSR will aim to reduce distribution network costs. While any changes in the demand profile caused by this locally-driven DSR will

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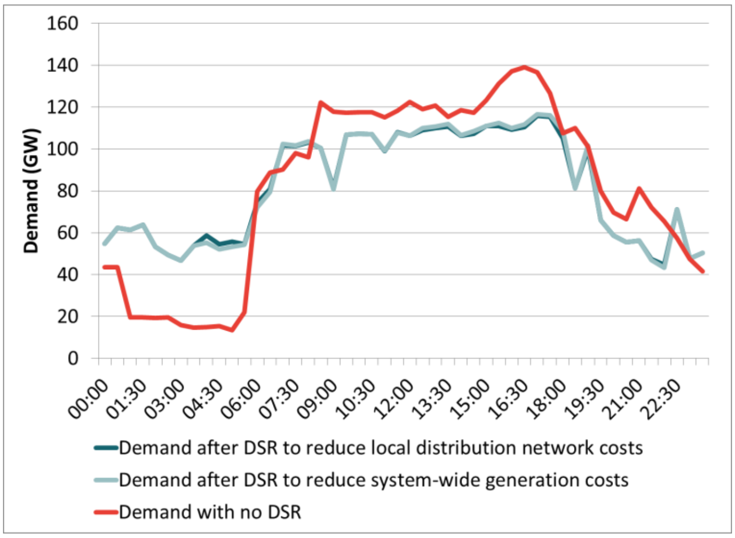
[70] 1 In this figure, the impact on CO_2 emissions is incorporated into the generation costs and losses category, valued according to Government guidance.

have an impact on generation costs, under the assumptions in our analysis, the impact of locally-driven DSR on the demand profile is relatively small.

The small size of the change in the demand profiles driven by smart grids under our assumptions is shown in Figure 38 which shows an illustrative daily demand profile for a winter peak day in 2050. The red line shows the demand profile before any DSR. The light blue line shows the demand profile once DSR facilitated by smart meters is in place. The dark blue line then shows the demand profile once locally-driven DSR has been applied.

Figure 38. Example of demand profile with DSR, 2050 winter peak day



Source: Frontier Economics.

Since the costs of the smart grid investments would also be borne by distribution networks, the results of this analysis therefore suggest that under our assumptions, the costs and benefits of smart grids are well aligned.

System operators

A smart grid could help National Grid to balance demand and supply on the system, to the extent that it facilitates DSR with a shorter latency period than smart meters alone.

In the analysis presented in Annexe B, we have produced an estimate for the upper limit of the cost saving associated with using DSR for these system operator services. However, we have not integrated this value into our analysis presented in Figure 37. This is because there is a risk of double counting, since reserving a unit of dynamic DSR for balancing purposes would preclude that unit of dynamic DSR from being used to minimise generation costs or reduce distribution network costs.

Overall cost benefit analysis

The analysis set out in Annexe B suggests that these alternative benefits could, at least in principle, be material.

6.4 Conclusions

The focus of this work has been to establish an analytical framework which can be used to increase understanding of the drivers of the value of smart grids, and which can be updated as new information on the rapidly developing smart grid technologies comes to light.

It is important that the results of this modelling are seen as a first step in understanding the drivers of the costs and benefits of smart grids, rather than as a definitive assessment of their value.

Under the set of assumptions used in the modelling, this analysis suggests the following.

- Smart grid technologies can allow significant savings in distribution network investment costs to be realised over the period to 2050. Including smart solutions in a strategy widens the set of options available to DNOs, and allows them to choose less costly measures and defer conventional investment.

- The benefits of smart grid strategies are highest under the scenarios with most low-carbon technologies. When penetration of low-carbon technologies is low, both conventional and smart distribution network investment levels are much lower. However, our analysis suggests that smart grid investments have a positive net benefit, even when the penetration of low-carbon technologies is relatively low.

- Of the low-carbon technologies included in the model, heat pumps have the biggest impact on the net benefit of smart grids. This is because we assume their demand is highest in the daytime, and that it is only flexible where heat pumps have storage. This means heat pump rollout has a large impact on peak demand faced by local networks, and therefore on required network investment costs.

- Although the benefits of smart grid strategies at first rise with an increase in peak demand on distribution networks, when a certain threshold increase in peak demand is reached, major conventional investments become more cost effective. This is due to the "lumpy" nature of many conventional reinforcement options (which while high cost, can often free up large amounts of headroom on networks). For this reason and because of other complexities, it is often not possible to predict the way in which a change in a value driver may affect the incremental value of the smart strategy.

- Some smart grid technologies aim to facilitate DSR. In addition, smart meters on their own may allow some forms of DSR to take place (which will itself lead to a change in the load faced by distribution networks). There is a great deal of uncertainty over the extent to which customers will engage with DSR. Under our assumptions, a reduction in the level of customer engagement with DSR has two impacts.
  - It increases peak demand on networks in the counterfactual since the impact that smart meters have on peak demand is reduced. Whether this has a positive or negative impact on the net benefit of smart grids will depend on threshold effects.
  - It reduces the effectiveness of smart grid technologies that facilitate DSR. This will have a negative impact on the net benefit of smart grid.

  Overall, under our assumptions, a reduction in the level of customer engagement with DSR reduces the net benefit of smart grids in Scenarios 1 and 3 and increases the net benefit of smart grids in Scenario 2.

- Because the penetration of low-carbon technologies is relatively low until the 2020s under the scenarios presented by WS1, there is not a clear case for immediate widespread rollout of smart grid technologies. However, where they are clustered there may be opportunities to reduce distribution network costs through the use of smart investments in the near term. Further, if there are long lead times associated with some aspects of the smart strategies, immediate action may be required.

- Our real-options based analysis suggests that the option value associated with widespread rollout of smart grids is low. Undertaking conventional investments now does not lead to lock-in to expensive strategies. However, there is likely to be significant option value associated with trialling new smart grid technologies, where this provides learning. We do not model this.

- Most of the benefits of smart grid strategies fall to distribution networks, under our assumptions. The costs and benefits of smart grid strategies are therefore likely to be reasonably aligned.

These results are robust to changes in assumptions around clustering, the functionality of smart meters, the cost of technologies, the extent to which customers engage with DSR, transmission investment costs and the variability of wind.

7 Further work

The aim of our work was to establish a flexible and transparent framework for the evaluation of smart grids. We have produced an initial set of model results which help identify the conditions which drive the value of smart grids. We have also analysed the distribution of the net benefits of smart grids under different conditions.

However, this project has not aimed to produce a definitive assessment of the net benefits associated with smart grids, and further work will be required to provide a more granular assessment in some areas. In particular, as described throughout this report:

- to maintain flexibility and transparency, the model has been simplified in a number of areas; and
- this work has focussed on developing a robust and flexible appraisal methodology and formalising this in a model, rather than on carrying out detailed research on each of the parameters included in the model.

We have tried to identify the main simplifications and data limitations within this report. This section describes further work that is already being undertaken to increase the functionality of this model by WS3 of SGF. We also outline some additional areas where further work may be beneficial to further the learning about the value of smart grids.

7.1.1 WS3 of the SGF

This framework is currently being developed further by WS3 of the SGF. The WS3 project will use the overall evaluation framework set out in this report but provide further detail in a number of areas.

- **Increase in granularity of the network modelling**. It will describe a range of typical network types from EHV to LV that can provide a modelling framework for the majority of GB network topologies.

- **Disaggregation of network conditions by region and sub-region.** It will characterise the national levels of uptake of low-carbon technologies, distributed generation, etc. on a regional or sub-regional basis and aggregate point loads up to the required level. This will improve the clustering assumptions applied in the model, which are recognised as having a dominant effect on investment trigger points associated with the transition to low carbon energy.

- **Increase in the number of smart grid technologies to be considered.** It will quantify, in terms of cost and headroom released, the range of 'smart grid' mitigating solutions identified in the WS3 Phase 1 report.

- **Incorporation of new learning from the LCNF projects.** Throughout the project reference will be made to existing LCN Fund projects that have the potential to improve any of the underlying assumptions of the model.

The outputs of WS3 are likely to be used by the DNOs to inform their RIIO-ED1 business plans.

7.1.2 Areas for further work

Beyond the work being taken forward by WS3, there are a number of other areas where further work may be useful.

Model scope

There is scope to increase the coverage of the evaluation framework and its granularity in some areas.

- **Coverage of additional benefits of smart grids.** Not all of the potential benefits of smart grids are included in the model. An important development would be to enable the evaluation framework to take account of differences in the speed of connection of low-carbon technologies, or fewer interruptions associated with these connections, associated with smart and conventional investments.

- **Demand side response.** Not all aspects of DSR have been included in the model. In particular:
  - only within-day changes in demand have been modelled; this is likely to represent the majority of DSR potential, however the benefits from shifting demand within a week could also be assessed; and
  - the model does not fully optimise between different types of DSR.

- **Rest of the electricity sector.** There is scope to increase the granularity at which the rest of the electricity sector is modelled. For example, the potential benefits of DSR to the system operator should be investigated further.

- **Inclusion of additional value drivers.** Not all potential value drivers have been fully characterised in the model. For example, the model does not represent vehicle to grid capacity on electric vehicles.

Data population

This work has focussed on developing a robust and flexible appraisal methodology and formalising this in a model, rather than on carrying out detailed research on each of the parameters.

It will be important to update the model as new information is provided, from LCNF projects or other trials and research.

8 Annexe A: Detailed model specification

This Annexe describes the specification of our model that we use to investigate the value of smart grid investments under uncertainty.

As we have described in the body of this report, our intention is that this model is transparent so that users can observe the impact of adjusting key assumptions. The model therefore allows users to determine the effect of changes in key smart grid value drivers (such as the level of customer engagement with DSR and the level of decarbonisation) on the net benefits of smart grids.

The model is implemented within Microsoft Excel[71], which enables users to alter the key assumptions without knowledge of more specialised software.

This Annexe has the following structure,

- We first describe the overall structure of the model, which can be divided into three main parts:
  - the **real options-based cost-benefit analysis model**, the component of the model which calculates net present values;
  - the **distribution network model**, the component which determines the costs of meeting peak demand on the distribution network; and
  - the **wider electricity sector model**, the component which calculates the cost of meeting GB electricity demand.
- We then describe each of these parts in more detail.
- Finally, we set out the interactions between the generation and network models.

71 While the network modelling work utilises the outputs of EA Technology's WinDebut low voltage network design tool, this is a "one-off" process which will not need to be re-run each time an assumption is changed within the model.

8.1 Structure of the model

This section begins by setting out the overall approach to estimating the costs and benefits of alternative smart grid investment strategies. It then discusses each element of the model at a high level, before outlining the interactions between each of these elements.

8.1.1 Overall approach to estimating costs and benefits

The model calculates the costs and benefits of alternative distribution network investment strategies. This is carried out:

- for each of the investment strategies (conventional, top-down and incremental) described in Section 5; and
- across each of the three scenarios described in Section 4.

There are a variety of ways in which smart grid technologies may allow benefits for society to be realised. Our model takes the following costs and benefits into account:

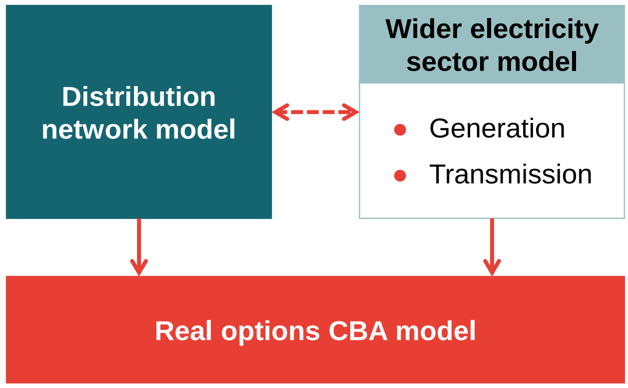
- **Distribution network reinforcement** – the value of the investments made in order to ensure that distribution networks can handle the load imposed upon them. This includes conventional reinforcement options, as well as any smart solutions.
- **Distribution network interruption costs** – the cost to customers of interruptions caused by distribution network faults.
- **Distribution network losses** – the cost associated with any change in losses caused by smart grid solutions.
- **Generation costs** – the resource costs (both opex and capex, and including carbon costs) of generating sufficient electricity to meet demand at all times.
- **DSR "inconvenience" costs** – an assumed monetary value associated with the inconvenience of using DSR to shift load.
- **Transmission network reinforcement** – an order-of-magnitude estimate of the cost of reinforcing the transmission network to handle GB-wide peak loads.

The model is also capable of capturing the costs of enabling DSR for particular appliances (for example, the incremental cost of a smart appliance over a regular one). However, we have not used this functionality in calculating the results presented in this report.

8.1.2 High level structure

Figure 39 illustrates the overall structure of the model.

Figure 39. Model overview



Source: Frontier Economics

The model has three parts.

- The "**distribution network model**" assesses those costs and benefits which accrue on the distribution networks. This includes the cost of distribution network reinforcement, in addition to interruption and cost of losses.

- The "**wider electricity sector model**" considers the costs and benefits which depend on nationwide electricity demand and supply. These include generation costs, transmission network reinforcement costs, and any costs associated with smart appliances. This part of the model is linked to the distribution network part of the model through the impact of DSR and embedded storage.

- Finally, the **"real options-based cost-benefit analysis model**" combines the outputs of these models to calculate net present values and related indicators for each of the investment strategies.

8.1.3 Interactions between the models

Some smart grid interventions modelled within the distribution network models will not impact on the wider electricity sector model. For example, installing dynamic line rating on a feeder (modelled within the network model) does not affect the overall demand profile for energy (which affects the cost of generation).

However, the presence of smart grid measures which impact on demand profiles, for example DSR and embedded storage, complicates this situation. If DNOs actively shape the demand profile on a sufficient number of feeders, then this will lead to changes in overall demand across Great Britain, with a consequent impact upon generation and transmission costs. Similarly, if suppliers or the system operator change demand profiles to better utilise increased wind capacity, this will result in differing levels of demand on each local feeder. This introduces interdependencies between the two main parts of the model (as shown in Figure 39). In Section 8.5.3, we set out how the interaction between these two parts of the model will work.

We first describe each section of the model in turn:

- the real options cost-benefit analysis model;
- the distribution network model; and
- the wider electricity sector model.

8.2 Real options-based cost-benefit analysis model

The real options-based cost-benefit analysis model allows three investment strategies (representing different grid investment options) to be assessed against three scenarios (representing different electricity demand and supply conditions).

For each combination of scenario and strategies, the network and generation models pass a yearly list of costs to the real options cost-benefit analysis model.

- As described in Section 3 above, the real options-based approach allows us to take account of the different investment profiles of the alternative strategies, and the different flexibility in the face of uncertainty that these profiles imply. In particular, it allows us to model the impact of lock-in. That is, it allows us to account for the fact that one investment option in the first period may lead to a reduced set of investment options for the second period, for example because a large amount of investment is undertaken up front.
- The real options-based approach involves the following steps:
  - carrying out cost-benefit analysis of each strategy against each scenario over two periods: 2012-2023 and 2023-2050;
  - ruling out strategies which are not possible in the second period, given the choice of strategy in the first period;
  - comparing the net benefits in the resulting matrix of possible outcomes; and
  - assigning probabilities to each scenario, and calculating probability-weighted net benefits for each strategy undertaken in the first period.

Figure 40 shows an example of the matrix of possible outcomes that the model produces. Lock-in means that some combinations of first-period and second-period investment will not be included within the output: these are shaded in grey in the illustrative example provided below. For our model runs, we have assumed that once a "top-down" smart technology has been installed, it is infeasible to abandon it after 2023.[72]

The model highlights, out of the remaining second-period investment options, the one which provides the highest costs (shaded blue in the illustrative example below). This indicates the optimal 2023 strategy, given the strategy taken previously and the scenario that is realised (and subject to any constraints regarding changes of strategy).

Figure 40. Illustrative output table

Period 1	Period 2	Possible?	Central	Low DSR	Low elec
BAU	BAU	TRUE	-621	-623	-594
BAU	Incremental	TRUE	-573	-585	-574
BAU	Top-down	TRUE	-572	-583	-574
Incremental	BAU	TRUE	-609	-611	-584
Incremental	Incremental	TRUE	-567	-579	-570
Incremental	Top-down	TRUE	-566	-578	-570
Top-down	BAU	FALSE	-	-	-
Top-down	Incremental	FALSE	-	-	-
Top-down	Top-down	TRUE	-566	-578	-570

Source: Frontier Economics

Using these figures, the model is capable of calculating:

- the net present value of each investment strategy (for user-entered scenario probabilities, and from both the perspective of society as a whole and DNOs alone);
- the worst possible outcome under each strategy (i.e. the costs under the scenario that the strategy is least suited to);
- whether either of the two smart strategies will produce a positive net benefit (compared to a conventional strategy), regardless of the scenario that occurs; and
- how the socially optimal first-period strategy varies with the subjective probabilities of each scenario occurring.

72 Note that this is not the only form of lock-in: even if a strategy does not preclude others from taking place, it may still lead to large sunk investments that may affect payoffs in the second period.

Figure 41 displays an example of one of the high-level outputs of the model, which provides net benefit under each scenario:

Figure 41. Model output example

	2012 strategy	
	Incremental	Top-down
Central	(0.73)	(0.81)
Low DSR	(0.91)	(1.01)
Low elec	(0.21)	(0.36)
Probability-weighted NPV	(0.62)	(0.73)
Worst-case outcome	(0.91)	(1.01)

All figures in £bn

"Least regret" analysis summary
No smart strategy is always lower cost than BAU

Source: Frontier Economics

The model additionally enables the user to "drill down" to the figures underlying the main results (for example, the split of costs between those associated with network reinforcement and those associated with generation), and how these are split between different stakeholder groups.

In addition to the real-options CBA output described above, the model is capable of outputting the "simple" CBA results described in section 6.1.1.

8.3 Distribution network model

The technical methodology used in the distribution network model has evolved from work completed by EA Technology to estimate the future cost savings to support both the Customer Led Network Revolution (August 2010) and New Thames Valley Vision (August 2011) LCNF Tier 2 projects.

In the following sections, we describe:

- the overall approach and coverage of the model;
- the representative network types that we use in the model;
- how the model calculates the available headroom for each feeder;

- the assumptions made regarding the penetration of low-carbon technologies (in particular, how they may cluster on feeders);
- the way in which the model applies investments in response to diminished headroom; and
- how the model incorporates more centralised investments, which may not take place on a feeder-by-feeder basis.

8.3.1 Overall approach

The philosophy behind the network modelling is to take a parametric, probabilistic approach, rather than a nodal approach. This permits significant simplification and avoids the need to model multiple feeders and load flows. A nodal model and parametric model are defined as follows:

- **Nodal model**: a full load flow of a network, modelled as a set of points (nodes) and connections. In this type of model, power draw-off (loads) and power injection (generation) can be added as time varying profiles.
- **Parametric model:** one which does not model load flow, but uses higher-level abstractions, such as various types of "headroom". Headroom is the difference between the actual power flows, voltages and power quality measurements and the limits set by network design, equipment ratings, or legal / licence requirements. Headroom is amenable to statistical treatment and enables the outcomes of a nodal model to be extrapolated to GB as a whole without a full time-varying load flow of the network being required.

This approach allows the model to represent a typical distribution network. It does not encompass every possible condition or topology that may occur on GB networks and does not attempt to allow for regional variations in networks.

Rather, the model considers a variety of representative feeder types. These types are composed of LV networks (with generic "urban", "suburban" and "rural" networks), in addition to higher voltage networks (HV and EHV).

The feeders' capacity to host higher levels of low-carbon technologies (such as EVs, heat pumps, solar PV or distributed wind generation) is determined by their available thermal and voltage headroom.[73]

The effect of the increasing penetration of low-carbon technologies is modelled, taking into account clustering that may occur. Engineering calculations are used

[73] As voltage and thermal issues are the dominant drivers for load related investment today, headroom for fault level and power quality are not incorporated into the model. Either could be built into the model in the future if it were deemed necessary and are being considered under Workstream 3 of the Smart Grid Forum.

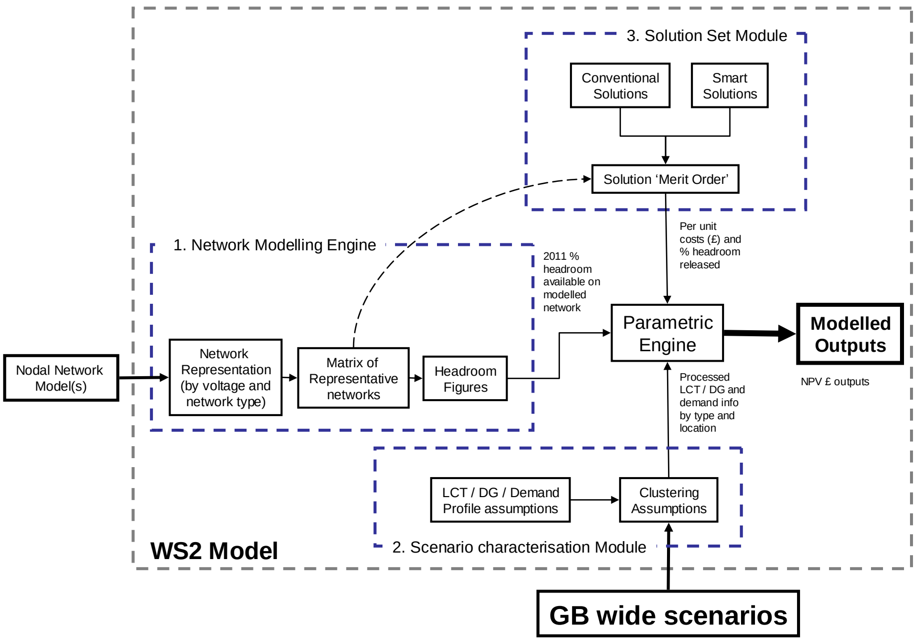
within the model to predict the effect of these low-carbon technologies upon thermal and voltage headroom.

When the model indicates that headroom will be breached for a particular group, then a network investment (whether a smart solution or conventional reinforcement) will be undertaken (though for the top-down strategy, some investment may occur ahead of need). This investment is associated with a cost, which then forms part of the overall cost used in the real options cost-benefit analysis model.

As outlined above, this model has been run for each combination of investment strategies and scenarios.

A representation of the structure of the model is given in Figure 42. The various sections of this figure (labelled as 1 – 3) are expanded upon in later diagrams in this section.

Figure 42. Network model overview



Source: EA Technology

8.3.2 Choice of representative networks

The parametric approach adopted avoids the need to model a network of multiple feeders. Instead, it makes use of selecting and modelling of a range of generic representative networks, the results for which are extrapolated across the country.

An important trade-off for this type of model involves the range of feeders which are modelled. Distribution networks in GB vary across a wide number of dimensions, including:

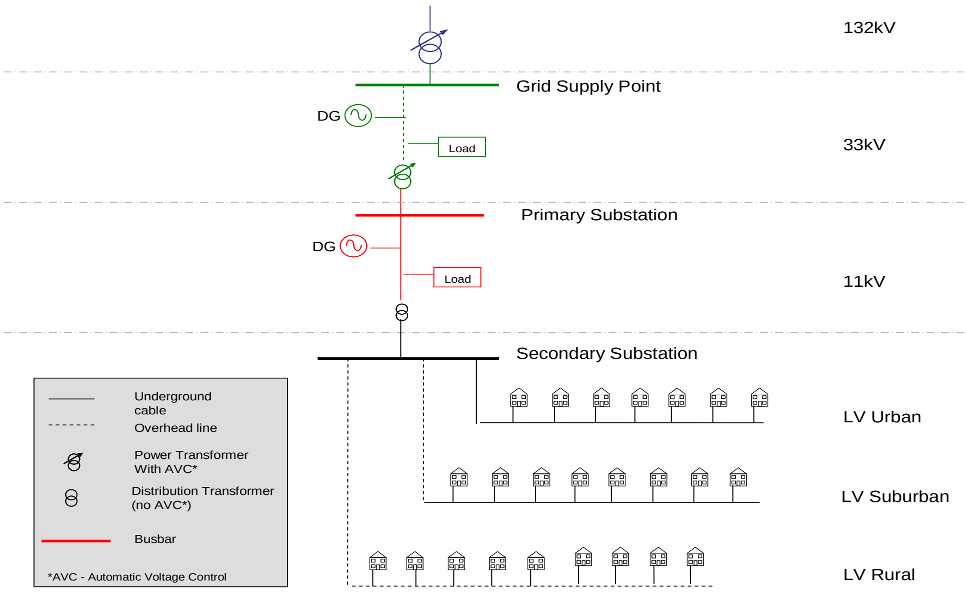
- voltage (e.g. 132kV, 66kV, 33kV, 20kV, 11kV, 6.6kV and LV);
- type of network (e.g. fully underground, fully overhead, or a mixture);
- network topology (e.g. radial, meshed, open ring, single circuit or double circuit);
- feeder length / impedance;
- the extent to which the feeder has additional capacity available;
- load density; and
- the distribution of demand along the feeder (e.g. uniformly distributed, or clustered near to or far away from the feeding substation).

Modelling all possible combinations of feeder (there would be in excess of 500) would produce an unwieldy model. It is therefore necessary to select a smaller number of representative feeders, which nonetheless encompass a large proportion of GB distribution networks.

Many of the drivers and smart grid interventions will occur at the LV level. We therefore model three generic LV feeder types (representative of urban, suburban and rural networks).

At the higher voltage levels, we have modelled generic 33kV and 11kV networks, using average network data at each voltage level. Figure 43 illustrates the relationship between the different voltage levels in the network.

Figure 43. Schematic diagram of the network model



Source: EA Technology

The schematic (nodal) model is represented by a series of parameters, as described in Table 26.

The design of the model is such that it is relatively easy to add further representative network types in future if desired, or to modify the parameters of the existing feeder types.

Table 26. The parametric model structure

	% Voltage Headroom	% Thermal Headroom	% of GB networks
132kV Grid Supply Point	×	✓	100%
33kV circuit	✓	✓	100%
33/11kV Primary transformer	×	✓	100%
11kV circuit	✓	✓	100%
11kV/LV Secondary transformer	×	✓	100%
LV circuit (urban)	✓	✓	45%*
LV circuit (suburban)	✓	✓	47%*
LV circuit (rural)	✓	✓	8%*

All ticks represent data input that will be preconfigured into the model based on measurement or estimates of current network operation in GB *

*For illustration only, scaling can be tailored to reflect the split of each type of networks in GB

Source: EA Technology

8.3.3 Headroom

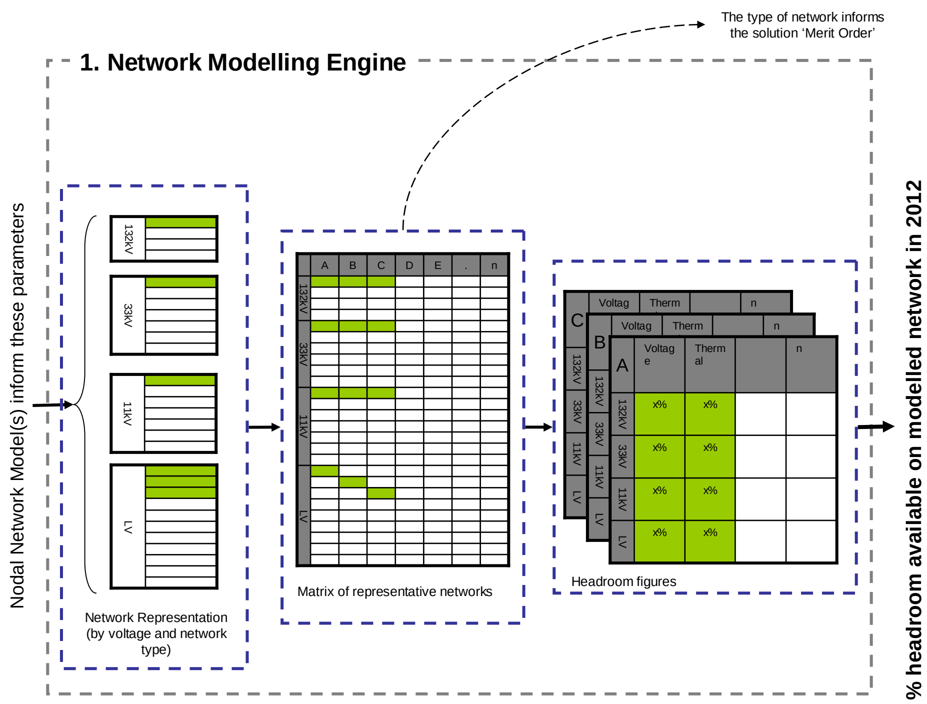
This section sets out our approach to modelling the headroom available for each type of feeder. As explained above, the concept of headroom provides us with a simple way of expressing how close each feeder is to requiring DNO intervention.

We have based the modelling on the outputs of a nodal time-stepped load flow model of representative feeders and the previous knowledge and experience gathered through carrying out projects on distribution networks over many years. This work is based on the outputs of previous modelling of real feeders and gives good estimates of the headroom for a typical range of networks.

We have represented networks by two figures for available headroom: one for thermal and one for voltage. For LV these figures are different depending upon the network type (urban, suburban or rural) as these networks have different design characteristics and different load profiles. Note that the initial headroom of feeders does not vary across low carbon technology uptake scenarios (since they all start with the current levels of demand), but the differing penetrations of low-carbon technologies across scenarios will cause headroom figures to diverge with headroom being reduced more rapidly for higher uptake scenarios.

The way in which the representative networks and headroom is modelled is illustrated in Figure 44.

Figure 44. Network modelling engine



Source: EA Technology

Figure 45 shows a portion of the model where initial headroom figures are set.

Figure 45. Network model - initial headroom

LV Networks	Number of Networks	Thermal(Cable)(kW)	Thermal(Transformer)(kW)	Voltage Headroom(kW)
Urban	273,300	147.2	167	20
Sub-Urban	182,200	164.6	125	20
Rural	56,938	82.8	100	20
11kV Normal	11,388	8193	6000	1000
33kV Normal	2,847	30865	20000	308651

	Urban	Sub-Urban	Rural
Number of Distribution Substations	6	4	5
Number of LV Feeders from distribution substations	4	4	1
11kV Normal	24	16	5

	11kV Normal
33kV Normal	4

Source: EA Technology

Headroom at low voltage

The headroom figures, both thermal and voltage, for the LV networks are based on a range of sources, including the outputs of nodal time-stepped load flow models using EA Technology's WinDebut LV network design software of representative feeders; details taken from the Strategic Technology Program project "Long Term Domestic Demands"; and data from publicly available Elexon profiles.[74] The combination of low-carbon technologies and small scale generation, taken from the WS1 scenarios, with the headroom available at a given point in time will determine when voltage and thermal limits on the LV network are breached with various low-carbon technologies connected:

- with different clustering levels; and
- for different low-carbon technology uptake levels.

Headroom at higher voltages

For the higher voltage networks, we have derived the network capacity figures by examining the design of HV networks and selecting a representative circuit rating. The low-carbon technologies that are connected at low voltage then have a cumulative effect on the network and by adopting a bottom-up analysis, their impact on the HV network is considered.

The combination of Distributed Generation, taken from the WS1 scenarios, with the headroom available at a given point in time determines when voltage and thermal limits on each of the higher voltage networks are breached.

For all network voltages a range of appropriate mitigating interventions can then be applied to the feeder model once thermal or voltage limits are breached. The

74 We are not aware of similar work with published figures. If DNOs have suitable design studies that they have carried out on other feeders then these can be incorporated in the future. The range of representative feeders will be increased by the WS3 modelling activity which will look at a significantly larger number of LV feeders.

number of low-carbon technologies, small-scale generation or distributed generation that can be connected without breaching limits is recorded. Then more low-carbon technologies, small-scale generation or distributed generation can be added until the limits are again breached. The new maximum number of devices will be recorded for each mitigating intervention. This process enables the "solution stacks" of interventions (described below) to be created.

DNOs have significantly more modelling expertise and data for higher voltage networks. In contrast, the LV network does not tend to be accurately modelled, nor is the infrastructure in place to derive accurate measurements. We therefore draw out our approach to determining LV headroom in more detail in the following section.

Specifics for representing LV thermal headroom

The triggers for enacting solutions to solve thermal headroom problems are usually a result of higher current than the static cable or plant ratings.

We have based the figures for urban, suburban and rural thermal headroom on outputs from the WinDebut model, sense checked by engineering judgements of DNO staff regarding where typical networks operate. Although data here is sparse, we would expect these assumptions to be sharpened with the output of LCN Fund projects (e.g. LV Templates, Customer Led Network Revolution, etc.). Once such data becomes available, the profiles and headroom values can be updated in the model as desired.

Specifics for representing LV voltage headroom

A sufficient concentration of distribution network-connected generation (such as PV) has the potential to lift the voltage on the network. In contrast, higher circuit loadings (e.g. caused by the connection of EVs) will depress the voltage. It is therefore necessary to model voltage headroom (the margin below the upper voltage limit) and legroom (the margin above the lower voltage limit).

As with thermal headroom, assumptions are required for the distribution of existing voltage headroom across the representative feeders. We have based these assumptions on data from the WinDebut model, together with knowledge and experience gained from working in this field. Again, data here is sparse, but we would expect these assumptions to be sharpened with the output of LCN Fund projects.

The outputs of this analysis is then extrapolated to give the number of small scale generation installations (such as PV) that can be connected to feeders without breaching voltage headroom, by assuming that voltage rise is proportional to the change in power.

We check the likely voltage legroom (available volts above statutory limits at end of LV feeder) by assuming that voltage drop is proportional to the change in power. This enables the model to check the numbers of electric vehicles and heat pumps that could be connected to LV feeders without breaching voltage legroom.

This gives us the network base case, represented as a series of figures of percentage of available connections.

8.3.4 Clustering of low-carbon technologies

Data regarding the proposed uptake levels of low-carbon technologies is input into the model based on the scenarios from WS1. This section sets out how the network model simulates the penetration of these technologies across feeders over time.

The impact of low-carbon technologies on networks will depend partly (and particularly in the near-term) on the extent to which they are clustered, rather than distributed evenly across feeders. Clustering may occur because those who purchase the technologies will be influenced by their friends and neighbours, and different social groups will adopt the technologies at different rates. This clustering has the potential to cause problems on the network significantly earlier than if the low-carbon technologies were distributed evenly.

The extent to which installations cluster has been estimated using the 'Feed-in Tariff Installation Report 30 June 2011' (henceforth referred to as: FiT data) provided by Ofgem. This provides the first few digits of post code for each installation of PV across the country.

We have no data relating to clustering of electric vehicles and heat pumps. In the absence of these data we have assumed, as a default, that electric vehicles and heat pumps will cluster in the same way as PVs. However, the clustering behaviour of each low-carbon technology is fully customisable within the model. Therefore, once data becomes available, these clustering factors can be updated by a user.

From inspection of the FiT data we identified that it was appropriate to divide the data into five groups, which are shown in the table below.

Table 27. Low-carbon technology clustering, based upon FiT data

Percentage of network	Percentage of low-carbon technology installations
1%	9%
4%	17%
25%	48%
30%	22%
40%	5%

Source: EA Technology

Figures do not add to 100% due to rounding errors

This information, together with the estimates of numbers of connections of each type of technology across GB, is then used to calculate how rapidly the five different groups will adopt the low-carbon technologies.

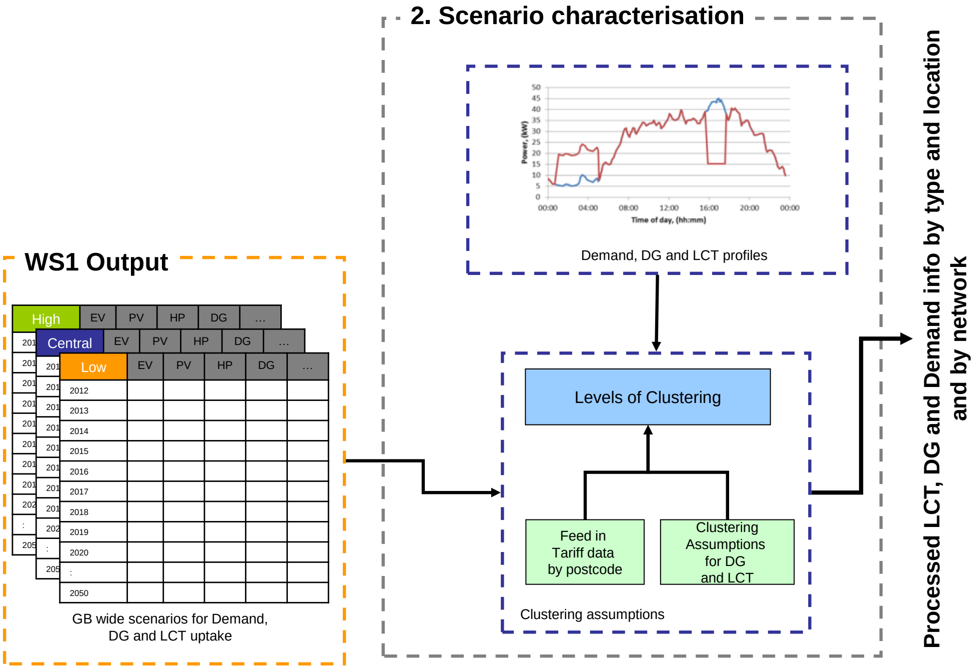
Once all connection points in a network group have been used, then those low-carbon technologies that can no longer be accommodated within that group are redistributed proportionally across the other groups. This ensures that, for example, the model does not imply that some households will have more than one heat pump.

The model assumes that the degree to which clustering occurs, for a given penetration of low-carbon technologies, is the same across the different scenarios. However, scenarios with a higher penetration of low-carbon technologies may be modelled as having a more uniform distribution of them. This is due to the issue explained above: once modelled penetration within a cluster reaches 100%, the model will have to allocate additional low-carbon technologies more widely across the feeders[75].

The characterisation of scenarios and clustering levels is illustrated in Figure 46.

75 This is simply due to the way in which (by definition) penetration cannot exceed 100% - it is not a result of headroom limits on the network.

Figure 46. Scenario characterisation



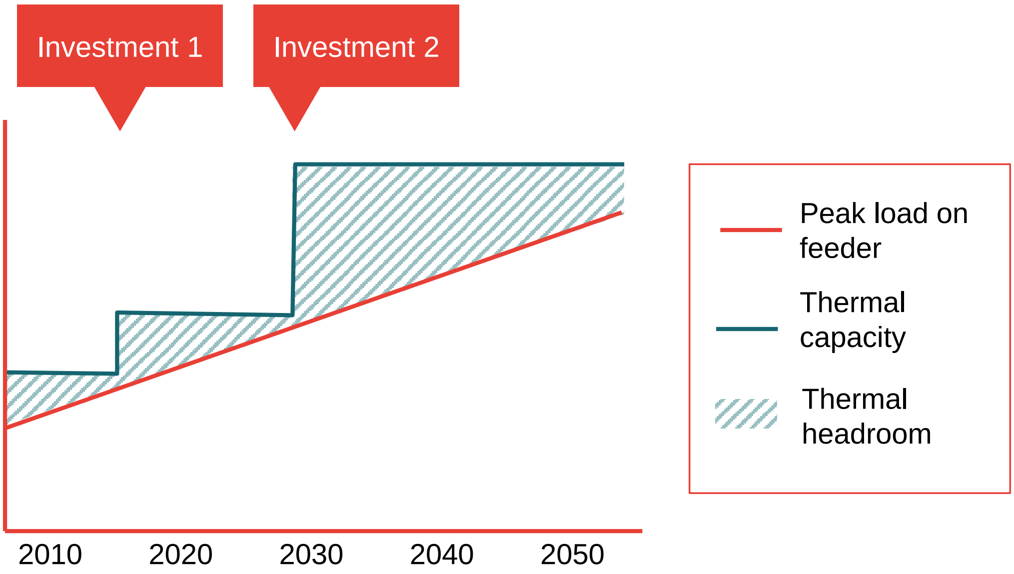
Source: EA Technology

8.3.5 Distribution network investment

This section explains how distribution network investments will be triggered by changes in the available headroom on each feeder.

The increased penetration of low-carbon technologies (as well as any organic growth in demand) leads to a reduction in headroom on each feeder. Each investment strategy (top-down and incremental) will be associated with a different priority stack of smart and conventional investment solutions. When the trigger points for thermal or voltage headroom (or voltage legroom) on a feeder are reached, the model looks to select the next available smart or conventional investment solution from a "priority stack" and implement this solution so as to increase the available headroom. Figure 47 provides a stylised illustration of this process. Note that, while this diagram only indicates thermal headroom, the model will simultaneously be ensuring that voltage headroom (or legroom) is within acceptable limits.

Figure 47. Illustration of network investments



Source: Frontier Economics

The model will allow various "solutions" to be applied to increase headroom. Some of these will be conventional reinforcement options. Under the conventional strategy these will be the only options available, while even under the smart grid strategies these will still generally be required (but their timing may be deferred). These are to:

- split the feeder (that is, transfer half of the load of the existing feeder onto a new feeder);
- replace the transformer;
- install a new split feeder (that is, run a new feeder from the substation to the midpoint of the already split feeder and perform some cable jointing to further split the load, resulting in three feeders each having approximately equal loads); and
- carry out major (and highly costly) work on the network to free up a substantial amount of headroom.

Under the two "smart" investment strategies, a number of additional technologies will become available. We recognise that there are a large number of potential smart grid technologies. The phase 1 report from WS3 identifies 12 categories or 'smart solution sets'. The model has been designed with a number of "spare" interventions to act as placeholders for when new technologies emerge. It should be noted that this model is concerned only with deploying solutions on the distribution network meaning that some of the (transmission-specific) solutions described in the WS3 Phase 1 report are out of scope.

At present, there are great uncertainties regarding the effect that some smart grid interventions will have. Populating the model with a large number of intervention types is therefore unlikely to provide a great increase in the accuracy of the cost/benefit estimates, but will lead to significantly increased data requirements.

- We have therefore pre-populated the model with five examples of smart solutions, which encompass the different types of intervention that are likely to be required:
  - dynamic thermal rating (releases thermal headroom);
  - enhanced automatic voltage control (releases voltage headroom);
  - electrical energy storage (releases both types of headroom);
  - DSR (releases headroom by changing the demand profile itself); and
  - active network management (releases thermal headroom by reconfiguring networks)

Each of these solutions has a cost, and each also has a headroom release figure associated with them (for thermal and voltage headroom). The order in which they are applied (the stack) depends on the network type, the low-carbon technology uptake scenario, and the investment strategy that is being modelled.

Table 28 shows how a collection of priority stacks might look for three types of LV network. It should be noted that this is for illustrative purposes only, to demonstrate how the network type, network voltage and low-carbon technology and generation uptake rate have an effect on the preferred order in which the solutions are applied. This is not a definitive list of the priority stack for the various smart and conventional solutions. It only shows the priority stacks for one particular investment strategy; the model contains a different collection of stacks for the conventional, top-down and incremental strategies.[76]

[76] We also model situations where the strategy changes in 2023 – for example, from a BAU to an incremental strategy. When this occurs, some of the investments in the stack for the new strategy may already have been made under the previous strategy. The model will skip such investments.

Table 28. Priority stack illustration for a single investment strategy (the solution stacks illustrated are for the three representative LV networks, and the single representative 11kV and 33kV networks).

	Scenario A	Scenario B	Scenario C
33kV	Conventional 1	Smart 1	Smart 1
	Smart 1	Conventional 1	Conventional 1
11kV	Conventional 1	Smart 1	Smart 1
	Smart 1	Conventional 1	Smart 2
	Smart 2	Smart 2	Conventional 1
LV Urban	Smart 1	Smart 1	Smart 1
	Smart 2	Smart 2	Conventional 1
	Smart 3	Conventional 1	Conventional 2
	Conventional 1	Smart 3	Smart 2
	Smart 4	Conventional 2	Conventional 3
	Conventional 2	Smart 4	Smart 3
	Conventional 3	Conventional 3	Smart 4
LV Suburban	Smart 3	Smart 3	Smart 3
	Smart 4	Smart 4	Conventional 1
	Smart 1	Conventional 1	Conventional 3
	Conventional 1	Smart 1	Smart 4
	Smart 2	Conventional 3	Smart 1
	Conventional 3	Smart 2	Conventional 2
	Conventional 2	Conventional 2	Smart 2
LV Rural	Smart 2	Smart 2	Conventional 1
	Smart 4	Conventional 1	Smart 2
	Smart 1	Smart 4	Smart 4
	Conventional 1	Smart 1	Conventional 2
	Smart 3	Conventional 2	Smart 1
	Conventional 2	Smart 3	Conventional 3
	Conventional 3	Conventional 3	Smart 3

Source: EA Technology

Figure 48 is an extract from the model, which shows how the solution stacks are built up (these are the stacks for thermal headroom issues on an urban LV feeder, under the incremental strategy).

Figure 48. Solution set model

Incremental Solution Stack		
	Urban	
	Thermal Cable	Thermal Transformer
Intervention 1	Dynamic Thermal Ratings - LV Cable	Dynamic Thermal Ratings - Distribution Transformer
Intervention 2	Demand Side Response at LV	LV New Transformer
Intervention 3	LV Split Feeder	Demand Side Response at LV
Intervention 4	LV New Split Feeder	Active Network Management at LV
Intervention 5	Active Network Management at LV	LV Major Work
Intervention 6	LV Major Work	Electrical Energy Storage at LV
Intervention 7	Electrical Energy Storage at LV	
Intervention 8		

Source: EA Technology

The model applies the solution from the priority stack and calculates how many years it will be before headroom is anticipated to be breached again and a second intervention is then required. Some solutions give a benefit to both headroom measures, for example if the problem is concerned with thermal headroom then a solution will be implemented to relieve this headroom issue, but may also release some voltage headroom as a secondary effect. The model will recalculate the headroom for both thermal and voltage parameters after applying an intervention such that it can accurately be determined when the next intervention (for thermal or voltage reasons) is required.

Depending on the network type and the low-carbon technology uptake rate, when a second intervention is required, the model will simply take the next solution from the stack and apply it and recalculate headroom. When a third intervention is required, the process is repeated and so on.

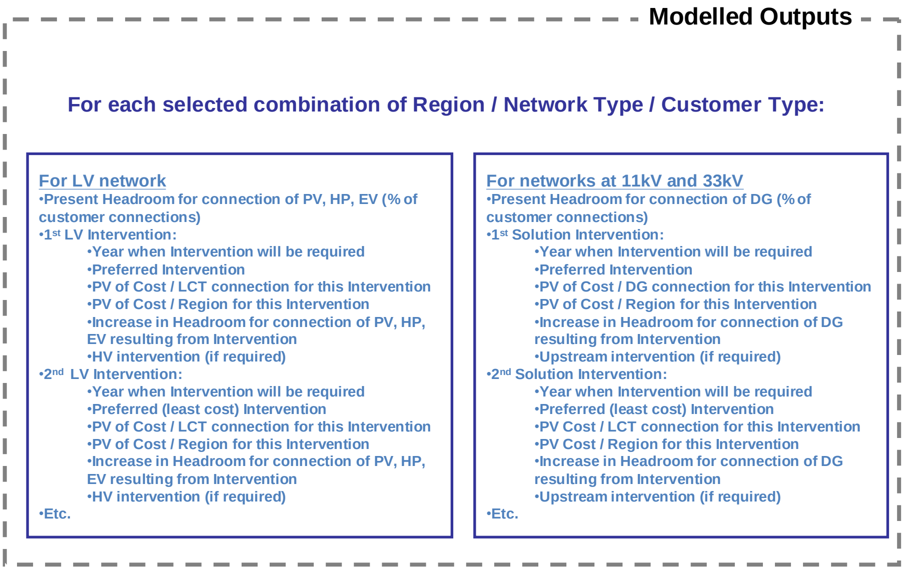
The solution stack is built as per the table above, but it can flex such that the priority of different solutions may change over time. Each solution has an implementation cost. Initially, some of the smart solutions may have a high implementation cost as the technology is still being developed. In the future, this cost may be reduced and the model makes use of different costs for these solutions as time progresses. Therefore, the solution stack may have its priority adjusted as a certain technology becomes more affordable in, say, 2030. The costs associated with each solution in the stack are fully flexible to users.

It should be noted that solutions have different lifetimes and the model allows for the fact that a solution may only be valid for, say, ten years before the installed components need to be replaced. At this point the solution is re-activated in the priority stack such that it can be re-applied as necessary. These solution lifetimes can also be customised by the user.

The final outputs are then scaled from a local level to GB level using feeder lengths from Regulatory Reporting Pack data.[77]

The output from the network model can be characterised as shown in Figure 49.

Figure 49. Network model outputs



Source: EA Technology

8.3.6 Top-down investment strategy

In the model described above, smart grid investments are made on a feeder-by-feeder basis as and when required due to diminishing headroom. However, it may also be possible to implement smart grid technologies by making large one-off investments that affect large numbers of feeders at once. In order that we capture such types of investment, our smart grid investment strategies assess both "top-down", and "incremental" investment strategies.

The top-down strategy is modelled in a similar way to the priority stacks described above. However, an initial "enabling" investment is made in the network (this investment amount can be customised by a user) to provide

[77] Ofgem's regulatory reporting pack is available here: http://www.ofgem.gov.uk/Networks/Trans/RegReporting/Pages/RegulatoryReporting.aspx

infrastructure to support smart solutions in the future. This has the effect of reducing the cost of a number of solutions in the stack (because the costs of installing communications and monitoring equipment, for example, have already been borne in the top-down investment).

All solutions are therefore equipped with separate cost functions for incremental and top-down strategies (the cost of traditional reinforcement is the same whether under conventional or incremental strategies).

The model is flexible enough to allow the overall costs of such investments to vary from the feeder-by-feeder approach (to take account of any economies of scale), as well as the benefits (in terms of headroom saved). This allows us to capture any possible benefits of adopting a more 'holistic' or top-down approach to smart grid investment.

8.4 Modelling the wider electricity sector

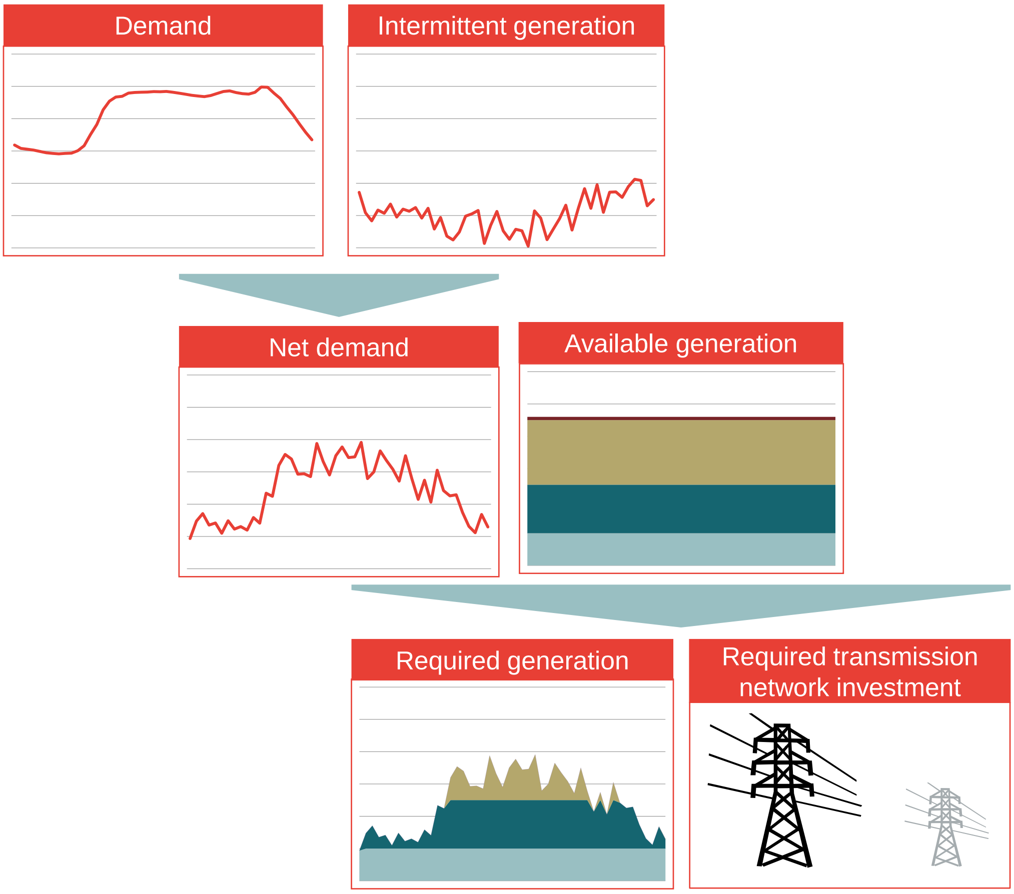
We now go on to describe the wider electricity sector model. This is set out in Figure 17 and involves:

- building representative half-hourly demand profiles for GB as a whole;
- creating representative half-hourly profiles of intermittent generation (the model considers both wind and micro solar PV generation);
- setting up a merit-order "stack" of other generation technologies; and
- determining the amount of energy required each for half hour from each of these generation types, to meet demand (net of intermittent generation).

In addition to generation costs, the model takes account of two further types of cost.

- **The cost of ensuring there is sufficient flexible generation to enable the system to be balanced at all times**. This is taken into account by using constraints upon the minimum reserve capacity that is required.
- **The cost of transmission network reinforcement to meet changed peak demand**. The model considers the peak power flows that the transmission network will be required to cope with and, and provides a very high-level estimate of any investments.

Figure 50. Wider electricity sector model overview



Source: Frontier Economics

8.4.1 Representing demand

In common with the distribution network model, demand is represented using a half-hourly profile across representative days. For each year, three representative days are considered:

- an average "summer" weekday, between April and September inclusive;
- an average "winter" weekday, between October and March inclusive (but excluding the 10% of days in this period with the highest demand); and
- a "peak winter" weekday, which represents the 10% of days between October and March with the highest demand.

The GB-wide demand profiles are built up from the same low-carbon technology penetration rates and hourly demand profiles as used in the distribution network model, to ensure consistency.

In addition to the load modelled by the distribution network model, it is necessary to add in two further sources of demand.

- **Transmission connected load.** Some very large industrial plants (such as aluminium smelters) are connected directly to the transmission network grid supply points. Power stations themselves will also draw some load from the grid. Analysis of National Grid's GSP demand projections[78] indicates that the peak level of such demand is likely to be between 1.7 GW and 2 GW.

- **HV/EHV connected load.** Smaller industrial users connect to the distribution network at higher voltages. These are not modelled by the distribution network model, since such users will tend to be on their own feeder. In the absence of firm evidence, we have therefore added a flat 5 GW of demand to all load profiles to represent industrial demand at higher voltages[79].

As explained above, some smart grid technologies will allow the demand profiles to be adjusted (e.g. embedded storage and technologies that enable DSR). The modelling of DSR is explored in Section 8.5.3.

8.4.2 Modelling intermittent generation

Our model considers two different types of intermittent generation:

- wind (onshore and offshore); and
- micro solar PV.

For the purposes of the cost calculations, it is assumed that these technologies have no variable costs (i.e. costs that vary directly with energy generation).

Wind

Wind generation (onshore and, increasingly, offshore) is likely to form a key element of the future generation mix[80]. Wind is, by its nature, intermittent. While on average the electricity supplied by wind generation follows predictable seasonal and hourly patterns, the actual power delivered by wind in a given period can vary widely from this average. Even though the distribution of wind

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[78] Appendix E of National Grid's 2011 seven-year statement (http://www.nationalgrid.com/uk/Electricity/SYS/current/)

[79] This likely to exhibit a very different load profile to the domestic and commercial customers which the distribution network model considers: Some continuous industrial processes may run throughout the night, while other industrial users might lower their demand after work hours, just as domestic load reaches its peak.

[80] See for example, CCC (2010) *The fourth carbon budget*, http://www.theccc.org.uk/reports/fourth-carbon-budget

turbines across the country can help to average out localised variation to some extent, the overall pattern of wind generation remains "noisy".

This variability and unpredictability of wind can have a large impact on the overall costs of generation. If demand cannot be time-shifted sufficiently, then large quantities of peak-load plant may be required to run when wind generation is insufficient. On the other hand, if high wind output coincides with low demand, curtailment of wind generators may be required (since some inflexible baseload plants will be unable to decrease their supply). Wind intermittency is therefore an important part of the generation model.[81]

In addition, a large amount of (generally onshore) wind will be connected to the distribution network. On feeders with a high penetration of wind, the pattern of generation may have a significant effect upon reinforcement costs.

Our approach has been to produce a "typical" half-hourly wind profile for the summer, winter and winter peak "seasons".[82] The profiles have been drawn from data on historical UK wind output (MW per half hour) from Elexon. To assess whether a profile is "typical", two characteristics were calculated for each day of data:

- First, the total daily wind output, as a percentage of the average for that month was calculated.

- Second, the ratio of total generation during the eight hours of highest evening peak (from 16:30 to 19:30 inclusive) to generation in off-peak hours (defined here as 3:00 to 6:00 inclusive). A high value here will tend to mean that wind output is correlated with electricity usage, which would (all else constant) tend to lead to a lesser role for DSR.

The representative days we picked have values of these parameters close to the average of all days in the respective seasons.

In addition, we calculated average (smoothed) wind profiles for each "season". Average profiles are used to set static DSR signals since, under static DSR, suppliers would set their DSR signals in advance, rather than in response to real time wind conditions.

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81 From a DNO perspective, the most significant result of increased wind penetration will be the way in which wind-following tariffs may lead to changes in demand profiles. Section 8.4.5 below describes how this will be taken into account.

82 The original specification for the model included a number of different "typical" profiles for each day, which would be assigned a probability weighting. This would allow the variation in wind to be better taken into account, however even using two representative profiles per "season" would double the run-time of the model. Given the increase in run-time caused by the need to model the deployment of DSR at each voltage level, the decision was made to use a single wind profile, and check how sensitive the model is to the choice of profile.

The wind profiles have been standardised such that the daily total output is consistent with predicted capacity factors (for example, if the capacity factor is 30%, then our profiles will be scaled such that 1MW nameplate capacity of wind will produce on average 300kW each period over the day). The capacity factors vary by season and by turbine type (offshore and onshore), with details on data sources provided within Section 4.

There are a number of limitations to this approach.

- While these profiles take into account the existing diversification of wind across the country, they will not make allowances for any further diversification that is expected with the major expansion of wind projected to 2050. This means that they may overestimate the variability of wind.

- These profiles are based on the current mix of onshore and offshore wind. This mix is likely to change significantly towards 2050, with a much greater proportion of offshore wind coming on line. Offshore wind is likely to exhibit a different pattern to onshore wind.

- The same wind profiles are used on the distribution network, the output of wind is likely to be considerably more variable at such a localised level (with consequent scope for causing more issues that can be mitigated with smart solutions). Our model therefore does not fully capture the varying conditions on those feeders with high wind penetration. However, given the majority of feeders within GB are unlikely to have such high penetration, a model which assumed they all[83] experience high levels of wind variability would be likely to overstate the problem.

Note that our model will not explicitly model the possibility of wind output being correlated between days (for example, an entire week with lower than expected wind output). However, since we assume that the transfer of energy enabled by DSR and embedded storage will always be within a single day, this will not affect the results of the generation model.

Micro solar PV

Micro Solar PV is assumed to be connected to the distribution network, and is modelled as a technology with a negative load profile (see Section 4). The power from solar PV installations varies both with the time of day (peaking at midday) as well as the season (it is typically highest in mid-summer). Both of these elements can be captured by a half-hourly generation profile for each season.

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83 To keep calculation times to a reasonable level, our model can only simulate a relatively small number of representative feeders. It is therefore not possible to separately model feeders with high wind penetration.

In addition, the output of each individual solar panel will vary according to the local weather conditions (being lower if the weather is cloudy). Although the total solar output across the whole of Great Britain will follow a smoother pattern, there will still be an element of solar intermittency (especially on individual feeders) that is not captured by the half-hourly profiles. However, for the purposes of this model, we do not model such solar intermittency in the same way as for wind.

It is also worth noting that the overall energy supply from micro PV will be considerably lower than that from wind, which decreases the importance of intermittency. For example, DECC's *2050 Pathways* analysis assumes that an achievable technical potential[84] for solar PV by 2050 is 60 TWh per year. By contrast, the equivalent assumption for both offshore and onshore wind is that it would deliver 237 TWh of electricity per year, almost four times as much.

8.4.3 Other forms of generation

The final main input into the model is the capacity of other forms of generation. For each form of generation technology, in each year, we require:

- the installed capacity (in GW);
- the operating cost per MWh of energy supplied (including fuel, variable O&M and the price of any carbon emissions);
- fixed O&M costs (per GW of capacity); and
- the capital cost per GW of capacity (expressed on a per-year basis[85]).

The data used to populate these assumptions is documented in Section 4.[86]

8.4.4 Modelling of required generation

For each season and each demand profile net of intermittent generation, the model can then determine the costs of generation. Starting with the lowest variable cost base load plants, the model will deploy sufficient generation to meet this demand. This enables both the overall operating cost of generation to be

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84 This is the "level 2" assumption, which "*describes what might be achieved by applying a level of effort that is likely to be viewed as ambitious but reasonable by most or all experts. For some sectors this would be similar to the build rate expected with the successful implementation of the programmes or projects currently in progress*".

85 Since a number of power plants are likely to be under construction during any given year, the fact that we do not account for the "lumpy" nature of capital expenditure should not have a material impact on the results.

86 While our data source did not include a figure for nuclear decommissioning, this will take place far into the future and would therefore be heavily discounted – a cost occurring 50 years in the future is worth (in present value terms) less than 20% of immediate capex.

determined, as well as the marginal (most expensive) plant, which will determine the market price of electricity.

If DSR or embedded storage is able to sufficiently smooth demand, then there may be a reduced requirement for peaking plants. The GB-wide required generation capacity is determined by considering, for each year, the half-hour period of highest demand (regardless of season). It would not be appropriate to net off typical wind generation from demand here, since there must be sufficient generation capacity to cope with rare events where there is an exceptionally low level of wind generation. We therefore only net off 5% of wind nameplate capacity.[87]

To ensure that short-term dips in demand do not lead to a corresponding drop in generation. a five-year rolling maximum is then taken of the resulting yearly peak demand. This is because, given the long lifetimes and lead times of power plants, it is not feasible for overall capacity to change rapidly in response to shocks to demand. Finally, generation is scaled up by 10% to account for the required capacity margin.[88] As the model takes into account capex and fixed O&M, any such decrease in plant capacity that occurs as a result of smart grid investments will be valued.

Given the requirement to produce a flexible and transparent model, we have not created a fully featured dispatch model for GB. As a result, technical constraints (such as ramping capabilities) are not taken into consideration. However, we have started our modelling from fully internally consistent generation scenarios (see Section 4). These will therefore include sufficient quantities of peaking plant to meet required security of supply. When the model (as discussed above) reduces the capacity of such plants, all generators in the stack are scaled proportionally. This should ensure that there is still an appropriate proportion of each type of generator.[89]

Pumped storage

Like DSR, pumped storage provides a way in which the demand and supply for electricity at the national level can be brought into balance. The use of pumped storage may therefore enable DSR to be deployed by DNOs to increase feeder

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87 Capacity credit assumption taken from National Grid's *New Future Energy Scenarios*

88 This figure is taken from DECC (2011) *EMR Capacity Mechanism: Impact Assessment* (http://www.decc.gov.uk/assets/decc/11/consultation/cap-mech/3883-capacity-mechanism-consultation-impact-assessment.pdf), which suggests that 10% is an acceptable margin.

89 The model does not take into account the effect that increasing wind penetration may have

headroom, while still enabling demand at GB level to follow intermittent renewable generation.[90]

The model incorporates a simplified treatment of pumped storage, which is described below. However, this has not been enabled for the runs of the model described in Section 6. This is because the UK's pumped storage capacity is typically deployed at shorter timescales than the 30-minute periods modelled here.

The modelling of pumped storage is somewhat more complex than simple generators. This is since, in addition to constraints regarding the overall capacity of the units, it is necessary over time for the energy produced by the pumped storage system to equal the energy consumed by the pumps (minus any losses that take place).

It is rational for a pumped storage unit to operate whenever the spread between the price of electricity used when generating and pumping is greater than its operating costs. Since the model produces the marginal cost of generation in each hour, it is possible to calculate this, and to determine the pair of half hours with the highest spread.

Starting with this pair of periods, and assuming the spread is sufficient to cover operating costs of pumped storage, the model employs pumped storage generation when the price is highest, and pumping when the price is lowest. Following this, the pair of periods with the second-highest spread is considered. This process continues until either the spread is insufficient to cover the pumped storage operating costs, or the pumped storage facility has been deployed the maximum number of times possible.[91] Note that it is possible to specify the efficiency of each unit (generator power output as a percentage of pump power requirements). The model will take the cost of the additional power requirements into account when determining whether to deploy the unit.

Within the model, a single pumped storage unit can only ever be in three states: pumping, generating or idle. However, a large pumped storage facility can be divided into different units to represent each generator. For example, we have pre-populated the model with simplified technical characteristics of Dinorwig's six generators, and Ffestiniog's four. The model dispatches the pumped storage units sequentially: any modifications to total load created by the first unit will be passed into the second unit, and so on. This avoids the need to carry out simultaneous optimisation, but does mean that the model may under-deploy

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[90] This is based on the assumption that DSR to minimise generation costs is enabled by smart meters alone.

[91] We assume that the pumped storage facility will carry out, at most, one full charge/discharge cycle. The length of time for which the facility can run is therefore equal to the amount of time taken to deplete the reservoir (which is assumed to be the same time taken to fill it up again).

pumped storage (this would be the case if a single unit's capacity is insufficient to lead to a decrease in the price of electricity, but if multiple units were activated simultaneously they would do so).

Note that the model applies pumped storage *after* demand profiles have been adjusted for DSR. As explained above, pumped storage and dynamic DSR to reduce generation costs can be seen as substitutes for one another. However, as it is currently setup, the model will never allow pumped storage to substitute DSR (although DSR could reduce the need for pumped storage, reducing opex and pumping losses).

The use of pumped storage may reduce the level of overall peak demand for which the generation stack has to be designed. To take this into account, the model actually performs two runs of the pumped storage algorithm:

- First, pumped storage is applied to the overall demand profile, with electricity costs based on a generation stack sized to match the profile.
- This produces a new, flatter demand profile, which is used to build another, smaller generation stack.
- Finally, the pumped storage algorithm is re-run, but this time using the modified generation stack.

Interconnection

Previous studies have found that DSR and interconnection have complementary roles to play in balancing supply and demand.[92] Since interconnection does not compete with DSR in the same way as pumped storage, it is more appropriate to take a high-level approach that abstracts away from complex factors such as European-wide correlations in wind generation and demand.

We have therefore included interconnector imports within the generation stack: the interconnector is assumed to be always available for imports, with electricity priced at the level of CCGT operating costs. Interconnector capex is not modelled.

In principle, it would be possible for a model to take into account the average price of electricity over time in each of the connected markets, and simulate exports and imports when it is profitable to do so. However, this would add considerable additional complexity to the modelling. In addition, it is unlikely that this would affect our overall results significantly. This is because generation costs tend to net off in the final cost-benefit analysis, since we are comparing all strategies to the conventional investment strategy, generation costs do not vary

92 Pöyry (2011), *DSR follow on*

much across strategies. This is since we have assumed that the benefits of DSR in lowering generation costs can be obtained without additional smart grid investment.

8.4.5 Transmission network investment

Significant investment in the GB transmission network will be required to meet changing patterns of demand and generation over the next 40 years. National Grid has indicated that it expects to undertake capital expenditure summing to £14 billion over the course of the RIIO-TD1 period alone. This capital expenditure will, in part, be required to accommodate changes in the location of generation as a result of the need to decarbonise the energy sector (e.g. the growth of wind power offshore and in Scotland). However, transmission network reinforcement may also, in the long run, be driven by increases in peak GB-wide demand for electricity (net of embedded generation) as the economy returns to growth and the electrification of heat and transport gathers pace.[93]

To the extent that it facilitates DSR, a smart grid could flatten the GB-wide demand profile, thereby reducing the rate of growth in peak demand. This could help defer the need for transmission network reinforcement, thereby helping to reduce capital expenditure. Figure 51 below provides a stylised illustration of this.

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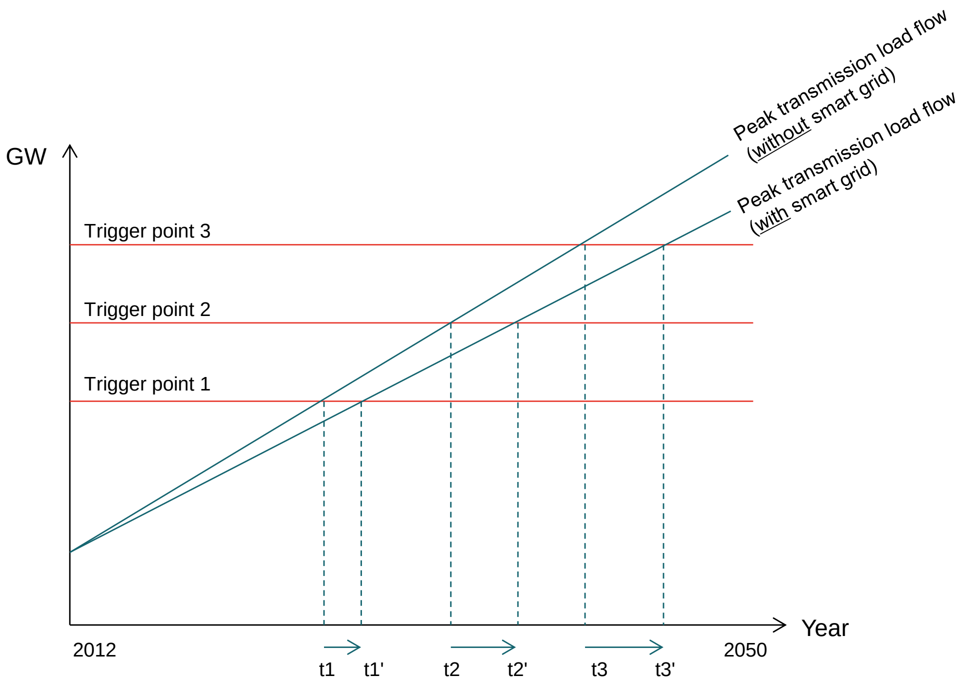
93 In the short run, National Grid might be able to absorb some increases in peak GB-wide demand using congestion management mechanisms. However any sustained growth in peak demand would, in the medium term, push up these congestion management costs to the point where it would be more cost effective to reinforce the network to create additional capacity. Given that our evaluation framework takes a 40-year perspective, our analysis focuses on the costs associated with long-run transmission network reinforcement requirements, rather than short-run congestion management.

Figure 51. Stylised illustration of how lower peak demand on the transmission network could defer network reinforcement



Source: Frontier Economics

In the stylised framework set out in Figure 51, the transmission network operator opts to reinforce the transmission network (rather than incur congestion) once peak load flow reaches certain 'trigger points'. Each of these network reinforcements adds a discrete lump of additional capacity that alleviates congestion on key points of the transmission network. The transmission network operator then returns to relying on congestion management tools as and when relevant until peak load hits the next reinforcement trigger point.

As Figure 51 illustrates, the introduction of smart-grid-enabled DSR could flatten the trajectory of peak load growth, thereby pushing back the dates at which these reinforcement 'trigger points' are hit. This will reduce the total cost of transmission network reinforcement between 2012 and 2050 in net present value (NPV) terms.

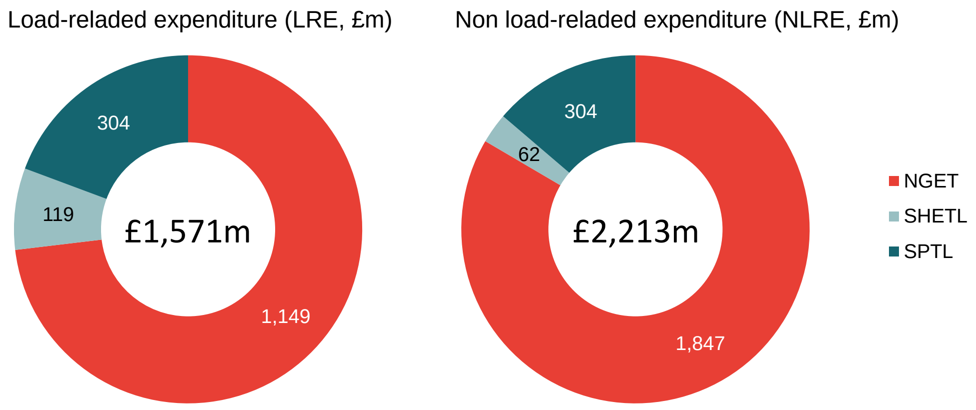
A comprehensive analysis of the impact of changes in peak demand on transmission network reinforcement costs would need to break the transmission network down into each of its constituent zones and separately map flows and resulting levels of congestion on the interconnectors between each of these zones. However, such an analysis is beyond the scope this project.

Annexe A: Detailed model specification

Instead, we have sought to analyse the historic relationship between growth in peak GB demand (net of embedded generation) and load-related capital expenditure (LRE) on the transmission network, to identify a simple £/GW network reinforcement cost measure.

Analysis of the LRE allowances permitted by Ofgem at the last price control (TPRC4) provides one such indication of this £/GW reinforcement cost. In its Final Proposals (published in December 2006), Ofgem allowed just under £1,600 million of LRE across the GB transmission network as a whole (2004/05 prices). This is equivalent to £1,960 million (2011/12 prices).

Figure 52. Capex allowances for TPCR4 (£m, 2004/05 prices)



Source: Ofgem, 'Transmission Price Control Review: Final Proposals', December 2006

National Grid's *Seven Year Statement* for 2006 suggests that, at the time that these allowances were set, the company expected peak demand on the GB transmission network as a whole to grow by 2 GW over the course of the TPCR4 period. Dividing this £1,960 million allowance for LRE by the 2 GW increase in peak demand would suggest a network reinforcement cost of about £980 million per GW.

However, this £/GW reinforcement cost estimate number may be too high for two reasons.

- First, there may be a time lag issue: network reinforcements are inherently 'lumpy', meaning that a given reinforcement could, in principle, add a significant amount of additional capacity to the network. By contrast, peak GB demand tends to grow slowly, meaning that it could take a number of years for the spare capacity created by a reinforcement programme to be used up. Given this, it is possible that the LRE undertaken during the TPCR4 period could have added more than 2 GW of additional capacity to the transmission network, even though demand itself was only projected to grow by 2 GW over the price control period.

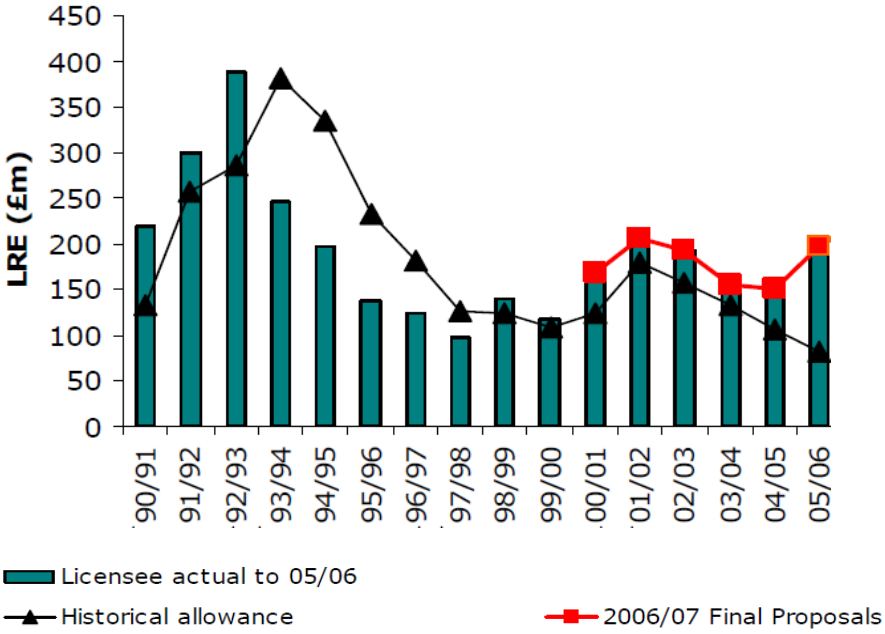
- Second, not all of the load-related network reinforcement undertaken during this period will be attributable to overall growth in GB demand; rather, as suggested above, LRE could also be partly driven by changes in the pattern and geographical location of generation as part of the push to decarbonise the energy sector. In other words, some LRE would have been incurred over the course of the TPCR4 period even if there had been no growth in overall GB demand net of embedded generation.

For these reasons, there may be a case for looking at the relationship between LRE on the transmission network and peak GB demand growth over a longer historical period. This has two advantages:

  - first, taking a longer term view would mitigate the time lag issue outlined above;
  - second, wind capacity on the GB network has only begun to increase significantly over the course of the TPCR4 period – this suggests changes in the pattern and location of generation are less likely to have been such a significant driver of LRE on the transmission network before 2006. By focusing on earlier price control periods, therefore, we may be better able to isolate the impact that peak demand growth has on LRE on the transmission network.

Detailed information on LRE before 2006 is not readily available. However, estimates compiled by Ofgem in 2006 suggest that LRE on the National Grid network summed to approximately £2,700 million between 1990/91 and 2003/04, or approximately £3,400 million in 2011/12 prices.

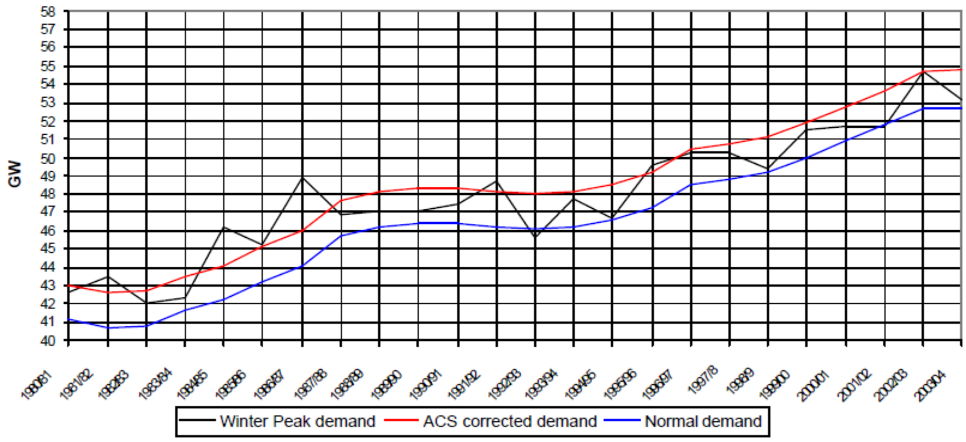
Figure 53. Ofgem estimates of NGET's historical performance against capital allowance (load-related expenditure only)*



Source: *Ofgem, Transmission Price Control Review: Final Proposals, December 2006*
** Note: figures are indicative only – Ofgem reports that data relating to the historical period before 2001/02 was obtained from various sources and may not be fully accurate.*

Over the same period (1990/91 – 2003/04), peak demand on the GB electricity network (corrected to reflect average-cold-spell conditions) increased from 48.3GW to 54.9GW, as Figure 54 below illustrates. This equates to an overall increase of 6.6GW on the NGET network in England and Wales. Assuming that peak demand grew at a similar rate on the SHETL and SPTL networks in Scotland over the period, this would imply a total growth in peak demand of 7.2GW across the GB transmission network as a whole. Dividing the total LRE of £3,400 million by this capacity implies a transmission reinforcement cost of approximately £470 million per GW.

Figure 54. Peak Winter electricity demand since 1908, and peak Winter demand corrected to reflect average cold spell (ACS)



Source: National Grid Transco, "*Preliminary Winter Outlook Report – 2004/05*"

This historic reinforcement cost of £470 million per GW may itself arguably be too low to use as a central estimate for reinforcement costs over the coming years, since labour and materials costs have increased in real terms since the 1990s. We have therefore used this number as a low-end estimate to complement the high-end estimate of £980 million per GW derived from the TPRC4 revenue allowance data. We have taken the average of these high-end and low-end estimates as our central estimate, as Table 29 below sets out.

Table 29. £/GW transmission network reinforcement cost estimates for 2012 used in our analysis

	Reinforcement cost estimate	Source of estimate
High-end estimate	£980 million per GW	Analysis of TPCR4 LRE allowances and peak demand growth projections
Central estimate	£730 million per GW	Average of high-end and low end estimates
Low-end estimate	£470 million per GW	Analysis of LRE allowances and peak demand growth projections for 1990/1 – 2003/04

Source: Frontier Economics

Our model assumes that these £/GW reinforcement costs will increase by 1% a year, in line with the annual increases in typical reinforcement costs that we have assumed for the transmission network. The model then combines these annual £/GW reinforcement cost projections with the various GB-wide peak demand growth projections for the BAU and smart grid investment scenarios. This provides us with projections of the total transmission network reinforcement cost (in NPV terms) between 2012 and 2050 under:

- conventional investment strategy;
- the top-down smart grid investment strategy; and
- the incremental smart grid investment strategy.

By comparing the different reinforcement cost projections associated with these different strategies, the model estimates the extent to which the introduction of smart grid technologies (either following a top-down strategy or following an incremental strategy) could reduce transmission network reinforcement costs between 2012 and 2050.

8.5 Demand profiles

This section provides further detail about the interdependencies between the generation and network models. The half-hourly demand profiles provide the main link between these models.

8.5.1 Types of demand profile

Both the network and generation models require half-hourly load profiles (whether at the individual feeder level for the network model, or in aggregate across the country for the generation model) as an input. However, the availability of technologies such as DSR means that the load profile itself becomes adjustable over time.[94] This section provides an overview of the different demand profiles that we will consider. For the runs of the model we have carried out, we have used the second of the three options for smart meter functionality set out in Section 2 which is explained in further detail below. However, the model is capable of simulating all options.

Table 30 sets out the demand profiles used with the model under Option 2. By enhanced smart meter communications, we mean technologies which deliver dynamic DSR to reduce generation costs (independent of smart grid investments) and are required for locally-driven DSR to be facilitated by smart grid investments.

94 Embedded storage also has the potential to influence aggregate demand profiles. However, the issues surrounding DSR are more complex (since forms of DSR are available even before any smart grid investment is made). We therefore concentrate in this section upon the treatment of DSR, however embedded storage is modelled in a similar way.

Table 30. Demand profiles used within the model

	Demand profiles under conventional strategy	Demand profiles with smart investments
Before enhanced smart meter communications available	Initially no DSR Increasing mix of static DSR over time	
After enhanced smart meter communications available	Dynamic DSR to reduce generation costs	Feeders without enabling technology remain as under conventional strategy Feeders with enabling technology have demand profile modified to reduce local network costs

Source: Frontier Economics

Before enhanced smart meter communications are available, under conventional investment strategy

The starting point for our model is the profile of demand without any DSR[95]. However, our assumptions for smart meters imply that they will be capable of "static" time-of-use tariffs, which can incentivise customers to shift demand to where (on average) energy costs are lower, even without any investment in smart grid technologies.

As a result, the increasing penetration of smart meters over time will lead to an increased contribution of static DSR to the GB-wide profile.

Before enhanced smart meter communications are available, with smart grid investments

We assume DSR to reduce local network costs is not possible without an enhanced communications system. This could be because the basic smart meter communications infrastructure may not enable time-of-use tariffs to be set separately for consumers on different feeders, as potentially required by DNOs.

The technology that allows demand profiles to be modified in response to local network conditions will therefore not appear in the smart solution stacks until the enhanced smart meter communications infrastructure is in place. Until this time, demand profiles will therefore be identical across the conventional and

95 This demand profile will incorporate the limited DSR that currently takes place (e.g. economy 7 tariffs) as this will be reflected in the demand profiles inputted into the model.

smart solution specifications, and so the generation model will produce identical costs for each (which will net off to zero).

After enhanced smart meter communications are available, under the conventional investment strategy

After a pre-set date[96], the model will allow "dynamic" DSR which can respond to system-wide generation conditions. Demand can be adjusted half-hour by half-hour to lower generation costs.

Note that our model will not explicitly differentiate between different ways in which DSR can be undertaken (e.g. via differing tariffs, or remote dispatch of household appliances). The assumptions made regarding the effectiveness of DSR will relate to the amount of energy that can be shifted for (for example) a heat pump, rather than the methods by which this is undertaken.

After enhanced smart meter communications are available, with smart grid investments

In this case, the demand can be modified in response to local network conditions to reduce peak loads (and therefore increase network headroom) on individual feeders. The implementation of such a DSR profile would require enabling "smart" investments for each relevant feeder[97]. This is therefore one of the smart solutions available on the priority stack in the network model.

The demand profile with such DSR responding to local network conditions will in many cases be very similar to that responding to system-wide generation costs. As long as network headroom is sufficient, the DNO will not need to adjust the profile of demand, and so the benefits in terms of generation cost savings will continue to accrue.

Simulating other options

The model includes four types of parameters relating to the roll-out and capabilities of DSR:

- the penetration of smart meters, which places an overall cap on the level of DSR (of any type) available in each year (on top of that already occurring through Economy 7 and through existing I&C schemes);
- whether dynamic DSR can be used to reduce generation costs in each year;

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96 As a default, the date has been set to 2023. This is purely a modelling assumption.

97 For example, this could involve substation sensing to identify the exact level of peak demand, which will depend on factors such as the clustering of low-carbon technologies.

- the year in which dynamic DSR can first be used to reduce local network costs; and
- if applicable (the year in which dynamic DSR to reduce local network costs becomes available independently of the "smart grid" (this is only relevant in Option 3 of smart meter functionality).

Four pre-set tables of parameters are provided, which correspond to the three smart meter capability options. These can be easily switched between.

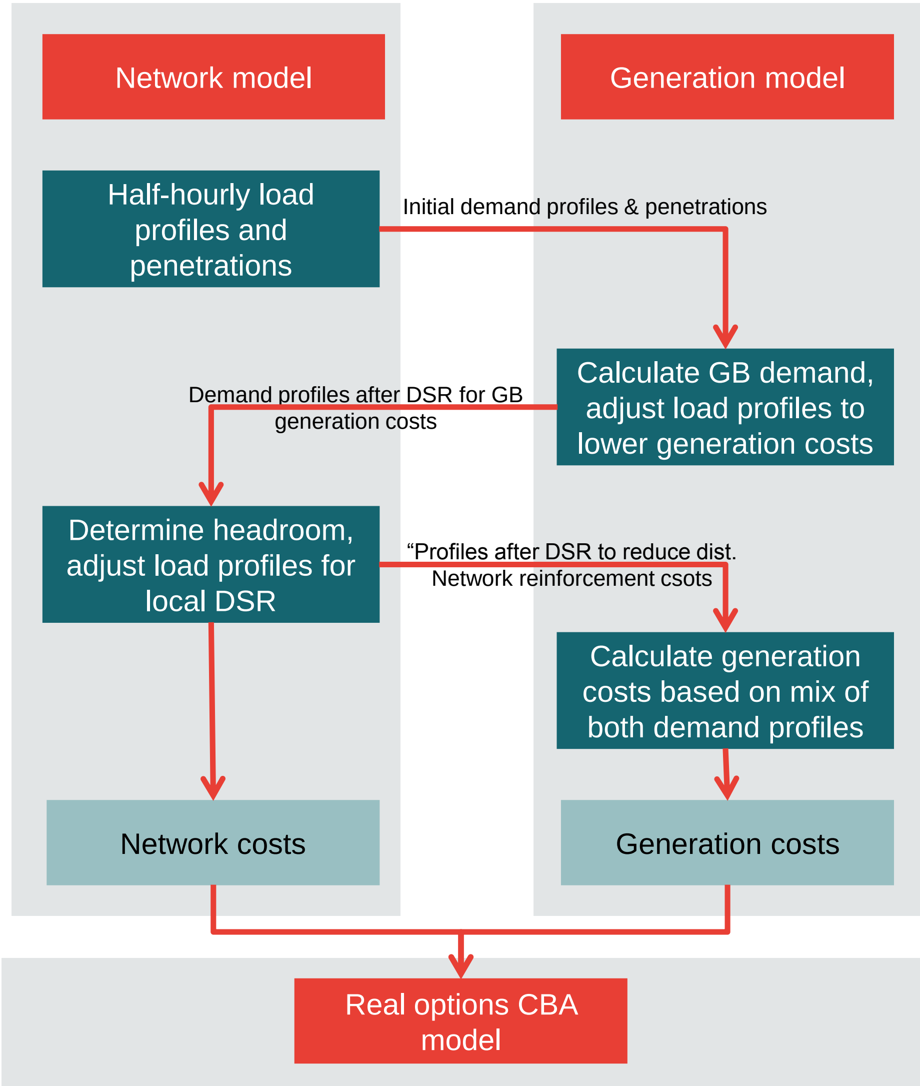
8.5.2 DSR for system security services

A final application for DSR involves the use of rapid DSR to compensate for unexpected losses of supply (for example if a power plant suddenly fails). In principle, the use of DSR for such system services could lessen the need for expensive spinning reserve. However, we have not modelled this type of DSR.

8.5.3 Modelling DSR

Figure 55 illustrates the process required to produce the various demand profiles required by the model. This involves the passing of demand profiles between the network and generation models. We explain each step in more detail below.

Figure 55. Overview of model interlinkages for DSR



Source: Frontier Economics

Modelling DSR to reduce system-wide generation costs

The starting point for modelling DSR to reduce system-wide generation costs is the existing half-hourly demand profiles for low-carbon technologies. These are held within the network model, along with overall penetration rates of low-carbon technologies.

The generation model combines these figures with estimates of overall demand to determine demand net of intermittent generation sources. The model then considers how the profile of technologies amenable to DSR (such as heat pumps) can be adjusted in such a way as to lower supply costs. This occurs in a similar (though slightly more sophisticated) fashion to the pumped storage model described above.

Each technology is given a half-hourly profile specifying the periods where demand is flexible. For example, electric vehicles that charge at home can only have their load shifted while they are charging, and this is assumed not to be something that happens during the middle of the day.

Two additional parameters determine whether any electricity losses take place during storage of energy (this implies that a 1kWh reduction of demand in one period will require a greater than 1kWh increase elsewhere), and whether there are any additional costs associated with DSR (notably the monetary value associated with any inconvenience to the consumer).

Like the pumped storage algorithm, the algorithm for DSR to reduce system-wide generation costs considers only one technology at a time (the new demand profile after the first technology has been subject to DSR is used as the input to the following technology, and so on). Again, the lack of simultaneous optimisation may lead to the model not always finding the truly optimal use of DSR. However, the model uses two basic heuristics to attempt to dispatch different types of DSR in a logical order.

- Technologies with a lower associated "inconvenience" cost are dispatched before those with higher costs. This helps to ensure that DSR requirements are met in a least-cost manner.

- When two technologies have the same cost, the least flexible one (that is, the one with the fewest periods where load-shifting can occur) is dispatched first. This should enable the most flexible appliances to be deployed at those times where other forms of DSR may not be feasible.

When "optimising" a single appliance type, the model (like that for pumped storage) starts by considering the pair of periods (of those which are flexible) with the highest spread in electricity costs. It then sees how much can be saved (in terms of wholesale electricity costs, less DSR "inconvenience" costs) if a varying amount of load[98] (between zero and 100% of load) is shifted from the period with higher load to the period with lower load. After trying the different possibilities, the model picks the one which minimises costs. It then moves on to the pair of periods with the next highest difference in demand.

As with the pumped storage model, the DSR model only permits load for a particular appliance type once. For example, if 50% of electric vehicle demand at

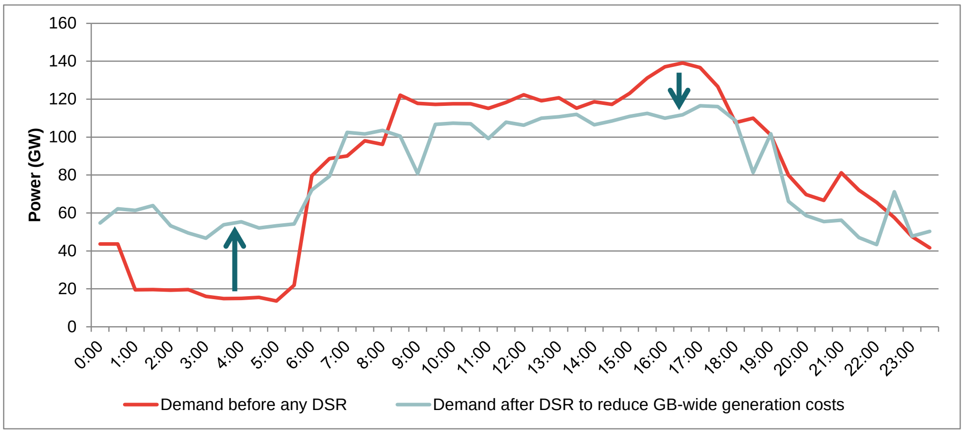
98 Unlike the pumped storage model, which allows each unit to be in one of only three states (pumping, generating or idle), the DSR model allows a variable portion of load to be shifted between periods.

18:00 is moved to 3:00, this demand cannot be shifted again. This helps ensure that the model will not carry out unrealistic applications of DSR (for example, moving huge amounts of load to one period in order to meet a sudden increase in wind generation), and avoids the need to make a very large number of assumptions regarding the constraints around load shifting.

In such a way, patterns of usage for each low-carbon technology in each season will be produced. These are used as the baseline demand profile for the network model (before the smart investment which enables DSR driven by local network conditions is made).

Figure 56 demonstrates how the model of DSR to reduce system-wide generation costs acts to flatten overall load:

Figure 56. Simulation of DSR to reduce generation costs



Source: Frontier Economics

A model that fully optimises the deployment of demand response is outside the scope of this project. As a result, the demand profiles that the model creates will still have scope for further optimisation. To the extent to which this occurs under both the conventional and smart strategies, the overall effect of any failure to optimise DSR will tend to net off in the overall calculations of net benefits. However, it would be possible in the future to replace the DSR module of the model with a more elaborate algorithm

Modelling DSR driven by local network conditions

For each representative feeder (and each level of clustering), the network model keeps track of a set of adjusted demand profiles for each technology which are just sufficient to bring peak load down to a point which defers the next required investment in the solution stack.

Again, these updated load profiles are required to be consistent with basic constraints regarding the transfer of energy over time, and have been constructed using a similar methodology to DSR to reduce system-wide generation costs. The model keeps track of how much demand-shifting capacity remains after DSR to reduce system-wide generation costs.

In theory, the modelled adjustments made by DNOs to demand could have an overall detrimental effect upon the net present value of smart grids (if the benefit of postponed reinforcement is outweighed by increased generation costs). Our model does not seek to select a fully "optimal" pattern of investment in DSR driven by local network conditions that minimises overall costs.[99] However, by adjusting the position of DSR within the network solution stacks, it will be possible to determine how sensitive the overall costs are to this issue. Further, the profile of demand after DSR driven by local network conditions is unlikely to vary greatly from the profile of DSR driven by system-wide generation costs (since both will tend to reduce peak demand where possible).

Final generation calculations

To calculate the overall costs of generation, the generation model builds a final aggregate demand profile, based upon the output of the distribution network model. This is then used for the generation cost calculations described in section 8.4.4.

8.5.4 Limitations regarding the treatment of DSR

To produce a tractable model, some of the more complex "feedback" effects that could be created by DSR nave been excluded. These are explained below.

If the demand profile adjusted for local-network conditions were significantly different to the demand profile adjusted for system-wide generation costs, the following sequence of events could take place:

- Over time, feeders would move from system-wide driven demand profiles to locally-driven demand profiles.
- This would lead to the overall GB-wide demand profile changing.
- This could itself result in the optimal system-wide profile changing, to ensure that demand net of intermittent sources is as flat as possible.

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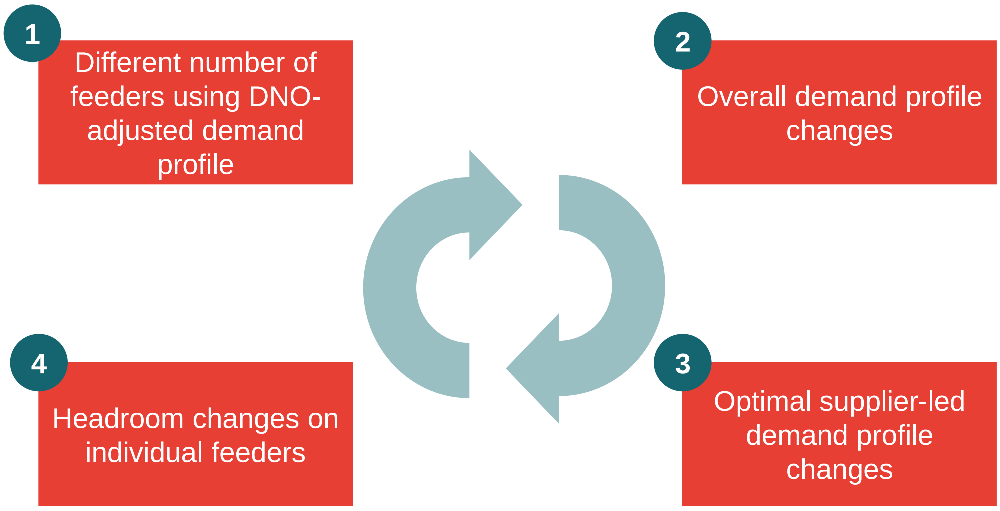
99 However, if a DNO has already invested in DSR and not conventional reinforcement, it would almost certainly be optimal for the DNO to use DSR (if available) to avoid breaching headroom limits. This is since the cost of running a feeder above its design capacity will probably exceed the costs associated with a short period of slightly higher-cost generation. Therefore, while the investments made by the DNO in the model may not be completely optimal, the modelled demand profiles (given these investments) are likely to be reasonable.

- The new demand profile could itself lead to different levels of headroom on individual feeders – which would itself lead to a different number of feeders on each demand profile.

Figure 57. Feedback effects



Source: Frontier Economics

A model which allowed this type of feedback effect would need to simultaneously optimise both the system-wide driven and locally-driven DSR profiles. This would greatly increase the complexity of the model.

Instead, our model explicitly rules out such feedback effects: the system-wide driven DSR profile will not be able to respond to changes in the locally-driven profile. Since the DNO will only need to adjust demand when headroom is breached, the overall change on the demand profile is likely to be small.

9 Annexe B: The potential value of DSR to the system operator

As the National Electricity Transmission System Operator (NETSO), National Grid acts as the residual purchaser and seller of electricity to ensure that supply and demand on the GB transmission network balance on a second-by-second basis. To achieve this, National Grid needs to be able to:

- increase generation output or reduce demand at short notice in order to accommodate higher-than-expected levels of demand or lower than expected levels of generation; and
- reduce generation output or increase demand in order to accommodate lower-than-expected levels of demand or higher-than-expected levels of generation output.

National Grid procures a range of balancing services from electricity consumers and generators in order to fulfil this role. At present, only generators and large demand loads are permitted to provide such short-term and real time balancing services.[100] However, in principle, small loads connected to the distribution network could also help balance the transmission system, provided that these loads could reliably be switched on or off at short notice for the requisite period of time. This in turn suggests that the introduction of smart grid technologies on the distribution networks could potentially help National Grid balance demand and supply, to the extent that these smart grid technologies would facilitate DSR with a shorter latency period than smart meter technologies, which will be rolled out anyway under business as usual.

To quantify the potential benefits that smart grid technologies could create for system balancing, we need to address the following three sets of questions:

- what residual balancing services does National Grid currently procure from generators and large demand customers?
- how much does it currently cost National Grid to procure these services? How much might it cost to procure these services over the coming 40 years if these balancing services retained their current form?
- to what extent might National Grid be able to make use of dynamic DSR on the distribution network to help supplement or replace these balancing services if smart grid technologies were introduced? To what extent would this help to reduce balancing costs?

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100 However, some smaller demand loads can contribute to some balancing services by aggregating loads together on a national scale (a number of companies provide such aggregation services).

We consider each of these questions in turn.

9.1.1 What residual balancing services does National Grid currently procure from generators and large demand customers?

National Grid procures a range of residual balancing services to ensure that demand exactly meets supply on the system on a second-by-second basis. We understand that the following three services are currently open to large demand customers as well as generators:

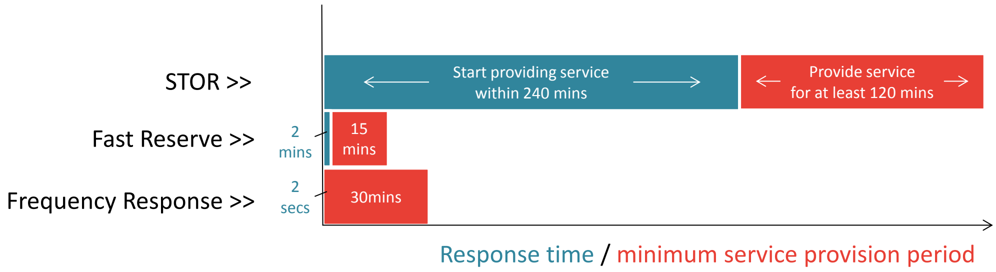
- **Frequency Response** – this is the first line of defence that National Grid uses for residual balancing. If demand exceeds generation on the network in any given second, frequency will immediately start to fall below the desired system frequency (50Hz). To help keep the system in balance, National Grid pays generators and demand customers to moderate their behaviour automatically when frequency falls below 50Hz. For example, some generators can provide continuous modulation power responses to counter the frequency changes (generators that meet these and certain other technical requirements are obliged to provide this frequency response service). Additionally, large demand customers might agree to have their power interrupted automatically (within two seconds) if network frequency falls below a certain level, provided that this interruption does not last for more than 30 minutes at a time.

- **Fast Reserve** – under this service, network users agree to increase generation output or reduce consumption by at least 50 MW within two minutes, following receipt of an electronic despatch instruction from National Grid. This reserve energy must be sustainable for a minimum of 15 minutes. Firm Fast Reserve is procured by a monthly tendering process.

- **Short-Term Operating Reserve (STOR)** – under this service, network users agree to increase generation output or reduce consumption within 240 minutes, following receipt of an electronic despatch instruction from National Grid. These parties must be able to provide at least 3MW of active power for at least 2 hours, up to three times a week. STOR is procured by competitive tender.

Figure 58 below provides an overview of the maximum response times and minimum service periods of each of these short-term balancing services.

Figure 58. Overview of response times and service provision periods for STOR, Fast Reserve and Frequency Response services



Source: Frontier Economics, based on information provided by National Grid

9.1.2 How much does it currently cost National Grid to procure these services? How much could it cost in the future?

National Grid reports that it spent the following amounts on balancing services in 2009/10:

- Frequency Response - £130,000,000
- STOR - £95,000,000
- Fast Reserve - £43,500,000

If National Grid were to incur a similar level of cost for procuring these services in future years, this would imply a total cost of between £5,5 billion and £6 billion (in NPV terms) between 2012 and 2050, assuming a 3.5% discount rate.

However, it is arguably not realistic to assume that residual balancing costs will remain constant in real terms going forwards; rather two factors are likely to drive up the total cost that National Grid incurs for procuring these services:

- first, it is likely that National Grid will need to procure additional capacity for residual balancing purposes in the future, in in order to accommodate changes in the generation mix; and
- second, it is possible that the unit cost of procuring a megawatt of capacity for balancing purposes will also increase over the coming years.

Projecting the total amount of capacity that National Grid will need to procure for residual balancing purposes in future years

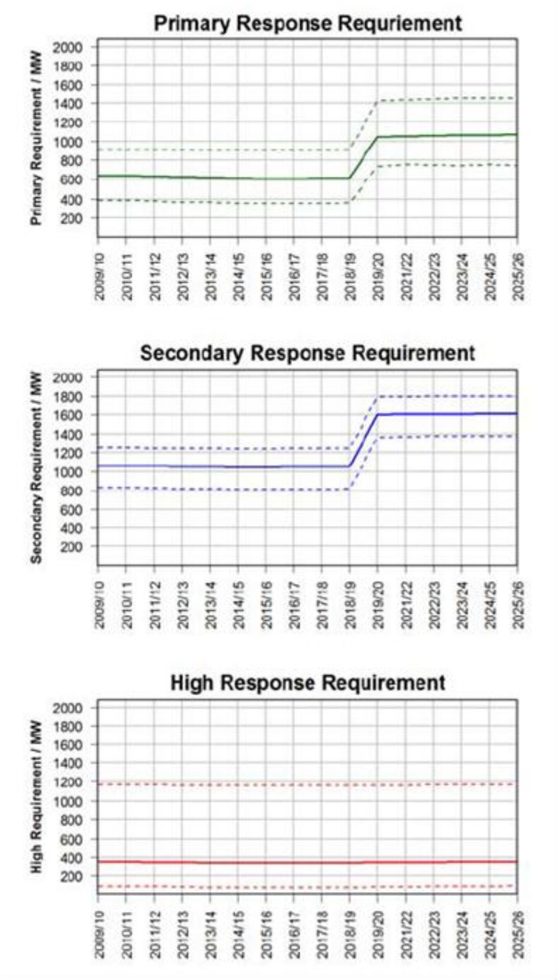
National Grid has undertaken detailed analysis of the implications of a change in the generation mix for the total amount of residual balancing capacity that it will need to procure for STOR and Frequency Response.

For **STOR**, recent National Grid analysis[101] suggests that increases in the level of capacity required will be driven primarily by increases in the total capacity of wind generation, since an increase in intermittent wind capacity can make it more difficult to projected levels of generation a few hours ahead. At the time that it produced its analysis, National Grid expected total installed wind capacity to increase from 2,228 MW in 2009/10 to 30,605 MW in 2025/26 for its 'Gone Green' scenario. In this scenario, National Grid project that the total positive capacity of STOR required would increase from 4,352 MW to 7,557 MW over the same period. Assuming a simple linear relationship between wind capacity and STOR requirements suggests that a 1 MW increase in wind capacity could lead to a 0.11 MW increase in the total STOR requirement. For our central ('Gone Green') generation scenario, this suggests that the total amount of STOR capacity that National Grid needs to procure could increase to approximately 9,500 MW by 2050 – nearly double the requirement for 2012.

For second-by-second **Frequency Response**, by contrast, we understand that the level of capacity required will be determined by the "largest credible generation loss" that could occur within a matter of seconds. The size of this credible generation loss is in turn determined by reference to the size of the largest generation units installed on the network. With the planned arrival of larger generation units in 2019 (under the 'Gone Green' scenario), National Grid projects that the largest credible generation loss will increase from 1320MW to 1800MW. As Figure 59 below illustrates, National Grid anticipates that this will result in a significant increase in the Response Requirement for two of the three mandatory Frequency Response services:

101 http://www.nationalgrid.com/NR/rdonlyres/55610D9A-C53A-4E28-88C6-29AE5DF72EF2/42697/Future_Balancing_Services_Requirements_Reserve1.pdf

Figure 59. Frequency Response requirement projections for the three mandatory Frequency Response services (Primary, Secondary and High[102])



Source: National Grid

102 According to National Grid's "*Ancillary Service Settlement Guide*", there are three types of Mandatory Frequency Response:

- Primary – an initial increase of generation, in response to system frequency being lower than target frequency, which is achieved within 10 seconds from the time of the frequency change and is sustained for a further 20 seconds.
- Secondary – an increase in generation, in response to system frequency still being lower than target frequency, which is achieved 30 seconds from the time of the frequency change and is sustained for a further 30 minutes.
- High Frequency – a decrease in generation, in response to system frequency being higher than target frequency, which is achieved 10 seconds from the time of the Frequency change and is sustained thereafter.

These projections suggest that the total mandatory Frequency Response requirement could increase by 50% from 2,000MW to 3,000MW between 2012 and 2050 (assuming that no even larger generating units are built after 2025). For the purposes of this estimation, we have therefore similarly assumed that the total Frequency Response requirement will increase by 50% over the period (though the timing of this 50% increase varies, depending on the different scenarios).

For **Fast Reserve**, future capacity requirement projections are less readily available. We have therefore assumed that the capacity requirement for this balancing service will grow at the average of the two growth rates projected for STOR and Frequency Response. Our rationale for this is that the Fast Reserve balancing service is designed to facilitate a balancing response within two minutes – i.e. a faster response time than STOR, but slower than Frequency Response. Given, this, we have assumed that the Fast Reserve requirement will increase partly in response to the projected growth in intermittent wind capacity (as for STOR) and partly in response to the projected arrival of larger baseload plants in 2019 (as for Frequency Response).

Projecting the average cost of procuring a MW of residual balancing capacity in future years

It is likely that the cost of procuring a unit of residual balancing capacity (be it Frequency Response, Fast Reserve or STOR) will increase in proportion to expected wholesale electricity price increases between 2012 and 2050. The rationale for this is that generators that agree to provide balancing services will need to be compensated for forgoing the revenue that they could otherwise have received by selling their electricity on the wholesale market. Where balancing services are procured by competitive tender (as is the case for STOR for example), one would expect procurement prices to evolve dynamically to reflect changes in this opportunity cost.[103] However, even for those balancing services where participation is mandatory (as is the case for some Frequency Response services), one would expect steps to be taken to ensure that the level of compensation paid for procuring these services remains broadly cost reflective. To the extent that wholesale electricity prices are likely to increase over the next 40 years, it is therefore reasonable to assume that the cost of procuring a given amount of capacity for residual balancing purposes will increase proportionally. Changes in the wholesale cost of electricity are difficult to predict accurately, but are likely to rise significantly with rising fossil fuel and carbon prices. We have made the conservative assumption that wholesale electricity prices, and hence

[103] This is because generators would not be incentivised to bid for such services unless the price reached a high enough level to compensate them for the revenue that they would otherwise have received from selling their electricity on the wholesale market.

average unit procurement costs for balancing purposes, will increase by 1% a year on average (in real terms)between 2012 and 2050 in our central scenario.

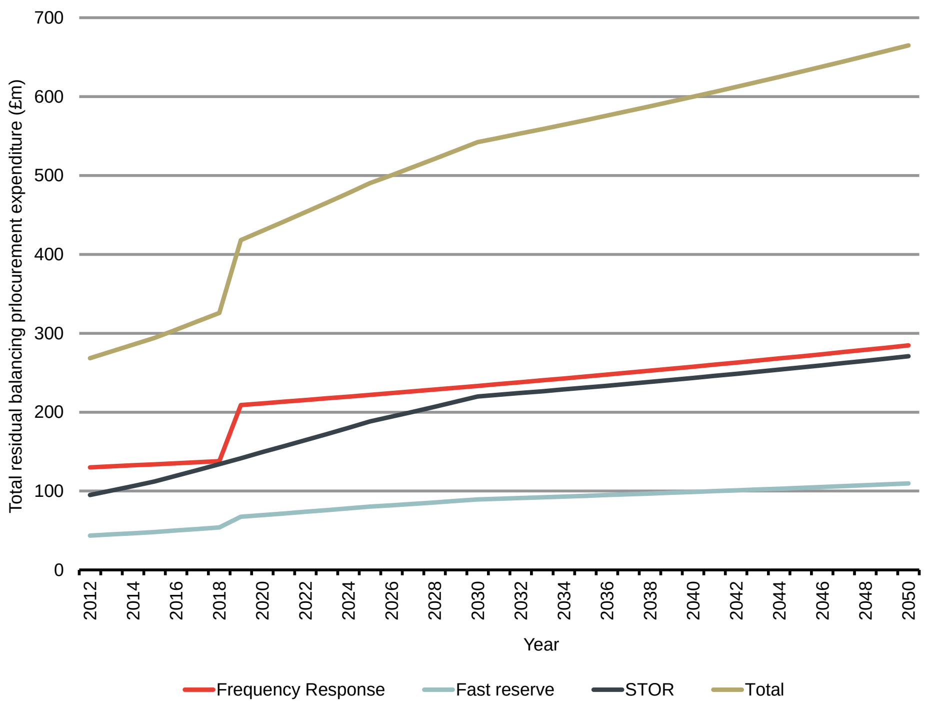
Table 31 below provides a summary of the assumptions that we have made about the development of residual balancing costs in the future on the basis of the analysis set out above.

Table 31. Balancing procurement cost projections for central ('gone green') scenario

	Frequency Response	Fast Reserve	STOR
Maximum response time	2 seconds	2 minutes	240 minutes
Key driver determining the level of capacity required	Size of largest generation units	Both size of largest generation units and wind capacity installed	Wind capacity installed
% increase in MW capacity required, 2012-2050	50%	73%	95%
% increase in real £/MW procurement cost, 2012-2050	46%	46%	46%
% increase in total procurement cost, 2012-2050	119%	152%	185%
Procurement cost in 2012	£130m	£44m	£95m
Procurement cost estimation for 2050	£285m	£110m	£271m

As the table sets out, our analysis suggests that the total cost of procuring balancing services would be likely to increase from £269m in 2012 to £665m in 2050 in our central ('Gone Green') generation scenario, following the path set out in Figure 60 below:

Figure 60. Residual balancing cost projections for central scenario



Source: Frontier Economics

Adding up these total procurement cost projections for ever year between 2012 and 2050 implies that, in NPV terms, the total cost of procuring these residual balancing services over the coming 40 years would sum to £10.5 billion in our central scenario if these balancing services retained their current form.[104]

9.1.3 To what extent could smart-grid-enabled dynamic DSR on the distribution network help to reduce these balancing procurement costs?

As outlined above, it is conceivable that the development of dynamic DSR on the distribution network could, under some circumstances, be used to help supplement or substitute for the residual balancing services that are currently provided by Frequency Response, Fast Reserve and STOR.

Figure 61 below sets out:

- projected trends in the average/minimum daily availability of distribution-connected DSR capacity under the 'gone green' scenario (as estimated by our model); and

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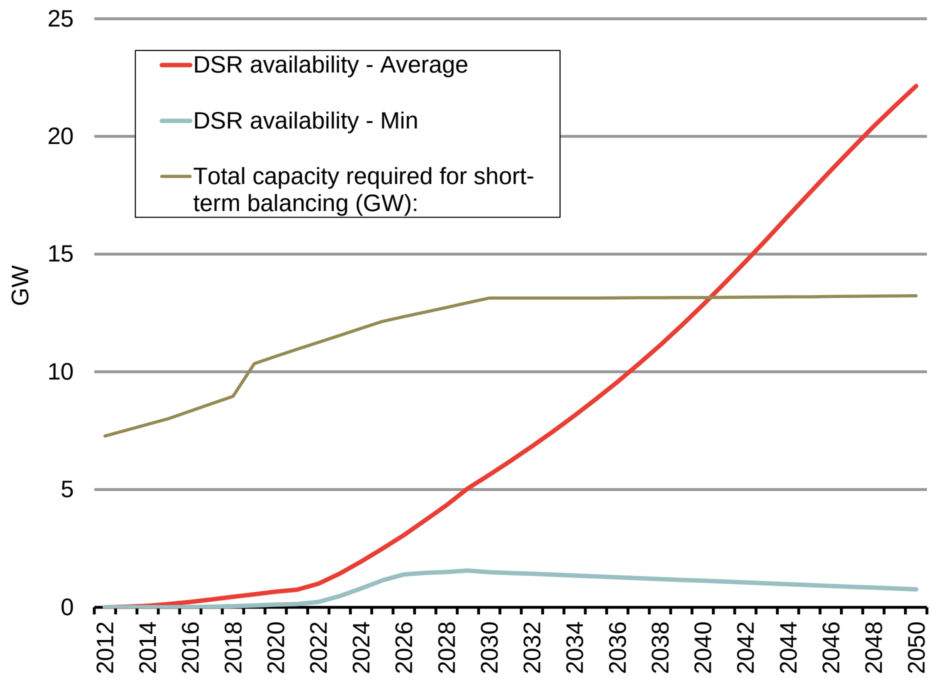
104 This calculation assumes a social discount rate of 3.5% for the next 30 years and 3% thereafter, in line with the Treasury Green Book.

- the projected trend for the total amount of capacity required for Frequency Reserve, Fast Response and STOR purposes (calculated using the methodology described in the previous section).

Figure 61. Comparison of growth in total capacity required for residual balancing and typical daily availability of DSR*



* '*DSR Availability – Min*' = minimum DSR availability on typical day (average across Summer & Winter); '*DSR Availability – Average*' = average DSR availability on typical day (average across Summer & Winter).

Source: Frontier Economics

As Figure 61 illustrates, the average level of DSR availability is projected to grow rapidly between 2012 and 2050, to the extent that it exceeds the total projected amount of capacity required for STOR, Frequency Response and Fast Reserve by 2041. If this DSR could be used to supplement or replace these residual balancing services, this could reduce the cost of procuring capacity for balancing between 2012 and 2050 from £10.5 billion (in NPV terms) to approximately £5.6 billion – a total saving of £4.9 billion.

This analysis therefore suggests that smart grid technologies could, in principle, help reduce network balancing costs significantly between 2012 and 2050, to the extent that they facilitate DSR with a shorter latency period than would otherwise be possible. However, it is important to recognise that this analysis only provides an estimate of the upper limit of the potential benefits that a smart grid could create for residual balancing on the transmission network. In practice, the net value that a smart grid could create for balancing could be lower than £4,900m for a number of reasons. For example:

- further work would need to be done to confirm the extent to which smart grid technologies would be required to facilitate the use of distribution-connected DSR for residual balancing purposes;
- in practice, it not clear whether all forms of distribution-connected DSR would be useful for all forms of residual balancing. For example, it may only be possible to switch domestic white goods and electric vehicles off for short periods of time without inconveniencing households. This might make them useful substitutes for Frequency Response or Fast Reserve (which only require outage periods of 30 minutes and 15 minutes respectively), but less so for STOR (which would require an outage period of at least two hours);
- there could be a mismatch between the times of day when balancing services are most likely to be called upon and the times of day when DSR is available. Our model suggests that, although more than 22GW of DSR could be available on average by 2050, there will still be certain times of day when less than 1GW of DSR is typically available (see Figure 61 above). This could reduce the ability of National Grid to use DSR for residual balancing purposes, particularly if balancing services are most likely to be required at times of day when little DSR is available;
- the analysis set out above also implicitly assumes that there would be no cost associated with using dynamic DSR on the distribution network for these balancing purposes. However, this is not correct, since reserving a unit of dynamic DSR for balancing purposes would preclude that unit of dynamic DSR from being put to other potentially beneficial uses, such as manipulating demand profiles to reduce network reinforcement requirements and generation costs. In other words, it is likely that using a megawatt of dynamic DSR for balancing purposes would have a significant opportunity cost.

Given the risk of double counting benefits of DSR, we have not integrated these potential balancing benefits into our final analysis. Nonetheless, it is important to recognise that smart grids could be used to bring about alternative benefits to those considered in our evaluation framework, and that these alternative benefits could, at least potentially, be substantial.

10 Annexe C: Summary of consultation responses

EVALUATION OF SMART GRIDS

Summary of respondents

- BEAMA
- British Gas
- EDF
- E.ON
- Electricity North West
- Elexon
- IBM
- National Grid
- Pöyry
- Scottish and Southern
- Smarter Grid Solutions
- SmartestEnergy
- SmartGrid GB
- SP Energy Networks
- UK Power Networks
- Western Power Distribution

Summary of responses to questions and actions

- **Do you agree with our definition of smart grids?**
  - **Summary of responses:** Most respondents were broadly content with the definition of smart grids though some respondents noted that the definition was not exhaustive and some felt it was too broad. Others noted that the definition should be more explicit about the role of suppliers and network operators.

- **Actions**: Continue to use this working definition, noting that there is not complete agreement among stakeholders on the definition.

- **Have we captured the main complexities associated with assessing the costs and benefits of smart grids?**

  - **Summary of responses:** Many respondents felt that we had captured the key complexities. However, a range of additional challenges were raised such as:

    - the need to capture indirect benefits, such as lower energy costs for industry which might result from smart grids;
    - the market arrangement which may be required to deliver smart grids;
    - wider non-market benefits such as reduced wirescape;
    - the need to consider improved quality of supply associated with smart grids, and the impact on losses;
    - benefits of more timely grid connection;
    - the fact that some assets will require replacing under business as usual; and
    - risks around the cost and functionality of smart grids.

  - **Actions:**

    - This analysis aims to produce a framework for the assessment of the direct costs and benefits of smart grids, and their distribution. Some issues raised, such as an assessment of the market arrangements required to deliver smart grids, and the indirect benefits to the economy which may be delivered by them go beyond the scope of this report. We will ensure that this is clearly acknowledged in the report.
    - Not all wider non-market benefits will be quantitatively assessed in the modelling. We will ensure that the fact that not all complexities will be captured in this analysis is clearly acknowledged in the report, and that the findings of this analysis are presented as a step towards investigating smart grid values, rather than as the definitive result.
    - The impact on quality of supply will now be considered as the impact of smart grid technologies on customer interruptions will be captured. Losses will also now be estimated.
    - The benefits of more timely grid connection will not be included in the model, but this simplification will be acknowledged.

- Replacement of existing assets will not be included in the modelling as our view is that this would greatly increase the complexity of the modelling but is unlikely to materially affect the results. This is because the amount of circuits that will be subject to asset replacement owing to deterioration in their condition (particularly at LV) as a proportion of the overall population of circuits will be very small. The likely synergies arising as a result of such circuits also being highlighted for intervention due to headroom violations within a similar timeframe are therefore expected to be of very small magnitude.
- Users will be able to adjust the cost and impact on headroom of all technologies in the model. Sensitivity analysis to test the impact of uncertainty over the cost and functionality of smart grid technologies will therefore be possible.

- **Do you agree with our approach to dealing with these complexities, in the overall evaluation framework, in particular: we propose to take a two-stage decision tree approach, rather than relying on a conventional cost-benefit analysis framework alone. Does this constitute an appropriate approach, given the need to measure differences in the "option value" that different smart grid investment strategies provide?**
  - **Summary of responses:** Many respondents agreed that the overall cost-benefit approach based on a two-stage decision tree was appropriate. Some concern was expressed was that complex modelling of this kind relied on too many assumptions and the difficulty in deriving reliable input to the modelling was highlighted. In contrast, some respondents argued that the approach was too simple.
  - **Actions:** Given the broad agreement with this approach and the need to produce a simple and transparent model, the overall assessment framework will be maintained. The large degree of uncertainty around the input assumptions will be highlighted in the report. Users of the model will be able to change the key input assumptions to run alternative scenarios or to test the significance of individual assumptions.

- **Do you agree that the year 2023 constitutes an appropriate decision point in our analysis?**
  - **Summary of responses:** Many respondents agreed that 2023 constitutes an appropriate decision point in this context, though some respondents felt it should be earlier. One respondent felt that there was

a danger than DNOs would assume that they do not need to undertake any smart grid investments until 2023.

- **Actions:** 2023 will remain the default point for the decision point in the model. However, the model is being set up so that the decision point is completely flexible. Users will be able to change it as they see fit. The significance of the decision point in the analysis will be clearly explained.

Section 3: Value drivers and scenarios

- **Do the technologies set out in the report constitute a sensible list of value drivers? Are there any other technologies that could have a significant impact on the value of smart grids?**
  - **Summary of responses:** There was broad agreement that all of the technologies listed as value drivers in the report were likely to be important. Some respondents suggested further technologies should be included, for example CHP, hydro, the European supergrid, electric storage heating, air conditioning, large-scale distribution connected onshore wind, solar PV with storage, feeder and substation automation, power routing, DEC interconnection at LEV level and network attached storage, technologies for the coordination of demand, and network connected and secondary storage.
  - **Actions:** The list of low carbon technologies being considered has been informed by the work in SGF WS1 and by our view of the technologies which will have the greatest impact on the value of smart grids GB-wide. Where technologies are not included in the model, this will be clearly acknowledged. We will now include the following:
    - commercial air conditioning;
    - the impact of changing levels of electric storage heating;
    - large-scale distribution network connected wind; and
    - heat pumps with storage.
- Do you agree with our assessment of the technical characteristics of each?
  - **Summary of responses:** Many respondents agreed with the assessment of the technical characteristics of the value drivers, though it was noted that some additional complexities had been excluded, for example, the impact of heat pumps on power factor, and the impact of value drivers on fault levels and power quality. It was also noted that we should take account of the changing characteristics of the value

driving technologies – for example, the charging capacity of EVs may increase over time.

- **Actions:** Given the need to keep the model simple and transparent, it will not be possible to include all aspects of the value drivers. However, where simplifications have been made, they will be clearly acknowledged. The model being developed for WS3 of the SGF will have additional layers built into it that can account for issues such as fault level.

- **Our analysis suggests that the most important factors to vary across the scenarios will be:**
  - **the pace of electrification of heat and transport;**
  - **the increase in distributed generation; and**
  - **the increase in intermittent and inflexible generation.**

- **Do you agree? Are there any other variables that we should look to vary across the scenarios and why?**
  - **Summary of responses:** There was some agreement that the key factors were being varied across scenarios. It was also suggested that uncertainty around whether the UK will meet its carbon targets domestically, whether customers will engage with DSR, and whether smart meters will be rolled out should be included.
  - **Actions:** The model has been set up to allow users to change the key characteristics of the scenarios, so it can be used to analyse a wide range of scenarios. We now propose to include the following three scenarios in the model as a default: (1) Medium-high levels of heat and transport electrification and intermittent and inflexible generation; (2) Medium-high levels of heat and transport electrification and intermittent and inflexible generation with low level of customer engagement in DSR (3) Low levels of domestic decarbonisation (UK meets its targets through purchase of credits).

Section 4: Smart grid and conventional investment strategies

- **Out of the options presented, which set of assumptions should we make on smart meter functionality?**
  - **Summary of responses:** There was little agreement among respondents over the appropriate set of assumptions to make on smart meter functionality.

- **Actions:** Users of the model will now be able to choose between three options for smart meter functionality when running the model.

- **Do you agree with our proposed approach of including smart appliances in the business as usual?**
  - **Summary of responses:** Respondents were split on whether smart appliance roll out should be considered as part of business as usual or as part of the smart grid. Some respondents felt that smart appliances will be more prevalent and better used when smart grids are rolled out.
  - **Actions:** Users of the model will now be able to choose whether to include smart appliance as part of the business as usual, or whether to allocate their costs and benefits to smart grids.

- **Do our proposed smart grid strategies capture the main deployment options?**
  - **Summary of responses:** Many respondents agreed that the strategies captured the main deployment options. Some felt that they were two simplistic and that a hybrid strategy, somewhere between the two, would be preferred.
  - **Actions:** Given the need to keep the model simple, we will maintain two strategies only. However, we will ensure that it is clearly acknowledged in the report that other investment strategies would be possible.

- **Have we provided an accurate overview of the main services that smart grid technologies can provide? Do you agree with our proposed assumptions on the characteristics of these technologies?**
  - **Summary of responses:** Some respondents agreed with overview of the main services smart grid technologies can provide. Others felt that the list of was not comprehensive and that in particular, Active Network Management should be included. Some respondents also provided very detailed comments on the technologies. Others noted that the costs of automation and monitoring should be included.
  - **Actions:**
    - The model will look at a range of solutions captured under the five areas listed in Table 7 (page 83), with a total of over twenty solutions being considered within these five areas, including key aspects of Active Network Modelling. The five technology areas typify the sort of investment that can be made on distribution networks. Each of these solutions will have associated costs and

headroom release figures. The figures for cost and headroom release can be customised by the model user as necessary. It should also be stressed that this model represents a framework and the specific technologies within this framework will be capable of being customised and extended such that different solutions can be added in easily by the user. In this way any solutions described in WS3, for example, can be added to this WS2 model as required.

- Where we cannot capture all of the aspects of technologies highlighted in the detailed comments, we will acknowledge this.
- The costs of automation and monitoring will be included. The model will include certain costs of automation within some of the solutions, i.e. in order to implement dynamic network reconfiguration (a form of active network management) some level of automation is required and the cost of implementing the solution includes the cost of the associated level of automation. Costs of monitoring are also wrapped into the costs of implementing the individual solutions, such as Electrical Energy Storage, Dynamic Thermal Ratings etc. In each case, the cost is reflective not only of the plant involved but also of the monitoring and control algorithms that need to be established to ensure the solution delivers the necessary results. We agree that there is no benefit in installing some solutions without the monitoring and control being in place. For each solution these costs are considered under the two investment strategies of "top-down" (an up-front, no regrets, investment) and "incremental" (an incremental investment as and when solutions are required). The difference between costs for each of these investment strategies will be clearly visible, highlighting the level of costs within the solution attributed to monitoring and control.

Section 5: Value chain analysis

- **Are there any other groups in society that we should consider in the value chain analysis?**
  - **Summary of responses:** Some respondents felt that the key groups had been identified. A range of additional groups for consideration in the value chain analysis were suggested. It was suggested that customers should be disaggregated in to customers of different types, and that Government, cities and towns, investors and house builders, suppliers and generators should not be aggregated together.
  - **Actions:** The model now allows costs to be allocated to each of the following groups: DNOs, generators, suppliers, TNO, system operator

and customers. To maintain the simplicity and transparency of the model, the additional groups will not be included.

- **Do you agree with our conclusions regarding the distribution of costs and benefits?**

  Summary of responses: There was broad agreement with these conclusions.

  Actions: No change.

- **Do you agree with our proposed approach to assessing the costs and benefits for the transmission network?**
  - **Summary of responses:** Many respondents felt that the proposed approach to transmission modelling was too simple. It was suggested that a clearer distinction between the TNO and TSO roles should be drawn
  - **Actions:** We are revising this approach to better take account of the complexities and more clearly distinguish between the TNO and TSO. However, the approach to transmission modelling will remain simple and this will be clearly acknowledged in the report.

Section 6: Proposed model specification

- **How suitable is the proposed network modelling methodology which use representative networks, with headroom used to model when network investments should be made on feeders?**
  - **Summary of responses:** Many respondents were happy with this approach. Some respondents felt that too many simplifications were being made in some areas – for example that the impact on fault levels and power quality should be included. Another respondent was concerned that the pre-population of the priority solution stack will give misleading results. A comparison of the results to full nodal flow analysis was also requested.
  - **Actions:** Where simplifications have been made, the limitations will be clearly acknowledged. More complex modelling will be carried out in WS3, which will take consideration of other drivers such as fault level. The priority solution stack is populated in order of cost and impact on headroom. Users of the model will be able to change these assumptions.

- **Are the voltage levels (from 132kV down to LV) being considered by the model appropriate, or should the model be limited to focus on any particular voltage levels?**

- **Summary of responses:** Most respondents agreed that this was appropriate.
- **Actions:** No change.

- **For each of the voltage levels we are considering, are current methods sufficient to recognise available headroom and the cost of releasing additional headroom in these networks? If not, is the proposed approach considered to be too simple or overly complex?**
  - **Summary of responses:** Most respondents agreed that this was appropriate, given that assumptions will be clearly stated.
  - **Actions:** No change.

- **Is our approach to estimating the clustering of low-carbon technologies appropriate? Is any other evidence available in this area?**
  - **Summary of responses**: Many respondents agreed with this approach. However some felt that it was too simple. The importance of distinguishing between clustering locally and regional patterns was noted.
  - **Actions**: Users of the model will be able to change all assumptions on clustering. At present, clustering assumptions are based on real data from FiT registered PV installations. However, the model is of sufficient granularity that these assumptions can be altered on a per technology basis, meaning that different clustering levels can be ascribed to each low-carbon technology, when better information is made available. The clustering approach will not detect regional variations, but this will be looked at again under SGF WS3 (rather than under the GB-wide WS2 model).

- **Are the proposed generation model assumptions (a simple stack of generator types, no technical dispatch constraints, half-hourly demand profiles for summer and winter, and representative wind profiles) suitable?**
  - **Summary of responses:** Most respondents agreed that this was appropriate. One respondent felt an alternative methodology would be more appropriate.
  - **Actions:** No change.

- **Should a simple representation of interconnection be included in the model?**

- **Summary of responses:** Most respondents thought a simple representation of interconnection should be included in the model.
- **Actions:** Within the model it will be possible to include a simple representation of interconnection, as a type of generation with a specific capacity and cost. A full model of electricity exports/imports (which would require considering the correlation of demand and generation across countries) is outside the scope of this model.

- **Does the model represent DSR appropriately?**
  - **Summary of responses:** Some respondents felt that the approach was appropriate. Others felt that the approach was too simple. The need to recognise that DSR should also encompass large customers was noted. The fact that different types of DSR are being considered sequentially rather than in parallel was also noted as a limitation.
  - **Actions:** The extent to which customers engage with DSR will now be fully flexible for model users to change. While DSR led by suppliers and DNOs will be considered sequentially, the cost of moving demand away from the generation cost-minimising pattern to the local network cost minimising pattern will be taken account of when determining whether or not to apply DSR to reduce local network costs. We do not propose to model a change in large consumers' engagement with DSR.

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